REPUBLIC OF KENYA

UPDATED LEAST COST POWER DEVELOPMENT PLAN
STUDY PERIOD: 2017 - 2037

June 2018

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List of Acronyms

EAPP	East Africa Power Pool
ERC	Energy Regulatory Commission
ENS	Energy Not Served
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
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IPP	Independent Power Producer
ISO	Independent System Operator
KEEP	Kenya Energy Sector Environment and Social Responsibility
KEMP	Kenya Energy Modernization Project
KenGen	Kenya Electricity Generating Company Limited
KETRACO	Kenya Electricity Transmission Company
KNEB	Kenya National Electricity Board (KNEB)
KPLC	Kenya Power & Lighting Company Limited
KWh	Kilo Watt hour

LCPDP	Least Cost Power Development Plan
LIPS OP/XP	Lahmeyer International Short term optimization and long term Expansion
MOE	Ministry of Energy
MORDA	Ministry of Regional Development and Authority
MSD	Medium Speed Diesel
HSD	High Speed Diesel
MW	Mega Watt(s)
MWh	Megawatt Hour(s)
O & M	Operation and Maintenance
FOM	Fixed operations and maintenance costs
PPA	Power Purchase Agreement
REA	Rural Electrification Authority
SAPP	Southern African Power Pool
SPV	Special Purpose Vehicle
VOM	Variable Operation and Maintenance Costs

Acknowledgements

The Least Cost Power Development Plan is a Kenya Energy Sector Report intended to guide the sector on sector status, generation exapansion opportunities, transmission infrastructure target network expansion as well as resource requirements for the exapansion programme. The 2017-2037 report was conducted through very close collaboration between sector utilities with the direct coordination of the Energy Regulatory Commission (ERC).

Policy guidance is provided by the Ministry of Energy (MOE) while regulatory issues as well as secretariat services are provided by the Commission.

The report borrowed heavily on technical parameters as well as international benchmarks from the 2015-2035 Electricity Generation and Transmission report prepared by *Lahmeyer international*. Training in generation planning tools LIPs OP/XP was provided by experts from Lahmeyer international who are also appreciated

Special acknowledgements on their efforts and dedication is to the technical committee of the LCPDP, representatives from the Ministry of Energy and Petroleum (MOE), The Kenya Power and lighting company (KPLC), The Geothermal Development corporation (GDC), The Kenya Electricity Transmission Company (KETRACO), Kenya Electricity Generation Company (KENGEN), and the Kenya Nuclear Electricity Board (KNEB) and the Rural Electrification Authority (REA). Oversight and quality assurance is provided by an Oversight Committee chaired by Mr Pavel Oimeke, Director General Energy Regulatory Commission as well as senior management of sector utilities. Private sector representation and representation from other public institutions including Vision 2030 Secretariat as well as the Ministry of Devolution and Planning is appreciated.

Monitoring of committed projects in the sector involved gathering performance data from ongoing projects and each person who provided either facilitation or performance data is hereby acknowledged and highly appreciated.

This report includes a brief chapter on environmental dimensions of the plan. This was courtesy of the Climate Network Institute, Germany under the leadership of Mr Lucas Kahlen to who we are thankful and hope to develop a good working relationship in future endeavors

EXECUTIVE SUMMARY

Introduction

Section 5g of the Energy Act 2006 mandates the Energy Regulatory Commision to prepare indicative energy plans. The Commission in turn coordinates this function through the preparation of Bi-annual Least Cost Power Development Plans (LCPDPs) in conjunction with sector utilities.

Over the years, the process has been undertaken through preparation of either medium term or long term plans in alternating years. This current edition is a long term 20 year rolling plan covering the period 2017-2037. It is largely an update of the 2015-2035 electricity Sector Masterplan prepared by *Lahmeyer International*-an international consultant, but integrating Feed-In-Tariff Policy approvals and providing a focus on the Government Big 4 Agenda in which energy is expected to be a central enabler of the programme.

The report covers a comprehensive load forecast, addresses the committed generation projects between 2017-2024 and also the expansion programme for the period 2025-2037.

In transmission the report covers the target network for the period 2017-2037 ensuring that the target network is adequate, secure and cost effective.

The update relied heavily on planning tools developed by Lahmeyer International in demand forecasting, short and long-term optimization as well as investment planning. Power System Simulation for Engineers (PSSE) was used for transmission network expansion.

Improvements from the previous masterplan

The report largely fits into the previous masterplan in terms of technical content, but Feed-InTariff (FiT) approved projects were integrated into the expansion in their entirety. Specific improvements included:

a) Improving the way commercial demand is treated in the forecast where Aggregate GDP is found to have a more reliable correlation with energy consumption.

b) Reviewed population, urbanization and efficiency gains in undertaking the demand forecast.

c) A review of Vision 2030 flagship projects and other investment projects given their current status.

d) Simulation of the 2*375MW LNG project proposed in Dongo Kundu.

Current status in the power sector

Generation of electricity increased to 10,205 GWh in 2016/17 from 9,817GWh the previous year. The growth is related to the positive expansion in the commercial/industrial electricity consumption. Similarly, the maximum peak demand rose from 1,586MW to 1,656MW by June 2017 and 1,710MW by the end of 2017 calendar year.

Demand forecast

Demand forecast has been done in 3 scenarios namely reference, high and low each based on specific assumptions of the evolution of the related demand drivers.

From the simulation results, estimated peak demand for the period 2017-2037 ranges from 1,754MW to 6,638MW in the reference case scenario, 1,754MW to 9,790MW in the high case and between 1754MWin 2017 to 4,763MW in 2037 in the low case scenario. Energy growth forecast is estimated at 10,465GWh in 2017 rising to 39,187GWh in 2037 in the reference case. Over the same period, it increases from 10,465GWh to 57,990GWh under the high case scenario and between 10,465GWh to 27,945 GWh in the low case scenario. There is therefore a very slight difference between this year's load forecast and the load forecast done in the last update of 2015-2035 which indicates a 0.02% deviation.

Generation Planning

The energy sources considered in the system expansion plan for the different cases are as tabulated

Fixed medium term plan case	Fixed system case	Optimised generation expansion case
Geothermal	Geothermal	Geothermal
Wind	Wind	Wind
Solar	Solar	Solar
Imports	Imports	Import
Petrol-thermal plants	Petrol-thermal plants	Hydropower
Coal	Coal	Natural gas

Natural gas	Hydropower	Coal
	Natural gas	
	Nuclear	

A comprehensive list of committed projects for the period 2017-2024 is as presented in the table below.

COD	Plant name	Type	Capacity [MW]
2018	Orpower IV plant 1	Geothermal	10
2018	Lake Turkana - Phase I, Stage 1	Wind	100
2018	Strathmore	PV	0.25
2019	HVDC Ethiopia	Import	400
2019	Olkaria 5	Geothermal	158
2019	Olkaria Modular	Geothermal	50
2019	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	17
2019	Lake Turkana - Phase I, Stage 2	Wind	100
2019	Lake Turkana - Phase I, Stage 3	Wind	100
2019	PV grid Garissa	PV	50
2019	Marcoborero	PV	2
2019	Kopere	PV	40
2020	Menengai 1 Phase I - Stage 1	Geothermal	103
2020	Olkaria 1 - Unit 6	Geothermal	70
2020	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	17
2020	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	17
2020	Kipeto - Phase I	Wind	50
2020	Kipeto - Phase II	Wind	50
2020	Alten, Malindi, Selenkei	PV	120
2020	Quaint Energy, Kenergy	PV	50
2021	Olkaria Topping	Geothermal	47
2021	Ngong 1 - Phase III	Wind	10
2021	Chania Green	Wind	50
2021	Aperture	Wind	50
2021	Eldosol	PV	40
2021	Makindu Dafre Rareh	PV	30
2021	Gitaru solar	PV	40
2022	Olkaria 6 PPP	Geothermal	140
2022	Menengai I - Stage 2	Geothermal	60
2022	Prunus	Wind	51
2022	Meru Phase I	Wind	80
2022	Ol-Danyat Energy	Wind	10
2022	Electrawinds Bahari	Wind	50
2022	Hanan, Greenmillenia, Kensen	PV	90
2023	Orpower4 plant 4		61
2023	Olkaria 7	Geothermal	140
2023	Eburru 2	Geothermal	25
2023	GDC Wellheads	Geothermal	30
2023	Wellhead leasing	Generic back-up capacity	50
2023	Karura	Hydropower	89
2023	Electrawinds Bahari Phase 2	Wind	40
2023	Sayor, Izera, Solar joule	PV	30
2023	Belgen, Tarita Green Energy Elgeyo	PV	80
2024	Lamu Unit 1	Coal	327
2024	Lamu Unit 2	Coal	327
2024	Lamu Unit 3	Coal	327
2024	Olkaria 8	Geothermal	140
2024	Menengai III	Geothermal	100
2024	Baringo Silali - Paka I	Geothermal	100
2024	Marine Power Akiira Stage 1	Geothermal	70
2024	Meru Phase II	Wind	100

2024	Tarita Green Energy Isiolo, Kengreen	PV	50
2024	Asachi, Astonfield Sosian, Sunpower	PV	81
TOTAL			**4419.25**

Expansion Planning

The total installed capacity for fixed MTP case grows from 2,234.83MW in 2017 to 7,213.88MW in 2030 and to 9,932.44MW in 2037. The contribution from the respective technologies for the period 2017-2037 is as outlined: Geothermal decreases from 29.1% to 26.7% , Hydropower decreases from 36% to 17.9%,Coal increases from 0% to 19.5% while Natural gas increases from 0% to 7.6%. It is noteworthy that Wind and solar will increasingly play a major role in the generation mix during the planning period, rising from 1.1% to 8.5% and 0% to 8.6% respectively.

Installed capacity in MW	2017		2030		2037	
	MW	%	MW	%	MW	%
Geo	650.8	29.1	1868.8	25.9	2647	26.7
Hydro	805.027	36.0	1522.427	21.1	1782.727	17.9
Coal	0	0.0	981	13.6	1941	19.5
Nuclear	0	0.0	0	0.0	0	0.0
Natural gas	0	0.0	0	0.0	750	7.6
Diesel engines	697.5	31.2	417.5	5.8	0	0.0
gasoil	54	2.4	0	0.0	0	0.0
Import	0	0.0	400	5.5	400	4.0
Cogeneration	2	0.1	220.4	3.1	278.36	2.8
Generic back-up capacity	0	0.0	160	2.2	440	4.4
Wind	25.5	1.1	861.4	11.9	841	8.5
Solar	0	0.0	782.35	10.8	852.35	8.6
TOTAL	2234.83	**100**	**7213.88**	**100**	**9932.44**	**100**

Key observation arising from the expansion plan

(i) Addition of 300 MW LTWP at the end of 2018, Ethiopia 400 MW in mid-2019, 158 MW Olkaria V geothermal among other committed projects would raise the existing capacity to above 3,900 MW by 2020 resulting in an average of 583 MW excess capacity in the period 2019-2023 should demand grow moderately as depicted in the reference forecast.

(ii) Addition of 981.5 MW Lamu coal plant in 2024 will aggravate the projected supply-demand imbalance as the surplus margin would surpass 1,500 MW being 43% above the sum of peak and required reserve, with 32% excess energy during the year. The system LEC would rise rapidly to reach Shs. 16.86/kWh by the year 2024.

(iii) Capacity factors for geothermal, hydro and coal plants average 71.7%, 44.9% and 0.9% over the period after 2019, implying that the power plants, and particularly Lamu coal, will be grossly underutilized should demand grow moderately.

(iv) Lower demand would worsen the system LEC and plant utilization levels while higher demand would improve the two parameters.

(v) Due to the heavy introduction of intermittent technologies, the system is unlikely to be stable, implying that there is need to introduce some backup capacity. The team has recommended an introduction of 2 backup plants in 2019 and 2020 amounting to 160MW for purposes of backup and provision of primary reserve and other ancialliary services

Transmission Planning

The objective of transmission planning is to plan the system assets in a way that a reliable, secure and cost effective transmission of power between generation and load centers' is ensured.

The transmission plan has taken into consideration system requirements, reliability based on an N-1 criteria and expected expansion to meet the adequacy requirement. Power System Simulation for Engineers (PSSE) has been utilized in system simulations to arrive at the ideal network expansion plan.

In assessing the transmission plan

The transmission development plan indicates the need to develop approximately:

- 2,493 km 2018 - 2020 – at a cost of USD 1.85B
- 5444 km 2021-2025 - at a cost of USD 3.48B
- 285 km 2026-2030 - at a cost of USD 0.251B
- 336km 2031-2035 - at a cost of USD 0.269B

A total of 8,478km is planned for the period at an approximate cost of USD 5.876 Billion. This includes the related substation costs

The expected target network selected after a comprehensive technical analysis is presented in annexes 1 through 3 of the report

Implementation of the Plan

The Implementation of the commited generation and transmission projects is as shown below:

Project description	Capacity MW / length of KM	Time lines	Implementing agencies	Cost of running the system
Committed generation projects	4,908.55 MW	2017-2024	KENGEN,IPP & GOK	US$ 12.71 billion
Candidate generation projects	9,497 MW	25-2037	KENGEN and IPP	US$40.4 billion
Proposed transmission projects	8,478Km	2017-2037	KETRACO	US$5.876 billion
TOTAL				US$58.986BILLION

Recommendations

Arising from this study, the following are recommended as necessary to ensure effective implementation and address implementation concerns highlighted in the study

a) Renegotiate PPAs for large power plants, to introduce operation flexibility, reduce reserve requirements and optimize energy costs.
b) Phase out committed medium term solar and wind projects under FiT policy & Fast-track the operationalization of the Energy Auction market for new intermittent capacity plants.
c) Delay development of new geothermal plants after implementation of the committed ones to allow demand to grow and match supply. This would ensure that venting of steam is minimized.
d) Fast-tracking the implementation of flagship projects as identified under Vision 2030 to accelerate demand creation.
e)
f) Expand Time-Of-Use tariffs to domestic consumers & re-introduce interruptible tariffs for irrigation load and other uses that encourages balancing of household consumption through shifting of peak load to earlier or later times.

g) Put mechanisms in place to manage delays in implementation of generation projects. Delays affect decision making in the energy sector and scheduling of future plants.
h) Closely match implementation of generation and transmission projects to avoid Deemed Generated Energy costs arising from non-dispatch of some plants
i) Encourage development of flexible geothermal generation technologies (using binary technology as opposed to single flash).
j) A clear policy from the Government on resettlement needs to be put in place to avoid unfair migration of populations to proposed power sites that eventually escalate project costs and sometimes delays implementation.
k) The Ministry of Energy needs to push for enactment of the Compulsory land acquisition primary legislation to facilitate easier implementation of strategic national projects such as power infrastructure.
l) There is need for a coordinating forum between KPLC, KETRACO and project proponents to harmonize generation plants completion with transmission evacuation to address avoidable Deemed Generated Energy Payments.
m) There is need for the sector to invest more heavily in development of technical skills and related capacities on project supervision, monitoring and evaluation.

1. INTRODUCTION

The Government through the Ministry in charge of Energy is responsible for energy policy as well as energy planning. Section 5g of the Energy Act 2006 however mandates the Energy Regulatory Commision to prepare indicative energy plans. The Commission in turn coordinates this function through the preparation of Bi-annual Least Cost Power Development Plans (LCPDPs) in conjunction with sector utilities.

Over the years, the process has been undertaken through preparation of either medium term or long term plans prepared in alternating years and designed to capture the rapidly changing circumstances in the sector over time. This current edition is a long term 20 year rolling plan covering the period 2017-2037. It is an update of the 2015-2035 Generation and Transmission Masterplan prepared by Lahmeyer International. The plan integrates changes in planned generation sequencing largely from the Feed-In-Tariff Policy approvals and also from new Government approved projects expected in the medium to long term. The report comes at a time when the Government focus is on the 'big 4' areas of development namely housing development, Manufacturing, food security and universal health care. The energy sector will be central to achievement of these 4 areas given that it acts as a core enabler for their realization. The Plan is categorised into three key areas;

Load forecasting – This comprises of an analysis of load projections in both energy and capacity to arrive at a reasonable projection of expected demand during the study period. It takes into consideration critical parameters that are likely to change over time including, the macro framework (consisting of Economic growth, inflation, world fuel prices among others), the population growth scenario, technology changes and therefore specific consumptions at household and industrial level and the expected connectivity rates

Generation Planning – Involving the application of short term and long term plan simulation by utilizing the Lahmeyer LIPs OP and LIPs XP respectively to arrive at an optimal generation sequence. The simulation tools take into consideration plant types by technology, system constraints as well as relevant costs. Through a comprehensive screening process, an optimal generation mix is developed for the period under review.

Transmission Planning – The transmission plan has taken into consideration system requirements, reliability based on an N-1 criteria and as well as expected expansion to meet the adequacy requirement. Power System Simulation for

Engineers (PSSE) has been utilized in system simulations to arrive at the ideal network expansion plan

The main objective of this update is to take into account new assumptions, reflect on emerging technologies as well as market dynamics that may influence future power expansion plan and accommodate new Government policy guidance on renewable energy expansion in the immediate to long term.

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 historical data, literature, committed and candidate projects;
- Simulate the generation plants;- and
- Prepare a Transmission System expansion plan in line with the generation expansion
- Assess the evolution of tariffs based on the estimated expansion costs for the plan period

1.1. The updating methodology

This update 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 Electricity Transmission Company Limited (KETRACO); and the Kenya Nuclear Electricity Board (KNEB). The Energy Regulatory Commission provided secretariat services and coordinated the process. Senior management from the institutions above in addition to the Kenya National Bureau of Statistics (KNBS); Kenya Investment Authority (Ken Invest) and the Kenya Private Sector Alliance (KEPSA) provided oversight and policy guidance.

The update relied heavily on planning tools developed by Lahmeyer International in demand forecasting, short and long-term optimization as well as investment planning. Evolution of tariffs was computed using an internally developed model. The transmission simulations on the other hand were undertaken using Power System Simulation for Engineers (PSSE) involving definition of the yearly network expansion based on an N-1 criteria and highlighting key features of the network per year.

The load forecast was developed using MAED methodology principles and assumptions. The specific demand model developed by Lahmeyer international is unique to the Kenyan power system. The forecast was done in there scenarios

The derived load forecast was used as an input into the short term optimization tools LIPs OP and the Long term optimization tool LIPS XP that are simulated to determine a least cost generation sequence. Key parameters necessary for the simulations include fuel cost of each thermal technology, capital investment costs for each power plant, Fixed and Variable Operations and Maintenance costs, plant life as well as start and decommissioning dates for the plants. Other information include maintenance schedules, as well as data on renewable energy technologies of wind solar, small hydro, biomass and biogas that were simulated to determine the least cost generation sequence to meet this demand.

Finally, simulating using Power System Simulation for Engineering (PSSE), the results of the least cost generation plan determine the ideal transmission network.

The arrangement of the report is a follows:

Chapter two describes the existing situation of the Kenyan power sector; chapter three gives a description of the electricity demand forecasting assumptions, data requirements, methodology, and forecast results; Chapter four provides a description of the country's natural energy resources base that includes geothermal hydropower, coal and renewable energy supply options; 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 methodology of the least cost generation planning and main the parameters and assumptions used in the simulation. It then presents the proposed least cost generation plan, chapter seven discusses the transmission network projects; Chapter eight describes the transmission system simulation methodology and gives the transmission system expansion plan; Chapter nine describes the cost of the plan as well as the tariff evolution while chapter 10 summarizes the monitoring and evaluation of the committed projects considered in this report. Finally Chapter 11 presents the conclusion and the way forward.

1.2. Improvements from the previous update

While the report largely fits into the previous masterplan in terms of technical content, there were efforts to incorporate new developments particularly with respect to integrating Feed-InTariff (FiT) approved projects into the planning process. Specific improvements included:

e) Improving the way commercial demand is treated in the forecast where previously only a correlation factor was applied but in the current process, Aggregate GDP is found to have a more reliable correlation with energy consumption
f) Reviewed population, urbanization and efficiency gains in undertaking the demand forecast.
g) Reviewed new potential demand arising from the effect of implementing Vision 2030 flagship projects and other investment projects given their current status and the potential for significant impact on demand during the plan period
h) The least cost generation simulation included new candidate projects and in particular the 2*375MW LNG project proposed in Dongo Kundu.
i) The report also provides more useful analytical information that provides more decision making information

2. EXISTING SITUATION IN THE KENYAN POWER SECTOR

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. KPC was 100% government owned. 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. In 2013, the Company rebranded to be renamed Kenya Power which is its current brand name

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 Power sector in 1997. Kenya Electricity 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 the development of an energy policy in 2004 and the subsequent enactment of the Energy Act of 2006 which established the Rural Electrification Authority (REA) and restructured the Electricity Regulatory Board (ERB) to Energy Regulatory Commission (ERC) whose mandate was expanded to encompass the entire Energy sector. The sessional paper No 4 of 2004 on energy also provided for the creation of Geothermal Development Company (GDC) and Kenya Electricity Transmission Company (KETRACO).

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 KPLC. This was driven by 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 following:

The Ministry of Energy (MOE) responsible for policy and planning guidance, Energy Regulatory Commission (ERC) with the mandate of a single energy sector regulator, Kenya Electricity Generating Company (KenGen) a large power generation entity, Kenya Power and Lighting Company (KPLC) which is a sole off taker for grid connected power with distribution and retail functions as well as the system operator, the Rural Electrification Authority (REA) which is a special purpose vehicle for opening of rural sector electrification, Kenya Electricity Transmission Company (KETRACO) in charge of high voltage transmission development for lines above 132kV, Geothermal Development Company (GDC) in charge of early geothermal steam development Independent Power Producers (IPPs) and Kenya Nuclear Electricity Board (KNEB) mandated to develop the framework and implement the national nuclear power development programme with a view to introducing nuclear power in the near future.

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.

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

d) **Rural Electrification Authority (REA)** was established in 2007 with a mandate of implementing the Rural Electrification Programme. Since the establishment of the Authority, there has been accelerated connectivity of rural customers which have increased from 133,047 in 2007 to 1,269,510 in 2017.

e) **The Kenya Electricity Generating Company (KenGen)** is the main player in electricity generation, with a current installed capacity of 1,610MW. 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 69% 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**.** As at June 2017, they accounted for 696MW. This is approximately 29.8% of the country's installed capacity from thermal, geothermal, hydro, Biogas and cogeneration, as follows:

Table 1: Installed capacity by plant: June December 2017

Plant		**Type**	**Installed capacity(MW)**
1	Iberafrica I&II	Thermal	108.5
2	Tsavo	Thermal	74.0
3	Thika Power	Thermal	87.0
4	Biojule Kenya Limited	Biogas	2.0
5	Mumias - Cogeneration	Cogeneration	26.0
6	OrPower 4 -Geothermal I,II&III	Geothermal	110.0
7	OrPower 4 -Geothermal (the 4th plant)	Geothermal	29.0
8	Rabai Power	Thermal	90.0
9	Imenti Tea Factory (Feed-in Plant)	Hydro	0.3
10	Gikira small hydro	Hydro	0.514
11	Triumph Diesel	Thermal	83.0
12	Gulf Power	Thermal	80.32
13	Regen-Teremi	Hydro	5.00
	IPP Total		**696**

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 most of the existing transmission and 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%.

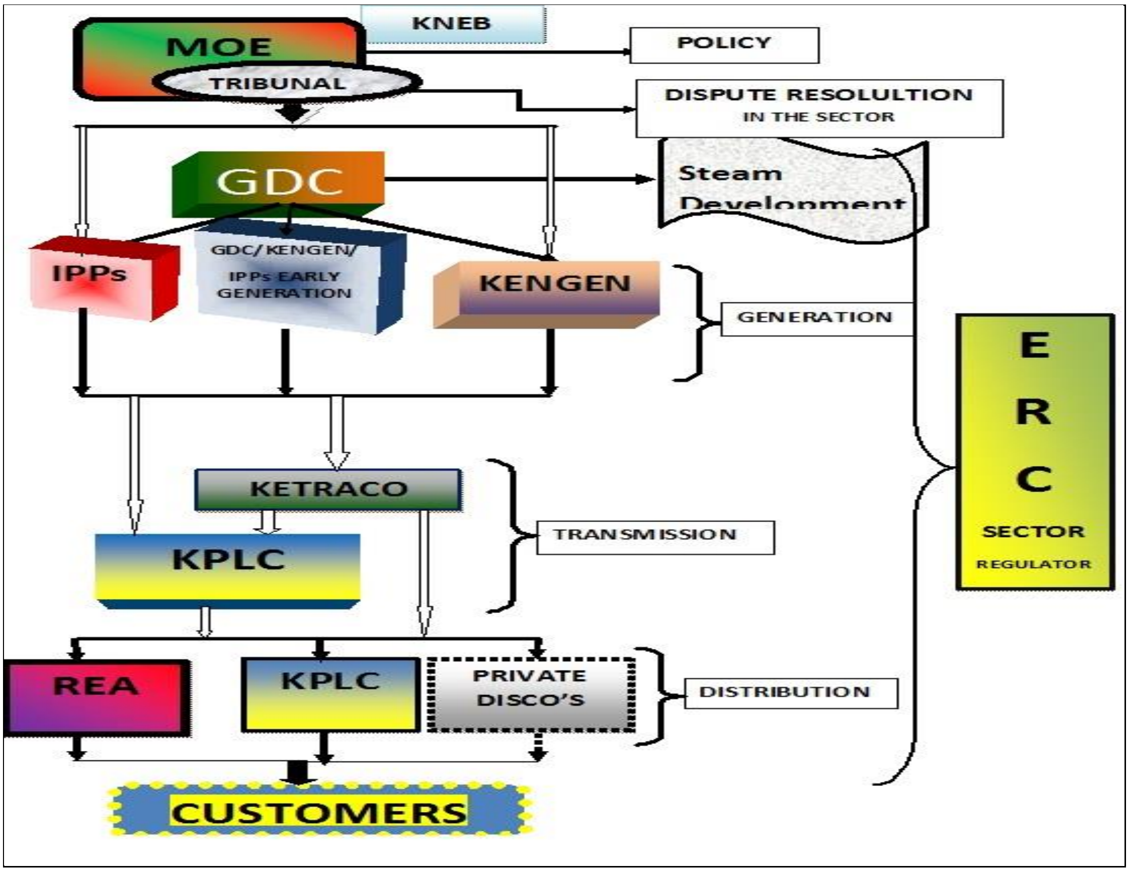
g) **Geothermal Development Company (GDC)** is a fully owned Government Special Purpose Vehicle (SPV) intended to undertake surface exploration of geothermal fields, undertake exploratory, appraisal and production drilling and manage proven steam fields as well as enter into steam sales agreements with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

h) **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.

i) **Private Distribution Companies** are proposed under the new Energy Act and are expected to improve the distribution function whose sole mandate rests with KPLC. It is envisaged that future power distribution will involve purchase of bulk power from the generators and with KETRACO facilitating the transmission; the power generators will be able to sell power directly to consumers. This is likely to enhance distribution competition and hence improve efficiency.

j) **Kenya Nuclear Electricity Board (KNEB)** is charged with the responsibility of developing a comprehensive legal and regulatory framework for nuclear energy use in Kenya.

Figure 1: Power sector institutional structure



2.3. Ongoing Reforms in the power sector

The adoption of the new constitution has seen the review of the energy sector policy and the energy bill. The revised energy policy and bill will be adopted upon completion of a stakeholder engagement process and formal adoption by cabinet and parliament. There are a number of reforms proposed in the new policy and legislative framework to improve sector performance and management. The key ones are:

2.3.1. Renewable energy

The Government shall establish an inter-ministerial Renewable Energy Resources Advisory Committee (RERAC) to advise the Cabinet Secretary on, inter alia:

a. Criteria for allocation to investors of energy resource areas such as geothermal fields, wind and hydro sites.
b. Licensing of geothermal fields.
c. Management of water towers and catchment areas.

d. Development of multi-purpose projects such as dams and reservoirs for power generation, portable water, flood control and irrigation with a view to ensuring proper coordination at policy, regulatory and operational levels on matters relating to the various uses of water resource.
e. Management and development of other energy resources such as agricultural and municipal waste, forests, and areas with good wind regimes, tidal and wave energy.

The Government shall transform the Rural Electrification Authority into the National Electrification and Renewable Energy Authority (NERA) to be the lead agency for development of renewable energy resources other than geothermal and large hydros. The institution will also develop renewable energy resources

2.3.2. Electricity

The National Government shall:-

(a) Transform the Kenya Nuclear Electricity Board into a Nuclear Electricity Corporation to promote and implement a nuclear electricity generation program.

(b) Develop and monitor implementation of electricity master plans for the country and the Eastern African Region.

(d) Facilitate open access to the transmission and distribution networks, designate a system operator and encourage regional interconnections to enhance regional electricity trade.

(e) Provide incentives for development of robust distribution networks, including gradual elimination of overhead distribution systems to ensure efficient and safe provision of distribution services by duly licensed network service providers, so as to reduce power supply interruptions and improve the quality of supply and service.

2.3.3. Energy Efficiency and Conservation

i. The Government shall establish the Energy Efficiency and Conservation Agency (EECA) as a fully-fledged national public entity to promote energy efficiency and conservation.

ii. EECA shall spearhead energy efficiency and conservation activities to improve the energy security and mitigate the effects of climate change by lowering Green House Gas emissions.

2.3.4. Land, Environment, Health and Safety

i. In carrying out its planning and development mandate pursuant to the Fourth Schedule, Part 2, paragraph 8(e) regarding electricity and gas reticulation and energy regulation, every county government shall set aside suitable land for energy infrastructure development purposes, including but not limited to projects recommended in **the Indicative National Energy Plans**.

ii. The Government shall facilitate:

(a) Development of a Resettlement Action Plan Framework for energy related projects; including livelihood restoration in the event of physical displacement of communities.

(b) Access to land where exploration blocks fall on private land, community land and cultural Heritage areas including game parks/reserves.

iii. The Government shall:

(a) Put in place mechanisms to eliminate kerosene as a household energy source by 2022.

(b) Ensure the creation of disaster response units in each county and in relevant energy sector entities.

2.3.5. Devolution and Access to Energy Services

i. The National Government will be responsible for energy policy and regulation as per the 4th schedule of the constitution while the County Governments will be responsible for planning and development, including electricity and gas reticulation and energy regulation within their jurisdictions.

ii. A framework on the functional devolution of roles between the two levels of government will be developed in consultation with all stakeholders to avoid the uncertainty/overlap of responsibilities. Amongst the roles to be addressed in the framework include:

(a) Provision of distribution and reticulation services.

(b) Establishment of energy disaster management centres in all the counties.

(c)NERA shall formulate cooperation arrangements with County Governments for implementation of rural electrification and renewable energy programmes.

2.3.6. Energy Financing, Pricing and Socio-Economic Issues

The Government shall:

(a) Explore and adopt all viable financing options from local and international sources for cost effective utilization of all its energy resources, and in so doing shall endeavour to maintain a competitive fiscal investment climate in the country.

(b) Support Public Private Partnerships in the development, operation and maintenance of energy infrastructure and delivery systems. The Government shall set up a Consolidated Energy Fund to cater for funding of the proposed National Energy Institute; acquisition of strategic petroleum reserves; energy sector environmental disaster mitigation, response and recovery; hydro risk mitigation; water towers conservation programs; energy efficiency and conservation programs as well as promotion of renewable energy

2.3.7. 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. Todate, the Kenya-Ethiopia 500MW HVDC bipolar line is at an advanced stage of construction while both the Isinya-Singida interconnector and the …..Tororo onterconnectors are also underway.

2.4. Electricity supply

Over the years, the installed generation capacity has considerably grown rising from 1,310 MW in 2008 up to 2,333 MW by June 2017. This represents an average growth rate of 7.8% annually. The peak demand also grew from 1,044MW in the same year to 1,656MW in 2017.

As at 30th June 2017, Kenya had an installed electricity generation capacity of 2,333MW comprising of hydro (824MW), thermal (803MW), geothermal (652MW), wind (26MW), biomass/cogeneration (28MW), and solar (0.55MW).

During this year, KenGen which is the largest power generator in the country accounted for 69.2% of the industry's effective generation capacity. The Independent Power Producers (IPPs) accounted for 29.0% including Emergency Power Producers during the same period. Isolated grid generation accounted for less than 1%(0.8%) under the Rural Electrification Programme (REP). This generation mix comprised of 36% of hydro, 34% fossil fuels, 28% geothermal, cogeneration 1.0% and 1% from wind and solar. Due to the poor hydrology during the period, hydro generation declined marginally. There was therefore increased generation from fossil fuel. Kenya's current effective installed (grid connected) electricity capacity is 2,259 MW as depicted in table 2

Table 2: Installed Capacity of Nominal and Effective Power Generation as at 30th June 2017

	June 2017				
	Installed MW	**% share**	**Effective MW**	**%share**	**Energy purchased (GWh)**
Hydro	824	35.31%	803	35.53%	3,340.98
Geothermal	652	27.95%	644	28.51%	4,450.92
Thermal	803	34.40%	762	33.74%	2,164.86
Cogeneration	28.0	1.20%	23.5	1.04%	0.71
Solar	0.55	0.02%	0.52	0.02%	0.54
Wind	26	1.12%	26	1.15%	63.18
Imports					183.66
	2,333	100%	2,259	100%	10,204.85

Source: KPLC annual report 2016/17

2.5. Sources of Energy in Kenya

Hydropower constitutes 37% of the installed capacity and accounts for 32.74% of the total sales in 2016/17. Thermal, Geothermal, Cogeneration and wind generation account for 67.26% of the total national sales.

The generation contribution from KenGen plants, Rural Electrification Plants, IPPs, EPPs and imports between 2012/13 and June 2017 are as shown in Table 2 below.

Table 3: Generation contribution of existing power plants (2012/13-2016/17 FY

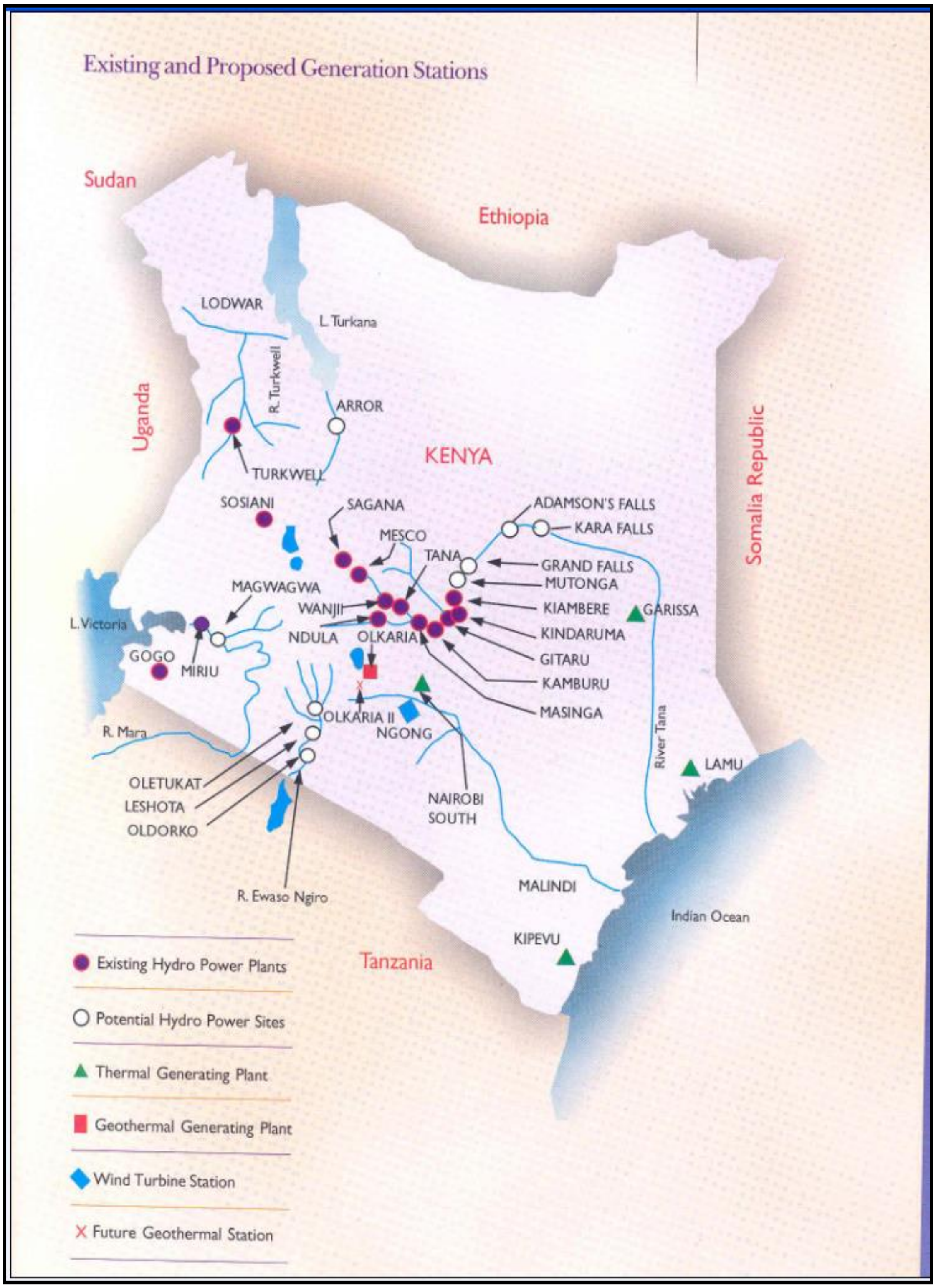
COMPANY	Capacity (MW) as at 30.06.2017		Energy purchased in GWh				
	Installed	Effective[1]	2012/13	2013/14	2014/15	2015/16	2016/17
KenGen							
Hydro:							
Tana	20.0	20.0	108	69	108	109	71
Kamburu	94.2	90.0	520	421	358	434	384
Gitaru	225.0	216.0	1,036	830	710	862	775
Kindaruma	72.0	70.5	252	201	165	208	183
Masinga	40.0	40.0	148	206	138	127	169
Kiambere	168.0	164.0	1,129	979	718	996	938
Turkwel	106.0	105.0	545	719	551	426	402
Sondu Miriu	60.0	60.0	393	351	376	419	282
Sangóro	21.0	20.0	110	109	125	140	90
Small Hydros	11.7	11.2	57	59	60	63	44
Hydro Total	**818**	**797**	**4,298**	**3,944**	**3,308**	**3,784**	**3,339**
Thermal:							
Kipevu I Diesel	73.5	52.3	185.2	219.9	156.5	128.6	211.3
Kipevu III Diesel	120.0	115.0	320.7	524.2	299.0	181.4	512.1
Embakasi GT	30.0	28.0	27.3	41.3	4.1	0.6	0.2
Muhoroni GT	30.0	27.0					108.0
Garissa & Lamu			26.9	27.6	11.7	12.4	
Garissa Temporary Plant (Aggreko)					21.0	18.6	
Thermal Total	**254**	**222**	**560**	**813**	**492**	**342**	**832**
Geothermal:							
Olkaria I	45.0	44.0	369	352	333	331	195
Olkaria II	105.0	101.0	696	712	756	814	791
Eburru Hill	2.5	2.2	9	7	11	10	0
Olkaria Mobile Wellheads	80.6	77.8	23	53	196	357	472
Olkaria IV	140.0	140.0	0	32	1064	976	852

Olkaria I 4 & 5	140.0	140.0			744	1055	968
Geothermal Total	**513**	**505**	**1096**	**1156**	**3104**	**3542**	**3279**
Wind							
Ngong	**25.5**	**25.5**	**13.9**	**17.6**	**37.7**	**56.7**	**63.2**
KenGen Total	**1,610**	**1,550**	**5,968**	**5,931**	**6,943**	**7,725**	**7,513**
Government of Kenya (REP)							
Thermal	26.2	17.0	26.0	29.8	35.1	39.9	40.8
Solar	0.550	0.520	0.6	0.8	0.9	0.8	0.5
Wind	0.660	0.494	0.7	0.4	0.0	0.000	0.003
Total Offgrid	**27**	**18**	**27**	**31**	**36**	**41**	**41**
IPP's							
Iberafrica I&II	108.5	108.5	592	550	198	128	252
Tsavo	74.0	74.0	178	152	83	39	121
Thika Power	87.0	87.0		454	233	70	168
Biojule Kenya Ltd	2.0	2.0				0	0.7
Mumias -Cogen	26.0	21.5	71	57	14	0	0
Opower 4	139	139	503	851	955	1066	1172
Rabai Power	90.0	90.0	443	633	609	536	606
Imenti Tea Factory	0.3	0.3	0.7	0.1	0.5	0.7	0.3
Gikira small hydro	0.514	0.514		0.4	1.6	1.9	0.9
Triumph Diesel	83.0	83.0			4.8	81.8	83
Gulf Power	80.32	80.32			60	8	61
Regen-Terem	5.00	5.00					1
IPP Total	**696**	**691**	**1,788**	**2,698**	**2,160**	**1,934**	**2,466**
Emergency Power Producers(EPP)							
Aggreko Power	0	0.0	261	94	63	50	1
EPP Total	**0**	**0**	**261**	**94**	**63**	**50**	**1**
Imports							
UETCL			41	83	76	65	180
TANESCO			1.2	1.3	0.6	0.0	0.0
EEPCO				2.1	2.8	2.6	3.4
Total Imports			**42**	**87**	**79**	**67**	**184**
SYSTEM TOTAL	**2,333**	**2,259**	**8,087**	**8,840**	**9,280**	**9,817**	**10,205**
SUMMARY OF KEY STATISTICS							
SALES - **KPLC System (GWh)**			6,144	6,751	7,090	7,330	7,701
REP System (GWh)			406	454	525	537	549

Export to Uganda (GWh)			30	37	38	43	20
Export to Tanesco (GWh)			1	2	2	2	2
TOTAL SALES (GWh)			**6,581**	**7,244**	**7,655**	**7,912**	**8,272**
System Losses (GWh)[2]			1,507	1,596	1,624	1,905	1,933
System Peak Demand (MW)[3]			1,354	1,468	1,512	1,586	1,656
System Load Factor			68.2%	68.7%	70.1%	70.6%	70.3%
Sales % of Energy Purchased			81.4%	81.9%	82.5%	80.6%	81.1%
Losses as % of Energy Purchased			18.6%	18.1%	17.5%	19.4%	18.9%
Annual Growth: - Energy Purchased			5.4%	9.3%	5.0%	5.8%	4.0%
- KPLC Sales			4.1%	9.9%	5.0%	3.4%	5.1%
- REP Sales			1.6%	11.8%	15.6%	2.3%	2.2%

Generation of electricity increased to 10,205 GWh in 2016/17 from 9,817GWh from the previous year. The positive growth of generation is also related to the positive growth in the commercial/industrial electricity consumption. This indicates that the consumption expanded by 4% from the previous year. Similarly, the maximum peak demand rose from 1,586MW to 1,656MW by June 2017.

Figure 2: Existing and selected proposed power plants



2.6. Transmission and Distribution

Transmission and distribution network's circuit length was 213,700 kilometres for all voltage levels in 2017. This represented a 19.2% annual growth rate compared to the previous period, 2015/16 and the highest growth rate since 2009. It has been greatly influenced by Kenya Electricity Transmission

Company (KETRACO) who have accelerated the development of distribution infrastructure for capacity above 132kV

Table 4: Transmission and distribution lines, circuit length in kilometres

VOLTAGE	Years				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
220 kV	1,331	1,434	1,527	1,527	1,527
132 kV	2,436	2,513	2,527	2,874	3,239
66 kV	1,097	1,212	1,212	1,212	1,212
33 kV	16,136	20,778	21,370	27,497	30,846
11 kV	28,818	30,860	32,823	35,383	37,234
Total HV and MV	**49,818**	**56,797**	**59,459**	**68,493**	**74,058**
415/240V or 433/250V				110,778	139,642
TOTAL	**49,818**	**56,797**	**59,459**	**179,271**	**213,700**
% INCREASE P.A.	**5.9%**	**14.0%**	**4.7%**	**15.2%**	**19.2%**

The total transmission network (220kV and 132kV) stood at 4,766Kms by June 2017 of which 839.11Kms (132 kV), 374.59KM (220 kV) and 585KM (400Kv) were under KETRACO while the rest were managed by KPLC. The entire national electricity distribution network is under KPLC and stood at 208,934KM of which 1,212 km is 66kV, 30,846 km is 33kV, and 37,234 km is 11kV while the balance is 250v-415v (139,642V). The distribution network consists of 66 kV feeder lines around Nairobi and 33kV and 11 kV medium-voltage lines distributed throughout the country. The total length of the MV and HV lines was 74, 058km. During the year, a 4% growth in the transmission and distribution networks was registered from the previous 15.2% to 19.2% in 2016/17.

Figure 3: Transmission network in Kenya

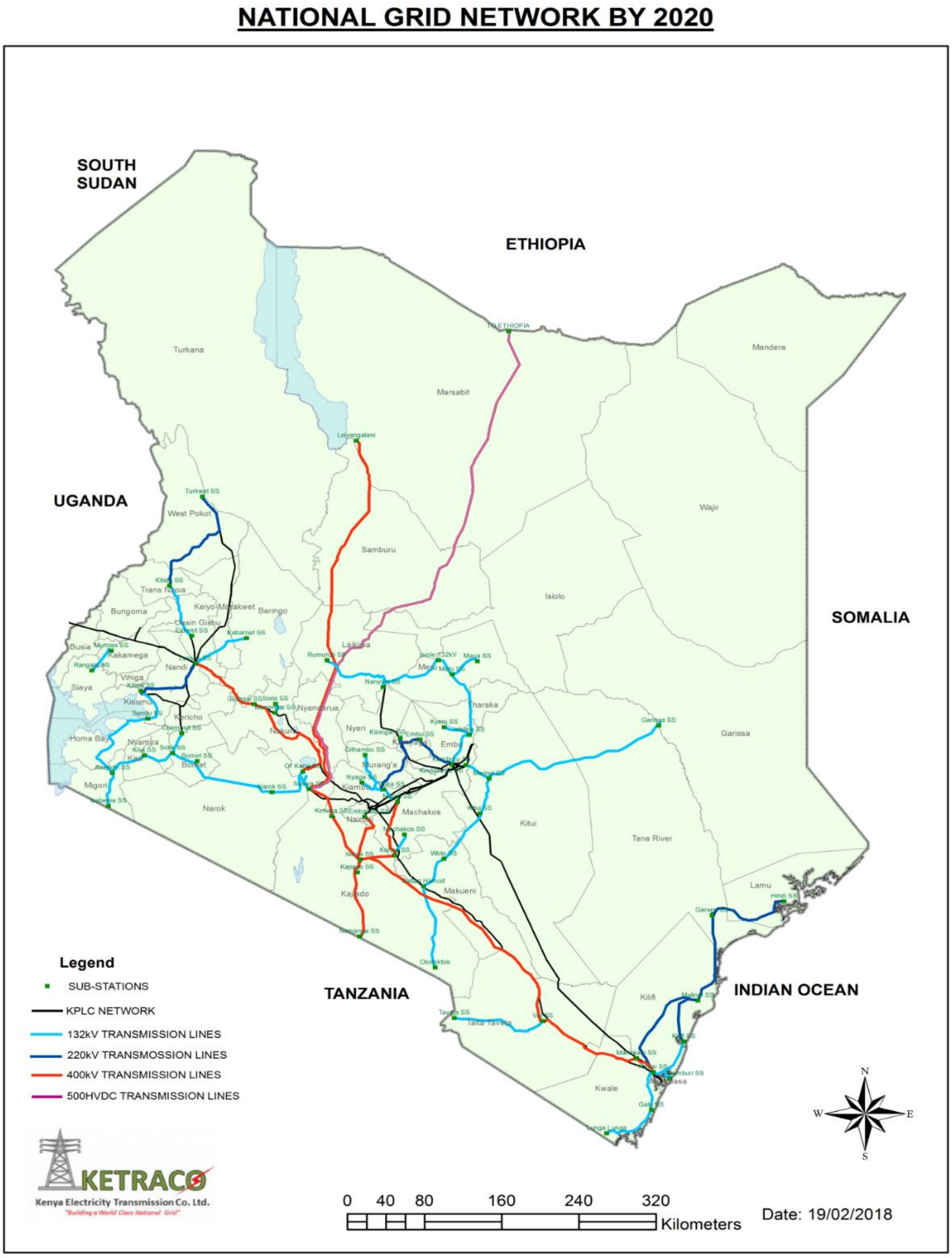


Table 5 represents the transmission and distribution sub-stations capacities between 2013 and 2017. There has been a tremendous expansion in generation sub stations over the period under review from 1,846MVA in 2012 to 3,116MVA in 2017. During the same period, transmission substation capacity expanded from **3,076**MVA to **4,787** while distribution sub-stations increased from **2,800** in 2012/13 to **4,416** in 2016/17 FY. Distribution transformer capacity significantly increased during the same period from **6,195**MVA to **7,275.83**MVA. An increase of about 17.44%.

Table 5: Transformers in service, total installed capacity in MVA as at 30th June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Generation Substations					
11/220kV	544	844	1292	1352	1352
11/132kV	889	889	1067	1067	1112
11/66kV	171	171	291	411	411
11/33kV	238	238	238	238	238
3.3/33kV	4	4	4	4	4
TOTAL	**1,846**	**2,146**	**2,891**	**3,071**	**3,116**
Transmission Substations					
132/220kV	620	620	620	620	620
220/132kV	730	835	1266	1266	1266
220/66kV	450	450	450	720	720
220/33kV		46	69	69	69
132/66kV	360	360	420	420	600
132/33kV	916	916	939	1229	1512
TOTAL	**3,076**	**3,227**	**3,764**	**4,324**	**4,787**
Distribution Substations					
66/11kV	1,608	1,332	1446	1768	2067
66/33kV	113	138	148	231	231
40/11kV	11	0	0	0	0
33/11kV	1068	1841	1841	2054	2118
TOTAL	**2,800**	**3,311**	**3,435**	**4,053**	**4,416**
Distribution Transformers					
11/0.415kV and					
33/0.415kV	**6,195**	**6,317**	**6,384.00**	**7,087.69**	**7,275.83**

2.6.1. Distribution network

As at June 2017, a number of critical grid expansion projects were completed. A total of 6 new and 22 upgrade substations were completed enhancing the transformation capacity by 633MVA which is adequate to serve over 200,000 standard households. During the year, 5,565KM of new and medium voltage lines were constructed. Moreover, more projects to construct distribution lines and establish new substations have been put in place to extend power supply in rural areas. The end goal is to attain universal access to by 2020. Currently, the nation stands at 73% access to electricity. The table below shows the ongoing capital projects aimed at advancing the distribution network nationally.

The distribution footprint in the period entails construction of 116 new primary distribution substations with a distribution capacity of 2,809 MVA and 1,244 km of associated 66 and 33kV lines, 20 new bulk supply substations and installation of 336.5MVAR reactive power compensation equipment in 15 transmission substations. To improve the efficiency of the power system, several projects and programs will be implemented to reduce system losses, namely; feeder metering, outdoor metering and smart metering among other projects to collect data on loss reduction and implement relevant solutions to the findings.

2.6.2. Improved power supply reliability

During the period, power supply reliability will be enhanced through network automation, system reinforcement and use of modern technologies. Some of the projects and activities that are under implementation to enhance supply reliability include; System audits to identify weak points in the network, initiate accurate calculation and monitoring of power supply quality indices such as System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI) using the completed Facilities Database (FDB) system.

To further improve the power supply reliability, Live Line Maintenance in the distribution network will be rolled out; automation of distribution network will be extended to Nairobi, Mombasa and other parts of the country. This will be done in addition to extending N-1 criteria on primary substation and primary feeders by developing redundancy in the network.

Overhead distribution power lines across major towns and their environs, such as Nairobi, Mombasa, Kisumu, Eldoret, Thika and Nakuru will be replaced with underground distribution power lines to reduce vandalism, destruction of trees, improve aesthetics in our towns and reduce outages. Upon successful implementation of these initiatives, it is expected that power supply reliability indicators CAIDI and SAIFI will improve by at least 20% by the end of the 2022.

2.7. Electricity demand and Customer Characteristics

The demand for electricity has shown an upward trend in the last 5 years. While the demand was 6,581GWh in 2012/13 it increased to 8,272 GWh in 2016/17. This represents an average annual percentage increase of 5% with the highest growth recorded in 2013/14 (10%). Overall, there has been a positive growth among all consumer categories. This is largely attributed to the increased efforts in attaining universal access to electricity by 2020. Table 6 summarizes trends in consumption among various customer categories during the last 5 years.

Table 6: Consumption in GWh among various categories of consumers 2012/13-

	TYPES OF CUSTOMERS		Sales in	GWh		
TARIFF	**COVERED BY THIS TARIFF**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
DC	Domestic	1,670	1,803	1,866	2,007	2,138
SC	Small Commercial	998	1,109	1,143	1,153	1,201
CI	Commercial and Industrial	3,440	3,818	4,030	4,104	4,266
IT	Off-peak	18	1	15	26	41
SL	Street lighting	18	20	35	40	55
	REP System (DC,SC,SL)	406	454	525	537	549
	Export to Uganda	30	37	38	43	20
	Export to Tanesco	1	2	2	2	2
	TOTAL	**6,581**	**7,244**	**7,655**	**7,912**	**8,272**
	% INCREASE P.A.	4%	**10%**	**6%**	**3%**	**5%**

Source: KPLC annual report 2016/2017

2.7.1. Electricity sales

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 and other sectors of the economy
- The company's initiative to connect new customers through intensive electrification programs.

Table 7: Total unit sales by region in GWh

REGION	2012/13	2013/14	2014/15	2015/16	2016/17
Nairobi North	**-**	-	1,032	1,187	1,301
Nairobi South	**-**	-	1,667	1,696	1,759
Nairobi West	**-**	-	1,059	808	853
Nairobi	**3,507**	**3,776**	**-**	**-**	**-**
Coast	**1,134**	**1,256**	1,312	1,338	1,389
Central Rift	-	-	456	569	596
North Rift	-	-	269	280	269

South Nyanza	-	-	0	48	86
West Kenya	-	-	525	320	313
West	**1,056**	**1,121**	**-**	**-**	**-**
Mt Kenya	**-**	**-**	309	413	431
North Eastern	**-**	**-**	461	671	704
Mt Kenya	**539**	**598**	**-**	**-**	**-**
KPLC Sales	**6,236**	**6,751**	**7,090**	**7,330**	**7,701**
R.E.P. Schemes	313	454	525	537	549
Export Sales***	32	39	40	45	22
TOTAL	**6,581**	**7,244**	**7,655**	**7,912**	**8,272**
%INCREASE P.A.	**3.8%**	**10.1%**	**5.7%**	**3.4%**	**4.5%**

The Nairobi region has consistently recorded the highest sales in electricity in the country, accounting for 47% of total sales. In the last 5 years, Nairobi sales increased from 3,505 GWh in 2012/13 to 3,913 GWh in 2016/17.

2.7.2. Retail electricity tariffs

The Kenya's electricity subsector is unbundled in nature with separate entities undertaking different functions pertaining to generation, transmission, distribution and retailing. The retail tariff is designed in a way that it incorporates costs associated with these functions. The tariffs structure follows KPLC's Underlying Long Run Marginal Cost (LRMC) 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 base tariff structure comprises of Fixed charge, Demand charge and 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 base tariffs in Kenya is as follows.

Table 8 : Retail Electricity Tariffs Structure

Tariff	Customer category	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	150	2.50	-
			51-1,500		12.75	
			1,500-15,000		20.57	
SC	Small Commercial	240 or 415	Up to 15,000	150	13.50	-
CI1	Commercial/ Industrial	415V-3 phase 4 wire	Over 15,000	2,500	9.20	**800**
CI2		11,000		4,500	8.00	**520**
CI3		33,000		5,500	7.50	**270**
CI4		66,000		6,500	7.30	**220**
CI5		132,000		17,000	7.10	**220**
IT	Interruptible Off-Peak supplies	240 or 415	Up to 15,000	150	13.50	-
SL	**Street Lighting**	**240 or 415**	**-**	**200**	**11.00**	**-**

In addition, the retail tariffs structure provides for four pass-through costs that are considered uncertain and largely outside the control of the utilities. They include

2.7.3. Fuel Cost Charge (FCC)

This is the added cost or rebates to the consumers as a result of fluctuations in world prices as well as fluctuations in the quantity of oil consumed by electricity generation. The fuel cost charge lags one month behind the actual price of the fuel. This money is collected by KPLC and all of it is passed on directly to electricity generation companies, who in turn pay fuel suppliers.

2.7.4. Foreign Exchange Rate Fluctuation Adjustment (FERFA)

Foreign exchange rate fluctuations are largely outside the control of the utilities and can constitute a significant proportion of the costs they face. Given the capital intensive nature of the industry and the heavy reliance on foreign currency denominated investments there is a need for these adjustments. These adjustments pass on this risk to the consumers thereby keeping the price signals to the consumers at efficient levels. KPLC is therefore covered for variations in exchange rates by an adjustment: Foreign Exchange Rate Fluctuations Adjustment (FERFA) for its own foreign exchange payments, as well as payments to KenGen and the IPPs.

2.7.5. Water Resource Management Authority Levy (WARMA Levy)

Represents the fee paid to the Water Resource Management Authority for water used by the hydro power plants in generation of electricity. This levy is charged on energy purchased from hydropower plants above 1MW.

2.7.6. Inflation Adjustment

This represents the amount charged as a result of the effect of domestic and international inflation on the supply of Electricity. It is adjusted on semi-annual basis.

2.7.7. 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 5 years are indicated in the table 9.

Table 9: Income, sales and average retail tariff of electricity

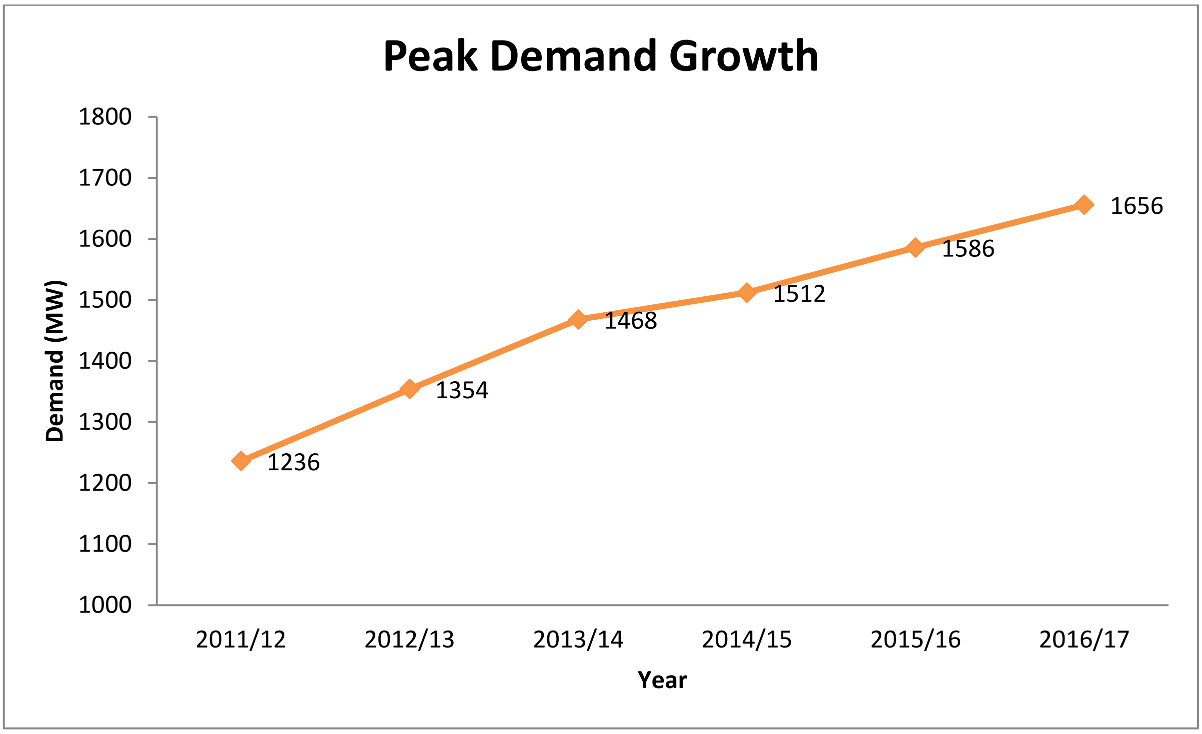
Year	2012/13	2013/14	2014/15	2015/16	2016/17
Total units sold (GWh)	**6,581**	**7,244**	**7,655**	**7,912**	**8,272**
Total income from electricity (Shs '000)	**94,921**	**112,625**	**114,814**	**118,186**	**131,118**
% Increase PA	**(6.5)**	**18.7%**	**1.9%**	**2.9%**	**10.9%**
Average retail tariff (Shs/kWh)	14.42	15.55	15.00	14.94	15.85

As shown in the table above the average retail tariff has been considerably stable ranging between Ksh 14 and Ksh 15 in the last 5 years. However, income from sale of electricity has been on the rise due to increased connections and loss reduction strategies. The highest growth in sale was registered in 2013/14 which amounted to 18.7% increase from the previous years.

2.8. Electricity demand

The nation has seen an upward trend in demand for electricity over the past decade. The peak demand increased from 1,236MW in 2011/12 to 1,656MW in 2017. This represents an average annual increase of 6%. See the figure below.

Figure 4: Electricity Peak Demand growth (2012/13-2016/17 FY



The rise in peak demand is associated with the increased number of consumers connected over the same period. The country has experienced a significant increase in the number of customers connected by an average annual growth of 25.1%.This is as a result of the accelerated electrifications.

2.8.1. Peak load and load duration 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 daily load curves for different months and weeks. Typical daily and weekly load duration curves are depicted in figure 5 and 6

Figure 5: Day Load curve, 25th Jan 2017

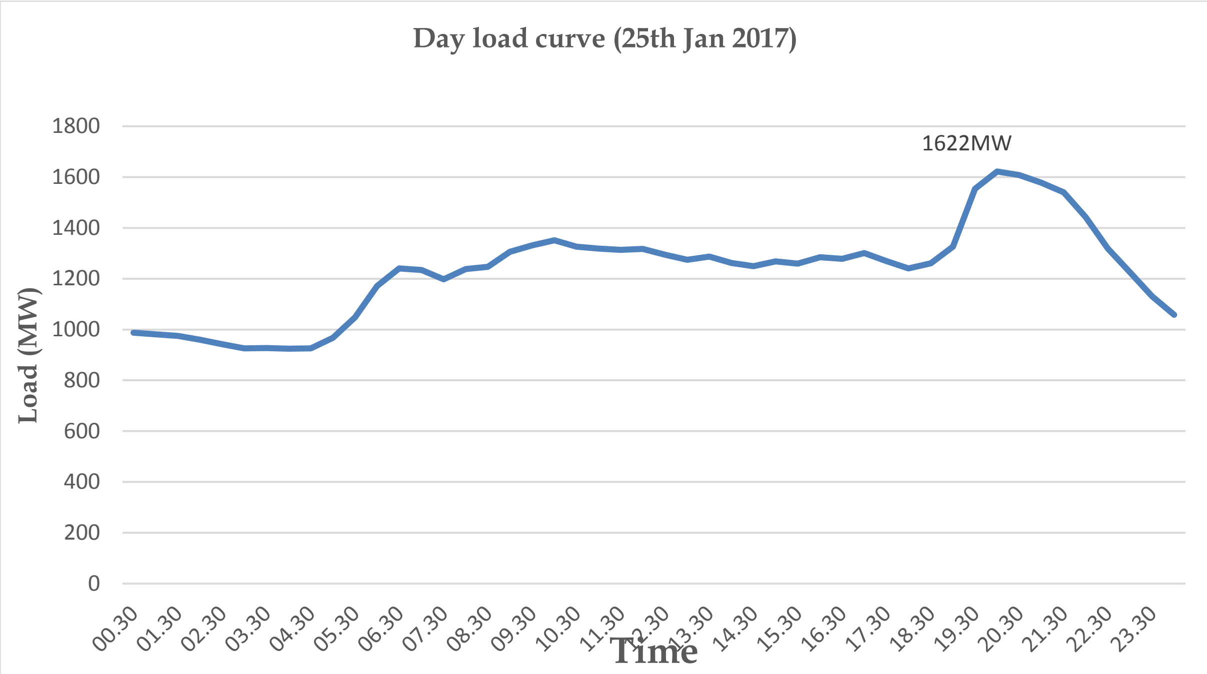
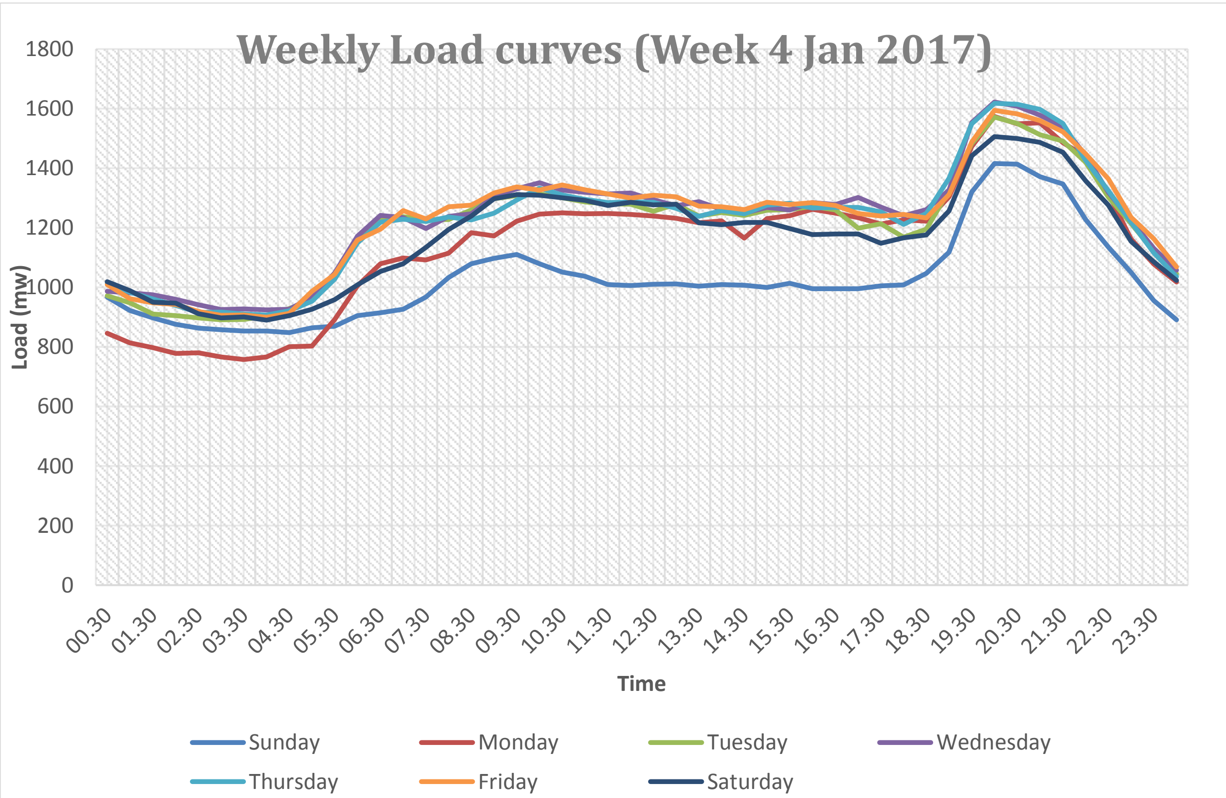
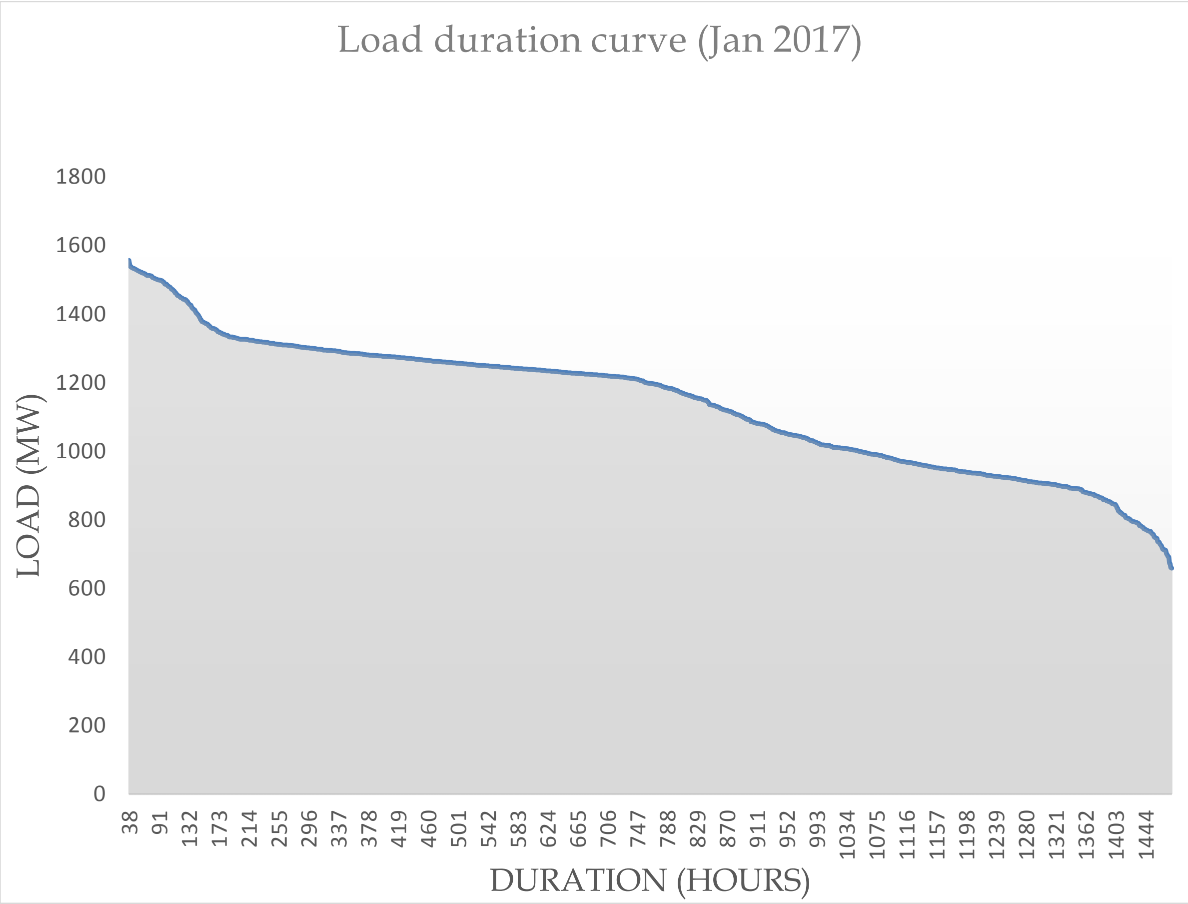


Figure 6: Weekly load curve, week 4 of January 2017



As indicated in the two figures there is no variation in the load pattern throughout the week and day. 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 figure 7.

Figure 7: Load duration curve – January 2017



2.8.2. Electricity balance

Table 9 represents the electricity supply and demand balance for the period between 2012/13 and 2016/17. During the period under review, the total generated capacity rose from 8,087 GWh to 10,205GWh, while the net supply increased from 6,581GWh to 8,272 GWh. However, the total loses have consistently increased over the same period from 1,507 GWh in 2013 to 1,933 in 2017. This is equivalent to a 28% increase. It can be deduced that with increased connectivity technical loses are expected to increase as a result of low voltage connections that have typical higher losses.

Table 10: Electricity supply/Demand balance 2012/13-2016/17 FY

Year	Peak Demand	Hydro	Thermal	Geothermal	Cogen	Solar	wind	Imports	Total Supply	Transmission Losses	Distribution & Commercial Losses	Total loses	Net Supply to Consumers	
	MW	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	**Net Supply**	**% of Total Supply**
2012/13	1,354	4,298	2,060	1,599	71	1	15	43	**8,087**	338	1,169	1,507	6,581	81%
2013/14	1,458	3,944	2,725	2,008	57	1	18	87	**8,840**	396	1,200	1,506	7,244	82%
2014/15	1,512	3,310	1,778	4,060	14	1	38	79	**9,280**	460	1,164	1,624	7,655	82%
2015/16	1,586	3,787	1,296	4,609	0	1	57	67	**9,817**	485	1,420	1,905	7,912	81%
2016/17	1,656	3,341	2,165	4,451	1	1	63	184	**10,205**	426	1,507	1,933	8,272	81%

2.8.3. Loss Reduction Strategies

Electricity utilities experience both technical and commercial losses along the value chain from the generation front to the retail end. Technical losses are inherent in the process of transmitting and distributing electrical energy because power networks consume and lose a proportion of the energy transported. Commercial losses occur due to electricity pilferages, faulty meters and inaccuracies in meter reading. As at June 2017 the system loses stood at 1,933 GWh which is about 18.9% of the total energy purchased. The Energy Regulatory Commission (ERC) allows an amount of total losses incurred not to be higher than 15.9% of the energy generated. This implies that more intensive programs are required to significantly reduce the current amount of losses incurred.

Reduction in energy losses leads to increase in the trading margin which ultimately improves financial sustainability. According to the KPLC annual report 2016/17, the Company is working towards reducing system losses from double to single digit over time to improve the energy balance, reduce energy purchase costs and consequently increase revenues. To achieve this, KPLC is investing in system management tools and bulk digital metering solutions that allow data gathering to effectively understand and monitor consumer behaviour, network impact and control energy usage.

In addition, the Company is adopting appropriate modern and more efficient cost saving technologies such as smart metering, feeder metering, and outdoor metering. Currently KPLC is in the process of adopting a loss reduction strategy that will focus on reducing technical loses and achieve revenue protection through automatic metering financed by World Bank. The Company aims at installing Automatic Metering Infrastructure (AMI) to 44,300 large and medium consumers.

2.8.4. Suppressed Demand

In the Kenyan system, a suppressed demand of about 3.58% has been assumed in recent years. In the projections 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 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.

2.8.5. 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 is 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 expected unserved energy used in the Kenya studies is $1.5/kWh.

2.8.6. The Cost of Expected Unserved Energy (CEUE)

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 is USD 1.5/kWh as recommended by Lahmeyer international. There are however studies that have shown this number to be as high as USD 7/kWh for the industrial sector (PB Power) and 1.79 USD/kWh (World Bank).

3. ELECTRICITY DEMAND FORECAST

3.1. Introduction

The load forecast presented in this Chapter covers a period of 20 years, from 2017 to 2037. It is an updated version of the load forecast presented in the Generation and Transmission master plan 2016. It sets out the following:

i. The economic context of Kenya's current and future development.
ii. The methodology used for preparing the forecast, the assumptions underlying the forecast, and the results of the forecast, both for energy and system peak load.

3.2. Objectives of the forecast

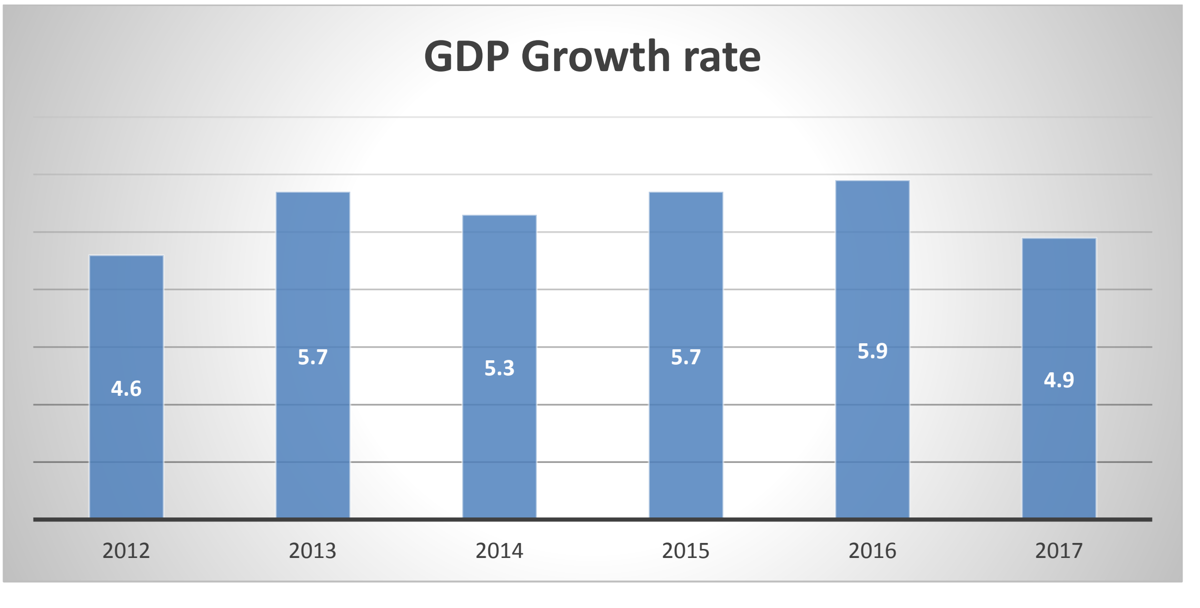
The main objective of this demand forecast is to develop an acceptable and accurate assessment of the future electricity demand for purposes of an optimal expansion plan. The specific objectives include:

i. Provide current and future context of the economy and the power sector
ii. Reviewing the key demand driving factors identified in previous plans.
iii. Updating assumptions used in the previous forecast.
iv. Updating the status of the flagship projects
v. Providing revised forecast results for the period 2017-2037.

3.3. Overview of the Domestic Economy

The country's real Gross Domestic Product growth over the last 6 years has been an average of 5.35%. The economy is estimated to have expanded by 4.9 percent in 2017 compared to growth of 5.9 percent in 2016. The slowdown in the performance of the economy was partly attributable to uncertainty associated with a prolonged electioneering period coupled with adverse effects of weather conditions.

Figure 8: GDP Growth Rate, 2012- 2017

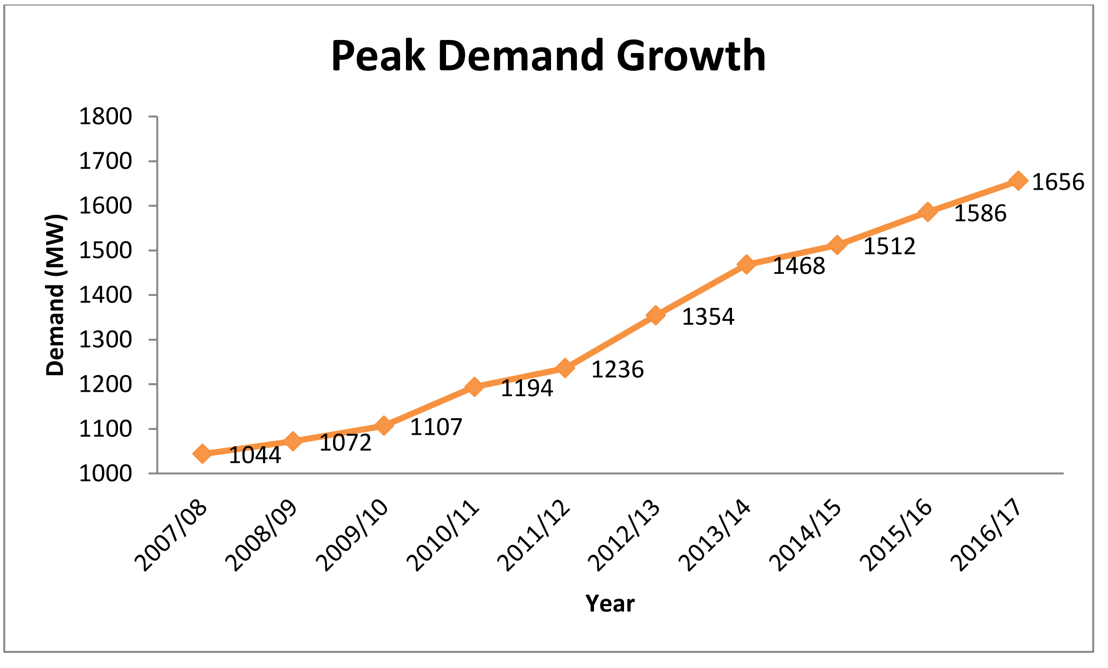


Performance across the various sectors of the economy varied widely, with Accommodation and Food services; Information and Communication Technology; Education; Wholesale and Retail trade; and Public Administration registering accelerated growths in 2017 compared to 2016. On the other hand, growths in Manufacturing; Agriculture, Forestry and Fishing; and Financial and Insurance decelerated significantly over the same period and therefore dampened the overall growth in 2017.

3.3.1. Past Performance of the Power Sector

Electricity peak demand has been growing gradually over the last 10yrs with an annual growth of approximately 5% per annum. The energy consumed increased from 6,692GWh in 2009/10 to 10,205GWh in 2016/17 representing a 52% growth.

Figure 9: Peak demand growth



The electricity consumption increased from 6,581 GWh in 2012/13 to 8,272 GWh in 2016/17 which is approximately 26% growth. Similarly, the country has experienced a significant increase in the number of customers connected by an average annual growth of 28%.This is as a result of the accelerated electrification initiative towards universal electricity access. The average consumption has shown a decline over the last five years.

Table 11 summarizes the consumption patterns, consumer trends and customer growth for the last 5yrs.

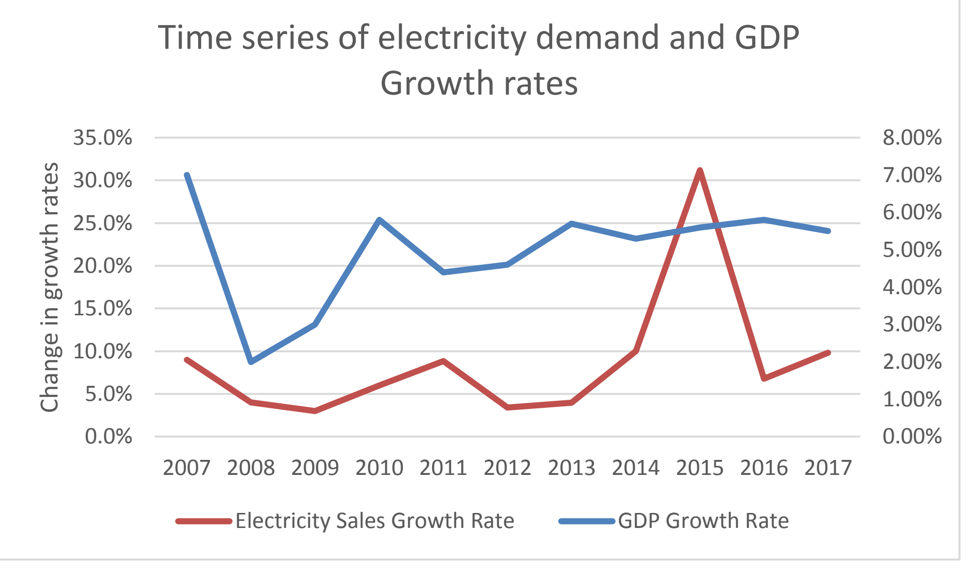
Table 11 : Consumption patterns, consumer trends and customer growth 2012/13 – 2016/17 FY

	2012/13	2013/14	2014/15	2015/16	2016/2017
NATIONAL					

Annual Consumption (GWh)	6,581	7,244	7,655	7,912	8,272
No. of customers	2,330,962	2,767,983	3,611,904	4,890,373	6,182,282
Average Consumption (kWh)	2,823	2,617	2,119	1,618	1,338

The commercial/industrial sales depend highly on the performance of the manufacturing sector and large commercial establishments in the economy which are highly driven by the GDP growth. For the past 10 years the GDP growth and Electricity sales has shown a correlation.

Figure 10: Annualized growth in electricity and GDP growth



3.3.2. Future Economic Outlook: The Vision 2030

The foundation upon which to build a prosperous Kenya is based on the Vision 2030's blueprint that aims to transform Kenya into a middle-income country by the year 2030 with an average GDP growth rate of 10% per annum over the years. During the second term of the current Government, a 'Big Four agenda" has been conceptualized . Key highlights of this agenda includes:

- Expanding the manufacturing sector through the blue economy, agro processing, textiles and leather. The government also committed to support growth of manufacturing by introducing Time of use of Tariffs between 10:00pm and 06:00am and creating an additional 1000SMEs among others.
- Access to affordable and decent shelter by making 500,000 new homeowners in the next 5 years.

- Universal healthcare by reducing the cost and ensuring universal access to quality healthcare by 2022. This will be achieved by ensuring all Kenyans are covered by NHIF
- Food security and nutrition. This will be achieved through among others, encouraging and facilitating large-scale commercial agriculture through irrigation and other technologies.

Infrastructure services such as electricity, transport and ICT are critical enablers of sustained economic growth and national transformation through the Vision 2030 and implementation of the Big Four Agenda placing the electricity sector at the core of this policy.

3.4. Demand forecasting Methodology

3.4.1. General approach of the forecast

The Laymeyer International Excel based Demand Forecast Model was used for energy demand forecasting. The Model was developed specifically for the Generation and Transmission Plan, Kenya case. It is based on the Model for Analysis of Energy Demand (MAED) principles and previous sector LCPDP plans. The following steps were followed in the development of the Model:

Trend-projection was used for correlation analysis of the different factors affecting electricity demand growth in the country.

A Bottom-up approach was adopted for calculation of demand for domestic consumers, street lighting and flagship projects as identified in the Vision 2030.

Sensitivity was carried out using three scenarios; reference, High and Low.

3.4.2. Energy demand structure

The forecasting approach followed the existing tariff categories and usage levels:

a) Domestic consumption: this includes KPLC, off peak tariff and REP domestic consumers.
b) Small commercial consumption: This includes Small commercial and off peak tariff small commercial consumers.
c) Commercial and Industrial consumption: this represents large power consumers in tariff categories CI1 to CI5.

3.4.3. Street Lighting:

Losses were dis-aggregated based on the voltage levels:

- Low Voltage level (415/220 V or 433/250V):
- Medium Voltage level (11 & 33 kV):
- High Voltage level (66, 132& 220 kV):

Main drivers of the projected demand

Key driving factors of demand considered are:

a) **Demography of Kenya**: This includes population growth and urbanization. It has an explicit effect on domestic consumption and connectivity level. Three scenarios have been considered in this plan; Reference, High and Low.
b) **GDP growth**: directly impacts on household's income and activity of the productive sector translated into electricity consumption of commercial and industrial customers. Three scenarios of GDP growth are assumed: low, reference and high scenario.
c) **Vision 2030 Flagship projects**: These projects have an impact on GDP growth and contribute to demand growth based on their specific load requirements. The impact of these projects have however been tempered with reality that not all the proposed projects will be realized in the time they are planned for hence only those foreseen to happen in the near future have been considered

3.5. Methodologies and assumptions

3.5.1. Definition of the Scenarios

3.5.1.1. Reference Scenario

This is the base case scenario with development projected from the historical growth

3.5.1.2. High Scenario

This scenario is based on the development patterns highly driven by Vision 2030 growth projections and implementation of flagship projects.

3.5.1.3. Low Scenario

The Scenario represents a low growth trajectory where most of the government plans are not implemented as planned. It is assumed that in this scenario economic development will be at the existing rate with no expected increase during the planning period.

3.5.2. Planning steps

The forecast is done along the following steps:

Step 1: Data input and assumptions on population growth/urbanization, electrification/connectivity, consumption trends, GDP and flagship projects assessment.

Step 2: Calculation for electricity consumption by tariff groups (domestic, street lighting, small commercial, large commercial / industrial) for four different geographic areas (power system areas: Nairobi, Coast, Mt Kenya, Western); applying the formulas for each year of the study period as indicated below:

For tariff groups: domestic, street lighting, small commercial,

$C_{B,TG,PSA}\,(y) = \{SC_{TG,PSA}(y) + SD_{TG,PSA}\,(y)\} \times \#c_{TG,PSA}(y)$

For tariff groups: large commercial / industrial

$C_{B,G,PSA}\,(y) = GDP_{KE}\,(y) \times a_{PSA} + b_{PSA}$

Where:

#c Number of connections

a, b Coefficients of (past) linear correlation between consumption and GDP in absolute figures

$(C = a \times GDP + b)$, by power system area

CB Consumption billed (net) in GWh

GDPKE Gross Domestic Product of Kenya in KES

PSA Power system area

SC Specific consumption in kWh/year

SD Suppressed demand (which can be served in this particular year) in kWh/year

TG Tariff group

y Year

This has been replicated for each power system area and for the entire country where:

$$PSA\ consumption = \left(\sum Tariff\ group\ consumption\right) + flagship\ projects\ load$$

$$Total\ consumption\ (Kenya) = \sum PSA\ consumption$$

Step 3: Demand from future flagship projects load is added to the existing consumer structure, assessed based on expected peak load and load (utilisations) factors. This is computed for the reference and high scenarios:

$$C_{B,FPS,PSA}(y) = \sum_{FP=1}^{x} [P_{FP}(y) \times LF_{FP}(y)]$$

Where:

CB Consumption billed (net)

FP Flagship project

LF Load factor of tariff group / flagship project in %

P Peak load in MW

PSA Power system area

y Year

Step 4: Total Losses for respective voltage levels are added (LV, MV, HV) to arrive at the total losses for each PSA and the overall national loss level.

The gross consumption (power plant and transmission network sent-out) is arrived at by a summation of the total consumption billed plus total losses. This has also been computed for each PSA:

$$C_{PP}(y) = \frac{C_B(y)}{(1 - L_{HV,MV,LV})}$$

$$C_{PP,PSA}(y) = \frac{C_{TN,PSA}(y)}{(1 - L_{HV})}$$

Where:

CB;CPP;CTN Consumption billed (net); power plant sent-out (gross); transmission network sent-out (substation, incl. distribution losses) in GWh

HV High voltage

L Losses (share of corresponding voltage level) in %

LV Low voltage

MV Medium voltage

PSA Power system area

y Year

It is assumed that losses as percentage share will be decreasing based on the KPLC loss reduction trajectory over the plan period.

