Modelling a Grid connected Distributed Generating Photovoltaic system for the capital city of Maldives

An Engineering and Economic Assessment

Thesis submitted to the University of Nottingham Malaysia Campus for the Degree of Master of Philosophy in Electrical Engineering

BY

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VENGIRI / DH.HULHUDHELI / REPUBLIC OF MALDIVES

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DECLARATION AND COPYRIGHT

Name **:** Mohamed Huzam Ahmed
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I hereby declare that this research is the result of my own investigations, except where otherwise stated. Other sources are acknowledged by explicit references and a list of references is appended.



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DEDICATION

I dedicate this work of mine, to my beloved parents and my beloved wife Zeenath Ibrahim, who has always been there for me and supported me with her love, to make it through extremely difficult circumstances I have been faced with.

I dedicate it to my precious children, Fawzan, Yanis and Ian Mohamed Huzam for their cheerful love and fun that helped me gain hope and confidence again and again throughout the process of this research. I would like to express my sincere and wholehearted Thanks to my 11years elder son Fawzan for his continued support and assistance in preparing all the graphical representations in this Thesis and his assistance and support in formatting this document.

This research would have been an impossible task without the mercy and blessings of Allah Almighty, the continued love and encouraging support of my wife and children during the unexpected and unforeseen catastrophe that changed my life.

I am in debt to thank Allah Almighty for his favors and blessings to make this dream of mine come true. I am in debt of words to thank my wife for her courage to take all responsibilities of my beloved family and providing me the encouragement to stand up with wisdom to complete the work that I assumed I would never be able to complete. A life lesson learned during the most unexpected time.

Abstract

The islands of the republic of Maldives, with 80% of the land mass less than 1m above the sea level and 44% of its' people living within 100 m of the coastline is one of the most threatened nations from sea level raise by global warming and climate change. The average sea level raise in the Maldives, recorded by the Meteorological Department of Male' International Airport is 1.7mm/year, with a maximum hourly sea level raise of approximately 7mm/year. This rate is far higher than the observed global trends in mean sea level raise. In consequence, the Maldives is well known for raising global warming and climate change to the attention of the international community, since, if the scientific warning is true, the entire country could be eradicated from the surface of earth. Considering this serious threat, the government has expressed its interest in exploring the possibility of switching from diesel to renewable sources to generate electricity. Beginning with experimental hybrid projects implemented in small islands, the government has recently started installing Photovoltaic (PV) on the rooftops of government buildings in the capital city of Male'. It has little contribution to cater the fast growing demand of electricity in Male'. Its contribution to serve the governments' initiative to deploy Renewable Energy Technology (RETs) at large scale too, is very much limited due to the limited space available. The capital city Male' consumes 71% of the total electricity generated by STELCO nationwide. This reflects the alarmingly high population density in the city which has a land area of just 5.8 km^2; the home for ~ 42% of the population. Thus, the research, contained in this thesis, is based on modelling a gird connected Distributed Generation Photovoltaic (DGPV) system that is technically sound and financially viable, and can effectively take over partial load on the State Electric Company (STELCO)s' national grid

in Male', which is planned to be extended to the newly build city of Hulhumale'; an island man-made to provide shelter for the homeless families in the highly populated Male'. This has not been done in any of the previous research. The hypothesis presented, justify the limitation of deploying RETs at a large scale in the Maldives from a techno-economic perspective. Despite the RET potential benefits, the study has focused on the severe constraints and challenges that would limit this change in generation technology. Based on accurate and reliable long term prediction of the future growth of electricity demand on the national grid of STELCO, the research demonstrates modelling of the proposed system using one of the most popular software, Hybrid Optimization of Multiple Energy Resources (HOMER) and the application of universally accepted design guidelines. Its economic feasibility has been done using an XL model developed by replicating the economic modeling of HOMER. The prediction of future growth on the grid for the next twenty years (2011-2030) has been made using multiple regression, one of the most widely used forecasting techniques. The predictions were validated by comparison with the results obtained from an industrial standard tool, the GMDH Shell. The modelling of the proposed supply system has been done using these predictions to identify the optimal system configuration that could meet the load requirement under the constraints specified in the simulation. HOMERs powerful sensitivity analysis feature has been used in this study to explore the energy yield that could be delivered to the grid under the constraints applied. The system being technically sound and financially viable, it represents a realistic and practical alternative solution for the energy requirement of Male'. Its implementation could be the turning point in transforming the energy sector of the country.

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PUBLICATIONS

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Nomenclature

Symbol	Description
H_0	Null Hypothesis
H_1	Alternate Hypothesis
β	Regression coefficients
df	Degree of Freedom
α	Confidence level
Y	Forecasted Electricity Demand
P_{pv_dc}	DC output power from PV
$P_{\boldsymbol{pv\_ac}}$	AC output power from Inverter
f_{PV}	The de − rating factor
Y_{PV}	The rated capacity of the PV array in (kW)
I_T	The solar irradiance on the PV array in (kW/m^2)
I_S	The solar irradiance on the PV array under standard test condition
$P_{de-rated\_man}$	De − rated power of the module due to manufacturers′tolerance
$P_{\max\_rated}$	Maximum rated power of the module in Wp
$P_{loss_{Man\_Tol}}$	Power loss due to the manufacturers′tolerance
$P_{de-rated\_dirt}$	De − rated power of the module due to dirt
$T_{cell-eff}$	The effective cell temperature of the module in $^\circ$ C
$T_{a\ day}$	The daytime ambient temperature $^\circ$ C
T_{STC}	The cell temperature unders Stnadard Test Condition in $^\circ$ C
T_{temp}	The temperrature de − rating factor, diamensionless
$\lambda_{\%/^\circ \mathrm{C}}$	Value of power temperature coefficient in % per $^\circ$ C
E_{sys}	The yearly energy output of the PV array, in watt − hours
P_{Array_STC}	The rated output power of the array under STC, in watts
f_{temp}	Temperature de − rating factor
f_{man}	de − rating factor for manufacturing tolerance
f_{dirt}	de − rating factor for dirt
H_{tilt}	Solar irradiance for the selected site (allowing for tilt angle)
$\eta_{pv_{inv}}$	Losses between the PV array and the inverter
η_{inv}	Efficiency of the inverter
η_{inv_sub}	Losses between the inverter and the switchboard
SY	Specific energy yied in kWh/kWp
YF	The Final Yield of the system
E	The annual energy output of the system [kWh/year]
Pr	The peak rated power of the system under STC in [kW]
YR	The Reference Yield
$\mathrm{H_t}$	The Total in − plane solar irradiation in kW/m^2
PR	The Performance Ratio
YF	The Final Yield of the system
E_{ideal}	The ideal energy output of the array

CF	Capacity Factor
V_{min_MPP}	Minumum MPP voltage allowed
$V_{MPP-STC}$	The MPP voltage of the module in (V)at STC
$\lambda_{v\_MPP\_\%/^\circ C}$	MPP temperature coefficient of the module in % per $^\circ$ C
T_{amb_max}	Maximum ambient temperature, measured in $^\circ$ C
$N_{\min\_per\_string}$	The minimum number of PV modules in a string
V_{inv_min}	The minimum inverter input voltage, in volts
V_{max-oc}	The maximum open circuit voltage at minimum cell temperature
V_{oc-STC}	The open circuit voltage in (V) at STC
$\lambda_{v-oc\_\%/^\circ C}$	Open Circuit Voltage temperature coefficient in % per $^\circ$ C
T_{min}	The minimum recorded temperature at site in $^\circ$ C
$N_{\max\_per\_string}$	The maximum number of PV modules in a string
V_{inv_max}	The maximum input voltage of the inverter, in volts
V_{max-oc}	The maximum open circuit voltage of a module
$N_{Parallel\_String}(max$	Maximum number of parallel strings
I_{inv} (max)	Maximum input current of the inverter
f_{over_size}	Oversizing factor (optional and if allowed by the manufacturer)
I_{Sc}	The short Circuit Current of the module at Standard Test Condition
$N_{PV\_Total\_Array}$	The total number of PV modules in the array
I_{inv} (max)	Maximum input current of the inverter
P_{array_STC}	Rated Power of the array at STC
$V_{(cal)\_max\_Array}$	The maximum voltage of the PV array
$I_{(cal)\_\max\_Array}$	The maximum current of the PV array
C_0	*Initial investment*
C_{1-T}	*Cash Flow throughout the project period*
r	*Discount Rate*
T	*Time (years)*
S	*The salvage Value*
C_{rep}	*The* replacement cost [$]
R_{rem}	*The remaining life of the component at the end of the project*
R_{comp}	*Component lifetime* [yr]
R_{rep}	*Component replacement cost duration*
R_{proj}	*The project lifetime*
INT()	A function that returns the integer amount of a real number
C_{ann_total}	*The total annualized cost* ($)
$CRF()$	*A function returning the capital recovery factor*
i	*The annual interest rate* (%)
R_{proj}	*The project life time (years)*

ABBREVIATIONS

(RETs) Renewable Energy Technologies

(DGPV) Distributed Generation Photovoltaic

(STELCO)State Electric Company

(HOMER)Hybrid Optimization of Multiple Energy Resources

(SIDS)Small Island Developing Nations

(NPV)Net Present Value

(PI) Profitability Index

(MEA)Maldives Energy Authority

(HDC) Hulhumale Development Cooperation

(PV)Photovoltaic

(IDC)Islands Development Committees

(MEEW) Ministry of Environment Energy and Water

(MEE) Ministry of Environment and Energy

(RE) Renewable Energy

(RF) Renewable Fraction

(NREL)National Renewable Energy Laboratory

(UKM) University Kebangsaan Malaysia

(IEEE) Institute of Electric and Electronic Engineers

(NPC)Net Present Cost

(COE) Cost of Energy

(CBE) Cost Benefit Evaluation

(UN)United Nations

(UNFCCC) United Nations Framework Convention on Climate Change

(ADB) Asian Development Bank

(STO) State Trading Organization

(MV) Medium Voltage

(SARI) South Asia Regional Initiative

(SMILES) Strengthening Maldivian Initiatives for a Long-term Energy Service

(RETDAP) Renewable Energy Technology Development and Application Project

(UNDP) United Nations Development Programs

(DLF)Distribution Loss Factors

(ANN) Artificial Neural Networking

(MAPE) Mean Average Percentage Error

(SF) Scaling Factor

(BIPV) Building Integrated Photovoltaic system

(HDC) Housing Development Cooperation

(MPPT) Maximum Power Point Tracker

(STC) Standard Test Condition

(O&M) Operation and Maintenance

(COE) Cost of Energy

(SAIMA) Sizing Algorithm using Iterative Manual Approach

(GCR)Ground Cover Ratio

(PR) Performance Ratio

(QF) Quality Factor

(CF) Capacity Factor

(EIA) Energy Information Administration, USA

CHAPTER 1

INTRODUCTION

1.1 OVERVIEW

Low-lying coastal countries, known as “Small Island Developing States (SIDS)” share common problems and difficulties that hinder their development. The very limited and costly transport, distribution of power and communication infrastructures (both physical and electronic) are huge barriers for their socio-economic development. The extremely fragile environment that limits the protection of its people from natural disasters could be said, the biggest threat that the inhabitants of these islands are exposed to. One of the main challenges these nations face, is the production of electricity for its people. Their dependency on imported fossil fuel as the source for the electricity production, makes the cost of electricity very expensive in these countries compared to the other parts of the world. Almost all of these nations possess a significant potential for renewable sources such as wind solar and biomass, which if used for the production of electricity, would make a significant contribution to the development of a sustainable economy and protect their environment.

1.2 THE REPUBLIC OF MALDIVES

The Republic of Maldives, is a small island nation with 1190 Islands formed within 25 low laying coral reefs known as “Atolls”. The country enjoys a tropical climate with an average daily temperature of 31-32°C [1]. About 80% of the land area of these islands are barely 1.5m above sea level, forcing about 44% of its people to live within 100m from coastline [1].

The warning on global warming and sea level raise delivered by scientists at the climate change summit in Copenhagen [2], of an increase in sea level of about 1m or more by 2100, was a serious warning to the 10% of the worlds' population (600 million people) living in vulnerable areas.[1] Due to its low laying costal nature of the islands, it has left the entire population of Maldives living in extreme fear of becoming climate refugees. Despite electricity being produced only by diesel fuel, its carbon emission has insignificant effect towards the global warming [3]. Its small population of 395,000 [4] living in 183[2] extremely small islands ranging from 0.1-5 square kilometers [5] can be considered as one of the major obstacles to its development. The country's present socio-economic development status clearly presents evidence of extremely limited natural resources making the provision of even the most basic necessities such as clean water, electricity, basic primary health care and education an impossible task for the Government of Maldives.

[1] .The predicted value is slightly higher than the Intergovernmental Panel on Climate Change (IPCC)s' report of 2007, which reported the sea level could raise up to 59cm this century[2]

[2] The revised figure 183 islands is information obtained from the Ministry of Housing and infrastructure. The number of inhabited islands are less now since some of the smaller communities have been relocated to other islands.

Considering the threat the country is exposed to as a result of climate change, the government of Maldives has made various scientific and technical assessement on the matter [1] with enormous effort to bring the matter to the attention of the international community. Reportedly, the matter was first brought to the attention of the United Nations (UN), by the former president Mr Maumoon Abdhul Qayyoom in 1992, at the United Nations Earth Summit, declaring that the nation was under threat of vanishing from the surface of the earth [5]. His government is known to have played an important role that lead to the United Nations Framework Convention on Climate Change (UNFCCC), and Maldives was the first to sign the Kyoto Protocol to the UNFCCC[1].

The present government seems to have further strengthened the measures taken to create public awareness on the issue and has been a leading voice in the international community, urging them to take preventive measures to stop green house emissions.

The rapid development of Renewable Energy Technologies (RETs) has shown evidence that its application in power generation in SIDS, for both grid connected and off grid systems, can be more promising and cost effective than using diesel based systems alone [6]. Previous research in Hybrid power systems for small and isolated islands has shown, RETs provide the most effective and viable solution to small islands and rural communities off grid [7&8]. Its application in grid connected systems is being studied by various researchers addressing its effectiveness in power generation [9-11]. However, despite the advancements in the renewable energy technology and the funding of exploration research on the feasibility of using the available renewable resources, the take up RETs in these countries is still very limited. [12]. It is reported in [13] that in some of

these countries, fossil fuel equals to a substantial portion of their total imports. Being a small island nation, the Maldives represent only a tiny fraction of the global greenhouse emission and yet, it is extremely vulnerable to the effects of climate change and the associated sea level raise [14&15]. It is believed that climate change will affect the Maldives' economy in a near future, as its' expensive resorts face the threat of massive soil erosion and coral bleaching. As part of the push to raise the awareness, the government is reported [16] to have made a policy level decision on investing for land, while declaring its revised energy policy with the challenging goal to become the worlds' first carbon neutral country by the year 2020. The content of its first energy plolicy draft [3] and that revised by the cabinet in 2010 have not been published and disclosed to the public.

The Maldives is definitely the most vulnerable country to the global warming and sea level rise. The green-house gases produced by its islands are insignificant when compared to the developed world, India and China. It is also evident that, reduction or eradication of the production of greenhouse gases in the Maldives, would have negligible effect on the global production of these gases. Thus, in a developing country like Maldives, policy level decisions of such a change in generation technology should be based on solid scientific findings on the benefits of deploying RETs at a large scale. Switching to RETs to go carbon neutral should be based on a study that precisely quantifies the required investment, its' impact on the economy of the country as well as its significance in mitigating the global warming and climate change. It would require a study that accurately models the technological adoption as well as its impact on the economy of the country in a much broader perspective.

Thus, the research contained in this thesis, do not consider assessing the techno-economic feasibility of Maldives going carbon neutral. Rather, it represents an alternative hybrid configuration of solar and diesel (the national grid) that could significantly benefit the energy sector of Maldives.

1.3 OBJECTIVE OF THE STUDY

The objective of this research is to model a grid connected distributed generating photo-voltaic (DGPV) system that can effectively cater for partial load on the national grid of State Electric Company (STELCO) in Male' and assessing its techno-economic feasibility. To facilitate this, assessing the energy requirement of the City, how the demand on the grid is being catered at present, forecasting the expected future growth of demand on the grid and exploring alternative options to meet this demand by deploying RETs are prioritized tasks of this study. The research proposes a technically sound and economically viable DGPV system and explore the amount of energy that can be delivered to the grid by it. This takes into account, no other research or published pilot projects have been conducted to deploy RETs to the national grid of STELCO despite the huge concentration of electricity consumption in the capital city Male' compared to other islands.

1.4 SCOPE OF THE STUDY

The scope of this study is limited to the design of a DGPV system that would serve as a practical solution in deploying RETs to the national grid of STELCO. It takes into consideration, the challenges of severe land constraints and the poor economy of the country indeploying RETs to transform the energy sector. Assessing the techno-economic feasibility of a complete transfer of power generation technology to transform the energy sector of the country, falls beyond the scope of this study. Hence, the proposed system is modelled to be connected to the national grid of STELCO in Male' and can be expanded to Hulhumale as the two cities gets interconnected. Hulhumale' is a new man-made island, within 5km distance from Male'. The city has been built to provide a housing solution to the over corwded Male'. To ensure the technical soundness of the proposed system, an accurate forecasting of the future demand on the grid have been given the highest priority in this study. This was done following an in depth analysis of the existing STELCO facility in Male, their power generation and distribution network with a detailed analysis on the load requirement and the deriving factors behind.. Predicting the future demand on the grid posed a real challenge since the hypothesis testing on the independent variables proved only the consumers in the domestic category carry the credibitlity to predict the future demand. This required accurate information on the expected growth of popupation which is very much subjective to the governments policy of social housing scheme in future. This is further discussed in section 1.6, limitation of the study.

The technical feasibility of the proposed system has been followed by its economic modelling, ensuring its financial feasibility. The modelling of its investment cost and financial feasibility have been done using a model, (an XL work sheet) developed in this study. It serves as a decision making tool based on the Net Present Value (NPV) and the profitability Index (PI) of the project, enhancing a broader understanding of the fraction of load that can be served by the proposed system. Thus, the study aims to provides a pre-feasibility assessment of an alternative mechanism of establishing such an infrastructure and its' investment options.

1.5 SIGNIFICANCE OF THE STUDY

Motivated by the governments' initiative to deploy RETs at a large scale to transform the energy sector of Maldives, this research has been conducted with a specific goal of modelling a DGPV system that would serve partial load on the national grid of STELCO. Careful consideration has been given to ensure the proposed system can be practically implemented. This is occasionally lacking in some academic work reviewed [3, 7& 20].

The primary data collected from the STELCO Head Office provided a broader understanding of the energy requirements of the country as well as the huge barriers that exists in providing electricity to the islands from a common grid. The analysis of STELCO and Maldives Energy Authority (MEA) institutional arrangements reveals a conflict of

interest[3] that inevitably hinder the effective delivery of the services each of these institutes provide. As the regulatory body MEA delegates the setting of standards and regulations to STELCO. This creates a conflict of interest since STELCO is also responsible for the delivery of the services. As a result STELCO can set regulations and standards in accordance with their capacity to deliver their services rather than the actual needs of the country. This effective dual role of STELCO makes the existence of the MEA insignificant and is seen as a significant barrier in developing the energy sector in Male' as well as nationwide.

The findings of this research, that Male' alone was consuming 71% of the electricity produced by STELCO nationwide, is the main reason for the study being focused on catering the demand on the STELCO grid in Male'. The study considers it as a clear indication that the exploration on the deployment of Solar Energy to the STELCO grid in Male' would have a significant contribution to the governments' initiative to deploy RETs at a large scale. In this respect, this study serves an accurate pre-feasibility study to achieve this purpose. The literature reviewed and the information gathered from STELCO revealed, this has not been done in any of the pilot projects to date.

Consideration is also given to the fact that the previous studies [3] being limited to the smaller islands, may not give a realistic analysis of the techno-economic feasibility of deploying RETs at a large scale in the Maldives. The majority of the inhabited islands in the Maldives are populated with less than 2000 people and some of them with a population of less than 500 people. The methodology adopted in this study to provide a solution to

[3] Explained in section 1.6.2

Male' by deploying RETs, could be used for the other two large cities namely "Addu City" and "Fuvammulaku City" which have a population of less than 40,000 people. Thus, the proposed DGPV system in this research and its modelling process can easily be replicated and adopted in any of these cities.

1.6 LIMITATIONS OF THE STUDY

This section represents the limitation of the study due various factors.

1.6.1 A complete Energy Audit

A complete energy audit of the usage of electricity nationwide, the tariffs, load profiling, types of equipment (low and high voltage) used in all the islands nationwide, would have further enhanced the accuracy of the modelling of the proposed system. It would have allowed an accurate analysis on the growth and consumption of electricity in other islands that are likely to be developed in the future. This would have been an advantage to assess the future growth of demand in Male', with an accurate assessment of the population that are likely to migrate to Male' in future. Accurate information on the future population of Hulhumale' which is going to be interconnected to the Male' national grid too would also have contributed to the accuracy of the prediction of the future growth on the grid by a great degree. However, obtaining reliable information was impossible since the information varied highly from island to island and is held by various companies and government departments. Reliable data was only available from the STELCO head office in Male'. The information obtained by the STELCO office in Male' reveals the company only supplies electricity to 60% [4] of the population nationwide, leaving the other 40%

obtaining electricity from poorly built power houses and distribution networks owned by islands themselves.

Similarly, the electricity in Hulhumale' at present is supplied by a small diesel power plant which in the future, is planned to be replaced by the national grid. Information on this strategic development plan could not be obtained from STELCO since they considers it confidential. However, since STELCO confirms integration of the two cities by a common grid, this study makes an implicit assumption that the governments' plan to provide shelter to the homeless families in the overcrowded city of Male' would remain unchanged, relocating them to Hulhumale' City. At present this is given the highest priority and hence those families that gets relocated in Hulhumale' would be domestic customers on the national grid. Thus, the accuracy of the prediction of future growth made in this research shall not be affected unless an unexpected rate of migration occur to Male' and Hulhumale'. It may also be affected by the nature of work in the industrial zone in Hulhumale'. However, this is very unlikely, since another island "Thilafushi" nearby Male' is used for all industrial work in Maldives and since Hulhumale' city is built to provide shelter for the homeless families. These information could not be obtained from the relevant government authorities since the city is still in its very early stage of development.

1.6.2 Conflict of interest between Institutional arrangements limiting access to required information

Access to the required information posed a real challenge during the initial phase of this research. It was found that the government organizations such as STELCO, the MEA and Hulhumale' Development Cooperation (HDC) now known as the Housing Development cooperation (HDC) were reluctant to provide information. The reasons for this reluctance is not clear. However the overlapping responsibilities between the organizations points to an internal competition and hence a reluctance to provide information which would be of the benefit to other governmental bodies.

1.6.3 Cost analysis in calculating the capital cost

The fast development of PV technology over the past decade as well as the price fluctuation in the world market of PV is of significant importance when gathering information from the manufacturers. For this research, a challenging but interesting fact faced with, was the huge difference in the cost of supply of system components from manufacturers in Singapore and China compared to the one and only supplier of RE systems in Maldives. Consideration was given to the fact that the international suppliers are not familiar with the physical and commercial environment of the Maldives and their quotes may not reflect these difficulties. Consequently the decision was made to choose the capital cost of supply from the Maldivian company. This was deemed necessary to avoid any error in the capital cost calculation based on the quotes from the international

suppliers who had no or little knowledge about the commercial environment of the country. The high cost quoted by Maldivian company adversely affects the profitability of the investment for the proposed system in the economic analysis. However, if a system is shown to be profitable using these higher costs then it will also be profitable using the lower costs quoted by the overseas suppliers.

1.6.4 Development and adaptation of RETs at a large scale nationwide

The development of RETs in the Maldives, not only requires infrastructure but also the necessary human capital to design, install and operate the facilities. Therefore, information regarding the skills set of employees is required. The governments' research [3] is the most up to date[4], but does not provide sufficient information that could be used in this research. Doing a complete survey to gather the required information would require significant engagement at senior levels of both the government and business. The person(s) undertaking the study would require expertise in socio-economic data gathering. This falls outside the scope of this project and hence the costs related to up-skilling of the workforce are ignored and it is therefore assumed the appropriate skill sets are available.

[4] Information on the ongoing projects of installing PV on roof tops of government buildings are not published. Its dsigned capacity could not be verified from the Ministry of Energy and Environment and STELCO. This is probably due to variation in the size of PV that can be installed on the roof top of each of these buildings.

1.7 ORGANIZATION OF THE THESIS

This thesis is presented in Nine Chapters as follows

1.7.1 CHAPTER 2: LITERATURE REVIEW

This chapter is based on the overall power sector of Maldives. It focuses on the power requirement of these islands and how they are being supplied. The research being done to explore the possibilities of deploying RETs at a large scale in the capital city of Male', a detailed analysis on the energy requirement of the city and how it is being met at present have been given priority in reviewing the literature available. This takes into account the total installed capacity nationwide, the installed capacity in STELCOs power plant in Male', the consumers and the percentage of consumption by each sector. The analysis have been done based on the primary data collected from the STELCO and data retrieved from publications of the Ministry of Environment Energy and Water (MEEW), now known as Ministry of Environment and Energy (MEE).

It further elaborates on the available renewable energy (RE) sources in the country the experimental pilot projects implemented in the past and the difference and contribution of this research compared to the previous studies.

1.7.2 CHAPTER 3: RESEARCH DESIGN AND METHODOLOGY

Chapter Three gives a comprehensive explanation of how the research has been structured, the methodologies used, assumptions made and the priorities set forth in

modelling the proposed system to ensure its practicality. It presents a review of the present energy requirement of Male', the institutional arrangements and the countries' energy policy which aims to deploy RETs at a large scale. Furthermore, it explains the contributions of previous researches that motivated the government of Maldives to deploy RETs to transform the energy sector and how this research has been structured to enhance this transfer of technology to the next level in a techno-economic perspective.

1.7.3 CHAPTER 4: DATA ANALYSIS

Chapter Four provides the analysis of the data collected for the research. The installed capacity of the STELCO power plant in Male' for the past 10 years, the load on the grid during this period and the distribution mechanism of STELCO have been discussed in detail. The analysis was important to understand the contributing factors of the increase in electricity demand on the grid. The results facilitated development of the load forecasting model that lead to an accurate prediction of the expected demand on the grid for the next twenty years. Further, it contributed to the study by enhancing the understanding of the present distribution mechanism of STELCO and the significant barriers and challenges they are faced with, in the future development of the network.

1.7.4 CHAPTER 5: LOAD FORECASTING

Chapter Five is based on the prediction of future demand of electricity on the grid. It provides a brief explanation of various techniques used in long term, medium and short-term electric demand forecasting used in similar researches. This is then, followed by a comprehensive explanation of the application of Multiple Regression Analysis for predicting the long term demand on the grid for the next twenty years. This includes linear and nonlinear regression modelling of the load using historic data of ten years, obtained from STELCO and identifying which model lead to better results. The driving factors that contribute to the electricity consumption were identified using the information provided by STELCO and the credibility of each of the independent variables used in developing the model was verified by using the standard techniques of hypothesis testing. Further to this, the chapter provides details of how the accuracy of the predictions made have been verified by comparison of it with the results obtained from one of the most popular software for electric load forecasting, the GMDH Shell.

1.7.5 CHAPTER 6: SYSTEM MODELLING

Chapter Six provides a comprehensive explanation of how the well-known software Hybrid Optimization of Multiple Energy Resources, (HOMER) have been used to model the proposed DGPV system in this study. It elaborates on the importance of input data, the application of constraints in the simulation and how the software models and gives the

most optimal system configuration that can meet the specified load requirement under the given constraints and without leaving any unmet load. Further to this, it explains in detail, how the fraction of renewable energy (RF) has been limited in the simulations, the reasons behind and how it lead to a realistic system design that can serve as a practical alternative solution to cater for partial load on the grid of STELCO. This ensures the proposed system is not based on mare theoretical concepts and software modelling but rather carry the credibility of being implemented in the proposed site, serving a significant contribution to the energy requirement of Male'. Additionally, the chapter provides a critical assessment on the sensitivity analysis done by HOMER using the forecasted load and other sensitive variables used in the simulation leading to a decisive assessment that allow well informed decision making.

1.7.6 CHAPTER 7: APPLYING SYSTEM DESIGN GUIDE LINES TO THE SIMULATION RESULTS

Chapter Seven is based on the application of universally accepted design guidelines to the results obtained from the simulation. This ensures a thorough assessment on the results obtained from the simulation, confirming their reliability. It shows how the optimal system architecture given by the software for each year throughout the project period can be built without compromising any of the preventive and safety measures of the system.

The reason for choosing HOMER to model the proposed system was not merely based on its popularity. Rather, consideration was given to the importance of obtaining

technical support from the developers of the software, the National Renewable Energy Laboratory (NREL, USA) since they provide technical support for the paid users. Technical support for various important matters that needed further clarification during the simulation, were obtained via email communication. In this regard, the load profiling and the sensitivity analysis were highly important matters that was discussed during the modelling process. Furthermore, the modelling of the proposed system was demonstrated in a work shop conducted by the Institute of Electrical and Electronic Engineers (IEEE) in the University Kebangsaan Malaysia (UKM) in May 2012[5]. An important matter discussed with the technical experts conducting the session was, how the long term forecasts of electricity could be used as sensitivity variables and why the optimization process of HOMER, ranks the optimal system configuration based on the lowest Net Present Cost (NPC) over the Cost of Energy (COE). The application of the guidelines further confirms the practicality of the results obtained from the simulation and chapter seven provides a detailed explanation of how this has been done and its importance.

1.7.7 CHAPTER 8: THE ECONOMIC MODELLING

Chapter Eight is based on the economic modelling of the proposed system. It is based on a Cost Benefit Evaluation (CBE), ensuring the proposed system carry the credibility of grid parity[6]. It is an important measure to assess the economic feasibility of

[5] In this workshop, the modelling of the proposed system was demonstrated to the experts, focusing on how HOMER uses the forecasted electric load as sensitivity variables and allows system modelling on a modular basis as per the increase in demand. This is further explained in Chapter 6.

[6] Grid parity is the Hybrid system configurations' ability to produce electricity at a rate competitive to the grid rates used in the simulation. This is determined by the calculation of the Cost of Energy from the system.

producing electricity from a DGPV system at a rate competitive or equivalent to the utility rates applied in the simulation. The evaluation presented in this chapter has been done using two standard methods of calculating the cost of energy (COE) and the Net Present Value (NPV).

The NPV represents a universally accepted standard for a CBE of the investment and the COE represents a strong measure indicating, the electricity produced by the proposed system carries economic merit. That is, the cost of electricity produced by the PV array could be economically offset with the cost of electricity from the grid. It has been done using an XL model (a working excel sheet) developed by replicating the economic modelling of HOMER. The reason for developing this model and how it enhanced the financial feasibility analysis is explained in detail in this chapter.

1.7.8 CHAPTER 9: CONCLUSION

Chapter Nine presents a summarized conclusion based on the findings of this research. It emphasizes on the contributions of it to meet the energy requirement of Male', further elaborating on the fact that the proposed system in this study serves a technically sound and financially feasible practical solution that could cater partial load on the grid. Furthermore, it emphasizes on the fact that the proposed system could serve as a turning point in transforming the energy sector of the country by deploying RETs.

CHAPTER 2

LITERATURE REVIEW

2.1 Electricity Demand in the Islands of the Republic of Maldives

Electricity was introduced in the Maldives in 1949, with an installed capacity of just 14kw, supplying electricity to the house holds of the capital city Male'. Since then, this government owned facility operated under various names. State Electric Company (STELCO) was formed in 1997, as a company fully owned by the government. Since its establishment, the supply of electricity has seen remarkable improvements nation wide. By the end of 2008, STELCO was supplying electricity in 28 islands nation wide, catering for 60% of the entire population[4].

At present, all the islands in Maldives have access to Electricity. The consumption of electricity in these islands is mainly for household use, since the use of high power equipment for industrial use is at a very small scale. With the change in life style of its people, the electricity demand has been increasing constantly over the years. Split Air conditioning systems and refrigerators are the main home appliances that consume most of the power in a typical household.

With its' population dispersed in 183 islands, reliable data on consumption of electricity is not available for smaller islands where the supply of electricity is not by the STELCO. STELCO maintains its records on power consumption in the highly populated islands, where the electricity is supplied by them. Despite the unavailability of reliable records on electricity consumption in smaller islands with lesser populations, the information obtained from STELCO confirms the demand for electricity has seen a continuous growth nationwide.

Reported by the Ministry of Energy Environment and Water (MEEW) [17], the tourism industry is the biggest consumer of electricity with the largest installed capacity. However, since all of the resorts have got their own power houses and none of them purchase electricity from the STELCO at present, data on their generation and consumption of power could not be obtained.

2.1.1 Electricity Demand in Capital Island Male' and Hulhumale'

The capital city Male' is said to be one of the worlds' most congested cities. It is very different from the rest of the country in all aspects. The home for 42% of the population of the country yet, Male' has a land area of 5.8km^2. Comparison of this, to an Island like Himmafushi with a land area of 4.75km^2, but with just 3% of the population, gives a clear understanding of the degree of dependency the people have on Male' for their daily needs like electricity, clean water and health care.

The high density housing in Male' with little natural cooling results in higher usage of air-conditioning units and hence power consumption. It has a higher consumption and demand for electricity, than any other island in the Maldives.

STELCO catogorises the consumption of electricity into three categories namely, domestic, business and government. The increased number of airconditioning units installed in house holds is the major factor for the increase in the consumption in

the domestic category. There are no factories in the island and no heavy load machinery is used, except for the machineries used in carpentries. Thus, the majority of consumption for the commercial or business category comes from the rapid increase in the construction of multistorey buildings resulting from lack of land and the installation of refrigerators and airconditioning units in shopping centres. Further, increased use of various types of electrical appliances in house holds and hotels and guest houses in the city is believed to have a siginificant contribution to the growing demand.

To meet the housing and industrial demand in Male', the government inaugrated its first mega project of reclaiming the shallow reef of Hulhule', in 2004, creating the first man-made island in the country, now known as Hulhumale'. It is believed that the development of Hulhumale', would provide a reasonable housing solution to the over crowded Male', as a significant number of the residents of Male' is expected to be relocated in Hulhumale, as soon as the homes become available. Thus, in a near future, it is very likely that more than half of the entire population of Maldives would be re-located in Male' and Hulhumale, which would eventually lead to a huge increase in the load on the STELCO national grid as it gets extended to cater for both the communities[7]. This expansion would have to be accompanied by major refurbishment to the existing transmission and distribution network of STELCO. One major planned infrastructure development is the connection of the power grids of the the two cities. This study assumes this connection would be in place as planned.

[7] The construction work of the bridge connecting the two cities are ongoing at present. The Ministry of Housing and Infrastructure has announced via public press conference, the work would be completed in 2018. This would allow STELCO to cater for the two cities via a common grid as planned.

Though mendated to supply electricity to the entire population, the heavy burden of dependency on imported fossil fuel limits the operation of STELCO by a great degree and the organisation has often failed to meet the growing demand in Male'. To date, such shortages are being met by adding capacity to the plant by installing new generating equipment. However, the review of the existing facility of STELCO and their operational data clearly shows that this is unlikely to be sustainable. It is inevitable that eventually, alternative sources along with new transmission and distribution networks has to be considered to formulate a sustainable solution to the energy requirement of the people of the Maldives.

The following section presents an assessment on the electricity supply in the Maldives since its introduction till today. It is based on the findings of the analysis on the data obtained from the STELCO and publications of other government authorities.

2.2 Generation and supply of Electricity in the Maldives

The primary data on the operational statistics of STELCO since its establishment, indicates STELCO has been supplying electricity in 28 islands nation wide, catering for 60% of the entire population by the end of 2008 [4]. This translates to 40% of the population, having electricity supplied to them by power houses fully owned and operated by the Island Development Committees (IDC). While some of these islands have been lucky in obtaining special loans from the government, or had their power houses and distribution networks refurbished by donors such as the Asian Development Bank (ADB) under a special electrification project [18], most of these islands funded the generating equipments in these power houses and the distribution

networks, by collecting funds from individual houses which did not have electricity and water supplied to them by the government. The operation of these power houses face severe budget constraints, though partial funds might be provided by the government as special loans . This often limits the number of hours a day, these communities had access to electricity. Yet, by the year 2000, nearly all of these islands had access to electricity round the clock.

The STELCO contributes for 35% of the total production capacity of the country[17], (see Fig 1). The total installed capacity of the country reported in, [17] by the Ministry of Energy Environment and Water (MEEW) is 106.2 MW, and the majority of the production capacity is installed in resorts with each of them having their own power generation facility. It is likely that total installed capacity would have changed in the past years. However, the Maldives Energy Authority (MEA) that acts as the regulatory body was contacted and was unable to provide any updates other than the publication referenced above. One possible reason behind the MEA not being able to provide the required information could be the conflict of interest highlighted earlier in section 1.6.2, chapter 1, as the power houses in smaller communities are now under the newly formed utility companies[8] which are state owned.

[8] Further explained in 2.2.1

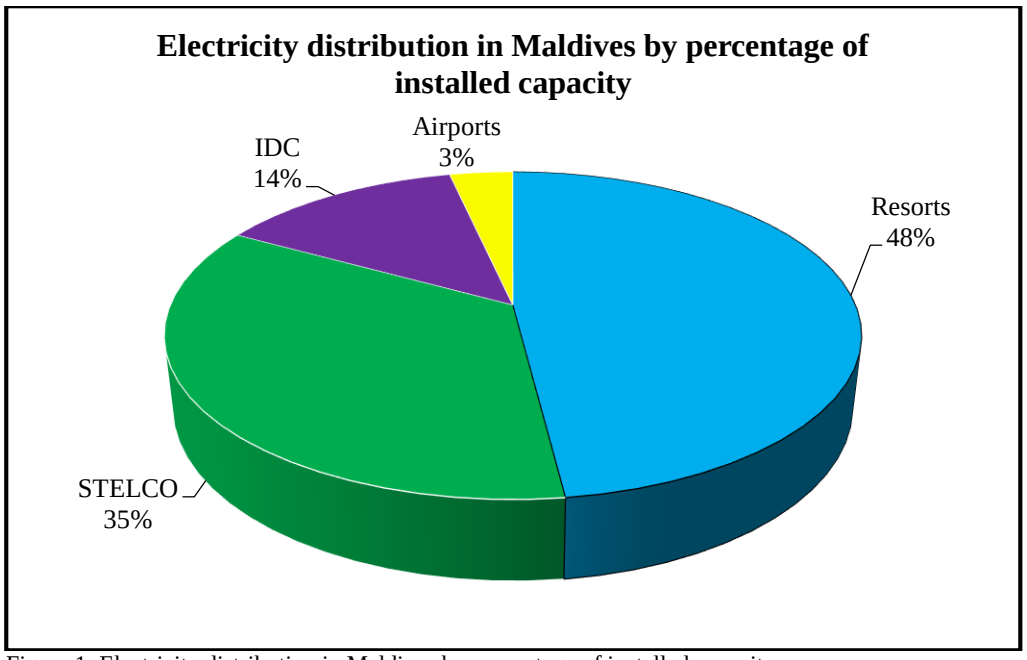


Figure 1: Electricity distribution in Maldives by percentage of installed capacity
Source: MEEW

2.2.1 Establishment of new Regional Utility Companies

In the year 2008, with the establishment of the new government, seven regional untility companies were formed. As a result, on May 1, 2009, STELCO handed over 22 power houses on different islands to their respective utility company [4]. This limited the mandate of STELCO, to supply the 9 islands in the central north province only. This is shown in table [1], with data on the installed capacity, annual consumption and annual peak load for each of the islands where the electricity is supplied by STELCO [4].

Table 1: Installed capacity, annual consumption and annual peak loads, for each Island where STELCO supply electricity

Upper North Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
HA. Thuraakunu	215,276	43	108	93
HA. Hoarafushi	1,153,924	270	400	514
HA. Dhidhdhoo	1,661,549	305	680	656
HDh. Hanimaadhoo	1,206,158	260	520	391
HDh. Kulhudhuffushi	5,407,777	958	2,360	1,647
SH. Milandhoo	889,570	193	400	395

North Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
N. Holhudhoo	832,478	165	320	393
N. Velidhoo	1,125,258	258	336	472
R. Hulhudhuffaaru	722,629	141	285	295
B. Eydhafushi	1,759,497	345	704	532
Lh. Hinnavaru	1,647,499	300	760	675
Lh. Naifaru	2,437,717	455	800	772
North Central Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
K. Kaashidhoo	906,018	169	438	384
K. Thulusdhoo	1,247,477	226	460	313
K. Himmafushi	2,040,260	420	650	230
K. Maafushi	3,398,547	586	1,100	321
K. Guraidhoo	1,026,999	248	368	305
Male'	179,911,219	32618	38760	25612
Villingili	5,896,812	1,075	2,800	1,211
Hulhumale'	6,444,761	1,190	3,640	1,012
K. Thilafushi	1,537,859	440	1,000	106
Table continued on the next page				
Central Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
Dh. Kudahuvadhoo	1,599,042	332	724	522
Upper South Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
GA. Villingili	2,075,671	384	1,406	501
GDh. Gadhdhoo	940,196	189	240	434
GDh. Thinadhoo	3,625,124	787	1,620	1,174
South Province				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
Gn. Fuahmulah	5,206,927	980	2,180	1,988
S. Hithahdoo CPS	15,547,171	2,900	4,250	3,956
S. HulhudhooMeedhoo	1,774,717	330	495	925
STELCO Nationwide				
Island	Annual Sales (kWh)	Annual Peak (kW)	Installed Capacity (kW)	Customers
Total	252,238,131	n/a	67,444	45,829

Source: Data obtained from STELCO head office

As seen from table [1], the consumption of electricity is concentrated in Male', with a significant difference in the installed capacity compared to all other islands. As of December 2010, the installed capacity in Male was 50MW [4].

The formation of the utility companies, are the result of ongoing progressive economic, social and political transformation in the Maldives. With this development, the power houses that was under the Island Development Committees (IDCs) of all the smaller islands, are now operated under the designated utility company (see Table 2) This is expected to improve the power generation and distribution in these islands. The installation and load forecasting of each of these new utility companies is a separate piece of work and is not considered in this research.

Table 2: The Regional Utility Companies formed in 2009

Province Local Name	**English Name**	**Consists of administrative atolls**	**Govt. Designated Electricity Service Provider (Utility Company)**
Mathi-Uthuru	Upper North	HaaAlif, HaaDhaalu, Shaviyani	Upper North Utilities Company
Uthuru	North	Noonu, Raa, Baa,Lhaviyani	North Utilities Company
Malé	Malé	Malé	State Electric Company (STELCO)
Medhu-Uthuru	North Central	Kaafu, AlifuAlifu,AlifuDhaalu, Vaavu	STELCO
Medhu	Central	Meemu, Faafu,Dhaalu Atoll	Central Utilities Company
Medhu-Dhekunu	South Central	Thaa, Laamu	South Central Utilities Company
Mathi-Dhekunu	Upper South	GaafuAlifu, GaafuDhaalu	Upper South Utilities Company
Dhekunu	South	Gnaviyani, Seenu	South Utilities Company

Source: Information obtained from STELCO

2.2.2 Challenges and Constraints

The biggest challenge in providing electricity in the Maldives is an efficient mechanism of power production and distribution. At present, the power plants operated by STELCO are the only reliable generation facilities in the country. The poorly built facilities in the smaller islands, face huge operational constraints in terms of the required technical support along with the huge financial constraints. Figure 2 shows a typical IDC power house which illustrates the power environment they operate in. By restricting the study to STELCO, the necessary human capital to maintain and operate the proposed system is more likely to be present.



Figure 2: A powerhouse operated by an IDC
Source:MEEW

2.2.3 Dependency on Fossil Fuel imports

The small scale of power generation, the geographic nature of the islands and being fully dependent on imported diesel for its' power generation, makes the cost of

electricity in Maldives relatively high. It is unlikely that STELCO or the recently formed utility companies would be able to take any measures to lower their tariffs. Figure 3, shows the trend for 5years (2004-2009), indicating the tariffs have not gone down at any time in history,except for late 2008 and early 2009. The trend shows, it has rather increased in response to fluctuations in the oil prices in the world oil market. The official foreign currency exchange rate in the Maldives at the time of this research is 1US$ = MVR 15.42.

Table 3: Fuel consumption of STELCO powerhouse in Male'

Year	Powerhouse Name	Installed Capacity (kW)	Unit (kWh)		Consumption (Lits)	
			Generated	Consumed	Fuel	Lub Oil
2006	Male'	33,490	156,107,764	148,814,676	40,151,086	161,103
2007	Male'	35,490	177,052,316	165,788,031	45,872,134	159,765
2008	Male'	38,760	195,105,695	179,911,219	50,460,116	198,696
2009	Male'	41,960	208,387,759	201,933,160	53,693,332	187,288
2010	Male'	49,960	217,330,899	201,419,216	56,015,591	236,379
2011	Male'	49,960	75,087,617	69,627,318	19,277,201	70,638

Source: Date collected from STELCO head office

Table 3, shows the fuel consumption of the STELCO facilities in Male' for the period of 2006 to 2010 and partial data for the year 2011 during which this research was initially carried out.

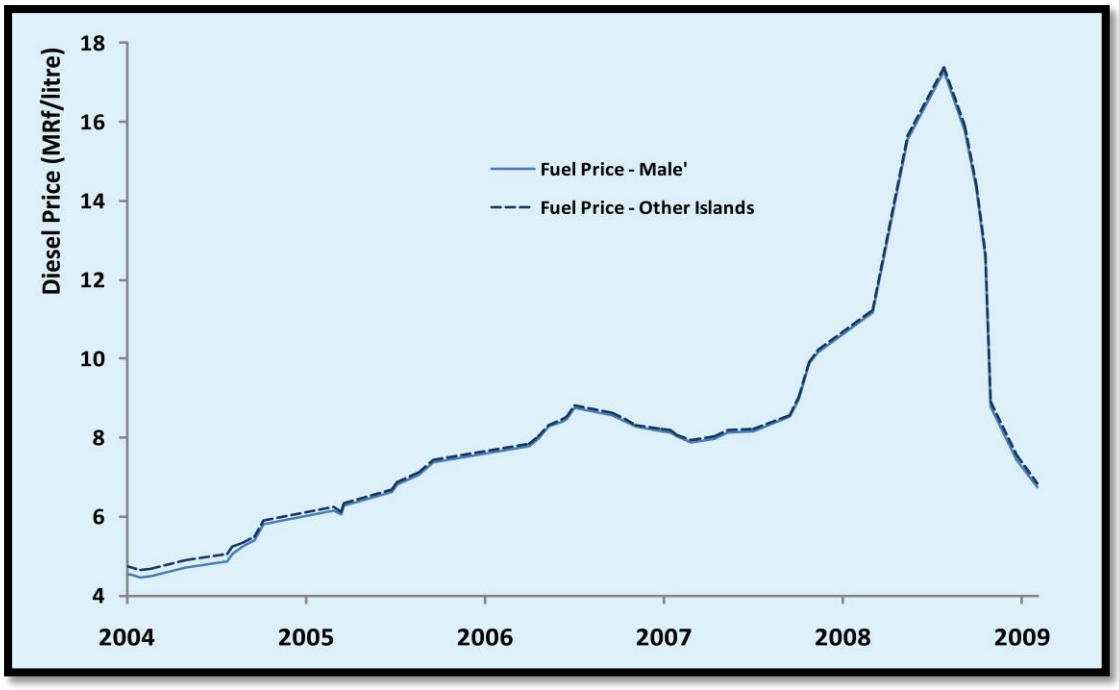


Figure 3: Cost of Diesel in MRf /Liter
Source: Data obtained from STELCO Head office

2.2.4 Tariff Disparity

Compared to smaller islands nation wide, electricity is much cheaper in Male', especally for domestic users. Table 4, shows the tariff charged per kWh in Male' and Hulhumale', effective from 2009. The cost of a unit for domestic uses, once the consumption reaches above 600 units, is MVR 3.85/kWh (equivalent to US$0.25/ kWh, with the present exchange rate) [4]. While there exists no specific law governing the tariffs charged, cost of energy per kWh charged in smaller communities has been as high as MVR 5 / kWh.

Table 4: Electricity tariffs (Mrf) in Male' effective from 2009

Tariff Description	0-100	101-300	301-500	501-600	>600
Domestic	2.25	2.5	2.95	3.55	3.85
Business, Government and others	3.3	3.35	3.65	4	4.35

Source: Data collected from STELCO head office

The issue of tariff disparity between the smaller islands and Male', would inevitably be a major issue in a near future unless a strategy is fomulated to remove it. This remains a major challenge for the government. It appears that the newly formed utility companies would be faced with the challenge of removing the tarrif difference between the islands within their respective regions. Even if they succeed in doing so, bringing down the tarrif to be the same as that charged in Male' and Hulhumale' would be next to an impossible task due to the small scale of operations. Thus, the development of Hulhumale', providing shelter for the smaller communities appears to be a solution to overcome this issue as well.

2.2.5 Land constraints faced by STELCO to expand their facility in Male'.

The STELCO facility in Male' is the largest and the most reliable power generation facility in the country. (Compare Figure 4; The STELCO power plant in Male' with the one in Figure 2).



Figure 4: The STELCO Power plant in Male'
Source: Data collected from STELCO head office

In order to meet the increasing demand in Male', STELCO is expanding their facility in Male'.According to information provided by STELCO, this expansion falls under the "4th power development project" in Male' [4] and involves installation of 3 units of 8MW diesel generators. It is designed to add 6 new Medium Voltage (MV) feeders to the existing distribution network [19]. The project is being funded by a mixed credit loan from Danida and the Maldivian government and was signed in October 2008 [4]. The work commenced in the in April 2009 [4] and was expected to be completed by the end of year 2012. However, at the time of this research, it is still

incomplete as the project has been delayed for various reasons . This expansion and the refurbishment of their existing distribution network is faced with huge challenges of land constraints in the overcrowded Male'. Due to the unavailability of land, STELCO has recently built new substations by building multistorey infrastructures within the existing substations. However this option is not available for all their substations.

2.3 SWITCHING TO RENEWABLE ENERGY

Maldives is blessed with abundant renewable energy sources that can be used to complement fossil fuel. Thus, the government of Maldives has expressed its interest in exploring the possibilities of switching from diesel to renewable sources such as solar wind and biomass to generate electricity for its people.

Though limited in their scope and outcome, there have been several RE projects such as South Asia Regional Initiative (SARI) [20], The Strengthening Maldivian Initiatives for a Long-term Energy Service (SMILES) [17] and the Renewable Energy Technology Development and Application Project (RETDAP) [3] implemented in the Maldives. Review on the outcome from these experimental work shows that the RETDAP delivered the most beneficial outcome to date. These projects are clearly the result of the Maldivian governments' initiative to pursue RETs as a means of sustainable development for transforming the energy sector of the country. With the result of these projects and similar work that will be done in future, a promising development and adaptation of the RETs in the Maldives is apparent. However, the Maldives still lacks the required policies and institutional capacity making this

transformation questionable. Based on the outcome of these projects, the Maldivian government disseminated its first energy policy in 2006 with a number of solar power projects. The policy was further revised in 2010 with the challenging aim to become the worlds' first carbon neutral country by the year 2020. However, since these policies have never been published, the objectives and milestones set-forth in these policies are not known. Hence, the effectiveness of the revised policy and its materialisation are yet to be seen.

There has been a small number of pilot projects of solar hybrid systems implemented in some inhabited islands of the Maldives to assess RE potential. The first of its kind to be installed in the Maldives was the PV-diesel hybrid system in the island of Mandhoo, located in the western part of the South Ari atoll, about 100 km South-West of Male'[21].The project was funded by European Union (EU) and the United Nations Development Programs (UNDP) and aimed at assisting the Maldives, develop a sustainable energy policy. The system was designed based on maximum load measured at the island, and the PV system was to supply power to all consumers during day time, while the diesel generator was to assume duty during night time. At the time of installation of the system, the island powerhouse had two generator sets of 31kW and 21.6kW and the annual load measured was 75000kWh. It is reported in [22], this project was unsuccessful since the demand during day exceeded the PV systems' capacity. The cause was inaccurate demand exacerbated by the demand increasing during the installation. With the lessons learned, similar systems were successfully installed on other islands. Table 5 presents the list of these projects as reported in [22]. These projects were hybrids of solar, wind and diesel. It is reported [23] that marine energy too could play a vital role in transforming the energy sector of Maldives in

future. Though these experimental projects (See table 5) explored the option of hybrid configuration with Wind and Solar, it is unlikely that the government of Maldives would compromise the coral reefs of these islands which stands as the backbone of the economy of the country, the tourism industry.

These pilot projects showed the potential benefits of such hybrid generation of electricity to these smaller islands with a population of just a few hundred people, where supply of electricity by the national grid is not attainable. As the work continued, and with the extreme difficulties STELCO was experiencing in catering for the fast growing demand of electricity in Male', the option of introducing renewable sources to cater for the load of STELCO grid in Male' came into the picture. But compared to other islands, the unavailability of land is a huge barrier in Male'. Thus, to cater for even partial load of Male', an alternative land space where the required plant can be installed is the first measure that has to be taken into consideration. To date, only a small number of solar panels have been installed in the roof tops of few government buildings which can only deliver an insignificant fraction of the power demand in Male'.

Table 5: RE Projects installed some of the inhabited islands of Maldives

	Island	**Renewable energy source**	**Capacity**
1	Adh. Mandhoo	Solar Diesel hybrid system	12.8kWp solar
2	R.Faninu	Wind-Solar-diesel hybrid	5kWp solar – 3.5 kW wind
3	B.Goidhoo	Wind-Solar-diesel hybrid	5kWp solar – 3.5 kW wind
4	L.Fonadhoo	Solar-diesel hybrid	5kWp Solar
5	L.Gan	Solar-diesel hybrid	10kWp Solar
6	HA. Uligamu	Solar-Wind-diesel hybrid	2.5kWp- 43.2kW
7	M.Raimandhoo	Solar-Wind-Diesel hybrid	2.5kWp -32.4kW
8	GA.Kondey	Solar-Wind-Diesel Hybrid	5kWp -10.8kW
	Total installed Capacity	**Solar: 47.8kWp**	**Wind: 93.4kW**

Source: Publications of MEEW, government of Maldives

In previous research [3], solar has been identified as the most potential renewable source available in the Maldives. It is an inevitable fact that installing solar panels on the roof tops of government buildings would not deliver anything of significance compared to the huge demand in Male'.The project "clean energy promotion in Male', [4] is a special project fully funded by the Japanese government, designed to deliver 400KW solar power and was expected to be completed in 2012. However, the project is still pending. The government of Maldives has now selected 6 islands [4] in which hybrid systems with diesel, is planned to be installed in a near future and expects STELCO to purchase power, from the said systems. The combined capacity of the system is reported [4] to be 1-1.5MW. The status of these projects, when they are planned to be implemented could not be clarified from the information obtained from STELCO head office as they consider it confidential. In 2010, STELCO opened bids for interested parties to supply renewable energy to Male' region. The capacity of the required system is reported [4] to be 15-20MW. The successful completion of such a project should contribute to ease the burden of capacity shortage STELCO is faced with by a great extent. But the fact that none of these projects has materialised to date, is a clear indication that much work needs to be done to convince domestic and international investors on the benefits of such an investment in Maldives. The assessment on the electricity requirement and generaion nationwide made in this research produced evidence that much research needs to be done if the government of Maldives is to deploy RETs to transform the energy sector of the country.

