LEAST COST POWER DEVELOPMENT PLAN

2021- 2030

April 2021

Table of contents

List of Tables

List of Figures

ANNEXURES

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
FOM	Fixed Operations and Maintenance Costs
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
IAEA	International Atomic Energy Agency
IDC	Interest During Construction
IEA	International Energy Agency
INEP	Integrated National Energy Plan

IPP	Independent Power Producer
ISO	Independent 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
LEC	Levelized Energy Cost
LCPDP	Least Cost Power Development Plan
LIPS OP	Lahmeyer International Short-term optimization
LIPS XP	Lahmeyer International Expansion Planning
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
O & M	Operation and Maintenance
PPA	Power Purchase Agreement
PSSE	Power System Simulation for Engineers
PV	Photo Voltaic
REREC	Rural Electrification Renewable Energy Corporation
SAIFI	System Average Interruption Frequency Index
SAPP	Southern African Power Pool
SME	Small Medium Enterprises
SWERA	Solar and Wind Energy Resource Assessment
SPV	Special Purpose Vehicle
TSO	Transmission System Operator
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
VOM	Variable Operation and Maintenance Costs
WARMA	Water Resource Management

ACKNOWLEDGEMENT

This report was prepared through collaborative effort amongst the Ministry of Energy, the energy sector regulator and utilities within the Kenyan power sector. It was derived from the 2020-2040 Least Cost Power Development Plan (LCPDP) which had benefited from quality assurance provided by the power sector planning Oversight Committee chaired by the Director General of the Energy and Petroleum Regulatory Authority (EPRA). The 20-year plan also benefited from broader input from relevant public institutions namely, the Vision 2030 Secretariat and the Kenya National Bureau of Statistics (KNBS).

A select team of the Technical Committee of the LCPDP carried out all relevant simulations and analyses, and drafted the report. Their concerted effort and dedication to duty are greatly acknowledged. The Ministry of Energy (MOE) provided 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, this report is intended to guide generation capacity development and provide the required signals to investors to participate in the power supply value chain in the country. The Management of EPRA is also acknowledged for continuing to provide regulatory and secretariat services in this work.

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

EXECUTIVE SUMMARY

This report presents a 10 year Least Cost Power Generation Expansion Plan (LCPDP) for the period 2021-2030, derived from a longer term LCPDP for 2020-2040. The report was prepared as part of National Government undertakings for post COVID-19 development support programme and the attendant engagements with Development Partners. The update was deemed necessary to make the long term planning assumptions more predictable given the relative certainty in planning for a 10 years period compared to 20 years. It takes into consideration the following previous efforts:

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

The study was carried out in the traditional LCPDP format as the Ministry completes preparation of both the INEP framework and the enabling regulations, both of which are at an advanced stage of development.

Power Demand-Supply Overview

As of December 2020, Kenya had a total interconnected effective capacity of 2,708 MW. The peak demand had grown from 1,512MW recorded in Financial Year (FY) 2014/15 to 1,926MW in FY 2019/20. The demand has maintained a general upward trend over the past decade. After the ravaging Covid-19 pandemic, a new peak of 1976MW was recorded in the month of December 2020, an indication of the gradual recovery from the slump caused by the pandemic between March and August 2020.

The country has also experienced a significant increase in the number of customers connected to the grid, from 3,611,904 recorded in financial year 2014/15 to 7,576,145 recorded 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 attributed to accelerated electrification programs implementation across the country. Network losses have remained significantly high, standing at 23.7% as of June 2020.

Demand Forecast

The 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. Battery energy storage technology has been considered in the plan to support the integration of Variable Renewable Energy technologies and for system support. It is assumed that through the deployment of grid sized batteries, energy is stored and can be utilized during peak hours, thus increasing off-peak demand which supports utilization of the base load capacity. It was assumed that the batteries are charged for four hours a day during off-peak which is equivalent to a load factor of 16.67%.

Electricity consumption is projected to rise over the planning period in all scenarios. The annual peak load is expected to grow in all scenarios over the planning period. Energy demand is forecasted to grow at an average of 5.21% while the peak load is forecasted to grow at an average of 4.91% in the reference scenario; and 8.13% and 7.99% in the vision scenario and 4.35% and 4.04% in the low scenario, respectively.

Peak demand is projected to grow at an average of 4.91% from 1,972MW in the base year to 3,183MW at the end of the planning period under the Reference scenario. Similarly, under the Vision scenario peak demand increases to 4,251MW in 2030 growing at an average rate of 7.99%. The Low scenario peak demand increases to 2,928MW in 2030 at an average rate of 4.04%.

Generation Expansion Plan

The LIPS-XP/OP generation planning software was used to simulate the expansion cases assembled based on various assumptions, and optimized over the period up to 2030 under the reference demand forecast. Battery Energy Storage Systems (BESS) was considered among the technologies under development within the 10-year period. BESS were modelled assuming characteristics of thermal plants that serve as peaking plants as the LIPS-XP/OP planning tool does not have the capability for modelling BESS as an independent storage unit. The specific load requirement for charging the batteries was incorporated by modifying the load curve to have the batteries charged for 4 hours during off-peak. The cost of the energy for charging the batteries was modelled as fuel cost for the BESS technology at 2 US$c/kWh equivalent to the cost of the vented steam.

The total interconnected effective capacity grows from the current 2708 MW in 2021 to 4,847 MW in 2030. The results indicate that there would be no annual excess energy as a share of generation following the introduction of battery energy storage systems (BESS). However, the system would still have vented steam averaging about 12% of the possible maximum geothermal generation over the planning period. The Levelised Cost of Energy (LEC) rises from US Cents 8.08/KWh in 2021 to peak at US Cents 9.17/KWh in 2027.

Reference Generation Expansion Plan Capacity and Forecast Demand

Installed capacity (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Geothermal	898	854	957	957	977	977	1,117	1,168	1,252	1,252
Hydropower	809	813	820	829	849	868	881	889	896	1,005
Diesel engines	566	566	506	506	506	506	506	506	506	418
Gas turbines (gasoil)	56	0	0	0	0	0	0	0	0	0
Import	0	200	200	200	400	400	400	400	400	400
Cogeneration	2	3	33	33	61	93	96	116	157	197
Wind	426	426	426	476	476	537	537	581	631	671
Solar PV	50	130	170	210	210	294	304	344	374	454
Gas turbines (LNG)	0	0	0	0	0	0	0	200	200	200
BESS	0	50	100	150	150	250	250	250	250	250
TOTAL (MW)	**2,807**	**3,043**	**3,212**	**3,361**	**3,629**	**3,925**	**4,091**	**4,455**	**4,667**	**4,847**
Demand Forecast										
Ref. Peak (MW)	**2,029**	**2,110**	**2,190**	**2,272**	**2,363**	**2,503**	**2,677**	**2,833**	**3,000**	**3,183**
Ref. Consumption (GWh)	**12,817**	**14,012**	**14,994**	**16,202**	**17,323**	**18,659**	**20,107**	**21,773**	**23,581**	**25,809**

1. INTRODUCTION

The Government through the Ministry responsible for Energy has over the years been undertaking power development planning for the country through a sector team consituted from diverse key stakehoders. Updates of the Least Cost Power Development Plan (LCPDP) are prepared biennially covering 20 year periods, and five-year medium term plans compiled in alternate years.

This report presents a 10 year Least Cost Power Generation Expansion Plan (LCPDP) covering the period 2021-2030 and is derived from a longer term LCPDP prepared for the period 2020-2040. The report was prepared as part of national government undertakings for post COVID-19 development support programme and the attendant engagements with development partners. The update was deemed necessary to make the long term planning assumptions more predictable given the relative certainty in planning for a 10 years period compared to 20 years.

Power planning is guided by the existing national policy frameworks as well as existing legislation intended to govern stakeholders on power supply over time. The Energy and Petroleum Regulatory Authority (EPRA) formerly ERC has been mandated to coordinate preparation of sector plans. EPRA established an electricity sub-sector Technical Committee of the LCPDP comprising all sector agencies. The Energy Act No 1 of 2019 vested this mandate on the Ministry of Energy going forward as articulated in part II section 5 of the act. This report is hence prepared within the framework of the Energy Act 2019 but tailored to addressing specific challenges the sector is facing post COVID 19.

Planning for power supply in the country involves integrating sequenced planned generation with the demand forecast. The objective, 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 targeted at stabilizing power in Kenya at affordable tariffs.

This 10 year Plan is structured into four (4) key areas;

(a) **Load forecast** – The section analyses energy demand drivers in the country and based on the power requirements for each of them, estimates long term demand 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 Energy 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.

(c) **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 provision of sufficient primary response to maintain power system frequency in the event of network or generation outages.

(d) **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. 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 of tariffs. Evolution of tariffs was computed using an excel based model developed internally by the technical team.

Following the outbreak of the COVID-19 pandemic, the power sector has been adversely impacted, with a significant reduction in electricity demand. This adhoc 10-year plan (LCPDP 2020-2030) derived from the LCPDP 2020-2040, involves realigning the demand forecast, re-simulation of the generation expansion plan and, in addition, incorporation of recommendations of the following reports;

v. Revised IPP/PPA Taskforce Report 2020.

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

vii. Post COVID-19 sector report.

viii. Revised planting sequence of approved generation projects based on their current development status.

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

1.1. Background and Objectives of the report

The main objective of this update is to derive a 10-year generation capacity expansion plan based on the LCPDP 2020-2040 Plan. The specific objectives are to:

i. Update the load forecast taking into account the performance of the economy in the wake of COVID-19.

ii. Update historical data, literature, committed and candidate projects;

iii. Simulate generation sequence of proposed power plants;

iv. Assess the evolution of tariffs based on the estimated expansion costs;

1.2. Methodology and assumptions

The methodology applied involved utilization of forecasting and simulation tools namely, a MAED based customized tool for load forecasting and LIPS-OP/XP for short/long term system optimization. The overall approach adopted in drafting the report was guided by just concluded long term plan for the period 2020-2040.

The report was prepared by a select team drawn from Technical Committee of the LCPDP, with EPRA coordinating and providing secretariat services.

1.3. Planning strategy

The Government policy in the sector has consistently been to enhance access to quality, adequate and affordable power supply in the country. The strategy includes accelerated support to universal access to electricity and a focus on continued resource assessment to ensure and guide sustainable exploitation of local resources.

1.4. Legal and policy framework

Under the Integrated National Energy Plan (INEP), the Ministry of Energy envisaged in the Energy Act 2019 that consultations amongst relevant stakeholders would be required to develop, publish and review the plan in respect of coal, renewable energy and electricity through consolidation of National Energy Services Providers' plans and County Government plans so as to ensure delivery of reliable energy. However, power planning has over the years been done in the context of the Energy Act 2006, specifically section 5g.

Preparation of Least Cost Power Development Plans (LCPDPs) has historically been guided by Sessional Paper No. 4 of 2004 on Energy Policy. The Energy Sector Technical Committee of the LCPDP in turn applies prevailing Government policies and guidelines to inform its forecasting, generation planning and transmission planning. These are used to account for changes in the macroeconomic environment, introduction and application of new technologies and changes in national priorities and imperatives, among other factors.

In preparing the plan, other national plans such as Kenya Vision 2030, Medium Term Plans and National Spatial Plans are considered. Emphasis is also made on international commitments such as the Sustainable Development Goals and Agenda 2063 to ensure harmony as well as effective and efficient use of scarce resources. The Government has in recent times emphasized on the Big 4 Agenda, with the power sector playing its pivotal role as an enabler for various economic sectors to meet their objectives.

The LCPDP 2021-2030 plan is intended to articulate Government commitment to the power sector recovery and is intended to align with development partners medium term view of the necessary recovery strategy and necessary interventions. It is also prepared within the disruptive environment of COVID-19, which has not only affected economic growth but has also slowed down sector activities in generation capacity development as well as implementation of transmission lines projects. The Ministry of Energy and its associated entities analyzed the current and projected effects of the COVID-19 pandemic on the energy sector, developed an energy sector crisis management plan and made the necessary recommendations. The recommendations include financial and other forms of support to cushion the sector through the pandemic.

Whereas the pandemic has led to delays in delivery of critical infrastructure projects due to challenges in the implementation of contracts, there is optimism that the sector will rebound fairly quickly. Such rebound is seen in the projected increase in GDP growth estimated to be above 5.9% beginning in the 2021/2022 financial year, which would translate to more sustainable energy sector recovery.

While the Ministry of Energy revised the Energy Policy of 2006 and produced a draft Energy Policy 2018, the report is yet to be approved as a sessional paper. However, its guiding principles are in operation and focus on the following critical areas:

a. Enhancing renewable energy technology integration in line with the world-wide falling costs and ensuring that Variable Renewable Energy (VRE) resources in the country are optimally utilized for power generation. This is articulated through a revised Feed-in Tariff framework (FiT) and the anticipated energy auctions both of which are at advanced stages of development and approval.

b. Encouraging private sector participation in power generation through the FiT, Energy Auctions and the Public –Private Partnerships (PPP) frameworks

c. Encouragement of Distributed Energy Resources (DER) and captive power generation in line with section 167 of the Energy Act 2019 by bringing these segment of developers into the regulated framework. EPRA has been licensing and documenting these players.

d. Improvements in, and greater deployment of, information and communications technology (ICT) in the energy sector including digitalization such as Big Data, Internet of Things (IOT), smart metering and the upcoming beyond the meter technologies. This will lead to significant changes in the number of service providers netted into the system, and will subsequently expand energy customer choices and control.

e. Focus on load growth through aggressive connections and application of specialized programmes such as the Last mile initiative, GPOBA and street lighting expansion.

f. Integration of environmental concerns such as the Nationally Agreed Targets in Green House Gas (GHG) emissions that require the sector to conserve the environment and limit such emissions.

g. Focus on emerging technologies and investment in primary data such as wind and solar insolation mapping necessary for attracting quality developers.

While the sector will continue to play its role as an enabler, it is itself facing challenges and accordingly has been revising policy tools to make it efficient and responsive to emerging challenges. It is currently reviewing the Independent Power Producers PPA framework, aligning it to current realities, and also strengthening planning of the sector to make it more responsive to country needs

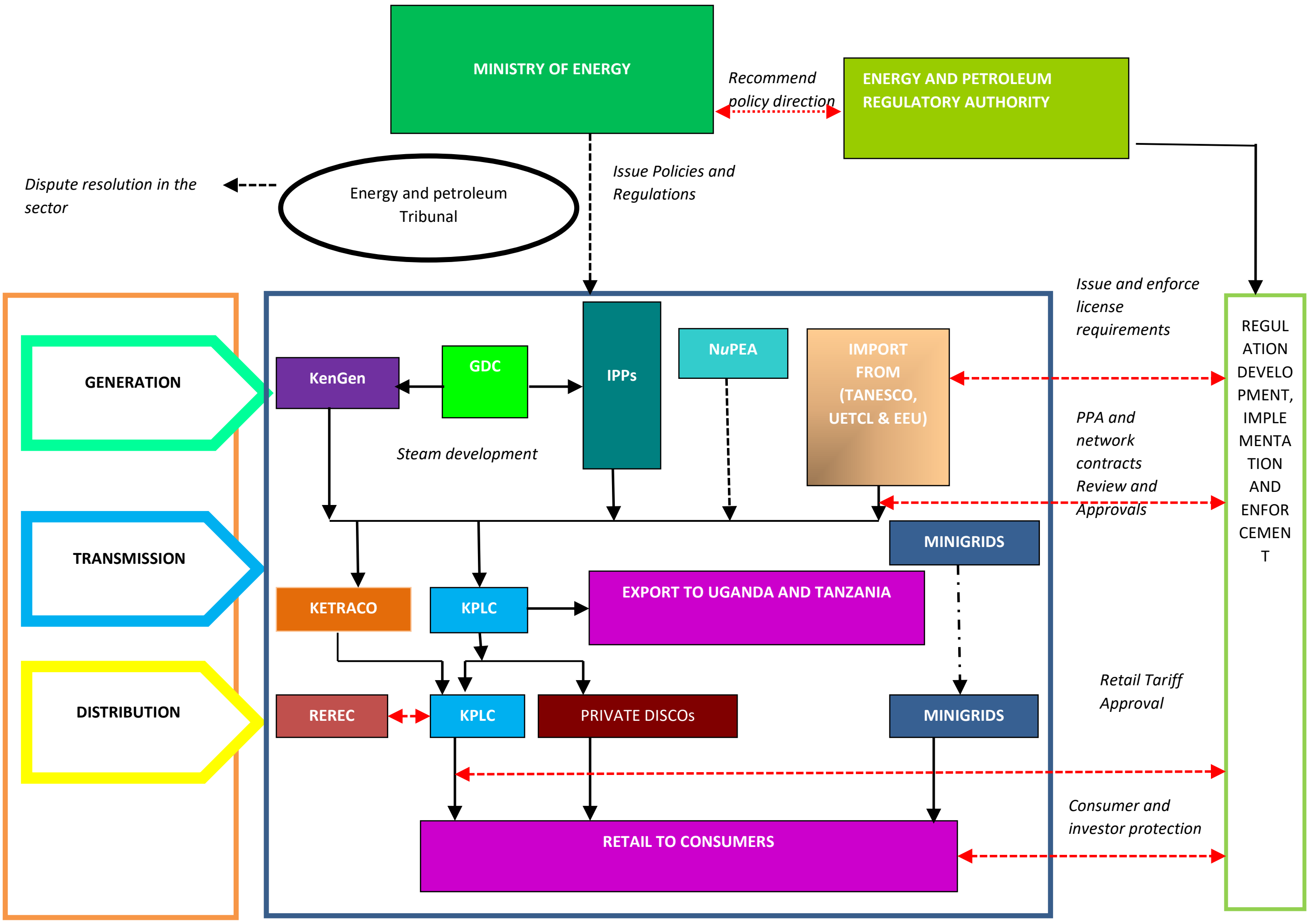
2. OVERVIEW OF THE KENYAN POWER SECTOR

The Kenyan power sector has gone through significant reforms from the late 1990s. These include review of the Electric Power Act 1997, Sessional Paper no. 4 of 2004, and enactment of the Energy Act 2006 which was recently succeeded by the Energy Act 2019. The new Act 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. The sector has also facilitated considerable expansion in electricity generation, transmission, distribution and access in the country particularly in recent years.

