DEVELOPMENT OF A GREEN LEAST-COST GENERATION EXPANSION PLAN FOR KENYA

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Development of A Green Least-Cost Generation Expansion Plan For Kenya

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DECLARATION

This thesis is my original work and has not been presented for a degree in any other University.

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DEDICATION

I dedicate this work to power system planners in Kenya and around the world.

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LIST OF NOMENCLATURE AND ABBREVIATIONS

AFC	**-**	Annual Fixed Cost
AVC	-	Annual Variable Cost
CDM	**-**	Clean Development Mechanisms
CER	**-**	Certified Emission Reductions
CONGEN	–	Configuration Generation
DP	-	Dynamic Programming
DYNPRO	–	Dynamic Programming Optimization
ENS	–	Energy Not Served
FIXSYS	–	Fixed System Description
GCM	**-**	Generation Cost Model
GEP	-	Generation Expansion Planning
GLCGEP	-	Green Least Cost Generation Expansion Plan
HDFS	**-**	Higher Demand Forecast Scenario
HFO	**-**	Heavy Fuel Oil
IAEA	-	International Atomic Energy Agency
IEA	**-**	International Energy Agency
IEEE	**-**	Institute of Electrical & Electronic Engineering
IPCC	-	Inter-governmental Panel on Climate Change
LCOE	–	Levelized Cost of Electricity

LCPDP	–	Least Cost Power Development Plan
LOADSY	–	Load System Description
LOLP	–	Loss of Load Probability
LRMC	**-**	Long Run Marginal Cost
MERSIM	–	Merge and Simulate
MEWNR	**-**	Ministry of Environment Water & Natural Resources
MOE	**-**	Ministry of Energy
NPV	**-**	Net Present Value
RDFS	**-**	Reference Demand Forecast Scenario
REPROBAT	–	Report Writer of Batched Environment
RE	-	Renewable Energy
SWERA	**-**	Solar & Wind Energy Resource Assessment
UNEP	**-**	United Nations Environmental Program
VARSYS	–	Variable System Description
WASP	–	Wien Automatic System Planning Package

ABSTRACT

The power generation sector is a huge CO_2 emitter that precipitate climate change. In mitigating CO_2 emissions/climate change, the study developed a green least cost generation expansion plan (GLCGEP) as a substitute of the previously proposed carbon intensive 2011-2031 least-cost power development plan (LCPDP) for Kenya. The study involved, determining the green candidate plants for GEP; deriving an optimal GLCGEP based on the green candidate plants and establishing the techno-economic characteristics of the GLCGEP and LCPDP. A generation cost model was formulated for selecting the green candidate plants based on the levelized cost of electricity (LCOE); the selected green candidate plants, the demand forecast, the existing and committed plants were simulated in the Wien Automatic Software Package (WASP) IV model and the optimal GLCGEP derived. The techno-economics of the optimal GLCGEP and the LCPDP were evaluated in a comparative study. The green base load candidate plants for GEP in Kenya were namely; 140 MW Geothermal, 140 MW low grand falls hydro, 300 MW Wind, 1000 MW Ethiopian imports and 60 MW Mutonga hydro. They are characterized by low levelized cost of electricity (LCOE) of US$ 6-13 cts /kWh. Suitable green peaking plants was mainly the 100 MW Solar PV with a higher LCOE of within US$ 15-30 cts/kWh. The 1000 MW nuclear and the 180 MW GT-Natural gas plants were complimentary base and peaking plants respectively The GLCGEP generation capacity was projected to grow from 1382 MW in the base year to 19828 by 2031. Out of the total capacity, 40.8% is geothermal, 19.5% wind, 11.1% Ethiopian imports, 10.9% natural gas, 9.1% nuclear, 5.2% hydro, 2.3% HFO and 1.0% solar PV. The generation system was expected to supply 7721 GWh to 105766 GWh by 2031. The GLCGEP and the LCPDP capacities depicted 25% and 28% average reserve margins respectively; the later providing excess. By 2031, the GLCGEP; 78% green almost twice the LCPDP at 49% was projected to accrue a total of 20.2 Mt CO_2 avoided CO_2 emissions estimated at US$ 62.9 million carbon credits besides other invaluable green fringe benefits. The GLCGEP was also more feasible as showed more revenues approximated at US$ +2.16 billion NPV unlike the US$ - 0.31 billion for the LCPDP. The study demonstrated a feasible future for green-based generation with security of supply and sustainable

development. Therefore, the study recommends that future studies be carried on modeling power system stability with high Wind and Solar PV integrated in Kenya.

CHAPTER ONE

INTRODUCTION

1.1 Background of the Study

According to the International Energy Agency (IEA), the power generation sector in the world is projected to undergo unprecedented demand growth due to rapid social-economic development. The demand is projected to grow from 17,408 TWh in 2004 to 33,750 TWh in 2030 translating to an average annual growth rate of 2.6%. To meet this demand, the generation sector will build an average capacity of 5,087GW of which more than 75% will be oil, coal and gas power plants (IEA, 2014). The Inter-governmental Panel Committee on Climate change (IPCC) estimates that these carbon-intensive plants are expected to raise the global emissions from 9600-16400 Mt CO_2 at an annual growth rate of 2%. The projected rapidly increasing global emissions is a major concern in climate change mitigations (IPCC, 2013).

Globally, the generation sector is faced with enormous pressure to lead the way in climate change mitigation strategies (IPCC, 2011). Generation companies (GENCOs) in many countries are currently planning towards environmentally-friendly generation investments (Geraldo *et al.,* 2010; Mejia *et al.,* 2012; Salvador *et al.*,2016). The most popular energy policy measure towards this course is the integration of green energy resources in the conventional power system (Rouhani *et al.*, 2013; Maslyuk *et al.*, 2013; REN21, 2014).

The green-based least-cost generation expansion planning (GEP) is rapidly gaining consideration in this era. Maslyuk *et al.,* (2013); Karapidakis *et al.,* (2014) and Lee *et al.,* (2015) have successfully demonstrated green-based GEP as sustainable options for security of power and CO_2 emission reductions. The integration of green power also presents a significant potential for carbon credits as revenues in the carbon market (Gupta, 2007; Shende *et al.*, 2014; Sukumaran, 2014). Other fringe benefits such as health environment, green jobs and foreign exchange savings prevail for sustainable development (UNEP, 2008; UNEP, 2011).

In Kenya, the power generation sector prepares 20 year rolling least cost power development plan (LCPDP) at the Energy Regulatory Commission (ERC) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP under the focus of this study projected a hydropower and heavy fuel oil (HFO) dominated power generation (MOE, 2011) that posed serious challenges for urgent attention to energy planners. The hydros were vulnerable to acute energy shortfalls due to the frequent droughts. On the other hand, the HFO and the planned conventional coal plants posed a CO_2 emissions dilemma (MOE, 2013; MEWNR, 2014).

Kenya had enormous unutilized green generation resources for GEP. The 60 MW Mutonga and 140 MW low grand falls (LGF) hydropower sites were due for immediate development (MOE, 2013). At least 7600 MW of unexploited feasible geothermal prospects exist for shifting the base load generation from the vulnerable hydropower (Kengen, 2013). The Kenya's strategic location along the equator offer about 638, 790 TWh solar PV potential as a probable peaking substitute for expensive HFO power (Bazilian, *et al.,* 2013; Ondraczek, 2014). The huge potential of about 346 W/M^2 and wind speeds of over $6ms^{-1}$for wind power base load generation exists besides geothermal (SWERA, 2008). An effective green generation portfolio requires a proportion of other resources for higher power system reliability and stability (Khatib, 2003). Therefore, complimentary energy resources include 2000 MW Ethiopian imports, about 2340 MW natural gas and about 4000 MW nuclear (MOE, 2013).

In this study, a green least cost generation expansion plan (GLCGEP) for Kenya was developed from the existing energy resource base. The study involved, firstly determining the green candidate plants for GEP. Secondly, an optimal GLCGEP based on the green candidate plants was derived using the Wien Automatic software package (WASP) IV model. Lastly, a comparative analysis of the optimal GLCGEP and LCPDP was undertaken.

1.2 Statement of the Problem

The 2011-2031 LCPDP has a portfolio of generating capacities from several energy sources to meet the projected energy demand in Kenya. By 2031, 26% is expected to come from geothermal, 19% from nuclear, 13% from coal, 11% from natural gas, 9% from HFO, 9% from Ethiopian imports and 5% from hydropower. However, this carbon-intensive capacity expansion plan will increase the CO_2 emissions in contradiction to the national and global climate change mitigation strategies (MEWNR, 2014). In view of this, a least cost GEP based on CO_2 emission reduction strategy (Geraldo *et al.*, 2010; Salvador *et al.*, 2016) was an urgent concern for energy planners. In this study, a green least cost GEP was undertaken to reduce the CO_2 emission profile of the 2011-2031 LCPDP without compromising the security of supply.

1.3 Rationale of the Study

The economic growth measured by gross domestic product (GDP) of a country goes hand in hand with increase in energy demand. This relationship necessitates precise annual capacity additions to meet the increasing demand at least-cost besides other set criteria. Therefore, GEP is a fundamental strategic development activity for any country (Meza *et al.*, 2007). In the 21st century, the global concerns on climate change have brought the global generation sector on the spotlight as the main cause of CO_2 emissions from its fossil-fuel power plants. There is immense pressure on the generation sector in the world to mitigate her CO_2 emissions (IPCC, 2011; Li *et al.*, 2016). Currently, green-based GEP is the best environmental protection policy to mitigate the rapid emission rates (Mejia *et al.*, 2012; Maslyuk *et al.*, 2013; Salvador *et al.*, 2016). This was the justification for developing the GLCGEP for Kenya to enhance clean power generation and sustainable development.

1.4 Objectives

1.4.1 Main Objective

The main objective of the study was to develop a green least cost generation expansion plan (GLCGEP) to substitute the carbon-intensive 2011–2031 LCPDP for Kenya.

1.4.2 Specific Objectives

The specific objectives were namely:

1. To determine the green candidate power plants for generation expansion planning in Kenya.
2. To derive the optimal GLCGEP based on the green candidate power plants for Kenya.
3. To establish the comparative techno-economic characteristics of the GLCGEP and 2011–2031 LCPDP.

1.5 Research Questions

1.5.1 Main Research Question

The main research question for the study was; ‘can the GLCGEP substitute the 2011–2031 LCPDP for Kenya?’

1.5.2 Specific Research Questions

The specific research questions were namely:

1. What are the green candidate power plants for generation expansion planning in Kenya?
2. Which is the optimal GLCGEP based on the green candidate power plants for Kenya?

3. What are the comparative techno-economic characteristics of the GLCGEP and 2011–2031 LCPDP?

1.6 Assumptions of the Study

In the study, the following applied:

i. Though the study was in 2014, the planning period was set as 2011–2031 with 2010 the base year to correspond with the duration considered in the LCPDP.

ii. The demand forecast was retained as in the 2011–2031 LCPDP.

iii. Three hydrological conditions in WASP IV (dry, average, and wet) were assumed same as in the 2011–2031 LCPDP.

iv. Sixteen out of the long list of committed power projects in the 2011–2031 LCPDP were considered for the study.

CHAPTER TWO

LITERATURE REVIEW

2.1 Introduction

In this chapter, an overview of the generation expansion planning (GEP) problem in terms of its conceptual model and pertinent optimization approaches are shown. An outline of related literature on green-based GEP is drawn and the research gap presented. Lastly, a summary of the chapter is given at the end.

2.2 Generation Expansion Planning Problem Overview

2.2.1 Generation Expansion Planning Conceptual Model

Generation expansion planning (GEP) is defined as the problem of determining the optimal technology type, size, timing and location of new generation plants to integrate in the existing power system over a long-range period to satisfy the forecast energy demand (Park *et al.*,2000; Phupha *et al.*, 2012). GEP is a strategic economic development activity as the GDP hence a country's economic growth increases with energy demand (Meza *et al.*, 2007). GEP involves three key input data on the: demand forecast; existing generation plants and screened candidate plants for capacity addition (IAEA, 2006).

Preliminary vetting of the generation candidates through the screening curve analysis (SCA) is necessary. SCA involves initial selection of candidate generation sources to establish the most economic supply options. In this approach, the total costs during the operation life of probable supply options are discounted and plotted against capacity factors. The resulting screening curves captures major trade-offs between capital and operation costs and the utilization levels of various generation technologies allowing higher cost options to be excluded for further GEP consideration (IAEA, 1984; Khatib, 2003; Zhang, 2013).

The GEP problem is relatively complex as there are numerous parameters and related uncertainties problematic to simplistic capacity expansion decision-making approaches. Therefore, GEP models are available for simulating the generating system's operation and optimizing the generation expansion plan. Figure 2.1 shows the GEP conceptual model. The key model inputs such as the demand forecast and generation system's characteristics that include forced outage rate (FOR), maintenance schedule, loading order, spinning reserves etc. for the existing and candidate plants are simulated and studied subject to given reliability criteria. Possible future events on the system's generation characteristics are simulated through scenarios to establish corresponding probable outcomes (IAEA, 1984; IAEA, 2006).

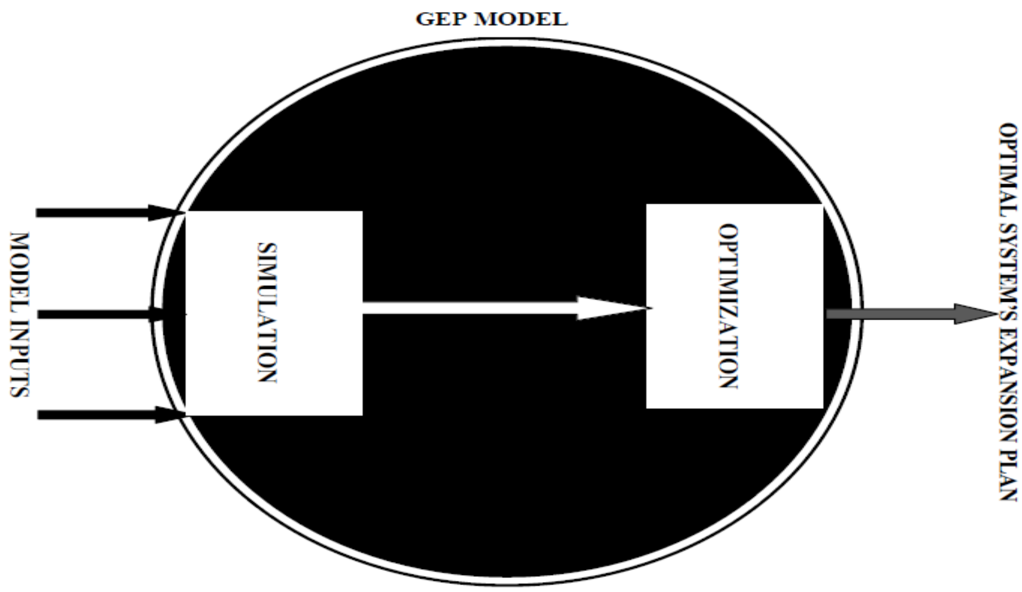

Figure 2.1: GEP Conceptual Model

An iterative optimization process is undertaken to establish the optimal least-cost generation expansion plan for the candidate plants' capacity addition subject to given constraints and uncertainties. Sensitivity analyses are carried out to ascertain factors that cause significant impact on the optimal system's performance. Changes in economic factors such as discounting rate; fuel cost and capital cost over time are investigated to assess their effect on system's performance (IAEA, 1984; IAEA, 2006; Elkarmi *et al.*, 2012).

GEP problem is a challenging because of the large-scale, long-term, non-linear, discrete and dynamic nature of the generation investment that can conveniently be solved by complete mathematical computation (IEEE, 2008). Mathematically, optimizing a GEP problem is equivalent to determining a set of optimal decision vectors that minimize an objective function within given constraints. Several mathematical programming models from operation research have been developed as optimization algorithms and probabilistic production costing (PPC) simulation (IAEA, 1984). The purpose of the models is to compute the generation plants to be constructed, the time to be constructed and the amount of power to be produced at minimal total cost and maximum reliability (Elkarmi *et al.*, 2012).

2.2.2 Dynamic Programming

Dynamic programming (DP) is an operation research technique for resolving a multi-stage problem by decomposing it into a sequence of nested sub-problems and the solution of one sub-problem derived from the solution of the preceding. At each stage, the planner chooses an action from a set of probable options that depend on the present state of the dynamic system. The main objective of DP is to determine a policy that optimizes the system's performance over the given period (Momoh, 2001).

In GEP problems, the number of generation plants of each type in the study represents the state variables. The candidate plants for annual capacity addition represent control variables where one year is the unit increment of the state variable. The DP algorithm begins with fixed initial condition, i.e., a state and derives the optimal least-cost solution for all the feasible states over the given planning period. However, the 'curse of dimensionality' limits the DP since all the possible solutions are searched from the initial to the least cost state (Momoh, 2001; IAEA, 2006). This limitation results in excessive computation time and storage that limit DP applications to practical GEP problems. The limitation is overcome by simplifying the GEP problem or eliminating some feasible states in the DP algorithm to check the DP processing and search for the optimal solution (IAEA, 1984).

In some cases, heuristic principles are integrated in the DP routine to truncate the state space and enhance optimization capabilities. It is common to truncate configurations with the highest reserve margins and cost as long as no adverse effect occurs on the DP optimization (IAEA, 2006). On the other hand, the DP's inability to withstand uncertainties is catered in a stochastic DP. Uncertainties in GEP model input data are captured to represent the generation system more accurately (Meza *et al.,* 2007).

2.2.3 Heuristics

Heuristics resolve large, non-linear and non-convex optimization problems initially complex to solve. Heuristic methodologies search the solution space directed by logic, empirical and sensitive rules. Genetic algorithms (GA), evolutionary programming (EP), blender's decomposition (BD) and particle swarm optimization (PSO) based on heuristic principles are widely appreciated in power system literature (Kannan *et al.,* 2005; IEEE, 2008).

GA operates based on population of individuals in which each is a potential solution. The search for the optimal solution is based on 'survival-for-the-fittest' with cross-over operation. An improved genetic algorithm (IGA) is modeled based on stochastic cross-over and elitism approaches to overcome GA difficulties in large-scale problems (Park *et al.,* 2000). The EP is an evolutionary computation in a stochastic optimization model similar to GA. Though the two use genetic operators, EP does not perform cross-over like GA but derives the optimal solution by selection, mutation and competition. Comparatively, EP is a better optimization method than DP for large generation systems (Kannan *et al.,* 2005).

BD techniques are proposed for resolving GEP problems iteratively. The lower bound of the GEP is computed iteratively as the generation investment sub-problem. The solution is then used as the input to the operation sub-problem and the corresponding solution comprising the upper bound form the new investment sub-problem. The overall investment problem is solved iteratively (Teixeira *et al.,* 2002).

The PSO technique use group and individual intelligence in a swarm to resolve combinatorial optimization problems. Initially, like EP a population of random probable solutions exists. However, in PSO each potential solution (particle) to the given GEP problem is assigned certain characteristics in space and the PSO probe the search using swarm intelligence (IEEE, 2008). In comparison, PSO resolves GEP problems within less computation time than DP for both small and large-scale systems (Coello *et al.*, 2002).

2.2.4 Wien Automatic System Planning (WASP) IV Model

The WASP is the most frequently used and best proven model for GEP analysis worldwide. It is developed and maintained by the International Atomic Energy Agency (IAEA). WASP IV model is the fourth version to be developed and distributed worldwide (Bhattacharyya *et al.*, 2010).

The WASP IV model is accomplished with powerful attributes to address new and emerging issues in the generation sector. The new features incorporated include: options for environmental emissions, fuel usage & energy generation constraints; environmental emission calculations and expanded capabilities for handling up to 90 plant types and 500 configurations per year. The model attributes designed in an enhanced DP algorithm incorporated with heuristic technique is capable of deriving the optimal solution for generation capacity addition that meets the energy demand for at most 30 years (Elkarmi *et al.*, 2012; Jayandra *et al.*, 2016).

Fundamentally, the evaluation of the optimal solution in WASP IV is based on minimizing the objective function that represents the envisaged energy system's cost that consists of the existing and candidate plants. The objective function (B_j) is the sum of the capital investment costs (I), operation & maintenance costs (M); fuel costs (F), fuel inventory cost (L) and the cost of energy not served $(\emptyset)$, less the salvage value (S) of the generation investment. Equation 2.1 shows the objective function which is subject to reliability, tunnel (construction), fuel availability and emission constraints (IAEA, 2006; Bhattacharyya, 2011; Elkarmi *et al.*, 2012; Jayandra *et al.*, 2016)

$$B_j = \sum_{t=1}^{T}\{\bar{I}_{jt} - \bar{S}_{jt} + \bar{F}_{jt} + \bar{L}_{jt} + \bar{M}_{jt} + \bar{\emptyset}_{jt}\} \qquad 2.1$$

In WASP IV, the system's cost is simulated through PPC besides the generation reliability while linear programming used in establishing the optimal generation dispatch plan that fulfills environmental emissions, fuel availability and energy generation constraints. An enhanced DP optimization in the model evaluates the costs of the alternative system expansion policies and derives the optimum solution (IAEA, 2006).