2.4 The difference in this research

In light of the literature reviewed and the analysis made on the data gathered for the research, this study aims to design a grid connected Distributed Generation Photovoltaic (DGPV) System that can cater for the partial load of national grid of STELCO. This has not been done in any of the previous research. It is seen from the reviewed literature, that all the pilot projects has been conducted focusing on the electric load of smaller islands where the consumption of electricity is insignificant compared to that in the capital city Male'. Further, the ongoing mega project of Hulhumale' to provide shelter for the homeless families in Male as well as those migrating from small rural islands coupled with the fact that 71% of the electricity produced by the STELCO nationwide is produced and consumed in Male', is considered as a clear indication for the need of a DGPV system as proposed in this study.

Different from the previous researches [3] [17] & [20, this, research is designed to produce an outcome that would enhance a clear understanding of using solar energy on the national grid at a large scale. The most cost effective way to deploy RETs in the STELCO grid is to use them to cater for the additional load and the proposed system models this. In this research, the factors that contribute to the consumption of electricity in Male' have been identified using the primary data obtained from the STELCO. Using this data, a long term forecasting of the expected demand on the grid for the next 20 years have been done and its accrete proven. The proposed generation system being modelled is based on this forecasted demand and its econmic feasibility assessed. This research is a prefeasibility study that assesses the techno-economic feasibility of a

DGPV system that can contribute to the increasing demand on the national grid of the STELCO.

2.5 Summary of Chapter 2

The objective of this study being modelling a DGPV system that can be practically implemented to contribute to the governments initiative to deploy RETs at large scale, the literature review has been focused on the energy requriement of the country, the available RE sources and the experimental work carreid out to explore its potential benefits. The capital city Male' was the first island in Maldives to have electricity supplied for the first time in history of Maldives in 1949 with a total installed capacity of of just 14kW, supplying electricity to the house holds of the capital city Male'. Since the formation of the State Electric Company (STELCO) in 1997, the supply of electricity has seen remarkable improvements nation wide, catering for 60% of the population in 28 islands by the end of 2008. Yet, it leaves the other 40% getting electricity supplied by poorly built power houses owned by Island Development Committee (IDC). In 2008, with the establishment of the regional utility companies to overtake the mendate of IDCs, STELCO also handed over 22 power houses on different islands to their respective utility companies, limiting their mendate to supply the 9 islands in the central north province only. At present, Male', the home for 42% of the population, is the highest consumer of electricity in the country. As the governments'effort to switch to RETs continued, STELCO opened bids in 2010, for interested parties to supply renewable energy to Male' region. Solar being reported as the most potential RE sorce in Maldives, it is unlikely that the government would comprimise the coral reefs of these small islands with hybrid system of wind, diesel and solar. The ongoing mega project of Hulhumale' to provide shelter for the homeless

families coupled with the fact that electricity consumption in Male' is icomaprable to all other islands nationwide, is considered as a clear indication for the need of a DGPV system as proposed in this study.

CHAPTER 3

RESEARCH DESIGN AND METHODOLOGY

3.1 RESEARCH DESIGN AND METHODOLOGY

Based on a quantitative research aimed at modelling a grid connected DGPV system that can effectively take over a portion of electric load on the STELCO national grid in Male, this study facilitates a detailed analysis of the current demand on the grid and how it is met by the STELCO power plant in Male'. The structure of this research takes into account a review of the present energy requirement of Male', the institutional arrangements and the countries' energy policy which aims to deploy RETs at a large scale nationwide. The previous research [3] [17] [20] conducted in the Maldives in assessing the potential RE sources are reviewed to critically assess the results delivered by these pilot projects. This was considered as an essential component of this research as it assured accurate information required for the adoption and sustainability of the proposed system. The proposed system has been modelled based on the long term predictions of electric load on the STELCO grid for the next twenty years. Analysis of the current demand and how it is supplied, was performed using primary data received from the STELCO head office in Male'. Using solar as the RE source, critical constraints such as the economic feasibility of the Renewable Fraction (RF) that can be delivered to the grid, the size of the required farm and the land constraints have been carefully evaluated in the modelling process. This have been given priority, ensuring the proposed system deliver a practical solution to the challenges faced by STELCO.

The sustainability of RETs in the Maldives can be a broad concept making it difficult to capture all factors that could have a significant effect on it. In this study the

techno-economic feasibility of the proposed system, the amount of carbon reduction that represents the fossil fuel savings that can be achieved by the implementation of the proposed system have been considered as an indicator reflecting the benefits, adaptation and sustainability of the proposed system.

The investment cost and financial modelling of the proposed system have been done to present a thorough assessment on the financial feasibility of the system. The Cost Benefit Evaluation (CBE) done in this study is based on the calculation of the Net Present Value (NPV), the Cost of Energy (COE) and the Profitability Index (PI) of the required investment and expected cash flow during the project period. This has been done by discounting the cash flow stream throughout the project period, at the real interest rate used in the simulation study. This is a widely used approach used in assessing the economic feasibility.

The following sections present a detailed account of the methodology in carrying out the research and modelling the proposed system.

3.1.1 Review of existing STELCO facility and current electricity demand in Male'

The proposed DGPV system in this research have been designed based on the electricity requirement of Male'. Hence, a comprehensive analysis on the existing facility of STELCO in Male' which is the largest power plant in the country, its' capacity, the demand and supply of electricity to the residents of Male' was carried out in the initial phase of the research. This analysis was done focusing on the present maximum and minimum load on the national grid, the peak hours for the electricity demand, the installed capacity of the STELCO plant in Male', and its' operational strategies. This included the mechanism employed by the company in meeting the expected and unexpected peaks. Studying the current distribution network of STELCO in Male' provided important information on identifying various issues and challenges faced by STELCO in supplying electricity in Male'. The lack of available land in Male for the expansion and necessary refurbishments of the existing network to cater for the growing demand was identified as the biggest constraint faced by the company at present. The fact that there is absolutely no space for the construction of a PV farm in Male', lead to the exploration of alternatives that could facilitate the construction of the DGPV system proposed in this study. Thus, the expansion of the STELCO grid to the nearby Hulhumale' and inter-connection of the two cities as planned by the government was considered as an available option to build the proposed system.

3.1.2 The Data used

This being a quantitative research, highest priority was given on the accuracy of data used in the research. Thus, all data on the electricity demand in Male', used in this research are primary data collected from the head office of STELCO in Male' [4]. These data have been used in the analysis of the current demand and supply of electricity in Male' to facilitate the know-how of the expected trend in demand. It facilitated an accurate prediction of the future growth of the demand on the STELCO grid.

The data on the sunshine, wind speed and temperature was collected from the Department of Meteorology in Male' [24] and NASA global data base linked to RETSCREEN software [25]. The data on the population of Maldives and Male' was obtained from the statistical data of Ministry of Planning and National Development [26]. Data on the total installed capacity of the country and the share of each sector that represent a stake holder in the power industry in the Maldives was collected from publications of the Ministry of Environment Energy and Water (17), now known as the Ministry of Environment and Energy. These data further enhanced an accurate account on the know-how of the overall power industry, energy requirement and available RE resources in the Maldives.

The technical data as well as the cost of the system components in this research was obtained from various manufacturers and suppliers from Singapore and China as well the

one and only supplier of RE systems in the Maldives [27]. For the modelling of the proposed system, the capital costing of the system components were calculated as a summation of all costs incurred in establishment and operation of the system. Assumptions were made as per the guide lines provided by the manufacturers. A wide range of prices were obtained from different manufacturers for all the components. These were used in the simulation process for comparison of system configuration derived, the economic feasibility and profitability of the proposed system. The optimal system architecture have been derived from simulation with costs obtained from the RE system supplier in the Maldives.

3.1.3 Electric load forecasting

In the initial phase of the research, a thorough analysis on the data obtained from STELCO was made to understand the current demand on the national grid of STELCO. This was then followed by the long term forecasting of the expected future demand for the next 20 years (2011-2030).

It has been done using multiple regression. Multiple regression is known to be one of the most commonly used industrially acceptable standard technique for forecasting of electricity demand due to its simplicity and flexibility [28 &29]. It has no limitation in short-term, medium and long-term forecasts since the accuracy of the forecasts made depends on the independent variables used in developing the forecasting model. The

predictability of the model relies on the ability of these variables to predict the future demand. Based on the method of least squares to determine the values of the coefficients in the multiple regression equation, this technique tests the relationship between a dependent variable, the electric load, in this case, and a set of independent variables (e.g. number of customers, customer types, weather, etc.) that has an impact on the electric load [29].

In this research, the customer classes and the number of customers in each class have been considered as the key factors that affect the consumption of electricity in Male'. The data on electric load, the customer classes and the number of customers in each class were collected from the STELCO head office in Male'. The information used in developing the regression equation is 10 years data received from the STELCO. The global test[9] was used on the variables to check the validity of these variables for forecasting electricity demand. It checks whether all of these independent variables could have a zero regression coefficient, which serves as the key for the validity of the variable in the model. On completion of the global test, each individual variable was tested with a confidence level of 95% for their rationality and eliminations were made until a stable regression model was achieved [29]. The resulting equation was then used to forecast the electricity demand in Male' for a period of 20 years. The process of deriving the equation to predict the future demand and validation of the results obtained is explained in detail in chapter 5.

[9] Explained in detail in chapter 5

3.2 SYSTEM MODELING

The proposed system in this research have been modelled using the popular commercial software Hybrid Optimization of Multiple Energy Resources, (HOMER) [11]. The simulations carried out, aimed to provide a pre-feasibility study that could offer a critical and convincing assessment on deploying RETs, as an alternative energy solution to meet the growing demand on the STELCO grid. The forecasted electricity demand for the 20 years was used as the load requirement to be met. The system has been modelled, taking into consideration the present constraints and the uncertainties that would be faced in implementing it in the Maldives. This has been done by allowing HOMER, to do a sensitivity analysis in the simulation runs. The sensitivity analysis[10], aims to represent reality when all the specified constraints are taken into consideration in the operation of the proposed system. The simulation assumes a minimum Renewable Fraction (RF) of 5 - 10%[11] to assess the fraction of the total estimated load on the grid that can be taken over by the proposed system. The RF represents the amount of energy that can be delivered by the system to the grid under the set constraints. The techno-economic feasibility of increasing the RF that offers financial feasibility with the applied constraints and costs was then carried out. In addition, financial feasibility and investment options were further investigated for construction of the DGPV facility in Hulhumale' which has some available land. This obviously assumes the proposed connection of the grid between Male' and Hulhumale' goes ahead.

[10] Explained in detail in section 6.1.10 and 6.1.12; chapter 6

[11] Going beyond this range was seen to produce no contribution to the research proposed. This is further explained in detail in chapter 6.

In the simulation process, HOMER ranks the optimal system architecture based on its' life cycle cost which represents the cost of installing and operating the system over its' life time. It considers a system as feasible if the system configuration can meet the required demand under the specified constraints. HOMER ranks the system configurations that meets the requirements by their Net Present Cost (NPC). It ranks the system configuration with the lowest NPC as the most optimal [11]. Thus, the modelling process ensures that the system can meet the demand while taking into account all the constraints and the resource availability as well as the variation in costs of technology. However, this does not take into account the financial feasibility of the system. While HOMER considers the NPC as the economic figure of merit, it does not rank the optimal system based on the financial feasibility, but rather on the lowest NPC regardless of the financial feasibility of the system.

Since the load forecasting done in this study revealed significant growth in future demand in Male' ,additional financial inputs are required to expand the system with the increase in demand and this feature is not available in HOMER. However, HOMER does offer a powerful feature of accounting for uncertainties such as increase in demand, cost of fuel, electricity tariff or grid rates etc., by performing a sensitivity analysis for each of the variables over the project period. However in a sensitivity analysis, HOMER considers each of these sensitivity cases as a different project (with the same project period, 20 years in this study) and presents the optimal system configuration by accounting for these uncertainties in the sensitivity analysis. In this respect, HOMER assumes all investment occurs at the start of the project even if additional capacity to the plant come on line later

in the project. As a result, the cash flow stream and the NPC given by each of the sensitivity cases do not represent the reality in the simulation in this project, because the additional investments of each year along with all other costs and revenues requires to be taken into account, for it to represent the real NPV[12] of the project[13]. Therefore, a model (a working XL spreadsheet) which performs similar calculations to HOMER, but took into account the correct depreciation of the additional investments that occur later in the project was developed by replicating the cash flow model of HOMER. It was tested for the accuracy of the results and then used to calculate the cash flow, the NPV and PI to see if the investment is financially feasible.

3.2.1 Load profile

HOMER models three types of loads. The primary load, the deferrable loads and the thermal load [11]. The primary Load is the electric load the system should serve leaving no unmet load. The deferrable load is the electric load that must be served within a specified time frame but not simultaneous with the primary load [11]. The thermal load refers to the load that the system serves using the thermal energy it generates throughout the year [11]. The proposed system in this study is expected to cater partial load on the STELCO grid and hence, it is considered as the primary load and no deferrable or thermal load have been considered in the simulation.

[12] The Net Present Value (NPV) is the same as the Net Present Cost (NPC) calculated by HOMER in its economic modelling

[13] Explained in detail in chapter 8

HOMER allows the option of entering a typical 24 hour load profile as input data, which is used to synthesize a load profile for each hour of the year with constraints and random variability specified by the system designer. This means, HOMER accounts for possible increase in demand throughout the year by the same load profile, discretised on a yearly time scale for each hour of each day throughout the year, with a random day to day variability specified by the system designer [11]. Similar projects using the HOMER [8-10] is seen to have used this approach to create the required annual load profile.

The option of using a typical 24 hour load profile, may be apropirate to produce reliable outcome for smaller rural communities where the increase in the demand from year to year is small. However, this is not the case for Male' where the demand is rapidly rising. Therefore, in the system modelling process, accounting for this rise was essential. This was done by using HOMERs sensitivity analysis feature to obtain appropriate system configurations. This is further explained in detail in chapter six.

3.2.2 Accounting for unavoidable technical constraints

The accuracy of the simulation results, the optimal system architecture and the performance of the system in the simulation process is entirely dependent on the accuracy of the input data. This data, its derivation and application in the simulation process have been explained and discussed in detail along with the results in chapter six, "System Modelling".

The simulation results did not take into account any unavoidable technical constraints (eg safety measures) [30]. These were taken into account in this work when choosing the optimal solution. This ensures the final system design is practical and does not compromise any of the necessary safety measures.

3.3 Summary of Chapter 3

This study being a quantitative research aimed at modelling a grid connected DGPV system that can effectively take over partial load on the STELCO national grid in Male, it is structured to take into account a detailed review of the present energy requirement of Male', the institutional arrangements and the governments' decision to deploy RETs at a large scale nationwide. In this respect, highest priority was given on the accuracy of data used, ensuring accurate prediction of the expected future demand for the next 20 years (2011-2030). These forecasts were used in the simulation as the load requirement to be met by the proposed system. The constraints applied in the simulation have been carefully chosen to ensure the study serves, a pre-feasibility study that could offer a critical and convincing assessment on deploying RETs, as an alternative energy solution to meet the growing demand on the STELCO grid. The simulation was carefully done allowing HOMERs powerful feature of sensitivity analysis, accounting for uncertainties such as increase in demand, electricity tariff or grid rates and more importantly the Renewable Fraction that can be delivered to the grid under the constraints applied. The serious land constraint of the country is given priority ensuring the proposed system is not based on

mare theoretical concepts, but rather serves a practical alternative solution that would cater for the need. The modelling process was carefully structured, to account for unavoidable technical constraints such as the safe operational requirement of the system components by applying universally acceptable design guidelines for DGPV systems, ensuring no safety measures are compromised. The economic feasibility of the system required accounting for the additional investments that gets injected on annual basis throughout the project period and this has been done using an XL spreadsheet developed by replicating the economic modelling of HOMER.

CHAPTER 4

LOAD ANALYSIS AND FORECASTING

4.1 LOAD ANALYSIS

All data used in this research is primary data gathered from the STELCO, the national power company of the Maldives. The analysis of this data strengthens the study on the requirement of the proposed DGPV System. It facilitated an in depth analysis of the existing STELCO power plant, the power generation and distribution in Male' with a thorough understanding on the load requirements and the plants' ability to meet the demand. This was seen as a crucial task before attempting to model the proposed system. The following sections present the results of this analysis.

STELCO characterizes its consumers into three categories of tariff; domestic, business and government. Domestic consumers represent personal consumption of power. The business customers vary from small businesses who have relatively low power consumptions to industrial plants like carpentries. The government is mainly the office blocks.

4.1.1 Electricity Demand in Male' at present

Male', the capital city of the Republic of Maldives is one of the worlds' most congested cities. With a land area of just 5.8km^2, it is home for 42% of the population of the country. This level of population density forces multiple families to live in the same apartment in multi-story buildings that offer little or no ventilation. To provide a comfortable living space, it has become a common practice to install split air-conditions in

households leading to a significant increase in electricity consumption in the domestic category. Consequently, its power consumption and demand for electricity, is significantly higher than any other island in the Maldives.

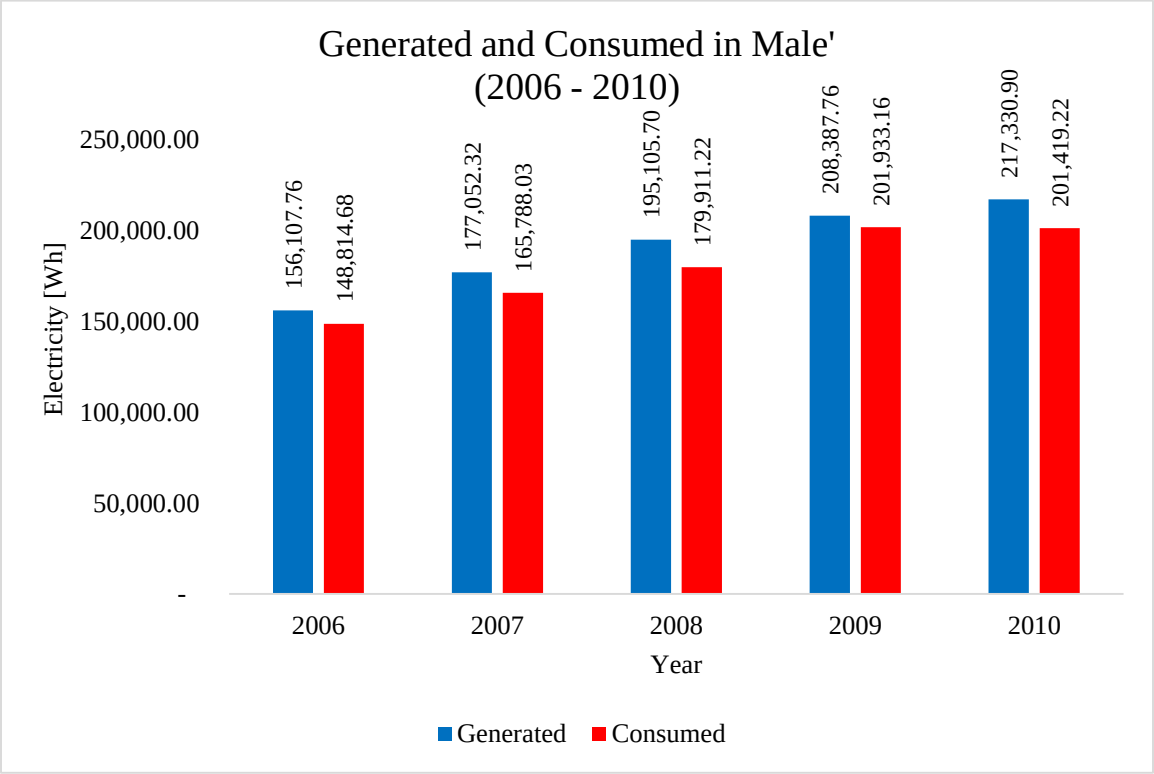


Figure 5: Electricity consumption in Male' (2006-2010)
Source: Plotted from Data collected from STELCO head office

Figure 5 shows the total power generated and consumed, the past 5 years (2006-2010) and Figure 6 shows, the installed capacity, the maximum and minimum demands for the same period. Table 6 shows a comparison of power consumed and unconsumed expressed as percentage of the total power generated, during this period [4]. The data shows, STELCOs plant generated 217.33 GWh in 2010 and the consumption was recorded to be 201.42 GWh. The total amount of generated power here is seen low compared to the total installed capacity of 50 MW. The exact reason behind this could not be verified and

it is likely to be due to plant maintenance. The difference between the power generated and consumed, represented as the unconsumed power is highly likely to be the losses in their distribution network. It could also represent a human error in measurement. The exact reason behind this variation, could not be verified form STELCO.

Year	Power Generated (MW)	Power Consumed (%)	Power unconsumed (%)
2006	156	95	5
2007	177	94	6
2008	195	92	8
2009	208	97	3
2010	217	93	7

Table 6: Electricity Generation Vs. consumption in Male' (2006-2010)
Source: Primary Data collected from STELCO head office

The constant growth in maximum demand throughout the five years period reflects the high consumption by all customer in all three categories with a relatively high consumption by the domestic customers which in turn reflects the continuous growth of people migrating to Male from other islands.

Although STELCO supplies electricity in all major islands with significant population nationwide, a common grid does not supply them since there is no interconnection between these islands. Male' being the capital city with STELCOs' largest power plant, critical analysis of the data on electricity generation by the STELCO nationwide indicates, 71% of it is produced and consumed in Male' while only 29% of it is consumed by the other 27 islands, where STELCO supplies power.

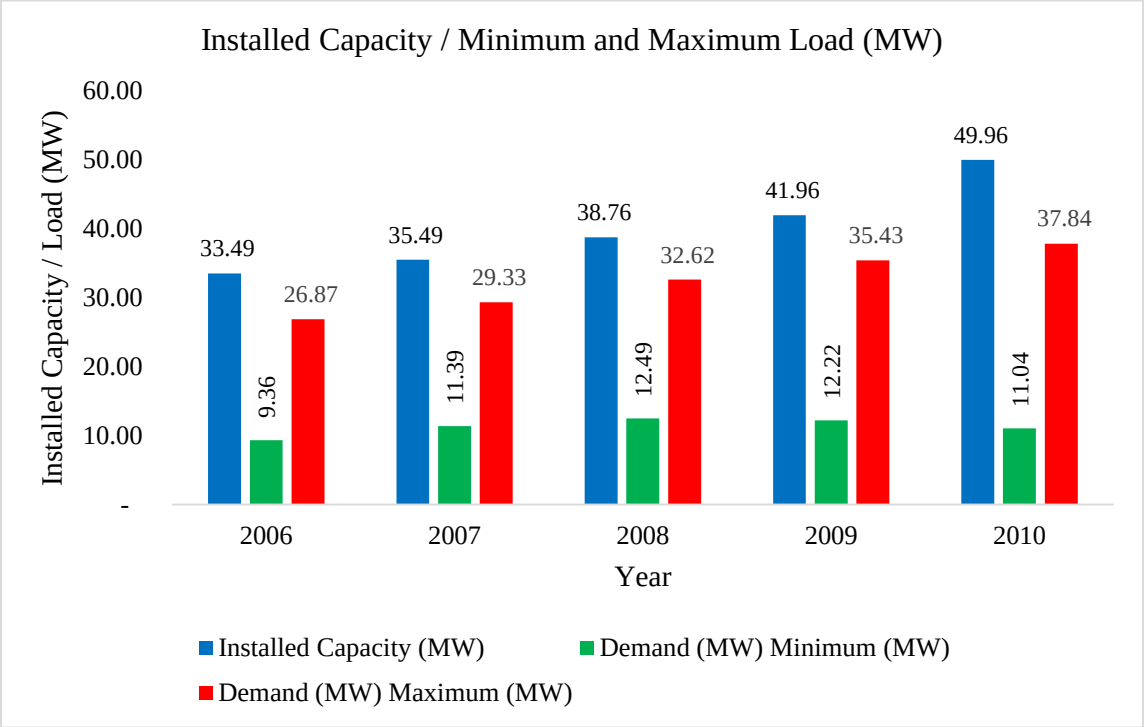


Figure 6: Power generated by STELCO VS Maximum and Minimum Demand in the Capital City Male' (2006-2010)
Source: Plotted from Data collected from STELCO head office

Further analysis on the data and the operational strategy of the facility aiming to measure the operational efficiency of the plant in relation with the installed capacity revealed that the plant capacity is often expanded (see Table 7), in order to meet the peak demand. The investment on this continuous expansion requires STELCO to charge relatively high prices for electricity.

While the performance of a power plant can be measured by factors such as, Heat rate (Energy Efficiency), Thermal Efficiency, Capacity Factor, Load Factor, Economic Efficiency and Operational Efficiency, this analysis is based on the operational efficiency of the plant due to the limited data available.

In practice, it is unlikely that a power plant would deliver to its' maximum designed or installed capacity. Various factors can contribute to this. Amongst them are the need for shutting down of generating equipment for routine or planned maintenance, emergency maintenance and various losses within the transmission and distribution network. Table 7 and Figure 5 &6 shows, STELCOs' existing facility has the capacity to meet the maximum demand. However, there has been several incidents of power failure in Male' and in absence of relevant information about the amount of capacity off line, it is not clear whether these power shortages were due to required plant maintenance. .

Other factors that would have a significant contribution to the power outages could be the distribution loss factors (DLF). At present STELCOs' distribution network comprises of 106 transformers within Male', each contributing to the loss on the network. To have a detailed understanding of this, the DLF could not be calculated since STELCO does not keep records of losses in these substations.

With the information available, the capacity factor served as the best indicator of the operational capacity of the plant, since it is a measure of operating efficiency and a measure of the plants' ability to deliver its full capacity. Thus, in this study, it represents a direct indicator of the reliability of STELCOs' existing facility.

The analysis revealed that as of December 2010, the capacity factor of the plant was 50%, while the facility had an installed capacity of 50 MW. This is low in terms of utilization of the installed capacity. Though STELCO does not maintain a formal plant margin, the installed capacity is significantly higher than the recorded peaks (see Table 7 & Fig 6) and hence, the plant is expected to be able to cater for it.

Set No	Make	Year	KVA	Set No	Make	Year	KVA
DG1	Wartsila	1998	5425	CG5	Cummins	2007	1250
DG2	Wartsila	1991	2700	CG6	Cummins	2007	1250
DG3	Wartsila	1991	2700	CG7	Cummins	2008	2000
DG4	Wartsila	1994	2700	CG8	Cummins	2008	2000
DG5	Wartsila	1996	7235	GE1	Cummins	2009	2000
DG6	Wartsila	2002	8143	GE2	Cummins	2009	2000
DG7	Wartsila	2002	8143	GE3	Cummins	2010	2000
CG1	Cummins	2006	1250	GE4	Cummins	2010	2000
CG2	Cummins	2006	1250	GE5	Cummins	2010	2000
CG3	Cummins	2006	1250	GE6	Cummins	2010	2000
CG4	Cummins	2006	1250	GE7	Cummins	2010	2000
Total Installed Capacity (MW)							49.960
Peak Load on 04-05-2010 (MW)							37.835
Total Power generated in 2010 (MWh)							217,330.899

Table 7: Generation Equipment installed in STELCO Power plant in Male', as of Dec 2010
Source: Data collected from STELCO head office

$$Capacity\ factor = \frac{Actual\ output\ of\ the\ plant}{The\ potential\ output\ if\ the\ plant\ operated\ at\ full\ capcity}$$

[1]

$$\text{Capacity Factor} = \frac{217330.899}{365\text{x}24\text{x}49.960}$$

$$\text{Capacity Factor} = 0.49658$$

$$= 50\%$$

Furthermore, the lack of land for newsubstations and refurbishment of the existing network infrastructure (eg construction over underground cables) are serious constraints that limits STELCO from improving their sevices. These are constraints that cannot be eliminated now. Hence, continued expansion of the plant by adding diesel generators may not provide a sustainable solution to the problems, STELCO faces at present. Thus, as planned by the government, switching to RE sources appear to be the ultimate solution to

overcome these barriers and transform the energy sector of the country, leading to a sustainable development. However, its adoptability, long term sustainability and more importantly its economic feasibility and the significance of reduction in carbon emission in a global perspective to contribute to the mitigation of global warming and climate change are factors that shall be taken into consideration to assess the benefits of such a transfer of technology in a developing country like Maldives.

The literature and the analysis of information received from STELCO indicates, much research needs to be carried out on the integration of this transfer of technology into power generation in the Maldives. Thus, in this research, assessing the fast growing demand on the national grid of STELCO has been considered as a crucial measure for sizing the proposed system. In this regard, accurate forecasting of the future demand on the STELCO grid has been considered as one of the most important tasks of this research.

4.2 LOAD FORECASTING

Electric load forecasting is a challenging task due to its stochastic nature. Its output is always in a probabilistic form explaining the behavior of some independent variables over a specific time horizon. Load forecasting models mathematically represent the relationship between the deriving factors and the load. Once a model has been developed or formulated, it can be used to predict the future demand. This is done by inferring the relationship between the load and the deriving factors over the desired time horizon. Well known and the most frequently used techniques in inferring this relationship between the

loads and the variables are multiple regression, exponential smoothing and statistical methods [31&32], Particle swarm optimization technique [33], Time series Analysis [34&35], and Artificial Neural Networking (ANN)[36&37].

Regression analysis is based on studying the trends in the historic data and creating a mathematical model that can be extrapolated into the future [32]. The applied model may be linear, polynomial, exponential and power. With multiple regression, accurate assessing of which factors drive the electricity demand is essential to the development of a credible model. Research [38] using the forecasted climate data of Italy to predict medium-term electricity demand presents a good example of this. In [38] the correlation between the temperature and the demand for electricity was found using linear and non-linear regression models. The increase in demand being attributed to the usage of air-conditioning, it proves the same correlation could be expected in hot tropical countries. It further explains, the temperature does not vary significantly in such countries and that it is unlikely to be the main driver.

Multiple regression being one of the most widely used techniques proven to lead to reliable prediction of electricity demand, some researchers have presented a strong argument [39] against the use of nonlinear models, since it leads to the model following random trends in the historic data, leading to inaccurate and unreliable predictions [39]. This also applies to polynomial regression for the same reason. (See for example; *http://blog.minitab.com/blog/adventures-in-statistics-2/the-danger-of-overfitting-regression-models*) The approach used in [39] to capture the non-linear change,

decomposes the historic data into multiple simple first order linear regression models, to extract the short-term correlation between the variables. A recursive iterative algorithm was then used to combine the linear component [39]. The methodology was tested using real data of one of the largest power utility company in Canada. Multiple regression being one of the most commonly used statistical techniques for forecasting electricity demand due to its simplicity and flexibility, it has been used in [28][32][38] & [40-42] for short, medium and long-term forecasts. With multiple regression, the accuracy of the forecasts depends on the independent variables used in deriving the regression equation.

The modelling of the proposed DGPV system in this research is limited to cater for the loads of Male' but can be expanded to cater for the joint cities of Male' and Hulhumale' via a common grid. Since STELCO is the only provider of electric power in Male', accurate forecasting of the expected demand is crucial for the effective operation and management of the facility.

Based on the information provided by STELCO, the company conducts its load forecasting based on the historic data of consumption alone. This data provides the actual rate of increase or decrease in electricity consumption in Male' on an annual basis. It is then, taken as the key to predict the expected demand for the future. In this research, all drivers that could have a significant contribution to the consumption of electricity in Male' have been identified and tested for their ability to predict the future demands.

The following section provides a comprehensive explanation of the process of forecasting the future demand on the STELCO grid carried out in this research.

4.2.1 Forecasting the future demand on STELCO national grid

The tariffs rates of STELCO are based on three categories of customers. The government, business and the domestic customers. In this study, data on the customer classes (the number of customers in each class) and the temperature were initially considered as the independent variables that could explain the variations in the electricity consumption in Male'. However, the analysis on this data showed that temperature is not a driving factor for the variations in electricity demand in Male', (see Table 8). Maldives being a tropical country not having seasonal changes, the slight variations in the temperature does not lead to a significant increase or decrease in electricity demand. The steady temperature of about 28 to 30 Degree Celsius, makes the usage of air-conditions a standard practice in all households. Hence, the effect of temperature would be present in electricity consumption by customers in all the three categories.

The regression analysis on these data to derive the equations (see equation 2- 4) to predict the future demand of electricity, is based on conducting the standard hypothesis testing which allows identifying and eliminating the independent variables that do not qualify to be a good indicator with the ability to predict the dependent variable. The variables that pass the hypothesis test are used to predict the future demand. The following section details this process.

		Customer Types			
Year	**Load (MW)**	**Domestic (X_1)**	**Business (X_2)**	**Government (X_3)**	**Temperature (X_4)**
2001	15430	10217	3568	548	28.51
2002	16250	11114	3835	594	28.57
2003	18157	12091	4122	645	28.68
2004	20178	13153	4431	700	28.58
2005	23151	14343	4794	780	28.79
2006	26507	15499	5001	757	28.57
2007	29328	16509	5366	796	28.74
2008	32700	17915	5700	817	28.55
2009	35428	19417	6069	805	28.78
2010	37835	21143	6546	754	28.85

Table 8: 10 Years data on electricity demand and the driving factors.
Source: Data collected from STELCO head office

4.2.2 Hypothesis testing on the independent variables

The hypothesis testing on a variable verifies the independence of the variable in predicting the dependent variable (Electricity Demand in this study). The standard practice [29] involves,

1. Making assumptions about the likely independent variables.
2. Stating the research and null hypotheses and setting a significance level, α (alpha)
3. Selecting the sampling distribution and specifying the test statistic
4. Computing the test statistic
5. Making decision and interpreting the results

With linear multiple regression, the following assumptions apply [29].

1. The independent variable is continuous with the least interval scales and has a linear relationship with the dependent variable.
2. The variations between the actual and predicted values are approximately the same for all fitted values of (Y), exhibiting homoscedasticity.
3. The residuals (difference between the actual and predicted value of dependent variable(Y) are normally distributed with a mean of zero, and,
4. The successive observations of the dependent variables are uncorrelated.

However, in practice, adherence to these assumptions are not always possible in multiple regression and it is said in [29] that violation of some of these assumptions such as autocorrelation between the independent variables are often possible in practical situations [29]. Yet, the technique has been proven to be robust enough to deliver a reliable equation capable of predicting the dependent variable even when one or more of these assumptions are violated. [29]

4.2.3 Defining the null Hypothesis, the significance level, (α), the sampling distribution and the test statistics:

The standard significance level α used in regressing the statistical data is 0.05, (i.e. 95% confidence level).The hypothesis is defined as;

The null hypothesis H_0: = $\beta_1 = \beta_2 = \beta_3 = 0$) and the alternate hypothesis H_1 = Not all βs are 0; where βs are the regression coefficients. That is;

$H_0 = \beta_1 = \beta_2 = \beta_3 = 0$;

$H_1 = Not\ all\ \beta_s\ are = 0$;

To test the null hypothesis, the F distribution is used. The specific characteristics of the F distribution is that, it is skewed positively with the critical value located at the right tail, which separates the region where the null hypothesis is not rejected. It is constructed based on the degree of freedom in the numerator (df_{num}) and the degree of freedom in the denominator (df_{denom}).

The$(df\ num) = k$ and the = $(df\ denom) = n - (k + 1)$;
Where $k = The\ number\ of\ independent\ variables\ and$
$n = the\ number\ of\ observations.$

This hypothesis test is also known as the global test [29] on the set of independent variables. In this case, it checks the validity of the four independent variables shown in table 8, for forecasting the future electricity demand. It investigates if the net regression coefficient of all independent variables shown in table 8, could be zero which serves as the decision making tool in deriving the regression equation. The decision is based on the implication that if the null hypothesis ($H_0 : \beta_1 = \beta_2 = \beta_3 = 0$), is true, then all the regression coefficients of the variables used are zero and so are of no use in predicting the dependent variable In other words, it explains the coefficient of multiple determination (R^2), which explains the percentage of the total variation of the dependent variable (Electricity Demand) explained by these independent variables and informs if the said variations could occur by chance. [29].

4.2.4 Computing the test statistics:

The F statistics represent the ratio of the explained variability of the dependent variable (Electricity Demand) by R^2 and the unexplained variability of it, reflected by (1-R^2), each divided by their corresponding degree of freedom. For a model to be accepted and to reject the null hypothesis, that the data occurred, have occurred randomly, the explained variability should be larger than the unexplained variability by a certain critical value of F. This critical value depends on the degree of freedom and are available in statistical tables or as functions in spreadsheets like Excel. The larger the F-value of the model, the more useful it is in terms of predicting the dependent variable [29].

To illustrate this test, the result of the global test given in table 10, are used to fit the load data. (See Table 10; where all three variables X_1, X_2 and X_3, representing the number of consumers in each of the tariff categories are regressed). The computed F-test for this data set is 292 (see Table 10) which is significantly higher than the critical value of F = 4.9 (derived from running F-test on XL) which means the null hypothesis should be rejected since at least one of the variables have the ability to predict the electricity demand. However, at this stage, the variable that have the ability to predict the load is unknown and further statistical tests on the individual variables is required.

To proceed, the student test or *t*-test on each independent variable is performed to assess its ability to predict the electricity demand. Any variable that does not qualify to be a good indicator to predict the dependent variable is expected to have a value close to zero.

Again, the cut-off which can be found from statistical tables or through spreadsheet functions, will depend on the confidence level and degree of freedom.

When there is more than one variable that fails the test, a decision to eliminate one of them is made based on standard practice [29]. That is, the variable with a *t*-value furthest from the *t*-test critical value is the one chosen. The formal measure of this distance is the *p*-value which is calculated along with the *t*-value. The higher the *p*-value, the further the variable is from the *t*-test critical value. Thus, when more than one variable fails the *t*-test, the one with the highest *p*-value is eliminated.

In this study, with the three variables X_1, X_2 and X_3, the *t*-test critical value is 2.26 (see Table 9). With the first regression run (see Table 10), all the three variables have a *t*-test value below the critical value and hence the variable with the highest *p*-value is eliminated from the model. This is variable X_2, the number of business users. This effectively informs there is little dependence of the electrical load on the number of business users. The regression is then repeated with the remaining variables X_1, the number of domestic customers and X_3, the number of governmental customers. Following the same process detailed above, the F-test shows that at least one variable has a non-zero regression coefficient. The t-test critical value for this data set is now 2.365. The results of the second regression (see table 11) shows, variable X_3 fails the test and is eliminated. The regression is then, repeated with variable (X_1). The result is shown in table 12.

	X_1	X_2	X_3
Mean	15140.04	4943.30	719.61
Variance	13151318.65	963044.90	8891.72
Stdv	3626.47	981.35	94.30
Count	10.00	10.00	10.00
df	9.00	9.00	9.00
Confidence	0.95	0.95	0.95
***t* critical**	**2.26**	**2.26**	**2.26**
Standard Error	1146.79	310.33	29.82

Table 9: computed test statistics for the three independent variables.
Source: Computation using Microsoft Excel

Regression Statistics	
Multiple R	0.99659547
R Square	0.99320252
Adjusted R Square	0.98980379
Standard Error	819.61243
Observations	10

ANOVA				
	df	***SS***	***MS***	***F***
Regression	3	588922859.2	196307619.7	292.2268285
Residual	6	4030587.214	671764.5356	
Total	9	592953446.4		
	Coefficients	***Standard Error***	***t Stat***	***P-value***
Intercept	-1088.63866	7004.220607	-0.155426096	0.881582504
X Variable 1	5.43809327	2.63743929	2.061883771	0.084834976
X Variable 2	-12.574102	10.14211941	-1.239790371	0.261340821
X Variable 3	8.90711649	7.179932356	1.24055716	0.261076746

Table 10: Summery output of rerunning the regression with all three variables
Source: Computation using Microsoft Excel Data Analysis tool pack

Regression Statistics	
Multiple R	0.995678519
R Square	0.991375714
Adjusted R Square	0.988911632
Standard Error	854.7180225
Observations	10

ANOVA				
	df	***SS***	***MS***	***F***
Regression	2	587839646.1	293919823.1	402.330683
Residual	7	5113800.286	730542.898	
Total	9	592953446.4		
	Coefficients	***Standard Error***	***t Stat***	***P-value***
Intercept	-9123.187571	2437.417636	-3.742972659	0.0072345
X Variable 1	2.180714808	0.138264828	15.77201405	9.9783E-07
X Variable 3	2.244795122	5.365786156	0.418353445	0.68822487

Table 11: Summery output of rerunning the regression after eliminating variable X2
Source: Computation using Microsoft Excel Data Analysis tool pack

Regression Statistics	
Multiple R	0.99557023
R Square	0.991160082
Adjusted R Square	0.990055093
Standard Error	809.4488569
Observations	10

ANOVA				
	df	***SS***	***MS***	***F***
Regression	1	587711786.8	587711786.8	896.98581
Residual	8	5241659.615	655207.4519	
Total	9	592953446.4		
	Coefficients	***Standard Error***	***t Stat***	***P-value***
Intercept	-8240.355378	1155.163281	-7.13349837	9.868E-05
X Variable 1	2.22831352	0.074401811	29.94972136	1.6757E-09

Table 12: Summery output of rerunning the regression after eliminating variable X3

Source: Computation using Microsoft Excel Data Analysis tool pack

The result of the above hypothesis testing confirms that only one variable, the number of Domestic Customers (X_1) qualify as a strong indicator of predicting the electricity demand, leading to the linear equation (Equation 1).

$$Y = \alpha + \beta_1 X_1 \quad (2)$$

Where Y= Electricity demand, α is the intercept, β_1 is the regression coefficient and $X_1$is the number of customers in the domestic category. With the results in table 12, equation 2 is re-written as;

$$Y = -8240.4 + 2.2283X_1 \quad (2a)$$

The regression fit is shown in Figure 7. In order to demonstrate the residuals are spread evenly, the Mean Absolute Percentage Error (MAPE) should also be calculated. This is shown in table 13.

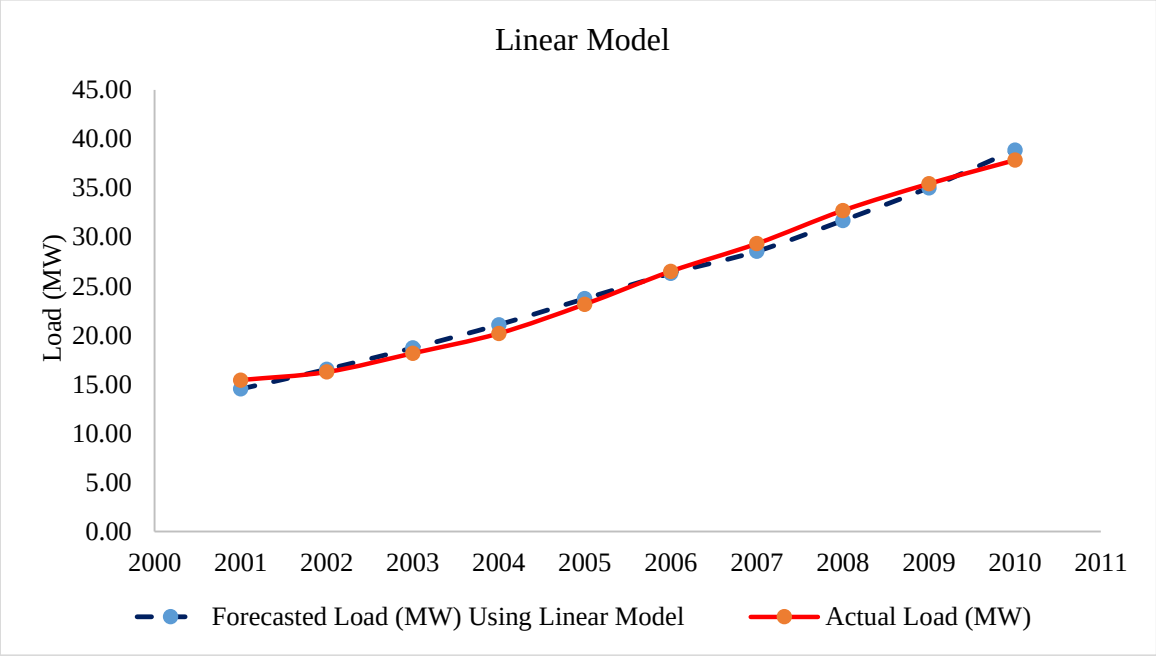


Figure 7: Linear Modelling of the Load (2a)
Source: Multiple regression analysis on 10 years' data provided by STELCO

	MAPE calculation for Linear Regression Model using customer as variable derived from MS XL					
Year	**Actual Load (MW)**	**Forecasted Load (MW)**	**Error**	**Absolute Error**	**Percentage Error**	**Absolute Percentage Error [APE]**
2001	15.43	14.53	0.90	0.90	0.06	0.06
2002	16.25	16.53	-0.28	0.28	-0.02	0.02
2003	18.16	18.70	-0.54	0.54	-0.03	0.03
2004	20.18	21.07	-0.89	0.89	-0.04	0.04
2005	23.15	23.72	-0.57	0.57	-0.02	0.02
2006	26.51	26.30	0.21	0.21	0.01	0.01
2007	29.33	28.55	0.78	0.78	0.03	0.03
2008	32.70	31.68	1.02	1.02	0.03	0.03
2009	35.43	35.03	0.40	0.40	0.01	0.01
2010	37.84	38.87	-1.04	1.04	-0.03	0.03
Mean Absolute Deviation[MAD]			**0.66**			
Mean Absolute Percentage Error [MAPE]			**2.79%**			

Table 13: MAPE Calculation for Linear Model (2a)
Source: Multiple regression analysis on 10 years data provided by STELCO

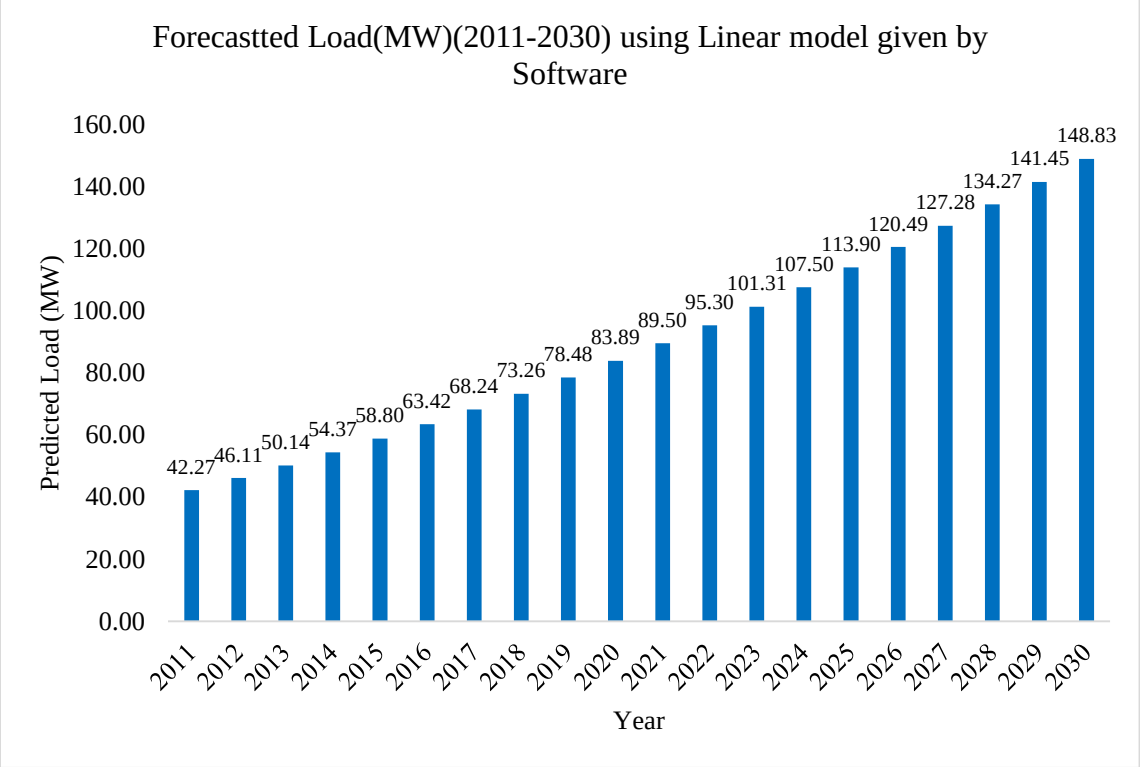


Figure 8: Predicted Load (MW), (2011-2030) using the linear Model given by the XL software (2a)
Source: Computation using the linear Model given by the software

Figure 8, shows the long-term prediction made using the linear model (equation1a) and the yearly projected number of Domestic Customers (see Appendix 1 for the projected number of domestic customers). The model predicts a rapid rise in the demand. The results were validated by using well known industrial software for electric load forecasting, GMDH Shell. GMDH Shell uses time series for electric load forecasting.

4.2.5 Mathematical modelling of the load by Linear and Polynomial regression.

The process of regressing the data using MS excel detailed in the previous section can also be done using mathematical techniques. The software application saves time from tedious calculations and often proves to be reliable. However, dependency on such applications without the technical knowledge of the process could result in inaccurate or even false results, especially when applied to electric load forecasting. Considering this possibility and its consequences, the process of developing the mathematical equation (equation 2) derived in the previous section is repeated here in this section by mathematical techniques. The purpose being, validating the results achieved using the software application. The variable that passed the hypothesis test in the previous section, is being used to develop the linear and polynomial models. This is being done by developing a vector matrix using the data in table 14, which is the same data that was used in the regression process in the previous section.

Year	Load(kW)	No of Customer [Domestic(X1)]
2001	15430	10217
2002	16250	11114
2003	18157	12091
2004	20178	13153
2005	23151	14343
2006	26507	15499
2007	29328	16509
2008	32700	17915
2009	35428	19417
2010	37835	21143

Table 14: Load and number customers in Domestic category
Source: Primary data from STELCO

The construction of the vector matrix using the data allows the unknown regression coefficients to be calculated simultaneously. However, higher order polynomials regression by this method require a significant amount of tiresome calculations to compute these unknown parameters. The process of constructing the matrices takes the form demonstrated below.

$$\begin{bmatrix} N & \sum X_1 & \sum X_1^2 & \cdots & \sum X_1^n \\ \sum X_1 & \sum X_1^2 & \sum X_1^3 & & \sum X_1^{n+1} \\ \sum X_1^2 & \sum X_1^3 & \sum X_1^4 & & \sum X_1^{n+2} \\ \vdots & \vdots & \vdots & & \vdots \\ \sum X_1^n & \sum X_1^{n+1} & \sum X_1^{n+2} & & \sum X_1^{2n} \end{bmatrix} \begin{bmatrix} \sum y \\ \sum y\,X_1 \\ \sum y X_1^2 \\ \vdots \\ \sum y X_1^n \end{bmatrix} = \begin{bmatrix} \alpha \\ \beta_1 \\ \beta_2 \\ \beta_3 \\ \vdots \\ \beta_n \end{bmatrix}$$

Where;

N = the number of Observations

X = the number customers in Domestic Category and

Y= the Predicted Electric Load.

α = the intercept and

β_{1-n}= the regression coefficients.

