REPUBLIC OF KENYA

MINISTRY OF ENERGY

UPDATED LEAST COST POWER DEVELOPMENT PLAN

STUDY PERIOD: 2011 - 2031

March 2011

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List of Acronyms

BPO	Business process outsourcing
CBK	Central Bank of Kenya
CPI	Consumer Price Index
CRF	Cost Recovery Factor
EAPP	East Africa Power Pool
EAP&LC	East Africa Power & Lighting Company
ERC	Energy Regulatory Commission
ERS	Economic recovery strategy
ENS	Energy Not Served
FY	Fiscal Year from 1st July to 30th June
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GoK	Government of Kenya
GT	Gas Turbine
GWh	Giga Watt hours
HFO	Heavy Fuel Oil
HPP	Hydro power project
IDC	Interest during Construction
IPP	Independent Power Producer
ISO	Independent System Operator
KEEP	Kenya Energy Sector Environment and Social Responsibility
KenGen	Kenya Electricity Generating Company Limited
KenInvest	Kenya Investment Authority
KEPSA	Kenya Private Sector Alliance
KETRACO	Kenya Electricity Transmission Company
KPLC	Kenya Power & Lighting Company Limited
KNBS	Kenya National Bureau of Statistics
KWh	Kilo Watt hour
LCPDP	Least Cost Power Development Plan
LOLP	Loss of Load Probability

LRMC	Long Run Marginal Cost
MOE	Ministry of Energy
MSD	Medium Speed Diesel
MW	Mega Watts
MWh	Megawatt Hours
PV	Present Value
O & M	Operation and Maintenance
OPEC	Oil Producing and Exporting Countries
PPA	Power Purchase Agreement
REA	Rural Electrification Authority
SAPP	Southern African Power Pool
SRMC	Short run marginal cost
TSDP	Transmission System Development Plan
UETCL	Uganda Electricity Transmission Company Limited
WASP	Wien Automatic Simulation Package

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Acknowledgements

Section 5(g) of the Energy Act No.4 of 2006 confers the responsibility of preparing Indicative Energy Plans on the Energy Regulatory Commission (ERC). The electric power sub-sector has been preparing the Least Cost Power Development Plan (LCPDP) as the sub-sector indicative plan. The purpose of the LCPDP is to guide stakeholders with respect to how the sub-sector plans to meet the energy needs of the nation for subsistence and development at least cost to the economy and the environment. The LCPDP as indicated in the Vision 2030 medium term plan aims at enhancing national power generation and supply by identifying new generation and supply sources to ensure that the national electric power supply exceeds 3,000MW by 2018.

To prepare the LCPDP, ERC set up a multi-stakeholder committee to undertake this task on an annual basis. The stakeholder committee includes representatives from the following key players: the Ministry of Energy (MoE), Ministry of State for Planning, National Development and Vision 2030, Kenya Electricity Generating Company (KenGen), Kenya Power and Lighting Company (KPLC), Geothermal Development Company (GDC), Rural Electrification Authority (REA), Kenya Electricity Transmission Company Limited (KETRACO), Kenya National Bureau of Statistics (KNBS), Kenya investment Authority(KenInvest), and the Kenya Private Sector Alliance(KEPSA) . This update has also benefitted from the technical assistance of the French government under the French Development Agency (AFD).

I wish to sincerely commend the technical study team for a job well done. I further wish to extend my gratitude to the Steering Committee and the AFD technical assistance for ably guiding the process. This process would not have been successful without the support of various stakeholders including: the Permanent Secretary, Ministry of Energy, the Commissioners and staff of ERC and the CEO's and Boards of participating institutions. To them all I say: thank you very much.

Eng. Kaburu Mwirichia
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Executive summary

Kenya's power industry generation and transmission system planning is undertaken on the basis of a 20 year rolling Least Cost Power Development Plan (LCPDP) updated every year. This study is an update of the LCPDP that was finalised in March 2010. The update involved review of the load forecast in light of changed pertinent parameters, commissioning dates for committed projects, hydro data, costs of generating plants and transmission system requirements for the Least Cost Power Development Plan. The update also incorporated key lessons learnt in the last update mainly the need to incorporate population, urbanization and efficiency gains and technology in undertaking the demand forecast and capturing of potential new demand arising from the vision 2030 flagship projects and other investor projects. The update was undertaken with the aid of several models: excel for load forecasting, VALORAGUA for hydro-thermal system optimization, WASP for the system expansion plan optimization and PSSE for transmission planning.

Load Forecast

The load forecast based on the MAED based excel worksheets indicates that the peak demand lies in the range of 1,227 MW in 2010 and between 12,738 and 22,985 MW in 2031. The reference case ranges from 1,227MW in 2010 to 3,751MW in 2018 to 15,026MW in 2030 and 16,905MW in 2031 while the energy demand increases from 7,296GWh in 2010 to 22,685GWh in 2018 to 91,946GWh in 2030 and 103,518GWh in 2031. The current peak load is estimated to grow 13 times by the year 2031. There is a very slight difference between this year's load forecast and the load forecast done in the last update of 2010-2030. The reference peak demand for 2030 in the last updates was 15,065MW which compares very closely to the revised peak demand of 15,026 MW.

Least Cost Expansion Plan

Candidate generation resources considered in the system expansion plan include geothermal, hydro, Wind, coal, oil-fired and nuclear power plants. The optimal development program is dominated by geothermal, Nuclear, coal, imports and Wind power plants. Geothermal resources are the choice for the future generating capacity in Kenya. The optimum solution indicates that geothermal capacity should be increased from the current 198MW to 5,530 MW in the planning period, equivalent to 26% of the system peak demand by 2031.

The system expansion plan over the 20 year plan period indicates that 26% of the total installed capacity will be obtained from geothermal, 19% from Nuclear Plants, 13% from coal plants and 9% from imports. Wind and Hydro plants will provide 9% and 5% respectively while Medium Speed Diesel (MSD) and Gas Turbines (GTs) - LNG plants will provide 9% and 11% of the total capacity respectively. The present value of the total system expansion cost over the period 2011-2031 for the reference case development plan amounts to U.S.$ 41.4 billion, expressed in constant prices as of the beginning of 2010.

Transmission Plan

Using the least cost generation development plan a transmission plan was developed for the period 2011-2031. The transmission development plan indicates the need to develop approximately 10,345KM of new lines at an estimated present cost of USD 4.48 Billion.

Implementation of the plan

The Ministry of Energy (MoE) shall ensure successful and timely implementation of the following projects through the project implementation committee.

Project description	Capacity MW / length of KM	Time lines	Implementing agencies	Approximated present value costs
Committed generation projects	1,815 MW	2011-2015	KENGEN and IPP	US$ 3.9 billion
Proposed generation projects	18,920 MW	2015-2031	KENGEN and IPP	US$41.4 billion
Proposed transmission projects	10,345Km	2011-2031	KETRACO	US$4.48billion
Total				US$ 49.78billion

Other specific activities will include:

- MoE through the Nuclear Energy Programme Implementation Office (NEPIO) shall undertake preparatory work for the nuclear power plant expected to come on stream in 2022.
- MoE shall continue exploration and subsequent mining of local coal to meet the high demand for coal arising from the proposed coal plants of up to 2,720MW.
- Monitoring strict adherence to the geothermal drilling programme shall be undertaken, since the commissioning of the proposed geothermal plants track the drilling plan

1 INTRODUCTION

Over the years the Government has been involved in medium to long term planning of the energy sector through the annual 20 year rolling Least Cost Power Development Plan (LCPDP). This is meant to identify exisiting potential in generation, possible investments in transmission as well as carefully forecasting on future demand for power and how best it can be met at least cost.

In this regard, the (LCPDP) is updated annually to take into account new information and new promising technologies with potential to generate power at competitive costs. This report is therefore an update of the LCPDP prepared in 2009/2010 and covers the period 2011 to 2031.

The main objective of this study is to update the LCPDP to account for the following:

(i) Review load forecast assumptions including variables, data set and load forecasting methodology taking into account anticipated performance of the macro-economy;
(ii) Review the commissioning dates for committed power generation and transmission projects;
(iii) Review and update the power system simulation data including plant types, system constraints and costs; and
(iv) Undertake power system transmission simulation

The specific objectives of this report are to:

- Update the load forecast taking into account the performance of the economy and the vision 2030 flagship projects
- Update the data, literature, candidate projects and the system simulation tools.
- Estimate Long Run Marginal Cost (LRMC) and Short-Run Marginal Cost (SRMC) of the generation system for allocation of peak capacity costs;
- Update hydro data and output;
- Prepare a least cost generation development plan; and
- Prepare a power transmission system development plan in line with the least cost generation development plan.

1.1 The updating methodology

The update of the 2010 LCPDP was undertaken by the least cost planning committee comprising of officers from Ministry of Energy (MoE), Kenya Electricity Generating Company (KenGen), Kenya Power and Lighting Company (KPLC), Geothermal Development Company (GDC), Rural Electrification Authority (REA), Kenya National Bureau of Statistics (KNBS) ,the Ministry of State for Planning, National Development and Vision 2030, Kenya Electricity Transmission Company Limited (KETRACO) , Kenya Vision 2030 Board, Kenya Investment Authority (KenInvest) and the Kenya Private Sector Alliance (KEPSA).The team undertook the update with the technical assistance of Mr. Yves Le Texier a technical assistant to the ministry of energy under the AFD, Mr Francis Jensen a MAED expert and Mr. Daniel D'hoop a PSSE expert from Egis Bceom International.

The teams started by developing the load forecast using excel worksheets based on MAED formulae and assumptions. MAED could not be used because of lack of the required data. The derived load forecast was simulated using Wien Automatic Simulation Package (WASP) to determine the least cost generation sequence to meet this demand. The least cost generation plan was simulated using Power System Simulation for Engineering (PSSE) to determine the transmission system development plan.

The report is arranged as follows; chapter two describes the existing situation of the Kenyan power sector; chapters three provides a description of the country's natural energy resources base that includes geothermal hydropower, coal and renewable energy supply options; chapter four gives a description of the electricity demand forecasting assumptions, data requirements, methodology, and forecast results; chapter five gives the list of candidate projects with their technical and economic characteristics and presents the screening of candidates that will be implemented in the least cost expansion; chapter six describes the modeling and modeling processes, discusses the planning parameters applied in the study and gives the least cost expansion plan and highlights various sensitivity scenarios; chapter seven discusses the transmission network projects; Chapter eight describes the transmission system simulation methodology and gives the transmission system plan; and finally chapter nine gives the conclusion and the implementation of the plan.

1.2 Improvements from the previous update

The team undertaking this update took cognizance of issues raised by key policy makers and various stakeholders and improved the report in the following areas:

a) Incorporated population, urbanization and efficiency gains and technology in undertaking the demand forecast
b) Captured potential new demand arising from the vision 2030 flagship projects and other investor projects
c) The least cost generation simulation included wind as a candidate project for the system optimization.
d) The transmission network planning was done using target network analysis an improvement from the last years update.
e) The structure of the report improved with more information that is considered useful to persons interested in the Energy sector. The structure followed the proposal done by the consultant under the AFD technical assistance to the Ministry of Energy.

2.1 Historical background

The history of Kenya's power sector can be traced back to 1922 when the East African Power and Lighting Company (EAP&L) was established through a merger of two companies. These were; the Mombasa Electric Power and Lighting Company established in 1908 by a Mombasa merchant Harrali Esmailjee Jeevanjee and Nairobi Power and Lighting Syndicate also formed in 1908 by engineer Clement Hertzel.

The Kenya Power Company (KPC) was later formed in 1954 as a subsidiary of the EAP&L with the sole mandate of constructing electricity transmission lines between Nairobi and Tororo in Uganda. This infrastructure was mainly to enable Kenya import power from the Owen Falls Dam in Uganda. With many operations of EAP&L largely confined to Kenya, the company finally changed its name to Kenya Power and Lighting Company Limited (KPLC) in 1983. KPC was 100% government owned.

Following the structural adjustments program in the 1990s, the Government of Kenya officially liberalized power generation as part of the power sector reforms in 1996. Among the first reforms to take place was the unbundling of the state utility in 1997. Kenya Generating Company Limited (KenGen) which remained entirely state owned became responsible for the generation assets while KPLC assumed responsibility for all distribution and transmission. The Electricity Regulatory Board was also established under the 1997 electric power Act as the sub sector regulator.

Reforms in the power sector have continued to take place especially with energy policy development of 2004 and the subsequent enactment of the energy Act of 2006 which established the Energy Regulatory Commission and the Rural Electrification Authority. The sessional paper No 4 of 2004 on energy also provides for the creating of the Geothermal Development Company (GDC) and Kenya Electricity Transmission Company (KETRACO). GDC is a special purposes vehicle for geothermal resource development and KETRACO is a state owned transmission company.

2.2 Institutional aspects in the power sector

2.2.1 Current situation

The reforms in the energy sector have seen a complete reorganization of functions hitherto concentrated in the ministry of energy and the Kenya Power and Lighting Company Limited. This was a result of the need to place responsibilities to specific institutions that would specialize in the mandates vested in them under the Energy Act to enhance efficiency. Accordingly these were unbundled into generation, transmission, distribution, oversight and policy functions. The institutional structure in the electricity sub sector in Kenya comprise the Ministry of Energy (MOE), Energy Regulatory Commission (ERC), Kenya Electricity Generating Company (KenGen), Kenya Power and Lighting Company (KPLC), the Rural Electrification Authority (REA), Kenya Electricity Transmission Company (KETRACO), Geothermal Development Company (GDC) and Independent Power Producers (IPPs). An elaboration of these functions is as follows

a) The Ministry of Energy (MOE) is in charge of making and articulating energy policies to create an enabling environment for efficient operation and growth of the sector. It sets the strategic direction for the growth of the sector and provides a long term vision for all sector players

b) The Energy Regulatory Commission (ERC) is responsible for regulation of the energy sector. Functions include tariff setting and oversight, coordination of the development of Indicative Energy Plans, monitoring and enforcement of sector regulations. It was established as a single sector regulator.

c) The Energy Tribunal is an independent legal entity and was set up to arbitrate disputes in the sector.

d) Rural Electrification Authority (REA) is charged with the mandate of implementing the Rural Electrification Programme and came into operation in July 2007. Since the establishment of the Authority, there has been accelerated connectivity of rural customers which have increased from 133,047 in 2007 to 251,056 in 2010.

e) The Kenya Electricity Generating Company (KenGen) is the main player in electricity generation, with a current installed capacity of 1,176MW of electricity. It is listed at the Nairobi Stock Exchange with the shareholding being 70% by the Government of Kenya and 30% by private shareholders. The Company accounts for about 75% of the installed capacity from various power generation sources that include hydropower, thermal, geothermal and wind.

f) Independent Power Producers (IPPs) are private investors in the power sector involved in generation either on a large scale or for the development of renewable energy under the Feed-in -Tariff Policy. Current players comprise IberAfrica, Tsavo, Or-power, Rabai, Imenti, and Mumias. Collectively, they account for about 26% of the country's installed capacity from thermal, geothermal and baggasse, as follows:

- Iberafrica (108 MW -thermal power plant),
- OrPower (48 MW -geothermal power plant),
- Tsavo (74 MW- thermal power plant).
- Mumias (26MW -Cogeneration)
- Imenti (900kW -Mini-Hydro)
- Rabai (90MW- Thermal power plant)

f) The Kenya Power and Lighting Company (KPLC) is the off-taker in the power market buying power from all power generators on the basis of negotiated Power Purchase Agreements for onward transmission, distribution and supply to consumers. It is governed by the State Corporations Act and is responsible for electricity transmission and all distribution systems in Kenya. The transmission system comprises 220kV, 132kV and 66kV transmission lines. KPLC is a listed company on the Nairobi Stock Exchange with the ownership structure being 50.1% by the National Social Security Fund (NSSF) and the GoK whereas the private shareholders own 49.9%.

g) **Private Distribution Companies** are expected to improve the distribution function currently the sole mandate of the KPLC. It is envisaged that future power distribution will involve purchase of bulk power from the generators and with KETRACO facilitating the transmission; it will be possible for independent players to sell power directly to consumers. This is likely to enhance distribution competition and hence improve efficiency.

2.2.1.1 Recent changes in the power sector

The power sector has seen changes that have allowed for implementation of the Energy Act and specifically, the unbundling of transmission services as well as the establishment of a Special Purpose Vehicle (SPV) for geothermal development

a) **Geothermal Development Company** is a fully owned Government Special Purpose Vehicle (SPV) intended to undertake surface exploration of geothermal fields, undertake exploratory, appraisal and production drilling develop and manage proven steam fields and enter into steam sales agreements with investors in the power.

b) **Kenya Electricity Transmission Company (KETRACO):** was incorporated in December 2008 as a State Corporation 100% owned by the Government of Kenya. The Mandate of the KETRACO is to plan, design, construct, own, operate and maintain new high voltage (132kV and above) electricity transmission infrastructure that will form the backbone of the National Transmission Grid & regional inter-connections. It is expected that this will also facilitate evolution of an open- access- system in the country.

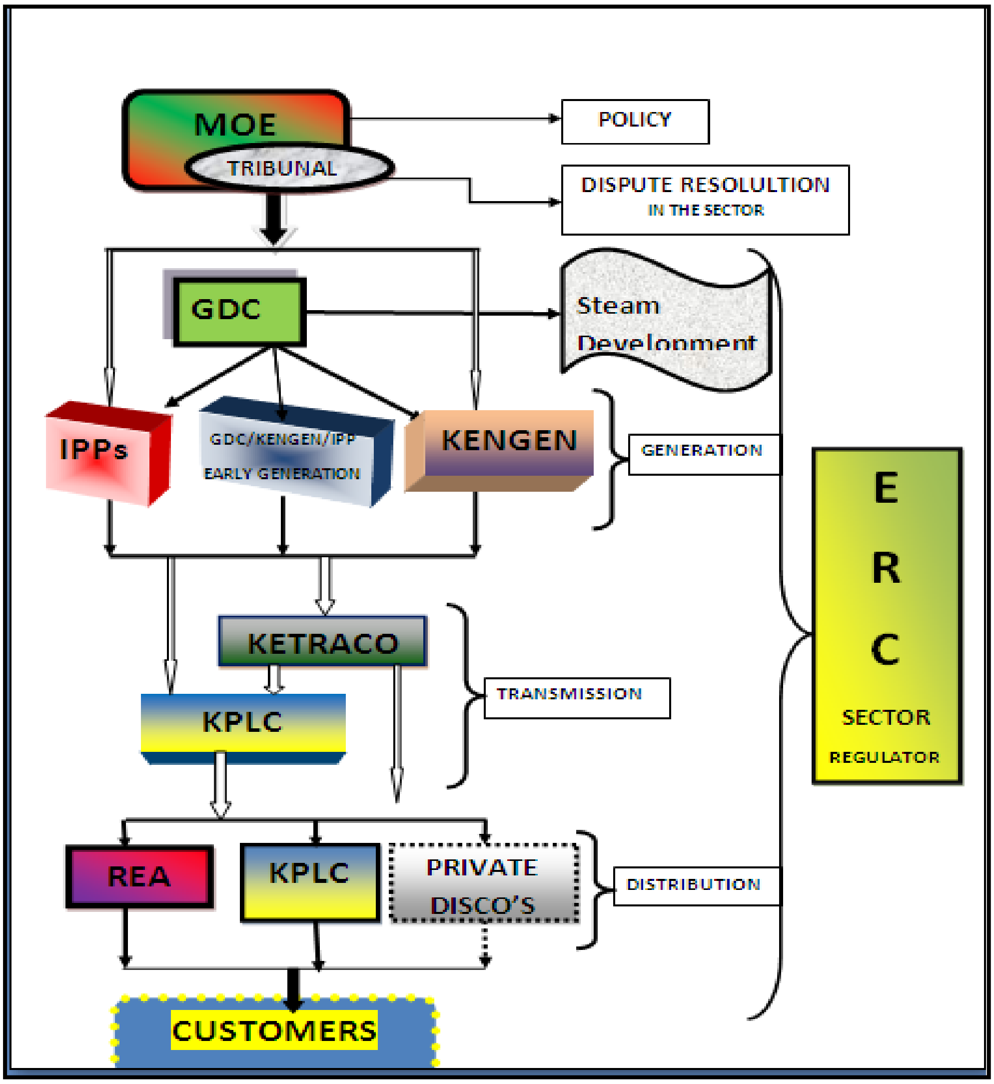
2.2.2 Further Reforms

Resulting from the current regional integration and the need to build synergies with other countries in the region in power development, the government has committed itself to entering into mutually beneficial regional interconnections with other African countries. As a result, the regional power market is progressively evolving into a power pool with the anticipated interconnections with Ethiopia, Tanzania and other Southern African power pool (SAPP) countries and strengthening of the interconnection with Uganda.

Further reforms envisaged under the Act but yet to be effected include;

- Establishment of a Centre of Excellence for Energy Efficiency and Conservation.
- Establishment of energy and equipment testing laboratories.
- Development of standards and codes of practice on cost-effective energy use.

Figure 1: Power sector institutional structure



2.3 *Electricity supply*

2.3.1 Description of the Interconnected System

The interconnected system in Kenya has a total installed capacity of 1,533 MW made up of 761.0 MW of hydro, 525 MW of thermal, 198 MW of geothermal, 5.45 MW of wind , 26MW from cogeneration and 17MW of isolated grid. The total effective capacity is 1,515 MW during normal hydrology. Hydro accounts for about 50% of the total energy supply. Registered interconnected national sustained peak demand is 1,178 (1,183 MW instantaneous).

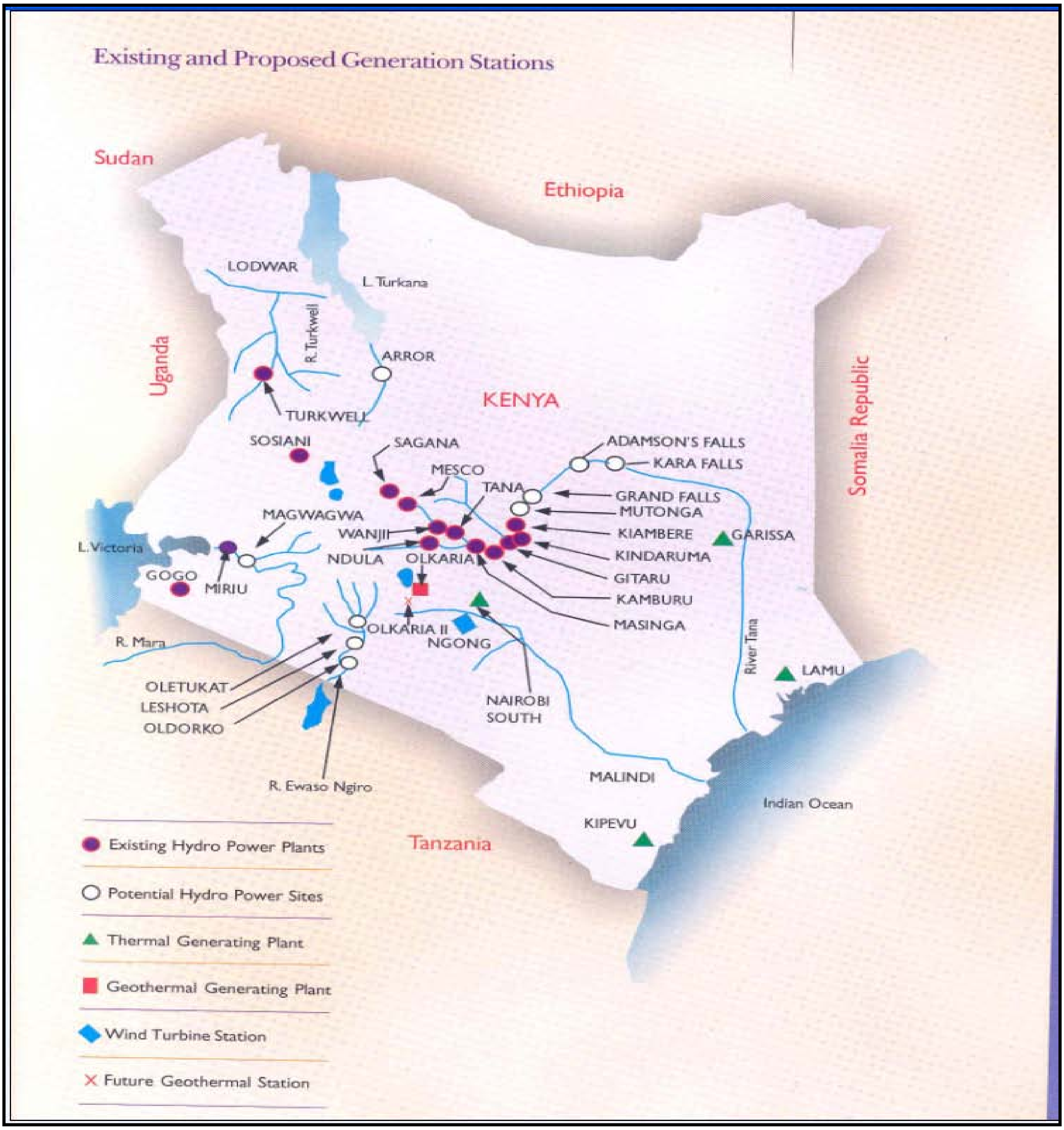
Table 1 gives a summary of the installed and effective generation capacity including the government owned isolated grid power stations while Figure 2 represents the location of all existing and proposed grid power plants in the country.

Table 1: Installed capacity, effective capacity and annual production, 2009/10

Sources	Installed Capacity (MW)	% Share	Effective Capacity (MW)	% Share	Annual Production (GWh)	% Share
Hydro	761	50%	745	49%	2,170.00	32.52%
Thermal	525	34%	525	35%	3,029.00	45.40%
Geothermal	198	13%	198	13%	1,339.00	20.07%
Cogeneration	26	2%	26	2%	99.00	1.48%
Wind	5.45	0%	5.45	0%	16.3	0.24%
Isolated Grid	18.0	1%	15.6	1%	19	0.28%
Total	1,533	100%	1,515	100%	6,672	100%

Source: KPLC Annual Accounts and Statistics 2010

Figure 2: Existing and proposed generation plants



2.3.2 Sources of Energy in Kenya

Hydropower constitutes 48% of the installed capacity and accounted for 33% of the total sales in 2009/10. The low energy contribution can be attributed to poor dam flows occasioned by the 2009 drought. Thermal, Geothermal, Cogeneration and wind generation account for 37%, 13%, and 2% (combined wind and cogen) of the installed capacity respectively.

The generation contribution from KenGen plants, Rural Electrification Plants, IPPs, EPPs and imports between 2005 and June 2010 are as shown in Table 2 below.

Table 2: Generation contribution of existing power plants (2005/06-2009/10)

Company		Capacity		Energy (GWh)				
	Year Installed	Installed	Effective[1]	2005/06	2006/07	2007/08	2008/09	2009/10
KenGen								
Hydro:								
Tana	1955	14.4	0.0	56	68	64	44	29
Kamburu	1974	94.2	90.0	399	464	489	348	244
Gitaru	1978 (unit 3 -1998)	225.0	216.0	795	945	977	655	457
Kindaruma	1968	40.0	40.0	190	215	239	157	111
Masinga	1981	40.0	40.0	170	183	230	128	61
Kiambere	1988	164.0	164.0	852	973	937	614	546
Turkwel	1991	106.0	105.0	520	372	341	524	335
Sondu Miriu	2008	60.0	60.0	0	0	150	333	340
Small Hydros	Various	14.7	12.8	43	57	60	46	46
Hydro Total		758	728	3,025	3,277	3,488	2,849	2,170
Thermal:								
Kipevu Steam	N/A	0.0	0.0	0	0	0	0	0
Kipevu I Diesel	1999	75.0	60.0	399	326	295	376	316
Fiat - Nairobi South	N/A	0.0	0.0	18	4	7	9	0
Kipevu Gas Turbines		60.0	60.0	194	75	88	184	145
Garissa & Lamu		5.4	5.2	15	16	18	17	19
Thermal Total		140	125	626	421	408	587	481
Geothermal:								
Olkaria I	1981	45.0	44.0	324	360	359	368	366
Olkaria II	2003	105.0	97.0	562	540	564	535	573
Geothermal Total		150	141	886	900	922	903	939
Wind								
Ngong	2009	5.45	5.45	0.4	0.2	0.2	0.3	16.3
KenGen Total		1,054	999	4,538	4,599	4,818	4,339	3,606
Rural Electrification Programme (REP)								
Off-grid Thermal Stations	Various	11.7	10.2	11	12	14	16	19

Independent Power Producers (IPP) - Thermal & Geothermal								
Iberafrica	1997 (56MW) 2004 (Remaining 52 MW unit)	108.5	108.5	408	321	306	344	621
Westmont[2]	N/a	0.0	0.0	0	0	0	0	0
Tsavo	2001	74.0	74.0	570	547	556	566	495
Mumias - Cogeneration	2008	26.0	26.0	9	4	9	4	99
OrPower 4 - Geothermal	2000(other 3 units 2008)	48.0	48.0	117	112	98	276	400
Rabai Power	2009	90.0	90.0	-	-	-	-	318
Imenti Tea Factory (Feed-in Plant)	2009	0.6	0.6	-	-	-	-	0.3
IPP Total		347	347	1,103	984	970	1,189	1,933
Emergency Power Producers(EPP)								
Aggreko energy to Kenyan Market	2008	60	60	30	561	499	885	1096
Aggreko energy to Uganda	2008	-	-			57	29	0
EPP Total		60	60	30	561	556	914	1,096
Imports								
UETCL	1957			15	13	25	29	37
TANESCO	2005			0.4	0.5	1.0	1.2	1.1
Total Imports				15	13	26	30	38

Generation of electricity increased in 2009/10 to 6,692GWh compared to 6489GWh for the same period in 2008/09. The positive growth of generation is also related to the positive growth in the commercial/industrial electricity consumption. This indicates that consumption expanded by 3.2 per cent from the previous year. The recorded total consumption in 2009/2010 was 5,624GWh compared to 5,432GWh the previous year. The maximum peak demand recorded in 2009/2010 was 1,107MW compared to 1,072MW in 2008/2009. Currently the peak demand stands at 1,178MW.

2.3.3 Committed generation projects

There are a number of projects committed to improve generation in the immediate to mid-term. Estimated committed generation between 2010 and 2015 is 1,815MW as shown in table 3 below.

Table 3: Committed projects as at February 2011

Developer	Project	Type	Capacity (MW)	Est. Commissioning Date	Current status
KenGen					
	Wellhead Units	Geothermal	70	Jun-2011	Procurement
	Eburru	Geothermal	2.2	Dec-2011	Testing for commissioning
	Sangoro	Hydro	21	Oct-2011	Construction
	Ngong 1 ph2 and Ngong 2 wind	Wind	20.4	Nov-2012	Construction
	Olkaria IV	Geothermal	140	Sep-2013	Construction
	Olkaria 1 –Life Extension	Geothermal	140	Sep-2013	Design
	Kindaruma 3rd unit	Hydro	32	Jun-2013	Procurement
	Muhoroni	MSD	80	Jan- 2013	
KENGEN/IPP	Mombasa Coal	Coal	300	Jul-2014	
Sub-total			806		
IPP	Athi River 1	MSD	81	Mar-2012	PPA negotiation
	Athi River 2	MSD	84	Mar-2012	
	Thika 1	MSD	87	Mar-2012	
	Garissa	MSD	10	Dec-2012	
	Lake Turkana	Wind	300	Jul-2013	Amending the PPA due to changes in the transmission line arrangement
	Osiwo wind	Wind	50	Jul-2013	Expression of interest was approved.
	Aeolus wind	Wind	60	Novl-2012	Draft PPA received and negotiation is ongoing
	ARM Coal	Coal	60	Jul-2014	The PPA negotiations had been concluded and contract signed but developer has asked for a higher tariff which KPLC has declined
	Orpower4	Geothermal	52	2014 (36) 2019 (16)	PPA ready for execution upon approval by ERC
	Small Hydros	hydro	25	2011-2015	Expressions of interest for have been approved for quite a number (81MW) of them but PPA negotiations have not started
IMPORT	Ethiopia	hydro	200	Jul 2014-Jul 2020	Detailed feasibility study bids evaluated and PPA negotiations will start soon
Sub-total			1,009		
Total			1,815		

2.3.4 Transmission and distribution system

The Kenyan electricity supply industry structure is of the single buyer model with all generators selling power in bulk to KPLC for dispatch and onward transmission and distribution to consumers.

The existing transmission network consists of 220 and 132 kV high-voltage transmission lines, and the distribution network consists of 66 kV feeder lines around Nairobi and 33 and 11 kV medium-voltage lines.

Existing Transmission and Distribution Network Lengths are as follows:

- 1,331km of 220kV
- 2,211km of 132kV
- 655km of 66kV
- 13,812km of 33kV, and
- 25,485km of 11kV lines

Figure 3 represents the national transmission and distribution network in Kenya. The sky blue line represents the 220kV lines, the red lines the 132kV while the navy blue ones represent the 11-66kV lines

Figure 3: Transmission network in Kenya

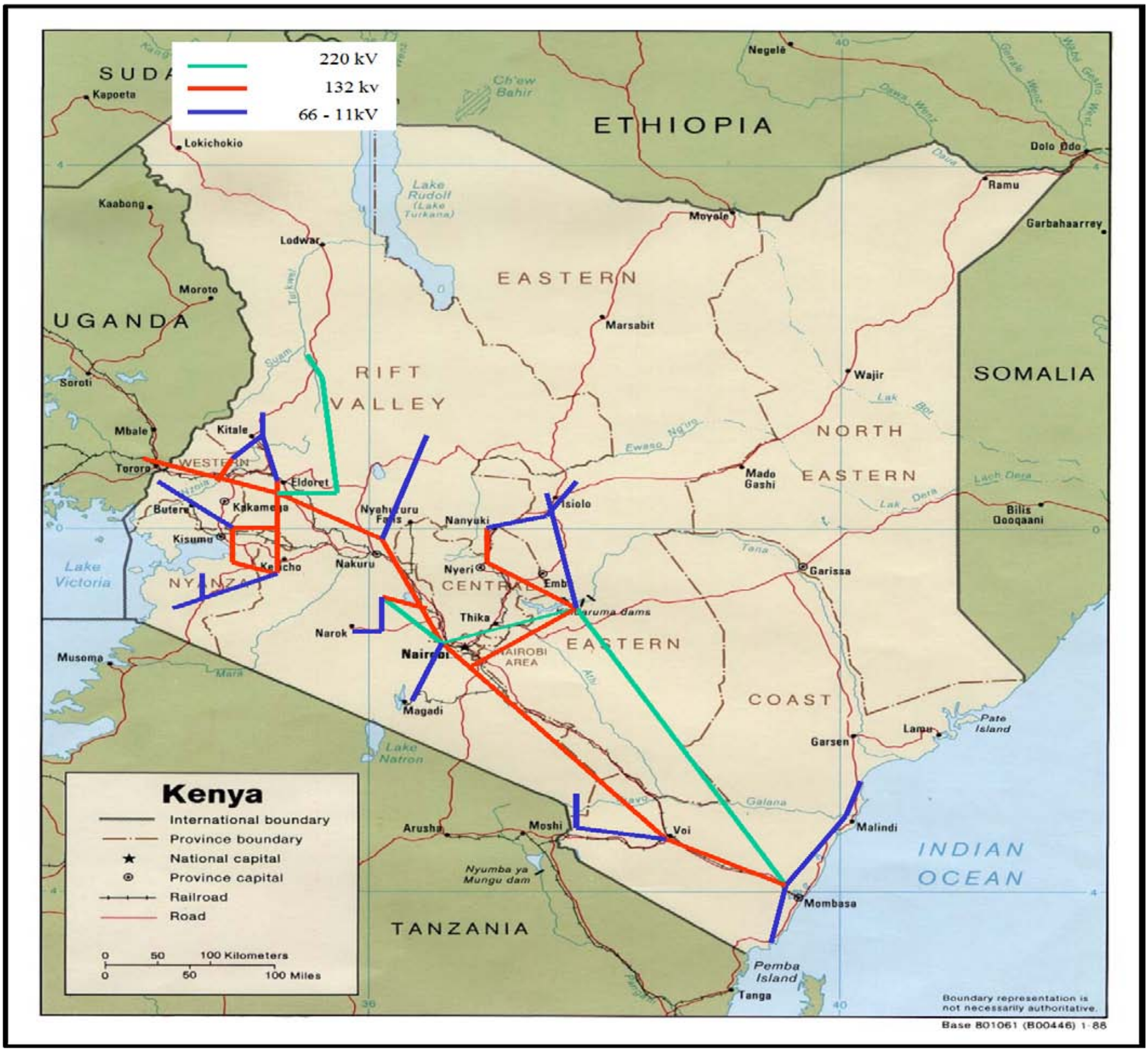


Table 4 represents the transmission and distribution sub-stations capacities between 2005 and 2010. There has been a marginal expansion in generation sub stations during the period under review from 1,537 MVA in 2005 to 1,601 MVA in 2010. During the same period, transmission substation capacity expanded from 2,625MVA to 2,841MVA while distribution sub-stations extended to 2,241MVA from 1,440MVA during the same period. Distribution transformer capacity significantly increased during the period from 3,081MVA to 4,688MVA an increase of about 27%.

Table 4: Transformers in service, total installed capacity in MVA as at 30th june 2010

	2005	2006	2007	2008	2009	2010
Generation Substations						
11/220kV	472	472	472	472	544	544
11/132kV	675	675	675	675	694	694
11/66kV	90	146	146	183	121	121
11/33kV	279	279	280	280	238	238
11/40kV	5	5	5	5	0	0
3.3/11/40kV	8	8	10	10	0	0
3.3/40kV	4	4	4	4	0	0
3.3/33kV	4	4	4	4	4	4
TOTAL	1,537	1,593	1,596	1,633	1,601	1,601
Transmission Substations						
132/220kV	620	620	620	620	620	620
220/132kV	730	730	730	730	730	730
220/66kV	360	360	360	360	360	360
132/66kV	255	375	375	375	375	375
132/33kV	660	621	629	652	687	756
TOTAL	2,625	2,706	2,714	2,737	2,772	2,841
Distribution Substations						
66/11kV	743	966	1,058	1,114	1,206	1,206
66/33kV	67	77	77	77	77	90
40/11kV	11	11	11	11	11	11
33/11kV	619	666	729	750	823	934
TOTAL	1,440	1,720	1,874	1,951	2,117	2,241
Distribution Transformers						
11/0.415kV and						
33/0.415kV	3,081	3,271	3,515	4,138	4,307	4,688

Source: KPLC Annual Accounts and Statistics 2010

2.3.4.1 Extension of the National Transmission Network

Kenya has experienced increased demand in electricity consumption in the last 5 years. This rise in consumption requires a corresponding increase in generation capacity and transmission network. Consequently, the LCPDP has put up the requisite plan to implement various plans on both generation and transmission. Table 5 shows the committed transmission projects.

Table 5: Committed and planned transmission network projects

	Transmission line / project	Length (Km)	Commissioning date
1.	Kilimambogo-Thika-Githambo 132 kVsingle circuit Transmission Line	67	2011
2.	Mumias – Rangala 132 kV single circuitTransmission Line	34	2011
3.	Reactive compensation Phase 1 – Nairobi Transmission system		2011
4.	Thika – Nyaga 132 kVsingle circuit Transmission Line	40	2011
5.	Mombasa – Nairobi 220/400 kV double circuit	475	2012
6.	Rabai-Malindi-Garsen-Lamu 220kV single circuit Transmission Line	320	2012
7.	Eldoret-Kitale 132kV Single Circuit Transmission Line	60	2013
8.	Kindaruma-Mwingi-Garissa 132kV Single Circuit Transmission Line	250	2013
9.	Kisii-Awendo 132kV Single Circuit Transmission Line	44	2013
10.	Loiyangalani-Suswa 400kV Double Circuit Transmission Line	430	2013
11.	Nairobi Ring: Suswa-Isinya 400kV double Circuit Transmission Line	100	2013
12.	Nairobi Ring: Suswa-Ngong 220kV double Circuit Transmission Line	46	2013
13.	Bomet-Sotik 132kV Single Circuit Transmission Line	33	2015
14.	Ishiara-Kieni-Embu 132kV Single Circuit Transmission Line	33	2015
15.	Lessos-Kabarnet 132kV Single Circuit Transmission Line	65	2015
16.	Mwingi-Kitui-Sultan Hamud-Wote 132kV Single Circuit Transmission Line	153	2015
17.	Nanyuki-Nyahururu 132kV Single Circuit Transmission Line	79	2015
18.	Olkaria-Lessos-Kisumu 220kV, Double Circuit Transmission	300	2015
19.	Olkaria-Narok 132kV Single Circuit Transmission Line	68	2015

2.3.4.2 Regional interconnections

The following regional interconnections are expected to be completed in 2014:

(a) Kenya (Lessos)-Uganda (Tororo), 127Km 220kV Double Circuit Transmission Line;

(b) Kenya (Isinya)-Tanzania(Singinda), 100Km 400kV Single Circuit Transmission Line;

(c) Kenya-Ethiopia (East Africa Interconnector), 686Km 500kV HVDC Transmission Line.

2.3.5 Distribution network

Proposed Energy Access Scale-Up involves expansion of the national power distribution grid to connect 1 million new customers spread country wide which would involve an additional 16,000kms of MV distribution lines, 1,000MVA of distribution substations, 50,000kms of LV distribution lines, 3,000MVA of distribution transformers and 1 million service lines. This in total is estimated to cost KShs 123billion with construction work to be shared out between KPLC, Turnkey contractors, Labour and Transport contractors.

In addition, more projects to construct distribution lines and establish new substations have been initiated to extend power supply in rural areas. Most of the projects are financed by development partners such as International Development Association (IDA), European Investment Bank (EIB), Agence Francaise de Development (AFD) and Nordic Development and Fund (NDF). The implementation of the projects is expected to be done during the medium term and started in 2008/09 covering the following key areas:

a) Upgrade of the Existing and Construction of New Substations;

b) Reinforcement and Extension of the Distribution network;

c) Upgrade of Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS).

2.4 Electricity demand

The demand for electricity has shown an upward trend in the last 6 years. While the demand was 4,200GWh in 2004/05 it increased 5,318GWh in the year 2009/10. The annual percentage increase was highest between 2005/06 and 2006/07 when it grew by 8.7%. Overall, there was positive growth in all customer categories where domestic category rose from 956GWh in 2004/05 to 1,290GWh in 2009/10. Small commercial customers on the other hand increased from 522GWh to 823GWh during the same period. The off-peak customer category has experienced reduced growth during the review period due to the cost of meter installations and the introduction of instant showers. Table 6 below summarizes trends in consumption among various customer categories during the last 6 years.

Table 6: Consumption in GWh among various categories of consumers (2004/05 - 2009/10)

TARIFF	TYPES OF CUSTOMERS COVERED BY THIS TARIFF	2004/05	2005/06*	2006/07	2007/08	2008/09	2009/10
DC	Domestic	956	1,028	1,113	1,255	1,254	1,290
SC	Small Commercial	522	522	558	590	823	823
B	Commercial (Medium) and and Industrial(Medium)	885	901	985	996	n/a	n/a
C	Commercial (Large) and Industrial (Large)	1,776	1,877	2,054	2,108	n/a	n/a
CI	Commercial and Industrial					3,020	3,153
IT	Off-peak	53	54	50	74	43	36
SL	Street lighting	8	9	11	13	15	16
	TOTAL	4,200	4,391	4,771	5,036	5,155	5,318
	% INCREASE P.A.	6.6%	4.5%	8.7%	5.6%	2.4%	3.2%

**Due to Tariff categories review with effect from July 2008, the sales have been reviewed to reflect the same.

2.4.1 Characteristic of customers

Trends in specific energy consumption have shown an upward trend in the last 6 years. Total consumption in urban areas increased from 1,028GWh in 2006 to 1,319GWh in 2010. During the same period, the number of urban customers rose from 587,786 to 1,006,639.

Total consumption in rural areas also revealed the same trend where annual consumption rose from 165GWh in 2006 to 290GWh in 2010. Global total stood at 1,609GWh in 2010 up from 1,247GWh in

2006. Total global customers increased from 698,510 in 2006 to 1,170,772 in 2010. Table 7 summarizes the consumption patterns, consumer trends and customer growth for the period 2006-2010.

Table 7: Urban and rural energy consumption (2006-2010)

	2006	2007	2008	2009	2010
URBAN					
Annual Consumption (GWh)	1,028	1,113	1,255	1,254	1,319
Off peak	54	50	74	43	39
No. of customers	587,786	681,060	780,515	932,073	1,006,639
Average Consumption (kWh)	1,841	1,708	1,703	1,392	1,311
RURAL					
Annual Consumption (GWh)	165	221	240	250	290
No. of customers	110,724	133,047	161,354	205,287	164,133
Average Consumption (kWh)	1,490	1,661	1,487	1,218	1,764
Share of urban consumption (%)	87%	84%	85%	84%	82%
Share of rural consumption	13%	16%	15%	16%	18%
GLOBAL TOTAL					
Annual Consumption (GWh)	1,247	1,384	1,569	1,547	1,609
No. of customers	698,510	814,107	941,869	1,137,360	1,170,772
Average Consumption (kWh)	1,785	1,700	1,666	1,360	1,462

Electricity sales

The commercial/industrial sales depend highly on the performance of the manufacturing sector and large commercial establishments in the economy. The relatively small number of customers in this category accounts for about 60% of total electricity sales. The positive growth in the manufacturing sector led to increased demand of electricity sales in 2009/10. The domestic customer category recorded a positive growth in energy sales in the same year. The closing gap between the domestic and off-peak tariffs has led to the reduction in the number of customers in the off-peak customer category.

In Kenya electricity is supplied to less than 15% of the total population. This is predominantly middle and upper income groups. The utility's strategy to connect more customers to enhance sales growth is currently under implementation. Strategies to enhance customer growth, energy sales and revenue through proactive marketing and speeding up of customer creation process are now under full implementation. Generally, the long-term commercial sales growth will be driven by the expansion of the economy and factors including:

- A growing population, which increases the demand for most general services using electricity
- Increases in electric intensity, a result of greater use of electronic and information end use technologies.
- Continued growth in the manufacturing, agricultural sector and other sectors of the economy
- The company's initiative to connect new customers.

Regional sales trends

The Nairobi region has consistently recorded the highest sales in electricity in the country, accounting for more than 50% of total sales. During the review period, sales increased from 2,234GWh in 2004/05 to 3,014GWh in 2009/10. The coast region is the second highest customer and recorded an increase of consumption from 808GWh to 1,027GWh during the same period.

Rural Electrification Programme (REP)

The rural electrification scheme has seen rapid expansion and recorded consumption of 279GWh in 2009/10 up from 164GWh in 2004/05 period. Recent accelerated growth can be attributed to the creation of the special purpose vehicle, Rural Electrification Authority, which is dedicated to expanding electricity access in rural areas as provided for in the Energy Act 2006. Trends in regional electricity sales in the period under review are shown in Table 8.

Table 8: Total unit sales by region in GWh

REGION	2004/05	%	2005/06*	%	2006/07	%	2007/08	%	2008/09	%	2009/10	%
Nairobi	2,234	51%	2,371	52%	2,595	51%	2,782	52%	2,898	53%	3,014	54%
Coast	808	18%	844	18%	908	18%	929	17%	979	18%	1,027	18%
West	792	18%	805	18%	872	17%	902	17%	867	16%	853	15%
Mt. Kenya	366	8%	371	8%	396	8%	423	8%	411	8%	424	8%
KPLC Sales	4,200	96%	4,391	96%	4,771	94%	5,036	95%	5,155	95%	5,318	95%
R.E.P. Schemes	164	4%	165	4%	221	4%	240	5%	250	5%	279	5%
Export Sales***	15	0.34%	24	0.52%	73	1.44%	46	0.86%	27	0.50%	27	0.48%
TOTAL	4,379	100%	4,580	100%	5,065	100%	5,322	100%	5,432	100%	5,624	100%
%INCREASE P.A.	7.10%		4.60%		10.60%		5.10%		2.10%		3.50%	

Regional comparisons - EAPP consumption

Total population in the EAPP region is approximately 386 million of which Kenya accounts for 10%.Total electrical consumption in the EAPP region is 128,000GWh whilst GDP for the region is US$ 143,000 (2004 prices). From table 9 below, the specific consumption in Kenya is approximately less than half the regional average. Kenya’s GDP per Capita is approximately 16 % higher than the regional average.

Table 9 : Regional Comparisons

Country/Region	Population (Millions)	Total Electrical Consumption (GWh)	Specific Consumption (KWh)	GDP (US$ Billions)	GDP Per Capita (US $)
EAPP	385.56	128,001	332	182.16	472
Egypt	75.68	104,092	1,375	113.48	1,500
DRC	64.39	5,997	93	0.74	12
Kenya	36.91	5,476	148	20.21	547
Sudan	39.38	3,438	87	13.25	337
Tanzania	39.38	3,182	81	11.75	298
Ethiopia	79.94	3,130	39	10.95	137
Uganda	30.26	2,068	68	8.11	268
Djibouti	0.69	260	375	0.54	777
Rwanda	10.14	232	23	2.46	242
Burundi	8.78	126	14	0.66	76

Source: Kenya Power Report Q3 2010 Published by Business Monitor International, June 2010.

2.4.2 Selling price of electricity

Kenya's retail tariff is bundled and incorporates the combined cost of the different functional components that is generation, transmission and distribution and ensures sustainability as it is based on the revenue requirements of the transmitting and distributing company i.e KPLC.

The tariffs structure follows KPLCs underlying long run marginal cost structure such that the utility is able to meet its revenue requirements. The revenue requirements are based on prudently incurred costs including power purchase costs; transmission, distribution and retailing costs as well as a reasonable rate of return on the capital invested to provide the services. The retail tariff structure comprises of:

- Fixed charge
- Demand charge
- Energy charge

The Fixed charge is set to recover the customer related costs of metering, meter reading, inspection, maintenance billing and customer accounting. These costs remain constant but vary with the customer category.

Demand charge recovers the costs associated with the transmission and distribution network. The demand charges are derived directly from the long run marginal cost related to the transmission and distribution network. The charges remain constant but vary with the customer category.

The Energy charges per kWh are set on the long run marginal costs tariff rates adjusted to the real financial revenue requirement of KPLC. The energy charges vary per kWh. The structure of the retail tariffs in Kenya is as follows.

Table 10: Retail Electricity Tariffs Structure

Tariff	Type of Customer	Supply Voltage (V)	Consumption (kWh/month)	Fixed Charge (KSh/month)	Energy Charge (KSh/kWh)	Demand Charge (KSh/kVA/month)
DC	Domestic Consumers	240 or 415	0-50	120.00	2.00	-
			51-1,500		8.10	
			Over 1,500		18.57	
SC	Small Commercial	240 or 415	Up to 15,000	120.00	8.96	-
CI1	Commercial/Industrial	415-3 phase	Over 15,000 No limit	800.00	5.75	600.00
CI2		11,000		2,500.00	4.73	400.00
CI3		33,000/40,000		2,900.00	4.49	200.00
CI4		66,000		4,200.00	4.25	170.00
CI5		132,000		11,000.00	4.10	170.00
IT	Interruptible Off-Peak supplies	240 or 415	Up to 15,000	240.00 – when used with DC or SC	4.85	-
SL	Street Lighting	240	-	120.00	7.50	-

In addition the retail tariffs structure provides for three pass-through costs that are considered uncertain and largely outside the control of the utilities. These are the fuel oil cost adjustment (FOCA), the foreign exchange rate fluctuations adjustment (FERFA) and inflation adjustment

2.4.2.1 Income, sales and average selling price of electricity

Based on the above tariff structure the total incomes from sale of electricity, units sold and the average yield for the last 6 years are indicated in the table 11 below.

Table 11 : Income, sales and average selling price of electricity

Year	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Total units sold (GWh)	3,940	4,215	4,444	4,818	5,082	5,182	5,624
Total income from electricity (Shs '000)	23,323,083	28,341,356	33,966,730	37,944,286	40,801,040	65,208,529	76,364,000
Average selling price (Shs/kWh)	5.92	6.72	7.64	7.88	8.03	12.58	13.58

The tariff increase from 8.03 to 12.58 in 2008-09 was a result of Tariff review of 2008 that made the tariffs as cost reflective as possible. The increase was mainly due to the removal of the generation cost subsidy of 6cents per kWh, rural electricity operations and maintenance costs subsidy and the inclusion of costs resulting from distribution projects in the period.

A further analysis of Income, unit's sold and average tariffs by customer category for the last five years are as indicated in table12 below. The highest average tariff has overtime been in street lighting and small commercial followed by domestic and commercial and industrial.

Table 12: units sold, revenue and average tariff per customer category

Customer category	Description	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10
Domestic	Sales in GWh	900	956	1028	1113	1255	1254	1290
	Revenue(Kshs M)	5,233	6,481	8,092	9,718	10,867	16,493	21,109
	Average tariff	5.81	6.78	7.87	8.73	8.66	13.15	16.36
Small Commercial	Sales in GWh	476	522	522	558	590	823	823
	Revenue(kshs M)	3,622	3,905	4,650	5,858	6,481	12,381	14,778
	Average tariff	7.61	7.48	8.91	10.50	10.98	15.04	17.95
Commercial and industrial	Sales in GWh	2,502	2,661	2,778	3,039	3,104	3,020	3,153
	Revenue (Kshs M)	14,145	17,400	20,632	21,832	22,864	36,014	36,603
	Average tariff	5.65	6.54	7.43	7.18	7.37	11.93	11.61

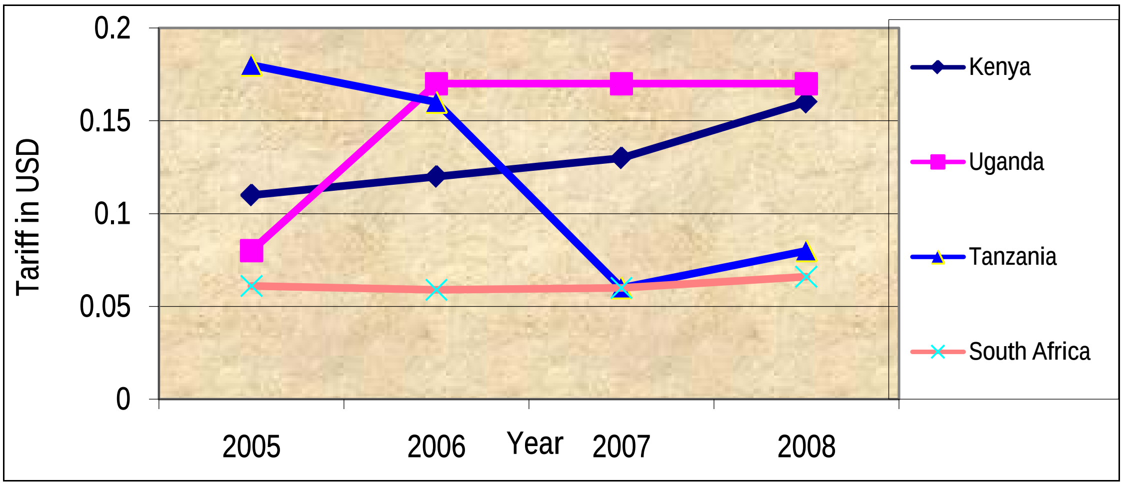
2.4.2.2 International and regional comparison of prices

Regional comparisons

Comparing the prices of electricity in the last four years in the region, we find that Uganda has the highest electricity tariffs, followed by Kenya with Tanzania and South Africa having the least tariffs, see figure 4 below. The countries tariffs structures are different. Uganda has an unbundled tariffs structure with well defined generation, transmission and distribution tariffs.

Kenya and Tanzania have bundled tariff structure that's has the generation, transmission and distribution tariffs combined together. However the Kenya tariff structure is such that there is provision for three pass-through costs that are considered uncertain and largely outside the control of the utilities. These are the fuel oil cost adjustment (FOCA), the foreign exchange rate fluctuations adjustment (FERFA) and inflation adjustment. The domestic consumers in Kenya are subjected to a fixed monthly charge of Kshs 120. Tanzania tariff structure has no provision for three pass-through costs and normally comprises of the service charge, demand charge and energy charge. The domestic low usage consumer category is subsidized by the company and is not subjected to service charge.

Figure 4: Average electricity tariffs (Kenya, Uganda, Tanzania and South Africa)



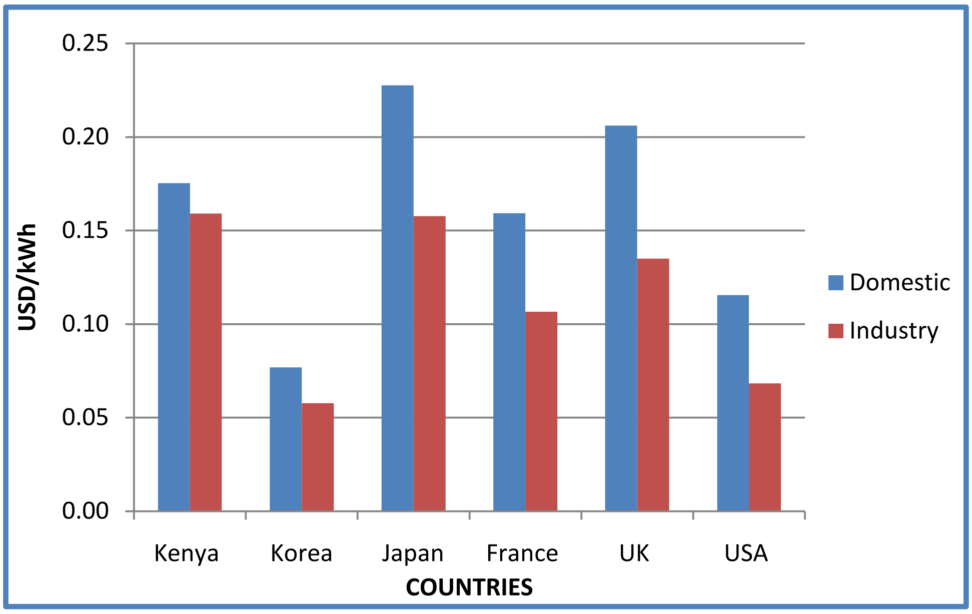
Source: Authors compilation for Kenya, Uganda and Tanzania, KIPPRA for S.A tariffs

International comparison

Domestic and industry electricity tariffs for Kenya were at US Cents 18 per kWh and US Cents 16 per kWh in 2010 higher than those of Korea (US cents 8 per kWh and US cents 6 per kWh), France (US 16 per kWh and US cents 11 per kWh), USA (US cents 12 per kWh and US cents 7 per kWh). Of importance to Kenya is Korea which has achieved an incredible record of growth and global integration to become a high-tech industrialized economy. Four decades ago, GDP per capita was comparable with levels in the poorer countries of Africa and Asia. In 2004, Korea joined the trillion dollar club of world economies, and currently is among the world's twenty largest economies. Kenya has borrowed very heavily on the Korea case in developing the Vision 2030.

Japan has the highest tariff at 23 US cents per kWh for domestic followed by the UK with a domestic tariff of 21 US cents per kWh. The industrial tariff for Japan is the same as that of Kenya with the UK having a lower industrial tariff at US cents 14 per kWh. Figure 5 indicates the different tariffs for the six countries.

Figure 5: International comparison of domestic and industrial tariffs



Source: Authors compilation

2.4.3 Electricity demand

The peak demand showed an upward trend in the last five years. While in 2004/05, peak demand was 899MW, it rose to 920MW in 2005/06 and further to 987MW in 2006/07. In 2007/08 the peak demand was 1,044 and rose to 1,072MW in 2007/08. In 2008/09 it was 1,072MW. The year 2010 recorded the highest ever peak demand of 1,127MW in October 2010 while the annual average for 2009/2010 stood at 1,107MW.