The PPC technique is affirmed by IAEA, (1984) and Fabien *et al.,* (2006) as the best analytical framework that GENCOs use when evaluating generation investment taking risks into account. The generation projects are capital intensive and often stay for long and their financial flows occur after some years. Discounting of costs and benefits with a proper discount rate to present value enables proper project evaluation. A proper choice of a discount rate cushions inflation and other generation investment uncertainties (Khatib, 2003; Bhattacharyya *et al.*, 2010; Elkarmi *et al.*, 2012; Jayandra *et al.*, 2016). Discounting (time value of money) is featured widely in literature for evaluating generation projects. Reliable financial techniques such as the net present value (NPV), future worth value (FWV) and internal rate of return (IRR) are applied extensively. However, NPV is the most effective project evaluation technique (Stoft, 2002; Bhattacharyya, 2011).

The economics of generation reliability often strikes a balance between cost and quality of service. Typically, the long-run marginal cost (LRMC) is the levelized cost where the marginal utility for the extra reliability enhancement to the consumer equals the marginal cost spent by the power supplier. The LRMC serves as the basis for determining electricity tariffs (Khatib, 2003; IES, 2004; Bhattacharyya *et al.*, 2010; Bhattacharyya, 2011; Jayandra *et al.,* 2016).

2.3 A Reviewon Green-Based Generation Expansion Planning

2.3.1 Transition to Green Least-Cost Generation Expansion Planning

Traditionally, the GEP problem is defined as the process of determining which, where and when new generation plants should be constructed over a long-range planning period to satisfy the energy demand forecast (Javadi *et al.*, 2011). This long-term generation investment criterion was usually minimizing the capital & operation costs and maximizing the system reliability with prevailing capacity, technology and operation constraints (Meza *et al*, 2007). However, the increasing concerns for the generation sector in the 21st century to mitigate climate change impacts has been added as an environment factor to the problem in terms of minimizing the environmental emissions (IPCC, 2011; Sadeghi *et al,* 2013; Li *et al.*,2016).

Currently, GENCOs are considering integration of green power as an important function of attaining crucial carbon emission reductions in the least-cost GEP (Geraldo *et al.*, 2010; Mejia *et al.*, 2012; Salvador *et al.*, 2016). Literature on green-based GEP by Maslyuk *et al.*, (2013); Karapidakis *et al.*, (2014); Lee *et al.*, (2015) amongst others demonstrates substantial capabilities for green generation investments in enormous carbon emission reduction and sustainable development. The authors show lots of green-based generation investment potential mainly in developing countries.

In Kenya, the 2011-2031 LCPDP projected a hydropower and heavy fuel oil (HFO) dominated power generation (MOE, 2011). The generation system was vulnerable to acute energy shortfalls due to the frequent droughts. The HFO as well as the planned conventional coal plants posed a CO_2 emissions dilemma (MOE, 2013; MEWNR, 2014). The need for enhanced security of power and emission reductions prompted the urgency for a green-based GEP for Kenya.

2.3.2 Carbon Emission Trading

The global quest for carbon emission reduction to mitigate climate change has generated business opportunities (Gupta, 2011). Many countries are beginning to appreciate the flexible global market-based mechanisms under the Kyoto Protocol (KP) for energy adequacy and emission reduction. The Clean Development Mechanism (CDM) is the most relevant mechanism for developing countries which have no binding commitment for emission reduction but can volunteer to enhance environmental sustainability (Shende *et al.*, 2014; Salvador *et al.*, 2016).

In CDM, a developed country can implement carbon emission reduction projects in a developing country where they are cheaper to set up. The avoided emissions on the projects generate carbon credits entitled certified emission reduction (CER) traded on the carbon market. The developing countries sell the carbon credits to the developed countries to help them meet their KP emission commitments. In this way, CDM promotes green power generation projects which currently comprise 68% of the total global registered CDM projects (Sukumaran, 2014).

Although CDM promotes green investments, the projects are characterized by high capital costs, long-returns-on investment periods and uncertainties. The green-based generation expansion investment risks are very high (Borenstein, 2011). However, some energy policy incentive measures such as power purchase agreements (PPA) and Feed-In-Tariffs (FiT), have been implemented with success in many countries in the world to hedge the risks and promote green power generation investment (UNEP, 2012; Javadi *et al.*, 2013).

The implementation of CDM is facing three main shortcomings observed by (Sukumaran, 2014) that limit its uptake globally. Firstly, the validation, registration and issuance of CERs for CDM projects take around 1.5-2 years hence very long for project developers. Secondly, the profit-regulated carbon market pricing subject to market demand and supply forces is so volatile. For instance, in the 2005 a CER was worth US$32.6 but over time fell to as low as US$ 3.04 by 2014 discouraging many investors. Lastly, fraud and forgery of CDM projects have had some fake projects approved at the expense of tax-payers. In spite of these bottle-necks, Shende *et al.*, (2014) is optimistic that proper price regulations as well as thorough and timely approval of green projects will stimulate rapid growth of CDM in the near future.

2.3.3 Green Jobs for the Low Carbon World

The global drive towards low carbon world has led to increasing green generation investment patterns that are in favor of green jobs. The green generation sector employs many in manufacturing of power plant machinery & equipment, project management, procurement & logistics, construction, operation & maintenance, financial, legal and consultation services. Besides, certain taxes are collected from green project owners (Borenstein, 2011).

Substantial research and development (R&D), production and investment in green power technology are in the US, Germany, China, Japan and Brazil. These countries comprise the bulk of the global green jobs. However, construction, operation and maintenance jobs that are more localized benefit many host countries in the developing nations (UNEP, 2008).

The green generation sector employs about 2.5 million workers globally. A huge chunk of about 52% are estimated employed in Brazil, the US, Germany and China. Others include; 13% in wind power; 7.4% in solar PV and 26% in solar thermal sector. Although growth in the green jobs are majorly in developed and fast developing countries, other developing nations are beginning to reap the fruits in these era of green growth for sustainable development (UNEP, 2011).

2.3.4 Renewable Energy Power Generation Technical Issues

Renewable energy (RE) integration as an important aspect of green growth is anticipated to grow significantly especially in developing countries. However, GENCOs and power system's operators face three challenges when integrating wind and solar in their power systems. The sources are site-specific and highly variable hence uncertain system's reliability. Unexpected system's disturbances stemming from load variation, grid faults and power outages arise from time to time (Khatib, 2003; Elkarmi *et al.*, 2012).

R&D studies have revealed novel solutions for the power system challenges. At the generation side, both RE and conventional power plants incorporated in an improved grid design with suitable automatic control capabilities mitigate the negative system's reliability impacts of RE integration (Elkarmi *et al.*, 2012). Demand response (DR) achieves flexibility from the load side through load shifting and balancing enhancing effective load management practices for RE integration. Energy storage serves as a back-up for the grid and load improving generation reliability (Khatib, 2003).

2.4 Research Gap

The generation sector; Kenya included is faced with enormous pressure to lead the way in climate change mitigation strategies due to its carbon-intensive power plants. The green-based least-cost GEP is rapidly gaining consideration as the most popular energy policy for integrating clean energy resources for security of power and CO_2 emission reductions. Green energy resource potential is enormous and largely untapped particularly in developing countries.

There are opportunities for green power generation such as green jobs, healthy environment, foreign exchange and carbon revenues for mitigating climate change. However, the green power generation is a capital intensive investment that discourages development in many developing countries like Kenya. However, appropriate incentives energy policy measures such as power purchase agreements (PPA) and feed-in-tariffs (FiT) that are successfully working in many countries around the world to lower the risks can be adopted to promote green generation investments.

2.5 Summary

In this chapter, an overview of GEP provides its fundamental principles. The GEP conceptual model is outlined to show the logic behind simulation and optimization. The DP and Heuristic optimization models are presented as building blocks for WASP IV model which is the main study tool. A review of green-based GEP outlines prevailing opportunities and challenges in the upcoming green power generation. In the long-run, the opportunities far outweigh the challenges for security of power and sustainable development. The drive to developing a green-based GEP for Kenya is to leverage the use of the numerous opportunities for security of power and sustainable development.

CHAPTER THREE

METHODOLOGY

3.1 Introduction

In this study, a generation expansion planning (GEP) involving modeling of a green least cost generation expansion plan (GLCGEP) for Kenya in the Wien Automatic System Planning (WASP) IV model was undertaken. The plan was a probable substitute for the 2011-2031 least cost power development plan (LCPDP) previously prepared by the power sector for Kenya. The main data sources were the Ministry of Energy & Petroleum, the Kenya Power & Lighting Company (KPLC) & Kenya Generating Company (Kengen).

3.2 Overview of the Generation Expansion Planning Methodology

The study mainly involved optimizing a portfolio of feasible green power plants in Kenya. To attain this goal, the study firstly involved determining the green candidate plants. Secondly based on the green candidate plants, an optimal GLCGEP was derived in the WASP IV model. Finally, techno-economic characteristics of the GLCGEP and 2011–2031 LCPDP were established in a comparative analysis. Figure 3.1 shows the GEP methodology for the study.

The WASP IV model, available at no cost was the main tool for GEP in this study. WASP IV was systematic and modular consisting of various modules. The first three modules were for basic input data on the demand forecast in Appendix II, existing & committed generation plants in Appendix IV to VI and candidate plants in Appendix VII to X. These include; **load sy**stem (LOADSY), **fix**ed **sy**stem (FIXSYS) and **var**iable **sys**tem (VARSYS) respectively. The three modules were executed independently of each other. The next four modules namely; **con**figuration **gen**erator (CONGEN), **mer**ge and **sim**ulate (MERSIM), **Re**-**mer**ge and **sim**ulate (REMERSIM) and **dyn**amic **pro**gramming (DYNPRO) were executed after analyzing the first three. Lastly REPROBAT module generated the study report.

The generation cost model (GCM) was constructed in Microsoft Excel to evaluate the techno-economic characteristics of the candidate generation plants. The GCM's screening curves; the level cost of electricity (LCOE) in particular formed the basis for selecting suitable green candidate plants for GEP. The generation characteristics of the selected candidates were used as VARSYS input.

The WASP IV modeling involved demand forecast input to LOADSY, the existing & committed plants' techno-economic characteristics to FIXSYS besides the VARSYS input. The reference demand forecast scenario (RDFS) and higher demand forecast scenario (HDFS) were considered. The optimal GLCGEP was obtained from CONGEN-MERSIM-DYNPRO iterations while REPROBAT gave the study report summary. A sensitivity analysis was carried out to assess the effect of discount rate, fuel cost and capital cost variations in DYNPRO on the GLCGEP system's cost. Similarly, CONGEN-MERSIM-DYNPRO iterations were undertaken to determine a new unconstrained optimal solution.

Finally, a comparative analysis was undertaken on the techno-economic characteristics of the GLCGEP in the RDFS with respect to the 2011-2031 LCPDP. Their relative capacity mix, CO_2 emissions and economic feasibility were evaluated. The outcomes of the comparative study provided an option of retaining the 2011-2031 LCPDP or adopting the GLCGEP.

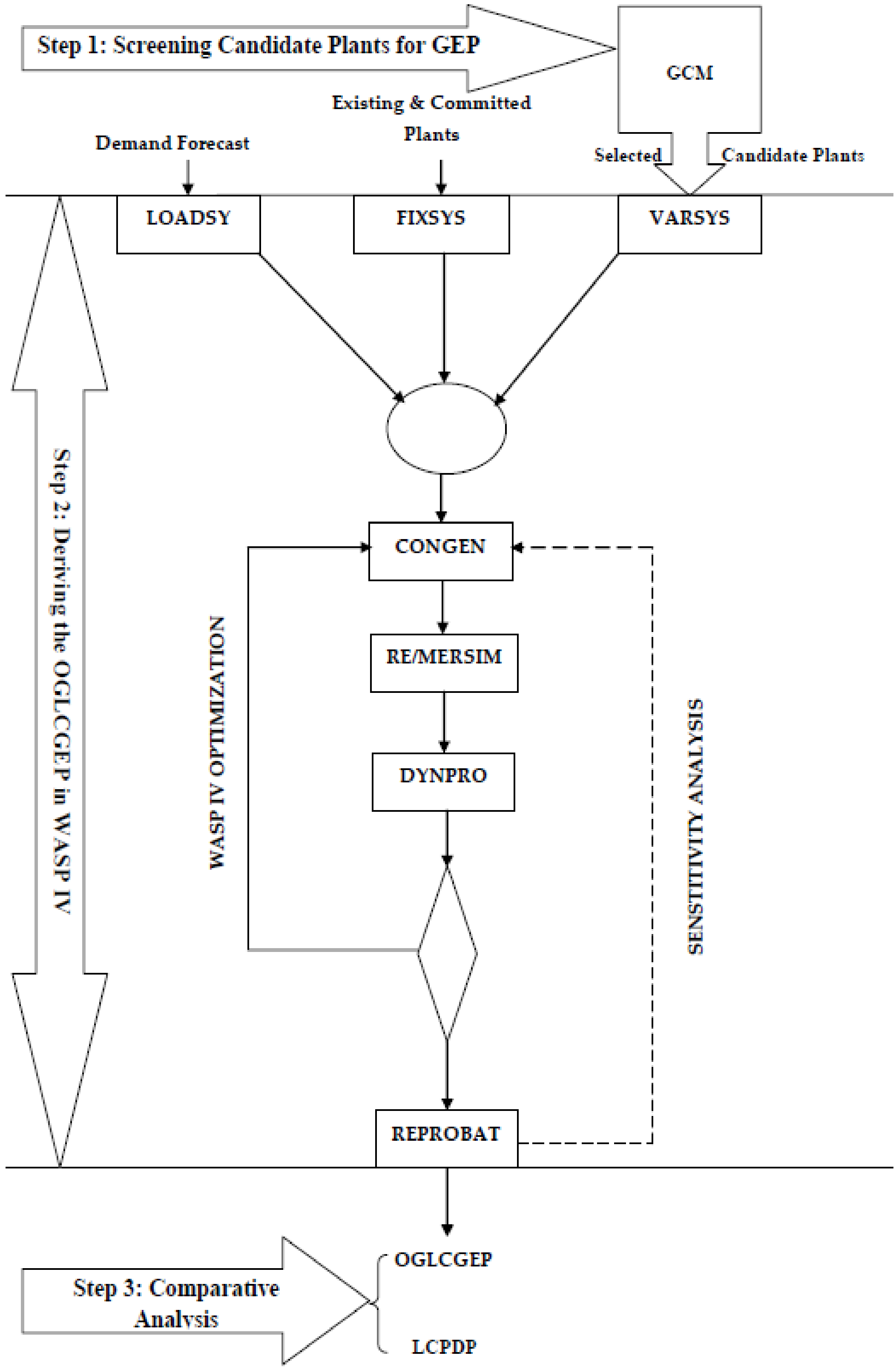

Figure 3.1: GEP Methodology for the Study

Source: Adapted from IAEA (2006)

3.3 Selecting Green Candidate Generation Plants for GLCGEP

The candidate generation plants for the study include; 140MW geothermal, 1000MW nuclear, 300MW coal and 180MW Gas Turbine (GT)-Kerosene. Others include 180MW GT-Natural gas, 160MW heavy fuel oil (HFO), 1000MW Ethiopia imports, 60MW Mutonga hydro, 140MW low grand falls (LGF), 300MW wind and 100MW solar photovoltaic (PV). These were Kenya’s feasible energy resources (SWERA, 2008; MOE, 2011; MOE, 2013) for the study.

A generation cost model (GCM) was set up in the Microsoft Excel encompassing each candidate plant. Figure 3.2 shows the GCM outline for all the candidate plants.

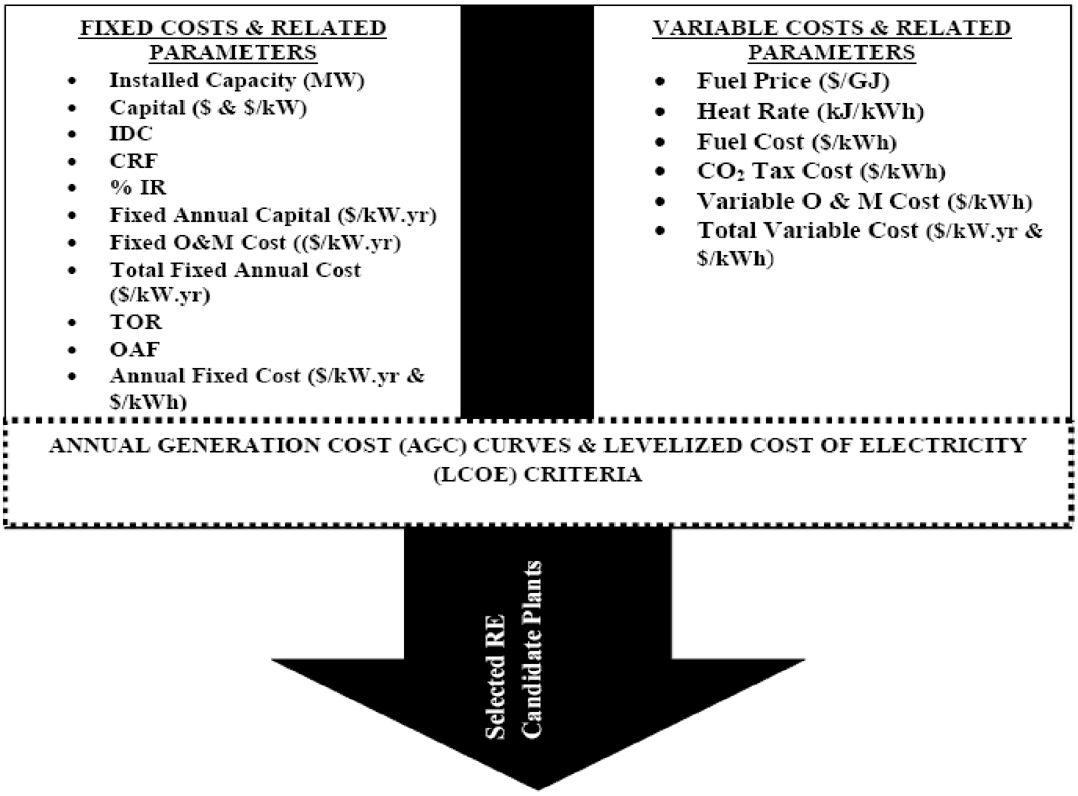

Figure 3.2: GCM Outline for all Candidate Generation Plants

The GCM mainly comprised the technical and economic power generation characteristics. The generation characteristics include; fixed & variable generation costs, total outage rate (TOR), outage adjustment factor (OAF), interim replacement (IR), interest during construction (IDC) and capital recovery factor (CRF). Some of the characteristics are shown in appendix IX. The model equations 3.1 to 3.9 as adapted from Stoft, (2002) and Khatib, (2003) were used to represent the power generation characteristics for all the candidates in the GCM.

$$Capital\ (\$X10^6) = \frac{Installed\ Capacity\ X\ Capital}{(10^3)} \tag{3.1}$$

$$Fixed\ Annual\ Capital = \{Capital\ X(IDC\ Factor)X(CRF + IR)\} \tag{3.2}$$

$$Total\ Fixed\ Annual\ Cost = \{Fixed\ Annual\ Capital + Fixed\ O\&M\} \tag{3.3}$$

$$OAF\ = \frac{1}{(1 - TOR)} \tag{3.4}$$

$$Annual\ Fixed\ Cost = \{Total\ Fixed\ Annual\ Cost\ X(OAF)\} \tag{3.5}$$

$$Annual\ Fixed\ Cost = \frac{Annual\ Fixed\ Cost}{(8760)} \tag{3.6}$$

$$Fuel\ Cost = \frac{Fuel\ Price\ X\ Heat\ Rate}{(10^6)} \tag{3.7}$$

$$Total\ Variable\ Cost = \{Fuel\ Cost\ + CO_2\ Tax\ Cost\ + Variable\ O\&M\ Cost\} \tag{3.8}$$

$$Total\ Variable\ Cost = \{Total\ Variable\ Cost\ X\ 8760\} \tag{3.9}$$

The GCM was used to evaluate the annual generation cost (AGC) for each candidate plant as a function of the annual variable cost (AVC); the annualized fixed cost (AFC) held constant. These cost variables for the candidates are shown in the AGC expression in equation 3.10. This is a linear equation where AFC is the intercept and AVC the slope.

$$AGC = \{(AVC).(Capacity\ Factor)\ + AFC\} \tag{3.10}$$

Similarly, the levelized cost of electricity (LCOE) for each candidate plant was calculated. The total variable cost (TVC), AFC and capacity factor are key LCOE components. The LCOE is shown in equation 3.11.

$$LCOE = TVC \quad + \frac{AFC}{(8760\, X\, \%\, Capacity\, Factor)} \qquad 3.11$$

The AGC and the LCOE curves were the screening curves for determining the green candidate plants for GEP. The base load and peaking candidates were chosen based on their relative generation costs. The power generation characteristics of the green candidates in the GCM were used as VARSYS input in the WASP IV model.

The generation candidate plants have certain technical and economic constraints that directly influenced their availability for capacity addition. In CONGEN model, this was specified in terms of when the plant(s) came first on-line. Table 3.1 displays the WASP IV modeling constraints for the reference demand forecast scenario (RDFS) and higher demand forecast scenario (HDFS).

