A CONCEPTUAL FRAMEWORK FOR A COGENERATION PLANT AT THE KNUST CAMPUS

By

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DECLARATION

I hereby declare that this submission is my own work towards the Master of Science degree in Mechanical Engineering and that, to the best of my knowledge, it contains no material previously published nor material which been accepted for the award of any other degree in this University or elsewhere, except where due acknowledgement has been made in the text.

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ABSTRACT

Ghana is currently plagued with a persistent trend of inadequate power supply, which has a ripple effect on all sectors of the economy. Efforts are being made at the national level via the Ministry of Energy and Ghana Energy Commission to arrest the current situation, through policies and agreements with multinational investors.

Modular biomass-based generation of electricity presents a promising avenue to harness locally available fuel resources in order to increase the national installed capacity. In this study, the technical and economic viability of a 6MWe cogeneration plant to be sited at KNUST campus was assessed as a model of community based electricity generation system. In addition to analysing the cost and thermodynamic efficiencies of the proposed system, an exergy analysis was also performed in order to establish a correlation between the exergetic measures of performance and the overall system's performance in terms of cost, energy savings and greenhouse gas (GHG) emissions.

A 6MWe biomass-based cogeneration plant is proposed with a capital cost of 11.21 US$ million and a levelised generation cost of US$ 0.08079/kWh. It has a second law efficiency of 50.6% and exergy destruction of 0.45 kW per KW of useful power generated. It is observed that second law thermodynamic assessment of a thermal system gives diverse ways of quantifying its performance because measures like the second law efficiency and the rates of exergy destruction depend on the extent of irreversibilities in the system.

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DEDICATION

To Mary Serwaa Nyamekye, Kingsley Boahene and Kate Mpemaah.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF THE STUDY

The growing trends of industrialisation and population increase have brought increasing demands on energy resources worldwide, a situation from which Ghana is not exempted. Issues like electricity load rationing on the national grid, shortage of liquefied petroleum gas (LPG) for domestic and industrial activities, fossil fuel price hikes on the world market, along with the looming threat of the depleting stock of fossil fuels, among others give a premonition of severe crisis in the near future if proactive measures are not taken. Measures are not only needed to make more energy resources available but also to make efficient use of what we have now. Obviously, this calls for extensive studies to explore the various energy conversion technologies as well as sustainable fuel alternatives to augment the current stock. One such window is biomass-fired cogeneration as it presents an environmentally friendly alternative.

In line with the national vision of attaining energy sufficiency for sustainable economic growth, the Ghana Energy Commission recommended that government speeds up the passage of the Renewable Energy Law to allow wind and other bulk power renewable sources to be developed quickly to access the grid [Ghana Energy Commission, 2010]. Thus, in this project, the viability of community based generation is evaluated using the KNUST campus as a pilot case.

As a leading technological university in Ghana the onus lies on KNUST not only to seek solutions to problems, but also to lead the crusade of addressing the technological issues that affect the nation – one of which is the current energy situation. A facility such as proposed in this thesis would be needed to ensure that the academic and business activities on campus are not unduly interrupted as a result of frequent power outages by the national grid. Furthermore, excess power from the facility would be fed into the national grid which would not only boost the central system but also raise revenue for its operators. Another indirect benefit is that the central grid would be relieved from the load which would have otherwise been consumed by the university community.

Biomass energy resources, which are usually waste by-products from both industrial and domestic activities, serve as attractive fuel sources because it helps in waste management as well as reducing the demand for non-renewable fuel resources. Cogeneration provides an avenue to utilise low availability thermal energy which would otherwise be dumped into the environment – thus reducing thermal pollution and also increasing the efficiency of energy utilisation. The overall efficiency of energy utilisation in combined heat and power (CHP) mode can be as high as 80 per cent [Mujeebu et al, 2009]. Along with savings of the depleting stock of fossil fuels, biomass-fired cogeneration comes with an additional advantage of reducing greenhouse gas emissions (particularly CO_2 emission) per unit of useful energy output – a condition that helps in achieving the aims of the Kyoto Protocol of 1997 which seeks to attain a set reduction in global greenhouse gas emission rates by the year 2012 [UN, 1998]. On-site generation reduces the burden on the utility networks and eliminates transmission line losses. If the utilization of biomass waste as fuel is also incorporated with CHP, it will lead to effective waste management, an additional ecological benefit. Biomass, which emanates from both natural and human activities, incorporates by-products from the timber industry, agricultural crops, forestry residues, household wastes, and wood [Zafar, 2011]. These resources range from corn kernels to corn stalks, from soybean and canola oils to animal fats, from prairie grasses to hardwoods.

From the perspective of electricity generation, the cost of collection and/or processing of the biomass residue becomes a key factor that determines the viability of the project. In the quest to harness the abundant biomass resources that are available in the country, it may be possible to use either grid dependent plants that feed power to the central grid or grid independent stations which serve the immediate community close to it depending on the requirement of the project. The former is termed as dispersed generation whilst the latter is called distributed generation, but they both fall under decentralised generation and can be powered by a wide variety of fuels depending on availability and requirements of the project. Each method has its associated merits and demerits. Distributed generation is used mainly for onsite power generation and has the advantage of eliminating the need for transmission lines all the way from a central station. On the other hand, in dispersed generation plants are strategically located on the transmission grid to overcome bottlenecks in the transmission and distribution system and to improve the stability of the system. Regardless of which mode is chosen, the end result is that the total installed capacity of the country is increased in the long run [Dondi et al, 2002].

In the design of any power plant facility, a critical issue that needs to be properly addressed is the source of fuel, its ecological implications and availability - whether seasonal or continuous. It is worth stating that there is a direct interdependence between the type of fuel and the most appropriate energy conversion technology. Other concerns such as capital and or operating cost exert a major influence on the success of any such design, notwithstanding its ecological advantages and/or technical superiority. The most appropriate technology and fuel for a given application depends on factors like availability and the regulatory framework of the area in question as well as what the project seeks to achieve. For instance, factors like greenhouse effect and global warming will advocate for a technology that helps achieve remarkable greenhouse gas savings. Areas that are close to oil reserves where natural gas and petroleum based fuels are in abundant supply are likely to use gas turbine technology all things being equal. From the foregoing background, there is every indication that power plant design involves complex linkages between energy efficiency, economics, statutory regulations and environmental sustainability, all of which demand adequate attention.

1.2 JUSTIFICATION

Energy forms the backbone and perhaps the core support on which every economy thrives. Like many developing countries, Ghana has to reckon with a perennial trend of energy insufficiency especially with electricity supply. The Ghana Energy Commission indicated a supply shortfall of 2700 GWh for the year 2010 [Ghana Energy Commission, 2010]. The discrepancy between the overall national demand of energy and the quantities being made available now yields a deficit that cripples many sectors of the economy. For instance, VALCO, a major producer of aluminium products for both local and international markets has a regrettable trend of shutting down or working below capacity due to shortfalls in national electricity supply.

A look at our daily schedules reveals how indispensable electricity becomes as far as the very execution of most of our routines at work is concerned; ranging from simple word processing to complex automated manufacturing and processing activities. Therefore, abrupt outages in power supply result in reduced productivity, loss of revenue, and occasional accidents, with a possible damage to both life and property. Thus, economically viable energy alternatives that would afford Ghanaians the luxury of uninterrupted electricity supply need to be developed and harnessed as a matter of urgency, if the country is to achieve its millennium development goals. This is because the aspirations of developing countries for higher living standards can only be satisfied through sustained development of electric power markets as part of the basic infrastructure requirement [Energy Center, KNUST, 2008]. From an in-depth assessment of how inadequate supply of energy affects all the sectors of the economy, an example of which is the disruption of academic studies as well as business activities on the KNUST campus, it is justified to research on the possibility of implementing community based generation to augment the existing electricity supply. Even though different locations may have varying biomass resources and technical capacity, the results of this work, will, to some extent highlight the key issues that underlie biomass-based power generation and serve as a stepping stone for future investigations.

1.3 OBJECTIVES

The main aim of the project is to investigate the technical and economic viability of a cogeneration plant that would produce electricity and process heat to meet the demand of the KNUST. The central focus of the study is the generation of electricity to meet the demand on campus using a thermal power plant, whilst harnessing the low temperature thermal energy which otherwise should have been rejected to the environment for productive uses.

The specific objectives are the following;

- Identify a suitable primary fuel and a corresponding conversion technology.
- Acquire data on energy usage at KNUST campus in order to determine the electrical power needs and possible uses of thermal output from a cogeneration facility.
- Provide a conceptual framework for the facility.
- Size major elements of the facility.
- Perform economic analysis on the proposed system.
- Perform a second law thermodynamic analysis of the proposed system

1.4 SCOPE OF WORK AND THESIS ORGANISATION

It is apparent that the emphasis of this study is on electric power generation, but advantage is taken of the fact that any cyclic conversion of heat to work must be accompanied by a corresponding heat rejection – a consequence of the second law of thermodynamics, to deliver a thermal energy output as well. The usage of this low level availability energy addresses an issue of thermal waste associated with condenser cooling water and cooling towers. Furthermore, the sustained use of biomass in energy generation offers a very ecologically sound solution to waste disposal.

Chapter One presents a summary of the current energy situation in Ghana, with emphasis on KNUST – thus setting the stage for a thorough discourse on the subject matter with the aim of unravelling an ecologically friendly and long-term sustainable solution.

Various technologies available for biomass-based cogeneration were studied in order to be abreast with the technicalities involved in the power plant studies. This is presented in Chapter Two. In Chapter Three, the procedures undertaken in the course of this study have been outlined and explained. The proposed concepts are presented in Chapter Three.

Chapter Four gives a detailed analysis of the proposed systems. A summary of the results and findings made from the study is presented in Chapter five for discussion. Additionally, the chapter five presents some practical implications of these findings and the extent to which they contribute to the success or otherwise of the power plant facility.

Chapter six elaborates further on the findings in order to arrive at practical conclusions and make policy recommendations for stakeholders in the energy sector and other interested clients.

1.5 EXPECTED OUTCOMES

Demonstration of the techno-economic viability of a community based cogeneration technology at such a scale encourages investment decisions of company owners towards implementing such projects. Institutions that produce combustible waste in large quantities or are sited near easily exploitable biomass resources, such as Sokoban saw mill and Ejura farms can take advantage of CHP technology to cater for their own power as well as process heating, space heating (or cooling) needs.

The energy ministry, district and metropolitan authorities, as well as other stake holders in energy conversion and utilisation can consider biomass-based generation as a sustainable alternative in the provision of clean, efficient energy to meet the socio-economic needs of the country.

CHAPTER TWO

LITERATURE REVIEW

2.1 COGENERATION: DEFINITION AND FUNDAMENTALS

Cogeneration, involves the thermodynamically sequential production of two or more useful forms of energy from a single primary energy source. The two most usual energy forms delivered from cogeneration systems are mechanical and thermal energy. Mechanical energy is usually used to drive an electric generator. Thus, even though restrictive, most literature defines cogeneration as the combined production of electrical (or mechanical) and useful thermal energy from the same primary energy source [EDUCOGEN, 2001] – hence it is also referred to as combined heat and power (CHP) system.

Auxiliary equipment such as compressors, pumps and fans can also be driven by the mechanical energy produced by the system, whilst the thermal energy output can be used either for heating or for cooling. Cooling is effected by an absorption unit, which can operate through hot water, steam or hot gases. In Ghana, institutions like Ghana oil Palm Development Company (GOPDC), Juaben Oil Mills, and Twifo Oil Palm Plantation make use of CHP's.

At GOPDC, by products from the oil processing namely palm kernel shells, palm kernel cake, palm fruit fibres and empty palm fruit bunches are used in firing the cogeneration plant. The facility operates a 2.5MWe two-stage extraction steam turbine at inlet pressure of 25 bars (2.5MPa). Steam is bled at after the first stage expansion at a pressure of 3 bars (0.3MPa) for sterilisation and heating at the oil mill.

Cogeneration systems often capture otherwise wasted thermal energy, usually from an electricity producing device like a heat engine and use it for space and water heating, industrial process heating, or as a thermal energy source for another system components [Lawn, 1981]. Since it provides a means of reducing primary energy consumption, it serves as an effective option in mitigating the environmental impacts associated with energy conversion, and can be adopted in various industrial sectors such as pulp and paper, brewery food processing among others.

The basic requirement for the implementation of a cogeneration system is that the industry must require both electrical power and heating (process heat) in its operations [UNEP, 2007]. In settings where there is a coordinated demand for both power and heat energy, cogeneration technology offers a promising energy conversion option as compared to the separate production of heat and centralised electricity [Fryling, 1966]. On the other hand, the potential of CHP could be limited due to the constraint of necessary heat demand.

2.2 BIOMASS AS A FUEL

Biomass is an ecological term for organic material, both above and below the ground, both living and dead, such as trees, crops, grasses, tree litter and roots. It excludes organic material which has been transformed by geological processes into substances such as coal or petroleum. The sources and quantities are wide and extensive such as industrial, agricultural, and municipal solid wastes [Sutton et al, 2012]. Generating electricity from biomass is a plausible way of utilising this valuable resource because it presents an opportunity for eliminating waste/pollution problems and simultaneously producing electricity. Burning of biomass as a means of waste disposal has become rampant in communities and industries that are overwhelmed by their high levels of waste generation. For instance, at Oforikrom saw mill, heaps of wood residues are burnt. Thus, it would be laudable if a conscious effort is made to harness the energy stored in these waste products for productive purposes thereby freeing the surroundings from solid waste.

Additionally, biomass fuels use the same technology that has become common in the power generation industry – burning fuel in furnaces to generate steam in boilers and then driving turbines with the steam's energy to produce mechanical or electrical energy. As a renewable energy resource biomass has become very attractive as a source of fuel due to its carbon neutral characteristics. Plants and trees extract CO_2 from the atmosphere and store it as they grow whilst burning of biomass in energy generation returns this captured CO_2 to the atmosphere, thereby keeping the atmospheric carbon cycle in a balance [UNEP, 2007].

Biomass fuel is very often available at low cost or may be available even free because in some cases wastes can only be disposed of at additional cost to a company or industrial entity. Hence, the generator of the waste will welcome any means to get rid of the waste at close to zero cost, if possible. From the perspective of electricity generation, the cost of collection of the residue becomes the key factor in determining its viability. If the fuel has a seasonal nature of supply, then the electric generating facility need to either have a large storage facility or alternative sources of fuel. Fuels such as rice husks and maize cobs are produced during processing of these crops. This takes place after harvesting of the crop, so the waste is already concentrated at a point and is an easily exploitable source of energy - particularly if it can be utilised on site to provide heat and power.

2.3 BIOMASS BASED COGENERATION PLANT TECHNOLOGIES

Cogeneration systems may be classified either as topping systems or as bottoming systems depending on the sequence of production of outputs. In topping systems, a high temperature working fluid (either exhaust gases or steam) drives an engine to produce electricity, while low temperature heat is used for thermal processes or space heating (or cooling). In bottoming systems, the primary fuel produces high temperature thermal output, and the rejected heat is used to generate power through a recovery boiler and turbine generator. Bottoming systems are suitable for manufacturing processes, where high quality thermal energy is required and usually used in cement, steel, ceramic, gas and petrochemical industries. Figure 2.1 shows representative temperature ranges for topping and bottoming cogeneration systems.

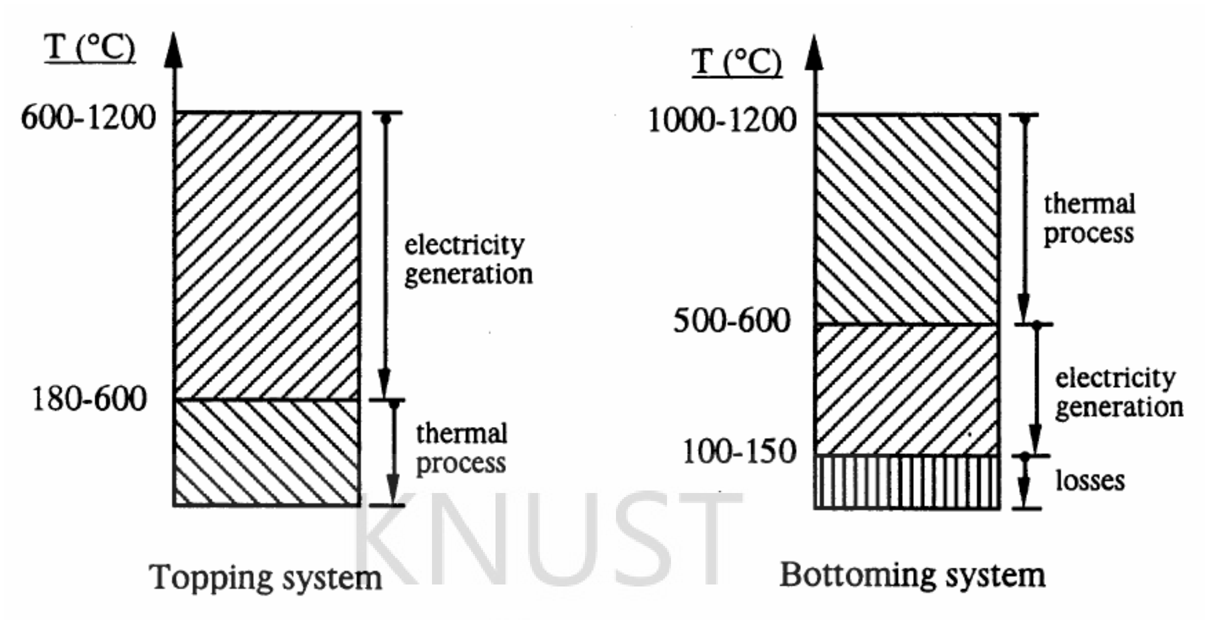

Figure 2. 1 Representative temperature ranges for topping and bottoming cogeneration systems [source: EDUCOGEN, 2001]

A CHP facility essentially consists of a prime mover, power production system, and a heat recovery system. According to the prime mover used, a biomass-based CHP system can be classified either as using a steam turbine technology (CHP-ST) or an integrated Gasification Combined Cycle Technology (CHP-IGCC)

2.3.1 STEAM TURBINE CHP SYSTEMS

Steam turbine generation systems are traditional thermo-electric power stations, where fossil fuels or biomass are used in direct-flame boilers to produce steam. Steam is then partially bled from the turbine and sent to meet process heating requirements, or it is used to heat a secondary fluid, usually water. A system based on steam turbine consists of three major components: a steam generator, a steam turbine and a heat sink. The system operates on the Rankine cycle, either in its basic form or in its improved versions with steam reheating and regenerative water preheating. The most common steam generator is a boiler, which can either burn any type of fuel or certain combinations of fuels, and may produce superheated steam. Steam turbine systems have a high reliability (which can reach 95%), high availability (in the range of 90-95%) and long life cycle (25-35 years). However, the installation period is rather long, requiring 12-18 months for small units, and up to three years for large systems [EDUCOGEN, 2001].

Steam turbines are the most commonly employed prime movers for cogeneration applications due to their simplicity and low capital cost. In the steam turbines, high pressure steam is expanded to a lower pressure level, converting part of its thermal energy to kinetic energy through nozzles and then to mechanical power through rotating blades. The types of steam turbine include back pressure steam turbines (BPST) and extraction-condensing type.

