Is Nuclear Power a Cost Optimal Solution for Kenya's Electricity Generation Mix?

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I Sarah Odera would like to declare that I know the meaning of plagiarism and that all the work in the document, save for that which is properly acknowledged, is my own

Signed by candidate

SARAH A ODERA

This thesis is dedicated to my family for their consistent support and encouragement.
Erokamano.

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List of Abbreviations

CCEP	Current Capacity Expansion Plan
ERC	Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt
IEA	International Energy Association
IAEA	International Atomic Energy Association
IPP	Independent Power Producer
KENGEN	Kenya Electricity Generation Company
KIPPRA	Kenya Institute of Public Policy Research and Analysis
KNEB	Kenya Nuclear Electricity Board
KNBS	Kenya National Bureau of Statistics
KPLC	Kenya Power and Lighting Corporation
LCPDP	Least Cost Power Development Plan
MAED	Model for Analysis of Energy Demand
MSD	Medium Speed Diesel
MW	Megawatt
MWp	Megawatt Peak
TWh	Terawatt hours
TIMES	The Integrated Markal EFOM Systems
UNFCC	United Nations Framework on Climate Change
WASP	Wien Automatic System Planning Package

Abstract

In 2010, the adoption of nuclear power was declared a national priority in Kenya. Thereafter, a target of obtaining 4000 MW of nuclear power by the year 2030 was documented in Kenya's Least Cost Power Development Plan (LCPDP) 2010-2031. The nuclear target has drawn a lot of opposition from some Kenyans whose concerns are centered on the cost and safety risks incurred by nuclear power. The government however states that nuclear power is necessary for the diversification of the electricity generation mix and satisfaction of future electricity demand. The aim of this thesis was therefore to determine whether electricity demand in Kenya could be met without nuclear power and whether it was more economical to utilize nuclear power in Kenya's electricity generation mix rather than increase the generation capacity of other sources of electricity available to Kenya.

To answer these questions, two capacity expansion models were developed. These models like the LCPDP studied the period between 2010 and 2031. The aim of the first model was to replicate LCPDP, and in doing so verify the necessity of nuclear power for meeting Kenya's future electricity demand. As far as was possible, the validation model utilized the same assumptions, including the same demand forecast that was used to develop the LCPDP 2010-2031. The validation was done to verify the necessity of nuclear power from the LCPDP's set of assumptions.

The second model was developed with the aim of obtaining an updated capacity expansion plan. This plan utilized recent assumptions including an updated demand forecast. The demand was forecasted using regression of historical electricity demand against GDP in the commercial and industrial category. In the domestic category historical demand was regressed against GDP per capita and population. Based on recent data and economic forecasts, a GDP growth rate of 6% was used to forecast the electricity demand instead of 9% used in the LCPDP's demand forecast.

The results showed that both the demand in the LCPDP and in the updated capacity expansion plan could have been met without the use of nuclear power. Further to this, nuclear power did not reduce the emissions substantially. Additionally, the case with nuclear power had the highest cost of electricity generation. It can therefore be concluded that nuclear power is not necessary to meet Kenya's electricity demand.

Moreover, it is not more economical to utilize nuclear power rather than locally available sources of energy. To enhance this piece of research, more electricity demand data should be gathered to enable use of a more sophisticated demand forecasting software. Further, the peaks and troughs of the various electricity consumption categories should be recorded. All this will serve to improve the accuracy of the demand forecast. On the supply side, the capital costs can be enhanced by developing supply curves for all the technologies.

1 INTRODUCTION

Kenya is located in Eastern Africa. It has an area of approximately 582,646 square kilometers and a population of 43 million as at July 2014 (KNBS, 2015) . It lies on the equator and therefore has no summer and winter seasons and its temperature does not vary much throughout the year. The country experiences two rainy seasons; one between mid-March and May termed the 'long rains' and the other between October and December termed the 'short rains'. In between the two rainy seasons are two dry periods, a hot one between January and March and one characterized by cooler temperatures between June and September (BBC, 2012; C.McSweeney, M.New & G. Lizcano, 2008).

Kenya is currently classified as a lower middle income economy. There are currently plans underway to transform the economy into an upper middle income country by 2030. This plan known as the Vision 2030 was launched in the year 2007 (Vision 2030, 2007). One of the enablers of transformation under vision 2030 is energy with a lot of emphasis being placed on electricity. The government aims to reduce dependence on hydropower by diversifying the energy sources used for electricity generation, reduce the cost of electricity generation and increase the efficiency of consumption. One of the primary sources of energy for electricity generation that has been identified is nuclear power (Vision 2030, 2007).

1.1 Research Problem

In 2010, the Kenya National and Economic Council, which is chaired by the president declared the adoption of nuclear power a national priority (Energy Regulatory Commission, 2011). Subsequently, the Nuclear Electricity Project Committee was formed to spearhead this goal. This committee has since been made a statutory body and renamed the Kenya Nuclear Electricity Board (KNEB) whose mandate is to fast track the development of nuclear power in Kenya. The target is to have 1000MW of nuclear power operating in Kenya in 2022 and by 2030 to have four nuclear power plants with a total capacity of 4,000MW (KNEB, 2014). This objective has been

documented in Kenya's capacity expansion plan known as the Least Cost Power Development Plan (LCPDP) 2010.

This development has drawn a lot of opposition from some Kenyans. A Kenyan Member of Parliament has filed a motion to stop the government from constructing a nuclear power plant. He has stated that Kenya has renewable sources of energy such as solar and wind which it can utilize and does not need nuclear power that has a questionable safety record and is expensive to construct (Daily Nation, 2014). Business Daily (2013) has reported that Kenyans concerns are centered on the safety risks incurred by nuclear power.

The decision to adopt nuclear power by the government seems to be influenced by two main issues. The first is the need to diversify the sources of energy that are used for electricity generation. The LCPDP states that one of the objectives of the energy planning process was to diversify the energy sources and reduce dependence on unsustainable sources of electricity like hydropower (Energy Regulatory Commission 2011). Second is to meet the increasing electricity demand in Kenya. In a presentation given to the IAEA, the director of technical affairs of the Nuclear Energy Project Committee (NEPC) stated that one of the reasons for wanting to utilize nuclear power in Kenya is the projected sharp increase in electricity demand (Juma, 2012) . The planning process also aims to improve national access to electricity from 32% to 100% and reduce the suppressed demand (AfdB, 2015; Energy Regulatory Commission, 2015b).

The Kenya Nuclear Energy Board (KNEB) states that nuclear power will produce affordable electricity because of its low fuel costs. Additionally, they say that nuclear power is a clean source of electricity like renewables but has the added advantage of having a high capacity factor and can therefore be utilized to supply base load. The Director General of KNEB and the Cabinet Secretary for energy have been quoted saying that Kenya cannot meet its growing electricity demand without nuclear power (KNEB, 2014; Daily Nation 2015). In light of the government's decision to adopt nuclear power and the concerns recorded by Kenyans, this thesis will seek to determine whether Kenya's growing electricity demand can be met more economically by exploiting locally available resources.

1.2 Research Question

This thesis will aim to answer the question: Is nuclear power a cost optimal solution for Kenya's electricity generation mix? Currently, only 32% of Kenyan's have access to electricity (AfDB, 2015). Access to clean energy is a requirement for socio-economic development and is listed as the seventh goal in the Sustainable Development Goals as documented by the United Nations (United Nations, 2015). The government's desire to increase the electricity capacity in Kenya while enhancing energy security is a noble one. The electricity must however be supplied in an economical manner. One of the tenets of energy security is affordability (Cherp et al., 2012; Ferguson, 2011; IAEA, 2008). Affordability can be looked at from two perspectives, the suppliers and the consumers. When the electricity price is affordable from the supplier's perspective they are able to recover the full cost of supply. When the price is affordable to the consumers it does not hinder their access to electricity (Hailu, 2014; IAEA, 2008). One of the aims of the government is to reduce the cost of electricity, thereby increasing affordability so as to improve national access rates and promote industrial growth. A least cost generation mix will promote affordability for the consumers and suppliers (Vision 2030, 2007). 'Economical' as used in this thesis therefore refers to affordability for both the supplier and consumer. This thesis will therefore aim to determine:

1. Whether electricity demand can be satisfied without using nuclear power
2. Whether it is indeed more economical to include nuclear power in the generational mix than increase the capacity of other resources available to Kenya.

1.3 Scope

In answering the above questions this thesis will cover the following:

1. Validation of the 2010 LCPDP results using TIMES, the International Energy Agency's least cost optimization energy systems planning software
2. Construction of an updated capacity expansion plan which includes multiple scenarios to analyse possible electricity futures and uncertainties in cost.
3. Comparison of the cost of electricity generation between the scenarios in the updated capacity expansion plan.

4. Comparison of emissions between scenarios in the updated capacity expansion plan.

1.4 Exclusions

1. This thesis will focus on a generation expansion plan for the electricity sector only. Other areas of the energy sector will not be covered.
2. The cost of transmission and distribution infrastructure will not be covered within the thesis; however their losses will be included.
3. Off-grid capacity expansion will be excluded however all the consumption in the rural electrification category will be included

1.5 Methodological Approach

The first step in this thesis was data collection. A generation expansion model requires data that can broadly be divided into two groups: electricity consumption data and electricity supply data.

The electricity consumption data includes consumer categories of electricity consumption, transmission and distribution losses and historical electricity consumption. In addition to this, socio-economic data that influences the consumption of electricity is also required including the gross domestic product (GDP), GDP growth rate, GDP per capita, population and the population growth rate.

The data required for the electricity supply sector includes the current and historical electricity generation capacity, the power plants under construction and their completion dates and committed generation projects. Technical and economic data describing specific technology types for electricity generation was also required. This includes cost of construction, fixed and variable cost of operation, lead time, plant life time, plant efficiency and availability. All the data listed above was collected from various published sources and communication from the LCPDP team.

Using the data collected, two software models were developed. The aim of the first model was to validate the LCPDP 2010 and will be referred to as the 'LCPDP Replica'. The second model is an updated capacity expansion plan referred to as the 'Current Capacity Expansion Plan' (CCEP). Both these models were built using IEA's TIMES (The

Integrated MARKAL-EFOM System), a technology rich energy systems model builder that can be used for local, national or multi-regional systems. It is typically used to analyze possible energy futures based on the outcome of different scenarios (IEA-ETSAP, 2011; Loulou & Labriet, 2008). TIMES does not forecast demand therefore a demand forecast was developed using regression and was used as an exogenous input.

The demand forecast used in the LCPDP 2010 was prepared by a team consisting of members from various governmental agencies in the Kenyan electricity sector and consultants from the private sector. This forecast was obtained for use in the LCPDP Replica with the aim of obtaining results that were similar to the LCPDP 2010. The CCEP's demand forecast was developed using regression of historical electricity demand against population and GDP per capita for domestic electricity consumption. Domestic electricity category contained residential and public streetlights electricity consumption. The commercial and industrial electricity consumption was developed using regression of historical electricity demand against the cost of electricity and GDP. The established relationships between the variables were used to forecast demand. The use of regression to forecast demand is classified as econometric modeling. Econometric models establish a causal relationship between dependent variables in this case electricity and independent variables such as GDP, population and the cost of electricity (Wang & McDonald, 1994; IAEA, 1984).

1.6 Thesis Outline

The rest of the thesis is structured as follows:

- Chapter 2 discusses the sources of energy available to Kenya, analyses the models that are relevant to the thesis and reviews the LCPDP 2010
- Chapter 3 discusses the methodology and assumptions used to forecast demand and develop the capacity expansion model
- Chapter 4 presents and discusses the results obtained
- Chapter 5 draws conclusions and gives recommendations based on the results obtained.

2 ELECTRICITY PLANNING IN KENYA

This chapter will cover the electricity planning in Kenya by discussing the following:

- Primary sources of energy for electricity generation
- Generation and consumption of electricity
- Basic concepts of electricity planning
- Review of TIMES, WASP and MAED
- Review of the LCPDP 2010

2.1 Primary sources of energy in Kenya

Primary energy is energy that has been extracted from a source or flow of natural resources and has not undergone any form of transformation (IEA, 2004). Kenya has a number of primary energy sources available to it for electricity generation. It is important to evaluate the primary sources of energy before building a capacity expansion plan so that technologies that are considered in the plan use available energy sources. The following section discusses these sources of energy.

2.1.1 Hydro energy

Hydropower is typically categorized as small (1-20MW), medium hydropower (20-100MW) and large hydropower (>100MW) (IRENA, 2012).

Currently the installed capacity of hydropower in Kenya is 822.8 MW, 39% of the installed capacity. While the potential of medium to large hydropower is 3-6GW, the unexploited resource with economic significance is about 1499 MW. Out of the 1499 MW, 1249 MW could be developed for projects of 30MW or bigger (Energy Regulatory Commission, 2011). For small hydropower, the potential is 3 GW and only 31MW of this has been exploited.

2.1.2 Geothermal

Energy from the earth's core is referred to as geothermal energy. One of the major tectonic structures of the earth where heat from the earth's core, escapes to the surface is known as East African Rift System. This system extends at its northern extreme, from the Dead sea-Jordan valley in the Middle East to Mozambique. (Omenda, Simiyu S & Mechemi. G, 2014). The principle of geothermal power is to transfer this heat to water which is then transformed to steam and can be used for generation of electricity.

The estimated resource potential of geothermal power in Kenya lies between 7-10GW. The installed capacity of geothermal power has risen from 198MW to 573 MW between 2011 and 2015 in Kenya. The government has a target of 5000MW by 2030 (Energy Regulatory Commission, 2011).

2.1.3 Oil

22% of Kenya's primary energy consumption comes from oil. The largest consumer of this fuel is the transport sector followed by the manufacturing sector. In the energy sector, petroleum based energy carriers fuel approximately 28% of the installed capacity. This capacity is split between plants consisting of medium speed diesel internal combustion engines fired by heavy fuel oil (591MW) and kerosene-fueled gas turbines (60MW) (KPLC, 2014). As will be discussed in 2.9 Kenya also uses diesel for emergency power when it is unable to meet electricity demand due to low water levels in dams that are used to generate hydroelectricity.

Kenya is currently a net importer of oil. In 2010, the quantity of oil imported was 3.8 million tons (Odhengo, 2012). After years of exploration, in 2012, oil was discovered in Lokichar, north of Kenya. Tullow oil estimates the reserve to be over 600 million barrels of oil which is above the threshold necessary for economic exploitation (Tullow oil, 2015). The government intends to commercially exploit this oil and there are plans to build a pipeline from Uganda to Lamu in Kenya. This pipeline will transport both oil originating from Uganda and Kenya to Lamu port where it will be exported (Business Daily, 2015b).

2.1.4 Natural Gas

There are currently no natural gas electricity plants in Kenya. The government had plans to construct a 700MW plant at the coast using gas imported from Qatar. The use of gas from Qatar was suspended following the discovery of 1.88 Tcf of gas in Wajir (Business Daily, 2015a). Off shore gas was also discovered off the Lamu coast but the well was plugged because the quantity of gas found was commercially unviable (Bloomberg News, 2012). Another discovery of gas has also been made in the northern part of Kenya and work is currently being done to ascertain commercial viability (Tullow oil, 2014).

2.1.5 Wind

The wind resource in Kenya has been estimated to be over 4 GW (Energy Regulatory Commission, 2015b). Currently the total installed wind capacity is 18.6 MW consisting of Ngong 1 and Ngong 2 wind farms which are 5.1MW and 13.6 MW respectively. Lake Turkana wind farm, 300MW in capacity reached financial closure in December 2014 and is undergoing construction. When completed the Lake Turkana Wind Power plant will be the largest in Africa (African Development Bank, 2015).

2.1.6 Solar

Kenya does not have any solar power generation at a utility scale. It does however have a developed solar PV market on a residential and institutional scale. The LCPDP, 2010 estimated that there are 200,000 solar home systems installed in Kenya whilst Hansen et al, 2014 and Ondraczek, 2014 estimate the number to be 320,000 in 2010. Installed capacity has been on the rise from 1.5MWp in the 1990s to 3.9MWp in 2000 and to 8-10MWp in 2010. It is estimated that the capacity could have reached 16MWp with an additional two projects of 0.635MWp (Hansen, Pedersen & Nygaard, 2014; Ondraczek, 2014).

The daily solar irradiation on average in Kenya is reported to be between 4-6kwh/m^2/day. The map in Figure 2-1 shows the distribution of global horizontal irradiation in Kenya. About 106,000km^2 (18.2%) of Kenya's land area experiences direct normal irradiation of 6kwh/m^2/day indicating that the Kenyan solar resource is still largely untapped. The LCPDP does not include solar as a capacity expansion option at a utility scale however the government does have feed in tariffs for solar power and hopes to draw international investors into the sector (Energy Regulatory Commission, 2015a; Hansen, Pedersen & Nygaard, 2014).

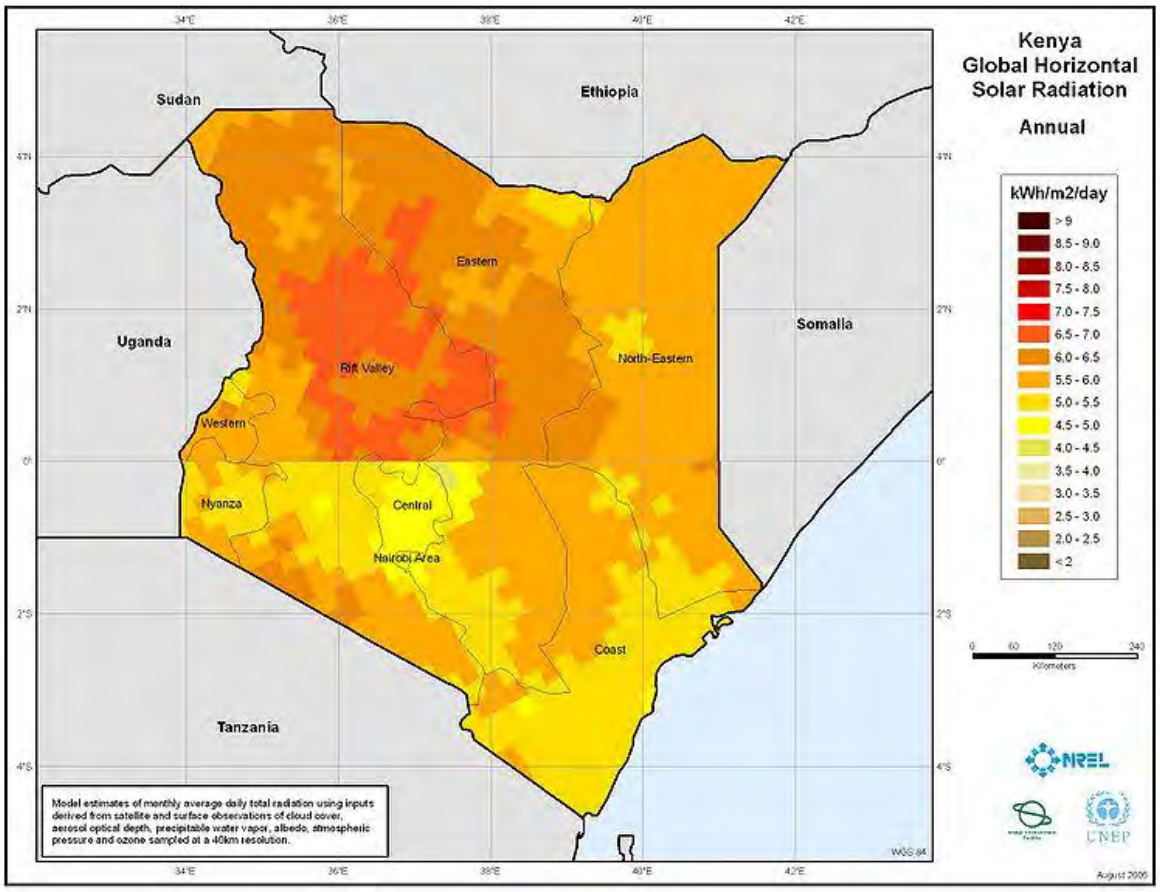


Figure 2-1: Global Horizontal Irradiation in Kenya (NREL, N.D)

2.1.7 Biomass

There are two categories of biomass utilization, traditional and modern biomass. Traditional biomass, mostly used in the residential sector by low income families, is usually unprocessed and has low conversion efficiencies. Examples of traditional biomass are wood, charcoal and agricultural residue (IEA, 2015). Modern biomass energy is characterized by the conversion of traditional biomass fuels to advanced fuels such as biofuels and wood pellets and the use of technologies with higher efficiencies (Karekezi, Lata & Coelho, 2006)

Kenya uses biomass for 68% of its energy needs (KIPRA, 2010). 57% of this is used in its traditional form while 43% is used in its modern form. Traditional biomass mainly consists of fuel wood and charcoal which promote deforestation. Additionally, indoor

combustion of these fuels exposes the users to pollutants which are harmful to their health (Mugo & Gathui, 2010) .

In Kenya, modern biomass utilization includes mainly biogas and bagasse. Biogas is used for the provision of heat for cooking and in electricity generation. In the years between 2009 and 2013, the Kenya National Domestic Biogas program rolled out a program that saw the installation of 11,579 biogas digesters. Further to this, the first biogas plant that will supply electricity to the grid in Kenya is expected to come on line in 2016 (Reuters, 2015; Tropical Power, 2015; Africa Bio-gas Partnership Programme, 2014)

Bagasse, the fiber that remains after sugarcane stalks have been crushed can be used in the generation of electricity. Mumias Sugar Company, the largest sugar manufacturing plant in Kenya, built a 35MW plant in 2010. It supplies 26MW to the grid and uses the rest of the power it generates to meet its own needs. Kwale sugar company has also reported that it has completed an 18MW bagasse powered plant and expects to supply electricity to the grid in 2015 (Business Daily, 2015c). The Energy Regulation Commission estimates the potential of electricity generation from bagasse as 193MW (Energy Regulatory Commission, 2012)

2.2 Electricity Generation in Kenya

As described above, currently electricity in Kenya is generated from petroleum fuels such as heavy fuel oil, diesel and kerosene and renewables such as hydropower, geothermal power, and a very small percentage of wind and solar. .

Since 2011, Kenya's electricity sector has made considerable progress towards increasing its capacity. The total capacity has increased from 1533 MW to 2109MW in 2015. Notably, 280MW of additional geothermal capacity was installed between 2014 and 2015, displacing hydropower as the largest generator of electricity. In January 2015, geothermal generated 51% of Kenya's electricity while hydro generated 36% (KENGEN, 2015).

Table 2-1 compares the technology capacity and capacity shares in the year 2011 and 2015.

Table 2-1 Kenyan electricity generation mix in 2011 and 2015 (Energy Regulatory Comission, 2013)

	2011		**2015**	
Source	**Capacity (MW)**	**Share (%)**	**Capacity (MW)**	**Share (%)**
Hydro	761	50%	822.8	39%
Geothermal	198	13%	578.3	27%
Wind	5.45	0.03%	39.1	2%
Thermal (petroleum fuels)	525	34.24%	625	30%
Co-generation (bagasse)	26	1.69%	26	1%
Various Technologies (Isolated grids)	17	1.1%	18	1%
Total	**1533**	**100%**	**2109**	**100%**

2.3 Electricity Consumption

Electricity consumers in Kenya can be divided into three categories according to supply voltage (Energy Regulatory Commission, 2011; KIPRA, 2010):

- Low voltage (240/415kV) – This category is comprised of domestic and small commercial consumers and street lights.
- Medium Voltage (33 kV) – This category is comprised of medium commercial and industrial consumers.
- High voltage (66 and 132 kV) - This category is comprised of large commercial and industrial consumers.

The pie chart in Figure 2-2 below shows the split of electricity consumption by sector in Kenya in 2013 (KNBS, 2014b).

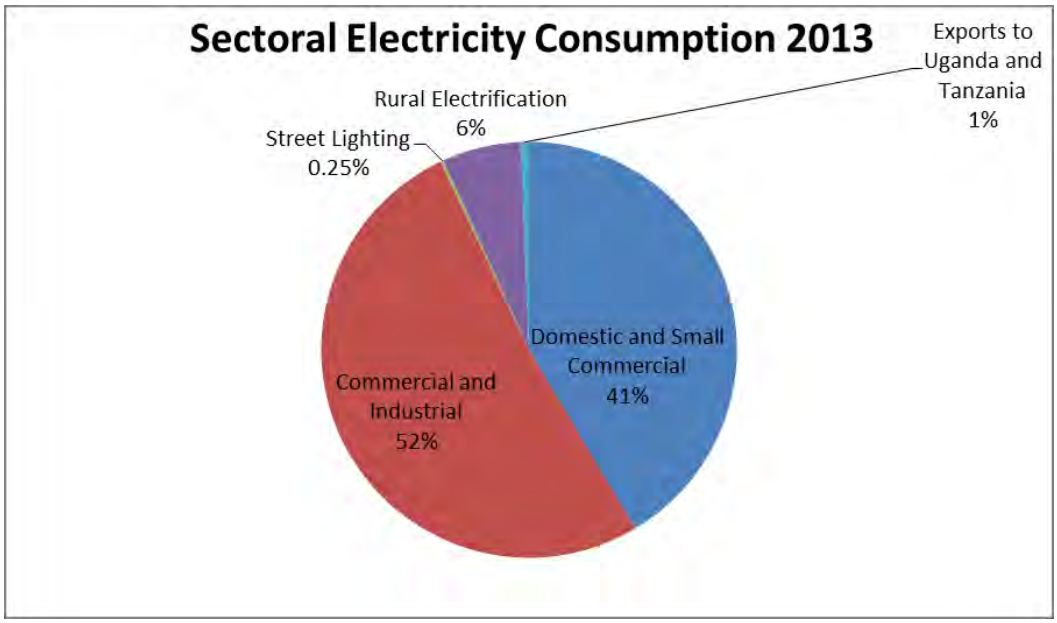


Figure 2-2 Showing sectoral electricity consumption 2013 (KNBS, 2014b) .

The category rural electrification contains electricity supply to the rural areas both on and off grid. This supply of electricity is managed by the Rural Electrification Authority (Kapika & Eberhard, 2013). It contains mainly schools, health and trading centers as well as domestic residences (Ayieko, 2011).

KNBS records combine electricity consumption from medium and large commercial and industrial into one category. The consumption from medium and high voltage categories was therefore aggregated in Figure 2-2 and is labelled commercial and industrial

electricity consumption. (Energy Regulatory Commission, 2013; Business Daily, 2014). This electricity consumption has been shifted to the off peak hours to lower demand during peak hours.

The World Bank records that national and rural access to electricity stood at 23% and 7% respectively in 2012 (World Bank, 2015). African Development Bank data suggests a significant improvement on this indicating that the national access to electricity in Kenya stood at 32% while access to electricity in the rural areas was at 19% in 2015 (AfDB, 2015). Despite the improvement, these figures remain low. The government has an ambitious plan to connect two million new electricity customers by 2017 and to have universal electricity access by 2020 (Vision 2030, 2007).

The following sections will discuss the concept of energy planning then review the models that are relevant to the thesis. The key official electricity planning document, the LCPDP will then be reviewed on detail. The review will focus on the LCPDP 2010 because its update, the LCPDP 2013, relies heavily on information obtained from the 2010 version.

2.4 Electricity planning

An energy plan can be defined as the roadmap for meeting the future energy needs of a nation (Randolph & Masters, 2008). Energy planning must conform to financial constraints, government policies and domestic resource availability (IAEA, 1984; Covarrubias, 1979). Electricity planning is a sub-set of energy planning. The relationship between energy planning and electricity planning is shown in the figure 2-3 below.

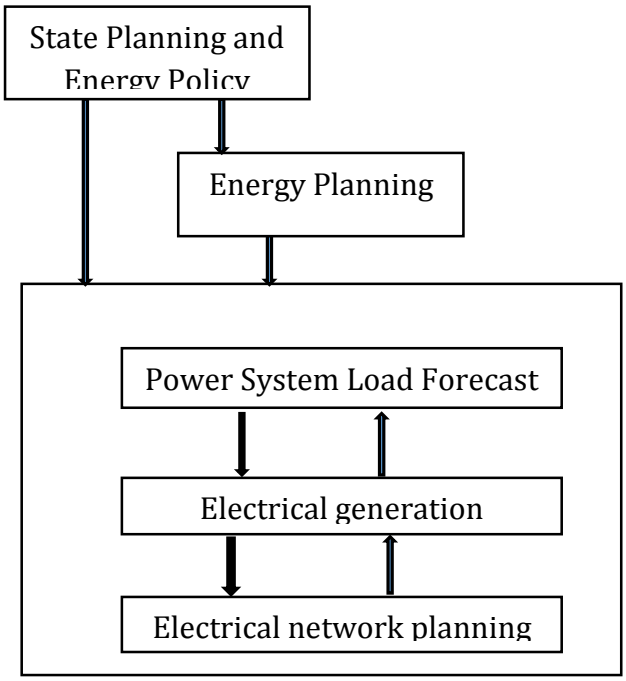


Figure 2-3 Relationship between energy planning and electricity planning (Wang & McDonald, 1994)

Electric system planning can be divided into three broad categories: generation, transmission and distribution. Since the scope of this thesis is limited to generational planning, the literature review will focus on generational planning which can further be divided into short, medium and long term planning. The planning range depends on its objective. Short term planning whose range spans less than 5 years can be carried out by load dispatchers to help with operation of the system. Medium term planning is carried out for a range of approximately 5 to 10 years. It can be used for financial planning such as determination of tariffs. Long term planning is carried out for a range longer than 10 years and can be used to establish a generational expansion plan (IAEA, 1984). This thesis will focus on long term planning because its aim is to develop a generation expansion plan for Kenya.

2.4.1 Generation Expansion Plan

Generation expansion planning is divided into two categories; capacity planning and energy planning. The objective of capacity planning is to develop a system that has the ability to reliably meet the largest expected demand, while the objective of energy planning is to meet the forecasted demand for energy over a specified period of time

(Hyman & Peterson, 1988). The holistic aim for a generational expansion plan is to to meet the demand for electricity at a minimum cost (Wang & McDonald, 1994; IAEA, 1984; Covarrubias, 1979)

In carrying out a generational expansion plan the following questions have to be answered (Wang & McDonald, 1994; IAEA, 1984):

1. What capacities should be installed to ensure adequate reliability?
2. What type of generational units should be installed?
3. Where should the power plants be located?
4. When is the proper time to incorporate power plants into the system?

The determination of a capacity expansion plan contains the following processes (Covarrubias, 1979):

1. The study of a reliable load forecast for the relevant duration.
2. The evaluation of energy sources available in the future and foreseeable trends in economic and technical developments.
3. Identifying the technical and economic characteristics of existing and potential power plants such as capital costs, operation costs, technical life, lead times, efficiencies etc.
4. The determination of technical and economic parameters affecting decisions such as level of reliability and discount rate
5. Selection of the choice of the procedure to determine the optimal expansion strategy within the imposed constraints
6. Qualitative review of the results to estimate the viability of the proposed solution.

A number of challenges can be faced during the generation expansion planning process. One of these challenges is uncertainty. Due to the long horizons being considered, uncertainties pertaining to load forecasts, improvements in technology, fuel availability, costs, financial conditions etc. are introduced. Each of these parameters can assume a range of possible values in the future. A plan that is least cost under certain conditions might not be least cost if those factors are changed. It is therefore important to have a plan that can be adapted to changing business conditions (Stoll & Garver, 1989; IAEA, 1984).

One of the ways of dealing with uncertainty is using the scenario method. A scenario is a sketch or outline of a possible future based on a given set of assumptions (Randolph & Masters, 2008). This method accepts that the future will be one of multiple possible outcomes. A scenario is therefore comprised of a possible future and the path towards it (Wang & McDonald, 1994). In planning, a number of scenarios are developed with the aim of generating discussion and identifying challenges, opportunities and undesired outcomes in the planning process (Randolph & Masters, 2008).

2.4.1.1 Load Forecasting

A load forecast is a projection of future load requirements determined using a systematic process. It should have sufficient quantitative detail to permit important system expansion details to be made (Sullivan, 1977). Load forecasts estimate both peak demand and energy requirements. The peak demand indicates to the planner the maximum amount of demand that the system experiences in a given time. This in turn tells the planner the capacity that the system needs to have. While the energy tells the planner the total amount of energy the entire system needs to produce in a given time frame (Hyman & Peterson, 1988). The estimation of both is important because it helps the planners determine what type of plants to install (Sullivan, 1977). A load forecast consists of three underlying elements, demand which has already been defined above, a time period and the assumptions underlying the forecast (Hyman & Peterson, 1988).

A load forecast is only as useful as the assumptions made. Assumptions may be as simple as tomorrow will be like today, or maybe very detailed and complex such as those requiring assumptions pertaining to a country's economic, social and political sectors and the relationships between these sectors and electricity consumption (Hyman & Peterson, 1988). Economic factors include growth of the Gross Domestic Product (GDP), specific assumptions about key energy intensive industries e.g. aluminium, steel and paper, price estimations for fuels that compete with or are sources of electricity such as wood, solar, gas, coal and oil. Social assumptions include factors like population growth rate, number of households, household income, and location of household in relation to weather. Political factors include policies in place such as those restricting use of charcoal and wood as fuels (Hyman & Peterson, 1988). A good load forecast should (IAEA, 1984):

1. Identify causality: This is the identification of factors that affect demand and the relationship between these factors and demand.
2. Be functional: The nature of the load forecast should be such that it fits the decision at hand for example a long term forecast should not be used for load dispatch because it will not capture the seasonal variations.
3. Be reproducible: Another person should be able to understand the process by which it was derived and reproduce the same load forecast using the same principles.
4. Test sensitivity: A good load forecast shows the sensitivity to the assumptions made. As previously mentioned one way of testing sensitivity is to use the scenario method.
5. Be simple: Only as much information as required for accurate prediction should be included. More information might mean more accuracy but might require more resources such as time and money. It is therefore necessary to strike a balance between accuracy and simplicity.

There are five main approaches to load forecasting. These include (Wang & McDonald, 1994; IAEA, 1984):

i) Subjective approach: This is the application of intuition, experience and judgement to load forecasting.

ii) Univariate forecasting: This method uses past observations in a given time series to forecast the future.

iii) Multivariate forecasting: This is the use of causal relationships between the demand volume and its drivers such as the relationship between GDP and demand. Examples of multivariate forecasting include econometric and regression models.

iv) End user approach: This method decomposes energy consumption into its elemental components. Energy consumption in this case would be broken down into its various groups such as residential, commercial, industrial etc. These categories would further be broken down into various activities underlying the consumption. Residential for example would be broken down into space heating, cooking, lighting etc.

v) Combination method: This uses a combination of all the methods described above in a load forecast.

In generating load forecasts, different types of demand need to be analysed. The following categories of demand have been suggested (Rosnes & Vennemo, 2009):

i. Market demand: Demand that is as a result of income growth or structural changes in the economy
ii. Suppressed Demand: Demand that is unmet due to blackouts or brown outs that occur as a result of a peak demand that is higher than the available capacity of supply or because of run down infrastructure
iii. Social demand: Demand due to expected new connections in the household sector. This demand should include the targets for electricity access set by the government.

Developing countries, in particular, have to deal with suppressed and social demand in addition to market demand. Kenya has a national electricity access rate of 32% and current suppressed demand has been estimated to be 100MW. (Energy Regulatory Commission 2015b; Energy Regulatory Commission, 2011). One challenge faced in meeting this demand is the large capital investment required. It has therefore been argued that demand forecasts of developing countries reflect the demand that the utility can afford to add into the system (IAEA, 1984). Power sector reforms such as unbundling the energy sector and allowing independent power producers (IPPs) to supply electricity have been used as an alternative route to raising the capital required to expand the electricity generation system(Clark et al., 2005). It had been observed that while these reforms had the effect of diversifying power supply and meeting demand that would have otherwise have been unserved, they have not improved electricity access among the poor (Wendle, 2013; Bazilian et al., 2012; Clark et al., 2005). This was because it was not deemed profitable for the private sector to supply electricity to low income communities (Bazilian et al., 2012). Currently, new developments which include new financing models and decreasing prices of some technologies like solar power are enabling the private sector to supply electricity to low income communities. Examples of this are M-Kopa which operates in Kenya, Uganda

and Tanzania and has a financing model that enables low income house-holds to obtain solar home systems (M-Kopa Solar, 2014).

The observed increase in electricity access has been credited to special programs run by governments however because of the new financing models, the private sector can also begin to take part. Governments in developing countries should therefore adopt an approach that allows all industry players, whether private or public, to take part in investing in new capacity. This will allow load forecasts to reflect a larger portion of the unserved demand.

Poor load forecasts can result in overbuilding or underbuilding. The result of underbuilding is obvious, industries might have to reduce their production due to interrupted service, goods may be damaged or people injured, commercial establishments may not be able to render the necessary services and households have to deal with the inconvenience of power black outs (IAEA, 1984). The effects of overbuilding include diversion of funds that would have been used in another sector of the economy and increased tariffs to pay for the construction of power plants that were not necessary (IAEA, 1984)

2.5 Models for Long Term Electric System Modelling

Initially, capacity expansion modelling was straight forward due to the rapid introduction of new technologies with little concern about health and environment. After the 1960s, capacity expansion became important due to (IAEA, 1984):

- The number of alternative technologies available and size of expansion units
- Operation costs that are sensitive to type, cost and availability of fuels
- Safety, health and environmental concerns
- Longer construction periods
- Uncertainties in load growth, interest rates and financing

Computerised models have therefore been developed that can help in this complex process of decision making. There are two broad approaches to computer modelling. These approaches are related to the driver of the system and are described below (Alfstad, 2004).

- Aggregate top down models which are driven by econometric factors like capital cost, labour and interest rates
- Technology rich models which are generally bottom-up models. These models focus on the technical characteristics of the energy sector and use highly disaggregated energy data to describe available options and energy end uses in detail (Van Beeck, 1999) .

Broadly, there are two categories of models used; optimisation models and simulation models. Optimisation models are designed to meet a certain objective or maximise an objective function. The objective function is usually described by the user. Examples of objective functions include minimal emissions and lowest system cost. The model usually has to meet these objective functions under a set of prescribed constraints such as supply must exceed demand, capacity must exceed peak demand and so on. Optimisation models are technology rich and require that the various technologies are described both technically and economically. Technical descriptions include efficiencies, availability and plant capacity among others while examples of economic descriptions are operating costs and capital investment. Examples of widely used optimisation models include the Market Allocation family of models (MARKAL) such as the IEA'S The Integrated Markal EFOM Systems (TIMES), the IAEA's Model for Energy Supply Alternatives and their General Environmental Impacts (MESSAGE) and Wien Automatic System Planning Package (WASP) (Alfstad, 2004).

Simulation models are used to predict system behaviour given a logical representation of the system (Van Beeck, 1999) . They have no objective functions and fewer degrees of freedom. Accounting models fall under the category of simulation models. They have zero degrees of freedom and therefore all the flows of energy and capacity variables have to be specified by the user (Merven et al., 2013; Alfstad, 2004). Accounting models can be said to serve as a sophisticated calculator and database which can be used to compare the effects of scenarios that are put into place by the analyst (UNFCC, 2008). Simulation models consist of a representation of the problem and a set of decision making rules. The main advantage of simulation models is that they have no solver thus they generally rely on less expensive software and don't require high computing power or long solution times. Examples of simulation models include the Stockholm

Environment Institute's Long Range Energy Alternative Planning model (LEAP) and the IAEA's Model for Analysis of Energy Demand (MAED) (Alfstad, 2004).

The following section contains a description of the MAED, TIMES and WASP models.

2.5.1 MAED

Model for Analysis of Energy Demand (MAED) is an Excel based bottom up energy model used for forecasting energy demand. It follows the scenario approach which assumes a set of consistent assumptions of the possible long term developmental path of a country or region (IAEA, 1984; IAEA 2006).

MAED is housed in two Excel work books: MAED_D and MAED_EL. MAED_D contains representations of the various economic sectors of electricity consumption such as households, industrial, transport, and services. It projects annual electricity demand in each of these economic sectors and then transmits them to MAED_EL which converts annual demand to hourly demand for each economic sector. MAED's is designed to reflect the changing structure of the country. It provides a framework for the detailed analysis of the social, economic and technical system of the country. It takes into account the changing social needs of the individual like heating and transport as well as the countries policies such as industrial and transport policies. MAED is also designed to reflect the change in markets for each energy carrier e.g. electricity, coal, gas, oil (IAEA, 1984; IAEA, 2006).

