FEASIBILITY STUDY OF SOLAR THERMAL ELECTRIC-POWER GENERATION IN NORTHERN GHANA

By

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DECLARATION

I hereby declare that this thesis is the result of my own original research work undertaken under the supervision of the undersigned, that all works consulted have been referenced and that no part of the thesis has been presented for another degree in this University or elsewhere.

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(Candidate)	Signature	Date

CERTIFICATION

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(Supervisor)	Signature	Date
Prof. F. K. Forson	……………………..	………………..
(Head of Department)	Signature	Date

DEDICATION

This work is to the glory of

God the Father,

God the Son and

God the Holy Spirit.

ACKNOWLEDGEMENT

I thank the Almighty God for His love and mercies that endures forever and for the strength, energy, protection and grace to complete this work. I also like to express my deepest gratitude to my pastor, mother and shepherd, Rev. (Mrs.) Docia Opoku-Gyemfi whose human love, prayers and encouragement is unparalleled to attaining such a feat. Mummy, I say ***thank you***.

This is an opportunity to express my utmost appreciation to my supervisor and advisor Professor Abeeku Brew-Hammond whose vision inspired and guided this work. I am highly indebted to him for the constructive criticisms, directions and opportunities created for me as a young researcher in the course of this challenging but interesting work.

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GlobalResolve of Arizona State University needs a special mention here for the award of a research grant which stirred this work to a success. I wish also to thank Professor Robert F. Boehm for the invitation which made facilities at the Centre of Energy Research at the University of Nevada, Las Vegas accessible to me during my independent research visit to the centre. Lastly, to my biological mum and dad, I say thank you for been there for me when I needed you most.

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ABSTRACT

This thesis looks at the viability of a 20 MW Solar Thermal Electric-Power Plant operating in northern Ghana. Available insolation data such as Solar Map, DNI Map, SWERA Report and NASA Data, as compiled in the RETScreen software places Wa, the capital city of the Upper West Region as the most appropriate site for the plant in northern Ghana. The DNI map puts the Direct Normal Insolation of Wa at 4.0-4.5 kWh/m^2.day.

The annual energy production of the plant is estimated by the RETScreen software at 27.6 GWh while an estimated value of the capacity factor using a methodology making use of monthly global irradiation values in the RETScreen software places it at 15.76%. The annual Green House Gas (GHG) savings is 13,503.4 tCO2.

The total initial cost of the 20 MW Central Receiver System with a capital cost of US $3,600/kW is about US $87 million. The system can be financially viable if there is a judicious mix of major capital subsidies and modest feed-in tariffs in the hope that Central Receiver System (CRS) cost would drop significantly. For a lifetime of 30 years: the plant is found to be financially viable at the current Bulk Supply Tariff (BST) of 8 US Cents if a minimum of 60% grant is provided at a capital cost of US $1000/kW. At the same tariff, a grant of 80% would make the system viable at a capital cost of US $2000/kW and below. Analysis with RETScreen software shows that if there is no capital subsidy or grant; at a capital cost of US $3600/kW, the plant becomes financially viable at a feed-in tariff of 40 US Cents or more.

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ABBREVIATIONS

atm	Atmosphere
BST	Bulk Supply Tariff
CF	Capacity Factor
CO_2	Carbon Dioxide
CRS	Central Receiver System
CSP	Concentrating Solar Power
DNI	Direct Normal Insolation
°C	Degree Celsius
°F	Degrees Fahrenheit
GHG	Greenhouse Gases
GW	Gigawatt
GWh	Gigawatt hour
HTF	Heat Transfer Fluid
IRR	Internal Rate of Return
IPP	Independent Power Producer
KNUST	Kwame Nkrumah University of Science and Technology
kW	Kilowatt
kW_e	Kilowatt-electric
kWh	Kilowatt hour
kWh/m^2.day	Kilowatt-hour per metre square per day
LFR	Linear Fresnel Reflector
MCS	Master Control System
MicroCSP	Micro Concentrating Solar Power

MPa	Mega Pascal
MW	Megawatt
MW_e	Megawatt-electric
MW_{th}	Megawatt-thermal
NASA	National Aeronautics and Space Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PHOEBUS-TSA	PHOEBUS Technology Programme Solar Air Receiver
PS 10	Planta Solar 10
PS 20	Planta Solar 20
PV	Present Value
SEGS	Solar Energy Generating System
SPB	Simple Payback Period
STPP	Solar Thermal Power Plant
SWERA	Solar and Wind Energy Resource Assessment
tCO_2	tonnes of CO_2
T&D	Transmission and Distribution
TMY	Typical Meteorological Year
US $	United States Dollars
USA	United States of America
USD	United States Dollars

CHAPTER ONE

INTRODUCTION

1.1 Background

The issues of climate change have forced an international consensus on the need to adopt a clean energy economy. Our climate has continually been damaged since the industrial revolution by the use of fossil fuels (oil, coal and gas) for transportation and energy. Aringhoff et al (2005) affirm that there has already been a global mean temperature rise of 0.6^{o}C during the last century; this is significantly due to the greenhouse gases that have been discharged into the atmosphere. This trend, if it continues would be a threat to the stability of our climate and eco-system. Solar thermal power is an energy option which is at the fore-front in generating competitive and practical renewable energy source on a large scale that can be a substitute for fossil fuels.

Solar Thermal Power Generation is a technology for focusing direct radiant energy from the sun to obtain thermal energy; it is normally sited in regions with high direct solar radiation. There is a striking semblance between conventional fossil-fuel power plant and Solar Thermal Power Plant (STPP), the difference lies in the mode of heat generation. While conventional power generation derives its heat source from the burning of fossil fuels, STPP uses radiant energy from the sun. In essence, Solar Thermal Power generates electricity on the principles of Rankine Cycle Power Plant (coal, gas or oil fired) or as an add-on to a natural gas combined cycle, substituting the heat source with solar collectors (EEL and MRCL, 1999). Comparatively, it is a new technology with a lot of promise and there is on-going research to make it cost-competitive. Researchers have observed that improved operations, mass production, economics of scale coupled with state-of-the art technology would make the reduction of the cost of solar electricity a reality (EEL and MRCL, 1999).

The oil crises of 1973 and 1979 led to contemporary use of solar technology resulting in Solar Energy Generating Systems (SEGS) in California and other smaller projects around the world (Butti and Perlin, 1981). The first STPP was constructed in the Mojave Desert in California in the year 1984. Nine additional power plants which fed about 800 million KWh per year into the grid was built by 1991 with a total capacity of 354 MW. There have been several large solar thermal power project erected across the world especially in Sun Belt regions ever since (Quaschning and Muriel, 2001).

1.2 Significance of Project to Ghana's Development

Ghana like most African countries with her rich endowment in energy resources is still caught up in 'energy poverty'. The intense radiant energy in the northern part of Ghana makes sunshine a plentiful energy resource, however, no study have been conducted to validate the performance of a Solar Thermal Power Plant in that part of the world. The financial assistance provided by the World Bank to the tune of about 200 million USD for new combined cycle gas and Solar Thermal Power Plant in developing countries (Quaschning and Muriel, 2001) should spur a new revolution in the search for clean energy from the abundant sunshine in places like the northern part of Ghana. This has a major advantage of savings in fossil-fuel import for our energy generation.

As a result of Ghana's expanding and growing economy, there is a major challenge of providing reliable and continuous energy supply to meet the needs of all sectors. The lessons learnt from over-reliance on hydro-electric generation cannot be over-emphasized, but should lead us as a nation to explore all possible form of energy generation to meet our aspiration to become an energy hub in the sub-region resulting in accelerated industrial development.

Solar Power provides compelling and attractive benefits; these include environmental protection, job creation, economic growth, rapid deployment and global potential for technology transfer and innovation. Considering the fact that solar energy is free, abundant and inexhaustible makes it, a major advantage to consider in the erection of Solar Thermal Power Plant (Aringhoff et al, 2005). This compelling attractiveness validates this project as of significant to Ghana's development.

1.3 Objectives

The main objective is to ascertain the viability of Solar Thermal Power Generation in the Sun-Belt regions of northern Ghana. The specific objectives include:

- To determine locations in northern Ghana with least diffuse radiation but high global irradiation and a choice of site made based on highest DNI.
- To choose Solar Thermal Power technology appropriate for the selected site in northern Ghana based on Literature Review.
- To assess the technical performance of a given 20MW Solar Thermal Power Plant using the selected technology at the selected site.
- To undertake Green House Gas Emission analysis for the 20MW Solar Thermal Power Plant.
- To undertake Financial Analysis and Investment Appraisal of the 20MW Solar Thermal Power Plant.

1.4 Methodology

The study will involve an extensive Literature Review including undertaking, investigating, reviewing and/or analyses of the following:

- **Technical and Financial Performance**

The RETScreen Software will be used to analyze performance characteristics with the aid of Energy Model, Cost Analysis, Emission Analysis, Financial Analysis and Risk Analysis interface. The analysis will be conducted for a synoptic station with the highest DNI.

- **Solar Irradiation Data**

Works have already been carried out in compiling solar irradiation across the country. These works would be consulted to determine the site with the highest irradiation in Ghana. An example of such work is the Solar and Wind Energy Resource Assessment (SWERA) by the Department of Mechanical Engineering, KNUST. The data available from SWERA report would be compared with NASA Satellite generated data as compiled in the RETScreen software. A Solar Map of Ghana would be consulted as a guide in the choice of a site for the project.

- **Project Engineering and Implementation Schedule**
    - **Location, Site and Environment**

Location and Site are often used interchangeably but to distinguish between the two, the choice of location is made from a fairly wide geographical area such as 'northern Ghana' from which several alternative sites can be considered. This will take into consideration the area with the highest DNI. The socio-economic and environmental impact will also be established.

- **Engineering, Technology and GHG analysis**

A review of the three commercially available technologies in Solar Thermal Power Generation would be carried out. The most appropriate technology for the site identified by means of insolation figures and analysis. Description and justification of the technology selected and a review of its advantages and disadvantages over its life cycle will be ascertained. This will take into consideration prevailing environmental conditions and costs. A Green House Gas analysis would be performed to ascertain emission level (if any) including Green House Gas savings and a layout of the 20 MW plant would be prepared.

- **Project Implementation and Schedule**

The project implementation will include:

- The duration of plant erection and installation.
- Duration of first power generation start-up period.
- Human Resource and expertise requirement

- **Financial analysis and Investment appraisal**

The RETScreen software will be used to perform analysis on the financial viability of the project. It would also be used to determine:

- Total Investment Cost
- Financial performance indicators (SPB, NPV)
- Sensitivity Analysis.

1.5 Scope of Work

This project focuses on three different technologies of Solar Thermal Power Plants making use of concentrating solar energy systems (that is, parabolic trough, power tower and parabolic dish technologies). Although the Linear Fresnel Reflector technology has chalked some commercial successes, it was not considered in this thesis. The most appropriate of the selected technology is recommended based on literature review coupled with socio-economic and environmental conditions in the northern part of Ghana.

RETScreen analysis would be conducted for the selected site to generate the various performance indicators. Since the RETScreen software does not have specific algorithm for the estimation of the Capacity Factor for Solar Thermal Power technologies, leaving the user to input a value, requires a methodology to be developed using the global irradiation values in the software and a beam fraction component to predict the Capacity Factor of the plant.

This work assumes the power unit of the plant would be installed by an Independent Power Producer (IPP) and has an efficiency which is specified by the manufacturer and known to the power producer. The analysis of the STPP would be conducted for a plant with no storage or fossil back-up.

CHAPTER TWO

DESCRIPTION OF SOLAR THERMAL POWER PLANT

2.1 Review of Existing Solar Thermal Power Plant

This review of existing Solar Thermal Power Plant include the 354 MW Solar Energy Generating Systems, 64 MW Nevada Solar One power plants both in the United States, also included is 50 MW Andasol 1, 20 MW PS 20 Solar Power Tower, 11 MW PS 10 Solar Power Tower, all in Spain.

The Solar Thermal Power industry has increased in popularity due to its use of renewable energy resource to produce power on a large scale, which is, what the world need in an attempt to make energy available while battling the issues of green house gas effect. In a little less than thirty years, Concentrating Solar Power (CSP) generation has experienced rapid growth with 1.2 GW under construction as of April 2009 and another 13.9 GW announced worldwide through 2014 (REN21, 2008).

Spain has been identified as the epicentre of Concentrating Solar Power (CSP) development with twenty two projects for 1,037 MW under construction which are all projected to start power production by the end of 2010. The United States with very good direct radiant energy in south western States have not been left out in these developments, 5,600 MW of Solar Thermal Power projects have been announced. Unfortunately, developing countries, like in Africa with very good solar energy resources (for example countries with the Sahara desert) have not embraced the technology to their fullest advantage. However, countries such as Egypt and Morocco have secured World Bank projects for Integrated Solar Thermal/Combined Cycle (ISCC) gas turbine power plants (REN21, 2008), which is currently at the construction stage. Also, the Hassi R’Mel ISCC plant in Algeria would begin producing electricity in June 2011.

A list of some existing Solar Thermal Power Plant is provided in the table below:

Table 2.1: Some operational Solar Thermal Power Plants in the world (Waite, 2001).

Capacity (MW)	**Technology Type**	**Name**	**Country**	**Location**	**Notes**
354	Parabolic Trough	Solar Energy Generating Systems	USA	Mojave Desert California	Collection of 9 units
64	Parabolic Trough	Nevada Solar One	USA	Boulder City, Nevada	Completed June 2007
50	Parabolic Trough	Andasol Solar Power Station	Spain	Near Gaudix, Granada	Andasol 1 (50MW) Completed Nov., 2008.
50	Parabolic Trough	Energia Solar De Puertollano	Spain	Puertollano, Ciudad Real	Completed May, 2009.
50	Parabolic Trough	Alvarado 1	Spain	Alvarado, Extremadura	Completed July, 2009.
20	Solar Power Tower	PS 20 Solar Power Tower	Spain	Seville	Completed April, 2009.
11	Solar Power Tower	PS 10 Solar Power Tower	Spain	Seville	Europe’s First Commercial Solar Tower

Capacity (MW)	Technology Type	Name	Country	Location	Notes
5	Solar Power Tower	Sierra Sun Tower	USA	Lancaster, California	
1.5	Solar Power Tower	Julich Solar Tower	Germany	Julich	Completed 2008
1.4	Solar Power Tower	THEMIS Solar Power Tower	France	Pyrénées-Orientales	Hybrid Solar/gas electric power, using Solar energy to heat the air entering a gas turbine
1	Parabolic Trough	Saguaro Solar Power Station	USA	Red Rock Arizona	
1	Parabolic Trough	Keahole Solar Power	USA	Hawaii	
0.1	Power Tower	Kibbutz Samar Power Flower	Israel	Kibbutz Samar	

The SEGS located in the Mojave Desert - California, U.S.A. has the largest installed solar energy capacity comprising nine collection units. Its operational data is provided below:

Table 2.2: SEGS plant history and operational data

(Sources: Cohen, (2006); Frier, (1999); Kearney, (1989) and Price, (2002))

Plant	Year built	Location	Net turbine capacity	Field area	Oil temperature	Gross solar production of electricity (MWh)	
			(MW)	(m^2)	(°C)	1996	average 1998–2002
SEGS I	1984	Daggett	14	82,960	307	19,900	16,500
SEGS II	1985	Daggett	30	165,376	316	36,000	32,500
SEGS III	1986	Kramer Junction	30	230,300	349	64,170	68,555
SEGS IV	1986	Kramer Junction	30	230,300	349	61,970	68,278
SEGS V	1987	Kramer Junction	30	233,120	349	71,439	72,879
SEGS VI	1988	Kramer Junction	30	188,000	391	71,409	67,758
SEGS VII	1988	Kramer Junction	30	194,280	391	70,138	65,048
SEGSVIII	1989	Harper Lake	80	464,340	391	139,174	137,990
SEGS IX	1990	Harper Lake	80	483,960		141,916	125,036

The detail of some Central Receiver Power Plant is provided in Appendix A. These details provide information on the Solar Field, Power Block and Financial Cost of the CRS.

2.2 Types and Components of Systems

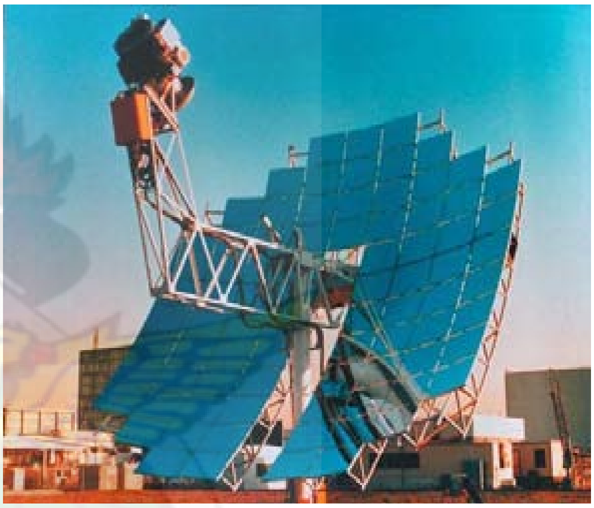
The various system designs can be distinguished by how the solar collectors concentrate the sun's radiation and track its position. The various types of technologies in use are: Parabolic Trough, Power Tower, Parabolic Dish, Linear Fresnel Reflector (LFR), Compact-LFR Technologies, Fresnel Lenses and MicroCSP (Waite, 2001 and Mills, 2004).

Parabolic trough has the longest track record of delivering utility-Scale power. This form of concentrated solar power plants uses a curved trough which reflects the direct solar radiation onto an absorption tube running along the trough, above the reflectors. The absorption tube contains transfer fluids, which is superheated and then travels to a collecting unit, where it heats water and generate steam to power turbines (Chiaro et al, 2008).

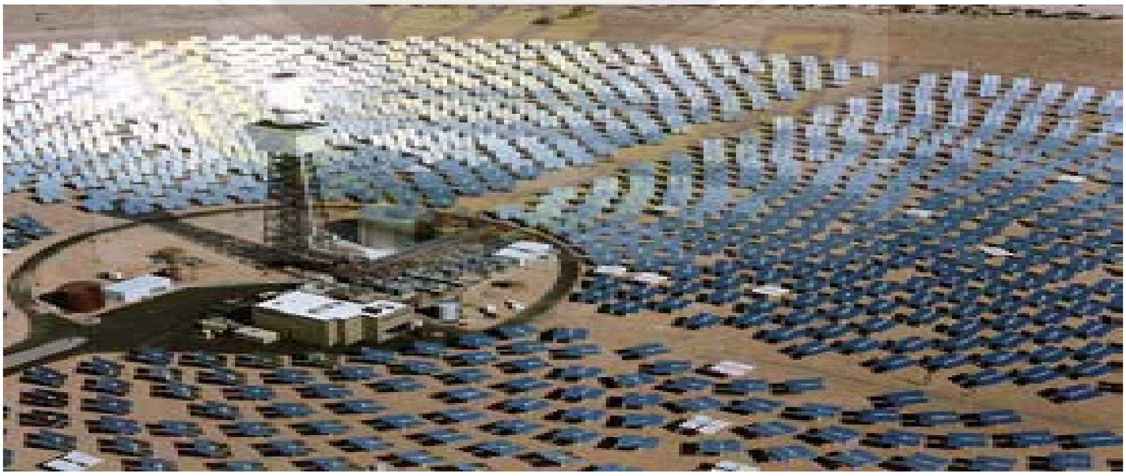
Parabolic solar dish receives radiant energy on a principle similar to the parabolic trough: curved mirror or reflective surface concentrates the sun's rays on the heating element of a Stirling engine. The entire unit acts as a solar tracker. A dish system uses a large, reflective, parabolic dish. It focuses all the sunlight that strikes the dish up onto a single point above the dish, where a receiver captures the heat and transforms it into a useful form. Typically the dish is coupled with a Stirling engine, in a Dish-Stirling System, but also sometimes a steam engine is used. These create rotational kinetic energy that can be converted to electricity using an electric generator (Chiaro et al, 2008).

Power towers (also known as 'central receivers') use an array of flat, moveable mirrors (called heliostats) to focus the sun's rays upon a collector tower (the receiver). It relies on this nearly flat tracking mirror arrayed around a stationary tower. Each heliostat in the array is free-standing and is able to independently track the sun. The Power tower operates at a higher temperature of up to 1,050 ^{o}C (Aringhoff et al, 2005). Inside the receiving tower, a heat transfer fluid (usually water or molten salt) absorbs the sun's thermal energy and is used to generate steam for turbines (Chiaro et al, 2008).

Parabolic Trough



Parabolic Dish



Power Tower

Fig 2.1: Type of Solar Thermal Power Plants

The other components include: Heat transfer fluid/steam generation unit, Power cycle unit and Thermal storage (optional). The fluid used for the heat transfer could be Synthetic Oil (Therminol or Dowtherm), Mineral Oil, Pressurized Water, Water/Steam, Silicon Oil or Nitrate salt. Water/Steam has found widespread application due to its application in steam turbine. The power cycle unit, as already been discussed, is like the conventional fossil fuel power plant. Thermal storage is included so that the heat from the sun could be stored for release when radiant energy is down; molten salt has been identified as the best storage medium.

2.3 Solar Collectors

2.3.1 Types of Solar Collectors

2.3.1.1 Low-Temperature Collectors

These are flat plates generally used to heat swimming pools; they can also be used for space heating. These collectors make use of air or water as the medium to transfer the heat to their destination. Due to the generally low working-fluid temperature attained by these collectors, they can only be employed in power generation in an Organic Rankine Cycle (ORC).

2.3.1.2 Medium-Temperature Collectors

These are also usually flat plates but a unit can be designed to attain moderately high temperatures, of up to about 200 ^{o}C (Grasse et al, 1990). They make use of both beam and diffuse solar radiation. They are mechanically simpler than concentrating collectors because they do not require tracking of the sun for optimum heat concentration. These collectors can be employed for power generation on a Rankine Cycle but would perform at a very low efficiency; hence, the major application of these systems is in solar water heating, building heating, air conditioning and industrial process heat (Duffie et al, 1991).

These collectors are almost always mounted in a stationary position with very little maintenance. They are position for optimum insolation at a particular location for the time of the year in which the solar device is intended to operate.

2.3.1.3 High-Temperature Collectors

These collectors concentrate sunlight using mirrors or lenses and are generally used for electric power production. This is because of the high working-fluid temperature attainable in excess of 300 ^{o}C (Garud and Purohit, Undated) which is required to change the phase of a working fluid from liquid to steam to be employed in driving a steam-turbine or a Stirling engine as in a conventional power plant.

These collectors are automated to track the position of the sun for optimum heat concentration during the day. The mirrors are maintained periodically for high reflectivity and prevention of breakages. Automated cleaning mechanism is employed especially in larger generating units and operators can turn the mirrors to protect them during intense wind storm.

2.3.2 Solar Thermal Power Collectors

High-temperature collectors have found major application in Solar Thermal Power generation. This has given rise to various designs in Solar Thermal Power Collectors. Of interest to this thesis is: Parabolic Trough, Parabolic Dish and Power Tower design.

2.3.2.1 Parabolic Trough

A parabolic trough-shaped mirror collector is used to concentrate sunlight onto an absorber tube which is placed at the focal line of the trough. These tubes have been designed to be thermally efficient such that a thermal transfer fluid, for example synthetic thermal oil, circulated in the tube is heated to approximately 400 ^{o}C by the concentrated sun's ray (Aringhoff et al, 2005). This oil is then made to pass through a series of heat exchangers by pumps to produce superheated steam. As in a conventional steam cycle, this steam is converted to electrical energy by means of the steam-turbine coupled to a generator or integrated into a combined steam and gas cycle. Fig. 2.2 shows how the parabolic trough concentrates radiant energy onto a focal line.

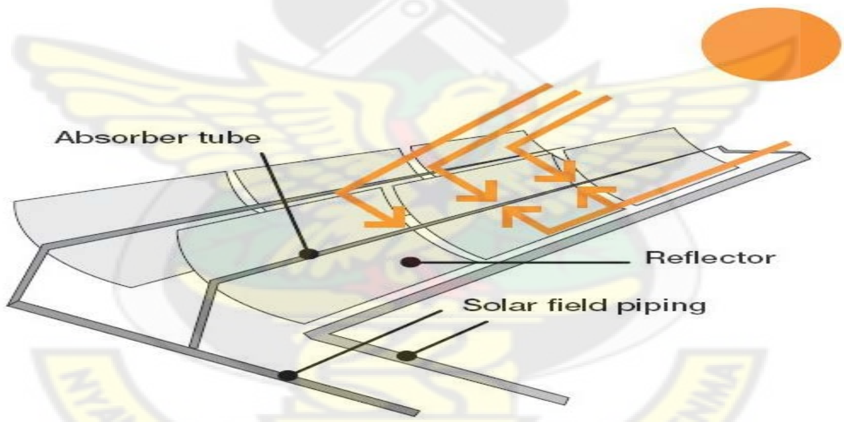


Fig 2.2: Parabolic Trough (Aringhoff et al, 2005)

2.3.2.2 <u>Parabolic Dish</u>

A parabolic dish-shaped concentrator is used to concentrate radiant energy on to a receiver placed at the focal point of the dish. The receiver absorbs energy which is reflected by the dish-shaped concentrator. This enables the fluid in the receiver to be heated to approximately 750 ^{o}C (Aringhoff et al, 2005). A Stirling engine or a micro turbine attached to the receiver would generate electricity. Fig 2.3 shows how the dish-shaped concentrator concentrates the intense radiant energy onto a receiver.