The back pressure turbine CHP arrangement becomes attractive due to its inherent high total efficiency because there is no rejection of heat through a condenser. There is a reduced or sometimes no need of cooling water and the avoidance of expensive low pressure turbine stages - thus resulting in a low capital cost. One drawback of BPST is that the flow rate of steam through the turbine depends on the thermal load. Consequently, the electricity generated by the steam is controlled by the thermal load, resulting in little or no flexibility in directly matching electrical output to electrical load. Due to this constraint BPST's are often used in CHP's where power and heat are needed simultaneously, and in rather stable shares, since they produce heat and electricity in a constant ratio. Therefore, it becomes necessary to provide a two-way connection to the grid for purchasing supplemental electricity or selling excess electricity generated. A rather inefficient and thus less elegant means of increasing the electricity production is by venting excess steam directly to the atmosphere, as any increase in power would require an increased steam flow rate.

The BPST is usually larger for the same power output than the extraction-condensing unit type, because the former operates under lower enthalpy difference as the steam is not expanded to the lowest permissible pressure in the cycle. The steam rather leaves the turbine at an intermediate pressure which is suitably high for the steam or process heating requirements. Generally, the steam leaving at high pressure from the BPST is superheated and therefore unsuitable for heating due to the low heat transfer rates of superheated steam [Singh, 2006]. Thus, it is usual to make provision for desuperheating as shown in Figure 2.2 in order to bring the steam to a saturated vapour state for higher heat transfer rates and convenient control of temperature in the process heater.

Extraction-condensing steam turbines, on the other, hand allow the extraction of steam from one or more intermediate stages at the appropriate pressures and temperatures for the process heating as shown in Figure2.3. The remaining steam is exhausted to the pressure of the condenser, which can be as low as 0.05 bar (5kPa) with corresponding condensing temperature of about 33°C. Generally, the condensing steam turbine has a higher capital cost and a lower total efficiency as compared to the back pressure system. However, the former allows to a certain extent, an independent control of the electrical power by proper regulation of the steam flow rate through the turbine.

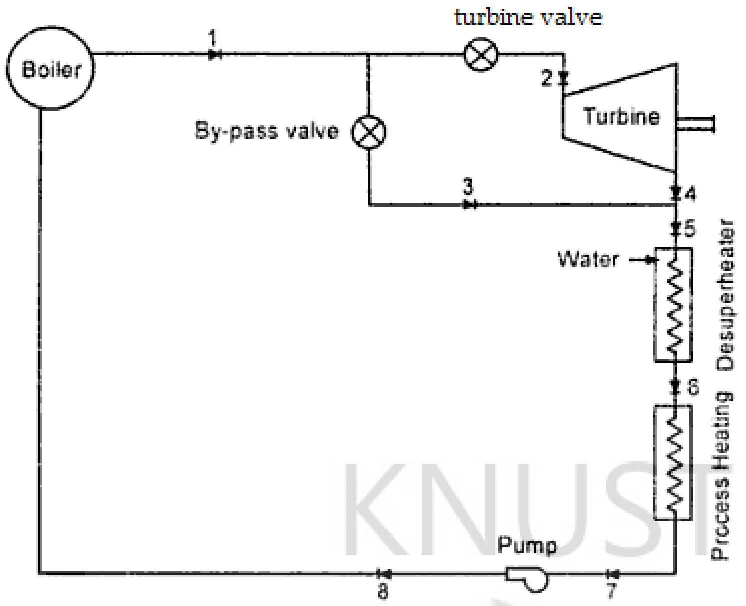

Figure 2. 2: Cogeneration plant with pressure turbine [Singh, 2006]

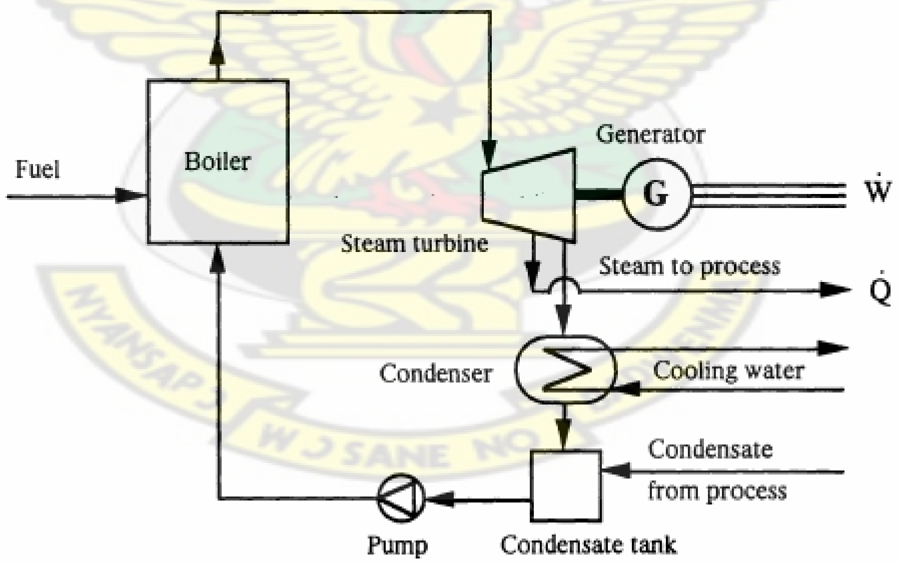

Figure 2. 3: Cogeneration system with condensing steam turbine [EDUCOGEN, 2001]

2.3.2 COMBINED CYCLE SYSTEMS

Combined cycle systems operate based on two thermodynamic cycles, which are connected with a working fluid and operate at different temperature levels. The high temperature cycle (topping cycle) rejects heat, which is recovered and used by the low temperature cycle (bottoming cycle) to produce additional electrical (or mechanical) energy, thus increasing the electrical efficiency [EDUCOGEN, 2001]. A widely used combined cycle configuration is the Joule-Rankine cycle. Figure 2.4 illustrates a simplified schematic of a Joule-Rankine combined cycle system, whilst Figure 2.5 shows a more elaborate system with double pressure boilers. Double- or triple-pressure steam boilers increase the efficiency of the system by enhancing the heat recovery, but add extra complexity; thus making it suitable only in large systems [EDUCOGEN, 2001].

The arrangement in Figure 2.4 uses a back pressure steam turbine. Condensing turbine is also possible, while extraction can also be used with either the backpressure or the condensing turbine.

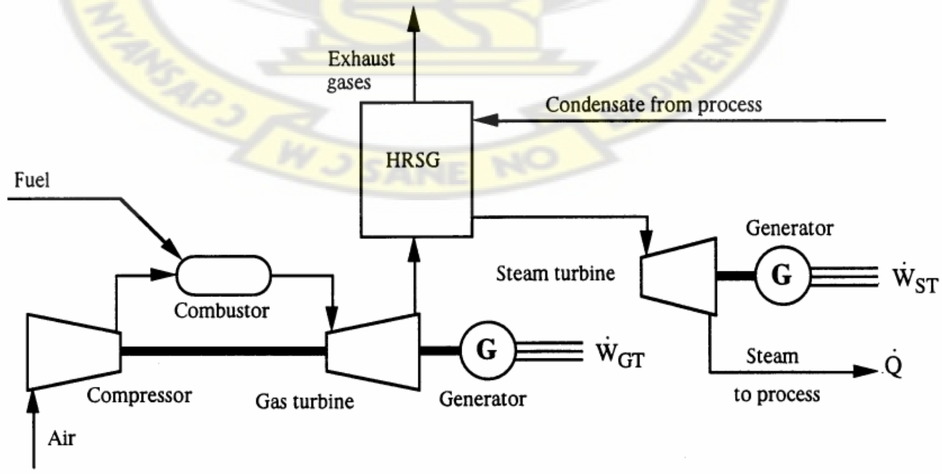

Figure 2. 4: Joule-Rankine cogeneration system with back pressure steam turbine [EDUCOGEN, 2001]

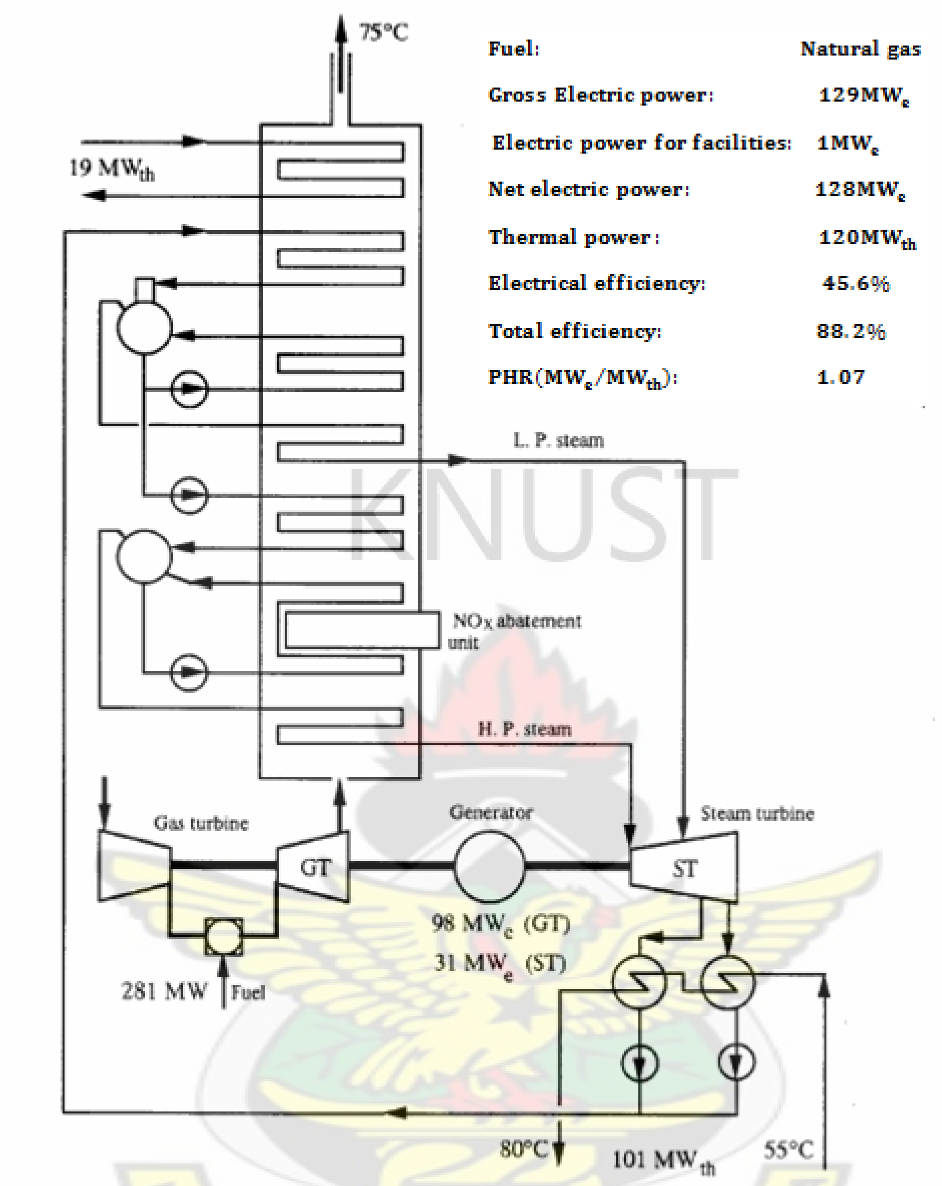

Figure 2. 5: ASEA STAL combined cycle system with extraction - condensing steam turbine [IEA, 1988]

In a combined cycle power station, a gas turbine (GT) is used to generate electricity, and the waste heat from the GT is used in a heat recovery steam generator to generate additional electricity. In conventional gas turbines, the use of distillate fuels usually diesel is common. In projects where the cost of a gas pipeline can be justified natural gas could be used.

Where the GT is fired on gas derived from the gasification of organic/ carbonaceous materials, the cycle is termed as Integrated Gasification Combined cycle. Integrated Biomass Gasification Combined Cycle (IBGCC) systems are such that the traditional combustor is replaced with a gasifier and gas turbine. Exhaust heat from the gas turbine is used to produce steam for a conventional steam turbine. The gas and steam turbines operate together as a combined cycle [Krigmont, 1999]. In essence, an IBGCC integrates a biomass gasification system into a typical combined cycle plant – hence its name (see Figure 2.6)

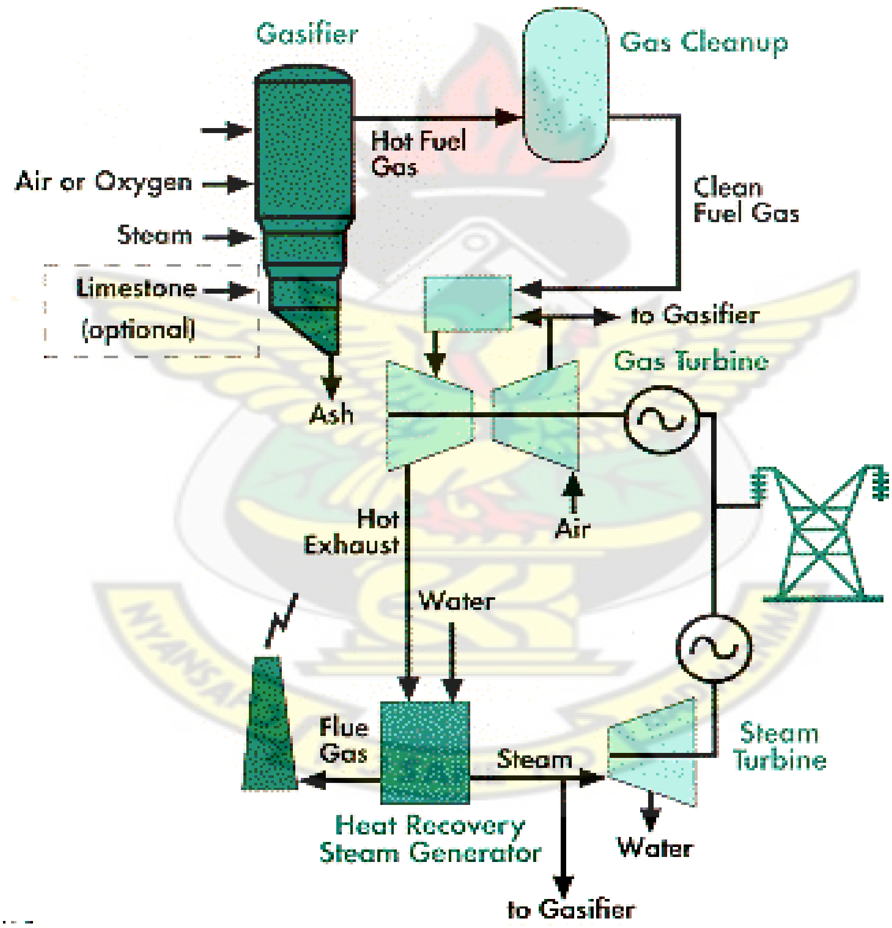

Figure 2. 6: Schematic of an IBGCC [Krigmont, 1999]

It is possible to attain high efficiencies with this technology based on a clean and renewable fuel. Such plants can run on low rank fuels at reasonable efficiencies of 35%-50% based on net heating value [Krigmont, 1999]. The attractive features of the IBGCC Power Generation technology include its environmental superiority to conventional green biomass fired plant, high thermal efficiencies, potential applicability to a variety of fuels and generation cost. The most pressing need for advanced gasification technology is the need to repower older coal-, oil-, and/or gas-fired boilers that typically have low efficiency and high emission levels. However, its inherent complexity and high capital cost does not make it attractive for small scale and modular generation. [Krigmont, 1999]

CHAPTER THREE

METHODOLOGY

3.1 SOURCES OF INFORMATION

In the course of this study, published literature materials were identified on areas such as cogeneration, biomass fuels and conversion technologies in order to gain an in-depth insight on the subject matter. Additionally, **s**ome Power plant facilities were visited, and observations were made on the systems and components. Places visited include the Ghana Oil palm development company (GOPDC), at Kwae, Takoradi Thermal Plant (TTP). Other areas like Sokoban wood village, dump fill sites, and saw mills in Kumasi were also visited in order to ascertain the viability of using biomass as a fuel. During the visits, questions like the type of fuel, the most suitable conversion technology, power plant specifications and operating conditions, economic and environmental sustainability among others were answered, thus leading to a clear cut path for the execution of the project. The RETScreen® software also has an in-built data which was utilised during the economic and emission analysis [Natural Resources Canada, 2012]. The Steamtab® companion, a steam property look up application was also used in reading the properties of the working fluids [ChemicaLogic®, 2003].

3.2 ENERGY UTILISATION STUDIES ON CAMPUS

Data on the electricity consumption at KNUST was acquired from the Energy Center, KNUST. The available data gives electricity consumption trends for the years 2006 through to 2008 as shown in Figure 3.1, having a peak demand of approximately 3.5MWe. The proposed concepts are designed to meet a requirement of 6MWe. In order to identify possible uses for the thermal energy output of the system, areas like absorption refrigeration, incubation in poultry rearing, crop drying, and space heating for farm animals during cold seasons were considered. In deciding on which need has to be satisfied in the execution of a cogeneration project on campus, attention was paid to the necessity to minimise capital as well as operating cost, whilst satisfying the needed purpose.

The thermal energy output of a thermal plant can be classified in three ranges according to the temperature at which heat is supplied [Toussaint, 2012]. At temperatures below 60 ^{o}C, it is considered as low grade (or "waste") heat because it has little availability for any useful work. Thermal outputs at temperatures ranging between 70 and 100 ^{o}C are considered as medium grade temperature and can be used for space heating or absorption cooling. For the purpose of industrial heating, usually, high grade heat is required at temperatures of 120^{o}C and above.