Table 3.1: WASP IV Modeling Constraints

No.	Plant	RDFS			HDFS		
		Min. Capacity (MW)	Max. Capacity (MW)	1st Capacity Addition	Min. Capacity (MW)	Max. Capacity (MW)	1st Capacity Addition
1	Geothermal	1x140	7x140	2012	1x140	9x140	2012
2	Wind	1x100	10x100	2017	1x100	10x100	2015
3	Nuclear	1x600	1x600	2023	1x600	2x600	2022
4	Imports	1x200	2x200	2017	1x200	4x200	2017
5	GT-Ngas	1x180	4x180	2016	1x180	7x180	2016
6	Solar PV	1x100	1x100	2023	1x100	1x100	2021
7	Mutonga	1x60	1x60	2018	1x60	1x60	2018
8	LGF	1x140	1x140	2018	1x140	1x140	2018

In Table 3.1, it is shown that the Ethiopian imports would be available earliest from 2017 after commissioning the 686KM 500kV Ethiopia-Kenya HVDC transmission line by the end of 2016. The LGF would come on line earliest in 2018 due to its 8 years construction period as shown in appendix IX (MOE, 2011). The year 2022 would be the earliest for nuclear power generation according the Kenya Nuclear Energy Board strategic plan (MOE, 2013).

3.4 Modeling the GLCGEP

3.4.1 Simulation & Optimization

In this study; the reference demand forecast scenario (RDFS) and the higher demand forecast scenario (HDFS) were simulated for the 2011-2031 planning period; 2010 the base year. The RDFS assumed Kenya's demand projections incorporated with energy requirements for part implementation of the Vision 2030 flag-ship projects. On the other hand, the HDFS assumed the country's demand forecast integrated with energy demands for full implementation of all the flagship projects.

The optimization process involved minimizing certain cost components in the WASP IV objective cost function discounting the energy system's cost at an 8% discount rate subject to capacity, technology and operational constraints. The objective function ($\boldsymbol{B_j}$) in equation 3.12 is composed of: capital investment costs (I), fuel costs (F), operation and maintenance (O&M) costs (M), fuel inventory costs (L), salvage value of investments (S) and cost of energy demand not served (**ø**). The planning period of time (**t**) is given in years while ***T*** (21) is the length of the study period in years. More related equations are shown in Appendix III.

$$B_j = \sum_{t=1}^{T}\{\bar{I}_{jt} - \bar{S}_{jt} + \bar{F}_{jt} + \bar{L}_{jt} + \bar{M}_{jt} + \bar{\emptyset}_{jt}\} \qquad 3.12$$

In WASP IV, the tunnel width for each candidate plant in each year was specified in the CONGEN module. CONGEN-MERSIM-DYNPRO sequential run were undertaken without changing any input in the other modules. After the initial successful run in each scenario, a number of CONGEN iterations and sequential runs were performed to obtain the optimal GLCGEP in DYNPRO.

Careful analysis of DYNPRO messages prior to new subsequent CONGEN iterations and runs was essential during optimization. As a rule of thumb, new iterative run(s) were prepared by increasing the minimum number of plants marked with (+) by one and decreasing by one those marked by (-) in CONGEN. In this study, preference was given to the selected green candidates besides nuclear and natural gas without going beyond their tunnel boundaries. The REBROBAT module provided a summary of attributes of the optimal GLCGEP namely generation capacity, energy, reliability and energy system's cost in the RDFS and HDFS.

3.4.2 CO_2 Emissions

The CO_2 emissions for the GLCGEP in the RDFS and HDFS were determined using relevant emission factors. Table 3.2 displays the emission factors for the energy generation technologies considered in the study. Table 3.2: Emission Factors for Energy Generation Technologies.

Table 3.2: Emission Factors for Energy Generation Technologies

SNo.	Energy Technology	TonCO$_2$/GWh
1	Baggase	301.8014
2	Kerosene	246.8583
3	HFO	249.7988
4	Natural gas	181.2356
5	Geothermal	25.6918
6	Coal	317.7424

Source: UNEP, (2011)

In each scenario, the energy technologies considered had varied emission factors based on their environmental pollution extents. The annual CO_2 emissions for the given energy technology in the planning period was computed using equation 3.13.

$$Annual\ Emission_{e\_technology} = \{G\_Energy_{e\_t} X\ Emission\ Factor_{e\_t}\} \quad 3.13$$

The total CO_2 emission for each technology in the period was established as the sum of the annual emissions in each of the RDFS and HDFS.

3.4.3 Generation Economics

Most economic costs of generation for the GLCGEP were obtained directly from the DYNPRO module in the WASP IV model. However, the average cost per unit generated was determined indirectly using the long-run marginal cost (LRMC). According to IES, (2004); the LRMC was the most convenient technique for calculating power tariffs.

In the LRMC, two optimal generation programs were considered in the WASP IV model. The first program was essentially the GLCGEP derived for the given demand forecast (RDFS or HDFS) while the second under an incremental load on the demand forecast. The REPROBAT results on energy, operation cost and capital cost for each program was utilized to generate a LRMC model in Microsoft Excel for the planning period. Figure 3.3 shows the LRMC model outline for the GLCGEP.

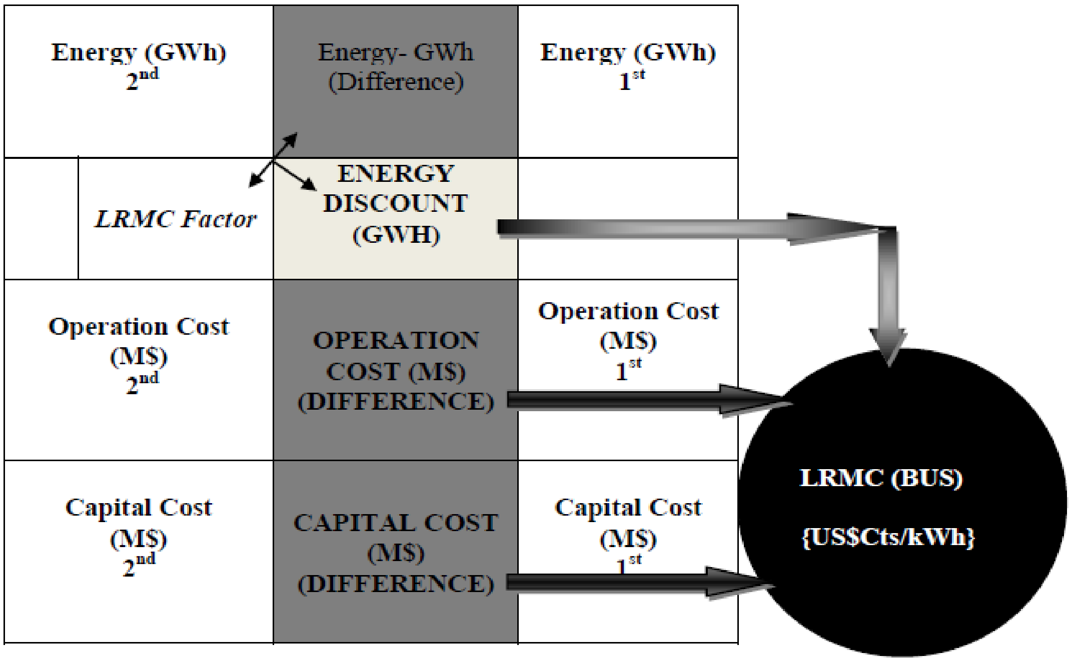

Figure 3.3: LRMC Model Outline for the GLCGEP

The energy, operation cost & capital cost differences in the REPROBAT results; LRMC factors (0.20 to 1.00) and energy discounts also comprised other essential LRMC model constituents. The energy discount was computed using equations 3.14. The operation and capital cost differences were crucial in the LRMC calculation at the bus and are shown in equations 3.15.

$$Energy\ Discount\ \{GWh\} = \{Energy\ Difference\ X\ LRMC\ Factor\} \quad 3.14$$

$$LRMC\,(bus) = \frac{\sum[Operation\ Cost\ Difference]}{\sum[EnergyDiscount]} + \frac{\sum[Capital\ Cost\ Difference]}{\sum[EnergyDiscount]} \quad 3.15$$

The present value (PV) inflows were calculated using equation 3.16 and the net present value (NPV) of the GLCGEP determined using equation 3.17. The energy generated was obtained from REPROBAT, the cost per unit generated from the LRMC technique and the salvage value & energy system's cost found in DYNPRO in the RDFS and HDFS.

$$Annual\,PV\,Inflows = \{Energy\,Generated\,X\,\mathbf{Cost\,per\,Unit\,Generated}\} \tag{3.16}$$

$$Annual\,Net\,Present\,Value = \{\mathbf{PV\,Inflows} + Salvage\,Value - System's\,Cost\} \tag{3.17}$$

3.4.4 Sensitivity Analyses

During the planning period, economic factors such as the discount rate; fuel cost and capital cost were anticipated to change over time. Sensitivity studies were conducted to identify the effect of these changes on the GLCGEP system's cost and NPV in the RDFS and HDFS. The study involved varying each of the given economic factors in DYNPRO module in WASP IV at reasonable steps. The discount rate was varied from 8% to 12% in steps of 2%; the fuel cost from 10% to 30% in steps of 10% and finally the capital cost from 5% to 15% in steps of 5%. A re-run of DYNAPRO was undertaken where the variations retained the optimal GLCGEP within its initial CONGEN tunnel boundaries. However, where the changes blew the tunnel boundaries, few CONGEN iterations and CONGEN-MERSIM-DYNPRO re-runs were executed to attain a new unconstrained optimal solution. The DYNPRO and REPROBAT results were used to assess the GLCGEP system's cost & NPV in the RDFS and HDFS.

3.5 Comparative Analysis

A comparative study of the GLCGEP in the RDFS and 2011-2031 LCPDP was carried out. In the analysis, the relative capacity mix, CO_2 emissions and NPV of the plans were assessed. The capacity mix for the GLCGEP and the LCPDP were obtained from Table 4.4 and Appendix XI respectively. The CO_2 emissions and NPV calculations in Sections 3.4.2 and 3.4.3 respectively applied. The study outcome established the basis for retaining the 2011-2031 LCPDP or adopting the GLCGEP under investigation.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Introduction

The selected green candidate plants for Generation Expansion Planning (GEP) are outlined. The optimal GLCGEP for the reference demand forecast scenario (RDFS) and higher demand forecast scenario (HDFS) are presented besides related sensitivity studies using WASP IV model. A comparative analysis of the GLCGEP (RDFS) and the 2011-31 least cost power development plan (LCPDP) is outlined.

4.2 Green Candidate Generation Plants

The generation cost model (GCM) that mainly comprise of technical and economic power generation characteristics was developed in Microsoft Excel for screening the candidate generation plants. The generation characteristics adopted from IAEA, (1984); Stoft, (2002); Khatib, (2003) and Bhattacharyya, (2011) that include; fixed & variable generation costs, total outage rate (TOR), outage adjustment factor (OAF), interim replacement (IR), interest during construction (IDC) and capital recovery factor (CRF) composed the GCM worksheet for the candidate plants. The equations 3.1 to 3.11 applied in formulating the GCM. Table 4.1 presents the GCM for all the candidate generation plants. Appendix VII shows extended models results.

The results show that capital costs widely varied across all the candidate generation plants. The 100 MW Solar PV plant had the highest capital cost of US$4450/kW/yr while the Ethiopian imports had the lowest of about a tenth of the solar PV's capital cost (US$455/kW/yr). On the other hand, the fuel cost was quite significant in the 180 MW GT-Kerosene plant that had the highest of U$ 22.2 cts/kWh while HFO the least at U$ 9.1 cts/kWh. Solar PV, wind, low grand falls (LGF), Mutonga hydro, imports and geothermal had no fuel costs.

Table 4.1: Generation Cost Model (GCM) for Candidate Generation Plants

Configuration (n x MW)	Geothermal 1 x 140	Nuclear 1 X 1000	Coal 1 X 300	GT-KERO 1 x 180	GT- N.GAS 1 x 180	HFO 1 x 160	Import 1000	Mutonga 1x60	LGF 1x140	Wind 300	Solar PV 100
Total Capacity (MW)	140	1000	300	180	180	160	1000	60	140	300	100
Fixed Cost											
Capital ($ x 10^6)	511	4055	631	135	135	218	455	259	507	690	445
Capital ($/kW)	3650	4055	2104	750	750	1364	455	4314	3621	2300	4450
IDC Factor	1.1344	1.2605	1.1341	1.0725	1.0725	1.0654	1.0654	1.3378	1.3378	1.0654	1.1380
Annuity Factor (or C.R.F.)	0.0937	0.0839	0.0937	0.1019	0.1019	0.1019	0.0937	0.0817	0.0817	0.0937	0.1114
Interim Replacement	0.921%	0.68%	0.921%	0.35%	0.35%	0.35%	0.35%	1.03%	0.87%	0.64%	0.63%
Fixed Annual Capital ($/kW/yr)	426.0	463.6	245.5	84.7	84.7	153.1	47.1	531.4	438.2	245.3	596.1
Fixed O&M Costs ($/kW/yr)	56.0	90.0	63	11.8	11.8	62.5	30.0	21.3	19.8	28.1	39.0
Total Fixed Annual Cost ($/kW/yr)	482	554	309	97	97	216	15	553	458	273	635
Total Outage Rate (TOR)	0.068	0.150	0.156	0.078	0.078	0.098	0.150	0.0969	0.0969	0.100	0.091
Outage Adjustment Factor (OAF)	1.073	1.177	1.185	1.085	1.085	1.108	1.176	1.107	1.107	1.111	1.100
Annual Fixed Cost ($/kW/yr)	**517**	**652**	**366**	**105**	**105**	**239**	**91**	**612**	**507**	**304**	**699**
Annual Fixed Cost ($/kWh)	**0.0590**	**0.0744**	**0.0417**	**0.0120**	**0.0120**	**0.0273**	**0.0104**	**0.0699**	**0.0579**	**0.0347**	**0.0798**

Variable Cost											
Configuration (n x MW)	**Geothermal 1 x 140**	**Nuclear 1 X 1000**	**Coal 1 X 300**	**GT-KERO 1 x 180**	**GT- N.GAS 1 x 180**	**HFO 1 x 160**	**Import 1000**	**Mutonga 1x60**	**LGF 1x140**	**Wind 300**	**Solar PV 100**
Heat Rate (kJ/kWh)	-		10900	11,440	11,447	8,197	-	-	-	-	-
Fuel Cost ($/kWh)	-	0.0087	0.0497	0.2216	0.1043	0.0909	-	-	-	-	-
CO_2 Tax Cost ($/kWh)	-		0.0221	0.0089	0.0066	0.0089	-	-	-	-	-
Variable O&M Cost ($/kWh)	0.00557	0.0049	0.0036	0.0120	0.0010	0.0089	-	0.0053	0.0053	0.0010	0.0010
Total Variable Cost ($/kWh)	**0.00557**	**0.0136**	**0.0754**	**0.2425**	**0.1119**	**0.1087**	**0.0500**	**0.0053**	**0.0053**	**0.0010**	**0.0010**
Total Variable Cost ($/kW/yr)	**49**	**119**	**660**	**2124**	**980**	**952**	**438**	**47**	**47**	**9**	**9**

The annualized fixed costs (AFC) and annualized variable costs (AVC) for the candidate plants at varied capacity factors yielded the annual generation cost curves (AGC) from the GCM. Figure 4.1 shows the AGC curves for all the candidate plants.

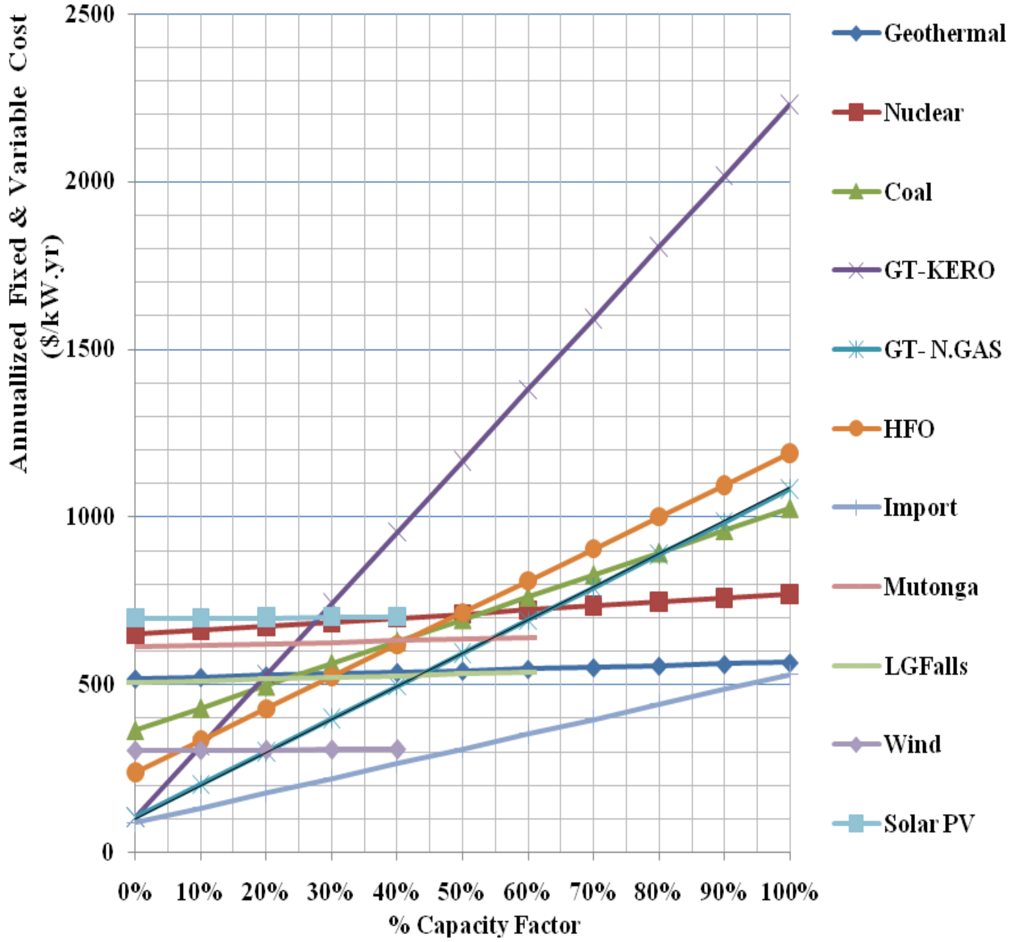

Figure 4.1: AGC Curves for Candidate Plants

The AGC show that the 100 MW solar PV plant had the highest AFC of US$ 699/kW/yr while the 1000 MW Ethiopian imports the least at US$ 91/kW/yr. The 180 MW GT-Kerosene plant had the highest AVC of US$ 2124/kW/yr while 300 MW wind and 100 MW solar PV plants the least at US$ 9/kW/yr each.

The unit cost for the candidate plants at varied capacity factors set up the levelized costs of electricity (LCOE) curves from the GCM. Figure 4.2 show the LCOE curves for the candidate plants. The LCOE show that solar PV plant at 30% capacity factor cost highest at US$ 20 cts /kWh while the Ethiopian imports at 90% capacity factor cost the least at US$ 6.2 cts/kWh.

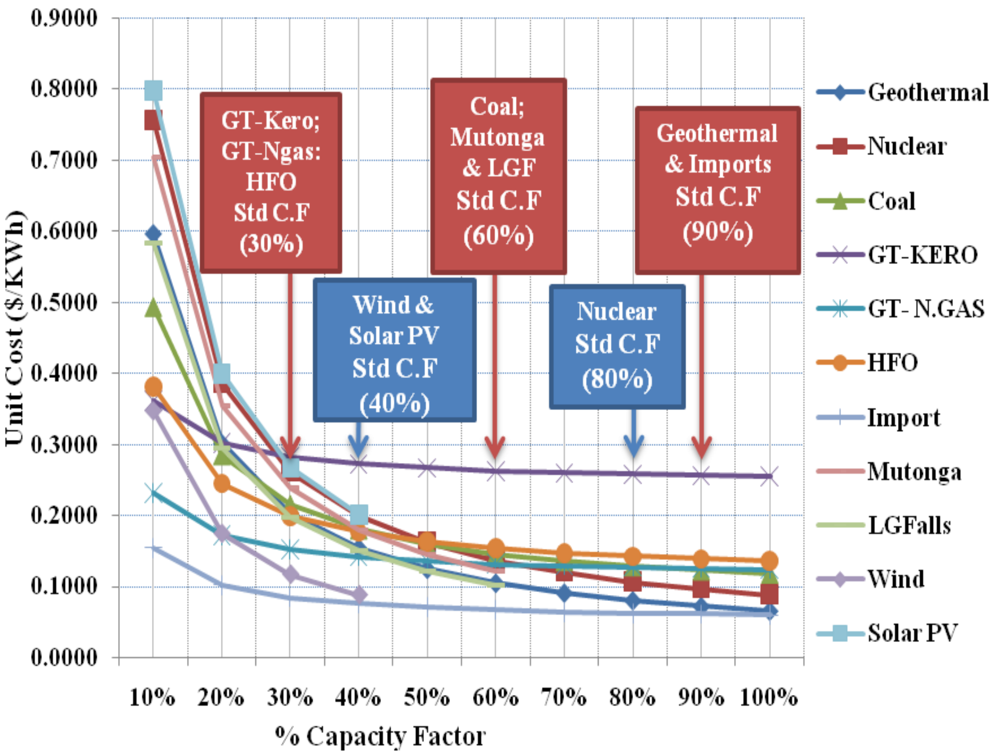

Figure 4.2: LCOE Curves for Candidate Plants

The results in AGC and LCOE screening curves were summarized in Table 4.2 to distinguish base loads from peaking power plants. In the results, it was observed that at high capacity factors of above 40%, the base load candidates incurred higher AFC than AVC and low LCOE. However, the case for 300 MW coal plant was rather incomparable with all the other base load plants. Coal had an AFC of US$ 366 per kW/yr lower than an AVC of US$ 660 per kW/yr. Coal plant's LCOE was highest in relation to all the base load candidate plants.