Step 5: System peak load is derived at by adding the total losses to the product of total consumption billed, load factor and responsibility factor.

$$P_{PP}(y) = \sum_{TG,FP=1,PSA=1} \{C_{PP,TG/FP,PSA}(y) \times LF_{TG/FP,PSA}(y) \times RF_{TG/FP,PSA}(y)\} \times SF$$

Where:

CCPP Consumption power plant sent-out (gross) in GWh

FP Flagship project

LF Load factor of tariff group / flagship project in %

P Peak load in MW

PSA Power system area

RF Responsibility factor (share of peak load contributing to system peak) of tariff group / flagship project in %

SF Simultaneous peak factor (of peak load power system area) = peak load system / sum peak loads power system areas in %

TG Tariff group

y Year

Table 12: Domestic consumption assumptions

Category	Data sources	Assumptions, parameters
Demography	KNBS Census 2009 (county level) CBS Census 1999	All scenarios: Census 2009 forecast basis, Census 1999 for past long term developments

Population growth	UN medium fertility scenario forecast LCPDP 2013 population forecast	Reference & low: 2017: 49.2 million; 2022: 55.5 million; 2037: 76.5 million; growth: 1.8% – 2.5%/year Vision: 2017: 46.1 million; 2022: 52.0 million; 2037: 71.7 million; growth: 1.71% – 2.5%/year (impact of stronger economic growth of Vision 2030)
Household size	KNBS Census 2009, Census 1969	2017: 4.1 (urban: 3.6 rural: 4.6) persons / household 2022: 4.0 (urban: 3.5 rural: 4.5) persons / household 2037: 3.5 (urban: 3.4 rural: 4.0) persons / household
Share of total urban population Urbanization rate,	UN World Urbanization Prospects - Urban Population 1950 - 2050 for Kenya: The 2011 Revision Vision 2030 Sessional Paper 2012 based on CBS 1999 projections	Reference & low: 2017: 35.4%; 2022: 38.5%, 2037: 48.6%; annual urbanization rate: 3.87% /year Vision: 2017: 38%; 2022: 47%, 2037: 76%; annual urbanization rate: 5.81% (representing impact of stronger economic growth of Vision 2030)
Electrification targets (connectivity level), connection rate	National Electrification Strategy KPLC historical data	Reference: 2017: 67%, 2022: 96%, 2024: 99%; 2017: 1.29 million connections, assumed 1.0 million connections per annum with a

		reduction of 5% per year. All scenarios: distribution of rural/urban connections according to historic split per power system area
		Low: 2017: 67% 2022: 84%; 2037: 86%; 2016: 0.824 million connections
		Vision: 2017: 70%, 2020 (onwards): 99%; 1.26 million connections per year
Annual consumption per connection (specific consumption) in kWh	KPLC annual reports Household survey 2012; Household survey 2015.	Reference: urban: 250, rural: 150, annual increase (connected): 4%
		Low: urban: 200, rural: 100, annual increase (connected): 4%;
		Vision: urban: 400, rural: 200, annual increase (connected): 6%;
Suppressed demand	KPLC annual Reports 2016/17 Load shedding data 2016/17	Outages (forced & Planned) Base year 2.93% Annual reduction of 0.1% Target 0% for Reference: 2037 Low: 2040 Vision: 2025

		Curtailed Demand Base year 5.63% Annual reduction of 0.3% Target 0% for Reference: 2037 Low: 2040 Vision: 2025

Table 13: Small commercial consumption assumption

Category	Data sources	Assumptions, parameters
Electrification / connections	KPLC annual reports 1989 – 2017 transferred to calendar years	All scenarios: growth new connections 44% of growth new domestic connections (= historic correlation 2005 – 2016)
Annual consumption per connection (specific consumption)	KPLC annual reports 1989 – 2017 transferred to calendar years	Increase in specific consumption Reference: annual increase: 1%; Low: annual increase: 1%; Vision: annual increase: 2%;
Suppressed demand	See domestic consumption assumption Table 12	

Table 14: Street lighting consumption assumption and calculation

Category	Data sources	Assumptions, parameters
Electrification / connections	KPLC annual reports 1989 – 2016 transferred to calendar years	All scenarios: growth new connections 80% of growth new domestic connections (= historic correlation)
Annual consumption per connection (specific cons.)	KPLC annual reports 1989 – 2017 transferred to calendar years	Increase in specific consumption Reference: annual increase: 1%; Low: annual increase: 1%; Vision: annual increase: 2%;
Suppressed demand	KPLC street lighting data	All scenarios: see domestic consumption assumption Table 12 2017: 30% of urban areas covered, Full coverage Reference: 2027, Low: 2032, Vision 2025. Repair of lamps Reference: 2027, Low 2032, Vision: 2025

Table 15: Large commercial & industrial consumption assumption

Determined by	Data sources	Assumptions, parameters
Connections & consumption through GDP growth	KPLC annual reports 1989 – 2017 transferred to calendar years, KNBS GDP 2006 – 2016 (the 2017 GDP growth estimate was applied (5.0%),	All scenarios: by power system area for historic linear correlation based on 2009 – 2016 GDP and consumption data

	IMF GDP projection 2018 – 2022, Vision 2030 documents	Nairobi: C = 0.44 x GDP + 449 Coast: C = 0.20 x GDP + 71 Mt Kenya: C = 0.09 x GDP - 59 Western: C = 0.17 x GDP - 9 Refer to equation on large commercial and industrial consumers Step 2 Reference: GDP growth = IMF projection up to 2022. from 2023 the applied GDP is an average of 7.5% with 10% GDP growth being achieved in 2030 Low: GDP growth = average 2009 – 2016 = 5.02% / year for the entire planning period Vision: GDP growth = Vision 2030 growth target 10% 2025 on-wards
Suppressed demand	See domestic consumption assumption Table 12	

3.5.3. Vision 2030 flagship projects

Vision 2030 recognizes energy as one of the enablers of sustained economic growth and a key foundation of Kenya's envisaged national transformation. The vision identifies projects that have a significant bearing on future GDP growth as well as an effective spike in energy demand.

Table 16 shows the flagship projects and their respective assumptions considered in the forecast.

Table 16: Flagship projects and their assumptions

Project	Reference				High			
	First year of operation	Initial load [MW]	Year of total load	Total load [MW]	**First year of operation**	Initial load [MW]	**Year of total load**	Total load [MW]
Electrified mass rapid transit system for Nairobi	**2024**	15	2030	50	**2022**	15	**2027**	50
Electrified standard gauge railway Mombasa - Nairobi	**2022**	98	2030	130	**2021**	100	**2028**	300
Electrified standard gauge railway Nairobi - Malaba	**2026**	61.74	2035	61.74	**2024**	63	**2032**	189
Electrified LAPSSET standard gauge railway	**-**	-	-	-	**2035**	30	**2037**	30
Oil pipeline and Port Terminal (LAPSSET)	**2025**	50	2037	150	**2022**	50	**2032**	150
Refinery and Petrochemical Industries (LAPSSET)	**2028**	25	2037	100	**2025**	50	**2030**	200
Konza Techno City	**2024**	2	2037	190	**2022**	2	**2034**	200
Special Economic Zones	**2021**	5	2037	110	**2020**	30	**2028**	110
Integrated Steel Mill					**2030**	100	**2035**	200

3.6. Demand forecast results

The forecast results developed for the peak load (MW) and energy consumption (GWh) for the long term period 2017 (base year) to 2037 are presented in this section based on the three defined scenarios:

3.6.1. Electricity consumption and peak load - reference, High, low scenarios

Annual electricity demand and peak load are expected to grow for all scenarios over the planning period. For the reference scenario, the gross electricity consumption grows from 10,465GWh in 2017 to 14,334GWh and 39,187GWh in 2022 and 2037 respectively as per Table 16. This represents an average annual growth of 6.7% per annum.

Table 17: Energy Demand by scenarios (with flagships)

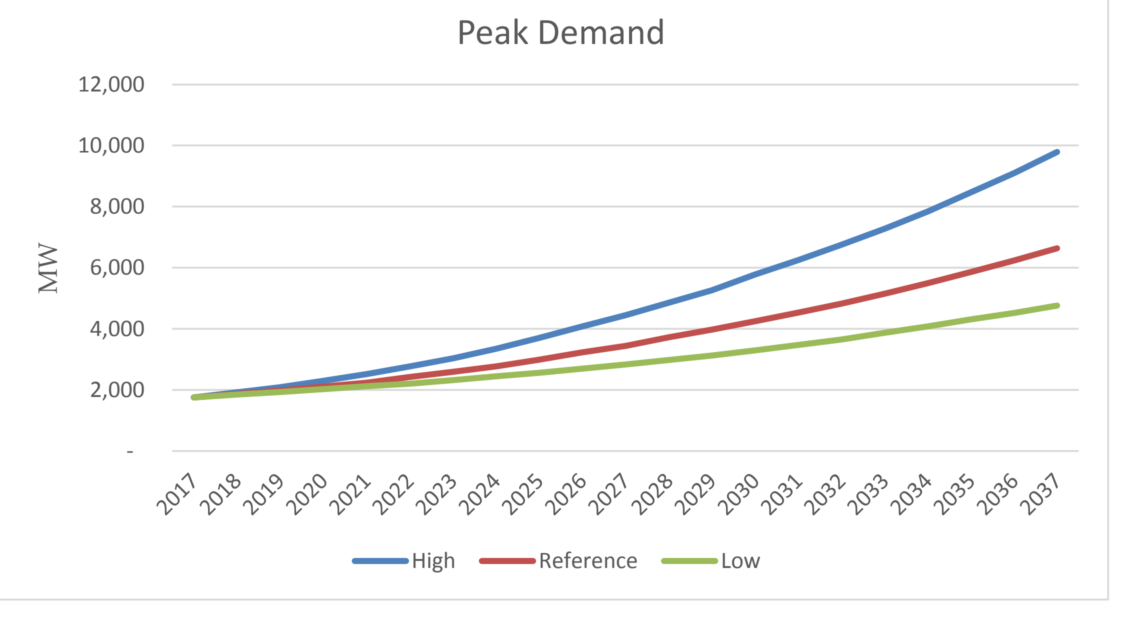
	Low			**Reference**			**High**			**Losses (Reference Scenario)**
Year	**GWh**	**Growth**	**MW**	**GWh**	**Growth**	**MW**	**GWh**	**Growth**	**MW**	%
2017	10,465	4.9%	1,754	10,465	4.9%	1,754	10,465	4.9%	1,754	19.0%
2018	11,032	5.4%	1,842	11,169	6.7%	1,866	11,470	9.6%	1,917	18.5%
2019	11,530	4.5%	1,928	11,820	5.8%	1,978	12,464	8.7%	2,088	18.0%
2020	12,071	4.7%	2,021	12,546	6.1%	2,103	13,676	9.7%	2,293	17.6%
2021	12,612	4.5%	2,114	13,312	6.1%	2,234	14,900	9.0%	2,516	17.0%
2022	13,156	4.3%	2,207	14,334	7.7%	2,421	16,456	10.4%	2,766	16.5%

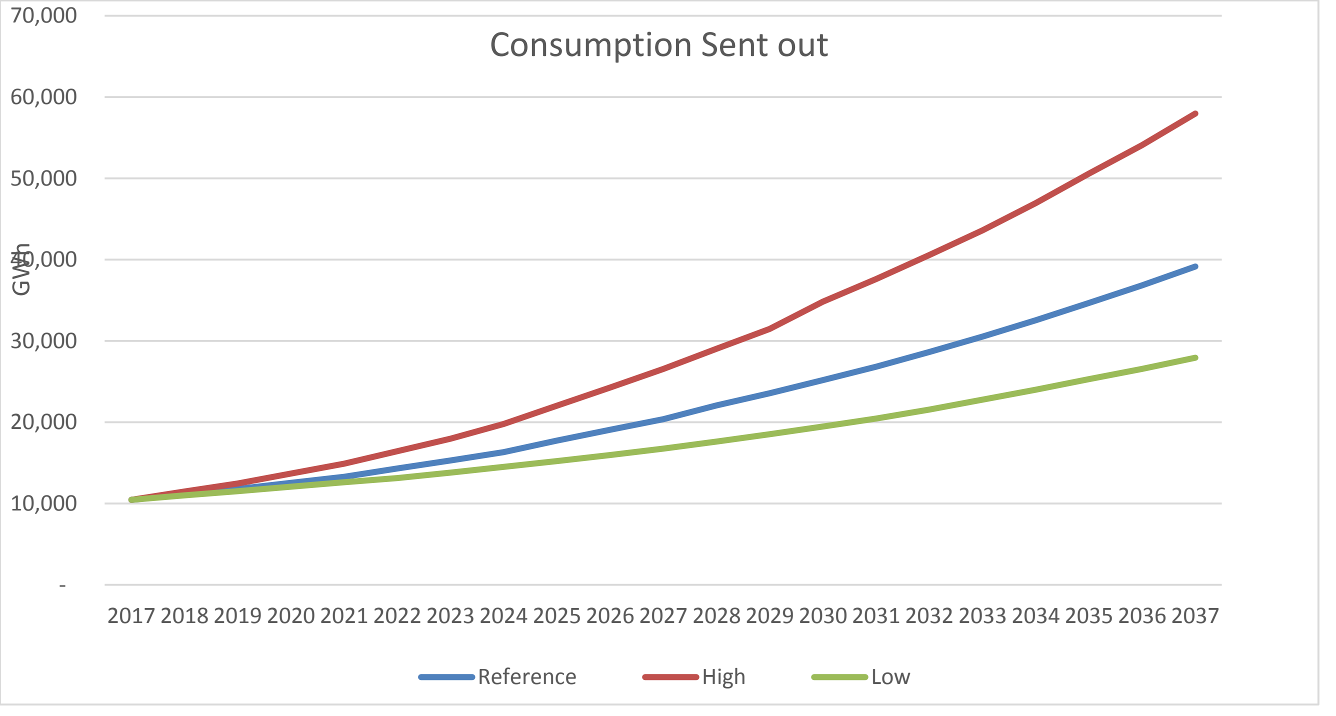
2023	13,810	5.0%	2,319	15,293	6.7%	2,586	17,989	9.3%	3,027	16.5%
2024	14,503	5.0%	2,438	16,327	6.8%	2,764	19,799	10.1%	3,342	16.6%
2025	15,229	5.0%	2,563	17,750	8.7%	2,989	22,056	11.4%	3,705	16.6%
2026	15,982	4.9%	2,692	19,098	7.6%	3,224	24,295	10.1%	4,078	16.6%
2027	16,780	5.0%	2,829	20,393	6.8%	3,441	26,572	9.4%	4,450	16.6%
2028	17,627	5.0%	2,975	22,082	8.3%	3,720	29,043	9.3%	4,854	16.6%
2029	18,525	5.1%	3,129	23,593	6.8%	3,974	31,509	8.5%	5,261	16.6%
2030	19,475	5.1%	3,293	25,195	6.8%	4,244	34,847	10.6%	5,780	16.6%
2031	20,482	5.2%	3,466	26,864	6.6%	4,525	37,632	8.0%	6,251	16.6%
2032	21,552	5.2%	3,651	28,640	6.6%	4,826	40,587	7.9%	6,752	16.6%
2033	22,798	5.8%	3,872	30,529	6.6%	5,148	43,635	7.5%	7,272	16.6%
2034	24,008	5.3%	4,081	32,542	6.6%	5,491	46,954	7.6%	7,842	16.6%
2035	25,297	5.4%	4,305	34,691	6.6%	5,859	50,595	7.8%	8,468	16.6%
2036	26,561	5.0%	4,523	36,848	6.2%	6,232	54,105	6.9%	9,094	16.6%
2037	27,945	5.2%	4,763	39,187	6.3%	6,638	57,990	7.2%	9,790	16.6%

Electricity demand is expected to grow to 9,790MW in 2037 which is more than five times of the peak demand of 1,754MW in 2017 in the high scenario. This is mainly driven by the utilization of load achieved through the implementation of the flagship projects. In this scenario the energy consumed grows from 10,465GWh in 2017 to 57,990GWh in 2037 which is approximately 8.8% growth per year.

In the low scenario, the electricity consumption growth is gradual over the planning period averaging 5% per annum. The energy consumed increases to 27,945 GWh by the year 2037 from 10,465 GWh in 2017.

Losses in the reference case are expected to reduce to 16.6 % in the year 2037 from 19% in the base year an annual average of 0.1% reduction.





The comparison of the consumption between the Reference scenario and the high scenario indicate that consumption for the high scenario is expected to almost double the reference scenario. This is as a result of the assumed higher GDP growth projection based on the Vision 2030 and the injection of the specific load requirements upon realization of the flagship projects.

3.6.2. Demand forecast by power system areas

Annual electricity consumption is expected to increase gradually over the planning period for all power system areas in all scenarios. The reference case shows that in the future a higher annual average growth will be recorded in Mt Kenya (7.8%) followed by western region (7.6%). Coast and Nairobi regions comes last with growth rates averaging at 6.9% and 5.8% respectively. However, even with low growth rate, Nairobi region records the highest consumption in both 2022 (6,252GWh) and 2037 (15,433GWh). The peak demand averages at about 1, 047MW in 2022 and 2, 655MW in 2037.

Injection of flagship projects prove to have a great impact on consumption and peak demand. In the vision scenario, demand in the western region grows from 359MW in 2017, 682MW in 2022 and 2,734MW in 2037. This is more than seven (7) times growth in demand in only one region. Thus growing capacity conjointly with demand will drive the country into an industrialized middle income nation as stipulated in the vision 2030. The tables below summarize growth in energy and demand in various region throughout to the LTP. A summary of the consumption and energy by regions is shown in annext 6 of this report

3.7. Comparison of the demand forecast results with the previous forecast

A comparison of the reference scenario forecast results indicate minimal deviation from the previous forecast. The energy consumption shows a 0.06% increase in the current forecast over the planning period. However, a slight decline in the forecast is recorded in the high and low scenarios.

Table 18: Comparison of electricity demand forecast (current and previous)

Year	**DESCRIPTION**	**GWh**	**MW**	**GWh**	**MW**	**GWh**	**MW**
		Low		**Reference**		**High**	
2022	CURRENT	13,156	2,207	14,334	2,421	16,456	2,766
	PREVIOUS	13,453	2,250	14,225	2396	17,516	2,954
	CHANGE	(297)	(43)	109	25	(1,060)	(188)
2037	CURRENT	27,945	4,763	39,187	6,638	57,990	9,790
	PREVIOUS	29,091	4,946	38,136	6,437	59,397	10,033
	CHANGE	(1,146)	(183)	1,051	201	(1,407)	(243)
2017-2037	Current Growth rate	5.00%		6.70%		8.8%	
2015-2035	Previous Growth rate	5.24%		6.68%		9.07%	
	CHANGE	-0.24%		0.02%		-0.27%	

4. ASSESSMENT OF NATURAL ENERGY RESOURCES IN KENYA

4.1. Current And Future Energy Sources

This chapter discusses the energy sources and fuels utilized for power generation in Kenya as well as the planned and potential energy sources for future electricity generation. It evaluates the characteristics of fossil fuels considering transport infrastructure and future fuel price developments. It also provides an overview of renewable energy sources including hydropower, solar, wind, biomass, biogas, waste-to-energy and geothermal energy. Nuclear fuel and interconnections with neighbouring countries as potential future energy sources has also been discussed.

4.1.1. Fossil energy sources

Fossil energy sources are defined as hydrocarbon deposits formed in the geological past from the remains of living organisms. In this study they are differentiated by their texture and aggregate state, i.e. liquid, solid and gaseous energy sources.

At present, coal is the only domestic fossil energy resource available for extraction and potential use in power generation. Exploration activities on crude oil and natural gas deposits are underway and for gas still in the appraisal stage. Currently, national primary energy consumption is dominated by biomass (charcoal and wood fuel) accounting for 69%. This was followed by petroleum products (22%), electricity (9%, about a third based on the fossil fuels heavy fuel oil (HFO) and gasoil products, the remaining based on renewable energy sources), and coal (1%). Demand for petroleum products has been increasing steadily by approximately10% annually.

4.1.2. Crude oil and liquid petroleum products

4.1.2.1. Crude oil

Crude oil is a liquid fossil fuel consisting of a complex mixture of hydrocarbons found in and extracted from geological formations beneath the Earth's surface. It is the basis for a wide range of liquid, gaseous and solid petroleum products produced in refineries.

During the past 50 years, crude oil has been the major energy source in the world measured by energy content, being nearly 10% ahead of the second placed coal. This is due to its dominance in the transport sector. For electricity generation it plays a less dominant role, though it is still important for some petroleum products (such as gasoil and HFO) as well as for selected oil producing countries. In Kenya there are no power plants fuelled by crude oil but successive petroleum products from the local refinery and imports, such as HFO and diesel oil, are used for power generation.

Kenya's electricity sector relies considerably on imported crude oil and petroleum products fuelling nearly 40% of the installed power generating capacity[1]. With the commissioning of geo- thermal power plants this dependency has decreased in recent years. To this day all petroleum products used in Kenya are imported including crude oil as well as refinery products. Until its operation stop in 2013, imported crude oil was refined in the Kenya Petroleum Refineries Limited (KPRL) and processed into various petroleum products for use in domestic power generation. Crude oil imported into Kenya is sourced from Abu Dhabi (referred to as "Murban crude") and Saudi Arabia (referred to as "Arabian Medium") with corresponding quantity shares of 75% and 25% respectively. The Abu Dhabi crude oil variety is of higher quality as it produces more diesel, gasoline, kerosene and less heavy fuel oil than the Arabian Medium variety.

Kenya had a total of 46 onshore and offshore exploration blocks across the country and off the coast and a total of 43 exploratory wells which have been drilled in four basins (Lamu, Mandera, Anza, Tertiary Rift) by 2015[2]. A corresponding number of 41 licences have been awarded to international oil firms (exploration and production companies) to carry out exploratory activities. Figure 1 below provides an overview of ongoing exploration activities in Kenya as from July 2015.

[1] KPLC, *Annual Report 2014/2015* (2015)
[2] Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (2015)

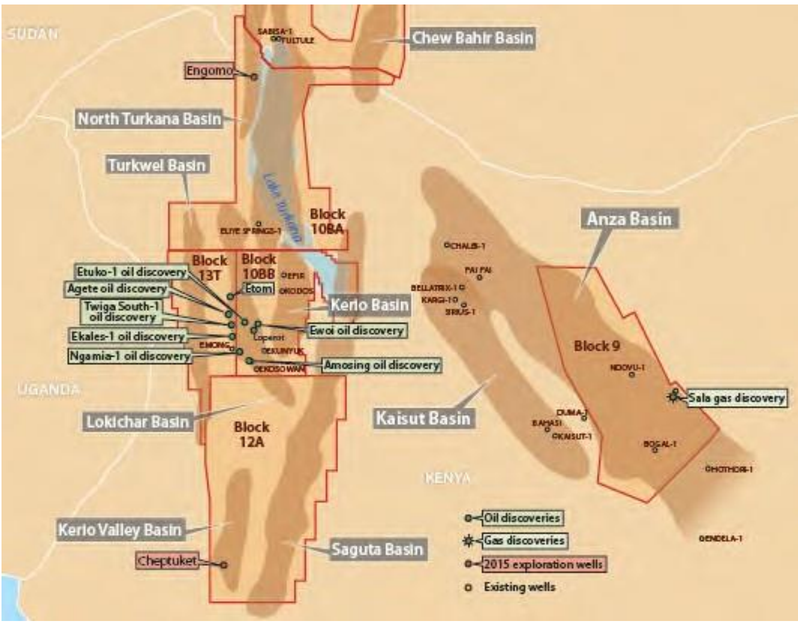


Figure 12: Exploration activities in Kenya

Domestic crude oil deposits have been located in Turkana, the northern most county of Kenya bordering Uganda and South Sudan. Extraction in Turkana is expected to start soon. The crude oil from Turkana is planned to be transported via a pipeline to Lamu for export. The commercial viability of exploitation and export or domestic refining of the crude is still being analyzed.

4.1.2.2. Heavy fuel oil

Heavy fuel oil (HFO) or residual oil is a fraction at the lower end of the fractioning column obtained during the distillation process in the refinery. As a residual product, it is of low quality compared to most petroleum products. High viscosities require pre-heating for transport. HFO also includes a high share of impurities, such as water, soil and sulphur depending on the crude oil. It is mostly used as a relatively cheap but still liquid fuel for power generation and shipping. Its use brings higher environmental risks than for other fuels through higher quantities combusted and a wider range of harmful substances (sulphur dioxide, soot, etc.) in the exhaust gases. As for every fraction, various kinds of HFO exist distinguished by their viscosity and net calorific value.

A large share of HFO used in Kenya is burned in diesel power plants, such as in the Kipevu Power Station in Mombasa. Besides power generation, the remaining share is used for industrial production. At present all HFO is imported through Mombasa port and transported by road to the power plant sites.

HFO is not recommended as suitable fuel option for any expansion candidate given its negative environmental impacts. Replacing its use at existing power plants should be also the aim of the expansion planning.

4.1.2.3. Gasoil and kerosene

Gasoil and kerosene are fractions at the middle of the fractioning column obtained during the distillation process in the refinery. Various kinds of gasoil exist distinguished by their viscosity and net calorific value. Gasoil and kerosene are at the upper end of the cost range of generation fuels. It is only used if heavier fuels such as HFO cannot or must not (for environmental reasons) be burned, if cheaper fuels are not available, or as a starter fuel. Kerosene is used in households (e.g. for lighting and generators), it powers jet engines of aircrafts, but also gas turbines in power stations.

The transport sector accounts for the largest share of the total gasoil consumption in Kenya. The remaining share of gasoil consumption is typically used for power generation in emergency power generation units, such as Aggreko rented power, and large isolated grids. For power generation in Kenya, kerosene is used in gas turbines such as for the Muhoroni Power Station.

Gasoil and kerosene are not recommended fuel options for expansion candidates given their high prices on the world market and, thus, high opportunity costs for Kenya. However, it could be an option to fuel backup and peaking capacity plants.

4.1.3. Gaseous fuels

4.1.3.1. Natural gas

Natural gas is a gaseous fossil fuel consisting of a mixture of hydrocarbons, primarily methane, found in and extracted from geological formations beneath the earth's surface. It can be distinguished by its composition and by the extraction technology required by the geological formation. Beside the natural gas extracted from gas fields, called natural gas that mainly consists of methane, there is also associated gas or flare gas. This gas is produced during the crude oil extraction process and is often flared. It generally shows a different composition than free gas. As relatively new gas types, unconventional gas resources are currently being developed such as shale gas or coal-bed methane trapped within shale and coal formations.

Natural gas has been the third important energy source in the world measured by energy content, behind crude oil and coal[3]. Its share has continuously increasing. Besides technical advances in the extraction and transport of natural gas as well as achieving a lower price than crude oil, the increased consumption is also due to its rather environmental friendly characteristics having virtually no sulphur content and low carbon dioxide emissions. This makes its important role for electricity generation to grow even further. However, the means of transport

[3] BP Statistical Review of World Energy June 2017

of natural gas are limited to gaseous form in pipelines or liquefied natural gas (LNG) in ships or trucks. These limitations restrict the use of natural gas to the vicinity of gas fields and an existing pipeline network with idle capacity or it requires relatively high investment costs for constructing new pipelines or the transport in form of LNG.

Africa Oil Corporation, a Canadian oil and gas exploration and production company, has discovered natural gas onshore in north-eastern Kenya. An appraisal plan to follow up the gas discovery is currently being evaluated in consultation with the Government of Kenya. In addition, the Africa Oil Corporation is considering drilling an appraisal well on the crest of the large Bogal structure to con-firm the large potential gas discovery which has closure over an area of up to 200 square kilometers. The gross best estimate of prospective resources for Bogal are 1.8 trillion cubic feet of gas based on a third-party independent resource assessment.

Due to the early stage of exploration, it is assumed that domestic natural gas will not be a potential energy source for power generation. If it were available in the long term, it would make economically sense in comparison to other energy source, in particular replacing environmentally more harmful fossil fuels. However, power generation based on domestic natural gas would have to compete (in terms of finite resources and price) with other consumers such as industry and households (e.g. for cooking).

4.1.3.2. Liquefied natural gas (LNG)

The supply of natural gas is mainly restricted by the available transport infrastructure. One relatively new option for large-scale power generation is the use of liquefied natural gas (LNG). This is natural gas liquefied at the country of origin, transported by special LNG ships to the port of destination, re-gasified in LNG terminals and then transported to the consumer through pipelines. The logistic facilities make up a considerable part of the overall LNG costs.

Due to the vast resources of natural gas worldwide, the potential for LNG is large in theory. It is restricted by required liquefaction and regasification facilities as well as competing demand on the world market. For Kenya, the discovery of natural gas deposits resulted in a government exploring opportunities for developing the domestic resource instead of importing.

LNG is recommended as an alternative fuel option to allow for the diversification of fuels used in power generation and its environmental advantage compared to more harmful fossil fuels. The import of LNG would also provide economic benefits for other consumers, such as in the industry, households or transport sector. If domestic gas resources were available imported LNG would most probably not be a competitive source.

4.1.4. Solid fuels

4.1.4.1. Coal

Coal is a solid fossil fuel consisting mainly of carbon, i.e. organic matters, and differing quantities of other substances such as minerals, sulphur or water. It is found in and extracted from geological formations beneath the earth's surface. For utilization in power plants, coal can be distinguished by the heating value and its composition ranging from lignite with a relatively low heating value to sub-bituminous coal. Coal has been the second most important fossil energy source in the world measured by energy content behind crude oil[4]. It is the most important fuel for power generation worldwide due to its abundant reserves, which are distributed relatively evenly among many countries. However, the use of coal is accompanied by strong environmental impacts, such as high emissions of sulphur dioxide, heavy metals and harmful greenhouse gases.

In Kenya local coal reserves can be found in the Mui Basin which runs across the Kitui county 200 km east of Nairobi. The coal basin stretches across an area of 500 square kilometers and is divided into four blocks: A (Zombe – Kabati), B (Itiku – Mutitu), C (Yoonye – Kateiko) and D (Isekele – Karunga). Coal of substantial depth of up to 27 meters was discovered in the said basin. 400 million tons of coal reserves were confirmed in Block C109. The Government of Kenya has awarded the contract for mining of coal in Blocks C and D. Coal mining, in particular open pit as planned for Mui basin, has strong environmental and social impacts. The mining will require large scale resettlement plans. Further, mining will produce considerable pollution. The local coal are of lower quality compared to imported coal from South Africa with regard to content of energy, ash, moisture and sulphur[5].

Due to its widespread deposits, production experience as well as relatively low costs, coal is an important fuel option for expansion planning but the negative environmental impacts has to be factored in. The planned Lamu power plant would be the first coal power plant in Kenya. Coal power plant based on domestic coal could be developed directly near the Mui Basin in Kitui County once the mine is developed.

4.1.5. Renewable energy sources

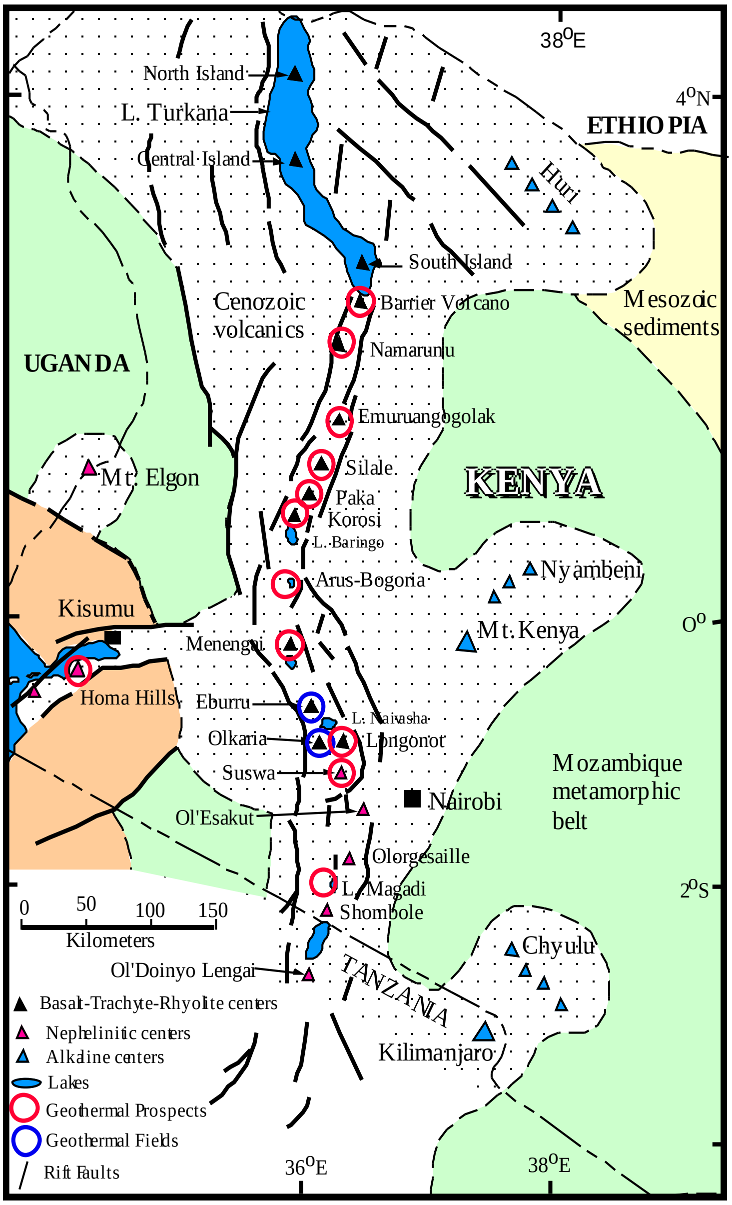
Kenya has promising potential for power generation from renewable energy sources. Abundant solar, hydro, wind, biomass and geothermal resources led the

[4] BP Statistical Review of World Energy June 2017
[5] Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (2015)

government to seek the expansion of renewable energy generation in the country. Following a least cost approach, the government has prioritized the development of geothermal and wind energy plants as well as solar-fed mini-grids for rural electrification.

4.1.5.1. Geothermal energy

Kenya is endowed with geothermal resources, mainly in the Rift Valley as shown in figure 2. Geothermal energy has comparably low electricity production costs. Currently, geothermal capacity provide nearly 50% of total power generation. The current total geothermal installed capacity amounts to nearly 650 MW. The KenGen power plants are equipped with single flash steam technology while the remaining capacity owned and operated by independent power producers (IPP) use binary steam cycle technology. Due to the low short-run marginal costs, geothermal power plants generally run as base load.



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**

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

Kenya geothermal resource potential is estimated at 10,000 MW along the Kenyan Rift Valley. Currently geothermal power is only being harnessed in the Olkaria, Menegai and Eburru fields. In the medium and long term new geothermal reservoirs, such as Suswa, Longonot, Akiira and Baringo Silali are planned to be developed. Other potential geothermal prospects within the Kenya Rift that have not been studied in great depth include Emuruangogolak, Arus, Badlands, Namarunu, Chepchuk, Magadi and Barrier.

The actual applicable medium and long term potential has been derived based on the current development status of the geothermal power plant pipeline. It is expected that an overall capacity of 539 MW of geothermal power could be implemented during the medium-term period since they are already at advanced stage of construction or planning.

It can be expected that geothermal power will play an essential role in the future Kenyan power system. Good knowledge and expertise in geothermal exploration, drilling, power plant implementation and operation is already present in the country. However, drilling risks, high upfront costs and a rather long implementation period have to be taken into account in the planning stage.

Geothermal is considered as “conventional" renewable energy source which is already well developed in Kenya and can compete with other sources. In the expansion planning this is done through the fully identified candidates which are selected through generation planning and optimization simulations according to their costs and plant characteristics.

Geothermal power provides reliable base load power at low operating cost. Single flash technology which is mainly being utilized in Kenya today, is restricted in providing flexible power due to technical reasons. Binary systems, however, are able to be operated very flexibly. With regard to future geothermal expansion and considering the power system needs (load following, regulation control), it is recommended that the opportunity to use binary technology is explored and deployed.

4.1.5.2. Hydropower

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 about 30% 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 (329MW), Rift Valley basin (305MW), Athi River basin (60MW) and Tana River basin (790MW).

Table 19: Hydropower Potential

Catchment area	Area (Km^2)	Identified Hydropower potential (MW)
Lake Victoria North	18,374	151
Lake Victoria South	31,734	178
Rift Valley	130,452	305
Tana	126,026	790
Athi	58,639	60
Ewaso Ng'iro North	210,226	0
TOTAL	**575,451**	**1,484**

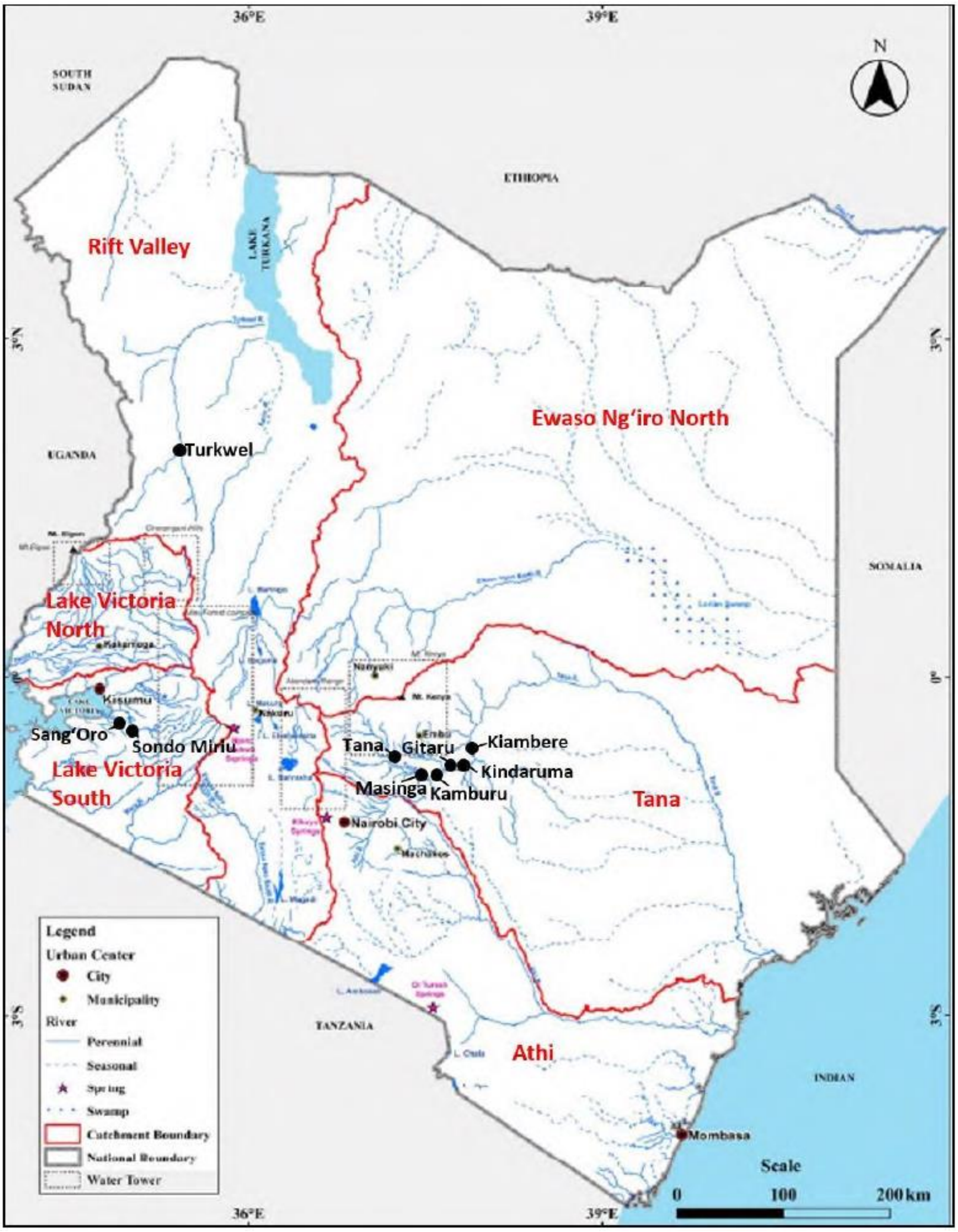


Figure 14: Major rivers of the six catchment areas ands location of existing large hydropower plants[6]

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 as shown in figure 3 or as stand-alone systems for agro-industrial establishments or missionary facilities.

[6] National Water Master Plan 2013

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 River Sondu that is in a densely populated area has not been implemented.

Beyond the existing schemes, Kenya still has substantial hydropower potential. This is reflected by current plans to develop large hydro projects in Karura and High Grand Falls (both in the Tana catchment area), Nandi Forest (in the Lake Victoria North catchment area) and Magwagwa (in the Lake Victoria South catchment area), and Arror (in the Rift Valley area). This development could lead to additional hydropower capacity of over 800 MW in the long term.

There is a large pipeline of small hydropower projects under the FiT scheme. Feasibility feasibility studies of smaller hydropower projects are still on-going.

4.1.5.3. Wind energy

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 25.5MW farm in Ngong comprising thirty (30) 850kW turbines. 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.

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

Grid-connected wind turbines already have a considerable impact in developed countries and are increasing in some developing countries as well. This is mainly through large-scale installations, either on land (on-shore) or in the sea on the continental shelf (off-shore).

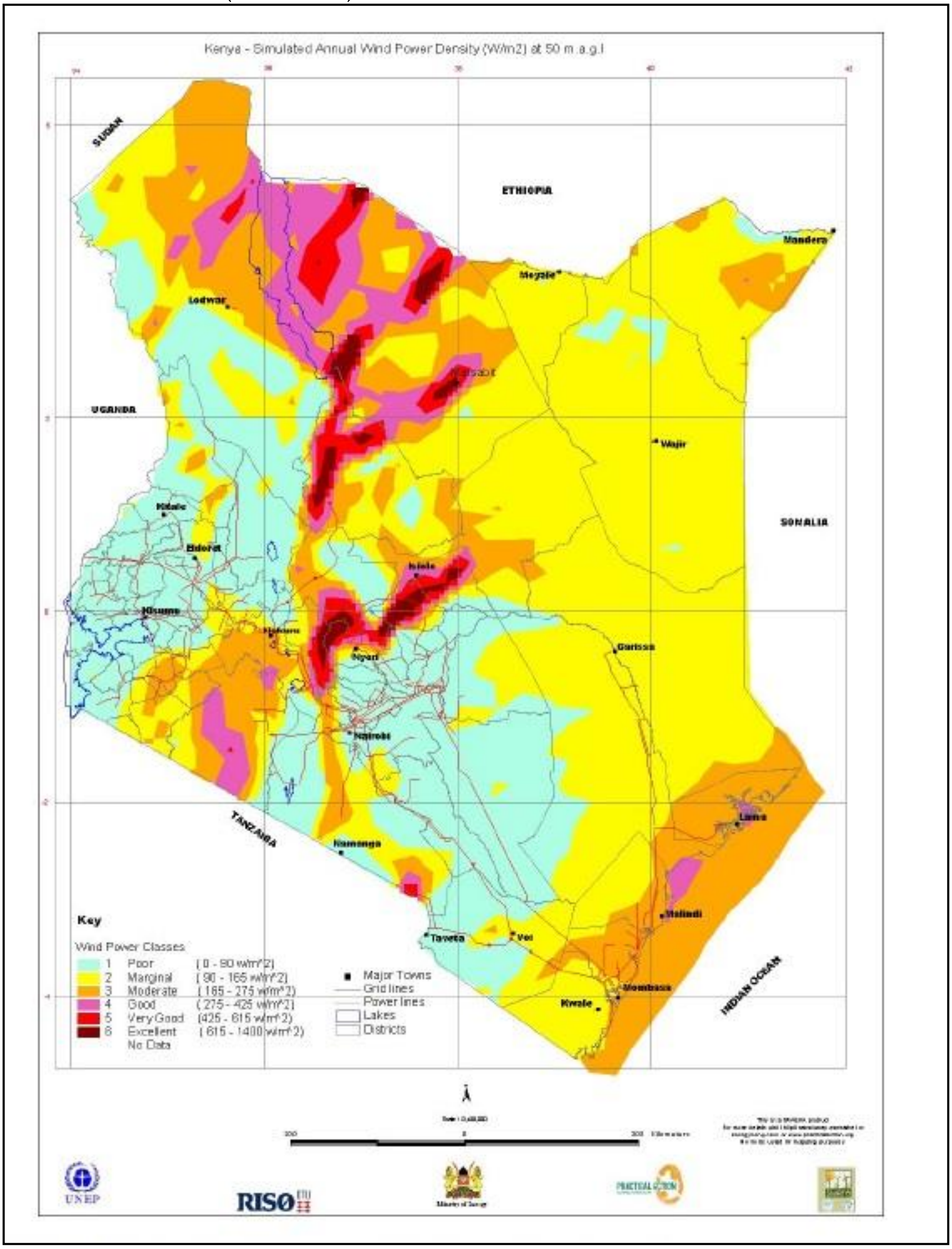


Figure 15: Wind energy density

However, wind turbines generate electricity intermittently in correlation to the underlying fluctuations of the wind speeds. Because wind turbines do not produce power constantly and at their rated power (which is only achieved at higher wind speeds), capacity factors are typically between 20 to 55%. One of the principal areas of concerns of wind energy is its variable power output, accommodation of which can be a challenge for the power network as the share of intermittent generation on the grid rises.

A remote Solar and Wind Energy Resource Assessment (SWERA) mapping exercise for Kenya was completed and published in 2008. This provides general information on the areas with the highest wind potential as shown on figure 4. A wind energy data analysis and development programme conducted in 2013 by WinDForce Management Services Pvt. Ltd indicates a total technical potential of 4,600 MW. This represents about two times the present overall installed power generation capacity in Kenya.

4.1.5.4. 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 $kWh/m^2/day$ levels of insolation. It is estimated that 200,000 photovoltaic solar home systems, most of which are rated between 10We and 20We 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 about 1.2% of households in Kenya.

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

Table 20: 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/m2 per day in the country is about 106,000 square kilometers whose potential is 638,790 TWh. See figure 5 for Map of Kenya showing 3 Year average Normal Direct Irradiance (NDI).

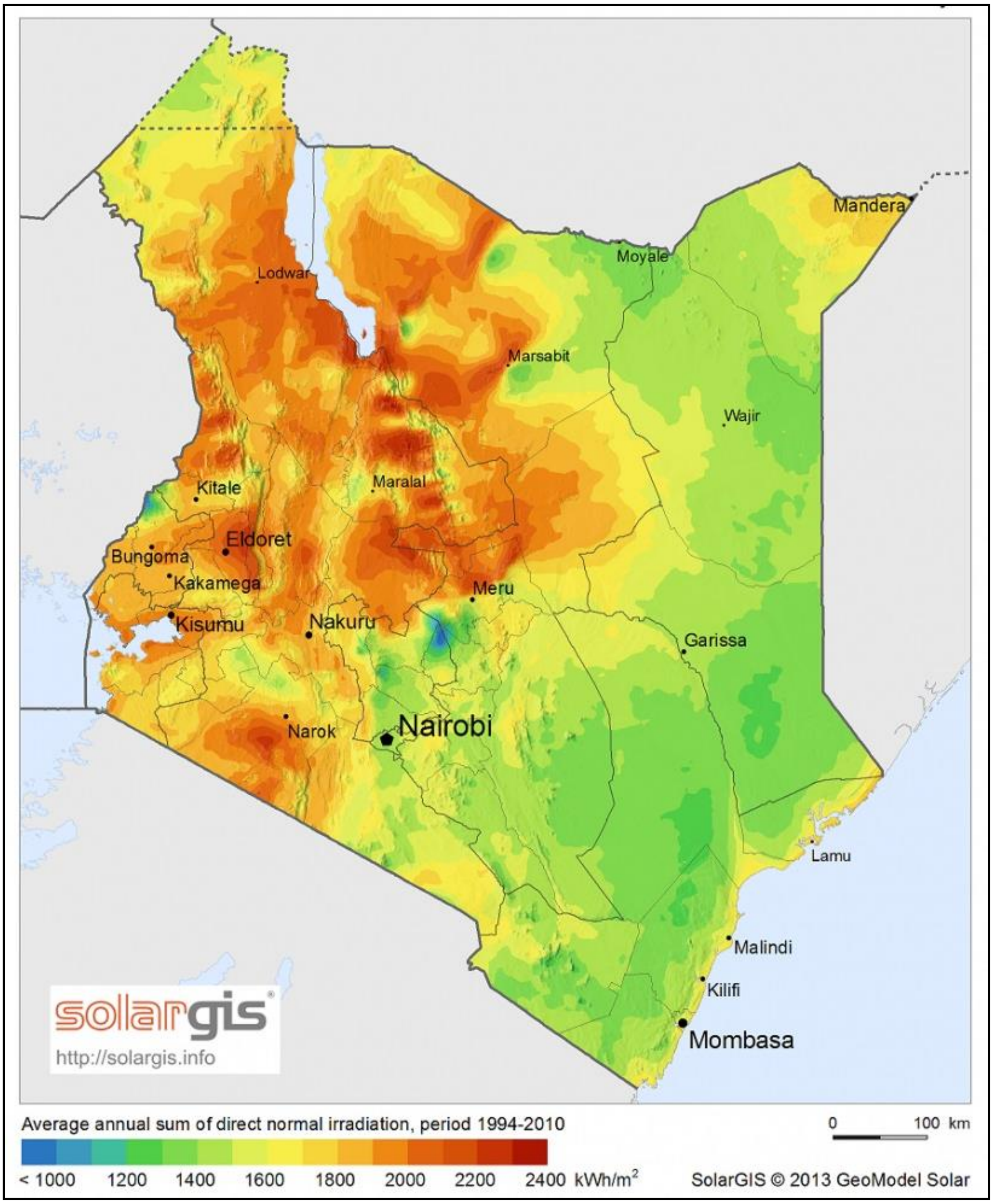


Figure 16: Normal direct Irradiance

4.1.5.5. Solar energy – photovoltaic (PV)

Photovoltaics (PV) devices convert solar energy directly into electrical energy. The amount of energy that can be produced is proportional to the amount of solar energy available on a specific site. PV has a seasonal variation in electricity production, with the peaks generally following months with the highest solar irradiation. Due to the stable climate, PV systems operating along the equator typically have a fairly consistent exploitable solar potential throughout the year.

Electricity production varies on a daily basis, with no generation when the sun has set. Short term fluctuations of weather conditions, including clouds and rainfall, impact the hourly amount of electricity that is produced.

Kenya is endowed with very high solar resources, among the highest of Sub-Saharan African countries. In favorable regions, the global horizontal irradiation (GHI) is up to 2,400 kWh/m²/year.

4.1.5.6. Solar energy – concentrated solar power (CSP)

Concentrated Solar Power (CSP) plants are thermal power plants that collect solar energy by using mirrors to concentrate direct sunlight onto a receiver. The receiver collects and transfers the solar thermal energy to a heat transfer fluid which can be used to generate electricity in a steam turbine. CSP plants typically include a thermal energy storage system. This allows for dispatchable electricity generation, including possible generation during night time and periods with passing clouds.

Compared to PV, one of the reasons for the slower development of CSP is its high levelised electricity cost. In general, the costs of CSP have dropped in recent years, but not as significantly as those of PV. Combined with long lead times, CSP deployment is expected to rapidly increase only after 2020 when it will become competitive with peak production costs.

CSP generation requires direct normal irradiation (DNI) to operate (i.e. a direct angle of incidence at clear skies without clouds). As mentioned earlier, Kenya is endowed with very high solar resources and is among the highest of Sub-Saharan African countries. Its solar direct normal irradiance is around 2,300 kWh/m²/year in favorable regions. However, there are presently no operational CSP plants in Kenya.

4.1.6. Biomass, biogas and waste-to-energy

Biomass energy usually means renewable energy coming from sources such as wood and wood residues, agricultural crops and residues, animal and human wastes. The conversion technology depends on the biomass itself and is influenced by demand side requirements. The final result of the conversion process is direct heat and electricity or a solid, liquid or gaseous fuel. This flexibility is one of the advantages of biomass compared to other renewable energy sources. There are numerous commercially available technologies for the conversion process and the utilisation of the resulting energy's for heating or for power generation. Cogeneration incorporates the simultaneous utilisation for both heating and power electricity generation.

Solid biomass, rich in lignin can be used in an incinerator where the produced flue gas provides heat and electricity or in a gasification process to provide a syngas for further use. Solid/liquid biomass, which is poor in lignin, is commonly used in fermenters and with the produced biogas also heat and electricity can be provided for further use.

Biogas is a mixture of methane and carbon dioxide with small amounts of other gases and needs a further cleaning step before it is usable. Biogas is similar to landfill gas, which is produced by the anaerobic decomposition of organic material in landfill sites.

Municipal Solid Wastes (MSW) constitutes a potential source of material and energy as well. Because of its heterogeneous components, it is necessary to pretreat this wastes (or collect it separated by source) before it can be used. The objective is to recycle as much as possible and use the remaining material with a high calorific value in an incinerator or gasification process to provide heat, electricity or syngas. The wet material can be used in a fermentation process to produce biogas.

Agricultural and agro-industrial residues and wastes have the potential to generate heat and/or power. The best example in several countries is power generation from bagasse. It is presently foreseen for power generation for grid supply in two sugar mills in Kenya: Mumias and Kwale. Besides the sugar bagasse, there could be some potential in the tea industry as well, which could co-generate about 1 MW in the 100 factories using their own wood plantations for drying.

A study conducted by GTZ in 2010 shows a biogas energy potential mainly for heat production and a rather small potential for power production. However, some biogas power projects have been submitted to the FiT scheme.

Biomass can appear as a rather modest potential at present, but could increase significantly with the agro industrial development and mainly through sugar mills revamping and future concentration of other agro industries. A specific survey of agro residues in the medium and long term, combined with the load centre and planned network could suggest lower investments in the power sector than conventional power supply and transmission.

4.1.7. Other energy sources

Besides fossil fuels and renewable energy sources as a basis for power generation, there is nuclear energy and energy imported from neighbouring countries through inter-connections (which could be based on various types of energy sources) which might reduce the need for energy generation.

4.1.7.1. Nuclear fuel

Conventional nuclear power production technology entails neutrons bombarding heavy elements such as uranium ("nuclear fuel") to disintegrate ("nuclear fission") which results in huge amounts of heat helping to produce steam and power through steam turbine operation and harmful radio-active material. Uranium ore is the raw material used in the production of nuclear power. Front end fuel cycle refers to the necessary processing of such raw material to prepare nuclear fuel. Yellow cake as an intermediate product is to be enriched to prepare the finished nuclear fuel product of Uranium oxide. Uranium oxide is formed into pellets which are inserted into cylindrical rods, also referred to as zircaloy tubes, which are bundled together. A great number of such bundles (approx. 100-200) are then included in and constitute a reactor core. Back end fuel cycle refers to the reprocessing and temporary or long-term storage of radioactive spent fuel or waste. The radioactive waste is to be contained, handled and safely stored for a long-term resulting in to very high long-term costs. Various options for management of radioactive waste and spent fuel are available.

Currently, only low levels of uranium oxide have been discovered in Kenya. However, exploration of uranium is still on-going[7].

Worldwide uranium reserves are estimated at 5 million tonnes[8]. At current consumption levels, these reserves would last more than 100 years[9]. Growing or diminishing future demand should affect the time taken for complete depletion of the resource. Nuclear energy is not a renewable energy. Compared to fossil fuels and the technology and investment to build and operate a nuclear power plant (NPP), the fuel supply is of minor importance for the evaluation of nuclear power as an expansion candidate. However, the relatively low costs for fuel as well as the considerably lower amounts of fuel to be replaced, stored and transported are advantages of nuclear power in terms of supply dependency and fluctuation of fuel cost.

4.1.7.2. Interconnections with neighboring countries

Interconnections with neighbouring countries provide mutual benefits. This may include additional sources of energy and power, the provision of axillary services (e.g. reactive power, black start power) and an overall higher security of supply as well as lower costs from sharing of generation back-up capacity or combining complementary generation systems (e.g. hydro versus thermal based generation). Currently, the Kenyan national grid is interconnected with Uganda

[7] Power Generation and Transmission Master Plan, Kenya, 2016
[8] World Nuclear Association
[9] OECD Nuclear Energy Agency, International Atomic Energy Agency: Uranium 2011: Resources, Production and Demand

via a 132 kV transmission line. The purpose of this interconnection is to mutually support system stability. To supply isolated boader areas the country has also established cross boarder distribution systems with Tanzania (Namanga) and Ethiopia (Moyale) . The interconnection with Uganda is about to be utilized for power exchange to Rwanda.
With the objective to increase transfer capacities and flexibility of grid operation and to improve sustainable electricity supply in Kenya, various interconnection projects are in the planning and implementation stage.

4.1.7.3. Eastern African Power Pool

The Eastern African Power Pool (EAPP) is an intergovernmental organisation established in 2005 with the objective to provide an efficient framework for pooling electricity resources and to promote power exchanges in Eastern Africa. So far, ten countries have joined EAPP, namely Burundi, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Libya, Rwanda, Sudan, Tanzania and Uganda. As part of the "Regional Power System Master Plan and Grid Code Study" published in 2011, major interconnection projects have been identified as well as planning criteria to support inter-regional power exchange and a phased interconnection plan for the EAPP countries has been developed. Additionally, a regional master plan study for the EAPP region has been carried out.

Interconnections with neighbouring countries provide mutual benefits such as purchasing energy from neighbouring countries at a lower price and receiving additional security of supply. In this regard, it is recommended to further extend interconnections with neighbouring countries in the long-term. Three interconnection projects between Kenya and neighbouring countries are already planned and more projects are in the planning stage. The actual status of implementation and planning of interconnections is described below.

4.1.7.4. Interconnection with Ethiopia

The construction of a high voltage direct current (HVDC) overhead transmission line between Ethiopia and Kenya is already under development. The 500 KV line is being constructed from Welayta Sodo in Ethiopia to Suswa in Kenya, a total length of approximately 1,045 km (433 km in Ethiopia and 612 km in Kenya). The line is a bipolar configuration and will be able to transfer 2 GW of electricity.

The Ethiopian Electric Power (successor of the restructured Ethiopian Electric Power Corporation EEPCo) will own the interconnection assets in Ethiopia. The interconnection assets on the Kenya side will be owned by Kenya Electricity Transmission Co. Ltd.

A 25-year power purchase agreement (PPA) was signed by the two parties, EEP Co. and KPLC, and approved by all relevant authorities in Ethiopia and Kenya in January 2012. The PPA defines 400 MW of firm power with the related energy at a cost of 7 USD cent/kWh and an availability of at least 85%. For the entire duration of the PPA, the price has been fixed, i.e. no price escalation is included. A take-or-pay clause on energy basis is included. Since the transmission line is dimensioned for a transfer capacity of 2 GW, it is recommended to increase imports through this inter-connector in the long-term, e.g. to cover peak demand or to transfer electricity to other countries. Construction started in 2015 and commercial operation of the HVDC line is expected in 2019.

4.1.7.5. Interconnection with Uganda

It is planned to interconnect Kenya, Uganda and Rwanda on 400 kV level with the objective to enable regional power trade. The interconnector between Kenya and Uganda is under construction. Feasibility studies for the 400 kV standardization in Uganda and Rwanda are currently on-going.

The project involves the construction of a 400 kV double circuit overhead line between Lessos in Kenya and Tororo in Uganda. The transmission line is designed for a capacity of 1,700 MW. The objective of this line is to support the market for power exchange within the EAPP. The existing interconnection with Uganda will be used for power export to Rwanda.

4.1.7.6. Interconnection with Tanzania

A 400 kV double circuit transmission line with a total length of 507.5 km between Tanzania and Kenya is under implementation. 93 km of the line will be located in Kenya and 415 km in Tanzania. The overhead line originates from Isinya substation in Kenya, passes Namanga and Arusha and terminates at Singida substation in Tanzania. The interconnector is designed for a capacity of 1,700 to 2,000 MW. On the Kenyan side, this project also includes the extension of the existing Isinya substation. The commercial operation is envisaged in 2019 . The objective of this line is to support the power market within the EAPP and to interconnect EAPP with Southern African Power Pool (SAPP).

An additional interconnection from Rongai through Kilgoris to complete the Lake Victoria Ring (through Tanzania to Rwanda) is under feasibility study.

5. EVALUATION OF POWER GENERATION EXPANSION CANDIDATES

5.1. Objectives and approach

The objective of this section is to assess candidate power generation projects to be considered in the expansion planning process for meeting the projected demand over the planning period. Preliminary economic assessment of the available and potential energy sources was performed using the screening curves methodology. The candidates evaluated include several committed projects expected to be commissioned in the short to medium term. Analysing these approved projects was necessary considering that it may be prudent to reschedule some depending on the system load growth.

5.2. Generation expansion candidates

Generation capacity expansion in Kenya is achieved through various approaches; the national generator KenGen, Independent Power Producers, steam development by GDC and power imports contracts. IPPs include those procured by GDC and developers of projects under the Feed in Tariffs policy for renewable energy sources.

A comprehensive list of projects being developed or considered for implementation over the planning horizon is shown in Table 21 These include committed projects and those being considered for development through public or private companies. In addition, a summary of committed projects for the period 2017-2024 is as presented in table 30. These are projects with approved PPA and COD, and those making significant progress in implementation or prioritised in the strategic plans of KenGen and GDC.

Table 21: Committed and candidate generation projects and estimated CODs

Year considered for system integration	Plant name	Type	Net capacity [MW]
2018	Orpower IV plant 1	Geothermal	10
2018	Lake Turkana - Phase I, Stage 1	Wind	100
2018	Strathmore	PV	0.25
2019	HVDC Ethiopia	Import	400
2019	Olkaria 5	Geothermal	158
2019	Olkaria Modular	Geothermal	50
2019	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	17
2019	Lake Turkana - Phase I, Stage 2	Wind	100

2019	Lake Turkana - Phase I, Stage 3	Wind	100
2019	PV grid Garissa	PV	50
2019	Marcoborero	PV	2
2019	Kopere	PV	40
2020	Menengai 1 Phase I - Stage 1	Geothermal	103
2020	Olkaria 1 - Unit 6	Geothermal	70
2020	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	17
2020	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	17
2020	Kipeto - Phase I	Wind	50
2020	Kipeto - Phase II	Wind	50
2020	Alten, Malindi, Selenkei	PV	120
2020	Quaint Energy, Kenergy	PV	50
2021	Olkaria Topping	Geothermal	47
2021	Ngong 1 - Phase III	Wind	10
2021	Chania Green	Wind	50
2021	Aperture	Wind	50
2021	Eldosol	PV	40
2021	Makindu Dafre rAREH	PV	30
2021	Gitaru solar	PV	40
2022	Olkaria 6 PPP	Geothermal	140
2022	Menengai I - Stage 2	Geothermal	60
2022	Prunus	Wind	51
2022	Meru Phase I	Wind	80
2022	Ol-Danyat Energy	Wind	10
2022	Electrawinds Bahari	Wind	50
2022	Hanan, Greenmillenia, Kensen	PV	90
2023	Orpower4 plant 4		61
2023	Olkaria 7	Geothermal	140
2023	Eburru 2	Geothermal	25
2023	GDC Wellheads	Geothermal	30
2023	Wellhead leasing	Generic back-up capacity	50
2023	Karura	Hydropower	89
2023	Electrawinds Bahari Phase 2	Wind	40
2023	Sayor, Izera, Solarjoule	PV	30
2023	Belgen, Tarita Green Energy Elgeyo	PV	80
2024	Lamu Unit 1	Coal	327
2024	Lamu Unit 2	Coal	327
2024	Lamu Unit 3	Coal	327
2024	Olkaria 8	Geothermal	140
2024	Menengai III	Geothermal	100
2024	Baringo Silali - Paka I	Geothermal	100
2024	Marine Power Akiira Stage 1	Geothermal	70
2024	Meru Phase II	Wind	100

2024	Tarita Green Energy Isiolo, Kengreen	PV	50
2024	Asachi, Astonfield Sosian, Sunpower	PV	81
2025	AGIL Longonot Stage 1	Geothermal	70
2025	Olsuswa 140MW unit I&II	Generic back-up capacity	140
2025	Meru Phase III	Wind	220
2026	Suswa I	Geothermal	100
2026	Baringo Silali - Silali I	Geothermal	100
2026	Aeolus Kinangop	Wind	60
2026	Solargen	PV	40
2027	Baringo Silali - Korosi I	Geothermal	100
2028	Menengai IV	Geothermal	100
2028	Marsabit Phase I - KenGen	Wind	300
2030	Olkaria 9 & other fields	Geothermal	420
2030	Suswa II	Geothermal	100
2031	Menengai V	Geothermal	100
2031	High Grand Falls Stage 1	Hydropower	495
2032	High Grand Falls Stage 1+2	Hydropower	693
2033	Suswa III	Geothermal	100
2034	Dongo Kundu CCGT - small 1	Natural gas	375
2035	Dongo Kundu CCGT - small 2	Natural gas	375
2036	Nuclear Unit 1	Nuclear	600
2037	Nuclear Unit 2	Nuclear	600
TOTAL MW			**9,497**

5.3. Fuel cost forecast

5.3.1. Crude oil price forecast

In the period 2015-2017, international crude oil prices remained relatively low averaging between US$42.8 and US$53 per barrel compared to US$ 96.2 in 2014. Coal and gas prices were also lower in the same period. Fuel prices are projected to increase over the medium to long term. According to the World Energy Resources 2016 report, the key factors determining long-term supply, demand, and prices for petroleum and other liquids can be summarized in four broad categories: the economics of non-OPEC supply, OPEC investment and production decisions, the economics of other liquids supply, and world demand for petroleum and other liquids. Factors such as the Organization of Petroleum Exporting Countries (OPEC) production decisions and expectations about future world demand for petroleum and other liquids, affect prices in the longer term.

Table 22 shows the fuel price projections by the World Bank as contained in the commodity price forecast released in October 2017.

In the reference forecast for this least cost plan, a base price of US$53.1/bbl rising to US$74.1 in 2020 and US$113 and US$128 respectively in 2030 and 2040 . A high price forecast of US$88.9/bbl in 2020 and rising to US$153.6 and US$153.6 in 2030 and 2040 respectively.

5.3.2. Coal price forecast

The first coal power plant in Kenya is expected to be in operation in the year 2024 running on imported coal until local deposits are exploited. South Africa is the likely choice of imported coal due to their proximity to the Mombasa Port compared to other export terminals. South Africa is the world's fifth-largest coal producer and has historically been mainly exporting coal to the European market but lately increased exports to Asian countries. Other African countries, besides South Africa, expected to play an emerging role in coal trade are Botswana, Mozambique and Tanzania. The World Bank reports average coal prices in South Africa rose to US$81.9/t in 2017 from 64.1/t in 2016 and stood at US$92.7 in December 2017. Australian coal prices rose to US$88.4/t from US$65.9/t in the corresponding period.

The World Oil Outlook 2016 by OPEC predicts that global coal demand will increase gradually by an average rate of 0.6% p.a up to 2040. The report attributes the high increase in coal prices at the end of 2017 to a surge in power demand in China and supply issues in some major exporters.

In the reference forecast of this study, the base price of US$81.9/t has been used on the basis of price movements alongside oil and natural gas prices. Coal prices are projected to rise to US$100 in 2020 to US$108/t in 2040. A high price forecast of US$102/t in 2020 is projected, rising to US$122.4/t and US$129.6/t in 2030 and 2040, respectively.

5.3.3. Natural gas price forecast

Natural gas is the number three fuel source, reflecting 24% of global primary energy, and is the second energy source in power generation, representing a 22% share. Natural gas prices, as with other commodity prices, are mainly driven by supply and demand fundamentals. Due to growing supply overhang of natural gas and LNG, lacklustre gas demand over the past few years, and the oil price drop coupled by abundance of supply have all caused gas prices to fall from 2014. In the long-term, however, the introduction of environmental policies should favour gas development versus coal. World Bank's 2017 Natural gas price forecast, also corroborates this with Liquefied Natural gas projected to grow accounting for a quarter of the global energy demand in the New Policies Scenario by 2040, becoming the second-largest fuel in the global mix.

Liquefied Natural gas will grow to account for a quarter of global energy demand in the New Policies Scenario by 2040, becoming the second-largest fuel in the global mix. The World Bank forecast for LNG is for price to rise to US$8.6MMbtu in 2020 and US$10.0 in 2030.

In the least cost plan, natural gas prices are forecast to be in line with forecast for Japan. A reference price of US$8.05 has been used rising to US$8.6 in 2020 and US$10.0/MMbtu and US$12.4 in 2030 and 2040 respectively (World bank). A high price forecast of US$10.3//MMbtu in 2020 rises to US$12.0 and US$14.9 in 2030 and 2040 respectively.

5.3.4. Nuclear fuel costs and forecast

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 (as of March 2017) cites prices of about US$1390 per kilogram of uranium as UO2 reactor fuel which works out to a fuel cost of US$ 0.00429 /kWh. A reference fuel price of $4.983Mkcal ($1.191/GJ) was computed for nuclear based on reference data. 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.

Table 22: World Bank Forecast Prices for Crude Oil, Gas and Coal

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030
Coal, Australia	$/MT	70.1	57.5	65.9	85.0	70.0	60.0	55.0	55.5	56.0	56.5	56.9	57.4	60.0
Crude oil, average	$/bbl	96.2	50.8	42.8	53.0	56.0	59.0	60.0	60.9	61.9	62.8	63.8	64.8	70.0
Natural Gas - Europe	$/ mmbtu	10.1	7.3	4.6	5.5	5.7	5.8	6.0	6.2	6.4	6.5	6.7	6.9	8.0
Natural Gas -US	$/ mmbtu	4.4	2.6	2.5	3.0	3.1	3.2	3.4	3.5	3.7	3.8	3.9	4.2	5.0
LNG-Japan	$/ mmbtu	16.0	10.2	6.9	8.2	8.3	8.5	8.6	8.7	8.9	9.0	9.1	9.3	10.0

5.4. Screening curve analysis

A comprehensive screening model was developed by Lahmeyer International consultants for the 2015-2035 Power Generation and Transmission Master Plan. In the tool, generation candidates are modelled based on their economic and technical characteristics and subjected to screening curve analysis, an economic evaluation methodology where their Levelized Electricity Cost (LEC) in per unit is calculated at given discount rate over a range of capacity factors.

The LEC is defined as the ratio of the present value of the projected costs of power production over the life of the project and the present value of such power production to reflect the real cost of the production per unit of electricity. This takes into account the average foreign and domestic cost of borrowing of the project executing agency. The discount rate is usually the Weighted Average Cost of Capital (WACC). The calculation of LEC enables direct comparison of the expected unit costs of electricity production of each candidate power plant and economic ranking of candidate plants based on respective generation tariffs.

5.4.1. Tecno-Economic data for candidate projects

Input data sets for the various candidates considered are presented below grouped under four categories:

a) Fuel switching fossil thermal candidates
b) Fossil fuel thermals and nuclear
c) Wind, solar, bagasse and geothermal
d) Hydropower

The renewables considered include solar, wind and biogas.

Table 23: Technical parameters of renewable energy plants

Annual average capacity factors of RE sources	
Ngong	27%
Kinangop	34%
Kipeto	46%
LTWP	55%
Meru wind	32%
Generic wind	40%
Generic PV	20%
Cogeneration	50%
Generic small hpp	50% average and 30% low hydrology

The technical data for candidate projects are shown in Tables 24 through 27. Results of the screening analyses are shown in Figures 17 and 18.

The results seem to place geothermal as a preffered candidate in the expansion together with hydro.

The generic nuclear plant, MSDs and gas turbines are the least preferred for expansion although at low capacity factors MSDs and the Gas turbines are quite competitive

When ranking technologies against discount factors, the Levelized costs changes on these factors but the outstanding feature is that Geothermal, wind hydro and biomass plants are competitive while nuclear coal, medium speed diesels and Natural gas technologies remain uncompetitive irrespective of the discount factor applied

The results however reveal critical energy planning information as follows:

- MSDs, natural gas and hydros are good for peaking
- Geothermal will remain the most competive technology with respect to development of base load capacity in the medium to long term
- Plants with a significant fuel cost charge are not preffered for base load expansion due to their relatively high variable costs

Table 24: Technical and cost data for fossil fuel switch candidates

Category / Topic	Sub-topic	Unit	Candidate inputs					
Subsets			**Fuel Switch**					
Energy source			**Fossil fueled**					
Status - existing / candidate			**Exists**	**Candidates**	**Exists**	**Candidates**	**Exists**	**Candidates**
2.1 Identification	Tag (name short & type & option)		Tsavo - MSD - HFO	Tsavo - MSD - LNG	Kipevu 3 - MSD - HFO	Kipevu 3 - MSD - LNG	Rabai - MSD - HFO	Rabai - MSD - LNG
	ID		FS1	FS2	FS3	FS4	FS5	FS6
	Name unit(s)		**Tsavo**	**Tsavo**	**Kipevu 3**	**Kipevu 3**	**Rabai**	**Rabai**
2.3 Fuel & Efficiency	Primary Fuel		HFO	LNG	HFO	LNG	HFO	LNG
	Price level transport cost		cif	cif	cif	cif	cif	cif
	Net Calorific Value (effective fuel)	MJ/kg	41.4	46.5	41.4	46.5	41.4	46.5
	Costs Effective Fuel (actual simulation year)	USD/GJ	7.3	12.7	7.3	12.7	7.3	12.7
	Max. Efficiency	%	40%	40%	42%	42%	44%	44%
	Specific Fuel Consumption (at max. efficiency)	kg/MWh	219.0	195.0	209.5	186.5	197.1	175.5
	Specific Fuel Costs (at max. efficiency)	USD/MWh	65.9	115.6	63.1	110.6	59.3	104.1
2.4 Capacity	Unit Type 1		ICE	ICE	ICE	ICE	ICE	ICE
	Capacity Installed (Gross)	MW	78.5	78.5	117.6	117.6	91.8	91.8
	Maximum Capacity Available (Net)	MW	77.0	77.0	115.2	115.2	89.9	89.9
2.5 Generation (net)	Average future generation	GWh/a	134.9	134.9	201.9	201.9	157.5	157.5
	Effective available generation (thermal)	GWh/a	601.7	601.7	930.5	930.5	725.9	725.9
	Average future capacity factor	%	20%	20%	20%	20%	20%	20%
2.6 Availability	Effective available capacity factor (thermal)	%	89%	89%	92%	92%	92%	92%
	Forced Outage Rate (FOR)	%	5%	5%	4%	4%	4%	4%
	Planned Outage Rate (POR)	days/year	21	21	14	14	14	14
2.7 Lifetime & Construction	Lifetime total (expected)	years	20	20	20	20	20	20
	1st year of operation	year	2001	2001	2011	2011	2009	2009
	Last year of operation (latest)	year	2021	2026	2031	2036	2029	2034
2.8 Costs	O&M Fixed	USD/kW/year	31.0	47.3	31.0	48.5	31.0	44.3
		TUSD/year	2,386.0	3,643.9	3,572.7	5,591.6	2,787.4	3,982.3
		% of CAPEX	42%	6%	4%	3%	4%	3%

	O&M Variable	USD/MWh	8.7	8.7	8.7	8.7	8.7	8.7
	O&M Total	% of CAPEX	63%	7%	6%	4%	6%	4%
	Specific Fuel Costs (at max. efficiency)	USD/MWh	65.9	115.6	63.1	110.6	59.3	104.1
	Inland fuel transport costs	USD/GJ	0.0	0.0	0.0	0.0	0.0	0.0
	Average Generation Costs (fuel + O&M variabl.)	USD/MWh	74.6	124.3	71.8	119.3	68.0	112.8
	Investment Costs Plant							
	TOTAL Investment Costs	MUSD	5.6	65.5	88.6	183.8	68.9	140.0
	Specific investment costs	USD/kW	73.1	850.5	768.3	1,594.9	765.7	1,557.1
	Residual value (HPP 60% of civil works)	% of CAPEX	0%	0%	0%	0%	0%	0%
	Civil works cost share	%	na	na	na	na	na	na
2.9 Net Heat Rate at load (TPP)	100%	kJ/kWh	9,066.6	9,066.6	8,673.3	8,673.3	8,161.5	8,161.5
	90%	kJ/kWh	9,068.3	9,068.3	8,674.9	8,674.9	8,163.2	8,163.2
	80%	kJ/kWh	9,070.2	9,070.2	8,676.8	8,676.8	8,165.6	8,165.6
	70%	kJ/kWh	9,072.9	9,072.9	8,679.4	8,679.4	8,168.6	8,168.6
	60%	kJ/kWh	9,076.2	9,076.2	8,682.5	8,682.5	8,173.2	8,173.2
	50%	kJ/kWh	9,081.3	9,081.3	8,687.4	8,687.4	8,179.5	8,179.5
	40%	kJ/kWh	9,088.3	9,088.3	8,694.1	8,694.1	8,191.0	8,191.0
	30%	kJ/kWh	9,101.1	9,101.1	8,706.3	8,706.3	8,212.0	8,212.0
	20%	kJ/kWh	9,124.5	9,124.5	8,728.7	8,728.7	na	na

Table 25: Technical and cost data for candidate fossil fuel and nuclear plants

Category / Topic	Sub-topic	Unit							
Subsets			**Thermal Power Plants (fossil fueled and nuclear)**						
Energy source			**Fossil fuelled**						**Nuclear**
Status - existing / candidate			**Candidates**						
2.1 Identification	Tag (name short & type & option)		Generic MSD - 18 MW	Dongo Kundu_2x(2+1)_1pressure - 751 MW	Wajir_2x(2+1)_1 pressure - 727 MW	Lamu - 3x327 MW	Kitui - 3x320 MW	Generic gas turbine (Kerosene) - 70 MW	Generic nuclear - 600 MW single
	ID		TPP1	TPP2	TPP5	TPP9	TPP12	TPP13	TPP14
	Name unit(s)		**Generic medium speed diesel**	**Dongo Kundu CCGT 2x(2+1) - 1pressure**	**Wajir County CCGT 2x(2+1) - 1pressure**	**Lamu Coal Plant 3x327MW**	**Kitui Coal Plant 3x320MW**	**Gas turbine generic**	**Generic Nuclear plant - single unit**
2.3 Fuel & Efficiency	Primary Fuel		HFO	LNG	NG	Coal	Coal	Gasoil/kerosene	Uranium
	Price level transport cost		cif	cif	fob	cif	fob	cif	cif
	Net Calorific Value (effective fuel)	MJ/kg	41.4	46.5	46.5	21.0	21.0	44.9	39,000.0
	Costs Effective Fuel (actual simulation year)	USD/GJ	7.3	12.7	7.6	4.2	3.9	12.5	1.2
	Max. Efficiency	%	45%	51%	48%	41%	37%	34%	37%
	Specific Fuel Consumption (at max. efficiency)	kg/MWh	194.7	151.2	160.2	414.1	458.3	237.4	0.2
	Specific Fuel Costs (at max. efficiency)	USD/MWh	58.6	89.7	56.8	36.8	37.5	133.1	11.6
2.4 Capacity	Unit Type 1		ICE	GT	GT	ST	ST	GT	ST
	Capacity Installed (Gross)	MW	18.4	769.6	751.7	1,069.5	1,058.2	71.4	630.0
	Maximum Capacity Available (Net)	MW	17.8	751.1	727.1	981.8	972.4	70.3	599.8
2.5 Generation (net)	Average future generation	GWh/a	31.2	4,934.9	4,777.2	6,450.1	6,388.5	123.2	4,465.8

	Effective available generation (thermal)	GWh/a	144.0	5,931.9	5,742.2	7,463.3	7,391.9	550.1	4,703.3
	Average future capacity factor	%	20%	75%	75%	75%	75%	20%	85%
2.6 Availability	Effective available capacity factor (thermal)	%	92%	90%	90%	87%	87%	89%	90%
	Forced Outage Rate (FOR)	%	4%	3%	3%	5%	5%	3%	5%
	Planned Outage Rate (POR)	days/year	14	25	25	30	30	28	20
2.7 Lifetime & Construction	Lifetime total (expected)	years	20	20	20	30	30	25	40
	1st year of operation	year	open	open	open	open	open	open	open
	Last year of operation (latest)	year	na	na	na	na	na	na	na
2.8 Costs	O&M Fixed	USD/kW/year	32.4	33.0	18.3	68.1	69.0	21.5	7.7
		TUSD/year	578.0	24,774.0	13,321.1	66,831.3	67,093.4	1,514.7	4,641.0
		% of CAPEX	2%	2%	2%	3%	3%	2%	0%
	O&M Variable	USD/MWh	8.8	13.8	16.6	1.3	1.4	12.9	10.5
	O&M Total	% of CAPEX	2%	9%	12%	3%	3%	5%	1%
	Specific Fuel Costs (at max. efficiency)	USD/MWh	58.6	89.7	56.8	36.8	37.5	133.1	11.6
	Inland fuel transport costs	USD/GJ	0.0	0.0	0.0	0.0	0.0	0.7	0.0
	Average Generation Costs (fuel + O&M variabl.)	USD/MWh	67.4	103.5	73.5	38.1	38.9	146.0	22.0
	Investment Costs Plant								
	TOTAL Investment Costs	MUSD	35.6	1,036.2	750.6	2,506.0	2,360.6	61.4	4,838.9
	Specific investment costs	USD/kW	1,993.9	1,379.5	1,032.2	2,552.5	2,427.7	873.5	8,068.1
	Residual value (HPP 60% of civil works)	% of CAPEX	0%	0%	0%	0%	0%	0%	0%
	Civil works cost share	%	na	na	na	na	na	na	na
2.9 Net Heat Rate at load (TPP)	100%	kJ/kWh	8,062.0	7,032.8	7,448.4	8,695.2	9,624.6	10,666.3	9,729.7
	90%	kJ/kWh	8,063.5	7,084.6	7,462.4	8,707.2	9,577.9	11,010.3	not considered
	80%	kJ/kWh	8,065.2	7,184.7	7,476.4	8,772.4	9,608.3	11,441.5	not considered
	70%	kJ/kWh	8,067.6	7,120.1	7,526.6	8,898.9	9,721.1	11,995.2	not considered
	60%	kJ/kWh	8,070.6	7,252.5	7,573.4	9,073.7	9,899.8	12,732.2	not considered

50%	kJ/kWh	8,075.1	7,032.8	7,448.4	9,336.3	10,145.3	13,760.2	not considered
40%	kJ/kWh	8,081.3	7,183.1	7,476.4	9,748.1	10,517.6	15,295.8	not considered
30%	kJ/kWh	8,092.6	7,471.3	7,885.2	10,419.0	11,130.5		not considered
20%	kJ/kWh	8,113.5	7,387.6	7,684.5	11,165.7	11,813.4		not considered

Table 26: Technical and cost data for candidate wind, solar, bagasse and geothermal plants

Category / Topic	**Sub-topic**	**Unit**								
Subsets										
Energy source			**Wind**	**Solar**	**Bagasse**	**Geothermal**				
Status - existing / candidate										
2.1 Identification	Tag (name short & type & option)		Generic wind - 50 MW	Generic PV - 10 MW	Generic bagasse - 25 MW	Suswa I Stage 2 GEO - 100 MW	Menengai 1 GEO - 102 MW	Greenfield single-flash GEO-GEO	Greenfield binary standalone GEO-GEO	Menengai GEO - 200 MW
	ID		RE2	RE3	RE4	RE8	RE9	RE16	RE17	RE18
	Name unit(s)		**Generic wind farm**	**Generic PV station**	**Generic Bagasse power plant**	**Suswa Phase I - Stage 2**	**Menengai Phase I, Stage 1**	**Greenfield single-flash GEO**	**Greenfield binary standalone GEO**	**Menengai 200 MW**
2.3 Fuel & Efficiency	Primary Fuel		Wind	Solar	Bagasse	GEO	GEO	GEO	GEO	GEO
	Price level transport cost		na	na	na	na	na	na	na	na
	Net Calorific Value (effective fuel)	MJ/kg	na	na	na	na	na	na	na	na
	Costs Effective Fuel (actual simulation year)	USD/GJ	na	na	na	na	na	na	na	na
	Max. Efficiency	%	na	na	25%	34%	34%	34%	34%	34%
	Specific Fuel Consumption (at max. efficiency)	kg/MWh	na	na	na	na	na	na	na	na
	Specific Fuel Costs (at max. efficiency)	USD/MWh	na	na	na	na	na	na	na	na
2.4 Capacity	Unit Type 1		WT		ST	ST	ST	ST	ST	ST
	Capacity Installed (Gross)	MW	50.2	10.1	35.2	104.7	107.4	31.5	33.5	209.4
	Maximum Capacity Available (Net)	MW	50.2	10.0	25.0	99.9	102.5	30.1	30.0	199.8
2.5 Generation (net)	Average future generation	GWh/a	175.7	17.2	175.2	787.6	808.1	236.9	236.9	1,575.2

	Effective available generation (thermal)	GWh/a	na	na	197.3	827.6	849.1	na	na	na
	Average future capacity factor	%	40%	20%	80%	90%	90%	90%	90%	90%
2.6 Availability	Effective available capacity factor (thermal)	%	100%	100%	90%	95%	95%	95%	95%	95%
	Forced Outage Rate (FOR)	%	0%	0%	5%	2%	2%	2%	2%	2%
	Planned Outage Rate (POR)	days/year	0	0	18	14	14	14	14	14
2.7 Lifetime & Construction	Lifetime total (expected)	years	20	20	20	25	25	25	25	25
	1st year of operation	year	open	open	open		2018	open	open	
	Last year of operation (latest)	year	na	na	na	na	2043	na	na	na
2.8 Costs	O&M Fixed	USD/kW/year	78.4	27.2	152.3	157.0	157.0	169.4	22.1	149.8
		TUSD/year	3,933.1	271.9	3,806.3	15,684.8	16,093.0	5,092.1	663.0	29,926.0
		% of CAPEX	4%	2%	5%	5%	5%	4%	0%	4%
	O&M Variable	USD/MWh	0.0	0.0	8.9	0.0	0.0	0.0	10.5	0.0
	O&M Total	% of CAPEX	4%	2%	7%	5%	5%	4%	2%	4%
	Specific Fuel Costs (at max. efficiency)	USD/MWh	na	na	na	na	na	na	na	na
	Inland fuel transport costs	USD/GJ	na	na	na	na	na	na	na	na
	Average Generation Costs (fuel + O&M variabl.)	USD/MWh	0.0	0.0	8.9	0.0	0.0	0.0	10.5	0.0
	Investment Costs Plant									
	TOTAL Investment Costs	MUSD	101.8	17.0	76.1	343.6	352.1	122.4	137.7	670.0
	Specific investment costs	USD/kW	2,030.0	1,695.1	3,045.0	3,439.0	3,435.0	4,073.1	4,582.4	3,353.4
	Residual value (HPP 60% of civil works)	% of CAPEX	0%	0%	0%	0%	0%	0%	0%	0%
	Civil works cost share	%	na	na	na	na	na	na	na	na
2.9 Net Heat Rate at load (TPP)	100%	kJ/kWh	na	na	14,400.0	10,499.7	10,499.7	10,499.7	10,499.7	10,499.7
	90%	kJ/kWh	na	na	not considered	10,514.5	10,514.5	10,514.5	10,514.5	10,514.5
	80%	kJ/kWh	na	na	not considered	10,532.9	10,532.9	10,532.9	10,532.9	10,532.9
	70%	kJ/kWh	na	na	not considered	10,556.7	10,556.7	10,556.7	10,556.7	10,556.7
	60%	kJ/kWh	na	na	not considered	10,588.4	10,588.4	10,588.4	10,588.4	10,588.4
	50%	kJ/kWh	na	na	not considered	10,632.7	10,632.7	10,632.7	10,632.7	10,632.7

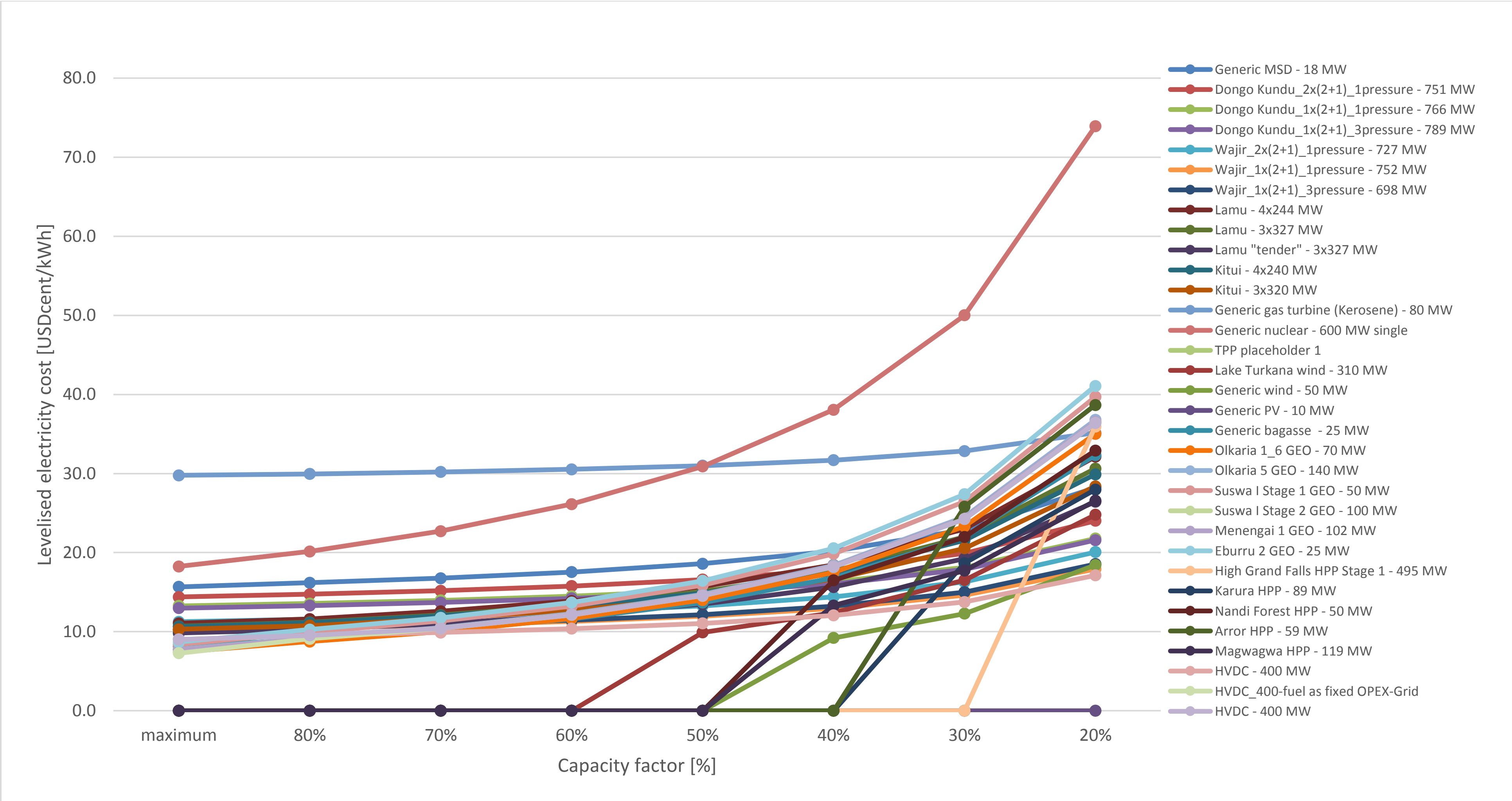
40%	kJ/kWh	na	na	not considered	10,699.2	10,699.2	10,699.2	10,699.2	10,699.2
30%	kJ/kWh	na	na	not considered	10,810.0	10,810.0	10,810.0	10,810.0	10,810.0
20%	kJ/kWh	na	na	not considered	na	na	na	na	na

Table 27: Technical and cost data for candidate hydropower plants

Category / Topic	Sub-topic	Unit					
Subsets							
Energy source			Hydro Power Plants				
Status - existing / candidate							
2.1 Identification	Tag (name short & type & option)		High Grand Falls HPP Stage 1 - 495 MW	Karura HPP - 89 MW	Nandi Forest HPP - 50 MW	Arror HPP - 59 MW	Magwagwa HPP - 119 MW
	ID		RE11	RE12	RE13	RE14	RE15
	Name unit(s)		**High Grand Falls - Stage 1**	**Karura**	**Nandi Forest**	**Arror**	**Magwagwa**
2.3 Fuel & Efficiency	Primary Fuel		Hydro	Hydro	Hydro	Hydro	Hydro
	Price level transport cost		na	na	na	na	na
	Net Calorific Value (effective fuel)	MJ/kg	na	na	na	na	na
	Costs Effective Fuel (actual simulation year)	USD/GJ	na	na	na	na	na
	Max. Efficiency	%	na	na	na	na	na
	Specific Fuel Consumption (at max. efficiency)	kg/MWh	na	na	na	na	na
	Specific Fuel Costs (at max. efficiency)	USD/MWh	na	na	na	na	na
2.4 Capacity	Unit Type 1		Francis	Kaplan	Pelton	Pelton	Francis
	Capacity Installed (Gross)	MW	500.0	90.0	50.0	60.0	120.0
	Maximum Capacity Available (Net)	MW	495.0	89.1	49.5	59.4	118.8
2.5 Generation (net)	Average future generation	GWh/a	1,213.0	234.5	185.0	189.5	510.0
	Effective available generation (thermal)	GWh/a	na	na	na	na	na

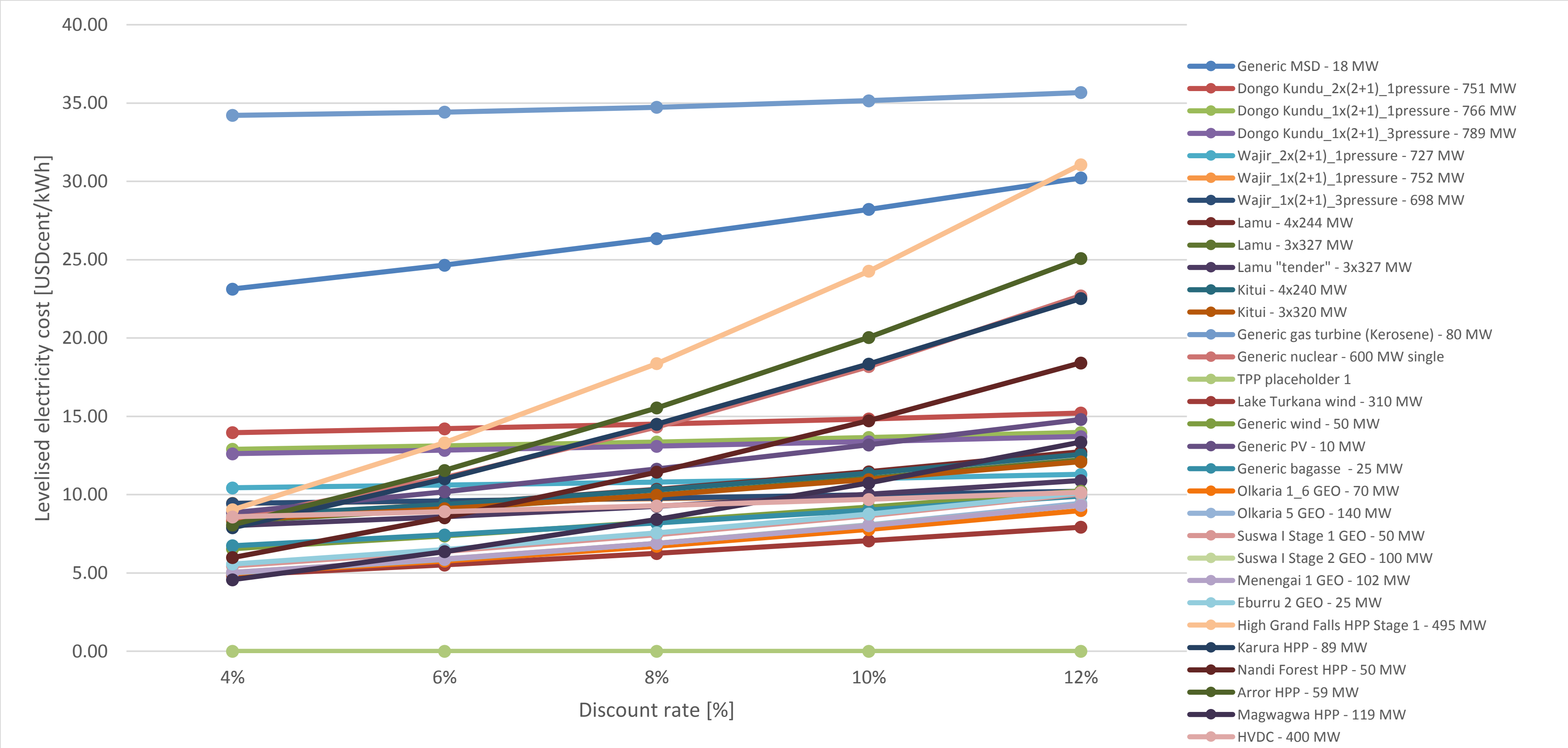
	Average future capacity factor	%	28%	30%	43%	36%	49%
2.6 Availability	Effective available capacity factor (thermal)	%	90%	90%	90%	90%	90%
	Forced Outage Rate (FOR)	%	2%	2%	2%	2%	2%
	Planned Outage Rate (POR)	days/year	30	30	30	30	30
2.7 Lifetime & Construction	Lifetime total (expected)	years	40	40	40	40	40
	1st year of operation	year	open	open	open	open	open
	Last year of operation (latest)	year	na	na	na	na	na
2.8 Costs	O&M Fixed	USD/kW/year	16.0	15.3	19.9	20.6	29.0
		TUSD/year	7,902.3	1,364.0	983.4	1,222.2	3,441.1
		% of CAPEX	0%	0%	1%	0%	1%
	O&M Variable	USD/MWh	0.5	0.5	0.7	0.5	0.5
	O&M Total	% of CAPEX	0%	0%	1%	0%	1%
	Specific Fuel Costs (at max. efficiency)	USD/MWh	na	na	na	na	na
	Inland fuel transport costs	USD/GJ	na	na	na	na	na
	Average Generation Costs (fuel + O&M variabl.)	USD/MWh	0.5	0.5	0.7	0.5	0.5
	Investment Costs Plant						
	TOTAL Investment Costs	MUSD	1,890.7	338.4	193.3	271.2	377.8
	Specific investment costs	USD/kW	3,819.7	3,798.2	3,905.8	4,565.2	3,180.5
	Residual value (HPP 60% of civil works)	% of CAPEX	56%	41%	50%	50%	47%
	Civil works cost share	%	94%	68%	83%	83%	78%

Figure 17: Generation candidates without transmission link costs, reference price forecast



Levelised electricity cost [USDcent/kWh]
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
maximum
80%
70%
60%
50%
40%
30%
20%
Capacity factor [%]
Generic MSD - 18 MW
Dongo Kundu_2x(2+1)_1pressure - 751 MW
Dongo Kundu_1x(2+1)_1pressure - 766 MW
Dongo Kundu_1x(2+1)_3pressure - 789 MW
Wajir_2x(2+1)_1pressure - 727 MW
Wajir_1x(2+1)_1pressure - 752 MW
Wajir_1x(2+1)_3pressure - 698 MW
Lamu - 4x244 MW
Lamu - 3x327 MW
Lamu "tender" - 3x327 MW
Kitui - 4x240 MW
Kitui - 3x320 MW
Generic gas turbine (Kerosene) - 80 MW
Generic nuclear - 600 MW single
TPP placeholder 1
Lake Turkana wind - 310 MW
Generic wind - 50 MW
Generic PV - 10 MW
Generic bagasse - 25 MW
Olkaria 1_6 GEO - 70 MW
Olkaria 5 GEO - 140 MW
Suswa I Stage 1 GEO - 50 MW
Suswa I Stage 2 GEO - 100 MW
Menengai 1 GEO - 102 MW
Eburru 2 GEO - 25 MW
High Grand Falls HPP Stage 1 - 495 MW
Karura HPP - 89 MW
Nandi Forest HPP - 50 MW
Arror HPP - 59 MW
Magwagwa HPP - 119 MW
HVDC - 400 MW
HVDC_400-fuel as fixed OPEX-Grid
HVDC - 400 MW

Figure 18: Generation candidates - w/o transmission link costs, high fuel price forecast



6. GENERATION EXPANSION PLANNING

6.1. Generation expansion planning approach

This chapter presents the approach used in generation expansion planning, the key assumptions, the modelling approach and the results obtained under different demand growth scenarios. The objective is to derive an optimal generation expansion plan for the country for the period 2017-2037 based on the prevailing commitments, available options and assumptions. The optimal plan would be the reference point for development of the corresponding transmission plan for the period. The section also analyses the medium-term period with a view to recommending adoption of possible alternatives to mitigate foreseeable challenges relating to the demand-supply imbalance over the medium term. The methodology adopted in the expansion planning work is outlined below.