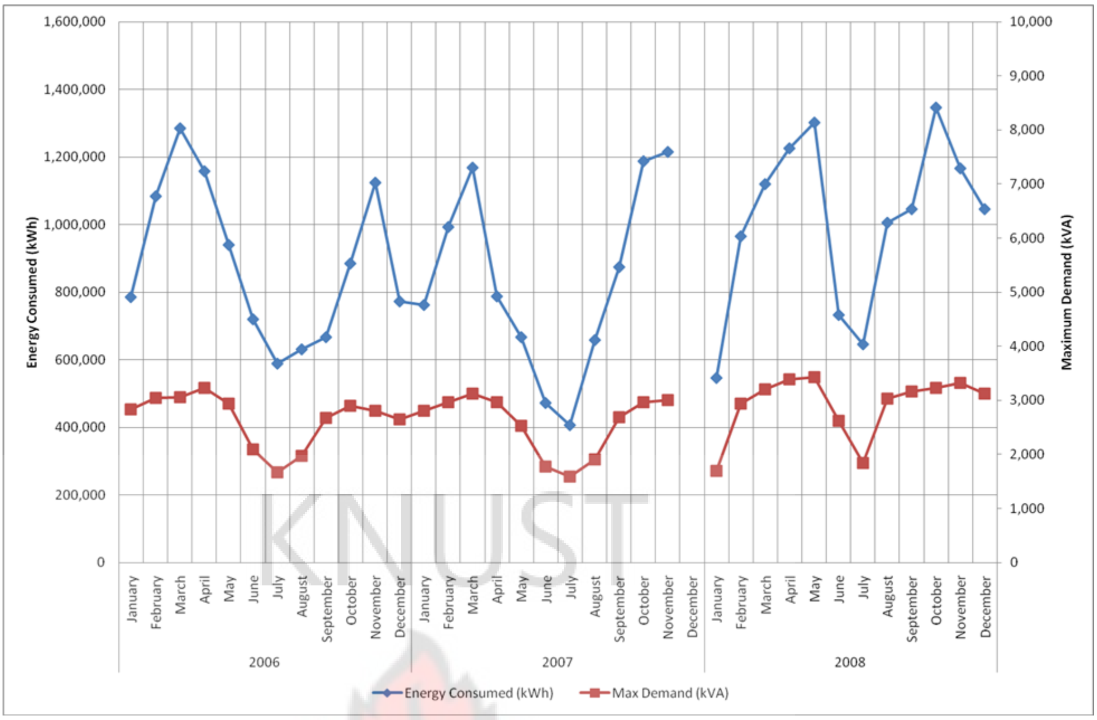

Figure 3. 1: Electricity demand curves for KNUST (2006 – 2008) [courtesy: Energy Center, KNUST]

3.3 ALTERNATE CONCEPTS FOR PROPOSED FACILITY

Two biomass fired concepts were developed and analysed as presented in the subsequent sections. Concepts ***A*** and ***B*** are both cogeneration plants, with their thermal outputs being used in absorption air conditioning as shown in Figure 3.4. The choice of absorption air-conditioning is due to the fact that predominantly high temperatures in a tropical location like Ghana makes it a more desirable, as compared to crop drying, and district heating. Though Ghana is mainly an agricultural country, the proposed facility would be sited in an academic community where there are several computers, laboratory instruments and laptops requiring low temperature environments for their usage – thus, making the choice of an absorption chiller a reasonable one.

Concept ***A*** utilises a back pressure steam turbine with the steam exhaust connected to the process heater. As shown in Figure 3.2, high temperature steam from the boiler is expanded in the turbine to produce power and the lower temperature exhaust steam is utilised in the process heater. The advantage of such a design lies in its simplicity, and low capital cost. However, it has an inherent limitation of constant heat to power ratio, which results in little or no flexibility of thermal/electrical load matching as the flow rate of the working fluid is determined by the thermal load. Additionally, the quality of thermal energy output needed may require that the turbine expansion is not carried out to the lowest permissible pressure in the system. Thus, a bigger steam turbine will be required for the same power output requirement due to the reduction in the enthalpy change across the turbine as a result of the constraint likely to be imposed by the process heater.

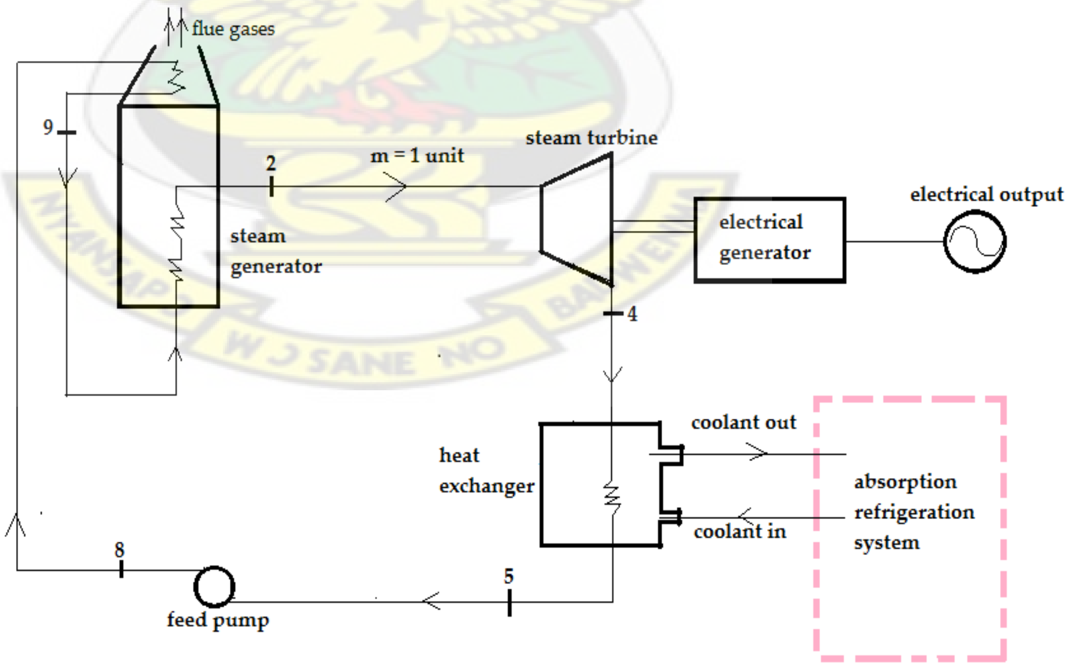

Figure 3. 2: Schematic diagram of concept *A*

Concept ***B*** uses a two stage steam turbine with inter-stage extraction (see Figure 3.3). The bled steam and the exhaust steam together exchange heat with the coolant without mixing. Thus, this heat exchanger replaces the condenser in a conventional plant. The only difference here is that the coolant in this case is a refrigerant which links the power plant facility to an absorption refrigeration circuit.

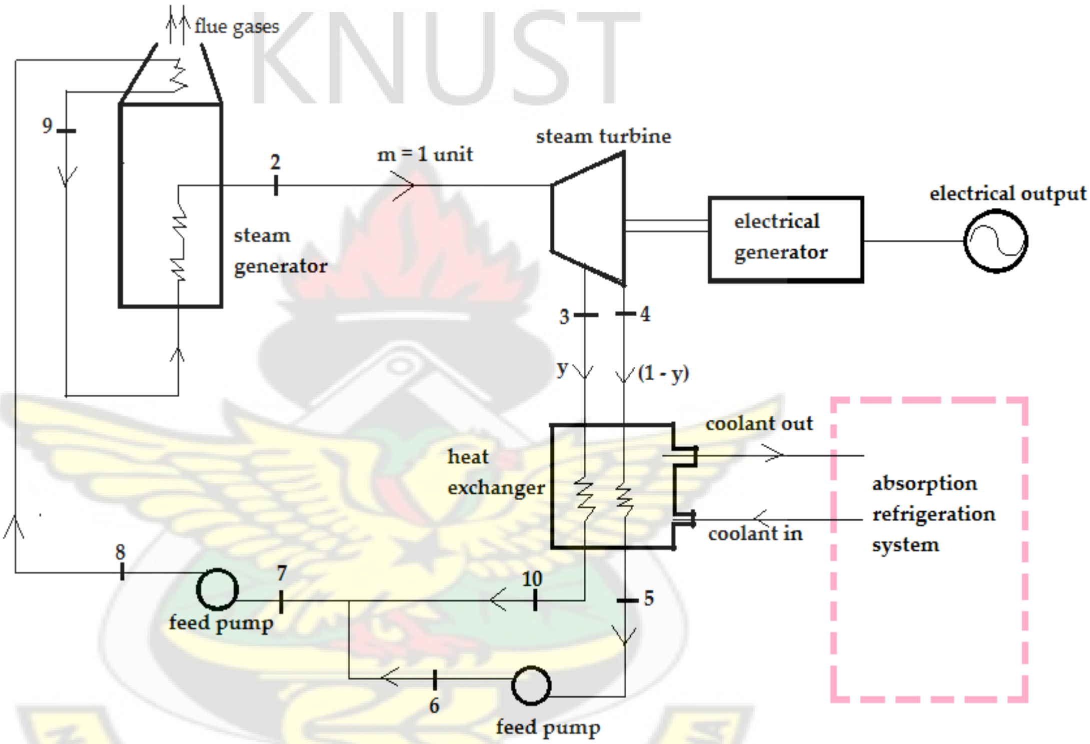

Figure 3. 3: Schematic of concept *B*

In the absorption refrigeration system coupled to the power plants, the traditional compressor as used in vapour compression systems is replaced by a rather intricate absorption compression system. The refrigerant used is aqueous ammonia. As shown in Figure 3.4, a low temperature, weak solution of the refrigerant enters a generator where it exchanges heat with the turbine exhaust steam from the steam cycle. The heat absorbed drives high pressure ammonia vapour out of the solution, and the liquid returns to an absorber via a throttling valve. The high pressure vapour is sent to the condenser, expansion valve and then to an evaporator where it extracts heat from the refrigerated space. The low pressure strong solution from the evaporator is sent to an absorber where it absorbed by the liquid. The process in the absorber is exothermic, thus requiring air or water cooling. The low pressure, low temperature weak solution from the absorber is pumped back to the generator to complete the cycle.

The nominal coefficient of performance (COP) of single-stage absorption chillers at generator heat input of 116°C (240°F) ranges from 0.65 to 0.70 (Cengel et al, 2006). It becomes a reasonable choice when the unit cost of heat (thermal energy) is low or thermal energy is available that would otherwise be wasted, such as in the steam turbine plant facility proposed in this work.

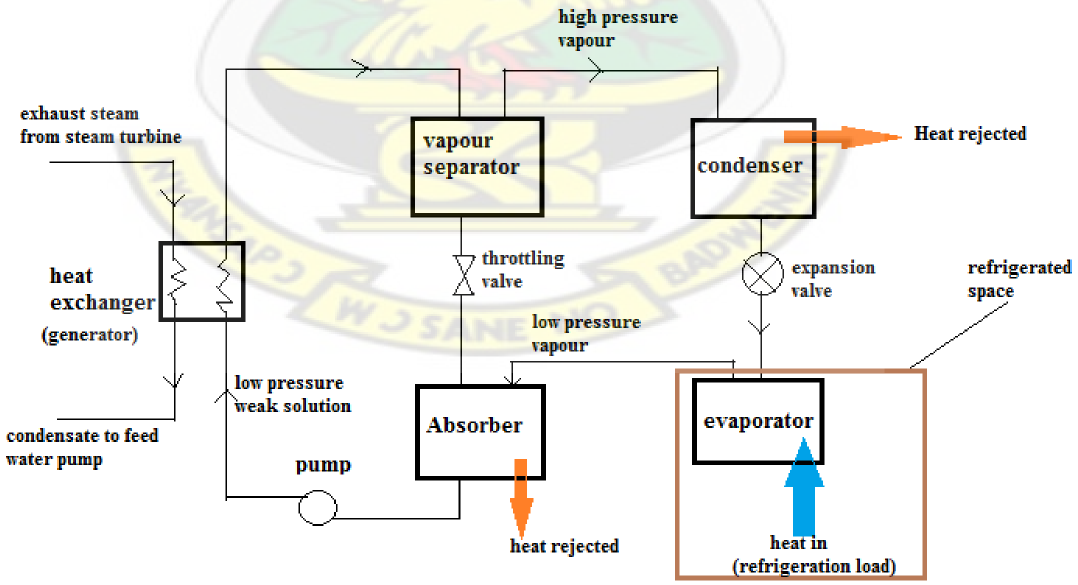

Figure 3. 4: Absorption Refrigeration system to be couple to the thermal plants

3.4 ANALYSIS AND EVALUATION OF CONCEPTS

The concepts were analysed and their performances were compared. The performance indices considered include overall efficiency, electrical efficiency, process heating efficiency, Fuel energy saving ratio (FESR)

- Electrical efficiency

$$\eta_e = \frac{\dot{W}_e}{\dot{H}_f} = \frac{\dot{W}_e}{\dot{m}_f H_u} \tag{3.1}$$

where $\dot{W}_e$ = net electrical power output

$\dot{m}_f$ = mass flow rate of fuel

H_u = lower heating value of fuel

$\dot{H}_f$ = rate of fuel energy supply

- Thermal efficiency

$$\eta_h = \frac{\dot{Q}}{\dot{H}_f} = \frac{\dot{Q}}{\dot{m}_f H_u} \tag{3.2}$$

$where\ \dot{Q} = useful\ thermal\ output\ of\ the\ cogeneration\ sytem$

- Utilisation factor

$$\zeta = \frac{\dot{W}_e + \dot{Q}}{\dot{H}_f} \tag{3.3}$$

It should be noted however that the quality of heat is lower than the quality of electricity, with the quality of heat further dependent on the temperature at which it is made available. For example, the quality of heat in the form of hot water is lower than the quality of heat in the form of steam. Consequently, it may be argued that adding heat and electricity is not very proper, as it appears in equation (3.3). It is true that sometimes a comparison between systems based on the energy efficiency may be misleading. Even though energy efficiencies are most commonly used up to now, a thermodynamically more accurate evaluation and a more fair comparison between systems would be one based on the second law efficiency. Hence, exergy analysis is also performed on the systems in order to obtain the second law efficiencies, the rates of exergy destruction and entropy generation per unit of useful output produced.

- Power to heat ratio

$$\mathrm{PHR} = \frac{\dot{W}_e}{\dot{Q}} \tag{3.4}$$

- Fuel energy saving ratio

$$\mathrm{FESR} = \frac{\dot{H}_{fs} - \dot{H}_{fc}}{\dot{H}_{fs}} \tag{3.5}$$

where $\dot{H}_{fs}$ = total fuel power utilised for separate production

$\dot{H}_{fc}$ = fuel power for cogeneration producing the same $\dot{W}_e$ and $\dot{Q}$

From the energy savings point of view, a cogeneration system will be worthwhile if it has FESR greater than zero as this value represents the percentage reduction in fuel demand attainable by using the cogeneration facility as against separate generation.

By combining equations (3.2), (3.4) and (3.5) we obtain;

$$\zeta = \eta_e \left(1 + \frac{1}{\mathrm{PHR}}\right) \tag{3.7}$$

This can further be rearranged to give;

$$PHR = \frac{\eta_e}{\zeta - \eta_e} \qquad (3.8)$$

For a system with known electrical efficiency, equations (3.6) and (3.7) help in the determination of the acceptable values of the power to heat ratio. It should be mentioned that the power to heat ratio is one of the main characteristics for selecting a cogeneration system for a particular application.

3.5 SITING THE FACILITY

The proposed sites were selected having in mind that the operation of the facility should not disturb the serene atmosphere for academic activities. Siting the facility near the banks of river Wiwi, guarantees the availability of water for running the plant and also minimises the pumping cost of water. Furthermore, the chosen locations are close to the electricity substation on campus as can be seen from figure 3.5 (see Appendix for B).

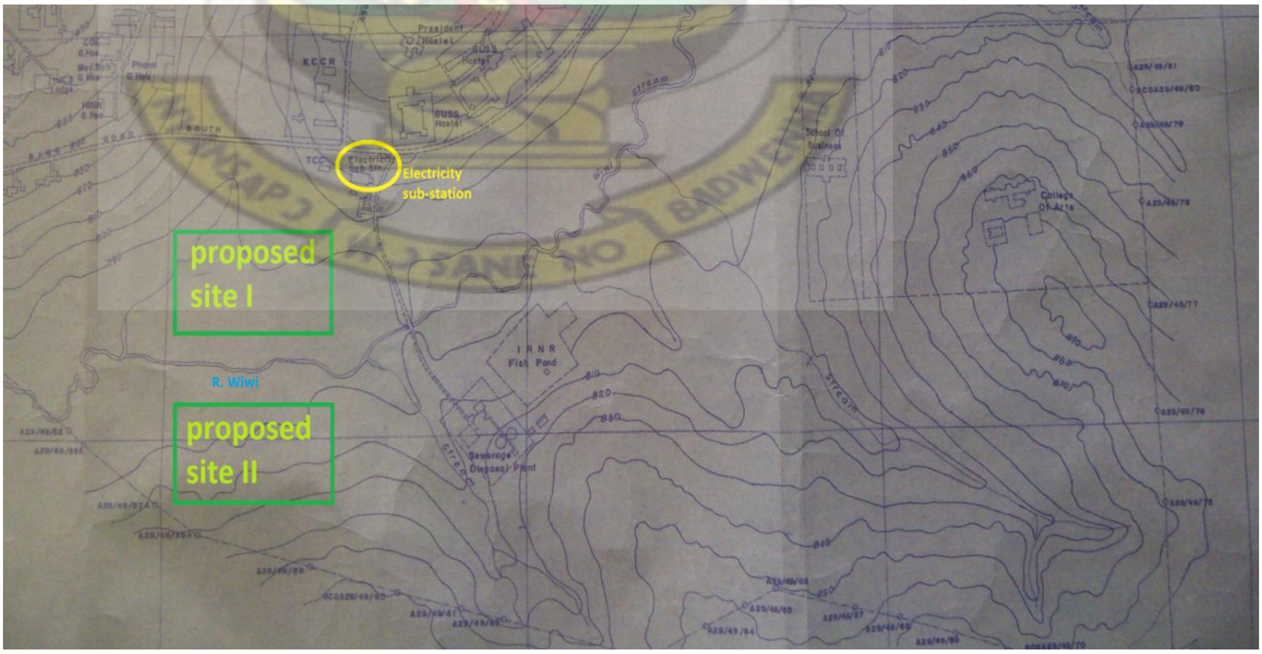

Figure 3. 5: Proposed sites for the plant

CHAPTER FOUR

SIZING, PERFORMANCE AND ECONOMIC ANALYSIS

4.1 PERFORMANCE SIZING OF SYSTEM COMPONENTS

The components of the various concepts were sized by a first law analysis of their thermodynamic cycles as presented in sections 4.11 and 4.12.

4.1.1 CONCEPT *A*

Mode of operation:

Heat supplied from the furnace is absorbed by the working fluid from state 9 to 2, as shown on the T-s diagram in figure 4.1. The superheated steam at 2 is expanded in a steam turbine to state 4 from pressure P_b to P_c. It is desired that at state for the working fluid possess thermal energy at a quality suitable to be used in a process heater, setting a constraint on the interval of expansion. Between state 4 and 5, the working fluid exchanges heat with a coolant. Essentially, this thermal energy extracted is the process heat output from this cogeneration system. The condensate at state 5 is pumped back to the boiler pressure P_b at state 8. The working fluid then enters an economiser section where it is preheated by the flue gases. The electrical generator coupled to the turbine converts the shaft power to electrical power.