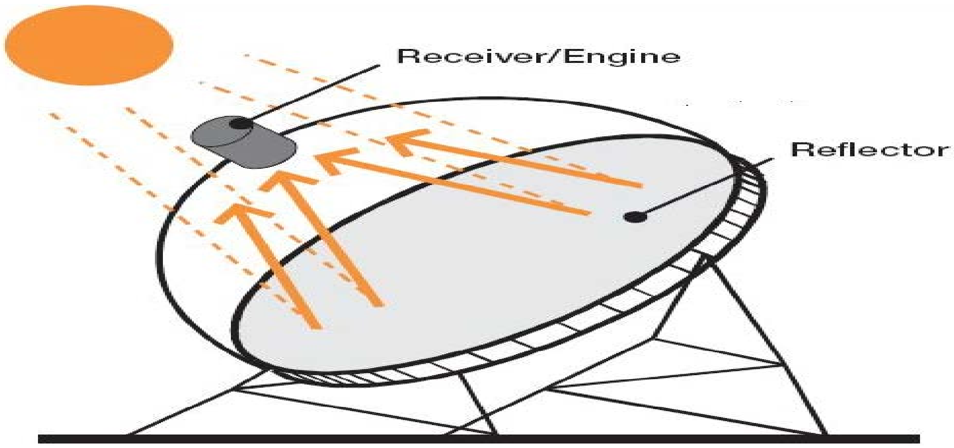


Fig 2.3: Parabolic Dish (Aringhoff et al, 2005)

2.3.2.3 Central Receiver (Power Tower)

An array of heliostats, that is, large individually-tracking mirrors is used to concentrate radiant energy on to a central receiver which is mounted at the top of a tower. A heat transfer medium usually water/steam, molten salts, liquid sodium or air in this central receiver absorbs the highly concentrated radiant energy reflected by the heliostats and converts it into thermal energy to be used for the subsequent generation of superheated steam for turbine operation. Fig 2.4 shows how the mirrors reflect sunlight into a central receiver.

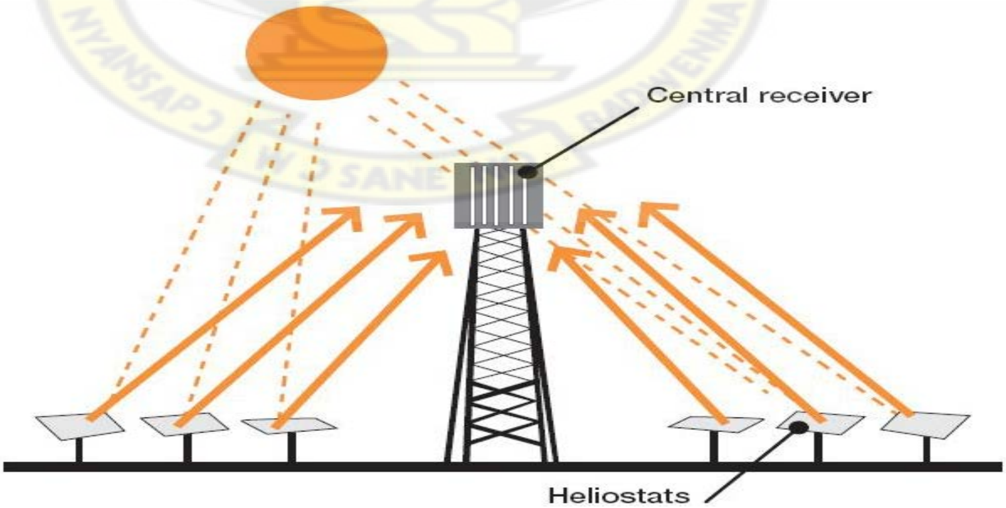


Fig 2.4: Central Receiver/Solar Tower (Aringhoff et al, 2005)

2.3.3 Collectors Suitable for 20 MW Plant

All the three major type of high-temperature collectors have been employed in large scale power generation in the Megawatts range.

Notably, the parabolic trough has a proven record of application in large-scale utilities. This large scale application is possible because a parabolic trough power plant's solar field consists of a large, modular array of single-axis-tracking parabolic trough solar collectors. Many parallel rows of these solar collectors span across the solar field, usually aligned on a north-south horizontal axis causing a high generating temperature in the Heat Transfer Fluid. A Heat Transfer Fluid (HTF) transports this heat from the solar field to the power block and other components of the system. The power block which is based on conventional power cycle technology uses a turbine to convert thermal energy from the solar field to electric energy.

The Parabolic Dish is a self-contained power producing unit. Several dish modules can be combined to form one solar power plant with their output collected electrically. The individual dish offers high concentration/temperature which provides the opportunity of coupling to high efficiency power converter such as a Stirling engine (Grasse et al, 1991). This system allows small to medium generating capacity to be achieved by collecting usually this 25/50 kWe Stirling engine output into the required capacity.

A power tower collector (also called central receiver) is employed in power system that consists of a heliostat field, tower and receiver, power block, and optional storage system. The field of flat, sun-tracking mirrors called heliostats focus direct normal solar radiation onto a receiver at the top of the tower. Power tower systems usually achieve concentration ratios of 300 to 1,500 and can operate at temperatures of up to 1,500^{o} C (Garud and Purohit, Undated). This high temperature attainable by the receiver is as a result of hundreds or thousands of these individually aimed mirrors reflecting sun rays to a common point. An appropriately sized receiver will intercept about 10 to 1,000 MW of sunlight to this central point (Vant-Hull, 1991).

2.3.4 Comparison of Solar Thermal Power Collectors

Solar Thermal Power systems use concentrated solar radiation as a high temperature energy source to produce electricity, since the average operating temperature of stationary non-concentrating collectors is low (max. up to 200^{0}C) as compared to the desirable input temperatures of heat engines (above 300^{0}C), the concentrating collectors are used for such applications.

The attainable temperature of solar collectors necessitates an in-depth comparison into their performance.

a. **Parabolic trough system:** at the receiver can reach 400 °C and produce steam for generating electricity by a transfer of heat from the HTF.

b. **Parabolic dish systems:** Parabolic dish systems can reach 1,000 °C at the receiver, and achieve the highest efficiencies for converting solar energy to electricity. (Garud and Purohit, Undated)

c. **Power tower system:** The reflected rays of the sun are always aimed at the receiver, where temperatures well above 1,000 °C can be reached hence generating steam of very high quality.

Table 2.3: Comparison of Solar Collectors

	Parabolic Trough	Parabolic Dish	Central Receiver
Applications	Grid-connected plants, process heat. Highest solar unit size built to date: 80 MWe (SEGS VIII & IX)	Stand-alone applications or small off-grid power systems. Highest solar unit size built to date: 50 kWe (Australian big Dish)	Grid-connected plants, high temp. process heat Highest solar unit size built to date: 20 MWe (PS 20)
Advantages	• Commercially available, over 10 billion kWh operational experience; operating temperature potential up to 500°C (400°C commercially proven) • Modularity • Lowest materials demand • Hybrid concept proven • Storage capability	• Very high conversion efficiencies – peak solar to electric conversion of about 30% • Modularity • Hybrid operation possible • Operational experience of first prototypes	• Good mid-term prospects for high conversion efficiencies, with solar collection; operating temperature potential up to 1,050°C (565°C proven at 10MW scale) • Storage at high temperatures •Hybrid operation possible
Disadvantages	• The use of oil based heat transfer media restricts operating temperatures to 400°C, resulting in moderate steam qualities • Land availability and water demand is too high. • The heat transfer thermal oil adds extra costs of investment and of operating & maintenance. • Some absorber tubes are still object of early degradation; reasons are the risk of breakage of absorber envelope glass tubes with loss of vacuum insulation and degradation of the absorber tube selective coating.	• Reliability needs to be improved • Projected cost goals of mass production still need to be achieved • The electricity output of single dish/Stirling unit is limited to small ratings of e.g. 25 kWe due to geometric and physic reasons (exception: Australian big dish designed for use of a 50 kWe steam engine or turbine generator). •Large-scale deployment has not yet occurred.	• Technologies are proven by few units (e.g. 10 MWe SOLAR TWO, PS 10 & PS 20). • Not yet verified is the good potential projected for the improvement of solar system performance and for cost reductions. •The industrial demonstration of volume production of heliostat components is still missing.

	Parabolic Trough	Parabolic Dish	Central Receiver
Disadvantages Contd.	• High winds may break mirror reflectors at field corners. • Low-cost and efficient energy storage systems have not been demonstrated up to now. • The direct steam generation trough technology is still in a developmental stage.	•The predicted potential for improvements of solar system performance and of cost reduction is still to be verified. • Hybrid systems have inherent low-efficient combustion and have to be proven. • No adequate energy storage system is applicable or available.	• Not yet verified are projections of the installed plant capital costs, operation and maintenance costs, electricity costs, solar subsystem performance, operational characteristics and of the annual plant availability.

(Sources: Aringhoff et al, 2005 and Becker et al, 2000)

2.4 Collector Choice for Northern Ghana

The insolation figures for Ghana, from NASA data compiled in the RETScreen software placed Bawku with average insolation value of 5.81 kWh/m^2.day as the site with the highest global irradiation. This figure is low as compared to Daggett, California, USA; a meteorological measurement site close to the Kramer Junction where the SEGS is sited with a total output of 354 MWe with a direct insolation of about 6.0 kWh/m^2.day (Stine and Geyer, 2001) which make use of Parabolic Trough collectors. Due to the high temperature needed to generate steam of very high quality for the operation of the power cycle, Central Receiver Systems which is able to work at the highest temperature due to thousands of heliostats reflecting the sun's rays to a central receiver comes at the forefront as the collector technology appropriate for the conditions in northern Ghana to achieve higher efficiencies in electricity production.

The various disadvantages of the Parabolic Trough and Dish collectors as discussed in Table 2.3 cannot be over-emphasized. This leaves the Central Receiver collector at the mercy of a mere commercial breakthrough while the technological limitations of the Trough and Dish technologies which cannot generate very high temperature as compared to a CRS for quality steam generation makes them less suitable for the meteorological conditions of northern Ghana.

The Central Receiver System when incorporated into a power cycle can make use of molten salt as the Heat Transfer Fluid (HTF). Molten salt can be used as both the HTF and as the heat storage medium in Power Tower Systems in contrast to Parabolic Trough system which uses high temperature oil as the HTF and requires oil-to-salt and salt-back-to-oil heat exchange for thermal storage. The result is that energy storage is less expensive and more efficient for Power Tower than for Trough systems (Stoddard et al, 2006).

The high temperature generated by the Central Receiver System has a good prospect for high conversion efficiencies which impacts on the overall efficiency of such plants. Since high overall efficiency is needed in accessing the profitability of a plant, the Central Receiver System would be favoured. On the basis of the comparison spelt out in Table 2.3 and the discussions above, the Central Receiver collector is the technology of choice for the location in northern Ghana.

2.5 Central Receiver Solar Thermal Power Plant

2.5.1 System Description

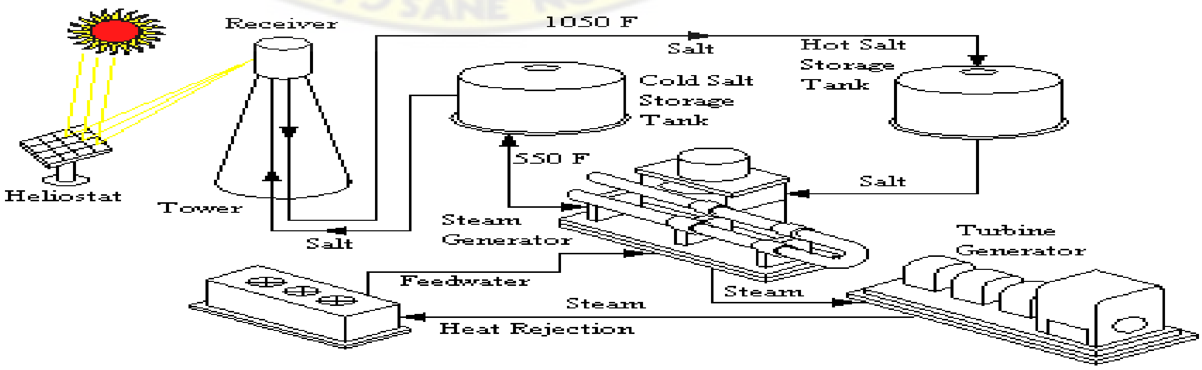


Fig 2.5: A Central Receiver Solar Plant with Storage

2.5.1.1 Heliostats

The heliostats consist of a reflecting element which is typically thin of low-iron glass mirror (Appendix B). The most commonly used heliostat is composed of several mirror module panels rather than a single large mirror. The thin glass mirrors are designed to form a slightly concave mirror surface on their supporting frame. Incident solar radiations on the mirrors are reflected toward a common point on the receiver. The heliostat focal length is approximately equal to the distance from the receiver to the farthest heliostat (Stine and Geyer, 2001).

A perfectly flat heliostat would produce an image of the sun on the receiver. In the usage of heliostat, each mirror segment is given a slight concave curvature. A heliostat is canted toward a focal point, so that this produces a higher flux density at the aim point.

In order to keep parasitic energy use low, fractional horsepower motors with high gear ratios are used to move the heliostat about its azimuth and elevation axes. This produces a slow, accurate, and powerful tracking motion.

2.5.1.2 Receiver

The receiver is placed at the top of a tower where reflected energy from the heliostats can be intercepted most efficiently. The receiver absorbs the energy being reflected from the heliostat field and transfers it into a heat transfer fluid. There are two basic types of receivers: external and cavity (Appendix C).

The choice of a particular type of receiver would depend on technical considerations such as: in a cavity receiver, the thermal losses are low since its configuration reduces radiative and reflective losses compared to an external receiver (Castro et al, 1991). The external receiver has a very wide acceptance angle while the maximum acceptance angle of the cavity receiver is 60^{o}.

The primary limitation on receiver design is the heat flux that can be absorbed through the receiver surface and into the heat transfer fluid, without overheating the receiver walls or the heat transfer fluid within them. The height of the tower on which the receiver is mounted is limited by cost. The weight and windage area of the receiver are the two most important factors in the design of the tower.

2.5.1.3 Field Layout

The best position for locating heliostats relative to the receiver and how high to place the receiver above the field constitute a multi-dimensional problem, in which costs and heliostat "loss" mechanisms are the variables. The major factor determining an optimum heliostat field layout is the cosine effect of the heliostat (Stine and Geyer, 2001). This effect depends on both the sun's position and the location of the individual heliostat relative to the receiver. A tracking mechanism positions the heliostat so that its surface's normal bisects the angle between the sun's rays and a line from the heliostat to the tower.

Heliostats opposite the sun are the most efficient. This is due to the fact that such heliostats have a reduced cosine loss. In the morning, heliostats west of the tower will have a high efficiency and those, east of the tower, a poorer efficiency. The opposite occurs in the afternoon, giving the east and west fields an average efficiency in between the high and the low.

There is the problem of one collector casting a shadow on an adjacent collector, thereby reducing the energy output of the shaded collector. There are two such interaction processes that reduce the amount of energy reaching the receiver. These are shadowing and blocking by adjacent heliostats. Due to the decrease collector energy as a result of shadowing and blocking, the arrangement below of heliostats has been found to decrease the effect of shadowing and blocking.

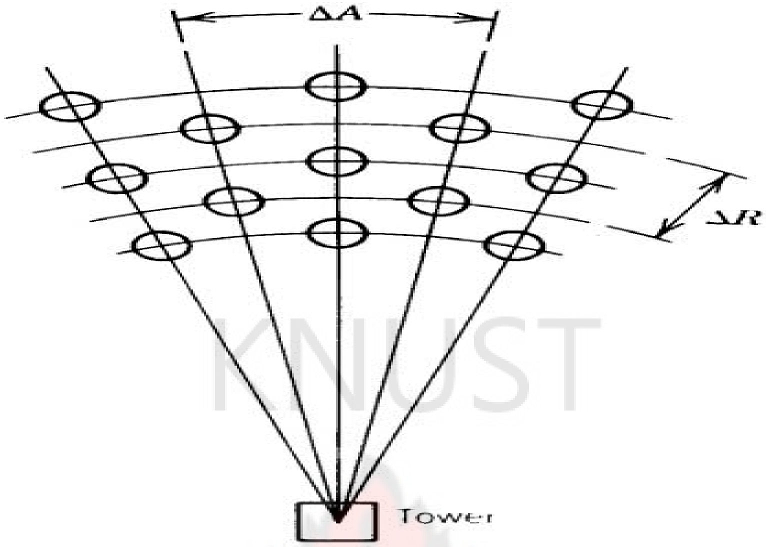


Figure 2.6: The radial stagger heliostat layout pattern developed by the University of Houston.

The radial spacing ΔR and the azimuthal spacing ΔA, defined in Figure 2.6, are given by Dellin et al (1981).

2.5.2 <u>Power Cycle</u>

The device used to produce mechanical work or electricity from solar generated heat is a power conversion cycle, or heat engine. Several considerations peculiar to solar energy systems affect the choice of the power conversion cycle and how the solar energy system is designed to incorporate it. Only those engine cycles that lend themselves to external heat addition are normally considered for solar applications. Unlike internal combustion engines where heat addition occurs within the working fluid, externally heated engines require that heat be transferred to the working fluid through containment walls (i.e., a heat exchanger).

Once an engine cycle and appropriate working fluid have been selected, a decision must be made as to whether to pump the engine's working fluid to the receiver of the solar collector and heat the working fluid directly, or to incorporate an intermediate heat-transfer fluid flowing between the receiver and a heat exchanger, and heat the working fluid in the heat exchanger. Incorporation of an intermediate heat-transfer fluid results in the addition of another pump, a heat exchanger, and a second fluid to the system.

Pumping the engine working fluid directly through the receiver can make the system difficult to control during solar irradiation transients (Stine and Geyer, 2001). This is especially true for Rankine cycle systems where preheating, evaporation, and superheating all must occur in the receiver; therefore, a specific liquid level must be maintained in the receiver.

2.5.2.1 Suitable Power Conversion Cycles

The various practical vapour power cycles that can be incorporated into the STPP, are namely (Rogers and Mayhew, 1994):

- Simple Rankine cycle
- Rankine cycle with superheat
- Reheat cycle
- Regenerative cycle

The choice of a particular power conversion mode would depend on the power producer and its targeted overall efficiency. A high overall efficiency is a good value for money; its concomitant complexity in plant design and size creates a high capital cost. An IPP would have to strike the balance between low operating cost and capital cost. Regenerative cycles have the highest overall efficiency compared to the other mode due to complexity in plant design.

2.5.2.2 Components

Steam Generators

A choice must be made whether to generate vapour in the receiver of the solar collector or to use an intermediate heat-transfer fluid between the receiver and the vapour generator. The choice generally depends on the specific design, but there are several primary considerations.

Receiver vapour generators: An advantage of generating steam in the receiver of the solar collector is that the receiver has fewer components and no loss of temperature with an intermediate transfer between a Heat Transfer Fluid and a working fluid. Extreme care must be taken when both liquid and vapour are in a receiver; the design of the receiver must ensures that the radiant flux incident on that portion of the receiver containing vapour is less than the flux incident in the regions with liquid and where boiling is taking place (Stine and Geyer, 2001). This is because the heat-transfer coefficient into a liquid is significantly higher than into superheated vapour. For similar values of solar flux, burnout of the receiver walls could occur in the regions where vapour exists on the other side of the receiver wall. Many concentrating collector designs require that the receiver change attitude while the collector tracks the sun. This change of attitude increases the chances of high flux on portions of the receiver containing vapour.

Heat-exchange vapour generators: The steam generator transfers thermal energy from molten salt to water and converts water to dry steam at a specified temperature and pressure to drive the turbine-electric generator. This system has four major components: preheater, evaporator, superheater and steam drum. The steam drum separates moist steam into water and dry steam. The direction of molten salt is from the hot salt storage through the superheater, evaporator, preheater and to the cold salt storage. Feedwater is pumped through the preheater, steam drum, evaporator, drum, superheater and to the turbine.

Condensers

From the Second Law of Thermodynamics, all power cycles must reject a large percentage of the heat added in order to produce mechanical work. For a Rankine cycle, this heat rejection occurs in conjunction with condensation of the working fluid vapour leaving the turbine at low pressure. The lower the heat rejection temperature, the greater the cycle efficiency. Heat rejection from the condenser to the surroundings can be either direct or through an intermediate heat-transfer fluid loop (usually water). The types of condensers commonly used in solar power systems are Tube-and-Shell Condenser, Dry Cooling Tower, Wet Cooling Tower and Natural-Draft Cooling Tower.

Each of these heat rejection schemes requires electrical power for operation. This power, considered a parasitic loss from the cycle's output, must be kept to a minimum. Highest parasitic power requirements are usually associated with dry cooling towers since they make use only of the sensible temperature of the air for cooling. This type of cooling is often selected for solar power systems because these systems are often located in hot, arid regions with minimal water resources.

Expanders

Turbines and reciprocating piston-cylinder devices are the two major expanders used most commonly for solar Rankine Cycle applications. Rotary-displacement machines (Roots type), scroll or screw expanders, and fluid drag disc turbines have also been proposed for small output applications.

Pumps

The pump being a component in a Rankine cycle is needed to raise the pressure of the liquid leaving the condenser to the pressure of the steam generator. Since pump work is inversely proportional to the fluid density, less work is required to pressurize a liquid than a vapour or gas. The ideal pump raises the pressure of a liquid in an adiabatic, reversible process. Real pumps, like turbines, produce an entropy increase in the fluid.

Working Fluid

The choice of the heat transfer fluid to be pumped through the receiver is determined by the application. The primary choice criterion is the maximum operating temperature of the system followed closely by the cost-effectiveness of the system and safety considerations. Five heat transfer fluids have been studied in detail for application to central receiver systems.

Heat transfer oils are the heat transfer fluids with the lowest operating temperature capabilities (Stine and Geyer, 2001). Both hydrocarbon and synthetic-based oils, for example Therminol, Dowtherm etc may be used, but their maximum temperature is around 425°C (797°F). However, their vapour pressure is low at these temperatures, thus allowing their use for thermal energy storage. Below temperatures of about -10°C (14°F), heat must be supplied to make most of these oils flow. Oils have the major drawback of flammable and thus require special safety systems when used at high temperatures.

The Solar One power plant used steam as the heat transfer fluid. Steam has been studied for many central receiver applications. Maximum temperature applications are around 540°C (1000°F) where the pressure must be about 10 MPa to produce a high boiling temperature. Freeze protection must be provided for ambient temperatures less than 0°C (32°F) (Stine and Geyer, 2001). The water used in the receiver must be highly de-ionized in order to prevent scale build-up on the inner walls of the receiver heat transfer surfaces. However, its cost is lower than that of other heat transfer fluids. Use of water as a high-temperature storage medium is difficult because of the high pressures involved.

Nitrate salt mixtures can be used as both a heat transfer fluid and a storage medium at temperatures of up to 565°C (1050°F). However, most mixtures currently being considered freeze at temperatures around 140 to 220°C (285 to 430°F) and thus must be heated when the system is shutdown. They have a good storage potential because of their high volumetric heat capacity. The cost of nitrate salt mixtures is relatively cheaper, making them an attractive heat transfer fluid candidate (Stine and Geyer, 2001).

Liquid sodium can also be used as both a heat transfer fluid and storage medium, with a maximum operating temperature of 600°C (1112°F). Sodium is liquid at temperature of 600^{o}C, hence its vapour pressure is low. However, it solidifies at 98°C (208°F), thereby requiring heating on shutdown. The cost of sodium-based systems is higher than the nitrate salt systems. For high-temperature applications such as Brayton cycles, it is proposed to use air or helium as the heat transfer fluid (Stine and Geyer, 2001). Operating temperatures of around 850°C (1560°F) at 12 atm pressure are being proposed. Although the cost of these gases would be low, they cannot be used for storage and require very large diameter piping to transport them through the system.

2.5.3 Balance of System

The Balance of System consists of the remaining systems, components and structures that comprise a complete power plant or energy system that are not included in the mechanism used to harvest the solar resource (for example, the Collector System and the Receiver System) and the application or load (such as a prime mover and waste heat recovery system). A Solar Thermal Power Plant would require the following auxiliary facilities:

- The Plant Control System
- The Beam Characterization System
- The Plant Support System
- Demineralisation Plant
- The Thermal Storage System (Optional)

2.5.3.1 The Plant Control System

The control system for the solar plant consists of four major elements: The Master Control System (MCS), the collector system, a conventional control panel and the solar protection system. The MCS is a distributed digital control system that directly monitors and controls the solar receiver, thermal storage, steam generator, and turbine generator. The solar collector control subsystem is separate but tied into the MCS through a digital link to control the heliostats during automatic sequences such as start-up and shutdown. The conventional control panel provides switches, meters, lights and annunciators to allow the operator to monitor all the systems effectively. The solar protection system is an independent system design to trip the plant, or a portion thereof, in the event of conditions that could be hazardous to plant personnel or equipment.

2.5.3.2 The Beam Characterization System

This is used for correcting the alignment of heliostats and for evaluating collector system performance. It uses video cameras located in the heliostats field to obtain images of reflected beams from individual heliostats. The images are analyzed to characterize beam size and shape, flux distribution, beam centroid and beam power. The sun's radiance distribution is also measured so that input flux to the heliostats is known. Heliostat tracking errors are calculated with this system and individual heliostats aim points are automatically adjusted.

The beam characterization system has proven to be very useful in keeping the heliostats properly aligned so that spillage is reduced and the concentrated flux on the receiver is properly distributed. Data from this system allows more accurate calculations of input energy to the receiver.

2.5.3.3 The Plant Support System

This consists of site structures and facility services. These include, but not, limited to Storehouses, Workshops, Offices, Solar Radiation and Wind data measurement installation and so on.

2.5.3.4 Demineralisation Plant

The water that would be used in the steam generator to produce steam has to be highly deionised to prevent scale build-up in the system and on the inner walls of the receiver heat transfer surfaces. This removes dissolved particles and minerals from the water supply to the plant to produce high quality feedwater to be used to generate steam in the steam generator and subsequently which would be used to drive the steam turbines.