At low capacity factors of 30% and 40%, the peaking candidate plants had higher AVC than AFC and high LCOE. However, this was an exception for the 100 MW solar PV plant which had a lower AVC of US$ 9 per kW/yr than AFC of US$ 699 per kW/yr. Comparatively, the 100 MW solar PV and 160

MW HFO plants have the same LCOE of US$ 20 cts/kWh; but the HFO's relatively higher AVC of US$ 952 per kW/yr gives the solar PV plant an economical advantage as a better peaking plant. Similarly, the 180 MW GT-Kerosene was as unfavorable as the HFO for peaking plant on account of its highest LCOE.

Table 4.2: Base Load and Peaking Candidate Plants

S.No	Candidate Generation Plants	Annual Fixed Cost ($/kW/yr)	Annual Variable Cost ($/kW/yr)	LCOE ($cts/kWh)	% Capacity Factors	Plant Type
1	140MW Geothermal	517	49	7.1	90	
2	300MW Wind	304	9	8.8	40	
3	140MW LGF	507	47	10.2	60	
4	1000MW Nuclear	652	119	10.7	80	
5	60MW Mutonga hydro	612	47	12.2	60	**Base Loads**
6	300MW Coal	366	660	14.5	60	
7	1000MW Imports	91	438	6.2	90	**Both**
8	180MW GT-Nat Gas	105	980	15.2	30	
9	160MW HFO	239	952	20.0	30	
10	100MW Solar PV	699	9	20.0	40	**Peak Loads**
11	180MW GT-Kero	105	2124	28.2	30	

The screening curves are preliminary vetting techniques for base load and peaking plants. The incorporated techno-economic generation characteristics are utilized for selecting appropriate energy options for further GEP consideration (IAEA, 1984; Bhattacharyya, 2011; Zhang, 2013). The LCOE is the best criteria for screening as it encompasses crucial generation cost variables such as AFC, AVC and capacity factor (Khatib, 2003; Elkarmi *et al.*, 2012). Therefore, the green base load plants are identified as those with low LCOE (US$ 6-13 cts/kWh) and include 140 MW Geothermal, 140 MW LGF hydro, 300 MW Wind, 1000 MW Ethiopian imports and 60 MW Mutonga hydro. Although nuclear plants aren't green; the country's ambitions for nuclear as recognized in MOE, (2013) was factored into this plan. Therefore, a 1000 MW nuclear plant complemented the selected green base load plants with similar characteristics. Suitable peaking plants were those with high LCOE (US$ 15-30 cts/kWh) namely 180 MW GT-Natural gas and 100 MW Solar PV. In this case, natural gas plants were preferable as cleaner than HFO although they were not green. The imports were partially considered as peaking plants because of their abundance and least-cost. Overall, the selected candidate plants were mainly the cleanest available generation options with minimal CO_2 emissions.

Kenya is well endowed with enormous green candidate options. The 60 MW Mutonga and 140 MW LGF hydropower sites were due for immediate development (MOE, 2013). Besides; the abundant unexploited feasible geothermal potential of about 7600 MW exist as cited in Kengen, (2013) and MOE, (2013). The Kenya's strategic location along the equator offer about 638, 790 TWh potential for solar PV as a potential peaking substitute for the costly HFO power (Bazilian, *et al.,* 2013; Ondraczek, 2014). There is huge potential of about 346W/M^2 for wind base load power generation besides geothermal (SWERA, 2008). The numerous local energy resources as well as imports provided Kenya with a rich generation portfolio in favor of a green-based GEP for security of power and CO_2 emission reduction.

4.3 Optimal GLCGEP

This section presents the outcomes of the GLCGEP modeling and optimization in WASP IV for the two scenarios. Capacity mix, energy and CO_2 emissions and related economics are presented in each case. Sensitivity studies are also included.

4.3.1 Reference Demand Forecast Scenario (RDFS)

a) Capacity Mix

The optimal solution for annual capacity addition for the selected green candidate plants was obtained for the planning period. Table 4.3 presents the green power capacity addition schedule in the RDFS. Nuclear and natural gas were included to complement the green power capacity addition. The results show that the initial capacity addition is 420 MW from geothermal. This increased gradually to a total of 17380 MW by 2031. Geothermal had the highest additions at 42.7% while hydro and solar PV each at 1.2% the least.

Table 4.3: Green Power Capacity Addition Schedule (MW) – RDFS

Year	Geothermal (140MW)	Wind (100MW)	Nuclear (600MW)	Imports (200MW)	Natural Gas (180MW)	Solar PV (100MW)	Mutonga Hydro (60MW)	LGF (140MW)	Total Added Capacity(MW)
2010	-	-	-	-	-	-	-	-	0
2011	-	-	-	-	-	-	-	-	0
2012	3×140	-	-	-	-	-	-	-	420
2013	-	-	-	-	-	-	-	-	0
2014	-	-	-	-	-	-	-	-	0
2015	1×140	-	-	-	-	-	-	-	140
2016	2×140	-	-	-	1×180	-	-	-	460
2017	1×140	1×100	-	1×200	1×180	-	-	-	620
2018	-	1×100	-	1×200	-	-	1×60	1×140	500
2019	1×140	1×100	-	2×200	-	-	-	-	640
2020	2×140	-	-	1×200	-	-	-	-	480
2021	3×140	1×100	-	1×200	-	-	-	-	720
2022	2×140	5×100	-	-	-	-	-	-	780
2023	1×140	-	1×600	-	-	1×100	-	-	840
2024	3×140	1×100	-	1×200	1×180	-	-	-	900
2025	5×140	3×100	-	1×200	-	-	-	-	1200
2026	5×140	4×100	-	-	-	-	-	-	1100
2027	3×140	2×100	-	-	4×180	-	-	-	1340
2028	6×140	5×100	-	1×200	-	-	-	-	1540
2029	5×140	-	1×600	1×200	1×180	-	-	-	1680
2030	3×140	-	1×600	1×200	3×180	1×100	-	-	1860
2031	7×140	10×100	-	-	1×180	-	-	-	2160
Total	**53**	**34**	**3**	**11**	**12**	**2**	**1**	**1**	**117**
	7420	**3400**	**1800**	**2200**	**2160**	**200**	**60**	**140**	**17380**
%	**42.7%**	**19.6%**	**10.4%**	**12.7%**	**12.4%**	**1.2%**	**1.2%**		**100%**

When the capacity additions were integrated in the existing system, the optimal GLCGEP was derived. Table 4.4 show the optimal GLCGEP capacity in the RDFS. The results show that the generation capacity is 1382 MW at a peak demand of 1227 MW in the base year. The capacity was predominated by hydropower (55%) and HFO (24%) with the least reserve capacity hence the highest LOLP of 23.3%.

The annual capacity additions at an average rate of 901 MW varied the system's capacity in the base year to 19828 MW at 16905 MW peak demand in 2031. The generation capacities were characterized by low LOLPs ranging from 0.003% to 6.67% and averaged at 1.94%. By 2031, the total generation capacity will be geothermal (40.8%) and wind (19.2%) dominated.

Table 4.4: Optimal GLCGEP Capacity (MW) – RDFS

Year	Hydropower (MW)	Natural Gas (MW)	HFO (MW)	Nuclear (MW)	Imports (MW)	Bagasse (MW)	Kerosene (MW)	Geothermal (MW)	Solar PV (MW)	Wind (MW)	System's Capacity (MW)	Peak Load (MW)	% Reserve Margin	% LOLP
2010	761	0	332	0	0	26	60	198	0	6	1382	1227	12.6	23.265
2011	761	0	452	0	0	26	60	198	0	6	1502	1302	15.3	6.669
2012	761	0	452	0	0	26	60	626	0	6	1929	1520	26.9	0.118
2013	761	0	704	0	0	26	60	791	0	126	2466	1765	39.7	0.003
2014	814	0	704	0	0	26	0	1211	0	476	3229	2064	56.5	0.006
2015	839	0	704	0	0	26	0	1306	0	476	3349	2511	33.4	0.019
2016	839	180	704	0	0	26	0	1586	0	476	3809	2866	32.9	0.007
2017	839	360	704	0	200	26	0	1771	0	576	4474	3292	35.9	0.016
2018	1039	360	704	0	400	26	0	1771	0	676	4974	3751	32.6	0.008
2019	1039	360	648	0	800	0	0	1911	0	776	5532	4216	31.2	0.023
2020	1039	360	648	0	1000	0	0	2191	0	776	6012	4755	26.4	0.091
2021	1039	360	574	0	1200	0	0	2611	0	876	6658	5388	23.6	0.223
2022	1039	360	574	0	1200	0	0	2891	0	1376	7438	6048	23.0	0.773
2023	1039	360	514	600	1200	0	0	3031	100	1376	8218	6784	21.1	1.244
2024	1039	540	514	600	1400	0	0	3451	100	1476	9118	7608	19.8	1.208
2025	1039	540	461	600	1600	0	0	4151	100	1776	10266	8528	20.4	1.051
2026	1039	540	461	600	1600	0	0	4851	100	2176	11366	9556	18.9	1.546
2027	1039	1260	461	600	1600	0	0	5271	100	2376	12706	10706	18.7	1.276
2028	1039	1260	461	600	1800	0	0	6063	100	2876	14198	11994	18.4	1.539
2029	1039	1440	461	1200	2000	0	0	6763	100	2876	15878	13435	18.2	1.092
2030	1039	1980	461	1800	2200	0	0	7113	200	2876	17668	15026	17.6	1.006
2031	1039	2160	461	1800	2200	0	0	8093	200	3876	19828	16905	17.3	1.595
%	**5.2%**	**10.9%**	**2.3%**	**9.1%**	**11.1%**	**0.0**	**0.0**	**40.8%**	**1.0%**	**19.5%**	**100%**			**1.94**

b). Energy Mix and CO_2 Emissions

The energy generated for the optimal GLCGEP was projected to grow steadily over the entire planning horizon while meeting the requisite demand. Figure 4.3 presents the optimal GLCGEP energy mix for the RDFS by fuel type. The results show that the energy supply mix rose steadily from 7721 GWh in the base year to 105766 GWh in 2031 at the rate of 4457 GWh per year.

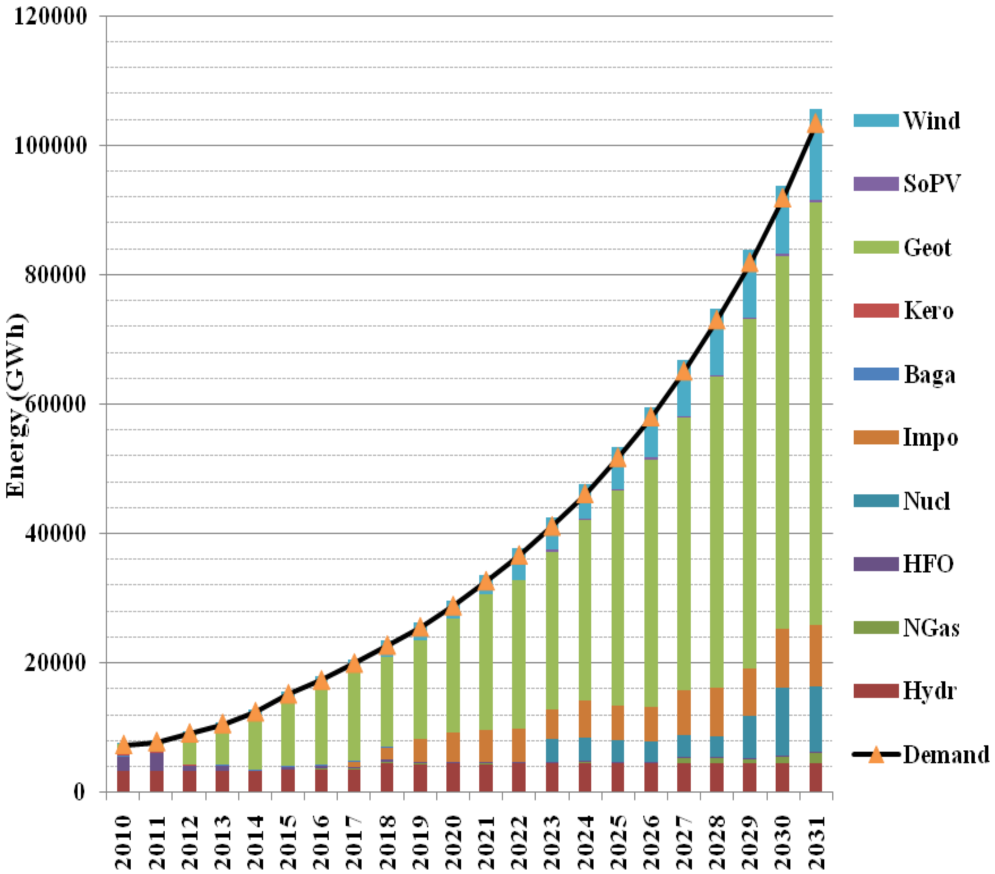

Figure 4.3: Optimal GLCGEP Energy Mix (GWh) – RDFS

The energy system was projected to emit some CO_2 emissions over the planning period due to the diverse fuels for power generation. Figure 4.4 illustrates the CO_2 emissions profile for the optimal GLCGEP in the RDFS by fuel type. In the base year, HFO was the highest emitter at about 78% of the total. However the trend changed to majorly geothermal by 2031 due to increasing green power capacity additions. The annual emissions grew from

0.73 Mt CO_2 in the base year to 2.0 Mt CO_2 in 2031. By 2031, a cumulative total of 18.1 Mt CO_2 was projected at an average rate of 0.86 Mt CO_2 per year.

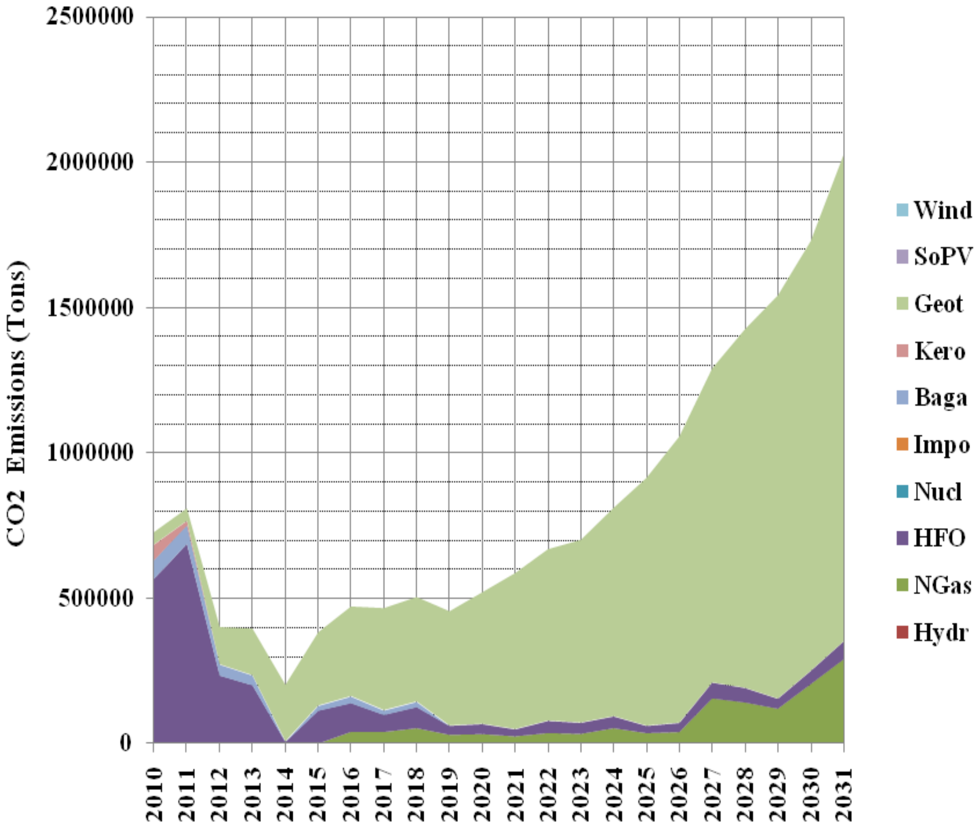

Figure 4.4: Optimal GLCGEPCO_2 Emission – RDFS

c). Generation Economics

The average power tariff per unit generated for the optimal GLCGEP was US$ 14.84 cts/kWh. Table 4.5 shows the optimal GLCGEP long-run marginal cost (LRMC) in the RDFS. The LRMC at the end of the generation bus was the unit selling price for electricity to power Distribution Company.

Table 4.5: Optimal GLCGEP LRMC - RDFS

Year	Energy (GWh) {2nd}	Energy (GWh) {1st}	Energy Differ. (GWh)	LRMC Factor	Energy Disco. (GWh)	Opern Cost (M$) {2nd}	Opern Cost (M$) {1st}	Opern Cost (M$) Differ.	Capital (M$) {2nd}	Capital (M$) {1st}	Capital Cost (M$) Differ.
				8.0							
2010	7772	7721	51.00	1.00	51.00	806.30	765.20	41.10	1419.34	1398.03	21.31
2011	8127	8047	80.00	0.93	74.07	502.10	479.80	20.65	614.22	593.05	19.60
2012	9496	9422	74.00	0.86	63.44	208.40	200.30	6.94	575.17	566.00	7.86
2013	11017	10944	73.00	0.79	57.95	222.50	215.40	5.64	387.60	361.93	20.38
2014	12874	12800	74.00	0.74	54.39	185.90	185.00	0.66	509.91	527.08	-12.62
2015	15640	15566	74.00	0.68	50.36	254.10	249.70	2.99	877.78	902.45	-16.79
2016	18038	17963	75.00	0.63	47.26	296.00	291.40	2.90	1374.70	1385.20	-6.62
2017	20707	20632	75.00	0.58	43.76	346.20	351.40	-3.03	1638.73	1663.71	-14.58
2018	23579	23503	76.00	0.54	41.06	441.70	436.90	2.59	1322.53	1322.53	0.00
2019	26491	26416	75.00	0.50	37.52	522.70	518.40	2.15	1388.58	1388.58	0.00
2020	29867	29793	74.00	0.46	34.28	615.00	610.70	1.99	2325.55	2325.55	0.00
2021	33835	33759	76.00	0.43	32.60	674.80	671.00	1.63	2537.15	2537.15	0.00
2022	37970	37895	75.00	0.40	29.78	737.70	733.50	1.67	2205.99	2205.99	0.00
2023	42575	42501	74.00	0.37	27.21	887.10	882.60	1.65	3154.58	3154.58	0.00
2024	47739	47665	74.00	0.34	25.19	1016.20	1011.60	1.57	3698.46	3748.62	-17.08
2025	53508	53433	75.00	0.32	23.64	1058.50	1054.50	1.26	3284.64	3267.92	5.27
2026	59762	59681	81.00	0.29	23.64	1142.30	1126.20	4.70	3690.28	3656.84	9.76
2027	66944	66869	75.00	0.27	20.27	1376.40	1371.30	1.38	2259.63	2259.63	0.00
2028	74983	74910	73.00	0.25	18.27	1486.60	1481.60	1.25	1429.47	1429.47	0.00
2029	84000	83920	80.00	0.23	18.54	1695.60	1691.00	1.07	2102.10	2102.10	0.00
2030	93935	93861	74.00	0.21	15.88	2082.50	2077.40	1.09	1003.06	1003.06	0.00
2031	105846	105766	80.00	0.20	15.89	2307.90	2301.60	1.25	0.00	0.00	0.00
Total	884705	883067	1638		806.02	18866.50	18706.50	103.11	37799.47	37799.47	16.50
					Bus						
					(US$ct/kWh)						
					Opern	**12.79**					
					Capital	**2.05**					
					LRMC	**14.84**					

The LRMC estimated the present value (PV) inflow streams accruing from power generation. Table 4.6 present the financial inflows and outflows of the optimal GLCGEP for the RDFS. The energy system's cost for the GLCGEP was projected to be US$ 14.62 billion with a salvage value of US$ 1.09 billion by 2031. On the other hand, the net present value (NPV) grew towards positive as the system approached 2031. The break-even point was around 2029-2030 and later attained US$ +2.16 billion in 2031.

Table 4.6: Optimal GLCGEP Financial Inflows & Outflows- RDFS

Year	PV – Inflow (US$ Billions)	Salvage Value (US$ Billions)	System's Cost (US$ Billions)	NPV (US$ Billions)
2031	15.70	1.09	14.62	2.16
2030	13.93	0.89	14.08	0.74
2029	12.45	0.93	13.48	-0.10
2028	11.12	0.74	12.83	-0.97
2027	9.92	0.42	12.14	-1.79
2026	8.86	0.58	11.52	-2.09
2025	7.93	0.54	10.76	-2.30
2024	7.07	0.31	9.93	-2.55
2023	6.31	0.58	9.23	-2.34
2022	5.62	0.32	8.25	-2.31
2021	5.01	0.26	7.43	-2.16
2020	4.42	0.15	6.62	-2.05
2019	3.92	0.11	5.98	-1.95
2018	3.49	0.17	5.38	-1.72
2017	3.06	0.10	4.74	-1.58
2016	2.67	0.12	4.08	-1.30
2015	2.31	0.05	3.29	-0.93
2014	1.90	0.00	2.83	-0.93
2013	1.62	0.00	2.70	-1.08
2012	1.40	0.11	2.54	-1.03
2011	1.19	0.00	1.16	0.03
2010	1.15	0.00	0.74	0.41

4.3.2 Higher Demand Forecast Scenario (HDFS)

a). Capacity Mix

The optimal solution in the HDFS had higher proportions of green power capacity additions than the RDFS. Table 4.7 presents the annual green power capacity addition schedule in the HDFS. Nuclear and natural gas were included to complement the green power capacity addition.

