REPUBLIC OF KENYA

KENYA VISION 2030

UPDATED LEAST COST POWER DEVELOPMENT PLAN

STUDY PERIOD: 2020- 2040

EPRA Energy & Petroleum Regulatory Authority
GDC Geothermal Development Company Powering the Vision
KenGen
Kenya Power
RURAL ELECTRIFICATION RENEWABLE ENERGY CORPORATION (Formerly Rural Electrification Authority)
KETRACO
NUCLEAR POWER AND ENERGY AGENCY (NuPEA)

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LIST OF ACRONYMS

AGC	Automatic Generator Control
CAIDI	Customer Average Interruption Duration Index
CCGT	Combined Cycle Gas Turbine
COD	Commercial Operation Date
CSP	Concentrated Solar Power
DNI	Direct Normal Irradiation
DGE	Deemed Generated Energy
EAPP	East Africa Power Pool
EECA	Energy Efficiency and Conservation Agency
EPRA	Energy and Petroleum Regulatory Authority
EEPCO	Ethiopian Electric Power Corporation
ENS (UE)	Energy Not Served (Unserved Energy)
FEC	Fuel Energy Cost
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GHG	Green House Gas
GHI	Global Horizontal Irradiation
GoK	Government of Kenya
GT	Gas Turbine
GWh	Giga Watt hours
HFO	Heavy Fuel Oil
HPP	Hydro Power Project
HSD	High Speed Diesel
HVDC	High Voltage Direct Current
IDC	Interest During Construction
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
INEP	Integrated National Energy Plan
IPP	Independent Power Producer
ISO	Independent System Operator

TSO	Transmission System Operator
KEEP	Kenya Energy Expansion Program
KEMP	Kenya Energy Modernization Project
KenGen	Kenya Electricity Generating Company Limited
KEPSA	Kenya Private Sector Alliance
KETRACO	Kenya Electricity Transmission Company
KNBS	Kenya National Bureau of Statistics
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 & long term Expansion
LEC	Levelized Energy Cost
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LTA	Long Term Average
LV	Low Voltage
MAED	Model for Analysis of Demand
MOE	Ministry of Energy
MORDA	Ministry of Regional Development and Authority
MSD	Medium Speed Diesel
MSW	Municipal Solid Waste
$MTCO_2e$	Metric Tonnes of Carbon Dioxide
MTP	Medium Term Plan
MW	Mega Watt(s)
MWh	Megawatt Hour(s)
NDC	National Determined Contribution
NHIF	National Hospital Insurance Fund

NPP	Nuclear Power Plant
PSSE	Power System Simulation for Engineers
PPA	Power Purchase Agreement
PV	Photo Voltaic
O & M	Operation and Maintenance
FOM	Fixed operations and maintenance costs
PPA	Power Purchase Agreement
REREC	Rural Electrification Renewable Energy Corporation
SAIFI	System Average Interruption Frequency Index
SME	Small Medium Enterprises
SWERA	Solar and Wind Energy Resource Assessment
SAPP	Southern African Power Pool
SPV	Special Purpose Vehicle
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
VOM	Variable Operation and Maintenance Costs
WARMA	Water Resource Management

ACKNOWLEDGEMENTS

This report is a product of joint effort between all sector utilities within the Kenyan power sector. Oversight and quality assurance is provided by a Committee chaired by the Director General, Energy and Petroleum Regulatory Authority (EPRA) as well as senior management of sector utilities. To enrich and provide a broader input to the report, relevant public institutions namely the Vision 2030 secretariat and Kenya National Bureau of Statistics (KNBS) as well as the Kenya private sector Aliance KEPSA provide input at oversight level.

The technical team of the LCPDP undertakes all relevant simulations, analysis and draft the report for consideration by the Oversight committee. Special acknowledgements to their efforts and dedication to duty that made the preparation of the report possible and to the highest technical standards.

The Ministry of Energy (MOE) continues to provide policy guidance that informed and steered the technical team towards the Government intended focus on provision of adequate, reliable and affordable power in the country. Accordingly, it is hoped that this report provides the required signals to investors to participate in the power supply value chain in the country. The Management of EPRA continues to provide regulatory and secretariat services during the report preparation.

All sector utilities' Chief Executive officers supported the process by facilitating technical teams to participate in the various working sessions and also providing oversight inpus and are appreciated.

EXECUTIVE SUMMARY

In accordance with Part 2 section 4-8 of the Energy Act of 2019, the Cabinet Secretary, in collaboration with other stakeholders is mandated to develop an Integrated National Energy Plan (INEP) in respect of coal, renewable energy and electricity so as to ensure delivery of reliable energy services at least cost. In the 2019/20 Financial year, the sector embarked on updating the 2017-2037 LCPDP Long term plan as a transitional process to INEP. The update was finalised and the reveised 2019-2039 LCPDP Long term plan was presented to the Oversignt committee for consideration. The committee however adviced that the report would not be truly reflective of circumstances in the sector owing to the emergence of Covid 19 pandemic that affected the economy and other factors that influence power demand and supply in the country. Accordingly, this report is an update of the the report presented then but also integrated reccomendations from the following sector reports:

i. Revised IPP/PPA taskforce report 2020
ii. Sustainability report for KPLC by joint EPRA/KPLC/Treasury team
iii. Post Covid 19 sector report
iv. Revised planting sequence of generation projects arising from Force Majeure reccomendations by sector players
v. Views from Mott Macdonald on areas of improvement to the plan

The report which initially intended to be an input to the proposed INEP has taken the traditional format as the Ministry completes both the INEP framework and the enabling regulation that are at an advanced stage of development. It covers the period 2020-2040.

Current Situation of in the Power Sector

As at December 2020, Kenya had a total installed generation capacity of 2,753MW. The peak demand has grown from 1,512MW recorded in FY 2014/15 to 1,976MW recorded in December 2020. Energy purchased declined to 11,462GWh in the FY 2019/20 from 11,493GWh in the previous financial year. Actual sales increased by 0.05% from 8,769 GWh in FY 2018/19 to 8,773GWh in FY 2019/20. Network losses remain a significant issue within the sector as they stood at 23.5% as at June 2020.

Demand Forecast

Demand forecast was modelled under three scenarios namely reference; low and vision. Each scenario was based on specific assumptions of the evolution of the related demand drivers.

Energy demand is forecasted to grow at an average of 5.28% while the peak load is forecasted to grow at an average of 5.38% in the reference scenario; 8.20% and 8.35% in the vision scenario and 4.78% and 4.89% in the low scenario respectively. Peak demand is forecasted to grow at an average of 5.3% from 1,972MW in the base year to 5,526MW at the end of the planning period under the Reference scenario. Similarly, under the Vision scenario peak demand increases to 9,635MW in 2040 growing at an average rate of 8.35%. The Low scenario peak demand increases to 5,028MW in 2040 at an average rate of 4.89%.

Generation Expansion Planning criteria and results

Simulations were done on selected cases based on various assumptions. The cases included; Fixed system with candidates and the Optimized case. The reference case demand forecast scenario reflects the most likely development path hence its use in deriving the long term expansion plan under the Fixed case with candidates and optimized case generation expansion scenarios.

Under the fixed case with candidates reference demand scenario, the total interconnected capacity grows from the current total interconnected capacity of 2,654 MW in 2020 to 8,371 MW in 2040. The reserve margin as percenatage of peak load averages 19% over the planning period, peaking at 27% in 2027 and low of 12% in 2023. The LEC increases from US Cents 8.31/kWh in 2020 to peak at US Cents 12.68/kWh in 2027, before decreasing to an average of US Cents 11.06 /kWh in the period from 2028 onwards.

Under the Optimised case reference demand scenario, the total interconnected capacity grows from the current 2,654 MW in 2020 to 8,186 MW in 2040. The average annual excess energy as share of generation in the period 2020-2030 is 1%, but increases thereafter to an average of 4%. However, the level of vented steam remains high at an average of 18% of the possible maximum geothermal generation over the planning period. The LEC, rises from US Cents 8.31/KWh in 2020 to peak at US Cents 10.23/KWh in 2033, before decreasing to an average of US Cents 9.82 /KWh in the period 2034-2040.

Optimised Reference Expansion Plan-Generation Capacity Summary Table

Generation Type	Installed Capacity (MW)							
	2020		2025		2030		2040	
	Units	%	Units	%	Units	%	Units	%
Hydro	829	30%	848.8	24.05%	1499.5	29.11%	1813.9	22.16%
Geothermal	783	28%	976.6	27.67%	1411.6	27.4%	2586.8	31.60%
Solar	53	2%	250.3	7.09%	454.3	9%	404	4.93%

Generation Type	Installed Capacity (MW)							
	2020		2025		2030		2040	
	Units	%	Units	%	Units	%	Units	%
Wind	336	12%	475.5	13.47%	771.4	20%	731	8.93%
Cogeneration	2	0%	71.44	2.02%	197.4	3.83%	239.8	2.93%
Thermal	749	27%	506.4	14.35%	417.8	8.11%	-	-
Biogas	-	-	-	-	-		-	-
Biomass	-	-	-	-	-		-	-
Imports	-	-	200	5.67%	200	3.88%	200	2.44%
Gas Turbines (LNG)	-	-	200	5.67%	200	3.88%	480	5.86%
Coal	-	-	-	-	-	-	981.0	11.98%
Natural Gas	-	-	-	-	-	-	750.0	9.16%
Nuclear	-	-	-	-	-	-	-	-
Total	**2,752**	**100**	**3,529**	**100**	**5,152**	**100**	**8,186.5**	**100**

Tariff evolution

From the simulations, the total cost implication for planned projects under the optimized case is KShs. 692,302,518,693. The average base retail tariff is projected to increase from KSh20.85/kWh in 2020 to KShs. 24.48/kWh in 2025. The generation cost in the rises from Kshs.9.82/kWh in 2020 to KSh. 11.68/kWh in 2025. The fixed case with candidates in the period 2020-2025 is KShs 723,806,943,976. The average base retail tariff is projected to increase from the KShs 20.85/kWh to KShs 25.98/kWh. Over the same period, the generation unit cost is estimated to rise from Kshs 9.82/kWh in 2020 to 13.00/kWh in 2025.

Summary of Recommendations

The following recommendations are made;

I. Acceleration of implementation of the Vision 2030 flagship projects and Big Four agenda to spur demand and enhance implementation of demand creation initiatives and promote development of demand creation strategies by various utilities in the sector.

II. Improved system management, automation and innovation to enhance supply reliability, efficiency and reduce system losses, and Provide incentives that promote conducive environment for growth of industrial customers and their associated energy consumption

III. Adoption of optimised case as the national long term generation expansion plan for the 2020-2040 period.

IV. For Solar and Wind projects that do not have PPAs, it is recommended that they are migrated to Renewable Energy Auctions.

V. Peaking capacity power plants and Battery storage should be developed immediately to avert peak capacity shortfalls, absorb excess energy presented as vented steam during off-peak hours, provide system reserves and prevent load shedding in Western Kenya in the short term as transmission projects are being implemented. In the long term the recommended projects for the same purpose are LNG gas turbines, Pumped Hydro Storage and peaking hydro plants.

VI. Demand side management relating to load shifting is recommended to enable optimal utilization of the excess energy in the system during off-peak hours. This includes initiatives like strengthening the time of use tariff, electrification of the transport sector among others.

VII. Negotiate for firm 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term.

VIII. Renegotiate CODs and tariffs for projects that have PPAs but are yet to commence construction, to be integrated according to the dates given in the optimal plan. Respective contingent liabilities for the committed projects should be determined to inform proposals and negotiations.

IX. Carry out a comprehensive study on ancillary services requirements for the system, including battery storage, pumped storage and reactive power compensation, with the increasing levels of intermittent renewable energy sources.

1. INTRODUCTION

Over the years, the Government through the Ministry responsible for Energy has been involved in planning for power supply in the country through a series of regular reports. These reports are guided by the existing policy framework as well as the supporting legislation and are intended to guide stakeholders on Government intentions and plans over a period of time. The mandate for coordination of sector plans has in recent times been housed in the Energy and Petroleum Regulatory Authority (EPRA) formerly ERC. The regulator established an electricity sub-sector Planning Committee comprising of all sector utlities. The Energy Act No 1 of 2019 vested this mandate to the Ministry of Energy going forward as articulated in part II section 5 of the act.

Section 4-8 of the Act provides for the development of an Energy Policy to be updated every 5 years and regular development of Integrated National Energy Plans (INEP) consisting of coal, Geothermal and electricity sub-plans in addition to County Energy Plans. This report is intended to transition the electric power sub-sector to the new dispensation as the Ministry prepares to take up the mandate after approval of the INEP framework and draft regulation.

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. In particular it attempts to restructure the generation sequence of power plants in a manner that matches the demand forecast closely. This is to ensure that the demand-supply balance is not skewed too heavily towards supply as to leave the sector with stranded generation investments and the attendant high system costs. In addition, the plan focuses on system requirements for integration of renewable energy technologies namely solar and wind and provides guidance on possible extra investment costs neccesary to ensure long term system stability and affordable end-user tariffs. This Plan is categorised into five key areas;

(a) **Load forecast** – The section analyses power demand drivers in the country and based on the power requirements for each of them, estimates long term by aggregating them to arrive at consumption in Gigawatt hour (GWh). It also aggregates all capacity requirements to arrive at peak load in Megawatts (MW). The demand forecast is developed in three scenarios; low, reference and vision. The forecast is prepared using a custom made excel based tool that uses Model for Analysis of Demand (MAED) principles and assumptions.

(b) **Generation Plan–** The section considers the current levels of approvals of generation projects in the power sector and applies short term and long term plan simulations by utilizing an inhouse software Lahmeyer International

Power System operation Planning (LIPs OP) and Lahmeyer International Power System Expansion Planning (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, a least cost optimal solution is developed for the period under review.

(c) **Transmission Plan** – The transmission plan has taken into consideration system requirements, reliability based on an N-1 criteria 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 development of the network requirements is informed by the load forecast and its distribution, existing commitments and proposed generation projects over the plan period.

(d) Ancillary service requirements - The technical team also attempted to analyse system requirements over the period. This involved identifying investment requirements that could make the system stable and reliable including the provision of sufficient primary response to maintain power system frequency in the event of network or generation outages.

(e) **Tariff evolution** - This section of the report provides an analysis of the impact of the plan on the end-user tariffs based on current tariff structure in the country. Since the report is a long term one, the technical team focuses on the period when the tariffs are fairly predictable namely the first 5 years of the plan. This is because in the long term, the level of unpredictability cannot allow for a meaningful forecast on tariffs. Evolution of tariffs was computed using an excel based model developed internally by the technical team.

(f) **Environmental considerations -** The report has also analysed the impact of the planned system on the environment and in particular the level of carbon emissions. This is important in meeting the country's obligations on the international convention on climate change to which Kenya is a signatory. LIPS XP/OP model was updated in 2019 to incorporate GHG emissions estimation. These model has been used in the preparation of the planting sequence and estimating the carbon emissions.

Following the completion of the Transitional LCPDP 2019-2039, the sector was adversley impacted by the outbreal of Covid-19. Electricity demand reduced significantly following implementation of health guidelines meant to curb the spread of the virus. There was unanimous decision by the sector on the need to review the finalised report and present a more accurate one having taken into account the impact of Covid-19. The revision of the LCPDP 2019-2039 involved revision of the demand forecast, re-simulation of generation and transmission plans and in addition, incorporation of recommendations of the following reports;

i. Revised IPP/PPA taskforce report 2020

ii. Sustainability report for KPLC by joint EPRA/KPLC/Treasury team

iii. Post Covid 19 sector report

iv. Revised planting sequence of generation projects arising from sector Force Majeure events

v. Views from Mott Macdonald on areas of improvement to the plan

1.1. Objectives of the report

The main objective of this update is to take into account new assumptions based on the impact of Covid-19, reccomednations of sector reports, as market dynamics that may influence future power expansion plan and accommodate new Government policy guidance on renewable energy expansion in the short to long term. In addition, the report is intended to provide a transition framework towards the power sector component of the INEP

The specific objectives are to:

- Update the load forecast taking into account the performance of the economy in the wake of Covid-19 and factor in reccomendations from various sectoral reports.
- Update historical data, literature, committed and candidate projects;
- Simulate generation sequence of proposed power plants;
- Prepare a Transmission System expansion plan in line with the generation plan which incorporates ancillary service requirements;
- Assess the evolution of tariffs based on the estimated expansion costs; and,
- Present Transisitonial LCPDP 2020-2040 plan to guide policy and investment decisions in the country.

1.1. The updating methodology

The update was undertaken by the Least Cost Technical 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 and Renewable Energy Corporation (REREC); Kenya Electricity Transmission Company Limited (KETRACO); and the Nuclear Power and Energy Agency (NuPEA). The Energy and Petroleum Regulatory Authority (EPRA) 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 methodology applied in preparing the report was utilization of forecasting and simulation tools namely a MAED based customized tool for load forecasting, LIPs-OP/XP for short/long term term system optimization and PSSE for transmission planning and simulations

2. STATUS OF THE POWER SECTOR IN KENYA

2.1. Background

Kenya's power sector has advanced in electricity generation, transmission, distribution and access arising from implementation of various reforms, notably the Electric Power Act 1997, Sessional Paper no. 4 of 2004, Energy Act 2006 and the recently enacted Energy Act 2019. The Energy Act 2019 has introduced significant changes to the mandate of the various sector institutions to align them to the requirements and provisions of the Constitution of Kenya 2010. These reforms are discussed in Section 2.3 of this report.

2.2. Sector Institutional Structure

After the enactment of the Energy Act in March 2019, there was reorganization of the institutional structure of the power sector. The redulting institutional structure is as represented in figure 1

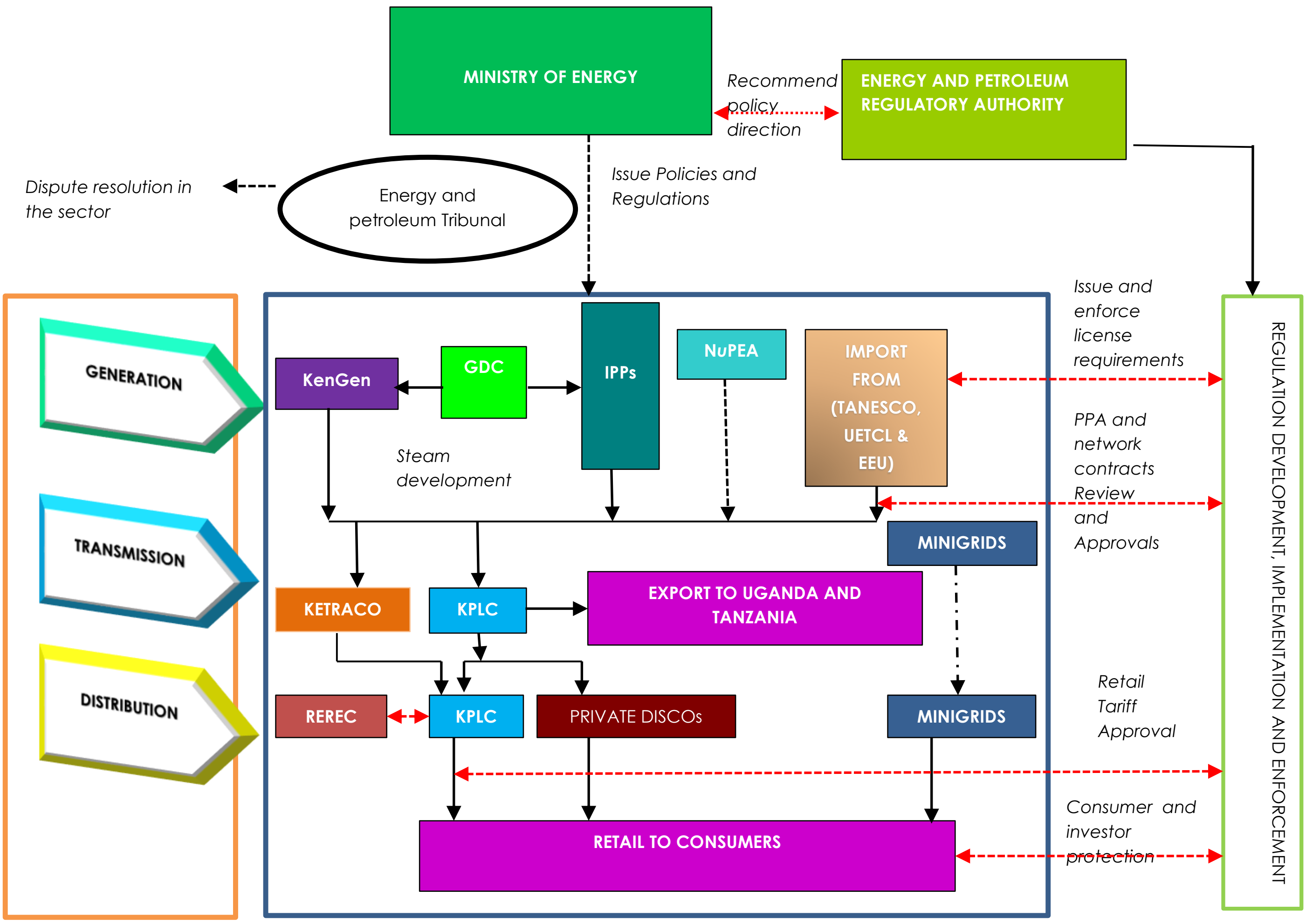


Figure 1 Power Sector Institutional Structure

Source: Ministry of Energy

a) **The Ministry of Energy (MOE)** is responsible for policy formulation and monitoring of policy implementation to enable an environment conducive 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 and Petroleum Regulatory Authority(EPRA)** is responsible for economic and technical regulation of the energy sector. Functions include Licensing of power sector facilities and technicians, Energy audit, tariff setting and sector oversight, regulations development and implementation including compliance and enforcement among others.
c) **Energy & Petroleum Tribunal** is an independent legal entity whose main purpose is hearing and determining disputes and appeals in accordance with the Constitution of Kenya 2010, Energy Act 2019 and any other relevant law.

d) **Rural Electrification and Renewable Energy Corporation(REREC)** is mandated by Energy Act 2019 to be the lead agency for development of renewable energy resources other than geothermal and large hydropower, in addition to its previous mandate of rural electrification.

e) **The Kenya Electricity Generating Company (KenGen)** is the main power generation entity in the country. It is also a repository of significant technical expertise in geothermal technology development

f) **Kenya Electricity Transmission Company (KETRACO)** has the mandate to plan, design, construct, own, operate and maintain new high voltage (132kV and above) electricity transmission lines 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.

g) **Nuclear Power and Energy Agency(N*u*PEA)** is the nuclear energy programme implementing organization responsible for promoting the development of nuclear electricity generation in Kenya and carrying out research, development and dissemination activities of energy related research findings . It is also expected to facilitate and coordinate capacity building activities in the energy sector.

h) **The Kenya Power and Lighting Company (KPLC)** is the system operator and the main off-taker in the power market buying bulk power from all power generators on the basis of negotiated Power Purchase Agreements (PPAs) for onward supply to consumers. It also owns and operates part of the existing transmission infrastructure and the entire interconnected distribution network

i) **Geothermal Development Company (GDC)** is a fully owned Government Special Purpose Vehicle (SPV) undertaking surface exploration of geothermal fields, exploratory, appraisal and production drilling and managing proven steam fields. It also enters into steam sales agreements with investors in the power sector.

j) **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**.**

k) **Mini-grids** are a set of electricity generators and energy storage systems interconnected to a distribution network that supplies electricity to a localized group of customers not covered by the national power grid as approved by EPRA.

l) **Solar home systems companies** supply the solar home systems for households far away from the grid and will play a significant role in ensuring universal access to electrification.

2.3. Reforms in the Power Sector

The enactment of the Energy Act No. 1 of 2019, that came into effect in March 2019 introduced a set of reforms as follows:

i. Establishment of an inter-ministerial Renewable Energy Resources Advisory Committee (RERAC).
ii. Transformation of the Kenya Nuclear Electricity Board(KNEB) into the Nuclear Power and Energy Agency (N*u*PEA) with expanded mandate to promote and implement a nuclear electricity generation program and implement a capacity building programme for the power sector.
iii. Introduction of an Integrated National Energy Plan consisting of a coal, electricity and renewable energy plan that incorporates County Energy Plans.
iv. Providing for open access to the transmission and distribution networks, with EPRA mandated to designate a System Operator and encourage regional interconnections to enhance regional electricity trade.

v. Establishment of the Energy Efficiency and Conservation Agency (EECA) as a fully-fledged national public entity to promote energy efficiency and conservation.
vi. Provision for county government to set aside suitable land for development of energy infrastructure including but not limited to projects recommended in the Integrated National Energy Plans
vii. Provision for national government to facilitate the development of a Resettlement Action Plan Framework for energy related projects; including livelihood restoration in the event of physical displacement of communities
viii. Provision for development of a framework on the functional devolution of roles between the National government and County governments in consultation with all stakeholders to avoid overlap of functions.
ix. Provision for viable financing options from local and international sources for cost effective utilization of all its energy resources, ensuring maintenance of a competitive fiscal investment climate in the country.

2.4. Regional Integration

The Kenya-Ethiopia 500kV HVDC bipolar line is expected to be completed in 2020 while both the Isinya-Singida 220kV and the Lessos - Tororo 220kV interconnectors are at advanced stages of construction. The intention is to facilitate regional trading and in the long run and ensure that power exchange between the countries in the region is facilitated. This will enhance grid stability and allow for introduction of more renewable technologies even where they are intermittent.

2.5. Electricity supply

The installed generation capacity has increased considerably over the past five years, rising from 2,299MW in FY 2014/15 to 2,712MW in FY 2018/19, representing an annual average growth rate of 4.52%. As at FY 2019/20, the installed capacity stood at 2,753 MW inclusive of off grid power. The peak demand also grew from 1,512MW recorded in FY 2014/15 to 1,882MW recorded in FY 2018/19, an annual average growth of 4.89%. A peak demand of 1,976MW was recorded in December 2020.

KenGen, which is the largest power generator in the country currently, accounts for 62.97% of the industry's effective generation capacity. The Independent Power Producers (IPPs) accounts for 35.95%while Isolated grid generation under the Rural Electrification Programme (REP), implemented by REREC, accounted for about 1.07%.

The effective capacity mix comprises of 30.2% of hydro, 24.7% thermal(MSD),2.1% Thermal (GT), 28.8% geothermal, 12.2% from wind and 1.96% from solar. Kenya's current effective installed (grid and off-grid) electricity capacity is 2,668 MW as depicted in Table 1.

Table 1:Installed and Effective Capacity

Capacity as at June 2020				
	Installed MW	% Installed Capacity (MW)	Effective*/Contracted MW	% (effective)
Hydro	833.90	29.94%	805.10	30.18%
Geothermal	811.14	29.12%	767.56	28.77%
Thermal (MSD)	689.53	24.76%	659.48	24.72%
Thermal (GT)	60.00	2.15%	56.00	2.10%
Biomass	2.00	0.07%	2.00	0.07%
Solar	52.51	1.89%	52.18	1.96%
Wind	336.05	12.07%	325.50	12.20%
Imports	-	0.00%	-	0.00%
	2,785	**100%**	**2,668**	**100%**

Source: Kenya Power

2.6. Energy Sources in Kenya

The power generation mix comprises of 45.6% of geothermal, 36.2% hydro, 6.7% fossil fuels, 9.6% wind and 0.8% from solar for the financial year ending June 2020. Figure 2 shows the evolution of the generation mix from 2017/18 to 2019/20.

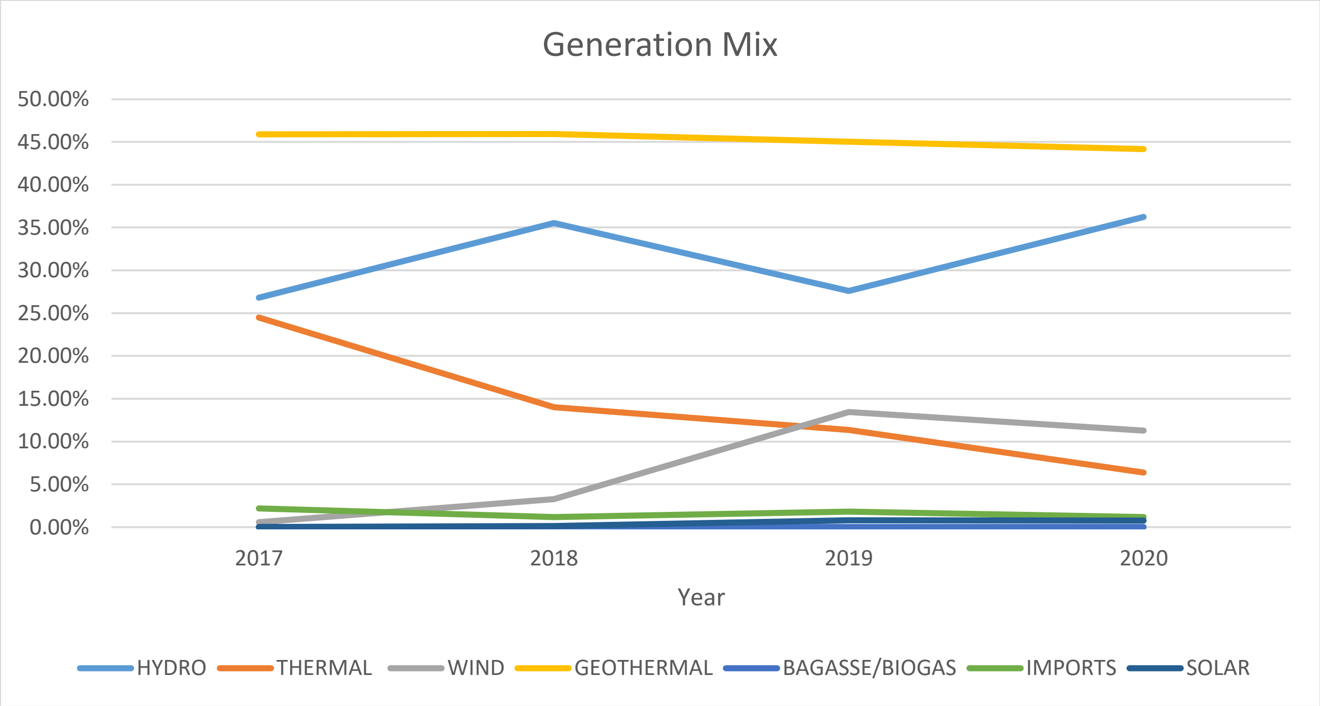


Figure 2 Generation Mix

Source: Kenya Power

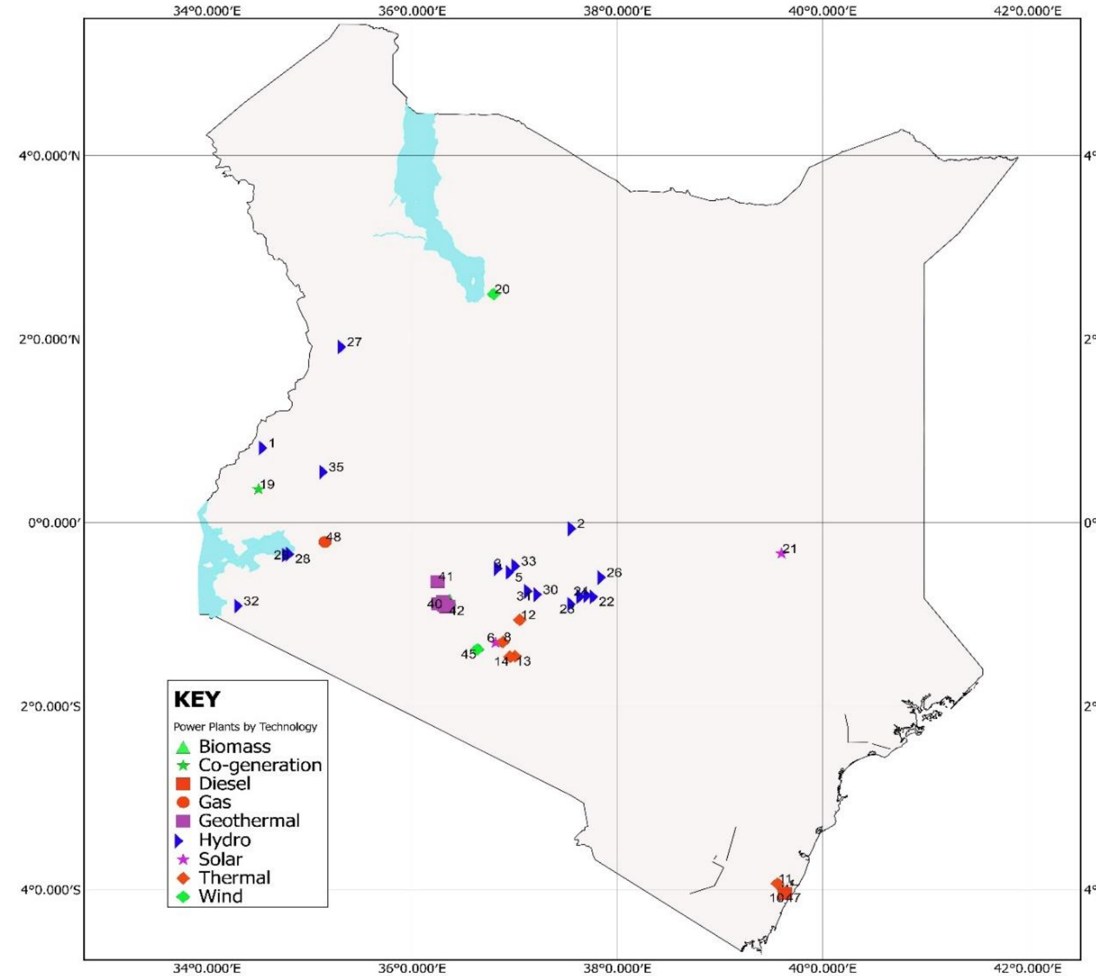
The FiT policy acceptance by IPPs and deliberate government policy to advance renewable energy generation has led to continous decline in energy purchased from Thermal generation. Energy purchased from thermals reduced from 1,298GWh in FY 2018/19 to 882 GWh in FY 2019/20. Energy purchases from Wind and Solar increased in FY 2019/20 with 1,284GWh and 91GWh of energy purchased respectively. This is as summarized in table 2

Table 2:Energy Purchased in GWh

Energy Purchased GWh						
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Hydro	3,310	3,787	3,341	3,224	3,741	3,693
Geothermal	4,060	4,609	4,451	5,053	5,033	5,352
Thermal	1,715	1,246	2,164	2,202	1,298	882
Cogeneration	14	0	1	4	0	0
Solar	1	1	1	0	60	91
Wind	38	57	63	47	1,192	1,284
Imports	79	67	184	171	170	161
Total	**9,217**	**9,767**	**10,204**	**10,702**	**11,493**	**11,462**

The location of power plants in the country are as depicted in figure 3, The figure shows that most plants in the country are located in the geothermal-rich Olkaria belt in rift valley with hydro plants largely located in the tana cascade. In recent years, other technologies are emerging with wind having the best prospects, Wind plants are already developed in Corner baridi in Rift valley as well as the prominent Lake Turkana wind in Marsabit

POWER PLANTS LOCATION IN KENYA



field_1	PROJECT NA	INSTALLED	Technology
1	GenPro, Shp	5	Hydro
2	Imenti Tea Factory, Shp	0.3	Hydro
3	KTDA Gura	2	Hydro
4	KTDA Ltd, River Chania	0.5	Hydro
5	Power Technologies (Gikira Mini Hydro)	0.5	Hydro
6	Strathmore University	0.3	Solar
7	Biojoule Kenya Limited	2	Biomass
8	Iberafrica I	56.3	Thermal
9	Iberafrica II	52.5	Thermal
10	Tsavo	74	Thermal
11	Rabai Power	90	Thermal
12	Thika Power	87	Thermal
13	Gulf Power	80.3	Thermal
14	Triumph Diesel	83	Thermal
15	Orpower 4 Inc. I	63.8	Geothermal
16	Orpower 4 Inc. II	39.6	Geothermal
17	Orpower 4 Inc. III	17.6	Geothermal
18	Orpower 4 Inc. IV	29	Geothermal
19	Mumias Sugar Company Ltd.	26	Co-generation
20	Lake Turkana Wind Power	310	Wind
21	REA Garissa Solar	50	Solar
22	Kindaruma	72	Hydro
23	Masinga	40	Hydro
24	Kamburu	94.2	Hydro
25	Gitaru	225	Hydro
26	Kiambere	168	Hydro
27	Turkwel	106	Hydro
28	Sondu	60	Hydro
29	Sangoro	21	Hydro
30	Tana	20	Hydro
31	Wanji	7.4	Hydro
32	Gogo	2	Hydro
33	Sagana	1.5	Hydro
34	Mesco	0.4	Hydro
35	Sosiani	0.4	Hydro
36	Olkaria 1	45	Geothermal
37	Olkaria II	105	Geothermal
38	Olkaria IV	150	Geothermal
39	Olkaria V	165.4	Geothermal
40	Olkaria 1 Unit 4&5	150	Geothermal
41	Eburru Wellheads	2.4	Geothermal
42	WellHeads	81.1	Geothermal
43	Ngong 1 Phase I	5.1	Wind
44	Ngong I Phase II	6.8	Wind
45	Ngong II	13.6	Wind
46	Kipevu 1 Diesel	73.5	Diesel
47	Kipevu III Diesel	120	Diesel
48	Gas Turbines (GT)	60	Gas

Figure 3 Power Plants location in Kenya

2.7. Transmission and Distribution

The total length of the Transmission and distribution network was 243,207 kilometers for all voltage levels in 2019/20 from 59,322 kilometers in 2014/15. This growth has been greatly influenced by Kenya Electricity Transmission Company (KETRACO), who have accelerated the development of transmission infrastructure within their mandate, consisting of 132kV, 220kV and 400kV. Table 3 provides transmission and distribution line lengths between FY 2014/15 and 2019/20.

Table 3:Transmission and Distribution Line Lengths between FY 2014/15-2019/20

VOLTAGE	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
400 kV			96.8	1,244.4	2,116.4	2,116.4
220 kV	1,352	1,452	1,555	1,686	1,686	1,686
132 kV	2,824	3,087	3,208	3,322	3,372	3,372
66 kV	952	977	1,000	1,168	1,187	1,187
33 kV	21,370	27,497	30,846	34,508	35,177	35,703
11 kV	32,823	35,383	37,234	38,968	39,797	40,616
Total HV and MV	59,322	68,396	73,940	80,897	83,335	84,681
415/240V or 433/250V		110,778	139,642	143,331	152,799	158,527
TOTAL	**59,322**	**179,174**	**213,582**	**224,228**	**236,134**	**243,207**
% INCREASE P.A.		**15.3%**	**19.2%**	**5%**	**5%**	**3%**

Source; Kenya Power

The total transmission network (400kV, 220kV, 132kV) stood at 7,174.35 kms by June 2020. The entire national interconnected electricity distribution network is under KPLC and stood at 243,207 in 2019/20. The distribution network consists of 66 kV feeder lines and 33kV and 11kV medium-voltage lines and 415/240V LV lines distributed across the country. There are plans to construct additional distribution lines and establish new substations to extend power supply in rural areas. The end goal is to attain universal access by 2022. Projects and programs are also being implemented to reduce system losses and improve system reliability.

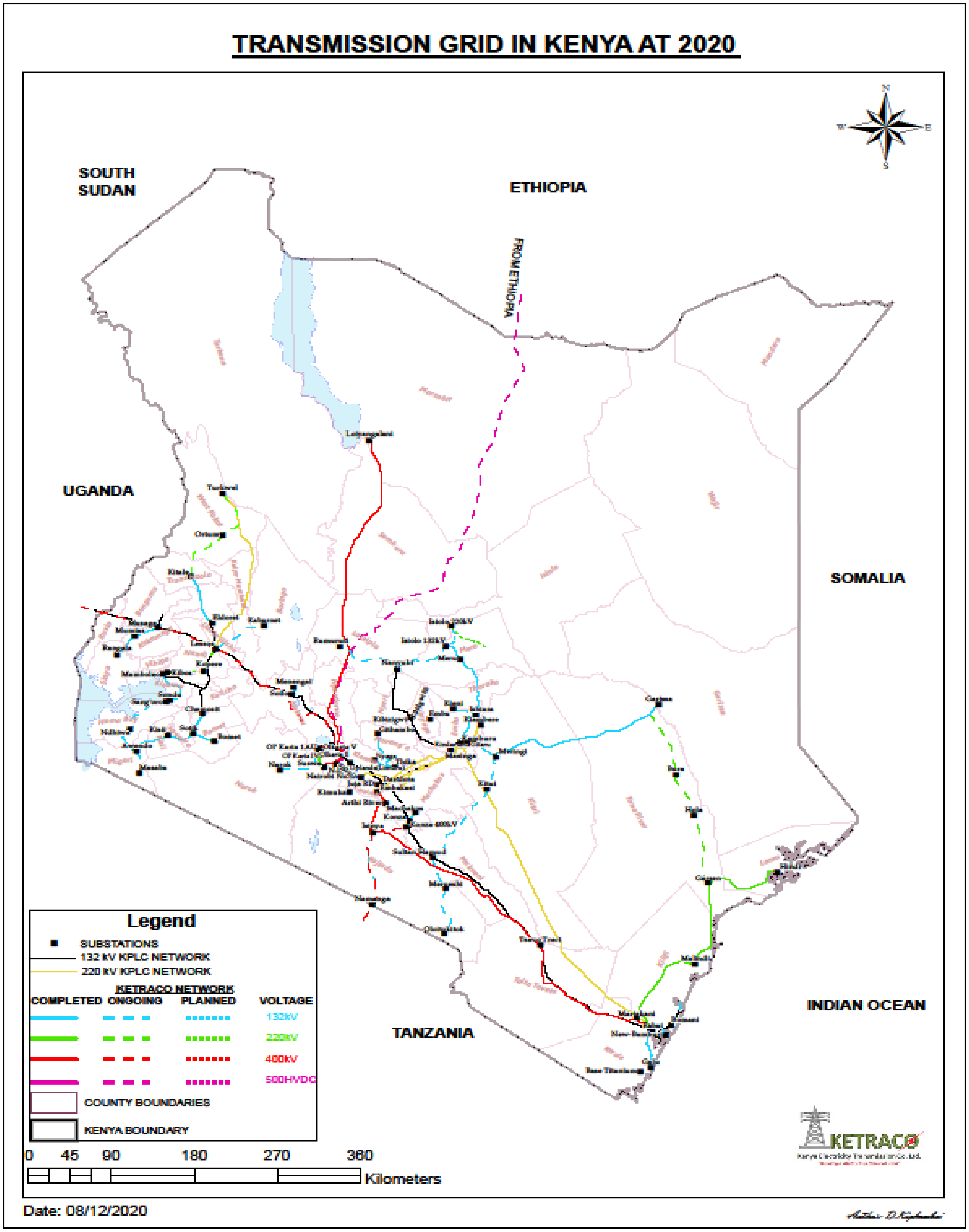


Figure 4 Transmission Network in Kenya 2019/20

Source KETRACO

Generation sub stations expansion was significant for the review period, rising from 3,025MVA in 2015 to 3,878MVA in 2020. During the same period, transmission substation capacity expanded from 3,144MVA to 4,942MVA while distribution sub-stations increased from 3,572MVA in 2014/15 to 4,563MVA in 2019/20 FY. Distribution transformer capacity significantly increased during the same period from 6,384MVA to 8,174MVA. Table 4 represents the transmission and distribution substations capacities For the period under review

Table 4: Transformers in Service,total installed capacity in MVA as at 30th June,2020

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Generation Substations TOTAL	3025	3145	3205	3370	3720	3878
Transmission Substations TOTAL	3144	3704	4376	4866	4942	4942
Distribution Substations Total	3572	3848	4056	4372	4480	4563
11/0.415 kV & 33/0.415 kV Distribution Transformers	6,384	7,088	7,276	7,606	7,844	8174

Source; Kenya Power

2.8. Electricity Consumption

The demand for electricity has shown an upward trend in the last 5 years. While the demand was **7,655** GWh in the 2014/15 financial year, it increased to 8,773 GWh in the 2019/20 financial year. This is largely attributed to the increased efforts in attaining universal access to electricity by 2022. A summary of trends in consumption among various customer categories, and consumption by region during the last 5 years is shown in Tables 5 and 6 respectively.

Table 5: Consumption in GWh among various categories 2014/15-2019/20

tariff	types of customers covered by this tariff	sales in GWh					
		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
DC	Domestic	1,866	2,007	2,138	2,335	2366	2,508
SC	Small Commercial	1,143	1,153	1,201	1,222	1250	1,262
CI	Commercial and Industrial	4,030	4,104	4,266	4,225	4462	4,308
IT	Off-peak	15	26	41	33	N/A	N/A
SL	Street lighting	35	40	55	66	68	76

	REP System (DC(*((DC,SC,SL)	525	537	549	554	595	602
	Export to Uganda	38	43	20	22	27	18
	Export to Tanesco	2	2	2	1	0.01	0
	TOTAL	**7,655**	**7,912**	**8,272**	**8,459**	**8,769**	**8,773**
	% INCREASE P.A.	**5.70%**	**3.40%**	**4.50%**	**2.30%**	**3.70%**	**0.0%**

Source: Kenya Power

Table 6:Consumption in GWh by Region

REGION	***2014/15***	***2015/16***	***2016/17***	***2017/18***	***2018/19***	***2019/20***
Nairobi North	1,032	1,187	1,301	1,204	1,219	1,209
Nairobi South	1,667	1,696	1,759	1,728	1,719	1,733
Nairobi West	1,059	808	853	898	958	960
Coast	1,312	1,338	1,389	1,435	1,477	1,464
Central Rift	456	569	596	650	689	680
North Rift	269	280	269	303	288	302
South Nyanza	0	48	86	88	104	123
West Kenya	525	320	313	361	376	376
Mt Kenya	309	413	431	437	456	439
North Eastern	461	671	704	776	862	869
KPLC Sales	**7,090**	**7,330**	**7,701**	**7,881**	**8,147**	**8,154**
R.E.P. Schemes	525	537	549	554	595	602
Export Sales	40	45	22	23	27	18
TOTAL	**7,655**	**7,912**	**8,272**	**8,459**	**8,769**	**8,773**
%INCREASE P.A.	**5.7%**	**3.4%**	**4.5%**	**2.3%**	**3.7%**	**0.0%**

Source: Kenya Power

Generally, the medium term commercial sales growth will be driven by the expansion of the economy and other factors which include: A growing population; urbanization; intensive electrification programs; and continued growth in the manufacturing, agricultural and other sectors of the economy that drive GDP growth.

2.9. Retail electricity tariffs

EPRA is mandated to set, review and adjust tariffs and tariff structures and the terms of electrical supply in the country from both the interconnected and the Off-Grid Systems. Retail electricity tariffs are set as per customer category as illustrated in table 7.

Table 7:Retail Electricity Tariff Effective Date 1st Novermber 2018

Customer Category	Energy Limit (kWh/Month)	Charge Rate (KES/kWh)	Demand Charge (KES/kVA)
DC- Lifeline	0-100	10.00	-
DC-Ordinary	>100-1500	15.80	-
Small Commercial SC-1	0-100	10.00	-
Small Commercial SC-2	>100-15000	15.60	-
Commercial and Industrial CI 1	No limit	12.00	800
Commercial and Industrial CI 2	No limit	10.90	520
Commercial and Industrial CI 3	No limit	10.50	270
Commercial and Industrial CI 4	No limit	10.30	220
Commercial and Industrial CI 5	No limit	10.10	220
Street Lighting	No Limit	7.50	-

Source: EPRA

Additionally, for CI1-CI5 customers operating at 100% production capacity during peak and off-peak periods and consume more than their average threshold, they enjoy a 5% discount on the applicable Energy Rate in respect of the Schedule of Tariffs - 2018 for the off-peak consumption. This is upon satisfactory confirmation by KPLC that their production is 100%. CI1-CI5 customers are required to meet their monthly Energy Consumption Threshold upon which any units over and above that threshold is billed at the 50% discounted Time of Use (TOU) Tariff. This discounted Time of Use Tariffs are applicable during off-peak period as shown in Table 8.

Table 8:Time of Use Schedule

Day	Start (Hrs.)	End (Hrs.)
Weekdays	00:00	06:00
	22:00	00:00
Saturday/Holidays	00:00	08:00
	14:00	00:00
Sunday	00:00	00:00

Source; EPRA

2.10. Pass through adjustment mechanisms

Fuel Energy Charge (FEC)- 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.

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

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

Foreign Exchange Rate Fluctuation Adjustment (FERFA)- These are adjustments made to cushion utilities from the effects of foreign exchange rate fluctuations, which has an impact on costs. These adjustments pass on this risk to the consumers thereby keeping the price signals to consumers at efficient levels.

2.11. Electricity demand

The nation has seen an upward trend in demand for electricity over the past decade. The peak demand increased from 1,512MW in FY 2014/15 to 1,926MW in FY 2019/20. A new peak of 1976MW was realized in the month of December 2020. Trend in peak demand for the period 2014/15-2019/20 is shown in Figure 5.

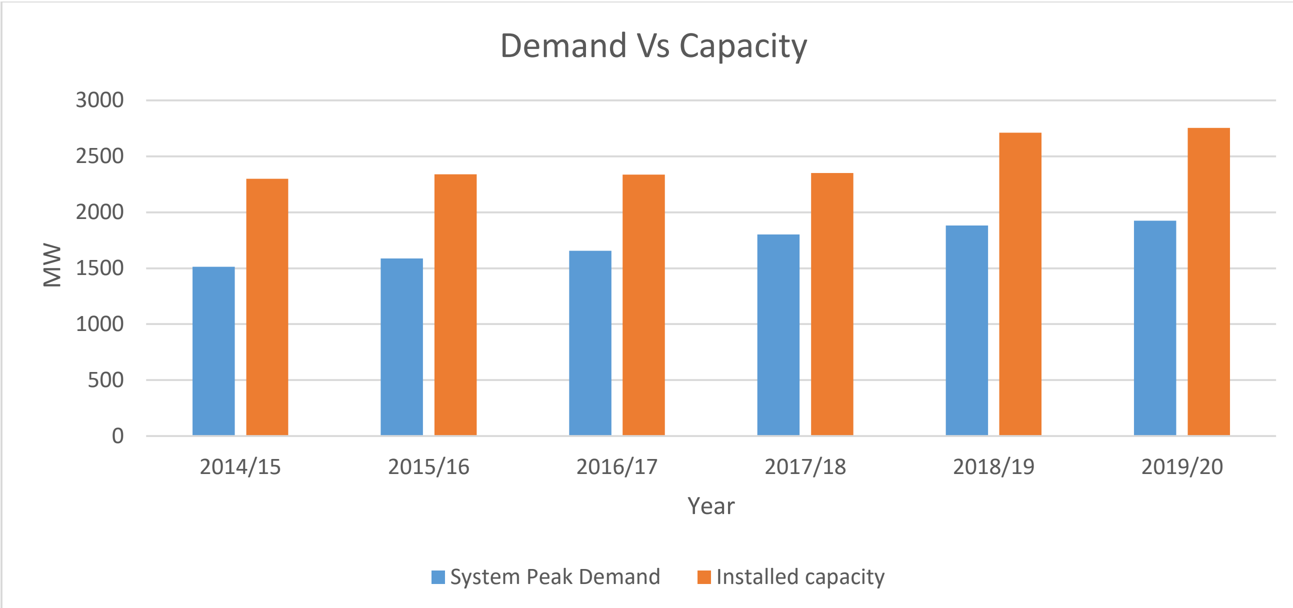


Figure 5 Electricity demand Vs Capacity

Source: Kenya Power

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 to the grid, from 3,611,904 recorded in financial year 2014/15 to 7,576,145recorded in financial year 2019/20, of which rural connections were 1,502,943, accounting for 20% of total connections. This is an annual average growth rate of 19.14% and is a result of the accelerated electrification programs across the country.

3. ELECTRICITY DEMAND FORECAST

3.1. Introduction

Electricity is considered an enabler to the world's economic growth and development. To this end, preparation of an optimal power system expansion plan begins with credible assessment and projection of the future electricity demand. Such an assessment is carried out based on historical load data, current energy demand and economic parameters such as national Gross Domestic Product (GDP), sectoral growth and end-use consumer behaviour. The aim is to arrive at a realistic forecast applicable to the entire power sector expansion programme. A demand forecast provides an insight into the sector's capital investment and expansion decisions. It indicates future capacity (in MW) and energy (in GWh) requirements to enable the planning of generation and transmission investments.

A realistic electricity demand forecast is critical to ensure an optimal power system expansion plan. A high load forecast may lead to over-investment in redundant capacities, while a low demand forecast may result in capacity shortfalls that would slow down economic development. The demand projection process calls for use of a proven methodology, appropriate assumptions and accurate input data.

This section of the report provides the national electricity demand forecast for the period 2020 to 2040. It is a revision of the 2019-2039 forecast to factor in the impacts of COVID-19 pandemic and recommendations from various sectoral reports.

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 for the period 2020-2040. The specific objectives include:

(i) Review the economic environment in relation to electricity demand;
(ii) Review the key demand driving factors identified in previous plans;
(iii) Update assumptions used in the previous forecasts;
(iv) Update the status of the flagship projects;
(v) Factor in the impacts of COVID-19 pandemic and recommendations from various sectoral reports.
(vi) Present demand forecast results for the period 2020-2040.