2.5.3.5 The Thermal Storage System

The thermal storage system is used to store energy for use in the evening and during cloud transients. The major components are hot and cold salt storage tanks. Molten salt at 566 ^{o}C is collected in the hot tank during the day. When required, the hot molten salt is pumped through the steam generator system, heat is extracted, and the salt transported to the cold tank at 277 ^{o}C. The process is repeated each day that solar energy is collected. A drainage tank with limited capacity and a heater for initial and make-up salt melting are also part of this system.

The hot storage tank is insulated internally and externally. The internal insulation is designed to reduce the temperature enough to use carbon steel for the tank structure. The cold tank is cool enough to use carbon steel without internal insulation and hence, is only insulated externally. Both tanks are supported by a reinforced concrete foundation which requires water cooling due to the temperature limit of concrete.

CHAPTER THREE

TECHNICAL ASSESSMENT AND PROJECT ENGINEERING

3.1 Solar Radiation in Northern Ghana

The Solar Map of Ghana shown in figure 3.1 below points out that location between 10º and 11º of latitude have very low diffuse radiation of about 32% of total radiation; this means that the Solar Thermal Power Plant would be more appropriate for locations in these regions of northern Ghana. These locations have to be checked with available solar irradiation data for the highest insolation figure and conditions such as environmental, climatic condition and socio-economic impact including proximity to grid system must be taken into consideration in the selection of the appropriate site for the plant. These conditions would make the following site: Navrongo, Wa, Bawku and Bolgatanga stand out for consideration.

3.1.1 Solar Map of Ghana

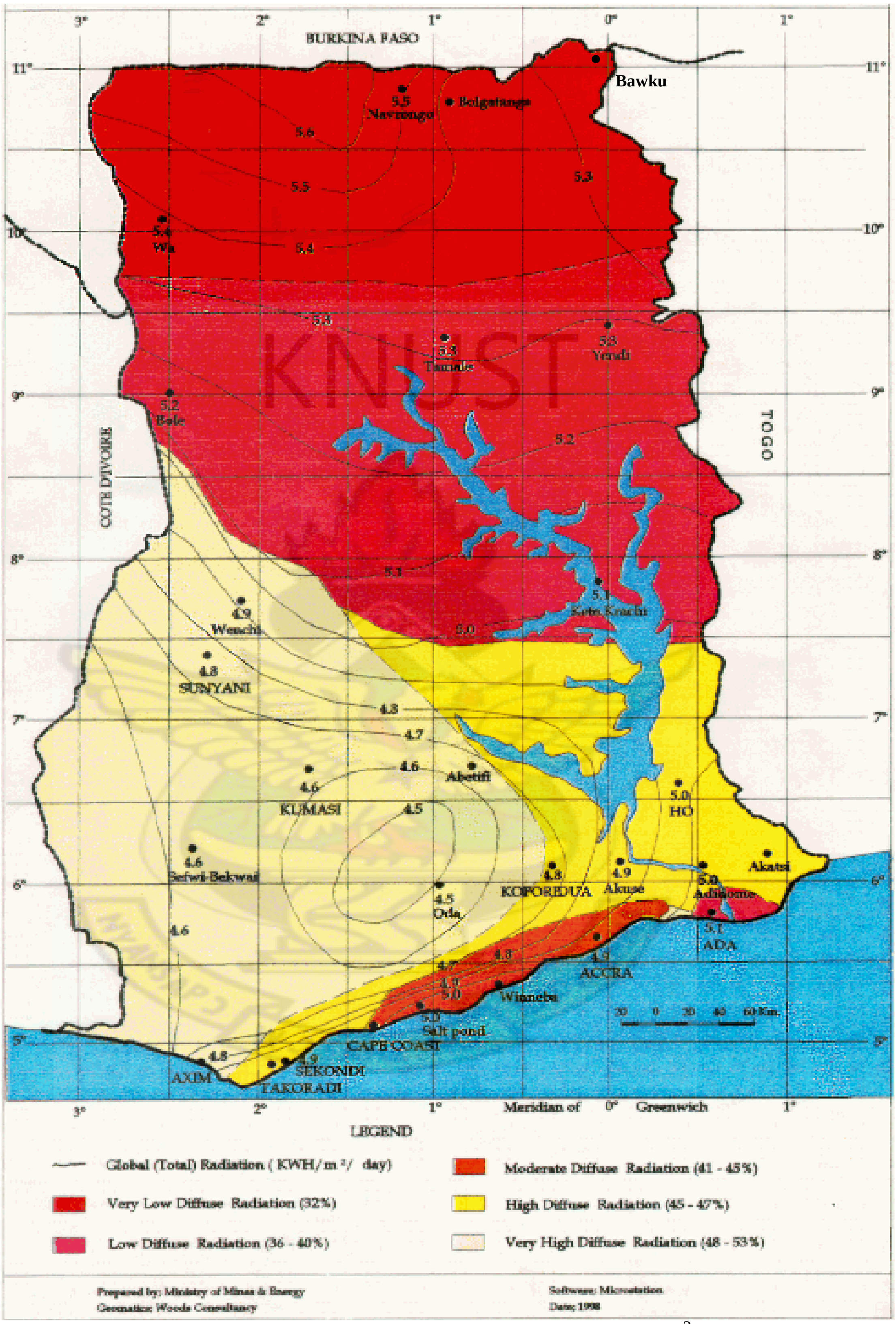


Fig 3.1 Year Monthly Averages of Solar Irradiation (kWh/m^2.day) at 19 Synoptic Station

3.1.2 Irradiation Data

On the basis of the data compiled in the Solar and Wind Energy Resource Assessment (SWERA) report, Wa, the capital of the Upper West Region with average insolation figure of 5.524 kWh/m^2.day has the highest global irradiation.

Table 3.1 Five highest synoptic stations with the highest global irradiation in Ghana from SWERA Report

MONTH	Monthly Global Irradiation/ (kWh/m^2.day)				
	Wa	**Navrongo**	**Tamale**	**Yendi**	**Bole**
JANUARY	5.464	5.391	5.124	5.156	5.422
FEBRUARY	5.809	5.400	5.479	5.462	5.821
MARCH	5.798	5.783	5.613	5.558	5.762
APRIL	5.859	5.958	5.890	5.862	5.797
MAY	5.873	5.934	5.869	5.919	5.710
JUNE	5.611	5.719	5.510	5.415	5.091
JULY	5.135	5.339	4.954	5.044	4.645
AUGUST	4.937	5.098	4.841	4.629	4.494
SEPTEMBER	5.125	5.324	5.004	4.957	4.827
OCTOBER	5.641	5.677	5.472	5.623	5.540
NOVEMBER	5.649	5.616	5.695	5.674	5.520
DECEMBER	5.381	4.824	5.213	5.165	5.251
AVERAGE	5.524	5.505	5.389	5.372	5.323

(Source: Department of Mechanical Engineering, KNUST (2003))

Table 3.2 Six highest synoptic stations with the highest global irradiation in Ghana from NASA compiled database

MONTH	Monthly Global Irradiation/ (kWh/m^2.day)					
	Bawku	**Wa**	**Navrongo**	**Bolga**	**Salaga**	**Tamale**
JANUARY	5.39	5.73	5.48	5.72	5.63	5.14
FEBRUARY	5.96	6.02	6.04	5.96	5.91	5.56
MARCH	6.21	6.15	6.11	6.11	6.03	5.75
APRIL	6.30	6.10	6.11	6.06	5.80	5.61
MAY	6.09	5.96	5.94	5.82	5.53	5.69
JUNE	5.61	5.39	5.39	5.32	4.93	5.31
JULY	5.22	4.92	4.90	4.88	4.58	4.61
AUGUST	4.94	4.67	4.61	4.61	4.31	4.25
SEPTEMBER	5.27	5.01	4.96	4.95	4.59	4.75
OCTOBER	5.73	5.60	5.62	5.58	5.21	5.47
NOVEMBER	5.47	5.59	5.66	5.56	5.49	5.44
DECEMBER	5.30	5.63	5.70	5.59	5.49	4.75
AVERAGE	5.62	5.57	5.54	5.51	5.29	5.19

(Source: RETScreen Software)

The figures from the SWERA report is validated with NASA generated satellite values as compiled in the RETScreen software. Since ground readings are more accurate than satellite readings, for example, 5.524 kWh/m^2.day is adopted as the average global irradiation value of Wa as seen in the SWERA report. This value is validated with NASA value of 5.57 kWh/m^2.day.

Bawku in the Upper East Region of Ghana is shown from Table 3.2 to be the synoptic station with the highest global insolation. However, the annual average direct normal Irradiance (DNI) map of Ghana from NREL (Appendix H, Fig H-1), shows that Bawku has a DNI in the range of 3.5-4.0 kWh/m^2.day while Wa has a DNI of 4.0-4.5 kWh/m^2.day. Since concentrating system makes use of the direct normal insolation, Wa is a preferred site compared to Bawku. Azoumah et al (2010) discusses criteria for site selection, this includes but is not limited to: solar resources, water resources, Soil structure and the geology, the availability of land, the topography and the energy demand. However, in this thesis the proximity to transmission system and DNI of the site is the sole criteria used in the selection of site.

On the basis of the analysis from all reference sources, that is, Solar Map, DNI Map of Ghana, SWERA Report and NASA Data, as compiled in the RETScreen software, Wa, the capital city of the Upper West Region of Ghana on 10.1º N latitude and -2.5º E longitude is the most suitable place for siting the Solar Thermal Electric-Power Plant. A further climatic detail of Wa is provided in Appendix D.

3.2 Power Consumption in the Three Northern Region

The Ghana Electricity Infrastructure developed by the Energy Commission of Ghana in 2005 and captured in a report 'Guide to Electric Power in Ghana' by the Resource Centre for Energy Economics and Regulation (RCEER) as shown in Fig

3.2 below indicates that the three northern regions described as Zone 5 and Zone 6 do not have any electric generating capacities. This places a lot of strain on our transmission system to deliver electric power to the northern sector especially since most of the power generating facilities are situated in the southern part of the country. This is without the related issues of losses in transmissions as a result of transporting electricity over very long distances through complicated networks of transformers and lines.

A load capability of 117 MW for zone 5 and 27 MW for zone 6, brings the total power consumption needs of the three northern region to 144 MW as of 2005 (RCEER, 2005) with a likely steady increase in consumption over the years. This brings to floor the need for a more diversified and multiplicity of energy sources to cater for the expanding energy economy in the northern part of Ghana and in the country as a whole. With the intense radiant energy in the region, a solar thermal plant cannot be sidelined. This renewable clean-form of energy would supplement the already existing plant to transform the economies of the north to compete with that of the south while addressing the issues of global warming.

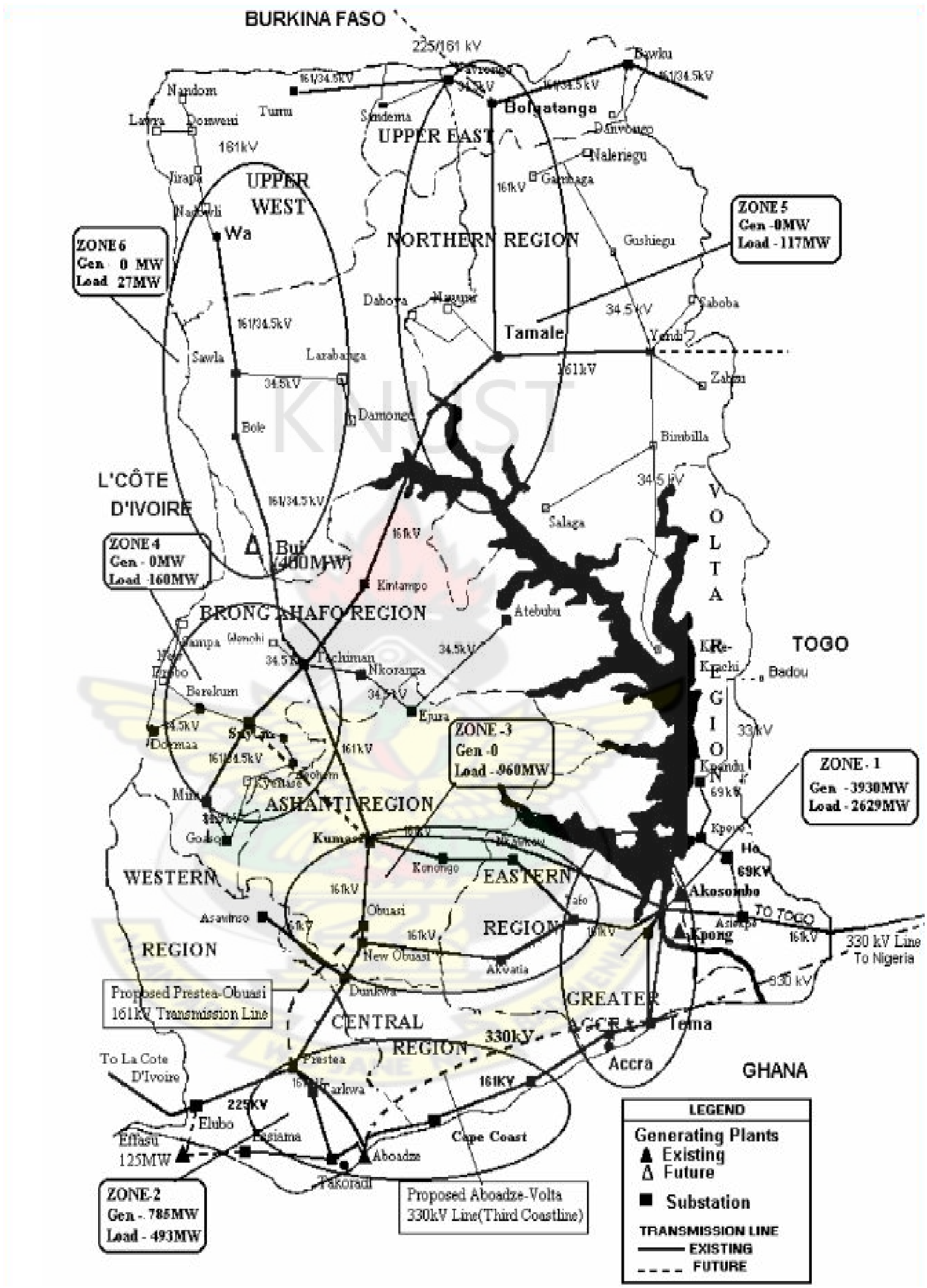


Fig 3.2: Ghana Electricity Infrastructure

Source: RCEER, 2005

3.3 Methodology for Capacity Factor Estimation for a CRS

Capacity Factor (C.F.) can be defined as:

$$\text{C.F.} = \frac{\textit{Actual energy generated in the Period}}{\textit{Rated Capacity X Total length of Period (hrs)}} \quad (1)$$

That is,

$$\text{C.F.} = \frac{E_{Actual}}{E_{Rated}} \quad (2)$$

Where,

$$E_{Rated} = P_{Rated} \times 8760 \quad (3)$$

Hence,

$$\text{C.F.} = \frac{E_{Actual}}{P_{Rated}\ X\ 8760} \quad (4)$$

Conversion efficiency from sunlight to electrical energy for a Central Receiver System can be expressed as:

$$\eta_{conversion} = \eta_{col}.\eta_{cycle}.\eta_{gen} \quad (5)$$

Where

η_{col} = collector efficiency

η_{cycle} = thermal cycle efficiency

η_{gen} = generator efficiency

The Central Receiver System makes use of only beam radiation.

Therefore, Power Output is given by

$$P_{Actual} = (I\beta).\ (N.A_h).\ \eta_{conversion} \quad \text{(Glasnovic et al, 2011)} \quad [W] \quad (6)$$

Where, $(I\beta)$ = Beam irradiance [W/m^2]

I = Global irradiance

β = Beam fraction

N = number of heliostats in the field

A_h= area of one heliostat

The clear day solar insolation on a surface perpendicular to incoming solar radiation is 1000 W/m^2 such that the Global Irradiance is 1000 W/m^2 and the Beam Fraction is 1. This is the maximum available insolation to the heliostats for the power conversion system.

Therefore, the Rated Capacity of the plant can be expressed as

$$P_{Rated} = \{(N.A_h)\ [m^2] \times 1000 \times 1\ [W/m^2]\}.\eta_{col}.\eta_{cycle}.\eta_{gen} \qquad [W] \qquad (7)$$

$$P_{Rated} = \{(N.A_h)\ [m^2] \times 1\ [kW/m^2]\}.\eta_{conversion} \qquad [kW] \qquad (8)$$

From equation (3)

$$E_{Rated} = \{(N.A_h)\ [m^2] \times 1\ [kW/m^2]\}.\eta_{conversion} \times 8760\ [h] \qquad [kWh] \qquad (9)$$

$$E_{Rated} = (N.A_h)\ .\eta_{conversion} \times 8760 \qquad [kWh] \qquad (10)$$

Now,

$$E_{Actual} = \int_0^{yr} P_{Actual}\ dt \qquad [Wh] \qquad (11)$$

Where,

P_{Actual} = actual power generated by plant based on beam irradiance available.

Substituting equation (6) into equation (11), we have

$$E_{Actual} = \int_0^{yr} (I\beta).(N.A_h).\eta_{conversion}\ dt \qquad (12)$$

$$E_{Actual} = (N.A_h).\ \eta_{conversion} \int_0^{yr} (I\beta)\, dt \qquad [Wh] \qquad (13)$$

Substituting equation (10) and (13) into equation (2), we have

$$C.F. = \frac{\int_0^{yr} (I\beta) dt}{8760\ X\ 1000} \qquad (14)$$

<u>Assumptions</u>

1. The Beam Fraction β is constant throughout the year
2. Constant global irradiance for the year which would be taken to be the annual mean global irradiance for Wa, Upper West Region of Ghana.

Therefore,

$$\int_0^{yr} (I\beta)\, dt = I_m \beta\, (\Delta T) \qquad (15)$$

Where

I_m = annual mean Irradiance

(ΔT) = total hours in a year

Hence

$$\int_0^{yr} (I\beta)\, dt = I_m\beta \times 8760 \qquad (16)$$

Substituting equation (16) into equation (14), we have

$$C.F. = \frac{I_m\, \beta}{1000} \qquad (17)$$

Since this algorithm would be incorporated into RETScreen, hence, making use of NASA solar irradiation data for Wa, Upper West Region of Ghana, the beam fraction β=0.68, since the region has about 32% diffuse irradiation (from solar map, fig 3.1). Hence, to estimate the total beam radiation over the year for Wa, Upper West Region, we have:

Table 3.3: Estimation of the Total Beam Radiation over the year for Wa, Upper West Region

Month	Global Irradiation [kWh/ m^2/day]	*Global Irradiance (I) [W/m^2]	Beam Irradiance (Iβ) [W/m^2]	Days in Month [days]	Hours in Month (Δt)[h]	I. Δt [Wh/m^2]	I β.Δt [Wh/m^2]
January	5.73	238.75	162.35	31	744	177630.0	120,788.40
February	6.02	250.83	170.56	28	672	168557.8	114,616.32
March	6.15	256.25	174.25	31	744	190650.0	129,642.00
April	6.10	254.17	172.84	30	720	183002.4	124,444.80
May	5.96	248.33	168.86	31	744	184757.5	125,631.84
June	5.39	224.58	152.71	30	720	161697.6	109,951.20
July	4.92	205.00	139.40	31	744	152520.0	103,713.60
August	4.67	194.58	132.31	31	744	144767.5	98,438.64
September	5.01	208.75	141.95	30	720	150300.0	102,204.00
October	5.60	233.33	158.66	31	744	173597.5	118,043.04
November	5.59	232.92	158.39	30	720	167702.4	114,040.80
December	5.63	234.58	159.51	31	744	174527.5	118,675.44
Total:						2 029 710	1 380190.08

* Conversion factor: 0.024 kWh/m^2/day = 1 W/m^2

Annual mean Irradiance I_m = $\frac{Annual\ Global\ Irradiance}{Hours\ in\ a\ year}$ (18)

that is,

$$I_m = \frac{\sum(I.\Delta t)}{8760} = \frac{2{,}029{,}710.0}{8760}$$

$$I_m = 231.70\ W/m^2$$

Hence, from equation (17)

C.F. = $\frac{231.70\ X\ 0.68}{1000}$ = 0.157 6 = 15.76%

Alternatively,

From equation (14)

$\int_0^{yr}(\mathrm{I}\beta)\ dt$ = 1,380,190.08

C.F. = $\frac{1{,}380{,}190.08}{8760\ X\ 1000}$ = 0.157 6 = 15.76%

3.4 RETScreen Simulation and Assessment of Power Tower Technology

The energy production and savings, costs, emission reductions, financial viability and risk for grid-connected, isolated-grid and off-grid solar thermal power projects, ranging in size from large scale central power plants, to small scale power systems can be evaluated using the RETScreen software. It can also be used to assess other technologies of solar thermal power generation, that is, solar parabolic troughs and solar dish engines.

The analysis of S&L (2003) of the cost-reduction potential of CSP technology over the next 10–20 years points out a capital cost of about US$ 3,600.00/kW for Tower technology. For an economic life of 30 years, the annual Operating and

Maintenance cost in ($k) was pegged at US$ 9,132.00 for a 200 MWe plant. The cost of construction and construction duration was placed at 7% of capital cost and one year respectively.

The analysis of the industry projections for technology improvement and plant scale-up in the S&L report was performed up to 2020. This includes a cost and detailed assessment of the cost and performance projections for future Tower Plants; it was based on factors such as research and development progress in Central Receiver System, economies of scale, economies of learning resulting from increased use of the technology, and O&M cost reductions resulting from deployments of technology (S&L, 2003).

These values were employed in RETScreen analysis in the Cost Analysis page, thus: the capital cost of US$ 3,600.00/kW is assumed to include Feasibility Study, Development, Power System, and Balance of System and Miscellaneous. A 15% contingency was allowed for Balance of System and Miscellaneous due to the running nature of this cost and general inflation level. An operating and maintenance cost of US$ 9,132,000.00 for a 200 MWe in the report, results in a scale-down of $ 913,200.00 for a 20 MW plant annually, assuming a scaling factor of 1. A 10% contingency was set to cater for any unseen shock.

A detail O&M cost for Power Tower technology has to be established in Ghana since values quoted in the S&L report (page 5-26) for average burdened labour rate ($k/yr), staff cost ($k/yr) and annual material & cost does not reflect conditions in Ghana.

3.5 Plant System Design and Layout

3.5.1 Plant Layout

The CRS concept for solar energy concentration and collection is based on a field of individually sun-tracking heliostats that reflect the incident radiation to a receiver (boiler) at the top of a centrally located tower. Typically 80 to 95 percent of the reflected energy is absorbed into the working fluid which is pumped up the tower and into the receiver. The heated fluid (or steam) returns down the tower and then to a thermal demand such as a thermal electrical power plant as shown in figure 3.3.

In CRS, all of the solar energy collected in the entire solar field is transmitted optically to a small central collection region rather than being piped around a field as hot fluid. Due to this characteristic, central receiver systems are characterized by large power levels (1 to 500 MW) and high temperatures of about 540 to 840°C (Stine et al, 2001).

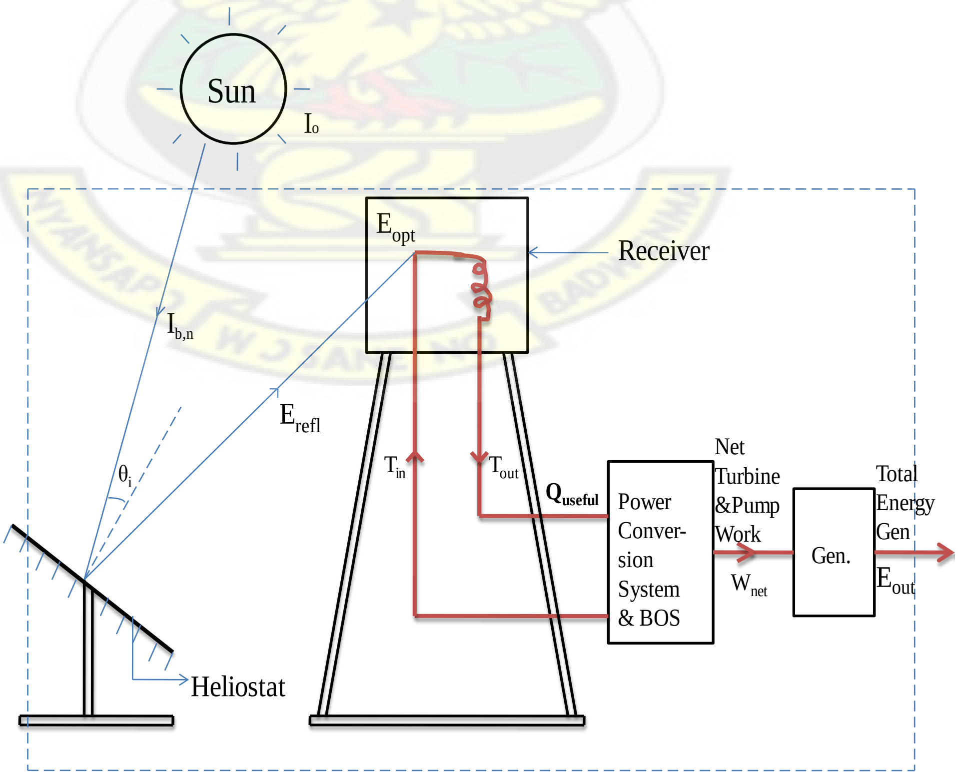


Fig 3.3: Layout of the Central Receiver System

3.5.2 Conceptual System Design

Design Conditions

1. Site Location
    - Location: Wa, Ghana
    - Longitude: - 2.5 ^{o}E
    - Latitude: 10.1 ^{o}N
    - Elevation: 271 m above sea level
2. Site Insolation (Direct Normal)
    - Design Point: 166.40 W/m^2
    - Annual Average: 1,371.06 kWh/m^2
3. Electrical Output: 20.0 MWe Net at Design Point

Configuration

1. Receiver
    - Receiver Fluid: Molten Salt (60% $NaNO_3$, 40% KNO_3 by mass)
    - Configuration: Cavity
    - Type Description: Forced Circulation, Once Through
    - Inlet and Outlet Fluid Temperature: Measured value
    - Tower Description: Conical Reinforced Concrete
2. Heliostats
    - Number: Depends on overall collector efficiency
    - Individual Heliostats Reflective Area: Must be specified by manufacturer
    - Type: Glass Mirrors
    - Control Approach: Distributed Digital Control, Open Loop

Estimated Plant Output

1. Overall System Performance Efficiency: IPP dependent
2. Capacity Factor: Annual 15.76%
3. Annual Energy Produced: 27,604 MWhe

3.6 Location, Site and Environment

Sitting requirement for a Power Tower system includes level land with less than 1% slope desirable. The land area must be one continuous parcel with essentially a circular footprint.