Year	Y = Load(MW)	X_1	X_1^2	X_1^3	X_1^4
2001	15.43	10217	$1.043x10^8$	$1.066x10^{12}$	$1.089x10^{16}$
2002	16.25	11114	$1.235x10^8$	$1.372x10^{12}$	$1.525x10^{16}$
2003	18.16	12091	$1.461x10^8$	$1.767x10^{12}$	$2.136x10^{16}$
2004	20.18	13153	$1.730x10^8$	$2.275x10^{12}$	$2.992x10^{16}$
2005	23.15	14343	$2.057x10^8$	$2.950x10^{12}$	$4.232x10^{16}$
2006	26.51	15499	$2.402x10^8$	$3.723x10^{12}$	$5.770x10^{16}$
2007	29.33	16509	$2.725x10^8$	$4.499x10^{12}$	$7.428x10^{16}$
2008	32.70	17915	$3.209x10^8$	$5.749x10^{12}$	$1.030x10^{17}$
2009	35.43	19417	$3.770x10^8$	$7.320x10^{12}$	$1.421x10^{17}$
2010	37.84	21143	$4.470x10^8$	$9.451x10^{12}$	$1.998x10^{17}$
$\sum$	$2.5496x10^2$	$1.514x10^5$	$2.410x10^9$	$4.017x10^{13}$	$6.967x10^{17}$
	X_1^5	X_1^6	YX_1	YX_1^2	YX_1^3
2001	$1.113x10^{20}$	$1.137x10^{24}$	$1.576x10^5$	$1.610x10^9$	$1.645x10^{13}$
2002	$1.695x10^{20}$	$1.884x10^{24}$	$1.806x10^5$	$2.007x10^9$	$2.230x10^{13}$
2003	$2.583x10^{20}$	$3.123x10^{24}$	$2.195x10^5$	$2.654x10^9$	$3.209x10^{13}$
2004	$3.936x10^{20}$	$5.177x10^{24}$	$2.654x10^5$	$3.490x10^9$	$4.591x10^{13}$
2005	$6.070x10^{20}$	$8.706x10^{24}$	$3.320x10^5$	$4.762x10^9$	$6.831x10^{13}$
2006	$8.943x10^{20}$	$1.386x10^{25}$	$4.108x10^5$	$6.367x10^9$	$9.868x10^{13}$
2007	$1.226x10^{21}$	$2.024x10^{25}$	$4.841x10^5$	$7.993x10^9$	$1.319x10^{14}$
2008	$1.845x10^{21}$	$3.305x10^{25}$	$5.858x10^5$	$1.049x10^{10}$	$1.880x10^{14}$
2009	$2.760x10^{21}$	$5.359x10^{25}$	$6.879x10^5$	$1.335x10^{10}$	$2.593x10^{14}$
2010	$4.225x10^{21}$	$8.933x10^{25}$	$7.999x10^5$	$1.691x10^{10}$	$3.575x10^{14}$
$\sum$	$1.249x10^{22}$	$2.301x10^{26}$	$4.123x10^6$	$6.965x10^{10}$	$1.220x10^{15}$

Table 15: Calculations for constructing the vector matrix
Source: Computation using Microsoft Excel

The Linear Model:

Table 15 shows the calculations for constructing the matrix. The vector matrix for the linear model is written in the form;

$$\begin{bmatrix} N & \sum X_1 \\ \sum X_1 & \sum X_1^2 \end{bmatrix} \begin{bmatrix} \sum y \\ \sum y X_1 \end{bmatrix} = \begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix}$$

$$\begin{bmatrix} 10 & 1.514\text{x}10^5 \\ 1.514\text{x}10^5 & 2.410\text{x}10^9 \end{bmatrix} \begin{bmatrix} 2.5496\text{x}10^2 \\ 4.123\text{x}10^6 \end{bmatrix} = \begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix}$$

The matrices are;

A= $\begin{bmatrix} 10 & 1.514\text{x}10^5 \\ 1.514\text{x}10^5 & 2.410\text{x}10^9 \end{bmatrix}$; B = $\begin{bmatrix} 2.5496\text{x}10^2 \\ 4.123\text{x}10^6 \end{bmatrix}$ and X = $\begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix}$

The unknown parameters (regression coefficient) α and β_1 are calculated by solving the simultaneous equations (Ref equation 3 and 3a) using inverse matrix. That is;

AX = B and X = A^{-1} B

$$10\alpha + 1.514\text{x}10^5\beta_1 = 2.5496\text{x}10^2 \quad (3)$$

$$1.514\text{x}10^5\alpha + 2.410\text{x}10^9\beta_1 = 4.123\text{x}10^6 \quad (3a)$$

Calculating the detriment of the matrix (A);

$$Det\ (A) = \left[[10\ x\ 2.410\text{x}10^9] - \left[1.514\text{x}10^5 x 1.514\text{x}10^5\right]\right]$$

$$Det\ (A) = \left[[2.410\text{x}10^{10}] - [2.292\ \text{x}10^{10}]\right]$$

$$Det\ (A) = 1183618072.24$$

$$Det\ (A) = 1.183\ \text{x}10^9$$

Calculating minor (M_{11}) and the cofactor (C_{11}) of matrix (A)

$$M11 = |2410569919.24|$$

$$M11 = |2.410\text{x}10^{9}|$$

$$C11 = [(-1^{1+1})x\ |2.410\text{x}10^{9}|]$$

$$C11 = 2410569919.24$$

$$C11 = 2.410\text{x}10^{9}$$

Calculating minor (M_{12}) and the cofactor (C_{12}) of matrix (A)

$$M12 = |151400.4|$$

$$M12 = \left|1.514\text{x}10^{5}\right|$$

$$C12 = \left[(-1^{1+2})x\ \left|1.514\text{x}10^{5}\right|\right]$$

$$C12 = |-151400.4|$$

$$C12 = -1.514\text{x}10^{5}$$

Calculating minor (M_{22}) and the cofactor (C_{22}) of matrix (A)

$$M12 = |10|$$

$$C12 = [(-1^{2+2})x\ |10|]$$

$$C12 = 10$$

The cofactors written as a matrix;

$$C = \begin{bmatrix} 2.410\text{x}10^{9} & -1.514\text{x}10^{5} \\ -1.514\text{x}10^{5} & 10 \end{bmatrix}$$

Transposing the cofactor matrix;

$$C^{T} = \begin{bmatrix} 2.410\text{x}10^{9} & -1.514\text{x}10^{5} \\ -1.514\text{x}10^{5} & 10 \end{bmatrix}$$

$$A^{-1} = \frac{C^{T}}{Det\ (A)} = \left[\frac{1}{Det\ (A)}\right] x [C^{T}]$$

$$A^{-1} = \frac{C^{T}}{Det\ (A)} = \left[\frac{1}{1.183\ \text{x}10^{9}}\right] x \begin{bmatrix} 2.410\text{x}10^{9} & -1.514\text{x}10^{5} \\ -1.514\text{x}10^{5} & 10 \end{bmatrix}$$

$$A^{-1} = \frac{C^T}{Det\ (A)} = \begin{pmatrix} \left[\frac{1}{1.183\ \text{x}10^9}\right][2.410\text{x}10^9] & \left[\frac{1}{1.183\ \text{x}10^9}\right][-1.514\text{x}10^5] \\ \left[\frac{1}{1.183\ \text{x}10^9}\right][-1.514\text{x}10^5] & \left[\frac{1}{1.183\ \text{x}10^9}\right][10] \end{pmatrix}$$

$$A^{-1} \approx \begin{pmatrix} 2.037 & -1.27\ x\ 10^{-4} \\ -1.28\ x\ 10^{-4} & 8.45\ x\ 10^{-9} \end{pmatrix}$$

$X = A^{-1} B$

$$\begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix} = \begin{bmatrix} 2.037 & -1.27\text{x}10^{-4} \\ -1.27\text{x}10^{-4} & 8.45\text{x}10^{-9} \end{bmatrix} \begin{bmatrix} 254.96 \\ 4123912 \end{bmatrix}$$

$$\begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix} = \begin{bmatrix} 2.037\ x\ 254.96 + & (-1.27\text{x}10^{-4})x4123912 \\ -1.27\text{x}10^{-4}x\ 254.96 + & 8.45\text{x}10^{-9}\ x\ 4123912 \end{bmatrix}$$

$$\begin{bmatrix} \alpha \\ \beta_1 \end{bmatrix} = \begin{bmatrix} 519.254412402052 - & 527.502925692388 \\ -0.0326127548145217 + & 0.0348415807152681 \end{bmatrix}$$

$$\alpha = -8.24851329033607$$

$$\beta_1 = 0.00222882590074637$$

$$\alpha \approx -8.2485$$

$$\beta_1 \approx 2.2288x10^{-3}$$

$$Y = \alpha + \beta_1 X_1$$

$$Y = -8.2485 + 2.2288x10^{-3} X_1 \qquad (3b)$$

The figures in table 15 and the calculations shown above are presented in the form of scientific notation for enhancing the readability. However, the calculations were done using an excel sheet with the exact figures without rounding off. This was done to ensure the accuracy of the final answer derived. The same process of solving the simultaneous equations were used in the 2nd order polynomial regression shown below. Once the matrix is formed to derive the simultaneous equations, they can also be solved by techniques other

than the inverse matrix used in this study. In this study, solving the higher order polynomials was done using software applications available online.

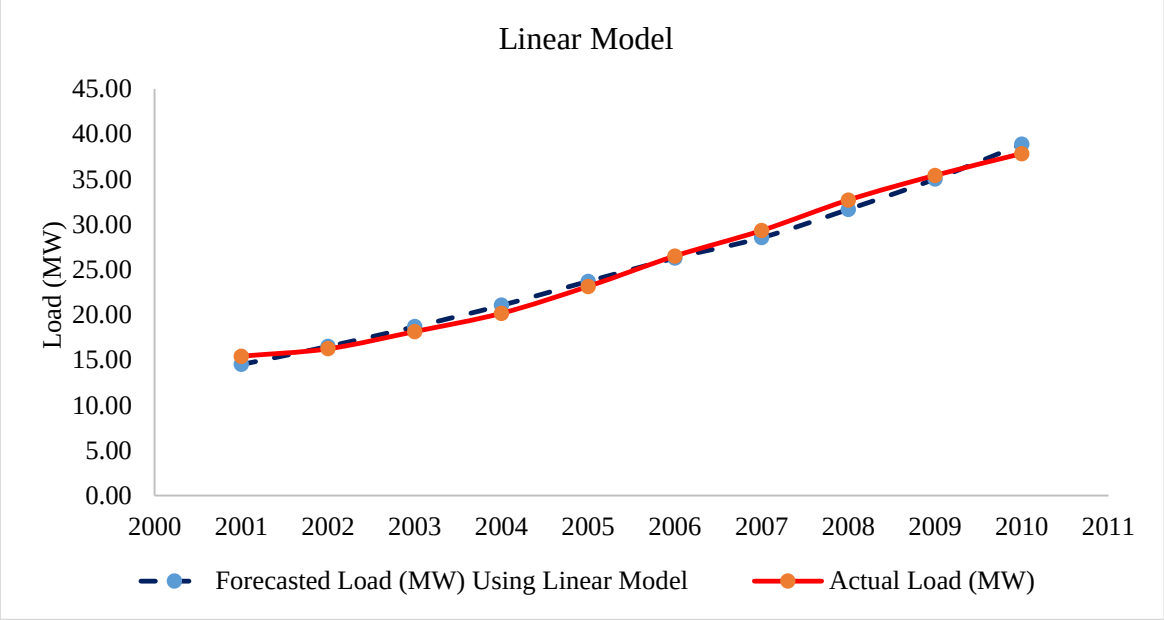


Figure 9: Linear Model fit with actual data (3b)
Source: Plotted using Microsoft Excel

	Linear Regression Model using customer as variable					
Year	**Actual Load (MW)**	**Forecasted Load (MW)**	**Error**	**Absolute Error**	**Percentage Error**	**Absolute Percentage Error [APE]**
2001	15.43	14.53	0.904718	0.904718	0.058634	0.058634
2002	16.25	16.53	-0.275514	0.275514	-0.016955	0.016955
2003	18.16	18.70	-0.544491	0.544491	-0.029988	0.029988
2004	20.18	21.07	-0.890652	0.890652	-0.044140	0.044140
2005	23.15	23.72	-0.569345	0.569345	-0.024593	0.024593
2006	26.51	26.30	0.210724	0.210724	0.007950	0.007950
2007	29.33	28.55	0.781127	0.781127	0.026634	0.026634
2008	32.70	31.68	1.020119	1.020119	0.031196	0.031196
2009	35.43	35.03	0.401192	0.401192	0.011324	0.011324
2010	37.84	38.87	-1.037877	1.037877	-0.027432	0.027432
Mean Absolute Deviation[MAD]			**0.6636**			
Mean Absolute Percentage Error [MAPE]			**2.79%**			

Table 16: MAPE Calculation for Linear Model (3b)
Source: Calculations using Microsoft Excel

Figure 9 shows the linear model fit of the data and figure 10 shows the predictions made using this model. Table 16 shows its MAPE calculation for comparison with that obtained from the linear model using the XL software (see Table 13) in the previous section.

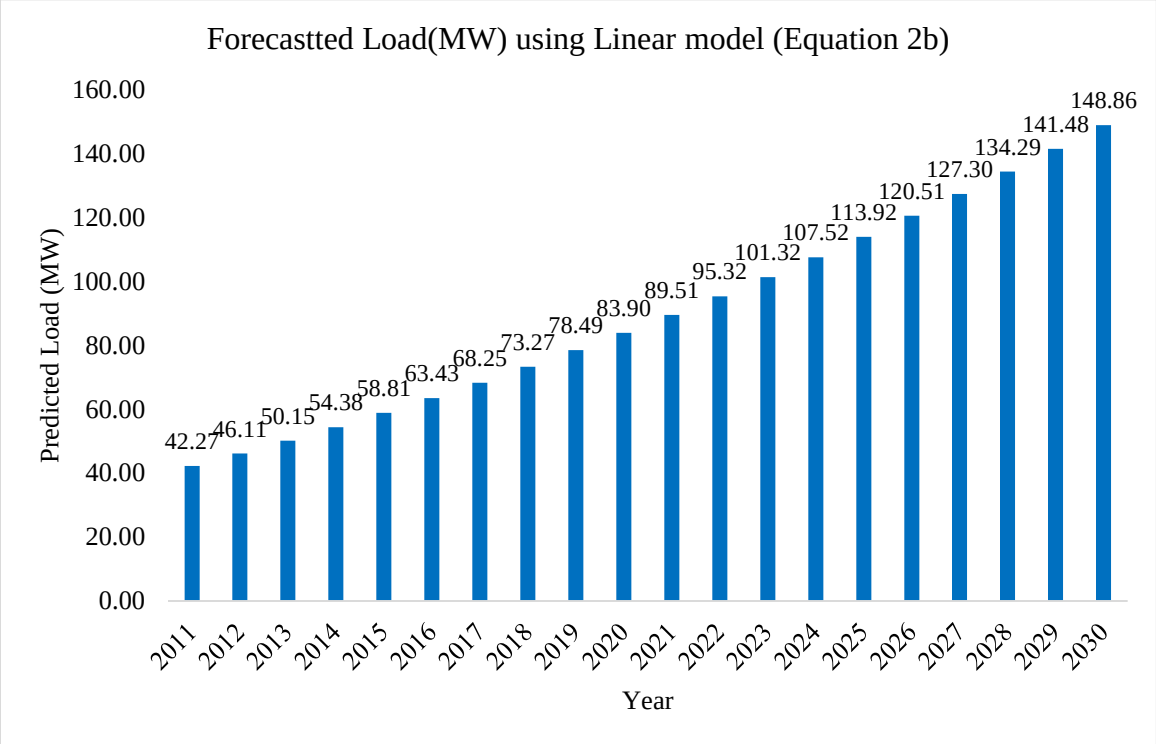


Figure 10: Predicted Load (MW), (2011-2030) using the linear Model (3b)
Source: Computation using the linear Model (Equation 3b)

The Polynomial Model:

The prediction made using equations 2a and 3b are the same indicating the results achieved from the MS XL software are indeed reliable. For comparison and further validation of the forecasts made using the linear model, the relationship between the electricity demand (Y) and the independent variable (X_1) is modelled at higher order polynomial for observing the nonlinear phenomena. The vector matrix for the 2nd order polynomial is written as;

$$\begin{bmatrix} N & \sum X_1 & \sum X_1^2 \\ \sum X_1 & \sum X_1^2 & \sum X_1^3 \\ \sum X_1^2 & \sum X_1^3 & \sum X_1^4 \end{bmatrix} \begin{bmatrix} \sum y \\ \sum y X_1 \\ \sum y X_1^2 \end{bmatrix} = \begin{bmatrix} \alpha \\ \beta_1 \\ \beta_2 \end{bmatrix}$$

$$\begin{bmatrix} 10 & 15.14x10^4 & 24.1057x10^8 \\ 15.14x10^4 & 24.1057x10^8 & 40.1774x10^{12} \\ 24.1057x10^8 & 40.1774x10^{12} & 69.6744x10^{16} \end{bmatrix}$$

$$\begin{bmatrix} 254.96 \\ 41.239x10^5 \\ 69.651x10^9 \end{bmatrix} = \begin{bmatrix} \alpha \\ \beta_1 \\ \beta_2 \end{bmatrix}$$

The matrices are;

A= $\begin{bmatrix} 10 & 15.14x10^4 & 24.1057x10^8 \\ 15.14x10^4 & 24.1057x10^8 & 40.1774x10^{12} \\ 24.1057x10^8 & 40.1774x10^{12} & 69.6744x10^{16} \end{bmatrix}$

B=$\begin{bmatrix} 254.96 \\ 41.239x10^5 4123912.46 \\ 69.651x10^9 \end{bmatrix}$

X=$\begin{bmatrix} \alpha \\ \beta_1 \\ \beta_2 \end{bmatrix}$

Solving for the unknown parameters;

AX = B and X = A^{-1} B

$10\alpha + 15.14x10^4\beta_1 + 24.1057x10^8\beta_2 = 254.96$ (4)

$15.14x10^4\alpha + 24.1057x10^8\beta_1 + 40.1774x10^{12}\beta_2 = 41.239x10^5$ (4a)

$24.1057x10^8\alpha + 40.1774x10^{12}\beta_1 + 69.6744x10^{16}\beta_2 = 69.651x10^9$ (4b)

A^{-1}= $\begin{bmatrix} 47.26111277 & -0.006248101 & 1.96781x10^{-7} \\ -0.006248101 & 8.36688x10^{-7} & -2.6630x10^{-11} \\ 1.96781x10^{-7} & -2.66301x10^{-11} & 8.56232x10^{-16} \end{bmatrix}$ X = A^{-1} B

$$\begin{bmatrix}\alpha\\ \beta_1\\ \beta_2\end{bmatrix} = \begin{bmatrix}47.26111277 & -0.006248101 & 1.96781x10^{-7}\\ -0.006248101 & 8.36688x10^{-7} & -2.6630x10^{-11}\\ 1.96781x10^{-7} & -2.66301x10^{-11} & 8.56232x10^{-16}\end{bmatrix}\begin{bmatrix}254.96\\ 41.239x10^{5}\\ 69.651x10^{9}\end{bmatrix}$$

$$\alpha = -10.8286454254012$$

$$\beta_1 = 0.00257799265671537$$

$$\beta_2 = -1.12266667539132 \text{ x } 10^{-08}\alpha$$

$$\alpha \approx -10.8286$$

$$\beta_1 \approx 2.57799x10^{-3}$$

$$\beta_2 \approx -1.12267x10^{-8}$$

$$Y = \alpha + \beta_1 X_1 + \beta_2 X_1^2$$

$$Y = -10.8286 + 2.57799x10^{-3}X_1 + (-1.12267x10^{-8})X_1^2 \quad (4c)$$

The above modelling of the same historic data at higher (2nd order) polynomial (see Figure 11 for the 2nd order polynomial fit and table 17 for its MAPE calculation) indicates load forecasting using polynomial models does not always produce reliable results (see Fig 12, for prediction made using this model). This is because, as highlighted by [39] the polynomial fit has more parameters and tends to fit the noise within the data. This is the case for electricity demand in Male'. The polynomial forecasts, sees a levelling of demand even though the population continues to rise. Consequently this model was rejected and will not be discussed further.

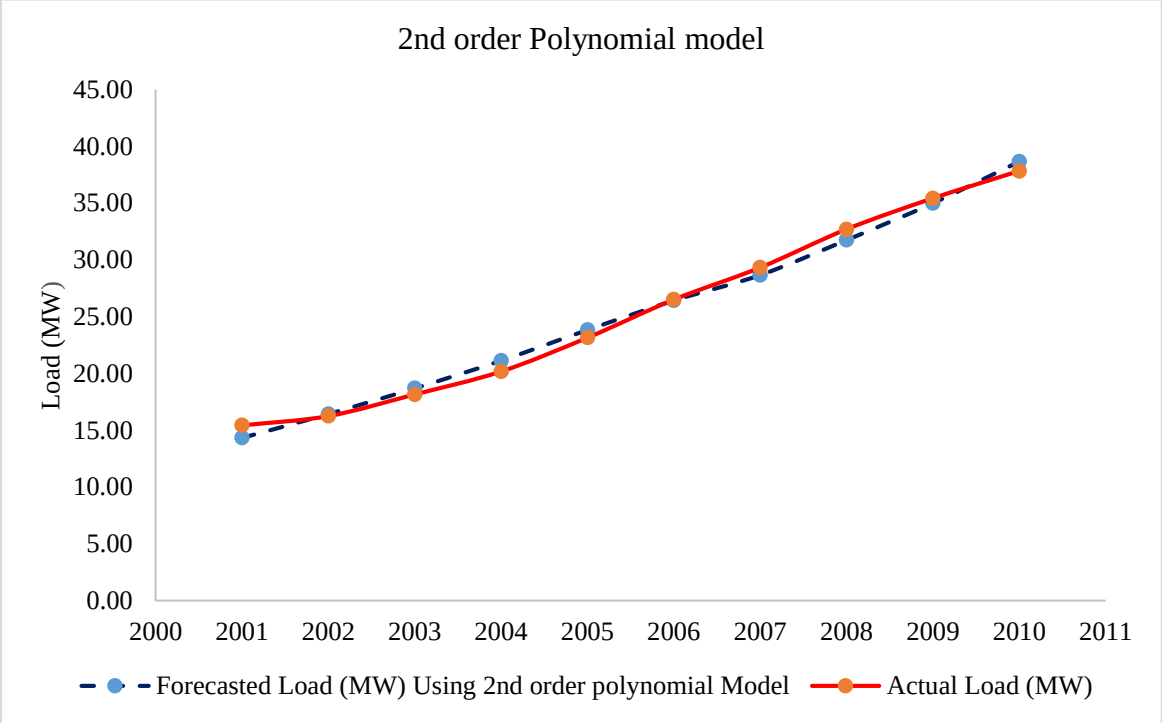


Figure 11: 2nd order Polynomial Model fit with actual data (4c)
Source: Plotted using Microsoft Excel

	2nd order Polynomial Regression Model					
Year	**Actual Load (MW)**	**Forecasted Load (MW)**	**Error**	**Absolute Error**	**Percentage Error**	**Absolute Percentage Error [APE]**
2001	15.43	14.34	1.092312	1.092312	0.070791	0.070791
2002	16.25	16.44	-0.186847	0.186847	-0.011498	0.011498
2003	18.16	18.70	-0.542895	0.542895	-0.029900	0.029900
2004	20.18	21.14	-0.959463	0.959463	-0.047550	0.047550
2005	23.15	23.84	-0.686935	0.686935	-0.029672	0.029672
2006	26.51	26.43	0.076196	0.076196	0.002875	0.002875
2007	29.33	28.67	0.656360	0.656360	0.022380	0.022380
2008	32.70	31.75	0.947075	0.947075	0.028963	0.028963
2009	35.43	35.00	0.432439	0.432439	0.012206	0.012206
2010	37.84	38.66	-0.824236	0.824236	-0.021785	0.021785
Mean Absolute Deviation[MAD]			**0.6405**			
Mean Absolute Percentage Error [MAPE]			**2.78%**			

Table 17: MAPE Calculation for 2nd order Polynomial Model (4c)
Source: Calculations using Microsoft Excel

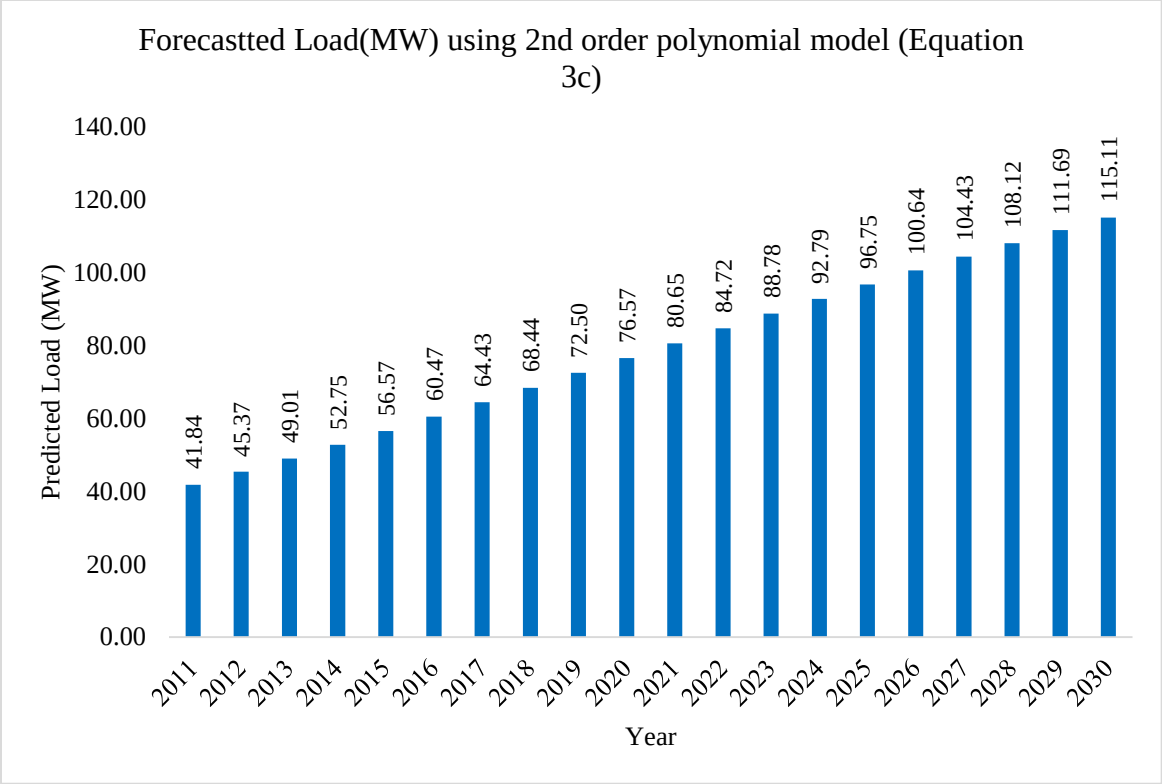


Figure 12: Predicted Load (MW), (2011-2030) 2nd order Polynomial Model (4c)
Source: Computation using the 2nd order Polynomial Model (4c)

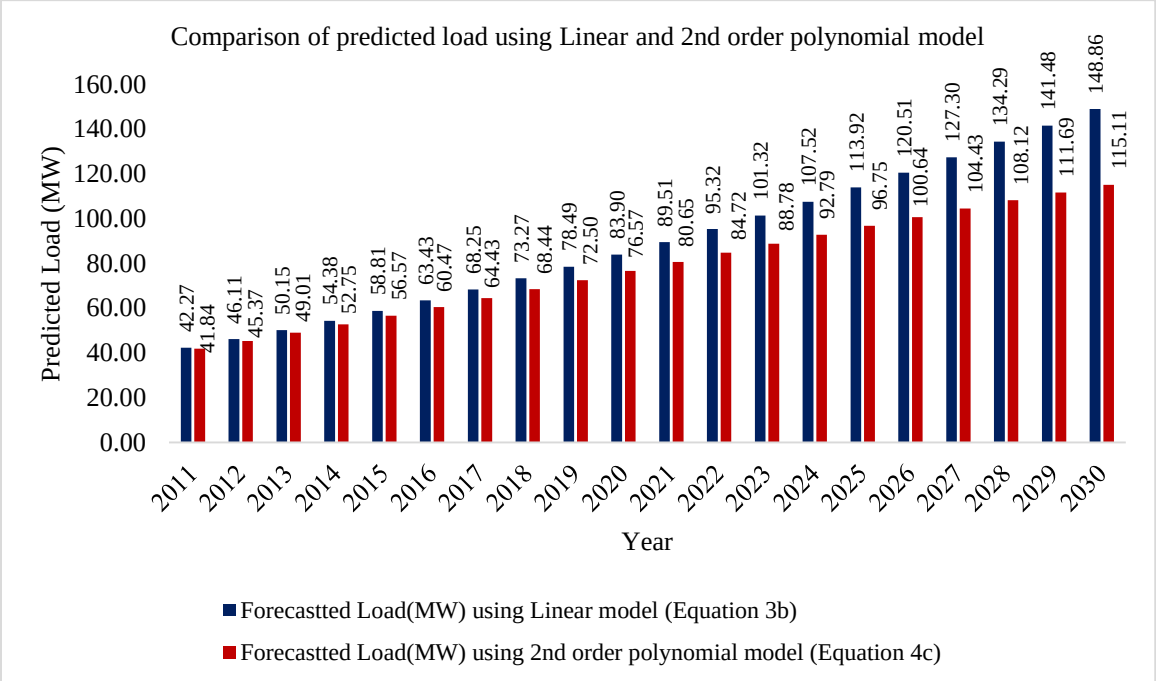


Figure 13: Comparison of Predicted Load (MW), (2011-2030) using the Linear and 2nd order Polynomial Model (3b and 4c)
Source: Computation using the linear and 2nd order Polynomial Model (3b and 4c)

Figure 13 shows a comparison of the predictions made using the linear and the 2nd order polynomial model. To investigate the possible reason leading to the trend observed with polynomial modeling and for verification of the model that produces the most reliable prediction, the forecasts for the same period was done using the same powerful software for electric load forecasting, GMDH Shell. Figure 14 shows the results plotted and table 18 shows the calculated MAPE.

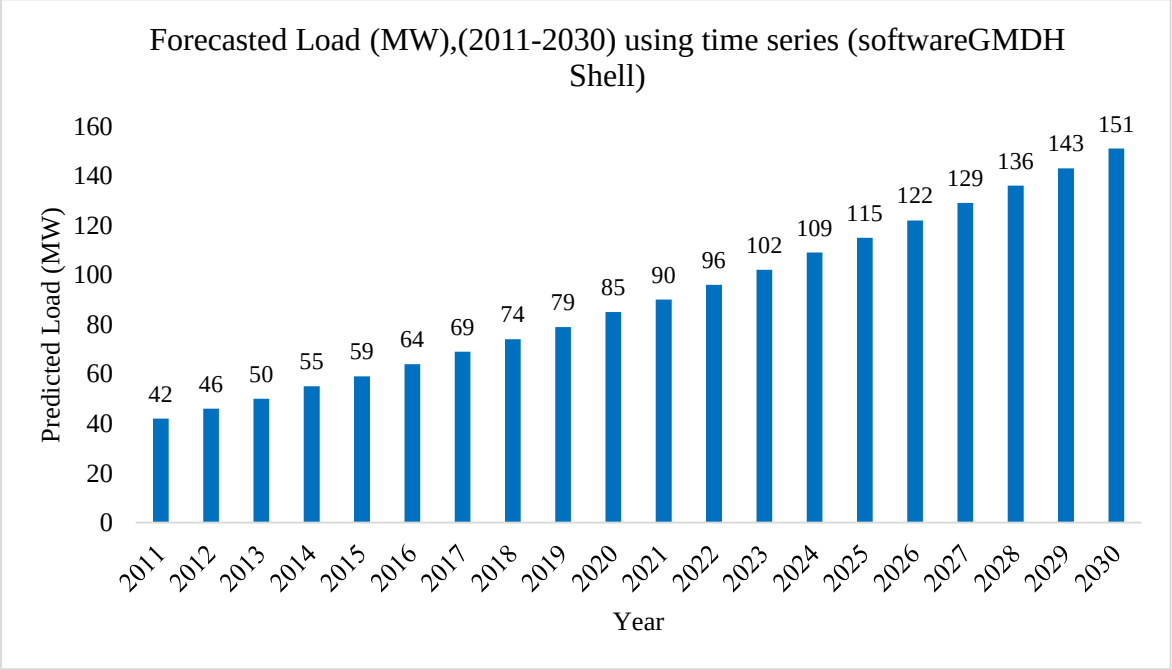


Figure 14: Predicted Load (MW), (2011-2030) using the Software GMDH Shell.
Source: Computation using Software GMDH Shell

	Times Series Model using GMDH Shell Software					
Year	**Actual Load (MW)**	**Forecasted Load (MW)**	**Error**	**Absolute Error**	**Percentage Error**	**Absolute Percentage Error [APE]**
2001	15.43	15.00	0.430000	0.430000	0.027868	0.027868
2002	16.25	17.00	-0.750000	0.750000	-0.046154	0.046154
2003	18.16	19.00	-0.843000	0.843000	-0.046428	0.046428
2004	20.18	21.00	-0.822000	0.822000	-0.040737	0.040737
2005	23.15	23.00	0.151000	0.151000	0.006522	0.006522
2006	26.51	26.00	0.507000	0.507000	0.019127	0.019127
2007	29.33	29.00	0.328000	0.328000	0.011184	0.011184
2008	32.70	32.00	0.700000	0.700000	0.021407	0.021407
2009	35.43	35.00	0.428000	0.428000	0.012081	0.012081
2010	37.84	39.00	-1.165000	1.165000	-0.030792	0.030792
Mean Absolute Deviation[MAD]			**0.6124**			
Mean Absolute Percentage Error [MAPE]			**2.62%**			

Table 18: MAPE Calculation for predictions made using the software GMDH Shell
Source: Computation using Software GMDH Shell

The 3rd order Polynomial model produced unacceptable results and hence it was concluded that with the data used in this study, the linear model produced reliable predictions as seen in figure 8 and 10. This was then further validated by comparison of the actual load for the years 2011-2015 (see Fig: 15), provided by STELCO. These data were not available at the initial stage of this research.

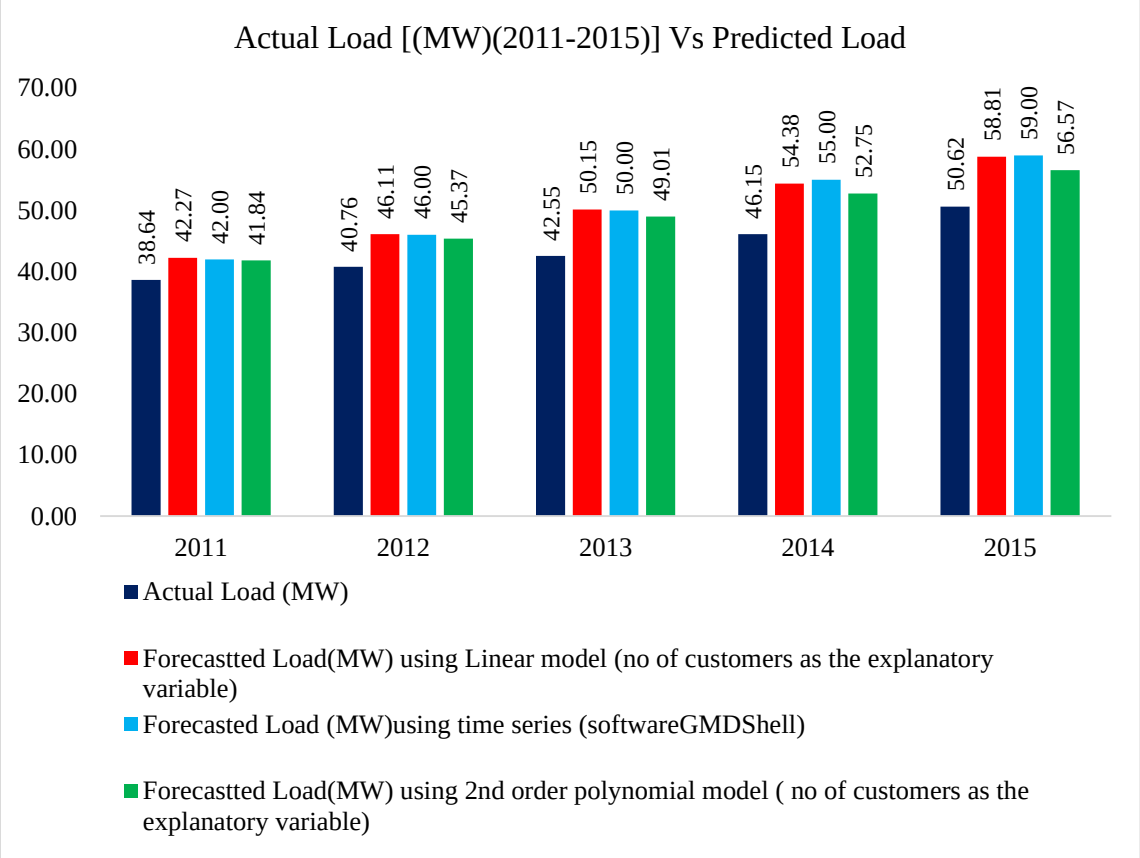


Figure 15: Actual Load vs. Predicted Load (MW), (2011-2015)
Source: Primary Data from STELCO and Computation using the Software, the Linear and the 2nd order Polynomial Model

4.2.6 Results and Discussion

Accurate and reliable long-term forecasts provide crucial information to the service provider for investment plans, ensuring sustainability of their services. The time horizon considered for the prediction of the future growth is a crucial element due to the uncertainties that could occur. In this respect, the accuracy of the predictions made in this study would change if the rate of increase in electricity consumption by customers of domestic category falls down in the years ahead. However, this is an unlikely scenario, since the migrants from smaller islands are inevitable to increase unless the national development plan considers developing few other cities in larger islands. The process of

regressing the data and hypothesis testing on the individual independent variables detailed, justifies that only one variable (X_1= The number of customers in the domestic category) qualified as a strong explanatory variable of predicting the future growth of electricity in Male'. However, this does not indicate the consumption by the government and businesses are insignificant. Rather, it reflects the reality of high consumption by the domestic customers, which represents close to half the population of the country. The congested city of Male' is now home for over 153,904 residents as per the census records of 2014. This is about 42% of the entire population of the country which is just 366 972. (Data that was available later).

The predictions made from both the Linear and the 2nd order Polynomial Model suggests either of the models could be used in this study since there is no significant difference in the model fit (See Fig 7, 9 &11) and MAPE calculated. (See Tables, 13, 16 & 17). Nonetheless, the Linear Model is chosen over the Polynomial Model in this study since long term prediction made using the 2nd order polynomial model show a decreasing trend in future demand compared to the linear model (See Fig 13) and the higher order polynomials starting from 3rd order produced unacceptable results. This confirms the findings of [39] which indicates polynomial and non-linear models are more susceptible to noise leading to poor forecasts in the long term. The comparison of the predictions from the linear model to that from the GMDH Shell software further justifies the linear model produced better results in this study. And their comparison to the actual load on the grid which was received at later stage (see Fig: 15) justifies these predictions are indeed accurate

and reliable. Furthermore, the process of constructing the models detailed above, allows exploring which model produces the best results.

4.3 Summary of Chapter 4

To ensure the proposed DGPV system in this study serves a practical solution to deploy solar energy to STELCO grid, accurate prediction of the future demand on STELCO grid was given high priority in this study. The future demand on STELCO grid have been predicted by modelling the historic data of 10 years using multiple regression. The hypothesis tests on the independent variables proved that only the number of customers in the domestic category qualify as a strong explanatory variable to predict the future demand. This reflects the significantly high consumption by the domestic customers, which represents close to half the population of the country, compared to the Businesses and government offices blocks, indicating there is little dependence of the electrical load on the number of users in these two categories. The predictions made from both the Linear and the 2nd order Polynomial Model proved, the linear model produced better and more reliable results in this study. Hence the linear model was chosen over the polynomial model to predict the future demand. The decision was made after careful comparison of the results obtained from both the models to the predictions made using the powerful software for electric load forecasting, the GMDH shell which uses time series for electric load forecasting. It was further validated by comparison with the actual measured load on the grid for the years 2011-2015.

CHAPTER 5

SYSTEM MODELING, SIMULATION AND OPTIMIZATION

5.1 SYSTEM MODELING, SIMULATION AND OPTIMIZATION

HOMER[14] [11] has been used to model and simulate the proposed system in this research. HOMER can model off-grid as well as grid connected hybrid systems. Grid connected PV systems are generally of two types. The Distributed Grid-connected Photovoltaic (DGPV) and Building Integrated Photovoltaic (BIPV) system. With the results of the experimental projects referred in the literature reviewed, the government of Maldives has recently started implementing BIPV systems using the roofs of the government buildings.

Inspired by the governments' initiative and considering the abundance of solar energy available in the country, the proposed DGPV system in this research has been modelled with consideration given to Renewable Fraction (RF) that is financially viable. The main reason being, it has not been done in the previous research [3]-[20-21], despite it being a crucial measure that allows decisive decision making in investment planning. The proposed system has been modelled with no storage, injecting all the power produced by the PV system to the grid of STELCO. Though, a large system of such capacity has not been designed and implemented in the Maldives to date, the governments' initiative to

[14] The Hybrid Optimization of Multiple Energy Resources (HOMER) is software widely used in modeling micro power systems with Renewable Energy Sources that facilitate the comparison of power generation technologies across a wide range of applications. It is developed by the U.S. National Renewable Energy Laboratory (NREL).

deploy RETs nationwide, has been considered as an indication for the requirement of such a system. Considering the severe land constraints in Maldives, the availability of the required land for the proposed system and the sunlight as a source was identified by contacting the relevant authorities, STELCO, the Housing Development Cooperation (HDC) and the Department of Meteorology. Equal importance has been given in determining the amount of energy the system can deliver to the grid and sizing the system arrays and inverters without compromising the safety measure of the system components. This has been done by applying the design guidelines of Australia and New Zealand [30] to the results of HOMER.

Based on the information received from STELCO and HDC, part of the land from Hulhumale' industrial zone is allocated for building a PV farm. Thus, the proposed system has been designed with the assumption that, the infrastructure could be built in this land. The industrial zone in Hulhumale' is a site where maximum solar irradiation can be obtained in Maldives since the site is bare reclaimed land with no trees and exposed to sun throughout the day. Hence the site serves as the ideal location for establishing the proposed system.

The design of a hybrid power systems can be challenging when dealing with uncertainties such as the future demand in load, the cost of fuel, tariff rates and the renewable sources. It is said [11] that, HOMER is designed to overcome such challenges, allowing system designers to analyze various situations that might be of concern and need to be accounted for, in the system modelling [11].

The major uncertainty in modelling the proposed system in this research was, dealing with the expected future growth in the electric demand. As addressed in the previous chapter, the electricity demand in Male' is incomparable to any other island in the Maldives and forecasting the future demand in Male' posed a real challenge in this research. However, the long term forecasts made in this study, have been proven to be accurate, and the proposed system has been modelled taking these forecasts into account. The uncertainties, minimum Renewable Fraction (RF) that could be delivered to the grid, the increase in electricity demand and possible changes in the grid rate of STELCO were included in the simulation by considering them as sensitive variables. The RF is the fraction of energy produced by the PV plant that is being delivered to the grid. This facilitates a deep insight into the required size of the plant, the required size of land to build that plant and the economic feasibility of the system.

In the simulation process, the electric demand for each hour of the year is compared to the energy that the system can supply, calculating the flow of energy to and from each component of the system. It then determines if the system is feasible based on its life cycle cost which represents the cost of installing and operating the system over its' life time. HOMER considers the life cycle cost as a convenient metric [11] for comparing the economics of different system configurations. In this respect, the system optimization process involves identifying the system configuration that can meet the demand under all constraints at the lowest NPC. Thus, the modelling process ensures the system can meet

the demand while taking into account all the constraints and the availability of resources as well as the variation in costs of technology.

5.1.1 The Load Profile

The load profile is one of the most important data in modelling the system, since it determines the system configuration required to meet the load under the given constraints.

One of the most common approach of hybrid system modelling using HOMER is, to use annual hourly load data as the load profile [43-46]. Another option HOMER allows is doing a sensitivity analysis on the load profile to account for the increase in demand. HOMER allows this to be done by using a scaling factor it calculates based on the annual average loads that the system designer enters as sensitivity variables [11]. Thus, in this research, the longs terms forecasts have been used as sensitivity variables in the simulation, because the predictions represents the expected average annual peaks . This effects the magnitude of the load data without effecting its' shape while the random day to day variability effects the shape of the load profile without effecting the magnitude of the load data [11]. This means the random day to day variability and the scaling applied together in the simulation, would produce the expected future load profile in terms of peaks and seasonal patterns [11]. This is one of the most powerful features of the software that allows the system designer to carefully account for the increase in future demand. Thus, in this study, the simulation has been done by applying both the random day to day variability and the scaled annual averages. The measured hourly load data of the year 2010 have been used

as the load profile allowing HOMER to do a sensitivity analysis by using the long term forecasts made. HOMER allows [11] this to be done by calculating the average of the hourly load of each month of the year (see Appendix 1). These data was not available at the initial stage of this research.

5.1.2 Dealing with the uncertainties (Sensitivity analysis)

The sensitivity analysis is one of the most powerful features of HOMER that allow the software to account for uncertainties such as the increase or decrease in demand, grid rates and fuel price and other similar factors that may effect the performance of the system. It determines how sensitive the outputs of the system would be in response to changes in these variables, allowing the system designer to make informed decisions. In this design the increase in demand (ie, the forecasted load for 2011-2030), the possible changes in grid rate of STELCO (based on the information obtained from STELCO) and the RF have been considered as the sensitive variables as they are the key factors that would determine if the proposed system is technically sound. To obtain the highest possible reliability of the optimal system configuration, the project life was set to a period of 20 years (considering the forecasts made for 20 year) with 10 possible changes in grid rates during this period and the RF ranging from 5%-10%. This is also, the range of RF given in HOMER system modelling guide [11], though HOMER allows it to be increased beyond this range. In this study, the 10% limit of RF takes into account the serious land constraints in Male' and Hulhumale'. Going beyond the RF of 10% in the simulation runs have no practical use because of the land constraints.

In previous designs using HOMER [43-46], the project life was always set to a period of 25 years. This is the default value set by HOMER. However, the software allows the system designer to change the project life to obtain higher accuracy depending on the factors that could affect the performance of the system. In this study, it was set to 20 years since the 20 years' demand forecasts were used as sensitivity variables to determine the optimal system configuration to cater for this load. The results further contributed to the study when the economic feasibility of the system was analysed.[15] The results of the sensitive analysis are discussed in section 6.1.12, " Discussion on Simulation Results".

5.1.3 System Components

For the simulation of the proposed system, PV modules and the Grid have been used as generating sources and inverters used to convert the DC power produced by the PV modules to AC power. A storage system has not been modelled since the PV system is to be directly connected to the grid of STELCO. However, modelling a storage should be considered in the future work, if adequate land space could be available for building larger PV plants.

[15] The financial model developed and used for assessing the economic feasibility was a replication of HOMER cash flow model with additional feature of allowing additional investment required during project life time as the load increases. This represents the exact cash flow stream during the project life time that determines the Net Present Value of the project.

5.1.4 PV Array

The modules used in this study are Mono crystalline PV modules with rated power of 300Wp. The PV Array has been modelled as a source that produces DC electricity in direct proportion to the solar irradiation that falls on it. The output power of the array depends on the solar irradiation and temperature the panel is exposed to. In reality, the output also depends strongly and non-linearly on the voltage (the voltage at which the power output is maximized) it is exposed to [11]. Therefore in standard practice, a Maximum Power Point Tracker (MPPT) should always be placed between the PV array and the other DC components of the system to decouple the array voltage from that of the other components of the system. If the MPPT is not installed and the PV array is directly connected to the other DC components, then the PV system would be often exposed to a voltage different from the MPPT and the performance will suffer. Hence in the simulation, HOMER assumes that a MPPT is present in the system [11]. Furthermore, this has also been taken into account by applying the design guidelines [30] to the simulation results.

Similarly consideration has also been given to the fact that the output of the array would also be effected by the environmental condition of the site where the system is installed. Hence the effect of dust, manufacturers' tolerance and the effect of temperature on the PV modules have been taken into account in the simulation. This is known as de-rating the modules for possible losses. The de-rating factor of 76% [11][16] used in this

[16] The de-rating factor is a scaling factor meant to account for effects of dust on the panel, wire losses, elevated temperature, or anything else that would cause the output of the PV array to deviate from that expected under ideal conditions. HOMER allows the user to reduce the de-rating factor to (crudely) correct for this effect when modeling systems for hot climates [11]

simulation, has been derived from the manufacturers' data and applying the design guideline [30]. The details of how the de-rating factor has been calculated is presented in the next chapter, where the design guidelines [30] has been applied to the results obtained from the simulation. In addition, the temperature coefficient of power of -0.45% / °C, the nominal operating cell temperature of 45°C and the cell transfer efficiency of PV modules of 15.4% at Standard Test Condition (STC), have been used in the simulation, to account for the effect of temperature. These data were obtained from the technical specification of the PV modules provided by the manufacturer.

HOMER calculates the power output of the PV array using the equation (5).

$$P_{PV} = f_{PV} Y_{PV} \frac{I_T}{I_S} \quad (5)$$

Where

$f_{PV} =$ The de − rating factor

$Y_{PV} =$ The rated capacity of the PV array in (kW)

$I_T =$ The solar irradiance on the PV array in $(\mathrm{kW/m^2})$ And

$I_S =$ The solar irradiance on the PV array under standard test condition, $(1\mathrm{kW/m^2})$

The software calculates the output power from the array using solar irradiance on the PV modules for 8760 hours of the year by taking into account the solar resource data and the average temperature for every month of the year entered. In this study, the solar irradiance on the site was obtained from the well-known software RETSCREEN which is

linked to global database of NASA. The average solar irradiance obtained from this data (see Table 19 and Appendix 1) is exactly the same as that obtained from the Department of Meteorology of Maldives. The data on average temperature used in the simulation was obtained from the Department of Meteorology of Maldives. No tracking was used in the simulation since the array is proposed to be built horizontal to the ground, allowing maximum exposure to the sun throughout the day. HOMER does not have a specific input window for DC and AC system losses. However, the system designer may increase the de-rating factor to include these losses if known. In this study, these losses are being taken into account by applying the design guideline presented in the next chapter.

5.1.5 The Grid

In modelling DGPV systems, HOMER recommends [11] the grid be modelled as a source that has the capacity to compensate for any deficiency. HOMER recommends [11] this to be done by specifying the maximum grid capacity much higher than the system peaks. Further, when no demand rate is applied, HOMER recommends [11] applying a single value for the maximum grid capacity. Similar to the size of the PV array, the maximum grid capacity is decision variable[17], whose optimal value is determined during the course of optimization process. In this work, the grid capacity was limited to 250MW.

[17] As defined in HOMER modelling guide [11], a decision variable is a variable whose optimal value is determined during the course of the optimization process. An example is the size of the PV array. HOMER considers each different PV array size specified and finds the value that results in the least net present cost.

This takes into account, STELCO would be required to increase the grid capacity to cater the increase in demand over the next 20 years. The predicted load on the grid by the year 2030 reaches 150MW and the simulation has been done with an additional capacity of 100MW to the maximum predicted load. This additional capacity of 100 WM was chosen after repetitive simulation and assessing the results to see the system is able to cater for the predicted load on the grid with no capacity shortages, under the constraints applied. (See Appendix 2, for details of important extracts from simulation results). By setting the maximum grid capacity to 250MW[18], the system modelling considers the predicted future load of 2011-2030, as the minimum demand (i.e. the primary load) the system must cater for without any capacity shortage, and the grid capacity as the maximum power that can be drawn from grid to cater for it. As a result, HOMER calculates the optimal size of the PV array, within the range of RF specified, considering the maximum power that can be drawn from the grid is 250MW. (See Appendix 2, for details of important extracts from simulation results).

In addition, an implicit assumption was also made on the grid capital cost, which essentially represents the one time interconnection charge to the grid. If the PV farm is to be funded by a third party, STELCO would most likely charge this one time interconnection charge. However, the current policy of STELCO is to fund the PV farm by themselves via loans. The information on the possible charge for this interconnection could not be obtained from STELCO. Therefore the interconnection charge was set to zero in the simulations. Hence, with the exclusion of this cost, the cash flow for the grid over the

[18] The maximum grid capacity of 250MW is proposed here, since the proposed system is modelled, ensuring no capacity shortages in serving the load throughout the project period of 20 years.

project life time comes from its operation and maintenance (O&M)[19]. In a DGPV system the operational and maintenance cost is represented by the annual cost of buying electricity from the grid. No demand rate has been applied in the simulation since the PV system is to inject all its energy to the STELCO grid. Further, since STELCO does not have a demand rate charged at present, assumptions on possible rates that could be applied, can lead to unrealistic result. The present grid rate (Cost of Energy (COE) in $/kWh, STELCO charges) have been used in the analysis with a range of values (obtained from STELCCO) that are likely to represent the changes in the future. These values have been used as sensitivity variables to account for its impact on the investment cost and future COE.

The assumption above is important in assessing the financial feasibility of the proposed system that would reflect a clear understanding of the possibility of implementation and adaptation of the proposed system. This entire process takes into account the constraints such as maximum annual capacity shortages that could be allowed, the minimum RE fraction that the system is to take into account in the simulation and optimization process, the capital costs of the system components, its operational and maintenance costs and salvage values of the remaining life of the system components at the end of the project life time. This in particular enhances the understanding of the financial feasibility of the system.

[19] The O&M of the grid is calculated by the rate at which power is purchased from the grid and the amount of power that is required to be purchased in order to cater for the shortages. This is the most important part of the system optimization in HOMER simulation since HOMER compares economics of the systems by the rate at which power is produced from the PV array to that of purchasing in order to obtain the lowest NPC which determines the optimal system configuration.

5.1.6 Inverter

The inverter used in this study is K-Star GSL series inverter with a rated output power of 500 kW. This is a product of a well-known manufacturer for high quality products from Singapore. Consideration have been given to inverters with MPPT since they serve the need of having a Maximum Power Point Tracker installed in the system, preventing the array being exposed to a voltage different from the MPPT voltage, causing the system to underperform. Similar to PV module sizes, multiple values ranging from 100 kW to 300 MW was used in the simulation allowing HOMER to determine the optimal system architecture with no capacity shortages in serving the load at the given RE fractions. Based on the results of the simulation, the 500 kW inverter was chosen after careful sizing of the PV array, as per the design guidelines [30], ensuring an efficient DGPV system is being modelled. A comprehensive explanation of the system sizing without compromising any safety measures of array and the inverter, is presented in the next chapter.

5.1.7 Resource allocation

In modelling the proposed system, solar energy have been used as the renewable resource. This takes into consideration that it has been ranked [3] as the highest potential source to transform the energy sector of Maldives.

Country/Region	Republic of Maldives
Province/State	
Climate Data Location	Male'
Latitude	4.2°N
Longitude	73.5°E
Month	Daily Solar radiation/Horizontal (kWh/m^2/day)
Jan	5.84
Feb	6.63
Mar	6.96
Apr	6.39
May	5.49
Jun	5.20
Jul	5.37
Aug	5.63
Sep	5.75
Oct	5.96
Nov	5.39
Dec	5.31
Annual Average	5.82

Table 19: Average Solar radiation for Male' (kWh/m2/day) Supplied to HOMER
Source: RETSCREEN software data base linked with NASA

For HOMER to simulate solar power generation, the average solar irradiance data of the location, the latitude and the longitude is required as input data. Table 19[20], shows

[20] The RETSCREEN is a free clean energy software package developed by the Government of Canada. The software integrates a number of databases to assist the user, including a global database of climatic conditions obtained from 6,700 ground-based stations and NASA's satellite data. (Source: http://en.wikipedia.org/wiki/RETScreen).The Solar data in this

the average monthly solar irradiance of the Male' and Hulhumale'. During the simulation process, HOMER generates an hourly solar irradiance profile representing 8760 hours of the year [11].

5.1.8 Simulation

The simulation of different system configuration is the fundamental aim of HOMER allowing a good understanding of how a particular system configuration or a combination of system components of specific sizes would perform within a specific time frame under specified conditions or constraints [11]. In modelling hybrid power systems, it allows reliable and informed decision making, such as the PV system sizing, consideration of alternative renewable sources and investment planning. However, the degree by which the results of the simulation represents reality, is dependent on the accuracy of the information used as key input data. In this respect, the capital cost of the system components, their relevant technical data and the operational and maintenance costs are highly important information that were carefully obtained from the manufacturers. The capital cost of PV modules used in this simulation is derived from cost information obtained from the Renewable Energy Maldives Pvt Ltd, which is the only company that supplies RE systems in Maldives. Information was also obtained from suppliers from Singapore and China. However, priority was given to the costs obtained from the Maldivian

project was taken from the data base of this software since it is linked to the NASA satellite data and proved to be more accurate than the primary data provided by the Department of Metrology in the Maldives. During Simulation HOMER continuously gave error suggesting that the data provided by the Department of Metrology did not match the longitude and latitude of the location and exceeded the amount of solar radiation that falls on the given location, Male and Hulhumale. Thus simulation was not possible with this data.

supplier since they are familiar with the commercial operating environment of the Maldives (For example, geographic remoteness). In addition, the cost provided by the Renewable Energy Maldives Pvt Ltd includes transportation, supply, installation and commissioning of the system in any location in the Maldives. The capital cost for the inverter is derived from cost information provided by the supplier from Singapore, as the Renewable Energy Maldives Pvt Ltd imports them from Singapore. The capital cost for each component is calculated as a summation of all costs involved [11]. The details of this and the technical data of the system components can be found in the appendix 1 and 4

5.1.9 System Optimization

In the simulation, HOMER analyses the operation or performance of the system configuration over a time with conditions or constraints applied [11]. HOMER does so, by performing a time series analysis on the operation of the specific system configuration over one year [11]. During the analysis, the software steps through each hour of the year, analyzing and calculating the energy yield from the renewable sources [11]. The analysis also includes the amount of energy used from the grid, under the circumstances where there is deficiency from the renewable source [11]. In this study, this represents a significant amount of energy since the PV farm required to be limited to the available land. In the optimization process HOMER simulates multiple system configuration, searching for the best configuration that meets the load requirement based on the constraints and the dispatch strategy specified by the system designer [11]. The software then produces a list of system configurations that meets the requirement under the set constraints and ranks them based

on the Net Present Cost (NPC) [11]. It ranks the system configuration with the lowest NPC, as the most optimal system configuration.