Figure 6: Peak demand (July 2009-June 2010)

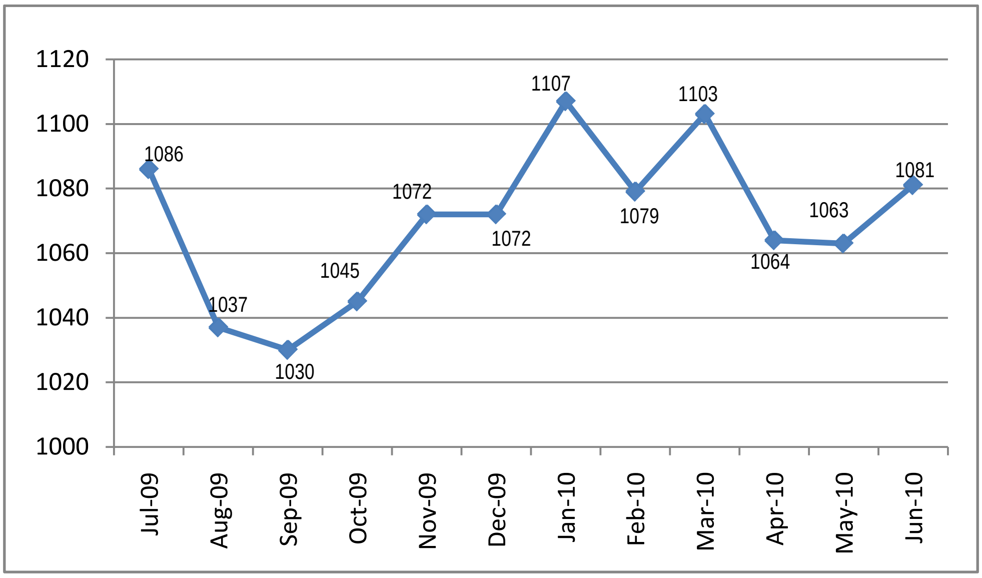
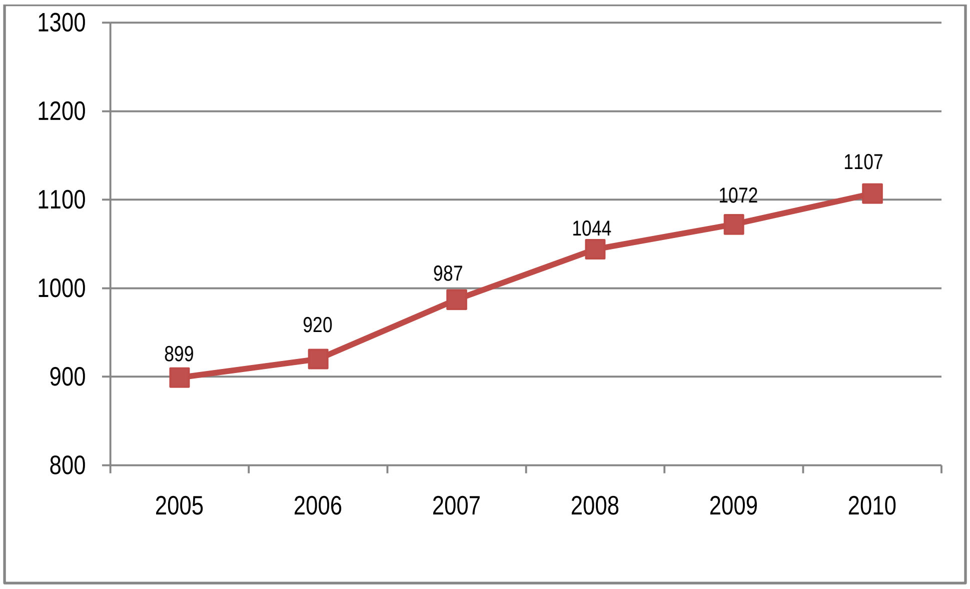


Figure 7: Annual peak demand



Load curves

A load curve is a chart showing the amount of electrical energy customers' use over the course of time. Power producers use this information to plan how much electricity they will need to make available at any given time. In Kenya electricity consumption pattern is the same throughout the year, this can be typically seen by looking at the day load curve as shown in Figure 8 and the January monthly load curve shown in Figure 9.

Figure 8: Day Load curves, January 2010

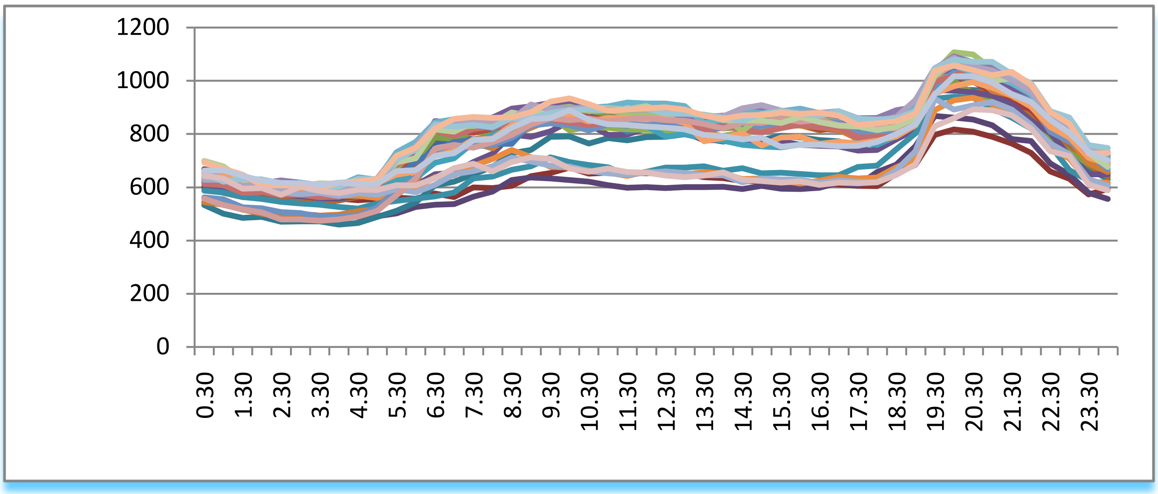
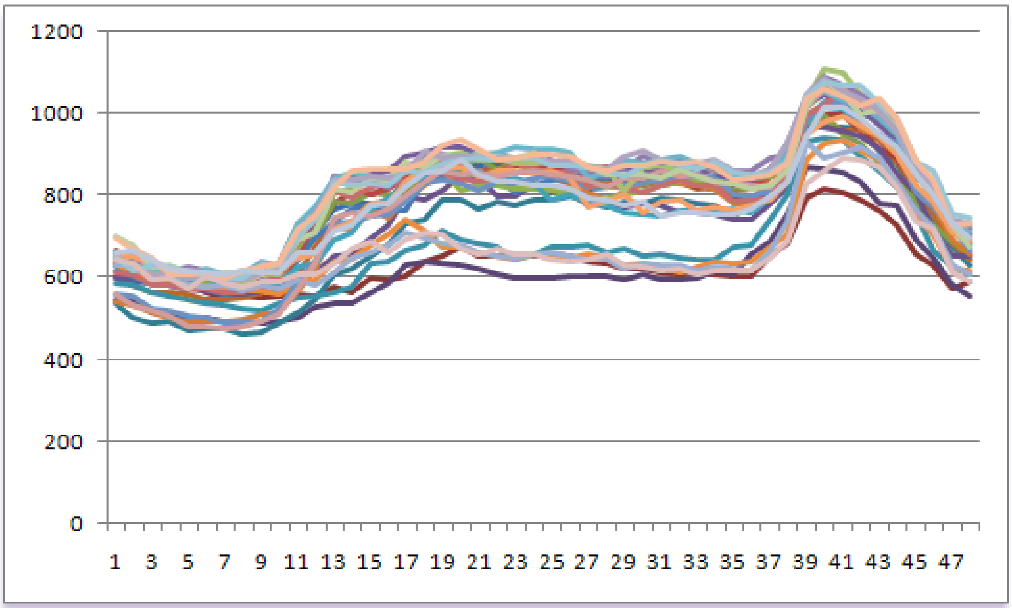
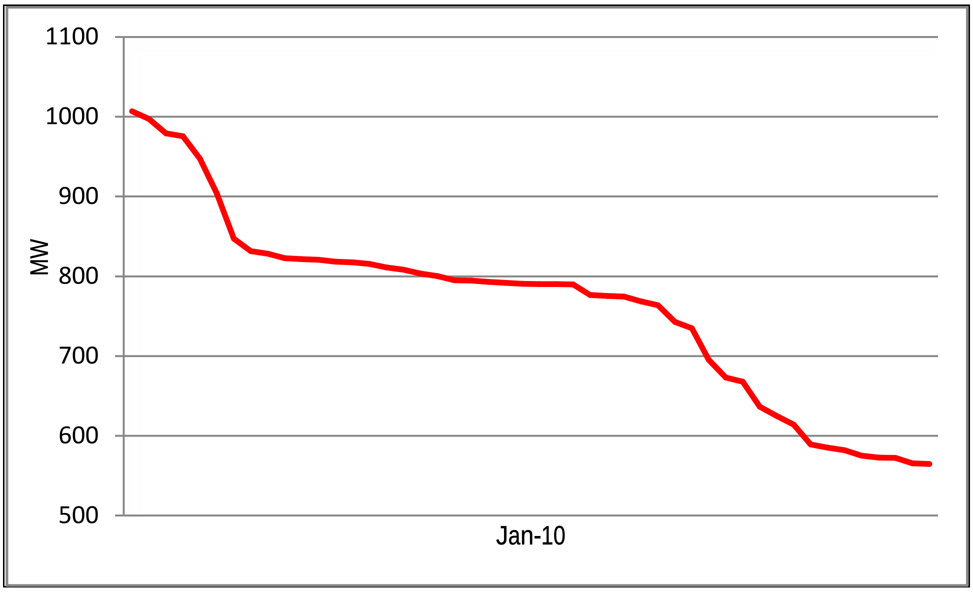


Figure 9: Monthly load curve, January 2010



As indicated in the two figures above there is no variation in the load pattern throughout the week and month. The system experiences a peak between 18:30hrs and 22:30hrs every day due to increased demand from the household's consumers during this period. The daily load duration curve is as illustrated in the figure below.

Figure 10: Load duration curve – January 2010



2.5 Electricity balance

Table 13 represents the electricity supply and demand balance for the period between 2002/03 and 2009/10. During the period under review, the total generated capacity rose from 4,618GWh to 6,654GWh, while the total supply increased from 3,801GWh to 5,624GWh.

Table 13: Electricity supply/Demand balance

YEAR	Peak Demand (MW)	Hydro (GWh)	Thermal (GWh)	Geot (GWh)	Total Gen. (GWh)	Net Gen. (GWh)	Imports (GWh)	Total Supply (GWh)	Transmission Losses (GWh)	Transmission Losses (%)	Distribution. & Commercial Losses (GWh)	Distribution. & Commercial Losses (%)	Net Supply to Consumers (GWh)	Net Supply to Consumers % of Total Supply	Net Supply to Consumers % Growth
2002/03	786	3,146	1,062	409	4,618	4,529	222	4,750	193.9	4.2	758.8	16.4	3,801	80	
2003/04	830	3,288	1344	813	4,951	4,864	171	5,035	196.5	3.97	752.5	15.2	4,090	81.2	7.6
2004/05	899	2,869	1,344	1,034	5,343	5,248	99	5,347	204.6	3.83	766.7	14.3	4,379	81.9	7.1
2005/06	920	3,025	1,654	1,003	5,778	5,682	15	5,697	210.3	3.64	910.6	15.8	4,580	80.4	4.6
2006/07	987	3,277	1,866	1,013	6,240	6,156	13	6,169	254	4.07	853.4	13.7	5,065	82.1	10.6
2007/08	1,044	3,488	1,850	1,020	6,430	6,359	26	6,385	233.691	3.66	829.4	12.9	5,322	83.4	5.1
2008/09	1,072	2,849	2,431	1,179	6,459	6,489	30	6,519	228.1577	3.5	834.4053	12.8	5,432	83.7	2.0
2009/10	1,107	2,170	3,145	1,339	6,654	6,692	38	6,730	235.5583	3.5	841.2796	12.5	5,624	84	4.0

2.5.1.1 Transmission Supply Quality and Losses

It is targeted that transmission faults be minimized in the system through adoption of N-1 criterion in all designs to create some redundancy capacity. It is also planned that KPLC and KETRACO comply with transmission system maintenance schedules entailing regular aerial and ground inspections of lines and substations. Further, it is planned that there is prompt remedy to defects when detected. This will reduce the national power outages that have been recurring in the recent past.

2.5.1.2 The quality of supply

It is essential that the transmission network operates optimally where its reliability and stability is maximized. The transmission network supply quality improvement strategies will entail reduction of fault levels complemented by efforts to reduce systems disturbances and instability and improve response time to breakdowns. This will be achieved by enhanced preventive maintenance on the transmission grid.

Implementation of the Least Cost Power Development Plan and in particular the Transmission Reinforcement Plan; and condition monitoring of equipment to forestall breakdowns are prioritized. The national System Stability improvement strategies will include Update of ancillary services guideline and structure, keeping System Frequency Deviations at a target of 1.54 hrs/day, keep bus bar Voltage deviations at 0.01hrs/day and Equip System Control with load flow and system studies software (PSS/E) and relevant training.

The key challenges to be overcome in order for transmission improvement objectives to be achieved include the no arms length relationship with distribution which makes it difficult to isolate management of the two functions, inadequate investment on distribution upgrade, huge funding requirement, and unclear positions on the market design, what KPLC shall be investing in.

System losses are dependent on the operation of the transmission system and the generation power plants among other factors. Appropriate development of the transmission network to minimize transmission distances and losses associated with reactive energy is ongoing. Loss minimization is reciprocated by financial gains of revenue and trading margin maximization. The target is to reduce transmission losses from 3.55% in 2009/10 to 3.5% from 2010/11 and throughout the next 5 year period. Transmission losses will be reduced by consideration for energy transmission distances and loss minimization in the economic merit order of generation plant loading; appropriate improvement in reactive compensation in the distribution network; installing reactive compensation equipment in the transmission network. Optimal dispatch of power plants is key for loss minimization in the transmission. System study is currently ongoing to identify requirements for new lines, new substations, substation upgrades and power compensation.

2.5.1.3 Distribution Loss Reduction Strategies

The power utility targets to reduce technical and commercial power losses arising during the transmission and distribution of electricity as it flows from generation sources to final end use customers, so as to maximize revenues and the trading margin. This would additionally, mitigate the need for tariff adjustments and reduce the level of new generation plant needed to meet demand growth. Statistics indicate that distribution losses were 12.9% in 2008/09 and 12.4% in 2009/10 dropping further to 12.0% in 2010/2011. The aim is to reduce the losses to 11.0% by 2012/13 with overall losses at 14.5% in that year from the current 16%. Table 14 provides the historical and projected system loss statistics.

Table 14: Targeted financial impact from Power System Loss Reduction

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Projected Transmission & Distribution Efficiency %	83.40%	83.70%	84.10%	84.50%	85.00%	85.50%	85.50%
Projected Total Losses %	16.60%	16.30%	15.90%	15.50%	15.00%	14.50%	14.50%
Transmission losses %	3.60%	3.40%	3.50%	3.50%	3.50%	3.50%	3.50%
Distribution losses %	13.00%	12.90%	12.40%	12.00%	11.50%	11.00%	11.00%
Technical Losses	13.20%	13.10%	12.90%	12.80%	12.50%	12.00%	12.00%
Non-technical losses	3.40%	3.20%	3.00%	2.80%	2.50%	2.50%	2.50%
Projected Incremental Loss Reduction %	1.30%	0.30%	0.40%	0.40%	0.50%	0.50%	0.00%

Strategies and programs are discussed in the KPLC 5 Year Business Plan period to reduce both technical and non-technical (Commercial) losses. Technical losses in the distribution system are expected to be reduced on completion of the Distribution System Reinforcement and Upgrade component of the Energy Sector Recovery Project; where loss reduction is a major objective. Inclusion and implementation of loss reduction projects (new substations) to reduce technical losses in the Distribution Expansion Plan beyond the ESRP project and other planned works which include intensifying power system maintenance; improving the reactive power compensation by installing more capacitors at 11kV level; extending the MV network to shorten LV lines, where losses are highest; increasing the number of small distribution transformers to shorten LV lines; and system studies to determine network sites having highest losses and thereafter implement recommended remedial actions, are measures that will further enhance the loss reduction efforts.

2.5.1.4 Suppressed Demand

In the Kenyan system, a suppressed demand of about 100 MW has been assumed in recent years. The demand is added to the existing maximum demand to account for power not supplied due to

- System load outages at the time the peak demand occurred
- Loads switched off by industrial customers at peak to avoid running their plants under poor voltages
- Customers disconnected from the system for various reasons
- new customers awaiting to be connected having paid fully

There are variant views on the postulate of suppressed demand concept. One key counter argument is that the power system often has some customers out of supply even if the capacity of the system is adequate and so there is no suppressed demand. This notwithstanding, the level of suppressed demand assumed is however moderate and it can be retained as it is within the bounds of reasonable system reserve margin for the current size of the power system. When the suppressed demand is included as the starting level for demand projections, it has some impact particularly in the initial years as it tends to result in higher peak loads. The effect is however diluted in the long run when the forecast peak loads reach several times the current demand

2.5.1.5 The Loss of Load Expectation (LOLE)

The Loss of Load Expectation (LOLE) is the expected number of days (or hours) per year for which available generating capacity is not sufficient to meet the daily peak load demand. LOLE may also be expressed as loss of load probability (LOLP), where LOLP is the proportion of days per year that available generating capacity is insufficient to serve the daily peak or hourly demand.

LOLE = LOLP × PERIOD

In previous studies, the LOLE used in Kenya was 10 days per year. This can be converted to LOLP as follows:

LOLP = 10/365 = 0.027

In the recent past, stakeholders in the power sector have recommended that a LOLE of 1 day in 10 years be applied for least cost planning studies in Kenya so that we can achieve reliability criteria suitable for the country's Vision 2030 goal. The corresponding LOLP is therefore derived as follows:

LOLP = 1/ (10 × 365)
= 0.00027

The Expected Unserved Energy (EUE) measures the expected amount of energy per year which will not be supplied owing to generating capacity deficiencies and/or shortages in basic energy supplies. The cost of unserved energy used in the Kenya studies in the recent years is $0.84/kWh.

3.0 Introduction

The broad objective of the energy policy is to ensure adequate, quality, cost effective and affordable supply of energy to meet development needs, while protecting and conserving the environment by use of natural energy resources. The natural resources available in Kenya for exploitation are Small Hydro, Geothermal, Coal, Biomass, Biogas, cogeneration, tidal waves, solar and wind.

Currently, to meet the energy demand the country depends on imports such as petroleum fuels and electricity from Uganda and Tanzania. Consequently the Government of Kenya has embarked on the following broad objectives in the medium term to mitigate the current situation:

a) Diversification of the country's energy sources in order to lessen dependence on unsustainable sources like hydro power;
b) Development, rehabilitation and expansion of generating power plants;
c) Regional interconnections;
d) Expansion and extension of the national grid; and,
e) Energy efficiency and conservation.

The specific objectives are to:

i. provide sustainable quality energy services for development;
ii. improve access to affordable energy services;
iii. provide an enabling environment for the provision of energy services;
iv. enhance security of supply;
v. promote development of indigenous energy resources; and,
vi. Promote energy efficiency and conservation as well as prudent environmental, health and safety practices.
vii. Increase power generation capacity;
viii. Development of new and renewable energy technologies; and,
ix. Security of supply of petroleum fuels

3.1 Resources currently mobilized for energy Consumption in Kenya

3.1.1 Energy Supply

a) Domestic resources:

Wood fuel and charcoal (Biomass) supply close to 76% of the total energy consumption in Kenya. Of the balance 21% is supplied by imported petroleum products (including LPG) and only 3% is supplied by electricity from hydro, thermal and geothermal resources.

Wood fuel is largely used in rural areas by almost 80% of the total population in Kenya mainly for cooking and heating. Charcoal and wood fuel is also widely used in urban areas for cooking and heating as electricity use is considered expensive for cooking and heating. National energy supply can be summarized as in table 15 below.

Table 15: National Energy Supply

Energy source	GJ(Mill)	%
wood fuel	250	36
Charcoal	280	40
Petroleum	150	21
Electricity	20	3
TOTAL	700	100

Source: Household Energy Survey: Kanfor 2002 (corrected to 2010)

b) Imported resources

i) Petroleum:

Petroleum accounts for 21% of the country's primary energy source. The demand for petroleum has been growing steadily at above 10% per annum. Some of the petroleum is used in electricity generation as HFO in thermal plants. Currently, Kenya does not have any confirmed Natural petroleum reserves and as such all petroleum products both crude and refined are imported. Volatile international oil prices have put Kenyan consumers in a precarious position as they have to pay dearly directly or indirectly whenever oil prices go up.

The demand for petroleum products in Kenya is met through importation of refined products and refining of crude oil at the Kenya Petroleum Refineries Limited (KPRL). Importation of such crude is through the open tender system commonly known as the OTS. The processed crude meets about 45% of national demand. The rest (55%) is imported as refined petroleum products of which 70% is also imported through the OTS. Importation of petroleum products through the OTS allows all the oil marketing companies to access petroleum products at the same price and therefore ensures competition in the petroleum market.

On average 75% of petroleum crude oil imported into Kenya is Murban crude from Abu Dhabi, with the balance largely being Arabian Medium from Saudi Arabia. Murban crude is preferred because when processed it generates more diesel, petrol and kerosene and much less fuel oil than other crude oils. A trend analysis of the Murban crude oil prices (Free on Board - FOB) shows that between 2005 and 2009 its prices varied from a low of US$ 42.10 per barrel in January 2005 to a high of US$ 78.6 per barrel in November 2009. The 2010 price of Murban crude oil was US$ 77.5 per barrel in the month of January, increasing steadily to a peak ofUS$ 84.4 in the month of April then decreasing to US$ 75.9 in the month of September. The lowest price recorded so far was US$ 73.0 in the month of July.

ii) Electricity Imports

Kenya has traditionally been importing electricity from Uganda since 1957 to take care of electricity shortfall and system stability. An insignificant amount of electricity has also been imported from Tanzania since 2005.

Currently the country is interconnected with Uganda and Tanzania. In 2009/2010 the total imports were 38GWh mainly from Uganda. Over the last five years most of the imports have been mainly from Uganda. The possibility of interconnecting the Kenyan grid with the neighboring Ethiopia was considered in writing this report. Table 16 indicates the amounts of energy imported and exported to Uganda and Tanzania over the last five years.

Table 16: The electricity imports in GWh from 2005/06-2009/ 10

Electricity imports (GWh)					
	2005/06	2006/07	2007/08	2008/09	2009/10
UETCL	15	13	25	29	37
TANESCO	0.4	0.5	1.0	1.2	1.1
Total Imports	15	13	26	30	38
UETCL	24	73	46	27	26
TANESCO					1
Total Exports	24	73	46	27	27

Source: KPLC Annual Report

The export of electricity to Uganda has been on the decline since 2007 due to rising energy demand in Kenya. In 2009 Kenya exported 27 GWh to Uganda against an import of 30 GWh from the same country. This is a near balance import/export energy trade depicting a system stabilization interconnection rather than critical source of power.

iii) Coal

In Kenya, coal is used on a limited scale in industries for heating furnaces and steam generation. Commercial generation of electricity using coal is anticipated in this least cost plan by 2014. The coal being used in our industries is imported mainly from South Africa and some Asian countries. There are confirmed coal reserves in Eastern parts of Kenya and commercial exploitation is due to take off by 2012.

3.1.2 Sectoral end-use energy consumption

a) Electricity consumption (MWh) by Type of User

Total electricity consumption during the four year period shows an increasing trend as depicted in the table above with the highest consumption being in large commercial and industry followed by the domestic consumers.

Table 17: KPLC sales in GWh by customer category

TARIFF	TYPES OF CUSTOMERS COVERED BY THIS TARIFF	2003/04	2004/05	2005/06*	2006/07	2007/08	2008/09	2009/10
DC	Domestic	900	956	1,028	1,113	1,255	1,254	1290
SC	Small Commercial	476	522	522	558	590	823	823
B	Commercial (Medium) and							
	and Industrial(Medium)	819	885	901	985	996	n/a	
C	Commercial (Large) and							
	Industrial (Large)	1,683	1,776	1,877	2,054	2,108	n/a	
CI	Commercial and Industrial						3,020	3,153
								36
IT	Off-peak	55	53	54	50	74	43	
SL	Street lighting	7	8	9	11	13	15	16
	TOTAL	3,940	4,200	4,391	4,771	5,036	5,155	5318
	% INCREASE P.A.	7.8%	6.6%	4.5%	8.7%	5.6%	2.4%	3.5%

Source: KPLC Annual report 2009/10

b) Petroleum consumption in tones by Type of User

During the year under review, net domestic sales recorded an increase of 15.2% compared to the previous year. All sectors of the economy recorded increased consumption during the period under review, except agriculture and rail transport which declined by 29.1% and 37.0%, respectively. The retail pump outlets and road transport ; and aviation sector continued to be the largest consumer of petroleum fuels, jointly accounting for 73.3% of total domestic sales.

Table 18: Net domestic Sales of petroleum fuels by consumer category 2005-2009

'000 Tonnes

Year / User	2005	2006	2007	2008	2009*
Agriculture	35.7	34.8	56.5	37.1	26.3
Retail pump outlets and road transport	1344.5	1542.4	1570.4	1609.3	2054.5
Rail transport	17.9	20.5	16.4	13.5	8.5
Tourism	17.1	8.9	11.6	8.1	8.3
Marine (excl Naval Forces)	1.3	0.9	0.7	0.8	0.8
Aviation (excl Government)	549.4	588.0	635.7	567.0	592.4
Power generation	319.3	386.6	399.9	360.4	372.2
Industrial, commercial and other	362.4	405.9	408.8	482.0	570.0
Government	57.8	31.2	8.3	12.5	18.9
Balancing item	10.4	19.0	13.5	42.5	(41.3)

Source: Ministry of Energy
*Provisional

3.1.3 Energy balance

The country's energy balance is as indicated in table 19 below.

Table 19: Energy Balance

	Electricity		Petroleum Products (1)	Biomass	Total
1. SUPPLY: PRIMARY ENERGY	GWh	ktoe	ktoe	ktoe	ktoe
Domestic production	4,330 (2)	372	-	13,732	14,104
Plus: Imports	25	2	3,148	-	3,150
Total supply in Kenya	4,355	374	3,148	13,732	17,254
Minus: Exports	-41	-3	-15	-	-18
Total available for consumption in Kenya	4,314	371	3,133	13,732	17,236
Primary energy breakdown		2%	18%	80%	100%
2. FROM PRIMARY TO SECONDARY ENERGY					
Conversion of petroleum products to electric power: Net electric thermal generation	2,145	+ 184	-184	-	-
Minus: losses in thermal power plants	-	+ 352	-352	-	-
TOTAL	2,145	+ 536	-536		-

3. DEMAND: SECONDARY ENERGY					
Residential sector (including street li)	1,582	135	370	13,732	14,237
Commercial & Industry	3,811	328	480	-	808
Transport	-	-	1,747	-	1,747
Total Consumption	5,393	463	2,597	13,732	16,792
Losses in network	1,067	92	-	-	92
Losses in power plants	-	352	-	-	352
Total demand in Kenya	6,460(3)	907	2,597	13,732	17,236
Secondary energy breakdown		5%	15%	80%	100%

SOURCES: KNBS Economic Survey 2009 and KPLC Statistics

(1) Including 111 ktoe of coal and coke
(2) This generation of 4,330GWh (KNBS) is lower than KPLC statistics: 3,488 GWh hydro plus 1,020 GWh geothermal plus 9 GWh cogeneration = 4,517 GWh
(3) KPLC Statistics give an amount of 6,385 GWh

Conversion factors: 1 GWh = 0.0857 ktoe, or 1 ktoe = 11.67 GWh1 thermal GWh = 0.250 ktoe

3.1.4 Energy selling prices

On average the price of energy in Kenya has been on the increase as illustrated in Table 20 below. The price of motor fuels and kerosene increased to reach a peak in 2008 before dipping in 2009 and has been on the rise in 2010. LPG and charcoal prices have steadily risen from 2007 to date. The average price of charcoal per a four kilogram Tin increased from 32.39 in 2007 to 42.1975 in 2010. The electricity selling price has averaged 12kshs with the highest being in 2010 at kshs12.58/kWh mainly due to Emergency power generation due to poor hydrology.

Table 20: Energy selling prices

WEIGHTED ANNUAL AVERAGE RETAIL PRICES FOR SELECTED FUELS IN KENYA							
PERIOD	MOTOR GASOLINE PREMIUM (KSh Per Litre)	MOTOR GASOLINE REGULAR (KSh per Litre)	LIGHT DIESEL OIL, GASOIL (KSh per Litre)	ILLUMINATING KEROSENE (KSh per Litre)	L.P.G (KSh per 13Kg)	Charcoal (KSh per 4 Kg Tin)	Electricity
2007	80.08	79.32	68.75	57.56	1631.90	32.39	7.67
2008	97.12	95.16	89.27	75.15	1800.65	35.95	12.00
2009	80.86	79.90	70.62	61.31	1919.18	39.60	12.08
2010	87.23	83.71	76.4	64.16	2000.53	42.1975	12.58

Source: Kenya National Bureau of Statistics

3.2 Energy resources available for future power supply

Energy is one of the enablers for Kenya Vision 2030. Currently, Kenya depends on biomass (68%), hydrocarbons (22%) electricity (9%), solar and other forms of energy (1%) for its energy needs with petroleum and electricity dominating the commercial energy. The country has an installed electricity generation capacity of 1,533 MW and an effective capacity of 1,515MW under average hydrological conditions. The unsuppressed peak demand stands at 1,178MW. This leaves no reserve margin to allow for reduced hydro generation as is being experienced currently, and plant breakdowns. In the short term the Government has contracted an emergency power producer to fill the gap by generating 60MW.

The supply of adequate energy for household and industrial needs has in the past faced major challenges which the sector is going to address over the plan period. Some of these challenges include high infrastructure development costs, long lead time required to implement energy projects, over reliance on hydro power, high cost of energy, inability to deliver adequate energy to meet national needs, and low investments in the sector, among others.

In the medium term, the sector plans to inject 1815MW which will be attained through commissioning of additional geothermal power plants (404.2MW), Hydro Plants (78MW), Coal fired plants (360 MW), Medium Speed Diesel Plants (342 MW) and 430.4 MW of wind plants. The sector will also enhance energy efficiency and conservation as well as expand and extend the national grid.

3.2.1 Renewable Energy

Under the renewable energy sub-sector the over-riding issue is the development of domestic renewable energy resources to reduce dependence on imported oil. In particular, the following is being undertaken:

a. Establishing an appropriate legal framework for wood fuel development;

b. Promoting consumption of cleaner energy such as LPG to reduce pressure on forests and vegetation;

c. Promoting energy conservation technologies including use of improved charcoal stoves and jikos and energy saving bulbs;

d. Giving duty and tax incentives for any renewable energy technologies.

3.2.1.1 Hydro potential

Kenya has a considerable hydropower potential estimated in the range of 3000-6000 MW. Currently over 750MW is exploited, mainly in large installations owned by the national power generation utility, KenGen. The existing hydropower plants contribute over 50% of national annual electricity generation. There are 8 power stations with capacity of more than 10MW each that have reservoirs. At least half of the overall potential originates from smaller rivers that are key for small-hydro resource generated electricity. With the introduction of the feed in tariff policy in 2008 small-scale candidate sites are likely to come up and serve well for the supply of villages, small businesses or farms.

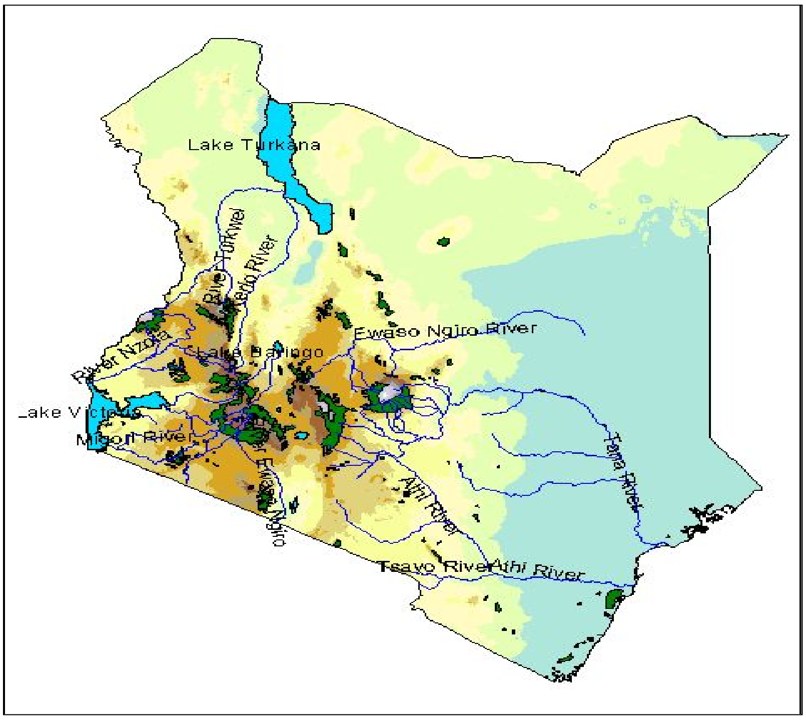
It is estimated that the undeveloped hydroelectric power potential of economic significance is 1,449 MW, out of which 1,249 MW is for projects of 30MW or bigger. Average energy production from these potential projects is estimated to be at least 5,605GWh per annum. This hydropower potential is located in five geographical regions, representing Kenya's major drainage basins. Lake Victoria basin (295MW), Rift Valley basin (345MW), Athi River basin (84MW), Tana River basin (570MW) and Ewaso Ngi'ro North River basin (146MW). Table 21 indicates the five major drainage basins in Kenya while Figure 11 shows the major rivers in Kenya

Table 21: Major Hydro Potential

River Basin	Potential Capacity (MW)	Average Energy (GWh/yr)	Firm Energy (GWh/yr)
Tana	570	2,490	1,650
Lake Victoria	295	1,680	1,450
Ewaso Ngiro North	155	675	250*
Rift Valley	345	630	300*
Athi Basin	84	460	290

Source: Kenya National Power Development Plan (1986-2006)
* Estimate

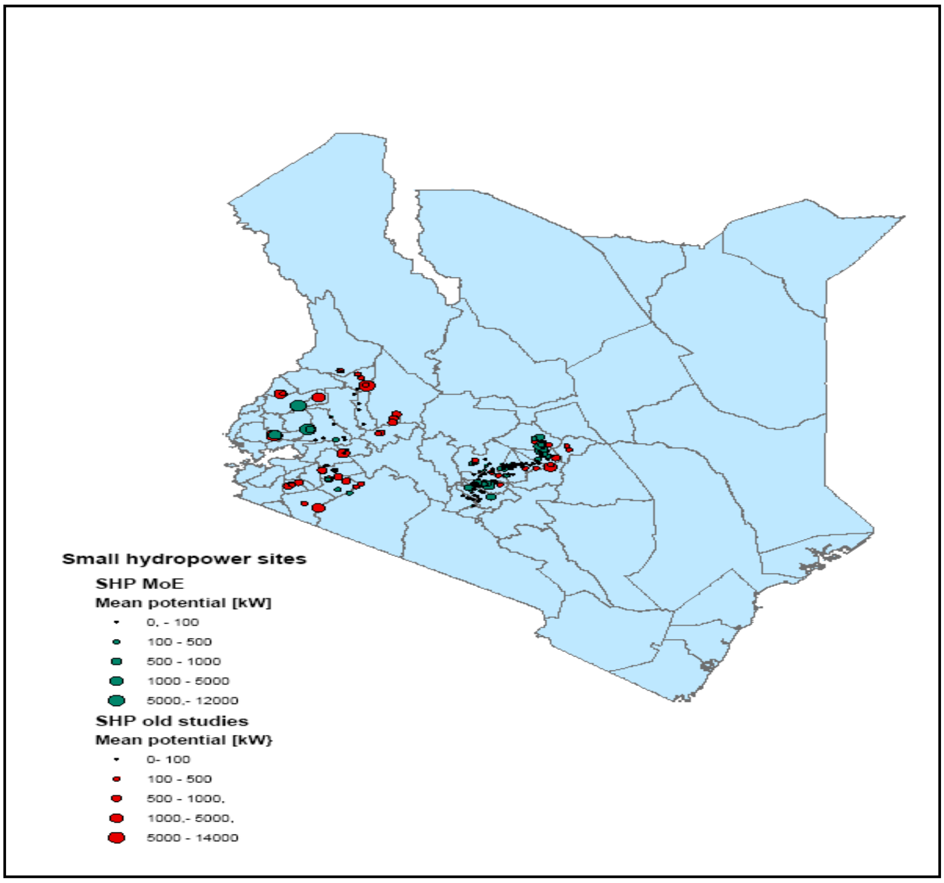
Figure 11: Major Rivers



Small hydroelectric potential:

There is a growing consciousness of the possibilities that small hydropower might offer vast generation options and several studies and investigations have been carried out. However, so far only a few small hydro schemes have been realized, either as part of the national grid supply or as stand-alone systems for agro-industrial establishments or missionary facilities. Figure 12 illustrates Small Hydropower Schemes Currently Investigated and or Implemented.

Figure 12: Small Hydropower Schemes Currently Investigated and or Implemented



Challenges for further development:

The economic risk in hydropower projects can be large, because they are capital intensive. There is uncertainty with regard to power prices in the future, and the costs of building and producing hydropower vary strongly from power plant to power plant with some of the main variables being the size and location of the plant. A small generator requires approximately as many people to operate as a large one. Larger hydro power plants normally have a lower cost per kilowatt.

A hydropower-dominated power system like Kenya's is vulnerable to large variations in rainfall and climate change. This has proved to be a big challenge in the recent past with the failure of long rains that resulted in power and energy shortfalls.

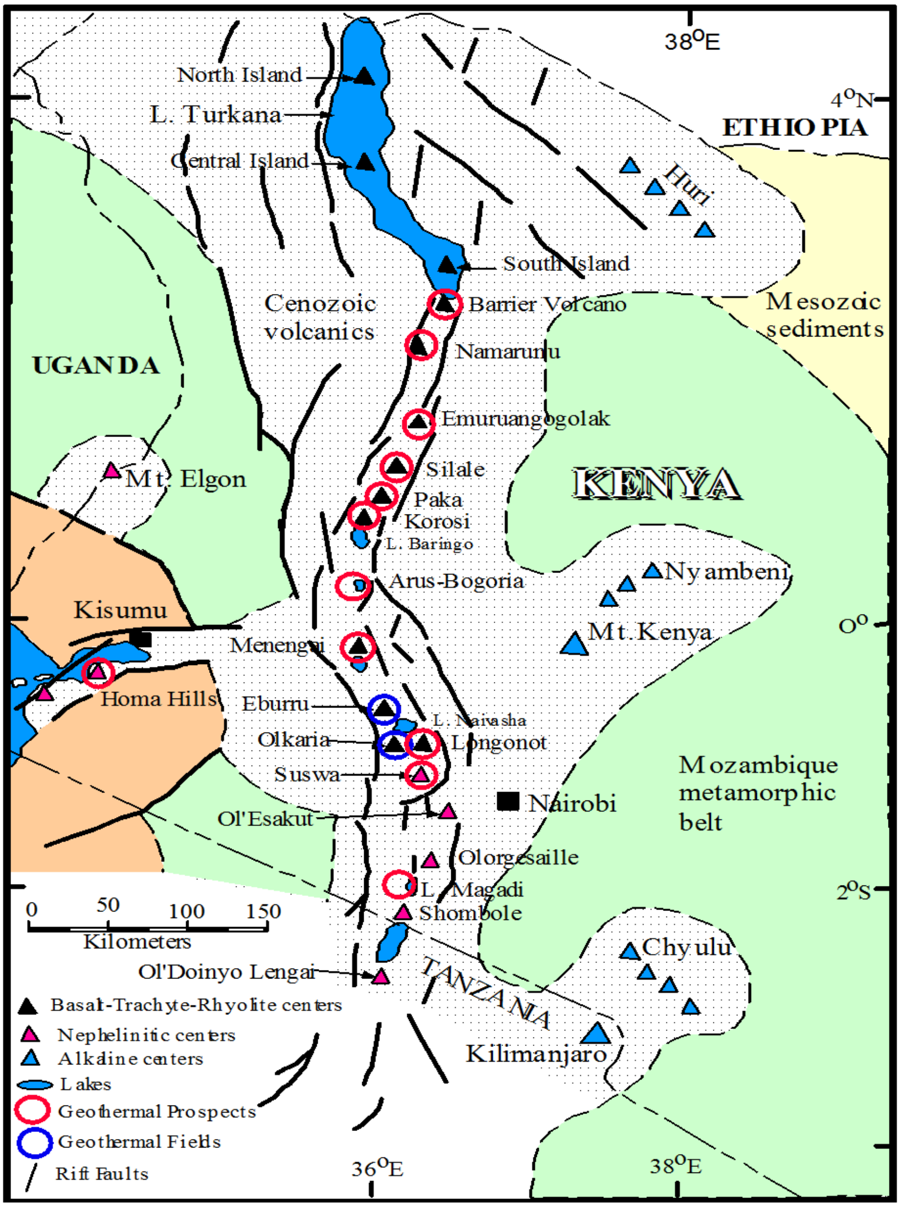
Naturally, it is a big challenge for a hydro project if people have to be relocated. This has been the main reason why the Magwagwa hydro project on river kipsomei-Kericho that is in a densely populated area has not been implemented.

3.2.1.2 Geothermal resources

Geothermal activities in Kenya are concentrated in the East African Rift which is associated with the worldwide rift system and is still active. The East African Rift system has been associated with intense volcanism and faulting which have resulted in development of geothermal systems. Over fourteen geothermal prospects have been identified in Kenya namely; Suswa, Longonot, Olkaria, Eburru, Menengai, Arus-Bogoria, Lake Baringo, Korosi, Paka, Lake Magadi, Badlands, Silali, Emuruangogolak, Namarunu and Barrier geothermal prospects.

The Government through the Ministry of Energy, GDC, KenGen and other partners has undertaken detailed surface studies of some of the most promising geothermal prospects in the country. Evaluation of these data sets suggest that 5,000MWe to 10,000MWe can be generated from the high temperature resource areas in Kenya in over fourteen sites. These prospects are clustered into three(3) regions namely the Central Rift(1,800MW), South Rift(2,450MW) and North Rift (3,450MW). See figure 13 for Location of geothermal prospects within the Kenyan Rift Valley. Geothermal is currently the most promising indigenous resource for development of power. At present, the country has 198MW installed capacity and a geothermal development plan (in Annex 2) is being implemented by the Geothermal Development Company (GDC).

Figure 13: Location of geothermal prospects within the Kenyan Rift Valley



Rift Region	Potential (MW)
Central Rift	
• Menengai	1,600MW
• Eburru	250MW
• Arus Bogoria	400MW
	2,250MW
South Rift	
• Olkaria	2,000MW
• Longonot	750MW
• Suswa	600MW
• Lake Magadi	100MW
	3,450MW
North Rift	
• Lake Baringo	200MW
• Korosi	450MW
• Paka	500MW
• Silali	1,200MW
• Emuruangogolak	650MW
• Namarunu	400MW
• Barrier	450MW
	3,850MW
Nyanza	
Homa hills	100MV
Akira	350MW
	450MW
Total Potential	10,000MW

3.2.1.3 Biomass

Biomass energy is derived from forest formations, farmlands, plantations and agricultural industrial residues and includes wood fuel and agricultural residues. Wood fuel remains the highest supplier of household energy consumption in rural Kenya. In addition, industries like the cottage industry including tea factories rely heavily on wood for their energy needs. This implies that wood production as a source of energy will be intensified so as to be made sustainable.

The Kenya Energy Sector Environment and Social Responsibility Programme (KEEP) within the energy sector has initiated the growing of trees as a source of energy. However this effort can only be sustained through collaboration with key sectors like forestry and agriculture. Equally important, sustainable production of other biomass requires similar collaboration because of the integrated nature of land use system.

At the national level, wood fuel and other biomass account for about 68% of the total primary energy consumption. To accelerate transition from traditional to modernized biomass energy use, the Ministry will conduct a comprehensive study to establish cogeneration potential from bagasse and other biomass waste.

3.2.1.4 Cogeneration

Cogeneration using bagasse as a primary fuel is common practice in the domestic sugar industry in Kenya. The industry comprising of six sugar companies produces an average 1.8 million tonnes of bagasse with fibre contents of about 18% by weight annually and a total export potential of 830GWh/year. Mumias is currently exporting 26MW energy to the national grid.

Table 22: Power Potential from Bagasse

	Cane crushing capacity (Tonnes crushed per Day)		Bagasse Available (Tonnes per Day)		Power Generation (MW)		Electrical Energy Generation Potential (GWh/Year)		Internal Usage (Gwh/year)		Export (Gwh/year)	
Factory	Current	Potential	Current	Potential	Current	Potential	Current	Potential	Current	Potential	Current	Potential
Chemelil	2,500	7,000	950	2,660	10	29	48	156	14	47	34	108
Muhoroni	2,200	4,000	800	1,720	9.8	19.8	35	134	7	27	28	108
Mumias	7,100	9,135	2,850	3,650	32	47	214	236	52	57	162	179
Nzoia	2,600	7,000	1,090	2,940	14	40	52	221	11	47	41	174
Sony	3,000	6,500	1,110	2,405	15	37	74	231	16	50	58	181
West Kenya	1,320	3,500	488	1,295	5	20	25	109	5	29	20	80
Total	18,720	37,135	7,288	14,670	85.8	192.8	448	1,087	105	257	343	830

3.2.1.5 Biogas

Biogas potential in Kenya has been identified in Municipal waste, sisal and coffee production. The total installed electric capacity potential of all sources ranges from 29-131MW, which is about 3.2 to 16.4% of the total electricity production. Table 23 depicts the various sources and their electricity production potential.

Table 23: Biogas Energy Potential by Source

Source	Energy potential (GWh)
Coffee	12.6 - 147.6
Chicken	5.8 – 24.7
Cut flowers	2.4 – 7.6
Tea	2.7 – 7.8
Sisal	65.4 – 284.3
Sugar	18.6 – 42.8
Milk	1.4 – 7.2
Pineapple	9.6 – 26.6
Municipal waste	80.6 – 512.6
Distillery	1.8 – 14.9
Meat	0.09 – 0.6
Pig	1.6 – 3.8
Vegetable	0.02 – 0.2

Source: GTZ 2009

Challenges in using Biomass resources

One of the most significant barriers to accelerated penetration of all biomass conversion technologies is that of adequate resource supply. Feedstock costs vary widely depending on the type of biomass and the transport distance. The most economical approach is to use bio-energy on site, where the residue is generated.

Since much bioenergy resources used today originate as waste products from industry and households, they have low heat value.

3.2.1.6 Solar Energy Resources

Kenya has great potential for the use of solar energy throughout the year because of its strategic location near the equator with 4-6 kWh/m2/day levels of insolation. It is estimated that 200,000 photovoltaic solar home systems, most of which are rated between 10 We and 20 We estimated at a cost of Kshs 1,000/We, are currently in use in Kenya and generate 9GWh of electricity annually, primarily for lighting and powering television sets. However this is only 1.2% of households in Kenya.

Over the last three years, the number of home systems installed has grown at an average of 20,000 units per annum and the demand is projected to reach 22GWh annually in the year 2020. This can be attributed to the launch of launch of a programme for installation of PV in educational and health institutions in arid and semi-arid areas by the Ministry of Energy, under Rural Electrification Programme. A separate programme on the provision of PV systems to about 100 health centres and 500 dispensaries has also been initiated.

With the enhanced state support, it is estimated that the rate of market penetration will improve considerably. Given that there are four million households in rural Kenya alone, the potential for photovoltaic solar home systems is virtually untapped. It is therefore expected that with the diversification of rural electrification strategies, the number of installed solar home systems will grow substantially. This can be harnessed for water heating, and electricity generation for households and telecommunications facilities in isolated locations.

Table 24 displays the distribution of the irradiance classes and the total area coverage in m^2 and km^2.

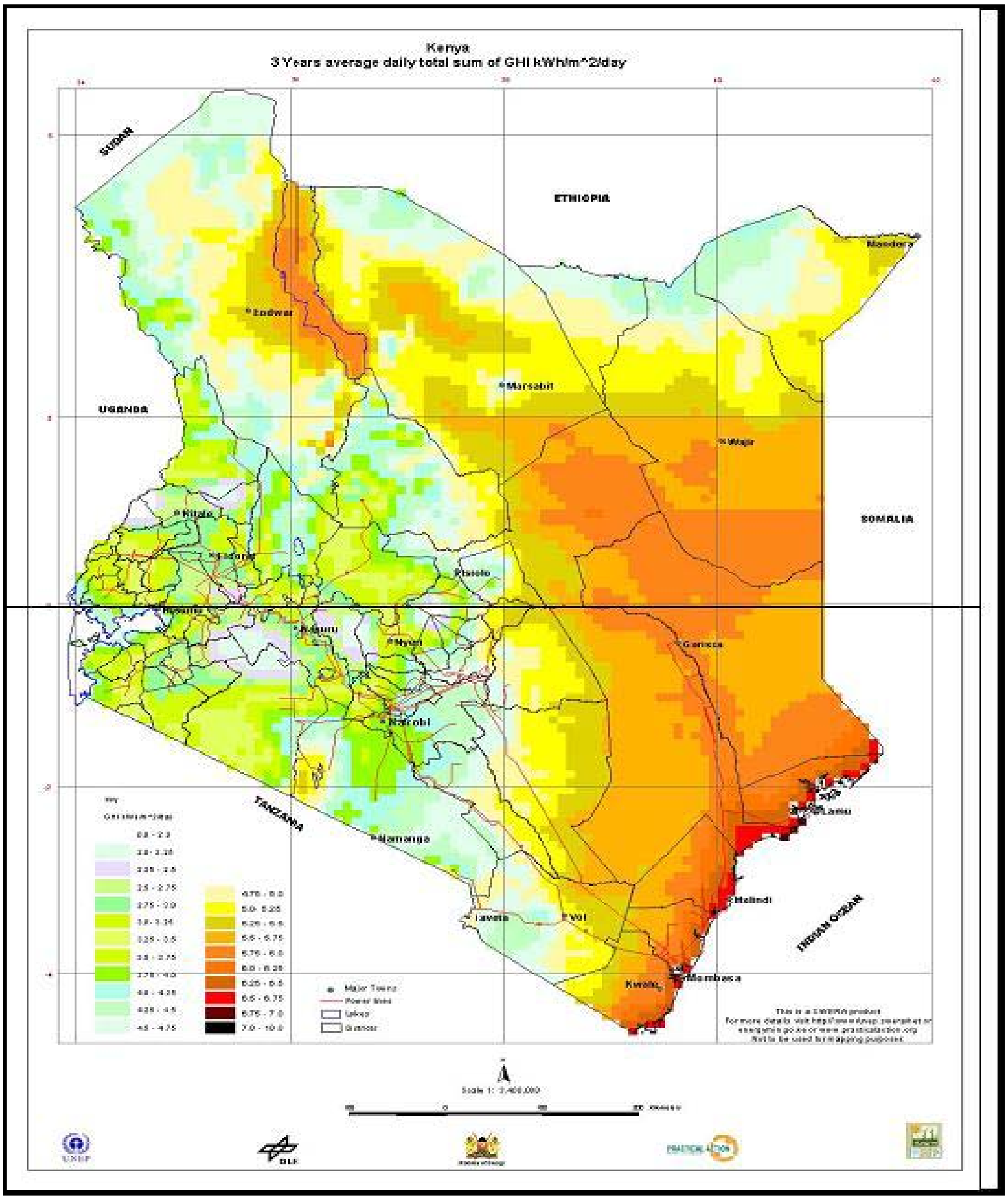
Table 24: Analysis of the solar energy available

Direct Normal irradiance classes (kW/m2)	Area in km2
3.50 - 3.75	41,721
3.75 - 4.00	61,515
4.00 - 4.25	140,326
4.25 - 4.50	177,347
4.50 - 4.75	137,572
4.75 - 5.00	96,199
5.00 - 5.25	62,364
5.25 - 5.50	48,826
5.50 - 5.75	33,848
5.75 - 6.00	20,211
6.00 - 6.25	24,675
6.25 - 6.50	33,690
6.50 - 6.75	22,468
6.75 - 7.00	16,240
7.00 - 7.25	6,736
7.25 - 7.50	2,656

Source: SWERA, 2008

Direct normal irradiance of 6.0kW/m^2 will provide heat for institutions, households and industry. As indicated in the table above the total area capable of delivering 6.0 kW/m^2 per day in the country is about 106,000 square kilometers whose potential is 638,790 TWh. See figure 14 for Map of Kenya showing 3 Year average Global Horizontal Irradiance (GHI).

Figure 14: Map of Kenya showing 3 Year average Global Horizontal Irradiance (GHI)



Source: SWERA, 2008

3.2.1.7 Wind resources

Of all renewable energy sources, wind power is the most mature in terms of commercial development. The development costs have decreased dramatically in recent years. Potential for development is huge, and the world's capacity is far larger than the world's total energy consumption. Worldwide, total capacities of about 60,000MW have been installed, with a yearly production of about 100 TWh.

There is still little experience in using wind for power generation in Kenya, however, awareness and interest is steadily growing. The most recent investment in wind energy in Kenya is KenGen's 5.1MW farm in Ngong comprising six 850kW turbines installed in August 2009. A further 610MW are to be developed by IPP's comprising; 300MW by Lake Turkana Wind, 60MW Aeolus Kinangop wind, 100MW Aeolus Ngong' wind, 60MW Osiwo Ngong' wind, 60MW Aperture Green Ngong' and 30MW Daewoo Ngong' wind.

Local production and marketing of small wind generators has started and few pilot projects are under consideration. However, only very few small and isolated wind generators are in operation so far.

Best Wind Areas excluding Protected Areas

The Best wind sites in Kenya are Marsabit district, Samburu, parts of Laikipia, Meru north, Nyeri and Nyandarua and Ngong hills. Other areas of interest are Lamu, off shore Malindi, Loitokitok at the foot of Kilimanjaro and Narok plateau, see Figure 15. On average the country has an area of close to 90,000 square kilometers with very excellent wind speeds of 6m/s and above.

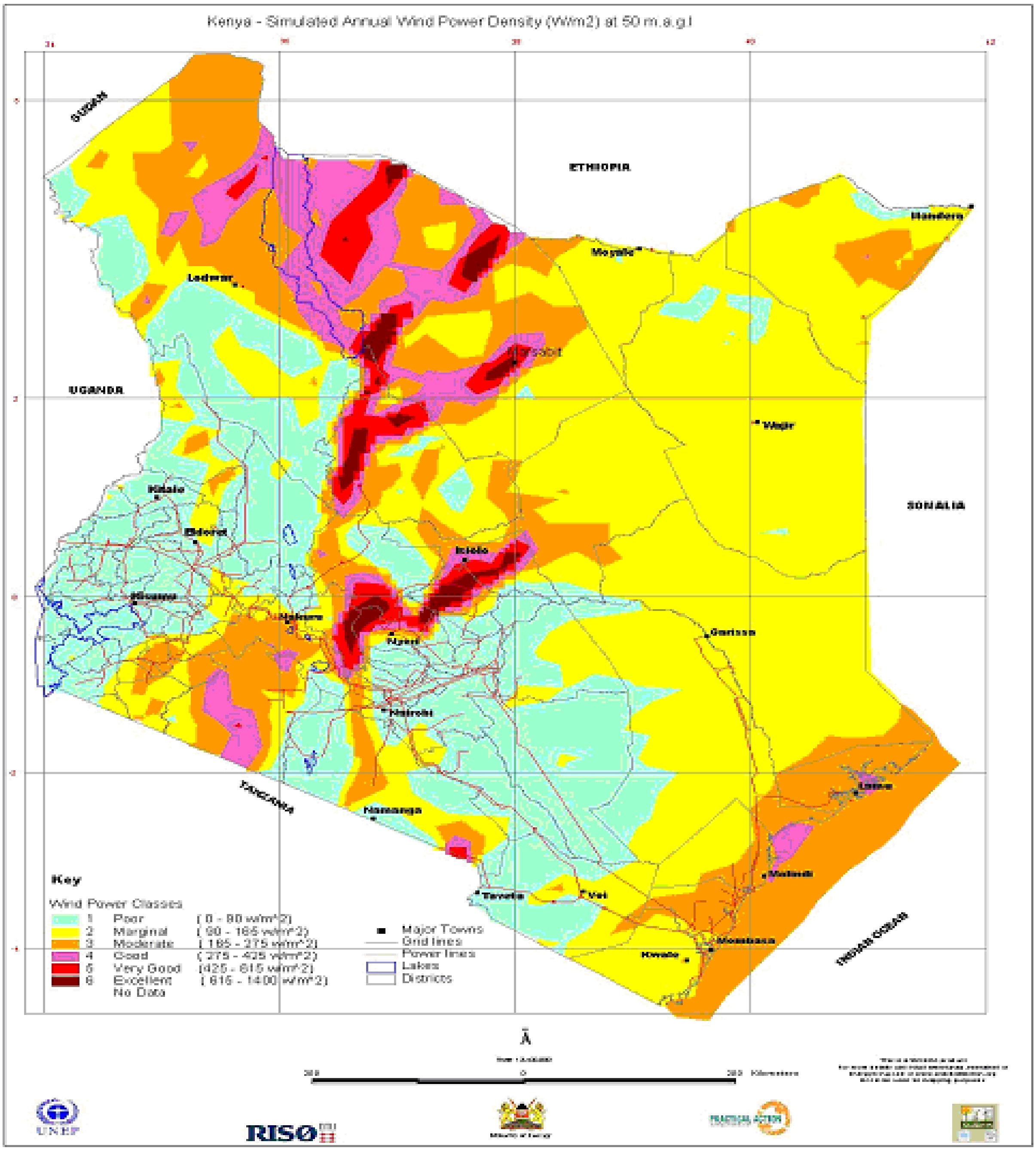
It is estimated that 3.75 million households in Kenya are in areas with wind speeds of less than 4 meters per second, considered as low energy areas. Some 2.3 million households are in areas with wind speeds between 4 and 6.98 meters per second, considered good wind potential areas. Only 132,000 households are in areas considered very good to excellent for wind investment which also provide good opportunity for development of large wind farms as there would be minimal human interference.

Potential Utilization Options for Wind Power

The following regions in Kenya are considered as promising and worth further investigations:

- Aberdare Mountains (Central Province, Nyeri and Nyandarua Districts);
- Wider surroundings of Mount Kenya, incl. the entire area between Aberdare Mountains, Mount Kenya and Nyambeni Hills (northern districts of Central and central districts of Eastern Province);
- Escarpments to the Rift Valley (mainly Rift Valley Province);
- Areas around Marsabit (Northern Kenya, northern part of Eastern Province, Marsabit District; already under consideration);
- Coastal area (Coast Province: Kwale, Mombasa, Kilifi, Tana River and Lamu Districts, plus North Eastern Province: southern part of Ijara District; with slightly lower potential).

Figure 15: Simulated annual wind power density at 50m above ground



Source: SWERA, 2008

3.2.2 Fossil fuels

3.2.2.1 Local coal reserves

The Government is currently undertaking coal exploration activities in Mui basin that traverses Kitui and Mwingi districts, about 200km from Nairobi to the Eastern side of the country. The basin is about 500 square kilometers in size divided into Zombe, Kabati, Itiko, Mutitu, Yoonye, Kateiko, Isekele and Karunga sub-basins. The Ministry of Energy has so far drilled 40 appraisal wells in the basin intercepting coal seams of up to 16 meters in 27 of the wells. Preliminary tests on the coal samples from Mui basin have exemplified close similarities with coal types used in South Africa for power generation as shown by Table 25.