2.1. Sector Institutional Structure

After the enactment of a new Energy Act in March 2019, the institutional structure of the power sector was reorganized as shown in Figure 1.

Figure 1:Institutional Structure of the power sector



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 most of the 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 interconnected 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.

2.2. 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. Despite the rampaging COVID-19 pandemic, a new peak of 1976MW was realized in the month of December 2020. The trend in peak demand growth for the period 2014/15-2019/20 is shown in Figure 2. The country has also experienced a significant increase in the number of customers connected to the grid, rising from 3,611,904 recorded in financial year 2014/15 to 7,576,145 recorded 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% is attributed to accelerated electrification programs implementation across the country;

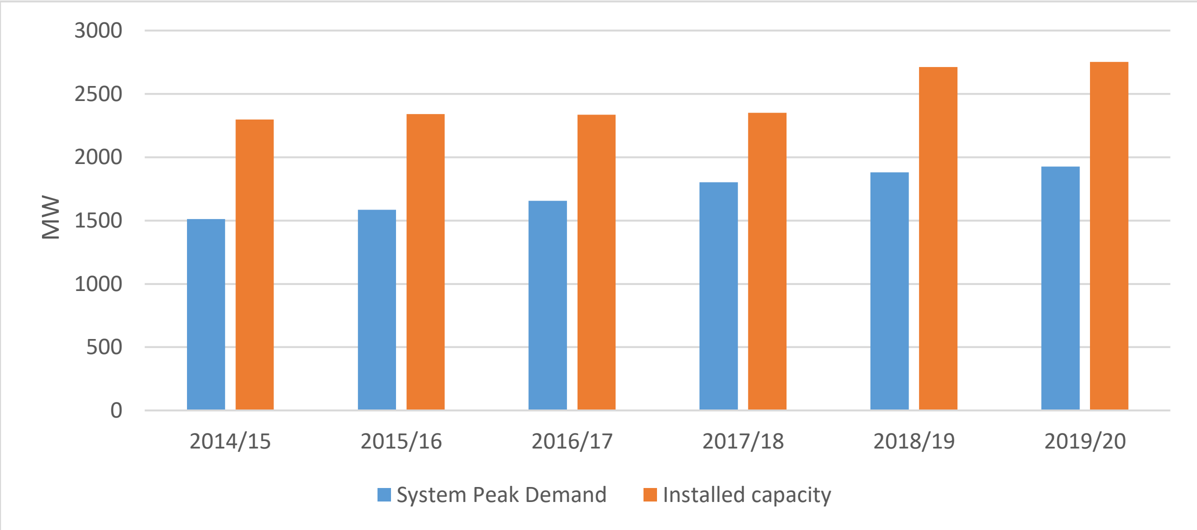


Figure 2:Electricity demand Vs Capacity
Source: Kenya Power

2.3. Electricity transmission and distribution

The total length of the Transmission and distribution network was 243,207 kilometers for all voltage levels in 2019/20 compared to 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 1 provides transmission and distribution line lengths between FY 2014/15 and 2019/20.

Table 1: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 as soon as is practically possible. Projects and programs are also being implemented to reduce system losses and improve system reliability.

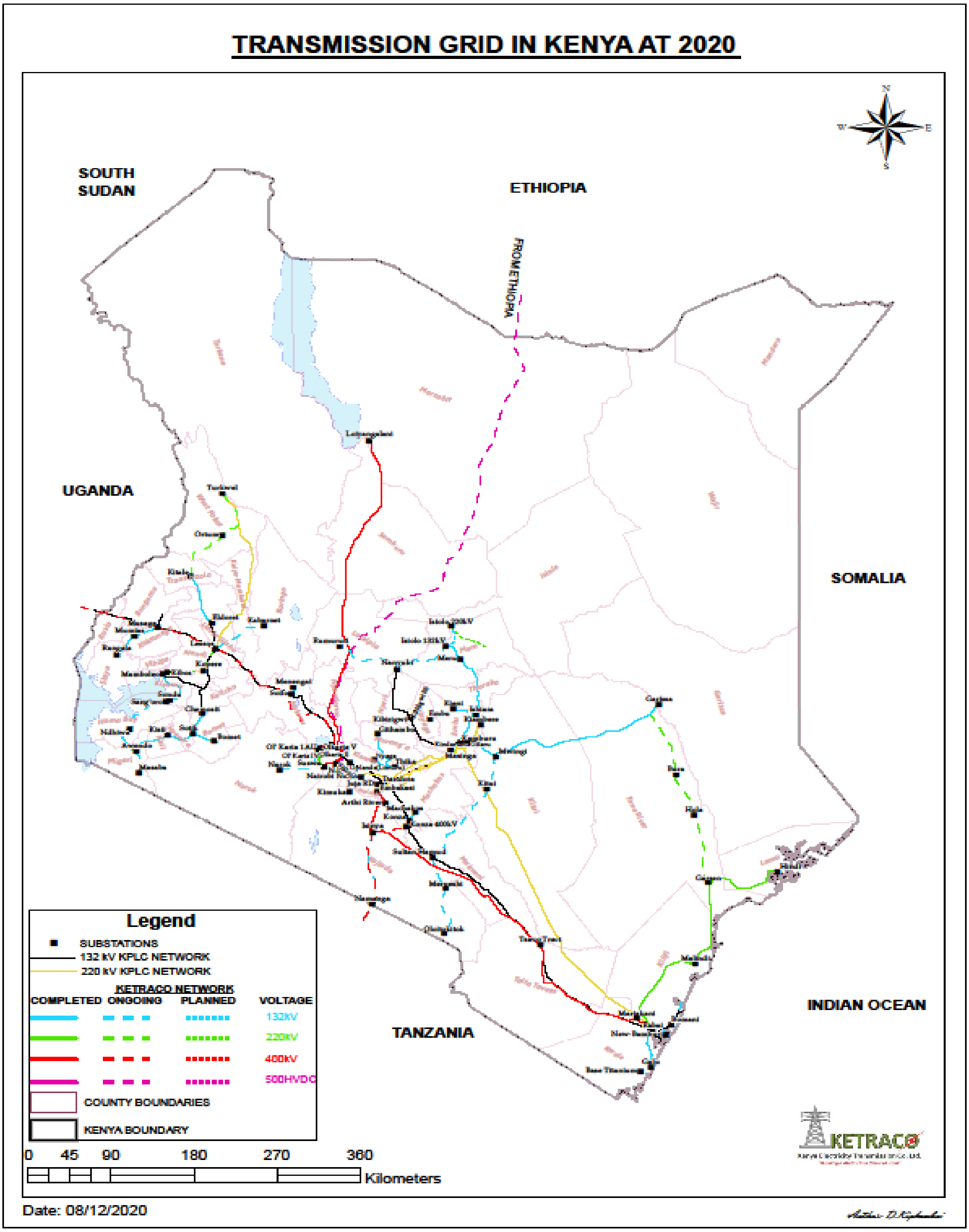


Figure 3:Transmission Network in Kenya 2019/20
Source KETRACO

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 capacity 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 2 represents the transmission and distribution substations capacities for the period under review

Table 2: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

2.4. Existing power grid/ Sources

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 as at the end of the financial 2019/20. Figure 4 shows the evolution of the generation mix from 2017/18 to 2019/20.

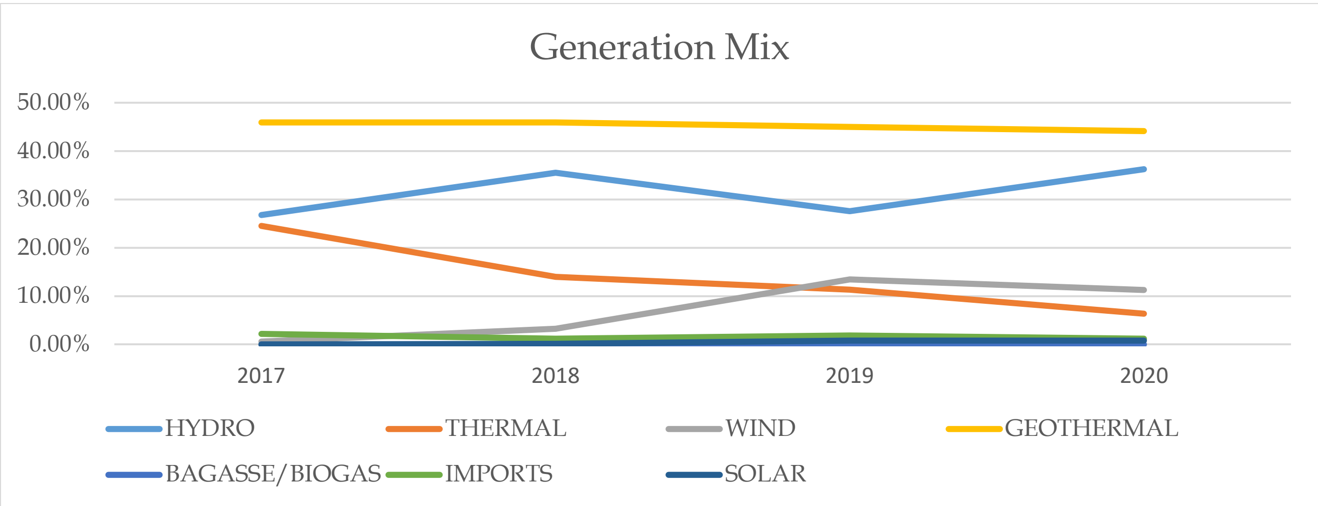


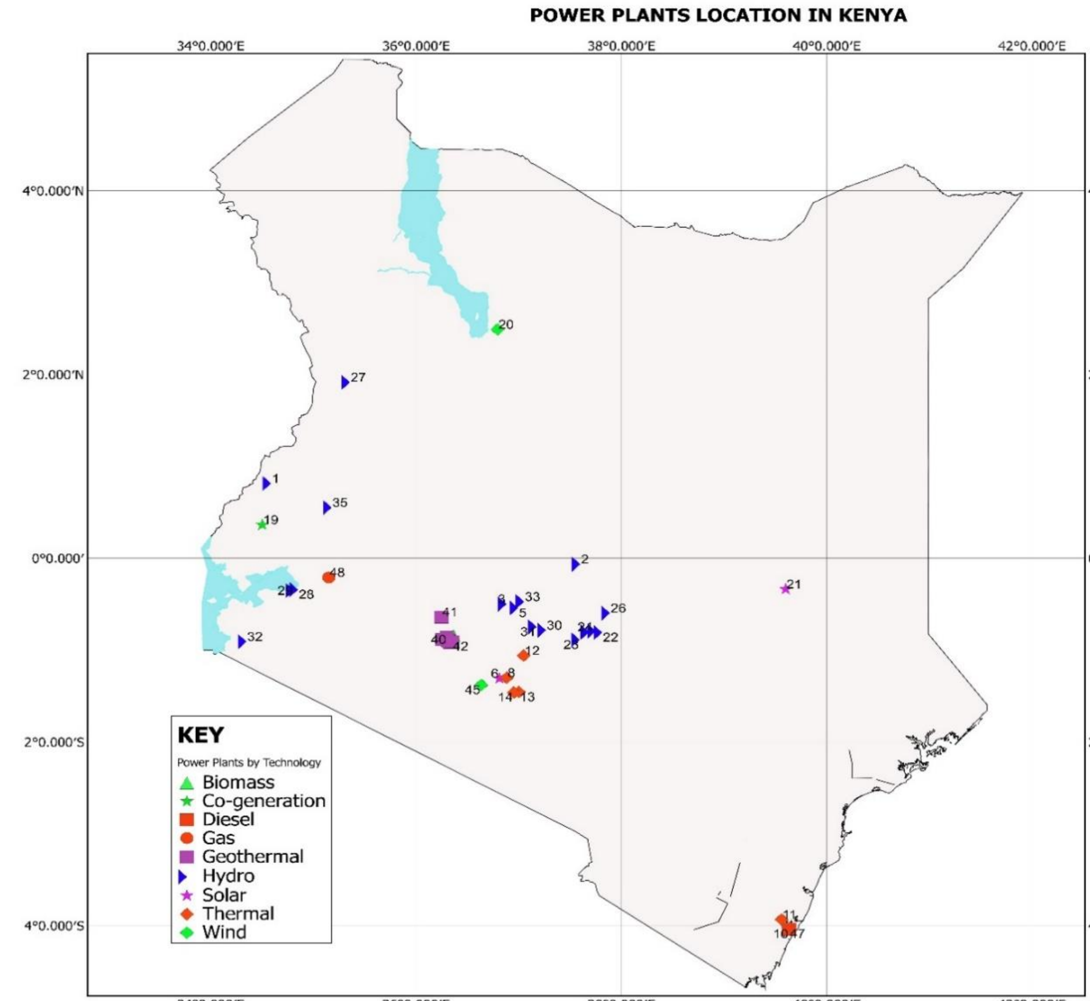
Figure 4:Generation Mix; Source: Kenya Power

The FiT policy acceptance by IPPs and deliberate government policy to advance renewable energy generation has led to continuous decline in energy purchased from conventional thermal power plants. Energy purchased from the thermals reduced to 882 GWh in FY 2019/20 from 2,202 GWh in FY 2017/18. Energy purchases from Wind and Solar increased considerably from FY 2018/19 with 1,284 GWh and 91 GWh purchased in the year 2019/20, respectively as summarized in Table 3.

Table 3: 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 5. 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 and solar having the best prospects. Wind plants are already developed in Corner Baridi in Rift Valley as well as the famous Lake Turkana wind in Marsabit.



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 5: Power Plants location in Kenya

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 2,840MW in FY 2019/20, representing an annual average growth rate of 4.49%. The peak demand also grew from 1,512MW recorded in FY 2014/15 to 1,938MW recorded in FY 2019/20, 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) account for 35.95%of the capacity while off-grid systems under the Rural Electrification Programme (REP) implemented account for about 1.07%.

Kenya's installed effective (grid and off-grid) electricity capacity was 2,708 MW as of December 2020 as shown in Table 4. The installed effective capacity mix comprises 29.73% hydro, 23.65% thermal(MSD), 2.07% Thermal (GT), 29.73% geothermal, 12.02% wind and 1.86% solar.

Table 4: Installed and Effective Capacity

	Installed	% (Installed)	**Effective* /Contracted**	% (effective)
Hydro	834	29.37%	805	29.73%
Geothermal	863	30.39%	805	29.73%
Thermal (MSD)	660	23.25%	640	23.65%
Thermal (GT)	60	2.11%	56	2.07%
Wind	336	11.81%	326	12.02%
Biomass	2	0.07%	2	0.07%
Solar	50	1.77%	50	1.86%
Interconnected System	**2805**	98.78%	**2684**	99.14%
Off grid thermal	32	1.12%	21	0.79%
Off-grid Solar	1	0.02%	0	0.00%
Off-grid Wind	2	0.08%	2	0.07%
Imports	0	0.00%	0	0.00%
Total Capacity MW	**2,840**	100%	**2,708**	100%

Source: Kenya Power

3. ELECTRICITY DEMAND FORECAST

3.1. Introduction

Electricity is considered an enabler of 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 can be 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 for developing 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 2021 to 2030.

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 2021-2030. 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) Include emerging technologies such as Battery Energy Storage Solution (BESS)
(vi) Present demand forecast results for the period 2021-2030.

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.

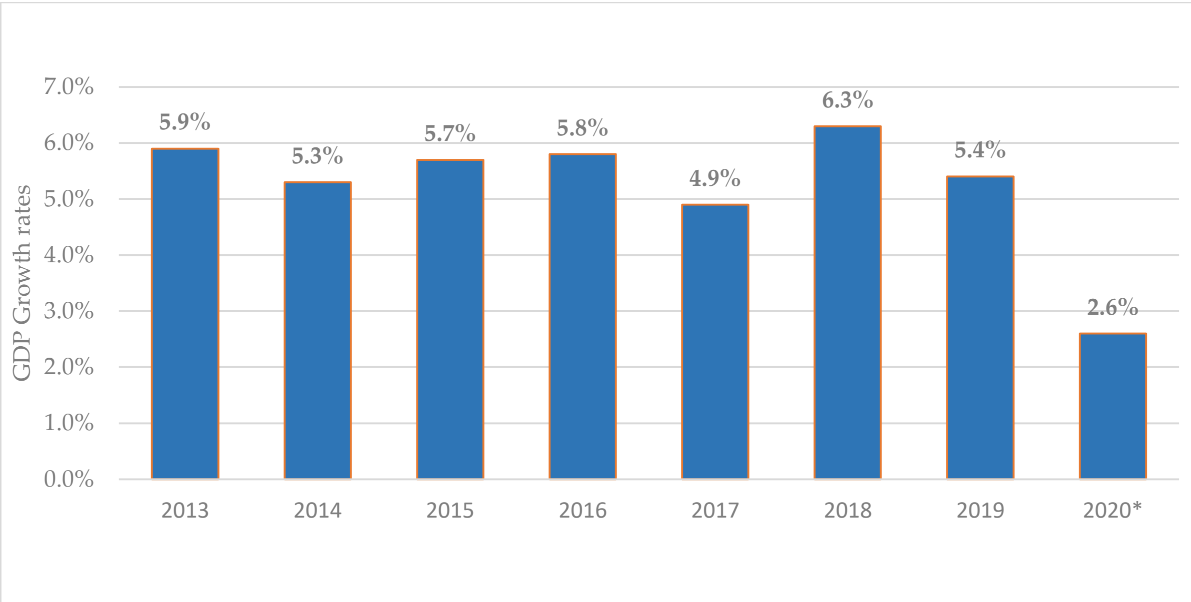


Figure 6: Kenya GDP Growth
Source: KNBS

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.