Table 4.7: Green Power Capacity Addition Schedule (MW) – HDFS

Year	Geothermal (140MW)	Wind (100MW)	Nuclear (600MW)	Imports (200MW)	Natural Gas (180MW)	Solar PV (100MW)	Mutonga Hydro (60MW)	LGF (140MW)	Total Added Capacity(MW)
2010	-	-	-	-	-	-	-	-	0
2011	-	-	-	-	-	-	-	-	0
2012	1×140	-	-	-	-	-	-	-	140
2013	1×140	-	-	-	-	-	-	-	140
2014	-	-	-	-	-	-	-	-	0
2015	2×140	1×100	-	-	-	-	-	-	380
2016	3×140	1×100	-	-	1×180	-	-	-	700
2017	2×140	-	-	1×200	-	-	-	-	480
2018	2×140	1×100	-	1×200	-	-	1×60	1×140	780
2019	3×140	2×100	-	-	1×180	-	-	-	800
2020	3×140	2×100	-	1×200	-	-	-	-	820
2021	4×140	1×100	-	1×200	-	1×100	-	-	960
2022	1×140	1×100	1×600	-	1×180	-	-	-	1020
2023	-	-	2×600	-	-	-	-	-	1200
2024	4×140	2×100	-	1×200	2×180	-	-	-	1320
2025	6×140	3×100	-	1×200	1×180	-	-	-	1520
2026	5×140	7×100	-	1×200	-	-	-	-	1600
2027	-	1×100	1×600	4×200	2×180	1×100	-	-	1960
2028	9×140	3×100	-	-	3×180	-	-	-	2100
2029	8×140	1×100	2×600	-	-	-	-	-	2420
2030	9×140	10×100	-	-	3×180	-	-	-	2800
2031	8×140	9×100	-	-	7×180	1×100	-	-	3380
Total	**71**	**45**	**6**	**11**	**21**	**3**	**1**	**1**	**159**
	9940	**4500**	**3600**	**2200**	**3780**	**300**	**60**	**140**	**24520**
%	**40.5%**	**18.4%**	**14.7%**	**9.0%**	**15.4%**	**1.2%**	**0.8%**		**100%**

The results show that all the candidate plants except Ethiopian imports and hydropower increased with reference to the RDFS during the planning period.

The green power generation capacities were added as follows relative to the RDFS; geothermal 7420 MW to 9940 MW; wind 3400 MW to 4500 MW; nuclear doubled from 1800 MW; natural gas from 2160 MW to 3780 MW and solar PV 200 MW to 300 MW. The total capacity addition of 17380 MW in the RDFS increased to 24520 MW in the HDFS. On aggregate, geothermal at 40.5% accounted for the highest total capacity additions while hydropower at 0.8% the least.

When the annual green power capacity additions were incorporated in the existing system, the optimal GLCGEP was derived. Table 4.8 shows the optimal GLCGEP capacity in the HDFS. The generation capacities were entirely the same as the RDFS in the base year. The capacity was dominated by hydropower (55%) and HFO (24%) with the highest LOLP of 23.3%.

However, the annual green power capacity additions at an average rate of 1226 MW varied the generation capacity to 26968 MW at 22985 MW peak demand in 2031. This was relatively higher than the corresponding 19828 MW capacity at 16905 MW peak demand in the RDFS. The capacities in the HDFS demonstrated higher annual LOLPs than the RDFS ranging from 0.013% to 9.88% and averaged at 3.02%. By 2031, the generation capacity will be dominated by geothermal (39.4%) and wind (18.5%) like the RDFS.

Table 4.8: Optimal GLCGEP Capacity (MW) – HDFS

Year	Hydropower (MW)	Natural Gas (MW)	HFO (MW)	Nuclear (MW)	Imports (MW)	Baggase (MW)	Kerosene (MW)	Geothermal (MW)	Solar PV (MW)	Wind (MW)	System's Capacity (MW)	Peak Load (MW)	% Reserve Margin	% LOLP
2010	761	0	332	0	0	26	60	198	0	6	1382	1227	12.6	23.265
2011	761	0	452	0	0	26	60	198	0	6	1502	1331	12.8	9.877
2012	761	0	452	0	0	26	60	346	0	6	1649	1584	4.1	20.337
2013	761	0	704	0	0	26	60	651	0	126	2326	1877	23.9	0.205
2014	814	0	704	0	0	26	0	1071	0	476	3089	2236	38.2	0.013
2015	839	0	704	0	0	26	0	1306	0	576	3449	2760	25.0	0.692
2016	839	180	704	0	0	26	0	1726	0	676	4149	3207	29.4	0.096
2017	839	180	704	0	200	26	0	2051	0	676	4674	3749	24.7	0.233
2018	1039	180	704	0	400	26	0	2331	0	776	5454	4322	26.2	0.150
2019	1039	360	648	0	400	0	0	2751	0	976	6172	4970	24.2	0.344
2020	1039	360	648	0	600	0	0	3171	0	1176	6992	5703	22.6	0.552
2021	1039	360	574	0	800	0	0	3731	100	1276	7878	6521	20.8	0.861
2022	1039	540	574	600	800	0	0	3871	100	1376	8898	7397	20.3	0.877
2023	1039	540	514	1800	800	0	0	3871	100	1376	10038	8388	19.7	0.860
2024	1039	900	514	1800	1000	0	0	4431	100	1576	11358	9509	19.4	0.714
2025	1039	1080	461	1800	1200	0	0	5271	100	1876	12826	10778	19.0	0.729
2026	1039	1080	461	1800	1400	0	0	5971	100	2576	14426	12217	18.1	1.301
2027	1039	1440	461	2400	2200	0	0	5971	200	2676	16386	13847	18.3	1.074
2028	1039	1980	461	2400	2200	0	0	7183	200	2976	18438	15697	17.5	1.039
2029	1039	1980	461	3600	2200	0	0	8303	200	3076	20858	17796	17.2	0.835
2030	1039	2520	461	3600	2200	0	0	9493	200	4076	23588	20156	17.0	1.155
2031	1039	3780	461	3600	2200	0	0	10613	300	4976	26968	22985	17.3	1.222
%	**3.9%**	**14.0%**	**1.7%**	**13.3%**	**8.2%**	**0**	**0**	**39.4%**	**1.1%**	**18.5%**	**100%**			**3.02**

b). Energy Mix and CO_2 Emissions

The optimal GLCGEP energy in the HDFS was capable of meeting the prevailing demand over the planning horizon. Figure 4.5 presents the optimal GLCGEP energy mix in the HDFS. The energy mix increased from 7721 GWh in the base year to 143830 GWh in 2031 at the rate of 6538 GWh per year. The rate of energy increase was higher than in RDFS due to a higher capacity addition rate.

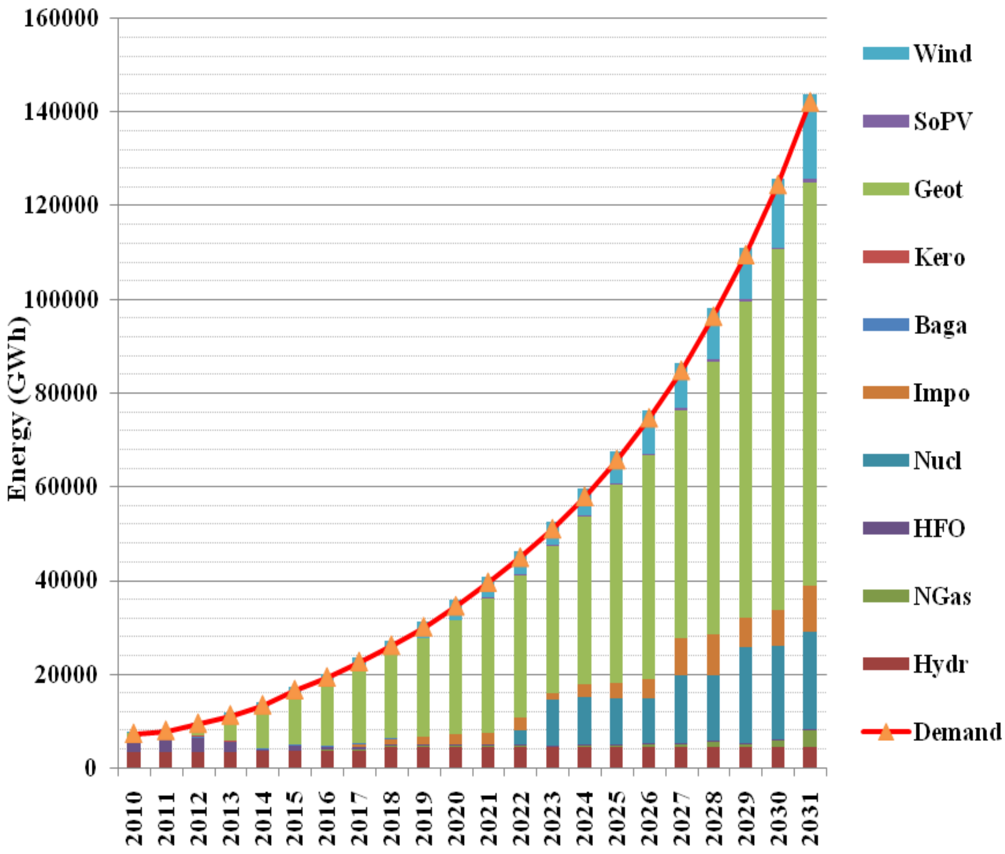

Figure 4.5: Optimal GLCGEP Energy Mix - HDFS

The energy system was projected to emit a higher quantity of CO_2 emissions compared to the RDFS over the planning period. Figure 4.6 illustrates the CO_2 emissions profile for the optimal GLCGEP in the HDFS. The annual CO_2 emissions grew from 0.73 Mt CO_2 in the base year to 2.9 Mt CO_2 in 2031. By 2031, a cumulative total of 23.6 Mt CO_2 would be attained at a higher rate of 1.12 Mt CO_2 per year compared to the RDFS.

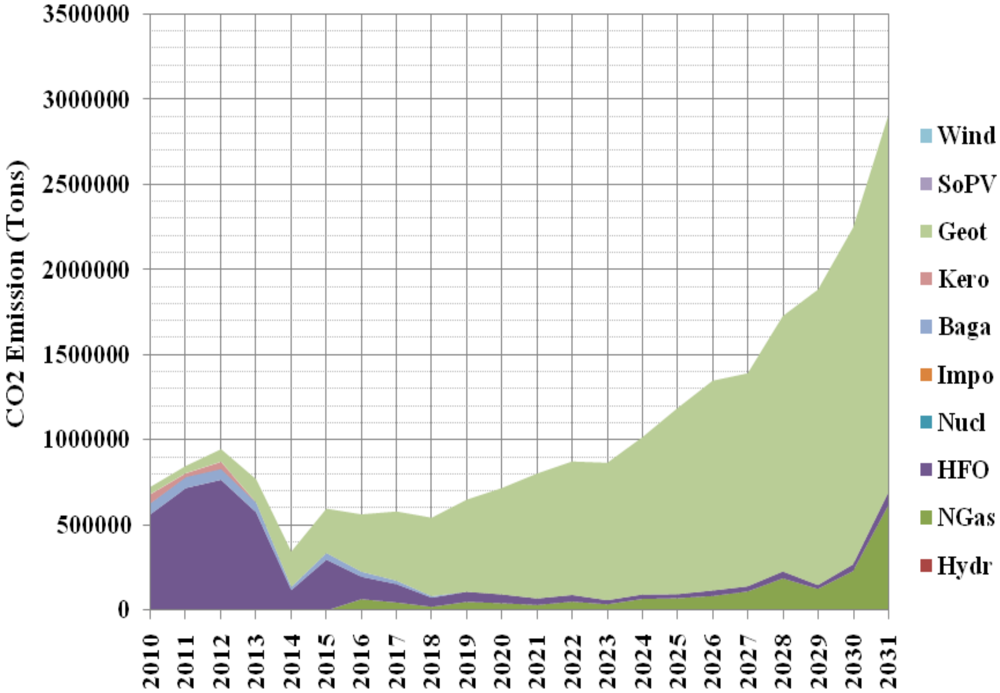

Figure 4.6: Optimal GLCGEPCO_2 Emission – HDFS

c). Generation Economics

The average power tariff per unit generated in the optimal GLCGEP is US$ 17.85 cts/kWh. Table 4.9 shows the optimal GLCGEP LRMC in the HDFS. This LRMC shows that the unit price for electricity at the end of the generation bus to the Distribution Company will be US$ 3.01 cts/kWh higher than the RDFS.

Table 4.9: Optimal GLCGEP LRMC - HDFS

Year	Energy (GWh) $\{2^{nd}\}$	Energy (GWh) $\{1^{st}\}$	Energy Diff. (GWh)	LRMC Factor	Energy Disc. (GWh)	Opern Cost (M$) $\{2^{nd}\}$	Opern Cost (M$) $\{1^{st}\}$	Opern Cost (M$) Differ.	Capital (M$) $\{2^{nd}\}$	Capital (M$) $\{1^{st}\}$	Capital Cost (M$) Diff.
				8.0							
2010	7742	7721	21.00	1.00	21.00	782.2	765.20	17.00	1154.80	1154.80	0.00
2011	8236	8210	26.00	0.93	24.07	537.1	528.00	8.43	893.16	893.16	0.00
2012	9707	9685	22.00	0.86	18.86	707.3	694.40	11.06	926.15	926.15	0.00
2013	11666	11636	30.00	0.79	23.81	429.6	425.00	3.65	1045.88	1045.88	0.00
2014	13895	13863	32.00	0.74	23.52	232.3	230.40	1.40	1428.94	1428.94	0.00
2015	17138	17106	32.00	0.68	21.78	362.2	358.70	2.38	1551.58	1551.58	0.00
2016	20126	20095	31.47	0.63	19.83	347.3	345.00	1.45	2552.12	2377.56	110
2017	23523	23491	32.26	0.58	18.82	417.3	415.30	1.17	2760.65	2819.10	-34.1
2018	27112	27080	32.00	0.54	17.29	450.4	448.70	0.92	2183.19	2250.64	-36.4
2019	31171	31142	29.00	0.50	14.51	514.6	512.80	0.90	2211.68	2333.12	-60.8
2020	35764	35733	31.00	0.46	14.36	596.5	594.80	0.79	2856.63	2843.94	5.88
2021	40890	40859	31.00	0.43	13.30	647.4	669.30	-9.39	2930.59	2870.48	25.8
2022	46378	46349	29.00	0.40	11.52	855.9	854.20	0.68	2544.21	2544.21	0.00
2023	52586	52554	32.00	0.37	11.77	1102.2	1100.60	0.59	4353.31	4181.71	63.1
2024	59612	59581	31.00	0.34	10.55	1267.2	1265.60	0.54	5160.33	5217.53	-19.5
2025	67565	67535	30.00	0.32	9.46	1357.1	1383.70	-8.39	4926.8	5041.20	-36.1
2026	76338	76307	31.00	0.29	9.05	1537.2	1535.60	0.47	4729.41	4729.41	0.00
2027	86523	86493	30.00	0.27	8.11	1993.7	1991.90	0.49	2825.00	2825.00	0.00
2028	98052	98052	0.00	0.25	0.00	2212.9	2212.90	0.00	2690.33	2690.33	0.00
2029	111167	111167	0.00	0.23	0.00	2464.9	2464.90	0.00	3355.86	3355.86	0.00
2030	125907	125907	0.00	0.21	0.00	2766.5	2766.50	0.00	1384.71	1384.71	0.00
2031	143830	143830	0.00	0.20	0.00	3388	3388.00	0.00	0.00	0.00	0.00
Total	1114929	1114396	532.7		291.6	24969.8	24951.5	34.12	54465.3	54465.3	17.9

	Bus
	US$cts/kWh
Opern	**11.70**
Capital	**6.15**
LRMC	**17.85**

The higher LRMC in the HDFS showed comparatively higher present value (PV) inflow streams from power generation than the RDFS. Table 4.10 present the financial inflows and outflows of the optimal GLCGEP in the HDFS. The GLCGEP energy system's cost was projected to be US$ 19.96 billion at a salvage value of US$ 1.37 billion by 2031. This system's cost was US$ 5.34 billion higher than the RDFS. The NPV was US$ 7.08 billion, US$ 4.92 billion higher than the RDFS.

Table 4.10: Optimal GLCGEP Financial Inflows & Outflows- HDFS

Year	PV – Inflow (US$ Billions)	Salvage Value (US$ Billions)	System's Cost (US$ Billions)	NPV (US$ Billions)
2031	25.67	1.37	19.96	7.08
2030	22.47	1.30	19.19	4.59
2029	19.84	1.64	18.35	3.13
2028	17.50	0.98	17.32	1.17
2027	15.44	0.66	16.34	-0.24
2026	13.62	0.70	15.47	-1.14
2025	12.05	0.64	14.50	-1.80
2024	10.64	0.44	13.46	-2.38
2023	9.38	0.85	12.52	-2.28
2022	8.27	0.55	11.19	-2.37
2021	7.29	0.41	10.10	-2.39
2020	6.38	0.28	9.03	-2.37
2019	5.56	0.27	8.08	-2.25
2018	4.83	0.30	7.04	-1.91
2017	4.19	0.12	5.96	-1.64
2016	3.59	0.20	5.21	-1.42
2015	3.05	0.12	4.00	-0.82
2014	2.47	0.00	3.04	-0.56
2013	2.08	0.04	2.87	-0.75
2012	1.73	0.04	2.18	-0.42
2011	1.47	0.00	1.21	0.26
2010	1.38	0.00	0.74	0.64

The optimal GLCGEP generation capacity was projected to grow from 1382 MW at 1227 MW peak demand in the base year to 19828 MW at a peak demand of 16905 MW in the RDFS by 2031. In the HDFS, the growth was projected to 26968 MW capacity at a peak demand of 22985 MW. The generation capacities were predominantly hydropower (55%) with the least reserve capacity hence the highest LOLP of 23.3% in the base year in both scenarios.

The green power capacity addition over the planning horizon was observed to change the entire generation portfolio. By 2031, out of the total capacity of 19828 MW; 40.8% is expected to come from geothermal, 19.5% from wind, 11.1% from Ethiopia imports, 10.9% from natural gas, 9.1% from nuclear, 5.2% from hydropower, 2.3% from HFO and 1.0% from solar PV in the RDFS. In the HDFS out of the 26968 MW; 39.4% is geothermal, 18.5% wind, 14.0% natural gas, 13.3% nuclear, 8.2% Ethiopian imports, 3.9% hydropower, 1.7% from HFO and 1.1% solar PV. The capacities in both scenarios were geothermal and wind dominated and characterized by low annual LOLPs averaged at 1.94% (RDFS) and 3.02% (HDFS) over the planning horizon. High LOLP(s) portrays low generation reliability to meet the requisite demand and vice versa (Khatib, 2003; IAEA, 1984). The hydropower dominated generation at the highest LOLP in the base year was vulnerable to power shortfalls due to recurrent droughts. MOE, (2013) and MEWNR, (2014) reported drought as the most frequent occurrence in Kenya citing cases in 1991–1992, 1995–1996, 1998–2000, 2004–2005, 2009 and projecting more to persist in future.

The characteristic low LOLP geothermal/wind dominated capacity additions in the GLCGEP over the planning horizon was a more reliable generation and justifiable substitute for the base year's system. These are low carbon and climate resilient energy resources with substantial capabilities of not only mitigating CO_2 emissions but also for security of power (IPCC, 2011; Mejia *et al.*, 2012; Rouhani *et al.*, 2013; Maslyuk *et al.*, 2013; Salvador *et al.*,2016; Li *et al.,*2016). The GLCGEP was also projected to supply 7721 GWh in the base year to 105766 GWh in RDFS and 143830 GWh in HDFS by 2031 with corresponding annual emission rates of 0.86 and 1.12 Mt CO_2.

The energy system's cost for the GLCGEP was projected to be US$ 14.62 billion in the RDFS, about US$ 5.34 billion more for the HDFS. The GLCGEP also showed significant revenue potential of US$ +2.16 billion and US$ +7.08 billion NPV for the RDFS and HDFS respectively by 2031.

4.3.3 Sensitivity Analyses

a). Variations in Discount Rate on System's Cost and NPV

When the discount rate was varied between 8% and 12%; the energy system's cost of the optimal GLCGEP decreased while NPV increased in the RDFS and HDFS. Table 4.11 shows the variations in the discount rate on system's cost and NPV of the GLCGEP. Despite these discount rate variations, the total number of generation plants for capacity addition remained unchanged at 117 in RDFS and 159 in the HDFS.

Table 4.11: Variations in Discount Rate on System's Cost and NPV of the GLCGEP

Discount Rate	System's Cost (US$ Billions)		NPV (US$ Billions)	
	RDFS	HDFS	RDFS	HDFS
8%	14.62	19.96	2.17	7.08
10%	12.49	17.03	3.94	9.56
12%	10.75	14.62	5.44	11.68

b). Variation in Fuel Cost on System's Cost and NPV

When the fuel cost was increased by 10% to 30%, the energy system's cost of the optimal GLCGEP in the RDFS and HDFS increased slightly whereas the NPV reduced marginally. Table 4.12 shows variations in fuel cost on system's cost and NPV of the GLCGEP. In spite of these fuel cost variations, the total number of plants for capacity addition remained constant in both scenarios.