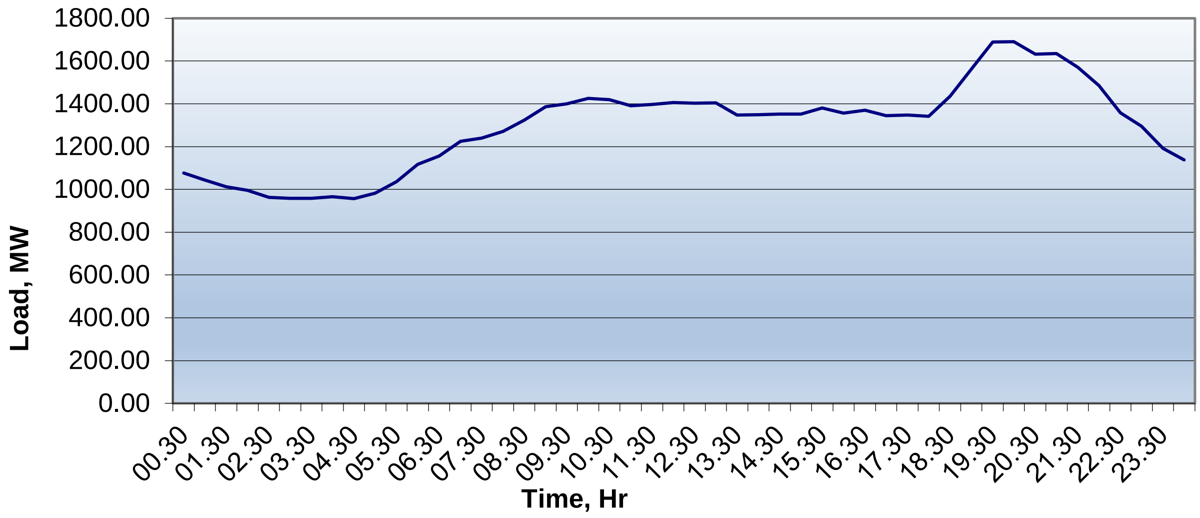
6.2. Demand forecast and load curve

Results from the three forecast scenarios described in chapter 3 are summarised in Table 28. The daily load duration curves developed in the 2015 Power Generation and Transmission Master Plan were retained in the generation expansion planning model. In the load projections, it was assumed that the peak will become increasingly steep as more domestic customers are connected and thereby decrease the load factor. In a typical day, power demand begins to rise rapidly around 5.00 hours to a peak level in the midmorning as shown in Figure 19. It generally stabilises in the afternoon hours before rising steeply to meet the evening peak which falls between 18.00 hours to 22.00 hours. Thereafter, demand decreases to the baseload level in the period after midnight. The planning models developed contain annual load duration curves based on current and projected demand profiles.

Table 28: summary of demand forecast results (MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2028	2030	2033	2035	2037
Low	1,754	1,842	1,928	2,021	2,114	2,207	2,319	2,438	2,563	2,975	3,293	3,872	4,305	4,763
Reference	1,754	1,866	1,978	2,103	2,234	2,421	2,586	2,764	2,989	3,720	4,244	5,148	5,859	6,638
Vision	1,754	1,917	2,088	2,293	2,516	2,766	3,027	3,342	3,705	4,854	5,780	7,272	8,468	9,790

Figure 19: Typical day load profile



6.3. Fuel projections

The fuel price projections discussed in the previous section were applied in the planning model both existing and candidate projects. Conversions were made to match fuel data with the requirements of the fuel files in the planning tools.

6.4. Updating of the existing and committed generating plants with CODs

The data input modules of the LIPSOP/XP model were updated to include existing and proposed generating were modelled. Additional projects were included largely based development plans by KenGen, GDC and Kenya Nuclear Electricity Board. The list of committed projects is presented in the previous chapter of this report.

6.4.1. Existing power generation

6.4.1.1. Technical parameters of hydro power plants

The available capacity and energy under average and dry conditions were revised. The assumption for average energy were adjusted to reduce the summed level close to the current average annual energy of about 3,334GWh. For the dry scenario, the energy outputs were adjusted upward to correspond to the lowest energy over the last ten years for existing plants, being 2250GWh. This ecenario is represented in table 29

Table 29: Available capacity and electricity generation for existing and candidate large hydropower plants

	Net MW	Available cap-Average MW	Gen-Average GWh	Available cap-Dry MW	Gen-Dry GWh
Tana	20	16	76	7	50
Masinga	40	33	151	10	100
Kamburu	90	85	401	75	264
Gitaru	216	199	781	138	515
Kindaruma	71	68	188	60	124
Kiambere	164	149	860	85	567
Turkwel	105	100	490	91	323
Sondu Miriu	60	58	371	45	245
Sangoro	20	19	125	14	83
Total	**786**	**727**	**3,443**	**525**	**2,272**
Karura	89	83	235	60	95
High Grand Falls 1	495	459	1213	331	493
High Grand Falls 2	198	184	57	132	23

6.4.1.2. Committed generating plants with CODs

Table 31 shows the list of harmonised generation projects that was used while deriving the list of committed projects. Candidate generation projects' data were updated in the planning model. The revised data include lower indicative tariffs for solar, wind, small hydro, biomass and biogas FiT candidates.

The technical team also feels that the system is vulnerable to instability arising from the relatively high additions of intermittent sources. In order to make it possible to run the wind and solar additions starting in 2018 (Lake turkana wind), an additional 160MW of backup capacity is necessary which is proposed to initially run on kerosene with potential to be converted into a LNG plant. These are proposed in 2019 (80MW) and 2020 (80 MW) all in the reference case scenario

Table 30: Schedule of committed projects for the period 2017-2024

		Jun-17	Dec-17	Jun-18	Dec-18	Jun-19	Dec-19	Jun-20	Dec-20	Jun-21	Dec-21	Jun-22	Dec-22	Jun-23	Dec-23	Jun-24	Dec-24	
	Wellheads	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	50
	Well Leasing	-	-	-	-	-	-	-	-	-	-	-	-	58	-	-	-	58
	Olkaria Turbine Uprate (topping)	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-	-	47
	OlkariaVII	-	-	-	-	-	-	-	-	-	-	-	140	-	-	-	-	140
	Olkaria I unit 6	-	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	70
	Olkaria V	-	-	-	-	158	-	-	-	-	-	-	-	-	-	-	-	158
	Olkaria VI-PPP	-	-	-	-	-	-	-	-	-	140	-	-	-	-	-	-	140
	Olkaria I Rehabilitation	-	-	-	-	-	17	17	17	-	-	-	-	-	-	-	-	51
	Geothermal Total	**0**	**0**	**0**	**0**	**208**	**87**	**17**	**64**	**0**	**140**	**0**	**140**	**58**	**0**	**0**	**0**	**714**
	Ngong Wind Farm III	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	10
	Meru Phase II	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	100
	Meru Phase III	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	220	220
	Meru (Isiolo) Wind Farm	-	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-	80
	Wind Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**10**	**0**	**80**	**0**	**0**	**0**	**0**	**100**	**220**	**410**
	Gitaru Solar	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-	40
	Karura Power Plant	-	-	-	-	-	-	-	-	-	-	-	-	90	-	-	-	90
	Other sources Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**40**	**0**	**0**	**0**	**0**	**90**	**0**	**0**	**0**	130
	TOTAL	**0**	**0**	**0**	**0**	**208**	**87**	**17**	**114**	**0**	**220**	**0**	**140**	**148**	**0**	**100**	**220**	**1254**
GDC (KenGen/KenGen IPPs)	Menengai I	-	-	-	-	-	103.5	-	-	-	-	-	-	-	-	-	-	104
	Menengai 1 Stage 2	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	60

	Paka I Wellhead	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	10
	Korosi 1 Well head	-	-	-	-	-	-	-	-	-	10		-	-	-	-	-	10
	Menengai 1 Wellhead	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	10
	Menegai III	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	100
	Baringo-Silali - Paka I	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	100
	TOTAL	**0**	**0**	**0**	**0**	**0**	**104**	**0**	**10**	**0**	**70**	**0**	**10**	**0**	**0**	**200**	**0**	**394**
IPPs/ FiT Projects	Agil	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	70	**70**
	Marine Power Akiira	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	70	**-**	**70**
	Olsuswa	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**		**-**	**-**	**-**	**140**	**140**
	Geothermal Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**70**	**210**	**280**
	Kipeto Wind	-	-	-	-	-	-	100	-	-	-	-		-	-	-	-	100
	Ol-Danyat Energy	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	10
	L. Turkana	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300
	Prunus	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	50
	Bahari Phase I	-	-	-	-	-	-	-	-	-	50	-	-					50
	Bahari Phase II	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	40
	Aperture Green	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	50
	Chania Green	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	50
	Wind Total	**0**	**0**	**0**	**300**	**0**	**0**	**100**	**50**	**0**	**110**	**0**	**40**	**0**	**50**	**0**	**0**	**650**
	Mt Kenya CBO	-	-	-	-	-	0.60	-	-	-	-	-	-	-	-	-	-	0.6
	KTDA Mathioya	-	-	3.60	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6
	Tindinyo Falls	-	-	-	-	-	1.50	-	-	-	-	-	-	-	-	-	-	1.5
	KTDA Lower Nyamindi	-	-	0.80		-	-	-	-	-	-	-	-	-	-	-	-	0.8

KTDA Iraru	-	-		1.0	-	-	-	-	-	-	-	-	-	-	-	-	1.0
KTDA South Maara	-	-	1.50	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5
KTDA Kipsonoi	-	-	-	-	-	-	-	0.60	-	-	-	-	-	-	-	-	0.6
KTDA Nyambunde (Nyakwana/Gucha)	-	-	-	-	-	-	-	-	-	-	0.50		-	-	-	-	0.5
KTDA Chania	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.5
KTDA Gura	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0
KTDA Metumi	-	-	3.60	-	-	-	-	-	-	-	-	-	-	-	-	-	3.6
KTDA Itare	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0
GenPro	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.0
Kleen Energy	-	-	-	6.0	-	-	-	-	-	-	-	-	-	-	-	-	6.0
Mutunguru Hydro	-	-	-		7.80		-	-	-	-	-	-	-	-	-	-	7.8
Global Sustainable Buchangu	-	-	-	-	-	-	-	4.50	-	-	-	-	-	-	-	-	4.5
Global Sustainable Kaptis	-	-	-	-	-	-	-	-	-	14.50	-	-	-	-	-	-	14.5
Hydel	-	-	-	-	-	-	-	-	-	-	-	5.0	-	-	-	-	5.0
Nithi Hydro Power Ltd (Frontier)	-	-	-	-	-	-	5.60	-	-	-	-	-	-	-	-	-	5.6
Kianthumbi Small Hydro	-	-	-	-	-	-	0.51	-	-	-	-	-	-	-	-	-	0.5
Tenwek	-	-	-	-	0.25	-	-	-	-	-	-	-	-	-	-	-	0.3
GreenLight Holdings	-	-	-	-	-	-	-	-	-	1.50	-	-	-	-	-	-	1.5
Western Hydro	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	-	-	10.0
Gatiki Small Hydro	-	-	-	-	-	9.40	-	-	-	-	-	-	-	-	-	-	9.4
Hydro Total	**7.5**	**0**	**10**	**7**	**8.1**	**12**	**16.11**	**5**	**0**	**16**	**1**	**5**	**0**	**0**	**0**	**0**	**86**
Alten Kenya Ltd	-	-	-	-	-	-	40.0	-	-	-	-	-	-	-	-	-	40

Malindi Solar- Vateki	-	-	-	-	-	-	40.0	-	-	-	-	-	-	-	-	-	40
Radiant- Selenkei	-	-	-	-	-	-	40.0	-	-	-	-	-	-	-	-	-	40
Eldosol-Cedate	-	-	-	-	-	-	-	40.0	-	-	-	-	-	-	-	-	40
Marco Borero	-	-	-	-	1.50	-	-	-	-	-	-	-	-	-	-	-	2
Hanan Arya Energy	-	-	-	-	-	-	-	-	-	10.0			-	-	-	-	10
Quaint	-	-	-	-	-	10.0											10
Strathmore University	-	-	0.25	-	-	-	-	-	-	-	-	-	-	-	-	-	0
Kenergy	-	-	-	-	-	40.0	-	-	-	-	-	-	-	-	-	-	40
Kensen	-	-	-	-	-	-	-	-	-	40.	-	-	-	-	-	-	40
Kaptagat	-	-	-	-	-	-	-	-	-	40.0	-	-	-	-	-	-	40
Belgen	-	-	-	-	-	-	-	-	-	-	-	40.0	-	-	-	-	40
Kengreen	-	-	-	-	-	-	-	-	-	-	-		-	10.0	-	-	10
Makindu- Rareh (Dafre)	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	30
Kopere Solar Park	-	-	-	-	40.0	-	-	-	-	-	-	-	-	-	-	-	40
REA Garissa Solar	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	50
Sayor Energy	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	10
Izera Ranch	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	10
Solarjule	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	10
Greenmillenia Energy Ltd	-	-	-	-	-	-	-	-	-	40.0	-	-	-	-	-	-	40
Tarita Green Energy (Isiolo)	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0	-	-	40
Tarita Green Energy (Elgeyo)	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0	-	-	40
Sunpower Kenya (Makindu-Kibwezi I)	-	-	-	-	-	-	-	-	-	-	-	-	-	40.0	-	-	40

	Asachi	-	-	-	-	-	-	-	-	-	-	-	-	-	30.60	-	-	30.6
	Astonfield Sosian Solar Ltd	-	-	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	10
	Solar Total	**0**	**0**	**0.25**	**50.0**	**41.5**	**50**	**120**	**40**	**30**	**130**	**0**	**70**	**0**	**170.6**	**0**	**0**	**702.4**
	Cummins	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	7.0
	Kwale Co-Generation	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	10.0
	Rea Vipingo (DWA Estates)	-	-	-	-	-	-	1.44	-	-	-	-	-	-	-	-	-	1.44
	Road Tech Solutions	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	10.0
	Crystal Energy Solutions	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-	40.0
	Sustainable Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40.0
	Sukari Industries	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35.0
	Thika Way Investments	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8.0
	Co-gen Total	**0**	**0**	**0**	**0**	**10**	**0**	**16**	**10**	**0**	**75**	**0**	**0**	**0**	**0**	**0**	**40**	**151**
	TOTAL	**7.5**	**0.0**	**9.8**	**357.0**	**59.6**	**61.5**	**252.6**	**105.1**	**30.0**	**331.0**	**0.5**	**115.0**	**0.0**	**220.6**	**70.0**	**250.0**	**1,590**
Coal																	**981**	**981**
IMPORTS	Ethiopia	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
	Total	**0**	**0**	**0**	**0**	**0**	**400**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**400**
	GRAND TOTAL	**7.5**	**0**	**10**	**357**	**268**	**652**	**270**	**229**	**30**	**621**	**1**	**265**	**148**	**221**	**370**	**1,451**	**4,899**

6.4.1.3. Decommissioning programme for existing plants

Table 32 shows the retirement schedule for existing power plants over the planning period. A total of 1,091 MW capacity including all existing thermal power plants are expected to be decommissioned.

Table 31: Decommissioning Schedule for existing power plants.

Phased out table			
Year considered for decommissioning	**Plant name**	**Type**	**Net capacity [MW]**
2019	Olkaria 1 Unit 1	Geothermal	15
2019	Iberafrica 1	Diesel engines	56
2019	Olkaria 1 Unit 2	Geothermal	15
2020	Olkaria 1 Unit 3	Geothermal	15
2021	Embakasi GT 1	Gas turbines (gasoil)	27
2021	Embakasi GT 2	Gas turbines (gasoil)	27
2021	Tsavo	Diesel engines	74
2023	Kipevu 1	Diesel engines	60
2028	Ngong 1, Phase I	Wind	5
2029	Olkaria 3 Unit 16 (OrPower4)	Geothermal	48
2030	Rabai Diesel (CCICE)	Diesel engines	90
2031	Kipevu 3	Diesel engines	115
2033	Olkaria 2	Geothermal	105
2034	Olkaria 3 Unit 79 (OrPower4)	Geothermal	62
2034	Iberafrica 2	Diesel engines	52.5
2034	Thika (CCICE)	Diesel engines	87
2034	Athi River Gulf	Diesel engines	80
2035	Triumph (Kitengela)	Diesel engines	83
2035	Ngong 1, Phase II	Wind	20
2036	KenGen Olkaria Wellheads I & Eburru	Geothermal	55
Total decommissioned			**1,091**

6.4.2. Modelling assumptions on power system and generating plants

6.4.2.1. Plant availability and energy generation

Large Hydropower: P90 exceedance probability value of monthly maximum output based on historical half hourly despatch data.

Small hydropower: 25% of the available net small hydropower capacity reflecting minimum of monthly average available capacity considering low hydrology.

Wind: 22% in 2017-2018 and 25% thereafter considering that diverse fields complement each other to support a quarter of the net capacity throughout.

Solar PV: 0% since solar is not available during peak.

Biomass: 50% of the available net capacity.

Load curve characteristics: The curves for different years developed during the master plan were retained as no major assumption was made to vary the profiles.

6.4.3. Reliability of the power system

6.4.3.1. Reserve requirements

The planning software used combines two tools that handle reserve requirements in different ways:

- For long-term expansion planning purpose, the LIPS-XP which applies more general requirements of overall reserve in relation to the annual peak load (but still based on hourly dispatch) for the identification of suitable expansion paths; and
- For operational considerations and testing of the above paths, the LIPS-OP which differentiates the requirements to test and analyse the possible behaviour of the system due to the overall purpose of long-term planning.

6.4.3.2. Reserve margin for expansion planning purposes

A lower level of detail for the reserve margin is required for expansion planning purposes in comparison to operational purposes. The power generation system is dimensioned in relation to the forecasted peak demand considering a reserve margin which is composed of the following parts:

- The reserve margin is considered to cover the loss of the largest unit in the system.
- In addition, cold reserve for balancing occasional unavailability of power plants due to planned maintenance and forced outages is considered.

6.4.3.3. Loss of load probability (LOLP)

The Loss-of-Load probability (LOLP) is a reliability indicator used to determine the adequacy of a power system to meet generation requirements. It determines the probability of not meeting demand over a given period. In this update, the LOLP is calculated for the total 8,760 hours in each year of the considered period. The LOLP is the ratio of total hours demand is not likely to be served called Loss of Load Expectation (LOLE) and the total hours in a year. In Kenya, the adopted LOLE is 24 hours in a year which gives a LOLP of 0.274% which is used in generation modelling.

6.4.3.4. Surplus energy

Generation projects anticipated in the medium term may result in surplus energy. The excess energy that would potentially be spilled include hydro, geothermal wind and solar. The energy import contract with Ethiopia is a take-or-pay and thus the surplus energy is considered spilled. The committed geothermal, wind, solar PV, run of river hydro, are among the must-run plants that are expected to result in significant surpluses between 2019 and 2024. Technical and economic system operation requirements may also result in less usage of hydropower energy from storage plants and thus lead to reservoir spillage. This is because the available hydro plants will be required to provide primary reserves in the management of the system with high intermittent energy. Thus, when reservoir of a hydropower plant reaches its maximum supply level, water must be spilled.

6.4.3.5. Hydrological Modeling

The actual available capacity and the annual generation of hydropower plants depend on the present hydrology. Long Term Average (LTA) hydrology conditions are considered for modelling the operational dispatch in the main expansion scenarios. This study considered long term monthly major hydropower plants production for a period of recent 8 years. The period and data is considered representative as it covers all the upgrades that had been carried out in various hydropower plants such as Tana, Masinga, Gitaru, Kindaruma and Kiambere and includes some drought periods in 2008/09 and 2011/12 financial years.

In the low hydrology case, 66% of the LTA hydrological conditions which is equivalent to the worst-case scenario observed in previous eight years are considered in analysing the operational dispatch of the detected expansion plan of the reference expansion scenario. However, for the design of the power system sufficient back-up capacity is provided for, adequate to compensate shortfalls in hydropower capacity during drought periods. For this reason, the generation expansion modelling considers the firm capacity of hydropower plants for dimensioning the power system. The firm capacity of hydropower plants is defined as the P90 exceedance probability value determined based on historic half hourly production data.

6.5. Generation Expansion Simulations using LIPS-OP/XP

Three expansion sequences described below were developed in this study, modelled, and simulations carried out.

6.5.1. Fixed System case

The case was modelled comprising the existing plants, committed additions and retirements over the planning period, and simulated under the three forecasts scenarios developed -reference, low and vision. Initial simulations were carried out to study the balance between the existing and committed projects and projected demand before the system. This enables the planner to have an overview of the demand-supply situation and implications of the scheduling of capacity addition projects in the medium term, and to visualise the level of gaps and surpluses based on the committed projectsThe base case was assembled consisting of committed generation additions and retirements over the planning horizon. Committed projects and the retirement schedule for existing plants are shown in Tables 31 and 32 respectively.

6.5.2. Optimised generation expansion case

This case was developed on the basis that projects beyond 2023 including the Lamu coal plant are considered candidates, with the committed solar PV and wind spread over the period up to 2029 in order to minimise surpluses seen in the fixed expansion case. Other projects were presented as candidates and the system optimized.

6.5.3. Fixed Medium-term case

In this sequence, fixed projects were modelled according to the medium-term plan and optimization followed through subsequent years. This case was used to derive the long term expansion plan having captured the most likely development path. This case was developed to derive an optimal expansion path assuming that projects scheduled for commissioning in the period up to 2024 shown in Table 31 are not flexible while the rest were presented as expansion candidates over the planning horizon. PV candidate units of 10MW were added each year from 2027 and simulations done under three demand scenarios. Additionally, Menengai geothermal wellheads each of 10MW were presented from 2021 to 2023.

The three basic cases developed were studied under three demand scenarios summarised below.

a. Reference demand expansion
b. Vision demand expansion
c. Low demand expansion

The Fixed Medium-term case described above was subjected to sensitivity analyses simulations based on the following variables:

a. Fuel cost -low and high fuel cost forecasts
b. Discount rates of 8%, 10%, 12% and14%
c. Capex change -variation of ±10% in capex for candidate projects for hydropower and geothermal candidates
d. Low annual hydro generation

6.6. Results for Generation Expansion Scenarios Simulations

6.6.1. Results for Fixed System expansion case

The fixed plan expansion sequence contains proposed projects by the various power sector players, public and private, involved in generation capacity development. The basically captures the visions of the companies and the ongoing projects regarded as committed. If implemented as proposed, the total capacity would grow from the current 2,235 MW to 10,897 MW in 2037. The results for the case are discussed below under the three load growth scenarios.

6.6.1.1. Results for Fixed System expansion- Reference Demand Growth

Table 32 shows the planting sequence for the fixed expansion plan case simulated using LIPS XP. It contains a fixed system being proposed projects by the various power sector players including the private sector over the entire period of study. If implemented as proposed, the total capacity would grow from the current 2,235 MW to 10,897 MW in 2037.

The demand supply balance is presented in Table 33. The results indicate that if projects are implemented as proposed, the system would experience a shortfall of 65MW in 2018 followed by huge surpluses above the peak plus reserve level and all the way to the end of the study period. Figure 20 shows the installed capacity versus demand and the excess capacity associated with fixed expansion plan. The surplus energy could be as high as 32% of the available generation and the vented steam reaching 27% of the geothermal generation.

Figures 21 and 22 show the firm capacity and the generation mix for this scenario. In the first and the last three years firm capacity levels are either just meeting or slightly below our reserve margin. The middle years however show large excesses. Geothermal would provide about 50% of energy and the renewables output ranging between 80% and 90%.

Development of the Levelized Cost of Energy for the case is shown Table 34. LEC will increase from US Cents 8.30/kWh in 2018 and peak at US Cents 16.86/kWh in 2024 before declining to a range between US Cents 14.06 /kWh and US Cents 12.95/kWh in the period 2030-2037. The rise in LEC could be because of the additional capacities in the system with the biggest additional of Lamu coal in 2024. The LEC then starts to fall as the additional capacity remains stable until 2030 with most additions being from Renewable resources. Table 35 shows the Long Term Planting Sequence-Reference scenario capacity factors for each plant.

Table 32: Long Term Planting Sequence-Reference scenario

Plant characteristics						Plant expansion status	COD
ID	PP name	PP group	Fuel	Net capacity [MW]	Use plant	Status in base year	
u1	Olkaria 1 - Unit 1	Geothermal	Geothermal	15	yes	existing	1981
u2	Olkaria 1 - Unit 4-5	Geothermal	Geothermal	140	yes	existing	2014
u3	Olkaria 2	Geothermal	Geothermal	105	yes	existing	2003
u4	Orpower4 Plant1 (Olkaria 3 - Unit 1-6)	Geothermal	Geothermal	48	yes	existing	2000
u5	OrPower4 Plant 2&3 (Olkaria 3 - Unit 7-9)	Geothermal	Geothermal	62	yes	existing	2014
u6	Olkaria 4	Geothermal	Geothermal	140	yes	existing	2014
u7	KenGen Olkaria Wellheads I & Eburru	Geothermal	Geothermal	55	yes	existing	2015
u8	Embakasi GT 1	Gas turbines (gasoil)	Gasoil Nairobi	27	yes	existing	1997
u9	Embakasi GT 2	Gas turbines (gasoil)	Gasoil Eldoret	27	yes	existing	1999
u10	Iberafrica 1	Diesel engines	HFO Nairobi	56	yes	existing	1997
u11	Iberafrica 2	Diesel engines	HFO Nairobi	53	yes	existing	2009
u12	Kipevu 1	Diesel engines	HFO Mombasa	60	yes	existing	1999
u13	Kipevu 3	Diesel engines	HFO Mombasa	115	yes	existing	2011

u14	Tsavo	Diesel engines	HFO Mombasa	74	yes	existing	2001
u15	Rabai Diesel (CC-ICE)	Diesel engines	HFO Mombasa	90	yes	existing	2010
u16	Thika (CC-ICE)	Diesel engines	HFO Nairobi	87	yes	existing	2014
u17	Athi River Gulf	Diesel engines	HFO Nairobi	80	yes	existing	2014
u18	Triumph (Kitengela)	Diesel engines	HFO Nairobi	83	yes	existing	2015
u20	Orpower4 Plant4 (Olkaria 3 Unit 10 - 16)	Geothermal	Geothermal	29	yes	existing	2015
u21	KenGen Olkaria Wellheads II	Geothermal	Geothermal	28	yes	existing	2016
u22	HVDC Ethiopia	Import	Ethiopia Import	400	yes	obligatory candidate	2019
u23	Lamu Unit 1	Coal	Coal imported	327	yes	obligatory candidate	2024
u24	Lamu Unit 2	Coal	Coal imported	327	yes	obligatory candidate	2024
u25	Lamu Unit 3	Coal	Coal imported	327	yes	obligatory candidate	2024
u26	Menengai 1 Phase I - Stage 1	Geothermal	Geothermal	103	yes	obligatory candidate	2020
u27	Olkaria 1 - Unit 6	Geothermal	Geothermal	70	yes	obligatory candidate	2020
u28	Olkaria 5	Geothermal	Geothermal	158	yes	obligatory candidate	2019
u29	Olkaria 6 PPP	Geothermal	Geothermal	140	yes	obligatory candidate	2022
u30	Olkaria 7	Geothermal	Geothermal	140	yes	obligatory candidate	2023
u31	Olkaria 8	Geothermal	Geothermal	140	yes	obligatory candidate	2024
u32	Olkaria 9 & other fields	Geothermal	Geothermal	420	yes	obligatory candidate	2030
u33	Eburru 2	Geothermal	Geothermal	25	yes	obligatory candidate	2023

u34	Menengai I - Stage 2	Geothermal	Geothermal	60	yes	obligatory candidate	2022
u35	Menengai III	Geothermal	Geothermal	100	yes	obligatory candidate	2024
u36	Menengai IV	Geothermal	Geothermal	100	yes	obligatory candidate	2028
u37	Menengai V	Geothermal	Geothermal	100	yes	obligatory candidate	2031
u38	Generic Geothermal	Geothermal	Geothermal	300	yes	obligatory candidate	
u40	Suswa I	Geothermal	Geothermal	100	yes	obligatory candidate	2026
u41	Suswa II	Geothermal	Geothermal	100	yes	obligatory candidate	2030
u42	Suswa III	Geothermal	Geothermal	100	yes	obligatory candidate	2033
u45	Baringo Silali - Korosi I	Geothermal	Geothermal	100	yes	obligatory candidate	2027
u46	Baringo Silali - Paka I	Geothermal	Geothermal	100	yes	obligatory candidate	2024
u47	Baringo Silali - Silali I	Geothermal	Geothermal	100	yes	obligatory candidate	2026
u48	GDC Wellheads	Geothermal	Geothermal	30	yes	obligatory candidate	2023
u50	AGIL Longonot Stage 1	Geothermal	Geothermal	70	yes	obligatory candidate	2025
u52	Marine Power Akiira Stage 1	Geothermal	Geothermal	70	yes	obligatory candidate	2024
u54	Olkaria Topping	Geothermal	Geothermal	47	yes	obligatory candidate	2021
u56	Dongo Kundu CCGT - small 1	Natural gas	LNG import	375	yes	obligatory candidate	2035
u57	Dongo Kundu CCGT - small 2	Natural gas	LNG import	375	yes	obligatory candidate	2036
u62	Nuclear Unit 1	Nuclear	Uranium	600	yes	obligatory candidate	2036
u63	Nuclear Unit 2	Nuclear	Uranium	600	yes	obligatory candidate	2037
u64	Olkaria Modular	Geothermal	Geothermal	50	yes	obligatory candidate	2019
u65	OrPower4 Plant 1 Additional	Geothermal	Geothermal	10	yes	obligatory candidate	2018
u70	OrPower4 Plant 4 Additional	Geothermal	Geothermal	61	yes	obligatory candidate	2023
u71	Wellhead Leasing	Geothermal	Geothermal	50	yes	obligatory candidate	2023
u72	Back-up capacity 80 MW - Unit 2	Generic back-up capacity	Gasoil Eldoret	80	yes	obligatory candidate	2019
u73	Back-up capacity 80 MW - Unit 3	Generic back-up capacity	Gasoil Eldoret	80	yes	obligatory candidate	2020

u81	Olsuswa 140MW unit 1 & 2	Generic back-up capacity	Geothermal	140	yes	obligatory candidate	2025
u96	Olkaria 1 - Unit 2	Geothermal	Geothermal	15	yes	existing	1981
u97	Olkaria 1 - Unit 3	Geothermal	Geothermal	15	yes	existing	1981
u98	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	Geothermal	17	yes	obligatory candidate	2019
u99	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	Geothermal	17	yes	obligatory candidate	2020
u100	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	Geothermal	17	yes	obligatory candidate	2020
h1	Tana	Hydropower	Water	20	yes	existing	1955
h2	Masinga	Hydropower	Water	40	yes	existing	1981
h3	Kamburu	Hydropower	Water	90	yes	existing	1975
h4	Gitaru	Hydropower	Water	216	yes	existing	1978
h5	Kindaruma	Hydropower	Water	70	yes	existing	1968
h6	Kiambere	Hydropower	Water	164	yes	existing	1988
h7	Turkwel	Hydropower	Water	105	yes	existing	1991
h8	Sondo	Hydropower	Water	60	yes	existing	2008
h9	Sang'oro	Hydropower	Water	20	yes	existing	2012
h10	High Grand Falls Stage 1	Hydropower	Water	495	yes	obligatory candidate	2031
h11	Karura	Hydropower	Water	89	yes	obligatory candidate	2023
h15	High Grand Falls Stage 1+2	Hydropower	Water	693	yes	obligatory candidate	2032
wi1	Ngong 1, Phase I	Wind	Wind	5	yes	existing	2008
wi2	Ngong 1, Phase II	Wind	Wind	20	yes	existing	2015
wi3	Ngong 1 - Phase III	Wind	Wind	10	yes	obligatory candidate	2021
wi4	Aeolus Kinangop	Wind	Wind	60	yes	obligatory candidate	2026
wi5	Kipeto - Phase I	Wind	Wind	50	yes	obligatory candidate	2020
wi6	Lake Turkana - Phase I, Stage 1	Wind	Wind	100	yes	obligatory candidate	2018
wi7	Prunus	Wind	Wind	51	yes	obligatory candidate	2022
wi8	Meru Phase I	Wind	Wind	80	yes	obligatory candidate	2022

wi9	Ol-Danyat Energy	Wind	Wind	10	yes	obligatory candidate	2022
wi10	Kipeto - Phase II	Wind	Wind	50	yes	obligatory candidate	2020
wi11	Lake Turkana - Phase I, Stage 2	Wind	Wind	100	yes	obligatory candidate	2019
wi12	Electrawinds Bahari	Wind	Wind	50	yes	obligatory candidate	2022
wi13	Lake Turkana - Phase I, Stage 3	Wind	Wind	100	yes	obligatory candidate	2019
wi15	Chania Green	Wind	Wind	50	yes	obligatory candidate	2021
wi16	Meru Phase II	Wind	Wind	100	yes	obligatory candidate	2024
wi17	Meru Phase III	Wind	Wind	220	yes	obligatory candidate	2025
wi18	Marsabit Phase I - KenGen	Wind	Wind	300	yes	obligatory candidate	2028
wi26	Electrawinds Bahari Phase 2	Wind	Wind	40	yes	obligatory candidate	2023
wi27	Aperture	Wind	Wind	50	yes	obligatory candidate	2021
pv1	PV grid Garissa	PV	PV	50	yes	obligatory candidate	2019
pv2	Marcoborero	PV	PV	2	yes	obligatory candidate	2019
pv3	Alten, Malindi, Selenkei	PV	PV	120	yes	obligatory candidate	2020
pv5	Eldosol	PV	PV	40	yes	obligatory candidate	2021
pv7	Solargen	PV	PV	40	yes	obligatory candidate	2026
pv8	Makindu Dafre rAREH	PV	PV	30	yes	obligatory candidate	2021
pv9	Kopere	PV	PV	40	yes	obligatory candidate	2019
pv10	Hanan, Greenmillenia, Kensen	PV	PV	90	yes	obligatory candidate	2022
pv11	Strathmore	PV	PV	0	yes	obligatory candidate	2018
pv12	Sayor, Izera, Solarjoule	PV	PV	30	yes	obligatory candidate	2023
pv13	Tarita Isiolo, Kengreen	PV	PV	50	yes	obligatory candidate	2024
pv14	Asachi, Astonfield Sosian, Sunpower	PV	PV	81	yes	obligatory candidate	2024
pv15	Quaint, Kenergy	PV	PV	50	yes	obligatory candidate	2020
pv16	Belgen, Tarita Green Energy Elgeyo	PV	PV	80	yes	obligatory candidate	2023
pv17	Gitaru Solar	PV	PV	40	yes	obligatory candidate	2021

Table 33: Demand supply balance -fixed case – reference forecast

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,866	1,978	2,103	2,234	2,421	2,586	2,764	2,989	3,224	3,441	3,720	3,974	4,244	4,525	4,826	5,148	5,491	5,859	6,232	6,638
Peak load + reserve margin	MW	2,037	2,150	2,279	2,429	2,545	2,747	2,931	3,550	3,790	4,039	4,264	4,550	4,800	5,099	5,416	5,733	6,054	6,370	6,764	7,526	8,017
Reserve margin	% of peak load	16%	15%	15%	16%	14%	13%	13%	28%	27%	25%	24%	22%	21%	20%	20%	19%	18%	16%	15%	21%	21%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,121	6,742	7,221	7,538	7,665	8,088	8,067	8,524	9,031	9,256	9,278	9,024	9,323	10,270	10,897
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,649	5,065	5,352	5,574	5,680	5,860	5,819	6,255	6,639	6,802	6,804	6,529	6,822	7,748	8,355
Supply - demand gap	MW	0	-65	488	650	487	574	718	1,515	1,562	1,535	1,416	1,310	1,019	1,156	1,223	1,069	750	158	58	223	338
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	11,101	11,751	12,476	13,240	14,270	15,226	16,259	17,699	19,032	20,323	22,001	23,508	25,104	26,766	28,537	30,421	32,431	34,577	36,734	39,073
Electricity generation	GWh	10,407	11,102	13,490	15,531	16,420	18,726	20,976	24,034	26,172	27,740	28,490	30,311	30,296	33,489	35,277	35,465	35,704	35,775	36,418	37,581	39,519
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	1,740	3,055	3,181	4,457	5,750	7,775	8,473	8,708	8,167	8,310	6,788	8,385	8,511	6,929	5,283	3,336	1,829	847	445
Excess energy - share on generation	%	0%	0%	13%	20%	19%	24%	27%	32%	32%	31%	29%	27%	22%	25%	24%	20%	15%	9%	5%	2%	1%
Vented GEO steam (assuming single-flash technology)	GWh	25	37	1,724	2,160	2,233	2,673	3,525	4,369	4,801	5,210	5,382	5,528	5,281	6,446	6,780	6,744	6,581	6,177	5,728	4,812	3,775
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	24%	25%	25%	25%	27%	26%	26%	26%	26%	25%	25%	25%	26%	25%	25%	24%	22%	19%	15%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 20: Installed capacity -fixed case – reference forecast

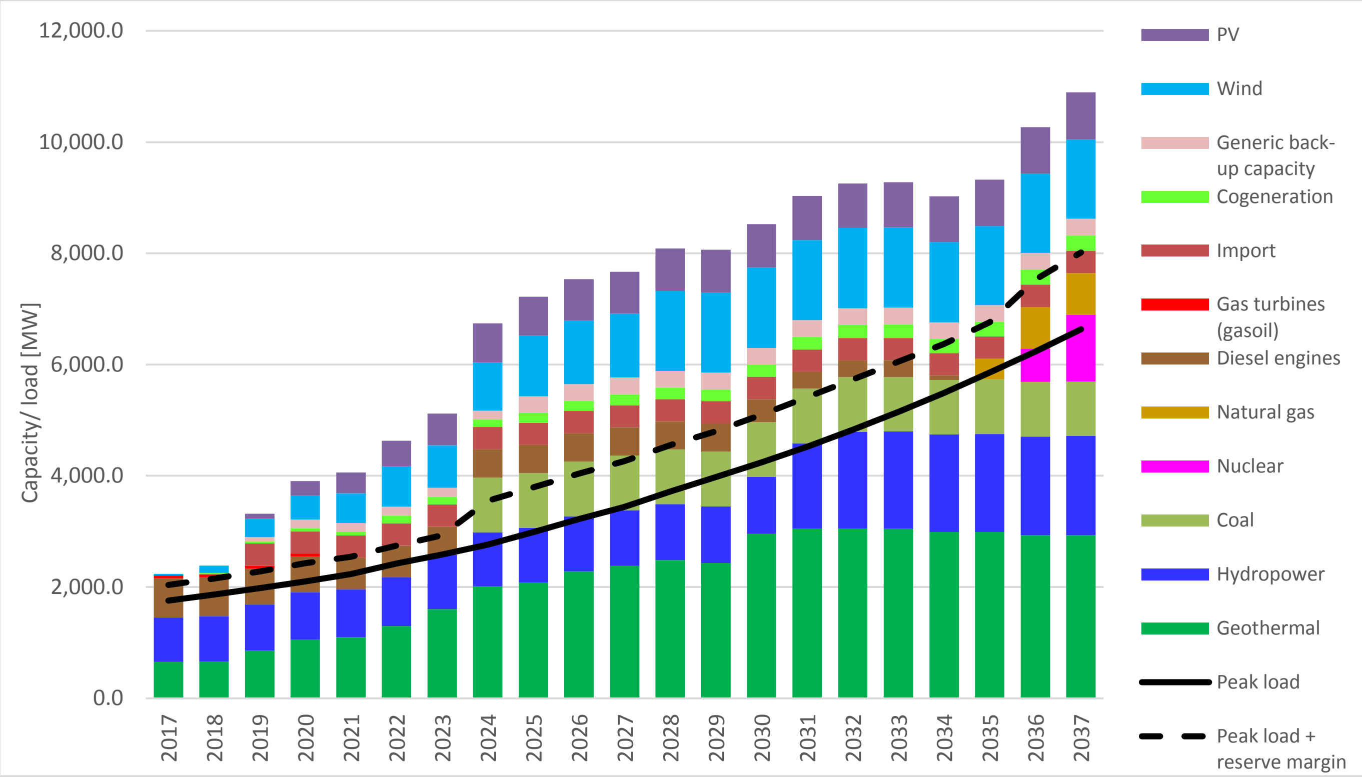


Figure 21: Firm generation capacity -fixed case – reference forecast

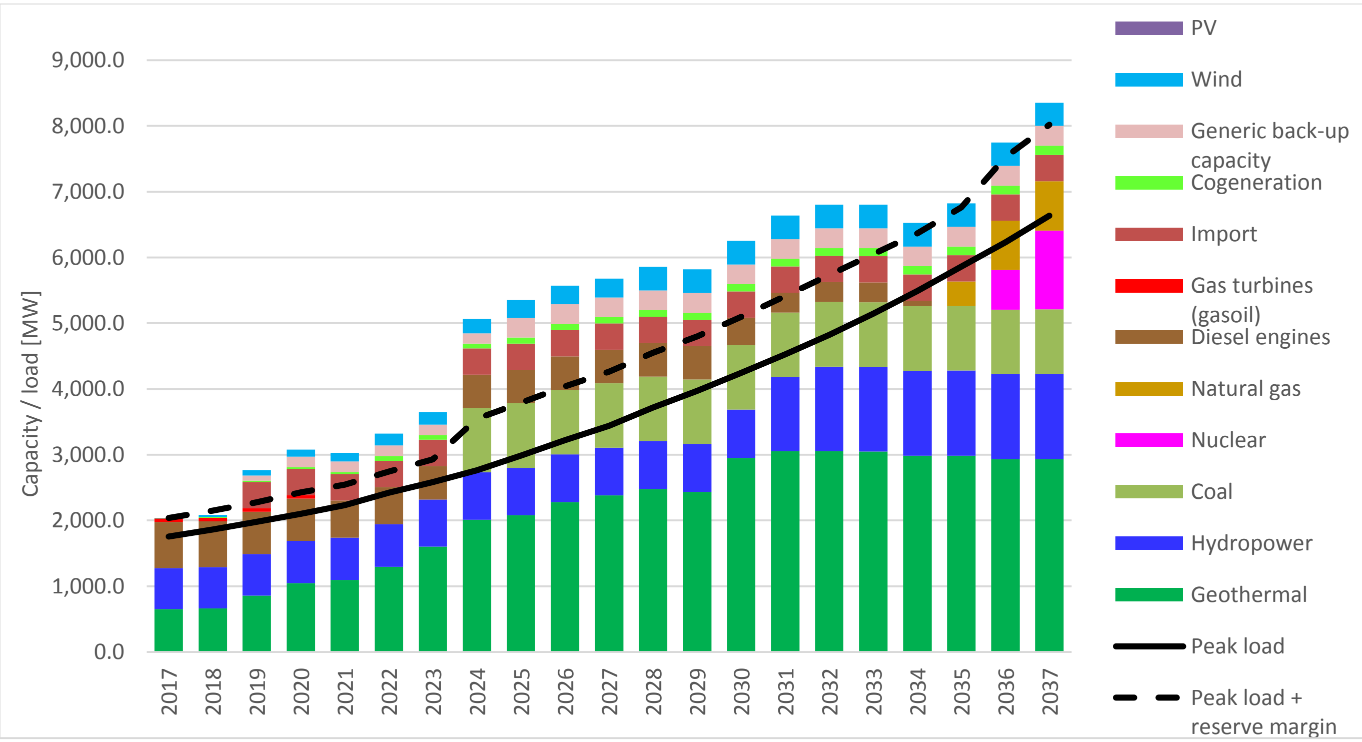


Table 34: Levelised Cost of Energy -fixed case -reference forecast

System cost		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPV
CAPEX	MUSD	688	657	887	1,059	1,101	1,294	1,498	2,033	2,182	2,299	2,352	2,394	2,383	2,595	2,813	2,828	2,870	2,807	2,858	3,504	4,040	**11,944**
Fixed OPEX	MUSD	140	153	212	254	270	329	379	517	572	609	626	666	662	740	761	766	767	755	765	775	781	**3,030**
Variable OPEX	MUSD	14	15	187	188	188	191	191	191	192	193	193	193	194	194	195	195	196	196	197	203	212	**1,150**
Fuel cost	MUSD	88	97	0	0	0	0	0	0	0	0	0	1	2	1	0	0	1	5	13	22	28	**164**
Total generation cost	**MUSD**	**930**	**922**	**1,286**	**1,501**	**1,560**	**1,814**	**2,068**	**2,741**	**2,946**	**3,102**	**3,171**	**3,253**	**3,242**	**3,530**	**3,769**	**3,790**	**3,833**	**3,763**	**3,832**	**4,504**	**5,061**	**16,288**
Cost for unserved energy	MUSD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
TOTAL	**MUSD**	**930**	**922**	**1,286**	**1,501**	**1,560**	**1,814**	**2,068**	**2,741**	**2,946**	**3,102**	**3,171**	**3,253**	**3,242**	**3,530**	**3,769**	**3,790**	**3,833**	**3,763**	**3,832**	**4,504**	**5,061**	**16,288**
System LEC	**US cent/kWh**	**8.94**	**8.30**	**10.94**	**12.03**	**11.78**	**12.71**	**13.58**	**16.86**	**16.64**	**16.30**	**15.60**	**14.79**	**13.79**	**14.06**	**14.08**	**13.28**	**12.60**	**11.60**	**11.08**	**12.26**	**12.95**	

Figure 22: Levelized Cost of Energy fixed case -reference forecast

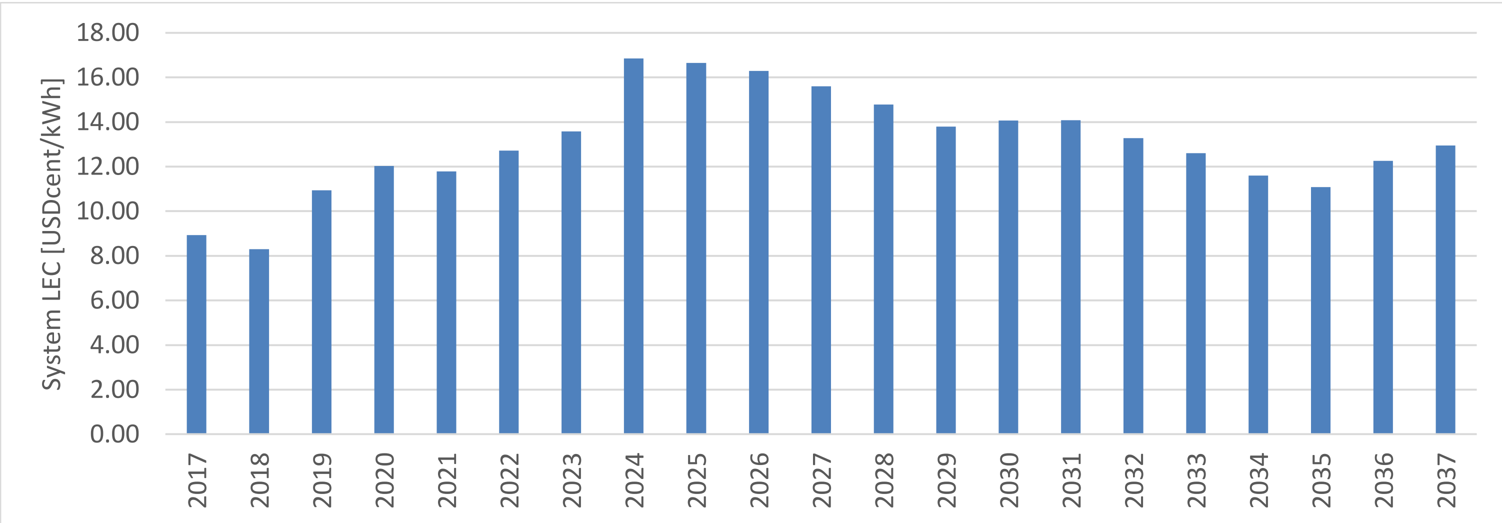
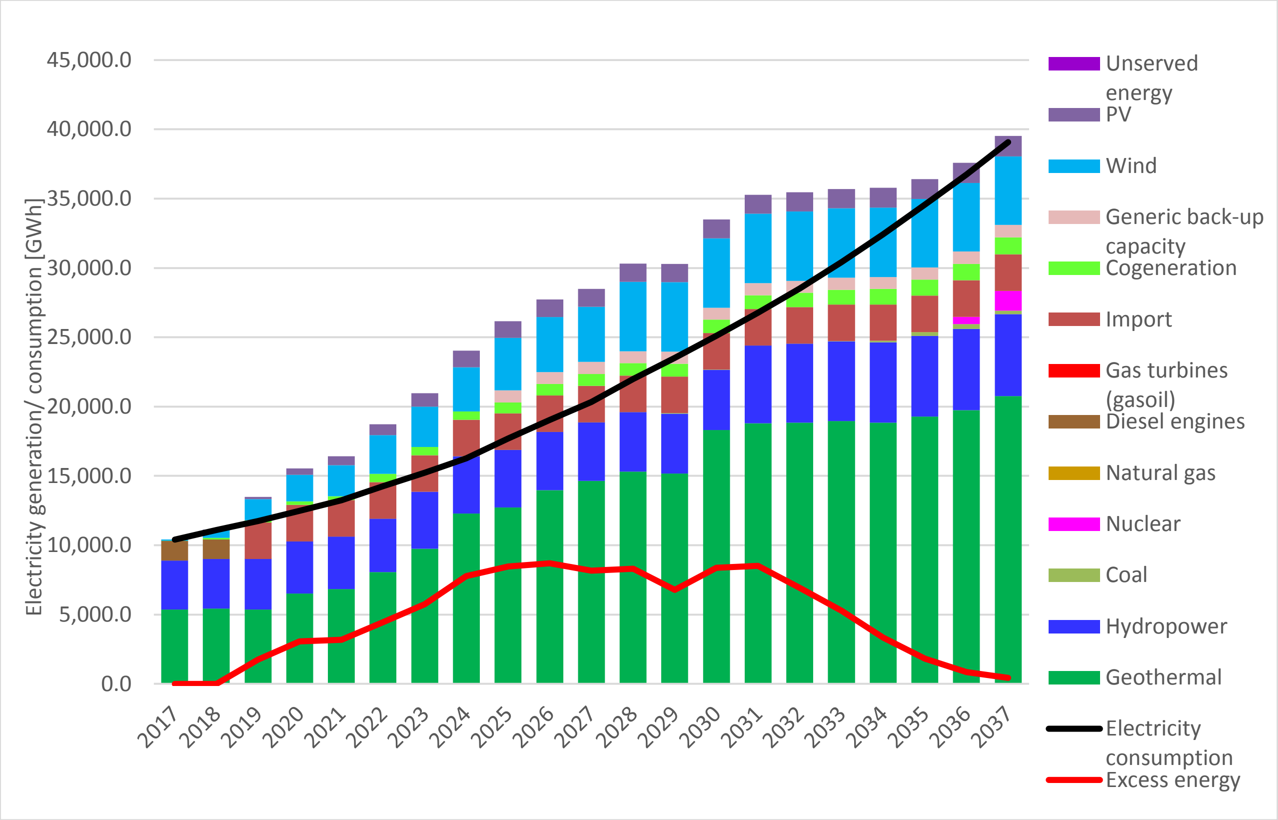


Table 35: Generating plants' capacity factors -Fixed case -Reference forecast

Capacity factor [%]	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Geothermal	94.1%	93.9%	71.6%	71.0%	71.3%	71.0%	69.4%	69.8%	69.8%	70.0%	70.2%	70.5%	71.2%	70.8%	70.3%	70.4%	71.0%	72.0%	73.7%	76.9%	80.9%
Hydropower	50.1%	50.1%	50.1%	50.1%	50.1%	50.1%	48.2%	48.2%	48.3%	48.3%	48.3%	48.3%	48.3%	48.3%	41.8%	37.4%	37.5%	37.5%	37.6%	37.7%	37.7%
Coal								0.0%	0.0%	0.0%	0.0%	0.1%	0.6%	0.2%	0.0%	0.1%	0.3%	1.4%	3.2%	4.1%	3.0%
Nuclear																				10.2%	13.7%
Natural gas																			0.1%	0.1%	0.0%
Diesel engines	23.3%	23.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%			
Gas turbines (gasoil)	0.0%	0.0%	0.0%	0.0%																	
Import			75.1%	75.0%	75.1%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
Cogeneration	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Generic back-up capacity			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.1%	33.5%	33.9%	34.3%
Wind	35.0%	50.9%	53.4%	51.7%	47.8%	43.6%	43.1%	41.9%	39.9%	39.5%	39.5%	39.6%	39.6%	39.6%	39.6%	39.6%	39.6%	39.6%	39.7%	39.7%	39.7%
PV		19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%

Figure 23: Annual generation -fixed case- Ref forecast



6.6.1.2. Results for Fixed System -Low Demand Growth Scenario

A lower forecast narrows the demand-supply gap to 42MW in 2018 and no gap over the rest of the period as shown in Table 37. however, the excess energy is significantly higher rising from 15% in 2019 to a peak of 42% in 2025 and again in 2028, before gradually declining to 21% in 2037. Vented steam would average 26% of the geothermal generation over the period 2019-2037. The system LEC would consequently be higher, rising from US Cents 8.31/kWh in 2018 to US Cents 19.51/kWh in 2026 before declining gradually to US Cents 15.54/kWh in 2037 as shown in Figures 27.

Table 36: results -fixed system-low demand

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,842	1,928	2,021	2,114	2,207	2,319	2,438	2,563	2,692	2,829	2,975	3,129	3,293	3,466	3,651	3,872	4,081	4,305	4,523	4,763
Peak load + reserve margin	MW	2,037	2,126	2,229	2,347	2,425	2,533	2,665	3,224	3,364	3,507	3,652	3,805	3,956	4,148	4,357	4,558	4,779	4,960	5,175	5,749	5,989
Reserve margin	% of peak load	16%	15%	16%	16%	15%	15%	15%	32%	31%	30%	29%	28%	26%	26%	26%	25%	23%	22%	20%	27%	26%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,121	6,742	7,221	7,538	7,665	8,088	8,067	8,524	9,031	9,256	9,278	9,024	8,948	9,520	9,547
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,649	5,065	5,352	5,574	5,680	5,860	5,819	6,255	6,639	6,802	6,804	6,529	6,447	6,998	7,005
Supply - demand gap	MW	0	-42	538	732	607	789	984	1,841	1,989	2,066	2,028	2,056	1,863	2,107	2,282	2,245	2,025	1,568	1,272	1,250	1,016
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	10,965	11,462	11,996	12,536	13,078	13,730	14,421	15,145	15,896	16,692	17,537	18,432	19,380	20,385	21,453	22,701	23,909	25,196	26,458	27,840
Electricity generation	GWh	10,407	10,965	13,466	15,511	16,380	18,694	20,966	24,010	26,142	27,700	28,412	30,160	29,961	33,267	35,191	35,341	35,402	35,112	35,152	35,011	35,222
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	2,005	3,516	3,845	5,616	7,236	9,590	10,997	11,372	11,513	12,624	11,530	13,487	14,261	13,888	12,701	11,204	9,956	8,554	7,382
Excess energy - share on generation	%	0%	0%	15%	23%	23%	30%	35%	40%	42%	41%	41%	42%	38%	41%	41%	39%	36%	32%	28%	24%	21%
Vented GEO steam (assuming single-flash technology)	GWh	25	39	1,746	2,180	2,271	2,705	3,535	4,392	4,831	5,250	5,459	5,667	5,560	6,655	6,864	6,864	6,853	6,722	6,712	6,499	6,402
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	25%	25%	25%	25%	27%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	25%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 24: Installed capacity versus load -fixed system -low demand

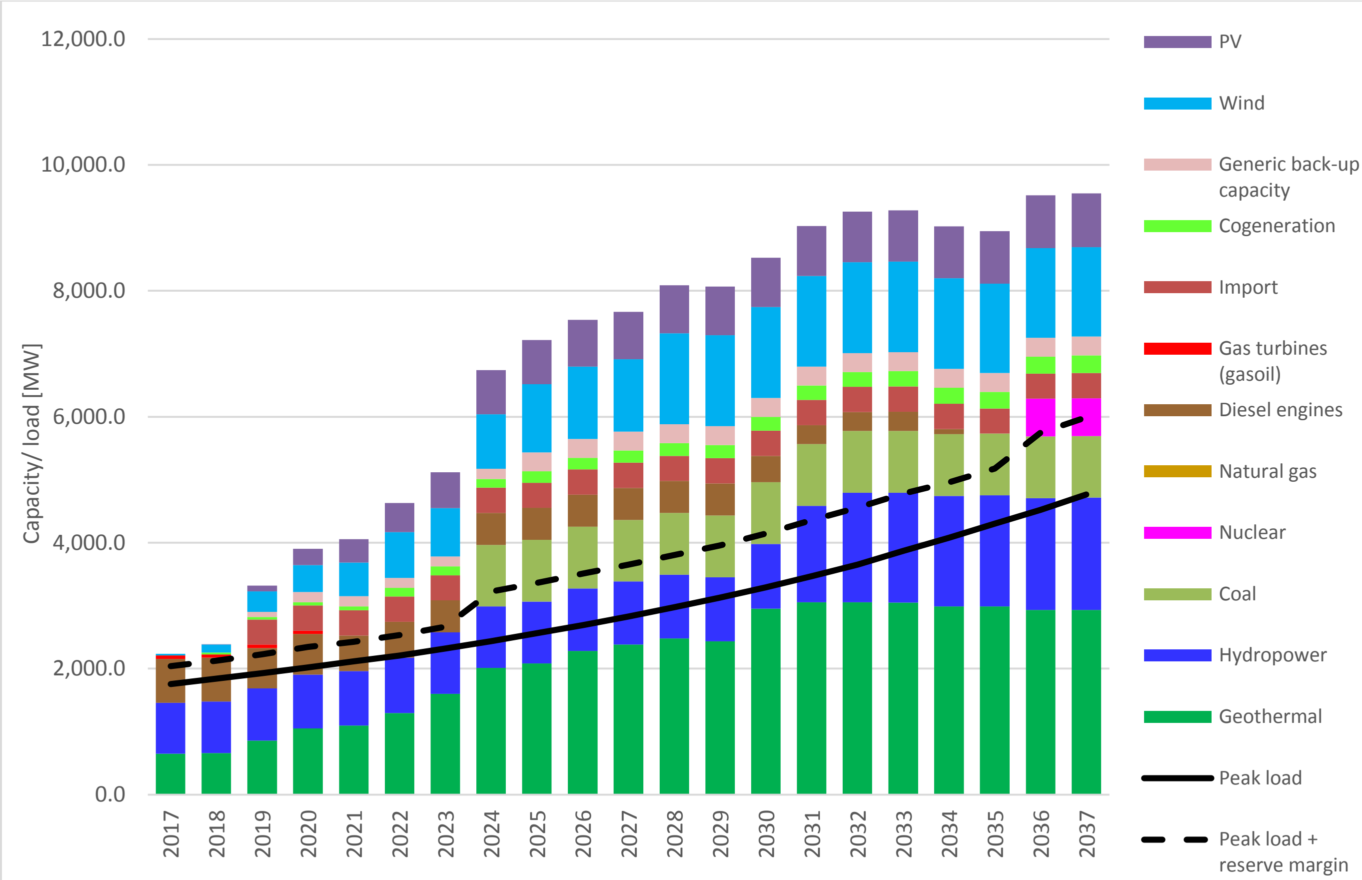


Figure 25: Firm capacity versus peak load- fixed system -low demand

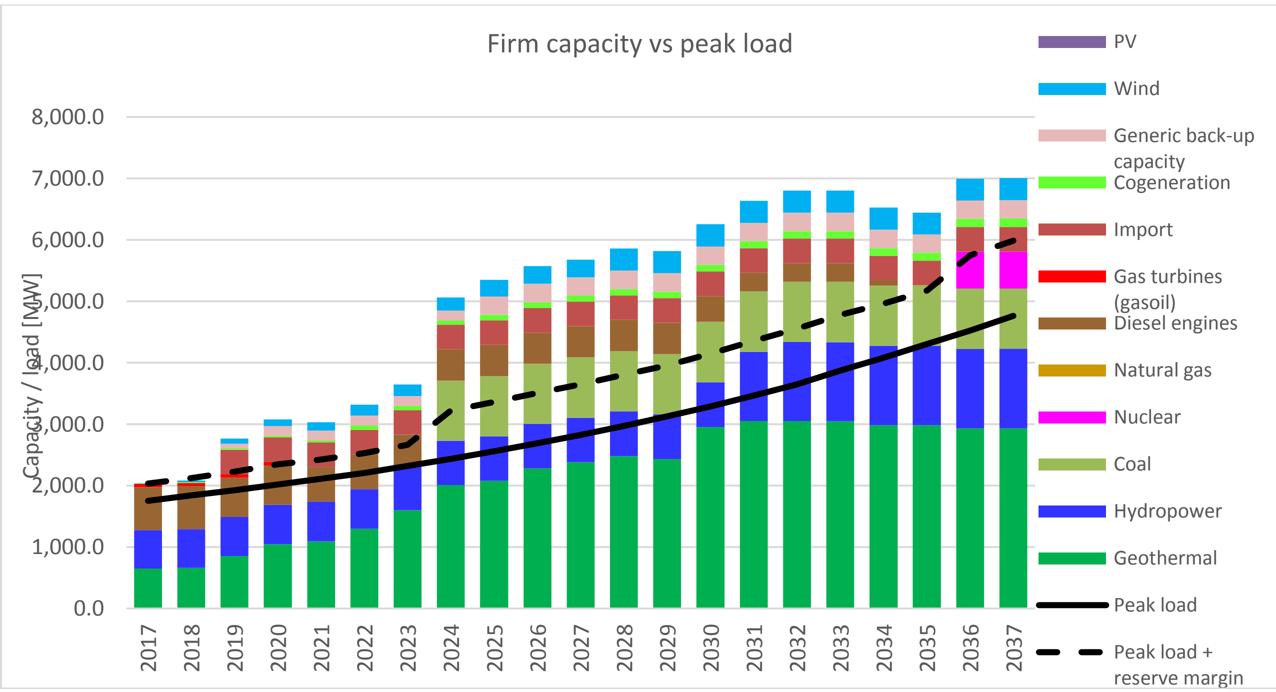


Figure 26: annual generation (GWh)- fixed system -low demand

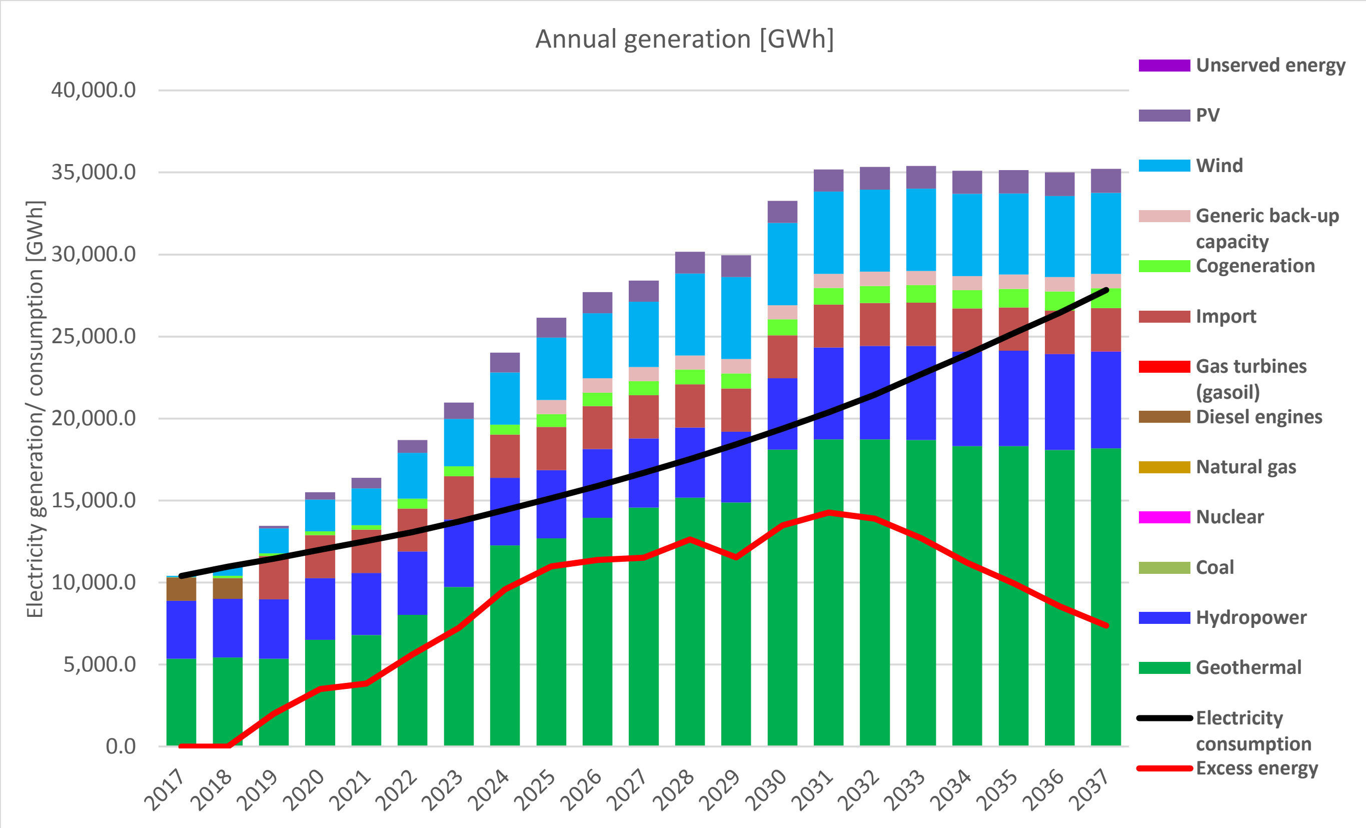
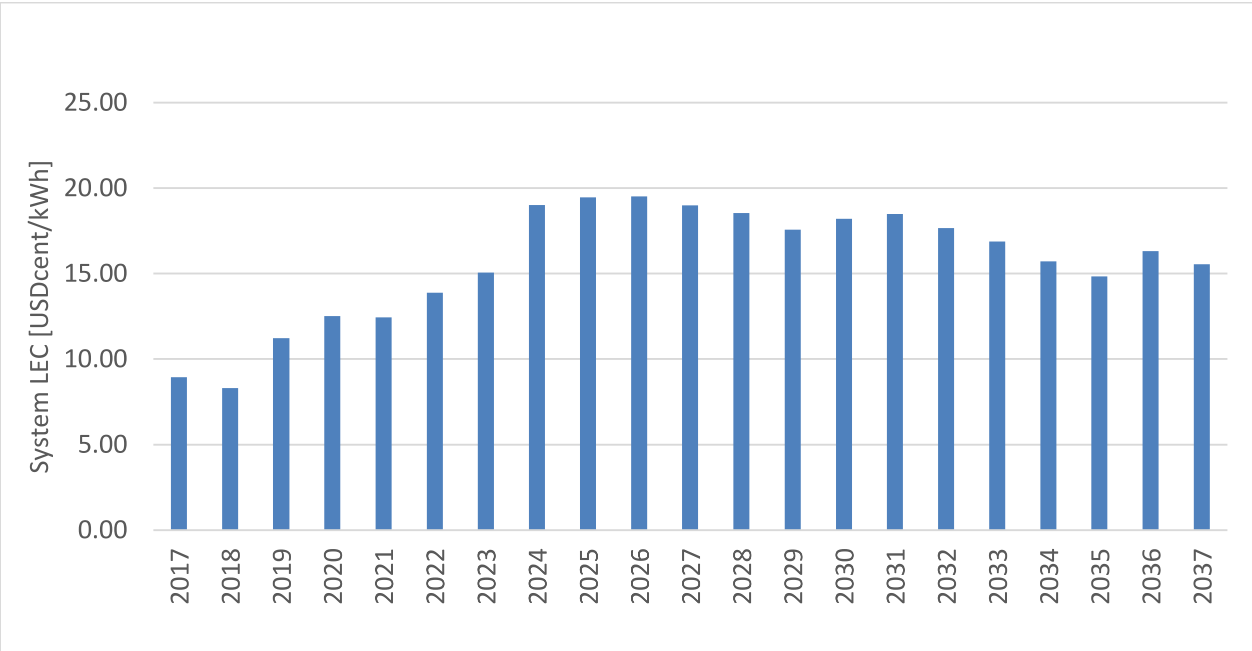


Figure 27: System LEC - fixed system -low demand



6.6.1.3. Results for Fixed System -Vision Demand Growth Scenario

In this scenario, there supply gaps of 117MW, 415MW and 1,232MW in 2018, 2033 and 2037 respectively. The rest of the years have surpluses except in the years 2034 – 2037, with the highest surplus occurring in 2025 and 2026 as shown in Table 38.

Figure 28 shows the installed capacity versus demand and the excess capacity associated with fixed expansion plan. The surplus energy is comparatively lower at between 9% and 19% in the period 2019 – 2024 of the available generation. Vented steam would be relatively lower than the reference with maximum of 24% of the geothermal generation in 2023 and 2024.

Figure 29 shows that under this scenario, the firm capacity would be considerably lower from the year 2034. The LEC will be on average lower than the base case, ranging between US Cents 8.29/kWh to US Cents 15.55/kWh the period 2018-2037 as shown in Figure 31.

Table 37: summary of results fixed system -vision growth scenario

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,917	2,088	2,293	2,516	2,766	3,027	3,342	3,705	4,078	4,450	4,854	5,261	5,780	6,251	6,752	7,272	7,842	8,468	9,094	9,790
Peak load + reserve margin	MW	2,037	2,201	2,389	2,619	2,826	3,091	3,372	4,128	4,506	4,893	5,272	5,684	6,122	6,703	7,209	7,748	8,269	8,811	9,429	10,410	11,192
Reserve margin	% of peak load	16%	15%	14%	14%	12%	12%	11%	24%	22%	20%	18%	17%	16%	16%	15%	15%	14%	12%	11%	14%	14%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,121	6,742	7,221	7,538	7,665	8,088	8,442	9,274	9,781	10,306	10,328	10,074	9,998	10,570	11,197
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,649	5,065	5,352	5,574	5,680	5,860	6,194	7,005	7,389	7,852	7,854	7,579	7,497	8,048	8,655
Supply - demand gap	MW	0	-117	378	460	205	230	277	937	847	681	408	176	72	302	180	104	-415	-1,232	-1,932	-2,361	-2,537
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	11,402	12,393	13,600	14,832	16,371	17,898	19,684	21,955	24,187	26,469	28,945	31,411	34,796	37,564	40,497	43,549	46,875	50,524	54,061	57,978
Electricity generation	GWh	10,407	11,403	13,570	15,633	16,619	18,945	21,171	24,357	26,633	28,416	29,616	31,837	32,821	36,281	38,237	41,061	43,788	46,836	49,267	52,709	55,792
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	111	1,275	1,353	2,186
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	4%
Excess energy	GWh	0	0	1,176	2,034	1,787	2,575	3,273	4,673	4,679	4,230	3,148	2,892	1,410	1,485	672	565	239	73	17	1	0
Excess energy - share on generation	%	0%	0%	9%	13%	11%	14%	15%	19%	18%	15%	11%	9%	4%	4%	2%	1%	1%	0%	0%	0%	0%
Vented GEO steam (assuming single-flash technology)	GWh	25	28	1,666	2,073	2,088	2,495	3,341	4,123	4,455	4,706	4,585	4,525	3,839	4,655	4,594	4,449	2,838	1,448	980	680	562
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	23%	24%	23%	23%	25%	25%	24%	23%	22%	21%	18%	18%	17%	15%	10%	5%	3%	2%	2%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 28: installed capacity vs load – Fixed System -Vision forecast

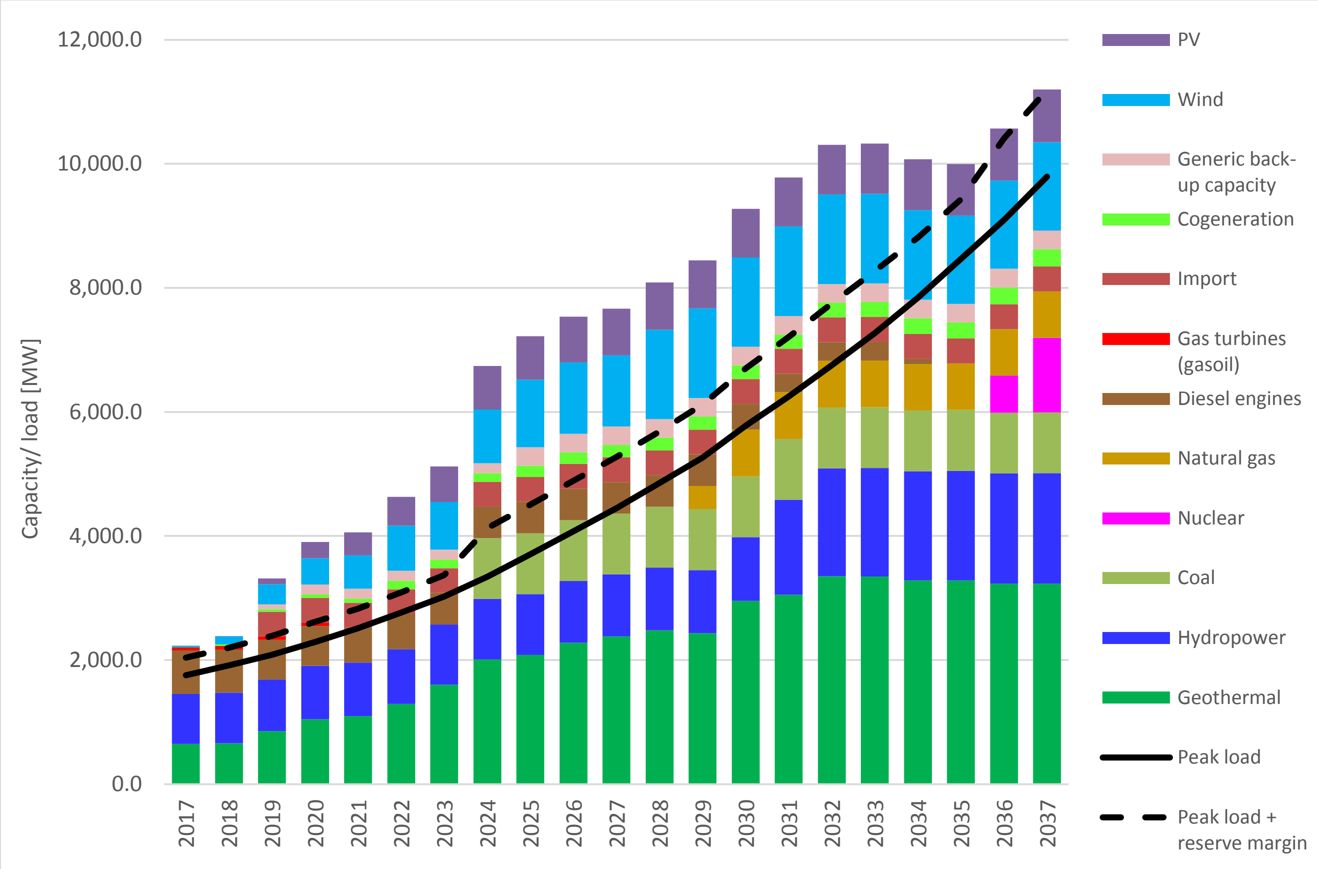


Figure 29: Firm capacity vs load - Fixed System -Vision forecast

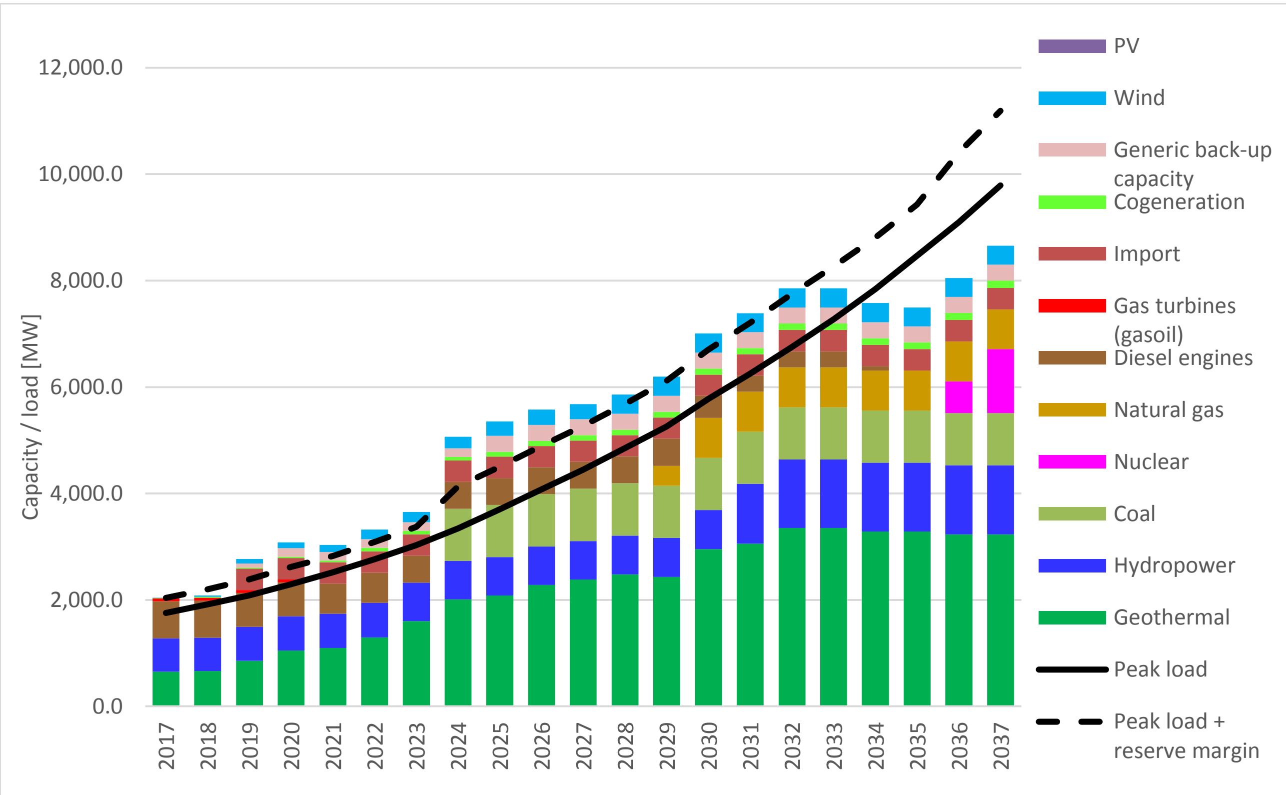


Figure 30: Annual generation - Fixed System -Vision forecast

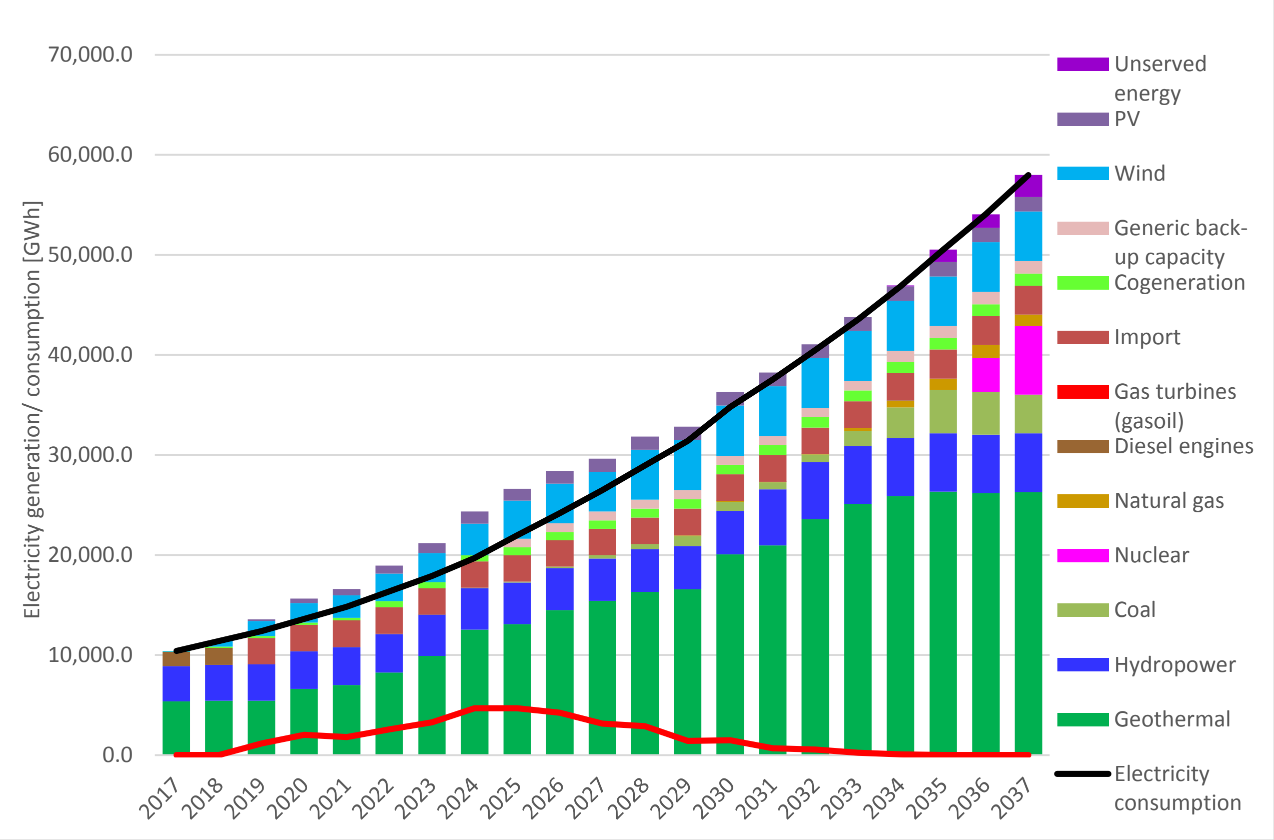
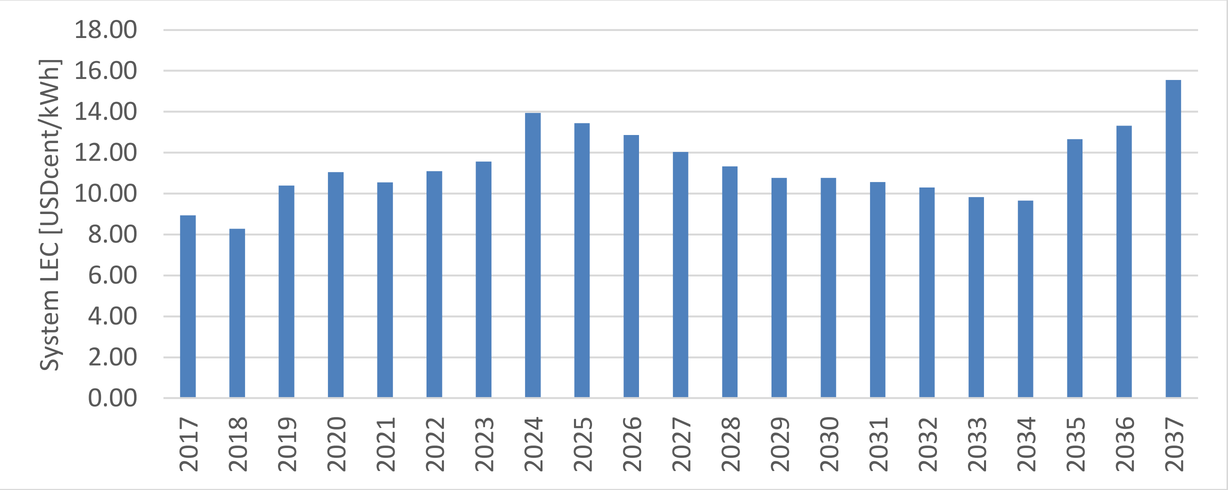


Figure 31: System LEC - Fixed System -Vision forecast



6.6.1.4. Results for Optimized expansion -Reference Demand Growth

Table 39 shows the demand-supply output for the optimal expansion plan. The total capacity grows from the current 2,340 MW in 2017 to 10,490 MW in 2037 compared to 10,897 MW in the fixed case. The system shortfall of 65 MW in 2018 is followed by high surplus capacity levels above the sum of peak load and reserve margin over the period 2019-2023. The surpluses decrease from 2024 onwards to between 23MW and 269MW. Figure 32 shows the generation versus demand balance graphically based on the installed and firm capacity respectively. In the optimized case, the firm capacity closely matches system demand and reserve requirements from the year 2024 as seen in figure 33.

The average annual excess energy as share of generation in the period 2019-2030 is 15%, but reduces significantly thereafter to an average of 3%. However, the level vented steam remains high at an average of 20% of the possible maximum geothermal generation over the period from 2019-2037.