Table 25: Preliminary Results on Local Coal Quality

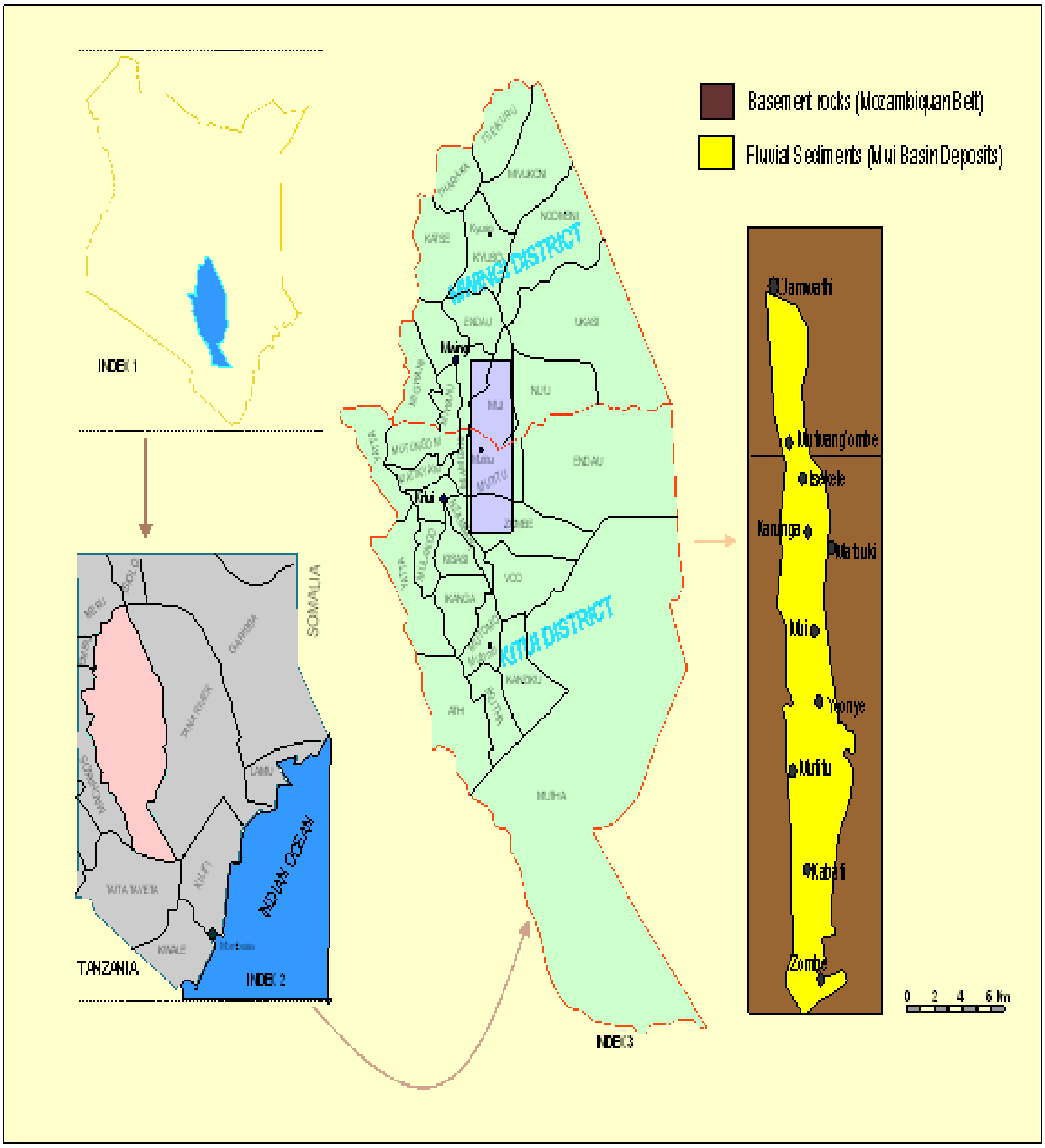
	Kenya	Eskom (general)	New Vaal
Calorific Value (MJ/kg)	18.0	21.0	16.0
% Ash content	37.0	30.0	40.0
% Volatiles	25.0	23.0	16.0
% Fixed Carbon	40.0	44.0	36.0
% Moisture content	8.0	4.0	6.0
% Sulphur content	2.4	1.0	0.5

To speed up exploration and development of the coal resources in the basin, the Government has contracted the services of an international company to firm up the quantity, quality and the commercial viability of the exploitation of the local coal resources for different applications, including power generation. In addition, the Government has demarcated the basin into four blocks with a view to offering concessions to private sector developers. Further coal resource exploration work has also commenced in other prospective sites such as Taru basin in Kwale District. Figure 16 indicates the Location of the Mui Basin.

3.2.2.2 Imports of coal

Kenya imports an average of 3.6 million tonnes of coal annually for use mainly in manufacturing industries. Coal can also be used as a substitute for more expensive oil in generation of electric power and also supplement hydro-generated electricity shortfalls whenever there is a prolonged drought. Kenya has potential for discovery of coal deposits. The Ministry will explore coal resources for exploitation including for power generation and industrial use. Coal blocks are currently being demarcated for ease of management

Figure 16 : Location of the Mui Basin



3.2.2.3 Imports of petroleum products

Currently about 35% of the country's electricity installed capacity is petro thermal based which requires a lot of imported petroleum products since Kenya doesn't have any oil of its own. In the recent past the value of imported petroleum products has been on the decline due to reduced prices as a result of reduced international demand. The value of import of petroleum products declined by 20.7% from Kshs 198.7 Billion in 2008 to stand at Kshs 157.5Billion in 2009. The value of crude oil imported into the country dropped by 33.1% from Kshs 81.5 Billion in 2008 to Kshs 54.5 Billion in 2009. Similarly, the value imported petroleum fuels decline by 15.5% compared to a significant increase of 59.3% in 2008. Despite the increase in the quantity of petroleum imports, the value of imported petroleum products decreased due to reduced oil prices in the international market.

3.2.3 Power Imports and Exports

This will be made possible by way of Regional Interconnections. The regional interconnections are progressively evolving with the expected planned transmissions lines linking regional countries likely to be implemented under the Eastern Africa Power Pool (EAPP) the Nile Basin Initiative and the Nile Equatorial Lakes Subsidiary Action Programme. These lines include Kenya- Isinya-Tanzania (Arusha) 400kV line, second Kenya (Lessos)-Uganda (Jinja) 220kV line, Kenya-Ethiopia 500kV DC line and a 132kV cross-border electrification line to Moyale town from Ethiopia.

4 LOAD FORECAST STUDY

4.1 Introduction

The first step in planning the development of a power system is the preparation of an acceptable and accurate assessment of the future electricity demand. The load forecast is used to shape the entire power sector expansion programme. It will determine future requirements for both the capacity (in MW) and energy (in GWh) for planning a supply system capable to match the demand and the future generation and transmission investments.

A reliable electricity demand forecast is deemed compulsory, because electricity supply is a public service using public funds, which must be used in the most appropriate way. A high load forecast would lead to overinvestment with extensive redundant capacities, while an insufficient demand forecast would result in capacity shortfalls when demand would outstrip supply.

As stated in the new Constitution promulgated in August 2010, "the values and principles of public service include…..efficient, effective and economic use of resources" (Art. 232). Achieving this objective requires the provision of a balanced load forecast, which implies the implementation of a proven methodology, accurate input data and appropriate assumptions.

The load forecast presented in this Chapter covers a period of 20 years, from 2011 to 2031. It sets out the following:

- First, the economic context of Kenya's current and future development.
  The power sector expansion is closely linked to the economic growth of the country and that of neighboring countries

- Secondly, the methodology used for preparing the forecast, the assumptions underlying the forecast, and then the results of the forecast, both for energy and system peak load.

- Finally, the demand coming from Flagship projects is described and added to the forecast worked.

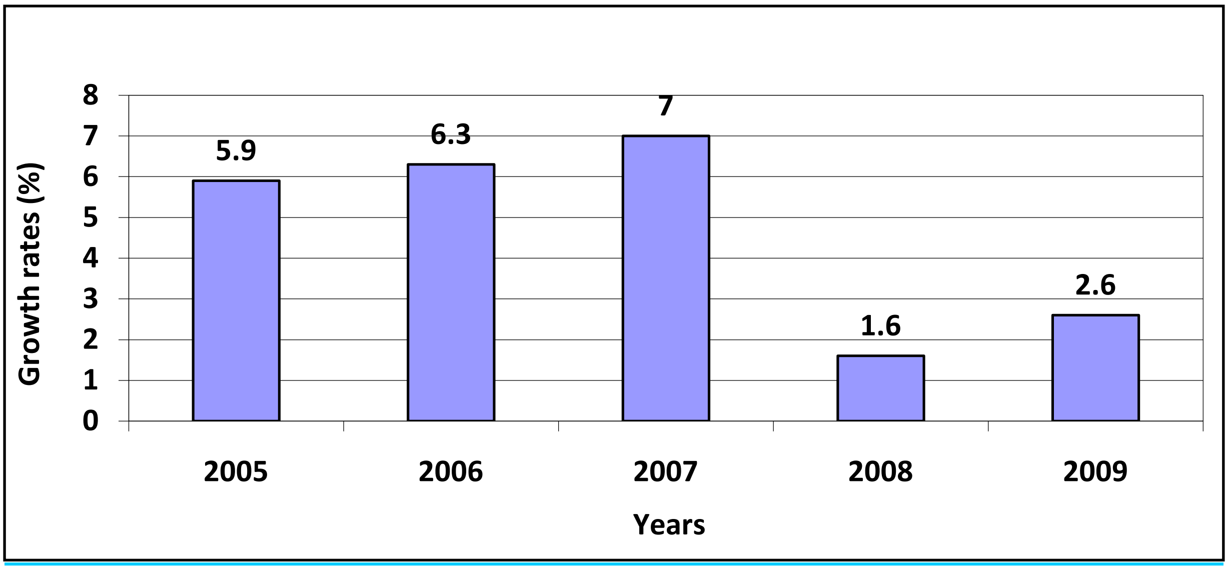
4.2 Overview of the Domestic Economy

4.2.1 Current GDP growth

The country's real Gross Domestic Product increased from 1.7% in 2008 to 2.6% in 2009. This growth was mainly supported by increased activity in the tourism sector, resilience in the building and construction industry and the government intervention through an economic stimulus package. However the growth rate was below the predicted rate of 5.7% due to unfavorable weather which reduced domestic demand and global economic recession which subdued external demand. The Global economic recession was felt mainly through depressed demand for horticultural produce abroad and inadequate recovery in tourism.

Kenya's growth has picked up and is now on upward trend. During the last quarter of 2009 the economic growth recorded an increase of 3.4%, raised to 4.4% in the first quarter of 2010. Based on this trend, it is anticipated that the past growth reported until 2007, when the economy grew at 7.1% per year, will be again achieved and even surpassed as the country progresses towards the realization of the Vision 2030. Figure 17 shows the annual real GDP growth pattern witnessed in the period 2005 to 2009.

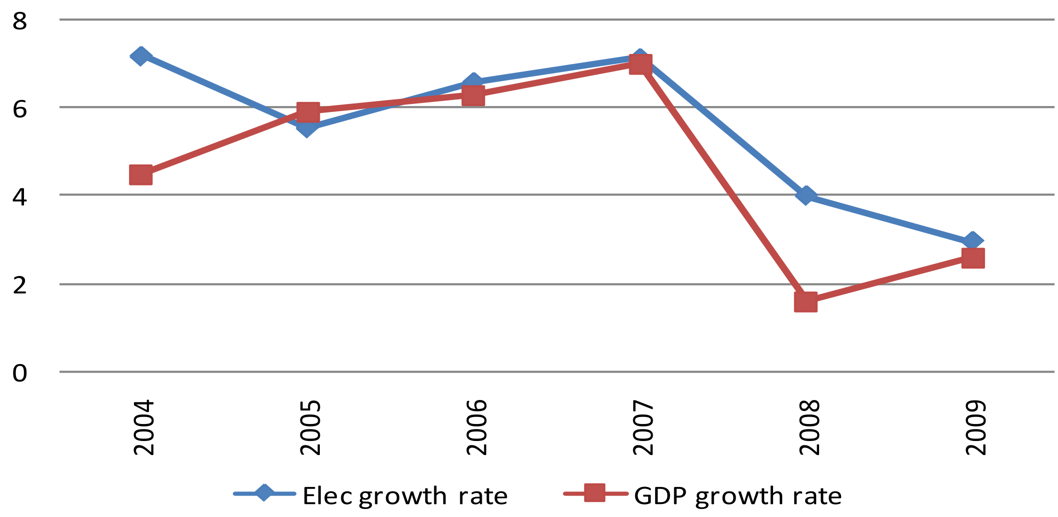
Figure 17 : Real GDP Growth Rate, 2005- 2009



4.2.2 Current performance of the Power Sector

The growth in electricity demand in Kenya shrunk from 8.75% in 2006/07 to 5.6% in 2007/08, 2.4% in 2008/9 and 3.2% in 2009/2010 primarily due to the depressed performance of the domestic economy over this period. In addition, electricity sales in the country were also affected by the implementation of a load shedding programme that was occasioned by poor hydrology in the country's Seven Forks cascade which accounts for over 40% of the total installed capacity. Figure 18 below shows the trending of growth in electricity sales and GDP over the period 2003 to 2009. It is apparent from the figure that electricity demand closely follows the economic growth pattern with electricity sales consistently staying above the GDP growth rate.

Figure 18: Time series of electricity demand and GDP



4.3 Future Economic Outlook: The Vision 2030

Until 2007, the Economic Recovery Strategy for wealth and employment creation (ERS) established the foundation upon which to build a prosperous Kenya and a robust economic growth. Following ERS, the Government launched the Vision 2030 for outlining the broader macro-economic objectives and strategy of the country up to the year 2030. The Vision 2030 was further elaborated in the Medium Term Plan 2008-2012 (MTP) which aims at consolidating the gains of the ERS. This is based on the implementation of a low and stable inflation and interest rates, sustainable public debt, competitive environment and refurbishing of infrastructures.

The Vision 2030 describes the way Kenya will be transformed from a low income agrarian economy into a newly industrialized middle income country, providing a high quality of life to all its citizens. This goal is based on three pillars, namely political stability, social development and economic growth. The economic objectives supporting the Vision 2030 require an annual GDP growth of at a least 10%, to be reached by the year 2015. For achieving this target six key sectors of production have been identified: tourism, agriculture, manufacturing, wholesale and retail trade, business processes out outsourcing (BPO) and financial services. The Vision 2030 identifies energy and electricity as a key element of Kenya's sustained economic growth and transformation.

4.4 Kenya in the African Context

4.4.1 Economic Growth in Africa

Although some conflicts persist within Africa, peace is returning to a number of countries devastated by decades of warfare. These include Angola, Mozambique, Rwanda and Sierra Leone. Above all, Africa is moving away from stagnant economy and persistent poverty. Throughout the last decade, economic growth has reached 5.3% per year, against 1.5% for developed countries and 1% for Europe, allowing Africa GDP to exceed 1,000 billion US$(2009).

Moreover, Africa has shown excellent resistance to the worldwide crisis. Economic activity has increased by 2% in 2009, which is in contrast with a recession of 2.4% in the United States, and 4% in Europe.

4.4.2 The new Economic African Way of Development

Current accelerated growth is the result of drastic changes in the African economic model:

a) First, choosing insertion in the global economy, as opposed to protectionism. Eight countries: South Africa, Algeria, Botswana, Egypt, Mauritius, Libya, Morocco, Tunisia, are entering the global world and display an income per capita of 10000 US$, higher than that of the BRIC (Brazil, Russia, India and China), which only reach 8800 US$.

b) Second, in addition to the traditional links with Europe and USA, the development of the South to South trade. For instance trade with China has increased tenfold, and is reaching 100b US$ per year. Links with India (40b US$) and Brazil (7 b US$) are also of increasing importance.

c) Replacing of purely state owned organizations with economic actors is a leading factor of development. Productivity gains are associated with an emerging African capitalism with 522 companies quoted on the stock exchange in 16 financial centers. In parallel, consumption is soaring, as shown by the success of mobile telephone (400 millions of headphones) sales and ownership.

According to IMF, Sub Sahara Africa's GDP increased by 4.5% in 2010, and will increase by 5.5% in 2011. This booming African economy is a real chance for Kenya, to achieve faster development than in the past decade. From this viewpoint, the future GDP growth in Kenya as forecast in the Vision 2030 seems quite feasible.

4.5 Demand forecasting Methodology

4.5.1 Introduction

The load forecast in the 2010-2030 LCPDP Update was done using a macro econometric model with the main driving factor for the electricity projections being future GDP growth. Although approach was acceptable, it presented a drawback due to its global approach which prevented in-depth investigations within the electricity demand.

For this reason it was decided that this year's update uses a more disaggregated approach the Model for Analysis of Energy Demand (MAED) software, a tool developed by the International Atomic Energy Agency for its member states. However due to data challenges it was not possible to run the model and instead an excel model was developed using MAED principles and assumptions which indicate that the nature and the level of demand for goods and services are driven by several determinants including;

- Population
- Household size
- Specific consumption (kWh/household/year)

- Expected social and economic evolution of the country including the saving from the energy efficiency programmes.
- Impact of major projects outlined in The Vision 2030; hereunder, these projects are referred to as flagship projects.

4.5.2 Energy forecast methodology

4.5.2.1 Customer categories

The demand analysis follows three end-use customer categories according to voltage levels:

Low voltage level (240 /415kV):	Domestic customers (including off peak tariff and REP)
	Street lighting
	Small commercial customers
Medium Voltage level (33 kV):	Medium commercial and industrial customers
High Voltage level (66 & 132 kV):	Large commercial and industrial customers

4.5.2.2 Principles used in the MAED spreadsheet

The demand forecast of a given customer category was divided into the forecast of two other parameters, the forecast of which was easier than the demand of that category.

a) For domestic consumption:

- Demand = Specific consumption x energy efficiency x number of customers

The starting point of the forecast was calibrating the spreadsheet, which meant finding the relevant assumptions or statistical input data (number of customers, specific consumption) enabling to reconstruct the past years, and specially the last known year, which is also the first year from which the forecast will proceed.

Then the forecast itself was based on the projection of the following parameters:

- Specific Consumption:

Specific consumption was categorized according to the income level of customers (high, medium or low). For each income level the specific consumption was assumed to change slowly, taking into account various parameters such as the impact of new customers entering the category, the type of appliances used by the customers and the efforts made for increasing their energy efficiency.

- Number of customers:

The study assumed that Customers would shift between income levels; from low to medium and from medium to high income. In addition, newly connected customers would progressively appear, according to electrification programmes throughout the country.

- Location of customers

Depending on their location the customers were classified to be either urban or rural areas.

b) For Street Lighting

The forecast followed a similar method as for the domestic category. It was based on the future changes of two parameters:

- Number of lamps used for street lighting,
- Specific consumption of the lamps, which was assumed to progressively decrease owing to a better efficiency.

c) For industrial and commercial consumption:

The general approach was:

Demand = Specific consumption of a production factor x number of factors

For instance, the demand forecast of the hotel sub-sector would be based on the specific consumption of a hotel room, and on the projection of the room number.

However, due to missing input data, this approach was not used. It was replaced by a global approach where the customer category was assumed to consume according to GDP growth, through a coefficient factor.

4.5.2.3 From demand to supply

Projections started with end-use consumptions, which meant forecasting the net energy consumed at each voltage level. From the end-use consumption, the supply forecast was derived by including technical and non technical losses. The losses were also projected until 2031.

In this regard the methodological approach included the following two stages:

- First stage: projections of end-use consumptions, or demand without technical losses but with commercial losses. Technical losses were based on input data concerning past years (period 2006-2010).

- Second stage: projections taking into account non-technical and technical losses, which added to the end-use consumptions end up to the demand with losses, equal to the supply that would be needed from the power plants.

4.5.3 Peak load forecast methodology

Instead of considering a constant load factor as in the past LCPDP versions, a spreadsheet was specially designed for obtaining both peak load and load factor forecasts. The design of the spreadsheet was based on a constant load factor attached to a given consumption category.

Two categories were chosen:

- Category 1 which grouped together the consumptions presenting a lower load factor: domestic consumption and street lighting.

- Category 2 which grouped together the other consumptions that have a higher load factor, commercial and industrial consumptions.

The load factor of each one of the two categories was assessed according to the global load factor reached for the past years. And thereafter these two load factors were assessed to remain constant (Category 2), or decreasing (Category 1), for taking into account the arrival of new low income customers in the power sector.

4.6 Assumptions and hypothesis used for the projections

4.6.1 a) Energy demand forecast

As in the previous LCPDP, three demand forecasts scenarios are considered, in line with the GDP growth rate projections. The high scenario assumes the Vision 2030 GDP growth rate projections. This scenario assumes complete implementation of the flagship projects while in the low and medium scenarios only part of the projects will be implemented.

Table 26: GDP growth scenarios

Year	Low scenario	Reference Scenario	High Scenario
2010	4.50%	4.50%	4.50%
2011	5.20%	5.40%	6.50%
2012	5.90%	6.30%	7.80%
2013	6.60%	7.20%	8.90%
2014	7.30%	8.10%	9.40%
2015 onwards	8.00%	9.00%	10.00%

The high scenarios were based on the KIPPRA Kenya Economic Report estimates

These GDP growths do not include the energy requirements for the flagship projects identified to drive the desired economic growth under the vision 2030. Flagship projects have an impact on both GDP growth and electricity consumption. The impact on electricity consumptions is computed in section 4.6. As for the GDP growth, the specific share of flagship projects has not been singled out since it is the whole economy which will be boosted by the projects. This could be considered as an iterative process where the flagship projects have an impact on the remaining parts of the economy and in return this remaining part of the economy is necessary to sustain the completion of the flagship projects.

4.6.1.1 Domestic consumptions

a) **Population**

The population determines the number of households and consequently the number of potential electricity customers. The population was assumed to grow from the current 38.6 million to 60.5 million by 2030 as projected in the Vision 2030.

b) **Urbanization**

This affects the numbers of households in urban areas and consequently the number of customers. The assumption was that the share of urban population would grow progressively reaching 63% by 2031

c) **Number of persons per household**

The total population divided by the number of persons per household gives the number of households. Currently and according to statistical data this number is 5 persons in urban areas and 6.5 in rural areas.

An assumption was made that by 2031 the average persons per household would be 4.90 with the urban high income having the least at 4 persons per household and the rural low income having the most at 6.5 persons per household.

d) **Supply rate**

The supply rate is the ratio of connected households to the total number of households. This ratio is currently 18.1%.

This supply rate will progressively increase as the government policy is to continue electrifying the urban, peri-urban and rural populations. The supply rate expected in 2031 will be higher for the high scenario, the lower for the low scenario, with an average of 88% for the medium scenario.

e) **Specific consumptions**

Specific consumption, or average yearly consumption of a household, is obviously linked to the income level of the household, and to the way electricity is used, more in urban than in rural areas. The assumptions made are presented in table herewith

Table 27: Specific assumptions

	Specific Consumption Assumption 2031 (kWh)				
URBAN[1]		Current	REF	LOW	HIGH
	HI	4795,	4,200	3,900	4,500
	MI	996	945	780	1200
	LI	131	300	240	360
RURAL					
	HI	2,737	4,000	3,800	4,200
	MI	586	800	730	1000
	LI	108	180	120	240

[1] The current monthly consumption in urban domestic consumers is 400(HI), 83(MI), 11(LI) rural is 228(HI), 49(MI), 9(LI)

	SUPPLY RATE 2031				
URBAN			REF	LOW	HIGH
	HI		100%	100%	100%
	MI		100%	95%	100%
	LI		95%	85%	100%
RURAL					
	HI		100%	90%	100%
	MI		60%	50%	70%
	LI		50%	40%	60%

4.6.1.2 Street lighting

a) Number of lamps

The number of lamps was assumed to be determined by the growth rate in the number of customers reduced by a coefficient factor of 80%. The 80% coefficient factor was derived by getting the average of street lighting growth divided by the average customer growth from 2005-2009

b) Specific consumption

It was assumed that owing to technological improvements; the efficiency of lamps will progressively increase, resulting in a specific consumption decreasing at a rate of 1% per year.

4.6.1.3 Commercial and industrial consumptions

Thus it was done by comparing the Commercial and Industrial growth to GDP growth.

The coefficient factors for LV, MV and HV was determined using consumption growth rates calculated above and the real GDP growth rate as follows:
Coefficient factor = consumption growth rate/Real GDP growth rate.
Global Coefficient factor = Global consumption growth rate/Real GDP growth rate.

For projection purposes, actual coefficient factors for the years 2007 and 2010 were calculated for low, medium and high scenario. A uniform increase of the coefficient factors as represented in Table 28 was then applied up to 2015.

Table 28: Coefficient factors

Year	2010	2011	2012	2013	2014	2015
Low scenario	1.13	1.18	1.22	1.27	1.32	1.38
Medium scenario	1.13	1.19	1.25	1.32	1.38	1.44
High scenario	1.13	1.20	1.27	1.35	1.42	1.50

Thereafter (beyond 2015) it was assumed that the coefficient factors will remain constant as shown in the table i.e.

- High scenario - coefficient factor of 1.5,
- Medium scenario - coefficient factor of 1.44 and
- Low scenario - coefficient factor of 1.38.

4.6.2 Losses adjustments and supply forecast

a) Definitions

Technical losses were split according to the voltage level: HV, MV and LV levels. Non technical losses were mostly concentrated at LV level.

- The actual definition of a loss rate is: losses divided by supplied energy, with the latter equal to the entering energy including losses.

Low voltage loss rate:	LV losses/LV consumption + LV losses
Medium voltage loss rate	MV losses/MV+LV consumption + MV + LV losses
High voltage loss rate	HV losses/HV + MV+LV consumption +HV+MV+LV losses
Global loss rate	Total losses/Total consumption + total losses

- Most often the losses are characterized by a ratio that does not represent the loss rates, but a breakdown of the losses at each voltage level divided by the global supply, sum of all consumptions and losses.

In that case, we have the following breakdown:

Share of LV loss rate:	LV losses/Global supply
Share of MV loss rate:	MV losses/Global supply
Share of HV loss rate:	HV losses /Global supply

With: Total share = global loss rate

b) Projections

Projections were based on the yellow tariffs book of 2008 and the Retail electricity tariff review policy (ERB2005). The following were the assumptions for the losses breakdown in 2015:

Breakdown of Technical losses	
Transmission, HV level	3%
Distribution, MV Level	4%
Distribution, LV level	6%
Global loss rate	13%
None technical losses (LV level)	1%
Global loss rate	14%

4.6.3 Load factor assumptions

a) **Load factors of categories 1 and 2**

To convert the energy forecast to capacity an assumed constant load factor was attached to each consumption category as indicated below:

	Input data	Projection	
	2010	2020	2031
Load factor of category 1 (domestic and street lighting)	55%	50%	45%
Load factor of category 2 (commercial and industrial)	76%	76%	76%
Resulting load factor	69%	65.5%	66.1%

It was also assumed that the peaks loads of all the customer categories happen at the simultaneously which is certainly not the case. This hypothesis leads to overestimating the load factors of each category. Annex 1 on the methodology of peak load forecast indicates this.

However, this overestimate does not induce any adverse effect on the global peak load forecast assessment. More reliable peak load forecast of categories 1 and 2 will need the implementation of the MAED-L software component.

4.7 Resulting Energy and Peak load forecast

4.7.1 Energy load forecast

Based on the above assumption, the energy forecast including technical and non technical losses i.e energy at generation level is shown in table 29 below. The supply for the reference case rises from 6683 in 2010 to 61490 GWh in 2031.

Table 29: Energy forecast in GWh

	LOW SCENARIO		REFERENCE SCENARIO		HIGH SCENARIO	
YEAR	GWh	Growth Rate	GWh	Growth Rate	GWh	Growth Rate
2010	6,683		6,683		6,683	
2011	7,238	8.3%	7,285	9.0%	7,428	11.1%
2012	7,781	7.5%	7,898	8.4%	8,175	10.1%
2013	8,398	7.9%	8,616	9.1%	9,061	10.8%
2014	9,152	9.0%	9,513	10.4%	10,179	12.3%
2015	10,040	9.7%	10,597	11.4%	11,554	13.5%
2016	11,028	9.8%	11,842	11.7%	13,149	13.8%
2017	12,099	9.7%	13,185	11.3%	14,939	13.6%
2018	13,260	9.6%	14,766	12.0%	16,949	13.5%
2019	14,519	9.5%	16,334	10.6%	19,206	13.3%
2020	15,887	9.4%	18,156	11.2%	21,744	13.2%
2021	17,528	10.3%	20,306	11.8%	24,548	12.9%
2022	19,323	10.2%	22,699	11.8%	27,701	12.8%
2023	21,289	10.2%	25,358	11.7%	31,251	12.8%

2024	23,440	10.1%	28,319	11.7%	35,251	12.8%
2025	25,795	10.1%	31,620	11.7%	39,762	12.8%
2026	28,372	10.0%	35,292	11.6%	44,855	12.8%
2027	31,195	10.0%	39,388	11.6%	50,610	12.8%
2028	34,293	9.9%	43,962	11.6%	57,118	12.9%
2029	37,684	9.9%	49,066	11.6%	64,487	12.9%
2030	41,409	9.9%	54,761	11.6%	72,837	12.9%
2031	45,735	10.4%	61,490	12.3%	82,882	13.8%

4.7.2 Peak load forecast

Based on assumed load factors and the assumption that the peaks happen simultaneously the results of the peak demand are in Table 30 below. The peak load for the reference case rises from 1,120 MW in 2010 to 10,612 MW in 2031.

Table 30: Peak load Forecast

	LOW SCENARIO			REFERENCE SCENARIO			HIGH SCENARIO		
YEAR	GWh	MW	Load factor	GWh	MW	Load factor	GWh	MW	Load factor
2010	6,683	1,120	68.12%	6,683	1,120	68.12%	6,683	1,120	68.12%
2011	7,238	1,221	67.69%	7,285	1,230	67.61%	7,428	1,256	67.53%
2012	7,781	1,321	67.23%	7,898	1,344	67.09%	8,175	1,394	66.95%
2013	8,398	1,434	66.87%	8,616	1,475	66.70%	9,061	1,555	66.52%
2014	9,152	1,570	66.54%	9,513	1,637	66.35%	10,179	1,757	66.15%
2015	10,040	1,729	66.29%	10,597	1,830	66.12%	11,554	2,001	65.93%
2016	11,028	1,905	66.10%	11,842	2,050	65.95%	13,149	2,282	65.78%
2017	12,099	2,095	65.92%	13,185	2,287	65.80%	14,939	2,597	65.66%
2018	13,260	2,301	65.77%	14,766	2,566	65.68%	16,949	2,951	65.57%
2019	14,519	2,525	65.64%	16,334	2,843	65.59%	19,206	3,347	65.51%
2020	15,887	2,768	65.53%	18,156	3,163	65.52%	21,744	3,791	65.48%
2021	17,528	3,060	65.39%	20,306	3,541	65.47%	24,548	4,278	65.51%
2022	19,323	3,379	65.27%	22,699	3,960	65.44%	27,701	4,823	65.56%
2023	21,289	3,729	65.17%	25,358	4,424	65.43%	31,251	5,435	65.64%
2024	23,440	4,111	65.09%	28,319	4,939	65.45%	35,251	6,120	65.75%
2025	25,795	4,528	65.03%	31,620	5,512	65.48%	39,762	6,890	65.88%
2026	28,372	4,983	64.99%	35,292	6,147	65.54%	44,855	7,755	66.02%
2027	31,195	5,481	64.97%	39,388	6,852	65.62%	50,610	8,728	66.19%
2028	34,293	6,026	64.97%	43,962	7,637	65.71%	57,118	9,823	66.38%
2029	37,684	6,620	64.98%	49,066	8,509	65.83%	64,487	11,056	66.58%
2030	41,409	7,254	65.17%	54,761	9,458	66.10%	72,837	12,423	66.93%
2031	45,735	8,012	65.16%	61,490	10,612	66.15%	82,882	14,113	67.04%

4.7.3 Vision 2030 flagship projects considerations

To cater for the energy requirements of the Vision 2030 flagship projects, amendments were done on the projected demand. The amendments were made based on the expected date of completion and the estimated capacity and energy requirements. The projects considered were those that were expected to require a lot of energy and cause a spike or shock in the peak demand in the country. The table below gives a summary of the estimated completion dates, energy and capacity requirements for the proposed projects.

Table 31: Vision 2030 projects energy requirements

Project	Estimated year of completion	Estimated Energy requirements (GWh)	Estimated capacity requirements MW
ICT Park	2012 - 2015	2,930	440
Second container terminal and a free port at the Mombasa port	2014	746	2
Standard gauge railway(Juba-Lamu)	2014	19	9[2]
Lamu port including resort cities	2014	26	4
Special economic zones	2015	333	50
Iron and steel smelting industry in Meru area 2015-2021	2015 – 2021	2,097	315
Standard gauge railway(Mombasa-Nairobi-Malaba, Kisumu)	2017	27	18
Light rail for Nairobi and suburbs	2017	16	8
Resort cities (Isiolo, kilifi and Ukunda)	2017	200	30

The energy requirements were estimated based on the following assumptions:

- The ICT Park was based on the Malaysian technology parks consumption. This is estimated at 181kWh/m2/year assuming energy efficiency measures are in place. The total consumption for the entire 5,000 acres ICT Park was estimated at 440MW.
- The consumption estimate for the port of Mombasa second container terminal was based on the NYK line container terminal in Japan which consumes 13GWh/year giving a capacity requirement of 2MW. The Lamu port was assumed to require double the energy requirements of one container terminal
- Standard gauge railway consumption was computed based on the German ICE High Speed whose consumption varies from 19-33kWh/km. The maximum consumption of 33kWh was

[2] The MW for the Railway lines are based on the speed in km/h times the consumption in KWh/km which gives the total KW required. The energy which is added onto the load forecast is based on the kwh per trip(distance in Km/ the speed per km multiplied by the KW)

assumed. The distance covered was on 3 trips Mombasa –Nairobi, 1 trip Nairobi –Malaba and 1 trip Juba- Lamu.

- Consumption for the special economic zones was based on the current consumption of EPZ
- The light rail consumption was based on London's underground trains which consume on average 15kWh/km. An assumption was made that the light rails will be doing 500 trips/week in the Nairobi metropolitan region.
- The resort cities assumption was based on the current Malindi consumption of 8MW with the possibilities of increasing to 10MW by the year 2017.
- Iron and steel smelting industry in Meru consumption was assumed to consume 315MW over a period of 7 years based on an average production of 13.5 million tones. This figure will be revised when the feasibility study on the potential of iron and smelting in the area is done.

Limitations of the estimates

These estimates are all based on conservative benchmarks from other countries. It expected that by the next update feasibility studies of all the flagship projects energy requirements will have been undertaken making the estimates more realistic. In most cases the estimates are expected to be higher. However the estimates assume the projects will be implemented as indicated above and that the peak demands of every project will occur simultaneous to the global system load. This can be seen to have taken care of any underestimation of the energy requirements of the projects.

Following these adjustments, the estimated capacity and related energy requirements for Vision 2030 flagship projects were incorporated in the projections thus increasing the forecast according to the schedule of project implementation.

4.7.4 Suppressed Demand

Owing to the low electricity penetration levels and power cuts mostly originating from medium and low voltage network failures, supply does not completely meet the demand at peak load hours.

The amount of suppressed demand in 2010 is estimated to be approximately 100MW. It was assumed that this amount would progressively decrease with the increased penetration levels and the refurbishment and upgrading of the network that is already committed. The resultant suppressed demand would therefore be as follows;

2011: 80MW
2012: 60MW
2013: 40MW
2014: 20MW

2015 and beyond: no more suppressed peak load.

Based on these adjustments, the energy forecast including technical and non technical losses i.e energy at generation level is shown in table 32 and 33 below. The supply for the reference case rises from 7296 in 2010 to 103,518GWh in 2031 while the peak load rises from 1227 MW in 2010 to 16,905MW in 2031.

Table 32: Energy forecast in GWh

Years	LOW SCENARIO		REFERENCE SCENARIO		HIGH SCENARIO	
	GWh	Growth Rate	GWh	Growth Rate	GWh	Growth Rate
2010	7,296	13%	7,296	13%	7,296	13%
2011	7,729	6%	7,775	7%	7,943	9%
2012	8,967	16%	9,084	17%	9,458	19%
2013	10,335	15%	10,560	16%	11,224	19%
2014	11,985	16%	12,376	17%	13,396	19%
2015	14,516	21%	15,155	22%	16,644	24%
2016	16,298	12%	17,300	14%	19,344	16%
2017	18,507	14%	19,902	15%	22,650	17%
2018	20,660	12%	22,685	14%	26,128	15%
2019	23,014	11%	25,512	12%	30,069	15%
2020	25,591	11%	28,795	13%	34,537	15%
2021	28,620	12%	32,651	13%	39,554	15%
2022	31,637	11%	36,652	12%	44,915	14%
2023	34,960	11%	41,130	12%	50,998	14%
2024	38,618	10%	46,147	12%	57,903	14%
2025	42,649	10%	51,771	12%	65,748	14%
2026	47,083	10%	58,069	12%	74,664	14%
2027	51,969	10%	65,133	12%	84,805	14%
2028	57,359	10%	73,065	12%	96,346	14%
2029	63,295	10%	81,964	12%	109,488	14%
2030	69,846	10%	91,946	12%	124,461	14%
2031	77,307	11%	103,518	13%	142,103	14%

Table 33: Energy and Peak load Forecast

YEAR	LOW SCENARIO			REFERENCE SCENARIO			HIGH SCENARIO		
	GWh	MW	Load factor	GWh	MW	Load factor	GWh	MW	Load factor
2010	7,296	1,227	67.88%	7,296	1,227	67.88%	7,296	1,227	67.88%
2011	7,729	1,293	68.24%	7,775	1,302	68.16%	7,943	1,331	68.11%
2012	8,967	1,498	68.35%	9,084	1,520	68.21%	9,458	1,584	68.14%
2013	10,335	1,723	68.49%	10,560	1,765	68.32%	11,224	1,877	68.25%
2014	11,985	1,993	68.64%	12,376	2,064	68.44%	13,396	2,236	68.38%
2015	14,516	2,398	69.10%	15,155	2,511	68.90%	16,644	2,760	68.83%
2016	16,298	2,693	69.10%	17,300	2,866	68.91%	19,344	3,207	68.86%
2017	18,507	3,053	69.19%	19,902	3,292	69.02%	22,650	3,749	68.97%
2018	20,660	3,408	69.20%	22,685	3,751	69.04%	26,128	4,322	69.01%
2019	23,014	3,796	69.21%	25,512	4,216	69.08%	30,069	4,970	69.07%
2020	25,591	4,220	69.23%	28,795	4,755	69.13%	34,537	5,703	69.14%
2021	28,620	4,720	69.22%	32,651	5,388	69.18%	39,554	6,521	69.24%
2022	31,637	5,222	69.16%	36,652	6,048	69.18%	44,915	7,397	69.32%
2023	34,960	5,775	69.11%	41,130	6,784	69.21%	50,998	8,388	69.41%
2024	38,618	6,382	69.08%	46,147	7,608	69.25%	57,903	9,509	69.51%
2025	42,649	7,050	69.06%	51,771	8,528	69.30%	65,748	10,778	69.64%
2026	47,083	7,783	69.06%	58,069	9,556	69.37%	74,664	12,217	69.77%
2027	51,969	8,590	69.06%	65,133	10,706	69.45%	84,805	13,847	69.91%
2028	57,359	9,478	69.09%	73,065	11,994	69.54%	96,346	15,697	70.07%
2029	63,295	10,453	69.12%	81,964	13,435	69.65%	109,488	17,796	70.23%
2030	69,846	11,510	69.27%	91,946	15,026	69.85%	124,461	20,156	70.49%
2031	77,307	12,738	69.28%	103,518	16,905	69.90%	142,103	22,985	70.57%

The average energy growth rates for the reference scenario are 14.5% for the period 2010-2020, the average growth drops to 12.2% for the period after giving an average growth rate of 13.4% for the entire period.

Table 34: Energy average growths

Scenario	Average yearly growth rates		
	2010 - 2020	2020 - 2031	2010 - 2031
High growth scenario	16.5%	14.1%	15.3%
Medium growth scenario	14.5%	12.2%	13.4%
Low growth scenario	13.4%	10.5%	11.9%

4.8 Limitations of the current load forecast

- Due to unavailability of data, the intended use of MAED software was shelved and subset excel worksheets were developed. This means that substitutable energy uses and hourly load characteristics were not taken care off.
- MAED – EL which is uses the total annual demand of electricity for each sector to determine the total electric power demand for each year. I.e. the hourly electric demand which is imposed on the power system was not used in this study. Instead the analysis assumed that the peaks loads of all the customer categories happen at the same time/simultaneously. This exaggerated the load forecast.

5.1 Introduction

This chapter provides a brief description of the technical and economic characteristics of different sources of power generation in Kenya. The power generation modes are divided into fossil fuels and renewable energy related sources. The renewable energy related sources include Hydroelectricity, Wind, Geothermal, Solar and Biomass energy while the fossil fuels energy related sources consist of Coal, Petroleum and Natural Gas. Nuclear energy is separately considered. The economic characteristics of the different energy resources mentioned are analyzed based on levelized cost of generating electricity from each source.

The levelised energy cost is the price at which electricity must be generated from a specific source to break even. It is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel and cost of capital.

On this basis, chapter five shows screening curves that are constructed for all candidate projects. The screening curve method expresses the total annualized electricity production cost for a generating unit, including all capital and operating expenses, as a function of the unit capacity factor. This approach is especially useful for quick comparative analyses of relative costs of different electricity generation technologies.

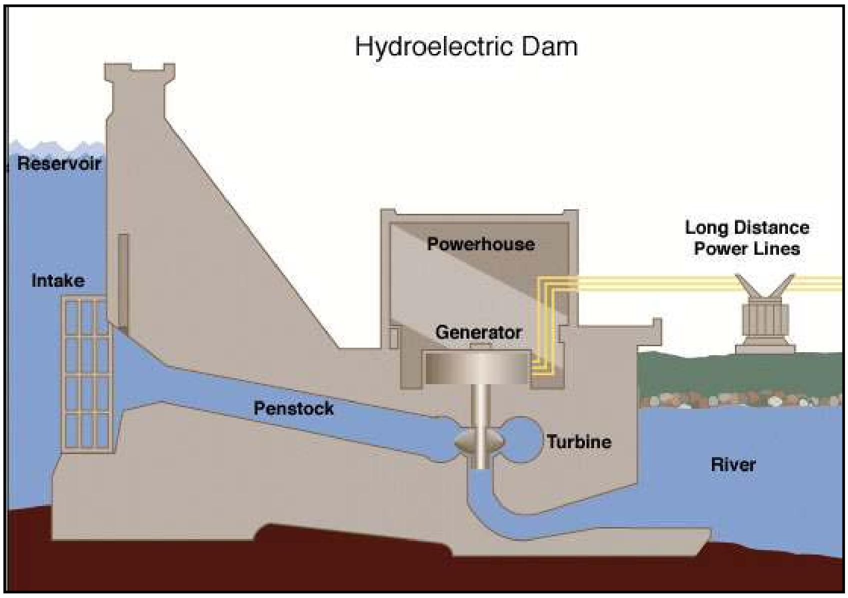
5.2 Technical characteristics of power plants using renewable energy sources

Hydroelectric power is the generation of electric power from the movement of water. A hydroelectric facility requires a dependable flow of water and a reasonable height of fall of water, called the head. In a typical installation, water is fed from a reservoir through a channel or pipe into a turbine. The pressure of the flowing water on the turbine blades causes the shaft to rotate. The rotating shaft is connected to an electrical generator which converts the motion of the shaft into kinetic energy[3].

Hydroelectric generating plants can "store" energy and then release water to generate electricity when it is needed. This gives them the ability to respond within short periods to changes in load demand. This flexibility characteristic enhances their value to the supply mix. However, their output depends on water availability thus making them vulnerable to unpredictable climate patterns. Figure 19 shows a Simple Schematic Diagram of Hydro Turbine.

[3] Kinetic Energy is the energy in form of motion

Figure 19: Simple Schematic Diagram of Hydro Turbine



SOURCE: http://www.uaf.edu/energyin/webpage/pages/renewable_energy_tech/hydro.htm

Hydropower stations have a long life and many existing stations around the world have been in operation for more than half a century and are still operating efficiently.

There are several types of hydroelectricity schemes existing today;

Run-of-the-river (RoR) power plants - These plants do not require dams or catchments since they are constructed on the run of the river. According to their size, RoR power plants can be split into:

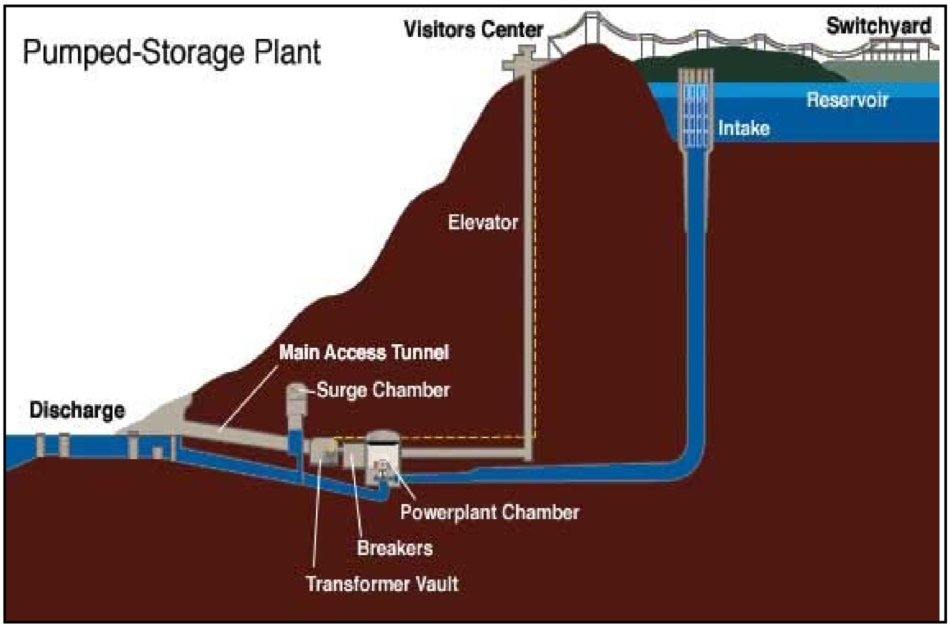
Pico-hydroelectric power plants: Very small power plants (under 10 kW) that incorporate all of the electro-mechanical elements into one portable device and typically installed on the river or stream embankment and can be removed during floods or low flow periods.

Micro-hydroelectric power plants: These are RoR plants (10kW-30MW) that divert some of the water flow through civil works into a turbine, which drives a generator producing electricity.

Dam storage power plants: They typically include dams and catchments for water storage in order to assure a very high capacity factor consistent with the very high construction costs of these facilities. The characteristics and costs of large hydroelectric power plants are greatly influenced by the natural site conditions.

Pumped storage power plants: The hydroelectric power plant acts both as a generator and a pump, allowing water in a lower reservoir to be pumped up to the upper reservoir during the low-load overnight period, and then generating electricity during peak load periods (see figure 20). These plants are mostly used in conjunction with base-load nuclear power plants.

Figure 20: Typical Pumped Storage Plant



5.2.1 Large Hydro Projects

There are five (5) large cascaded hydro stations along Tana River with a total installed capacity of 585MW. The other major hydro stations are Turkwel power station that was commissioned in 1991 with an installed capacity of 106 MW and Sondu Miriu (60 MW) commissioned early 2008. Consequently, an additional 73MW[4] comprising of Sangoro (21MW), Tana Redevelopment (20MW) and Kindaruma 3rd Unit (32MW) are expected to be commissioned between 2010 and 2012. Table 35 shows the technical characteristics of the large hydro projects in Kenya.

Table 35: Technical Characteristics of Existing Large Hydro Projects in Kenya

Station	River or Location	No. of Units	Rating per Unit	Installed Capacity (MW)	Supplier	Year Installed	Age	Remaining Economic Lives (Years)
Kindaruma	Tana River	2	20	40	AEI/Bovin g	1968	42	8
Kamburu 1&2	Tana River	2	31.4	62.8	Litostroj/R ade Koncar	1974	36	14
Kamburu 3	Tana River	1	31.4	31.4	Litostroj/R ade Koncar	1976	34	16
Gitaru	Tana River	2	72.5	145	Siemens/V oith	1978	32	18
Gitaru Unit 3	Tana River	1	80	80		1999	11	39
Masinga	Tana River	2	20	40	BBC/Esche r WYSS	1981	29	21
Kiambere	Tana River	2	84	168	Marine Industries Ltd	1988	22	28
Turkwel	Turkwel River	2	53	106	Neyrpic/Al sthom Jeumont	1991	19	31
Sondu	Sondu River	2	30	60	Toshiba/Mi tsui	2008	2	48
Total		**16**		**733.2**				

[4]KenGen G2G Strategy Horizon 1 Report

5.2.2 Small Hydro Projects

Small hydro power stations in Kenya are defined as plants whose installed capacity is greater or equal to 500kW but less than or equal to10MW[5].

These plants may be connected to conventional electrical distribution networks as a source of low-cost renewable energy. Alternatively, small hydro projects may be built in isolated areas that would be uneconomic to serve from a network, or in areas where there is no national electrical distribution network.

Several small hydroelectric power plants in Kenya were commissioned between 1925 and 1958. The first small hydro electric power station known as Ndula with an installed capacity of 2MW on Thika River was constructed in 1925 and is currently decommissioned. Table 36 reflects the Technical Characteristics of Small Hydros in Kenya

Table 36: Technical Characteristics of Small Hydro Projects in Kenya

Plant		**Year**	**Installed by**	**No. of Units**	**Rating per unit (MW)**	**Total installed Capacity (MW)**
Ndula		1925	KPLC	2	2.000	2.000
MESCO		1933	KPLC	1	0.380	0.350
Selby falls(sosiani)		1952	KPLC	2	2.000	0.400
Sagana Falls		1955	KPLC	3	0.500	1.500
Gogo Falls		1958	Mining Co.	2	1.000	2.000
Tana 1 & 2		1952	KPC	2	2.000	4.000
Tana 3		1952	KPC	1	2.400	2.400
Tana 4		1954	KPC	1	2.000	4.000
Tana 5		1955	KPC	1	2.400	2.400
Tana 6		1956	KPC	1	2.000	2.000
Wanjii 1 & 2		1952	KPC	2	2.700	5.400
Wanjii 3 & 4		1952	KPC	2	1.000	2.000
	1	1934		2	0.150	0.300
James Finlay (K) Ltd	2	1934		2	0.200	0.400
	3	1980		2	0.060	0.120
	4	1984		1	0.320	0.320
	5	1999		2	0.536	1.072
	1					0.090
Brooke Bond	2					0.120
	3					0.180
	4					0.240
Savani		1927	Eastern Produce			0.095
Diguna		1997	Missionary			0.400
Tenwek			Missionary	1		0.320
Mujwa			Missionary	1		0.068
Community MHPs		2002				0.017
Total						**31.822**

[5] Feed In Tariff Policy, Ministry of Energy, January 2010

The Government of Kenya (GoK) established a Feed-In Tariff Policy in 2008 (Revised in January 2010) to attract investment and development of small and mini hydro plants. Table 37 shows the Feed-In Tariff Policy for Small Hydro Plants.

Table 37: Feed in tariffs policy for hydro's

	Plant Capacity (MW)	Maximum Firm Power Tariff (US$/kWh) at the Interconnection Point	Maximum Non Firm Power Tariff ($/kWh) at the Interconnection Point
Small Hydro	0.5 – 0.99	0.12	0.10
	1.0 – 5.0	0.10	0.08
	5.1 – 10	0.08	0.06

So far 19 expression of interest have been received of which 16 have been approved giving an expected capacity if 81MW. Only two have negotiated a PPA and out the two only one a 0.9MW plants has started generating electricity.

Economic Characteristics

The economies of scale favor large hydro power projects over small ones as capital costs per KWh generally decrease with increasing scale. However, the combination of a long lead time, uncertain growth in demand for electricity and price, and uncertainty in the total cost of financing construction increase risks for larger hydro projects. Table 38 shows the levelised cost of generating hydroelectricity.

Table 38: Levelized Cost of Generating Hydroelectricity

International Energy Agency (IEA) Projected Cost of Generating Electricity 2010 Hydro Power Plants						
Item	**Off-grid pico-hydro schemes**		**Micro-hydro plant**	**Grid connected mini hydro plant**	**Large hydro plant**	**Pumped storage hydro plant**
Capacity	300 W	1 kW	100 kW	5 MW	100	150
Source	river	river	river	river/tributary	Dam - Gravity concrete	Dam - Gravity concrete
Life span (years)	5	15	30	30	40	40
Capacity factor (%)	30 (range: 25-35)	30 (range: 25-35)	30 (range: 25-35)	45 (range: 35-55)	50	10
Fixed O&M cost (2004 US$/MWh)	0	0	10.5	7.4	5	3.2
Fixed O&M cost (2004 US$/kW-yr)	0.0	0.0	27.6	29.2	21.9	2.8
Variable O&M cost (2004 US$/MWh)	9	5.4	4.2	3.5	3.2	3.3
Total 2010 capital cost (2004 US$/kW)	**1560**	**2680**	**2600**	**2370**	**2140**	**3170**
Equipment	1560	1970	1400	990	560	810
Civil works	-	570	810	1010	1180	1760
Engineerig	-	-	190	200	200	300
Erection	-	140	200	170	200	300

Source: Projected Cost of Generating Electricity 2010 - International Energy Agency (IEA)

In the case for Kenya, the country has marginal commercially viable large hydro power resources as most of the promising hydro sites have already been exploited. Technical and cost data for a few candidate hydropower sites are available, but two sites Mutonga (60MW) and Low Grand Falls (140MW), are considered most promising for immediate development in the planning period. Table 39 below indicates the economic characteristics cost for Mutonga and Lower grand falls respectively.

Table 39: Candidate Hydropower Plants' Data

	Low Grand Falls	Mutonga
Configuration (n x MW)	2 x 70	2 x 30
Total Capacity (MW)	140	60
Fixed Cost		
Total plant and line Capital ($ x 10^6)	507.0	258.8
Unit Cost ($/kW)	3,621	4,314
IDC Factor	1.2092	1.2092
C.R.F.	0.1019	0.1019
Interm Replacement	0.0103	0.0103
Fixed Annual Capital ($/kW.yr)	484.2	585.2
Fixed O & M ($/kW.yr)	19.8	21.3
Total Fixed Cost ($/kW.yr)	504	606
Total Outage Rate	0.0785	0.0785
Outage Adjustment	1.085	1.085
Annual Fixed Cost ($/kW.yr)	547	658
Annual Average Energy (GWh/yr)	715.000	337.000
Annual Fixed Cost ($/kWh)	0.107	0.117
Total Variable ($/kWh)	0.0053	0.0053
Unit Cost ($/kWh) at 60% plant factor	0.112	0.123

5.2.3 Geothermal Resources

Geothermal energy is power extracted from the heat of the earth. Globally, about 10715 MW of geothermal power is online in 24 countries expected to generate 67246 GWh of electricity in 2010[6]. It takes approximately seven (7) years from surface exploration to development of a geothermal power plant taking into consideration of the site specifications[7].

The nature of the geothermal resource at the site plays a major role on the type of plant to be constructed namely the dry steam[8], flash steam and binary steam power plants.

Flash Steam Power Plant

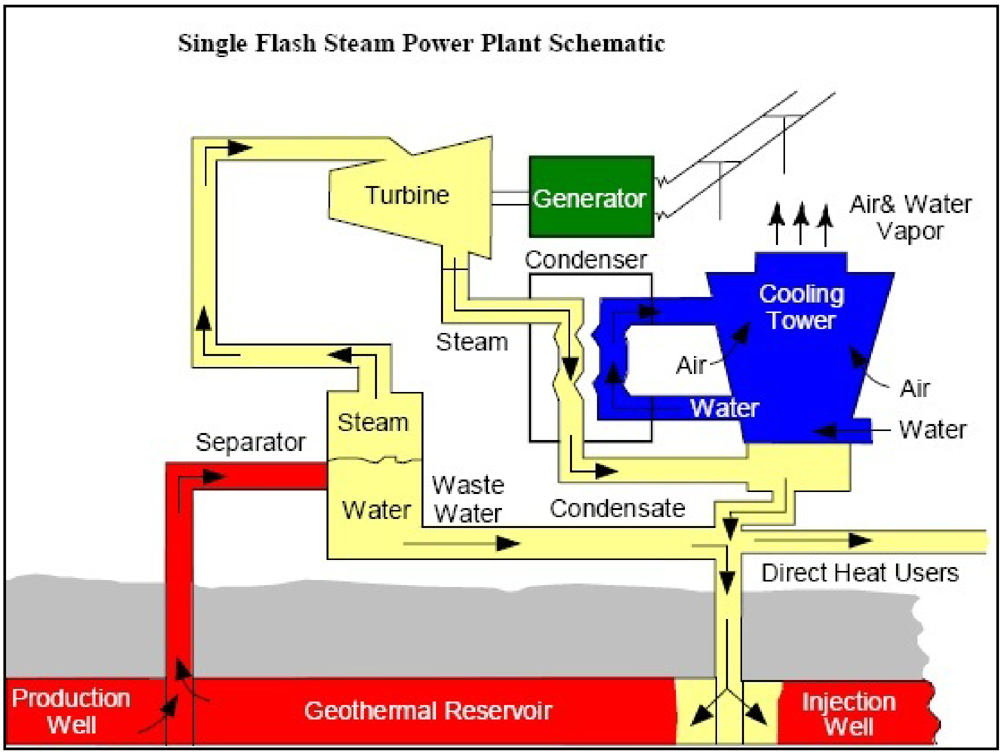
KenGen operates two flash steam power plants in its Olkaria geothermal fields taking into consideration that this kind of plant is the most common type of geothermal power plant to date.

In a flash-steam plant, hot, liquid water from deep in the earth is under pressure and thus kept from boiling. As this hot water moves from deeper in the earth to shallower levels, it quickly losses pressure, boils and "flashes" to steam. The steam is separated from the liquid in a surface vessel (steam

[6] International Geothermal Association http://www.geothermal-energy.org
[7] Surface Exploration(2 yrs), Exploration and Appraisal Drilling (2yrs), Production Drilling –Steam Collection-Power Plant Installation (3yrs)
[8] **Dry Steam Plant** – power plant where the steam produced directly from the geothermal reservoir runs the turbines that power the generator. Such geothermal reservoirs are rare (The Geysers in California)

separator) and is used to turn the turbine, and the turbine powers a generator. Figure 21 shows a typical Flash Steam Power Plant.

Figure 21 : Typical Flash Steam Power Plant



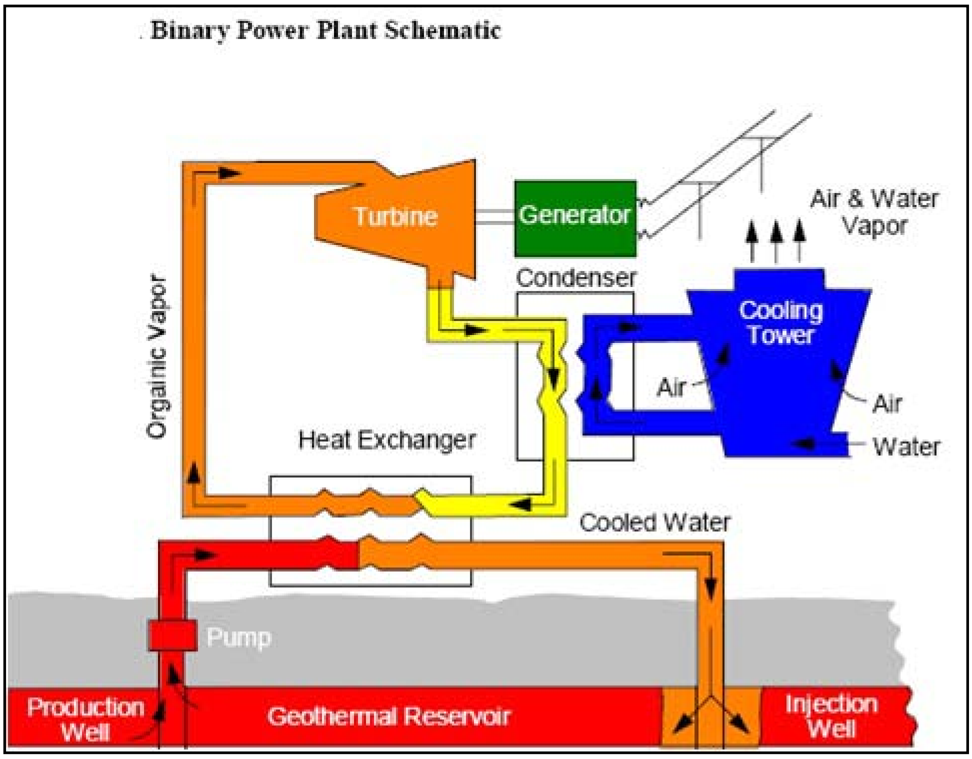
Flash power plants typically require resource temperatures in the range of 177°C to 260°C (350°F to 500°F). The flashing process can be done in a single step (single-flash), or being repeated at lower pressure levels (double-flash, triple-flash) in order to fully exploit the energy of the hot water.