3.3. Overview of the Domestic Economy

The Gross Domestic Product (GDP) for the year 2019 expanded by an average of 5.4%, which was lower than 6.3% growth registered in 2018 as shown in figure 6.

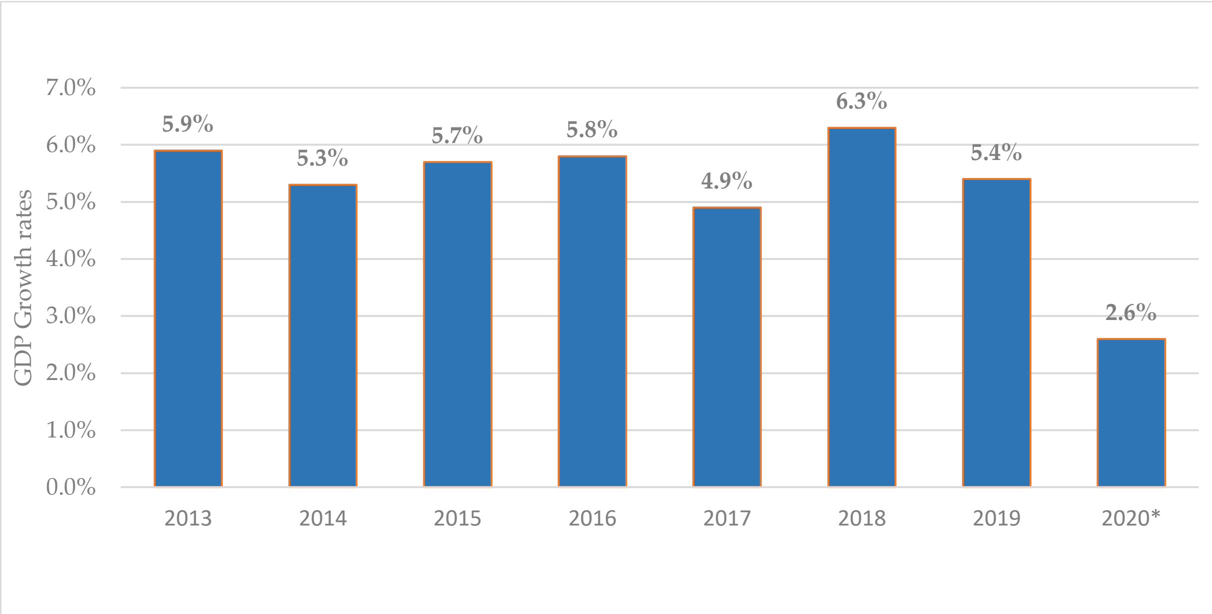


Figure 6 Kenya GDP Growth[1]

Source: KNBS

In 2019, a number of sectors posted impressive performances but the overall growth was curtailed mostly by a slowdown in agriculture, manufacturing and transportation subsectors. The Macroeconomic environment remained largely conducive for growth throughout the year.

The provisional estimate for GDP growth in 2020 is 2.6% mainly due to COVID-19 containment measures that have led to a disruption on livelihoods and businesses. This slowed down economic activities in the country and negatively impacted the performance of various sectors and in particular demand for power in the country

3.4. Performance of the Power Sector

Electricity peak demand has been growing gradually over the last 6yrs with an annual growth of approximately 4.6% per annum. The energy consumption increased from 9,280GWh in 2014/15 to 11,462GWh in 2019/20 representing an average growth of 4.5% over the last six years as shown in figure 7.

[1] 2020* GDP based on Draft BROP 2020

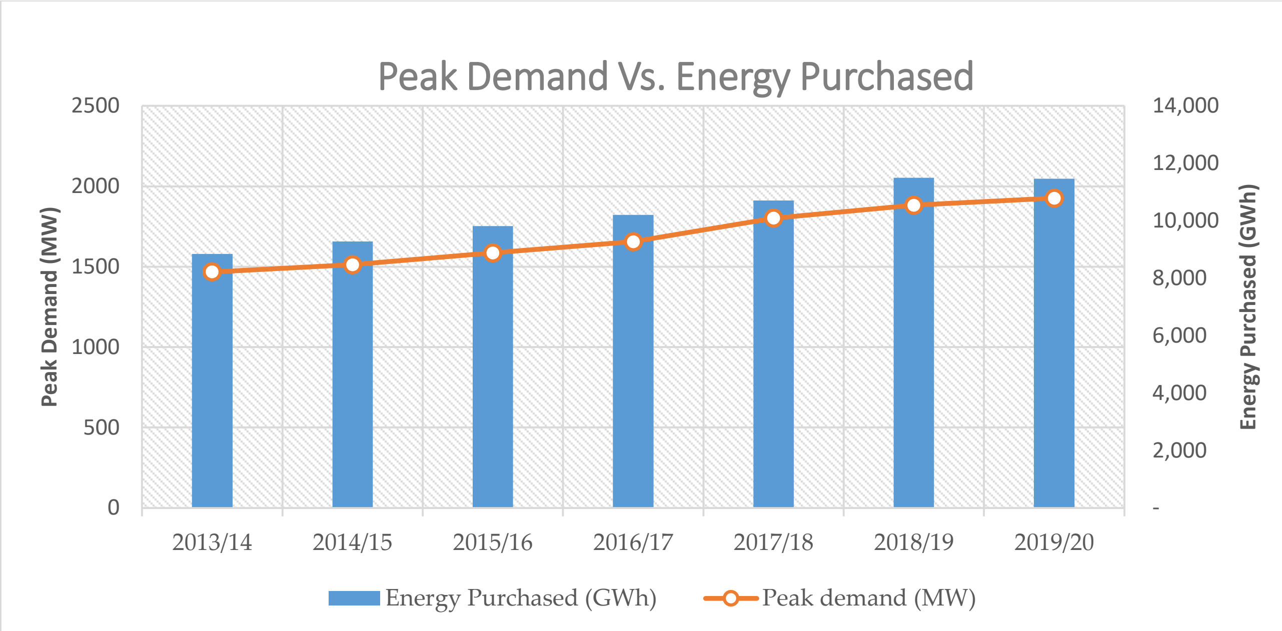


Figure 7 Peak Demand and energy consumption 2013/14 to 2019/20

In 2019/20, energy consumption decreased to 11,462GWh compared to 11,493GWh in the previous year. The overall energy consumption in the financial year recorded marginal growth of 0.05% compared to the previous year 3.7%, while energy purchased contracted by 0.3% from a growth of 7.4% the previous year. On the other hand, peak demand grew to 1,926MW in 2019/20 FY from 1,882MW the previous FY.

The onset of COVID-19 pandemic in the second half of the 2019/20 financial year and subsequent government containment measures created economic shocks, adversely affecting the energy sector. During this period, peak electricity demand declined from 1,926MW in February 2020 to 1,765MW in April 2020, a decline of 9.1% as shown in figure 8.

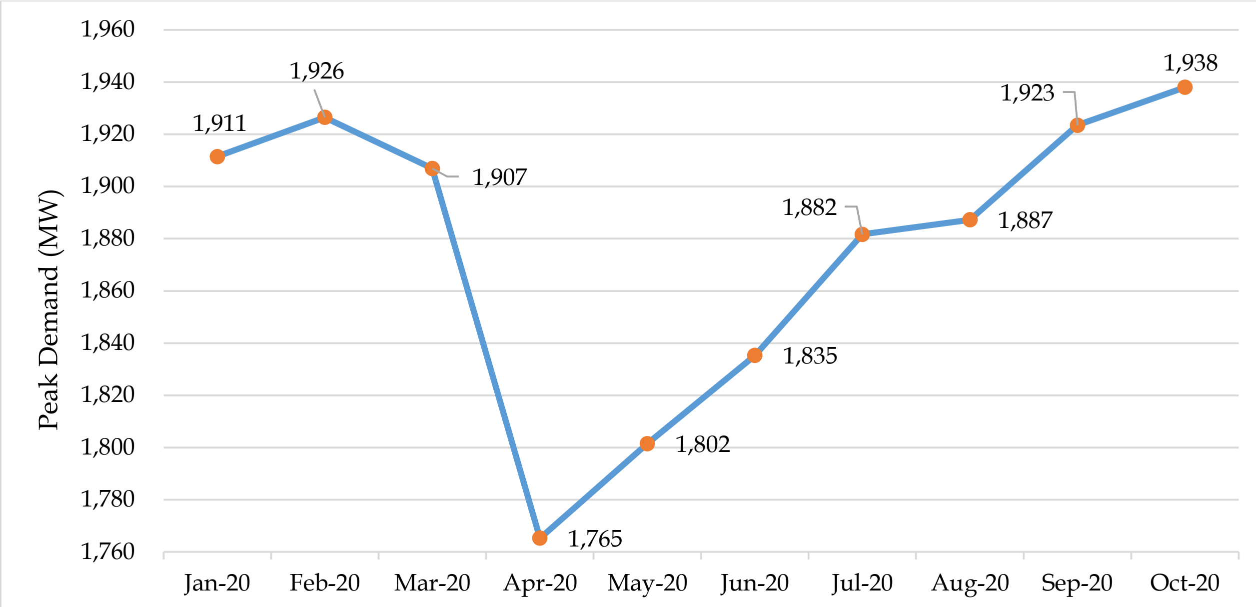


Figure 8 Monthly Actual Peak Demand for 2020

The steep decline was followed by a gradual recovery as the government eased the containment measures enabling resumption of various economic activities. Peak electricity demand improved continually and attained the pre-COVID level in October 2020.

The specific consumption has also shown a decline over the last five years due to increased connections of low consuming customers and use of energy and equipment efficiency. Table 9 summarizes the consumption patterns, consumer trends and customer growth for the last 6yrs

Table 9: Consumption patterns, consumer trends and customer growth 2014/15 – 2019/20FY

	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Annual Consumption (GWh)	7,615	7,867	8,250	8,435	8,742	8,755
No. of Customers	3,611,904	4,890,373	6,182,282	6,761,090	7,067,861	7,726,188
Specific Consumption (kWh)	2,108.40	1,608.65	1,334.46	1,247.59	1,236.87	1,133.2

3.5. Future Economic Outlook: The Vision 2030 and The Big Four Agenda

The Vision 2030 and the Big 4 Agenda identify energy as one of the enablers for sustained economic growth and a key foundation for Kenya's envisaged national transformation. The Vision 2030, the country's economic blue print, aims to transform Kenya from a low income, agrarian economy into a newly industrialized middle-income country by the year 2030, with an average GDP growth rate of 10% per annum.

In 2017, the Government conceptualized a development agenda, dubbed "Big 4 Agenda", based on the Vision 2030. The pillars of the agenda are enhancing manufacturing, affordable housing, universal health coverage and food security and nutrition.

Manufacturing: The Government's aim is to expand the manufacturing sector's contribution to GDP to 20% by 2022 through promoting key projects in the textiles and leather industry; blue economy; and agro-processing. The overall enablers for growth being: Small and Medium Enterprises (SMEs); Ease of doing business rank to 50th globally; industrial parks/zones; and market access and standards. Various Special Economic zones (SEZ) have been earmarked for electricity supply including Dongo Kundu, Kedong Industrial Park, Konza Technopolis, and Africa Economic Zones. As at 2019, manufacturing sector contributed 8.2%[2] as a share of GDP. Various SEZ are under construction and are expected to commence electricity consumption towards the end of the medium term.

Affordable Housing: Increasing access to affordable and decent shelter by facilitating mass house production of at least five hundred thousand (500,000) housing units by 2022 across the country. This target will be achieved by working in partnership with financial institutions, private developers, manufacturers of building materials and cooperatives to deliver homes faster and reduce the cost of construction by at least 50%.

The Energy sector is in the process of supplying power to a number of already developed housing projects in Nairobi and Naivasha. The following projects have been approved for the financial year 2020/2021: Kisima Park in Lukenya Mavoko, Habitat Heights in Lukenya Mavoko, Moke Gardens in Lukenya Mavoko, Jewel Heights in Juja Kiambu, Benvar Estate in Juja Kiambu, Kenlek Ventures in Ruiru Kiambu, Rea Vipingo in Mombasa and Muselele Estate in Athi River.

Universal Health Care: The target under this pillar are to achieve 100% universal health care by reducing the cost and ensuring universal access to quality healthcare by 2022. This will be achieved by scaling up NHIF uptake, launching multi-tier insurance plan

[2] KNBS Economic Survey 2020 exclusive of Taxes

and commissioning of key equipment in hospitals. The sector plans to supply electricity to all level 3 and 4 hospitals in the country.

A total of 635 health facilities were identified to be within the threshold of 15km from the grid. These facilities will be connected by extension of the national grid. A total of 354 health facilities have been identified to be above the threshold of 15km from the grid. These health facilities would therefore require to be supplied using a solar stand-alone system.

Enhancing food security and nutrition: The Government aims at achieving 100% food security and nutrition by 2022. This will be achieved through enhanced large-scale production; increased smallholder productivity and agro-processing; and reduced cost of food. The Sector is focusing on electrification of food processing facilities across the country, irrigation and livestock holding grounds.

3.6. Demand Forecasting Methodology

3.6.1. General approach

Electricity demand growth is mainly a consequence of economic activities and household needs. These sources make electricity demand forecasting a complex exercise, due to unavailability of the individual consumers' data thereby necessitating use of aggregated data for system load forecasting.

To forecast the electricity demand, both parametric methods that integrate main variables and non-parametric methods such as pattern recognition, have been used. The Lahmeyer International Excel based Demand Forecast Model was used for energy demand forecasting. This Model was developed specifically for demand forecat in the Kenyan context and aligned with the requirements of generation expansion planning and transmission simulations. It is based on MAED principles and previous sector LCPDPs.

The following steps were taken in the development of the forecast:

i. Trend-projection was used for correlation analysis of the different factors affecting electricity demand growth in the country.
ii. A bottom-up approach was adopted for calculation of demand for domestic and industrial consumers; street lighting; and flagship projects as identified in the Vision 2030.
iii. Sensitivity was carried out using three scenarios; vision, reference, and low.

3.6.2. Energy demand structure

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

i. Domestic consumption: this includes KPLC and REREC domestic consumers connected at 250-415 volts
ii. Small commercial consumption: this includes KPLC and REREC consumers also connected at 250-415 Volts.
iii. Commercial and Industrial consumption: this represents large power consumers in tariff categories CI1 to CI5.
iv. Street lighting consumption: These are the number of lamps installed in urban areas for lighting and are considered to grow at 85% of domestic consumer growth.

Losses were dis-aggregated based on the following voltage levels:

i. Low Voltage level (415/220 V or 433/250V)
ii. Medium Voltage level (11 and 33 kV)
iii. High Voltage level (66, 132 and 220 kV)

3.6.3. Planning steps

The procedure for forecasting is as follows:

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

Step 2: Calculation of 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 (low case assumes that all flagship projects will not happen):

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

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:

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

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

Where:

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

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 of the units purchased will be decreasing based on the KPLC annual loss reduction trajectory over the planning period.

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

$$P_{pp}(y)=\sum_{TG,FP=1,PSA=1}\{(C_{pp,TG,FP,PSA}(y) \text{X} LF_{pp,TG,FP,PSA}(y) \text{X} RF_{pp,TG,FP,PSA}(y))/H_y\} \text{XSF}$$

Where:

CPP 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

Hy Hours in a year.

3.6.4. Main drivers of the projected demand

Key driving factors of demand considered are:

i. **Demography of Kenya:** This includes population growth and urbanization. It has an explicit effect on domestic consumption and connectivity level. It also has a direct effect on economic activity that is easily quantifiable.

ii. **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 envisaged: High scenario of attaining 6.3% GDP growth by 2022, 2020 Draft Budget Review Outlook Paper Projections and the 10yr historical GDP growth average. All the scenarios assume that the overall GDP grows from 2.6% in 2020. This is an estimate based on the Draft Budget Review Outlook Paper Projection.

iii. **Vision 2030 Flagship projects:** These projects have an impact on GDP growth under the reference and high scenarios, and contribute to demand growth based on their specific load requirements. The plan considers projects that are expected to be realised within the medium and long term periods. The projects are also assumed to have gradual increase in the load. A 2% load impact on demand has been factored in based on the assumed year of initial load and year of full load per project.

3.7. Definition of the Scenarios

The forecast considers three scenarios for the LTP period 2020 -2040 with 2020 as the base year.

3.7.1. Reference Scenario

This is the base case scenario with projection based on historical data trends.

3.7.2. Vision Scenario

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

3.7.3. 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.

3.8. Forecast Assumptions

3.8.1. Suppressed Demand

In the forecast, a suppressed demand of 4.61% has been assumed for the base year. 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. Accordingly:

SD= (O+LS)/CBK

O= C X S X P

Where

SD Suppressed demand

O Outages in GWh for the base financial year

LS Load shed in GWh for the base financial year

CBK Consumption billed/sales KPLC in the base financial year

P Peak load in MW for the base financial year

C Customer Average Interruption Duration Index (CAIDI) in hours for the base financial year

S System Average Interruption Frequency Index (SAIFI) for the base financial year.

3.8.2. Domestic consumption

Future growth in electricity demand across the domestic consumers in Kenya will be strongly influenced by population growth, urbanisation and the number of customers connected. Table 10 indicates the assumptions made for domestic demand:

Table 10:Domestic Consumption Assumptions

Category	Data sources	Assumptions, parameters
Demography	KNBS Census 2019 (county level)	2019 Census of 47.56Million, grown by 1.55% to get 48.3 million as the base figure across the scenarios.
Population growth	UN High fertility scenario forecast UN medium fertility scenario forecast UN low fertility scenario forecast	Low: 2020: 48.3 million, grown by average growth 2.26%/year Reference: 2020: 48.3 Million: average growth 1.97%/year Vision: 2020: 48.3 Million: average growth 1.67%/year
Household size	KNBS 2019 Census	2019: 3.92 persons / household
Share of total urban population Average Annual Urban growth rate	World Urbanization Prospects: The 2018 Revision-Annual Rate of Change of the urban population. Kenya Household Integrated Budget Survey 2015/2016	Share of urban population 2020 estimated based on KHIBS data 2015/16 (28.2%) and projected based on UN Average Annual Urban growth rate of 3.79%
Electrification targets (connectivity level), connection rate	KPLC Annual statistics 2019/20 Generation and Transmission masterplan 2015	Vision: 99% connectivity by 2030 Reference: 611,251 no. of new customers connected based on average last 10 years, with a reduction of 0.5% every year

		Low: 464,621 no. of new customers based on 3 year average from 2017/18 to 2019/20 with a reduction of 0.5% every year
Annual consumption per connection (specific consumption) in kWh	KPLC annual reports 2019/20 Generation and Transmission Masterplan 2015	Reference: 2020: urban: 327.96 (Urban connected customers Specific Consumption). Computed based on 81% urban share (KPLC DC) of total domestic customers for all scenarios. Rural: 78.39 (Rural connected customers Specific Consumption). Computed based on 19% Rural share (REREC DC) of total domestic customers for all scenarios. Annual increase in specific consumption: 4%
		Low: 2020: urban: 277.24 Rural: 58.91, Annual increase in specific consumption: 4%
		Vision: 2020: urban: 554.47, Rural: 117.81, Annual increase in specific consumption: 6%
Suppressed demand		Outages (Forced & Planned) Base year 4.61% (Based on CAIDI=4.32, SAIFI=48.6) Target

		Reference: 0% in 2030 Vision: 0% in 2025 Low: 0.5% in 2040
		Curtailed Demand Base year 4.61% (Sum of outages & Load shedding, divided by Sales)

3.8.3. Small commercial consumption assumption

Small Commercial electricity sales account for about 16% of total retail sales in Kenya and are dependent on changes in population and urbanisation. Demand from this category has grown over the past 10 years at an average growth rate of 5.1% due to theemergence of small market centres.

Table 11:Small Commercial Assumptions

Category	Data sources	Assumptions, parameters
Electrification / connections	2019/20 KPLC Annual accounts	All scenarios: growth new connections 44% of growth in new domestic connections (historic correlation 2009/10 – 2019/20)
Annual consumption per connection (specific consumption, SC)	2019/20 KPLC Annual accounts	Increase in specific consumption Reference: annual increase: 1.5%; (based on an average growth in SC over the 5yrs) Low: annual increase: 0.6% (assumed from actual growth recorded in 2019/20) Vision: annual increase: 2.2% (assumed from average last five years pre-COVID-19)
Suppressed demand	See domestic consumption assumption Table 10	

3.8.4. Large Commercial and Industrial consumption

For industrial and commercial consumption, the driving factor considered is the correlation of consumption to GDP growth.

Table 12 shows assumptions made in the development of Large Commercial and Industrial forecast:

Table 12: Large Commercial and Industrial Assumptions

Determined by	Data sources	Assumptions, parameters
Connections & consumption through GDP growth	Draft 2019/20 KPLC Annual accounts transferred to calendar years Draft Budget Review Outlook Paper 2020 KIPPRA Kenya Economic Report 2020	GDP Growth of 2.6% assumed for the base year across the three scenarios. Reference: GDP growth: Draft BROP 2020-2025, and retained the growth rate of 2025 (5.9%) for the remainder of the planning period. Low: Average historic GDP growth for past 10yrs (2010-2019) at 5.3% Low: Average historic GDP growth for past 10yrs (2010-2019) at 5.4% Vision: GDP growth based on KIPPRA Economic Report 2021 (5.3%), 2022 (6.3%) and Maintained 2022 growth rate for the rest of the planning period. Average injection of GDP by Flagship projects is 2%.
Suppressed demand	See domestic consumption assumption Table 10	

3.8.5. Street lighting

The driving factors for street lighting demand are:

i. Number of poles indexed to the number of customers
ii. The specific consumption of the lamps

For the purpose of this forecast, each customer as per the KPLC street-lighting category was assumed to represent a meter, which in turn represents 10 lamps/pole each 130 watts operating from 6:00pm to 6:00am.

Table 13:Street Lighting Assumptions

Category	Data sources	Assumptions, parameters
Street Lighting Coverage	KPLC Street Lighting Division.	National street lighting coverage of 52.6% 4.1% street lights not in operation in the base year (out of 151,000 lamps, 6,200 are not in operation.)
Electrification / connections	Draft 2019/20 KPLC Annual accounts.	All scenarios: growth in new connections = 85% of growth in new domestic connections (2009/10 – 2017/18 historic correlation)
Annual consumption per connection (specific cons.)	KPLC Street Lighting Division	Specific consumption: 5,694 kWh/a - ((130*10*12*365)/1000) (10 lamps each 130 Watt on 6pm to 6am)
Suppressed demand	KPLC Street Lighting Division	All scenarios: see domestic consumption assumption Table 10

3.8.6. Target Loss Levels

The target loss levels are assumed to be the same towards the end of the medium and long period across all scenarios. The base year losses are apportioned at 12.7% (LV), 6.4% (MV) and 4.4% (HV) respectively. This is as indicated in table 14.

Table 14:Target Loss Levels

VOLTAGE LEVEL	BASE YEAR	END OF MTP	END OF LTP
LV	12.7%	11.5%	11.5%
MV	6.4%	5.5%	5.5%
HV	4.4%	3.5%	3.5%

3.8.7. 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 but are significant power consumers. The forecast factors various flagship projects as identified under the Vision 2030 and shown in table 15.

Table 15: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 operatio n	Initial load [MW]	Year of total load	Total load [MW]
ELECTRIFIED MASS RAPID TRANSIT SYSTEM FOR NAIROBI					2030	15	2038	50
ELECTRIFIED STANDARD GAUGE RAILWAY MOMBASA - NAIROBI					2030	98	2039	130
SPECIAL ECONOMIC ZONES(TATU CITY, ATHI RIVER,ELDORET)					2024	15	2038	60
SPECIAL ECONOMIC ZONES(KEDONG,DONGO KUNDU,KONZA)	2022	10	2040	60	2022	15	2038	60
SPECIAL ECONOMIC ZONES(KENGEN)					2023	15	2030	50

SPECIAL ECONOMIC ZONES(TILISI,LAMU)					2025	10	2040	40
SPECIAL ECONOMIC ZONES(GDC,EGERTON,INFINITY,OSERIAN,VIKINGS)					2026	15	2041	60
SPECIAL ECONOMIC ZONES(MUMIAS,SONDU,HOMABAY,KISUMU)					2030	20	2045	80

3.9. Results of the forecast

3.9.1. Electricity consumption and peak load - reference, vision, low scenarios

The annual forecasted electricity demand and peak load respectively are expected to grow for all scenarios over the planning period. Energy demand is forecasted to grow at an average of 5.28% while the peak load is forecasted to grow at an average of 5.38% in the reference scenario; 8.20% and 8.35% in the vision scenario and 4.78% and 4.89% in the low scenario respectively as shown in figure 9. The vision scenario increases at a higher rate due to an assumed higher GDP growth and early impact of flagship projects.

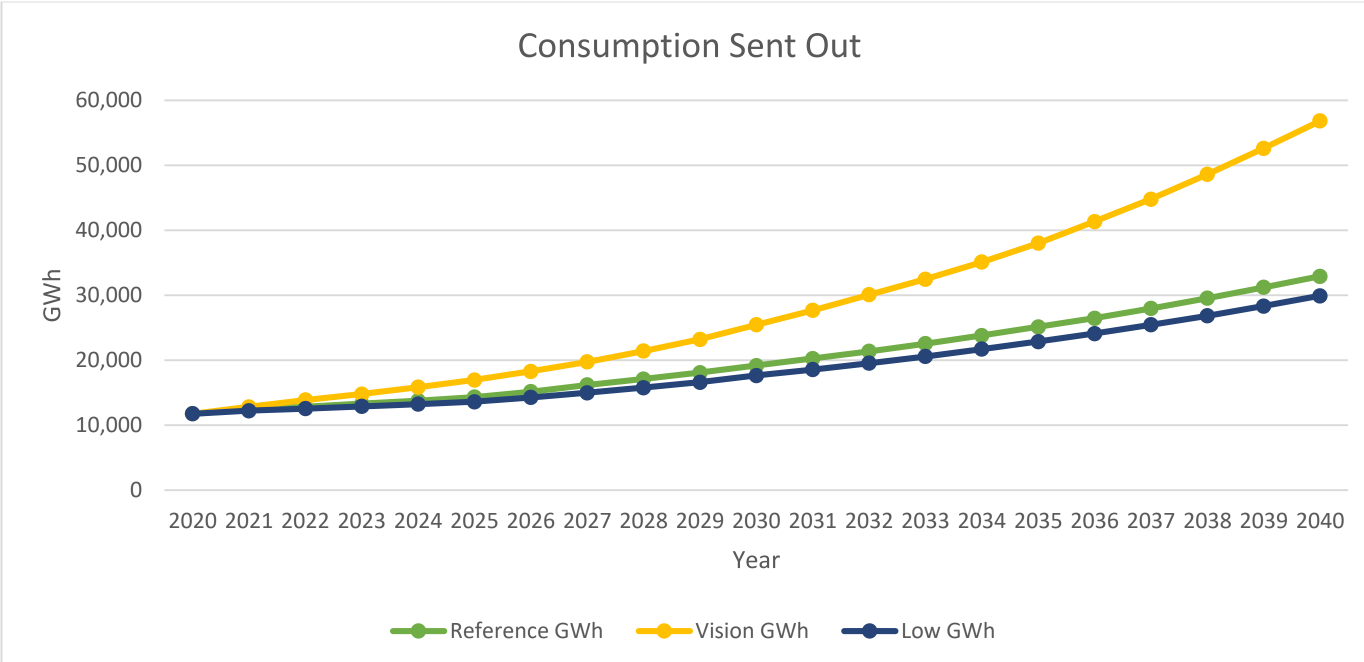


Figure 9 Forecasted Electricity consumption

Electricity consumption is expected to rise over the planning period in all scenarios. Energy demand in the reference scenario grows at an average of 5.28% to reach 14,320GWh in 2025 and 32,914GWh by the end of the planning period as shown in figure 9. Under the Vision scenario energy demand increases at an average of 8.20% to 16,958GWh by 2025 from 11,760GWh in the base year. Consumption is forecasted to reach 56,845GWh by 2040 under this scenario. The Low scenario expands moderately at an average of 4.78% to reach 29,906GWh by the end of the planning period as shown in Table 16.

Table 16:Energy Demand Forecast 2020-2040

	Reference		Vision		Low	
Year	**GWh**	**Growth**	**GWh**	**Growth**	**GWh**	**Growth**
2020	11,760		11,760		11,760	
2021	12,344	4.97%	12,817	8.99%	12,235	4.04%
2022	12,831	3.95%	13,866	8.19%	12,556	2.62%
2023	13,299	3.65%	14,775	6.55%	12,883	2.60%
2024	13,787	3.67%	15,837	7.19%	13,227	2.67%
2025	14,320	3.87%	16,958	7.08%	13,607	2.87%
2026	15,152	5.81%	18,294	7.88%	14,270	4.87%
2027	16,182	6.80%	19,742	7.92%	14,988	5.03%
2028	17,106	5.71%	21,408	8.44%	15,760	5.15%
2029	18,095	5.78%	23,216	8.45%	16,598	5.32%
2030	19,177	5.98%	25,444	9.59%	17,637	6.26%

	Reference		Vision		Low	
Year	**GWh**	**Growth**	**GWh**	**Growth**	**GWh**	**Growth**
2031	20,259	5.64%	27,665	8.73%	18,558	5.22%
2032	21,369	5.48%	30,089	8.76%	19,540	5.29%
2033	22,551	5.53%	32,473	7.92%	20,586	5.36%
2034	23,811	5.59%	35,122	8.16%	21,703	5.42%
2035	25,131	5.54%	38,007	8.21%	22,875	5.40%
2036	26,461	5.29%	41,340	8.77%	24,096	5.34%
2037	27,976	5.73%	44,795	8.36%	25,443	5.59%
2038	29,547	5.62%	48,601	8.50%	26,842	5.50%
2039	31,206	5.61%	52,616	8.26%	28,327	5.53%
2040	32,914	5.47%	56,845	8.04%	29,906	5.57%
Average Growth		**5.28%**		**8.20%**		**4.78%**

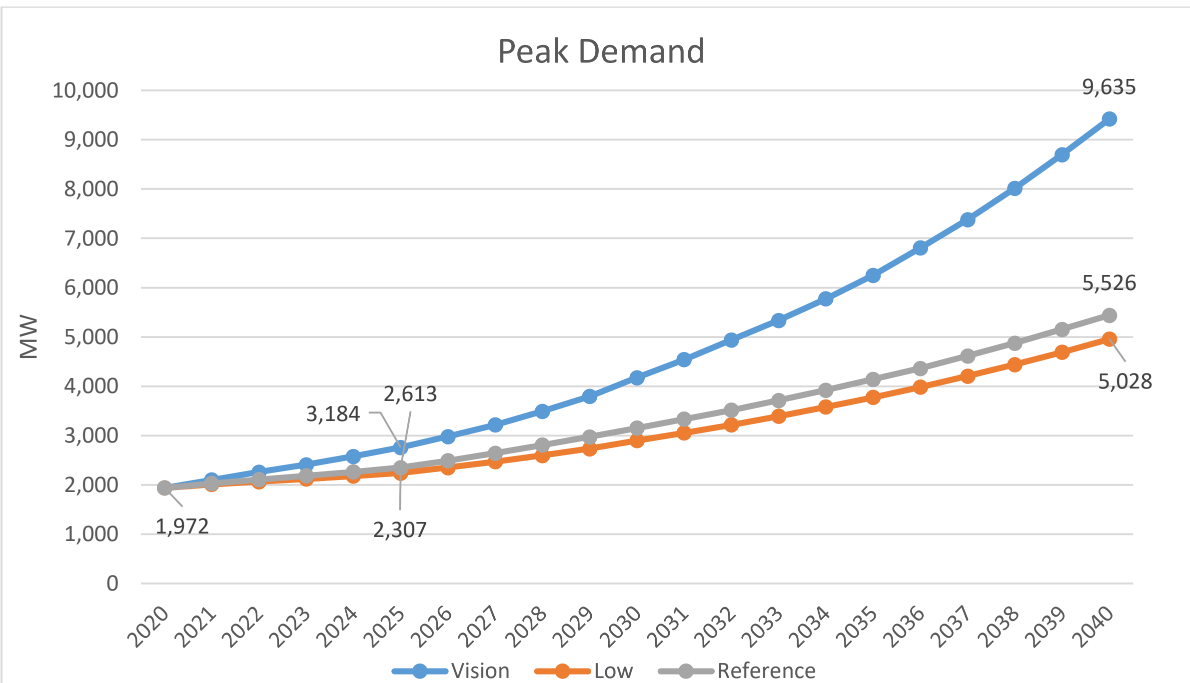


Figure 10 Forecasted Peak Load

Peak demand is forecasted to grow at an average of 5.3% from 1,972MW in the base year to 5,526MW at the end of the planning period under the Reference scenario. Similarly, under the Vision scenario peak demand increases to 9,635MW in 2040 growing at an average rate of 8.35%. The Low scenario peak demand increases to 5,028MW in 2040 at an average rate of 4.89% as shown in table 17.

Table 17:Peak Demand Forecast 2020-2040

	Reference		Vision		Low	
	MW	Growth	MW	Growth	MW	Growth
2020	1976		1976		1976	
2021	2029	2.64%	2108	6.6%	2010	1.7%
2022	2110	4.04%	2281	8.2%	2065	2.7%
2023	2190	3.76%	2435	6.7%	2121	2.7%
2024	2272	3.78%	2610	7.2%	2180	2.8%
2025	2363	3.97%	2799	7.2%	2245	3.0%
2026	2503	5.93%	3024	8.0%	2357	5.0%
2027	2677	6.94%	3269	8.1%	2478	5.2%
2028	2833	5.83%	3550	8.6%	2609	5.3%
2029	3000	5.90%	3859	8.7%	2751	5.4%
2030	3183	6.10%	4251	10.2%	2928	6.4%
2031	3368	5.82%	4627	8.8%	3084	5.3%
2032	3556	5.58%	5037	8.9%	3251	5.4%
2033	3757	5.64%	5441	8.0%	3429	5.5%
2034	3971	5.70%	5891	8.3%	3620	5.6%
2035	4195	5.65%	6382	8.3%	3820	5.5%
2036	4421	5.40%	6951	8.9%	4031	5.5%
2037	4680	5.84%	7542	8.5%	4261	5.7%
2038	4948	5.73%	8194	8.6%	4501	5.6%
2039	5232	5.75%	8892	8.5%	4757	5.7%
2040	5526	5.62%	9635	8.4%	5028	5.7%
Average Growth		5.3%		8.2%		4.8%

3.9.2. Losses

Under all scenarios, losses reduce from the initial 23.5% in 2020 to 16.7% at the end of the planning period.

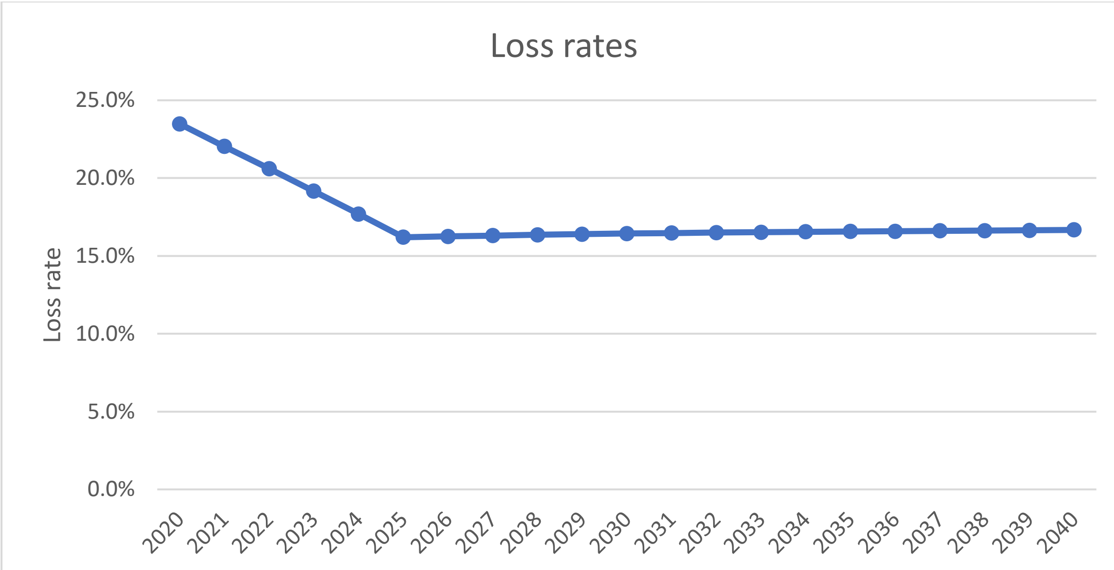


Figure 11 Trend Losses

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

A comparison of the current forecast results in all scenarios indicate a reduction from the previous forecast. The energy consumption shows a 0.02%, 0.44% and 0.58% reduction in the low, reference and vision scenarios respectively. The peak demand shows a reduced growth of 0.02%, 0.52% and 0.58% in low, reference and vision scenarios respectively as indicated in table 18

Table 18:Comparison of current demand forecast with previous forecast

Plan Period	**DESCRIPTION**	**Energy**	**Peak**	**Energy**	**Peak**	**Energy**	**Peak**
		Low		**Reference**		**Vision**	
2020-2040	Current Growth rate	4.78%	4.89%	5.28%	5.38%	8.20%	8.35%
2019-2039	Previous Growth rate	4.76%	4.91%	5.72%	5.90%	8.78%	8.93%
	CHANGE	-0.02%	-0.02%	-0.44%	-0.52%	-0.58%	-0.58%

3.9.4. Demand Forecasting Conclussion and Reccomendation.

The review of the demand forecast incorporating the impact of the COVID-19 pandemic and the recommendations of various sectoral reports indicates a slower demand growth rate compared to the pre-COVID forecast. This is due to the decline in consumption by commercial consumers adhering to government containment measures. However, this is a temporary position that is likely to recover in the short to medium term, In addition, it has been noted over time that flagship projects are not being implemented within the timelines as envisaged, therefore slowing down both the economic and demand growth. It has also been noted that specific consumption has declined due to low consumption by newly connected customers.

The following are the recommendations:

i. Acceleration of implementation of the Vision 2030 flagship projects and Big Four agenda to spur demand
ii. Enhance implementation of demand creation initiatives and promote development of demand creation strategies by various utilities in the sector
iii. Allocate sufficient budget to implement the demand creation initiatives such as new customer connections and grid enhancement
iv. Enhance coordination between various State departments, Agencies and County governments to promote productive use of electricity
v. Improve system management, automation and innovation to enhance supply reliability, efficiency and to reduce system losses
vi. Provide incentives that promote conducive environment for growth of industrial customers and their associated energy consumption

4. ASSESSMENT OF NATURAL ENERGY RESOURCES IN KENYA

4.1. Current and Future Energy Sources

This chapter discusses the energy sources utilized for electric power generation as well as the planned and potential energy sources for future electricity generation in Kenya. It evaluates the characteristics of fossil fuels considering infrastructure and future developments, overview of the available renewable energy sources and nuclear power as potential future energy source. The regional power interconnections with neighbouring countries as electricity supply options have also been discussed.

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 approximately 10% annually.

4.2. Fossil energy sources

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

At present, crude oil and coal are the only domestic fossil energy resources available for extraction and potential use in power generation. Exploration activities on natural gas deposits are underway.

4.3. Crude oil and liquid petroleum products

4.3.1. 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, which can be attributed to its dominance in the transport sector. Some petroleum products such as gasoil and HFO are used for electricity generation.

Kenya has 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[3]. A corresponding number of 41 licences have been awarded to international oil firms (exploration and production companies) to carry out exploratory activities. Figure 12 provides an overview of ongoing exploration activities in Kenya as from July 2015.

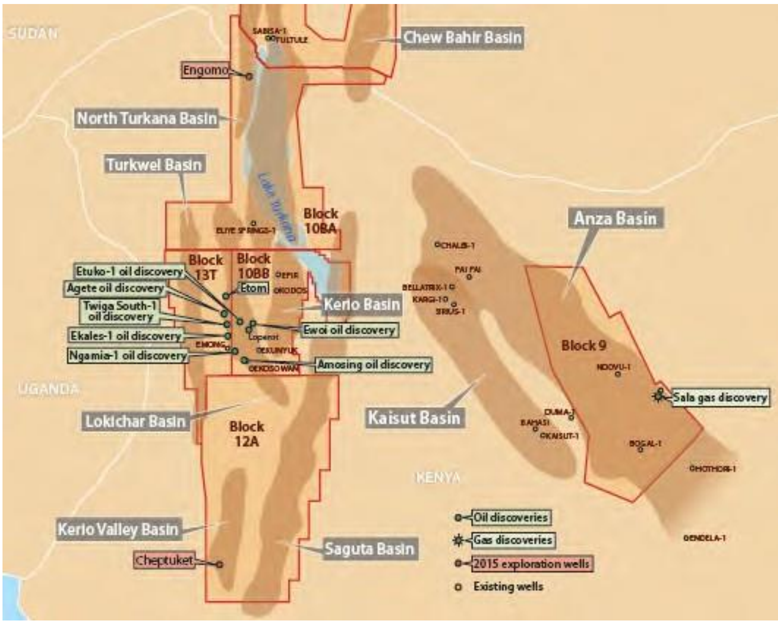


Figure 12 Exploration Activities in Kenya

Domestic crude oil deposits have been located in Turkana, the northern most county of Kenya bordering Uganda and South Sudan. Extraction in Turkana is ongoing with the crude oil transported by trucks to Mombasa for export. Plans are underway to construct a pipeline from Turkana to Lamu for export.

About 25% of the installed power generating capacity of Kenya's electricity sector relies on imported petroleum products. The dependence on petroleum products has been declining over time. This is due to the increase in the installed capacity from renewable energy sources such as geothermal, wind and solar.

4.3.2. 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 crude oil 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

3 Ministry of Energy and Petroleum, Draft National Energy and Petroleum Policy (2015)

used as a relatively cheap but still liquid fuel for power generation and shipping. Its use causes higher environmental pollution compared to other fuels. For every fraction, various kinds of HFO exist distinguished by their viscosity and net calorific value.

HFO is mainly used in diesel power plants, such as in the Kipevu Power Station in Mombasa while the remaining proportion is used for industrial production. At present all HFO is imported through Mombasa port and thereafter transported by road to the power plant locations. It is currently not recommended as suitable fuel option due to its negative environmental impact.

4.3.3. Gasoil and kerosene

Gasoil and kerosene are fractions at the middle of the fractioning column of the distillation process. Various kinds of gasoil are also distinguished by their viscosity and net calorific value. Gasoil and kerosene are at the upper end of the cost range of generation fuels. 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 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 recommended fuel options for backup and peaking capacity plants.

4.3.4. 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, 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 coal4. Its share has continuously been 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 importance for electricity generation to grow even further. However, the means of transport 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.

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 economic sense in comparison to other energy sources, particularly 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 industries and households (e.g. for cooking).

4.3.5. Liquefied natural gas (LNG)

The supply of natural gas is mainly restricted by the available transport infrastructure. The use of liquefied natural gas (LNG) is relatively a new option for large-scale power generation. 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 prospects of

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discovering natural gas deposits has resulted in the 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 use of LNG would also provide economic benefits for other consumers, such as industries, households and transport sector.

4.4. Solid fuels

4.4.1. Coal

Coal is a solid fossil fuel consisting mostly of carbon with variable amounts of other elements mainly hydrogen, sulphur, oxygen, and nitrogen. Coal is formed when dead plant matter decays into peat and is converted into coal by the heat and pressure of deep burial over millions of years. 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 oil5. It is the most important fuel for power generation worldwide due to its abundant reserves, which are relatively distributed 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

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mining will require large scale resettlement plans. Further, mining will produce considerable pollution.

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 coal power plant in Lamu would be the first in Kenya. More coal power plants in future, utilizing domestic coal, could be developed directly near the Mui Basin in Kitui County.

4.5. Renewable energy sources

Kenya has promising potential for power generation from renewable energy sources. Availability of solar, hydro, wind, biomass and geothermal resources has necessitated the government to seek expansion of renewable energy generation in the country. Through least cost approach, the government has prioritized the development of geothermal, wind and solar energy plants as well as solar-fed mini-grids for rural electrification.

4.5.1. Geothermal energy

Kenya's geothermal resource is located within the Rift Valley area, with recent estimates putting the resource potential at about 10,000MW spread over 14 sites as shown in figure 13. Currently, geothermal capacity provides nearly 50% of total power generation with an installed capacity of 828 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, geo-thermal power plants generally run as base load.

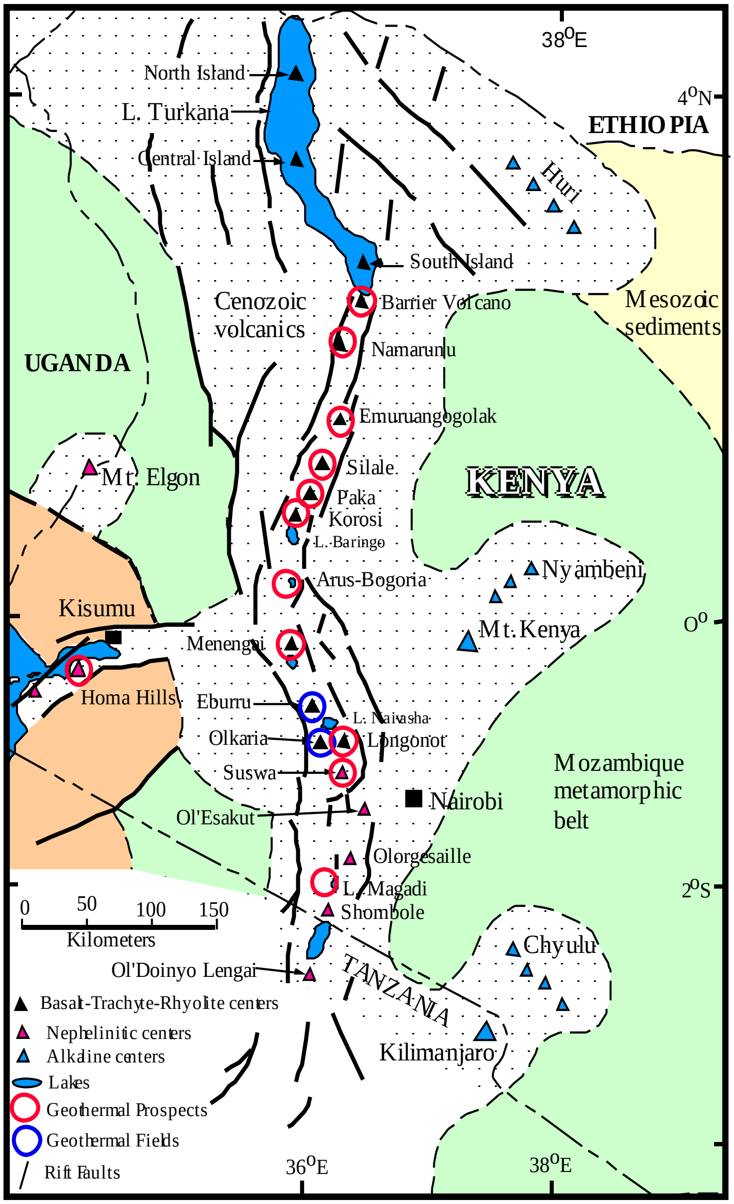
At present, geothermal power is only being harnessed in the Olkaria, Menegai and Eburru fields. In the medium and long term new geothermal reservoirs are being explored in Suswa, Longonot, Akiira and Baringo Silali. Other potential geothermal sites within the Kenya Rift that have not been studied in 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 603 MW of geothermal power could be implemented during the medium-term period since they are already at advanced stage of construction or planning.

It is 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, which is considered as “conventional" renewable energy source is already well developed in Kenya and can compete with other sources. The expansion planning is done through the fully identified candidates 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 mainly used in Kenya today is technically unable to provide flexible power. On the other hand, Binary systems are able to be operated in a flexible way. 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.



Rift Region	Potential (MW)
Central Rift	
Menengai	1,600MW
Eburru	250MW
	1,850MW
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
Arus Bogoria	400MW
	4,250MW
Nyanza	
Homa hills	100MW
Akira	350MW
	450MW
Total Potential	**10,000MW**

Figure 13 Location of geothermal projects within Kenya Rift valley

4.5.2. Hydropower

4.5.2.1. Conventional Hydropower

Kenya has a considerable hydropower potential estimated in the range of 3,000-6,000 MW. Over 800MW is already 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 eight (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. With the introduction of the feed-in-tariff policy in 2008, small-scale candidate sites are already being developed across the country with the majority being implemented by Kenya Tea Development Authority (KTDA).

The undeveloped hydroelectric power potential of economic significance is estimated at 1,484 MW, out of which 1,249 MW is for projects of 30MW and above. This hydropower potential is located in five geographical regions, mainly in Kenya's major drainage basins as shown in table 19. These include Lake Victoria basin (329MW), Rift Valley basin (305MW), Athi River basin (60MW) and Tana River basin (790MW).

Table 19:Hydropower potential

Catchment area	Area (Km2)	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 Ngiro North	210,226	0
TOTAL	575,451	1,484

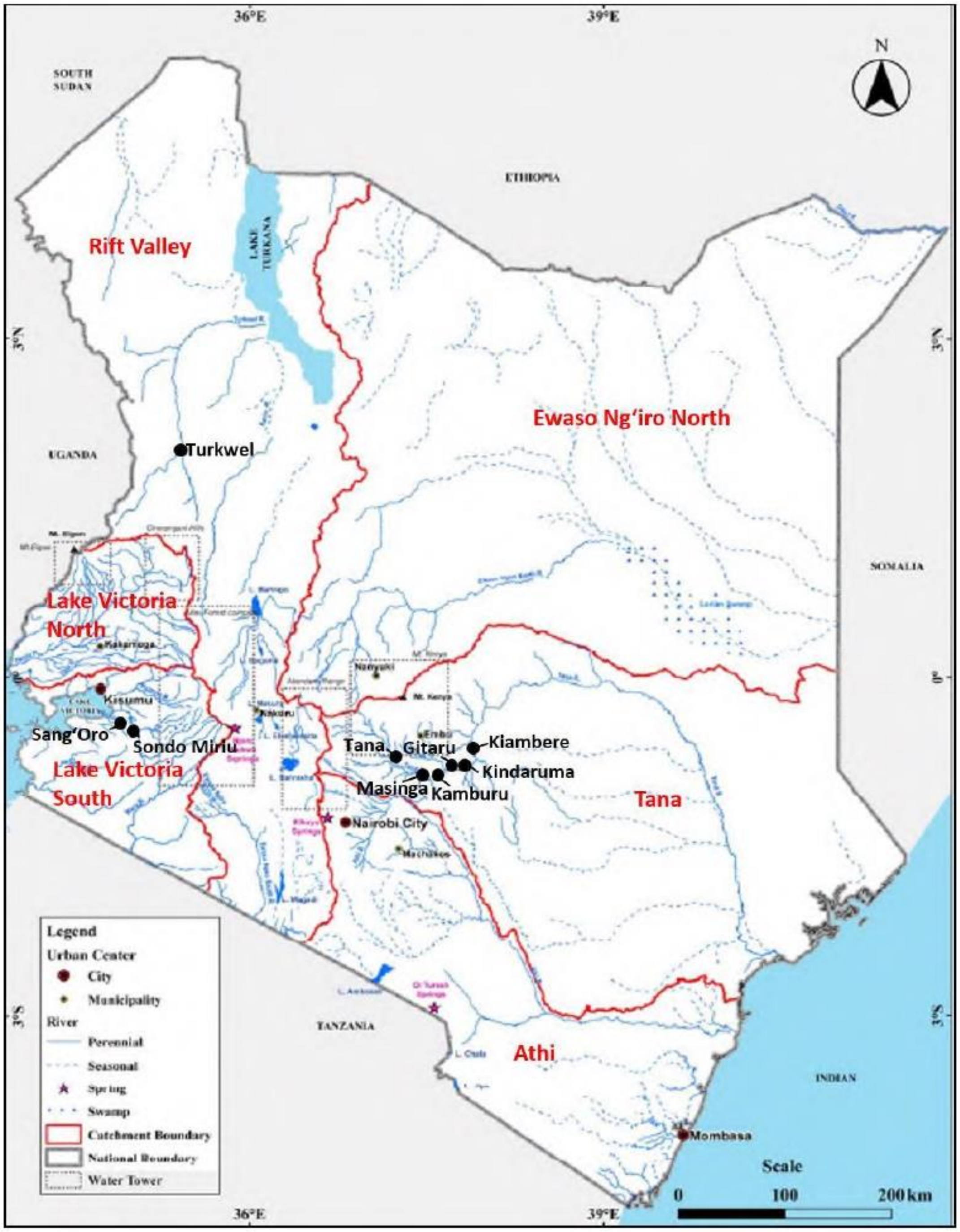


Figure 14 Major rivers of the catchment areas and location of existing large hydropower plants

There is a growing consciousness of the possibilities that small hydropower might offer vast generation options. Several studies and investigations have been carried out and only a few small hydro schemes have been realized, either as part of the national grid supply as shown in figure 14 or as stand-alone systems for agro-industrial establishments or missionary facilities.

The economic risk in hydropower projects can be enormous, 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 plant 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 system is vulnerable to large variations in hydrological conditions. This has proved to be a big challenge in the recent past with the failure of adequate rainfall resulting in power and energy shortfalls. Normally, it is a big challenge for a hydro project in case people have to be relocated and this has been the main reason why the Magwagwa hydro project on River Sondu has not been implemented due to high population density that requires relocation.