Table 40 indicates the development of the LEC, rising from US Cents 8.30/kWh in 2018 to peak at US Cents 12.45/kWh in 2022, before decreasing to an average of US Cents 10.92 /kWh in the period 2023-2037.

Table 38: Demand-supply- Optimised generation expansion plan-Reference forecast

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,866	1,978	2,103	2,234	2,421	2,586	2,764	2,989	3,224	3,441	3,720	3,974	4,244	4,525	4,826	5,148	5,491	5,859	6,232	6,638
Peak load + reserve margin	MW	2,037	2,150	2,267	2,406	2,522	2,724	2,886	3,064	3,300	3,612	3,836	4,135	4,645	4,946	5,239	5,574	5,951	6,337	6,806	7,237	7,673
Reserve margin	% of peak load	16%	15%	15%	14%	13%	12%	12%	11%	10%	12%	11%	11%	17%	17%	16%	15%	16%	15%	16%	16%	16%
Installed system capacity	MW	2,235	2,381	3,237	3,744	3,848	4,421	4,457	4,537	4,794	5,337	5,584	6,137	6,876	7,368	7,878	8,280	8,900	9,073	9,644	10,043	10,490
Firm system capacity	MW	2,037	2,085	2,687	2,919	2,859	3,149	3,181	3,181	3,334	3,740	3,859	4,199	4,693	5,017	5,240	5,621	6,221	6,373	6,938	7,316	7,743
Supply - demand gap	MW	0	-65	419	513	337	425	295	117	34	129	23	64	48	70	1	47	269	36	132	79	70

Electricity consumption versus generation		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Electricity consumption	GWh	10,407	11,101	11,751	12,476	13,240	14,270	15,226	16,259	17,699	19,032	20,323	22,001	23,508	25,104	26,766	28,537	30,421	32,431	34,577	36,734	39,073
Electricity generation	GWh	10,407	11,102	13,488	15,526	16,308	18,615	19,235	19,490	20,313	21,016	22,124	24,615	26,747	27,750	29,529	30,159	31,018	32,774	34,747	36,827	39,218
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	1,738	3,051	3,069	4,346	4,009	3,232	2,614	1,985	1,801	2,614	3,239	2,646	2,763	1,622	597	342	171	94	144
Excess energy - share on generation	%	0%	0%	13%	20%	19%	23%	21%	17%	13%	9%	8%	11%	12%	10%	9%	5%	2%	1%	0%	0%	0%
Vented GEO steam (assuming single-flash technology)	GWh	25	37	1,726	2,165	2,235	2,675	2,832	2,727	2,952	2,811	2,924	3,463	3,421	3,716	3,936	3,575	2,470	1,923	1,364	948	1,382
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	24%	25%	25%	25%	25%	24%	25%	24%	23%	23%	22%	24%	24%	21%	16%	12%	8%	6%	7%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 39: Costs data and LEC for the optimal expansion plan

System cost		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CAPEX	MUSD	688	657	878	1,042	1,070	1,263	1,306	1,322	1,393	1,503	1,582	1,686	1,907	2,132	2,211	2,287	2,370	2,452	2,631	2,766	2,954
Fixed OPEX	MUSD	140	153	210	250	263	322	331	333	352	375	398	459	522	533	572	586	582	607	648	679	744
Variable OPEX	MUSD	14	15	187	188	188	191	191	192	194	198	200	199	199	196	197	199	204	205	205	207	206
Fuel cost	MUSD	88	97	0	0	0	0	0	0	1	9	15	12	20	9	8	21	50	87	149	206	171
Total generation cost	MUSD	930	922	1,276	1,480	1,522	1,776	1,828	1,848	1,940	2,085	2,194	2,356	2,648	2,871	2,987	3,093	3,206	3,351	3,632	3,858	4,076
Cost for unserved energy	MUSD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**MUSD**	**930**	**922**	**1,276**	**1,480**	**1,522**	**1,776**	**1,828**	**1,848**	**1,940**	**2,085**	**2,194**	**2,356**	**2,648**	**2,871**	**2,987**	**3,093**	**3,206**	**3,351**	**3,632**	**3,858**	**4,076**
System LEC	**USDcent/kWh**	**8.94**	**8.30**	**10.86**	**11.86**	**11.49**	**12.45**	**12.01**	**11.37**	**10.96**	**10.95**	**10.80**	**10.71**	**11.26**	**11.44**	**11.16**	**10.84**	**10.54**	**10.33**	**10.50**	**10.50**	**10.43**

Figure 32: Installed capacity vs load -Optimised generation expansion plan -Reference forecast

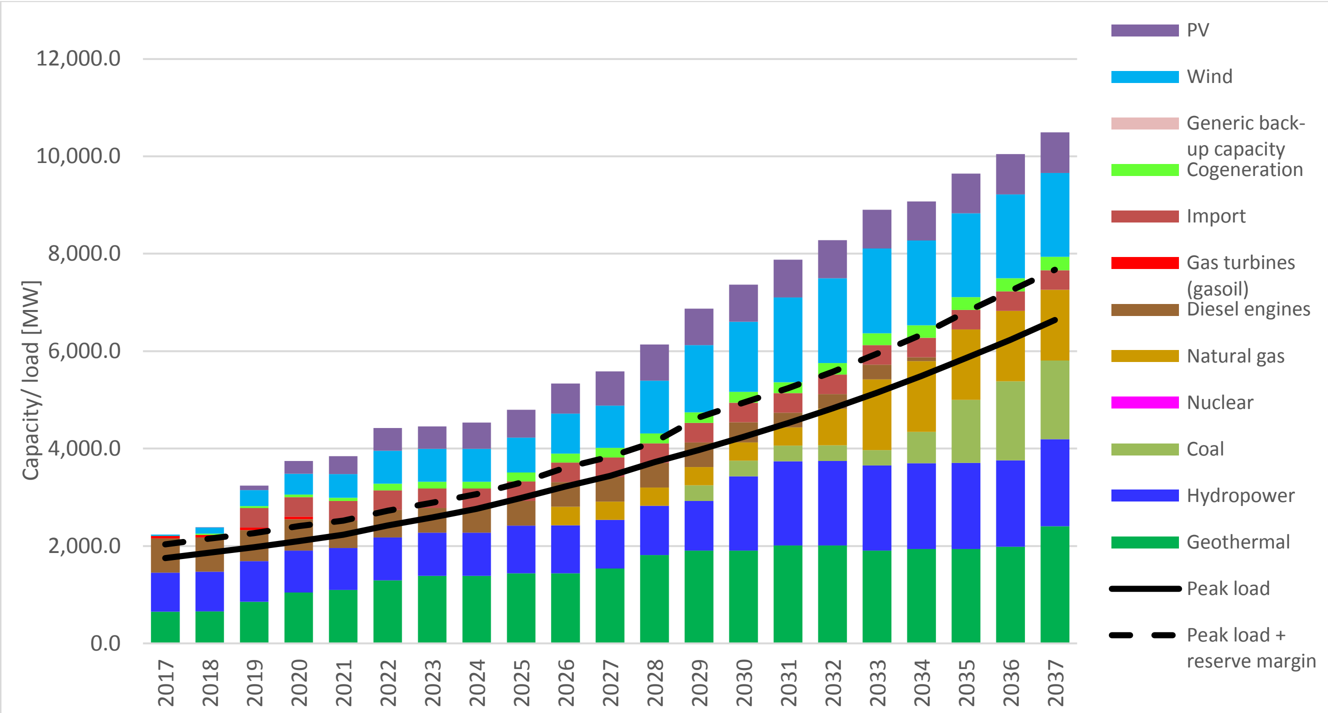


Figure 33: Firm capacity vs peak load Optimized generation expansion plan -Reference forecast

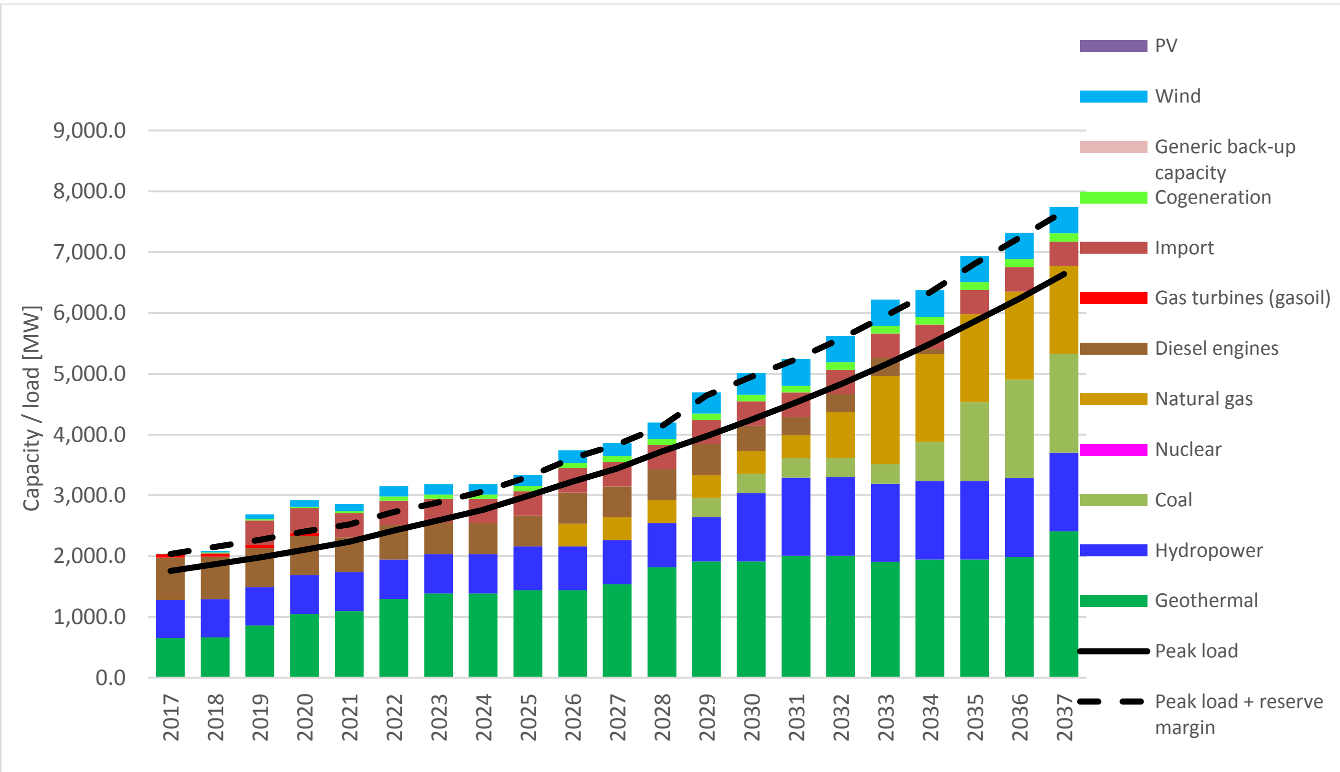


Figure 34: Annual generation -Optimized generation expansion plan - Reference forecast

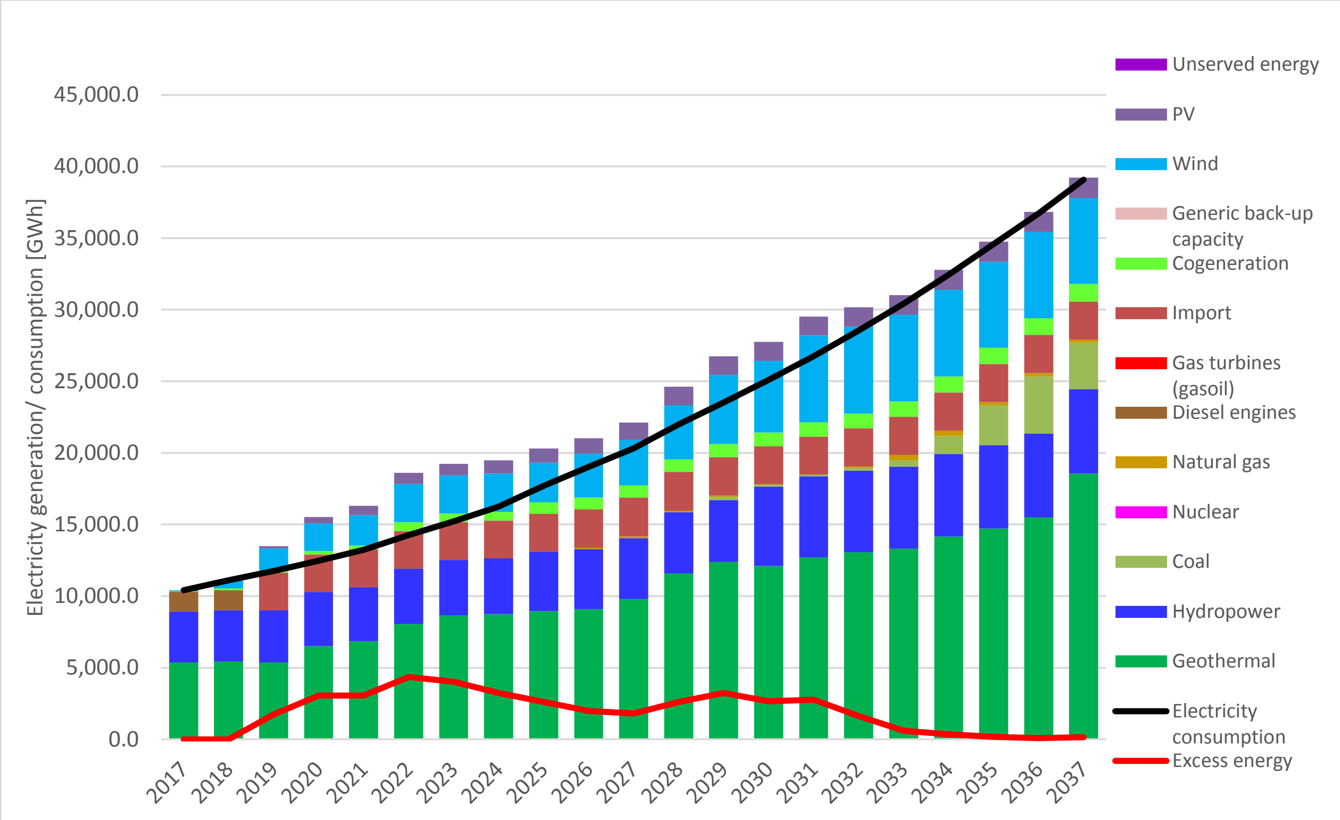


Figure 35: System LEC Optimised generation expansion plan -Reference forecast

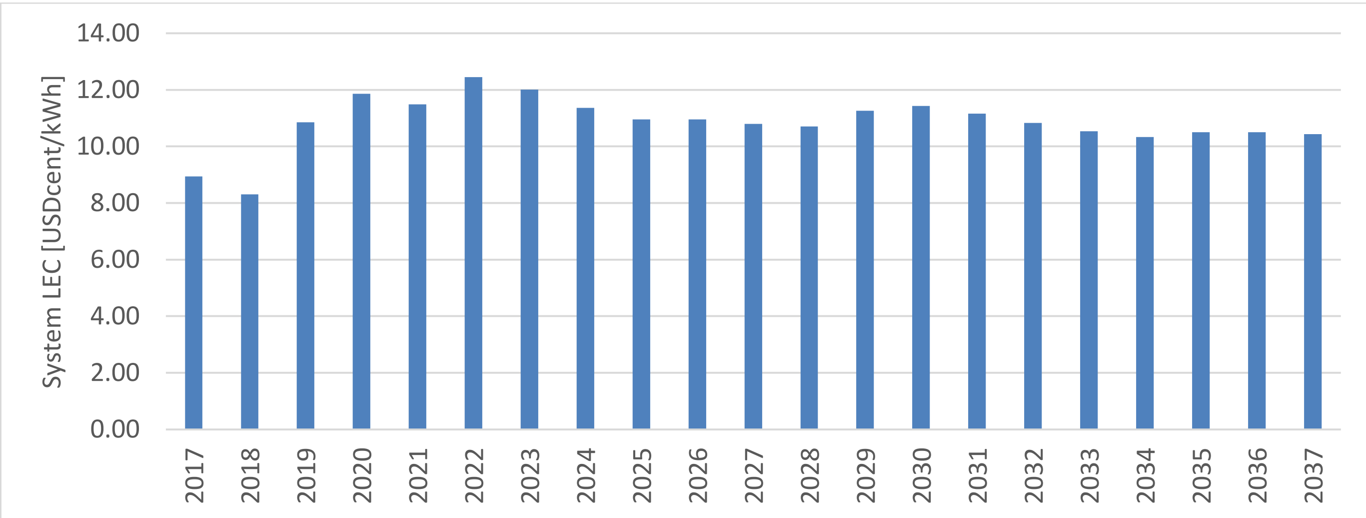


Table 40: Generating plants' capacity factors -Optimised expansion -Reference forecast

Capacity factor [%]	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Geothermal	94.1%	93.9%	71.5%	71.0%	71.3%	71.0%	71.2%	72.1%	71.1%	72.2%	72.8%	72.8%	74.1%	72.3%	72.2%	74.2%	79.7%	83.2%	86.5%	89.1%	88.0%
Hydropower	50.1%	50.1%	50.1%	50.1%	50.1%	50.1%	50.1%	50.1%	48.3%	48.3%	48.3%	48.3%	48.3%	41.7%	37.4%	37.4%	37.5%	37.5%	37.6%	37.7%	37.7%
Coal													7.9%	4.7%	4.0%	6.8%	15.6%	22.0%	24.6%	27.9%	22.9%
Nuclear																					
Natural gas										2.6%	4.0%	3.3%	2.5%	0.9%	0.7%	1.7%	3.0%	2.9%	1.8%	1.9%	1.7%
Diesel engines	23.3%	23.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%	0.3%	0.3%	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%			
Gas turbines (gasoil)	0.0%	0.0%	0.0%	0.0%																	
Import			75.1%	75.0%	75.0%	75.0%	75.0%	75.3%	75.5%	76.6%	77.0%	76.8%	76.4%	75.5%	75.4%	75.7%	76.2%	76.2%	75.8%	75.9%	75.8%
Cogeneration	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Generic back-up capacity																					
Wind	35.0%	50.9%	53.4%	51.7%	50.1%	45.0%	45.0%	45.0%	44.4%	42.9%	41.9%	39.9%	39.9%	39.6%	39.7%	39.7%	39.7%	39.7%	39.8%	39.8%	39.8%
PV		19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%

6.6.1.5. Results for Optimized expansion - low load growth

The surplus capacity above the peak demand plus reserve ranges between 5 MW and 639 MW annually in the period between 2019 and 2033. The average annual excess energy is 19% above demand from 2019 to the end of the planning period. The LEC of energy generation rises to peak at US cents 13.58 /kWh in 2022 and thereafter declines gradually to a low of US cents 10.89 /kWh in 2037 as shown in Figure 39.

Figure 36: Installed capacity vs load -low forecast

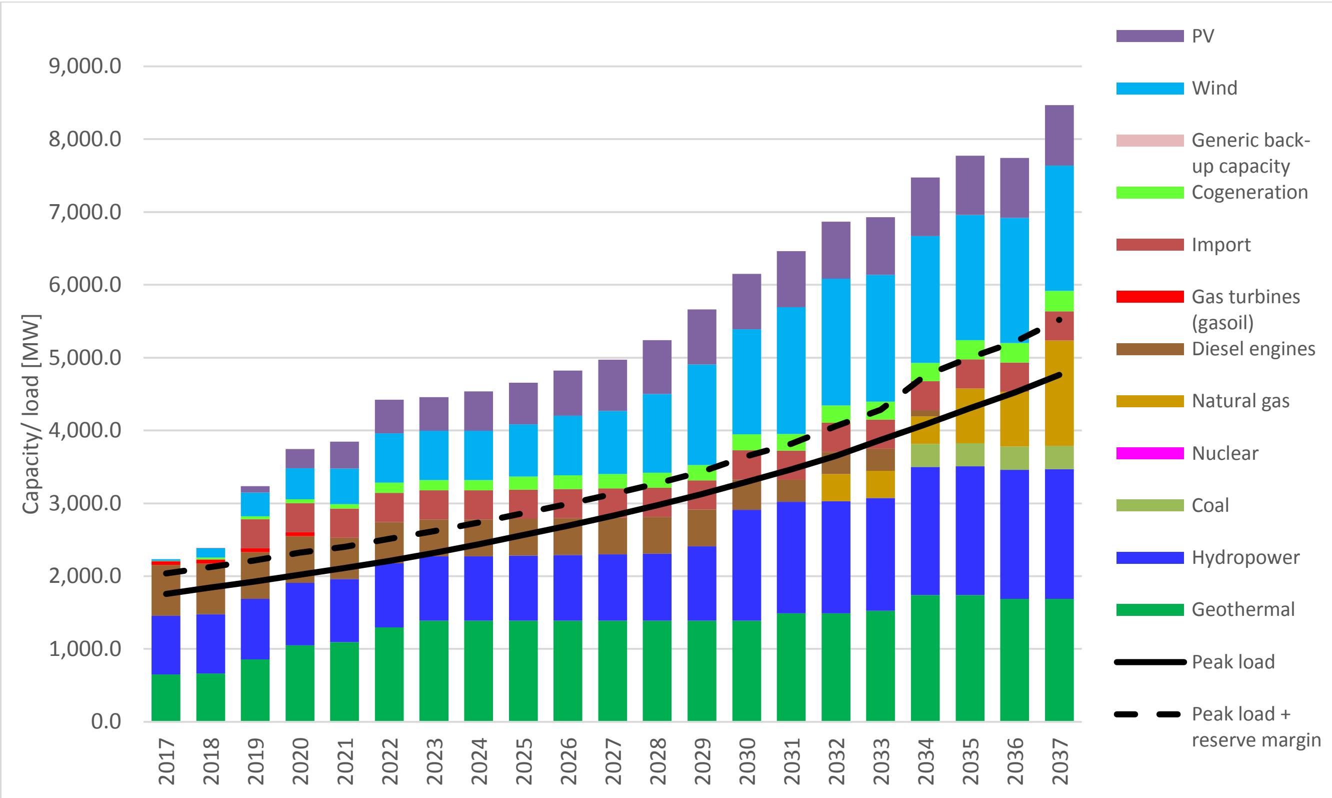


Figure 37: Firm capacity vs peak load -Low forecast

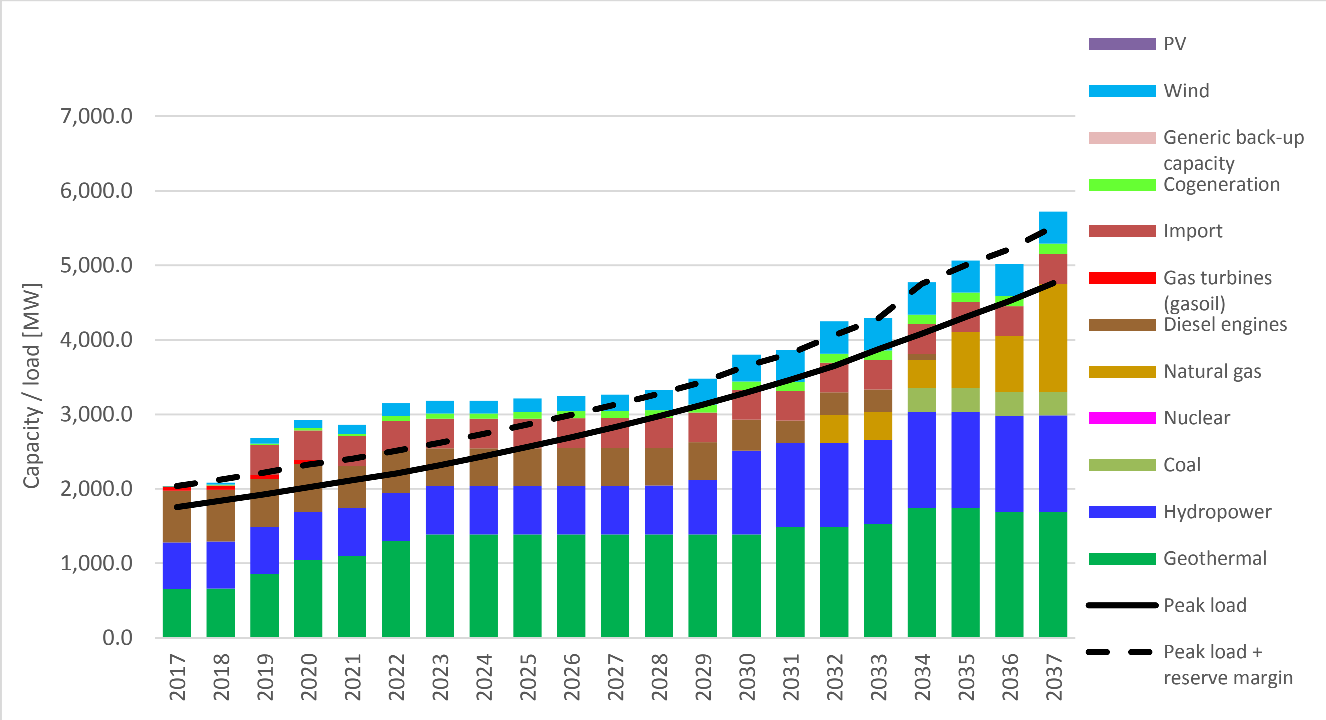


Figure 38: Annual generation - low forecast

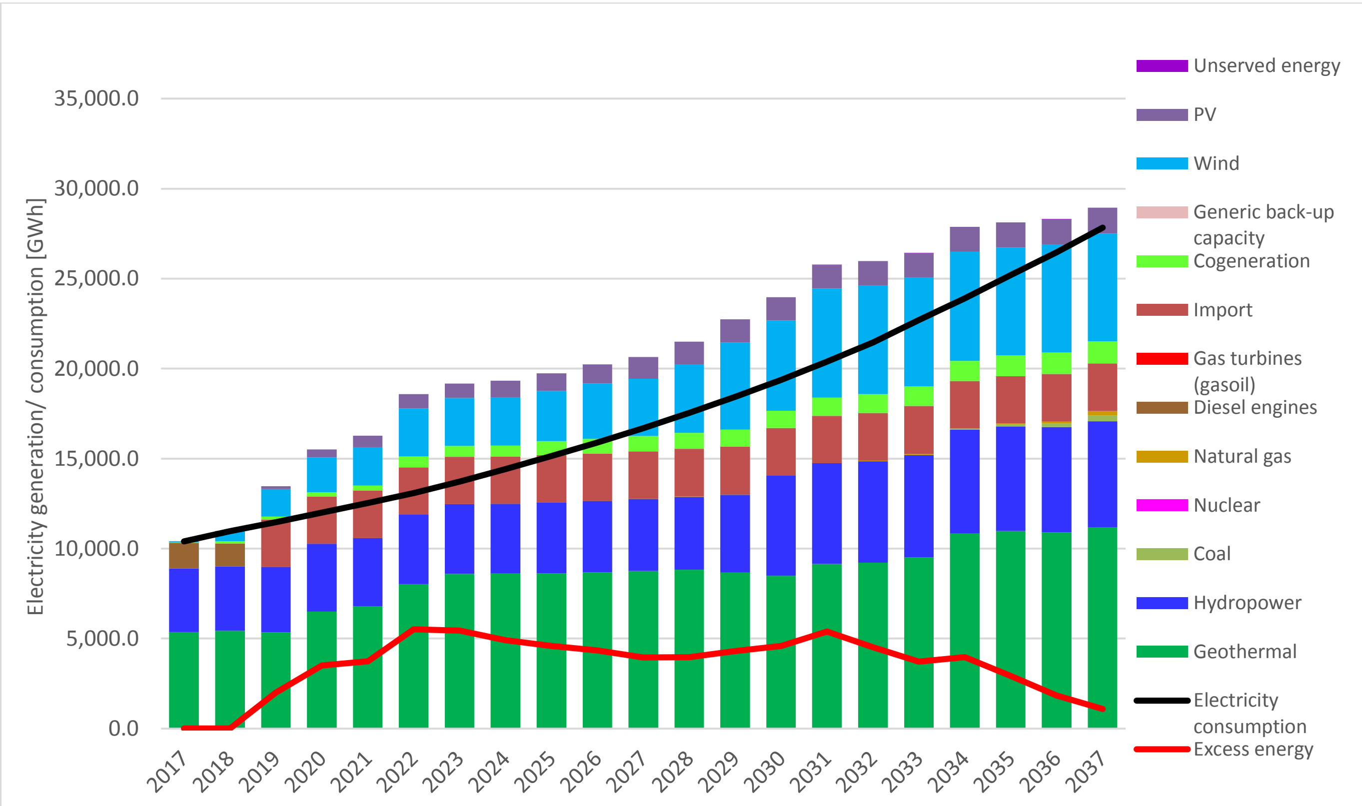
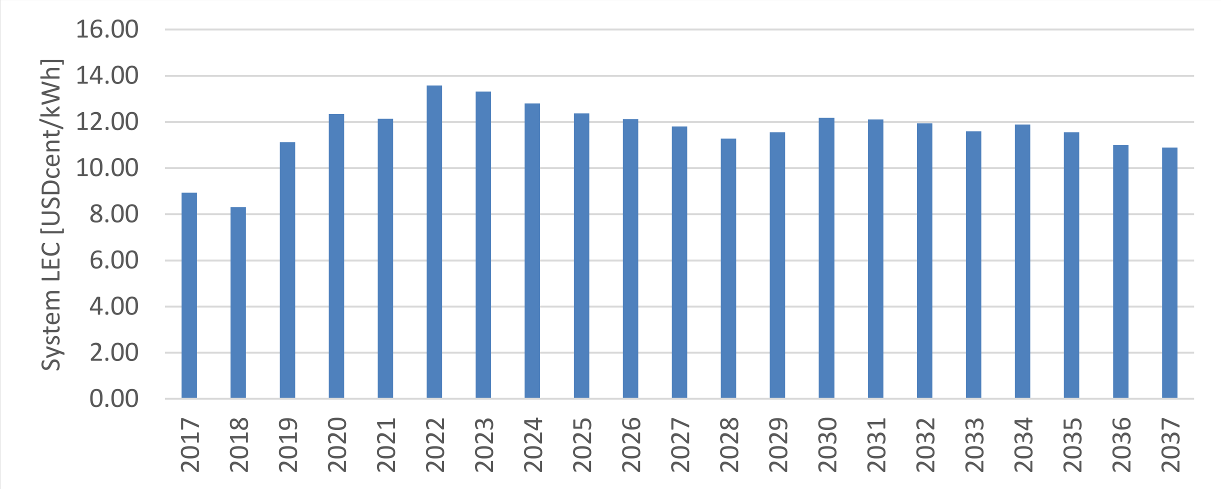


Figure 39: System LEC -Optimised plan- low forecast



6.6.1.6. Results for Optimised expansion -Vision load growth

The high demand forecast reduces the levels surplus capacity above the peak demand plus reserve ranges to a maximum of 322MW in 2020 and an average of 90MW between 2019 and 2030 with the rest of the years being well balanced, except 2018 which would have a shortfall of 117 MW as shown in Table 42.

The LEC of energy peaks at US cents 11.77 /kWh in 2024 and declines to an average of US cts 10.58 /kWh over the rest of the study period. This would be more favourable compared to the low scenario since the committed capacity addition would be better utilised with higher growth in consumption. Figure 43 shows the LEC trend over the period.

Table 41: Demand-supply- Optimised generation expansion plan-Vision forecast

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,917	2,088	2,293	2,516	2,766	3,027	3,342	3,705	4,078	4,450	4,854	5,261	5,780	6,251	6,752	7,272	7,842	8,468	9,094	9,790
Peak load + reserve margin	MW	2,037	2,201	2,378	2,597	2,804	3,069	3,341	4,011	4,429	4,842	5,247	5,686	6,134	6,681	7,230	7,768	8,344	8,963	9,716	10,447	11,588
Reserve margin	% of peak load	16%	15%	14%	13%	11%	11%	10%	20%	20%	19%	18%	17%	17%	16%	16%	15%	15%	14%	15%	15%	18%
Installed system capacity	MW	2,235	2,381	3,237	3,744	3,898	4,471	4,847	5,731	6,327	6,939	7,378	8,076	8,570	9,327	9,939	10,466	11,086	11,691	12,495	13,267	14,494
Firm system capacity	MW	2,037	2,085	2,687	2,919	2,872	3,161	3,394	4,073	4,477	4,891	5,250	5,705	6,178	6,690	7,281	7,787	8,387	8,971	9,769	10,520	11,727
Supply - demand gap	MW	0	-117	309	322	68	93	53	61	48	48	3	19	45	9	51	20	42	7	53	74	139
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	11,402	12,393	13,600	14,832	16,371	17,898	19,684	21,955	24,187	26,469	28,945	31,411	34,796	37,564	40,497	43,549	46,875	50,524	54,061	57,978
Electricity generation	GWh	10,407	11,403	13,567	15,628	16,615	18,939	20,872	22,116	23,706	24,896	26,744	29,169	31,520	35,109	37,823	40,855	43,672	46,921	50,546	54,072	57,982
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	1,174	2,028	1,783	2,569	2,974	2,432	1,751	709	275	224	109	313	259	358	124	46	21	12	4
Excess energy - share on generation	%	0%	0%	9%	13%	11%	14%	14%	11%	7%	3%	1%	1%	0%	1%	1%	1%	0%	0%	0%	0%	0%
Vented GEO steam (assuming single-flash technology)	GWh	25	28	1,666	2,074	2,086	2,494	3,212	2,850	2,534	2,642	2,252	1,722	1,298	2,226	2,097	2,855	1,520	895	630	482	485
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	23%	24%	23%	23%	25%	22%	19%	20%	16%	12%	9%	12%	10%	11%	6%	4%	2%	2%	2%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 40: Installed capacity vs peak load Optimised plan -Vision forecast

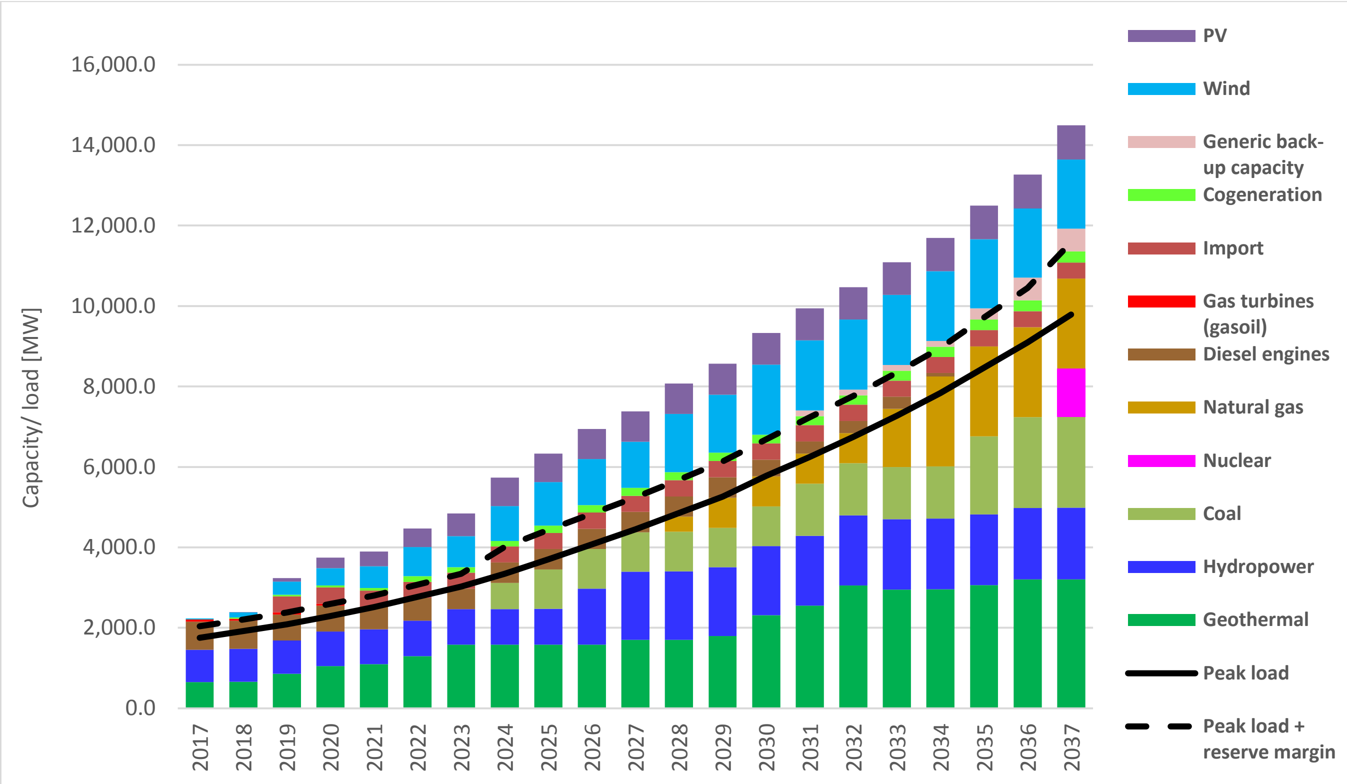


Figure 41: Firm capacity vs peak load Optimised plan -Vision forecast

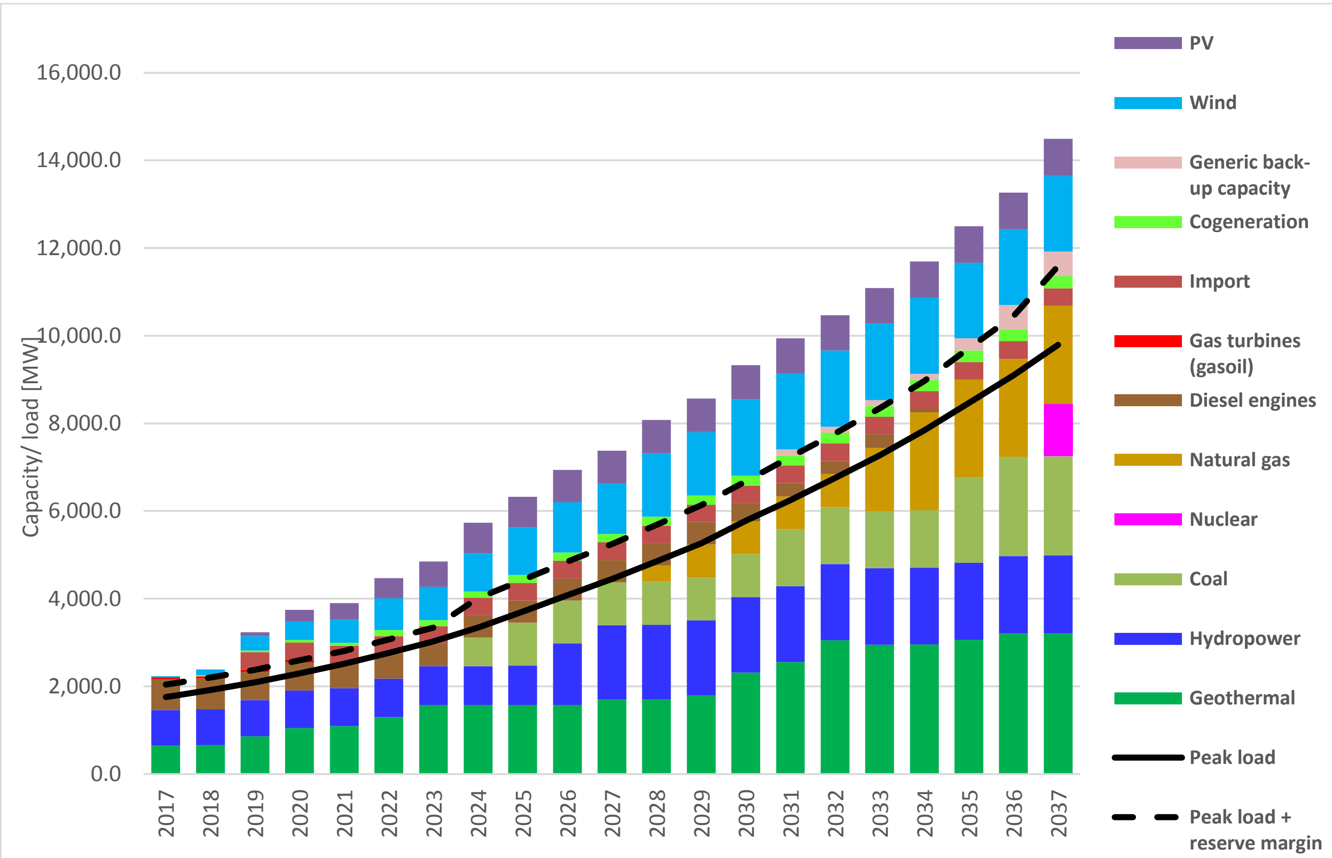


Figure 42: Annual generation - Optimised plan -Vision forecast

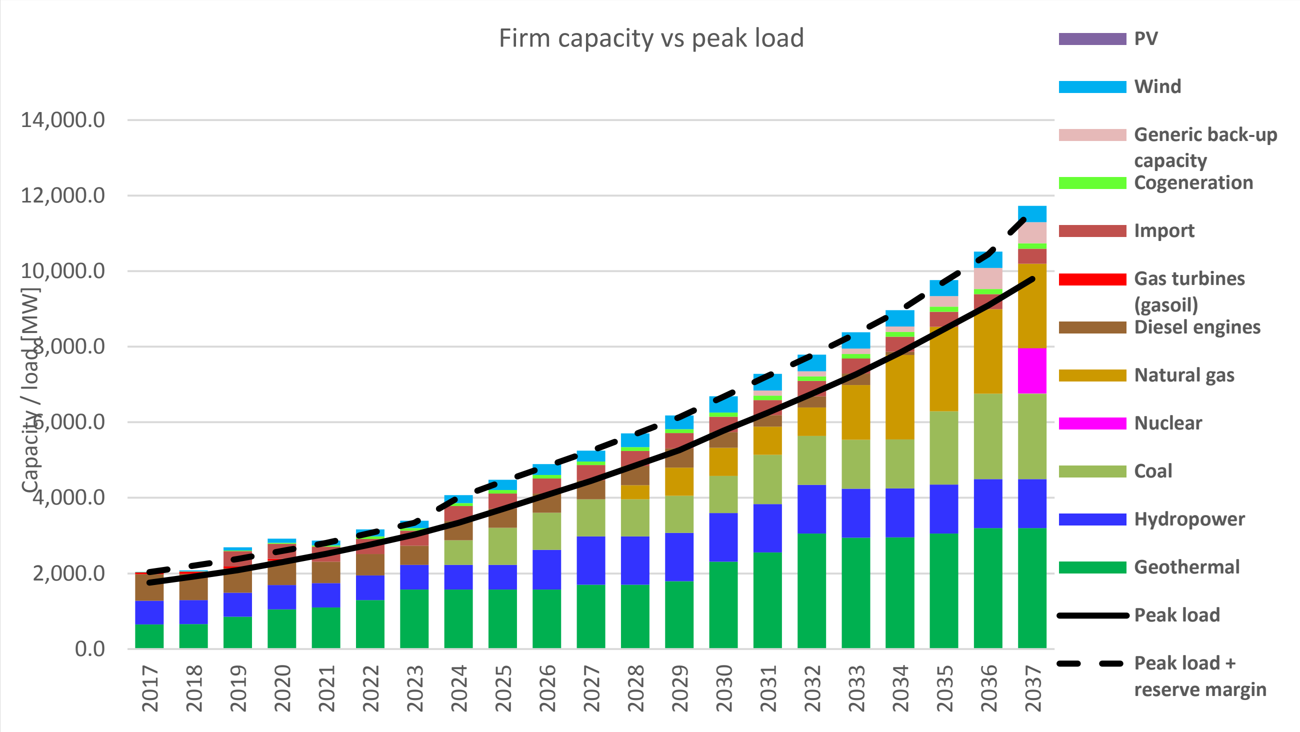
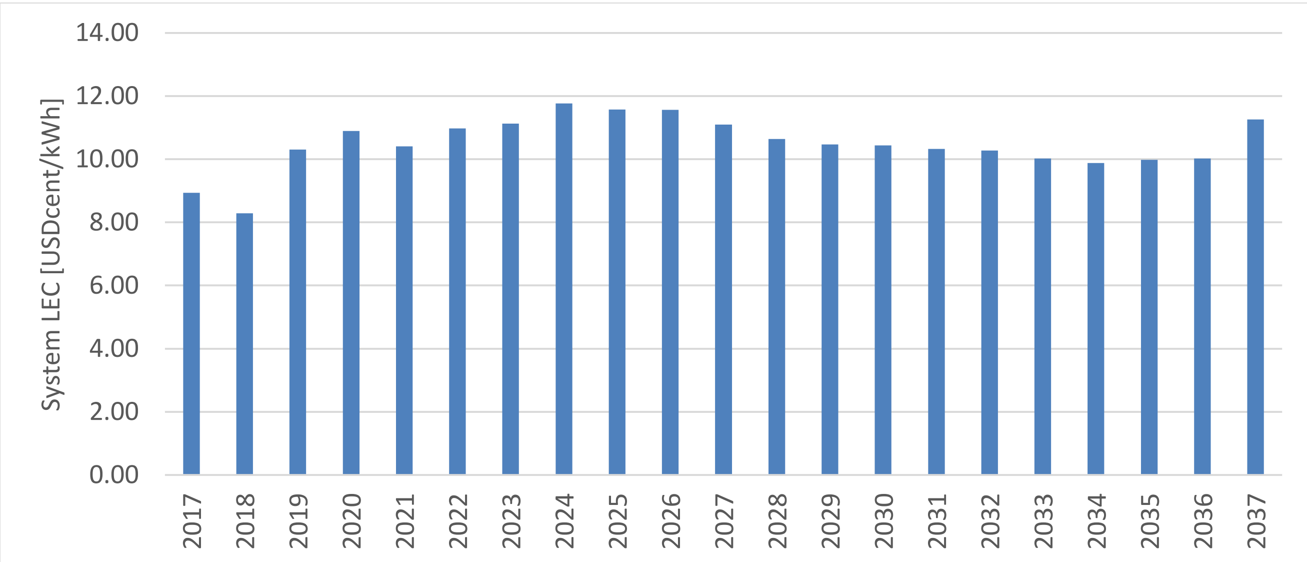


Figure 43: System LEC – Optimised plan -Vision forecast



6.6.1.7. Results for Fixed Medium term-Reference Demand Growth

Table 42 shows the demand-supply output for the Fixed medium term optimal expansion plan. The total capacity grows from the current 2,340 MW in 2017 to 9,932 MW in 2037 compared to 10,666 MW in the fixed case. The system shortfall of 65 MW in 2018 is followed by high surplus capacity levels above the sum of peak load and reserve margin over the period 2019-2030. The surpluses decrease towards the end of the planning period to between 75MW and 188MW. Figures

43 and 44 show the generation versus demand balance graphically based on the installed and firm capacity respectively. In the optimized case, the firm capacity closely matches system demand and reserve requirements from the year 2024.

The average annual excess energy as share of generation in the period 2019-2029 is 20%, but reduces significantly thereafter to an average of 1%. However, the level vented steam remains high at an average of 20% of the possible maximum geothermal generation over the period from 2019-2037. Figure 44 shows the annual generation balance.

Figure 47 indicates the development of the LEC, rising from US Cents 8.30/kWh in 2018 to peak at US Cents 16.25/kWh in 2024, before decreasing to an average of US Cents 10.74 /kWh in the period 2029-2037.

Table 42: Demand-supply balance- Fixed medium term -Reference forecast

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,866	1,978	2,103	2,234	2,421	2,586	2,764	2,989	3,224	3,441	3,720	3,974	4,244	4,525	4,826	5,148	5,491	5,859	6,232	6,638
Peak load + reserve margin	MW	2,037	2,150	2,279	2,429	2,545	2,747	2,929	3,538	3,768	4,003	4,220	4,499	4,749	5,051	5,346	5,677	6,041	6,446	6,866	7,304	7,743
Reserve margin	% of peak load	16%	15%	15%	16%	14%	13%	13%	28%	26%	24%	23%	21%	20%	19%	18%	18%	17%	17%	17%	17%	17%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,096	6,577	6,696	6,753	6,780	6,803	6,782	7,214	7,464	7,771	8,253	8,694	9,038	9,530	9,932
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,624	4,900	4,992	4,999	5,005	5,010	4,969	5,278	5,466	5,752	6,214	6,634	6,972	7,443	7,825
Supply - demand gap	MW	0	-65	488	650	487	574	695	1,362	1,224	996	785	511	220	227	120	75	173	188	106	140	81
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	11,101	11,751	12,476	13,240	14,270	15,226	16,259	17,699	19,032	20,323	22,001	23,508	25,104	26,766	28,537	30,421	32,431	34,577	36,734	39,073
Electricity generation	GWh	10,407	11,102	13,490	15,531	16,420	18,726	20,823	23,044	23,755	24,058	24,362	24,849	25,252	26,098	27,318	28,914	30,906	32,596	34,673	36,804	39,100
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	1,740	3,055	3,181	4,457	5,598	6,786	6,056	5,027	4,039	2,848	1,744	994	552	377	484	164	96	70	26
Excess energy - share on generation	%	0%	0%	13%	20%	19%	24%	27%	29%	25%	21%	17%	11%	7%	4%	2%	1%	2%	1%	0%	0%	0%
Vented GEO steam (assuming single-flash technology)	GWh	25	37	1,724	2,160	2,233	2,673	3,470	3,994	4,088	3,976	3,846	3,603	3,194	3,409	3,469	3,253	3,929	2,408	1,913	1,691	993
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	24%	25%	25%	25%	27%	26%	26%	25%	24%	23%	21%	22%	21%	18%	19%	12%	9%	8%	5%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 44: Installed capacity vs peak load -Fixed medium term -Reference forecast

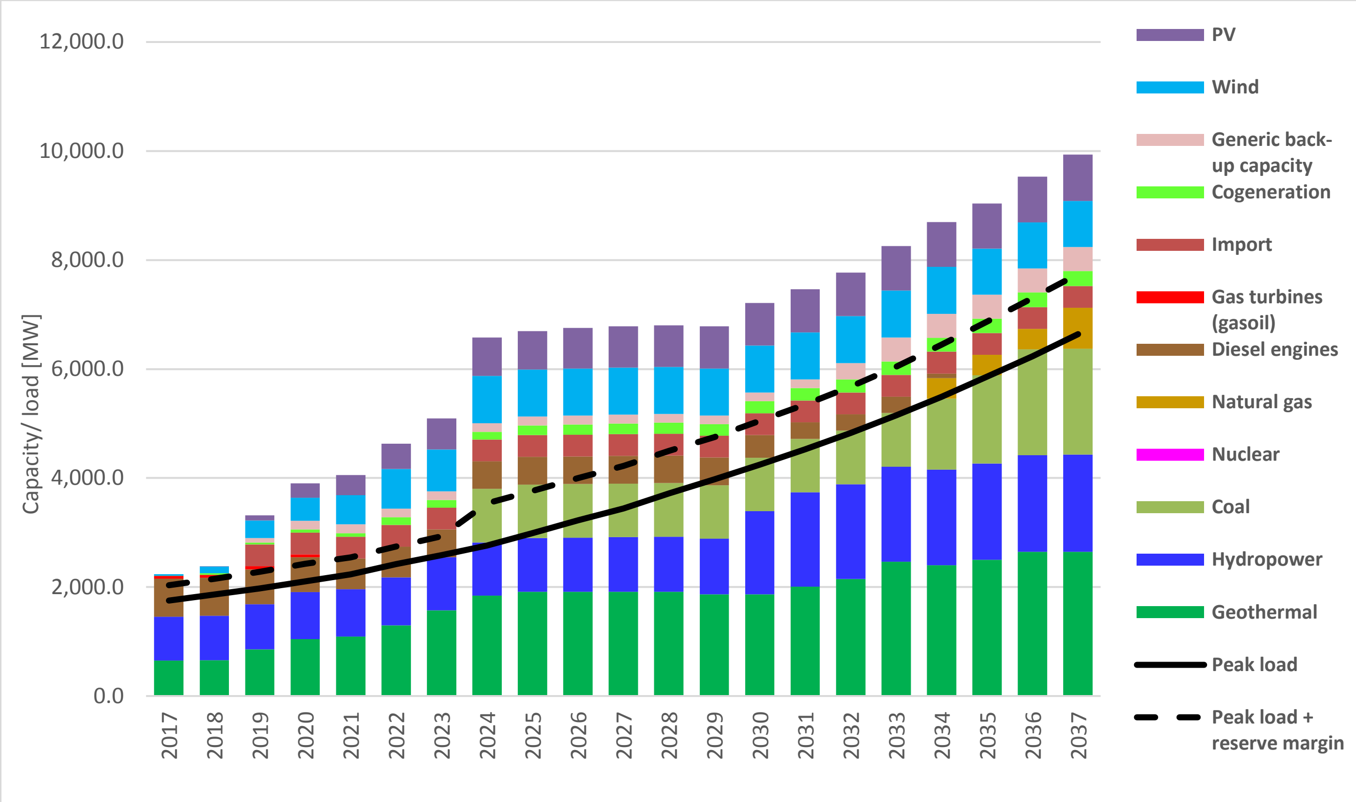


Figure 45: Firm capacity vs peak load -Fixed medium term -Reference forecast

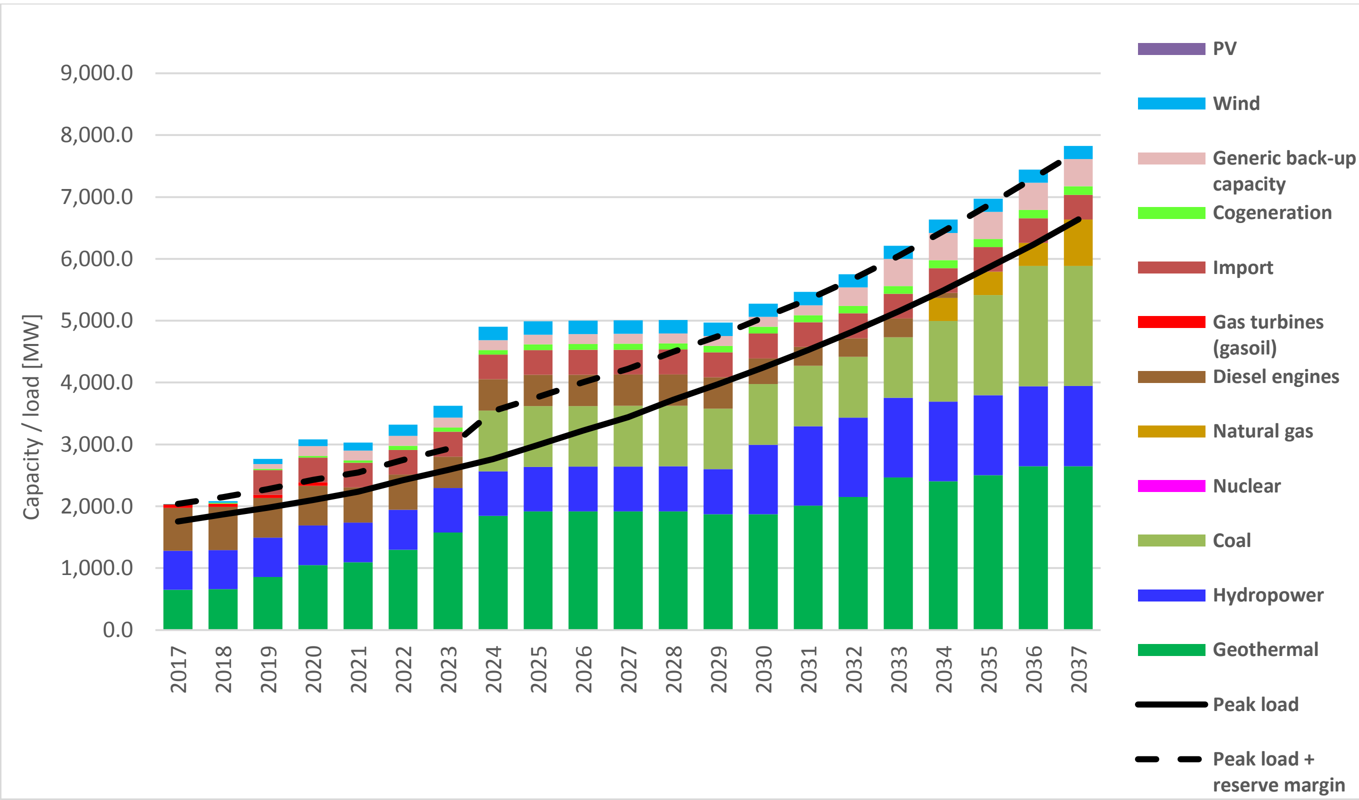


Figure 46: Annual energy -Fixed medium term -Reference forecast

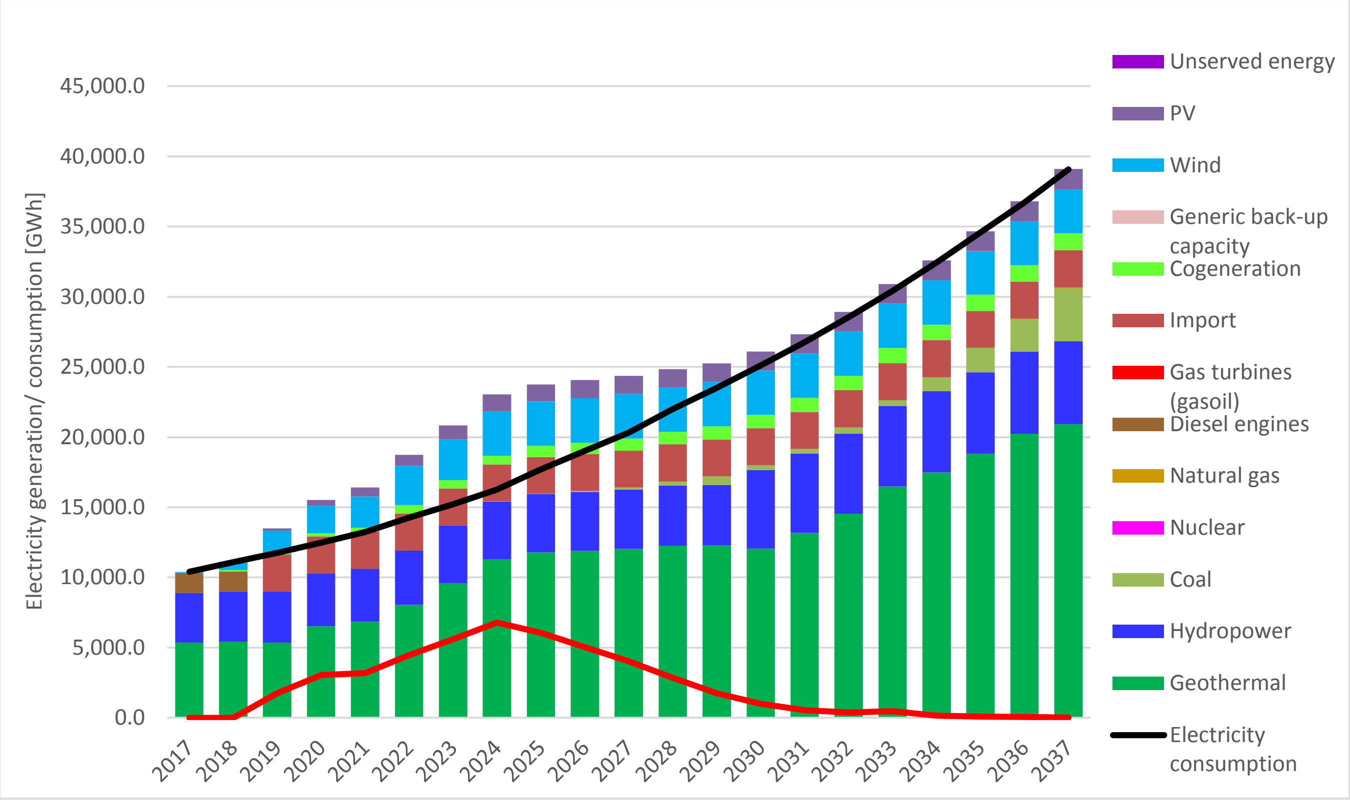


Figure 47: System LEC – Fixed medium term -Reference forecast

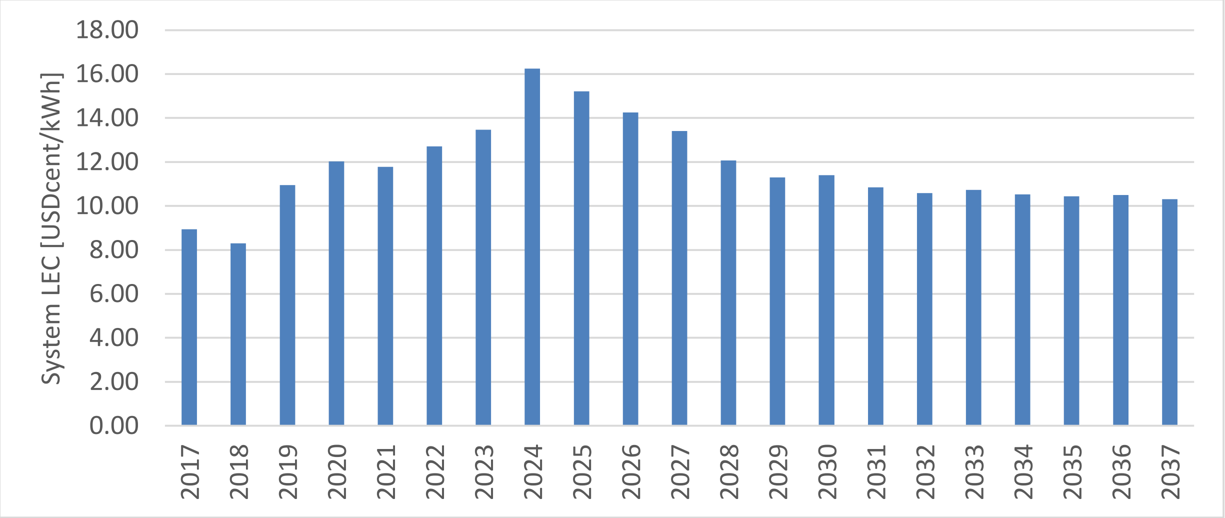


Table 43:Table 7.15: Generating plants' capacity factors -Fixed Medium term-Reference forecast

Capacity factor [%]	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Geothermal	94.1%	93.9%	71.6%	71.0%	71.3%	71.0%	69.4%	69.9%	70.2%	70.9%	71.6%	73.1%	75.0%	73.7%	74.8%	77.3%	76.3%	83.1%	85.8%	87.3%	90.3%
Hydropower	60.1%	60.1%	60.1%	60.1%	60.1%	60.1%	48.2%	48.2%	48.3%	48.3%	48.3%	48.3%	48.3%	41.7%	37.4%	37.4%	37.5%	37.5%	37.6%	37.7%	37.7%
Coal								0.0%	0.2%	0.7%	1.7%	3.6%	7.0%	4.2%	3.9%	6.4%	6.0%	8.9%	12.2%	13.8%	22.3%
Nuclear																					
Natural gas																		0.2%	0.2%	0.1%	1.0%
Diesel engines	23.3%	23.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%			
Gas turbines (gasoil)	0.0%	0.0%	0.0%	0.0%																	
Import			75.1%	75.0%	75.1%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.1%	75.0%	75.0%	75.0%	75.0%	75.1%	75.1%	75.1%	75.4%
Cogeneration	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
Generic back-up capacity			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	35.0%	60.9%	63.4%	61.7%	47.8%	43.6%	43.1%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	41.9%	42.1%	42.1%	42.1%
PV		19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%

6.6.1.8. Results for Fixed Medium term -low Forecast

The demand-supply balance results for the Low forecast scenario are shown in Table 45 and Figures 48 through 50 and the associated LEC presented in Figure 51. In this scenario, the excess energy increases compared to the reference scenario to an average of 25% between 2019-2030 due to the higher consumption before reducing to lower levels in the period after. The LEC for the period 2019-2037 averages Shs.13.46/kWh with the highest being Shs. 17.77/kWh in 2024.

Table 44: Demand-supply- Fixed medium term -Low forecast

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,842	1,928	2,021	2,114	2,207	2,319	2,438	2,563	2,692	2,829	2,975	3,129	3,293	3,466	3,651	3,872	4,081	4,305	4,523	4,763
Peak load + reserve margin	MW	2,037	2,126	2,229	2,347	2,425	2,533	2,663	3,212	3,342	3,471	3,608	3,754	3,905	4,059	4,261	4,446	4,659	4,857	5,102	5,347	5,621
Reserve margin	% of peak load	16%	15%	16%	16%	15%	15%	15%	32%	30%	29%	28%	26%	25%	23%	23%	22%	20%	19%	19%	18%	18%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,096	6,577	6,696	6,753	6,780	6,803	6,782	6,719	7,126	7,153	7,075	7,019	7,223	7,475	7,877
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,624	4,900	4,992	4,999	5,005	5,010	4,969	4,885	5,169	5,175	5,077	4,959	5,157	5,388	5,770
Supply - demand gap	MW	0	-42	538	732	607	789	961	1,688	1,651	1,528	1,397	1,257	1,064	826	908	730	418	101	55	42	149
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	10,965	11,462	11,996	12,536	13,078	13,730	14,421	15,145	15,896	16,692	17,537	18,432	19,380	20,385	21,453	22,701	23,909	25,196	26,458	27,840
Electricity generation	GWh	0,407	0,965	3,466	5,511	6,380	8,694	0,811	2,991	3,641	3,799	3,918	4,048	3,956	4,177	5,252	5,450	5,150	5,111	6,176	7,092	8,122
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	2,005	3,516	3,845	5,616	7,081	8,570	8,497	7,903	7,227	6,512	5,524	4,797	4,868	3,997	2,449	1,199	972	634	281
Excess energy - share on generation	%	0%	0%	15%	23%	23%	30%	34%	37%	36%	33%	30%	27%	23%	20%	19%	16%	10%	5%	4%	2%	1%
Vented GEO steam (assuming single-flash technology)	GWh	25	39	1,746	2,180	2,271	2,705	3,482	4,044	4,188	4,175	4,149	4,104	3,923	3,841	3,999	3,926	3,569	3,281	3,449	3,412	2,781
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	25%	25%	25%	25%	27%	26%	26%	26%	26%	26%	25%	25%	26%	25%	24%	23%	23%	21%	17%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 48: Installed capacity vs peak load -Fixed medium term -Low forecast

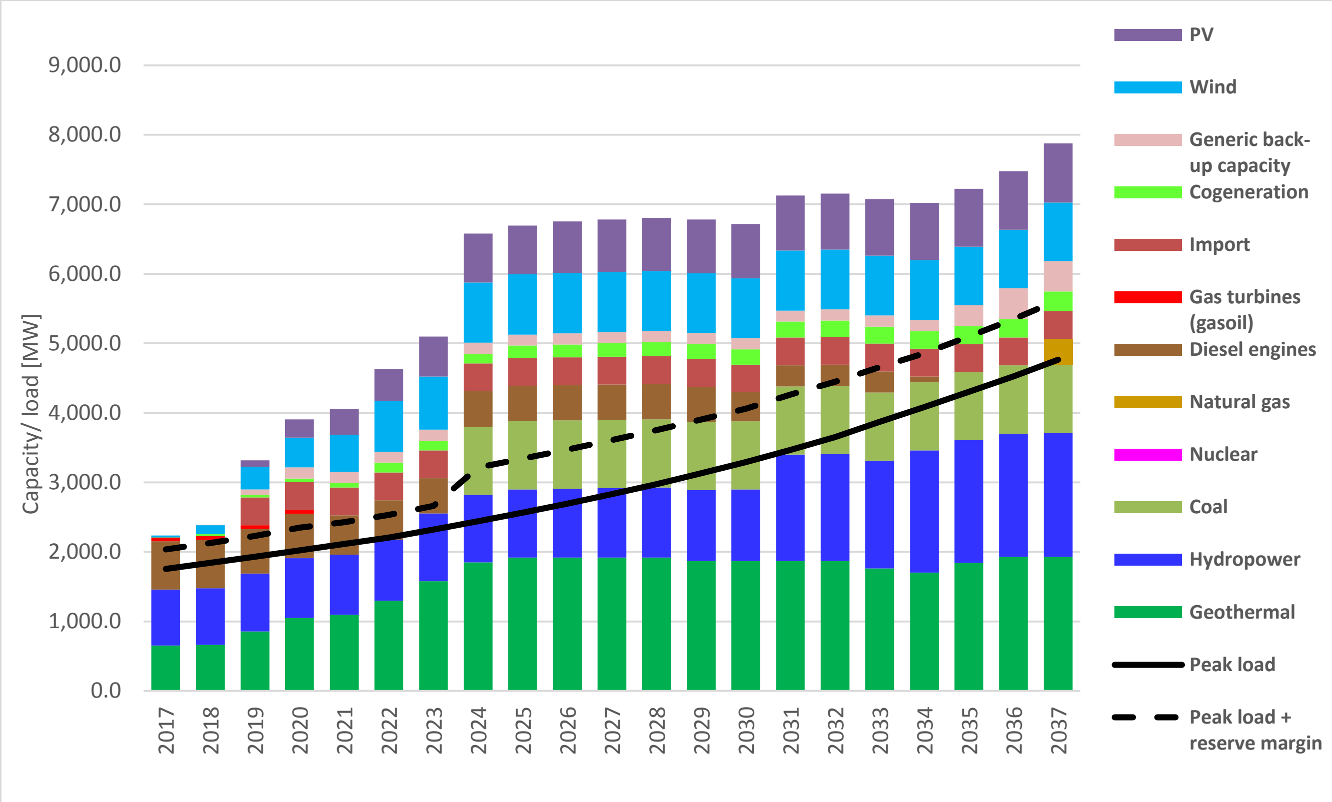


Figure 49: Firm capacity vs peak load -Fixed medium term -Low forecast

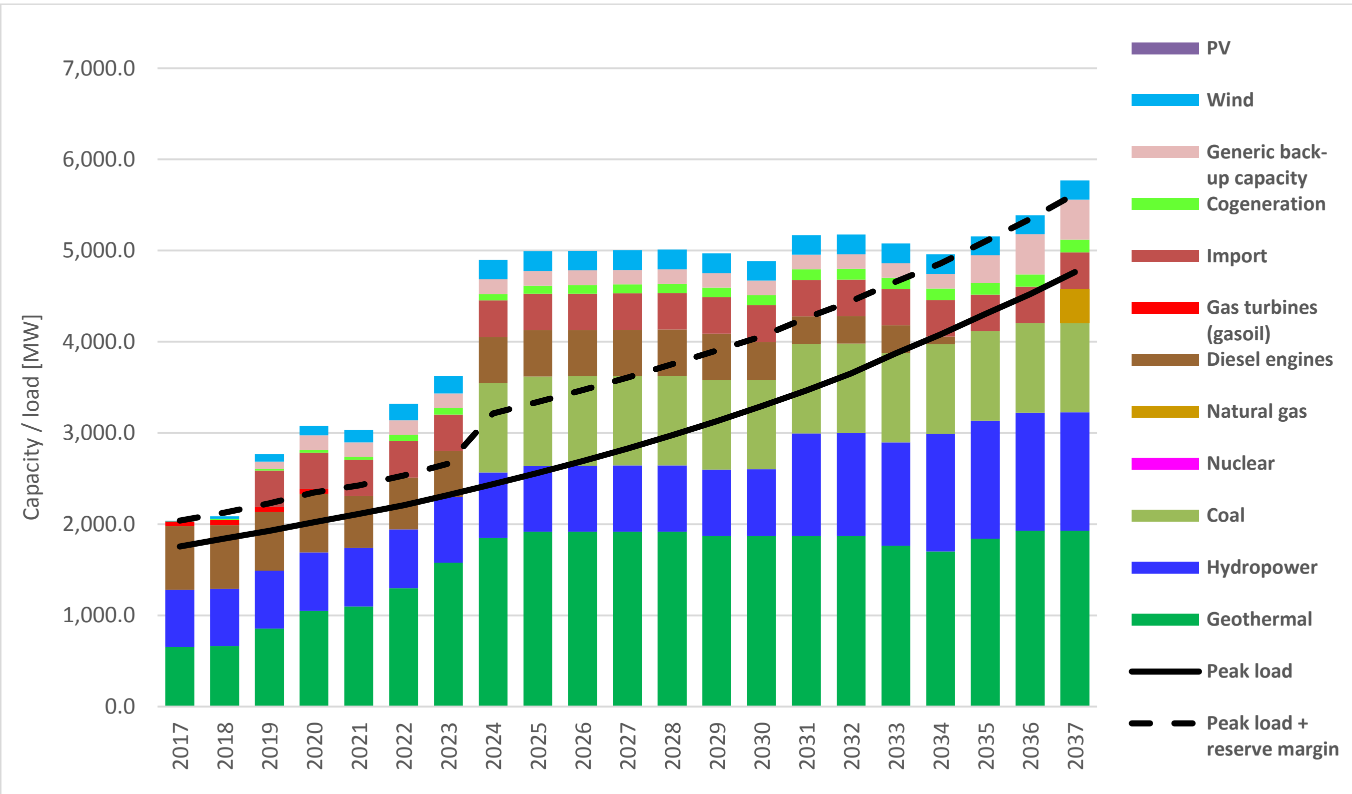


Figure 50: Annual energy -Fixed medium term -Low forecast

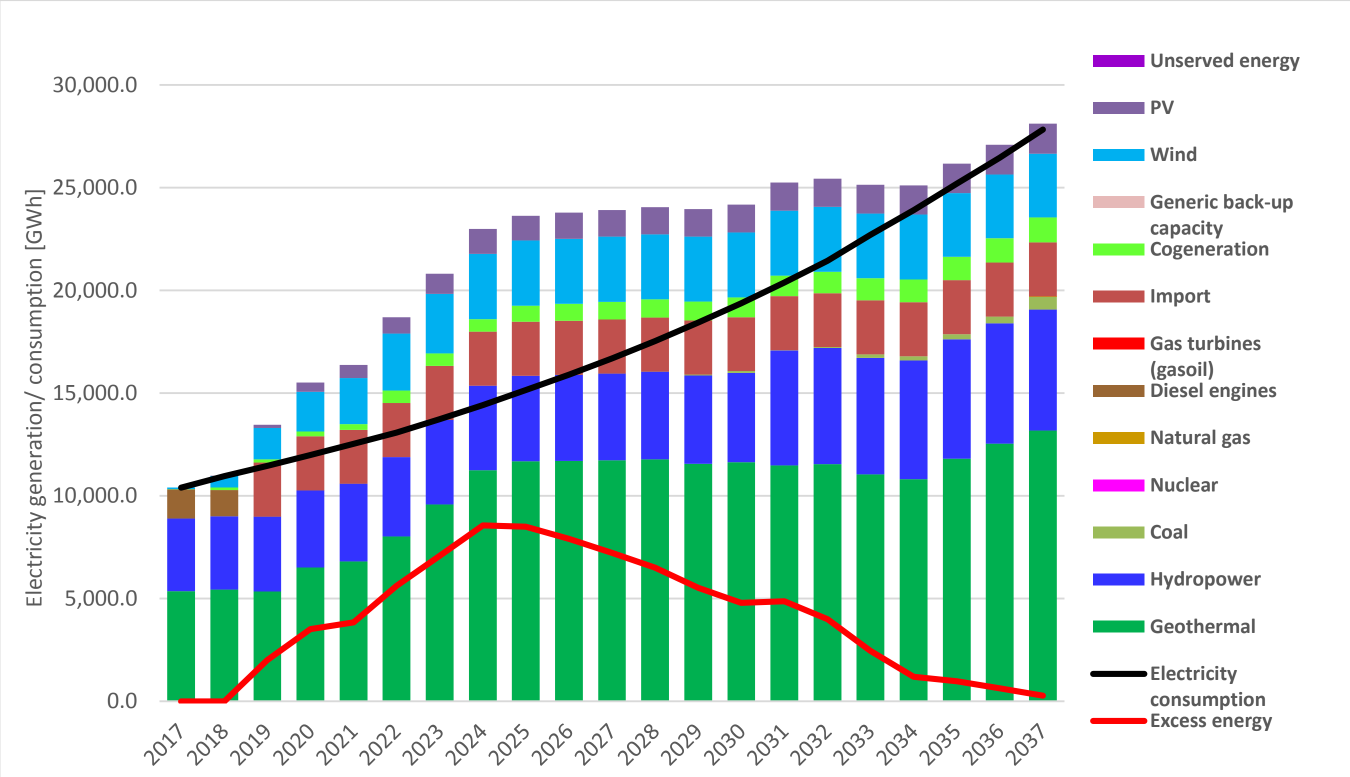
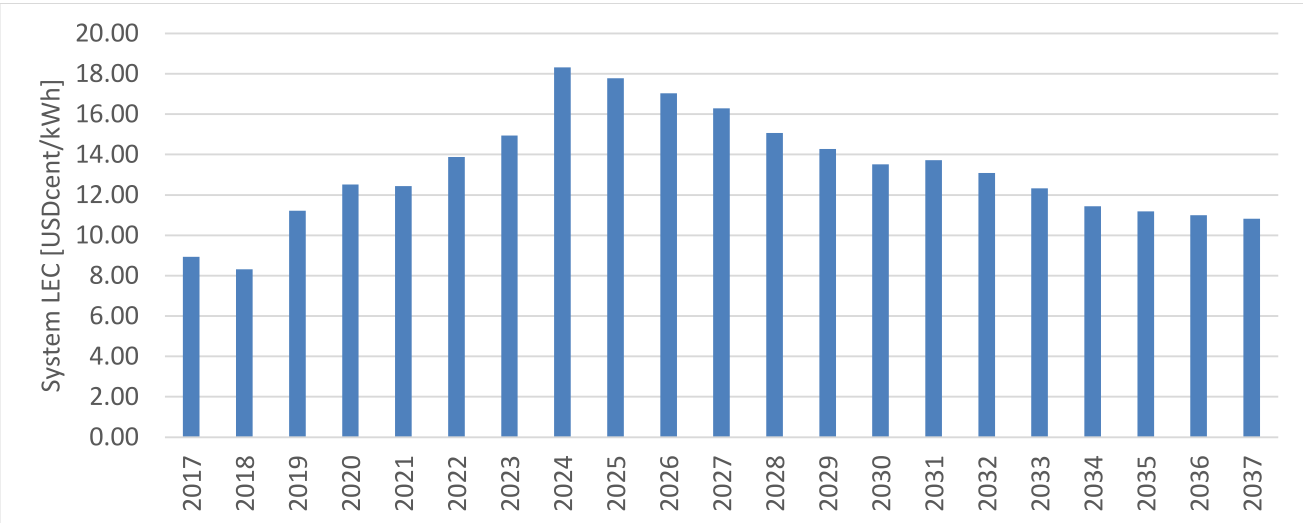


Figure 51: System LEC – Fixed medium term -Low forecast



6.6.1.9. Results for Fixed Medium term -Vision Forecast

The demand-supply balance results for the Vision forecast scenario are shown in Table 46 and Figures 52 through 54 and the associated LEC presented in Figure 55. in this scenario, the excess energy is minimized by the higher consumption to an average of 12% between 2019-2026 and to negligible levels thereafter. The LEC for the period 2019-2037 averages Shs.10.73/kWh with the highest being Shs. 13.46/kWh in 2024.

Table 45: Demand-supply- Fixed medium term -Vision forecast

Peak demand versus generation capacity		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Peak load	MW	1,754	1,917	2,088	2,293	2,516	2,766	3,027	3,342	3,705	4,078	4,450	4,854	5,261	5,780	6,251	6,752	7,272	7,842	8,468	9,094	9,790
Peak load + reserve margin	MW	2,037	2,201	2,389	2,619	2,826	3,091	3,371	4,116	4,484	4,857	5,269	5,737	6,157	6,738	7,217	7,768	8,330	8,982	9,695	10,740	11,543
Reserve margin	% of peak load	16%	15%	14%	14%	12%	12%	11%	23%	21%	19%	18%	18%	17%	17%	15%	15%	15%	15%	14%	18%	18%
Installed system capacity	MW	2,235	2,381	3,317	3,904	4,058	4,631	5,096	6,577	6,696	6,753	7,275	8,216	8,393	9,119	9,611	10,198	10,995	11,701	12,480	13,497	14,324
Firm system capacity	MW	2,037	2,085	2,767	3,079	3,032	3,321	3,624	4,900	4,992	4,999	5,398	6,156	6,271	6,977	7,223	7,789	8,341	9,026	9,754	10,750	11,557
Supply - demand gap	MW	0	-117	378	460	205	230	254	784	509	142	129	419	114	238	6	21	11	43	58	11	14
Electricity consumption versus generation		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Electricity consumption	GWh	10,407	11,402	12,393	13,600	14,832	16,371	17,898	19,684	21,955	24,187	26,469	28,945	31,411	34,796	37,564	40,497	43,549	46,875	50,524	54,061	57,978
Electricity generation	GWh	10,407	11,403	13,570	15,633	16,619	18,945	21,033	23,486	24,580	25,565	26,844	29,151	31,460	34,805	37,594	40,540	43,601	46,938	50,555	54,074	57,985
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	0	0	1,176	2,034	1,787	2,575	3,135	3,802	2,626	1,378	375	206	50	9	30	43	52	63	31	14	7
Excess energy - share on generation	%	0%	0%	9%	13%	11%	14%	15%	16%	11%	5%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Vented GEO steam (assuming single-flash technology)	GWh	25	28	1,666	2,073	2,088	2,495	3,276	3,700	3,569	3,127	3,016	2,099	1,136	375	641	896	873	1,121	802	737	519
Vented GEO steam - share on potential max. GEO generation	%	0%	1%	23%	24%	23%	23%	25%	24%	22%	20%	19%	13%	7%	2%	4%	4%	4%	4%	3%	3%	2%
Spilled water	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Spilled water - share on potential max. generation of large HPPs with dam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 52: Installed capacity vs peak load -Fixed medium term -Vision forecast

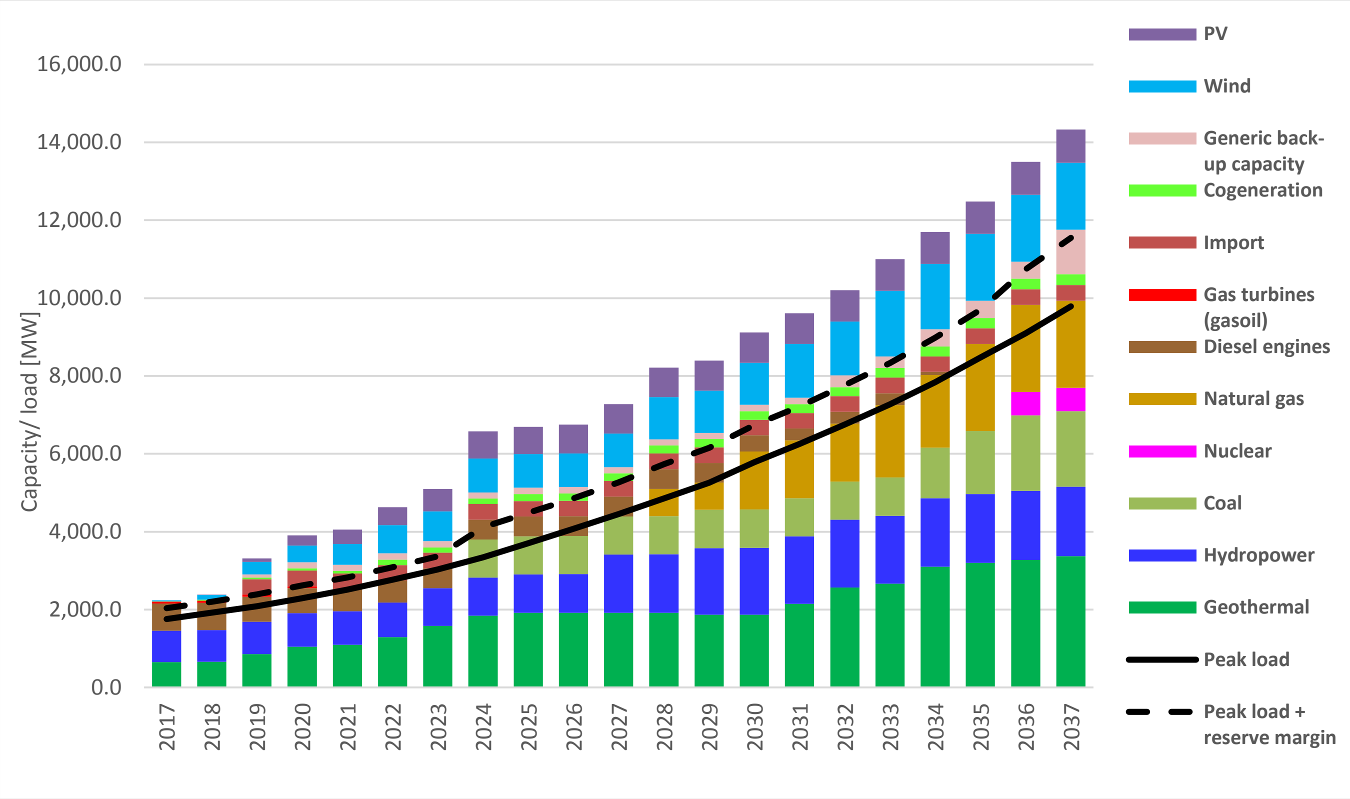


Figure 53: Firm capacity vs peak load -Fixed medium term -Vision forecast

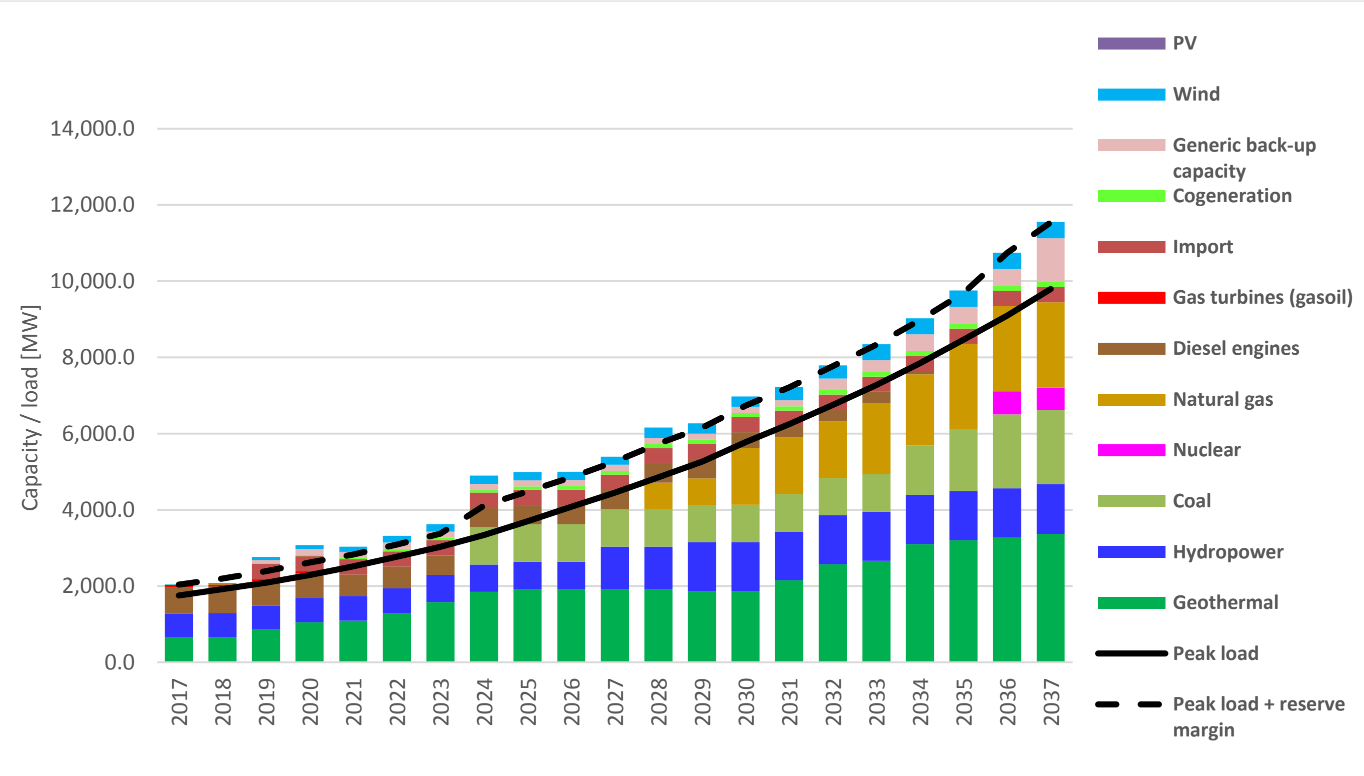


Figure 54: Annual energy -Fixed medium term -Vision forecast

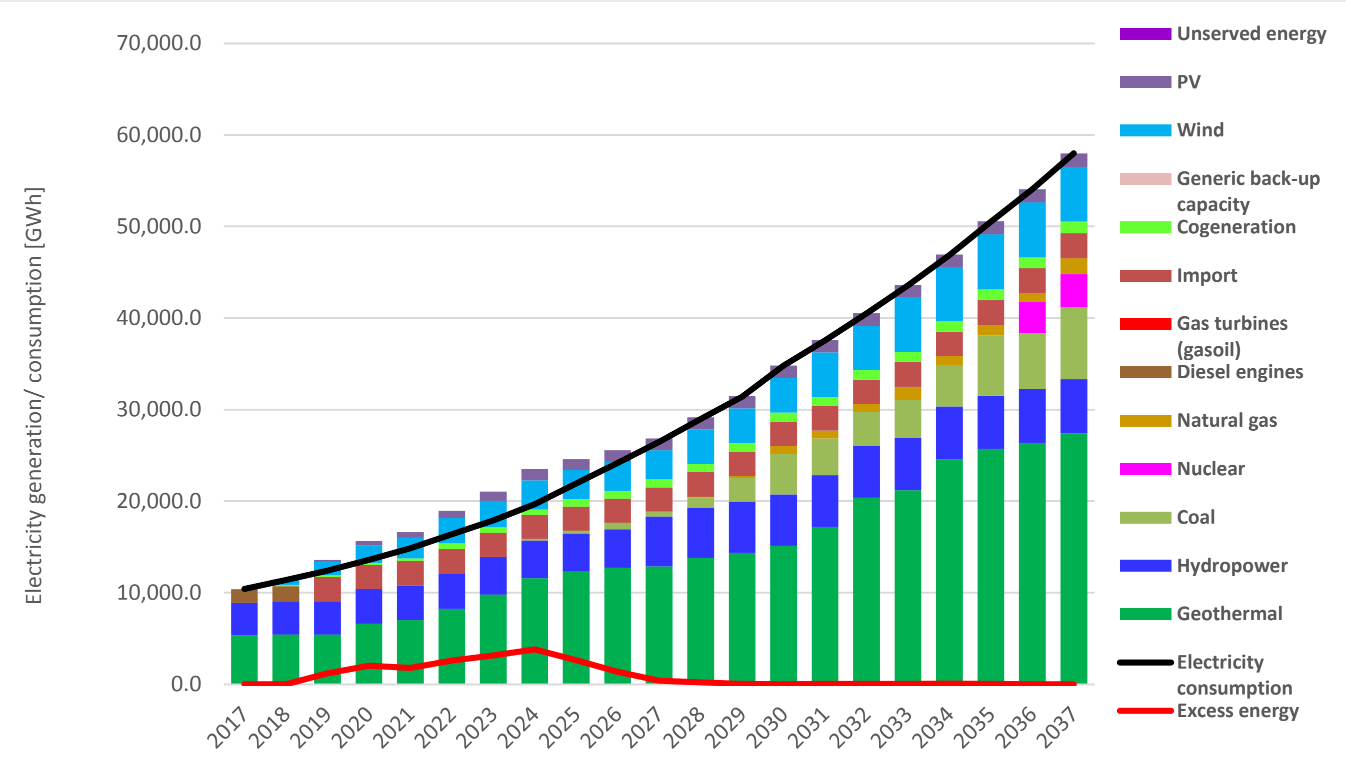
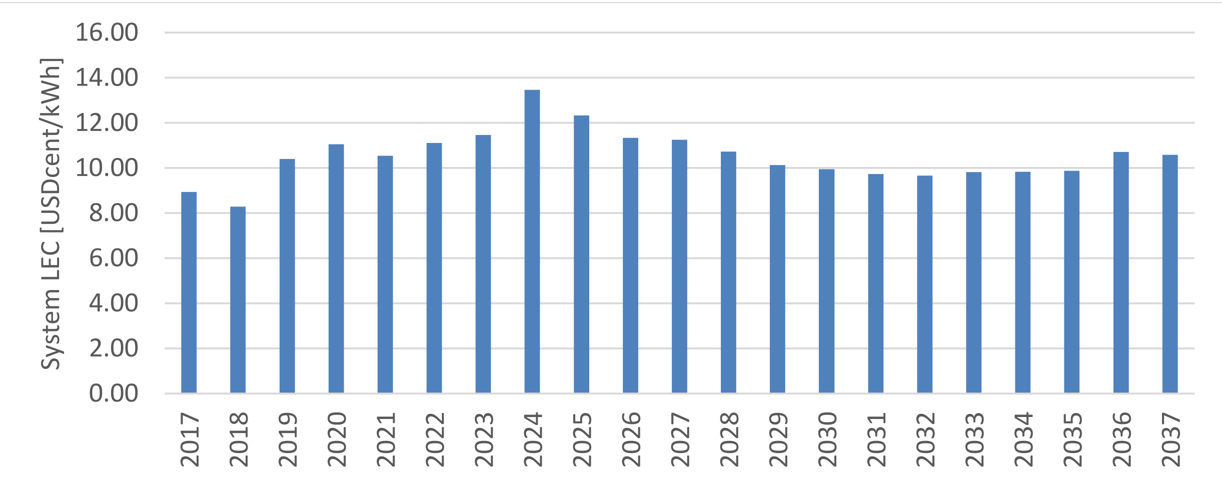


Figure 55: System LEC – Fixed medium term -Vision forecast



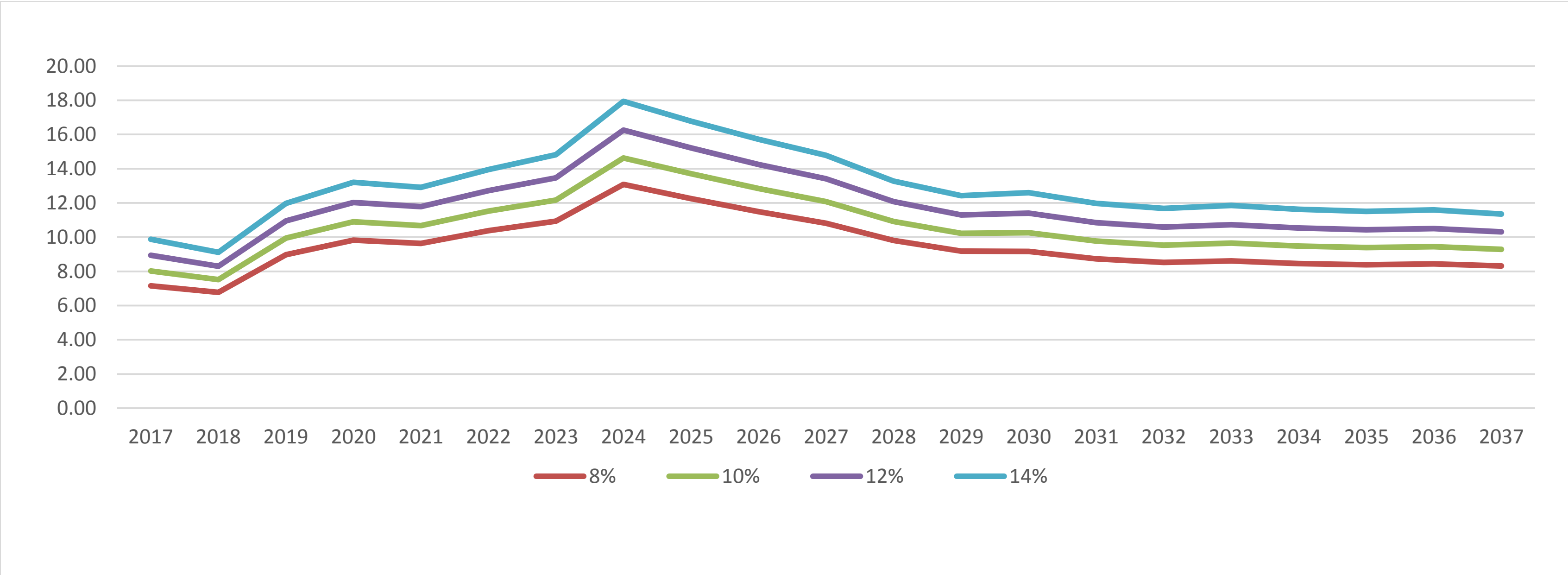
6.6.2. Sensitivity Results for Fixed Medium Term –Change in Discount Rate-Reference forecast

The optimal reference expansion sequence was subjected to sensitivity analysis to changes in discounting rates of 8%, 10 %, 12% and 14%. The results are presented in Table 47 and Figure 56. The results show that there would be significant gains in reducing the LEC if the projects are implemented using low cost financing.