MAED does not use prices to reflect interchangeability of fuels rather; it uses the scenario approach to do this. The prices are used within the model to observe their effect on other factors which in turn might influence demand for example the price of fuel might influence the distance travelled by motor vehicles which will in turn influence demand (IAEA, 2006; IAEA, 1984).

The following is the methodology which MAED follows while projecting energy demand (IAEA, 2006; IAEA, 1984)

i) Breaking down the countries energy demand into pre-defined categories of use.

ii) Identification of social, economic and technological factors that affect the countries energy demand and establishing mathematical relationships between demand and the factors that affect this demand.

iii) Development of consistent scenarios for social, economic and technological progress

iv) Evaluation of energy demand observed in each scenario and selection of the most probable pattern of development

The operation of MAED is divided into 4 modules which are further described below (IAEA, 2006; IAEA, 1984):

a) Module 1: It is further divided into two subroutines. The first describes the fundamental characteristics of the socio-economic development of the country while the second describes the technology factors which must be taken into account such as technological penetration and efficiency.
b) Module 2: Is operated within the MAED_EL workbook and converts annual electricity demand into hourly electricity demand
c) Module 3: Ranks the hourly demand in order of magnitude from the largest to the smallest and in doing so provides the load duration curve.
d) Module 4: Describes the variation in hourly load.

When there is competition between energy carriers in one of the economic sectors, energy demand will be calculated in terms of useful energy and converted to final energy demand by use of the assumed technology efficiencies (Bhattacharyya, 2011). Useful energy is the actual energy used for an end use application while final energy is the energy which the consumer receives. Final energy is useful energy divided by the appliance efficiency. Non-substitutable energy forms are calculated in terms of final energy (IAEA, 2006; IAEA, 1984). All this is done so that the modeller can represent technology change and fuel switching. Figure 2-4 illustrates how MAED handles substitutable and non-substitutable fuels.

Fossil fuels such as coal, oil and gas are considered as a group within the various economic sectors because substitution of the various fuels is largely related to the demand and supply of the fuels which is beyond the scope of MAED. The substitution of fossil fuels by alternative energy forms like solar, district heating and so on is

considered by MAED because this is largely influenced by policy (IAEA, 2006; IAEA, 1984).

As mentioned above energy demand is projected in each of the four economic sectors then aggregated. The four economic sectors within MAED are briefly described below (IAEA, 2006):

i) Industrial Sector: The industrial sector is further divided into agriculture, mining, construction and manufacturing. Each of these sections can further be divided into another 10 sections as specified by the user. Energy is considered as follows: electricity for specific uses like lighting and motive power, thermal uses (space heating, steam generation, furnaces etc.) and motor fuels. Coke used in steel production and feedstock requirements for the petrochemical industry are considered separately. Energy demand is influenced by the level of economic activity (which is influenced by the GDP) and energy intensity of each industry.
ii) Transport: It is divided into passenger and freight transport. Freight transportation is determined as a subset of the GDP contribution of the various sub-sectors of the industrial sector while passenger transport demand is driven by the population, its distribution and its habits; car ownership, disposable income etc.
iii) Services sector: End use categories here are electricity for specific uses such as lighting, thermal uses such as space heating and motor fuels. The demand is influenced by the level of economic activity and the size of the labour force.
iv) The household sector has the same end use categories as the services sector however, the driving factors of end use demand are different. Factors that influence the household sector are population and its distribution, number of dwellings and whether the dwellings are located in a rural or urban area.

Figure 2-4 is a schematic showing how the MAED model operates

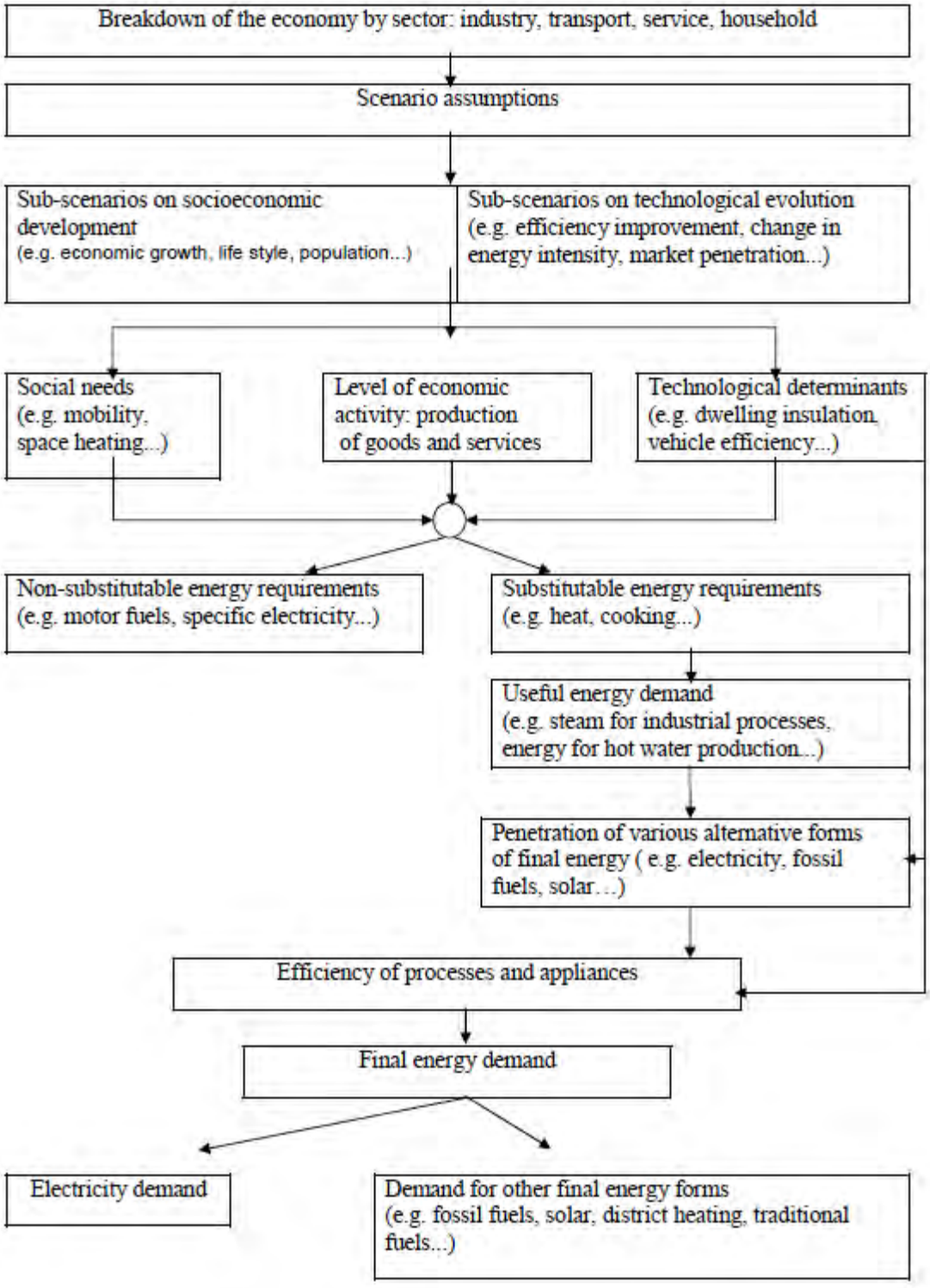


Figure 2-4 Schematic showing how MAED operates (IAEA, 2006).

MAED enables the user to understand and forecast the demand for various energy carriers but it does not generate an expansion plan. The demand forecast obtained from

MAED therefore has to be used as an exogenous input to a capacity expansion model such as WASP which is described below.

2.5.2 WASP

WASP was developed in 1972 to meet the International Atomic Energy Agency's (IAEA) needs of determining the economic competitiveness of nuclear power in comparison with other generation options. It is designed to find the most cost optimal expansion solution within user specified constraints (IAEA, 2001). Since 1972, four versions of WASP have been released, each being an improvement of its predecessor. The current one, WASP IV, is the most widely used capacity expansion tool in developing countries (Howells, 2008)

WASP is a probabilistic, linear optimization, dynamic model. These terms shall now be elaborated on in the context of WASP. WASP's objective is to minimize total discounted expenditure cash flows, while maintaining system reliability set by the user. It uses linear programming to solve for this problem within a set of specified constraints. This makes it a linear optimization model. (IAEA, N.D; Jenkins and Joy 1974). WASP finds the optimum solution for all periods in the time of the modeling horizon and presents it to the user as the most optimum solution which makes it a dynamic model (Roy and Jenkins 1974; IAEA, 2001).

WASP is a probabilistic model. It calculates the systems loss of load probability and uses it to estimate the system's reliability. It also determines the energy generated by each configuration and associated production costs. It does this by plotting the plants that are used to generate electricity, referred to as units from here onwards, onto an inverted load duration curve and factoring in their probabilities of success of failure into the calculation for electricity generated. It should be noted that two similar plants that have different capacity will be plotted as two different units, for example two coal plants with capacities of 600 MW and 1000 MW will be plotted as two separate units (Jenkins and Roy, 1974; IAEA 2001). The following is an explanation on how this is done.

First the system load curve is obtained, an example of which is shown below in figure 2-5

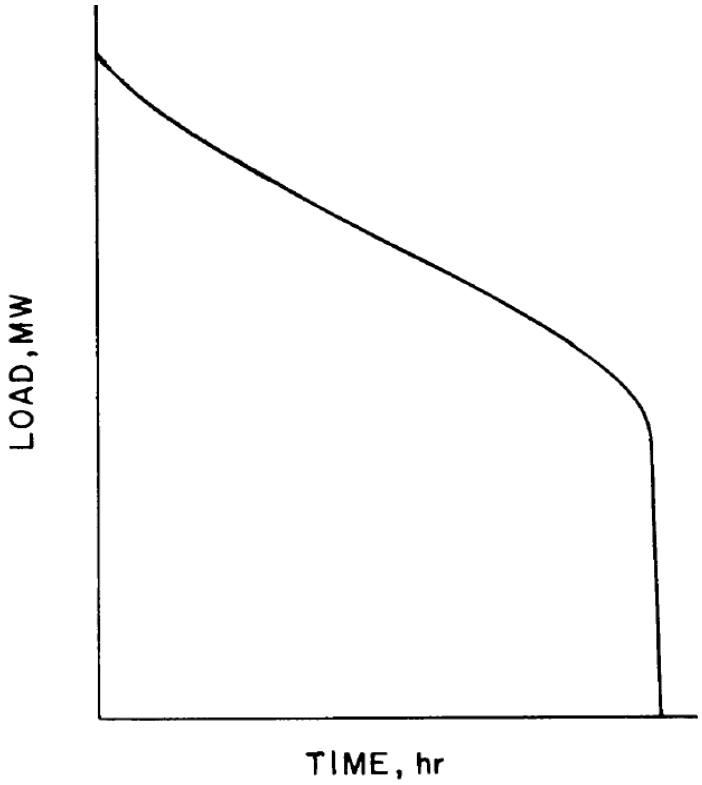


Figure 2-5 Load duration Curve (Jenkins & Joy, 1974)

A load duration curve is a graph that arranges the load experienced by a system in descending order. Load duration curves can also be interpreted as giving the amount of time that that a system load equals or exceeds a certain value. If time was normalized i.e. dividing by the maximum amount of time, it can give the probability that the load will equal or exceed a certain value (Jenkins and Roy 1974; Wadhwa 1989)

To determine the amount of electricity generated using probability of success or failure of the units in question; the inverted load duration curve is used. An example of which is shown below:

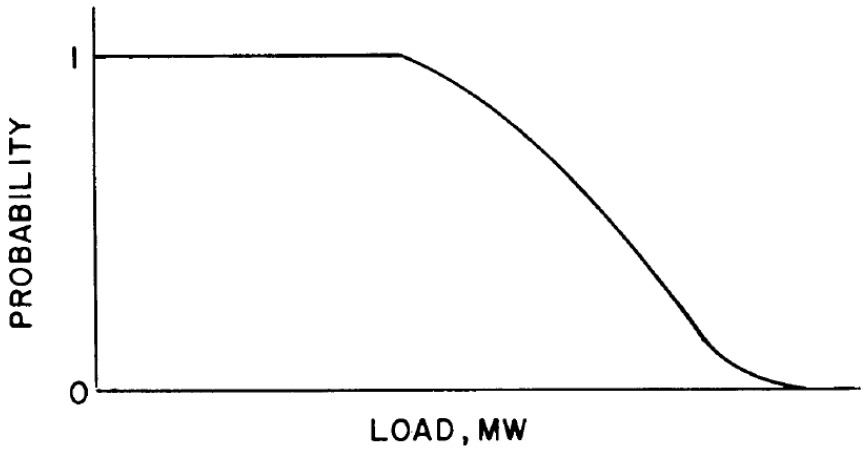


Figure 2-6 Inverted load curve (Jenkins & Joy, 1974)

The area under the curve is used to determine the quantity of electricity generated however as mentioned above, the units and their respective probabilities of success or failure need to be incorporated into the calculation. The various units are plotted onto the graph in their dispatch order as shown in figure 2-7a ; their width on the x-axis should be equal to their capacity. Each unit is then assigned a probability of use. The probability of forced outage then becomes (1-p) where p is the probability of use. The probability of use is always less than 1 due to forced outages for maintenance purposes.

The units are loaded onto the graph as shown in figure 2-7a below. When unit 1 fails, unit 2 steps up to take its place as shown in figure 2-7a The amount of energy generated by the system is then calculated using the probabilities of availability and forced outage, the capacity size of each unit and the equation of the inverted load duration curve.

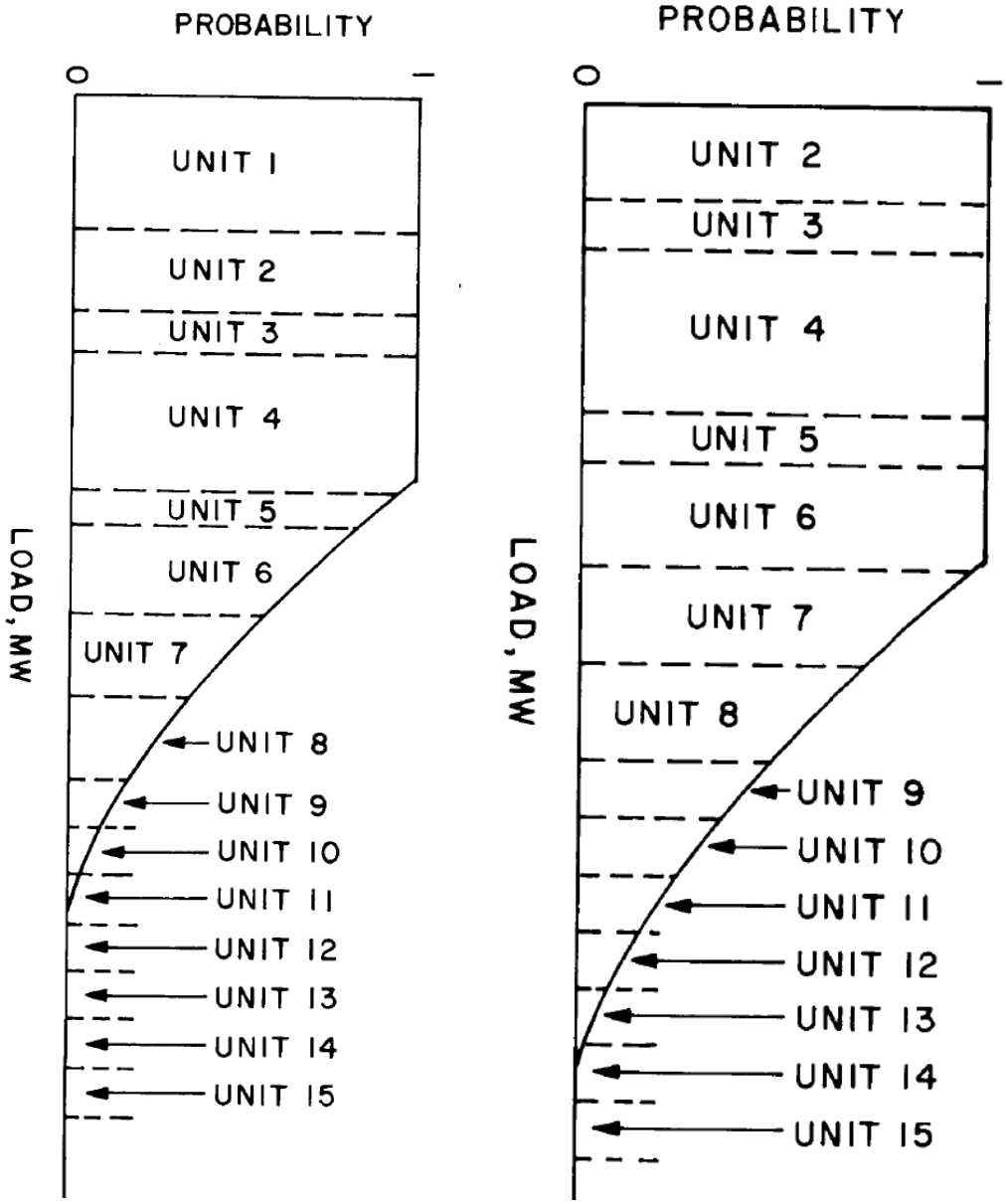


Figure 2-7a **Figure 2-7b**

Figures showing loading order of units onto inverted load duration curve (Jenkins & Joy, 1974)

As mentioned above WASP is an optimization program the objective function of which is to minimize discounted costs for both capital and operation. The approach used is based on Bellman's theory of optimality. Bellman's theory of optimality analyses the different paths that the decision could take and chooses the most optimal one. From

analyzing Figure Figure 2-8 below, we see that there are two paths to C from A, either on the solid line or on the dashed line from A to B then on the solid line from B to C. WASP will find the most optimal path from A to B then from A to C. If the dashed line from A to B is more optimal than the solid line from A to B but the path from A to C is most optimal on the solid line, it will then use the path on the solid line since C is the end point (Jenkins and Roy, 1974).

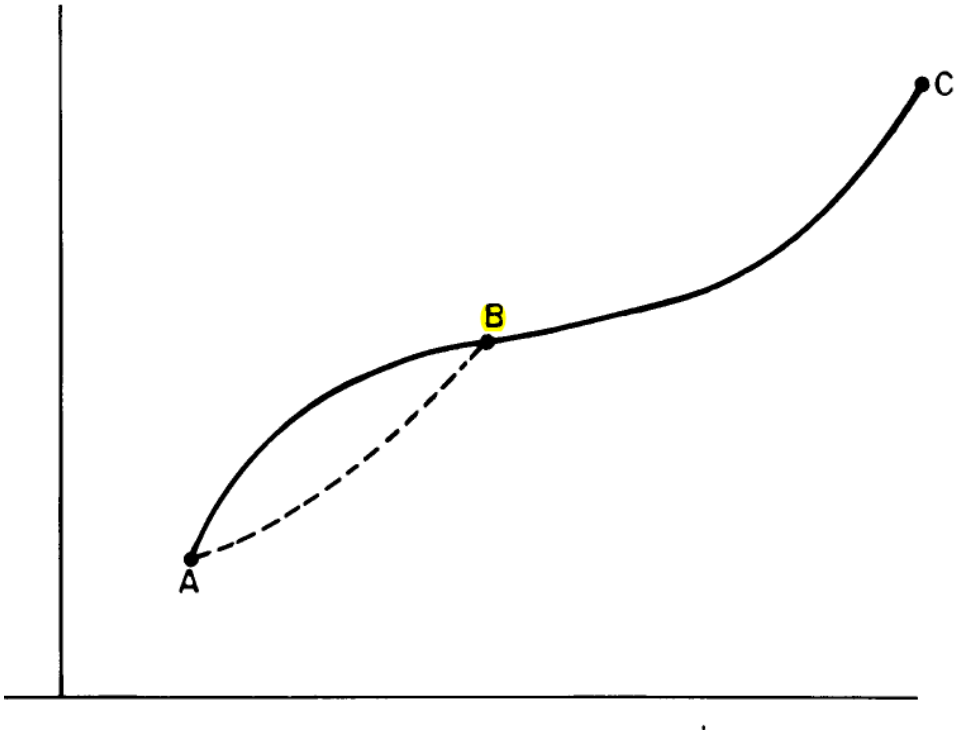


Figure 2-8 Bellman's theory of optimisation

2.5.3 TIMES

The Integrated Markal EFOM Systems (TIMES) is an extension of the Market Allocation (MARKAL) family of models. MARKAL was developed in the 1980s by the IEA's Energy Technology System Analysis Program (ETSAP).

2.5.3.1 TIMES Description

TIMES is a bottom-up, partial equilibrium, dynamic, linear optimization model. This description will be elaborated on in the context of TIMES. As stated above bottom-up energy models have a rich technology database that is able to describe a variety of energy services. Each technology within TIMES is identified and described according to

its techno-economic parameters such as efficiency and capital cost (Loulou & Remne, 2005). The technologies can represent various stages of energy use from extraction of primary energy resources to electricity generation, transmission and consumption.

The term partial equilibrium implies that the model represents a section of the economy i.e. energy and not the whole economy as would have been the case if it was a total equilibrium model. The term equilibrium denotes that its aim is to maximize both producer and consumer surplus which is equivalent to minimizing total cost. Producer surplus is the difference between the maximum amount of money a producer is willing to pay to produce a good and what they actually pay to produce the good. Consumer surplus is the difference between the maximum amount of money a consumer is willing to pay to obtain the good and they actually pay. Producer and consumer surplus can be illustrated graphically as shown below in Figure 2-9(Church and Ware 2000).

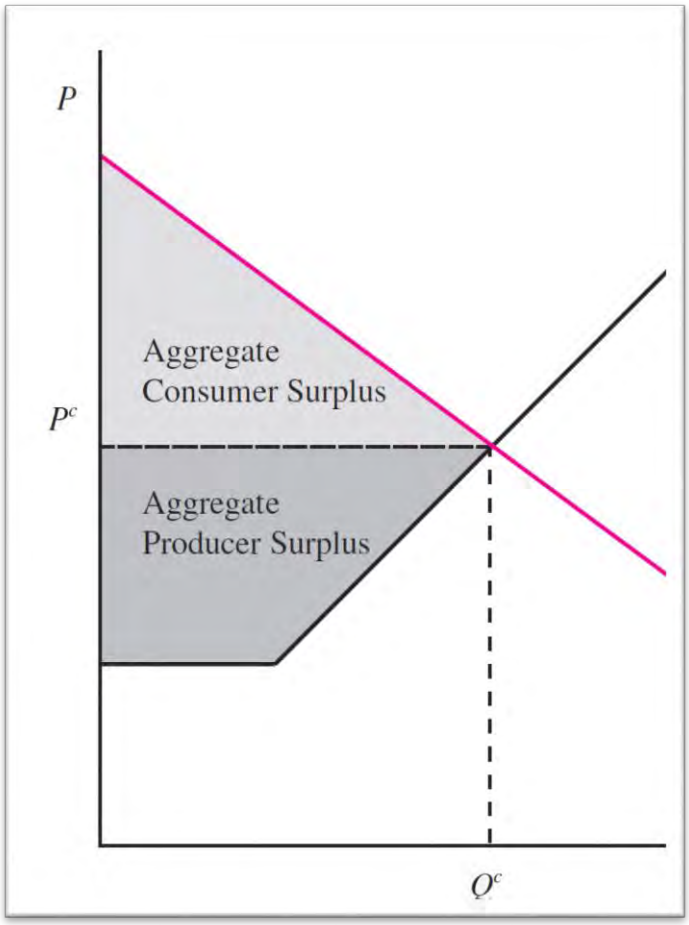


Figure 2-9 Producer and consumer surplus (Church & Ware, 2000)

The above graph shows the producer and consumer surplus which is given by the shaded regions of the graph and the point of equilibrium that is obtained at point Q^c. Equilibrium is the point that the consumer is willing to purchase no more than goods Q^c at price P^c and the producer is not willing to produce more than Q^c at price P^c (Church and Ware, 2000). In TIMES, the suppliers of a commodity are technologies that produce the same commodity and consumers are demand technologies that consume a commodity within TIMES (Loulou & Remne, 2005).

Maximization of the total surplus can be defined as the objective function in TIMES making it an optimization model. Optimization models approach complex decision problems which involve the selection of values from a number of interrelated variables by focusing on a single aspect of the problem, in the case of TIMES maximization of the total surplus within a set of constraints (Luenberger, 1973). To achieve this goal TIMES uses linear programming. Linear programming is a method used to achieve optimum results in a mathematical model whose functions, inequalities and equalities are represented in a linear fashion. It is characterized by an objective function, constraints and decision variables.

The fact that linear programming is used does not mean that all the relationships are linear. There are many cases of non-linear relationships which are represented using a

step wise linear approach as shown in Figure 2-10.

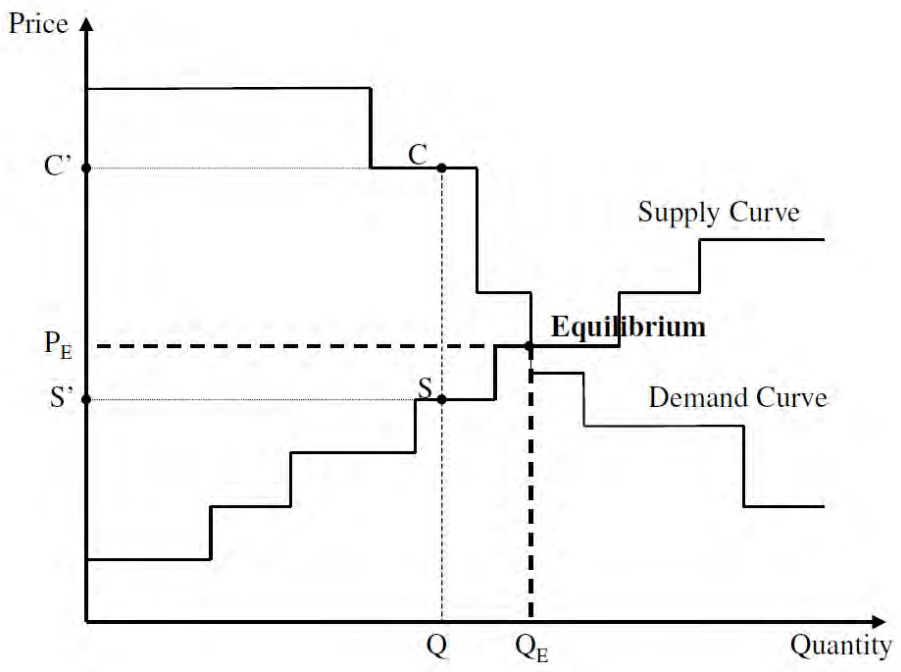


Figure 2-10: Graph showing stepwise linear function

Initially each agent within TIMES had complete foresight while solving linear equations, with the aim of attaining equilibrium. Recently however versions of TIMES which run myopically were introduced. In the myopic versions of TIMES, the decisions made depend only on the past and there is limited knowledge of the future (Remme and Blesl, 2006). TIMES attempts to maintain equilibrium in each period of the modelling horizon making it a dynamic model. Additionally, it also provides a perfect competitive market so that that neither the amount produced by any supplier nor the amount consumed by any consumer is enough to affect the equilibrium market price. This is because TIMES assumes that many other consumers and producers exist to replace the existing ones (Loulou & Remme, 2005).

2.5.3.2 The Structure Of TIMES

The structure of TIMES will be handled by discussing the data inputs, temporal desegregation and the Reference Energy System (RES) which shows the relationship between the various entities in TIMES.

2.5.3.3 Data inputs

The structure of TIMES is determined by the data input from the user. This data which is both qualitative and quantitative determines the set of variables and equations that TIMES will use. Qualitative data includes technology and commodity identities while the quantitative data includes the techno-economic parameters such as costs, efficiencies and availabilities.

TIMES uses the scenario approach to obtain a capacity expansion plan for the future. As previously mentioned a scenario consists of a set of assumptions about the main drivers of an energy system and, in simple terms, creates a story line that the model follows to obtain results (Loulou & Labriet, 2008). Scenarios have two components; demand and supply. In the demand component different demand technologies can be described by their efficiencies however the demand forecast has to be exogenously input into TIMES as it does not forecast demand.

The supply component consists of supply curves for each primary energy resource. The supply curves are multi-stepped curves and are defined in TIMES as the quantity of the resource available at a particular cost. They may also be expressed as the cumulative potential of the resource available over the model horizon, as annual potential for example maximum annual extraction of a resource or maximum area available for utilization of a resource (Loulou & Labriet, 2008; Loulou & Remme, 2005).

2.5.3.4 Temporal Disaggregation

One of the first steps of modelling is to identify a reference year which is considered a past year. This year is used for model calibration and has zero degrees of freedom (Loulou & Labriet, 2008; Loulou & Remme, 2005).

All the years within TIMES modelling horizon are considered identical. The set capacities and commodity flows will be the same for all the years of the model horizon. The only anomaly to this rule is the investments (capital costs) which occur once in a given period of time (Loulou & Labriet, 2008; Loulou & Remme, 2005).

The user can choose to divide the model horizon into time slices. The time slices can be at the level of seasons, weeks or day-night. This is done to reflect technologies whose availability depends on the season or time or for demand that varies according to the season or time. An example of this is hydropower the availability increases in the rainy

season and decreases in the dry season or solar power which is not available at night (Loulou & Remne, 2005).

2.5.3.5 RES Concept

The Reference Energy System (RES) is a network diagram that represents the flow of energy within TIMES. The energy can either be embodied in a commodity or transformed by a technology. The basic entities represented by the RES diagram will now be defined below (Loulou & Labriet, 2008; Loulou & Remme, 2005).

- Technologies/Processes: Devices that convert energy from one form to another
- Commodities: These are energy carriers including fuels, energy services, materials, monetary flows and emissions. They are either produced or consumed by a technology.
- Commodity flows: This is an amount of a given commodity that is either consumed or produced by a process. They are links between the commodity and a process for example natural gas is a commodity whereas natural gas for electricity generation is a commodity flow.

An example of a RES diagram is shown in Figure 2-11 below

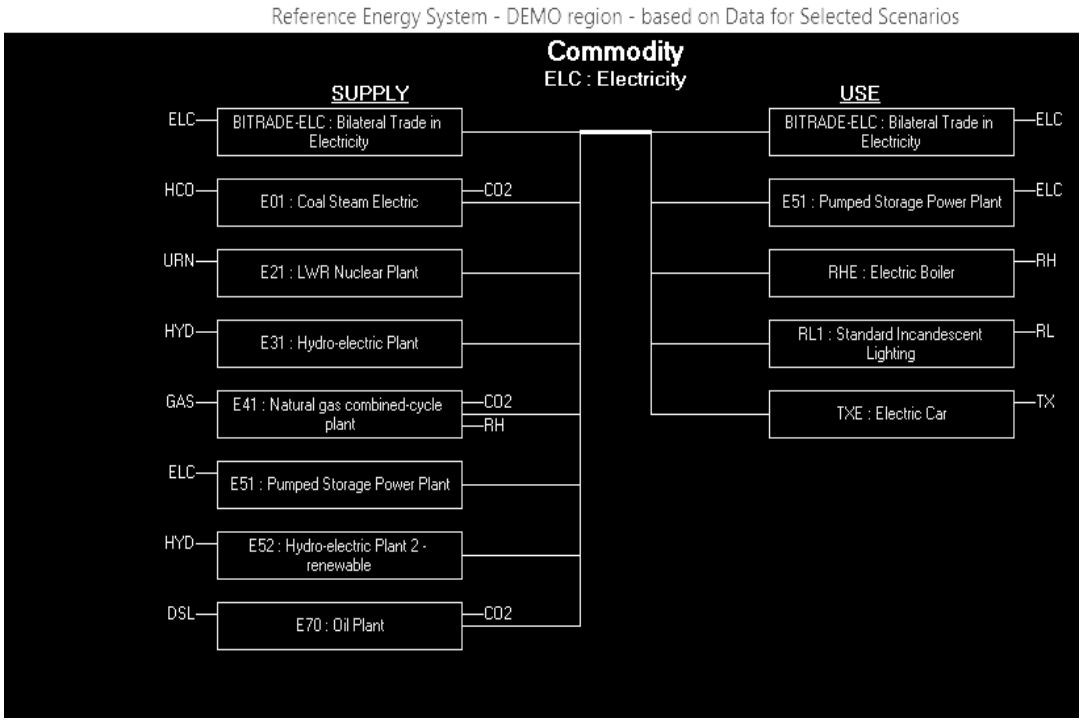


Figure 2-11 RES Diagram (Source authors model)

2.5.3.6 The Mathematics Of TIMES

As has been mentioned in section 2.5.3.1 the objective of TIMES is to find the energy technology configuration in terms of the installed capacity and production level (X) that minimize the total discounted costs of the system subject to imposed constraints. The constraints include:

- Demand must be met
- Production of an energy commodity must balance consumption
- Production of energy by a technology is limited by its capacity and its capacity factor
- And others such as limits on total installed capacity (resource limits), annual limits on new capacity and reserve margin,

The total discounted costs can be represented by equation 2-1 below (Alfstad, 2004).

$$C_{tot} = C_{inv} + C_{sun} + C_{fix} + C_{var} + C_{sur} + T + C_{dec} - S - M - V \qquad 2\text{-}2$$

Where

C_{tot} is total costs

C_{inv} is investment costs

$C_{fix\ is}$ fixed costs

C_{var} is variable costs

C_{sun} is sunk material costs

C_{sur} is surveillance costs

T is taxes

C_{dec} is decommissioning costs

S is subsidies

M is recuperation of sunk costs

V is salvage value

The linear equations which are solved by TIMES are as follows in equations 2-3, 2-4 and 2-5, below:

$$Min\ \mathrm{C}.X \qquad 2\text{-}3$$

s.t

$$\sum_{\mathrm{k}} \mathrm{CAP}_{k,i}(t) \geq DM_i(t) \qquad 2\text{-}4$$

and

$$B.X \geq b \qquad 2\text{-}5$$

Where

c.X is the total discounted costs given values for variables X,

CAP is the capacity,

DM is the demand, and

B describes other constraints that may have been set on X.

Equation 2-3 shows the objective function to be minimized while 2-4 sets the constraint which states that capacity must be greater than demand. Equation 2-5 sets other constraints that the user may want the model to meet.

When the demand is inelastic, the above linear equations are enough for TIMES to obtain equilibrium however if the demand is elastic, TIMES has to factor in elasticity and an elasticity factor has to be set by the user for TIMES to solve the equations (Loulou et al, 2005). The version of TIMES used in this assumes that demand is inelastic.

The following section is a review of Kenya's capacity expansion plan.

2.6 Least Cost Power Development Plan Review

Kenya's electricity plan is recorded in a document known as the Least Cost Power Development Plan (LCPDP). This document covers a period of 20 years and is updated every two years (Energy Regulatory Commission, 2011). As stated in the introduction, one of the aims of this thesis was to validate the results obtained in the LCPDP 2010, given the assumptions of that study. After validation, an updated capacity expansion plan was developed for this study which was called the 'Current Capacity Expansion Plan'. This plan adopted some of the constraints contained in the update to the LCPDP 2010, the LCPDP 2013-2033 and therefore the results obtained in the current capacity plan were compared to the LCPDP 2013-2033. The following is a review of the LCPDP 2010-2031.

The Ministry of Energy is responsible for the preparation of Kenya's capacity expansion plan in collaboration with the following institutions (Energy Regulatory Commission, 2011):

- Geothermal Development Company: Responsible for prospecting and developing geothermal resources in the country
- Rural Electrification Authority: Responsible for rural electrification
- Energy Regulatory Commission: Regulates Kenya's energy sector and facilitates the preparation of the national energy plan
- Kenya Transmission Company: Responsible for the construction and maintenance of high voltage lines
- Kenya Nuclear Electricity Board: To fast track the development of nuclear electricity in Kenya.

As per best practice as described in 2.4.1, capacity expansion in Kenya was done in two phases; first a load forecast was generated to estimate the demand and energy requirements during the stipulated horizon. After this a capacity expansion plan was modeled to aid in the selection of appropriate electricity generation technologies and their required capacities (Energy Regulatory Commission, 2011).

The following sections will therefore describe the phases above as documented in the LCPDP 2010.

2.6.1 Load Forecast

The load forecast consisted of the following categories

- Domestic
- Commercial and Industrial
- Vision 2030 flagship projects
- Suppressed Demand

Two methodologies were used to carry out the Kenyan load forecast. The domestic load forecast was carried out using MAED principles (see section 2.5.1i above) on a simplified excel spreadsheet instead of the actual full-scale IAEA published modelling framework due to insufficient data. The commercial and industrial load forecast was regressed using with GDP growth and price as the independent variables (Nzia, 2013; Energy Regulatory Commission, 2011)

The load forecast categories listed above will now be discussed below.

2.6.1.1 Domestic

The domestic category consisted of residential electricity consumption and public streetlights. The considered parameters when generating the domestic load forecast were:

- Population growth
- Location (whether rural or urban)
- Household size
- Income level

The population growth was assumed to grow from 38.6 million to 60.5 million in 2030. The household sizes were assumed to be 5 people per house in the urban areas and 6.5 people per house in the rural areas. In 2031, the number of people per house was projected to be 4 people in urban areas and 6.5 in rural areas. The share of urban population was projected to grow from 24% to 63%. The supply rate which is the ratio of connected households to the total number of households was assumed to be at 18.1%. The government aims to have 100% connectivity by 2020. This target was used as the assumption in the high demand growth rate scenario. In the reference scenario

the supply rate is assumed to grow to 88% (World Bank, 2015; Energy Regulatory Commission, 2011)

Table 2-2 describes the current and projected specific electricity consumption in Kenyan rural and urban households. Specific electricity consumption is the average electricity consumed by each household per annum. The households are grouped by their level of income i.e low, medium and high income. The projected specific consumption given in

Table 2-2 covers all the demand forecast scenarios i.e. low load, reference and high load scenarios (Energy Regulatory Commission, 2011).

Table 2-2: current and specific consumption in Kenyan households

	Specific Consumption (KWh/household/annum)			
Urban	**Current**	**Low Load**	**Reference**	**High**
Low Income.	131	240	300	360
Medium Income	996	780	945	1200
High Income	4795	3900	4200	4500
Rural				
Low Income	108	120	180	240
Medium Income	586	730	800	2000
High Income	2731	3800	4000	4200

Public street lights were projected using the average growth rate in the number of customers multiplied by a coefficient factor of 0.8 which was obtained by dividing the average growth rate by the growth rate from 2005-2009. It was also assumed that the efficiency would increase such that it would cause a consumption decrease of 1% per year. (Energy Regulatory Commission, 2011).

2.6.1.2 Commercial and Industrial Load Forecast

As mentioned above, energy forecasting in this sector was carried out by regressing the energy consumption against the GDP growth. (Energy Regulatory Commission 2011). Vision 2030 (Kenya's national planning strategy) targets a GDP growth rate of 10% by the year 2015 which should be maintained till 2030. This growth rate is used in the LCPDP's high load growth scenario. The reference scenario assumes a GDP growth rate of 9% from 2015 and the low scenario assumes a GDP growth rate of 8.

The projected economic growth rate in the LCPDP from 2009 to 2015 and the actual growth rate experienced are shown in Table 2-3

Table 2-3 Projected verses actual GDP (KNBS, 2014b; Energy Regulatory Commission, 2011)

Year	Low	High	Reference	Actual
2010	4.5	4.5	4.5	5.8
2011	5.2	6.5	5.4	4.4
2012	5.9	7.8	6.3	4.6
2013	6.6	8.9	7.2	4.7
2014	7.3	9.4	8.1	5.3*
2015	8	10	9	6-7%*
Average	6.3	7.8	6.8	4.9

**it is assumed that the GDP growth rates above were generated before the economy was rebased from 2001 to 2009. This is because the LCPDP was published in 2010 and the rebasing was done in 2014. The GDP growth rates given in 2014 and 2015 above were however obtained after the economy had been rebased because the values using 2001 as a base year were unknown. It is however known that the rebased GDP growth rates given in 2014 and 2015 are higher than the values that would have been obtained using 2001 as a base year (KNBS, 2014)*

The figure given for the actual GDP growth rate in 2015 is an estimate by the World Bank (World Bank, 2015). From the table above it is observed that the GDP surpassed the expected growth for the reference scenario in 2010 and 2011. From 2012 onwards the GDP did not meet the expected target.