Beyond the existing schemes, Kenya still has substantial hydropower potential. This is evident by current plans to develop large hydro projects in Karura (90MW) and High Grand Falls (500MW) in the Tana catchment area, Nandi Forest (50MW) in the Lake Victoria North catchment area, Magwagwa (115MW) in the Lake Victoria South catchment area, and Arror (80MW) 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 whose feasibility studies are still ongoing while other are under implementation.

4.5.2.2. Pumped Storage Hydropower

There is potential for pumped storage hydropower. Pumped storage is a type of hydroelectric power generation that stores energy in the form of water in an upper reservoir, pumped from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines in the same manner as a conventional hydro station. Excess energy is used to recharge the reservoir by pumping the water back to the upper reservoir. The system operates as both a pump and a turbine.

Pumped storage stations differ from conventional hydro stations in that they are a net consumer of electricity. In reality, pumped storage plants can be considered as transmission facilities. They can be economical from an overall system operation perspective due to peak/off-peak price differentials and, more importantly, the provision of ancillary grid services. It is the largest-capacity and most cost-effective form of grid energy storage currently available. Pumped storage stations also provide ancillary electrical grid services such as network frequency control and critical system reserves. This is due to the ability of pumped storage plants, like other hydroelectric plants, to respond to load changes within seconds.

Pumped storage is currently being utilized to stabilize the variability of intermittent renewable power sources such as wind and solar. It is capable of absorbing excess generation (or negative load) at times of high output and low demand. It also releases the stored energy during peak demand periods, proving to be an enabling technology for wind and solar power growing penetration into the national energy supply system.

In response to the growing need for storage and the exceptional synergy between pumped storage and variable renewable energy sources such as wind and solar, the hydro industry is proposing to accelerate the development of pumped storage capacity in the near future.

Preliminary studies indicate that suitable sites for pumped storage hydropower projects are located in the north western, western and south western parts of Kenya. Some of the sites include Lake Turkana west, Samburu, Kapenguria, Kipcherere, Lomut, Sondu and Homabay south among others.

4.5.3. Wind energy

Wind power is among the most mature technologies of all renewable energy sources in terms of commercial development. The development costs have decreased dramatically in recent years and still coming down. Potential for development is huge, and the world's capacity is far larger than the world's total energy consumption.

Awareness and interest in wind power generation in Kenya 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 and Lake Turkana Wind Power (LTWP)'s 310MW farm in Loiyangalani comprising 365 turbines of 850kW each.

In the short term, several wind power projects are planned and are in various stages of implementation and more proposals pending approvals.

The Best wind sites in Kenya are located in Marsabit, Samburu, Laikipia, Meru, Nyeri, 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 excellent wind speeds of 6m/s and above.

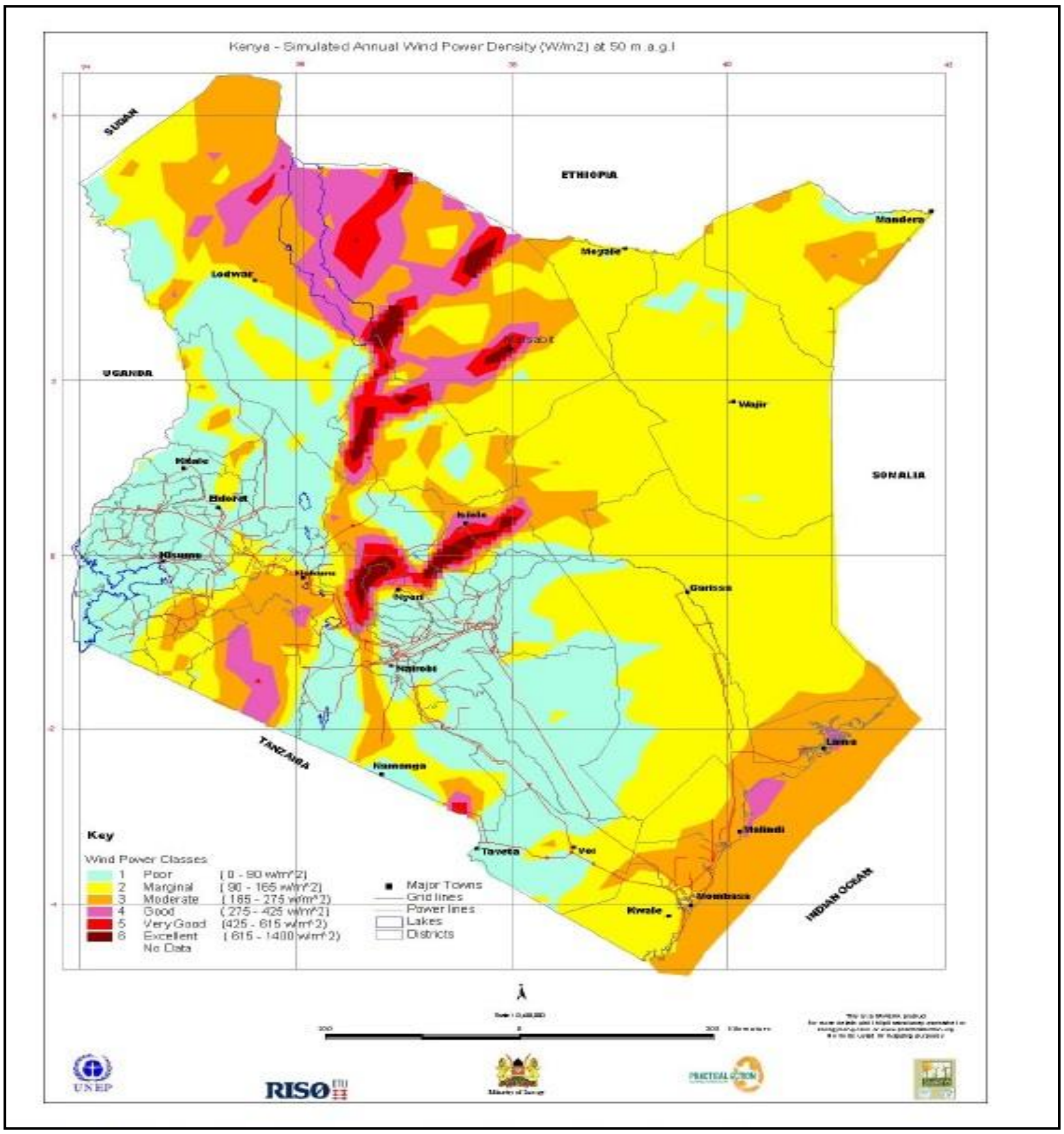


Figure 15 Wind Energy Capcity

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 and 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 15. A wind energy data analysis and development programme conducted in 2013 by Wind Force Management Services Pvt. Ltd indicates a total technical potential of 4,600 MW.

4.5.4. Solar Energy Resources

Kenya has high insolation rates, with an average of 5-7 peak sunshine hours and average daily insolation of 4-6 kWh/m2 due to its strategic location near the equator. 10-14% of this energy can be converted into electricity due to the dispersion and conversion efficiency of PV modules. Solar power is largely seen as an option for rural electrification and decentralised applications.

With the enhanced state support and continuous decrease in development costs, it is estimated that the rate of market penetration is set to improve considerably. With the diversification of rural electrification strategies, it is expected that the number of installed solar home systems will grow substantially. This can be harnessed for water heating, electricity generation for households and telecommunications facilities in isolated locations.

4.5.4.1. Photovoltaic (PV)

Kenya is endowed with very high solar resources, among the highest of Sub-Saharan African countries. In favourable regions, the global horizontal irradiation (GHI) is up to 2,400 kWh/m²/year. The average GHI received and photovoltaic power potential in Kenya are shown in figure 16 and 17 respectively. Global Horizontal Irradiance is the total amount of shortwave radiation received from above by a horizontal surface. It is of particular interest to photovoltaic installations and includes both Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DIF).

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 at night. Short term fluctuations of weather conditions, including clouds and rainfall, impact the hourly amount of electricity that is produced.

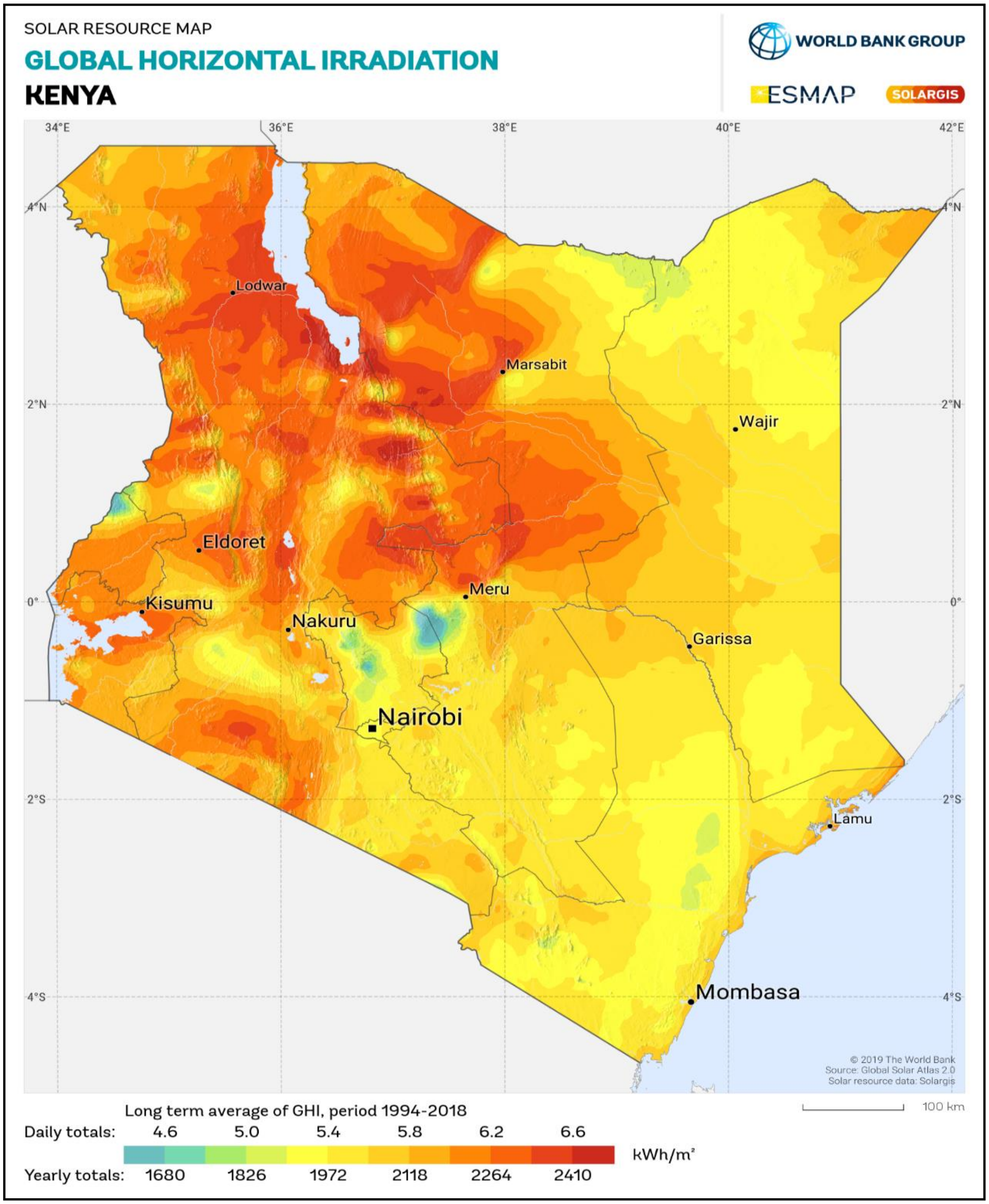


Figure 16 global horinzatal irradiation

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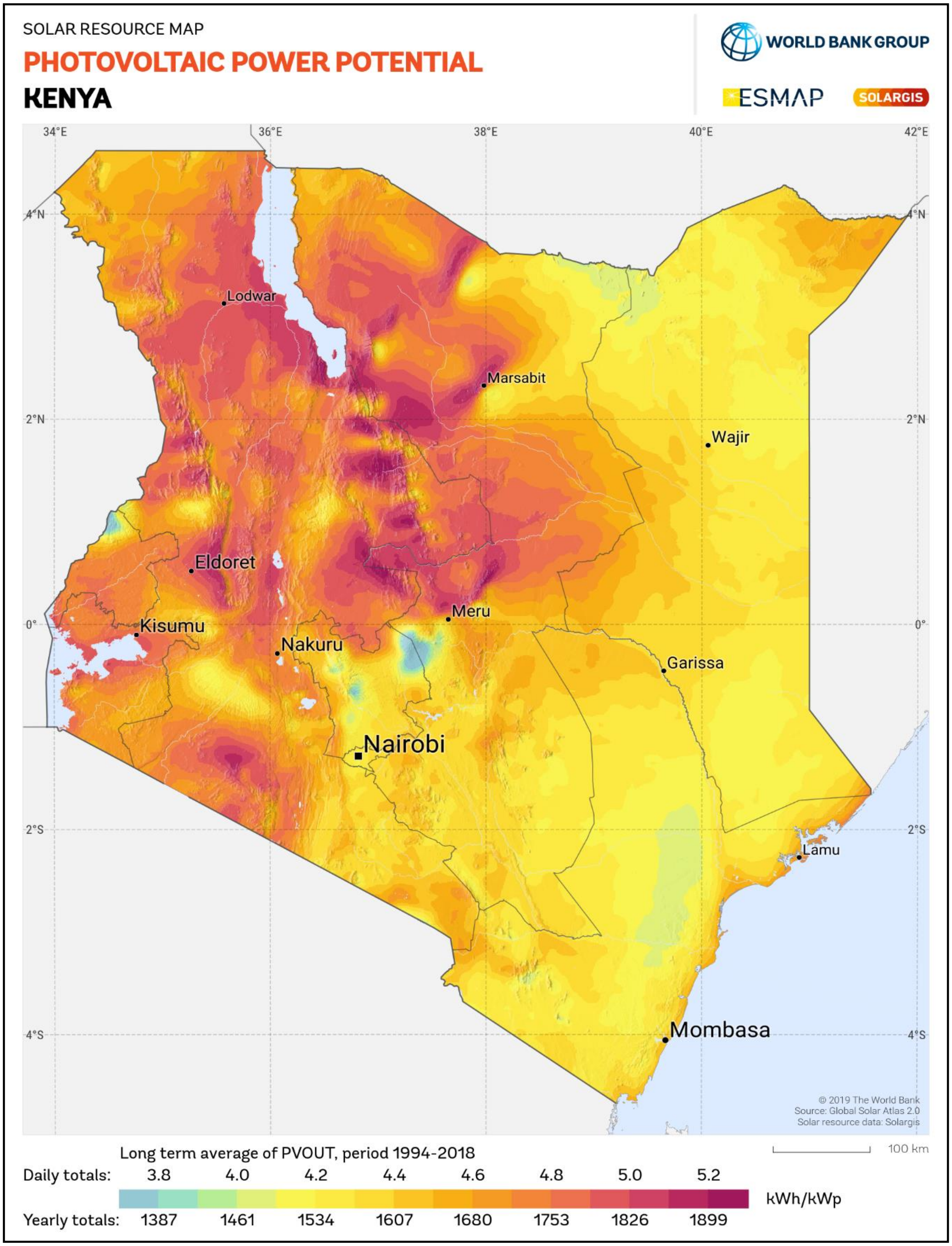


Figure 17 Photovoltaic power potential

4.5.4.2. 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 used to generate electricity in a steam turbine. CSP plants typically include a thermal energy storage system, which 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 significant as those of PV. CSP deployment is expected to increase rapidly when it becomes competitive with peak production costs.

CSP generation requires direct normal irradiation (DNI) to operate. Direct Normal Irradiance is the amount of solar radiation received per unit area by a surface that is always perpendicular (or normal) to the rays that come in a straight line from the direction of the sun at its current position in the sky. Typically, the amount of irradiance received can be maximized annually by keeping the surface normal to incoming radiation. This concept is of particular interest to concentrating solar thermal installations and installations that track the position of the sun. DNI received is approximately 2,300 kWh/m^2/year in favourable regions as shown in figure 18. However, there are presently no operational CSP plants in Kenya.

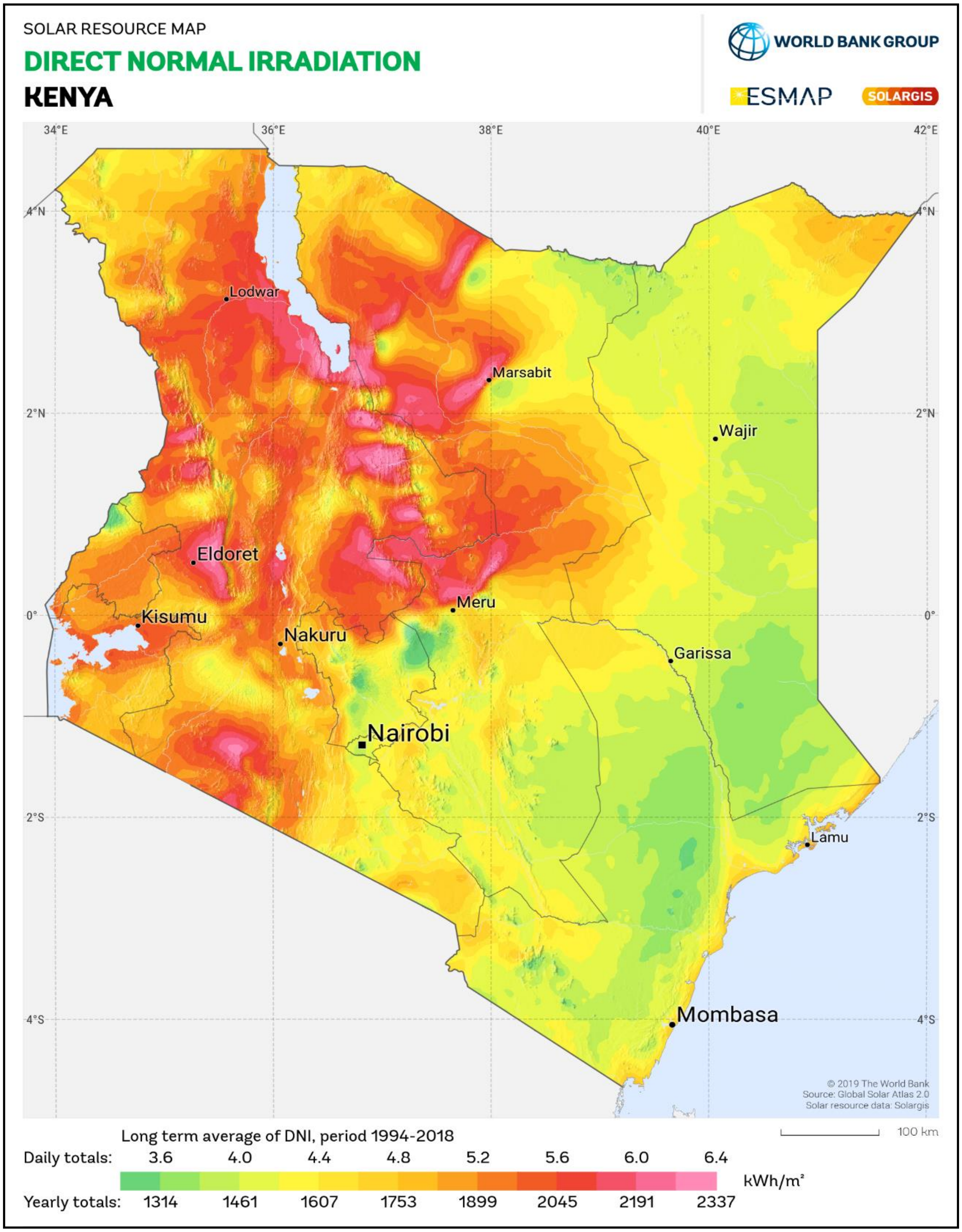


Figure 18 Direct normal irradiation in Kenya

4.5.5. 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 for heating or for power generation. Co-generation incorporates the simultaneous utilisation for both heating and electric power generation.

Solid biomass, rich in lignin, is 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 produced 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 anaerobic decomposition of organic material in landfill sites.

Municipal Solid Waste (MSW) constitutes a potential source of material and energy as well. Because of its heterogeneous components, it is necessary to pre-treat this waste (or collect it separated by source) before it can be used. The objective is to re-cycle 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 is 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. Presently, its use for power generation into the national electricity grid is being explored. 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 electric power production. Currently, some biogas power projects have been submitted for implementation under the FiT policy.

Biomass appears modest potential at present, but could increase significantly with the agro industrial development and mainly through revamping sugar mills 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.

4.6. Other energy sources

Other than the indigenous energy resources as a basis for power generation, there is 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. The country is also exploring the use of nuclear energy for power generation.

4.6.1. Battery Storage

The expected excess energy off peak hours and increased intermittent capacity in the national grid during present opportunity for introduction of battery storage to balance demand and supply in the system. This will assist in addressing the following in the grid:

(i) Frequency regulation reserves especially due to the relatively large proportion of variable renewable energy in the system.
(ii) Voltage instability in the system in some parts of the country.
(iii) Management of geothermal resources through reduction of steam venting.
(iv) Increased penetration of variable renewable energy (VRE) generation.
(v) Provide system security by supplying energy during the shortage in electricity generation.
(vi) Enable transmission and distribution replacement and deferrals as they reduce loading on the lines during peak times.

Given that costs are on the decline, it is notable that even within the African context where financing costs are sometimes higher, battery storage may compete with fossil thermal power especially where the storage facility derives multiple network services such as frequency regulation, load shifting and network reliability concurrently.

A comprehensive analysis is required for the Kenyan system followed by a comptetitive procurement process to obtain least cost prices for energy storage.

4.6.2. Nuclear Power

Nuclear power is an important contributor to the World electricity generation accounting for 2563 TWhs in 2018 (~12% of total electricity production). The growing awareness of benefits of nuclear power such as climate change mitigation and energy security, has resulted in increased interest in nuclear power for electricity production in several countries around the world including Kenya.

The total identified resource recoverable of uranium reserves worldwide are estimated at 6.14 million tonnes6 in 2017. At current consumption levels, these reserves would last more than 130 years7. Growing or diminishing future demand should affect the time taken for complete depletion of the resource. Nuclear energy is not a renewable energy. Currently, only low levels of uranium oxide have been discovered in Kenya. However, exploration of uranium is still on-going8.

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

6 World Nuclear Association

7 OECD Nuclear Energy Agency, International Atomic Energy Agency: Uranium 2018: Resources, Production and Demand

8 Power Generation and Transmission Master Plan, Kenya, 2016

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.

Compared to fossil fuels, the technology and investment costs required to build and operate a nuclear power plant (NPP) are significant in 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.

4.6.3. 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 via 132 kV transmission line and the other neighbouring countries via distribution lines. The purpose of these interconnections is to mutually support system stability (with Uganda) and to supply isolated areas in the border (with Tanzania and Ethiopia). With the objectives to increase transfer capacities, flexibility of grid operation and to improve sustainable electricity supply in Kenya, various interconnection projects are in the planning and implementation stages.

4.6.3.1. 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 under implementation and more projects are in the planning stage. The actual status of implementation and planning of interconnections is described below.

4.6.3.2. Interconnection with Ethiopia

The construction of a high voltage direct current (HVDC) overhead transmission line between Ethiopia and Kenya is already under development and will be completed in April 2020. The 500 KV line is constructed from Welayta Sodo in Ethiopia to Suswa in Kenya resulting in 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 site will be owned by Kenya Electricity Transmission Co. Ltd.

4.6.3.3. Interconnection with Uganda

It is planned to interconnect Kenya, Uganda and Rwanda on 400 kV level with the objective of enabling regional power trade. The interconnector between Kenya and Uganda is under construction.

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.

4.6.3.4. Interconnection with Tanzania

A 400 kV double circuit transmission line with a total length of 507.5 km between Tanzania and Kenya is in 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, pass Namanga and Arusha and terminate at Singida substation in Tanzania. The interconnector is designed for a capacity of 1,700 MW. On the Kenyan side, this project also includes the extension of the existing Isinya substation. The objective of this line is to support the market for power exchange within the EAPP as well as the interconnection with the Southern Africa Power Pool through Zambia.

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

5. EVALUATION OF POWER GENERATION EXPANSION PROJECTS

5.1. Objective

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

5.2. Technical parameters of hydro power plants/hydrological modelling

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 the 10 years preceding the simulations. 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, 2011/12 and 2016/17 financial years.

In the low hydrology case, 66% of the LTA hydrological conditions, which is equivalent to the worst-case scenario observed in previous ten years are considered in analyzing 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 which isadequate 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.

5.3. Fuel cost forecast

According to the International Energy Outlook 2019, global energy consumption is expected to increase almost 50% by 2050. Consumption is expected to skyrocket in India and China because of the high energy requirements by their intensive manufacturing sectors. Renewable energy (including wind, solar, and hydropower) is projected to be the world's fastest-growing form of energy over the next several decades (growing at a rate of over 3.1% per year). Despite that, fossil fuels are expected to meet most of the world's energy demand. Liquid fuels are expected to remain the primary energy source for transportation, but electric-powered transport, particularly for personal electric vehicles, is expected to grow in popularity. Below is an overview of some of the fuels forecasted in this chapter.

5.3.1. Coal

According to International Energy Agency, Coal remains a major fuel in global energy systems, accounting for almost 40% of electricity generation and more than 40% of energy-related carbon dioxide emissions. This is despite the growing prominence of renewable energy sources. Global coal demand increased by approximately 1.1% in 2019, continuing the rebound that began in 2017 after three years of decline. The main driver was coal power generation, which rose almost 2% in 2019 to reach an all-time high. It is however expected that demand for coal will remain under pressure due to strong uptake of renewables-based capacity and, in the United States, the availability of inexpensive natural gas.

One of the most important coal markets is China, due to its large share in both global coal demand and production. Any significant shifts in Chinese coal usage or output has an immediate effect on other world's markets. Although China's coal demand increased marginally since the rebound in 2017, the country is increasing its efforts to reduce coal's share in its energy mix. A large amount of coal-fired capacity was taken offline in 2017 in order to reduce local pollution. Many of those plants were smaller, old and inefficient coal-fired units, using mostly low-quality coal, thus, contributing significantly to local air pollution. This is part of a broader plan to cap coal-fired capacity at 1,100 gigawatts (GW) by 2020. Furthermore, the Chinese government has decided to stop or delay more than 100 GW of previously planned and under construction coal power projects by 2020. This is in line with the series of medium to long-term actions that the government is taking to achieve its 13th Five Year Plan (FYP) climate related goals.

5.3.2. Crude Oil

Oil markets are going through a period of extraordinary change as the United States is increasingly leading the expansion of global oil supplies, and demand is shifting from developed economies and transportation fuels to Asia and petrochemicals.

Fundamentally, oil demand depends on the strength of the global economy - in particular the expansion of developing economies such as China and India. At the same time, around the world, increasing consumer demand means more plastic, which in turn means more petrochemicals. Despite efforts to curb plastics use and encourage recycling, demand for plastics and petrochemicals is growing strongly. Another major growth sector is aviation. In recent years, the air travel industry has witnessed a spectacular expansion thanks to rising passenger numbers.

The rise of electric vehicles and improvements in battery pack technology is believed to expose global oil demand under an imminent threat. About a third of global oil demand is from cars, and 40 percent of the growth since the year 2000 has come from cars. Electric Vehicles are expected to be 30% of new car sales by 2040 from 1% in 2019. In 2017, there were 2.8 million electric cars on the road compared to 1.5 billion oil fueled vehicles, and they could reach 36 million by 2025.

5.3.3. Nuclear

Uranium has the advantage of being highly concentrated source of energy which is cheap and easy to transport. A kilogram of natural uranium will yield approximately 20,000 as much energy as the same amount of coal.

Uranium is also available in abundance. The contribution of fuel to the overall cost of electricity generated from nuclear power plants is relatively small. Low fuel costs give nuclear energy an edge over other fossil fired plants. Uranium, however, has to be processed, enriched and fabricated into fuel elements. This constitutes half the total fuel cost.

The world's power reactors with a combined capacity of approximately 400GWe require 65,000 tons of uranium each year. The uranium fuel requirement is increasing but the factors increasing fuel demand are offset by the trend for higher burnup of fuel and other efficiencies, so demand is steady.

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.

5.3.4. Natural Gas

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane (CH4). It is the cleanest fossil fuel. Natural gas prices consist of two main components which include various taxes and fees:

Commodity cost – The cost of the natural gas itself, either as produced natural gas or as natural gas purchased at a market trading hub or under a contract by marketers and utilities.

Transmission and distribution costs – The costs to move the natural gas by tankers and pipeline from where it is produced or stored to local natural gas distribution utilities and the cost to deliver it to consumers.

Table 20 Forecast assumptions

Product	Data sources	Assumptions & parameters
Crude oil	EPRA Historical data on Murban crude prices WTI Crude Price forecast: https://www.barchart.com/futures/quotes/CL*0/futures-prices	Historical correlation exists between EPRA and WTI Crude prices Adopted WTI crude forecast between 2020 & 2030 Adopted average growth of 0.67% to forecast for period between 2031 & 2040 0.67% growth is derived from the average growth rate between 2020 & 2030
Coal	ICE Richards Bay Coal Prices FOB South Africa https://www.barchart.com/futures/quotes/LVY00/futures-prices	Adopted ICE Richards Bay Coal Price projects for period between 2020 & 2025. Average growth rate of -3.47% has been used to forecast the period between 2025 & 2040 -3.47% is based on a 5yr average growth rate between 2019 and 2025
Gasoline	2015-2035 Electricity Masterplan by Lahmeyer International	A historical high correlation (99%) between gasoline and crude prices has been observed. Therefore the price of gasoline is assumed to be 135% of the crude price
HFO	2015-2035 Electricity Masterplan by Lahmeyer International	A historical high correlation (98%) between gasoline and crude prices has been observed. Therefore the price of gasoline is assumed to be 75% of the crude price
Natural Gas	BP Statistics Review World Energy 2019,	Adopted historical Average German Import Price at FOB for the period 1988 to 2018 Adopted a 15yr average growth rate of 6% between 2004 & 2018.
LNG	BP Statistics Review World Energy 2019,	Adopted historical LNG Japan Price at CIF for the period 1988 to 2018 Adopted a 10yr average growth rate of 1.5% between 2009 & 2019.

Uranium	https://atb.nrel.gov/electricity/2019/index.html?t=cc www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf www.world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx http://euanmearns.com/how-long-does-it-take-to-build-a-nuclear-power-plant/	The fuel cost ($) per GJ ($/GJ) was computed to $1.08/GJ. This price was adopted over the planning period (2019 - 2039). The fixed and variable OM costs for the 600MWand 1000MW used were the same.

5.4. Assumptions on transport costs

International and national transport costs have to be considered in order to calculate the actual fuel costs at the respective power plants. On top of the international fuel prices (FOB), corresponding transport prices, have to be considered to reflect the import prices applicable at Kenya's border. Similarly, domestic transport costs have been considered to reflect the fuel prices at the major towns.

Table 21:International shipping cost assumptions

Fuel	Assumption	Data Source
Crude oil	5% mark-up on FOB	2015-2035 Masterplan Assumptions by Lahmeyer International
HFO	13% mark-up on FOB	
Gasoil	4% mark-up on FOB	
Coal	7 USD/ton	

5.5. Domestic Shipping cost assumptions

KPC has had four pipeline tariff adjustments since 1994. The first review was in 2009 when the tariff was increased by 47% from Kshs 3.40/M^3/km through a phased adjustment to Kshs 4.50/M^3/km effective April 2009 and Kshs 5.00/M^3/km effective April 2010. The third adjustment was in April 2016 when the Energy and Petroleum Regulatory Authority advised the Minister to approve a 4.4% increase to Kshs 5.22/M^3/km effective June 2016 for a three-year period. The current tariff averages at Kshs 3.93/M^3/km and will run through to 2020.

The pipeline tariff forecast has adopted the historical average growth of 2% between the tariff control periods since 1994. Similarly, a constant trucking cost of USD 49/ton has been adopted over the planning period. The distances considered between Mombasa and Nairobi is 487 km and a distance of 798 km from Mombasa to Eldoret. These distances are based on the current pricing formula used by EPRA in computation of maximum petroleum pump prices.

5.6. Fuel Forecast Results

WTI Crude and LNG prices are expected to rise in 2020 then gradually dip to a minimum in 2023. From 2023, the prices are expected to rise gradually through 2039 at a rate of 0.67%. This behavior is attributable to increased oil and gas demand due to global economic growth and industrial production. See figure 20

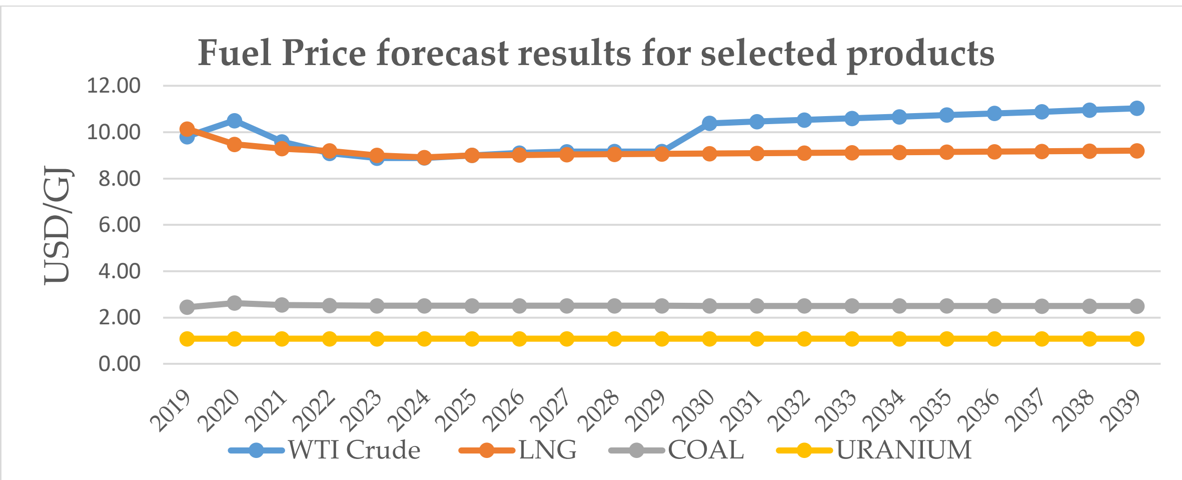


Figure 19 Fuel Price forcast for selected products

Nuclear fuel, Uranium, has a very high calorific value, and improved technology has led to fuel burn up increase by over 50%. This means that less fuel is required to get an equivalent amount of power.

The cost of uranium is assumed to remain relatively constant at $1.08/GJ because it is supplied under long term contracts since the demand is much more predictable. Uranium is also abundant hence the stable prices.

Coal sold for electric power generation is sold through long term contracts and supplemented with spot purchases. The spot prices are more vulnerable to short term market conditions.

In addition to electricity generation, coal is also used to produce coke which is used in smelting iron ore to make steel. Coal prices have been changing at an average rate of -3.57%. This change is attributable to the fact that coal is mainly used for power generation and there is a global shift from coal power generation to renewable and cleaner sources of electricity generation like wind, solar, geothermal, nuclear etc.

5.7. Screening curve analysis

Screening curves were constructed for selected Thermals, Nuclear, Coal, Geothermal, Imports and Hydro Candidate plants. The screening curve technique is an approximate method that captures major tradeoffs between capital costs, operating costs and utilization levels for various types of generating capacity in the system. The screening curve method expresses the total annualized electricity production cost for a generating unit, including all capital and operating expenses, as a function of the unit capacity factor. This approach is especially useful for quick comparative analyses of relative costs of different electricity generation technologies.

Also assumed in the screening model is a discount factor of 10% and an exchange rate of Ksh/$ 101. However, a sensitivity analysis at a discount rate of 8% was carried out. The results of the sensitivity analysis are discussed under screening results.

Table 22:List of screened candidates

Candidate	Technology	Capacity (MW)
KenGen Olkaria	Geothermal	140
GDC-Silali	Geothermal	140
Generic Coal	Coal	300
Lamu Coal	Coal	981
Kitui Coal	Coal	960
Nuclear Unit 1	Nuclear	600
Nuclear Unit 2	Nuclear	1000
High Grand Falls	Hydro	495
Karura	Hydro	90

Ethiopia HVDC	Import	200
Wajir CCGT	Natural Gas	375
KenGen LNG	LNG	200
Medium Speed Diesel	Thermal	80

Table 23 Techno-economic Data for screend projects

	Geothermal-Olkaria KenGen	**Geothermal-Silali**	**Nuclear 1**	**Nuclear 2**	**Coal**	**Kitui Coal**	**Lamu Coal**	**GT- LNG KenGen**	**Wajir CCGT**	**MSD**	**Import**	**Karura**	**HGFalls**
Configuration (n x MW)	1 x 140	1 x 140	(1 X 600)	(1 X 1000)	2 X 150	3 X 320	3 X 327	2 x 100	3 x 125	1 x 80	200	2 X 45	5 X 99
Total Capacity (MW)	140	140	600	1000	300	960	981	200	375	80	200	90	495
Economic Life	25	25	60	60	30	30	30	25	20	20	25	40	40
Construction Period (yrs)	7	7	8	8	5	5	5	3	3	3	Complete	5	7
Maintenance schedule	2.0	2.0	2.9	2.9	4.3	4.3	4.3	3.6	3.6	2.0	0	4.3	4.2
Fixed Cost													
Capital ($ x 10^6)	511	481	3900	5900	828	2331	2504	137	506	132		342	1891
Capital ($/kW)	3650	3439	6500	5900	2760	2428	2553	686	1349	1650		3798	3820
Annuity Factor (or C.R.F.)	0.1102	0.1102	0.1003	0.1003	0.1061	0.1061	0.1061	0.1102	0.1175	0.1175		0.1023	0.1023
Interim Replacement	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	0.35%	0.35%	0.35%		1.05%	1.05%
Fixed Annual Capital ($/kW/yr)	542.5	511.1	1052.3	955.2	412.8	363.1	381.7	85.1	179.7	221.9		539.3	566.6
Fixed O&M Costs ($/kW/yr)	151.9	151.9	66.3	66.3	51	69	68	20.9	18.0	7.1		15.3	16.0
Total Fixed Annual Cost ($/kW/yr)	694	663	1119	1021	464	432	450	106	198	229		555	583
Total Outage Rate	0.0585	0.0585	0.1049	0.1049	0.1324	0.1324	0.1324	0.0987	0.0987	0.0785		0.1024	0.1024
Annual Fixed Cost ($/kW/yr)	**737**	**704**	**1250**	**1141**	**534**	**498**	**519**	**118**	**219**	**248**	**521**	**618**	**649**
Annual Fixed Cost ($/kWh)	**0.0842**	**0.0804**	**0.1427**	**0.1303**	**0.0610**	**0.0569**	**0.0592**	**0.0134**	**0.0250**	**0.0284**	**0.0595**	**0.0705**	**0.0741**
Variable Cost													
Fuel Price ($/GJ)	-	-	1.08	1.08	3.109	3.109	3.109	11.29	6.33	8.63	-	-	-
Heat Rate (kJ/kWh)	10,700.00	10,700.00	9,231.30	9,231.30	10,159	10,159	9,338	12,740	12,740	12,653	-	-	-
Fuel Cost ($/kWh)	0.00	0.00	0.01	0.01	0.03	0.03	0.03	0.14	0.08	0.11	0.00	0.00	0.00
Variable O&M ($/kWh)	0.00000	0.00000	0.000	0.000	0.0050	0.0046	0.0046	0.0036	0.0036	0.0060	-	0.0005	0.0005
Total Variable ($/kWh)	**0.00000**	**0.00000**	**0.0105**	**0.0105**	**0.0366**	**0.0362**	**0.0336**	**0.1474**	**0.0843**	**0.1153**	**0.0000**	**0.0005**	**0.0005**
Total Variable ($/kW/yr)	**0**	**0**	**92**	**92**	**320**	**317**	**295**	**1292**	**738**	**1010**	**0**	**4**	**4**

5.8. Results of the Screening Analysis

The results of the screening curves indicated Gas Turbines running on LNG and MSD Plants are cheaper when run at very low capacity factors. This means that they are more suitable to serve as peaking plants. At very high plant utilization levels, these plants are more expensive due to associated higher variable costs. See figure 21 & 22

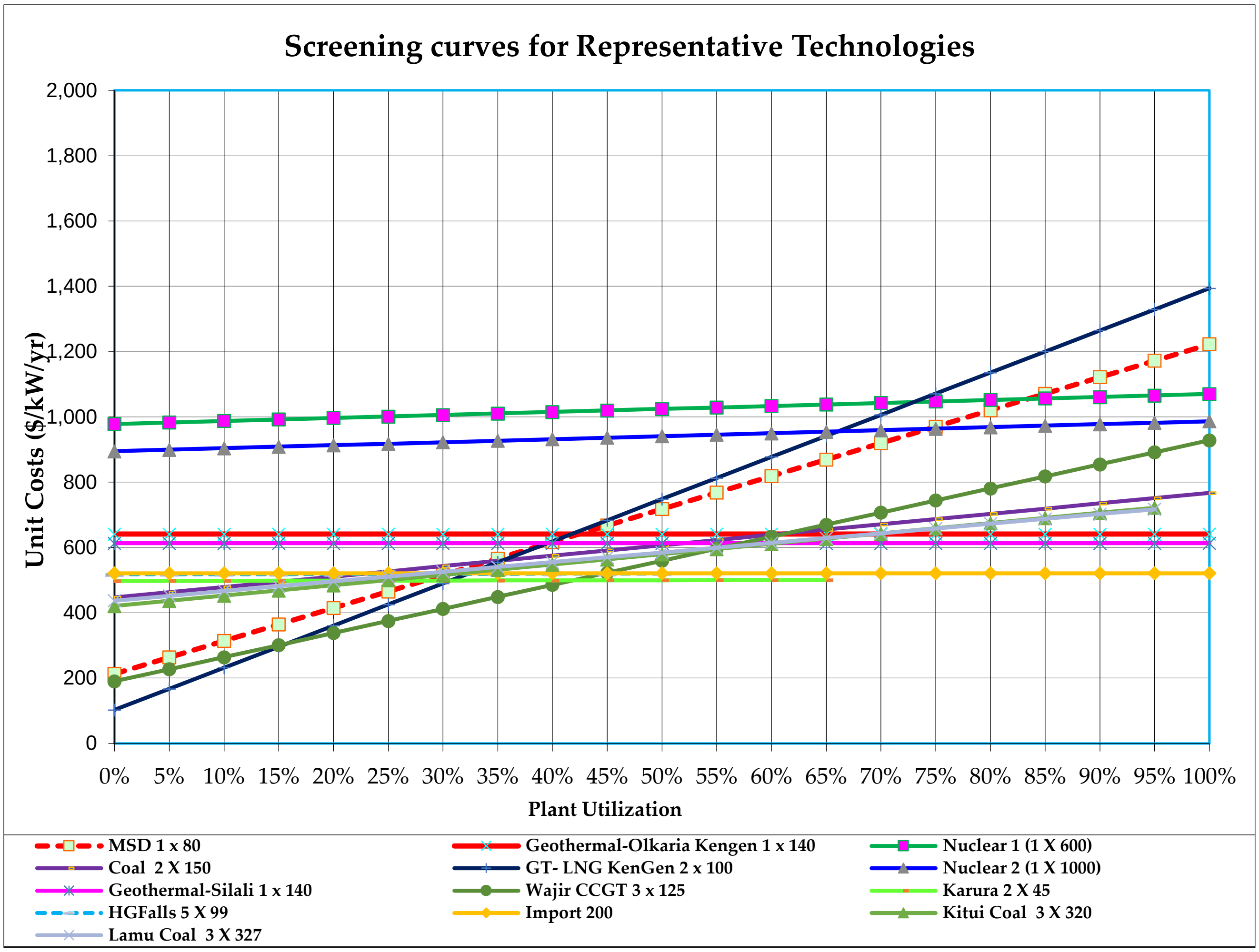


Figure 20 Results of screening analysis

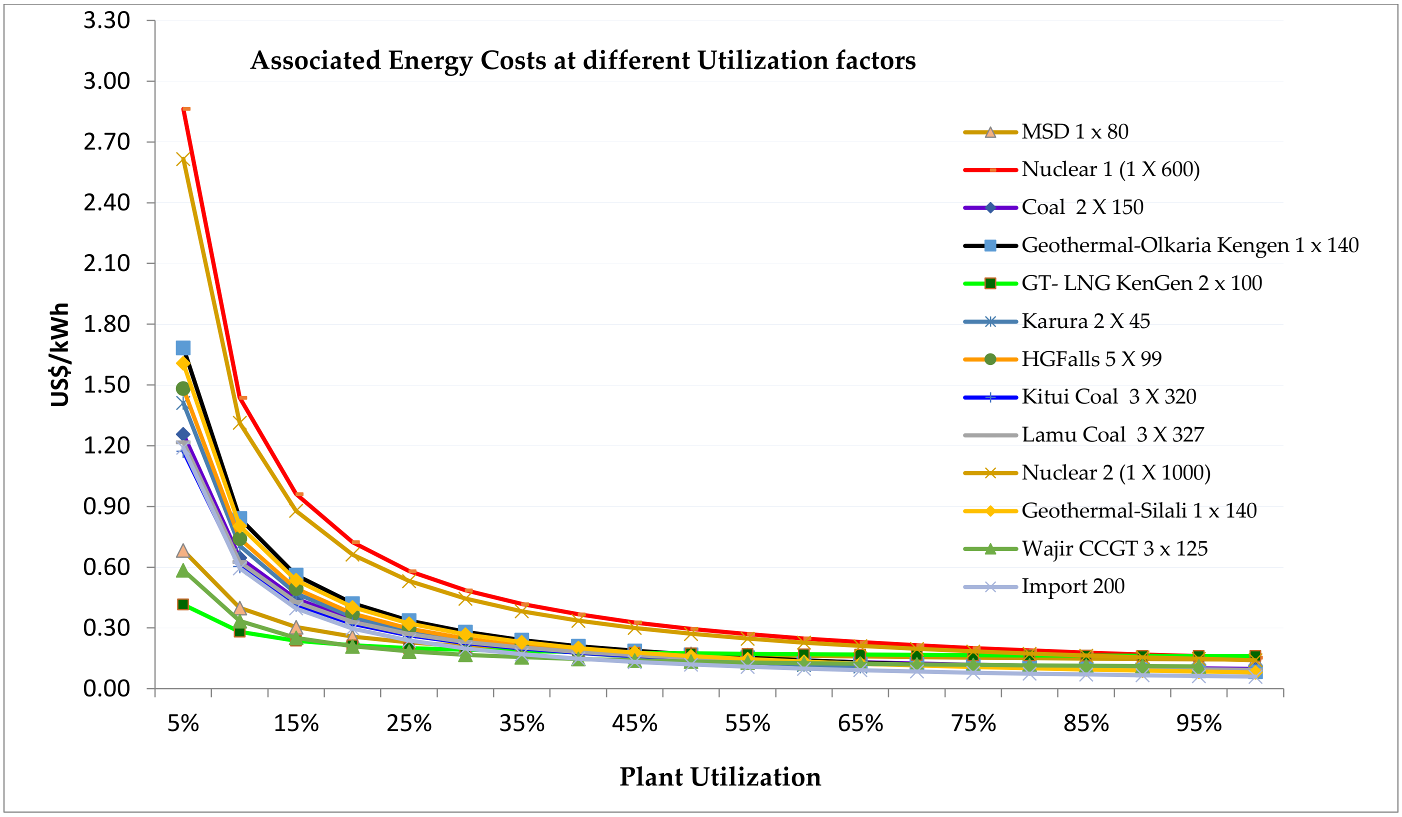


Figure 21 Associated Energy costs at different plant utilization level

On the other hand, Nuclear Power Plants, are very expensive when run at very low capacity factors. As the plants are run at higher and higher utilization levels, the cost of running them is relatively constant due to low fuel costs and associated variable costs. It would therefore make no economic sense to run these plants at low capacity factors while they can comfortably serve as base loads.

Geothermal and hydro plants also serve as base load plants and are relatively cheaper compared to nuclear plants and thus rank higher in the merit order. It is therefore advisable to run these technologies exhaustively before turning to Nuclear Plants.

5.9. Sensitivity Analysis

If concessional funding is available for public utilities, the cost of financing will be lower. Then, the unit cost for various technologies would considerably come down. The model adopted a lower discount factor of 8% which brings down the energy costs across the technologies by more than 50%.

6. GENERATION EXPANSION PLANNING

This chapter provides an overview of the generation expansion planning approach, the expansion scenarios modelled and the results obtained from the various simulations carried out. It also presents the recommended national generation expansion plan for the period 2020-2040. The expansion plan adopted as the least cost plan forms the basis for preparation of a power transmission plan

6.1. Generation expansion planning approach

6.1. Generation expansion planning approach

The LIPS-XP/OP tool was used to model the power system. Respective input data for power plants, hourly electricity demand forecasts and planning criteria were updated. Key modelling parameters include capital investment costs for each power plant, fuel cost, fixed and variable operations and maintenance costs, economic life and planned commissioning and decommissioning dates for the power plants. Simulations were done on the cases assembled based on various assumptions. The modelling assumptions and inputs are further discussed below.

6.2. Existing and Committed Generation Plants

6.2.1 Existing Generation Plants

The interconnected system effective generation capacity was 2,654MW as at December 2020, against a peak demand of 1,976MW. KenGen, the largest power generator in the country, accounted for 1,742 MW of the industry's installed generation capacity, and the Independent Power Producers (IPPs) 946MW. Annex 1 shows the existing plants with their commissioning and planned decommissioning dates.

6.2.2. Committed Generation Projects

Committed projects are defined as those with PPAs and for KenGen as approved by EPRA. These projects are listed in table 24. From the list, projects that are advanced in development and have commenced construction were identified as indicated in table 25. The total capacity of committed projects was 2,839 MW for the optimised and fixed cases respectively.