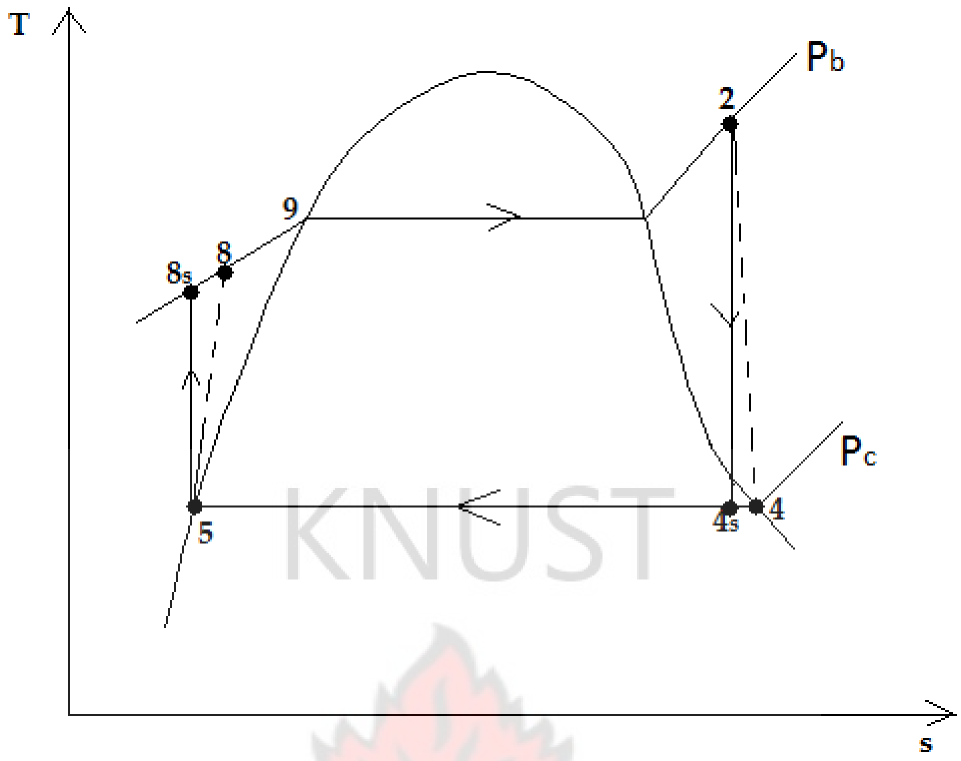

Figure 4. 1: **T-s diagram of concept A**

Assumptions

- The system and all components operate in steady state.
- All heat transfer processes in the steam cycle occur at constant pressures.
- Heat losses through pipes as the working fluid moves from one component to another are negligible.
- The steam turbine and pump processes are adiabatic.
- For all the components, changes in potential energy and kinetic energy are negligible.
- he ambient behaves as a thermal reservoir.

Cycle efficiency:

$$\eta_{cy} = \frac{w_{net}}{q_{in}} = \frac{[h_2 - h_4] - [h_8 - h_5]}{[h_2 - h_8]} \tag{4.1}$$

Electrical generator efficiency:

$$\eta_g = \frac{\text{Electrical power output}}{\text{Shaft power}} = \frac{\dot{W}_e}{\dot{W}_{net}} \tag{4.2}$$

Steam generator efficiency:

$$\eta_{sg} = \frac{\dot{Q}_{cyle}}{\dot{Q}_{fuel}} = \frac{h_2 - h_8}{\dot{m}_f H_u} \tag{4.3}$$

Turbine isentropic efficiency:

$$\eta_T = \frac{h_2 - h_4}{h_2 - h_{4s}} \tag{4.4}$$

$$h_2 = \frac{h_4 - \eta_T h_{4s}}{1 - \eta_T} \tag{4.5}$$

Net cycle work per unit flow through the boiler:

$$\frac{\dot{w}_{net}}{\dot{m}} = [h_2 - h_4] - [h_8 - h_5] \tag{4.6}$$

Pump work:

Process 5-8_s is isentropic;

$$h_{8s} - h_5 = \upsilon_5[P_8 - P_5]$$

$$h_{8s} = h_5 + \upsilon_5[P_8 - P_5] \tag{4.7}$$

Pump efficiency

$$\eta_P = \frac{h_{8s} \quad - h_5}{h_8 - h_5} \tag{4.8a}$$

$$h_8 = h_5 + \frac{h_{8s} - h_5}{\eta_P} \tag{4.8b}$$

- The electrical output $\dot{W}_e$ was set as 6MW.
- The generator efficiency η_g is known from the electrical generator.
- The net cycle power $\dot{W}_{net}$ is calculated from equation (4.2)
- Boiler pressure (P_b) and Condenser (P_c) pressure are known from the proposed steam turbine to be used.
- Since state 5 is a saturated liquid at P_c, $h_5 = h_f$ @ P_c
- $h_4 = h_f + x_4(h_g - h_f)$ (4.9)

  Setting a suitable steam exit quality at state 4 helps to determine h_4
- The pump and turbine efficiencies, η_P and η_T can be obtained from manufacturers or assumed from literature.

- $\dot{W}_{net}/\dot{m}$ is recognised to be proportional to the inverse of specific steam consumption (ssc) which can be set by the designer
- $h_{8s}, h_8, h_2, \eta_{cy}$ can be calculated using equations (4.7), (4.8b), (4.6) and (4.1) respectively.
- The required flow rate through the boiler is calculated using equation (4.6)
- Size of turbine (gross turbine power required)

$$\dot{W}_T = \dot{m}[h_2 - h_4] \tag{4.10}$$

- Size of pump (pump power required)

$$\dot{W}_P = \dot{m}[h_8 - h_5] \tag{4.11}$$

- Rate of heat rejection from steam cycle

$$\dot{Q}_C = \dot{m}[h_4 - h_5] \tag{4.12}$$

- Heat input rate required by cycle

$$\dot{Q}_{cy} = \dot{m}[h_2 - h_8] \tag{4.13}$$

- Heat available for the process heating

$$\dot{Q}_h = \varepsilon \dot{Q}_C = \varepsilon \dot{m}[h_4 - h_5] \tag{4.14}$$

Now,

$$\dot{Q}_h = \varepsilon \dot{m}[h_4 - h_5] = \dot{m}_c[h_{out} - h_{in}] \tag{4.15}$$

With the assumption that the coolant (aqueous ammonia refrigerant) undergoes a constant temperature process

$$\dot{m}_c = \frac{\varepsilon \dot{m}[h_4 - h_5]}{c_p[T_{out} - T_{in}]} \tag{4.16}$$

where ε = heat exchanger effectiveness

$\dot{m}_c$ = mass flow rate of coolant

c_p = specific heat of coolant at constant pressure

T_{out} = temperature of coolant leaving heater

T_{in} = temperature of coolant entering heater

- Fuel Requirements:

  From equation (4.3) the gross heating rate required in the furnace is calculated as

$$\dot{H}_{fc} = \frac{\dot{m}[h_2 - h_8]}{\eta_{sg}} \tag{4.17}$$

With a corresponding fuel supply rate given as

$$\dot{m}_f = \frac{\dot{m}[h_2 - h_8]}{\eta_{sg} H_u} \tag{4.18}$$

- Efficiency of electrical power generation

$$\eta_e = \frac{\dot{W}_e}{\dot{H}_{fc}} = \left(\frac{\dot{W}_e}{\dot{W}_{net}}\right)\left(\frac{\dot{W}_{net}}{\dot{Q}_{cy}}\right)\left(\frac{\dot{Q}_{cy}}{\dot{H}_{fc}}\right) \tag{4.19a}$$

$$\eta_e = \eta_g \eta_{cy} \eta_{sg} \tag{4.19b}$$

- Efficiency of thermal output

$$\eta_h = \frac{\eta_{sg} \varepsilon [h_4 - h_5]}{[h_2 - h_8]} \tag{4.20}$$

- Utilisation factor

$$\zeta = \frac{\dot{Q}_h + \dot{W}_e}{\dot{H}_{fc}} \tag{4.21}$$

Comparison to separate generation of the same $\dot{W}_e$ and $\dot{Q}_h$

- Assuming the same steam generator is used to provide the process heat, the fuel energy required for heating only is given as;

$$\dot{H}_{fh} = \frac{\dot{Q}_h}{\eta_{sg}} \tag{4.22}$$

- Fuel energy required to generate electrical power only

$$\dot{H}_{fe} = \frac{\dot{W}_e}{\eta_{sg}\eta_g\eta_{cy}} \tag{4.23}$$

In equation (4.23), the only efficiency term that might differ from that of the cogeneration system is η_{cy}, because the absence of a thermal output requirement in the case of separate generation of electricity means that P_c can be made lower than in the former.

- Overall efficiency of separate generation

$$\eta_c = \frac{\dot{Q}_h + \dot{W}_e}{\dot{H}_{fc}} \tag{4.24}$$

- Fuel energy saving ratio

$$FESR = \frac{\dot{H}_{fs} - \dot{H}_{fc}}{\dot{H}_{fs}} \tag{4.25}$$

All other things being equal, it will makes technical sense to operate in cogeneration mode if $\zeta > \eta_c$ and $FESR > 0$.

4.1.2 CONCEPT *B*

The operation of concept B is illustrated on the T-s diagram in figure 4.2.

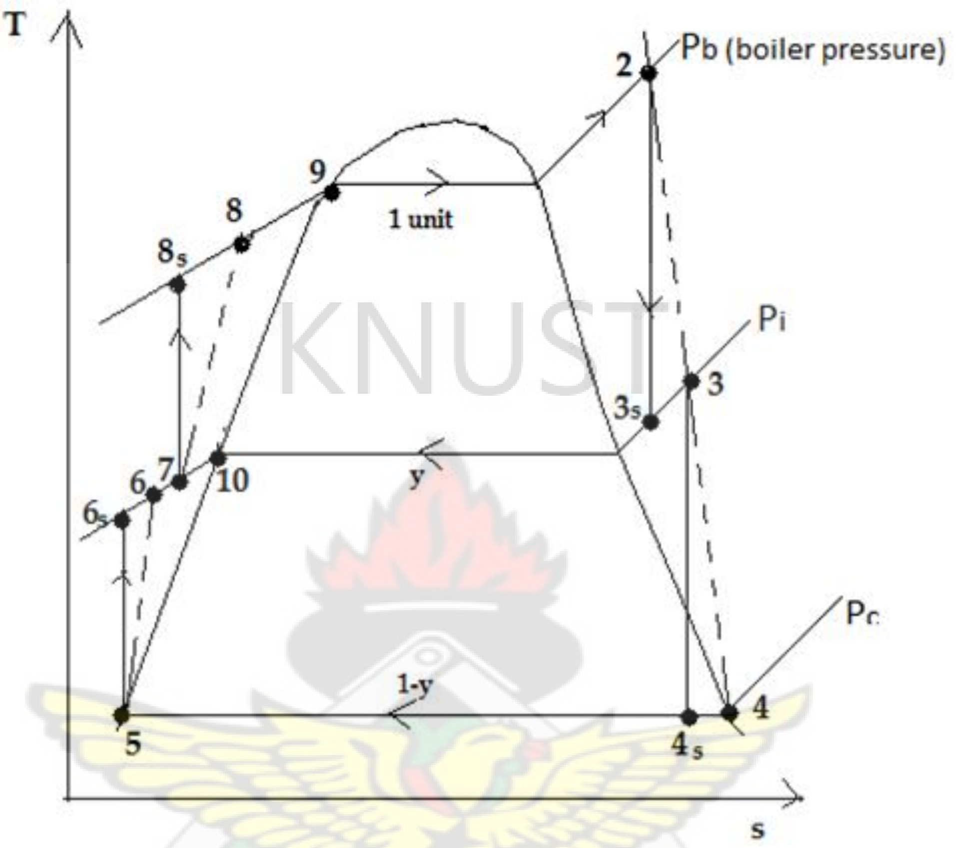

Figure 4. 2: T-s diagram of concept *B*

Based on the same assumptions set forth for Concept ***A*** in section 4.11**,** concept ***B*** was also analysed as follows;

Cycle efficiency

$$\eta_{cy} = \frac{w_{net}}{q_{in}} = \frac{[w_{23} + w_{34}] - [w_{56} + w_{78}]}{q_{82}}$$

$$\eta_{cy} = \frac{w_{net}}{q_{in}} = \frac{[h_2 - h_3] + (1-y)[h_3 - h_5] - (1-y)[h_6 - h_5] - [h_8 - h_7]}{[h_2 - h_8]} \qquad (4.26)$$

Net cycle work per unit flow through the boiler

$$\frac{\dot{W}_{net}}{\dot{m}} = [h_2 - h_3] + (1-y)[h_3 - h_5] - (1-y)[h_6 - h_5] - [h_8 - h_7] \tag{4.27}$$

Turbine isentropic efficiency:

For process 2-3:

$$\eta_T = \frac{h_2 - h_3}{h_2 - h_{3s}} \tag{4.28}$$

For process 3-4

$$\eta_T = \frac{h_2 - h_3}{h_2 - h_{3s}} \tag{4.29}$$

Pump processes

Process 5-6_s is isentropic

$$h_{6s} - h_5 = \upsilon_5[P_6 - P_5]$$

$$h_{6s} = h_5 + \upsilon_5[P_6 - P_5] \tag{4.30}$$

From the definition of pump efficiency

$$\eta_P = \frac{h_{6s} - h_5}{h_6 - h_5} \tag{4.31a}$$

$$h_6 = h_5 + \frac{h_{6s} - h_5}{\eta_P} \tag{4.31b}$$

Process 7-8$_s$:

$$h_{8s} - h_7 = \upsilon_7[P_8 - P_7]$$

$$h_{8s} = h_7 + \upsilon_7[P_8 - P_7] \tag{4.32}$$

$$\eta_P = \frac{h_{8s} - h_7}{h_8 - h_7} \tag{4.33a}$$

$$h_8 = h_7 + \frac{h_{8s} - h_7}{\eta_P} \tag{4.33b}$$

- Rate of heat rejection from steam cycle

$$\dot{Q}_C = \dot{m}\{[h_3 - h_{10}] + (1 - y)[h_4 - h_5]\} \tag{4.34}$$

- Heat available for process heating

$$\dot{Q}_h = \varepsilon\dot{m}\{[h_3 - h_{10}] + (1 - y)[h_4 - h_5]\} \tag{4.35}$$

- The electrical output

$$\dot{W}_e = \dot{m}\eta_g\{[h_2 - h_3] + (1 - y)[h_3 - h_4] - (1 - y)[h_6 - h_5] - [h_8 - h_7]\} \tag{4.36}$$

- Power to heat ratio

$$PHR = \frac{\dot{W}_e}{\dot{Q}_h} = \frac{\eta_g\{[h_2 - h_3] + (1 - y)[h_3 - h_4] - (1 - y)[h_6 - h_5] - [h_8 - h_7]\}}{\varepsilon\{[h_3 - h_{10}] + (1 - y)[h_4 - h_5]\}} \tag{4.37}$$

- Size of turbine (gross turbine power required)

$$\dot{W}_T = \dot{m}\{[h_2 - h_3] + (1 - y)[h_3 - h_5]\} \tag{4.38}$$

- Size of pump (pump power required)

  Feed pump one: $\dot{W}_{P1} = \dot{m}\{(1 - y)[h_6 - h_5]\}$ (4.39)

  Feed pump two: $\dot{W}_{P2} = \dot{m}[h_8 - h_7]$ (4.40)

- Heat input rate required by cycle

  $\dot{Q}_{cy} = \dot{m}[h_2 - h_8]$ (4.41)

Equations (4.17) through to (4.23) for concept ***A*** also apply for concept ***B***.

The equations developed in sections 4.11 and 4.12 for Concepts ***A*** and ***B*** respectively were executed with Microsoft® Excel worksheets. The detailed results can be found at Appendix A. A summary of the results is presented in Chapter 5 for discussion.

4.2 EXERGY ANALYSIS

Exergy represents the theoretical maximum amount of work that can be derived from a system when it is brought into thermodynamic equilibrium with its surroundings [Jϕrgensen, 2000]. In order to specify exergy as a property of any given system, a reference state has to be specified for the surrounding (also known as dead state) [Çengel et al, 2006]. It is often convenient to use it on a unit mass basis; thus specific exergy is defined as the exergy per unit mass of the system. It consists of both thermo-mechanical (which depends on its thermodynamic state) and chemical exergy if there is the potential for a chemical change to occur.

An extended control volume around system *A*, indicating the flux of exergy across the control volume is shown in Figure 4.3.

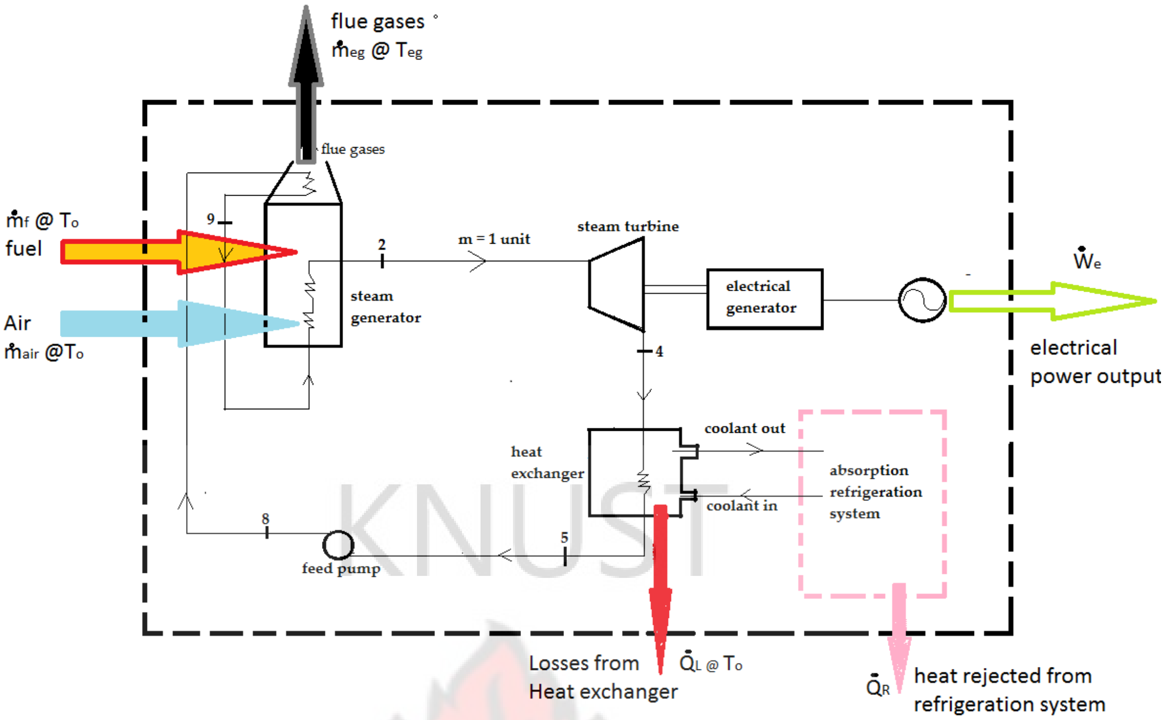

Figure 4. 3: Extended control volume of system *A*

System ***A*** was analysed as follows;

Invoking the exergy balance equation for the extended control volume:

$$\sum \text{exergy flux in} - \sum \text{exergy flux out} - \begin{pmatrix}\text{Rate of exergy}\\ \text{destruction}\end{pmatrix} = \begin{pmatrix}\text{Rate of exergy}\\ \text{change}\end{pmatrix}_{\substack{\text{control}\\ \text{volume}}}$$

$$\dot{m}_{air}\psi_{air} + \dot{m}_{fuel}\psi_{fuel} - \dot{m}_{eg}\psi_{eg} - \dot{Q}_L\left(1 - \frac{T_o}{T_o}\right) - \dot{Q}_R\left(1 - \frac{T_o}{T_o}\right) - \dot{W}_e - \dot{X}_{des} = \left(\frac{\Delta X}{\Delta t}\right)_{cv}$$

(4.42)

Where ψ represents the specific exergy carried by the respective masses.