In modelling the proposed system in this research, the dispatch strategy was set to "Load Flowing" so that all energy produced by the PV array would be directly delivered to the grid. The performance of the system was analyzed by doing a sensitivity analysis.

5.2 The sensitivity analysis

The sensitivity analysis allows the system designer to have a good understanding of the consequences or impact of parameter variations on the performance of the system.

In this research, the grid rates, the minimum RF that the PV system should deliver to the grid and the expected increase in the electricity demand have been considered as sensitive variables since these variables have a high chance of varying over the project period. The annual interest rate, the temperature and the maximum annual capacity shortage too could be considered as sensitive variables. However, the information obtained from STELCO revealed that establishment of an infrastructure such as the proposed system is likely to be part of their future investment and that all such investments in the past have been financed by loans with fixed interest rates. The temperature in the Maldives is within the range of 28 -32 °C and so was not included in the list of sensitive variables. The annual capacity shortage allowed was set to 5%. No sensitivity analysis were performed on the annual capacity shortages since the modelling was aimed at identifying the system

configuration with minimum or no capacity shortage in serving the primary load. The optimal system configuration that served the load with no capacity shortage was then chosen as the optimal system. It is the system configuration with the lowest NPC as well.

5.2.1 Discussion on the Results of Simulation

The analysis on the data obtained for this research, the high increase in electricity demand in Male' posed a real challenge in terms of the size of the system required. Identifying the constraints that could possibly prevent such an infrastructure being built in Maldives was given high priority because it reflects the degree at which solar energy can be deployed to transform the energy sector of Maldives. The analysis presented in chapter four clearly indicated that Male' should be considered as the starting point for such a transformation. Should the proposed design in this study be implemented, it would serve as the key turning point in transforming the energy sector of Maldives. Considering the land constraints and with the size of a PV modules used in this research occupying an area of 1.6 m^2, the maximum capacity of the proposed system was seen required to be limited to 20 – 30 MW occupying a minimum area of 106,666.67 m^2– 160,000 m^2. This is equivalent to 26.36 – 39.54 Acre. The total land area of Hulhumale' at present is 465 acre and the amount of land that would be reclaimed in the 2nd and 3rd phase of this ongoing project is yet to be seen. However, according to the information provided by the Housing Development Cooperation (HDC), a total area of 40 to 50 Acre from the industrial zone is to be allocated for a PV farm. In fact, STELCO has already informed via public press conference held in 2010 that they aim to establish a PV farm of 20 MW to be connected to

their grid. The same was confirmed from the company at the initial stage of obtaining the required data for this research. Thus, this study assumes an area of 40-50 acre would be available to build the proposed PV farm in Hulhumale'.

Table 20-22, shows important extracts from the optimal system architecture given by HOMER for the years, 2010, 2020 and 2030 and table 23 shows the minimum land area required to build the infrastructure. The optimal system architecture of all 20 years considered in the simulation, is included in the appendix 2.

Extracts from HOMER simulation result					
System Architecture for 2010					
Source	**Capacity**	**Unit**			
PV	7500	kW			
Grid	250	MW			
Inverter	5000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	11,120,579	5	AC Primary Load	216,953,840	100
Grid	206,026,304	95	Total	216,953,840	100
Total	217,146,883	100			
Quantity	**kWh/year**	**%**			
Excess electricity	82,162	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			

Table 20: Extracts from HOMER simulation for the system configuration of 2010
Source: HOMER Simulation

Extracts from HOMER simulation result					
System Architecture for 2020					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	5	AC Primary Load	481,951,392	100
Grid	452,607,808	95	Total	481,951,392	100
Total	482,262,604	100			
Quantity	**kWh/year**	**%**			
Excess electricity	15,471	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			

Table 21: Extracts from HOMER simulation for the system configuration of 2020
Source: HOMER simulation

Extracts from HOMER simulation result					
System Architecture for 2030					
Source	**Capacity**	**Unit**			
PV	30,000	kW			
Grid	250	MW			
Inverter	20000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	44,482,316	5	AC Primary Load	855,061,184	100
Grid	811,350,912	95	Total	855,061,184	100
Total	855,833,228	100			
Quantity	**kWh/year**	**%**			
Excess electricity	328,880	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	4158.00	0.00			

Table 22: Extracts from HOMER simulation for the system configuration of 2030

Source: HOMER simulation

Year	PV Array Size (MW)	Minimum Land required (Acre)
2010	7.5	9.88
2020	20	26.36
2030	30	29.54

Table 23: Size of PV farm and the minimum land area required for the system of 2010, 2020 and 2030
Source: Calculation made using results of HOMER simulation

Table 21-23 shows, the size of the PV farm being carefully limited to the land available, ensuring no unmet load is left while maintaining a minimum RF of 5%. This has been done to ensure that the proposed system is practically implementable. The following section, "Discussion on Sensitivity Analysis" explains how this is being achieved by allowing HOMER, do a sensitivity analysis within the set constraints.

5.2.2 Discussion on Sensitivity Analysis

In this research, the high increase in electricity demand and the land constraints have been considered as the most important issues to be addressed in the system design. This was deemed essential, to ensure the proposed system is a technically sound, practical solution to cater part of the increasing load on the national grid at a minimum RF of 5%.

<table>
<tr><th colspan="3">Sensitivity Variables used in the simulation</th></tr>
<tr><td>Grid Rate (US$ / kWh)</td><td>Forecasted Load (MW)</td><td>Minimum RF (%)</td></tr>
<tr><td>0.25</td><td>42</td><td>5%</td></tr>
<tr><td>0.26</td><td>46</td><td>6%</td></tr>
<tr><td>0.28</td><td>50</td><td>7%</td></tr>
<tr><td>0.3</td><td>54</td><td>8%</td></tr>
<tr><td>0.32</td><td>59</td><td>9%</td></tr>
<tr><td>0.34</td><td>63</td><td>10%</td></tr>
<tr><td>0.36</td><td>68</td><td rowspan="14">Note: The minimum renewable fraction (RF) is being chosen after careful evaluation of the circumstances and constraints at present. A minimum RF ranging from 5%-10% is seen to be used in other similar studies referred in the literature review as well as system modelling guide of HOMER recommends it.</td></tr>
<tr><td>0.38</td><td>73</td></tr>
<tr><td>0.4</td><td>78</td></tr>
<tr><td>0.42</td><td>84</td></tr>
<tr><td rowspan="10">Note: The expected change in grid rates are based on the information provided by STELCO head office.</td><td>89</td></tr>
<tr><td>95</td></tr>
<tr><td>101</td></tr>
<tr><td>108</td></tr>
<tr><td>114</td></tr>
<tr><td>120</td></tr>
<tr><td>127</td></tr>
<tr><td>134</td></tr>
<tr><td>141</td></tr>
<tr><td>149</td></tr>
</table>

Table 24: Sensitivity variables used in the simulation
Source: Information obtained from STELCO and forecasts made in this research

Table 24, shows the sensitive variables used in this simulation. The purpose of the sensitivity analysis in this simulation was to;

1- Identify the energy yield that can be obtained from the maximum size of the PV plant that can be built in Hulhumale'.
2- Identify the portion of the total load on the grid that the proposed system can serve.
3- Study the impact of increasing the renewable penetration in comparison with the possible increase in grid rates and electricity demand in future.
4- Study the limitations of the annual increment to the system in future, considering the land constraint and changes in the grid rate.
5- Derive a technically sound system configuration and its energy yield under the set constraints, which would serve as the key factor for investment planning.

When the forecasted load is used as a sensitivity variable, HOMER scales the hourly annual load data of the base year (2010 in this study) so that its' magnitude increases by the scaling factor calculated by HOMER, using the forecasted load and the load profile of the base year. The load profile created for each year under question also carry the random day to day variability applied by the system designer. This powerful feature of HOMER is similar to running separate simulations with exact annual hourly load profiles for each of those years, provided the data is available (see Appendix 1 for a comparison of separate simulation with measured load and that predicted for the years 2011-2015) and Appendix 3 for important extracts from the sensitivity analysis). It is said in HOMER modelling guide [11], that HOMER uses a complex algorithm with multiple mathematical

functions to create the said load profile for each year under question. Analysis of this complex algorithm falls beyond the scope of this work.

Several simulations were done in the initial stage of this research, to study the process of optimization and the sensitivity analysis and how the sensitivity analysis could be applied in the design of the proposed system. In this respect, the sensitivity analysis has been used beyond dealing with uncertainties such as possible changes in the grid rates, but rather, it has been applied to analyses trade-offs such as the amount of investment that would be required for adding capacity to the system and the energy yield that could be expected in each of the years throughout the project period.

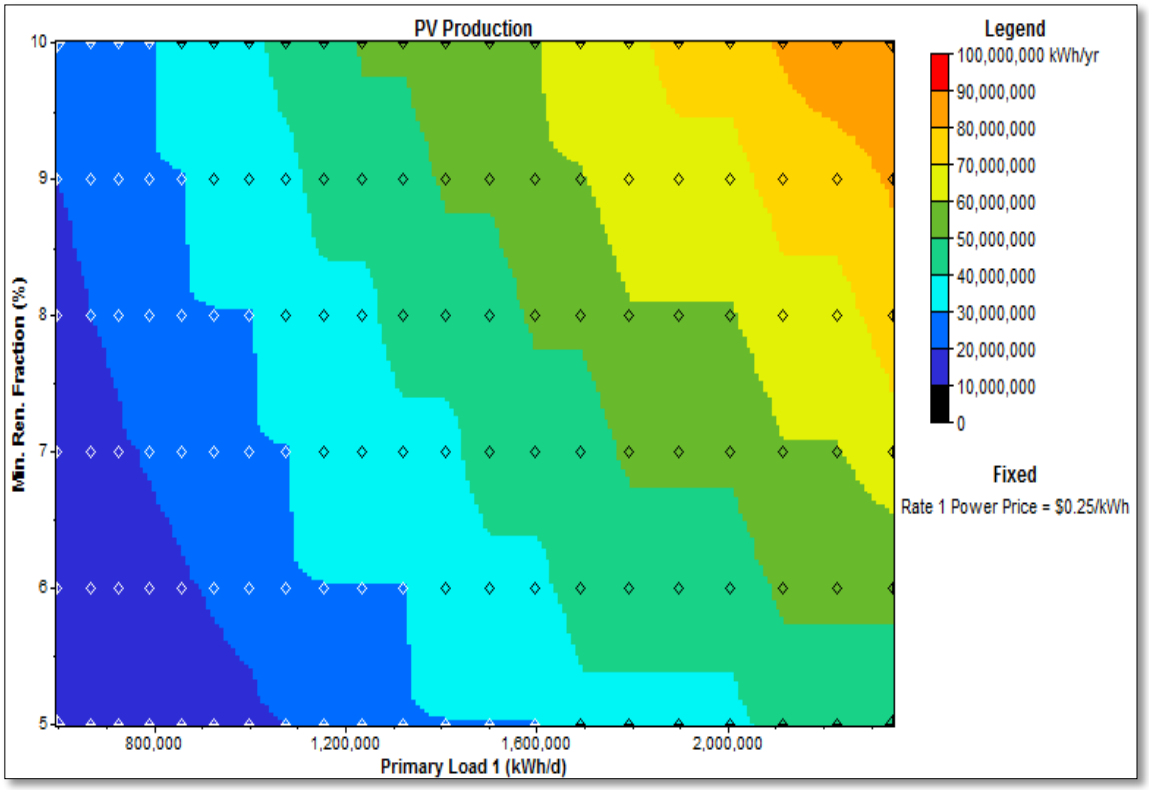


Figure 16: Plot from sensitivity analysis representing the energy from PV vs. the minimum RF applied
Source: HOMER simulation result

Figure 16, shows a plot of the sensitivity analysis, showing the effect of system performance or energy produced by the PV system, within the range of RFs applied in this simulation. Tables 25-29 shows, these important results derived from the sensitivity analysis summarized and tabulated to enhance the readability.

Year 2011				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	8500	5%	12,603,287
	6	10000	6%	14,635,023
	7	12000	7%	17,482,928
	8	13500	8%	19,667,778
	9	20000	12%	29,654,796
	10	20000	12%	29,329,388
0.4	5%-8%	14500	9%	21,196,474
0.42	5%-10%	35000	21%	50,823,552

Table 25: Important extracts from the sensitivity analysis for the load of 2011
Source: HOMER simulation results

Year 2015				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	12000	5%	17,792,882
	6	14000	6%	20,758,406
	7	20000	9%	29,654,796
	8	20000	9%	29,654,796
	9	25000	11%	37,068,548
	10	25000	11%	37,068,548
0.4	5%-10%	30,000	13%	44,482,316
0.42	5%-10%	45000	20%	66,723,320

Table 26: Important extracts from the sensitivity analysis for the load of 2015
Source: HOMER simulation result

Year 2020				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	6%	29,654,796
	6	20000	6%	29,654,796
	7	25000	8%	37,068,548
	8	30000	9%	44,482,316
	9	30000	9%	44,482,316
	10	35000	11%	51,895,896
0.4	5%-9%	30000	9%	44,482,316
0.42	5%-10%	65,000	20%	96,378,272

Table 27: Important extracts from the sensitivity analysis for the load of 2020
Source: HOMER simulation results

Year 2025				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	25000	6%	37,068,548
	6	30000	7%	44,482,316
	7	35000	8%	51,895,896
	8	40000	9%	59,309,592
	9	45000	10%	66,723,320
	10	45000	10%	66,723,320
0.4	5%-10%	45000	10%	66,723,320
0.42	5%-10%	95,000	21%	140,860,400

Table 28: Important extracts from the sensitivity analysis for the load of 2025.
Source: HOMER simulation results

Year 2030				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	30000	5%	44,482,316
	6	35000	6%	51,895,896
	7	45000	8%	66,723,320
	8	50000	9%	74,137,096
	9	55000	10%	81,550,984
	10	60000	10%	88,964,632
0.4	5%-10%	65000	11%	96,378,272
0.42	5%-10%	120,000	21%	177,929,264

Table 29: Important extracts from the sensitivity analysis for the load of 2030

Source: HOMER simulation results

With the sensitivity analysis, HOMER steps though each of the sensitivity variables shown in table 24, analyzing its impact on the performance of the system. That is, with each grid rate, Homers' algorithm checks the amount of energy that can be produced by the PV (with the applied RF), without any capacity shortage, (i.e., serving 100% of the load for each year under consideration). It checks, the economics of increasing the PV penetration in comparison with the grid rates applied, leaving no unmet load. In this study, since limiting the PV farm to 30 MW is given priority, the results are analyzed, to compare the amount of PV penetration that can be achieved within the grid rates applied.

Careful observation of these results reveal, from 2011- 2020, the plant can be operated with a RF of 5%-9% delivering up to 43.7 GWh/ year, serving 9% of the total load on the grid for the year 2020. Further, it shows that this can be achieved with a PV plant not exceeding 30MW which is the maximum size of PV plant considered in this study. Furthermore, it reveal, this can be achieved within the grid rates of US$ 0.25 to 0.38 / kWh; (1US$ = MVR 15.42) per kWh. For the load of year 2020, the plant capacity is seen to be 35MW, if the system is to serve at a minimum RF of 10%. This does not affect the decision in terms of investment planning, since the target farm capacity is to be maintained at a maximum of 30MW, serving the load at a minimum RF of 5%.

With grid rates starting from US$ 0.40/kWh and above, it is seen that the farm capacity exceeds 30MW. This is where HOMER considers adding more PV capacity to the system, informing the economic merit of the proposed system configuration is still

maintained. This applies to all the years under consideration, with the exception of 2011 where a farm capacity of 14.5 MW is attainable with the grid rate of US$ 0.40/kWh. This is due to the small load on the grid for the year 2011. Another exception from the above observation is, the farm capacity exceeding 30MW, (i.e. 35MW at RF 10%) for the load of the year 2020, serving 11% of the load, with grid rates ranging from US$0.25-US$0.38 per kWh. It should be noted that, the percentage of load taken over by the PV system is higher than the RF due to the discrete sizing of the inverters. Again, these two exceptions do not represent a significant difference in terms of investment planning because only the case of 2020 with an RF of 10% exceeds the farm capacity by 5MW (i.e., for the 10 year period of 2011-2020). The important information derived from the above observation is that, within grid rates of US$0.25-US$0.38 per kWh, the farm capacity can be well maintained within 30 MW with the PV penetration of 5%-9% for 10 successive years. The information is crucial for investment planning.

The most important matter assessed with this sensitivity analysis is, the uncertainty whether the farm capacity can be maintained at 30MW throughout the project period of 20 years and yet serve the increasing demand at a minimum RF of 5% and assess the range of grid rates within which, this can be achieved. (See Appendix 3 for extracted information for all 20 years). Table 30 below shows the required farm capacity and the energy yield throughout the project period indicating that indeed, this can be achieved.

Additionally, the analysis also shows, despite the increase in demand, the farm capacity can be maintained at a maximum of 20MW from year 2019 to 2023, and at 25MW from 2023 to 2028 and yet serve the load at a minimum RF of 5% (see Table 30). Consequently, no additional investment would be required to expand the plant capacity during the period, 2019-2023 and 2024-2028. This information is considered essential for decision making and investment planning.

Year	PV Capacity (kW)	RF	Energy Yield (kWh/year)	% of Load served
2011	8500	5%	12,333,241	5%
2012	9500	5%	13,726,611	5%
2013	10000	5%	14,519,937	5%
2014	11000	5%	15,916,022	5%
2015	12000	5%	17,484,644	5%
2016	12500	5%	18,253,002	5%
2017	13500	5%	19,670,476	5%
2018	15400	5%	21,078,634	5%
2019	20000	5%	29,342,370	5%
2020	20000	5%	29,342,934	6%
2021	20000	5%	29,343,514	6%
2022	20000	5%	29,344,116	5%
2023	20000	5%	29,344,740	5%
2024	25000	5%	35,717,368	6%
2025	25000	5%	35,718,032	6%
2026	25000	5%	35,718,712	5%
2027	25000	5%	36,693,932	5%
2028	25000	5%	43,710,376	6%
2029	30000	5%	43,711,128	5%
2030	30000	5%	43,711,892	5%

Table 30: Important extracts from the sensitivity showing the size of PV farm, % of RF, Energy yield and % of load served (2011-2030)
Source: HOMER simulation results

5.3 Summary of Chapter 6

The data analysis in chapter four and the prediction of future demand on STELCO grid in chapter five, clearly indicated, Male' should be considered as the starting point, if the government is to deploy RETs at large scale to transform the energy sector of the country. The proposed system in this research has been carefully modelled to serve this purpose, identifying the constraints that could possibly prevent such an infrastructure being built in Maldives. HOMERs powerful feature of sensitivity analysis have been used in the simulation to analyze the performance of the system under the set constraints and the uncertainties. The renewable fraction attainable with possible changes in the grid rates in future, leaving no unmet load, were the most important parameter variations considered in the simulation. It was necessary to ensure sizing of the proposed PV farm to be limited to the maximum size that can be built in Hulhumale'. The most important matter assessed with the sensitivity analysis, was the uncertainty whether the farm capacity can be maintained at 30MW throughout the project period of 20 years and yet serve the increasing demand at a minimum RF of 5% and assess the range of grid rates within which, this can be achieved. The results reveal, this can be well achieved (see Table 30). Further, the results revealed, within grid rates ranging from US$0.25-US$0.38 per kWh, the farm capacity can be well maintained within 30 MW (the maximum size that can be built in Hulhumale') with the PV penetration of 5%-9% for 10 successive years, delivering an energy yield of up to 43.7 GWh /year. This is 6 - 9% of the total load on the grid for the year 2020. With grid rates starting from US$ 0.40/kWh and above, the farm capacity exceeded 30MW, with two exceptional cases of 2011 and 2020 highlighted in section 6.1.12. Further, the analysis

also reveal, despite the increase in demand, the farm capacity can be maintained at a maximum of 20MW from year 2019 to 2023, and at 25MW from 2023 to 2028 and yet serve the load at a minimum RF of 5% (see Table 30) indicating, no additional investment would be required to expand the plant capacity during the period, 2019-2023 and 2024-2028.

CHAPTER 6

APPLYING SYSTEM DESIGN GUIDE LINES TO THE SIMULATION RESULTS

6.1 APPLYING SYSTEM DESIGN GUIDELINE OF AUSTRALIA AND NEW ZEALAND, [AS/NZS 5033] TO THE SIMULATION RESULTS

The proposed DGPV system in this research can be designed using a powerful software like HOMER or by manual methods such a Sizing Algorithm using Iterative Manual Approach (SAIMA) [47]. With SAIMA, the system designer chooses PV modules and Inverters from a list and matches their characteristic. The algorithm is used for computing the PV array size taking into consideration the electrical characteristics of the PV modules and the inverter, attempting to match their operational requirements [47]. Once the PV system is matched with the inverters' operational requirements without compromising the safety measures of the PV and the inverter, the designer considers it as the optimal system configuration [47].

This is similar to the system modelling using HOMER, detailed in the previous chapter. With HOMER, the iteration is done by the software in the simulations, calculating the optimal system architecture and ranking them based on the lowest NPC. In this research, HOMER has been considered over manual system design approach since the software is well known for its powerful features that accounts for uncertainties. Regardless of the design approach, the designers' first priority is understanding the amount of the energy the system should deliver and to optimize the system configuration that can deliver the required output.

Considering the large size of the system that would be required over the period for which the load forecasting has been done in this study, a modular system design approach have

been considered in this research allowing informed investment decisions to be made for the expansion of the system based on the future load requirement.

With the results obtained from the simulations, the functional requirement of the system have been assessed in this chapter, to ensure its practicality. This requires application of design standards, rules and regulations of the country where the infrastructure is to be built. Since Maldives is in its infant stage of exploring renewable energy, the country does not have a specific design and installation guideline for such power systems. Thus, in this research, the relevant design guidelines of Australia and New Zealand for grid connected PV systems (AS/NZS 5033) [30][21] have been applied to the results obtained from the simulation. The section below provides a comprehensive explanation of how this has been done.

6.2 DESIGN GUIDE LINES APPLIED TO THE SIMULATION RESULTS

Table 31 below shows the technical data obtained from the manufacturers of the PV modules and the inverter used in the simulation. The complete technical specification of the PV modules and the inverter used in this study can be found in Appendix 4. Table 32, shows the system architecture given by HOMER for 2010.The system architecture of the year 2010 is used here for calculation of the safe operating parameters of the system components in this section since the hourly load data of this year was used in this

[21] The complte book of design guideline (AS/NZS 5033) is available only for paid users, The reference material [30 and 50] are extracts of this document available online for free. The formulas used in this chapter are adopted from these documents and can be found in various materials available online.

simulation. The annual additional capacity requirement of the system (see Table 33 below) reflects the required capacity of the plant to cater for the expected increase in demand for each year ahead, at a minimum renewable fraction of 5%.

PV Modules			
Electrical Characteristics		**Mechanical Characteristics**	
Open - Circuit Voltage (Voc)	45	Solar Cell	Poly-crystalline 156×156mm (6 inch)
Maximum Power Voltage (V)	37.5V	No. of Cells	72 (6×12) matrix connection in series
Short - Circuit Current (Isc)	8.60A	Dimensions	1965×992×45mm
Optimum Operating Current (Imp)	8.00A	Weight	27 kg (59.5 lbs.)
Maximum Power at STC (P(max)	300Wp	Front Glass	4mm(0.16 inch) tempered glass
Operating Temperature	-40ºC to +85ºC	Frame	Anodized aluminum alloy
Maximum System Voltage	1000V DC	Junction Box	IP65 rated
Maximum Series Fuse Rating	14 AMPS	Output Cables	H+S RADOX® SMART cable 4.0mm2 (0.006inch2), symmetrical lengths (-) 1000mm (39.4inch) and (+) 1000mm (39.4inch), RADOX® SOLAR integrated twist locking connectors
Power Tolerance	±3 %	**Central inverter's specifications**	
STC: AM=1.5 irradiance 1000W/m2, Module temperature 25ºC		Max. Input Power (KW)	550
Temperature Coefficients		Input Operating Range (Vdc)	450 to 900; Absolute Max @ 1000
Nominal Operating Cell Temperature (NOCT) ℃	45±2 ℃	MPPT Operating Range (Vdc)	450 to 850; Nominal @ 576
Temperature Coefficient of P (max) %/℃	– 45 ℃	Max. No. of Inputs	24
Temperature Coefficient of Voc %/℃	-0.34ºC	Max. Branch Current (A)	120
Temperature Coefficient of Isc %/℃	0.045%/ºC	Max. Input Current (A)	1030

Table 31: Extracts from the technical specification of the PV module and Inverter
Source: Manufacturers' data

Extracts from HOMER simulation result
System Architecture for 2010

Source	Capacity	Unit			
PV	7500	kW			
Grid	250	MW			
Inverter	5000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	11,120,579	5	AC Primary Load	216,953,840	100
Grid	206,026,304	95	Total	216,953,840	100
Total	217,146,883	100			
Quantity	**kWh/year**	**%**			
Excess electricity	82,162	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	7,500	kW	**Minimum output**	0	kW
Mean output	1,269	kW	**Maximum output**	6,020	kW
Mean output	30,467	kWh/d	**PV penetration**	5.13	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	11,120,579	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	5,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,247	kW	**Energy in**	11,038,444	kWh/yr
Minimum output	0	kW	**Energy out**	10,928,031	kWh/yr
Maximum output	5,000	kW	**Losses**	110,413	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	130,208,624	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	564,512	kg/year			
Nitrogen oxides	276,075	kg/year			

Table 32: System architecture given by HOMER for the load of 2010
Source: HOMER simulation

System configurations		Additional capacity required		
Year		Additional PV Capacity (kW)		

	PV capacity (kW)		No of inverters	Additional Inverters
2011	8500	None	17	None
2012	9500	1000	19	2
2013	10000	500	20	1
2014	11000	1000	22	2
2015	12000	1000	24	2
2016	12500	500	25	1
2017	13500	1000	27	2
2018	14500	1000	29	2
2019	20000	5500	40	11
2020	20000	No additional capacity required	40	No additional inverters
2021	20000		40	
2022	20000		40	
2023	20000		40	
2024	25000	5000	50	10
2025	25000	No additional capacity required	50	No additional inverters
2026	25000		50	
2027	25000		50	
2028	30000	5000	60	10
2029	30000	No additional capacity	60	No additional inverters
2030	30000		60	

Table 33: System configuration for each year and the additional capacity requirement
Source: HOMER simulation

6.2.1 De-rating the PV modules to account for possible power losses

The output power of any PV system is effected by the losses caused by the environmental condition of the site where they are installed. These losses include, power losses due to the dust that gathers on the surface of the PV modules, losses due to the increased operating temperature of the PV modules caused by the cell directly absorbing the solar energy and the losses due to the manufacturers' tolerance. It also varies with the solar irradiation that falls on it and depends on the tilt angle at which the array is installed. These factors were taken into account in the simulation, as explained in the previous

chapter. The design guide lines [30] recommends these losses be taken into account in calculating the output of a DGPV system. They are equally important when sizing the PV array and the inverter. The formulas used in calculating these parameters are adopted from [30].

6.2.2 De-rating due to Manufacturers Output Tolerance

The manufacturers' tolerance given in the technical data (see Table 31) represents the possible variation of the output power from that of its Standard Test Condition (STC). In the modules used in this research, it is given as ±3 % which indicates that the output of the module can be above or below its rated power by 3%. Thus, as per the recommendation of [30] the output of the module require to be de-rated for this variation as;

$$P_{de-rated\_man} = P_{\max\_rated} - P_{loss_{Man\_Tol}} \quad (6)$$

Where;

$P_{de-rated\_man}$ = De − rated power of the module due to manufacturers′tolerance

$P_{\max\_rated}$ = Maximum rated power of the module in Wp

$P_{loss_{Man\_Tol}}$ = Power loss due to the manufacturers′tolerance

With the manufacturers' output tolerance of ±3%; the de-rated power of the module would be;

$$P_{de-rated} = 300 - [(\frac{3}{100}) * 300)]$$

$$P_{de-rated} = 300 * 0.97$$

$$P_{de-rated} = 291\text{Wp}$$

6.2.3 De-rating due to dirt

The de-rating due to the dust that could built on the surface of the module would be dependent on the location where the system is built. Maldives being a tropical country, the amount of dust built up on the surface of the module is likely to be high. As such, an acceptable de-rating factor for dirt, as per the guideline [30] for such locations is 5%. Thus, the output of the module require to be further de-rated to account for this loss as;

$$P_{de-rated\_dirt} = P_{de-rated\_man} - P_{loss\_dirt} \quad (7)$$

Where;

$P_{de-rated\_dirt} = \text{De} - \text{rated power of the module due to dirt}$

$P_{de-rated\_man} = \text{De} - \text{rated power of the module due to manufacturers}'\text{tolerance}$

$P_{loss\_dirt} = \text{Power loss due to the dirt}$

$$P_{de-rated} = 291 - [(\frac{5}{100}) * 291)]$$

$$P_{de-rated\_dirt} = 291 * 0.95$$

$$P_{de-rated\_dirt} = 276.45\ \text{Wp}$$

6.2.4 De-rating due to Temperature

In this research, the temperature effect on the output of the modules has been calculated taking into consideration, the minimum requirement set forth in [30]. That is;

$$T_{cell-eff} = T_{a\ day} + T_{STC} \quad (8)$$

Where;

$T_{cell-eff}$ = The effective cell temperature of the module in °C

$T_{a\ day}$ = The daytime ambient temperature °C

T_{STC} = The cell temperature unders Stnadard Test Condition in°C

Though a rare occurrence, the highest temperature recorded in Hulhumale' where the system is to be built is 40°C. Thus the effective cell temperature of each module of an array installed in Hulhumale' should be estimated as;

$$T_{cell-eff} = T_{a\ day} + T_{STC}$$

$$T_{cell-eff} = 40 + 25$$

$$T_{cell-eff} = 65°C$$

For certain type of installation such as grid connected system, the guideline [30] recommends, the effective cell temperature be calculated using the formula;

$$T_{cell-eff} = T_{a\ day} + T_r \quad (9)$$

Where;

$T_{cell-eff}$ = The effective cell temperature of the module in °C

$T_{a\ day}$ = The daytime ambient temperature

T_r = The effective temperature raise for specific type of installation

The guideline [30] recommends the following temperature raise T_r be used for different array frames;

- Parallel to roof (<150mm standoff): +35°C
- Rack-type mount (>150mm standoff): +30°C
- Top-of-pole mount, free standing frame and frame on roof with tilt angle of about + 20 degrees to slope of roof: +25°C.

Thus for rack-type mount frames, such as the modules used in this research, the effective raise in temperature of the cell would be $T_r = +30°C$. Hence, in this particular circumstance where the ambient temperature may raise to $40°C$, the effective cell temperature of the module would be;

$T_{cell-eff} = T_{a\,day} + T_r$

$T_{cell-eff} = 40 + 30$

$T_{cell-eff} = 70°C$

That is;

$T_{a\,day} = 40°C$ [The expected maximum ambient temperature at the site]

$T_r = 30°C$ [The effective raise in temperature of the cell]

Since the average ambient temperature at site varies between 20°C – 30°C, with a very rare and occasional highest recorded temperature of 40°C, in this study, the maximum effective cell temperature on the module is considered to be 65°C.

The temperature de-rating factor is calculated as follows:

$$T_{temp} = 1 + [\lambda_{\%/°C}\left(T_{cell-eff} - T_{STC}\right)] \quad (10)$$

Where;

T_{temp} = The temperrature de − rating factor, diamensionless

$\lambda_{\%/°C}$ = Value of power temperature coefficient in % per °C

$T_{cell-eff}$ = The daily effective cell temperature in °C

T_{STC} = The cell temperature at statndard test condition in °C

Thus, the temperature de-rating factor is;

$$T_{temp} = 1 + [-0.45\%(65 - 25)]$$

$$T_{temp} = 1 + [-0.45\%(40)]$$

$T_{temp} = 0.82$ [A further loss of 18% from the output of each PV module in the array]

If, the maximum effective cell temperature of 70°C is considered, the temperature de-rating factor would be;

$$T_{temp} = 1 + [-0.45\%(70 - 25)]$$

$$T_{temp} = 1 + [-0.45\%(45)]$$

$$T_{temp} = 0.7975$$

$T_{temp} = 0.80$ [A further loss of 20% from the output of each PV module in the array]

Thus, the de-rated power of the module would be;

$$P_{de-rated\_temp} = [276.45(0.82)]$$

$$P_{de-rated\_temp} = 226.689$$

$P_{de-rated\_temp} = 227$ Wp

Or;

$$P_{de-rated\_temp} = [276.45(0.80)]$$

$P_{de-rated\_temp} = 221.16$

$P_{de-rated\_temp} = 221$ Wp [If a maximum effective cell temperature of 70°C is considered]

Considering the de-rating shown above, the total de-rated output power of the array is calculated using the total number of PV modules that is connected to the array. This require calculation of the optimal array size that can be connected to the inverter. For the proposed system in this study, the total number of PV modules in the array is 1666 (See section 7.6, for details of array sizing). Thus, the total de-rated output power of the array is calculated as;

$P_{de-rated} = 226.689$ Wp x 1666 modules

$P_{de-rated} = [226.689 \text{ x } 1666]/1000$

$P_{de-rated} = 377.663874$ kW

$P_{de-rated} = 377$ kW

Or;

$P_{de-rated} = 221.16$Wp x 1666 modules

$P_{de-rated} = [221 \text{ x } 1666]/1000$

$P_{de-rated} = 368.186$ kW [If a maximum effective cell temperature of 70°C is considered]

$P_{de-rated} = 368$ kW

6.3 DC ENERGY OUTPUT FROM ARRAY

The output power of the array depends on the amount of sunlight (i.e., the solar irradiation) and the losses born by the system. The solar irradiation that falls on the array would depend on the orientation or tilt angle at which the modules are mounted. The system

losses comprised of the power loss due to the factors explained earlier in the de-rating of the module, losses due to inverter efficiency and installation quality [30].

The arrays can be made automatically track the sun light maximizing the exposure. However such automated mechanism increases the cost of the system and brings along the challenges of proper maintenance. The proposed system in this study is fixed and utilizes no tracking mechanism. This is reported [11] to be the most common type of solar arrays and since the Maldives is yet to explore the technology, this study considers it as an appropriate method of installation for the proposed system at this stage. However, the automated tracking mechanism can be deployed in the future, if found feasible and necessary. The output power is calculated using the formula;

$$P_{pv\_dc} = f_{pv} Y_{pv} \frac{I_T}{I_s} \quad (5)$$

Where;

$P_{pv\_dc} =$ DC Power output of the array

$f_{pv} =$ The de − rating factor [ie; 0.97 x 0.95 x 0.82 = 0.75563; as detailed above]

$Y_{pv} =$ The rated capacity of the PV array [ie; 300Wp x 1666 = 499,800Wp]

$I_T =$ The solar radiation on the surface of the PV array

$I_s =$ Standard amount of radiation used to rate the module capacity under STC

Therefore;

$$P_{pv\_dc} = 0.75563\ x\ 499800\ x \frac{5.82}{1}$$

$$P_{pv\_dc} = 2198004 \text{ Wh/day}$$

$$\boldsymbol{P_{pv\_dc}} = 2198.004 \text{ kWh/day}$$

The power output from the PV array would be further decreased due to other losses in the system. These losses include the DC cable loss, the loss due to the efficiency of the inverter used and the AC cable losses [30]. These losses are calculated as;

6.3.1 DC cable loss

The [30] recommends the maximum voltage drop allowed between the PV array and the inverter should not be greater than 3%. Thus the expected output power of the array require to be further de-rated by 3%.

$$P_{pv\_dc} = 2198.004\ x\ 0.97$$

$$P_{pv\_dc} = 2132.06\ \text{kWh/day}$$

6.3.2 Inverter efficiency

The power output from the PV array will be further decreased due to the losses in the inverter. The technical data provided by the manufacture indicates the inverter used have an efficiency of 99%. (See Table 31). Thus, the power output of the array will be further decreased by 1%.

$$P_{pv\_ac} = 2132.06\ x\ 0.99$$

$$P_{pv\_ac} = 2110.74\ \text{kWh/day}$$

6.3.3 AC Cable loss

It is recommended in [30] the maximum voltage drop allowed between the inverter and the main switchboard should not be greater than 1%. Thus, the daily AC output from the array comprising 1666 modules of 300Wp using an inverter with an efficiency of 99% is calculated as;

$P_{\boldsymbol{pv\_ac}} = 2132.06\ x\ 0.99\ x\ 0.99 = 2089.64\ \text{kWh/day}$

$P_{\boldsymbol{pv\_ac}} = 2089.64\ x\ 365 = 762716.98\ \text{kWh/year}$

This would be the annual average AC power delivered to the grid from each of the arrays in the system.

Using the AC energy formula in [30], it is expressed as;

$E_{sys} = P_{Array\_STC}\ x\ f_{temp}\ x\ f_{man}\ x\ f_{dirt}\ x\ H_{tilt}\ x\ \eta_{pv\_inv}\ x\ \eta_{inv}\ x\ \eta_{inv_{sub}}$

$[Equation(11)]$

$E_{sys} = [(300x1666)\ x\ 0.82\ x0.97\ x0.95\ x\ 5.82\ x0.97\ x0.99\ x\ 0.99]/1000$

$E_{sys} = [499800\ x\ 0.82\ x0.97\ x0.95\ x\ 5.82\ x0.97\ x0.99\ x\ 0.99]/1000$

$E_{sys} = 2089.64\ \text{kWh/day}$

$E_{sys} = 2089.64\ x\ 365 = 762716.98\ \text{kWh/year}$

Where;

E_{sys} = The yearly energy output of the PV array, in watt − hours

P_{Array_STC} = The rated output power of the array under STC, in watts

f_{temp} = Temperature de − rating factor

f_{man} = de − rating factor for manufacturing tolerance

f_{dirt} = de − rating factor for dirt

H_{tilt} = Solar irradiance (kWh/m2)for the selected site (allowing for tilt angle)

$\eta_{pv_{inv}}$ = Losses between the PV array and the inverter

η_{inv} = Efficiency of the inverter

η_{inv_sub} = Losses between the inverter and the switchboard.

This is also known as the energy yield of the system and in a DGPV system. It represents a crucial measure of the actual energy delivered to the grid which is an important measure for the investment planning.

If the losses due to shading is known for the site where the system is to be built, it should also be taken into account in the calculation. In this research, since the system is proposed to be built in Hulhumale', the shading losses is not considered as the site is bare reclaimed land with no trees.

6.3.4 The specific energy yield

The specific energy yield of the array is the ratio of the actual energy delivered by the system over the rated power of the array expressed in kWh / kWp. It is the energy delivered per rated peak power of the module and is a very useful ratio since the actual energy yield represents the earning potential of the system while the rated peak power represents its cost. In [30], it is calculated using the formula;

$$SY = \frac{E_{sys}}{P_{array-STC}} \quad (12)$$

Where;

SY = Specific energy yied in kWh/kWp

E_{sys} = Average yearly energy output of the PV array, in Watts or kW − hours

P_{Array_STC} = Rated output power of the array under STC, in W or kW

$$SY = \frac{762716.98 \text{ kWh/year}}{[\frac{1666\ x\ 300}{1000}]\text{kWp}}$$

$$SY = 1526.044 \text{ kWh/kWp}$$

6.3.5 Performance Analysis of the System

The performance of a DGPV system can be measured using three of the IEC standard 61724 performance parameters explained in [48]. They are used to define the system performance of a PV farm with respect to the energy production, solar resource and overall effect of the system losses. These parameters are the performance ratio, the final PV system yield and the reference yield. The calculation of these parameters are explained here for demonstrating how the performance of a DGPV system are measured. It is not part of the design of the proposed system in this study. In practice, these ratios would be calculated using data obtained from the system, to assess its performance, once it has been up and running for a certain period of time. However, these performance measures at the design stage, can be calculated as demonstrated here, using the expected energy yield calculated.

6.3.6 The final yield

The final yield is defined as the ratio of the annual, monthly or daily net AC energy output of the system over the peak power of the installed PV array at STC [48]. This is the same as the Specific Yield calculated above.

$$\mathrm{YF} = \frac{\mathrm{E[kWh\ AC]}}{\mathrm{Pr[kWDC]}} \qquad (13)$$

Where;

$\mathrm{YF} = \text{The Final Yield of the system}$

$\mathrm{E} = \text{The annual energy output of the system [kWh/year]}$

$\mathrm{Pr} = \text{The peak rated power of the system under STC in [kW]}$

$$YF = \frac{762716.98\ \text{kWh/year}}{[\frac{1666\ x\ 300}{1000}]\text{kWp}}$$

$$YF = \frac{762716.98\ \text{kWh/year}}{[\frac{1666\ x\ 300}{1000}]\text{kWp}}$$

$$YF = 1526.044\ \text{kWh/ year /kWp}$$

6.3.7 The reference yield

The reference yield is the ratio of the total in-plane solar irradiation H_t (kW h/m^2) over the array reference irradiance under standard test condition of (1 kW/m^2). Thus, it represents the number of peak sun-hours on the system [48]. This is equal to the annual solar irradiation on the PV system.

In this research, with the assumption that the losses due to shading are insignificant, the expected total solar irradiation would be, the measured annual average solar irradiation at the site (see Table 19 in chapter 6) multiplied by 365 days to represent a typical year.

Thus;

$$YR = \frac{H_t\ [\mathrm{kWh/m^2}]}{1\mathrm{kW/m^2}} \qquad (14)$$

Where;

$YR =$ The Reference Yield

$\mathrm{H_t} =$ The Total in $-$ plane solar irradiation in $\mathrm{kW/m^2}$

$$YR = \frac{5.82 \text{ x } 365}{1}$$

$$YR = 2124.3\ \mathrm{kWh/m^2}$$

6.3.8 The performance ratio

The performance ratio (PR) which is also known as the Quality Factor (QF) [30] represents a measure of the installation quality. It is expressed [48] as the ratio of the final yield over the reference yield. Again, in practice these performance measures are calculated only when the plant has been running for a period of time and in this respect, the PR represents the quality of the installation of the system. The calculation shown here are based on the expected final yield and reference yield of the system calculated.

$$PR = \frac{\mathrm{YF}}{\mathrm{YR}} = \frac{E_{sys}}{E_{ideal}} \qquad (15)$$

Where;

PR = The Performance Ratio

YF = The Final Yield of the system

YR = The Reference Yield

E_{sys} = Average yearly energy output of the PV array

E_{ideal} = The ideal energy output of the array

The design guide lines [30] defines two standard methods of calculating the ideal energy output of the array

Method 1:

$$E_{ideal} = P_{Array\_STC} \; x \; H_{tilt} \quad (16)$$

Where;

H_{tilt} = The average daily irradiation (kWh/m2) for the selected site

P_{Array_STC} = Rated output power of the array under STC

Method 2:

$$E_{ideal} = H_{pv} \; x \; \eta_{pv} \quad (17)$$

Where:

H_{pv} = The actual irradiation that falls on the array surface area

η_{pv} = The efficiency of the PV modules

And

$$H_{pv} = H_{tilt} \; x \; A_{pv} \quad (18)$$

Where:

H_{tilt} = The average daily irradiation (kWh/m2) for the selected site

A_{pv} = The total area of the PV array

Using method 1, the ideal energy output of the array is;

$$E_{ideal} = \left[\frac{1666 * 300}{1000}\right] x\ [5.82x365]$$

$$E_{ideal} = 1061725.14\ \text{kW/year}$$

Thus, the performance ratio of the proposed system is;

$$PR \qquad \frac{\text{YF}}{\text{YR}} = \frac{E_{sys}}{E_{ideal}}$$

$$PR = \frac{1526.044}{2124.3} = \frac{762716.98\ \text{kWh/year}}{1061725.14\ \text{kW/year}}$$

$$PR = 0.718375$$

$$PR = 0.72$$

It is said [48] that, for an efficient system, the PR values fall within the range 0.6- 0.8 and considering the increasing effectiveness of systems, it can reach ideal annual values between 0.8-0.84.

6.3.9 The Capacity factor

The capacity factor (CF) is defined [49] as the ratio of the actual annual energy output to the amount of energy the PV system would generate if it operated at full rated power for 24 hours per day for a year.

$$CF = \frac{YF[\text{kWh/ year /kWp}]}{8760\ hr/year} = \frac{E_{sys}\ \text{kWh/year}}{E_{ideal}\text{kWp x 8760 hrs}} \quad (19)$$

$$CF = \frac{1526.044\ \text{kWh/ year /kWp}}{8760\ hr/year} = \frac{762716.98\ \text{kWh/year}}{\left[\frac{1666\ x\ 300}{1000}\right]\text{kWp x 8760 hrs}}$$

$$CF = \frac{762716.98\ \text{kWh/year}}{4378248\text{kWh/year}}$$

$$CF = 0.17420$$

$$CF = 17.4\%$$

Figure 21, shows an extract from the publications of the US Energy Information Administration (EIA) [49]. The capacity factor of a PV plant is seen to vary between 10% - 19% on average (see Fig 17). The value of capacity factor for all optimal system configurations in HOMER simulations in this study was observed to be 16.9% (see Appendix 2; Extracts from HOMER simulation).

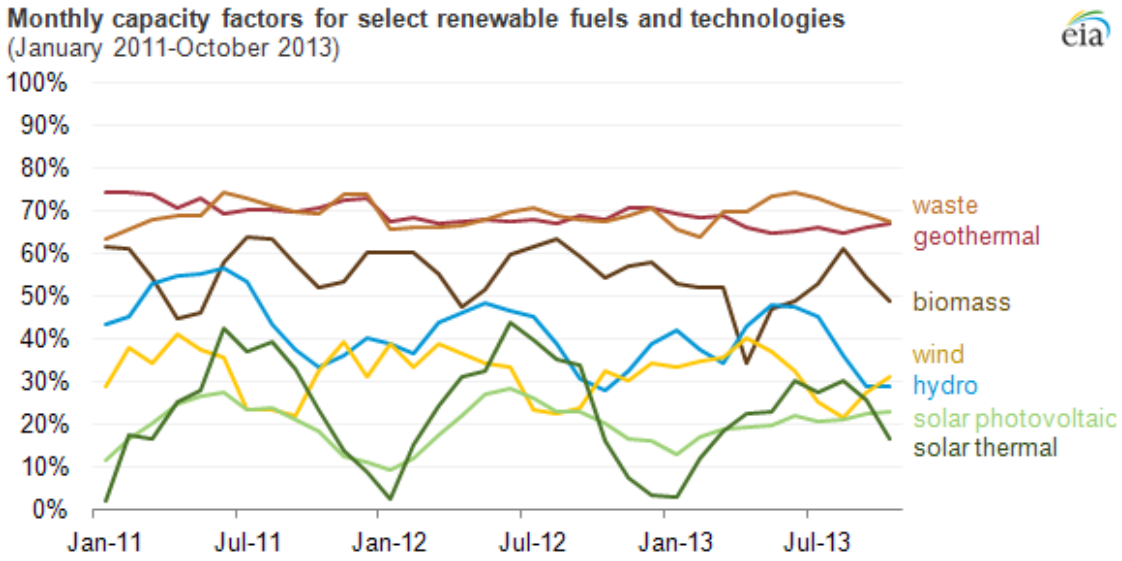


Figure 17: Capacity Factors for selected RETs, by US Energy Information Administration (EIA)

Source: Published data by US Energy Information Administration (EIA)

Thus, the CF calculated indicates that, a PV plant in Hulhumale' could be expected to operate within the range 10% - 19%, given in [49].

6.4 INVERTER SELECTION

As recommended in [30&50], the selection of inverters in this study is based on the energy output of the PV array taking into account the size of the array and the size of the individual PV modules within the array. Moreover, the minimum and maximum number of modules that can be connected to one string without compromising the operational safety measures of the inverter, needs to be considered. Thus, calculating the maximum and minimum voltage window of the inverter is crucial in determining the string configuration of the PV array.

For optimum performance, the PV array configuration should be set to be within the manufacturers' maximum allowable array size. However, the manufacturer of the chosen inverter does not provide this information and hence, in this work, its' calculation has been done as per the recommendation in guidelines [30 &50] ensuring, the nominal AC power output of the inverter is equal or greater than 75% of the peak power of the array. To achieve this, the array size has been carefully calculated to match the allowable array configuration of the inverter until the above condition is met without compromising other safety measures.

Another important design choice is, whether to use multiple inverters or one central inverter. For large installations, like the one proposed in this work, the guide line [50] recommends multiple inverters for a variety of reason such as balancing the phases, maximization of energy deliver, continued, albeit at reduced power during maintenance.

6.5 SIZING THE PV ARRAY AND MATCHING THE ARRAY VOLTAGE TO THE MAXIMUM AND MINIMUM OPERATING VOLTAGES OF THE INVERTER

A common practice in determining the PV array size in grid connected systems is connecting the PV modules in series. With series connection, the voltage increases while the current through the array remains constant. Since the voltage across the cell depends inversely on the temperature, the output of the PV cells will vary and needs to be within the allowed operational voltage windows of the inverter. For the inverters chosen for this

work, this range is between 450-850V (see Table 31). The system configuration given in table 32, indicates inverter capacity of 5500 kW would be required for the PV firm of 7500 kW.

The PV array configuration, to match the operational requirement of the inverter is calculated as detailed below. The calculations of these parameters are crucial and apply equally to manual system designs as well as system modelling by simulation studies.

6.5.1 MINIMUM VOLTAGE WINDOW

One of the crucial condition set forth in the design guidelines [30&50] is, at the highest ambient temperature, the maximum power point voltage (MPP voltage) of the array should never fall below the minimum operating voltage of the inverter. This is an important parameter, since the inverter may not work or its' performance could be significantly lowered if the solar array voltage drops below this value.

Thus, the calculation of the minimum MPP voltage (V_{min_MPP}) of each of the modules in the array at the highest temperature is important to determine the minimum MPP voltage of the array. It is calculated using the formula;

$$V_{min\_MPP} = V_{MPP-STC}\left[1 - \lambda_{v\_MPP\_\%/°C}\left(T_{amb\_max} - T_{STC}\right)\right] \qquad (20)$$

Where;

V_{min_MPP} = Minumum MPP voltage allowed (at highest temperature), in volts

$V_{MPP-STC}$ = The MPP voltage of the module in (V)at STC

$\lambda_{v\_MPP\_\%/°C}$ = MPP temperature coefficient of the module in % per °C

T_{amb_max} = Maximum ambient temperature, measured in °C

T_{STC} = Cell temperature at STC, measured in °C

At the highest recorded temperature of 40°C, the, minimum MPP voltage (V_{min_MPP}) of each of the modules in the array is calculated as;

$V_{min\_MPP} = V_{mp-STC}[1 - \lambda_{v\_MPP\_\%/°C}(T_{amb\_max} - T_{STC})]$

$V_{min\_MPP} = 37.5[1 - 0.45\%(40 - 25)]$

$V_{min\_MPP} = 37.5[1 - 0.45\%(15)]$

$V_{min\_MPP} = 37.5[0.9325]$

$V_{min\_MPP} = 34.96875$

$V_{min\_MPP} = 35$ V

That is;

$\lambda_{v\_MPP\_\%/°C}$ = -0.45% per °C [Given in the manufacturers′ data]

T_{amb_max} = 40 °C [Provided by Maldives Department of Meteorology]

$V_{MPP-STC}$ = 37.5 V [Given in the manufacturers′ data]

T_{STC} = 25 °C [Given in the manufacturers′ data]

The guidelines [30&50] recommends a maximum voltage drop of 3% to be allowed in calculating the voltage at the inverter for each module. Thus, at the highest expected ambient temperature, the minimum MPP voltage (V_{min_MPP}) of each of the modules in the array would be;

$V_{min\_MPP} = 35\ x0.97\ \text{V}$

$V_{min\_MPP} = 33.95\ \text{V}$

$V_{min\_MPP} = 34\ \text{V}$

In determining the string configuration, this voltage is being used [30&50] to calculate the minimum number of the PV modules that can be connected in one string. Therefore, the minimum number of PV modules in a string is calculated using the formula in [50];

$$N_{\min\_per\_string} = \frac{V_{inv\_min}(V)}{V_{min\_MPP}(V)} \quad (21)$$

Where;

$N_{\min\_per\_string}$ = The minimum number of PV modules in a string

V_{inv_min} = The minimum inverter input voltage, in volts

$V_{min\_MPP}(V)$ = The MPP voltage at effective cell temperature, in volts

$$N_{\min\_per\_string} = \frac{450\ \text{V}}{34\ \text{V}}$$

$N_{\min\_per\_string} = 14\ \text{Modules}$

6.5.2 MAXIMUM VOLTAGE WINDOW

In cold weather, the voltage of the PV module increases. As a result, there is a risk of the open circuit voltage of the PV array exceeding the maximum allowed input voltage of the inverter. Thus, it is crucial that the lowest expected temperature at the site where the system is to be installed is measured and used in calculating the maximum open circuit voltage of the array.

In calculating the maximum voltage of the array, the open circuit voltage of the PV modules given in the manufacturers' data is being used [30&50] emphasizing on the fact that it is the applied voltage prior to the inverter starts operating. This is a recommendation in the guidelines [30&50].

The lowest temperature measured at the site of Hulhumale' is 20 °C. The technical data in table 31 shows that the open circuit voltage of the PV module is 45 V with an open circuit voltage coefficient of -0.35% per °C. The maximum open circuit voltage is calculated using the formula;

$$V_{max-oc} = V_{oc-STC}\left[1 - \lambda_{v-oc\_\%/°C}(T_{min} - T_{STC})\right] \quad (22)$$

Where;

V_{max-oc} = The maximum open circuit voltage at minimum cell temperature

V_{oc-STC} = The open circuit voltage in (V) at STC

$\lambda_{v-oc\_\%/°C}$ = Open Circuit Voltage temperature coefficient in % per °C

T_{min} = The minimum recorded temperature at site in °C

T_{STC} = Cell temperature at STC, measured in °C

Therefore, the maximum open circuit voltage of the module is calculated as;

$V_{max-oc} = 45[1 - 0.35\%(20 - 25)]$

$V_{max-oc} = 45[1 - 0.35\%(-5)]$

$V_{max-oc} = 45[1 + (0.0175)]$

$V_{max-oc} = 45[1.0175]$

$V_{max-oc} = 45.7875$ V

$V_{max-oc} = 46$ V

Thus, for each module in the array, the maximum open circuit voltage input at the inverter would be 46 V. The maximum open circuit voltage is an important measure recommended in [30&50] to calculate the maximum number of modules that can be connected in a string.