2.6.1.3 Flagship Projects

The Kenyan vision 2030 involves the implementation of various projects known as flagship projects that are expected to aid in the transformation of the economy. Some of these projects will have a large effect on Kenya's electricity demand and therefore the demand was amended according to their dates of implementation. The projects and their energy and capacity requirements are tabulated in Table 2-4

Table 2-4 Energy requirements of flagship projects as projected in the low scenario

Projects	**YEARS (GWh)**								
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Standard Gauge Railway	-	-	-	-	1084	-	-	-	-
ICT park	331	442	442	215	215	215	215	215	190
LAPSSET		184	184	184	184	184	184	184	184
Iron& Smelting Industry	-	-	-	-	-	-	613	1226	1226
Special Economic Zones	215	215	215	-	-	-	-	-	-
Total	**546**	**841**	**841**	**399**	**399**	**399**	**1012**	**1625**	**1600**

Technical and Non-technical losses

The losses assumed in the LCPDP at each voltage level are tabulated in Table 2-5

Table 2-5 Projected transmission and distribution losses

Voltage level	Loss (%)
Low	6
Medium	4
High	3
Non-technical	1
Total	14%

Based on the above considerations a load forecast was obtained. Figure 2-12 shows the load forecast for the reference, high and low demand scenarios (Energy Regulatory Commission, 2011). The load forecast data is tabulated in Appendix 1

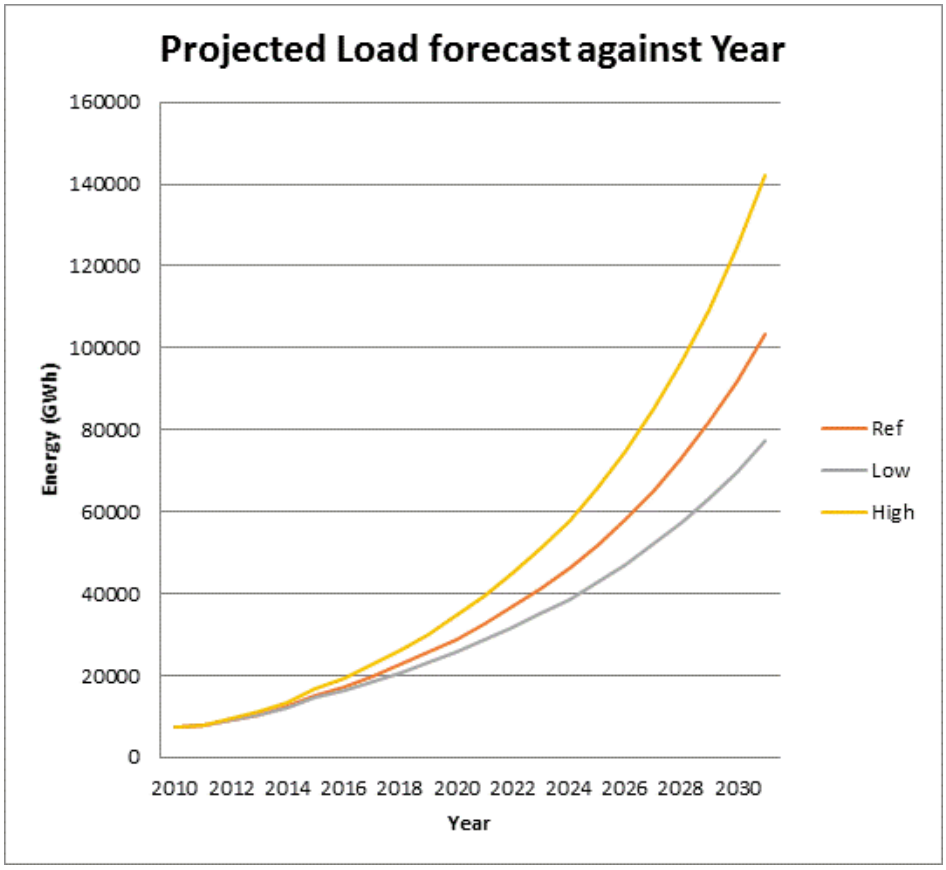


Figure 2-12 Load forecast for reference, low and high demand scenarios

2.7 Capacity Expansion

The technical parameters describing the technologies used in the LCPDP are tabulated in Table 3-18. The constraints documented in the LCDP 2010 are tabulated in Table 2-6

Table 2-6: Constraints employed in capacity expansion (Energy Regulatory Commission, 2011)

Technology	Constraints
Geothermal	Maximum 3×140 MW
Coal	Earliest commissioning date 2014
	Maximum per year 3×300MW
Mutonga Hydropower (60MW)	Earliest commissioning date 2018
Low Grand falls (140 MW)	Earliest commissioning date 2018
Gas Turbines*	Earliest commissioning date 2015
Wind	Maximum per year 3×100
Nuclear	First plant in 2022
	Maximum per year 2×600MW
Medium Speed Diesel Cycle Turbines (HFO) fueled (160MW)	Earliest date 2018
Import (200MW)	Earliest date 2018

**The LCPDP does not specify whether the gas turbines are combined cycle gas turbines (CCGTs) or open combustion gas turbines (OCGTs).*

It is noted that only two options for hydro were considered, Lower Grand Falls and Mutonga in LCPDP 2011. An impression is therefore obtained that one of the aims was to divest from hydro dependence as much as possible.

The 2010 LCPDP found the generation mix shown in Table 2-7 to be optimum (Energy Regulatory Commission, 2011).

Table 2-7 Generational mix obtained in LCPDP 2010 for the year 2031

Technology	Capacity (MW)	Share (%)	Potential
Hydro	1039	5	1.499 GW unexploited
Geothermal	5530	26	7-10GW
Nuclear	4000	19	-
Wind	2036	9	More than 4GW
Imports	2000	9	-
Medium Speed Diesel Cycle	1955	9	[1]2.5GW/annum(Approximately 600mmboe)
Gas Turbines (NG)	2340	11	[1]766MW/annum (1.6 Tcf)
Coal	2720	13	[1]5.0 GW/annum (400 Million metric tonnes)
Total	21620	100	

1. Conversion from physical units to electric units was calculated by assuming a lifetime of 50 years and an availability of 90%

Three new additions to Kenya's generation mix are evident; coal, nuclear and natural gas. Of all these technologies, nuclear power has generated a lot of controversy. A Kenyan member of parliament has filed a motion to stop the government from constructing a nuclear power plant. He states that Kenya has renewable sources of energy such as solar and wind which it can utilize and does not need nuclear power which has a questionable safety record and is expensive to construct (Daily Nation, 2014). An article published in the Standard Newspaper records that Kenyan concerns are centered on the financial implications and safety risks of nuclear power (Agina & Nyabiage, 2015)

The government however states that a generational mix including nuclear power is the only way to provide adequate and reliable electrical energy in Kenya. According to the LCPDP, Kenya aims to increase generational capacity to 21620 MW (Energy Regulatory Commission, 2011). Another objective is to diversify the generational mix from hydropower which is currently 39% of installed capacity. This is because over reliance on hydro has caused unreliable electricity supply during dry spells.

The following sections will analyze contentious issues behind Nuclear power and the climate vulnerability of hydropower.

2.8 Nuclear Power

In the 1970s it was assumed that the cost of nuclear power would progressively decrease due to implementation of learning rates and low operation and maintenance costs. This has not been the case. The implementation of stringent safety standards and new designs have instead progressively increased the capital costs (Martin & Fig, 2015; Schneider et al., 2014; von Hippel et al., 2012; Davis, 2011).

Nuclear power plant costs are mainly influenced by overnight capital costs, financing costs and construction time. The reported capital costs of nuclear power plants have large variations which have been attributed to a number of reasons, for example ambiguity over the number of parameters included in the cost. Some cost estimates include parameters like transmission costs and site preparation costs while others do not. Another source of variation is biases held by the estimator; for example vendors may give a low estimate to obtain a contract or utilities may give high estimates to obtain higher loans (von Hippel et al., 2012). The costs in Europe and America have also been reported to be higher than in Asia. This has been attributed to lower labor costs, higher economies of scale and experience obtained due to mass construction in Asia. In Europe and America new plant designs are being employed which have caused higher costs (von Hippel et al., 2012).

Table 2-8 below shows capital costs of nuclear power from various sources

Table 2-8 Capital costs of Nuclear Power

Source	Overnight Cost per (US$/ KW)
IEA 2010	1600-5900 (4100 median value)
EIA 2010	5335
NREL 2010	6100
MIT 2009	4000
LCPDP 2010	4055
IRP 2010 Update	5800

**It was assumed that the dollar year was the year of publication*

In July 2014, the IAEA reported that there were 67 nuclear power plants under construction. Of these plants, 8 have been under construction for more than 20 years and one has been under construction for 12 years. 49 out of the 67 have experienced delays running from several months to several years and for the first time delays running up to two years have been reported in China. Out of the 67 reported reactors, 18 have not reached construction startup date so it is difficult to record delays (Schneider et al., 2014). Delays in construction increase the costs of the power plant due to accumulated interest.

Other uncertainties faced by nuclear power plants include those faced in regulatory development, and in the planning process. Due to these uncertainties, some institutions such as the World Bank have policies that do not allow them to finance nuclear power (Schneider et al., 2014).

On the positive side nuclear power has low fuel costs compared to coal and gas supply. In the OECD the fuel cost for nuclear is a quarter that of coal and a fifth that of gas. 15% of the levelised cost of nuclear electricity is the fuel cost. The fuel costs can also be reduced by reprocessing the fuel and boosting the enrichment levels (World Nuclear Association, 2015).

Safety and security are the other contentious issues when it comes to nuclear power. The main source of public concern when it comes to nuclear power is radioactive waste and potential for high impact accidents (von Hippel et al., 2012). Accidents such as the Three Mile Island accident in 1979, Chernobyl disaster in 1986 and more recently the Fukushima disaster in 2011 have served to sensitize the public towards the impact of nuclear disasters. Nuclear experts say that the probability of injuries occurring per GW-yr of nuclear energy generated is low and that nuclear energy is not particularly dangerous.

In the 1990s there were campaigns that equated the risk from proximity to a nuclear power plant to riding an automobile for three extra hours per year (von Hippel et al, 2012). The public has also reported concerns that nuclear power plants may provide opportunities for terrorists. This sentiment hits close to home with Kenya having experienced a myriad of terrorist attacks in the recent past.

Nuclear power has been presented in some quarters as being the solution to global warming, overdependence on fossils fuels and in Kenya's case overdependence on hydropower however it is clear that it is plagued by uncertainties and poor public acceptance. Kenya is not the only African country that has made the decision to adopt nuclear power. The following section discusses nuclear power in an African context.

2.8.1 Africa and Nuclear Power

Global interest in nuclear power has resurfaced due to concerns over energy security and climate change (Jewell, 2011) Africa is at the forefront of this quest for nuclear power with countries like Nigeria, Ghana, Namibia, Uganda and Kenya expressing their interest to the IAEA (Martin & Fig, 2015). South Africa which holds Africa's only functioning nuclear power plant also intends to increase its nuclear capacity by 9600MW. (DoE, 2013).

One of the motivations for the nuclear power on the continent is to improve energy access. Currently, Africa is home to 13% of the global population but only accounts for 4% of global electricity demand (IEA, 2014). Another motivation is to increase the reliability of electricity supply. With the exception of South Africa, sub-Saharan Africa is largely dependent on hydropower and imported fossil fuels. Hydropower which is vulnerable to drought is the largest source of electricity generation in sub-Saharan Africa (Blackshear et al, 2011). Countries like Kenya, Uganda, Ghana and Zimbabwe have been affected by climate variability which has on occasion caused droughts that have affected their energy supply. Drought causes reduction of water in the dams which reduces the electricity that is generated (UNEP 2010).These countries have had to implement load shedding and increase their thermal generation during these seasons.

Strong opposition towards nuclear power has been recorded in some countries in Africa. In South Africa, the plans to construct an additional nuclear power plant have been met with opposition from a number of people due to the following (Fourie, Kritzinger-van Niekerk & Nel, 2015; Eberhard, 2013)

- Lower electricity demand than was forecasted due to low economic growth
- Increased capacity due to a renewables procurement program which had successfully procured 4.122GW by March 2015

- Completion of Kusile and Medupi coal power plants will add a capacity of approximately 9600MW.

It has been estimated that it will not be necessary to make this decision of whether or not to add a nuclear power plant until 2020 (Eberhard, 2011).

Another country where opposition has been recorded is Nigeria. It holds the largest oil reserve in Africa and also a large quantity of coal and natural gas. Hydropower is used for 17% of its generation needs. Only 40% of its population has access to electricity and the government has plans to introduce 1000MW of nuclear electricity to the grid by 2020 and to increase it to 4000MW by 2030. (IAEA, 2011; Aliyu et al, 2013). Opposition to nuclear power in Nigeria is centered on the following (Ejiogu, 2013):

- Lack of human resource with the relevant training on nuclear power
- Lack of safety culture
- Threats from terrorists
- Lack of emergency response capability

The other countries considering nuclear energy rely on hydroelectricity for the majority of their energy needs. Ghana relies on hydroelectricity for 54% of its energy needs while Namibia relies on hydro for 63% of its energy need and Uganda relies on it for 78% of its electricity. Ghana and Uganda, similarly to Kenya, have faced situations where they have experienced droughts and had a shortfall in electricity generation. They had to turn to rely on rented temporary diesel-fueled capacity to meet this shortfall which is expensive to operate and exposed them to the fluctuations of the oil price (Kapika and Eberhard 2013)

Uganda suffered due to war and decreasing water levels in Lake Victoria. These are some of the reasons behind its low electricity consumption rates of 67.9 KWh per capita. Due to insufficient generation and increasing demand, the government had to resort to emergency thermal generation, this caused a spike in electricity tariffs and made Uganda's electricity prices one of the highest in Africa (Kapika and Eberhard 2013; Eberhard and Shkaratan 2011). The country has decided to resort to nuclear power because of its current unmet demand, and the effects of climate variability on the country's hydropower. Additionally, the government claims that the resource potential of the primary energy sources available for electricity generation are insufficient for the

development required to transform Uganda into a middle income country (ESI Africa, 2008, Ocilaje, 2014)

Namibia faces an interesting situation where it imports more electricity than it generates. This has been the case since 2004. Its electricity imports have been from the South African Power Pool and this has put it in a precarious situation as the electricity generation in the SAPP is getting constrained and they have been unable to secure a long term contract from Eskom whom they have been importing a large percentage of their electricity. In 2009, Namibia imported 60% of its electricity and 92% of what it locally generated was hydropower (Kapika and Eberhard 2013; Oertzen, 2012). Namibia is the fourth largest producer of Uranium in the world and has two mines that are capable of producing 10% of the world's uranium (World Nuclear organization, 2014). As such, they are currently considering taking advantage of their resources by utilizing nuclear power to generate the electricity to meet their demand.

Ghana suffered from drought in the 1980s and this caused reduction in its generational ability which led to load shedding. Similar droughts were observed in 2007 and caused the country to turn to thermal generation. Ghana has decided to pursue Nuclear power as an option due to their unreliable electricity supply and increasing demand (Ennison et al, 2012).

2.9 Effect of Drought on Energy Security in Kenya

The essential concepts of energy security are availability, reliability and affordability (Ferguson, 2011). During drought, the affordability and reliability of Kenya's energy is hampered. As has been previously stated, Kenya derives most of its electricity from hydropower. When the amount of rainfall decreases the levels of water in the dams used for hydropower generation also decrease leading to loss of hydro capacity. Over reliance on hydro-power is therefore a threat to Kenya's energy security. Energy security is enhanced when the country's electricity generation mix is diversified (Ferguson, 2011).

In 1999, Kenya experienced the worst drought in 50 years. This resulted in a reduction of available hydropower capacity from 501MW to 104MW and caused the implementation of a load shedding program in the latter part of 2000. To mitigate the

situation, the government contracted foreign firms to provide emergency power and two IPP's increased their generation capacity by 16MW. It is estimated that KPLC lost Ksh. 1.6 billion during that period (Nyoike, 2002).

Between the year 2008-2011, the country experienced another drought which caused electricity generation from thermal sources to increase to 37% in 2009 and 45% in 2010, from 29% in 2008 (GoK, 2012). When the capacity of hydropower is reduced during dry spells, thermal power which uses petroleum based fuels such as diesel and heavy fuel oil are typically used to compensate for the loss of hydropower capacity. Depending on the loss of capacity, part of the thermal power capacity may be sourced from emergency power generation suppliers. Emergency power typically consists of diesel engines supplied in containerized units. They can be eight times more expensive than hydropower. The government absorbs some of this cost in the short term however the fuel cost is transferred to the consumer. This increases the consumer cost of electricity during dry spells (Kapika & Eberhard, 2013; Hille & Franz, 2011).

One of the aims of the government in incorporating nuclear power into the energy mix is increasing energy security by diversification. Nuclear power has high availabilities and is less affected by climate variability, particularly if open-loop cooling systems are not used, which will make it more reliable than hydropower (Buyukah, 2014). It has however been put forward that Kenya has other sources of energy that it can utilize which can serve the purpose of increasing generational capacity and diversification. These resources along with their potential and current level of utilization are tabulated in Table 2-9 below:

Table 2-9: Resource potential and Utilisation (Energy Regulatory Commission, 2011)

Source	Capacity (MW)	Resource potential
Hydro	820.2	1.499GW Unexploited
Geothermal	573	7-10 GW
Wind	18.6	4GW
Solar	Approximately 200,000 solar home systems	Average insolation 4-6KWh/m^2/day
Coal	N/A	Approximately 400 million metric tonnes available
Oil	591	Approximately 600 mmboe
Gas	-	1.6 Tcf

According to the Least Cost Development Plan, local resources were more affordable than imported resources. The aim therefore was to exploit local resources as much as possible and then utilize imported resources (Energy Regulatory Commission, 2011)

3 MODELLING KENYA'S ELECTRICITY GENERATION EXPANSION

This chapter will give a detailed explanation of the methodology, input data and assumptions that were used to forecast demand and model a least cost generation expansion plan for Kenya. Factors affecting the model such as time with respect to the model horizon, seasonal and day and night time slices will be discussed. In addition to this, the equations used to forecast demand and the methodology used and assumptions made to obtain these equations will also be discussed. The demand forecast results will also be presented in this chapter given that the main focus of this thesis is the generation expansion plan which is covered in the results chapter. Further to this, the relevant techno-economic parameters and the screening curves for technologies that will be available for capacity expansion will be presented and, where necessary, discussed.

Two capacity expansion plans were developed; one was an attempt to replicate the LCPDP and will from here onward be referred to as the LCPDP replica. In this plan, the assumptions and constraints employed in the LCPDP were used. The second plan incorporated more recent data and assumptions into the model and used a different demand forecast. It is referred to as the CCEP. These plans are discussed below.

3.1 Model Structure

This section will discuss the model structures of the CCEP and LCPDP highlighting the differences between the LCPDP and the CCEP.

3.1.1 Least Cost Power Development Plan Replica

As mentioned above, the LCPDP replica was an attempt to replicate the LCPDP. Two scenarios of the LCPDP replica were created, one with the last model year as 2031 and the other as 2040. This was done because it was unclear whether end effects had been taken into account in the LCPDP. End effects can occur in the last year of the time horizon in the event that the model does not consider that electricity demand will continue past that year and will therefore under-build in the last years of the time horizon (IAEA, 1984). The model horizon therefore needs to be extended beyond the last year of study to eliminate end effects. In this case, both scenarios of the LCPDP

Replica will be compared to the LCPDP to determine whether the LCPDP considered end effects.

To replicate the LCPDP, the demand forecast used by the LCPDP team was required. Further, it was necessary that the demand forecast be segregated into the voltage categories used for transmission which are high voltage, medium voltage and low voltage as described in section 2.3. A demand forecast in this form was obtained from the LCPDP team. Also included in the demand forecast, were the transmission and distribution losses (LCPDP team, 2015).

After the demand forecast was obtained, it was used to generate a capacity expansion plan. The TIMES modelling framework, which was described in detail in section 2.5.3 was used for this process. All the technological and economic data required to describe the electricity generation plants in TIMES was obtained from the LCPDP documentation. Committed generation projects were also obtained from the LCPDP 2010 and are tabulated in Appendix 11

The model was given the freedom to construct new power plants from 2011. Although the period between 2010 and 2014 has already elapsed, the model was allowed to construct new power plants from 2011 so that the results obtained would be similar to the LCPDP.

Figure 3-1 below represents the flow of electricity in the LCPDP replica from the transmission to all the categories of demand mentioned above.

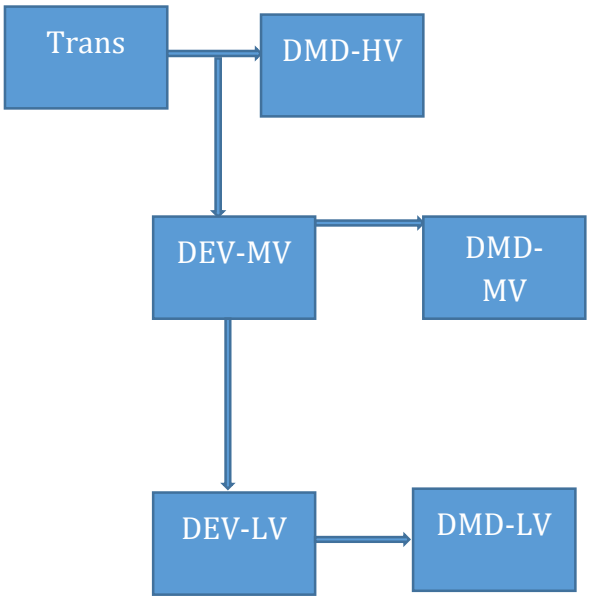


Figure 3-1: Flow of electricity in the LCPDP Replica

Where:

- Trans is transmission
- DMD HV is high voltage demand
- DEV-MV Is a distribution device that steps down high voltage electricity to medium voltage electricity
- DMD-MV is medium voltage demand
- DEV-LV is a distribution device that steps down medium voltage electricity to low voltage electricity
- DMD-LV is low voltage demand

3.1.2 Current Capacity Expansion Plan

The current capacity expansion plan (CCEP) is an attempt to update the LCPDP using recent assumptions. As in the LCPPD replica, the study period was 2010-2031. One of the major differences between this model and the LCPDP replica is the demand forecast. In this case, the demand forecast contained actual electricity consumption between 2010 and 2013 while demand was forecasted between 2014 and 2040. Additionally, an

attempt was made to have the peak demand in 2010 as close to the peak of demand recorded by KPLC in that year.

As mentioned in section 2.6, all the voltage groups i.e. low voltage, medium voltage and high voltage contain a portion of commercial electricity consumption while the medium and high voltage category each contain a portion of industrial consumption. For the purposes of the load forecast, the commercial and industrial consumption in all the voltage groups i.e. low, medium and high were aggregated as it was impossible to determine the portion of GDP responsible for electricity consumption in each voltage category. Once the forecast had been carried out, it was impossible to split the aggregated commercial and industrial electricity into the relevant voltage categories since the quantity belonging to each category was unknown. The load forecast for industrial and commercial demand was thus allocated in its aggregated form to the medium voltage category, Consumption in the domestic category remained in the low voltage group as it was forecasted separately while the high voltage group was left without consumption in the CCEP as all commercial and industrial consumption was allocated to medium voltage supply as described above. The electricity flow diagram was similar to that of the LCPDP replica and is shown in Figure 3-1

The demand forecast used in the LCPDP was derived using an assumed GDP growth rate of 8% from the year 2015 to 2031. As seen in Table 2.3, the only year that the actual GDP growth rate surpassed the predicted growth rate was 2010. The rest of the years recorded a GDP growth rate that was less than the predicted growth rate. Additionally, the World Bank predicts a GDP growth rate of 6-7% for 2015, while GDP growth rates of between 5.8% to 6.7% have been forecasted for the period of 2015 to 2031 as will be seen in section 3.2.1. For this reason it was decided to use a GDP growth rate of 6% for the reference case as this seemed more realistic than the 8% used in the LCPDP. Additional improvements in the CCEP are the inclusion of solar power as a technology option for expansion as it was not included in the LCPDP and the utilisation of different peaks for the different consumer groups. The LCPDP assumes that all the sectors experience their peak demand at the same time. As highlighted in the LCPDP itself, this assumption exaggerates the load forecast (Energy Regulatory Commission, 2011).

The modelling horizon in the CCEP was divided into two periods. The first period was between 2010 and 2014 while the second period was from 2015 to 2040. This division was executed by limiting the model's freedom to construct new power plants in the fore-mentioned period and allowing construction in the latter years. Construction was limited in the first period because it had already elapsed. This was different from the LCPDP replica where the model was allowed to construct new power plants from 2011. The model however was forced to construct power plants which came online in this period such as 280MW of geothermal which were connected to the grid in 2014 (KENGEN, 2015) In the second period the model was given the freedom to construct new power plants. The aim behind this was to make the model as realistic as possible.

A large number of committed generation projects where construction had commenced or where a power purchase agreement had been signed and financial closure had been attained were documented in the Power Sector Medium Term Plan 2015-2020 (ERC, 2015b). It was assumed that all these projects (tabulated in Appendix 11) would attain completion and they were forced into the model as constraints.

The government states that future electricity demand in Kenya cannot be satisfied without using nuclear power (Buyukah, 2014). The LCPDP replica aims to verify the validity of the statement that the demand forecasted in 2010 cannot be met without the use of nuclear power given the assumptions made in the LCPDP. The CCEP then aims to update the LCPDP replica using a more realistic demand forecast then determine the necessity of nuclear power from this perspective.

The results from the CCEP will be compared to the LCPDP 2010 and the LCPDP 2013. The LCPDP 2013-2033 is update of the LCPDP 2010 and relies heavily on the information published in the 2010 version. For this reason, the LCPDP replica validates the LCPDP 2010 and not the 2013 version.

3.2 Demand Forecast

The demand forecast was carried out from the years 2014-2040 although the last year of study for this thesis was 2031 with the aim of eliminating end effects as discussed in section 3.1

The demand forecast used was generated using econometric equations which were developed using least-squares regression. This regression utilised historical electricity demand as a dependent variable and GDP as an independent variable in the case of commercial-industrial demand. In the case of domestic demand GDP per capita, the cost of electricity and population were used as independent variables.

The Cobb-Douglas production function, which is commonly used in econometric load forecasting was used as a model for the regression exercise. The Cobb Douglas equation expressed in its log-linear form is shown in equation 3-1 below (Debertin, 1986).

$$\text{Ln } E = \alpha \ln gdp - \beta \ln P \qquad 3\text{-}1$$

Where:

P is the cost of electricity

GDP is the Gross Domestic Product

α is the elasticity of electricity demand with respect to GDP

β is the elasticity of electricity demand with respect to electricity price.

In the equation above the drivers of electricity demand are GDP and electricity price.

Electricity price is assigned a negative elasticity constant in the equation above because in general, when the price of electricity increases, the demand is observed to decrease (Parsons and Brickerhoff, 2010).

The following historical data between the years 1998 to 2013 was used for regression:

- Electricity consumption obtained from the Kenya Statistical Abstracts (2006; 2014)
- Cost of electricity calculated by dividing revenue from electricity sales with quantity of electricity sold obtained from the Kenya Power annual reports (2004-2014)
- GDP, GDP per capita and population obtained from the World Bank Databank (World Bank, 2015)

After data collection the electricity consumption data was split into two groups; domestic and commercial-industrial as mentioned in section 3.1.2.

3.2.1 Domestic forecast

The domestic sector had two sub-sectors of consumption; Residential consumption and Public Street lights. Residential electricity consumption is influenced by income, price of electricity, population and its distribution (Mabea, 2014; ERC, 2011) . To forecast residential demand a model based on a Cobb Douglas production function was developed. The coefficients of the function were estimated by regressing historical residential electricity demand against population, GDP per capita (a proxy for income) and electricity price (KPLC, 2015; KNBS, 2014). The fit of the model to historical data and in particular the consumption in the last 2 years, 2012 and 2013, was used to validate the forecasting model.

The price of electricity in Kenya is volatile due to fluctuating oil prices and currency. As previously mentioned Kenya obtains a large quantity of the electricity supplied from hydro power. During dry seasons, MSD generation capacity has been used to compensate for the reduction in hydro power capacity availability. Kenya's MSD plants are fuelled by heavy fuel oil, the price of which fluctuates with the price of oil. KPLC passes this risk to the consumer resulting in fluctuation of the electricity price. To obtain an average price of electricity, KPLC's annual sales in the residential category together with the quantity of electricity sold were used. KPLC publishes its annual statements in financial years i.e. from June of one year to June of the following year. To convert this to calendar years, an average of two successive years was used.

After collection the natural logarithm of the data was determined and the natural logarithm of domestic electricity consumption was regressed against the natural logarithm of electricity price and population and GDP per capita.

Using the above data the regression yielded the results shown in Table 3-1: Table showing regression results of demand analysis.

Table 3-1: Table showing regression results of demand analysis.

	Coefficients	***Standard Error***	***t Stat***	***P-value***
Intercept	-25.3601	3.210068	-7.90018	2.45E-05
Population	0.837596	0.304337	2.752202	0.022396
GDP/capita	2.262359	0.545616	4.146433	0.002498
Electricity price	-0.15387	0.069841	-2.20321	0.055051

The p value obtained for the electricity price was greater than 0.05 therefore another regression was performed with only GDP per capita and population as independent variables. This regression yielded the results shown in Table 3-2 and Table 3-3 below.

Table 3-2: Table showing regression results

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-25.2027	4.158708	-6.06023	0.000122
Population	1.039247	0.36081	2.880314	0.016377
gdp/p	1.899196	0.690813	2.749219	0.020506

Table 3-3: Table showing regression statistics

Regression Statistics	
Multiple R	0.953472
R Square	0.90911
Adjusted R Square	0.890932
Standard Error	0.070357
Observations	13

Using the above results equation 3-2 was obtained.

$$LnE = 1.88 \ln GDP/P + 1.0392 \ln pop - 25.207 \quad (3\text{-}2)$$

Where:

Pop is population

GDP/P is GDP per capital

E is domestic electricity consumption

The equation yielded the results shown in Table 3-4 from 2012 to 2013. The actual electricity consumption used to calculate the error was obtained from the Kenya Statistical Abstract (KNBS, 2014c).

Table 3-4: Table showing forecasted results verses actual consumption.

Year	**Forecast**	**Actual**	**Error**
2012	1989.9558	2005.05	1%
2013	2210.9237	2173.3	-2%

The graph in Figure 3-2 below shows a comparison between the electricity consumption obtained using the regression equation and the actual electricity consumption between 1998 and 2013.

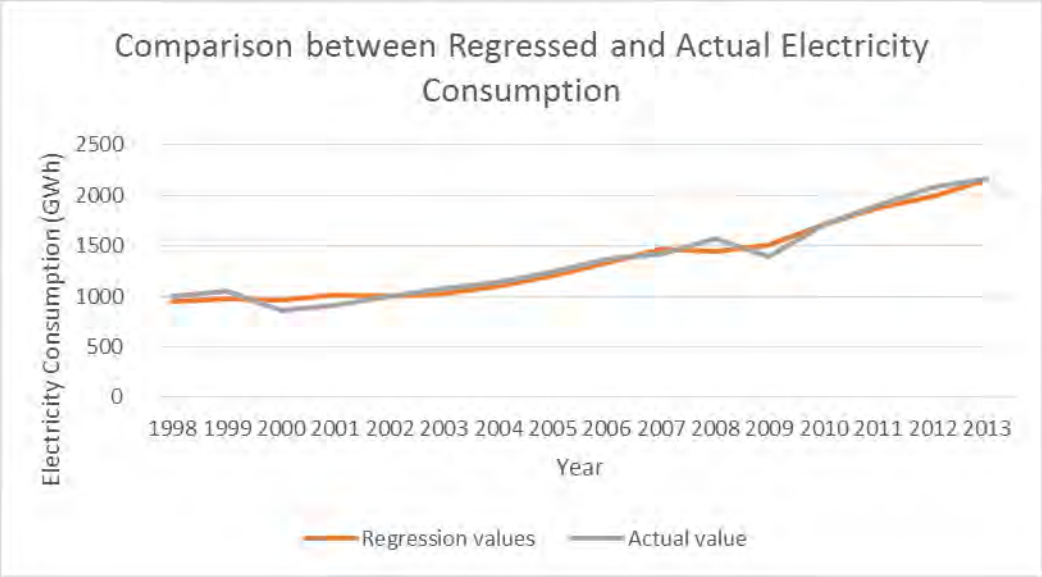


Figure 3-2: Comparison between Actual and Regressed Electricity Consumption

Using Equation 3-2, two scenarios of residential demand, the reference demand and the optimistic GDP, were forecasted using different GDP growth rates. The reference demand forecast was based on an assumption that the GDP growth rate would grow at a constant 6% from 2015 to 2031. This was based on a number of economic forecasts. A forecast done by the IMF indicates that Kenya will likely have an economic growth of approximately 6% between 2014 and 2018, the Harvard School of Business predicts an average of 6.74% until 2023 while the HSBC Bank forecast predicts an average of 5.8% from 2020 to 2030 and 6% from 2030 to 2040 (Centre for International Development at Harvard University, 2015; Africa Bio-gas Partnership Programme, 2014; IMF, 2013; HSBC Global Research, 2012). For the optimistic case a GDP growth of 8% was used from 2015 to 2031. This is because a GDP growth rate of 8% was used for the low load growth rate in the LCPDP and would enable further comparison between the results obtained in the LCPDP and the CCEP.

Between the years of 2031 and 2040 the GDP growth rate used to forecast the demand was reduced by 2% in both the reference demand scenario and the optimistic GDP scenario. This was done because it was assumed that a high economic growth rate for a long period of time would increase the economic base causing a reduction in GDP growth rate. Additionally, it was assumed that the population growth will be 2.4% till 2031 (UNICEF, 2013).

After the forecast was complete suppressed demand was added. The LCPDP assumed supressed demand of 100MW (ERC, 2011). In 2015, the suppressed demand was still estimated to be 100MW by the Energy Regulatory Commission (ERC, 2015). The demand was assumed to be suppressed throughout the day. It was assumed that the suppressed demand would gradually be added to the demand forecast so that the electricity generation capacity would cater to it. The years 2018-2022 were selected for the addition of suppressed demand. They were selected because the model has no flexibility between 2010 and 2015 and therefore it would not be able to add new power plants to meet the supressed demand. The year 2018 was selected as the first year for the addition of suppressed demand so that the model would have sufficient time to respond to the increased demand.

20MW of demand were incrementally added to the forecasted demand until all 100MW of the assumed suppressed demand was catered for. The suppressed demand was added to the low voltage category. This decision was made because this category had the lowest efficiency therefore would require the most energy supply. In the case that some of the suppressed demand lies in the other voltage categories i.e. medium voltage or high voltage, the capacity built by the model will still be enough to conservatively supply the required demand. To incorporate suppressed demand into the forecasted demand the following procedure was used:

- The year on year percentage increase in energy consumption was calculated using the energy forecast.
- The suppressed energy was calculated
- A portion of the suppressed energy was added to the energy forecast for 2018
- The total energy i.e. energy forecast and suppressed energy was increased by the year on year percentage increase of energy consumption. This gave the new forecasted energy for 2019
- An additional portion of the suppressed energy was added to the energy forecast for 2019. The total energy consumed was also then increased by the annual percentage of increase to obtain the energy forecast for the year 2020
- This procedure was repeated until all the suppressed demand had been incorporated.

The graphs in Figure 3-3 and Figure 3-4 below shows the energy forecast with and without the suppressed demand (SD).

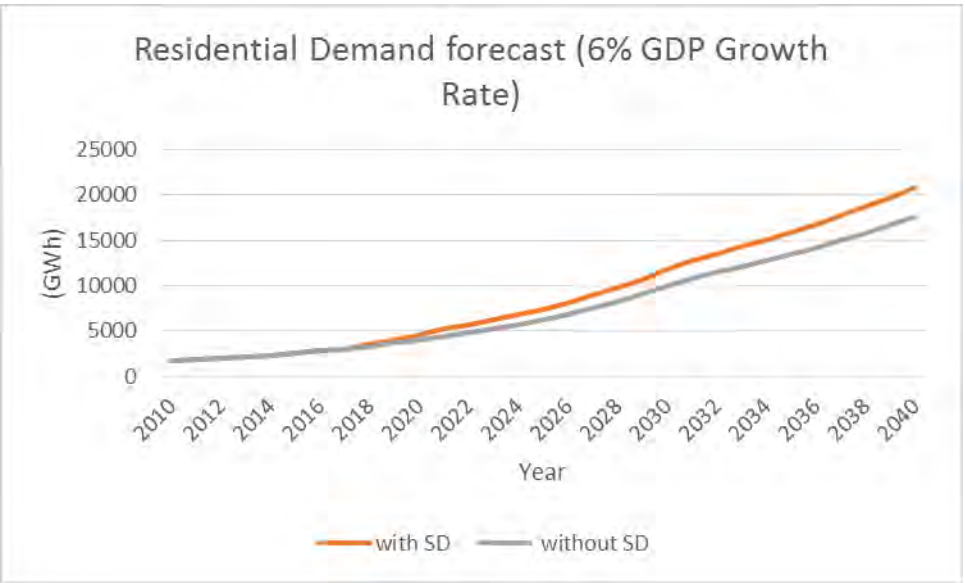


Figure 3-3 Residential demand forecast GDP growth rate 6%

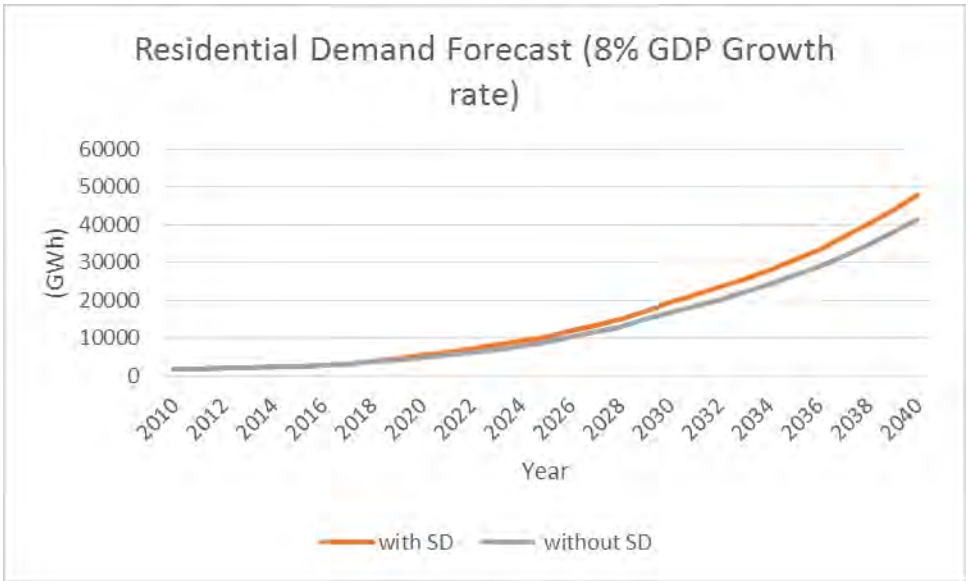


Figure 3-4 Residential demand forecast GDP growth rate 8%

Table 3-5 shows the average growth obtained in the cases with and without suppressed demand

Table 3-5 Average growth obtained in reference and optimistic GDP scenarios

Scenario	**Average growth (%)**	
	With Supressed Demand	Without Suppressed Demand
Reference case	9%	8%
Optimistic GDP growth rate	11.8%	11.2%

The results obtained for the domestic demand forecast in the reference and optimistic GDP growth rate scenario are tabulated in Appendix 6 and Appendix 8 respectively.

The second sub-sector within the residential demand forecast was public street lights. The electricity consumption of street lights is driven by their specific consumption and number of customers. Lack of the aforementioned data or any other independent variable for the regression analysis led to the use of the trend method to forecast demand by street lights. The growth of public street lights was determined by establishing the trend in the growth of consumption of electricity from 1998 to 2011. This trend was then used to project the future consumption by street lights. The graph in Figure 3-5 shows historical consumption and the trend used for the forecast.