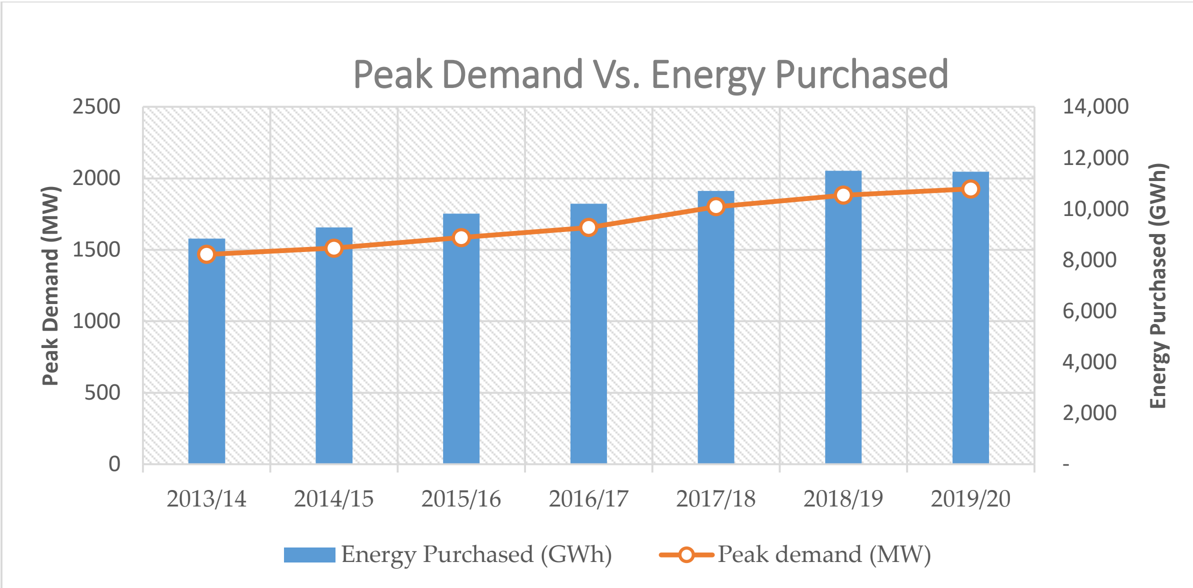


Figure 7: Yearly Peak demand and Energy Consumption

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 8.3% as shown in Figure 8.

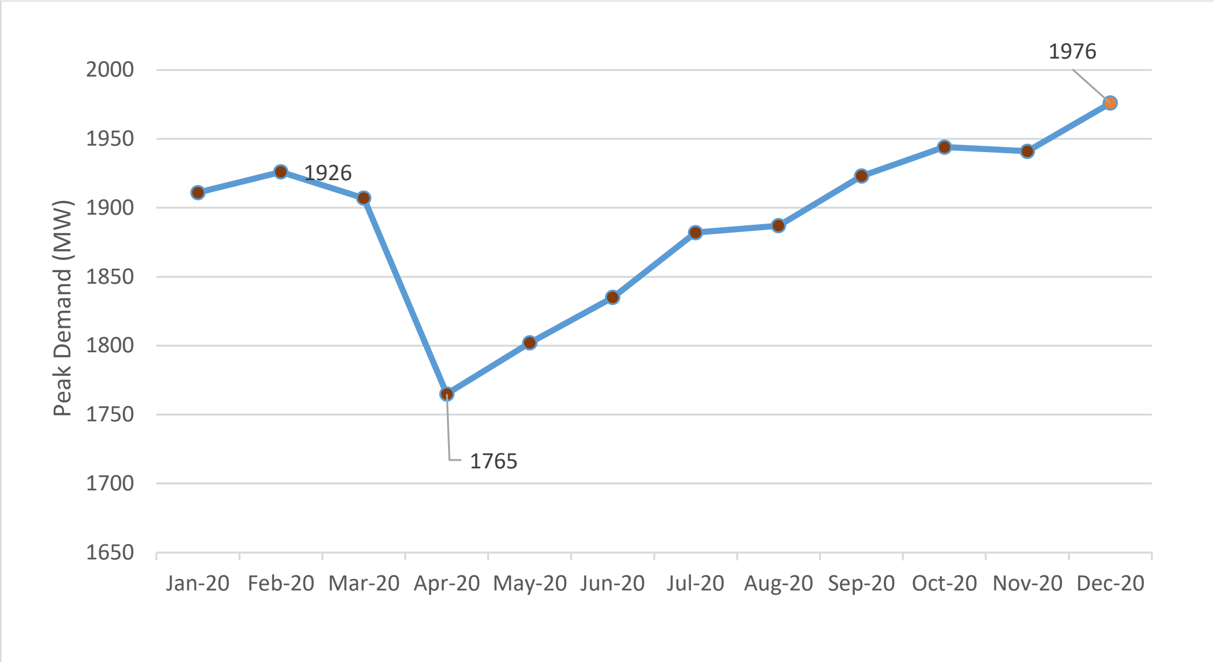


Figure 8: Monthly actual Peak demand for the year 2020

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 gradually and reached the pre-COVID level in October 2020. This was followed by the peak demand of 1,976MW for the year recorded in December 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 more energy-efficient equipment. Table 5 summarizes the consumption patterns, consumer trends and customer growth for the last 6 years.

Table 5: Consumption patterns, consumer trends and customer growth 2014/15 – 2019/20

	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 lower middle 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-sized Enterprises (SMEs); Ease of doing business ranked 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 of 2019, the manufacturing sector contributed 8.2% 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 is to achieve 100% universal health care by reducing the associated cost and ensuring universal access to quality healthcare by 2022. This will be achieved by scaling up NHIF uptake, launching multi-tier insurance plan 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 forecast 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 LCPDP.

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:

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

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

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.

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

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.

3.7. 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.

3.8. Definition of the Scenarios

The forecast considers three scenarios for the LTP period 2020 -2030 with 2020 as the base year.

3.8.1. Reference Scenario

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

3.8.2. Vision Scenario

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

3.8.3. 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.

3.9. Forecast Assumptions

3.9.1. 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.

3.9.2. 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 6 indicates the assumptions made for domestic demand:

Table 114: 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	Low: 2020: 48.3 million, grown by average growth 2.26%/year

	UN medium fertility scenario forecast UN low fertility scenario forecast	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)

3.9.3. 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 the emergence of small market centres.

Table 6: 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 6	

3.9.4. Large Commercial and Industrial consumption.

For industrial and commercial consumption, the driving factor considered is the correlation of consumption to GDP growth. Table 8 shows assumptions made in the development of Large Commercial and Industrial forecast.

Table 7: 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 6	

3.9.5. 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 8: 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 6

3.9.6. 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 10.

Table 9: 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%

3.9.7. 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 11.

Table 10: Flagship projects and their assumptions

Project	Reference				High			
	First year of operation	Initial load [MW]	Year of total load	Total load [MW]	First year of operation	Initial load [MW]	Year of total load	Total load [MW]
ELECTRIFIED MASS RAPID TRANSIT SYSTEM FOR NAIROBI					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

3.9.8. Battery Energy Storage Systems

There has been significant development in the advancement of battery storage systems and this has led to a reduction in the prices. This is one of the technologies that has been considered in the plan to support the integration of Variable Renewable Energy Technologies. Battery storage systems will be used for system support. It is assumed that through the deployment of grid sized batteries, energy is stored and can be utilized during peak hours. The technology also contributes in increasing off -peak demand which supports the utilization of the base load capacity.

It is assumed that the Batteries will be charged for four hours during off peak which is a load factor of 16.67% for BESS consumption.

Table 12 indicate the estimated energy consumption attributed to the BESS charging.

Table 11: BESS Energy Consumption

Year	BESS Capacity (MW)	Energy Consumption (GWh)
2020	0	0
2021	0	0
2022	100	146
2023	150	219
2024	250	365
2025	250	365
2026	250	365
2027	250	365
2028	250	365
2029	250	365
2030	250	365

3.10. Results of the forecast.

3.10.1. 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 5.21% while the peak load is forecasted to grow at an average of 4.91% in the reference scenario; 8.13% and 7.99% in the vision scenario and 4.35% and 4.04% in the low scenario respectively. The vision scenario increases at a higher rate due to an assumed higher GDP growth and early impact of flagship projects. Figure 9 illustrates forecasted electricity consumption.

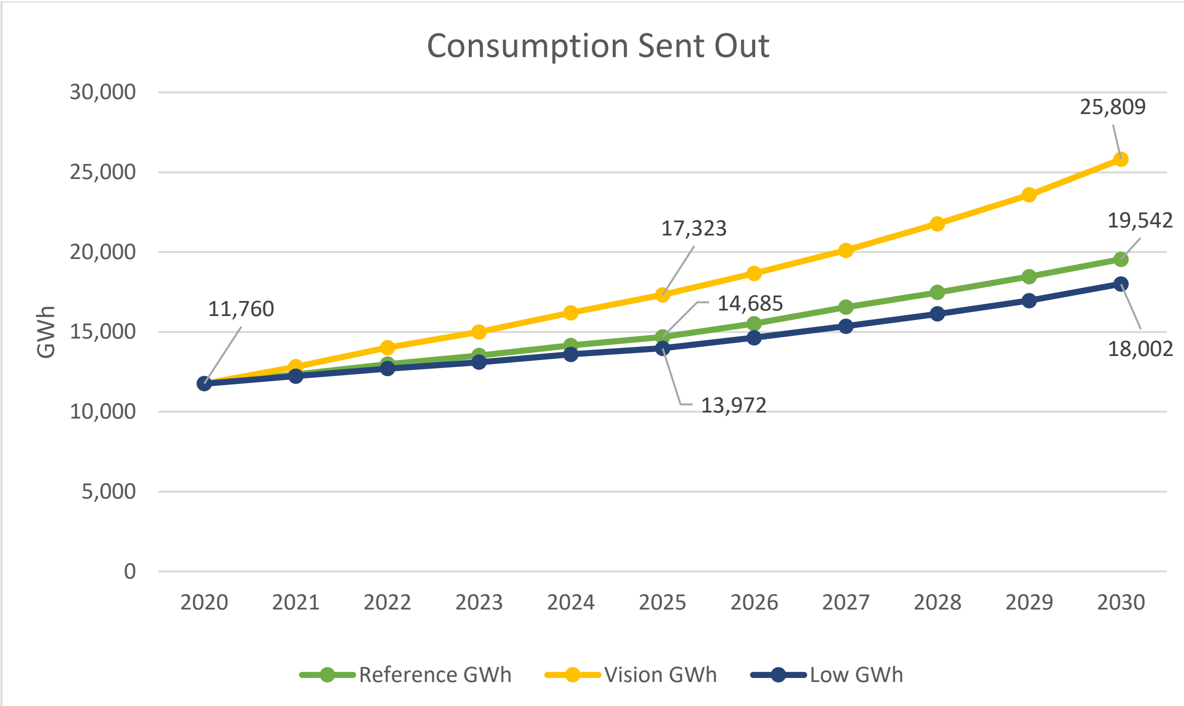


Figure 9: Forecasted Electricity consumption.

Electricity consumption is expected to rise over the planning period in all scenarios. Energy demand in the reference scenario grows at an average of 5.21% to reach 14,685GWh in 2025 and 19,542GWh by the end of the planning period as shown in Figure 9. Under the Vision scenario energy demand increases at an average of 8.18% to 17,323GWh by 2025 from 11,760GWh in the base year. Consumption is forecasted to reach 25,809GWh by 2030 under this scenario. The Low scenario expands moderately at an average of 4.35% to reach 18,002GWh by the end of the planning period as shown in Table 13.

Table 12: Energy Demand Forecast

	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	12,977	5.13%	14,012	9.32%	12,702	3.82%
2023	13,518	4.17%	14,994	7.01%	13,102	3.15%
2024	14,152	4.69%	16,202	8.06%	13,592	3.74%
2025	14,685	3.77%	17,323	6.92%	13,972	2.80%
2026	15,517	5.67%	18,659	7.71%	14,635	4.75%
2027	16,547	6.64%	20,107	7.76%	15,353	4.91%
2028	17,471	5.58%	21,773	8.29%	16,125	5.03%
2029	18,460	5.66%	23,581	8.30%	16,963	5.20%
2030	19,542	5.86%	25,809	9.45%	18,002	6.13%
Average Growth		**5.21%**		**8.18%**		**4.35%**

Peak demand grows at an average of 4.89% from 1,976MW in the base year to 3,183MW at the end of the planning period under the Reference scenario. Similarly, under the Vision scenario peak demand increases to 4,251MW in 2030 growing at an average rate of 7.97%. The Low scenario peak demand increases to 2,928MW in 2030 at an average rate of 4.02% as shown in Figure 10 and Table 14

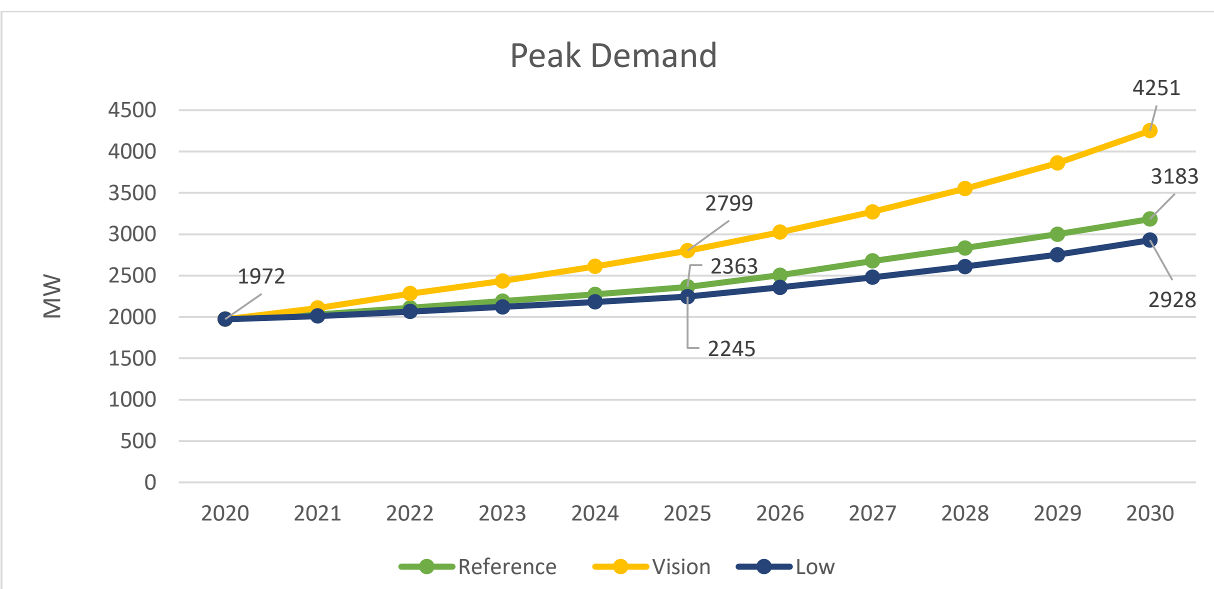


Figure 10: Peak Demand Forecast

Table 13: Demand Forecast

	Reference		Vision		Low	
Year	MW	Growth	MW	Growth	MW	Growth
2020	1976		1976		1976	
2021	2029	2.68%	2108	6.68%	2010	1.72%
2022	2110	3.99%	2281	8.21%	2065	2.74%
2023	2190	3.79%	2435	6.75%	2121	2.71%
2024	2272	3.74%	2610	7.19%	2180	2.78%
2025	2363	4.01%	2799	7.24%	2245	2.98%
2026	2503	5.92%	3024	8.04%	2357	4.99%
2027	2677	6.95%	3269	8.10%	2478	5.13%
2028	2833	5.83%	3550	8.60%	2609	5.29%
2029	3000	5.89%	3859	8.70%	2751	5.44%
2030	3183	6.10%	4251	10.16%	2928	6.43%
Average Growth		4.89%		7.97%		4.02%

3.10.2. Demand Forecasting Conclusion and Recommendation.

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 as reflected in the recoded actual peak demand for the year 2020. 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.

In the long term, grid energy consumption is expected to reduce due to increased captive power generation particularly by large power consumers. Key factors that contribute to captive power generation in Kenya include the need for reliable and quality supply and perceived high cost of retail tariff. In the case of solar PV, the levelised cost of electricity has been coming down over the years. The cost of energy generated from solar plants that do not incorporate battery storage is low compared to power from the grid, hence the preference to self-generate. Solar generation presents a challenge to the off taker in that it still has to avail power to meet peak demand since solar is not available at peak.

In addition, the access and availability to resources such as bagasse by potential generators such as Nzoia and Sony Sugar Companies provides an incentive towards captive generation. As at December 2020, the total licenced captive generation capacity was 140.875MW with an additional capacity of 28.94MW in new applications. Annex 1 provides details of licensed captive power generators in the country.

Approximately 55% of revenues realised from energy sales come from industrial and commercial customers, majority of whom are shifting towards captive generation. This will have a negative impact on the achievement of demand projections in the plan.

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
vii. There is need to enhance power supply reliability to meet customer expectations

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 presents characteristics of fossil fuels considering infrastructure and future developments, an overview of the available renewable energy sources and nuclear power as a potential future energy source. The regional power interconnections with neighbouring countries as electricity supply options have also been discussed.