Probably the most important environmental design criterion that must be met by a heliostat design is the wind condition. Typical requirements may be for the heliostat to meet its operating requirements in a 12 m/s wind, to survive a 22 m/s wind, and to continue to operate or move to the stow position in a 40 m/s wind (a position usually horizontal with mirrors face-up or face-down) (Stine and Geyer, 2001). Since the average annual wind speed for Wa is 2.2 m/s (Appendix D), the performance of a heliostat in a CRS installation in Wa is unlikely to be affected due to wind speed.

Solar technologies using concentrating systems for electrical production require sufficient beam normal radiation, which is the beam radiation which comes from the sun and passes through the planet's atmosphere without deviation and refraction. Consequently, appropriate site locations are normally situated in arid to semi-arid regions. On a global scale, the solar resource in such regions is very high. More exactly, acceptable production costs of solar electricity typically occur where radiation levels exceed about 1,700 kWh/m^2-yr (Stine et al, 2001).

Solar electricity generation costs and feasibility of the project highly depend on the project site itself. A good site has to have a high annual beam insolation to obtain maximum solar electricity output. It must be reasonably flat to accommodate the solar field without prohibitive expensive earth works. It must also be close to the grid and a substation to avoid the need to build expensive electricity lines for evacuating the power. Access roads must be suitable for transporting the heavy equipment like turbine generators to the site. Skilled personnel must be available to construct and operate the plants.

3.7 Socio-economic and Environmental Impact

Solar energy technologies offer the potential to assist our nation with several critical national problems. First, it can be used to produce heat or electricity in homes, factories, and power plants—displacing fossil fuels—and eliminating harmful pollutants that can contribute to climate and health issues. Secondly, solar energy captured and used to create electricity or thermal energy enables diversity in our energy mix and reduces our dependence on foreign oil. Finally, solar energy components are high technology and their manufacture creates high-paying jobs. Thus, it can provide critically needed energy, reduce the impact on our environment, enhance our nation's security, and create economic development in the three northern regions of Ghana.

No hazardous gaseous or liquid emissions are released during operation of the solar power tower plant. If a salt spill occurs, the salt will freeze before significant contamination of the soil occurs. Salt is picked up with a shovel and can be recycled if necessary. If the power tower is hybridized with a conventional fossil plant, emissions will be released from the non-solar portion of the plant. Solar energy can directly benefit the nation by substantially contributing toward resolving three national problems—air quality, energy reliability and security, and economic development.

3.8 Green House Gas Emission Analysis

RETScreen determines the annual greenhouse gas emission reduction for a clean energy technology compared to a conventional technology base case. Results are presented in terms of the tonnes of carbon dioxide per year that would be equivalent to the emission reduction, regardless of the actual gases that compose the emissions. To do this, methane and nitrous oxide emissions are converted to the equivalent carbon dioxide emissions in terms of their global warming potential.

3.8.1 Base and Proposed Case Emission Estimation

For an assumed use of 90% Natural Gas and a 10% use of oil as a base case power system, the RETScreen model estimates the GHG emission factor to be 0.569 tCO_2/MWh. It also estimates the GHG emission as 15,701.6 tCO_2.

The proposed case being the Solar Thermal Power Plant makes use of solar radiation which is devoid of green gas emission, hence, the GHG emission factor (tCO_2/MWh) and the GHG emission (tCO_2) is zero. The detail of this analysis is found in Appendix E (Figure E-4).

3.8.2 GHG Emission Reduction Estimation

GHG emission savings as a result of using solar in the proposed case is estimated by the formula (RETScreen International, 2004).

Annual GHG		Base case GHG		Proposed case		End-use	
emission	=	[emission	-	GHG emission]	X	annual energy	.............(a)
reduction		factor		factor		delivered	
(tCO2)		(tCO2/MWh)		(tCO2/MWh)		(MWh)	

This value is adjusted to account for transmission and distribution losses.

Therefore, substituting into equation (a),

Annual GHG emission reduction (tCO_2) = (0.569 – 0) [tCO_2/MWh] x 27,604 [MWh]

= 15,706.68 tCO_2

A T&D loss of 14% in Ghanaian electrical infrastructure gives the annual GHG emission reduction to be adjusted by 2,198.94 tCO_2.

Hence,

Annual GHG emission reduction (tCO_2) = (15,706.68 – 2,198.94)

= 13,507.74 tCO_2

This value agrees favourably with RETScreen estimation of 13,503.4 tCO_2 as shown in Appendix E (Figure E-4).

3.9 Duration of Plant Erection and First Power Generation Start-up Period

In constructing a CRS, time has to be allowed for planning and applying for construction permit from the appropriate agencies. After a detailed engineering phase and procurement of main components, the plant construction works commences. The tower building can be erected first while large main components like turbine, boilers and so on are set in position when the corresponding storey is finished. This can be followed by installation of minor components.

The great challenge in this construction is that all plant components has to be installed one over the other inside of the tower in a very demanding time schedule including the erection of the concrete tower. A set time can be achieved through a day by day planned time schedule that is kept almost with daily preciseness until the end of the project with high performance in Project Management.

Power Tower plants require one to two hours of continuous irradiation, in order to start up successfully. A higher beam insolation would normally result in a shorter start-up time. The start-up time for the receiver of a CRS is defined as the time required to preheat the receiver such that a stable outlet temperature of around 500 ^{o}C is obtained. For the steam generator, it is the time necessary to achieve such working temperatures and pressures that good quality steam is produced-normally 100 bars, 480 ^{o}C (Kesselring et al, 1985).

The start-up time can vary considerably, and depends very much on the receiver flow rate and the available insolation at that time. A higher insolation can result in a much lower start-up time, that is, if all heliostat are in track and the receiver put into operation just around solar noon when the intensity of solar radiation is high, the start-up time of the CRS can be in less than 30 minutes.

The start-up time may be longer due to tracking accuracy errors and in particular, the large morning and afternoon sun images, which can cause problem with smaller available aiming area especially with the use of cavity type Receiver.

3.10 Human Resource and Expertise

Ghana’s experience in constructing and managing various conventional power plants is advantageous to getting the right human resource requirement for the power block of a STPP. However, constructing and maintaining the solar field will require training of personnel for such highly specialized task.

During construction phase of a typical medium size CRS facility, about 455 job-years of direct employment are created which will include both skilled and unskilled workers (S&L, 2003). About 38 permanent jobs would be expected to be available once power production starts; another 56 jobs are indirectly created by the operation of such plants (S&L, 2003).

CHAPTER FOUR

FINANCIAL ANALYSIS AND INVESTMENT APPRAISAL

4.1 Evaluation Criteria

The 20 MW CRS with no thermal storage and fossil buck-up is analyzed for financial viability. There are various criteria for determining the financial attractiveness of a project. The Simple Payback Period and the Net Present Value Criteria is used in this thesis. However, the NPV criterion has been widely accepted by financial analyst, economist and accountants as the only one that yields correct project choice in all circumstances.

4.1.1 Simple Payback Period

The simple payback is the time in years starting in year one of the project that it takes for the cumulative cash flow to switch from negative to positive. It measures the time required for the cash inflows to equal the capital invested.

Obviously, shorter payback periods are preferable to longer payback periods. However, the payback period is considered a method of analysis with serious limitation, because it does not properly account for the time value of money, risk, financing or other important consideration such as opportunity cost.

Mathematically, Simple Payback is defined as (RETScreen International, 2005):

$$\text{SPB} = \frac{C - IG}{(C_{ener} + C_{capa} + C_{RE} + C_{GHG}) - (C_{O\&M} + C_{fuel})}$$

Where,

SPB = Simple Payback

C = total initial cost of the project

IG = incentives and grants

C_{ener} = annual energy savings of income

C_{capa} = annual capacity savings or income

C_{RE} = annual renewable energy (RE) production credit income

C_{GHG} = GHG reduction income

$C_{O\&M}$ = yearly operation and maintenance costs

C_{fuel} = annual cost of fuel or electricity

4.1.2 Net Present Value

Net Present Value (NPV) is the total Present Value (PV) of a time series of cash flow. The NPV criterion ensures that each inflow and/or outflow is discounted back to its Present Value (PV) and then they are summed up.

Mathematically, NPV is defined as:

$$\text{NPV} = \sum_{t=0}^{n} \frac{R_t}{(1+i)^t}$$

Where

t = time of the cash flow

i = discount rate

R_t = net cash flow (the amount of cash inflow minus outflow) at time t.

A project will be commercially viable if the present value of the discounted cash flows is greater than zero. If the NPV is less than zero, the investors cannot expect to earn a rate of return equal to its alternative use of funds and hence the project can be rejected from the financial standpoint.

4.2 Total Investment Cost

On the basis of the analysis in section 3.4 of this thesis, the total investment cost is analyzed in the Cost Analysis page of the RETScreen software. The data below is the breakdown of the total monetary investment in the project:

ITEM	COST (U.S. $)
Capital Cost	72,000,000.00
BOS & Miscellaneous	14,526,000.00
Total Initial Cost	**86,526,000.00**
Annual O&M	1,004,520.00

Table 5.1: Total Initial and annual O&M cost for the Power Tower Plant

4.3 Revenue from Plant

For a Feed-in Tariff of 8 US Cent/kWh, RETScreen analysis places the yearly revenue generated by the plant at US $1,203,815.00. This revenue generated over the next 30 years amount to US $36,114,450.00.

A summary of important generating parameters of the plant is provided below:

Annual electricity generation: 27,604 MWh

Total electricity generated: 828,120 MWh

Current Bulk Supply Tariff: 8 U.S. Cent/kWh

Total revenue: US $36,114,450.00

4.4 Cash Flow Analysis

The evaluation of the energy economic figures of merit, for example NPV, of an energy project, the cash flows has to be calculated, including operating, investing and financing cash flows. The most complete analysis of an investment in a technology or a project requires that at least each year of the lifetime of the investment be analyzed, taking into account relevant direct costs, indirect and overhead costs, taxes, and returns on investment, plus any externalities, such as environmental impacts, that are relevant to the decision to be made. In this study, the level of detail in the cash flows is low, as a highly detailed cash flow analysis would go beyond the scope of this study.

The cash flow period calculated in this study is the lifetime of the project. Costs and revenues are expressed in US $. A constant US $ cash flow does not include inflation and represents the number of US $ that would have been required if the cost was paid in the base year. It is assumed that the duration of the construction period is one year and that the plant generates electricity for 30 years. Taxes are not considered in the cash flow below (i.e. before tax cash flow).

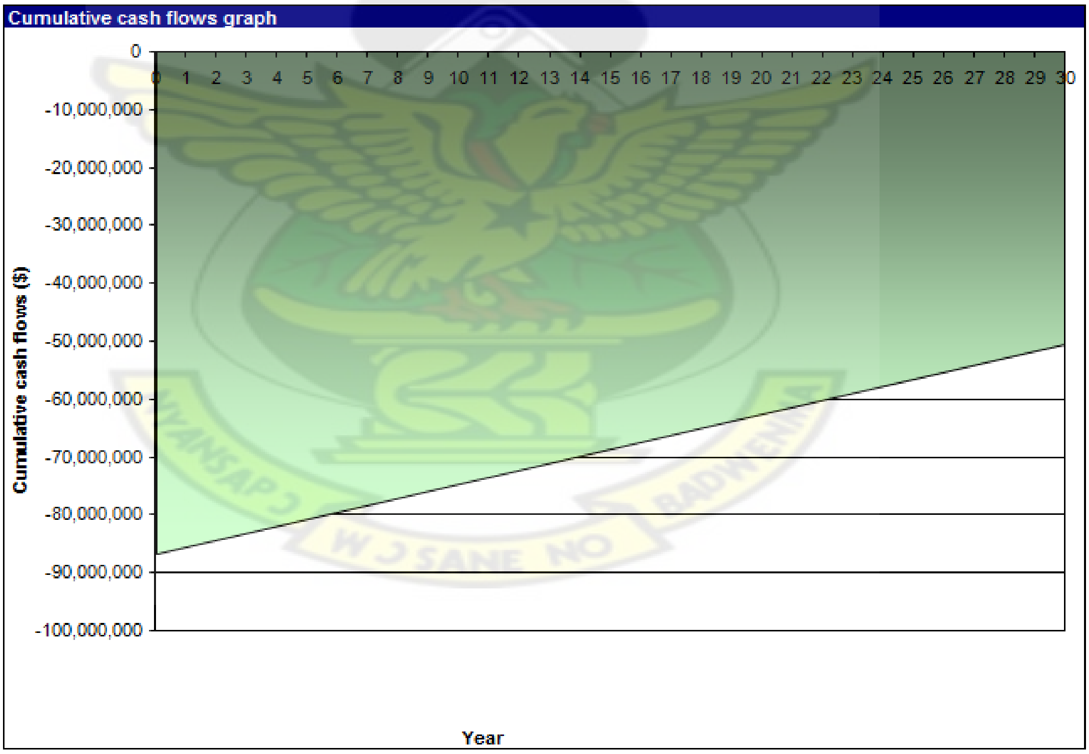


Fig 5.1.1 Cumulative cash flow graph of the plant generated by RETScreen software.

The cash flow shows that it is not possible to operate a pure solar Central Receiver System profitably in Wa under reference conditions as indicated in section 4.5 below. In 30 years, total revenue of about US $36.0 million is generated without inflation, and before tax. This amount is meagre compared to the initial investment of about US $ 87 million, yielding a simple payback period of 71.9 years from RETScreen analysis.

However, figure 5.1.2 shows that a combination of 8 US Cents Feed-in Tariff, 60% Grant and capital cost of US $1000/kW makes the plant financially viable giving rise to a simple payback period of eight (8) years. Some interesting cash flows for viable conditions are provided in Appendix I.

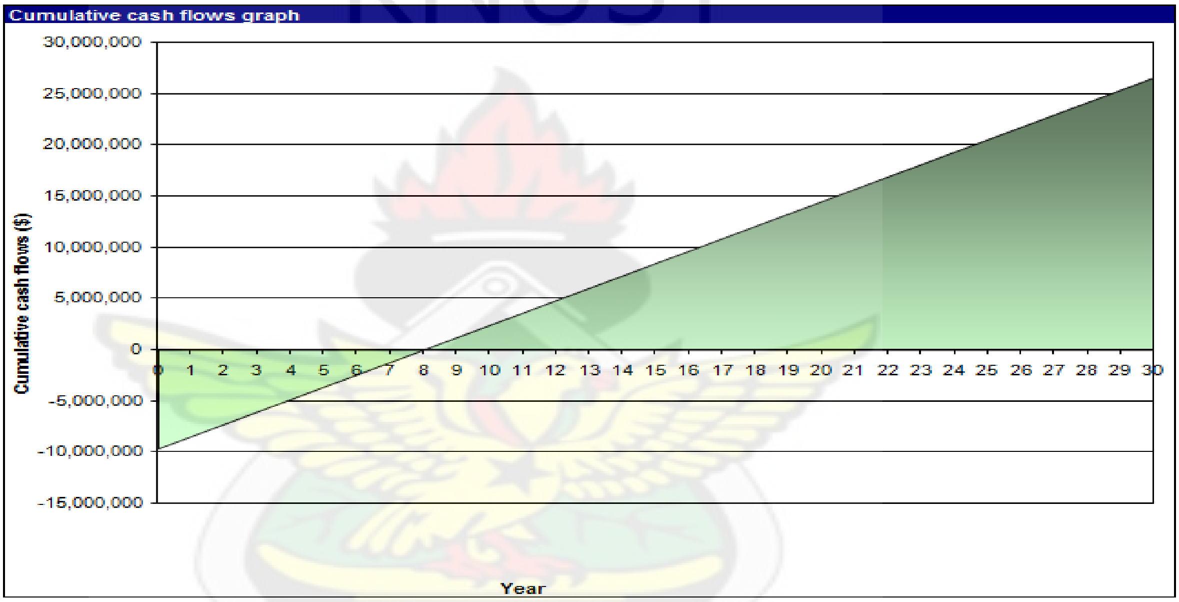


Figure 5.1.2: Cumulative cash flows of a combination of 8 US Cents Feed-in Tariff, 60% Grant and US $1000/kW Capital Cost.

4.5 Sensitivity Analysis

A reference case was established using the following data set:

- Project location: Wa, Ghana
- Technology type: Central Receiver System (Power Tower)
- Power Capacity: 20 MW
- Power Tower Capital Cost: US $3,600.00/kW
- Electricity Export rate: 8 US cent/kWh

- GHG Credit: \$0/tonne
- Grant/Capital Subsidy: 0%
- Inflation: 0%
- Discount Rate: 10%

The simple payback period is calculated by the RETScreen software and various scenarios were as follows:

- Scenario Analysis 1- effect of tariff changes on simple payback period and NPV for the reference case.

- Scenario Analysis 2- effect of GHG income on the simple payback period and NPV under different tariff conditions.

- Scenario Analysis 3- effect of grants/capital subsidies on the simple payback period and NPV under different tariff conditions.

- Scenario Analysis 4- effect of drop in capital cost of Tower technology on the simple payback period and NPV under different tariff conditions.

- Scenario Analysis 5- effect of drop in O&M Cost of Tower technology on the simple payback period and NPV under different tariff conditions.

- Scenario Analysis 6- effect of reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period and NPV for the reference case under different bulk supply tariffs.

4.5.1 Effect of tariff changes on simple payback period and NPV for the reference case

The reference case gave a simple payback period of 71.9 years, which is not attractive from a financial standpoint. The simple payback period improves with increasing tariffs, reaching under 10 years for tariffs around 40 US cents/kWh and higher, as shown in Figure 5.2.1.

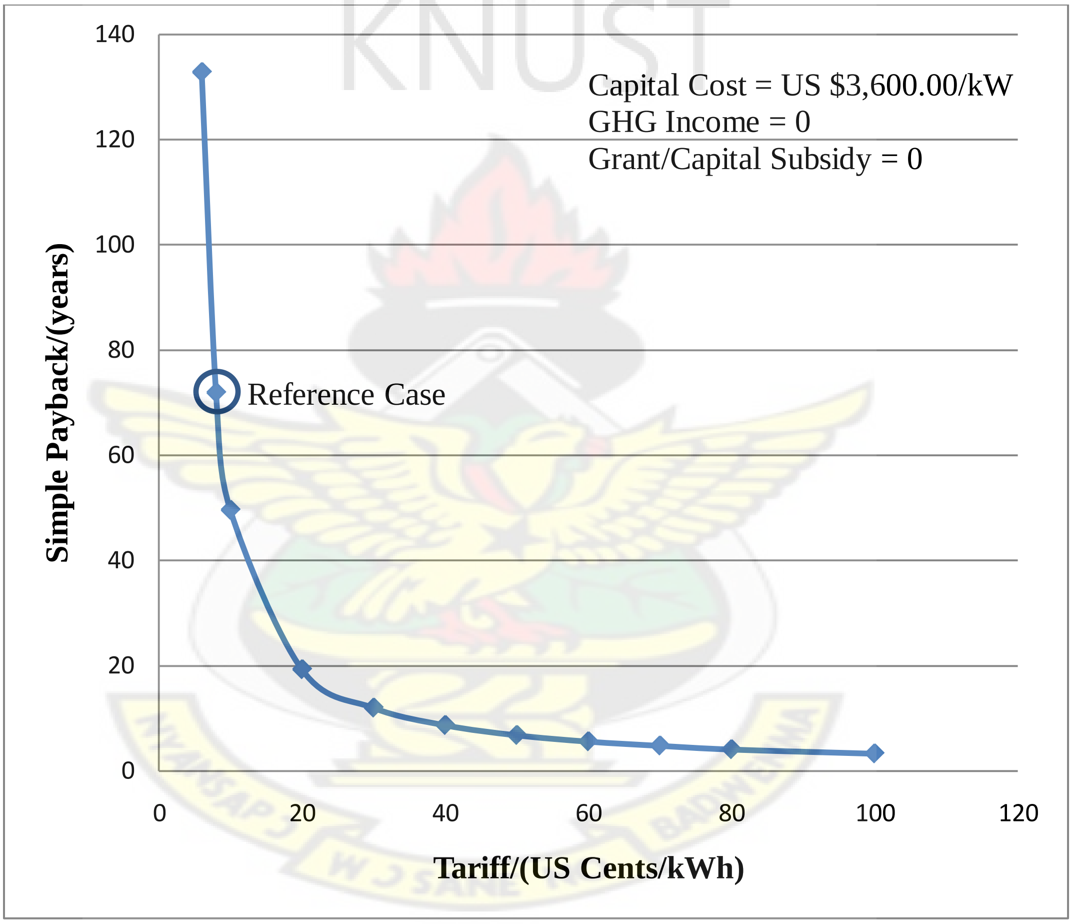


Figure 5.2.1 Effect of tariff changes on Simple Payback Period

The attractiveness of the project is validated for tariff of 40 US cents/kWh and above as can be seen from a graph of NPV against different bulk supply tariffs as shown in figure 5.2.2. This is due to the positive yield in NPV at this higher rate.

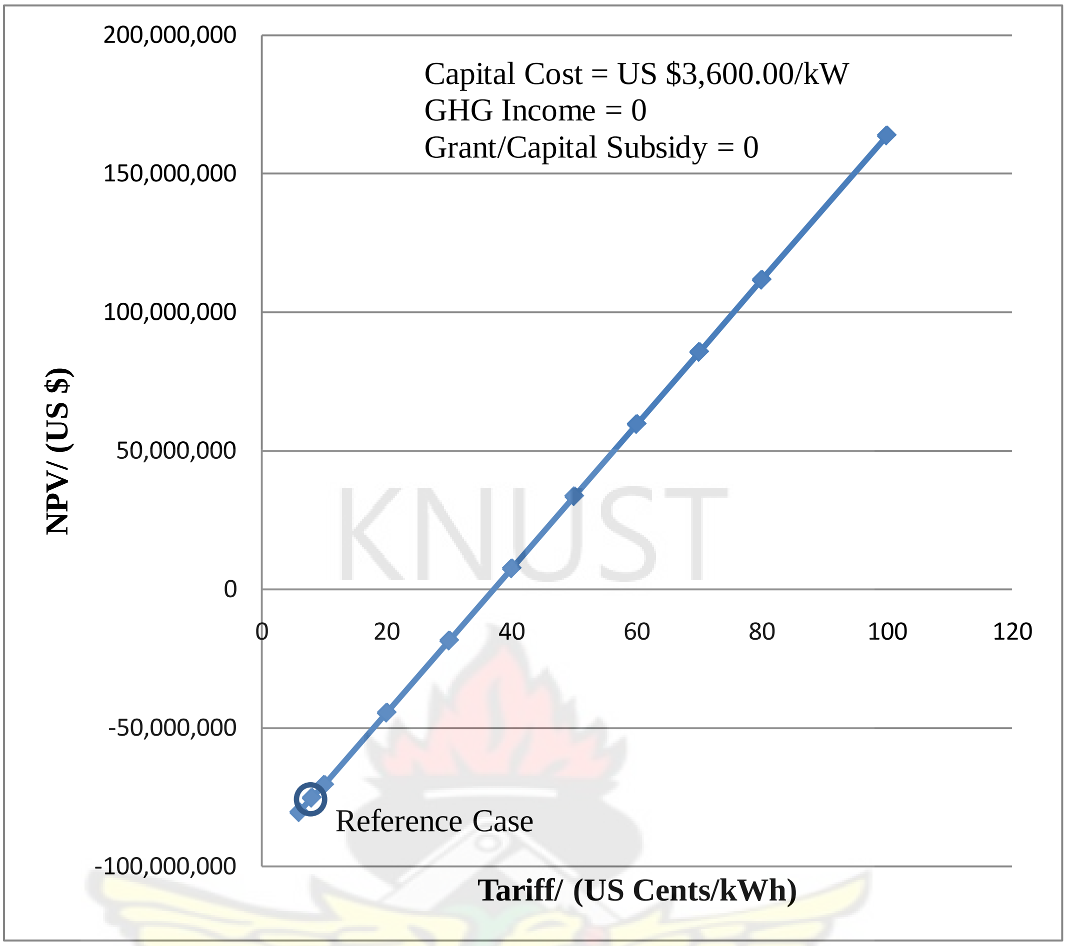


Figure 5.2.2 Effect of tariff changes on NPV

4.5.2 Effect of GHG income on the simple payback period and NPV under different tariff conditions

GHG credits provide additional cash inflow into the RETScreen analysis; however, Figure 5.3 shows that, this does not have any significant effect on the simple payback period. Figure 5.3 also shows that the higher the tariff, the less the effect of GHG credits. This can be seen from the graph below where tariffs of 20 US cents/kWh and above are almost plotted on the same point for $0, $10, $20/tonne GHG income.