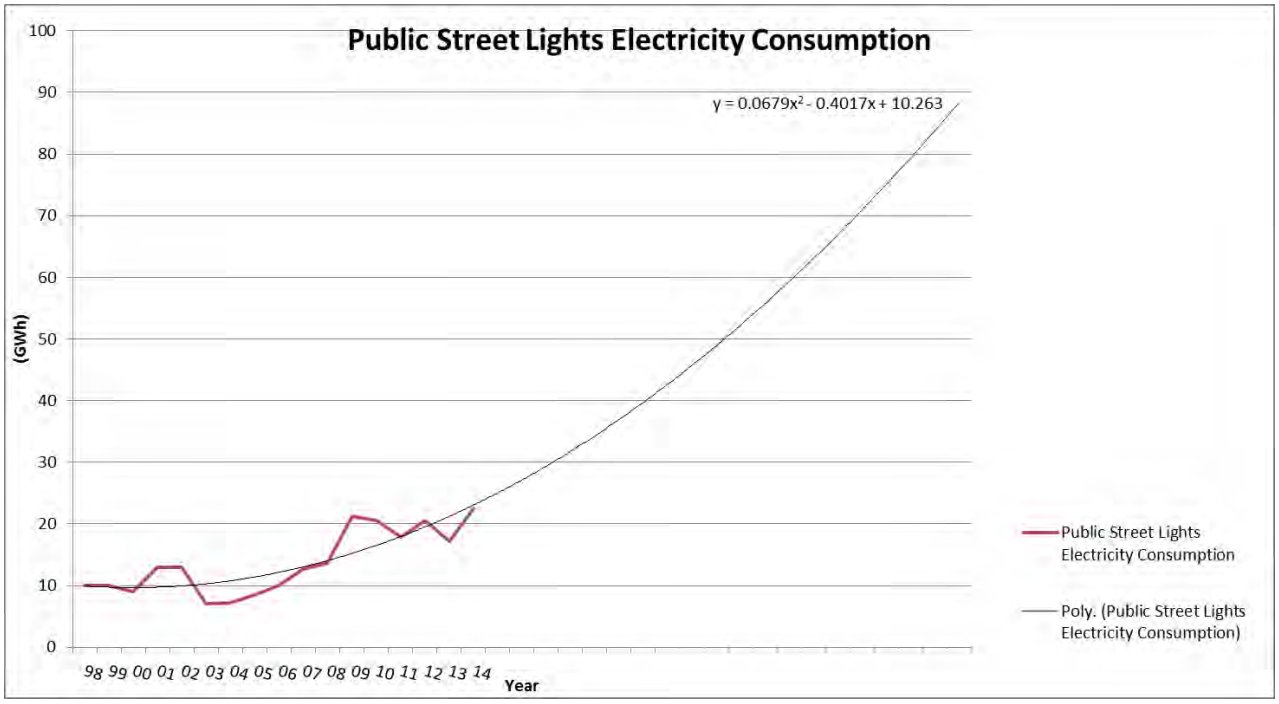


Figure 3-5: Figure showing the trend in growth of electricity consumption by street lights

Equation 3-3 shows the equation used to forecast electricity demand by street lights

$$Y = 0.0679x^2 - 0.04017x + 10.263 \qquad 3\text{-}3$$

Where:

Y is electricity demand

X is the numerical value of the year with 1998 beginning the series as the year 1

The results of the forecast are seen in Appendix 10.

It must be noted that the consumption by public street lights is so small that any error would have a negligible effect on the forecast.

3.2.2 Commercial and Industrial Demand Forecast

This category consisted of small commercial customers in the low voltage group as well as medium and high voltage commercial and industrial customers (KPLC, 2014). As mentioned in section 3.1.2 above, the consumption was aggregated so as to perform a regression analysis with GDP as the dependant variable. The results of the regression are tabulated in Table 3-6 and Table 3-7.

Table 3-6: Table showing regression results

	Coefficients	***Standard Error***	***t Stat***	***P-value***	***Lower 95%***	***Upper 95%***	***Lower 95.0%***	***Upper 95.0%***
Intercept	-17.86	2.50	-7.14	1.89E-05	-23.36	-12.35	-23.36	-12.35
GDP constant	1.15	0.087	13.11	4.65E-08	0.958	1.34	0.95	1.344

Table 3-7: Regression Statistics

Regression Statistics	
Multiple R	0.969477
R Square	0.939886
Adjusted R Square	0.934421
Standard Error	0.046487
Observations	13

The resulting equation is as follows:

$$\ln E = 1.15 \ln(gdp) - 17.864 \qquad 3\text{-}4$$

Where:

E is commercial and Industrial electricity consumption

GDP is the Gross Domestic Product

Using this equation, the forecasted results were compared to the actual results. The error is tabulated in

Table 3-8 below

Table 3-8: Table showing percentage error in forecasted results

Year	**Forecast results**	**actual consumption**	**error**
2012	4734558	4311700	10%
2013	5045851	4741100	6%

The graph in Figure 3-6 below shows a comparison between regressed and actual electricity consumption between 1998 and 2013.

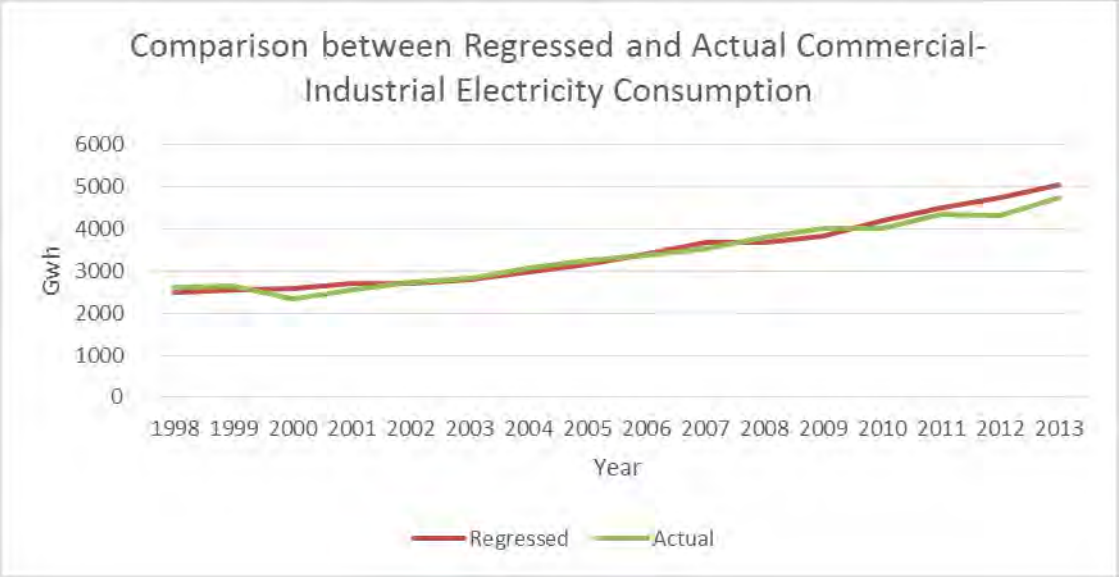


Figure 3-6: Comparison between Regressed and Actual Commercial-Industrial electricity Consumption

Using the above methodology, demand was forecasted for both 6% and 8% GDP growth. The GDP growth was kept constant from 2014 to 2040.

After the forecast the energy requirements of the vision 2030 flagship projects were added. The procedure for adding the energy requirements is as follows:

- The percentage annual energy growth was calculated for all the years.
- The energy requirements for the first year i.e. 2016 was added to the forecasted energy.
- The total energy was then increased by the percentage annual energy growth to obtain 2017 energy
- The flagship energy requirements were then added to the energy requirements from 2017 to obtain the total 2017 energy.
- This procedure was repeated until all the flagship energy requirements had been incorporated into the energy forecast.

The graphs in Figure 3-7 and Figure 3-8 Show the results of the commercial industrial demand forecast for both the reference and optimistic demand scenarios.

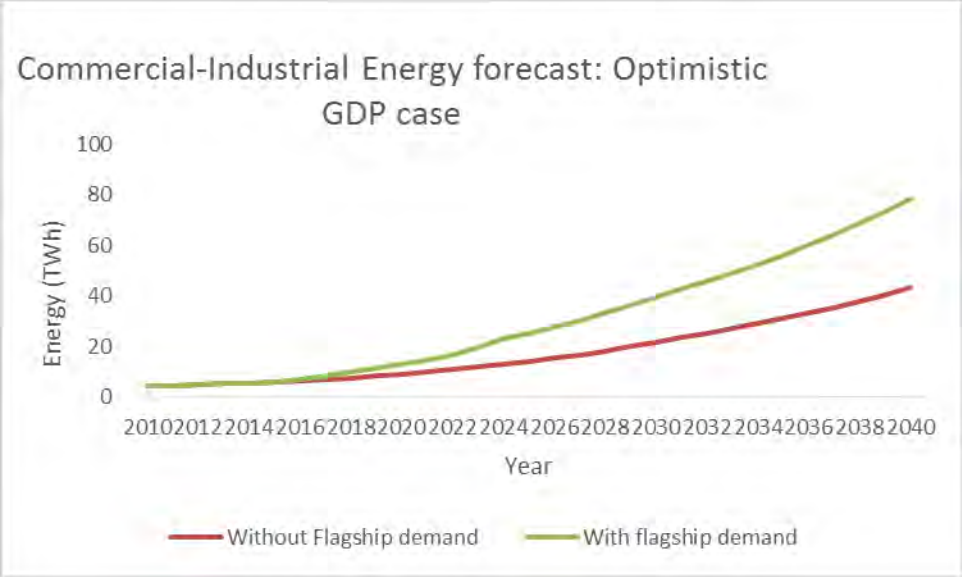


Figure 3-7: Commercial-Industrial Demand forecast Reference GPD growth scenario

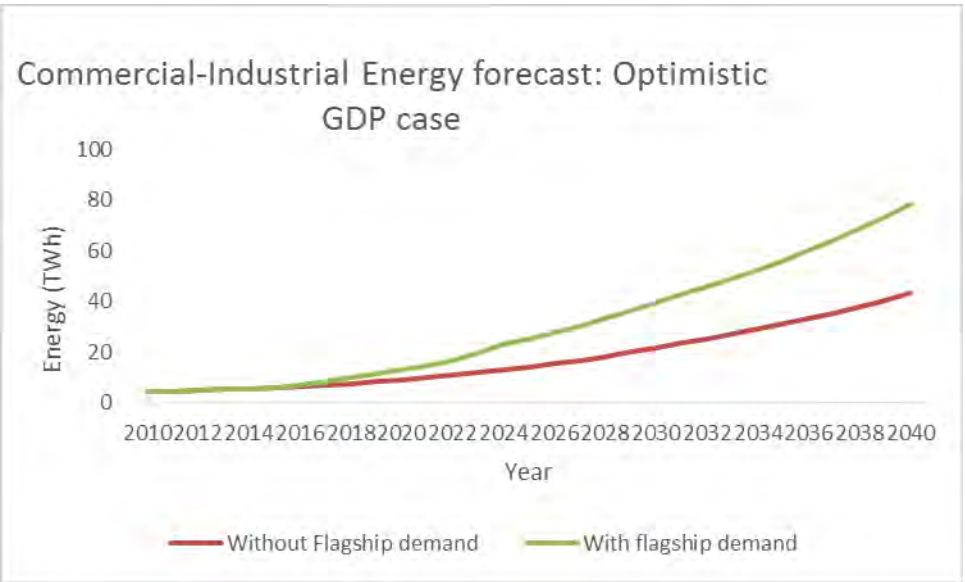


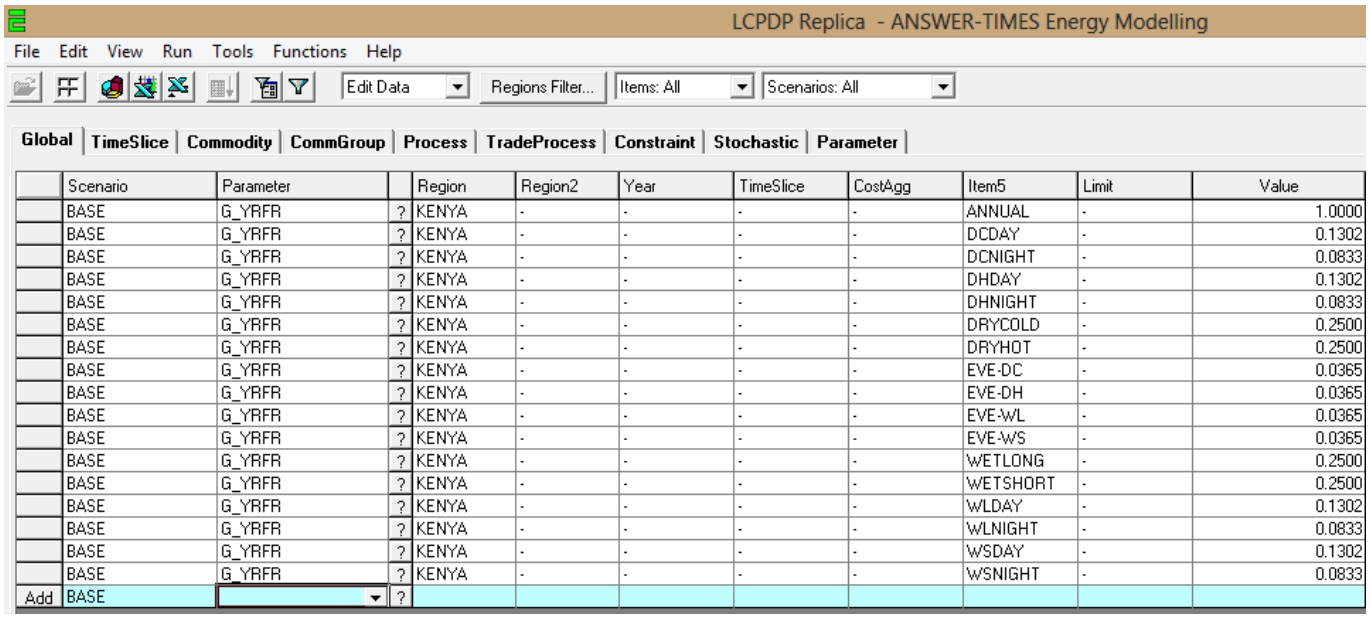
Figure 3-8: Commercial Industrial Demand Forecast Optimistic GDP growth case

3.3 Temporal Disaggregation

As mentioned in section 2.5.3.4 TIMES allows the user to divide a year into seasonal, weekly and day-night time slices when required. In the case where the model is multi-regional, different time slices can be specified for each region. The user can specify as many time slices as required for example, the seasonal time slices can be twelve, one for each month and the day night time slices can be 24, one for each hour. Increasing the number of time slices however, has the disadvantage of increasing the solution time due to the large number of equations that have to be solved by the TIMES LP (Noble-Soft Systems, 2014; Noble-Soft Systems, 2009)

These time slices are used to represent the share of electricity consumption within various seasons and parts of the day. The most important use of time slices for demand is the representation of peak demand which the model uses to determine the required electricity generation capacity.

Time slices are also used for generation technologies which have different availabilities during different seasons such as hydropower or during different times of the day such as solar power. The model then has to make sure that there is sufficient energy generation to meet demand in each time slice. The image in Figure 3-9 below shows a screen shot of the set-up of time slices in TIMES. The use of time slices in the LCPDP replica and CCEP is discussed below.



	Scenario	Parameter		Region	Region2	Year	TimeSlice	CostAgg	Item5	Limit	Value
	BASE	G_YRFR	?	KENYA	-	-	-	-	ANNUAL	-	1.0000
	BASE	G_YRFR	?	KENYA	-	-	-	-	DCDAY	-	0.1302
	BASE	G_YRFR	?	KENYA	-	-	-	-	DCNIGHT	-	0.0833
	BASE	G_YRFR	?	KENYA	-	-	-	-	DHDAY	-	0.1302
	BASE	G_YRFR	?	KENYA	-	-	-	-	DHNIGHT	-	0.0833
	BASE	G_YRFR	?	KENYA	-	-	-	-	DRYCOLD	-	0.2500
	BASE	G_YRFR	?	KENYA	-	-	-	-	DRYHOT	-	0.2500
	BASE	G_YRFR	?	KENYA	-	-	-	-	EVE-DC	-	0.0365
	BASE	G_YRFR	?	KENYA	-	-	-	-	EVE-DH	-	0.0365
	BASE	G_YRFR	?	KENYA	-	-	-	-	EVE-WL	-	0.0365
	BASE	G_YRFR	?	KENYA	-	-	-	-	EVE-WS	-	0.0365
	BASE	G_YRFR	?	KENYA	-	-	-	-	WETLONG	-	0.2500
	BASE	G_YRFR	?	KENYA	-	-	-	-	WETSHORT	-	0.2500
	BASE	G_YRFR	?	KENYA	-	-	-	-	WLDAY	-	0.1302
	BASE	G_YRFR	?	KENYA	-	-	-	-	WLNIGHT	-	0.0833
	BASE	G_YRFR	?	KENYA	-	-	-	-	WSDAY	-	0.1302
	BASE	G_YRFR	?	KENYA	-	-	-	-	WSNIGHT	-	0.0833
Add	BASE		?								

Figure 3-9: Set-up of Time slices in TIMES

3.3.1 Seasonal Time Slices

Each year was divided into four seasonal time slices of equal duration. The seasons which are listed below were selected because they reflect Kenya's climate and its influence on electricity generation. They affect the availability of hydropower which varies according to the amount of rainfall and solar power which varies due to cloud cover.

- Dry hot season-January to March
- Wet long season -April to May
- Dry cold season -July to September
- Wet short season -October to December

It was assumed that the seasonal time slices did not affect electricity consumption. This assumption was arrived at as follows: Monthly electricity consumption data from 2006 to 2014 was obtained from the Kenya Monthly Economic indicators published by Kenya National Bureau of Statistics (KNBS). The monthly consumption was adjusted by dividing by an adjustment factor. This was done to remove the change caused by GDP growth so that only the change due to seasonal variation remained.

A graph of adjusted electricity consumption against the months was plotted in Figure 3-10 covering the period 2006 to 2013.

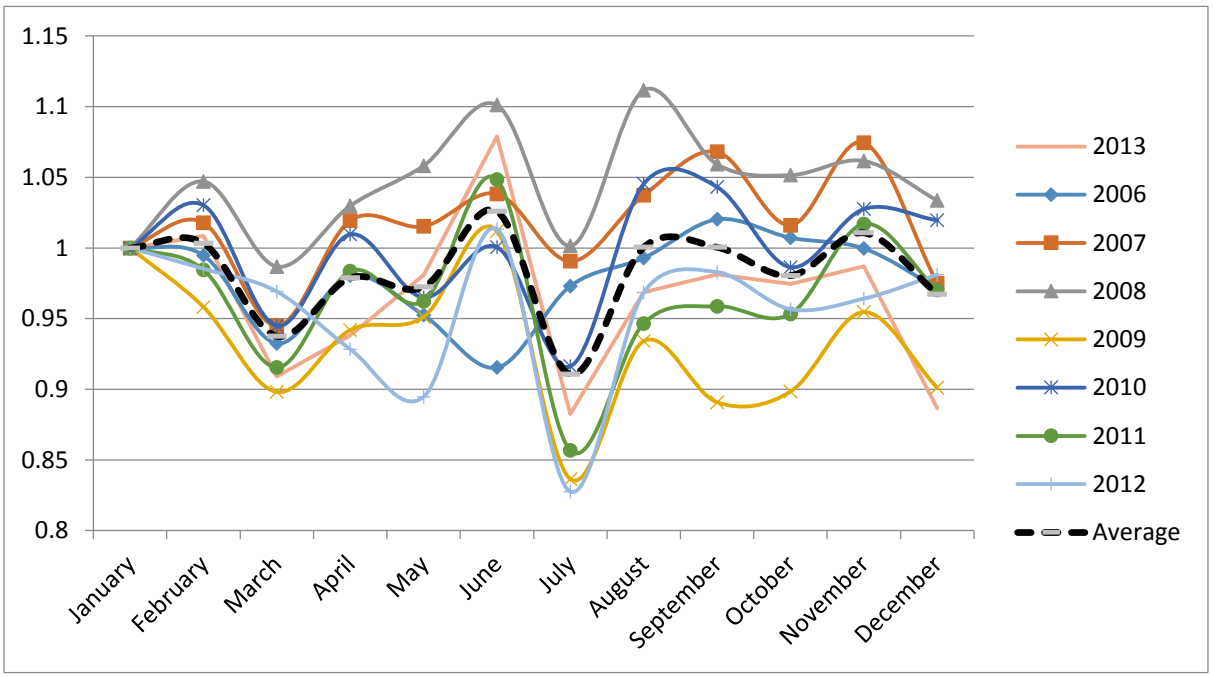


Figure 3-10 Graph showing monthly electricity consumption from 2006 to 2013.

An average of the adjusted electricity consumption of the months in each season as defined in section 3.3.1was plotted and is shown in Figure 3-11

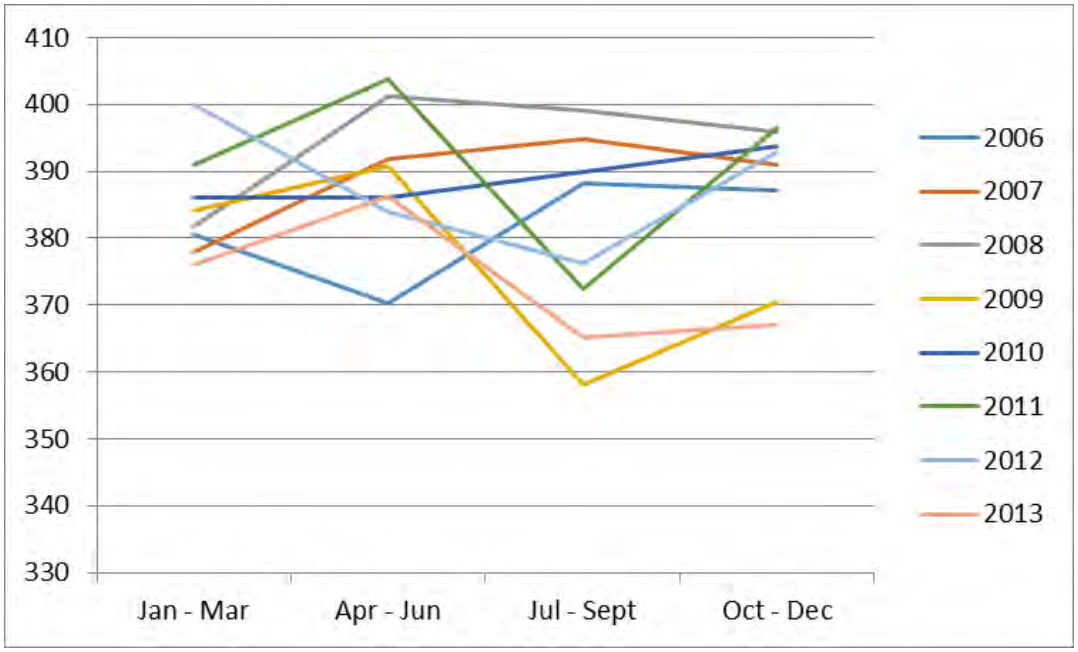


Figure 3-11: Average adjusted electricity consumption

From Figure 3-11 no clear pattern is observed. Due to this observation it was decided to split electricity consumption equally between all the three seasons. The graph additionally shows that the consumption in the year 2009 was abnormal. This was because it had the lowest electricity consumption in the duration covered due to a period of drought as was discussed in 2.9. This is attested to by Figure 3-12 below.

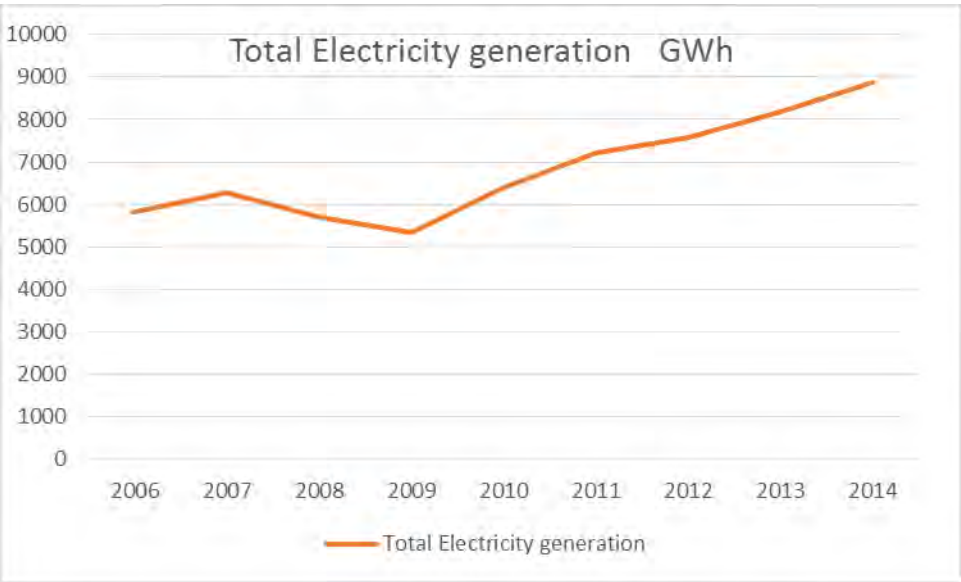


Figure 3-12: Total annual electricity generation

.

This is supported by Rose and Amy who state that seasonal variation in Kenya is limited (2015). Based on this, it was decided to distribute consumption in the seasonal time slices equally as shown in Table 3-9

Table 3-9 Table showing seasonal distribution of electricity consumption

Season	Distribution
Dry hot	0.25
Long rains	0.25
Dry cold	0.25
Short rains	0.25

3.3.2 Day Night Time Slices

The seasonal time slices were further divided into three day-night time slices. These time slices were generated using iteration and trial and error because the exact

distribution of energy consumption within the time slices was unknown. The aim was to obtain a peak demand that was similar to that documented in the LCPDP for the LCPDP replica and similar to that observed in reality in the year 2010 for the CCEP. Solver, an Excel add in was used for the process of iteration. For the LCPDP replica, it was found that a peak time slice of 3.5 hours gave a peak of 1.222GW which was the closest the iteration could come to the LCPDP's the peak demand OF 1.227GW. The time slices used for the LCPDP replica are tabulated in Table 3-11. The day-night time slices were used to reflect solar power technology which has zero availability from 1830 hrs and the peak time slice which has the highest electricity demand. Table 3-10 below shows the time slices used in the LCPDP replica.

Table 3-10: Table showing distribution of assumed distribution energy consumption in the LCPDP replica

Time slice name	**Time**	**Duration (Hours)**	**Daily distribution of energy**	**Energy Demand (MW)**
Day	0630-1900	12.5	0.172	1020.20
Evening (Peak)	1900-2230	3.5	0.208	1222.36
Night	2230-0630	8	0.62	442.22
Total energy consumption 2010 (GWh)			**7507**	

The total energy obtained using the figures in Table 3-10 was higher than the energy recorded in the LCPDP demand forecast for the year 2010 by 1267 GWh. The time slices above represented the day of maximum electricity consumption as their aim was to capture peak demand so as to enable the model to build enough generation capacity. Peak demand as represented in the model was equal in all the days of the week. This is realistic as in most cases electricity consumption during weekends will be lower than weekdays. For this reason, it was impossible to obtain the exact amount of energy forecasted in the LCPDP for the year 2010.

The graph in Figure 3-13 below shows the average load curves in the year 2010 for all the categories of consumption i.e. low voltage, medium voltage and high voltage. The load curves were derived from the data given in Table 3-10 above i.e. the duration of the time slice and the daily distribution of energy consumption.

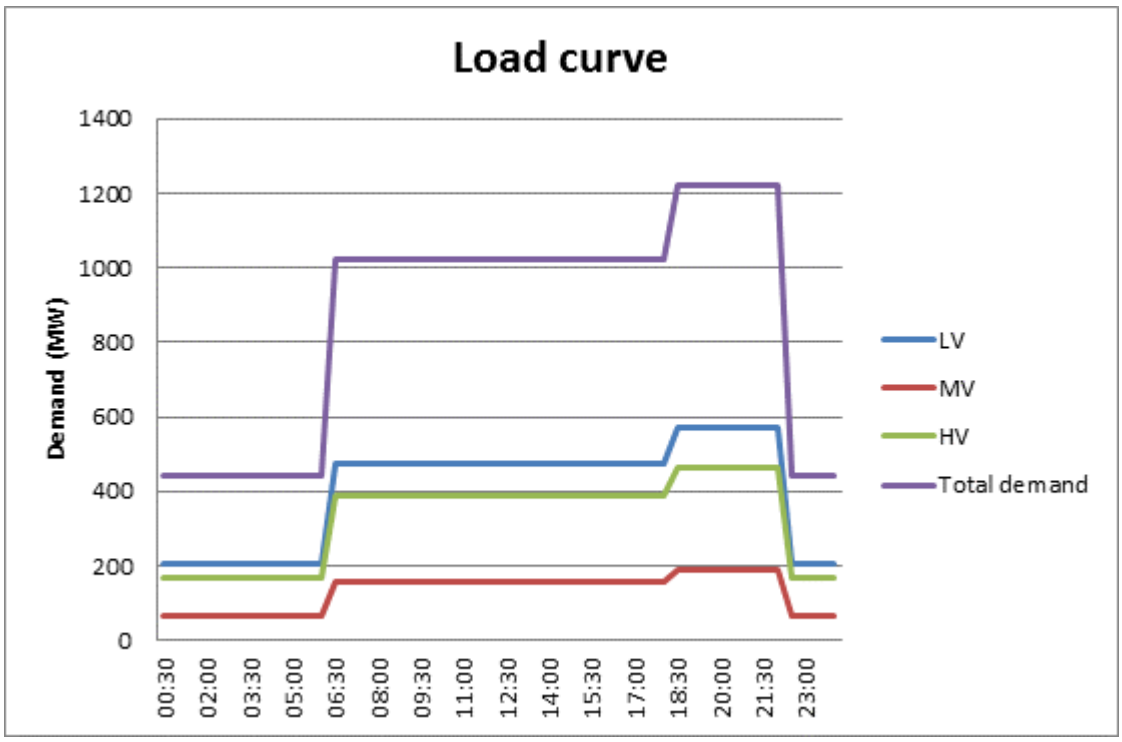


Figure 3-13: Average load curves in all categories of consumption

In the CCEP, the curves in Figure 3-14 and Figure 3-15 curves were used to derive the shape of the load curve for the commercial-industrial and domestic load curve.

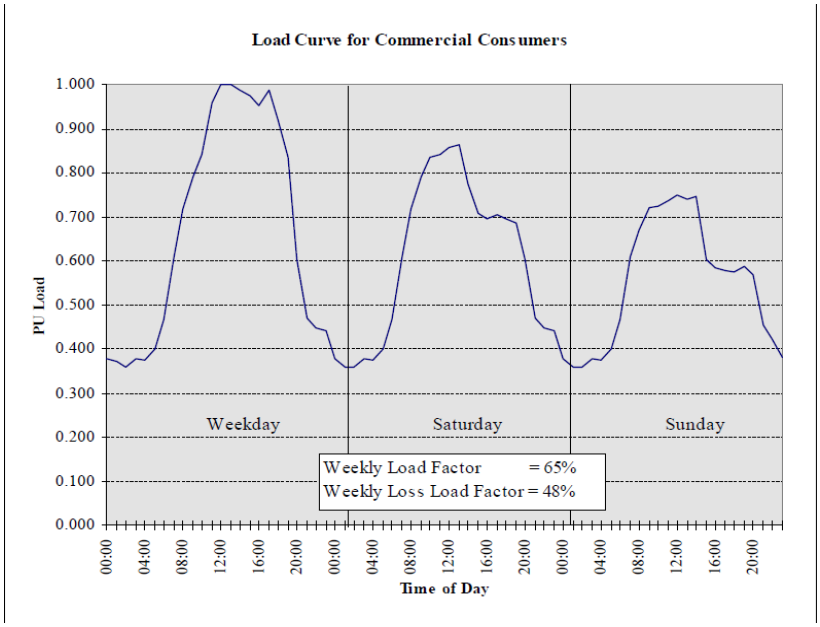


Figure 3-14 Load curve for commercial consumers

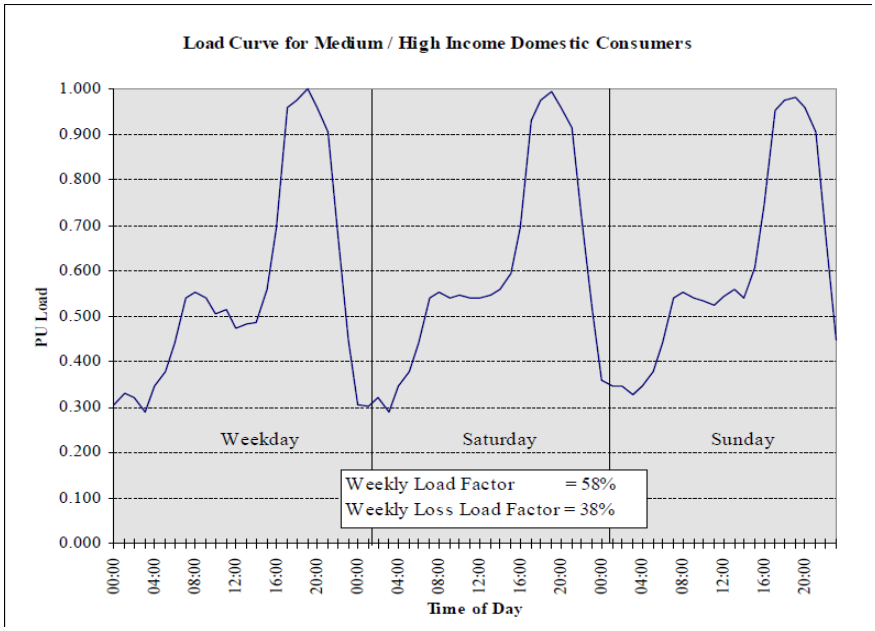


Figure 3-15 Load curve for domestic customers

(Parsons and Brickerhoff, 2013)

The graphs above were taken from a study performed on behalf of KPLC which notes that, "load curves of different consumer categories may be similar though the load factors may vary," (Parsons and Brickerhoff, 2013) . Based on this statement, it was assumed that the load curves for domestic consumers was similar to that in Figure 3-15

while the commercial-industrial load curve was similar to Figure 3-14. The constraints used to establish the load curve distribition for both the consumer categories were based on the afore mentioned assumption. The constraints in the domestic consumer group are as follows:

- The evening time slice is the peak time slice and therefore has the highest demand
- The demand in the day time slice is higher than the demand in the night time slice

The constraints used to establish the commercial-industrial demand distribution are as follows:

- The peak time slice is the day time slice
- The demand during the night time slice is equal or less than the demand during the day

The peak obtained was 1.102GW which was close to the peak demand of 1.106GW experienced in 2010. As mentioned in section 3.1.2, an attempt was made to have a peak demand of the CCEP in the year 2010 similar to the actual peak demand that was experienced in that year. The actual demand shown in Figure 3-16 shows the actual load curve on the day of peak demand in the year 2010 which was obtained from KPLC officials (KPLC, 2015). The total load curve, residential load curve and the commercial-industrial load curve are also shown in Figure 3-16 while the demand distribution is shown in Table 3-11

As in the LCPDP replica, the aim of the time slices used was to capture the peak demand of the year 2010. In the case of the CCEP however, the peak demand that was to be represented was the actual peak demand experienced in the year 2010 which was obtained from KPLC officials (KPLC, 2015). In this case, an attempt was made to have the total energy consumption represented by the time slices in Table 3-11 equal to the daily average energy consumption of the year 2010. The utilisation of the average energy consumption enabled the energy forecast to better represent weekdays and weekends while using one set of time slices. The disadvantage of this however, was that

the demand in the other time slices especially the night was lower than would have been expected.

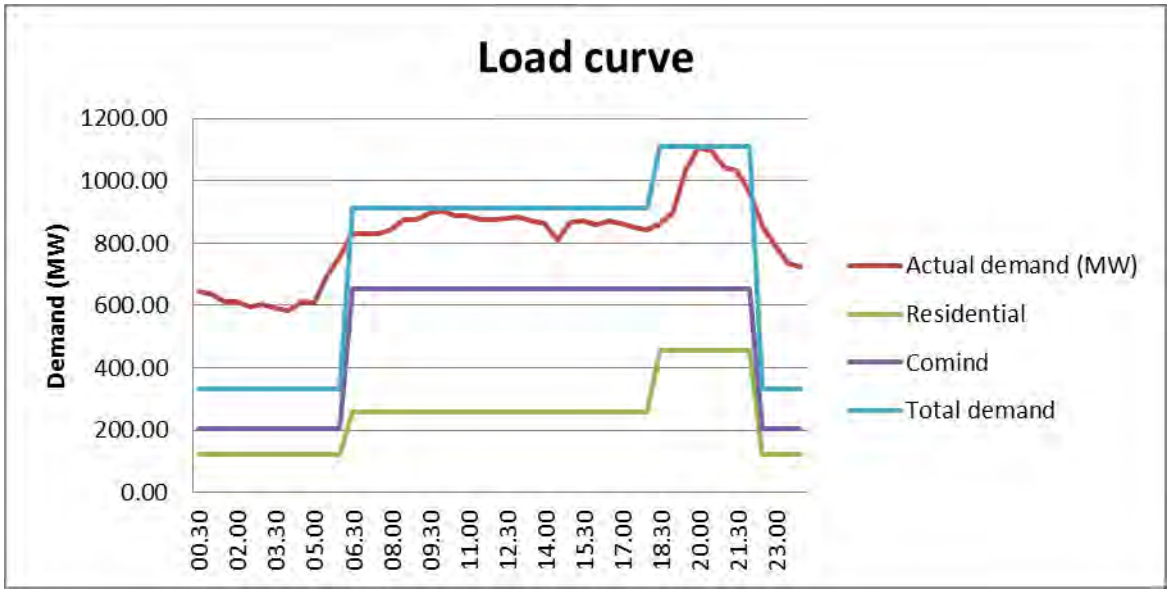


Figure 3-16: Graph showing average load curve used in the CCEP compared to the actual demand curve on the peak demand day in 2010

Table 3-11: Table showing daily distribution of energy consumption

Time slice name	Time	Duration	Commercial - Industrial	Domestic	Demand (MW)	Total
Day	0630-1900	12.5	0.5864	0.44	910.56	0.725
Evening	1900-2230	3.5	0.1407	0.378	1108.85	0.247
Night	2230-0630	8	0.2729	0.182	330.94	0.169
Total energy consumption 2010				**5734.2 GWh**		

3.3.3 Peak analysis

One of the determinants of the models choice for technological composition and electricity production is the ratio of peak to average demand. If the ratio of peak to average demand is high, it will result in increased peaking capacity and electricity production from peak power plants (IAEA, 1984). Peaking power plants typically have low construction costs and high operating costs. They can also be used to provide spinning reserve. Spinning reserve can be defined as unused capacity, which is

connected to the network and can be brought online when required by the decision of the system operator (Rebours & Kirschen, 2005) .

In both the LCPDP replica and the CCEP the average load distribution was assumed to stay constant throughout the study period. This section will discuss the peak to average demand obtained in the LCPDP replica and CCEP.

3.3.3.1 LCPDP Replica

Table 3-12 below shows the required demand in each time slice. The required demand was obtained by dividing the demand in each time slice by the relevant transmission and distribution efficiencies. The demand was divided by the peak to obtain the required capacity.