Therefore, the maximum number of PV modules in a string is calculated using the formula;

$$N_{\max\_per\_string} = \frac{V_{inv\_max}(\mathrm{V})}{V_{max-oc}(\mathrm{V})} \quad (23)$$

Where;

$N_{\max\_per\_string}$ = The maximum number of PV modules in a string

V_{inv_max} = The maximum input voltage of the inverter, in volts

V_{max-oc} = The maximum open circuit voltage of a module

The maximum input voltage of the inverter (see Table 31) is 850 – 900 V. For the calculation 850 V have been used and hence, the maximum number of PV modules that should be connected in a string is;

$$N_{\max\_per\_string} = \frac{850}{45.7875}$$

$$N_{\max\_per\_string} = 18.564$$

$$N_{\max\_per\_string} = 19 \text{ Modules}$$

The results obtained from the above calculation indicates the array can be configured within the limits of 14 to 19 modules in each string, without compromising the manufacturers' recommended operating voltage windows of the inverter (see Table 31).

In summary, above calculations ensure the array configuration meets the following requirements set forth in the standard design guideline [30 & 50].

That is,

1- At the highest temperature, the minimum MPP voltage V_{min_MPP} of the array should never fall below the minimum operating voltage of the inverter. The minimum operating voltage of the inverter (see Table 31) is 450V. Thus, with the V_{min_MPP} of 34 V, the MPP voltage of the array would be;

$V_{MPP\_array} = 34x\ 14 = 476$ V [Considering the minimum number of modules] And;

$V_{MPP\_array} = 34x\ 19 = 646$ V [Considering the maximum number of modules]

In both cases the minimum MPP voltage V_{min_MPP} of the array is higher than the minimum operating voltage 450V of the inverter. This meets the requirement set forth in [30 &50].

2- At the lowest temperature, the maximum open circuit voltage of the array should not exceed the maximum input voltage of the inverter allowed by the manufacturer. The input operating range of the inverter (see Table 31) is 450 to 900 V; with MPPT operating range of 450 to 850. Thus, with the maximum open circuit voltage of 46V obtained from the above calculations, the maximum open circuit voltage of the array at the lowest temperature would be;

$V_{\max\_OC\_array} = 46\ x\ 14 = 644$ V [Considering the minimum number of modules]

And

$V_{\max\_OC\_array} = 46\ x\ 19 = 874$ V [Considering the maximum number of modules]

With 19 modules, since the maximum open circuit voltage of 874 V of the array exceeds the maximum MPPT voltage of 850 V of the inverter allowed by the manufacturer, the array configuration of the system is set within 14 to 18 modules in a string.

6.6 SIZING THE ARRAY

The appropriate sizing of the array is a crucial task in designing a DGPV system. Consideration should be taken to all the parameters that could affect the performance of the system. In this respect,

1- The maximum number of parallel strings in the array
2- The exact number of modules in the array and
3- The maximum current and voltage of the array are important parameters that needs to be calculated, ensuring safety measures of the system components are not violated.

6.6.1 The maximum number of parallel strings in the array

To find the maximum number of parallel strings that can be connected to the inverter without compromising its safety measures, consideration should be given to the maximum input current of the inverter and the short circuit current of the PV module. This value is specified on the manufacturers' data (See Table 31). It is being calculated [47] using the formula;

$$N_{Parallel\_String}(max) = \frac{I_{inv\,(\max)}}{(1 + f_{over\_size})\, x I_{Sc}} \qquad (24)$$

Where;

$N_{Parallel\_String}(max) =$ Maximum number of parallel strings

$I_{inv\,(\max)} =$ Maximum input current of the inverter

f_{over_size} = Oversizing factor (optional and if allowed by the manufacturer)

I_{Sc} = The short Circuit Current of the module at Standard Test Condition)

In the standard system design guidelines of [30&50], using an over rating factor is not recommended and consideration is given to the safe operational requirement of the system. In this study, an over rating factor is not considered and hence the maximum number of parallel strings that can be connected to one inverter is calculated as;

$$N_{Parallel\_String}(max) = \frac{I_{inv\,(\max)}}{(1+0)\,xI_{Sc}} \qquad (25)$$

$$N_{Parallel\_String}(max) = \frac{I_{inv\,(\max)}}{I_{Sc}}$$

$$N_{Parallel\_String}(max) = \frac{1030}{8.6}$$

$$N_{Parallel\_String}(max) = 119 \text{ strings}$$

The calculations shown in the previous section showed, the number of modules that can be connected in one string of this system should be limited to 14 to 18 modules. The exact number of modules in the string should be based on the current that flow through the string. It should not exceed the maximum input current of the inverter.

6.6.2 **The exact number of modules in the array**

The maximum total number of PV modules in the array, if the maximum number of PV modules that could be connected in one string is considered, would be;

$$N_{PV\_Total\_Array\_max} = \frac{I_{inv\,(\max)}}{(1 + f_{over\_size})\, x I_{Sc}}\; x \frac{V_{inv\_max}(\mathrm{V})}{V_{\mathrm{oc\_max}}(\mathrm{V})} \qquad (26)$$

Where;

$N_{PV\_Total\_Array}$ = The total number of PV modules in the array

$I_{inv\,(\max)}$ = Maximum input current of the inverter (A)

$V_{inv}(max)$ = The maximum input voltage of the inverter in (V)

$V_{PV}(\max)$ = The maximum operating voltage at the maximum power of the module

$V_{oc}(\max)$ = The maximum open circuit voltage at the MPP of the module (V)

Therefore, the total number of modules in one array is calculated as;

$$N_{PV\_Total\_Array} = \frac{1030\mathrm{A}}{8.6\mathrm{A}}\; x \frac{850\mathrm{V}}{46\mathrm{V}}$$

$N_{PV\_Total\_Array} = 119$ strings $x 18$ modules

$N_{PV\_Total\_Array} = 2142$ modules

Considering this configuration, the output power of the array is calculated as;

$P_{array\_STC} = N_{PV\_Total\_Array}\; x\; P_{mod\_STC}$

Where;

P_{array_STC} = Rated Power of the array at STC

$N_{PV\_Total\_Array}$ = Total number of modules in the array

$P_{mod\_STC} = \text{Rated Power of the module at STC}$

Thus, the output power of the array would be;

$P_{array\_STC} = 2142\ x\ 300\ \text{Wp}$

$P_{array\_STC} = 642600\ \text{Wp}$

$P_{array\_STC} = 643\text{kW}$

This is higher than the rated output power 500kW of the inverter indicating 18 modules should not be connected in one string.

The maximum total number of PV modules in the array, if the minimum number of PV modules that could be connected in one string is considered, would be;

$$N_{PV\_Total\_Array\_max} = \frac{I_{inv\ (\max)}}{(1 + f_{over\_size})\ xI_{Sc}}\ x\frac{V_{inv\_min}(V)}{V_{min\_MPP}(V)} \qquad (26a)$$

$$N_{PV\_Total\_Array\_max} = \frac{1030\text{A}}{8.6\text{A}}\ x\frac{450\ \text{V}}{34\ \text{V}}$$

$N_{PV\_Total\_Array\_max} = 119\ \text{strings}\ x14\ \text{modules}$

$N_{PV\_Total\_Array\_max} = 1666\ \text{Modules}$

And;

$P_{array\_STC} = N_{PV\_Total\_Array}\ x\ P_{mod\_STC}$

$P_{array\_STC} = 1666x\ 300\ \text{Wp}$

$P_{array\_STC} = 499800\ \text{Wp}$

$P_{array\_STC} = 500\text{kW}$

As seen here, with 14 modules in a string, the rated output power of the array matches that of the inverter and hence the total number of modules in the array should be limited to 1666 modules. That is, limiting the number of modules in one string to 14.

6.6.3 **The maximum current and voltage of the array**

The maximum voltage of the PV array is calculated [47&50] using the formula;

$$V_{(cal)\_max\_Array} = \frac{V_{inv\_min}(V)}{V_{min\_MPP}(V)}\ x\ V_{\mathrm{oc}_{\max}}(\mathrm{V}) \qquad (27)$$

$$V_{(cal)\_max\_Array} = [\frac{450\ \mathrm{V}}{34\ \mathrm{V}}]\ x\ 46\mathrm{V}$$

$$V_{(cal)\_max\_Array} = 14\ [\ \mathrm{modules}] x\ 46\mathrm{V} = 644\ \mathrm{V}$$

And the maximum current of the PV array is calculated [47&50] as;

$$I_{(cal)\_\max\_Array} = \left[N_{Parallel\_String(max)} x\ I_{Sc}\right] \qquad (28)$$

$$I_{(cal)\_\max\_Array} = 119\ x\ 8.6$$

$$I_{(cal)\_\max\_Array} = 1023\ \mathrm{A}$$

In addition to this, the optimal string configuration for a given inverter should be determined, ensuring the inverters' maximum input current allowed is not compromised.

For safe operation of the system, the total number of strings in the array requires to be limited to the inverters' maximum input current and the short circuit current of the PV module.

The inverters' maximum input current is 1030 A and the short circuit current of the PV module is 8.60 A. (see Table 31)

The optimal string configuration is calculated [47&50] as;

$$N_{\text{opt\_string\_config}} = N_{strings} x\ N_{inv_{input}} x I_{\text{s}_{\text{mod}}}(\text{A}) <= I_{inv\_max}(\text{A}) \quad (29)$$

Where;

$N_{\text{opt\_string\_config}}$ = The optimal string configuration for a given inverter

$N_{inv_{input}}$ = The number of inputs of the inverter

$N_{strings}$ = The optimal number of strings

$I_{\text{s}_{\text{mod}}}(\text{A})$ = The short circuit current of PV modules

Thus, for the optimal system architecture given by HOMER (see Table 32), the optimal string configuration should be;

7 strings using 17 inputs of the inverter, ensuring the maximum allowed input current of the inverter 1030 A is not exceeded.

That is;

$N_{\text{opt\_string\_config}}$ = 7 x17 x 8.6 = 1023 A

In summery this is;

- 7 strings x 17 inputs x 8.6 A $= 1023$ A which is < 1030 A
- 14 modules x 7 strings x 17 inputs $= 1666$ modules of each 300 W_p
- 1666 x 300 $= 499800$ $W_p = 500$ kW .

This matches the rated AC output power of the inverter. And the AC output power of the inverter 500 kW is greater than 75% of the output power of the array indicating the system can be considered as an efficient system [30&50].

The maximum voltage of the PV array is = 644 V <850 and < 900 V [The maximum operating voltage of the inverter] and the maximum current of the array is = 1023 A which is less than the maximum input current of the inverter (1030 A), ensuring the string configuration is set with the safe operational requirement of the inverter.

Thus, the optimal configuration for the system is;

7 strings of 14 modules in each string and use 17 inputs of the inverter for a total of 119 parallel strings. (That is; 17inputs x 7strings per input = 119 strings)

The string configuration can be changed to use more than 17 inputs by varying the number of strings and the number of modules per string. However, any configuration that violates the above conditions should be discarded.

Using the calculations above, the proposed system by HOMER for 2010 (see Table 32), would require 15 inverters of 500kW with the above array configuration. That is (7500 kW/0.3kWp = 25000 modules) occupying a minimum land area of 40,000 m^2. (That is, 25,000 x 1.6 m^2 = 40,000 m^2 = 9.88 Acre). This is the minimum land area required for the system of 2010, where 1.6 m^2, is the area occupied by one module used in this research. To connect 25000 modules, 15 inverters are required. (That is; 25000/1666= 15 inverters).

The process detailed above is applicable and should be applied to all system architectures derived from the HOMER simulations in accordance with the required annual additional capacity. (See Table 30, Chapter 6 and Appendix2). Table 34 shows a summary of the important calculations presented above and table 35 shows a comparison of calculated annual energy yield from the system compared with that derived from HOMER simulations. Table 36 shows a quick checklist that can be used to ensure the designed system is efficient and does not violate the standards set forth in the design guidelines [30&50].

Calculating the de-rated Annual Energy Yield (kWh/year) for each Array in the System	
Rated Power of the PV System (kW)	499.80
Rated Power of the Inverter (kW) of the System	500
Rated Power of the PV Module (kW)	0.30
Number of PV Modules in one Array	1666.00
Rated Power of the PV Array (kW) under STC	499.80
Solar irradiance (kWh/m^2/day)	5.82
De-rating the output of PV array	
De-rated Power of the module due to Manufacturers Output Tolerance (±3%) (kW)	0.291
De-rated Power of the module due to dirt (±5%) (kW)	0.276
De-rating due to Temperature	
Maximum temperature at site	40°C
STC Temperature	25°C
Maximum effective cell temperature on PV module	65°C
This is 40°C above STC of 25°C	40°C
Power Loss due to temperature [T-coefficient of the PV Module (-0.45%/°C)]	18%
De-rated output power of one module (kW)	0.227
De-rated output power of the Array (kW)	377.66
De-rating for System Losses	
DC system Losses (3%)	366.33
Inverter Efficiency (99%)	362.67
DC Energy Output from the Array (kWh/day)	2110.74
AC Energy Output of the Array (kWh/day)	2089.64
The average daily AC energy delivered by the array to the grid (kWh/day)	2089.64
Annual Energy Yield of the solar array (kWh/year)	762716.98
Specific Energy Yield (kWh/year)	1526.04
Yearly irradiation (kWh/m2/year)	2124.30
Ideal Annual Energy Yield of the solar array (kWh/year)	1061725.14
Performance Ratio (PR)	0.72
Capacity Factor	17%

Table 34: A summary of the calculations shown in this section

Source: Calculations using design guidelines for Grid connected PV systems [30&50]

The calculations summarized in table 34 above is for one array of the system. The system for 2010 would comprise 15 inverters and hence 15 arrays of the same configuration. Comparison of the systems' annual energy yield obtained from HOMER simulation and the manual calculation (see table 35) shows a difference of 512 MWh / year, which does not represent a significant difference. The reason for this difference is,

HOMERs' simulation takes into account the number of hours throughout the year, when there would be no sun light on the array and the array produces no energy. The manual calculation was done using the average daily solar irradiation. Furthermore, HOMER does not take into account the AC and DC cables losses in its simulation. .

Comparison of Annual Energy Yield obtained from HOMER and by manual calculation	
Annual Energy Yield of the solar array by manual calculation (kWh/year) (Total)	11440754.70
Annual Energy Yield from HOMER simulation (kWh/year)	10,928,031
Energy Losses from HOMER simulation (kWh/year)	110,413
Difference in Annual Energy Yield between HOMER and manual calculation (kWh/year)	512723.70

Table 35: Comparison of calculated annual energy yield from the system compared with that derived from HOMER simulations

Source: Calculations using design guidelines for Grid connected PV systems [30&50]

Figure 18 shows the general schematic diagram of the proposed system and table 37 represents the technical details of this schematic. The technical details are for a typical array configuration for the system of the year 2010. The array configuration would be the same for all the systems with variations in the number of arrays and the number of inverters as per the size of the system.

Quick Check on the Array configuration and inverter selection				
1	Peak power of the array at STC		499.8	kW
2	75% of the array peak power at STC		374.85	kW
3	De-rated power of the array		377.66	kW
4	Maximum allowable array size for one inverter		1666	Modules
5	Nominal AC Power of the inverter		500	kW
6	Is the maximum allowable array size greater than peak power of the array? (No array size given by manufacturer)	EQUAL	499.8	kW
7	Is the nominal AC power of the inverter greater than 75% of the peak power of the array?	YES	500 >374.85	kW
8	Is the peak power of the proposed array and inverter sizing acceptable?	YES	500	kW
9	Is The maximum voltage of the PV array within the acceptable range of the inverter?	YES	644 < 850 <900	V
10	Does the maximum current of the array exceed the maximum input current of the inverter?	NO	1023 < 1030	A
11	Is the maximum number of strings limited to the maximum input current of the inverter?	YES	7 strings x 17 inputs x 8.6 A =1023 A < 1030 A	A
12	Does the number of parallel string per input exceed the branch current of the inverter?	NO	7strings x 8.6 A = 60.2 <120	A
13	Is the maximum current flow through the optimal string configuration achieved, below the maximum allowed current of the inverter?	YES	7 strings x 17 inputs x 8.6 A =1023 A < 1030 A	A
14	Does the peak power of the array with the optimal string configuration match the AC output power of the inverter?	YES	499.8	kW
15	Is the performance ratio of the array within the acceptable range?	YES	0.72	within 0.6-0.8

Table 36: A quick checklist that can be used to ensure the designed system is efficient

Source: Calculations using design guidelines for Grid connected PV systems [30&50]

Technical details of the System (2010)	
System consists of Mono Crystalline PV Modules and Kstar GSL series Inverters	
Rated Power of the PV System (kW)	499.80
Rated Power of the Inverter (kW)	500
Rated Power of the PV Module (kW)	0.30
Number of PV Modules in one Array	1666.00
The maximum number of parallel strings	119.00
Rated Power of the PV Array (kW) under STC	499.80
Total number of PV modules in the system	25000.00
Total number of PV inverters in the system	15.00
Solar irradiance (kWh/m^2/day)	5.82
De-rated output power of the Array	377.66
DC Energy Output from the Array (kWh/day)	2110.74
AC Energy Output of the Array (kWh/day)	2089.64
The average daily AC energy delivered to the grid (kWh/day)	2089.64
The maximum voltage of the array (V)	644.00
The maximum current of the array (A)	1023.00
The performance ratio of the array	0.72
The Capacity Factor of the system	17%

Table 37: Technical details of the System for 2010

Source: Calculations using design guidelines for Grid connected PV systems [30&50]

Source: Drawn by Mohamed Huzam (Details of the system configuration for each year in appendix)

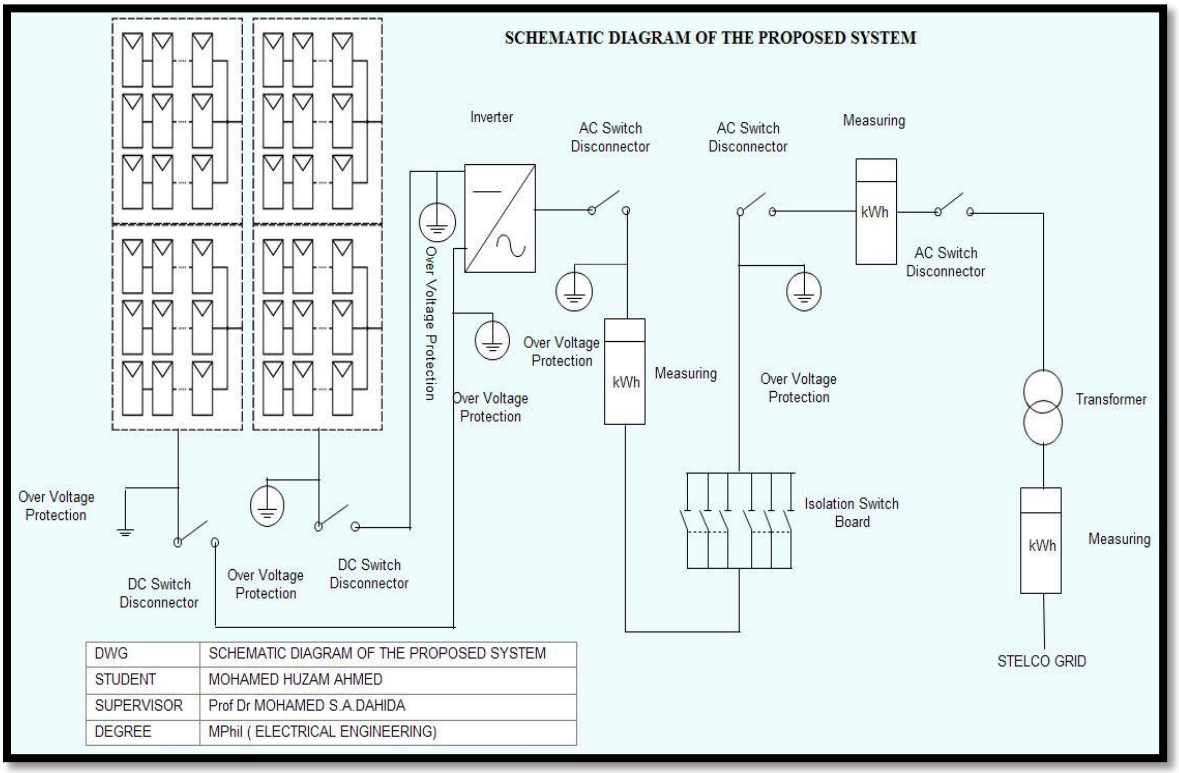


Figure 18: General Schematic Diagram of the proposed system

6.7 Summary of Chapter 7

The application of standard design guidelines to the simulation results, ensures the optimal PV array sizes and inverter selection for the proposed system. The selection of inverters in this study is based on the energy output of the PV array, considering the optimal size of the PV array and the size of the individual PV modules within the array, by calculating the minimum and maximum number of modules that can be connected to each string of the array, without compromising the operational safety measures of the inverter. For optimum performance, the PV array configuration requires to be within the manufacturers' maximum allowable array size. In absence this data, it is required to be

calculated, sizing the array, ensuring its peak power does not exceed 75% of the nominal AC power output of the inverter. In this respect, one of the crucial parameter that is essential to be taken into account is, the maximum power point voltage (MPP voltage) of the array at the highest and lowest ambient temperature. At the highest ambient temperature, the minimum MPP voltage of the array should never fall below the minimum operating voltage of the inverter. And at the lowest ambient temperature, the open circuit voltage of the array should not exceed the maximum allowed input voltage. The maximum current through the array, should not exceed the maximum input current of the inverter. The sizing of the array is a crucial task and should take into account all the parameters that could affect the performance of the system. This includes, the maximum number of parallel strings in the array, the exact number of modules in the array and the maximum current and voltage of the array, ensuring safety measures of the system components are not violated. For the proposed system, the optimal array configuration is; 7 strings of 14 modules in each string and use 17 inputs of the inverter for a total of 119 parallel strings. (That is; 17inputs x 7strings per input = 119 strings). That is;

- 7 strings x 17 inputs x 8.6 A $= 1023$ A which is < 1030 A
- 14 modules x 7 strings x 17 inputs $= 1666$ modules of each 300 W_p
- 1666 x 300 $= 499800$ $W_p = 500$ kW .

CHAPTER 7

ECONOMIC MODELING

7.1 ECONOMIC MODELING

The proposed system being modelled as a DGPV system, HOMERs economic modelling gives careful consideration to grid parity. Grid parity is defined [51] as the moment when the levelized cost of electricity (COE) from the DGPV system becomes competitive with grid electricity prices. It is an important measure to assess the economic feasibility of producing electricity from the proposed system at a rate competitive or equivalent to the utility rates applied in the simulation. In this study, all the optimal system configuration given by HOMER simulation was seen to achieve it (see Appendix 3). In standard practice, there are two indicators that are being used [51, 52] in assessing the economic feasibility of a DGPV system. They are the COE and the NPV of the cash flow throughout the project period. Both these measures are dependent on the cost of the system components and the sensitive variables used in the simulation. While the NPV represents a universally accepted standard [29] for a Cost Benefit Evaluation (CBE) of the investment, the COE represents a strong measure indicating, the electricity produced by the DGPV system carries the economic merit. That is, the cost of electricity produced by the system could be economically offset with the cost of electricity from the grid. The simulation takes into account, all the costs and any revenue that incur during the project period in the optimization process in which the COE is calculated. In this study, the costs include, the capital cost, replacement cost and the operational and maintenance cost. In the modelling process, no revenue is calculated, except for the salvage values since the system has been modelled to directly inject all its power to the grid.

In the modelling process, HOMERs algorithm, checks the size of the PV plant required to cater for the load under the set constraints by analyzing the systems' ability to achieve grid parity. This is done by doing the sensitivity analysis on each of the sensitive variables as explained in chapter 6. (See Appendix 3, for the important extracts from the results of the sensitivity analysis, the COE and grid parity)

The process of calculating the NPC by HOMER in its simulation and system optimization, is the same as that of calculating the Net Present Value (NPV) of an investment, where all the costs and revenues that occur during the project life time gets discounted to the present value [11]. Thus the NPC calculated by HOMER is the same as the NPV (the sign being negative), representing the cash flow stream throughout the project life time discounted to the present [11].

However, since the sensitivity analysis models the system requirement for each year considering the forecasted load for that particular year as the sensitivity variable, the additional investment that is required to be injected on an annual basis required additional analysis in calculating the NPV of the cash flow throughout the project. This is because HOMER assumes the total investment including the additional investment, occurs at the beginning of the project and presents each sensitivity case as a separate project (with a project life of 20 years, in this study).

The proposed system being modelled as a modular system that requires a capacity expansion as the demand for electricity increases, accounting for all the additional investments to represent the true cash flow throughout the project period is as an essential task. Thus, to represent the true cash flow throughout the entire project, the economic modelling of HOMER has been replicated and modified in this study, so that the additional investments injected on an annual basis are accounted for. This has been done by using an excel sheet. The result of the calculation was validated by comparing it to that produced by HOMER and is demonstrated in the following sections.

The capital, operational and maintenance cost of the grid have been excluded in the XL model since they would be present even without the installation of the proposed system. The cost components used in this model, the formulas used and how it calculates the associated costs are detailed below.

1. **Capital Costs:** Represents the cost that occur at the beginning of the project. (See Appendix 1 for details)
2. **Replacement Costs:** Represents the cost that would incur at the end of the life of any of the system components which would then require replacement. (See Appendix 1 for details)
3. **The additional capital cost:** Represents the additional investment on the system components as per the capacity expansion. (See Table 38, for details).
4. **The Operating and Maintenance Costs:** Represents the cost that incurs for the operation and maintenance of the system. The cost is being calculated for the PV

array and inverters based on the information provided by the supplier. (See Appendix 1 for details).

5. **Salvage Value:** Represents a positive cash flow that would occur at the end of the project life time, if any of the system components has a remaining life at the end of the project life [11]. In this design, the salvage values represents a significant positive cash flow, due to the capacity expansion that occur on annual basis in accordance with the increase in demand in electricity. All the system components except for the initial system configuration (That is the system of 2011) would have a remaining life at the end of the project life. (See Table 39, for details).

The model discounts the cash flow stream using the standard formula [29];

$$NPV = -C_0 + \sum_{i=1}^{T} \left(\frac{C_i}{(1+r)^i} \right) \quad (30)$$

$$\text{NPV} = -C_0 + \frac{C_1}{(1+r)^1} + \frac{C_2}{(1+r)^2} + \cdots + \frac{C_T}{(1+r)^T}$$

Where

$-C_0 = Initial\ investment$
$C_{1-T} = Cash\ Flow\ throughout\ the\ project\ period$
$r = Discount\ Rate$
$T = Time\ (years)$

The variables considered are, the additional costs that gets injected annually as per requirement of the system expansion (represented by$C_1 - C_T$) and the interest rate (r) which has been considered fixed at 6%. The time (*T*), representing each year of the project life and (C_0) representing the initial capital cost of the investment.

7.1.1 Calculation of the Salvage Value:

The salvage value is the value of remaining life of a system component at the end of the project lifetime [11]. It is being calculated using the formula [11] used by HOMER.

$$S = C_{rep}.\frac{R_{rem}}{R_{comp}} \quad (31)$$

$$R_{rem} = R_{comp} - [R_{proj} - R_{rep}]$$

$$R_{rep} = R_{comp}.\text{INT}[\frac{R_{proj}}{R_{comp}}]$$

$S = The\ salvage\ Value$

$C_{rep} = The$ replacement cost [$]

$R_{rem} = The\ remaining\ life\ of\ the\ component\ at\ the\ end\ of\ the\ project\ lifetime$

$R_{comp} = Component\ lifetime\ [yr]$

$R_{rep} = Component\ replacement\ cost\ duration$

$R_{proj} = The\ project\ lifetime$

$\text{INT}() =$ A function that returns the integer amount of a real number

For example, for the system of 2011,(The beginning of the project) all the modules in the PV farm would require replacement and would have no salvage value at the end of the project period 2030. That is, (20 years project life time and 20 years life of PV module). The life of the PV modules have been limited to 20 years in this study despite the

manufacturers' data indicating a life of 25 years. This takes into consideration the possible early de-generation of the modules due to the environmental conditions of the site where the system is proposed to be installed. However, the inverters installed in 2011, would have a remaining life of 5 years at the end of the project life and hence would have a salvage value of US$1403061 for all 17 inverters used. This is calculated as;

$$S = C_{rep}.\frac{R_{rem}}{R_{comp}}$$

$$S = 412500.\left[\frac{5}{25}\right] [17]$$

$$S = \text{US\$}1403061$$

Table 38 shows, the system configuration and the additional cost incurred each year. The tables 39 and 40 shows the calculations of the remaining life of the system components at the end of the project life and its salvage value, as they would occur at the end of the project period. The excel model calculates it the same manner as HOMER, includes them in the cash flow throughout the project life and discounts them to the present, to calculate the NPV of the project.

System configurations			Additional components required					
Year	PV capacity (kW)	Cost (US$)	PV Capacity (kW)	Cost (US$)	inverters	Cost (US$)	Inverters	Cost (US$)
2011	8500	46750000	None	None	17	7015306.12	None	None
2012	9500	52250000	1000	5500000	19	7840636.25	2	825330.13
2013	10000	55000000	500	2750000	20	8253301.32	1	412665.07
2014	11000	60500000	1000	5500000	22	9078631.45	2	825330.13
2015	12000	66000000	1000	5500000	24	9903961.58	2	825330.13
2016	12500	68750000	500	2750000	25	10316626.65	1	412665.07
2017	13500	74250000	1000	5500000	27	11141956.78	2	825330.13
2018	14500	79750000	1000	5500000	29	11967286.91	2	825330.13
2019	20000	110000000	5500	30250000	40	16506602.64	11	4539315.73
2020	20000	110000000	No additional capacity required	No additional investment required	40	16506602.64	No additional inverters	0.00
2021	20000	110000000			40	16506602.64		0.00
2022	20000	110000000			40	16506602.64		0.00
2023	20000	110000000			40	16506602.64		0.00
2024	25000	137500000	5000	27500000	50	20633253.30	10	4126650.66
2025	25000	137500000	No additional capacity required	No additional investment required	50	20633253.30	No additional inverters	0.00
2026	25000	137500000			50	20633253.30		0.00
2027	25000	137500000			50	20633253.30		0.00
2028	30000	165000000	5000	27500000	60	24759903.96	10	4126650.66
2029	30000	165000000	No additional capacity	No additional investment	60	24759903.96	No additional inverters	0.00
2030	30000	165000000			60	24759903.96		0.00

Table 38: The costs of the system expansion as per the increase in demand
Source: Cash flow from the model developed

Year	PV Additional Capacity (kW)	Remaining Life at the end of project life	Additional Number of Inverter	Remaining Life at the end of project life
2011	Initial @8500	0	Initial @ 17	5
2012	1000	1	2	6
2013	500	2	1	7
2014	1000	3	2	8
2015	1000	4	2	9
2016	500	5	1	10
2017	1000	6	2	11
2018	1000	7	2	12
2019	5500	8	11	13
2020	No additional capacity required if the system is to serve the load at a minimum renewable fraction of 5%			
2021				
2022				
2023				
2024	5000	13	10	18
2025	No additional capacity required if the system is to serve the load at a minimum renewable fraction of 5%			
2026				
2027				
2028	5000	17	10	22
2029	**Note**: Complete PV array of 2011 require replacement at the end of 2030		All 17 inverters installed in the year 2011 would require replacement 5 years after	
2030				

Table 39: Capacity of the system component and their remaining life at the end of the project
Source: Calculations from the model developed

System configurations			Additional components required and their salvage value					
Year	PV capacity (kW)	Cost (US$)	Capacity (kW)	Salvage Value (US$)	Inverters	Cost (US$)	Inverters	Salvage Value (US$)
2011	8500	46750000			17	7015306.12		1403061
2012	9500	52250000	1000	275000	19	7840636.25	2	198079
2013	10000	55000000	500	275000	20	8253301.32	1	115546
2014	11000	60500000	1000	825000	22	9078631.45	2	264106
2015	12000	66000000	1000	1100000	24	9903961.58	2	297119
2016	12500	68750000	500	687500	25	10316626.65	1	165066
2017	13500	74250000	1000	1650000	27	11141956.78	2	363145
2018	14500	79750000	1000	1925000	29	11967286.91	2	396158
2019	20000	110000000	5500	12100000	40	16506602.64	11	2360444
2020	20000	110000000	0	0	40	16506602.64	0	0
2021	20000	110000000	0	0	40	16506602.64	0	0
2022	20000	110000000	0	0	40	16506602.64	0	0
2023	20000	110000000	0	0	40	16506602.64	0	0
2024	25000	137500000	5000	17875000	50	20633253.30	10	2971188
2025	25000	137500000	0	0	50	20633253.30	0	0
2026	25000	137500000	0	0	50	20633253.30	0	0
2027	25000	137500000	0	0	50	20633253.30	0	0
2028	30000	165000000	5000	23375000	60	24759903.96	10	3631453
2029	30000	165000000	0	0	60	24759903.96	0	0
2030	30000	165000000	0	0	60	24759903.96	0	0

Table 40: Capacity of the system components and their salvage value at the end of the project
Source: Calculations from the model developed

7.1.2 The annualized cost

The annualized cost of a component is the cost that would give the same net present cost as the actual cash flow sequence associated with that component, if it were to occur equally in every year of the project lifetime [11]. It is the annualized value of the Net Present Cost.

HOMER calculates it using the formula;

$$C_{ann\_total} = CRF\left(i, R_{proj}\right) x\ C_{NPC\_total} \quad (32)$$

$C_{ann\_total} = The\ total\ annualized\ cost$ (\$)

$CRF() =\ A\ function\ returning\ the\ capital\ recovery\ factor$

$i = The\ annual\ interest\ rate$ (%)

$R_{proj} = The\ project\ life\ time\ (years)$

The capital recovery factor is a ratio used to calculate the present value of an annuity (a series of equal annual cash flows) and HOMER calculates it using the formula;

$$CRF(i, N) = \frac{i(1+i)^N}{(1+i)^N - 1} \quad (33)$$

Where;

$i =\ Real\ interst\ rate$ (%)

$N =\ Number\ of\ years$

For the investment of the proposed system, the CRF is calculated as;

$$CRF(i,N) = \frac{0.06(1+0.06)^{20}}{(1+0.06)^{20}-1}$$

$$CRF(i,N) = 0.0871845569768514$$

$$CRF(i,N) = 0.087$$

Thus the model calculates total annualized cost for all system components by multiplying the NPC of all system components by this factor. This is demostrated in table 41 and 42, showing a comparison of results obtained from the model with that of the HOMER.

Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	46,750,000	0	4,874,719	0	0	51,624,716
Grid	0	0	660,953,664	0	0	660,953,664
Converter	4,537,500	0	693,931	0	-282,963	4,948,467
System	51,287,500	0	666,522,240	0	-282,963	717,526,848

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	4,075,878	0	425,000	0	0	4,500,878
Grid	0	0	57,624,952	0	0	57,624,952
Converter	395,600	0	60,500	0	-24,670	431,430
System	4,471,478	0	58,110,444	0	-24,670	62,557,260

Table 41: The summarized cash flow showing the NPC for the system of 2011, from HOMER simulation
Source: HOMER simulation result

NET PRESENT COST						
ENTIRE SYSTEM	**Component**	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
	PV	-46750000	0	-4874717	0	-51624717
	INVERTER	-4537500	0	-693930	282963	-4948467
	SYSTEM	-51287500	0	-5568647	0	-56856147
ANNUALIZED						
ENTIRE SYSTEM	**Component**	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
	PV	-4075878	0	-425000	0	-4500878
	INVERTER	-395600	0	-60500	24670	-431430
	SYSTEM	-4471478	0	-485500	0	-4956978

Table 42: The summarized result of cash flow showing the NPC for the system of (2011) from the model developed
Source: Cash flow from the model developed

To demonstrate; the model calculates the total annualized cost of the system of 2011 as;

- Total Annualized Cost = Total NPC of $ 56856147 x 0.087184556 = $ 4956977.96. (See table 42 above)

- The addition of the grid O&M cost of $660,953,664 (See table 41) to the result obtained from the model gives the same value of NPC as that in the table 41, the HOMER simulation result.

- That is (NPC of PV$ 51624717 + NPC of Inverters $4948467 (See Table 42) + grid O&M cost of $ 660,953,664 (See Table41) = $717,526,848).

This is because the XL model is an exact replication of the HOMER economic modelling but with extra fields to account for the additional investments. With this validation, it has been used to calculate the NPV of the cash flow stream though out the project period, to assess the economic feasibility of the proposed system with additional investments that are required each successive year.

7.2 THE LEVELIZED COST OF ENERGY (COE)

In designing DGPV systems, the Levelized COE is used as a benchmarking or ranking tool to assess the economic feasibility of comparing energy production by different technologies [51]. In this study, the comparison is between diesel energy (the grid) and the energy production from the DGPV system. The COE represents an estimated price per unit of energy ($/kWh), considering the total cost and the energy generated by the system over the period under consideration. It is calculated [51] by dividing the total annualized cost of the DGPV system by the energy delivered by the system for the period under consideration. HOMER calculates it using the same formula as in [51].

$$COE = \frac{Total\ annualized\ Cost\ of\ the\ system}{Total\ Energy\ delivered\ by\ the\ system\ over\ the\ same\ period} \quad (34)$$

The annualized cost of the system is calculated using the formula;

$$C_{ann\_total} = CRF\left(i, R_{proj}\right) x\ C_{NPC\_total}$$

Applying the formulas for NPV, CRF (to represent the total annualized cost) and the total energy delivered by the system, the formula is re-written as;

$$COE = \frac{\left[\frac{i(1+i)^N}{(1+i)^N - 1}\right] x[-C_0 + \sum_{i=1}^{T}\left(\frac{C_i}{(1+r)^i}\right)]}{\left[f_{pv} Y_{pv} \frac{I_T}{I_s}\right] + E_{grid}} \qquad (34a)$$

$$COE = \frac{CRF\left(i, R_{proj}\right) x\, C_{NPC\_total}}{f_{pv} Y_{pv} \frac{I_T}{I_s} + E_{grid}} \qquad (34b)$$

To demonstrate the process of calculating the COE by HOMER, the values calculated for the CRF, the NPV and the total energy delivered by the system of 2011(see Table 43 for the total energy = 243,102,983), are applied;

$$COE = \frac{[0.0871845569768514][717{,}526{,}848]}{12603287 + 230499696}$$

$$COE = \frac{62557260.36}{243102983}$$

$$COE = \$0.257/\text{kWh}$$

Extracts from HOMER simulation result					
System Architecture for 2011					
Source	**Capacity**	**Unit**			
PV	8500	kW			
Grid	250	MW			
Inverter	5500	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	12,603,287	5	AC Primary Load	242,832,880	100
Grid	230,499,696	95	Total	242,832,880	100
Total	243,102,983	100			
Quantity	**kWh/year**	**%**			

Excess electricity	145,482	0.06	
Unmet electric load	0.00	0.00	
Capacity shortage	0.00	0.00	

Table 43: Extracted data from HOMER simulation for the system configuration of year 2011

Source: HOMER simulation



Figure 19: Cropped Screen Shot of HOMER simulation (sensitivity analysis for load of 2011)
Source: HOMER Simulation

Figure 19 show a copped screen shot of results obtained from the sensitivity analysis for the load of the year 2011 from HOMER simualtion. The slight variation in the NPC of figure 23, as HOMER generates the report does not affect the result. The calculations demonstrated above, shows how the economic modelling of HOMER have been replacated to calculate the COE of the proposed system.

The same process have been repeated for each year of the project to assess its ability to achieve grid parity which is considered as the economic merit of the system. (See Appendix 3)

7.2.1 Achieving grid parity

During the repetitive simulation runs using the lowest and the highest capital cost used in this study, it was observed that HOMER does not rank a system configuration as an optimal system, unless it achieves grid parity. Though it ranks the system configuration with the lowest NPC as the most optimal system configuration, the result gives a lists of optimal system configurations (202 system configurations in this simulation, for the year 2030, ranging from 30MW-800MW PV) that can serve the load under the specified constraints.

Figures 20 and 21 show a comparison of electricity production from the proposed system for the load of year 2020 by using the cost of the PV modules provided by the Maldivian supplier, Renewable Energy Maldives Pvt Ltd and one of the suppliers from China, the SOLOPO. They represent the highest and the lowest capital cost used in the simulation. The plots in these figures show the power generated and does not show grid parity. The results of the grid parity is extracted from the sensitivity analysis and is presented in Appendix 3.

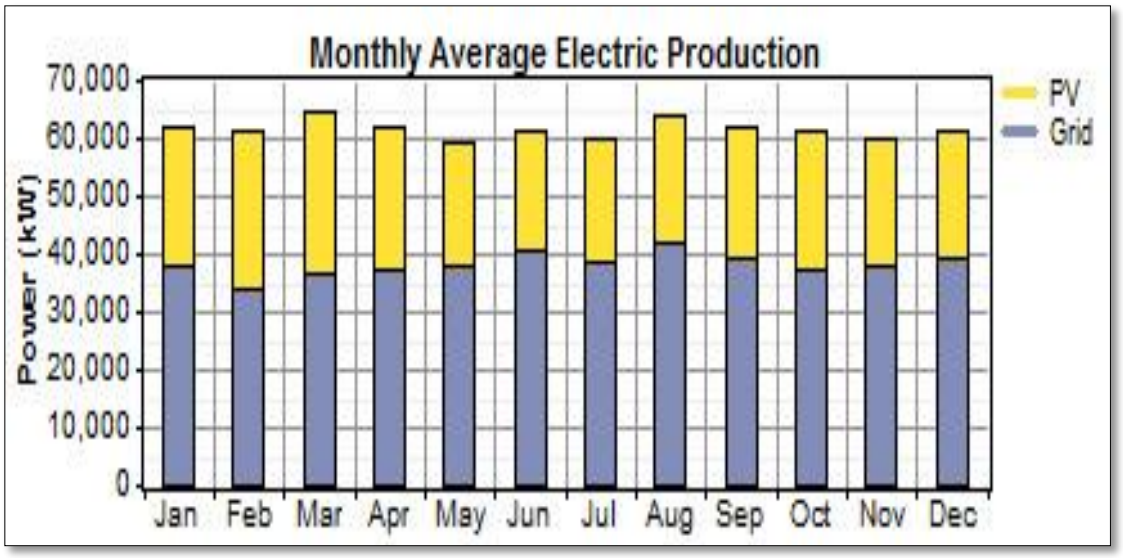


Figure 20: Cropped screen shot of Electricity production by using costs provided by SOLOPO (CHINA)
Source: HOMER simulation

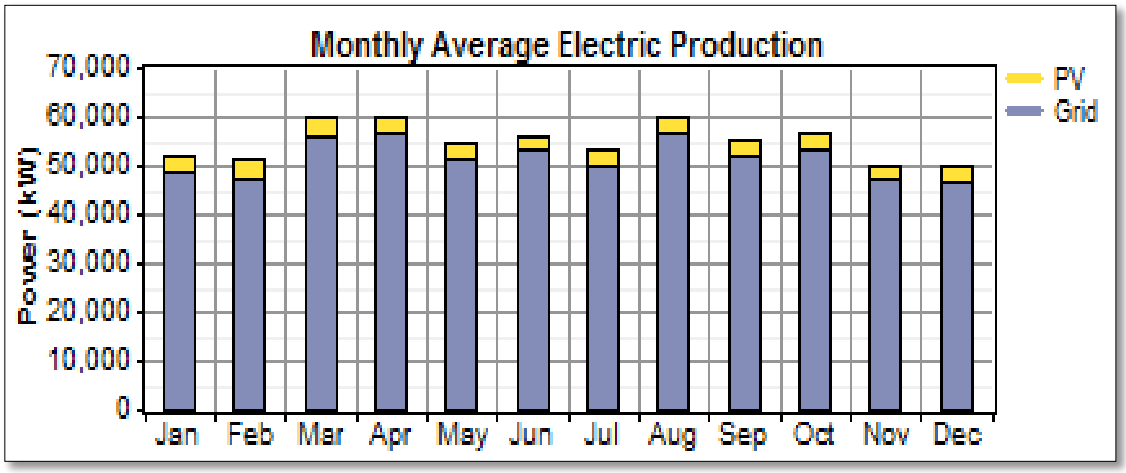


Figure 21: Cropped screen shot of Electricity production by using costs provided by Renewable Energy Maldives Pvt Ltd
Source: HOMER simulation

Both these simulations being performed with the same constraints, the results indicates electricity production from the PV array is significantly increased with the low cost PV modules. This increases the size of the PV farm as well. This is well expected as HOMERs

optimization process would consider maximum PV penetration to the grid, as long as the applied constraints are not violated.

Thus COE of the proposed system, using the capital costs of both suppliers were compared, to assess its ability to achieve grid parity. The details of the results for the system of each year have been tabulated and presented in the appendix 3. Table 44 - 47 shows the results of COE for the systems for the years 2011, 2015, 2020,2025, using the capital cost of obtained from the Maldivian supplier (The highest capital cost). Table 48 and 49 shows the COE of the system for the year 2030, comparing the COE obtained using the capital cost from both suppliers. The important observation here is, the change in the annualized cost (derived as demonstrated in the previous section) in line with the applied grid rates to maintain grid parity. HOMER maintains it, by simulating each of the grid rates as a separate sensitive case and identifying the size of the PV farm required to maintain a minimum RF of 5%-10% to the grid and achieve grid parity. (See Appendix 3 for details of the exact RF attained). The COE obtained and the grid rates are the same throughout the project, with the highest capital cost and it is low with the lowest capital cost used in the simulation (see Table 49). This implies that HOMERs sensitivity analysis and the optimization process discards any system configuration that produces electricity at a rate higher than the grid rates applied. Furthermore, it shows the impact of variation in each of the sensitive variables (the load, grid rates and the RF) on the NPC which is used to calculate the annualized cost.

Summarized results showing grid parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2011	8500	17	243,102,983	62,557,260	0.250	0.257
				64,862,256	0.260	0.267
				69,472,248	0.280	0.286
				74,082,248	0.300	0.305
				78,692,224	0.320	0.324
				83,302,232	0.340	0.343
				87,910,664	0.360	0.362
				92,518,400	0.380	0.381
				97,117,000	0.400	0.399
				101,138,024	0.420	0.416

Table 44: Summarized results of grid parity for the system of 2011 (using the highest capital cost)

Source: HOMER simulations

Summarized results showing grid parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2015	12,000	24	338,112,242	87,061,584	0.250	0.257
				90,264,776	0.260	0.267
				96,671,184	0.280	0.286
				103,077,568	0.300	0.305
				109,483,936	0.320	0.324
				115,890,328	0.340	0.343
				122,296,728	0.360	0.362
				128,703,144	0.380	0.381
				135,102,624	0.400	0.400
				140,669,728	0.420	0.416

Table 45: Summarized results of grid parity for the system of 2015 (using the highest capital cost)

Source: HOMER simulation

Summarized results showing grid parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2020	20,000	40	482,262,604	124,918,936	0.250	0.259
				129,445,024	0.260	0.268
				138,497,168	0.280	0.287
				147,549,360	0.300	0.306
				156,601,472	0.320	0.325
				165,653,632	0.340	0.343
				174,705,824	0.360	0.362
				183,757,968	0.380	0.381
				192,752,944	0.400	0.400
				200,688,640	0.420	0.416

Table 46: Summarized results of grid parity for the system of 2020 (using the highest capital cost)

Source: HOMER simulations

Summarized results showing grid parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2025	25,000	50	655,729,476	169,079,808	0.250	0.258
				175,266,416	0.260	0.267
				187,639,664	0.280	0.286
				200,012,928	0.300	0.305
				212,386,128	0.320	0.324
				224,759,296	0.340	0.343
				237,132,576	0.360	0.362
				249,505,760	0.380	0.381
				261,712,400	0.400	0.399
				272,459,840	0.420	0.416

Table 47: Summarized results of grid parity for the system of 2025 (using the highest capital cost)

Source: HOMER simulations

Summarized results showing grid parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2030	30,000	60	855,833,228	220,292,128	0.250	0.257
Note: This table is presented here for comparison with the results obtained by using the capital cost provided by the supplier with the lowest price. (See Table 49 below)				228,405,616	0.260	0.267
				244,632,672	0.280	0.286
				260,859,648	0.300	0.305
				277,086,688	0.320	0.324
				293,313,760	0.340	0.343
				309,540,736	0.360	0.362
				325,767,744	0.380	0.381
				341,964,032	0.400	0.400
				356,025,152	0.420	0.416

Table 48: Summarized results of grid parity for the system of 2030 (using the highest capital cost) (using the highest capital cost)

Source: HOMER simulations

Summarized results showing grid parity being achieved					
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Load Served (kWh/Year)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2030	75	150	498,264,128	0.25	0.22
Note: This table shows the COE of the system by using PV modules of lower cost. It's presented here for comparison with the results obtained the highest capital cost used in this study, see Table 48)				0.26	0.23
				0.28	0.24
				0.30	0.25
				0.32	0.27
				0.34	0.28
				0.36	0.29
				0.38	0.30
				0.40	0.32
				0.42	0.33

Table 49: Summarized results of grid parity for the system of 2030 (using the lowest capital cost)

Source: HOMER simulations

7.2.2 Calculating COE for the PV array alone

The economic modelling detailed in the previous section demonstrated the proposed system is economically viable. In standard practice, the economic feasibility of a DGPV system is calculated [51&52] based on;

- The initial capital cost of the system. (In this study, the capital costs have been calculated using the highest and the lowest cost of system components provided by the suppliers and both were used in the simulation for comparison of the results obtained)
- The energy delivered by the system every year. (Obtained from simulation results and by manual calculation for comparison, as demonstrated in the previous chapter)
- The cost of the operation and maintenance of the system. (calculated using the model developed, using the costs obtained from the suppliers)
- The future cost of electricity from the grid (In this study, it represents the grid rates provided by STELCO, applied in the sensitivity analysis)
- The financial terms (i.e., if the investment is financed by loan. In this study a fixed interest rate of 6% have been used based on the information obtained from STELCO)

- The project life (20 years in this study) and
- The salvage values of the all system components at the end of the project. (Calculated using the model developed, and tabulated in Table 40)

As shown in the previous section, all of these have been taken into account in calculating the COE of the proposed system. HOMER calculates the COE for the PV, using the same formula (Equation 34a).

For example, the capital cost of the PV system configuration of year 2030 is $ 165,000,000, (See Appendix 5, for HOMER results) which when discounted (depreciated) throughout the project period of 20 years, gives a NPC of $182,204,896 (see Appendix 5, for HOMER results). With the total electricity production of 44482316 kWh (see Table 51) and an energy yield of = 43711892 kWh (see Table 52), HOMER calculates the COE limiting it to the PV alone as;

$$COE = \frac{\$\ 182204896 * \ 0.0871845569768514}{44482316\ \text{kWh/ year}}$$

$$COE = \frac{\$\ 15885453.1367733}{44482316\ \text{kWh/ year}}$$

$$COE = \$\ 0.35711/kWh$$

In reality, the total investment for the PV system reaches to $ 165,000,000 in the year 2028, which is the 18th year of the project period, if the investment is to start in the year 2011. (See Table 51 &52). See Appendix 2, for extracts for HOMER simulation results for all 20 years. Here, COE for the PV alone is higher compared to the grid rates

and the COE for the DGPV system because HOMER calculates the COE for each sensitive case of increase in electric demand as a separate project, with a project duration of 20 years. The high capital cost of PV used, is another contributing factor to the COE.

However, under the circumstance where the economic feasibility of the system is required to be assessed based on the COE delivered by the PV array alone, (often done for standalone PV systems), the COE limited to the PV system alone should be expressed in terms of the capital recovery factor CRF explained earlier.

That is;

$$CRF(i,N) = \frac{0.06(1+0.06)^{20}}{(1+0.06)^{20}-1}$$

$$CRF(i,N) = 0.0871845569768514$$

$$CRF(i,N) = 0.087$$

The total NPC of the investment for the PV system, with annual additional investment = $104,113,003 (derived from the model developed, see Table 50). Thus, the annualized cost of the system is calculated as;

$$PMT_{annual} = \$104113003x\ \frac{0.06(1+0.06)^{20}}{(1+0.06)^{20}-1}$$

$$PMT_{annual} = \$\ 9077046/\ year$$ [See Table 53]

The energy yield (the exact amount of energy delivered to the grid) of the system for the PV array of 30MW for 2030 = 43711892 kWh/ year, (see Table 52).

Thus the COE is calculated as;

$$COE = \frac{\$\ 9077046}{43711892\ \text{kWh/ year}}$$

$$COE = 0.20765621401151$$

$$COE = \$\ 0.207\ /kWh$$

Or;

$$COE = \frac{\$\ 9077046}{44482316\ \text{kWh/ year}}\ [\ Using\ Total\ electricity\ production\ from\ PV\ ]$$

$$COE = 0.204059653728461$$

$$COE = \$\ 0.204\ /kWh$$

Comparison of the COE $0.207 or 0.204 / kWh (limiting it to the PV system alone) with the COE of $ 0.26 / kWh for the DGPV system of the same capacity, applying the same grid rates, proves the PV array produces electricity at a lower rate than the grid rates applied in the sensitivity analysis proving its' ability to achieve grid parity. The difference seen here is the reason for developing the XL model to assess the financial feasibility of the proposed system if it was to be built on a modular basis.

In summary; the important information obtained here is;

- HOMERs' complex algorithm optimizes the system configuration based on the lowest NPC it calculates in the economic modelling, after analyzing and comparing the results of each sensitive variable case that it simulates as a separate project with the same project life.

- HOMER assumes the capital cost of the required system configuration for each sensitive case of increase in electric demand, occur at the beginning of the project and depreciates it throughout the project life. As a result, the additional investment that gets injected as the demand increases, require additional assessment and analysis to derive the cash flow stream throughout the project period to calculate the NPC and the annualized cost. This is seen in table 50 & 53; the result obtained from the XL model.

- In modelling a DGPV system, HOMER does not rank a system configuration as optimal, unless the optimal system configuration carry the credibility of grid parity.

- The levelized cost is derived from the electricity generated from system and its' annualized NPC for the project life. HOMER maintains the grid parity by calculating the annualized cost for each sensitive variable, under the constraints applied in the simulation.