Table 24 Committed Projects

	Project Company	**Capacity (MW)**	**Technology**	PPA DATE	Optimised Case COD	Fixed case COD
1	Kleen Energy Limited	6	Hydro	Dec-20	2022	2022
2	Hydro Project Service Peters Kianthumbi	0.51	Hydro	Apr-21	2021	2021
3	KTDA - Nyambunde, Nyakwana	0.5	Hydro	Jun-21	2022	2022
4	KTDA Ltd, South Maara (Greater Meru Power Co.)	1.5	Hydro	Dec-21	2022	2022
5	KTDA Ltd, Lower Nyamindi	0.8	Hydro	Dec-21	2022	2022
6	KTDA Ltd, Iraru	1	Hydro	Dec-21	2022	2022
7	Power Technologies (Gatiki Small Hydro Plant)	9.6	Hydro	Jun-22	2022	2022
8	Mt Kenya Community Based Organisation	0.6	Hydro	Dec-22	2023	2023
9	Tindinyo Falls Resort	1.5	Hydro	Jun-23	2023	2023
10	Frontier Investment Management/ Nithi Hydro	5.6	Hydro	Dec-24	2025	2025
11	KTDA, Kipsonoi (Settet Power Co.)	0.6	Hydro	Feb-25	2025	2025
12	Global Sustainable-Kaptis	14.7	Hydro	Dec-25	2026	2026
13	Global Sustainable Ltd-Buchangu	4.5	Hydro	Dec-25	2026	2026
	Total Hydro	**47MW**				
14	Cummins Cogeneration Kenya Limited	10	Biomass	Jun-20	2023	2023
15	REA Vipingo Plantations Ltd (DWA Estates Ltd)	1.44	Biomass	Dec-20	2022	2022
16	Kwale Int. Sugar Co. Ltd	10	Biomass	Dec-21	2023	2023

17	Thika Way Investments (Homa Bay Biogas One)	8	Biogas	Jun-23	2023	2023
18	Roadtech Solutions Ltd	10	Biomass	Dec-24	2025	2025
	Total Biomass/Biogas	**39MW**				
19	Kipeto Energy Limited	100	Wind	Jul-21	2021	2021
20	Chania Green	50	Wind	May-22	2024	2024
21	Aperture Green Power Ltd / Limuru Wind	50	Wind	Dec-22	2026	2023
22	Bahari Winds (Electrawinds Kenya)	50	Wind	Dec-24	2028	2025
23	Bahari Winds (Electrawinds Kenya)	40	Wind	Dec-25	2029	2026
24	Prunus Energy	50	Wind	Dec-25	2029	2026
	Total Wind	**340MW**				
25	Marco Borero Co Ltd.	1.5	Solar	Jun-20	2022	2022
26	Alten Kenya Limited	40	Solar	May-21	2024	2022
27	Selenkei (Radiant)	40	Solar	Dec-21	2022	2022
28	Eldosol (Cedate)	40	Solar	Dec-21	2023	2022
29	Hannan Arya Energy (K) Ltd	10	Solar	Dec-21	2027	2023
30	Vateki International Holdings /Malindi Solar Limited	40	Solar	Jan-22	2023	2022
31	Kenergy Renewables Ltd-Rumuruti	40	Solar	Dec-22	2028	2023
32	Kopere Solar Park Limited	40	Solar	Jun-23	2024	2023
33	Dafre Holdings Company Ltd /Makindu solar ltd	30	Solar	Dec-23	2029	2024
34	Seven Forks Solar Power Plant	42.5	Solar	Jun-24	2026	2024
35	Greenmillenia Energy Limited	40	Solar	Dec-25	2030	2026
36	Sun Power Kenya Limited (Kibwezi)	40	Solar	Jun-26	2030	2026
	Total Solar	**404MW**				
36	Olkaria I Unit 6	83	Geothermal	Jul-21	2021	2021
38	Sosian-Menengai Geothermal Power Ltd	35	Geothermal	Dec-21	2023	2023
39	Quantum/QPEA GT Menengai Limited (Menengai)	35	Geothermal	Jan-22	2023	2023
40	Orpower 22 (Menengai)	32.5	Geothermal	Jun-22	2023	2023

41	Olkaria I AU/IV Uprating Unit 4	10	Geothermal	Jul-22	2025	2023
42	Olkaria I AU/IV Uprating Unit 5	10	Geothermal	Jun-23	2025	2023
43	Olkaria I AU/IV Uprating Unit 1	10	Geothermal	Sep-22	2026	2023
44	Olkaria I AU/IV Uprating Unit 2	10	Geothermal	Jul-23	2026	2023
45	Olkaria I Rehab unit 1	16.9	Geothermal	May-23	2026	2023
46	Olkaria I Rehab unit 2	16.9	Geothermal	Dec-23	2027	2024
47	Olkaria I Rehab unit 3	16.9	Geothermal	Apr-24	2027	2024
48	Olkaria VI(PPP)	140	Geothermal	Jun-24	2029	2024
49	Akiira Geothermal Ltd & Marine Power Generation Company Ltd	70	Geothermal	Jun-25	2031	2025
50	Africa Geothermal International (Kenya) Ltd - AGIL	140	Geothermal	Jun-25	2029-39	2026-29
	Total Geothermal	**626MW**				
51	Amu Coal	981.5	Coal	Dec-26	2037	2027
52	Ethiopia HVDC phase 1	200	import	Jul-21	2021	2021
53	Ethiopia HVDC phase 2	200	import	Jul-24		
	Total	**2839MW**				

Table 25 Candidate Projects

No	Project Company	Capacity (MW)	Technology	Aproved COD	Optimised case COD	Fixed Case COD
1	Hydel	5	Hydro	Dec-20	2027	2027
2	Mutunguru Hydroelectric Company Ltd	7.8	Hydro	Dec-20	2027	2027
3	Ventus Energy Ltd	7.67	Hydro	Dec-21	2028	2028
4	Mwikhupo-Mwibale Hydro Power Kenya	7	Hydro	Dec-22	2029	2029
5	Raising Masinga	0	Hydro	Jun-23	2023	2023
6	Njega/Rukenya Hydro Power Limited (Rights transfer)	3.5	Hydro	Dec-23	2030	2030
7	Greenlight Holdings/ Rianjue/Gichuki Ventures	1.5	Hydro	Dec-23	2030	2030
8	Virunga Power Holdings Ltd, R. Sossio, Kaptama	4.5	Hydro	Dec-23	2030	2030

No	Project Company	Capacity (MW)	Technology	Aproved COD	Optimised case COD	Fixed Case COD
9	Karuga Gitugi Electrification Project	2.7	Hydro	Dec-24	2032	2032
10	Kibisi Kinetic Energy Limited/Virunga Power Holdings	6.5	Hydro	Jan-24	2031	2031
11	Rareh Nyamindi Hydro Ltd	5.2	Hydro	Jan-24	2031	2031
12	Rareh Nyamindi Hydro Ltd	9.4	Hydro	Jan-24	2031	2031
13	Rareh Nyamindi Hydro Ltd	6	Hydro	Jan-24	2031	2031
14	VSHydro Kenya Ltd	9.1	Hydro	Jan-24	2031	2031
15	Kirogori Electrification Project	7	Hydro	Jun-24	2031	2031
16	KTDA R. Chemosit, Chemosit	2.5	Hydro	Jun-24	2031	2031
17	KTDA Chemosit, Kiptiget	3.3	Hydro	Dec-24	2032	2032
18	KTDA Ltd, Yurith, Chemosit	0.9	Hydro	Dec-24	2032	2032
19	KTDA R. Rupingazi, Rutune	1.8	Hydro	Dec-24	2032	2032
20	KTDA, R. Itare, Chemosit	1.3	Hydro	Dec-24	2032	2032
21	KTDA, R. Yala, Taunet	2.77	Hydro	Dec-24	2032	2032
22	Tridax Limited	4.2	Hydro	Dec-24	2032	2032
23	Truck city ltd	5.28	Hydro	Dec-24	2032	2032
24	Karura Hydro Power Plant	90	Hydro	Dec-24	2026	2026
25	Gogo upgrade	12	Hydro	Dec-24	2025	2025
26	Khalala Hydro Power Kenya Limited (Coastal Energy Ltd, Navakholo)	20	Hydro	Dec-25	2033	2033
27	Dominion Farms	1	Hydro	Dec-25	2033	2033
28	Chevron Africa Limited	7.8	Hydro	Dec-25	2033	2033
29	Njumbi Hydropower Plant Ltd (Hydroneo)	9.6	Hydro	Dec-25	2033	2033
30	High Grand Falls Multipurpose Project	693	Hydro	Dec-25	2037	
	Total Hydro	**938MW**				
31	Sukari Industries Ltd	22	Biomass	Dec-19	2026	2026
32	VR Holding AB-Local Trade Ltd	3	Biomass	Dec-21	2027	2027
33	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	20	Biogas	Jun-22	2028	2028

No	Project Company	Capacity (MW)	Technology	Aproved COD	Optimised case COD	Fixed Case COD
34	Municipal Waste to Energy	30	Biomass	Dec-22	2023	2023
35	West Kenya Sugar Company Limited	6	Biomass	Mar-23	2029	2029
36	Ray Power Limited	35	Biomass	Jun-23	2029	2029
37	Sustainable Energy Management	40	Biomass	Jan-24	2030	2030
38	Crystal Energy Solutions (Kavuko Power Ltd)	40	Biomass	Dec-24	2031	2031
39	Viability Africa (Northern Energy Limited)	2.4	Biomass	Dec-24	2031	2031
	Total Biogas/Biomass	**198MW**				
40	Ngong 1 Phase III	11	Wind	Dec-23	2026	2023
41	Marsabit Phase 1	100	Wind	Dec-24	2028	2028
42	Meru Wind Phase I	80	Wind	Dec-25	2031	2027
43	Marsabit Phase 2	200	Wind	Dec-28	2031	2030
	Total Wind	**391MW**				
44	Brine power Production	15	Geothermal	Jun-22	2033	2033
45	Paka I Wellhead	10	Geothermal	Dec-22	2036	
46	Olkaria VII	140	Geothermal	Dec-23	2033	2034
47	Menengai 1 Stage 2	60	Geothermal	Dec-23	2027	2035
48	Korosi 1 Well head	10	Geothermal	Dec-23	2036	
49	Eburru Geothermal	25	Geothermal	Jun-24	2027	2035
50	Wellhead Modular Plants	55	Geothermal	Jun-24	2027	2034
51	Menengai 1 Wellhead	10	Geothermal	Dec-24	2036	
52	Baringo-Silali - Korosi	100	Geothermal	Jun-25	2028	2034
53	Wellhead Leasing	50	Geothermal	Jun-25	2034	2035
54	Orpower IV	50	Geothermal	Jun-25	2029	2035
55	Olkaria VIII	140	Geothermal	Dec-25	2039	2037
56	Baringo-Silali - Paka I	100	Geothermal	Jun-26	2032	2034
57	Olkaria IX	140	Geothermal	Dec-26	2040	2040
58	Baringo-Silali - Silali	100	Geothermal	Dec-26	2032	2036
59	Suswa 1	100	Geothermal	Dec-27	2035	2035
60	Suswa 2	100	Geothermal	Dec-29	2035	2036
61	Menegai III	100	Geothermal	Dec-29	2034	2036
62	Suswa 3	100	Geothermal	Jun-30	2040	2037
63	Menengai IV	100	Geothermal	Dec-30	2035	2037
64	Menengai V	100	Geothermal	Dec-30	2035	2038
	Total Geothermal	**1605MW**				
65	LNG Gas Turbine	200	LNG	Dec-22	2024	2024
66	Dongo Kundu	375	LNG		2036	2036

No	Project Company	Capacity (MW)	Technology	Aproved COD	Optimised case COD	Fixed Case COD
67	Dongo Kundu	375	LNG		2038	2038
	Total LNG	**950MW**				
68	Nuclear Power Generation	600	Nuclear	2035	0	2039
69	Battery Storage South Nyanza	50	Storage		2022	2022
70	Pumped Hydro Storage	300	Hydro	Dec-25	2024	2024
	Grand Total	**5,033MW**				

6.3. Planning Criteria and Modelling assumptions

The key planning assumptions and criteria applied relate to plant availability and generation, planning reserves, intermittent energy balancing and hydrological forecasts

6.3.1. Plant availability and energy generation

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

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

Wind: 50% in 2020-2021 to cater for generation from Lake Turkana Wind Park (LTWP), 45% in 2022-2023 and 35% 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 2019 annual load curve was developed and retained throughout the study plan as no major assumption was made to vary the profiles.

6.3.2. Reserve requirements

In LIPS-XP planning tool, 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 while considering a reserve margin which is composed of the following parts:

- The reserve margin to cover the loss of the largest unit in the system.
- Cold reserves for balancing occasional unavailability of power plants due to planned maintenance and forced outages

6.3.3. Loss of load probability (LOLP)

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

6.3.4. Spinning Reserves Requirement

Spinning reserves provide system stability through load-following, wind/solar balancing, and generating power in case of an outage. For operational considerations, reserve requirements are typically divided into two categories according to the delay acceptable in their availability:

1) **Primary reserve** allows for urgent measures to maintain system frequency by fast actions of committed units (within a few seconds).

2) **Secondary reserve** is needed for covering deviations from the scheduled load demand with a delay of a couple of minutes in order to allow for the ramp-up of not yet committed units.

6.3.5. Operational Reserves for Wind and Solar Balancing

The spinning reserves requirement for all the intermittent renewables was estimated at 15% based on previous studies. However, when the intermittent renewable plants are geographically dispersed then the variability tends to reduce. The variability of the largest wind farm and solar farms are considered in this analysis to arrive at the operational spinning reserve requirements.

6.3.6 Expansion Planning Reserve Margins

The spinning reserves requirement for all the intermittent renewables was estimated at 15% based on previous studies. However, when the intermittent renewable plants are geographically dispersed then the variability tends to reduce. The variability of the largest wind farm and solar farms are considered in this analysis to arrive at the operational spinning reserve requirements.

6.3.7. Hydrology forecast

This study considered long-term monthly major hydropower plants production for a period of 10 years, 2010-2019. The firm capacity of hydropower plants is defined as the P90 exceedance probability value determined based on historic half hourly production data shown in annex 2.

6.4. Generation Expansion Simulations using LIPS-OP/XP

The generation expansion was simulated based on Optimised case and Fixed system case, each with a base discount rate of 12% and assuming average hydrology.

a) **Optimised case**- adopted as the basis for the least cost expansion plan, considering only projects under construction within the medium term (2020-2025) as committed, all other projects with PPAs, KenGen's approved projects, and small hydro and cogeneration projects with CODs were optimised for the rest of the planning period. The Optimised case was based on Reference demand growth.

b) **Fixed system case** – adopted committed projects as projects with PPAs, and KenGen projects as approved by EPRA. All the projects were simulated based on respective PPA date and status of development. Projects with CODs but without PPAs were modelled as candidates and optimised beyond the medium term. The Fixed case considered the Reference, Vision and Low demand growth scenarios

6.5. Results for Generation Expansion Scenarios Simulations

This section presents the results of the optimised case and the fixed system case considered in the generation expansion scenarios.

6.5.1. Optimised Case – Reference demand

The demand-supply output for the optimised expansion plan presented in Table 28, indicates that the total interconnected capacity grows from 2,654 MW in 2020 to 3,529MW and 8,186 MW in 2025 and 2040 respectively. The average annual excess energy as share of generation in the period 2020-2030 is 1%, but increases thereafter to an average of 4%. The level of vented steam grows over the years with vented steam growing from 166Gwh in 2020 to over 2000GWh from 2030. An average of 18% vented steam of the possible maximum geothermal generation over the planning period is observed.

The excess generation and the vented steam are due to the increase in planting of the baseload plants which also provide firm capacity during peak hours. Ideally, optimisation should allow introduction of suitable capacity options other than the projects with COD that were presented as candidates over the planning period.

Table 26 Demand- Supply balance

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Peak load	MW	1,972	2,078	2,158	2,233	2,315	2,404	3,220	4,220	5,526
Peak load + reserve margin	MW	2,255	2,350	2,429	2,503	2,620	2,711	3,596	4,662	6,461
Reserve margin	% of peak load	14%	13%	13%	12%	13%	13%	12%	10%	17%
Installed system capacity	MW	2,654	2,907	2,968	3,151	3,481	3,529	5,152	6,395	8,186
Firm system capacity	MW	2,260	2,463	2,448	2,520	2,695	2,724	3,717	4,682	6,679
Supply - demand gap	MW	4	114	18	17	75	14	121	21	217
Electricity consumption versus generation		2020	2021	2022	2023	2024	2025	2030	2035	2040
Electricity consumption	GWh	12,072	12,720	13,207	13,670	14,171	14,718	19,710	25,830	33,830
Electricity generation	GWh	12,078	12,866	13,283	13,930	14,393	14,844	20,412	27,994	33,871

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Excess energy	GWh	6	146	76	261	222	125	702	2,161	41
Excess energy - share on generation	%	0%	1%	1%	2%	2%	1%	3%	8%	0%
Vented GEO steam (assuming single-flash technology)	GWh	166	1,357	1,159	1,640	1,558	1,443	2,691	4,595	1,402
Vented GEO steam - share on potential max. GEO generation	%	3%	19%	16%	21%	20%	18%	23%	24%	7%

Figure 22 shows the annual generation balance

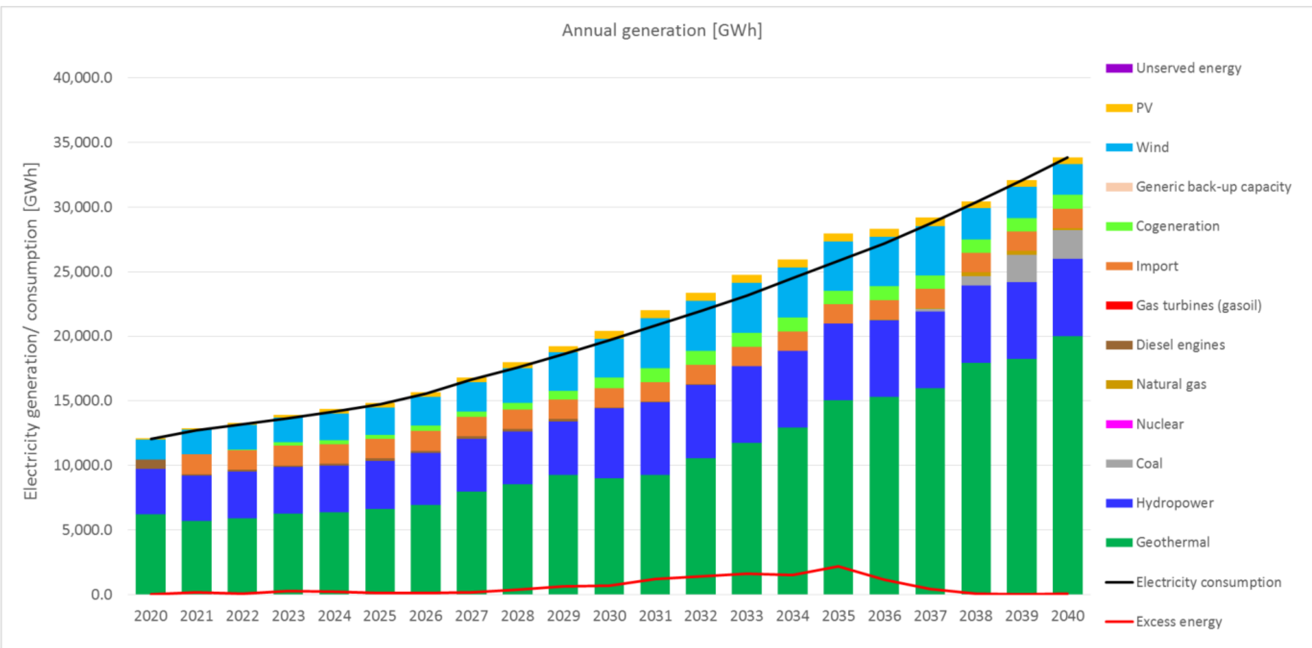


Figure 22 Optimised Case- Annual generation balance

The excess generation between 2029 and 2037 is due to the baseload capacity developed to complement the intermittent plants. Table 27 shows the optimised system expansion plan.

Table 27 Optimised Case Reference scenario expansion – generation expansion overview

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
End of 2020				2,653.6	2,260.0	1,972.1			14%
2021	HVDC Ethiopia	Import			200.0				
2021	Olkaria 1 - Unit 6	Geothermal			83.3				
2021	Kipeto - Phase I	Wind			25.0				
2021	Kipeto - Phase II	Wind			25.0				
2021	KTDA -	Small Hydro							
2021	Muhoroni GT 1	Gas turbines							
2021	Muhoroni GT 2	Gas turbines							
2021	Tsavo	Diesel							
End of 2021				2,907.4	2,463.4	2,078.0		113.6	13%
2022	Selenkei	PV			-				
2022	Hydro Project	Small Hydro							
2022	KTDA Ltd, South	Small Hydro							
2022	KTDA Ltd, Lower	Small Hydro							
2022	KTDA Ltd, Iraru	Small Hydro							
2022	Power	Small Hydro							
2022	Kleen Energy	Small Hydro							
2022	REA Vipingo	Cogeneration							
End of 2022				2,968.2	2,447.7	2,157.6			13%
2023	Menengai 1	Geothermal			102.5				
2023	Mt Kenya	Small Hydro							
2023	Tindinyo Falls	Small Hydro							
2023	Malindi Solar	PV			-				
2023	Eldosol (Cedate)	PV			-				
2023	Cummins	Cogeneration							
2023	Kwale Int. Sugar	Cogeneration							
2023	Thika Way	Cogeneration							

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
2023	Municipal Waste	Cogeneration			15.0				
2023	Kipevu 1	Diesel							
End of 2023				3,150.8	2,519.7	2,233.0			12%
2024	LNG Gas Turbine	Gas turbines			200.0				
2024	Chania Green	Wind			17.5				
2024	Alten Kenya	PV			-				
2024	Kopere Solar	PV			-				
s				3,480.8	2,694.7	2,314.9			13%
2025	Olkaria I Uprating	Geothermal			20.0				
2025	Frontier	Small Hydro							
2025	KTDA, Kipsonoi	Small Hydro							
2025	Gogo upgrade	Small Hydro							
2025	RoadTech	Cogeneration							
End of 2025				3,529.0	2,724.2	2,404.4			13%
2026	Olkaria IV	Geothermal			20.0				
2026	Olkaria 1 - Unit 1	Geothermal			17.0				
2026	Karura	Hydropower			70.7				
2026	Aperture	Wind			17.5				
2026	Ngong 1 - Phase	Wind							
2026	Marco Borero Co	PV			-				
2026	Seven Forks Solar	PV			-				
2026	Global	Small Hydro							
2026	Global	Small Hydro							
2026	Sukari Industries	Cogeneration			11.0				
End of 2026				3,802.2	2,869.1	2,544.2			12%
2027	Eburru 2	Geothermal			25.0				
2027	Menengai I -	Geothermal			60.0				
2027	Olkaria Modular	Geothermal			55.0				
2027	Olkaria 1 - Unit 2	Geothermal			17.0				

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
2027	Olkaria 1 - Unit 3	Geothermal			17.0				
2027	Hannan Arya	PV			-				
2027	Hydel	Small Hydro							
2027	Mutunguru	Small Hydro							
2027	VR Holding AB-	Cogeneration							
End of 2027				4,002.0	3,047.8	2,717.1			12%
2028	Baringo Silali -	Geothermal			100.0				
2028	Electrawinds	Wind			17.5				
2028	Marsabit Phase I	Wind			35.0				
2028	Kenergy	PV			-				
2028	Ventus Energy	Small Hydro							
2028	Tana Biomass	Cogeneration			10.0				
2028	Ngong 1, Phase I	Wind							
End of 2028				4,314.6	3,210.5	2,872.2			12%
2029	Olkaria 6 PPP	Geothermal			140.0				
2029	AGIL Longonot	Geothermal			35.0				
2029	OrPower4 Plant 4	Geothermal			50.0				
2029	Prunus	Wind			17.5				
2029	Electrawinds	Wind			14.0				
2029	Makindu solar ltd	PV			-				
2029	Mwikhupo-	Small Hydro							
2029	Ray Power Ltd	Cogeneration			17.5				
2029	West Kenya	Cogeneration							
2029	Olkaria 2	Geothermal							
End of 2029				4,606.6	3,388.2	3,038.2			11%
2030	High Grand Falls	Hydropower			392.7				
2030	Greenmillenia	PV			-				
2030	Sun Power Kenya	PV			-				
2030	Gem Gen Power	Small Hydro							

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
2030	Greenlight	Small Hydro							
2030	Njega/Rukenya	Small Hydro							
2030	Virunga Power	Small Hydro							
2030	Sustainable	Cogeneration			20.0				
2030	Rabai Diesel	Diesel							
End of 2030				5,152.0	3,717.0	3,219.8		120.9	12%
2031	Marine Power	Geothermal			70.0				
2031	Meru Phase I	Wind			28.0				
2031	Marsabit Phase II	Wind			70.0				
2031	Kibisi Kinetic	Small Hydro							
2031	Kirogori	Small Hydro							
2031	KTDA R.	Small Hydro							
2031	Rareh Nyamindi	Small Hydro							
2031	Rareh Nyamindi	Small Hydro							
2031	Rareh Nyamindi	Small Hydro							
2031	VSHydro Kenya	Small Hydro							
2031	Crystal Energy	Cogeneration			20.0				
2031	Viability Africa -	Cogeneration							
2031	Kipevu 3	Diesel							
2031	KenGen Olkaria	Geothermal							
End of 2031				5,447.1	3,774.6	3,401.5			11%
2032	Baringo Silali -	Geothermal			100.0				
2032	Baringo Silali -	Geothermal			100.0				
2032	Karuga Gitugi	Small Hydro							
2032	KTDA Chemosit,	Small Hydro							
2032	KTDA Ltd, Yurith,	Small Hydro							
2032	KTDA R.	Small Hydro							
2032	KTDA, R. Itare,	Small Hydro							
2032	KTDA, R. Yala,	Small Hydro							

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
2032	Tridax Limited	Small Hydro							
2032	Truck city ltd	Small Hydro							
End of 2032				5,669.4	3,980.2	3,587.9			11%
2033	Olkaria 7	Geothermal			140.0				
2033	AGIL Longonot	Geothermal			35.0				
2033	Olkaria Brine	Geothermal			15.0				
2033	Chevron Africa	Small Hydro							
2033	Dominion Farms	Small Hydro							
2033	Khalala Hydro	Small Hydro							
2033	Njumbi	Small Hydro							
2033	Western Hydro	Small Hydro							
End of 2033				5,907.8	4,182.3	3,786.4			10%
2034	Menengai III	Geothermal			100.0				
2034	Wellhead leasing	Geothermal			50.0				
2034	AGIL Longonot	Geothermal			35.0				
2034	LNG Gas Turbine	Geothermal			280.0				
2034	Iberafrica 2	Diesel							
2034	Thika (CC-ICE)	Diesel							
2034	Athi River Gulf	Diesel							
End of 2034				6,152.9	4,427.5	3,998.0			11%
2035	Menengai IV	Geothermal			100.0				
2035	Menengai V	Geothermal			100.0				
2035	Suswa I	Geothermal			100.0				
2035	Suswa II	Geothermal			100.0				
2035	KenGen Olkaria	Geothermal							
2035	Triumph	Diesel							
2035	Ngong 1, Phase II	Wind							
End of 2035				6,394.7	4,682.5	4,219.5			10%
2036	Dongo Kundu	Natural gas			375.0				

Year	Plant name	Type	Net	Installed	Firm	Peak	Reserve	Surplus/	Reserve
End of 2036				6,769.7	5,057.5	4,442.9		113.2	11%
2037	Lamu Unit 1	Coal			327.0				
2037	High Grand Falls	Hydropower			549.7				
2037	High Grand Falls	Hydropower							
End of 2037				7,294.7	5,541.6	4,697.4			16%
2038	Dongo Kundu	Natural gas			375.0				
2038	Lake Turkana -	Wind							
2038	Lake Turkana -	Wind							
2038	Lake Turkana -	Wind							
2038	REA Garissa	PV			-				
2038	Strathmore	PV			-				
End of 2038				7,319.5	5,811.6	4,961.1			16%
2039	Lamu Unit 2	Coal			327.0				
2039	Olkaria 8	Geothermal			140.0				
2039	Olsuswa 70MW	Geothermal			70.0				
2039	AGIL Longonot	Geothermal			35.0				
2039	Olsuswa 70MW	Geothermal			70.0				
2039	Olkaria 4	Geothermal							
2039	OrPower4 Plant	Geothermal							
2039	Olkaria 1 - Unit 4-	Geothermal							
End of 2039				7,619.5	6,111.6	5,239.6			16%
2040	Lamu Unit 3	Coal			327.0				
2040	Olkaria 9	Geothermal			140.0				
2040	Suswa III	Geothermal			100.0				
End of 2040				8,186.5	6,678.6	5,526.5		217.3	17%

6.5.2. Fixed System Case

The modelled case consists of the existing plants, committed KenGen and GDC projects and IPP projects with PPAs over the planning period. This case was simulated under the three demand forecast scenarios developed -Reference, Vision and Low. This case results are summaried below;

6.5.2.1. Fixed System Case- reference demand scenario

The total interconnected capacity grew from 2,654 MW in 2020 to 8,371 MW in 2040, with system reserve margins averaging 19% over the planning period. Table 28 summarises the demand – supply balance for the fixed system case reference scenario. With the high percentage of intermittent capacity, the system required peaking capacity from 2024. Subsequently, an LNG plant, Karura and High Grand Falls hydropower plants were picked in 2024, 2026 and 2030, respectively, to provide firm and peaking capacity.

Table 28 Demand Supply Balance - Fixed System case reference demand scenario

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Peak load	MW	1,972	2,078	2,158	2,233	2,315	2,404	3,220	4,220	5,526
Peak load + reserve margin	MW	2,255	2,350	2,429	2,507	2,636	2,731	3,980	4,987	6,783
Reserve margin	% of peak load	14%	13%	13%	12%	14%	14%	24%	18%	23%
Installed system capacity	MW	2,654	2,907	3,090	3,400	3,897	4,045	6,298	6,716	8,371
Firm system capacity	MW	2,260	2,463	2,448	2,604	2,947	3,044	4,681	5,003	6,864
Supply - demand gap	MW	4	114	18	97	311	313	701	16	80

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Electricity consumption versus generation		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**
Electricity consumption	GWh	12,072	12,720	13,207	13,670	14,171	14,718	19,710	25,830	33,830
Electricity generation	GWh	12,078	12,866	13,307	14,479	15,714	16,402	20,878	26,482	33,866
Excess energy	GWh	6	146	99	810	1,543	1,684	1,166	653	36
Excess energy - share on generation	%	0%	1%	1%	6%	10%	10%	6%	2%	0%
Vented GEO steam	GWh	166	1,357	1,279	1,873	2,264	2,402	2,394	3,357	1,581
Vented GEO steam - share on potential max. GEO flash steam generation	%	3%	19%	18%	22%	23%	23%	22%	20%	8%

From 2024 to 3031, the excess capacity in the system ranged between 300-800 MW largely due to the Lamu coal plant, and the average annual excess energy as share of generation in the period 2020-2030 at 6%. The level of vented steam was 1,200 GWh from 2021 to the end of the planning period. The average vented steam was 18% of the possible maximum geothermal generation, with a high of 23% in 2024-2026. The excess energy and vented steam was mainly due to the high amounts of solar, wind and geothermal baseload capacity in the system, as well as imports from Ethiopia.

Capacity factors for the coal plant was significantly low at an average of 7% over the planning period. Geothermal plants' capacity factors declined beginning 2021 to an average of 77.5% over the planning period.

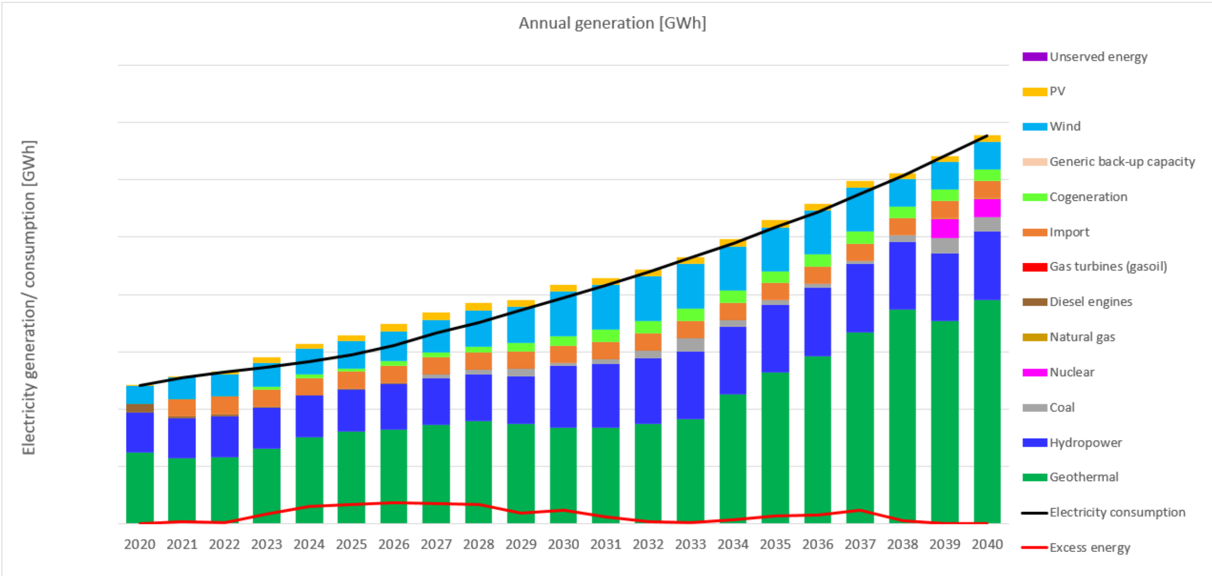


Figure 23 Annual generation balance - Fixed System Reference demand scenario

6.5.2.2. Fixed System case - low demand Scenario

The capacity requirement for this scenario is lower due to the low demand forecast, growing from 2,654 MW in 2020 to 7,421 MW in 2040. However, excess capacity was higher, ranging from 400 MW to 900MW, due to the large number of committed plants. The steam vented over the planning period averaged 19% or 2,100 GWh of the possible maximum geothermal annual generation. The annual generation mix over the period is shown in Figure 29.

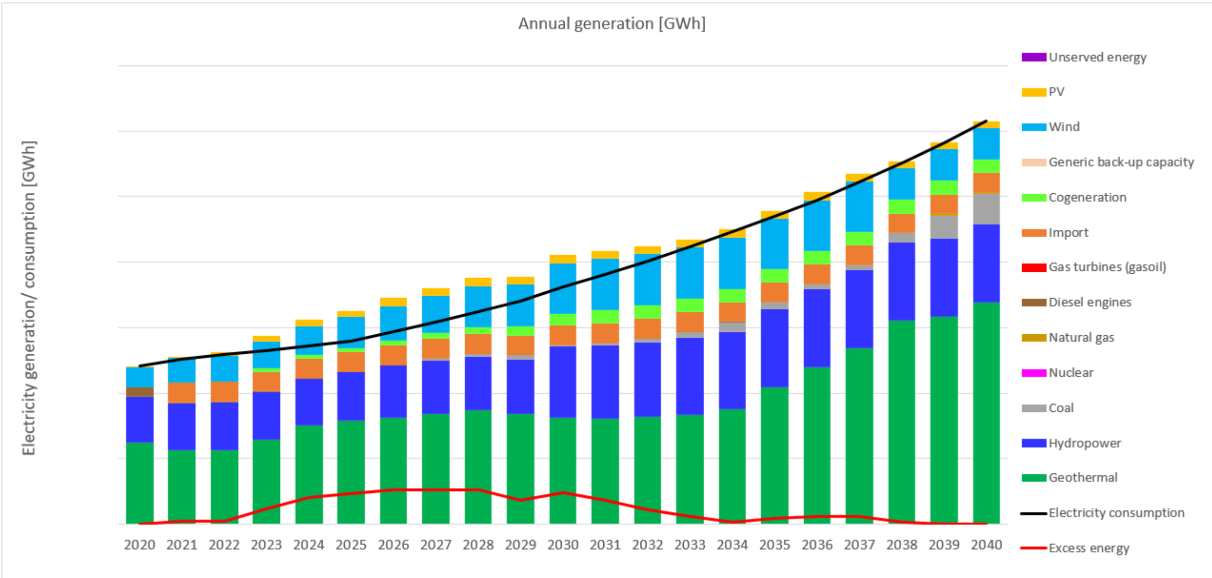


Figure 24 Annual Generation balance - Fixed system low demand scenario

6.5.2.3. Fixed System Case - vision demand scenario

With the higher demand in this scenario, the interconnected system capacity was higher growing from 2,654 MW in 2020 to 17,175 MW in 2040. This accommodated all the committed projects and the excess capacity decreased compared to the other scenarios, to an average of 96MW over the planning period. The excess energy was also lower averaging 3% over the period. The Vented steam was also lower with an average of 18%, and dispatch of plants more optimal with capacity factors of 83.6% for Geothermal and 28.2% for coal. The annual generation is illustrated in figure 25.

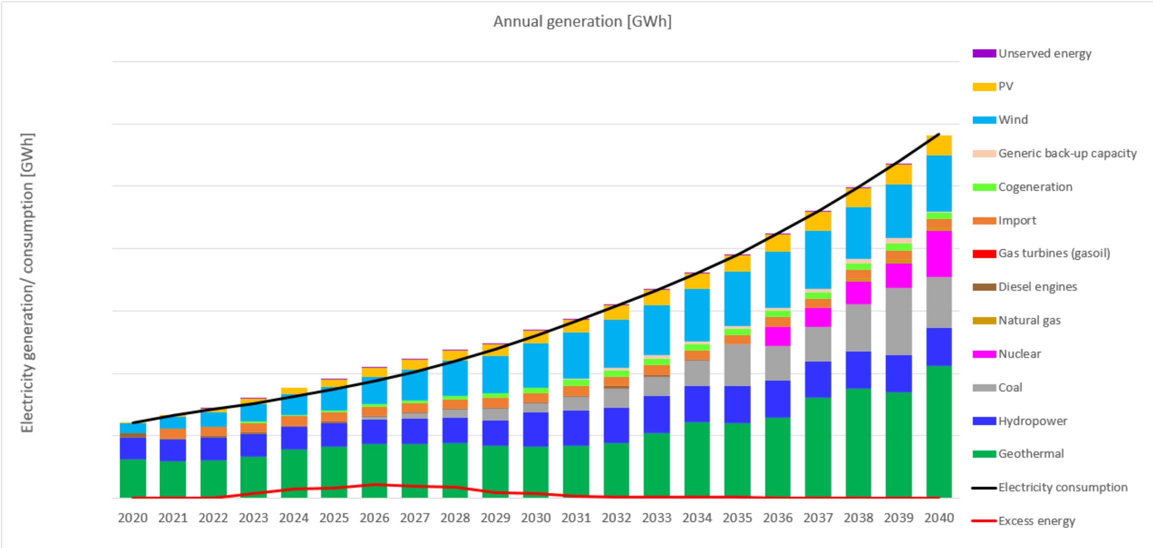


Figure 25 Annual generation Balance - Fixed system Vision demand scenario

6.6. Conclussions and Recommendations

a) The optimised case to be adopted as the national long term generation expansion plan for the 2020-2040 period.

b) The proposed solar and wind projects which are likely to deliver higher intermittent capacity in the system than required should be spread to minimise energy curtailment.

c) For Solar and Wind projects that do not have PPAs, it is reccomended that they are migrated to renewable energy auctions.

d) Peaking capacity power plants and Battery storage should be developed immediately to avert peak capacity shortfalls, absorb excess energy presented as vented steam during off-peak hours, provide system reserves and prevent load shedding in Western Kenya in the short term as transmission projects are being implemented. In the long term the recommended projects for the same purpose are LNG gas turbines, Pumped Hydro Storage and peaking hydro plants.

e) Demand side management relating to load shifting is recommended to enable optimal utilisation of the excess energy in the system during off-peak hours. This includes initiatives like strengthening the time of use tariff, electrification of the transport sector among others.

f) Demand creation efforts to be enhanced to support optimal use of the existing generation capacity and projects under implementation.

g) Negotiate for firm 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term.
h) In the period between 2022 and 2024, there is a risk of firm capacity shortfalls if Ethiopia imports and the KenGen Olkaria I unit 6 plant are not realised as planned. This may necessitate extension of the plants scheduled for retirement.
i) Renegotiate CODs and tariffs for projects that have PPAs but are yet to commence construction, to be integrated according to the dates given in the optimal plan. Respective contingent liabilities for the committed projects should be determined to inform proposals and negotiations.
j) Carry out a comprehensive study on ancillary services requirements for the system, including battery storage, pumped storage and reactive power compensation, with the increasing levels of intermittent renewable energy sources.
k) The Automatic Generation Control (AGC) to be implemented as a matter of urgency to improve the management of secondary reserves to ensure smoother system frequency control.
l) Focus on sustainable technology for geothermal expansion that will minimize steam venting and enhance flexibility

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

7.1. Introduction

This chapter covers generation costs for the period 2020-2040 as simulated in the chapter 6, and the evolution of tariffs for the medium term period 2020-2025 where the projects are committed and fixed. In the simulations for tariffs, only two cases were considered; the Optimised Case Reference demand scenario and fixed Case Reference demand scenario. This is primarily based on the fact the two cases provide a more realistic forecast for policy formulation and implementation.

7.2. Optimized Case – Reference Demand Scenario

The implementation of an additional capacity of 8,186.5MW will require a capital cost of USD 2.4725 billion. Figure 26 shows the total capital requirement for the generation expansion plan and specific requirements for different technologies for the period 2020 – 2040.

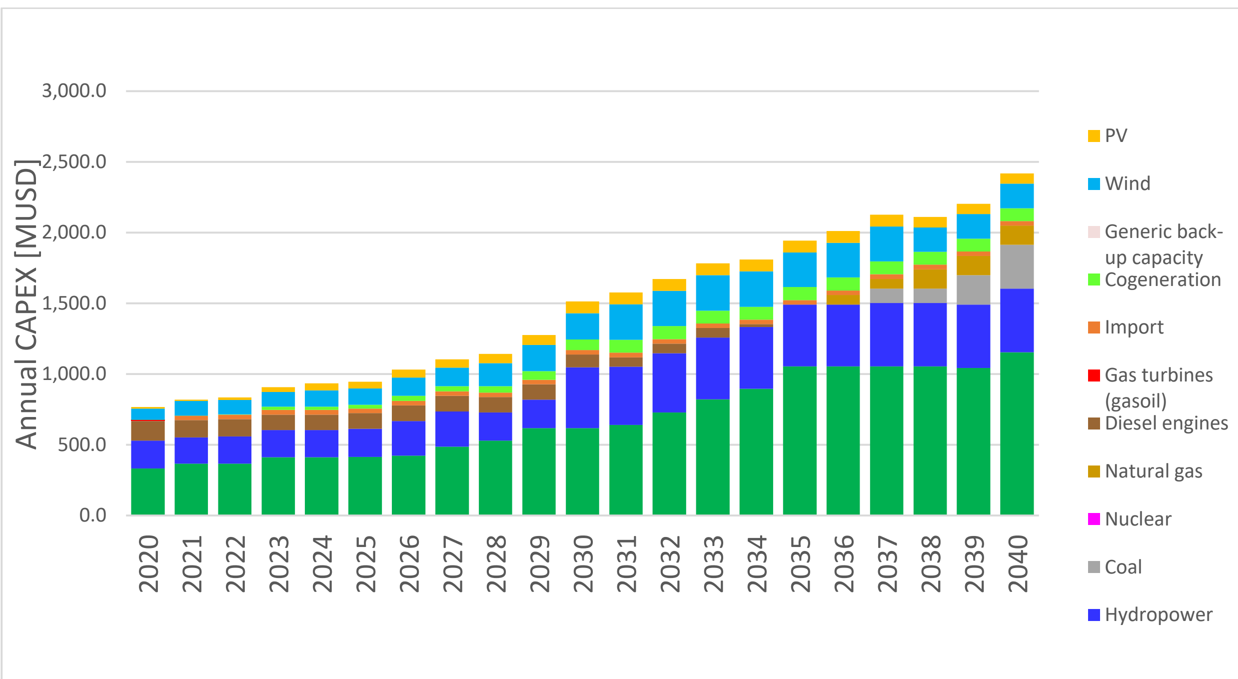


Figure 26 Investments costs for various techniologies.

Figure 27 shows the Levelised cost of electricity of the system from 2020-2040. It indicates that the LEC will increase from 8.31 USDCents/kWh in 2020 to 9.69USDCents/KWh in 2040, with the highest LEC cost recorded in 2033, 10.23 USDCents/KWh.

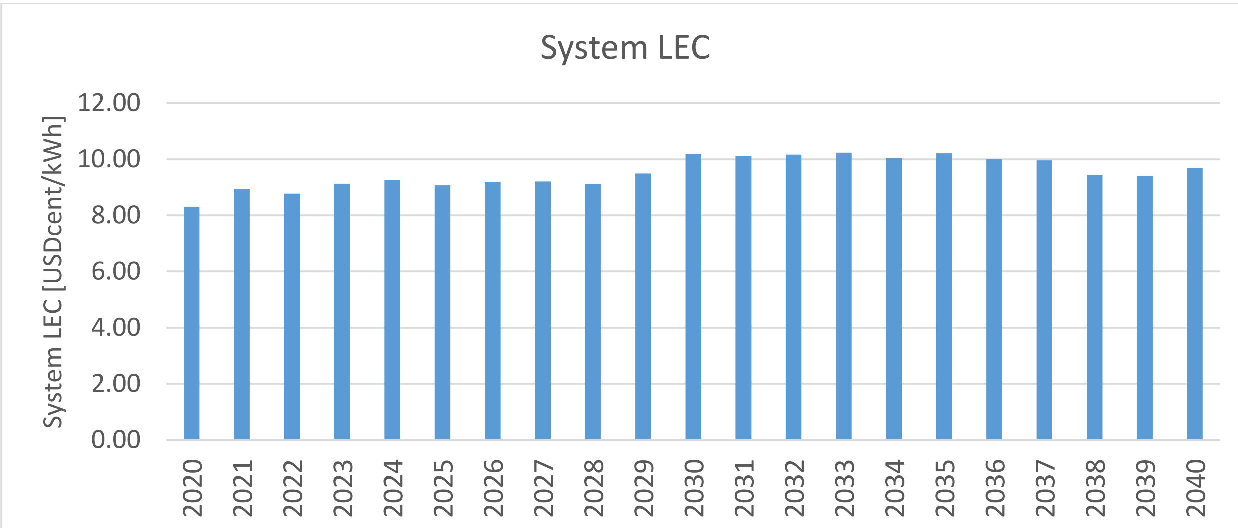


Figure 27 Levelised costs under the optimised case reference scenario.

From the simulations, the total cost implication for planned projects under the optimized case is KShs. 692,302,518,693. Figure 28 illustrats the average base retail tariff is projected to increase from KSh20.85/kWh in 2020 to KShs. 24.48/kWh in 2025. The generation cost in the rises from Kshs.9.82/kWh in 2020 to KSh. 11.68/kWh in 2025. The costs summary is attached herein as *annex 8*

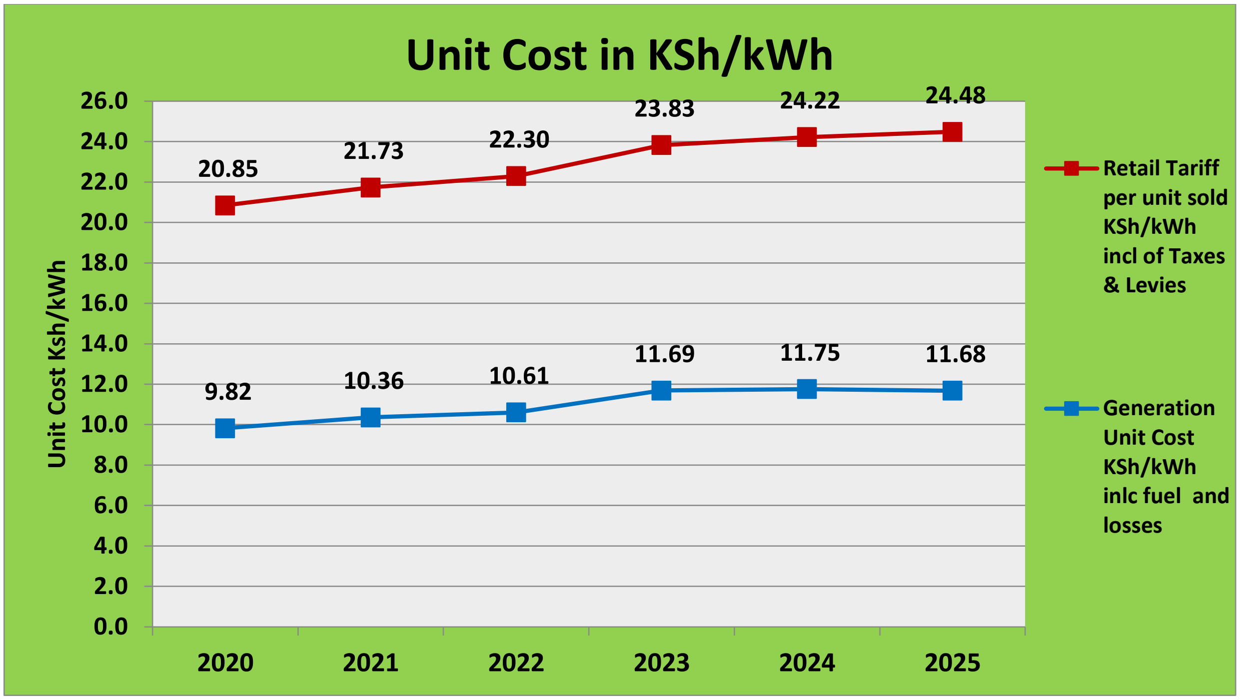


Figure 28 Tariff evolution - Optimised Reference case

7.3. Fixed system case – Reference Scenario

The implementation of the additional capacity of 8,371.5MW will require a capital cost of USD 10,055.1 billion. Figure 29 shows the total investment requirement for the generation expansion plan and specific requirements for different technologies for the period 2020-2040. Figure 30 shows the annual system cost for the period 2020-2040. The results indicate Geothermal shall require a larger share of the Capital requirement.

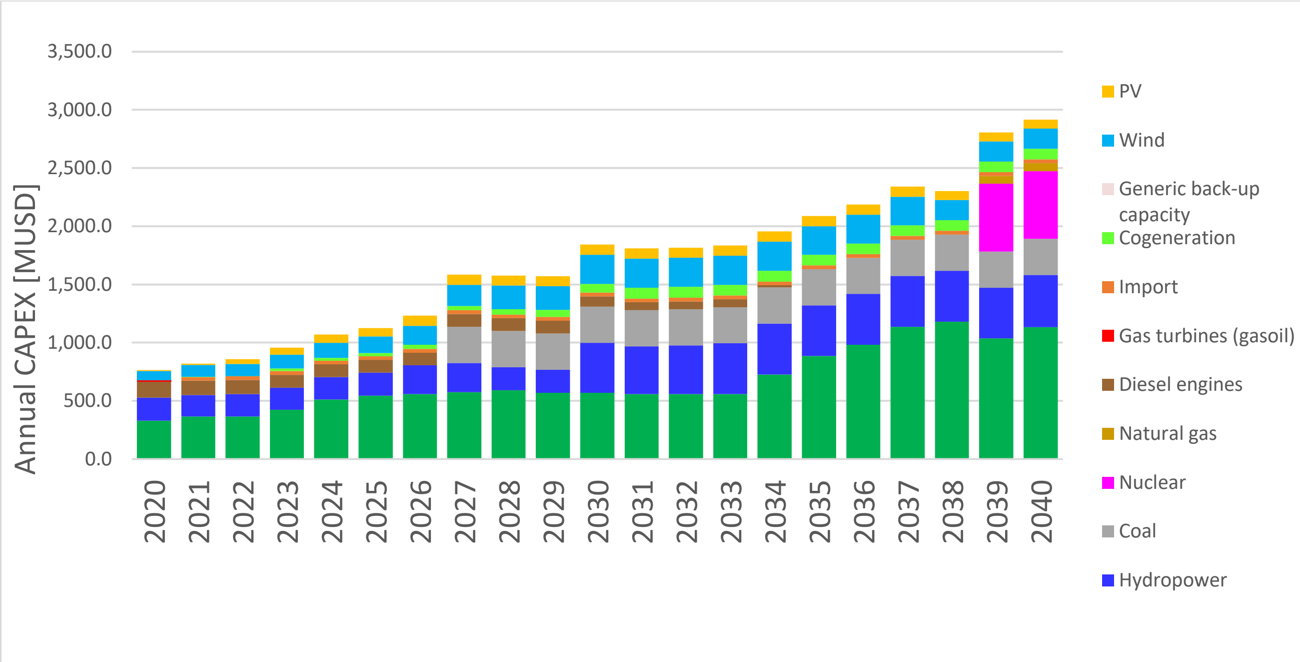


Figure 29 Annual investme t costs for various technologies in the fixed case - Reference scenario

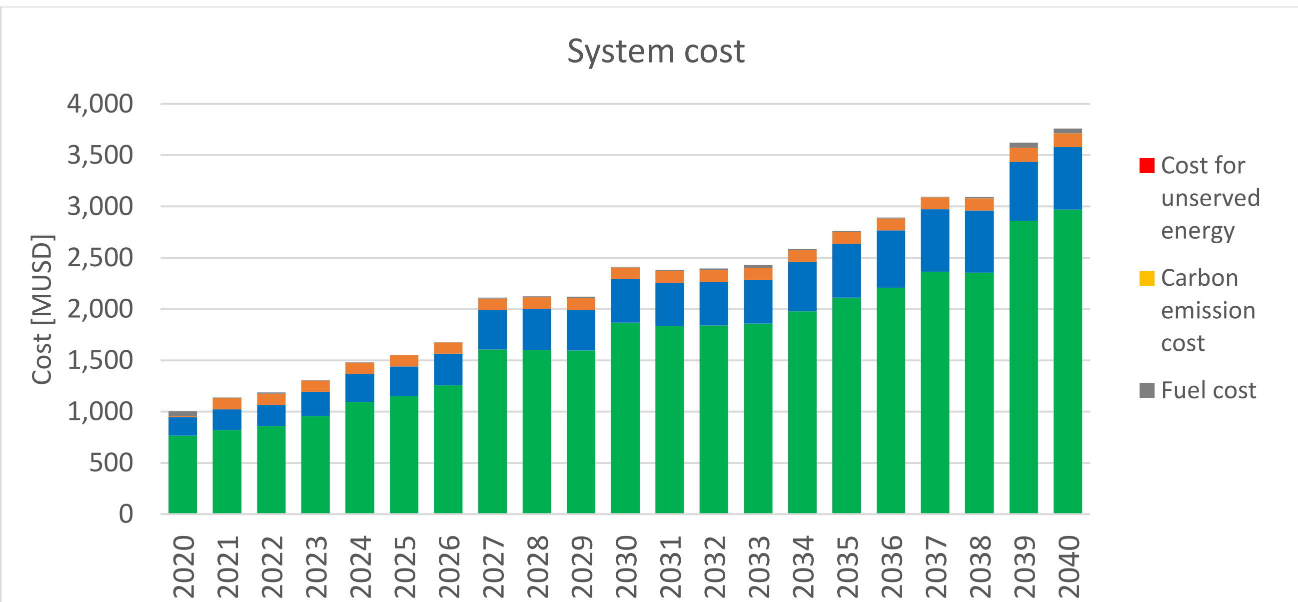


Figure 30 Annual Systems cost

Figure 31 shows the Levelised costs for the planned fixed system case. The cost ranges from 8.31 USDCents/kWh in 2020, to 11.12 USDCents/kWh in 2040. The highest Levelised cost of 12.68USDCent/kWh, is realized in 2027. The spike is attributable to commissioning of the Lamu Coal power plant.