Table 3-12: Demand distribution across time slices in 2031

Time slice	**Required Demand (GW)**
Day	14.19
evening	17.01
night	6.15
Average Demand	12.45

The calculated peak demand to average demand ratio is 1.36. The graph in Figure 3-17 shows the average load curve in 2031

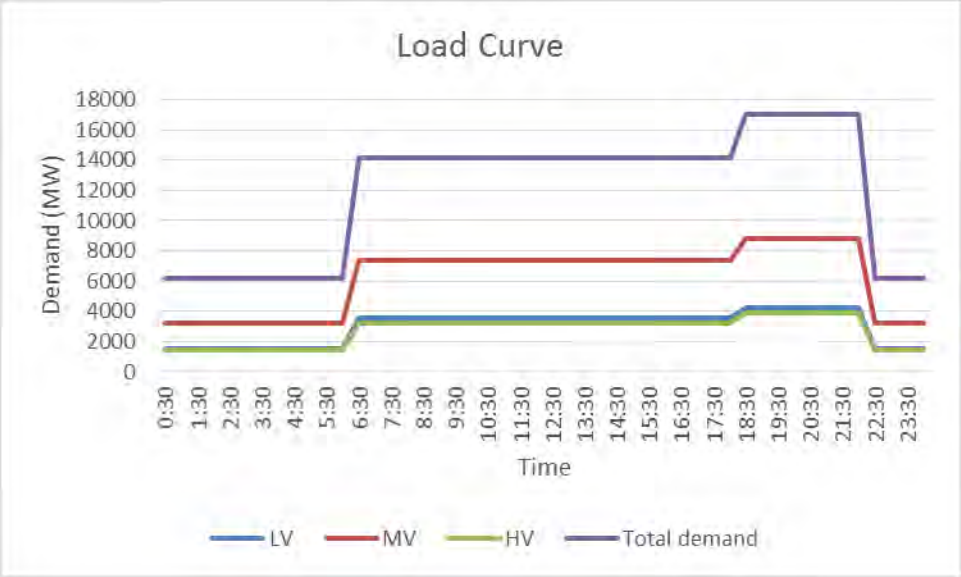


Figure 3-17: Average load curve in the LCPDP replica in 2031

3.3.3.2 CCEP

As in the LCPDP replica, the required demand distribution was obtained after dividing the demand within the time slices by the relevant efficiencies. Figure 3-18 shows the load curves obtained in the CCEP in the year 2031.

Figure 3-18: Load curve in 2031

Table 3-13 below shows the required demand in each time slice and the average demand.

Table 3-13: Required Demand in the CCEP

Time slice	Required Demand (GW)
Day	6.67
evening	8.15
night	2.43
Average Demand	5.75

The peak to average demand ratio of the CCEP is 1.41, 3.6% more than the LCPDP replica. This means that that the percentage of peaking technologies in the LCPDP replica and the CCEP should be similar.

3.4 Techno-Economic Parameters

The discount rate was set at 8% as is used in the LCPDP (ERC, 2011). The base year for discounting was 2010 and all the costs are given in 2010 US dollars. The only technology where learning rates were utilised was solar PV. Availabilities and efficiencies were also assumed to stay constant throughout the model horizon. The reserve margin used in the LCPDP replica was 25% from 2014 onwards (ERC, 2011).

The assumed technology costs are tabulated in Appendix 2 whilst the assumed technology efficiencies, availabilities, lead and lifetimes are tabulated in Table 3-18. Seasonal availabilities for hydropower and solar power were not included in the LCPDP. The steps taken to obtain availabilities for solar and hydropower for inclusion in the CCEP model are documented below. The transmission and distribution efficiencies are also discussed below

3.4.1 Transmission and Distribution Efficiencies

The transmission and distribution efficiencies in the LCPDP 2010 document were different from those used in the LCPDP demand forecast provided by the LCPDP team (LCPDP team, 2010). A snapshot of the efficiencies assumed in the demand forecast are tabulated in Table 3-14

Table 3-14: transmission and distribution efficiencies assumed for the LCPDP Replica

Distribution level	**Year**			
	2010	2015	2020	2030
Low Voltage	0.82	0.86	0.88	0.87
Medium Voltage	0.9	0.93	0.95	0.95
High Voltage	0.965	0.97	0.97	0.97

In the CCEP, the actual observed transmission and distribution efficiencies were used between 2010 and 2014 and are tabulated in Table 3-15 (ERC, 2015b). From the year 2020, the CCEP assumed the LCPDP supply efficiencies and assumed they stayed constant for the rest of the modelling horizon.

Table 3-15: Transmission and Distribution efficiencies Assumed for the CCEP

Distribution level	Year					
	2010	2011	2012	2013	2014	2020
Low Voltage	0.89	0.88	0.88	0.86	0.88	0.88
Medium Voltage	0.943	0.942	0.938	0.938	0.94	0.95
High Voltage	0.963	0.962	0.958	0.958	0.96	0.97

It must be reiterated that there was no high voltage demand in the CCEP as mentioned in section 3.1.2. The high voltage efficiency tabulated above was the transmission efficiency while the medium and low voltage efficiencies were the distribution efficiencies.

3.4.2 Hydropower availability

In the LCPDP, the Valoragua model was used to determine the seasonal availability of hydropower. Valoragua is a model which provides a framework for determining the optimum operating strategy for an electricity generation system. It takes into account parameters of a stochastic nature such as water availability and unplanned outages. In Kenya, it was used to determine the optimum hydrothermal configuration (ERC, 2011; IAEA, 1992). Its results consist of expected annual generation of hydropower configurations for different hydrological conditions against their probabilities of occurrence. These results were fed into WASP as an input and WASP selects the most optimum configuration (ERC, 2011).

In the LCPDP Replica using TIMES however, seasonal availabilities were used to model the generational variation of hydropower. The seasons used have been defined in section 3.3.1. The following process was used to estimate seasonal availability:

- The monthly hydro generation for the years 2012 to 2014 were obtained from the leading economic indicators published by KNBS
- The hydropower capacity of the selected years was taken from the Kenya Power Annual reports
- Availability was calculated by dividing the monthly generation by the maximum monthly generation.
- Averaging the availabilities of the months within a season to obtain the seasonal availabilities.
- An average of the seasonal availabilities for the selected years was obtained and used as the hydropower availabilities

Table 3-16 below shows the monthly generation by hydropower from the year 2012-2014 and the average seasonal availability in these years.

Table 3-16 Table showing hydropower availability

Month	**2012**	**2013**	**2014**	**Average**
January	329.53	377.24	339.2	0.58
February	331.64	322.99	269.93	
March	292.5	347.6	286.74	
April	272.88	345.05	307.53	0.56
May	323.37	376.96	250.18	
June	341.75	378.41	263.41	
July	358.34	385.86	263.41	0.60
August	347.5	376.91	293.87	
September	333.73	376.95	277.62	
October	359.87	384.52	279.02	0.61
November	372.05	357.67	307.25	
December	368.04	346.51	282.25	

For the dry year scenario availabilities from the year 2009 were used. This year was selected as the country experienced a period of drought between the years 2008-2010 (Global Facility for Disaster Reaction and Recovery, 2012).

The availabilities that were used are tabulated in Table 3-17

Table 3-17: Dry year availabilities

Month	Generation	Monthly	Seasonal Average
January	231.75	0.43	0.42
February	215.16	0.40	
March	237.11	0.44	
April	202.51	0.38	0.37
May	212.16	0.39	
June	189.95	0.35	
July	172.52	0.32	0.26
August	138.29	0.26	
September	115.34	0.21	
October	120.28	0.22	0.24
November	140.81	0.26	
December	129.50	0.24	
total	2105.38	0.33	

3.4.3 Solar Power Availabilities

Solar power availability varies according to season and time of day. The LCPDP does not consider solar power for generation expansion at a utility level and therefore does not publish availabilities. It however does state that Kenya has a sufficient solar resource to be used for electricity generation (ERC, 2011). Due to the sufficient solar resource it was decided to include solar technology for capacity expansion at a utility and commercial/residential level. The availabilities were calculated using equation 3-5 below:

$$\text{A. F} = \frac{average\ monthly\ electricity\ output}{maximum\ generational\ output} \qquad 3\text{-}5$$

The average potential monthly solar electricity output was obtained from solar GIS maps published by the European Commission's Joint Research Institute (Europa Joint Research Commission, 2015). The GIS map is an interactive map which issues both average potential electricity output and average global horizontal radiation per month and per day. The user has to select the location of use and technological parameters that will reflect their desired condition before obtaining the required output. The selected solar panel was 1KWp and the system losses assumed were 14%. At a utility scale output was obtained for horizontal and inclined panels. For the residential and commercial solar panels the option of building integrated panels was selected as opposed to free standing.

It was assumed that at a utility scale, the locations with the best solar radiation would be selected. The selected locations used to calculate an average solar availability for the utility scale were Garissa, Isiolo and Lodwar which had monthly yields of between 135KWh/KW and 145 KWh/KW. For the residential and commercial level it was assumed that the technology would be more dispersed and therefore the monthly electricity output obtained from the cities of Mombasa, Nairobi and Kisumu were added to those used for the utility scale. The yields observed in this category were between 118-145 KWh/KW.

Since the peak power selected for the electricity output was 1KWp, the maximum generational output was obtained by multiplying the peak power by the number of hours in the relevant month. For the day capacity factor the number of hours used per day was 12.5 which is the number of hours in the day time slice. The evening and night availabilities were set at zero

The capacity factors for utility scale solar power for both horizontal and inclined solar panels are tabulated in Factors whilst residential and commercial capacity factors are tabulated in Appendix 4: Solar Power Capacity Factors Residential and Commercial Scale.

The costs for solar power are tabulated in Appendix 5: Capital Overnight Costs for Solar Power in 2010 US.

3.4.4 Screening Curves

A screening curve is a plot of annualised power costs against capacity factor. They are used to determine the most cost effective operating region of generation technologies (with regards to capacity factor). It can also be used to validate a model's technology choice or give an indication of the model's likely selection preference at different parts of the load curve (Kannan & Turton, 2013; IAEA, 1984).

Due to their limitations screening curves have to be used in conjunction with other methods of capacity expansion planning. Some of their limitations are as follows (Kannan & Turton, 2013; IAEA, 1984):

- They do not take into account cost changes due to learning rates or diminishing resources across the period of study
- They do not consider demand side factors such as load profile.
- It is difficult to analyse system reliability using screening curves as they do not account for forced outage rates, unit sizes and maintenance requirements
- They do not take into account availabilities that are dependent on seasons or time of day. Most renewable energy technologies fall into this category thus screening curves do not provide a good method for planning for renewable energy technologies.

Screening curves for the technologies considered for capacity expansion are shown in Figure 3-19 and Figure 3-20 below. The overnight capital costs which are assumed to be constant (with the exception of solar power) during the modelling horizon and other technical parameters describing relevant technologies are tabulated in Table 3-18 while the fixed and variable operating costs are tabulated Appendix 2

Table 3-18: Technical parameters of technologies considered for capacity expansion planning

Technology	Unit capacity	Fuel type	Plant life	Lead time	Efficiency	Availability (%)	Overnight Cost ($/KW)
Geothermal	140	Geo-thermal energy	25	5	-	93	3650
MSD	160	HFO	20	2	0.38	28	1364
Gas turbines	180	Natural gas	20	2	0.37	55/20	750
Coal	300	Coal	25	4	0.36	73	2104
Nuclear	1000	Uranium	40	7	NG	85	4055
Wind	300	Wind	25	2	-	40	2300
Hydro-1 Mutonga	60	Hydro	50	5	-	60	4314
Hydro-2 Lower Grand falls	140	Hydro	50	5	-	60	3621
Imports	200	Hydro	20	3	-	60	

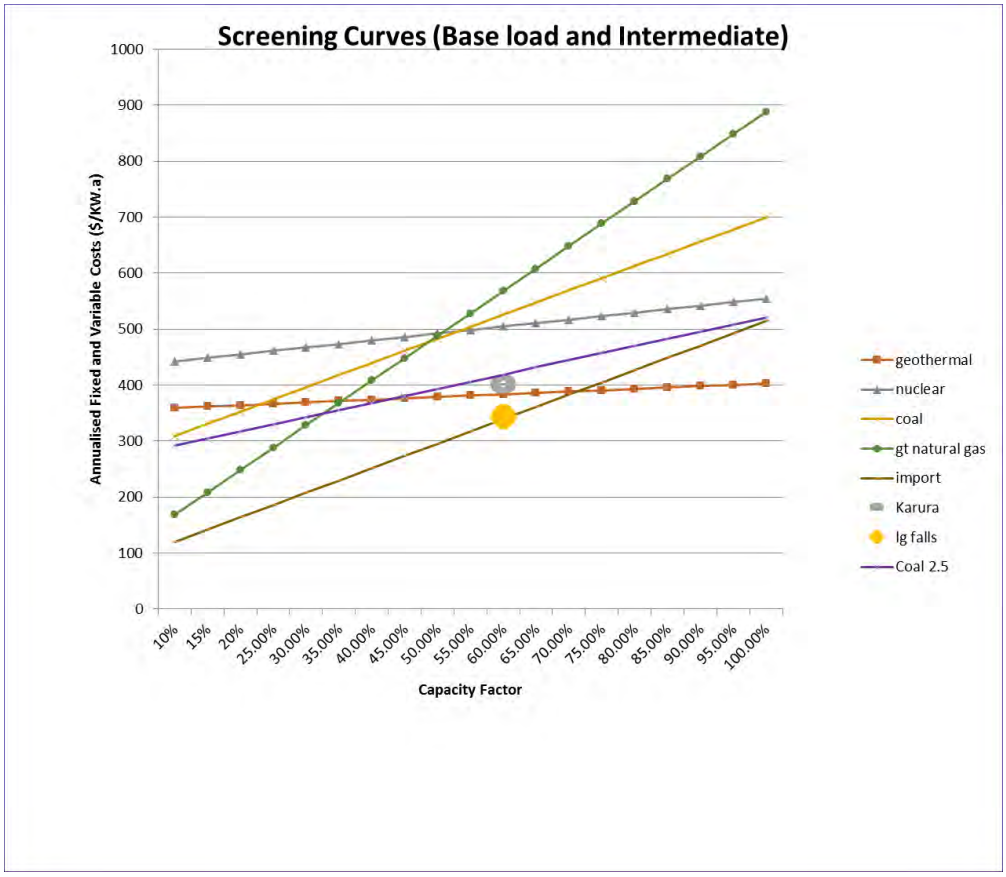


Figure 3-19: Screening curves for base load and Intermediate Plants

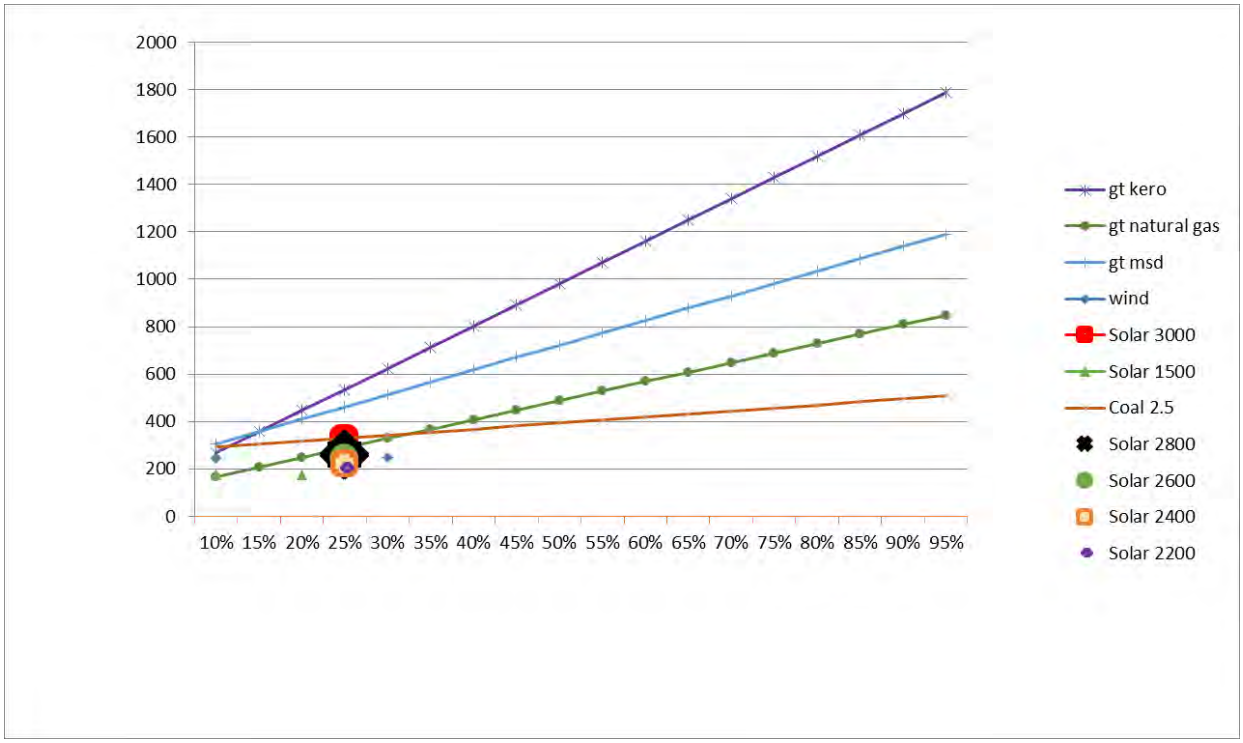


Figure 3-20: Screening curves for Renewables and peaking plants

The LCPDP states that gas turbines will be used for both intermediate and peaking plants. Therefore this technology was displayed on both Figure 3-19 and Figure 3-20. Renewable technologies have been represented in both figures as data points at their maximum capacity factors rather than curves. A learning rate was implemented on the capital cost of solar power and therefore solar power has multiple points on the graph, one for each capital cost. The maximum annual capacity factor for solar PV was assumed to remain the same throughout the study period. Hydropower is a renewable energy technology however, it has been categorised with the baseload and intermediate load plants because it operates at a higher capacity factor than the other renewables and can be considered an intermediate plant.

From the screening curves in Figure 3-19 and Figure 3-20, it is expected that the model will first utilise geothermal power for base load power then hydropower imports from Ethiopia. In the case of peaking power plants the model will likely utilise natural gas first.

3.4.5 Cases

A 'case' in the TIMES modelling framework convention consists of a combination of different scenarios that are combined to represent a possible future where the scenarios typically represent different views of the future, values of a parameter or group of parameters like a commodity price or capital cost time series of a technology. A combination of different scenarios is referred to as a case and thus the use of the words 'scenario' and 'case' may differ from that commonly used in other models and analyses.

The following cases were run under the LCPDP replica and the CCEP

3.4.5.1 ***Least Cost Power Development Plan replica***

As mentioned above, this model was built with the aim of validating the LCPDP. Two scenarios of the LCPDP replica were built; one had the last result year as 2031 while the other had the last result year as 2040. This was done because it was unclear whether end effects had been considered in the LCPDP. Within these scenarios, two cases of the LCPDP were developed, the free run and the forced nuclear run. The cases below were run in both scenarios of the LCPDP replica and the results compared to the LCPDP.

In both the free run and the forced nuclear run, the only capacity bounds that were implemented were due to resource limits and are tabulated in Table 3-19 below. The geothermal resource limit has been established to lie between 7-10GW (ERC, 2011). The lower limit of 7GW was taken to be the maximum available resource and the capacity bound of 6.4 GW was selected because the existing geothermal capacity is 0.55GW. The wind resource was constrained at 4 GW, the minimum figure given in the latest power sector planning document issued by the Energy Regulatory Commission. At the time the LCPDP 2010 was published the wind resource was still being measured. It is unclear whether the selection of wind power was limited by other constraints (Energy Regulatory Commission, 2015b; Energy Regulatory Commission, 2011). The hydropower import limit has been set by the maximum capacity of the transmission line from Ethiopia which is 2 GW (ERC, 2011). Annual new build capacity bounds are implemented as in Table 2-6. This table published in the LCPDP 2010 did not contain annual new build constraints for natural gas and medium speed diesel. The constraints were therefore taken from the LCPDP 2013-2033 which list them as 480MW and

540MW for medium speed diesel and natural gas respectively. It was assumed that the same constraints were used in the 2010 version of the LCPDP.

Table 3-19: Table showing capacity bound employed due to resource limits

Technology	Capacity bound (GW)
Geothermal	6.4
Wind	4
Hydro imports	2

The following is a description of the free run and forced nuclear run cases:

- Free run: In this run, the only constraints applied were annual new build capacity bounds and total capacity bounds described in
- Table 2-6 and Table 3-19. The annual new build capacity bounds limited the amount of new capacity per technology that can be added in a year whilst the total capacity bound limits the total capacity of a technology during the modelling horizon.
- In the forced nuclear case the model was forced to begin construction of a total of 4GW of nuclear power between the years 2015 and 2021. . An additional constraint was placed on the model prohibiting it from constructing kerosene fuelled gas turbines. This is because the LCPDP indicates that gas turbines will in the future be fuelled by natural gas in preference to kerosene and that gas turbines should be installed near prospective natural gas facilities.
- The demand forecast used in both these cases was the same demand forecast used in the LCPDP base case scenario which assumed GDP growth of 9% from 2015.

3.4.5.2 CCEP

In this model, the constraints were obtained from the LCPDP 2010-2033 and are tabulated in Table 3-20

Table 3-20: Table showing constraints implemented in the CCEP

Technology	**Constraints**
Geothermal	Maximum 3×140 MW
Coal	Earliest commissioning date 2018
	Maximum per year 3×300MW
Karura*[1] Hydropower (90MW)	Earliest commissioning date 2021
Low Grand* falls (140 MW)	Earliest commissioning date 2021
Gas Turbines	Earliest commissioning date 2018
Wind	Maximum per year 3×100MW and after 2025 4×100(MW)
Nuclear	First plant in 2022
	Maximum per year 2×600MW
Medium Speed Diesel Turbines	Earliest date 2018
Ethopia hydropower Import	Earliest date 2018

**Karura and Low grand falls are the hydropower technology options availed to the model 1.It is noted that the LCPDP 2013-2033 replaces the Mutonga hydropower plant with Karura as a generation technology*

Under this model the cases run were based on the following scenarios:

- Reference case: In this case the demand forecast used was developed using a GDP growth rate of 6%.
- Optimistic GDP growth rate: In this scenario the demand was forecasted using a GDP rate of 8%
- Solar case: As previously mentioned the LCPDP does not consider solar power for capacity expansion. This scenario was thus selected to observe the models technology choice when solar power is included in the technology pool.
- Optimistic solar scenario: This scenario was run to observe the impact of having a lower capital cost for solar.
- Dry year scenario: In this scenario a dry year was assumed to occur every 5 years. The seasonal availabilities tabulated in Table 3-17 were used to define the dry year in the model. (Global Facility for Disaster Reaction and Recovery, 2012).

- Nuclear scenario: The model was forced to build 1.2MW of nuclear power which would come online in 2024 and 2026
- Coal scenario: The model was forced to build coal which would come online in 2019 and 2020.
- Low fuel cost scenario: This was done to observe the impact of having a lower coal fuel cost on the model as would be the case if coal reserves recently discovered in Kenya were available.

4 RESULTS & DISCUSSION

In this section, the results obtained for least cost generation expansion plans for both LCPDP replica and the CCEP models will be presented and analysed. The LCPDP replica will be discussed first. As mentioned in section 1.3, its aim was to validate Kenya's 2010 capacity expansion plan and in doing so determine whether nuclear power was indeed necessary for meeting Kenya's future electricity demand under those assumptions. As far as possible, all the assumptions that were utilised for developing the LCPDP replica including the electricity demand forecast were the same as those used in the LCPDP.

After the LCPDP replica has been discussed the CCEP results are presented. As mentioned in section 1.3, its aim was to develop an updated capacity expansion plan which utilised more recent assumptions than the LCPDP 2010. One of the objectives of the CCEP runs was to observe whether nuclear power would be included in the least cost generation mix selected by the model. Other aims were to observe the affordability of a scenario which includes nuclear power compared to scenarios without nuclear power and to analyse the emissions in all the generated scenarios.

4.1 Least Cost Power Development Plan Replica

As has been discussed in Section 3 above, two scenarios of the LCPDP replica were created. One scenario had a time horizon to 2031 and the second scenario had a time horizon to 2040. This was done because it was unclear from the LCPDP 2010 whether years beyond the study period had been included in the model to eliminate end effects. The scenario with the time horizon to 2040 eliminates end effects and will be referred to as "no end effects-last year 2040". The scenario with the time horizon to 2031 contains end effects and will be referred to as "end effects-last year 2031". The results for both scenarios will be presented with special focus on the year 2031, which is the final year of study and compared to the LCPDP results.

4.1.1 Free case

As the name suggests, other than the capacity bounds in Table. 3:19 and annual new build capacity bounds in Table 2.6 no other constraints were implemented. The following presents the results obtained in both scenarios of the LCPDP replica.

4.1.1.1 No end effects-last year 2040

The technology capacity obtained across the study period is shown in Figure 4-1.

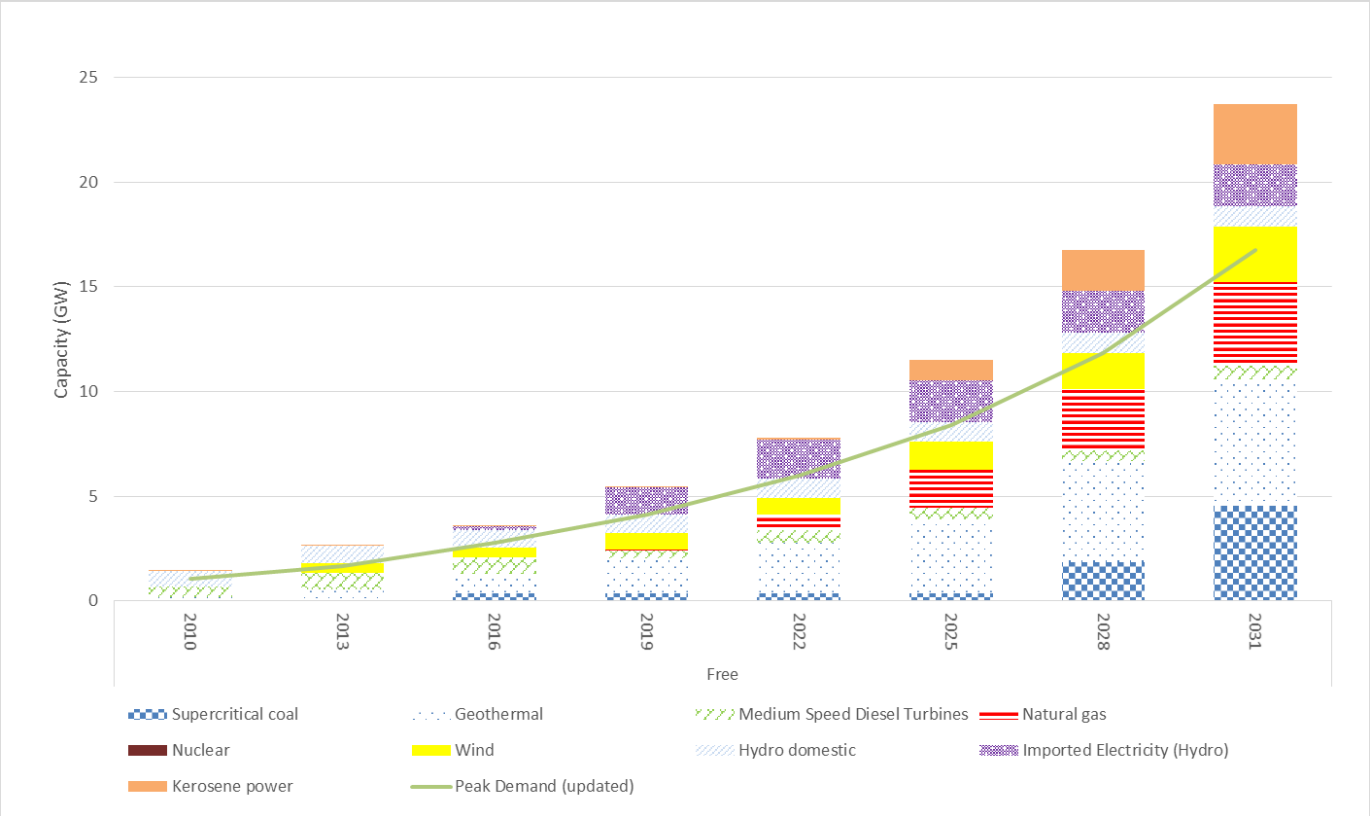


Figure 4-1 Technology capacity in the Free case, LCPDP replica, no end effects last year 2040

From Figure 4-1, it is noted that the model does not construct nuclear power within the study period. This implies that nuclear power is not needed to meet the demand forecast modelled in the LCPDP.

The electricity generation is shown in Figure 4-2

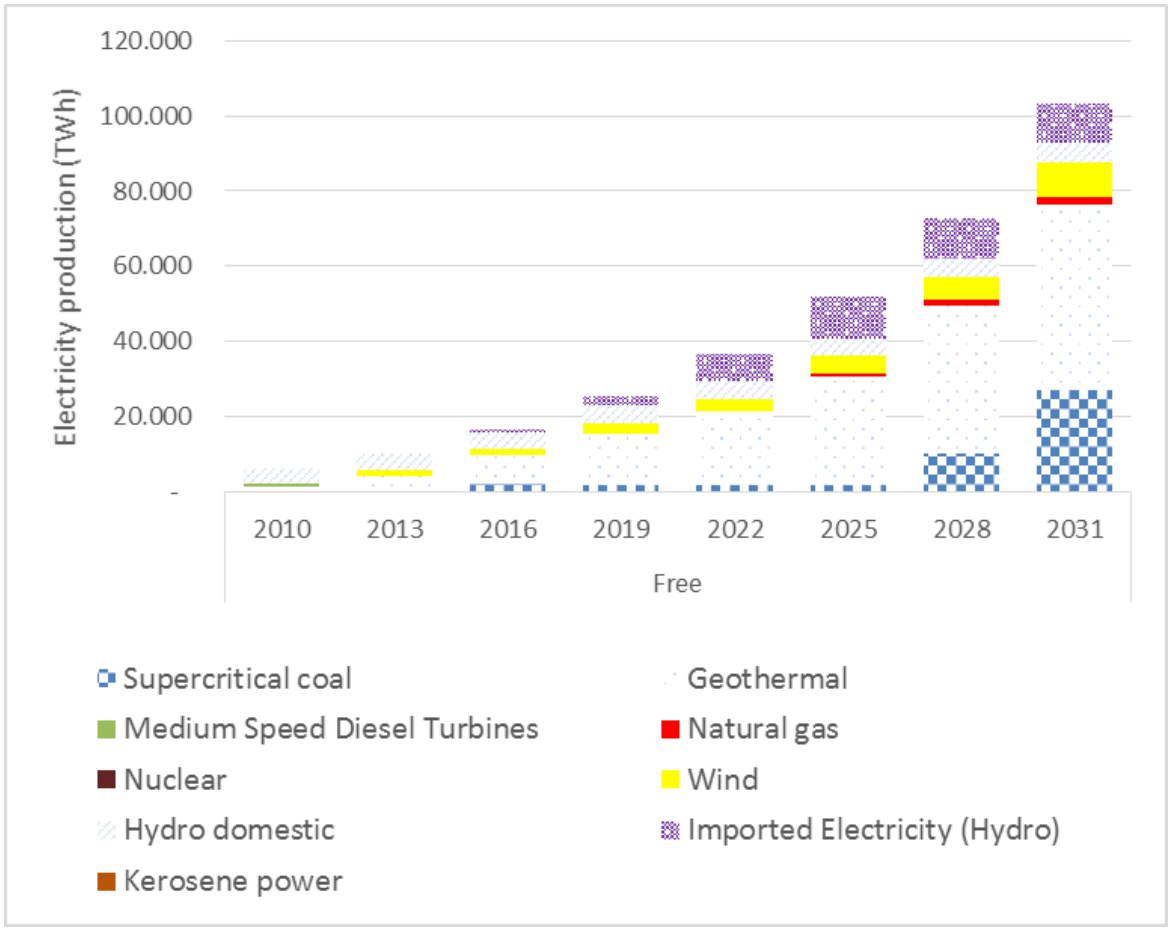


Figure 4-2 Electricity production in free case LCPDP replica, no end effects last year 2040

Figure 4-3 below shows the new capacity constructed between 2010 and 2031

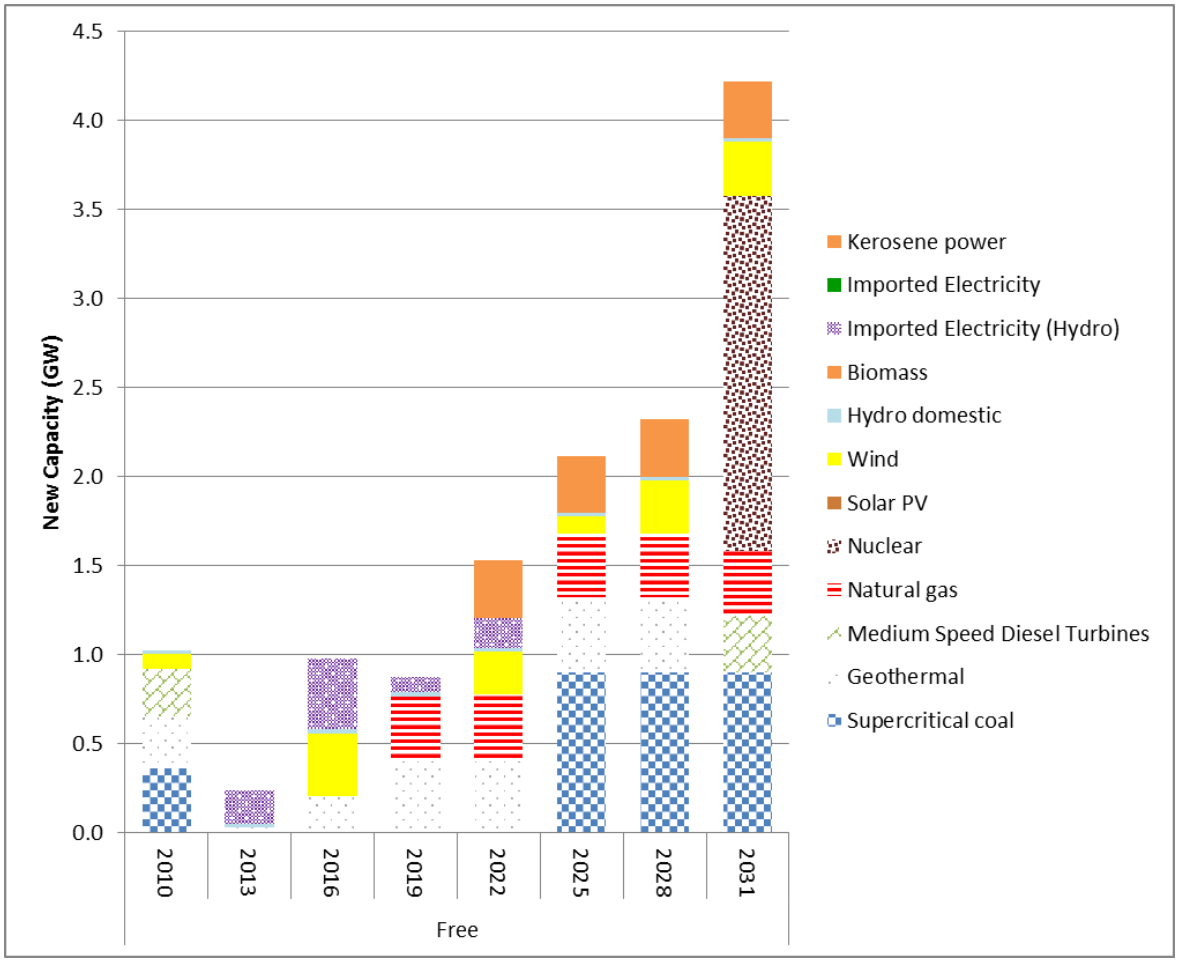


Figure 4-3 New capacity in the Free Case LCPDP Replica no end effects last year 2040

It must be noted that Figure 4-3 above and all the succeeding figures showing new capacity indicate the year of construction commencement not completion. As such all the technologies in the graph begin to generate electricity after their respective lead times have elapsed. The construction of nuclear power for example begins in 2031 and ends in 2038 which is after the end of the period of study.

4.1.1.2 End effects-End year 2031

The graph in Figure 4-4 shows the capacity of the various technologies across the model horizon

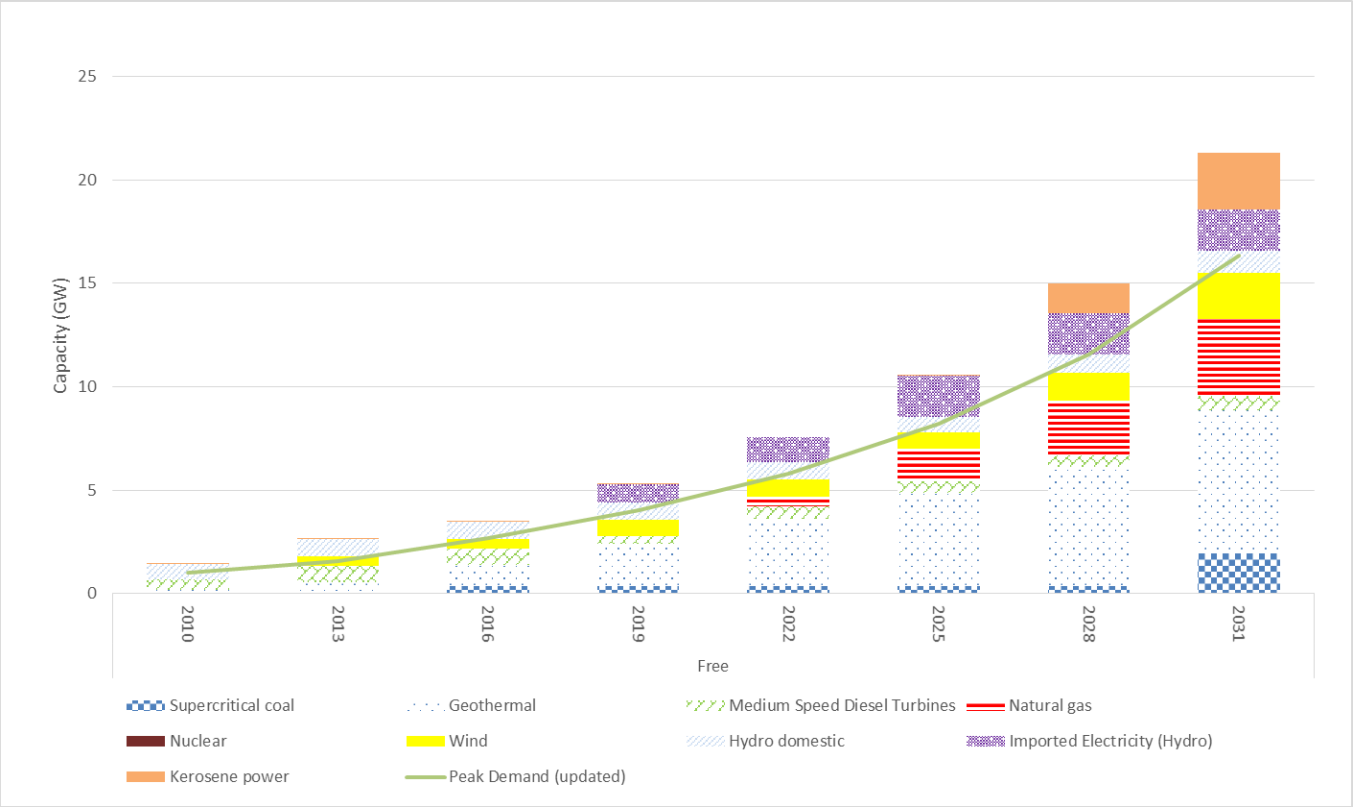


Figure 4-4 Technology capacity in LCPDP replica, end effects end year 2031 scenario

Figure 4-4 above shows that the model does not construct nuclear power within the study period in this scenario. This implies that nuclear power is not necessary to meet the demand forecast assumed in the LCPDP when end effects are not considered. The run for which end effects are considered however indicated that, given the assumptions in the LCPDP hold true in the longer term, that initiation of construction of 2GW of nuclear capacity at the very end of the study period would be cost optimal to meet demand beyond 2030

The graph in Figure 4-5 below shows the electricity production across the study period.