The national primary energy consumption is dominated by biomass (charcoal and wood fuel) accounting for 69%. This is 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 aggregate state, 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.

Over the last 50 years, crude oil has been the major energy source in the world when measured by energy content, being nearly 10% ahead of the second placed coal. This is largely 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 offshore, and a total of 43 exploratory wells which had been drilled in four basins (Lamu, Mandera, Anza, Tertiary Rift) by 2015[1]. A corresponding number of 41 licences have been awarded to international oil firms (exploration and production companies) to carry out exploratory activities. Figure 11 provides an overview of ongoing exploration activities in Kenya as of July 2015.

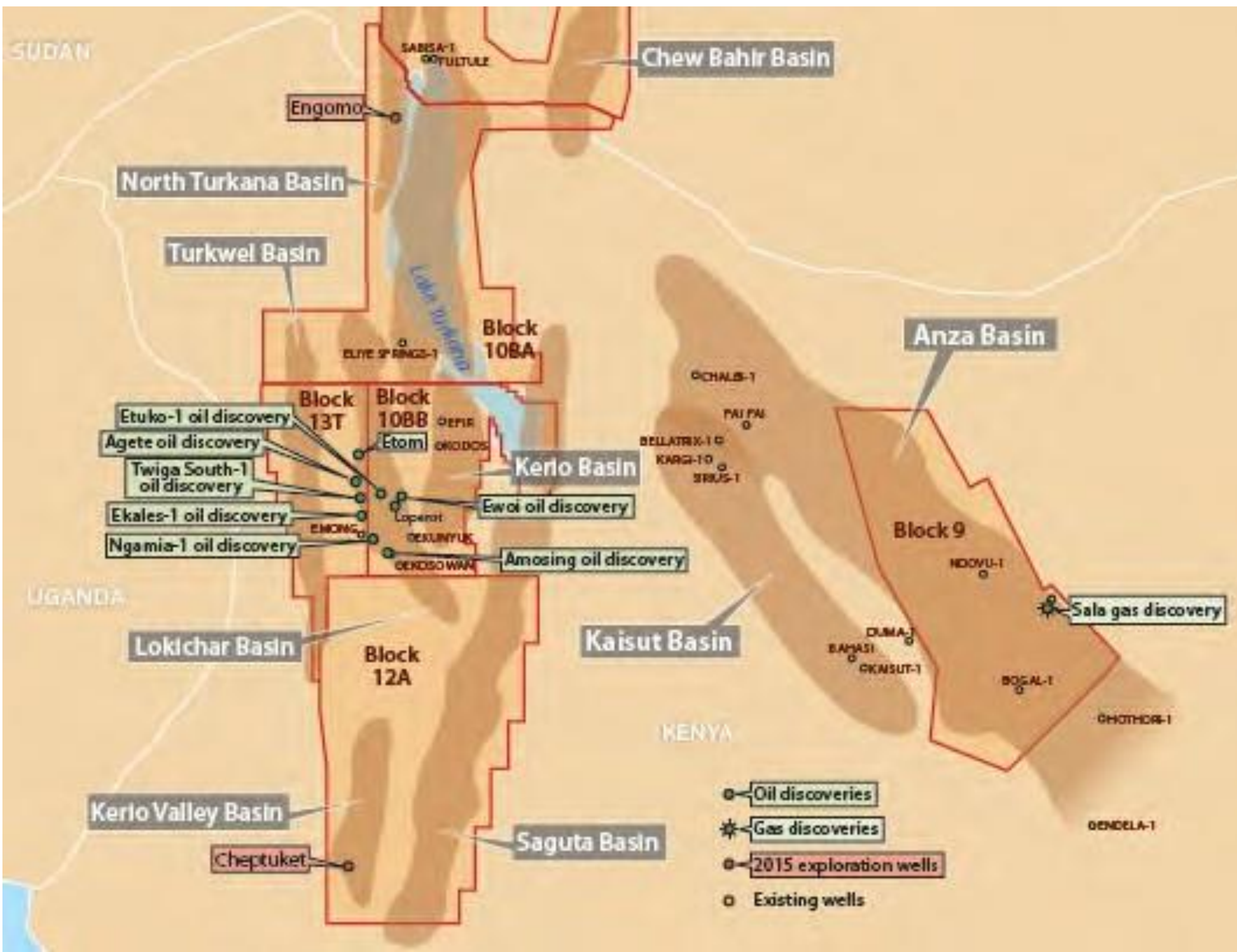


Figure 11 Exploration Activities in Kenya

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

Domestic crude oil deposits have been located in Turkana, the northern most county of Kenya bordering Uganda and South Sudan. Extraction in Turkana commenced with the crude oil transported by trucks to Mombasa for export. Plans are underway to construct a pipeline from Turkana to the Lamu port 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 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 at the Coast and Nairobi 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 thermal Muhoroni power plant. 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 coal[2]. 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,

2 BP Statistical Review of World Energy June 2017

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 a relatively 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 consumers through pipelines. The logistics 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 discovering natural gas deposits has encouraged the government to explore 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

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 considerable environmental and social impacts.

The 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 have to be factored in. The Lamu coal power project was expected to be the first coal plant in Kenya. More coal power plants utilizing domestic coal, are planned for development in 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.

4.6. 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.

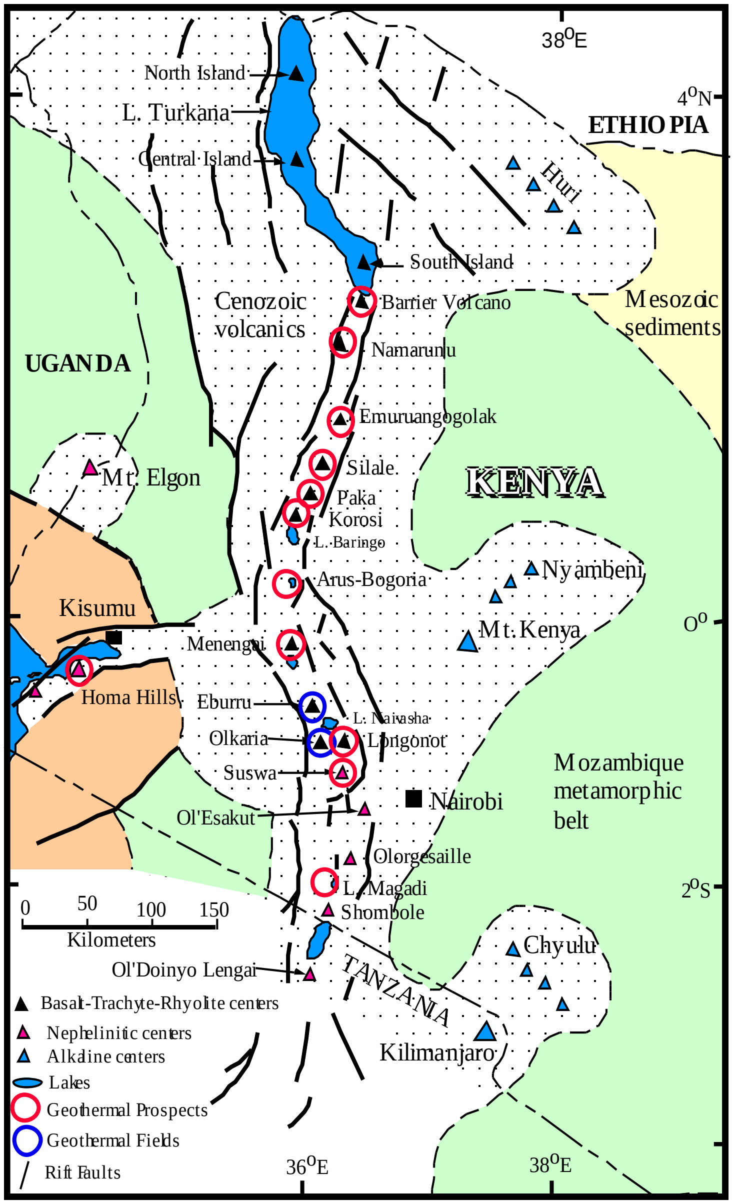
At present, geothermal power is only being harnessed in the Olkaria, Menegai and Eburru fields. In the medium and long term new geothermal reservoirs are being explored in Suswa, Longonot, Akiira and Baringo Silali. Other potential geothermal sites within the Kenya Rift that have not been studied in 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

Figure 12 Location of geothermal projects within Kenya Rift valley

4.7. Hydropower

4.7.1. 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 15. These include Lake Victoria basin (329MW), Rift Valley basin (305MW), Athi River basin (60MW) and Tana River basin (790MW).

Table 14: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

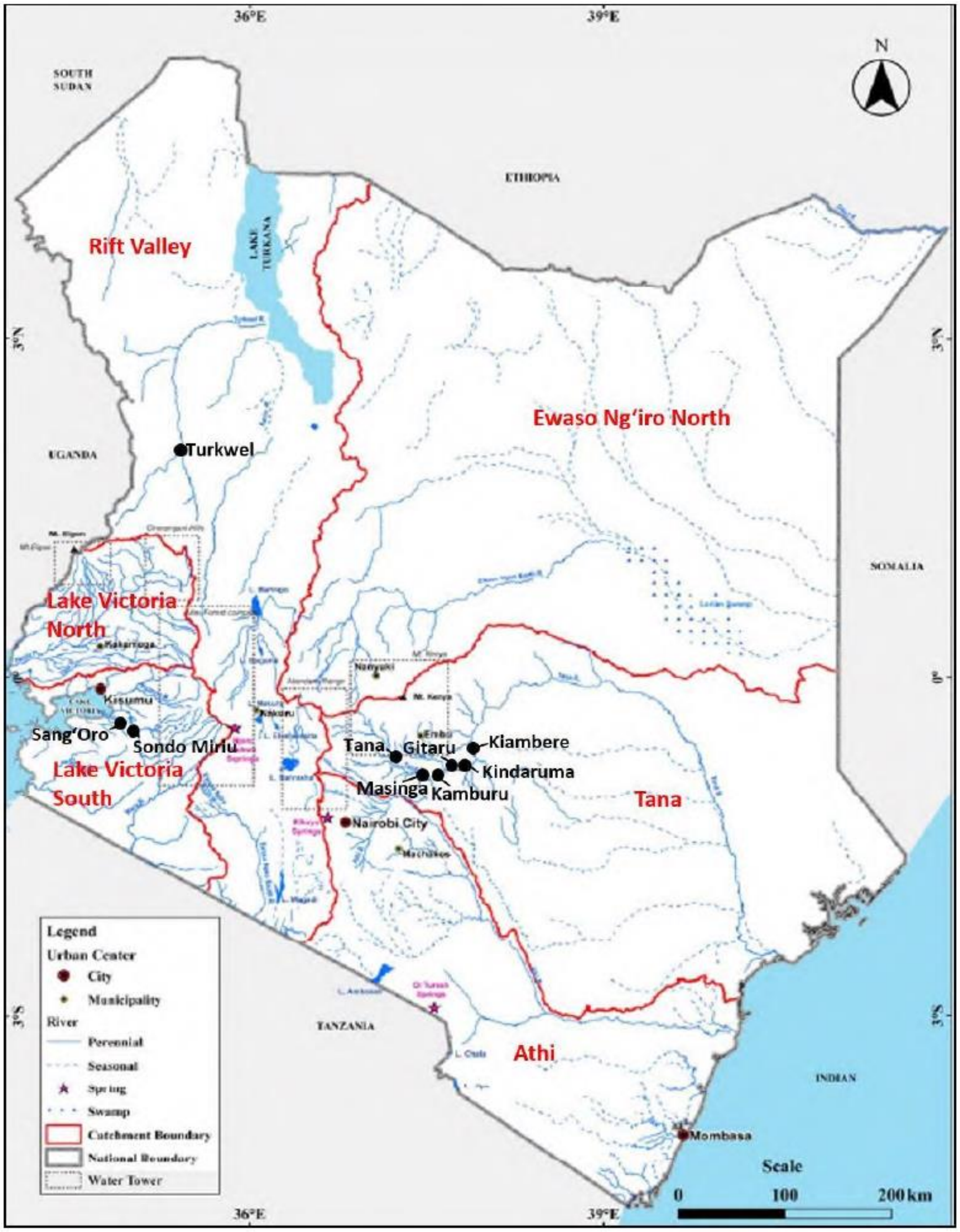


Figure 13 Major rivers of the catchment areas and location of existing large hydropower plants

There is a growing consciousness of possibility of small hydropower offering vast generation options in the future. 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 13 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 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.

4.7.2. 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 can be 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.

4.8. 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 are still on downward trend. 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 wind 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 are 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.

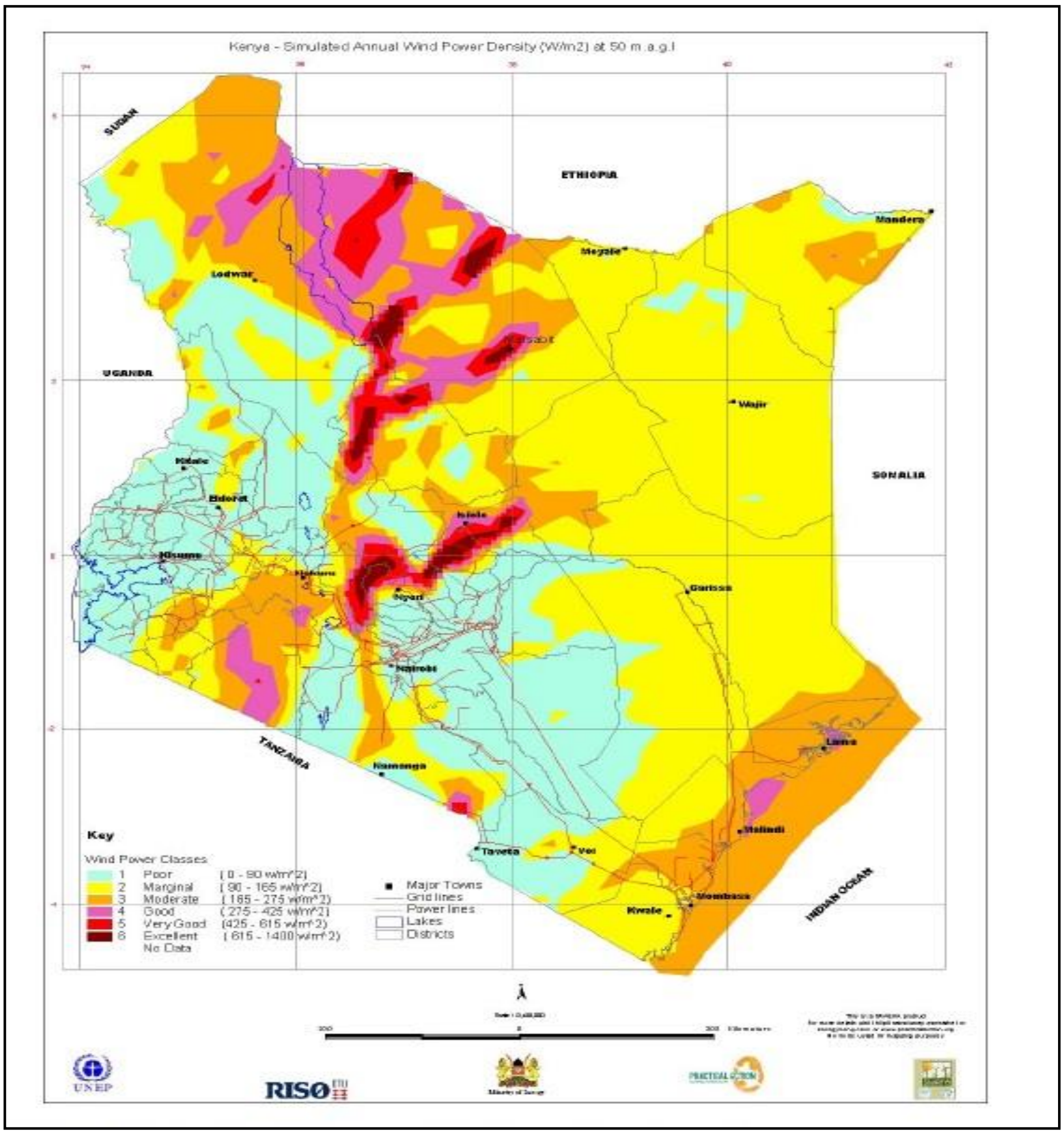


Figure 14 Wind Energy Capacity

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 14. 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.

4.9. 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.

4.9.1. 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/m^2/year. The average GHI received and photovoltaic power potential in Kenya are shown in Figure 15 and 16 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.