Since the system operates in steady state $\left(\frac{\Delta X}{\Delta t}\right)_{cv} = 0$

Additionally, the exergy flux due to the heat leaving the control volume in the equation (4.42) go to zero because they are both rejected at ambient temperature to the surroundings. Thus the rate of exergy destruction associated with the plant is given obtained as;

$$\dot{X}_{des} = \dot{m}_{air}\psi_{air} + \dot{m}_{fuel}\psi_{fuel} - \dot{m}_{eg}\psi_{eg} - \dot{W}_e \quad (4.43)$$

$$\dot{X}_{des} = \dot{m}_{air}\{(h - h_o) - T_o(s - s_o)\}_{air} + \dot{m}_{fuel}\{(h - h_o) - T_o(s - s_o)\}_{fuel} - \dot{m}_{eg}\{(h - h_o) - T_o(s - s_o)\}_{eg} - \dot{W}_e$$
(4.44)

If the air enters the system at ambient conditions as in the proposed case, then its specific exergy relative to the surroundings is zero as $(h - h_o)$ and $(s - s_o)$ will both be zero.

The rate of exergy destruction also represents the rate of lost work and it is related to the rate of entropy generation rate as;

$$\dot{S}_{gen} = \dot{X}_{des}/T_o \quad (4.45)$$

Second law efficiency:

$$\eta_{II} = \frac{\text{exergy leaving}}{\text{exergy entering}}$$

$$\eta_{II} = \frac{\dot{m}_{eg}\psi_{eg} + \dot{W}_e}{\dot{m}_{air}\psi_{air} + \dot{m}_{fuel}\psi_{fuel}}$$

$$\eta_{II} = \frac{\dot{m}_{eg}\{(h - h_o) - T_o(s - s_o)\}_{eg} + \dot{W}_e}{\dot{m}_{air}\{(h - h_o) - T_o(s - s_o)\}_{air} + \dot{m}_{fuel}\{(h - h_o) - T_o(s - s_o)\}_{fuel}} \quad (4.46)$$

From the exergy model for concept ***B*** as shown in figure 4.4, it is observed that it interacts in the same qualitative manner as Concept ***A***. Thus equations 4.43 through to 4.46 also hold for Concept ***B***.

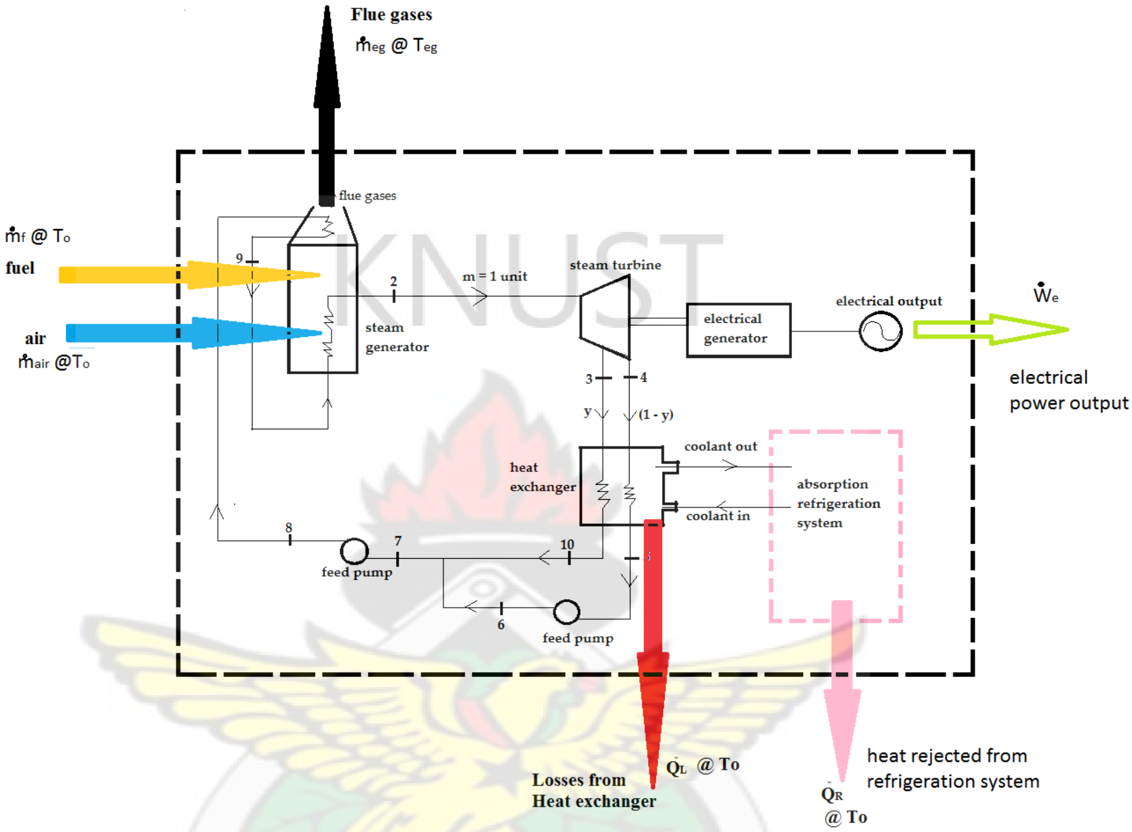

Figure 4. 4: Extended control volume of Concept B

4.3 ECONOMIC ANALYSIS AND GREENHOUSE GAS SAVINGS

Both the economic and emission analyses were obtained with the aid of the RETScreen® software. The results obtained from the sizing analysis, together with other economic and empirical indices were entered into the RETScreen® spread sheet platform (see Appendix C). A summary of the results as retrieved from the RETScreen® application is presented and discussed in Chapter 5.

In any investment project, cost is usually a monetary valuation of effort, material, resources, time and utilities consumed, risks incurred, and opportunity forgone in production and delivery of a good or service (Business Dictionary, 2012). In the implementation of the project under consideration, the costs can be broken down into initial (or capital) cost and operating (or annual) cost.

The initial cost represents the initial investment or money used to start the project. The money is used to cover such start-up costs as purchasing building, purchasing equipment and supplies, and hiring employees all form part of the initial costs. The funds, or capital, may come from a bank loan, a government grant, outside investors, or the business owner's personal savings. The operating cost can be quantified as the cost per unit of a product or service, or the annual cost incurred on a continuous basis. It involves as maintenance, labour and cost of inputs such as fuel. Operating costs do not include capital outlays or the costs incurred in design and implementation phases of a new process.

One useful indicator of the feasibility of an energy project is the cost per unit of energy generated usually presented as cost/kWh. This cost build up has components from both the initial and annual costs and its instantaneous value depends on the prevailing macroeconomic environment as well as cost of inputs. However, for the sake of evaluation, the levelised generation cost can be defined on the premise that the requisite economic indicators remain the same over the period within which the plant will be operational

The levelised generation cost was calculated as

$$\mathrm{LGC} = \frac{\left(\text{initial cost}/\text{project life}\right)+\text{total annual cost}}{\text{Annual energy supplied}} \qquad (4.47)$$

CHAPTER FIVE

RESULTS AND DISCUSSION

5.1 PERFORMANCE AND SIZING

Both systems ***A*** and ***B*** were designed to meet an electrical output requirement of 6MWe. For a plant that is available 85% of the time, each plant is expected to generate 42394 MWh of electricity annually. The slightly varying configurations of the two plants resulted in different thermal energy outputs, efficiencies, among others as shown in Table 4.1. Concept ***B*** which has an extraction condensing type steam turbine was designed to have a maximum extraction of 15%. Thus, results of the analysis are presented for both zero extraction and maximum extraction.

Both systems were observed to have a similar performance in terms of energy efficiencies, with Concept ***B*** performing slightly better than Concept ***A***. For instance, it can be seen from Table 4.1 that a gross energy of 29.44 MW is required by Concept ***A***, whilst Concept ***B*** requires 26.13 MW at no extraction to provide the same power output (representing a difference of about 3MW). The quantity of biomass (with a heating value of approximately 15 MJ/kg) required per day is 141 tonnes and 133 tonnes respectively for Concepts ***A*** and ***B***.

Additionally, Concept ***B*** has a relatively high power to heat ratio (PHR), which can also be varied between 0.4 and 0.44 by adjusting the turbine bypass ratio. On the other hand, Concept ***A*** has a fixed PHR of 0.38 implying no flexibility in electricity to thermal load matching.

Comparing Concepts ***A*** and ***B*** to a system that separately generates the same respective amounts of electricity and thermal outputs, it is observed that fuel energy savings of 20% and 24% can be achieved respectively using the cogeneration plants. These resulting energy savings translated into higher overall efficiencies than the combined efficiency for separate generation. A sankey diagram illustrating the energy savings achieved by Concept ***B*** is shown in Figure 5.1.

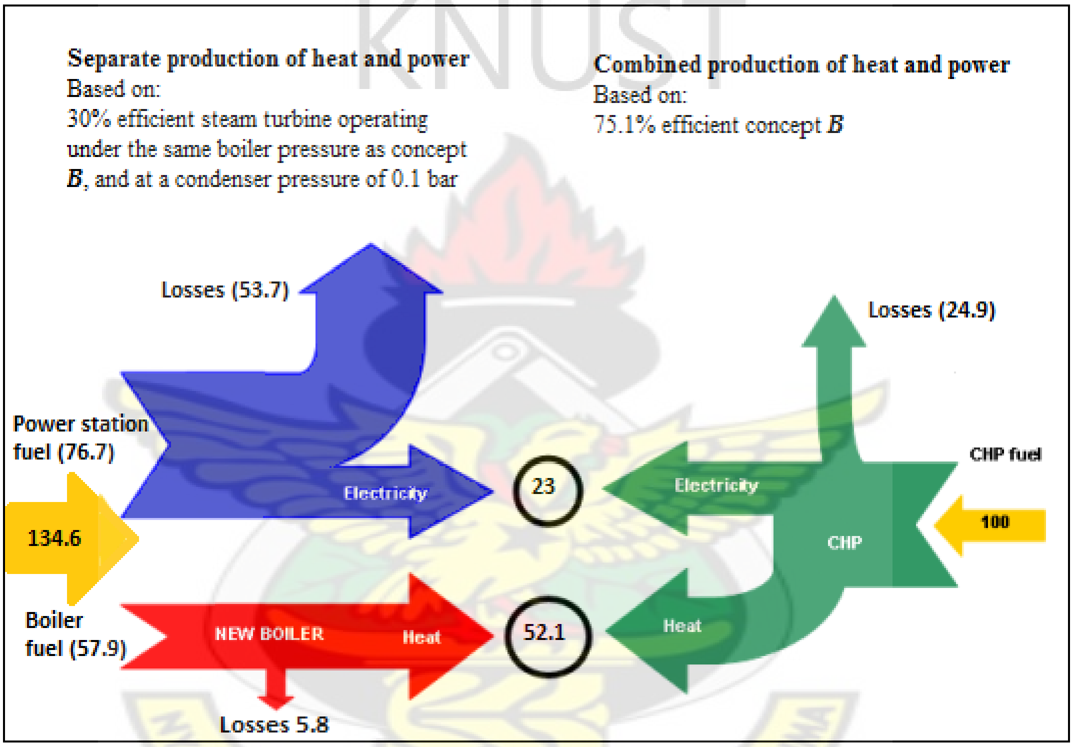

Figure 5. 1: Sankey diagram showing 24% energy savings by using the CHP of concept *B*

The results of the exergy analysis show second law efficiencies of 47%, 49%, and 51% respectively for systems ***A***, ***B*** at full extraction and ***B*** at no extraction. These values give an indication of the extent to which the available potential of the exergy supplied is utilised to provide useful outputs. The rather low second law efficiencies of the systems is due to the fact that they are also producing thermal output in addition to the electrical loads, knowing that heat has a lower quality than work.

With regards to entropy generation and exergy destruction, Concept ***B*** performs better. For every kW of useful power generated using system ***A*,** 0.49 kW of exergy is destroyed alongside, whilst ***B*** destroys 0.45 kW of exergy for the same output. It is worth stating that since energy in itself cannot be destroyed, this exergy destruction represents the amount of energy that has been degraded or rendered useless by the system.

A cursory glance through Tables 5.1 and 5.2, reveal that the lower energy efficiencies of Concept ***A*** resulted in lower second law efficiency and were carried through to give high rates of exergy destruction and entropy generation, whilst Concept ***B*** performed better at all those levels. Thus, it can be deduced that exergy analysis provides a potent tool for assessing power plants because any of the exergetic measures of a system's performance carry an implied indication of the overall system's performance.

Table 5. 1: Results of sizing analysis of the concepts

	Concept	A	B (y=0.15)	B (y=0)	
Quantity	**Symbol**	**Value**	**Value**	**Value**	**Units**
electrical power output	$\dot{W}_e$	6	6	6	MW
specific enthalpy at 8	h_8	515.05	491.15	427.8	kJ/kg
return temp	T_8	121.4	115.7	100.6	^oC
specific steam consumption	ssc	5.50	5.14	4.73	kg/kWh
steam flow rate	$\dot{m}$	10.19	9.53	8.76	kg/s
		36.67	34.30	31.55	tons/hr
steam inlet temperature	T_2	440	440	440	^oC
Heat input required by cycle	$\dot{Q}_{cycle}$	27.97	26.39	24.83	MW
gross turbine power	$\dot{W}_t$	6.77	6.76	6.76	MW
Pumping power	$\dot{W}_p$	105	97	90	kW
Available process heat	$\dot{Q}_h$	15.98	14.79	13.62	MW
Fuel Requirement and efficiencies					
Fuel energy required	$\dot{H}_{fc}$	29.44	27.78	26.13	MW
Flow rate of fuel required	$\dot{m}_{fuel}$	1.64	1.54	1.45	kg/s
		141.3	133.3	125.4	tonnes/day
thermal cycle efficiency	η_{cy}	23.84	25.26	26.85	%
efficiency of electrical power generation	η_e	20.38	21.6	22.96	%
efficiency of thermal output	η_e	54.27	53.25	52.11	%
Utilisation factor	ζ	74.65	74.85	75.08	%
power to heat ratio	PHR	0.376	0.406	0.441	
Comparing to separate production of electricity and thermal energy					
Total fuel energy required for separate production	H_{fs}	36.82	35.57	34.34	MW
combined efficiency of separate generation	η_{co}	59.69	58.45	57.14	%
Fuel energy saving ratio	FESR	0.20	0.22	0.24	

Table 5. 2: Results of exergy analysis

Exergy Analysis					
	Concept	**A**	**B (y=0.15)**	**B (y=0)**	
Rate of exergy destruction	$\dot{X}_{des}$	10.71	9.77	8.83	MJ/s
Rate of entropy generation	$\dot{S}_{gen}$	36	33	30	kJ/s.K
Rate of exergy into system	$\dot{X}_{in}$	20147.1	19010.2	17883.4	kJ/s
Rate of exergy out of system	$\dot{X}_{out}$	9438.3	9244.3	9052.0	kJ/s
second law efficiency	η_{II}	46.85	48.63	50.61	%
Entropy generation per unit output	$\dot{S}_{gen}/\text{kW}$	0.001635	0.001576	0.001511	/K
Exergy destruction kW of useful power	$\dot{X}_{des}/\text{kW}$	0.49	0.47	0.45	kW/kW

5.2 FINANCIAL ANALYSIS

As shown in tables 5.3 and 5.4, Concept ***A*** has a total initial cost of 10.7 million US$ and an annual cost of 3.04 million US$. For a project life of 24 years, this represents a levelised generation cost of US$ 0.08219/kWh. It has an equity payback period of 2.9 years and a net present value of 37.8 million US$. Figure 5.1 shows the cumulative cash flow over the entire project life for Concept ***A***.

Concept ***B*** has a total initial cost of 11.2 million US$ and an annual cost of 2.96 million US$, as shown in table 5.5 and 5.6. For a project life of 24 years, this represents a levelised generation cost of US$ 0.08079/kWh. It has an equity payback period of 2.8 years and a net present value of 39.7 million US$. Figure 5.2 shows the cumulative cash flow over the entire project life of Concept ***B***.

The results of the economic analysis suggests that it would be more profitable to operate Concept ***B,*** because even though it has a higher initial cost, it has a lesser annual cost – hence making it cheaper to operate and accruing a grater net present value.