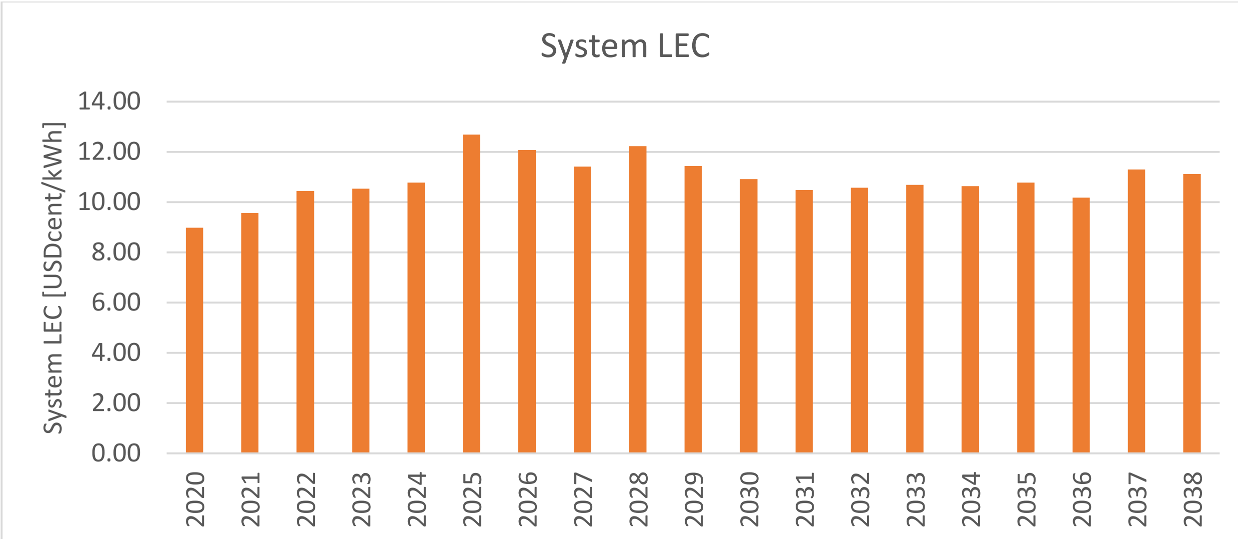


Figure 31 Levelised electricity cost - Fixed case Reference scenario

The total cost implication for planned projects in the period 2020-2025 is KShs 734,215,403,304 . The total cost is the sum of capacity payment obligations, Energy Costs, Fuel Energy Costs and Deemed generated costs. Table 37 shows the costs and tariff evolution under the fixed system case for the period 2020-2025.

The cost implication in fixed system case, in the period 2020-2025 is KShs 723,806,943,976. The total cost breakdown is attache in annex 9. Figure 32 illustrates the average base retail tariff is projected to increase from the KShs 20.85/kWh to KShs 25.98/kWh. Over the same period, the generation unit cost is estimated to rise from Kshs 9.82/kWh in 2020 to 13.00/kWh in 2025.

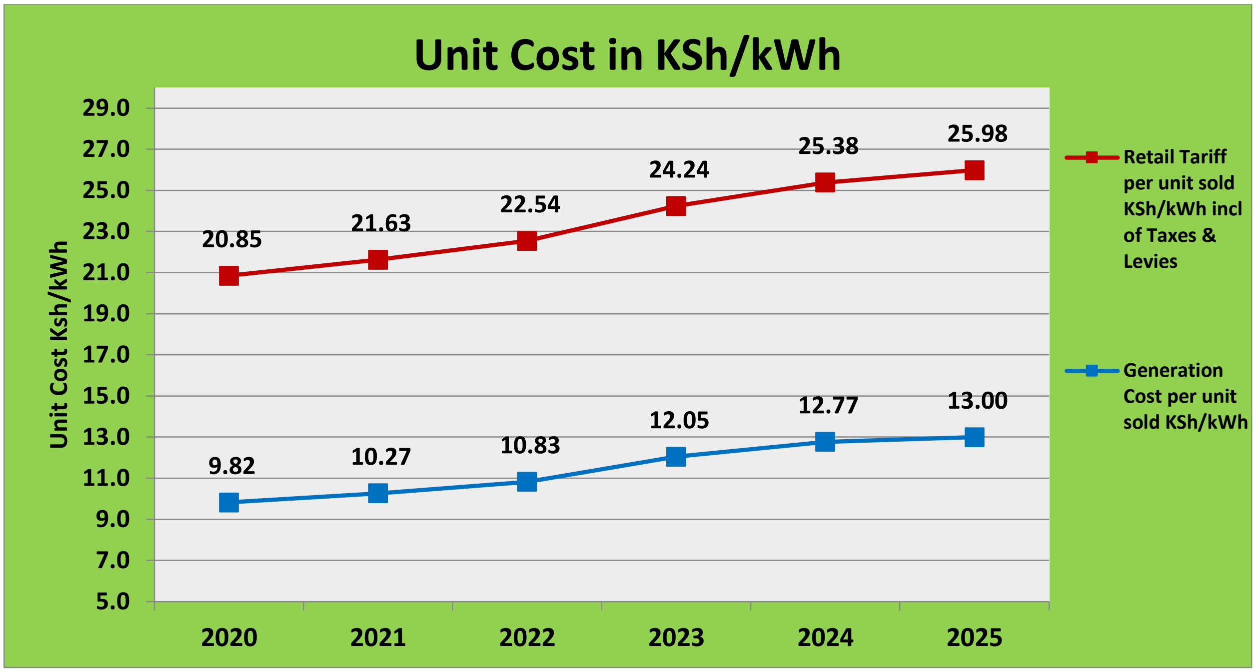


Figure 32 Tariff evolution - Fixed System case

7.4. Comparison of the Retail tariff scenarios

The tariffs are expected to rise over the planning period in the Fixed Case and optimised case scenarios considered. The fixed case system reference scenario however, has higher tariffs compared to the optimized reference scenario. This is primarily attributed to the fixed scheduling of projects in the fixed case system.

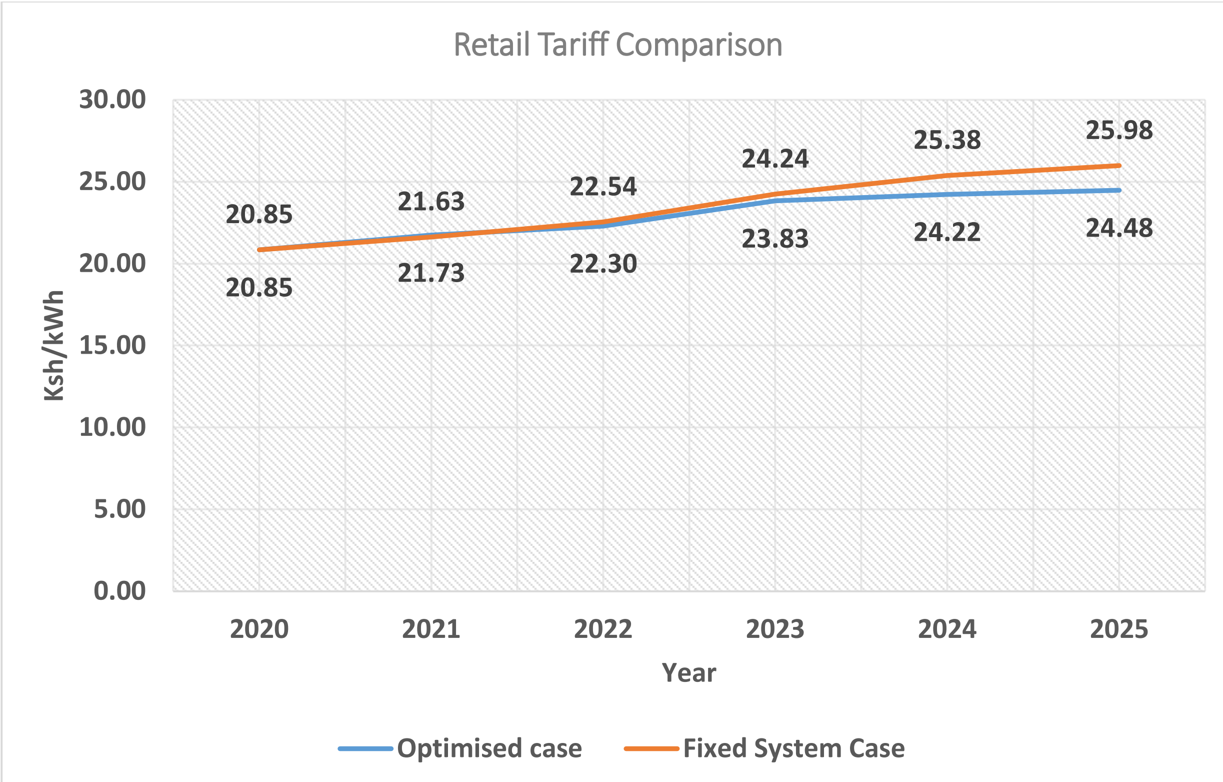


Figure 33 Retail tariff Comparison

8. TRANSMISSION PLANNNING

Transmission plan can be classified into: - Long term, medium-term and short term transmission planning. This planning is vital for the development of the electricity grid in the country. Long term transmission planning determines the long-term strategic development of the transmission system. It highlights the transmission system investments required to meet the long term plan for all generators and loads, and achieve steady system stability while meeting the requirements of the grid code. Short and Medium-term transmission planning are used for preliminary evaluation of the alternatives/options proposed for improved system performance and requirements for with the generation evacuation and, reinforcement of power distribution.

8.1. Objectives of transmission planning

The main objectives of the transmission planning component are:

a) To ensure efficient and reliable supply of planned power generation to demand centers economically
b) To minimize the expected energy not served and investment cost subject to power flow and grid security constraints
c) To determine an optimal long term transmission system expansion investment plan
d) To develop cost estimates for the planned investments.

8.2. Methodology

The transmission network expansion planning involved:

- Analysis of committed medium term (5 year) transmission plan through detailed technical studies
- Development of a set of transmission network solutions for the planning horizon (year 2040) to be considered in selection of a target network on which the transmission expansion plan shall be based.

- Preparation of detailed alternative long term transmission development sequences for comparison and determination of the least cost option.
- Optimization of the alternative transmission development sequences through detailed technical studies
- Development of cost estimates for the alternative sequences of planned investments.
- Economic analysis and comparative evaluation of alternative investment plans to arrive at the least cost option.

8.3. 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 in the short term 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 2025) committed transmission system model and then building alternative functional network models for the planning horizon (year 2040) having taken into consideration the demand forecast and planned generation plants for the years up to 2040.

The process of developing a target network thus involves;

i. Determining the location of future generation facilities; 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.
ii. Splitting the power network into several regions, determining the regional power balances and estimating future potential flows between regions. For instance, table 29 below estimates regional power balance expected for the year

2040 as per the assumed dispatch, while table 30 presents potential regional exchange between regions in that year.

Table 29 Year 2040 regional power balances (MW)

Region	**Generation**	**Demand**	**Surplus/ Deficit (As per assumed dispatch)**
NAIROBI	109.3	2346.1	-2236.8
COAST	1027.9	956	71.9
MT KENYA	1543.3	522.8	1020.5
C RIFT	1750.1	418.5	1331.6
W REGION	150.2	730.8	-580.6
N RIFT	545.2	266.4	278.8
ETHIOPIA(Imports)	600.7	-	-
EKT(Exports)	-	200	-
Totals	**5726.7**	**5440.6**	

Source: KETRACO

Table 30 Year 2040 Regional Power Interchange

REGION		**NAIROBI**	**COAST**	**MT KENYA**	**C CRIFT**	**W KENYA**	**N RIFT**	**UGANDA**	**ETHIOPIA**	**TANZANIA**
NAIROBI	MW	-	-60	-1260	-102	0	-568	-	-590	200
	MVAr	-	249	108	-200	0	-36	-	266	-65
COAST	MW	60	-	-4	-	-	45	-	-	-
	MVAr	-249	-	-20	-	-	19	-	-	-
MT KENYA	MW	1260	4		-395	-	111	-	-	-
	MVAr	-108	20		-17	-	-5	-	-	-
C CRIFT	MW	102	-	395		111	693	-	-	-
	MVAr	200	-	17		192	-82	-	-	-
W KENYA	MW	0	-	-	-111	-	-493	0	-	-
	MVAr	0	-	-	-192	-	-34	0	-	-
N RIFT	MW	568	-45	-111	-693	493	-	0	-	-
	MVAr	36	-19	5	82	34	-	-29	-	-
UGANDA	MW	-	-	-	-	0	0	-	-	-
	MVAr	-	-	-	-	0	29	-	-	-
ETHIOPIA	MW	590	-	-	-	-	-	-	-	-
	MVAr	-266	-	-	-	-	-	-	-	-
TANZANIA	MW	-200	-	-	-	-	-	-	-	-
	MVAr	65	-	-	-	-	-	-	-	-

Source: KETRACO

iii. Estimating the number of transmission lines to plan between regions; In estimating the number of transmission lines between regions 220kV and 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.

8.4. Planning assumptions and criteria

8.4.1 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.
- 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, the following is assumed:
    - Kenya will import 200 MW from Ethiopia from 2021 and another 200 MW from 2023.
    - 200MW will be exported from Ethiopia to Tanzania through Kenya from the year 2022.
- Due to anticipated right of way challenges and 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

8.4.2. Planning criteria

As guided by the Kenya National Transmission Grid Code, the following gives the major aspects that were considered during the planning exercise;

8.4.2.1. System Voltage

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

8.4.2.2. 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 a short duration of time, the time that the operator applies remedial actions for bringing the system back to a normal situation.

8.4.2.3. Voltage selection

Transmission development during the planning horizon will be based on 132, 220 and 400 kV. To enhance system operation and optimize way leaves cost all future inter region transmission lines and regional interconnections shall be designed as 400 kV but may be initially operated at 220 kV. In determining voltage levels for new power evacuation lines, consideration for all power plants to be developed in any given location shall be taken into account to optimize overall transmission cost.

8.4.2.4. Reliability criteria

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

8.4.2.5. Fault levels

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

8.4.2.6. Power losses

The transmission 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).

8.4.2.7. Catalogue of equipment and materials

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 estimated unit cost is summarized table 31 to table 33. Table 34 gives the cost estimates for wayleaves and substation land. The tables were compiled using KETRACO estimated costs.

Table 31 Power transformers

POWER TRANSFORMERS							
MAXIMUM CAPACITY/RATING	**VOLTAGE RATIO - kV (Costs in MUSD)**						
	132/33	**220/33**	**220/66**	**220/132**	**400/132**	**400/220**	**500/400**
23MVA	0.5	0.62	0.7	-	-	-	-
45/60MVA	0.75	0.8	0.9				
90MVA	-	-	-	0.98	1.5	-	-
150MVA	-	-	-	1.15	2	-	-
200MVA (3-ph units for 220/66 rest 1-ph)	-	-	1.5	-	1.8	2.2	-
400MVA (1-ph unitsX3)	-	-		-	-	3	4.11

REACTOR BANKS					
MAXIMUM CAPACITY/RATING	**VOLTAGE RATING- kV & UNIT COST in MUSD**				
	33	**66**	**132**	**220**	**400**
7.5 MVAr	0.25	0.	0.3	0.370	-
10-15MVAr	0.38	0.	0.508	0.685	-
50 MVAr	-	-	-	-	0.75
100 MVAr	-	-	-	-	1.4

CAPACITOR BANKS					
MAXIMUM CAPACITY/RATING	**VOLTAGE RATING- kV & UNIT COST in MUSD**				
	33	**66**	**132**	**220**	**400**
7.5 MVAr	-	-		-	-
10-15 MVAr	0.54			0.75	-
50 MVAr	-	-	-	0.85	8.7
100 MVAr	-	-	-	1.3	1.4

STATCOMS					
	VOLTAGE RATING- kV & UNIT COST in MUSD				
CAPACITY/RATING	**33**	**66**	**132**	**220**	**400**
– 50Mvar inductive and 50Mvar capacitive 1x-/+50Mvar.	-	-	18.5	-	-

POWER TRANSFORMERS							
MAXIMUM CAPACITY/RATING	VOLTAGE RATIO - kV (Costs in MUSD)						
	132/33	**220/33**	**220/66**	**220/132**	**400/132**	**400/220**	**500/400**
–100Mvar Inductive and 50Mvar capacitive (-/+1x50Mvar DRPC and 1x-50Mvar MSR)	-		-	-	22.0	-	
–200Mvar Inductive and 100Mvar capacitive (-/+2x50Mvar DRPC and 2x-50Mvar MSR)	-		-	-	-	37.0	

Source: KETRACO

Table 32 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/Bay	0.1	0.13	0.22	1	1.7	inc
Partial Diameter	-	-	-	0.5	0.85	-
Bus Coupler	0.025	0.05	0.22	0.34	-	-
Power Transformer (see table above)	-	-	-	-	-	-
Reactor/Capacitor banks (see table above)	-	-	-	-	-	-
Bus Bars	inc	inc	inc	inc	inc	
Protection & Control	inc	inc	inc	inc	inc	
Telecom	inc	inc	inc	inc	inc	
Control Room building			0.9	1	1.2	2
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: KETRACO

Table 33 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: KETRACO

Table 34 Cost of RAP, Land (Way Leaves)

SUBSTATION 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: KETRACO

The costs will be expanded and revised in future to include equipment that 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. The cost for wayleaves assumes highly populated and built up area, this represents the worst case scenario.

8.5. Generation and load data

8.6. Generation data 2020 – 2040.

The future generation plants considered in this plan are provided in section 6.2.

8.7. Load data.

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 as per the demand forecast.
- The Big 4 Agenda among other flagship projects as indicated in table 15 were assumed.

8.8. Distributed load forecast 2020 -2040

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

Table 35 Peak Load Distribution in Regions

	2021		2025		2030		2035		2040	
Region	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**
Nairobi	941.02	309.30	1151.18	378.37	1337.5	439.6	1767.7	582.8	2311.7	762.2
Coast	279.23	91.78	338.44	111.24	595.2	202.4	757.4	255.8	962.6	323.2
Mt. Kenya	227.83	74.88	273.43	89.87	303.1	99.7	400.6	130.7	523.8	170.9
C Rift	119.73	39.35	153.09	50.32	260.8	85.7	338	117.8	435.6	152
N Rift	75.51	24.82	94.38	31.02	431.8	141.9	571	193.4	747.1	253
Western	218.58	71.84	268.27	88.18	152.6	50.2	201.8	65.7	264	85.9
Grand Total	1861.89	611.97	2278.78	749.00	3081	1019.5	4036.5	1346.2	5244.8	1747.2

Source: KETRACO

8.9. Development of Target network candidates

The target transmission network candidates for the previous horizon planning year (2019 - 2039) were revisited. Alternative transmission system was then developed considering the regional power balance as shown in table 36. 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 8.4.

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 these line loading limit guidelines were adopted:

- 0- 80 km (short lines) – thermal limits
- 80 – 499 km (medium length) – transient stability and surge impedance loading limit of 1.5x SIL
- Long lines 500 km and above –Voltage drop and surge impedance loading limits of 1xSIL

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.

8.9.1. Overview of the developed target network

In the previous planning exercise, a combination of projects (in addition to the committed network) were selected so as to address the following network issues/challenges:

i. Provision of alternative source of supply for Lessos for improved reliability of supply for larger West Kenya
ii. Extending transmission lines to cater for new point loads and generation.
iii. Reinforcing southern parts of West Kenya (Chemosit and South Nyanza).
iv. Grid extension to off-grid areas currently supplied by diesel generator sets (Wajir, 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.

The following projects were selected and included in the Transmission Plan

Table 36 Transmission Projects from the 2019-2039 plan

S/n	PROJECT	Length (km)	Cost (USD)
1	400kV Maralal/Loosuk- Baringo-Lessos	179	202
2	220kV Keringet - Chemosit (cost includes inter tie with 132kV system at Chemosit)This is included as part of Rongai-Keringet	73	72.05
3	220kV Mariakani- Bamburi Cement-Kilifi	81	92.86
4	Gilgil/Thika LILO - Longonot - Thika and 400 kV Longonot Suswa	12	47.46
5	220kV Wajir-Mandera	250	161.1
6	220kV Marsabit-Moyale	180	119.94
	TOTALS	**775**	**695.41**

Source: KETRACO

In the current planning period the only issue required to be addressed by network expansion was supply to proposed ship recycling and steel making factory at Shimoni/Kibuyuni in Kwale County. The developer has already applied for supply to meet an estimated demand of 80MVA by 2023. The two options were proposed to supply the proposed developments transmission projects as given in Table 37.

Table 37 Target Network elements

Cluster A			**Length Km**	**Cost/Modelling Details/Remarks**	**YEAR**	**COST MUSD**
Segment 1: Power Supply to Shimoni/Kibuyuni						
A1	Opt 1	Mariakani – Kibuyuni 220kV line	120	220kV transmission line, new 220/132/33kV substation at Shimoni/Kibuyuni	2023	96

A2	Opt 2	LILO on Mariakani/Dongo Kundu to Kibuyuni	70	220kV LILO on both circuits of Mariakani-Dongo Kundu, 220kV Switch station at Kwale and 220kV double circuit transmission line from the Switch station to Kibuyuni, new 220/132/33kV substation at Kibuyuni.	2023	85

Source: KETRACO

Two target networks given below were considered in the further analysis: - Preliminary analysis and observation (cost and grid code's reliability requirement) was done/considered to disregard the other combinations.

Table 38 Selected Options for Further Analyses Included

Segment	TN 1	TN 2
1	A1	A2

Source: KETRACO

The following describes the two networks elements that were added/modelled into the target network considered in the previous planning period to develop the two target networks options:

Network Element 1

Project A1: This option considers development of approximately 120km of 220kV line from Mariakani to Kibuyuni, establishment of 220kV bay extension at Mariakani and construction of a new 220/132/33kV substation at Shimoni/Kibuyuni area.

Network Element 2

Project A2: This option considers cutting in and out of both circuits of the 220kV Mariakani-Dongo Kundu Transmission line, construction of a 220kV Switch Station at Bang'a in Kwale, approximately 2 sets of 10km 220kV double circuit transmission lines between the LILO and the switch station, new 220/132/33kV at Shimoni/Kibuyuni and approximately 70km of 220kV double circuit transmission line between the switch station at Bang'a and new substation at Shimoni/Kibuyuni.

The link to the 132kV system considered to be terminating at Kwale Sugar so as reinforce the existing 132kV system from Rabai was included in both of the networks above.

8.10. Developing Models for Target Networks Options

Initially the committed projects for 2020-2025 were modelled as expected in the network for each year. System simulation were carried out to verify their adequacy and highlight on any network constraints. Need to address these constraints informed on additional investments required in the medium term and in a way respond to the updated demand forecast and generation plan. The network models for horizon year (2040) was developed and included the planned generation plants, planned loads and all the transmission lines expected by 2040 as per the previous planning period

Upon modelling targeted network, additional system reinforcements using the standard network equipment tabulated in section 8.6 were identified and modelled to create a converging model over the planning period. Reactive power compensation devices were modelled at various nodes to provide variable reactive power. Optimal sizes and ranges of reactive compensation equipment were determined for optimised target network.

The network elements (options to supply Shimoni) were at different instances included in the horizon network model. Since the supply to Shimoni is required by 2023, the network elements were included for models from the year 2023. Two target network options were then developed. Network analysis was carried out for 2020, 2025, 2030 2035 and 2040 as detailed in the next section. This compared the performance of the target two network options.

8.11. 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

8.12. 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. The system losses and the impact of target network elements on system losses was determined from load flows.

8.13. 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 the development of the target networks.

8.14. Fault Level studies

Fault level computations were carried out to ensure that network circuit breakers capacities are not exceeded within 20% 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.

8.15. Simulation Results

The simulation results that are characterized by loss performance for each of the target networks were analysed and used to rank the best target network alternatives. The table 39 gives the simulated network losses for the four target networks.

Table 39 Simulated network losses for the four target networks

YEAR	NETWORK LOSSES IN MW	
	TN 1	**TN 2**
2025	85.41	85.49

2030	137.6	137.6
2035	184.5	186.3
2040	287.6	284.0

The network losses for the five networks compare closely, target networks with slightly higher losses over the period included target networks 1, 4 and 5. In 2040 and beyond, target network 5 recorded lower losses hence more efficient. The cost of the projects and these formed the basis for target network selection and hence assisted in providing the transmission investment sequences that best met the set technical criteria. PSS/E load flow models for the four target networks are attached in the Appendices. Cost estimates for network elements in each target network was determined and used in the economic analysis.

8.16. Simulations Key Findings

Network constraints in the short term (2020-2025):

The following network constraints were identified in the existing and committed network 2020-2025 and recommendations made for their resolutions;

i. Over loading due to inadequate transmission and transformation 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 (66 kV feedouts pending) and Malaa 220kV substations)
    - Malaa substation location being very far from the load centre (inner Nairobi Region).
iii. System over-voltages at Garissa, Rabai and the other regions. The situation is worse after commissioning of proposed 400kV networks and commissioning of HVDC converter stations and especially during off peak period.
iv. System under voltages at various substations in Nairobi, Coast, Mt Kenya and West regions during peak periods.

v. Reliability 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 (4.7% in 2020) in the short term due to delayed commissioning of various committed projects, attributed to wayleaves problems, vandalism and non-performance of contractors.

Network constraints in the short term (2030-2040):

The following network constraints were identified in the proposed networks 2030-2040 and recommendations made for their resolution;

2030 constraints are as follows:

Over loading due to inadequate transmission and transformation capacity in

- Mt Kenya – Nairobi regional link, (132kV New Thika -Mangu-Juja Rd)
- West Kenya Region (Chemosit 132/33kV transformers;
- Coast regions (Bamburi 132/33kV transformers.

Over voltages at Off peak due to inadequate reactive power compensation at low loading periods:

- Mt Kenya Region and Coast Region (220kV Garissa-Bura-Hola-Garsen System)
- 400kV system in the North Rift region (Lessos Hub).

2035 Constraints are as follows:

Over loading due to inadequate transmission and transformation capacity in

- Mt Kenya Region (132/33kV transformer at Githambo, Kiganjo, Kutus and Garissa)
- West Kenya Region (Kisii 132/33kV transformers;
- Central Rift Region (Lanet 132/33kV transformers); and
- North Rift region (Kabarnet 132/33kV transformers).

Over voltages at Off peak due to inadequate reactive power compensation at low loading periods:

- Mt Kenya Region (220kV Garissa-Habaswein-Wajir, Garissa-Garbatula, Isiolo System)
- 400kV system in the Mt. Kenya region (Thika Hub).

2040 constraints are as follows:

Over loading due to inadequate transmission and transformation capacity in

- Mt Kenya – Nairobi regional link, (132kV New Thika -Mangu-Juja Rd, Juja Rd 132/66kV transformers, 220/66kV transformers at Nairobi North, City Centre and Embakasi)
- West Kenya Region (Kisumu/Mamboleo 132/33kV transformers);
- North Rift Region (Lessos 132/33kV transformers);
- Central Rift Region (Soilo 132/33kV transformers); and
- Coast regions (Bamburi 132/33kV transformers).

8.17. Recommendations – (short to medium term).

8.17.1. Transmission Capacity

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. Fast track completion of 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. Fast track completion of Olkaria – Narok and Narok – Bomet 132 kV line sections. This will off-load Muhoroni – Chemosit and improve voltages in South Nyanza sub-region

iii. Fast track completion of Sondu-Ndhiwa 132kV transmission line. This will de-load Chemosit - Muhoroni and Sotik –Kisii lines and improve system voltages in West Kenya.

b) Central Rift Region

i. Implement the second LILO to Soilo (Lanet-Makutano) – This will de- load the lines to Makutano once Menengai generation is commissioned
ii. Uprate transformers at Soilo Substation from 2x23MVA to 2x45MVA
iii. Fast track completion of 132kV Olkaria-Narok. This will alleviate overloading of the 132kV Olkaria Naivasha 132kV line.
iv. Installation of fast acting reactive power compensation at Suswa 400/200kV substation on the 400kV bus.

c) Coast Region

i. Fastrack completion of Rabai –Kilifi 132kV line upgrade to double circuit construction and steel tower construction.
ii. Implement Malindi – Kilifi 220 kV line and new Kilifi 220/132/33 kV substation. This alleviate over loading on the 132kV circuits from Rabai and improve system voltages
iii. Implement Kipevu – Mbaraki 132 kV line and 132/33 kV substation. This will alleviate the overloading Bamburi-Kilifi.
iv. Installation of fast acting dynamic reactive power compensation at strategic locations in Galu and Kilifi.

d) Mt Kenya Region

i. Complete Nanyuki - Isiolo and Nanyuki-Rumuruti transmission lines. These will alleviate overloading on the Kiganjo-Nanyuki line and improve the system voltages in the Region.

e) Nairobi Region

i. Fast track commissioning of the Nairobi 220kV ring substations and associated 66kV feedouts.

8.17.2. Network Reliability

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

(a) Construct Olkaria 1AU – Olkaria V 220 kV double circuit line. This will improve power evacuation reliability between Olkaria complex and Suswa substation with the commissioning of Olkaria V power plant.
(b) Re-conductoring of Dandora-Nairobi North-Suswa and Dandora-Juja transmission lines using high capacity high temperature low sag conductors. This will additionally improve the reliability of Suswa – Nairobi North and Dandora – Juja –Ruaraka corridors.

8.17.3. 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, Athi River, and Malaa 220/66 kV substations along with their feeder outlets. 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.

8.17.4. System voltage control

Operate sections of committed 400 kV system at 220 kV initially to limit system voltages and need for extensive voltage control equipment deployment. It is recommended that lightly loaded sections of 400kV network (outer ring) be operated at 220kV to address system over voltages, for instance simulation indicated/confirmed that Malaa-Thika-Gilgil-Lessos section of the 400kV can be operated at 220kV up to 2030. Additionally, reactive power compensation equipment should be employed to ensure effective system operation and voltage stability in the event of a fault.

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 220/400 kV system as well as the under voltages observed in Nairobi, Mt.

Kenya, Coast and West Kenya at peak periods. The study should consider and optimize deployment of fast acting dynamic reactive compensation equipment e.g. STATCOMs having simulated and estimated the interactions with already installed power electronic based grid-based devices (DRPCs and HVDC converter stations).

8.18. Recommendations – (Long term 2030 - 2040).

8.18.1. Transmission Capacity and System Voltage Control

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) 2030

   i. Uprating 132/33kV to 2x45MVA at Chemosit from 2030.
   ii. Load transfers from New Bamburi to Bomani 132/33kV substation from 2030
   iii. New Thika -Mangu 132kV line - second line added (or effecting LILO on the Mangu/Gatundu 132kV line to terminate in New Thika)
   iv. Installation of 100MVAr reactor at Lessos.

b) 2035

   i. Installation of second 132/33kV transformer at Githambo, Othaya and Kabarnet.
   ii. Effecting load transfer from Kiganjo to Othaya and from Kilifi to Bomani.
   iii. Uprate/Replace all 18/23MVA transformers at Kisii/Kegati , Kutus to 45/60MVA,
   iv. Uprate/Replace all 7.5MVA transformers at Garissa to 23MVA,
   v. Installation of 100MVAr reactor at Thika and uprating the 9MVAr reactor to 30MVAr.

c) 2040

i. Reconductoring 132kV Mangu -Juja, New Thika-Mangu using High Temp Low Sag (HTLS) Conductors
ii. Introduction of 2x200MVA 220/66kV step down at Dandora and transferring about 200MW from Juja Rd to Dandora.
iii. Uprate/Replace two (2) of the 220/66kV 90MVA transformers at Nairobi North with 200MVA 220/66kV transformer.
iv. Effecting load transfer from Embakasi to Athi River substation.
v. Installation of third 220/66kV transformer at City Centre.
vi. Installation of new 45MVA 132/33kV transformer at New Bamburi.
vii. Uprate/Replace the 132/33kV 45MVA transformers at Kisumu with 90MVA 132/33kV transformers.
viii. Uprate/Replace the 132/33kV 23MVA transformers at Lessos with 45MVA 132/33kV transformers.

8.18.2. Optimization of wayleaves

It is recommended that all wayleaves for transmission system required in the medium and long term in fashion that will guarantee timely completion of project. The size secured must be able to accommodate double circuit construction for all transmission circuits. 400kV construction be considered for all regional (country – country or power pool - power pool) and inter region (regions within the country). These may be initially operated at 220 kV.

8.18.3. Network Reliability

220 and 400kV elements critical in the transmission system to comply to with N-1 reliability criteria. Maintaining a sizable number of standard transformers for possible deployment in the event one of the transformers put out of service.

8.18.4. Optimization and Improvement of network performance

Optimize and improve supply system by maintaining normally open (NO) in some interconnected 132kV lines and 220kV lines to avoid unnecessary overloading and hence reduce transmission losses

8.19. Optimizing the future Transmission Network.

8.19.1. Methodology

This entails finding acceptable sequence of investment starting from the 2020-2025 committed transmission networks and ending up to the developed target network. The investment sequence for the target network was established by creating and optimizing network models at 5 year intervals between 2025 and 2040, with the investment conforming to the selected 2040 target network requirements. This is done by starting with the 2040 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 are once again optimized through load flow, contingency and short circuit studies to ensure transmission system criteria is complied with at every stage. This is covered and the findings/recommendations discussed in the previous section. The simulation results are attached in the Appendices.

8.19.2. 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.

For the purpose of comparison of different strategies, transmission losses cost 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 (2020) 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.

In addition to transmission lines and substations reinforcement requirements for each snapshot year, reactive compensation requirements were also determined and transmission losses evaluated.

8.19.3. Comparison of investment strategies

Table 40 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 40 Summary of cost of investment of the three alternatives in USD

TARGET NETWORK	1	2
Total Cost (EPC_RAP+O&M + Losses)	**9,498**	**9,492**
Total PV Cost	**4,640**	**4,631**

From the above analysis, Target Network 2 results to lower NPV, this makes it the least cost development plan compared to Target Network 1, Target Network 2 is thus recommended for implementation. The present value of investments for this option is estimated at **MUSD 4,631.00.** Detailed investment analysis for the two option is tabulated in the *annex 10.*

8.19.4. Investment Sequence

8.19.4.1. Transmission lines and substations

The transmission lines and substations expected in the 2020-2040 planning period are listed in table 41 and 42

Table 41 Ongoing Projects

S/n	TRANSMISSION LINES		SUBSTATIONS			Projected Commissioning Date[9]	Estimated Project Cost
	TL Name	Length (KM)	S/n	SS Name	MVA		
1	Nairobi Ring substations (Isinya, Athi River, Kimuka, Malaa)	-	1	Athi River 220/66kV 2x200MVA	400	Nov-21	243.50
			2	Kimuka 220/66 2x200MVA	400	Nov-21	
			3	Malia 220/66 2x200MVA	400	Nov-21	
2	System Reinforcement (Isinya 400/220kV Substation)	-	4	Isinya 400/220 4x200MVA	800	Dec-21	624.78
3	Eastern Electricity Highway Project 500kV (EEHP)	612	5	Suswa 500/400kV 4x350MVA	1400	Jun-21	
4	Mwingi – Kitui 132kV	46	6	Kitui 132/33 1x23MVA	23	Mar-21	105.38
5	Kitui – Wote 132kV	66				Mar-21	
6	Lessos – Kabarnet 132kV	65	7	Kabarnet 132/33 1x23MVA	23	Dec-21	
7	Olkaria – Narok 132kV	68	8	Narok 132/33 1x23MVA	23	Dec-21	

[9] The dates are as projected in Dec 2020.Some dates are to be revised subject to the prevailing site condition, progress in acquisition of wayleaves and approval of the existing contract time extensions applications. For simulation purposes it was assumed that the projects were commissioned in the year following the year indicated in this table.

S/n	TRANSMISSION LINES		SUBSTATIONS			Projected Commissioning Date[9]	Estimated Project Cost
	TL Name	Length (KM)	S/n	SS Name	MVA		
8	Olkaria – Lessos – Kisumu (Kibos) 400/220/132kV	279	9	Kibos 220/132 1x150MVA	150	Feb-21	178.48
			10	Kibos 132/33 1x45MVA	45	Feb-21	
9	Isinya (Kajiado) – Namanga 132kV	80	11	Namanga 132/33 23 MVA	23	Jun-21	42.57
			12	Isinya 132/33 23MVA	23	Jun-21	
			13	Isinya 220/132 110MVA	110	Jun-21	
10	Turkwel – Ortum – Kitale 220kV	135	14	Ortum 220/33 23MVA	23	Nov-21	45.07
11	Olkaria II additional transformer (90MVA)	-	-	-	90	Jun-21	-
12	Nanyuki – Rumuruti 132kV	79	15	Rumuruti 132/33 23MVA	23	Dec-21	Cost incl. (item 6,7,8)
13	Nanyuki – Isiolo 132kV	70	-	-		Dec-21	54.78
14	Nanyuki – Rumuruti 132kV 14.5 km UG cable	14.5	-	-		Dec-21	10
15	Nanyuki – Isiolo 132kV 5 km UG cable	5	-	-		Dec-21	

S/n	TRANSMISSION LINES		SUBSTATIONS			Projected Commissioning Date[9]	Estimated Project Cost
	TL Name	Length (KM)	S/n	SS Name	MVA		
16	Mariakani 400/220kV substation	-	16	Mariakani 400/220 4x200MVA	800	Dec-21	29.02
17	Garsen -Bura-Hola – Garissa 220kV	240	17	Bura 220/33 1x23MVA	23	Dec-21	102.11
			18	Hola 220/33 1x23MVA	23	Dec-21	
2021 TOTAL		**1759.5**			**1333.00**		**1,435.69**
18	Sultan Hamud – Meruesh i- Loitoktok 132kV	120	19	Loitoktok 132/33 23MVA	23	Jun-22	129.69
			20	Merueshi 132/33 23MVA	23	Jun-22	
19	Awendo- Isebania	50	21	Isebania 132/33 1x23	23	Jun-22	
20	Isinya-Konza 400KV	45	-	Konza 400/132 2x150MVA	300	Jun-22	
21	Rabai-Bomani-Kilifi 132kV	67	22	Bomani 132/33 2x45MVA	90	Mar-22	32.41
2022 TOTAL		**282**			**459**		**162.1**
22	Lessos – Tororo 400kV	132	-	-	-	Dec-23	86.36
23	Kamburu-Embu-Thika 220KV	150 -	23	Embu 220/132 2x90MVA	180	Dec-23	140.77

S/n	TRANSMISSION LINES		SUBSTATIONS			Projected Commissioning Date[9]	Estimated Project Cost
	TL Name	**Length (KM)**	**S/n**	**SS Name**	**MVA**		
			24	Thika 220/132 2x90MVA	180	Dec-23	
24	Uplands (Limuru) substation		25	Uplands132/66 2x60MVA	120	Dec-23	
2023 TOTAL		**282**			**480**		**227.13**
25	Sondu (Thurdibuoro) – Ongeng (Homa Bay/Ndhiwa) 132kV	69	26	Thurdibuoro 1x23MVA	23	Jun-25	31.09
2025 TOTAL		**69**			**23**		**31.09**
	Total Length (KM)	**2392.5**		**Total SS Capacity Added**	**2295**		
TOTAL COST (MUSD)							**1,856.01**

Table 42 Planned Projects

TRANSMISSION LINES			SUBSTATIONS			Year Expected in the System	Estimated Cost (MUSD)	Implementing Agency
S/n	**Project Name**	**Length (KM)**	**S/n**	**SS Name**	**MVA**			
YEAR 2021								
1	Second Circuit LiLo Nakuru West – Lanet 132KV	1.5	-			2021	3.54	Kenya Power/
2021 TOTALS		**1.5**	**-**	**0**	**0**		**3.54**	
YEAR 2022								
1	Rongai Substation 132/33kV	1.5	1	Rongai 132/33 2x45MVA	90	2022	12.83	Kenya Power
2	Fast acting reacting power and voltage control devices at various regions for improved power quality (Coast, Nairobi).		-	4x -200MVAr , +150MVAr STATCOM/DRPC)	-200 and +150 MVAr	2022	74	KETRACO
2022 TOTALS		**1.5**	**1**		**90**		**86.83**	
YEAR 2023								
1	Olkaria 1 AU-Olkaria IV /V 220KV	8	-	-		2023	14.76	Generation KenGen
2	Kimuka Substation	0	1	Kimuka 400/220 2x400MVA	800	2023	28.59	KETRACO
3	Substation Extensions works for improved reliability and increased power quality (Garsen, Kitale, Kibos, Olkaria IAU)	-	-	Garsen 220/33 23MVA	23	2023	40.64	KETRACO
			-	Kitale 220/132 110MVA	110	2023		
			-	Kibos 220/132 150MVA	150	2023		
			-	Kibos 132/33 45MVA	45	2023		
			-	Olkaria IAU 220/132 90MVA	90	2023		

4	Substation Extensions works for improved reliability and increased power quality (Garsen, Kitale, Kibos, Olkaria IAU)	-	-	Kyeni 132/33 23MVA	23	2023	35	KETRACO
			-	Mwingi 132/33 23MVA	23	2023		
			-	Wote 132/33 23MVA	23	2023		
			-	Kitui 132/33 23MVA	23	2023		
			-	Narok 132/33 23MVA	23	2023		
			-	Bomet 132/33 23 MVA	23	2023		
5	Narok – Bomet 132kV	88		-	-	2023	34.62	Kenya Power
6	Weru – Kilifi 220kV	48.5	2	Kilifi 220/132 2x150MVA	300	2023	52.89	KETRACO
7	Malindi -Weru (Circuit II) 220kV	22	-	Malindi 220/33 45MVA	45	2023	27.13	KETRACO
8	Gilgil – Thika – Malaa– Konza 400kV	205	3	Thika 400/220 2x400MVA	800	2023	227	KETRACO – some sections to be operated t 220kV.
9	Mariakani – Dongo Kundu 220kV Line	55	4	Dongo Kundu 2x75MVA	150	2023	56.5	KETRACO – Required urgently considering Wasini Maritime Ltd load expected in 2023
10	Juja-Ruaraka 132KV	6.5	-	-	-	2023	1.71	KETRACO/KPLC
11	Musaga-Webuye 132KV	18	-	-	-	2023	2.79	KETRACO/KPLC
12	Kwale LILO (Mariakani/Dongo Kundu) -Kibuyuni (including switch station at Bang'a)		6	Kwale Sugar 220/132 2x90MVA	180	2023	84.9	KETRACO
13	Kipevu - Mbaraki 132kV	6.5	7	Mbaraki 132/33 2x45MVA	90	2023	14.44	KENYA POWER
	2023 TOTALS	**457.5**	**7**		**2921**		**620.97**	
				YEAR 2024				
1	Rongai 400/220		1	Rongai 400/220 2x200	400	2023	34.05	KETRACO

2	Rongai 220/132		2	Rongai 220/132 2x150	300	2023	18.85	KETRACO
3	Makindu substation	-	3	Makindu 400/132 2x150	300	2024	32.05	KETRACO
4	National System Control Centre	-				2024	50	KETRACO
5	400kV Gilgil and Lessos substations	-	4	Gilgil 400/220 2x400MVA	800	2024	48.73	KETRACO
			5	Lessos 400/220 2x400MVA	800	2024	32.16	KETRACO
6	Menengai - Olkalou – Rumuruti 132kV	70	6	Olkalou 132/33 2x60MVA	120	2024	34.34	KETRACO
			-	Rumuruti Tx 2 1x23MVA	23	2024		KETRACO
7	Sotik – Kilgoris 132kV	50	7	Kilgoris 132/33 2x23MVA	46	2024	22	KETRACO
8	Rumuruti – Kabarnet 132kV	111	-	Rumuruti Tx 2 1x23MVA	23	2024	79.45	KETRACO
9	Kisumu (Kibos) - Kakamega – Musaga 220kV	73	8	Kakamega 220/33	23	2024		KETRACO/PPP
10	Lessos-Loosuk (Through Baringo) 400kV	179	-	-	-	2024	202	KETRACO/PPP
11	Meru –Maua 132kV	35	9	Maua 132/33 1x23MVA	23	2024	25.63	KETRACO
12	Rumuruti – Maralal/Loosuk 132kV	148	10	Loosuk 132/33 1x23MVA	23	2024	48.84	KETRACO
	2024 TOTALS	**666**	**10**		**2881**		**628.1**	
YEAR 2025								
1	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	80	1	Mwala 1x23MVA	23	2025	51.74	KETRACO
2	Voi –Taveta 132kV	110	2	New Voi 132 132/33 1x23	23	2025	40.96	KETRACO
			3	Taveta 132/33 1x23MVA	23	2025		KETRACO
3	Kilgoris – (Isebania/Kehancha) 132kV	40	4	Isebania/Kehancha 132/33 1x23MVA	23	2025	29.2	KETRACO
4	Supply to Samburu SEZ from Mariakani	30	5	Samburu 220/132kV 2x60MVA	90	2025	41.57	KETRACO – Subject to customer scheduling of the project

5	Rangala - Bondo – Ndigwa 132kV	57	6	Bondo 132/33 1x23MVA	23	2025	33.85	KETRACO
			7	Ndwiga 132/33 1x23MVA	23	2025		KETRACO
6	Kitui - Mutomo – Kibwezi 132kV	132	8	Mutomo 132/33 1x23MVA	23	2025	59.35	KETRACO
			9	Kibwezi 132/33 1x23MVA	23	2025		KETRACO
7	220kV Rongai – Keringet-Chemosit -	96	10	Keringet 220/33 2x60MVA	120	2025	100	KETRACO/PPP
			11	Chemosit 220/132kV 2x90MVA	180	2025		KETRACO/PPP
8	Kiambere - Maua – Isiolo 220kV -	145	12	Maua 220/132 1x90MVA	90	2025	120.94	KETRACO
			13	Isiolo 220/132 1x90MVA	90	2025		KETRACO
9	Githambo - Othaya-Kiganjo 132kV	72	14	Othaya 132/33 1x23MVA	23	2025	34.9	KETRACO
	2025 TOTALS	**762**	**14**		**777**		**512.51**	
YEAR 2026								
1	Kiambere-Karura 220KV	20		-	-	2026	22.92	Generation KenGen
2	Awendo – Gogo – Magunga/ (Karungu Bay/Sindo) Bay 132Kv	48		-	-	2026	25	Generation - KenGen at Gogo
3	Reconductoring 220kV Suswa-NN with HTLS (39km 2 cts)	39		-	-	2026	9.8	KETRACO/KPLC
	2026 TOTALS	**107**		**0**	**0**		**57.72**	
YEAR 2027								
1	Loiyangalani – Marsabit 400kV	136	1	Marsabit 400/220 2x200MVA	400	2027	139	KETRACO + Generation
2	Kisumu(Kibos) – Bondo 132kV	61		-		2027	33	KETRACO/PPP
3	Kieni – Chogoria 132kV	23	2	Chogoria 132/33 1x23MVA	23	2027	18	KETRACO
4	Webuye - Kimilili – Kitale 132kV	73	3	Kimilili 132/33 1x23MVA	23	2027	35	KETRACO
5	Rangala – Busia 132kV	34		-	-	2027	15.1	KETRACO
6	Isiolo – Marsabit 220kV	240		-	-	2027	140	KETRACO+Generation

	2027 TOTALS	**567**	**3**	**0**	**446**		**380.1**	
YEAR 2028								
1	Isiolo – Garba Tula – Garissa 220kV	320	1	Garba Tulla 220/33 2x60MVA	120	2028	168.78	KETRACO
	-	-		Garissa 220/132 1x110MVA	110	2028		KETRACO
2	Garissa – Habaswein – Wajir 220kV	330	2	Habaswein 220/33 23MVA	-	2028	176.7	KETRACO
	-	-	3	Wajir 220/33 23MVA	-	2028		KETRACO
3	Uprating reactors at Garissa (from9MVAR to 30MVAr)	5		-	-	2028	0.85	KETRACO/KPLC
4	Myanga – Busia 132kV	27	4	Busia 132/33 2x23MVA	46	2028	23.91	KETRACO
5	Turkwel – Lokichar – Lodwar 220kV	120	5	Lokichar 220/66 1x60MVA	60	2028	100	KETRACO
	-		6	Lodwar 220/33 1x60MVA	60	2028		KETRACO
6	Baringo/Silali/Silale – Lokichar 220kV	245		-		2028	151	KETRACO+Generation GDC
7	Ndhiwa (Ongeng)- Magunga (Karungu Bay/Sindo) 132kV	50	7	Magunga 132/33 1x23MVA	23	2028	26.6	KETRACO
8	Uprating Chemosit SS (replace 23MVA with 45MVA TX)	-		Chemosit 132/33kV 2x45MVA	90	2028	3.16	
9	Baringo/Silali/Silale/Paka - Loosuk 400kV SS (LILO)	-	8	2x400MVA 400/220	800	2028	35.24	KETRACO + Generation - GDC
10	Suswa - Longonot –Olkaria VII 220KV	30		-	-	2028	24.92	Generation - KenGen/Agil
	2028 TOTALS	**1127**	**8**	**0**	**1309**		**711.16**	
YEAR 2030								
1	Lodwar – Lokichoggio 220kV	190	1	Lokichoggio 220/33 1x23 MVA	23	2030	120	KETRACO
2	Isiolo – Loosuk (Maralal) 132kV	150		-		2030	121	KETRACO
3	Thika/Gilgil LILO - Longonot 400/220kV Substation.	12	2	Longonot 400/220 2x400MVA	800	2030	47.46	GENERATION/KETRACO

								Reliability for Suswa Substation
4	Malaa – Thika Road 220kV	30		-		2030	24.5	KETRACO+ Reinforcement
5	Kolwa Substation (Sondu-Kisumu LILO)	2	3	Kolwa 132/33 2x45MVA	90	2030	10.4	KETRACO _ Expansion
6	Reinforcement of 132kV MNTL (Voi 400/132kV SS)	-	4	Voi 400/132 2x150MVA	300	2030	27.5	KETRACO
7	Fast acting reacting power and voltage control devices at various regions for improved power quality (West Kenya, N Rift & Mt. Kenya)			4x -200MVAr , +150MVAr STATCOM/DRPC)	-200 and +150 MVAr	2030	111	KETRACO
8	220kV Kilifi-Bamburi/Bomani-Mariakani	81	5	Bamburi 220/132 2x110MVA	220	2030	92.86	KETRACO
9	220kV Wajir-Mandera	250	6	Mandera 220/33 1x23MVA	23	2030	161.1	KETRACO
10	220kV Marsabit-Moyale	180	7	Moyale 220/33 1x23	23	2030	119.94	KETRACO
11	Thika/Malaa – HG Falls 400kV	200	7	-	-	2030	180.34	Generation HG Falls
	2030 TOTALS	**1095**	**7**		**1479**		**1016.1**	
				YEAR 2034				
1	Menengai – Rongai 400kV	45	1	Menengai 400/132 2x150	300	2034	76.08	KETRACO + Generation GDC
	2034 TOTALS	**45**	**1**		**300**		**76.08**	
				YEAR 2035				
1	Ngong (Kimuka) – Magadi 220kV	88	1	Magadi 220/66 1x60MVA	60	2035	74.12	KETRACO
2	Substation Extensions works for improved reliability and increased transformation capaicty (Othaya, Githambo,Kabarnet)	-		Othaya 132/33 23MVA	23	2023	1.15	KETRACO
				Githambo 132/33 23MVA	23	2023	1.15	KETRACO
				Kabarnet 132/33 23MVA	23	2023	1.15	KETRACO
3	Uprating/Replace all 23MVA transformers with 45/60MVA	-		Kisii/Kegati 132/33 2x45MVA	45	2023	3.16	KETRACO /KPLC

	transformers for improved reliability and increased transformation capaicty (Kisii/Kegati and Kutus)			Kutus 132/33 2x45MVA	45	2023	3.16	KETRACO/KPLC
4	Uprating/Replace all 7.5 MVA transformers with 18/23MVA transformers for improved reliability and increased transformation capaicty (Garissa)			Garissa 132/33 23MVA	23	2023	1.15	KETRACO
				Garissa 132/11 23MVA	23	2023	1.15	KETRACO
5	Dandora –Juja Rd 132kV(cct 3)	5		-	-	2035	12.14	Reinforcement Kenya Power/ KETRACO
6	Kimuka (Ngong)- Matasia 220kV	10	2	Matasia 220/66 2x60MVA	120	2035	25	KETRACO
	2035 TOTALS	**103**	**2**		**385**		**123.33**	
				YEAR 2037				
1	Lamu –Lamu Coal 220KV	20		-		2037	20.37	KETRACO+Generation
2	Malaa-Lamu 400KV	520	1	Lamu 400/220 2x200MVA	400	2037	487.65	KETRACO+Generation
3	Malindi-Garsen 220kV(line II)	104		-		2037	29	KETRACO + Generation
4	Garsen-Lamu 220kV (line II)	96		-		2037	27.3	KETRACO + Generation
	2037 TOTALS	740	1	-	400		564.32	
				YEAR 2038				
1	Longonot –Olkaria VIII 220KV	20		-	-	2038	22.92	Generation - KenGen/Agil
2	Loiyangalani – Lodwar 220kV	180	1	Loiyangalani 400/220 2x150MVA	300	2038	115.7	KETRACO
3	Substation Extensions works to accommodate additional transformer for improved reliability and increased transformation	-		City Centre 220/66 200MVA	200	2023	5.25	KETRACO

	capaicty (City Centre, New Bamburi,)			New Bamburi 132/33 45MVA	45	2023	1.79	KETRACO
4	Uprating/Replace 90MVA transformers with 200VA transformers for improved reliability and increased transformation capacity (Nairobi North, Kisumu-Mamboleo, Lessos)	-		Nairobi North 220/66 2x200MVA	400	2023	7.3	KETRACO
				Kisumu (Mambo Leo) 132/33 2x90MVA	180	2023	5.06	KETRACO
				Lessos 132/33 2x45MVA	45	2023	3.16	KETRACO
5	Dandora 220/66kV SS	-	2	Dandora 220/66 2x200MVA	400	2038	16.9	KETRACO
6	Reconductoring 132kV Mangu-Juja with HTLS (46km 2 cts)	46		-	-	2038	5.76	KETRACO
7	Reconductoring 132kV New Thika-Mangu HTLS (9km 2 ccts)	9		-	-	2038	1.134	KETRACO
	2038 TOTALS	**255**	**2**		**1570**		**184.974**	
				YEAR 2040				
1	Longonot –Olkaria IX 220KV	20		-	-	2040	22.92	Generation - KenGen/Agil
2	Weru-Galana 220kV	51	1	Galana 220/66 2x60MVA	120	2040	38.5	Subject to Volume of operation at Galana
3	Suswa-NIP	18	2	NIP 220/66kV 2x45MVA	90	2040	33.58	Subject to Volume of operation at NIP
4	Rongai - Kilgoris (Part of Lake Victoria Ring) 400kV	235	3	Kilgoris 400/132 2x150MVA	300	2040	219	KETRACO
	2040 TOTALS	**324**	**3**		**510**		**314**	
89	**GRAND TOTAL**	**6252.5**	**59**		**13068**		**5279.734**	

8.19.5. Reactive Compensation Sequence

The Reactive Compensation[10] Investment Sequence is as shown in table 43.