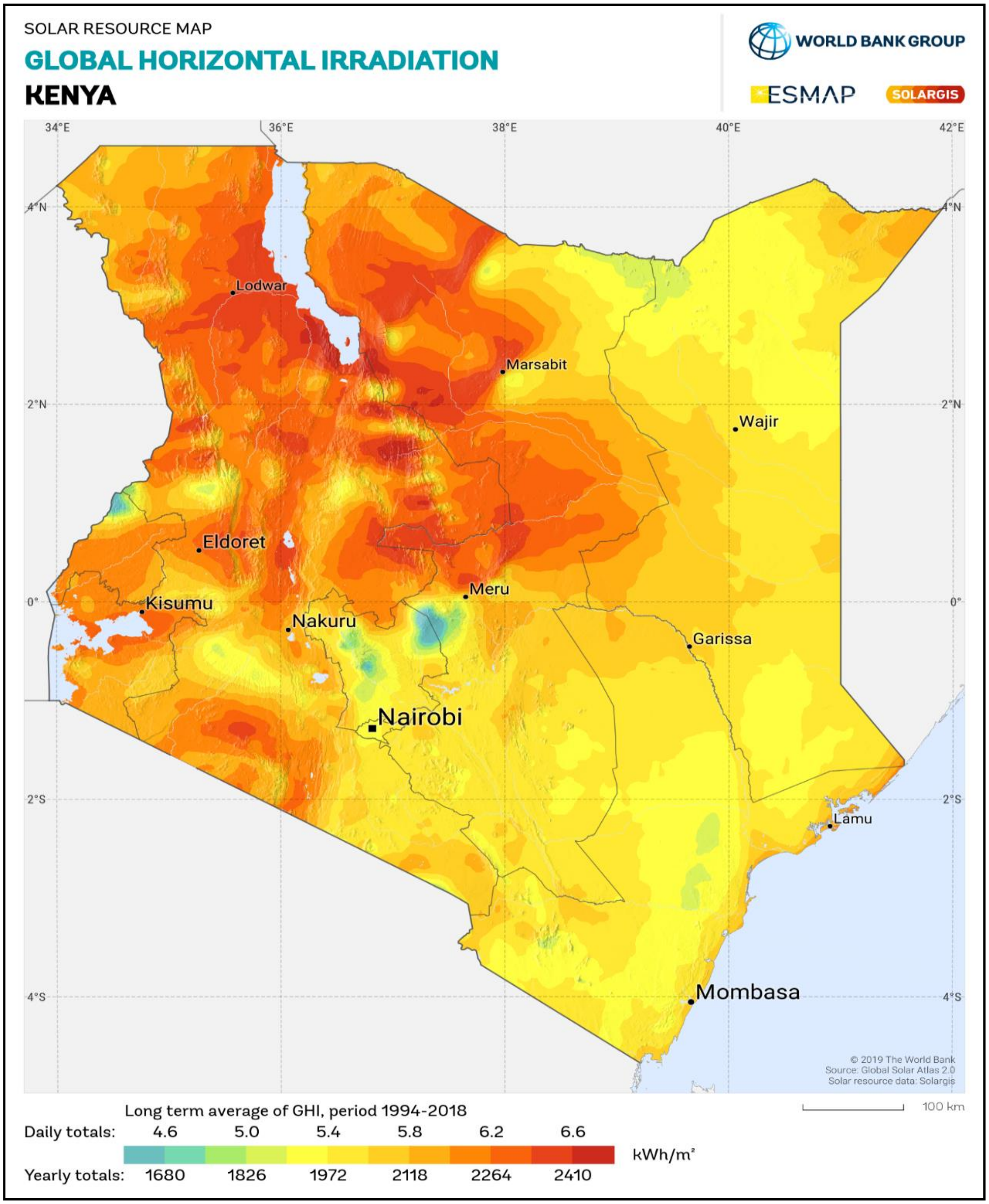


Figure 15: Global Horizontal Irradiation

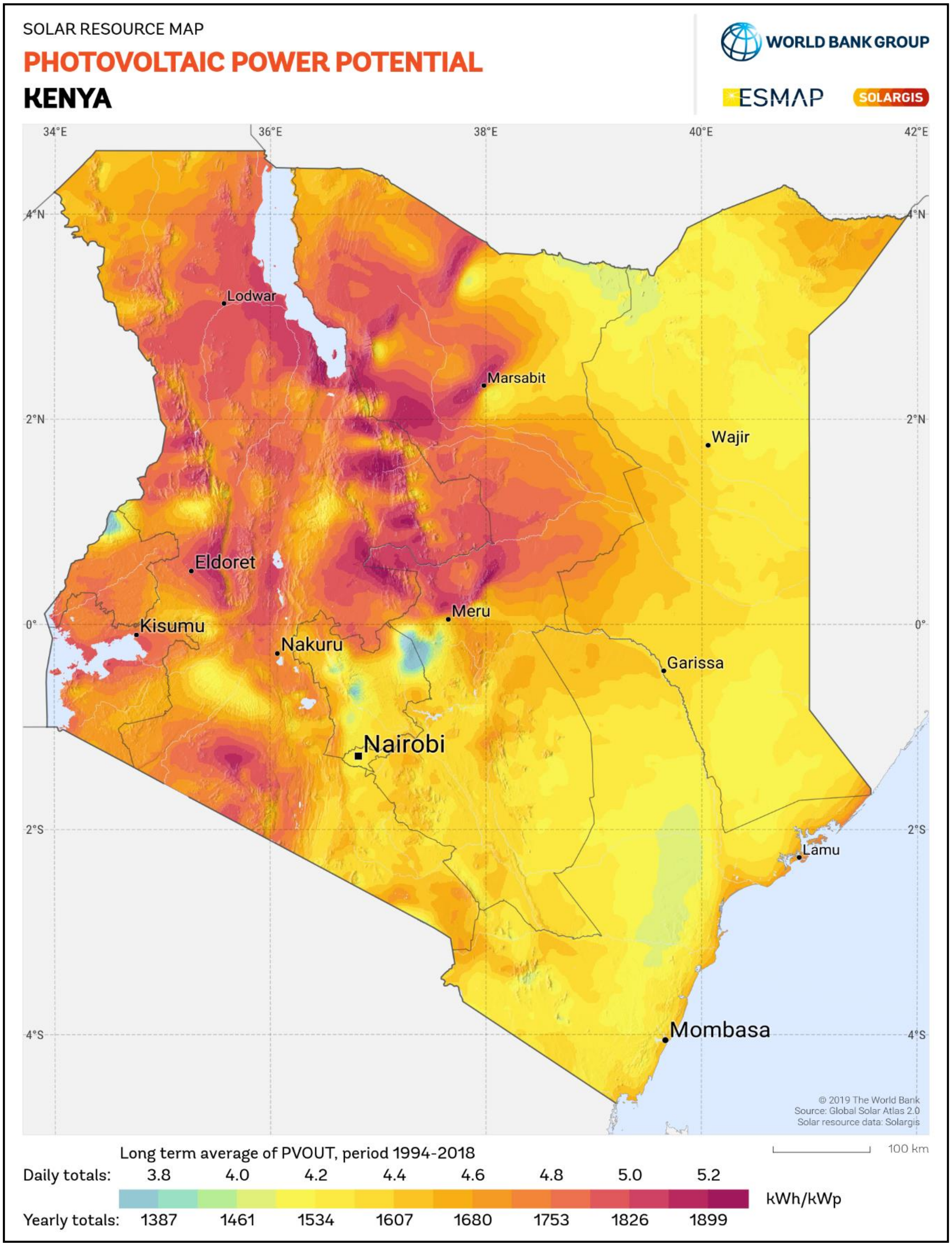


Figure 16: Photovoltaic power potential

4.9.2. 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 17. However, there are presently no operational CSP plants in Kenya.

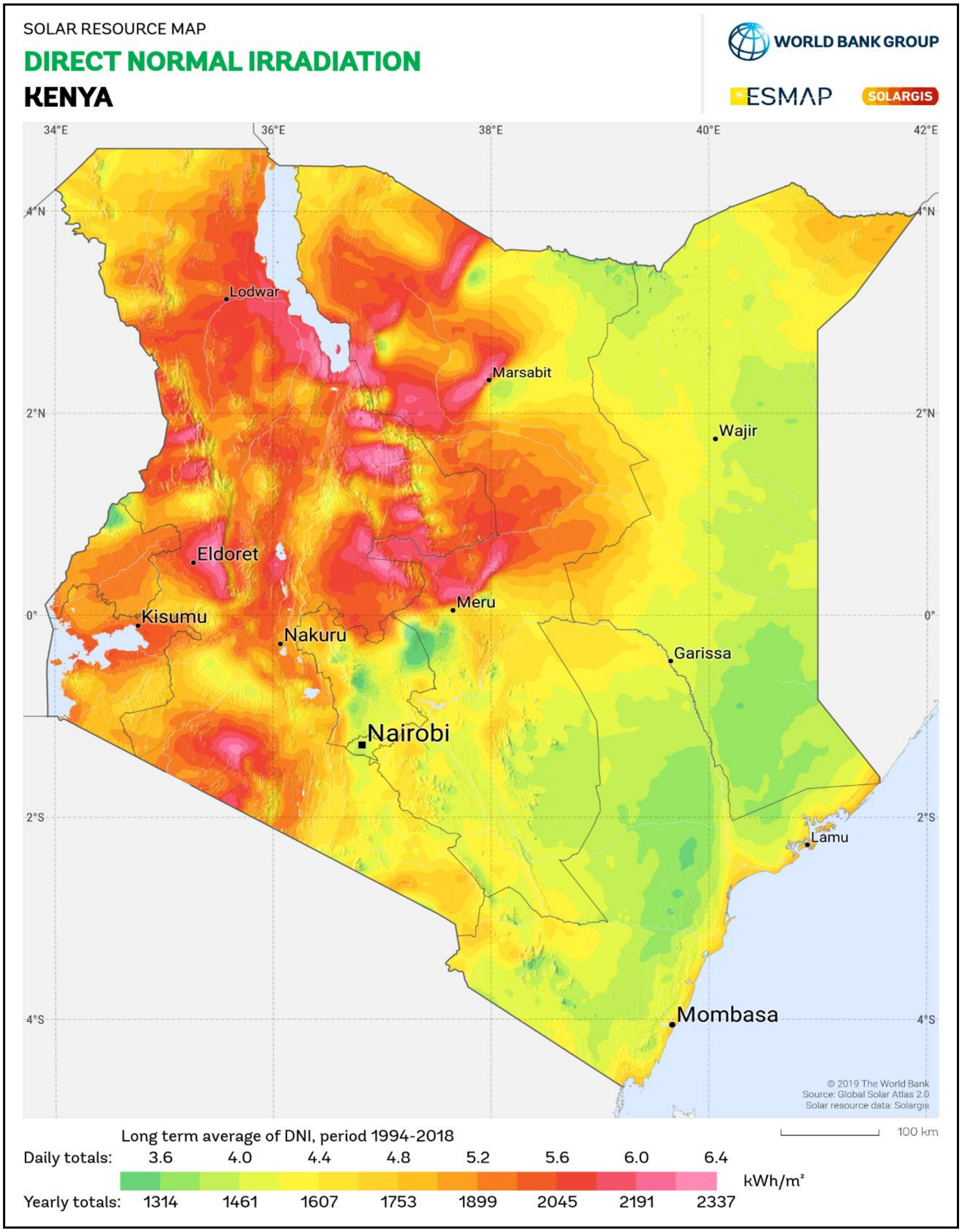


Figure 17 Direct normal irradiation in Kenya

4.10. 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.

4.11. 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.

4.11.1. Battery Storage

The expected excess energy during off peak hours and increased intermittent capacity in the national grid presenting 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 shortages 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.

An analysis by the IPP-PPA Taskforce of the power system noted that the system requires spinning reserves of approximately 150MW. This could be provided by use of different technologies including battery storage. The Technical Committee of the LCPDP simulated BESS Deployment in the following substations regions

- 50MW in Nairobi / 132kV Juja Rd
- 50MW in Western Kenya / 132 Kisii
- 50MW in Coast/Kilifi

Fast tracking of the ancillary services study is recommended. The study will assess the role of grid energy storage system such as pumped storage hydro, battery storage and hybrid systems for grid stability purposes.

4.11.2. 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 tonnes3 in 2017. At current consumption levels, these reserves would last more than 130 years4. 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-going5.

3 World Nuclear Association

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

5 Power Generation and Transmission Master Plan, Kenya, 2016

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

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.

4.12. Interconnections with Neighbouring 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.

4.13. 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.

4.13.1. 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 2021. 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 up to 2 GW of electricity.

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

4.13.2. 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 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.

4.13.3. 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 terminates at Singida substation in Tanzania. The interconnector is designed for a capacity of 1,700 MW. On the Kenyan side, this project also includes 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 and approach

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

5.2. Fuel cost forecast

According to the World Energy Outlook 2020, global energy demand is set to drop by 5% in 2020, energy-related CO_2 emissions by 7%, and energy investment by 18%. The impacts vary by fuel. The estimated falls of 8% in oil demand and 7% in coal use stand in sharp contrast to a slight rise in the contribution of renewables. The reduction in natural gas demand is around 3%, while global electricity demand looks set to be down by a relatively modest 2% for the year. Prior to the COVID-19 crisis, energy demand was projected to grow by 12% between 2019 and 2030. Growth over this period is now project to be 9%. Below is an overview of some of the fuels forecasted in this chapter.

5.2.1. Coal

According to the World Energy Outlook 2020, Coal remains on average 8% lower through to 2030 than in pre-crisis levels due to a combination of expanding renewables, cheap natural gas and coal phase-out policies. In advanced economies, coal demand in 2030 is nearly 45% lower than in 2019. Demand for coal in the power and industry sectors continues to grow in India, Indonesia and Southeast Asia, but its rate is slower than previously projected. In China by far the world's largest global coal consumer.

5.2.2. Crude Oil

The COVID-19 pandemic has shaken up the outlook for fuels, forcing producers to cope with greater uncertainty than ever before. The sharp fall in demand and prices in 2020 has meant extreme financial stress for many companies engaged in fuel supply, and especially for those that came into the crisis in a relatively weak position. It has also, in many countries, intensified pressures on the industry not just to deliver fuels but also to play a more significant role in reducing greenhouse gas (GHG) emissions. Some major elements of the oil and gas supply chain have been hit particularly hard by the downturn. As market conditions worsened, financial pressures led to major layoffs in the global oilfield supply and services industry, and massive strains on countries that rely heavily on hydrocarbon revenue, such as Iraq and Nigeria. This has undermined the ability of major producer economies to provide essential services to their populations and squeezed the funds available for continued investment in the energy sector.

5.2.3. 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.

According to the World Nuclear Association around 10% of the world's electricity is generated by about 440 nuclear power reactors. About 50 more reactors are under construction, equivalent to approximately 15% of existing capacity. In 2019 nuclear plants supplied 2657 TWh of electricity, up from 2563 TWh in 2018. This is the seventh consecutive year that global nuclear generation has risen, with output 311 TWh higher than in 2012.

5.2.4. Natural Gas

Natural gas recovers quickly from a drop in demand in 2020. Demand rebounds by almost 3% in 2021, then rises to 14% above 2019 levels by 2030, with growth concentrated in Asia. In established markets, easy gains from coal-to-gas switching are largely exhausted by the mid-2020s, after which the prospects for gas start to deteriorate as a result of environmental considerations, increasing competition from renewables, efficiency gains, growing electrification of end-use demand and improving prospects for alternative low-carbon gases, including hydrogen.

5.3. Assumptions of the underlying fuel price forecast

The underlying fuel forecast assumptions adopted in the plan are as described in Table 16.

Table 15 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 2021 & 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 & 2030
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 2020,	Adopted historical Average German Import Price at FOB for the period 1988 to 2019 Adopted a 15yr average growth rate of 4% between 2005 & 2019 to forecast for the period between 2020 and 2030.
LNG	BP Statistics Review World Energy 2020,	Adopted historical LNG Japan Price at CIF for the period 1988 to 2019 Adopted a 10yr average growth rate of 3.7% between 2010 & 2019 to forecast for the period between 2020 and 2030.
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 (2020 - 2030). 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 as shown in table 17.

Table 16: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. In 2019, the rate was revised to 5.07/M^3/km which dropped to 4.81//M^3/km in 2020. This tariff will run through to 2021.

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

LNG prices faced a huge dip in 2020 owing to the COVID-19 pandemic. The impacts of the pandemic on gas producers have not been felt equally. The main declines in price occurred as a result of a drop in output from gas fields associated with oil production and a reduction in gas volumes earmarked for exports in an oversupplied market. It is forecasted that demand for LNG will decline by approximately 1% between 2020 and 2024 and later increase slightly over the rest of the planning period. See Figure 18.

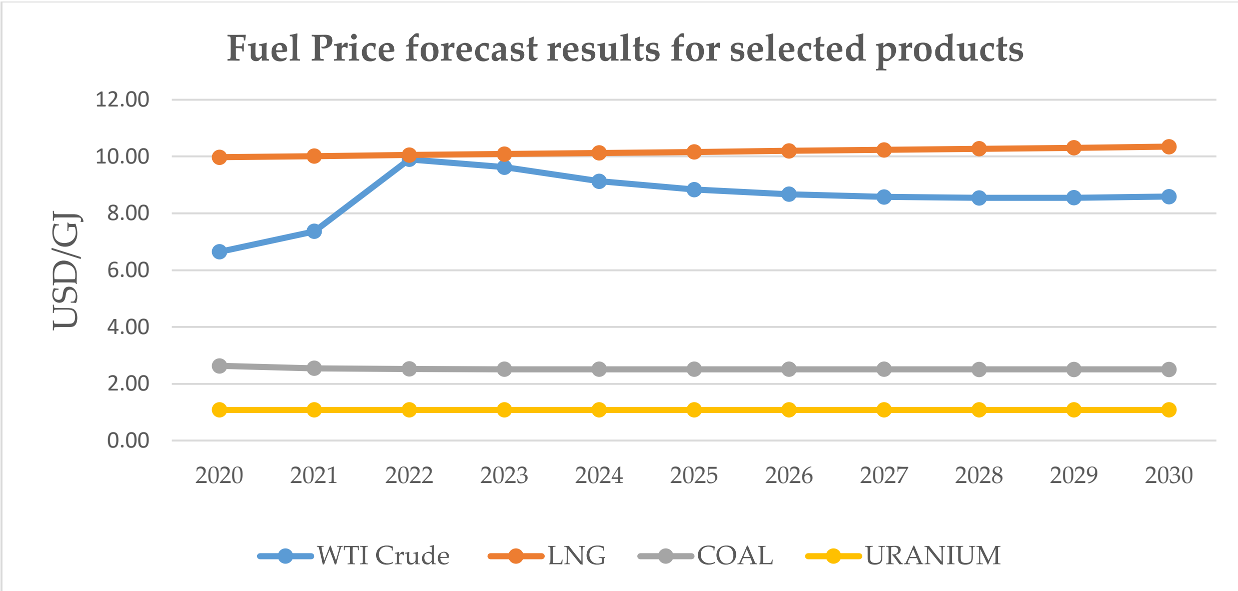


Figure 18: Fuel Price Forecast for selected products

The COVID-19 pandemic greatly affected the oil markets owing to restrictive measures put globally in efforts to curb the spread of the pandemic. With travel bans and lockdowns demand for crude oil shrunk heavily in 2020. However, oil markets continue to improve and price increase in the medium term the dip and stabilizes between 2026 and 2030.