NET PRESENT COST					
Component	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
PV	-111170251	0	-9634498	29554658	-91250091
INVERTER	-16682211	0	-2120438	5939737	-12862911

	SYSTEM	-127852462	0	-11754936	35494395	-104113003
ANNUALIZED						
	Component	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
	PV	-9692329	0	-839979	2576710	-7955599
	INVERTER	-1454431	0	-184869	517853	-1121447
	SYSTEM	-11146760	0	-1024849	3094563	-9077046

Table 50: Calculation of NPC and the Annualized cost using the model developed

Source: Calculation from the model developed

Year	System Size (kW)	Cost (US$)	Additional Capacity (kW)	Additional Cost (US$)	Total production (kWh)
2011	8500	46750000			12603287
2012	9500	52250000	1000	5500000	14086047
2013	10000	55000000	500	2750000	14827398
2014	11000	60500000	1000	5500000	16310166
2015	12000	66000000	1000	5500000	17792882
2016	12500	68750000	500	2750000	18534274
2017	13500	74250000	1000	5500000	20017040
2018	14500	79750000	1000	5500000	21499724
2019	20000	110000000	5500	30250000	29654796
2020	20000	110000000	0	0	29654796
2021	20000	110000000	0	0	29654796
2022	20000	110000000	0	0	29654796
2023	20000	110000000	0	0	29654796
2024	25000	137500000	5000	27500000	37068548
2025	25000	137500000	0	0	37068548
2026	25000	137500000	0	0	37068548
2027	25000	137500000	0	0	37068548
2028	30000	165000000	5000	27500000	44482316
2029	30000	165000000	0	0	44482316
2030	30000	165000000	0	0	44482316

Table 51: Annual PV capacity expansion and total energy produced
Source: HOMER simulation and the model developed to assess the financial feasibility

Year	Number of inverters	Cost (US$)	Additional Number of Inverter	Additional Cost (US$)	Energy Yield (kWh)
2011	17.0068	7015306			12333241
2012	19.0076	7840636	2.0008	825330.1	13726611
2013	20.008	8253301	1.0004	412665.1	14519937
2014	22.0088	9078631	2.0008	825330.1	15916022
2015	24.0096	9903962	2.0008	825330.1	17484644
2016	25.01	10316627	1.0004	412665.1	18253002
2017	27.0108	11141957	2.0008	825330.1	19670476
2018	29.0116	11967287	2.0008	825330.1	21078634
2019	40.01601	16506603	11.0044	4539316	29342370
2020	40.01601	16506603	0	0	29342934
2021	40.01601	16506603	0	0	29343514
2022	40.01601	16506603	0	0	29344116
2023	40.01601	16506603	0	0	29344740
2024	50.02001	20633253	10.004	4126651	35717368
2025	50.02001	20633253	0	0	35718032
2026	50.02001	20633253	0	0	35718712
2027	50.02001	20633253	0	0	36693932
2028	60.02401	24759904	10.004	4126651	43710376
2029	60.02401	24759904	0	0	43711128
2030	60.02401	24759904	0	0	43711892

Table 52: Annual Inverter capacity expansion and total energy yield
Source: HOMER simulation and the model developed to assess the financial feasibility

In similar previous studies [51 &52], a hybrid systems is considered economically feasible if the system is able to achieve grid parity. However, it is said in the HOMER modelling guide [11], that HOMER gives priority to the system with the lowest NPC rather than the lowest COE [11] considering the NPC, a more reliable figure than the COE [11].

This is the reason why HOMER considers the NPC as the economic metric for ranking the most optimal system under the costs, loads and constraints applied [11]. The justification for this explained in HOMER modelling guide [11] falls beyond the scope of the analysis of this study.

To assess the profitability of the investment for the proposed system, the revenue that would be generated by selling electricity generated by the PV system to the STELCO requires to be included in the cash flow throughout the project period. This has been done, by using the grid rates ($0.25 - $0.38) that allowed the system to be maintained within the maximum size of PV system allowed in this study, while serving the load at a minimum RF of 5% in the sensitivity analysis (see Appendix 3). Here, an implicit assumption made is that electricity from the PV system would not be sold to STELCO grid, at a rate lower than these rates. Table 53 shows the summary of the output from the cash flow model when the revenues earned at a selling rate of $ 0.38 is applied. The results indicate, with the high capital cost of PV and inverter used in this simulation, the lowest rate at which energy could be sold is $0.38 /kWh.

NET PRESENT COST						
	Component	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
	PV	-111170251	0	-9634498	29554658	-91250091
	INVERTER	-16682211	0	-2120438	5939737	-12862911
	SYSTEM	-127852462	0	-11754936	35494395	2371005
ANNUALIZED						
	Component	**Capital**	**Replacement**	**O&M**	**Salvage**	**Total**
	PV	-9692329	0	-839979	2576710	-7955599
	INVERTER	-1454431	0	-184869	517853	-1121447
	SYSTEM	-11146760	0	-1024849	3094563	206715
NPV (US$)	2371005					

Profitability Index	1.04

Table 53: Calculation of NPC and the annualized cost for the project

Source: Calculation from the cash flow model

In standard practice [29], the NPV and the Profitability Index (PI) of the expected cash flow (including all costs and revenue) throughout the project period is considered as strong and reliable indicators in assessing the profitability of an investment. It serves as a decision making tool on the basis that a positive NPV indicates the investment would be profitable [29]. The minimum acceptable standard value of PI for an investment is 1 [29]. Thus, the investment for the proposed DGPV system in this study would be a profitable investment, if the energy from the PV can be sold at a rate not lower than $0.38 /kWh. The higher the rate at which the energy could be sold, and the lower the cost of the system components, the more profitable the investment would prove to be. The cost benefit analysis presented above would produce more accurate and reliable results, if the exact terms of the financing, rate of selling to STELCO grid and applicable taxes are known.

7.2.3 Fossil Fuel Savings and the CO_2 reduction from the proposed DGPV system

The fossil fuel saving and the CO_2 reduction from the proposed system is presented in Table 54. In this study, it is calculated using the formula 35, considering the publication [53] is based on experimental projects carried out in the Maldives.

$$tCO_2 = 3.667 * m_f * HV_f * CEF_f * X_c \quad (35)$$

Where $m_f = The\ fuel\ quantity\ in\ Litres$

$HV_f = The\ fuel\ heating\ value\ (MJ/l)$

$CEF_f = The\ carbon\ emission\ factor\ (ton\ Carbon/TJ)$

$X_c = oxidized\ carbon\ fraction$

For diesel fuel, the heating value is 38.99MJ /L, the carbon emission factor (CEF) is 20.2 t C /TJ and the oxidized carbon fraction is 0.99 [53]. The CO_2 reduction from the proposed system is calculated using diesel fuel that would be saved by implementing the proposed system. That is, the energy yield from the PV represents the energy that would be required to be generated by diesel otherwise. This takes in to account the standard electricity production by 1L diesel is equal to 11kWh [54]. Thus, the equation is simplified to

$$tCO_2 = 2.86 * 10^{-3} * m_f \quad (35)$$

The results presented in Figure 26 shows the benefits of the proposed system in terms of fossil fuel savings and CO_2 reduction. It does not represent the adaptation and sustainability of RETs in a country like Maldives.

Year	System Size (kW)	Energy Yield	Fuel Savings (L) / Year	COE reduction (T) / year
2011	8500	12333241	1121203.73	3206.64
2012	9500	13726611	1247873.73	3568.92
2013	10000	14519937	1319994.27	3775.18
2014	11000	15916022	1446911.09	4138.17
2015	12000	17484644	1589513.09	4546.01
2016	12500	18253002	1659363.82	4745.78
2017	13500	19670476	1788225.09	5114.32
2018	14500	21078634	1916239.45	5480.44

2019	20000	29342370	2667488.18	7629.02
2020	20000	29342934	2667539.45	7629.16
2021	20000	29343514	2667592.18	7629.31
2022	20000	29344116	2667646.91	7629.47
2023	20000	29344740	2667703.64	7629.63
2024	25000	35717368	3247033.45	9286.52
2025	25000	35718032	3247093.82	9286.69
2026	25000	35718712	3247155.64	9286.87
2027	25000	36693932	3335812.00	9540.42
2028	30000	43710376	3973670.55	11364.70
2029	30000	43711128	3973738.91	11364.89
2030	30000	43711892	3973808.36	11365.09

Table 54: Fossil fuel saving and the Co2 reduction from the proposed system

Source: Simulation results and calculation using equation 35

7.3 Summary of Chapter 8

The proposed system being modelled as a DGPV system, HOMERs economic modelling gives careful consideration to grid parity. In this study, all the optimal system configuration given by HOMER simulation was seen to achieve it. In standard practice, two indicators that are being used in assessing the economic feasibility of a DGPV system are, the COE from the system and the NPV of the cash flow throughout the project period. HOMERs system optimization is based on its economic modelling where it ranks the system configuration with the lowest NPC, as the most optimal system configuration. The process of calculating the NPC by HOMER, is the same as that of calculating the Net Present Value (NPV) of an investment, where all the costs and revenues that occur during the project life time gets discounted to the present value. Thus the NPC calculated by HOMER is the same as the NPV (the sign being negative). It calculates the NPC of each case of increase in demand, as a separate project with the same project period. As a result, to represent the actual cash flow stream throughout the project period, the economic modelling and calculation of the NPC for the proposed system required accounting for the

additional investment that gets injected on annual basis as the load increases. This was done using the XL spreadsheet developed by replicating the HOMERs economic modelling. This further enhanced the calculation of COE limited to the PV system alone, explained in section 8.2.2, justifying the economic feasibility of the proposed system. The calculation of COE being based on the total energy production from the system and the annualized cost of the system, HOMER maintains grid parity by simulating each of the grid rates applied in the simulation, as a separate sensitive case and identifying the system configuration that carry this merit.

CHAPTER 8

CONCLUSION

8.1 CONCLUSION

An indepth analysis on the operational data of the STELCO power plant in Male' done in this research revealed the major difficulties STELCO would be be faced with when expanding their distribution network in the future due to the land constraints. The analysis further revealed that the low operating capacity factor at which the plant is being operated, the losses in the distribution network and poor maintenance could have a significant contribution to STELCOs' failure to meet the growing demand in Male'. Furthermore, it revealed the electricity consumption in the capital city of Male' is significantly higher than any other island in the country, consuming 71% of the total electricity produced by STELCO nationwide. Thus, this study, considered this fact as a strong indication that if Maldives is to deploy RETs to transform its energy sector, high importance should be given to deploy it to the national grid of STELCO in Male'. The analysis being based on the primary historic data obtained from STELCO, it gave a strong indication that the load on their grid will increase in future at a rate not lower than the past ten years (2001-1010).

Thus, forecasting the expected long-term electricity demand on the STELCO grid was deemed as an essential task in this research. The forecasts made have been validated by comparing it with the results obtained from one of the most powerful electric load forecasting software GMDH Shell. Furthermore, its comparison to the actual measured load on the STELCO grid confirmed the predictions made are accurate and reliable.

Hence, the proposed DGPV system in this work has been modelled using these predictions as the system requirement.The results of the HOMER simulations have been further analyzed by applying the standard design guidelines for DGPV systems which are not included in HOMER. Its techno-economic feasibility represents a strong measure of its adoptability and contribution towards transforming the energy sector of the country.

The financial modelling of the proposed system was performed using a model developed by replicating the economic modelling of the HOMER software that took account of the staged capital investments. The cost benefit analysis performed proves the financial feasibility of the modular system desing approach used in this study. Furthermore, the systems' ability to produce electricity at grid parity represents a strong measure indicating, the proposed system is a technically sound and economically viable alternative energy solution to meet the energy requirement of Male'.

The proposed system has been carefully modelled considering the serious land constraints in Maldives. The prediction of future growth in electricity demand on the STELCO grid in Male', shows that the electricity demand in Male could reach up to 84MW by the year 2020 and 149 MW in 2030. The simulations being done with a minimum RF of 5%-10%, the optimal system configuration for the year 2020 requires 20MW of PV occupying a minimum land space of 26.36 acre. The optimal system configuration for the year 2030, require 30MW of PV occupying a minimum land area of 29.54 acre. Hulhumale' having a total reclaimed land area of 465 acre, a PV farm larger than 30MW would be unrealistic as it would be faced with serious land constraints for its construction.

Thus, the proposed system has been limited to a PV plant of 30MW, based on the STELCOs' estimation of purchasing 15-20MW from RE sources for Male region (The two cities of Male' and Hulhumale' interconnected and to be supplied by the national grid) [4]. This has been taken as a bench mark in this research since STELCO and the HDC are government organisations that could provide reliable information on the approximate land area available from Hulhumale' industrial zone for construction of a PV farm. However, the economic feasibility proves it as feasible even beyond this capacity.

Hence, this study concludes that the proposed system in this research presents a pre-feasibility assessment on deploying solar energy in transforming the energy sector of the country. The system being technically sound and financially viable, this research concludes that the proposed system could serve, a realistic and practical alternative solution for the energy requirement of Male'. Its implementation could be the turning point in transforming the energy sector of the country, since its being designed to cater for partial load on the national grid of STELCO, which represent a significantly high fraction of the electricity produced and consumed nationwide.

8.2 Need for Future Work

This research being focused on modelling a DGPV system to deploy RETs on the STELCO grid in Male', the findings of the research revealed alarming facts of high cocentration of electricity consumption in Male', which is explained by the continuous migration of families from smaller islands. With the severe land constraints of the city, a sustainable solution to the problem faced by STELCO seem, next an impossible task. The

governments' policy on delpolying RETs to transform the energy sector requires serious cosideration of its ecomonic benefits in comparison with the existing convernsional power plants. In this respect, a complete energy autdit of the country on a annual basis facilitating an accurate measure of the consumption in all the inhabited islands as well as the resorts which are the back bone of the economy of the nation is essential. Maldives being one of the most vulnerable island nation to the impact of climate change, the governments initiative to transform the energy sector by deploying RETs and lowering the carbon emission is an excellent initiative that would further contribute to its voice in the international community to save the nation from the serious impact of climate change and sea level raise. In this respect, future research on hybrid power generation in the maldives should take into consderation a complete energy audit, the required production capacity and its economic merit. Considering the serious land constraints of Maldives, future research shall consider exporing the technical soundness of using floatin solar modules as well the techno-echonomics of large energy storage for these islands, adressing the economic merit of transfer of generation technology to minimise the use of diesel fuel for electricity production. This shall facilitate a broader cost benefit analysis that would allow informed decition making in planing the future investment in energy sector, both by the government and the investors in the tourism industry.

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Appendix 1

Hourly Data used in Simulation

Average of hourly data for each month used in HOMER simulation						
2010						
Hrs	Jan	Feb	Mar	Apr	May	Jun
0:00	21,762.26	22,274.64	23,731.94	25,043.00	23,778.06	23,277.67
1:00	20,183.23	20,617.14	22,094.52	23,284.67	21,976.13	21,754.67
2:00	18,906.45	19,297.86	20,761.94	21,763.33	20,576.13	20,280.33
3:00	18,051.94	18,434.64	19,714.19	20,770.67	19,724.52	19,191.33

4:00	17,472.58	17,773.21	19,042.58	20,119.33	19,059.35	18,324.73
5:00	17,114.84	17,416.79	18,720.32	19,713.33	18,694.84	18,082.33
6:00	17,200.32	17,573.93	18,663.55	19,676.17	18,574.52	17,974.00
7:00	17,508.39	17,517.86	18,964.19	19,999.00	18,962.58	18,464.67
8:00	20,377.74	20,522.50	21,960.32	22,811.67	22,032.26	21,348.33
9:00	24,179.68	24,592.50	26,186.13	27,346.67	26,097.42	25,280.67
10:00	26,976.77	27,404.29	29,292.26	30,088.00	29,069.03	28,100.00
11:00	28,221.61	28,617.86	30,565.48	31,333.00	30,437.42	29,218.33
12:00	28,539.35	29,318.21	31,174.19	31,834.33	30,897.13	29,637.00
13:00	27,218.39	27,963.57	29,787.42	30,628.00	29,676.77	28,371.33
14:00	28,397.10	29,218.21	31,163.55	31,802.00	30,638.71	29,467.00
15:00	29,160.97	30,212.86	32,063.23	32,916.00	31,497.10	30,119.33
16:00	27,864.52	28,612.14	30,368.71	31,256.33	29,617.42	28,576.67
17:00	27,045.16	27,777.86	29,616.77	30,111.00	28,756.45	27,936.67
18:00	25,542.90	26,081.43	27,781.94	28,430.00	27,272.58	26,652.00
19:00	25,331.29	25,629.64	27,344.84	28,025.43	26,970.97	26,044.57
20:00	25,453.87	25,743.57	27,657.74	28,506.67	26,966.77	26,178.33
21:00	27,306.77	27,908.57	29,690.32	30,632.67	29,432.90	28,310.33
22:00	26,590.32	27,220.00	28,850.90	30,101.67	28,688.10	28,035.00
23:00	25,193.55	25,645.71	28,173.23	28,666.67	27,501.94	26,541.00
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	22,602.90	24,573.87	23,215.00	23,317.42	21,709.00	21,044.52
1:00	21,040.97	22,918.06	21,591.67	21,612.90	20,285.00	19,535.16
2:00	19,737.10	21,433.55	20,394.67	20,216.45	19,019.33	18,268.71
3:00	18,666.45	20,518.71	19,390.67	19,164.84	18,129.00	17,441.94
4:00	17,985.16	19,842.26	18,837.33	18,516.45	17,502.67	16,809.03
5:00	17,604.52	19,229.35	18,417.67	18,147.42	17,070.67	16,467.42
6:00	17,563.23	18,617.42	18,099.33	17,975.81	16,931.33	16,315.48
7:00	17,956.77	18,491.29	18,201.00	18,589.35	17,285.67	16,506.77
8:00	20,805.16	20,094.52	20,217.67	21,588.71	19,935.67	19,213.23
9:00	24,122.58	23,981.29	23,584.00	25,915.81	23,672.33	22,850.97
10:00	27,029.03	27,855.16	27,192.00	29,074.84	26,174.00	25,675.16
11:00	28,288.71	29,476.13	28,566.67	30,317.10	27,579.67	26,475.48
12:00	28,998.23	29,794.84	28,666.67	30,729.35	27,876.00	27,186.77
13:00	27,646.45	28,903.55	27,773.07	29,531.94	26,782.33	26,049.35
14:00	28,855.16	30,098.06	29,039.73	30,690.65	27,636.67	26,851.94
15:00	29,649.03	30,219.42	29,378.33	31,425.81	28,548.33	27,785.81
16:00	27,873.23	28,393.55	28,158.33	30,090.32	27,148.67	26,162.90
17:00	27,223.23	27,729.35	27,177.00	28,879.03	26,813.67	25,733.87
18:00	25,850.77	25,595.48	25,464.00	27,312.58	25,111.00	24,534.19
19:00	25,392.13	25,060.32	25,107.00	27,176.45	25,073.67	24,214.19
20:00	25,889.03	25,847.42	25,777.67	27,259.35	25,052.67	24,259.03
21:00	28,068.06	29,189.35	28,338.33	29,183.23	26,759.67	26,005.81
22:00	27,463.55	29,183.55	27,905.13	28,586.13	26,068.33	25,338.71
23:00	26,129.35	27,977.42	26,675.67	27,007.42	24,948.77	24,073.87

Average of houly data for each month used in HOMER simulation

2011

Hrs	Jan	Feb	Mar	Apr	May	Jun
0:00	22,336.45	22,906.07	24,975.16	25,371.00	24,872.26	invalid data
1:00	20,683.87	21,081.79	23,130.71	23,505.00	23,057.42	
2:00	19,062.90	19,695.36	22,158.06	21,937.00	21,629.03	
3:00	18,252.26	18,713.57	20,547.74	20,857.00	20,393.87	

4:00	17,652.58	18,010.00	19,727.74	20,104.33	19,877.65	
5:00	17,302.26	17,604.29	19,297.42	19,658.67	19,480.32	
6:00	17,327.10	17,648.21	19,268.71	19,646.00	19,354.52	
7:00	17,635.81	18,100.00	19,597.42	20,104.00	19,993.87	
8:00	20,565.16	20,770.00	22,838.06	23,032.33	23,362.06	
9:00	24,457.74	24,129.29	27,131.94	27,498.33	27,392.26	
10:00	27,548.39	27,806.07	30,540.00	30,509.33	30,417.10	
11:00	28,641.29	28,905.00	31,859.35	32,181.67	31,586.45	
12:00	29,321.61	29,622.86	32,610.00	32,713.33	32,021.61	
13:00	28,245.48	28,395.71	31,223.23	31,324.00	30,804.84	
14:00	29,169.68	29,615.36	32,622.90	32,629.50	31,652.39	
15:00	30,296.77	30,709.29	33,723.55	33,701.67	32,598.45	
16:00	28,467.74	29,181.43	32,018.06	32,098.00	30,664.52	
17:00	27,960.65	28,675.71	31,326.45	31,151.67	30,155.81	
18:00	26,526.13	26,581.43	29,350.32	29,279.67	28,423.55	
19:00	26,069.35	26,453.57	28,713.23	28,966.00	28,263.65	
20:00	25,954.52	26,538.57	28,716.81	29,012.67	28,272.10	
21:00	28,109.03	28,619.29	30,973.23	32,726.67	30,561.29	
22:00	27,387.42	27,982.50	30,442.58	30,764.33	30,058.06	
23:00	26,088.06	26,505.36	29,025.16	29,286.67	28,486.45	
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	invalid data	26,080.32	24,790.00	25,130.32	23,492.67	23,618.71
1:00		24,397.74	23,006.00	23,234.52	21,710.33	22,006.77
2:00		23,020.61	21,543.03	21,705.16	20,389.67	20,476.94
3:00		21,913.55	20,585.00	20,735.81	19,477.33	19,539.68
4:00		21,366.45	19,929.67	20,086.13	18,906.00	18,889.03
5:00		20,602.19	19,540.33	19,694.19	18,492.00	18,482.58
6:00		19,750.65	19,407.67	19,604.58	18,231.33	18,084.19
7:00		19,355.48	19,978.00	20,364.19	18,658.33	18,621.84
8:00		20,096.77	22,921.67	23,747.42	21,338.00	21,598.16
9:00		23,545.16	26,942.00	28,150.32	25,121.33	25,661.61
10:00		28,212.90	29,875.00	31,142.26	28,168.67	28,551.61
11:00		30,127.74	31,161.67	32,215.81	29,210.67	29,702.90
12:00		30,463.68	31,770.67	32,632.90	29,502.00	30,158.06
13:00		29,965.48	30,497.00	31,389.06	28,623.00	29,119.77
14:00		30,964.06	31,565.67	32,540.32	29,392.33	30,229.35
15:00		31,051.94	32,422.00	32,840.65	30,191.00	31,140.97
16:00		28,855.19	31,349.00	31,765.48	28,761.00	29,370.32
17:00		28,504.19	30,302.67	30,563.23	28,014.00	28,723.23
18:00		26,211.94	28,620.00	29,037.42	26,819.33	27,398.39
19:00		25,269.03	28,287.33	28,824.19	26,753.67	27,040.97
20:00		26,425.81	28,520.67	29,247.74	27,018.33	26,941.61
21:00		30,342.90	30,708.00	30,878.39	28,571.33	28,874.19
22:00		30,676.13	29,974.67	30,425.48	28,004.00	28,204.19
23:00		29,443.23	28,544.03	28,849.03	26,746.67	26,770.32

Average of hourly data for each month used in HOMER simulation						
2012						
Hrs	Jan	Feb	Mar	Apr	May	Jun
0:00	23,889.68	24,969.31	26,151.68	27,845.00	27,458.81	26,766.00
1:00	22,060.00	23,203.79	24,202.58	25,898.00	25,407.74	25,025.93
2:00	20,631.29	21,556.21	22,560.65	24,109.67	23,834.19	23,171.00

3:00	19,619.35	20,582.76	21,506.45	22,954.00	22,703.87	21,954.30
4:00	18,920.65	19,911.72	20,690.65	22,058.67	21,775.61	21,213.67
5:00	18,544.19	19,516.72	20,210.65	21,599.67	21,351.94	20,789.33
6:00	18,574.19	19,646.55	20,173.87	21,394.30	21,086.13	20,674.67
7:00	18,923.55	20,105.52	20,726.45	22,182.67	21,714.52	21,116.67
8:00	21,771.94	22,902.07	23,524.84	25,828.93	25,175.48	24,370.33
9:00	26,084.52	27,111.03	28,165.48	30,618.00	29,726.45	28,625.00
10:00	28,856.26	30,294.48	31,105.48	33,626.00	32,929.03	31,820.83
11:00	30,249.03	31,527.24	32,543.00	34,472.63	33,706.45	32,152.83
12:00	30,916.13	32,203.79	33,206.77	34,568.33	34,245.97	33,097.17
13:00	29,459.03	30,642.41	31,923.23	33,862.67	33,354.68	32,314.17
14:00	30,617.42	31,862.07	33,242.58	34,595.83	34,419.84	33,333.33
15:00	31,567.10	32,752.76	33,102.58	35,172.50	34,837.58	34,210.33
16:00	29,942.26	31,318.28	32,336.13	33,948.53	33,611.94	32,504.60
17:00	29,190.32	30,509.66	31,902.26	33,418.00	32,679.03	32,048.17
18:00	27,707.10	28,909.66	29,929.68	31,738.00	30,975.81	30,203.23
19:00	27,226.77	28,518.62	29,718.39	31,318.33	30,654.84	29,865.67
20:00	27,246.13	28,823.79	30,079.35	31,563.67	30,955.48	29,936.33
21:00	29,377.42	30,817.07	31,947.42	34,068.00	33,074.03	32,402.10
22:00	28,771.94	30,319.31	31,427.74	33,458.33	32,492.26	31,577.67
23:00	27,519.03	28,750.21	30,066.77	31,780.00	31,320.74	30,304.00
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	27,420.00	27,551.94	26,608.00	26,067.74	25,708.33	24,069.68
1:00	25,517.10	25,948.39	24,800.33	23,990.97	24,091.00	22,483.23
2:00	23,856.77	24,654.26	23,124.50	22,448.39	22,426.80	20,983.23
3:00	22,837.42	23,155.81	21,893.00	21,302.29	21,326.13	19,943.55
4:00	22,056.13	22,648.06	21,155.27	20,610.81	20,540.67	19,309.03
5:00	21,552.26	22,001.61	20,797.67	20,325.16	20,188.33	18,980.65
6:00	21,086.13	21,213.87	20,800.07	20,219.03	20,053.00	18,790.97
7:00	21,291.29	21,022.90	21,658.33	20,920.65	20,644.00	19,150.00
8:00	23,810.48	22,390.97	25,071.00	23,613.55	23,478.00	22,108.03
9:00	27,835.81	25,926.13	29,570.00	28,040.65	27,786.33	26,432.26
10:00	31,510.48	30,109.16	32,605.57	31,207.55	31,094.00	29,384.19
11:00	32,967.58	31,491.29	34,050.67	32,531.61	32,475.33	30,575.03
12:00	33,755.48	32,250.35	34,269.33	33,079.84	33,061.67	30,904.03
13:00	32,708.71	31,290.81	32,824.33	31,950.65	31,694.67	29,615.81
14:00	33,971.77	32,415.90	34,301.70	32,728.71	32,422.67	30,403.55
15:00	34,332.74	33,042.74	35,131.00	33,211.87	33,318.43	31,066.52
16:00	32,380.65	31,113.19	33,065.67	31,569.03	31,595.87	29,341.94
17:00	31,784.19	30,801.29	32,000.43	31,217.10	30,906.00	29,130.65
18:00	29,943.87	28,731.94	30,568.67	29,904.71	29,427.67	27,794.84
19:00	29,219.68	27,685.16	30,133.73	29,655.16	29,551.33	27,490.97
20:00	29,782.39	28,590.65	30,243.33	29,657.74	29,629.73	27,586.13
21:00	32,496.29	31,797.10	32,344.67	31,392.26	31,392.33	29,304.84
22:00	32,422.10	32,096.13	31,713.33	30,896.13	30,630.67	28,628.39
23:00	31,191.13	30,888.71	30,354.67	29,577.10	28,724.33	27,401.94

Average of hourly data for each month used in HOMER simulation						
2013						
Hrs	Jan	Feb	Mar	Apr	May	Jun
0:00	25,837.45	26,446.43	27,905.81	29,520.00	26,597.74	26,968.00
1:00	23,955.48	24,756.07	26,044.19	27,518.33	25,224.84	25,146.67

2:00	22,341.61	23,068.57	24,215.16	25,617.33	23,536.45	23,427.33
3:00	21,210.00	21,839.36	22,993.23	24,393.67	22,198.06	22,347.67
4:00	20,507.74	21,044.29	22,134.84	23,570.67	21,509.03	21,502.33
5:00	20,099.68	20,620.00	21,750.00	23,137.00	21,123.55	21,181.00
6:00	20,093.23	20,707.50	21,720.65	23,034.00	21,079.68	21,029.67
7:00	20,541.94	21,269.64	22,165.16	23,867.33	21,889.68	21,660.33
8:00	23,322.26	24,203.57	25,139.68	27,247.00	24,895.81	24,846.33
9:00	27,875.81	28,626.07	30,096.45	32,468.00	29,779.68	29,193.00
10:00	31,075.81	32,366.07	33,547.42	36,098.63	32,597.42	32,703.00
11:00	32,429.35	33,748.57	35,130.32	37,460.67	34,109.03	34,078.33
12:00	33,353.87	34,381.89	35,804.19	38,336.33	34,626.13	34,744.33
13:00	31,845.16	32,765.11	34,133.55	36,744.67	33,237.74	32,974.33
14:00	33,142.35	34,115.36	35,464.52	38,226.00	34,349.35	34,180.00
15:00	33,930.97	35,039.71	36,235.16	39,321.00	35,264.52	35,047.33
16:00	32,145.32	33,231.43	34,450.97	37,397.00	33,392.26	33,135.33
17:00	31,479.03	32,242.50	33,389.03	36,221.33	32,623.87	32,390.00
18:00	29,783.23	30,316.79	31,713.29	33,976.33	31,116.77	30,683.33
19:00	29,151.29	29,947.50	31,187.10	33,586.00	30,687.42	30,294.67
20:00	29,478.06	30,277.50	31,496.45	33,797.67	30,840.00	30,498.67
21:00	31,696.97	32,567.50	33,729.35	36,154.33	33,090.32	32,734.67
22:00	30,992.58	31,807.14	33,059.03	35,419.33	32,232.90	32,286.67
23:00	29,397.42	30,113.93	31,625.48	33,677.33	30,874.19	30,623.33
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	28,759.35	27,510.65	27,421.77	27,186.77	26,440.67	25,284.84
1:00	26,824.52	25,630.00	25,450.33	25,198.71	24,459.33	23,600.97
2:00	25,123.55	23,820.97	23,657.07	23,483.55	22,836.00	22,240.65
3:00	23,980.65	22,724.84	22,462.43	22,315.16	21,674.00	21,175.81
4:00	23,274.58	22,074.19	21,779.77	21,690.97	20,919.67	20,496.71
5:00	22,565.48	21,527.74	21,453.77	21,310.65	20,642.00	20,204.81
6:00	21,779.03	21,263.23	21,469.43	21,151.94	20,539.00	20,059.35
7:00	21,709.39	21,649.68	22,518.38	21,930.45	21,102.30	20,337.87
8:00	23,365.16	24,051.94	25,532.65	24,689.19	23,423.97	23,393.52
9:00	27,080.97	28,127.10	30,400.25	28,842.06	27,805.17	27,906.26
10:00	31,985.61	31,419.03	33,484.00	32,324.90	31,055.47	31,309.74
11:00	34,003.23	32,938.71	34,902.24	33,763.97	32,700.63	32,624.03
12:00	34,424.84	33,488.71	35,396.97	34,093.79	32,982.33	33,087.45
13:00	33,709.03	32,128.39	33,971.05	32,800.35	31,904.60	31,490.68
14:00	34,577.74	33,321.61	35,228.75	33,976.84	32,656.93	32,348.90
15:00	34,755.16	34,051.61	36,016.49	34,630.19	33,613.33	33,256.16
16:00	32,669.03	32,373.23	34,435.92	32,901.45	32,011.37	31,478.19
17:00	31,868.06	31,862.58	33,218.76	32,092.92	31,436.97	30,801.26
18:00	29,742.58	30,226.13	31,697.87	30,802.87	30,032.00	29,368.29
19:00	28,365.00	29,228.71	31,519.87	30,650.32	30,011.00	28,728.39
20:00	29,398.71	30,030.32	31,637.20	30,771.61	30,129.00	28,828.39
21:00	32,774.52	32,280.97	33,560.53	32,487.10	31,646.00	30,495.16
22:00	33,334.84	32,078.71	32,865.20	31,853.87	31,007.67	29,722.26
23:00	31,973.23	30,808.39	31,437.77	30,620.65	29,793.00	28,544.19

Average of hourly data for each month used in HOMER simulation						
2014						
Hrs	Jan	Feb	Mar	Apr	May	Jun
0:00	26,366.13	27,702.86	28,988.13	31,076.33	30,100.32	31,652.33

1:00	24,377.42	25,604.29	26,893.87	28,874.67	27,977.74	29,503.93
2:00	22,965.48	23,901.07	25,109.68	26,987.67	26,054.52	27,716.33
3:00	21,813.03	22,657.50	23,924.19	25,574.00	24,791.55	26,413.53
4:00	21,048.00	21,857.14	23,028.71	24,596.00	24,010.32	25,287.67
5:00	20,668.26	21,428.21	22,865.48	24,285.33	23,689.68	24,732.33
6:00	20,794.00	21,624.11	22,798.06	24,307.67	23,578.06	24,422.00
7:00	21,262.58	22,260.00	23,312.03	25,051.83	24,341.71	25,106.33
8:00	24,172.32	25,386.79	26,584.94	28,471.80	27,502.00	28,429.37
9:00	28,482.03	30,233.11	31,721.42	33,593.13	32,348.52	33,707.10
10:00	31,519.90	33,490.86	35,211.32	37,193.73	35,962.10	37,595.10
11:00	33,193.39	35,216.96	36,857.74	38,787.63	37,305.71	38,813.30
12:00	33,990.39	35,832.68	37,413.87	39,644.87	38,287.39	39,797.43
13:00	32,513.39	34,322.04	36,122.13	38,411.40	36,663.16	38,257.43
14:00	33,602.94	35,370.11	37,189.35	40,050.77	37,579.58	39,598.73
15:00	34,278.32	36,312.14	38,210.94	40,370.57	38,431.19	40,194.00
16:00	32,708.97	34,792.36	36,304.00	38,937.23	36,811.45	38,527.17
17:00	32,083.90	33,979.93	35,405.48	38,005.73	36,106.71	37,379.50
18:00	30,546.35	31,973.32	33,539.00	35,775.17	34,425.00	35,618.17
19:00	29,938.10	31,494.11	32,912.26	35,052.33	34,084.03	34,964.60
20:00	30,086.13	31,757.00	33,084.87	35,463.00	34,387.77	35,389.67
21:00	31,976.77	33,835.71	35,119.35	37,436.67	36,192.90	37,444.33
22:00	31,317.42	33,063.18	34,519.35	36,670.33	35,413.84	36,854.67
23:00	30,047.10	31,574.29	32,843.87	34,794.67	33,939.81	35,347.00
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	30,982.90	28,505.81	28,973.67	27,891.94	27,339.00	27,942.58
1:00	29,245.16	26,496.13	26,582.33	25,620.65	25,175.33	26,360.97
2:00	27,647.74	24,662.90	24,743.67	23,941.94	23,416.67	24,720.32
3:00	26,489.68	23,467.74	23,598.33	22,744.84	22,189.00	23,711.94
4:00	25,745.16	22,700.97	22,862.67	22,046.77	21,578.67	22,974.52
5:00	24,858.06	22,362.90	22,498.33	21,716.77	21,268.33	22,647.42
6:00	23,515.48	22,291.61	22,668.67	21,747.10	21,192.67	22,498.90
7:00	23,166.45	22,953.87	23,546.33	22,334.52	21,885.67	22,797.74
8:00	23,675.16	25,879.65	26,917.67	24,982.58	24,774.33	25,212.90
9:00	25,869.03	30,042.58	30,925.43	29,610.97	29,093.67	29,561.94
10:00	32,107.10	33,437.10	34,075.67	32,409.03	32,260.47	32,795.48
11:00	35,158.39	34,771.65	35,553.00	33,993.55	33,781.00	34,152.90
12:00	35,727.26	35,756.77	36,399.00	34,652.26	34,554.67	34,728.26
13:00	34,717.42	34,264.19	34,663.67	33,207.42	33,205.33	33,492.90
14:00	36,243.23	35,423.55	35,797.33	34,346.77	33,995.00	34,472.58
15:00	36,692.42	36,066.45	36,564.33	35,000.32	34,650.33	34,928.06
16:00	34,749.35	34,560.97	34,873.67	33,540.32	33,266.33	33,526.13
17:00	34,440.32	34,079.03	34,126.33	32,890.65	32,730.00	33,046.77
18:00	32,118.71	32,393.55	32,750.63	31,771.29	31,290.33	31,941.29
19:00	29,908.71	31,595.48	32,349.50	31,619.35	31,289.33	31,517.42
20:00	31,306.42	31,992.26	32,532.10	31,646.29	31,200.33	31,720.32
21:00	34,708.39	34,159.03	34,361.00	33,618.71	32,890.33	33,018.00
22:00	35,755.81	33,592.90	33,860.80	33,050.65	32,326.67	32,327.74
23:00	34,766.13	32,274.52	32,403.20	31,607.74	30,887.50	31,172.19

Average of hourly data for each month used in HOMER simulation						
2015						
Hrs	Jan	Feb	Mar	Apr	May	Jun

0:00	30,591.61	31,861.79	34,158.06	36,230.67	34,928.39	35,559.33
1:00	28,854.19	29,495.36	31,762.26	33,794.00	32,530.00	33,638.00
2:00	27,063.23	27,658.21	29,824.84	31,527.67	30,509.35	31,541.30
3:00	25,821.94	26,320.36	28,413.55	30,064.67	29,135.81	30,326.33
4:00	25,046.45	25,583.21	27,519.03	29,354.00	28,284.84	29,431.53
5:00	24,680.65	25,130.00	27,029.35	28,728.67	27,831.29	28,684.67
6:00	24,764.84	25,309.75	27,121.94	28,570.00	27,709.68	28,033.00
7:00	25,306.45	26,220.00	28,007.74	29,700.00	28,526.77	28,180.67
8:00	28,337.10	29,028.14	31,427.42	33,231.00	32,496.13	30,541.33
9:00	32,760.32	34,360.89	36,912.90	39,075.67	37,375.16	34,910.33
10:00	35,926.77	37,866.07	40,754.19	42,730.00	41,360.74	39,483.80
11:00	37,780.65	39,247.86	42,351.94	44,321.00	42,722.58	41,771.00
12:00	38,552.90	40,187.14	43,066.77	45,229.67	43,740.65	42,379.67
13:00	37,167.10	38,597.50	41,753.55	43,764.73	42,423.87	41,333.67
14:00	38,242.90	39,778.21	42,854.19	45,203.33	43,414.19	42,588.33
15:00	39,208.39	40,653.93	43,671.84	46,190.00	44,248.39	43,134.57
16:00	37,903.87	39,276.07	42,234.26	44,422.67	42,594.19	41,235.00
17:00	36,907.74	38,456.07	41,413.23	43,572.33	41,709.03	40,617.33
18:00	35,143.87	36,501.79	39,199.35	41,325.33	39,770.00	38,420.33
19:00	34,630.65	36,043.57	38,616.13	41,003.33	39,627.32	37,449.33
20:00	34,934.52	36,235.36	38,733.23	41,392.00	39,999.35	38,297.00
21:00	36,681.94	38,114.29	40,723.23	43,112.67	41,456.45	40,361.73
22:00	35,957.10	37,402.14	40,061.61	42,008.67	40,636.74	40,524.33
23:00	34,439.00	35,921.25	37,885.81	37,885.50	36,728.06	38,016.67
Hrs	Jul	Aug	Sep	Oct	Nov	Dec
0:00	34,541.61	32,452.26	31,084.07	32,236.77	32,546.67	31,670.97
1:00	32,857.74	30,456.77	29,207.33	30,218.39	30,411.33	29,941.13
2:00	31,168.19	28,563.58	27,322.00	28,310.65	28,483.33	28,353.55
3:00	29,809.35	27,310.00	26,143.00	27,107.42	27,162.33	27,232.58
4:00	29,045.16	26,495.74	25,331.00	26,274.52	26,415.67	26,345.48
5:00	28,298.71	26,212.26	25,038.67	25,861.61	26,074.33	25,953.71
6:00	27,289.68	26,261.94	25,012.67	25,795.48	25,916.33	25,705.16
7:00	26,743.55	27,060.00	25,729.00	26,756.45	26,782.33	26,124.19
8:00	27,782.90	30,763.81	28,509.00	29,951.29	30,574.67	29,657.10
9:00	31,234.19	35,486.65	33,374.47	34,447.42	35,833.33	34,412.90
10:00	36,322.90	39,138.06	36,708.43	37,951.61	39,220.00	38,022.42
11:00	38,929.68	40,444.23	37,845.67	39,484.32	40,603.50	39,197.65
12:00	39,477.74	41,005.16	38,621.00	40,216.13	41,445.67	39,974.52
13:00	38,742.90	39,154.52	37,235.50	39,152.58	40,148.40	38,602.26
14:00	39,820.65	40,725.03	37,873.33	40,301.13	40,979.23	39,473.87
15:00	39,992.90	40,934.52	38,606.33	40,659.03	41,451.00	39,812.58
16:00	38,721.94	39,530.65	37,063.33	39,118.39	40,106.67	38,403.55
17:00	38,625.81	38,745.16	36,268.57	38,330.32	39,157.33	37,795.16
18:00	36,580.32	37,075.16	35,206.33	37,110.32	37,785.83	36,608.71
19:00	34,990.00	36,895.81	34,930.00	37,141.61	37,729.67	36,227.10
20:00	35,977.10	37,113.23	35,040.23	37,323.23	37,760.00	36,454.19
21:00	38,530.65	38,709.35	36,602.77	38,368.39	39,125.67	37,513.77
22:00	38,771.45	37,933.23	35,809.67	37,396.45	38,132.00	36,526.13
23:00	37,267.74	34,083.23	32,272.67	33,986.45	34,527.00	33,517.42

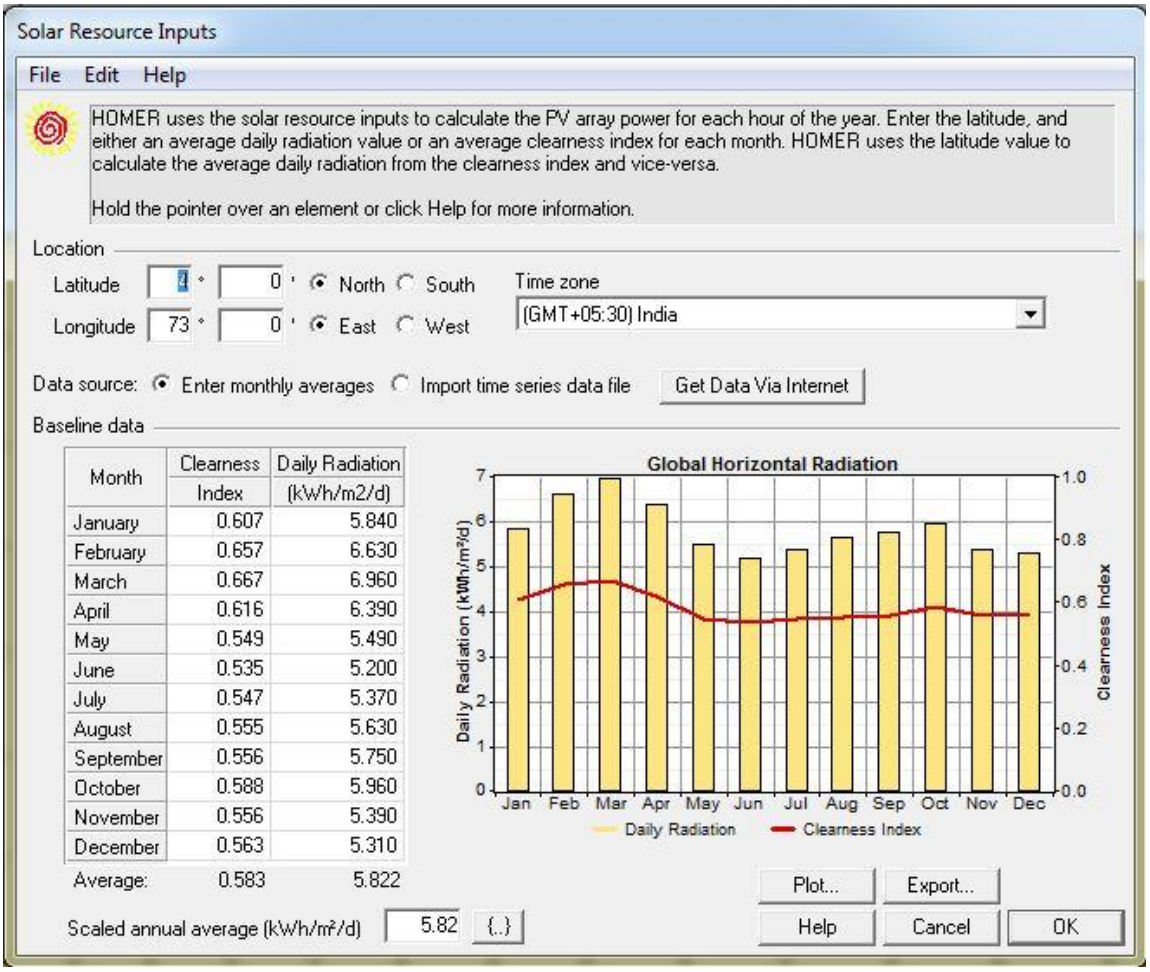
10 Years Data on Electric Load and the Variables used in demand forecasting

		Customer Types			
Year	**Load (MW)**	**Domestic (X1)**	**Business (X2)**	**Government (X3)**	**Temperature (X4)**
2001	15430	10217	3568	548	28.51
2002	16250	11114	3835	594	28.57
2003	18157	12091	4122	645	28.68
2004	20178	13153	4431	700	28.58
2005	23151	14343	4794	780	28.79
2006	26507	15499	5001	757	28.57
2007	29328	16509	5366	796	28.74
2008	32700	17915	5700	817	28.55
2009	35428	19417	6069	805	28.78
2010	37835	21143	6546	754	28.85

Population Estimates for future load prediction

Domestic Category			
Year	**No of Customers**	**Year**	**No of Customers**
2001	10217	2016	32161
2002	11114	2017	34324
2003	12091	2018	36576
2004	13153	2019	38917
2005	14343	2020	41345
2006	15499	2021	43862
2007	16509	2022	46467
2008	17915	2023	49161
2009	19417	2024	51943
2010	21143	2025	54813
2011	22668	2026	57771
2012	24390	2027	60818
2013	26200	2028	63953
2014	28099	2029	67177
2015	30086	2030	70488

Temperature Data



Annual Peaks (2010 – 2015)

Year	Measured Peak Load (kW)
2010	37,835
2011	38,638
2012	40,761
2013	42,554
2014	46,147
2015	50,623

Capital cost of PV and Inverter

	CIF Price US$/Wp	Installation/Mounting Structure with single axis tracking	Transformers and cablings	Installation and Commissioning	Miscellaneous including transportation	Operation and maintenance US$/Year
U$/Wp	1.5	10				all inclusive price
US$/kW	1500					
Total	1510					50
Capital Cost of Inverter						
	CIF Price US$/unit	Mounting Structure with single axis tracking	Transformers and cablings	Installation and Commissioning	Miscellaneous including transportation	Operation and maintenance
500kW	43500	0	0.06			
US$/kW	87		60	75	75	11
	297					
Total	148500					5500
PV Cost from Maldives						
US$/kW	5500	This includes transportation installation commissioning				
	Inverter/based on PV from Maldives					
US$/kW	110		220	385	110	11
	825					
500kW	412500					5500

Assumptions	
Cost of module	As given
Type of modules	Mono Crystalline
Type of system	Single axis tracking array
Life span of solar modules	25 years
Cost of mounting structure and trackers	Included in the unit cost
Transformers and cablings	4% of cost of PV modules
Installation and commissioning costs	7% of cost of PV modules
Miscellaneous cost	5% of cost of PV modules
For Maldivian Supplier	
Installation and commissioning costs	7% of cost of PV modules
Transformers and other electrical equipment	4% of cost of PV modules
Miscellaneous cost	2% of cost of PV modules

Simulation done with the exact hourly load of years (2011-2015)

To further validate the results of the simulation obtained from the sensitivity analysis using the predicted load, the simulation was repeated with the actual measured load of 2011-2015, which was received at a later stage of this research. The data of June and July 2011, was invalid, as it had a repetition of the same figure throughout. Hence in the simulation, they were replaced by the data of the May and August, 2011, for the running the simulation.

The table below shows the summarized result of these 5 individual simulations, showing the farm capacity and the energy yield delivered, compared with that obtained from the simulation done with the forecasted load.

Comparison of the optimal size of PV farm from simulation with actual load and the forecasted load

With actual Load			**With Forecasted Load (Sensitivity analysis)**		
Year	Size of PV array (kW)	Energy Yield (kWh/year)	Year	Size of PV array (kW)	Energy Yield (kWh/year)
2011	8000	11,535,927	2011	8500	12,333,241
2012	8500	12,333,101	2012	9500	13,726,611
2013	9,000	13,114,899	2013	10,000	14,519,937
2014	9,500	13,727,823	2014	11,000	15,916,022
2015	11,000	15,917,272	2015	12,000	17,484,644

Source: HOMER simulation results

Comparison of the results shows a slight difference in farm capacity varying between 500-1000KW, with the exception of the year 2014, where an additional capacity of 500KW (Total capacity difference of 1500KW) is required. However the results do indicate that the results obtained from the simulation done with the forecasted load are reliable, since the farm capacity is not seen under estimated or over-estimated by a significant difference, when compared to the simulation results obtained using the actual measured load. Thus, this further validates the load forecasting done in this study as well.