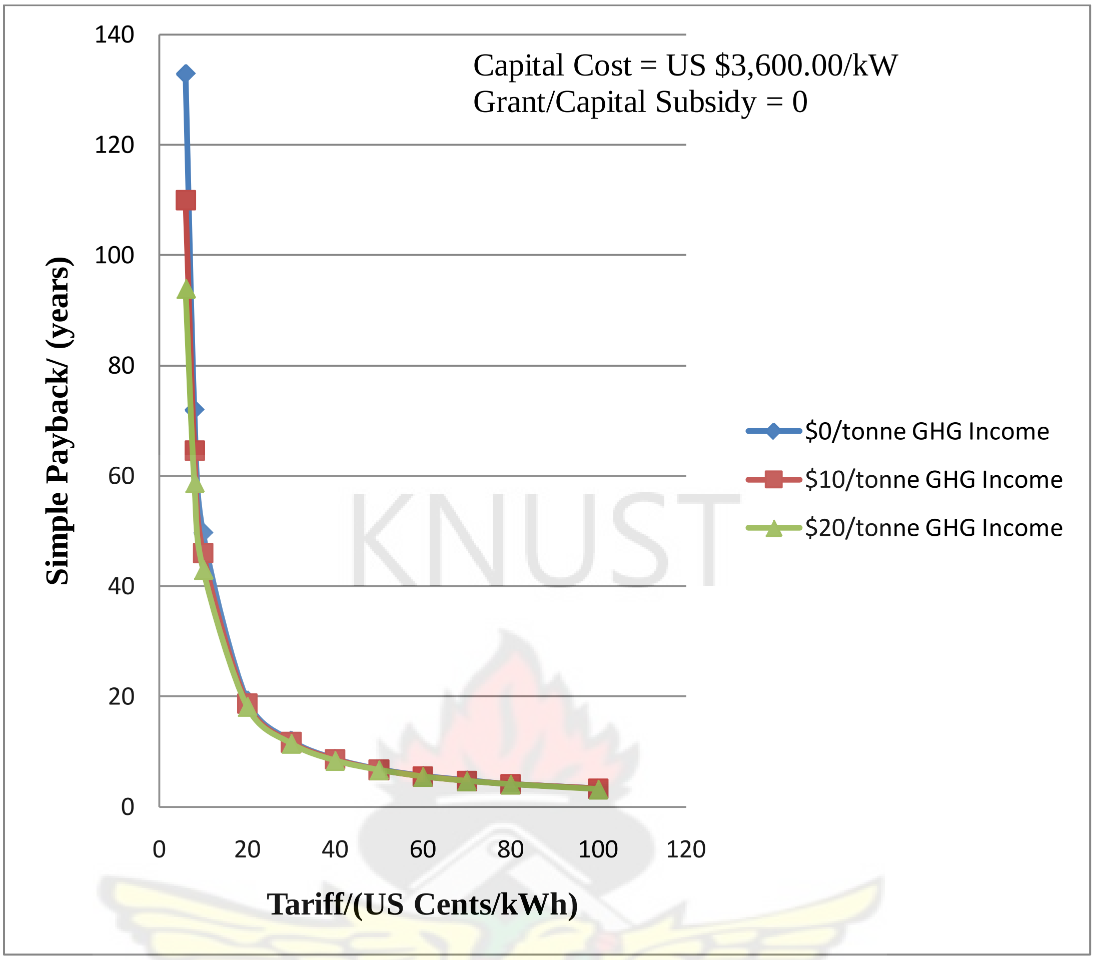


Figure 5.3 Effect of GHG price changes on Simple Payback Period

RETScreen analysis of the effect of GHG price changes on NPV showed that there is no marked difference in values generated for prices of US $10/tonne and US $20/tonne from the reference case of US $0/tonne. This analysis gave rise to the same graph as shown in fig 5.2.2.

4.5.3 Effect of grants/capital subsidies on the simple payback period and NPV under different tariff conditions

Capital injection into a project in the form of grants and/or capital subsidies helps to improve the profitability or financial viability of a solar thermal plant project significantly. Figure 5.4.1 shows that, a grant of about 80% of the total initial cost is able to reduce the simple payback period of the reference case from 71.9 years to about 14.4 years, while a 40% grant place the simple payback period at 43.1 years.

Figure 5.4.1 also shows that a judicious mix of capital subsidy with the right tariff is needed to bring the payback period below 10 years, which is what a private investor would look out for, since most investors are interested in project with simple payback period of 10 years or below. A 40% capital subsidy, for instance, will put the payback period at 7.1 years (i.e. below 10 years) at tariffs around 30 US cents/kWh.

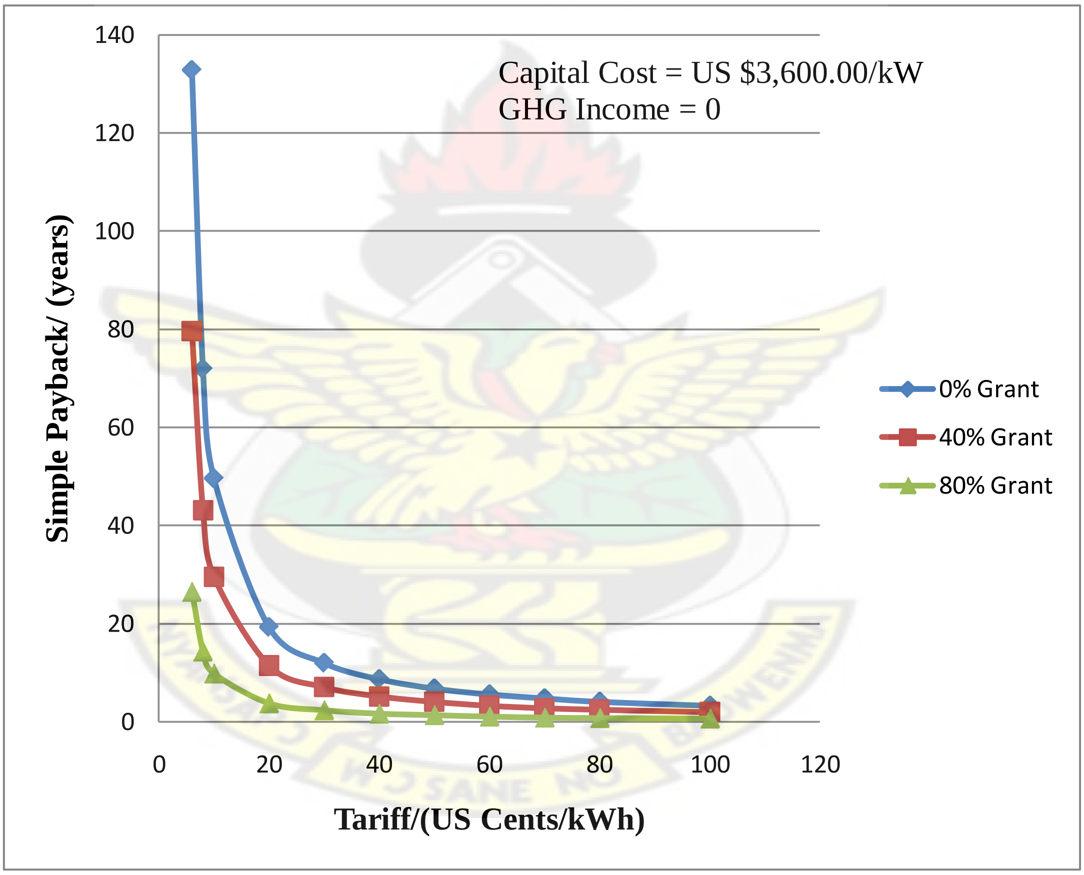


Figure 5.4.1: Effect of Grants/Capital subsidies on Simple Payback Period.

Figure 5.4.2 provides an indication that a 40% capital subsidy and a tariff of 24 US cents/kWh or higher would result in a project with a good value for money. On the other hand, a 80% grant would generate an attractive project at a bulk supply tariff of 10.3 US cents/kWh and higher.

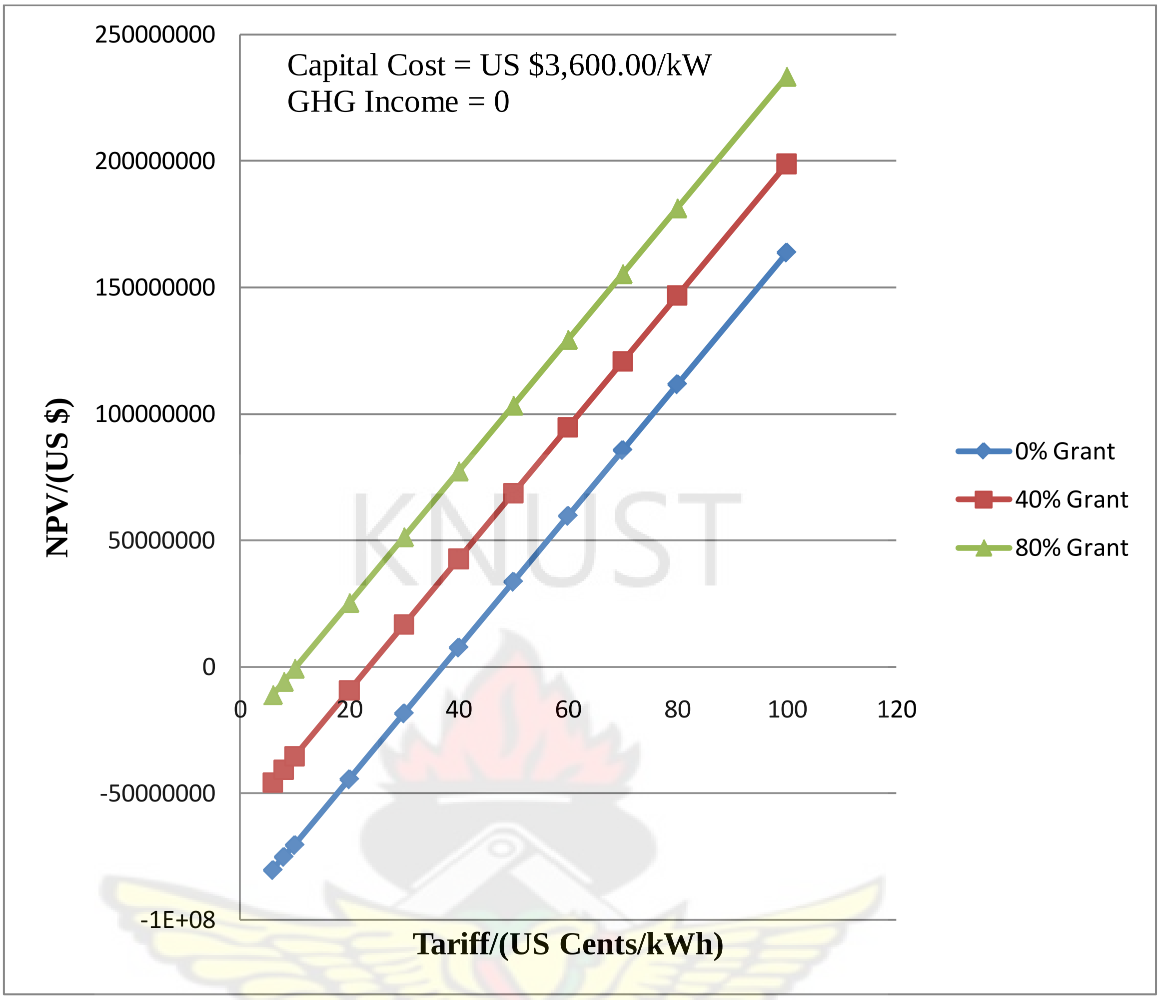


Figure 5.4.2: Effect of Grants/Capital subsidies on NPV.

4.5.4 Effect of drop in Capital Cost of Tower technology on the simple payback period and NPV under different tariff conditions.

Trough and tower plants, with their large central turbine generators and balance of system equipment, can take advantage of economies of scale for cost reduction, as cost per kW goes down with increased size.

From S&L (2003) report, a summary of Tower Cost projections by ‘SunLab’ and ‘Sargent & Lundy’ place power tower capital cost at about US $3,600.00/kWe, forecasting US $3,100/kWe for mid term (up to 2010); and US $2,270/kWe for long term (up to 2020) by SunLab’s projection. The only projected figure lower than US

$3,600.00/kWe from Sargent & Lundy's forecast is US $3,591/kWe for long term (up to 2020).

Analysis of impact on simple payback and NPV is then conducted for the following capital cost US $2,200.00/kWe, US $3,100.00/kWe and US $3,500.00/kWe. The capital cost of US $3,100.00/kWe for mid term (up to 2010) in the S&L (2003) report is validated by the value for Solar Thermal Power Plant in Appendix G. In spite of the US $3,100.00 projection for 2010 in the S&L (2003) report which is validated by data in Appendix G; US $3,600.00 is employed in the reference case analysis as capital cost is expected to be higher for countries outside of the USA and Europe (see notes in Appendix G).

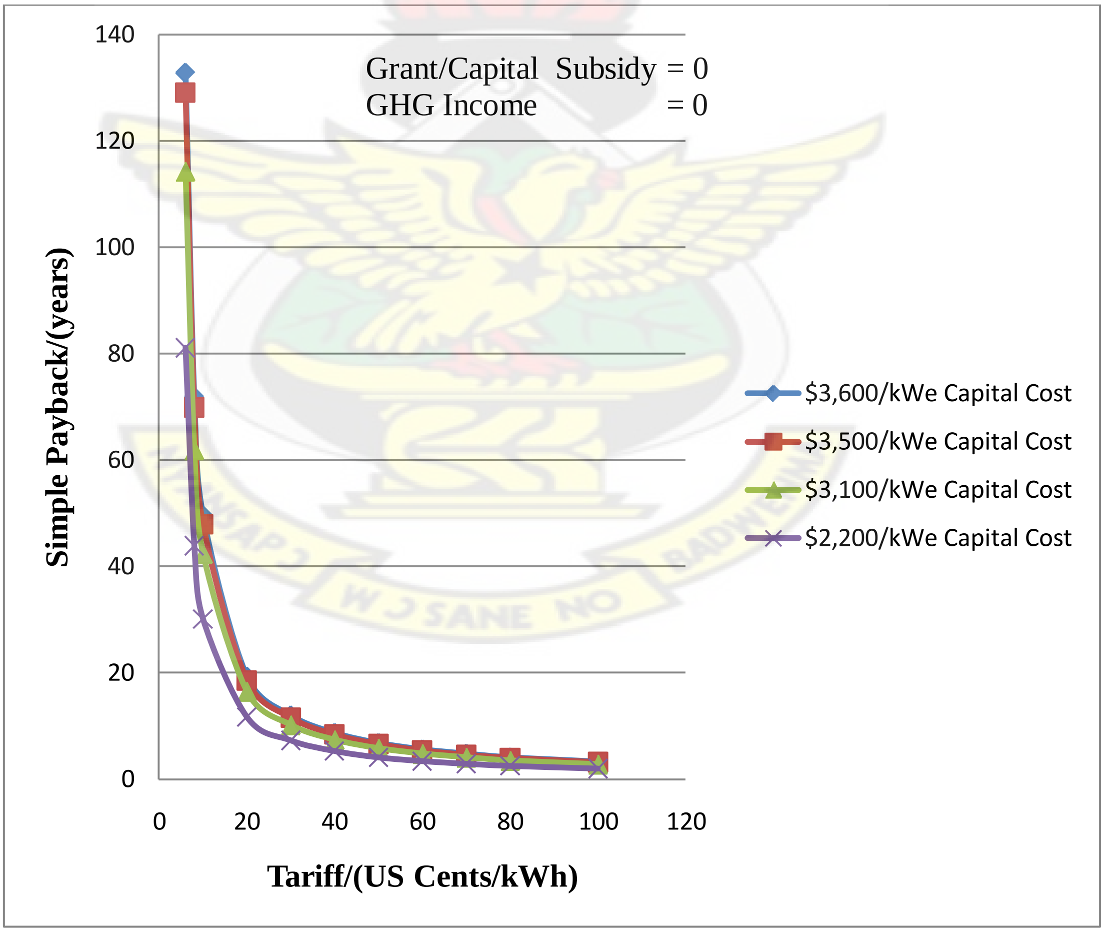


Figure 5.5.1: Effect of tariff changes and reducing Power Tower cost on Simple Payback Period.

Reduction in capital cost of a CRS from U.S. $3,600.00/kWe to U.S. $ 2,200.00/kWe results in the simple payback period reducing from 71.9 years to 43.9 years respectively at reference case of 8 US Cents/kW. The simple payback period further decreases with increasing tariff. However, it can be shown from figure 5.5.1 that at higher tariff, the effect of capital cost on simple payback is minimal.

Figure 5.5.2 shows that at a capital cost of U.S. $2,200.00/kWe (which is forecasted to happen ten years from now) the project would be attractive at a bulk supply tariff of 24 US cents/kWh or higher with no grant/capital subsidy or GHG revenue.

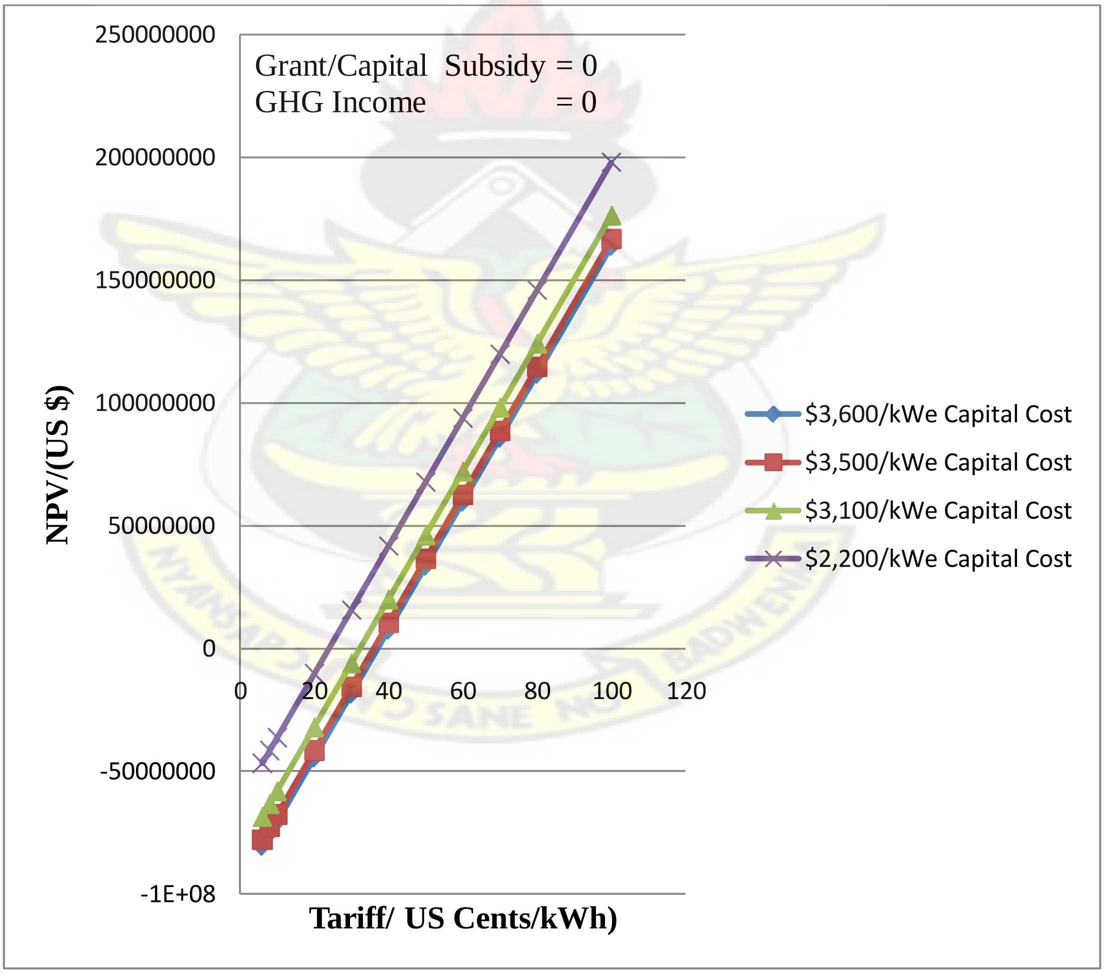


Figure 5.5.2: Effect of tariff changes and reducing Power Tower cost on NPV.

4.5.5 Effect of drop in O&M Cost of Tower technology on the simple payback period and NPV under different tariff conditions.

The reduction in O&M cost is primarily a result of the increase in annual plant capacity factor. The plant capacity increases directly as a result of the increase in thermal storage. Increasing the size (MWe) and utilization (capacity factor) of the power plant incurs very little increase in O&M expenses ($/year). This is because the quantity and complexity of the equipment remain constant and staffing remains fairly constant (S&L, 2003).

Figure 5.6.1 shows that at higher tariff there is no significant effect of reducing O&M cost on simple payback period. The NPV is not significantly affected too as a result of O&M cost reduction as shown in figure 5.6.2.

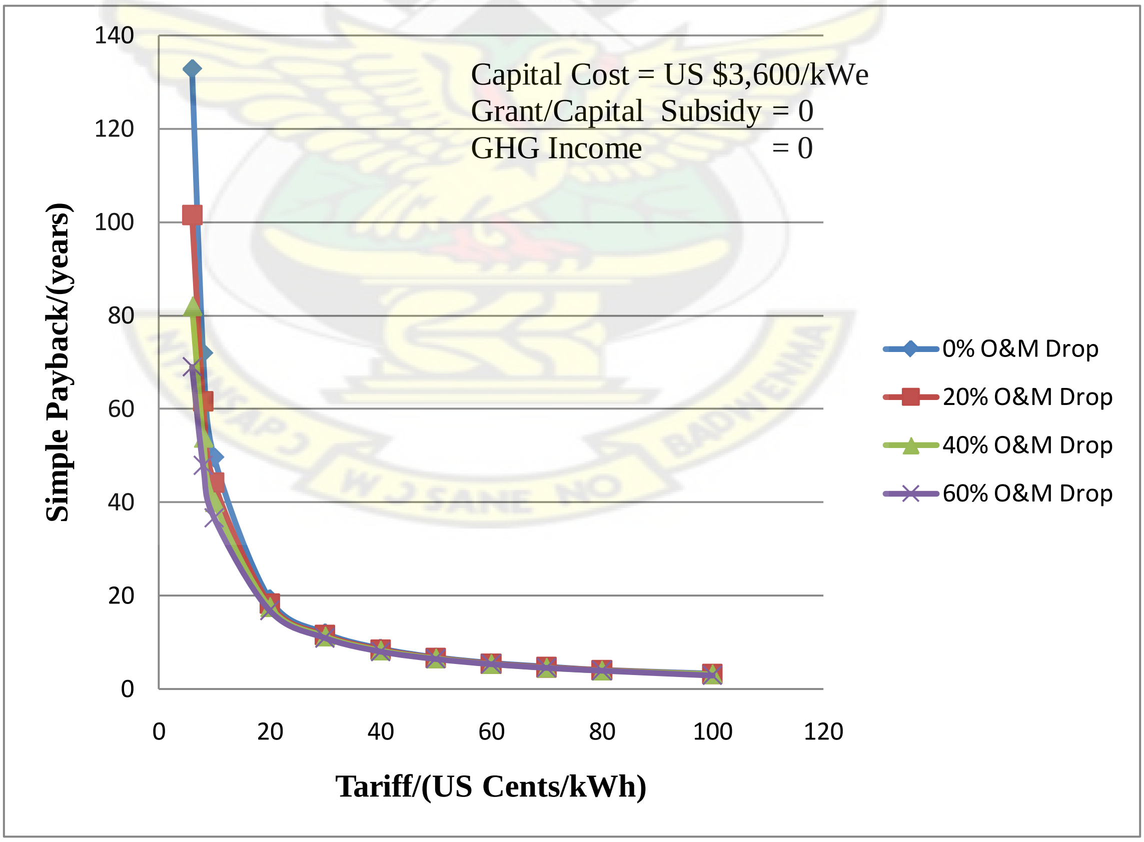


Figure 5.6.1: Effect of tariff changes and reducing O&M cost on Simple Payback Period.

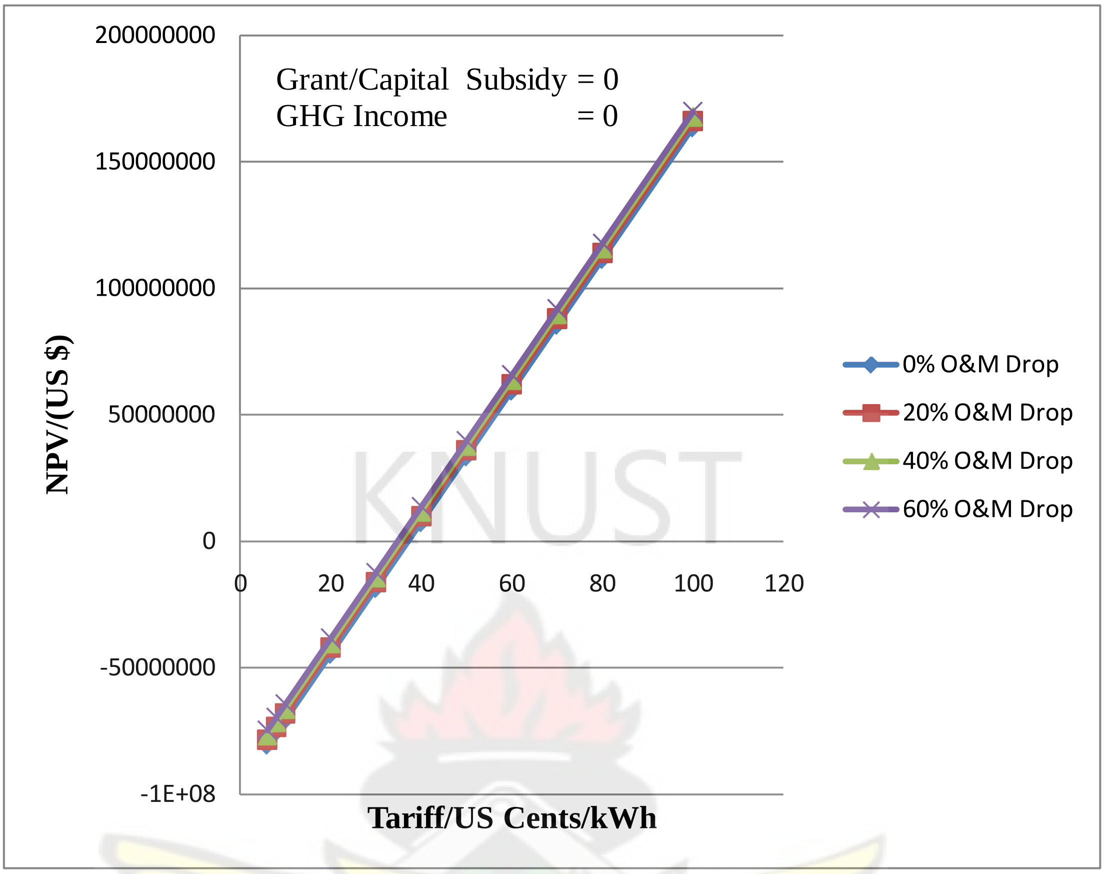


Figure 5.6.2: Effect of tariff changes and reducing O&M cost on NPV.