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 because 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, Hydro and wind plants. The screening curve technique is an approximate method that captures major trade-offs 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 12% and an exchange rate of Ksh/$ 108.5. However, a sensitivity analysis at a discount rate of 10% was carried out. The results of the sensitivity analysis are discussed under screening results.

Table 17:List of screened candidates

Candidate	Technology	Capacity (MW)
KenGen Olkaria	Geothermal	140
Generic Geo	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
Generic Wind	Wind	300

Table 18 Techno-economic Data for screened projects

	Geo Kengen	Generic Geo	Nuclear 1	Nuclear 2	Coal	Kitui Coal	Lamu Coal	GT-LNG	Wajir CCGT	MSD	Import	Karura	HGFalls	Wind
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**	**4 X 75**
Total Capacity (MW)	140	140	600	1000	300	960	981	200	375	80	200	90	495	300
Fixed Cost														
Capital ($ x 10^6)	511	481	3900	5900	828	2331	2504	137	506	132		342	1891	586
Capital ($/kW)	**3650**	**3439**	**6500**	**5900**	2760	2428	2553	686	1349	1650		3798	3820	1952
IDC Factor	1.2620	1.2620	1.5448	1.5448	1.3236	1.3236	1.3236	1.1091	1.1218	1.1345		1.3172	1.3893	1.1091
Annuity Factor (or C.R.F.)	0.1275	0.1275	0.1201	0.1201	0.1241	0.1241	0.1241	0.1275	0.1339	0.1339		0.1213	0.1213	0.1339
Interim Replacement	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	0.35%	0.35%	0.35%		1.05%	1.05%	0.76%
Fixed Annual Capital ($/kW/yr)	643.5	606.3	1328.8	1206.2	498.1	438.1	460.6	99.7	207.9	257.2		659.4	699.4	306.2
Fixed O&M Costs ($/kW/yr)	151.9	151.9	66.3	66.3	51	69	68	20.9	18.0	7.1		15.3	16.0	26.1
Total Fixed Annual Cost ($/kW/yr)	795	758	1395	1272	549	507	529	121	226	264		675	715	332
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	0.138
Outage Adjustment	1.062	1.062	1.117	1.117	1.153	1.153	1.153	1.109	1.109	1.085		1.114	1.114	1.160
Annual Fixed Cost ($/kW/yr)	**845**	**805**	**1559**	**1422**	**633**	**585**	**609**	**134**	**251**	**287**	**521**	**752**	**797**	**385**
Annual Fixed Cost ($/kWh)	**0.0964**	**0.0919**	**0.1779**	**0.1623**	**0.0722**	**0.0667**	**0.0696**	**0.0153**	**0.0286**	**0.0327**	**0.0595**	**0.0858**	**0.0910**	**0.0440**
Variable Cost														
Fuel Price ($/GJ)	-	-	1.08	1.08	2.546	2.546	2.546	10.49	6.33	9.34	-	-	-	-
Heat Rate (kJ/kWh)	10,700.00	10,700.00	9,231.30	9,231.30	10,159	10,159	9,338	12,740	12,740	12,653	-	-	-	-
Fuel Cost ($/kWh)	0.00	0.00	0.01	0.01	0.03	0.03	0.02	0.13	0.08	0.12	0.00	0.00	0.00	-
Variable O&M ($/kWh)	0.00000	0.00000	0.000	0.000	0.0050	0.0046	0.0046	0.0036	0.0036	0.0060	-	0.0005	0.0005	0.001
Total Variable ($/kWh)	**0.00000**	**0.00000**	**0.0105**	**0.0105**	**0.0309**	**0.0305**	**0.0284**	**0.1372**	**0.0843**	**0.1242**	**0.0000**	**0.0005**	**0.0005**	**0.0010**
Total Variable ($/kW/yr)	**0**	**0**	**92**	**92**	**270**	**267**	**249**	**1202**	**738**	**1088**	**0**	**4**	**4**	**9**

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 19 & 20

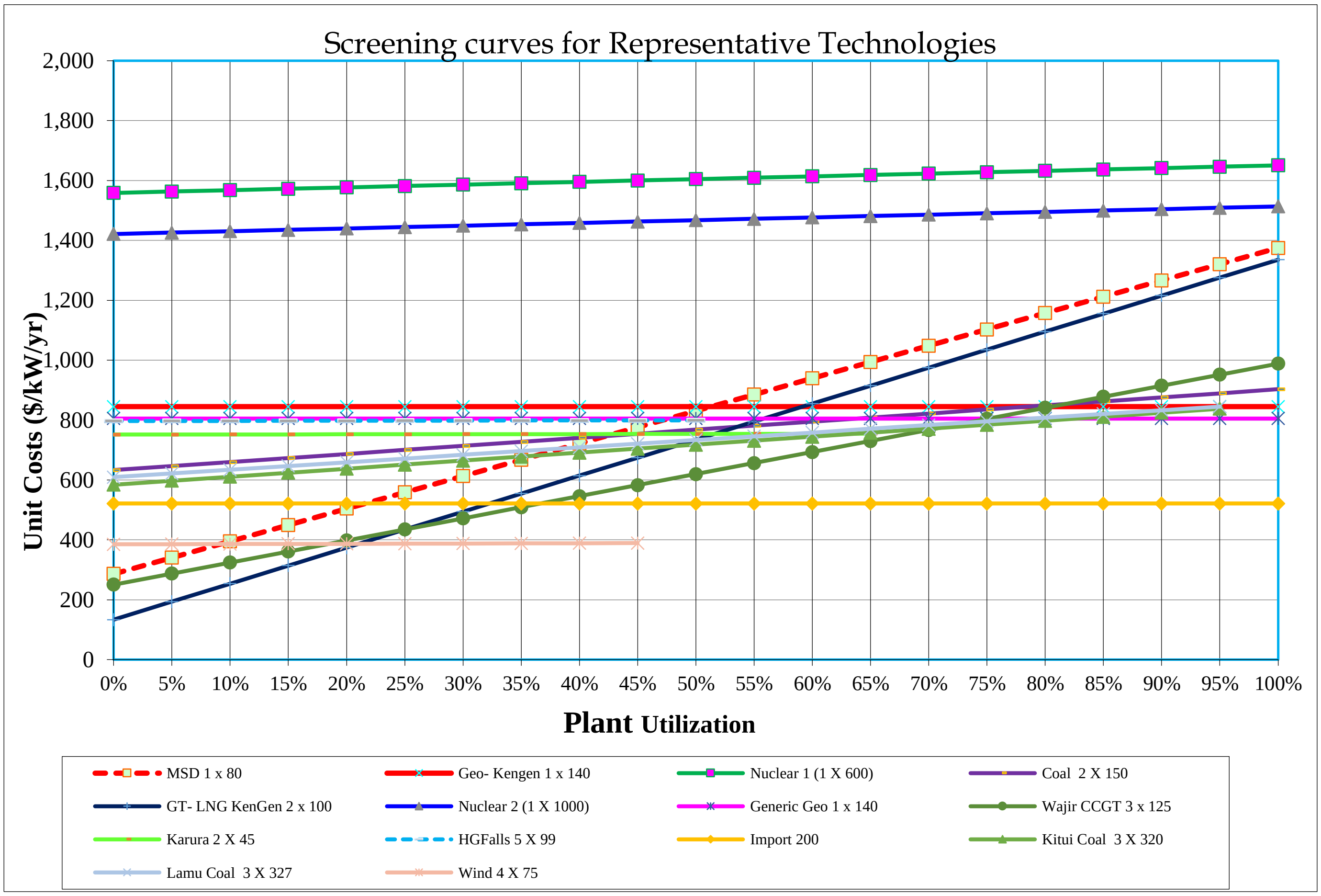


Figure 19 Results of screening analysis

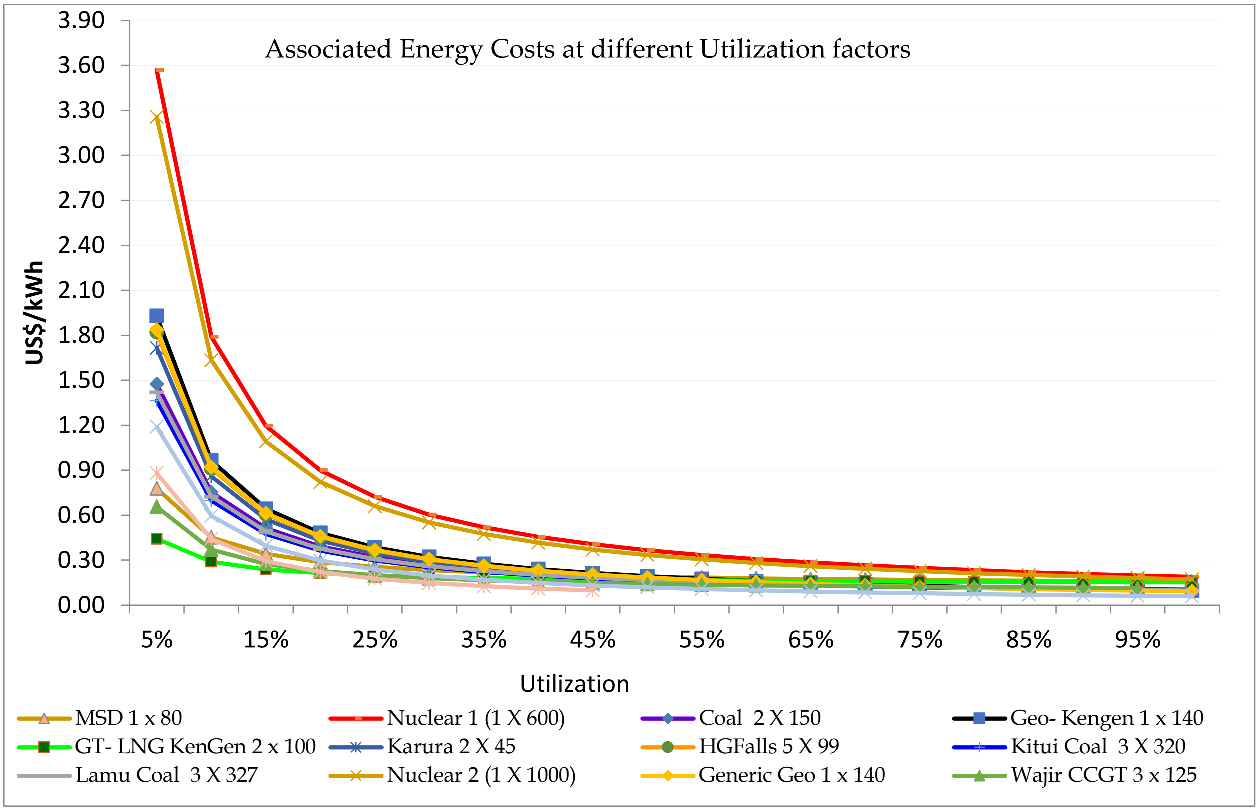


Figure 20: Associated Energy costs at different plant utilization level

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 discount factor of 12%, however when this rate is reduced to 10% the energy costs across the technologies reduces by more than 20%.

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 10-year period 2020-2030.

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 for an optimized case, were carried out 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 system effective generation capacity (grid and off-grid) was 2,708MW as at December 2020, against a peak demand of 1,976MW. KenGen, the largest power generator in the country, accounted for 1,708 MW of the effective generation capacity, Independent Power Producers (IPPs) 976MW and REA Garissa 50MW. Annex 2 shows the existing plants with their commissioning and planned decommissioning dates.

6.2.2. Committed Generation Projects

Committed projects are defined as under construction. These projects are listed in Table 20. The total capacity of committed projects is 853MW.

Table 19: Committed Projects

Project Company	**Capacity(MW)**	**PPA DATE**	**Optimised Case COD**
Hydro Project Service Peters Kianthumbi	0.51	Apr-21	2021
KTDA Ltd, South Maara (Greater Meru Power Co.)	1.5	Dec-21	2022
KTDA Ltd, Lower Nyamindi	0.8	Dec-21	2022
KTDA Ltd, Iraru	1	Dec-21	2022
Kleen Energy Limited	6	Dec-20	2023
KTDA - Nyambunde, Nyakwana	0.5	Jun-21	2023
Total Hydro	**10**		
Cummins Cogeneration Kenya Limited	10	Jun-20	2026
Kwale Int. Sugar Co. Ltd	10	Dec-21	2025
KenGen & NMS Waste to Energy	30	Dec-23	2023
Total Biogas/Biomass	**50**		
Kipeto Energy Limited	100	Jul-21	2021
Total Wind	**100**		
Selenkei (Radiant)	40	Dec-21	2022
Eldosol (Cedate)	40	Dec-21	2022
Alten Kenya Limited	40	May-21	2024
Vateki International Holdings /Malindi Solar Limited	40	Jan-22	2023
Total Solar	**160**		
Olkaria I Unit 6	83	Jul-21	2021
Total Geothermal	**83**		
Ethiopia HVDC phase 1	200	Jul-21	2022
Imports Total	**200**		
BESS South Nyanza	50	Jan-22	2022
BESS Coast1	50	Jan-23	2023
BESS Coast2	50	Jan-24	2024
BESS Nairobi	100	Jan-26	2026
BESS Total	**250**		
Grand Total	**853**		

6.2.3 Candidate Generation Projects

Projects with valid PPAs and for KenGen approved by EPRA were modelled as candidate projects and optimised within the 10-year term. Table 21 provides a list of the candidate projects. The total capacity of the planned projects is 1,552 MW for the modelled case.

Table 20: Candidate Projects

Project Company	Capacity (MW)	PPA DATE	Optimised Case COD
Mt Kenya Community Based Organisation	0.6	Dec-22	2023
Power Technologies (Gatiki Small Hydro Plant)	9.6	Jun-22	2024
Tindinyo Falls Resort	1.5	Jun-23	2025
Frontier Investment Management / Nithi Hydro	5.6	Dec-24	2025
Gogo HPP	12		2025
KTDA, Kipsonoi (Settet Power Co.)	0.6	Feb-25	2025
Global Sustainable-Kaptis	14.7	Dec-25	2026
Global Sustainable Ltd-Buchangu	4.5	Dec-25	2026
Karura	90	Jun-26	2030
Total Hydro	**139**		
REA Vipingo Plantations Ltd (DWA Estates Ltd)	1.44	Dec-20	2022
Thika Way Investments (Homa Bay Biogas One)	8	Jun-23	2023
Roadtech Solutions Ltd	10	Dec-24	2025
Total Biogas/Biomass	**19**		
Chania Green	50	May-22	2024
Aperture Green Power Ltd / Limuru Wind	50	Dec-22	2026
Ngong 1 Phase III	11	Jun-21	2026
Bahari Winds (Electrawinds Kenya)	50	Dec-24	2028
Bahari Winds (Electrawinds Kenya)	40	Dec-25	2030
Prunus Energy	50	Dec-25	2029
Total Wind	**251**		
Marco Borero Co Ltd.	1.5	Jun-20	2026

Hannan Arya Energy (K) Ltd	10	Dec-21	2027
Kenergy Renewables Ltd-Rumuruti	40	Dec-22	2028
Kopere Solar Park Limited	40	Jun-23	2026
Dafre Holdings Co.Ltd /Makindu solar ltd	30	Dec-23	2029
Seven Forks Solar Project	43	Jun-24	2026
Greenmillenia Energy Limited	40	Dec-25	2030
Kibwezi One Energy Limited	40	Jun-26	2030
Total Solar	**244**		
Sosian-Menengai Geothermal Power Ltd	35	Dec-21	2023
Quantum/QPEA GT Menengai Limited (Menengai)	35	Jan-22	2023
Orpower 22 (Menengai)	32.5	Jun-22	2023
Olkaria I AU/IV Uprating Unit 4	10	Jul-22	2025
Olkaria I AU/IV Uprating Unit 5	10	Jun-23	2025
Olkaria I AU/IV Uprating Unit 1	10	Sep-22	2029
Olkaria I AU/IV Uprating Unit 2	10	Jul-23	2029
Olkaria I Rehab unit 1	17	May-23	2028
Olkaria I Rehab unit 2	16.9	Dec-23	2028
Olkaria I Rehab unit 3	17	Apr-24	2028
Olkaria VI(PPP)	140	Jun-24	2027
Menengai 1 Stage II	60	Jun-24	2029
Akira Geothermal Ltd	70	Jul-25	2029
Africa Geothermal International (Kenya) Ltd - AGIL	35	Jun-25	2029
Total Geothermal	**498**		
LNG Gas Turbine	200		2028
LNG Total	**200**		
Ethiopia HVDC phase 2	200	Jul-24	2025
Imports Total	**200**		
Grand Total	**1552**		

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: 45% in 2020, 40% in 2021-2022 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), divided by 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 and Expansion Reserves 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.

6.3.6. 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 3 and annex 4.