Table 4.12: Variations in Fuel-Cost on System's Cost and NPV of the GLCGEP

Fuel Cost	System's Cost (US$ Billions)		NPV (US$ Billions)	
	RDFS	HDFS	RDFS	HDFS
10%	13.64	18.65	3.15	8.39
20%	13.71	18.79	3.08	8.25
30%	13.77	18.92	3.02	8.12

c). Variations in Capital Cost on System's Cost and NPV

When the capital cost was increased by 5% to 15%, the energy system's cost of the optimal GLCGEP narrowly increased while the NPV decreased slightly in each scenario. Table 4.13 shows the variations in capital cost on system's cost and NPV of the GLCGEP. Despite these capital cost variations, the total number of plants for capacity addition remained the same in both scenarios.

Table 4.13: Variations in Capital Cost on System's Cost and NPV of the GLCGEP

Capital Cost	System's Cost (US$ Billions)		NPV (US$ Billions)	
	RDFS	HDFS	RDFS	HDFS
10%	15.02	20.52	1.82	6.59
20%	15.41	21.08	1.49	6.10
30%	15.81	21.64	1.14	5.61

During the sensitivity analyses of the GLCGEP in the RDFS and HDFS, it was observed that discount rate increased with NPV but decreased with energy system's cost. On the other hand, the fuel and capital cost increased with system's cost but decreased with NPV. The inverse relationship between the energy system's cost and NPV during the variations was observed consistent with the inferences by Khatib, (2003) and Bhattacharyya, (2011).

The effect of fuel cost variations was observed as very low; as an increase in fuel cost should significantly escalate the energy system's cost over NPV as remarked by Bhattacharyya *et al.*, (2010) and Bhattacharyya, (2011). The GLCGEP was less sensitive to fuel cost rise because of its majorly fuel-free power generation resources at 78% of the total capacity. Despite the discount rate, fuel cost and capital cost variations; the total number of plants for capacity additions remained constant at 117 in RDFS and 159 in the HDFS.

4.4 Comparative Analysis of the Optimal GLCGEP and LCPDP

4.4.1 Capacity Mix

In the base year, the optimal GLCGEP had an installed capacity of 1382 MW; 19 MW more than the LCPDP though both were against 1227 MW peak demand. Annual capacity additions over the same planning period was projected to vary the GLCGEP to 19828 MW against a peak demand of 16905 MW with average reserve margins of 25% by 2031. On the other hand, the LCPDP capacity was projected to rise to 21620 MW at 28% average reserve margins; 1792 MW higher than the GLCGEP. Figure 4.7 shows the generation capacities for the GLCGEP and the LCPDP.

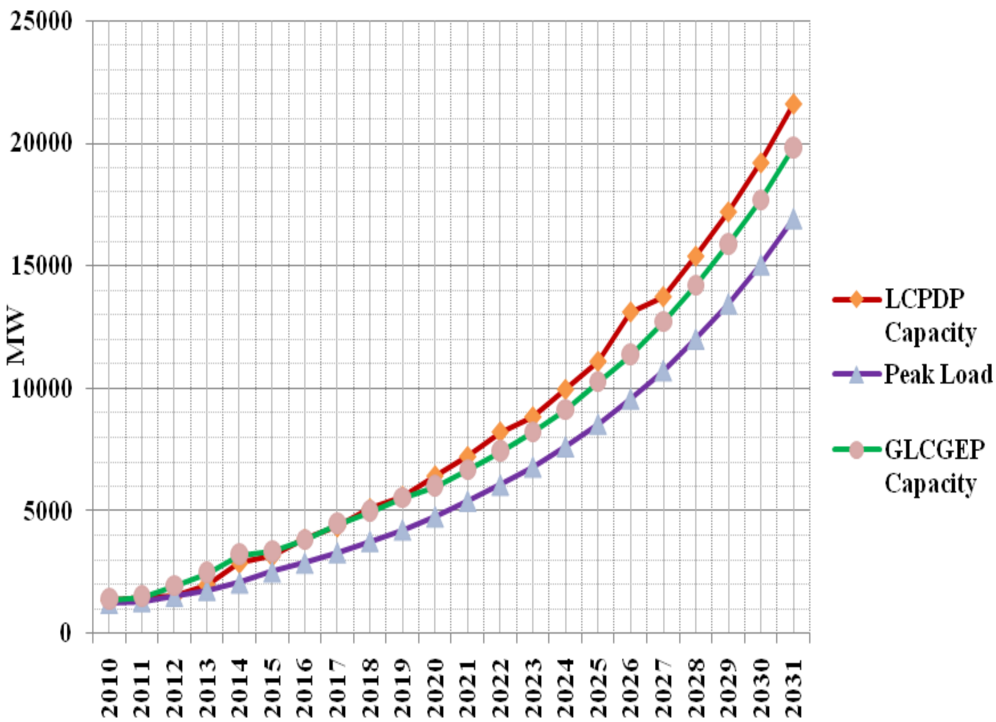

Figure 4.7: GLCGEP and LCPDP Generation Capacities

Although, both capacities were capable of satisfying the same prevailing demand, the LCPDP trend provided excess from 2018. Probable idle capacity will prevail if proper plans will not be in place for utilizing the excess capacity. Khatib, (2003); Bhattacharyya, (2011) and Elkarmi *et al.*, (2012) asserts a 15-25% reserve margin as modest for sound reliability which was in favour of the GLCGEP.

In the GLCGEP's total capacity of 19828 MW; 40.8% is expected to come from geothermal, 19.5% from wind, 11.1% from Ethiopian imports, 10.9% from natural gas, 9.1% from nuclear, 5.2% from hydropower, 2.3% from HFO and 1.0% from solar PV. Comparatively out of the 21620 MW LCPDP capacity; 26% is expected to come from geothermal, 19% from nuclear, 13% from coal, 11% from natural gas, 9% each from HFO, wind & Ethiopian imports and 5% from hydropower. The GLCGEP which was highly integrated with green generation resources was 78% green almost twice the LCPDP at 49%. It had numerous potential green candidate power projects that could be developed through clean development mechanism (CDM) for enhancing environmental sustainability. The green energy technologies outlined in the GLCGEP qualified the attributes documented by Shende *et al.*, (2014) on CDM candidacy.

4.4.2 Energy Mix and CO_2 Emissions

The 78% GLCGEP was projected to supply 7721 GWh in the base year steadily rising to 105766 GWh by 2031 at an average annual rate of 4457 GWh. In comparison, the 49% green LCPDP was to supply 7160 GWh to 105773 GWh at a higher annual average rate of 4482 GWh during the same period. Therefore, the two energy systems were anticipated to emit varied CO_2 emissions due to their unique generation portfolios. Figure 4.8 presents the CO_2 emission profiles for the GLCGEP and LCPDP.

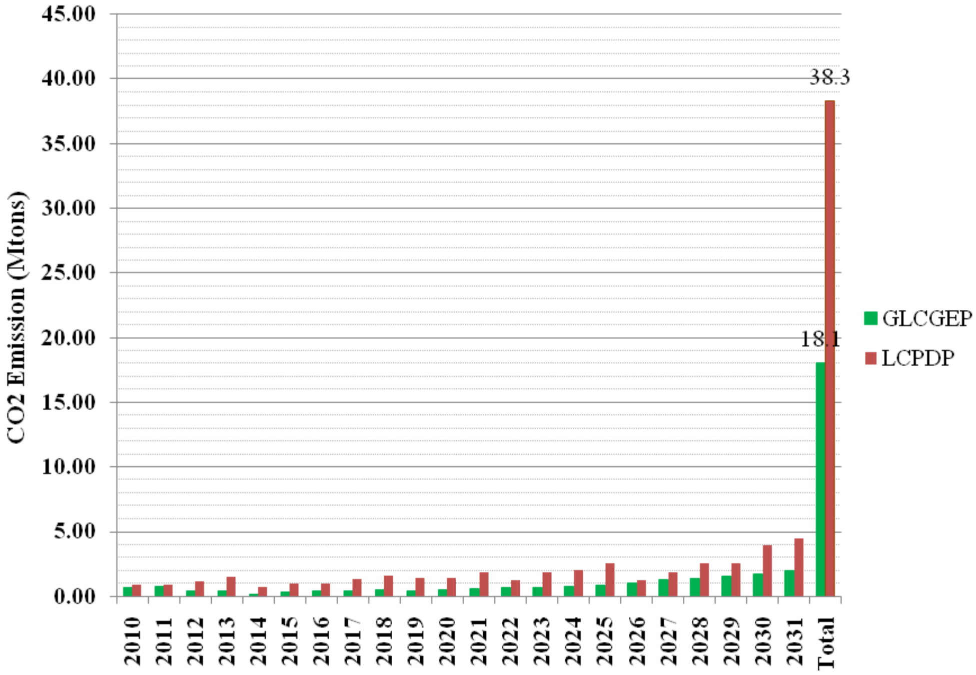

Figure 4.8: GLCGEP and LCPDP CO_2 Emissions

The results show that the GLCGEP had about 0.73 Mt CO_2 in the base year which will rise at an annual emission rate of 0.82 Mt CO_2 to 2.0 Mt CO_2 in 2031. During the same period, the LCPDP will emit 0.85 Mt CO_2 to 4.4 Mt CO_2 at an annual rate of 1.82 Mt CO_2. There will be significant annual net avoided emissions on the GLCGEP's probable CDM projects over the LCPDP. The avoided emissions will earn carbon credits at the prevailing rate of US$ 3.04 per ton CO_2 as per Sukumaran, (2014). Table 4.14 presents the avoided CO_2 emissions and carbon credits on the GLCGEP.

Table 4.14: GLCGEP Avoided CO_2 Emissions and Carbon Credits

Year	OGLCGEP Avoided CO_2 Emissions (ton.)	Carbon Credits (US$) Earned
2010	126109.6	392200.86
2011	52294.9	162636.99
2012	703036.0	2186441.99
2013	1090274.8	3390754.63
2014	483700.8	1504309.55
2015	561582.2	1746520.60
2016	486545.4	1513156.22
2017	802616.5	2496137.30
2018	1039097.7	3231593.98
2019	914984.4	2845601.49
2020	854357.5	2657051.77
2021	1233817.2	3837171.61
2022	557056.3	1732445.23
2023	1102345.0	3428292.88
2024	1211414.2	3767498.03
2025	1616568.7	5027528.75
2026	199906.3	621708.61
2027	523990.0	1629608.87
2028	1133198.7	3524247.88
2029	957625.0	2978213.65
2030	2173752.2	6760369.46
2031	2411320.7	7499207.29
Total	**20235594.1**	**62932697.7**

The avoided emissions/carbon credits doesn't depict a consistent upward trend from the base year to the end in Table 4.14. However, the lowest values; 0.05 Mt CO_2/US$ 0.16 million credits are recorded in 2011 while the highest; 2.4 Mt CO_2/ US$ 7.5 million credits noted in 2031. On aggregate, a total of 20.2 Mt CO_2 of avoided CO_2 emissions estimated at US$ 62.9 million carbon credits by the end of the planning period will prevail.

Although the revenues obtained from the carbon credits were quite low, there are numerous green power generation benefits. Green jobs, healthy environment and foreign exchange earnings & savings for green growth are the main benefits outlined by Khatib, (2003); UNEP, (2008) and UNEP, (2011). In the researcher's view, the benefits besides the meagre carbon credits are invaluable economics for green growth.

4.4.4 Generation Economics

The relative revenue streams for generation system expansion in the GLCGEP were consistently higher than the LCPDP. Table 4.15 shows the financial inflows and outflows for the two generation expansion plans. The results show that the GLCGEP energy system was rather costly than the LCPDP in terms of energy system's cost because traditionally green energy projects had higher upfront investments costs.

Table 4.15: GLCGEP & LCPDP Financial Inflows & Outflows

Year	GLCGEP (US$ Billions)				LCPDP (US$ Billions)			
	PV - Inflow	Salvage Value	System's Cost	NPV	PV - Inflow	Salvage Value	System's Cost	NPV
2031	15.70	1.09	14.62	2.16	12.54	0.34	13.18	-0.30
2030	13.93	0.89	14.08	0.74	11.13	0.30	12.68	-1.25
2029	12.45	0.93	13.48	-0.10	9.95	0.28	12.19	-1.96
2028	11.12	0.74	12.83	-0.97	8.88	0.33	11.68	-2.46
2027	9.92	0.42	12.14	-1.79	7.93	0.19	11.12	-3.00
2026	8.86	0.58	11.52	-2.09	7.08	0.19	10.58	-3.32
2025	7.93	0.54	10.76	-2.30	6.34	0.20	10.01	-3.48
2024	7.07	0.31	9.93	-2.55	5.65	0.12	9.36	-3.59
2023	6.31	0.58	9.23	-2.34	5.04	0.13	8.80	-3.62
2022	5.62	0.32	8.25	-2.31	4.49	0.26	8.17	-3.42
2021	5.01	0.26	7.43	-2.16	4.00	0.12	7.28	-3.15
2020	4.42	0.15	6.62	-2.05	3.53	0.09	6.53	-2.90
2019	3.92	0.11	5.98	-1.95	3.13	0.09	5.83	-2.61
2018	3.49	0.17	5.38	-1.72	2.79	0.12	5.06	-2.14
2017	3.06	0.10	4.74	-1.58	2.45	0.01	4.08	-1.63
2016	2.67	0.12	4.08	-1.30	2.13	0.00	3.61	-1.48
2015	2.31	0.05	3.29	-0.93	1.85	0.06	3.31	-1.41
2014	1.90	0.00	2.83	-0.93	1.52	0.01	2.52	-1.00
2013	1.62	0.00	2.70	-1.08	1.26	0.00	2.07	-0.81
2012	1.40	0.11	2.54	-1.03	0.99	0.00	1.74	-0.74
2011	1.19	0.00	1.16	0.03	0.86	0.00	1.13	-0.27
2010	1.15	0.00	0.74	0.41	0.85	0.00	0.75	0.10

However, the green generation portfolio effectively minimized the cost by generating higher revenues on its investment. This was why it had consistently higher NPVs than the LCPDP throughout the planning horizon. By 2031, the GLCGEP had US$ +2.16 billion unlike the US$ - 0.31 billion for the LCPDP hence more economically feasible. These characteristics of feasible projects were consistent with Khatib, (2003); Bhattacharyya *et al.*, (2010) and Elkarmi *et al.*, (2012) on economic evaluation of projects.

CHAPTER FIVE

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Introduction

In this chapter, the answers to the research questions from the research results in the previous chapter are given. These answers serve as summary of the main findings for the study. Moreover, conclusions and areas of further research are proposed.

5.2 Summary

The development of the green least-cost generation expansion plan (GLCGEP) for Kenya as a feasible substitute for the 2011–2031 LCPDP was the answer to the main research question for the study. The answers to the specific research questions are as follows.

5.2.1 Green candidate power plants

The green base load candidate plants for GEP in Kenya were namely; 140 MW Geothermal, 140 MW low grand falls hydro, 300 MW Wind, 1000 MW Ethiopian imports and 60 MW Mutonga hydro. They are characterized by low levelized cost of electricity (LCOE) of US$ 6-13 cts /kWh. The suitable green peaking plants was mainly the 100 MW Solar PV with a higher LCOE of US$ 15-30 cts/kWh. The 1000 MW nuclear and the 180 MW GT-Natural gas plants complimented the base and peaking plants respectively owing to their large energy densities and low CO_2 emissions. Parts of imports also served as peaking plants due to their low cost and abundance.

5.2.2 Optimal GLCGEP

In the RDFS, 40.8% is expected to come from geothermal, 19.5% from wind, 11.1% from Ethiopian imports, 10.9% from natural gas, 9.1% from nuclear, 5.2% from hydropower, 2.3% from HFO and 1.0% from solar PV of the 19828 MW total capacity by 2031. In the HDFS's 26968 MW total capacity 39.4% is expected to be geothermal, 18.5% wind, 14.0% natural gas, 13.3% nuclear, 8.2% Ethiopian imports, 3.9% hydropower, 1.7% from HFO and 1.1% solar PV. In both scenarios, nuclear and GT-Natural gas plants were included to compliment the green energy options due to their high energy densities and low CO_2 emissions. The capacities were geothermal-wind dominated characterized by low annual LOLPs averaged at 1.94% (RDFS) and 3.02% (HDFS) over the planning horizon. The characteristic low LOLP GLCGEP was a reliable power generation system. The generation system was projected to supply 7721 GWh in the base year to 105766 GWh in RDFS and 143830 GWh HDFS by 2031. This was sufficient to meet the prevailing demand with corresponding system's annual emission rates of 0.86 and 1.12 Mt CO_2. The GLCGEP energy system's cost was projected to be US$ 14.62 billion in the RDFS by 2031; about US$ 5.34 billion more in the HDFS. The system also showed significant revenues of US$ +2.16 billion and US$ +7.08 billion respectively.

5.2.3 Comparative Study of the GLCGEP and 2011-2031 LCPDP

The optimal GLCGEP and the LCPDP capacities had average reserve margins of 25% and 28% respectively. Although, both capacities would satisfy the same prevailing demand, the LCPDP provided excess capacity with possibility of economic losses. The GLCGEP which was highly integrated with green generation resources was 78% green almost twice the LCPDP at 49%. Thus the GLCGEP would emit about 0.86 Mt CO_2 annually lower than LCPDP's 1.82 Mt CO_2 hence significant annual net avoided emissions on the GLCGEP over the LCPDP was projected to prevail during the planning period. A total of 20.2 Mt CO_2 of avoided CO_2 emissions estimated at US$ 62.9 million carbon credits besides other benefits such as green jobs, health benefits and foreign exchange earnings & savings was anticipated. The GLCGEP energy system also showed US$ +2.16 billion more revenue unlike the US$ - 0.31 billion for the LCPDP.

5.3 Conclusions

i. The green base load candidate plants for GEP were namely; 140 MW Geothermal, 140 MW low grand falls hydro, 300 MW Wind, 1000 MW Ethiopian imports and 60 MW Mutonga hydro characterized by low LCOE of US$ 6-13 cts /kWh. The suitable green peaking plants was mainly the 100 MW Solar PV with a higher LCOE of US$ 15-30 cts/kWh. The 1000 MW nuclear and the 180 MW GT-Natural gas plants complimented the base and peaking plants respectively. Parts of imports also served as peaking plants.

ii. The GLCGEP generation capacity was projected to grow from 1382 MW at 1227 MW peak demand in the base year to 19828 MW at a peak demand of 16905 MW by 2031. Out of the total capacity, 40.8% is expected to come from geothermal, 19.5% from wind, 11.1% from Ethiopian imports, 10.9% from natural gas, 9.1% from nuclear, 5.2% from hydropower, 2.3% from HFO and 1.0% from solar PV. The geothermal-wind dominated capacity characterized by annual LOLPs and reserve margins averaged at 1.94% and 25% respectively signified a reliable power generation system. The generation system was projected to supply 7721GWh in the base year to 105766 GWh with corresponding annual emission rates of 0.86 Mt CO_2. The energy system's cost was projected to be US$ 14.62 billion and net present value (NPV) of US$ +2.16 billion by 2031.

iii. The GLCGEP and the LCPDP capacities projected against the same peak demand depicted 25% and 28% average reserve margin respectively; the LCPDP providing excess capacity subjected to probable future economic loss. The GLCGEP which was highly integrated with green generation resources was 78% green almost twice the LCPDP at 49% had a 0.86 Mt CO_2 annual emission rate lower than the LCPDP's 1.82 Mt CO_2. Hence a total of 20.2 Mt CO_2 of avoided CO_2 emissions estimated at US$ 62.9 million carbon credits was projected by 2031 besides other green fringe benefits such as green jobs, health benefits and foreign exchange earnings & savings. The GLCGEP was also more feasible in that it showed more revenues approximated at US$ +2.16 billion NPV unlike the US$ - 0.31 billion for the LCPDP. Therefore, the study demonstrated a feasible future for green-based generation with security of supply and sustainable development.

5.4 Recommendations

The research recommends the following for future research:

i. Modeling power system stability with high Wind and Solar PV integrated in Kenya.

ii. Off-grid generation systems to be included in future generation expansion plans in Kenya.

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APPENDICES

I. Operation Definition of Terms

Climate Change – refers to changes in the state of climate due to anthropogenic activities like combustion of fossil fuels.

Generation Expansion Planning – is the process of finding the optimal strategy for constructing new generation plants while satisfying technical and economic constraints.

Green Power –is electricity generated from energy sources with lesser environmental impact than conventional electricity generation.

Least-Cost Generation Expansion Planning - is determining the minimum cost generation capacity addition that meets the forecasted demand within pre-specified reliability criteria over a given planning period

Long-Run Marginal Cost - the levelized cost of meeting a unit increase in demand over an extended period of time

Loss of Load Probability – the proportion of days per year that available generation capacity is insufficient to serve the daily peak or hourly demand.