Table 43 Reactive Compensation Investment Sequence

NEW INVESTMENT IN REACTIVE POWER COMPENSATION					REMARKS
YEAR	**BUS NAME**	**VOLTAGE (kV)**	**MVAr**	**COST (MUSD)**	
2020	**ISINYA**	**400**	**2x-100**	**-**	**To be relocated from Embakasi currently operated at 220kV**
2020	**LOIYANGALANI**	**400**	**2x-100**	**-**	**Currently being operated at 220kV**
2023	ORTUM	220	2x-15	0.87	
2021	RANGALA	132	18	0.4	
2022	MERU	132	-7.5	0.25	
2022	BONDO	132	18	0.4	
2022	GARSEN	220	-10	0.4	
2022	GARISSA	220	-15	0.45	
2022	KIPEVU	132	27.5	0.7	
2024	KILGORIS	132	-30	0.7	
2024	OTHAYA	132	20	0.46	
2020	KILIFI	132	15	0.4	
2025	ONGENG	132	25	0.46	

[10] Variable reactive power equipment to be considered in place for the traditional fixed shunt reactors
Fast acting reactive power to be considered in the short term. These are as per system requirements resulting from the simulations. Additional studies are necessary to determine the best technology, minimum step size and confirm/determine the most strategic location for effectiveness.
Reactive power requirements for distribution network not included as these as well require additional analysis and accurate load data for the various substations.

TOTALS	5.49	

Table 44 Reactive Power equipment included as part of transmission lines cost in the transmission lines cost.

REACTIVE POWER COMPENSATION INCLUDED IN TL COST TABLE			**REMARKS**
BUS NAME	**Base kV**	**MVAr**	
GILGIL	400	-100	To be considered under fast acting q and v devices
GILGIL	400	-100	To be considered under fast acting q and v devices
KIMUKA	400	-100	To be considered under fast acting q and v devices
KIMUKA	400	-100	To be considered under fast acting q and v devices
ISIOLO	220	-30	
MAKINDU	400	-100	
VOI	400	-100	
RONGAI	400	-100	
RONGAI	400	-100	
KILGORIS	400	-100	
KILGORIS	400	-100	
SUSWA	400	-100	To be considered under fast acting q and v devices
SUSWA	400	-100	To be considered under fast acting q and v devices
LESSOS	400	-100	To be considered under fast acting q and v devices
LESSOS	400	-100	To be considered under fast acting q and v devices
MALAA	400	-100	To be considered under fast acting q and v devices
THIKA	400	-100	To be considered under fast acting q and v devices

MALAA	400	-100	To be considered under fast acting q and v devices
GARISSA	220	-15	
WAJIR	220	-45	
GARBA TULLA	220	-30	
HABASWEIN	220	-35	
LOKICHOGIO	220	-25	
LODWAR	220	-25	
MANDERA 220.00	220	-25	
MOYALE 220.00	220	-20	
MOYALE 220.00	220	-20	
KISUMU EAST (KOLWA)	132	25	To be considered under fast acting q and v devices
KISUMU EAST (KOLWA)	132	25	To be considered under fast acting q and v devices
KILGORIS	132	-25	

9. CONCLUSIONS AND RECOMMENDATIONS

This report is a revision of the finalised transitional report 2019-2039. The report takes into account changes in demand due to the adverse impact of the global pandemic covid-19. The report undertook a review of committed power generation and transmission projects and updated the power system simulation data including plant types, system constraints and costs. The report is an improvement over its predecessor in that it fully utilizes recent data by taking into account the findings of the 2019 census report. It further provides energy requirements for the proposed industrial/Special economic zones, updates emission data from the proposed planting sequences and also provides ancillary service requirements analysed by projects, providing general system requirements for integration of intermittent renewable technologies going forward.

The report is aligned to the Energy Act 2019 which provides for development of an Integrated National Energy Plans (INEP) consisting of coal, geothermal and electricity sub-plans in addition to County Energy Plans. The plan is intended to transition the electric power sub-sector to the new dispensation as the Ministry prepares to take up the full mandate of preparing the Integrated National Energy Plans going forward.

9.1. Conclusions

9.1.1. Demand Forecast

The review of the demand forecast incorporating the impact of the COVID-19 pandemic and the recommendations of various sectoral reports indicates a slower demand growth rate compared to the pre-COVID forecast. This is due to the decline in consumption by commercial consumers adhering to government containment measures. In addition, it has been noted over time that flagship projects are not being implemented within the timelines as envisaged, therefore slowing down both the economic and demand growth. It has also been noted that specific consumption has declined due to low consumption by newly connected customers

9.1.2. Generation Expansion planning

Simulations were done on the cases assembled based on various assumptions as discussed in chapter 6. Simulations were run based on three demand growth scenarios namely; Reference, Vision and Low. The "***Fixed Case Reference Scenario and optimized case reference scenario***" encapsulated the most likely development path hence it was used in deriving the long term expansion plan.

Annual generation analysis indicates progressive addition of intermittent capacity (solar and wind) in the planning period necessitates the selection of High Grand falls hydro plant, Dongo Kundu CCGT and Back up diesel generation for system support. Addition of 981MW Lamu coal generation in year 2027 to the system results in huge surpluses over and above peak and reserve requirements.

9.1.3. Ancillary Services Requirements

Preparation of this report comes at a time when the level of intermittent wind and solar energy is expected to rise rapidly in the Kenyan system, due to commitment by the Offtaker. This calls for the need to consistently evaluate the capability of the system to accommodate these technologies and hence extra investment in ancillary services. Critical ancillary services required include frequency control, voltage control, congestion management and black start capability.

Commissioning of large intermittent renewable plants such as Lake Turkana 300MW wind and the 50MW Garissa Solar, has led to additional requirements of ancillary services, especially primary reserves for system balancing to ensure frequency stability. Currently, only hydro units are being used to stabilize the grid in response to loss of generation, load variation and variability of wind and solar generation.

Required contingency reserves are generally considered to be at least equal to the size of the largest single generator connected to the power system. The largest unit in the current system is 82 MW (Kiambere 2 x 82MW units). No generator larger than Kiambere units is expected to be connected to the grid between now and 2023 except the Ethiopia import whose minimum with the two poles in operation is expected to be 200MW. Therefore, loss of one pole constitutes the largest system contingency which is 100MW.It is estimated that operational reserve for load

9.2. Summary of recommendations

i. Acceleration of implementation of the Vision 2030 flagship projects and Big Four agenda to spur demand and enhance implementation of demand creation initiatives and promote development of demand creation strategies by various utilities in the sector.

ii. Improved system management, automation and innovation to enhance supply reliability, efficiency and reduce system losses, and Provide incentives that promote conducive environment for growth of industrial customers and their associated energy consumption.

iii. The optimised case to be adopted as the national long term generation expansion plan for the 2020-2040 period.

iv. The proposed solar and wind projects which are likely to deliver higher intermittent capacity in the system than required should be spread to minimise energy curtailment.

v. For Solar and Wind projects that do not have PPAs, it is reccomended that they are migrated to renewable energy auctions.

vi. Peaking capacity power plants and Battery storage should be developed immediately to avert peak capacity shortfalls, absorb excess energy presented as vented steam during off-peak hours, provide system reserves and prevent load shedding in Western Kenya in the short term as transmission projects are being implemented. In the long term the recommended projects for the same purpose are LNG gas turbines, Pumped Hydro Storage and peaking hydro plants.

vii. Demand side management relating to load shifting is recommended to enable optimal utilisation of the excess energy in the system during off-peak hours. This includes initiatives like strengthening the time of use tariff, electrification of the transport sector among others.

viii. Demand creation efforts to be enhanced to support optimal use of the existing generation capacity and projects under implementation.

ix. Negotiate for firm 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term.

x. In the period between 2022 and 2024, there is a risk of firm capacity shortfalls if Ethiopia imports and the KenGen Olkaria I unit 6 plant are not realised as planned. This may necessitate extension of the plants scheduled for retirement.

xi. Renegotiate CODs and tariffs for projects that have PPAs but are yet to commence construction, to be integrated according to the dates given in the optimal plan. Respective contingent liabilities for the committed projects should be determined to inform proposals and negotiations.

xii. Carry out a comprehensive study on ancillary services requirements for the system, including battery storage, pumped storage and reactive power compensation, with the increasing levels of intermittent renewable energy sources.

xiii. The Automatic Generation Control (AGC) to be implemented as a matter of urgency to improve the management of secondary reserves to ensure smoother system frequency control.

xiv. Focus on sustainable technology for geothermal expansion that will minimize steam venting and enhance flexibility

ANNEXURES

ANNEX 1 Existing generation Plants

PPA	Plants in the PPA		Technology	Contracted Capacity (MW)	Installed Capacity (MW)	Term of PPA (years)	Payment Terms (Firm/ Non-Firm)	COD/ DCD/ OPS	Expiry Date
KENGEN (Major Hydros)	8	Masinga	Hydro	40	41.2	20	Firm	01-Jul-08	Jul-28
		Kamburu		90	94.2				
		Kindaruma (Redeveloped)		70.5	72				
		Gitaru		216	225				
		Kiambere		164	168				
		Tana (Redeveloped)		20	25.7				
		Sondu Miriu		60	60.7				
		Turkwel		105	106				
KENGEN (Small Hydros and Wind)	6	Wanjii	Hydro	7.4	7.4	15	Non-firm	Jul-09	Jul-24
		Gogo		1.6	2				
		Sosian		0.4	0.4				
		Sagana		1.5	1.5				
		Mesco		0.4	0.4				
		Ngong I Phase I	Wind	5.1	5.1				Jan-35

PPA	Plants in the PPA		Technology	Contracted Capacity (MW)	Installed Capacity (MW)	Term of PPA (years)	Payment Terms (Firm/ Non-Firm)	COD/ DCD/ OPS	Expiry Date
Olkaria II	1		Geothermal	101	105	20	Firm	Jul-08	Jul-28
Olkaria IV	1		Geothermal	140	149.8	25	Firm	Sep-14	Sep-39
Olkaria I (Unit 4&5)	1		Geothermal	140	150.5	25	Firm	Dec-14	Dec-39
Olkaria V	2		Geothermal	158	172.3	25	Firm	Nov-19	Nov-44
Kipevu Diesel Power I	1		Thermal	60	73.5	15	Firm	Jul-08	Jul-23
Kipevu Diesel Power III	1		Thermal	115	120	20	Firm	Mar-11	Mar-31
Muhoroni Gas Turbine	1		Thermal	56	60	2	Firm	Apr-19	Apr-21
Well Heads	8	Well head 37	Geothermal	5	5.5	15	Non-firm	May-12	Apr-33
		Well head 37 kwg 12		5	5				
		Well head 37 kwg 13		5	5				
		Well head 39		5	5				
		Well head 43		12.8	12.8				
		Well head 905		5	5				
		Well head 914 & 915		37.8	37.8				
		Well head 919		5	5				
Eburru	1		Geothermal	2.44	2.44	20	Non-firm	Feb-12	Feb-32
Sang'oro	1		Hydro	20	21.2	25	Non-firm	Aug-12	Aug-37

PPA	Plants in the PPA		Technology	Contracted Capacity (MW)	Installed Capacity (MW)	Term of PPA (years)	Payment Terms (Firm/ Non-Firm)	COD/ DCD/ OPS	Expiry Date
Ngong 1 Phase II and Ngong 2	1	Ngong 1 Phase II	Wind	6.8	6.8	20	Non-firm	Jan-15	Jan-35
		Ngong 2		13.6	13.6				
UETCL (Export & Import)				-	-	3	Non-firm	Jun-20	Jun-21
REA Garissa	1		Solar	50	50	20	Non-firm	FCOD not achieved	2038
Iberafrica Power Company		Plant2	Thermal	52.5	52.5	25	Firm	Oct-09	Oct-34
Tsavo Power Company Ltd.	1		Thermal	74	74	20	Firm	Sep-01	Sep-21
Rabai Power	1		Thermal	88.6	90	20	Firm	May-10	May-30
Orpower 4 Inc.	4	Expanded Plant1	Geothermal	63.8	63.8	25	Firm	Jun-18	Jan-43
		Plant2	Geothermal	39.6	39.6			Apr-13	Apr-38
		Plant3	Geothermal	17.6	17.6			Jan-14	Jan-39
		Plant 4	Geothermal	29	29			Jan-16	Jan-41
Imenti Tea Factory Ltd.	1		Hydro	0.283	0.283	15	Non-firm	Sep-09	Sep-24
Gikira Small Hydro	1		Hydro	0.514	0.514	20	Non-Firm	May-14	May-34
Thika Power (Melec)	1		Thermal	87	87	20	Firm	Mar-14	Mar-34

PPA	Plants in the PPA		Technology	Contracted Capacity (MW)	Installed Capacity (MW)	Term of PPA (years)	Payment Terms (Firm/ Non-Firm)	COD/ DCD/ OPS	Expiry Date
Gulf Power	1		Thermal	80.32	80.32	20	Firm	Dec-14	Dec-34
Triumph Power	1		Thermal	83	83	20	Firm	Jul-15	Feb-35
Biojoule Kenya	1		Biogas	2	2	20	Non-Firm	Jan-16	Jan-36
GenPro-Teremi Falls	1		Hydro	5	5	20	Non-firm	Jun-17	Jun-37
Chania Power Co- KTDA	1		Hydro	0.5	0.5	20	Non-firm	FCOD not achieved	May-37
Gura KTDA	1		Hydro	2	2	20	Non-firm	Jun-19	Jun-39
Strathmore Solar	1		Solar	0.25	0.25	20	Non-firm	Sep-19	Sep-39
Lake Turkana Wind Power	1		Wind	300	310	20	Non-firm	Mar-19	Mar-39
KTDA Metumi (North Mathioya)	1		Hydro	3.6	3.6	20	Non-firm	FCOD not achieved	Jul-40
				2,676	**2,757**				

ANNEX 2 Average Hydrology forecast

Average Hydrology MWh per day												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Tana	215	126	129	208	303	348	254	205	174	190	307	303
Masinga	394	521	508	318	214	331	466	568	525	439	329	412
Kamburu	1073	1037	1032	1063	1095	1109	1063	1120	1103	1035	1151	1043
Gitaru	2199	2043	2044	2138	2251	2314	2254	2225	2197	2050	2274	2011
Kindaruma	486	479	488	501	557	619	537	524	502	469	555	483
Kiambere	2418	2409	2342	2273	2573	2579	2555	2509	2519	2442	2394	2432
Turkwel	1461	1545	1593	1287	1079	1069	1216	1360	1418	1384	1343	1283
Sondu	720	424	432	823	1171	1317	1239	1290	1292	1169	1120	961
Sang'oro	201	121	115	259	357	431	380	404	431	385	370	300
Karura	607	599	610	626	696	774	671	655	628	586	693	604

ANNEX 3 Dry Hydrology forecast

Dry Hydrology MWh per day												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Tana	142	83	85	137	200	230	168	136	115	126	202	200
Masinga	260	344	335	210	141	218	308	375	346	290	217	272
Kamburu	708	684	681	702	723	732	702	739	728	683	760	688
Gitaru	1451	1348	1349	1411	1486	1527	1488	1468	1450	1353	1501	1327
Kindaruma	321	316	322	331	368	408	354	346	332	309	366	319
Kiambere	1596	1590	1546	1500	1698	1702	1686	1656	1663	1612	1580	1605
Turkwel	964	1020	1051	850	712	705	802	898	936	913	886	847
Sondu	475	280	285	543	773	869	817	851	853	771	739	634
Sang'oro	132	80	76	171	236	285	251	266	284	254	245	198
Karura	401	395	403	413	459	511	443	432	414	387	458	399

ANNEX 4 IPP Projects with PPA considered Under Fixed System case

	Project Company	Capacity(MW)	Technology	PPA DATE	Fixed case COD	Optimised Case COD
1	Alten Kenya Limited	40	Solar	May-21	2022	2024
2	Aperture Green Power Ltd / Limuru Wind	50	Wind	Dec-22	2023	2026
3	Cummins Cogeneration Kenya Limited	10	Biomas	Jun-20	2023	2023
4	Dafre Holdings Company Ltd /Makindu solar ltd	30	Solar	Dec-23	2024	2029
5	Frontier Investment Management/ Nithi Hydro	5.6	Hydro	Dec-24	2025	2025
6	Global Sustainable-Kaptis	14.7	Hydro	Dec-25	2026	2026
7	Global Sustainable Ltd-Buchangu	4.5	Hydro	Dec-25	2026	2026
8	Greenmillenia Energy Limited	40	Solar	Dec-25	2026	2030
9	Hydro Project Service Peters Kianthumbi	0.51	Hydro	Apr-21	2021	2021
10	Kenergy Renewables Ltd-Rumuruti	40	Solar	Dec-22	2023	2028
11	Kipeto Energy Limited	100	Wind	Jul-21	2021	2021
12	KTDA, Kipsonoi (Settet Power Co.)	0.6	Hydro	Feb-25	2025	2025
13	KTDA Ltd, South Maara (Greater Meru Power Co.)	1.5	Hydro	Dec-21	2022	2022
14	KTDA Ltd, Lower Nyamindi	0.8	Hydro	Dec-21	2022	2022
15	KTDA Ltd, Iraru	1	Hydro	Dec-21	2022	2022

	Project Company	Capacity(MW)	Technology	PPA DATE	Fixed case COD	Optimised Case COD
16	Kwale Int. Sugar Co. Ltd	10	Biomas	Dec-21	2023	2023
17	Marco Borero Co Ltd.	1.5	Solar	Jun-20	2022	2022
18	Mt Kenya Community Based Organisation	0.6	Hydro	Dec-22	2023	2023
19	Power Technologies (Gatiki Small Hydro Plant)	9.6	Hydro	Jun-22	2022	2022
20	REA Vipingo Plantations Ltd (DWA Estates Ltd)	1.44	Biomas	Dec-20	2022	2022
21	Sun Power Kenya Limited (Kibwezi)	40	Solar	Jun-26	2026	2030
22	Thika Way Investments (Homa Bay Biogas One)	8	Biogas	Jun-23	2023	2023
23	Tindinyo Falls Resort	1.5	Hydro	Jun-23	2023	2023
24	Vateki International Holdings /Malindi Solar Limited	40	Solar	Jan-22	2022	2023
25	Kopere Solar Park Limited	40	Solar	Jun-23	2023	2024
26	Quantum/QPEA GT Menengai Limited (Menengai)	35	Geothermal	Jan-22	2023	2023
27	Sosian-Menengai Geothermal Power Ltd	35	Geothermal	Dec-21	2023	2023
28	Orpower 22 (Menengai)	32.5	Geothermal	Jun-22	2023	2023
29	Akiira Geothermal Ltd & Marine Power Generation Company Ltd	70	Geothermal	Jun-25	2025	2031
30	Kleen Energy Limited	6	Hydro	Dec-20	2022	2022
31	Selenkei (Radiant)	40	Solar	Dec-21	2022	2022

	Project Company	Capacity(MW)	Technology	PPA DATE	Fixed case COD	Optimised Case COD
32	Eldosol (Cedate)	40	Solar	Dec-21	2022	2023
33	Chania Green	50	Wind	May-22	2024	2024
34	Roadtech Solutions Ltd	10	Biomas	Dec-24	2025	2025
35	Hannan Arya Energy (K) Ltd	10	Solar	Dec-21	2023	2027
36	Bahari Winds (Electrawinds Kenya)	50	Wind	Dec-24	2025	2028
37	Bahari Winds (Electrawinds Kenya)	40	Wind	Dec-25	2026	2029
38	Prunus Energy	50	Wind	Dec-25	2026	2029
39	KTDA - Nyambunde, Nyakwana	0.5	Hydro	Jun-21	2022	2022
40	Africa Geothermal International (Kenya) Ltd - AGIL	35	Geothermal	Jun-25	2026	2029
41	Africa Geothermal International (Kenya) Ltd - AGIL	35	Geothermal		2027	2033
42	Africa Geothermal International (Kenya) Ltd - AGIL	35	Geothermal		2028	2034
43	Africa Geothermal International (Kenya) Ltd - AGIL	35	Geothermal		2029	2039
44	Amu Coal	981.5	Coal	Dec-26	2027	2037
45	Ethiopia HVDC phase 1	200	import	Jul-21	2021	2021
46	Ethiopia HVDC phase 2	200	import	Jul-24		

ANNEX 5 IPP Projects without PPA consdered under Fixed system case

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
1	APGL Investments Kenya Limited	40	Solar	Aug-21	Not Selected - Does not meet Peak load requirments	Not Optimised
2	Asachi powertech limited	30.6	Solar	Dec-21	Not Selected - Does not meet Peak load requirments	Not Optimised
3	Azania Power Limited	40	Solar	Dec-22	Not Selected - Does not meet Peak load requirments	Not Optimised
4	Biogas Holdings Ltd	0.25	Biogas	Not set		
5	BLA Machakos Solar Park /BELGEN	40	Solar	Dec-26	Not Selected - Does not meet Peak load requirments	Not Optimised
6	Blue Sea Energy Ltd	50	Wind	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
7	Chemelil Green Energy	40	Solar	Dec-22	Not Selected - Does not meet Peak load requirments	Not Optimised
8	Chevron Africa Limited	7.8	Hydro	Dec-25	2033	2033
9	Crystal Energy Solutions (Kavuko Power Ltd)	40	Biomas	Dec-24	2031	2031
10	Dominion Farms	1	Hydro	Dec-25	2033	2033

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
11	Ergon Solair	10		Nov-21	Not Selected - Does not meet Peak load requirments	
		30	Solar	Nov-22	Not Selected - Does not meet Peak load requirments	Not Optimised
12	Escalate Group Limited	40	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised
13	Frontier Investment Management Africa Ltd & Craftskills Wind Energy International Ltd	50	Wind	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
14	Gem Gen Power Company Limited	9.5	Hydro	Dec-23	2030	2030
15	Gigawatt Global Cooperatief U.A	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
16	Gigawatt Global Cooperatief U.A	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
17	Glevantas Ltd	2	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
18	Greenlight Holdings/ Rianjue/Gichuki Ventures	1.5	Hydro	Dec-23	2030	2030
19	Greenwood Power	40	Solar	Jan-23	Not Selected - Does not meet Peak load requirments	Not Optimised
20	Hydel	5	Hydro	Dec-20	2027	2027
21	Innowind Kenya Ltd	30.5	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
22	Kajire Energy Ltd (Rights transferred from Sagalla)	10	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised
23	Kamukuru Energy Limited	20	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
24	Karuga Gitugi Electrification Project	2.7	Hydro	Dec-24	2032	2032
26	Kengreen Energy Ltd	10	Solar	Dec-26	Not Selected - Does not meet Peak load requirments	Not Optimised
27	Kenya Light Project Ltd	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
28	Kenya Solar Energy Ltd (Kensen)	40	Solar	Jun-22	Not Selected - Does not meet Peak load requirments	Not Optimised
29	Khalala Hydro Power Kenya Limited (Coastal Energy Ltd, Navakholo)	20	Hydro	Dec-25	2033	2033
30	Kiamariga Solar Energy Ltd	40	Solar	Jun-25	Not Selected - Does not meet Peak load requirments	Not Optimised
31	Kibisi Kinetic Energy Limited/Virunga Power Holdings	6.5	Hydro	Jan-24	2031	2031
33	Kingdom Cell Lighting Company (Adenium Energy Ltd/Mwingi One Solar Project)	10	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
34	Kirogori Electrification Project	7	Hydro	Jun-24	2031	2031
35	KTDA Chemosit, Kiptiget	3.3	Hydro	Dec-24	2032	2032

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
36	KTDA Ltd, Yurith, Chemosit	0.9	Hydro	Dec-24	2032	2032
37	KTDA R. Chemosit, Chemosit	2.5	Hydro	Jun-24	2031	2031
38	KTDA R. Rupingazi, Rutune	1.8	Hydro	Dec-24	2032	2032
39	KTDA, R. Itare, Chemosit	1.3	Hydro	Dec-24	2032	2032
40	KTDA, R. Yala, Taunet	2.77	Hydro	Dec-24	2032	2032
41	Lakini Energy East Africa Ltd (Adenium Energy Ltd/Gogar 1 Solar Park)	10	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
42	Midlands Solar Energy Limited	50	Wind	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
43	Midlands Solar Energy Limited	40	Solar	Dec-26	Not Selected - Does not meet Peak load requirments	Not Optimised
44	Multilink Investments Group Ltd (Maingi Solar Project Ltd)	40	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
45	Mutunguru Hydroelectric Company Ltd	7.8	Hydro	Dec-20	2027	2027
46	Mwikhupo-Mwibale Hydro Power Kenya	7	Hydro	Dec-22	2029	2029
47	Naanovo Kenya Limited	30	Solar	Dec-22	Not Selected - Does not meet Peak load requirments	Not Optimised
48	Nelios (Orion SARL) Solarion Investments Ltd	10	Solar	Jan-23	2023	2023

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
		10	Solar	Jun-23	2023	2023
		10	Solar	Dec-23	2023	2023
		10	Solar	Jun-24	2024	2024
49	Njega/Rukenya Hydro Power Limited (Rights transfer)	3.5	Hydro	Dec-23	2030	2030
50	Njumbi Hydropower Plant Ltd (Hydroneo)	9.6	Hydro	Dec-25	2033	2033
51	Northern Power Ltd/Maralal Energy Ltd	50	Wind	Jun-25	Not Selected - Does not meet Peak load requirments	Not Optimised
52	Pearl Zone KE Ltd	40	Solar	Jun-21	Not Selected - Does not meet Peak load requirments	Not Optimised
53	Quaint Energy Kenya Limited	40	Solar	Jul-21	Not Selected - Does not meet Peak load requirments	Not Optimised
54	Range Technologies Kenya Limited	60.8	Wind	Dec-21	Not Selected - Does not meet Peak load requirments	Not Optimised
55	Rareh Nyamindi Hydro Ltd	5.2	Hydro	Jan-24	2031	2031
56	Rareh Nyamindi Hydro Ltd	9.4	Hydro	Jan-24	2031	2031
57	Rareh Nyamindi Hydro Ltd	6	Hydro	Jan-24	2031	2031
58	Ray Power Limited	35	Biomas	Jun-23	2029	2029

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
59	Sayor Energy Ltd	10	Solar	Dec-20	Not Selected - Does not meet Peak load requirments	Not Optimised
60	Solar Century E.A Ltd (Sergoit Plant)	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
61	Solar Stream Corporation	40	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
62	Solarcentury East Africa Ltd (Lewa Borana Plant)	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
63	Solargen Energy Corporation	40	Solar	Jun-22	Not Selected - Does not meet Peak load requirments	Not Optimised
64	Solarjoule Ltd	10	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised
65	Sosian Astonfield	10	Solar	Dec-20	Not Selected - Does not meet Peak load requirments	Not Optimised
		20	Solar	Dec-22	Not Selected - Does not meet Peak load requirments	Not Optimised
		10	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised
66	Soy Solar Ltd	40	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised

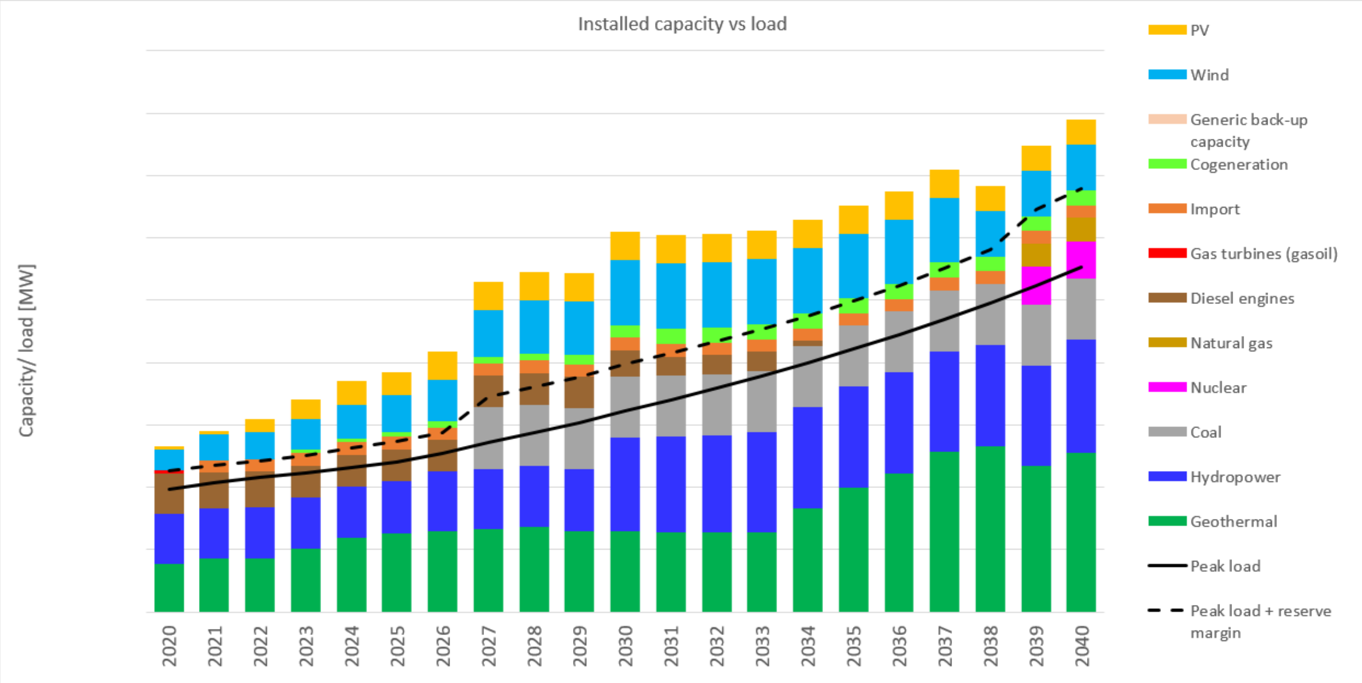
	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
67	Sukari Industries Ltd	22	Biomas	Dec-19	2026	2026
68	Sustainable Energy Management	40	Biomas	Jan-24	2030	2030
69	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	20	Biogas	Jun-22	2028	2028
70	Tarita Green Energy Company Limited (Cherab)	40	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
71	Tarita Green Energy Company Limited(Kaptagat)	40	Solar	Dec-23	Not Selected - Does not meet Peak load requirments	Not Optimised
72	Tellux Africa Limited	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
73	Tellux Africa Limited	10	Solar	Dec-24	Not Selected - Does not meet Peak load requirments	Not Optimised
74	Tenwek Hospital	0.25	Hydro	Jun-19	Expired	Expired
75	Tridax Limited	4.2	Hydro	Dec-24	2032	2032
76	Truck city ltd	5.28	Hydro	Dec-24	2032	2032
77	Turaco Energy Ltd	10	Solar	Dec-25	Not Selected - Does not meet Peak load requirments	Not Optimised
78	Unilever Tea Kenya Ltd	2.85	Hydro	Not set	Not simulated	Not simulated
79	Ventus Energy Ltd	7.67	Hydro	Dec-21	2028	2028

	Project Company	Capacity(MW)	Technology	Expected COD	Fixed Case COD	Optimised case COD
80	Viability Africa (Northern Energy Limited)	2.4	Biomas	Dec-24	2031	2031
81	Virunga Power Holdings Ltd, R. Sossio, Kaptama	4.5	Hydro	Dec-23	2030	2030
82	VR Holding AB-Local Trade Ltd	3	Biomas	Dec-21	2027	2027
83	VSHydro Kenya Ltd	9.1	Hydro	Jan-24	2031	2031
84	West Kenya Sugar Company Limited	6	Biomas	Mar-23	2029	2029
85	Xago Africa Limited	40	Solar	Dec-21	Not Selected - Does not meet Peak load requirments	Not Optimised
86	Western Hydro	10	Hydro	Dec-25	2033	2033
87	High Grand Falls Multipurpose Project	693	Hydro	Dec-25		2037
88	Dongo Kundu	375	LNG		2036	2036
89	Dongo Kundu	375	LNG		2038	2038
91	Orpower IV	50	Geothermal	Jun-25	2030	2030

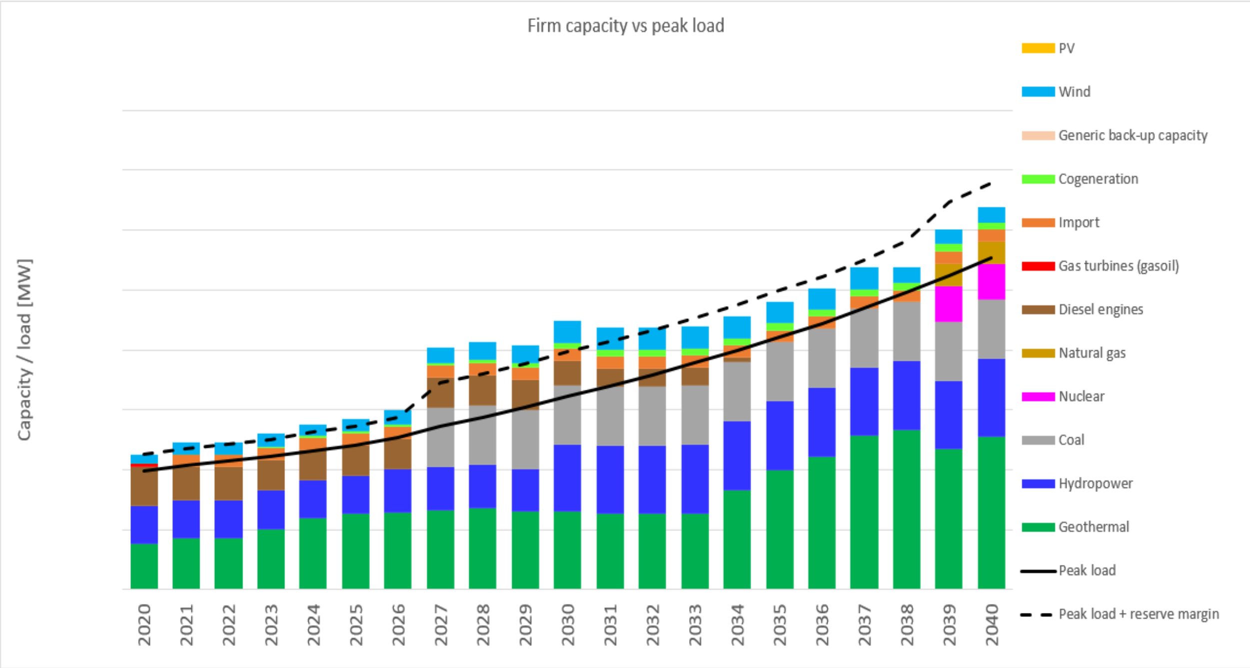
ANNEX 6 Technology capacity factors - Fixed system case Reference demand

Capacity factor [%]	2021	2022	2023	2024	2025	2030	2035	2040
Geothermal	76.4%	77.5%	73.5%	72.8%	72.7%	73.5%	75.3%	87.4%
Hydropower	49.6%	49.6%	49.6%	49.6%	49.6%	41.3%	41.9%	37.7%
Coal						2.8%	4.6%	14.4%
Nuclear								30.9%
Natural gas								1.5%
Diesel engines	2.1%	3.2%	1.8%	0.9%	0.8%	0.0%		
Import		86.6%	85.6%	85.3%	85.3%	85.0%	85.0%	85.2%
Cogeneration	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Wind	51.7%	51.7%	48.6%	47.8%	46.2%	42.3%	42.5%	37.3%
PV	19.6%	15.9%	16.4%	14.8%	14.8%	15.6%	15.6%	15.2%
Gas turbines (LNG)				0.0%	0.0%	0.0%	0.1%	0.2%

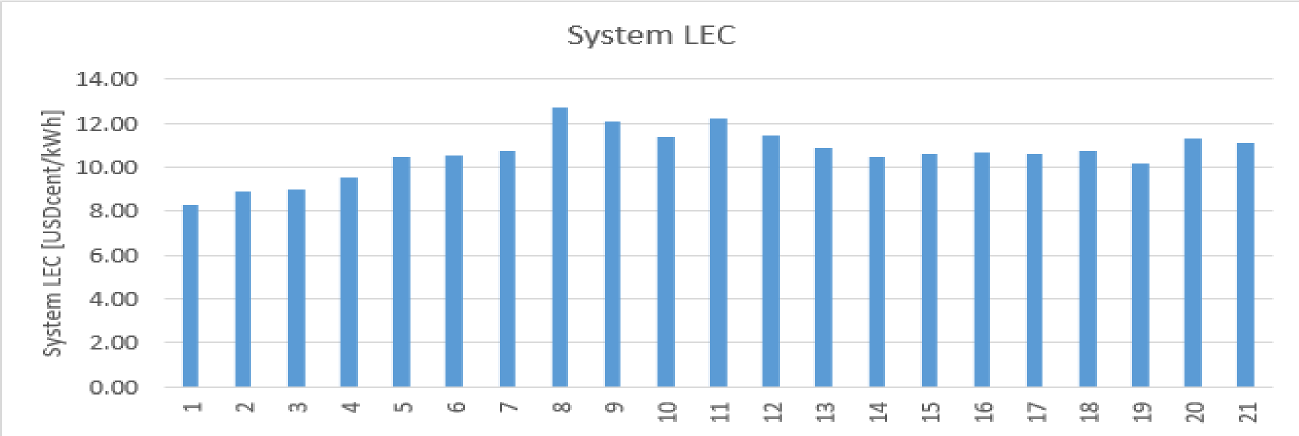
ANNEX 7 Installed Capacity vs Load - Fixed System Reference



ANNEX 8 Frim capacity vs Peak Load - Fixed system case Refernce scenario



ANNEX 9 Levelised cost of energy - Fixed case with candidates - Reference scenario



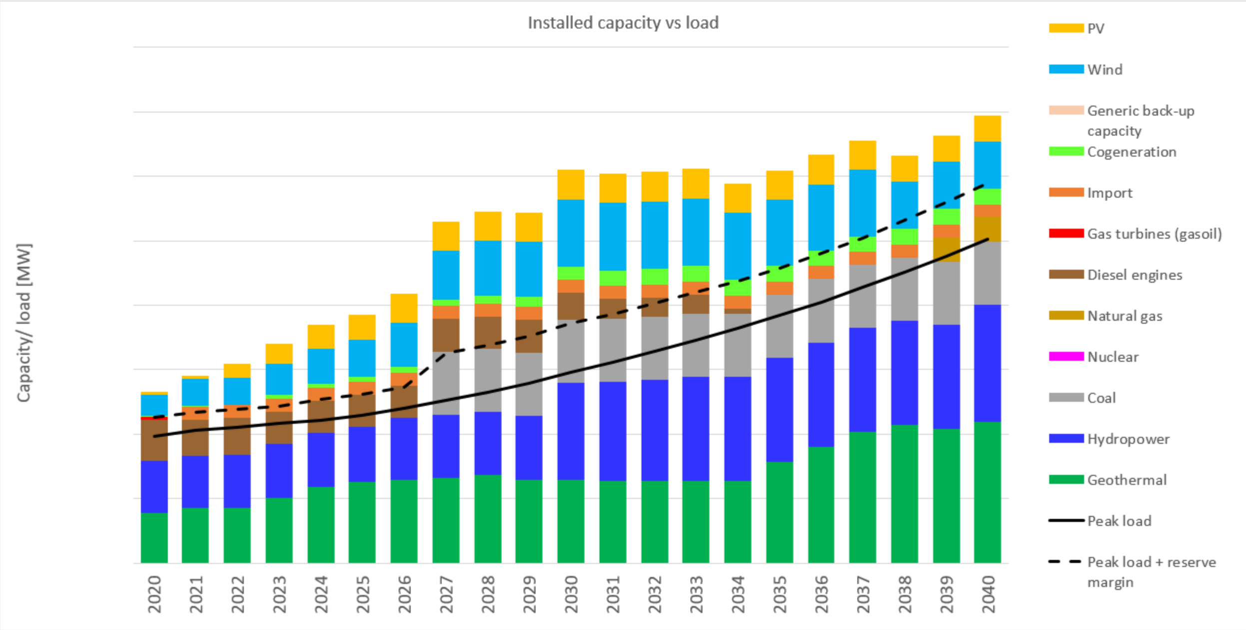
ANNEX 10 Demand Supply balance - Fixed System Low Demand

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Peak load	MW	1,972	2,060	2,111	2,163	2,221	2,285	2,962	3,841	5,028

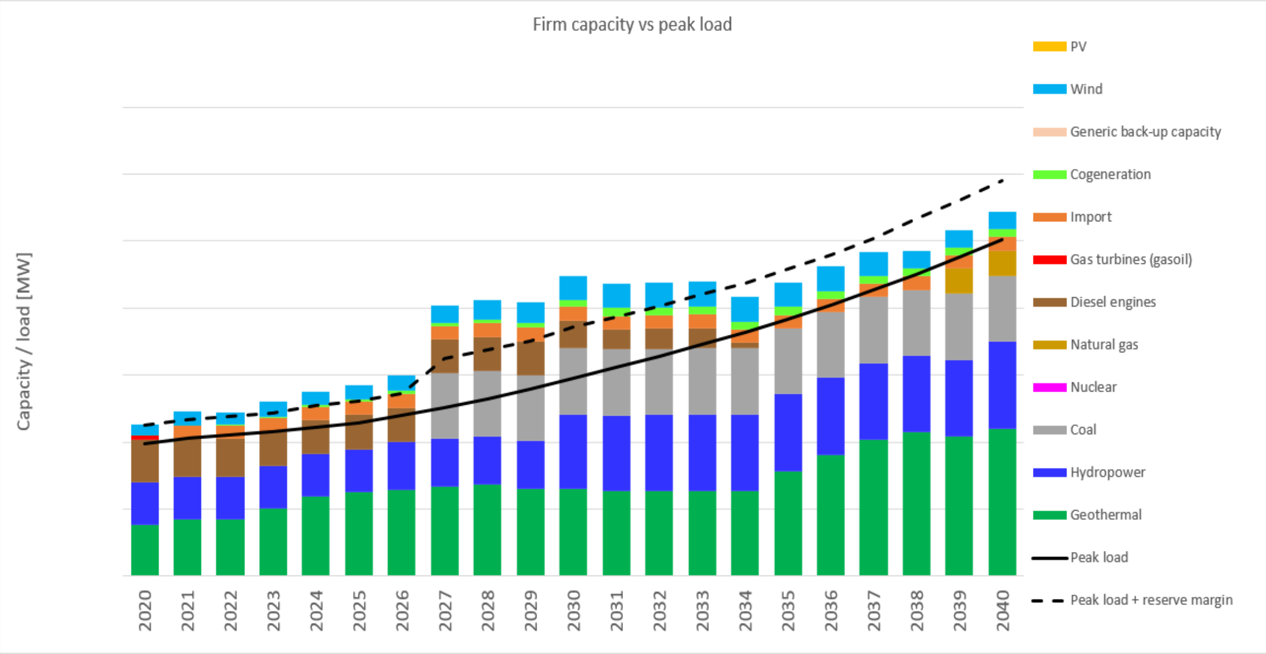
		2020	2021	2022	2023	2024	2025	2030	2035	2040
Peak load + reserve margin	MW	2,255	2,332	2,383	2,437	2,543	2,612	3,722	4,578	5,901
Reserve margin	% of peak load	14%	13%	13%	13%	14%	14%	26%	19%	17%
Installed system capacity	MW	2,654	2,907	3,090	3,400	3,897	4,045	6,298	6,291	7,421
Firm system capacity	MW	2,260	2,463	2,448	2,604	2,947	3,044	4,681	4,578	5,914
Supply - demand gap	MW	4	131	64	167	404	433	959	0	13
Electricity consumption versus generation		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**
Electricity consumption	GWh	12,072	12,612	12,925	13,243	13,598	13,988	18,131	23,515	30,743
Electricity generation	GWh	12,078	12,805	13,127	14,395	15,621	16,288	20,542	23,943	30,775
Unserved energy	GWh	0	0	0	0	0	0	0	0	563
Unserved energy -	%	0%	0%	0%	0%	0%	0%	0%	0%	2%

		2020	2021	2022	2023	2024	2025	2030	2035	2040
share on consumption										
Excess energy	GWh	6	192	202	1,152	2,023	2,301	2,412	428	32
Excess energy - share on generation	%	0%	2%	2%	8%	13%	14%	12%	2%	0%
Vented GEO steam	GWh	166	1,405	1,417	1,919	2,330	2,486	2,590	2,514	1,238
Vented GEO steam - share on potential max. GEO flash steam generation	%	3%	20%	20%	23%	24%	24%	24%	19%	7%

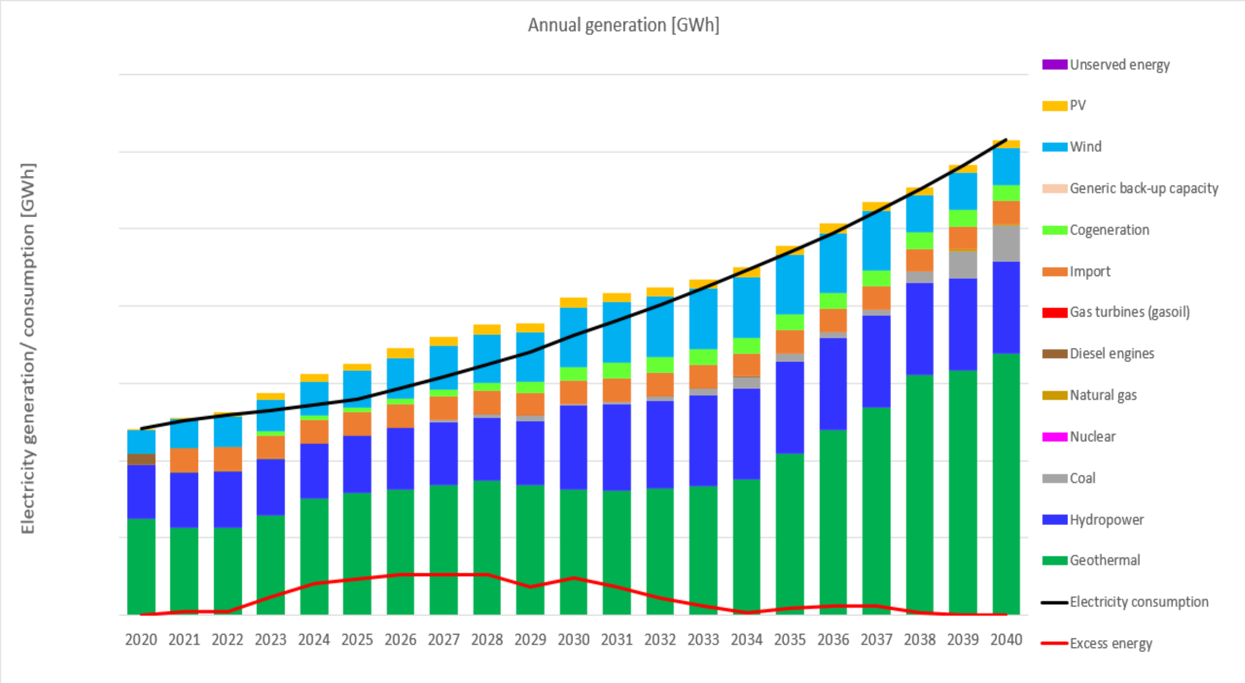
ANNEX 11 Installed capacity vs Load - Fixed system Low demand



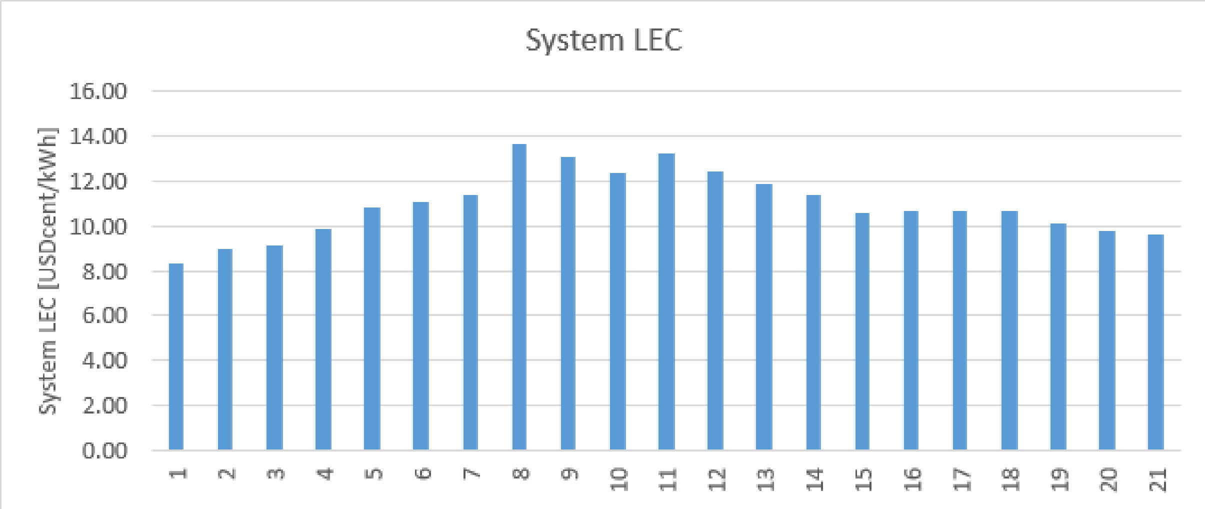
ANNEX 12 Firm capacity vs peak load - Fixed system Low demand scenario



ANNEX 13 Annual generaion - Fixed System Low demand scenario



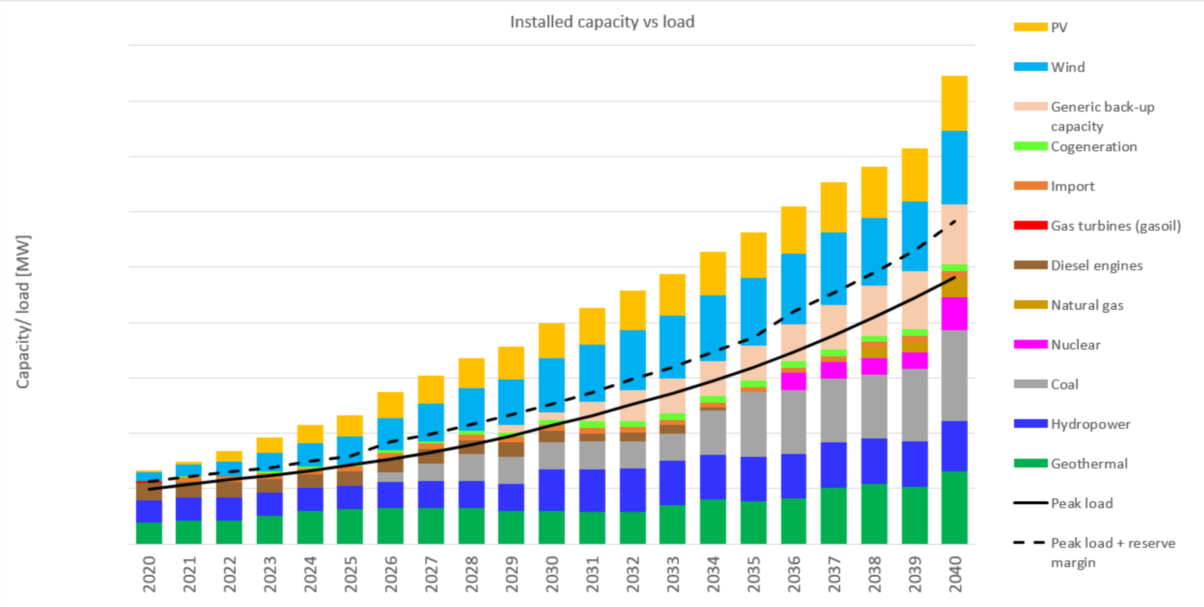
ANNEX 14 Levelised cost of energy - Fixed case with candidates - low scenario