6.3.7. Battery Energy Storage System

The LIPS_XP planning tool does not have the capability for modelling Battery Energy Storage Systems (BESS). To simulate BESS as one of the technologies under development within the 10year period, it was modelled assuming characteristics of thermal plants that serve as peaking plants.

The specific load requirement for charging the batteries was incorporated by modifying the load curve to have the batteries charged for 4 hours during off-peak.

The cost of the energy for charging the batteries was assumed to be equivalent to the cost of steam that was vented and given an assumption of 2USc/KWh. The cost for charging was factored in and modelled as fuel cost for the BESS technology.

6.4. Generation Expansion Simulations using LIPS-OP/XP

The generation expansion was simulated based on a discount rate of 12% and average hydrology. Only projects under construction were considered as committed. Other projects with PPAs and KenGen's approved projects were optimised over the 10 year planning period. The optimization was based on reference demand growth.

6.5. Results for Generation Expansion Scenarios Simulations

This section presents the results of the generation expansion simulation.

6.5.1. Results Optimised Case – Reference demand

The demand-supply output for the optimised expansion plan presented in Table 22, indicates that the total interconnected effective capacity grows from 2,708MW in 2020 to 3,639MW and 4,857MW in 2025 and 2030 respectively. The average annual excess energy as share of generation in the period 2020-2030 is less than 1%. The level of vented steam grows over the years with vented steam growing from 213GWh in 2020 to about 1,136GWh in 2025 and declines thereafter to 854GWh in

2030. An average of 11% vented steam of the possible maximum geothermal generation is observed over the 10 year planning period.

The vented steam is due to the increase in planting of the intermittent plants which displace the baseload plants which also provide firm capacity during peak hours. The installation of battery storage systems helps in the optimisation of the system by creating a load during the off peak and providing capacity during peaking hours.

Table 21:Demand- Supply balance

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak load	MW	1,976	2,078	2,158	2,233	2,315	2,404	2,544	2,717	2,872	3,038	3,220
Peak load + reserve margin	MW	2,259	2,361	2,433	2,509	2,594	2,685	2,832	3,015	3,208	3,380	3,560
Reserve margin	% of peak load	15%	14%	13%	12%	12%	12%	11%	11%	12%	11%	11%
Installed system capacity	MW	2,708	2,807	3,043	3,212	3,361	3,629	3,925	4,091	4,455	4,667	4,847
Firm system capacity	MW	2,288	2,321	2,473	2,560	2,630	2,869	3,011	3,156	3,435	3,558	3,579
Supply - demand gap	MW	29	-40	40	51	36	184	180	141	226	178	19
Electricity consumption versus generation		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Electricity consumption	GWh	12,072	12,720	13,353	13,889	14,536	15,083	15,939	16,998	17,947	18,963	20,075
Electricity generation	GWh	12,078	12,732	13,392	13,983	14,577	15,120	15,971	17,037	17,985	19,009	20,109
Unserved energy	GWh	0	0	0	0	0	0	0	0	0	0	0
Unserved energy - share on consumption	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Excess energy	GWh	6	12	39	95	42	37	32	39	37	45	33
Excess energy - share on generation	%	0.05%	0.09%	0.29%	0.68%	0.29%	0.24%	0.20%	0.23%	0.21%	0.24%	0.17%
Vented GEO steam	GWh	213	426	1,065	1,513	1,262	1,136	924	1,119	1,009	1,121	854
Vented GEO steam - share on potential max. GEO flash steam generation	%	3%	6%	15%	19%	16%	14%	11%	12%	10%	11%	8%

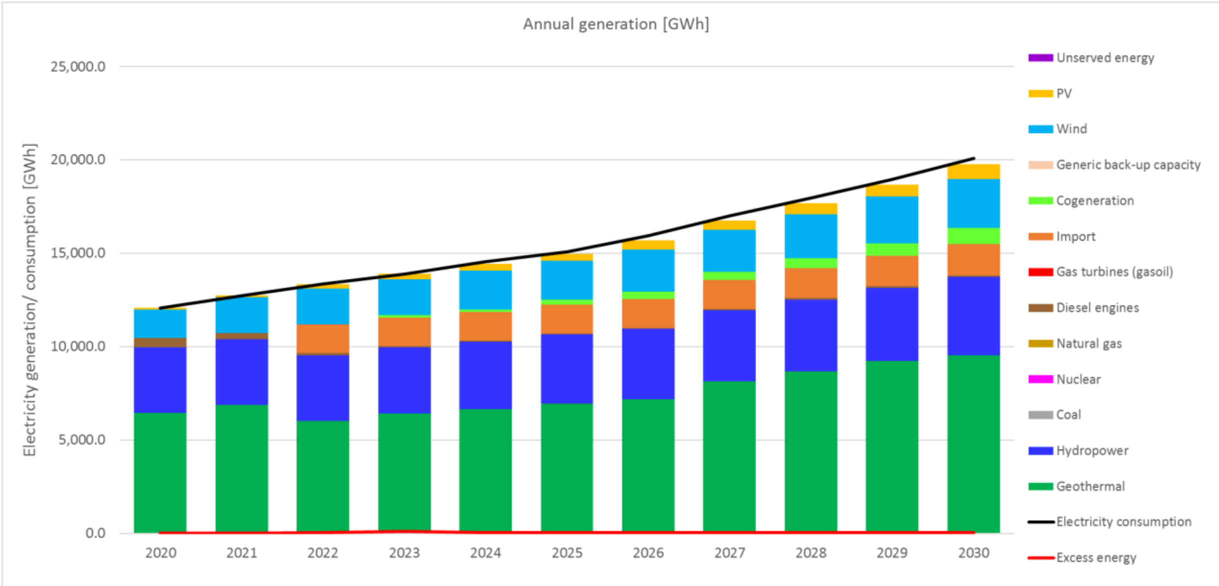


Figure 21: Optimised Case- Annual generation balance

Table 23 presents the plant's capacity factors. The BESS has an average Capacity factor of 12.7% over the 10 year planning period. Geothermal plants' capacity factors declined marginally from 90.2% in 2020 to 81.3% in 2025 and later increasing to 86.8% in 2030. Table 24 shows the optimised system expansion plan. However, it is noteworthy that Geothermal plants have a generally high capacity factor due to increased peak demand arising from BESS while the diesel engines have reduced capacity factor as they are dispatched less.

Table 22 Capacity factor

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Geothermal	87.4%	80.3%	76.5%	79.5%	81.3%	83.8%	83.1%	84.7%	84.3%	86.8%
Hydropower	49.6%	49.6%	49.6%	49.6%	49.6%	49.6%	49.6%	49.6%	49.6%	47.8%
Diesel engines	6.4%	2.5%	1.4%	1.5%	1.3%	1.3%	1.4%	2.1%	2.4%	2.7%
Gas turbines (gasoil)	0.1%									
Import		86.3%	85.9%	85.9%	44.0%	44.1%	44.3%	45.4%	45.8%	47.6%
Cogeneration	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Wind	51.7%	51.7%	51.7%	50.4%	50.4%	47.8%	47.8%	46.3%	45.2%	44.6%
PV	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%	19.6%
Gas turbines (LNG)								0.0%	0.0%	0.1%
BESS		11.9%	9.4%	10.2%	11.3%	12.4%	12.5%	14.5%	14.7%	16.1%

Table 23 Optimised Case Reference Scenario Expansion – Generation Expansion Table

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Peak load (MW)	Reserve (MW)	Surplus/ Deficit (MW)	Reserve Margin (%)
End of 2020				**2,708.0**	**2,287.7**	**1,976.5**	**287.2**	**24.0**	**15%**
2021	Olkaria 1 - Unit 6	Geothermal	83.3		83.3				
2021	Kipeto	Wind	100.0		40.0				
2021	Hydro Project Service Peters Kianthumbi	Small Hydro	0.5		0.1				
2021	Tsavo	Diesel engines	(74.0)		(74.0)				
End of 2021			**109.8**	**2,817.8**	**2,320.9**	**2,078.0**	**283.3**	**(40.5)**	**14%**
2022	HVDC Ethiopia	Import	200.0		200.0				
2022	Selenkei (Radiant)	PV	40.0		-				
2022	Eldosol (Cedate)	PV	40.0		-				
2022	KTDA - Nyambunde, Nyakwana	Small Hydro	0.5		0.1				
2022	KTDA Ltd, South Maara (Greater Meru Power Co.)	Small Hydro	1.5		0.4				
2022	KTDA Ltd, Lower Nyamindi	Small Hydro	0.8		0.2				
2022	KTDA Ltd, Iraru	Small Hydro	1.0		0.3				
2022	REA Vipingo Plantations Ltd (DWA Estates Ltd)	Cogeneration	1.4		0.7				
2022	BESS South Nyanza	BESS	50.0		50.0				
2022	Olkaria 1 - Unit 1	Geothermal	(14.7)		(14.7)				
2022	Olkaria 1 - Unit 2	Geothermal	(14.7)		(14.7)				
2022	Olkaria 1 - Unit 3	Geothermal	(14.7)		(14.7)				

2022	Muhoroni GT 1	Gas turbines (gasoil)	(28.0)		(28.0)				
2022	Muhoroni GT 2	Gas turbines (gasoil)	(28.0)		(28.0)				
End of 2022			**235.2**	**3,053.1**	**2,472.5**	**2,157.6**	**275.0**	**40.0**	**13%**
2023	Menengai 1 Phase I - Stage 1	Geothermal	102.5		102.5				
2023	Mt Kenya Community Based Organisation	Small Hydro	0.6		0.2				
2023	Kleen Energy	Small Hydro	6.0		1.5				
2023	Malindi Solar Limited	PV	40.0		-				
2023	BESS Coast1	BESS	50.0		50.0				
	Municipal Waste to Energy	Cogeneration	30.0		15.0				
2023	Kipevu 1	Diesel engines	(60.0)		(60.0)				
End of 2023			**169.1**	**3,222.2**	**2,560.4**	**2,233.0**	**276.3**	**51.1**	**12%**
2024	Power Technologies (Gatiki Small Hydro Plant)	Small Hydro	9.6		2.4				
2024	Chania Green	Wind	50.0		17.5				
2024	Alten Kenya Limited	PV	40.0		-				
2024	BESS Coast2	BESS	50.0		50.0				
End of 2024			**149.6**	**3,371.8**	**2,630.3**	**2,314.9**	**304.7**	**10.7**	**13%**
2025	Olkaria I Uprating (Topping)	Geothermal	20.0		20.0				
2025	HVDC Ethiopia2	Import	200.0		200.0				
2025	Tindinyo Falls Resort	Small Hydro	1.5		0.4				
2025	Frontier Investment Management/ Nithi Hydro	Small Hydro	5.6		1.4				
2025	KTDA, Kipsonoi (Settet Power Co.)	Small Hydro	0.6		0.2				

2025	Gogo upgrade	Small Hydro	12.0		3.0					
2025	Kwale Int. Sugar Co. Ltd	Cogeneration	10.0		5.0					
2025	Thika Way Investments (Homa Bay Biogas One)	Cogeneration	8.0		4.0					
2025	RoadTech Solutions	Cogeneration	10.0		5.0					
End of 2025			**267.7**	**3,639.5**	**2,869.2**	**2,404.4**	**306.2**	**158.6**	**13%**	
2026	Aperture Green	Wind	50.0		17.5					
2026	Ngong 1 - Phase III	Wind	11.0		3.9					
2026	Marco Borero Co Ltd.	PV	1.5		-					
2026	Seven Forks Solar Power Plant	PV	42.5		-					
2026	Kopere Solar Park Limited	PV	40.0		-					
2026	Global Sustainable-Kaptis	Small Hydro	14.7		3.7					
2026	Global Sustainable Ltd-Buchangu	Small Hydro	4.5		1.1					
2026	Cummins Cogeneration Kenya Limited	Cogeneration	10.0		5.0					
2026	Sukari Industries	Cogeneration	22.0		11.0					
2026	BESS Nairobi	BESS	100.0		100.0					
End of 2026			**296.2**	**3,935.7**	**3,011.4**	**2,544.2**	**316.2**	**151.1**	**12%**	
2027	Olkaria 6 PPP	Geothermal	140.0		140.0					
2027	Hannan Arya Energy (K) Ltd	PV	10.0		-					
2027	Hydel	Small Hydro	5.0		1.3					
2027	Mutunguru Hydroelectric Company Ltd	Small Hydro	7.8		2.0					
2027	VR Holding AB-Local Trade Ltd	Cogeneration	3.0		1.5					
End of 2027			**165.8**	**4,101.5**	**3,156.1**	**2,717.1**	**328.8**	**110.3**	**12%**	
2028	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	17.0		17.0					

2028	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	17.0		17.0				
2028	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	17.0		17.0				
2028	LNG Gas Turbine	Gas turbines (LNG)	200.0		200.0				
2028	Electrawinds Bahari	Wind	50.0		17.5				
2028	Kenergy Renewables Ltd-Rumuruti	PV	40.0		-				
2028	Ventus Energy Ltd	Small Hydro	7.7		1.9				
2028	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	Cogeneration	20.0		10.0				
2028	Ngong 1, Phase I	Wind	(5.1)		(1.8)				
End of 2028			**363.6**	**4,465.0**	**3,434.8**	**2,872.2**	**336.0**	**226.5**	**12%**
2029	AGIL Longonot Stage 1	Geothermal	35.0		35.0				
2029	Olkaria IV Uprating (Topping)	Geothermal	20.0		20.0				
2029	Menengai I - Stage 2	Geothermal	60.0		60.0				
2029	Marine Power Akiira Stage 1	Geothermal	70.0		70.0				
2029	Prunus	Wind	50.0		17.5				
2029	Makindu solar ltd	PV	30.0		-				
2029	Mwikhupo-Mwibale Hydro Power Kenya	Small Hydro	7.0		1.8				
2029	Ray Power Ltd	Cogeneration	35.0		17.5				
2029	West Kenya Sugar Company Limited	Cogeneration	6.0		3.0				
2029	Olkaria 2	Geothermal	(101.0)		(101.0)				
End of 2029			**212.0**	**4,677.0**	**3,558.5**	**3,038.2**	**345.0**	**175.3**	**11%**
2030	Karura	Hydropower	90.0		70.7				
2030	Greenmillenia Energy Limited	PV	40.0		-				

2030	Kibwezi one Energy Limited	PV	40.0		-				
2030	Electrawinds Bahari Phase 2	Wind	40.0		14.0				
2030	Gem Gen Power Company Limited	Small Hydro	9.5		2.4				
2030	Greenlight Holdings / rianjue/Gichuki Ventures	Small Hydro	1.5		0.4				
2030	Njega/Rukenya Hydro power ltd(rights transfer)	Small Hydro	3.5		0.9				
2030	Virunga Power Holdings, R Sossio, Kaptama	Small Hydro	4.5		1.1				
2030	Sustainable Energy Management Solutions	Cogeneration	40.0		20.0				
2030	Rabai Diesel (CC-ICE)	Diesel engines	(88.6)		(88.6)				
End of 2030			**180.4**	**4,857.4**	**3,579.4**	**3,219.8**	**376.3**	**(16.8)**	**12%**

6.6. Observations and conclusions

a) The proposed solar and wind projects which are likely to deliver higher intermittent capacity in the system have been spread out to optimize the system and minimize energy curtailment.

b) Introduction of BESS helps to optimize the system by increasing the load during the off-peak and providing peaking capacity. Solar projects proposed as hybrids with storage component may be given priority in selection of intermittent capacity as they can assist in system stabilization.

c) Peaking capacity power plants and Battery storage should be developed immediately to avert peaking 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 additional peaking projects are LNG gas turbines and hydro power plants.

d) 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 such as strengthening the Time of Use tariff, electrification of the transport sector (EVs), among others.

7. FINANCIAL AND TARIFF IMPLICATIONS OF THE PLAN

This chapter covers generation costs for the period 2021-2030 as simulated in chapter 6, and the evolution of tariffs for the medium term period 2021-2025 where the projects are committed. The Optimised Case Reference demand scenario as simulated in generation planning was used in tariff simulations primarily based on the fact that the reference demand scenario provides a more realistic forecast for policy formulation and implementation.

7.1. Projected Financial Cost

The implementation of an additional capacity of 4,847MW will require a capital cost of USD 14,177 billion. Figure 23 shows the total capital requirement for the generation expansion plan, while Figure 23 illustrates the share of capital per technology for the period 2020 – 2030.