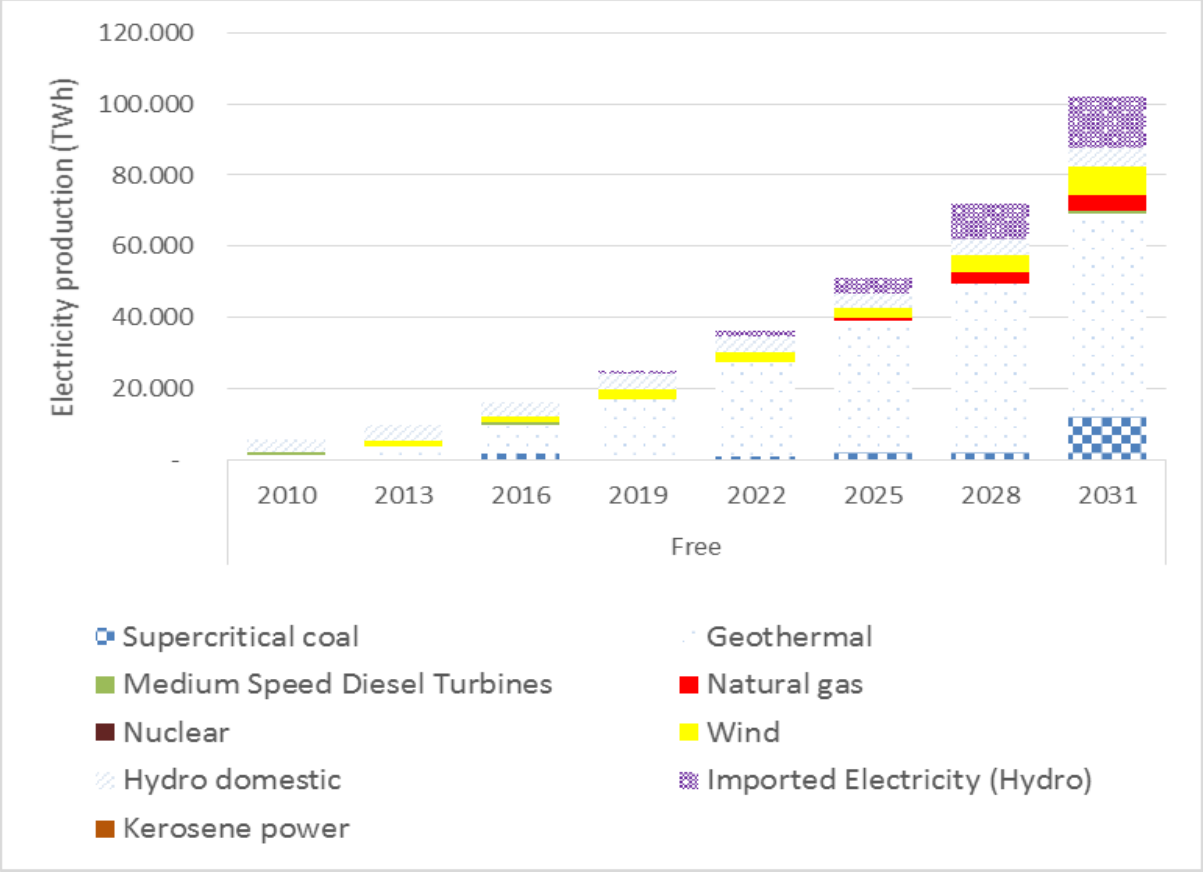


Figure 4-5: Electricity production in the LCPDP replica end effects end year 2031 scenario

Figure 4-6 shows the new capacity added between 2010 and 2031

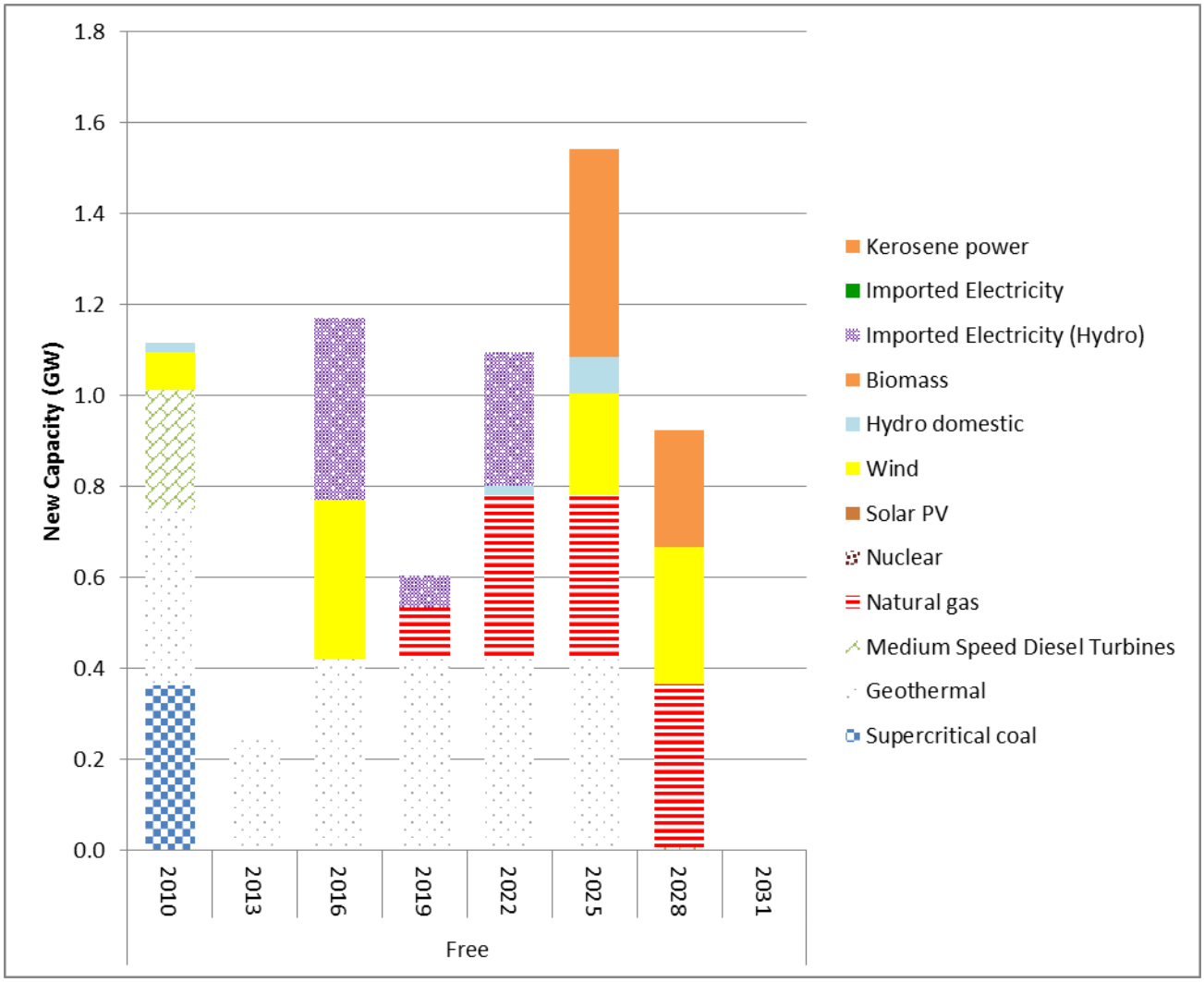


Figure 4-6: New Capacity Free case LCPDP Replica end effects last year 2031

From figure 4-6, it is observed that the model does not construct any power plants in 2031. This is different from the scenario without end effects which begins the construction of a nuclear power in 2031. This is occurs because the model does not 'see' any demand in the future.

Table 4-1 below shows a summary of the results obtained for the year 2031 in both scenarios of the LCPD replica.

Table 4-1: Summary of results obtained in the end year 2031 and 2040 scenarios of the LCPDP

Technology	Capacity in 2031		Capacity share in 2031		Generation share in 2031	
	End effects 2031 (GW)	No End effects 2040 (GW)	End effects 2031	No end effects 2040	End effects 2031	No end effects 2040
Coal	1.9	4.6	9%	19%	12%	26%
Geothermal	7.0	6.0	33%	25%	56%	48%
MSD	0.7	0.7	3%	3%	1%	0%
Natural gas	3.7	4	17%	17%	4%	2%
Nuclear	0.0	0.0	0%	0%	0%	0%
Wind	2.2	2.4	10%	11%	8%	9%
Domestic Hydropower	1.0	1.0	5%	4%	5%	5%
Imported Hydropower	2.0	2	9%	8%	14%	10%
Kerosene power	2.8	2.9	13%	12%	0%	0%
Total	21.3	23.7	100%	100%	100%	100%

The most notable difference in the table above is the capacity of coal power. The capacity of coal in the scenario with no end effects-last year 2040 is 2.5 times higher than the scenario with end effects-last year 2031. This makes the total capacity in the scenario without end effects 10.8% higher than the scenario with end effects. It is also

noted that the model begins to construct 1GW of nuclear power in 2031 for the free case of the LCPDP replica scenario 'without end effects-end year 2040' as opposed to 2022 which is the year that the government intends to begin the construction of nuclear power. This implies that using the demand forecast utilised in the LCPDP, nuclear power is needed by 2038 which is out of the scope of the period of study.

4.1.1.1 Forced Nuclear case

The aim of this case was to obtain results that were similar to the LCPDP 2010. The model was therefore forced to build 1GW of nuclear power in alternating years from 2015 to 2021 adding up to a capacity of 4GW. Furthermore, the model is restrained from building additional kerosene power. This is because the LCPDP does not consider kerosene power as an expansion option and aims to convert the existing 60MW kerosene plant into a natural gas plant. The results obtained in this run are presented below

4.1.1.3 No end effects-Last year 2040

The capacity obtained in this scenario is shown in Figure 4-7

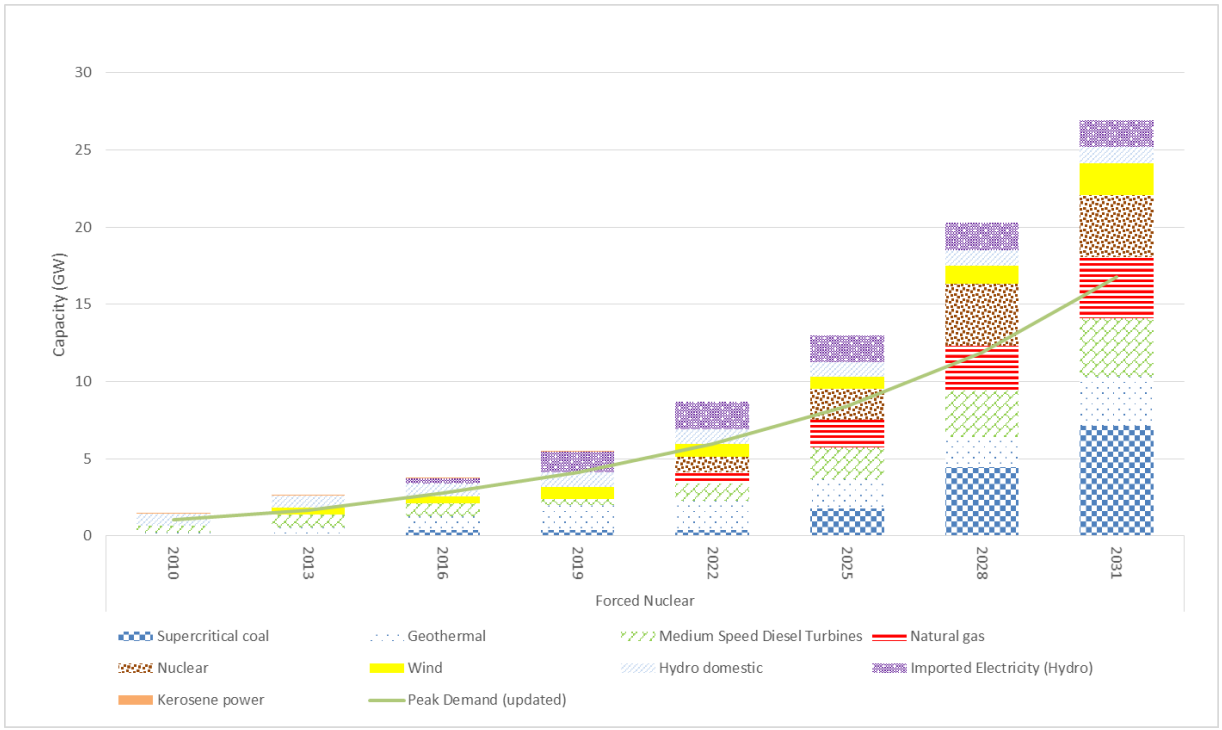


Figure 4-7: Technology capacity in the LCPDP replica, last year 2040 scenario

From figure 4-7 above it is observed that the only nuclear power plants constructed by the model are those which it was forced to construct.

The graph in Figure 4-8 below shows the electricity generation across the modelling horizon.

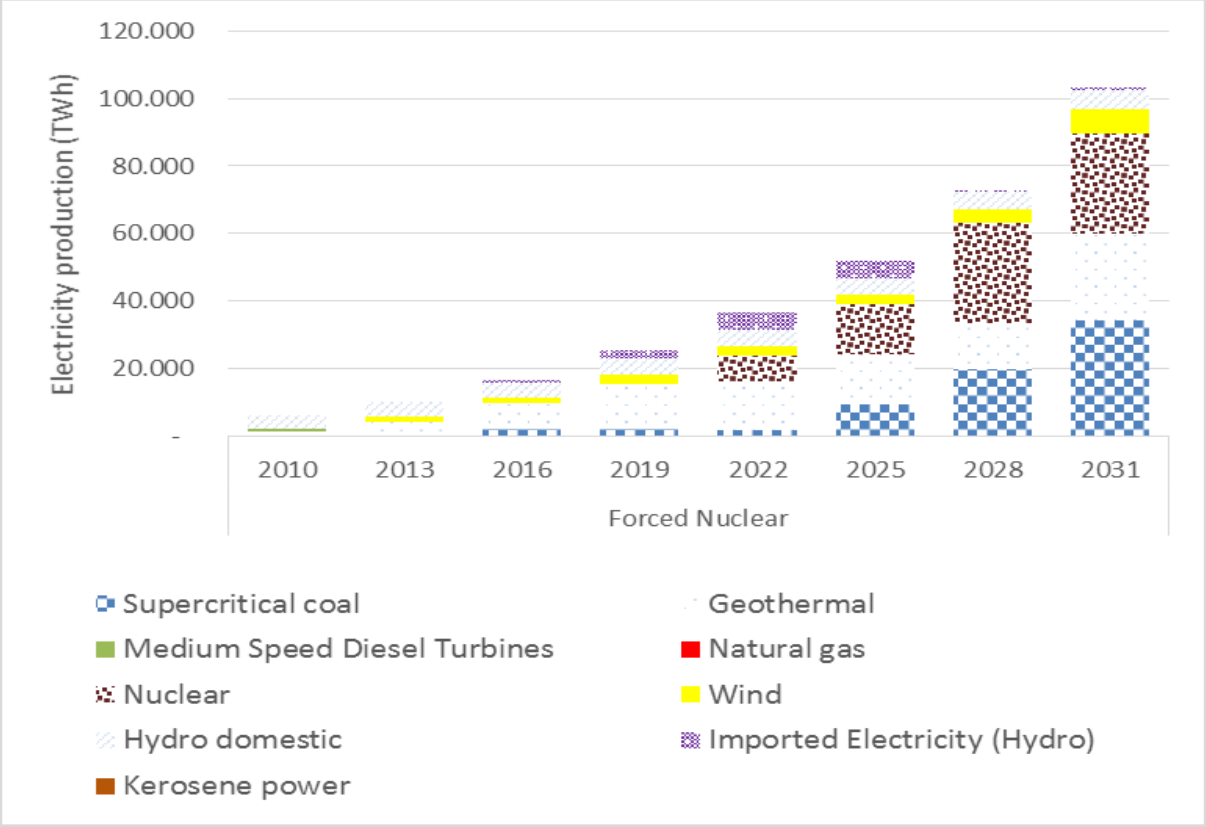


Figure 4-8 Electricity generation across model horizon LCPDP Replica no end effects last year 2040

The graph above shows a nuclear plant which begins to generate electricity in 2022. This construction of this plant begun in 2015. As previously mentioned the model was forced to construct 1GW of nuclear power in alternating years from 2015 to 2021.

Figure 4-9 shows the new build capacity in the forced nuclear case in the scenario without end effects between 2010 and 2031.

Figure 4-9 New Capacity in the Forced Nuclear Case, LCPDP Replica End year 2040

It must be reiterated that the new capacity build graphs show the year of construction commencement. The nuclear capacity shown in Figure 4-9 indicates the year that construction begun.

4.1.1.4 With end effects-End Year 2031

The graph in Figure 4-10 below shows the capacity between 2010 and 2031

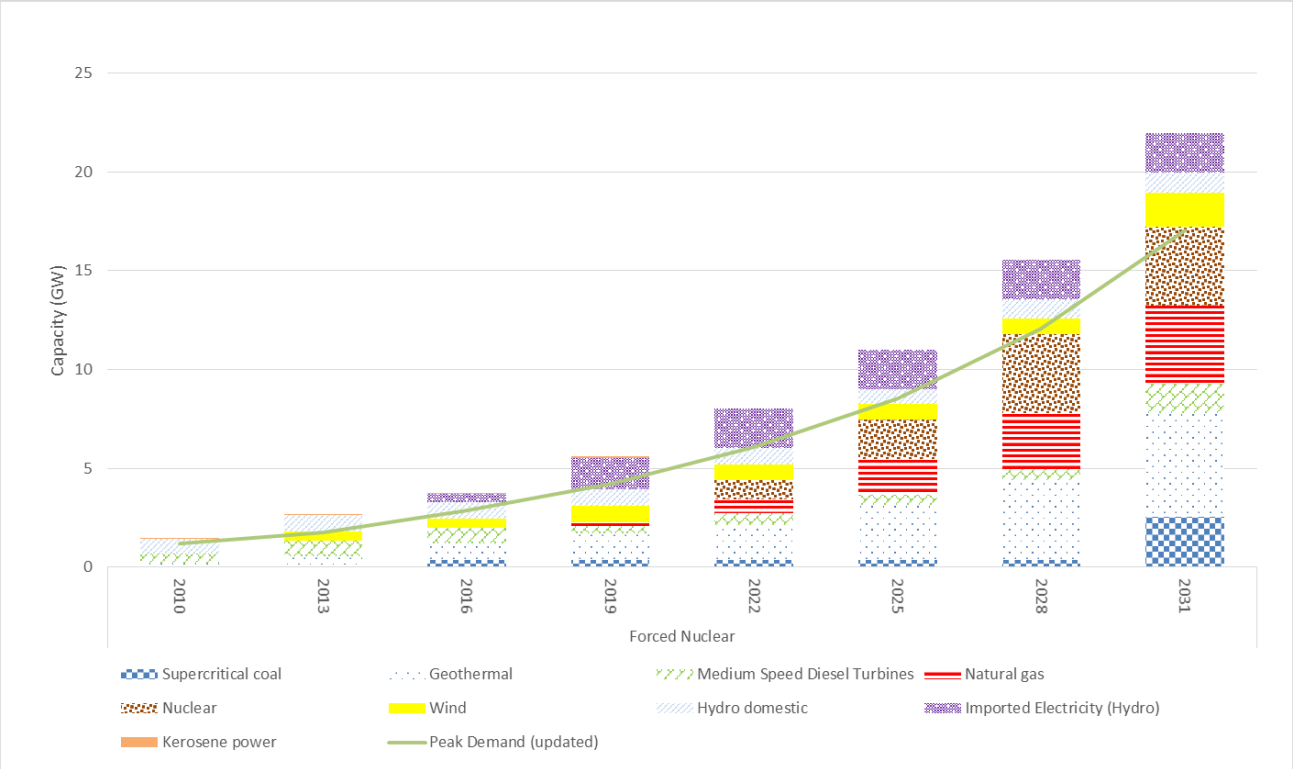


Figure 4-10: Technology capacity, Forced Nuclear case, LCPDP replica last year 2031

It is observed from Figure 4-10 above that the model only constructs nuclear power plants that it was forced to construct. This is similar to the scenario without end effects.

The graph in Figure 4-11 below shows the electricity production of the technologies

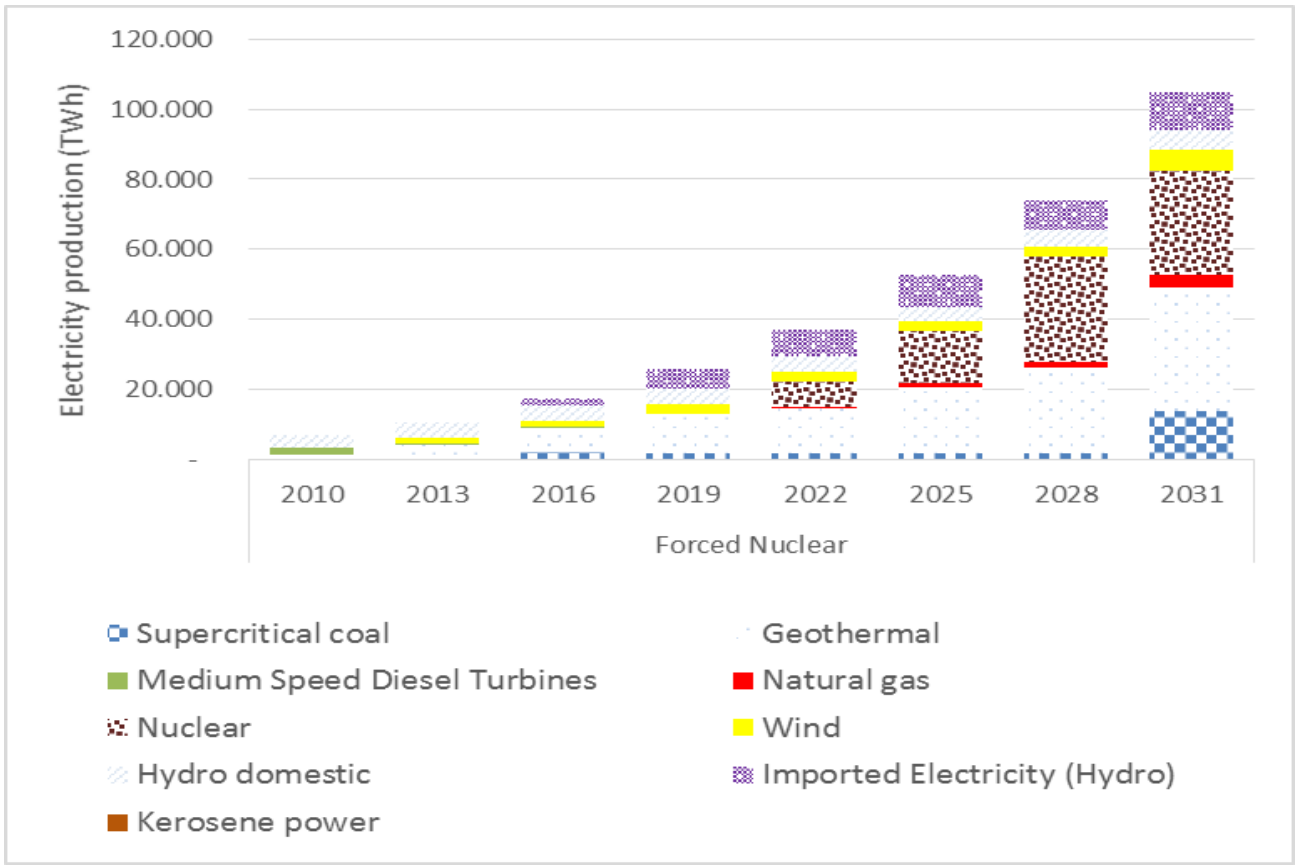


Figure 4-11 Electricity production forced nuclear scenario end effects end year 2031

Figure 4-12 shows the new build capacity

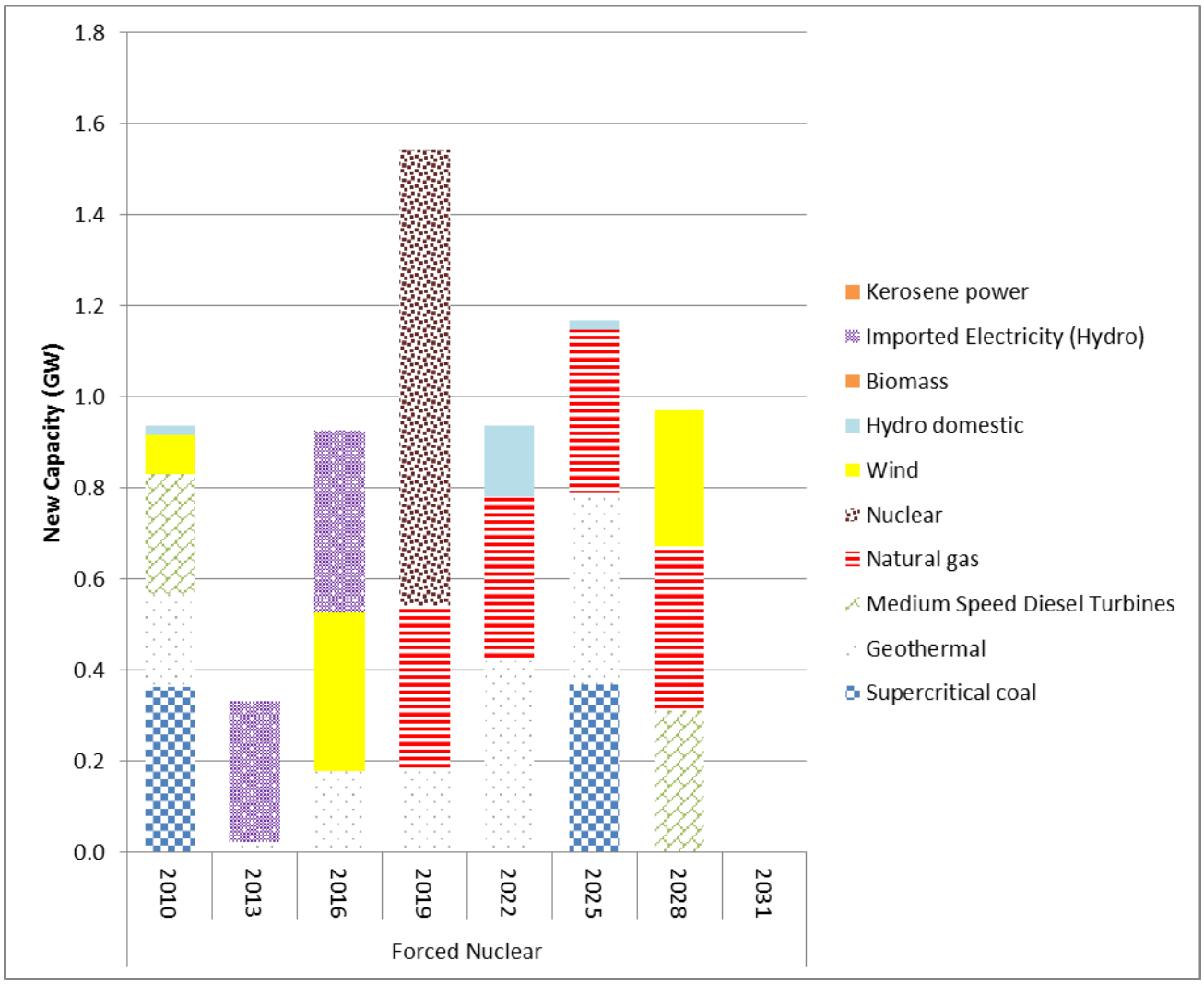


Figure 4-12: New Capacity Forced Nuclear case, LCPDP Replica end effects last year 2031

As in Figure 4-9, the nuclear power plant observed on Figure 4-12 comes online in 2026.

Table 4-2 below gives a summary of the results presented above and compares the results to the LCPDP.

Table 4-2: Comparison of LCPDP replica forced nuclear case and LCPDP

	Capacity in 2031			Capacity share in 2031			Generation share in 2031		
Technology	**End effects 2031**	**No end effects 2040**	**LCPDP**	**End effects 2031**	**No end effects 2040**	**LCPDP**	**End effects 2031**	**No End effects 2040**	**LCPDP**
Coal	2.5	6.4	2.7	12%	26%	13%	13%	32%	9%
Geothermal	5.2	3.2	5.5	24%	13%	26%	34%	25%	43%
Medium Speed Diesel	1.5	3.4	2.0	7%	14%	9%	0%	0%	0%
Natural gas	3.9	4.0	2.3	18%	16%	11%	3%	0%	1%
Nuclear	4.0	4.0	4.0	18%	16%	19%	28%	29%	27%
Wind	1.7	2.1	2.0	8%	8%	9%	6%	7%	6%
Domestic Hydropower	1.0	1.0	1.0	5%	4%	5%	5%	5%	3%
Biomass	0.0	0.0	0.0	0%	0%	0%	0%	0%	0%
Imported Hydropower	2.0	1.0	2.0	9%	4%	9%	10%	1%	11%
Kerosene power	0	0	0	0%	0%	0.0	0%	0%	0%
Total	21.1	25.1	21.6						

From Table 4-2 above it is evident that the scenario that is most similar to the LCPDP is the 'End Effects Last Year 2031'.The greatest deviations from the LCPDP in the last year 2031 scenario are the capacity of coal and natural gas. The other technologies vary by at most 0.3 GW. The total capacity of the LCPDP is 2% more than the capacity of the end year 2031 scenario. The capacity of the last year 2040 is 16% more than the LCPDP.

In both the free run and the forced nuclear run the scenario with no end effects-last year 2040 is observed to favour coal as opposed to geothermal. In the screening curves shown in Figure 3-19 and Figure 3-20, the cost of coal is lower than geothermal until a capacity factor of 25%. It is therefore expected that the model would favour geothermal

instead of coal as seen in the scenario with end effects. The only difference between the scenario with end effects and the one with no end effects is the addition of extra years. As mentioned in section 4.1, the scenario without end effects has the last year in the modelling horizon as 2040 while the one with end effects has the last modelling year as 2031. Additionally, the only technology where learning rates were considered is solar PV as mentioned in section 3.4. Further to this efficiencies and availabilities also remained constant throughout the modelling horizon.

In the absence of any other reason that would cause the model to favour coal in the scenario with no end effects, it is assumed that the capacity bound in place for geothermal and the increased model horizon causes the model to construct more coal in the earlier years, before the end of the model horizon in 2040. To test this theory the capacity bound on geothermal was increased from 7GW to 10GW. In this scenario, the model built 7.12 GW of geothermal and 3.24 GW of coal in the free run. In the forced nuclear run the model built 6.78GW of geothermal and 4.80GW coal. It is observed that in both cases of the scenario with no end effects the model builds geothermal instead of nuclear. The interaction between the increased model horizon and the geothermal capacity bound can therefore be said to be responsible for the increased construction of coal observed in the scenario with no end effects.

In the absence of further constraints used in the LCPDP the following can be concluded from the above models

- It is probable that the model was forced to build nuclear power or constraints on technology construction which are not documented in the LCPDP were put in place to make the model build nuclear power
- It is probable that the LCPDP did not consider end effects.
- The demand forecasted during the study period of the LCPDP could have been met without the use of nuclear power as seen in the free case

4.2 Current capacity expansion plan (CCEP)

The current capacity expansion plan was developed with the aim of incorporating recent data. This data includes recent and current technology capacity, peak demand,

GDP growth rate, transmission and distribution efficiency as well as electricity consumption between the period of 2010 and 2013. Some of this data was used to update Kenya's demand forecast. In this model the last result year was 2040. This was done to eliminate end effects in the final year of study which was 2031 as in the LCPDP.

The following cases were selected because they best represent Kenya's possible electricity futures:

- Reference case
- Optimistic GDP case
- Dry year case
- Low cost coal fuel case
- Solar case
- Optimistic solar learning case

As the name suggests, the reference case is expected to occur under business as usual conditions and will be compared to the LCPDP's 2010 and 2013 base case. The optimistic GDP growth rate scenario is expected to occur if the Kenyan economy performs better than expected. Results from this case will also be compared to the LCPDP. The results from the rest of the cases will be compared to the reference case of the CCEP. Finally, the necessity of nuclear power for Kenya's capacity expansion plan will be discussed. The total capacity constraints are the same as those imposed in the LCPDP replica and are found in Table 3-19. The date of first construction and the annual capacity bound limits were taken from the LCPDP 2013-2033 and are tabulated in Table 3-20

4.2.1 Reference case

The graph in Figure 4-13 below shows the technology capacity through the study period in the reference scenario

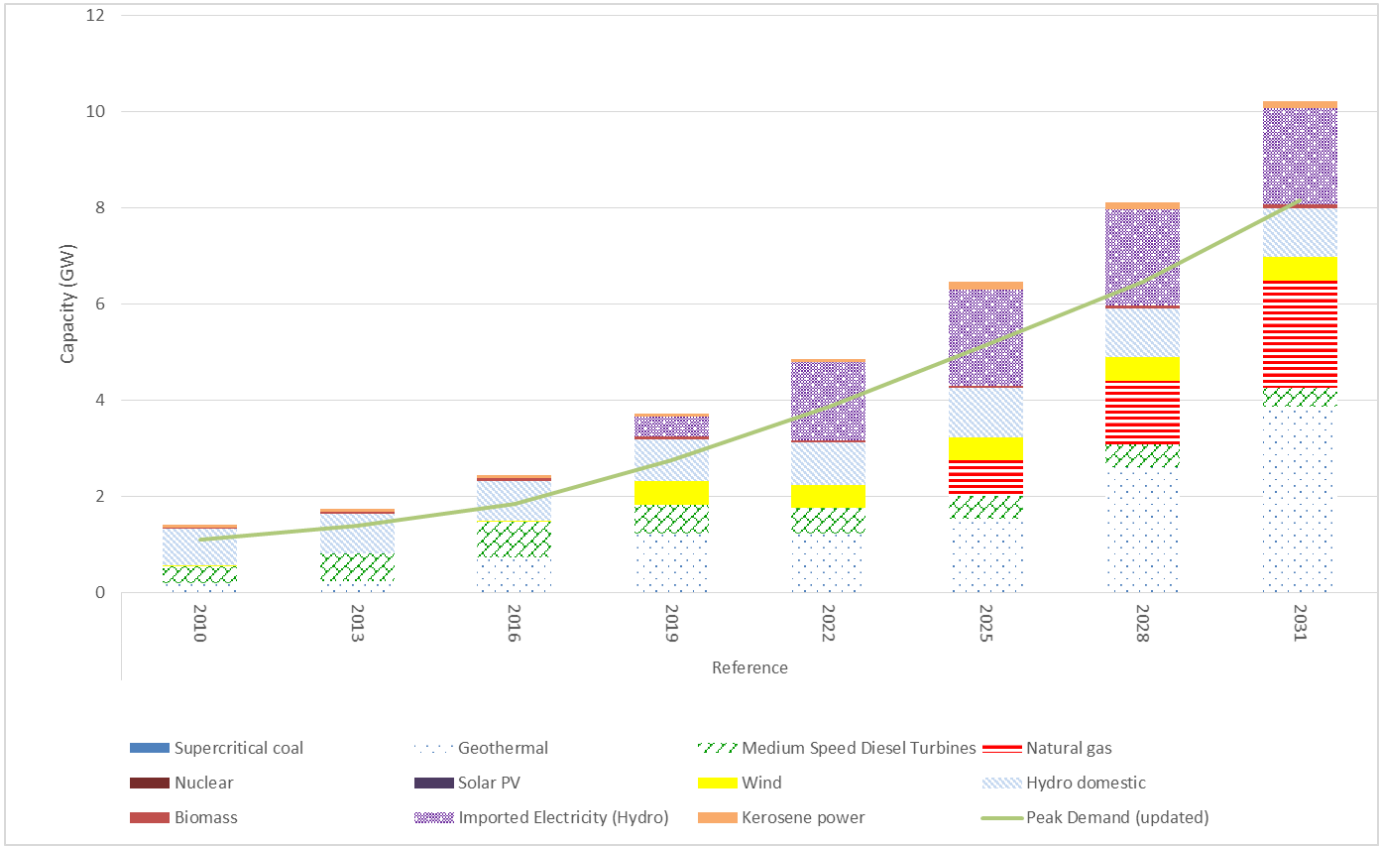


Figure 4-13: Technology capacity in the reference scenario

The installed capacity rises from 1.5 to 10.2 GW while the peak demand rises from 1.102GW to 8.139 GW. The peak demand in the year 2031 is almost equal to the peak demand which was calculated in section 3.3.3 and found to be 8.148 GW (0.1% difference) which validates that the results are consistent with the approximated load curve that was assumed. The graph in Figure 4-14 below shows the electricity production by this scenario.

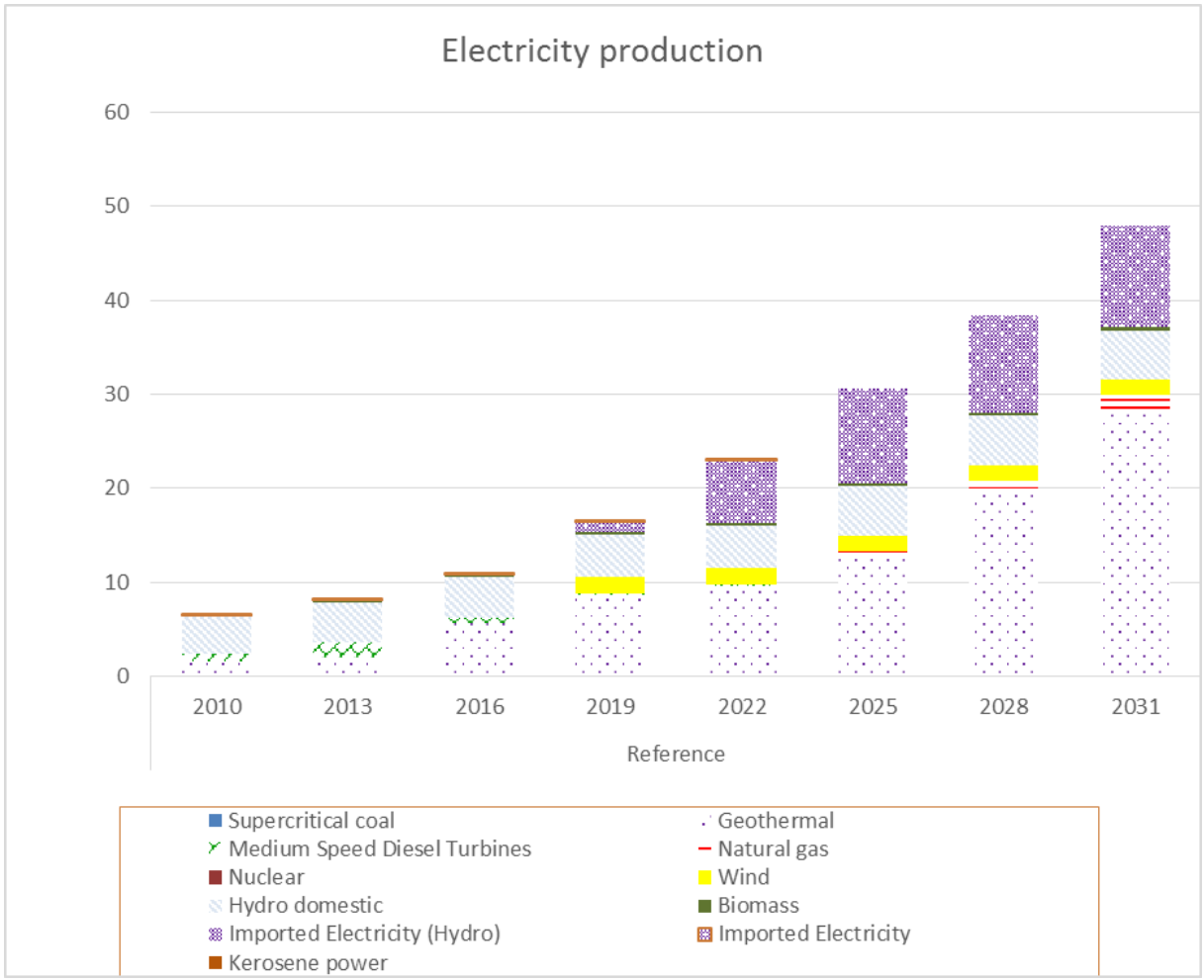


Figure 4-14: Electricity production in the reference case

From the graph above it is evident that more than half of the electricity in 2031 is produced by geothermal. The rest of the electricity is produced by domestic hydropower, imported hydropower, wind and natural gas. Though the model builds kerosene fuelled capacity it does not use it to generate electricity.