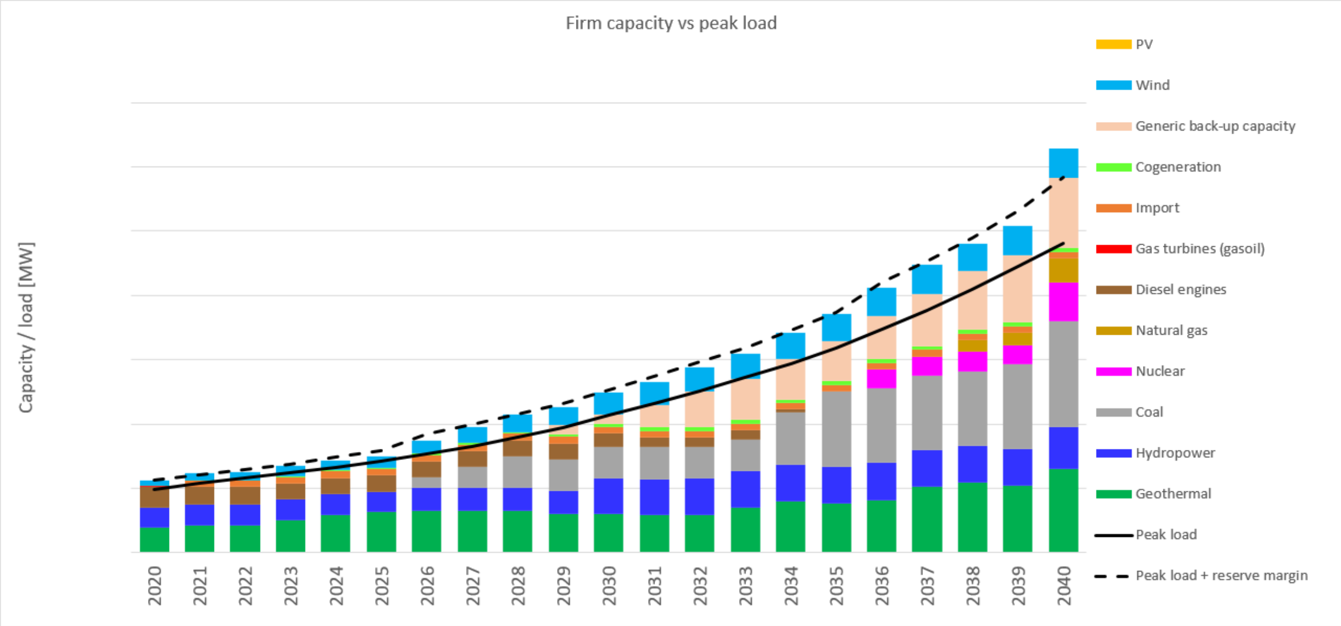
		2020	2021	2022	2023	2024	2025	2030	2035	2040
Peak load	MW	1,972	2,155	2,331	2,478	2,656	2,844	4,268	6,382	9,635
Peak load + reserve margin	MW	2,255	2,427	2,602	2,752	2,978	3,171	5,061	7,468	11,659
Reserve margin	% of peak load	14%	13%	12%	11%	12%	11%	19%	17%	21%
Installed system capacity	MW	2,654	2,987	3,350	3,840	4,517	4,845	8,173	11,459	17,394
Firm system capacity	MW	2,260	2,463	2,493	2,694	3,052	3,184	5,171	7,636	13,052
Supply - demand gap	MW	4	36	-110	-58	74	13	110	169	1,393
Electricity consumption versus generation		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2030**	**2035**	**2040**
Electricity consumption	GWh	12,072	13,194	14,267	15,170	16,261	17,412	26,125	39,025	58,367
Electricity generation	GWh	12,078	13,266	14,336	15,917	17,718	19,031	26,827	39,114	58,372
Unserved energy	GWh	0	0	2	2	0	1	1	3	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	6	73	71	749	1,457	1,620	702	92	5
Excess energy - share on generation	%	0%	1%	0%	5%	8%	9%	3%	0%	0%
Vented GEO steam	GWh	166	1,163	1,041	1,714	2,055	2,127	1,595	659	428

		2020	2021	2022	2023	2024	2025	2030	2035	2040
Vented GEO steam - share on potential max. GEO flash steam generation	%	3%	16%	15%	20%	21%	20%	16%	5%	2%

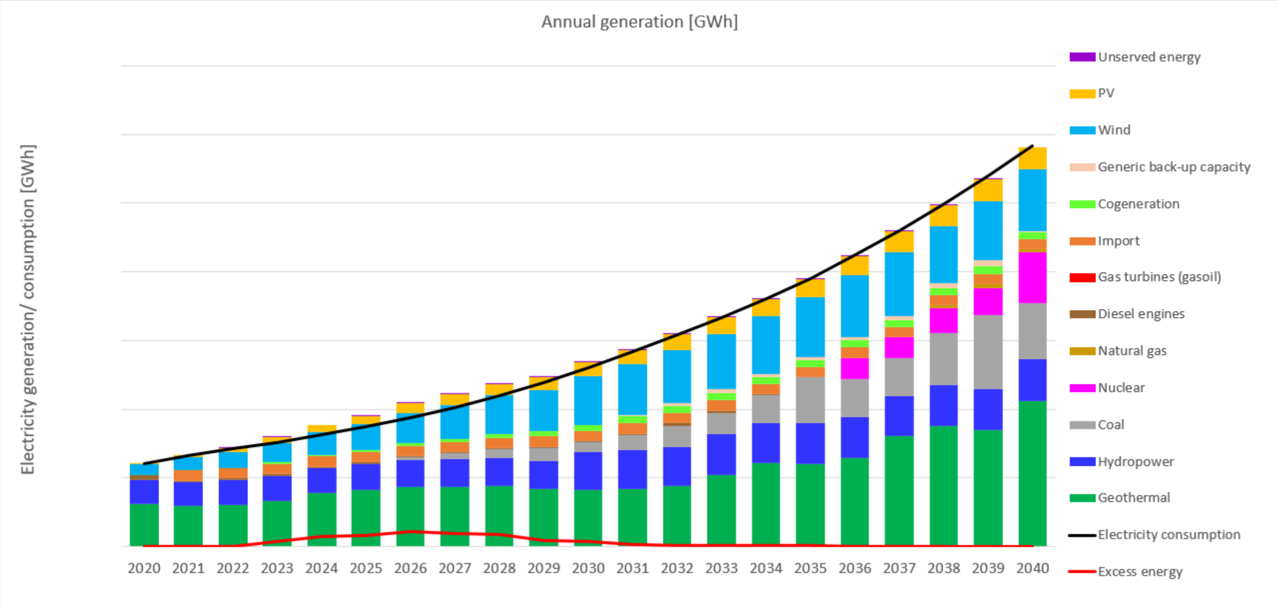
ANNEX 16 Installed capacity vs Laod - Fixed System vision scenario



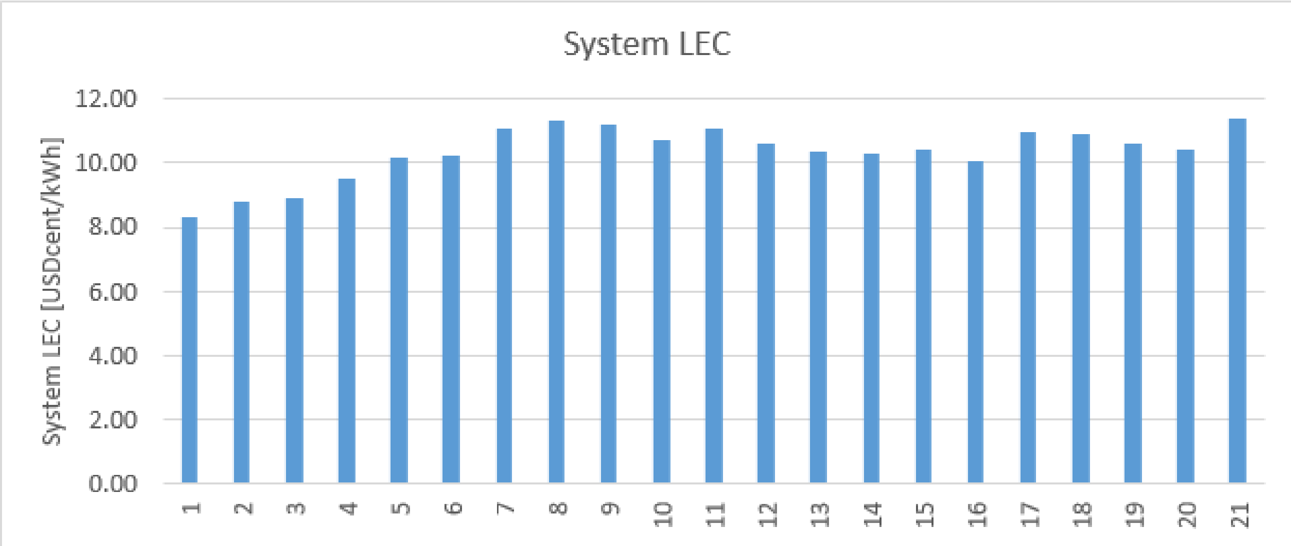
ANNEX 17 Firm Capacity vs Peak Load - Fixed system vision scenario



ANNEX 18 Annual generation - Fixed System vision scenario



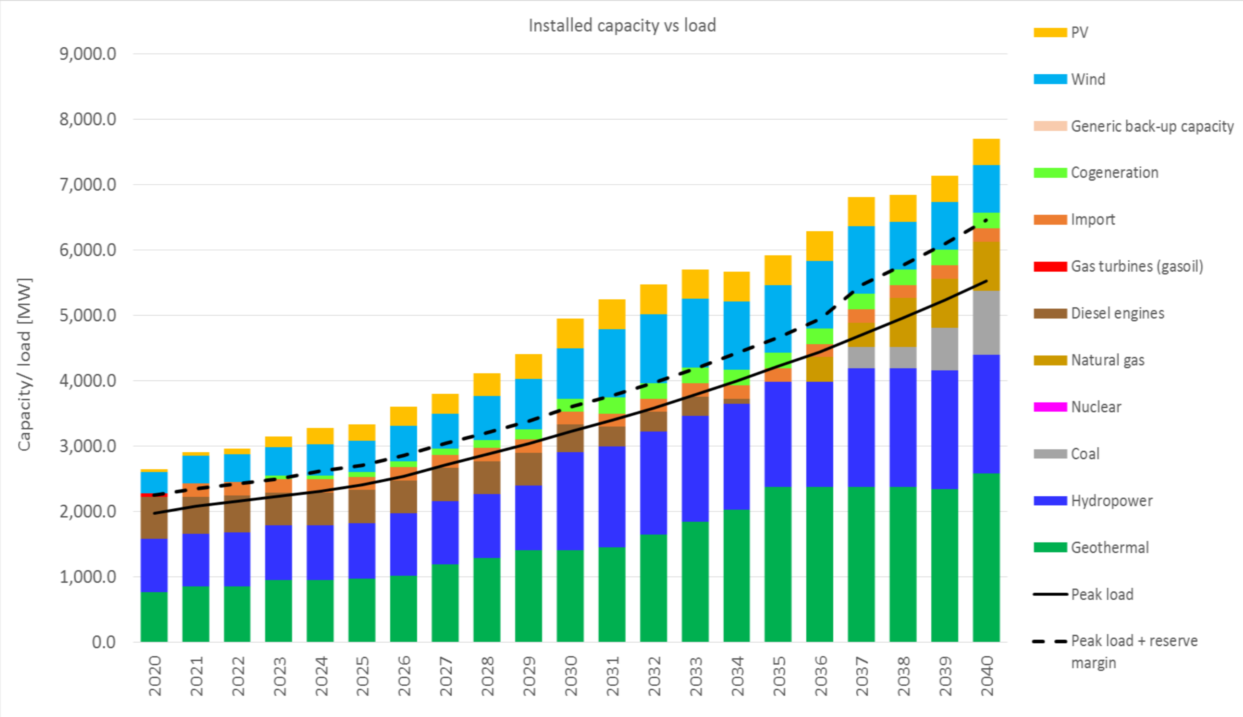
ANNEX 19Levelised cost of Energy - fixed case with candidates - vision scenario



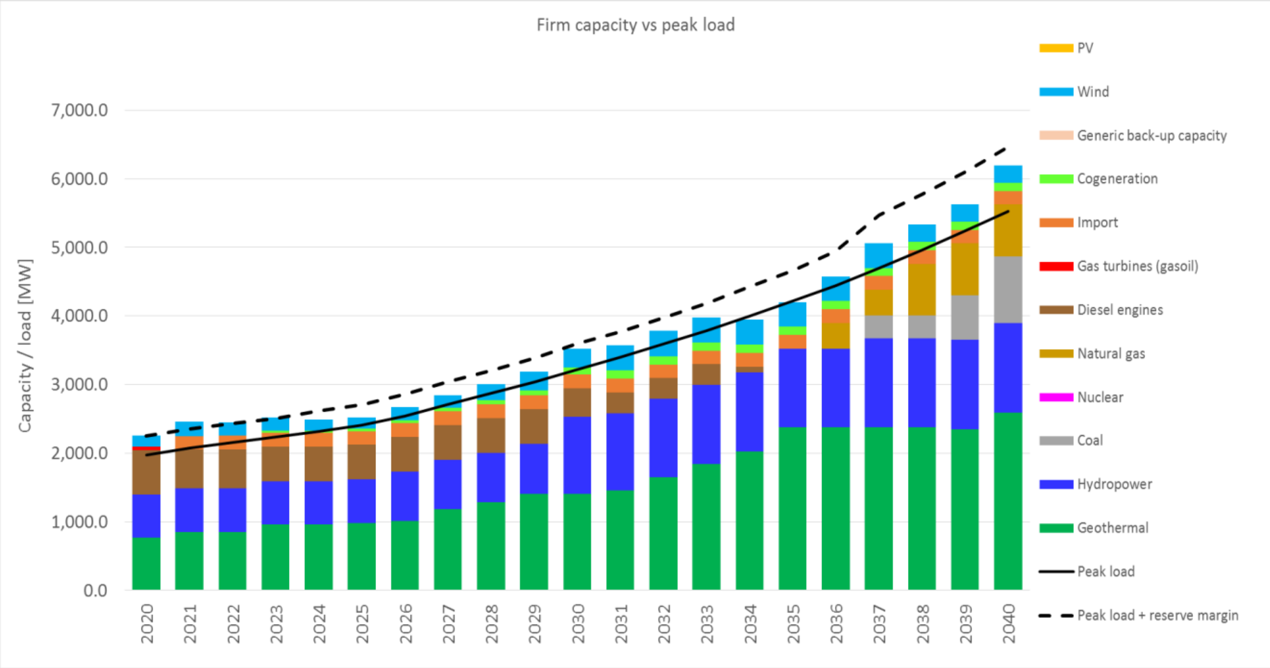
ANNEX 20 Technology capacity factors - Optimised case Reference demand

Capacity factor [%]	2020	2021	2022	2023	2024	2025	2030	2031	2035	2040
Geothermal	92.1%	76.4%	79.1%	75.0%	76.0%	77.7%	72.8%	72.9%	72.3%	88.3%
Hydropower	49.6%	49.6%	49.6%	49.6%	49.6%	49.6%	41.3%	41.5%	41.9%	37.7%
Coal										26.2%
Natural gas										2.3%
Diesel engines	13.0%	2.1%	3.2%	2.6%	4.0%	5.0%	0.9%	2.0%		
Gas turbines (gasoil)	0.1%									
Import			86.6%	85.8%	86.1%	86.4%	85.5%	85.6%	85.2%	85.6%
Cogeneration	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Wind	53.4%	51.7%	51.7%	51.7%	50.4%	50.4%	44.0%	42.3%	42.5%	37.3%
PV		19.6%	19.6%	15.0%	16.5%	16.5%	15.6%	15.6%	15.6%	15.2%

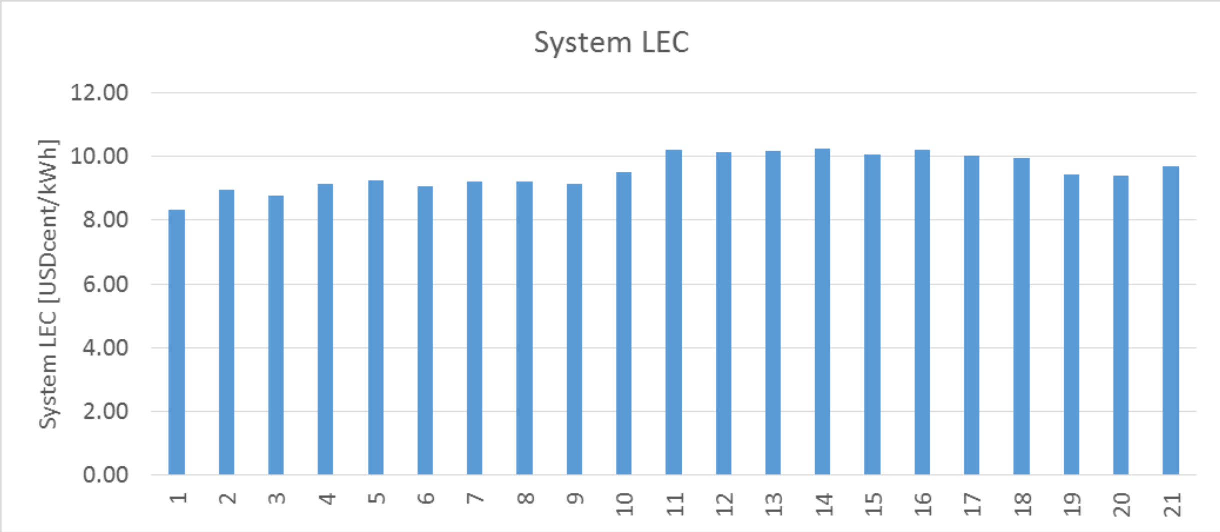
ANNEX 21 Installed Capacity vs Peak Load- Optimised Reference case



ANNEX 22 Firm vs Peak load - Optimised Reference scenario



ANNEX 23 System LEC - Optimised Case - Reference scenario



ANNEX 24 Electricty Generation costs - Optimised case

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Energy Purchased (kWh)	11,759,896,671	12,344,223,163	12,831,379,780	13,299,480,505	13,787,072,192	14,320,066,159
Deemed Energy (kWh)	-	613,200,000	611,740,000	1,224,940,000	1,224,940,000	1,224,940,000
Energy Cost Amount Ksh	25,210,836,063	31,416,774,634	40,936,038,134	51,511,003,654	55,807,163,408	58,954,203,016
Fuel Cost Amount in KSh	14,209,780,391	9,124,842,717	6,796,188,614	7,151,970,618	7,371,888,578	7,651,135,478
Capacity Charge Amount in KSh	53,104,411,678	57,283,151,503	55,968,359,720	55,729,294,553	56,557,238,803	57,433,819,083
Deemed Energy Cost Amount in KSh	-	4,635,792,000	5,323,603,665	10,087,952,637	10,072,347,526	9,964,722,219
Total Cost (KSh)	**92,525,028,132**	**102,460,560,854**	**109,024,190,134**	**124,480,221,462**	**129,808,638,315**	**134,003,879,796**
Generation Unit Cost KSh/kWh (without fuel cost)	6.66	7.56	7.97	8.82	8.88	8.82
Fuel Cost Charge KSh/kWh	1.51	0.92	0.66	0.67	0.67	0.67
Generation Unit Cost KSh/kWh inlc fuel and losses	**9.82**	**10.36**	**10.61**	**11.69**	**11.75**	**11.68**

Year	2020	2021	2022	2023	2024	2025
Generation Unit Cost US¢/kWh incl fuel and losses	9.02	9.51	9.74	10.73	10.79	10.72
Forex Charge (est.) KSh/kWh	0.55	0.55	0.55	0.55	0.55	0.55
Levies and inflation (est.) KSh/kWh	1.21	1.21	1.21	1.21	1.21	1.21
T&D costs (est.) KSh/kWh	3.92	4.16	4.41	4.67	4.95	5.25
Capital related revenue requirement Ksh/kWh	3.00	3.00	3.00	3.00	3.00	3.00
Retail Tariff per unit sold KSh/kWh excl of Taxes & Levies	16.75	17.52	18.02	19.36	19.71	19.93
Retail Tariff per unit sold KSh/kWh incl of Taxes & Levies	20.85	21.73	22.30	23.83	24.22	24.48
Retail Tariff US¢/kWh	19.13	19.95	20.46	21.87	22.23	22.47
Loss Factor	0.199	0.199	0.199	0.199	0.199	0.199

ANNEX 25 Electricity generation costs - Fixed Case system

Year	2020	2021	2022	2023	2024	2025
Energy Purchased (kWh)	11,759,896,671	12,344,223,163	12,831,379,780	13,299,480,505	13,787,072,192	14,320,066,159
Deemed Energy (kWh)	-	613,200,000	611,740,000	1,224,940,000	1,224,940,000	1,224,940,000
Energy Cost Amount Ksh	25,210,836,063	31,416,774,634	40,936,038,134	51,511,003,654	55,807,163,408	58,954,203,016
Fuel Cost Amount in KSh	14,209,780,391	9,124,842,717	6,796,188,614	7,151,970,618	7,371,888,578	7,651,135,478
Capacity Charge Amount in KSh	53,104,411,678	57,283,151,503	55,968,359,720	55,729,294,553	56,557,238,803	57,433,819,083
Deemed Energy Cost Amount in KSh	-	4,635,792,000	5,323,603,665	10,087,952,637	10,072,347,526	9,964,722,219
Total Cost (KSh)	**92,525,028,132**	**102,460,560,854**	**109,024,190,134**	**124,480,221,462**	**129,808,638,315**	**134,003,879,796**
Generation Unit Cost KSh/kWh (without fuel cost)	6.66	7.56	7.97	8.82	8.88	8.82
Fuel Cost Charge KSh/kWh	1.51	0.92	0.66	0.67	0.67	0.67
Generation Unit Cost KSh/kWh inlc fuel and losses	**9.82**	**10.36**	**10.61**	**11.69**	**11.75**	**11.68**
Generation Unit Cost US¢/kWh incl fuel and losses	9.02	9.51	9.74	10.73	10.79	10.72
Forex Charge (est.) KSh/kWh	0.55	0.55	0.55	0.55	0.55	0.55
Levies and inflation (est.) KSh/kWh	1.21	1.21	1.21	1.21	1.21	1.21
T&D costs (est.) KSh/kWh	3.92	4.16	4.41	4.67	4.95	5.25

Year	2020	2021	2022	2023	2024	2025
Capital related revenue requirement Ksh/kWh	3.00	3.00	3.00	3.00	3.00	3.00
Retail Tariff per unit sold KSh/kWh excl of Taxes & Levies	16.75	17.52	18.02	19.36	19.71	19.93
Retail Tariff per unit sold KSh/kWh incl of Taxes & Levies	20.85	21.73	22.30	23.83	24.22	24.48
Retail Tariff US¢/kWh	19.13	19.95	20.46	21.87	22.23	22.47
Loss Factor	0.199	0.199	0.199	0.199	0.199	0.199

ANNEX 26 Tranmisssion investment Analysis

1. COST OF LOSSES

	TN1			TN 2		
Year	**Losses (MW)**	**Losses (GWh)**	**Cost of Losses (MUSD)**	**Losses (MW)**	**Losses (GWh)**	**Cost of Losses (MUSD)**
2021	85.41	409	61	85.5	409	61
2022	85.41	408	61	85.5	408	61
2023	85.41	407	61	85.5	408	61
2024	85.41	407	61	85.5	407	61
2025	85.41	406	61	85.5	406	61
2026	137.6	653	98	137.6	653	98
2027	137.6	651	98	137.6	651	98
2028	137.6	650	98	137.6	650	98
2029	137.6	649	97	137.6	649	97
2030	137.6	648	97	137.6	648	97
2031	184.5	866	130	186.3	874	131
2032	184.5	865	130	186.3	873	131
2033	184.5	863	129	186.3	872	131
2034	184.5	862	129	186.3	870	131
2035	184.5	860	129	186.3	869	130
2036	287.6	1339	201	284.0	1322	198
2037	287.6	1336	200	284.0	1320	198
2038	287.6	1334	200	284.0	1317	198
2039	287.6	1331	200	284.0	1314	197
2040	287.6	1328	199	284.0	1312	197

2. DISCOUNTING FACTORS (DF)

RATE	0.12																			
YEAR	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
YEAR NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DF	0.892857	0.797194	0.71178	0.635518	0.567427	0.506631	0.452349	0.403883	0.36061	0.321973	0.287476	0.256675	0.229174	0.20462	0.182696	0.163122	0.145644	0.13004	0.116107	0.103667

3. TARGET NETWORK 1 ANALYSIS

Assumptions																				
Discount Rate	**12%**																			
Cost of Losses	**0.15**	USD/kWh																		
O&M Cost	**2.5%**	of investment Cost																		
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Investment Cost (MUSD)	1439.23	313.96	859.27	628.1	543.6	57.72	380.1	711.16	0	1016.1	0	0		76.08	123.33	0	564.32	184.974	0	314
O & M Cost (MUSD)	35.98075	7.849	21.48175	15.7025	13.59	1.443	9.5025	17.779	0	25.4025	0	0	0	1.902	3.08325	0	14.108	4.62435	0	7.85
Cost of Losses (MUSD)	92	72	81	76	88	99	98	98	97	97	88	88	88	88	87	142	142	141	141	203
Total Cost (MUSD)	1,567	394	962	720	645	158	488	827	97	1,139	88	88	88	166	214	142	720	331	141	524
PV of Costs (MUSD)	1,399	314	685	457	366	80	221	334	35	367	25	23	20	34	39	23	105	43	16	54
Total PV of Costs (MUSD)	**4,640**																			

4. TARGET NETWORK 2 ANALYSIS

Assumptions		
Discount Rate	**12%**	
Cost of Losses	**0.15**	USD/kWh
O&M Cost	**2.5%**	of investment Cost

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Investment Cost (MUSD)	1439.23	313.96	848.1	628.1	543.6	57.72	380.1	711.16	0	1016.1	0	0	0	76.08	123.33	0	564.32	184.974	0	314
O & M Cost (MUSD)	35.98075	7.849	21.2025	15.7025	13.59	1.443	9.5025	17.779	0	25.4025	0	0	0	1.902	3.08325	0	14.108	4.62435	0	7.85
Cost of Losses (MUSD)	92	72	81	76	88	91	98	98	97	97	89	89	89	89	88	144	144	143	143	202
Total Cost (MUSD)	1,567	394	951	720	645	150	488	827	97	1,139	89	89	89	167	215	144	722	333	143	524
PV of Costs (MUSD)	1,399	314	677	457	366	76	221	334	35	367	26	23	20	34	39	24	105	43	17	54

Total PV of Costs (MUSD)	**4,631**

ANNEX 27 Three phase Short circuit current

YEAR 2020 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_KAMBURU11 132.00]	132	12.075	31.5	38.33
[K_KAMBTRF11 132.00]	132	12.02	31.5	38.16
[K_DANDORA11 132.00]	132	11.199	31.5	35.55
[K_JUJA RD11 132.00]	132	11.026	31.5	35.00
[K_LOIY1 220.00]	220	10.607	31.5	33.67
[K_LOIY2 220.00]	220	10.607	31.5	33.67
[K_SUSWA21 220.00]	220	10.607	31.5	33.67
[K_GITARU11 132.00]	132	10.416	31.5	33.07
[K_OLKARIAIAU220.00]	220	9.889	31.5	31.39
[K_OLKARIA II220.00]	220	9.867	31.5	31.32
[K_RUARAK TE1132.00]	132	9.747	31.5	30.94
[K_RUARAKAT12132.00]	132	9.747	31.5	30.94
[K_RUARAKA11 132.00]	132	9.657	31.5	30.66
[K_DANDORA21 220.00]	220	9.15	31.5	29.05
[K_OLKARIA IV220.00]	220	9.031	31.5	28.67
[K_NBNORTH21 220.00]	220	8.901	31.5	28.26
[K_THIKA RD21220.00]	220	8.76	31.5	27.81
[KOLKARIAIII2220.00]	220	8.373	31.5	26.58
[K_RABAI11 132.00]	132	8.167	31.5	25.93
[K_KIPEVU11 132.00]	132	8.103	31.5	25.72
[K_KAMBURU21 220.00]	220	8.07	31.5	25.62
[K_KIPEVUDII1132.00]	132	8.067	31.5	25.61
[K_RABAITRF11132.00]	132	7.937	31.5	25.20
[K_RABTRF12 132.00]	132	7.937	31.5	25.20
[K_RABAITR 13132.00]	132	7.937	31.5	25.20
[K_EMBAKASI21220.00]	220	7.819	31.5	24.82
[K_OLKARIAIAU132.00]	132	7.661	31.5	24.32
[K_OLKARIA1 1132.00]	132	7.586	31.5	24.08
[K_CABLE-OHL2220.00]	220	7.56	31.5	24.00
[K_CBD 220.00]	220	7.475	31.5	23.73
[K_CABLE-OHL 220.00]	220	7.407	31.5	23.51
[K_OLKARIA II132.00]	132	7.305	31.5	23.19
[K_TEE OFF 132.00]	132	7.266	31.5	23.07
[K_KINDARUMA1132.00]	132	7.263	31.5	23.06
[K_JOMVU 132.00]	132	7.252	31.5	23.02
[K_NAIVASHA11132.00]	132	7.073	31.5	22.45

YEAR 2020 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_GITARU21 220.00]	220	6.923	31.5	21.98
[K_WELLHED37-132.00]	132	6.813	31.5	21.63
[K_KOKOTONI11132.00]	132	6.799	31.5	21.58
[K_ATHI RIVER220.00]	220	6.626	31.5	21.03
[K_KIAMBERE21220.00]	220	6.246	31.5	19.83
[K_MASINGA11 132.00]	132	6.13	31.5	19.46
[K_ISINYA 220.00]	220	5.884	31.5	18.68
[K_BAMBURI11 132.00]	132	5.406	31.5	17.16
[K_MARIAKANI1132.00]	132	4.79	31.5	15.21
[K_THIKA11 132.00]	132	4.773	31.5	15.15
[K_THIKA12 132.00]	220	4.747	31.5	15.07
[K_SUS1 220.00]	220	4.336	31.5	13.77
[K_SUS2 220.00]	220	4.336	31.5	13.77
[K_LOYAN 220.00]	220	4.336	31.5	13.77
[K_LANET11 132.00]	132	4.305	31.5	13.67
[K_ISHIARA11 132.00]	132	4.278	31.5	13.58
[K_LESSOS11 132.00]	132	4.258	31.5	13.52
[K_LESSTRF11 132.00]	132	4.258	31.5	13.52
[K_TOP STEEL 132.00]	132	4.242	31.5	13.47
[K_RABAI21 220.00]	220	4.208	31.5	13.36
[K_ISINYA 220.00]	220	4.114	31.5	13.06
[K_BAMB TEE 132.00]	132	3.864	31.5	12.27
[K_MUHORONI11132.00]	132	3.783	31.5	12.01
[K_SOILO11 132.00]	132	3.566	31.5	11.32
[K_MARIAKANI 220.00]	220	3.434	31.5	10.90
[K_KYENI11 132.00]	132	3.215	31.5	10.21
[K_RONGAI_NC 132.00]	132	3.191	31.5	10.13
[K_GATUNDU11 132.00]	132	3.181	31.5	10.10
[K_MWINGI11 132.00]	132	3.178	31.5	10.09
[K_VIPINGO31 132.00]	132	3.022	31.5	9.59
[K_SAMBURU11 132.00]	132	2.979	31.5	9.46
[K_MAKUTANO11132.00]	132	2.903	31.5	9.22
[K_MAKUTEE12 132.00]	132	2.871	31.5	9.11
[K_OLKARIA V 220.00]	220	2.805	31.5	8.90
[K_KISUMU 132132.00]	132	2.759	31.5	8.76
[K_MSCEMTEE31132.00]	132	2.661	31.5	8.45
[K_GALU11 132.00]	132	2.645	31.5	8.40
[K_SONDU11 132.00]	132	2.571	31.5	8.16

YEAR 2020 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_ELDORET11 132.00]	132	2.493	31.5	7.91
[K_MSACEM31 132.00]	132	2.491	31.5	7.91
[K_KAPSABET11132.00]	132	2.476	31.5	7.86
[K_SANGORO11 132.00]	132	2.443	31.5	7.76
[K_KONZA 132.00]	132	2.411	31.5	7.65
[K_CHEMOSIT11132.00]	132	2.401	31.5	7.62
[K_MSACEMTEE3132.00]	132	2.346	31.5	7.45
[K_ULU11 132.00]	132	2.316	31.5	7.35
[K_MUSAGA11 132.00]	132	2.27	31.5	7.21
[K_GITHAMBO11132.00]	132	2.231	31.5	7.08
[K_TITANIUM11132.00]	132	2.197	31.5	6.97
[K_KUTUSTEE2 132.00]	132	2.178	31.5	6.91
[K_TESTBUS 220.00]	220	2.135	31.5	6.78
[K_KITUI11 132.00]	132	2.085	31.5	6.62
[K_MUSAGATEE 132.00]	132	2.084	31.5	6.62
[K_LESSOS21 220.00]	220	2.083	31.5	6.61
[K_NEWMAUNGU 132.00]	132	2.049	31.5	6.50
[U_TORO11 132.00]	132	2.011	31.5	6.38
[K_MAUNGU11 132.00]	132	1.93	31.5	6.13
[K_KILIFI11 132.00]	132	1.903	31.5	6.04
[K_MACHAKOS11132.00]	132	1.901	31.5	6.03
[K_WEBUYE11 132.00]	132	1.862	31.5	5.91
[K_MALINDI21 220.00]	220	1.848	31.5	5.87
[K_NEW SULTAN132.00]	132	1.835	31.5	5.83
[K_SULTAN HA1132.00]	132	1.809	31.5	5.74
[K_TURKWEL21 220.00]	220	1.78	31.5	5.65
[K_SOTIK 132.00]	132	1.775	31.5	5.63
[K_KAINUK21 220.00]	220	1.775	31.5	5.63
[K_EMBU11 132.00]	132	1.733	31.5	5.50
[K_MUMIAS11 132.00]	132	1.704	31.5	5.41
[K_VOI11 132.00]	132	1.677	31.5	5.32
[K_KIBOKO11 132.00]	132	1.568	31.5	4.98
[K_MANYANI11 132.00]	132	1.504	31.5	4.77
[K_MAKINDU 132.00]	132	1.492	31.5	4.74
[K_MERU11 132.00]	132	1.481	31.5	4.70
[K_KUTUSTEE1 132.00]	132	1.437	31.5	4.56
[K_KITALE11 132.00]	132	1.435	31.5	4.56
[K_KISII11 132.00]	132	1.411	31.5	4.48

YEAR 2020 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_MTITO AND1132.00]	132	1.409	31.5	4.47
[K_BOMET11 132.00]	132	1.37	31.5	4.35
[K_WOTE11 132.00]	132	1.368	31.5	4.34
[K_RANGALA11 132.00]	132	1.337	31.5	4.24
[K_ISIOLO11 132.00]	132	1.222	31.5	3.88
[K_KIGANJO11 132.00]	132	1.109	31.5	3.52
[K_GARSEN21 220.00]	220	1.091	31.5	3.46
[K_AWENDO11 132.00]	132	1.09	31.5	3.46
[K_OLKIVWELLH220.00]	220	0.928	31.5	2.95
[K_NDHIWA11 132.00]	132	0.92	31.5	2.92
[K_NANYUKI11 132.00]	132	0.846	31.5	2.69
[K_LAMU21 220.00]	220	0.797	31.5	2.53
[K_GARISSA11 132.00]	132	0.725	31.5	2.30
[K_GARISA PV1132.00]	132	0.705	31.5	2.24

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITHOUT 400KV				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_KAMBURU11 132.00]	132	13.3403	31.5	42.35
[K_SUSWA21 220.00]	220	13.3118	31.5	42.26
[K_LOIY2 220.00]	220	13.3118	31.5	42.26
[K_LOIY1 220.00]	220	13.3118	31.5	42.26
[K_KAMBTRF11 132.00]	132	13.3085	31.5	42.25
[K_OLKARIAIAU220.00]	220	13.2155	31.5	41.95
[K_OLKARIA II220.00]	220	13.1691	31.5	41.81
[K_DANDORA11 132.00]	132	12.9109	31.5	40.99
[K_JUJA RD11 132.00]	132	12.7128	31.5	40.36
[K_GITARU11 132.00]	132	11.2606	31.5	35.75
[K_RUARAKAT12132.00]	132	11.0732	31.5	35.15
[K_RUARAK TE1132.00]	132	11.0732	31.5	35.15
[K_DANDORA21 220.00]	220	11.0069	31.5	34.94
[K_RUARAKA11 132.00]	132	10.9704	31.5	34.83
[K_OLKARIA1 1132.00]	132	10.9607	31.5	34.80
[E_WOLAYTA 400.00]	400	13.8878	40	34.72
[K_A_DC1 400.00]	400	13.8878	40	34.72
[K_A_DC2 400.00]	400	13.8878	40	34.72
[K_SIDE_A 400.00]	400	13.8878	40	34.72
[K_OLKARIAIAU132.00]	132	10.8766	31.5	34.53
[K_OLKARIA II132.00]	132	10.8259	31.5	34.37
[K_OLKARIA V 220.00]	220	10.7981	31.5	34.28
[K_OLKARIAIII220.00]	220	10.648	31.5	33.80
[K_OLKARIA IV220.00]	220	10.3973	31.5	33.01
[K_NBNORTH21 220.00]	220	10.1201	31.5	32.13
[K_EMBAKASI21220.00]	220	10.0949	31.5	32.05
[K_THIKA RD21220.00]	220	10.0829	31.5	32.01
[K_ISINYA 220.00]	220	9.7867	31.5	31.07
[K_CABLE-OHL 220.00]	220	9.7064	31.5	30.81
[K_CABLE-OHL2220.00]	220	9.7064	31.5	30.81
[K_ATHI RIVER220.00]	220	9.6986	31.5	30.79
[K_CBD 220.00]	220	9.5365	31.5	30.27
[K_WELLHED37-132.00]	132	9.3681	31.5	29.74
[K_KAMBURU21 220.00]	220	8.8539	31.5	28.11
[K_KIMUKA 220220.00]	220	8.4911	31.5	26.96
[K_NAIVASHA11132.00]	132	8.448	31.5	26.82
[K_KINDARUMA1132.00]	132	8.1594	31.5	25.90

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITHOUT 400KV				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_RABAI11 132.00]	132	7.9327	31.5	25.18
[K_KIPETO 220220.00]	220	7.7976	31.5	24.75
[K_RABAITR 13132.00]	132	7.7763	31.5	24.69
[K_RABTRF12 132.00]	132	7.7763	31.5	24.69
[K_RABAITRF11132.00]	132	7.7763	31.5	24.69
[K_GITARU21 220.00]	220	7.4604	31.5	23.68
[K_KIPEVU11 132.00]	132	7.4511	31.5	23.65
[K_KIPEVUDII1132.00]	132	7.3872	31.5	23.45
[K_KIAMBERE21220.00]	220	7.0329	31.5	22.33
[K_MASINGA11 132.00]	132	6.9001	31.5	21.91
[K_JOMVU 132.00]	132	6.8447	31.5	21.73
[K_TEE OFF 132.00]	132	6.7043	31.5	21.28
[K_KOKOTONI11132.00]	132	6.6304	31.5	21.05
[K_BAMBURI11 132.00]	132	6.1723	31.5	19.59
[K_THIKA11 132.00]	132	5.8476	31.5	18.56
[K_THIKA12 132.00]	132	5.8095	31.5	18.44
[K_BOMANI 132.00]	132	5.7751	31.5	18.33
[K_MALAA 220.00]	220	5.6855	31.5	18.05
[K_LESSTRF11 132.00]	132	5.5114	31.5	17.50
[K_LESSOS11 132.00]	132	5.5114	31.5	17.50
[K_VIPINGO31 132.00]	132	5.4779	31.5	17.39
[K_LANET11 132.00]	132	5.3936	31.5	17.12
[K_SOILO11 132.00]	132	5.3495	31.5	16.98
[K_SOILO TEE 132.00]	132	5.3026	31.5	16.83
[K_KIBOS 132 132.00]	132	5.2273	31.5	16.59
[K_KISUMU 132132.00]	132	5.1799	31.5	16.44
[K_BAMB TEE 132.00]	132	5.0927	31.5	16.17
[K_ISHIARA11 132.00]	132	5.0902	31.5	16.16
[K_MSCEMTEE31132.00]	132	4.9082	31.5	15.58
[K_RABAI21 220.00]	220	4.7656	31.5	15.13
[MWALA 132.00]	132	4.7571	31.5	15.10
[K_KILIFI11 132.00]	132	4.7323	31.5	15.02
[K_MSACEM31 132.00]	132	4.726	31.5	15.00
[K_MARIAKANI1132.00]	132	4.7047	31.5	14.94
[K_MSACEMTEE3132.00]	132	4.6021	31.5	14.61
[K_MAUA11 132.00]	132	4.5059	31.5	14.30
[K_MARIAKANI2220.00]	220	4.4967	31.5	14.28
[K_ISIOLO11 132.00]	132	4.4208	31.5	14.03

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITHOUT 400KV				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_MUSAGA11 132.00]	132	4.3962	31.5	13.96
[K_MENENGAI11132.00]	132	4.3921	31.5	13.94
[K_MUHORONI11132.00]	132	4.2859	31.5	13.61
[K_RONGAI_NC 132.00]	132	4.2358	31.5	13.45
[K_KOPERE 132.00]	132	4.2074	31.5	13.36
[K_SIDE_B 400.00]	400	5.3044	40	13.26
[K_B_DC1 400.00]	400	5.3044	40	13.26
[K_B_DC2 400.00]	400	5.3044	40	13.26
[K_TOP STEEL 132.00]	132	4.1646	31.5	13.22
[K_KIBOS 220 220.00]	220	4.0629	31.5	12.90
[K_MERU11 132.00]	132	4.0292	31.5	12.79
[K_SONDU11 132.00]	132	3.9319	31.5	12.48
[K_LOYAN 220.00]	220	3.6872	31.5	11.71
[K_SUS2 220.00]	220	3.6872	31.5	11.71
[K_SUS1 220.00]	220	3.6872	31.5	11.71
[K_NANYUKI11 132.00]	132	3.6703	31.5	11.65
[K_MWINGI11 132.00]	132	3.663	31.5	11.63
[K_ISINYA 132.00]	132	3.657	31.5	11.61
[K_KYENI11 132.00]	132	3.6101	31.5	11.46
[K_SANGORO11 132.00]	132	3.6047	31.5	11.44
[K_KIGANJO11 132.00]	132	3.5695	31.5	11.33
[K_GATUNDU11 132.00]	132	3.5646	31.5	11.32
[K_LESSOS TEE220.00]	220	3.5376	31.5	11.23
[K_LESSOS TEE220.00]	220	3.5376	31.5	11.23
[K_MAKUTANO11132.00]	132	3.5351	31.5	11.22
[K_WALE TEE 220.00]	220	3.53	31.5	11.21
[K_OLKALOU132132.00]	132	3.501	31.5	11.11
[K_GITHAMBO11132.00]	132	3.4684	31.5	11.01
[K_KONZA 132.00]	132	3.4519	31.5	10.96
[K_MAKUTEE12 132.00]	132	3.4511	31.5	10.96
[K_CHEMOSIT11132.00]	132	3.3327	31.5	10.58
[K_ELDORET11 132.00]	132	3.332	31.5	10.58
[K_KUTUSTEE2 132.00]	132	3.3013	31.5	10.48
[K_DONGO_KU 220.00]	220	3.2718	31.5	10.39
[K_ULU11 132.00]	132	3.2201	31.5	10.22
[K_MACHAKOS11132.00]	132	3.1618	31.5	10.04
[K_RUMURUTI11132.00]	132	3.1522	31.5	10.01
[K_OTHAYA 132.00]	132	3.1433	31.5	9.98

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITHOUT 400KV				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_SOTIK 132.00]	132	3.1386	31.5	9.96
[K_EMBU11 132.00]	132	3.0985	31.5	9.84
[K_MAUA 220 220.00]	220	3.082	31.5	9.78
[K_WEBUYE11 132.00]	132	3.0585	31.5	9.71
[K_KAKMEGA220220.00]	220	3.0472	31.5	9.67
[K_KUTUSTEE1 132.00]	132	3.0348	31.5	9.63
[K_NAROK11 132.00]	132	2.9376	31.5	9.33
[K_SAMBURU11 132.00]	132	2.9208	31.5	9.27
[K_KAPSABET11132.00]	132	2.8535	31.5	9.06
[K_MUSAGA220 220.00]	220	2.8456	31.5	9.03
[K_WERU 220.00]	220	2.8295	31.5	8.98
[K_MUMIAS11 132.00]	132	2.6878	31.5	8.53
[K_ISIOLO 220220.00]	220	2.6845	31.5	8.52
[K_BOMET11 132.00]	132	2.6392	31.5	8.38
[U_TORO11 132.00]	132	2.6361	31.5	8.37
[K_KILIFI 220220.00]	220	2.6335	31.5	8.36
[K_GALU11 132.00]	132	2.5688	31.5	8.15
[K_KISII11 132.00]	132	2.5463	31.5	8.08
[K_MUSAGATEE 132.00]	132	2.5082	31.5	7.96
[K_AWENDO11 132.00]	132	2.5025	31.5	7.94
[K_NDHIWA11 132.00]	132	2.4799	31.5	7.87
[K_KITALE11 132.00]	132	2.4326	31.5	7.72
[K_MALINDI21 220.00]	220	2.4117	31.5	7.66
[K_KILGORS132132.00]	132	2.4071	31.5	7.64
[K_LESSOS21 220.00]	220	2.2991	31.5	7.30
[K_KITUI11 132.00]	132	2.2819	31.5	7.24
[K_NEW SULTAN132.00]	132	2.235	31.5	7.10
[K_SULTAN HA1132.00]	132	2.1881	31.5	6.95
[K_TESTBUS 220.00]	220	2.1826	31.5	6.93
[K_TITANIUM11132.00]	132	2.1552	31.5	6.84
[K_TEE 220.00]	220	2.1307	31.5	6.76
[K_SELENKEI 220.00]	220	2.1159	31.5	6.72
[K_TURKWEL21 220.00]	220	2.0679	31.5	6.56
[K_KAINUK21 220.00]	220	2.0635	31.5	6.55
[K_ISIBENIA11132.00]	132	2.0362	31.5	6.46
[K_NEWMAUNGU 132.00]	132	1.9952	31.5	6.33
[K_KABARNET11132.00]	132	1.9735	31.5	6.27
[K_MAUNGU11 132.00]	132	1.8926	31.5	6.01

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITHOUT 400KV				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_RANGALA11 132.00]	132	1.8707	31.5	5.94
[K_KIBOKO11 132.00]	132	1.7777	31.5	5.64
[K_K0RTUM21 220.00]	220	1.7741	31.5	5.63
[K_VOI11 132.00]	132	1.6743	31.5	5.32
[K_MAKINDU 132.00]	132	1.6517	31.5	5.24
[K_KITALE 220.00]	220	1.6039	31.5	5.09
[K_WOTE11 132.00]	132	1.5884	31.5	5.04
[K_MANYANI11 132.00]	132	1.53	31.5	4.86
[K_GARISSA11 132.00]	132	1.5238	31.5	4.84
[K_MTITO AND1132.00]	132	1.4774	31.5	4.69
[K_GARISA PV1132.00]	132	1.4378	31.5	4.56
[K_BONDO 132.00]	132	1.4201	31.5	4.51
[K_GARSEN21 220.00]	220	1.405	31.5	4.46
[K_NAMANGA 132.00]	132	1.3951	31.5	4.43
[K_MERUWESHI 132.00]	132	1.2681	31.5	4.03
[K_MUTOMO 132.00]	132	1.2141	31.5	3.85
[K_NDIGWA 132.00]	132	1.1679	31.5	3.71
[K_HOLA 220.00]	220	1.156	31.5	3.67
[K_BURA 220.00]	220	1.0699	31.5	3.40
[K_OLKIVWELLH220.00]	220	0.9569	31.5	3.04
[K_LAMU21 220.00]	220	0.9519	31.5	3.02
[K_TAVETA11 132.00]	132	0.9119	31.5	2.89
[K_GARISSA 220.00]	220	0.8906	31.5	2.83
[K_LOITOKTOK 132.00]	132	0.8892	31.5	2.82
[K_MARALAL11 132.00]	132	0.8694	31.5	2.76
[K_KIBWEZI 132.00]	132	0.8522	31.5	2.71

ANNEX 29 Three phase short circuit current with 400kv Year 400kV

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITH 400kV				
Bus Name	**Base Voltage (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**%Breaker Capacity**
[K_SUSWA21 220.00]	220	13.6105	31.5	43.21
[K_OLKARIAIAU220.00]	220	13.2484	31.5	42.06
[K_OLKARIA II220.00]	220	13.1955	31.5	41.89
[K_KAMBURU11 132.00]	132	13.0164	31.5	41.32
[K_KAMBTRF11 132.00]	132	12.9872	31.5	41.23
[K_DANDORA11 132.00]	132	12.1567	31.5	38.59
[K_JUJA RD11 132.00]	132	11.9876	31.5	38.06
[K_SIDE_A 400.00]	400	14.1255	40	35.31
[E_WOLAYTA 400.00]	400	14.1255	40	35.31
[K_GITARU11 132.00]	132	11.0671	31.5	35.13
[K_OLKARIA V 220.00]	220	10.7836	31.5	34.23
[K_OLKARIA1 1132.00]	132	10.6897	31.5	33.94
[K_OLKARIAIII220.00]	220	10.6235	31.5	33.73
[K_OLKARIAIAU132.00]	132	10.601	31.5	33.65
[K_OLKARIA II132.00]	132	10.5667	31.5	33.55
[K_DANDORA21 220.00]	220	10.5506	31.5	33.49
[K_RUARAK TE1132.00]	132	10.5121	31.5	33.37
[K_RUARAKAT12132.00]	132	10.5121	31.5	33.37
[K_OLKARIA IV220.00]	220	10.4981	31.5	33.33
[K_RUARAKA11 132.00]	132	10.4032	31.5	33.03
[K_ISINYA 220.00]	220	10.2789	31.5	32.63
[K_ISINYA21 220.00]	220	10.2789	31.5	32.63
[K_EMBAKASI21220.00]	220	9.8805	31.5	31.37
[K_NBNORTH21 220.00]	220	9.8326	31.5	31.21
[K_THIKA RD21220.00]	220	9.6862	31.5	30.75
[K_ATHI RIVER220.00]	220	9.6463	31.5	30.62
[K_RABAI11 132.00]	132	9.537	31.5	30.28
[K_CABLE-OHL2220.00]	220	9.5127	31.5	30.20
[K_CABLE-OHL 220.00]	220	9.5127	31.5	30.20
[K_RABAITRF11132.00]	132	9.3915	31.5	29.81
[K_RABTRF12 132.00]	132	9.3915	31.5	29.81
[K_RABAITR 13132.00]	132	9.3915	31.5	29.81
[K_CBD 220.00]	220	9.2895	31.5	29.49
[K_WELLHED37-132.00]	132	9.1972	31.5	29.20
[K_MAKINDU 132.00]	132	8.9967	31.5	28.56
[K_KONZA 132.00]	132	8.8357	31.5	28.05
[K_KIPEVU11 132.00]	132	8.6909	31.5	27.59

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITH 400kV				
Bus Name	Base Voltage (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	%Breaker Capacity
[K_KAMBURU21 220.00]	220	8.6371	31.5	27.42
[K_KIPEVUDII1132.00]	132	8.6087	31.5	27.33
[K_NAIVASHA11132.00]	132	8.2356	31.5	26.14
[K_KINDARUMA1132.00]	132	8.2034	31.5	26.04
[K_LESSOS11 132.00]	132	8.0794	31.5	25.65
[K_LESSTRF11 132.00]	132	8.0794	31.5	25.65
[K_KIPETO 220220.00]	220	8.0651	31.5	25.60
[K_JOMVU 132.00]	132	7.8718	31.5	24.99
[K_KIMUKA 220220.00]	220	7.8483	31.5	24.92
[K_TEE OFF 132.00]	132	7.7717	31.5	24.67
[K_KOKOTONI11132.00]	132	7.7101	31.5	24.48
[K_ULU11 132.00]	132	7.5177	31.5	23.87
[K_GILGIL 220220.00]	220	7.3144	31.5	23.22
[K_GITARU21 220.00]	220	7.291	31.5	23.15
[K_BAMBURI11 132.00]	132	7.0313	31.5	22.32
[K_RONGAI220 220.00]	220	6.9697	31.5	22.13
[K_KIAMBERE21220.00]	220	6.947	31.5	22.05
[K_LESSOS21 220.00]	220	6.8954	31.5	21.89
[K_MASINGA11 132.00]	132	6.7547	31.5	21.44
[K_BOMANI 132.00]	132	6.5238	31.5	20.71
[K_MARIAKANI2220.00]	220	6.5048	31.5	20.65
[K_RABAI21 220.00]	220	6.3641	31.5	20.20
[K_VIPINGO31 132.00]	132	6.1543	31.5	19.54
[K_SIDE_B 400.00]	400	7.2532	40	18.13
[K_BAMB TEE 132.00]	132	5.7087	31.5	18.12
[K_THIKA11 132.00]	132	5.6715	31.5	18.00
[K_THIKA12 132.00]	132	5.6357	31.5	17.89
[K_KIBOKO11 132.00]	132	5.5804	31.5	17.72
[K_KIBOS 132 132.00]	132	5.5148	31.5	17.51
[K_MALAA 220.00]	220	5.4999	31.5	17.46
[K_KISUMU 132132.00]	132	5.4921	31.5	17.44
[K_LANET11 132.00]	132	5.4499	31.5	17.30
[K_SOILO11 132.00]	132	5.4486	31.5	17.30
[K_MSCEMTEE31132.00]	132	5.4272	31.5	17.23
[K_SOILO TEE 132.00]	132	5.4049	31.5	17.16
[K_MACHAKOS11132.00]	132	5.4001	31.5	17.14
[K_KIMUKA 400.00]	400	6.7678	40	16.92
[K_RONGAI 132132.00]	132	5.323	31.5	16.90
[K_MUHORONI11132.00]	132	5.314	31.5	16.87