Appendix 2

EXTRACTS FROM HOMER SIMULATION RESULTS

Extracts from HOMER simulation result					
System Architecture for 2010					
Source	**Capacity**	**Unit**			
PV	7500	kW			
Grid	250	MW			
Inverter	5000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	11,120,579	5	AC Primary Load	216,953,840	100
Grid	206,026,304	95	Total	216,953,840	100
Total	217,146,883	100			
Quantity	**kWh/year**	**%**			
Excess electricity	82,162	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	7,500	kW	**Minimum output**	0	kW
Mean output	1,269	kW	**Maximum output**	6,020	kW
Mean output	30,467	kWh/d	**PV penetration**	5.13	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	11,120,579	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	5,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,247	kW	**Energy in**	11,038,444	kWh/yr
Minimum output	0	kW	**Energy out**	10,928,031	kWh/yr
Maximum output	5,000	kW	**Losses**	110,413	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	130,208,624	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	564,512	kg/year			
Nitrogen oxides	276,075	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2011					
Source	**Capacity**	**Unit**			
PV	8500	kW			
Grid	250	MW			
Inverter	5500	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	12,603,287	5	AC Primary Load	242,832,880	100
Grid	230,499,696	95	Total	242,832,880	100
Total	243,102,983	100			
Quantity	**kWh/year**	**%**			
Excess electricity	145,482	0.06			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	8,500	kW	**Minimum output**	0	kW
Mean output	1,439	kW	**Maximum output**	6,823	kW
Mean output	34,530	kWh/d	**PV penetration**	5.19	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	12,603,287	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	5,500	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,408	kW	**Energy in**	12,457,842	kWh/yr
Minimum output	0	kW	**Energy out**	12,333,241	kWh/yr
Maximum output	5,500	kW	**Losses**	124,601	kWh/yr
Capacity factor	26	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	145,675,808	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	631,569	kg/year			
Nitrogen oxides	308,870	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2012					
Source	**Capacity**	**Unit**			
PV	9500	kW			
Grid	250	MW			
Inverter	6000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	14,086,047	5	AC Primary Load	264,879,872	100
Grid	251,152,608	95	Total	264,879,872	100
Total	265,238,655	100			
Quantity	**kWh/year**	**%**			
Excess electricity	220,771	0.08			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	9,500	kW	**Minimum output**	0	kW
Mean output	1,608	kW	**Maximum output**	7,626	kW
Mean output	38,592	kWh/d	**PV penetration**	5.32	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	14,086,047	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	6,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,567	kW	**Energy in**	13,865,323	kWh/yr
Minimum output	0	kW	**Energy out**	13,726,611	kWh/yr
Maximum output	6,000	kW	**Losses**	138,712	kWh/yr
Capacity factor	26	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	158,728,448	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	688,158	kg/year			
Nitrogen oxides	336,545	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2013					
Source	**Capacity**	**Unit**			
PV	10,000	kW			
Grid	250	MW			
Inverter	6500	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	14,827,398	5	AC Primary Load	288,052,224	100
Grid	273,532,416	95	Total	288,052,224	100
Total	288,359,814	100			
Quantity	**kWh/year**	**%**			
Excess electricity	160,797	0.06			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	10,000	kW	**Minimum output**	0	kW
Mean output	1,693	kW	**Maximum output**	8,027	kW
Mean output	40,623	kWh/d	**PV penetration**	5.15	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	14,827,398	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	6,500	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,658	kW	**Energy in**	14,666,646	kWh/yr
Minimum output	0	kW	**Energy out**	14,519,937	kWh/yr
Maximum output	6,500	kW	**Losses**	146,709	kWh/yr
Capacity factor	26	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	172,872,480	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	749,479	kg/year			
Nitrogen oxides	336,545	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2014					
Source	**Capacity**	**Unit**			
PV	11,000	kW			
Grid	250	MW			
Inverter	7000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	16,310,166	5	AC Primary Load	312,365,440	100
Grid	296,448,864	95	Total	312,365,440	100
Total	312,759,030	100			
Quantity	**kWh/year**	**%**			
Excess electricity	233,364	0.06			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	11,000	kW	**Minimum output**	0	kW
Mean output	1,862	kW	**Maximum output**	8,830	kW
Mean output	44,685	kWh/d	**PV penetration**	5.22	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	16,310,166	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	7,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,817	kW	**Energy in**	16,076,836	kWh/yr
Minimum output	0	kW	**Energy out**	15,916,022	kWh/yr
Maximum output	7,000	kW	**Losses**	160,814	kWh/yr
Capacity factor	26	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	187,355,680	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	812,270	kg/year			
Nitrogen oxides	397,242	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2015					
Source	**Capacity**	**Unit**			
PV	12,000	kW			
Grid	250	MW			
Inverter	8000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	17,792,882	5	AC Primary Load	337,804,416	100
Grid	320,319,360	95	Total	337,804,416	100
Total	338,112,242	100			
Quantity	**kWh/year**	**%**			
Excess electricity	131,629	0.06			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	12,000	kW	**Minimum output**	0	kW
Mean output	2,031	kW	**Maximum output**	9,632	kW
Mean output	48,748	kWh/d	**PV penetration**	5.27	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	17,792,882	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	8,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	1,996	kW	**Energy in**	17,661,266	kWh/yr
Minimum output	0	kW	**Energy out**	17,484,644	kWh/yr
Maximum output	8,000	kW	**Losses**	176,622	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	202,441,840	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	877,675	kg/year			
Nitrogen oxides	429,228	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2016					
Source	**Capacity**	**Unit**			
PV	12,500	kW			
Grid	250	MW			
Inverter	8500	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	18,534,274	5	AC Primary Load	364,369,440	100
Grid	346,116,928	95	Total	364,369,440	100
Total	364,651,202	100			
Quantity	**kWh/year**	**%**			
Excess electricity	96,883	0.03			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	12,500	kW	**Minimum output**	0	kW
Mean output	2,116	kW	**Maximum output**	10,034	kW
Mean output	50,779	kWh/d	**PV penetration**	5.09	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	18,534,274	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	8,500	kW	**Hours of operation**	4,380	hrs/yr
Mean output	2,084	kW	**Energy in**	18,437,396	kWh/yr
Minimum output	0	kW	**Energy out**	18,253,002	kWh/yr
Maximum output	8,500	kW	**Losses**	184,394	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	218,745,904	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	948,360	kg/year			
Nitrogen oxides	463,797	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2017					
Source	**Capacity**	**Unit**			
PV	13,500	kW			
Grid	250	MW			
Inverter	9000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	20,017,040	5	AC Primary Load	392,062,176	100
Grid	372,391,872	95	Total	392,062,176	100
Total	392,408,912	100			
Quantity	**kWh/year**	**%**			
Excess electricity	147,863	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	13,500	kW	**Minimum output**	0	kW
Mean output	2,285	kW	**Maximum output**	10,837	kW
Mean output	54,841	kWh/d	**PV penetration**	5.11	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	20,017,040	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	9,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	2,245	kW	**Energy in**	19,869,154	kWh/yr
Minimum output	0	kW	**Energy out**	19,670,476	kWh/yr
Maximum output	9,000	kW	**Losses**	198,678	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	235,351,664	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,020,354	kg/year			
Nitrogen oxides	499,005	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2018					
Source	**Capacity**	**Unit**			
PV	14,500	kW			
Grid	250	MW			
Inverter	9500	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	21,499,724	5	AC Primary Load	420,894,208	100
Grid	399,815,552	95	Total	420,894,208	100
Total	421,315,276	100			
Quantity	**kWh/year**	**%**			
Excess electricity	208,183	0.05			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	14,500	kW	**Minimum output**	0	kW
Mean output	2,454	kW	**Maximum output**	11,639	kW
Mean output	58,903	kWh/d	**PV penetration**	5.11	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	21,499,724	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	9,500	kW	**Hours of operation**	4,380	hrs/yr
Mean output	2,406	kW	**Energy in**	21,291,542	kWh/yr
Minimum output	0	kW	**Energy out**	21,078,634	kWh/yr
Maximum output	9,500	kW	**Losses**	212,908	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	252,683,424	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,095,495	kg/year			
Nitrogen oxides	535,753	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2019					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	5	AC Primary Load	450,865,568	100
Grid	421,523,232	95	Total	450,865,568	100
Total	451,178,028	100			
Quantity	**kWh/year**	**%**			
Excess electricity	16,038	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	20,000	kW	**Minimum output**	0	kW
Mean output	3,385	kW	**Maximum output**	16,054	kW
Mean output	81,246	kWh/d	**PV penetration**	6.58	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	29,654,796	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	3,350	kW	**Energy in**	29,638,764	kWh/yr
Minimum output	0	kW	**Energy out**	29,342,370	kWh/yr
Maximum output	15,000	kW	**Losses**	296,394	kWh/yr
Capacity factor	22	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	266,402,688	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,154,974	kg/year			
Nitrogen oxides	564,841	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2020					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	5	AC Primary Load	481,951,392	100
Grid	452,607,808	95	Total	481,951,392	100
Total	482,262,604	100			
Quantity	**kWh/year**	**%**			
Excess electricity	15,471	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	20,000	kW	**Minimum output**	0	kW
Mean output	3,385	kW	**Maximum output**	16,054	kW
Mean output	81,246	kWh/d	**PV penetration**	6.58	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	29,654,796	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	3,350	kW	**Energy in**	29,639,332	kWh/yr
Minimum output	0	kW	**Energy out**	29,342,934	kWh/yr
Maximum output	15,000	kW	**Losses**	296,398	kWh/yr
Capacity factor	22	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	286,048,128	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,240,145	kg/year			
Nitrogen oxides	606,495	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2021					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	6	AC Primary Load	514,174,848	100
Grid	484,831,872	94	Total	514,174,848	100
Total	514,486,668	100			
Quantity	**kWh/year**	**%**			
Excess electricity	14,882	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	20,000	kW	**Minimum output**	0	kW
Mean output	3,385	kW	**Maximum output**	16,054	kW
Mean output	81,246	kWh/d	**PV penetration**	5.77	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	29,654,796	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	3,350	kW	**Energy in**	29,639,920	kWh/yr
Minimum output	0	kW	**Energy out**	29,343,514	kWh/yr
Maximum output	15,000	kW	**Losses**	296,406	kWh/yr
Capacity factor	22	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	306,413,728	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,328,439	kg/year			
Nitrogen oxides	649,675	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2022					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	5	AC Primary Load	547,527,616	100
Grid	518,182,560	95	Total	547,527,616	100
Total	547,837,356	100			
Quantity	**kWh/year**	**%**			
Excess electricity	14,274	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	20,000	kW	**Minimum output**	0	kW
Mean output	3,385	kW	**Maximum output**	16,054	kW
Mean output	81,246	kWh/d	**PV penetration**	5.42	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	29,654,796	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	3,350	kW	**Energy in**	29,640,526	kWh/yr
Minimum output	0	kW	**Energy out**	29,344,116	kWh/yr
Maximum output	15,000	kW	**Losses**	296,410	kWh/yr
Capacity factor	22	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	327,491,392	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,419,820	kg/year			
Nitrogen oxides	694,365	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2023					
Source	**Capacity**	**Unit**			
PV	20,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	29,654,796	5	AC Primary Load	582,016,640	100
Grid	552,672,704	95	Total	582,016,640	100
Total	582,327,500	100			
Quantity	**kWh/year**	**%**			
Excess electricity	13,644	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	20,000	kW	**Minimum output**	0	kW
Mean output	3,385	kW	**Maximum output**	16,054	kW
Mean output	81,246	kWh/d	**PV penetration**	5.42	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	29,654,796	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	3,350	kW	**Energy in**	29,641,154	kWh/yr
Minimum output	0	kW	**Energy out**	29,344,740	kWh/yr
Maximum output	15,000	kW	**Losses**	296,414	kWh/yr
Capacity factor	22	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	349,289,152	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,514,323	kg/year			
Nitrogen oxides	740,581	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2024					
Source	**Capacity**	**Unit**			
PV	25,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	37,068,548	6	AC Primary Load	617,635,200	100
Grid	581,917,568	94	Total	617,635,200	100
Total	618,986,116	100			
Quantity	**kWh/year**	**%**			
Excess electricity	990,387	0.16			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	25,000	kW	**Minimum output**	0	kW
Mean output	4,232	kW	**Maximum output**	20,068	kW
Mean output	101,558	kWh/d	**PV penetration**	6	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	37,068,548	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Unit**	**Quantity**	**Inverter**	**Unit**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,077	kW	**Energy in**	36,078,348	kWh/yr
Minimum output	0	kW	**Energy out**	35,717,368	kWh/yr
Maximum output	15,000	kW	**Losses**	360,980	kWh/yr
Capacity factor	27	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	367,771,904	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,594,454	kg/year			
Nitrogen oxides	779,770	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2025					
Source	**Capacity**	**Unit**			
PV	25,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	37,068,548	6	AC Primary Load	654,379,008	100
Grid	618,660,928	94	Total	654,379,008	100
Total	655,729,476	100			
Quantity	**kWh/year**	**%**			
Excess electricity	989,716	0.15			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	25,000	kW	**Minimum output**	0	kW
Mean output	4,232	kW	**Maximum output**	20,068	kW
Mean output	101,558	kWh/d	**PV penetration**	5.66	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	37,068,548	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,077	kW	**Energy in**	36,079,016	kWh/yr
Minimum output	0	kW	**Energy out**	35,718,032	kWh/yr
Maximum output	15,000	kW	**Losses**	360,984	kWh/yr
Capacity factor	27	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	390,993,696	kg/year			
Carbon monoxide	0				
Unburned hydrocarbons	0				
Particulate matter	0				
Sulfur dioxide	1,695,131	kg/year			
Nitrogen oxides	829,006	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2026					
Source	**Capacity**	**Unit**			
PV	25,000	kW			
Grid	250	MW			
Inverter	15000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	37,068,548	5	AC Primary Load	692,250,304	100
Grid	656,530,880	95	Total	692,250,304	100
Total	693,599,428	100			
Quantity	**kWh/year**	**%**			
Excess electricity	989,025	0.14			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	25,000	kW	**Minimum output**	0	kW
Mean output	4,232	kW	**Maximum output**	20,068	kW
Mean output	101,558	kWh/d	**PV penetration**	5.35	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	37,068,548	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	15,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,077	kW	**Energy in**	36,079,708	kWh/yr
Minimum output	0	kW	**Energy out**	35,718,712	kWh/yr
Maximum output	15,000	kW	**Losses**	360,996	kWh/yr
Capacity factor	27	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	414,927,520	kg/year			
Carbon monoxide	0	kg/year			
Unburned hydrocarbons	0	kg/year			
Particulate matter	0	kg/year			
Sulfur dioxide	1,798,895	kg/year			
Nitrogen oxides	879,751	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2027					
Source	**Capacity**	**Unit**			
PV	25,000	kW			
Grid	250	MW			
Inverter	20000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	37,068,548	5	AC Primary Load	731,259,648	100
Grid	694,565,760	95	Total	731,259,648	100
Total	731,634,308	100			
Quantity	**kWh/year**	**%**			
Excess electricity	3,941	0			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	25,000	kW	**Minimum output**	0	kW
Mean output	4,232	kW	**Maximum output**	20,068	kW
Mean output	101,558	kWh/d	**PV penetration**	5.07	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	37,068,548	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	20,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,189	kW	**Energy in**	37,064,600	kWh/yr
Minimum output	0	kW	**Energy out**	36,693,932	kWh/yr
Maximum output	19,867	kW	**Losses**	370,668	kWh/yr
Capacity factor	21	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	438,965,568	kg/year			
Carbon monoxide	0	kg/year			
Unburned hydrocarbons	0	kg/year			
Particulate matter	0	kg/year			
Sulfur dioxide	1,903,110	kg/year			
Nitrogen oxides	930,718	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2028					
Source	**Capacity**	**Unit**			
PV	30,000	kW			
Grid	250	MW			
Inverter	20000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	44,482,316	6	AC Primary Load	771,397,248	100
Grid	727,686,208	94	Total	771,397,248	100
Total	772,168,524	100			
Quantity	**kWh/year**	**%**			
Excess electricity	330,407	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	30,000	kW	**Minimum output**	0	kW
Mean output	5,078	kW	**Maximum output**	24,081	kW
Mean output	121,869	kWh/d	**PV penetration**	5.77	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	44,482,316	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	20,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,990	kW	**Energy in**	44,152,016	kWh/yr
Minimum output	0	kW	**Energy out**	43,710,376	kWh/yr
Maximum output	20,000	kW	**Losses**	441,640	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	459,897,696	kg/year			
Carbon monoxide	0	kg/year			
Unburned hydrocarbons	0	kg/year			
Particulate matter	0	kg/year			
Sulfur dioxide	1,993,860	kg/year			
Nitrogen oxides	975,100	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2029					
Source	**Capacity**	**Unit**			
PV	30,000	kW			
Grid	250	MW			
Inverter	20000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	44,482,316	5	AC Primary Load	812,673,024	100
Grid	768,961,600	95	Total	812,673,024	100
Total	813,443,916	100			
Quantity	**kWh/year**	**%**			
Excess electricity	329,654	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	0.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	30,000	kW	**Minimum output**	0	kW
Mean output	5,078	kW	**Maximum output**	24,081	kW
Mean output	121,869	kWh/d	**PV penetration**	5.47	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	44,482,316	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	20,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,990	kW	**Energy in**	44,152,768	kWh/yr
Minimum output	0	kW	**Energy out**	43,711,128	kWh/yr
Maximum output	20,000	kW	**Losses**	441,640	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	485,983,744	kg/year			
Carbon monoxide	0	kg/year			
Unburned hydrocarbons	0	kg/year			
Particulate matter	0	kg/year			
Sulfur dioxide	2,106,955	kg/year			
Nitrogen oxides	1,030,409	kg/year			

Extracts from HOMER simulation result					
System Architecture for 2030					
Source	**Capacity**	**Unit**			
PV	30,000	kW			
Grid	250	MW			
Inverter	20000	kW			
Electrical					
Production	**kWh/year**	**%**	**Consumption**	**kWh/year**	**%**
PV array	44,482,316	5	AC Primary Load	855,061,184	100
Grid	811,350,912	94	Total	855,061,184	100
Total	855,833,228	100			
Quantity	**kWh/year**	**%**			
Excess electricity	328,880	0.04			
Unmet electric load	0.00	0.00			
Capacity shortage	4158.00	0.00			
PV					
Quantity	**Value**	**Unit**	**Quantity**	**Value**	**Unit**
Rated capacity	30,000	kW	**Minimum output**	0	kW
Mean output	5,078	kW	**Maximum output**	24,081	kW
Mean output	121,869	kWh/d	**PV penetration**	5.2	%
Capacity factor	16.9	%	**Hours of operation**	4,380	hr/yr
Total production	44,482,316	kWh/yr	**Levelized cost**	0.357	$/kWh
Inverter					
Quantity	**Inverter**	**Units**	**Quantity**	**Inverter**	**Units**
Capacity	20,000	kW	**Hours of operation**	4,380	hrs/yr
Mean output	4,990	kW	**Energy in**	44,153,544	kWh/yr
Minimum output	0	kW	**Energy out**	43,711,892	kWh/yr
Maximum output	20,000	kW	**Losses**	441,652	kWh/yr
Capacity factor	25	%			
Emissions					
Pollutant	**Emissions**	**Unit**			
Carbon dioxide	512,773,792	kg/year			
Carbon monoxide	0	kg/year			
Unburned hydrocarbons	0	kg/year			
Particulate matter	0	kg/year			
Sulfur dioxide	2,223,102	kg/year			
Nitrogen oxides	1,087,210	kg/year			

Appendix 3

Important Extracts from Sensitivity Analysis

Important Extracts from Sensitivity Analysis

The extracted results here shows how the proposed system is modelled to deliver a minimum RF of 5% and shows the changes in the system configuration of each year with the percentage of load on the grid served by the system as the RF is increased from 5%-10%.

Year 2010				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	7500	5%	11,120,579
	6	9000	6%	13,344,677
	7	11000	8%	16,310,166
	8	12000	8%	17,792,882
	9	13500	9%	20,017,040
	10	15000	10%	22,241,158
0.4	5%-9%	14000	10%	20,758,406
0.42	5%-10%	30000	20%	44,482,316

Year 2011				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	8500	5%	12,333,241
	6	10000	6%	14,635,023
	7	12000	7%	17,482,928
	8	13500	8%	19,667,778
	9	20000	12%	29,654,796
	10	20000	12%	29,329,388
0.4	5%-8%	14500	9%	21,196,474
0.42	5%-10%	35000	21%	50,823,552

Year 2012				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	9500	5%	14,086,047
	6	11000	6%	16,310,166
	7	13000	7%	19,275,666
	8	14500	8%	21,499,724
	9	20000	11%	29,654,796
	10	20000	11%	29,654,796
0.4	5%-8%	14500	8%	21,499,724
0.42	5%-10%	35000	20%	51,895,896

Year 2013				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	10000	5%	14,827,398
	6	12000	6%	17,792,882
	7	14000	7%	20,758,406
	8	20000	10%	29,654,796
	9	20000	10%	29,654,796
	10	20000	10%	29,654,796
0.4	5%-7%	14500	7%	21,499,724
0.42	5%-10%	45000	23%	66,723,320

Year 2014				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	11000	5%	16,310,166
	6	13000	6%	19,275,666
	7	15000	7%	22,241,158
	8	20000	9%	29,654,796
	9	20000	9%	29,654,796
	10	25000	12%	37,068,548
0.4	5%-6%	14500	7%	21,499,724
0.42	5%-10%	45000	21%	66,723,320

Year 2015				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	12000	5%	17,792,882
	6	14000	6%	20,758,406
	7	20000	9%	29,654,796
	8	20000	9%	29,654,796
	9	25000	11%	37,068,548
	10	25000	11%	37,068,548
0.4	5%-10%	30,000	13%	44,482,316
0.42	5%-10%	45000	20%	66,723,320

Year 2016				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	12500	5%	18,534,274
	6	15000	6%	22,241,158
	7	20000	8%	29,654,796
	8	20000	8%	29,654,797
	9	25000	10%	37,068,548
	10	25000	10%	37,068,549
0.4	5%-10%	30,000	12%	44,482,316
0.42	5%-10%	50000	20%	74,137,096

Year 2017				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	13500	5%	20,017,040
	6	20000	8%	29,654,796
	7	20000	8%	29,654,796
	8	25000	9%	37,068,548
	9	25000	9%	37,068,548
	10	30000	11%	44,482,316
0.4	5%-10%	30000	11%	44,482,316
0.42	5%-10%	60,000	23%	88,964,632

Year 2018				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	14500	5%	21,499,724
	6	20000	7%	29,654,796
	7	25000	9%	37,068,548
	8	25000	9%	37,068,548
	9	30000	11%	44,482,316
	10	30000	11%	44,482,317
0.4	5%-10%	30000	11%	44,482,316
0.42	5%-10%	60,000	21%	88,964,632

Year 2019				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	7%	29,654,796
	6	20000	7%	29,654,796
	7	25000	8%	37,068,548
	8	25000	8%	37,068,548
	9	30000	10%	44,482,316
	10	35000	11%	51,895,896
0.4	5%-9%	30000	10%	44,482,316
0.42	5%-10%	65,000	21%	96,378,272

Year 2020				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	6%	29,654,796
	6	20000	6%	29,654,796
	7	25000	8%	37,068,548
	8	30000	9%	44,482,316
	9	30000	9%	44,482,316
	10	35000	11%	51,895,896
0.4	5%-9%	30000	9%	44,482,316
0.42	5%-10%	65,000	20%	96,378,272

Year 2021				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	6%	29,654,796
	6	25000	7%	37,068,548
	7	25000	7%	37,068,548
	8	30000	9%	44,482,316
	9	35000	10%	51,895,896
	10	40000	11%	59,309,592
0.4	5%-10%	45000	13%	66,723,320
0.42	5%-10%	75,000	22%	111,205,680

Year 2022				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	5%	29,654,796
	6	25000	7%	37,068,548
	7	30000	8%	44,482,316
	8	30000	8%	44,482,316
	9	35000	9%	51,895,896
	10	40000	11%	59,309,592
0.4	5%-10%	45000	12%	66,723,320
0.42	5%-10%	80,000	22%	118,619,184

Year 2023				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	20000	5%	29,654,796
	6	25000	6%	37,068,548
	7	30000	8%	44,482,316
	8	35000	9%	51,895,896
	9	40000	10%	59,309,592
	10	40000	10%	59,309,592
0.4	5%-10%	45000	11%	66,723,320
0.42	5%-10%	80,000	20%	118,619,184

Year 2024				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	25000	6%	37,068,548
	6	30000	7%	44,482,316
	7	30000	7%	44,482,316
	8	35000	8%	51,895,896
	9	40000	10%	59,309,592
	10	45000	11%	66,723,320
0.4	5%-10%	45000	11%	66,723,320
0.42	5%-10%	90,000	21%	133,446,640

Year 2025				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	25000	6%	37,068,548
	6	30000	7%	44,482,316
	7	35000	8%	51,895,896
	8	40000	9%	59,309,592
	9	45000	10%	66,723,320
	10	45000	10%	66,723,320
0.4	5%-10%	45000	10%	66,723,320
0.42	5%-10%	95,000	21%	140,860,400

Year 2026				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	25000	5%	37,068,548
	6	30000	6%	44,482,316
	7	35000	7%	51,895,896
	8	40000	9%	59,309,592
	9	45000	10%	66,723,320
	10	50000	11%	74,137,096
0.4	5%-10%	65000	14%	96,378,272
0.42	5%-10%	95,000	20%	140,860,400

Year 2027				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	25000	5%	37,068,548
	6	30000	6%	44,482,316
	7	35000	7%	51,895,896
	8	40000	8%	59,309,592
	9	45000	9%	66,723,320
	10	50000	10%	74,137,096
0.4	5%-10%	65000	13%	96,378,272
0.42	5%-10%	110,000	22%	163,101,968

Year 2028				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	30000	6%	44,482,316
	6	35000	7%	51,895,896
	7	40000	8%	59,309,592
	8	45000	9%	66,723,320
	9	50000	10%	74,137,096
	10	55000	11%	81,550,984
0.4	5%-10%	65000	12%	96,378,272
0.42	5%-10%	110,000	21%	163,101,968

Year 2029				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	30000	5%	44,482,316
	6	35000	6%	51,895,896
	7	40000	7%	59,309,592
	8	45000	8%	66,723,320
	9	50000	9%	74,137,096
	10	60000	11%	88,964,632
0.4	5%-10%	65000	12%	96,378,272
0.42	5%-10%	120,000	22%	177,929,264

Year 2030				
Grid Rate (US$ /kWh)	RF %	PV (kW)	% of Load	Total electricity production from PV (kWh/year)
0.25-0.38	5	30000	5%	44,482,316
	6	35000	6%	51,895,896
	7	45000	8%	66,723,320
	8	50000	9%	74,137,096
	9	55000	10%	81,550,984
	10	60000	10%	88,964,632
0.4	5%-10%	65000	11%	96,378,272
0.42	5%-10%	120,000	21%	177,929,264

Levelized cost of energy (COE) and Grid Parity

The Levelized cost of energy (COE) is calculated using the same formula in [51]. The COE given by HOMER which is the same as calculated below can be found in the captured screen shots of HOMER simulation in the appendix 5.

$$COE = \frac{Total\ annualized\ Cost\ of\ the\ system}{Total\ Energy\ delivered\ by\ the\ system\ over\ the\ same\ period}$$

The annualized cost of the system is calculated using the formula;

$$C_{ann\_total} = CRF\left(i, R_{proj}\right) x\ C_{NPC\_total}$$

Applying the formulas for NPV, CRF (to represent the total annualized cost) and the total energy yield of the system, the formula is re-written as;

$$COE = \frac{\left[\frac{i(1+i)^N}{(1+i)^N - 1}\right] x[-C_0 + \sum_{i=1}^{T}\left(\frac{C_i}{(1+r)^i}\right)]}{\left[f_{pv} Y_{pv} \frac{I_T}{I_s}\right] + E_{grid}} \qquad [Equation\ (34)]$$

$$COE = \frac{CRF\left(i, R_{proj}\right) x\ C_{NPC\_total}}{f_{pv} Y_{pv} \frac{I_T}{I_s} + E_{grid}} \qquad [Equation\ (34a)]$$

Thus, applying the values calculated for the CRF, the NPV and Energy yield of the system of 2011 = 243,102,983, the COE for the proposed system of 2011 is;

$$COE = \frac{[0.0871845569768514][717{,}809{,}811]}{12603287 + 230499696}$$

$$COE = \frac{62581930.3656}{243102983}$$

$$COE = \$0.257/\text{kWh}$$

Grid Parity

Grid Parity / Section A						
Year	PV array capacity (kW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized COE Calculated (US$/kWh)
2010	7,500	15	217,146,880	55,870,172	0.250	0.257
What's observed here is; the change in annualized cost with the change in grid rates to maintain grid parity. The change in COE with the grid rates is the same for all the year. This remain true for changes in system size with increased RF for the same load as well. Ref tables in section B				57,930,440	0.260	0.267
				62,050,964	0.280	0.286
				66,171,488	0.300	0.305
				70,292,024	0.320	0.324
				74,412,552	0.340	0.343
				78,533,088	0.360	0.362
				82,653,600	0.380	0.381
				86,766,152	0.400	0.400
				90,336,360	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2011	8500	17	243,102,983	62,557,260	0.250	0.257
				64,862,256	0.260	0.267
				69,472,248	0.280	0.286
				74,082,248	0.300	0.305
				78,692,224	0.320	0.324
				83,302,232	0.340	0.343
				87,910,664	0.360	0.362
				92,518,400	0.380	0.381
				97,117,000	0.400	0.399
				101,138,024	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2012	9,500	19	265,238,655	68,289,224	0.250	0.257
				70,800,088	0.260	0.267
				75,820,064	0.280	0.286
				80,840,056	0.300	0.305
				85,860,048	0.320	0.324
				90,880,040	0.340	0.343
				95,900,008	0.360	0.362
				100,919,984	0.380	0.380
				105,935,344	0.400	0.399
				110,329,640	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2013	10,000	20	288,359,814	74,188,160	0.250	0.257
				76,923,480	0.260	0.267
				82,394,128	0.280	0.286
				87,864,792	0.300	0.305
				93,335,424	0.320	0.324
				98,805,896	0.340	0.343
				104,274,232	0.360	0.362
				109,742,560	0.380	0.381
				115,204,440	0.400	0.400
				119,964,888	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2014	11,000	22	312,759,030	80,486,016	0.250	0.257
				83,450,496	0.260	0.267
				89,376,544	0.280	0.286
				95,302,536	0.300	0.305
				101,228,504	0.320	0.324
				107,154,448	0.340	0.343
				113,080,424	0.360	0.362
				119,006,392	0.380	0.381
				124,929,272	0.400	0.399
				130,058,312	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2015	12,000	24	338,112,242	87,061,584	0.250	0.257
				90,264,776	0.260	0.267
				96,671,184	0.280	0.286
				103,077,568	0.300	0.305
				109,483,936	0.320	0.324
				115,890,328	0.340	0.343
				122,296,728	0.360	0.362
				128,703,144	0.380	0.381
				135,102,624	0.400	0.400
				140,669,728	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2016	12,500	25	364,651,202	93,814,960	0.250	0.257
				97,276,112	0.260	0.267
				104,198,464	0.280	0.286
				111,120,808	0.300	0.305
				118,043,160	0.320	0.324
				124,965,504	0.340	0.343
				131,887,840	0.360	0.362
				138,810,160	0.380	0.381
				145,726,336	0.400	0.400
				151,730,528	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2017	13,500	27	392,408,912	100,952,448	0.250	0.257
				104,676,360	0.260	0.267
				112,124,192	0.280	0.286
				119,572,040	0.300	0.305
				127,019,888	0.320	0.324
				134,467,712	0.340	0.343
				141,915,552	0.360	0.362
				149,363,408	0.380	0.381
				156,801,328	0.400	0.400
				163,265,264	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2018	14,500	29	421,315,276	108,377,104	0.250	0.257
				112,375,240	0.260	0.267
				120,371,568	0.280	0.286
				128,367,904	0.300	0.305
				136,364,192	0.320	0.324
				144,358,544	0.340	0.343
				152,352,432	0.360	0.362
				160,346,304	0.380	0.381
				168,332,368	0.400	0.400
				175,246,160	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2019	20,000	40	451,178,028	117,147,784	0.250	0.260
				121,363,008	0.260	0.269
				129,793,496	0.280	0.288
				138,223,936	0.300	0.306
				146,654,416	0.320	0.325
				155,084,896	0.340	0.344
				163,515,344	0.360	0.362
				171,945,808	0.380	0.381
				180,319,472	0.400	0.400
				187,731,136	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2020	20,000	40	482,262,604	124,918,936	0.250	0.259
				129,445,024	0.260	0.268
				138,497,168	0.280	0.287
				147,549,360	0.300	0.306
				156,601,472	0.320	0.325
				165,653,632	0.340	0.343
				174,705,824	0.360	0.362
				183,757,968	0.380	0.381
				192,752,944	0.400	0.400
				200,688,640	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2021	20,000	40	514,486,668	132,974,952	0.250	0.258
				137,823,280	0.260	0.268
				147,519,936	0.280	0.287
				157,216,560	0.300	0.306
				166,913,216	0.320	0.324
				176,609,856	0.340	0.343
				186,306,512	0.360	0.362
				196,003,184	0.380	0.381
				205,640,704	0.400	0.400
				214,087,744	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2022	20,000	40	547,837,356	141,312,640	0.250	0.258
				146,494,480	0.260	0.267
				156,858,128	0.280	0.286
				167,221,792	0.300	0.305
				177,585,440	0.320	0.324
				187,949,104	0.340	0.343
				198,312,736	0.360	0.362
				208,676,384	0.380	0.381
				218,978,192	0.400	0.400
				227,976,192	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2023	20,000	40	582,327,500	149,935,184	0.250	0.257
				155,461,904	0.260	0.267
				166,515,328	0.280	0.286
				177,568,800	0.300	0.305
				188,622,272	0.320	0.324
				199,675,728	0.340	0.343
				210,729,200	0.360	0.362
				221,782,624	0.380	0.381
				232,772,112	0.400	0.400
				242,340,544	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2024	25,000	50	618,986,116	159,893,968	0.250	0.258
				165,713,168	0.260	0.268
				177,351,536	0.280	0.287
				188,989,888	0.300	0.305
				200,628,240	0.320	0.324
				212,266,560	0.340	0.343
				223,904,976	0.360	0.362
				235,543,360	0.380	0.381
				247,016,784	0.400	0.399
				257,164,960	0.420	0.415

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2025	25,000	50	655,729,476	169,079,808	0.250	0.258
				175,266,416	0.260	0.267
				187,639,664	0.280	0.286
				200,012,928	0.300	0.305
				212,386,128	0.320	0.324
				224,759,296	0.340	0.343
				237,132,576	0.360	0.362
				249,505,760	0.380	0.381
				261,712,400	0.400	0.399
				272,459,840	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2026	25,000	50	693,599,428	178,547,312	0.250	0.257
				185,112,608	0.260	0.267
				198,243,248	0.280	0.286
				211,373,840	0.300	0.305
				224,504,480	0.320	0.324
				237,635,136	0.340	0.343
				250,765,744	0.360	0.362
				263,896,336	0.380	0.380
				276,858,368	0.400	0.399
				288,236,768	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2027	25,000	50	731,634,308	188,448,224	0.250	0.258
				195,393,904	0.260	0.267
				209,285,280	0.280	0.286
				223,176,576	0.300	0.305
				237,067,840	0.320	0.324
				250,959,184	0.340	0.343
				264,850,480	0.360	0.362
				278,723,424	0.380	0.381
				292,453,376	0.400	0.400
				304,494,528	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2028	30,000	60	772,168,524	199,375,936	0.250	0.258
				206,652,784	0.260	0.268
				221,206,496	0.280	0.286
				235,760,256	0.300	0.305
				250,313,968	0.320	0.324
				264,867,696	0.340	0.343
				279,421,440	0.360	0.362
				293,975,136	0.380	0.381
				308,503,584	0.400	0.400
				321,175,808	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2029	30,000	60	813,443,916	209,694,768	0.250	0.258
				217,384,368	0.260	0.267
				232,763,632	0.280	0.286
				248,142,880	0.300	0.305
				263,522,112	0.320	0.324
				278,901,344	0.340	0.343
				294,280,608	0.360	0.362
				309,659,840	0.380	0.381
				325,010,944	0.400	0.400
				338,380,128	0.420	0.416

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2030	30,000	60	855,833,228	220,292,128	0.250	0.257
				228,405,616	0.260	0.267
				244,632,672	0.280	0.286
				260,859,648	0.300	0.305
				277,086,688	0.320	0.324
				293,313,760	0.340	0.343
				309,540,736	0.360	0.362
				325,767,744	0.380	0.381
				341,964,032	0.400	0.400
				356,025,152	0.420	0.416

Section B

In this section, the same calculation is repeated for 2011-2015 & 2020, 2025&2030, with the exact total electricity production with change in grid rate, showing how HOMER maintains grid parity, as shown in Section A. The COE of all systems configurations are the same for all grid rates, achieving grid parity. This is because as HOMER runs the sensitivity analysis and optimizes the system, its complex algorithm checks and discards any system that do not achieve grid parity under the constraints and costs applied.

Grid Parity

Year	PV array capacity (kW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized COE Calculated (US$/kWh)
2010	7,500	15	217,146,880	55,870,172	0.250	0.257
	What's observed here is; The change in energy and the annualized cost of the system with change in grid rate, maintaining the grid parity. This is what HOMER does in its optimization process with the sensitivity variables		217,146,880	57,930,440	0.260	0.267
			217,146,880	62,050,964	0.280	0.286
			217,146,880	66,171,488	0.300	0.305
			217,146,880	70,292,024	0.320	0.324
			217,146,880	74,412,552	0.340	0.343
			217,146,880	78,533,088	0.360	0.362
			217,146,880	82,653,600	0.380	0.381
			217,277,632	86,766,152	0.400	0.399
	30000	60	218,010,992	90,336,360	0.420	0.414

Grid Parity

Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2011	8500	17	243,102,983	62,557,260	0.250	0.257
			243,102,976	64,862,256	0.260	0.267
			243,102,976	69,472,248	0.280	0.286
			243,102,976	74,082,248	0.300	0.305
			243,102,976	78,692,224	0.320	0.324
			243,102,976	83,302,232	0.340	0.343
			242,989,696	87,910,664	0.360	0.362
			242,989,696	92,518,400	0.380	0.381
	14500	29	243,136,176	97,117,000	0.400	0.399
	35000	70	243,905,216	101,138,024	0.420	0.415

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2012	9,500	19	265,238,655	68,289,224	0.250	0.257
			265,085,264	70,800,088	0.260	0.267
			265,085,264	75,820,064	0.280	0.286
			265,085,264	80,840,056	0.300	0.305
			265,085,264	85,860,048	0.320	0.324
			265,085,264	90,880,040	0.340	0.343
			265,085,264	95,900,008	0.360	0.362
			265,085,264	100,919,984	0.380	0.381
	14500	29	265,182,048	105,935,344	0.400	0.399
	35000	70	265,790,016	110,329,640	0.420	0.415

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2013	10,000	20	288,359,814	74,188,160	0.250	0.257
			288,359,808	76,923,480	0.260	0.267
			288,359,808	82,394,128	0.280	0.286
			288,359,808	87,864,792	0.300	0.305
			288,359,808	93,335,424	0.320	0.324
			288,243,904	98,805,896	0.340	0.343
			288,243,904	104,274,232	0.360	0.362
			288,243,904	109,742,560	0.380	0.381
	14500	29	288,354,720	115,204,440	0.400	0.400
	30000	60	290,017,152	119,964,888	0.420	0.414

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2014	11,000	22	312,759,030	80,486,016	0.250	0.257
			312,759,040	83,450,496	0.260	0.267
			312,608,512	89,376,544	0.280	0.286
			312,608,512	95,302,536	0.300	0.305
			312,608,512	101,228,504	0.320	0.324
			312,608,512	107,154,448	0.340	0.343
			312,608,512	113,080,424	0.360	0.362
			312,608,512	119,006,392	0.380	0.381
	14500	29	312,666,816	124,929,272	0.400	0.400
	45000	90	314,049,120	130,058,312	0.420	0.414

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2015	12,000	24	338,112,242	87,061,584	0.250	0.257
			338,112,256	90,264,776	0.260	0.267
			338,112,256	96,671,184	0.280	0.286
			338,112,256	103,077,568	0.300	0.305
			338,112,256	109,483,936	0.320	0.324
			338,112,256	115,890,328	0.340	0.343
			338,112,256	122,296,728	0.360	0.362
			338,112,256	128,703,144	0.380	0.381
	30000	60	338,602,976	135,102,624	0.400	0.399
	45,000	90	339,314,400	140,669,728	0.420	0.415

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2020	20,000	40	482,262,604	124,918,936	0.250	0.259
			482262592	129,445,024	0.260	0.268
			482262592	138,497,168	0.280	0.287
			482262592	147,549,360	0.300	0.306
			482262592	156,601,472	0.320	0.325
			482262592	165,653,632	0.340	0.343
			482262592	174,705,824	0.360	0.362
			482262592	183,757,968	0.380	0.381
	30000	60	482,728,768	192,752,944	0.400	0.399
	65000	130	483854976	200,688,640	0.420	0.415

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2025	25,000	50	655,729,476	169,079,808	0.250	0.258
			655,729,472	175,266,416	0.260	0.267
			655,729,472	187,639,664	0.280	0.286
			655,729,472	200,012,928	0.300	0.305
			655,729,472	212,386,128	0.320	0.324
			655,729,472	224,759,296	0.340	0.343
			655,729,472	237,132,576	0.360	0.362
			655,729,472	249,505,760	0.380	0.381
	45000	90	655,550,464	261,712,400	0.400	0.399
	65000	130	657,663,104	272,459,840	0.420	0.414

Grid Parity						
Year	PV array capacity (MW)	Number of inverters of rated capacity (500kW)	Total Production (kWh/Year)	Annualized cost (US$)	Grid Rate (US$/kWh)	Levelized Cost of Energy (US$/kWh)
2030	30,000	60	855,833,228	220,292,128	0.250	0.257
			855,833,216	228,405,616	0.260	0.267
			855,833,216	244,632,672	0.280	0.286
			855,833,216	260,859,648	0.300	0.305
			855,833,216	277,086,688	0.320	0.324
			855,833,216	293,313,760	0.340	0.343
			855,833,216	309,540,736	0.360	0.362
			855,833,216	325,767,744	0.380	0.381
	65000	130	856,417,152	341,964,032	0.400	0.399
	120000	240	859,376,576	356,025,152	0.420	0.414

Appendix 4

Technical Specification of PV and Inverter used

SOLPO PHOTOVOLTAIC CO., LTD

Rated Maximum Power	Wp	240	245	250	270	275	280	285	290	295	275	280	285	290	295	300
Power Tolerance	%	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3	±3
Maximum Power Voltage	V	30.8	30.9	31.0	36.6	36.7	36.9	37.0	37.2	37.4	36.7	36.9	37.0	37.2	37.3	37.5
Maximum Power Current	A	7.80	7.93	8.05	7.40	7.50	7.60	7.70	7.80	7.90	7.50	7.60	7.70	7.80	7.90	8.00
Open Circuit Voltage	V	37.6	37.7	37.8	44.2	44.4	44.6	44.8	45.0	45.2	44.0	44.2	44.4	44.6	44.8	45.0
Short Circuit Current	A	8.40	8.50	8.60	8.00	8.10	8.20	8.30	8.40	8.50	8.10	8.20	8.30	8.40	8.50	8.60
Maximum System Voltage	V	1000			1000						1000					
Cell Transfer Efficiency	%	16.7	17.1	17.4	15.4	15.7	16.0	16.3	16.6	16.8	16.2	16.4	16.7	17.0	17.1	17.6
Transfer Efficiency	%	14.7	15.0	15.3	13.9	14.1	14.4	14.6	14.9	15.1	14.1	14.4	14.6	14.9	15.1	15.4
Cell Number & Size		156mm x 156mm (60pcs)			156mm x 156mm (72pcs)						156mm x 156mm (72pcs)					
Cell Type		Mono Crystalline			Poly Crystalline						Mono Crystalline					
Cell Combination		6×10 matrix connection in series			6×12 matrix connection in series						6×12 matrix connection in series					
Cable Type $ Diameter		4mm² (12AWG),TUV Certified			4mm² (12AWG),TUV Certified						4mm² (12AWG),TUV Certified					
Connector Type		IP67,Multi-Contact Type IV			IP67,Multi-Contact Type IV						IP67,Multi-Contact Type IV					
Junction Box		IP65,1000VDC,TUV&UL Certified			IP65,1000VDC,TUV&UL Certified						IP65,1000VDC,TUV&UL Certified					
Bypass Diodes No. & Type		3Nos,Schottky By-pass diodes			3Nos,Schottky By-pass diodes						3Nos,Schottky By-pass diodes					
Max. Series Fuse Rating	A	14			14						14					
Tempe.Coefficient of Power	%/℃	0.45			-0.45						-0.45					
Temp. Coefficient of Voc	%/℃	0.35			-0.35						-0.35					
Temp. Coefficient of Isc	%/℃	0.05			0.05						0.05					
Nominal Operating Cell Temperature	℃	45±2			45±2						45±2					
Standard Test Condition	STC	STC：AM=1.5,1000W/㎡,Cells Tempeature 25℃			STC：AM=1.5,1000W/㎡,Cells Tempeature 25℃						STC：AM=1.5,1000W/㎡,Cells Tempeature 25℃					
Operating Temperature	℃	-40~+85			-40~+85						-40~+85					
Dimension A*B*C	mm	1650*992*45			1965*992*45						1965*992*45					
Installation Hole DIM. E*F	mm	990*941			1177*941						1177*941					
Cable Length G	mm	1000			1000						1000					
Weight	kg	19.5			25						25					
Draining Holes No.in Frame		8			12						12					
Construction		Super Strate High transission 3.2Omm temperedlow iron glass; Substrate ， White Backsheet,Encapsulant, Fast Cure EVA			Super Strate High transission 3.2Omm temperedlow iron glass; Substrate ， White Backsheet,Encapsulant, Fast Cure EVA						Super Strate High transission 3.2Omm temperedlow iron glass; Substrate ， White Backsheet,Encapsulant, Fast Cure EVA					
Frame		Clear anodized aluminum alloy type 6063T5,Color:Silver			Clear anodized aluminum alloy type 6063T5,Color:Silver						Clear anodized aluminum alloy type 6063T5,Color:Silver					
Packing and Quantity		20pcs per carton with per pallet			20pcs per carton with pallet						20pcs per carton with pallet					

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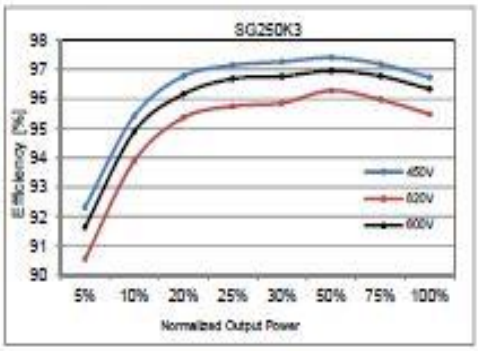


SG 250K3

Features:

- Reactive Power Control with power factor from 0.9 lagging to 0.9 leading
- German BDEW medium voltage guideline compliant
- Max. efficiency at 97.3%
- Easy installation and maintenance
- Multilingual touch screen monitoring and control interface
- Suitable for harsh grid environment
- Auxiliary heater (optional)
- Max. working altitude at 6000m (operation with derating above 3000m)
- TÜV ,CE ,Enel-GUIDA certification

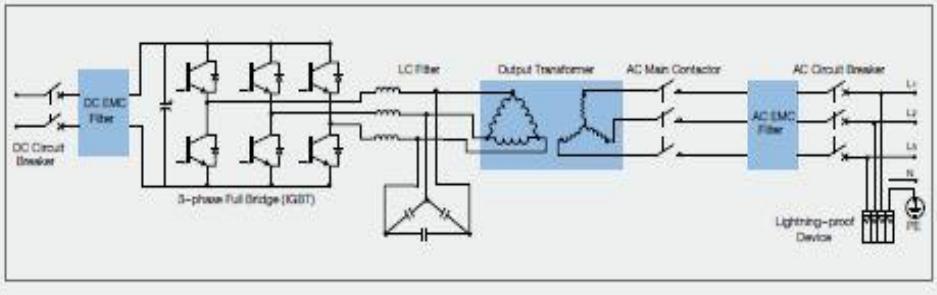
Efficiency Curve



Technical Specifications:

	SG 250K3
DC SIDE DATA	
Max. DC Voltage	900Vdc
Start Voltage	470V
MPP Voltage	450~820V
Min. DC Voltage	450V
Max. DC Power	275kWp
Max. Input Current	600A
AC SIDE DATA	
Rated Output Power	250kW
Max. AC Output Current	397A
Rated Grid Voltage	400Vac
Grid Voltage Range	310~450Vac
Rated Grid Frequency	50Hz/60Hz
Grid Frequency Range	47~52Hz/57~62Hz
Output Current THD	<3% (at nominal power)
DC Current Injection	<0.5% of rated inverter output current
Power factor (cos ϕ)	0.9 (lagging) ~0.9 (leading)
SYSTEM	
Max. Efficiency	97.3% (with transformer)
Euro. Efficiency	96.7% (with transformer)
Protection Degree	IP20 (Indoor)
Power Consumption at Night	<100W
Operating Temperature	-25~+55℃
Cooling Method	controlled forced-air cooling
Relative Humidity	0~95%, non-condensing
Max. Working Altitude	6000m (operation with derating above 3000m)
DISPLAY AND COMMUNICATIONS	
Display	touch screen LCD
Standard Comm. Interfaces	RS485
Optional Comm. Interfaces	Ethernet
MECHANICAL DATA	
Dimensions (WxHxD)	1800x2180x850mm
Net Weight	2100kg

Circuit Diagram:



Specifications subject to change without notice.

Printed in December 2011 E.S NLDX-0414-CA

Appendix 5

Captured screen shots of HOMER simulation results (2010-2030) at a minimum RF of 5%

Year 2010

Sensitivity case

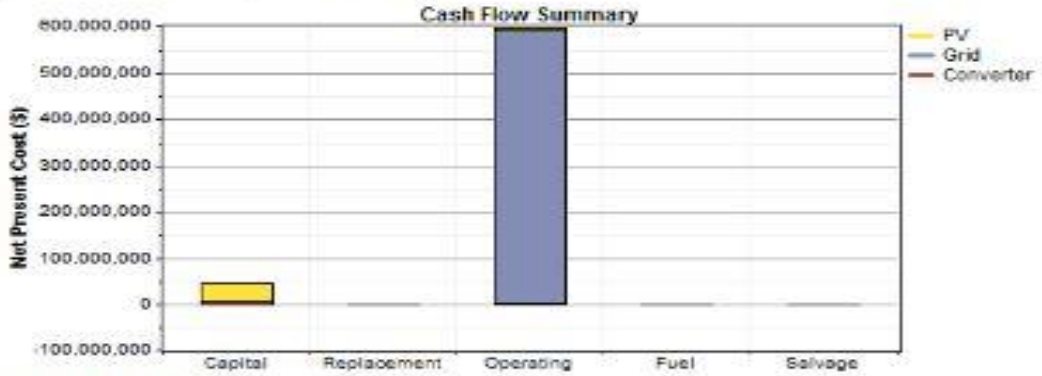
Primary Load 1 Scaled Average: 594,394 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	7,500 kW
Grid	250,000 kW
Inverter	5,000 kW
Rectifier	5,000 kW

Cost summary

Total net present cost	$ 640,826,176
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 51,914,148/yr

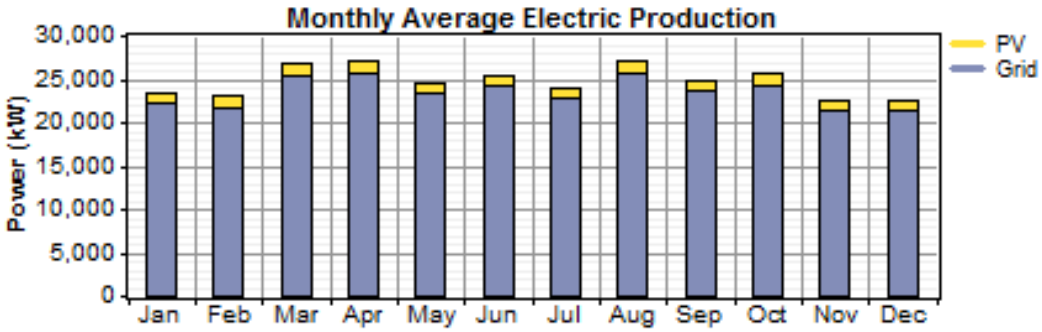


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	41,250,000	0	4,301,223	0	0	45,551,224
Grid	0	0	590,776,704	0	0	590,776,704
Converter	4,125,000	0	630,846	0	-257,239	4,498,606
System	45,375,000	0	595,708,736	0	-257,239	640,826,496

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	3,596,363	0	375,000	0	0	3,971,363
Grid	0	0	51,506,604	0	0	51,506,604
Converter	359,636	0	55,000	0	-22,427	392,209
System	3,955,999	0	51,936,600	0	-22,427	55,870,172



Year 2011

Sensitivity case

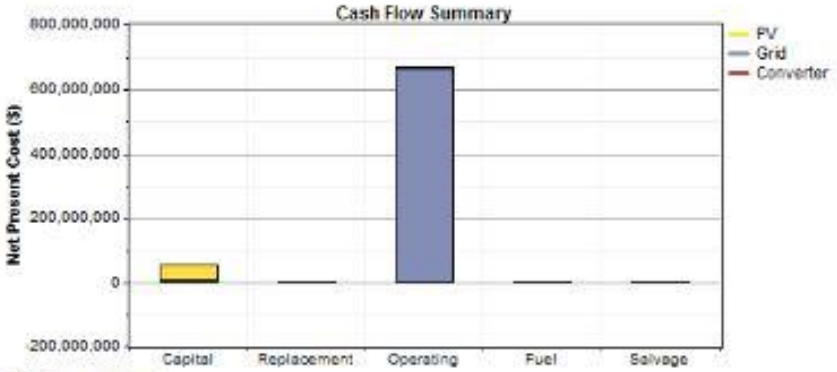
Primary Load 1 Scaled Average: 665,294 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	8,500 kW
Grid	250,000 kW
Inverter	5,500 kW
Rectifier	5,500 kW

Cost summary

Total net present cost	$ 717,526,526
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 58,085,752/yr

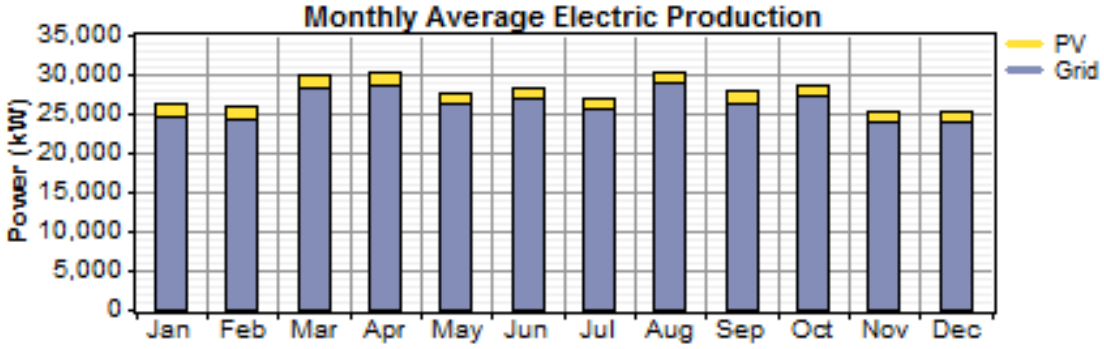


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	46,750,000	0	4,874,719	0	0	51,624,716
Grid	0	0	660,953,664	0	0	660,953,664
Converter	4,537,500	0	693,931	0	-282,963	4,948,467
System	51,287,500	0	666,522,240	0	-282,963	717,526,848

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	4,075,878	0	425,000	0	0	4,500,878
Grid	0	0	57,624,952	0	0	57,624,952
Converter	395,600	0	60,500	0	-24,670	431,430
System	4,471,478	0	58,110,444	0	-24,670	62,557,260



Year 2012

Sensitivity case

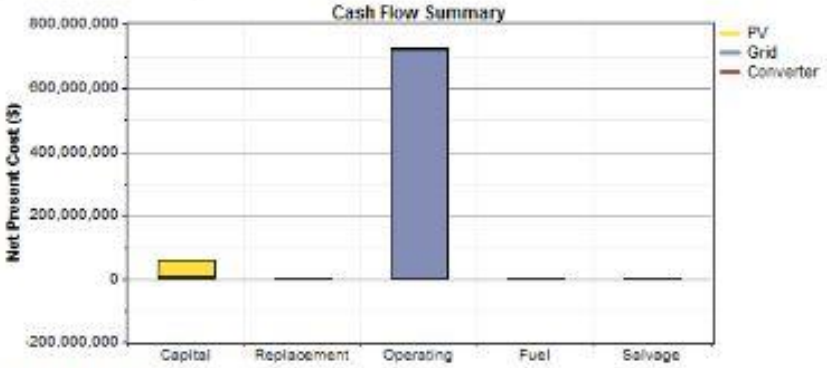
Primary Load 1 Scaled Average: 725,695 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	9,500 kW
Grid	250,000 kW
Inverter	6,000 kW
Rectifier	6,000 kW

Cost summary

Total net present cost	$ 783,271,680
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 63,302,236/yr

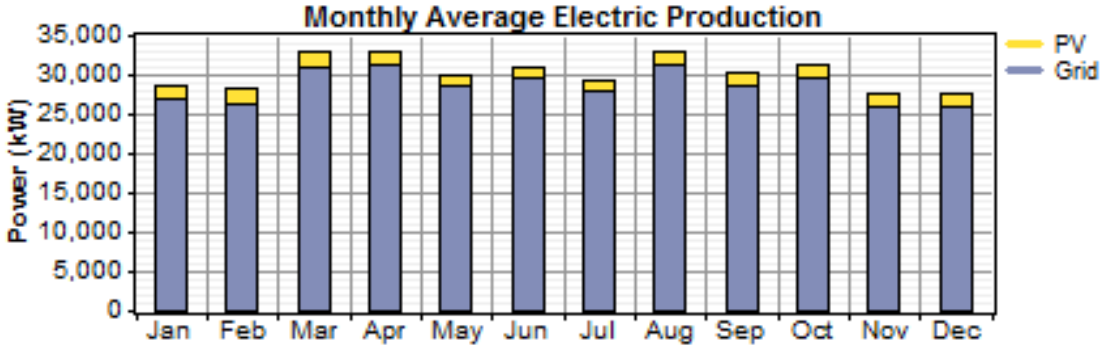


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	52,250,000	0	5,448,216	0	0	57,698,212
Grid	0	0	720,175,424	0	0	720,175,424
Converter	4,950,000	0	757,015	0	-308,687	5,398,328
System	57,200,000	0	726,380,736	0	-308,687	783,272,000

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	4,555,393	0	475,000	0	0	5,030,393
Grid	0	0	62,788,176	0	0	62,788,176
Converter	431,564	0	66,000	0	-26,913	470,651
System	4,986,957	0	63,329,180	0	-26,913	68,289,224