Binary Steam Power Plant

Orpower4 (an Independent Power Producer) in Olkaria, operates a binary steam power plant.

In the binary process, the geothermal fluid, which can be either hot water, steam, or a mixture of the two, heats another liquid such as isopentane or isobutane (known as the "working fluid"), that boils at a lower temperature than water. The two liquids are kept completely separate through the use of a heat exchanger used to transfer heat energy from the geothermal water to the working fluid. When heated, the working fluid vaporizes into gas and (like steam) the force of the expanding gas turns the turbines that power the generators.

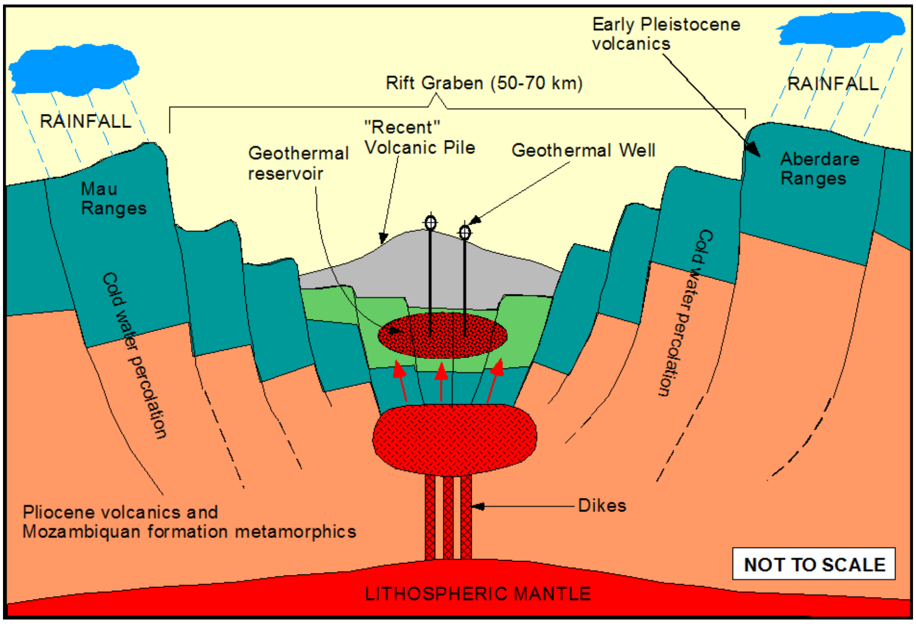
Figure 22: Binary Steam Power Schematic



Geothermal In Kenya

Geothermal resources in Kenya are located within the East African Rift system associated with intense volcanism and faulting which have resulted in development of geothermal systems. Figure 23 below shows the East Africa Rift Geothermal Model

Figure 23: Rift Geothermal Model



Currently 198MW geothermal capacity has already been developed comprising of 150MW by KenGen(Flash Steam Plant) and 48MW by Orpower4(Binary Steam Plant). Figure 24 below shows a picture of an existing geothermal plant in Olkaria.

Figure 24: Olkaria II Geothermal Power Station (Flash Steam Power Plant)

Table 40: Technical Characteristics of Geothermal Plants

Station	Location	Type	No of Units	Rating per Unit	Installed Capacity	Supplier	Effective Capacity (MW)	Year Installed	Age
Olkaria 1	Olkaria	Geothermal	3	15	45	Mitshubishi industries Ltd	45	1981	29
Olkaria 2	Olkaria	Geothermal	2	35	70	Mitshubishi industries Ltd	70	2004	6
Olkaria 2 unit 3	Olkaria	Geothermal	1	35	35	Mitshubishi industries Ltd	35	2010	1
Sub-Total			6		150		150		

Geothermal Economic Characteristics

Geothermal plants generally operate as base-loaded generators with capacity factors comparable to or higher than conventional generation (~ 90%). Capital costs are very site-specific, varying significantly with the characteristics of the local resource system and reservoir. Well-drilling makes up a large share of the overnight costs[9] of geothermal electricity generation, sometimes accounting for as much as one-third to one-half of the total cost of a geothermal project.

5.2.4 Wind Resources

Kenya has an installed wind capacity of 5.45MW. The turbines are located at Ngong Hills under the ownership of KenGen. The country has proven wind energy potential of as high as 346W/m2 in parts of Eastern, North Eastern and Coast Provinces. Confirmed wind energy potentials for other areas considered to be large load centres include Garissa with 132W/m2, Malindi with 111W/m2, Lamu with 79W/m2 and Mandera with 75W/m2.

[9] Overnight Costs do not include interest during construction

The future exploitation of wind energy in Kenya is oriented towards power generation, both decentralised and for the national grid. Within an integrated energy planning approach, the wind power potential should also be exploited for substituting fossil fuels and developing the energy sector in line with the national economic, social and environmental policies. Table 41 gives an energy generation potential estimate of a typical 1 MW turbine for the different wind speed zones.

Table 41: Generation Potential of a Typical 1 MW Wind Turbine

Wind speed at 50 m measuring height	Gross Production of a typical modern 1 MW turbine (at sea level, 15°C, shape parameter k=2)	Net production of typical modern 1 MW turbine in a wind park at 2000 m a.s.l.*	Estimated available area** with min. wind speed [km²]
6 m/s	1,945 MWh/a	1,360 MWh/a	50,000
7 m/s	2,675 MWh/a	1,921 MWh/a	4,500
8 m/s	3,375 MWh/a	2,482 MWh/a	1,500
9 m/s	4,000 MWh/a	3,000 MWh/a	700
10 m/s	4,520 MWh/a	3,453 MWh/a	10***

Notes:

* Project efficiency of 85% (park losses, availability, electrical losses)

** According to model calculations based on the wind map and excluding altitudes above 3300 m and protected areas, resulting in indicative and rather conservative estimations.

*** However, Fig. 3-4 (referring to the Marsabit area only) suggests that this area may be considerably larger.

5.2.5 Solar Resources

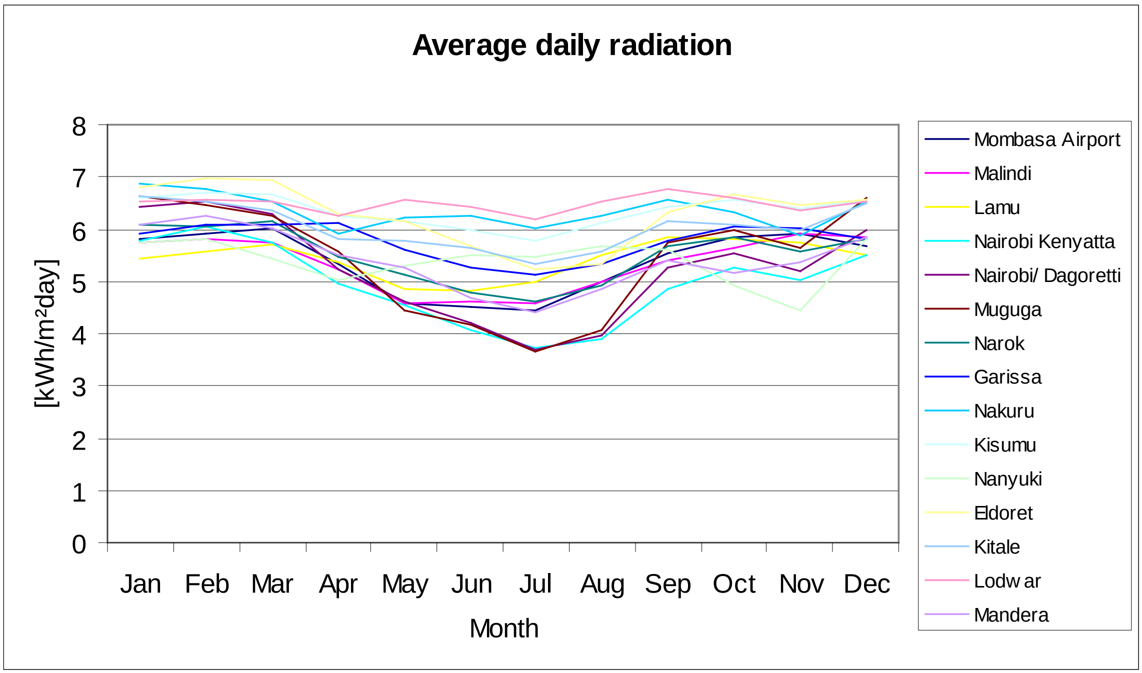
Solar is a renewable source of electricity generation with both lower emissions and a higher efficiency of conversion to electricity than conventional fossil fuel technologies, It has recently become of interest to policy makers in the context of rising prices for primary energy.

Current Situation of Solar Energy Utilisation in Kenya

Kenya is well known for a large-scale market-driven penetration of very small photovoltaic (PV) systems in rural areas. It is estimated that about 200,000 rural households already use PV systems, and that the figure is growing by about 20,000 user’s p.a. The PV systems have a capacity of 12-50W consisting of low-cost amorphous modules and car batteries. Due to comparatively low costs, the use of PV in rural households is much more widespread in Kenya than in other African countries though some of them have special PV household electrification programs.

The average daily radiation in more than 28,000km^2 of land in Kenya is above 6 kWh/m^2*d throughout the year, thus resulting in a continuously good and relatively stable potential for electricity generation from solar.

Figure 25: Average Daily Radiation Measured at 15 Meteorological Stations in Kenya by Month of Year in the Period 1964-1993



Solar Technical Characteristics

Solar technologies for generating electricity are of two general types:

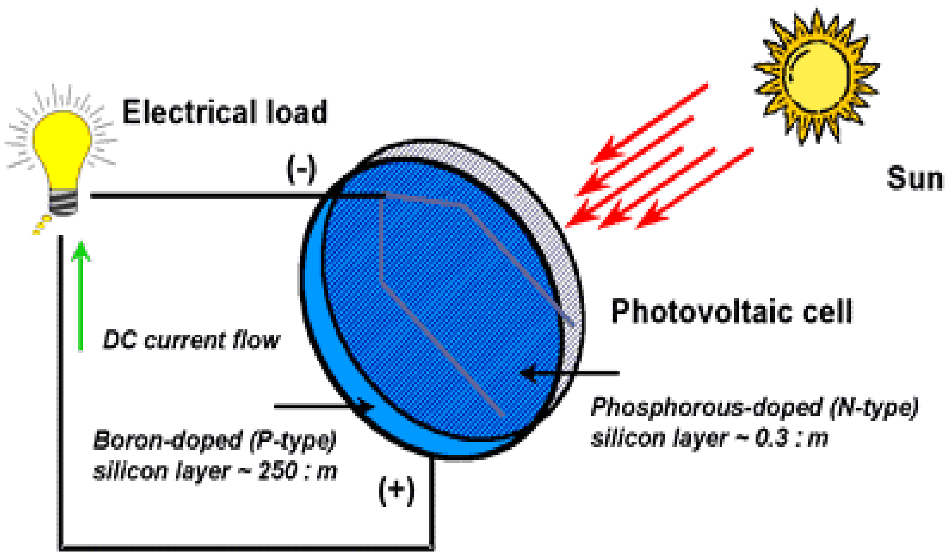
i) Photovoltaic (PV)

ii) Solar thermal electricity conversion (STEC)

Photovoltaic (PV) technology

Photovoltaic technology uses solid-state semiconductor devices to convert sunlight into direct current electricity as shown in figure 25. Although the underlying science was discovered by Becquerel in the nineteenth century, significant progress in commercialization became possible with Bell Labs' invention of the silicon solar cell in 1954 and its early use in powering earth satellites.

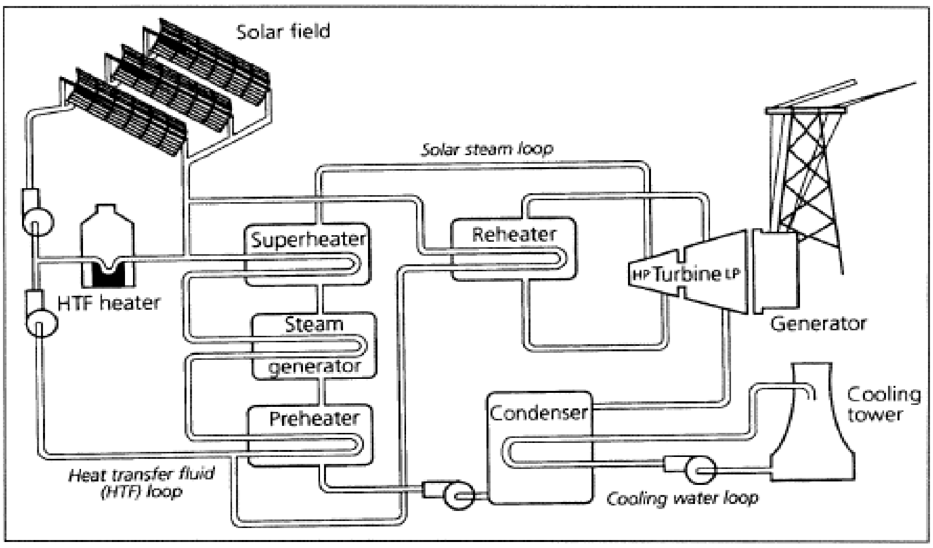
Figure 26: Photovoltaic cell



Solar thermal electricity Conversion (STEC)

In the late 1970s solar thermal electricity production was born in the desert of southern California. Concentrated sunlight heated a fluid creating steam, which in turn drove a turbine generator.

Figure 27: Solar Thermal Electric Technology



Solar thermal energy is a technology for harnessing solar energy for heat using solar thermal collectors often characterized low, medium, or high temperature collectors. Low temperature collectors are flat plates generally used to heat swimming pools. Medium-temperature collectors are also usually flat plates but are used for creating hot water for residential and commercial use while high temperature collectors concentrate sunlight using mirrors or lenses and are generally used for electric power production.

Low- and Medium Temperature Collectors

Assuming a cut off line for low temperature collectors of 5.0 kWh /m2 then Kenya has an area of 825,000 square kilometers of resource available. It is important to note that the cut off line is arbitrary and some technologies will deliver heating even in lower thermal resource space heating. Collectors can use air or water as the medium to transfer the heat to its destination. The medium temperature collectors could be used to produce approximately 50% of the hot water needed for residential and commercial and a typical system costs $5,000- $6,000. Medium-temperature installations can use any of several designs like are pressurized glycol, drain back, and batch systems.

High Temperature collectors

Where temperatures below about 95°C are sufficient, as for space heating, flat-plate collectors of the non concentrating type are generally used. The fluid-filled pipes can reach temperatures of 150 to 220 degrees Celsius when the fluid is not circulating. This temperature is too low for efficient conversion to electricity, since the efficiency of any heat engine increases as the temperature of its heat source increases. In concentrated solar power plants, the solar radiation is concentrated by mirrors or lenses to obtain a higher temperature.

Since the Concentrated Solar Power (CSP) plant generates first heat, it is possible to store the heat before conversion to electricity. With current technology, storage of heat is much cheaper and efficient than storage of electricity. In this way, the CSP plant can produce electricity day and night. If the CSP site has predictable solar radiation, then the CSP plant becomes a reliable power plant. Reliability can further be improved by installing a back-up system that uses fossil energy. The back-up system can reuse most of the CSP plant, which decreases the cost of the back-up system.

Economic Characteristics

The OECD recently published the findings of an assessment of levelized cost of electricity generation. The study applied field surveys and covered a multitude of electricity generating technologies in a few countries including Canada and the USA.

The OECD study applied generic assumptions in order to derive its calculations. Salient assumptions included: economic lifetime of 40 years, average load factor for base-load plants of
85 percent, discount rates of 5 percent and 10 percent, and (July) 2003 base year. The electricity generation costs are busbar costs, and therefore do not include transmission, distribution or environmental costs.

Table 42 shows the levelized cost of electricity generation by component for solar technologies. The study did not divulge the assumed capacity factor for solar technologies, nor is it entirely clear that a forty-year life was assumed. (An operating life of 25 or 30 years is a more common assumption for solar technologies.)

Table 42: Levelized Cost of Electricity Generation from Solar (2003 USD/MWh)

	Discount Rate	Net Capacity MW	Overnight Const Cost – millions of US$	Levelized Capital Cost	Levelized O&M Cost	Levelized Electricity Cost
USA Solar thermal parabolic	5%	100	277.5	127.4	38.1	165.5
USA Solar thermal parabolic	10%	100	277.5	231.4	38.1	269.4
USA Solar Photovoltaic	5%	5	20.8	115.8	4.8	120.6
USA Solar Photovoltaic	10%	5	20.8	204.4	4.8	209.1

SOURCE: OECD (NEA/IEA), Projected Cost of Generating Electricity: 2005 Update, Paris, France.

The Electricity Market Module (EMM) of The National Energy Modeling System (NEMS) assesses the most economical way to supply electricity, within environmental and operational constraints. The EMM consists of four sub-models: electricity capacity planning, electricity fuel dispatching, load and demand-side management, and finance and pricing.

Costs and performance characteristics of solar according to NEMS are summarized in table 43.

Table 43: Costs and Performance Characteristics of Solar Technologies (2003 USD)

Technology	Solar Thermal	Photovoltaic
Capacity (MW)	100	5
Heat rate (Btu/kWh)	10,280	10,280
Overnight Cost[1] (2003 $/kW)	2,960	4,467
Variable O&M (2003 mills[2]/kWh)	0.00	0.00
Fixed O&M (2003 $/KW)	50.23	10.34
Lead times (Years)	3	2
Online[3]	2007	2006

SOURCE: Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38

For comparison purposes, overnight construction costs have been taken together with fixed annual O&M costs for STEC and PV as reported by NEMS and calculated levelized costs as shown in table 44. At a discount rate of 5 percent for 25-year and 30-year economic lives was assumed applying capacity factors of 15 percent and 25 percent.

Table 44: Levelized Cost of Electricity from Solar (2003 USD/MWh)

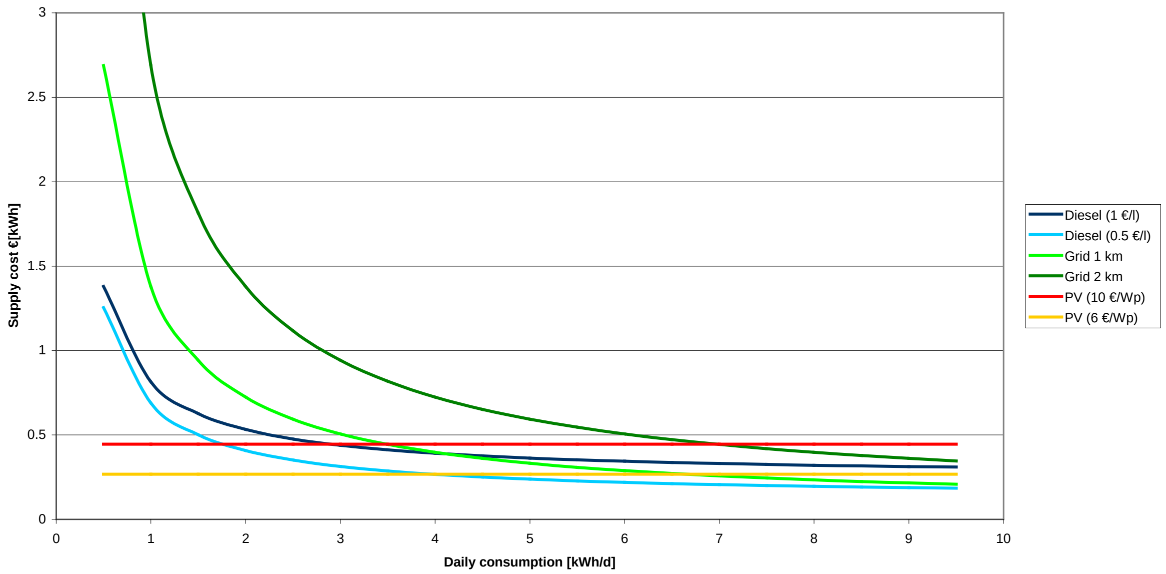
	Capacity Factor	Operating Life	Net Capacity MW	Overnight Const Cost – millions of US$	Levelized Capital Cost	Levelized O&M Cost	Levelized Electricity Cost
USA Solar thermal	15%	25 years	100	296	92.8	84.6	177.4
parabolic	25%	25 years	100	296	55.7	50.8	106.5
USA Solar thermal	15%	30 years	100	296	85.1	80.8	165.8
parabolic	25%	30 years	100	296	51.0	48.5	99.5
USA Solar Photovoltaic	15%	25 years	5	22.3	214.1	7.9	222.0
	25%	25 years	5	22.3	128.4	4.7	133.2
USA Solar Photovoltaic	15%	30 years	5	22.3	196.3	7.9	204.1
	25%	30 years	5	22.3	117.8	4.7	122.5

SOURCES: United States Energy Information Administration, Assumptions to the Annual Energy Outlook 2005, Table 38; Canadian Energy Research Institute.
NOTE: 5 percent discount rate is applied for estimation of levelized cost.

It turns out that levelized costs for solar technologies are highly sensitive to capacity factor and less sensitive to assumed economic life. It was also found that levelized costs are quite sensitive to discount rates. At a 10 percent discount rate, levelized costs as calculated were about 50 percent higher than the corresponding figures in the final column of Table 44. Photovoltaic, being more capital-intensive than STEC, is more sensitive to choice of discount rate.

The following graph illustrates a comparison of the overall costs of a PV system and the conventional alternatives of diesel power generation and grid extension. It is obvious that, the lower the total demand and the larger the distance from the grid, the more likely PV is an economic solution.

Figure 28: Comparison of the Overall Costs of a Solar PV System and of Conventional Alternatives (Diesel Power Supply and Grid Extension)



5.2.6 Biomass Resources

Biomass energy resources are derived from forests formations such as closed forests, woodlands, bush lands, grasslands, farmlands, plantations and agricultural and industrial residues. These resources include woodfuel (firewood and charcoal) and agricultural residues. Biomass fuels are the most important source of primary energy in Kenya with woodfuel consumption accounting for over 68% of the total primary energy consumption.

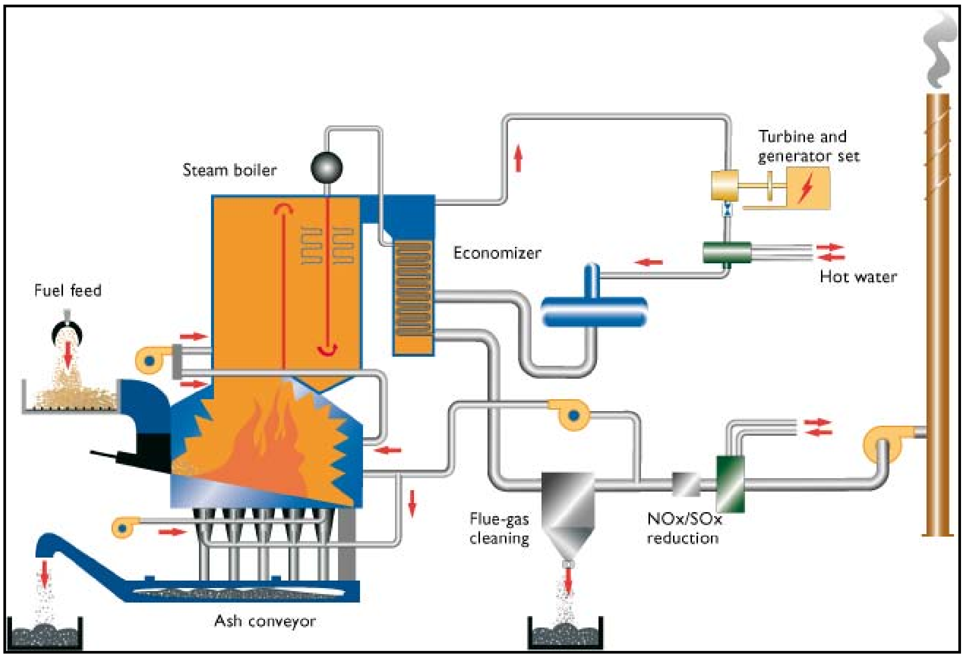
There exists substantial potential for power generation using biomass resources such as animal waste for agro based industries, baggasse by the sugar industry in a process called cogeneration and municipal waste by the local authorities for own consumption and export to the grid.

Cogeneration

Cogeneration, also known as “combined heat and power” (CHP) is the simultaneous production of heat (usually in the form of hot water and/or steam) and power, utilizing one primary fuel

A typical cogeneration system consists of an engine, steam turbine, or combustion turbine that drives an electrical generator. A range of technologies can be applied to cogenerate electricity and heat. These technologies are widespread notably; Steam turbines, Gas turbines, Combined Cycle (gas and steam turbines) and Diesel engines. The figure 29 below shows a diagram of Cogeneration (Combined Heat and Power) Plant.

Figure 29: Cogeneration (Combined Heat and Power) Plant



Source: KMW Energy Company

In Kenya, cogeneration using bagasse as a primary fuel is a common practice in its domestic sugar industry. The industry comprising of six sugar companies produces an average 1.8 million tonnes of bagasse with fiber contents of about 18% by weight annually. Mumias Sugar Company is currently exporting 26MW of power to the national grid.

5.3 *Technical characteristics of power plants using fossil fuels and nuclear fuel*

5.3.1 Gas Turbines

Gas Turbine is a machine that converts energy generated by combustion fuel which is mixed with compressed air to drive a turbine which in turn produces work. The energy generated through combustion of the fuel drives both the compressor and turbine. Heavy duty gas turbines are used for power generation whereas aero derivates are preferably used in the aircraft industry.

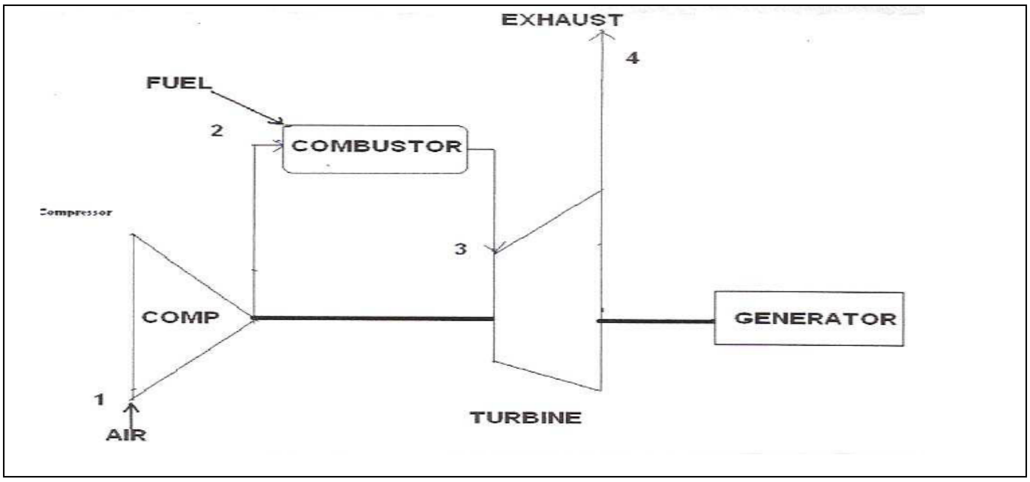
Gas turbines are the most common prime movers in recent large cogeneration systems and follow the Brayton process. These systems include gas turbines and electrical generators, with exhaust gases from the gas turbines typically fed to heat recovery steam generators (HRSGs). They range in electricity output from 250 kW to 200 MW. In general, they produce more electricity per unit of fuel than steam turbine systems and have an average heat-to-power ratio of 2:1. Supplemental heating through secondary firing of exhaust gases can increase this ratio to 5:1. Steam injection increases electrical output by 15 percent.

Gas turbine Technologies

The air that enters the axial flow compressor is compressed to some higher pressure. The compression raises the air temperature so that the air at the discharge of the compressor is at a higher temperature and pressure. Only a portion of this air is used for combustion. The remainder is used as dilution air to lower the temperature of the products of combustion and also serves as a source of cooling air for the turbine nozzles, turbine wheels and other portions of the hot gas path.

The compressor adds velocity energy to the air, and then converts the velocity energy to a pressure increase. The air which continuously discharges from the compressor will occupy a similar volume at the compressor discharge than at the inlet and, due to heating during compression, will have a temperature of 288oC ton315oC. Upon leaving the compressor, air enters the combustion system where fuel is injected and combustion occurs. The combustion process occurs at essentially constant pressure. Although high local temperatures are reached within the primary combustion zone (approaching Stoichiometric conditions), the combustion system is designed to provide mixture, burning, dilution and cooling. Thus by the time the combustion mixture leaves the combustion system and enters the turbine it is at a mixed average temperature.

Figure 30: This technology is illustrated in the figure below



Performance Characteristics

The knowledge of electric efficiency of cogeneration systems and the heating value of the chosen input fuel determines the amount of fuel required for electricity generation. Higher amounts of fuel are needed when fuels with lower heating values are used for electricity generation.

Heating values of fuels (thermal efficiency) express the amount of energy which is released on combustion of a given quantity of fuel. Heating values are typically expressed in Btu per fuel unit. Two types of high heating value (HHV) 63 and low heating value (LHV) 64 are used for measuring the energy content of a fuel. The heating value of natural gas is 1,000 Btu per cubic foot. The level of emissions produced from burning natural gas is substantially lower than the level from burning coal. Natural gas can be gasified but this process is not economically viable and cogeneration cannot benefit economically from this option.

Efficiency

Efficiencies with heat recovery range from 25 percent to 40 percent and the overall efficiency, after heat recovery, could reach 80 to 90 percent. (Thermal efficiency is a power source that transforms the potential heat of its fuel into work or output (heat energy)[10] Electrical efficiency is the ratio of useful electrical power output to the total electrical power input (heat resource).[11] Overall efficiency is the sum of the heat and electricity generation energy values to the total heat energy content in the fuel burned[12])

Economic characteristics - Capital and Operating Costs

Natural gas has not been the fuel of choice for large steam cycle plants due to the price and availability of natural gas. Although the price of natural gas is substantially higher than coal, the effective cost of natural gas as a fuel can be reduced if a cogeneration unit is equipped with a dual fuel boiler and the owner of the facility pays for the interruptible rather than firm price of natural gas. Economic justification of cogeneration investment requires both the price and supply of natural gas to be taken into account over the life of investment decision. The capital cost of the gas turbine power plants depends on the size of the plant and the selected technology of turbine systems. The main component of generation costs are the installed cost of the equipment, fuel costs, and non-fuel operation and maintenance (O&M) costs.

One factor that affects cogeneration system economics is system availability and reliability. Electricity is not produced during hours when the cogeneration system is down. Not only must electricity be purchased, but outages can also affect costs of standby service.
Availability is the percentage of time the plant is available for generation taking into account scheduled and unscheduled outages. Reliability is the probability that a device, system, or process will perform its prescribed duty without failure for a given time when operated correctly in a specified environment.

[10] $E_{th} = Q_{th}/Q_{fuel}$
[11] $Ee = Qe / Q\ fuel$
[12] $E_{tot} = (Q_{th} + Q_{e}) / Q_{fuel}$

5.3.2 Diesel Power Plants MSD

Power utilities in the developing countries use between 1 to 300MW Plants to generate power. These plants are flexible to follow the actual load and produce the necessary electricity typically from natural gas, heavy fuel oil and from bio fuels. They can start and ramp up to full load very rapidly, in less than 10 minutes and can start up a grid or a large power plant after shut down, without any external input of energy.

Due to very high simple cycle efficiency on part and full load, they can provide very competitive power regulation and spinning reserve services to large grids, which both require operation on partial load. These very same same plants can be used for peaking services during peak electricity demand hours. The main fuel used is gas, LFO, HFO or a multi-fuel combination of these.

Diesel Fuel Prices

In Kenya there are several thermal plants located at different parts of the country. One of the reasons why this source of generation is not preferred in Kenya is the fuel price fluctuations and instability. Due to the skyrocketing of the diesel oil prices, thermal power has become too expensive and hence the need to look at alternative sources of power generation.

Environmental Effect

Operation of a diesel power plant entails a potential for adverse effects on the environment. They may include:

Air pollution – Combustion of heavy fuel oil that may lead to release of air pollutants including sulphur dioxide, nitrogen oxides and particulates.

Water pollution – The oil can contaminate the effluent and water drainage systems.

Noise – Diesel generators produce significant noise levels which have to be mitigated to reduce health hazards.

5.3.3 Coal Fired Power Plants

Since Industrial revolution, coal has been the most widely used fuel for power generation. When coal is used for electricity generation, it is usually pulverized and then combusted (burned) in a furnace with a boiler. The furnace heat converts boiler water to steam, which is then used to spin the turbines

A fundamental approach to the cleaner use of coal is to reduce emissions by reducing the formation of pollutants. However, a parallel approach is to develop more thermally efficient coal plants so that less coal is used to generate the same amount of power. This has resulted in development of Clean Coal Technologies (CCTs) which facilitate the use of coal to meet various regulations covering emissions[13], effluents, and residues. These CCTs can be categorized into two major groups i.e. Combustion and Gasification. Figure 31 shows the Clean Coal Technologies.

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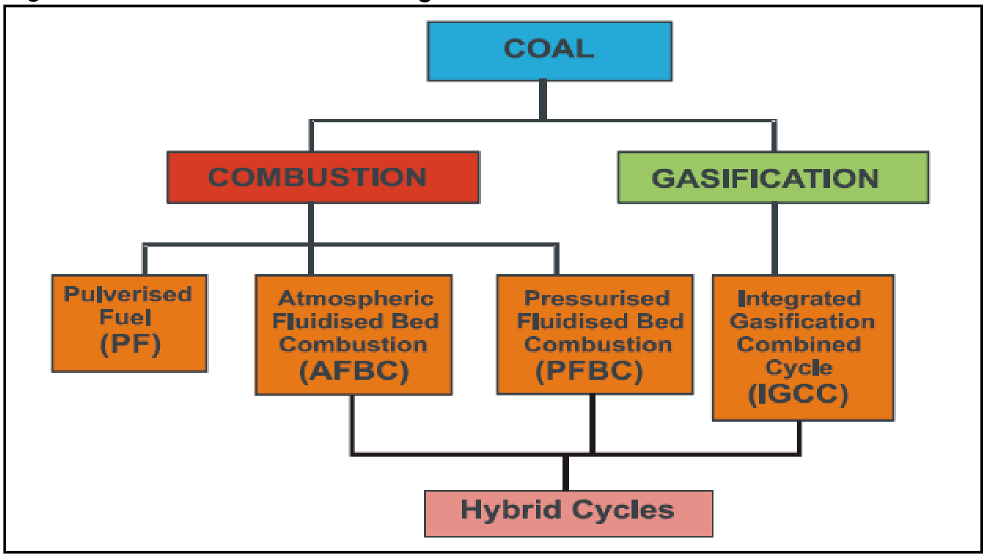
[13] When coal burns, the impurities are released into the air. Sulphur combines with water vapor to form acid rain while carbon combines with oxygen in the air to form carbon dioxide.

Figure 31: Clean Coal Technologies



The Combustion technologies are further categorized into:

Pulverised Coal Combustion

Pulverized Coal Combustion (PCC) is the most commonly used technology in coal-fired power plants. It is based on the utilization of very finely ground (pulverized) coal that feeds a conventional steam boiler and steam turbine that runs the generator.

In PCC, before coal arrives at the power plant one way of cleaning the coal is by simply crushing it into small chunks and washing it in the coal preparation plants. The coal floats to the surface while the sulfur impurities sink

A variety of technologies have been developed in order to provide an environmentally satisfactory method of using coal for power production in new plants. The principal developments involve increasing plant energy/thermal efficiencies by raising the steam pressure and temperature, and ensuring that flue gas cleaning units meet emissions limits and environmental requirements.

Therefore steam pressure and temperature are critical in achieving the coal power plant's efficiency levels. For this reason the PCC technology has been further classified into Sub-critical steam cycle (SC), Supercritical steam cycle (SCC) and Ultra Supercritical steam cycle (USC).

Sub-critical steam cycles plants operate at steam conditions below 165 bar pressure and temperature at 565°C. The efficiency levels are low in the region of 34% - 36%

The laws of thermodynamics dictate that higher steam temperatures and pressures allow higher efficiencies to be achieved from potentially smaller equipment. Therefore the SCC and USC fit this profile as described as follows.

Supercritical steam cycles plants operate at steam conditions above 221 bar pressure[14] whereby the supercritical water absorbs only heat energy which is converted to mechanical energy in the steam

[14] It is the water-steam critical point where there is no observable change of state from liquid to gas and no latent heat requirement.

turbine to drive the electrical generator. The steam pressures are between 240bar and 300bar with temperatures being 620°C.

Modern coal-fired power plants employ supercritical steam conditions to achieve high overall plant efficiency levels, typically between 39% and 46%, measured on the fuel's lower heating value basis (net calorific value).

Ultra-Supercritical steam cycles plants – although there is no agreed definitions of when a power plant might be considered ultra-supercritical, manufacturers refer to plants operating at steam conditions above 350 bar pressure and temperatures up to at 700°C as USC. The efficiency levels are expected to be around 50%

In conclusion Supercritical plant designs are ostensibly simpler than subcritical designs because no steam drum is required to separate steam and water. However, this cost saving is balanced by the use of more expensive materials, more complex boiler fabrication and the need for more precise control systems. On balance, the higher cost of supercritical designs can be justified by the improved fuel efficiency, except in situations where coal costs are very low e.g. power plants sitting adjacent to easily worked coal reserves.

Fluidized Bed Coal Combustion

This is an advanced clean coal technology commonly used with high-sulphur coal. In a typical coal boiler, coal would be crushed into very fine particles, blown into the boiler, and ignited to form a long, lazy flame. In a "fluidized bed boiler" the red-hot mass of floating coal (called bed) would bubble and tumble around which is called fluidized.

In a fluidized bed boiler, upward blowing jets of air suspend burning coal, allowing it to mix with limestone that absorbs sulfur pollutants. As coal burns in a fluidized bed boiler, it releases sulphur but the limestone tumbling around beside the coal captures the sulfur. A chemical reaction occurs, and the sulfur gases are changed into a dry powder that can be removed from the boiler. The largest fluidised bed project is the 460 MWe Łagisza supercritical plants in Poland

Fluidized Bed Combustion (FCC) is further classified into **Atmospheric Pressurized Fluidized Bed Combustion** (AFBC) and **Pressurized Fluidized Bed Combustion** (PFBC)

Integrated Gasification Combined Cycle

The Integrated Gasification Combined Cycle (IGCC) is very different from conventional coal-fired plants, having more similarities to natural gas combined cycle gas turbine (CCGT) plants.

Under the IGCC, fuel gas is produced from coal in a gasifier, cleaned and then fed to a gas turbine with heat recovery to generate steam to drive the turbines. Gasification takes place in a pressurized vessel with partial combustion of the coal in a limited supply of air or oxygen, with or without steam. Low emissions are achieved as an inherent part of the process and the potential for high efficiency is comparable to that for supercritical PC plants.

However, complexity and cost mean that IGCC has not yet achieved commercialisation, although a small number of demonstration plants are operating successfully at the 250 MWe to 300 MWe scale in countries like the Czech Republic and the USA.

Coal Economic Characteristics

It should be noted that one of the driving forces which is currently encouraging the use of more efficient coal power plant is the environmental concern for CO2 emissions. Therefore one of the less expensive ways of reducing CO2 emissions is increasing the thermal efficiency of converting coal to power. This can result to reduced costs in new coal plants since less fuel is needed.

5.3.4 Nuclear power plants

The uptake of Nuclear power technology has been growing over time across different countries and regions. Various countries without existing nuclear power technology in their power systems have expressed interest in investing in initial nuclear power projects, while developed countries with existing nuclear plants have been expanding their capacities.

Design and development of nuclear reactors is a major undertaking, which requires significant technical and financial resources. Recent developments in the nuclear power market have led to the consolidation of the nuclear power supplier companies. This means that the countries considering the implementation of nuclear power should be familiar with the range of options offered by these suppliers.

In recent decades the nuclear power industry has managed to improve the output of existing nuclear power plants quite dramatically. Nuclear reactors produce, contain and control the release of energy from splitting of U235 atoms. In electric power plants, this energy heats water to make steam. The steam, in turn, drives the turbine-generators to make electricity. The fission of uranium is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas or oil is used as a source of heat in a fossil fuel power plant. Nuclear reactors are essentially large steam engines.

The net capacity of recently reviewed nuclear reactors in a joint 2010 study by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA), finds that nuclear reactors ranges from 954 MWe in the Slovak Republic to 1,650 MWe in the Netherlands, with the largest site to be constructed in China consisting of 4 units of 1,000 MWe each, (OECD, 2010). Owing to differences in country-specific financial, technical and regulatory boundary conditions, overnight costs for the new nuclear power plants currently under consideration in the OECD area vary substantially across the countries, ranging from as low as 1,556 USD/kWe in Korea (noting the generally low construction costs in that country, as well as its recent experience in building new reactors) to as high as 5,863 USD/kWe in Switzerland, with a standard deviation of 1 338 USD/kWe, median of 4,102 USD/kWe and mean of 4,055 USD/kWe. Table 45 provides an overview of nuclear generation costs for different technologies used in various countries.

Table 45: nuclear generation costs for different technologies used in various countries

COUNTRY	NUCLEAR TECHNOLOGY	USD/kWe
Belgium	EPR-1600	5,383
Czech Republic	Pressurised Water Reactor (PWR)	5,858
France	EPR	3,860
Germany	PWR	4,102
Hungary	PWR	5,198
Japan	Advanced Boiling Water Reactor (ABWR)	3,009
Korea	Optimised Power Reactor (OPR-1000)	1,876
	APR-1400	1,556
Netherlands	PWR	5,105
Slovak Republic	WER	4,261
Switzerland	PWR	5,863
	PWR	4,043
United States	Adv Gen III+	3,382
Brazil	PWR Siemens/Areva	3,798
China	Chinese Pressurised Reactor (CPR-1000)	1,763
	CPR-1000	1,748
	AP-1000	2,302
Russia	WER-1150	2,933

Source: OECD & IEA joint report on Projected Costs of Generating Electricity, 2010 Edition

Each reactor type is characterized by the choice of a neutron moderator and cooling medium, which leads to different fuel designs. The fact that all data submissions in the present study are based on light water reactor technologies reflects the larger industry trend, as more than 88% of the commercial reactors currently in operation worldwide are cooled and moderated by light (ordinary) water.

The two major types of light water reactors are pressurized water reactors (PWRs), including the Russian-designed VVER, and boiling water reactors (BWRs). Only about 7% of the installed capacity in the world use heavy water (deuterium oxide) as coolant and moderator, with the remaining reactors in operation being based on various other designs.

In PWRs, the reactor design chosen for 78% of the planned capacity additions worldwide, water is maintained in liquid form by high pressure; while in BWRs, selected for the remaining 22% of planned capacity, water is kept at a lower pressure and is allowed to boil as it is heated by the reactor. In either type, the heat removed from the core is ultimately used to create steam that drives turbine generators for electricity production.

Nuclear Fuel

Fuel costs are an important risk parameter for all investments. For nuclear power plants, the fuel price risk is generally much lower than for fossil-fuelled plants, since fuel costs are a small share of total cost.

For light water reactors, the main front-end (before fuel loading in the reactor) fuel cycle steps are: uranium mining and milling, conversion, enrichment and fuel fabrication. The general study assumption adopted for the front-end fuel cycle cost component is USD 7 per MWh of output. At the back end of the fuel cycle, after the unloading of spent fuel from the reactor, two options are available: direct disposal (once-through cycle) or recycling (reprocessing fuel cycle) of spent fuel.

In the first option, spent fuel is conditioned after a period of cooling into a form adequate for long-term storage. In the second option, recyclable materials (representing around 95% of the mass of the spent fuel) are separated from the fission products and minor actinides. Without fast breeder reactors, the current method to reuse the separated plutonium is through the use of mixed oxide (MOX) fuel in light water reactors. The high-level waste from reprocessing is then stored, usually in vitrified form, either at reprocessing plant sites or in purpose-built high-level waste repositories.

Most countries provided cost estimates for the reactors that operate on once-through cycles; EDF and Japan reported cost data for a reprocessing fuel cycle. The general study assumption for the back-end fuel cycle cost is USD 2.33 per MWh for both closed and once-through fuel cycles.

Uranium prices

Most uranium is sold under confidential terms and conditions specified in long-term (multiannual) contracts. A number of long-term price indicators are produced that provide some indication of current prices. A more transparent spot market provides prices for uranium purchased for near term delivery, but this represents only a small part of the market. The quantity of uranium traded on the spot market in a given year is usually equivalent to under 15% of the total quantity of uranium traded,18 although in 2008 the volume of spot market transactions approached 25% of the total traded (this trend was continuing in 2009). The uranium market continues to rely on stockpiles of previously mined uranium (so-called secondary supplies) to meet demand, with freshly mined uranium typically supplying 55% to 60% of yearly demand. Since the early 1990s, one of the secondary sources of reactor-grade fuel has been augmented by uranium obtained from down-blending weapons grade uranium, which has had the effect of depressing prices and, in turn, investment in mine development.

The current agreement under which Russian warheads are being dismantled and the uranium down blended to produce nuclear fuel ends in 2013. This, combined with renewed interest in constructing nuclear power plants to generate base load electricity, has driven prices for uranium upwards, particularly since 2003. This has led to increased investment in uranium exploration, the identification of additional uranium resources of economic interest and increased investment in uranium mine development. These are timely developments, since secondary supplies are declining in availability at the same time that nuclear plants are being planned and built, increasing the need for freshly mined uranium.

According to the NEA/IAEA[i] “Red Book” uranium is mined in 20 countries, eight of which account for about 90% of world production (Australia, Canada, Kazakhstan, Namibia, Niger, the Russian Federation, the United States and Uzbekistan).

Load factor

The OECD 2010 study assumption for the average lifetime load factor for calculating the levelised costs of nuclear generation is 85%. The load factor is an important performance indicator measuring the ratio of net electrical energy produced during the lifetime of the plant to the maximum possible electricity that could be produced at continuous operation. In 2008, globally, the weighted average load factor reported for PWRs (a total of 265 reactors) was 82.27%, for BWRs (total of 94 reactors) it was 73.83%, with larger reactors (>600 MWe) exhibiting on average a 2% higher load factor than smaller reactors. Lifetime load factors can be somewhat lower due to start-up periods and unplanned outages. Although somewhat higher than the load factors currently reported for the existing nuclear fleet, the generic assumption of 85% used in this study is consistent with the advertised maximum performance characteristics of the planned Generation III+ reactor designs.

Decommissioning

The decommissioning costs of the nuclear power plants reviewed in this study have also been included in the levelised costs calculation. Where no country-specific cost figure was provided, a generic study assumption of 15% of the overnight cost has been applied to calculate the costs incurred during all the management and technical actions associated with ceasing operation of a nuclear installation and its subsequent dismantling to obtain its removal from regulatory control. Disbursed during the ten years following shut-down, the decommissioning cost is discounted back to the date of commissioning and incorporated in the overall levelised costs. While an incontestably important element of a nuclear power plant's operation, decommissioning accounts for a smaller portion of the LCOE due to the effect of discounting. In particular, the fact that for nuclear power plants decommissioning costs are due after 60 years of operation and are discounted back to the commissioning date, makes the net present value of decommissioning in 2015 close to zero, even when applying lower discount rates or assuming much higher decommissioning costs.

5.4 Assumptions for fuel costs

Projection of Fuel Prices

Thermal generation has been rising in Kenya in recent years as new thermal plants are constructed and also due to reducing output from hydropower plants as a result of recurrent drought. In fiscal year 2009/10, thermal plants produced 40% of electricity supplied using imported fossil fuels. The electricity tariffs policy allows for pass through of fuel costs to consumers and therefore retail customer bills fluctuate with monthly fuel usage and fuel prices. Currently, coal and natural gas are not used for electricity generation in Kenya but they are likely to be introduced in the medium to long term. The country has not struck any crude oil or natural gas reserves despite continued exploration mainly in the Northern and Coastal regions. The Ministry of Energy however indicates that there are good coal deposits in the Mui Basin in the Kitui County located about 300km from Nairobi. Exploratory drilling has been going on for the last decade to map out and ascertain quantities of the coal deposits.

Recent unconfirmed reports indicate that economically viable coal and iron deposits have been discovered in the semi-arid Tharaka-Nithi County neighbouring Kitui, and the government is keen to move in and start exploiting the natural resource to help alleviate poverty among the residents as well as boost the county's income. The coal deposits in the country, including others in Mwingi and Kwale Districts, would therefore be large enough to set up a steel mill capable of lasting for more than 30 years". Prospective mining companies have expressed interest in setting up steel mills to smelt iron from neighbouring Mwingi and Kitui districts as well as Tanzania. Once mines are set up, the proceeds will greatly benefit the residents of the County and boost the national economy.

Two neighboring countries, Tanzania and Uganda, have been lucky to discover substantial natural gas and crude oil deposits respectively. It is likely that natural gas may be imported to Kenya through a pipeline from Songo Songo in Tanzania to Mombasa, for power generation and industrial use. Landlocked Uganda has historically imported oil through Kenya. There is an existing pipeline from Mombasa to Eldoret town located close to the border with Uganda. The pipeline was to be extended in to Uganda but the project is now being reviewed to have the pipeline extended but with flow of oil in the reverse direction following discovery of oil in Uganda.

5.4.1 Crude Oil Price Forecast

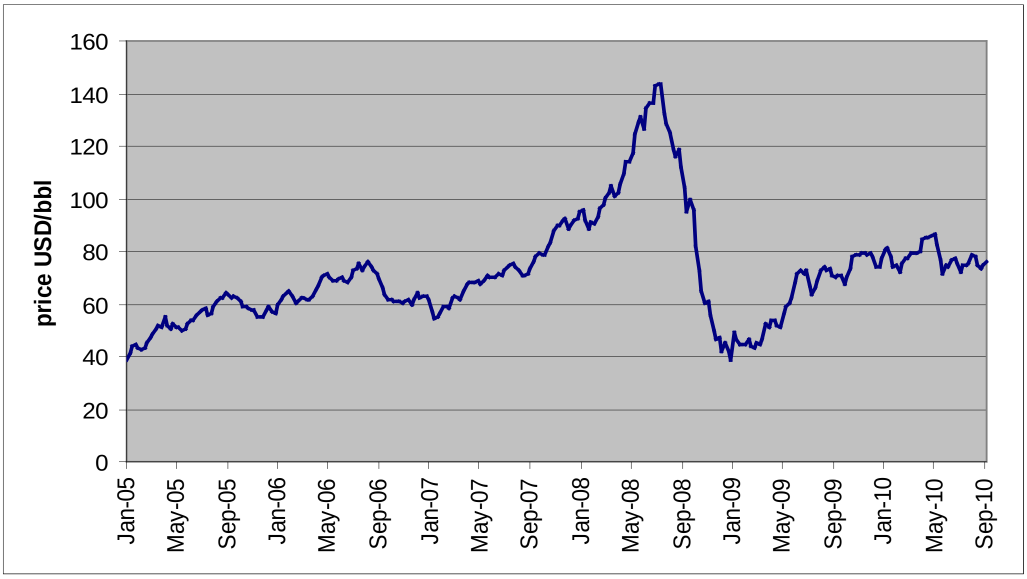
Crude oil prices remained relatively stable in the period between July 2009 and September 2010, with OPEC Countries FOB spot price weighted at 74 USD per Barrel and Abu Dhabi Murban FOB price at 76 USD per Barrel. Previously, a high of 141 USD per Barrel had been experienced in 2008 before plummeting to a low of 36 USD per Barrel in 2009. OPEC attributed the freefall to the financial crisis that originated in the US before spilling over to most of the other countries leading to rapidly deteriorating global economic conditions and prospects reducing demand for oil. According to the World Bank, sharp decline in crude oil prices, from more than $140 a barrel in July 2008, reflected weaker global demand and the relaxation of some refining capacity constraints that had contributed to high prices in the first half of the year.

The fall in demand reflected both the declines in industrial activity and the effects of high oil prices during the first half of 2008. The Bank projected the 2009 world oil demand to fall by 2.6 million barrels a day (mb/d), with continuing large falloffs in high-income countries and slight declines across most developing regions as production by members of the Organization of the Petroleum Exporting Countries (OPEC) is being curtailed sharply, while non-OPEC oil deliveries are expected to fall by 0.3 mb/d this year. The Bank further indicates that prices are anticipated to continue rising at a moderate rate over the medium term, with the weak pace of global GDP and ample spare capacity precluding a rapid rise in oil prices.

The World Bank projects that world oil demand to grow only moderately in the medium term, owing to efficiency improvements in transport and ongoing efforts by governments and industry to reduce carbon emissions, particularly in high-income countries. The Bank views that if non-OPEC oil production continue to rise modestly, as production increases in Brazil, Canada, the Caspian and West Africa, are offset by declines in yields from older fields, especially in the North Sea and Mexico then globally there will be no resource constraints; a long-term forecast of $75/bbl in real terms would be commensurate with the higher end cost of developing additional oil capacity, notably from oil sands in Canada. However, other factors are likely to come into play, occasionally pushing upstream costs higher or lower with mirrored consequences downstream.

In the reference forecast for this least cost plan, an average oil price of US$90/bbl in the planning period has been assumed. Low and high price forecasts of $75/bbl and $110/bbl respectively are recommended for the corresponding scenarios of the least cost plan, the lower price being a variation of negative 15% from the reference, and the latter being the upper range projected by OPEC. Figure 32 shows the historical prices of the Abu Dhabi Spot prices in the period 2005-2010.

Figure 32: Abu Dhabi Murban Spot Price FOB (Dollars per Barrel



5.4.2 Coal Price Forecast

The first coal power plant in Kenya is expected to be in operation within the next four years. Currently, cement factories are the largest users of coal imported from Southern Africa, mainly done in small quantities for conversion of raw limestone into clinker. The world's leading producers of coal include Australia, Indonesia, China and South Africa. Other African countries, besides South Africa, expected to play an emerging role in coal trade are Botswana, Mozambique and Tanzania.

The coal plant in Kenya is expected to use imported coal until local coal is exploited. South Africa is the likely choice of imported coal due to its close proximity to the Mombasa Port compared to other export terminals. The country is the world's fifth-largest coal producer and has historically been exporting coal to the European market but has lately increased exports to Asian countries. Last year, South Africa sold more coal to Asia than to Europe for the first time, India being the predominant buyer. Coal prices at the South Africa's Richards Bay Terminal remained around $96/t in 2010.

The World Bank forecasts Australian coal prices to ease from the 2010 average of $95/t, to $80/t in 2020. In the reference forecast of this study, a base price of $100/t was assumed for coal imported to Mombasa, and $124/t and $81/t assumed in the high and low price scenarios respectively, representing a moderate ±15% deviation from the forecast base price.

5.4.3 Natural Gas Price Forecast

The power generation sector is the only sector which offers the propect of sufficient volume and ability to contract forward for Liquified Natural Gas (LNG) supplies on a long term basis.

Natural gas prices, as with other commodity prices, are mainly driven by supply and demand fundamentals. However, natural gas prices may also be linked to the price of crude oil and/or petroleum products. It is touted as the clean fuel of 21st century, is fast emerging as a major energy source all over the world. Yet another fossil fuel and often found in oil fields and coal beds natural gas is estimated to contribute around 26% of global energy consumption by 2030. Natural Gas consumption is expected to increase from 95 trillion cubic feet in 2003 to 182 trillion cubic feet in 2030.

Nearly three quarter of the total global natural gas reserves are located in the West Asian and Eurasia regions. Iran, Qatar and Russia together accounts for nearly 58% of global natural gas reserve.

In the least cost plan, natural gas price was indexed to the crude oil price as in deriving the base, low and high scenarios. In the reference forecast for this study, the base, low and high scenario of natural gas price was assumed at US$9.11/Gj , US$6.37/Gj and US$13.20/Gj respectively. The indexation of natural gas price to the crude oil price was 0.085, 0.101 and 0.120 for the low, base and high scenarios respectively.

5.4.4 Nuclear fuel costs

Nuclear energy has low fuel costs compared to coal, oil and gas-fired plants. Uranium, however, has to be processed, enriched and fabricated into fuel elements, and about half of the cost is due to enrichment and fabrication. In the assessment of the economics of nuclear power allowances must also be made for the management of radioactive used fuel and the ultimate disposal of this used fuel or the wastes separated from it. But even with these included, the total fuel costs of a nuclear power plant in the OECD are typically about a third of those for a coal-fired plant and between a quarter and a fifth of those for a gas combined-cycle plant.

The World Nuclear Association cites prices of about US$2,555 per kilogram of uranium as UO_2 reactor fuel which works out to a fuel cost of US c 0.71 /kWh. A reference data fuel price of $1,015/Mkcal was assumed for the nuclear based on data reference data, and low and high forecast prices of 863$/Mkcal and $1,167/Mkcal respectively for sensitivity. The fuel's contribution to the overall cost of the electricity produced is relatively small, so even a large fuel price escalation will have relatively little effect.

5.5 Discount Rate

The reference discount rate was assumed to be 8% for the all the plants, 10% and 12% discount rate was considered for sensitivity analysis.

5.6 Summarized Technical and Economic characteristics

The candidate power generation alternatives for meeting load forecast include geothermal, coal, imports, thermal, hydropower, wind and nuclear power plants.

5.6.1 Hydroelectric Resources

The most promising viable large hydro power resources in Kenya being considered currently are Mutonga (60MW) and Low Grand Falls (140MW) (or High Grand Falls (250-450MW) in place of Mutonga and Low Grand Falls), Arror (60MW), Magwagwa (120 MW) projects, and Nandi (50MW) and Karura (60MW). Ewaso Ngiro South (220 MW) which has outstanding environmental concerns beyond Kenya’s borders. Two candidate hydropower, Mutonga and Low Grand Falls, are considered most promising for immediate development in the planning period. A feasibility study on the High Grand Falls is currently being carried out. The other prospective hydro power sites have not been simulated as candidate projects because either they require new or updated feasibility studies or have outstanding issues that need to be resolved. The hydro data describing the operational characteristics of these candidate projects for three hydrological conditions (wet, average, and dry) required by WASP were determined on the basis of the analysis of system operation with the VALORAGUA model

5.6.2 Geothermal Resources

Currently, GDC is in the process of acquiring 12 modern deep drilling rigs at a total cost of US$360Million to enable drilling of at least 60 wells per year with140MW geothermal generation capacity every year beginning from 2012/13. Candidate geothermal projects have been modeled in units of 140MW at an estimated capital cost of 3,650$/kW which includes drilling costs. The geothermal indigenous resource has characteristically high upfront costs but very competitive operational costs compared to other technologies.

5.6.3 Coal Power Plants

A feasibility study undertaken in 2009 for installation of a coal plant in Kenya evaluated several plant sizes and design options and recommended 1 x 300 MW net output units as the most economical option. The study was updated in 2010 and recommended 2 x 150 MW coal plants for the future. The committed coal plant has been configured to use imported coal. However, with the ongoing appraisal of local coal resource in Kitui County by the Ministry of Energy, it is anticipated that the candidate coal plants will utilize the local resource in future. The plants were modeled at an estimated cost of 2,104$/kW.