Table 46: System LEC and NPV Variations with discount rates in US cents/kWh

Rate	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	NPV MUSD
8%	7.15	6.77	8.98	9.82	9.63	10.37	10.94	13.08	12.26	11.48	10.81	9.81	9.18	9.16	8.73	8.52	8.61	8.46	8.39	8.44	8.32	17,292
10%	8.02	7.52	9.94	10.90	10.68	11.52	12.17	14.63	13.70	12.83	12.08	10.91	10.22	10.26	9.77	9.53	9.65	9.47	9.39	9.45	9.29	15,979
12%	8.94	8.30	10.94	12.03	11.78	12.71	13.47	16.25	15.21	14.25	13.41	12.07	11.30	11.41	10.85	10.58	10.73	10.53	10.43	10.50	10.30	14,872
14%	9.88	9.11	11.98	13.20	12.92	13.95	14.81	17.93	16.78	15.71	14.79	13.28	12.43	12.60	11.97	11.68	11.85	11.63	11.51	11.59	11.35	13,926

Figure 56: System LEC Variations with discount rates



6.6.3. Sensitivity Results for Fixed Medium Term - change in geothermal capex

Simulations were carried on the reference expansion case with the geothermal capex varied by ± 10%. With increase in geothermal capex, the optimal expansion has reduced geothermal in favour of additional coal unit, natural gas and generic thermal back capacities. Decrease in geothermal price resulted in selection of more geothermal capacities Suswa I, Suswa II and Menengai V, while a coal unit, a generic thermal unit and a small Dongo Kundu gas plant II are dropped. The trends of the LEC for the two scenarios are shown in Table 48.

Table 47: System LEC trend with increase and decrease in geothermal capex

System cost		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2033	2034	2035	2036	2037
System LEC -capex increase	**US cent/ kWh**	8.94	8.30	10.94	12.03	11.78	12.71	13.47	16.25	15.21	14.25	13.41	12.07	11.30	11.41	10.40	10.49	10.34	10.34	10.42
System LEC -capex decrease	**US cent/ kWh**	8.94	8.30	10.94	12.03	11.78	12.71	13.47	16.25	15.21	14.25	13.41	12.07	11.30	11.41	10.57	10.21	10.21	10.25	10.21

6.6.4. Sensitivity to change in capex for hydro candidates

The reference expansion case was simulated with the capex for the two hydro candidates varied by ± 10%. There was however no change in the planting up sequence since the system requires these power plants for regulation.

6.6.5. Sensitivity to change in hydro generation output

Increase in hydro generation results in reduction in the geothermal and generic thermal capacity installed in the system. Conversely, a decrease in hydro has no effect of the planting up of the optimal expansion plan. The LEC for the two scenarios remain largely the same with only slight variations occurring from 2030.

6.6.6. Summary of Results -Long Term Expansion Plan

The recommended generation expansion plan derived from the planning analysis is shown in Table 49. the plan is based on the case named Fixed Medium-term Reference Forecast.

Table 48: Reference Expansion Plan-Generation Capacity Expansion Overview

Year considered for system integration	Plant name	Type	Net capacity [MW]	Net Installed Capacity Effective [MW]	Firm Addition (MW)	Net Installed Capacity Effective [MW]	Firm margin (MW)	Net Firm Addition (MW)	Peak load (MW)	Reserve margin (MW)	Firm margin (MW)	Surplus/ Gap with reserve (MW)	Surplus /Gap without reserve (MW)	Surplus/ Gap without reserve (%)
2017				2235		2235								
2018	OrPower4 Plant 1 Additional	Geothermal	10	2245	10		10							
2018	Lake Turkana - Phase I, Stage 1	Wind	100	2345	25		25							
2018	Strathmore	PV	0	2345	0		0							
End of 2018				2345		2345	2085	35	1866	284	2085	-65	479	-3%
2019	HVDC Ethiopia	Import	400	2745	400		400							
2019	Olkaria 5	Geothermal	158	2903	158		158							
2019	Olkaria Modular	Geothermal	50	2953	50		50							
2019	Back-up capacity 80 MW - Unit 2	Generic back-up capacity	80	3033	80		80							
2019	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	17	3050	17		17							
2019	Lake Turkana - Phase I, Stage 2	Wind	100	3150	25		25							
2019	Lake Turkana - Phase I, Stage 3	Wind	100	3250	25		25							
2019	PV grid Garissa	PV	50	3300	0		0							
2019	Marcoborero	PV	2	3302	0		0							
2019	Kopere	PV	40	3342	0		0							
2019	Olkaria 1 - Unit 1	Geothermal	-15	3327	-15		-15							
2019	Iberafrica 1	Diesel engines	-56	3271	-56		-56							
2019	Olkaria 1 - Unit 2	Geothermal	-15	3256	-15		-15							
End of 2019				3256		3256	2767	670	1978	301	2767	488	1278	25%
2020	Menengai 1 Phase I - Stage 1	Geothermal	103	3359	103		103							
2020	Olkaria 1 - Unit 6	Geothermal	70	3429	70		70							

2020	Back-up capacity 80 MW - Unit 3	Generic back-up capacity	80	3509	80		80							
2020	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	17	3526	17		17							
2020	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	17	3543	17		17							
2020	Kipeto - Phase I	Wind	50	3593	13		13							
2020	Kipeto - Phase II	Wind	50	3643	13		13							
2020	Alten, Malindi, Selenkei	PV	120	3763	0		0							
2020	Quaint, Kenergy	PV	50	3813	0		0							
2020	Olkaria 1 - Unit 3	Geothermal	-15	3799	-15		-15							
End of 2020				3799		3799	3079	297	2103	326	3079	650	1696	31%
2021	Olkaria Topping	Geothermal	47	3846	47		47							
2021	Ngong 1 - Phase III	Wind	10	3856	3		3							
2021	Chania Green	Wind	50	3906	13		13							
2021	Aperture	Wind	50	3956	13		13							
2021	Eldosol	PV	40	3996	0		0							
2021	Makindu Dafre rAREH	PV	30	4026	0		0							
2021	Gitaru Solar	PV	40	4066	0		0							
2021	Embakasi GT 1	Gas turbines (gasoil)	-27	4039	-27		-27							
2021	Embakasi GT 2	Gas turbines (gasoil)	-27	4012	-27		-27							
2021	Tsavo	Diesel engines	-74	3938	-74		-74							
End of 2021				3938		3938	3032	-54	2234	311	3032	487	1704	22%
2022	Olkaria 6 PPP	Geothermal	140	4078	140		140							
2022	Menengai I - Stage 2	Geothermal	60	4138	60		60							
2022	Prunus	Wind	51	4189	13		13							
2022	Meru Phase I	Wind	80	4269	20		20							
2022	Ol-Danyat Energy	Wind	10	4279	3		3							
2022	Electrawinds Bahari	Wind	50	4329	13		13							
2022	Hanan, Greenmillenia, Kensen	PV	90	4419	0		0							

End of 2022				4419		4419	3321	248	2421	325	3321	574	1997	24%
2023	Olkaria 7	Geothermal	140	4559	140		140							
2023	GDC Wellheads	Geothermal	30	4589	30		30							
2023	OrPower4 Plant 4 Additional	Geothermal	61	4650	61		61							
2023	Wellhead Leasing	Geothermal	50	4700	50		50							
2023	Karura	Hydropower	89	4789	71		71							
2023	Electrawinds Bahari Phase 2	Wind	40	4829	10		10							
2023	Sayor, Izera, Solarjoule	PV	30	4859	0		0							
2023	Belgen, Tarita Green Energy Elgeyo	PV	80	4939	0		0							
2023	Kipevu 1	Diesel engines	-60	4879	-60		-60							
End of 2023				4879		4879	3624	302	2586	344	3624	695	2293	27%
2024	Lamu Unit 1	Coal	327	5206	327		327							
2024	Lamu Unit 2	Coal	327	5533	327		327							
2024	Lamu Unit 3	Coal	327	5860	327		327							
2024	Menengai III	Geothermal	100	5960	100		100							
2024	Baringo Silali - Paka I	Geothermal	100	6060	100		100							
2024	Marine Power Akiira Stage 1	Geothermal	70	6130	70		70							
2024	Meru Phase II	Wind	100	6230	25		25							
2024	Tarita Isiolo, Kengreen	PV	50	6280	0		0							
2024	Asachi, Astonfield Sosian, Sunpower	PV	81	6360	0		0							
End of 2024				6360		6360	4900	1276	2764	774	4900	1362	3596	49%
2025	AGIL Longonot Stage 1	Geothermal	70	6430	70		70							
End of 2025				6430		6430	4992	70	2989	779	4992	1224	3441	41%
2026	Solargen	PV	40	6470	0		0							
End of 2026				6470		6470	4999	70	3224	779	4999	996	3246	31%
2027				6470	0		0							
End of 2027				6470		6470	5005	0	3441	779	5005	785	3029	23%
2028	Ngong 1, Phase I	Wind	-5	6465	-5		-5							

End of 2028				6465		6465	5010	-5	3720	779	5010	511	2745	14%
2029	Orpower4 Plant1 (Olkaria 3 - Unit 1-6)	Geothermal	-48	6417	-48		-48							
End of 2029				6417		6417	4969	-48	3974	775	4969	220	2443	6%
2030	High Grand Falls Stage 1	Hydropower	495	6912	495		495							
2030	Rabai Diesel (CC-ICE)	Diesel engines	-90	6822	-90		-90							
End of 2030				6822		6822	5278	405	4244	807	5278	227	2578	5%
2031	Olkaria 8	Geothermal	140	6962	140		140							
2031	High Grand Falls Stage 1+2	Hydropower	693	7655	550		550							
2031	Kipevu 3	Diesel engines	-115	7540	-115		-115							
End of 2031				7540		7540	5466	575	4525	821	5466	120	3015	3%
2032	Olsuswa 140MW unit 1 & 2	Geothermal	140	7680	140		140							
2032	Back-up capacity 140 MW - Unit 2	Generic back-up capacity	140	7820	140		140							
End of 2032				7820		7820	5752	280	4826	851	5752	75	2994	2%
2033	Olkaria 9 & other fields	Geothermal	420	8240	420		420							
2033	Back-up capacity 140 MW - Unit 3	Generic back-up capacity	140	8380	140		140							
2033	Olkaria 2	Geothermal	-105	8275	-105		-105							
End of 2033				8275		8275	6214	735	5148	894	6214	173	3127	3%
2034	Dongo Kundu CCGT - small 1	Natural gas	375	8650	375		375							
2034	Kitui Coal Unit 1	Coal	320	8970	320		320							
2034	OrPower4 Plant 2&3 (Olkaria 3 - Unit 7-9)	Geothermal	-62	8908	-62		-62							
2034	Iberafrica 2	Diesel engines	-53	8856	-53		-53							
2034	Thika (CC-ICE)	Diesel engines	-87	8769	-87		-87							
2034	Athi River Gulf	Diesel engines	-80	8689	-80		-80							
End of 2034				8689		8689	6634	414	5491	954	6634	188	3197	3%
2035	Menengai IV	Geothermal	100	8789	100		100							
2035	Kitui Coal Unit 2	Coal	320	9109	320		320							

2035	Triumph (Kitengela)	Diesel engines	-83	9026	-83		-83								
2035	Ngong 1, Phase II	Wind	-20	9005	-5		-5								
End of 2035				9005		9005	6972	332	5859	1007	6972	106	3146	2%	
2036	Baringo Silali - Korosi I	Geothermal	100	9105	100		100								
2036	Baringo Silali - Silali I	Geothermal	100	9205	100		100								
2036	Kitui Coal Unit 3	Coal	320	9525	320		320								
2036	KenGen Olkaria Wellheads I & Eburru	Geothermal	-55	9470	-55		-55								
End of 2036				9470		9470	7443	465	6232	1072	7443	140	3238	2%	
2037	Dongo Kundu CCGT - small 2	Natural gas	375	9845	375		375								
End of 2037				9845		9845	7825	375	6638	1106	7825	81	3208	1%	

6.7. Conclusions

6.7.1. Fixed System expansion case

(vi) Existing capacity and demand- The existing capacity and demand are currently closely balanced indicating a reserve margin of 16% and a shortfall of 65 MW which may not arise as the recorded peak demand is still below 1,790 MW compared to the projected 1,866MW in 2018.

(vii) The delay in completion of the LTWP power evacuation line project has denied the system an additional 300 MW which would be displacing thermal generation and minimizing the fuel cost charge.

(viii) Addition of 300 MW LTWP at the end of 2018, Ethiopia 400 MW in mid-2019, 158 MW Olkaria V geothermal among other committed projects would raise the existing capacity to above 3,900 MW by 2020 resulting in an average of 583 MW excess capacity in the period 2019-2023 should demand grow moderately as depicted in the reference forecast.

(ix) Addition of 981.5 MW Lamu coal plant in 2024 will aggravate the projected supply-demand imbalance as the surplus margin would surpass 1,500 MW being 43% above the sum of peak and required reserve, with 32% excess energy during the year. The system LEC would rise rapidly to reach Shs. 16.86/kWh by the year 2024.

(x) Capacity factors for geothermal, hydro and coal plants average 71.7%, 44.9% and 0.9% over the period after 2019, implying that the power plants, and particularly Lamu coal, will be grossly underutilized should demand grow moderately.

(xi) Lower demand would worsen the system LEC and plant utilization levels while higher demand would improve the two parameters.

(xii) Due to the heavy introduction of intermittent technologies, the system is unlikely to be stable, implying that there is need to introduce some backup capacity. The team has recommended an introduction of 2 backup plants in 2019 and 2020 amounting to 160MW for purposes of backup and provision of primary reserve and other ancialliary services

6.7.2. Optimised expansion plan

(i) The demand-supply balance in the period 201-2023 remains as in (a) above since the projects that were considered as committed within this period are the same.

(ii) With model given the opportunity to optimise the expansion plan, the first unit of coal is selected is Kitui 320MW coal added 2029. The next coal unit would be Lamu 327MW in 2034 followed by 320 Kitui coal unit in 2035 and another 327MW Lamu unit in 2036.

(iii) The excess capacity would reduce from an average of 398MW between 2019 and 2023 to an average of 80MW of the rest of the planning period.

(iv) The system LEC would rise gently to reach Shs. 12.45/kWh by the year 2022 and stabilize to an average of Shs. 11.07/kWh over the rest of the planning period.

(v) Capacity factors for geothermal, hydro and coal plants average 77.8%, 30.0% and 24.7% over the period 2019-2037, implying that the power plants and particularly the Lamu coal plant will be grossly underutilized.

(vi) Lower demand would worsen the system LEC and plant utilization levels while higher demand would improve the two parameters.

6.7.3. Fixed Medium-term case

(i) Implementation of all committed projects by 2024 would raise the existing capacity to 3,538 MW resulting in an average of 709 MW excess capacity with demand growing moderately according to the reference forecast.

(ii) Addition of 981.5 MW Lamu coal plant in 2024 aggravates the projected supply-demand imbalance as the excess capacity would be 1,362 MW being 39% above the sum of peak and required reserve, with 29% excess energy during the year. The system LEC would rise rapidly to reach Shs. 16.25/kWh by the year 2024.

(iii) Capacity factors for geothermal, hydro and coal plants average 75.5%, 44.3% and 6.3% over the period 2019-2037, implying that some power plants, especially the Lamu coal plant, will be grossly underutilized.

(iv) Lower demand would worsen the system LEC and plant utilization levels while higher demand would improve the two parameters.

(v) Sensitivity analyses results show that there would be significant gains in achieving lower LEC if the projects are implemented using low cost financing.

(vi) Variation of generating plants capex for the two hydro candidates by ± 10% did not change in the planting up sequence since the system requires the hydro plants.

(vii) Simulations were carried on the reference expansion case with the geothermal capex varied by ± 10%. With increase in geothermal capex, the optimal expansion has reduced geothermal in favour of additional coal unit, natural gas and generic thermal back capacities. Decrease in geothermal price favoured selection of more geothermal capacities; Suswa I, Suswa II and Menengai V, while a coal unit, a generic thermal unit and a small Dongo Kundu gas plant II were dropped.

6.8. Recommendations

The following recommendations are derived based on the generation expansion planning analyses carried out.

(i) Renegotiate the PPAs for large power plants such as Ethiopia HVDC and Lamu Coal to introduce operation flexibility and minimize energy costs.

(ii) Implementation of Lamu coal should be phased and the plant to constitute smaller units of 150MW each to minimise requirement of primary reserves.

(iii) Phase out committed medium term solar and wind projects under Feed-In-Tariff (FiT) policy, negotiate generation tariffs downward and suspend procurement of new intermittent capacity plants under the FiT policy.

(iv) The team has recommended an introduction of 2 backup plants in 2019 and 2020 amounting to 160MW for purposes of backup and provision of primary reserve and other ancialliary services

(v) Fast-track the operationalisation of the Energy Auction market for the solar and wind projects and adoption of a new FiT policy for integration of small hydros and biomass technology into the grid.

(vi) Delay the development of new geothermal plants after implementation of the committed ones to allow demand to grow and match supply.

(vii) Demand creation-Fast-track implementation of flagship projects as identified under Vision 2030 such as electrification of Standard Gauge Railway, introduction of the light rail transport and establishment of industrial zones.

(viii) Introduce interruptible tariff for domestic load that encourages balancing of household consumption through shifting of load to 4.00 pm-6.00 pm and from 10.00 pm to 5.am.

(ix) Put mechanisms in place to manage delays in implementation of generation projects such as Menengai, Agil, Akira and Fit projects such as Kipeto and Kinangop wind. Delays affect decision meaning in the energy sector and scheduling of future plants.

(x) Closely match implementation of generation and transmission projects to avoid deemed energy costs arising from non-dispatch of some plants such as Lake Turkana Wind and utilization of Olkaria geothermal in West Kenya region.

(xi) Commit development of the candidate large hydro candidates, Karura and High Grand Falls, for commissioning in the medium term.

7. TRANSMISSION PLANNING

7.1. Objectives of transmission planning

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 (2037) 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 optimize the alternative transmission development sequences through detailed technical studies and economic analysis to arrive at the least cost option
- To develop and present cost estimates for the planned investments.

7.2 Methodology

This transmission plan development employed target network concept of transmission planning which ensures a coordinated investment strategy and therefore optimal network development using the Least Cost Planning concept. In addition, alternatives approach was used in selection of appropriate reinforcements required to alleviate network challenges within a given target network.

7.2.1 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 sequence variants.

The process of developing the target network candidates begins with development of the short term (year 2024) 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 table 54, 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. For instance, table 49 below estimates regional power balance expected for the year 2037.

Table 49: Year 2037 regional power balances (MW) and Potential imports/exports from/to other regions

Region	Generation	Demand	Surplus/ Deficit	Nairobi	North Rift	West Kenya	Tanzania (EKT)	Uganda (KUR)
Coast	1,841	1132	709	709	-	-	-	-
Nairobi	227	3376	-3149	-	-	-	-	-
Mt Kenya	3,209	726	2483	2483	-	-	-	-
Central Rift	2,660	411	2,249	1976	-	273	-	50
North Rift	526	288	238	-	-	238	-	-
West Kenya	194	705	-511	-	-	-	-	-
Ethiopia	600	0	400	400	-	-	200	-
EKT	0	200	-200	-	-	-	-	-
KUR	0	50	-50	-	-	-	-	-
Totals	**9,257**	**6888**	**2,369**	**3,149**	**0**	**511**	**200**	**50**

- 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, the transfer capacity, limited by both the thermal rating and the surge impedance loading (for long EHV lines), are considered.

7.3 Planning assumptions and criteria

7.3.1 Planning assumptions

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

- Future thermal generation (coal and gas turbines) will be developed mainly 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 KenGen and GDC.
- Firm power imports will be available only from Ethiopia. However surplus power exchange and trans-border wheeling within the region are envisaged hence regional interconnections with Uganda and Tanzania are considered in the transmission development plan.
  - o Kenya will import 400 MW from Ethiopia from 2019
  - ✓ 200MW will be exported from Ethiopia to Tanzania through Kenya from the year 2020.
  - ✓ 50MW will be exported to Rwanda through Uganda primarily via the 400kV KUR Interconnector

- Due to anticipated right of way challenges and rapid demand growth, major transmission lines will be designed as double circuits (and at higher system voltages) for higher transmission capacity, with a possibility of initial operation at lower voltage levels to reflect existing system strength and limit requirements for other line equipment

7.3.2 Planning criteria

As guided by the Kenya national Transmission Grid Code, the following gives the major aspects that were considered during the planning exercise: -

7.3.2.1 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.

7.3.2.2 Equipment loading

- 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.

7.3.2.3 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.

7.3.2.4 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.

7.3.2.5 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 replacement of some breakers (i.e. upgrade) or to identification of mitigation actions for limiting the fault levels.

7.3.2.6 Power losses

The system is planned to operate efficiently with power losses likely not to exceed 5% at system peak: the economic comparison of variants will take the cost of losses into account and identify the least (global) cost variant..

For economic comparison of alternative transmission development plans peak power losses are converted to corresponding energy losses and costed at the LRMC of energy (15 US cents/kWh).

7.4 Catalogue of equipment

Standard equipment and materials (e.g. transformers, conductors, capacitors, substation diameters and bays e.t.c) 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 equipment 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 **Error! Reference source not found.** and Table 51. The tables were compiled using KETRACO estimated costs.

7.5 Catalogue of equipment and materials

Table 50: power transformers

POWER TRANSFORMERS							
	VOLTAGE RATIO - kV (Costs in MUSD)						
MAXIMUM CAPACITY/RATING	132/33	220/33	220/66	220/132	400/132	400/220	500/400
23MVA	0.55	0.72	-	-	-	-	-
45MVA	0.7	0.85					
90MVA	-	-	-	0.95	1.1	-	-
150MVA	-	-	-	1.15	2	-	-
200MVA (3-ph units for 220/66 rest 1-ph)	-	-	1.5	-	1.8	2.2	-
400MVA (1-ph units)	-	-		-	-	3	4.11

REACTOR BANKS					
	VOLTAGE RATING- kV & UNIT COST in MUSD				
MAXIMUM CAPACITY/RATING	33	66	132	220	400
7.5 MVAr	0.25	0.	0.275	0.370	-
10-15MVAr	0.38	0.	0.508	0.685	-
50 MVAr	-	-	-	-	0.75
100 MVAr	-	-	-	-	1.4

CAPACITOR BANKS					
	VOLTAGE RATING- kV & UNIT COST in MUSD				
MAXIMUM CAPACITY/RATING	33	66	132	220	400
7.5 MVAr	-	-		-	-
10-15 MVAr	0.54			1.012	-
50 MVAr				-	-
100 MVAr				-	-

Table 51: Other line equipment

PARTICULARS	EQUIPMENT COST (MUSD) & VOLTAGE CLASS (kV)					
	33	**66**	**132**	**220**	**400**	**500DC**
Line Terminal Equipment	0.02	0.045	0.1	0.23	0.34	15.13 (per pole)
Transformer Terminal Equipment	0.02	0.045	0.1	0.24	0.36	
Diameter	-	-	0.22	1	1.7	inc
Partial Diameter	-	-	-	0.5	0.85	-
Bus Coupler	0.025	0.05	0.22	-	-	-
Power Transformer	-	-	-	-	-	-
Reactor/Capacitor banks	-	-	-	-	-	-
Bus Bars	inc	inc	inc	inc	inc	
Protection & Control	inc	inc	inc	inc	inc	
Telecom	inc	inc	inc	inc	inc	
Control Room building			0.5	0.6	0.8	1
SS Extension			0.2	0.35	0.4	-
Civil Structural Works	35% of cost of equipment					
Design & Installation	27% of cost of equipment and civil-structural works					
PM and Supervision	5% of total EPC cost					
Contingency	15% of Total EPC + Supervision					

Source: Author

7.6 Catalogue of transmission lines

Table 52: Catalogue & Unit Cost of Equipment-Transmission Lines Cost (MUSD/km)

LINE VOLTAGE (KV)	EPC+PM	EPC+PM	EPC+PM	EPC+PM
	OHL DC	OHL SC	Mono Pole DC	UG CABLE DC
132kV	0.156	0.1	0.244	1
220kV	0.3124	0.20	0.488	2
400kV	0.456	0.292	0.713	2.5

Source: Authors

7.7 Resettlement and land (wayleaves)

Table 53: Cost of RAP, Land (Way Leaves)

SUSBTATION LAND COSTS					
PRIMARY VOLTAGE (kV)	**SIZE (ACRES)**	**COST (M KES)**	**COST (MUSD)**		
132	5	12.5	0.120192		
220	10	25	0.240385		
400	15	37.5	0.360577		
WAYLEAVE COSTS					
LINE VOLTAGE	**SIZE (m)**	**SIZE Sqm/KM**	**SIZE ACRES/KM**	**COST (M KES)/KM**	**COST/KM (MUSD)**
132	30	30000	7.413	18.533	0.178
220	40	40000	9.884	24.711	0.238
400	60	60000	14.826	37.066	0.356

Source: Author

The above tables on cost will be expanded and revised in future to include equipment has been installed in the system and that which becomes available in the market. This will be used for defining the many scenarios whose comparison provides the Least Cost Scenarios.

7.8 Generation and load data

7.8.1 Generation data 2017 - 2037

The future generation plants considered in this plan are described here below.

Table 54: Generation data

YEAR	S/No	PLANT NAME	CAPACITY (MW)	REGION	PLANT TYPE
2018	1.	LTWP Phase I Stage I	100	N Rift	WIND
	2.	Garissa PV	50	Mt.Kenya	PV
2019	3.	Olkaria V	158	C Rift	GEOTH
	4.	Olkaria Modular	50	C Rift	GEOTH
	5.	HVDC Ethiopia imports	400	Ethiopia	IMP
	6.	Marcoborero	2	Mt.Kenya	PV

	7.	LTWP Phase I Stage II	100	N Rift	WIND
	8.	LTWP Phase II	100	N Rift	WIND
	9.	Kopere	40	West	PV
	10.	Olkaria Topping	47	C Rift	GEOTH
2020	11.	Menengai I Phase I - Stage 1	103	C Rift	GEOTH
	12.	Olkaria 1 - Unit 6	70	C Rift	GEOTH
	13.	Malindi Solar	40	C Rift	PV
	14.	Kenergy	40	Mt. Kenya	PV
	15.	Selenkei	40	N Rift	PV
	16.	Alten	40	N Rift	PV
	17.	Kipeto Phase I	50	Nairobi	WIND
	18.	Kipeto Phase II	50	Nairobi	WIND
	19.	Quaint	10	West	PV
	20.	Ngong I Phase III	10	Nairobi	WIND
2021	21.	Chania Green	50	Nairobi	WIND
	22.	Aperture	50	Nairobi	WIND
	23.	Cedate	40	N Rift	PV
	24.	Gitaru Solar	40	Mt.Kenya	PV
	25.	Ngong I Phase III	10	Nairobi	WIND
2022	26.	Olkaria 6 PPP	140	C Rift	GEOTH
	27.	Menengai I Stage II	60	C Rift	GEOTH
	28.	Electrawinds Bahari	50	Coast	WIND
	29.	Greenmillenia	40	Mt. Kenya	PV
	30.	KenGen	40	Mt.Kenya	PV
	31.	Meru Phase I	80	Mt.Kenya	WIND
	32.	Hanan	90	Nairobi	PV
	33.	Prunus	51	Nairobi	WIND

2023	34.	Ol Ndanyat	10	Nairobi	WIND
	35.	Ol Karia 7	140	C Rift	GEOTH
2023	36.	GDC wellheads	30	C Rift	GEOTH
	37.	Wellhead leasing	50	C Rift	GEOTH
	38.	Solarjoule	10	C Rift	PV
	39.	Izera	10	Coast	PV
	40.	Eletrawinds Bahari Phase II	40	Coast	WIND
	41.	Karura	89	Mt. Kenya	HYDRO
	42.	Belgen	40	Mt.Kenya	PV
	43.	Tarita Green	40	N Rift	PV
	44.	Sayor	10	Nairobi	PV
	45.	Menengai III	100	C Rift	GEOTH
2024	46.	Baringo Silali - Paka I	100	C Rift	GEOTH
	47.	Marine Power Akiira Stage 1	70	C Rift	GEOTH
	48.	Astonfield Sosian	81	C Rift	PV
	49.	Lamu Unit 1	327	C Rift	COAL
	50.	Lamu Unit 2	327	C Rift	COAL
	51.	Lamu Unit 3	327	C Rift	COAL
	52.	Tarita Isiolo	40	Mt.Kenya	PV
	53.	Meru Phase II	100	Mt.Kenya	WIND
	54.	Kengreen	10	Nairobi	PV
	55.	Sachi	81	Nairobi	PV
	56.	Sunpower	40	Nairobi	PV
	57.	AGIL Longonot Stage I	70	C Rift	GEOTH
2025	58.	Solargen	40		PV
2026	59.	High Grand Falls Stage I	495	Mt. Kenya	HYDRO
2030	60.	Ol Karia 8	140	C Rift	GEOTH

2031	61.	Olsuswa unit I & II	140	C Rift	GEOTH
2032	62.	Ol Karia 9 & other fields	420	C Rift	GEOTH
	63.	Dongo Kundu CCGT 1	375	Coast	GT
2034	64.	Kitui Coal Unit I	320	Mt Kenya	COAL
	65.	Menengai IV	100	C Rift	GEOTH
2035	66.	Kitui Coal Unit II	320	Coast	COAl
	67.	Baringo Silali - Korosi I	100	C Rift	GEOTH
2036	68.	Kitui Coal Unit III	320	Mt.Kenya	COAL
	69.	Dongo Kundu CCGT 2	375	Coast	GT

7.9 Load data

7.9.1 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
- Vision 2030 flagship projects as follows as indicated in table 55:

Table 55: Vision 2030 flagship projects

Project	**Reference**				**High**			
	First year of operation	Initial load [MW]	Year of total load	Total load [MW]	First year of operation	Initial load [MW]	Year of total load	Total load [MW]
Electrified mass rapid transit system for Nairobi	2024	15	2030	50	2022	15	2027	50
Electrified standard gauge railway Mombasa - Nairobi	2022	98	2030	130	2021	100	2028	300
Electrified standard gauge railway Nairobi - Malaba	2026	61.74	2035	61.74	2024	63	2032	189
Electrified LAPSSET standard gauge railway	-	-	-	-	2035	30	2037	30

Oil pipeline and Port Terminal (LAPSSET)	2025	50	2037	150	2022	50	2032	150
Refinery and Petrochemical Industries (LAPSSET)	2028	25	2037	100	2025	50	2030	200
Konza Techno City	2024	2	2037	190	2022	2	2034	200
Special Economic Zones	2021	5	2037	110	2020	30	2028	110
Integrated Steel Mill					2030	100	2035	200

7.9.2 Distributed load forecast 2020 -2035

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 56: Peak load distribution in regions

	2018		**2020**		**2025**		**2030**		**2035**	
Region	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**
Nairobi	1009	309	1048	321	2159	661	2980	913	3376	1034
Coast	301	108	354	127	724	259	999	358	1132	405
Mt. Kenya	167	59	243	85	464	162	641	224	726	254
West	389	147	457	173	898	340	1239	469	1404	532
Grand Total	**1866**	**623**	**2103**	**706**	**4244**	**1423**	**5859**	**1964**	**6638**	**2225**

Detailed distributed forecast by substation for 2018 and 2037 is provided in Annex 5.

7.10 Development of Target network candidates

Four target transmission network candidates for the horizon planning year (2037) were developed as the basis for preparation of four alternative transmission system development plans for detailed analysis and optimization.

The basic consideration in developing the target networks is the regional power balance as shown in table 49 , which was 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 section 7.3, 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, 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 Rift 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 network and the regional standards, 220kV and 400 kV lines were considered as the main inter regional and regional transmission system voltages.

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 chronologically.

7.11 Overview of Developed target networks

A combination of projects (in addition to the committed network) were selected so as to address the following network issues:

i. Provision of alternative source of supply for Lessos for improved reliability of supply for larger West Kenya
ii. Reinforcing existing Juja – Naivasha 132kV and development of supply improvements for Central Rift load between Naivasha and Lanet (Gilgil and environs).
iii. Reinforcing southern parts of West Kenya (Kisii and South Nyanza).

iv. Grid extension to off-grid areas currently supplied by diesel generator sets (Moyale and Mandera).
v. Revamping and increasing evacuation capacity for transmission system from Olkaria geo complex hence reducing reliance to Suswa substation.
vi. Reinforcing 132kV and existing transmission network in Coast region - Mombasa town, Bamburi and environs.

A number of alternatives (proposed transmission projects) were grouped into Six (6) clusters that sought to address the above. Out of several combinations, four target networks were selected for more analysis.

The following describes the four target network alternatives that were considered for further analysis.

7.11.1 Target network 1

i. This option considers cutting into the Loiyangalani-Suswa 400kV line and looping it into the proposed Baringo 400/220kV substation and extending a 220kV line to the proposed Eldoret North substation.

ii. It is also proposed that in order to meet the N-1 reliability criteria in Nairobi's Juja Rd Substation and reinforce Juja Naivasha link, the existing Naivasha -Juja 132kV line be upgraded to 220kV by constructing a new 220kV Naivasha-Uplands-Ruaraka-Juja line with substations in Uplands, Ruaraka and Juja.

iii. To reinforce the South Nyanza system, a 220kV line be constructed . between Kilgoris 400/220 substation and a proposed Kisii/Rongo substation. Additionally, to complete the 220 kV ring, another link; 220 kV Rongai-Kericho/Chemosit-Kisii/Rongo be establised. Under this option, it is also proposed that a 220kV link be established between the proposed Kericho/Chemosit and Muhoroni substations.

iv. To supply the Northern Kenya region, it is proposed that two 220kV lines; (i) between Wajir and Mandera and (ii) between Marsabit and Moyale be constructed.

v. To reinforce the 400kV Nairobi ring, it is proposed that 400kV lines (i) between the proposed Longonot 400kV substation and Thika and (ii) between Longonot and Suswa 400kV substations be established.

vi. To reinforce the existing 220kV link between Rabai and Malindi, it is proposed that a second 220kV line be established between the proposed switch station on the Rabai-Malindi line at Weru and the proposed Bamburi Cement substation and extend it all the way to Mariakani 400/220kV substation.

7.11.2 Target Network 2

i. This option considers cutting into the Loiyangalani-Suswa 400kV line and looping it into the proposed Baringo 400/220kV substation and extending a 400kV line to Lessos substation.

ii. It is also proposed that in order to meet the N-1 reliability criteria in Nairobi, the existing Naivasha -Juja 132kV line be upgraded to 220kV by constructing a new 220kV Naivasha-Uplands-Ruaraka-Juja line with substations in Uplands, Ruaraka and Juja. To reinforce the Central Rift system, it is proposed that the Juja-Lessos 132kV line be looped in and out at the Gilgil 400/220kV substation and establish of a 220/132/33kV substation to supply the local load.

iii. To reinforce the South Nyanza system, it is proposed that the Rongai-Kilgoris 400kV line, which is committed be constructed. Additionally 2 220kV lines (i) from Manengai-Kisii and (ii) from Rongai to Kericho and Chemosit be established to supply the growing loads in the region.

iv. To supply loads in Northern Kenya, it is proposed that in addition to the 220kV lines from Marsabit-Moyale and Wajir-Mandera, a 220 kV link be established between Wajir and Marsabit to increase reliability.

v. In terms of reinforcing the 400kV ring in Nairobi, an option similar to target network 1 above is proposed.

vi. To reinforce the existing 220kV link between Rabai and Lamu and establish an alternative route for evacuating power from the Lamu Coal Power Plant, it is proposed that a 400kV link be established between

Lamu and Mariakani substations and a 220kV line be constructed between the proposed switch station on the Rabai-Malindi line at Weru and the proposed Bamburi Cement substation.

7.11.3 Target Network 3

i. This option considers cutting into the Loiyangalani-Suswa 400kV line and looping it into the proposed Baringo 400/220kV substation and extending a 220kV line to the proposed Eldoret North substation.

ii. To reinforce the Central Rift system, it is proposed that the Juja-Lessos 132kV line be looped in and out at the Gilgil 400/220kV substation along with establishment of a 220/132/33kV substation to supply the local load. It is also proposed that in order to meet the N-1 reliability criteria in Nairobi, the existing Naivasha -Juja 132kV line be upgraded to 220kV by constructing a new 220kV Naivasha-Uplands-Ruaraka-Juja line with substations in Uplands, Ruaraka and Juja

iii. In terms of reinforcing the South Nyanza system, this option is similar to target network 1 above except that in in this case, the Kericho/Chemosit -Muhoroni 220kV link is omitted. .

vii. To supply loads in Northern Kenya, an option similar to target network 1 above is proposed.

iv. It is proposed that a 400kV line between the proposed Longonot 400kV substation and the 400kV Thika substation be established without the link between Longonot.

v. In terms of reinforcing the existing 220kV link between Rabai and Lamu and establish an alternative route for evacuating power from the Lamu Coal Power Plant, this option is similar to target network 1 above.

7.11.4 Target Network 4

i. This option considers cutting into the Loiyangalani-Suswa 400kV line and looping it into the proposed Baringo 400/220kV substation and extending a 220kV line to the proposed Eldoret North substation.

ii. It is also proposed that in order to meet the N-1 reliability criteria in Nairobi, the existing Naivasha -Juja 132kV line be upgraded to 220kV by constructing a new 220kV Naivasha-Uplands-Ruaraka-Juja line with substations in Uplands, Ruaraka and Juja. To reinforce the Central Rift system, it is proposed that the Juja-Lessos 132kV line be looped in and out at the Gilgil 400/220kV substation and establish a 220/132/33kV substation to supply the local load.

iii. To reinforce the South Nyanza system, a 220kV line be constructed between Kilgoris 400/220 substation and the proposed Kisii/Rongo substation. Additionally, a 220 kV line from Rongai to Kericho/Chemosit and onwards to Kisii/Rongo is proposed to complete the 220 kV ring. Under this option, it is also proposed that a 220kV link be established between the proposed Kericho/Chemosit and Muhoroni substations.

iv. This option is also similar to target network 1 in terms od supply options to Northern Kenya.

v. To reinforce the 400kV Nairobi ring, a 400kV line is proposed between the proposed Longonot 400kV substation and the 400kV Thika substation, without the link between Longonot and Suswa substations.

vi. To reinforce the existing 220kV link between Rabai and Lamu and establish an alternative route for evacuating power from the Lamu Coal Power Plant, it is proposed that a 400kV link be established between Lamu and Mariakani substations and a 220kV line be constructed between the proposed switch station on the Rabai-Malindi line at Weru and the proposed Bamburi Cement substation.

From further preliminary assessment, observation and discussions, Target networks 1, 3, and 4 as described above were selected for further analysis and optimization.

7.11.5 Developing Models for Target Networks Alternatives

Initially the committed projects for 2018-2022 were modeled each year and studies carried out to verify their adequacy and identify required further investments in response to the updated demand forecast.

Further, and at different instances, the 2037 planning horizon year target networks projects elements were modeled in PSS/E, in addition to modeling all the planned generation plants, loads and transmission lines by 2037. Upon modeling the conceptual network elements described in section 7.7.1 above, additional system reinforcements using the standard network equipment tabulated in section 7.4. 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 were determined when target networks were optimized.

7.11.6 System Studies and Analysis

Each of the planning horizon networks developed has to comply with the transmission system criteria applied. To optimize the networks, a series of studies were conducted in PSS/E modelling and analysis tool as follows:

7.11.6.1 Load flow studies

Load flow studies were 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.

7.11.6.2 Contingency studies

Contingency studies are an extension of load flow studies carried out to ensure the target network meets the loading and 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.

7.11.6.3 Fault Level studies

Fault level computations were 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.

7.12 Simulation Results

The simulation results as attached in the appendices, were analyzed and used to rank the best target network alternatives. These formed the basis for target network selection and hence transmission investment sequences that best met the set technical criteria.

PSS/E load flow models for the three target networks are attached in the Appendices.

Cost estimates for network elements in each target network was determined and used in the subsequent sections.

7.13 Key Findings

Network constraints in the short term (2017-2024):

The following network constraints wee identified in the existing and committed network 2018: 2024, and recommendations made for their resolution as detailed in section 7.10

i. In adequate transmission capacity in West Kenya, Central Rift and Coast regions.
ii. System sub-optimal performance in Nairobi region due to;
    - Delayed Nairobi 220 kV Ring projects (Kimuka, Athi River, Thika road and Malaa 220 Kv substations)
    - Malaa substation location being very far from the load centre (inner Nairobi Region).
iii. System over voltages upon commissioning of proposed 400kV networks.
iv. System under voltages at various substations in Nairobi, Coast and West regions
v. Reeliability criteria (n-1) not met for the following major transmission corridors.
    - Olkaria complex - Suswa
    - Suswa - Nairobi North - Dandora
    - –Dandora – Juja road - Ruaraka
vi. Relatively high transmission losses in the short term due to delayed commissioning of various committed projects, attributed to wayleaves problems, vandalism and non performance of contractors.

7.14 Recommendations

7.14.1 Network constraints

Address inadequate transmission capacity in West Kenya, Central Rift and Coast in the short term by fast tracking the following on going and committed transmission projects.;

a) West Kenya Region
   i. Olkaria-Lessos-Kisumu 400kV/ 220 kV transmission line. This will offload Olkaria – Naivasha 132 kV line, Naivasha – Lanet-Lessos and Lessos – Muhoroni – Kisumu lines.
   ii. Olkaria – Narok and Narok – Bomet 132 kV line sections. This will off-load Muhoroni – Chemosit and improve voltages in South Nyanza sub-region

b) Coast Region
   i. Rabai –Kilifi kV line upgrade to double circuit construction and steel tower construction
   ii. Malindi – Kilifi 220 kV line and Kilifi 220 kV substation
   iii. Kipevu – Mbaraki 132 kV line and 132/33 kV substation
   iv. Uprate Rabai substation 220/132 kV transformers

7.14.2 Network reliability

Reinforce committed transmission network to improve supply reliability (compliance with n-1 redundancy criteria)

(a) Construct Olkaria 1AU – Olkaria IV 220 kV double circuit line. This will improve power evacuation reliability between Olkaria complex and Suswa substation when Olkaria V power plant is commissioned.

(b) Convert Olkaria 1 – Naivasha 132 kV line to 220 kV operation and establish Naivasha 220/132 kV substation. Additionally convert Naivasha –Juja road 132 double circuit line to 220 kV and upgrade the associated substations. This will improve the reliability of Suswa – Nairobi North and Dandora – Juja –Ruaraka corridors to the required level and optimize supply reliability and improve network performance in Nairobi.

7.14.3 Optimization and improvement of network performance

Optimize and improve supply system in Nairobi by fast tracking construction of Nairobi 220 kV ring project including Kimuka, Thika road, Athi river, and Malaa 220/66 kV substations along with their feeder outlets. Due to the distance of Malaa substation from the load center, upon completion of Naivasha – Juja 132 kV line conversion to 220 kV, it is recommended that a 220/132/66 Kv substation be constructed at Juja road to facilitate 66 kV supply system optimization.

Additionally, to optimize network losses it is recommended that ongoing other transmission line projects be fast tracked including connection of Suswa-Isinya-Mariakani and Isinya- Athi River- Embakasi 220 kV lines to operate as double circuits as constructed.

7.14.4 System voltage control

Operate committed 400 kV system at 220 kV initially to limit system voltages and need for extensive voltage control equipment deployment. Additionally reactive power compensation equipment should be employed to ensure effective system operation. It is recommended that a complete system reactive compensation study over the medium term be carried out with a view to addressing the high voltages expected in the 400 kV system as well as the under voltages observed in Nairobi, coast and West Kenya. The study should consider and optimize deployment of dynamic reactive compensation equipment like SVCs and STATCOMS.

7.14.5 Optimization of wayleaves

It is recommended that long term way leaves traces be secured through;

i. Double circuit construction for all transmission circuits
ii. 400kV construction for all regional and inter regional. These may be initially operated at 220 kV

8. OPTIMIZING THE FUTURE TRANSMISSION NETWORK

8.1 Methodology

This entails finding acceptable sequences of investments starting from the 2018-2024 committed transmission networks and ending up to each of the developed target network alternative.

The investment sequences for each target network alternative were established by creating and optimizing network models at 5 year intervals between 2025 and 2035, with each of the investments conforming to the 2037 target network requirements. This is done by starting with the 2037 target network and developing 2035, 2030, and 2025 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 (for each of the three target network alternative) are once again optimized through load flow, contingency and short circuit studies to ensure transmission system criteria is complied with at every stage. The simulation results are attached in the Appendices.

8.2 Development of sequence of investments

The alternative investment strategies were developed each from the initially identified target network alternatives 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 section 7.4. 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 (2018) at the rate of 12%. 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

Table 58 represents a summary of investment cost streams and analysis of the three alternative investment strategies. Summary of investment cost of three alternatives in US Dollar.

Table 57: Summary of cost of investment of the three alternatives in USD

	Target Network 1	Target Network 2[10]	Target Network 3	Target Network 4
PV of cost (MUSD)	5,203.39	5,410.21	5,061.69	5,268.09
Non discounted total	8,463.16	9,038.48	8,165.84	8,563.60

From the above analysis, the present value of cost for Target Network 3 is the lowest, which makes it the least cost development plan. The present value of investments for this option is estimated at **MUSD 5061.69**.

Detailed investment analysis for these option is tabulated in table 61

[10] Although this option was dropped in preliminary stage, economic analysis was done using losses for TN 1.

Table 58: Economic Analyses –TARGET NETWORK 1

Transmission Plan 2017 2037-Target Network 1															
Cost (MUSD)															
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2030**	**2031**	**2032**	**2035**	**2037**
Lines/Substations	530.62	854.09	995.11	1,168.86	630.07	910.02	129.15	1,173.06	254.16	293.75	265.00	242.40	12.83	73.58	
Reactive compensation	-	3.45	2.64	-	2.65	-	0.91	3.86	-	-	-	1.82	-	-	0
O$M Cost (2.5%)	13.27	21.44	24.94	29.22	15.82	22.75	3.25	29.42	6.35	7.34	6.63	6.11	0.32	1.84	0.00
Losses(KUSD)	45.15	57.72	48.76	47.87	50.17	0.00	0.00	63.72	0.00	0.00	104.21	0.00	0.00	151.71	157.11
Total cost (MUSD)	589.03	936.71	1,071.45	1,245.95	698.71	932.77	133.31	1,270.06	260.51	301.10	375.84	250.33	13.15	227.13	157.11
PVS (I=12%)	589.03	836.35	854.15	886.84	444.04	529.28	67.54	574.51	105.22	108.58	96.47	57.37	2.69	33.08	18.24
PV of cost (MUSD)	**5,203.39**														
Non discounted total	**8,463.16**														
Total cost less losses (MUSD)	543.89	878.98	1,022.69	1,198.08	648.54	932.77	133.31	1,206.34	260.51	301.10	271.63	250.33	13.15	75.42	0.00
PVS (I=12%)	543.89	784.81	815.29	852.77	412.16	529.28	67.54	545.69	105.22	108.58	69.72	57.37	2.69	10.98	0.00
PV of investments (MUSD)	**4,905.97**														
Non discounted total investments	**7,736.73**														
Assumptions:															
Discount rate	12%														
Cost of Losses	0.15	USD/kWh													
O & M Cost	2.5%	of Capex													

Table 59: Economic Analyses –TARGET NETWORK 2

Transmission Plan 2017 2037-Target Network 2															
Cost (MUSD)															
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2030**	**2031**	**2032**	**2035**	**2037**
Lines/Substations	530.62	854.094	995.11	1188.801	512.937	1058.02	129.15	1201.089	254.16	753.4747	265	340.4	12.83	73.58	
Reactive compensation	0	3.45	2.64	0	2.65	0	0.91	3.86	0	0	0	1.82	0	0	0
O$M Cost (2.5%)	13.27	21.44	24.94	29.72	12.89	26.45	3.25	30.12	6.35	18.84	6.63	8.56	0.32	1.84	0.00
Losses(KUSD)	45.15	57.72	48.76	47.87	50.17	0.00	0.00	64.21	0.00	0.00	0.00	0.00	0.00	151.53	183.85
Total cost (MUSD)	589.03	936.71	1,071.45	1,266.39	578.65	1,084.47	133.31	1,299.28	260.51	772.31	271.63	350.78	13.15	226.95	183.855
PVS (I=12%)	589.03	836.35	854.15	901.39	367.74	615.36	67.54	587.73	105.22	278.50	69.72	80.39	2.69	33.05	21.34681
PV of cost (MUSD)	**5,410.21**														
Non discounted total	**9,038.48**														
Total cost less losses (MUSD)	543.89	878.98	1,022.69	1,218.52	528.48	1,084.47	133.31	1,235.07	260.51	772.31	271.63	350.78	13.15	75.42	0
PVS (I=12%)	543.89	784.81	815.29	867.32	335.86	615.36	67.54	558.68	105.22	278.50	69.72	80.39	2.69	10.98	0
PV of investments (MUSD)	**5,136.24**														
Non discounted total investments	**8,389.21**														
Assumptions:															
Discount rate	12%														
Cost of Losses	0.15	USD/kWh													
O & M Cost	2.5%	of Capex													

Table 60: Economic Analyses –TARGET NETWORK 3

Transmission Plan 2017 2037-Target Network 3															
Cost (MUSD)															
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2030**	**2031**	**2032**	**2035**	**2037**
Lines/Substations	530.62	854.1	995.	1110.	512.937	910.02	129.15	1228.81	254.16	293.7	69.1	242.4	12.83	73.58	
Reactive compensation	0	3.45	2.64	0	2.65	0	0.91	3.86	0	0	0	1.82	0	0	0
O$M Cost (2.5%)	13.27	21.44	24.94	27.75	12.89	22.75	3.25	30.82	6.35	7.34	1.73	6.11	0.32	1.84	0.00
Losses(KUSD)	45.15	57.72	48.76	47.87	50.17	0.00	0.00	64.21	0.00	0.00	103.86	0.00	0.00	151.53	183.85
Total cost (MUSD)	589.03	936.71	1,071.4	1,185.6	578.65	932.77	133.31	1,327.6	260.51	301.10	174.68	250.33	13.15	226.95	183.85
PVS (I=12%)	589.03	836.35	854.15	843.92	367.74	529.28	67.54	600.58	105.22	108.58	44.84	57.37	2.69	33.05	21.35
PV of cost (MUSD)	**5,061.7**														
Non discounted total	**8,165.8**														
Total cost less losses (MUSD)	543.89	878.98	1,022.69	1,137.77	528.48	932.77	133.31	1,263.49	260.51	301.10	70.82	250.33	13.15	75.42	-
PVS (I=12%)	543.89	784.81	815.29	809.84	335.86	529.28	67.54	571.54	105.22	108.58	18.18	57.37	2.69	10.98	-
PV of investments (MUSD)	**4,761.0**														

Non discounted total investments	**7,412.7**	
Assumptions:		
Discount rate	12%	
Cost of Losses	0.15	USD/kWh
O & M Cost	2.5%	of Capex

Table 61: Economic Analyses –TARGET NETWORK 4

Transmission Plan 2017 2037-Target Network 4															
Cost (MUSD)															
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2030**	**2031**	**2032**	**2035**	**2037**
Lines/Substations	530.62	854.09	995.11	1188.80	630.07	910.02	129.15	1138.06	254.16	612.50	69.09	242.40	12.83	73.58	
Reactive compensation	0.00	3.45	2.64	0.00	2.65	0.00	0.91	3.86	0.00	0.00	0.00	1.82	0.00	0.00	0.00
O$M Cost (2.5%)	13.27	21.44	24.94	29.72	15.82	22.75	3.25	28.55	6.35	15.31	1.73	6.11	0.32	1.84	0.00
Losses(KUSD)	45.15	57.72	48.76	47.87	50.17	0.00	0.00	70.04	0.00	0.00	99.58	0.00	0.00	144.66	152.43
Total cost (MUSD)	589.03	936.71	1071.45	1266.39	698.71	932.77	133.31	1240.51	260.51	627.81	170.40	250.33	13.15	220.08	152.43
PVS (I=12%)	589.03	836.35	854.15	901.39	444.04	529.28	67.54	561.14	105.22	226.39	43.74	57.37	2.69	32.05	17.70
PV of cost (MUSD)	**5268.09**														

Non discounted total	**8563.60**														
Total cost less losses (MUSD)	543.89	878.98	1022.69	1218.52	648.54	932.77	133.31	1170.47	260.51	627.81	70.82	250.33	13.15	75.42	0.00
PVS (I=12%)	543.89	784.81	815.29	867.32	412.16	529.28	67.54	529.46	105.22	226.39	18.18	57.37	2.69	10.98	0.00
PV of investments (MUSD)	**4970.56**														
Non discounted total investments	**7847.21**														
Assumptions:															
Discount rate	12%														
Cost of Losses	0.15	USD/kWh													
O & M Cost	2.5%	of Capex													

8.4 Investment Sequence

8.4.1 Transmission lines and substations

The transmission lines and substations expected in the 2017-2037 planning period are listed in the table below

Table 62: Transmission lines and substations investment sequence

PROJECTS COMMITTED & EXPECTED BY 2018			
S/No.	**Transmission Line**	**Length (KM)**	**Projected Cost (USD Million)**
1	Loiyangalani – Suswa 400kV line	430	161
2	Nairobi Ring substations	-	46.17
3	Nanyuki – Isiolo 132kV (cable pending)	70	54.25
4	Turkwel – Ortum – Kitale 220kV	135	18.59
5	Isinya – Namanga 132kV	80	12.62
6	Wote – Sultan Hamud 132kV	42	6.75
7	Mwingi – Kitui 132kV	60	9.68
8	Kitui – Wote 132kV	60	9.68
9	Nanyuki – Rumuruti 132kV (cable pending)	79	20.27
10	Lessos – Kabarnet 132kV	65	16.55
11	Olkaria – Narok 132kV	68	17.45
12	Embakasi-Athi River (Cable section repairs) 220kV	6.75	1.56
13	Olkaria – Lessos – Kisumu 400/220/132kV	279	156.05
14	**2018 TOTALS**	**1,374.75**	**530.62**
PROJECTS EXPECTED BY 2019			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Kenya – Tanzania line 400kV	100	65.02

2	Sondu – Homa Bay (Ndhiwa) – Awendo 132kV	96	28.80
3	System Reinforcement (Isinya 400/220kV & Nairobi North 220/66kV substation)	-	45
4	Eastern Electricity Highway Project 500kV	612	509.95
5	Rabai –Bamburi- Kilifi 132kV	56	30.95
6	Voi –Taveta 132kV	110	40.69
7	Mariakani Substation 400/220kV	-	30
8	Awendo –Isebania 132kV	39	23.57
9	Meru –Maua 132kV	35	25.63
10	Second Circuit LiLo Nakuru West –Lanet 132KV	1.5	3.54
11	Olkaria IV –Olkaria V 220KV	10	16.324
	2019 TOTALS	**1,059.5**	**819.47**
PROJECTS EXPECTED BY 2020			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Lessos – Tororo 400kV	132	49.98
2	Olkaria 1 AU- Naivasha 220KV	22.5	16.28
3	Olkaria 2-Olkaria 3 220KV	7	9.54
4	Olkaria 1 AU-Olkaria VI 220KV	5	14.76
5	Juja-Ruaraka 132KV poles to towers so is Webuye	6.5	1.71
6	Musaga-Webuye 132KV	18	2.79
7	Thika 400/220KV –Thika 220/132KV	1	0.28
8	Garsen -Bura-Hola –Garissa 220kV	260	154.33
9	Sultan Hamud – Loitoktok 132kV	120	46.75
10	Isinya – Konza 400kV	38	48.61

11	Rumuruti – Maralal 132kV	148	46.84
12	Malindi(Kakoneni) – Kilifi* 220kV	60	50.28
13	400kV Gilgil, Kimuka and Lessos substations	-	134.52
14	Kamburu – Embu – Thika 220kV	153	154.97
15	Uplands (Limuru) substation	-	15.98
16	Ishiara – Chogoria 132kV	40	27.28
17	Galu - Lunga Lunga 132kV	66	28.32
18	Kisumu - Kakamega – Musaga 220kV	73	79.45
19	Galu T-off – Likoni 132kV	15	13
20	Menengai - Olkalou – Rumuruti 132kV	70	34.34
21	Dongo Kundu – Mariakani 400kV	50	52
22	Narok – Bomet 132kV	88	34.62
23	Kipevu-Mbaraki	6.5	13.1
24	**2020 TOTALS**	**1,379.5**	**1,029.73**
PROJECTS EXPECTED BY 2021			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Longonot –Olkaria VII 220KV	20	22.92
2	Longonot –Suswa PP 220KV	20	22.92
3	Lamu –Lamu Coal 220KV	20	20.37
4	Malaa-Lamu 400KV	520	487.65
5	Makindu substation	-	32.05
6	Gilgil – Thika – Malaa– Konza 400kV	205	291.25
7	Kitui - Mutomo – Kibwezi 132kV	132	59.34
8	Kiambere - Maua – Isiolo 220kV	145	120.94

9	Voi Substation 400/132kV	-	31.93
10	**2021 TOTALS**	**1,062**	**1089.37**
PROJECTS EXPECTED BY 2022			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Rumuruti – Kabarnet 132kV	111	42.19
2	Menengai – Rongai 400kV	45	35.16
3	Webuye - Kimilili – Kitale 132kV	73	35
4	Sotik – Kilgoris 132kV	50	22
5	Ngong (Kimuka) – Magadi 220kV	88	74.12
6	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	80	51.74
7	Githambo- Othaya-Kiganjo 132kV	72	34.9
8	6 Substation Reinforcement works	-	29.72
9	Kiambere-Karura 220KV	20	22.92
10	Longonot –Olkaria VIII 220KV	25	25.63
11	Malaa – Thika Road 220kV	30	19.177
12	Mariakani – Kwale 220kV Line	55	40
13	6 Substation Reinforcement works	-	29.72
14	Electrification of SGR Phase 1	57.5	50.66
15	**2022 TOTALS**	**706.5**	**512.94**
PROJECTS EXPECTED BY 2023			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Baringo – Rongai 400kV	150	25.96

2	Baringo – Lokichar 220kV	245	80
3	Rangala – Busia 132kV	34	15.1
4	Rongai – Kericho 220kV	70	62.79
5	Longonot –Olkaria IX 220KV	25	25.63
6	Isiolo – Garba Tula – Garissa 220kV	320	168.78
7	Garissa – Habasewin – Wajir 220kV	330	176.17
8	Myanga – Busia 132kV	27	23.91
9	Rangala - Bondo – Ndigwa 132kV	57	33.85
10	Isiolo – Baringo220kV	323	149.83
11	Rongai - Kilgoris (Lake Victoria Ring) 400kV	235	148
12	**2023 TOTALS**	**1,816**	**910.02**
PROJECTS EXPECTED BY 2024			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Kisumu(Kibos) – Bondo 132kV	140	63.03
2	Malindi(Kakoneni) – Galana 220kV Line	60	66.12
3	**2024 TOTALS**	**200**	**129.15**
PROJECTS EXPECTED BY 2025			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Loiyangalani – Marsabit 400kV	136	65.67
2	Ndhiwa (Ongeng)- Sindo 132kV	39	19.15
3	Ndhiwa (Ongeng)- Karungo Bay 132kV	50	21.08
4	Isiolo – Marsabit 220kV	240	120.29

5	Kericho –Chemosit 220KV	30	40.96
6	Eldoret –Baringo 220KV	95	76.27
7	Loiyangalani – Lodwar 220kV	180	83.21
8	Eldoret – Kapsowar 132kV	110	71
9	Bomet – Olenguruone – Rongai 132kV	165	78.47
10	Kilgoris – Lolgorien – Kihancha 132kV	80	51.74
11	Awendo– Gogo – Karungu Bay 132kV	48	25
12	Lessos– Kapsabet 220kV	27	36
13	Turkwel – Lokichar – Lodwar 220kV	120	60
14	Lodwar – Lokichoggio 220kV	190	78
15	Isiolo – Baringo 220kV	150	65
16	Malindi-Garsen 220kV	104	40.06
17	Garsen-Lamu 220kV	96	37.5
18	**2025 TOTALS**	**1,860**	**969.4**
PROJECTS EXPECTED BY 2026			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Electrification of SGR Phase 2	57.5	50.66
2	Thika –Thika Rd 220kV	1	23.16
3	Thika – HG Falls 400kV	200	180.34
4	**2026 TOTALS**	**258.5**	**254.16**
PROJECTS EXPECTED BY 2031			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**

1	Chavakali Substation 220/33	-	18.32
2	Musaga Substation 400/220	-	37.38
3	Dandora –Juja Rd 132kV	5	12.14
4	Menengai-Kisii 220kV	150	101.29
5	Eldoret-Eldoret North 132kV	5	13.27
6	**2031 TOTALS**	**160**	**182.4**
PROJECTS EXPECTED BY 2032			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Gilgil Substation 132/33kV[11]	1.5	12.83
2	**2032 TOTALS**	**1.5**	**12.83**
PROJECTS EXPECTED BY 2035			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Matasia-Ngong(Kimuka) 220kV	10	25.47
2	Baringo-Maralal 132kV	165	48.11
3	**2035 TOTALS**	**175**	**73.58**

[11] This has been brought forward to before 2026.

Table 63: Recommeded For Inclusion In The Sequence (Inluding Target Network 3 Projects)

S/n	PROJECT	Length (km)	Cost (USD)	EXPECTED YEAR
1	400kV Loiya/Suswa LiLo to Baringo	60	61	2031
2	220kV Ruaraka-Uplands-Naivasha	100	79.5	2021
3	220kV Olkaria IAU – Olkaria IV	10	4	2020
4	220/132kV Rabai Transformers and upgrade of Kipevu lines	10	6	2021
5	220/132kV Gilgil and 132kV Naivasha/Lanet LiLo	12	20.7	2021
6	220kV Rongai-Kericho/Chemosit-Kisii/Rongo	135	117	2022
7	220kV Kilgoris- Rongo/Kisii 132kV Awendo/Kisii LILO	50	61.7	2025
8	220kV Wajir-Mandera	250	159	2027
9	220kV Marsabit-Moyale	180	120	2027
10	400kV Longonot-Thika	78	69.1	2030
11	220kV Bamburi Cement-Weru	30	35	2025
12	220kV Bamburi Cement- Mariakani	40	15	2027
	TOTALS	**955**	**753**	

8.5 Reactive Compensation[12] Investment Sequence

Table 64: Reactive Compensation Investment Sequence

NEW INVESTMENT IN REACTIVE POWER COMPENSATION				
YEAR	**BUS NAME**	**VOLTAGE (kV)**	**MVAr**	**COST(MUSD)**
2019	LAMU (ADDITIONAL CAPACITY)	33	-7.5	0.27
2019	ORTUM	220	-15	0.35
2019	RANGALA	132	18	0.4
2019	RUARAKA	66	32	0.5
2019	LIKONI TEE	132	38	0.5
2019	THIKA RD BSP	220	50	0.9
2019	NRBINORTH	66	60	0.8
2020	KENERGY SLR	132	-70	0.6
2020	RUMURUTI	132	-30	0.5
2020	RADIANT (Lessos-Turkwel Line)	220	-21	0.46
2020	MERU	132	-7.5	0.25
2020	TRIUMPH	66	15	0.3
2021	ISIOLO	220	-30	0.85
2022	BONDO	132	18	0.5

[12] Variable reative power equipment to be considered.

NEW INVESTMENT IN REACTIVE POWER COMPENSATION				
YEAR	**BUS NAME**	**VOLTAGE (kV)**	**MVAr**	**COST(MUSD)**
2022	BONDO	132	-10	0.3
2022	GARSEN	33	-4	0.2
2022	KIPEVU	132	27.5	0.7
2022	NDWIGA	132	-10	0.4
2022	KIBOS	33	21	0.45
2022	KIBOS	33	21	0.45
2024	KILGORIS	132	-30	0.7
2024	OTHAYA	132	20	0.46
2025	ONGENG	33	25	0.46
2027	KISUMU EAST	33	25	0.46
2027	KISUMU EAST	33	25	0.46
2030	ISABENIA	33	25	0.46
2030	ISABENIA	33	25	0.46
TOTALS				14

Table 65: Reactive Power equipment included as part of transmission lines cost in the transmission lines cost table above

REACTIVE POWER COMPENSATION INCLUDED IN TL COST TABLE		
BUS NAME	**VOLTAGE (kV)**	**MVAr**
GILGIL	400	-100
GILGIL	400	-100
ISINYA	400	-100

REACTIVE POWER COMPENSATION INCLUDED IN TL COST TABLE		
BUS NAME	**VOLTAGE (kV)**	**MVAr**
ISINYA	400	-100
KIMUKA	400	-100
KIMUKA	400	-100
LOIYANGALANI	400	-100
LOIYANGALANI	400	-100
MAKINDU	400	-100
MAKINDU	400	-100
RONGAI	400	-100
RONGAI	400	-100
KILGORIS	400	-100
KILGORIS	400	-100
SUSWA	400	-100
SUSWA	400	-100
LESSOS	400	-100
LESSOS	400	-100
MALAA	400	-100
MALAA	400	-100

9. INVESTMENT COSTS OF THE INTERCONNECTED SYSTEM AND THE EVOLUTION OF TARIFFS IN THE MEDIUM TERM

9.1. Introduction

This chapter on evolution of tariffs considers only the medium term period where the projects are committed and fixed. While the generation expansion costs will be given for the period 2017-37, the evolution of tariff will only be for the years 2017-24 when the projects are committed. The evolution of tariff in the short period gives a more precise figure unlike over a long period of time when several factors at play might change.

Evolution of tariff was simulated for only ***Fixed Medium Term Case*** which is the most preferred scenario. Under this scenario, an analysis of how the tariff evolves under three demand growth scenarios namely ***Reference demand growth***, ***Vision Demand growth*** and ***Low demand growth*** has been simulated

9.1.1. Fixed Medium Term Case

In this sequence, fixed projects were modelled according to the medium-term plan and optimization followed through subsequent years. This case was used to derive the long term expansion plan having captured the most likely development path. Furthermore, the case was developed to derive an optimal expansion path assuming that projects scheduled for commissioning in the period up to 2024 are not flexible while the rest were presented as expansion candidates over the planning horizon

It is expected that under the fixed medium term case, as more projects are being brought on board to meet the same demand, the DGE payments would increase significantly. In this case, Lamu Coal Project is treated as a committed project and the entire capacity will come into the system in the year 2024.

9.1.2. Generation expansion costs under Reference Scenario

Under this scenario, peak demand grows from 1,754MW (2017) to 2,764MW (2024). This constitutes about 57.6% increase in load growth. Consequently, capital costs increase from Ksh 84,861,047,719 (2017) to 250,544,243,315 in 2024. This represents an average increase of 17% per annum. Generation projects are capital intensive and financing of the optimal expansion plan requires active participation of both the public and private sectors through various models including project financing (Development Partners) and public private partnerships. Figure 57 shows the total

Capital requirement for the generation expansion plan and specific requirements for different technologies for the period 2017– 2037 under the *fixed medium term reference load growth scenario*. Figure 58 shows the annual capital requirements for the period with optimal load growth. Geothermal and hydro power sources shall require a larger share of the Capital requirement.

Figure 57: Investment Costs for various technologies with Reference load growth

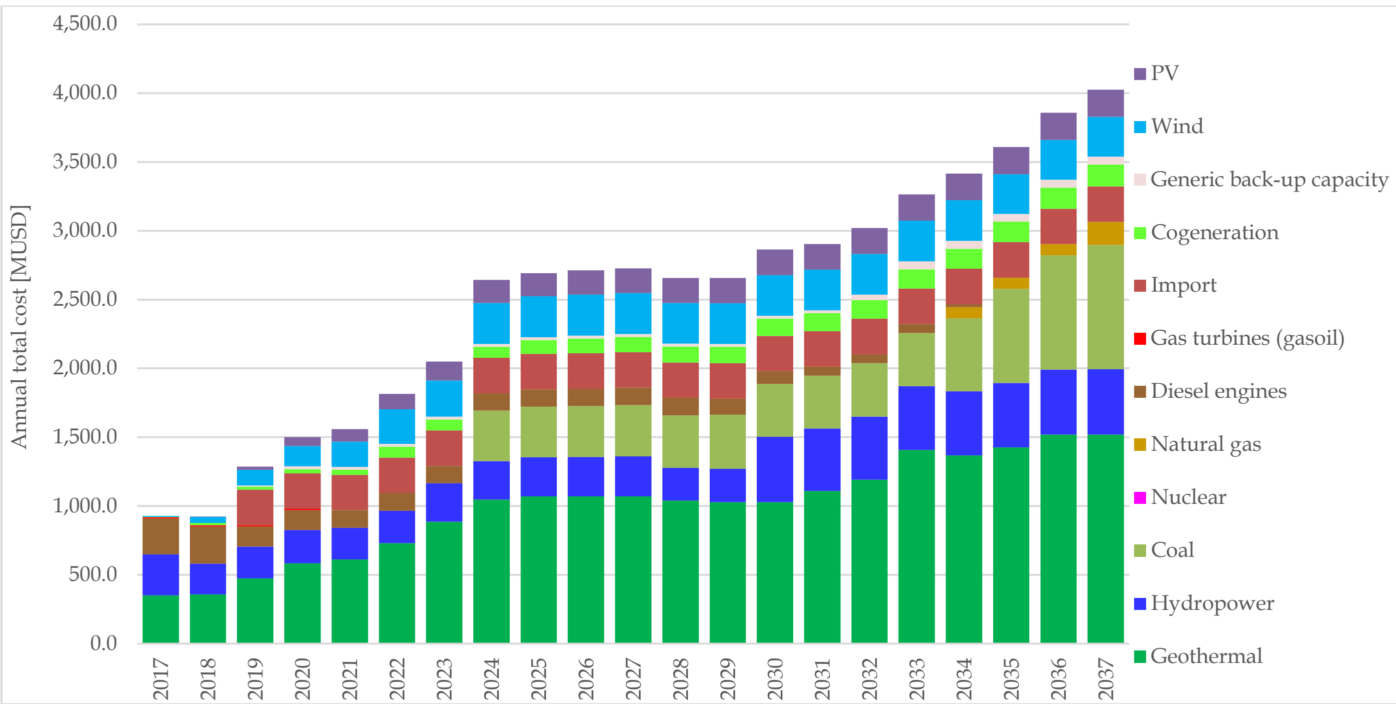
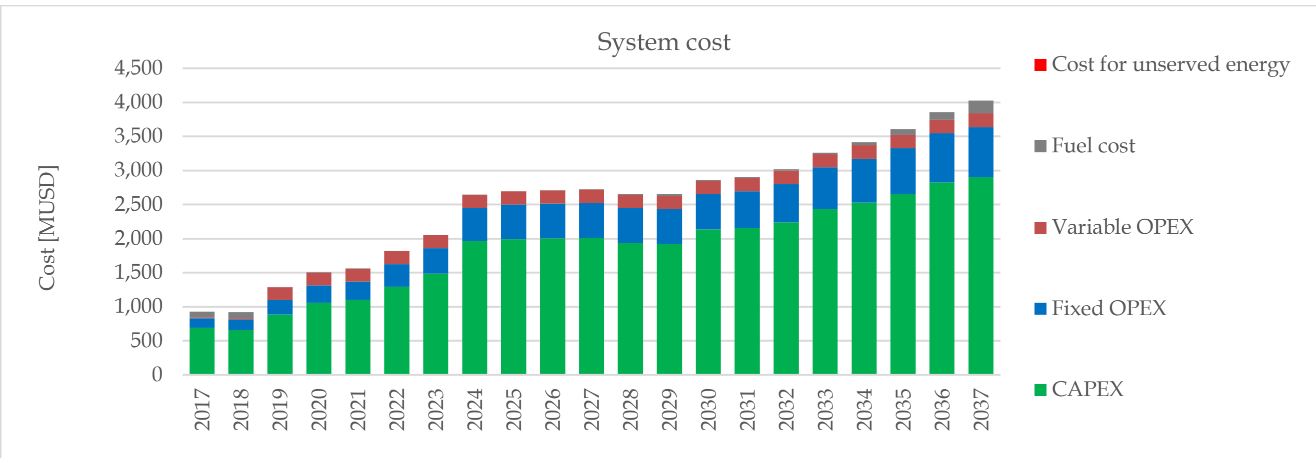


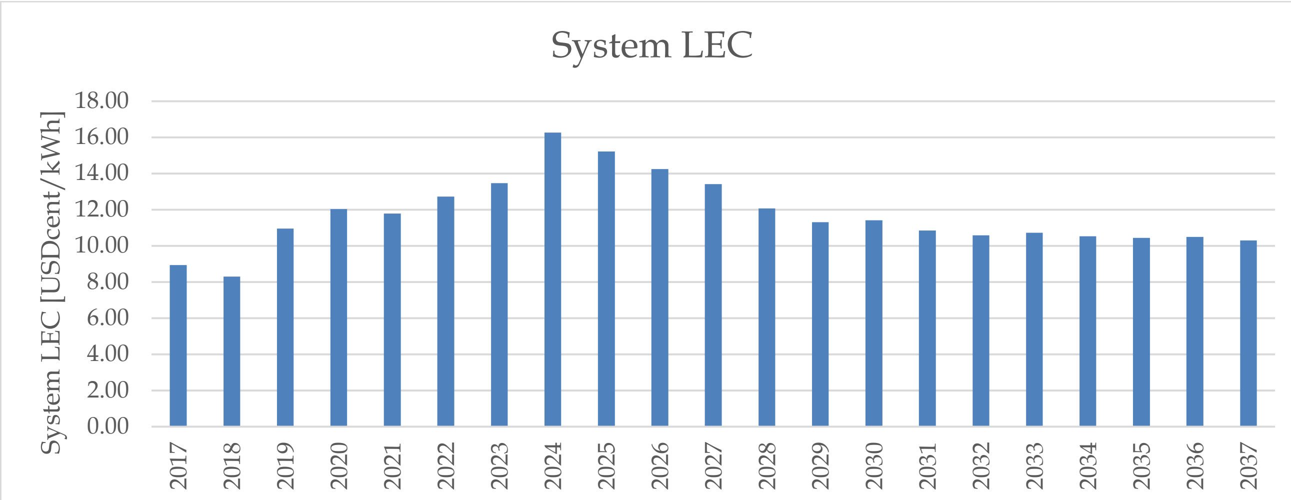
Figure 58: Annual capital requirements with Enhanced load growth scenario



9.1.3. Levelised Electricity Cost

Figure shows the levelised Cost of Electricity of the system from 2017-2037.

Figure 59: Levelized Electricity Costs, Medium Term Reference case



9.1.4. Cost Implications of the Plan

This scenario assumes the reference demand forecast and that the projects implemented will be selected by the system through balancing (costs of the project, energy needs per year). The energy generation will grow from 10,465 GWh in 2017 to 16, 327 GWh in 2024 while the peak load demand grows from 1,754MW in 2017, to 2,764MW in 2024.

Under this scenario, the total cost implication of the plan at the end of tariff control period is KShs 250,544,243,315. This includes, a sum of the capacity payment obligations for the capacity based Power Purchase Agreements of KShs 104,610,680,594 the Energy costs of KShs 130,077,537,593 Fuel cost of KShs 19,466,995,944. The total cost grows significantly from 84,861,047,719 in 2017. A summary of these costs is as shown in table 66.

During the period 2017-2024, average base retail tariff will need to be adjusted from the current KShs/kWh 16.20 (2017) to KShs/kWh 24.65 (2024), representing a 52% increase. Deemed Generated Energy payments for the period will average KShs 960,434,961.

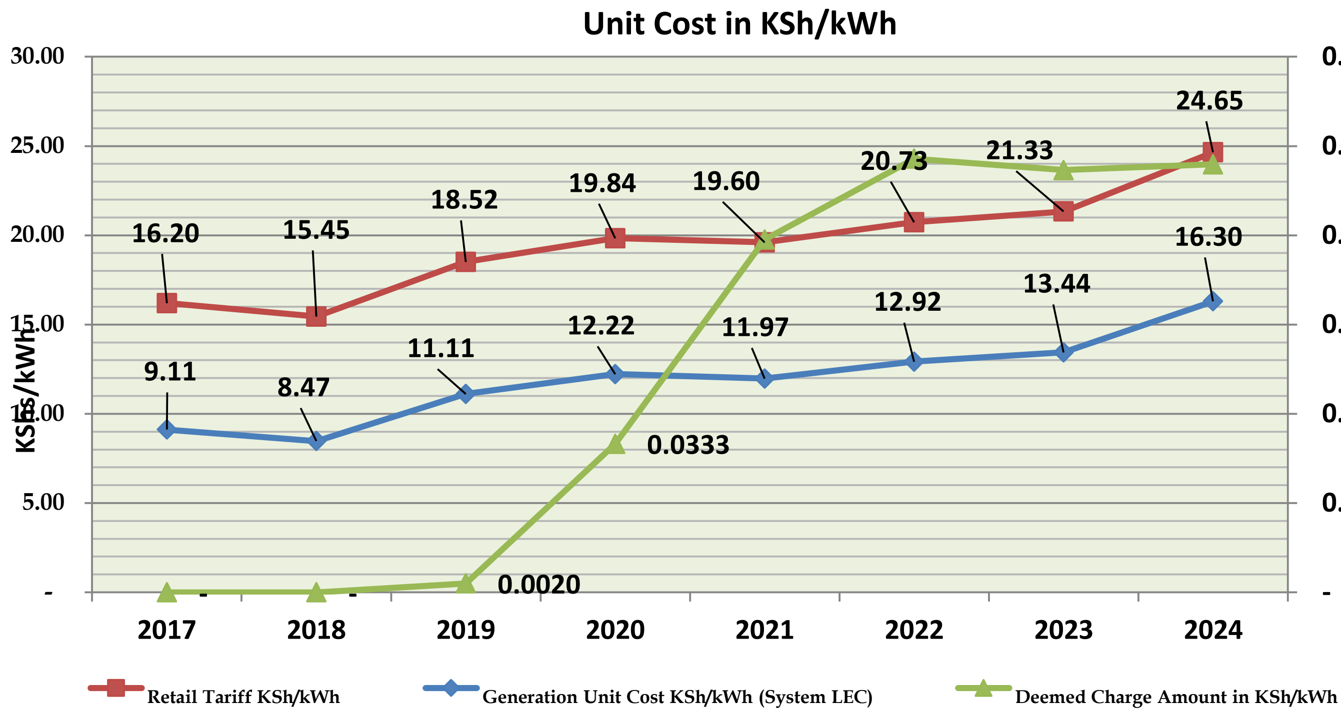
In the year 2017 and 2018, there are no deemed energy costs being paid, but it is anticipated that once Marco Borero, Kopere and Garissa solar projects are commissioned in 2019, the deemed energy costs will increase to KShs 26,272,078 in 2019. The Deemed energy costs will rise to KShs 1,265,289,995 in 2021 and KShs 1,973,476,527in 2024. The unit cost of DGE (KShs/kWh) is shown in the figure 60

The fuel costs will decreases slightly from KShs 17,451,274,113 in 2017 to KShs 14,223,530,127 in 2023 majorly due to a shift to renewable energy sources and the decommissioning of Iberafrica 56.35MW Old Plant, Embakasi and Muhoroni GT in 2019. However, this cost increases to 19,466,995,944 due to commissioning of geothermal power plants that attracts a significant steam charge.

Table 66: Summary of costs under the Fixed Medium Term Reference case

Year	2017	2018	2019	2020	2021	2022	2023	2024
Energy Purchased (kWh)	10,048,953,754	10,710,949,963	13,138,601,789	15,106,814,539	15,995,732,185	18,297,047,262	19,679,317,025	22,774,335,307
Energy Cost Amount Ksh	20,607,210,221	25,762,876,426	53,652,184,279	68,618,539,811	75,508,622,946	91,993,893,432	99,110,305,890	121,762,741,214
Fuel Cost Amount in KSh	17,451,274,113	18,370,642,870	7,196,074,375	9,740,912,507	10,370,463,922	12,851,432,995	14,223,530,127	19,466,995,944
Capacity Charge Amount in KSh	46,802,563,385	46,921,775,885	53,554,633,257	56,350,677,652	57,548,872,243	59,758,193,706	68,256,333,094	104,610,680,594
Deemed Charge Amount in KSh	0	0	26,272,078	502,872,242	1,265,289,995	1,567,602,057	1,651,034,633	1,973,476,527
Total Cost (KSh)	84,861,047,719	91,055,295,180	114,429,163,989	135,213,002,213	144,693,249,106	166,171,122,190	183,241,203,745	247,813,894,278
Generation Unit Cost USD Cent/kWh (System LEC)	8.94	8.30	10.89	11.98	11.73	12.67	13.18	15.98
Generation Unit Cost KSh/kWh (System LEC)	9.11	8.47	11.11	12.22	11.97	12.92	13.44	16.30
Forex Charge (est.) KSh/kWh	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Levies and inflation (est.) KSh/kWh	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
T&D costs (est.) KSh/kWh	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
Retail Tariff KSh/kWh	16.20	15.45	18.52	19.84	19.60	20.72	21.32	24.64
Retail Tariff US¢/kWh	15.88	15.15	18.15	19.45	19.22	20.31	20.90	24.15
Deemed Charge Amount in KSh/kWh	-	-	0.0020	0.0333	0.0791	0.0857	0.0839	0.0867

Figure 60: Tariff evolution under Medium Term Case-Reference Demand Growth



9.1.5. Generation expansion costs under vision scenario

Under this scenario, peak demand grows from 1,754MW (2017) to 3,342MW (2024). This constitutes about 90.5% increase in load growth. Consequently, capital costs increase from Ksh 84,861,047,719 (2017) 240,935,012,210 in 2024. This represents an average increase of 16% per annum. The growth in total costs under this scenario is significantly lower than in the reference scenario. Since committed projects are similar across the three demand scenarios, the difference in cost is brought about by the amount of DGE payements. In this scenarios, it is expected that demand will grow significantly to take up the increased supply thus resulting to lower excess energy and the corresponding DGE payments. Figure 61 shows the total Capital requirement for the generation expansion plan and specific requirements for different technologies for the period 2017– 2037 under the fixed medium term high demand growth scenario. Figure 62 shows the annual capital requirements for the period with optimal load growth. Geothermal production constitutes the highest amount of total costs.

Figure 61: Investment Costs for various technologies with high load growth

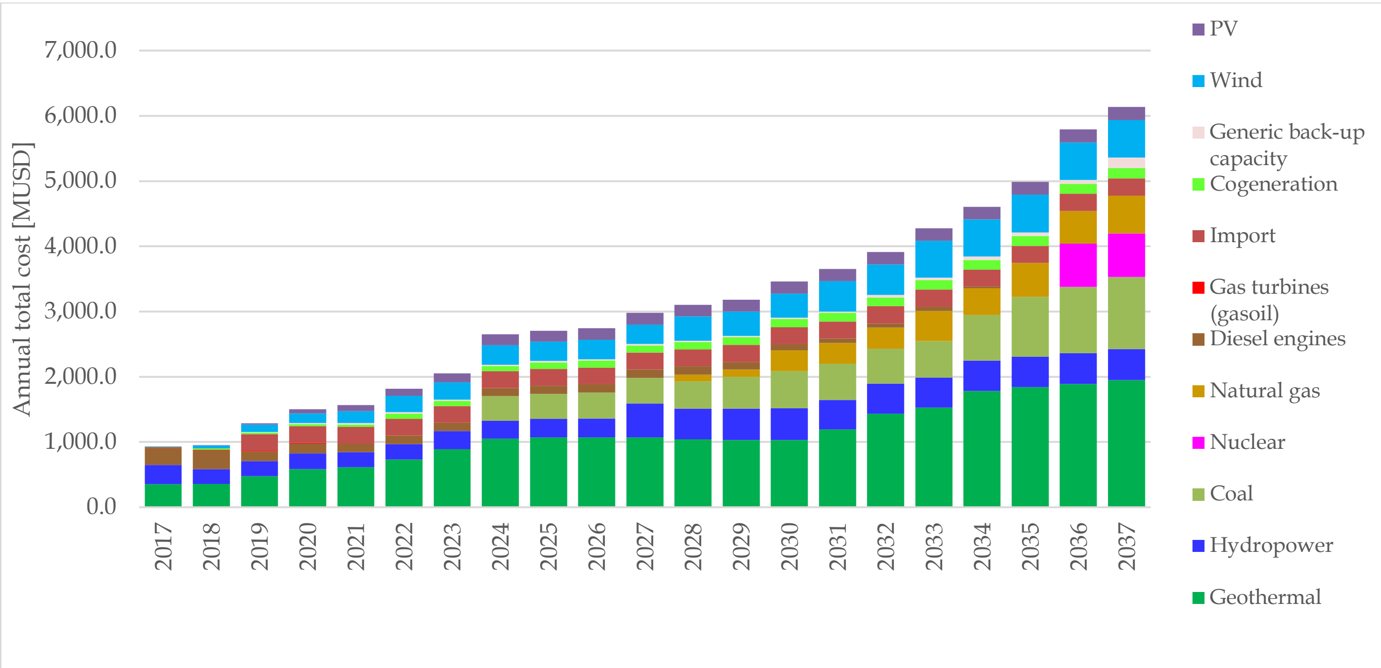
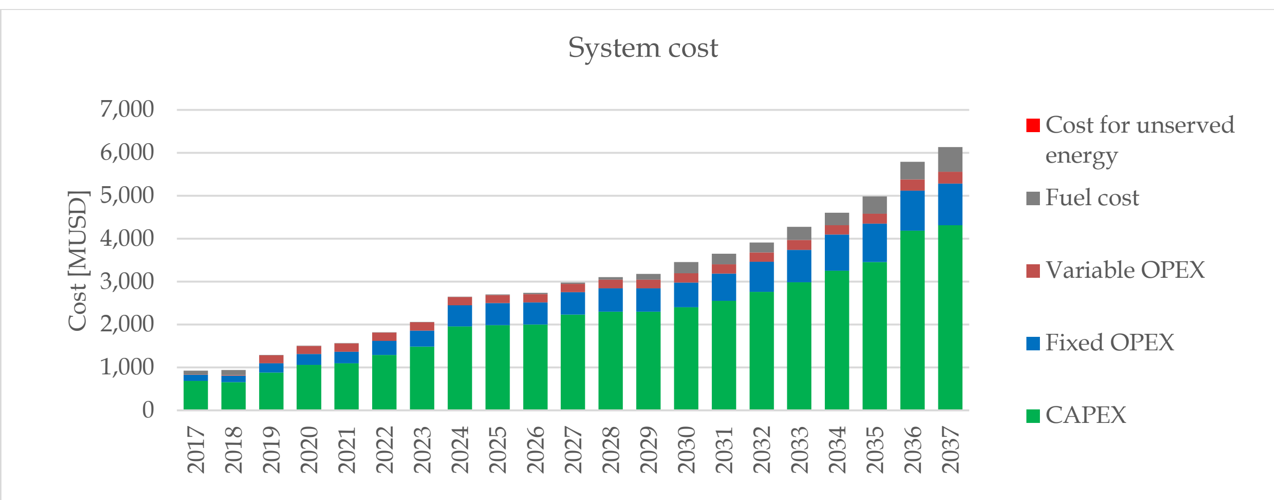


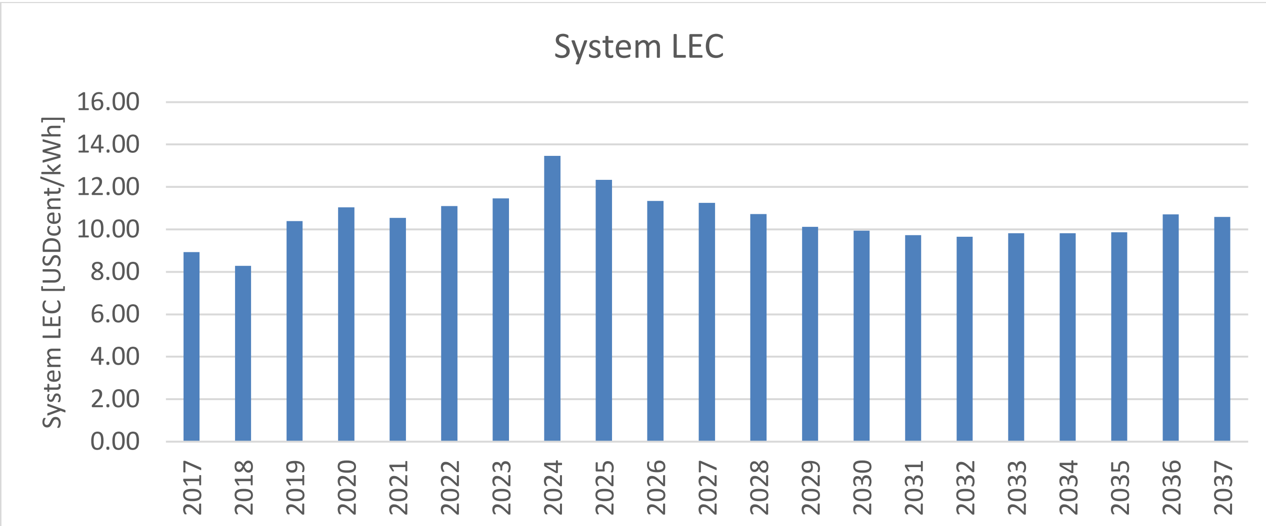
Figure 62: Annual capital requirements with Enhanced load growth scenario



9.1.6. Levelised Electricity Cost

The figure below shows the levelised Cost of Electricity of the system from 2017-2037.