4.5.6 Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period and NPV for the reference case under different feed-in tariffs.

The effect of a combination of feed-in tariffs and capital subsidies, together with reducing CRS capital cost, is illustrated in Figures 5.7 and 5.8. Figure 5.7a shows that a capital subsidy level as high as 80% will not be sufficient to bring the payback period below 10 years (14.4 years, see Appendix F, Table F-6-2a), at the system cost of U.S. $3,600.00/kWe and the reference case tariff of 8 US cents/kWh. Figure 5.7b shows variations for a reasonable feed-in tariff of 14 US cents/kWh. Figure 5.7c shows that, with a tariff of 20 US cents/kWh, a grant of about 60% is enough to reduce the simple payback period below 10 years at reference system cost.

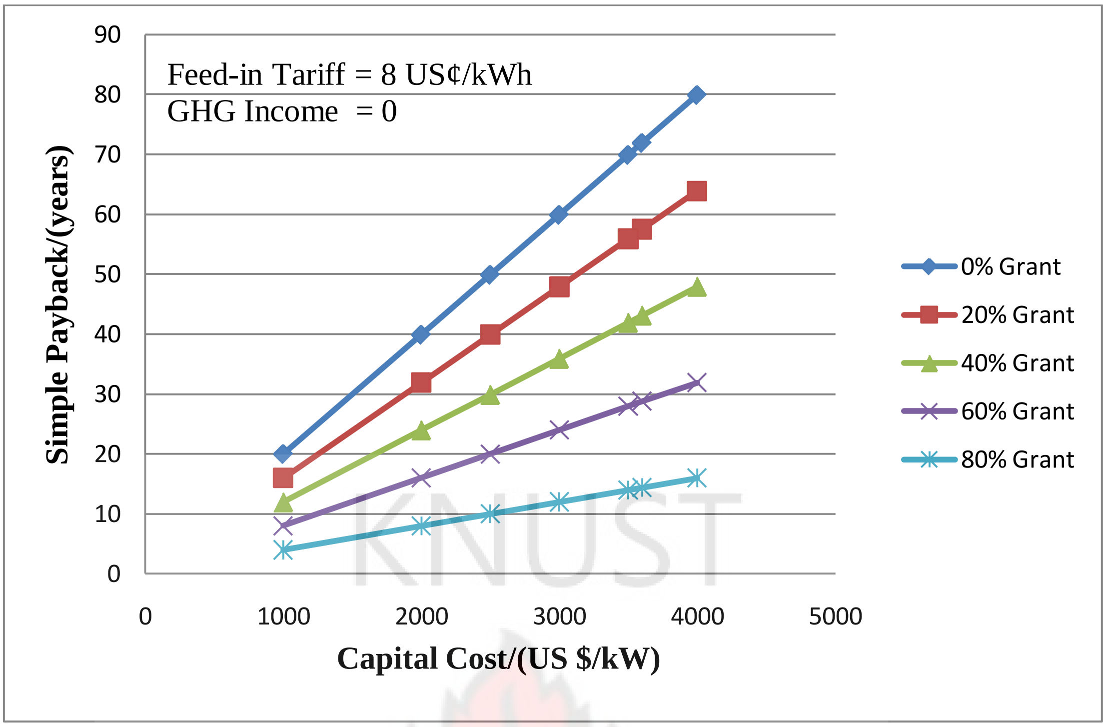


Figure 5.7a

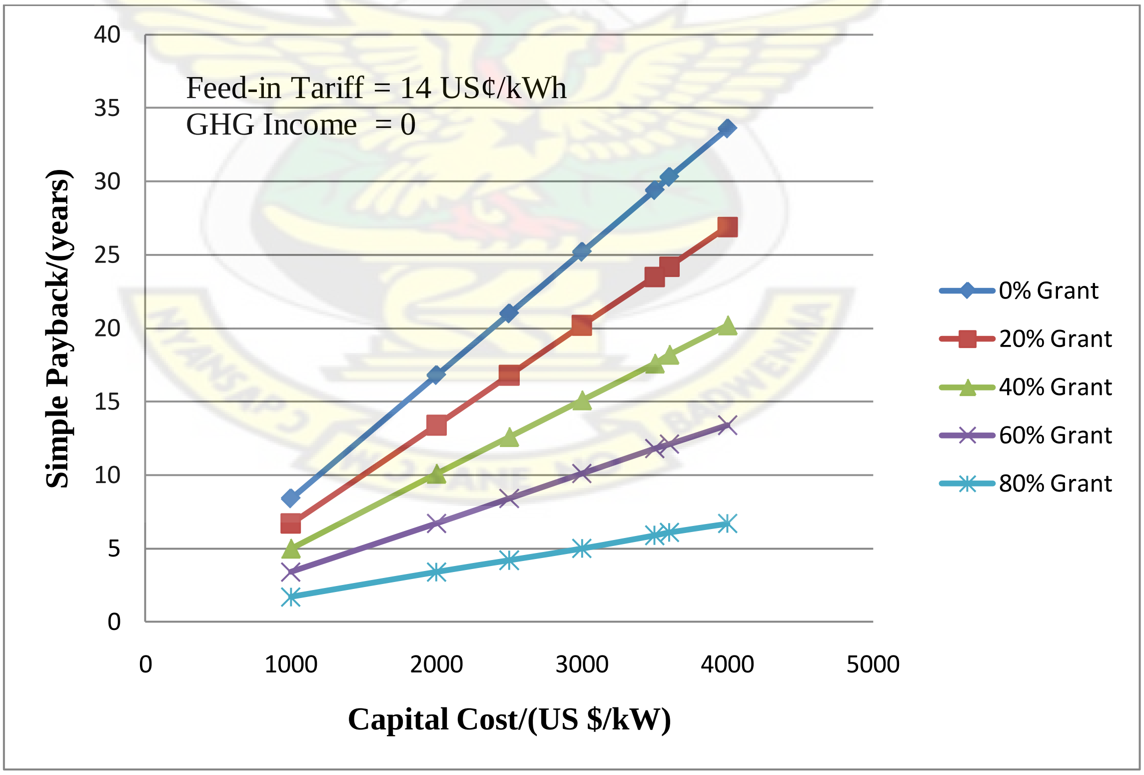


Figure 5.7b

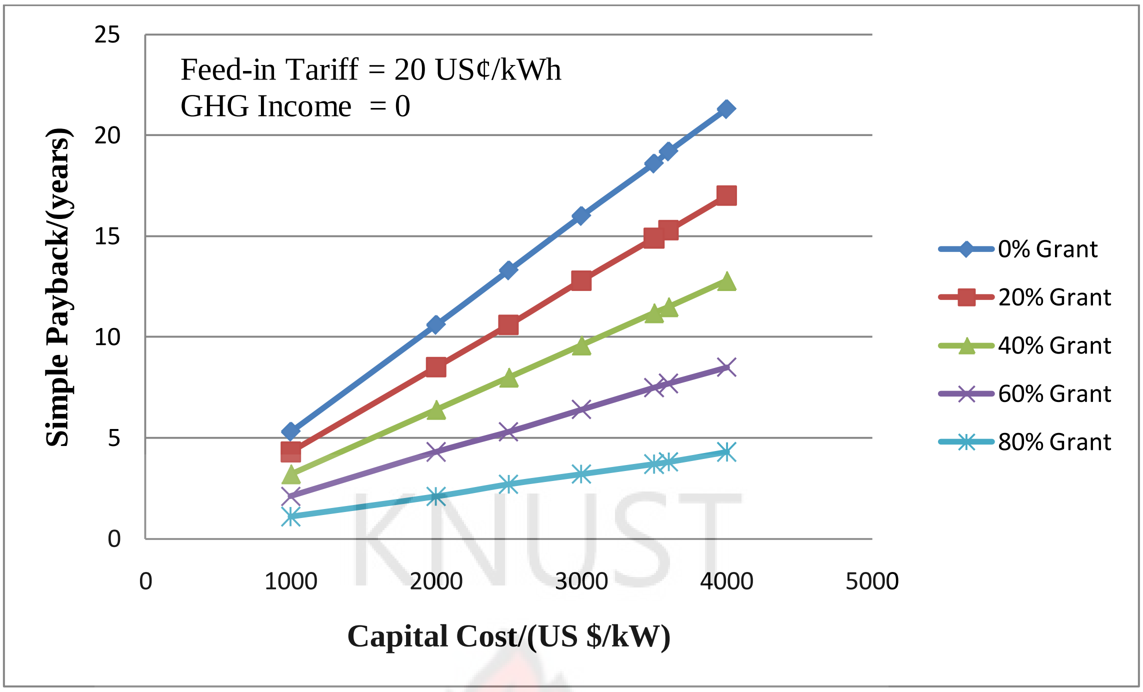


Figure 5.7c

Figure 5.7: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period under different feed-in tariffs.

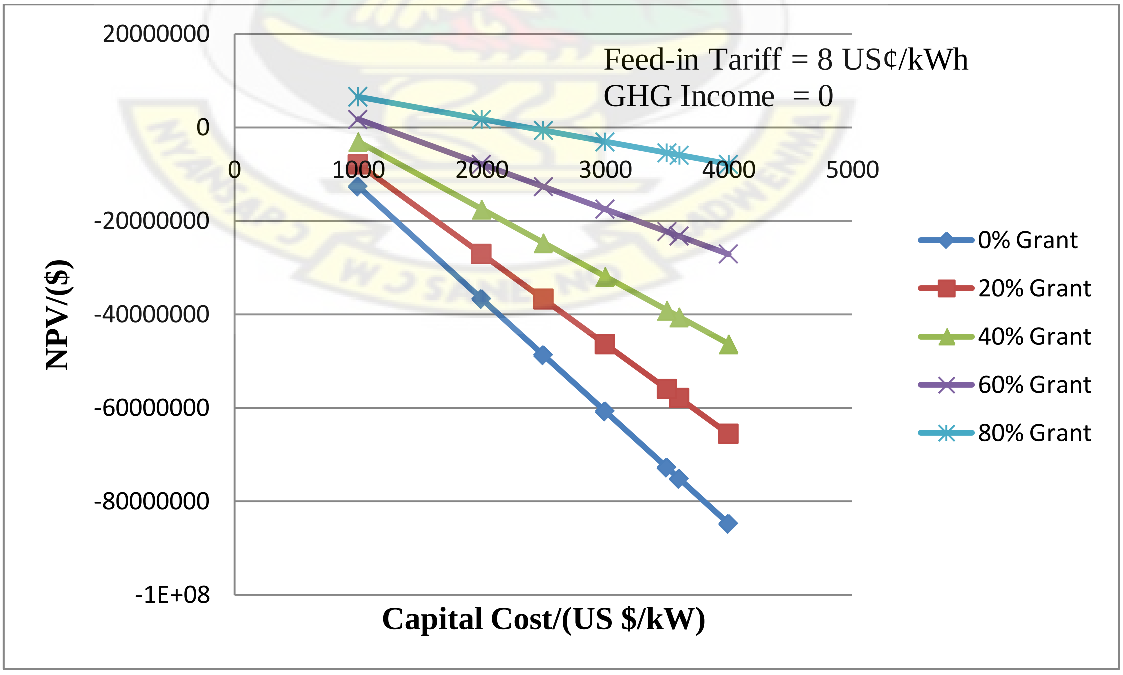


Figure 5.8a

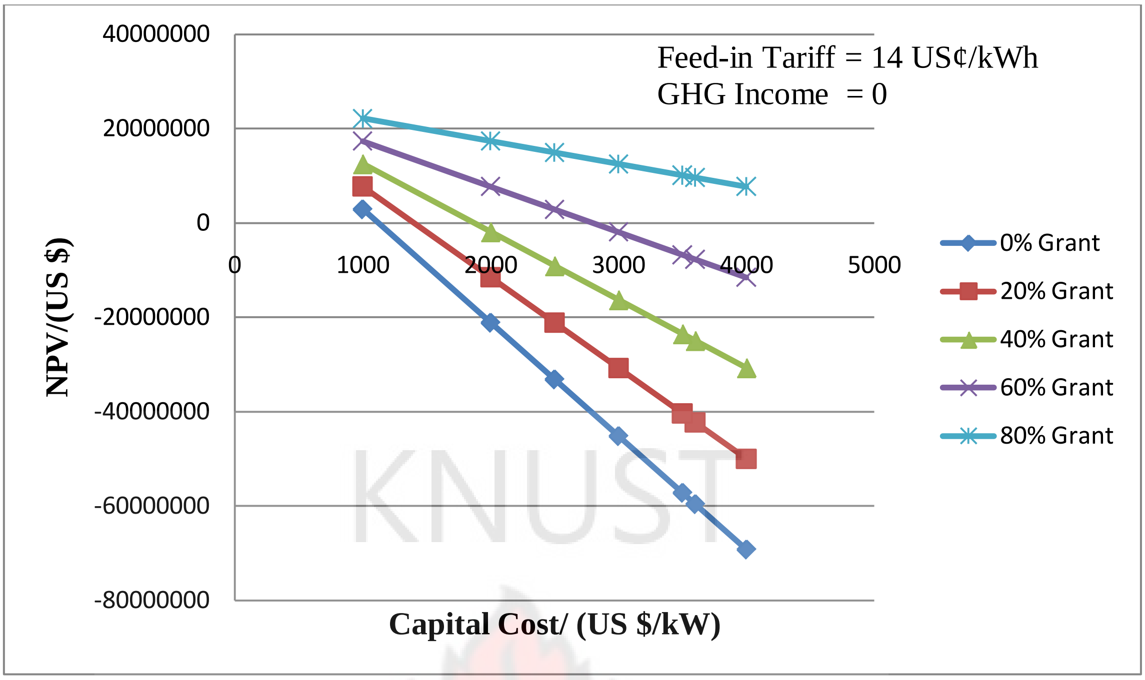


Figure 5.8b

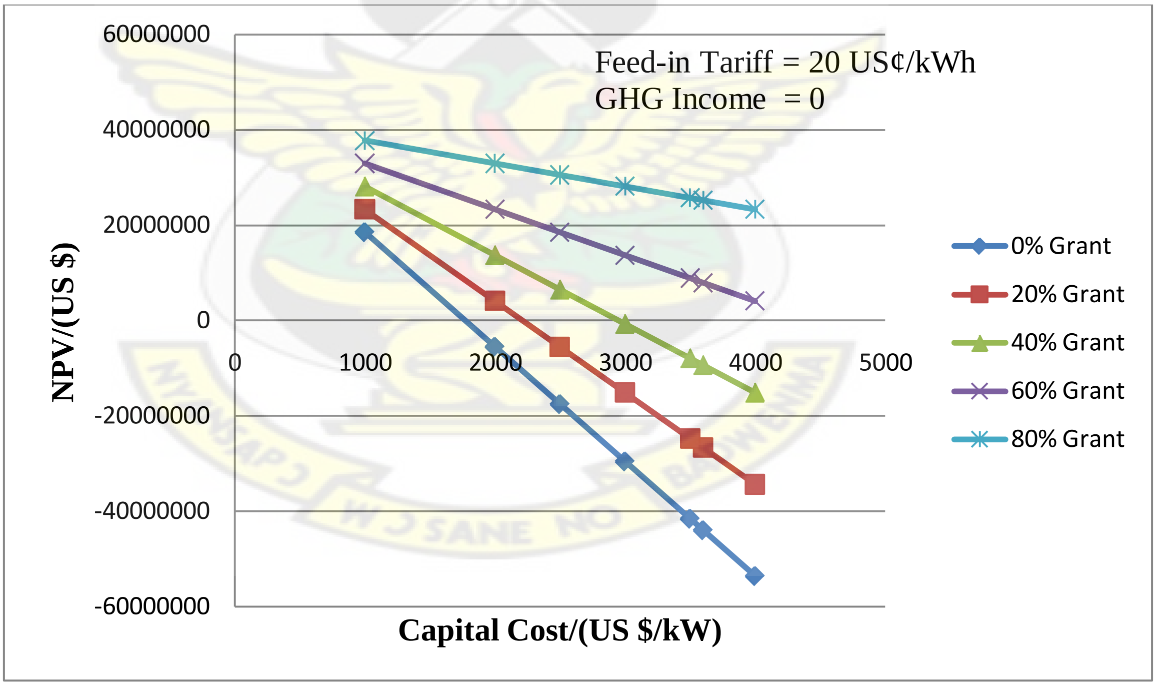


Figure 5.8c

Figure 5.8: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on NPV under different feed-in tariffs.

Figure 5.8 shows that, for 0% grant or capital subsidy, the system only become financially viable at a feed-in tariff of about 14 US cent/kWh and higher with a capital cost of US $1,000.00 and below. The graphs also clearly spells out that there is decrease in profitability for increasing capital cost. Interesting cash flows of profitable mix of modest feed-in tariffs, grants and capital subsidies is shown in Appendix I.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

The capital city of the Upper West Region of Ghana (Wa) is selected for the construction of the Central Receiver System (CRS) based on its good solar resource in northern Ghana. An estimation of the capacity factor of the system based on solar resource place this value at 15.76%. This result in electricity exported to the grid in a year from the system to be 27,604 MWh. The GHG savings arising from the construction of the 20 MW CRS would amount to 13,503.4 tCO2. The total initial cost needed to construct the plant requires a huge capital of almost US $ 90 million.

The results of this study show that at the current Ghanaian Bulk Supply Tariff (BST) of 8 US Cents/kWh, the system yields a simple payback period of 71.9 years which does not make it an attractive business venture. Feed-in tariffs as high as 35 US cent/kWh will be required in order to have a simple payback period of around 10 years under other reference conditions.

This study identifies grants/capital subsidies as one of the ways of improving the profitability of the CRS in Ghana. At reference condition, a RETScreen simulation shows that, 87% capital subsidy is what is needed to give a simple payback period of slightly less than 10 years with a positive yield in NPV.

The study results also show that reduction in the capital cost of CRS systems could be one of the ways of improving the simple payback period, hence increasing its financial viability. RETScreen analysis of the reference case indicates that if the CRS system cost was to go as low as US $470.00/kW, this would give a simple payback period of slightly less than 10 years with a positive NPV.

Therefore, a country like Ghana needs a judicious mix of major capital subsidies and modest feed-in tariffs in the hope that CRS system cost would drop significantly in time as forecasted in the S&L report.

5.2 Recommendations

The recommendations of this study are as follows:

1. These plants can make use of thermal storage or hybrid fossil systems or both to achieve greater operating flexibility and dispatchability. This provides the ability to produce electricity when needed by the utility system, rather than only when sufficient solar insolation is available to produce electricity, for example, during short cloudy periods or after sunset. Studies must be carried out to establish the viability of these systems.
2. The ground measurement of the direct normal component of the solar irradiance has to be measured with a Normal Incidence Pyrheliometer for Wa and other promising sites across Ghana.
3. Typical meteorological year or TMY data sets have to be developed for Wa using ground readings. A typical meteorological year data set is made up from historical weather observations for a set of 12 'typical' months, at a specific location. Each typical month is chosen from a multi-year set of data for a specific month, and selected because of having the 'average' solar radiation for that month. For example, solar radiation data for January of maybe 30 different years is searched to determine in which year the January was typical or average. Next, 30 different February data sets are searched to determine the typical February. An hour-by-hour data base is then generated of readings for all recorded weather parameters from each of the 'typical'

months and is called a typical meteorological year. This is needed because the best way to predict the energy-production performance of a solar energy system would be to know what the hour-by-hour solar irradiance levels will be, over the lifetime of the system.

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APPENDIX

APPENDIX A: Central Receiver Solar Power Plant – Facility Data

Name		Solar One	Themis	CESA-1	IEA-SSPS	Sunshine	Eurelios	SES-5
Location		Barstow	Targasonne	Almeria	Almeria	Nio	Adrano	Kertsch
Country		USA	France	Spain	Spain	Japan	Italy	USSR
Design Conditions								
Coordinates	deg	35 N	43 N	37 N	37 N	34 N	38 N	45 N
	deg	117 W	2 E	2 E	2 E	134 E	15 E	36 E
Altitude	m	593	1,660	500	500	6	215	.
Irradiance	W(DNI)/m^2	950	1,040	700	920	750	850	800
Solar Multiple		1	.	1.93	.	.	0.75	.
Output	MWe	10	2.4	1	0.5	1	1	5
Efficiency	% net	17.4	20.5	12.9	16.5	10.3	14.5	.
Plant Area	ha	52.6	.	.	.	.	.	24

Name		Solar One	Themis	CESA-1	IEA-SSPS	Sunshine	Eurelios	SES-5
Location		Barstow	Targasonne	Almeria	Almeria	Nio	Adrano	Kertsch
Country		USA	France	Spain	Spain	Japan	Italy	.USSR
Project Data								
Operation Start		1982	1982	1983	1981	1981	1981	1985
Const. Time	month	30	36	36	18	32	.	.
Cost	US$(m)	141	37	18	18	25	8.2	.
O&M Staff	Man-year	36	37	32	27.5	10	20	.
O&M Cost	US$(m)/a	2.97	2.53	.	.	2.1	.	.
Heliostat								
Manufacturer		MMC	Cethel	Casa/Sener	MMC/MBB	Mitsubishi	MBB/Cethel	.
# of Units		1,818	201	300	93	807	112/70	1,600
Refl. Area	m^2	71,095	10,740	11,880	3,655	12,912	2,576/3,640	40,000
Target Height	m	90.8	106	60	43	69	55	80
Receiver		External	Cavity	Cavity	Cavity/External	Cavity	Cavity	External
Manufacturer		Rockedyne	CNIM	TR/Babcock	IA/Sulzer	Mitsubishi	Ansaldo	.
Rating	MW_t	43.4	8.9	7.7	2.5	.	.	5
Aperture	m^2	302	16	11.6	9.7/8.3	56.7	15.9	154
Heat Transfer		2-loop	2-loop	1-loop	2-loop	1-loop	1-loop	.
Medium		Water/Steam	Salt	Water/Steam	Sodium	Water/Steam	Water/Steam	Water/Steam
Temperature	^oC	104/516	250/450	190/525	270/530	115/249	37/512	256
Pressure	bar	105	1.0-2.0	132	6	40	62	40

Name		Solar One	Themis	CESA-1	IEA-SSPS	Sunshine	Eurelios	SES-5
Location		Barstow	Targasonne	Almeria	Almeria	Nio	Adrano	Kertsch
Country		USA	France	Spain	Spain	Japan	Italy	USSR
Power Conversion		2-inlet	.	2-inlet	6-pist/5-Sta	Impulse Sat.	2-inlet	.
Engine		Condens.Turb.	.	Condens.Turb.	Steam Motor	Steam Turbine	Conden. Turb.	Condens. Turb.
Manufacturer		GE	Alstrom	Siemens/Bazan	Spilling	.	Ansaldo	.
Medium		Water/Steam	Water/Steam	Water/Steam	Water/Steam	Water/Steam	Water/Steam	Sat. Steam
Temperature	^{o}C	45/510	89/410	55/520	193/500	115/187	36/510	256
Pressure	bar	0.09/100	0.19/40	0.15/98	0.3/100	12	64	40
Generator Rating	kVA	12,500	2,300	1,500	617	.	1100	.
Storage		Oil/Rocks	2-tank Salt	2-tank Salt	2-tank Sodium	Water/Steam	Water/Steam	Press. Water
Capacity	MWh_e	28	12.5	3.5	1	3	.	140
	MWh_t	182	40	16	5.5	17.8	0.036	.
Temp. Range	^{o}C	218/302	250/450	220/340	275/530	197/249	275/430	.

Name		Solar One	Themis	CESA-1	IEA-SSPS	Sunshine	Eurelios	SES-5
Location		Barstow	Targasonne	Almeria	Almeria	Nio	Adrano	Kertsch
Country		USA	France	Spain	Spain	Japan	Italy	USSR
Performance								
Average								
Irradiation	kWh/m^2d	6.97	4.51	.	5.37	.	.	.
Threshold	$W(DNI)/m^2$	450	300	.	300	250	450	.
Production	MWh_e/a	15,350	574	.	39	517	130	.
Yearly Eff	% gross	8.49	12.4	.	.	.	.	.
	% net	5.78	10.4	.	.	.	.	.
Peak								
Output	MW_t	37	.	.	.	.	.	.
	MWa	11.7	.	.	.	0.8	0.75	.
Production	MWh_e/d	87	.	.	.	2.4	.	.
Efficiency	% gross	.	19	27	9.5	9.2	.	.
	% net	8.7	17	.	8.1	.	.	.
Monthly CF	%	24	.	.	.	.	.	.