5.6.4 Conventional Thermal Plants

The Kenyan power system has continued to expand thermal plants to mitigate shortfalls and to provide peaking capacity in the long term. The plants were considered in the capacity expansion planning and were selected based on technology, capital and operational costs that contribute to the overall unit generation costs. Gas turbines and medium speed diesel plants were modeled at an estimated costs of 750$/kW and 1,364$/kW, respectively. Though these plants have low initial capital outlay, they have high operational costs subject to fluctuation in international crude prices. However, they shall be required to provide peaking capacity in the long term. The new plants are expected to be able to switch from diesel and kerosene to natural gas in future.

5.6.5 Nuclear Power Plants

Nuclear power was considered a potential long-term option for electricity generation in Kenya. Nuclear generating units are characterized by high capital investment and low operating costs, and in electric power systems these units normally serve as base load units. In April 2010, Kenya's National Economic and Social Council (NESC) which is chaired by the President, adopted introduction of nuclear power programme as a national priority. Moreover, the then Director General of the IAEA while visiting Kenya in July 2009 expressed the Agency's will to support the country to exploit nuclear power. The Director spoke when he met the President of the Republic of Kenya in Nairobi. The government's commitment on the nuclear power programme was also expressed at the 53rd IAEA Annual General Conference in Vienna. The Government has provided a budget for the year 2010/11 for the programme and created the Nuclear Electricity Development Project and a committee to spearhead the process.

In this update, it was assumed that as the electricity demand expands, the Kenyan power system would accommodate nuclear power plants from year 2022. Candidate plants were configured in units of 1000MW at a cost of 4055$/kW.

5.6.6 Electricity Imports

Countries in Eastern and Central African region are jointly pursuing power grid interconnection in order to facilitate power trade in the entire region. The second Kenya-Uganda line has obtained funding while the proposed Ethiopia-Kenya HVDC line is at detailed design stage. In this study, it was assumed that 200MW imports shall be available in 2014. Additional import in units of 200 MW were presented as candidate sources in the period between 2015 and 2031 so as to investigate the suitability of imports compared to local candidate generation projects. The imported energy cost was estimated at about UScts6.5/kWh.

5.6.7 Modeling of the Expansion Candidates

Considering that the least-cost system planning analysis is, by nature, an economic comparison of long-term generating system expansion options, no financial costs such as taxes and duties were included in the estimate of investment costs for the expansion candidates. The investment costs and the technical and economic data for modeling conventional thermal, coal, nuclear and geothermal candidate units are presented in Table 46.

Table 46: Data for Candidate Units

Name	WASP	Net Capacity (MW)	Fuel Type	Fuel Cost	Plant Life	Const.	Capital Cost
	Name			($/kWh)	(year)	Period (year)	($/kW)
Geothermal	GEOT	140	Steam	-	25	5	3,650
Medium Speed Diesel	MD20	160	HFO	0.0909	20	2	1,364
Gas Turbine	GT90	180	Natural Gas	0.1043	20	2	750
Coal	C150	300	Coal	0.0497	25	4	2,104
Nuclear	NUCL	1000	Uranium	0.0087	40	7	4,055
Wind	WIND	300	Wind	-	25	2	2,300
Hydro 1– Mutonga	HYD1	60	Hydro	-	50	5	4,314
Hydro 2 - Lower Grand falls	HYD2	140	Hydro	-	50	5	3,621
Imports	IMPT	200	Hydro	-	20	3	455

5.7 Screening Candidate Generation Projects

5.7.1 Screening curves

Screening curves were constructed for all candidate units to provide an illustration of annualized costs of electricity generation for different candidate technologies. The screening curve technique is an approximate method that captures major tradeoffs between capital costs, operating costs and utilization levels for various types of generating capacity in the system. The screening curve method expresses the total annualized electricity production cost for a generating unit, including all capital and operating expenses, as a function of the unit capacity factor. This approach is especially useful for quick comparative analyses of relative costs of different electricity generation technologies. Table 47 shows the plant data for the various candidate generation plants screened while Figure 33 shows the screening curves for the reference fuel cost scenario. The results of the screening curve analysis indicate that the hydro, MSD, and GTs are suitable for peaking capacity. Nuclear, geothermal, wind and coal are suitable for base load operation. Imports are suitable for both base load and peaking.

Table 47: Screening of Candidate Sources – Reference Forecast scenario

Thermal Generation Unit Cost
Crude Oil Price = 90US$/bbl
Coal Price =100 US$/tone
Natural Gas = 9.11 US$/Gj

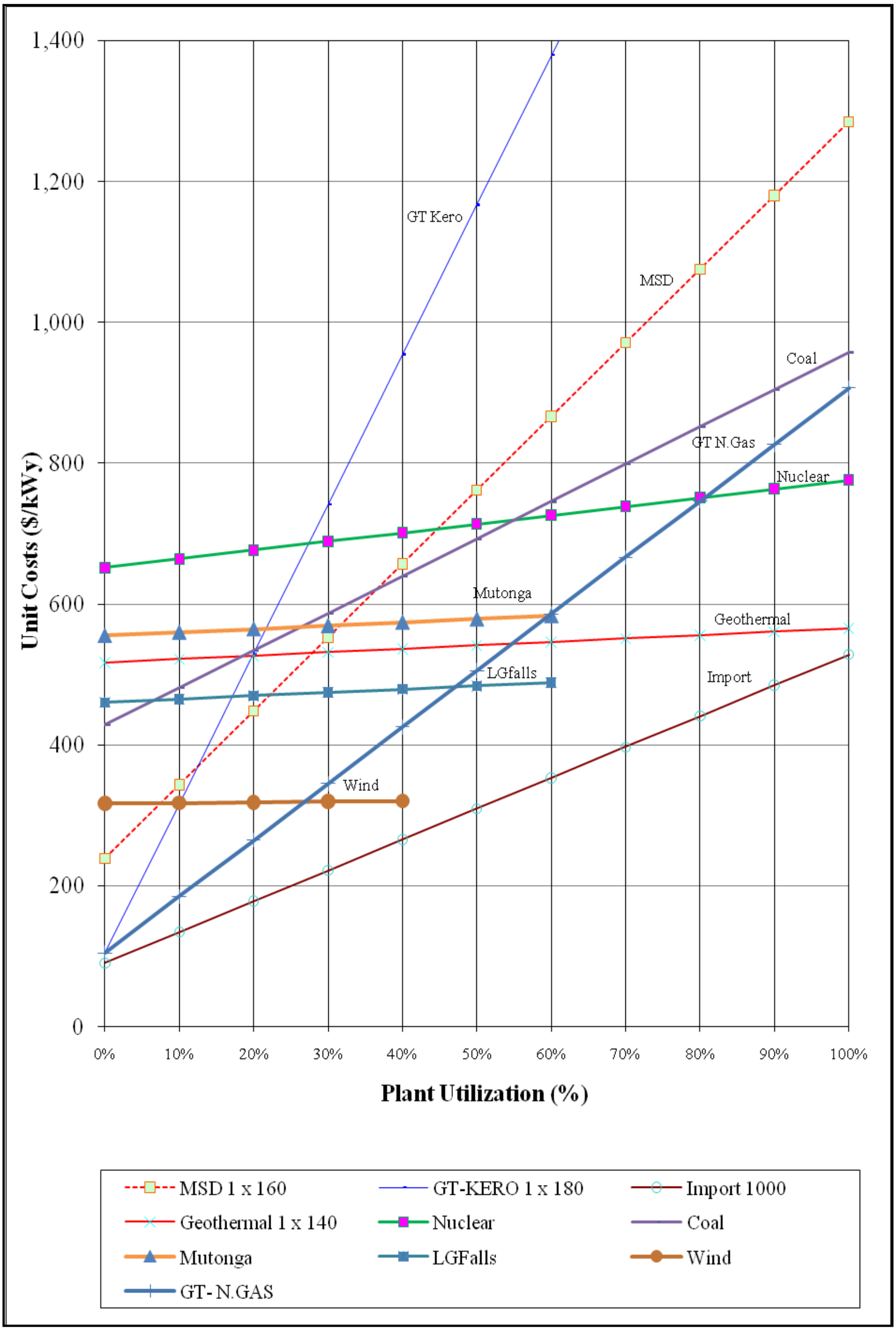
	Geothermal	**Nuclear**	**Coal**	**GT-KERO**	**GT- N.GAS**	**MSD**	**Import**	**Mutonga**	**LGFalls**	**Wind**
Configuration (n x MW)	**1 x 140**	**1 X 1000**	**1 X 300**	**1 x 180**	**1 x 180**	**1 x 160**	**1000**	**60**	**140**	**300**
Total Capacity (MW)	140	1000	300	180	180	160	1000	60	140	300
Fixed 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**

Table 47 cont: Screening of Candidate Sources – Reference Forecast scenario

Thermal Generation Unit Cost
Crude Oil Price = 90US$/bbl
Coal Price =100 US$/tone
Natural Gas = 9.11 US$/Gj

		Geothermal	Nuclear	Coal	GT-KERO	GT- N.GAS	MSD	Import	Mutonga	LGFalls	Wind
Unit Cost ($/kW.yr)		**1 x 140**	**1 X 1000**	**1 X 300**	**1 x 180**	**1 x 180**	**1 x 160**	**1000**	**60**	**140**	**300**
Plant Factor.............	0%	517	652	429	105	105	239	91	555	461	317
Plant Factor.............	10%	522	664	482	317	185	344	135	560	465	318
Plant Factor.............	20%	527	677	535	530	265	448	178	565	470	319
Plant Factor.............	30%	532	689	587	742	345	553	222	569	475	320
Plant Factor.............	40%	536	701	640	954	426	657	266	574	479	321
Plant Factor.............	50%	541	714	693	1167	506	762	310	579	484	
Plant Factor.............	60%	546	726	746	1379	586	866	354	583	489	
Plant Factor.............	70%	551	739	799	1592	666	971	397			
Plant Factor.............	80%	556	751	852	1804	746	1076	441			
Plant Factor.............	90%	561	764	904	2017	827	1180	485			
Plant Factor.............	100%	566	776	957	2229	907	1285	529			
Unit Cost ($/kWh)											
Plant Factor.............	10%	0.5957	0.758	0.550	0.362	0.211	0.392	0.154	0.639	0.531	0.363
Plant Factor.............	20%	0.3006	0.386	0.305	0.302	0.151	0.256	0.102	0.322	0.268	0.182
Plant Factor.............	30%	0.2023	0.262	0.224	0.282	0.131	0.210	0.085	0.217	0.181	0.122
Plant Factor.............	40%	0.1531	0.200	0.183	0.272	0.121	0.188	0.076	0.164	0.137	0.0915
Plant Factor.............	50%	0.1236	0.163	0.158	0.266	0.115	0.174	0.071	0.132	0.110	
Plant Factor.............	60%	0.1039	0.138	0.142	0.262	0.111	0.165	0.067	0.111	0.093	
Plant Factor.............	70%	0.0899	0.120	0.130	0.260	0.109	0.158	0.065			
Plant Factor.............	80%	0.0793	0.107	0.122	0.257	0.107	0.153	0.063			
Plant Factor.............	90%	0.0711	0.097	0.115	0.256	0.105	0.150	0.062			
Plant Factor.............	100%	0.0646	0.089	0.109	0.254	0.104	0.147	0.060			

Figure 33: Screening curve for candidate units – Reference scenario @ 8% Discount Rate



5.7.2 Ranking of candidate projects.

The screening curves show the yearly cost of one firm kilowatt according to the load factor of the power plant. For a given load factor, we obtain the levelised cost of energy (LCOE) related to this load factor. This LCOE is used hereunder for the economic ranking of the candidate projects. The more attractive candidate is ranked first with an index of 100 and then all the other candidates are ranked against the benchmark of the candidate ranked first.

The load factor chosen is the highest one attainable for each type of candidate. It takes into account schedule and unscheduled outages and also takes into account the availability of water for hydro candidates and wind for wind candidates.

The candidates are categorized according to the type of supply they are designed for; either base load or peak load.

a) Ranking of base load projects

Two discount rates are considered, 8% for base case and 12% for sensitivity analysis.

Table 48: Ranking of base load projects

Discount rate – 8%

CANDIDATE POWER PLANT	LOAD FACTOR	LCOE USc/kWh 8% Disc Rate	INDEX
1. GEOTHERMAL	93%	6.9	100%
2. WIND	40%	9.1	132%
3. LOW GRAND FALLS	60%	9.3	135%
4. NUCLEAR	85%	10.2	148%
5. MUTONGA	60%	11.1	161%
6. GAS TURBINE - Natural Gas	55%	11.3	164%
7. COAL	73%	12.7	184%
IMPORTS FROM ETHIOPIA	70%	6.5	-

Discount rate – 12%

CANDIDATE POWER PLANT	LOAD FACTOR	LCOE USc/kWh 12% Disc. Rate	INDEX
1. GEOTHERMAL	93%	9.2	100%
2. GAS TURBINE - Natural Gas	55%	12.0	130%
3. WIND	40%	12.2	133%
4. LOW GRAND FALLS	60%	14.1	153%
5. NUCLEAR	85%	14.5	158%
6. COAL	55%	14.9	162%
7. MUTONGA	60%	16.8	183%
IMPORTS FROM ETHIOPIA	70%	6.8	-

The ranking of projects shows that local energy resources (geothermal, low grand falls hydro and wind) are the most economically attractive. This is true for 8% discount rate while at 12%, the ranking is changed. Gas turbine using natural gas becomes more attractive than wind and then low grand falls.

Imported resources (nuclear and coal) are more expensive than local resources (geothermal and wind) in both discount rate scenarios.

As a conclusion, this means that the expansion plan designed in the next chapter will first resort to local resources as far as possible. The capacity needed in addition to wind and geothermal should be supplied by natural gas and nuclear.

The imports from Ethiopia are only marginally cheaper in comparison to geothermal. In addition, these imports could be subject to unforeseen price fluctuations and unexpected unavailability. The imports should be used basically for replacing as much as possible high priced imported fuels consumed in thermal power plants in Kenya.

b) Ranking of Peak Load Candidates

Table 49: Ranking of peak load projects

Discount rate – 8%

CANDIDATE POWER PLANT	LOAD FACTOR	LCOE USc/kWh 8% Disc Rate	INDEX
1. GAS TURBINE - Natural Gas	20%	15.1	100%
2. MEDIUM SPEED DIESEL	28%	21.7	144%
3. GAS TURBINE - Kerosene	20%	30.2	200%

Discount rate - 12%

CANDIDATE POWER PLANT	LOAD FACTOR	LCOE USc/kWh 12% Disc. Rate	INDEX
1. GAS TURBINE - Natural Gas	20%	17.0	100%
2. MEDIUM SPEED DIESEL	28%	24.1	142%
3. GAS TURBINE - Kerosene	20%	32.1	189%

The results of the ranking show that gas turbine on natural gas should be selected for peak load capacities when and where natural gas is available in Kenya. Conversely, when kerosene is used for gas turbine, LCOE doubles. However, this fact should not prevent installation of gas turbines running on kerosene if such gas turbines are designed for burning both kerosene and natural gas. It means also that the gas turbines should be installed at locations where the natural gas facilities would be constructed in Kenya.

As concerns MSD, it should be noted that this facilities could be used both as peaking facilities and intermediate load facilities. MSD remains cheaper than coal up to a load factor of 35%. In addition, the small size of diesel units (20MW) provide for gradual implantation while a coal fired power plant units are assumed in units of 300MW.

6 METHODOLOGY OF THE LEAST COST GENERATION PLANNING

6.1 Introduction

Following the screening analysis carried out in Chapter 5, and the selection of candidate projects with the lowest LCEO, either for peak or base load, the next step of the generation planning involves:

(i) Setting up expansion sequences upto the year 2031, capable of meeting the projected demand;

(ii). Comparing the cost of the sequences in order to choose the least cost one.

The cost of the sequences that is assessed in this Chapter is the incremental cost of the power generating system over the period 2011-2031, also called the long run marginal cost. The outline of the chapter is as follows: Section 6.2 of this chapter discusses the marginal cost concept, Section 6.3 the VALORAGUA model and its inputs are briefly discussed, the results of the short run marginal cost are compared to monthly hydro generations in section 6.4 of this chapter, Section 6.5 discusses long term optimization using the WASP Model, Results of long term optimization are presented in section 6.6, The summarized results for the three load growth scenarios are given in section 6.7, Sensitivity to fuel costs, discount rates and imports phasing results are given in section 6.8 and the long run marginal cost results using WASP are given in section 6.9.

6.2 General points on marginal costs

Economic theory shows that in a power generating system that is expanding in an optimal way, i.e. following a least cost expansion path, the short run marginal cost (SRMC) and the long run marginal cost (LRMC) are equal. Moreover, the maximization of economic welfare of both the producers (power sector companies) and the consumers (subscribers) is obtained when electricity is sold at a price equal to marginal cost (also known as Pareto optimum).

This broad assertion is valid only under a number of restrictive conditions (for instance a perfectly competitive market) that are supposed to be met for power system operation and planning. Marginal cost measures the cost of increasing production by one additional unit. For a power system it means the cost of generating one additional kWh.

6.2.1 Short run marginal cost.

In the short-run, the power plant mix remains unchanged, that is, there is no investment on additional new power generating capacity.
In such a case, electricity generation only entails running costs, composed of fuel costs for thermal generation, and the cost of energy not served. Minimizing SRMC requires that power plants are adequately managed, especially when hydroelectric power is stored in dams. Optimum power generation management entails deciding, at each hour, whether to consume fuel, or to use hydro power plants, or to accept a small shortage now in order to avoid a larger outage later on.

These “shortage costs” call for a careful explanation. They represent the value of drawbacks inflicted on consumers when power supply cannot meet demand. They do not represent the amount of money lost by the power company when it is unable to supply electricity, which is the financial cost. The economic cost of the unserved energy is much higher, since it must be considered from a global (macroeconomic) viewpoint. It actually measures both:

(i) The production lost in the productive sector due to electricity shortage, the value of which is different in every sub-sector, in particular depending on the part played by electricity in the related activity.

(ii) The drawbacks affecting domestic customers, or even their losses in the households.

6.2.2 Long run marginal cost

When the risk of shortage becomes too high, and demand exceeds supply for a significant time span, the macroeconomic costs created by the shortage of power will increase the short run marginal cost. This will continue until a cost-effective way to cancel the shortage occurs such as expanding generating capacity. This will involve heavy investment expenditures, which will show up in long run marginal cost.

From such a long-term perspective, all additional costs (or incremental costs, or development costs) due to power system expansion make up the long term marginal cost. They include future investment cost, fixed operation and maintenance costs and fuel costs. While fixed costs relate exclusively to additional facilities, fuel costs relate to both future and existing facilities.

This is expressed in the following formula:

LRMC = Additional Investment + O & M costs + fuel costs

Since generation expansion aims at eliminating power shortages, the cost of the shortages becomes negligible.

Minimizing this LRMC is the goal of the current least cost generation plan. For this purpose various long term expansion sequences based on the projects selected in the screening analysis will be compared, until the one presenting the lowest cost, also called least cost expansion plan, is eventually obtained.

6.2.3 Comparison between LRMC and SRMC

a) Both short run and long run marginal costs consider the future costs, not the past. All existing or committed power plants are considered as sunk investment and account for running costs only. It is only future costs for which additional generation is responsible.

b) When SRMC = LRMC, the expansion path is optimal for a given cost of unserved energy and it achieves the lowest possible cost.

c) Since this LCPDP is a long-term plan, this chapter should focus only on LRMC, instead of both LRMC and SRMC. However, SRMC is also considered. There are two reasons for this:
   (i) It is important to check if LRMC and SRMC are consistent. For the current 2011 update, the following costs (refer to results hereunder) are obtained:
      - SRMC = 9.2 USc/kWh in 2011,

- LRMC = 14.82 USc/kWh, this LRMC being assessed by the average expansion cost of the generation system until 2031

In 2011 the short run cost is much lower than the long run cost. This means that the Kenyan generation system is currently far from optimum, and that as more plants are brought online progressively, the system is expected to get closer to optimum.

(ii) Modeling the long term expansion is based on the WASP software described hereunder. For practical reasons a separate software package was used to determine the optimal generation output for the hydroelectric power plants (refer to comments about SRMC Section 6.2.1 hereabove).

This software is called "VALORAGUA" and will be described below, followed by a description of the WASP software.

d) From a practical viewpoint, the LRMC is expressed in two different ways:

(i) $$\text{LRMC} = \frac{\text{Discounted global expansion cost over the period 2011-2031}}{\text{Discounted global generated energy over the same period}}$$

The results obtained using this are approached are to be found in sections 6.6-6.8.

(ii) $$\text{LRMC} = \frac{\text{Total NPV of incremental cost of Generation (US\$)}}{\text{Incremental net energy generation (GWh)}}$$

Related results from this approach are shown in section 6.9.

6.3 Short Term Optimization: The VALORAGUA Model

VALORAGUA Model is software developed in FORTRAN, composed of several modules implemented to perform the management of a mixed hydrothermal electric power system, at a national level or with interconnections with other countries (or areas). It establishes the optimal strategy of operation for a given power system by the use of the "value of water" concept (in energy terms) in each power station, for each time interval (i.e. month/week) and for each hydrological condition. For hydro power plants, the model takes into account that the water may have other utilizations rather than energy generation.

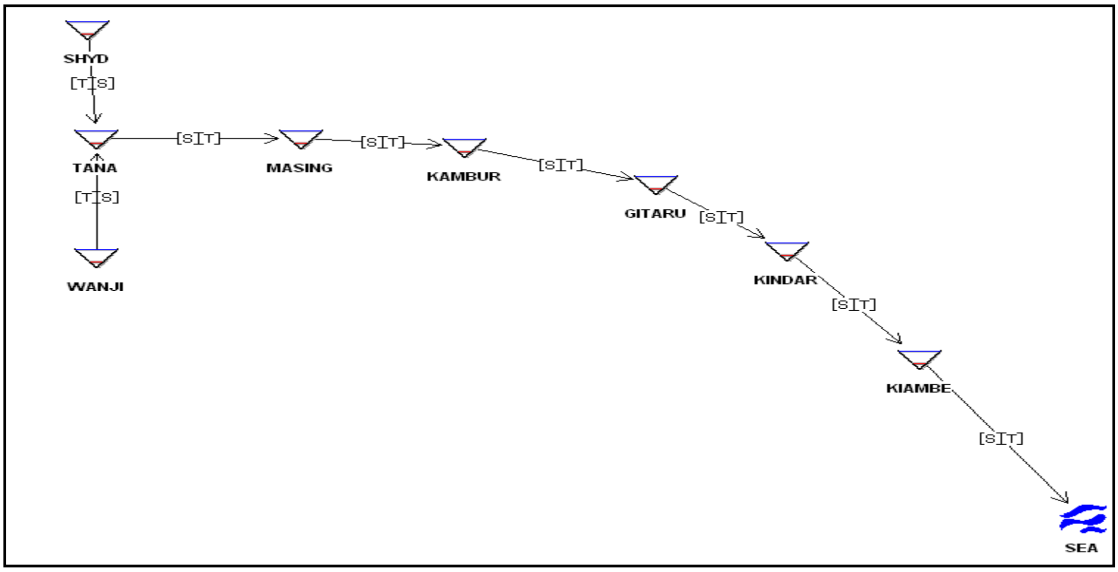
The VALORAGUA model is used to determine optimal operating strategy for a given configuration of the electric power system made up of hydro and thermal power plants. It minimizes power system plant operation costs over one year, month-by-month or week-by-week. It involves modeling of the hydro system according to seasonal variations and optimizing the system operation and maximizing the hydro output. The model comprises several modules that optimize the hydrothermal electric power system at national level or with interconnections with other countries. It does not take into account capital cost but only running cost, namely fuel cost and cost of unserved energy.

Using technical input data namely, reservoir storage capacity, dead volume level/ volume water level and average operation costs, the model optimizes the management of reservoirs by minimizing the expected value of future generation costs and performing the management of the electric power in order to minimize the sum of generation costs and the expected value of future generation costs. The model simulates system operation over a time period of one year, for up to 30 different hydrological conditions (hydrological years). The period considered for inflows in the study is 1980 -2009. Table 50 shows the parameters used in the VALORAGUA model while Fig 34 displays the schematic representation of the hydraulic network of the Tana cascade.

Table 50: Defined Parameters for the VALORAGUA Model

1. Initial Data:			2. Electrical:
Period of study period:	2011-2031		Electric nodes
First period:		January	: Nairobi
			: Western
Load step duration			: Coast
:1st step =		5.71 %	: Mt Kenya
:2nd step =		5.71 %	
:3rd step =		45.66 %	3. Hydraulic Cascades
:4th step =		11.41%	: Tana cascade
:5th step =		31.51%	: Turkwel
			: Sondu cascade
Testflows data base			
The first year was 1980			
The last year was 2009			

Figure 34: Schematic diagram of Tana cascade



KEY: SHYD- small hydro Masing- Masinga Kambur- Kamburu Kindar- Kindaruma Kiambe-Kiambere

6.3.1 VALORAGUA SIMULATION RESULTS

Figures 35, 36 and 37 provide the results from VALORAGUA Simulation tool. Figure 35 compares the VALORAGUA average annual output and the actual average output over a 5-year period. The results obtained from the model closely track the actual 5-year generation average.

Figure 35: Comparison of VALORAGUA Results with 2009 Actual Generation

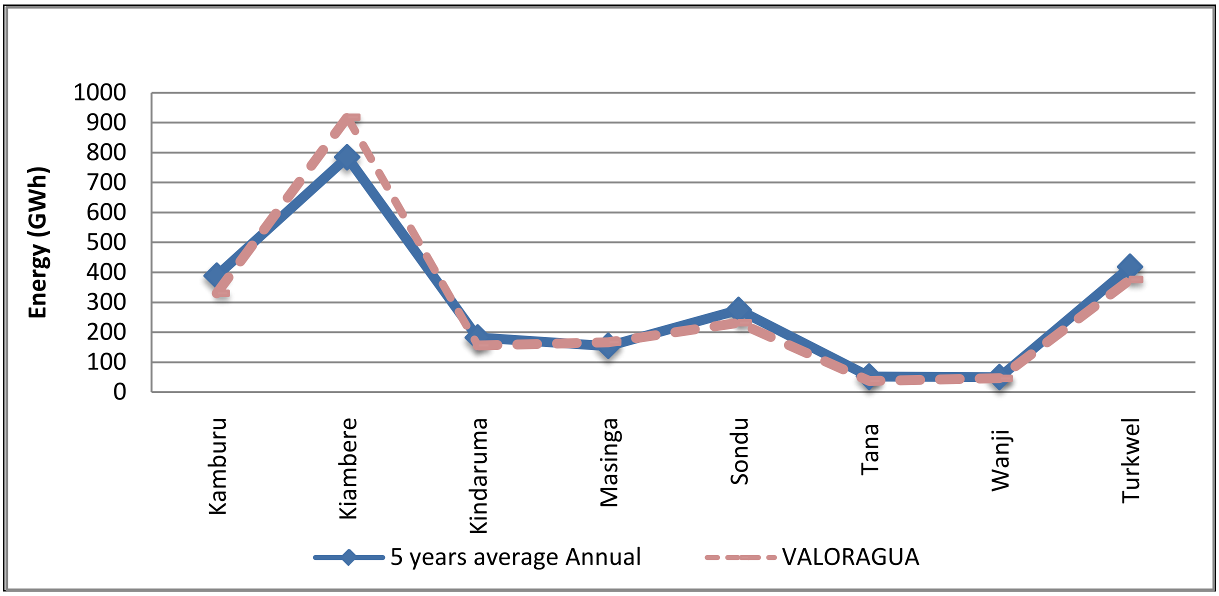
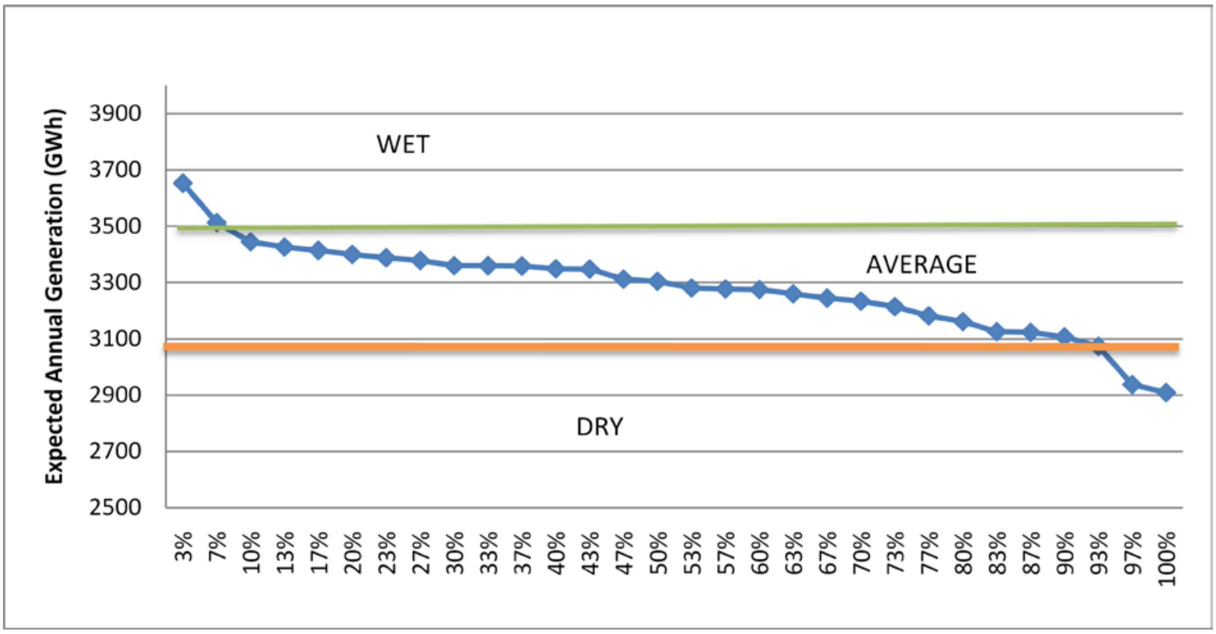


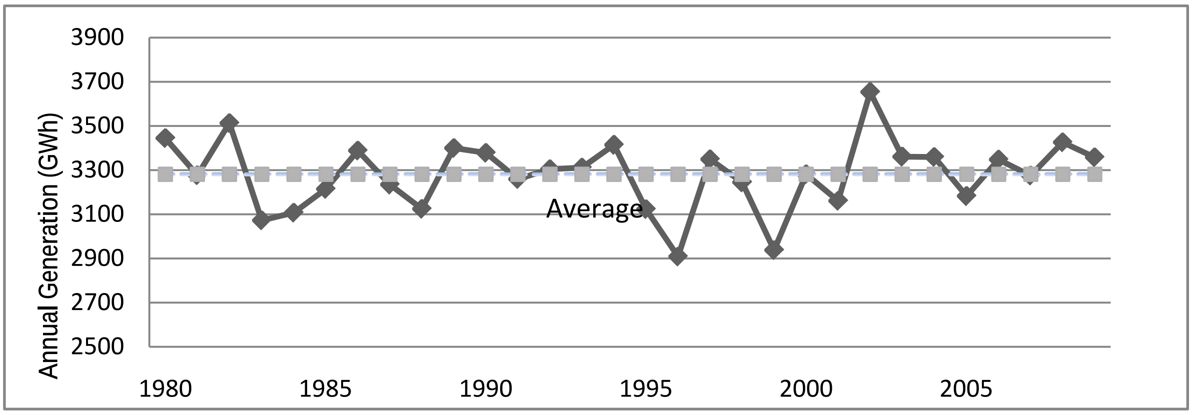
Figure 36: Probability of Hydro Generation – System Configuration



Based on the results of the VALORAGUA simulation, the probability of exceeding a given level of generation from hydro power plants can be determined from Figure 36 above. From the figure, it is evident that there is a 7% probability of generating 3,500 GWh or more annually which corresponds to the wet hydrological year of 1982. Likewise, there is a 50% probability of generating 3,300GWh or more annually which corresponds to the average hydrological year of 1992. In addition, there is a 90% probability of generating 3,100 GWh or more annually which corresponds to the dry hydrological year of 1984.

Figure 37 below shows the annual average generation from hydro power plants using historical inflow data for the period 1980 to 2009. The average generation for the period was 3280 GWh.

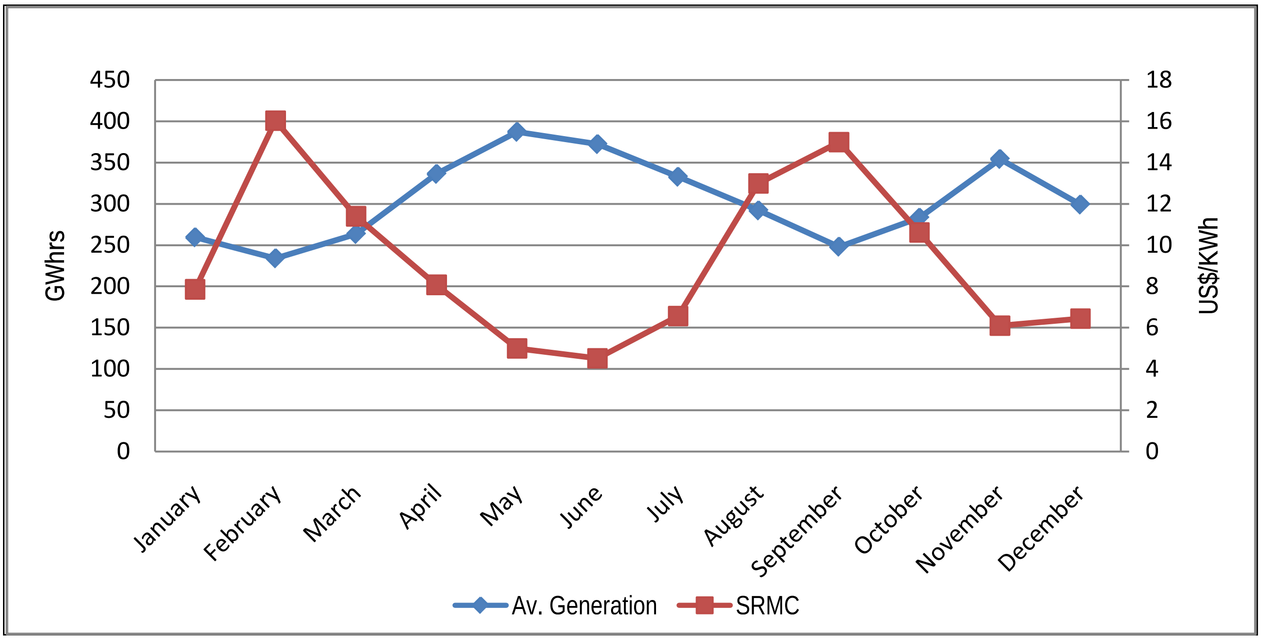
Figure 37: Output of VALORAGUA Results Using Historical Inflow Data



6.4 Short Run Marginal Cost Results (SRMC)

Figure 38 shows relationship between the SRMC and average monthly hydropower generation.

Figure 38: Monthly SRMC

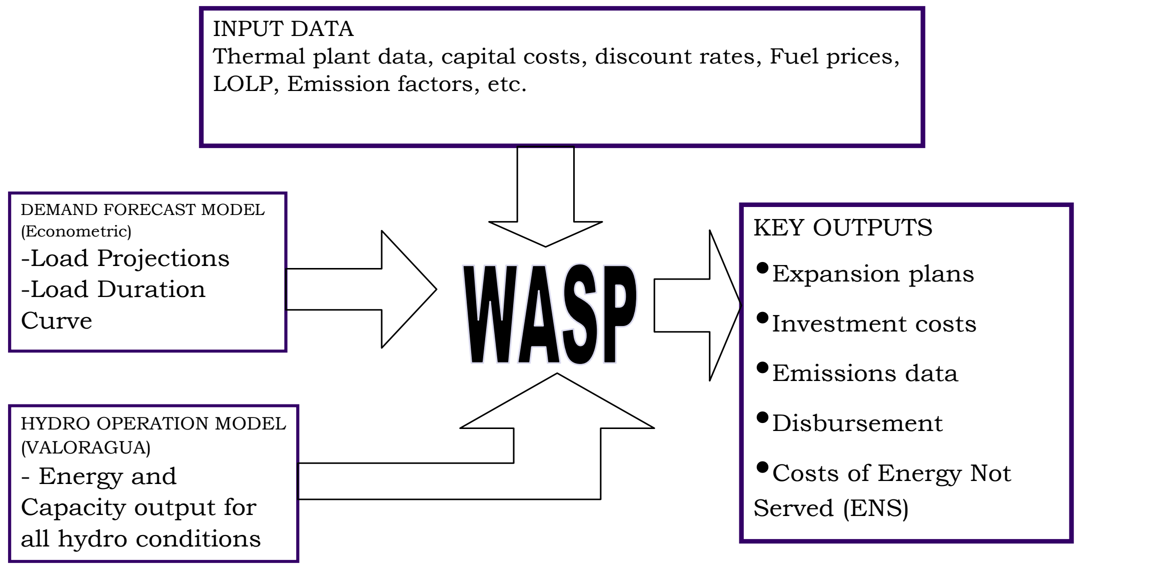


From the above it is apparent that the SRMC varies from month to month ranging from a high of 16 US cents/kWh in February to a low of 5 US cents/kWh in June every year. This is due to the inverse correlation between the SRMC of the system and energy generation from hydro power plants due to the substitution effect of thermal generation for hydro based generation during the wet seasons of the year and vice versa. Due to the high operation and maintenance costs of thermal based plants including fuel costs, the SRMC of the system increases as hydro capacity declines during short rains (September to November) and decreases as hydro capacity increase in the long rains (April to July). The average SRMC from the results was 9.22 US cents/kWh.

6.5 Long -term optimization: the WASP model

The goal of electric power systems expansion planning is to determine the optimal pattern of system expansion to meet the electricity requirements over a given period. The Wien Automatic Simulation Planning Package (WASP) helps to find the economically optimum expansion plan for a power generating system for up to 30 years, within constraints specified by the planner. WASP utilizes the load forecast and outputs of VALORAGUA in addition to other power system parameters. The model evaluates many combinations of candidate generation projects to obtain the least-cost expansion plan (optimal solution) for a given period. The outputs of WASP include the alternative expansion plans and their Present Value (NPV) costs, annual financing requirements and summary reports. Figure 39 illustrates the relationships between WASP, demand forecasting tools and VALORAGUA.

Figure 39: Operations in the WASP Model



WASP is a cost minimization tool whose objective function is to generate the power planning expansion plan with the lowest present worth cost for the planning period. The model is probabilistic and not deterministic. The objective function can be represented by the following equation:

Expression of the Objective Function

$$B_j = \sum_{t=1}^{T} I_{j,t} - S_{j,t} + F_i + L_{j,t} + M_{j,t} + O_{j,t}$$

Investment cost

Salvage value

Fuel cost

Fuel inventory cost

Operation & Maintenance costs (non-fuel)

Cost of energy not served

Where:

Bj is the discounted present worth costs of the expansion plan j;

t is the time period in years from year 1 to T (1, 2, 3, …….,T);

T is the study period in years (total number of years); and

I the discount rate.

The objective function is therefore to minimize Bj for all j.

WASP measures system reliability with three indices namely:

i.) Reserve margin;

ii.) Loss-of-load-probability (LOLP); and

iii.) Expected Energy Not Served (ENS).

These reliability indices and the maximum number of thermal or hydroelectric units that can be added each year are entered into the model as user-specified constraints that an expansion plan must meet to be acceptable. In addition, plant specific data for generation plants are entered into the programme as a fixed plan.

6.5.1 Basic assumptions and key parameters

The basic assumptions and key parameters for the least-cost planning study using the WASP and VALORAGUA computer models are as follows:

(a) Study period: 21 years (from 2010 to 2031);

(b) Planning period: 20 years (from 2011 to 2031);

(c) Reference year for cost discounting: Beginning of 2010;

(d) Real discount rate: 8%;

(e) Number of periods per year: 12 (from July to June);

(f) Number of hydrological conditions in WASP: 3 (dry, average, and wet);

(g) Number of hydrological conditions in VALORAGUA: 30 (historical series of monthly water inflows from 1980 to 2009); and

(h) Cost data: - all costs are expressed in constant 2010 U.S. dollars.

Most of the assumptions adopted for the reference (base) case are also valid for other analyzed scenarios and sensitivity studies. In the sections describing the other scenarios, only the assumptions that are different from those in the reference case will be presented.

6.5.2 Economic Parameters

The economic parameters and criteria used for the evaluation of different expansion alternatives can be summarized as follows:

(a) Planning Period

The planning period was defined as a 20-year period from 2011 to 2031.

(b) Reference Year

The reference year for all cost discounting and escalation calculations was 2010. All costs are expressed in U.S. dollars (constant prices of 2010).

(c) Present worth Date

Present-worth date is 2010. All costs except for fuel costs, operating and maintenance (O&M) costs, and energy not served (ENS) costs are assumed to occur at the beginning of the time period in which they are incurred. Fuel, O&M, and ENS costs are assumed to occur in the middle of the period in which they are incurred.

(d) Present Value of Total System Cost

The objective function of the WASP optimization is to minimize the present value of the total system costs over the study period. The objective function consists of the following cost components:

- Capital investment costs (I)
- Salvage value of investment costs (S)
- Fuel costs (F)
- Fuel inventory costs (L)
- Non-fuel operation and maintenance costs (M)
- Cost of the energy not served (O)

The cost function that is evaluated by WASP can be represented by the following expression:

$$B_j = \sum_{t=1}^{Ti} I_{j,t} - S_{j,t} + F_{j,t} + L_{j,t} + M_{j,t} + O_{j,t}]$$

Where:

B_j is the objective function attached to the expansion plan j,

t is the time in years (t =1, 2, …, T),

T is the length of the study period (total number of years).

All cost components in the above expression are discounted to the present worth date using the given discount rate i. For the optimization of system development, the capital investment costs for candidate projects are considered to occur at the beginning of the year in which they are commissioned into the system. A dynamic programming algorithm, searching for the least-cost expansion path that satisfies given reliability criteria, is applied in the optimization of system development.

(e) Discount Rate

A real discount rate of 8 percent was used when calculating the present-value of all investment and operating costs.

(f) Cost Escalation

All cost evaluations are expressed in real U.S. dollars as of the mid of 2010. No escalation rate was applied to the capital investment and operating costs. Fuel costs were assumed to escalate at different rates. The cost escalation for natural gas, fuel oil and imported coal were calculated based on historical trends and information gathered from relevant sources.

(g) Salvage Value of Capital Investments

The sinking fund depreciation method was applied to calculate the salvage values of the plants committed during the study period.

6.5.3 Operation Criteria and Reliability Constraints

The following optimization criteria and reliability constraints were used in the conduct of the analysis:

(a) Loading Order

The economic loading order, based on the operational costs of the existing thermal generating units and candidates for system expansion, was calculated by the WASP program and used in all scenarios.

(b) Reserve Margin

The planning reserve margin is defined as the ratio of system available capacity to peak load in the critical period, and usually is expressed as a percentage of the peak load. A reserve margin of at least 25% was used in the study from the year 2014 to 2031.

(c) Cost of Energy-not-Served

An estimate of 84 US cents/kWh for the cost of energy not served was used in the base case analysis.

(d) Loss-of-Load-Probability (LOLP)

The upper limit for the LOLP reliability parameter was specified as 2.7% starting from 2014, thus providing a significant contribution to overall system reliability. The initial years were not constrained as 2014 was assumed to be the earliest year in which additional new generating capacity other than the committed projects could be required. 2.7% LOLP is equivalent to not meeting demand for about 10 days per year. In the later years the same LOLP was retained and found to have no significant impact since the reserve margin settings were high throughout. The results indicate that LOLP would be very low meaning that the demand shall be met every day.

6.5.4 Modeling of the Existing Generating System

The hydropower plants currently existing in Kenya are presented in Table 51 while thermal and geothermal plants modeled in WASP are shown in Table 52.

Table 51: Existing Hydro Power Plants Modeled in WASP (Status: Year 2010)

Hydro Plant Name	WASP Name	Installed Capacity (MW)
Wanji	WANJ	7.4
Tana	TANA	20
Masinga	MASI	40
Kamburu	KAMB	94
Gitaru	GITA	225
Kindaruma	KIND	40
Kiambere	KIAM	168
Turkwel	TURK	106
Sondu	SOND	60
TOTAL		760.4

Table 52: Existing Thermal Generating Units Modeled in WASP (Status: Year 2010).

Unit Name	WASP Name	Installed Capacity (MW)	Net Available Capacity (MW)	Fuel Type
Kipevu I	KDP1	75	60	Fuel Oil
Kipevu III	KDP3	120	120	
Tsavo	TSVO	74	74	Fuel Oil
Kipevu GT1	KGT1	30	30	Kerosene
Kipevu GT2	KGT2	30	30	Kerosene
Iberafrica 1	IBA1	56	56	Fuel Oil
Iberafrica 2	IBA2	52.5	52.5	Fuel Oil
Rabai Diesel	RAB1	83.3	83.3	Fuel Oil
Rabai Steam	RAB2	5.3	5.5	steam
Olkaria I	OLK1	45	45	Steam
Olkaria II	OLK2	70	70	Steam
Olkaria III	OLK3	48	48	Steam
Mumias cogeneration	MCOG	26	26	Bagasse
TOTAL		715.1	700.3	

The operational parameters for the hydro power plants and necessary hydro data input to the WASP model were determined on the basis of the VALORAGUA analysis of the electric power system in

Kenya for several system configurations that included both existing and candidate hydro projects. In order to determine possible hydro generations and available capacities for the 3 hydrological conditions required by WASP, the operation of hydro power plants and optimization of hydro-cascades were performed with the VALORAGUA model for a set of historical monthly water inflows from 1980 through 2009.

The uncertainty of hydrological inflows was modeled in WASP by simulating the system operation for three hydrological conditions: wet, average and dry. The probabilities of occurrence of these hydro conditions were determined on the basis of the VALORAGUA results. The values obtained are 0.21, 0.26 and 0.53 for the three hydro conditions respectively, based on recent hydrology and performance.

6.5.5 Implementation constraints for candidate projects

The constraints applied in Base Case WASP simulations are shown in Table 53.

Table 53: Implementation constraints

1. GEOTHERMAL	2. NUCLEAR
Maximum 3 x 140MW in a year	Maximum 2 x 1,000 MW
	First plant in 2022
3. COAL	4. MEDIUM SPEED DIESEL(160MW)
Earliest commissioning date 2014	Earliest date 2017
Maximum per year 3 x 300MW	
5. MUTONGA (60MW)	6. LOW GRAND FALLS (140MW)
Earliest date 2018	Earliest date 2018
7. GT(180MW)	8. IMPORT (200MW)
Earliest date 2015	Earliest date 2014
8. WIND (100MW)	
Maximum 3 X 100 MW	

6.6 Results of the Analysis

The operational characteristics of hydro power plants obtained from the hydro operations studies carried out with the VALORAGUA model were further used in the systems planning analysis. The characterization of hydro power plants operation was performed for the three hydrological conditions (wet, average, and dry) considered in the WASP model. The input data regarding the possible electricity production and available capacities of hydro power plants for each of the three hydrological conditions were prepared on the basis of the VALORAGUA analysis of the whole electric power system in Kenya, including both hydro and thermal power plants. VALORAGUA, as a hydro-thermal coordination model was used to optimize the operation of the entire system.

System expansion analyses were performed for the medium, high, and low load forecasts, with the medium load forecast considered as the reference case. The probabilities for the three seasons were set at 0.53, 0.26 and 0.21 for dry, average and wet respectively. Several different scenarios were examined. The scenario assumptions were providing general guidelines and directions for future system development, while the WASP expansion analysis was actually examining thousands of possible future system configurations (combinations of the existing generating units and candidates for system expansion) to determine the least-cost path for a set of given scenario assumptions and constraints. The results obtained from the system expansion analysis are presented below.

6.6.1 Base Case Analysis (Medium load growth scenario)

The Base Case expansion analysis was performed respecting the limitation in number of geothermal plants per year, maximum number of nuclear plants in the period, project lead times among other constraints. The WASP optimum solution obtained for the reference (Base Case) analysis is presented in Table 54.

The first new project that was achieved in the least cost plan is 200MW imported power in 2014 and a 280 MW geothermal plant in 2015. The first two gas fired power plants utilizing natural gas come online in the year 2017 and will mainly be used as peaking plants. The next varying type of technology, a 300 MW coal plant, will be required in 2020. The first nuclear plant in the least-cost expansion is a 1,000 MW to be commissioned in 2022.

Table 54: The WASP Optimal Solution Base Case and Reference Fuel

YEAR	NAME	GEOT	COAL	GT	MSD	WIND	NUCL	IMPORT	HYD1	HYD2
	SIZE (MW) CAP	140	300	180	160	100	1000	200	60	140
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-
2014	200	-	-	-	-	-	-	200	-	-
2015	280	280	-	-	-	-	-	-	-	-
2016	400	-	-	-	-	-	-	400	-	-
2017	460	140	-	-	320	-	-	-	-	-
2018	740	140	300	-	-	100	-	-	60	140
2019	580	280	-	-	-	100	-	200	-	-
2020	840	280	-	360	-	-	-	200	-	-
2021	860	280	300	180	-	100	-	-	-	-
2022	1,000	-	-	-	-	-	1,000	-	-	-
2023	680	280	300	-	-	100	-	-	-	-
2024	1,120	420	-	180	320	-	-	200	-	-
2025	1,140	420	-	360	160	200	-	-	-	-
2026	2,020	420	-	-	-	200	1,000	400	-	-
2027	620	420	-	-	-	-	-	200	-	-
2028	1,700	420	600	180	-	300	-	200	-	-
2029	1,880	420	-	360	-	100	1,000	-	-	-
2030	2,000	420	600	360	320	300	-	-	-	-
2031	2,400	420	300	360	320	-	1,000	-	-	-
TOTAL	18,920	5,040	2,400	2,340	1,440	1,500	4,000	2,000	60	140

The total new additional capacity to the system over the study period is 18,920 MW comprising of 5,040 MW geothermal, 2,400 MW new coal units,2,000 MW imports, 4,000 MW nuclear, 2,340 MW of new gas turbines 1,440 new medium speed diesel units ,1,500 MW of wind and 200MW of Hydro Power plants. The present value of the total system expansion cost over the period 2010-2031 for the base case development plan amounts to U.S.$ 41.4 billion (committed projects excluded), expressed in constant prices as of the beginning of 2010. The least cost development plan based on the optimum solution is presented in Table 55.

Table 55: Least Cost Expansion Program for the Base Case Analysis

Year ending 30th June	Configuration				Indicative Capital Cost (Mln US$)	Type	Added Capacity MW	Total Capacity MW	System Peak MW	Reserve Margin MW	Reserve Margin as % of Peak
2010								1,363	1,227	136	11%
2011	1	×	10	TANA		HYRO	20				
	12	×	10	KIP3	156	MSD	120	1,503	1,302	201	15%
2012	1	×	2.2	EBURRU	8.03	Geothermal	2				
	1	×	5	OLKWH		Geothermal	5				
	2	×	10.3	SANG	78	HYDRO	21	1,531	1,520	11	0.7%
2013	10	×	16	AEOLUS	368	WIND	60				
	5	×	16	TRIUMPH	110	MSD	81				
	5	×	17	GULF	114	MSD	84				
	5	×	17	MELEC	118	MSD	87				
	7	×	5	OLKWH	127	Geothermal	35				
	5	×	16	MUHORONI	110	WIND	80				
	3	×	7	WIN1	15	Ngong 3	21	1,979	1,765	214	12%
2014	2	×	70	OLK4	511	Geothermal	140				
	353	×	0.85	LTWP	538	Turkana	300				
	1	×	-30	KGT1		Gas Turbine	-30				
	1	×	-30	KGT2		Gas Turbine	-30				
	2	×	26	OLK3	131	Geothermal	36				
	5	×	10	OSIWO	115	WIND	50				
	1	×	200	IMPORT		HYDRO	200				
	7	×	5	OLKWH	127	Geothermal	35				
	1	×	32	KIND	115	HYDRO	32				
	2	×	70	OLK1-4&5	511	Geothermal	140	2,852	2,064	788	38%
2015	3	×	-15	OLKI		Geothermal	-45				
	1	X	25	SMHY		Hydro	25				
	2	×	140	GEOT	1022	Geothermal	280				
	1	×	20	ARM		Coal	20	3,132	2,511	621	25%
2016	2	×	200	IMP0RT		IMPORT	400	3,832	2,866	970	34%
	1	×	300	COAL	631.2	COAL	300				
2017	1	×	140	GEOT	511	Geothermal	140				
	2	×	160	MSD	436.48	MSD	320				
	3	×	15	OLK1		Geothermal	45	4,337	3,292	1,045	32%
2018	1	×	300	COAL	631.2	COAL	300				
	1	×	100	WIND	230	WIND	100				
	1	×	60	MUTO	259	HYDRO	60				
	1	×	140	LGF	507	HYDRO	140				
	1	×	140	GEOT	511	Geothermal	140	5,077	3,751	1,326	35%
2019	1	×	200	IMPORT		IMPORT	200				
	1	x	100	WIND	230	WIND	100				
	1	x	16	OLK3	58	Geothermal	16				
	10	×	-5.6	IBR1		MSD	-56				
	1	×	-26	MUMIAS		COGEN	-26				
	2	×	140	GEOT	1022	Geothermal	280	5,591	4,216	1,375	33%
2020	2	×	180	GT-NGAS	270	GT	360				
	1	×	200	IMPORT		IMPORT	200				
	2	×	140	GEOT	1022	Geothermal	280	6,431	4,755	1,676	36%
2021	2	×	140	GEOT	1022	Geothermal	280				
	10	×	-7.4	TSAVO		MSD	-74				

Year ending 30th June	Configuration				Indicative Capital Cost (Mln US$)	Type	Added Capacity MW	Total Capacity MW	System Peak MW	Reserve Margin MW	Reserve Margin as % of Peak
	1	×	300	COAL	631.2	COAL	300				
	1	×	180	GT-NGAS	135	GT	180				
	1	×	100	WIND	230	WIND	100	7,217	5,388	1,829	34%
2022	1	×	1000	NUCL	4055	NUCLEAR	1000	8,217	6,048	2,169	36%
2023	2	×	140	GEOT	1022	Geothermal	280				
	1	×	300	COAL	631.2	COAL	300				
	1	×	100	WIND	230	WIND	100				
	6	×	-10	KDP1		MSD	-60	8,837	6,784	2,053	31%
2024	1	×	200	IMPORT		IMPORT	200				
	2	×	160	MSD	436.48	MSD	320				
	1	×	180	GT-NGAS	135	GT	180				
	3	×	140	GEOT	1533	Geothermal	420	9,957	7,608	2,349	31%
2025	3	×	140	GEOT	1533	Geothermal	420				
	2	×	180	GT-NGAS	270	GT	360				
	1	×	160	MSD	218.24	MSD	160				
	2	×	100	WIND	460	WIND	200	11,097	8,528	2,569	30%
2026	2	×	100	WIND	460	WIND	200				
	3	×	140	GEOT	1533	Geothermal	420				
	1	×	1000	NUCL	4055	NUCLEAR	1000				
	2	×	200	IMORT		IMPORT	400	13,117	9,556	3,561	37%
2027	3	×	140	GEOT	1533	Geothermal	420				
	1	×	200	IMPORT		IMPORT	200	13,737	10,706	3,031	28%
2028	3	×	140	GEOT	1533	Geothermal	420				
	1	×	200	IMPORT		IMPORT	200				
	1	×	180	GT-NGAS	135	GT	180				
	3	×	100	WIND	690	WIND	300				
	-4	×	12	ORP4		Geothermal	-48				
	2	×	300	COAL	1262.4	COAL	600	15,389	11,994	3,395	28%
2029	2	×	180	GT-NGAS	270	GT	360				
	1	×	100	WIND	230	WIND	100				
	2	×	-35	OLK2		Geothermal	-70				
	3	×	140	GEOT	1533	Geothermal	420				
	1	×	1000	NUCL	4055	NUCLEAR	1000	17,199	13,435	3,764	28%
2030	3	×	140	GEOT	1533	Geothermal	420				
	2	×	300	COAL	1262.4	COAL	600				
	2	×	180	GT-NGAS	270	GT	360				
	2	×	160	MSD	436.48	MSD	320				
	3	×	100	WIND	690	WIND	300	19,199	15,026	4,173	28%
2031	3	×	140	GEOT	1533	Geothermal	420				
	1	×	300	COAL	631.2	COAL	300				
	2	×	180	GT-NGAS	270	GT	360				
	2	×	160	MSD	436.48	MSD	320				
	1	×	1000	NUCL	4055	NUCLEAR	1000	21,599	16,905	4,694	28%

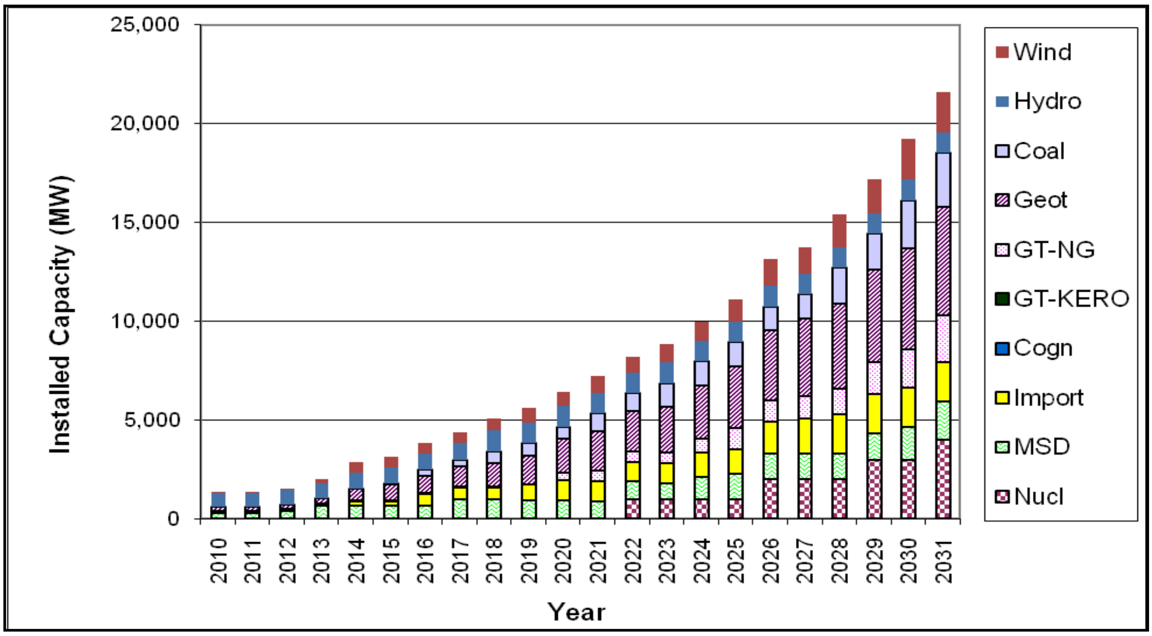
Key: NUCL-Nuclear power, ORP4 -Orpower 4,OKWH-Olkaria Well Head, GEOT- Geothermal, , SANG – Sangoro, , ARMC - Athi River Mining Coal, THK - Thika MSD, LTWP- Lake Turkana Wind, KIND – Kindaruma, IBR-Iberafrica, COA- Coal, KGT-Kipevu GT, MCOG- Mumias Cogen, MUTO- Mutonga, LGF-Lower Grand Falls,NGAS-Natural Gas, MSD- Medium speed Diesel, GT- gas turbine, OLK1- Olkaria 1.

Table 56 and Figure 40 show the installed capacity by fuel type for the least cost plan over the planning period. The results indicate that future capacity is likely to be dominated by geothermal, nuclear, coal, and imports.