Scenario – a set of illustrative pathways that indicates how the future may unfold

Sensitivity Analysis – the process of evaluating the effect of various parameters on the reference optimal solution

II. Demand Forecast

Year	Reference Demand Forecast Scenario (RDFS)			Higher Demand Forecast Scenario (HDFS)		
	Peak Load (MW)	Energy (GWh)	% Load Factor	Peak Load (MW)	Energy (GWh)	% Load Factor
2010	1227	7296	67.88	1227	7296	67.88
2011	1302	7775	68.16	1331	7943	68.11
2012	1520	9084	68.21	1584	9458	68.14
2013	1765	10560	68.32	1877	11224	68.25
2014	2064	12376	68.44	2236	13396	68.38
2015	2511	15155	68.90	2760	16644	68.83
2016	2866	17300	68.91	3207	19344	68.86
2017	3292	19902	69.02	3749	22650	68.97
2018	3751	22685	69.04	4322	26128	69.01
2019	4216	25512	69.08	4970	30069	69.07
2020	4755	28795	69.13	5703	34537	69.14
2021	5388	32651	69.18	6521	39554	69.24
2022	6048	36652	69.18	7397	44915	69.32
2023	6784	41130	69.21	8388	50998	69.41
2024	7608	46147	69.25	9509	57903	69.51
2025	8528	51771	69.30	10778	65748	69.64
2026	9556	58069	69.37	12217	74664	69.77
2027	10706	65133	69.45	13847	84805	69.91
2028	11994	73065	69.54	15697	96346	70.07
2029	13435	81964	69.65	17796	109488	70.23
2030	15026	91946	69.85	20156	124461	70.49
2031	16905	103518	69.90	22985	142103	70.57
Avg.	**6420.3**	**39022.1**	**69.00**	**8102.6**	**49530.6**	**69.20**

III. Other WASP IV Model Equations

The alternative expansion policies for the power system are required as the starting point in the WASP IV analysis. If the power generation capacity installed in a given *year t* for a given expansion plan is represented as a vector $[K_t]$, then this vector must satisfy equation 1.0:

$$[K_t] = [\ K_{t-1}\ ] + [\ A_t\ ] - [\ R_t\ ] + [\ U_t\ ] \qquad 1.0$$

Where: $[A_t]$ is a vector of units committed as additions in *year t*, $[R_t]$ is a vector of units committed to retirement in *year t*, $[U_t]$ is a vector unit of candidate generating units added to the system in *year t* $[U_t] \geq [0]$. $[A_t]$ and $[R_t]$ are given data while $[U_t]$ is the unknown variable to be determined called the *system configuration*. $[K_t]$ is a [1x1] vector, representing this year's unit which is last year's units plus certain additions less retirements, plus the candidate units added.

The critical period (p) of the year is defined when the difference between the corresponding available generation capacity and the peak demand has the smallest value. If P $(K_{t,p)}$ is the installed power system capacity in the critical period of the *yeart*, the acceptable configurations should satisfy the constraints in equation 2.0.

$$(1+ a_{t)}\ Dt_p \geq P\ (K_{tp)}) \geq (1 + b_t)\ D_{tp} \qquad 2.0$$

In the equation 2.0, the installed capacity in the critical period must lie between the given minimum and maximum *reserve margins* (RM) a_t and b_t respectively. It follows that in each selected configuration it must lie above the peak demand $\boldsymbol{D_{tp}}$ in the critical period of the year.

The *Loss of Load Probability (LOLP)* is evaluated as the system reliability in the model and estimated for each condition and period of the year. The LOLP $(K_{t,a})$ and $(K_{t,i})$ represents the annual and periods' **LOLP** respectively. Thus, all accepted configurations should satisfy equation 3.0 a and b:

$$\mathbf{LOLP\ (K_{t,a}) \leq C_{t,a}} \qquad 3.0\mathbf{a}$$

$$\mathbf{LOLP\ (K_{t,i}) \leq C_{t,p}} \qquad 3.0\mathbf{b}$$

Where; $C_{t,a}$ and $C_{t,p}$ are limiting input values specified by the user.

The cost of Energy-Not-Served (ENS) can be calculated as a result of annual energy demand; $\boldsymbol{E_t}$ being greater than the expected total annual energy generated; $\boldsymbol{G_t}$ by all the existing units in the configuration for the corresponding year $\boldsymbol{t}$. Thus, the cost of ENS calculated as a function of the amount of **ENS;**$\boldsymbol{N_t}$ is shown in equation 4.0:

$$\mathbf{N_t = E_t - G_t} \qquad 4.0$$

Where; $\boldsymbol{N_t}$ is the amount of ENS, $\boldsymbol{E_t}$ the annual energy demand and $\boldsymbol{G_t}$ the annual energy generated.

The *tunnel constraints* is specified by the user on configuration vector; [Ut] as shown in equation 5.0:

$$\mathbf{U^0_t \leq U_t \leq U^0_t + [\Delta U_t]} \qquad 5.0$$

Where; $[U_t]$ is the configuration vector, ΔU_t the tunnel constraint or width and U_t^0 is the smallest permitted value of the configuration vector. The tunnel constraints ensure that a certain number of power units are built in year $\boldsymbol{t}$.

The optimal power dispatch policy is dependent on plants' availability, maintenance requirements, spinning reserves requirements and any exogenous constraints imposed by the user on emissions, fuel availability and generation by some plants. Therefore, the *user's specified constraints* on fuel availability, level of emissions and generation of energy is as in equation 6.0.

$$\textstyle\sum_{i \in I_j} COEF_{ij} \cdot G_i \leq LIMIT_j \quad j=1\ldots M . \qquad 6.0$$

Where; $COEF_{ij}$is the constraints on per unit fuel usage or per unit emissions in limitation groupj by plant $\boldsymbol{i}$, $G_i$the generation by plant $\boldsymbol{i}$ and $LIMIT_j$are the limitations specified by user and Ij is the set of plants in limitation group.

IV. Existing & Committed Thermal Plants' Generation Characteristics

					Heat Rate (Kcal/KWh)		Fuel Costs (cts/Million Kcal)										Emission Factor (% Wt of Fuel)	
No	Plant	No of	Mi	Ca	Base Load	AVg Incr	Domestic	Foreign	Fuel	%	%	Da	Mai	Fixe	Va	Heat Va	So2	No2
1	Kipevu1	6	4	10	2362	2147	9176	0	HFO	0	0.4	28	10	3.5	30	9889	2.5	1
2	Tsavo	7	4	11	2384	2167	0	9176	HFO	0	0.4	21	10	3.5	30	9889	2.5	1
3	Kipevu GT1	1	15	30	3529	3208	9999	9999	Kero	0	3.5	28	30	6.81	4.7	10356	2.5	1
4	Kipevu GT2	1	15	30	3586	3260	9999	9999	Kero	0	3.5	28	30	3.5	4.7	10356	2.5	1
5	IberAfrica1	10	3	6	2449	2226	9176	0	HFO	0	0.4	21	10	3.5	30	9889	1.8	1
6	IberAfrica2	10	3	5	2390	2173	9176	0	HFO	0	0.4	21	10	3.5	30	9889	1.8	1
7	Osiwo Wind	0	1	10	5467	4970	0	0	Wind	0	56	28	10	3.1	4.9	10730	0	0
8	Olkaria1	3	4	15	2629	2390	0	0	Geot	0	1	14	30	4.58	9.7	1800	2.5	1
9	Olkaria 2	3	15	35	2629	2390	0	0	Geot	0	1	14	50	4.58	9.7	2200	2.5	1
10	OrPower4A	3	3	4	2629	2390	0	0	Geot	0	1	14	10	4.58	9.7	1800	2.5	1
11	OrPower4B	3	4	12	2629	2390	0	0	Geot	0	1	14	10	4.58	9.7	1800	2.5	1
12	Aeolus Wind1	0	1	10	5467	4970	0	0	Wind	0	56	28	10	3.1	4.9	10730	0	0
13	Aeolus Wind2	0	1	10	5467	4970	0	0	Wind	0	56	28	10	3.1	4.9	10730	0	0
14	Rabai Power1	5	8	18	2363	2149	917.6	0	HFO	0	4	21	50	3.5	30	9889	2.5	1
15	Olkaria 4	0	35	70	2390	2629	0	0	Geot	0	1	14	100	4.58	9.7	2200	2.5	1
16	L.Turkana	0	1	10	5467	4970	0	0	Wind	0	56	28	10	3.1	4.9	10730	0	0
17	Kipevu3	0	6	17	2363	2149	9176	0	HFO	0	4	21	0	3.5	30	9889	2.5	1
18	Mumias Cogen	3	4	9	2183	2183	0	0	Baga	0	2	21	0	0	60	1800	0	0.1
19	Eburru	0	1	2	2183	2183	0	0	Geot	0	1	7	10	3.58	9.7	1800	2.5	1
20	Olkaria 1B	0	35	70	2390	2629	0	0	Geot	0	1	14	100	3.58	9.7	1800	2.5	1
21	Athi R. MSD1	0	4	16	2363	2149	9176	0	HFO	0	4	21	10	3.5	30	10201.2	2.5	1
22	Athi R. MSD2	0	6	17	2022	2111	9176	0	HFO	0	4	21	10	3.5	30	9818	2.5	1
23	Thika P. MSD	0	4	17	1954	1893	9176	0	HFO	0	4	21	10	3.5	30	9819	2.5	1
24	Olkaria Well Hd.	0	1	5	2390	2629	0	0	Geot	0	1	7	10	3.58	9.7	2200	2.5	1
25	OrPower4C	0	10	26	2629	2390	0	0	Geot	0	1	14	10	3.58	9.7	1800	2.5	1
26	Ngong Wind	4	0	2	5467	4970	0	0	Wind	0	56	14	1	3.1	4.9	10730	0	0

V. Thermal Power Plants' Addition and Retirement Schedule

	Additions (+MW) and Retirements (-MW)																				
NO.	**NAME**	**2011**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**2030**
1	Kipevu1													-60							
2	Tsavo											-77									
3	Kipevu GT1				-30																
4	Kipevu GT2				-30																
5	IberaAfrica1									-50											
6	IberaAfrica2															-60					
7	Osiwo Wind				+50																
8	Olkaria1					-45		+45													
9	Olkaria2																				-105
10	Orpower4A																		-12		
11	Orpower4B																		-36		
12	Aeolus Wind 1			+60																	
13	Aeolus Wind 2			+60																	
14	Olkaria4				+140																
15	Lake Turkana Wind Power				+300																
16	Kipevu3	+119																			
17	Mumias Sugar Cogeneration									-26											
18	Eburru		+2																		
19	Olkaria1B				+280																
20	Athi-River MSD1			+80																	
21	Athi-River MSD2			+85																	
22	Thika MSD			+85																	
23	Olkaria Well-Head		+5	+45																	
24	Orpower4C			+130																	
Net (+/-)		**+119**	**+7**	**+545**	**+710**	**-45**	**0**	**+45**	**0**	**-76**	**0**	**-77**	**0**	**-60**	**0**	**-60**	**0**	**0**	**-48**	**0**	**-105**

VI. Existing & Committed Hydropower Plants' Generation Characteristic

Masinga (40MW)											
Hydro 1 (Dry)				***Hydro 2 (Avg)***				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	6.2	2.9	11.9	1	9.7	7.2	16.8	1	11.5	7.1	20.6
2	5.1	2.4	10.5	2	7.9	6.1	15.0	2	10.4	8.7	18.8
3	4.2	1.8	10.5	3	10.9	8.6	20.4	3	14.2	12.5	21.1
4	11.9	9.7	20.2	4	16.5	10.7	31.3	4	16.4	11.7	30.3
5	14.6	8.6	28.7	5	20.4	11.9	33.6	5	18.0	11.0	31.0
6	16.0	12.6	27.8	6	22.1	19.7	33.8	6	20.2	14.4	33.7
7	9.1	7.0	16.8	7	10.1	7.8	19.1	7	18.2	16.9	28.0
8	8.9	4.4	15.2	8	8.9	6.3	14.2	8	8.6	4.7	15.2
9	5.5	2.3	10.0	9	8.1	4.6	14.2	9	7.4	3.4	13.6
10	6.0	2.7	11.9	10	8.5	5.8	14.8	10	12.9	9.8	19.9
11	12.3	10.3	19.8	11	16.3	13.1	28.3	11	16.5	14.1	25.6
12	11.7	9.1	23.2	12	16.7	14.1	25.7	12	14.4	8.7	31.8
Kamburu (94MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	12.7	6.8	94.9	1	32.0	29.5	49.4	1	26.1	15.0	52.9
2	11.1	5.9	24.6	2	16.2	11.3	33.4	2	19.1	10.2	45.1
3	9.3	6.5	27.0	3	29.6	24.2	50.9	3	35.2	29.9	57.4
4	29.1	24.2	52.9	4	49.1	29.9	85.1	4	50.5	38.5	82.4
5	50.6	38.6	78.3	5	48.3	27.9	82.4	5	47.4	26.1	84.0
6	49.1	39.7	77.8	6	51.3	44.2	82.8	6	50.5	32.3	85.3
7	23.2	15.1	46.5	7	31.3	25.6	51.6	7	41.9	36.7	71.9
8	19.7	9.3	34.9	8	18.1	12.5	32.3	8	25.8	15.0	44.2
9	11.8	0.5	25.3	9	23.4	8.7	43.6	9	20.3	6.9	38.7
10	15.4	6.0	31.4	10	16.9	10.3	36.5	10	24.9	16.5	41.6
11	31.3	21.5	58.9	11	42.1	31.7	72.5	11	49.3	41.9	75.0
12	30.6	23.2	74.5	12	35.1	30.4	80.6	12	47.3	36.3	83.5
Gitaru (225MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			

Period	I.E (GWh)	M.G (GWh)	A.C (MW)	Period	I.E (GWh)	M.G (GWh)	A.C (MW)	Period	I.E (GWh)	M.G (GWh)	A.C (MW)
1	81.5	27.0	160.3	1	85.9	65.6	149.7	1	72.0	25.5	209.6
2	70.0	9.0	184.3	2	74.1	21.9	119.7	2	86.6	51.0	172.9
3	81.5	72.0	196.6	3	79.7	64.2	176.7	3	101.3	100.7	172.9
4	91.1	80.5	196.6	4	125.0	84.9	205.0	4	100.8	49.4	205.4
5	121.3	70.4	193.5	5	129.6	86.3	205.0	5	117.7	49.7	205.4
6	99.7	70.7	205.6	6	120.7	105.9	175.1	6	111.6	51.0	205.4
7	61.4	26.8	169.2	7	83.8	63.1	173.3	7	99.0	73.5	205.4
8	53.5	0.0	120.1	8	48.7	20.5	141.9	8	67.3	0.0	134.3
9	73.1	0.0	142.2	9	57.7	0.0	114.4	9	63.7	0.0	65.9
10	77.3	17.5	130.7	10	79.2	42.3	199.9	10	44.9	24.8	135.6
11	82.8	26.2	201.5	11	117.6	83.8	199.9	11	114.2	74.4	201.5
12	93.7	43.6	177.8	12	71.3	21.9	201.8	12	112.1	74.4	200.8
Kindaruma (40MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	8.8	8.2	12.4	1	13.3	8.1	15.8	1	11.5	8.1	20.5
2	5.4	5.5	8.7	2	8.1	6.1	14.0	2	10.4	8.4	18.9
3	6.3	6.0	9.5	3	9.9	8.6	21.4	3	14.1	11.6	20.1
4	13.7	13.4	19.7	4	15.7	10.7	30.3	4	16.3	11.7	29.8
5	15.6	12.5	23.2	5	19.4	11.9	32.7	5	19.0	10.0	30.7
6	13.9	12.8	20.8	6	21.2	19.7	34.0	6	20.1	13.9	32.8
7	10.6	10.0	15.3	7	10.1	7.8	18.0	7	17.9	17.8	27.6
8	8.3	6.4	12.3	8	9.8	6.3	15.2	8	9.4	5.7	15.2
9	5.9	5.3	8.7	9	8.3	4.6	15.2	9	7.6	4.6	14.1
10	8.0	7.2	11.4	10	8.4	5.8	13.8	10	13.3	9.9	20.1
11	13.1	13.2	18.5	11	15.7	13.1	27.2	11	17.2	13.1	24.4
12	12.9	12.2	17.9	12	15.8	14.1	26.7	12	14.9	8.7	30.7
Kiambere (168MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	25.5	13.6	189.8	1	64.0	59.1	98.7	1	52.1	30.1	105.8
2	22.2	11.9	49.2	2	32.3	22.7	66.8	2	38.1	20.3	90.1
3	18.6	13.1	53.9	3	59.2	48.5	101.8	3	70.4	59.8	114.8
4	58.3	48.3	105.8	4	98.3	59.9	170.2	4	101.0	77.0	164.8
5	101.2	77.3	156.6	5	96.6	55.8	164.7	5	94.7	52.2	168.0
6	98.2	79.3	155.6	6	102.7	88.4	165.7	6	100.9	64.6	170.5

7	46.3	30.1	93.0	7	62.6	51.2	103.1	7	83.7	73.3	143.8
8	39.4	18.5	69.8	8	36.2	24.9	64.6	8	51.5	29.9	88.5
9	23.6	0.9	50.7	9	46.8	17.3	87.2	9	40.6	13.9	77.3
10	30.7	12.0	62.8	10	33.7	20.6	73.0	10	49.9	33.1	83.2
11	62.5	42.9	117.9	11	84.1	63.4	144.9	11	98.6	83.9	149.9
12	61.3	46.4	148.9	12	70.2	60.8	161.2	12	94.5	72.6	167.0
Turkwel (106MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	21.9	16.0	104.1	1	41.2	38.7	58.5	1	35.2	24.2	62.1
2	20.3	15.1	33.8	2	25.3	20.5	42.6	2	28.2	19.3	54.2
3	18.5	15.7	36.1	3	38.8	33.4	60.1	3	44.4	39.1	66.6
4	38.3	33.3	62.1	4	58.3	39.1	94.3	4	59.7	47.7	91.6
5	59.8	47.8	87.5	5	57.5	37.1	91.5	5	56.5	35.3	93.2
6	58.3	48.8	87.0	6	60.5	53.4	92.0	6	59.6	41.5	94.4
7	32.3	24.2	55.7	7	40.5	34.8	60.7	7	51.0	45.8	81.1
8	28.9	18.4	44.1	8	27.3	21.6	41.5	8	34.9	24.1	53.4
9	21.0	9.6	34.5	9	32.6	17.8	52.8	9	29.5	16.1	47.8
10	24.5	15.2	40.6	10	26.0	19.5	45.7	10	34.1	25.7	50.8
11	40.4	30.6	68.1	11	51.2	40.9	81.6	11	58.5	51.1	84.1
12	39.8	32.4	83.6	12	44.3	39.6	89.8	12	56.4	45.5	92.7
Sondu Miriu (106MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	9.4	4.3	18.0	1	14.7	10.8	25.4	1	17.3	10.7	31.1
2	7.7	3.6	15.9	2	11.9	9.2	22.7	2	15.6	13.1	28.4
3	6.3	2.7	15.8	3	16.4	12.9	30.7	3	21.5	18.8	31.9
4	17.9	14.6	30.5	4	24.9	16.1	47.2	4	24.7	17.6	45.8
5	22.0	13.0	43.4	5	30.8	18.0	50.8	5	27.2	16.5	46.9
6	24.2	19.0	42.0	6	33.3	29.7	51.0	6	30.5	21.8	50.9
7	13.7	10.6	25.3	7	15.2	11.8	28.8	7	27.5	25.5	42.3
8	13.5	6.6	23.0	8	13.4	9.5	21.5	8	13.0	7.1	22.9
9	8.3	3.5	15.1	9	12.3	7.0	21.5	9	11.2	5.1	20.6
10	9.1	4.0	17.9	10	12.8	8.7	22.3	10	19.5	14.8	30.0
11	18.6	15.5	29.9	11	24.6	19.8	42.8	11	24.9	21.3	38.7
12	17.7	13.7	35.0	12	25.2	21.3	38.7	12	21.7	13.2	47.9
Tana (20MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			

Period	I.E (GWh)	M.G (GWh)	A.C (MW)		I.E (GWh)	M.G (GWh)	A.C (MW)	Period	I.E (GWh)	M.G (GWh)	A.C (MW)
1	2.9	1.3	5.5	1	4.5	3.3	7.7	1	5.3	3.3	9.5
2	2.3	1.1	4.8	2	3.6	2.8	6.9	2	4.8	4.0	8.6
3	1.9	0.8	4.8	3	5.0	3.9	9.4	3	6.5	5.7	9.7
4	5.5	4.5	9.3	4	7.6	4.9	14.4	4	7.5	5.4	13.9
5	6.7	4.0	13.2	5	9.4	5.5	15.5	5	8.3	5.0	14.3
6	7.4	5.8	12.8	6	10.1	9.1	15.5	6	9.3	6.6	15.5
7	4.2	3.2	7.7	7	4.6	3.6	8.8	7	8.4	7.8	12.9
8	4.1	2.0	7.0	8	4.1	2.9	6.5	8	4.0	2.2	7.0
9	2.5	1.1	4.6	9	3.7	2.1	6.5	9	3.4	1.6	6.3
10	2.8	1.2	5.5	10	3.9	2.6	6.8	10	5.9	4.5	9.1
11	5.7	4.7	9.1	11	7.5	6.0	13.0	11	7.6	6.5	11.8
12	5.4	4.2	10.7	12	7.7	6.5	11.8	12	6.6	4.0	14.6
Sangoro (21MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	3.0	1.4	5.7	1	4.7	3.5	8.1	1	5.5	3.4	10.0
2	2.4	1.2	5.1	2	3.8	2.9	7.3	2	5.0	4.2	9.1
3	2.0	0.9	5.1	3	5.3	4.1	9.8	3	6.9	6.0	10.2
4	5.7	4.7	9.7	4	8.0	5.2	15.1	4	7.9	5.6	14.6
5	7.0	4.2	13.9	5	9.9	5.8	16.2	5	8.7	5.3	15.0
6	7.7	6.1	13.4	6	10.7	9.5	16.3	6	9.8	7.0	16.3
7	4.4	3.4	8.1	7	4.9	3.8	9.2	7	8.8	8.2	13.5
8	4.3	2.1	7.4	8	4.3	3.1	6.9	8	4.2	2.3	7.3
9	2.7	1.1	4.8	9	3.9	2.2	6.9	9	3.6	1.6	6.6
10	2.9	1.3	5.7	10	4.1	2.8	7.1	10	6.2	4.7	9.6
11	5.9	5.0	9.6	11	7.9	6.3	13.7	11	8.0	6.8	12.4
12	5.7	4.4	11.2	12	8.1	6.8	12.4	12	6.9	4.2	15.3
Small Hydros (25MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	3.6	1.6	6.8	1	5.6	4.1	9.7	1	6.6	4.1	11.9
2	2.9	1.4	6.1	2	4.5	3.5	8.6	2	6.0	5.0	10.8
3	2.4	1.0	6.0	3	6.3	4.9	11.7	3	8.2	7.2	12.1
4	6.8	5.6	11.6	4	9.5	6.1	18.0	4	9.4	6.7	17.4
5	8.4	4.9	16.5	5	11.7	6.9	19.3	5	10.4	6.3	17.8
6	9.2	7.2	16.0	6	12.7	11.3	19.4	6	11.6	8.3	19.4