Figure 63: LEC under high demand scenario



9.1.7. Cost Implications of the Plan

This scenario assumes the vision demand forecast and that the projects implemented will be selected by the system through balancing (costs of the project, energy needs per year). The energy generation will grow from 10,465 GWh in 2017 to 19,799 GWh in 2024 while the peak load demand grows from 1,754MW in 2017, to 3,342MW in 2024.

Under this scenario, the total cost implication of the plan at the end of tariff control period is KShs 240,935,012,210. This includes, a sum of the capacity payment obligations for the capacity based Power Purchase Agreements of KShs 100,063,198,744the Energy costs of KShs 118,332,782,146Fuel cost of KShs 20,603,920,125. The total cost grows significantly from 84,861,047,719in 2017. A summary of these costs is as shown in the table 67.

During the period 2017-2024, average base retail tariff will need to be adjusted from the current KShs/kWh 16.20 (2017) to KShs/kWh 21.65 (2024), representing a 34% increase. Deemed Generated Energy payments for the period will average KShs 863,727,109.

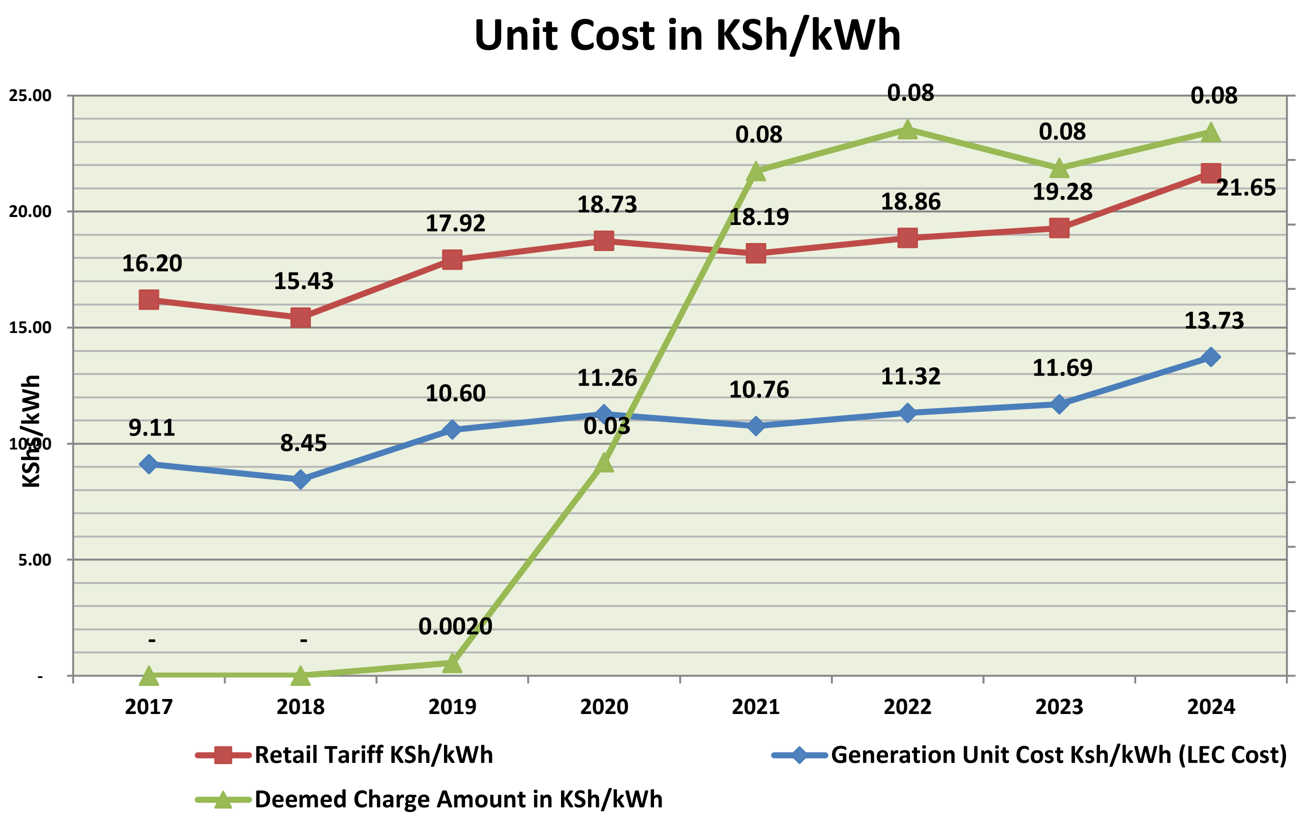
In the year 2017 and 2018, there are no deemed energy costs being paid, but it is anticipated that once Marco Borero, Kopere and Garissa solar projects are commissioned in 2019, the deemed energy costs will increase to KShs 26,272,078 in 2019. The Deemed energy costs will rise to KShs 1,265,289,995in 2021 and KShs 1,935,111,195in 2024. The unit cost of DGE (KShs/kWh) is shown in figure 64

The fuel costs will decreases slightly from KShs 17,451,274,113 in 2017 to KShs 15,986,598,943in 2023 majorly due to a shift to renewable energy sources and the decommissioning of Iberafrica 56.35MW Old Plant, Embakasi and Muhoroni GT in 2019. However, this cost increases to 20,603,920,125due to commissioning of geothermal power plants that attracts a significant steam charge.

Table 67: summary of cost under the Fixed MT vision scenario

Year	2017	2018	2019	2020	2021	2022	2023	2024
Energy Purchased (kWh)	10,048,953,754	10,927,655,741	13,198,365,298	15,195,735,282	16,159,900,758	18,490,097,557	20,477,624,593	22,940,614,760
Energy Cost Amount Ksh	20,607,210,221	25,749,607,342	53,645,820,482	67,991,218,328	75,099,454,815	91,706,894,569	98,004,096,966	118,332,782,146
Fuel Cost Amount in KSh	17,451,274,113	20,417,704,943	6,991,921,326	9,567,965,732	10,450,224,523	12,939,820,232	15,986,598,943	20,603,920,125
Capacity Charge Amount in KSh	46,802,563,385	46,802,563,385	53,435,420,757	56,231,465,152	57,429,659,743	59,638,981,206	67,277,941,516	100,063,198,744
Deemed Charge Amount in KSh	0	0	26,272,078	502,872,242	1,265,289,995	1,567,602,057	1,612,669,302	1,935,111,195
Total Cost (KSh)	**84,861,047,719**	**92,969,875,670**	**114,099,434,643**	**134,293,521,455**	**144,244,629,076**	**165,853,298,065**	**182,881,306,727**	**240,935,012,210**
Generation Unit Cost USD Cents/kWh (LEC Cost)	8.94	8.29	10.39	11.04	10.55	11.10	11.47	13.46
Generation Unit Cost Ksh/kWh (LEC Cost)	9.11	8.45	10.60	11.26	10.76	11.32	11.69	13.73
Fuel Cost Charge KSh/kWh	2.06	2.22	0.63	0.75	0.77	0.83	0.93	1.07
Generation Unit Cost KSh/kWh	11.00	10.51	11.02	11.79	11.31	11.93	12.39	14.53
Generation Unit Cost US¢/kWh	10.79	10.30	10.80	11.56	11.09	11.70	12.15	14.24
Forex Charge (est.) KSh/kWh	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Levies and inflation (est.) KSh/kWh	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
T&D costs (est.) KSh/kWh	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50

Figure 64: Tariff evolution under Fixed Medium Term-Reference Demand Growth



9.1.8. Generation expansion costs under Low Scenario

Under this scenario, peak demand grows from 1,754MW (2017) to 2,438MW (2024). This constitutes about 39% increase in load growth. Consequently, capital costs increase from Ksh 84,861,047,719 (2017) 252,102,789,292 in 2024. The growth in total costs under this scenario is significantly higher in the three scenarios. This is due to slow growth in demand and hence large amount of excess energy. Figure 65 shows the total Capital requirement for the generation expansion plan and specific requirements for different technologies for the period 2017– 2037 under the fixed medium term low demand growth scenario. Figure 66 shows the annual capital requirements for the period with optimal load growth. Geothermal production constitutes the highest amount of total costs.

Figure 65: Investment Costs for various technologies with optimized MT low scenario load growth

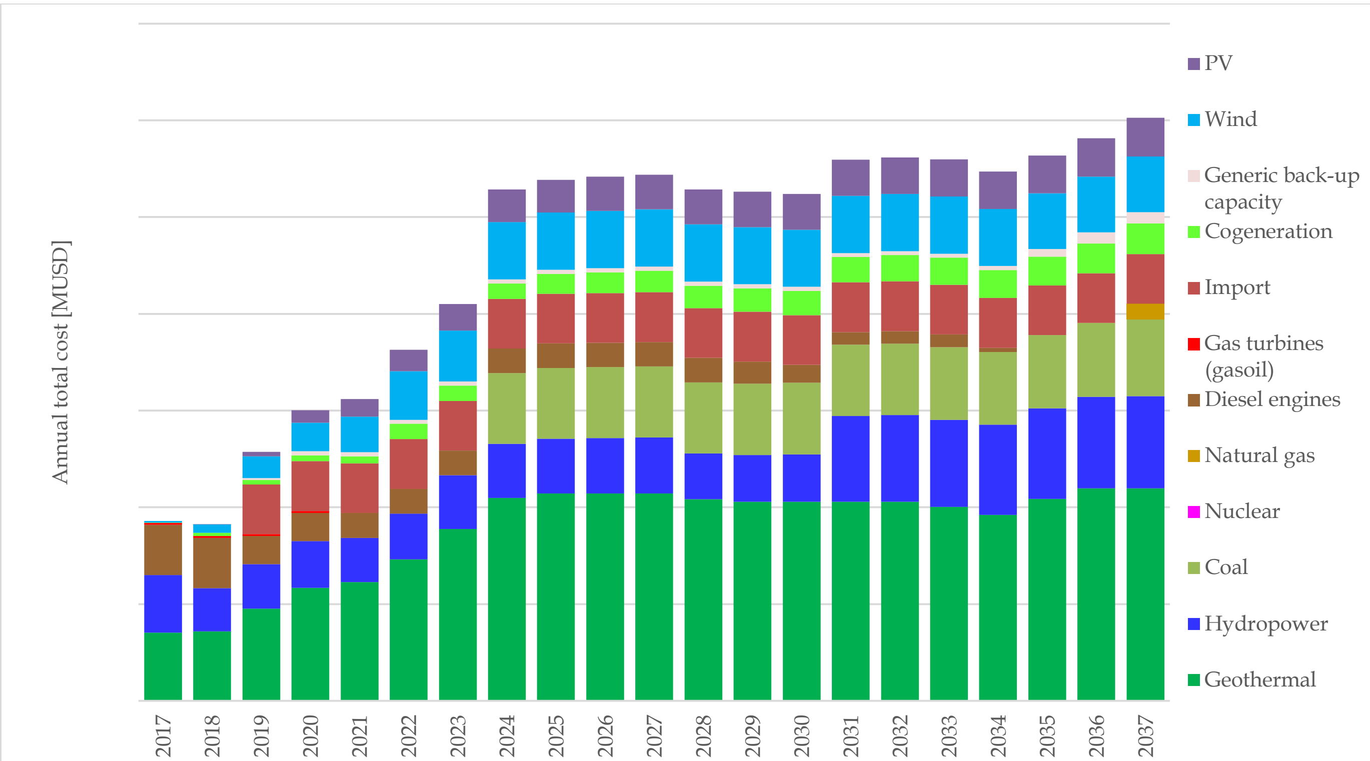
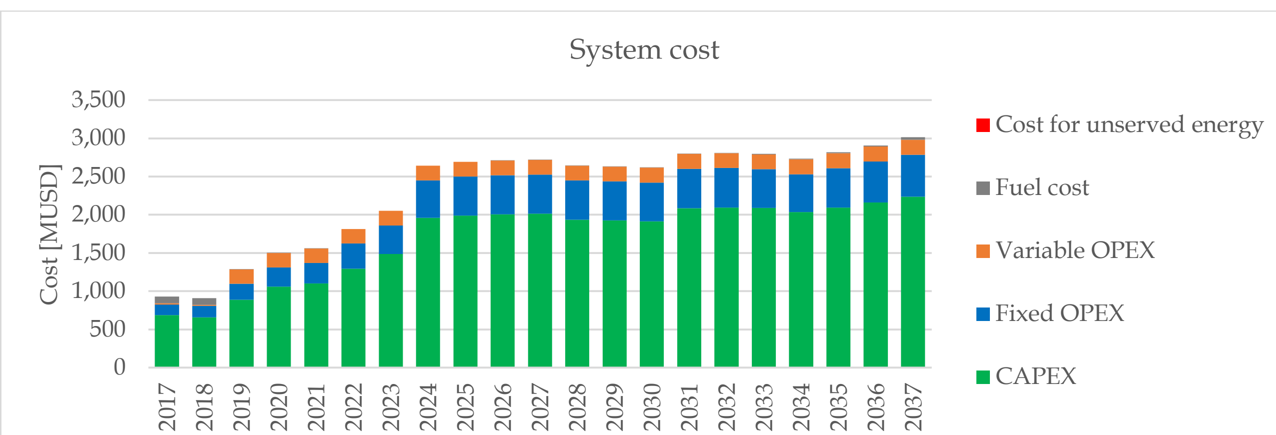


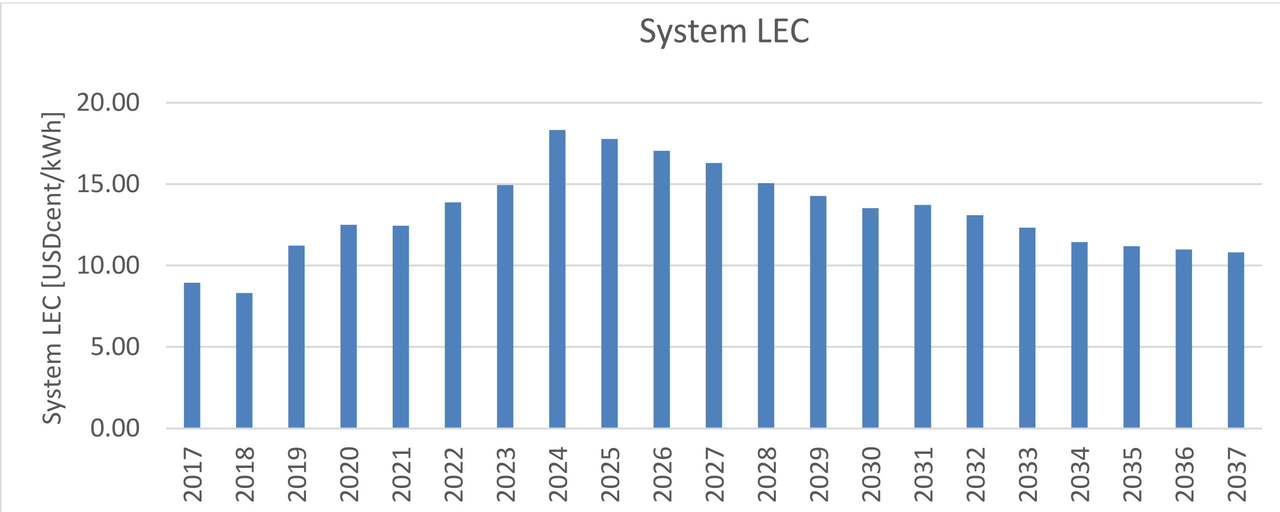
Figure 66: Annual capital requirements with low load growth scenario



9.1.9. Levelised Electricity Cost

Figure 67 shows the levelised Cost of Electricity of the system from 2017-2037.

Figure 67: LEC low demand growth MTP scenario



9.1.10. Cost Implications of the Plan

This scenario assumes the low demand scenario and that the projects implemented will be selected by the system through balancing (costs of the project, energy needs per year). The energy generation will grow from 10,465 GWh in 2017 to 14,503 GWh in 2024 while the peak load demand grows from 1,754MW in 2017, to 2,438MW in 2024.

Under this scenario, the total cost implication of the plan in 2017 is KShs 84,863,118,419. This includes, a sum of the capacity payment obligations for the capacity based Power Purchase Agreements of KShs 46, 802, 563, 385 the Energy costs of KShs 20,614,337,378 Fuel cost of KShs 17,446,217,656. The total cost grows significantly to 247,188,013,132 in 2024. A summary of these costs is as shown in the Table 68.

During the period 2017-2024, average base retail tariff will need to be adjusted from the current KShs/kWh 16.20 (2017) to KShs/kWh 27.41 (2024), representing a 69% increase. Deemed Generated Energy payments for the period will average KShs 872,170,111.

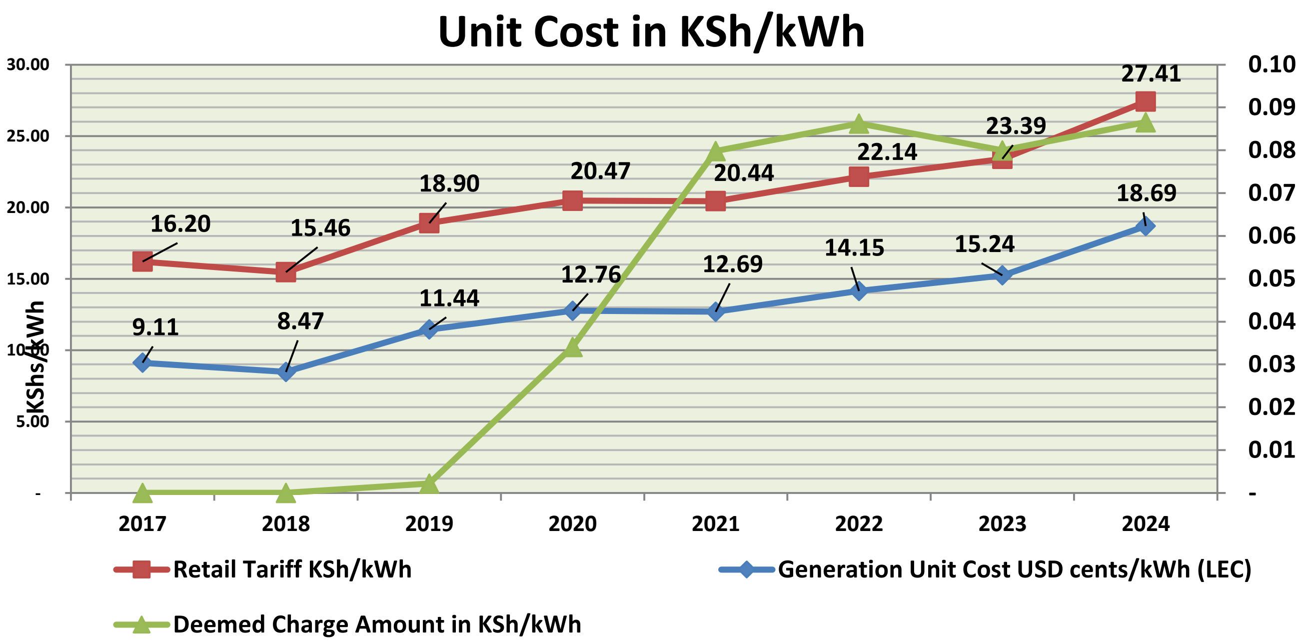
In the year 2017 and 2018, there are no deemed energy costs being paid, but it is anticipated that once Marco Borero, Kopere and Garissa solar projects are commissioned in 2019, the deemed energy costs will increase to KShs 25,930,802 in 2019. The Deemed energy costs will rise to KShs 1,278,867,053 in 2021 and KShs 1,948,688,253 in 2024. The unit cost of DGE (KShs/kWh) is also shown in figure 68

The fuel costs will decrease slightly from KShs 17,446,217,656 in 2017 to KShs 15,639,303,624in 2023 majorly due to a shift to renewable energy sources and the decommissioning of Iberafrica 56.35MW Old Plant, Embakasi and Muhoroni GT in 2019. However, the cost will rise to 19,036,986,724 in 2024 due to commissioning of geothermal power plants with significant steam charges

Table 68: summary of cost under the optimized reference case

Year	2017	2018	2019	2020	2021	2022	2023	2024
Energy Purchased (kWh)	10,051,176,943	9,743,261,600	12,051,336,636	15,155,499,146	16,021,237,105	18,334,297,366	20,338,325,362	22,518,433,570
Energy Cost Amount Ksh	20,614,337,378	21,105,299,447	46,000,256,554	69,398,289,092	75,600,367,322	92,151,625,255	97,504,225,505	106,291,269,038
Fuel Cost Amount in KSh	17,446,217,656	15,806,908,491	6,834,577,411	9,399,242,797	9,993,931,821	12,488,628,382	15,639,303,624	19,036,986,724
Capacity Charge Amount in KSh	46,802,563,385	46,921,775,885	53,554,633,257	56,970,738,979	58,168,933,570	60,378,255,033	72,453,112,468	124,825,845,278
Deemed Charge Amount in KSh	0	0	25,930,802	516,449,301	1,278,867,053	1,581,179,115	1,626,246,360	1,948,688,253
Total Cost (KSh)	**84,863,118,419**	**83,833,983,822**	**106,415,398,023**	**136,284,720,169**	**145,042,099,766**	**166,599,687,785**	**187,222,887,956**	**252,102,789,292**
Generation Unit Cost USD cents/kWh (LEC)	8.94	8.31	11.22	12.51	12.44	13.87	14.94	18.32
Generation Unit Cost Ksh/kWh (LEC)	9.11	8.47	11.44	12.76	12.69	14.15	15.24	18.69
Fuel Cost Charge KSh/kWh	2.06	1.93	0.67	0.74	0.74	0.81	0.91	1.01
Generation Unit Cost KSh/kWh	11.00	10.24	11.89	13.25	13.18	14.68	15.85	19.33
Generation Unit Cost US¢/kWh	10.78	10.04	11.66	12.99	12.92	14.39	15.54	18.95
Forex Charge (est.) KSh/kWh	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Levies and inflation (est.) KSh/kWh	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
T&D costs (est.) KSh/kWh	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
Retail Tariff KSh/kWh	16.20	15.46	18.90	20.47	20.44	22.14	23.39	27.41
Retail Tariff US¢/kWh	15.88	15.15	18.53	20.07	20.04	21.71	22.93	26.87
Deemed Charge Amount in KSh/kWh	-	-	0.0022	0.03	0.08	0.09	0.08	0.09

Figure 68: Tariff evolution under Low Demand Growth



10. MONITORING AND EVALUATION OF COMMITTED GENERATION AND TRANSMISSION PROJECTS

10.1. Introduction

The technical team of the LCPDP monitors the implementation of projects approved and under implementation, partly as part of the necessary input to the next planning cycle but also a process is surveillance intended to identify challenges that may need the attention of either management within the sector utilities or the Government in general for policy interventions or as the case may be.

1. The KEY objectives of monitoring these projects are to:
   - Track implementation and relate physical progress with planned targets with a view to identifying and addrerssing deviations
   - pick out implementation *red flags* that are an early warning for the sector policy makers, with the intension of making timely interventions where necessary.
   - The report acts as a continuous oversight tool for policy and regulatory interventions that may be necessary to ensure that energy demand, generation sequencing and power evacuation expand in synch

During the preparation of this report the team undertook 2 monitoring exercises, one each for generation and transmission for selected projects, the findings of which are summarized in this chapter. While the monitoring exercise involves physical visits to selected ongoing projects, an update of the entire portfolio of committed ongoing projects is made based on information collected from the implementing agencies

10.2. Generation monitoring

In the 2017/18 Financial year, there were 95 committed generation projects across the country for the period up to December 2024 considered the Medium Term period in this case. The distribution of the projects is as follows: 70 projects are being developed by Independent Power Producers (IPPs) amounting to 1590.05MW of additional capacity. One of the projects involves the importation of power from Ethiopia.

KenGen has commitments of 17 projects with an estimated capacity of 1,254MW. GDC which is dedicated to early development of geothermal resources has 7 committed projects with an estimated capacity of 394MW.

In total there are committed generation commitments amounting to 3,917.75MW at various stages of development up to December 2024.

10.2.1. Visited sites

The specific sites visited during the period were:

- Kleen Energy Power (6MW)
- KTDA Ltd, Lower Nyamindi (1.8MW)
- KTDA NorthMathioya (Metumi Power Plant) (5.6MW)
- Gura Mini Hydro (5.8MW)
- Garissa 50MW solar project
- GDC Geothermal sites in Baringo county namely Silali and Paka

10.2.2. Transmission monitoring

There are 140 committed and proposed transmission projects and associated infrastructure across the country for the period 2015-2035. Most if not all of these projects are under KETRACO.

During the financial year 2017/18 the LCPDP technical team for purpose of this monitoring exercise sampled and visited 6 key ongoing works on the Ethiopia-Kenya Electricity Highway project which is at an advanced stage of implementation. The site visited were as follows:

- Suswa Converter Sub-station, classified as Lot 1 of Kenya – Ethiopia project.
- Ethiopia-Kenya Line between Suswa in Narok County and Oldonyiro in Samburu County- Lot 6
- Ethiopia-Kenya line between Loglogo in Marsabit County and Oldonyiro in Samburu County-Lot 5
- Between Loglogo and Elle-bor border-point in Marsabit County- Lot 4
- The Olkaria II - Lessos – Kisumu transmission Line and Olkaria II sub-station extension-Lot 1

10.2.3. General observations/Challenges

Each of the projects monitored had unique challenges that are well articulated in the individual monitoring reports shared with sector utilities. The general ones however are

- It was observed that land issues remain thorny due to local communities' desire to benefit from proposed projects. There is a significant migration to proposed areas for steam development in the geothermal sites aimed at benefiting from resettlement programs. A clear policy from the Government on resettlement needs to be put in place to avoid unfair migration to proposed sites that eventually escalate project costs and sometimes delays implementation as communities become reluctant to move if their demands are not fully met.
- Access roads and other infrastructure in most of these sites are lacking and when inbuilt into project development costs end up increasing the cost of the project hence increasing the end user tariffs. Government may consider pre-investing in basic infrastructure in proposed sites to reduce the cost of power.
- The team noted significant delays in connecting generation plants to evacuation facilities once projects have been completed due to lack or poor planning for power evacuation.
- For the transmission lines, the common challenge was noted to be the wayleave acquisition. The contractors could not carry out the tower foundations preparation continuously since some private land owners and in particular community land could not be accessed in some sections. In some cases, the contractors and project clients realized there were family feuds in land utilization and compensation
- Cumbersome excavation due to very hard rocks, had to blast some locations.
- Difficult to access some locations due to rocky outcrops.
- Challenges associated with poorly financed contractors who abandon work midstream occasioning huge losses to the utilities involved

10.2.4. Specific reccomendations

- It is recommended that there is need for a coordinating forum between KPLC, KETRACO and other project proponents whether KENGEN or IPPs to resolve and harmonize generation plants with transmission evacuation. This will address the challenge witnessed about Lake Turkana wind and to a lesser extent about some of the geothermal capacity that comes ahead of evacuation lines and could occasion avoidable Deemed Generated Energy Payments

- Due to the heavy project portfolio both in generation and transmission, there is need for the sector to invest more heavily in development of technical skills and related capacities on project supervision, monitoring and evaluation
- It is critical for the Government to release necessary project finances to KETRACO in a timely manner to enable the Company expedite pending wayleave compensation issues.
- The government should engage County Governments to facilitate quick acquisition of wayleaves
- The government through the Ministry of Energy needs to push for enactment of the Compulsory land acquisition primary legislation to facilitate easier implementation of strategic national projects such as power infrastructure. Huge losses are being occasioned by project delays sometimes in the form of Deemed Generated Energy (DGE) payments that could be avoidable with timely projects completion

11. IMPLICATIONS OF LCPDP SCENARIOS FOR NATIONAL CLIMATE CHANGE OBJECTIVES

11.1. Introduction

The combustion of fossil fuels for power generation causes the emissions of greenhouse gases (GHGs), a primary cause of climate change. Whilst Kenya's electricity generation mix generally has a relatively low emissions intensity, medium speed diesel, natural gas and coal plants are significant emitters of GHG emissions.

Kenya has committed to reducing annual GHG emissions by 30% by 2030, compared to the business-as-usual baseline growth of emissions. This target is equivalent to a maximum limit of GHG emissions in 2030 of 100 MtCO2e. This target was communicated in Kenya's Nationally Determined Contribution (NDC) to the Paris Agreement, the global climate change agreement signed by 197 Parties of the United Nations Framework Convention on Climate Change (UNFCCC) in 2015. Kenya's ambition to tackle climate change is enshrined in the 2016 Climate Change Act (CC Act), which requires all government institutions to mainstream climate change objectives in their planning and sectoral strategy development processes (CC Act, Paragraph 15.5).

Figure 76 indicates the implications of the 2017-2037 LCPDP pathway for GHG emissions, in the period up to 2035. The Figure shows that under the LCPDP pathways, emissions will reduce to near-zero by 2019 due to the phase out of inefficient medium speed diesel plants. Emissions will increase again due to the planned opening of the coal power plant in Lamu in 2024. However, even after the opening of the 981 MW coal plant, the LCPDP generation projections show very limited use of coal for generation under the reference demand scenario, leading to average annual emissions of 0.3 MtCO2e in 2030 and 1.08 in 2035. Under the 2017-2037 LCPDP vision scenario, emissions would increase to 4.1 MtCO2e in 2030 and 6.1 MtCO2e in 2035.

This trend is in stark contrast to historical estimates from the 2013 LCPDP report, in which major new investments in coal, oil and gas were projected to increase electricity sector emissions to over 40 MtCO2e. Adjusted demand forecasts and increased installation of wind, solar PV and geothermal technologies has brought the electricity sector more in line with national climate change objectives.

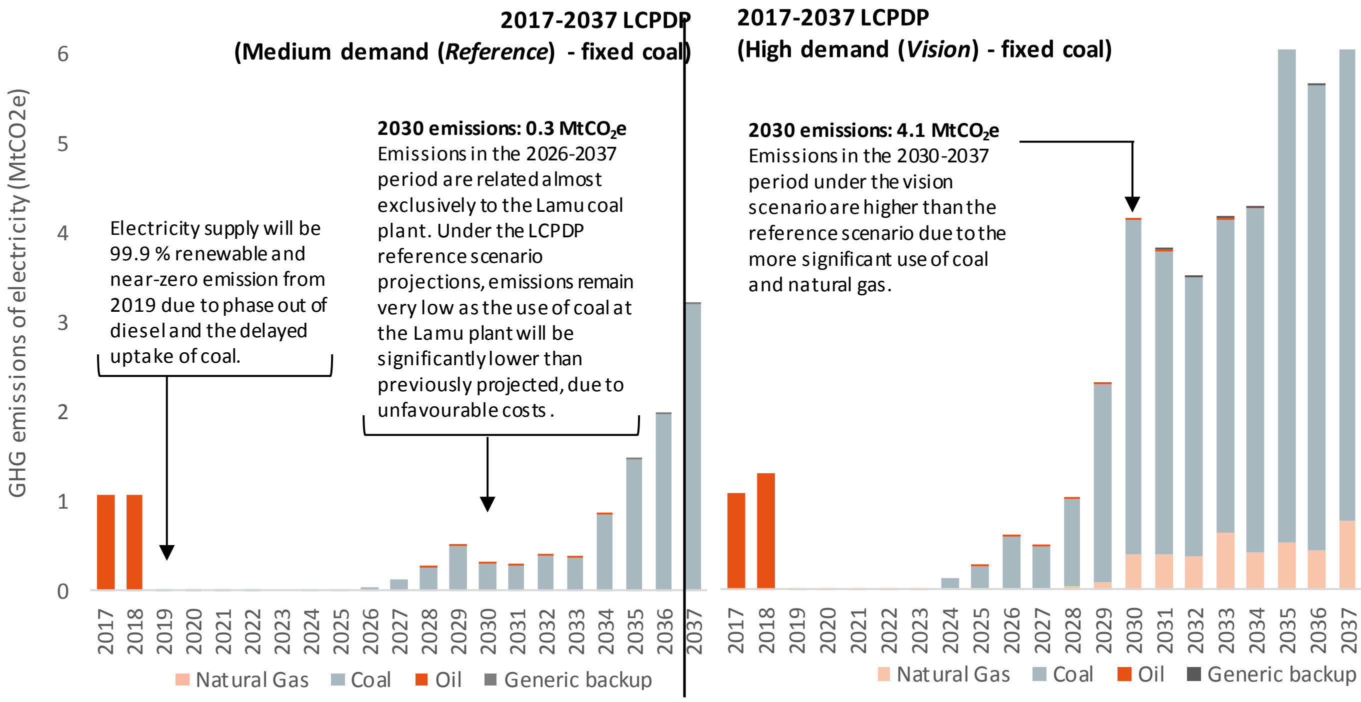


Figure 69: 2015-2035 GHG emissions from the 2017-2037 LCPDP scenario.

The left chart in figure 76 shows the LCPDP generation plan with the medium (reference) demand profile, and right chart with the high (vision) demand profile. Both charts represent the fixed medium term (fixed coal) scenario for supply.

Figure 70: shows how the projected electricity supply sector emissions in the period 2015-2030 relate to the national target for limiting the growth of GHG emissions to 100 $MtCO_2e$ by 2030 (Kenya's NDC), when combined with the emissions from other sectors. The Figure shows that the projected generation pathways of the 2017-2037 LCPDP would have an insignificant impact on national GHG emissions up to 2028. However, under the *vision* scenario – total national GHG emissions would increase to 108.7 $MtCO_2e$ in 2030, 9% higher than the 2030 limit of 100 $MFtCO_2e$, with electricity supply accounting for approximately 4% of these national GHG emissions.

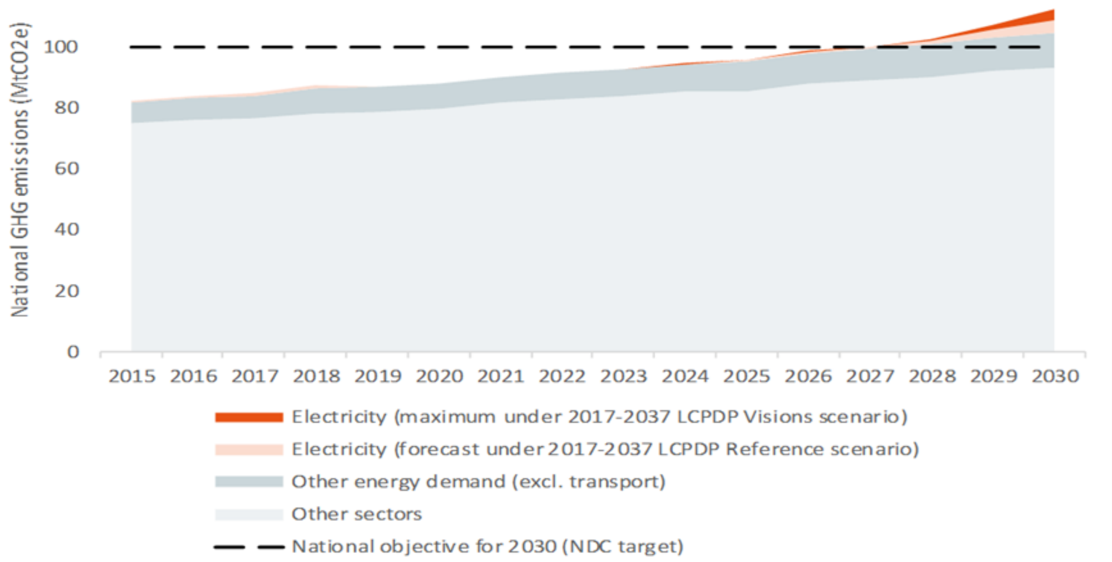


Figure 70: Total GHG emissions from all sectors in Kenya with the LCPDP reference pathway

The 2017-2037 LCPDP projections have significant implications for mitigation options in the electricity supply sector. The current context shows that emissions from the electricity sector will be lower than previously estimated, and that there is a more limited scope for further mitigation measures in the electricity sector, if the role of coal remains low, as projected in the LCPDP reference.

The projections in Figure 69: show that the main measure required to ensure near-zero emissions from the sector would be the restricted use or avoided installation of coal and natural gas capacity, through further expansion of other electricity supply options and/or energy efficiency improvements; annual emissions in the years around 2030 could deviate between zero and 9.1 $MtCO_2e$, depending entirely on the rate of the utilisation of the installed coal and natural gas capacities, so the mitigation potential of alternative technologies would be a maximum of 9.1 $MtCO_2e$ per year if they entirely displace generation from coal and natural gas capacities.

In the case that developments proceed along the lines of the LCPDP *reference* scenario, with very limited use of coal and no use of natural gas, climate change mitigation targets would be met at the electricity supply sector level and also almost at the national level, with only moderate further reductions from other sectors required to meet the national objective for 2030, as shown in Figure 77.

12. ANNEXES

Annex 1: Transmission lines and substations investment sequence

PROJECTS COMMITTED & EXPECTED BY 2018			
S/No.	**Transmission Line**	**Length (KM)**	**Projected Cost (USD Million)**
1	Loiyangalani – Suswa 400kV line	430	161
2	Nairobi Ring substations (Malaa)	-	46.17
3	Nanyuki – Isiolo 132kV (cable pending)	70	54.25
4	Turkwel – Ortum – Kitale 220kV	135	18.59
5	Isinya – Namanga 132kV	80	12.62
6	Wote – Sultan Hamud 132kV	42	6.75
7	Mwingi – Kitui 132kV	60	9.68
8	Kitui – Wote 132kV	60	9.68
9	Nanyuki – Rumuruti 132kV (cable pending)	79	20.27
10	Lessos – Kabarnet 132kV	65	16.55
11	Olkaria – Narok 132kV	68	17.45
12	Embakasi-Athi River (Cable section repairs) 220kV	6.75	1.56
13	Olkaria – Lessos – Kisumu 400/220/132kV	279	156.05
14	**2018 TOTALS**	**1,374.75**	**530.62**
PROJECTS EXPECTED BY 2019			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Kenya – Tanzania line 400kV	100	65.02
2	Sondu – Homa Bay (Ndhiwa) – Awendo 132kV	96	28.80
3	System Reinforcement (Isinya 400/220kV & Nairobi North 220/66kV substation)	-	45
4	Eastern Electricity Highway Project 500kV	612	509.95
5	Rabai –Bamburi- Kilifi 132kV	56	30.95
6	Voi –Taveta 132kV	110	40.69

7	Mariakani Substation 400/220kV	-	30
8	Awendo –Isebania 132kV	39	23.57
9	Meru –Maua 132kV	35	25.63
10	Second Circuit LiLo Nakuru West –Lanet 132KV	1.5	3.54
11	Olkaria IV –Olkaria V 220KV	10	16.324
	2019 TOTALS	**1,059.5**	**819.47**
PROJECTS EXPECTED BY 2020			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Lessos – Tororo 400kV	132	49.98
2	Olkaria 1 AU- Naivasha 220KV	22.5	16.28
3	Olkaria 2-Olkaria 3 220KV	7	9.54
4	Olkaria 1 AU-Olkaria VI 220KV	5	14.76
5	Juja-Ruaraka 132KV poles to towers so is webuye	6.5	1.71
6	Musaga-Webuye 132KV	18	2.79
7	Thika 400/220KV –Thika 220/132KV	1	0.28
8	Garsen -Bura-Hola –Garissa 220kV	260	154.33
9	Sultan Hamud – Loitoktok 132kV	120	46.75
10	Isinya – Konza 400kV	38	48.61
11	Rumuruti – Maralal 132kV	148	46.84
12	Malindi(Kakoneni) – Kilifi* 220kV	60	50.28
13	400kV Gilgil, Kimuka and Lessos substations	-	134.52
14	Kamburu – Embu – Thika 220kV	153	154.97
15	Uplands (Limuru) substation	-	15.98
16	Ishiara – Chogoria 132kV	40	27.28
17	Galu - Lunga Lunga 132kV	66	28.32
18	Kisumu - Kakamega – Musaga 220kV	73	79.45

19	Galu T-off – Likoni 132kV	15	13
20	Menengai - Olkalou – Rumuruti 132kV	70	34.34
21	Dongo Kundu – Mariakani 400kV	50	52
22	Narok – Bomet 132kV	88	34.62
23	Kipevu-Mbaraki	6.5	13.1
24	**2020 TOTALS**	**1,379.5**	**1,029.73**
	PROJECTS EXPECTED BY 2021		
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Longonot –Olkaria VII 220KV	20	22.92
2	Longonot –Suswa PP 220KV	20	22.92
3	Lamu –Lamu Coal 220KV	20	20.37
4	Malaa-Lamu 400KV	520	487.65
5	Makindu substation	-	32.05
6	Gilgil – Thika – Malaa– Konza 400kV	205	291.25
7	Kitui - Mutomo – Kibwezi 132kV	132	59.34
8	Kiambere - Maua – Isiolo 220kV	145	120.94
9	Voi Substation 400/132kV	-	31.93
10	**2021 TOTALS**	**1,062**	**1089.37**
	PROJECTS EXPECTED BY 2022		
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Rumuruti – Kabarnet 132kV	111	42.19
2	Menengai – Rongai 400kV	45	35.16
3	Webuye - Kimilili – Kitale 132kV	73	35
4	Sotik – Kilgoris 132kV	50	22
5	Ngong (Kimuka) – Magadi 220kV	88	74.12

6	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	80	51.74
7	Githambo- Othaya-Kiganjo 132kV	72	34.9
8	6 Substation Reinforcement works	-	29.72
9	Kiambere-Karura 220KV	20	22.92
10	Longonot –Olkaria VIII 220KV	25	25.63
11	Malaa – Thika Road 220kV	30	19.177
12	Mariakani – Kwale 220kV Line	55	40
13	6 Substation Reinforcement works	-	29.72
14	Electrification of SGR Phase 1	57.5	50.66
15	**2022 TOTALS**	**706.5**	**512.94**
PROJECTS EXPECTED BY 2023			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Baringo – Rongai 400kV	150	25.96
2	Baringo – Lokichar 220kV	245	80
3	Rangala – Busia 132kV	34	15.1
4	Rongai – Kericho 220kV	70	62.79
5	Longonot –Olkaria IX 220KV	25	25.63
6	Isiolo – Garba Tula – Garissa 220kV	320	168.78
7	Garissa – Habasewin – Wajir 220kV	330	176.17
8	Myanga – Busia 132kV	27	23.91
9	Rangala - Bondo – Ndigwa 132kV	57	33.85
10	Isiolo – Baringo220kV	323	149.83
11	Rongai - Kilgoris (Lake Victoria Ring) 400kV	235	148
12	**2023 TOTALS**	**1,816**	**910.02**
PROJECTS EXPECTED BY 2024			

	Transmission Line	Length (KM)	Projected Cost (USD Million)
1	Kisumu(Kibos) – Bondo 132kV	140	63.03
2	Malindi(Kakoneni) – Galana 220kV Line	60	66.12
3	**2024 TOTALS**	**200**	**129.15**
PROJECTS EXPECTED BY 2025			
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Loiyangalani – Marsabit 400kV	136	65.67
2	Ndhiwa (Ongeng)- Sindo 132kV	39	19.15
3	Ndhiwa (Ongeng)- Karungo Bay 132kV	50	21.08
4	Isiolo – Marsabit 220kV	240	120.29
5	Kericho –Chemosit 220KV	30	40.96
6	Eldoret –Baringo 220KV	95	76.27
7	Loiyangalani – Lodwar 220kV	180	83.21
8	Eldoret – Kapsowar 132kV	110	71
9	Bomet – Olenguruone – Rongai 132kV	165	78.47
10	Kilgoris – Lolgorien – Kihancha 132kV	80	51.74
11	Awendo– Gogo – Karungu Bay 132kV	48	25
12	Lessos– Kapsabet 220kV	27	36
13	Turkwel – Lokichar – Lodwar 220kV	120	60
14	Lodwar – Lokichoggio 220kV	190	78
15	Isiolo – Maralal 220kV	150	65
16	Malindi-Garsen 220kV	104	40.06
17	Garsen-Lamu 220kV	96	37.5
18	**2025 TOTALS**	**1,860**	**969.4**
PROJECTS EXPECTED BY 2026			

	Transmission Line	Length (KM)	Projected Cost (USD Million)
1	Electrification of SGR Phase 2	57.5	50.66
2	Thika –Thika Rd 220kV	1	23.16
3	Thika – HG Falls 400kV	200	180.34
4	**2026 TOTALS**	**258.5**	**254.16**
	PROJECTS EXPECTED BY 2031		
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Chavakali Substation 220/33	-	18.32
2	Musaga Substation 400/220	-	37.38
3	Dandora –Juja Rd 132kV	5	12.14
4	Menengai-Kisii 220kV	150	101.29
5	Eldoret-Eldoret North 132kV	5	13.27
6	**2031 TOTALS**	**160**	**182.4**
	PROJECTS EXPECTED BY 2032		
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Gilgil Substation 132/33kV	1.5	12.83
2	**2032 TOTALS**	**1.5**	**12.83**
	PROJECTS EXPECTED BY 2035		
	Transmission Line	**Length (KM)**	**Projected Cost (USD Million)**
1	Matasia-Ngong(Kimuka) 220kV	10	25.47
2	Baringo-Maralal 132kV	165	48.11
3	**2035 TOTALS**	**175**	**73.58**

PROPOSED TARGET NETWORK PROJECTS INVESTMENTS

S/n	PROJECT	Length (km)	Cost (USD)	EXPECTED YEAR
1	400kV Loiya/Suswa LiLo to Baringo	60	61	2031
2	220kV Ruaraka-Uplands-Naivasha	100	79.5	2021
3	220/132kV Gilgil and 132kV Naivasha/Lanet LiLo	12	20.7	2021
4	220kV Rongai-Kericho/Chemosit-Kisii/Rongo	135	117	2022
5	220kV Kilgoris-Rongo/Kisii 132kV Awendo/Kisii LILO	50	61.7	2025
6	220kV Wajir-Mandera	250	159	2027
7	220kV Marsabit-Moyale	180	120	2027
8	400kV Longonot-Thika	78	69.1	2030
9	220kV Bamburi Cement-Weru	30	35	2025
10	220kV Bamburi Cement-Mariakani	40	15	2027
	TOTALS	**935**	**738**	

ANNEX 2: SIMULATION RESULTS ANALYSIS – TARGET NETWORK 3 (TN3) TRANSMISSION SYSTEM LOSSES ANALYSIS (132kV TO 500kV HVDC)

YEAR	Generation (MW)	LOAD FACTOR	LOSS LOAD FACTOR	POWER LOSSES (MW)	POWER LOSSES (%)	ENERGY LOSSES (GWh)	ENERGY LOSSES (%)
2018	1855.9	0.7	0.553	62.13	3.35%	300.98	2.64%
2019	2010.9	0.7	0.553	79.44	3.95%	384.83	3.12%
2020	2110.6	0.7	0.553	67.1	3.18%	325.05	2.51%
2021	2211.6	0.7	0.553	65.88	2.98%	319.14	2.35%
2022	2355.8	0.7	0.553	69.05	2.93%	334.50	2.32%
2025	3126.5	0.7	0.553	88.36	2.83%	428.04	2.23%
2030	4457.4	0.7	0.553	142.93	3.21%	692.39	2.53%
2035	6179.3	0.7	0.553	208.54	3.37%	1010.23	2.67%
2037	7051.4	0.7	0.553	253.02	3.59%	1225.70	2.83%

It is noted that the losses slightly rise in the year 2019 but starts going down progressively when more 220kV and 400kV lines are commissioned upto the year 2025. As the demand grows, the losses start going upto the target network year.

CONTIGENCY ANALYSIS AND SYSTEM CONSTRAINTS

2018 SYSTEM-BASE CASE CONSTRAINTS

Overloaded lines	% Loading	Mitigation
Rabai-Bamburi line	157.3	Reconstruction of the line using a big conductor and on steel towers
Naivasha-Olkaria I AU	113.1	Olkaria-Lessos 220kV line, Olkaria-Narok Line, Charging the line at 220kV
Muhoroni-Chemosit 132 kV line	104.0	Olkaria-Narok line

2019 SYSTEM CONTIGENCY ANALYSIS (TARGET NETWORK 3)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Juja-Dandora 132kV line	Second circuit of Dandora-Juja line	108.98	220kV Naivasha-Juja Rd line proposed

Loss of one circuit of Suswa-Nairobi North 220 kV line	Second circuit of Suswa- Nairobi North line	141.76	220kV Naivasha-Juja Rd line proposed
Loss of one circuit of SuswaIsinya line	Dandora - Embakasi line	110.67	220kV Naivasha-Juja Rd line proposed
	Circuit one Nairobi North-Suswa line	102.83	220kV Naivasha-Juja Rd line proposed
	Circuit two Nairobi North-Suswa line	102.83	220kV Naivasha-Juja Rd line proposed
Loss of Malaa-Kiambere line	Overloading of Dandora - Embakasi line	103.19	Completion of the other Nairobi 220kV Ring projects (Athi River, Kimuka, Malaa and Thika Road

2020 SYSTEM CONTIGENCY ANALYSIS (TARGET NETWORK 3)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of circuit one Juja Road-Ruaraka Tee 1 132 kV line	overload of circuit two Juja Road-Ruaraka Tee 1 132 kV line	100.7	220kV Naivasha-Juja Rd line proposed with a substation in Ruaraka
Loss of one circuit of Suswa-Nairobi North line	overload of one circuit of Suswa-Nairobi North line	114.46	220kV Naivasha-Juja Rd line proposed with a substation in Upland, Ruaraka and Juja

2021 SYSTEM CONTIGENCY ANALYSIS (TARGET NETWORK 3)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Juja Road-Ruaraka	Second circuit of Juja Road-Ruaraka	108.15	220kV Naivasha-Juja Rd line proposed with a substation in Upland, Ruaraka and Juja

Loss of one circuit of Suswa- Nairobi North 220 kV line	Second circuit of Suswa- Nairobi North line	107.56	220kV Naivasha-Juja Rd line proposed with a substation in Upland, Ruaraka and Juja
Loss of one circuit of Olkaria IV -Suswa line	Second circuit of Olkaria IV -Suswa line	123.13	Double circuit 220kV line proposed between Olkaria IV and Olkaria 1AU

2022 SYSTEM CONTIGENCY ANALYSIS (TARGET NETWORK 3)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Olkaria IV - Suswa line	Second circuit of Olkaria IV -Suswa line	119.63	Double circuit 220kV line proposed between Olkaria IV and Olkaria 1AU

2030 SYSTEM CONTIGENCY ANALYSIS (WITH TARGET NETWORK)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Malaa -Embakasi	Second circuit of Malaa -Embakasi	103.92	Connecting Malaa with Thika Rd Substation
Loss of one circuit of Garsen-Lamu	Second circuit of Garsen-Lamu	100.52	400kV line between Lamu and Mariakani

2035 SYSTEM CONTIGENCY ANALYSIS (WITH TARGET NETWORK)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Malaa -Embakasi	Second circuit of Malaa - Embakasi	106.23	Connecting Malaa with Thika Rd Substation
Loss of one circuit of Garsen-Lamu	Second circuit of Garsen-Lamu	102.35	

Loss of one circuit of Garsen-Malindi	Second circuit of Garsen-Malindi	109.02	
Loss of one circuit of Malindi-Weru Switch Station	Second circuit of Malindi-Weru Switch Station	104.50	
Loss of one circuit of Olkaria 4-Olkaria 1AU	Second circuit of Olkaria 4-Olkaria 1AU	140.08	Line to Longonot Substation
Loss of one circuit of Isinya-Athi River	Second circuit of Isinya-Athi River	103.48	
Loss of one circuit of Kipevu-Mbaraki	Second circuit of Kipevu-Mbaraki	119.78	
Loss of Galu-Likoni Tee	Titanium-Kwale Sugar	100.92	
Loss of Titanium-Kwale Sugar	Rabai-Likoni Tee	114.72	
Loss of Kwale Sugar-Shimoni	Rabai-Likoni Tee	106.18	
Loss of Shimoni-Lungalunga	Rabai-Likoni Tee	110.25	
Loss of Rabai-Jomvu	Rabai-Kipevu Lines	106.77	

2037 SYSTEM CONTIGENCY ANALYSIS (WITH TARGET NETWORK)

Contingency	Overloaded lines	% Loading	Mitigation
Loss of one circuit of Malaa -Embakasi	Second circuit of Malaa -Embakasi	106.23	Connecting Malaa with Thika Rd Substation
Loss of one circuit of Dandora-Juja Rd	Second circuit of Dandora-Juja Rd	118.25	

Loss of one circuit of Mombasa Cement-Kilifi	Second circuit of Mombasa Cement-Kilifi	114.72	
Loss of one circuit of New BamburiBamburi Cement	Second circuit of New BamburiBamburi Cement	108.14	
Loss of of KipevuRabai 1	Kipevu-Rabai 2 line	116.90	
Loss of one circuit of Kibos-Kisumu	Second circuit of Kibos-Kisumu	102.50	
Loss of one circuit of Soilo-Menengai	Second circuit of Soilo-Menengai	100.31	
Loss of one circuit of Malindi-Weru Switch Station	Second circuit of Malindi-Weru Switch Station	125.74	400kV line between Lamu and Mariakani
Loss of one circuit of Olkaria 4-Olkaria 1AU	Second circuit of Olkaria 4-Olkaria 1AU	135.00	Line to Longonot Substation
Loss of one circuit of Olkaria 1AU-Naivasha	Second circuit of Olkaria 1AU-Naivasha	115.42	Line to Longonot Substation
Loss of Rabai-Jomvu	Rabai-Kipevu Lines	100.44	

ANNEX 3 LOSSES TABLES TN 3

TRANSMISSION SYSTEM ANALYSIS TN 3

YEAR	Generation (MW)	LOAD FACTOR	LOSS LOAD FACTOR	POWER LOSSES (MW)	POWER LOSSES (%)	ENERGY LOSSES (GWh)	ENERGY LOSSES (%)
2018	1855.9	0.7	0.553	62.13	3.35%	300.98	2.64%
2019	2010.9	0.7	0.553	79.44	3.95%	384.83	3.12%
2020	2110.6	0.7	0.553	67.1	3.18%	325.05	2.51%
2021	2211.6	0.7	0.553	65.88	2.98%	319.14	2.35%
2022	2355.8	0.7	0.553	69.05	2.93%	334.50	2.32%
2025	3126.5	0.7	0.553	88.36	2.83%	428.04	2.23%
2030	4457.4	0.7	0.553	142.93	3.21%	692.39	2.53%
2035	6179.3	0.7	0.553	208.54	3.37%	1010.23	2.67%
2037	7051.4	0.7	0.553	253.02	3.59%	1225.70	2.83%

Losses Graph TN 3

Annex 4: Economic Analyses –TARGET NETWORK 3

Cost (MUSD)															
Year	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2030**	**2031**	**2032**	**2035**	**2037**
Lines/Substations	530.62	854.1	995.	1110.	512.937	910.02	129.15	1228.81	254.16	293.7	69.1	242.4	12.83	73.58	
Reactive compensation	0	3.45	2.64	0	2.65	0	0.91	3.86	0	0	0	1.82	0	0	0
O$M Cost (2.5%)	13.27	21.44	24.94	27.75	12.89	22.75	3.25	30.82	6.35	7.34	1.73	6.11	0.32	1.84	0.00
Losses(KUSD)	45.15	57.72	48.76	47.87	50.17	0.00	0.00	64.21	0.00	0.00	103.86	0.00	0.00	151.53	183.85
Total cost (MUSD)	589.03	936.71	1,071.45	1,185.64	578.65	932.77	133.31	1,327.69	260.51	301.10	174.68	250.33	13.15	226.95	183.85
PVS (I=12%)	589.03	836.35	854.15	843.92	367.74	529.28	67.54	600.58	105.22	108.58	44.84	57.37	2.69	33.05	21.35
PV of cost (MUSD)	**5,061.69**														
Non discounted total	**8,165.84**														
Total cost less losses (MUSD)	543.89	878.98	1,022.69	1,137.77	528.48	932.77	133.31	1,263.49	260.51	301.10	70.82	250.33	13.15	75.42	-
PVS (I=12%)	543.89	784.81	815.29	809.84	335.86	529.28	67.54	571.54	105.22	108.58	18.18	57.37	2.69	10.98	-
PV of investments (MUSD)	**4,761.05**														
Non discounted total investments	**7,412.71**														
Assumptions:															
Discount rate	12%														
Cost of Losses	0.15	USD/kWh													
O & M Cost	2.5%	of Capex													

Annex 5: Equipment loading

2018 THREE PHASE SCC LEVELS (MAX)							
S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE
1	ULU11	132	31.5	2.1	487.0	7%	-63.65
2	JUJA RD11	132	31.5	12.2	2791.0	39%	-65.51
3	DANDORA11	132	31.5	12.3	2822.4	39%	-65.98
4	SULTAN HA11	132	31.5	1.6	358.2	5%	-63.39
5	KIBOKO11	132	31.5	1.4	322.9	4%	-63.11
6	MTITO AND11	132	31.5	1.4	309.0	4%	-62.98
7	RUARAK TE11	132	31.5	10.7	2445.2	34%	-64.78
8	RUARAKA11	132	31.5	10.6	2424.4	34%	-64.61
9	MAKINDU	132	31.5	1.4	315.8	4%	-63.08
10	KONZA	132	31.5	2.2	505.2	7%	-63.7
11	MACHAKOS11	132	31.5	1.8	405.9	6%	-64.04
12	RUARAKA TEE	132	31.5	10.7	2445.2	34%	-64.78
13	KIPEVU11	132	31.5	7.7	1758.1	24%	-63.73
14	MANYANI11	132	31.5	1.4	328.2	5%	-62.91
15	SAMBURU11	132	31.5	2.5	564.6	8%	-63.29
16	KIPEVUDII11	132	31.5	7.7	1755.3	24%	-63.74
17	KOKOTONI11	132	31.5	5.6	1272.3	18%	-63.06
18	RABAI11	132	31.5	7.8	1779.1	25%	-63.73
19	KILIFI11	132	31.5	2.0	466.4	6%	-58.12
20	BAMBURI11	132	31.5	4.1	933.3	13%	-59.61
21	VOI11	132	31.5	1.6	373.3	5%	-62.77
22	MAUNGU11	132	31.5	1.8	421.7	6%	-62.9
23	MARIAKANI11	132	31.5	4.4	1000.0	14%	-62.64
24	GALU11	132	31.5	2.5	579.5	8%	-61.73
25	RABAITRF11	132	31.5	7.6	1734.8	24%	-63.93
26	RABTRF12	132	31.5	7.6	1734.8	24%	-63.93
27	VIPINGO31	132	31.5	3.2	735.0	10%	-59.01
28	MSCEMTEE31	132	31.5	2.8	650.9	9%	-58.58
29	MSACEM31	132	31.5	2.7	611.6	8%	-58.33
30	MSACEMTEE32	132	31.5	2.5	575.4	8%	-58.32
31	TITANIUM11	132	31.5	2.1	485.5	7%	-62.21

32	JOMVU	132	31.5	6.9	1577.1	22%	-63.41
33	KINDARUMA11	132	31.5	7.4	1698.7	24%	-67.24
34	GITARU11	132	31.5	10.5	2390.1	33%	-69.02
35	KAMBURU11	132	31.5	12.1	2773.2	39%	-69.36
36	MASINGA11	132	31.5	6.2	1420.4	20%	-72.21
37	NANYUKI11	132	31.5	1.1	248.0	3%	-58.46
38	KYENI11	132	31.5	3.1	711.1	10%	-72.96
39	ISHIARA11	132	31.5	4.2	950.3	13%	-75.26
40	MERU11	132	31.5	1.4	322.7	4%	-75.52
41	GITHAMBO11	132	31.5	2.4	543.6	8%	-65.53
42	KIGANJO11	132	31.5	1.6	366.1	5%	-58.99
43	KAMBTRF11	132	31.5	12.1	2760.8	38%	-69.28
44	EMBU11	132	31.5	2.6	586.7	8%	-61.97
45	OLKARIA1 11	132	31.5	8.8	2016.8	28%	-75.13
46	AIVASHA11	132	31.5	7.6	1740.6	24%	-68.15
47	OLKARIAIAU1	132	31.5	8.9	2034.2	28%	-74.94
48	LANET11	132	31.5	4.5	1023.1	14%	-61.35
49	SOILO11	132	31.5	3.7	840.6	12%	-61.6
50	OLKARIA II1	132	31.5	8.3	1908.9	27%	-75.83
51	MAKUTANO11	132	31.5	2.9	661.7	9%	-61.86
52	WELLHED37-1	132	31.5	7.8	1778.6	25%	-74.25
53	MUHORONI11	132	31.5	3.5	794.8	11%	-57.28
54	KISUMU11	132	31.5	2.7	607.8	8%	-58.14
55	CHEMOSIT11	132	31.5	2.3	516.0	7%	-53.9
56	WEBUYE11	132	31.5	1.8	419.5	6%	-60.61
57	MUSAGA11	132	31.5	2.2	512.2	7%	-60.2
58	MUMIAS11	132	31.5	1.7	389.3	5%	-59.99
59	SONDU11	132	31.5	2.5	582.7	8%	-63.9
60	SANGORO11	132	31.5	2.4	553.6	8%	-63.89
61	BOMET11	132	31.5	1.3	298.8	4%	-57.39
62	KKISII11	132	31.5	1.3	301.4	4%	-56.63
63	SOTIK	132	31.5	1.7	381.2	5%	-55.85
64	AWENDO11	132	31.5	1.0	227.9	3%	-58.18
65	RANGALA11	132	31.5	1.3	308.2	4%	-63.12

66	ELDORET11	132	31.5	2.4	559.6	8%	-57.66
67	LESSOS11	132	31.5	4.2	950.1	13%	-59.1
68	KAPSABET11	132	31.5	2.4	558.4	8%	-60.97
69	KITALE11	132	31.5	1.4	316.4	4%	-60.51
70	LESSTRF11	132	31.5	4.2	950.1	13%	-59.1
71	GATUNDU11	132	31.5	3.4	767.2	11%	-65.85
72	MWINGI11	132	31.5	3.2	735.0	10%	-66.28
73	GARISSA11	132	31.5	0.7	166.2	2%	-65.25
74	ISIOLO11	132	31.5	1.1	261.6	4%	-73.92
75	THIKA11	132	31.5	5.3	1216.2	17%	-65.38
76	THIKA12	132	31.5	5.3	1210.1	17%	-65.4
77	TORO11	132	31.5	2.0	455.3	6%	-65.32
78	DANDORA21	220	31.5	9.4	3595.4	30%	-64.18
79	EMBAKASI21	220	31.5	8.0	3044.6	25%	-63.87
80	ATHI RIVER2	220	31.5	6.8	2578.8	21%	-68.1
81	CABLE-OHL	220	31.5	7.7	2944.8	25%	-64.76
82	CBD	220	31.5	7.6	2891.5	24%	-64.58
83	RABAI21	220	31.5	3.5	1339.1	11%	-73.12
84	MALINDI21	220	31.5	1.7	655.2	5%	-73.41
85	GARSEN21	220	31.5	1.1	407.6	3%	-74.25
86	LAMU21	220	31.5	0.8	302.0	3%	-74.66
87	TESTBUS	220	31.5	2.1	788.8	7%	-74.1
88	KAMBURU21	220	31.5	8.2	3143.5	26%	-68.95
89	KIAMBERE21	220	31.5	6.4	2423.9	20%	-71.08
90	GITARU21	220	31.5	7.0	2684.2	22%	-70.59
91	OLKARIAIAU2	220	31.5	10.8	4130.2	34%	-70.08
92	OLKARIAIII2	220	31.5	9.1	3476.8	29%	-72
93	OLKARIA II2	220	31.5	10.8	4124.1	34%	-70.14
94	SUSWA21	220	31.5	11.3	4324.9	36%	-68.9
95	OLKARIA IV	220	31.5	9.5	3611.9	30%	-71.23
96	OLKIVWELLHD	220	31.5	8.8	3350.5	28%	-71.89
97	TURKWEL21	220	31.5	1.7	654.9	5%	-70.31
98	LESSOS21	220	31.5	1.9	740.9	6%	-64.28
99	LOYAN	220	31.5	4.2	1598.4	13%	-83.9
100	KAINUK21	220	31.5	1.7	653.1	5%	-70.32

101	NBNORTH21	220	31.5	9.1	3485.3	29%	-67.35
2018 THREE PHASE SCC LEVELS (MIN)							
S/n	**BUS**	**BUS VOLTAGE**	**SC RATING**	**FAULT LEVEL (kA)**	**FAULT LEVEL (MVA)**	**% of SC TO EQUIPMENT RATING**	**ANGLE**
1	ULU11	132	31.5	1.9	445.6	6%	-63.76
2	JUJA RD11	132	31.5	11.7	2667.8	37%	-66.11
3	DANDORA11	132	31.5	11.8	2701.9	38%	-66.58
4	SULTAN HA11	132	31.5	1.4	327.0	5%	-63.48
5	KIBOKO11	132	31.5	1.3	294.7	4%	-63.2
6	MTITO AND11	132	31.5	1.2	282.1	4%	-63.07
7	RUARAK TE11	132	31.5	10.1	2318.9	32%	-65.28
8	RUARAKA11	132	31.5	10.1	2298.1	32%	-65.1
9	MAKINDU	132	31.5	1.3	288.2	4%	-63.17
10	KONZA	132	31.5	2.0	462.4	6%	-63.82
11	MACHAKOS11	132	31.5	1.6	371.0	5%	-64.14
12	TEE	132	31.5	10.1	2318.9	32%	-65.28
13	KIPEVU11	132	31.5	7.4	1701.1	24%	-64.12
14	MANYANI11	132	31.5	1.3	299.9	4%	-63.01
15	SAMBURU11	132	31.5	2.3	520.6	7%	-63.45
16	KIPEVUDII11	132	31.5	7.4	1698.3	24%	-64.12
17	KOKOTONI11	132	31.5	5.3	1204.2	17%	-63.33
18	RABAI11	132	31.5	7.5	1716.8	24%	-64.12
19	KILIFI11	132	31.5	1.9	429.3	6%	-58.23
20	BAMBURI11	132	31.5	3.8	872.0	12%	-59.8
21	VOI11	132	31.5	1.5	341.7	5%	-62.89
22	MAUNGU11	132	31.5	1.7	386.7	5%	-63.03
23	MARIAKANI11	132	31.5	4.1	936.8	13%	-62.86
24	GALU11	132	31.5	2.3	536.4	7%	-61.85
25	RABAITRF11	132	31.5	7.3	1670.4	23%	-64.3
26	RABTRF12	132	31.5	7.3	1670.4	23%	-64.3
27	VIPINGO31	132	31.5	3.0	682.2	9%	-59.17
28	MSCEMTEE31	132	31.5	2.6	602.5	8%	-58.73
29	MSACEM31	132	31.5	2.5	565.4	8%	-58.47
30	MSACEMTEE32	132	31.5	2.3	531.3	7%	-58.45
31	ITANIUM11	132	31.5	2.0	448.0	6%	-62.33

32	JOMVU	132	31.5	6.6	1513.9	21%	-63.75
33	KINDARUMA11	132	31.5	7.1	1612.8	22%	-67.4
34	GITARU11	132	31.5	10.1	2306.8	32%	-69.23
35	KAMBURU11	132	31.5	11.8	2694.6	37%	-69.64
36	MASINGA11	132	31.5	5.9	1340.0	19%	-72.46
37	NANYUKI11	132	31.5	1.0	226.7	3%	-58.5
38	KYENI11	132	31.5	2.9	656.9	9%	-73.12
39	ISHIARA11	132	31.5	3.9	882.7	12%	-75.53
40	MERU11	132	31.5	1.3	295.4	4%	-75.64
41	GITHAMBO11	132	31.5	2.2	499.8	7%	-65.65
42	KIGANJO11	132	31.5	1.5	335.6	5%	-59.02
43	KAMBTRF11	132	31.5	11.7	2682.6	37%	-69.55
44	EMBU11	132	31.5	2.4	540.9	8%	-62.01
45	OLKARIA1 11	132	31.5	8.6	1955.6	27%	-75.57
46	AIVASHA11	132	31.5	7.2	1636.0	23%	-68.61
47	OLKARIAIAU1	132	31.5	8.6	1972.0	27%	-75.4
48	LANET11	132	31.5	4.1	946.6	13%	-61.66
49	SOILO11	132	31.5	3.4	775.6	11%	-61.89
50	OLKARIA II1	132	31.5	8.1	1847.7	26%	-76.28
51	MAKUTANO11	132	31.5	2.7	610.8	8%	-62.22
52	WELLHED37-1	132	31.5	7.5	1712.1	24%	-74.6
53	MUHORONI11	132	31.5	3.3	753.5	10%	-58
54	KISUMU11	132	31.5	2.5	574.5	8%	-58.74
55	CHEMOSIT11	132	31.5	2.1	480.8	7%	-54.42
56	WEBUYE11	132	31.5	1.7	388.0	5%	-61.03
57	MUSAGA11	132	31.5	2.1	475.8	7%	-60.7
58	MUMIAS11	132	31.5	1.6	359.6	5%	-60.38
59	SONDU11	132	31.5	2.5	561.8	8%	-64.38
60	SANGORO11	132	31.5	2.3	532.6	7%	-64.34
61	BOMET11	132	31.5	1.2	275.4	4%	-57.78
62	KKISII11	132	31.5	1.2	277.7	4%	-57.06
63	SOTIK	132	31.5	1.5	352.7	5%	-56.32
64	AWENDO11	132	31.5	0.9	209.2	3%	-58.52
65	RANGALA11	132	31.5	1.2	283.6	4%	-63.47

66	ELDORET11	132	31.5	2.3	517.9	7%	-58.07
67	LESSOS11	132	31.5	3.9	892.4	12%	-59.77
68	KAPSABET11	132	31.5	2.3	517.3	7%	-61.4
69	KITALE11	132	31.5	1.3	290.3	4%	-60.78
70	LESSTRF11	132	31.5	3.9	892.4	12%	-59.77
71	GATUNDU11	132	31.5	3.1	708.9	10%	-66.02
72	MWINGI11	132	31.5	3.0	680.7	9%	-66.34
73	GARISSA11	132	31.5	0.7	151.7	2%	-65.26
74	ISIOLO11	132	31.5	1.0	239.2	3%	-74
75	THIKA11	132	31.5	5.0	1134.8	16%	-65.63
76	THIKA12	132	31.5	4.9	1129.0	16%	-65.65
77	TORO11	132	31.5	1.9	426.0	6%	-66.01
78	DANDORA21	220	31.5	9.0	3420.1	28%	-64.85
79	EMBAKASI21	220	31.5	7.5	2874.4	24%	-64.54
80	ATHI RIVER2	220	31.5	6.3	2418.6	20%	-68.76
81	CABLE-OHL	220	31.5	7.3	2776.1	23%	-65.43
82	CBD	220	31.5	7.1	2724.0	23%	-65.25
83	RABAI21	220	31.5	3.4	1278.7	11%	-73.26
84	MALINDI21	220	31.5	1.6	610.0	5%	-73.52
85	GARSEN21	220	31.5	1.0	376.1	3%	-74.33
86	LAMU21	220	31.5	0.7	277.6	2%	-74.73
87	TESTBUS	220	31.5	1.9	728.4	6%	-74.27
88	KAMBURU21	220	31.5	7.9	3024.4	25%	-69.39
89	KIAMBERE21	220	31.5	6.0	2303.6	19%	-71.51
90	GITARU21	220	31.5	6.7	2565.5	21%	-71
91	OLKARIAIAU2	220	31.5	10.5	3996.2	33%	-70.62
92	OLKARIAIII2	220	31.5	8.8	3334.6	28%	-72.52
93	OLKARIA II2	220	31.5	10.5	3990.2	33%	-70.68
94	SUSWA21	220	31.5	11.0	4178.8	35%	-69.5
95	OLKARIA IV	220	31.5	9.1	3468.9	29%	-71.74
96	OLKIVWELLHD	220	31.5	8.4	3205.9	27%	-72.39
97	TURKWEL21	220	31.5	1.7	637.0	5%	-70.61
98	LESSOS21	220	31.5	1.9	708.2	6%	-64.54
99	LOYAN	220	31.5	3.9	1498.6	12%	-84.15
100	KAINUK21	220	31.5	1.7	635.1	5%	-70.62

101	NBNORTH21	220	31.5	8.7	3306.6	28%	-68.02
2025 THREE PHASE SCC LEVELS (MAX)							
S/n	**BUS**	**BUS VOLTAGE**	**SC RATING**	**FAULT LEVEL (kA)**	**FAULT LEVEL (MVA)**	**% of SC TO EQUIPMENT RATING**	**ANGLE**
1	ULU 132	132	31.5	10.4	2367.8	33%	-74.25
2	DANDORA 132	132	31.5	18.6	4244.4	59%	-74.26
3	JUJA RD 132	132	31.5	19.2	4393.0	61%	-73.75
4	KIBOKO	132	31.5	4.4	1006.1	14%	-68.78
5	MAKINDU 132	132	31.5	5.0	1143.3	16%	-71.26
6	UPLANDS	132	31.5	10.0	2279.5	32%	-77.23
7	RUARAKA 132	132	31.5	14.6	3336.5	46%	-79.23
8	SULTAN HAMUD	132	31.5	5.1	1160.4	16%	-67.26
9	KAJIADO	132	31.5	3.5	811.6	11%	-85.4
10	KONZA	132	31.5	13.5	3075.4	43%	-77.9
11	MACHAKOS	132	31.5	7.0	1602.9	22%	-70.21
12	NAMANGA	132	31.5	1.4	318.0	4%	-72.87
13	ISINYA 132	132	31.5	3.7	843.0	12%	-86.24
14	KONZA SGR	132	31.5	7.6	1728.1	24%	-72.46
15	SULTAN SGR	132	31.5	4.6	1058.1	15%	-66.58
16	MAKINDU NEW	132	31.5	7.4	1698.5	24%	-78.32
17	MAKINDU SGR	132	31.5	6.7	1529.2	21%	-77.02
18	MKD TEE	132	31.5	6.6	1518.3	21%	-76.15
19	MKD T-OFF	132	31.5	6.5	1486.8	21%	-76.19
20	NDALSYN TEE1	132	31.5	3.5	806.3	11%	-68.71
21	NDALSYN TEE2	132	31.5	3.5	793.8	11%	-68.55
22	NDALSYAN SGR	132	31.5	3.5	800.2	11%	-68.61
23	TSAVO TEE 1	132	31.5	3.6	815.8	11%	-68.16
24	TSAVO TEE 2	132	31.5	3.7	856.7	12%	-68.41
25	TSAVO SGR	132	31.5	3.7	835.5	12%	-68.23
26	THIKARD132	132	31.5	14.6	3341.1	46%	-79.26
27	OWEN FALLS	132	31.5	2.1	471.0	7%	-59.89
28	VOI 132	132	31.5	7.5	1713.1	24%	-74.57
29	VIPINGO RANG	132	31.5	3.8	880.2	12%	-69.24
30	KIPEVU 2	132	31.5	5.5	1254.3	17%	-66.73
31	KIPEVU	132	31.5	5.5	1260.5	18%	-66.71

32	KOKOTONI	132	31.5	5.5	1249.1	17%	-66.71
33	MARIAKANI	132	31.5	4.3	993.6	14%	-66.05
34	MAUNGU132	132	31.5	4.0	920.1	13%	-68.57
35	MOMBASA CEM	132	31.5	3.9	889.8	12%	-69.75
36	MBSACEM TEE1	132	31.5	3.9	884.3	12%	-69.53
37	MBSACEM TEE2	132	31.5	3.9	896.1	12%	-70.11
38	NEW BAMB 132	132	31.5	4.5	1019.4	14%	-66.21
39	RABAI 132	132	31.5	6.2	1406.8	20%	-67.14
40	RABAI POWER	132	31.5	6.1	1393.8	19%	-67.21
41	SAMBURU 132	132	31.5	3.3	746.4	10%	-65.84
42	GALU	132	31.5	3.7	851.3	12%	-65.23
43	MANYANI	132	31.5	3.9	893.3	12%	-68.71
44	KILIFI	132	31.5	4.1	928.2	13%	-71.41
45	MTITO ANDEI	132	31.5	3.4	775.4	11%	-68.38
46	TITANIUM 132	132	31.5	3.3	763.6	11%	-65.89
47	GARISSA	132	31.5	4.4	1000.4	14%	-77.83
48	JOMVU	132	31.5	5.2	1191.8	17%	-67.5
49	KWALE SC	132	31.5	3.1	699.7	10%	-68.01
50	LIKONI	132	31.5	3.3	754.0	10%	-65.38
51	BAMBURI CEME	132	31.5	4.0	925.3	13%	-69.38
52	S_HAMUD_NEW	132	31.5	4.8	1086.8	15%	-66.64
53	MBARAKI	132	31.5	4.7	1073.8	15%	-66.02
54	TAVETA	132	31.5	1.4	321.1	4%	-66.7
55	S_HAMUD_TEE	132	31.5	5.3	1203.5	17%	-67.23
56	LIKONI TEE	132	31.5	4.4	1010.0	14%	-65.66
57	LUNGA LUNGA	132	31.5	3.2	734.5	10%	-69.88
58	LOITOKTOK	132	31.5	1.8	417.5	6%	-65.91
59	MERUWESHI	132	31.5	4.7	1076.9	15%	-66.63
60	MTWAPA	132	31.5	3.9	891.3	12%	-68.98
61	SHIMONI	132	31.5	3.1	710.2	10%	-69.19
62	VOI 132 NEW	132	31.5	8.7	1989.9	28%	-77.61
63	MACKNN TEE 1	132	31.5	3.2	727.8	10%	-66.68
64	MACKNN TEE2	132	31.5	3.0	687.5	10%	-65.97
65	MAKINNON SGR	132	31.5	3.1	698.2	10%	-66.11
66	MARIAKNI NEW	132	31.5	4.0	910.2	13%	-66.06

67	MARIAKN SGR	132	31.5	4.3	993.6	14%	-66.05
68	KWALE	132	31.5	4.7	1072.0	15%	-77.07
69	GITARU 132	132	31.5	9.6	2191.9	30%	-78.93
70	GITHAMBO	132	31.5	4.5	1035.7	14%	-68
71	KAMBURU 132	132	31.5	11.6	2659.4	37%	-78.76
72	KIGANJO	132	31.5	10.4	2386.6	33%	-75.15
73	KILBOGO TEE1	132	31.5	8.1	1857.2	26%	-69.88
74	KINDARUMA	132	31.5	5.3	1215.2	17%	-70.03
75	KILBOGO TEE2	132	31.5	7.3	1677.8	23%	-70.15
76	MANGU	132	31.5	14.2	3236.9	45%	-77.32
77	MASINGA	132	31.5	7.1	1623.5	23%	-78.49
78	MERU 132	132	31.5	8.4	1924.0	27%	-74.01
79	NANYUKI 132	132	31.5	7.7	1763.5	24%	-68.29
80	GATUNDU	132	31.5	5.5	1261.5	18%	-70.14
81	KUTUS 132	132	31.5	11.2	2561.7	36%	-78
82	KUTUS_T1	132	31.5	7.8	1778.4	25%	-76.15
83	KUTUS_T2	132	31.5	6.7	1531.5	21%	-77.01
84	THIKAPWR 132	132	31.5	13.9	3187.2	44%	-77.15
85	ISIOLO	132	31.5	10.0	2276.1	32%	-73.47
86	MWINGI	132	31.5	3.6	833.6	12%	-67.5
87	KITUI	132	31.5	2.6	590.3	8%	-65.62
88	KYENI	132	31.5	5.5	1261.8	18%	-71.33
89	MAUA	132	31.5	9.0	2050.6	28%	-78.91
90	TATU CITY	132	31.5	7.1	1634.1	23%	-71.61
91	MUTOMO	132	31.5	1.3	294.9	4%	-64.9
92	KIBWEZI	132	31.5	0.9	203.6	3%	-64.62
93	KIBR TEE 2	132	31.5	11.9	2716.3	38%	-77.15
94	OTHAYA	132	31.5	4.7	1077.8	15%	-68.43
95	WOTE	132	31.5	2.9	664.7	9%	-65.82
96	ISHIARA SWST	132	31.5	6.2	1411.9	20%	-75.51
97	KIBIRIGWI	132	31.5	11.9	2716.3	38%	-77.15
98	THIKA NEW	132	31.5	14.2	3236.9	45%	-77.32
99	ISIOLO SS2	132	31.5	10.5	2404.5	33%	-77.39
100	GARISSA SS2	132	31.5	4.4	1000.4	14%	-77.83
101	CHOGORIA	132	31.5	2.9	652.1	9%	-68.49

102	MWALA	132	31.5	6.5	1493.6	21%	-68.87
103	LANET	132	31.5	10.9	2497.6	35%	-70.35
104	NAIVASHA 132	132	31.5	12.5	2866.7	40%	-77.34
105	OLKARIA1 132	132	31.5	9.5	2167.2	30%	-84.6
106	NAKRUWEST_T1	132	31.5	12.1	2756.2	38%	-72.09
107	NAKRUWEST_T2	132	31.5	11.8	2708.5	38%	-72.03
108	MAKUTANO_T1	132	31.5	7.9	1795.4	25%	-67.72
109	MAKUTANO_T2	132	31.5	8.0	1819.4	25%	-67.7
110	OLK 1AU 132	132	31.5	9.5	2182.0	30%	-84.7
111	OLKALOU	132	31.5	6.9	1580.1	22%	-68.87
112	AEOLUS WIND	132	31.5	6.9	1579.0	22%	-73.8
113	NAROK	132	31.5	4.2	953.0	13%	-69.39
114	GILGIL	132	31.5	12.1	2760.7	38%	-76.25
115	GILGIL TEE1	132	31.5	11.0	2504.7	35%	-73.45
116	GILGIL TEE2	132	31.5	11.0	2504.7	35%	-73.45
117	OLK I WE	132	31.5	8.7	1983.3	28%	-83.02
118	KAKAMEGA132	132	31.5	7.0	1592.1	22%	-75.66
119	WEBUYE	132	31.5	5.7	1308.9	18%	-69.24
120	CHEMOSIT	132	31.5	6.7	1540.7	21%	-74.56
121	KISII	132	31.5	6.2	1413.8	20%	-72.7
122	KISUMU 132	132	31.5	8.9	2040.2	28%	-70.47
123	MUHORONI 132	132	31.5	7.2	1638.2	23%	-72.92
124	MUMIAS 132	132	31.5	4.9	1111.1	15%	-67.7
125	MUSAGA 132	132	31.5	8.6	1976.6	27%	-71.75
126	RANGALA 132	132	31.5	5.2	1190.5	17%	-66.61
127	SANGORO	132	31.5	4.5	1037.7	14%	-70.56
128	SONDU MIRIU	132	31.5	5.1	1172.5	16%	-71.23
129	AWENDO	132	31.5	3.7	854.0	12%	-67.68
130	BOMET	132	31.5	4.9	1111.7	15%	-68.68
131	ONGENG	132	31.5	3.5	805.6	11%	-67.65
132	SOTIK	132	31.5	8.6	1955.1	27%	-72.07
133	BONDO	132	31.5	3.6	816.6	11%	-65.92
134	CHAVAKALI	132	31.5	7.4	1681.9	23%	-70.31
135	KISUMU EAST	132	31.5	8.1	1861.2	26%	-69.82
136	MALABA TEE2	132	31.5	3.5	796.8	11%	-65.15

137	ISABENIA	132	31.5	2.0	454.4	6%	-66.8
138	TORORO 132	132	31.5	5.0	1145.2	16%	-66.02
139	MAKUTANO 132	132	31.5	8.0	1827.7	25%	-67.72
140	NAKURU_W 132	132	31.5	12.1	2764.2	38%	-72.21
141	KILGORIS	132	31.5	11.1	2549.2	35%	-78.95
142	MYANGA	132	31.5	6.0	1376.9	19%	-67.59
143	BUSIA	132	31.5	5.2	1178.9	16%	-66.98
144	NDWIGA	132	31.5	2.8	634.6	9%	-65.6
145	SINDO	132	31.5	2.0	455.6	6%	-66.78
146	KARUNGO	132	31.5	1.8	404.1	6%	-66.88
147	KIMILILI	132	31.5	5.0	1152.5	16%	-69.21
148	KAIMOSI	132	31.5	7.4	1681.9	23%	-70.31
149	SUKARI	132	31.5	3.3	744.2	10%	-67.49
150	ELDORET	132	31.5	4.8	1092.9	15%	-66.16
151	LESSOS 132	132	31.5	11.4	2609.1	36%	-72.14
152	KITALE	132	31.5	5.0	1139.7	16%	-71
153	KABARNET	132	31.5	3.3	765.5	11%	-66.83
154	KAPSABET	132	31.5	6.4	1474.5	20%	-68.97
155	KIBOS1	132	31.5	9.1	2073.8	29%	-70.77
156	RUMURUTI	132	31.5	6.7	1531.4	21%	-67.66
157	SILALI	132	31.5	11.7	2670.4	37%	-82
158	ELDORET NTH	132	31.5	4.1	947.0	13%	-82.68
159	MOI BRCKS	132	31.5	4.1	928.8	13%	-67.42
160	MARALAL	132	31.5	4.5	1019.2	14%	-68.76
161	KERINGET	132	31.5	2.6	604.3	8%	-64.15
162	MENENGAI 132	132	31.5	12.5	2868.1	40%	-75.19
163	GENERIC 2023	132	31.5	3.3	753.6	10%	-70.5
164	GENERIC 2024	132	31.5	4.2	953.0	13%	-69.39
165	GENERIC 2034	132	31.5	2.7	627.2	9%	-69.83
166	SUSTAINABLE	132	31.5	19.2	4393.0	61%	-73.75
167	MAKINDU SLR	132	31.5	4.4	1006.1	14%	-68.78
168	CHERAB	132	31.5	10.5	2404.5	33%	-77.39
169	MERU WIND	132	31.5	10.5	2404.5	33%	-77.39
170	CRYSTAL	132	31.5	0.9	203.6	3%	-64.62
171	KIBR TEE 1	132	31.5	11.5	2635.6	37%	-76.77
172	KOPERE	132	31.5	6.6	1512.2	21%	-72.19

173	QUAINT	132	31.5	4.6	1061.6	15%	-70.36
174	KAPTIS	132	31.5	7.4	1681.9	23%	-70.31
175	K TE 1	132	31.5	8.5	1948.7	27%	-68.82
176	K TE 2	132	31.5	8.5	1948.7	27%	-68.82
177	TARITA SLR	132	31.5	3.9	899.8	12%	-67.36
178	KENERGY SLR	132	31.5	6.7	1531.4	21%	-67.66
179	SUNPOWER	132	31.5	3.1	708.3	10%	-66.48
180	GITARU SLR	132	31.5	7.2	1655.4	23%	-79.35
181	DANDORA 220	220	31.5	12.7	4838.8	40%	-74.57
182	RUARAKA 220	220	40	11.3	4299.6	28%	-74.74
183	JUJA RD	220	40	11.4	4332.4	28%	-74.35
184	EMBAKASI	220	31.5	10.6	4023.7	34%	-71.29
185	EMBAKASI_CC	220	31.5	10.5	3989.3	33%	-71.41
186	THIKA RD BSP	220	31.5	14.3	5451.8	45%	-73.48
187	CBD	220	31.5	9.9	3787.7	32%	-71.89
188	NRBI NORTH	220	31.5	13.0	4953.6	41%	-74.96
189	ISINYA	220	31.5	11.7	4448.7	37%	-76.39
190	SUSWA	220	31.5	20.6	7836.2	65%	-78.57
191	LONGONOT	220	31.5	11.4	4341.6	36%	-79.37
192	UPLANDS 220	220	40	10.6	4029.7	26%	-76.44
193	ATHI RIVER	220	31.5	10.3	3930.8	33%	-71.61
194	MALAA220	220	31.5	15.0	5707.5	48%	-74.21
195	NGONG	220	31.5	12.4	4722.3	39%	-80.91
196	LONGONOT	220	40	5.7	2156.8	14%	-79.7
197	RABAI 220	220	31.5	6.0	2282.7	19%	-69.19
198	GARSEN 220	220	31.5	5.1	1960.5	16%	-73.84
199	LAMU 220	220	31.5	6.9	2610.7	22%	-80.4
200	MALINDI 220	220	31.5	4.1	1580.9	13%	-70.46
201	BAMBUR CE220	220	31.5	3.0	1156.5	10%	-67.61
202	GALANA 220	220	40	3.0	1148.9	8%	-72.3
203	SWTCH STN	220	40	4.1	1571.8	10%	-69.59
204	KILIFI 220	220	40	3.2	1222.9	8%	-70.64
205	MARIAKANI EH	220	31.5	6.8	2579.4	21%	-71.57
206	LAMU 220_2	220	31.5	7.7	2935.1	24%	-82.3
207	NNDONGO KUND	220	31.5	4.4	1690.0	14%	-73