Table 5. 3: Project cost savings/ income summary for Concept *A*

Project costs and savings/income summary			
Initial costs			
Feasibility study	0.4%	$	40,000
Development	0.0%	$	0
Engineering	9.4%	$	1,000,000
Power system	72.4%	$	7,706,672
Heating system	0.0%	$	0
Cooling system	0.0%	$	0
Balance of system & misc.	17.8%	$	1,896,694
Total initial costs	**100.0%**	**$**	**10,643,365**
Incentives and grants		$	0
Annual costs and debt payments			
O&M		$	1,050,000
Fuel cost - proposed case		$	1,990,079
Debt payments - 0 yrs		$	0
Total annual costs		**$**	**3,040,079**
		$	0
End of project life – cost		$	0
Annual savings and income			
Fuel cost - base case		$	6,843,954
CE production income - yrs		$	0
Total annual savings and income		**$**	**6,843,954**

Table 5. 4: Financial viability summary for Concept *A*

Financial viability		
Equity payback	Yr	2.8
Net Present Value (NPV)	$	37,759,408
Annual life cycle savings	$/yr	1,573,309
Benefit-Cost (B-C) ratio		4.55
Debt service coverage		No debt

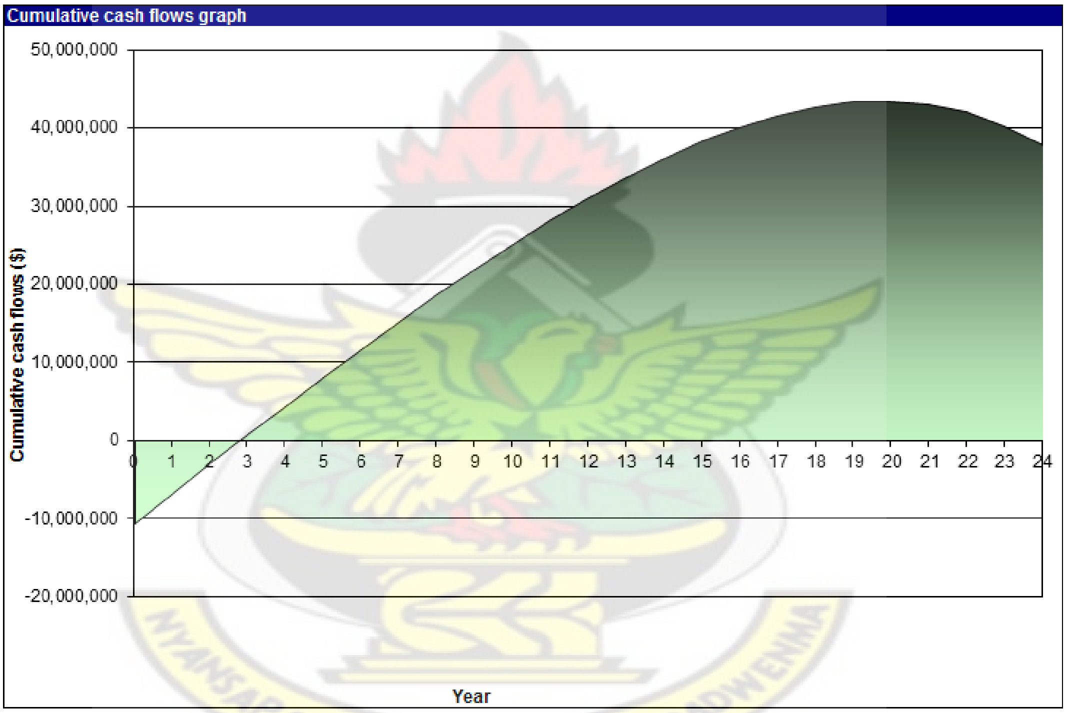

Figure 5. 2: Cumulative cash flow graph for Concept *A*

Table 5. 5: Project cost savings/ income summary for Concept *B*

Project costs and savings/income summary			
Initial costs			
Feasibility study	0.4%	$	40,000
Development	0.0%	$	0
Engineering	10.7%	$	1,200,000
Power system	71.6%	$	8,023,042
Heating system	0.0%	$	0
Balance of system & misc.	17.3%	$	1,944,200
Total initial costs	**100.0%**	**$**	**11,207,242**
Annual costs and debt payments			
O&M		$	1,050,000
Fuel cost - proposed case		$	1,908,270
Debt payments - 20 yrs		$	0
Total annual costs		**$**	**2,958,270**
End of project life – cost		$	0
Annual savings and income			
Fuel cost - base case		$	6,843,954
Electricity export income		$	0
Total annual savings and income		**$**	**6,843,954**

Table 5. 6: Financial viability summary for Concept *B*

Financial viability		
Equity payback	Yr	2.9
Net Present Value (NPV)	$	39,734,088
Annual life cycle savings	$/yr	1,655,587
Benefit-Cost (B-C) ratio		4.55

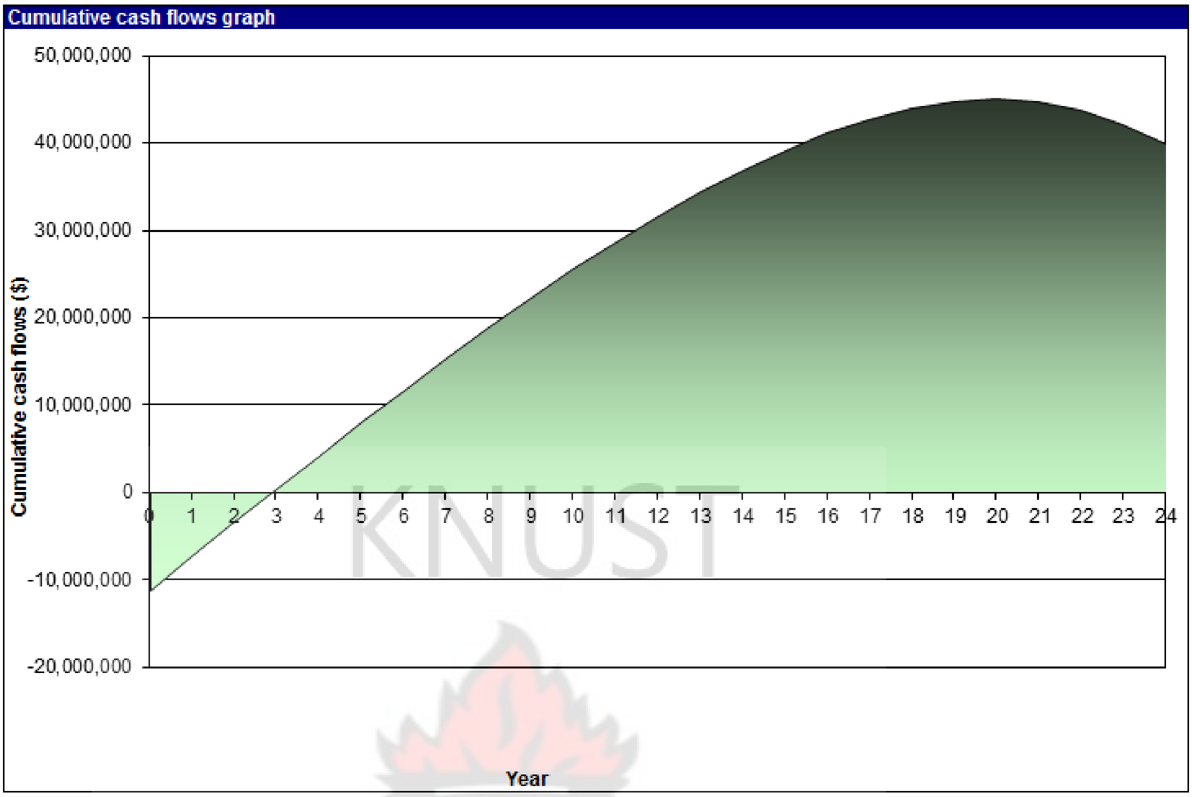

Figure 5. 3: cumulative cash flow for Concept *B*

5.3 GREEN HOUSE GAS (GHG) SAVINGS

The greenhouse gas emission reduction summary as presented in Tables 5.7 and 5.8 , shows a net annual reduction equivalent to16, 947 tons of CO_2 for Concept ***A*** (representing 3104 cars and light truck not used), whilst Concept ***B*** has 17,022 tons (representing 3118 cars and light trucks not used) . This emission reduction as obtained from the RETScreen® software is based on a global average GHG displacement. For Ghana, the GHG emission displacement factor is 0.56 tonnes/MWh (Ghana Energy, 2009). For an annual energy generation of 42394 MWh, this gives a corresponding emissions reduction of 23740 tonnes of GHG's per annum for the selected Concept B.

Table 5. 7: Emission reduction summary for Concept *A*

GHG emission reduction summary					
	Base case GHG emission tCO2	Proposed case GHG emission tCO2		Gross annual GHG emission reduction tCO2	Net annual GHG emission reduction tCO2
Power project	19,317.5	2,370.8		16,946.7	16,946.7
Net annual GHG emission reduction	16,947	tCO2	equivalent	3,104	Cars & light trucks not used

Table 5. 8: Emission reduction summary for Concept *B*

GHG emission reduction summary					
	Base case GHG emission tCO2	Proposed case GHG emission tCO2		Gross annual GHG emission reduction tCO2	Net annual GHG emission reduction tCO2
Power project	19,317.5	2,295.7		17,021.8	17,021.8
Net annual GHG emission reduction	17,022	tCO2	equivalent	3,118	Cars & light trucks not used

CHAPTER SIX

CONCLUSIONS AND RECOMMENDATIONS

The proposed system is concept B, with the following specifications:

- Fuel: Biomass at 133 tons/day
- Steam generator: 35 metric tonnes/ hr CFBC boiler
- Turbine: 7MW two stage extraction steam turbine
- Net Electric power: 6MW
- Thermal power: 13.6 to 14.8 MW
- Electrical efficiency: 23%
- Utilisation factor: 75%
- Second law efficiency: 50.6%
- Annual emissions reduction: 23740 tCO_2 (ie 4354 cars not used)
- Initial cost: US$ 11.21 million
- Levelised generation cost: 8.079 US cents/kWh

Since biomass has low heating values, large amounts are required for the purpose of power generation. For instance, 133 metric tonnes/day of biomass is required to generate 6MWe using the proposed system. Thus, in order to meet the high fuel requirements, the unhindered operation of any biomass-based generation facility will require the collaboration of a competent waste management organisation. In that way the power station serves a dual purpose; energy generation and incineration of waste.

Urban/ domestic waste presents a good potential for the purpose of energy generation. Data received from the Waste Management Division of the Kumasi Metropolitan Assembly indicates that an average of 1000 tons of solid waste is collected daily within the metropolis representing approximately 23MWe of generation capacity based on the performance of the proposed concept. The only issue that requires attention is that the collected wastes always have non-biomass materials like glasses, metal scraps and stones commingled with them – which would impose an additional cost of separation. Thus in order to use the collected waste in thermal plants, provision has to be made for urban waste to be collected separately, combustibles from incombustibles.

A second law assessment of thermal systems gives diverse ways of quantifying the performance of the system, such as the second law efficiency, rates of exergy destruction, and entropy generation. They are all complimentary as they say virtually the same things in slightly different representations. As was observed from the results, these exergetic measures of performance have a direct dependence on the extent of irreversibilities in the system. These irreversibilities will ultimately reflect in the total cost/profit build up as well as environmental degradation. For instance, adiabatic efficiency losses in the turbine means lost enthalpy, requiring more heating to make up, and friction related irreversibilities increase the rates of wear and tear in addition to increasing the fuel cost.

For further study, an investigation into the prospects of an absorption refrigeration system to be used in conjunction with the proposed power plant is recommended.

Additionally, it is recommended that provision be made by waste management organisations for combustible wastes to be collected separately from scraps and metals in order to be used in power generation. The enormous generation capacity presented by the vast amounts of municipal and urban waste might even pass to enjoy the economies of scale of integrated biomass gasification (IBGCC) generation facility, making it even more efficient and cheaper to operate. This ultimately leads to a long lasting sustainable solution to the national energy situation, as well as helping in the management of solid waste. This is an option that requires further study to determine the economic and technical feasibility of a biomass generation facility which doubles as an incineration facility and the production of electrical energy.

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APPENDICES

APPENDIX A: RESULTS OF SIZING AND PERFORMANCE ANALYSIS

Table A. 1: Concept A

Quantity	Symbol	Value	Units	Remarks
Electrical power	$\dot{W}_e$	6000	kW	
generator efficiency	η_e	0.9		
Net cycle power	$\dot{W}_{net}$	6666.667	kW	
boiler pressure	P_b	8000	kPa	
turbine exhaust pressure	P_c	200	kPa	
quality at turbine exhaust	x_4	0.95		
hg @pc	h_g	2706.23	kJ/kg	
hf@pc	h_f	504.71	kJ/kg	
vf@pc	v_f	0.001061	m3/kg	
specific enthalpy at 4	h_4	2596.154	kJ/kg	
turbine efficiency	η_T	0.85		
pump efficiency	η_p	0.8		
specific enthalpy at 8s	h_{8s}	512.9819	kJ/kg	
specific enthalpy at 8	h_8	515.0499	kJ/kg	
return temp	T_8	121.4	^oC	
specific steam consumption	ssc	5.5	kg/kWh	
net power per unit flow rate	W_{netcy}	654.5455	kJ/kg	
steam flow rate	$\dot{m}$	10.18519	kg/s	
specific enthalpy at 2		3261.039	kJ/kg	
steam inlet temperature	T_2	445	^oC	read@h2, and Pb
gross turbine power	$\dot{W}_T$	6771.98	kW	
pump power	$\dot{W}_P$	105.3135	kW	
Heat rejected from cycle	$\dot{Q}_c$	21301.74	kW	
Heat input required by cycle	$\dot{Q}_{cycle}$	27968.41	kW	
Effectiveness	ε	0.75		
Available process heat	$\dot{Q}_h$	15976.31	kW	
cycle efficiency	η_{cy}	0.238364		
work ratio	r_w	0.984449		
steam generator efficiency	η_{sg}	0.95		
gross heating rate	$\dot{H}_{fc}$	29440.43	kW	

Lower heating value of fuel	$\dot{H}_u$	18000	kJ/kg	Variable
fuel flow rate	$\dot{m}_{fuel}$	1.63558	kg/s	141.3141
efficiency of electrical power generation	η_e	0.203801		
efficiency of thermal output	η_h	0.542666		
utilization factor	ζ	0.746467		
power to heat ratio	PHR	0.375556		
Comparing to separate production of electricity and thermal energy				
Fuel energy required for heating only	$\dot{H}_{fh}$	16817.17		
Fuel energy required for electrical power only	$\dot{H}_{fe}$	20000.00		
Fuel energy required to separately generate both	$\dot{H}_{fs}$	36817.17		
Utilisation factor	η_c	0.5969		
Fuel energy saving ratio	FESR	0.2000		
Exergy Analysis				
Ambient temperature	T_o	298	K	
Air fuel ratio	AFR	1.3		
mass flow rate of air	$\dot{m}_a$	2.126253	kg/s	
flow rate of flue gases	$\dot{m}_{eg}$	3.761833	kg/s	
specific enthalpy of inlet air	$h_a" < h - h_o > "$	0	kJ/kg	
specific entropy of inlet air	$s_a" < s - s_o > "$	0	kJ/kg.K	
specific enthalpy of fuel	$h_{fuel}" < h - h_o > "$	15000	kJ/kg	
specific entropy of fuel	$s_{fuel}" < s - s_o > "$	9	kJ/kg.K	
specific enthalpy of flue gases	$h_{eg}" < h - h_o > "$	3000	kJ/kg	
specific entropy of flue gases	$s_{eg}" < s - s_o > "$	7	kJ/kg.K	
Rate of exergy destruction	$\dot{X}_{des}$	10708.75	KJ/s	
Rate of entropy generation	$\dot{S}_{gen}$	35.93542	kJ/s.K	
Rate of exergy into system	$\dot{X}_{in}$	20147.07	kJ/s	
Rate of exergy out of system	$\dot{X}_{out}$	9438.315	kJ/s	
second law efficiency	η_{II}	0.468471		
Entropy generation per unit output	$\dot{S}_{gen}/kW$	0.001635	/K	
Exergy destruction kW of useful power	$\dot{X}_{des}$	0.487286	kW/kW	

Table A. 2:Concept B

		At maximum extraction	At no extraction		
Quantity	Symbol	Value	Value	Units	
Electrical power	$\dot{W}_e$	6000	6000	kW	
generator efficiency	η_g	0.9	0.9		
Net cycle power	$\dot{W}_{net}$	6666.667	6666.667	kW	
boiler pressure	P_b	8000	8000	kPa	
turbine exhaust pressure	P_c	100	100	kPa	
Saturation temperature at boiler pressure	T_{bsat}	295	295	^oC	
saturation temperature at 2nd stage turbine exit pressure	T_{csat}	99.6	99.6	^oC	
saturation temperature at 1st stage turbine exit pressure	T_{isat}	197.3	197.3	^oC	
Saturation pressure corresponding to 1st stage turbine exit	P_{isat}	1475	1475	kPa	read@Tisat
bypass ratio	y	0.15	0		
-	h_5	417.504	417.504	kJ/kg	hf@pc
-	h_{10}	840.977	840.977	kJ/kg	hf@pi
-	v_5	0.001043	0.001043	m^3/kg	vf@pc
-	v_{10}	0.001153	0.001153	m^3/kg	vf@pi
-	h_{6s}	418.9383	418.9383	kJ/kg	
-	h_6	419.2969	419.2969	kJ/kg	
-	T_6	99.8	99.8	^oC	read@h6 and pi
-	T_2	445	445	^oC	
-	h_2	3261	3261	kJ/kg	
-	s_2	6.54075	6.54075	kJ/kg.K	read@T2,h2
-	s_{3s}	6.54075	6.54075	kJ/kg.K	
-	h_{3s}	2834.36	2834.36	kJ/kg	read@s3s and pi
-	h_3	2898.356	2898.356	kJ/kg	
-	s_3	6.6689	6.6689	kJ/kg.K	read@h3,pi
-	s_{4s}	6.6689	6.6689	kJ/kg.K	
-	h_{4s}	2417.8	2417.8	kJ/kg	read@s4s,pc
-	h_4	2489.883	2489.883	kJ/kg	
steam quality at 4	x_4	0.91	0.91		
-	h_7	482.5489	419.2969		
-	T_7	114.8	99.8	^oC	read@h7,pi
-	v_7	0.001055	0.001043	m^3/kg	

-	h_{8s}	489.4328	426.1025		
-	h_8	491.1538	427.8039		
Return temperature	T_8	115.7	100.6		read@h8,Pb
turbine efficiency	η_T	0.85	0.85		
pump efficiency	η_P	0.8	0.8		
specific steam consumption	ssc	5.144938	4.731757	kg/kWh	
net power per unit flow rate	$\dot{W}_{netcy}$	699.7169	760.8167	kJ/kg	
steam flow rate	$\dot{m}$	9.527663	8.762513	kg/s	
steam cycle efficiency	η_{cy}	0.252619	0.268537		
work ratio	r_w	0.887158	0.887979		
high pressure turbine output	$\dot{W}_{T1}$	3455.15	3177.673	kW	
low pressure turbine output	$\dot{W}_{T2}$	3308.021	3579.247	kW	
gross turbine power	$\dot{W}_T$	6763.171	6756.92	kW	
lp_pump power	$\dot{W}_{P1}$	14.51994	15.71043	kW	
hp pump power	W_{P2}	81.98405	74.54243	kW	
Gross pump power	$\dot{W}_P$	96.50399	90.25286	kW	
Heat rejected from cycle	$\dot{Q}_c$	19723.49	18159.25	kW	
Heat input required by cycle	$\dot{Q}_{cycle}$	26390.16	24825.92	kW	
Effectiveness	ε	0.75	0.75		
Available process heat	$\dot{Q}_h$	14792.62	13619.44	kW	
steam generator efficiency	η_{sg}	0.95	0.95		
gross heating rate	$\dot{H}_{fc}$	27779.12	26132.55	kW	
Lower heating value of fuel	H_u	18000	18000	kJ/kg	
required fuel flow rated	$\dot{m}_{fuel}$	1.543284	1.451808	kg/s	
efficiency of electrical power generation	η_e	0.21599	0.229599		
efficiency of thermal output	η_h	0.532509	0.521168		
Utilisation factor	ζ	0.748498	0.750766		
power to heat ratio	PHR	0.405608	0.440547		
Comparing to separate production of electricity and thermal energy					
Fuel energy required for heating only	$\dot{H}_{fh}$	15571.18	14336.25	kW	
Fuel energy required for electrical power only	$\dot{H}_{fe}$	20000.00	2000.00	kW	

Fuel energy required to separately generate both	$\dot{H}_{fs}$	36260.8	34336.25	kW	
combined efficiency of separate generation	η_{co}	0.5784	0.5713		
Fuel energy saving ratio	FESR	0.2191	0.2389		
Exergy Analysis					
Ambient temperature	T_o	298	298	K	
Air fuel ratio	AFR	1.3	1.3		
mass flow rate of air	$\dot{m}_a$	2.00627	1.887351	kg/s	
flow rate of flue gases	$\dot{m}_{eg}$	3.549554	3.339159	kg/s	
specific enthalpy of inlet air	h_a"<h-h_o>"	0	0	kJ/kg	
specific entropy of inlet air	s_a"<s-s_o>"	0	0	kJ/kg.K	
specific enthalpy of fuel	h_{fuel}"<h-h_o>"	15000	15000	kJ/kg	
specific entropy of fuel	s_{fuel}"<s-s_o>"	9	9	kJ/kg.K	
specific enthalpy of flue gases	h_{eg}"<h-h_o>"	3000	3000	kJ/kg	
specific entropy of flue gases	s_{eg}"<s-s_o>"	7	7	kJ/kg.K	
Rate of exergy destruction	$\dot{X}_{des}$	9765.884	8831.381	KJ/s	
Rate of entropy generation	$\dot{S}_{gen}$	32.77142	29.63551	kJ/s.K	
Rate of exergy into system	$\dot{X}_{in}$	19010.18	17883.37	kJ/s	
Rate of exergy out of system	$\dot{X}_{out}$	9244.292	9051.991	kJ/s	
second law efficiency	η_{II}	0.486281	0.506168	%	
Entropy generation per unit output	$\dot{S}_{gen}/kW$	0.001576	0.001511	/K	
Exergy destruction kW of useful power	$\dot{X}_{des}/kW$	0.46968	0.450134	kW/kW	