7	5.2	4.0	9.6	7	5.8	4.5	11.0	7	10.5	9.7	16.1
8	5.1	2.5	8.8	8	5.1	3.6	8.2	8	5.0	2.7	8.7
9	3.2	1.3	5.8	9	4.7	2.7	8.2	9	4.2	1.9	7.8
10	3.5	1.5	6.8	10	4.9	3.3	8.5	10	7.4	5.6	11.4
11	7.1	5.9	11.4	11	9.4	7.5	16.3	11	9.5	8.1	14.7
12	6.7	5.2	13.3	12	9.6	8.1	14.7	12	8.3	5.0	18.3
Wanji (7MW)											
Hydro 1 (Dry)				**Hydro 2 (Avg)**				**Hydro 3 (Wet)**			
Period	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**	**Period**	**I.E (GWh)**	**M.G (GWh)**	**A.C (MW)**
1	1.0	0.5	1.9	1	1.6	1.2	2.7	1	1.8	1.1	3.3
2	0.8	0.4	1.7	2	1.3	1.0	2.4	2	1.7	1.4	3.0
3	0.7	0.3	1.7	3	1.8	1.4	3.3	3	2.3	2.0	3.4
4	1.9	1.6	3.2	4	2.7	1.7	5.0	4	2.6	1.9	4.9
5	2.3	1.4	4.6	5	3.3	1.9	5.4	5	2.9	1.8	5.0
6	2.6	2.0	4.5	6	3.6	3.2	5.4	6	3.3	2.3	5.4
7	1.5	1.1	2.7	7	1.6	1.3	3.1	7	2.9	2.7	4.5
8	1.4	0.7	2.5	8	1.4	1.0	2.3	8	1.4	0.8	2.4
9	0.9	0.4	1.6	9	1.3	0.7	2.3	9	1.2	0.5	2.2
10	1.0	0.4	1.9	10	1.4	0.9	2.4	10	2.1	1.6	3.2
11	2.0	1.7	3.2	11	2.6	2.1	4.6	11	2.7	2.3	4.1
12	1.9	1.5	3.7	12	2.7	2.3	4.1	12	2.3	1.4	5.1
Key: I.E –Inflow Energy (GWh); M.G-Minimum Generation (GWh); A.C-Avg Capacity (MW)											

VII. Candidate Generation Plants' Generation Cost Model (GCM) Data

				Unit Cost ($/kW.yr)							
Cap. Factor	**Geoth**	**Nuclea**	**Coal**	**GT-KER**	**GT- N.GA**	**MSD**	**Impo**	**Muto**	**LGF**	**Win**	**SoPV**
0%	517	652	366	105	105	239	91	612	507	304	699
10%	522	663	432	317	203	334	135	617	512	305	700
20%	527	675	498	530	301	429	178	621	517	305	700
30%	532	687	564	742	399	525	222	626	521	306	701
40%	536	699	630	954	497	620	266	631	526	307	702
50%	541	711	696	1167	595	715	310	635	531	-	-
60%	546	723	762	1379	693	810	354	640	535	-	-
70%	551	735	828	1592	791	905	397	-	-	-	-
80%	556	747	894	1804	889	1001	441	-	-	-	-
90%	561	759	960	2017	987	1096	485	-	-	-	-
100%	566	770	1026	2229	1085	1191	529	-	-	-	-

				Unit Cost ($/kWh)							
Cap.Factor	**Geoth**	**Nuclear**	**Coal**	**GT-KER**	**GT- N.GA**	**MSD**	**Impo**	**Muto**	**LGF**	**Win**	**SoPV**
10%	0.5957	0.757	0.493	0.362	0.231	0.382	0.154	0.704	0.584	0.348	0.799
20%	0.3006	0.385	0.284	0.302	0.172	0.245	0.102	0.355	0.295	0.174	0.400
30%	0.2023	0.262	0.215	**0.282**	**0.152**	**0.200**	0.085	0.238	0.198	0.117	0.267
40%	0.1531	0.200	0.180	0.272	0.142	0.177	0.076	0.180	0.150	**0.088**	**0.200**
50%	0.1236	0.162	0.159	0.266	0.136	0.163	0.071	0.145	0.121	-	-
60%	0.1039	0.138	**0.145**	0.262	0.132	0.154	0.067	**0.122**	**0.102**	-	-
70%	0.0899	0.120	0.135	0.260	0.129	0.148	0.065	-	-	-	-
80%	0.0793	**0.107**	0.128	0.257	0.127	0.143	0.063	-	-	-	-
90%	**0.0711**	0.096	0.122	0.256	0.125	0.139	**0.062**	-	-	-	-
100%	0.0646	0.088	0.117	0.254	0.124	0.136	0.060	-	-	-	-

VIII. Selected Thermal Candidate Plants' Generation Characteristics

					Heat Rate (Kcal/kWh)		Fuel Costs (cts/Million Kcal)										Emission Factor (Wt% of Fuel)	
No.	Plant	Units	Min. Load (MW)	Capacity (MW)	Base Load	Avg. Incr.	Domestic	Foreign	Fuel Type	%Spinning Reserve	% Forced Outage Rate	Days Scheduled Maint.	Maint. Class (MW)	Fixed O&M ($/kW-Month)	Variable O&M ($/MWh)	Heat Value (Kcal/Kg)	So_2	No_2
1	Geothermal	0	35	140	2390	2629	0	0	Geot	0	1.0	21	100	4.67	5.57	1800	2.5	1.0
2	Wind	0	20	100	2537	1907	0	0	Wind	0	56.0	21	100	2.34	1.0	1800	0.0	0.0
3	Nuclear	0	400	600	2520	2520	1015	0	Nucl	0	3.5	42	600	7.5	4.9	1800	2.5	1.0
4	Import	0	100	200	2111	2023	0	0	Hydr	0	6.0	21	20	2.5	50	9200	0.0	0.0
5	GT-Ngas	0	100	180	2720	3012	5600	0	Ngas	0	2.0	21	100	0.98	1.0	10210	1.0	1.0
6	SoPV	0	50	100	5400	4500	0	0	Solar	0	70.0	21	20	3.25	1.0	2200	0.0	0.0

IX. Candidate Plants' GCM Characteristics

Plant	Confign	Economic Life yrs	Scheduled Maint. (wks/yr)	(%) Forced Outage Rate	% Availab.	Total Outage Rate	Outage Adjustm.	---- Schedule of Expenditures in % per year -----									Total (%)	IDC Factor	CRF
								-8	**-7**	**-6**	**-5**	**-4**	**-3**	**-2**	**-1**	**+1**			
Gas Tur...	2 x 90	20	2	2.00	92	0.078	1.09							40.0	60.0	0.0	100	1.0725	0.1019
Geoth...	1 x 140	25	3	1.00	93	0.068	1.07				5.1	11.9	11.9	28.4	42.7		100	1.1344	0.0937
Import	2000	20	3	6.00	70	0.150	1.18						25.0	50.0	25.0		100	1.0654	0.0937
Mutonga	2 x 30	50	4	2.00	90	0.097	1.11			2.2	8.5	23.3	33.6	18.2	12.7	1.5	100	1.3378	0.0817
LGF	2 x 70	50	4	2.00	90	0.097	1.11	0.5	1.7	1.8	10.7	19.6	25.2	18.4	16.8	5.3	100	1.3378	0.0817
Nuclear	1000	40	6	3.50	85	0.150	1.18		5.0	10.0	10.0	15.0	25.0	25.0	10.0		100	1.2605	0.0839
Wind	300	25	3	56.00	41	0.100	1.11							40.0	60.0		100	1.0654	0.0937
Solar PV	100	40	3	70.00	40	0.091	1.10							40.0	60.0		100	1.1380	0.1114
MSD	8 x 20	20	3	4.00	90	0.098	1.11							50.0	30.0	20	100	1.0654	0.1019
Coal	1 x 300	25	5	6.00	85	0.156	1.19					10.0	20.0	40.0	30.0	0.0	100	1.1341	0.0937

X. Selected Hydropower Candidate Plants' Generation Characteristics

1. Mutonga (60MW)

	Hydro 1(Dry)			**Hydro 2 (Avg)**			**Hydro 3 (Wet)**		
Period	I.E (Gwh)	M.G (GWh)	A.C (MW)	I.E (Gwh)	M.G (GWh)	A.C (MW)	I.E (Gwh)	M.G (GWh)	A.C (MW)
1	15.7	13.4	24.1	17.3	16.6	23.7	17.3	16.3	24.1
2	13.0	12.1	24.0	14.3	13.6	23.7	15.8	15.7	24.1
3	11.2	8.5	20.9	13.4	12.8	18.4	16.5	15.1	23.7
4	15.6	15.2	23.5	17.6	16.7	24.6	17.5	16.8	24.4
5	18.1	17.5	25.7	18.4	18.1	25.8	17.5	17.1	25.8
6	16.1	14.1	24.8	17.9	15.1	25.8	17.9	15.1	25.8
7	17.3	16.1	24.8	18.5	18.1	25.8	18.5	18.1	25.8
8	17.4	15.9	24.8	18.5	18.1	25.8	18.5	18.1	25.8
9	13.9	11.8	24.0	16.3	15.4	24.1	17.4	16.6	24.1
10	13.8	10.9	24.7	17.5	16.7	24.8	18.5	18.1	25.8
11	17.9	17.1	24.8	17.9	17.1	24.8	17.9	17.1	24.8
12	17.8	17.4	25.1	17.9	17.6	25.1	17.9	15.6	25.1

2. LGF (140MW)

	Hydro 1 (Dry)			**Hydro 2 (Avg)**			**Hydro 3 (Wet)**		
Period	I.E (Gwh)	M.G (GWh)	A.C (MW)	I.E (Gwh)	M.G (GWh)	A.C (MW)	I.E (Gwh)	M.G (GWh)	A.C (MW)
1	82.2	65.5	128.8	72.5	53.9	121.2	66.5	49.1	109.0
2	74.0	69.6	123.1	61.3	52.0	113.3	54.9	42.8	107.0
3	66.3	46.7	111.6	53.6	34.4	98.6	74.7	64.0	112.1
4	42.3	28.8	94.9	55.4	49.5	92.4	66.1	64.8	99.5
5	39.5	37.5	59.1	76.0	74.1	104.4	95.5	93.7	131.3
6	56.2	40.0	106.3	89.5	88.6	128.1	96.7	95.0	134.3
7	39.2	24.1	89.5	60.4	37.7	120.0	85.5	74.0	134.3
8	31.9	9.6	83.8	51.5	16.9	128.1	67.6	47.2	134.3
9	44.6	22.7	94.7	50.5	33.4	105.8	50.4	29.6	113.7
10	41.5	23.6	83.6	51.5	30.0	113.4	66.4	51.0	130.7
11	42.2	24.0	89.0	73.2	62.9	124.9	94.6	93.9	131.4
12	50.2	39.0	101.0	71.1	57.6	128.1	92.1	85.5	131.3

Key: I.E –Inflow Energy (GWh); M.G-Minimum Generation (GWh); A.C-Avg Capacity (MW)

XI. 2011-2031 LCPDP Capacity (MW)

Yr	Hydro	Nuclear	HFO	Imports	Baggase	GT-Kero	GT-NGAS	Geo	Coal	Wind	Total
2010	2,299	-	2,602	-	223	379	-	1,640	-	17	7,160
2011	2,335	-	2,620	-	223	393	-	1,640	-	17	7,228
2012	2,441	-	3,587	-	223	387	-	1,704	-	17	8,359
2013	2,441	-	5,170	-	223	301	-	2,000	-	472	10,607
2014	2,504	-	1,994	1,410	188	-	-	5,036	-	1,659	12,791
2015	2,540	-	2,649	1,426	194	-	-	6,949	139	1,660	15,557
2016	2,540	-	592	4,215	172	-	-	6,957	1,821	1,660	17,957
2017	2,540	-	1,512	4,317	183	-	-	8,473	1,941	1,660	20,626
2018	3,338	-	780	4,324	187	-	-	9,615	3,285	1,973	23,502
2019	3,338	-	472	5,445	-	-	-	11,898	2,975	2,286	26,414
2020	3,338	-	251	6,649	-	-	247	14,184	2,839	2,286	29,794
2021	3,338	-	192	6,781	-	-	312	16,470	4,066	2,600	33,759
2022	3,338	7,108	84	5,766	-	-	157	16,476	2,367	2,600	37,896
2023	3,338	7,174	113	6,038	-	-	221	18,762	3,941	2,913	42,500
2024	3,338	7,198	143	7,278	-	-	347	22,191	4,259	2,913	47,667
2025	3,338	7,199	279	7,417	-	-	856	25,619	5,184	3,540	53,432
2026	3,338	13,488	51	7,975	-	-	137	29,047	1,487	4,167	59,690
2027	3,338	13,908	97	9,704	-	-	389	32,478	2,788	4,167	66,869
2028	3,338	14,197	91	11,369	-	-	434	35,511	4,864	5,108	74,912
2029	3,338	20,924	82	10,861	-	-	512	38,364	4,410	5,421	83,912
2030	3,338	21,402	158	11,600	-	-	966	41,796	8,229	6,361	93,850
2031	3,338	28,464	178	11,509	-	-	1,226	45,228	9,469	6,361	105,773

XII. 2011-2031 LCPDP Energy Mix (MW)

Yr	Hydro	Nuclear	HFO	Imports	Baggase	GT-Kero	GT-NGAS	Geo	Coal	Wind	Total
2010	2,299	-	2,602	-	223	379	-	1,640	-	17	7,160
2011	2,335	-	2,620	-	223	393	-	1,640	-	17	7,228
2012	2,441	-	3,587	-	223	387	-	1,704	-	17	8,359
2013	2,441	-	5,170	-	223	301	-	2,000	-	472	10,607
2014	2,504	-	1,994	1,410	188	-	-	5,036	-	1,659	12,791
2015	2,540	-	2,649	1,426	194	-	-	6,949	139	1,660	15,557
2016	2,540	-	592	4,215	172	-	-	6,957	1,821	1,660	17,957
2017	2,540	-	1,512	4,317	183	-	-	8,473	1,941	1,660	20,626
2018	3,338	-	780	4,324	187	-	-	9,615	3,285	1,973	23,502
2019	3,338	-	472	5,445	-	-	-	11,898	2,975	2,286	26,414
2020	3,338	-	251	6,649	-	-	247	14,184	2,839	2,286	29,794
2021	3,338	-	192	6,781	-	-	312	16,470	4,066	2,600	33,759
2022	3,338	7,108	84	5,766	-	-	157	16,476	2,367	2,600	37,896
2023	3,338	7,174	113	6,038	-	-	221	18,762	3,941	2,913	42,500
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2025	3,338	7,199	279	7,417	-	-	856	25,619	5,184	3,540	53,432
2026	3,338	13,488	51	7,975	-	-	137	29,047	1,487	4,167	59,690
2027	3,338	13,908	97	9,704	-	-	389	32,478	2,788	4,167	66,869
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2030	3,338	21,402	158	11,600	-	-	966	41,796	8,229	6,361	93,850
2031	3,338	28,464	178	11,509	-	-	1,226	45,228	9,469	6,361	105,773

XIII. Abstracts for Journal Publications

1. Screening Power Plants for Green-Based Generation Expansion Planning for Kenya.

IOSR Journal of Electrical and Electronics Engineering (IOSR-JEEE)
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Screening Power Plants for Green-Based Generation Expansion Planning for Kenya

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Abstract: *The main concern in the global generation sector was the huge CO_2 emissions from the conventional power generation. In Kenya, the sector prepares 20 year rolling least cost power development plan (LCPDP) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP generation plan proposed a system expansion that would result in a 33% fossil fuel power generation posing a huge CO_2 emission dilemma. However, renewable energy integration in the least-cost generation expansion planning (GEP) was considered key to energy security and emission reduction. During GEP, the screening curves are useful preliminary tool in selecting candidate generation options. In this study the screening curves were used in vetting the candidate plants for green-base GEP in Kenya. The findings showed that the green base load candidate plants were namely; 140MW Geothermal, 140MW low grand falls hydro, 300MW Wind, 1000MW imports, 60MWMutonga hydro and 1000MW nuclear plants characterized by US$ 90-660/kW.yr fixed cost, more than 40% capacity factor and US$cts 6-13/kWh levelized cost of electricity (LCOE). Suitable green peaking plant were 180MW GT-Natural gas, 100MW Solar PV and imports depicted by US$ 100-700/kW.yr fixed cost, less than 40% capacity factor and US$cts 15-30/kWh LCOE. These were a mix of green generation plants for cost effective utilization and environmental sustainability in Kenya. Therefore, the research recommended the selected candidate plants for simulation and optimization of a green-based generation expansion plan for Kenya using relevant GEP models.*

Key Words*: annual generation cost curves; base load plants; generation expansion planning; levelized cost of electricity; screening curves; peaking plants.*

2. Green-Based Generation Expansion Planning for Kenya using Wien Automatic Software Package (WASP) IV Model.

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Green-Based Generation Expansion Planning For Kenya Using Wien Automatic Software Package (WASP) IV Model.

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ABSTRACT: In 21st Century, there is growing interests in the global power generation sector to integrate more renewable energy (RE) resources in least-cost generation expansion planning for security of supply and sustainable development. However, little has been done in Kenya yet she was endowed with enormous unexploited RE resources. For this reason, the study derived an optimal green least-cost generation expansion plan (OGLCGEP) taking 2010 as the base year to 2031 using the WASP IV model. The study findings showed that the OGLCGEP had a capacity of 1382MW at a peak demand of 1227MW in the base year. However, annual RE capacity additions over the planning horizon will raise the capacities to 19828MW at a peak demand of 16905MW in the reference demand forecast scenario (RDFS) and 26968MW at a peak demand of 22985MW in the higher demand forecast scenario (HDFS). Consequently a 71% to 78% green generation would be realized with 1.94 -3.02 % LOLP. Additionally, the envisaged RE system would supply 7721GWh to 105766 GWh in the RDFS and 143830GWh in the HDFS with a cumulative total of 18 to 23.6Mt CO_2 emissions. Moreover, the energy system's cost would be US$ 14.62 billion in the RDFS; US$ 5.34 billion higher in the HDFS by 2031. Subsequently, the system's net present value would be US$ +2.16 billion in the RDFS; US$ +4.92 billion higher in the HDFS besides potential carbon credits. Thus, the OGLCGEP would be a feasible option and the future for high RE grid integration for Kenya. Therefore, the research recommends future studies to focus on modeling of the Kenya national-grid reliability and stability with high penetration of variable renewable energy sources.

Keywords : Generation Expansion Planning; Renewable energy; WASP IV; Optimal Solution; Senstivity Analysis; CO_2 emissions; net present value

3. Why a Green-Based Generation Expansion Plan for Kenya? A Comparative Analysis.

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Why A Green-Based Generation Expansion Plan For Kenya? A Comparative Analysis

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ABSTRACT: The main concern in the global generation sector was the huge CO_2 emissions from the conventional power generation. In Kenya, the sector prepares 20 year rolling least cost power development plan (LCPDP) for expanding the power system to meet the current and future power demands. The 2011-2031 LCPDP generation plan proposed a system expansion that would result in a 33% fossil fuel power generation posing a huge CO_2 emission dilemma. Consequently, a green least-cost generation expansion plan (GLCGEP) was derived from the Kenya's numerous renewable energy resources. However, the question of whether or not the plan was preferable over the LCPDP and the way forward for the Kenya's generation sector remained unanswered. This study sought the answer to this question through a comparative study of the two generation expansion plans. The findings of the study established that the GLCGEP would have a relatively modest reserve margin averaged at 25% and more than US$2.16 billion net revenues by the end of the 2011-31 planning period. Nothwitstanding, the envisaged energy system showed ample social-economic benefits for green growth. Therefore the research recommended future studies on modelling grid reliability and stability with high penetration of variable renewable energy sources.

Keywords : generation expansion planning; capacity; reserve margins, carbon credits, system's cost, net present value.