208	KWALE	220	31.5	4.6	1750.0	15%	-72.88
209	TEE-OFF	220	31.5	4.9	1871.5	16%	-72.56
210	DOGO LNG	220	40	4.4	1666.6	11%	-73.1
211	GITARU 220	220	31.5	7.8	2982.7	25%	-77.03
212	KAMBURU 220	220	31.5	10.1	3847.9	32%	-76.13
213	KIAMBERE 220	220	31.5	9.7	3694.4	31%	-77.42
214	KARURA	220	40	8.1	3085.6	20%	-78.45
215	KIBIRIGWI	220	31.5	8.7	3314.4	28%	-76.58
216	EMBU	220	31.5	8.9	3397.0	28%	-76.25
217	THIKA 220	220	31.5	11.8	4504.6	38%	-77.81
218	ISIOLO 220	220	31.5	7.4	2803.4	23%	-77.53
219	MAUA 220	220	31.5	7.1	2695.6	22%	-77.38
220	GARISSA	220	31.5	3.4	1281.4	11%	-75.13
221	BURA	220	31.5	2.7	1029.8	9%	-74.36
222	HOLA	220	31.5	3.0	1150.7	10%	-74.18
223	GARBATULA	220	31.5	3.6	1388.2	12%	-77.08
224	OLKARIA2 220	220	31.5	21.3	8122.6	68%	-79.22
225	OLKARIA3 220	220	31.5	18.0	6842.0	57%	-79.72
226	OLKARIA 4	220	31.5	21.7	8285.3	69%	-79.19
227	OLK IAU 220	220	31.5	21.7	8285.9	69%	-79.19
228	MENENGAI	220	31.5	10.1	3860.9	32%	-79.31
229	OLKARIA V	220	31.5	12.1	4600.1	38%	-79.91
230	RONGAI	220	31.5	11.4	4333.8	36%	-78.95
231	GILGIL 220	220	40	14.5	5523.4	36%	-79.61
232	AKIRA 220	220	40	6.1	2324.1	15%	-79.96
233	OLKARIA VI	220	40	17.2	6554.3	43%	-79.39
234	OLKARIA VII	220	40	11.3	4299.6	28%	-79.27
235	OLK IX	220	40	8.0	3058.4	20%	-79.59
236	NAIVASHA 220	220	40	14.9	5661.2	37%	-78.38
237	KAKAMEGA	220	40	6.6	2527.4	17%	-74.36
238	MUHORONI	220	40	5.0	1914.7	13%	-75.48
239	TORORO 2	220	40	4.9	1853.4	12%	-76.74
240	TURKWEL	220	31.5	4.3	1628.7	14%	-78.32
241	LESSOS 220	220	31.5	9.6	3666.7	31%	-75.65
242	KITALE	220	31.5	2.8	1064.2	9%	-74.84

243	BARINGO 220	220	40	5.4	2047.8	13%	-80.29
244	LOKICHAR	220	40	4.2	1594.2	10%	-79.11
245	KIBOS	220	31.5	6.5	2495.6	21%	-74.76
246	ORTUM	220	31.5	3.2	1232.0	10%	-77.43
247	MUSAGA	220	40	7.2	2735.6	18%	-74.48
248	KERICHO	220	40	6.3	2391.4	16%	-76.28
249	CHEMOSIT 220	220	40	5.7	2177.0	14%	-75.5
250	KISII 220	220	40	4.0	1540.3	10%	-77.31
251	SILALI 220	220	40	8.8	3355.6	22%	-80.99
252	RADIANT	220	40	1.7	648.6	4%	-77.82
253	TURKWELL TEE	220	40	3.3	1242.6	8%	-75.88
254	KAPSOWAR	220	40	3.0	1133.8	7%	-75.86
255	AGIL 220	220	40	13.2	5023.6	33%	-79.79
256	MARSABIT	220	40	4.3	1656.1	11%	-79.8
257	KAINUK	220	31.5	4.2	1618.6	13%	-78.36
258	LOKICHOGGIO	220	40	1.8	702.8	5%	-79.43
259	LODWAR	220	40	4.2	1596.4	10%	-79.13
260	LOYAN	220	40	8.2	3115.5	20%	-81.97
261	ELD NTH 220	220	40	3.9	1478.3	10%	-79.9
262	BUJAGALI	220	40	3.0	1148.9	8%	-79.66
263	KAINUK 66	220	40	2.5	936.4	6%	-83.05
264	OLKARIA 4 WE	220	31.5	21.5	8187.9	68%	-79.22
265	GENERIC2028	220	40	8.1	3085.6	20%	-78.45
266	GENERIC 2033	220	40	11.8	4504.6	30%	-77.81
267	GENERIC 2025	220	40	7.4	2814.8	18%	-82.09
268	GENERIC 2031	220	40	6.5	2495.6	16%	-74.76
269	GENERIC 2035	220	40	3.9	1494.3	10%	-79.18
270	SUSWA PP	220	40	10.4	3979.2	26%	-79.44
271	CHAGEM	220	40	12.4	4722.3	31%	-80.91
272	ELEKTRA	220	40	6.9	2610.7	17%	-80.4
273	VATEKI	220	40	4.1	1580.9	10%	-70.46
274	MERU WIND220	220	40	6.8	2575.2	17%	-78.06
275	HABASWEIN	220	40	1.0	386.9	3%	-78.85
276	ISINYA4	400	40	10.1	7032.3	25%	-73.7
277	SUSWA	400	40	11.2	7739.3	28%	-78.37
278	KIMUKA	400	40	10.6	7377.6	27%	-76.29

279	KONZA4	400	40	9.9	6845.6	25%	-74.03
280	NAMANGA	400	40	6.8	4685.1	17%	-75.95
281	MALAA 400	400	40	10.1	6977.5	25%	-74.31
282	MAKINDU 400	400	40	6.9	4752.9	17%	-73.71
283	MARIAKANI	400	40	4.4	3014.2	11%	-72.51
284	LAMU	400	40	5.7	3980.2	14%	-82.57
285	VOI 400	400	40	5.1	3549.0	13%	-72.93
286	THIKA 400	400	40	9.6	6666.1	24%	-75.4

287	GILGIL	400	40	10.9	7578.4	27%	-76.18
288	RONGAI 400	400	40	9.3	6444.6	23%	-76.1
289	KILGORIS	400	40	4.9	3372.7	12%	-77.75
290	LOYAN 400	400	40	5.9	4076.9	15%	-80.75
291	SILALI	400	40	6.2	4271.3	15%	-78.55
292	RUMRT400 TEE	400	40	10.5	7252.3	26%	-76.59
293	SILALI4 TEE1	400	40	7.9	5491.6	20%	-78.86
294	LONG_HVDC	400	40	11.2	7739.3	28%	-78.37
295	LESSOS 400	400	40	7.2	4999.6	18%	-76.55
296	ARUSHA	400	40	4.9	3411.5	12%	-76.79
297	MEGA_HVDC	400	40	7.5	5174.6	19%	-79.31
298	WOLYATA	400	40	7.5	5174.6	19%	-79.31

2025 THREE PHASE SCC LEVELS (MIN)

S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE
1	ULU 132	132	31.5	9.9	2257.0	31%	-74.54
2	DANDORA 132	132	31.5	17.7	4057.1	56%	-74.77
3	JUJA RD 132	132	31.5	18.4	4202.6	58%	-74.25
4	KIBOKO	132	31.5	4.1	934.2	13%	-68.83
5	MAKINDU 132	132	31.5	4.7	1071.5	15%	-71.34
6	UPLANDS	132	31.5	9.6	2189.8	30%	-77.47
7	RUARAKA 132	132	31.5	14.2	3243.7	45%	-79.47
8	SULTAN HAMUD	132	31.5	4.7	1074.9	15%	-67.33
9	KAJIADO	132	31.5	3.5	803.5	11%	-85.45
10	KONZA	132	31.5	13.0	2982.9	41%	-78.5

11	MACHAKOS	132	31.5	6.5	1496.5	21%	-70.3
12	NAMANGA	132	31.5	1.3	298.4	4%	-72.51
13	ISINYA 132	132	31.5	3.7	837.4	12%	-86.37
14	KONZA SGR	132	31.5	7.1	1628.9	23%	-72.6
15	SULTAN SGR	132	31.5	4.3	978.2	14%	-66.64
16	MAKINDU NEW	132	31.5	7.2	1640.2	23%	-78.81
17	MAKINDU SGR	132	31.5	6.4	1467.7	20%	-77.38
18	MKD TEE	132	31.5	6.4	1452.6	20%	-76.46
19	MKD T-OFF	132	31.5	6.2	1421.9	20%	-76.49
20	NDALSYN TEE1	132	31.5	3.3	746.6	10%	-68.74
21	NDALSYN TEE2	132	31.5	3.2	734.5	10%	-68.58
22	NDALSYAN SGR	132	31.5	3.2	740.7	10%	-68.64
23	TSAVO TEE 1	132	31.5	3.3	753.1	10%	-68.18
24	TSAVO TEE 2	132	31.5	3.5	791.7	11%	-68.44
25	TSAVO SGR	132	31.5	3.4	771.7	11%	-68.26
26	THIKARD132	132	31.5	14.2	3248.4	45%	-79.5
27	OWEN FALLS	132	31.5	1.9	431.9	6%	-59.98
28	VOI 132	132	31.5	7.1	1623.7	23%	-74.74
29	VIPINGO RANG	132	31.5	3.6	822.1	11%	-69.4
30	KIPEVU 2	132	31.5	5.2	1187.6	16%	-67.43
31	KIPEVU	132	31.5	5.2	1193.8	17%	-67.4
32	KOKOTONI	132	31.5	5.2	1180.2	16%	-67.33
33	MARIAKANI	132	31.5	4.1	928.2	13%	-66.5
34	MAUNGU132	132	31.5	3.7	851.8	12%	-68.65
35	MOMBASA CEM	132	31.5	3.6	832.0	12%	-69.92
36	MBSACEM TEE1	132	31.5	3.6	826.4	11%	-69.7
37	MBSACEM TEE2	132	31.5	3.7	838.5	12%	-70.3
38	NEW BAMB 132	132	31.5	4.2	957.2	13%	-66.73
39	RABAI 132	132	31.5	5.9	1338.5	19%	-67.88
40	RABAI POWER	132	31.5	5.8	1325.5	18%	-67.95
41	SAMBURU 132	132	31.5	3.0	689.6	10%	-66.11
42	GALU	132	31.5	3.5	792.5	11%	-65.61
43	MANYANI	132	31.5	3.6	826.4	11%	-68.73
44	KILIFI	132	31.5	3.8	871.4	12%	-71.65

45	MTITO ANDEI	132	31.5	3.1	716.8	10%	-68.41
46	TITANIUM 132	132	31.5	3.1	709.3	10%	-66.21
47	GARISSA	132	31.5	4.1	942.5	13%	-77.9
48	JOMVU	132	31.5	4.9	1125.7	16%	-68.18
49	KWALE SC	132	31.5	2.8	650.8	9%	-68.29
50	LIKONI	132	31.5	3.1	700.5	10%	-65.74
51	BAMBURI CEME	132	31.5	3.8	866.8	12%	-69.54
52	S_HAMUD_NEW	132	31.5	4.4	1005.2	14%	-66.7
53	MBARAKI	132	31.5	4.4	1010.3	14%	-66.6
54	TAVETA	132	31.5	1.3	294.1	4%	-66.68
55	S_HAMUD_TEE	132	31.5	4.9	1115.5	15%	-67.3
56	LIKONI TEE	132	31.5	4.1	945.7	13%	-66.13
57	LUNGA LUNGA	132	31.5	3.0	685.3	10%	-70.03
58	LOITOKTOK	132	31.5	1.7	382.1	5%	-65.93
59	MERUWESHI	132	31.5	4.4	995.9	14%	-66.69
60	MTWAPA	132	31.5	3.6	832.9	12%	-69.13
61	SHIMONI	132	31.5	2.9	661.4	9%	-69.37
62	VOI 132 NEW	132	31.5	8.3	1906.6	26%	-77.93
63	MACKNN TEE 1	132	31.5	2.9	670.3	9%	-66.81
64	MACKNN TEE2	132	31.5	2.8	633.1	9%	-66.16
65	MAKINNON SGR	132	31.5	2.8	642.7	9%	-66.27
66	MARIAKNI NEW	132	31.5	3.7	848.3	12%	-66.47
67	MARIAKN SGR	132	31.5	4.1	928.2	13%	-66.5
68	KWALE	132	31.5	4.5	1023.4	14%	-77.32
69	GITARU 132	132	31.5	9.1	2077.1	29%	-79.23
70	GITHAMBO	132	31.5	4.2	955.5	13%	-68.06
71	KAMBURU 132	132	31.5	11.1	2542.1	35%	-79.11
72	KIGANJO	132	31.5	9.9	2257.4	31%	-75.49
73	KILBOGO TEE1	132	31.5	7.6	1731.1	24%	-70.01
74	KINDARUMA	132	31.5	5.0	1132.1	16%	-70.28
75	KILBOGO TEE2	132	31.5	6.8	1564.8	22%	-70.26
76	MANGU	132	31.5	13.7	3130.8	43%	-77.97
77	MASINGA	132	31.5	6.6	1515.3	21%	-78.71
78	MERU 132	132	31.5	7.9	1811.1	25%	-74.3
79	NANYUKI 132	132	31.5	7.1	1634.7	23%	-68.4
80	GATUNDU	132	31.5	5.1	1174.5	16%	-70.21

81	KUTUS 132	132	31.5	10.6	2433.4	34%	-78.36
82	KUTUS_T1	132	31.5	7.3	1657.8	23%	-76.37
83	KUTUS_T2	132	31.5	6.2	1424.6	20%	-77.2
84	THIKAPWR 132	132	31.5	13.5	3079.7	43%	-77.77

85	ISIOLO	132	31.5	9.4	2140.8	30%	-73.72
86	MWINGI	132	31.5	3.4	768.3	11%	-67.59
87	KITUI	132	31.5	2.4	541.2	8%	-65.68
88	KYENI	132	31.5	5.1	1166.8	16%	-71.4
89	MAUA	132	31.5	8.5	1950.8	27%	-79.2
90	TATU CITY	132	31.5	6.7	1532.5	21%	-71.75
91	MUTOMO	132	31.5	1.2	269.3	4%	-64.93
92	KIBWEZI	132	31.5	0.8	185.6	3%	-64.64
93	KIBR TEE 2	132	31.5	11.3	2584.7	36%	-77.55
94	OTHAYA	132	31.5	4.4	994.7	14%	-68.5
95	WOTE	132	31.5	2.7	610.1	8%	-65.87
96	ISHIARA SWST	132	31.5	5.7	1307.4	18%	-75.68
97	KIBIRIGWI	132	31.5	11.3	2584.7	36%	-77.55
98	THIKA NEW	132	31.5	13.7	3130.8	43%	-77.97
99	ISIOLO SS2	132	31.5	10.0	2285.3	32%	-77.81
100	GARISSA SS2	132	31.5	4.1	942.5	13%	-77.9
101	CHOGORIA	132	31.5	2.6	598.0	8%	-68.5
102	MWALA	132	31.5	6.1	1385.9	19%	-68.97
103	LANET	132	31.5	10.3	2363.0	33%	-70.54
104	NAIVASHA 132	132	31.5	12.1	2765.1	38%	-77.74
105	OLKARIA1 132	132	31.5	9.4	2140.7	30%	-84.9
106	NAKRUWEST_T1	132	31.5	11.5	2623.2	36%	-72.45
107	NAKRUWEST_T2	132	31.5	11.3	2575.9	36%	-72.39
108	MAKUTANO_T1	132	31.5	7.3	1674.7	23%	-67.89
109	MAKUTANO_T2	132	31.5	7.4	1697.6	24%	-67.88
110	OLK 1AU 132	132	31.5	9.4	2157.0	30%	-85
111	OLKALOU	132	31.5	6.4	1470.0	20%	-69.02
112	AEOLUS WIND	132	31.5	6.5	1491.4	21%	-73.98
113	NAROK	132	31.5	3.9	882.7	12%	-69.26
114	GILGIL	132	31.5	11.6	2658.2	37%	-76.75
115	GILGIL TEE1	132	31.5	10.4	2386.9	33%	-73.69

116	GILGIL TEE2	132	31.5	10.4	2386.9	33%	-73.69
117	OLK I WE	132	31.5	8.5	1945.3	27%	-83.16
118	KAKAMEGA132	132	31.5	6.6	1517.8	21%	-76.12
119	WEBUYE	132	31.5	5.3	1222.1	17%	-69.53
120	CHEMOSIT	132	31.5	6.4	1464.7	20%	-74.91
121	KISII	132	31.5	5.8	1326.3	18%	-72.98
122	KISUMU 132	132	31.5	8.4	1931.7	27%	-70.99
123	MUHORONI 132	132	31.5	6.8	1544.3	21%	-73.25
124	MUMIAS 132	132	31.5	4.5	1033.0	14%	-67.96
125	MUSAGA 132	132	31.5	8.2	1879.0	26%	-72.37
126	RANGALA 132	132	31.5	4.8	1106.2	15%	-66.88
127	SANGORO	132	31.5	4.3	977.5	14%	-70.98
128	SONDU MIRIU	132	31.5	4.8	1108.3	15%	-71.71
129	AWENDO	132	31.5	3.5	790.1	11%	-67.82
130	BOMET	132	31.5	4.5	1027.7	14%	-68.65
131	ONGENG	132	31.5	3.3	745.6	10%	-67.81
132	SOTIK	132	31.5	8.0	1833.6	25%	-72.19
133	BONDO	132	31.5	3.3	753.7	10%	-66.1
134	CHAVAKALI	132	31.5	6.9	1577.6	22%	-70.6
135	KISUMU EAST	132	31.5	7.7	1756.3	24%	-70.26
136	MALABA TEE2	132	31.5	3.2	736.6	10%	-65.31
137	ISABENIA	132	31.5	1.8	417.0	6%	-66.86
138	TORORO 132	132	31.5	4.7	1066.5	15%	-66.27
139	MAKUTANO 132	132	31.5	7.5	1705.5	24%	-67.89
140	NAKURU_W 132	132	31.5	11.5	2631.9	37%	-72.58
141	KILGORIS	132	31.5	10.6	2417.3	34%	-79.23
142	MYANGA	132	31.5	5.6	1288.2	18%	-67.91
143	BUSIA	132	31.5	4.8	1096.7	15%	-67.25
144	NDWIGA	132	31.5	2.6	583.8	8%	-65.74
145	SINDO	132	31.5	1.8	418.3	6%	-66.86
146	KARUNGO	132	31.5	1.6	370.7	5%	-66.95
147	KIMILILI	132	31.5	4.7	1071.7	15%	-69.45
148	KAIMOSI	132	31.5	6.9	1577.6	22%	-70.6
149	SUKARI	132	31.5	3.0	687.3	10%	-67.61
150	ELDORET	132	31.5	4.4	1011.8	14%	-66.32

151	LESSOS 132	132	31.5	10.9	2487.4	35%	-72.82
152	KITALE	132	31.5	4.6	1060.1	15%	-71.24
153	KABARNET	132	31.5	3.1	703.0	10%	-66.92
154	KAPSABET	132	31.5	6.0	1373.5	19%	-69.21
155	KIBOS1	132	31.5	8.6	1965.7	27%	-71.31
156	RUMURUTI	132	31.5	6.2	1415.0	20%	-67.77
157	SILALI	132	31.5	11.2	2571.9	36%	-82.25
158	ELDORET NTH	132	31.5	3.9	903.0	13%	-82.66
159	MOI BRCKS	132	31.5	3.8	857.9	12%	-67.56
160	MARALAL	132	31.5	4.1	939.3	13%	-68.73
161	KERINGET	132	31.5	2.4	554.0	8%	-64.19
162	MENENGAI 132	132	31.5	12.1	2756.3	38%	-75.8
163	GENERIC 2023	132	31.5	3.0	692.3	10%	-70.57
164	GENERIC 2024	132	31.5	3.9	882.7	12%	-69.26
165	GENERIC 2034	132	31.5	2.5	577.7	8%	-69.73
166	SUSTAINABLE	132	31.5	18.4	4202.6	58%	-74.25
167	MAKINDU SLR	132	31.5	4.1	934.2	13%	-68.83
168	CHERAB	132	31.5	10.0	2285.3	32%	-77.81
169	MERU WIND	132	31.5	10.0	2285.3	32%	-77.81
170	CRYSTAL	132	31.5	0.8	185.6	3%	-64.64
171	KIBR TEE 1	132	31.5	11.0	2503.7	35%	-77.15
172	KOPERE	132	31.5	6.2	1413.3	20%	-72.56
173	QUAINT	132	31.5	4.4	997.8	14%	-70.75
174	KAPTIS	132	31.5	6.9	1577.6	22%	-70.6
175	K TE 1	132	31.5	8.0	1825.9	25%	-69.12
176	K TE 2	132	31.5	8.0	1825.9	25%	-69.12
177	TARITA SLR	132	31.5	3.6	828.8	12%	-67.48
178	KENERGY SLR	132	31.5	6.2	1415.0	20%	-67.77
179	SUNPOWER	132	31.5	2.8	651.2	9%	-66.51
180	GITARU SLR	132	31.5	6.8	1553.7	22%	-79.59
181	DANDORA 220	220	31.5	12.1	4601.0	38%	-75.18
182	RUARAKA 220	220	40	10.8	4110.1	27%	-75.22
183	JUJA RD	220	40	10.9	4145.0	27%	-74.82
184	EMBAKASI	220	31.5	10.0	3818.4	32%	-71.89
185	EMBAKASI_CC	220	31.5	9.9	3785.5	32%	-72.02

186	THIKA RD BSP	220	31.5	13.6	5197.8	43%	-74.18
187	CBD	220	31.5	9.4	3586.1	30%	-72.47
188	NRBI NORTH	220	31.5	12.3	4683.7	39%	-75.55
189	ISINYA	220	31.5	11.3	4305.9	36%	-77.07
190	SUSWA	220	31.5	20.0	7638.9	64%	-79.29
191	LONGONOT	220	31.5	10.8	4102.5	34%	-79.79
192	UPLANDS 220	220	40	10.0	3814.3	25%	-76.87
193	ATHI RIVER	220	31.5	9.8	3731.8	31%	-72.22
194	MALAA220	220	31.5	14.4	5496.6	46%	-75.03
195	NGONG	220	31.5	12.1	4618.4	38%	-81.33
196	LONGONOT	220	40	5.2	1997.8	13%	-79.91
197	RABAI 220	220	31.5	5.6	2146.2	18%	-69.68
198	GARSEN 220	220	31.5	4.8	1831.4	15%	-74.19
199	LAMU 220	220	31.5	6.6	2497.6	21%	-80.84
200	MALINDI 220	220	31.5	3.8	1465.0	12%	-70.83
201	BAMBUR CE220	220	31.5	2.8	1067.8	9%	-67.86
202	GALANA 220	220	40	2.8	1058.7	7%	-72.61
203	SWTCH STN	220	40	3.8	1456.2	10%	-69.97
204	KILIFI 220	220	40	3.0	1128.6	7%	-70.94
205	MARIAKANI EH	220	31.5	6.4	2435.6	20%	-72.12
206	LAMU 220_2	220	31.5	7.4	2836.2	24%	-82.84
207	NNDONGO KUND	220	31.5	4.1	1574.1	13%	-73.45
208	KWALE	220	31.5	4.3	1631.7	14%	-73.34
209	TEE-OFF	220	31.5	4.6	1748.0	15%	-73.04
210	DOGO LNG	220	40	4.1	1551.6	10%	-73.55
211	GITARU 220	220	31.5	7.3	2791.9	23%	-77.46
212	KAMBURU 220	220	31.5	9.5	3633.4	30%	-76.65
213	KIAMBERE 220	220	31.5	9.2	3504.7	29%	-77.95
214	KARURA	220	40	7.7	2921.3	19%	-78.9
215	KIBIRIGWI	220	31.5	8.2	3125.4	26%	-77.02
216	EMBU	220	31.5	8.4	3193.8	27%	-76.72
217	THIKA 220	220	31.5	11.4	4352.6	36%	-78.39
218	ISIOLO 220	220	31.5	6.9	2647.3	22%	-77.95
219	MAUA 220	220	31.5	6.6	2532.0	21%	-77.78
220	GARISSA	220	31.5	3.1	1181.5	10%	-75.37
221	BURA	220	31.5	2.5	947.3	8%	-74.59

222	HOLA	220	31.5	2.8	1060.6	9%	-74.43
223	GARBATULA	220	31.5	3.4	1282.0	11%	-77.33
224	OLKARIA2 220	220	31.5	20.8	7943.4	66%	-79.94
225	OLKARIA3 220	220	31.5	17.4	6620.4	55%	-80.32
226	OLKARIA 4	220	31.5	21.3	8116.8	68%	-79.92
227	OLK IAU 220	220	31.5	21.3	8117.4	68%	-79.92
228	MENENGAI	220	31.5	9.8	3725.7	31%	-79.76
229	OLKARIA V	220	31.5	11.5	4363.4	36%	-80.32
230	RONGAI	220	31.5	11.0	4208.8	35%	-79.45
231	GILGIL 220	220	40	14.0	5352.6	35%	-80.12
232	AKIRA 220	220	40	5.7	2160.2	14%	-80.2
233	OLKARIA VI	220	40	16.6	6318.4	41%	-79.97
234	OLKARIA VII	220	40	10.7	4058.7	27%	-79.68
235	OLK IX	220	40	7.5	2856.7	19%	-79.89
236	NAIVASHA 220	220	40	14.2	5412.6	36%	-78.9
237	KAKAMEGA	220	40	6.3	2384.3	16%	-74.78
238	MUHORONI	220	40	4.7	1795.6	12%	-75.59
239	TORORO 2	220	40	4.5	1731.7	11%	-77.14
240	TURKWEL	220	31.5	4.0	1532.3	13%	-78.62
241	LESSOS 220	220	31.5	9.2	3521.2	29%	-76.2
242	KITALE	220	31.5	2.6	994.0	8%	-74.84
243	BARINGO 220	220	40	5.0	1920.0	13%	-80.47
244	LOKICHAR	220	40	3.9	1485.2	10%	-79.35
245	KIBOS	220	31.5	6.2	2357.9	20%	-75.14
246	ORTUM	220	31.5	3.0	1149.2	10%	-77.62
247	MUSAGA	220	40	6.8	2589.5	17%	-74.93
248	KERICHO	220	40	5.9	2250.7	15%	-76.52
249	CHEMOSIT 220	220	40	5.4	2046.3	13%	-75.66
250	KISII 220	220	40	3.8	1441.4	9%	-77.34
251	SILALI 220	220	40	8.4	3209.9	21%	-81.3
252	RADIANT	220	40	1.6	595.3	4%	-77.95
253	TURKWELL TEE	220	40	3.0	1150.5	8%	-76.08
254	KAPSOWAR	220	40	2.8	1048.1	7%	-76.04
255	AGIL 220	220	40	12.5	4780.9	31%	-80.24
256	MARSABIT	220	40	4.0	1535.6	10%	-80.01

257	KAINUK	220	31.5	4.0	1521.7	13%	-78.65
258	LOKICHOGGIO	220	40	1.7	645.7	4%	-79.54
259	LODWAR	220	40	3.9	1487.2	10%	-79.36
260	LOYAN	220	40	7.8	2963.2	19%	-82.34
261	ELD NTH 220	220	40	3.6	1374.0	9%	-80.02
262	BUJAGALI	220	40	2.8	1062.2	7%	-79.97
263	KAINUK 66	220	40	2.4	903.0	6%	-83.06
264	OLKARIA 4 WE	220	31.5	21.0	8014.5	67%	-79.94
265	GENERIC2028	220	40	7.7	2921.3	19%	-78.9
266	GENERIC 2033	220	40	11.4	4352.6	29%	-78.39
267	GENERIC 2025	220	40	7.1	2689.5	18%	-82.38
268	GENERIC 2031	220	40	6.2	2357.9	15%	-75.14
269	GENERIC 2035	220	40	3.6	1389.9	9%	-79.4
270	SUSWA PP	220	40	9.8	3747.7	25%	-79.82
271	CHAGEM	220	40	12.1	4618.4	30%	-81.33
272	ELEKTRA	220	40	6.6	2497.6	16%	-80.84
273	VATEKI	220	40	3.8	1465.0	10%	-70.83
274	MERU WIND220	220	40	6.4	2428.0	16%	-78.47
275	HABASWEIN	220	40	0.9	353.2	2%	-78.93
276	ISINYA4	400	40	9.8	6757.6	24%	-74.53
277	SUSWA	400	40	10.8	7501.5	27%	-79.2
278	KIMUKA	400	40	10.3	7119.6	26%	-77.12
279	KONZA4	400	40	9.5	6567.9	24%	-74.86
280	NAMANGA	400	40	6.4	4414.8	16%	-76.64
281	MALAA 400	400	40	9.7	6707.2	24%	-75.13
282	MAKINDU 400	400	40	6.5	4481.6	16%	-74.37
283	MARIAKANI	400	40	4.1	2807.5	10%	-72.99
284	LAMU	400	40	5.5	3822.4	14%	-83.1
285	VOI 400	400	40	4.8	3316.7	12%	-73.49
286	THIKA 400	400	40	9.2	6386.0	23%	-76.2
287	GILGIL	400	40	10.6	7317.3	26%	-77.01
288	RONGAI 400	400	40	8.9	6174.7	22%	-76.84
289	KILGORIS	400	40	4.5	3150.8	11%	-78.16
290	LOYAN 400	400	40	5.5	3828.4	14%	-81.25
291	SILALI	400	40	5.8	4029.6	15%	-79.08

292	RUMRT400 TEE	400	40	10.1	6982.6	25%	-77.4
293	SILALI4 TEE1	400	40	7.5	5208.3	19%	-79.54
294	LONG_HVDC	400	40	10.8	7501.5	27%	-79.2
295	LESSOS 400	400	40	6.8	4734.9	17%	-77.14
296	ARUSHA	400	40	4.6	3179.6	11%	-77.35
297	MEGA_HVDC	400	40	7.4	5140.2	19%	-79.92
298	WOLYATA	400	40	7.4	5140.2	19%	-79.92
2030 THREE PHASE SCC LEVELS (MAX)							
S/n	**BUS**	**BUS VOLTAGE**	**SC RATING**	**FAULT LEVEL (kA)**	**FAULT LEVEL (MVA)**	**% of SC TO EQUIPMENT RATING**	**ANGLE**
1	ULU 132	132	31.5	11.0	2506.7	35%	-73.5
2	DANDORA 132	132	31.5	20.3	4650.6	65%	-71.29
3	JUJA RD 132	132	31.5	21.3	4863.3	68%	-70.43
4	KIBOKO	132	31.5	4.5	1036.0	14%	-68.09
5	MAKINDU 132	132	31.5	5.2	1178.8	16%	-70.62
6	UPLANDS	132	31.5	15.3	3490.6	48%	-68.15
7	RUARAKA 132	132	31.5	20.4	4655.5	65%	-70.69
8	RUARKTEE2	132	31.5	19.6	4473.2	62%	-69.94
9	RUARKTEE1	132	31.5	19.6	4473.2	62%	-69.94
10	SULTAN HAMUD	132	31.5	5.3	1202.3	17%	-66.5
11	KAJIADO	132	31.5	3.6	829.8	12%	-85
12	KONZA	132	31.5	14.5	3309.5	46%	-77.19
13	MACHAKOS	132	31.5	7.3	1676.1	23%	-69.56
14	NAMANGA	132	31.5	1.4	322.0	4%	-72.33
15	ISINYA 132	132	31.5	3.8	862.3	12%	-85.87
16	KONZA SGR	132	31.5	7.9	1801.9	25%	-71.91
17	SULTAN SGR	132	31.5	4.8	1095.5	15%	-65.82
18	MAKINDU NEW	132	31.5	7.8	1774.9	25%	-77.69
19	MAKINDU SGR	132	31.5	7.0	1590.5	22%	-76.39
20	MKD TEE	132	31.5	6.9	1579.2	22%	-75.5
21	MKD T-OFF	132	31.5	6.8	1544.8	21%	-75.54
22	NDALSYN TEE1	132	31.5	3.6	823.8	11%	-68.13
23	NDALSYN TEE2	132	31.5	3.5	810.8	11%	-67.97
24	NDALSYAN SGR	132	31.5	3.6	817.5	11%	-68.02
25	TSAVO TEE 1	132	31.5	3.7	834.9	12%	-67.43

26	TSAVO TEE 2	132	31.5	3.8	878.1	12%	-67.64
27	TSAVO SGR	132	31.5	3.7	855.7	12%	-67.48
28	THIKARD132	132	31.5	20.3	4641.6	64%	-70.74
29	OWEN FALLS	132	31.5	2.1	481.4	7%	-59.6
30	VOI 132	132	31.5	7.9	1808.8	25%	-73.1
31	VIPINGO RANG	132	31.5	4.7	1071.5	15%	-67.52
32	KIPEVU 2	132	31.5	6.5	1486.7	21%	-61.83

33	KIPEVU	132	31.5	6.5	1495.8	21%	-61.77
34	KOKOTONI	132	31.5	6.3	1450.3	20%	-62.2
35	MARIAKANI	132	31.5	4.8	1102.0	15%	-62.89
36	MAUNGU132	132	31.5	4.2	950.2	13%	-67.43
37	MOMBASA CEM	132	31.5	4.6	1047.7	15%	-67.4
38	MBSACEM TEE1	132	31.5	4.6	1053.4	15%	-67.42
39	MBSACEM TEE2	132	31.5	4.6	1043.8	14%	-67.62
40	NEW BAMB 132	132	31.5	5.1	1160.7	16%	-62.31
41	RABAI 132	132	31.5	7.3	1680.2	23%	-61.81
42	RABAI POWER	132	31.5	7.3	1662.0	23%	-61.95
43	SAMBURU 132	132	31.5	3.5	791.2	11%	-63.96
44	GALU	132	31.5	4.0	915.4	13%	-61.59
45	MANYANI	132	31.5	4.0	916.8	13%	-67.89
46	KILIFI	132	31.5	4.6	1049.2	15%	-68.4
47	MTITO ANDEI	132	31.5	3.5	791.8	11%	-67.79
48	TITANIUM 132	132	31.5	3.5	809.1	11%	-62.88
49	GARISSA	132	31.5	4.5	1027.0	14%	-77.24
50	JOMVU	132	31.5	6.1	1396.8	19%	-63.02
51	KWALE SC	132	31.5	3.2	728.1	10%	-65.79
52	LIKONI	132	31.5	3.5	808.3	11%	-62.11
53	BAMBURI CEME	132	31.5	5.4	1243.2	17%	-69.42
54	S_HAMUD_NEW	132	31.5	4.9	1126.2	16%	-65.86
55	MBARAKI	132	31.5	5.5	1246.3	17%	-61.62
56	TAVETA	132	31.5	1.4	326.4	5%	-65.95
57	S_HAMUD_TEE	132	31.5	5.5	1249.1	17%	-66.45
58	LIKONI TEE	132	31.5	4.8	1105.4	15%	-61.29
59	LUNGA LUNGA	132	31.5	3.3	761.7	11%	-67.83
60	LOITOKTOK	132	31.5	1.9	424.4	6%	-65.43

61	MERUWESHI	132	31.5	4.9	1115.6	15%	-65.85
62	MTWAPA	132	31.5	5.0	1135.4	16%	-68
63	SHIMONI	132	31.5	3.2	736.2	10%	-67.14
64	VOI 132 NEW	132	31.5	9.3	2119.7	29%	-76.16
65	MACKNN TEE 1	132	31.5	3.3	751.5	10%	-65.54
66	MACKNN TEE2	132	31.5	3.1	715.4	10%	-64.62
67	MAKINNON SGR	132	31.5	3.2	723.2	10%	-64.88
68	MARIAKNI NEW	132	31.5	4.4	1000.5	14%	-63.19
69	MARIAKN SGR	132	31.5	4.8	1102.0	15%	-62.89
70	KWALE	132	31.5	4.9	1129.5	16%	-74.85
71	GITARU 132	132	31.5	14.1	3235.1	45%	-80.68
72	GITHAMBO	132	31.5	4.7	1066.9	15%	-67.2
73	KAMBURU 132	132	31.5	16.2	3701.4	51%	-80
74	KIGANJO	132	31.5	11.5	2618.5	36%	-74.91
75	KILBOGO TEE1	132	31.5	8.5	1947.3	27%	-68.98
76	KINDARUMA	132	31.5	6.0	1381.0	19%	-70.84
77	KILBOGO TEE2	132	31.5	7.7	1771.3	25%	-69.55
78	MANGU	132	31.5	15.6	3575.9	50%	-76.59
79	MASINGA	132	31.5	8.4	1919.3	27%	-79.09
80	MERU 132	132	31.5	9.0	2057.8	29%	-73.75
81	NANYUKI 132	132	31.5	8.1	1851.5	26%	-67.45
82	GATUNDU	132	31.5	5.7	1312.1	18%	-69.45

83	KUTUS 132	132	31.5	13.1	2990.5	42%	-78.5
84	KUTUS_T1	132	31.5	8.5	1949.8	27%	-76.24
85	KUTUS_T2	132	31.5	7.4	1699.9	24%	-77.3
86	THIKAPWR 132	132	31.5	15.4	3515.1	49%	-76.42
87	ISIOLO	132	31.5	10.6	2412.8	34%	-72.92
88	MWINGI	132	31.5	3.9	885.2	12%	-67.37
89	KITUI	132	31.5	2.7	612.2	9%	-65.09
90	KYENI	132	31.5	6.0	1370.5	19%	-71
91	MAUA	132	31.5	9.5	2181.3	30%	-78.8
92	TATU CITY	132	31.5	7.5	1716.5	24%	-70.91
93	MUTOMO	132	31.5	1.3	302.1	4%	-64.3
94	KIBWEZI	132	31.5	0.9	208.0	3%	-63.92
95	KIBR TEE 2	132	31.5	13.3	3047.5	42%	-77.26

96	OTHAYA	132	31.5	4.8	1102.9	15%	-67.45
97	WOTE	132	31.5	3.0	683.6	9%	-65.38
98	ISHIARA SWST	132	31.5	6.8	1561.8	22%	-75.63
99	KIBIRIGWI	132	31.5	13.3	3047.5	42%	-77.26
100	THIKA NEW	132	31.5	15.6	3575.9	50%	-76.59
101	ISIOLO SS2	132	31.5	11.1	2532.4	35%	-76.98
102	GARISSA SS2	132	31.5	4.5	1027.0	14%	-77.24
103	CHOGORIA	132	31.5	3.0	681.4	9%	-68.08
104	MWALA	132	31.5	6.9	1582.9	22%	-68.41
105	LANET	132	31.5	12.4	2826.4	39%	-69.7
106	NAIVASHA 132	132	31.5	13.3	3043.5	42%	-73.91
107	OLKARIA1 132	132	31.5	9.6	2188.6	30%	-84.5
108	NAKRUWEST_T1	132	31.5	13.6	3106.7	43%	-71.51
109	NAKRUWEST_T2	132	31.5	13.3	3044.6	42%	-71.45
110	MAKUTANO_T1	132	31.5	8.6	1956.2	27%	-66.93
111	MAKUTANO_T2	132	31.5	8.7	1984.3	28%	-66.9
112	OLK 1AU 132	132	31.5	9.6	2203.5	31%	-84.6
113	OLKALOU	132	31.5	7.3	1675.1	23%	-68.24
114	AEOLUS WIND	132	31.5	7.1	1619.1	22%	-72.03
115	NAROK	132	31.5	4.2	971.1	13%	-69.01
116	GILGIL	132	31.5	14.2	3244.0	45%	-76.62
117	GILGIL TEE1	132	31.5	13.4	3053.1	42%	-74.72
118	GILGIL TEE2	132	31.5	12.5	2854.9	40%	-73.13
119	OLK I WE	132	31.5	8.8	2001.0	28%	-82.91
120	KAKAMEGA132	132	31.5	7.5	1724.2	24%	-75.5
121	WEBUYE	132	31.5	6.3	1436.3	20%	-68.35
122	CHEMOSIT	132	31.5	7.2	1639.3	23%	-73.88
123	KISII	132	31.5	6.5	1483.7	21%	-71.72
124	KISUMU 132	132	31.5	9.8	2243.8	31%	-68.91
125	MUHORONI 132	132	31.5	7.7	1769.7	25%	-72.22
126	MUMIAS 132	132	31.5	5.2	1181.0	16%	-66.65
127	MUSAGA 132	132	31.5	9.7	2213.0	31%	-70.81
128	RANGALA 132	132	31.5	5.5	1260.0	17%	-65.21
129	SANGORO	132	31.5	4.6	1056.6	15%	-69.45
130	SONDU MIRIU	132	31.5	5.2	1197.6	17%	-69.98
131	AWENDO	132	31.5	3.7	852.9	12%	-65.57

132	BOMET	132	31.5	5.0	1148.1	16%	-68.08
133	ONGENG	132	31.5	3.5	798.2	11%	-65.64
134	SOTIK	132	31.5	9.1	2084.6	29%	-71.41
135	BONDO	132	31.5	3.7	850.4	12%	-64.88
136	CHAVAKALI	132	31.5	8.0	1831.7	25%	-69.52
137	KISUMU EAST	132	31.5	8.8	2017.6	28%	-68.16
138	MALABA TEE2	132	31.5	3.6	830.7	12%	-64.55
139	ISABENIA	132	31.5	1.9	440.4	6%	-64.75
140	TORORO 132	132	31.5	5.3	1216.6	17%	-65.19
141	MAKUTANO 132	132	31.5	8.7	1994.1	28%	-66.91
142	NAKURU_W 132	132	31.5	13.6	3115.2	43%	-71.63
143	KILGORIS	132	31.5	12.1	2762.7	38%	-79.01
144	MYANGA	132	31.5	6.5	1482.3	21%	-66.55
145	BUSIA	132	31.5	5.5	1252.7	17%	-65.86
146	NDWIGA	132	31.5	2.9	655.4	9%	-64.76
147	SINDO	132	31.5	2.0	453.9	6%	-65.55
148	KARUNGO	132	31.5	1.8	402.2	6%	-65.86
149	KIMILILI	132	31.5	5.5	1267.1	18%	-68.51
150	KAIMOSI	132	31.5	8.0	1831.7	25%	-69.52
151	SUKARI	132	31.5	3.2	741.3	10%	-65.65
152	ELDORET	132	31.5	8.5	1935.4	27%	-71.96
153	LESSOS 132	132	31.5	13.6	3119.4	43%	-71.37
154	KITALE	132	31.5	5.7	1295.6	18%	-70.78
155	KABARNET	132	31.5	3.5	795.1	11%	-66.37
156	KAPSABET	132	31.5	7.0	1599.8	22%	-68.26
157	KIBOS1	132	31.5	10.0	2287.1	32%	-69.3
158	RUMURUTI	132	31.5	7.0	1606.6	22%	-67.08
159	SILALI	132	31.5	14.2	3245.8	45%	-82.9
160	ELDORET NTH	132	31.5	8.4	1921.3	27%	-73.04
161	MOI BRCKS	132	31.5	5.4	1232.1	17%	-69.38
162	MARALAL	132	31.5	4.7	1067.9	15%	-68.28
163	KERINGET	132	31.5	2.7	624.1	9%	-63.59
164	MENENGAI 132	132	31.5	14.1	3215.8	45%	-74.99
165	GENERIC 2023	132	31.5	3.4	766.1	11%	-69.85
166	GENERIC 2024	132	31.5	4.2	971.1	13%	-69.01

167	GENERIC 2034	132	31.5	2.9	654.3	9%	-69.49
168	SUSTAINABLE	132	31.5	21.3	4863.3	68%	-70.43
169	MAKINDU SLR	132	31.5	4.5	1036.0	14%	-68.09
170	CHERAB	132	31.5	11.1	2532.4	35%	-76.98
171	MERU WIND	132	31.5	11.1	2532.4	35%	-76.98
172	CRYSTAL	132	31.5	0.9	208.0	3%	-63.92
173	KIBR TEE 1	132	31.5	12.9	2941.9	41%	-76.81
174	KOPERE	132	31.5	7.1	1621.5	23%	-71.36
175	QUAINT	132	31.5	4.7	1079.2	15%	-69.12
176	KAPTIS	132	31.5	8.0	1831.7	25%	-69.52
177	K TE 1	132	31.5	9.5	2173.9	30%	-68
178	K TE 2	132	31.5	9.5	2173.9	30%	-68
179	TARITA SLR	132	31.5	4.1	944.0	13%	-66.88
180	KENERGY SLR	132	31.5	7.0	1606.6	22%	-67.08
181	SUNPOWER	132	31.5	3.2	724.8	10%	-65.97
182	GITARU SLR	132	31.5	9.5	2179.4	30%	-80.6

183	DANDORA 220	220	31.5	14.1	5367.0	45%	-72.3
184	EMBAKASI	220	31.5	11.4	4358.9	36%	-68.4
185	EMBAKASI_CC	220	31.5	11.4	4327.3	36%	-68.57
186	THIKA RD BSP	220	31.5	16.3	6225.1	52%	-70.09
187	CBD	220	31.5	10.7	4071.0	34%	-69.17
188	NRBI NORTH	220	31.5	14.7	5610.6	47%	-73.21
189	ISINYA	220	31.5	13.0	4952.2	41%	-74.92
190	SUSWA	220	31.5	24.6	9370.8	78%	-78.85
191	LONGONOT	220	31.5	9.1	3464.3	29%	-82.94
192	ATHI RIVER	220	31.5	11.2	4283.0	36%	-68.86
193	MALAA220	220	31.5	17.6	6696.9	56%	-70.66
194	NGONG	220	31.5	13.5	5158.8	43%	-80.84
195	MAGADI	220	31.5	2.8	1067.1	9%	-80.23
196	LONGONOT	220	31.5	5.9	2258.7	19%	-79.81
197	RABAI 220	220	31.5	6.5	2481.0	21%	-63.62
198	GARSEN 220	220	31.5	5.7	2183.3	18%	-72.74
199	LAMU 220	220	31.5	7.3	2768.9	23%	-79.81
200	MALINDI 220	220	31.5	5.1	1944.0	16%	-67.28
201	BAMBUR CE220	220	31.5	5.2	1994.9	17%	-66.14

202	GALANA 220	220	31.5	3.6	1362.7	11%	-70.08
203	SWTCH STN	220	31.5	5.2	1989.8	17%	-65.64
204	KILIFI 220	220	31.5	3.2	1209.5	10%	-68.6
205	MARIAKANI EH	220	31.5	7.6	2899.9	24%	-65.79
206	LAMU 220_2	220	31.5	8.1	3100.0	26%	-81.78
207	NNDONGO KUND	220	31.5	4.8	1834.5	15%	-69.16
208	KWALE	220	31.5	5.0	1901.2	16%	-68.98
209	TEE-OFF	220	31.5	5.4	2045.0	17%	-68.35
210	DOGO LNG	220	31.5	4.7	1807.2	15%	-69.32
211	GITARU 220	220	31.5	10.0	3820.4	32%	-78.13
212	KAMBURU 220	220	31.5	13.2	5041.9	42%	-77
213	KIAMBERE 220	220	31.5	11.2	4286.5	36%	-77.39
214	KARURA	220	31.5	9.0	3444.4	29%	-78.5
215	KIBIRIGWI	220	31.5	10.1	3840.8	32%	-76.66
216	EMBU	220	31.5	10.9	4162.9	35%	-76.73
217	THIKA 220	220	31.5	13.7	5221.3	43%	-77.4
218	HG FALLS 220	220	31.5	9.5	3631.1	30%	-81.28
219	ISIOLO 220	220	31.5	7.9	3010.9	25%	-77.16
220	MAUA 220	220	31.5	7.7	2919.6	24%	-77.15
221	GARISSA	220	31.5	3.5	1323.0	11%	-74.38
222	BURA	220	31.5	2.8	1072.3	9%	-74.04
223	HOLA	220	31.5	3.2	1210.3	10%	-73.8
224	WAJIR	220	31.5	0.8	289.1	2%	-77.77
225	MANDERA	220	31.5	0.6	219.2	2%	-78
226	GARBATULA	220	31.5	3.8	1459.7	12%	-76.85
227	MOYALE	220	31.5	2.0	776.7	6%	-80.17
228	OLKARIA2 220	220	31.5	22.1	8417.4	70%	-79.37
229	OLKARIA3 220	220	31.5	18.5	7040.1	59%	-79.84
230	OLKARIA 4	220	31.5	19.8	7562.8	63%	-81.25
231	OLK IAU 220	220	31.5	22.0	8365.6	70%	-79.33
232	MENENGAI	220	31.5	12.6	4802.1	40%	-79.97
233	OLKARIA V	220	31.5	12.3	4672.2	39%	-81.48
234	RONGAI	220	31.5	13.9	5305.9	44%	-79.44
235	GILGIL 220	220	31.5	16.5	6304.7	53%	-80.17
236	AKIRA 220	220	31.5	5.4	2054.4	17%	-81.98

237	OLKARIA VI	220	31.5	17.5	6665.1	56%	-79.59
238	OLKARIA VII	220	31.5	12.7	4845.0	40%	-79.74
239	OLK IX	220	31.5	6.8	2595.8	22%	-82.23
240	OLKARIA VIII	220	31.5	6.9	2615.2	22%	-82.46
241	NAIVASHA 220	220	31.5	9.9	3759.6	31%	-79.11
242	KAKAMEGA	220	31.5	7.5	2875.7	24%	-74.16
243	MUHORONI	220	31.5	5.5	2086.9	17%	-75.23
244	TORORO 2	220	31.5	5.3	2028.4	17%	-76.95
245	TURKWEL	220	31.5	5.0	1887.6	16%	-78.18
246	LESSOS 220	220	31.5	11.2	4271.2	36%	-75.64
247	KITALE	220	31.5	3.1	1173.9	10%	-75.14
248	BARINGO 220	220	31.5	8.0	3055.1	25%	-78.24
249	LOKICHAR	220	31.5	5.6	2139.1	18%	-78.64
250	KIBOS	220	31.5	7.6	2878.3	24%	-74.73
251	ORTUM	220	31.5	3.6	1362.6	11%	-77.48
252	MUSAGA	220	31.5	8.2	3126.9	26%	-74.32
253	KERICHO	220	31.5	7.0	2665.3	22%	-76.11
254	CHEMOSIT 220	220	31.5	6.3	2401.6	20%	-75.24
255	KISII 220	220	31.5	4.3	1648.9	14%	-77.07
256	SILALI 220	220	31.5	12.0	4558.2	38%	-80.43
257	RADIANT	220	31.5	1.8	670.2	6%	-77.79
258	TURKWELL TEE	220	31.5	3.5	1323.1	11%	-75.68
259	KAPSOWAR	220	31.5	3.2	1201.0	10%	-75.65
260	AGIL 220	220	31.5	12.9	4909.3	41%	-81.25
261	MARSABIT	220	31.5	4.7	1787.5	15%	-80
262	KAINUK	220	31.5	4.9	1882.1	16%	-78.21
263	LOKICHOGGIO	220	31.5	2.1	793.1	7%	-79.23
264	LODWAR	220	31.5	5.6	2148.2	18%	-78.65
265	LOYAN	220	31.5	9.1	3454.3	29%	-82.02
266	ELD NTH 220	220	31.5	6.1	2318.5	19%	-76.91
267	BUJAGALI	220	31.5	3.2	1214.7	10%	-79.97
268	KAINUK 66	220	31.5	2.7	1018.8	8%	-83.38
269	OLKARIA 4 WE	220	31.5	19.6	7482.9	62%	-81.25
270	GENERIC2028	220	31.5	9.0	3444.4	29%	-78.5
271	GENERIC2029	220	31.5	5.0	1921.3	16%	-73.04
272	GENERIC2030	220	31.5	13.5	5158.8	43%	-80.84

273	GENERIC 2033	220	31.5	13.7	5221.3	43%	-77.4
274	GENERIC 2025	220	31.5	7.7	2932.3	24%	-82.02
275	GENERIC 2031	220	31.5	7.6	2878.3	24%	-74.73
276	GENERIC 2035	220	31.5	5.2	1963.0	16%	-78.76
277	SUSWA PP	220	31.5	8.5	3229.8	27%	-82.75
278	CHAGEM	220	31.5	13.5	5158.8	43%	-80.84
279	ELEKTRA	220	31.5	7.3	2768.9	23%	-79.81
280	VATEKI	220	31.5	5.1	1944.0	16%	-67.28
281	MERU WIND220	220	31.5	7.2	2744.3	23%	-77.76
282	HABASWEIN	220	31.5	1.0	386.4	3%	-77.67

283	ISINYA4	400	40	12.1	8360.4	30%	-71.59
284	SUSWA	400	40	13.5	9319.0	34%	-77.5
285	KIMUKA	400	40	12.7	8783.0	32%	-74.92
286	KONZA4	400	40	11.8	8145.4	29%	-72.07
287	NAMANGA	400	40	7.6	5249.1	19%	-75.11
288	LONGONOT	400	40	8.2	5714.8	21%	-77.98
289	MALAA 400	400	40	12.1	8369.8	30%	-72.34
290	MAKINDU 400	400	40	7.7	5333.4	19%	-71.46
291	KITUI	400	40	4.3	2986.1	11%	-80.24
292	MARIAKANI	400	40	4.9	3374.0	12%	-68.74
293	LAMU	400	40	6.0	4183.9	15%	-82.17
294	VOI 400	400	40	5.7	3953.6	14%	-69.99
295	THIKA 400	400	40	11.9	8210.8	30%	-74.22
296	HG FALL 400	400	40	5.7	3952.9	14%	-80.35
297	GILGIL	400	40	13.6	9424.6	34%	-75.61
298	RONGAI 400	400	40	11.6	8048.5	29%	-75.88
299	KILGORIS	400	40	5.4	3758.6	14%	-77.79
300	LOYAN 400	400	40	6.5	4517.8	16%	-80.93
301	SILALI	400	40	8.0	5541.4	20%	-78.66
302	RUMRT400 TEE	400	40	12.9	8913.7	32%	-76.15
303	SILALI4 TEE1	400	40	9.2	6345.0	23%	-78.92
304	LONG_HVDC	400	40	13.5	9319.0	34%	-77.5
305	LESSOS 400	400	40	8.4	5829.5	21%	-76.61
306	ARUSHA	400	40	5.3	3695.2	13%	-76.45

307	MEGA_HVDC	400	40	7.5	5174.6	19%	-79.31
308	WOLYATA	400	40	7.5	5174.6	19%	-79.31
2030 THREE PHASE SCC LEVELS (MIN)							
S/n	**BUS**	**BUS VOLTAGE**	**SC RATING**	**FAULT LEVEL (kA)**	**FAULT LEVEL (MVA)**	**% of SC TO EQUIPMENT RATING**	**ANGLE**
1	ULU 132	132	31.5	10.4	2384.1	33%	-73.8
2	DANDORA 132	132	31.5	19.4	4435.6	62%	-71.91
3	JUJA RD 132	132	31.5	20.3	4645.2	64%	-71.03
4	KIBOKO	132	31.5	4.2	960.4	13%	-68.14
5	MAKINDU 132	132	31.5	4.8	1103.1	15%	-70.7
6	UPLANDS	132	31.5	14.4	3284.0	46%	-68.41
7	RUARAKA 132	132	31.5	19.4	4444.8	62%	-71.28
8	RUARKTEE2	132	31.5	18.6	4256.2	59%	-70.44
9	RUARKTEE1	132	31.5	18.6	4256.2	59%	-70.44
10	SULTAN HAMUD	132	31.5	4.9	1111.6	15%	-66.58
11	KAJIADO	132	31.5	3.6	821.3	11%	-85.07
12	KONZA	132	31.5	14.0	3204.9	44%	-77.8
13	MACHAKOS	132	31.5	6.8	1561.4	22%	-69.66
14	NAMANGA	132	31.5	1.3	302.0	4%	-71.99
15	ISINYA 132	132	31.5	3.7	856.5	12%	-86.01
16	KONZA SGR	132	31.5	7.4	1694.9	24%	-72.06
17	SULTAN SGR	132	31.5	4.4	1010.9	14%	-65.89
18	MAKINDU NEW	132	31.5	7.5	1712.5	24%	-78.15
19	MAKINDU SGR	132	31.5	6.7	1524.9	21%	-76.74
20	MKD TEE	132	31.5	6.6	1508.9	21%	-75.79
21	MKD T-OFF	132	31.5	6.5	1475.6	20%	-75.83
22	NDALSYN TEE1	132	31.5	3.3	761.8	11%	-68.16
23	NDALSYN TEE2	132	31.5	3.3	749.3	10%	-68
24	NDALSYAN SGR	132	31.5	3.3	755.7	10%	-68.06
25	TSAVO TEE 1	132	31.5	3.4	769.7	11%	-67.46
26	TSAVO TEE 2	132	31.5	3.5	810.3	11%	-67.67
27	TSAVO SGR	132	31.5	3.5	789.2	11%	-67.51
28	THIKARD132	132	31.5	19.4	4431.7	62%	-71.34

29	OWEN FALLS	132	31.5	1.9	441.0	6%	-59.7
30	VOI 132	132	31.5	7.5	1711.3	24%	-73.23
31	VIPINGO RANG	132	31.5	4.4	1004.4	14%	-67.78
32	KIPEVU 2	132	31.5	6.1	1396.5	19%	-62.53
33	KIPEVU	132	31.5	6.1	1405.4	20%	-62.47
34	KOKOTONI	132	31.5	5.9	1359.6	19%	-62.84
35	MARIAKANI	132	31.5	4.5	1022.6	14%	-63.36
36	MAUNGU132	132	31.5	3.8	877.8	12%	-67.52
37	MOMBASA CEM	132	31.5	4.3	980.7	14%	-67.66
38	MBSACEM TEE1	132	31.5	4.3	986.5	14%	-67.67
39	MBSACEM TEE2	132	31.5	4.3	977.0	14%	-67.87
40	NEW BAMB 132	132	31.5	4.7	1082.0	15%	-62.84
41	RABAI 132	132	31.5	6.9	1585.9	22%	-62.55
42	RABAI POWER	132	31.5	6.9	1568.1	22%	-62.7
43	SAMBURU 132	132	31.5	3.2	727.8	10%	-64.25
44	GALU	132	31.5	3.7	847.6	12%	-62
45	MANYANI	132	31.5	3.7	846.8	12%	-67.92
46	KILIFI	132	31.5	4.3	982.7	14%	-68.68
47	MTITO ANDEI	132	31.5	3.2	731.0	10%	-67.82
48	TITANIUM 132	132	31.5	3.3	748.2	10%	-63.25
49	GARISSA	132	31.5	4.2	966.0	13%	-77.29
50	JOMVU	132	31.5	5.7	1309.0	18%	-63.7
51	KWALE SC	132	31.5	3.0	675.0	9%	-66.1
52	LIKONI	132	31.5	3.3	746.9	10%	-62.5
53	BAMBURI CEME	132	31.5	5.2	1178.6	16%	-69.79
54	S_HAMUD_NEW	132	31.5	4.5	1039.7	14%	-65.93
55	MBARAKI	132	31.5	5.1	1163.6	16%	-62.21
56	TAVETA	132	31.5	1.3	298.8	4%	-65.94
57	S_HAMUD_TEE	132	31.5	5.1	1155.5	16%	-66.53
58	LIKONI TEE	132	31.5	4.5	1028.2	14%	-61.81
59	LUNGA LUNGA	132	31.5	3.1	708.8	10%	-68.01
60	LOITOKTOK	132	31.5	1.7	388.0	5%	-65.46
61	MERUWESHI	132	31.5	4.5	1029.8	14%	-65.93
62	MTWAPA	132	31.5	4.7	1068.6	15%	-68.3
63	SHIMONI	132	31.5	3.0	683.8	9%	-67.35
64	VOI 132 NEW	132	31.5	8.9	2028.7	28%	-76.41

65	MACKNN TEE 1	132	31.5	3.0	690.5	10%	-65.68
66	MACKNN TEE2	132	31.5	2.9	656.7	9%	-64.82
67	MAKINNON SGR	132	31.5	2.9	663.9	9%	-65.05
68	MARIAKNI NEW	132	31.5	4.1	926.6	13%	-63.63
69	MARIAKN SGR	132	31.5	4.5	1022.6	14%	-63.36
70	KWALE	132	31.5	4.7	1076.6	15%	-75.09

71	GITARU 132	132	31.5	13.6	3113.6	43%	-81
72	GITHAMBO	132	31.5	4.3	982.7	14%	-67.27
73	KAMBURU 132	132	31.5	15.6	3571.3	50%	-80.34
74	KIGANJO	132	31.5	10.8	2473.6	34%	-75.25
75	KILBOGO TEE1	132	31.5	7.9	1810.7	25%	-69.14
76	KINDARUMA	132	31.5	5.6	1291.6	18%	-71.17
77	KILBOGO TEE2	132	31.5	7.2	1648.5	23%	-69.67
78	MANGU	132	31.5	15.1	3456.3	48%	-77.28
79	MASINGA	132	31.5	7.8	1791.2	25%	-79.27
80	MERU 132	132	31.5	8.5	1932.8	27%	-74.04
81	NANYUKI 132	132	31.5	7.5	1710.9	24%	-67.55
82	GATUNDU	132	31.5	5.3	1219.5	17%	-69.54
83	KUTUS 132	132	31.5	12.5	2847.5	40%	-78.88
84	KUTUS_T1	132	31.5	7.9	1815.8	25%	-76.45
85	KUTUS_T2	132	31.5	6.9	1580.3	22%	-77.47
86	THIKAPWR 132	132	31.5	14.8	3394.0	47%	-77.08
87	ISIOLO	132	31.5	9.9	2261.0	31%	-73.15
88	MWINGI	132	31.5	3.6	815.8	11%	-67.48
89	KITUI	132	31.5	2.5	560.8	8%	-65.15
90	KYENI	132	31.5	5.5	1265.7	18%	-71.04
91	MAUA	132	31.5	9.1	2070.4	29%	-79.06
92	TATU CITY	132	31.5	7.0	1606.8	22%	-71.07
93	MUTOMO	132	31.5	1.2	275.7	4%	-64.33
94	KIBWEZI	132	31.5	0.8	189.6	3%	-63.94
95	KIBR TEE 2	132	31.5	12.7	2899.7	40%	-77.67
96	OTHAYA	132	31.5	4.4	1016.2	14%	-67.52
97	WOTE	132	31.5	2.7	626.7	9%	-65.43
98	ISHIARA SWST	132	31.5	6.3	1443.7	20%	-75.78
99	KIBIRIGWI	132	31.5	12.7	2899.7	40%	-77.67

100	THIKA NEW	132	31.5	15.1	3456.3	48%	-77.28
101	ISIOLO SS2	132	31.5	10.5	2397.4	33%	-77.36
102	GARISSA SS2	132	31.5	4.2	966.0	13%	-77.29
103	CHOGORIA	132	31.5	2.7	624.2	9%	-68.08
104	MWALA	132	31.5	6.4	1466.1	20%	-68.52
105	LANET	132	31.5	11.7	2668.4	37%	-69.89
106	NAIVASHA 132	132	31.5	12.7	2893.6	40%	-74.29
107	OLKARIA1 132	132	31.5	9.4	2155.9	30%	-84.76
108	NAKRUWEST_T1	132	31.5	12.9	2951.0	41%	-71.87
109	NAKRUWEST_T2	132	31.5	12.6	2889.7	40%	-71.81
110	MAKUTANO_T1	132	31.5	8.0	1818.8	25%	-67.1
111	MAKUTANO_T2	132	31.5	8.1	1845.5	26%	-67.07
112	OLK 1AU 132	132	31.5	9.5	2172.2	30%	-84.86
113	OLKALOU	132	31.5	6.8	1554.5	22%	-68.39
114	AEOLUS WIND	132	31.5	6.6	1517.8	21%	-72.29
115	NAROK	132	31.5	3.9	898.2	12%	-68.88
116	GILGIL	132	31.5	13.7	3126.5	43%	-77.18
117	GILGIL TEE1	132	31.5	12.8	2922.5	41%	-75.1
118	GILGIL TEE2	132	31.5	11.9	2716.1	38%	-73.38
119	OLK I WE	132	31.5	8.6	1957.6	27%	-83.02
120	KAKAMEGA132	132	31.5	7.2	1643.8	23%	-75.99
121	WEBUYE	132	31.5	5.8	1337.5	19%	-68.65
122	CHEMOSIT	132	31.5	6.8	1556.9	22%	-74.25
123	KISII	132	31.5	6.1	1390.7	19%	-72.03
124	KISUMU 132	132	31.5	9.3	2122.7	29%	-69.52
125	MUHORONI 132	132	31.5	7.3	1665.2	23%	-72.57
126	MUMIAS 132	132	31.5	4.8	1095.4	15%	-66.93
127	MUSAGA 132	132	31.5	9.2	2099.9	29%	-71.46
128	RANGALA 132	132	31.5	5.1	1168.1	16%	-65.5
129	SANGORO	132	31.5	4.3	994.0	14%	-69.93
130	SONDU MIRIU	132	31.5	4.9	1130.4	16%	-70.53
131	AWENDO	132	31.5	3.4	788.5	11%	-65.76
132	BOMET	132	31.5	4.6	1059.7	15%	-68.06
133	ONGENG	132	31.5	3.2	738.2	10%	-65.85
134	SOTIK	132	31.5	8.5	1951.6	27%	-71.54

135	BONDO	132	31.5	3.4	783.5	11%	-65.08
136	CHAVAKALI	132	31.5	7.5	1715.2	24%	-69.84
137	KISUMU EAST	132	31.5	8.3	1901.4	26%	-68.69
138	MALABA TEE2	132	31.5	3.4	766.5	11%	-64.72
139	ISABENIA	132	31.5	1.8	404.0	6%	-64.87
140	TORORO 132	132	31.5	4.9	1130.4	16%	-65.46
141	MAKUTANO 132	132	31.5	8.1	1854.8	26%	-67.09
142	NAKURU_W 132	132	31.5	12.9	2960.2	41%	-72.01
143	KILGORIS	132	31.5	11.5	2618.0	36%	-79.3
144	MYANGA	132	31.5	6.1	1383.6	19%	-66.9
145	BUSIA	132	31.5	5.1	1162.7	16%	-66.15
146	NDWIGA	132	31.5	2.6	602.0	8%	-64.93
147	SINDO	132	31.5	1.8	416.6	6%	-65.67
148	KARUNGO	132	31.5	1.6	368.8	5%	-65.97
149	KIMILILI	132	31.5	5.1	1175.3	16%	-68.74
150	KAIMOSI	132	31.5	7.5	1715.2	24%	-69.84
151	SUKARI	132	31.5	3.0	684.1	9%	-65.83
152	ELDORET	132	31.5	8.0	1819.2	25%	-72.29
153	LESSOS 132	132	31.5	13.0	2967.6	41%	-72.06
154	KITALE	132	31.5	5.3	1202.8	17%	-71
155	KABARNET	132	31.5	3.2	728.8	10%	-66.46
156	KAPSABET	132	31.5	6.5	1486.4	21%	-68.51
157	KIBOS1	132	31.5	9.5	2166.5	30%	-69.94
158	RUMURUTI	132	31.5	6.5	1480.4	21%	-67.19
159	SILALI	132	31.5	13.8	3150.1	44%	-83.15
160	ELDORET NTH	132	31.5	7.9	1809.5	25%	-73.41
161	MOI BRCKS	132	31.5	5.0	1141.4	16%	-69.53
162	MARALAL	132	31.5	4.3	982.8	14%	-68.23
163	KERINGET	132	31.5	2.5	571.3	8%	-63.62
164	MENENGAI 132	132	31.5	13.5	3088.0	43%	-75.63
165	GENERIC 2023	132	31.5	3.1	703.0	10%	-69.93
166	GENERIC 2024	132	31.5	3.9	898.2	12%	-68.88
167	GENERIC 2034	132	31.5	2.6	602.5	8%	-69.36
168	SUSTAINABLE	132	31.5	20.3	4645.2	64%	-71.03
169	MAKINDU SLR	132	31.5	4.2	960.4	13%	-68.14
170	CHERAB	132	31.5	10.5	2397.4	33%	-77.36

171	MERU WIND	132	31.5	10.5	2397.4	33%	-77.36
172	CRYSTAL	132	31.5	0.8	189.6	3%	-63.94
173	KIBR TEE 1	132	31.5	12.2	2793.6	39%	-77.2
174	KOPERE	132	31.5	6.6	1512.5	21%	-71.79
175	QUAINT	132	31.5	4.4	1013.0	14%	-69.56
176	KAPTIS	132	31.5	7.5	1715.2	24%	-69.84
177	K TE 1	132	31.5	8.9	2029.8	28%	-68.29
178	K TE 2	132	31.5	8.9	2029.8	28%	-68.29
179	TARITA SLR	132	31.5	3.8	867.5	12%	-67
180	KENERGY SLR	132	31.5	6.5	1480.4	21%	-67.19
181	SUNPOWER	132	31.5	2.9	665.5	9%	-66.02
182	GITARU SLR	132	31.5	9.0	2059.3	29%	-80.81
183	DANDORA 220	220	31.5	13.3	5075.8	42%	-73.02
184	EMBAKASI	220	31.5	10.8	4115.1	34%	-69.06
185	EMBAKASI_CC	220	31.5	10.7	4085.4	34%	-69.23
186	THIKA RD BSP	220	31.5	15.5	5903.3	49%	-70.9
187	CBD	220	31.5	10.1	3834.0	32%	-69.8
188	NRBI NORTH	220	31.5	13.8	5272.9	44%	-73.84
189	ISINYA	220	31.5	12.5	4782.1	40%	-75.65
190	SUSWA	220	31.5	23.9	9113.1	76%	-79.51
191	LONGONOT	220	31.5	8.8	3346.2	28%	-83.19
192	ATHI RIVER	220	31.5	10.6	4046.8	34%	-69.53
193	MALAA220	220	31.5	16.9	6432.7	54%	-71.65
194	NGONG	220	31.5	13.2	5042.7	42%	-81.22
195	MAGADI	220	31.5	2.6	984.5	8%	-80.3
196	LONGONOT	220	31.5	5.5	2086.2	17%	-79.98
197	RABAI 220	220	31.5	6.1	2321.7	19%	-64.18
198	GARSEN 220	220	31.5	5.3	2034.9	17%	-73.17
199	LAMU 220	220	31.5	6.9	2640.2	22%	-80.27
200	MALINDI 220	220	31.5	4.7	1804.0	15%	-67.79
201	BAMBUR CE220	220	31.5	4.9	1852.5	15%	-66.64
202	GALANA 220	220	31.5	3.3	1256.6	10%	-70.51
203	SWTCH STN	220	31.5	4.9	1848.4	15%	-66.17
204	KILIFI 220	220	31.5	2.9	1119.9	9%	-68.94
205	MARIAKANI EH	220	31.5	7.2	2726.7	23%	-66.43
206	LAMU 220_2	220	31.5	7.8	2985.6	25%	-82.34

207	NNDONGO KUND	220	31.5	4.5	1701.9	14%	-69.69
208	KWALE	220	31.5	4.6	1765.4	15%	-69.53
209	TEE-OFF	220	31.5	5.0	1902.1	16%	-68.92
210	DOGO LNG	220	31.5	4.4	1675.9	14%	-69.85
211	GITARU 220	220	31.5	9.5	3604.9	30%	-78.61
212	KAMBURU 220	220	31.5	12.6	4799.9	40%	-77.6
213	KIAMBERE 220	220	31.5	10.7	4064.2	34%	-77.94
214	KARURA	220	31.5	8.5	3255.3	27%	-78.95
215	KIBIRIGWI	220	31.5	9.5	3616.9	30%	-77.11
216	EMBU	220	31.5	10.3	3922.2	33%	-77.22
217	THIKA 220	220	31.5	13.2	5043.4	42%	-77.99
218	HG FALLS 220	220	31.5	9.0	3426.4	29%	-81.69
219	ISIOLO 220	220	31.5	7.4	2829.2	24%	-77.55
220	MAUA 220	220	31.5	7.2	2731.3	23%	-77.52

221	GARISSA	220	31.5	3.2	1216.7	10%	-74.61
222	BURA	220	31.5	2.6	984.4	8%	-74.29
223	HOLA	220	31.5	2.9	1113.2	9%	-74.08
224	WAJIR	220	31.5	0.7	263.4	2%	-77.83
225	MANDERA	220	31.5	0.5	199.6	2%	-78.05
226	GARBATULA	220	31.5	3.5	1344.0	11%	-77.09
227	MOYALE	220	31.5	1.9	710.9	6%	-80.25
228	OLKARIA2 220	220	31.5	21.4	8136.6	68%	-79.97
229	OLKARIA3 220	220	31.5	17.7	6747.2	56%	-80.34
230	OLKARIA 4	220	31.5	19.2	7318.0	61%	-81.76
231	OLK IAU 220	220	31.5	21.2	8083.9	67%	-79.92
232	MENENGAI	220	31.5	12.2	4649.6	39%	-80.44
233	OLKARIA V	220	31.5	11.6	4434.6	37%	-81.79
234	RONGAI	220	31.5	13.5	5161.8	43%	-79.96
235	GILGIL 220	220	31.5	16.0	6112.8	51%	-80.69
236	AKIRA 220	220	31.5	5.1	1937.8	16%	-82.1
237	OLKARIA VI	220	31.5	16.7	6361.8	53%	-80.07
238	OLKARIA VII	220	31.5	12.0	4564.1	38%	-80.1
239	OLK IX	220	31.5	6.5	2468.7	21%	-82.39
240	OLKARIA VIII	220	31.5	6.5	2491.4	21%	-82.64
241	NAIVASHA 220	220	31.5	9.3	3539.1	29%	-79.31

242	KAKAMEGA	220	31.5	7.1	2710.5	23%	-74.58
243	MUHORONI	220	31.5	5.1	1952.8	16%	-75.32
244	TORORO 2	220	31.5	5.0	1891.7	16%	-77.34
245	TURKWEL	220	31.5	4.6	1768.8	15%	-78.48
246	LESSOS 220	220	31.5	10.8	4102.9	34%	-76.22
247	KITALE	220	31.5	2.9	1095.9	9%	-75.11
248	BARINGO 220	220	31.5	7.5	2872.7	24%	-78.48
249	LOKICHAR	220	31.5	5.2	1988.0	17%	-78.91
250	KIBOS	220	31.5	7.1	2721.5	23%	-75.12
251	ORTUM	220	31.5	3.3	1267.0	11%	-77.66
252	MUSAGA	220	31.5	7.8	2957.4	25%	-74.76
253	KERICHO	220	31.5	6.6	2501.9	21%	-76.32
254	CHEMOSIT 220	220	31.5	5.9	2252.0	19%	-75.37
255	KISII 220	220	31.5	4.0	1539.9	13%	-77.06
256	SILALI 220	220	31.5	11.5	4377.8	36%	-80.85
257	RADIANT	220	31.5	1.6	614.0	5%	-77.9
258	TURKWELL TEE	220	31.5	3.2	1221.6	10%	-75.87
259	KAPSOWAR	220	31.5	2.9	1107.2	9%	-75.82
260	AGIL 220	220	31.5	12.2	4659.0	39%	-81.56
261	MARSABIT	220	31.5	4.3	1651.6	14%	-80.19
262	KAINUK	220	31.5	4.6	1762.6	15%	-78.5
263	LOKICHOGGIO	220	31.5	1.9	726.9	6%	-79.34
264	LODWAR	220	31.5	5.2	1996.4	17%	-78.92
265	LOYAN	220	31.5	8.6	3272.8	27%	-82.38
266	ELD NTH 220	220	31.5	5.7	2167.7	18%	-77.01
267	BUJAGALI	220	31.5	2.9	1121.3	9%	-80.25
268	KAINUK 66	220	31.5	2.6	982.6	8%	-83.36
269	OLKARIA 4 WE	220	31.5	19.0	7236.3	60%	-81.75
270	GENERIC2028	220	31.5	8.5	3255.3	27%	-78.95
271	GENERIC2029	220	31.5	4.7	1809.5	15%	-73.41
272	GENERIC2030	220	31.5	13.2	5042.7	42%	-81.22
273	GENERIC 2033	220	31.5	13.2	5043.4	42%	-77.99
274	GENERIC 2025	220	31.5	7.3	2796.0	23%	-82.28
275	GENERIC 2031	220	31.5	7.1	2721.5	23%	-75.12
276	GENERIC 2035	220	31.5	4.8	1820.9	15%	-79.01

277	SUSWA PP	220	31.5	8.2	3106.6	26%	-82.97
278	CHAGEM	220	31.5	13.2	5042.7	42%	-81.22
279	ELEKTRA	220	31.5	6.9	2640.2	22%	-80.27
280	VATEKI	220	31.5	4.7	1804.0	15%	-67.79
281	MERU WIND220	220	31.5	6.8	2575.3	21%	-78.13
282	HABASWEIN	220	31.5	0.9	352.4	3%	-77.75
283	ISINYA4	400	40	11.5	8001.9	29%	-72.5
284	SUSWA	400	40	13.0	9007.0	33%	-78.41
285	KIMUKA	400	40	12.2	8442.9	30%	-75.82
286	KONZA4	400	40	11.2	7787.7	28%	-72.97
287	NAMANGA	400	40	7.1	4922.1	18%	-75.84
288	LONGONOT	400	40	7.8	5385.7	19%	-78.7
289	MALAA 400	400	40	11.6	8027.3	29%	-73.24
290	MAKINDU 400	400	40	7.2	5004.9	18%	-72.16
291	KITUI	400	40	4.0	2764.6	10%	-80.71
292	MARIAKANI	400	40	4.5	3131.6	11%	-69.17
293	LAMU	400	40	5.8	4003.8	14%	-82.71
294	VOI 400	400	40	5.3	3679.3	13%	-70.54
295	THIKA 400	400	40	11.4	7864.9	28%	-75.11
296	HG FALL 400	400	40	5.3	3703.5	13%	-80.88
297	GILGIL	400	40	13.1	9092.1	33%	-76.56
298	RONGAI 400	400	40	11.1	7721.0	28%	-76.71
299	KILGORIS	400	40	5.1	3502.4	13%	-78.21
300	LOYAN 400	400	40	6.1	4226.7	15%	-81.41
301	SILALI	400	40	7.6	5259.8	19%	-79.27
302	RUMRT400 TEE	400	40	12.4	8568.6	31%	-77.07
303	SILALI4 TEE1	400	40	8.7	5994.2	22%	-79.64
304	LONG_HVDC	400	40	13.0	9007.0	33%	-78.41
305	LESSOS 400	400	40	8.0	5519.5	20%	-77.25
306	ARUSHA	400	40	4.9	3429.4	12%	-77.02
307	MEGA_HVDC	400	40	7.4	5140.2	19%	-79.92
308	WOLYATA	400	40	7.4	5140.2	19%	-79.92
2035 THREE PHASE SCC LEVELS (MAX)							

S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE
1	ULU 132	132	31.5	11.8	2702.7	38%	-74.31
2	DANDORA 132	132	31.5	22.7	5188.8	72%	-72.81
3	JUJA RD 132	132	31.5	23.6	5402.1	75%	-72.06
4	KIBOKO	132	31.5	4.7	1074.0	15%	-68.08
5	MAKINDU 132	132	31.5	5.4	1225.6	17%	-70.88
6	UPLANDS	132	31.5	10.9	2489.5	35%	-76.64
7	RUARAKA 132	132	31.5	16.9	3867.9	54%	-78.46
8	SULTAN HAMUD	132	31.5	5.5	1251.7	17%	-66.44
9	KAJIADO	132	31.5	3.7	852.6	12%	-85.03
10	KONZA	132	31.5	16.0	3654.1	51%	-78.67
11	MACHAKOS	132	31.5	7.7	1758.0	24%	-69.74
12	NAMANGA	132	31.5	1.4	327.5	5%	-71.81
13	ISINYA 132	132	31.5	3.9	886.4	12%	-85.95
14	KONZA SGR	132	31.5	8.3	1901.2	26%	-72.39
15	SULTAN SGR	132	31.5	5.0	1137.7	16%	-65.66
16	MAKINDU NEW	132	31.5	8.2	1879.1	26%	-78.69
17	MAKINDU SGR	132	31.5	7.3	1674.2	23%	-77.22
18	MKD TEE	132	31.5	7.3	1661.9	23%	-76.25
19	MKD T-OFF	132	31.5	7.1	1624.7	23%	-76.31
20	NDALSYN TEE1	132	31.5	3.7	849.3	12%	-68.32
21	NDALSYN TEE2	132	31.5	3.7	835.7	12%	-68.15
22	NDALSYAN SGR	132	31.5	3.7	842.6	12%	-68.22
23	TSAVO TEE 1	132	31.5	3.8	864.6	12%	-67.66
24	TSAVO TEE 2	132	31.5	4.0	911.4	13%	-67.88
25	TSAVO SGR	132	31.5	3.9	887.1	12%	-67.71
26	THIKARD132	132	31.5	16.9	3874.2	54%	-78.49
27	OWEN FALLS	132	31.5	2.1	487.7	7%	-59.4
28	VOI 132	132	31.5	8.6	1966.0	27%	-74.22
29	VIPINGO RANG	132	31.5	5.2	1196.6	17%	-66.92
30	KIPEVU 2	132	31.5	7.4	1699.9	24%	-59.88
31	KIPEVU	132	31.5	7.5	1711.8	24%	-59.78
32	KOKOTONI	132	31.5	7.2	1648.4	23%	-61.04

33	MARIAKANI	132	31.5	5.3	1207.0	17%	-62.29
34	MAUNGU132	132	31.5	4.4	998.0	14%	-67.76
35	MOMBASA CEM	132	31.5	5.2	1180.4	16%	-66.83
36	MBSACEM TEE1	132	31.5	5.2	1182.5	16%	-66.84
37	MBSACEM TEE2	132	31.5	5.2	1179.8	16%	-67.13
38	NEW BAMB 132	132	31.5	5.7	1293.0	18%	-61.17
39	RABAI 132	132	31.5	8.6	1956.5	27%	-60.26
40	RABAI POWER	132	31.5	8.5	1932.1	27%	-60.45
41	SAMBURU 132	132	31.5	3.7	838.4	12%	-63.8
42	GALU	132	31.5	4.4	1014.2	14%	-60.65
43	MANYANI	132	31.5	4.2	953.6	13%	-68.16
44	KILIFI	132	31.5	5.3	1201.4	17%	-68.18
45	MTITO ANDEI	132	31.5	3.6	815.8	11%	-67.96
46	TITANIUM 132	132	31.5	3.9	886.8	12%	-62.32
47	GARISSA	132	31.5	4.7	1063.9	15%	-77.54
48	JOMVU	132	31.5	6.9	1587.0	22%	-61.51
49	KWALE SC	132	31.5	3.5	791.5	11%	-65.87
50	LIKONI	132	31.5	3.9	881.0	12%	-61.24
51	BAMBURI CEME	132	31.5	6.0	1381.9	19%	-69.01
52	S_HAMUD_NEW	132	31.5	5.1	1170.9	16%	-65.7
53	MBARAKI	132	31.5	6.1	1402.6	19%	-59.72
54	TAVETA	132	31.5	1.5	334.6	5%	-65.47
55	S_HAMUD_TEE	132	31.5	5.7	1302.5	18%	-66.37
56	LIKONI TEE	132	31.5	5.4	1239.1	17%	-60.23
57	LUNGA LUNGA	132	31.5	3.7	839.9	12%	-68.5
58	LOITOKTOK	132	31.5	1.9	432.1	6%	-65.16
59	MERUWESHI	132	31.5	5.1	1159.4	16%	-65.7
60	MTWAPA	132	31.5	5.5	1262.3	18%	-67.41
61	SHIMONI	132	31.5	3.5	806.9	11%	-67.62
62	VOI 132 NEW	132	31.5	10.2	2330.5	32%	-77.86
63	MACKNN TEE 1	132	31.5	3.4	784.8	11%	-65.69
64	MACKNN TEE2	132	31.5	3.3	749.2	10%	-64.65
65	MAKINNON SGR	132	31.5	3.3	755.8	10%	-64.97
66	MARIAKNI NEW	132	31.5	4.8	1086.4	15%	-62.68
67	MARIAKN SGR	132	31.5	5.3	1207.0	17%	-62.29

68	KWALE	132	31.5	5.8	1328.7	18%	-77.88
69	GITARU 132	132	31.5	14.6	3347.0	46%	-81.06
70	GITHAMBO	132	31.5	4.8	1098.6	15%	-66.95
71	KAMBURU 132	132	31.5	16.9	3873.6	54%	-80.52
72	KIGANJO	132	31.5	12.2	2791.9	39%	-75.13
73	KILBOGO TEE1	132	31.5	8.9	2037.8	28%	-69.27
74	KINDARUMA	132	31.5	6.2	1409.8	20%	-70.76
75	KILBOGO TEE2	132	31.5	8.1	1843.4	26%	-69.71
76	MANGU	132	31.5	16.9	3872.9	54%	-77.5
77	MASINGA	132	31.5	8.6	1968.4	27%	-79.35
78	MERU 132	132	31.5	9.4	2151.6	30%	-73.74
79	NANYUKI 132	132	31.5	8.4	1916.7	27%	-67.05
80	GATUNDU	132	31.5	5.9	1353.8	19%	-69.42
81	KUTUS 132	132	31.5	13.8	3157.6	44%	-78.9
82	KUTUS_T1	132	31.5	8.9	2026.4	28%	-76.48
83	KUTUS_T2	132	31.5	7.6	1748.7	24%	-77.48
84	THIKAPWR 132	132	31.5	16.6	3802.0	53%	-77.29
85	ISIOLO	132	31.5	11.0	2510.8	35%	-72.86
86	MWINGI	132	31.5	3.9	902.8	13%	-67.16
87	KITUI	132	31.5	2.7	626.1	9%	-64.63
88	KYENI	132	31.5	6.1	1405.2	20%	-70.83
89	MAUA	132	31.5	9.9	2254.8	31%	-78.98
90	TATU CITY	132	31.5	7.8	1784.9	25%	-71.05
91	MUTOMO	132	31.5	1.3	307.3	4%	-63.76
92	KIBWEZI	132	31.5	0.9	211.4	3%	-63.29
93	KIBR TEE 2	132	31.5	14.3	3273.1	45%	-77.84
94	OTHAYA	132	31.5	5.0	1136.6	16%	-67.22
95	WOTE	132	31.5	3.1	700.6	10%	-65.07
96	ISHIARA SWST	132	31.5	7.0	1599.9	22%	-75.68
97	KIBIRIGWI	132	31.5	14.3	3273.1	45%	-77.84
98	THIKA NEW	132	31.5	16.9	3872.9	54%	-77.5
99	ISIOLO SS2	132	31.5	11.5	2630.2	37%	-77.13
100	GARISSA SS2	132	31.5	4.7	1063.9	15%	-77.54
101	CHOGORIA	132	31.5	3.0	691.9	10%	-67.79
102	MWALA	132	31.5	7.2	1640.7	23%	-68.47
103	LANET	132	31.5	13.1	3004.8	42%	-69.27

104	NAIVASHA 132	132	31.5	14.2	3255.8	45%	-76.83
105	OLKARIA1 132	132	31.5	10.0	2293.3	32%	-84.93
106	NAKRUWEST_T1	132	31.5	14.6	3342.7	46%	-71.3
107	NAKRUWEST_T2	132	31.5	14.3	3272.2	45%	-71.24
108	MAKUTANO_T1	132	31.5	9.0	2058.4	29%	-66.51
109	MAKUTANO_T2	132	31.5	9.1	2089.3	29%	-66.48
110	OLK 1AU 132	132	31.5	10.1	2310.2	32%	-85.04
111	OLKALOU	132	31.5	7.6	1744.3	24%	-67.88
112	AEOLUS WIND	132	31.5	7.3	1673.1	23%	-73.17
113	NAROK	132	31.5	4.3	993.5	14%	-68.64
114	GILGIL	132	31.5	15.0	3436.6	48%	-77.05
115	GILGIL TEE1	132	31.5	14.1	3222.8	45%	-75
116	GILGIL TEE2	132	31.5	13.2	3008.9	42%	-73.39
117	OLK I WE	132	31.5	9.1	2087.8	29%	-83.22
118	KAKAMEGA132	132	31.5	8.0	1822.9	25%	-75.39
119	WEBUYE	132	31.5	6.6	1507.3	21%	-67.51
120	CHEMOSIT	132	31.5	7.4	1680.6	23%	-72.82
121	KISII	132	31.5	6.9	1569.9	22%	-70.92
122	KISUMU 132	132	31.5	10.6	2423.4	34%	-67.46
123	MUHORONI 132	132	31.5	8.3	1895.4	26%	-71.85
124	MUMIAS 132	132	31.5	5.4	1229.9	17%	-65.75
125	MUSAGA 132	132	31.5	10.4	2376.5	33%	-70.09
126	RANGALA 132	132	31.5	5.7	1308.3	18%	-63.95
127	SANGORO	132	31.5	4.5	1036.9	14%	-67.9
128	SONDU MIRIU	132	31.5	5.1	1172.4	16%	-68.17
129	AWENDO	132	31.5	3.8	879.7	12%	-64.24
130	BOMET	132	31.5	5.2	1182.0	16%	-67.53
131	ONGENG	132	31.5	3.6	813.0	11%	-64.4
132	SOTIK	132	31.5	9.6	2191.6	30%	-70.91
133	BONDO	132	31.5	3.8	864.4	12%	-63.64
134	CHAVAKALI	132	31.5	8.5	1942.7	27%	-68.93
135	KISUMU EAST	132	31.5	9.4	2154.7	30%	-66.67
136	MALABA TEE2	132	31.5	3.7	852.0	12%	-64.12
137	ISABENIA	132	31.5	2.0	448.5	6%	-63.97
138	TORORO 132	132	31.5	5.5	1263.0	18%	-64.59

139	MAKUTANO 132	132	31.5	9.2	2100.3	29%	-66.48
140	NAKURU_W 132	132	31.5	14.7	3353.7	47%	-71.43
141	KILGORIS	132	31.5	12.9	2959.6	41%	-79.52
142	MYANGA	132	31.5	6.8	1553.1	22%	-65.74
143	BUSIA	132	31.5	5.7	1303.1	18%	-64.92
144	NDWIGA	132	31.5	2.9	664.1	9%	-63.78
145	SINDO	132	31.5	2.0	459.6	6%	-64.73
146	KARUNGO	132	31.5	1.8	406.0	6%	-65.24
147	KIMILILI	132	31.5	5.8	1320.9	18%	-67.74
148	KAIMOSI	132	31.5	8.5	1942.7	27%	-68.93
149	SUKARI	132	31.5	3.3	758.4	11%	-64.52
150	ELDORET	132	31.5	9.1	2087.1	29%	-71.41
151	LESSOS 132	132	31.5	15.0	3425.5	48%	-71.01
152	KITALE	132	31.5	5.9	1349.1	19%	-70.03
153	KABARNET	132	31.5	3.6	813.6	11%	-66.05
154	KAPSABET	132	31.5	7.3	1679.8	23%	-67.83
155	KIBOS1	132	31.5	10.8	2473.6	34%	-67.92
156	RUMURUTI	132	31.5	7.3	1660.2	23%	-66.83
157	SILALI	132	31.5	17.5	4003.7	56%	-84.48
158	ELDORET NTH	132	31.5	9.1	2074.0	29%	-72.62
159	MOI BRCKS	132	31.5	5.6	1285.0	18%	-68.88
160	MARALAL	132	31.5	4.9	1109.3	15%	-67.95
161	KERINGET	132	31.5	2.8	638.1	9%	-63.11
162	MENENGAI 132	132	31.5	15.2	3476.7	48%	-75.22
163	GENERIC 2023	132	31.5	3.4	782.4	11%	-69.74
164	GENERIC 2024	132	31.5	4.3	993.5	14%	-68.64
165	GENERIC 2034	132	31.5	3.0	680.4	9%	-69.22
166	SUSTAINABLE	132	31.5	23.6	5402.1	75%	-72.06
167	MAKINDU SLR	132	31.5	4.7	1074.0	15%	-68.08
168	CHERAB	132	31.5	11.5	2630.2	37%	-77.13
169	MERU WIND	132	31.5	11.5	2630.2	37%	-77.13
170	CRYSTAL	132	31.5	0.9	211.4	3%	-63.29
171	KIBR TEE 1	132	31.5	13.8	3152.9	44%	-77.31
172	KOPERE	132	31.5	7.5	1715.5	24%	-70.7
173	QUAINT	132	31.5	4.7	1063.9	15%	-67.54