Year 2012

Sensitivity case

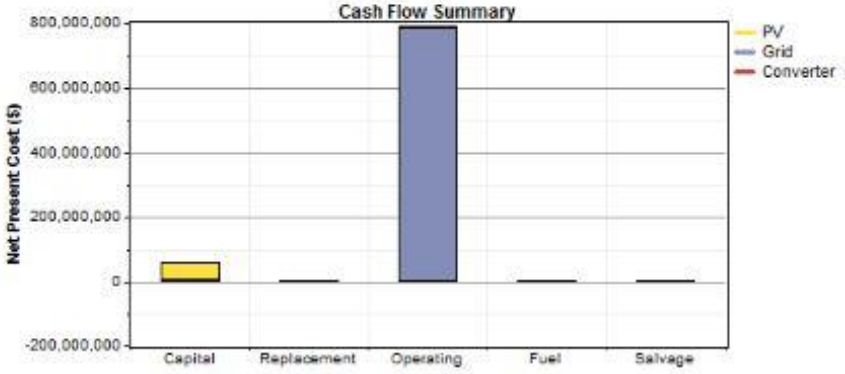
Primary Load 1 Scaled Average: 789,183 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	10,000 kW
Grid	250,000 kW
Inverter	6,500 kW
Rectifier	6,500 kW

Cost summary

Total net present cost	$ 850,931,968
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 68,925,448/yr

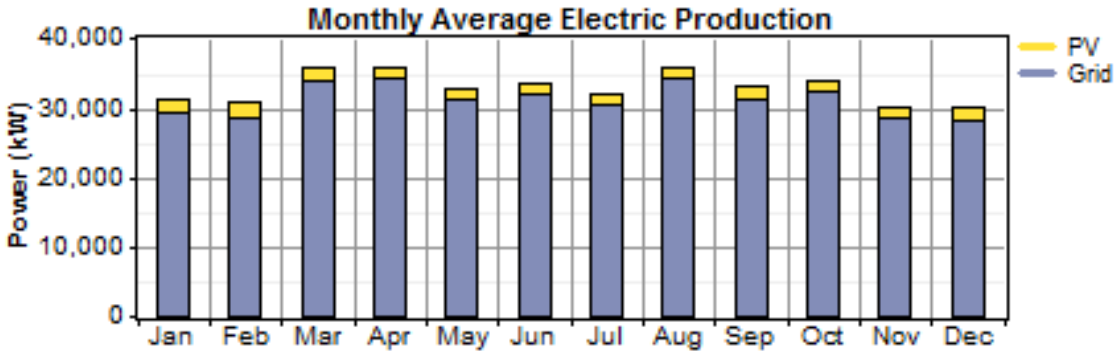


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	55,000,000	0	5,734,963	0	0	60,734,964
Grid	0	0	784,349,120	0	0	784,349,120
Converter	5,362,500	0	820,100	0	-334,411	5,848,189
System	60,362,500	0	790,904,192	0	-334,411	850,932,352

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	4,795,151	0	500,000	0	0	5,295,151
Grid	0	0	68,383,128	0	0	68,383,128
Converter	467,527	0	71,500	0	-29,155	509,872
System	5,262,678	0	68,954,632	0	-29,155	74,188,160



Year 2013

Sensitivity case

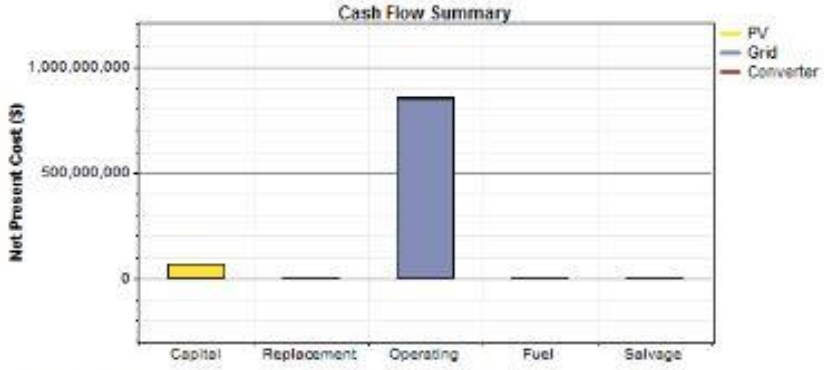
Primary Load 1 Scaled Average: 855,792 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	11,000 kW
Grid	250,000 kW
Inverter	7,000 kW
Rectifier	7,000 kW

Cost summary

Total net present cost	$ 923,167,808
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 74,707,816/yr

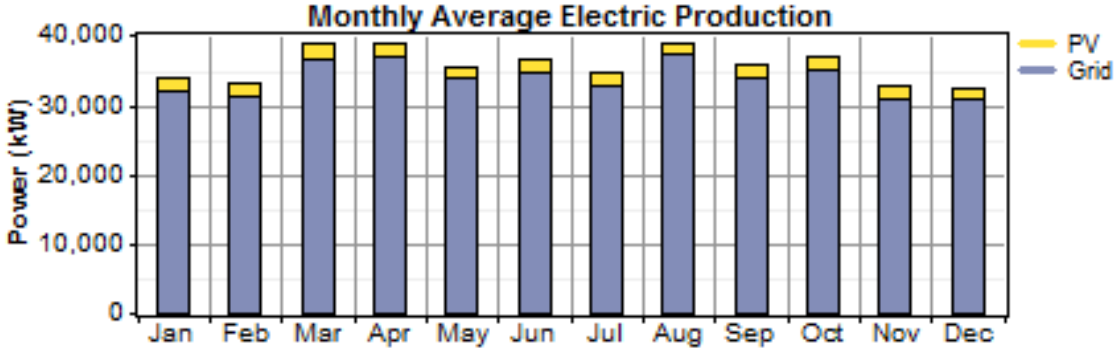


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	60,500,000	0	6,308,460	0	0	66,808,452
Grid	0	0	850,061,696	0	0	850,061,696
Converter	5,775,000	0	883,184	0	-360,135	6,298,049
System	66,275,000	0	857,253,376	0	-360,135	923,168,256

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	5,274,666	0	550,000	0	0	5,824,665
Grid	0	0	74,112,248	0	0	74,112,248
Converter	503,491	0	77,000	0	-31,398	549,093
System	5,778,157	0	74,739,256	0	-31,398	80,486,016



Year 2014

Sensitivity case

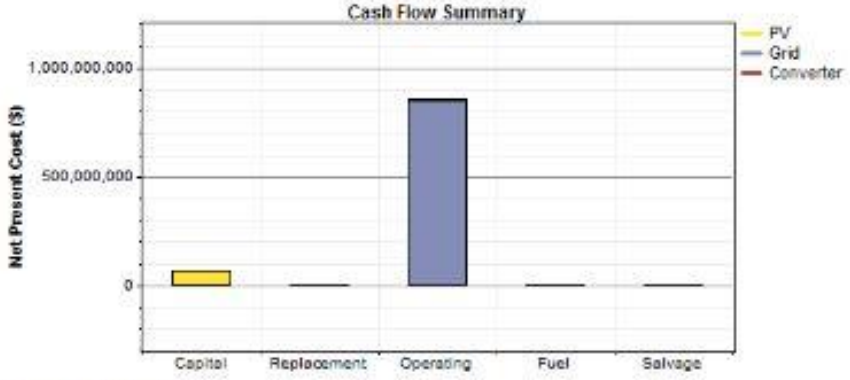
Primary Load 1 Scaled Average: 855,792 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	11,000 kW
Grid	250,000 kW
Inverter	7,000 kW
Rectifier	7,000 kW

Cost summary

Total net present cost	$ 923,167,808
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 74,707,816/yr

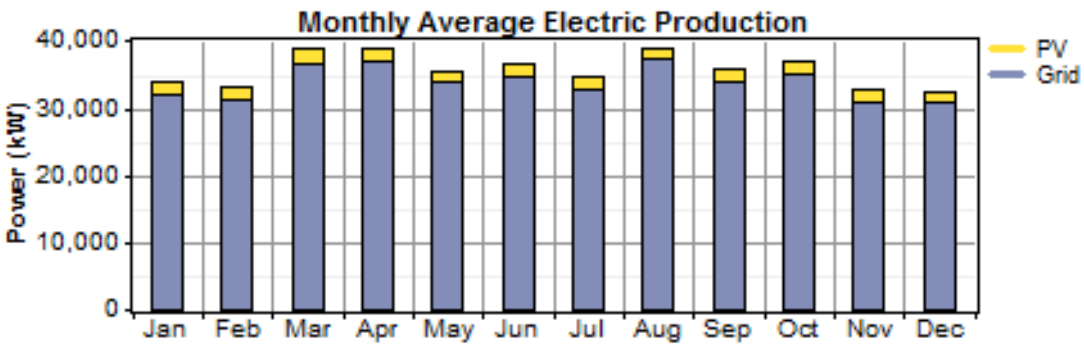


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	60,500,000	0	6,308,460	0	0	66,808,452
Grid	0	0	850,061,696	0	0	850,061,696
Converter	5,775,000	0	883,184	0	-360,135	6,298,049
System	66,275,000	0	857,253,376	0	-360,135	923,168,256

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	5,274,666	0	550,000	0	0	5,824,665
Grid	0	0	74,112,248	0	0	74,112,248
Converter	503,491	0	77,000	0	-31,398	549,093
System	5,778,157	0	74,739,256	0	-31,398	80,486,016



Year 2015

Sensitivity case

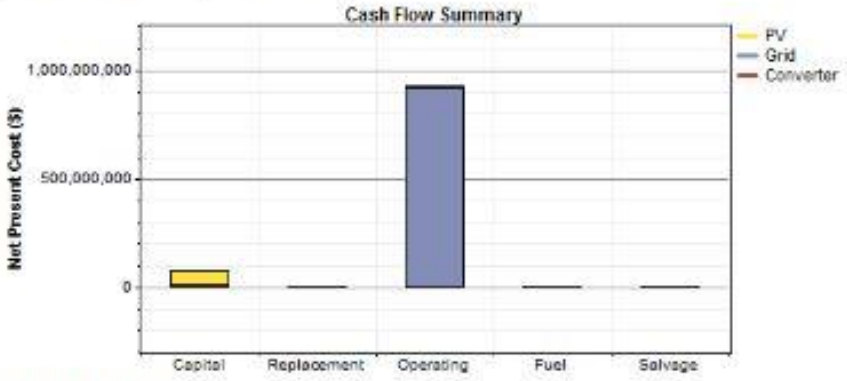
Primary Load 1 Scaled Average: 925,488 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	12,000 kW
Grid	250,000 kW
Inverter	8,000 kW
Rectifier	8,000 kW

Cost summary

Total net present cost	$ 998,589,184
Levelized cost of energy	$ 0.255/kWh
Operating cost	$ 80,731,952/yr

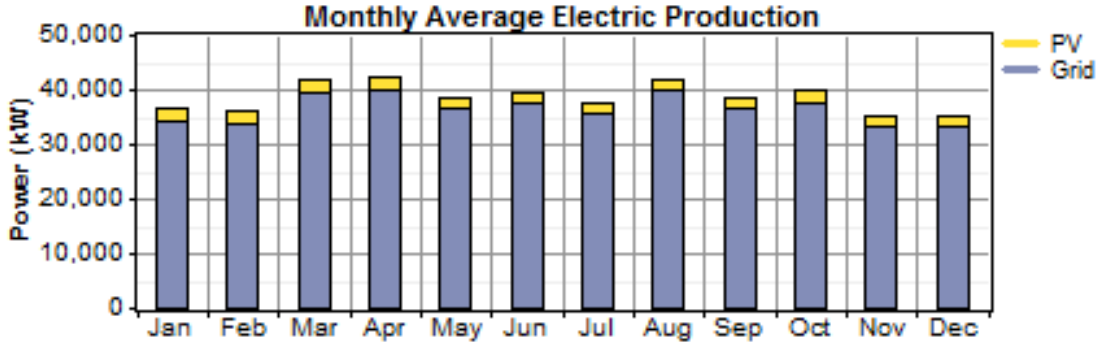


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	66,000,000	0	6,881,956	0	0	72,881,944
Grid	0	0	918,509,696	0	0	918,509,696
Converter	6,600,000	0	1,009,354	0	-411,583	7,197,772
System	72,600,000	0	926,401,152	0	-411,583	998,589,504

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	5,754,181	0	600,000	0	0	6,354,180
Grid	0	0	80,079,856	0	0	80,079,856
Converter	575,418	0	88,000	0	-35,884	627,535
System	6,329,599	0	80,767,872	0	-35,884	87,061,584



Year 2016

Sensitivity case

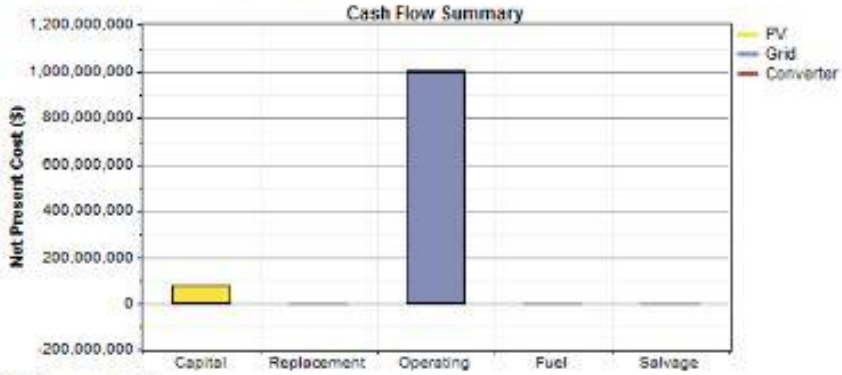
Primary Load 1 Scaled Average: 998,271 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	12,500 kW
Grid	250,000 kW
Inverter	8,500 kW
Rectifier	8,500 kW

Cost summary

Total net present cost	$ 1,076,049,792
Levelized cost of energy	$ 0.257/kWh
Operating cost	$ 87,209,608/yr

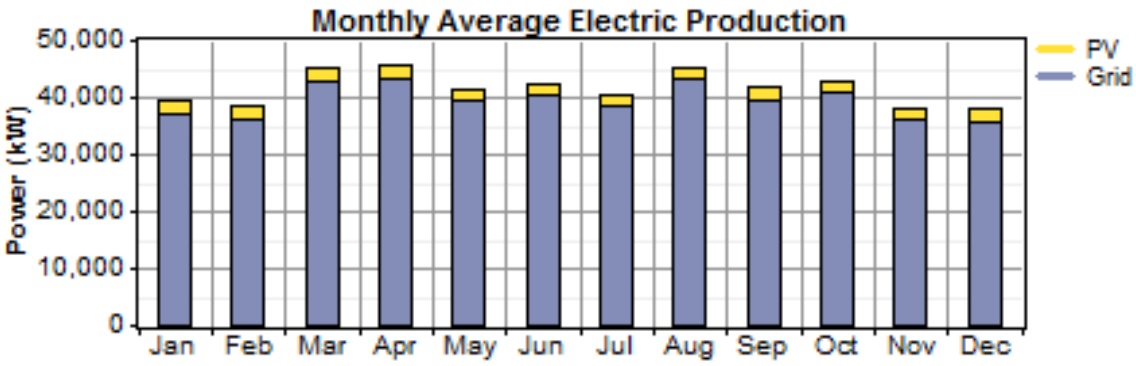


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	68,750,000	0	7,168,704	0	0	75,918,720
Grid	0	0	992,483,840	0	0	992,483,840
Converter	7,012,500	0	1,072,438	0	-437,307	7,647,631
System	75,762,496	0	1,000,724,928	0	-437,307	1,076,050,176

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	5,993,938	0	625,000	0	0	6,618,940
Grid	0	0	86,529,264	0	0	86,529,264
Converter	611,382	0	93,500	0	-38,126	666,755
System	6,605,320	0	87,247,760	0	-38,126	93,814,960



Year 2017

Sensitivity case

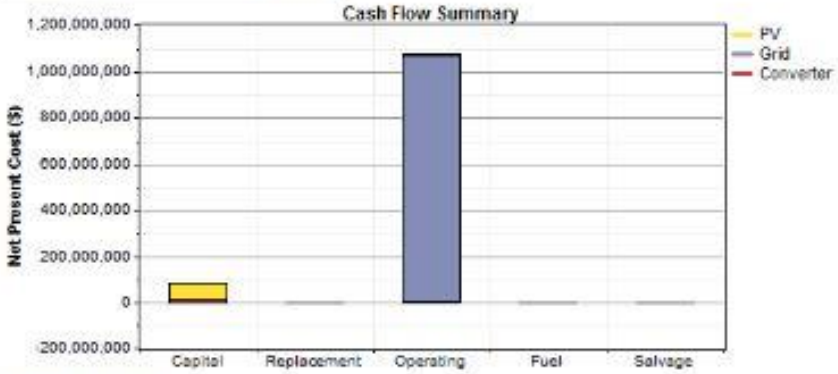
Primary Load 1 Scaled Average: 1,074,141 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	13,500 kW
Grid	250,000 kW
Inverter	9,000 kW
Rectifier	9,000 kW

Cost summary

Total net present cost	$ 1,157,916,032
Levelized cost of energy	$ 0.257/kWh
Operating cost	$ 93,831,600/yr

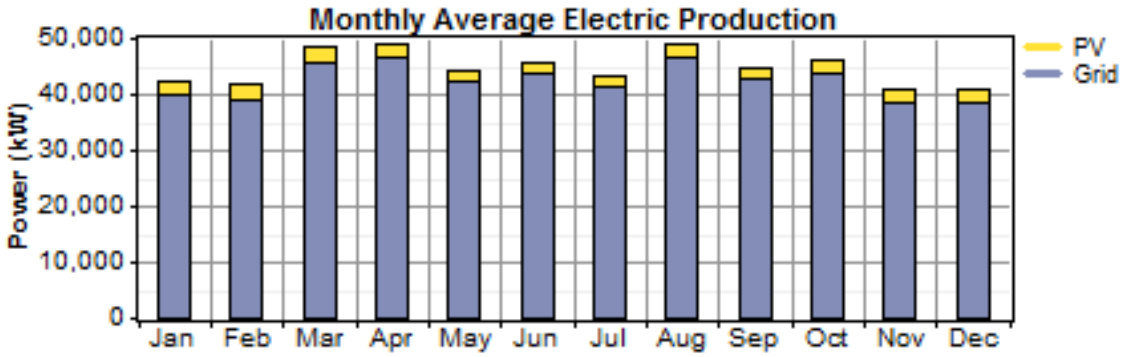


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	74,250,000	0	7,742,201	0	0	81,992,200
Grid	0	0	1,067,826,816	0	0	1,067,826,816
Converter	7,425,000	0	1,135,523	0	-463,031	8,097,492
System	81,675,000	0	1,076,704,640	0	-463,031	1,157,916,672

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	6,473,454	0	675,000	0	0	7,148,454
Grid	0	0	93,098,008	0	0	93,098,008
Converter	647,345	0	99,000	0	-40,369	705,976
System	7,120,799	0	93,872,016	0	-40,369	100,952,448



Year 2018

Sensitivity case

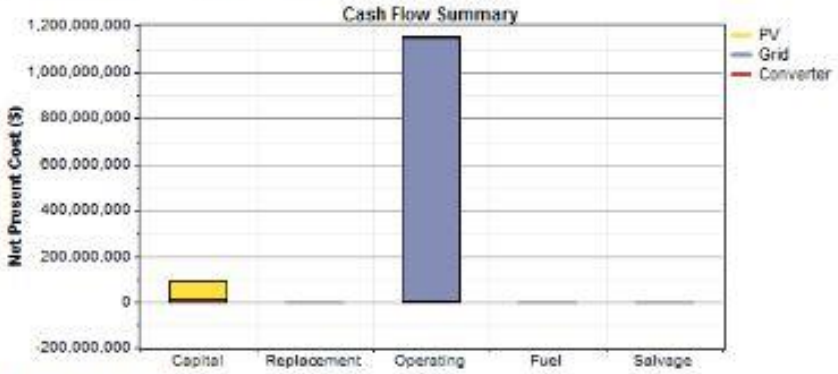
Primary Load 1 Scaled Average: 1,153,132 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	14,500 kW
Grid	250,000 kW
Inverter	9,500 kW
Rectifier	9,500 kW

Cost summary

Total net present cost	$ 1,243,076,352
Levelized cost of energy	$ 0.257/kWh
Operating cost	$ 100,740,776/yr

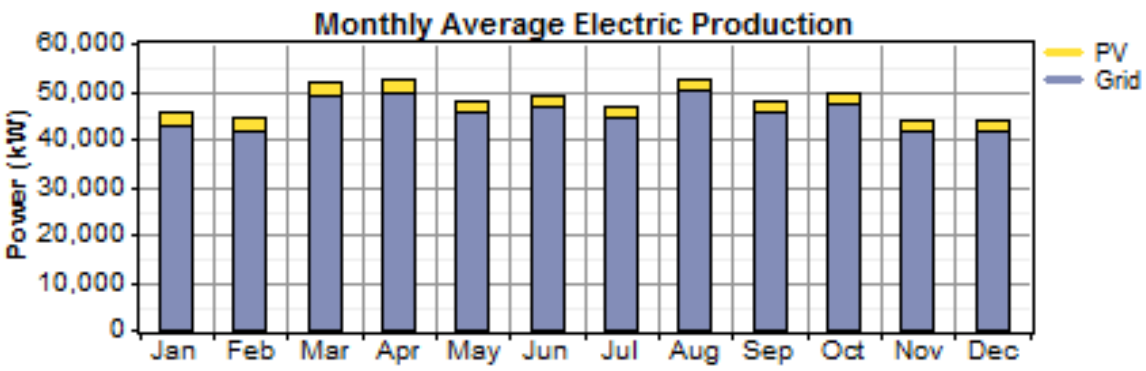


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	79,750,000	0	8,315,696	0	0	88,065,712
Grid	0	0	1,146,453,616	0	0	1,146,453,616
Converter	7,837,500	0	1,198,607	0	-488,754	8,547,352
System	87,587,504	0	1,155,977,984	0	-488,754	1,243,076,864

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	6,952,969	0	725,000	0	0	7,677,970
Grid	0	0	99,953,920	0	0	99,953,920
Converter	683,309	0	104,500	0	-42,612	745,197
System	7,636,278	0	100,783,424	0	-42,612	108,377,104



Year 2019

Sensitivity case

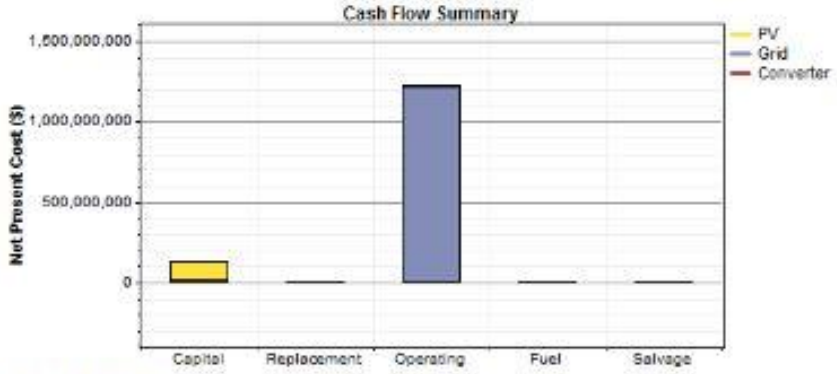
Primary Load 1 Scaled Average: 1,235,245 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	20,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,343,675,254
Levelized cost of energy	$ 0.260/kWh
Operating cost	$ 105,478,528/yr

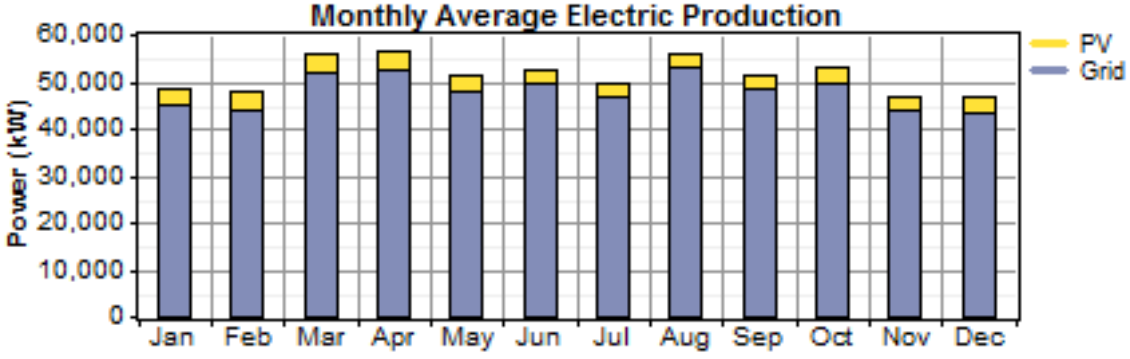


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	110,000,000	0	11,469,926	0	0	121,469,928
Grid	0	0	1,208,710,144	0	0	1,208,710,144
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	122,375,000	0	1,222,072,704	0	-771,718	1,343,675,904

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	9,590,301	0	1,000,000	0	0	10,590,302
Grid	0	0	105,380,856	0	0	105,380,856
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	10,669,210	0	106,545,864	0	-67,282	117,147,784



Year 2020

Sensitivity case

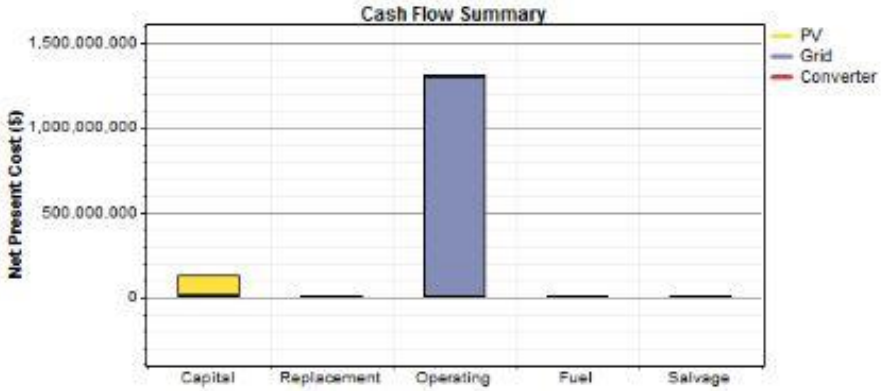
Primary Load 1 Scaled Average: 1,320,410 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	20,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,432,809,728
Levelized cost of energy	$ 0.259/kWh
Operating cost	$ 114,249,672/yr

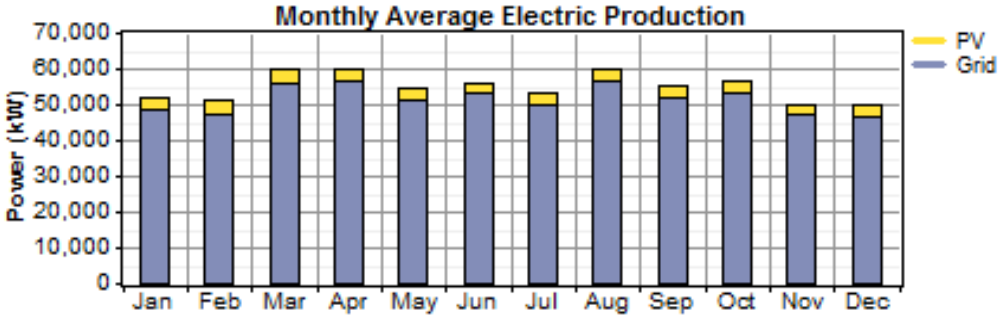


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	110,000,000	0	11,469,926	0	0	121,469,928
Grid	0	0	1,297,844,480	0	0	1,297,844,480
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	122,375,000	0	1,311,207,040	0	-771,718	1,432,810,368

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	9,590,301	0	1,000,000	0	0	10,590,302
Grid	0	0	113,151,992	0	0	113,151,992
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	10,669,210	0	114,317,000	0	-67,282	124,918,936



Year 2021

Sensitivity case

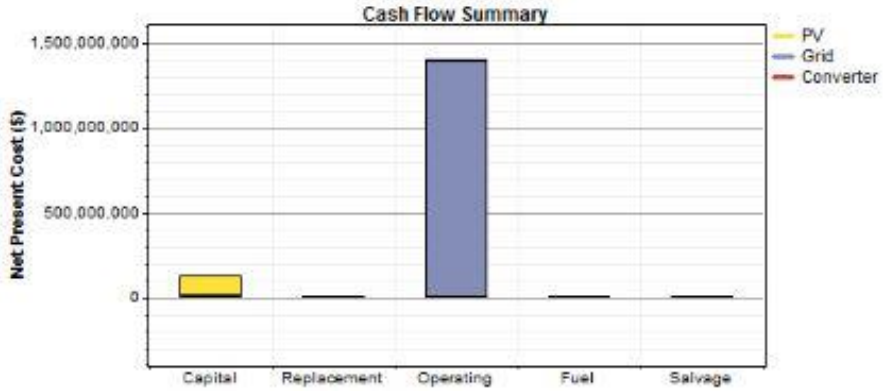
Primary Load 1 Scaled Average: 1,408,696 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	20,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,525,211,648
Levelized cost of energy	$ 0.259/kWh
Operating cost	$ 122,305,688/yr

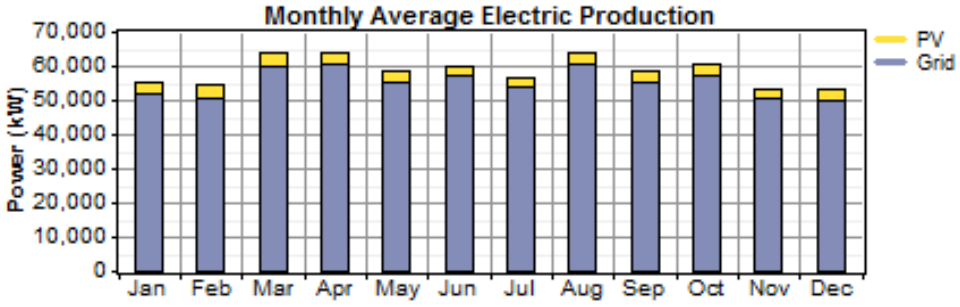


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	110,000,000	0	11,469,928	0	0	121,469,928
Grid	0	0	1,390,246,528	0	0	1,390,246,528
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	122,375,000	0	1,403,609,088	0	-771,718	1,525,212,288

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	9,590,301	0	1,000,000	0	0	10,590,302
Grid	0	0	121,208,024	0	0	121,208,024
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	10,669,210	0	122,373,032	0	-67,282	132,974,952



Year 2022

Sensitivity case

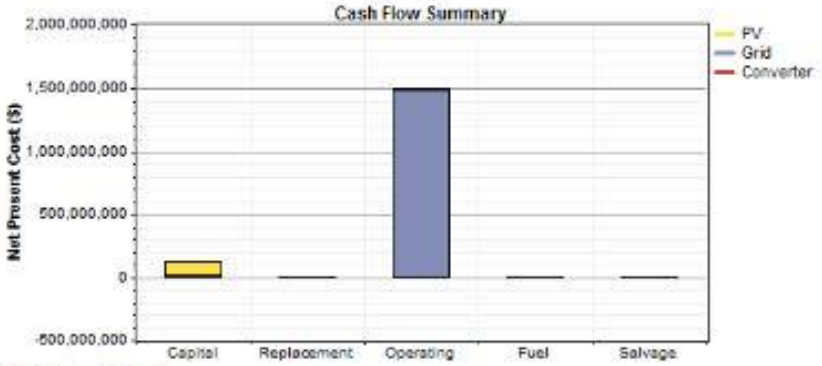
Primary Load 1 Scaled Average: 1,500,069 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	20,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,620,844,160
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 130,643,368/yr

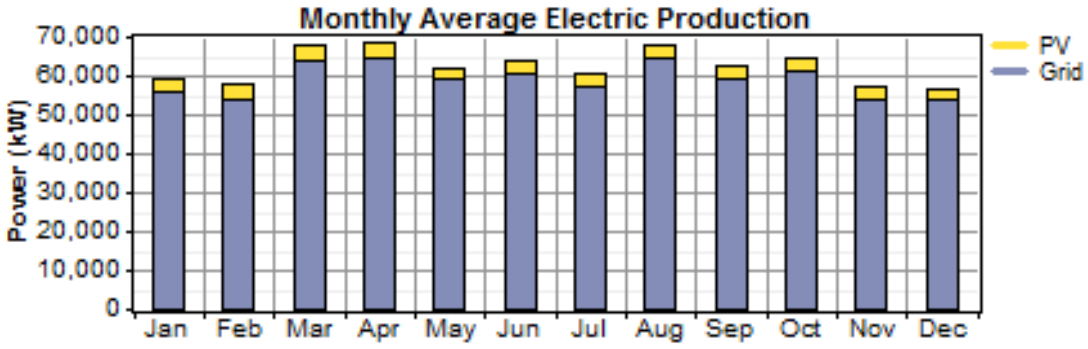


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	110,000,000	0	11,469,926	0	0	121,469,926
Grid	0	0	1,485,878,912	0	0	1,485,878,912
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	122,375,000	0	1,499,241,472	0	-771,718	1,620,844,928

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	9,590,301	0	1,000,000	0	0	10,590,302
Grid	0	0	129,545,696	0	0	129,545,696
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	10,669,210	0	130,710,704	0	-67,282	141,312,640



Year 2023

Sensitivity case

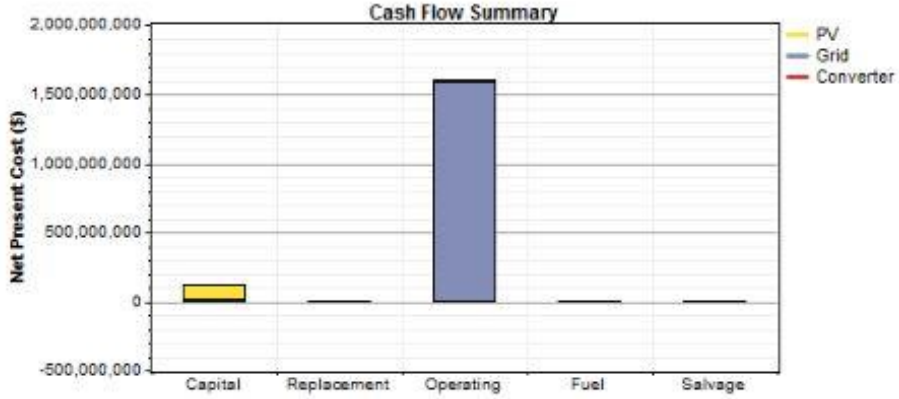
Primary Load 1 Scaled Average: 1,594,564 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	20,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,719,743,872
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 139,285,888/yr

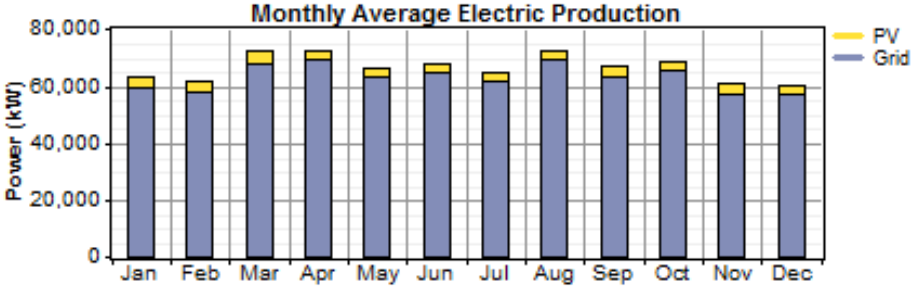


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	110,000,000	0	11,469,926	0	0	121,469,928
Grid	0	0	1,584,778,752	0	0	1,584,778,752
Converter	12,375,000	0	1,992,538	0	-771,718	13,495,819
System	122,375,000	0	1,598,141,312	0	-771,718	1,719,744,768

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	9,590,301	0	1,000,000	0	0	10,590,302
Grid	0	0	138,168,224	0	0	138,168,224
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	10,669,210	0	139,333,248	0	-67,282	149,935,184



Year 2024

Sensitivity case

Primary Load 1 Scaled Average: 1,692,146 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	25,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,833,970,304
Levelized cost of energy	$ 0.259/kWh
Operating cost	$ 146,827,104/yr

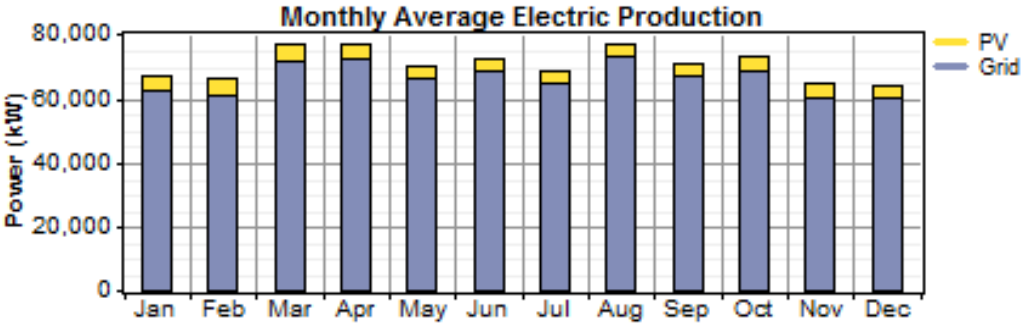


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	137,500,000	0	14,337,408	0	0	151,837,440
Grid	0	0	1,668,637,952	0	0	1,668,637,952
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	149,875,008	0	1,684,867,968	0	-771,718	1,833,971,200

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	11,987,876	0	1,250,001	0	0	13,237,880
Grid	0	0	145,479,456	0	0	145,479,456
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	13,066,786	0	146,894,464	0	-67,282	159,893,968



Year 2025

Sensitivity case

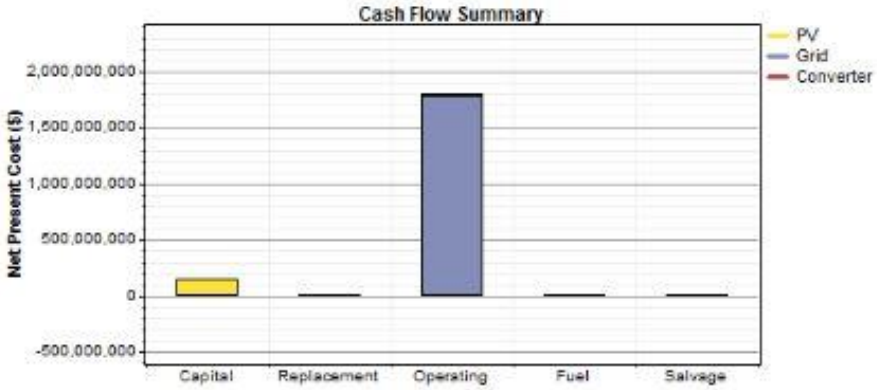
Primary Load 1 Scaled Average: 1,792,814 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	25,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 1,939,331,200
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 156,012,944/yr

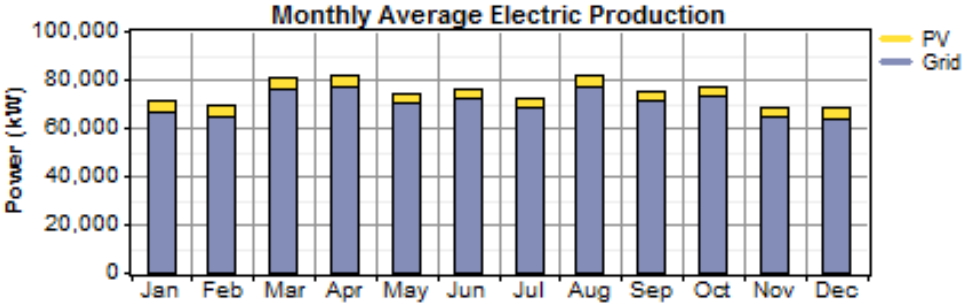


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	137,500,000	0	14,337,408	0	0	151,837,440
Grid	0	0	1,773,998,720	0	0	1,773,998,720
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	149,875,008	0	1,790,228,864	0	-771,718	1,939,332,096

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	11,987,876	0	1,250,001	0	0	13,237,880
Grid	0	0	154,665,296	0	0	154,665,296
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	13,066,786	0	156,080,304	0	-67,282	169,079,808



Year 2026

Sensitivity case

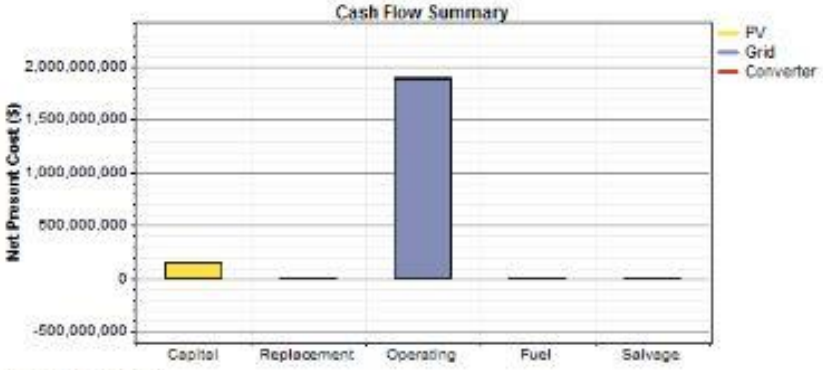
Primary Load 1 Scaled Average: 1,896,569 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	25,000 kW
Grid	250,000 kW
Inverter	15,000 kW
Rectifier	15,000 kW

Cost summary

Total net present cost	$ 2,047,922,560
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 165,480,432/yr

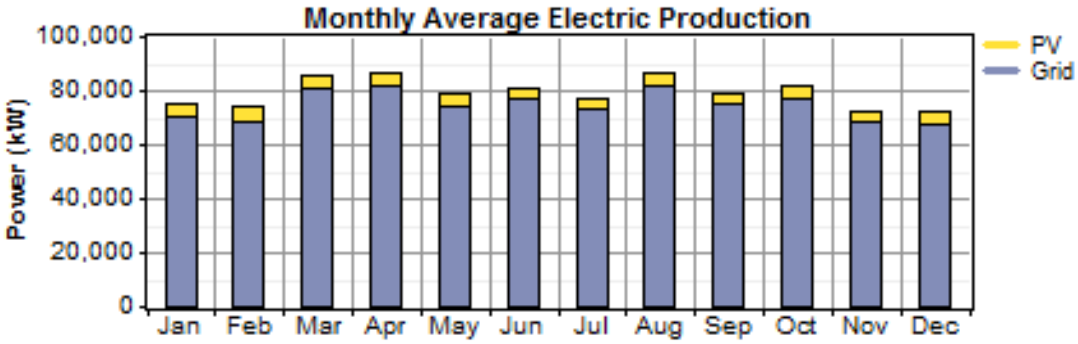


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	137,500,000	0	14,337,408	0	0	151,837,440
Grid	0	0	1,882,590,464	0	0	1,882,590,464
Converter	12,375,000	0	1,892,538	0	-771,718	13,495,819
System	149,875,008	0	1,898,820,352	0	-771,718	2,047,923,584

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	11,987,876	0	1,250,001	0	0	13,237,880
Grid	0	0	164,132,816	0	0	164,132,816
Converter	1,078,909	0	165,000	0	-67,282	1,176,627
System	13,066,786	0	165,547,808	0	-67,282	178,547,312



Year 2027

Sensitivity case

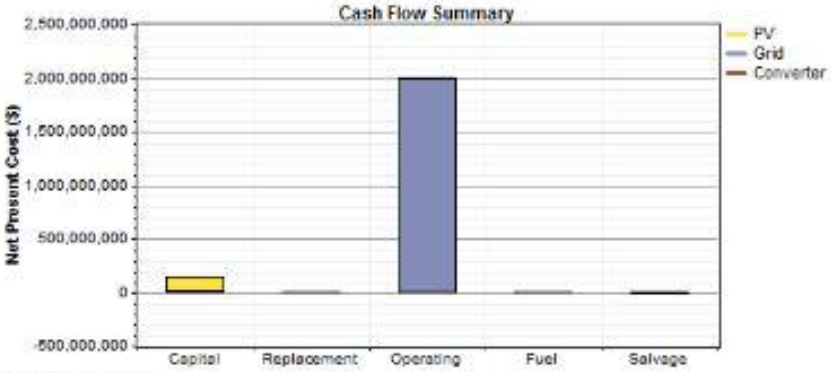
Primary Load 1 Scaled Average: 2,003,446 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	25,000 kW
Grid	250,000 kW
Inverter	20,000 kW
Rectifier	20,000 kW

Cost summary

Total net present cost	$ 2,161,485,568
Levellized cost of energy	$ 0.258/kWh
Operating cost	$ 175,021,744/yr

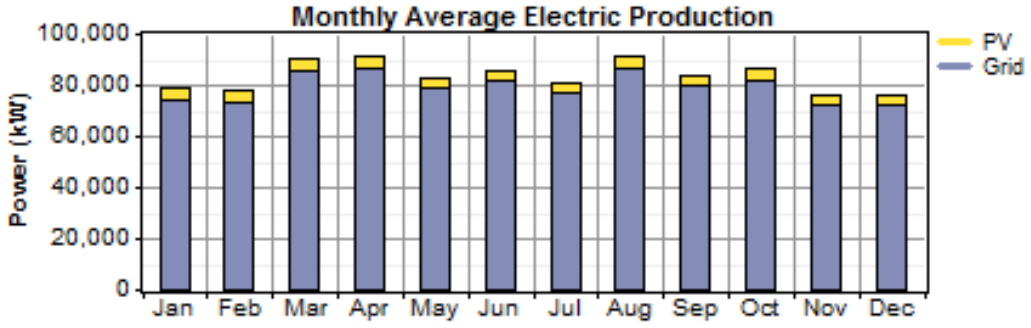


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	137,500,000	0	14,337,408	0	0	151,837,440
Grid	0	0	1,991,654,656	0	0	1,991,654,656
Converter	16,500,000	0	2,523,384	0	-1,028,957	17,994,422
System	154,000,000	0	2,008,515,200	0	-1,028,957	2,161,486,336

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	11,987,876	0	1,250,001	0	0	13,237,880
Grid	0	0	173,641,520	0	0	173,641,520
Converter	1,438,545	0	220,000	0	-89,709	1,568,836
System	13,426,422	0	175,111,504	0	-89,709	188,448,224



Year 2028

Sensitivity case

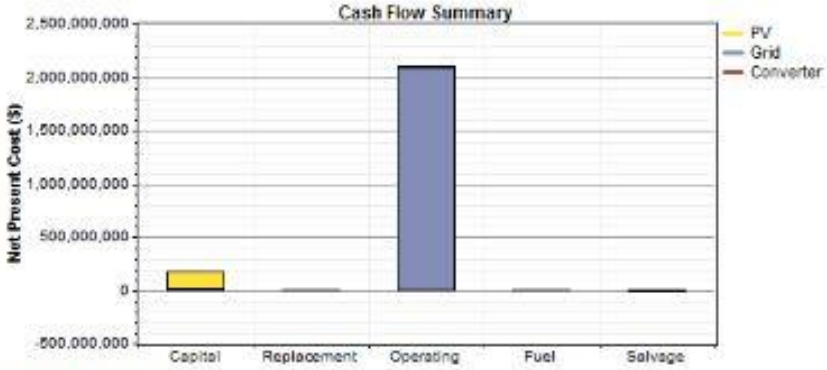
Primary Load 1 Scaled Average: 2,113,410 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	30,000 kW
Grid	250,000 kW
Inverter	20,000 kW
Rectifier	20,000 kW

Cost summary

Total net present cost	$ 2,286,825,216
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 183,551,840/yr

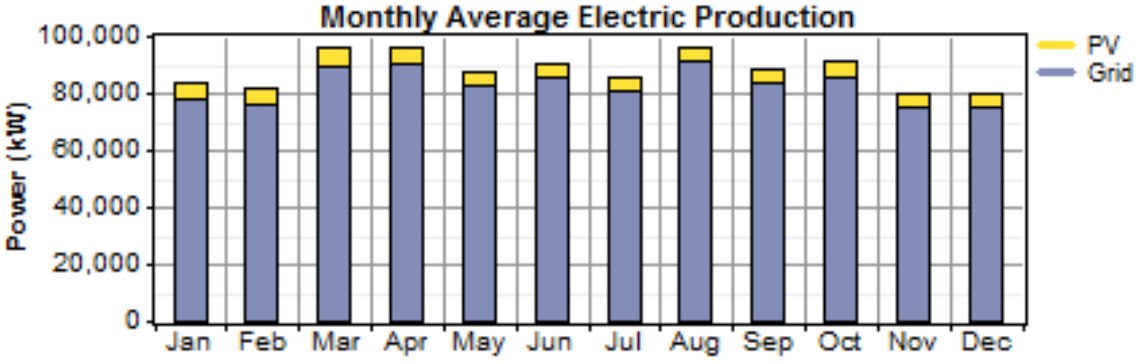


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	165,000,000	0	17,204,890	0	0	182,204,896
Grid	0	0	2,086,627,072	0	0	2,086,627,072
Converter	16,500,000	0	2,523,384	0	-1,028,957	17,994,422
System	181,500,000	0	2,106,355,072	0	-1,028,957	2,286,826,240

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	14,385,452	0	1,500,001	0	0	15,885,453
Grid	0	0	181,921,648	0	0	181,921,648
Converter	1,438,545	0	220,000	0	-89,709	1,568,836
System	15,823,997	0	183,641,632	0	-89,709	199,375,936



Year 2029

Sensitivity case

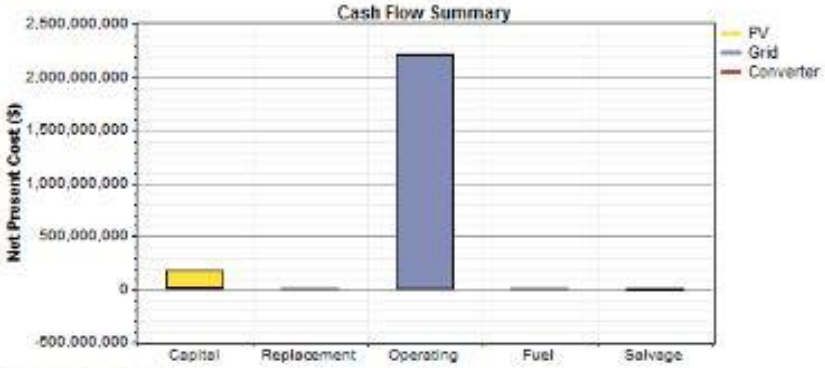
Primary Load 1 Scaled Average:	2,226,495	kWh/d
Rate 1 Power Price:	0.25	$/kWh
Minimum Renewable Fraction:	5	%

System architecture

PV Array	30,000 kW
Grid	250,000 kW
Inverter	20,000 kW
Rectifier	20,000 kW

Cost summary

Total net present cost	$ 2,405,181,696
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 193,870,688/yr

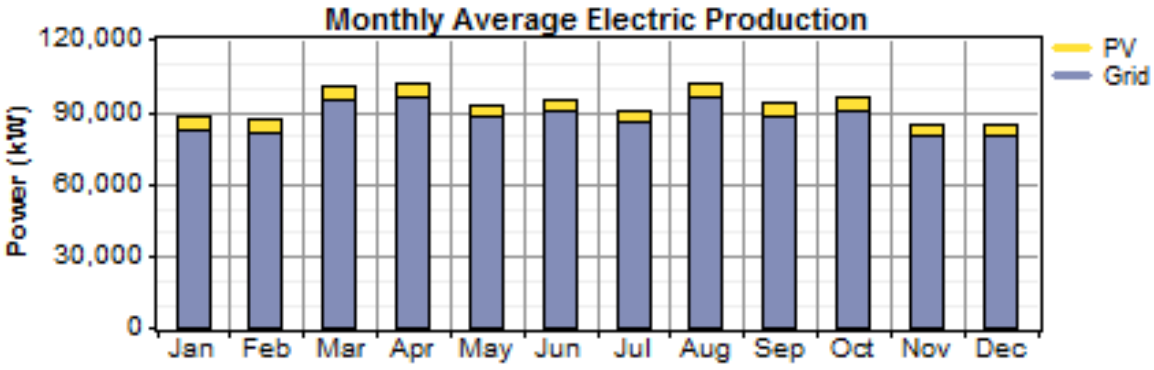


Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	165,000,000	0	17,204,890	0	0	182,204,896
Grid	0	0	2,204,983,296	0	0	2,204,983,296
Converter	16,500,000	0	2,523,384	0	-1,028,957	17,994,422
System	181,500,000	0	2,224,711,680	0	-1,028,957	2,405,182,464

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	14,385,452	0	1,500,001	0	0	15,885,453
Grid	0	0	192,240,496	0	0	192,240,496
Converter	1,438,545	0	220,000	0	-89,709	1,568,836
System	15,823,997	0	193,960,496	0	-89,709	209,694,768



Year 2030

Sensitivity case

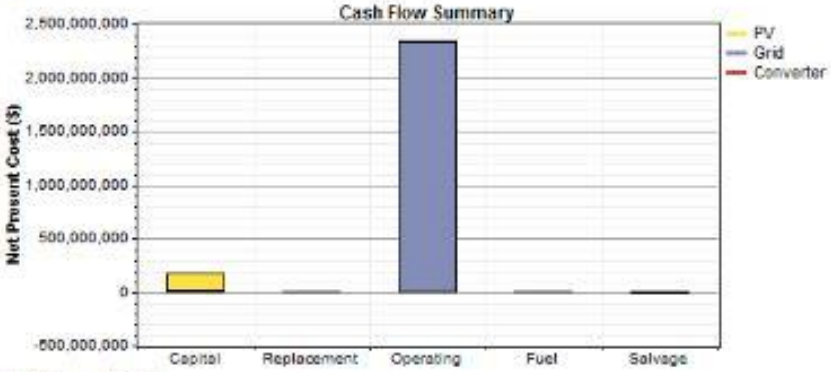
Primary Load 1 Scaled Average: 2,342,632 kWh/d
Rate 1 Power Price: 0.25 $/kWh
Minimum Renewable Fraction: 5 %

System architecture

PV Array	30,000 kW
Grid	250,000 kW
Inverter	20,000 kW
Rectifier	20,000 kW

Cost summary

Total net present cost	$ 2,526,732,032
Levelized cost of energy	$ 0.258/kWh
Operating cost	$ 204,468,016/yr



Net Present Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($)	($)	($)	($)	($)	($)
PV	165,000,000	0	17,204,890	0	0	182,204,896
Grid	0	0	2,326,533,888	0	0	2,326,533,888
Converter	16,500,000	0	2,523,384	0	-1,028,957	17,994,422
System	181,500,000	0	2,346,262,272	0	-1,028,957	2,526,733,312

Annualized Costs

Component	Capital	Replacement	O&M	Fuel	Salvage	Total
	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)
PV	14,385,452	0	1,500,001	0	0	15,885,453
Grid	0	0	202,837,824	0	0	202,837,824
Converter	1,438,545	0	220,000	0	-89,709	1,568,836
System	15,823,997	0	204,557,840	0	-89,709	220,292,128