Name		Solar Two	Solar Tres	PS 10	PS 20
Location		Barstow	Sevilla	Sanlúcar la Mayor	Sanlúcar la Mayor
Country		USA	Spain	Spain	Spain
Design Conditions					
Coordinates	deg	35 N	37.2N	37.4N	37.4N
	deg	117 W	-5.9E	-5.9E	-5.9E
Altitude	m	593	30	30	30
Irradiance	W(DNI)/m^2	950			
Solar Multiple		1		1.3	
Output	MWe	10	17	11	20
Efficiency	% net	.			
Plant Area	ha	.		60	

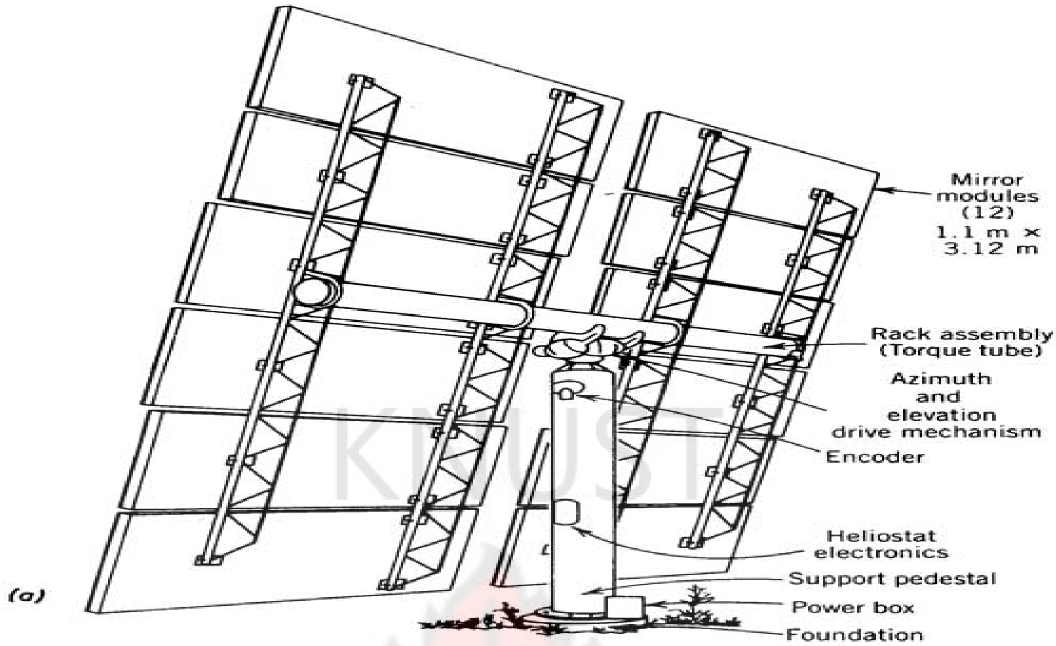
Name		Solar Two	Solar Tres	PS 10	PS 20
Location		Barstow	Sevilla	Sanlúcar la Mayor	Sanlúcar la Mayor
Country		USA	Spain	Spain	Spain
Project Data					
Operation Start		1996		2007	2009
Const. Time	month	.			
Cost	US$(m)	58	€53m	€35m	
O&M Staff	Man-year	.			
O&M Cost	US$(m)/a	3			
Techn. Information					
Heliostat					
Manufacturer		.			
# of Units		1926	2590	624	1255
Refl. Area	m^2	.	298,000	75,000	
Target Height	m	300ft	130	115	160

Name		Solar Two	Solar Tres	PS 10	PS 20
Location		Barstow	Sevilla	Sanlúcar la Mayor	Sanlúcar la Mayor
Country		USA	Spain	Spain	Spain
Receiver				Cavity	
Manufacturer		Rocketdyne		Abengoa Solar NT	
Rating	MW_t	43	120	55	
Aperture	m^2	.			
Heat Transfer					
Medium		Nitrate Salt	Nitrate Salt	Water/Steam	
Temperature	^oC	290/565		250-255	
Pressure	bar	.			
Power Conversion		.			
Engine		.			
Manufacturer		.			
Medium		Water/Steam		Water/Steam	
Temperature	^oC	.		250	
Pressure	bar	.		40	
Generator Rating	kVA	.			

Name		Solar Two	Solar Tres	PS 10	PS 20
Location		Barstow	Sevilla	Sanlúcar la Mayor	Sanlúcar la Mayor
Country		USA	Spain	Spain	Spain
Storage		Nitrate Salt	Nitrate Salt	Water/Steam	
Capacity	MWh_e	.			
	MWh_t	114			
Temp. Range	^oC	290/565			
Performance					
Average					
Irradiation	kWh/m^2d	6.97			
Threshold	$W(DNI)/m^2$	450	235		
Production	MWh_e/a	17,500			
Yearly Eff	% gross	8.5			
	% net	.			

Name		Solar Two	Solar Tres	PS 10	PS 20
Location		Barstow	Sevilla	Sanlúcar la Mayor	Sanlúcar la Mayor
Country		USA	Spain	Spain	Spain
Peak					
Output	MW_t	.			
	MWa	.			
Production	MWh_e/d	.			
Efficiency	% gross	.			
	% net	.			
Monthly CF	%	20	74		

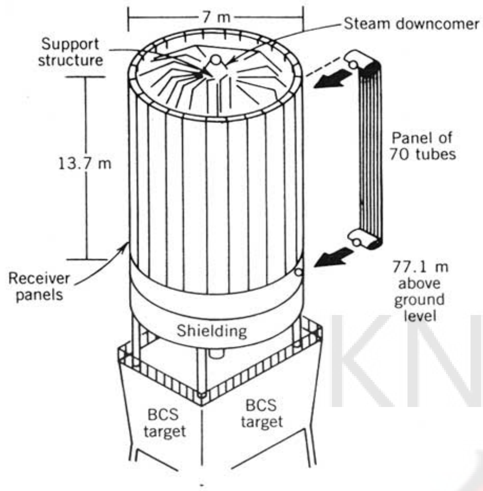
APPENDIX B: Heliostats

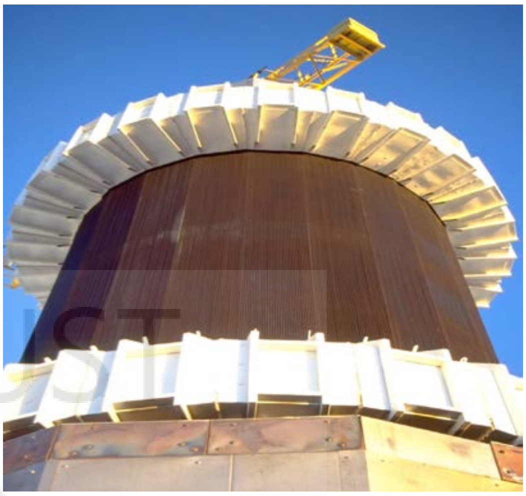


Heliostats components

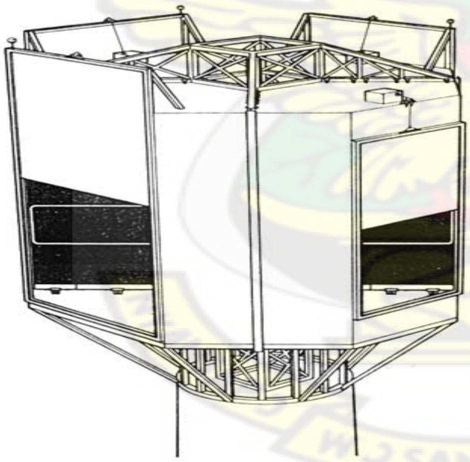
(b) Two heliostat designs. The stretched-membrane heliostat (Left) and Lugo heliostat (Right) tested at Solar II tested in Almeria, Spain (Sandia, 1997).

APPENDIX C: Types of Receivers





External Receiver



Cavity Receiver

APPENDIX D: Climatic Detail of Wa

	Unit	Climate data location	Project location
Latitude	˚N	10.1	10.1
Longitude	˚E	-2.5	-2.5
Elevation	m	271	271
Heat Design Temp.	°C	19.7	
Cool Design Temp.	°C	35.5	
Earth Temp. Amplitude	°C	14.7	

Month		Air Temp.	Relative humidity	Daily solar radiation – horizon-tal	Atmosp-heric pressure	Wind speed	Earth Temp.	Heating degree-days	Cooling degree-days
		°C	%	kWh/m²/d	kPa	m/s	°C	°C-d	°C-d
January		26.8	23.0%	5.73	98.0	1.8	29.2	0	522
February		28.4	28.0%	6.02	97.9	1.8	31.3	0	514
March		29.5	44.4%	6.15	97.8	2.5	32.7	0	605
April		28.4	64.3%	6.10	97.8	2.5	30.6	0	551
May		27.1	73.4%	5.96	97.9	2.6	28.5	0	529
June		25.6	79.8%	5.46	98.1	2.5	26.5	0	467
July		24.6	82.5%	4.92	98.2	2.5	25.3	0	451
August		24.4	82.7%	4.67	98.2	2.4	25.1	0	447
September		25.2	78.3%	5.01	98.1	1.9	26.0	0	456
October		26.8	65.8%	5.60	98.0	1.8	28.2	0	522
November		28.1	44.8%	5.59	98.0	2.1	30.6	0	544
December		27.1	26.0%	5.63	98.0	2.0	29.3	0	530
Annual		26.8	57.9%	5.57	98.0	2.2	28.6	0	6,137
Measured at	m					10.0	0.0		

Source: RETScreen Software

APPENDIX E: RETScreen Software Analysis

Figure E-1: Basic Data Input into RETScreen Software

Project information

See project database

Project name	M.Sc. Thesis
Project location	Wa
Prepared for	TEC
Prepared by	Frimpong Opoku
Project type	Power
Technology	Solar thermal power
Grid type	Central-grid
Analysis type	Method 2
Heating value reference	Lower heating value (LHV)
Show settings	☑
Language - Langue	English - Anglais
User manual	English - Anglais
Currency	$
Units	Metric units

Site reference conditions

Select climate data location

Climate data location	Wa
Show data	☑

	Unit	Climate data location	Project location
Latitude	°N	10.1	10.1
Longitude	°E	-2.5	-2.5
Elevation	m	271	271
Heating design temperature	°C	19.7	
Cooling design temperature	°C	35.5	
Earth temperature amplitude	°C	14.7	

Month		Air temperature	Relative humidity	Daily solar radiation - horizontal	Atmospheric pressure	Wind speed	Earth temperature	Heating degree-days	Cooling degree-days
		°C	%	kWh/m²/d	kPa	m/s	°C	°C-d	°C-d
January		26.8	23.0%	5.73	98.0	1.8	29.2	0	522
February		28.4	28.0%	6.02	97.9	1.8	31.3	0	514
March		29.5	44.4%	6.15	97.8	2.5	32.7	0	605
April		28.4	64.3%	6.10	97.8	2.5	30.6	0	551
May		27.1	73.4%	5.96	97.9	2.6	28.5	0	529
June		25.6	79.8%	5.46	98.1	2.5	26.5	0	467
July		24.6	82.5%	4.92	98.2	2.5	25.3	0	451
August		24.4	82.7%	4.67	98.2	2.4	25.1	0	447
September		25.2	78.3%	5.01	98.1	1.9	26.0	0	456
October		26.8	65.8%	5.60	98.0	1.8	28.2	0	522
November		28.1	44.8%	5.59	98.0	2.1	30.6	0	544
December		27.1	26.0%	5.63	98.0	2.0	29.3	0	530
Annual		26.8	57.9%	5.57	98.0	2.2	28.6	0	6,137
Measured at	m					10.0	0.0		

Figure E-2: RETScreen Energy Model Page

RETScreen Energy Model - Power project

Proposed case power system

Technology		Solar thermal power
Solar thermal power		
Power capacity	kW	20,000
Manufacturer		
Model		
Capacity factor	%	15.8%
Electricity exported to grid	MWh	27,604
Electricity export rate	$/MWh	60.00

Figure E-3: RETScreen Cost Analysis Page

RETScreen Cost Analysis - Power project

Settings			
Method 1	Notes/Range		
Method 2	Second currency	Notes/Range	None
	Cost allocation		

Initial costs (credits)	Unit	Quantity	Unit cost	Amount	Relative costs
Feasibility study					
Feasibility study	cost			$ -	
Sub-total:				$ -	0.0%
Development					
Development	cost			$ -	
Sub-total:				$ -	0.0%
Engineering					
Engineering	cost	1		$ -	
Sub-total:				$ -	0.0%
Power system					
Solar thermal power	kW	20,000.00	$ 3,600	$ 72,000,000	
Road construction	km			$ -	
Transmission line	km			$ -	
Substation	project			$ -	
Energy efficiency measures	project			$ -	
User-defined	cost			$ -	
				$ -	
Sub-total:				$ 72,000,000	83.2%
Balance of system & miscellaneous					
Spare parts	%			$ -	
Transportation	project			$ -	
Training & commissioning	p-d			$ -	
User-defined	cost			$ -	
Contingencies	%	10.0%	$ 72,000,000	$ 7,200,000	
Interest during construction	18.50%	12 month(s)	$ 79,200,000	$ 7,326,000	
Sub-total:				$ 14,526,000	16.8%
Total initial costs				$ 86,526,000	100.0%

Annual costs (credits)	Unit	Quantity	Unit cost	Amount
O&M				
Parts & labour	project	1	$ 913,200	$ 913,200
User-defined	cost			$ -
Contingencies	%	10.0%	$ 913,200	$ 91,320
Sub-total:				$ 1,004,520

Periodic costs (credits)	Unit	Year	Unit cost	Amount
	cost			$ -
				$ -
End of project life	cost			$ -

Figure E-4: RETScreen Emission Reduction Analysis Page

Method 1
Method 2
Method 3

Global warming potential of GHG	
25	tonnes CO2 = 1 tonne CH4
298	tonnes CO2 = 1 tonne N2O

Base case electricity system (Baseline)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Electricity generation efficiency %	T&D losses %	GHG emission factor tCO2/MWh
Natural gas	90.0%	54.5	0.0040	0.0010	45.0%	14.0%	0.510
Oil (#6)	10.0%	77.8	0.0030	0.0020	30.0%	14.0%	1.095
Electricity mix	100.0%	156.8	0.0105	0.0031		14.0%	0.569

Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	156.8	0.0105	0.0031	27,604	0.569	15,701.6
Total	100.0%	156.8	0.0105	0.0031	27,604	0.569	15,701.6

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Solar	100.0%				27,604	0.000	0.0
Total	100.0%	0.0	0.0000	0.0000	27,604	0.000	0.0
				T&D losses			
Electricity exported to grid	MWh	27,604		14.0%	3,865	0.569	2,198.2
						Total	2,198.2

GHG emission reduction summary

	Base case GHG emission tCO2	Proposed case GHG emission tCO2	Gross annual GHG emission reduction tCO2	GHG credits transaction fee %	Net annual GHG emission reduction tCO2
Power project	15,701.6	2,198.2	13,503.4		13,503.4

Net annual GHG emission reduction	13,503	tCO2	is equivalent to	2,473	Cars & light trucks not used

Figure E-5: RETScreen Financial Analysis Page

RETScreen Financial Analysis - Power project

Financial parameters

General		
Fuel cost escalation rate	%	0.0%
Inflation rate	%	0.0%
Discount rate	%	10.0%
Project life	yr	30
Finance		
Incentives and grants	$	0
Debt ratio	%	0.0%
Income tax analysis		

Annual income

Electricity export income		
Electricity exported to grid	MWh	27,604
Electricity export rate	$/MWh	60.00
Electricity export income	$	1,656,252
Electricity export escalation rate	%	0.0%
GHG reduction income		
Net GHG reduction	tCO_2/yr	13,503
Net GHG reduction - 30 yrs	tCO_2	405,102
GHG reduction credit rate	$/$tCO_2$	0.00
Customer premium income (rebate)		
Electricity premium (rebate)	%	

Project costs and savings/income summary

Initial costs			
Power system	83.2%	$	72,000,000
Balance of system & misc.	16.8%	$	14,526,000
Total initial costs	**100.0%**	**$**	**86,526,000**
Annual costs and debt payments			
O&M		$	1,004,520
Fuel cost - proposed case		$	0
Total annual costs		**$**	**1,004,520**
Periodic costs (credits)			
Annual savings and income			
Fuel cost - base case		$	0
Electricity export income		$	1,656,252
Total annual savings and income		**$**	**1,656,252**

Financial viability

Pre-tax IRR - equity	%	-7.8%
Pre-tax IRR - assets	%	-7.8%
After-tax IRR - equity	%	-7.8%
After-tax IRR - assets	%	-7.8%
Simple payback	yr	132.8
Equity payback	yr	> project
Net Present Value (NPV)	$	-80,382,183
Annual life cycle savings	$/yr	-8,526,882
Benefit-Cost (B-C) ratio		0.07
Energy production cost	$/MWh	368.90
GHG reduction cost	$/$tCO_2$	631

Yearly cash flows

Year #	Pre-tax $	After-tax $	Cumulative $
0	-86,526,000	-86,526,000	-86,526,000
1	651,732	651,732	-85,874,268
2	651,732	651,732	-85,222,537
3	651,732	651,732	-84,570,805
4	651,732	651,732	-83,919,074
5	651,732	651,732	-83,267,342
6	651,732	651,732	-82,615,611
7	651,732	651,732	-81,963,879
8	651,732	651,732	-81,312,148
9	651,732	651,732	-80,660,416
10	651,732	651,732	-80,008,685
11	651,732	651,732	-79,356,953
12	651,732	651,732	-78,705,222
13	651,732	651,732	-78,053,490
14	651,732	651,732	-77,401,759
15	651,732	651,732	-76,750,027
16	651,732	651,732	-76,098,296
17	651,732	651,732	-75,446,564
18	651,732	651,732	-74,794,833
19	651,732	651,732	-74,143,101
20	651,732	651,732	-73,491,370
21	651,732	651,732	-72,839,638
22	651,732	651,732	-72,187,907
23	651,732	651,732	-71,536,175
24	651,732	651,732	-70,884,444
25	651,732	651,732	-70,232,712
26	651,732	651,732	-69,580,980
27	651,732	651,732	-68,929,249
28	651,732	651,732	-68,277,517
29	651,732	651,732	-67,625,786
30	651,732	651,732	-66,974,054

Other income (cost)		
Energy	MWh	
Rate	$/MWh	
Other income (cost)	$	0
Duration	yr	
Escalation rate	%	
Clean Energy (CE) production income		
CE production	MWh	27,604
CE production credit rate	$/kWh	0.000
CE production income	$	
CE production credit duration	yr	
CE production credit escalation rate	%	

Fuel type	**Energy delivered (MWh)**	
Solar	27,604	Yes

Cumulative cash flows graph

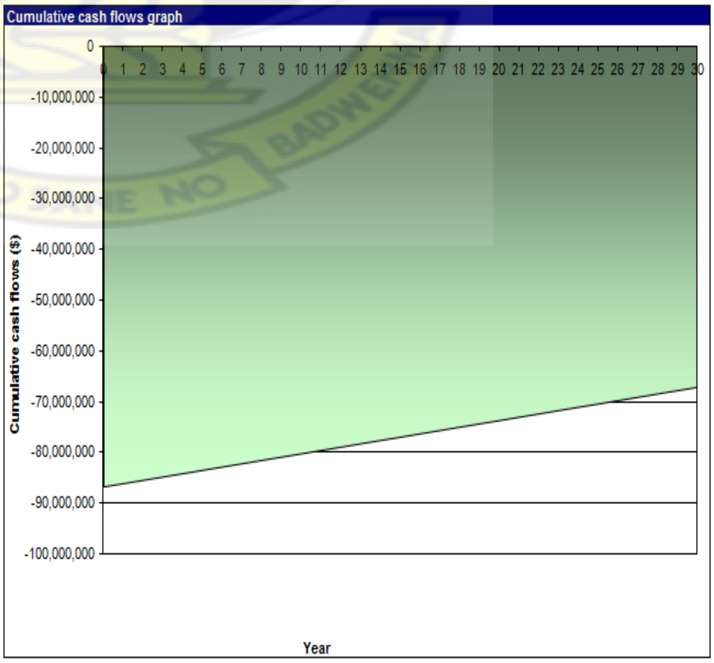


Figure E-6: Capacity Factor Estimation Page

Beam Factor	β	0.68						
	Month	Global Irradiation	Global Irradiance	Beam Irradiance	Days in Month	Hours in Month		
			(I)	(β)		(Δt)	(IΔt)	(β Δt)
		[kWh/m2/day]	[W/m2]	[W/m2]	[days]	[h]	[Wh/m2]	[Wh/m2]
	January	5.73	238.75	162.35	31	744	177630	120788.4
	February	6.02	250.8333333	170.5666667	28	672	168560	114620.8
	March	6.15	256.25	174.25	31	744	190650	129642
	April	6.1	254.1666667	172.8333333	30	720	183000	124440
	May	5.96	248.3333333	168.8666667	31	744	184760	125636.8
	June	5.39	224.5833333	152.7166667	30	720	161700	109956
	July	4.92	205	139.4	31	744	152520	103713.6
	August	4.67	194.5833333	132.3166667	31	744	144770	98443.6
	September	5.01	208.75	141.95	30	720	150300	102204
	October	5.6	233.3333333	158.6666667	31	744	173600	118048
	November	5.59	232.9166667	158.3833333	30	720	167700	114036
	December	5.63	234.5833333	159.5166667	31	744	174530	118680.4
							2029720	1380209.6
						Capacity Factor	0.157558174	
						Capacity Factor(%	15.7558173	

APPENDIX F: Sensitivity Analysis – DATA

Table F-1: Effect of tariff changes on simple payback period and NPV.

Tariff (US¢/kWh)	SPB/(yrs)	NPV/(US $)
6	132.8	-80,382,183
8	71.9	-75,177,736
10	49.6	-70,502,058
20	19.3	-44,479,823
30	12.0	-18,457,587
40	8.7	7,564,649
50	6.8	33,586,884
60	5.6	59,609,120
70	4.8	85,631,356
80	4.1	111,653,591
100	3.3	163,698,063

Table F-2: Effect of GHG income on the simple payback period and NPV under different tariff conditions.

Tariff (US¢/kWh)	Simple Payback Period/(yrs)			Net Present Value/(US $)		
	$0/ton CO_2	$10/ton CO_2	$20/ton CO_2	$0/ton CO_2	$10/ton CO_2	$20/ton CO_2
6	132.8	110.0	93.9	-80,382,183	-80,382,183	-80,382,183
8	71.9	64.6	58.7	-75,177,736	-75,177,736	-75,177,736
10	49.6	46.0	43.0	-70,502,058	-70,502,058	-70,502,058
20	19.3	18.7	18.2	-44,479,823	-44,479,823	-44,479,823
30	12.0	11.7	11.5	-18,457,587	-18,457,587	-18,457,587
40	8.7	8.6	8.4	7,564,649	7,564,649	7,564,649
50	6.8	6.7	6.7	33,586,884	33,586,884	33,586,884
60	5.6	5.5	5.5	59,609,120	59,609,120	59,609,120
70	4.8	4.7	4.7	85,631,356	85,631,356	85,631,356
80	4.1	4.1	4.1	111,653,591	111,653,591	111,653,591
100	3.3	3.3	3.2	163,698,063	163,698,063	163,698,063

Table F-3: Effect of grants/capital subsidies on the simple payback period and NPV under different tariff conditions.

Tariff (US¢/kWh)	Simple Payback Period/(yrs)			Net Present Value/(US $)		
	0% Grant	40% Grant	80% Grant	0% Grant	40% Grant	80% Grant
6	132.8	79.7	26.6	-80,382,183	-45,771,783	-11,161,383
8	71.9	43.1	14.4	-75,177,736	-40,567,336	-5,956,936
10	49.6	29.6	9.9	-70,502,058	-35,362,888	-752,488
20	19.3	11.5	3.8	-44,479,823	-9,340,653	25,269,747
30	12.0	7.1	2.4	-18,457,587	16,681,583	51,291,983
40	8.7	5.2	1.7	7,564,649	42,703,819	77,314,219
50	6.8	4.1	1.4	33,586,884	68,726,054	103,336,454
60	5.6	3.3	1.1	59,609,120	94,748,290	129,358,690
70	4.8	2.8	0.9	85,631,356	120,770,526	155,380,926
80	4.1	2.5	0.8	111,653,591	146,792,761	181,403,161
100	3.3	2.0	0.7	163,698,063	198,837,233	233,447,633

Table F-4: Effect of drop in capital cost of Tower technology on the simple payback period and NPV under different tariff conditions.

Tariff (US¢/kWh)	Simple Payback Period/(yrs)			Net Present Value/(US $)		
	$3,500/ kWe	$3,100/ kWe	$2,200/ kWe	$3,500/kWe	$3,100/kWe	$2,200/kWe
6	129.1	114.3	81.1	-77,978,683	-68,364,683	-46,733,183
8	69.9	61.9	43.9	-72,774,236	-63,160,236	-41,528,736
10	47.9	42.4	30.1	-67,569,788	-57,955,788	-36,324,288
20	18.6	16.5	11.7	-41,547,553	-31,933,553	-10,302,053
30	11.6	10.2	7.3	-15,525,317	-5,911,317	15,720,183
40	8.4	7.4	5.3	10,496,919	20,110,919	41,742,419
50	6.6	5.8	4.1	36,519,154	46,133,154	67,764,654
60	5.4	4.8	3.4	62,541,390	72,155,390	93,786,890
70	4.6	4.1	2.9	88,563,626	98,177,626	119,809,126
80	4.0	3.5	2.5	114,585,861	124,199,861	145,831,361
100	3.2	2.8	2.0	166,630,333	176,244,333	197,875,833

Table F-5: Effect of drop in O&M Cost of Tower technology on the simple payback period and NPV under different tariff conditions.