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITH 400kV				
Bus Name	Base Voltage (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	%Breaker Capacity
[K_MARIAKANI1132.00]	132	5.2401	31.5	16.64
[K_KILIFI11 132.00]	132	5.2195	31.5	16.57
[K_KOPERE 132.00]	132	5.1985	31.5	16.50
[K_MSACEM31 132.00]	132	5.1914	31.5	16.48
[K_ISINYA41 400.00]	400	6.5189	40	16.30
[MWALA 132.00]	132	5.1301	31.5	16.29
[K_MSACEMTEE3132.00]	132	5.0511	31.5	16.04
[K_CHEMOSIT11132.00]	132	5.0176	31.5	15.93
[K_ISHIARA11 132.00]	132	4.9892	31.5	15.84
[K_TEE 220.00]	220	4.939	31.5	15.68
[K_GILGIL 400.00]	400	6.2166	40	15.54
[K_SELENKEI 220.00]	220	4.8601	31.5	15.43
[K_MUSAGA11 132.00]	132	4.7043	31.5	14.93
[K_WALE TEE 220.00]	220	4.6539	31.5	14.77
[K_TOP STEEL 132.00]	132	4.6041	31.5	14.62
[K_NEW SULTAN132.00]	132	4.5909	31.5	14.57
[K_SULTAN HA1132.00]	132	4.5509	31.5	14.45
[K_MENENGAI11132.00]	132	4.4439	31.5	14.11
[K_MAUA11 132.00]	132	4.4428	31.5	14.10
[K_KERINGET20220.00]	220	4.4393	31.5	14.09
[K_RONGAI_NC 132.00]	132	4.3653	31.5	13.86
[K_ISIOLO11 132.00]	132	4.3635	31.5	13.85
[K_RONGAI 400400.00]	400	5.4314	40	13.58
[K_KIBOS 220 220.00]	220	4.229	31.5	13.43
[K_DONGO_KU 220.00]	220	4.2108	31.5	13.37
[K_MAKINDU400400.00]	400	5.2577	40	13.14
[K_SONDU11 132.00]	132	4.1251	31.5	13.10
[K_ELDORET11 132.00]	132	3.9727	31.5	12.61
[K_MERU11 132.00]	132	3.9642	31.5	12.58
[K_CHEMOSIT 2220.00]	220	3.9437	31.5	12.52
[K_SOTIK 132.00]	132	3.8754	31.5	12.30
[K_MAKUTEE12 132.00]	132	3.7855	31.5	12.02
[K_MAKUTANO11132.00]	132	3.7852	31.5	12.02
[K_SANGORO11 132.00]	132	3.767	31.5	11.96
[K_MWINGI11 132.00]	132	3.7038	31.5	11.76
[K_LESSOS 400400.00]	400	4.6769	40	11.69
[K_ISINYA 132.00]	132	3.673	31.5	11.66
[K_NANYUKI11 132.00]	132	3.6435	31.5	11.57
[K_LESSOS TEE220.00]	220	3.6111	31.5	11.46

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITH 400kV				
Bus Name	**Base Voltage (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**%Breaker Capacity**
[K_LESSOS TEE220.00]	220	3.6111	31.5	11.46
[K_THIKA 400 400.00]	400	4.546	40	11.37
[K_KYENI11 132.00]	132	3.5414	31.5	11.24
[K_OLKALOU132132.00]	132	3.5188	31.5	11.17
[K_GATUNDU11 132.00]	132	3.4847	31.5	11.06
[K_KIGANJO11 132.00]	132	3.4452	31.5	10.94
[K_KAPSABET11132.00]	132	3.4446	31.5	10.94
[K_GITHAMBO11132.00]	132	3.3381	31.5	10.60
[K_MALAA 400 400.00]	400	4.1499	40	10.37
[K_WERU 220.00]	220	3.2464	31.5	10.31
[K_SAMBURU11 132.00]	132	3.2216	31.5	10.23
[K_WEBUYE11 132.00]	132	3.2041	31.5	10.17
[K_KUTUSTEE2 132.00]	132	3.1767	31.5	10.08
[K_KAKMEGA220220.00]	220	3.1729	31.5	10.07
[K_RUMURUTI11132.00]	132	3.1584	31.5	10.03
[K_ONZA 400.00]	400	3.9271	40	9.82
[K_MARIAKANI4400.00]	400	3.8869	40	9.72
[K_MAUA 220 220.00]	220	3.0438	31.5	9.66
[K_OTHAYA 132.00]	132	3.0353	31.5	9.64
[K_NAROK11 132.00]	132	3.0154	31.5	9.57
[K_BOMET11 132.00]	132	2.982	31.5	9.47
[K_MUSAGA220 220.00]	220	2.9772	31.5	9.45
[K_EMBU11 132.00]	132	2.9302	31.5	9.30
[K_KILIFI 220220.00]	220	2.9265	31.5	9.29
[K_KUTUSTEE1 132.00]	132	2.9081	31.5	9.23
[K_KISII11 132.00]	132	2.8885	31.5	9.17
[U_TORO11 132.00]	132	2.8464	31.5	9.04
[K_MUSAGATEE 132.00]	132	2.8162	31.5	8.94
[K_LOYAN 400 400.00]	400	3.5724	40	8.93
[K_KILGORS132132.00]	132	2.7867	31.5	8.85
[K_MUMIAS11 132.00]	132	2.7721	31.5	8.80
[K_KITALE11 132.00]	132	2.7702	31.5	8.79
[K_AWENDO11 132.00]	132	2.7506	31.5	8.73
[K_MALINDI21 220.00]	220	2.7125	31.5	8.61
[K_NDHIWA11 132.00]	132	2.6517	31.5	8.42
[K_ISIOLO 220220.00]	220	2.6497	31.5	8.41
[K_MTITO AND1132.00]	132	2.6447	31.5	8.40
[K_TURKWEL21 220.00]	220	2.6398	31.5	8.38
[K_KAINUK21 220.00]	220	2.6325	31.5	8.36

YEAR 2025 THREE PHASE SHORT CIRCUIT CURRENT WITH 400kV				
Bus Name	**Base Voltage (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**%Breaker Capacity**
[K_GALU11 132.00]	132	2.6036	31.5	8.27
[K_WOTE11 132.00]	132	2.4636	31.5	7.82
[K_TESTBUS 220.00]	220	2.3278	31.5	7.39
[K_NEWMAUNGU 132.00]	132	2.2974	31.5	7.29
[K_KITUI11 132.00]	132	2.2936	31.5	7.28
[K_ISIBENIA11132.00]	132	2.2464	31.5	7.13
[K_MAUNGU11 132.00]	132	2.2128	31.5	7.02
[K_KABARNET11132.00]	132	2.1952	31.5	6.97
[K_TITANIUM11132.00]	132	2.1617	31.5	6.86
[K_K0RTUM21 220.00]	220	2.1613	31.5	6.86
[K_MANYANI11 132.00]	132	2.1064	31.5	6.69
[K_VOI11 132.00]	132	2.0787	31.5	6.60
[K_KITALE 220.00]	220	1.8957	31.5	6.02
[K_RANGALA11 132.00]	132	1.8767	31.5	5.96
[K_MERUWESHI 132.00]	132	1.8044	31.5	5.73
[K_GARISSA11 132.00]	132	1.7145	31.5	5.44
[K_GARISA PV1132.00]	132	1.6073	31.5	5.10
[K_GARSEN21 220.00]	220	1.5306	31.5	4.86
[K_BONDO 132.00]	132	1.4284	31.5	4.53
[K_NAMANGA 132.00]	132	1.4061	31.5	4.46
[K_HOLA 220.00]	220	1.2497	31.5	3.97
[K_MUTOMO 132.00]	132	1.2146	31.5	3.86
[K_NDIGWA 132.00]	132	1.1751	31.5	3.73
[K_BURA 220.00]	220	1.1508	31.5	3.65
[K_LOITOKTOK 132.00]	132	1.1224	31.5	3.56
[K_TAVETA11 132.00]	132	1.0211	31.5	3.24
[K_LAMU21 220.00]	220	1.0052	31.5	3.19
[K_OLKIVWELLH220.00]	220	0.9583	31.5	3.04
[K_GARISSA 220.00]	220	0.926	31.5	2.94
[K_MARALAL11 132.00]	132	0.8805	31.5	2.80
[K_KIBWEZI 132.00]	132	0.8496	31.5	2.70

2030

ANNEX 30 Three phase short circuit current 2030

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_JUJA RD11	132	18.28	31.5	58.03
[K_DANDORA11	132	18.28	31.5	58.03
[K_RUARAK TE1	132	18.24	31.5	57.90
[K_RUARAKAT12	132	18.24	31.5	57.90
[TEE 2	132	18.08	31.5	57.40
[K_THIKA11	132	18.09	31.5	57.43
[K_THIKA12	132	17.73	31.5	56.29
[K_RUARAKA11	132	17.01	31.5	54.00
[K_KAMBURU11	132	16.81	31.5	53.37
[K_KAMBTRF11	132	16.81	31.5	53.37
[K_THIKA NEW	132	15.05	31.5	47.78
[K_SUSWA21	220	19.36	40	48.40
[K_LESSOS11	132	14.67	31.5	46.57
[K_LESSTRF11	132	14.67	31.5	46.57
[K_NIP CC	220	18.58	40	46.45
[K_NIP CC	220	18.58	40	46.45
[K_OLKARIAIAU	220	18.14	40	45.35
[K_NIP 220	220	17.91	40	44.78
[K_GITARU11	132	13.81	31.5	43.84
[K_OLK V	220	17.4	40	43.50
[K_OLKARIA II	220	17.55	40	43.88
[K_OLKARIA IV	220	17.32	40	43.30
[K_KONZANEW	132	12.79	31.5	40.60
[K_UPLANDS	132	12.49	31.5	39.65
[K_SOILO11	132	12.67	31.5	40.22
[K_RONGAI 132	132	12.58	31.5	39.94
[K_MENE_NEW	132	12.58	31.5	39.94
[K_MENENGAI11	132	12.41	31.5	39.40
[K_KONZA	132	11.82	31.5	37.52
[K_ULU11	132	11.81	31.5	37.49
[K_MACHAKOS11	132	11.75	31.5	37.30
[K_DANDORA21	220	14.81	40	37.03
[K_MALAA220	220	14.69	40	36.73
[K_THIKA RD21	220	14.86	40	37.15

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity(kA)	% of Breaker Capacity
[K_EMBU13	132	11.11	31.5	35.27
[K_ISINYA21	220	14.17	40	35.43
[K_KUTUS11	132	10.58	31.5	33.59
[K_EMBA DUMMY	220	13.59	40	33.98
[K_EMBA-DUMMY	220	13.59	40	33.98
[K_NRB NORTH	220	13.6	40	34.00
[K_EMBAKASI21	220	13.59	40	33.98
[K_MAKINDU	132	10.5	31.5	33.33
[K_OLKARIA II	132	10.34	31.5	32.83
[K_KIMUKA 220	220	13.08	40	32.70
[K_OLKARIA1 1	132	10.08	31.5	32.00
[K_CABLE-OHL2	220	12.87	40	32.18
[K_ATHI RIVER	220	13	40	32.50
[K_CABLE-OHL	220	12.87	40	32.18
[K_KINDARUMA1	132	9.68	31.5	30.73
[K_OLKARIAIAU	132	9.83	31.5	31.21
[K_CBD	220	12.56	40	31.40
[K_GILGIL 220	220	12.39	40	30.98
[TEE 1	132	9.47	31.5	30.06
[K_GATUNDU11	132	9.35	31.5	29.68
[K_LANET11	132	9.5	31.5	30.16
[K_KILGORS132	132	9.6	31.5	30.48
[K_KAMBURU21	220	11.88	40	29.70
[K_LONGONOT	220	11.96	40	29.90
[K_WELLHED37-	132	8.67	31.5	27.52
[K_RONGAI_NC	132	8.92	31.5	28.32
[K_LESSOS	220	11.06	40	27.65
[K_LESSOS TEE	220	11.06	40	27.65
[K_LESSOS TEE	220	11.06	40	27.65
[K_B_DC2	400	11.08	40	27.70
[K_B_DC1	400	11.08	40	27.70
[K_SUSWA	400	11.08	40	27.70
[K_GILGIL	400	11.19	40	27.98
[K_NEW_VOI	132	8.61	31.5	27.33
[K_KIBOS 132	132	8.59	31.5	27.27

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity(kA)	% of Breaker Capacity
[K_RONGAI220	220	10.87	40	27.18
[K_THIKA 400	400	10.75	40	26.88
[K_KISUMU 132	132	8.23	31.5	26.13
[K_KIPETO 220	220	10.43	40	26.08
[K_KIMUKA	400	10.23	40	25.58
[K_MALAA 400	400	10.53	40	26.33
[K_LONGONOT	400	10.5	40	26.25
[K_MASINGA11	132	7.96	31.5	25.27
[K_CHEMOSIT11	132	7.73	31.5	24.54
[K_BARINGO21	220	10.1	40	25.25
[K_ISINYA41	400	9.98	40	24.95
[K_KONZA4	400	10.02	40	25.05
[TEE 1	132	7.68	31.5	24.38
[TEE2	132	7.72	31.5	24.51
[K_SOTIK	132	7.59	31.5	24.10
[K_MATASIA BS	220	9.44	40	23.60
[K_EMBU	220	9.54	40	23.85
[K_RONGAI 400	400	9.59	40	23.98
[K_ISIOLO11	132	7.36	31.5	23.37
[K_KIAMBERE21	220	9.31	40	23.28
[K_GITARU21	220	9.33	40	23.33
[K_OLKALOU132	132	6.81	31.5	21.62
[K_MUHORONI11	132	6.86	31.5	21.78
[K_KOLWA	132	6.89	31.5	21.87
[K_LOYAN	220	8.82	40	22.05
[K_MENENGAI40	400	8.78	40	21.95
[K_RABAI11	132	6.69	31.5	21.24
[K_RABAITRF11	132	6.63	31.5	21.05
[K_RABTRF12	132	6.63	31.5	21.05
[K_RABAITR 13	132	6.63	31.5	21.05
[K_MWALA	132	6.49	31.5	20.60
[K_NAIVASHA11	132	6.67	31.5	21.17
[K_KOPERE	132	6.54	31.5	20.76
[K_HG FALL 40	400	8.21	40	20.53
[K_MARAL/LOOS	400	8.31	40	20.78

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_LESSOS 400	400	8.49	40	21.23
[K_KIBOKO11	132	6.38	31.5	20.25
[K_MAUA11	132	6.28	31.5	19.94
[K_BARINGO	400	8.1	40	20.25
[K_SULTAN HA1	132	5.95	31.5	18.89
[K_NEW SULTAN	132	6.14	31.5	19.49
[K_MERUWESHI	132	6.06	31.5	19.24
[K_LOITOKTOK	132	5.99	31.5	19.02
[K_KOKOTONI11	132	5.92	31.5	18.79
[K_BAMBURI11	132	5.89	31.5	18.70
[K_TEE OFF	132	5.99	31.5	19.02
[K_BOMANI	132	5.83	31.5	18.51
[K_KUTUSTEE1	132	5.94	31.5	18.86
[K_TEE 2	132	6.12	31.5	19.43
[K_RUMURUTI11	132	5.85	31.5	18.57
[K_MUSAGA11	132	5.98	31.5	18.98
[K_MYANGA	132	5.93	31.5	18.83
[MYANGA TEE1	132	5.93	31.5	18.83
[MYANGA TEE2	132	5.93	31.5	18.83
[K_THIKA 220	220	7.78	40	19.45
[K_OLKA VIII	220	7.53	40	18.83
[K_KIPEVU11	132	5.71	31.5	18.13
[K_JOMVU	132	5.58	31.5	17.71
[K_ISHIARA11	132	5.65	31.5	17.94
[K_MAUNGU11	132	5.32	31.5	16.89
[K_VIPINGO31	132	5.33	31.5	16.92
[K_MERU11	132	5.45	31.5	17.30
[K_ELDORET11	132	5.36	31.5	17.02
[U_TORO11	132	5.21	31.5	16.54
[K_OLKA VII	220	6.99	40	17.48
[K_TEE	220	6.65	40	16.63
[K_NAMANGA	400	6.63	40	16.58
[K_MAKINDU400	400	6.67	40	16.68
[K_KILIFI11	132	5	31.5	15.87
[K_VOI11	132	5.17	31.5	16.41

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_KIGANJO11	132	5.05	31.5	16.03
[K_MWINGI11	132	5	31.5	15.87
[K_MAKUTANO11	132	5.19	31.5	16.48
[K_OLK IX	220	6.36	40	15.90
[K_AKIRA 220	220	6.5	40	16.25
[K_AGIL 220	220	6.5	40	16.25
[K_SELENKEI	220	6.51	40	16.28
[K_LOYAN 400	400	6.37	40	15.93
[K_MARIAKANI1	132	4.74	31.5	15.05
[K_MSCEMTEE31	132	4.81	31.5	15.27
[K_MSACEM31	132	4.66	31.5	14.79
[K_MSACEMTEE3	132	4.58	31.5	14.54
[K_BAMB TEE	132	4.8	31.5	15.24
[K_NEWMAUNGU	132	4.59	31.5	14.57
[K_NANYUKI11	132	4.84	31.5	15.37
[K_GITHAMBO11	132	4.73	31.5	15.02
[K_NAROK11	132	4.62	31.5	14.67
[K_SONDU11	132	4.75	31.5	15.08
[K_KITALE11	132	4.79	31.5	15.21
[K_KARURA	220	6	40	15.00
[K_KERINGET20	220	5.87	40	14.68
[K_KIBOS 220	220	6.17	40	15.43
[K_TOP STEEL	132	4.41	31.5	14.00
[K_WEBUYE11	132	4.53	31.5	14.38
[K_MUMIAS11	132	4.29	31.5	13.62
[K_SANGORO11	132	4.26	31.5	13.52
[K_BOMET11	132	4.34	31.5	13.78
[K_KISII11	132	4.51	31.5	14.32
[K_RANGALA11	132	4.47	31.5	14.19
[K_MUSAGATEE	132	4.36	31.5	13.84
[K_MARIAKANI2	220	5.75	40	14.38
[K_ISINYA	132	4.03	31.5	12.79
[K_KIPEVUDII1	132	4.08	31.5	12.95
[K_OTHAYA	132	4.01	31.5	12.73
[K_AWENDO11	132	4.11	31.5	13.05

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_BUSIA	132	4.25	31.5	13.49
[K_KAPSABET11	132	4.24	31.5	13.46
[K_RABAI21	220	5.13	40	12.83
[K_CHEMOSIT 2	220	5.19	40	12.98
[K_LOKICHAR	220	5.18	40	12.95
[K_MARSABIT	220	5.08	40	12.70
[K_LODWAR	220	5.17	40	12.93
[K_SAMBURU11	132	3.78	31.5	12.00
[K_KIBUYUNI	132	3.88	31.5	12.32
[K_KYENI11	132	3.88	31.5	12.32
[K_WOTE	132	3.9	31.5	12.38
[K_KITUI11	132	3.71	31.5	11.78
[K_KABARNET11	132	3.88	31.5	12.32
[K_ISIBENIA11	132	3.69	31.5	11.71
[K_BONDO	132	3.91	31.5	12.41
[K_KIMILILI	132	3.86	31.5	12.25
[K_ISIOLO 220	220	4.88	40	12.20
[K_TURKWEL21	220	4.79	40	11.98
[K_KAINUK21	220	4.8	40	12.00
[K_VOI 400	400	4.9	40	12.25
[K_KILGORIS	400	4.93	40	12.33
[T_TARUSHA41	400	4.79	40	11.98
[K_MANYANI11	132	3.38	31.5	10.73
[K_NDHIWA	132	3.55	31.5	11.27
[K_SAMBURU 22	220	4.4	40	11.00
[K_KWALE TEE	220	4.39	40	10.98
[K_MAUA 220	220	4.56	40	11.40
[K_MTITO AND1	132	3.2	31.5	10.16
[K_GALU11	132	3.28	31.5	10.41
[K_KWALE SC	132	3.11	31.5	9.87
[K_TITANIUM11	132	3.11	31.5	9.87
[K_GOGO	132	3.08	31.5	9.78
[K_DONGO_KU	220	4	40	10.00
[K_KAKMEGA220	220	4.14	40	10.35
[K_MARIAKANI4	400	4.09	40	10.23

YEAR 2030 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_GARISSA11	132	2.76	31.5	8.76
[K_MAGUNGA	132	2.74	31.5	8.70
[K_WERU	220	3.5	40	8.75
[K_KILIFI	220	3.5	40	8.75
[K_BAMBUR CE2	220	3.49	40	8.73
[K_MUSAGA220	220	3.61	40	9.03
[K_KORTUM21	220	3.45	40	8.63
[K_GARISA PV1	132	2.49	31.5	7.90
[K_NDIGWA	132	2.47	31.5	7.84
[K_MALINDI21	220	3.22	40	8.05
[K_KIBUYUNI2	220	3.23	40	8.08
[U_TORORO21	220	3.32	40	8.30
[K_CHOGORIA	132	2.34	31.5	7.43
[K_MAGADI	220	2.78	40	6.95
[K_GARBATULA	220	2.85	40	7.13
[K_KITALE	220	2.95	40	7.38
[K_MARALAL11	132	1.93	31.5	6.13
[K_GARSEN21	220	2.4	40	6.00
[K_GARISSA	220	2.49	40	6.23
[K_NAMANGA	132	1.44	31.5	4.57
[K_TAVETA11	132	1.64	31.5	5.21
[K_MUTOMO	132	1.52	31.5	4.83
[K_HOLA	220	2.06	40	5.15
[K_BURA	220	2	40	5.00
[K_LOKICHOGIO	220	2.05	40	5.13
[K_LAMU21	220	1.7	40	4.25
[K_KIBWEZI	132	0.99	31.5	3.14
[K_MOYALE	220	1.32	40	3.30
[K_WAJIR	220	0.69	40	1.73
[K_HABASWEIN	220	0.92	40	2.30

ANNEX 31 Three phase short circuit current Year 2035

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_JUJA RD11	132	20.98	31.5	66.60
[K_DANDORA11	132	20.98	31.5	66.60
[K_RUARAK TE1	132	20.92	31.5	66.41
[K_RUARAKAT12	132	20.92	31.5	66.41
[TEE 2	132	20.7	31.5	65.71
[K_THIKA11	132	20.71	31.5	65.75
[K_THIKA12	132	20.24	31.5	64.25
[K_RUARAKA11	132	19.34	31.5	61.40
[K_SUSWA21	220	24.06	40	60.15
[K_NIP CC	220	22.85	40	57.13
[K_NIP CC	220	22.85	40	57.13
[K_KAMBURU11	132	17.66	31.5	56.06
[K_KAMBTRF11	132	17.65	31.5	56.03
[K_OLKARIAIAU	220	21.98	40	54.95
[K_NIP 220	220	21.85	40	54.63
[K_THIKA NEW	132	16.7	31.5	53.02
[K_OLKARIA II	220	21.32	40	53.30
[K_LESSOS11	132	16.45	31.5	52.22
[K_LESSTRF11	132	16.45	31.5	52.22
[K_OLK V	220	20.7	40	51.75
[K_OLKARIA IV	220	20.58	40	51.45
[K_GITARU11	132	14.32	31.5	45.46
[K_SOILO11	132	14.2	31.5	45.08
[K_RONGAI 132	132	14.11	31.5	44.79
[K_MENE_NEW	132	14.15	31.5	44.92
[K_KONZANEW	132	13.9	31.5	44.13
[K_MENENGAI11	132	13.88	31.5	44.06
[K_DANDORA21	220	17.61	40	44.03
[K_MALAA220	220	17.5	40	43.75
[K_THIKA RD21	220	17.64	40	44.10
[K_UPLANDS	132	13.69	31.5	43.46
[K_ISINYA21	220	16.88	40	42.20
[K_KONZA	132	12.78	31.5	40.57
[K_EMBA DUMMY	220	16.3	40	40.75

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_EMBA-DUMMY	220	16.3	40	40.75
[K_EMBAKASI21	220	16.3	40	40.75
[K_ULU11	132	12.76	31.5	40.51
[K_MACHAKOS11	132	12.69	31.5	40.29
[K_NRB NORTH	220	15.83	40	39.58
[K_ATHI RIVER	220	15.47	40	38.68
[K_GILGIL	400	15.57	40	38.93
[K_CABLE-OHL2	220	15.27	40	38.18
[K_KIMUKA 220	220	15.34	40	38.35
[K_CABLE-OHL	220	15.27	40	38.18
[K_OLK III	220	15.39	40	38.48
[K_EMBU13	132	11.65	31.5	36.98
[K_CBD	220	14.86	40	37.15
[K_GILGIL 220	220	14.85	40	37.13
[K_MAKINDU	132	11.42	31.5	36.25
[K_LONGONOT	220	14.55	40	36.38
[K_BARINGO21	220	14.21	40	35.53
[K_B_DC2	400	14.56	40	36.40
[K_B_DC1	400	14.56	40	36.40
[K_SUSWA	400	14.56	40	36.40
[K_KUTUS11	132	11.08	31.5	35.17
[K_THIKA 400	400	13.84	40	34.60
[K_RONGAI 400	400	13.81	40	34.53
[K_OLKARIA II	132	10.85	31.5	34.44
[K_LONGONOT	400	13.74	40	34.35
[K_OLKARIA1 1	132	10.55	31.5	33.49
[K_OLKARIAIAU	132	10.27	31.5	32.60
[K_LANET11	132	10.25	31.5	32.54
[K_RONGAI220	220	13.24	40	33.10
[K_LESSOS	220	13.1	40	32.75
[K_LESSOS TEE	220	13.1	40	32.75
[K_LESSOS TEE	220	13.1	40	32.75
[K_KIMUKA	400	13.08	40	32.70
[K_MALAA 400	400	13.27	40	33.18
[K_RABAI11	132	9.97	31.5	31.65

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_KINDARUMA1	132	9.98	31.5	31.68
[TEE 1	132	10.11	31.5	32.10
[K_GATUNDU11	132	9.97	31.5	31.65
[K_KAMBURU21	220	12.87	40	32.18
[K_ISINYA41	400	12.69	40	31.73
[K_MENENGAI40	400	12.75	40	31.88
[K_RABAITRF11	132	9.73	31.5	30.89
[K_RABTRF12	132	9.73	31.5	30.89
[K_RABAITR 13	132	9.73	31.5	30.89
[K_RONGAI_NC	132	9.67	31.5	30.70
[K_KONZA4	400	12.58	40	31.45
[K_NEW_VOI	132	9.55	31.5	30.32
[K_WELLHED37-	132	9.01	31.5	28.60
[K_KIBOS 132	132	9.03	31.5	28.67
[K_KIPETO 220	220	11.74	40	29.35
[K_LESSOS 400	400	11.39	40	28.48
[K_KIPEVU11	132	8.58	31.5	27.24
[K_TEE OFF	132	8.35	31.5	26.51
[TEE 1	132	8.42	31.5	26.73
[TEE2	132	8.5	31.5	26.98
[K_KISUMU 132	132	8.59	31.5	27.27
[K_BARINGO	400	10.85	40	27.13
[K_MARAL/LOOS	400	10.8	40	27.00
[K_KOKOTONI11	132	8.21	31.5	26.06
[K_JOMVU	132	8.05	31.5	25.56
[K_MASINGA11	132	8.15	31.5	25.87
[K_MATASIA BS	220	10.57	40	26.43
[K_EMBU	220	10.23	40	25.58
[K_HG FALL 40	400	10.42	40	26.05
[K_BAMBURI11	132	8.01	31.5	25.43
[K_BOMANI	132	7.79	31.5	24.73
[K_KIAMBERE21	220	9.9	40	24.75
[K_GITARU21	220	9.89	40	24.73
[K_ISIOLO11	132	7.62	31.5	24.19
[K_SUSWA GEN	220	9.51	40	23.78

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_OLKALOU132	132	7.26	31.5	23.05
[K_CHEMOSIT11	132	7.19	31.5	22.83
[K_KOLWA	132	7.13	31.5	22.63
[K_LOYAN	220	9.28	40	23.20
[K_VIPINGO31	132	6.93	31.5	22.00
[K_NAIVASHA11	132	7.01	31.5	22.25
[K_MUHORONI11	132	6.97	31.5	22.13
[K_KOPERE	132	6.81	31.5	21.62
[K_KIBOKO11	132	6.7	31.5	21.27
[K_MAUA11	132	6.46	31.5	20.51
[K_MWALA	132	6.72	31.5	21.33
[K_THIKA 220	220	8.38	40	20.95
[K_SULTAN HA1	132	6.21	31.5	19.71
[K_NEW SULTAN	132	6.41	31.5	20.35
[K_MERUWESHI	132	6.33	31.5	20.10
[K_LOITOKTOK	132	6.25	31.5	19.84
[K_TEE 2	132	6.27	31.5	19.90
[K_RUMURUTI11	132	6.17	31.5	19.59
[K_MUSAGA11	132	6.23	31.5	19.78
[K_MAKINDU400	400	7.99	40	19.98
[K_KILIFI11	132	6.12	31.5	19.43
[K_MARIAKANI1	132	5.9	31.5	18.73
[K_MSCEMTEE31	132	6.02	31.5	19.11
[K_BAMB TEE	132	6.14	31.5	19.49
[K_KUTUSTEE1	132	6.11	31.5	19.40
[K_MYANGA	132	6.1	31.5	19.37
[MYANGA TEE1	132	6.1	31.5	19.37
[MYANGA TEE2	132	6.1	31.5	19.37
[K_OLKA VII	220	7.7	40	19.25
[K_NAMANGA	400	7.71	40	19.28
[K_MAUNGU11	132	5.79	31.5	18.38
[K_MSACEM31	132	5.77	31.5	18.32
[K_MSACEMTEE3	132	5.61	31.5	17.81
[K_ISHIARA11	132	5.76	31.5	18.29
[K_MERU11	132	5.61	31.5	17.81

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_ELDORET11	132	5.59	31.5	17.75
[K_MARIAKANI2	220	7.14	40	17.85
[K_AKIRA 220	220	7.32	40	18.30
[K_AGIL 220	220	7.18	40	17.95
[K_TEE	220	7.29	40	18.23
[K_SELENKEI	220	7.12	40	17.80
[K_LOYAN 400	400	7.09	40	17.73
[K_VOI11	132	5.5	31.5	17.46
[K_TOP STEEL	132	5.33	31.5	16.92
[K_MAKUTANO11	132	5.43	31.5	17.24
[U_TORO11	132	5.3	31.5	16.83
[K_KIBOS 220	220	6.7	40	16.75
[K_KIPEVUDII1	132	5.11	31.5	16.22
[K_NEWMAUNGU	132	4.98	31.5	15.81
[K_NANYUKI11	132	4.93	31.5	15.65
[K_GITHAMBO11	132	4.89	31.5	15.52
[K_KIGANJO11	132	5.18	31.5	16.44
[K_MWINGI11	132	5.12	31.5	16.25
[K_SOTIK	132	4.97	31.5	15.78
[K_KITALE11	132	4.9	31.5	15.56
[K_RABAI21	220	6.48	40	16.20
[K_KARURA	220	6.23	40	15.58
[K_KERINGET20	220	6.36	40	15.90
[K_NAROK11	132	4.62	31.5	14.67
[K_WEBUYE11	132	4.67	31.5	14.83
[K_SONDU11	132	4.65	31.5	14.76
[K_RANGALA11	132	4.63	31.5	14.70
[K_VOI 400	400	5.8	40	14.50
[K_SAMBURU11	132	4.27	31.5	13.56
[K_KIBUYUNI	132	4.27	31.5	13.56
[K_MUMIAS11	132	4.43	31.5	14.06
[K_MUSAGATEE	132	4.46	31.5	14.16
[K_BUSIA	132	4.36	31.5	13.84
[K_KAPSABET11	132	4.38	31.5	13.90
[K_CHEMOSIT 2	220	5.49	40	13.73

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_ISINYA	132	4.13	31.5	13.11
[K_KYENI11	132	3.95	31.5	12.54
[K_WOTE	132	4.01	31.5	12.73
[K_OTHAYA	132	4.14	31.5	13.14
[K_KABARNET11	132	4.03	31.5	12.79
[K_SANGORO11	132	4.19	31.5	13.30
[K_BONDO	132	4.03	31.5	12.79
[K_KIMILILI	132	3.94	31.5	12.51
[K_SAMBURU 22	220	5.15	40	12.88
[K_KWALE TEE	220	5.17	40	12.93
[K_ISIOLO 220	220	5.06	40	12.65
[K_MARSABIT	220	5.23	40	13.08
[T_TARUSHA41	400	5.31	40	13.28
[K_GALU11	132	3.77	31.5	11.97
[K_KITUI11	132	3.79	31.5	12.03
[K_BOMET11	132	3.63	31.5	11.52
[K_DONGO_KU	220	4.63	40	11.58
[K_MAUA 220	220	4.71	40	11.78
[K_TURKWEL21	220	4.7	40	11.75
[K_LOKICHAR	220	4.63	40	11.58
[K_KAINUK21	220	4.71	40	11.78
[K_LODWAR	220	4.62	40	11.55
[K_MARIAKANI4	400	4.83	40	12.08
[K_MTITO AND1	132	3.31	31.5	10.51
[K_MANYANI11	132	3.51	31.5	11.14
[K_KWALE SC	132	3.43	31.5	10.89
[K_TITANIUM11	132	3.51	31.5	11.14
[K_KISII11	132	3.51	31.5	11.14
[K_KILGORS132	132	3.31	31.5	10.51
[K_KILIFI	220	4.28	40	10.70
[K_BAMBUR CE2	220	4.31	40	10.78
[K_KAKMEGA220	220	4.4	40	11.00
[K_AWENDO11	132	3.28	31.5	10.41
[K_NDHIWA	132	3.1	31.5	9.84
[K_WERU	220	4.19	40	10.48

YEAR 2035 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity(kA)**	**% of Breaker Capacity**
[K_MUSAGA220	220	3.81	40	9.53
[K_MALINDI21	220	3.78	40	9.45
[K_KIBUYUNI2	220	3.64	40	9.10
[K_KORTUM21	220	3.44	40	8.60
[U_TORORO21	220	3.48	40	8.70
[K_GARISSA11	132	2.6	31.5	8.25
[K_GARISA PV1	132	2.37	31.5	7.52
[K_ISIBENIA11	132	2.58	31.5	8.19
[K_NDIGWA	132	2.52	31.5	8.00
[K_MAGUNGA	132	2.41	31.5	7.65
[K_GOGO	132	2.64	31.5	8.38
[K_CHOGORIA	132	2.36	31.5	7.49
[K_MAGADI	220	2.87	40	7.18
[K_GARSEN21	220	2.64	40	6.60
[K_GARBATULA	220	2.91	40	7.28
[K_KITALE	220	2.98	40	7.45
[K_MARALAL11	132	1.96	31.5	6.22
[TEST BUS	220	2.35	40	5.88
[K_GARISSA	220	2.52	40	6.30
[K_NAMANGA	132	1.46	31.5	4.63
[K_TAVETA11	132	1.69	31.5	5.37
[K_MUTOMO	132	1.54	31.5	4.89
[K_LAMU21	220	1.81	40	4.53
[K_HOLA	220	2.18	40	5.45
[K_BURA	220	2.1	40	5.25
[K_LOKICHOGIO	220	1.92	40	4.80
[K_KIBWEZI	132	1	31.5	3.17
[K_MOYALE	220	1.33	40	3.33
[K_WAJIR	220	0.71	40	1.78
[K_HABASWEIN	220	0.95	40	2.38
[K_MANDERA	220	0.45	40	1.13

2040

ANNEX 32 Three phase short circuit current Year 2040

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_JUJA	132	22.66	31.5	71.94
[K_DANDORA11	132	22.66	31.5	71.94
[K_RUARAK	132	22.59	31.5	71.71
[K_RUARAKAT	132	22.59	31.5	71.71
[TEE	132	22.29	31.5	70.76
[K_THIKA11	132	22.32	31.5	70.86
[K_THIKA12	132	21.77	31.5	69.11
[K_RUARAKA11	132	20.77	31.5	65.94
[K_SUSWA21	220	25.95	40	64.88
[K_NIP	220	24.54	40	61.35
[K_NIP	220	24.54	40	61.35
[K_KAMBURU11	132	18.21	31.5	57.81
[K_KAMBTRF11	132	18.19	31.5	57.75
[K_NIP	220	23.39	40	58.48
[K_OLKARIAIAU	220	22.94	40	57.35
[K_LESSOS11	132	17.31	31.5	54.95
[K_LESSTRF11	132	17.31	31.5	54.95
[K_OLKARIA	220	22.11	40	55.28
[K_OLK	220	21.77	40	54.43
[K_OLKARIA	220	21.64	40	54.10
[K_THIKA	132	16.76	31.5	53.21
[K_DANDORA	220	19.61	40	49.03
[K_MALAA220	220	19.72	40	49.30
[K_THIKA	220	19.62	40	49.05
[K_THIKA	132	15.03	31.5	47.71
[K_KONZANEW	132	14.71	31.5	46.70
[K_SOILO11	132	14.85	31.5	47.14
[K_RONGAI	132	14.7	31.5	46.67
[K_MENE_NEW	132	14.68	31.5	46.60
[K_ISINYA21	220	18.88	40	47.20
[K_UPLANDS	132	14.35	31.5	45.56
[K_GITARU11	132	14.64	31.5	46.48
[K_MENENGAI	132	14.41	31.5	45.75
[K_EMBA	220	18.26	40	45.65

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_EMBA-DUMMY	220	18.26	40	45.65
[K_EMBAKASI	220	18.26	40	45.65
[K_HG	132	14.04	31.5	44.57
[K_GILGIL	400	17.72	40	44.30
[K_ULU11	132	13.44	31.5	42.67
[K_KONZA	132	13.46	31.5	42.73
[K_NRB	220	17.28	40	43.20
[K_ATHI	220	17.22	40	43.05
[K_MACHAKOS	132	13.37	31.5	42.44
[K_CABLE-OHL22	220	16.97	40	42.43
[K_CABLE-OHL	220	16.97	40	42.43
[K_LAMU	220	16.95	40	42.38
[K_KIMUKA	220	16.31	40	40.78
[K_CBD	220	16.5	40	41.25
[K_B_DC2	400	16.42	40	41.05
[K_B_DC1	400	16.42	40	41.05
[K_SUSWA	400	16.42	40	41.05
[K_MALAA	400	16.39	40	40.98
[K_GILGIL	220	15.83	40	39.58
[K_LONGONOT	220	15.88	40	39.70
[K_BARINGO21	220	16.14	40	40.35
[K_LONGONOT	400	15.98	40	39.95
[K_OLK	220	15.55	40	38.88
[K_MAKINDU	132	11.92	31.5	37.84
[K_RABAI11	132	12.12	31.5	38.48
[K_KONZA4	400	15.07	40	37.68
[K_RONGAI	400	15.23	40	38.08
[K_RABAITRF	132	11.76	31.5	37.33
[K_RABTRF12	132	11.76	31.5	37.33
[K_RABAITR	132	11.76	31.5	37.33
[K_ISINYA41	400	14.99	40	37.48
[K_KIMUKA	400	14.83	40	37.08
[K_OLKARIA	132	11.03	31.5	35.02
[K_RONGAI220	220	13.92	40	34.80
[K_LESSOS	220	13.95	40	34.88

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_LESSOS	220	13.95	40	34.88
[K_LESSOS	220	13.95	40	34.88
[K_MENENGAI	400	13.86	40	34.65
[K_OLKARIA1	132	10.73	31.5	34.06
[K_LANET11	132	10.67	31.5	33.87
[K_KILGORS	132	10.83	31.5	34.38
[K_KAMBURU21	220	13.44	40	33.60
[K_NEW_VOI	132	10.37	31.5	32.92
[K_OLKARIAIAU	132	10.45	31.5	33.17
[K_KIPEVU11	132	10	31.5	31.75
[K_KINDARUMA	132	10.21	31.5	32.41
[K_RONGAI_NC	132	9.94	31.5	31.56
[K_KIPETO	220	12.64	40	31.60
[K_TEE	132	9.91	31.5	31.46
[K_KIBOS	132	9.82	31.5	31.17
[K_LESSOS	400	12.42	40	31.05
[K_KOKOTONI	132	9.57	31.5	30.38
[K_BAMBURI11	132	9.59	31.5	30.44
[K_JOMVU	132	9.32	31.5	29.59
[K_BOMANI	132	9.34	31.5	29.65
[K_EMBU13	132	9.49	31.5	30.13
[TEE	132	9.48	31.5	30.10
[K_GATUNDU11	132	9.36	31.5	29.71
[K_KISUMU	132	9.39	31.5	29.81
[K_LAMU21	220	12.09	40	30.23
[K_BARINGO	400	11.98	40	29.95
[K_MARAL/LOOS	400	11.87	40	29.68
[TEE	132	9.06	31.5	28.76
[TEE2	132	9.17	31.5	29.11
[K_KUTUS11	132	9.23	31.5	29.30
[K_WELLHED37	132	9.15	31.5	29.05
[K_CHEMOSIT	132	8.59	31.5	27.27
[K_SOTIK	132	8.39	31.5	26.63
[K_MATASIA	220	10.87	40	27.18
[K_VIPINGO31	132	8.17	31.5	25.94

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_MASINGA11	132	8.22	31.5	26.10
[K_KIAMBERE	220	10.32	40	25.80
[K_GITARU21	220	10.2	40	25.50
[K_EMBU	220	10.47	40	26.18
[K_OLK	220	10.26	40	25.65
[K_ISIOLO	132	7.8	31.5	24.76
[K_SUSWA	220	9.87	40	24.68
[K_LOYAN	220	10	40	25.00
[K_KILIFI11	132	7.43	31.5	23.59
[K_ISIOLO11	132	7.48	31.5	23.75
[K_OLKALOU	132	7.44	31.5	23.62
[K_MUHORONI	132	7.52	31.5	23.87
[K_KOLWA	132	7.69	31.5	24.41
[K_MARIAKANI	220	9.56	40	23.90
[K_NAIVASHA	132	7.18	31.5	22.79
[K_MAKINDU	400	9.09	40	22.73
[K_KIBOKO11	132	6.9	31.5	21.90
[K_MSCEMTEE3	132	7.02	31.5	22.29
[K_BAMB	132	7.02	31.5	22.29
[K_MWALA	132	6.86	31.5	21.78
[K_KOPERE	132	7.06	31.5	22.41
[K_NEW	132	6.61	31.5	20.98
[K_MERUWESHI	132	6.53	31.5	20.73
[K_MARIAKANI	132	6.52	31.5	20.70
[K_MSACEM31	132	6.72	31.5	21.33
[K_MSACEMTEE	132	6.54	31.5	20.76
[K_MAUA11	132	6.66	31.5	21.14
[K_RABAI21	220	8.48	40	21.20
[K_NAMANGA	400	8.5	40	21.25
[K_SULTAN	132	6.4	31.5	20.32
[K_LOITOKTOK	132	6.45	31.5	20.48
[K_RUMURUTI	132	6.29	31.5	19.97
[K_MUSAGA11	132	6.4	31.5	20.32
[K_MYANGA	132	6.22	31.5	19.75
[MYANGA	132	6.22	31.5	19.75

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[MYANGA	132	6.22	31.5	19.75
[K_THIKA	220	8.07	40	20.18
[K_OLKA	220	8.02	40	20.05
[K_MAUNGU11	132	6.13	31.5	19.46
[K_ISHIARA11	132	5.85	31.5	18.57
[K_TEE	132	5.91	31.5	18.76
[K_AKIRA	220	7.63	40	19.08
[K_AGIL	220	7.63	40	19.08
[K_TEE	220	7.55	40	18.88
[K_LOYAN	400	7.65	40	19.13
[K_KIPEVUDII	132	5.62	31.5	17.84
[K_VOI11	132	5.77	31.5	18.32
[K_TOP	132	5.81	31.5	18.44
[K_MERU11	132	5.71	31.5	18.13
[K_KUTUSTEE1	132	5.76	31.5	18.29
[K_MAKUTANO	132	5.53	31.5	17.56
[K_ELDORET11	132	5.73	31.5	18.19
[K_KWALE	220	7.16	40	17.90
[K_OLK	220	7.33	40	18.33
[K_KIBOS	220	7.09	40	17.73
[K_SELENKEI	220	7.37	40	18.43
[K_NEWMAUNGU	132	5.25	31.5	16.67
[K_KIGANJO11	132	5.24	31.5	16.63
[K_MWINGI11	132	5.25	31.5	16.67
[U_TORO11	132	5.36	31.5	17.02
[K_KERINGET	220	6.66	40	16.65
[K_VOI	400	6.76	40	16.90
[K_LAMU	400	6.98	40	17.45
[K_NANYUKI11	132	5	31.5	15.87
[K_GITHAMBO	132	5.02	31.5	15.94
[K_SONDU11	132	4.96	31.5	15.75
[K_KISII11	132	4.89	31.5	15.52
[K_KITALE11	132	5.05	31.5	16.03
[K_GARSEN21	220	6.42	40	16.05
[K_SAMBURU	220	6.3	40	15.75

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_WERU	220	6.21	40	15.53
[K_DONGO_KU	220	6.55	40	16.38
[K_KARURA	220	6.39	40	15.98
[K_KIBUYUNI	132	4.83	31.5	15.33
[K_NAROK11	132	4.81	31.5	15.27
[K_WEBUYE11	132	4.78	31.5	15.17
[K_RANGALA11	132	4.77	31.5	15.14
[K_MALINDI21	220	5.9	40	14.75
[K_CHEMOSIT	220	5.81	40	14.53
[K_MARIAKANI	400	5.82	40	14.55
[K_KILGORIS	400	6.02	40	15.05
[K_SAMBURU	132	4.54	31.5	14.41
[K_MUMIAS11	132	4.54	31.5	14.41
[K_SANGORO11	132	4.43	31.5	14.06
[K_BOMET11	132	4.56	31.5	14.48
[K_AWENDO11	132	4.37	31.5	13.87
[K_MUSAGATEE	132	4.52	31.5	14.35
[K_BUSIA	132	4.45	31.5	14.13
[K_KAPSABET	132	4.44	31.5	14.10
[K_KILIFI	220	5.77	40	14.43
[K_LOKICHAR	220	5.48	40	13.70
[K_LODWAR	220	5.47	40	13.68
[T_TARUSHA41	400	5.67	40	14.18
[K_ISINYA	132	4.19	31.5	13.30
[K_GALU11	132	4.13	31.5	13.11
[K_KYENI11	132	4	31.5	12.70
[K_WOTE	132	4.1	31.5	13.02
[K_OTHAYA	132	4.19	31.5	13.30
[K_KABARNET	132	4.15	31.5	13.17
[K_BONDO	132	4.15	31.5	13.17
[K_KIMILILI	132	4.02	31.5	12.76
[K_BAMBUR	220	5.37	40	13.43
[K_ISIOLO	220	5.26	40	13.15
[K_TURKWEL21	220	5.07	40	12.68
[K_KAINUK21	220	5.08	40	12.70

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	**Voltage Level (kV)**	**Maximum Fault Current (kA)**	**Breaker Capacity (kA)**	**% of Breaker Capacity**
[K_MARSABIT	220	5.37	40	13.43
[K_KWALE	132	3.76	31.5	11.94
[K_TITANIUM	132	3.83	31.5	12.16
[K_KITUI11	132	3.88	31.5	12.32
[K_NDHIWA	132	3.73	31.5	11.84
[K_ISIBENIA	132	3.88	31.5	12.32
[K_MAUA	220	4.88	40	12.20
[K_MTITO	132	3.38	31.5	10.73
[K_MANYANI	132	3.61	31.5	11.46
[K_KIBUYUNI2	220	4.44	40	11.10
[K_KAKMEGA	220	4.55	40	11.38
[K_GOGO	132	3.22	31.5	10.22
[K_MUSAGA220	220	3.92	40	9.80
[K_OLSUSWA	220	4.06	40	10.15
[K_GARISSA11	132	2.75	31.5	8.73
[K_MAGUNGA	132	2.85	31.5	9.05
[K_KORTUM21	220	3.61	40	9.03
[U_TORORO21	220	3.54	40	8.85
[K_CHOGORIA	132	2.38	31.5	7.56
[K_GARISA	132	2.48	31.5	7.87
[K_NDIGWA	132	2.57	31.5	8.16
[K_HOLA	220	3.34	40	8.35
[K_GARBATULA	220	3.12	40	7.80
[K_KITALE	220	3.09	40	7.73
[K_MAGADI	220	2.9	40	7.25
[K_BURA	220	2.87	40	7.18
[K_GARISSA	220	2.82	40	7.05
[K_MARALAL11	132	1.98	31.5	6.29
[K_MUTOMO	220	2.44	40	6.10
[K_TEE	220	2.44	40	6.10
[K_NAMANGA	132	1.47	31.5	4.67
[K_TAVETA11	132	1.72	31.5	5.46
[K_MUTOMO	132	1.56	31.5	4.95
[K_LOKICHOGIO	220	2.1	40	5.25
[K_KIBWEZI	132	1.01	31.5	3.21

YEAR 2040 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
[K_MOYALE	220	1.34	40	3.35
[K_WAJIR	220	0.72	40	1.80
[K_HABASWEIN	220	0.98	40	2.45
[K_MANDERA	220	0.46	40	1.15

ANNEX 33 System Losses

1. Losses without 400kV Network

1.

VOLTAGE LEVEL (kV)	2020	2021	2022	2023	2024	2025
	MW	MW	MW	MW	MW	MW
DC	0	0.01	0.01	0.01	0.01	0.01
400	0	0	0	0	0	0
220	48.16	45.56	47.17	26.87	27.68	26.87
132	35.67	30.4	33.78	33.22	29.54	30
TOTAL	**83.83**	**75.97**	**80.96**	**60.1**	**57.23**	**56.88**
% POWER LOSSES	**4.26**	**3.70**	**3.79**	**2.76**	**2.57**	**2.43**

2) **Losses with 400kV Network**

VOLTAGE LEVEL (kV)	2021	2022	2023	2024	2025	2030	2035	2040
	MW	MW	MW	MW	MW	MW	MW	MW
DC	1.2	1.2	1.2	1.2	1.2	10.77	10.77	10.77
400	2.56	3.58	3.52	5.48	5.93	22.69	28.57	28.29
220	39.71	40.2	16.09	17.53	18.33	34.22	52.68	71.37
132	30.58	34.24	32.62	29.13	25.64	30.1	41.63	66.42
TOTAL	**74.05**	**79.22**	**53.43**	**53.34**	**51.1**	**97.78**	**133.65**	**176.85**
%POWER LOSS	**3.56**	**3.56**	**2.5**	**2.29**	**2.27**	**3.3**	**3.53**	**3.48**

ANNEX 34 System Summary (generation, Load and Losses)

1. ***Medium Term***

ZONE	2020			2025		
	Generation	Load	Losses	Generation	Load	Losses
ETHIOPIA	0	0	0	200.1	0	2.9
	0	0	0	-113.3	0	143.5
NAIROBI	103.8	1017.4	31	180.2	1219.3	30.8
	75.4	334.4	234.3	38.9	400.8	281.3
UGANDA	61.2	0	0	50	0	0
	20.9	0	0	-19	0	0.5
COAST	288.9	290.9	10.3	300	325.5	6.4
	13.2	95.6	77.9	-65.7	107.4	54
MT KENYA	651.9	132.1	13.7	569.1	194.1	14.5
	50.2	43.4	93.5	-4.6	63.4	92.4
C RIFT	636	112.5	46.5	811.2	166.7	20.3
	142.6	37	339.4	-12	54.8	207.2
W REGION	86.4	213.7	14.3	85.2	258.2	8.8
	28.5	70.8	52.2	-13.5	84.9	43.3
N RIFT	139.1	64	19.4	145.1	86.2	5.5
	24.4	21	77.5	9.9	28.3	52.3
Active Power (MW)	**1967.3**	**1830.6**	**135.2**	**2340.9**	**2250**	**89.2**
Reactive Power (MVAr)	**355.2**	**602.3**	**874.7**	**-179.4**	**739.6**	**874.7**

*2. **Long Term***

ZONE	2030			2035			2040		
	Generation	Load	Losses	Generation	Load	Losses	Generation	Load	Losses
NAIROBI	45.5	1337.5	41.3	109.3	1767.7	71.6	109.9	2311.3	114.8
	9.7	439.6	419.6	176.1	582.8	701.4	49.4	762	1143.6
COAST	0	595.8	20.2	198.6	757.4	19	880.4	962.6	26
	0	202.9	158.5	268.8	254.9	189.6	8	323.2	223.6
MT KENYA	1090	298.2	24.3	1053.5	400.6	26	1543.3	523.8	43.3
	-194.2	98.8	203.3	-226.8	130.7	189.5	-235.3	170.9	314.4
C RIFT	1192.5	260.8	19.6	1587.6	338	33.5	1700.1	435.6	40
	-98.9	85.7	236	-190.5	117.8	356.6	-53.9	152	399.2
W REGION	92.2	431.8	10.1	92.2	571	15.3	150.2	747.1	24.2
	-13.7	141.9	62.2	46.5	190.4	107.2	28.5	253	184.5
N RIFT	545	152.6	10.4	745.1	201.8	22.5	695.2	264	23.6
	-31.7	50.2	129.6	-281.4	65.7	235.3	-60.3	85.9	252.9
Active Power (MW)	**2965**	**3076.7**	**126.5**	**3786.2**	**4036.5**	**187.9**	**5078.5**	**5244.4**	**273.3**
Reactive Power (MVAr)	**-328.8**	**1019.2**	**1209.1**	**-207.4**	**1342.2**	**1779.7**	**-292.9**	**1747.1**	**2518.9**