Figure 4-15 shows the new build capacity in the reference case

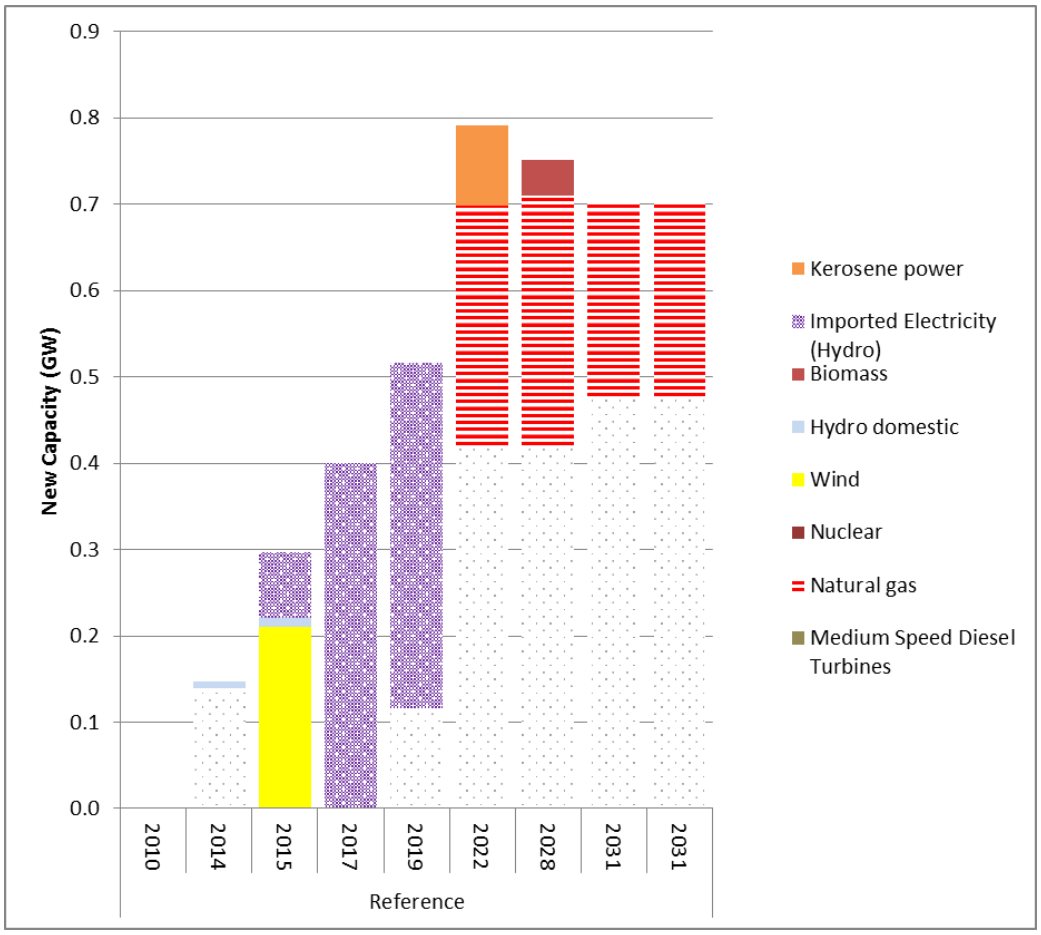


Figure 4-15: New build capacity in the Reference case

Table 4-3 below gives a summary of the results above for the year 2031 and compares the results to the LCPDP 2010 and the LCPDP 2013.

Table 4-3 : Table comparing CCEP and LCPDP results

	CAPACITY SHARE IN 2031			ELECTRICITY GENERATION SHARE IN 2031		
Technology	**CCEP**	**LCPDP 2010**	**LCPDP 2013**	**CCEP**	**LCPDP 2010**	**LCPDP 2013**
Supercritical coal	0%	13%	17%	0%	18%	12%
Geothermal	38%	26%	31%	58%	51%	54%
Medium Speed Diesel Turbines	4%	9%	2%	0%	2%	0%
Natural gas	22%	11%	16%	4%	2%	2%
Nuclear	0%	19%	8%	0%	0%	10%
Wind	5%	9%	11%	4%	8%	6%
Hydro domestic	10%	5%	4%	11%	7%	3%
Biomass	1%	0%	0%	1%	0%	0%
Imported Electricity (Hydro)	20%	9%	10%	22%	13%	12%
Kerosene power	1%	0%	0%	0%	0%	0%

The major difference between both the LCPDP's and the CCEP is the GDP growth rate used for the demand forecast. The GDP growth rate assumed for the demand forecast in

the reference case of the LCPDP 2010 is 9% from the year 2015. In the case of the LCPDP 2013, the GDP growth rate assumed for the forecast demand is unclear however, a GDP growth rate of 10% is implied though whether it used for the reference or optimistic demand scenario is unknown (ERC, 2013; ERC, 2011). The GDP growth rate assumed for the CCEP is 6% from the year 2015.

The total technology capacity of the LCPDP 2010 and LCPDP 2013 in 2031 is 21.6 GW and 19.561 GW respectively whilst the capacity of the CCEP is 10.2 GW. The capacity of the LCPDP 2010 and LCPDP 2013 are larger than the CCEP by 112% and 92% respectively. This was expected as the demand forecast used in the LCPDP is much higher than the case of the CCEP. By 2031, the demand forecasted in the LCPDP 2010 and 2013 are larger than the CCEP demand forecast by 144% and118% respectively. The demand forecast is higher because the annual GDP growth rate assumed in the CCEP from the year 2015 was lower than that used in the LCPDP 2010 by 3%. In addition, the GDP growth rate assumed in the LCPDP 2010 between 2010 and 2015 was not attained as seen in Table 2-3.

A comment on the GDP growth rates used in the LCPDP 2013 cannot be made as they have not been specifically indicated.The comparison of results between the LCPDP 2010, LCPDP 2013 and CCEP indicate the importance of a demand forecast. In an econometric demand forecast, the variables influencing demand should be well researched so that trends assumed in the demand forecast are based on possible futures. In Kenya's case for example, if the estimated GDP growth rate is not attained then a large portion of the built electricity capacity will lie idle resulting in wasted capital that could have been utilized elsewhere.

Another observation from the reference case is the importance of updating of a capacity expansion plan. Updating the plan enables the agencies in question to have a plan that reflects the situation on the ground. The demand forecast of the LCPDP 2013 is less than that of the LCPDP 2010 by 11% in the year 2031. It is assumed that this is because the LCPDP 2013 was able to use more recent assumptions than the LCPDP 2010. If another update of the LCPDP was to be developed, the demand forecast would likely decrease further. This is because the GPD growth rates in the years at the beginning of the modelling horizon could be based on more recent trends.

A similarity between the CCEP and LCPDP replica is the share of peaking plant capacity (MSD, Natural Gas and Kerosene fuelled capacity). In the CCEP the share of peaking plant capacity is 27% of the total capacity as observed in Table 4-3. In the LCPDP replica, the forced nuclear run, the scenario without end effects had a peaking capacity which was 30% of the total capacity while the scenario with end effects the peaking capacity was 25%. The free run of the LCPDP replica had a peaking capacity of 33% in the scenario with end effects and 32% in the scenario without end effects as observed in Table 4-1. The largest deviation from the CCEP is 6% in the free run case of the LCPDP replica's scenario with end effects. This similarity in peaking capacity was expected as mentioned in section 3.3.3

4.2.2 Optimistic GDP Growth

In this scenario, a GDP growth rate of 8% was used to generate the demand forecast. The technology capacity obtained throughout the modelling horizon is shown in Figure 4-16 below

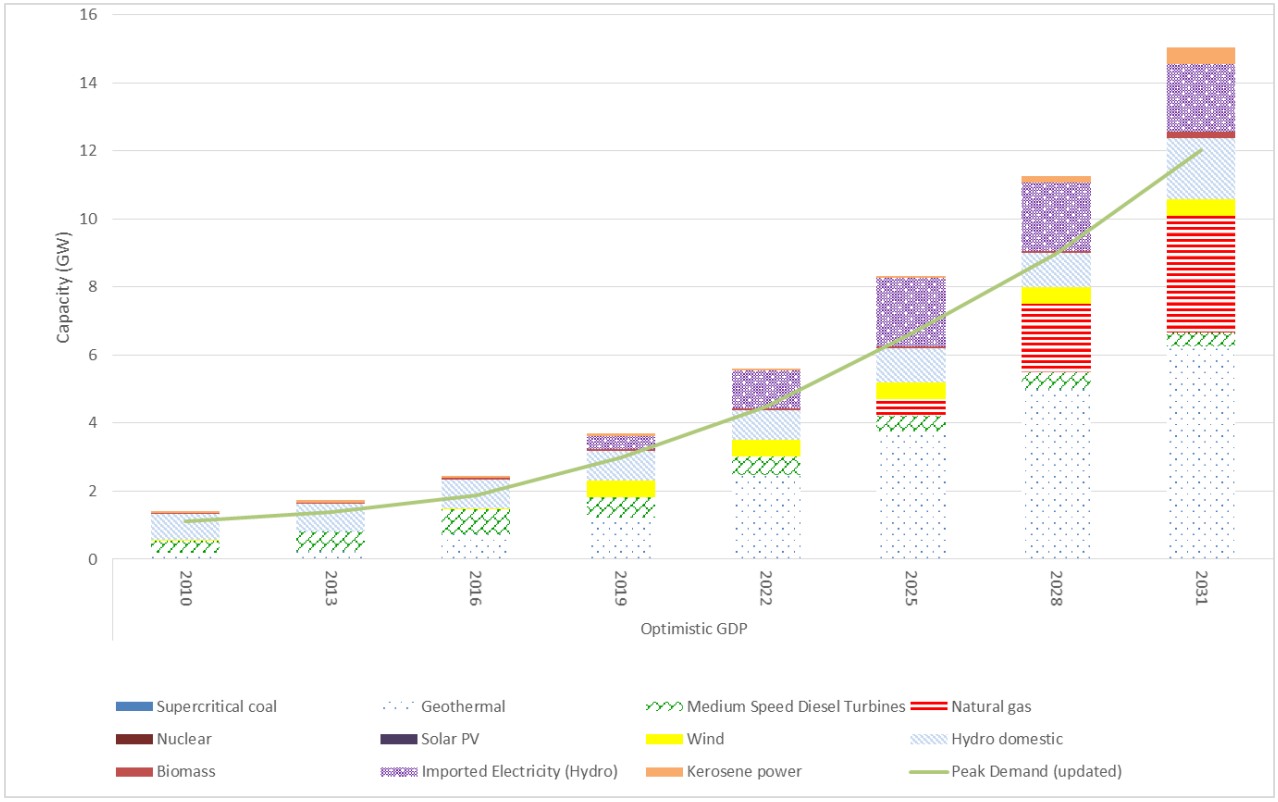


Figure 4-16: Capacity in the optimistic GDP case

The total capacity rises from 1.5 GW to 15.1 GW whilst the peak demand rises from 1.102 to 12.012 GW. It is observed that the model does not construct nuclear power even with the increased demand.

The electricity production across the study period is shown in Figure 4-17

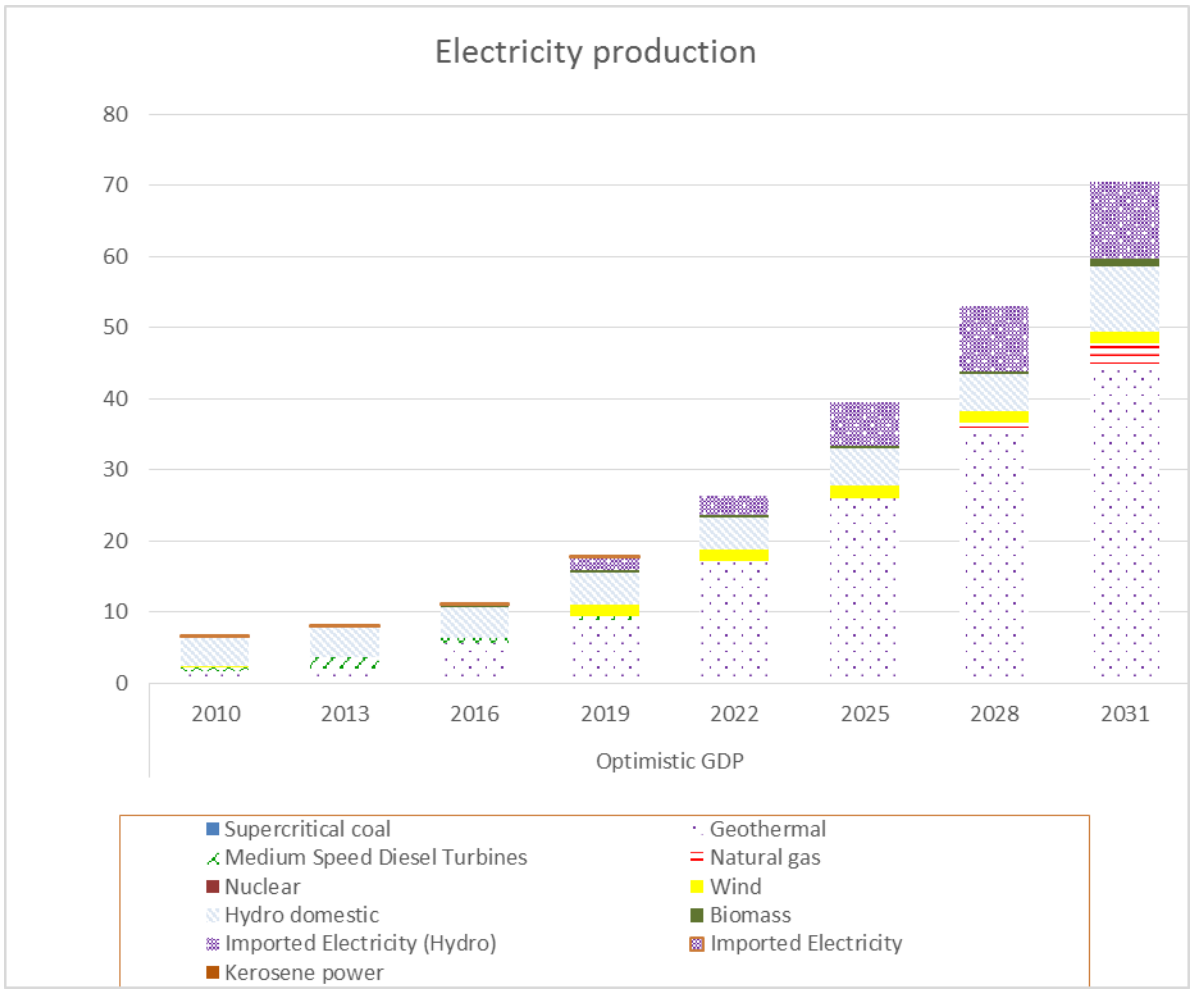


Figure 4-17: Electricity production in the optimistic GDP growth rate case

From Figure 4-17 above, it is observed that the geothermal power generates the largest share of electricity.

Figure 4-18 shows new build capacity in the optimistic GDP case

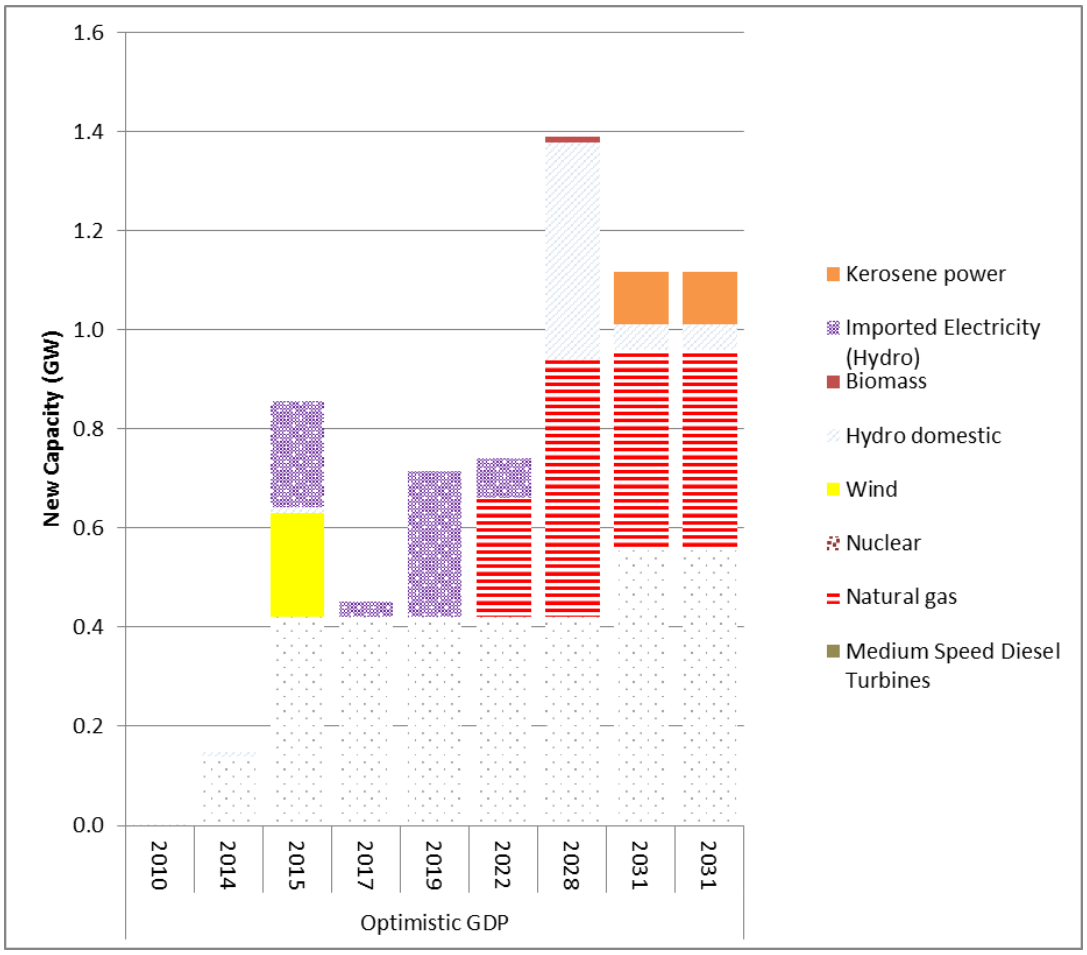


Figure 4-18: New Capacity Build in the Optimistic GDP case

Table 4-4 compares the results of this scenario to the LCPDP.

Table 4-4: Comparison between LCPDP and the Optimistic growth rate case

	CAPACITY SHARE			**ELECTRICITY GENERATION SHARE**		
Technology	**Opt-GDP**	**LCPDP 2010**	**LCPDP 2013**	**Opt-GDP**	**LCPDP 2010**	**LCPDP 2013**
Supercritical coal	0%	13%	17%	0%	18%	12%
Geothermal*	42%	26%	31%	63%	51%	54%
Medium Speed Diesel Turbines	3%	9%	2%	0%	2%	0%
Natural gas	23%	11%	16%	4%	2%	2%
Nuclear	0%	19%	8%	0%	0%	10%
Wind	3%	9%	11%	2%	8%	6%
Hydro domestic	12%	5%	4%	13%	7%	3%
Biomass	1%	0%	0%	2%	0%	0%
Imported Electricity (Hydro)	13%	9%	10%	15%	13%	12%
Kerosene power	3%	0%	0%	0%	0%	0%

**The assumed capacity factor of geothermal power was the same as that of the LCPDP*

As seen in Table 4-4 above, even with increased demand the model does not select nuclear power and super critical coal. Most of the baseload capacity comes from geothermal and most of the peaking capacity comes from natural gas. It should be reiterated that the capacity of natural gas was limited by using the annual new build constraint of 480MW per year obtained from the LCPDP 2013 as stated in Section 3.4.5.1

As discussed in section 2.6.1 the GDP growth rate used for the low load scenario of the LCPDP is 8% which is equal to that of the optimistic GDP growth rate. The LCPDP 2010 does not give a breakdown of total technology capacity that includes pre-existing capacity in the results of the low load scenario. It does however state that the total added capacity is 13.6GW. Notably, this capacity includes 3GW of nuclear power and 1.2 GW of supercritical coal. If the total added capacity is subtracted from the total capacity (which includes pre-existing capacity and total added capacity) of the LCPDP's base case, a capacity of 2.7GW is obtained. This capacity is higher than the pre-existing capacity of 1.5GW assumed for the LCPDP Replica and CCEP models. It is assumed that this discrepancy is caused by committed generation projects which are implemented between 2010 and 2014. This assumption is based on the fact that the addition of new plants in the results obtained from the LCPDP 2010 model begins in 2014 however the detailed expansion power plan which contains the names and capacities of power plants to be added, incorporates the addition of power plants between 2010 and 2014 (Energy Regulatory Commission, 2011).

If the pre-existing capacity obtained from the analysis of the LCPDP 2010 base case results is added to the total added capacity of low load scenario a total capacity of 16.28GW is obtained. This capacity is higher than the capacity of the optimistic GDP growth rate scenario by 8%. This variation can be attributed to the difference between the estimated and actual GDP growth rate between 2010 and 2015 as seen in In this case, the importance of regular updates of the capacity expansion plans is seen once again.

When comparing the total capacity of the LCPDP 2010's reference case to the optimistic GDP growth rate, it is observed that the LCPDP's electricity generation capacity is higher by 43%. This shows the effect of a 1% difference in GDP growth rate compounded from 2015 to 2031. Once again, the importance of a realistic range of estimation of GDP growth is seen. Nils Bohr the physicist, has been quoted severally as saying that prediction is difficult especially when it is about the future (Gigineishvili, Mauro & Wang, 2014). Further to this, the economist's ability to forecast economic growth for a period greater than a year has been said to be weak (Gigineishvili, Mauro & Wang, 2014) . The uncertainty of other factors affecting electricity demand also needs to be considered, for instance as used in this model; the price of electricity, the population

growth and the average income of the population. They key lesson to be leant here is that of flexibility. Capacity expansion plans should be flexible and able to respond to situations on the ground. One of the ways of dealing with uncertainty is to update the capacity expansion plans regularly. Contracts with construction companies should have clauses that allow for delayed construction of power plants if the demand is less than expected. To implement this effectively power plants could be built in smaller units to allow for delayed construction (IAEA, 1984).

Another aspect of flexibility is that between different scenarios. As was previously discussed in 2.4 the scenario method used in this thesis allows the planners to examine the consequences of different futures. Plans need to be implemented in such as a way as to allow movement from one future to another once it is clear that the situation on the ground is different from the plan being implemented (Gordon, 1984).

Other scenarios that were considered in the CCEP model are discussed below.

4.2.3 Dry year.

In this case a dry year was implemented every 5 years. Figure 4-19 shows a comparison between technology capacity obtained across the model horizon of the dry year case and the reference case.

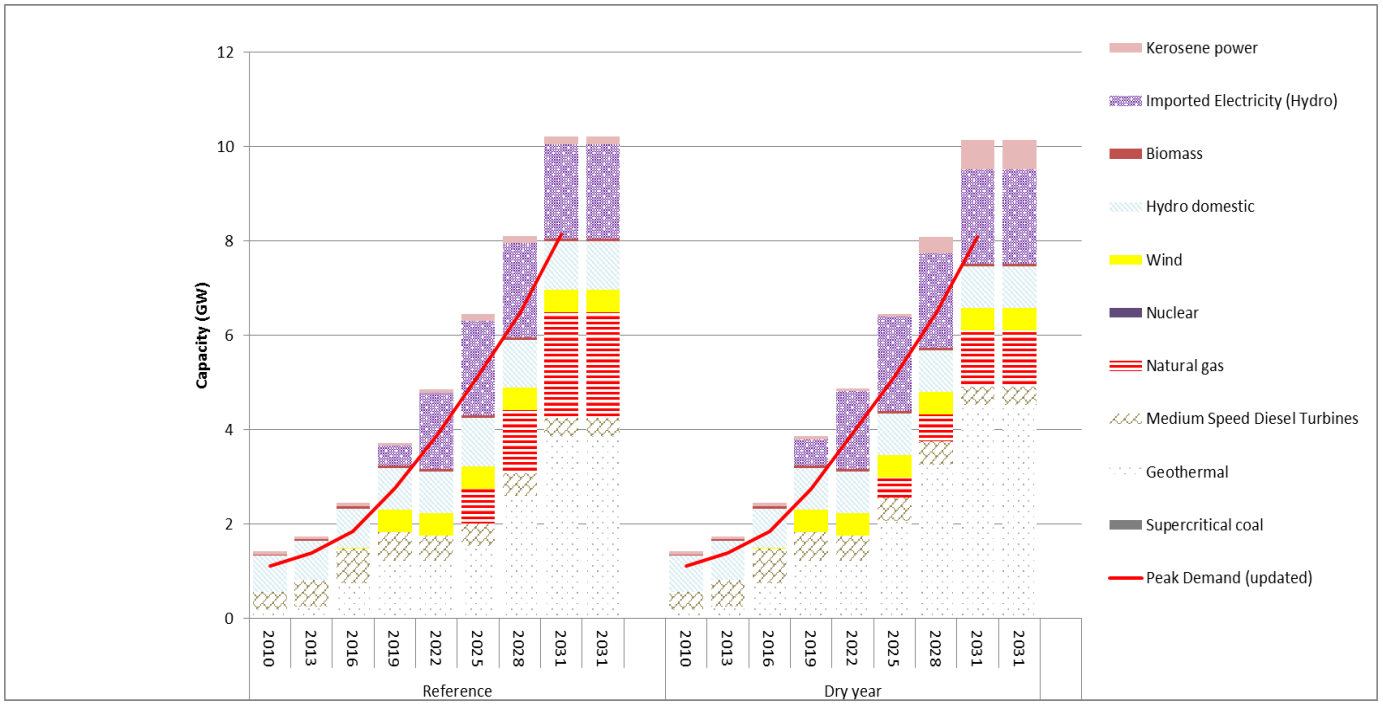


Figure 4-19: Comparison of Technology capacity in the dry year case and the reference case

From Figure 4-19, it is observed that the model does not construct nuclear power in the dry year case

Figure 4-20 shows a comparison between electricity production in the dry year case and the reference case:

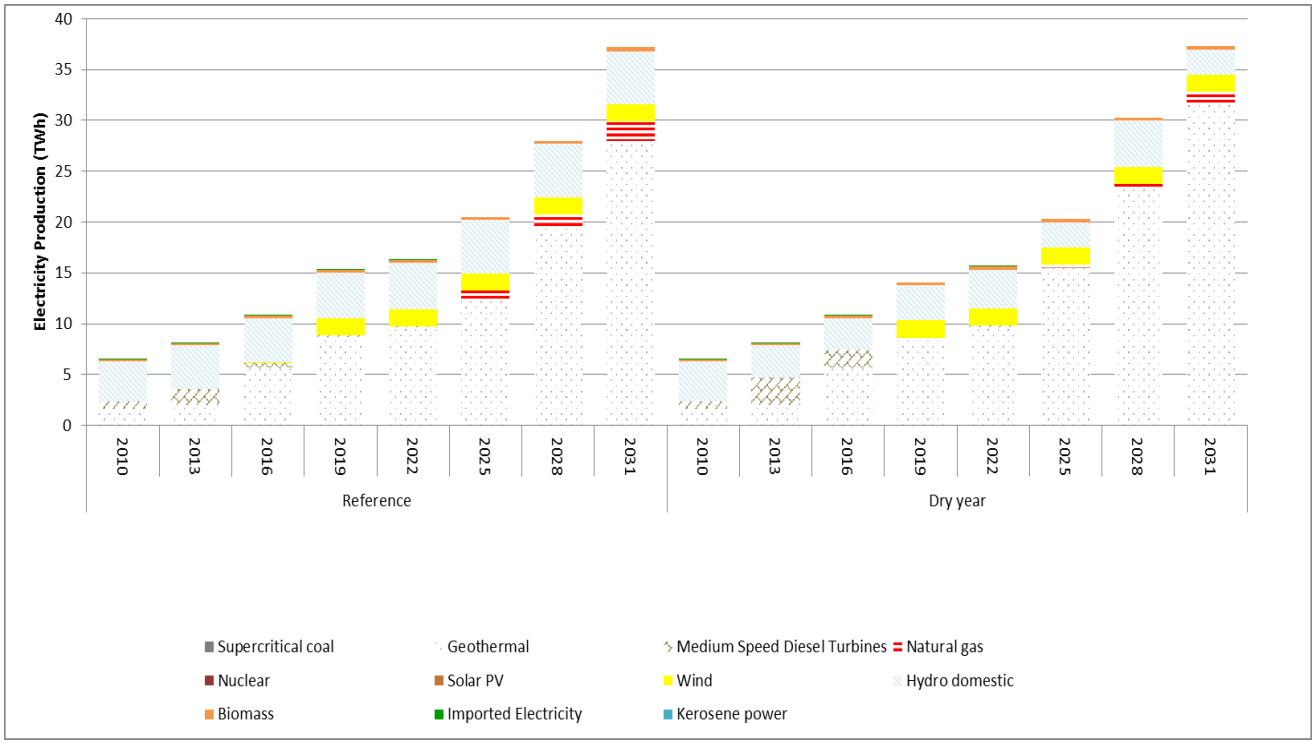


Figure 4-20: Comparison of Electricity production in the dry year case and the Reference case

Figure 4-21 shows that new capacity build for the dry year case

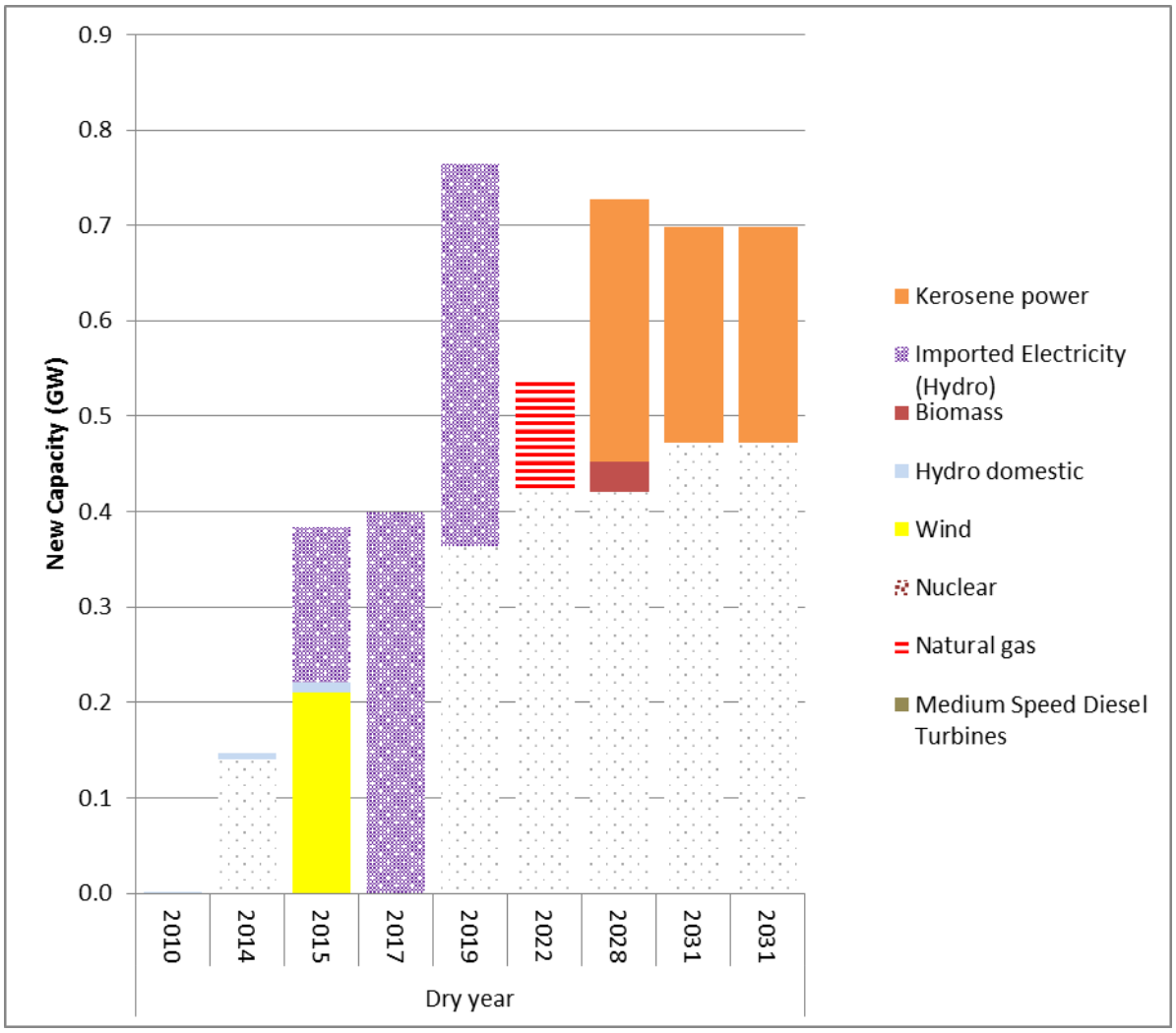


Figure 4-21: New Capacity Build in the Dry year case

Table 4-5 below gives a summary of the results obtained in this case and compares it to the reference case

Table 4-5: Summary of results for the dry year case in 2031

	CAPACITY SHARE		ELECTRICITY GENERATION SHARE	
Technology	**Dry year**	**CCEP**	**Dry year**	**CCEP**
Supercritical coal	0%	0%	0%	0%
Geothermal	44%	38%	66%	58%
Medium Speed Diesel Turbines	4%	4%	0%	0%
Natural gas	12%	22%	2%	4%
Nuclear	0%	0%	0%	0%
Wind	5%	5%	4%	4%
Hydro domestic	9%	10%	5%	11%
Biomass	1%	1%	1%	1%
Imported Electricity (Hydro)	20%	20%	22%	22%
Kerosene power	6%	1%	0%	0%

From the table above the following is observed:

- Capacity share of hydropower reduced by 4% and its share of electricity production reduced by 6%.
- The capacity share of natural gas decreases by 10% and its generation share by 2%.
- The capacity share of geothermal power increased by 6% and its generation share increased by 8%
- The capacity share of kerosene decreased by 5%

It is probable that kerosene provides spinning reserve. Spinning reserve as defined in section 3.3.3 is unused reserve which can be brought online when required by the system operator. In the previous cases i.e. the reference scenario and the optimistic GDP scenario, the model choses to build kerosene but does not use it to generate electricity. In the dry year case, the capacity share of kerosene reduces. The deduction that kerosene is used to provide spinning reserve is therefore based on the fact that when the capacities of the other generating technologies increase, the capacity of kerosene reduces. This is because the total electricity generation capacity provides the stipulated reserve margin therefore spinning reserve margin is not required

4.2.4 Nuclear case

In this case, a total of 1.2 GW of nuclear power is forced into the model in 2015 and 2016. The technology capacity obtained across the model horizon is shown in Figure 4-22 below.