174	KAPTIS	132	31.5	8.5	1942.7	27%	-68.93
175	K TE 1	132	31.5	10.1	2307.4	32%	-67.61
176	K TE 2	132	31.5	10.1	2307.4	32%	-67.61
177	TARITA SLR	132	31.5	4.2	969.4	13%	-66.6
178	KENERGY SLR	132	31.5	7.3	1660.2	23%	-66.83
179	SUNPOWER	132	31.5	3.3	743.1	10%	-65.87
180	GITARU SLR	132	31.5	9.7	2229.0	31%	-80.85
181	DANDORA 220	220	31.5	16.1	6137.3	51%	-73.33
182	RUARAKA 220	220	31.5	13.8	5241.7	44%	-73.43
183	JUJA RD	220	31.5	13.9	5303.8	44%	-72.88
184	EMBAKASI	220	31.5	13.3	5078.6	42%	-67.53
185	EMBAKASI_CC	220	31.5	13.2	5044.0	42%	-67.72
186	THIKA RD BSP	220	31.5	18.5	7064.2	59%	-71.21
187	CBD	220	31.5	12.3	4695.3	39%	-68.44
188	NRBI NORTH	220	31.5	16.2	6160.3	51%	-73.59
189	ISINYA	220	31.5	15.2	5780.6	48%	-76.24
190	SUSWA	220	31.5	28.1	10715.9	89%	-79.21
191	LONGONOT	220	31.5	11.8	4492.4	37%	-84.99
192	UPLANDS 220	220	31.5	12.5	4762.1	40%	-75.95
193	ATHI RIVER	220	31.5	13.1	5009.0	42%	-68.01
194	MALAA220	220	31.5	20.3	7726.2	64%	-73.14
195	NGONG	220	31.5	14.9	5677.6	47%	-82.12
196	MAGADI	220	31.5	2.9	1087.9	9%	-80.47
197	LONGONOT	220	31.5	6.1	2329.3	19%	-79.93
198	RABAI 220	220	31.5	7.9	3007.6	25%	-64.24
199	GARSEN 220	220	31.5	6.1	2319.4	19%	-73.43
200	LAMU 220	220	31.5	7.5	2841.8	24%	-80.41
201	MALINDI 220	220	31.5	5.7	2181.4	18%	-67.49
202	BAMBUR CE220	220	31.5	6.1	2306.8	19%	-66.92
203	GALANA 220	220	31.5	3.9	1492.6	12%	-70.56
204	SWTCH STN	220	31.5	6.0	2278.6	19%	-65.8
205	KILIFI 220	220	31.5	4.4	1664.0	14%	-67.81
206	MARIAKANI EH	220	31.5	9.8	3719.3	31%	-67.68
207	LAMU 220_2	220	31.5	8.3	3160.2	26%	-82.38
208	NNDONGO KUND	220	31.5	7.2	2754.9	23%	-73.66

209	KWALE	220	31.5	6.9	2634.9	22%	-72.69
210	TEE-OFF	220	31.5	7.7	2929.9	24%	-72.18
211	DOGO LNG	220	31.5	7.2	2732.0	23%	-73.94
212	GITARU 220	220	31.5	10.6	4033.6	34%	-78.66
213	KAMBURU 220	220	31.5	14.3	5442.7	45%	-77.7
214	KIAMBERE 220	220	31.5	11.9	4527.8	38%	-78.02
215	KARURA	220	31.5	9.4	3582.7	30%	-78.97
216	KIBIRIGWI	220	31.5	11.1	4221.3	35%	-77.48
217	EMBU	220	31.5	11.8	4490.8	37%	-77.35
218	THIKA 220	220	31.5	17.2	6543.4	55%	-79.68
219	HG FALLS 220	220	31.5	18.4	6996.9	58%	-83.69
220	ISIOLO 220	220	31.5	8.3	3147.0	26%	-77.45
221	MAUA 220	220	31.5	8.0	3045.9	25%	-77.44
222	GARISSA	220	31.5	3.7	1417.2	12%	-74.99
223	BURA	220	31.5	2.9	1110.1	9%	-74.59
224	HOLA	220	31.5	3.3	1254.5	10%	-74.37
225	WAJIR	220	31.5	0.8	294.4	2%	-77.52
226	MANDERA	220	31.5	0.6	222.5	2%	-77.74
227	GARBATULA	220	31.5	3.9	1498.9	12%	-77.13
228	MOYALE	220	31.5	2.1	791.4	7%	-80.26
229	OLKARIA2 220	220	31.5	28.8	10973.5	91%	-79.89
230	OLKARIA3 220	220	31.5	22.7	8647.7	72%	-80.26
231	OLKARIA 4	220	31.5	29.7	11317.2	94%	-79.86
232	OLK IAU 220	220	31.5	29.7	11318.3	94%	-79.86
233	MENENGAI	220	31.5	15.9	6052.1	50%	-81.29
234	OLKARIA V	220	31.5	14.9	5694.4	47%	-80.71
235	RONGAI	220	31.5	17.1	6521.7	54%	-80.76
236	GILGIL 220	220	31.5	18.6	7077.7	59%	-81.4
237	AKIRA 220	220	31.5	6.2	2367.6	20%	-82.84
238	OLKARIA VI	220	31.5	29.7	11311.6	94%	-79.86
239	OLKARIA VII	220	31.5	13.6	5169.4	43%	-79.94
240	OLK IX	220	31.5	9.0	3443.9	29%	-84.14
241	OLKARIA VIII	220	31.5	8.2	3141.7	26%	-83.69
242	NAIVASHA 220	220	31.5	18.4	7010.6	58%	-78.59
243	KAKAMEGA	220	31.5	8.3	3165.4	26%	-74.07
244	MUHORONI	220	31.5	6.0	2290.9	19%	-75.11

245	TORORO 2	220	31.5	5.7	2170.9	18%	-77.03
246	TURKWEL	220	31.5	5.1	1939.3	16%	-77.99
247	LESSOS 220	220	31.5	12.7	4855.5	40%	-76.11
248	KITALE	220	31.5	3.2	1211.6	10%	-74.8
249	BARINGO 220	220	31.5	9.4	3572.5	30%	-78.74
250	LOKICHAR	220	31.5	5.7	2185.0	18%	-78.35
251	KIBOS	220	31.5	8.4	3191.2	27%	-74.78
252	ORTUM	220	31.5	3.7	1397.5	12%	-77.26
253	MUSAGA	220	31.5	9.1	3461.5	29%	-74.28
254	KERICHO	220	31.5	7.8	2990.2	25%	-76.05
255	CHEMOSIT 220	220	31.5	7.1	2690.3	22%	-75.05
256	KISII 220	220	31.5	4.6	1761.2	15%	-77.1
257	SILALI 220	220	31.5	16.6	6332.5	53%	-82.01
258	RADIANT	220	31.5	1.8	681.0	6%	-77.75

259	TURKWELL TEE	220	31.5	3.6	1365.3	11%	-75.54
260	KAPSOWAR	220	31.5	3.2	1236.3	10%	-75.48
261	AGIL 220	220	31.5	16.1	6136.6	51%	-80.41
262	MARSABIT	220	31.5	4.9	1867.7	16%	-80.32
263	KAINUK	220	31.5	5.1	1933.1	16%	-78.02
264	LOKICHOGGIO	220	31.5	2.1	800.4	7%	-79
265	LODWAR	220	31.5	5.8	2194.2	18%	-78.36
266	LOYAN	220	31.5	10.3	3925.7	33%	-82.98
267	ELD NTH 220	220	31.5	6.8	2578.5	21%	-77.09
268	BARRIER	220	31.5	2.2	848.1	7%	-82.32
269	BUJAGALI	220	31.5	3.3	1265.2	11%	-80.14
270	KAINUK 66	220	31.5	2.7	1033.6	9%	-83.36
271	OLKARIA 4 WE	220	31.5	29.2	11128.3	93%	-79.88
272	GENERIC2028	220	31.5	9.4	3582.7	30%	-78.97
273	GENERIC2029	220	31.5	5.4	2074.0	17%	-72.62
274	GENERIC2030	220	31.5	14.9	5677.6	47%	-82.12
275	GENERIC 2033	220	31.5	17.2	6543.4	55%	-79.68
276	GENERIC 2025	220	31.5	8.0	3059.2	25%	-82.53
277	GENERIC 2031	220	31.5	8.4	3191.2	27%	-74.78
278	GENERIC 2035	220	31.5	5.3	2001.6	17%	-78.5
279	SUSWA PP	220	31.5	10.8	4124.7	34%	-84.61

280	CHAGEM	220	31.5	14.9	5677.6	47%	-82.12
281	ELEKTRA	220	31.5	7.5	2841.8	24%	-80.41
282	VATEKI	220	31.5	5.7	2181.4	18%	-67.49
283	MERU WIND220	220	31.5	7.5	2853.5	24%	-78.03
284	HABASWEIN	220	31.5	1.0	395.0	3%	-77.61
285	ISINYA4	400	40	15.6	10832.3	39%	-73.81
286	SUSWA	400	40	16.7	11567.9	42%	-79.28
287	KIMUKA	400	40	15.8	10939.5	39%	-76.89
288	KONZA4	400	40	15.7	10903.6	39%	-74.56
289	NAMANGA	400	40	8.8	6109.7	22%	-77.24
290	LONGONOT	400	40	10.7	7428.0	27%	-80.63
291	MALAA 400	400	40	17.2	11929.9	43%	-75.09
292	MAKINDU 400	400	40	9.3	6445.6	23%	-73.94
293	KITUI	400	40	9.3	6455.5	23%	-81.84
294	MARIAKANI	400	40	6.0	4147.1	15%	-71.41
295	LAMU	400	40	6.1	4212.6	15%	-82.94
296	VOI 400	400	40	6.9	4759.7	17%	-72.55
297	THIKA 400	400	40	17.2	11889.7	43%	-77.07
298	HG FALL 400	400	40	9.8	6782.4	24%	-83.3
299	GILGIL	400	40	17.8	12347.2	45%	-77.52
300	RONGAI 400	400	40	14.6	10148.5	37%	-77.38
301	KILGORIS	400	40	6.0	4143.9	15%	-78.51
302	LOYAN 400	400	40	7.9	5446.1	20%	-81.79
303	SILALI	400	40	13.3	9228.8	33%	-79.15
304	RUMRT400 TEE	400	40	16.8	11632.4	42%	-77.96
305	SILALI4 TEE1	400	40	13.6	9447.8	34%	-79.22
306	LONG_HVDC	400	40	16.7	11567.9	42%	-79.28
307	LESSOS 400	400	40	9.9	6880.7	25%	-77.79
308	ARUSHA	400	40	5.9	4084.4	15%	-78.21
309	MEGA_HVDC	400	40	7.5	5170.7	19%	-79.3
310	WOLYATA	400	40	7.5	5170.7	19%	-79.3

2035 THREE PHASE SCC LEVELS (MIN)

S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE

1	ULU 132	132	31.5	11.2	2568.9	36%	-74.51
2	DANDORA 132	132	31.5	21.5	4925.2	68%	-73.21
3	JUJA RD 132	132	31.5	22.4	5129.9	71%	-72.45
4	KIBOKO	132	31.5	4.4	994.6	14%	-68.09
5	MAKINDU 132	132	31.5	5.0	1146.1	16%	-70.92
6	UPLANDS	132	31.5	10.4	2383.5	33%	-76.8
7	RUARAKA 132	132	31.5	16.4	3752.0	52%	-78.57
8	SULTAN HAMUD	132	31.5	5.1	1155.6	16%	-66.47
9	KAJIADO	132	31.5	3.7	843.9	12%	-85.11
10	KONZA	132	31.5	15.5	3542.5	49%	-79.22
11	MACHAKOS	132	31.5	7.2	1635.2	23%	-69.77
12	NAMANGA	132	31.5	1.3	306.9	4%	-71.48
13	ISINYA 132	132	31.5	3.9	880.7	12%	-86.11
14	KONZA SGR	132	31.5	7.8	1786.5	25%	-72.46
15	SULTAN SGR	132	31.5	4.6	1048.5	15%	-65.69
16	MAKINDU NEW	132	31.5	7.9	1814.7	25%	-79.13
17	MAKINDU SGR	132	31.5	7.0	1606.0	22%	-77.53
18	MKD TEE	132	31.5	6.9	1588.5	22%	-76.51
19	MKD T-OFF	132	31.5	6.8	1552.5	22%	-76.57
20	NDALSYN TEE1	132	31.5	3.4	784.9	11%	-68.32
21	NDALSYN TEE2	132	31.5	3.4	771.9	11%	-68.15
22	NDALSYAN SGR	132	31.5	3.4	778.5	11%	-68.21
23	TSAVO TEE 1	132	31.5	3.5	796.7	11%	-67.65
24	TSAVO TEE 2	132	31.5	3.7	840.7	12%	-67.88
25	TSAVO SGR	132	31.5	3.6	817.8	11%	-67.71
26	THIKARD132	132	31.5	16.4	3758.5	52%	-78.61
27	OWEN FALLS	132	31.5	2.0	446.4	6%	-59.5
28	VOI 132	132	31.5	8.1	1863.3	26%	-74.32
29	VIPINGO RANG	132	31.5	4.9	1121.6	16%	-67.18
30	KIPEVU 2	132	31.5	7.0	1595.4	22%	-60.61
31	KIPEVU	132	31.5	7.0	1606.9	22%	-60.51
32	KOKOTONI	132	31.5	6.8	1544.2	21%	-61.71
33	MARIAKANI	132	31.5	4.9	1118.5	16%	-62.77
34	MAUNGU132	132	31.5	4.0	921.7	13%	-67.8
35	MOMBASA CEM	132	31.5	4.8	1105.6	15%	-67.08

36	MBSACEM TEE1	132	31.5	4.8	1107.6	15%	-67.09
37	MBSACEM TEE2	132	31.5	4.8	1105.3	15%	-67.38
38	NEW BAMB 132	132	31.5	5.3	1203.7	17%	-61.71
39	RABAI 132	132	31.5	8.1	1847.3	26%	-61.05
40	RABAI POWER	132	31.5	8.0	1823.3	25%	-61.24
41	SAMBURU 132	132	31.5	3.4	770.3	11%	-64.07
42	GALU	132	31.5	4.1	938.3	13%	-61.05
43	MANYANI	132	31.5	3.9	880.5	12%	-68.15

44	KILIFI	132	31.5	4.9	1127.9	16%	-68.46
45	MTITO ANDEI	132	31.5	3.3	752.8	10%	-67.96
46	TITANIUM 132	132	31.5	3.6	819.6	11%	-62.67
47	GARISSA	132	31.5	4.4	1002.1	14%	-77.61
48	JOMVU	132	31.5	6.5	1485.7	21%	-62.23
49	KWALE SC	132	31.5	3.2	734.0	10%	-66.16
50	LIKONI	132	31.5	3.6	813.0	11%	-61.63
51	BAMBURI CEME	132	31.5	5.7	1310.0	18%	-69.4
52	S_HAMUD_NEW	132	31.5	4.7	1079.4	15%	-65.72
53	MBARAKI	132	31.5	5.7	1307.6	18%	-60.33
54	TAVETA	132	31.5	1.3	306.2	4%	-65.44
55	S_HAMUD_TEE	132	31.5	5.3	1203.1	17%	-66.4
56	LIKONI TEE	132	31.5	5.0	1151.3	16%	-60.76
57	LUNGA LUNGA	132	31.5	3.4	783.5	11%	-68.65
58	LOITOKTOK	132	31.5	1.7	394.8	5%	-65.17
59	MERUWESHI	132	31.5	4.7	1068.8	15%	-65.72
60	MTWAPA	132	31.5	5.2	1187.5	16%	-67.7
61	SHIMONI	132	31.5	3.3	750.7	10%	-67.8
62	VOI 132 NEW	132	31.5	9.8	2237.7	31%	-78.11
63	MACKNN TEE 1	132	31.5	3.2	720.6	10%	-65.8
64	MACKNN TEE2	132	31.5	3.0	687.1	10%	-64.82
65	MAKINNON SGR	132	31.5	3.0	693.3	10%	-65.1
66	MARIAKNI NEW	132	31.5	4.4	1004.7	14%	-63.11
67	MARIAKN SGR	132	31.5	4.9	1118.5	16%	-62.77
68	KWALE	132	31.5	5.6	1281.3	18%	-78.26
69	GITARU 132	132	31.5	14.1	3214.3	45%	-81.3
70	GITHAMBO	132	31.5	4.4	1010.7	14%	-66.99

71	KAMBURU 132	132	31.5	16.3	3729.2	52%	-80.78
72	KIGANJO	132	31.5	11.5	2632.2	37%	-75.39
73	KILBOGO TEE1	132	31.5	8.3	1891.8	26%	-69.36
74	KINDARUMA	132	31.5	5.8	1316.6	18%	-71.06
75	KILBOGO TEE2	132	31.5	7.5	1713.3	24%	-69.78
76	MANGU	132	31.5	16.4	3747.2	52%	-78.15
77	MASINGA	132	31.5	8.0	1833.5	25%	-79.46
78	MERU 132	132	31.5	8.8	2018.1	28%	-73.98
79	NANYUKI 132	132	31.5	7.7	1766.6	25%	-67.12
80	GATUNDU	132	31.5	5.5	1257.3	17%	-69.49
81	KUTUS 132	132	31.5	13.1	2999.3	42%	-79.18
82	KUTUS_T1	132	31.5	8.2	1882.9	26%	-76.62
83	KUTUS_T2	132	31.5	7.1	1622.5	23%	-77.59
84	THIKAPWR 132	132	31.5	16.1	3674.4	51%	-77.92
85	ISIOLO	132	31.5	10.3	2347.0	33%	-73.03
86	MWINGI	132	31.5	3.6	831.1	12%	-67.25
87	KITUI	132	31.5	2.5	573.1	8%	-64.67
88	KYENI	132	31.5	5.7	1295.3	18%	-70.84
89	MAUA	132	31.5	9.3	2136.3	30%	-79.18
90	TATU CITY	132	31.5	7.3	1669.4	23%	-71.17
91	MUTOMO	132	31.5	1.2	280.2	4%	-63.78
92	KIBWEZI	132	31.5	0.8	192.6	3%	-63.3
93	KIBR TEE 2	132	31.5	13.6	3108.4	43%	-78.15
94	OTHAYA	132	31.5	4.6	1045.9	15%	-67.26
95	WOTE	132	31.5	2.8	641.6	9%	-65.1
96	ISHIARA SWST	132	31.5	6.5	1476.2	20%	-75.78
97	KIBIRIGWI	132	31.5	13.6	3108.4	43%	-78.15
98	THIKA NEW	132	31.5	16.4	3747.2	52%	-78.15
99	ISIOLO SS2	132	31.5	10.9	2484.7	34%	-77.45
100	GARISSA SS2	132	31.5	4.4	1002.1	14%	-77.61
101	CHOGORIA	132	31.5	2.8	633.2	9%	-67.77
102	MWALA	132	31.5	6.6	1517.1	21%	-68.53
103	LANET	132	31.5	12.4	2830.7	39%	-69.38
104	NAIVASHA 132	132	31.5	13.7	3126.2	43%	-77.15
105	OLKARIA1 132	132	31.5	9.9	2263.2	31%	-85.19

106	NAKRUWEST_T1	132	31.5	13.9	3169.3	44%	-71.6
107	NAKRUWEST_T2	132	31.5	13.6	3100.0	43%	-71.54
108	MAKUTANO_T1	132	31.5	8.3	1909.0	27%	-66.65
109	MAKUTANO_T2	132	31.5	8.5	1938.2	27%	-66.61
110	OLK 1AU 132	132	31.5	10.0	2281.8	32%	-85.3
111	OLKALOU	132	31.5	7.1	1615.6	22%	-67.99
112	AEOLUS WIND	132	31.5	6.9	1573.8	22%	-73.33
113	NAROK	132	31.5	4.0	917.9	13%	-68.5
114	GILGIL	132	31.5	14.5	3310.2	46%	-77.51
115	GILGIL TEE1	132	31.5	13.5	3082.4	43%	-75.28
116	GILGIL TEE2	132	31.5	12.5	2860.0	40%	-73.54
117	OLK I WE	132	31.5	8.9	2045.3	28%	-83.32
118	KAKAMEGA132	132	31.5	7.6	1735.7	24%	-75.85
119	WEBUYE	132	31.5	6.1	1400.2	19%	-67.78
120	CHEMOSIT	132	31.5	7.0	1589.5	22%	-73.13
121	KISII	132	31.5	6.4	1468.1	20%	-71.2
122	KISUMU 132	132	31.5	10.0	2285.4	32%	-68.06
123	MUHORONI 132	132	31.5	7.8	1780.3	25%	-72.14
124	MUMIAS 132	132	31.5	5.0	1138.4	16%	-66.01
125	MUSAGA 132	132	31.5	9.8	2250.0	31%	-70.71
126	RANGALA 132	132	31.5	5.3	1210.1	17%	-64.23
127	SANGORO	132	31.5	4.2	970.4	13%	-68.36
128	SONDU MIRIU	132	31.5	4.8	1100.0	15%	-68.69
129	AWENDO	132	31.5	3.5	811.2	11%	-64.42
130	BOMET	132	31.5	4.8	1089.0	15%	-67.49
131	ONGENG	132	31.5	3.3	749.8	10%	-64.61
132	SOTIK	132	31.5	8.9	2045.3	28%	-70.99
133	BONDO	132	31.5	3.5	795.0	11%	-63.84
134	CHAVAKALI	132	31.5	7.9	1814.3	25%	-69.22
135	KISUMU EAST	132	31.5	8.9	2023.6	28%	-67.18
136	MALABA TEE2	132	31.5	3.4	784.9	11%	-64.29
137	ISABENIA	132	31.5	1.8	410.9	6%	-64.09
138	TORORO 132	132	31.5	5.1	1171.1	16%	-64.84
139	MAKUTANO 132	132	31.5	8.5	1948.7	27%	-66.62
140	NAKURU_W 132	132	31.5	13.9	3181.2	44%	-71.74
141	KILGORIS	132	31.5	12.2	2798.5	39%	-79.72

142	MYANGA	132	31.5	6.3	1446.3	20%	-66.06
143	BUSIA	132	31.5	5.3	1206.8	17%	-65.19
144	NDWIGA	132	31.5	2.7	609.2	8%	-63.94
145	SINDO	132	31.5	1.8	421.1	6%	-64.86
146	KARUNGO	132	31.5	1.6	371.8	5%	-65.36
147	KIMILILI	132	31.5	5.3	1222.4	17%	-67.95
148	KAIMOSI	132	31.5	7.9	1814.3	25%	-69.22
149	SUKARI	132	31.5	3.1	698.2	10%	-64.69
150	ELDORET	132	31.5	8.6	1958.3	27%	-71.7
151	LESSOS 132	132	31.5	14.2	3249.9	45%	-71.65
152	KITALE	132	31.5	5.5	1249.6	17%	-70.23
153	KABARNET	132	31.5	3.3	744.7	10%	-66.13
154	KAPSABET	132	31.5	6.8	1556.6	22%	-68.05
155	KIBOS1	132	31.5	10.2	2336.1	32%	-68.56
156	RUMURUTI	132	31.5	6.7	1526.3	21%	-66.9
157	SILALI	132	31.5	17.1	3916.7	54%	-84.68
158	ELDORET NTH	132	31.5	8.5	1950.4	27%	-72.95
159	MOI BRCKS	132	31.5	5.2	1188.0	16%	-69.01
160	MARALAL	132	31.5	4.5	1019.3	14%	-67.86
161	KERINGET	132	31.5	2.6	583.6	8%	-63.13
162	MENENGAI 132	132	31.5	14.6	3336.6	46%	-75.82
163	GENERIC 2023	132	31.5	3.1	717.1	10%	-69.79
164	GENERIC 2024	132	31.5	4.0	917.9	13%	-68.5
165	GENERIC 2034	132	31.5	2.7	625.9	9%	-69.07
166	SUSTAINABLE	132	31.5	22.4	5129.9	71%	-72.45
167	MAKINDU SLR	132	31.5	4.4	994.6	14%	-68.09
168	CHERAB	132	31.5	10.9	2484.7	34%	-77.45
169	MERU WIND	132	31.5	10.9	2484.7	34%	-77.45
170	CRYSTAL	132	31.5	0.8	192.6	3%	-63.3
171	KIBR TEE 1	132	31.5	13.1	2988.2	41%	-77.61
172	KOPERE	132	31.5	7.0	1595.5	22%	-71.1
173	QUAINT	132	31.5	4.3	993.6	14%	-67.98
174	KAPTIS	132	31.5	7.9	1814.3	25%	-69.22
175	K TE 1	132	31.5	9.4	2148.3	30%	-67.86
176	K TE 2	132	31.5	9.4	2148.3	30%	-67.86

177	TARITA SLR	132	31.5	3.9	889.4	12%	-66.71
178	KENERGY SLR	132	31.5	6.7	1526.3	21%	-66.9
179	SUNPOWER	132	31.5	3.0	681.5	9%	-65.89
180	GITARU SLR	132	31.5	9.2	2102.3	29%	-81
181	DANDORA 220	220	31.5	15.2	5784.7	48%	-73.85
182	RUARAKA 220	220	31.5	13.1	4975.0	41%	-73.79
183	JUJA RD	220	31.5	13.2	5038.8	42%	-73.23
184	EMBAKASI	220	31.5	12.5	4771.5	40%	-68.06
185	EMBAKASI_CC	220	31.5	12.4	4739.5	39%	-68.25
186	THIKA RD BSP	220	31.5	17.5	6672.5	56%	-71.87
187	CBD	220	31.5	11.5	4400.8	37%	-68.93
188	NRBI NORTH	220	31.5	15.1	5764.5	48%	-74.08
189	ISINYA	220	31.5	14.6	5574.6	46%	-76.88
190	SUSWA	220	31.5	27.2	10381.2	86%	-79.83
191	LONGONOT	220	31.5	11.5	4364.3	36%	-85.13
192	UPLANDS 220	220	31.5	11.7	4469.6	37%	-76.26
193	ATHI RIVER	220	31.5	12.4	4711.3	39%	-68.55
194	MALAA220	220	31.5	19.4	7408.0	62%	-74
195	NGONG	220	31.5	14.6	5548.6	46%	-82.4
196	MAGADI	220	31.5	2.6	1002.6	8%	-80.5
197	LONGONOT	220	31.5	5.6	2146.3	18%	-80.06
198	RABAI 220	220	31.5	7.4	2817.0	23%	-64.68
199	GARSEN 220	220	31.5	5.7	2155.8	18%	-73.77
200	LAMU 220	220	31.5	7.1	2697.0	22%	-80.77
201	MALINDI 220	220	31.5	5.3	2020.4	17%	-67.9
202	BAMBUR CE220	220	31.5	5.6	2140.1	18%	-67.33
203	GALANA 220	220	31.5	3.6	1374.2	11%	-70.91
204	SWTCH STN	220	31.5	5.5	2113.6	18%	-66.23
205	KILIFI 220	220	31.5	4.0	1539.5	13%	-68.14
206	MARIAKANI EH	220	31.5	9.2	3512.9	29%	-68.29
207	LAMU 220_2	220	31.5	7.9	3026.3	25%	-82.82
208	NNDONGO KUND	220	31.5	6.9	2610.6	22%	-74.35
209	KWALE	220	31.5	6.5	2480.0	21%	-73.33
210	TEE-OFF	220	31.5	7.3	2769.4	23%	-72.86
211	DOGO LNG	220	31.5	6.8	2590.1	22%	-74.64

212	GITARU 220	220	31.5	9.9	3790.7	32%	-79.03
213	KAMBURU 220	220	31.5	13.5	5156.8	43%	-78.16
214	KIAMBERE 220	220	31.5	11.2	4275.3	36%	-78.44
215	KARURA	220	31.5	8.9	3374.4	28%	-79.32
216	KIBIRIGWI	220	31.5	10.4	3960.8	33%	-77.8
217	EMBU	220	31.5	11.1	4212.6	35%	-77.71
218	THIKA 220	220	31.5	16.7	6346.8	53%	-80.17
219	HG FALLS 220	220	31.5	17.7	6756.8	56%	-83.97
220	ISIOLO 220	220	31.5	7.7	2949.0	25%	-77.76
221	MAUA 220	220	31.5	7.5	2841.1	24%	-77.72
222	GARISSA	220	31.5	3.4	1306.4	11%	-75.22
223	BURA	220	31.5	2.7	1018.5	8%	-74.79
224	HOLA	220	31.5	3.0	1152.6	10%	-74.6
225	WAJIR	220	31.5	0.7	268.4	2%	-77.58
226	MANDERA	220	31.5	0.5	202.7	2%	-77.79
227	GARBATULA	220	31.5	3.6	1380.0	11%	-77.33
228	MOYALE	220	31.5	1.9	723.8	6%	-80.31
229	OLKARIA2 220	220	31.5	28.0	10656.5	89%	-80.49
230	OLKARIA3 220	220	31.5	21.8	8291.6	69%	-80.73
231	OLKARIA 4	220	31.5	28.9	11017.8	92%	-80.49
232	OLK IAU 220	220	31.5	28.9	11018.9	92%	-80.49
233	MENENGAI	220	31.5	15.4	5869.9	49%	-81.63
234	OLKARIA V	220	31.5	14.1	5381.4	45%	-81.03
235	RONGAI	220	31.5	16.6	6335.5	53%	-81.13
236	GILGIL 220	220	31.5	18.0	6852.9	57%	-81.82
237	AKIRA 220	220	31.5	5.9	2230.5	19%	-82.85
238	OLKARIA VI	220	31.5	28.9	11012.0	92%	-80.49
239	OLKARIA VII	220	31.5	12.7	4850.2	40%	-80.26
240	OLK IX	220	31.5	8.7	3305.0	28%	-84.22
241	OLKARIA VIII	220	31.5	7.9	2994.3	25%	-83.73
242	NAIVASHA 220	220	31.5	17.4	6640.2	55%	-78.99
243	KAKAMEGA	220	31.5	7.8	2974.2	25%	-74.4
244	MUHORONI	220	31.5	5.6	2137.2	18%	-75.09
245	TORORO 2	220	31.5	5.3	2018.7	17%	-77.34
246	TURKWEL	220	31.5	4.8	1813.4	15%	-78.24

247	LESSOS 220	220	31.5	12.2	4652.2	39%	-76.56
248	KITALE	220	31.5	3.0	1129.6	9%	-74.72
249	BARINGO 220	220	31.5	8.8	3352.2	28%	-78.88
250	LOKICHAR	220	31.5	5.3	2026.2	17%	-78.55
251	KIBOS	220	31.5	7.9	3011.0	25%	-75.07
252	ORTUM	220	31.5	3.4	1297.1	11%	-77.4
253	MUSAGA	220	31.5	8.6	3263.1	27%	-74.62
254	KERICHO	220	31.5	7.3	2796.2	23%	-76.14
255	CHEMOSIT 220	220	31.5	6.6	2514.9	21%	-75.06
256	KISII 220	220	31.5	4.3	1640.5	14%	-76.99
257	SILALI 220	220	31.5	16.1	6131.4	51%	-82.35
258	RADIANT	220	31.5	1.6	623.2	5%	-77.84
259	TURKWELL TEE	220	31.5	3.3	1257.9	10%	-75.68
260	KAPSOWAR	220	31.5	3.0	1137.6	9%	-75.61
261	AGIL 220	220	31.5	15.2	5802.5	48%	-80.75
262	MARSABIT	220	31.5	4.5	1723.4	14%	-80.44
263	KAINUK	220	31.5	4.7	1806.4	15%	-78.26
264	LOKICHOGGIO	220	31.5	1.9	732.8	6%	-79.08
265	LODWAR	220	31.5	5.3	2034.6	17%	-78.56
266	LOYAN	220	31.5	9.8	3729.6	31%	-83.25
267	ELD NTH 220	220	31.5	6.3	2404.2	20%	-77.1
268	BARRIER	220	31.5	2.1	790.7	7%	-82.48
269	BUJAGALI	220	31.5	3.1	1165.5	10%	-80.37
270	KAINUK 66	220	31.5	2.6	996.2	8%	-83.3
271	OLKARIA 4 WE	220	31.5	28.4	10821.7	90%	-80.49
272	GENERIC2028	220	31.5	8.9	3374.4	28%	-79.32
273	GENERIC2029	220	31.5	5.1	1950.4	16%	-72.95
274	GENERIC2030	220	31.5	14.6	5548.6	46%	-82.4
275	GENERIC 2033	220	31.5	16.7	6346.8	53%	-80.17
276	GENERIC 2025	220	31.5	7.6	2911.2	24%	-82.72
277	GENERIC 2031	220	31.5	7.9	3011.0	25%	-75.07
278	GENERIC 2035	220	31.5	4.9	1853.0	15%	-78.69
279	SUSWA PP	220	31.5	10.5	3985.4	33%	-84.72
280	CHAGEM	220	31.5	14.6	5548.6	46%	-82.4
281	ELEKTRA	220	31.5	7.1	2697.0	22%	-80.77
282	VATEKI	220	31.5	5.3	2020.4	17%	-67.9

283	MERU WIND220	220	31.5	7.0	2671.2	22%	-78.33
284	HABASWEIN	220	31.5	0.9	360.4	3%	-77.68
285	ISINYA4	400	40	14.9	10328.5	37%	-74.56
286	SUSWA	400	40	16.0	11112.9	40%	-80.02
287	KIMUKA	400	40	15.1	10456.1	38%	-77.63
288	KONZA4	400	40	15.0	10400.6	38%	-75.31
289	NAMANGA	400	40	8.2	5699.9	21%	-77.8
290	LONGONOT	400	40	10.1	7014.4	25%	-81.17
291	MALAA 400	400	40	16.5	11460.2	41%	-75.84
292	MAKINDU 400	400	40	8.7	6031.9	22%	-74.5
293	KITUI	400	40	8.8	6114.4	22%	-82.37
294	MARIAKANI	400	40	5.6	3872.3	14%	-71.76
295	LAMU	400	40	5.8	4003.2	14%	-83.34
296	VOI 400	400	40	6.4	4435.4	16%	-73
297	THIKA 400	400	40	16.5	11426.8	41%	-77.81
298	HG FALL 400	400	40	9.4	6511.7	23%	-83.66
299	GILGIL	400	40	17.1	11871.4	43%	-78.3
300	RONGAI 400	400	40	14.0	9689.0	35%	-78.04
301	KILGORIS	400	40	5.5	3842.9	14%	-78.8
302	LOYAN 400	400	40	7.3	5090.9	18%	-82.17
303	SILALI	400	40	12.7	8782.5	32%	-79.77
304	RUMRT400 TEE	400	40	16.1	11147.9	40%	-78.72
305	SILALI4 TEE1	400	40	13.0	8983.9	32%	-79.86
306	LONG_HVDC	400	40	16.0	11112.9	40%	-80.02
307	LESSOS 400	400	40	9.4	6479.9	23%	-78.25
308	ARUSHA	400	40	5.4	3774.7	14%	-78.62
309	MEGA_HVDC	400	40	7.4	5136.6	19%	-79.91
310	WOLYATA	400	40	7.4	5136.6	19%	-79.91

2037 THREE PHASE SCC LEVELS (MAX)

S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE
1	ULU 132	132	31.5	12.0	2750.7	38%	-74.46
2	DANDORA 132	132	31.5	23.1	5284.7	73%	-71.82

3	JUJA RD 132	132	31.5	24.1	5499.1	76%	-70.92
4	KIBOKO	132	31.5	4.7	1085.9	15%	-68.12
5	MAKINDU 132	132	31.5	5.4	1238.0	17%	-70.95
6	UPLANDS	132	31.5	11.0	2520.4	35%	-76.58
7	RUARAKA 132	132	31.5	17.4	3967.7	55%	-78.35
8	SULTAN HAMUD	132	31.5	5.5	1265.6	18%	-66.54
9	KAJIADO	132	31.5	3.8	859.8	12%	-85.25
10	KONZA	132	31.5	16.4	3740.1	52%	-78.96
11	MACHAKOS	132	31.5	7.8	1779.1	25%	-69.74
12	NAMANGA	132	31.5	1.4	327.6	5%	-72.23
13	ISINYA 132	132	31.5	3.9	894.0	12%	-86.18
14	KONZA SGR	132	31.5	8.4	1924.9	27%	-72.46
15	SULTAN SGR	132	31.5	5.0	1149.9	16%	-65.78
16	MAKINDU NEW	132	31.5	8.3	1902.8	26%	-78.88
17	MAKINDU SGR	132	31.5	7.4	1693.1	24%	-77.37
18	MKD TEE	132	31.5	7.4	1681.2	23%	-76.39
19	MKD T-OFF	132	31.5	7.2	1642.9	23%	-76.45
20	NDALSYN TEE1	132	31.5	3.7	855.9	12%	-68.37
21	NDALSYN TEE2	132	31.5	3.7	842.3	12%	-68.2
22	NDALSYAN SGR	132	31.5	3.7	849.3	12%	-68.26
23	TSAVO TEE 1	132	31.5	3.8	872.3	12%	-67.71
24	TSAVO TEE 2	132	31.5	4.0	920.2	13%	-67.95
25	TSAVO SGR	132	31.5	3.9	895.4	12%	-67.77
26	THIKARD132	132	31.5	17.4	3974.2	55%	-78.38
27	OWEN FALLS	132	31.5	2.1	489.6	7%	-59.31
28	VOI 132	132	31.5	8.8	2005.3	28%	-74.49
29	VIPINGO RANG	132	31.5	6.7	1536.3	21%	-62.41
30	KIPEVU 2	132	31.5	8.9	2039.3	28%	-58.94
31	KIPEVU	132	31.5	9.0	2056.2	29%	-58.82
32	KOKOTONI	132	31.5	8.6	1960.3	27%	-60.24
33	MARIAKANI	132	31.5	5.9	1345.0	19%	-62.05
34	MAUNGU132	132	31.5	4.4	1016.2	14%	-67.9
35	MOMBASA CEM	132	31.5	6.3	1450.1	20%	-63.04
36	MBSACEM TEE1	132	31.5	6.4	1473.5	20%	-62.81

37	MBSACEM TEE2	132	31.5	6.2	1428.9	20%	-63.56
38	NEW BAMB 132	132	31.5	9.4	2158.8	30%	-60.82
39	RABAI 132	132	31.5	10.7	2439.1	34%	-58.93
40	RABAI POWER	132	31.5	10.5	2401.5	33%	-59.19
41	SAMBURU 132	132	31.5	3.9	884.8	12%	-63.84
42	GALU	132	31.5	4.9	1114.9	15%	-60.69
43	MANYANI	132	31.5	4.2	963.3	13%	-68.23
44	KILIFI	132	31.5	6.2	1406.6	20%	-65.14
45	MTITO ANDEI	132	31.5	3.6	822.3	11%	-68.01
46	TITANIUM 132	132	31.5	4.2	956.1	13%	-62.52
47	GARISSA	132	31.5	4.7	1074.0	15%	-77.51
48	JOMVU	132	31.5	8.2	1885.4	26%	-60.94
49	KWALE SC	132	31.5	3.7	835.8	12%	-66.21
50	LIKONI	132	31.5	4.2	963.7	13%	-61.25
51	BAMBURI CEME	132	31.5	9.5	2172.2	30%	-61.45
52	S_HAMUD_NEW	132	31.5	5.2	1183.7	16%	-65.82
53	MBARAKI	132	31.5	7.1	1630.0	23%	-59.19
54	TAVETA	132	31.5	1.5	339.1	5%	-65.33
55	S_HAMUD_TEE	132	31.5	5.8	1317.5	18%	-66.48
56	LIKONI TEE	132	31.5	6.1	1404.4	19%	-60.04
57	LUNGA LUNGA	132	31.5	3.9	886.7	12%	-69
58	LOITOKTOK	132	31.5	1.9	435.4	6%	-65.15
59	MERUWESHI	132	31.5	5.1	1172.1	16%	-65.81
60	MTWAPA	132	31.5	7.7	1752.3	24%	-61.66
61	SHIMONI	132	31.5	3.7	850.4	12%	-68.06
62	VOI 132 NEW	132	31.5	10.4	2377.2	33%	-78.22
63	MACKNN TEE 1	132	31.5	3.5	803.2	11%	-65.8
64	MACKNN TEE2	132	31.5	3.4	774.3	11%	-64.75
65	MAKINNON SGR	132	31.5	3.4	776.7	11%	-65.07
66	MARIAKNI NEW	132	31.5	5.2	1197.0	17%	-62.5
67	MARIAKN SGR	132	31.5	5.9	1345.0	19%	-62.05
68	KWALE	132	31.5	6.3	1445.1	20%	-79.5
69	GITARU 132	132	31.5	14.8	3374.3	47%	-81.05
70	GITHAMBO	132	31.5	4.9	1109.7	15%	-66.79
71	KAMBURU 132	132	31.5	17.1	3916.3	54%	-80.51
72	KIGANJO	132	31.5	12.4	2839.4	39%	-74.88

73	KILBOGO TEE1	132	31.5	9.0	2058.2	29%	-69.11
74	KINDARUMA	132	31.5	6.2	1417.6	20%	-70.71
75	KILBOGO TEE2	132	31.5	8.1	1862.2	26%	-69.63
76	MANGU	132	31.5	17.3	3963.3	55%	-77.43
77	MASINGA	132	31.5	8.7	1980.3	27%	-79.33
78	MERU 132	132	31.5	9.5	2180.7	30%	-73.44
79	NANYUKI 132	132	31.5	8.5	1936.3	27%	-66.83
80	GATUNDU	132	31.5	6.0	1366.3	19%	-69.26
81	KUTUS 132	132	31.5	14.0	3201.2	44%	-78.81
82	KUTUS_T1	132	31.5	8.9	2045.0	28%	-76.4
83	KUTUS_T2	132	31.5	7.7	1760.8	24%	-77.43
84	THIKAPWR 132	132	31.5	17.0	3889.0	54%	-77.22
85	ISIOLO	132	31.5	11.1	2539.5	35%	-72.67
86	MWINGI	132	31.5	4.0	909.0	13%	-67.12
87	KITUI	132	31.5	2.8	632.2	9%	-64.58
88	KYENI	132	31.5	6.2	1416.5	20%	-70.71
89	MAUA	132	31.5	10.0	2275.4	32%	-78.9
90	TATU CITY	132	31.5	7.9	1805.9	25%	-70.94
91	MUTOMO	132	31.5	1.4	309.8	4%	-63.73
92	KIBWEZI	132	31.5	0.9	213.1	3%	-63.31
93	KIBR TEE 2	132	31.5	14.6	3327.7	46%	-77.7
94	OTHAYA	132	31.5	5.0	1148.3	16%	-67.05
95	WOTE	132	31.5	3.1	707.1	10%	-65.08
96	ISHIARA SWST	132	31.5	7.0	1610.9	22%	-75.6
97	KIBIRIGWI	132	31.5	14.6	3327.7	46%	-77.7
98	THIKA NEW	132	31.5	17.3	3963.3	55%	-77.43
99	ISIOLO SS2	132	31.5	11.6	2656.9	37%	-77.02
100	GARISSA SS2	132	31.5	4.7	1074.0	15%	-77.51
101	CHOGORIA	132	31.5	3.0	696.7	10%	-67.69
102	MWALA	132	31.5	7.2	1655.5	23%	-68.42
103	LANET	132	31.5	13.3	3049.6	42%	-69
104	NAIVASHA 132	132	31.5	14.4	3293.0	46%	-76.72
105	OLKARIA1 132	132	31.5	10.1	2306.7	32%	-84.95
106	NAKRUWEST_T1	132	31.5	14.8	3393.9	47%	-71.03
107	NAKRUWEST_T2	132	31.5	14.5	3321.2	46%	-70.98

108	MAKUTANO_T1	132	31.5	9.1	2081.5	29%	-66.26
109	MAKUTANO_T2	132	31.5	9.2	2113.0	29%	-66.22
110	OLK 1AU 132	132	31.5	10.2	2323.8	32%	-85.06
111	OLKALOU	132	31.5	7.7	1762.8	24%	-67.71
112	AEOLUS WIND	132	31.5	7.4	1681.3	23%	-73.09
113	NAROK	132	31.5	4.4	1000.4	14%	-68.51
114	GILGIL	132	31.5	15.2	3472.6	48%	-76.96
115	GILGIL TEE1	132	31.5	14.2	3253.9	45%	-74.88
116	GILGIL TEE2	132	31.5	13.3	3038.2	42%	-73.27
117	OLK I WE	132	31.5	9.2	2098.9	29%	-83.22
118	KAKAMEGA132	132	31.5	8.1	1847.7	26%	-75.16
119	WEBUYE	132	31.5	6.7	1532.3	21%	-67.17
120	CHEMOSIT	132	31.5	7.5	1717.9	24%	-72.27
121	KISII	132	31.5	7.0	1595.4	22%	-70.37
122	KISUMU 132	132	31.5	10.9	2498.7	35%	-66.8
123	MUHORONI 132	132	31.5	8.4	1925.6	27%	-71.44
124	MUMIAS 132	132	31.5	5.5	1248.6	17%	-65.42
125	MUSAGA 132	132	31.5	10.6	2425.6	34%	-69.67
126	RANGALA 132	132	31.5	5.8	1329.8	18%	-63.49
127	SANGORO	132	31.5	4.6	1049.1	15%	-67.54
128	SONDU MIRIU	132	31.5	5.2	1188.4	17%	-67.76
129	AWENDO	132	31.5	3.9	894.1	12%	-63.54
130	BOMET	132	31.5	5.2	1193.7	17%	-67.3
131	ONGENG	132	31.5	3.6	824.7	11%	-63.86
132	SOTIK	132	31.5	9.7	2222.7	31%	-70.54
133	BONDO	132	31.5	3.8	875.8	12%	-63.31
134	CHAVAKALI	132	31.5	8.6	1974.1	27%	-68.57
135	KISUMU EAST	132	31.5	9.7	2218.4	31%	-66.02
136	MALABA TEE2	132	31.5	3.8	858.5	12%	-63.94
137	ISABENIA	132	31.5	2.0	452.9	6%	-63.57
138	TORORO 132	132	31.5	5.6	1277.4	18%	-64.31
139	MAKUTANO 132	132	31.5	9.3	2124.4	29%	-66.22
140	NAKURU_W 132	132	31.5	14.9	3405.2	47%	-71.16
141	KILGORIS	132	31.5	13.0	2981.6	41%	-79.41
142	MYANGA	132	31.5	6.9	1576.6	22%	-65.38

143	BUSIA	132	31.5	5.8	1322.5	18%	-64.55
144	NDWIGA	132	31.5	2.9	671.3	9%	-63.52
145	SINDO	132	31.5	2.0	464.2	6%	-64.42
146	KARUNGO	132	31.5	1.8	409.0	6%	-64.98
147	KIMILILI	132	31.5	5.9	1340.3	19%	-67.46
148	KAIMOSI	132	31.5	8.6	1974.1	27%	-68.57
149	SUKARI	132	31.5	3.4	768.8	11%	-63.96
150	ELDORET	132	31.5	9.2	2093.7	29%	-70.85
151	LESSOS 132	132	31.5	15.2	3485.2	48%	-70.58
152	KITALE	132	31.5	6.0	1369.3	19%	-69.81
153	KABARNET	132	31.5	3.6	818.8	11%	-65.91
154	KAPSABET	132	31.5	7.4	1698.3	24%	-67.56
155	KIBOS1	132	31.5	11.1	2548.2	35%	-67.26
156	RUMURUTI	132	31.5	7.3	1672.3	23%	-66.7
157	SILALI	132	31.5	15.4	3523.1	49%	-83.74
158	ELDORET NTH	132	31.5	9.1	2074.2	29%	-72.03
159	MOI BRCKS	132	31.5	5.6	1291.5	18%	-68.59
160	MARALAL	132	31.5	4.8	1098.3	15%	-68.03
161	KERINGET	132	31.5	2.8	644.6	9%	-62.94
162	MENENGAI 132	132	31.5	15.4	3522.6	49%	-75
163	GENERIC 2023	132	31.5	3.4	787.9	11%	-69.65
164	GENERIC 2024	132	31.5	4.4	1000.4	14%	-68.51
165	GENERIC 2034	132	31.5	2.9	665.1	9%	-69.43
166	SUSTAINABLE	132	31.5	24.1	5499.1	76%	-70.92
167	MAKINDU SLR	132	31.5	4.7	1085.9	15%	-68.12
168	CHERAB	132	31.5	11.6	2656.9	37%	-77.02
169	MERU WIND	132	31.5	11.6	2656.9	37%	-77.02
170	CRYSTAL	132	31.5	0.9	213.1	3%	-63.31
171	KIBR TEE 1	132	31.5	14.0	3205.0	45%	-77.16
172	KOPERE	132	31.5	7.6	1747.5	24%	-70.38
173	QUAINT	132	31.5	4.7	1077.4	15%	-67.15
174	KAPTIS	132	31.5	8.6	1974.1	27%	-68.57
175	K TE 1	132	31.5	10.2	2333.6	32%	-67.33
176	K TE 2	132	31.5	10.2	2333.6	32%	-67.33
177	TARITA SLR	132	31.5	4.3	975.3	14%	-66.46
178	KENERGY SLR	132	31.5	7.3	1672.3	23%	-66.7

179	SUNPOWER	132	31.5	3.3	748.2	10%	-65.95

180	GITARU SLR	132	31.5	9.8	2240.9	31%	-80.84
181	DANDORA 220	220	31.5	16.6	6336.1	53%	-72.97
182	RUARAKA 220	220	31.5	14.0	5342.6	45%	-72.56
183	JUJA RD	220	31.5	14.2	5403.4	45%	-71.88
184	EMBAKASI	220	31.5	14.2	5399.9	45%	-67.5
185	EMBAKASI_CC	220	31.5	14.1	5354.8	45%	-67.68
186	THIKA RD BSP	220	31.5	19.4	7373.6	61%	-70.91
187	CBD	220	31.5	13.1	4979.0	41%	-68.47
188	NRBI NORTH	220	31.5	16.5	6276.7	52%	-73.2
189	ISINYA	220	31.5	15.9	6041.1	50%	-76.69
190	SUSWA	220	31.5	29.1	11070.5	92%	-79.31
191	LONGONOT	220	31.5	12.0	4576.3	38%	-85.3
192	UPLANDS 220	220	31.5	12.7	4844.1	40%	-75.62
193	ATHI RIVER	220	31.5	13.9	5297.0	44%	-67.91
194	MALAA220	220	31.5	21.5	8181.2	68%	-73.4
195	NGONG	220	31.5	15.4	5883.6	49%	-82.32
196	MAGADI	220	31.5	2.9	1095.4	9%	-80.5
197	LONGONOT	220	31.5	6.2	2345.6	20%	-79.95
198	RABAI 220	220	31.5	8.8	3343.3	28%	-65.37
199	GARSEN 220	220	31.5	6.4	2431.9	20%	-73.81
200	LAMU 220	220	31.5	7.8	2976.4	25%	-80.82
201	MALINDI 220	220	31.5	6.3	2392.2	20%	-67.31
202	BAMBUR CE220	220	31.5	7.0	2668.1	22%	-66.74
203	GALANA 220	220	31.5	4.2	1602.4	13%	-70.61
204	SWTCH STN	220	31.5	6.7	2540.8	21%	-65.32
205	KILIFI 220	220	31.5	4.9	1865.0	16%	-67.02
206	MARIAKANI EH	220	31.5	11.0	4188.4	35%	-68.7
207	LAMU 220_2	220	31.5	8.7	3329.0	28%	-82.89
208	NNDONGO KUND	220	31.5	9.4	3569.6	30%	-76.44
209	KWALE	220	31.5	8.4	3182.3	27%	-74.84
210	TEE-OFF	220	31.5	9.5	3630.0	30%	-74.46
211	DOGO LNG	220	31.5	9.4	3563.2	30%	-76.81
212	GITARU 220	220	31.5	10.7	4085.0	34%	-78.64
213	KAMBURU 220	220	31.5	14.5	5541.8	46%	-77.65

214	KIAMBERE 220	220	31.5	12.0	4591.6	38%	-78.05
215	KARURA	220	31.5	9.5	3618.6	30%	-79
216	KIBIRIGWI	220	31.5	11.3	4302.7	36%	-77.44
217	EMBU	220	31.5	12.0	4569.5	38%	-77.28
218	THIKA 220	220	31.5	17.8	6764.4	56%	-79.94
219	HG FALLS 220	220	31.5	19.4	7383.2	62%	-84.04
220	ISIOLO 220	220	31.5	8.3	3181.5	27%	-77.38
221	MAUA 220	220	31.5	8.1	3079.4	26%	-77.37
222	GARISSA	220	31.5	3.8	1436.7	12%	-75.03
223	BURA	220	31.5	3.0	1127.7	9%	-74.79
224	HOLA	220	31.5	3.4	1279.8	11%	-74.62
225	WAJIR	220	31.5	0.8	296.2	2%	-77.35
226	MANDERA	220	31.5	0.6	223.4	2%	-77.57
227	GARBATULA	220	31.5	4.0	1512.9	13%	-77.15
228	MOYALE	220	31.5	2.1	789.4	7%	-80.24
229	OLKARIA2 220	220	31.5	29.7	11331.3	94%	-79.99

230	OLKARIA3 220	220	31.5	23.2	8858.0	74%	-80.33
231	OLKARIA 4	220	31.5	30.7	11707.3	98%	-79.97
232	OLK IAU 220	220	31.5	30.7	11708.7	98%	-79.96
233	MENENGAI	220	31.5	16.1	6122.5	51%	-81.22
234	OLKARIA V	220	31.5	15.2	5779.4	48%	-80.75
235	RONGAI	220	31.5	17.3	6605.4	55%	-80.69
236	GILGIL 220	220	31.5	18.9	7206.2	60%	-81.57
237	AKIRA 220	220	31.5	6.3	2390.3	20%	-82.97
238	OLKARIA VI	220	31.5	22.6	8601.8	72%	-80.1
239	OLKARIA VII	220	31.5	13.8	5247.9	44%	-80
240	OLK IX	220	31.5	9.2	3488.2	29%	-84.33
241	OLKARIA VIII	220	31.5	8.3	3181.5	27%	-83.88
242	NAIVASHA 220	220	31.5	18.8	7164.7	60%	-78.55
243	KAKAMEGA	220	31.5	8.5	3233.1	27%	-73.78
244	MUHORONI	220	31.5	6.1	2326.3	19%	-74.89
245	TORORO 2	220	31.5	5.8	2212.5	18%	-76.78
246	TURKWEL	220	31.5	5.1	1938.9	16%	-77.77
247	LESSOS 220	220	31.5	13.0	4950.7	41%	-75.88
248	KITALE	220	31.5	3.2	1223.4	10%	-74.69

249	BARINGO 220	220	31.5	8.7	3328.0	28%	-78.52
250	LOKICHAR	220	31.5	5.7	2158.1	18%	-77.96
251	KIBOS	220	31.5	8.5	3256.2	27%	-74.53
252	ORTUM	220	31.5	3.7	1403.0	12%	-77.11
253	MUSAGA	220	31.5	9.3	3539.8	29%	-73.97
254	KERICHO	220	31.5	8.0	3039.6	25%	-75.8
255	CHEMOSIT 220	220	31.5	7.2	2737.2	23%	-74.79
256	KISII 220	220	31.5	4.7	1777.9	15%	-76.94
257	SILALI 220	220	31.5	13.6	5186.0	43%	-81.41
258	RADIANT	220	31.5	1.8	683.0	6%	-77.7
259	TURKWELL TEE	220	31.5	3.6	1373.3	11%	-75.41
260	KAPSOWAR	220	31.5	3.3	1243.5	10%	-75.36
261	AGIL 220	220	31.5	16.4	6241.4	52%	-80.46
262	MARSABIT	220	31.5	4.9	1857.8	15%	-80.32
263	KAINUK	220	31.5	5.1	1931.9	16%	-77.8
264	LOKICHOGGIO	220	31.5	2.1	798.1	7%	-78.8
265	LODWAR	220	31.5	5.7	2166.6	18%	-77.97
266	LOYAN	220	31.5	10.0	3792.4	32%	-82.95
267	ELD NTH 220	220	31.5	6.5	2491.6	21%	-76.88
268	BARRIER	220	31.5	2.2	843.5	7%	-82.34
269	BUJAGALI	220	31.5	3.4	1279.7	11%	-80.03
270	KAINUK 66	220	31.5	2.7	1033.5	9%	-83.24
271	OLKARIA 4 WE	220	31.5	30.2	11504.5	96%	-79.98
272	GENERIC2028	220	31.5	9.5	3618.6	30%	-79
273	GENERIC2029	220	31.5	5.4	2074.2	17%	-72.03
274	GENERIC2030	220	31.5	15.4	5883.6	49%	-82.32
275	GENERIC 2033	220	31.5	17.8	6764.4	56%	-79.94
276	GENERIC 2025	220	31.5	8.2	3106.0	26%	-82.59
277	GENERIC 2031	220	31.5	8.5	3256.2	27%	-74.53
278	GENERIC 2035	220	31.5	5.2	1979.0	16%	-78.14
279	SUSWA PP	220	31.5	11.0	4195.1	35%	-84.89
280	CHAGEM	220	31.5	15.4	5883.6	49%	-82.32
281	ELEKTRA	220	31.5	7.8	2976.4	25%	-80.82
282	VATEKI	220	31.5	6.3	2392.2	20%	-67.31
283	MERU WIND220	220	31.5	7.6	2881.1	24%	-77.97

284	HABASWEIN	220	31.5	1.0	397.4	3%	-77.5
285	ISINYA4	400	40	16.7	11601.3	42%	-74.45
286	SUSWA	400	40	17.4	12078.5	44%	-79.69
287	KIMUKA	400	40	16.7	11548.7	42%	-77.4
288	KONZA4	400	40	17.0	11811.1	43%	-75.23
289	NAMANGA	400	40	9.2	6342.7	23%	-77.79
290	LONGONOT	400	40	11.1	7724.0	28%	-81.09
291	MALAA 400	400	40	19.1	13235.0	48%	-75.82
292	MAKINDU 400	400	40	9.7	6698.9	24%	-74.61
293	KITUI	400	40	11.6	8048.2	29%	-83.35
294	MARIAKANI	400	40	6.2	4309.0	16%	-72.43
295	LAMU	400	40	6.5	4527.5	16%	-83.5
296	VOI 400	400	40	7.1	4891.4	18%	-73.29
297	THIKA 400	400	40	18.4	12752.0	46%	-77.66
298	HG FALL 400	400	40	10.3	7121.2	26%	-83.67
299	GILGIL	400	40	18.3	12706.9	46%	-77.87
300	RONGAI 400	400	40	14.8	10267.9	37%	-77.49
301	KILGORIS	400	40	6.0	4174.9	15%	-78.48
302	LOYAN 400	400	40	7.3	5033.3	18%	-82.15
303	SILALI	400	40	9.3	6452.4	23%	-79.77
304	RUMRT400 TEE	400	40	17.0	11766.2	42%	-78.4
305	SILALI4 TEE1	400	40	10.9	7565.0	27%	-80.79
306	LONG_HVDC	400	40	17.4	12078.5	44%	-79.69
307	LESSOS 400	400	40	10.1	6970.0	25%	-77.8
308	ARUSHA	400	40	6.0	4183.2	15%	-78.63
309	MEGA_HVDC	400	40	7.5	5170.7	19%	-79.3
310	WOLYATA	400	40	7.5	5170.7	19%	-79.3

2037 THREE PHASE SCC LEVELS (MIN)

S/n	BUS	BUS VOLTAGE	SC RATING	FAULT LEVEL (kA)	FAULT LEVEL (MVA)	% of SC TO EQUIPMENT RATING	ANGLE
1	ULU 132	132	31.5	11.4	2613.8	36%	-74.64
2	DANDORA 132	132	31.5	22.0	5020.3	70%	-72.16
3	JUJA RD 132	132	31.5	22.9	5227.1	73%	-71.24
4	KIBOKO	132	31.5	4.4	1005.3	14%	-68.12
5	MAKINDU 132	132	31.5	5.1	1157.4	16%	-70.97

6	UPLANDS	132	31.5	10.6	2412.6	33%	-76.72
7	RUARAKA 132	132	31.5	16.8	3848.6	53%	-78.39
8	SULTAN HAMUD	132	31.5	5.1	1167.9	16%	-66.55
9	KAJIADO	132	31.5	3.7	851.0	12%	-85.31
10	KONZA	132	31.5	15.9	3626.3	50%	-79.47
11	MACHAKOS	132	31.5	7.2	1654.0	23%	-69.75
12	NAMANGA	132	31.5	1.3	307.0	4%	-71.88
13	ISINYA 132	132	31.5	3.9	888.2	12%	-86.31
14	KONZA SGR	132	31.5	7.9	1808.1	25%	-72.51
15	SULTAN SGR	132	31.5	4.6	1059.3	15%	-65.79
16	MAKINDU NEW	132	31.5	8.0	1838.0	26%	-79.31
17	MAKINDU SGR	132	31.5	7.1	1624.4	23%	-77.67
18	MKD TEE	132	31.5	7.0	1606.9	22%	-76.63
19	MKD T-OFF	132	31.5	6.9	1570.0	22%	-76.69
20	NDALSYN TEE1	132	31.5	3.5	791.0	11%	-68.36
21	NDALSYN TEE2	132	31.5	3.4	777.8	11%	-68.18
22	NDALSYAN SGR	132	31.5	3.4	784.5	11%	-68.25
23	TSAVO TEE 1	132	31.5	3.5	803.8	11%	-67.69
24	TSAVO TEE 2	132	31.5	3.7	848.7	12%	-67.92
25	TSAVO SGR	132	31.5	3.6	825.4	11%	-67.75
26	THIKARD132	132	31.5	16.9	3855.3	54%	-78.43
27	OWEN FALLS	132	31.5	2.0	448.0	6%	-59.41
28	VOI 132	132	31.5	8.3	1901.4	26%	-74.56
29	VIPINGO RANG	132	31.5	6.2	1426.0	20%	-62.85
30	KIPEVU 2	132	31.5	8.3	1905.4	26%	-59.64
31	KIPEVU	132	31.5	8.4	1921.6	27%	-59.52
32	KOKOTONI	132	31.5	8.0	1828.5	25%	-60.88
33	MARIAKANI	132	31.5	5.4	1241.8	17%	-62.48
34	MAUNGU132	132	31.5	4.1	938.2	13%	-67.91
35	MOMBASA CEM	132	31.5	5.9	1346.9	19%	-63.45
36	MBSACEM TEE1	132	31.5	6.0	1368.0	19%	-63.23
37	MBSACEM TEE2	132	31.5	5.8	1328.2	18%	-63.96
38	NEW BAMB 132	132	31.5	8.8	2020.8	28%	-61.47
39	RABAI 132	132	31.5	10.0	2294.2	32%	-59.7

40	RABAI POWER	132	31.5	9.9	2257.5	31%	-59.96
41	SAMBURU 132	132	31.5	3.5	811.3	11%	-64.07
42	GALU	132	31.5	4.5	1028.5	14%	-61.03
43	MANYANI	132	31.5	3.9	889.3	12%	-68.21
44	KILIFI	132	31.5	5.7	1311.9	18%	-65.54
45	MTITO ANDEI	132	31.5	3.3	758.6	11%	-67.99
46	TITANIUM 132	132	31.5	3.9	881.7	12%	-62.8
47	GARISSA	132	31.5	4.4	1011.4	14%	-77.57
48	JOMVU	132	31.5	7.7	1757.1	24%	-61.62
49	KWALE SC	132	31.5	3.4	774.3	11%	-66.44
50	LIKONI	132	31.5	3.9	886.7	12%	-61.58
51	BAMBURI CEME	132	31.5	8.9	2036.3	28%	-62.11
52	S_HAMUD_NEW	132	31.5	4.8	1090.9	15%	-65.83
53	MBARAKI	132	31.5	6.6	1512.8	21%	-59.74
54	TAVETA	132	31.5	1.4	310.3	4%	-65.3
55	S_HAMUD_TEE	132	31.5	5.3	1216.5	17%	-66.49
56	LIKONI TEE	132	31.5	5.7	1300.1	18%	-60.51
57	LUNGA LUNGA	132	31.5	3.6	827.3	11%	-69.09
58	LOITOKTOK	132	31.5	1.7	397.8	6%	-65.16
59	MERUWESHI	132	31.5	4.7	1080.0	15%	-65.82
60	MTWAPA	132	31.5	7.1	1630.1	23%	-62.17
61	SHIMONI	132	31.5	3.5	791.0	11%	-68.18
62	VOI 132 NEW	132	31.5	10.0	2284.4	32%	-78.46
63	MACKNN TEE 1	132	31.5	3.2	737.0	10%	-65.88
64	MACKNN TEE2	132	31.5	3.1	709.3	10%	-64.89
65	MAKINNON SGR	132	31.5	3.1	711.9	10%	-65.18
66	MARIAKNI NEW	132	31.5	4.8	1103.2	15%	-62.89
67	MARIAKN SGR	132	31.5	5.4	1241.8	17%	-62.48
68	KWALE	132	31.5	6.1	1400.0	19%	-79.87
69	GITARU 132	132	31.5	14.2	3238.3	45%	-81.27
70	GITHAMBO	132	31.5	4.5	1020.4	14%	-66.82
71	KAMBURU 132	132	31.5	16.5	3767.5	52%	-80.74
72	KIGANJO	132	31.5	11.7	2674.4	37%	-75.1
73	KILBOGO TEE1	132	31.5	8.4	1909.6	27%	-69.19
74	KINDARUMA	132	31.5	5.8	1323.1	18%	-71

75	KILBOGO TEE2	132	31.5	7.6	1729.6	24%	-69.69
76	MANGU	132	31.5	16.8	3832.0	53%	-78.06
77	MASINGA	132	31.5	8.1	1843.5	26%	-79.44
78	MERU 132	132	31.5	8.9	2043.8	28%	-73.66
79	NANYUKI 132	132	31.5	7.8	1783.1	25%	-66.88
80	GATUNDU	132	31.5	5.5	1268.1	18%	-69.31
81	KUTUS 132	132	31.5	13.3	3037.9	42%	-79.07
82	KUTUS_T1	132	31.5	8.3	1898.6	26%	-76.53
83	KUTUS_T2	132	31.5	7.1	1632.6	23%	-77.53
84	THIKAPWR 132	132	31.5	16.4	3755.9	52%	-77.82
85	ISIOLO	132	31.5	10.4	2371.6	33%	-72.82
86	MWINGI	132	31.5	3.7	836.4	12%	-67.19
87	KITUI	132	31.5	2.5	578.5	8%	-64.61
88	KYENI	132	31.5	5.7	1305.0	18%	-70.71
89	MAUA	132	31.5	9.4	2154.2	30%	-79.07
90	TATU CITY	132	31.5	7.4	1688.0	23%	-71.04
91	MUTOMO	132	31.5	1.2	282.5	4%	-63.75
92	KIBWEZI	132	31.5	0.8	194.1	3%	-63.32
93	KIBR TEE 2	132	31.5	13.8	3157.1	44%	-77.99
94	OTHAYA	132	31.5	4.6	1056.0	15%	-67.08
95	WOTE	132	31.5	2.8	647.4	9%	-65.1
96	ISHIARA SWST	132	31.5	6.5	1485.4	21%	-75.69
97	KIBIRIGWI	132	31.5	13.8	3157.1	44%	-77.99
98	THIKA NEW	132	31.5	16.8	3832.0	53%	-78.06
99	ISIOLO SS2	132	31.5	11.0	2507.6	35%	-77.32
100	GARISSA SS2	132	31.5	4.4	1011.4	14%	-77.57
101	CHOGORIA	132	31.5	2.8	637.4	9%	-67.67
102	MWALA	132	31.5	6.7	1529.9	21%	-68.47
103	LANET	132	31.5	12.6	2869.8	40%	-69.1
104	NAIVASHA 132	132	31.5	13.8	3159.9	44%	-77.03
105	OLKARIA1 132	132	31.5	10.0	2276.1	32%	-85.2
106	NAKRUWEST_T1	132	31.5	14.1	3214.1	45%	-71.32
107	NAKRUWEST_T2	132	31.5	13.7	3142.7	44%	-71.26
108	MAKUTANO_T1	132	31.5	8.4	1928.4	27%	-66.38
109	MAKUTANO_T2	132	31.5	8.6	1958.2	27%	-66.35
110	OLK 1AU 132	132	31.5	10.0	2294.9	32%	-85.32

111	OLKALOU	132	31.5	7.1	1631.5	23%	-67.82
112	AEOLUS WIND	132	31.5	6.9	1580.8	22%	-73.24
113	NAROK	132	31.5	4.0	923.9	13%	-68.37
114	GILGIL	132	31.5	14.6	3342.0	46%	-77.41
115	GILGIL TEE1	132	31.5	13.6	3109.4	43%	-75.15
116	GILGIL TEE2	132	31.5	12.6	2885.4	40%	-73.41
117	OLK I WE	132	31.5	9.0	2055.7	29%	-83.32
118	KAKAMEGA132	132	31.5	7.7	1757.7	24%	-75.6
119	WEBUYE	132	31.5	6.2	1422.0	20%	-67.44
120	CHEMOSIT	132	31.5	7.1	1623.0	23%	-72.57
121	KISII	132	31.5	6.5	1490.4	21%	-70.65
122	KISUMU 132	132	31.5	10.3	2352.6	33%	-67.38
123	MUHORONI 132	132	31.5	7.9	1807.0	25%	-71.72
124	MUMIAS 132	132	31.5	5.1	1154.6	16%	-65.67
125	MUSAGA 132	132	31.5	10.0	2293.6	32%	-70.27
126	RANGALA 132	132	31.5	5.4	1228.7	17%	-63.76
127	SANGORO	132	31.5	4.3	980.9	14%	-68.01
128	SONDU MIRIU	132	31.5	4.9	1113.8	15%	-68.28
129	AWENDO	132	31.5	3.6	823.9	11%	-63.72
130	BOMET	132	31.5	4.8	1099.1	15%	-67.26
131	ONGENG	132	31.5	3.3	760.0	11%	-64.07
132	SOTIK	132	31.5	9.1	2071.9	29%	-70.61
133	BONDO	132	31.5	3.5	804.8	11%	-63.5
134	CHAVAKALI	132	31.5	8.1	1841.4	26%	-68.85
135	KISUMU EAST	132	31.5	9.1	2080.1	29%	-66.52
136	MALABA TEE2	132	31.5	3.5	790.4	11%	-64.09
137	ISABENIA	132	31.5	1.8	414.7	6%	-63.69
138	TORORO 132	132	31.5	5.2	1183.5	16%	-64.56
139	MAKUTANO 132	132	31.5	8.6	1969.0	27%	-66.35
140	NAKURU_W 132	132	31.5	14.1	3226.3	45%	-71.46
141	KILGORIS	132	31.5	12.3	2816.9	39%	-79.59
142	MYANGA	132	31.5	6.4	1466.6	20%	-65.7
143	BUSIA	132	31.5	5.4	1223.6	17%	-64.82
144	NDWIGA	132	31.5	2.7	615.4	9%	-63.67
145	SINDO	132	31.5	1.9	425.2	6%	-64.54

146	KARUNGO	132	31.5	1.6	374.3	5%	-65.1
147	KIMILILI	132	31.5	5.4	1239.3	17%	-67.67
148	KAIMOSI	132	31.5	8.1	1841.4	26%	-68.85
149	SUKARI	132	31.5	3.1	707.3	10%	-64.14
150	ELDORET	132	31.5	8.6	1960.8	27%	-71.13
151	LESSOS 132	132	31.5	14.4	3301.3	46%	-71.21
152	KITALE	132	31.5	5.5	1267.3	18%	-70
153	KABARNET	132	31.5	3.3	749.1	10%	-65.98
154	KAPSABET	132	31.5	6.9	1572.1	22%	-67.78
155	KIBOS1	132	31.5	10.5	2402.5	33%	-67.86
156	RUMURUTI	132	31.5	6.7	1536.4	21%	-66.76
157	SILALI	132	31.5	15.0	3422.9	48%	-83.89
158	ELDORET NTH	132	31.5	8.5	1946.8	27%	-72.35
159	MOI BRCKS	132	31.5	5.2	1192.9	17%	-68.72
160	MARALAL	132	31.5	4.4	1009.0	14%	-67.94
161	KERINGET	132	31.5	2.6	589.3	8%	-62.95
162	MENENGAI 132	132	31.5	14.8	3377.0	47%	-75.59
163	GENERIC 2023	132	31.5	3.2	722.0	10%	-69.69
164	GENERIC 2024	132	31.5	4.0	923.9	13%	-68.37
165	GENERIC 2034	132	31.5	2.7	611.9	8%	-69.28

166	SUSTAINABLE	132	31.5	22.9	5227.1	73%	-71.24
167	MAKINDU SLR	132	31.5	4.4	1005.3	14%	-68.12
168	CHERAB	132	31.5	11.0	2507.6	35%	-77.32
169	MERU WIND	132	31.5	11.0	2507.6	35%	-77.32
170	CRYSTAL	132	31.5	0.8	194.1	3%	-63.32
171	KIBR TEE 1	132	31.5	13.3	3034.5	42%	-77.42
172	KOPERE	132	31.5	7.1	1623.3	23%	-70.77
173	QUAINT	132	31.5	4.4	1005.2	14%	-67.59
174	KAPTIS	132	31.5	8.1	1841.4	26%	-68.85
175	K TE 1	132	31.5	9.5	2170.1	30%	-67.58
176	K TE 2	132	31.5	9.5	2170.1	30%	-67.58
177	TARITA SLR	132	31.5	3.9	894.3	12%	-66.56
178	KENERGY SLR	132	31.5	6.7	1536.4	21%	-66.76
179	SUNPOWER	132	31.5	3.0	686.1	10%	-65.96
180	GITARU SLR	132	31.5	9.2	2112.4	29%	-80.98

181	DANDORA 220	220	31.5	15.7	5965.3	50%	-73.42
182	RUARAKA 220	220	31.5	13.3	5073.8	42%	-72.85
183	JUJA RD	220	31.5	13.5	5137.4	43%	-72.15
184	EMBAKASI	220	31.5	13.3	5066.9	42%	-67.9
185	EMBAKASI_CC	220	31.5	13.2	5024.7	42%	-68.1
186	THIKA RD BSP	220	31.5	18.3	6955.0	58%	-71.47
187	CBD	220	31.5	12.2	4661.3	39%	-68.84
188	NRBI NORTH	220	31.5	15.4	5864.6	49%	-73.63
189	ISINYA	220	31.5	15.3	5820.8	48%	-77.24
190	SUSWA	220	31.5	28.1	10710.5	89%	-79.88
191	LONGONOT	220	31.5	11.7	4443.7	37%	-85.39
192	UPLANDS 220	220	31.5	11.9	4544.9	38%	-75.9
193	ATHI RIVER	220	31.5	13.1	4974.6	41%	-68.35
194	MALAA220	220	31.5	20.6	7839.3	65%	-74.17
195	NGONG	220	31.5	15.1	5745.5	48%	-82.56
196	MAGADI	220	31.5	2.6	1008.9	8%	-80.51
197	LONGONOT	220	31.5	5.7	2160.0	18%	-80.07
198	RABAI 220	220	31.5	8.2	3135.7	26%	-65.7
199	GARSEN 220	220	31.5	5.9	2258.4	19%	-74.09
200	LAMU 220	220	31.5	7.4	2826.4	24%	-81.13
201	MALINDI 220	220	31.5	5.8	2213.9	18%	-67.63
202	BAMBUR CE220	220	31.5	6.5	2483.2	21%	-67.05
203	GALANA 220	220	31.5	3.9	1474.2	12%	-70.88
204	SWTCH STN	220	31.5	6.2	2355.5	20%	-65.64
205	KILIFI 220	220	31.5	4.5	1724.0	14%	-67.24
206	MARIAKANI EH	220	31.5	10.4	3957.4	33%	-69.2
207	LAMU 220_2	220	31.5	8.4	3192.9	27%	-83.29
208	NNDONGO KUND	220	31.5	9.0	3421.0	29%	-77.12
209	KWALE	220	31.5	7.9	3011.2	25%	-75.41
210	TEE-OFF	220	31.5	9.1	3455.8	29%	-75.08
211	DOGO LNG	220	31.5	9.0	3418.7	28%	-77.5
212	GITARU 220	220	31.5	10.1	3834.4	32%	-78.98
213	KAMBURU 220	220	31.5	13.8	5242.8	44%	-78.07
214	KIAMBERE 220	220	31.5	11.4	4329.8	36%	-78.44
215	KARURA	220	31.5	8.9	3404.6	28%	-79.32

216	KIBIRIGWI	220	31.5	10.6	4031.9	34%	-77.72
217	EMBU	220	31.5	11.2	4280.5	36%	-77.61
218	THIKA 220	220	31.5	17.2	6556.3	55%	-80.37
219	HG FALLS 220	220	31.5	18.7	7131.2	59%	-84.27
220	ISIOLO 220	220	31.5	7.8	2978.2	25%	-77.66
221	MAUA 220	220	31.5	7.5	2869.2	24%	-77.63
222	GARISSA	220	31.5	3.5	1323.4	11%	-75.23
223	BURA	220	31.5	2.7	1034.0	9%	-74.96
224	HOLA	220	31.5	3.1	1175.1	10%	-74.8
225	WAJIR	220	31.5	0.7	269.9	2%	-77.4
226	MANDERA	220	31.5	0.5	203.4	2%	-77.61
227	GARBATULA	220	31.5	3.7	1392.0	12%	-77.33
228	MOYALE	220	31.5	1.9	721.8	6%	-80.28
229	OLKARIA2 220	220	31.5	28.8	10990.5	92%	-80.54
230	OLKARIA3 220	220	31.5	22.3	8482.1	71%	-80.76
231	OLKARIA 4	220	31.5	29.9	11385.1	95%	-80.54
232	OLK IAU 220	220	31.5	29.9	11386.4	95%	-80.54
233	MENENGAI	220	31.5	15.6	5931.6	49%	-81.53
234	OLKARIA V	220	31.5	14.3	5455.8	45%	-81.05
235	RONGAI	220	31.5	16.8	6408.8	53%	-81.03
236	GILGIL 220	220	31.5	18.3	6965.3	58%	-81.93
237	AKIRA 220	220	31.5	5.9	2250.7	19%	-82.95
238	OLKARIA VI	220	31.5	21.6	8216.2	68%	-80.52
239	OLKARIA VII	220	31.5	12.9	4918.4	41%	-80.28
240	OLK IX	220	31.5	8.8	3345.4	28%	-84.38
241	OLKARIA VIII	220	31.5	8.0	3030.4	25%	-83.89
242	NAIVASHA 220	220	31.5	17.8	6778.4	56%	-78.91
243	KAKAMEGA	220	31.5	8.0	3033.8	25%	-74.07
244	MUHORONI	220	31.5	5.7	2168.7	18%	-74.83
245	TORORO 2	220	31.5	5.4	2055.3	17%	-77.07
246	TURKWEL	220	31.5	4.8	1812.4	15%	-78.02
247	LESSOS 220	220	31.5	12.4	4736.1	39%	-76.29
248	KITALE	220	31.5	3.0	1140.3	10%	-74.59
249	BARINGO 220	220	31.5	8.2	3119.1	26%	-78.63
250	LOKICHAR	220	31.5	5.2	2000.5	17%	-78.16
251	KIBOS	220	31.5	8.1	3068.9	26%	-74.78

252	ORTUM	220	31.5	3.4	1301.9	11%	-77.24
253	MUSAGA	220	31.5	8.7	3332.5	28%	-74.27
254	KERICHO	220	31.5	7.5	2840.0	24%	-75.87
255	CHEMOSIT 220	220	31.5	6.7	2557.0	21%	-74.77
256	KISII 220	220	31.5	4.3	1655.4	14%	-76.81
257	SILALI 220	220	31.5	13.0	4972.2	41%	-81.67
258	RADIANT	220	31.5	1.6	624.9	5%	-77.78
259	TURKWELL TEE	220	31.5	3.3	1264.7	11%	-75.55
260	KAPSOWAR	220	31.5	3.0	1143.7	10%	-75.48
261	AGIL 220	220	31.5	15.5	5895.0	49%	-80.77
262	MARSABIT	220	31.5	4.5	1712.6	14%	-80.42
263	KAINUK	220	31.5	4.7	1804.8	15%	-78.04
264	LOKICHOGGIO	220	31.5	1.9	730.7	6%	-78.88
265	LODWAR	220	31.5	5.3	2008.3	17%	-78.17

266	LOYAN	220	31.5	9.4	3587.8	30%	-83.18
267	ELD NTH 220	220	31.5	6.1	2323.0	19%	-76.86
268	BARRIER	220	31.5	2.1	786.1	7%	-82.49
269	BUJAGALI	220	31.5	3.1	1178.0	10%	-80.24
270	KAINUK 66	220	31.5	2.6	995.9	8%	-83.17
271	OLKARIA 4 WE	220	31.5	29.3	11175.1	93%	-80.54
272	GENERIC2028	220	31.5	8.9	3404.6	28%	-79.32
273	GENERIC2029	220	31.5	5.1	1946.8	16%	-72.35
274	GENERIC2030	220	31.5	15.1	5745.5	48%	-82.56
275	GENERIC 2033	220	31.5	17.2	6556.3	55%	-80.37
276	GENERIC 2025	220	31.5	7.7	2952.5	25%	-82.75
277	GENERIC 2031	220	31.5	8.1	3068.9	26%	-74.78
278	GENERIC 2035	220	31.5	4.8	1831.5	15%	-78.33
279	SUSWA PP	220	31.5	10.6	4051.2	34%	-84.95
280	CHAGEM	220	31.5	15.1	5745.5	48%	-82.56
281	ELEKTRA	220	31.5	7.4	2826.4	24%	-81.13
282	VATEKI	220	31.5	5.8	2213.9	18%	-67.63
283	MERU WIND220	220	31.5	7.1	2694.3	22%	-78.24
284	HABASWEIN	220	31.5	1.0	362.5	3%	-77.56
285	ISINYA4	400	40	15.9	11042.8	40%	-75.1
286	SUSWA	400	40	16.7	11572.5	42%	-80.33

287	KIMUKA	400	40	15.9	11014.0	40%	-78.04
288	KONZA4	400	40	16.2	11247.8	41%	-75.88
289	NAMANGA	400	40	8.5	5907.7	21%	-78.27
290	LONGONOT	400	40	10.5	7277.4	26%	-81.55
291	MALAA 400	400	40	18.3	12704.5	46%	-76.46
292	MAKINDU 400	400	40	9.0	6267.5	23%	-75.09
293	KITUI	400	40	11.1	7699.7	28%	-83.82
294	MARIAKANI	400	40	5.8	4040.2	15%	-72.72
295	LAMU	400	40	6.2	4310.9	16%	-83.85
296	VOI 400	400	40	6.6	4566.7	16%	-73.68
297	THIKA 400	400	40	17.6	12225.9	44%	-78.3
298	HG FALL 400	400	40	9.9	6836.2	25%	-83.98
299	GILGIL	400	40	17.6	12166.4	44%	-78.56
300	RONGAI 400	400	40	14.1	9783.8	35%	-78.07
301	KILGORIS	400	40	5.6	3867.8	14%	-78.72
302	LOYAN 400	400	40	6.8	4688.0	17%	-82.46
303	SILALI	400	40	8.8	6096.7	22%	-80.18
304	RUMRT400 TEE	400	40	16.2	11220.1	40%	-79.06
305	SILALI4 TEE1	400	40	10.2	7091.2	26%	-81.27
306	LONG_HVDC	400	40	16.7	11572.5	42%	-80.33
307	LESSOS 400	400	40	9.5	6555.2	24%	-78.19
308	ARUSHA	400	40	5.6	3861.3	14%	-78.98
309	MEGA_HVDC	400	40	7.4	5136.6	19%	-79.91
310	WOLYATA	400	40	7.4	5136.6	19%	-79.91

Annex 6: Demand forecast by consumption areas (low, reference and vision scenarios)

	Reference case											
	Nairobi			Coast			Mt Kenya			Western		
	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW
2017	4,917	4.3%	810	1,750	4.5%	299	1,718	5.2%	276	2,080	6.6%	359
2018	5,156	4.9%	853	1,874	7.1%	321	1,871	8.9%	303	2,267	9.0%	392
2019	5,366	4.1%	889	1,954	4.3%	335	2,016	7.8%	327	2,483	9.5%	430
2020	5,605	4.4%	930	2,044	4.6%	351	2,165	7.4%	352	2,733	10.1%	474
2021	5,862	4.6%	974	2,153	5.4%	370	2,304	6.4%	375	2,992	9.5%	519
2022	6,252	6.7%	1,047	2,388	10.9%	416	2,454	6.5%	400	3,241	8.3%	563
2023	6,607	5.7%	1,108	2,544	6.6%	443	2,636	7.5%	430	3,506	8.2%	609
2024	7,033	6.4%	1,182	2,710	6.5%	472	2,832	7.4%	462	3,752	7.0%	653
2025	7,496	6.6%	1,262	2,977	9.9%	514	3,183	12.4%	513	4,094	9.1%	707
2026	8,010	6.8%	1,350	3,179	6.8%	548	3,431	7.8%	553	4,479	9.4%	779
2027	8,535	6.6%	1,437	3,392	6.7%	585	3,695	7.7%	595	4,771	6.5%	831
2028	9,155	7.3%	1,542	3,743	10.3%	639	4,079	10.4%	655	5,104	7.0%	891
2029	9,729	6.3%	1,640	4,020	7.4%	685	4,406	8.0%	706	5,439	6.6%	950

2030	10,335	6.2%	1,744	4,310	7.2%	733	4,753	7.9%	761	5,797	6.6%	1,014
2031	10,950	5.9%	1,849	4,610	6.9%	783	5,123	7.8%	820	6,181	6.6%	1,082
2032	11,603	6.0%	1,962	4,924	6.8%	835	5,519	7.7%	883	6,594	6.7%	1,155
2033	12,290	5.9%	2,081	5,256	6.7%	890	5,943	7.7%	951	7,040	6.8%	1,235
2034	13,017	5.9%	2,207	5,606	6.7%	949	6,397	7.6%	1,024	7,521	6.8%	1,321
2035	13,789	5.9%	2,342	5,976	6.6%	1,011	6,885	7.6%	1,103	8,042	6.9%	1,413
2036	14,582	5.8%	2,483	6,345	6.2%	1,075	7,373	7.1%	1,182	8,547	6.3%	1,504
2037	15,433	5.8%	2,635	6,738	6.2%	1,143	7,906	7.2%	1,268	9,110	6.6%	1,604

Vision Scenario												
	Nairobi			Coast			Mt Kenya			Western		
	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW
2017	4,917	4.3%	810	1,750	4.5%	299	1,718	5.2%	276	2,080	6.6%	359
2018	5,245	6.7%	868	1,892	8.1%	324	1,938	12.8%	314	2,395	15.2%	414
2019	5,547	5.8%	920	1,997	5.6%	343	2,113	9.0%	344	2,807	17.2%	486
2020	5,884	6.1%	978	2,193	9.8%	374	2,295	8.6%	374	3,304	17.7%	571
2021	6,366	8.2%	1,067	2,465	12.4%	427	2,495	8.7%	408	3,575	8.2%	619
2022	6,855	7.7%	1,153	2,769	12.4%	476	2,855	14.5%	460	3,976	11.2%	682

2023	7,450	8.7%	1,256	3,035	9.6%	522	3,147	10.2%	507	4,356	9.6%	748
2024	8,119	9.0%	1,372	3,322	9.4%	571	3,467	10.1%	559	4,892	12.3%	846
2025	8,832	8.8%	1,493	3,865	16.3%	651	3,972	14.6%	634	5,388	10.1%	933
2026	9,609	8.8%	1,626	4,330	12.0%	724	4,442	11.8%	708	5,913	9.8%	1,027
2027	10,389	8.1%	1,756	4,808	11.0%	798	4,917	10.7%	781	6,457	9.2%	1,123
2028	11,211	7.9%	1,891	5,315	10.5%	878	5,440	10.6%	862	7,076	9.6%	1,232
2029	12,013	7.1%	2,027	5,767	8.5%	947	6,004	10.4%	950	7,726	9.2%	1,347
2030	13,076	8.9%	2,197	6,380	10.6%	1,035	6,817	13.6%	1,070	8,573	11.0%	1,488
2031	14,039	7.4%	2,360	6,772	6.1%	1,101	7,420	8.8%	1,168	9,401	9.7%	1,633
2032	15,047	7.2%	2,531	7,151	5.6%	1,164	8,084	8.9%	1,277	10,306	9.6%	1,791
2033	16,126	7.2%	2,716	7,568	5.8%	1,235	8,751	8.3%	1,388	11,190	8.6%	1,946
2034	17,288	7.2%	2,915	8,015	5.9%	1,311	9,484	8.4%	1,511	12,168	8.7%	2,118
2035	18,448	6.7%	3,115	8,525	6.4%	1,399	10,339	9.0%	1,654	13,283	9.2%	2,315
2036	19,574	6.1%	3,319	8,981	5.3%	1,483	11,175	8.1%	1,797	14,374	8.2%	2,512
2037	20,818	6.4%	3,543	9,467	5.4%	1,573	12,106	8.3%	1,957	15,599	8.5%	2,734

Low Scenario												
	Nairobi			Coast			Mt Kenya			Western		
	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW	GWh	Growth	MW
2017	4,917	4.3%	810	1,750	4.5%	299	1,718	5.2%	276	2,080	6.6%	359
2018	5,133	4.4%	849	1,852	5.8%	317	1,829	6.5%	296	2,218	6.7%	384
2019	5,313	3.5%	880	1,925	4.0%	330	1,954	6.8%	317	2,337	5.4%	405
2020	5,515	3.8%	914	2,000	3.9%	343	2,088	6.9%	339	2,468	5.6%	428
2021	5,727	3.8%	951	2,079	3.9%	357	2,199	5.4%	358	2,607	5.6%	453
2022	5,951	3.9%	989	2,161	4.0%	371	2,317	5.3%	377	2,727	4.6%	474
2023	6,225	4.6%	1,036	2,260	4.6%	389	2,459	6.1%	401	2,867	5.1%	498
2024	6,516	4.7%	1,086	2,364	4.6%	407	2,609	6.1%	426	3,015	5.2%	525
2025	6,817	4.6%	1,138	2,473	4.6%	426	2,767	6.1%	452	3,172	5.2%	552
2026	7,118	4.4%	1,189	2,588	4.7%	446	2,935	6.1%	480	3,340	5.3%	582
2027	7,435	4.5%	1,243	2,710	4.7%	467	3,114	6.1%	510	3,521	5.4%	614
2028	7,769	4.5%	1,301	2,838	4.7%	490	3,304	6.1%	541	3,716	5.5%	649
2029	8,121	4.5%	1,361	2,973	4.8%	513	3,507	6.1%	575	3,924	5.6%	686
2030	8,491	4.6%	1,425	3,116	4.8%	538	3,722	6.1%	611	4,146	5.7%	725

2031	8,881	4.6%	1,491	3,267	4.8%	565	3,951	6.2%	650	4,383	5.7%	767
2032	9,294	4.7%	1,562	3,427	4.9%	593	4,195	6.2%	691	4,636	5.8%	812
2033	9,780	5.2%	1,649	3,605	5.2%	625	4,482	6.8%	740	4,932	6.4%	866
2034	10,233	4.6%	1,727	3,784	5.0%	656	4,762	6.3%	788	5,229	6.0%	919
2035	10,711	4.7%	1,809	3,973	5.0%	689	5,063	6.3%	838	5,550	6.1%	976
2036	11,205	4.6%	1,894	4,162	4.7%	722	5,354	5.8%	887	5,840	5.2%	1,028
2037	11,733	4.7%	1,985	4,363	4.8%	758	5,674	6.0%	942	6,175	5.7%	1,088