APPENDIX B: SITE SELECTION (Maps)

Figure B. 1: Google Map of KNUST

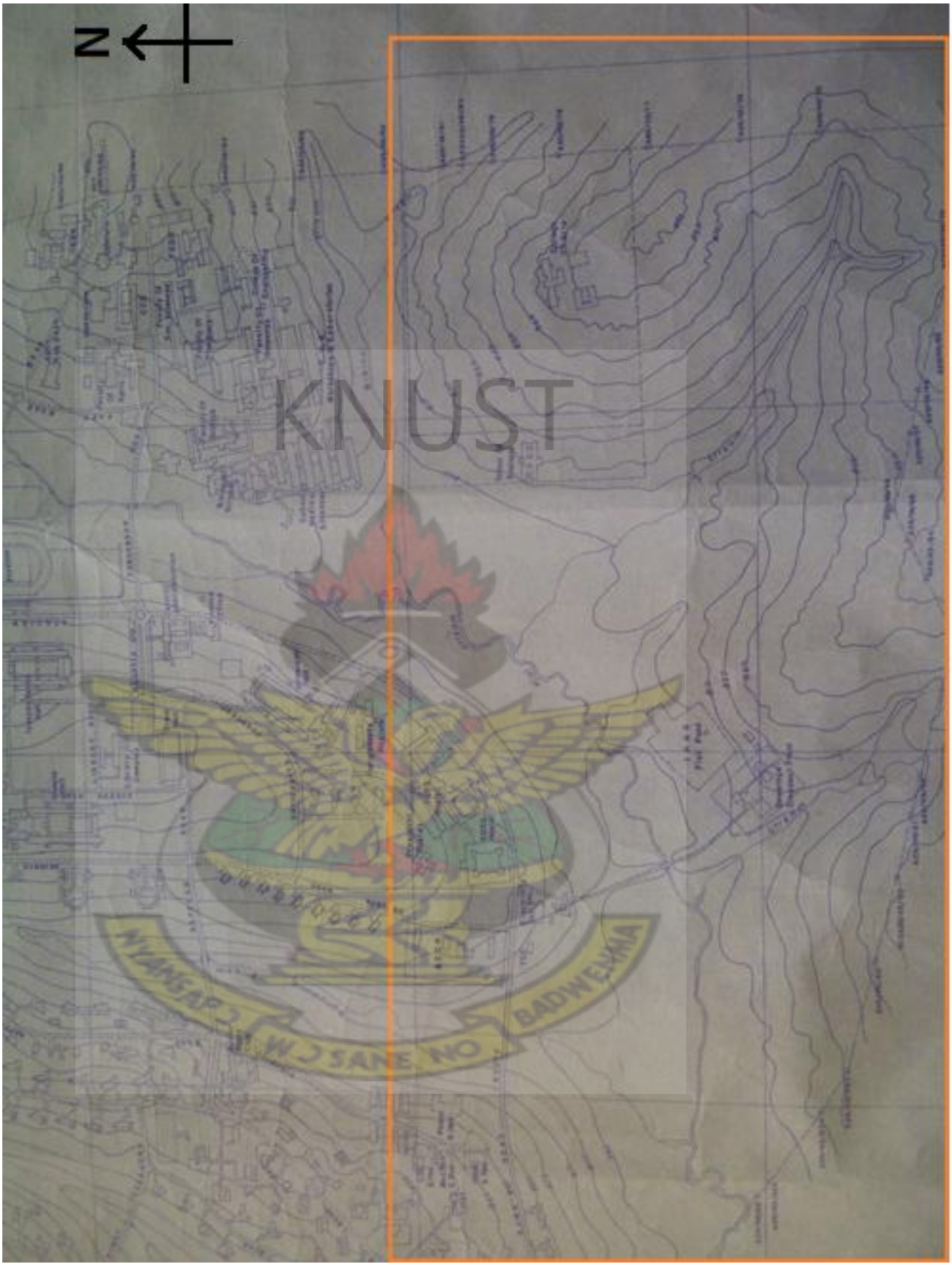


Figure B. 2:Map of KNUST [Courtesy: Geomatic Eng. Dept, KNUST]

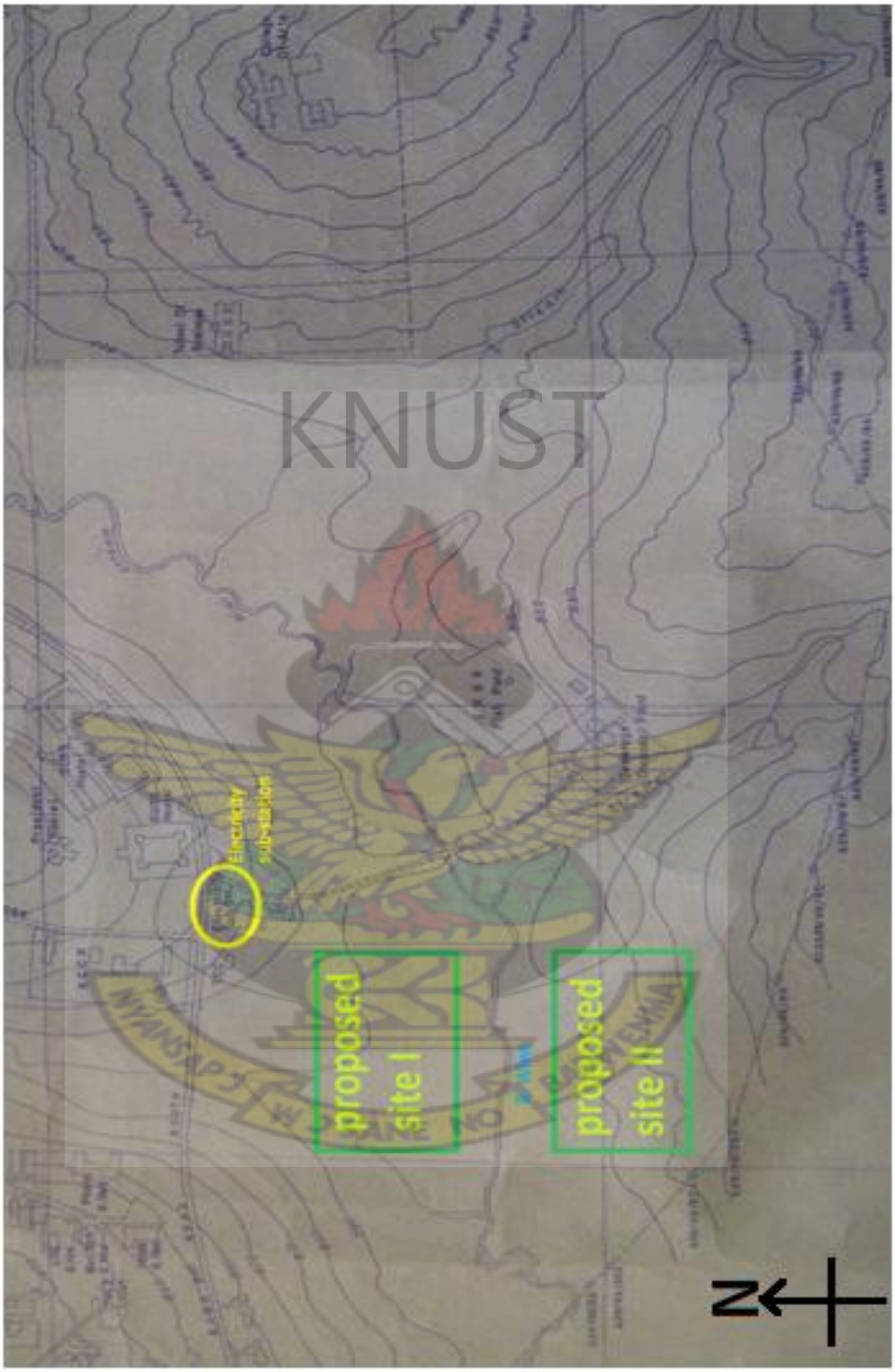


Figure B. 3: proposed sites.

APPENDIX C: RESULTS FROM RETSCREEN® ANALYSIS

See the following pages


Natural Resources Canada
Ressources naturelles Canada
Canada
RETScreen® International
www.retscreen.net
Clean Energy Project Analysis Software
Project information
See project database
Project name
nvestigating the conceptual design of a cogeneration plan
Project location
KNUST, Kumasi
Prepared for
School of Graduate Studies/ Dept of Mech. Eng.
Prepared by
Augustine Akuoko Kwarteng
Project type
Power - multiple technologies
Grid type
Central-grid & internal load
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
Kumasi
Show data
Complete Load & Network sheet
RETScreen4 2011-09-01
© Minister of Natural Resources Canada 1997-2011.
NRCan/CanmetENERGY

CONCEPT A

Natural Resources Canada Ressources naturelles Canada

Canada

RETScreen® International
www.retscreen.net

Clean Energy Project Analysis Software

Project information

See project database

Project name	nvestigating the conceptual design of a cogeneration plan
Project location	KNUST, Kumasi
Prepared for	School of Graduate Studies/ Dept of Mech. Eng.
Prepared by	Augustine Akuoko Kwarteng
Project type	Power - multiple technologies
Grid type	Central-grid & internal load
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	Kumasi
Show data	☐

Complete Load & Network sheet

RETScreen4 2011-09-01 NRCan/CanmetENERGY

RETScreen Load & Network Design - Power project

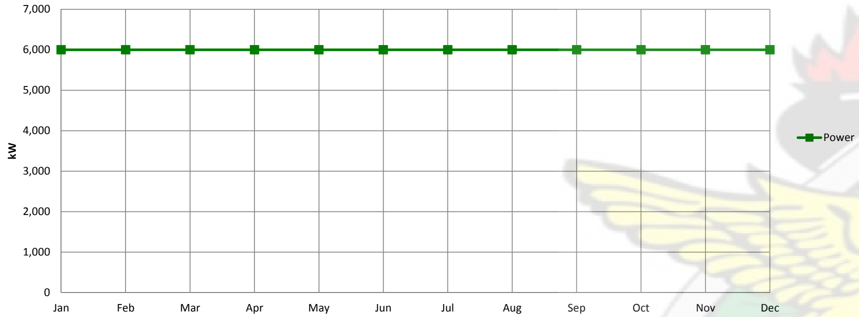
Power project	Unit	
Base case power system		
Grid type		Central-grid & internal load

Base case load characteristics

Month	Power gross average load kW
January	6,000
February	6,000
March	6,000
April	6,000
May	6,000
June	6,000
July	6,000
August	6,000
September	6,000
October	6,000
November	6,000
December	6,000

System peak electricity load over max monthly average		10.0%
Peak load - annual		6,600
Electricity	MWh	52,646
Electricity rate - base case	$/kWh	0.130
Total electricity cost		$ 6,843,954

Base case system load characteristics graph



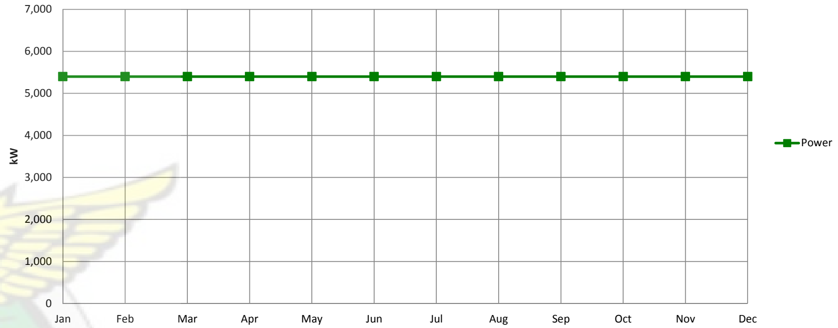
Proposed case energy efficiency measures

End-use energy efficiency measures	%	10%
Net peak electricity load	kW	5,940
Net electricity	MWh	47,381

Proposed case load characteristics

Month	Power net average load kW
January	5,400
February	5,400
March	5,400
April	5,400
May	5,400
June	5,400
July	5,400
August	5,400
September	5,400
October	5,400
November	5,400
December	5,400
Peak load - annual	5,940

Proposed case system load characteristics graph



Proposed case load and energy		Power
System peak load	kW	5,940
System energy	MWh	47,381

RETScreen Energy Model - Power project

☐ Show alternative units

Proposed case power system

Base load power system

Technology		Hydro turbine		
Analysis type		⦿ Method 1 / ○ Method 2		
Hydro turbine #1				
Power capacity	kW		0.0%	*See product database*
Manufacturer				
Model				
Capacity factor	%			
Electricity delivered to load	MWh	0	0.0%	
Electricity exported to grid	MWh	0		

Intermediate load power system

Technology		Steam turbine		
Availability	%		95.0%	8,322 h
Fuel selection method		Single fuel		
Fuel type		Biomass		
Fuel rate	$/t	40.000		
Steam turbine #2				
Steam flow	kg/h	36,666		
Operating pressure	bar	80		
Saturation temperature	°C	295		
Superheated temperature	°C	440		
Enthalpy	kJ/kg	3,259		
Entropy	kJ/kg/K	6.54		
Extraction port		No		
Back pressure	kPa	150		
Temperature	°C	111		
Mixture quality		0.88		Steam is wet
Enthalpy	kJ/kg	2,429		
Theoretical steam rate (TSR)	kg/kWh	4.34		
Steam turbine (ST) efficiency	%	85.0%		
Actual steam rate (ASR)	kg/kWh	5.11		
Summary				
Power capacity	kW	7,178	120.8%	
Minimum capacity	%	50.0%		
Manufacturer				*See product database*
Model and capacity				
Electricity delivered to load	MWh	45,012	95.0%	
Electricity exported to grid	MWh	0		
Seasonal efficiency	%	85.0%		
Return temperature	°C	113		
Fuel required	GJ/h	120.2		
Heating capacity	kW	0.0		

Electricity rate - base case	$/MWh	130.00
Fuel rate - proposed case power system	$/MWh	7.81
Electricity export rate	$/MWh	100.00
Electricity rate - proposed case	$/MWh	150.00

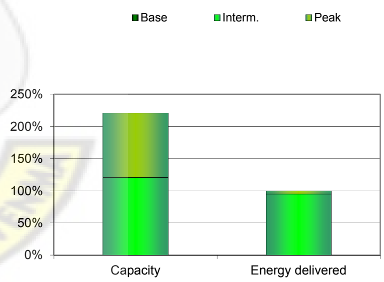
Operating strategy	Electricity delivered to load MWh	Electricity exported to grid MWh	Remaining electricity required MWh	Power system fuel MWh	Operating profit (loss) $	Efficiency %
Full power capacity - without extraction	45,012	14,727	2,369	277,887	5,107,331	21.5%
Power load following - without extraction	**45,012**	**0**	**2,369**	**209,382**	**4,169,479**	**21.5%**

Select base load power system	Power system #1	Hydro turbine #1
Select operating strategy	Power load following - without extraction	

Proposed case system characteristics

Proposed case system characteristics	Unit	Estimate	%
Power			
Base load power system			
Technology		Hydro turbine	
Operating strategy		Full power capacity output	
Capacity	kW	0	0.0%
Electricity delivered to load	MWh	0	0.0%
Electricity exported to grid	MWh	0	
Intermediate load power system			
Technology		Steam turbine	
Operating strategy		Power load following - without extraction	
Capacity	kW	7,178	120.8%
Electricity delivered to load	MWh	45,012	95.0%
Electricity exported to grid	MWh	0	
Peak load power system			
Technology		Grid electricity	
Suggested capacity	kW	5,940.0	
Capacity	kW	5,940	100.0%
Electricity delivered to load	MWh	2,369	5.0%
Back-up power system (optional)			
Technology			
Capacity	kW	0	

System design graph



Proposed case system summary	Fuel type	Fuel consumption - unit	Fuel consumption	Capacity (kW)	Energy delivered (MWh)
Power					
Base load	Hydro			0	0
Intermediate load	Biomass	t	40,868	7,178	45,012
Peak load	Electricity	MWh	2,369	5,940	2,369
			Total	13,118	47,381

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	2	$ 20,000	$ 40,000	
Sub-total:				**$ 40,000**	0.4%
Development					
Development	cost			$ -	
Sub-total:				**$ -**	0.0%
Engineering					
Engineering	cost	1	$ 1,000,000	$ 1,000,000	
Sub-total:				**$ 1,000,000**	9.4%
Power system					
Base load - Hydro turbine	kW	0.00		$ -	
Intermediate load - Steam turbine	kW	7,178.46	$ 600	$ 4,307,074	
Peak load - Grid electricity	kW	5,940.00		$ -	
Road construction	km			$ -	
Transmission line	km			$ -	
Substation	project	2	$ 50,000	$ 100,000	
Energy efficiency measures	project			$ -	
Heat exchanger	cost	1	$ 500,000	$ 500,000	
FBC Boiler and accessories		1	$ 2,799,598	$ 2,799,598	
Sub-total:				**$ 7,706,672**	72.4%
Balance of system & miscellaneous					
Spare parts	%			$ -	
Transportation	project			$ -	
Training & commissioning	p-d			$ -	
Miscellaneous (Training, comissioning, Transportation	cost	1	$ 1,000,000	$ 1,000,000	
Contingencies	%	5.0%	$ 9,746,672	$ 487,334	
Interest during construction	12.00%	8 month(s)	$ 10,234,005	$ 409,360	
Sub-total:				**$ 1,896,694**	17.8%
Total initial costs				**$ 10,643,365**	100.0%

Annual costs (credits)	Unit	Quantity	Unit cost	Amount
O&M				
Parts & labour	project	1	$ 1,000,000	$ 1,000,000
User-defined	cost			$ -
Contingencies	%	5.0%	$ 1,000,000	$ 50,000
Sub-total:				**$ 1,050,000**
Fuel cost - proposed case				
Biomass	t	40,868	$ 40.000	$ 1,634,720
Electricity	MWh	2,369	$ 150.000	$ 355,359
Sub-total:				**$ 1,990,079**

Annual savings	Unit	Quantity	Unit cost	Amount
Fuel cost - base case				
Electricity	MWh	52,646	$ 130.000	$ 6,843,954
Sub-total:				**$ 6,843,954**

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

RETScreen Emission Reduction Analysis - Power project

Emission Analysis

- ◉ Method 1
- ○ Method 2
- ○ Method 3

Base case electricity system (Baseline)

Country - region	Fuel type	GHG emission factor (excl. T&D) tCO2/MWh	T&D losses %	GHG emission factor tCO2/MWh
Ghana	All types	0.275	25.0%	0.367

☐ Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	52,646	0.367	19,317.5
Total	100.0%	52,646	0.367	19,317.5