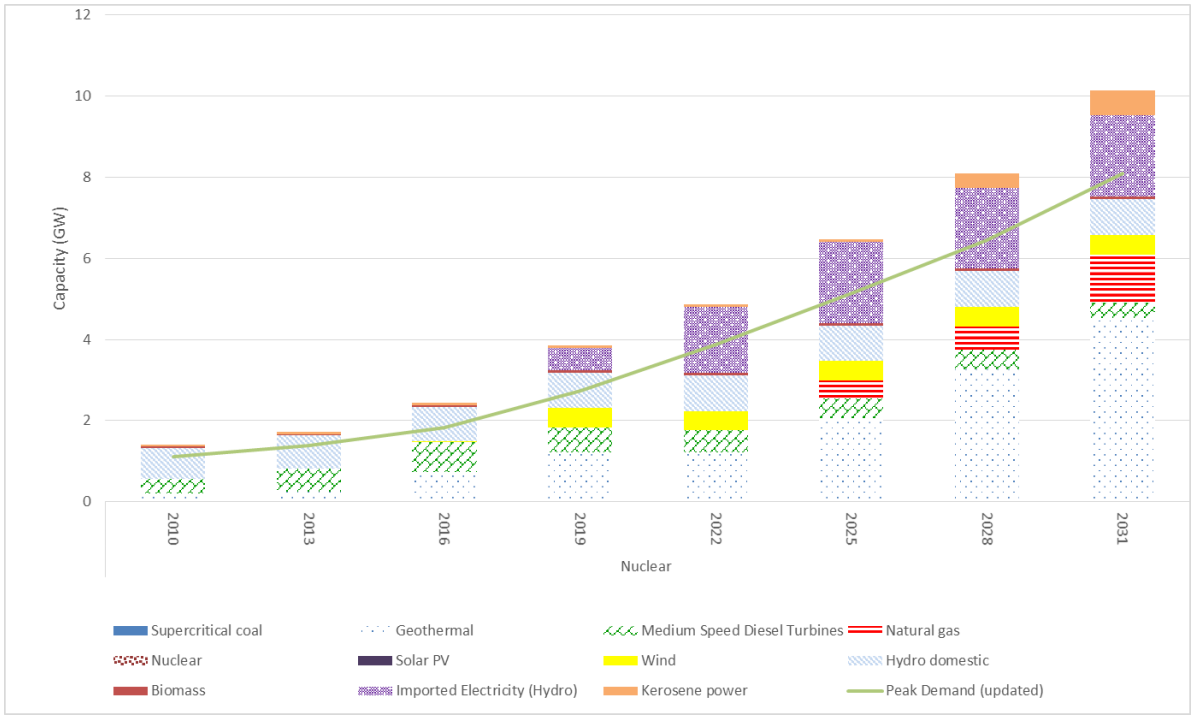


Figure 4-22: Technology capacity in nuclear case

The electricity production is shown in Figure 4-23 below

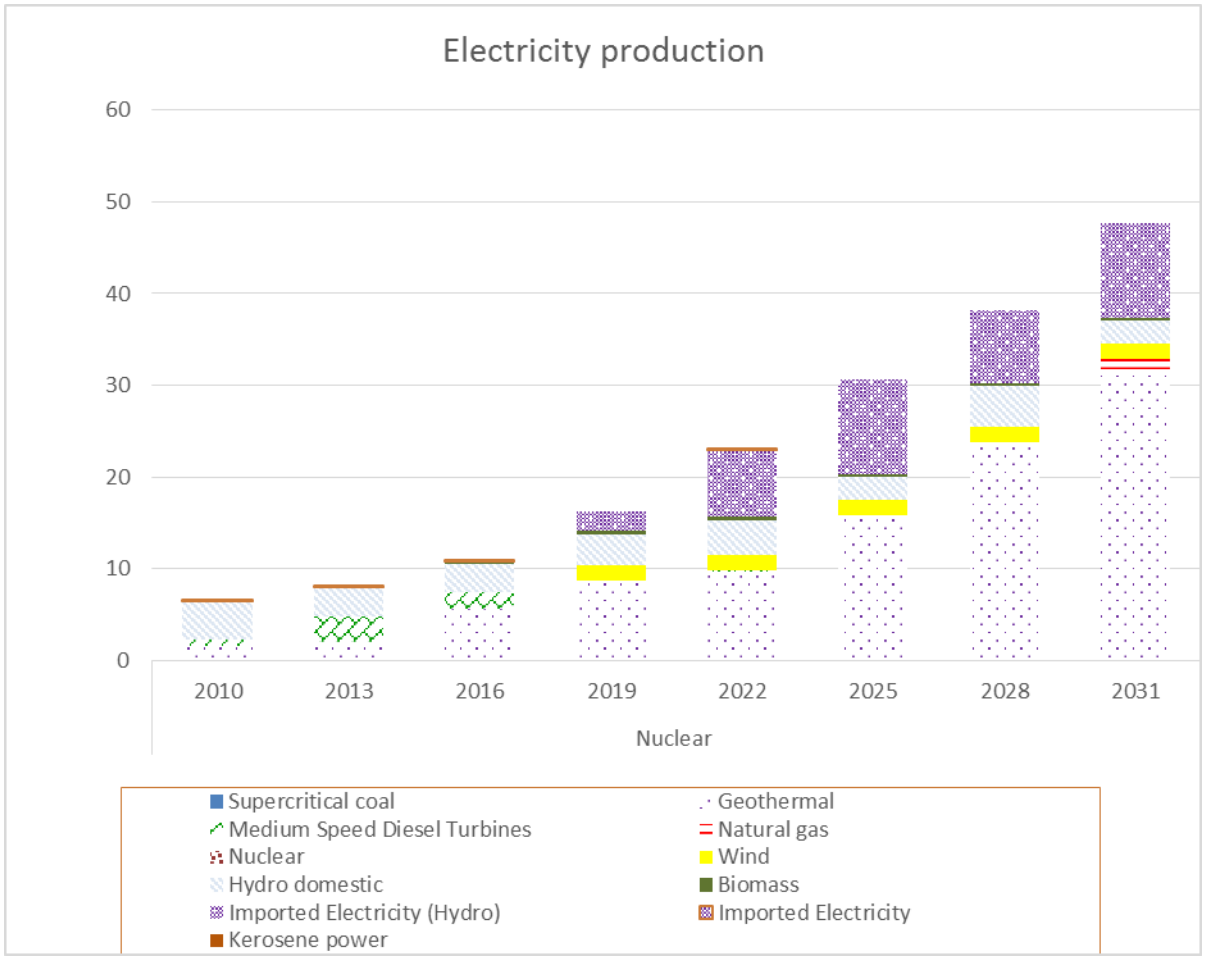


Figure 4-23: Electricity production in nuclear case

Figure 4-24 shows the new capacity build in the nuclear case

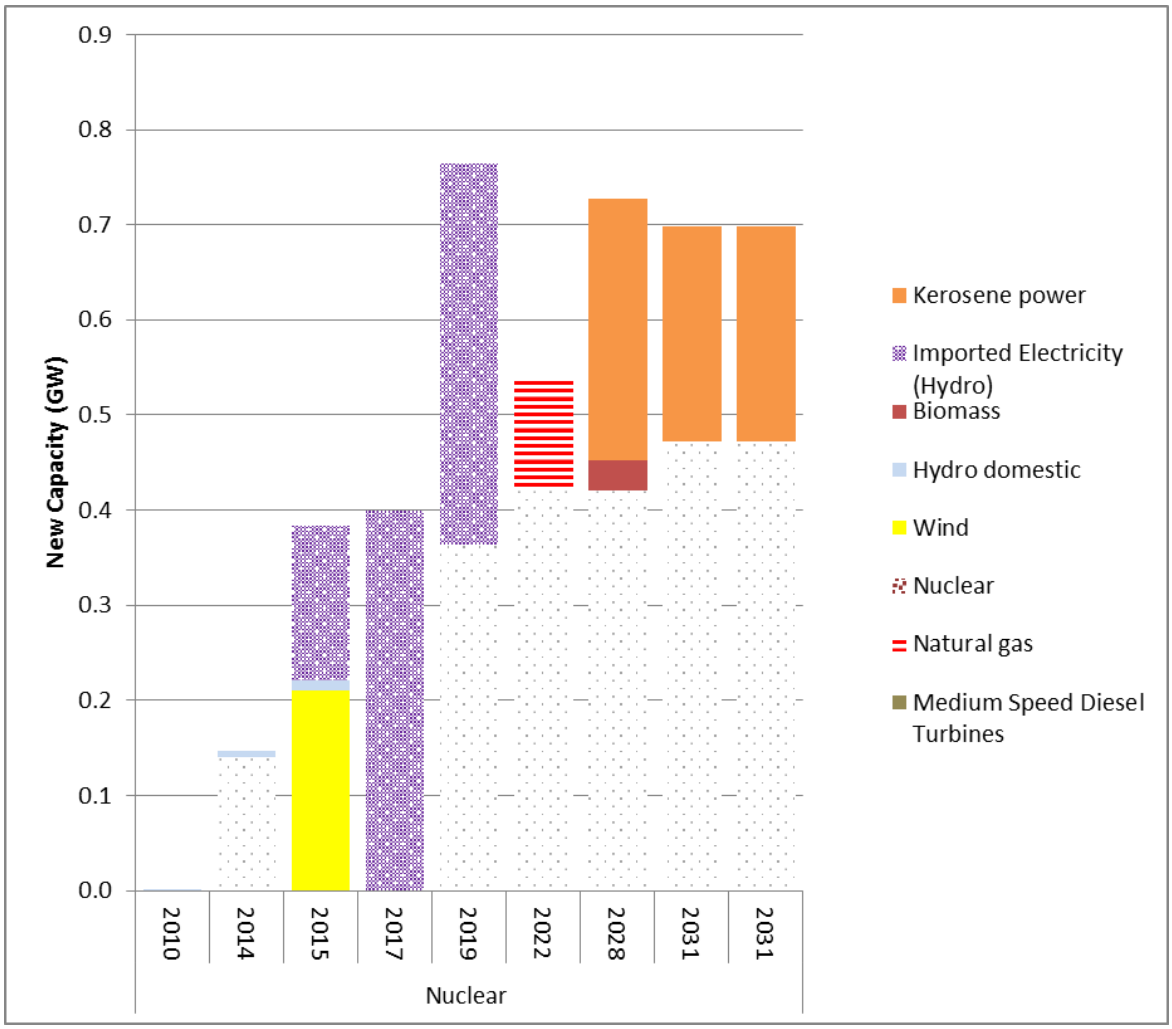


Figure 4-24: New Capacity Build Nuclear case

Table 4-6 below shows a summary of the results obtained above in comparison to the Reference case

Table 4-6: Comparison of the results between Nuclear and CCEP cases in 2031

	Capacity share in 2031		**Electricity Generation Share in 2031**	
Technology	**Nuclear**	**CCEP**	**Nuclear**	**CCEP**
Supercritical coal	0%	0%	0%	0%
Geothermal	27%	38%	40%	58%
Medium Speed Diesel Turbines	4%	4%	0%	0%
Natural gas	15%	22%	4%	4%
Nuclear	12%	0%	19%	0%
Wind	5%	5%	4%	4%
Hydro domestic	10%	10%	11%	11%
Biomass	0%	1%	0%	1%
Imported Electricity (Hydro)	20%	20%	23%	22%
Kerosene power	7%	1%	0%	0%

From the table above it is observed that:

- The capacity share of kerosene power decreases by 6%
- The capacity share of biomass decreases by 1%
- The capacity share of natural gas decreases by 7%
- The capacity share of geothermal decreases by 11% and decreases its generation share by 18%
- The electricity generation share of imported hydro-electricity decreases by 1%.

The capacity share of geothermal decreases because of the incorporation of nuclear as baseload power generation capacity. The capacity of kerosene increases because of the decrease in capacity other generation technologies such as geothermal and natural gas causing a need for spinning reserve.

4.1.1.2 Other scenarios

Other cases that were run include the solar scenario, coal scenario and the low cost coal scenario. All these scenarios were run with reference demand and optimistic GDP demand. The model only builds coal power plants when the low cost coal fuel and optimistic GDP scenarios are combined. In this case, the coal power plant is built after 2031 which is beyond the study period. Solar power is not selected in any case. This is attributed to solar power's lack of electricity generation in the peak time slice which occurs in the evening as seen in section 3.3.2.

4.2.5 Cost of Electricity generation

One of the models outputs is the cost of electricity generation. This cost includes the annualised investment cost as well as fixed and variable (including fuel) operating and maintenance costs. The graph in Figure 4-25 shows the cost of generating electricity in 2010 US cents from 2010 to 2031.

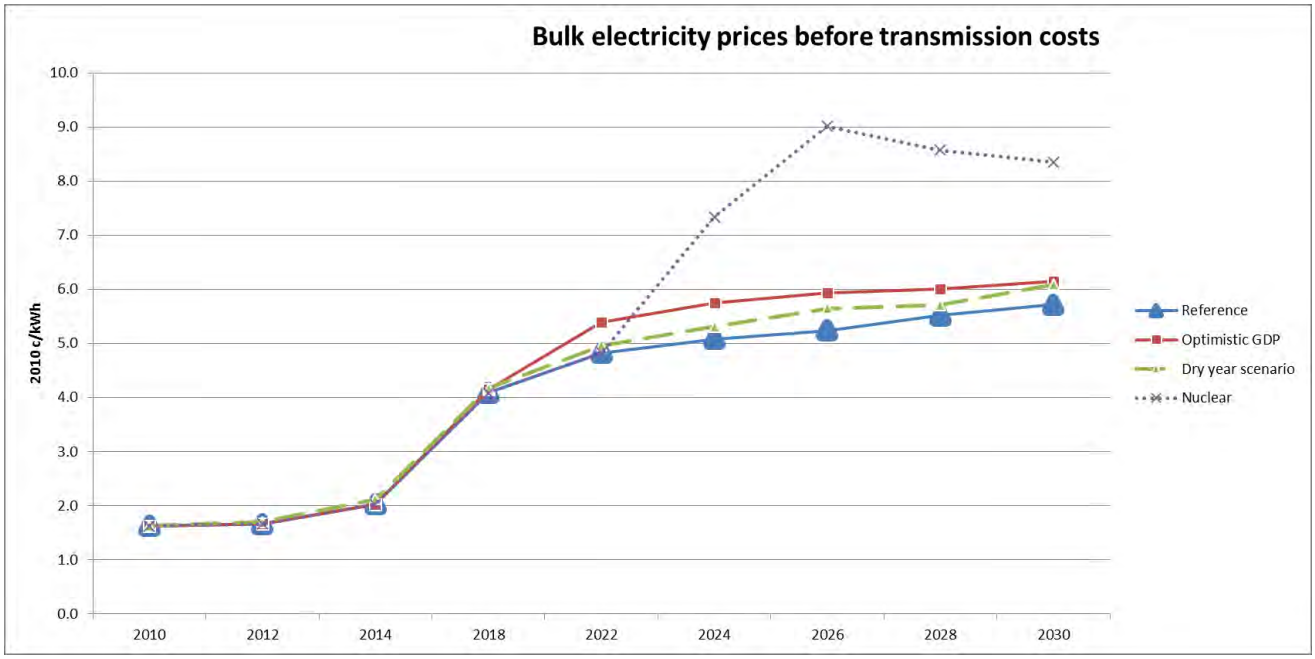


Figure 4-25: Cost of electricity generation

The graphs follow a similar pattern with the exception of the nuclear case, which becomes more expensive than the rest of the cases in 2022 the first nuclear power plant is forced to come online in 2022.

Analysing the results of the LCPDP Replica and CCEP, indicates a cost of electricity generation of US 1.6c/KWh in the reference year 2010. The LCPDP reports that the average tariff in 2010 was US 17c/KWh. One of the reasons for this large discrepancy is the components of the tariff obtained from the LCPDP. The tariff in Kenya is bundled and consists of the cost of electricity generation, transmission and distribution (Energy Regulatory Commission, 2011). The cost seen in Figure 4-25 only reflects the cost of electricity generation. Additionally, it is assumed that the cost indicated in the LCPDP includes the annualised cost of investment of the existing fleet which was not included in the TIMES models developed for this study.

4.1.1.3 Emissions

Kenya is located at the horn of Africa, which is highly vulnerable to climate change. This has elicited a commitment from the government to reduce carbon emissions by 30% by the year 2030. It is therefore in the country's best interest to develop its future

electricity generation capacity on a green path (Ministry of Environment and Natural Resources, 2015).

The graph in Figure 4-26 shows the carbon emissions by selected cases from 2010 to 2031

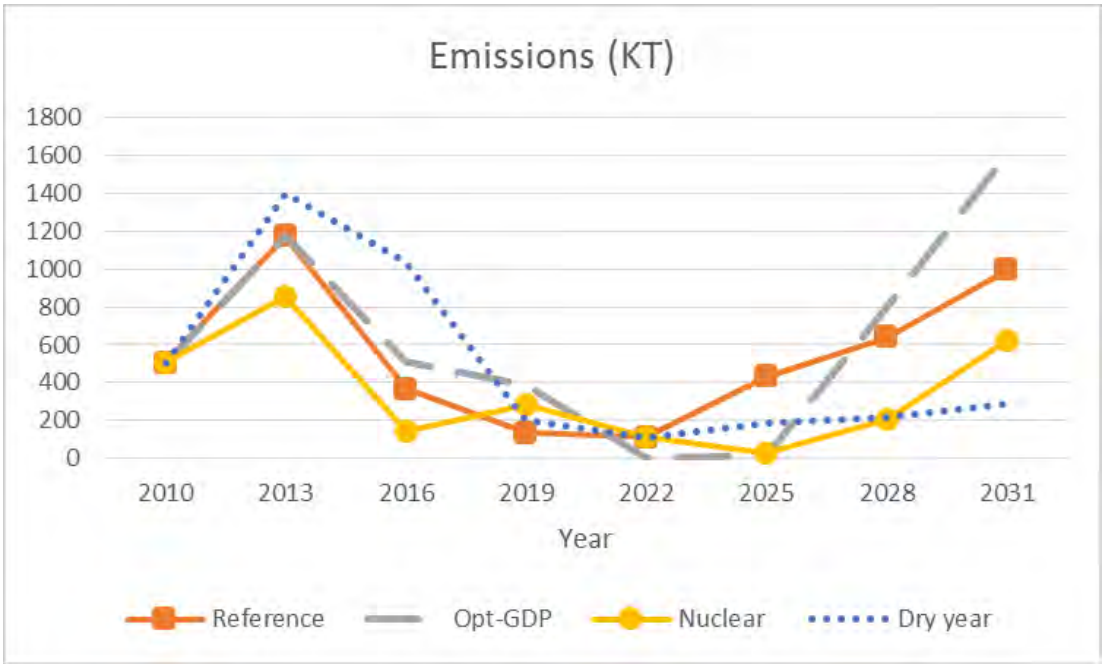


Figure 4-26: Emissions from 2010 to 2031

From the graph above, it is noted that with the exception of the years between 2022 and 2028 the emissions in the nuclear and the reference case are similar. The dry year case has higher emissions at the beginning of the study period because of increased generation from thermal sources to compensate for the loss of hydropower availability. The hydropower availability was reduced as shown in Table 3-17

After 2019, the emissions reduce and become lower than the reference and nuclear scenario. This is because the model chooses to increase the capacity of geothermal to compensate for the loss of hydropower as shown in Table 4-15

The optimistic GDP growth rate also has higher emissions than the reference and nuclear case at the beginning of the modelling horizon. This is because the model uses thermal generation to cater to the increased demand. In between 2022 and 2025 the emissions are observed to be zero because the model does not use any thermal

generation. From 2025, the emissions increase and by 2031 they are higher than all the cases. This is because the model begins to increase its use of natural gas. The table in Appendix 13 shows the quantity of electricity generation in TWh from the available technologies between 2019 and 2031.

4.3 The Necessity of Nuclear Power

From the above cases, it is observed that the model only selects nuclear power when it is forced to as was expected from the screening curves shown in Figure 3-19 and Figure 3-20. In the LCPDP replica whose demand is higher than the CCEP demand by a factor of 144% in 2031, the model begins to construct a 1GW nuclear power plant in 2031. This plant comes online in 2038 which is beyond the study period. From the graph in Figure 4-25, it is seen that forcing nuclear power into the energy mix causes an increased cost in electricity generation.

From the graph shown in Figure 4-26: Emissions from 2010 to 2031 the emissions produced by the case with nuclear power are similar to the emissions in the reference case. Nuclear power might therefore not be necessary as the demand could be met without its utilization. Furthermore, its incorporation into the technology mix only serves to increase the cost of electricity without any benefits, such as the reduction in emissions.

5 RECOMMENDATIONS LIMITATIONS AND CONCLUSIONS

One of the aims of this thesis was to establish the necessity of nuclear power in Kenya. This was approached from two perspectives, the LCPDP 2010 perspective and the CCEP perspective. The LCPDP 2010 states that nuclear power is included in Kenya's least cost electricity plan. A model referred to as the LCPDP replica was therefore built in an attempt to establish the veracity of this statement. Two scenarios of the same model were built; one with the last result year being 2031 and the other with the last result year being 2040. This was done because it was unclear whether the LCPDP had factored in end effects. From the LCPDP replica the following conclusions were drawn:

- It appears that the projected electricity demand could have been met without the use of nuclear power, given the assumptions made.
- The most similar case to the LCPDP 2010 occurred where the model was forced to build nuclear power in the scenario with the last result year as 2031. This implies that possibly nuclear capacity was forced into the model and also that possibly end effects were not considered.

The second approach created a model that would utilise recent data and assumptions. This model was termed the Current Capacity Expansion Plan. In addition to the recent data and assumptions, its reference case utilised a demand forecast that assumed a GDP growth rate of 6% instead of 9% as seen in the LCPDP while the optimistic scenario utilised a GDP growth rate of 8%. From this model the following conclusions were drawn:

- The electricity demand in both the reference case and the optimistic GDP growth rate can be met without the use of nuclear power
- The highest cost of electricity generation occurs in the case with nuclear power. By 2031, the cost of nuclear power is 8.4US Cents/KWh while the reference cost is 6.1 US Cents/KWh. This implies that nuclear power is not an economic alternative for Kenya's least cost generation mix.
- The emissions in the case with the nuclear power are similar to the reference case. This shows that nuclear power does not necessarily offer the added benefit of reduced emissions

5.1 Limitations

The TIMES modelling framework has some limitations in the level of detail to which the real world can be represented. One of the major limitations is that dispatch within TIMES is done in an aggregate manner. This was further enhanced because the time slices used in both the LCPDP replica and the CCEP were few in number. This reduces the ability of the model to account for varying electricity demand and technology availability (Kannan & Turton, 2013).

The costs used in both the LCPDP Replica and the CCEP did not include regulation costs, transmission and distribution costs. Additionally, the cost used for nuclear power is lower than that used in some countries such as South Africa's IRP update (IRP, 2013).

Time slice representation was identical in all the days of the modelling horizon. The time slices used in this thesis had the aim of capturing the peak demand. This caused peak demand to be experienced in all the days of the modelling horizon. This is not realistic as electricity consumption and thereby demand on some days especially weekends and public holidays will be lower.

5.2 Recommendations

Further research on the following areas can contribute to enhancing the results obtained in this thesis. In the area of renewables, additional effort should be put in quantifying the available wind and biomass resource to enable more accurate resource constraints to put in place. Solar PV should be explored further to obtain a better understanding as to why it wasn't selected as a capacity expansion option in this thesis. Additionally, other renewable options such as Concentrated Solar Power (CSP) should also be explored as capacity expansion options.

Supply curves should be developed to more realistically represent the capital costs of technologies used for electricity generation especially geothermal power as Kenya has a

large capacity available and the model seems to rely on it for most of its baseload power. Additionally, the likely fuel costs of locally available like coal should be determined to enable a more realistic levelised cost in for Kenyan expansion plan models.

Kenya aims to reduce its greenhouse gas emissions by 30% in 2030 relative to the business as usual scenario (Ministry of Environment and Natural Resources, 2013). Research on the impact of this constraint on Kenya's future generation mix should be carried out.

On the demand side more data should be gathered to enable a detailed representation that can respond to technology change and fuel switching. The data gathered should include the major electricity consumers and the factors that influence their consumption. This will enable the demand to be forecasted using the end uses approach which is in general more reliable than the econometric method as it incorporates features such as increase in efficiency. Furthermore the timings of peaks and troughs for different consumer categories should be observed and recorded so as to enable reliable load duration curves to be used for capacity expansion planning. As stated in the LCPDP the assumption that the peaks occur at the same time causes an over estimation of the peak demand (Energy Regulatory Commission, 2011).

From the results of this thesis it is strongly recommended that the procurement of nuclear power should be reviewed as it bears high cost implications for Kenya. The year on year growth of the demand used in the LCPDP was 9% which was very high. Even with this high demand growth, the model started nuclear power construction in 2031 not 2022 as stated in the LCPDP documentation.

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Appendix 1: LCPDP Demand Forecast (GWh)

Year	Low voltage	Medium Voltage	High Voltage
2010	2 486	1008	2 133
2011	2 849	1067	2 259
2012	3 169	1878	2 424
2013	3 513	2777	2 639
2014	3 926	3861	2 917
2015	4 393	5702	3 278
2016	4 908	6743	3 704
2017	5 467	8161	4 185
2018	6 075	9522	4 729
2019	6 734	11059	5 343
2020	7 449	12795	6 038
2021	8 229	14758	6 822
2022	9 076	16676	7 709
2023	9 995	18843	8 711
2024	10 994	21292	9 843
2025	12 079	24059	11 122
2026	13 258	27185	12 568
2027	14 541	30718	14 201
2028	15 937	34711	16 047
2029	17 458	39222	18 132
2030	19 118	44319	20 489
2031	21 254	50078	23051

Appendix 2: Costs in 2010 USD

	Geothermal	Nuclear	Coal	GT-KERO	GT- N.GAS	MSD	Import	Mutonga	LGFalls	Wind
Configuration (n x MW)	**1 x 140**	**1 X 1000**	**1 X 300**	**1 x 180**	**1 x 180**	**1 x 160**	**1000**	**60**	**140**	**300**
Total Capacity (MW)	140	1000	300	180	180	160	1000	60	140	300
Fixed Cost	579.69	5,111.18	715.82	144.79	144.79	232.51	484.76	312.95	613.00	740.02
Capital ($ x 10^6)	511	4055	631	135	135	218	455	259	507	690
Capital ($/kW)	3650	4055	2104	750	750	1364	455	4314	3621	2300
IDC Factor	1.1344	1.2605	1.1341	1.0725	1.0725	1.0654	1.0654	1.2092	1.2092	1.0725
Annuity Factor (or C.R.F.)	0.0937	0.0839	0.0937	0.1019	0.1019	0.1019	0.0937	0.0817	0.0817	0.0937
Interim Replacement	0.921%	0.68%	0.921%	0.35%	0.35%	0.35%	0.35%	1.03%	0.87%	0.64%
Fixed Annual Capital ($/kW/yr)	426.0	463.6	245.5	84.7	84.7	153.1	47.1	480.3	396.1	246.9
Fixed O&M Costs ($/kW/yr)	56.0	90.0	69	11.8	11.8	62.5	30.0	21.3	19.8	28.1
Total Fixed Annual Cost ($/kW/	482	554	314	97	97	216	15	502	416	275
Total Outage Rate	0.068	0.150	0.267	0.078	0.078	0.098	0.150	0.0969	0.0969	0.133
Outage Adjustment	1.073	1.177	1.364	1.085	1.085	1.108	1.176	1.107	1.107	1.153
Annual Fixed Cost ($/kW.yr	**517**	**652**	**429**	**105**	**105**	**239**	**91**	**555**	**461**	**317**
Annual Fixed Cost ($/kWh)	**0.0590**	**0.0744**	**0.0490**	**0.0120**	**0.0120**	**0.0273**	**0.0104**	**0.0634**	**0.0526**	**0.0362**
Variable Cost										
Fuel Price ($/GJ)	-	-	4.557	19.37	9.11	11.08	-	-	-	-
Heat Rate (kJ/kWh)	-	-	9914	11,440	9,504	9,336	-	-	-	-
Fuel Cost ($/kWh)	-	0.0093	0.0452	0.2216	0.0866	0.1035	-	-	-	-
CO_2 Tax ($/kWh)	-	-	0.0109	0.0089	0.0040	0.0069	-	-	-	-
Variable O&M ($/kWh)	0.00557	0.0049	0.0043	0.0120	0.0010	0.0090	0.0500	0.0053	0.0053	0.0010
Total Variable ($/kWh)	**0.00557**	**0.0142**	**0.0603**	**0.2425**	**0.0916**	**0.1194**	**0.0500**	**0.0053**	**0.0053**	**0.0010**
Total Variable ($/kW.yr)	**49**	**125**	**528**	**2124**	**802**	**1046**	**438**	**47**	**47**	**9**

Appendix 3: Utility Scale solar Power Capacity Factors

Horizontal												
Average day and night capacity factors							Day capacity factors					
Month	**Garissa**	**Isiolo**	**Lodwar**	**Kisumu**	**Monthly Average**	**Season Average**	**Garissa**	**Isiolo**	**Lodwar**	**Kisumu**	**Monthly Average**	**Season Average**
January	0.19	0.20	0.21	0.21	0.20	0.20	0.36	0.39	0.39	0.40	0.39	0.36
February	0.18	0.19	0.19	0.20	0.19		0.34	0.37	0.37	0.38	0.36	
March	0.22	0.21	0.22	0.23	0.22		0.41	0.41	0.42	0.43	0.42	
April	0.19	0.19	0.19	0.19	0.19	0.20	0.37	0.37	0.37	0.37	0.37	0.38
May	0.18	0.21	0.20	0.19	0.20		0.35	0.40	0.38	0.37	0.38	
June	0.17	0.20	0.19	0.18	0.18		0.32	0.38	0.37	0.34	0.35	
July	0.17	0.20	0.20	0.18	0.19	0.20	0.33	0.38	0.38	0.35	0.36	0.38
August	0.18	0.21	0.21	0.19	0.20		0.35	0.41	0.39	0.37	0.38	
September	0.19	0.22	0.21	0.20	0.21		0.37	0.43	0.40	0.38	0.39	
October	0.21	0.21	0.21	0.20	0.21	0.18	0.39	0.41	0.40	0.39	0.40	0.35
November	0.18	0.18	0.19	0.19	0.18		0.35	0.34	0.36	0.36	0.35	
December	0.19	0.19	0.20	0.20	0.19		0.36	0.36	0.38	0.39	0.37	
Inclined												
Month	**Garissa**	**Isiolo**	**Lodwar**	**Kisumu**	**Monthly Average**	**Season Average**	**Garissa**	**Isiolo**	**Lodwar**	**Kisumu**	**Monthly Average**	**Season Average**
January	0.24	0.27	0.27	0.28	0.27	0.25	0.47	0.51	0.52	0.54	0.51	0.48
February	0.23	0.26	0.25	0.26	0.25		0.45	0.49	0.48	0.50	0.48	
March	0.28	0.28	0.28	0.30	0.28		0.54	0.53	0.54	0.57	0.55	
April	0.26	0.26	0.25	0.26	0.26	0.26	0.49	0.50	0.48	0.50	0.49	0.51
May	0.25	0.29	0.26	0.26	0.26		0.47	0.55	0.51	0.50	0.51	
June	0.22	0.27	0.25	0.25	0.25		0.42	0.52	0.49	0.47	0.47	
July	0.23	0.27	0.26	0.25	0.25	0.27	0.44	0.53	0.50	0.48	0.49	0.51
August	0.24	0.29	0.28	0.26	0.27		0.46	0.56	0.53	0.50	0.51	
September	0.26	0.30	0.28	0.26	0.27		0.49	0.57	0.54	0.50	0.53	
October	0.27	0.28	0.27	0.27	0.27	0.24	0.51	0.53	0.52	0.51	0.52	0.47
November	0.24	0.22	0.24	0.24	0.24		0.46	0.43	0.47	0.47	0.46	
December	0.24	0.24	0.26	0.27	0.25		0.46	0.46	0.50	0.51	0.48	

Appendix 4: Solar Power Capacity Factors Residential and Commercial Scale

Average day and night Capacity Factors									Day Capacity Factors							
Month	**Garissa**	**Lodwar**	**Isiolo**	**Nairobi**	**Kisumu**	**Mombasa**	**Month**	**Season**	**Garissa**	**Lodwar**	**Isiolo**	**Nairobi**	**Kisumu**	**Mombasa**	**Month**	**Season**
Jan	0.18	0.19	0.19	0.20	0.19	0.19	0.19	0.19	0.31	0.34	0.36	0.38	0.37	0.37	0.36	0.36
Feb	0.17	0.18	0.18	0.18	0.18	0.18	0.18		0.30	0.32	0.34	0.35	0.35	0.34	0.33	
Mar	0.20	0.20	0.20	0.21	0.21	0.22	0.21		0.36	0.39	0.38	0.41	0.41	0.42	0.39	
Apr	0.18	0.18	0.18	0.17	0.18	0.17	0.18	0.17	0.32	0.35	0.35	0.32	0.35	0.33	0.34	0.32
May	0.18	0.19	0.20	0.15	0.18	0.15	0.17		0.31	0.34	0.39	0.29	0.35	0.28	0.33	
Jun	0.16	0.18	0.19	0.13	0.17	0.14	0.16		0.28	0.30	0.36	0.25	0.33	0.27	0.30	
Jul	0.17	0.19	0.19	0.13	0.18	0.15	0.17	0.18	0.29	0.32	0.37	0.24	0.34	0.28	0.31	0.33
Aug	0.17	0.20	0.20	0.13	0.18	0.17	0.18		0.31	0.33	0.39	0.25	0.35	0.33	0.32	
Sept	0.18	0.20	0.21	0.16	0.18	0.19	0.19		0.33	0.35	0.40	0.31	0.35	0.37	0.35	
Oct	0.19	0.19	0.20	0.18	0.19	0.20	0.19	0.18	0.34	0.37	0.38	0.34	0.37	0.39	0.36	0.35
Nov	0.17	0.18	0.16	0.16	0.17	0.19	0.17		0.31	0.33	0.31	0.31	0.33	0.37	0.33	
Dec	0.17	0.18	0.18	0.18	0.19	0.19	0.18		0.31	0.33	0.34	0.35	0.36	0.37	0.34	

Appendix 5: Capital Overnight Costs for Solar Power in 2010 US$ (IEA, 2014)

	Utility capital cost USD/KW	
Year	Optimistic	Reference
2010	3,000.00	3,000.00
2015	2,200.00	2,800.00
2020	1,500.00	2,600.00
2025	2,000.00	2,400.00
2030	1,000.00	2,200.00

	Residential and commercial capital cost USD/KW	
Year	Optimistic	Reference
2010	4,790.00	4,790.00
2015	2,200.00	3,840.00
2020	1,800.00	3,340.00
2025	1,600.00	3,090.00
2030	1,500.00	2,960.00

Appendix 6: Residential forecast 6% GDP growth (GWh)

Year	Without Suppressed demand	With Suppressed Demand
2010	1712	1712
2011	1872	1872
2012	1991	1991
2013	2161	2161
2014	2331	2331
2015	2551	2551
2016	2792	2792
2017	3056	3056
2018	3520	3344
2019	4027	3660
2020	4583	4006
2021	5191	4385
2022	5681	4799
2023	6218	5252
2024	6806	5748
2025	7449	6291
2026	8152	6886
2027	8922	7536
2028	9765	8248
2029	10688	9027
2030	11697	9880
2031	12802	10813
2032	13514	11414
2033	14265	12049
2034	15058	12719
2035	15895	13425
2036	16778	14172
2037	17711	14959
2038	18695	15791
2039	19735	16669
2040	20832	17595

Appendix 7: Commercial Industrial Forecast 6% GDP growth (GWh)

Year	With flagship demand	Without Flagship demand
2010	4027	4027
2011	4355	4355
2012	4312	4312
2013	4741	4741
2014	5357	5357
2015	5728	5728
2016	6126	6671.651
2017	6551	7975.536
2018	7005	9369.886
2019	7491	10418.98
2020	8011	11540.85
2021	8567	12740.57
2022	9161	14636.52
2023	9797	17277.02
2024	10476	18475.71
2025	11203	19769.01
2026	11981	21152.84
2027	12812	22633.54
2028	13701	24217.89
2029	14651	25913.14
2030	15668	27727.06
2031	16755	29667.95
2032	17529	31151.35
2033	18338	32708.92
2034	19185	34344.36
2035	20071	36061.58
2036	20998	37864.66
2037	21968	39757.89
2038	22983	41745.79
2039	24044	43833.08
2040	25155	46024.73

Appendix 8: Residential forecast 8% GDP growth (GWh)

Year	With Suppressed Demand	Without Suppressed
2010	1712	1712
2011	1872	1872
2012	1991	1991
2013	2161	2161
2014	2331	2331
2015	2551	2551
2016	2893	2893
2017	3281	3281
2018	3895	3720
2019	4593	4219
2020	5383	4784
2021	6280	5425
2022	7122	6153
2023	8076	6977
2024	9159	7912
2025	10386	8973
2026	11778	10175
2027	13356	11539
2028	15146	13085
2029	17176	14839
2030	19478	16827
2031	21319	18417
2032	23332	20157
2033	25537	22061
2034	27949	24145
2035	30589	26426
2036	33479	28923
2037	36642	31655
2038	40103	34645
2039	43892	37918
2040	48038	41500

Appendix 9: Commercial-Industrial 8% GDP growth (GWh)

Year	Without Flagship demand	With flagship demand
2010	4201	4201
2011	4498	4498
2012	4735	4735
2013	5046	5046
2014	5357	5357
2015	5728	5728
2016	6259	6805
2017	6839	8276
2018	7472	9884
2019	8165	11199
2020	8921	12635
2021	9747	14205
2022	10650	16533
2023	11637	19689
2024	12715	23113
2025	13893	25255
2026	15180	27594
2027	16586	30151
2028	18123	32944
2029	19802	35996
2030	21637	39331
2031	23641	42974
2032	25281	45956
2033	27035	49144
2034	28911	52554
2035	30917	56200
2036	33062	60099
2037	35356	64269
2038	37809	68728
2039	40432	73497
2040	43237	78596

Appendix 10: Street Lights (GWh)

Year	Demand
2010	21
2011	18
2012	21
2013	17
2014	23
2015	25
2016	27
2017	29
2018	32
2019	34
2020	37
2021	40
2022	43
2023	46
2024	49
2025	52
2026	56
2027	59
2028	63
2029	67
2030	71
2031	75
2032	79
2033	84
2034	88
2035	93
2036	98
2037	103
2038	108
2039	113
2040	119

Appendix 11: Committed Generation Projects LCPDP 2010

Committed Generation projects LCPDP

Project	Type	Capacity (MW)
Wellhead Units	Geothermal	70
Eburru	Geothermal	2.2
Sangoro	Hydro	21
Ngong 1 ph2 and Ngong 2 wind	Wind	20.4
Olkaria IV	Geothermal	140
Olkaria 1 –Life Extension	Geothermal	140
Kindaruma 3rd unit	Hydro	32
Muhoroni	MSD	80
Mombasa Coal	Coal	300
		806
Athi River 1	MSD	81
Athi River 2	MSD	84
Thika 1	MSD	87
Garissa	MSD	10
Lake Turkana	Wind	300
Osiwo wind	Wind	50
Aeolus wind	Wind	60
ARM Coal	Coal	60
Orpower4	Geothermal	52
Small Hydros	hydro	25
Ethiopia	hydro	200

Committed Generation projects CCEP

Project Na+A4+A3:D33	Type	Capacity (MW)
Olkaria IV Unit 2	Geothermal	70
Olkaria I Unit 4&5	Geothermal	140
Olkaria Wellhead	Geothermal	15
Ngong I Phase 2	Wind	6.8
Ngong II Phase 1	Wind	13.6
Olkaria Wellhead	Geothermal	35
Ngong 1 Phase III	Wind	10
Orpower 4	Geothermal	50
AGIL 1	Geothermal	70
AGIL 2	Geothermal	70
Marine Power (AKIIRA)	Geothermal	70
Kinangop /Aeolus	Wind	60
Lake Turkana Wind Power	Wind	150
Lake Turkana Wind Power	Wind	150
Prunus	Wind	50
Kipeto	Wind	100
Gulf Power	Thermal	80
Kitengela MSD (Triump)	Thermal	83
Biojoule	Biogas	2.4
Cummins	Biomass	10
Kwale Co- Generation	Cogeneration	10
KTDA Chania	Hydro	1
KTDA Itare	Hydro	1.3
KTDA Metumi	Hydro	5.6
KTDA Maara	Hydro	2
KTDA L. Nyamindi	Hydro	1.8
KTDA Iraru	Hydro	1.5
KTDA Kipsonoi	Hydro	3.6
KTDA Gucha	Hydro	3.6
KTDA Gura	Hydro	5.8
Mt. Kenya CBO	Hydro	0.6
Klean Energy	Hydro	6.0
Genpro- Teremi Falls	Hydro	5.0
Tindinyo	Hydro	1.5
Global	Hydro	11
Oldanyat	Wind	10
Ormat Menengai	Geothermal	32
Quantum Menengai	Geothermal	35
Sosian Menengai	Geothermal	35
IMPORTS	Hydro	400
Total (MW)		**1,808**

Appendix 12: Electricity generation in TWh from 2019 to 2031

	Reference case (TWh)					Opt-GDP (TWh)					Dry year (TWh)					Nuclear (TWh)				
Technology	2019	2022	2025	2028	2031	2019	2022	2025	2028	2031	2019	2022	2025	2028	2031	2019	2022	2025	2028	2031
coal	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0
Geothermal	8.7	9.6	12.4	19.6	28.0	8.87	17.15	26.07	35.10	44.73	8.64	9.64	15.47	23.23	31.66	8.6	9.6	9.3	10.7	19.1
MSD	0.2	0.2	0.0	0.0	0.0	0.53	0.00	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.1	0.2	0.0	0.0	0.0
Natural gas	0.0	0.0	0.8	1.2	1.9	0.00	0.00	0.03	1.50	3.00	0.00	0.00	0.36	0.54	1.18	0.0	0.0	0.5	1.2	1.8
Nuclear	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	4.5	8.9	8.9
Wind	1.7	1.7	1.7	1.7	1.7	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.7	1.7	1.7	1.7	1.7
Hydro domestic	4.5	4.5	5.2	5.2	5.2	4.47	4.52	5.24	5.24	9.23	3.46	3.84	2.46	4.52	2.48	4.5	4.5	5.2	5.2	5.2
Biomass	0.3	0.3	0.3	0.3	0.4	0.31	0.31	0.31	0.31	1.07	0.31	0.31	0.31	0.31	0.35	0.3	0.3	0.3	0.3	0.2
Imported Electricity (Hydro)	1.1	6.6	10.1	10.3	10.8	1.92	2.73	6.13	9.16	10.83	2.21	7.36	10.36	7.95	10.39	1.1	6.7	9.1	10.2	10.8
Kerosene power	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0	0.0	0.0	0.0	0.0

EBE Faculty: Assessment of Ethics in Research Projects

Any person planning to undertake research in the Faculty of Engineering and the Built Environment at the University of Cape Town is required to complete this form before collecting or analysing data. When completed it should be submitted to the supervisor (where applicable) and from there to the Head of Department. If any of the questions below have been answered YES, and the applicant is NOT a fourth year student, the Head should forward this form for approval by the Faculty EIR committee: submit to Ms Zulpha Geyer (Zulpha.Geyer@uct.ac.za; Chem Eng Building, Ph 021 650 4791). Students must include a copy of the completed form with the thesis when it is submitted for examination.

Name of Principal Researcher/Student: SARAH ODERA Department: ENERGY RESEARCH CEN

If a Student: Degree: Msc Sustainable Energy Engineering Supervisor: ADRIAN STONE

If a Research Contract indicate source of funding/sponsorship:

Research Project Title: Is Nuclear Power a Cost Optimal Solution for Kenya's Future Generation Mix

Overview of ethics issues in your research project:

Question 1: Is there a possibility that your research could cause harm to a third party (i.e. a person not involved in your project)?	YES	NO
Question 2: Is your research making use of human subjects as sources of data? If your answer is YES, please complete Addendum 2.	YES	NO
Question 3: Does your research involve the participation of or provision of services to communities? If your answer is YES, please complete Addendum 3.	YES	NO
Question 4: If your research is sponsored, is there any potential for conflicts of interest? If your answer is YES, please complete Addendum 4.	YES	NO

If you have answered YES to any of the above questions, please append a copy of your research proposal, as well as any interview schedules or questionnaires (Addendum 1) and please complete further addenda as appropriate.

I hereby undertake to carry out my research in such a way that

- there is no apparent legal objection to the nature or the method of research; and
- the research will not compromise staff or students or the other responsibilities of the University;
- the stated objective will be achieved, and the findings will have a high degree of validity;
- limitations and alternative interpretations will be considered;
- the findings could be subject to peer review and publicly available; and
- I will comply with the conventions of copyright and avoid any practice that would constitute plagiarism.

Signed by:

	Full name and signature	Date
Principal Researcher/Student:	SARAH ANYANGO ODERA	22/01/2015

Signed by candidate

This application is approved by:

Supervisor (if applicable):	
HOD (or delegated nominee): Final authority for all assessments with NO to all questions and for all undergraduate research.	02/02/2015