Table 56: Installed Capacity by Type for the Least Cost Plan (Base case) MW

Year	Hydro	Nuclear	MSD	Import	Cogen	GT-KERO	GT-NG	Geothermal	Coal	Wind	Total	Peak Load	Reserve Margin	% LOLP
2010	741	-	333	-	26	60	-	198	-	5	1,363	1,227	11	39.304
2011	761	-	453	-	26	60	-	198	-	5	1503	1302	15	43.244
2012	782	-	453	-	26	60	-	206	-	5	1,532	1,520	0.7	47.758
2013	782	-	705	-	26	60	-	241	-	186	2,000	1,765	13.2	23.389
2014	814	-	705	200	26	-	-	608	-	535	2,888	2,064	39.9	0.177
2015	839	-	705	200	26	-	-	843	20	535	3,168	2,511	26.1	1.707
2016	839	-	705	600	26	-	-	843	320	535	3,868	2,866	34.9	0.096
2017	839	-	1,025	600	26	-	-	1,028	320	535	4,373	3,292	32.8	0.078
2018	1,039	-	1,025	600	26	-	-	1,168	620	635	5,113	3,751	36.3	0.082
2019	1,039	-	969	800	-	-	-	1,448	620	735	5,611	4,216	33.1	0.147
2020	1,039	-	969	1,000	-	-	360	1,728	620	735	6,451	4,755	35.6	0.028
2021	1,039	-	895	1,000	-	-	540	2,008	920	835	7,237	5,388	34.3	0.038
2022	1,039	1,000	895	1,000	-	-	540	2,008	920	835	8,237	6,048	36.2	0.115
2023	1,039	1,000	835	1,000	-	-	540	2,288	1,220	935	8,857	6,784	30.5	0.251
2024	1,039	1,000	1,155	1,200	-	-	720	2,708	1,220	935	9,977	7,608	31.1	0.104
2025	1,039	1,000	1,315	1,200	-	-	1,080	3,128	1,220	1,136	11,118	8,528	30.3	0.082
2026	1,039	2,000	1,315	1,600	-	-	1,080	3,548	1,220	1,336	13,138	9,556	37.5	0.019
2027	1,039	2,000	1,315	1,800	-	-	1,080	3,968	1,220	1,336	13,758	10,706	28.5	0.071
2028	1,039	2,000	1,315	2,000	-	-	1,260	4,340	1,820	1,636	15,410	11,994	28.5	0.073
2029	1,039	3,000	1,315	2,000	-	-	1,620	4,690	1,820	1,736	17,220	13,435	28.2	0.063
2030	1,039	3,000	1,635	2,000	-	-	1,980	5,110	2,420	2,036	19,220	15,026	27.9	0.064
2031	1,039	4,000	1,955	2,000	-	-	2,340	5,530	2,720	2,036	21,620	16,905	27.9	0.037
Total	5%	19%	9%	9%	0%	0%	11%	26%	13%	9%				

Figure 40: Development of System Capacity for the Base Case under Reference Fuel Cost

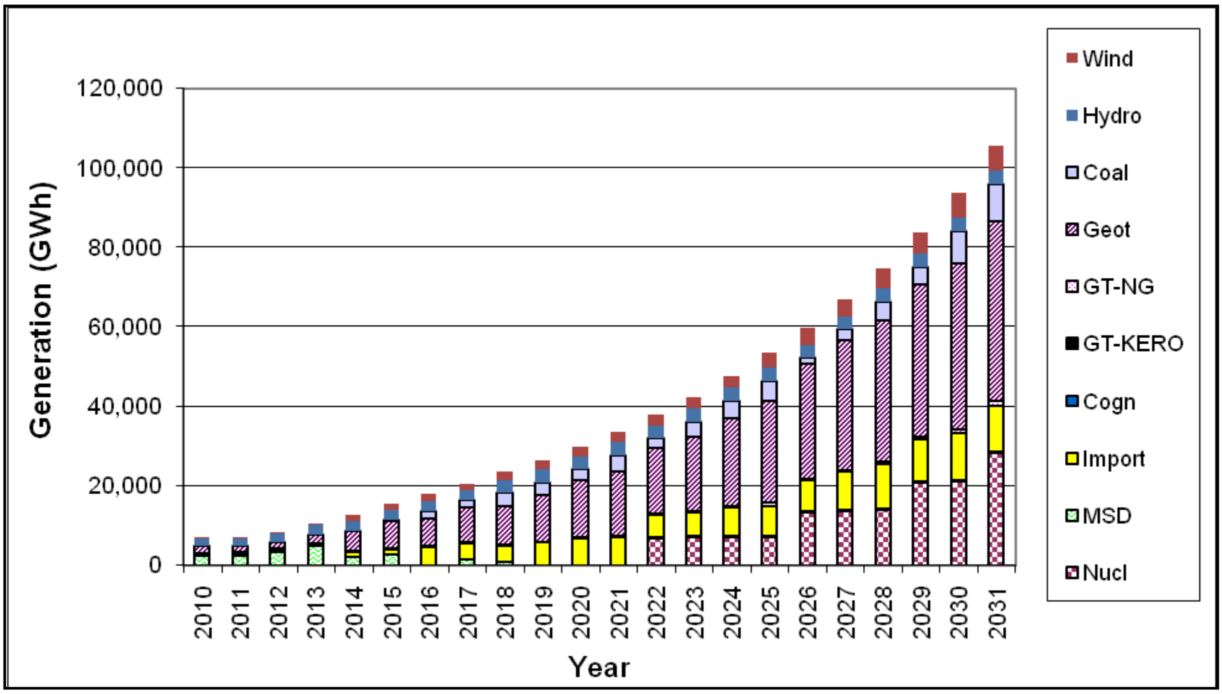


The REPROBAT module of WASP generates a summary report describing the most important input data and output results of the optimization analysis. Table 57 and figure 41 show the energy outputs for the base case under hydro condition 1. Thermal power plants are expected to mainly provide the required system reserve capacity.

Table 57: Electricity Generation by Type (Base Case) Hydro Condition 1 in GWh

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

Figure 41: Generation by Type for Base Load Forecast and Reference Fuel Cost



6.6.2 The Low Load Forecast Scenario

The low load growth scenario was investigated using the WASP model. The number of geothermal plants required in the planning period reduced from 36 to 27, coal plants reduced from 8 to 4, Medium Speed Diesel plants reduced from 9 to 5, Gas turbines plants reduced from 13 to 9, wind from 15 to 10 and Nuclear from 4 to 3. Imports and Hydro power plants remained the same. This is illustrated in table 58 and figure 42. The generation by type is illustrated in figure 43.

Table 58: Optimal Solution for Low Load Forecast Case Reference Fuel cost scenario

	NAME	GEOT	COAL	GT	MSD	WIND	NUCL	IMPORT	HYD1	HYD2
	SIZE (MW)	140	300	180	160	100	1000	200	60	140
YEAR	CAPACITY									
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-
2014	200	-	-	-	-	-	-	200	-	-
2015	140	140	-	-	-	-	-	-	-	-
2016	400	-	-	-	-	-	-	400	-	-
2017	320	-	-	-	320	-	-	-	-	-
2018	740	140	300	-	-	100	-	-	60	140
2019	440	140	-	-	-	100	-	200	-	-
2020	520	140	-	180	-	-	-	200	-	-
2021	760	140	-	360	160	100	-	-	-	-
2022	1,140	140	-	-	-	-	1,000	-	-	-
2023	240	140	-	-	-	100	-	-	-	-
2024	660	280	-	180	-	-	-	200	-	-
2025	880	140	-	180	160	200	-	200	-	-
2026	1,280	280	-	-	-	-	1,000	-	-	-
2027	620	420	-	-	-	-	-	200	-	-
2028	1,200	420	300	180	-	100	-	200	-	-
2029	1,420	420	-	-	-	-	1,000	-	-	-
2030	1,100	420	300	180	-	-	-	200	-	-
2031	1,540	420	300	360	160	300	-	-	-	-
TOTAL	13,600	3,780	1,200	1,620	800	1,000	3,000	2,000	60	140

Figure 42: Development of System Capacity for Low Load Forecast Reference Fuel scenario

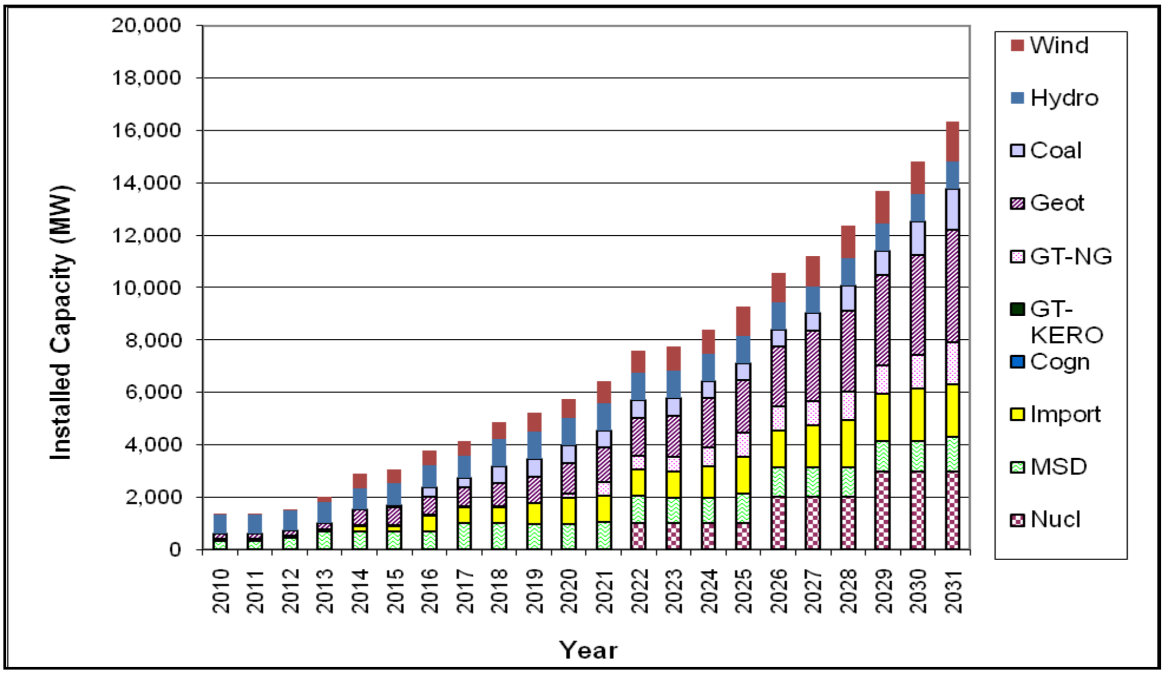
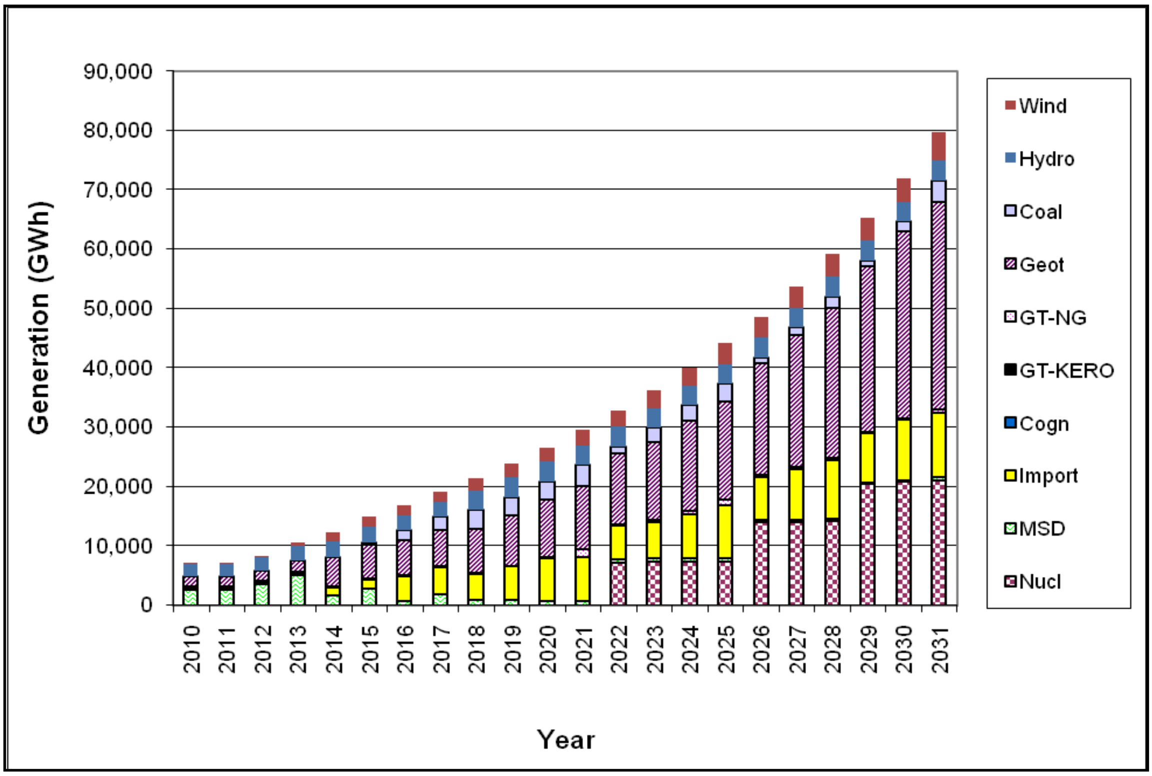


Figure 43: Generation by Type for Low Load Forecast Reference Fuel



6.6.3 The High Load Forecast Scenario

A high load growth scenario was investigated using the WASP model. The number of geothermal plants required in the planning period increased from 36 in the Base Case to 40, nuclear plants increased from 4 to 9, coal plants from 8 to 13, Medium Speed Diesel and Gas turbine plants remained the same, wind power plants from 15 from 15 to 20 and imports remained the same. The two hydro plants were also picked in the plan.

Table 59: High Load Forecast Reference Fuel Scenario Optimum solution table

	NAME	GEOT	COAL	GT	MSD	WIND	NUCL	IMPORT	HYD1	HYD2
	SIZE (MW)	140	300	180	160	100	1000	200	60	140
YEAR	CAP									
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-
2015	700	140	-	360	-	-	-	200	-	-
2016	500	140	-	-	160	-	-	200	-	-
2017	800	-	600	-	-	200	-	-	-	-
2018	480	280	-	-	-	-	-	-	60	140
2019	860	280	300	180	-	100	-	-	-	-
2020	1,280	280	300	-	-	100	-	600	-	-
2021	1,080	420	-	180	480	-	-	-	-	-
2022	1,520	420	-	-	-	100	1,000	-	-	-
2023	820	420	-	-	-	-	-	400	-	-
2024	1,540	420	-	360	160	200	-	400	-	-
2025	1,480	420	300	360	-	200	-	200	-	-
2026	2,280	280	-	-	-	-	2,000	-	-	-
2027	1,660	420	600	180	160	300	-	-	-	-
2028	2,520	420	-	-	-	100	2,000	-	-	-
2029	2,400	420	600	180	-	200	1,000	-	-	-
2030	3,000	420	600	360	320	300	1,000	-	-	-
2031	3,560	420	600	180	160	200	2,000	-	-	-
TOTAL	26,480	5,600	3,900	2,340	1,440	2,000	9,000	2,000	60	140

Figure 44: Development of System Capacity for High Load Forecast scenario

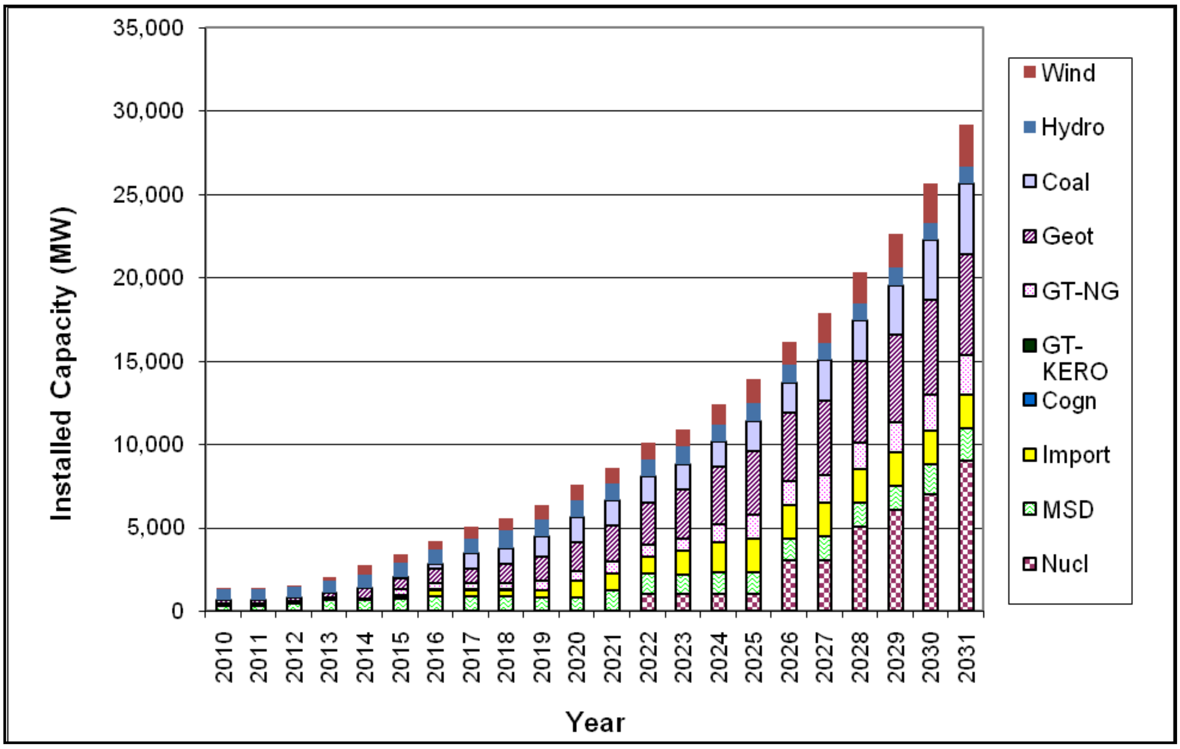
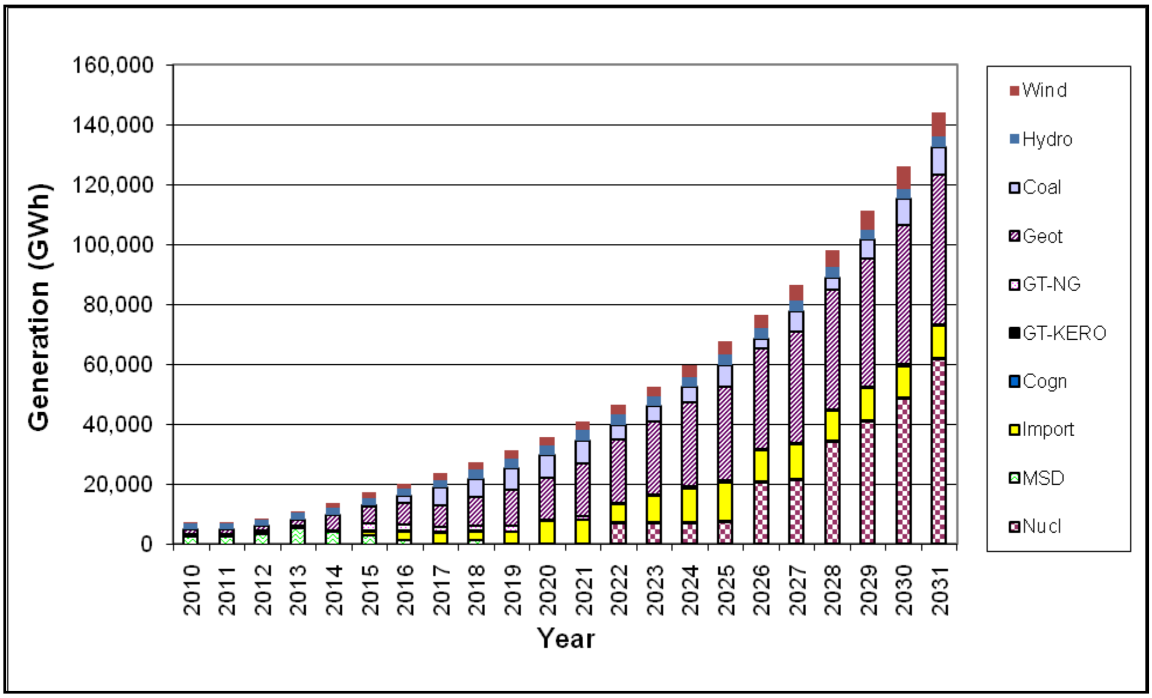


Figure 45: Generation by Type for High Load Forecast Scenario



6.7 Supply Costs of the Growth scenarios

The table below shows the following cumulative results until the year 2031 for the two discount rates (8% and 12%):

- The discounted supplied energy,
- The total expansion cost which includes investment of the selected projects, operations and maintenance cost and fuel cost of existing and selected power plants.

Using the discounted supplied energy and expansion costs the table also shows the average discounted supply cost which is obtained by dividing the total discounted cost by the total discounted energy.

Table 60: Average supply costs at 8% and 12% discount rates

Load forecast Scenario	Discounted Supply in GWh	Discounted cost in M $	Av.Disc. supply cost in Usc/KWh
8% discount rate			
High growth scenario	372887	54692	14.7
Medium growth scenario	305557	41358	13.5
Low growth scenario	262401	30863	11.8
12% discount rate			
High growth scenario	238230	37237	15.6
Medium growth scenario	198992	29295	14.7
Low growth scenario	174215	21878	12.6

Based on these results the following was compared:

- Average discounted costs of supply according to the load growth scenario,
- Average discounted costs according to the discount rate,
- Average discounted costs of supply versus current supply cost.

a) Impact of the load growth on future supply discounted cost (or average expansion cost)

As indicated in the tables above the average expansion cost is higher when the load growth is higher: 11.8, 13.5 and 14.7 USc/kWh for the low, medium and high forecast scenarios respectively in the 8% discount scenario. This can be explained as follows: the local resources which are cheaper compared to foreign resources are mobilized first in all three scenarios but they are implemented faster in the high scenario than in the medium and low growth scenarios. The additional resources that are requested in the medium and even more in the high growth scenario are more expensive than the local resources. For instance in the high scenario, 9 nuclear plants are implemented and only 4 and 3 are implemented for the medium and low scenarios respectively. For this reason the higher the load growth, the higher the supply cost. And this remains true for both discounted rates.

b) Impact of the discount rate on the average discounted cost

As anticipated, the average discounted costs are higher for a 12% discount rate than for the 8% discount rate, however, the impact is moderate.

c) Discounted expansion cost compared to current cost

Comparing the future average energy generation cost (11.8USc/kWh in medium scenario) to current average generation cost (9.3USc/kWh) shows that a 27% increase in the generation cost should be anticipated. However the current generation cost is low due to the fact most of the costs had been paid for by the government by the time the current generation tariff to KenGen was determined, therefore the current average generation tariff doesn't represent the actual cost of generation. The increase can also be attributed to the high reserve margin of 25% adopted by the expansion plan, which should ensure an adequate quality of supply in the future years, provided that the planned power plants are implemented in due time.

6.8 Sensitivity Analyses

6.8.1 Sensitivity to Low Fuel Costs

The base case was also studied further under low and high fuel prices. With lower fuel prices the coal power plant which is supposed to come online in the year 2023 is delayed by one year and one MSD power plant and GT plant are picked instead. The number of power plants at the end of the planning horizon remains the same as in the base case.

6.8.2 Sensitivity to High Fuel Costs

Under the high fuel price, the planting up programme remained exactly the same as in the base case scenario.

6.8.3 Sensitivity to change in discount rate

a.) 10% discount rate

The coal power plant which is supposed to come online in the year 2023 is delayed by one year and one MSD power plant and GT plant picked are picked instead. The number of power plants at the end of the planning horizon remains the same as in the base case.

b.) 12% discount rate

At 12% discount rate, the Mutonga hydro power plant which comes online in the year 2018 in the base case is completely dropped from the planting up programme and the coal power plant which is supposed to come online in the year 2023 is delayed by one year and one MSD power plant and GT plant picked are picked instead.

6.8.4 Sensitivity to change in imports Phasing

A scenario where the imports are phased as follows was also studied; the first batch of 1000MW comes in between 2014-2020 and the remaining batch of 1000MW comes in at once in the year 2021.In this scenario the coal power plants increased from 8 to 9 compared to the base case scenario, GT power plants from 13 to 14 and the MSD plants decreased from 9 to 6. The installed capacity at the end of the planning horizon remained the same.

6.9 Long Run Marginal Cost (LRMC)

A classic definition of LRMC of generation is defined as the levelized cost of meeting a unit increase in demand over an extended period of time. It is calculated by determining the difference in the NPV of two optimal generation development (installation) programs over an extended period (say 20 years). Each of the optimal generation programs utilizes existing generation plant, committed developments and the most efficient new generation entry. Sunk costs are not included in the analysis. The first generation installation is done under the current load forecast and the second under a load forecast that has a defined increment of load added. The LRMC is the change in NPV of costs divided by the change in NPV of load. This is a long run marginal cost basis as it determines the marginal increase in costs associated with meeting a marginal increase in demand with all factors of production variable.

An important aspect of this definition is that it determines the marginal cost of supply based on utilizing existing and new generating capacity. Consequently, this definition can yield very different LRMC results depending on the current demand/supply balance and the amount of committed new generation. When excess capacity exists, additional energy can be supplied at close to short run marginal cost, as there is sufficient capacity to supply the additional demand. When there is no excess capacity the marginal cost of producing additional energy includes the full costs of capacity and operations.

Given the basic definition of the LRMC of electricity in Kenya, there are a number of issues that require clear specification. These issues relate to:

- The generation plant that is assumed available to satisfy Kenya demand;
- The optimal plant combination;
- The determination of the marginal cost profile;
- Revenue neutrality (i.e. no producer surplus);

Fuel availability in Kenya determines the assumed availability of generation plant. This is considered reasonable, as a review of fuel cost differences between regions would show that when transmission costs are considered, the lowest cost options to supply Kenya load would be generation plant developed within Kenya.

The generator technologies assumed available are:

- Geothermal power plant
- Hydro power plants
- Coal power plants
- Open cycle gas turbines
- Medium speed diesel plant
- Nuclear power plant
- Wind power plant

Using this generating plant, an optimal plant portfolio can be constructed using a dynamic programming model WASP. Such an approach ensures that given the Kenya load profile, the combination of plant chosen would minimize the total costs (capacity plus operating costs) of meeting the demand. In order to determine long run marginal costs the dynamic program assumes the capacity of all of the classes of plant is variable. With this assumption, the dynamic programming approach can generate the costs of meeting additional load. These costs are the marginal costs of supplying an additional unit of load.

For a generator to be economical, the average price for energy produced needs to match its average cost of producing this energy (both capital and fuel). In the choice of a generation portfolio there is a trade-off between capital costs and operating costs. The lower capital cost plant tends to have higher fuel costs and hence higher operating costs. For each of the classes of plant we have identified there is an operating cycle for which they are the least cost source of supply.

The next Table shows the calculation of the LRMC using the result of the WASP for two optimal solutions: A) original load and B) incremental load, subtracting the NPV of operation cost of two cases as well as capital costs and dividing the NPV of total cost with the NPV of energy difference of two cases. The results for LRMC costs are given in Table 61.

Table 61: Long Run Marginal Cost - WASP Results

YEAR	ENERGY (GWh) B	ENERGY (GWh) A	ENERGY (GWh) DIFFER.		ENERGY (GWh) DISC.	OPERATI. COST (M $) B	OPERATI. COST (M $) A	OPERATI. COST (M $) DIFFER.	CAPITAL COST (MILL. $) B	CAPITAL COST (MILL. $) A	CAPITAL COST (MILL. $) DIFFER.	NET SUPL. (GWh)
	0.0	0.0	0	8.0	-	0	0	0	0	-	-	1
2010	7,160	7,160	0	1.00	-	1,120	1,120	-	522	522	-	-
2011	7,228	7,228	0	0.93	-	1,148	1,148	-	563	563	-	-
2012	8,359	8,359	0	0.86	-	1,597	1,597	-	977	395	500	-
2013	10,607	10,607	0	0.79	-	2,166	2,166	-	1,342	713	500	-
2014	12,791	12,791	0	0.74	-	804	804	-	1,640	1,473	123	-
2015	15,557	15,560	3	0.68	-2	1,126	1,126	-	2,128	2,174	-31	-2
2016	19,211	17,958	1,253	0.63	790	941	801	88	2,392	2,586	-122	671
2017	21,879	20,627	1,252	0.58	731	1,002	1,160	-92	1,658	1,980	-188	621
2018	24,755	23,503	1,252	0.54	676	1,090	1,137	-25	1,891	2,238	-188	575
2019	27,668	26,414	1,254	0.50	627	1,084	1,101	-9	3,246	3,186	30	533
2020	31,048	29,793	1,255	0.46	581	1,170	1,162	3	4,124	4,059	30	494
2021	35,012	33,759	1,253	0.43	537	1,426	1,392	14	3,610	3,497	48	457
2022	39,147	37,896	1,251	0.40	497	1,396	1,368	11	3,330	3,321	4	422
2023	43,756	42,504	1,252	0.37	460	1,708	1,668	15	4,358	4,480	-45	391
2024	48,921	47,666	1,255	0.34	427	1,916	1,887	10	4,864	4,864	-	363
2025	54,684	53,434	1,250	0.32	394	2,283	2,248	11	5,728	5,658	22	335
2026	60,938	59,690	1,248	0.29	364	1,920	1,895	7	4,752	4,633	35	310
2027	68,120	66,868	1,252	0.27	338	2,317	2,285	9	5,315	4,946	100	288
2028	76,163	74,913	1,250	0.25	313	2,790	2,749	10	4,077	3,729	87	266
2029	85,164	83,913	1,251	0.23	290	3,067	3,025	10	2,366	2,539	-40	246
2030	95,100	93,848	1,252	0.21	269	3,911	3,866	10	1,493	1,680	-40	228
2031	107,026	105,772	1,254	0	249	4,510	4,511	-	-	-	-	212
TOTAL	900,294	880,263	20,031		7,542	40,490	40,217	71	60,375	59,236	823	6,411

ENERGY		*BUS*	*SALE*	
		c/kWh	*c/kWh*	
		0.95	1.11	*OPERATION*
		10.91	12.84	*CAPITAL*
	LRMC	11.86	13.95	*TOTAL*

7 TRANSMISSION NETWORK PROJECTS

7.1 Introduction

The transmission planning component of the least cost power development planning is essential if desired long term goal of the national power system will be realized. In the past least cost power development plans carried out between 2000 and 2008, transmission planning was limited to the committed projects in the medium term and estimated power evacuation lines associated with each generation plant added. Transmission planning function has been strengthened in the country since the function of preparing the indicative power development plan was taken up by the Energy Regulatory Commission following enactment of the Energy Act 2006. The planning approach applied in Kenya involves assembling a technical generation and transmission planning team comprising of members drawn from relevant government institutions.

In the 2010-2030 least cost power development planning activity which began in the last quarter of the year 2009, transmission planning function was considered in more detail for the first time by the national planning team. Simulations carried out to ensure adequate evacuation of generation from the power plants that were gradually expected to be added to the power system in the long term. The Power System Simulation for Engineering (PSSE) software was used in the planning. Simulations require to be carried out to establish the situation of the system in each year and put in place appropriate interventions for meeting the requirements of the system. Transmission planning and assessment of capacity using the PSSE software has mainly been provided by KPLC, due to the fact that historically it has been the main entity charged with most of the power system responsibilities prior to creation of new sector organizations and that it holds the only available licence for the software. The planning capacity of the national team is now being enhanced for the key sector organizations. In this update of the least cost power development plan, the French Development Agency (AFD) provided capacity building support by attaching a full time consultant to the Ministry of Energy to work with the power system planning team. The arrangement made it possible to engage other international short term basis to train the team and assist in the various components of updating the plan including the transmission planning.

- The planning activity commenced with demand forecasting in September 2010 which was followed by generation planning and release of the first draft of the least cost plan in October 2010. The draft update was taken up by the transmission planning team soon after for preparation for this activity. The team held a five days working and training retreat in November 2010, under the AFD appointed consultant from Belgium obtained through EGIS-BCEOM. The teams were assigned responsibilities to undertake before the next session planned for February 2011. The final deliverables for the transmission planning component are expected to be completed by end of February so as to meet the overall target of completing the least cost update by end of March 2011.

7.2 Objectives

The main objectives of the transmission planning component are:

- Present the methodology used in developing the transmission development plan

- To develop a set of transmission network solutions for the planning horizon year 2031 to be considered in selection and recommendation of a final target network on which the transmission plan shall be based.
- To prepare detailed alternative transmission development sequences for comparison and determination of the least cost transmission plan
- To develop and present cost estimates for the planned investments

7.3 Methodology

This transmission plan development employs the target network concept of transmission planning which ensures a coordinated investment strategy and therefore optimal network development using the Least Cost Planning concept.

7.3.1 Target Network concept

Target network concept aims at solving the network expansion planning problem anti chronologically. Planning starts with developing a network solution for the horizon planning year and then working backwards to identify network solutions required for previous years at defined time intervals. This ensures that any network investment is used in the long term, and therefore is useful in the long term, contrarily to the chronological approach where network investments identified in the shorter term may not be required and have to be modified or discarded in future. The process therefore ensures a coordinated development of an efficient and economical transmission system. However, in both approaches the minimization of the costs is to be carried out by comparing development variants.

7.3.2 Methodology

The process of developing the target network candidates begins with development of the short term (year 2015) committed transmission system model and then building alternative functional network models for the planning horizon year.

The process of developing a target network involves:

- Determining the location of future generation facilities

  Starting from the schedule of investments described in chapter 6, the future plant locations were selected considering the nature of each generation plant and its basic requirements, its existing resource development plans and its established policies.
- Splitting the power network into several regions, determining the regional power balances and estimating future potential flows between regions. In Kenya, seven regions are defined as follows.

Table 62: Year 2031 regional power balances (MW) Potential imports from other regions

Region	Generation	Demand	Surplus	Nairobi	North Rift	West Kenya
Coast	5,104	3,373	1,731	1,731		
Nairobi	964	6,745	-5,781			
Mt Kenya	3,840	2,178	1,662	1,662		
Central Rift	5,893	1,174	4,719	2,388	334	794
North Rift	425	759	-334			
West Kenya	967	1,761	-794			
North Kenya	1,300	70	1,230	1,230		
Ethiopia	1,700	0	1,700	1,700		
Tanzania	400	0	400	400		
Uganda	300	0	300			300
Totals	20,893	16,060	4,833	5,781	334	794

- Estimating the number of transmission lines to plan between regions

  In estimating the number of transmission lines between regions 400 kV is adopted as the backbone transmission voltage in conformity with the current regional standards, transmission distances and level of system demand.

  In determining the number of transmission lines between regions it is estimated that power transfer capability of the lines:

  - for a short 400 kV line, the thermal capacity is considered as the transfer limit
  - For very long 400 KV lines, the transfer limit is much lower than the thermal limit and is assumed to be equal SIL (Surge Impedance Loading).
  - medium length lines, these are assumed to be capable of up transmitting up to 1.5 SIL
  - SIL for a typical bundled conductor 400 kV transmission line is estimated at 680 MW

7.4 Planning assumptions and criteria and catalogue of equipment

7.4.1 Planning assumptions

In preparation of the transmission development plan the following basic assumptions were made:

- Future thermal generation (coal, fuel oil and gas turbines) will be developed in coast area to reduce the cost of fuel transportation and consequent environmental impact. The only exceptions are with regard to coal fired generation in the longer term of the development plan when local coal production is expected at Kitui and in cases where thermal generation is required elsewhere in the system for voltage support.

- Future geothermal generation will follow the established geothermal development plan developed and provided by GDC

- Firm power imports will be available only from Ethiopia. However surplus power exchange and trans boarder wheeling within the region are envisaged hence regional interconnections with Uganda and Tanzania are considered in the transmission development plan
- Nuclear power plants will be located in relatively unpopulated areas near large water masses for environmental reasons and their water requirements.
- Due to anticipated right of way challenges and rapid demand growth major transmission lines will be designed for higher level voltages and transmission capacity, with a possibility of initial operation at lower voltage levels to reflect existing system strength and limit requirements for other line equipment

7.4.2 Planning criteria

7.4.2.1 System Voltage

Under normal conditions all system voltages from 132 kV and above (i.e. 132kV, 220kV, and 400kV) should be within ± 5% of the nominal value and should not exceed ±10% at steady state following a single contingency. In order to maintain a satisfactory voltage profile both static and dynamic reactive power compensation will be deployed as required.

7.4.2.2 Equipment loading

Classic planning criteria indicate that:

- Under normal conditions and at steady state following single contingencies all transmission equipment should not exceed 100% of the continuous rating.
- During contingency conditions loading will be allowed to increase to 120%, which is a threshold justified by the fact that the equipment can stand this level for about 20 minutes, the time that the operator applies remedial actions for bringing the system back to a normal situation.

7.4.2.3 Voltage selection

Transmission development during the planning horizon will be based on 132, 220 and 400 kV. To enhance system operation and optimize way leaves cost all future inter region transmission lines and regional interconnections shall be designed as 400 kV but may be initially operated at 220 kV.

In determining voltage levels for new power evacuation lines, consideration for all power plants to be developed in any given location shall be taken into account to optimize overall transmission cost.

7.4.2.4 Reliability criteria

The future transmission system is planned to operate satisfactorily under the condition of a single element contingency, N-1 for transmission lines and transformers. However in assessing system reliability a double circuit line will be considered as two separate circuits.

7.4.2.5 Fault levels

To allow for system growth, maximum fault levels should not exceed 80% of the rated fault interrupting capacity of the circuit breakers. This criterion may lead either to replace some breakers (i.e. upgrade) or to identify mitigation actions for limiting the fault levels.

7.4.2.6 Power losses

The system is planned to operate efficiently with power losses likely not to exceed 5%: the economic comparison of variants will take the cost of losses into account and identify the least (global) cost variant. Note that: Where the power plants could be located almost anywhere, e.g. diesel plants and gas turbines that may not be site specific, the preference for locating these close to the load centers also leads to preserve a moderate level of transmission losses (usually between 1% and 5%) Where the optimal generation plan leads to locate generation units at specific sites or regions (because the primary resource is located there: hydro plants, geothermal, coal mines, wind farms e.t.c), transmission losses may be significantly higher without reducing the optimality of the whole system design.

Therefore, there is no strict acceptable limit for losses but rather the introduction of costs related to losses within the economic comparison of scenarios or costs of necessary infrastructure to cope with the losses. Losses are often valued per kW at peak, and indicative computation on a planning period lead to about 100 USD/kWpk in generation, 150 USD/kWpk in HV, 190 USD/kWpk in MV and 230 USD/kWpk in LV. Specific values for Kenya could be investigated in the frame work of future LCPDP study, analyzing separately the costs related to additional investments and the costs related to additional fuel.

For economic comparison of alternative transmission development plans peak power losses are converted to corresponding energy losses and costed at the LRMC of energy (14.28 cents/Kwh).

7.4.3 Catalogue of equipment

Standard equipment and materials (e.g. transformers, conductors, capacitors, substation diameters and bays etc) are recommended for electricity transmission grid infrastructural development for reasons that:

- They offer economic and monetary value due to bulk purchase
- These equipment and materials are easily stocked for replacement in cases of failure and redundancy: standardization allows reduction of the amount of spare parts.
- It offers ease in operation and maintenance owing to its uniformity and commonality.
- It makes it easier for the utility to train its technical staff on the standard equipment
- It makes it easier to up rate certain equipments by substituting them with others that may be recovered.

The catalogue of equipment and materials used in development of the transmission plan and their unit cost is summarized the table here below. The table was compiled using the consultant, KPLC and KETRACO estimated costs.

Table 63: Catalogue of equipment and materials

	Unit	Unit cost		
		kUSD		
CIVIL WORKS AND AUXILIARIES				
Civil Works - new site	1	2,113	1,000	1,500
Civil Works - Extension	1	681		
Civil Works - Major Extension	1	1,362		
Communications Cost	1	204	204	204
New site auxiliaries	1	141	141	141
Location				
Land cost - New Site in costly land (ex: near town)	1	6,808		
Land cost - Extension of S/S- costly land	1	2,723		
Land Cost - Other new site	1	2,723	563	750
Land Cost - Other extension	1	1,362		
S/S (Land + Works)				
New 400 kV in costly land	1	8,374		
Extension 400 kV in costly land	1	4,836		
New 400 kV Other	1	4,289		
Extension 400 kV Other	1	3,475		
New 132 kV average	1	1,908		
New 220 kV average	1	2,595		
	1			
Bays (include 1 and a half breaker per bay)	-			
132 kV bay Air Insulated System 31,5 kA	1	450		
132 kV bay Air Insulated System 31,5 kA	1	512		
220 kV bay Air Insulated System 40 kA	1	2,800		
220 kV bay Air Insulated System 50 kA	1	3,200		
400 kV bay Air Insulated System 40 kA	1	4,000		
400 kV bay Air Insulated System 50 kA	1	4,700		
Transformers	Unit	kUSD	kUSD/MVA	Rating (MVA)
400/220 kV transformer 800 MVA	1	5,700	7.1	800
400/220 kV transformer 500 MVA	1	5,100	10.2	500
400/220 kV transformer 350 MVA	1	4,700	13.4	350
400/220/132 kV transformer 350 MVA	1	5,000	14.3	350
400/220 kV transformer 350 MVA	1	4,700	13.4	350
400/132/33 kV transformer 400 MVA	1	6,306	12.5	400
400/132/33 kV transformer 240 MVA	1	4,730	12.5	240
400/132 kV transformer 150 MVA	1	1,875	12.5	150
220/132 kV transformer 90 MVA	1	1,690	18.8	90
220/66 kV transformer 90 MVA	1	1,690	28.2	60

220/66 kV transformer 60 MVA	1	1,400	23.3	60
220/33 kV transformer 45 MVA	1	1,235	27.4	45
132/66 kV transformer 60 MVA	1	1,300	21.7	60
132/33 kV transformer 45 MVA	1	1,040	23.1	45
LINES	Unit	kUSD/unit		Rating (MVA)
66 kV 1 circ. of 1 x 300 mm²	km	70		
132 kV 1 circ. of 1 x 300 mm²	km	80		
132 kV 2 circ. of 1 x 300 mm²	km	130		
132 kV 2 circ. of 1 x 300 mm², but only 1st is installed	km	91		
132 kV 2 circ. of 1 x 300 mm², installation of 2nd circuit	km	65		
220 kV 1 circ. of 1 x 400 mm²	km	160		
220 kV 2 circ. of 1 x 400 mm²	km	220	single canary	315
220 kV 2 circ. of 2 x 400 mm²	km	270	twin canary	630
220 kV 2 circ. of 1 x 400 mm², but only 1st is installed	km	189		
220 kV 2 circ. of 1 x 400 mm², installation of 2nd circuit	km	135		
400 kV 1 circ. of 4 x 400 mm²	km	200	quad lark	
400 kV 2 circ. of 4 x 400 mm²	km	320	quad lark	1405
400 kV 2 circ. of 4 x 400 mm², but only 1st is installed	km	224		
400 kV 2 circ. of 4 x 400 mm², installation of 2nd circuit	km	160		
400 kV 2 circ. of 3 x 900 mm²	km	400	triple canary900	1718
500 kV 1 circ. Made from 2 conductors of 4 x 400 mm² each	km	176		
Shunt Capacitor banks	Unit	kUSD	kUSD/Mvar	
33 kV Capacitor Bank - 4 x 10 MVAR	1	600	15.0	40
33 kV Capacitor Bank - 4 x 7.5 MVAR	1	550	18.3	30
11 kV Capacitor Bank - 12 MVAR	1	87	7.3	12
132 kV Capacitor Bank - 75 MVAR	1	433.5	5.8	75
66 kV Capacitor Bank - 20 MVAR	1	295.5	14.8	20
33 kV Capacitor Bank - 15 MVAR	1	225	15.0	15
11 kV Capacitor Bank - 5 MVAR	1	130.5	26.1	5
Shunt Reactor banks		kUSD		
10MVAR		132	13.2	
16MVAR		165	10.3	
25MVAR		212	8.5	
32MVAR		276	8.6	

The above table will be expanded and revised in future to include equipment that become available in the market for defining the many scenarios whose comparison provides the Least Cost Scenarios.

In terms of standardization of transformers, studies [1] have shown that the ratio between two successive transformer ratings applied in a power grid should be between 1.5 and 1.8. The ratios observed in the above catalogue of equipment are in line with this recommendation except for transformers of 45 and 60 MVA, which are not used for successive replacement in the development plan.

7.5 Generation and load data

7.5.1 Generation data 2015 -2031

The future generation plants are described here below

7.5.1.1 Generation Data - Wet Hydrology

Table 64: Generation data - Wet Hydrology

YEAR	PLANT LOCATION	CAPACITY (MW)	REGION	PLANT TYPE
2015	Menengai 1,2	280	6	GEOTH
2020	Athi River	160	2	MSD
	Lamu	300	4	COAL
	Mariakani	180	4	GT
	Mariakani	180	4	GT
	Grand Falls	140	5	HYDRO
	Menengai 3,4	280	6	GEOTH
	Menengai 5,6	280	6	GEOTH
	Longonot 1,2	280	6	GEOTH
	Lessos	160	8	MSD
	L. Turkana	100	9	WIND
	Marsabit	100	9	WIND
	Marsabit	100	9	WIND
2025	Isinya	180	2	GT
	Isinya	180	2	GT
	Lamu	300	4	COAL
	Malindi	100	4	WIND
	Malindi	100	4	WIND
	Kilifi	1,000	4	NUCL
	Mutonga	60	5	HYD
	Kitui	300	5	COAL
	Kitui	300	5	COAL
	Longonot 3	140	6	GEOTH
	Longonot 4	140	6	GEOTH
	Silali 1,2	280	6	GEOTH
	Paka 1,2	280	6	GEOTH
	Paka 3, Barrieri 1	280	6	GEOTH
	Kisii	160	7	MSD

YEAR	PLANT LOCATION	CAPACITY (MW)	REGION	PLANT TYPE
	Eldoret	160	8	MSD
2030	Lamu	600	4	COAL
	Galu	160	4	MSD
	Kilifi	1,000	4	NUCL
	Malindi	160	4	MSD
	Machakos	160	5	MSD
	Kitui	900	5	COAL
	Isiolo	180	5	GT
	Thika	180	5	GT
	Silali 3,4,5	420	6	GEOTH
	Korosi 1,2,3	420	6	GEOTH
	Emuruango 1,2	280	6	GEOTH
	Suswa 1,2,3	420	6	GEOTH
	ArusBogoria 1,2,3	420	6	GEOTH
	Kinangop	200	6	WIND
	Kisumu	180	7	GT
	Kakamega	160	7	MSD
	Marsabit	100	9	WIND
	Marsabit	300	9	WIND
2031	Kitui	900	5	COAL
	Emuruango 3, Barrier 2,3	420	6	GEOTH
	Lanet	320	6	MSD
	Kisumu	360	7	GT
	Marsabit	100	9	WIND

Key
2 - Nairobi
4 - Mombasa
5 – Mt Kenya
6- Central Rift
7-West Kenya
8- North Rift
9 – North Kenya

7.5.1.2 Generation data - Dry Hydrology (hydro 60%)

Generation data for dry hydrology is presented in annex 6. Most generation during the period 2015-2031 is thermal with exception of Lower Grand falls and Mutonga Hydro plants which are expected to operate at 60% generation in the dry hydrology scenario.

7.5.2 Load data

7.5.2.1 Distributed load forecasting

In disaggregating the national load forecast to individual substations in the regions, the following assumptions are made:

- Uniform load growth rate in individual KPLC regions reflecting historical growth
- Higher load growth rates in other regions compared to Nairobi in the longer term to reflect increased rate of access in these regions and planned flagship projects
- Variation of relative demand in the regions as follows:-
  2015 – Nairobi 52%, West Kenya 20%, Coast 17% and Mount Kenya 11%

2031 – Nairobi 42%, West Kenya 23%, Coast 21% and Mount Kenya 14%

- Vision 2030 flagship projects as follows as indicated in table below:

Table 65: Vision 2030 flagship projects

Project	Completion date	Estimated demand (MW)
ICT Park	2012 – 2014	440
Second container terminal and a free port at the Mombasa port	2014	2
Standard gauge railway(Juba-Lamu)	2014	9
Lamu port	2014	4
Special economic zones	2015	50
Iron and steel smelting industry in Meru area 2015-2021	2015 – 2021	315
Standard gauge railway(Mombasa-Nairobi-Malaba, Kisumu)	2017	8
Light rail for Nairobi and suburbs	2017	33
Resort cities (Isiolo, Kilifi and ukunda)	2017	30

7.5.2.2 Distributed load forecast 2015 -2031

The forecast for the peak load as distributed per region is as follows. In developing the distributed forecast it is assumed that peak demand occurs simultaneously in all regions.

Table 66: Peak load distribution in regions

	2015		2020		2025		2030		2031	
Region	MW	MVar	MW	MVar	MW	MVar	MW	MVar	MW	MVar
Nairobi	1,241	538	2,214	959	3,726	1603	5,996	2,550	6,746	2,868
Coast	413	187	813	346	1,542	688	2,997	1,336	3,373	1,503
Mount Kenya	256	99	573	232	1,052	425	1,939	780	2,177	874
North Rift	105	44	199	83	402	166	681	281	760	313
Central Rift	157	69	292	127	560	245	1,040	455	1,174	514
West Kenya	476	202	904	383	1,753	743	3,283	1,391	3,694	1,566
North Kenya	0	0	14	6	29	12	58	25	70	30
Grand Total	2,386	1,,026	4,519	1,926	8,102	3,471	14,273	6,082	16,061	6,810

Detailed distributed forecast by substation is provided in Annex 3.

7.6 Development of Target network candidates

Three target transmission network candidates for the horizon planning year (2031) were developed as the basis for construction of three alternative transmission system development plans for detailed analysis and optimization.

The basic consideration in developing the target networks is the regional power balance (table 1.1, section 6.2.2 above), which is prepared by disaggregating the national load forecast into regional demands at the local existing and potential substations and locating the generation plants on the basis of assumptions outlined in 6.4.1 above. For example, apart from power plants that may be required for voltage support in major load centers it is assumed that most future thermal generation (coal, diesel, gas turbines and nuclear plants) will be located in the coast region, making it a net power exporter to Nairobi, the major load center. Similarly site specific power plants e.g. Geothermal and wind power plants will be concentrated in Central Rift and North Kenya regions, making these regions net exporters to Nairobi and West Kenya.

Based on the demand/supply assessment in all regions, inter regional supply lines and voltages to meet the required transmission capacities were approximated in consideration of the distances involved. In so doing the following line loading limit guidelines were adopted:

- 0- 80 km (short lines) – thermal limits

- 80 – 320 km (medium length) – voltage drop limitation of 1.5 times SIL

- Long lines 500 km and above – Voltage drop limitation of 1 times SIL

In view of the existing and the regional standards, 220 and 400 kV lines were considered as the main inter regional and regional transmission system.

One of the important advantages of the target network approach is that it leads to more optimal investment as the future load centers and power generation sites are already decided and the inter regional transmission lines are designed to interlink them. This avoids redundancies which are common when transmission systems are designed sequentially.

7.6.1 Overview of Developed target networks

There exists many possibilities of interconnecting the planned generation to the load centers and three possible backbone transmission concepts were initially approximated for simulation and analysis as follows:

- Target network 1

  This option considers a second Coast – Nairobi double circuit 400 kV line originating from Lamu which is targeted for development of a resort city, free port and a source of a modern international railway network. Lamu is also expected to be a generation center for wind and coal fired power plants. From Lamu the 400 kV line is designed to interconnect Kilifi, which is expected to be a major thermal generation center in the coast due to growing congestion at Mombasa. From Kilifi the new 400 kV line will export power to Nairobi, terminating at a new Kangundo 400/220 kV bulk substation.

  To evacuate geothermal generation a 400 kV double circuit line is envisaged from Barrieri near Lake Turkana, through the geothermal fields in North and Central Rift to Menengai. To export this power to Nairobi and environs, a second 400 kV, Menengai- Uplands, Kiambu North, Thika double circuit line will be required towards the planning horizon. This is to be interconnected to the second

Coast- Nairobi line at Kangundo bulk supply substation. To export power to West Kenya, a 400 kV double circuit Silali – Eldoret East- Kisumu East line, emanating from Silali, which is in the mid of the geothermal belt is proposed. A 400 kV Kitui-Kangudo double circuit line will evacuate coal fired generation from Kitui coal fields. Further a second 400 kV Kitui- Mutonga-Nanyuki double circuit to export power to Mount Kenya region in view of unreliable hydro generation is envisaged.

- Target Network 2

  This is a close variant of target network 1 which considers conversion of existing inter regional 132 kV lines to 220 kV system.

- Target network 3

  This considers a wider network of 400 kV lines additional to target network 1. It forms a 400 kV ring interconnecting Kitui – Nanyuki to Lumuruti and the Menengai – Barrieri line and also interconnects Suswa to southern part of West Kenya at 400 kV, effectively replacing part of the 220 kV network proposed in target network 1.

7.6.2 Developing target networks

The 2031 planning horizon year target networks were modeled in PSSE, starting with the committed 2015 networks and modeling all the planned generation plants and loads by 2031. Upon modeling the conceptual networks described in 6.1 above and loads, further system reinforcements using the standard network equipment tabulated in 6.4.3 above were identified and modeled to create a converging model. In so doing reactive compensation sources were modeled at various nodes to provide variable reactive power. Optimal sizes and ranges of reactive compensation equipment are finally determined when target networks are optimized.

7.6.3 Optimization of target networks.

Each of the planning horizon networks developed has to comply with the transmission criteria applied. To optimize the networks, a series of studies are conducted in PSSE as follows:

- Load flow studies

  Load flow studies are carried out iteratively with further network reinforcements to ensure that all system buses meet the +/- 5% voltage criteria and no system equipment are overloaded at steady state. A load flow study forms the basis for all other network studies.

- Contingency studies

  Contingency studies are an extension of load flow studies carried out to ensure the target network meets the voltage criteria following a defined contingency, and to identify the required further network reinforcements to meet the redundancy criteria. n-1 criterion was investigated in development of the target networks.

- Fault Level studies

  Fault level computations are carried out to ensure that network circuit breakers capacities are not exceeded within 10% margin at the planning horizon. If exceeded corrective network designs will be required; such as reinforcement of switchboards and replacement of breakers, reconfiguration of transmission lines and specification of open substation bus couplers.

7.6.4 Target networks

Three target networks were identified and developed. These will form the basis for development of three alternative transmission investment sequences meeting the set technical criteria, to be compared on economic basis in selection of the least cost transmission development plan. PSSE load flow models for the three target networks are attached as Annex 4.

8.1 Methodology

The planning methodology entails finding acceptable sequences of investments starting from the 2015 committed transmission networks and ending up to each of the developed target networks. Initially the committed network 2012 -2015 investments are modeled each year and studies carried out to verify their adequacy and identify required further investments in response to the updated demand forecast.

The investment sequences are established by creating and optimizing network models at 5 year intervals between 2015 and 2030, with each of the investments conforming to the 2031 target network requirements. This is done by starting with the 2031 target network and developing 2025, 2020, and 215 network models in reverse sequence by switching generators and loads as per the generation development plan and load forecast, and equipment not required as a result. Network models for each of the snapshot years are optimized through load flow, contingency and short circuit studies to ensure transmission criteria is complied with at every stage.

Detailed studies are carried out for peak load, minimum load, wet hydrology and dry hydrology for each of the snapshot years. Whereas peak load studies are required to establish equipment and conductor ratings, minimum load studies confirm voltage criteria and establish reactive compensation requirements. Dry and wet hydrology studies are necessary to establish transmission system capacity adequacy in sections of the grid with increased or reduced hydro generation.

8.2 Development of sequence of investments

Three alternative investment strategies were developed each from the initially identified target networks by application of the above methodology. For each snapshot year in addition to transmission lines and substations reinforcement requirements, reactive compensation requirements were also determined and transmission losses evaluated. Cost estimates for the relevant investments were developed using unit costs tabulated in 7.4.3. For the purpose of comparison of different strategies, transmission losses costed at the LRMC of energy were considered as a cost and added to the cost of investments.

To arrive at the least cost transmission plan, the annual costs of each sequence of investment were discounted to the base year (2012) at the rate of 8%. A summation of the present values of annual investments gives the PV of cost for each investment strategy. The investment strategy with the least PV of cost is determined as the least cost transmission expansion plan.

8.3 Comparison of investment strategies

The table below is a summary of investment cost streams and analysis of the three alternative investment strategies.

Table 67: Summary of investment cost of three alternatives in US Dollars

INVESTMENT COST OPTION 1 COST ('000 USD)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Lines	41,4816	588,963	764,200	111,490	67,826	67,826	67,826	67,826	67,826	180,493	180,493	180,493	180,493	180,493	184,336	184,336	184,336	184,336	184,336	44,780
Substations	57,333	89,091	140,187	20,374	56,400	56,400	56,400	56,400	56,400	74,047	74,047	74,047	74,047	74,047	86,064	86,064	86,064	86,064	86,064	0
Reactive compensation	11,094	3,759	6,587	3,137	4,681	4,681	4,681	4,681	4,681	7,924	7,924	7,924	7,924	7,924	9,535	9,535	9,535	9,535	9,535	27,129
O$M Cost (2.5%)	12,081	17,045	5,699	3,375	3,223	3,223	3,223	3,223	3,223	6,,562	6,562	6,562	6,562	6,562	6,998	6,998	6,998	6,998	6,998	1,798
Losses(KUSD)	22,851	28,868	36,865	41,733	49,168	57,929	68,250	80,410	94,737	110,856	129,717	151,787	177,612	207,831	226,637	247,145	269,508	293,894	320,488	368,107
Total cost (MUSD)	518,175	727,726	970,614	180,109	181,298	190,059	200,380	212,540	226,867	379,881	398,742	420,813	446,638	476,857	513,571	534,079	556,442	580,829	607,422	441,814
PVS (I=8%)	518,175	673,820	832,145	142,976	133,260	129,351	126,273	124,015	122,569	190,035	184,695	180,479	177,366	175,339	174,851	168,364	162,420	156,980	152,007	102,374
PV of cost (KUSD)	4,627,494																			

INVESTMENT COST OPTION 2 COST ('000 USD)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Lines	413,370	561,740	766,920	123,090	85,675	85,675	85,675	85,675	85,675	168,909	168,909	168,909	168,909	168,909	207,550	207,550	207,550	207,550	207,550	26,646
Substations	57,333	89,091	140,187	20,374	56,400	56,400	56,400	56,400	56,400	74,047	74,047	74,047	74,047	74,047	86,064	86,064	86,064	86,064	86,064	0
Reactive compensation	11,094	4,341	6,587	6,641	4,995	4,995	4,995	4,995	4,995	8,047	8,047	8,047	8,047	8,047	9,837	9,837	9,837	9,837	9,837	9,837
O$M Cost (2.5%)	12,045	16,379	5,767	3,753	3,677	3,677	3,677	3,677	3,677	6,275	6,275	6,275	6,275	6,275	7,586	7,586	7,586	7,586	7,586	912
Losses(KUSD)	22,851	28,868	36,865	40,914	48,322	57,071	67,403	79,606	94,019	111,692	132,687	157,628	187,257	222,455	237,570	253,712	270,951	289,361	309,022	362,780
Total cost (KUSD)	516,692	700,419	973,402	194,772	199,069	207,817	218,150	230,353	244,766	368,971	389,965	414,906	444,536	479,734	548,608	564,751	581,989	600,399	620,061	400,176
PVS (I=8%)	516,692	648,536	834,535	154,617	146,321	141,437	137,471	134,409	132,239	184,577	180,629	177,946	176,531	176,397	186,780	178,033	169,877	162,269	155,170	92,726
PV of cost (KUSD)	4,687,194																			

INVESTMENT COST OPTION 3 COST ('000 USD)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Lines	365,522	520,562	766,920	283,461	94,561	94,561	94,561	94,561	94,561	56,692	56,692	56,692	56,692	56,692	129,536	129,536	129,536	129,536	129,536	13,380
Substations	54,983	87,191	144,752	606,375	40,381	40,381	40,381	40,381	40,381	53,183	53,183	53,183	53,183	53,183	60,074	60,074	60,074	60,074	60,074	6,625
Reactive compensation	11,094	4,343	6,543	8,618	2,808	2,808	2,808	2,808	2,808	7,253	7,253	7,253	7,253	7,253	10,379	10,379	10,379	10,379	10,379	36,850
O$M Cost (2.5%)	10,790	15,302	5,880	22,461	3,444	3,444	3,444	3,444	3,444	2,928	2,928	2,928	2,928	2,928	5,000	5,000	5,000	5,000	5,000	1,421
Losses(KUSD)	22,851	28,868	36,865	22,895	28,164	34,646	42,621	52,431	64,498	78,082	94,527	114,435	138,537	167,714	185,623	205,445	227,384	251,665	278,539	335,765
Total cost (MUSD)	465,240	656,267	978,036	943,809	169,358	175,840	183,814	193,624	205,692	198,139	214,584	234,492	258,593	287,770	390,612	410,434	432,372	456,654	483,528	394,041
PVS (I=8%)	465,240	607,654	838,508	749,226	124,483	119,674	115,834	112,978	111,129	99,119	99,394	100,570	102,691	105,813	132,988	129,386	126,205	123,419	121,002	91,304
PV of cost (KUSD)	4,476,616																			

From the above analysis the present value of cost for investment sequence 3 is the lowest hence option 3 is the least cost development plan. The present value of investments for this option is estimated at USD 4.48 Billion. Detailed investment sequence for this option is tabulated in section 8.4 below.