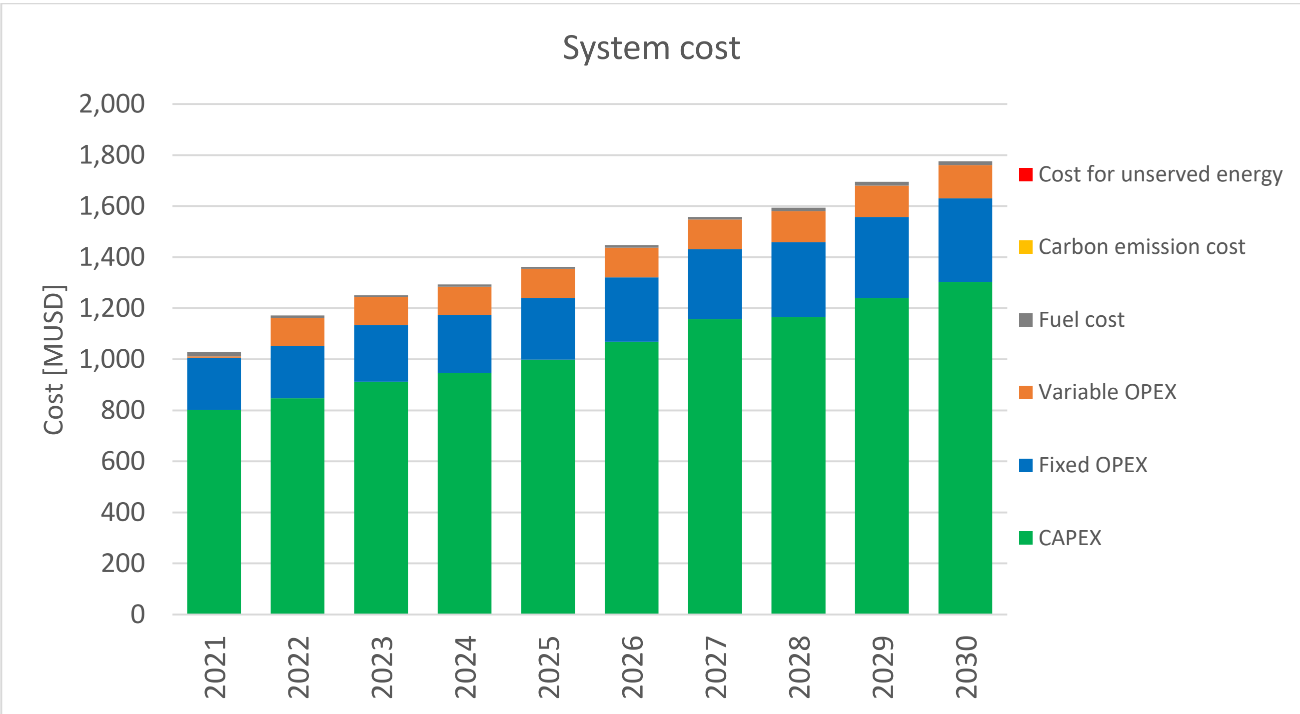


Figure 22: Investments costs for various technologies.

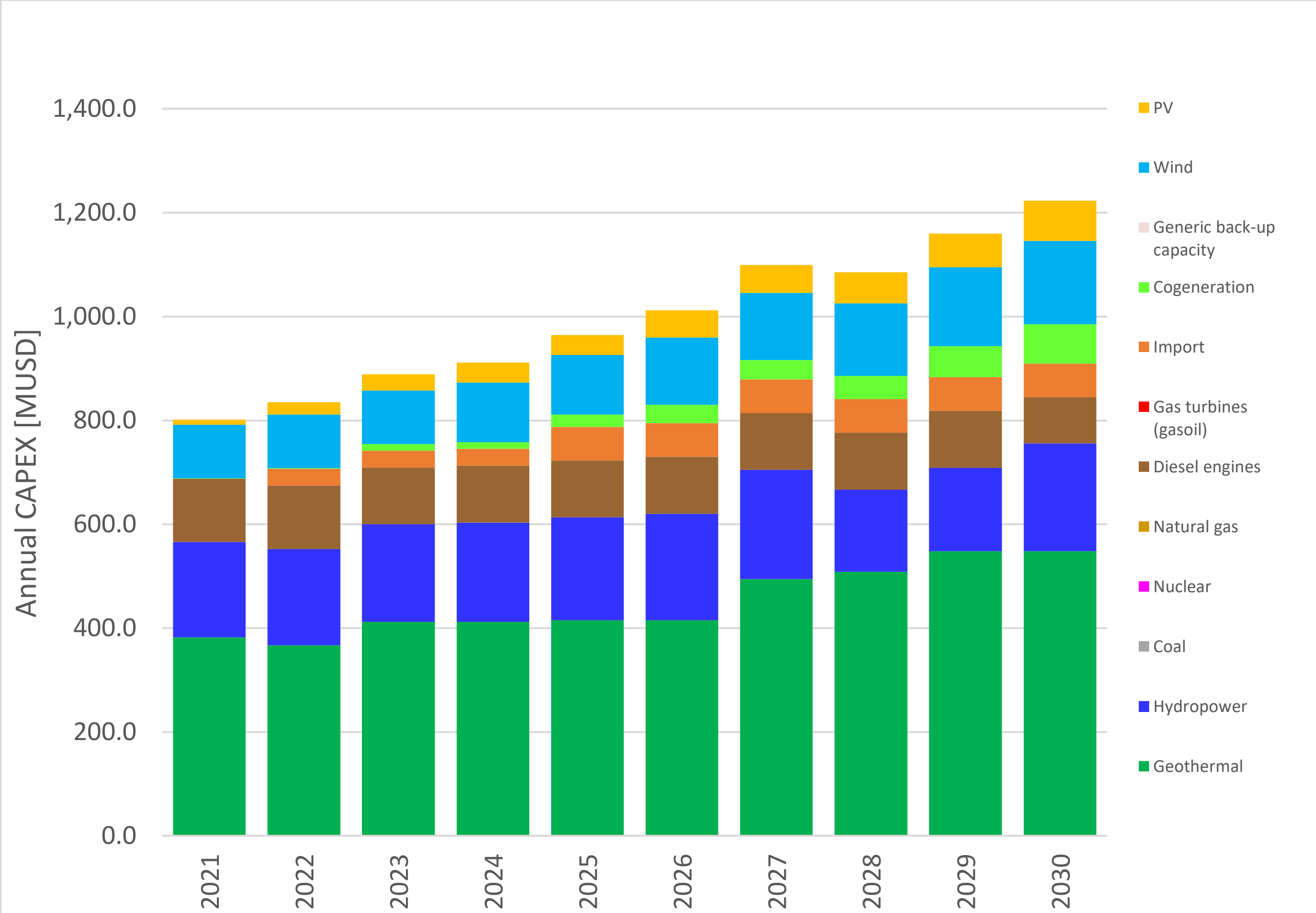


Figure 23 Annual Capex per technology

The annual system cost indicates that geothermal will require larger share of the capital requirement with estimates USD 548.5 million by 2030 from USD 346.4 million in 2020. Hydropower is estimated to require the second largest annual Capex, at USD 207.1 million by 2030, Wind is estimated to have an annual capex of USD 160.9 million by the end of the planning period. Geothermal, Hydropower and Wind Technology account for estimated 70.35%.

Figure 25 shows the Levelised cost of electricity of the system from 2020-2030. It indicates that the LEC will increase from 8.26 USDCents/kWh in 2020 to 8.85USDCents/KWh in 2030, with the highest LEC cost of 9.17 USDCents/KWh recorded in 2027.

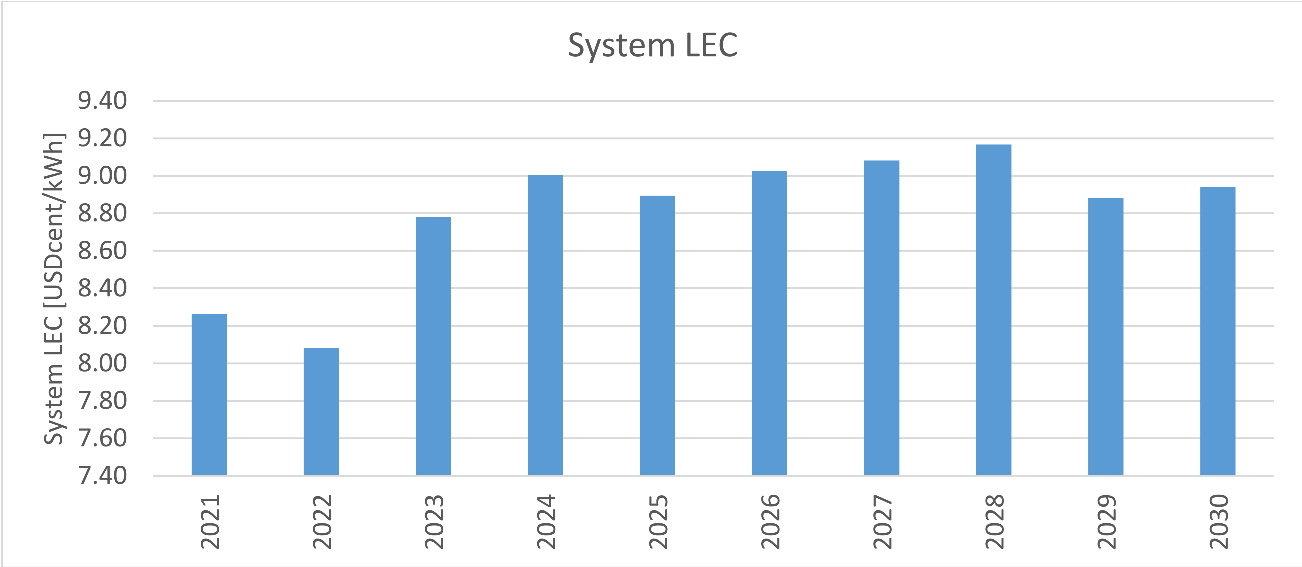


Figure 24 Levelised costs under the optimised case reference scenario

7.2. Tariff Evolution.

The tariff evolution has taken into consideration projects' CODs as simulated in the generation plan in chapter 6, for the period 2021-2025. Figure 26 illustrates the tariff evolution for the medium term period based on the reference demand forecast.

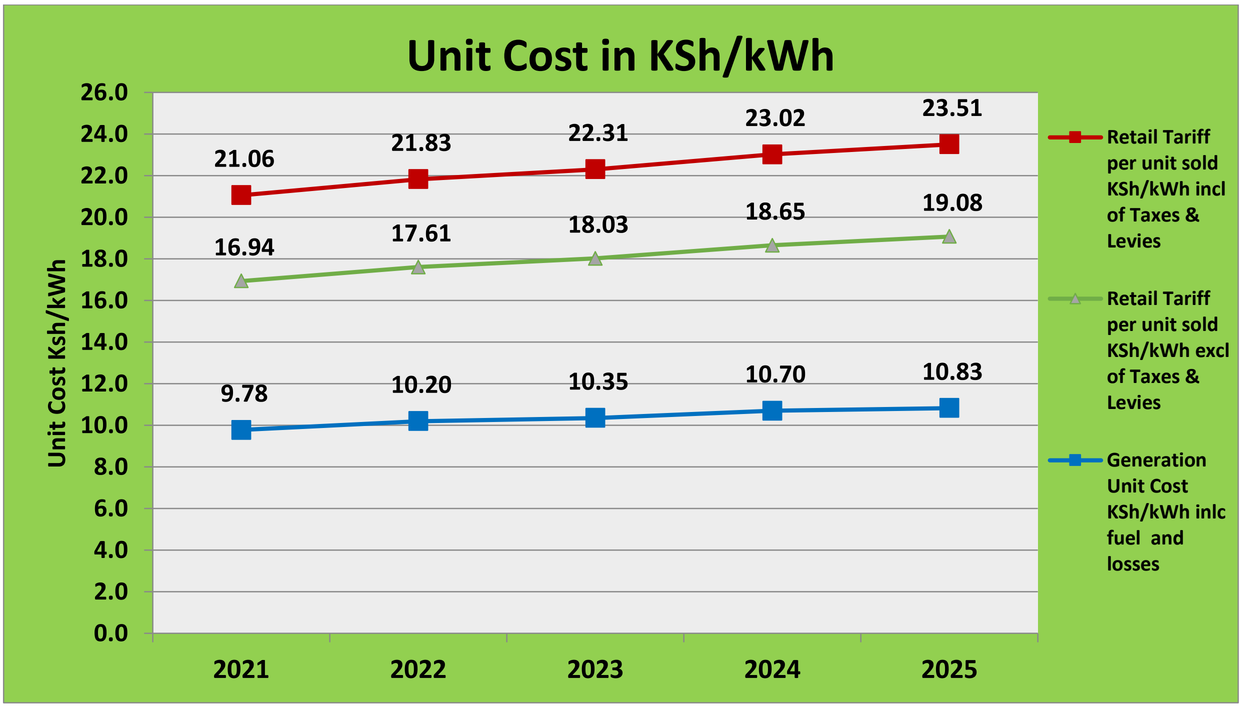


Figure 25 Tariff evolution - Optimised case

From the simulations, the average base retail tariff is projected to increase from KSh21.06/kWh in 2021 to KShs. 23.51/kWh in 2025. The generation cost during the period rises from Kshs.9.78/kWh in 2021 to KSh. 10.83/kWh in 2025. The total cost implication for planned projects is KShs. 563,402,532,579. It rises from Kshs **96,659,006,460** in 2021, to Ksh. 127,350,351,895 in 2025. The rise is due to increased generation, with committed projects being commissioned in the medium term.

8. CONCLUSIONS AND RECOMMENDATIONS

This report presents the indicative national power development plan recommended for implementation in the next 10 years. The report takes into account changes in electricity demand, planned projects and the adverse impact of the COVID-19 pandemic. It reviewed the committed power generation projects without an analysis of the transmission expansion plan. The plan relates the current status of projects with the expansion sequence and attempts to reduce the level of vented steam in the system due to overplanting of baseload capacity. Battery energy storage has also been included in the plan to support the system. The plan is aligned to the Energy Act 2019 and the long term plan 2020-2040. However, some projects' timing were adjustment during the optimization process to include the battery storage.

8.1.Conclusions

8.1.1. Demand Forecast

The review of the demand forecast incorporated the impact of the COVID-19 pandemic and the recommendations of various sectoral reports which indicate a slower demand growth rate compared to the pre-COVID -19 pandemic forecast. This is due to the slowed economic activity and 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 envisaged timelines, 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 largely those connected under the Last Mile Connectivity initiative. The conclusion however, is that demand is recovering fairly noting that as and at the end of 2020 it had peaked at 1,976MW compared to the previous peak of 1,926MW in FY 2018/19. The outlook shows possibility of full recovery in a fairly short period if no severe pandemic containment measures are implemented.

8.1.2. Generation Expansion Planning

Simulations were done on the cases assembled based on various assumptions as discussed in chapter 6. The simulations were based on an optimized case using reference demand scenario" which encapsulated the most likely development path.

The results indicate there is no excess energy over the planning period. This is because the optimized scenario allows the model to optimize supply based on demand and eventually delays most of the intermittent capacity towards the end of the planning period. Vented steam reduces upon introduction of the proposed battery storage capacity. The is need to manage vented steam further as it averages 12% of the share of potential maximum geothermal steam generation over the period. It is noteworthy that the optimized scenario does not accommodate the proposed Amu coal.

8.1.3. Summary of Recommendations

The proposed demand creation initiatives, and in particular flagship projects, need to be given enough attention as the plan depends on their implementation. This particular plan considers Dongo Kundu Industrial Park, Naivasha Industrial Park and Konza Technopolis as critical demand drivers in the reference demand forecast, which need to be given close attention to meet this plan objective

i. The proposed projects identified in this plan be adopted for implementation in the next 10 years. Future revisions of this planting sequence will be based on continued monitoring of the implementation of the projects.

ii. There is need to introduce targeted incentives to attract industrial consumers to enhance base load consumption in the country. This would assist in absorbing vented steam and improve the country load behaviour during off-peak period.

iii. Solar and Wind projects that do not have PPAs and have no storage component should be migrated to the proposed renewable energy auctions.

iv. Due to the technical operation challenges largely revolving around ancillary services and the lack of automatic generation control (AGC), there is need for improved system management, automation and innovation to enhance supply reliability, efficiency and reduce system losses.

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.

vi. Recommended peaking projects for the long term are LNG gas turbines proposed in 2028, Pumped Hydro Storage which is not considered in this plan but is a viable candidate in future optimization, and peaking hydro plants such as Karura, High grand falls and Arror Hydro projects.

vii. Demand Side Management (DSM) relating to load shifting is recommended to enable optimal utilization of the excess energy in the system during off-peak hours. This includes initiatives such as strengthening the Time of Use (TOU) tariff, electrification of the transport sector (EVs) among others.

viii. Negotiate for firm 200MW Ethiopia imports peaking capacity for at least 3 years to allow for development of local firm capacity in the medium term. A further 200MW is proposed which may run as variable capacity from 2025.

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

x. All projects not meeting peak load requirements in the proposed case scenario should, where appropriate, be considered for development, subject to meeting criteria set by the Ministry of Energy for integration when the supply and demand balance situation improves.

xi. Proposed geothermal capacity development should be aligned with the terms and conditions of the concessions/licences issued by the Government and phase of development of the resource by the licensee in the development of the project. This would be the basis for revision of CODs previously issued and shall also be informed by the demand-supply balance.

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 and ensure smoother system frequency control.

xiv. Focus on sustainable technologies that will minimize geothermal steam venting and enhance flexibility of geothermal plants.

xv. Future demand forecasting to incorporate information on micro and mini grids and prosumers as the approved projects under these categories have increased.

ANNEXURES

ANNEX 1: Licensed Captive Power Generators

	Licensee	Capacity(MW)	Technology	Site
1	James Finlay	6.7	Hydro and Thermal	Kericho
2	Sotik Tea	1.5	Thermal	Bomet
3	Sotik Highlands	1.06	Thermal	Bomet
4	Unilever	4.66	Hydro and Thermal	Kericho
5	Cemtech Ltd	30	Coal	West Pokot
6	Devki Energy Co Ltd	15	Coal	Merrueshi, Kajiado
7	Butali Sugar Mills Limited	11	Cogen	Kakamega
8	Chemelil Sugar Co Limited	3	Cogen	Kisumu
9	SONY Co. Ltd	8.7	Bagasse	Migori
10	Ofgen Power Ltd	0.455	Solar	Nairobi & Taita Taveta
11	Pwani oil products limited	1.5	Biomass	Kilifi
12	Nzoia Sugar Co. Ltd	7	Bagasse	Bungoma
13	Oserian Development Co.ltd	1	Solar	Nakuru
14	Kaimosi Tea Estates Ltd	1.5	Solar	Nandi
15	Tatu city power company sez limited	30	Solar	Kiambu
22	Two Rivers Power Company Ltd	12	Solar and Diesel	Nairobi
23	KTDA-GURA	5.8	Hydro	Nyeri
	Total	**140.875**		

ANNEX 2: 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 3: 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 4: 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