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Biomass	98.9%	209,382	0.007	1,501.5
Hydro	0.0%	0	0.000	0.0
Electricity	1.1%	2,369	0.367	869.3
Total	100.0%	211,751	0.011	2,370.8

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	19,317.5	2,370.8	16,946.7		16,946.7

Net annual GHG emission reduction	16,947	tCO2	is equivalent to	3,104	Cars & light trucks not used

RETScreen Financial Analysis - Power project

Financial parameters

General

Fuel cost escalation rate	%	2.0%
Inflation rate	%	10.0%
Discount rate	%	0.0%
Project life	yr	24

Finance

Incentives and grants	$	
Debt ratio	%	0.0%

Income tax analysis ☐

Annual income

Electricity export income

GHG reduction income ☐

Net GHG reduction	tCO2/yr	16,947
Net GHG reduction - 24 yrs	tCO2	406,721

Customer premium income (rebate) ☐

Other income (cost) ☐

Clean Energy (CE) production income ☐

Project costs and savings/income summary

Initial costs

Feasibility study	0.4%	$	40,000
Engineering	9.4%	$	1,000,000
Power system	72.4%	$	7,706,672
Balance of system & misc.	17.8%	$	1,896,694
Total initial costs	**100.0%**	**$**	**10,643,365**

Annual costs and debt payments

O&M	$	1,050,000
Fuel cost - proposed case	$	1,990,079
Total annual costs	**$**	**3,040,079**

Periodic costs (credits)

Annual savings and income

Fuel cost - base case	$	6,843,954
Total annual savings and income	**$**	**6,843,954**

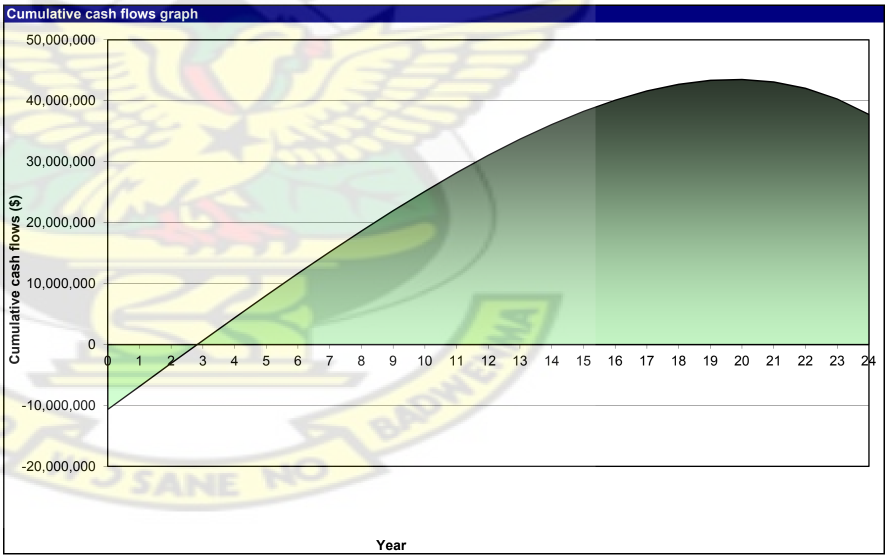
Financial viability

Pre-tax IRR - equity	%	34.1%
Pre-tax IRR - assets	%	34.1%
After-tax IRR - equity	%	34.1%
After-tax IRR - assets	%	34.1%
Simple payback	yr	2.8
Equity payback	yr	2.8
Net Present Value (NPV)	$	37,759,408
Annual life cycle savings	$/yr	1,573,309
Benefit-Cost (B-C) ratio		4.55
GHG reduction cost	$/tCO2	(93)

Yearly cash flows

Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-10,643,365	-10,643,365	-10,643,365
1	3,795,952	3,795,952	-6,847,413
2	3,779,471	3,779,471	-3,067,942
3	3,753,421	3,753,421	685,479
4	3,716,685	3,716,685	4,402,164
5	3,668,034	3,668,034	8,070,198
6	3,606,112	3,606,112	11,676,310
7	3,529,423	3,529,423	15,205,733
8	3,436,320	3,436,320	18,642,053
9	3,324,984	3,324,984	21,967,037
10	3,193,417	3,193,417	25,160,454
11	3,039,411	3,039,411	28,199,865
12	2,860,537	2,860,537	31,060,401
13	2,654,120	2,654,120	33,714,521
14	2,417,211	2,417,211	36,131,732
15	2,146,566	2,146,566	38,278,298
16	1,838,608	1,838,608	40,116,906
17	1,489,403	1,489,403	41,606,309
18	1,094,615	1,094,615	42,700,924
19	649,474	649,474	43,350,398
20	148,727	148,727	43,499,126
21	-413,408	-413,408	43,085,718
22	-1,043,297	-1,043,297	42,042,421
23	-1,747,946	-1,747,946	40,294,475
24	-2,535,066	-2,535,066	37,759,408

Cumulative cash flows graph

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Project information
See project database
Project name
nvestigating the conceptual design of a cogeneration plan
Project location
KNUST, Kumasi
Prepared for
School of Graduate Studies/ Dept of Mech. Eng.
Prepared by
Augustine Akuoko Kwarteng
Project type
Power - multiple technologies
Grid type
Central-grid & internal load
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
Kumasi
Show data
NASA
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GEF
reeep
Complete Load & Network sheet
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CONCEPT B

Project information

See project database

Project name	nvestigating the conceptual design of a cogeneration plan
Project location	KNUST, Kumasi
Prepared for	School of Graduate Studies/ Dept of Mech. Eng.
Prepared by	Augustine Akuoko Kwarteng
Project type	Power - multiple technologies
Grid type	Central-grid & internal load
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	Kumasi
Show data	☐

Complete Load & Network sheet

RETScreen Load & Network Design - Power project

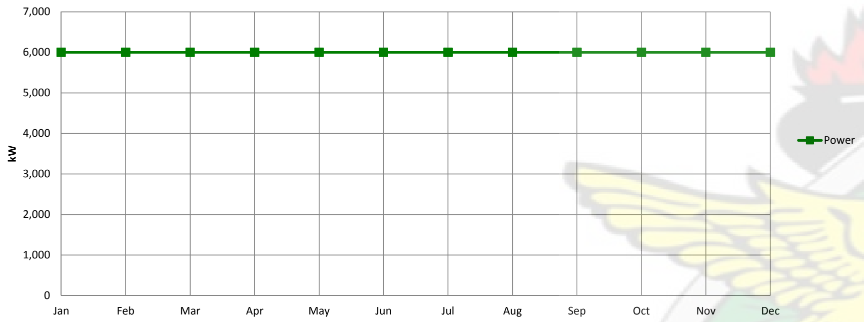
Power project	Unit	
Base case power system		
Grid type		Central-grid & internal load

Base case load characteristics

Month	Power gross average load kW
January	6,000
February	6,000
March	6,000
April	6,000
May	6,000
June	6,000
July	6,000
August	6,000
September	6,000
October	6,000
November	6,000
December	6,000

System peak electricity load over max monthly average		10.0%
Peak load - annual		6,600
Electricity	MWh	52,646
Electricity rate - base case	$/kWh	0.130
Total electricity cost		$ 6,843,954

Base case system load characteristics graph

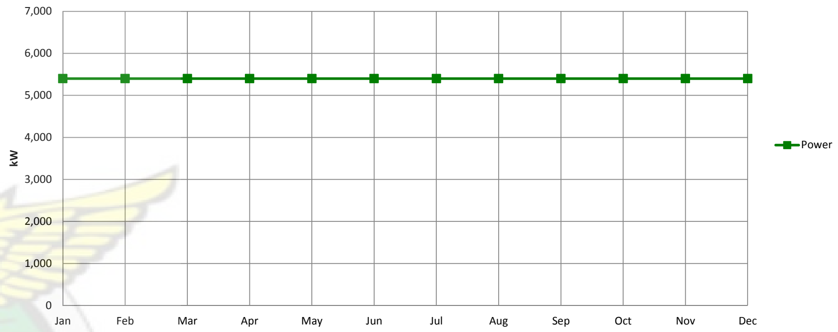


Proposed case load characteristics

Month	Power net average load kW
January	5,400
February	5,400
March	5,400
April	5,400
May	5,400
June	5,400
July	5,400
August	5,400
September	5,400
October	5,400
November	5,400
December	5,400

Peak load - annual	5,940

Proposed case system load characteristics graph



Proposed case energy efficiency measures

End-use energy efficiency measures	%	10%
Net peak electricity load	kW	5,940
Net electricity	MWh	47,381

Proposed case load and energy

		Power
System peak load	kW	5,940
System energy	MWh	47,381

RETScreen Energy Model - Power project

☑ Show alternative units

Proposed case power system

	Unit	Value	%	Alt. unit	Alt. value	
Base load power system						
Technology		Hydro turbine				
Analysis type		⦿ Method 1 / ○ Method 2				
Hydro turbine #1						
Power capacity	kW	0	0.0%			*See product database*
Manufacturer						
Model						
Capacity factor	%	0.6%				
Electricity delivered to load	MWh	0	0.0%			
Electricity exported to grid	MWh	0				
Intermediate load power system						
Technology		Steam turbine				
Availability	%		95.0%	8,322 h		
Fuel selection method		Single fuel				
Fuel type		Biomass				
Fuel rate	$/t	40.000				
Steam turbine #2						
Steam flow	kg/h	34,300				
Operating pressure	bar	80				
Saturation temperature	°C	295		°F	563.0	
Superheated temperature	°C	440				
Enthalpy	kJ/kg	3,259		Btu/lb	1,401.0	
Entropy	kJ/kg/K	6.54		Btu/lb/°R	1.6	
Extraction port		Yes				
Maximum extraction	%	15.0%				
Extraction	kg/h	5,145		lb/h	2,333.7	
Extraction pressure	kPa	1,475				
Temperature	°C	197		°F	387.5	
Mixture quality		1.02				
Enthalpy	kJ/kg	2,832		Btu/lb	1,217.6	
Theoretical steam rate (TSR)	kg/kWh	8		lb/kWh	18.6	
Back pressure	kPa	100				
Temperature	°C	100		°F	211.3	
Mixture quality		0.86				Steam is wet
Enthalpy	kJ/kg	2,369		Btu/lb	1,018.4	
Theoretical steam rate (TSR)	kg/kWh	4.05		lb/kWh	8.9	
Steam turbine (ST) efficiency	%	85.0%				
Actual steam rate (ASR)	kg/kWh	5.53		lb/kWh	12.2	
Summary						
Power capacity - with extraction	kW	6,198	104.3%			
Power capacity - without extraction	kW	7,207	121.3%			
Minimum capacity	%	50.0%				
Manufacturer						*See product database*
Model and capacity						
Electricity delivered to load	MWh	45,012	95.0%			
Electricity exported to grid	MWh	0				
Seasonal efficiency	%	85.0%				
Return temperature	°C	100				
Fuel required	GJ/h	114.7		million Btu/h	108.7	
Heating capacity - without extraction	kW	0.2		million Btu/h	0.0	
Heating capacity - with extraction	kW	3,451.1		million Btu/h	11.8	

	Unit	Value	Alt. unit	Alt. value
Electricity rate - base case	$/MWh	130.00	$/kWh	0.130
Fuel rate - proposed case power system	$/MWh	7.81	$/kWh	0.008
Electricity export rate	$/MWh	100.00	$/kWh	0.100
Electricity rate - proposed case	$/MWh	150.00	$/kWh	0.150

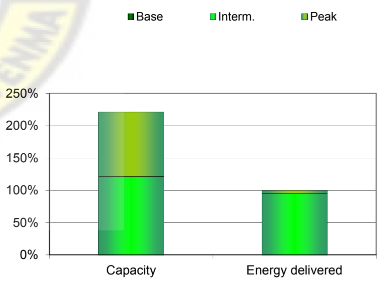
Operating strategy	Electricity delivered to load MWh	Electricity exported to grid MWh	Remaining electricity required MWh	Power system fuel MWh	Operating profit (loss) $	Efficiency %
Full power capacity - without extraction	45,012	14,967	2,369	265,040	5,231,615	22.6%
Power load following - without extraction	**45,012**	**0**	**2,369**	**198,904**	**4,251,288**	**22.6%**

Select base load power system	Power system #1	Hydro turbine #1
Select operating strategy	Power load following - without extraction	

Proposed case system characteristics

	Unit	Estimate	%
Power			
Base load power system			
Technology		Hydro turbine	
Operating strategy		Full power capacity output	
Capacity	kW	0	0.0%
Electricity delivered to load	MWh	0	0.0%
Electricity exported to grid	MWh	0	
Intermediate load power system			
Technology		Steam turbine	
Operating strategy		Power load following - without extraction	
Capacity	kW	7,207	121.3%
Electricity delivered to load	MWh	45,012	95.0%
Electricity exported to grid	MWh	0	
Peak load power system			
Technology		Grid electricity	
Suggested capacity	kW	5,940.0	
Capacity	kW	5,940	100.0%
Electricity delivered to load	MWh	2,369	5.0%
Back-up power system (optional)			
Technology			
Capacity	kW	0	

System design graph



Proposed case system summary	Fuel type	Fuel consumption - unit	Fuel consumption	Capacity (kW)	Energy delivered (MWh)
Power					
Base load	Hydro			0	0
Intermediate load	Biomass	t	38,823	7,207	45,012
Peak load	Electricity	MWh	2,369	5,940	2,369
			Total	**13,147**	**47,381**

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	2	$ 20,000	$ 40,000	
Sub-total:				**$ 40,000**	0.4%
Development					
Development	cost			$ -	
Sub-total:				**$ -**	0.0%
Engineering					
Engineering	cost	1	$ 1,200,000	$ 1,200,000	
Sub-total:				**$ 1,200,000**	10.7%
Power system					
Base load - Hydro turbine	kW	0.00		$ -	
Intermediate load - Steam turbine	kW	7,207.27	$ 620	$ 4,468,510	
Peak load - Grid electricity	kW	5,940.00		$ -	
Road construction	km			$ -	
Transmission line	km			$ -	
Substation	project	1	$ 50,000	$ 50,000	
Energy efficiency measures	project			$ -	
Heat exchangers	cost	1	$ 600,000	$ 600,000	
FBC boiler and accessories		1	$ 2,904,532	$ 2,904,532	
Sub-total:				**$ 8,023,042**	71.6%
Balance of system & miscellaneous					
Spare parts	%			$ -	
Transportation	project			$ -	
Training & commissioning	p-d			$ -	
Miscellaneous (Training, comissioning, Transportation	cost	1	$ 1,000,000	$ 1,000,000	
Contingencies	%	5.0%	$ 10,263,042	$ 513,152	
Interest during construction	12.00%	8 month(s)	$ 10,776,194	$ 431,048	
Sub-total:				**$ 1,944,200**	17.3%
Total initial costs				**$ 11,207,242**	100.0%

Annual costs (credits)	Unit	Quantity	Unit cost	Amount
O&M				
Parts & labour	project	1	$ 1,000,000	$ 1,000,000
User-defined	cost			$ -
Contingencies	%	5.0%	$ 1,000,000	$ 50,000
Sub-total:				**$ 1,050,000**
Fuel cost - proposed case				
Biomass	t	38,823	$ 40.000	$ 1,552,911
Electricity	MWh	2,369	$ 150.000	$ 355,359
Sub-total:				**$ 1,908,270**

Annual savings	Unit	Quantity	Unit cost	Amount
Fuel cost - base case				
Electricity	MWh	52,646	$ 130.000	$ 6,843,954
Sub-total:				**$ 6,843,954**

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

RETScreen Emission Reduction Analysis - Power project

Emission Analysis

- (•) Method 1
- ( ) Method 2
- ( ) Method 3

Base case electricity system (Baseline)

Country - region	Fuel type	GHG emission factor (excl. T&D) tCO2/MWh	T&D losses %	GHG emission factor tCO2/MWh
Ghana	All types	0.275	25.0%	0.367

☐ Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	52,646	0.367	19,317.5
Total	100.0%	52,646	0.367	19,317.5

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Biomass	98.8%	198,904	0.007	1,426.4
Hydro	0.0%	0	0.000	0.0
Electricity	1.2%	2,369	0.367	869.3
Total	100.0%	201,273	0.011	2,295.7

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	19,317.5	2,295.7	17,021.8		17,021.8

Net annual GHG emission reduction 17,022 tCO2 is equivalent to 3,118 Cars & light trucks not used

RETScreen Financial Analysis - Power project

Financial parameters

General		
Fuel cost escalation rate	%	2.0%
Inflation rate	%	10.0%
Discount rate	%	0.0%
Project life	yr	24
Finance		
Incentives and grants	$	
Debt ratio	%	0.0%
Income tax analysis		☐

Annual income

Electricity export income		
GHG reduction income		☐
Net GHG reduction	tCO2/yr	17,022
Net GHG reduction - 24 yrs	tCO2	408,524
Customer premium income (rebate)		☐
Other income (cost)		☐
Clean Energy (CE) production income		☐

Project costs and savings/income summary

Initial costs			
Feasibility study	0.4%	$	40,000
Engineering	10.7%	$	1,200,000
Power system	71.6%	$	8,023,042
Balance of system & misc.	17.3%	$	1,944,200
Total initial costs	**100.0%**	**$**	**11,207,242**
Annual costs and debt payments			
O&M		$	1,050,000
Fuel cost - proposed case		$	1,908,270
Total annual costs		**$**	**2,958,270**
Periodic costs (credits)			
Annual savings and income			
Fuel cost - base case		$	6,843,954
Total annual savings and income		**$**	**6,843,954**

Financial viability

Pre-tax IRR - equity	%	33.1%
Pre-tax IRR - assets	%	33.1%
After-tax IRR - equity	%	33.1%
After-tax IRR - assets	%	33.1%
Simple payback	yr	2.9
Equity payback	yr	2.9
Net Present Value (NPV)	$	39,734,088
Annual life cycle savings	$/yr	1,655,587
Benefit-Cost (B-C) ratio		4.55
GHG reduction cost	$/tCO2	(97)

Yearly cash flows

Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-11,207,242	-11,207,242	-11,207,242
1	3,879,397	3,879,397	-7,327,844
2	3,864,585	3,864,585	-3,463,259
3	3,840,237	3,840,237	376,978
4	3,805,238	3,805,238	4,182,216
5	3,758,358	3,758,358	7,940,574
6	3,698,242	3,698,242	11,638,816
7	3,623,396	3,623,396	15,262,212
8	3,532,172	3,532,172	18,794,384
9	3,422,754	3,422,754	22,217,138
10	3,293,141	3,293,141	25,510,279
11	3,141,130	3,141,130	28,651,408
12	2,964,290	2,964,290	31,615,699
13	2,759,948	2,759,948	34,375,647
14	2,525,156	2,525,156	36,900,804
15	2,256,670	2,256,670	39,157,473
16	1,950,914	1,950,914	41,108,388
17	1,603,955	1,603,955	42,712,342
18	1,211,458	1,211,458	43,923,801
19	768,655	768,655	44,692,455
20	270,291	270,291	44,962,747
21	-289,413	-289,413	44,673,334
22	-916,822	-916,822	43,756,512
23	-1,618,942	-1,618,942	42,137,570
24	-2,403,482	-2,403,482	39,734,088

Cumulative cash flows graph