8.4 Kenya Power Transmission System Development Plan 2011-2031

8.4.1 Transmission Lines Investment Sequence

Table 68: Transmission Lines Investment Sequence

YEAR	LINE	CIRCUIT NO.	LENGTH	LINE COST	BAYS
			(KM)	(KUSD)	(KUSD)
2012	ISINYA__KONZA__132kV	1	45	4,095	900
	OLKARIA I__DOMES__132kV	1	6	546	900
	OLKARIA I__NAROK__132kV	1	68	6,188	900
	OLKARIA II__OLKARIA 1A__132kV	1	4	364	900
	DOMES__OLKARIA 1A__132kV	1	10	910	900
	MANGU__GATUNDU__132kV	1	20	1,820	900
	MANGU__GITHAMBO__132kV	1	43	3,913	900
	ELDORET__KITALE__132kV	1	60	5,460	900
	KISUMU__RANGALA__132kV	1	63	5,733	900
	MASINGA__EMBU__132kV	1	44	4,027	900
	NANYUKI__NYAHURURU__132kV	1	80	7,280	900
	LESSOS__KABARNET__132kV	1	65	5,915	900
	SULTAN HAMUD__WOTE__132kV	1	37	3,367	900
	VOI__TAVETA__132kV	1	110	10,010	900
	MUMIAS__RANGALA__132kV	1	34	3,094	900
	ISHIARA__KYENI__132kV	1	18	1,638	900
	KYENI__EMBU__132kV	1	35	3,185	900
	BOMET__SOTIK__132kV	1	30	2,730	900
	SONDU__SANGORO__132kV	1	4	364	900
	SONDU__KISII__132kV	1	45	4,095	900
	KISII__AWENDO__132kV	1	44	4,004	900
	KINDARUMA__MWINGI__132kV	1	32	2,912	900
	MWINGI__GARISSA__132kV	1	192	17,472	900
	MARIAKANI__ISINYA__220kV	1	429	137,280	9,400
	MARIAKANI__ISINYA__220kV	2			9,400
	MARIAKANI__RABAI__220kV	1	30	6,600	2,252
	MARIAKANI__RABAI__220kV	2			2252
	ISINYA__EMBAKASI__220kV	1	35	7,700	2,252
	ISINYA__EMBAKASI__220kV	2			2,252
	MUSAGA__LESSOS__220kV	1	60	13,200	2,252
	MUSAGA__LESSOS__220kV	2			2,252
	MUSAGA__TORORO__220kV	1	60	13,200	2,252

	MUSAGA__TORORO__220kV	2			2,252
	TORORO__BUJAGALI__220kV	1	120	26,400	2,252
	TORORO__BUJAGALI__220kV	2			2,252
2013	ISINYA__KAJIADO__132kV	1	10	910	900
	MAGADI__KAJIADO__132kV	1	93	8,463	900
	OLKARIA I__NAIVSHA__132kV	1	23	2,102	900
	NANYUKI__ISIOLO_MERU132kV	1	79	7,189	900
	NAROK__BOMET__132kV	1	88	8,008	900
	GITHAMBO__MURANGA_KIGANJO_132kV	1	75	6,825	900
	MWINGI__KITUI__132kV	1	30	2,730	900
	LOYANGALANI__SUSWA__220kV	1	429	171,600	9,400
	LOYANGALANI__SUSWA__220kV	2			9,400
	ISINYA__SUSWA__220kV	1	100	32,000	9,400
	ISINYA__SUSWA__220kV	2			9,400
	RABAI__MALINDI__220kV	1	110	20,790	5,600
	MALINDI__GARSEN__220kV	1	116	21,924	5,600
	GARSEN__LAMU__220kV	1	110	20,790	5,600
	SUSWA__OLKARIA IV__220kV	1	45	9,900	5,600
	SUSWA__OLKARIA IV__220kV	2			5,600
	SUSWA__NGONG__220kV	1	40	8,800	5,600
	SUSWA__NGONG__220kV	2			5,600
	EMBAKASI TEE__ATHI RIVER__220kV	1	15	3,311	5,600
	EMBAKASI TEE__ATHI RIVER__220kV	2			5,600
	OLKARIA II__RONGAI__220kV	1	80	17,600	5,600
	OLKARIA II__RONGAI__220kV	2			5,600
	RONGAI__LESSOS__220kV	1	123	27,060	5,600
	RONGAI__LESSOS__220kV	2			5,600
	LESSO__KISUMU__220kV	1	103	22,660	5,600
	LESSO__KISUMU__220kV	2			5,600
2014	KILIFI PS__KILIFI__132kV	1	20	1,820	900
	TURKWEL__ORTUM__220kV	1	80	12,800	5,600
	ORTUM_KITALE__220kV	1	40	6,400	5,600
	MARIAKANI__KILIFI PS__400kV	1	100	32,000	9,400
	MARIAKANI__KILIFI PS__400kV	2			9,400
	ISINYA__PIPELINE__SUSWA_400kV*	1			
	ISINYA__PIPELINE__SUSWA_400kV*	2			
	ETHIOPIA__KENYA_ 500kV HVDC		600	683,000	
2015	OLKARI__NAROK__132kV	2	68	6,188	900
	KIPEVU__MBARAKI__132kV	1	15	1,950	900
	KIPEVU__MBARAKI__132kV	2			900
	RABAI__1BAMB__132kV	2	25	1,968	900

	ELDORET__LESSOS__132kV	2	32	2,568	900
	KILIFI__BAMBURI__132kV	2	49	3,888	900
	MUSAGA__BUNGOMA__132kV	1	30	2,730	900
	MUMIAS__KAKAMEGA__132kV	1	30	2,730	900
	NAROK__BOMET__132kV	2	88	7,040	900
	BOMET__SOTIK__132kV	2	30	2,400	900
	MIGORI__AWENDO__132kV	1	30	2,730	900
	GARISSA__WAJIR__132kV	1	300	27,300	900
	NYAHURURU__KABARNET__132kV	1	90	8,190	900
	NYAHURURU__RUMURUTI__132kV	1	20	2,600	900
	NYAHURURU__RUMURUTI__132kV	2			900
	MWINGI__KITUI__132kV	2	30	2,730	900
	ISINYA__1DANDOR__220kV	1	34	7,480	5,600
	ISINYA__1DANDOR__220kV	2			5,600
	ISINYA__MALILI__220kV	1	40	8,800	5,600
	ISINYA__MALILI__220kV	2			5,600
	ISINYA__KAJIADO__220kV	1	10	2,200	5,600
	ISINYA__KAJIADO__220kV	2			5,600
	ISINYA__ATHI RIVER__220kV	3	20	4,389	5,600
	ISINYA__ATHI RIVER__220kV	4			5,600
	KAMBURU__EMBU__220kV	1	40	8,800	5,600
	KAMBURU__EMBU__220kV	2			5,600
	OLKARIA II__NBNORTH__220kV	1	69	15,180	5,600
	OLKARIA II__NBNORTH__220kV	2			5,600
	RONGAI__LANET__220kV	1	25	5,500	5,600
	RONGAI__LANET__220kV	2			5,600
	MENENGAI__RONGAI__400kV	1	20	6,400	4,700
	MENENGAI__RONGAI__400kV	2			9,400
	ISINYA__ARUSHA__400kV	1	150	24,000	9,400
	ISINYA__ARUSHA__400kV	2			9,400
2020	MARIAKANI SS__MARIAKANI__220kV	1	5	1,100	5,600
	MARIAKANI SS__MARIAKANI__220kV	2			5,600
	SUSWA__CHEMOSIT__220kV	1	230	73,600	9,400
	SUSWA__CHEMOSIT__220kV	2			9,400
	NAIVASHAL__GILGIL__220kV	1	30	6,633	5,600
	NAIVASHAL__GILGIL__220kV	2			5,600
	GILGIL__LANET__220kV	1	37	8,107	5,600
	GILGIL__LANET__220kV	2			5,600
	ELDORET EAST__ELDORET__220kV	1	30	6,600	5,600
	ELDORET EAST__ELDORET__220kV	2			5,600
	KINAGOP W__NAIVASHA__220kV	1	30	4,800	5,600
	KIAMBERE__MUTONGA__220kV	2	40	6,400	5,600
	MUTONGA__KATHWANA__220kV	1	20	4,400	5,600

	MUTONGA__KATHWANA__220kV	2			5,600
	MUTONGA__NANYUKI__220kV	1	150	48,000	9,400
	MUTONGA__NANYUKI__220kV	2			9,400
	MUTONGA__LG FALLS__220kV	1	20	4,400	5,600
	MUTONGA__LG FALLS__220kV	2			5,600
	MANGU__THIKA__220kV	1	20	3,120	5,600
	THIKA__MURANGA__220kV	1	46	8,600	5,600
	MURANGA__KIGANJO__220kV	1	45	8,505	5,600
	KIGANJO__NANYUKI__220kV	1	52	8,240	5,600
	RUARAKA__NAIVASHA__220kV	1	75	16,500	5,600
	RUARAKA__NAIVASHA__220kV	2			5,600
	KILIFI__KILIFI PS__220kV	1	20	4,400	5,600
	KILIFI__KILIFI PS__220kV	2			5,600
	LONGONOT__SUSWA__400kV	1	20	6,400	9,400
	LONGONOT__SUSWA__400kV	2			9,400
	MARSABIT__LOYANGALANI__400kV	1	200	64,000	9,400
2025	MARIAKANI__MIRITINI__220kV	1	20	4,400	5,600
	MARIAKANI__MIRITINI__220kV	2			5,600
	MIRITINI__GALU__220kV	1	80	12,800	5,600
	SUSWA__SUSWA G__220kV	1	20	4,400	5,600
	SUSWA__SUSWA G__220kV	2			5,600
	SUSWA__THIKA RD__220kV	1	70	15,400	5,600
	SUSWA__THIKA RD__220kV	2			5,600
	EMBU__KIGANJO__220kV	1	45	7,200	5,600
	KISAUNI__MBARAKI__220kV	1	20	4,400	5,600
	KISAUNI__MBARAKI__220kV	2			5,600
	ISIOLO__NANYUKI__220kV	1	50	10,890	5,600
	ISIOLO__NANYUKI__220kV	2	50		5,600
	KITALE__WEBUYE__220kV	1	50	8,000	5,600
	WEBUYE__MUSAGA__220kV	1	50	8,000	5,600
	KISUMU EAST__KAKAMEGA__220kV	1	50	8,000	5,600
	LESSOS__ELDORET EAST__220kV	3	31	4,920	5,600
	MARIAKANI__VOI__220kV	1	114	25,080	5,600
	MARIAKANI__VOI__220kV	2			5,600
	VOI__MTITO ANDEI__220kV	1	90	19,800	5,600
	VOI__MTITO ANDEI__220kV	2			5,600
	MTITO ANDEI__SULTAN HAMUD__220kV	1	129	28,380	5,600
	MTITO ANDEI__SULTAN HAMUD__220kV	2			5,600
	MALILI__SULTAN HAMUD__220kV	1	75	12,000	5,600
	MANGU__THIKA__220kV	2	20	2,633	5,600
	THIKA__MURANGA__220kV	2	46	6,143	5,600
	MURANGA__KIGANJO__220kV	2	45	6,075	5,600
	KIGANJO__NANYUKI__220kV	2	52	6,953	5,600

	KANGUNDO__KAMULU__220kV	1	30	6,600	5,600
	KANGUNDO__KAMULU__220kV	2			5,600
	MALILI__MACHAKOS__220kV	1	30	6,600	5,600
	MALILI__MACHAKOS__220kV	2			5,600
	KILIFI PS _MTWAPA__220kV	1	30	6,600	5,600
	KILIFI PS _MTWAPA__220kV	2			5,600
	KILIFI PS__LAMU__400kV	1	300	96,000	9,400
	KILIFI PS__LAMU__400kV	2			9,400
	KILIFI PS__KISAUNI__400kV	1	70	22,400	9,400
	KILIFI PS__KISAUNI__400kV	2			9,400
	KITUI _KANGUNDO__400kV	1	120	38,400	9,400
	KITUI _KANGUNDO__400kV	2			9,400
	RONGAI__BOGORIA__400kV	1	60	19,200	9,400
	RONGAI__BOGORIA__400kV	2			9,400
	BOGORIA_KOROSI__400kV	1	50	16,000	9,400
	BOGORIA_KOROSI__400kV	2			9,400
	KOROSI_PAKA__400kV	1	20	6,400	9,400
	KOROSI_PAKA__400kV	2			9,400
	PAKA_SILALI__400kV	1	35	11,200	9,400
	PAKA_SILALI__400kV	2			9,400
	SILALI__ELDORET EAST__400kV	1	160	51,200	9,400
	SILALI__ELDORET EAST__400kV	2			9,400
	SILALI__EMURULONGOYAK__400kV	1	40	12,800	9,400
	SILALI__EMURULONGOYAK__400kV	2			9,400
	EMURULONGOYAK__BARRIERI__400kV	1	80	25728	9,400
	EMURULONGOYAK__BARRIERI__400kV	2			9,400
	ISINYA__MALILI__400kV	1	40	12800	9,400
	ISINYA__MALILI__400kV	2			9,400
2030	ONGATARONGAI__PIPELINE__220kV	1	30	6,600	5,600
	ONGATARONGAI__PIPELINE__220kV	2			5,600
	CHEMOSIT__KISII__220kV	1	60	13,200	5,600
	CHEMOSIT__KISII__220kV	2			5,600
	KISII__AWENDO__220kV	1	44	9,680	5,600
	KISII__AWENDO__220kV	2			5,600
	MTWAPA__KISAUNI__220kV	1	20	4400	5,600
	MTWAPA__KISAUNI__220kV	2			5,600
	KILIFI PS__KANGUNDO__400kV	1	450	144,000	9,400
	KILIFI PS__KANGUNDO__400kV	2			9,400
	KANGUNDO__THIKA__400kV	1	60	19,200	9,400
	KANGUNDO__THIKA__400kV	2			9,400
	THIKA__KIAMBU NORTH__400kV	1	40	12800	9,400
	THIKA__KIAMBU NORTH__400kV	2			9,400
	KIAMBU NORTH__UPLANDS__400kV	1	40	12,800	9,400

	KIAMBU NORTH__UPLANDS__400kV	2			9,400
	UPLANDS__LANET__400kV	1	100	32,000	9,400
	UPLANDS__LANET__400kV	2			9,400
	LANET__MENENGAI__400kV	1	20	6,400	9,400
	LANET__MENENGAI__400kV	2			9,400
	KITUI__MUTONGA__400kV	1	120	38,400	9,400
	KITUI__MUTONGA__400kV	2			9,400
	NANYUKI__RUMURUTI__400kV	1	80	25,600	9,400
	NANYUKI__RUMURUTI__400kV	2			9,400
	RUMURUTI__BOGORIA__400kV	1	100	32,000	9,400
	RUMURUTI__BOGORIA__400kV	2			9,400
	ELDORET EAST__KISUMU EAST__400kV	1	120	38,400	9,400
	ELDORET EAST__KISUMU EAST__400kV	2			9,400
	SUSWA__PIPELINE__400kV	3	50	10,000	9,400
	SUSWA__CHEMOSIT__400kV*	1			
	SUSWA__CHEMOSIT__400kV*	2			
2031	MWINGI__GARISSA__132kV	2	192	12,480	900
	MUTONGA_NANYUKI _400 kV*	1			
	MUTONGA_NANYUKI _400 kV*	2			
	* - Conversion to 400 kV operation				

8.4.2 Substations Investment Sequence

Table 69: Substations Investment Sequence

	TRANSFORMERS	UNIT	RATING	TX COST	BAYS	SS COST
			(MVA)	KUSD	KUSD	KUSD
2012	ISINYA__132__220kV	1	100	1,878	900	2,595
	MANGU__132__66kV	1	45	1,040	900	1,908
	MANGU__132__66kV	2	45	1,040	900	
	GATUNDU__132__33kV	1	23	529	900	1,908
	KYENI__132__33kV	1	23	529	900	1,908
	NAROK__132__33kV	1	23	529	900	1,908
	BOMET__132__33kV	1	5	115	900	1,908
	AWENDO__132__33kV	1	23	529	900	1,908
	TAVETA__132__33kV	1	5	115	900	1,908
	RANGALA__132__33kV	1	23	529	900	1,908
	KITALE__132__33kV	1	23	529	900	1,908
	NYAHURURU__132__33kV	1	23	529	900	1,908
	KABARNET__132__33kV	1	15	345	900	1,908
	GITHAMBO__132__33kV	1	23	529	900	1,908
	MWINGI__132__33kV	1	7.5	173	900	1,908

	WOTE__132__33kV	1	7.5	173	900	1,908
	GARISSA__132__33kV	1	15	345	900	1,908
2013	KISUMU__132__220kV	1	150	1,875	3,250	2595
	KISUMU__132__220kV	2	150	1,875	3,250	
	CHEMOSIT__132__220kV	1	150	1,875	3,250	2,,595
	NAIVASHA__132__33kV	1	23	529	900	1,000
	NAIVASHA__132__33kV	2	23	529	900	
	NAIVASHA__132__33kV	3	23	529	900	
	EMBU__132__33kV	1	23	529	900	1,000
	KAJIADO__132__33kV	1	15	345	900	1,908
	ISIOLO__132__33kV	1	23	529		1,908
	DANDORA__220__66kV	1	150	1,875	3,250	2,595
	DANDORA__220__66kV	2	150	1,875	3,250	
	THIKA RD__220__66kV	1	150	1,875	3,250	2,595
	THIKA RD__220__66kV	2	150	1,875	3,250	
	NGONG__220__66kV	1	150	1,875	3,250	2,595
	NGONG__220__66kV	2	150	1,875	3,250	
	ATHI RIVER__220__66kV	1	150	1,875	3,250	2,595
	ATHI RIVER__220__66kV	2	150	1,875	3,250	
	DIANI__33__132kV	1	45	1040	900	
	EMBU__132__33kV	2	23	529	900	1000
2014	MARIAKANI__400__220kV	1	350	4,700	7,500	
	MARIAKANI__400__220kV	2	350	4,700	7,500	3,475
	KILIFI PS__400__220kV	1	350	4,700	7,500	4,289
	ISINYA__400__220kV	1	350	4,700	7,500	4,289
	ISINYA__400__220kV	2	350	4,700	7,500	
	SUSWA__400__220kV	1	350	4,700	7,500	4,289
	SUSWA__400__220kV	2	350	4,700	7,500	
	SUSWA__400__220kV	3	350	4,700	7,500	
	MUHORONI__132__33kV	2	23	529	900	1,000
	KISUMU__132__33kV	1	45	1,040	900	1,000
	KISUMU__132__33kV	2	45	1,040	900	
	KISUMU__132__33kV	3	45	1,040	900	
	LESSOS__132__33kV	1	23	529	900	1,000
	LESSOS__132__33kV	2	23	529	900	
	LANET__132__33kV	1	45	1,040	900	1000
	LANET__132__33kV	2	45	1,040	900	
	BOMET__132__33kV	1	45	345	900	
	KITALE__132__33kV	2	23	529	900	
	KITALE__132__220kV	1	150	1,875	3,250	2,595
2015	ISINYA__400__220kV	3	350	4,700	7,500	3,475
	RUMURUTI__400__132kV	1	150	1,875	5,150	4,289

	RUMURUTI__400__132kV	2	150	1,875	5,150	
	RONGAI__400__220kV	1	750	5,344	7,500	4,289
	RONGAI__400__220kV	2	750	5,344	7,500	
	RONGAI__400__220kV	3	750	5,344	7,500	
	LOYANGALANI__400__33kV	1	120	1,500	5,150	4,289
	LOYANGALANI__400__33kV	2	120	1,500	5,150	
	LOYANGALANI__400__33kV	3	360	4,500	5,150	
	ISINYA__132__220kV	1	350	4,700	3,250	2,595
	OLKARIA II__132__220kV	2	90	1,690	3,250	
	KIPEVU__132__33kV	1	150	1,875	900	1,000
	KIPEVU__132__33kV	2	150	1,875	900	
	KIPEVU__132__33kV	3	150	1,875	900	
	JUJA__132__66kV	1	150	1,875	900	1000
	JUJA__132__66kV	2	150	1,875	900	
	JUJA__132__66kV	3	150	1,875	900	
	JUJA__132__220kV	1	350	4,700	3,250	2,595
	JUJA__132__220kV	2	350	4,700	3,250	
	CHEMOSIT__132__220kV	1	350	1,875	3,250	2,595
	CHEMOSIT__132__220kV	2	350	1,875	3,250	
	MUSAGA__132__220kV	1	150	1,875	3,250	2,595
	MUSAGA__132__220kV	2	150	1,875	3,250	
	LANET__132__220kV	1	150	1,875	3,250	2,595
	LANET__132__220kV	2	150	1,875	3,250	
	LANET__132__220kV	3	150	1,875	3,250	
	EMBU__132__220kV	1	150	1,875	3,250	2,595
	KISII__132__220kV	1	150	1,875	3,250	2,595
	AWENDO__132__220kV	1	150	1,875	3,250	
	KAJIADO__132__33kV	1	150	1,875	900	1,000
	KAJIADO__132__33kV	2	150	1,875	900	
	RANGALA__132__33kV	2	23	529	900	1,000
	GARISSA__132__33kV	1	23	529	900	1,000
	DANDORA__220__66kV	3	350	4,700	3,250	2,595
	NBNORTH__220__66kV	1	350	1,875	3,250	
	NBNORTH__220__66kV	2	350	1,875	3,250	
	NBNORTH__220__66kV	3	150	1,875	3,250	1,500
	RABAI__220__132kV	1	150	4,700	3,250	1,500
	RABAI__220__132kV	2	150	4,700	3,250	
	LESSOS__220__132kV	1	150	1,875	3,250	
	LESSOS__220__132kV	2	150	1,875	3,250	
	LESSOS__220__132kV	3	150	1,875	3,250	1,500
	THIKA RD__220__66kV	3	250	3,357	3,250	1,500
	NGONG__220__66kV	3	250	3,357	3,250	1,500
	ATHI RIVER__220__66kV	3	150	1,875	3,250	1,500
2020	KILIFI PS__400__220kV	1	350	4,700	7,500	4,289

	KILIFI PS__400__220kV	2	350	4,700	7,500	
	MARSABIT__400__33kV	1	360	6,760	5,150	4,289
	MARSABIT__400__33kV	2	360	6,760	5,150	
	MARSABIT__400__33kV	3	120	2,253	5,150	
	MARSABIT__400__132kV	1	120	2,253	5,150	4,289
	MANGU__132__220kV	1	150	1,875	3,250	2,595
	MANGU__132__220kV	2	150	1,875	3,250	
	ELDORET__132__220kV	1	150	1,875	3,250	2,595
	ELDORET__132__220kV	2	150	1,875	3,250	
	KIGANJO__132__220kV	1	150	1,875	3,250	2,595
	KIGANJO__132__220kV	2	150	1,875	3,250	
	NANYUKI__132__220kV	1	150	1,875	3,250	2,595
	NANYUKI__132__220kV	2	150	1,875	3,250	
	NANYUKI__132__220kV	3	150	1,875	3,250	
	KILIFI__132__220kV	1	150	1,875	3,250	2,595
	KILIFI__132__220kV	2	150	1,875	3,250	
	NAIVSHA__132__220kV	1	150	1,875	3,250	2,595
	NAIVSHA__132__220kV	2	150	1,875	3,250	
	MARIAKANI__132__220kV	1	150	1,875	3,250	2,595
	MARIAKANI__132__66kV	2	150	1,875	3,250	
	RUARAKA__132__220kV	1	350	4,700	3,250	2,595
	RUARAKA__132__220kV	2	350	4,700	3,250	
	MURANGA__132__220kV	1	90	1,690	3,250	2,595
	MURANGA__132__220kV	2	90	1,690	3,250	
2025	KANGUNDO__400__220kV	1	350	4,700	7,500	4,289
	KANGUNDO__400__220kV	2	350	4,700	7,500	
	LAMU__400__220kV	1	350	4,700	7,500	4,289
	LAMU__400__220kV	2	350	4,700	7,500	
	ELDORET EAST__400__220kV	1	350	4,700	7,500	4,289
	ELDORET EAST__400__220kV	2	350	4,700	7,500	
	KITUI__400__132kV	1	150	1,875	5,150	4,289
	KITUI__400__132kV	2	150	1,875	5,150	
	MALILI__400__220kV	1	350	4,700	7,500	4,289
	MALILI__400__220kV	2	350	4,700	7,500	
	MALILI__400__220kV	3	350	4,700	7,500	
	KISAUNI__400__220kV	1	350	4,700	7,500	4,289
	KISAUNI__400__220kV	2	350	4,700	7,500	
	KISAUNI__400__220kV	3	350	4,700	7,500	
	WEBUYE__132__220kV	1	150	1,875	3,250	2,595
	SULTAN HAMUD__132__220kV	1	150	1,875	3,250	2,595
	MTITANDEI__132__220kV	1	150	1,875	3,250	2,595
	VOI__132__220kV	1	150	1,875	3,250	2,595
	EMBU__132__220kV	1	150	1,875	3,250	2,595
	EMBU__132__220kV	2	150	1,875	3,250	

	ISIOLO__132__220kV	1	150	1,875	3,250	2,595
	ISIOLO__132__220kV	2	150	1,875	3,250	
	KAKAMEGA__132__220kV	1	150	1,875	3,250	2,595
	MBARAKI__132__220kV	1	150	1,875	3,250	2,595
	MBARAKI__132__220kV	2	150	1,875	3,250	
	GALU__132__220kV	1	150	1,875	3,250	2,595
2030	LANET__400__220kV	1	350	4,700	7,500	4,836
	LANET__400__220kV	2	350	4,700	7,500	
	THIKA__400__220kV	1	350	4,700	7,500	4,836
	THIKA__400__220kV	2	350	4,700	7,500	
	UPLANDS__400__220kV	1	350	4,700	7,500	4,836
	UPLANDS__400__220kV	2	350	4,700	7,500	
	KIAMBU NORTH__400__220kV	1	350	4,700	7,500	4,836
	KIAMBU NORTH__400__220kV	2	350	4,700	7,500	
	MUTONGA__400__220kV	1	350	4,700	7,500	4,836
	MUTONGA__400__220kV	2	350	4,700	7,500	
	NANYUKI__400__220kV	1	350	4,700	7,500	4,836
	NANYUKI__400__220kV	2	350	4,700	7,500	
	KISUMU EAST__400__220kV	1	350	4,700	7,500	4,836
	KISUMU EAST__400__220kV	2	350	4,700	7,500	
	KISUMU EAST__400__220kV	3	350	4,700	7,500	
	PIPELINE__400__220kV	1	350	4,700	7,500	4,836
	PIPELINE__400__220kV	2	350	4,700	7,500	
	PIPELINE__400__220kV	3	350	4,700	7,500	
	CHEMOSIT__400__220kV	1	350	4,700	7,500	4,836
	CHEMOSIT__400__220kV	2	350	4,700	7,500	
	KISII__132__220kV	2	150	1,875	3,250	
	AWENDO__132__220kV	2	150	1,875	3,250	2,595
2031	ELDORET__132__220kV	3	150	1,875	3,250	1,500

8.4.3 Reactive Compensation Investment Sequence

Table 70: Reactive Compensation Investment Sequence

	BUS	NAME	VOLTAGE	MIN	MAX	COST
			(kV)	Mvar	Mvar	(KUSD)
2012	800	MARIAKANI	220	-94	0	969
	820	ISINYA	220	-92	0	948
	1187	GARISSA	132	-9	0	97
	1668	JUJA	66	-30	60	1,875
	1132	KIGANJ0	132	0	12	313
	1133	NANYUKI	132	0	6	157
	1134	KILIFI	132	0	14	365
	1129	KISUMU	132	0	12	313
	1127	ELDORET	132	0	10	261
	1130	CHEMOSIT	132	0	10	261
	1141	LANET	132	0	20	522
	1172	KISII	132	0	10	261
	1625	EMBAKASI	66	0	90	2,349
	1640	NBNORTH	66	0	60	1,566
	1668	JUJA	66	-30	60	1,875
	1601	RUARAKA	66	0	32	835
2013	800	MARIAKANI	220	0	0	-
	100	LOYANGALANI	400	-146	0	1,506
	1211	SUSWA	220	-130	0	1,341
	1129	KISUMU	132	-70	0	722
	1132	KIGANJ0	132	0	23	606
	1288	LAMU	220	-16	0	167
2014	800	MARIAKANI	220	-46	0	472
	820	ISINYA	220	-40	0	413
	100	LOYANGALANI	400	4	0	- 41
	1132	KIGANJ0	132	0	29	752
	1194	DIANI	132	0	31	802
	1134	KILIFI	132	-32	0	330
	1211	SUSWA	220	-78	0	804
	1129	KISUMU	132	0	0	-
	55	KILIFI	400	-292	0	3,011
2015	800	MARIAKANI	220	-124	0	1,279
	820	ISINYA	220	-201	0	2,073
	1187	GARISSA	132	-9	0	93
	100	LOYANGALANI	400	-46	0	474
	1211	SUSWA	220	-45	0	464

	1129	KISUMU	132	-5	0	52
	1668	JUJA	66	-30	0	309
	76	RUMURUTI	400	-282	0	2,908
	55	KILIFI	400	0	14	365
	1114	KIPEVU	132	0	23	600
2020	1132	KIGANJ0	132	0	27	705
	1129	KISUMU	132	0	12	313
	1668	JUJA	66	0	60	1,566
	1601	RUARAKA	66	0	38	992
	1240	LESSOS	220	0	34	887
	1194	DIANI	132	0	26	679
	1114	KIPEVU	132	0	30	783
	1116	MANGU	132	0	77	2,010
	1143	SULTAN HAMUD	132	0	19	496
	1160	MERU	132	0	19	496
	1179	KITALE	132	0	12	300
	1695	NGONG	66	0	43	1,122
	100	LOYANGALANI	400	-65	0	670
	1133	NANYUKI	132	-81	0	835
	1211	SUSWA	220	-31	0	320
	1141	LANET	132	-60	0	619
	55	KILIFI	400	-54	0	557
	110	MARSABIT	400	-67	0	691
2025	820	ISINYA	220	0	42	1,096
	1132	KIGANJO	132	0	37	966
	1134	KILIFI	132	0	11	287
	1129	KISUMU	132	0	54	1,409
	1130	CHEMOSIT	132	0	52	1,357
	1625	EMBAKASI	66	0	50	1,305
	1640	NBNORTH	66	0	96	2,506
	1601	RUARAKA	66	0	80	2,088
	1240	LESSOS	220	0	21	548
	1194	DIANI	132	0	3	78
	1116	MANGU	132	0	37	966
	1143	SULTAN HAMUD	132	0	3	78
	1160	MERU	132	0	29	757
	1167	WAJIR	132	0	0	12
	1179	KITALE	132	0	28	718
	1695	NGONG	66	0	116	3,028
	1146	VOI	132	0	25	653
	1157	MAGADI	132	0	14	365
	1174	AWENDO	132	0	28	731
	1178	RANGALA	132	0	45	1,175

	1273	MACHAKOS	220	0	197	5,142
	1696	ATHI RIVER	66	0	96	2,506
	800	MARIAKANI	220	0	0	-
	100	LOYANGALANI	400	-1	0	10
	1133	NANYUKI	132	-1	0	10
	55	KILIFI	400	-105	0	1,083
	76	RUMURUTI	400	-5	0	52
	61	LAMU	400	-219	0	2,258
	66	SILALI	400	-375	0	3,867
	81	KITUI	400	-118	0	1,217
2030	1187	GARISSA	132	0	10	261
	1132	KIGANJO	132	0	57	1,488
	1134	KILIFI	132	0	50	1,305
	1129	KISUMU	132	-44	36	1,393
	1130	CHEMOSIT	132	0	47	1,227
	1625	EMBAKASI	66	0	20	522
	1601	RUARAKA	66	0	122	3,184
	1240	LESSOS	220	0	94	2,453
	1114	KIPEVU	132	0	176	4,594
	1116	MANGU	132	0	23	600
	1143	SULTAN HAMUD	132	0	53	1,383
	1160	MERU	132	0	67	1,749
	1163	NAROK	132	0	35	914
	1167	WAJIR	132	0	18	458
	1179	KITALE	132	0	76	1,984
	1146	VOI	132	-17	23	776
	1157	MAGADI	132	0	13	339
	1174	AWENDO	132	0	47	1,227
	1178	RANGALA	132	0	30	783
	1180	NYAHURURU	132	0	59	1,540
	1292	KISAUNI	220	0	226	5,899
	1696	ATHI RIVER	66	0	48	1,253
	1268	KANGUNDO	220	-88	16	1,325
	1149	BUNGOMA	132	0	55	1,436
	1212	ONGATA RONGAI	220	0	107	2,793
	1267	KIAMBU	220	0	155	4,046
	1177	TAVETA	132	0	18	470
	100	LOYANGALANI	400	11	0	- 113
	1133	NANYUKI	132	-24	0	248
	1129	KISUMU	132	-44	36	1,393
	1141	LANET	132	-45	0	464
	55	KILIFI	400	-104	0	1,073
	76	RUMURUTI	400	-219	0	2,258
	66	SILALI	400	-63	0	650

	81	KITUI	400	-186	0	1,918
	1146	VOI	132	-17	23	776
	1268	KANGUNDO	220	-88	16	1,325
2031	800	MARIAKANI	220	0	0	-
	1187	GARISSA	132	0	8	209
	1132	KIGANJO	132	0	24	626
	1133	NANYUKI	132	-92	6	1,105
	1130	CHEMOSIT	132	0	43	1,122
	1625	EMBAKASI	66	0	20	522
	1640	NBNORTH	66	0	20	522
	1668	JUJA	66	0	40	1,044
	1601	RUARAKA	66	0	21	548
	1240	LESSOS	220	0	55	1,436
	1194	DIANI	132	0	14	365
	1114	KIPEVU	132	0	57	1,488
	1143	SULTAN HAMUD	132	0	21	548
	1160	MERU	132	0	27	705
	1163	NAROK	132	0	7	183
	1167	WAJIR	132	0	6	148
	1695	NGONG	66	0	50	1,305
	1157	MAGADI	132	0	3	78
	1174	AWENDO	132	0	24	626
	1178	RANGALA	132	0	27	705
	1180	NYAHURURU	132	0	23	600
	1273	MACHAKOS	220	0	57	1,488
	1292	KISAUNI	220	0	63	1,644
	1696	ATHI RIVER	66	0	32	835
	1268	KANGUNDO	220	-9	43	1,215
	1149	BUNGOMA	132	0	14	365
	1212	ONGATA RONGAI	220	0	115	3,002
	1267	KIAMBU	220	0	53	1,383
	1188	MURANGA	132	0	155	4,046
	1676	THIKA RD	66	0	103	2,688
	1181	KABARNET	132	0	56	1,462
	100	LOYANGALANI	400	4	0	- 41
	1133	NANYUKI	132	-92	6	1,105
	1141	LANET	132	-13	0	134
	55	KILIFI	400	-75	0	773
	61	LAMU	400	-385	0	3,970
	1268	KANGUNDO	220	-9	43	1,215

9 CONCLUSION AND IMPLEMENTATION PLAN

This study sought to update the 2010-2030 LCPDP taking into account changes in demand in line with anticipated macroeconomic performance, committed power generation and transmission projects and update the power system simulation data including plant types, system constraints and costs. ERC, MOE, KenGen, GDC, KNBS, REA, KETRACO and KPLC staff participated actively in the studies and new team members received training in the operation of these models. MAED based excel worksheets were developed and used for the development of electricity forecasts, VALORAGUA and WASP models were used to optimize the hydro-thermal generation mix of Kenya power system and select the least cost power plants to be added in future years while PSSE was used to determine the transmission system plan. The planning team reviewed the assumptions that were made in this study and ran additional sensitivity scenarios to test new inputs. From the study the following conclusions and recommendations emerge.

9.1 Conclusions

9.1.1 Load Forecasting

The load forecast was done using an excel model developed using MAED principles and assumptions which indicate that the nature and the level of demand for goods and services are driven by several determinants including; Population, Household size , Specific consumption (kWh/household/year) and Expected social and economic evolution of the country

Three demand scenarios were developed based on assumptions which were defined to reflect both current and future economic and social outlook in the vision 2030. The low GDP forecast reflected a pessimistic case while the high scenario gives an optimistic case based on the vision 2030 aspiration while the reference scenario was the middle ground between the two scenarios.

Based on the assumptions the load forecast based indicates that the peak demand lies in the range of 1227 MW in 2010 and between 12,738 and 22985 MW in 2031. The reference case ranges from 1227MW in 2010 to 3751MW in 2018 to 15026MW in 2030 and 16,905MW in 2031 while the energy demand increases from 7296GWh in 2010 to 22,685GWh in 2018 to 91,946GWh in 2030 and 103,518GWh. The current peak load is expected to grow 12 times by the year 2030.

There is a very slight difference between this and the load forecast done in the last update of 2010-2030. The reference peak demand for 2030 in the last updates was 15,065MW which compares very closely to the current peak demand of 15, 026MW.

9.1.2 Least Cost Generation and Transmission plan

Using annual data for the last 30 years (1980-2009) VALORAGUA hydrothermal optimization indicated that the average hydro generation in Kenya is about 3,280GWh with the highest hydro generation being experienced in May during the long rains and the lowest in February. The study also found a strong inverse correlation between the SRMC of the system and energy generation from hydro power plants due to the substitution effect of thermal generation. The SRMC of the system increases as hydro capacity declines during short rains (September to November) and decreases as hydro capacity increases in the long rains (April to July)

Using screening curves, the study found that hydro, MSD, and GTs are suitable for peaking capacity. Nuclear, geothermal, wind and coal are suitable for base load operation. Imports are suitable for both base load and peaking.

The optimal development program is dominated by geothermal, nuclear and coal power plants. Geothermal resources are the choice for the future generating capacity in Kenya. The optimum solution indicates that geothermal capacity should be increased from the current 198MW to 5,530 MW in 2031 contributing 26% of the total energy required by the system. The present value of the system expansion is approximately US$41.4 billion.

Using the least cost generation development plan, a transmission system plan was developed for the period beginning 2010 to 2028. The transmission development plan indicates the need to develop approximately 10345km of new lines at an approximated present value cost of USD 4.48 Billion

9.2 Implementation Plan

To guide the implementation of the findings of this study, the following implementation plan was developed. The plans cover short, medium and long term.

9.2.1 Short term 2010-2015

Generation projects

1. Timely implementation of committed power generation projects in order to attain an additional capacity of at least 1,815MW by 2015. This will require an investment of approximately US$ 3.9 billion.

Transmission projects

2. Timely implementation of 2,597Km of commtted power transmission projects and a further proposed 2,980Km of new transmission lines by 2015. The total non discounted cost of this projects is approximately USD3.043 billion.

Modelling - Load forecast

3. In order to develop an energy database for use in the complete MAED model a survey is required. The AFD Consultant on the Technical Assistance programme seconded to the planning committee has already embarked on preparing the terms of reference and has initiated discussions with the KNBS on undertaking a households survey based on MAED model data requirements. The remaining surveys on transport, manufacturing, industry, services, construction and mining will be undertaken when the funds are available.

4. All the institutions involved in the LCPDP preparation; i.e. MOE, ERC, KPLC, KETRACO, GDC, REA and KenGen should continue training the members of the planning team in their respective institutions.

Independent System Operator

5. MOE and ERC shall take the necessary steps to transfer system operation and dispatch functions from KPLC to KETRACO by 2013

Nuclear

6. MoE shall undertake preparatory work for the nuclear power plant expected to come on stream in 2022. Preparatory work includes among others:
    a) The just Established Nuclear electricity project committee which is the country Nuclear Energy Programme Implementation Office (NEPIO) will start the establishment of appropriate infrastructure for a nuclear programme in Kenya.
    b) Enact the Atomic Energy Act by 2012
    c) Establish a Nuclear Regulatory Authority under the Act by 2013
    d) Commence human resource development including recruitment of high quality human resource and continued technical training by 2012.
    e) Site evaluation and selection of at least six (6) candidate sites to be communicated to IAEA by 2015.

Coal

7. In order to realize the development of the second 300 MW coal plant by the year 2018; KETRACO should float tenders for the development of the coal plant latest by 2013 to accommodate a 4 year construction period.

8. Ministry of energy shall continue exploration and subsequent mining of local coal to meet the high demand for coal arising from the proposed coal plants of up to 2400MW. The coal plants proposed in the plan other than the committed projects will be located in the Kilifi area to minimize transportation costs while meeting the requirements of proximity to large water bodies.

Geothermal

9. Geothermal Development Company shall develop and implement a rigorous monitoring and evaluation framework for the Geothermal Development Plan of drilling at least 1,100 wells to provide steam to the planned 5,530MW of new capacity by 2031. Timely implementation of the drilling programme is vital for the realization of this least cost generation plan since the commissioning of the proposed geothermal plants track the drilling plan.

10. Geothermal Development Company shall immediately invite Expressions of Interest from companies willing to develop power plants and well head generating units in line with the drilling plan. This is will ensure that for every well drilled a company will be in line to develop a plant. Well head generation will involve the tapping of steam from wells, which are undergoing tests, or are awaiting connection to permanent plants to benefit from early generation.

Hydro

11. Because of the long plant life and the multi-purpose nature of hydropower projects these plants might not be attractive to independent power producers who would typically prefer shorter amortization periods and who focus exclusively on power generation projects. Mutonga and Lower Grand Falls hydroelectric power plants are the only hydro projects considered in the current plan. Assuming a construction period of six years, the government

of Kenya should through KenGen commence the construction of the two hydro projects by the year 2012 to allow for commissioning in 2018.

9.2.2 Medium –Long term 2016-2031

Geothermal

12. In order to ensure continuity in drilling until the full geothermal potential of 10,000MW is achieved GDC shall prepare a drilling plan for completion of drilling in the remaining sites by the year 2020.The four remaining geothermal potential sites not covered by the drilling plan; are Eburru, Namrunu, Lake Baringo, Lake Magadi and Badlands.

Nuclear

13. In order for the first 1,000 MW nuclear plant to be commissioned by 2022 the Nuclear Regulatory Authority will issue three licences for the identified sites: a licence to prepare the sites, a licence to construct the plants and a licence to operate the nuclear power plant, respectively. The licensing process must be completed at least six years (2016) ahead of the commissioning dates.
14. Commission the first 1,000 MW nuclear plants in 2022 and issue necessary licences for the other nuclear power plants.

Coal

15. The Ministry of Energy shall complete assessment and development of the coal resources in the Mui Basin and invite bids for the commencement of mining and exploitation of the resource by 2020
16. The tenders for the other coal plants will be advertised in 2016, 2019, 2023, and 2025, and 2026 for the remaining 2,000MW of coal to be commissioned in 2021, 2023, 2028, 2030, and 2031. The coal plants will be located in Kitui, which is near the Mui basin.

Transmission system development plan

17. A total of 4,768 Km of new lines will be developed in the medium to long term period of 2016-2031. The approximated non discounted cost is USD 4.69 billion.

Annexes

Annex 1: *Methodology of the Peak Load Forecast*

1. Methodology of the MAED-EL software

Forecasting the future peak load using the MAED-EL component would be based on an analysis of the past yearly load curves, which are projected to the future according to the following elements:

- Energy forecast of various customer categories, prepared with the excel worksheets based on MAED-D formulae.
- Existing yearly load curve of each customer category, either kept unchanged, or modified if any information is available for modifying the shape of the future load curves.

The yearly load curve is usually obtained by a combination of 3 typical days per week: average week day (5 per week), Saturday and Sunday. Then the weekly load curve is extended to the whole year according to the load variations during the year. The forecast gives the global peak load, and the peak load of each customer category with the related load factors.

2. Methodology used in the current forecast

2.1 Customer categories

Implementing the MAED-EL software needs the availability of load curves for each category of customer, or at least for two categories. In the current forecast not only the load curves were unknown, but also the peak load of the two categories of customers considered in the forecast.

The two categories chosen for energy forecast are:

First category:

- Domestic and Street lighting consumptions (LV level)

Second category:

- Commercial & Industrial consumptions (LM+MV+HV levels).

Concerning their load factor, these two categories present the following usual characteristics:

- First category has a lower load factor,
- Second category has a higher load factor.

Therefore the actual load factor of each category has been assumed for the past years, taking into account:

- The global current load factor and peak load, as displayed in the statistical results (categories 1+2 together)

- The consumption of each category

2.2. Computation of load factors

Let us call: E_1 = energy consumption of category 1 (including losses)
E_2 = energy consumption of category 2 (including losses)
$E = E_1 + E_2$, total supply

P_1 = peak load of category 1
P_2 = peak load of category 2

F_1 = load factor of category 1
F_2 = load factor of category 2

In the forecast it was assumed that the global peak load P would be the sum of $P_1 + P_2$. This means that we are also assuming that the two peaks occur simultaneously.

Thus if h = number of hours per year (8760 hours), we have the following:

. $F_1 = \dfrac{E_1}{hP_1}$, $F_2 = \dfrac{E_2}{hP_2}$

. and $$F = \frac{F_1 E_1 + F_2 E_2}{E_1 + E_2} \quad (1)$$

. and $$F = \frac{E}{hP}$$

2.3 Example of the year 2010

a) Statistical results

. E_1 = 1936 GWh, E_2 = 4747 GWh, $E_1 + E_2$ = 6683 GWh

. P = 1120 MW, and F = 68.12%

b) Assumptions for past years (in our case: 2010)

Since $F_1 < F_2$, several options of F1 and F2 have been tested, until an agreement was reached on the following figures:

- F_1 = 55%, which gives P_1 = 402 MW
- F_2 = 75.46%, which gives P_2 = 718 MW,

(and $P_1 + P_2$ = 1120 MW)

c) Forecast

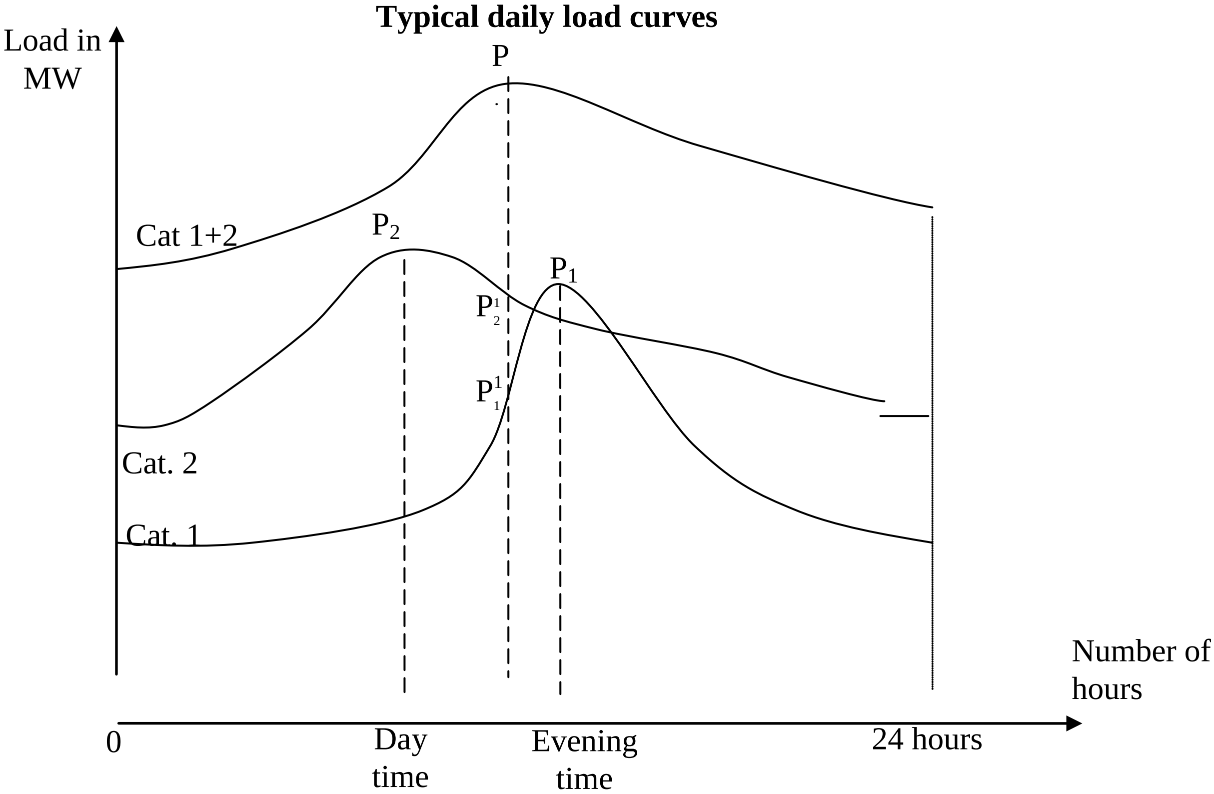
It was assumed that F_2 would remain constant, while F_1 would decrease to 50% in 2020 and to 45% in 2031. Then F was derived from formula (1) here above and eventually P was obtained.

3. The issue of simultaneous peak loads P_1 and P_2.

Both load factors F_1 and F_2 seem overestimated, although this fact has no impact on the peak load forecast. We may assume that the actual load factors are lower, resulting in higher peak loads P_1 and P_2, while P would remain unchanged.

Explanation is shown in the graph hereunder, where P_1 and P_2 are not simultaneous:

Typical daily load curves



In that case it is clear that the global peak load P is not the sum of $P_1 + P_2$, but the sum of $P'_1 + P'_2$, with the relations: $P'_1 < P_1$, and $P'_2 < P_2$. The loads P'_1 and P'_2 are the contributions to the peak of each category, not the peaks P_1 and P_2.

Consequently, the peak loads actually taken into account in the current forecast are P'_1 and P'_2. These loads are not the actual peaks, since these actual peaks are $P_1 > P'_1$ and $P_2 > P'_2$.

Underestimating the real P_1 and P_2 also leads to overestimate F_1 and F_2 since the computation has actually determined F'_1 and F'_2, with $F'_1 > F_1$ and $F'_2 > F_2$.

4. Conclusion and summary

The assumptions made in the forecast have given P'_1 and P'_2, instead of the correct P_1 and P_2 that are not simultaneous and still unknown.

There is no consequence on P, since $P = P'_1 + P'_2 < P_1 + P_2$. But there is a consequence on the real load factors of each category, which are overestimated.

For correcting this computation, and having access to the real P_1, P_2, F_1 and F_2, it will be compulsory to use the MAED-EL software, and have the relevant information on the load curves of each customer category.