Tariff (US¢/kWh)	Simple Payback Period/(yrs)			Net Present Value/(US $)		
	20% Drop	40% Drop	60% Drop	20% Drop	40% Drop	60% Drop
6	101.5	82.1	69.0	-78,488,278	-76,594,373	-74,700,468
8	61.6	53.9	47.9	-73,283,831	-71,389,926	-69,496,021
10	44.2	40.1	36.7	-68,079,384	-66,185,479	-64,291,574
20	18.3	17.6	16.9	-42,057,148	-40,163,243	-38,269,338
30	11.6	11.3	11.0	-16,034,912	-14,141,007	-12,247,103
40	8.5	8.3	8.1	9,987,323	11,881,228	13,775,133
50	6.7	6.6	6.5	36,009,559	37,903,464	39,797,369
60	5.5	5.4	5.4	62,031,795	63,925,700	65,819,605
70	4.7	4.6	4.6	88,054,031	89,947,935	91,841,840
80	4.1	4.0	4.0	114,076,266	115,970,171	117,864,076
100	3.2	3.2	2.96	166,120,738	168,014,642	169,908,547

(0% reduction corresponds to the reference case)

Table F-6-1a: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period for feed-in tariffs of **6 US Cents/kWh**.

Capital Cost Of Power Tower (US $/kW)	Simple Payback/(years)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	147.5	118.0	88.5	59.0	29.5
3600	132.8	106.2	79.7	53.1	26.6
3500	129.1	103.3	77.4	51.6	25.8
3000	110.6	88.5	66.4	44.3	22.1
2500	92.2	73.8	55.3	36.9	18.4
2000	73.8	59.0	44.3	29.5	14.8
1000	36.9	29.5	22.1	14.8	7.4

Table F-6-1b: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on NPV for feed-in tariffs of **6 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Net Present Value/(US $)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	-89,996,183	-70,768,183	-51,540,183	-32,312,183	-13,084,183
3600	-80,382,183	-63,076,983	-45,771,783	-28,466,583	-11,161,383
3500	-77,978,683	-61,154,183	-44,329,683	-27,505,183	-10,680,683
3000	-65,961,183	-51,540,183	-37,119,183	-22,698,183	-8,277,183
2500	-53,943,683	-41,926,183	-29,908,683	-17,891,183	-5,873,683
2000	-41,926,183	-32,312,183	-22,698,183	-13,084,183	-3,470,183
1000	-17,891,183	-13,084,183	-8,277,183	-3,470,183	1,336,817

Table F-6-2a: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period for the reference case at feed-in tariffs of **8 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Simple Payback/(years)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	79.9	63.9	47.9	31.9	16.0
3600	71.9	57.5	43.1	28.8	14.4
3500	69.9	55.9	41.9	28.0	14.0
3000	59.9	47.9	35.9	24.0	12.0
2500	49.9	39.9	29.9	20.0	10.0
2000	39.9	31.9	24.0	16.0	8.0
1000	20.0	16.0	12.0	8.0	4.0

Table F-6-2b: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on NPV for the reference case at feed-in tariffs of **8 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Net Present Value/(US $)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	-84,791,736	-65,563,736	-46,335,736	-27,107,736	-7,879,736
3600	-75,177,736	-57,872,536	-40,567,336	-23,262,136	-5,956,936
3500	-72,774,236	-55,949,736	-39,125,236	-22,300,736	-5,476,236
3000	-60,756,736	-46,335,736	-31,914,736	-17,493,736	-3,072,736
2500	-48,739,236	-36,721,736	-24,704,236	-12,686,736	-669,236
2000	-36,721,736	-27,107,736	-17,493,736	-7,879,736	1,734,264
1000	-12,686,736	-7,879,736	-3,072,736	1,734,264	6,541,264

Table F-6-3a: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period for feed-in tariffs of **14 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Simple Payback/(years)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	33.6	26.9	20.2	13.4	6.7
3600	30.3	24.2	18.2	12.1	6.1
3500	29.4	23.5	17.6	11.8	5.9
3000	25.2	20.2	15.1	10.1	5.0
2500	21.0	16.8	12.6	8.4	4.2
2000	16.8	13.4	10.1	6.7	3.4
1000	8.4	6.7	5.0	3.4	1.7

Table F-6-3b: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on NPV for feed-in tariffs of **14 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Net Present Value/(US $)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	-69,178,394	-49,950,394	-30,722,394	-11,494,394	7,733,606
3600	-59,564,394	-42,259,194	-24,953,994	-7,648,794	9,656,406
3500	-57,160,894	-40,336,394	-23,511,894	-6,687,394	10,137,106
3000	-45,143,394	-30,722,394	-16,301,394	-1,880,394	12,540,606
2500	-33,125,894	-21,108,394	-9,090,894	2,926,606	14,944,106
2000	-21,108,394	-11,494,394	-1,880,394	7,733,606	17,347,606
1000	2,926,602	7,733,606	12,540,606	17,347,606	22,154,606

Table F-6-4a: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on simple payback period for the feed-in tariffs of **20 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Simple Payback/(years)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	21.3	17.0	12.8	8.5	4.3
3600	19.2	15.3	11.5	7.7	3.8
3500	18.6	14.9	11.2	7.5	3.7
3000	16.0	12.8	9.6	6.4	3.2
2500	13.3	10.6	8.0	5.3	2.7
2000	10.6	8.5	6.4	4.3	2.1
1000	5.3	4.3	3.2	2.1	1.1

Table F-6-4b: Effect of increase/reduction in capital cost of Power Tower Technology and grants/capital subsidies on NPV for feed-in tariffs of **20 US Cents/kWh**

Capital Cost Of Power Tower (US $/kW)	Net Present Value/(US $)				
	0% Grant	20% Grant	40% Grant	60% Grant	80% Grant
4000	-53,565,053	-34,337,053	-15,109,053	4,118,947	23,346,947
3600	-43,951,053	-26,645,853	-9,340,653	7,964,547	25,269,747
3500	-41,547,553	-24,723,053	-7,898,553	8,925,947	25,750,447
3000	-29,530,053	-15,109,053	-688,053	13,732,947	28,153,947
2500	-17,512,553	-5,495,053	6,552,447	18,539,947	30,557,447
2000	-5,495,053	4,118,947	13,732,947	23,346,947	32,960,947
1000	18,539,947	23,346,947	28,153,947	32,960,947	37,767,947

APPENDIX G: Capital Cost of Power Plants

Based on the US Energy Information Administration (EIA) which forms the basis for the calculation of 2007 Annual Energy Outlook, the estimated capital cost of constructing a solar thermal power generating plant is indicated in the table below:

Table G: Capital Cost of Power Plants (Source: www.jcmiras.net/surge/p130.htm)

Technology	**Year on line**	**Capital Cost/($/kW)**
Advanced open cycle gas turbine	2008	398
Conventional open cycle gas turbine	2008	420
Advanced gas/oil combined cycle	2009	594
Conventional gas/oil combined cycle	2009	603
Distributed generation (base load)	2009	859
Distributed generation (peak load)	2008	1032
Advanced combined cycle with sequestration	2010	1185
Wind	2009	1208
Coal-fired plant with scrubber	2010	1290
IGCC	2010	1490
Conventional hydropower	2010	1500
Biomass	2010	1869
Geothermal	2010	1880
Advanced nuclear	2011	2081
IGCC with carbon sequestration	2010	2134
Solar thermal	2009	3149
Fuel cell	2009	4520
Photovoltaic	2008	4751

Notes

These costs are based on the United States where plant equipment are more likely to be sourced and the unit size of generating units are relatively bigger than what other small countries usually have. Thus, the cost per megawatt of constructing a power plant will be higher to other countries outside of the United States and Europe and if the generating unit size is lower (Source: www.jcmiras.net/surge/p130.htm).

APPENDIX H: DNI Maps

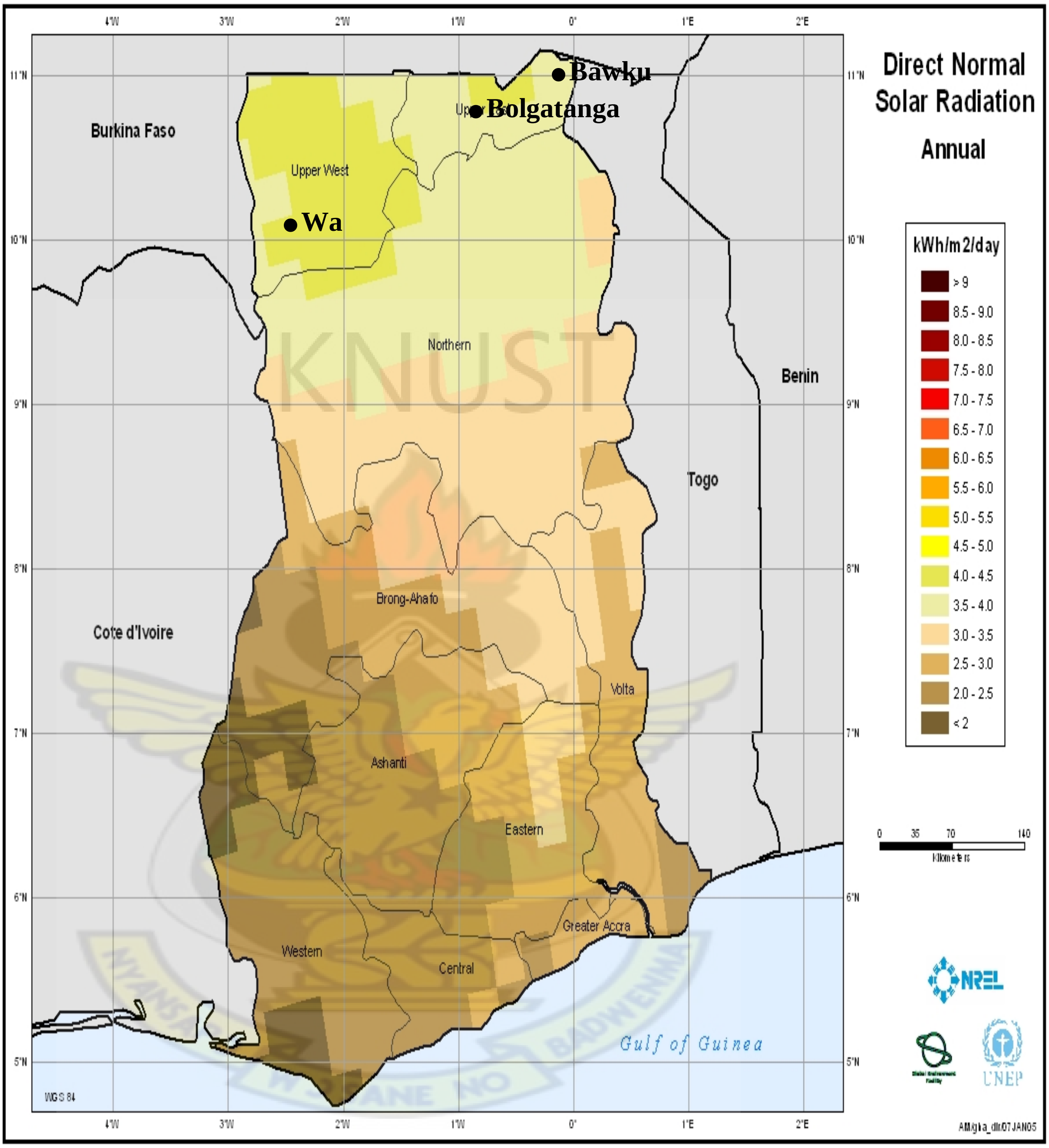


Fig H-1: Annual average direct normal Irradiance (DNI) map of Ghana from NREL

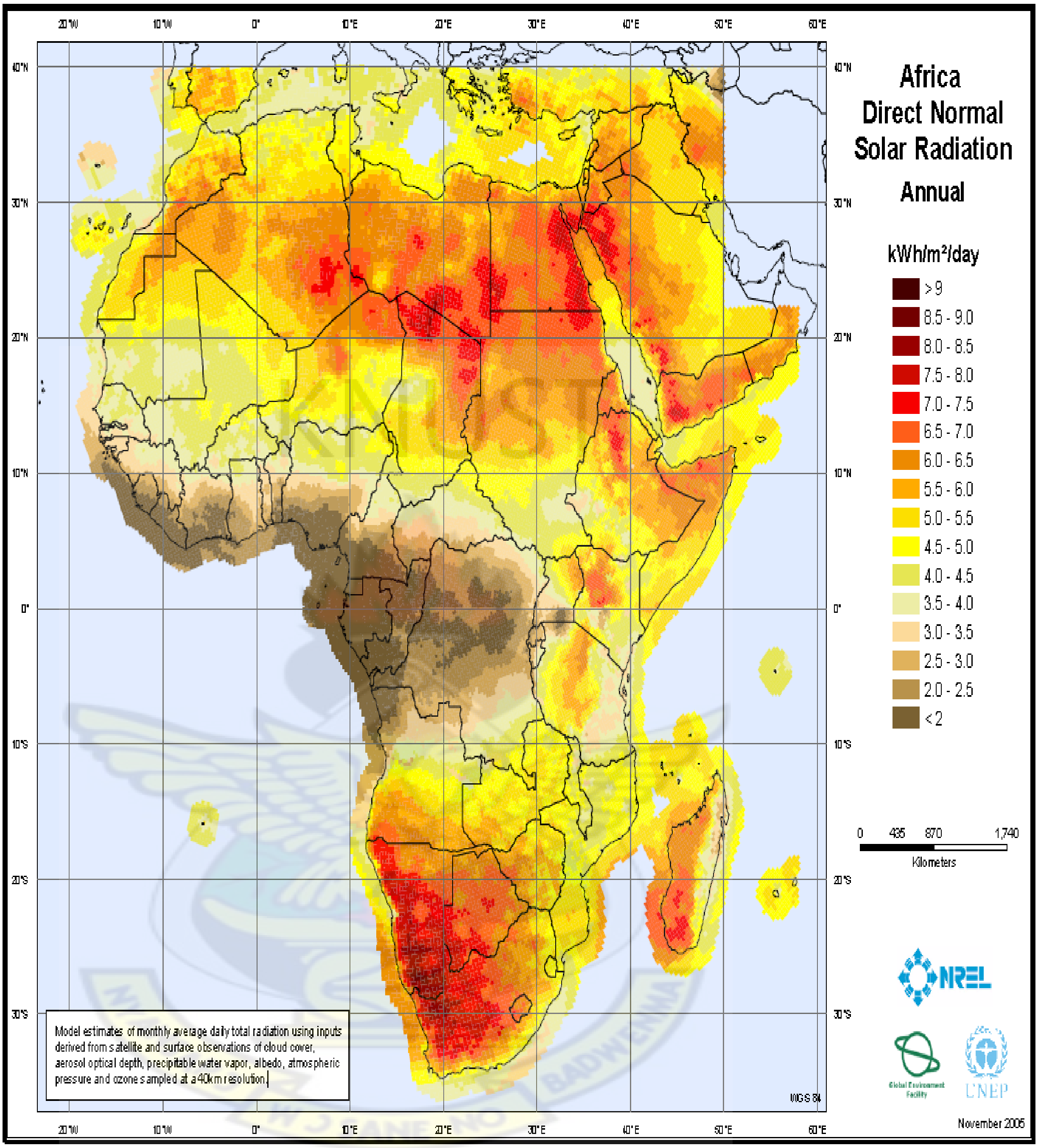


Fig H-2: Annual average direct normal Irradiance (DNI) map at 40km resolution for Africa from NREL

APPENDIX I: Cash Flows of Some Profitable Mix of Modest Feed-in Tariffs, Capital Subsidies and Capital Cost.

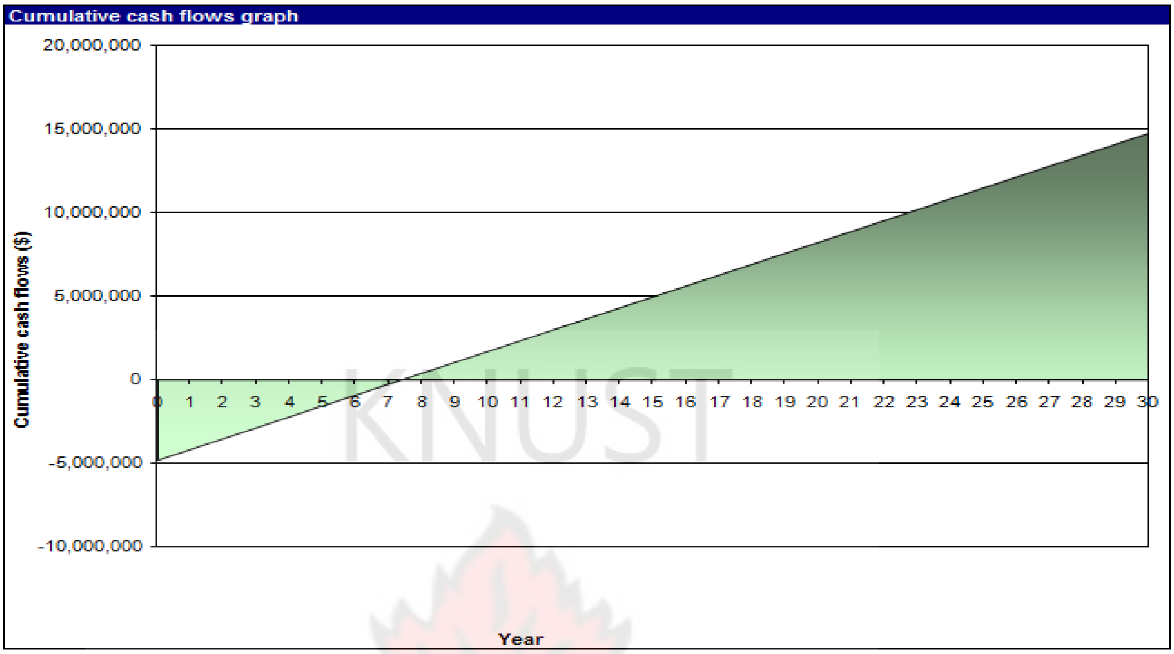


Figure I-1: Cash Flows of a combination of 6 US Cents Feed-in Tariff, 80% Grant and US $1000/kW Capital Cost

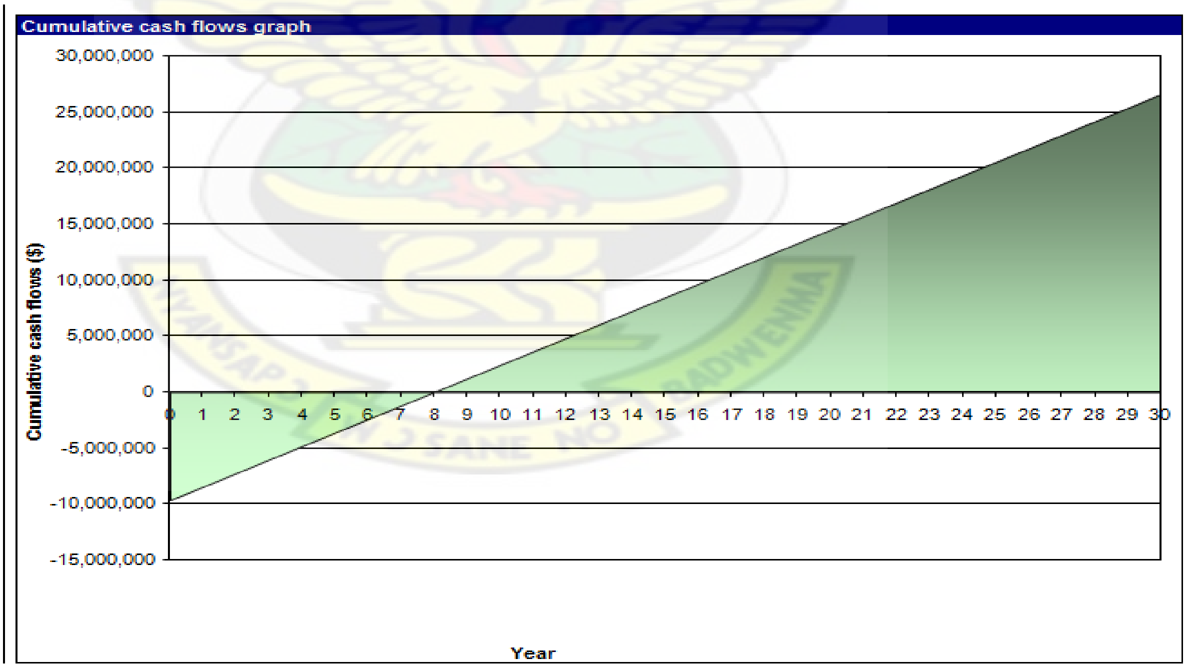


Figure I-2: Cash Flows of a combination of 8 US Cents Feed-in Tariff, 80% Grant and US $2000/kW Capital Cost.

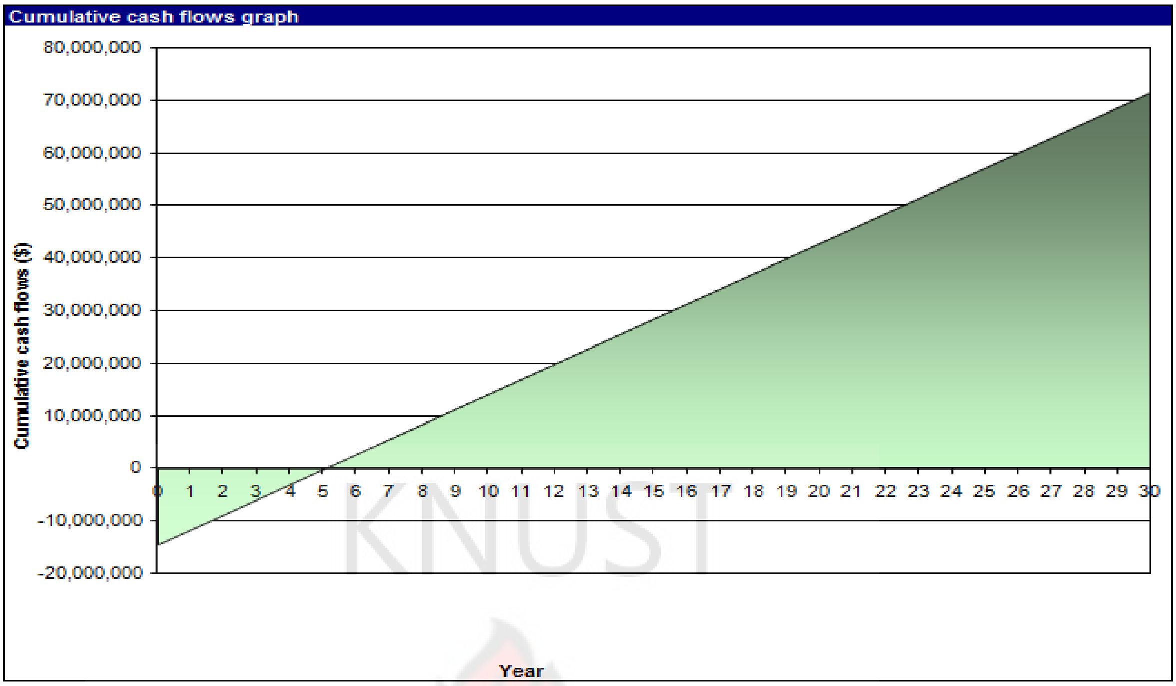


Figure I-3: Cash Flows of a combination of 14 US Cents Feed-in Tariff, 40% Grant and US $1000/kW Capital Cost.

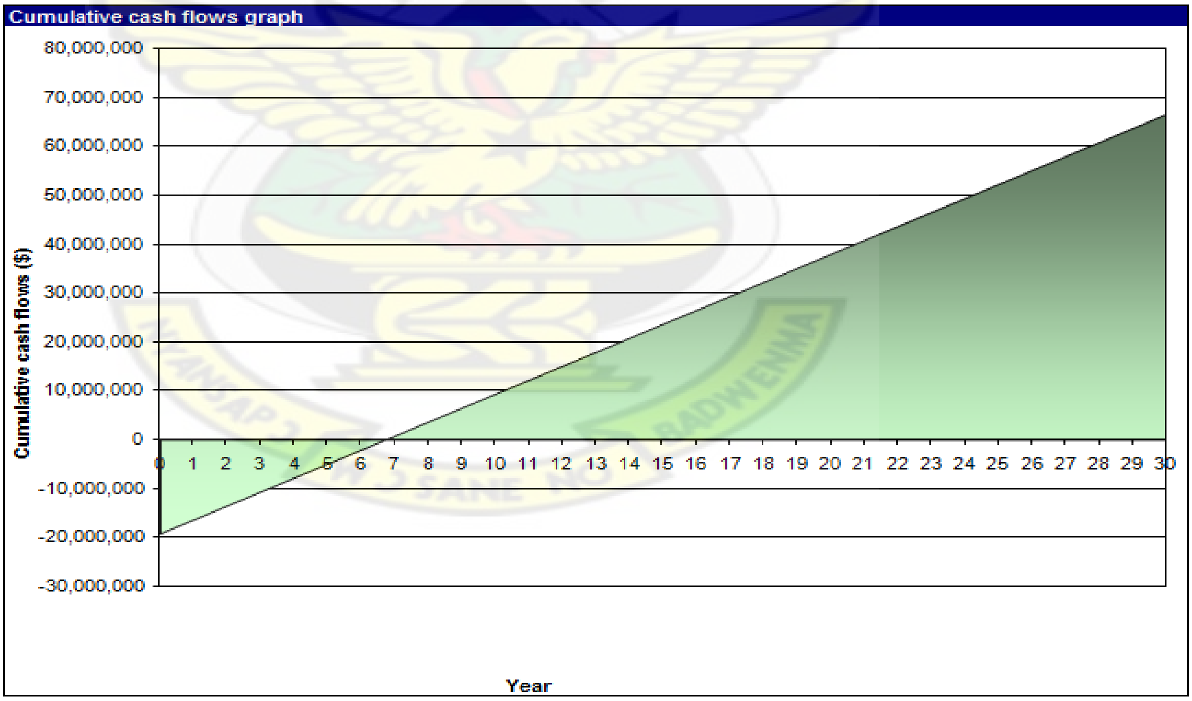


Figure I-4: Cash Flows of a combination of 14 US Cents Feed-in Tariff, 60% Grant and US $2000/kW Capital Cost.