Annex 2: Geothermal development plan

Column1	PLANT SIZE	TOTAL WELLS NO.	Rigs	2009 / 10	2010 / 11	2011 / 12	2012 / 13	2013 / 14	2014 / 15	2015 / 16	2016 / 17	2017 / 18	2018 / 19	2019 / 20	2020 / 21	2021 / 22	2022 / 23	2023 / 24	2024 / 25	2025 / 26	2026 / 27	2027 / 28	2028 / 29	2029 / 30	2030 / 31	2031 / 32	2032 / 33	Column2
OLKARIA IV	140	18	hired 1&2	6	10	2	Com.																					18
OLKARIA I	140	23	hired 3	2	5	13	3	Com.																				23
MENENGAI I	140	41	GDC 1-3		6	15	15	5	Com.																			41
MENENGAI II	140	40	GDC 3-6				10	15	15	Com.																		40
MENENGAI III	140	40	GDC 1-3					10	15	15		Com.																40
MENENGAI IV	140	40	GDC 3-6							15	15	10	Com.															40
MENENGAI V	140	40	GDC 1-3								15	15	10	Com.														40
MENENGAI VI	140	40	GDC 3-6									5	15	15	5	Com.												40
LONGONOT I	140	41	GDC 6,7,8			5	5	10	10	10	1	Com.																41
LONGONOT II	140	40	GDC 6,7,8								9	10	15	6		Com.												40
LONGONOT III	140	40	GDC 6,7,8											9	15	15	1	Com.										40
LONGONOT IV	140	40	GDC 6,7,8														14	15	11	Com.								40
SILALI I	140	41	GDC 5,11,12			5	5	10	10	10	1	Com.																41
SILALI II	140	40	GDC 5,11,12								9	10	10	11	Com.													40
SILALI III	140	40	GDC 5,11,12											4	15	15	6	Com.										40
SILALI IV	140	40	GDC 5,11,12														9	15	15	1	Com.							40
SILALI V	140	40	GDC 5,11,12																	9	10	10	10	1	Com.			40
PAKA I	140	41	GDC 8,11,12				5	10	10	10	6	Com.																41
PAKA II	140	40	GDC 8,11,12								4	10	10	15	1	Com.												40
PAKA III	140	40	GDC 8,11,12												14	15	11	Com.										40
KOROSI I	140	41	GDC 8,11,12														4	15	15	7	Com.							41
KOROSI II	140	40	GDC 8,11,12																	8	15	15	2	Com.				40
KOROSI III	140	40	GDC 8,11,12																				13	15	12	Com.		40
Emuruangogolak I	140	41	GDC 4,6,9												5	5	5	5	5	10	6	Com.						41
Emuruangogolak II	140	40	GDC 4,6,9																		5	10	10	10	5	Com.		40
BARRIER I	140	41	GDC 5,7,10																4	10	10	10	7	Com.				41
SUSWA I	140	41	hired 1&2												5	10	10	10	6	Com.								41
SUSWA II	140	40	GDC 6,7,10																4	15	15	6	Com.					40
ARUS BOGORIA	140	41	GDC 1-3																			9	15	15	2	Com.		41
	4060	1130	Wells	8	21	40	43	60	60	60	60	60	60	60	60	60	60	60	60	60	61	60	57	41	19	0	0	1130
		Cummulative MWe		0	0	0	140	140	140	140	0	560	140	140	140	420	0	420	0	280	280	140	140	280	140	420	0	4060

ANNEX 3: DISTRIBUTED LOAD FORECAST BY SUBSTATIONS

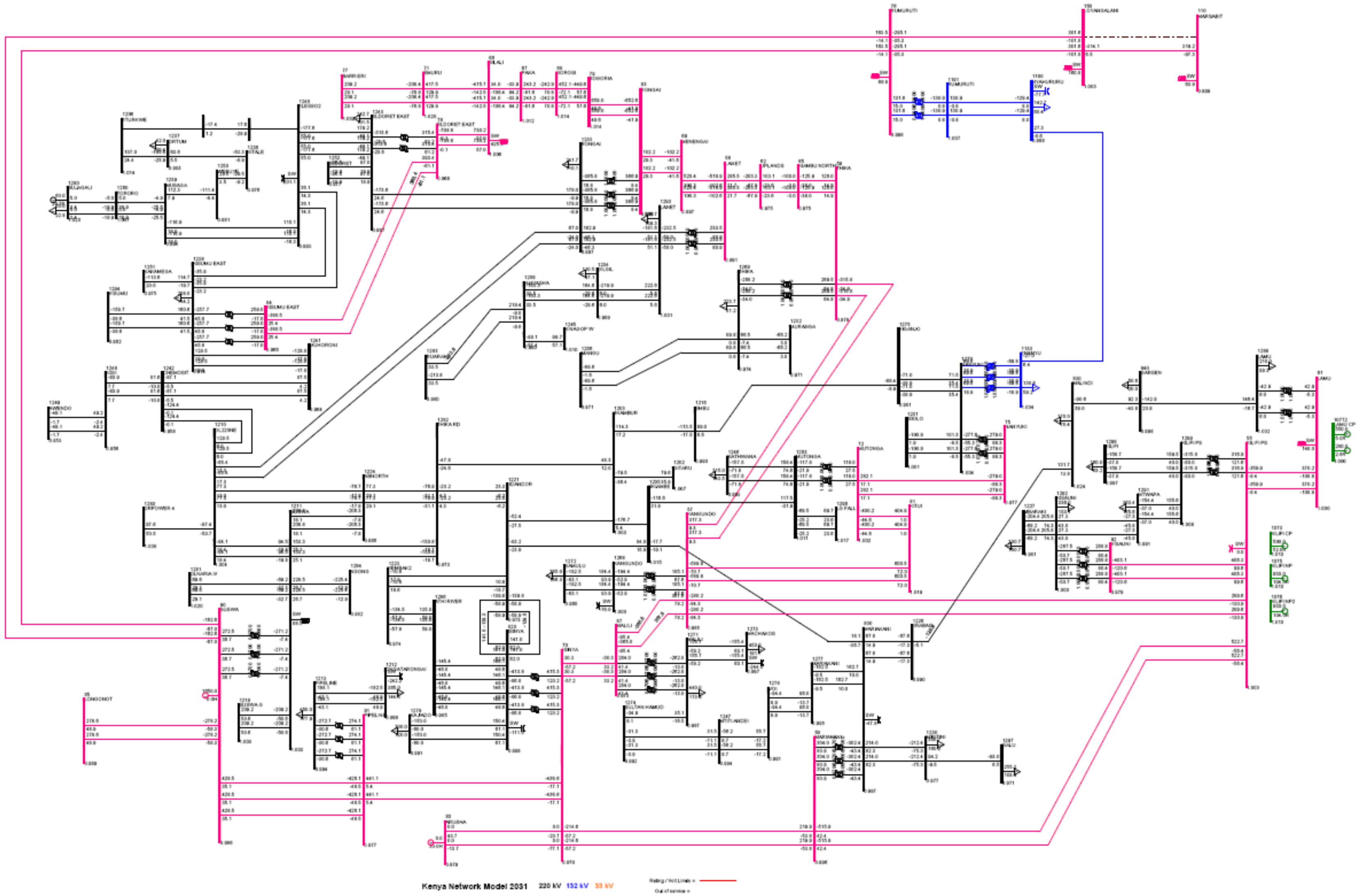
	2015		2020		2025		2030		2031	
Bus Name	MW	MVar	MW	MVar	MW	MVar	MW	MVar	MW	MVar
MALILI	91	36	166	66	276	109	439	173	440	174
KAJIADO	34	13	68	27	134	54	274	110	300	120
MAGADI	12	6	22	10	39	18	55	25	60	27
RUARAKA	75	33	134	59	231	102	394	175	427	189
THIKAROAD	148	67	251	114	434	198	394	180	427	195
GATUNDU	8	4	13	6	23	11	42	19	47	22
KIAMBU	0	0	0	0	0	0	415	189	450	205
NAIROBI NORTH	121	49	216	87	373	150	415	167	450	181
UPLANDS	0	0	0	0	0	0	269	107	365	144
NGONG	125	49	223	88	386	152	415	164	450	178
PIPELINE	0	0	0	0	0	0	386	152	450	178
ONGATA RONGAI	0	0	0	0	0	0	269	107	365	144
JUJA ROAD 66	231	106	412	190	312	143	300	138	350	161
DANDORA	147	67	263	120	329	150	415	189	450	205
KAMULU	0	0	0	0	235	107	269	123	365	166
EMBAKASI	133	58	237	103	312	135	415	180	450	195
ATHI RIVER	116	50	208	89	311	132	415	177	450	192
MACHAKOS	0	0	0	0	331	141	415	177	450	192
TOTAL NAIROBI	1,241	538	2,214	959	3,726	1,603	5,996	2,550	6,746	2,868
MALINDI	24	9	45	18	92	36	150	59	178	70
GARSEN	6	2	10	4	20	8	45	18	51	20
KILIFI 132	24	9	54	21	36	14	69	27	76	30
KILIFI 220	0	0	0	0	70	28	140	55	160	63
BAMBURI	51	23	103	47	50	23	97	45	100	46
KISAUNI	0	0	0	0	147	67	300	137	336	153
SULTAN HAMUD	13	5	26	10	50	20	102	40	115	45
KIBOKO	2	1	5	2	9	3	19	6	21	7
MTITU ANDEI	4	2	8	4	15	7	30	15	34	17
VOI	4	2	8	3	16	6	32	13	36	14
MAUNGU	3	2	7	3	13	6	26	12	29	13
MARIAKANI	16	8	33	17	64	32	129	65	145	73
KIPEVU	176	86	163	79	156	76	294	143	331	161
MIRITINI	0	0	0	0	156	76	294	142	331	160
MBARAKI	0	0	171	78	156	71	294	134	331	151

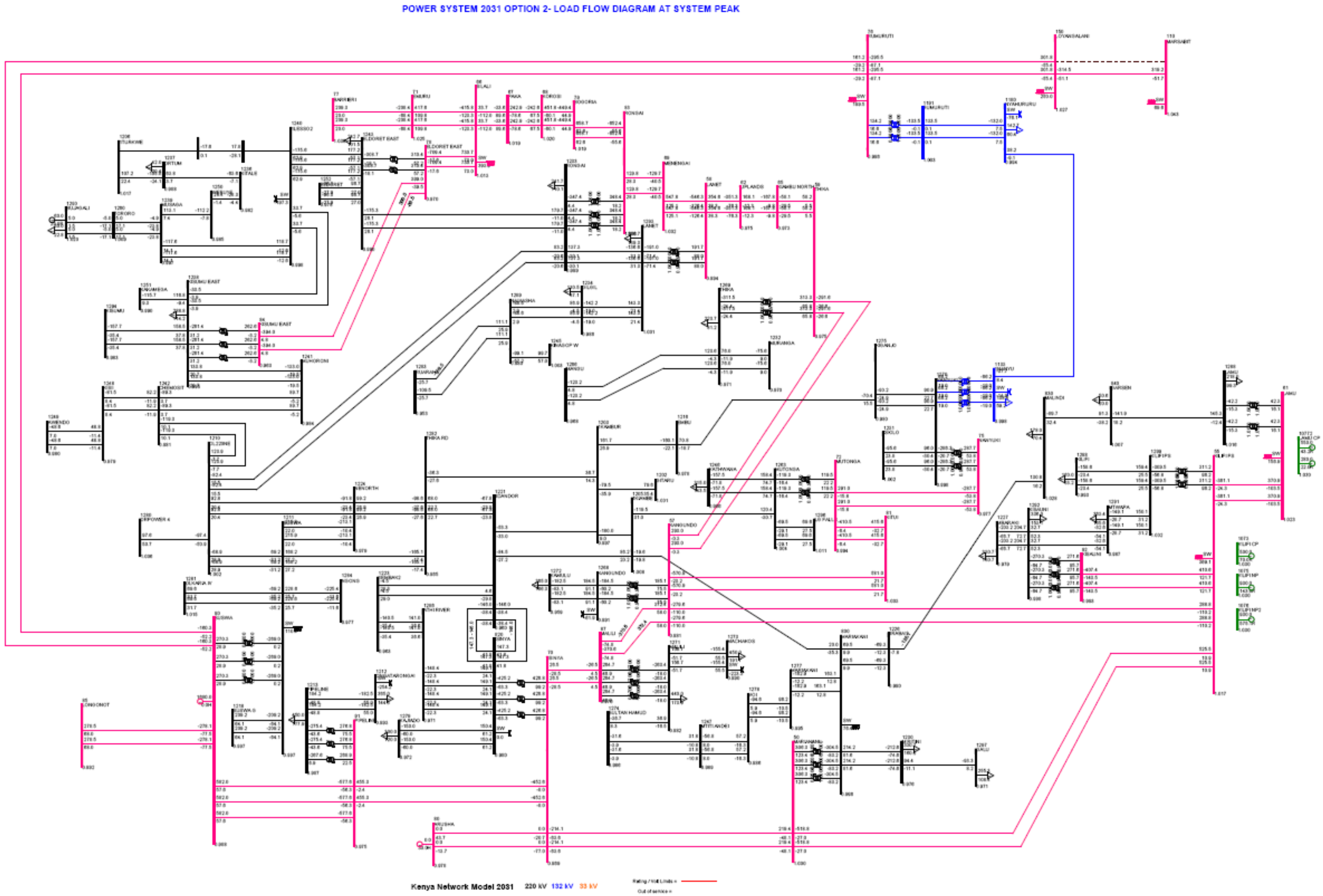
	2015		2020		2025		2030		2031	
Bus Name	MW	MVar	MW	MVar	MW	MVar	MW	MVar	MW	MVar
MTWAPA	0	0	0	0	156	71	323	147	363	166
RABAI	23	9	42	0	81	33	177	72	200	82
DIANI	27	12	61	26	118	50	227	96	255	108
TAVETA	3	1	6	2	11	4	25	9	28	10
WOTE	4	2	7	3	14	6	31	12	35	14
LAMU	32	14	63	29	112	51	194	88	218	99
TOTAL COAST	413	187	813	346	1,542	688	2,997	1,336	3,373	1,503
TANA	1	0	1	0	2	0	4	1	4	1
MANGU	81	29	120	43	214	77	196	70	223	80
THIKA 220	0	0	0	0	0	0	196	71	224	81
KIGANJO	43	17	63	24	120	47	249	97	284	111
NANYUKI	18	8	31	13	49	21	122	52	139	59
GITHAMBO	8	3	20	7	38	14	77	28	88	32
MURANGA	10	4	27	11	50	20	101	40	116	46
KYENI	15	6	19	7	40	15	75	28	85	31
EMBU (KUTUS)	26	10	38	15	70	28	148	59	170	68
MERU	22	9	38	16	60	26	147	63	169	72
THARAKA	0	0	133	61	226	103	315	144	315	144
ISIOLO	7	3	41	17	87	37	165	70	191	81
MWINGI	10	4	17	7	40	16	61	24	70	28
KITUI	10	4	17	7	40	16	61	24	70	27
GARISSA	7	3	10	4	16	6	25	10	30	12
MOUNT KENYA	256	99	573	232	1,052	425	1,939	780	2,177	874
LANET	81	37	70	32	149	68	272	124	307	139
RONGAI	0	0	56	26	118	54	214	98	242	110
NAIVASHA	34	14	48	21	91	39	188	80	212	90
GILGIL	0	0	32	14	54	23	98	42	111	47
NAROK	12	5	25	10	42	17	76	31	86	35
MAKUTANO	10	4	19	8	36	15	66	28	74	32
NYAHURURU	21	9	41	17	70	29	127	54	143	60
CENTRAL RIFT	157	69	292	127	560	245	1,040	455	1,174	514
WEBUYE	9	4	18	8	34	16	62	29	70	33
MUSAGA	16	8	13	6	38	19	75	37	85	42
BUNGOMA	0	0	13	6	30	14	75	34	85	39
KAKAMEGA	0	0	15	7	50	23	108	49	121	55

	2015		2020		2025		2030		2031	
Bus Name	MW	MVar	MW	MVar	MW	MVar	MW	MVar	MW	MVar
KISUMU	76	30	135	54	256	101	256	101	289	114
KISUMU EAST	0	0	0	0	0	0	256	101	289	114
BOMET	5	2	10	4	18	7	43	17	49	19
CHEMOSIT	38	15	74	29	140	55	254	100	286	113
KISII	16	7	31	13	59	25	107	45	121	51
AWENDO	13	6	15	6	36	15	90	38	101	43
MIGORI	0	0	8	3	13	5	32	14	36	15
MUHORONI	23	10	45	20	49	22	80	35	90	39
RANGALA	19	8	36	16	69	30	125	54	140	60
WEST KENYA	214	89	413	172	791	331	1,562	655	1,761	738
ELDORET	37	16	73	31	55	23	108	46	121	52
ELDORET EAST	0	0	0	0	110	46	216	90	243	101
KABARNET	12	5	24	10	46	18	82	32	91	36
LESSOS	17	7	33	13	71	28	80	31	90	35
KITALE	24	9	46	18	88	35	154	61	173	68
ORTUM	15	7	22	11	32	15	41	20	42	20
TOTAL NORTH RIFT	105	44	199	83	402	166	681	281	760	313
TOTAL WEST KENYA	476	202	904	383	1,753	743	3,283	1,391	3,694	1,566
WAJIR	0	0	6	3	12	5	25	11	30	13
MARSABIT	0	0	6	3	12	5	25	11	30	13
LOIYANGALANI	0	0	2	1	4	2	8	4	10	4
NORTH KENYA	0	0	14	6	29	12	58	25	70	30
GRAND TOTAL	2,386	1,026	4,519	1,926	8,102	3,471	14,273	6,082	16,061	6,810

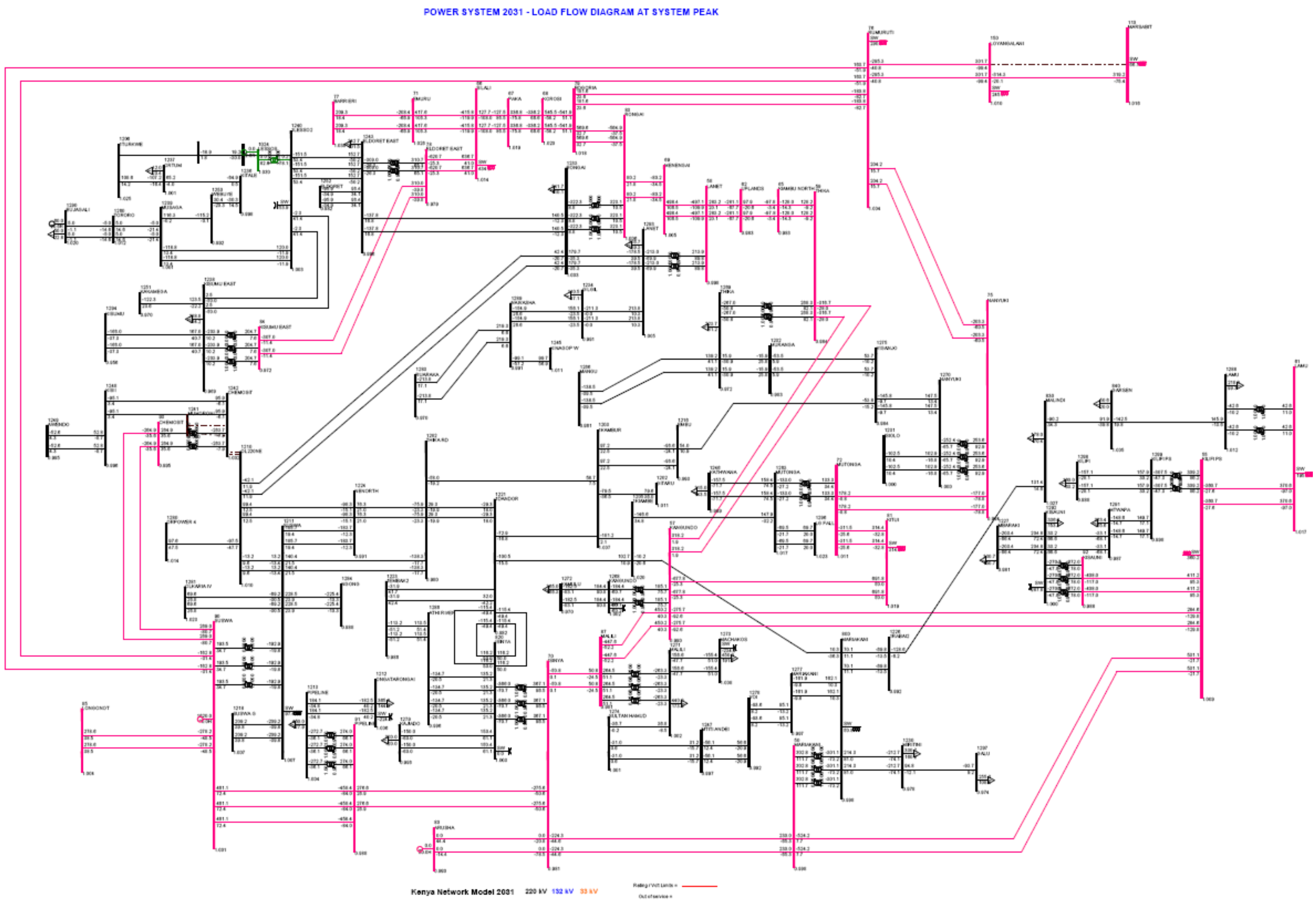
ANNEX 4: 2031 TARGET NETWORKS LOAD FLOW DIAGRAMS

POWER SYSTEM 2031 OPTION 1 - LOAD FLOW DIAGRAM AT SYSTEM PEAK



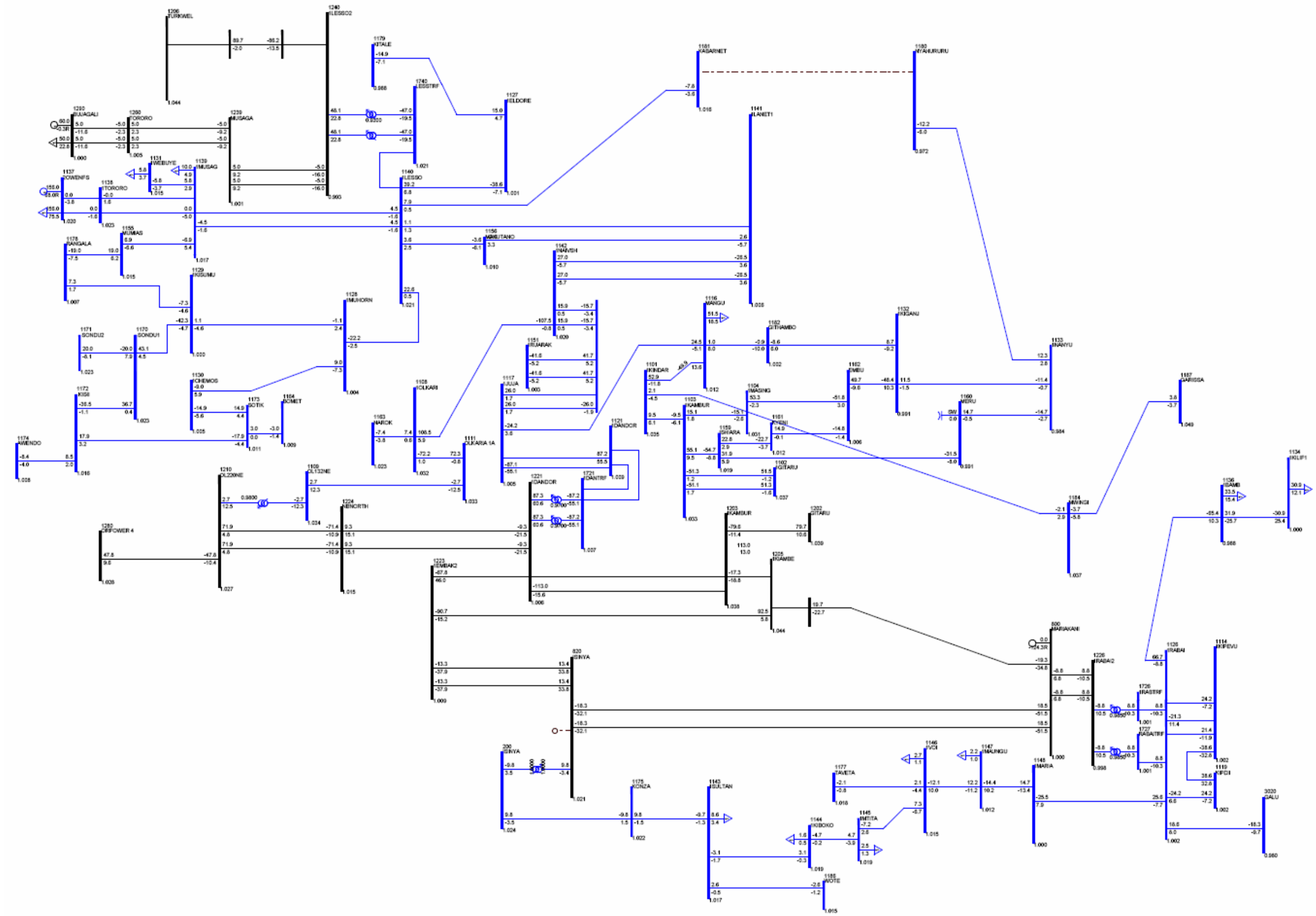


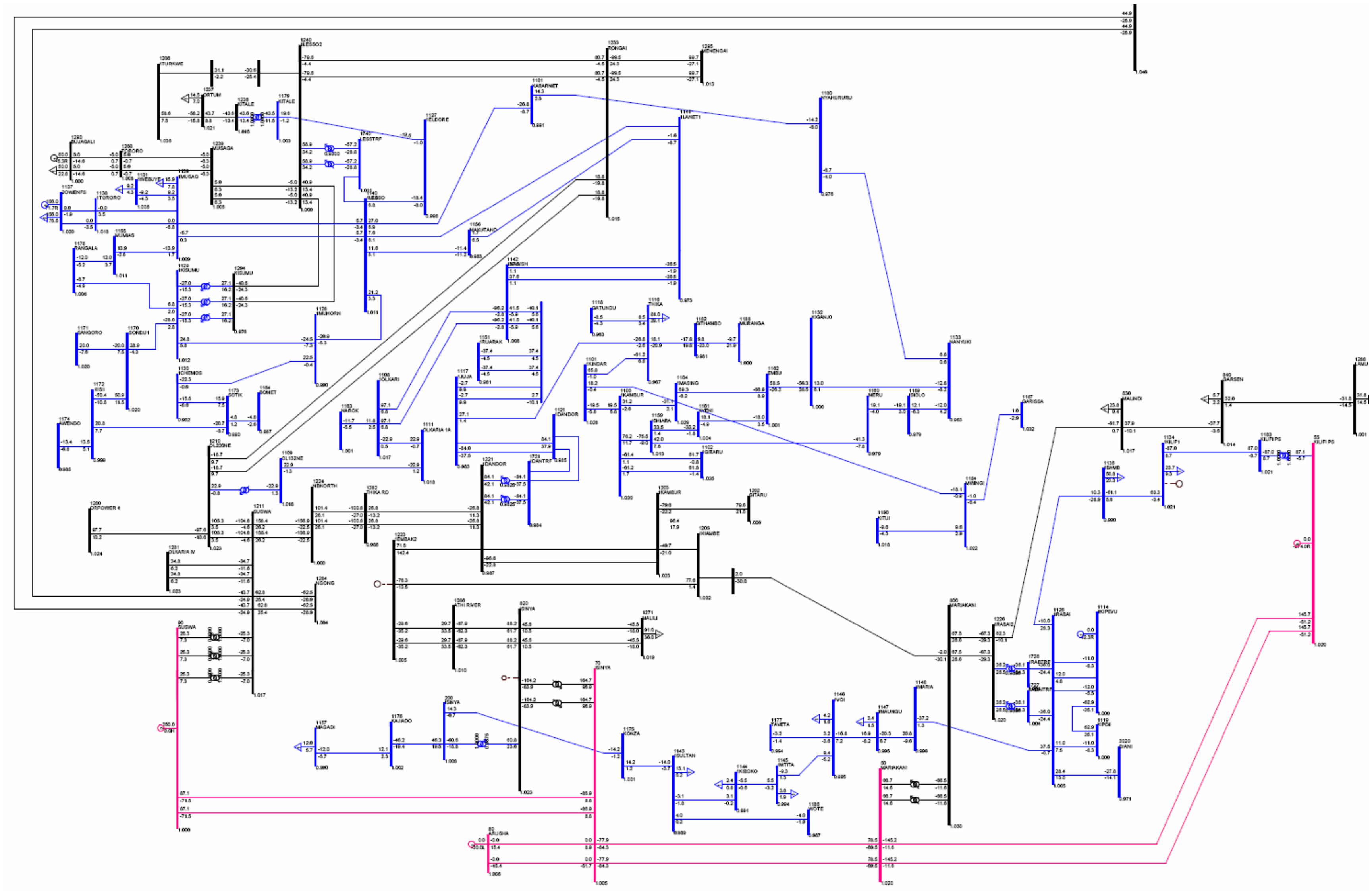
Target network 2 diagram

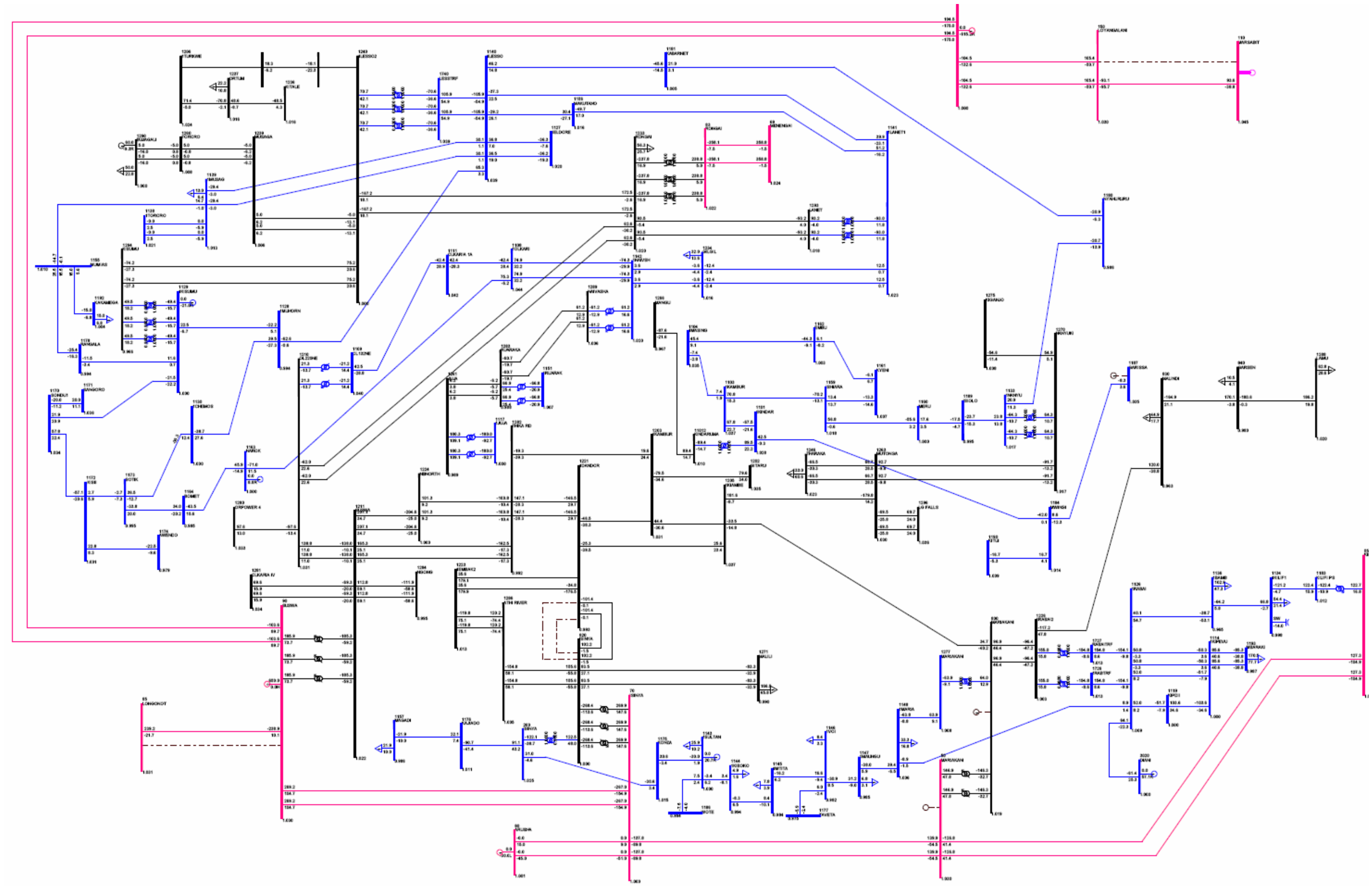


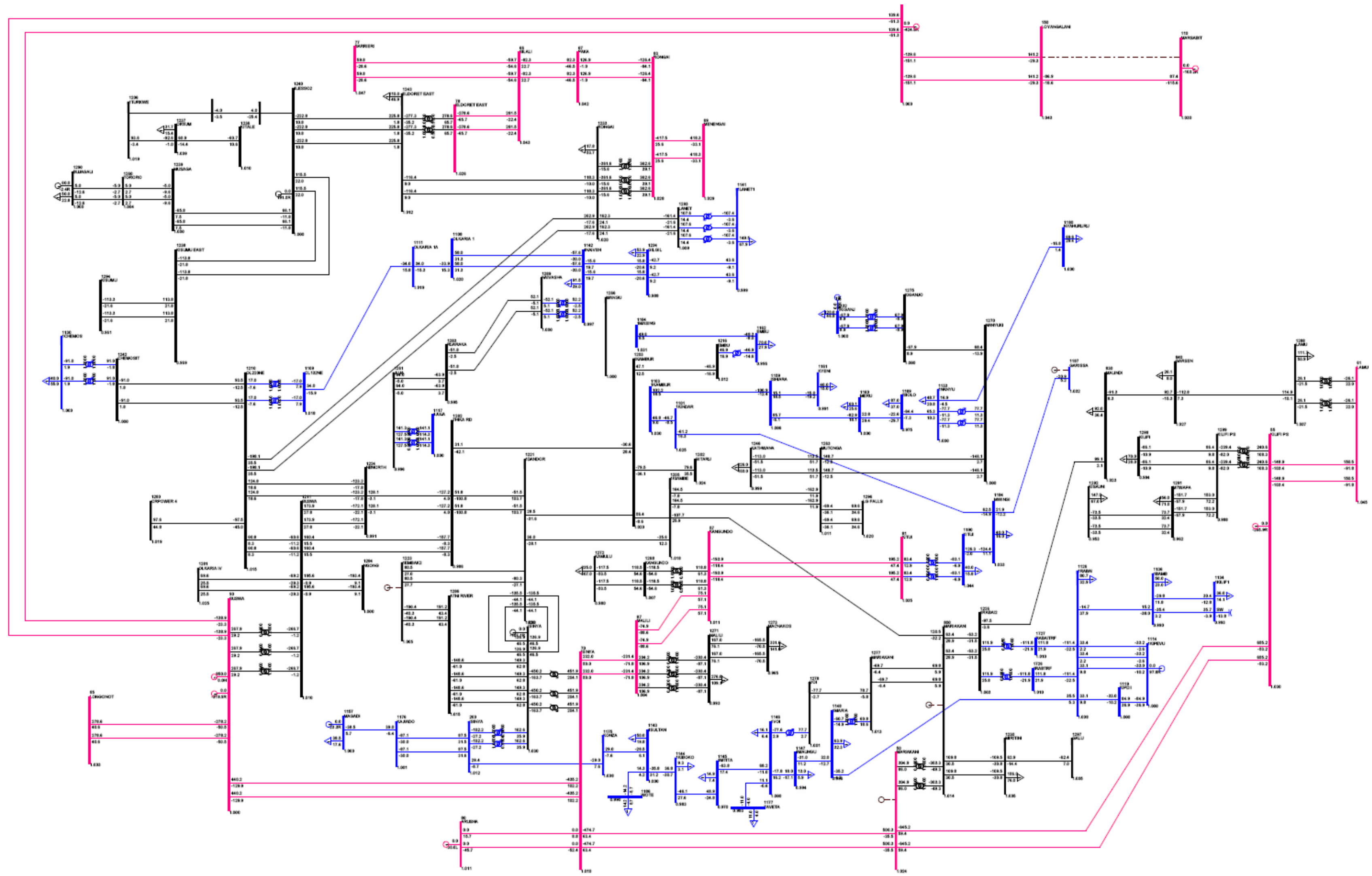
Target network 3 diagram

ANNEX 5: System configuration 2012, 2015, 2020, 2025, 2030 and 2031 Network Load flow diagrams

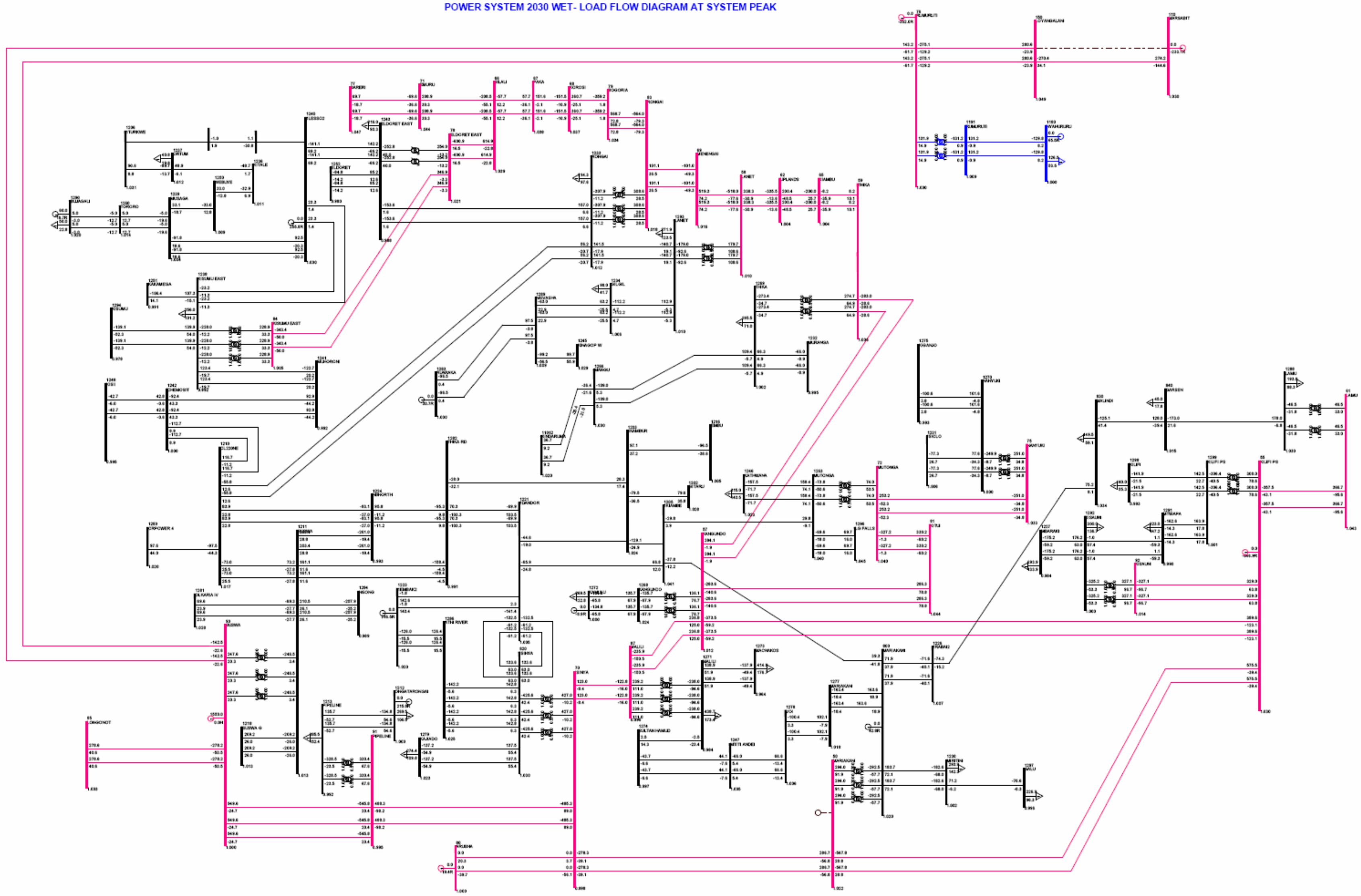




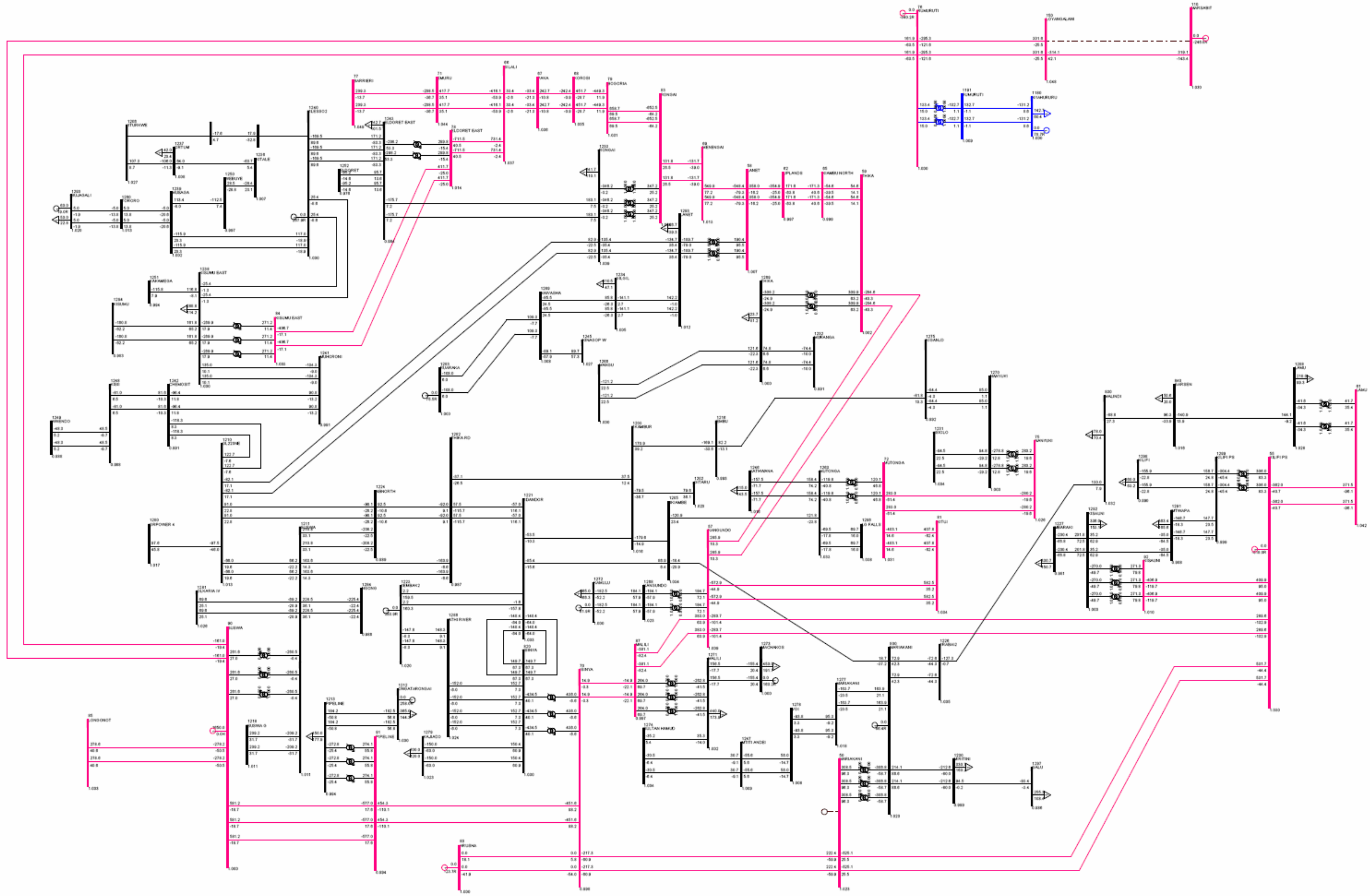




POWER SYSTEM 2030 WET- LOAD FLOW DIAGRAM AT SYSTEM PEAK



POWER SYSTEM 2031 - LOAD FLOW DIAGRAM AT SYSTEM PEAK



Annex 6: Generation Data for Dry Hydrology

YEAR	PLANT LOCATION	CAPACITY (MW)	REGION	PLANT TYPE
2015	Menengai 1,2	280	6	GEOTH
2020	Athi River	160	2	MSD
	Lamu	300	4	COAL
	Mariakani	180	4	GT
	Mariakani	180	4	GT
	Grand Falls	70	5	HYDRO
	Menengai 3,4	280	6	GEOTH
	Menengai 5,6	280	6	GEOTH
	Longonot 1,2	280	6	GEOTH
	Lessos	160	8	MSD
	L. Turkana	100	9	WIND
	Marsabit	100	9	WIND
	Marsabit	100	9	WIND
2025	Isinya	180	2	GT
	Isinya	180	2	GT
	Lamu	300	4	COAL
	Malindi	100	4	WIND
	Malindi	100	4	WIND
	Kilifi	1,000	4	NUCL
	Mutonga	30	5	HYD
	Kitui	300	5	COAL
	Kitui	300	5	COAL
	Longonot 3	140	6	GEOTH
	Longonot 4	140	6	GEOTH
	Silali 1,2	280	6	GEOTH
	Paka 1,2	280	6	GEOTH
	Paka 3, Barrieri 1	280	6	GEOTH
	Kisii	160	7	MSD
	Eldoret	160	8	MSD
2030	Lamu	600	4	COAL
	Galu	160	4	MSD
	Kilifi	1,000	4	NUCL
	Malindi	160	4	MSD
	Machakos	160	5	MSD
	Kitui	900	5	COAL
	Isiolo	180	5	GT
	Thika	180	5	GT
	Silali 3,4,5	420	6	GEOTH
	Korosi 1,2,3	420	6	GEOTH
	Emuruango 1,2	280	6	GEOTH

YEAR	PLANT LOCATION	CAPACITY (MW)	REGION	PLANT TYPE
	Suswa 1,2,3	420	6	GEOTH
	ArusBogoria 1,2,3	420	6	GEOTH
	Kinangop	200	6	WIND
	Kisumu	180	7	GT
	Kakamega	160	7	MSD
	Marsabit	100	9	WIND
	Marsabit	300	9	WIND
2031	Kitui	900	5	COAL
	Emuruango 3, Barrier 2,3	420	6	GEOTH
	Lanet	320	6	MSD
	Kisumu	360	7	GT
	Marsabit	100	9	WIND

ANNEX 7 : COMPARISON OF ALTERNATIVE NETWORK SEQUENCE LOSSES

INVESTMENT SEQUENCE OPTION 3

	2012	2013	2014	2015	2020	2025	2030	2031
VOLTAGE LEVEL	MW	MW	MW	MW	MW	MW	MW	MW
	WET	WET	WET	WET	WET	WET	WET	WET
400			5	3	17	78	188	225
220	12	15	17	13	43	109	138	168
132	20	25	30	16	30	46	63	75
TOTAL (MW)	32	40	51	32	90	234	388	468
ENERGY LOSS (MWH/Y)	154,193	194,788	248,754	154,484	435,210	1,131,672	1,879,484	2,265,621

INVESTMENT SEQUENCE OPTION 1

	2012	2013	2014	2015	2020	2025	2030	2031
VOLTAGE LEVEL	MW	MW	MW	MW	MW	MW	MW	MW
	WET	WET	WET	WET	WET	WET	WET	WET
400			5	3	14	117	207	235
220	12	15	17	23	67	115	163	189
132	20	25	30	32	52	58	76	89
TOTAL (MW)	32	40	51	58	132	289	446	513
ENERGY LOSS (MWH/Y)	154,193	194,788	248,754	281,598	639,251	1,402,371	2,162,535	2,483,856

INVESTMENT SEQUENCE OPTION 1

	2012	2013	2014	2015	2020	2025	2030	2031
VOLTAGE LEVEL	MW	MW	MW	MW	MW	MW	MW	MW
	WET	WET	WET	WET	WET	WET	WET	WET
400			5	3	14	107	210	238
220	12	15	17	22	70	139	148	180
132	20	25	30	32	46	64	73	88
TOTAL (MW)	32	40	51	57	131	310	430	505
ENERGY LOSS (MWH/Y)	154,193	194,788	248,754	276,076	634,407	1,501,049	2,085,172	2,447,912

ANNEX 8 : TRANSMISSION SYSTEM FAULT LEVELS

The table below is a summary of fault level calculations for the recommended transmission development plan

			2013		2014		2015		2020		2025		2030		2031	
BUS NO	BUS NAME	VOLTAGE	WET	DRY	WET	DRY	WET	DRY	WET	DRY	WET	DRY	WET	DRY	WET	DRY
		KV	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS	AMPS
200	ISINYA	132	3169	3206	3203	3242	12209	13006	12894	12889	14920	15143	17236	17232	17532	17536
1101	1KINDAR	132	9067	9151	8975	9057	9824	9934	9792	9790	11818	11812	13183	13183	13302	13306
1102	1GITARU	132	11220	11335	11123	11238	12108	12285	12216	12221	13361	13346	14980	14974	15101	15110
1103	1KAMBUR	132	12880	13047	12773	12924	14248	14527	14483	14493	16410	16423	19275	19294	19520	19549
1104	1MASING	132	6712	6779	6653	6719	7670	7768	7473	7488	8196	8209	8905	8930	8945	8974
1108	1OLKARI	132	9814	9880	9757	9859	12706	12955	12374	12374	13136	13148	14369	14369	14600	14599
1109	OL132NE	132	8422	8476	8379	8470	11318	11495	11220	11221	11857	11875	12818	12818	13008	13007
1110	DOMES	132	6094	6122	6060	6105	6980	7053	6908	6909	7091	7101	7453	7453	7532	7532
1111	OLKARIA 1A	132	9047	9106	9000	9094	11750	11951	11551	11552	12214	12229	13252	13252	13453	13452
1114	1KIPEVU	132	7738	9196	8892	8924	10188	10786	12449	13266	15401	16199	17094	17916	17259	18061
1116	MANGU	132	5933	6030	5638	5753	6777	6824	8150	8148	8130	8122	17782	17789	17577	17589
1117	1JUJA	132	12329	12786	11958	12501	15075	15370	13741	13745	13561	13645	14624	14625	14815	14819
1118	GATUNDU	132	3423	3467	3289	3341	3720	3735	4104	4102	4101	4094	5626	5629	5637	5642
1119	KIPDII	132	7738	9196	8892	8924	10188	10786	12449	13266	15401	16199	17094	17916	17259	18061
1121	1DANDOR	132	12436	12890	12116	12650	15269	15584	14156	14161	14186	14279	15373	15374	15583	15588
1126	1RABAI	132	7590	9118	9025	9065	11322	12181	14126	14768	17404	17992	20090	20668	20368	20951
1127	1ELDORE	132	2960	2962	3498	3499	5789	6104	6787	6778	9300	9285	10670	10697	10924	10945
1128	1MUHORN	132	4329	4326	4156	4160	4946	5278	6067	6068	6516	6521	7385	7394	7485	7489
1129	1KISUMU	132	6041	6047	5607	5626	6702	7239	6945	6943	7870	7865	10382	10403	10852	10866
1130	1CHEMOS	132	3356	3348	3263	3259	3931	4297	7207	7211	7593	7599	9636	9630	9722	9713
1131	1WEBUYE	132	3265	3265	3206	3209	4327	4427	4187	4187	8482	8467	9525	9538	9702	9712
1132	1KIGANJ	132	3156	3191	3086	3120	4635	4740	6729	6733	7455	7449	9997	10010	10167	10183
1133	1NANYU	132	2124	2144	2107	2127	3855	4033	8651	8644	10852	10834	25353	25342	25935	25923
1134	1KILIF1	132	1698	1785	4754	4782	4080	4151	6304	6349	7056	7096	7937	7948	8051	8087
1135	GILGIL	132					8393	8506	7905	7905	8374	8381	9666	9670	9852	9854
1136	1BAMB	132	3572	3907	5024	5046	6791	7062	6522	6601	7093	7160	7623	7650	7695	7758
1138	1TORORO	132	3987	3987	3941	3943	4701	4760	4605	4606	4939	4945	5089	5096	5113	5118
1139	1MUSAG	132	5084	5085	4963	4970	8162	8529	7715	7711	10082	10062	11683	11702	11935	11949
1140	1LESSO	132	6929	6939	6668	6694	10088	10670	9984	9973	12448	12409	15050	15092	15539	15572
1141	1LANET1	132	4663	4680	4603	4629	9768	9948	9620	9619	10584	10587	13555	13562	14000	14005
1142	1NAIVSH	132	8597	8675	8514	8623	11209	11386	10663	10663	11482	11489	13536	13538	13833	13833
1143	1SULTAN	132	1429	1447	1444	1456	1840	2317	1872	1868	4612	4628	4831	4826	4870	4876
1144	1KIBOKO	132	1268	1285	1278	1288	1518	1802	1559	1555	2938	2945	3021	3016	3052	3056
1145	1MTITA	132	1199	1220	1206	1214	1337	1565	1406	1403	4123	4132	4289	4282	4335	4343
1146	1VOI	132	1437	1478	1454	1461	1564	2023	1732	1729	4561	4574	4717	4709	4778	4791
1147	1MAUNGU	132	1631	1687	1656	1664	1776	2150	2027	2025	3610	3620	3692	3685	3731	3742

1148	1MARIA	132	4062	4468	4385	4402	4906	5245	8766	8908	10047	10163	11005	11065	11143	11246
1149	BUNGOMA	132	11074	11435	10780	11210	3776	3844	3392	3393	3788	3796	3957	3965	3983	3989
1151	1RUARAK	132	10541	10872	10267	10663	12601	12804	4458	4459	4621	4626	5313	5315	5308	5308
1155	MUMIAS	132	4104	4104	4007	4011	5007	5302	4922	4922	6362	6363	7598	7606	7714	7719
1156	MAKUTANO	132	3134	3139	3080	3090	6140	6256	6086	6085	6555	6561	7295	7310	7423	7435
1157	MAGADI	132	1211	1219	1228	1240	1730	2166	1751	1748	1781	1790	1812	1812	1825	1825
1159	ISHIARA	132	5060	5106	5013	5059	6120	6324	6034	6037	6689	6687	7365	7377	7403	7419
1160	MERU	132	2084	2102	2069	2087	2631	3072	3046	3045	3992	3984	4700	4701	4711	4713
1161	KYENI	132	3972	4008	3932	3968	5407	5532	5020	5022	5809	5806	6342	6351	6373	6385
1162	EMBU	132	4269	4313	4214	4257	8179	8344	5699	5702	9184	9183	10918	10929	11041	11057
1163	NAROK	132	2796	2796	2756	2758	5307	5522	5224	5225	5336	5336	5655	5654	5700	5697
1164	BOMET	132	2680	2672	2622	2616	4152	4629	4821	4823	4956	4954	5629	5626	5679	5673
1165	MIGORI	132					1479	2434	1554	1555	1571	1570	2546	2544	2563	2559
1166	MARSABIT	132							2656	2656	2735	2736	3038	3038	3025	3025
1167	WAJIR	132					713	713	318	318	340	341	341	341	410	410
1170	SONDU1	132	4344	4334	4224	4219	4697	5292	4988	4989	5174	5164	6154	6146	6196	6184
1171	SANGORO	132	4011	4001	3906	3900	4305	4790	4541	4542	4688	4678	5464	5455	5493	5480
1172	KISII	132	3230	3221	3157	3151	3754	5169	4281	4282	4405	4401	7203	7197	7274	7266
1173	SOTIK	132	3389	3378	3305	3297	4376	5127	5584	5586	5793	5790	7000	6995	7070	7062
1174	AWENDO	132	1747	1741	1714	1710	1966	4123	2102	2103	2120	2118	4371	4367	4383	4377
1175	KONZA	132	1958	1980	1980	2000	3198	3541	3249	3244	4305	4329	4476	4473	4514	4518
1176	KAJIADO	132	2690	2718	2724	2755	7324	7839	7551	7543	8199	8280	8855	8853	8957	8960
1177	TAVETA	132	729	743	729	732	764	860	804	801	1139	1140	1129	1125	1140	1143
1178	RANGALA	132	3515	3516	3415	3419	3882	4343	3884	3884	4292	4297	4851	4859	4886	4891
1179	KITALE	132	1497	1497	2622	2622	3286	3766	3392	3380	5269	5254	5548	5558	5608	5614
1180	NYAHURURU	132	1105	1115	1100	1111	6554	6647	7028	7017	7355	7339	8196	8200	8357	8362
1181	KABARNET	132	1984	1984	1956	1958	3552	3592	3609	3607	3776	3777	3845	3856	3841	3850
1182	GITHAMBO	132	3205	3239	3120	3160	3762	3790	4313	4313	4440	4433	5776	5779	5855	5861
1184	MWINGI	132	3409	3429	3379	3400	3663	3679	3541	3540	7382	7404	8158	8166	8320	8327
1185	AEOLUS	132	3546	3565	3509	3535	4325	4348	4252	4252	4342	4345	4564	4565	4602	4603
1186	WOTE	132	1077	1088	1086	1095	1302	1525	1323	1320	2269	2275	2331	2328	2357	2360
1187	GARISSA	132	759	761	754	757	1006	1007	769	768	846	848	861	862	1510	1511
1188	MURANGA	132	2878	2908	2820	2853	3555	3597	5626	5627	6347	6339	8848	8853	8757	8765
1189	ISIOLO	132	1983	2001	1969	1988	2711	2991	3509	3507	6157	6144	8771	8769	8867	8865
1190	KITUI	132	2194	2205	2175	2186	2825	2834	2759	2758	8610	8637	10188	10192	10581	10584
1191	RUMURUTI	132					7518	7623	8087	8079	8527	8520	10035	10037	10279	10283
1192	KAKAMEGA	132					2741	2821	2715	2716	4634	4639	6232	6237	6341	6344
1193	MBARAKI	132					7916	8277	9339	9774	12071	12503	13237	13623	13364	13782
1194	GALU	132	2288	2435	2365	2372	2535	2584	2681	2697	4458	4485	4912	4912	4919	4949
1703	1KAMTRF	132	12876	13043	12763	12913	14282	14568	14480	14493	16463	16482	19306	19330	19547	19580
1721	1DANTRF	132	12327	12783	11969	12509	15076	15373	13813	13819	13681	13766	14753	14755	14948	14953
1726	1RABTRF	132	7994	9754	9578	9621	11980	13002	15184	15988	19096	19858	22004	22783	22238	23005

1727	RABAITRF	132	7994	9754	9578	9621	11980	13002	15184	15988	19096	19858	22004	22783	22238	23005
1740	LESSTRF	132	6929	6939	6668	6694	10088	10670	9984	9973	12448	12409	15050	15092	15539	15572
800	MARIAKANI	220	3814	4097	5340	5390	7701	8029	9452	9660	12259	12457	15153	15313	15448	15615
820	ISINYA	220	8229	8555	8050	8337	13494	14226	14802	14816	18904	19496	26506	26500	27358	27361
830	MALINDI	220	1273	1323	1374	1380	1507	1528	2087	2093	3213	3222	3871	3876	3917	3924
840	GARSEN	220	845	871	884	888	939	948	1638	1640	2913	2918	3195	3197	3212	3215
906	TURKLIN	220	2068	2069	2359	2362	2633	2754	2625	2622	3278	3279	3439	3441	3464	3465
940	LESSOLI	220	6043	6057	4818	4853	7540	7966	6852	6844	9676	9614	12584	12611	13158	13181
1202	GITARU	220	7111	7211	7096	7190	7867	7992	7975	7972	8937	8933	10565	10566	10690	10699
1203	1KAMBUR	220	8480	8627	8477	8611	9662	9861	9860	9857	11524	11529	14537	14539	14803	14815
1205	1KIAMBE	220	6516	6620	6548	6628	7207	7304	8424	8417	9057	9045	11876	11877	11857	11868
1206	1TURKWE	220	2068	2069	2359	2362	2633	2754	2625	2622	3278	3279	3439	3441	3464	3465
1210	OL220NE	220	9054	9201	9159	9557	12971	13299	14152	14155	16533	16598	19576	19575	20065	20064
1211	SUSWA	220	9794	10035	10171	10898	13483	13866	15341	15352	19140	19279	24271	24267	24841	24838
1212	ONGATAR ONGAI	220											7570	7568	7633	7633
1213	PIPELINE	220											12253	12249	12475	12475
1216	EMBU	220					6537	6646			8252	8248	10728	10732	10908	10917
1218	SUSWA G	220									19140	19279	24271	24267	24841	24838
1221	1DANDOR	220	9841	10254	10034	10464	14155	14847	15306	15316	19018	19400	24638	24632	25350	25354
1223	1EMBAK2	220	9014	9488	9094	9461	12507	13142	13513	13520	16352	16673	20684	20676	21245	21249
1224	NBNORTH	220	8286	8507	8542	8943	12085	12422	13284	13286	15204	15308	17754	17750	18115	18113
1226	1RABAI2	220	3790	4123	4961	5000	7035	7433	8470	8728	10405	10633	12224	12421	12412	12623
1227	MBARAKI	220									7037	7100	9521	9563	9698	9749
1230	MIRITINI	220									8885	8989	10557	10622	10731	10816
1231	ISIOLO	220									5022	5011	9222	9218	9355	9351
1232	MURANGA	220							4145	4145	5680	5674	10849	10851	10970	10974
1233	RONGAI	220	5774	5814	5411	5508	8531	8741	10149	10144	13008	12986	23199	23206	24763	24769
1234	GILGIL	220							6383	6382	7160	7161	10335	10337	10753	10755
1236	KITALE	220			1663	1665	1968	2168	2003	2002	4037	4031	4366	4373	4425	4431
1237	ORTUM	220			1788	1791	2061	2221	2082	2081	3329	3332	3536	3541	3570	3574
1238	KISUMU EAST	220					4665	4922	4600	4599	5704	5694	10442	10460	11381	11395
1239	MUSAGA	220	3741	3747	3263	3278	5236	5444	4950	4947	6476	6455	7573	7583	7761	7768
1240	1LESSO2	220	6043	6057	4818	4853	7540	7966	6852	6844	9676	9614	12584	12611	13158	13181
1242	CHEMOSIT	220					1861	1990	4602	4602	4862	4863	7602	7597	7698	7690
1243	ELDORET EAST	220					6842	7121	6826	6816	10105	10053	13722	13752	14406	14432
1245	KINAGOP W	220							3617	3617			4937	4939	5027	5028
1246	KATHWAN A	220							4856	4852	5337	5328	9274	9272	8687	8688
1247	MTITI ANDEI	220									4295	4312	4595	4591	4653	4663
1248	KISII	220											5099	5094	5144	5136
1249	AWENDO	220											3931	3926	3957	3951
1250	WEBUYE	220									5092	5083	5719	5726	5825	5830
1251	KAKAMEGA	220									3431	3433	4594	4602	4737	4744

1252	ELDORET	220							5458	5451	7355	7334	8997	9019	9282	9300
1260	TORORO	220	2765	2768	2512	2520	3471	3554	3357	3356	3953	3947	4309	4313	4366	4369
1263	MUTONGA	220							5753	5748	6433	6424	13257	13255	12085	12086
1266	MANGU	220							4886	4885	4977	4973	10692	10696	11006	11013
1267	KIAMBU	220											8616	8614	8706	8707
1268	KANGUNDO	220									7051	7088	9487	9484	9767	9769
1269	THIKA	220							4315	4314	5034	5029	13645	13647	14026	14032
1270	NANYUKI	220							5191	5187	6514	6503	15228	15221	15577	15571
1271	MALILI	220					8355	8627	8900	8899	10186	10265	13952	13950	14214	14218
1272	KAMULU	220									5253	5275	6464	6462	6644	6646
1273	MACHAKOS	220									6714	6750	8589	8586	8672	8673
1274	SULTAN HAMUD	220									4706	4724	5153	5149	5218	5225
1275	KIGANJO	220							4424	4423	6992	6986	12514	12515	12766	12769
1277	MARIAKANI	220							8871	9056	11406	11578	13839	13970	14096	14240
1278	VOI	220									5103	5129	5486	5487	5569	5589
1279	KAJIADO	220					10958	11435	11846	11851	14390	14734	18402	18399	18857	18860
1280	ORPOWER 4	220	7675	7780	7781	8059	10276	10474	10979	10980	12283	12322	13796	13795	14045	14045
1281	OLKARIA IV	220	6661	6756	6214	7020	7822	7924	8308	8309	9081	9108	9855	9854	9962	9962
1282	THIKA RD	220	8809	9111	9031	9405	12574	13038	13646	13649	17476	17691	21248	21243	21708	21709
1283	RUARAKA	220							3324	3325	3486	3489	4142	4143	4196	4197
1284	NGONG	220	5943	6038	6029	6290	7236	7339	7578	7579	8393	8421	9227	9226	9336	9336
1285	UPLANDS	220											8434	8432	8625	8626
1286	ATHI RIVER	220	8450	8831	8435	8749	12386	12992	13359	13367	16401	16793	21565	21559	22156	22159
1288	LAMU	220	646	664	667	669	697	703	1657	1659	6054	6070	7363	7369	7455	7459
1289	NAIVASHA	220							5725	5725	6281	6283	8566	8568	8805	8806
1291	MTWAPA	220	1898	1899							5645	5670	11104	11144	11344	11387
1292	KISAUNI	220									8172	8242	12176	12231	12444	12499
1293	LANET	220					7114	7262	8313	8310	9879	9872	17991	17995	19525	19527
1294	KISUMU	220	3997	4000	3595	3608	4438	4699	4433	4432	5318	5311	8513	8526	9085	9093
1296	LG FALLS	220							4966	4961	5441	5433	9410	9406	8815	8815
1297	GALU	220									3362	3380	4160	4162	4200	4220
1298	KILIFI	220							5253	5295	6587	6624	9009	9034	9187	9219
1299	KILIFI PS	220							5929	5979	7822	7869	11929	11972	12191	12234
50	MARIAKANI	400			3850	3907	4748	4908	6008	6094	8446	8546	11346	11414	11677	11739
55	KILIFI PS	400			3609	3652	4118	4221	5003	5062	8245	8327	13204	13274	13679	13726
57	KANGUNDO	400									8006	8092	16943	16947	18319	18324
58	LANET	400											14130	14129	15001	15000
59	THIKA	400											14388	14386	15154	15154
61	LAMU	400									4454	4471	6009	6017	6080	6085
62	UPLANDS	400											12319	12317	12850	12849
65	KIAMBU NORTH	400											12902	12900	13470	13470
66	SILALI	400									5866	5849	11549	11554	12563	12567

67	PAKA	400									6033	6017	12561	12563	13568	13569
68	KOROSI	400									6059	6044	13226	13226	14265	14264
69	MENENGAI	400					3907	3982	4879	4877	6497	6484	14717	14717	15677	15676
70	ISINYA	400			4988	5190	7451	7784	8506	8517	11310	11530	18163	18164	19065	19068
71	EMURU	400									5168	5155	9275	9277	10155	10157
72	MUTONGA	400											8093	8085	11789	11778
75	NANYUKI	400											10118	10106	13212	13203
76	RUMURUTI	400					4944	5053	5645	5646	6530	6557	14592	14583	16589	16583
77	BARRIERI	400									4211	4202	6495	6496	7150	7151
78	ELDORET EAST	400									5024	5008	8037	8055	8537	8553
79	BOGORIA	400									6261	6247	15644	15641	16991	16988
81	KITUI	400									6053	6089	11798	11796	14815	14812
83	RONGAI	400					4058	4139	5008	5006	6817	6803	15238	15238	16331	16331
84	KISUMU EAST	400											6113	6127	6505	6516
85	LONGONOT	400							7663	7672	9509	9594	14119	14118	14681	14681
87	MALILI	400									9602	9743	16796	16799	17717	17721
90	SUSWA	400			5020	5263	7122	7364	8354	8365	10520	10629	16652	16651	17454	17454
91	PIPELINE	400					7117	7387	8200	8209	10457	10602	16259	16256	16957	16957
92	KISAUNI	400									6349	6406	9107	9146	9317	9349
93	CHEMOSIT	400											5800	5797	5897	5892
110	MARSABIT	400							2105	2105	2244	2245	3054	3054	3190	3190