MINISTRY OF ENERGY & PETROLEUM

LEAST COST POWER DEVELOPMENT PLAN

2024 - 2043

June 2024

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CAIDI :	Customer Average Interruption Duration Index
EAPP:	Eastern Africa Power Pool
EECA:	Energy Efficiency and Conservation Agency
ENS:	Energy Not Served
EPRA:	Energy & Petroleum Regulatory Authority
FOM:	Fixed operations and maintenance costs
GDC:	Geothermal Development Company
GDP:	Gross Domestic Product
GoK:	Government of Kenya
GT:	Gas Turbine
GWh:	Giga Watt hours
HFO:	Heavy Fuel Oil
HPP:	Hydro Power Plant
HSD:	High Speed Diesel
HVDC:	High Voltage, Direct Current
IAEA:	International Atomic Energy Agency
IEA:	International Energy Agency
IDC:	Interest During Construction
IPP:	Independent Power Producer
ISO:	Independent System Operator
KEEP:	Kenya Electricity Expansion Program
KEMP:	Kenya Energy Modernization Project

KenGen: Kenya Electricity Generating Company Limited

KES: Kenya Shilling

KETRACO: Kenya Electricity Transmission Company

KNEB: Kenya Nuclear Electricity Board (KNEB)

KPLC: Kenya Power & Lighting Company Limited

KWh: Kilo Watt hour

KVA: Kilo Volt Ampere

LCPDP: Least Cost Power Development Plan

LNG: Liquefied Natural Gas

LIPS OP/XP: Lahmeyer International Power System Short term Optimization and Long term Expansion

MAED: Model for Analysis of Energy Demand

MOE&P: Ministry of Energy & Petroleum

MSD: Medium Speed Diesel

MtCO2e Million Tonnes Carbon Dioxide Equivalent

MTP: Medium Term Plan

MW: Mega Watt

MWh Megawatt Hour(s)

MVA Mega Volt Ampere

NuPEA: Nuclear Power and Energy Agency

O & M Operation and Maintenance

PPA Power Purchase Agreement

PSA Power System Area

PSSE	Power System Simulation for Engineering
PGTMP	Power Generation and Transmission Masterplan 2012-2020
REA	Rural Electrification Authority
REP	Rural Electrification Programme
REREC	Rural Electrification and Renewable Energy Corporation
SAIFI	System Average Interruption Frequency Index
SAPP	Southern Africa Power Pool.
SPV	Special Purpose Vehicle
VOM	Variable Operation and Maintenance Costs

FOREWORD

Kenya is on the brink of a transformative decade, driven by rapid technological advancements characterized by dynamic economic and policy factors. The convergence of these developments is revolutionizing foundational sectors such as energy, leading to disruptions in major industries and profound societal impact. The choices made today will shape the future.

The continuing energy transition globally presents unparalleled opportunities for innovation and modernization. It influences the development and adoption of efficient technologies that reduce carbon emissions while considering flexibility in the electricity sector. This transformation requires a stable policy environment with long-term goals that ensure sustainable development in the evolving energy supply landscape and market. As Kenya integrates more renewable energy sources, innovative solutions are essential to facilitate the smooth adoption of variable energy sources, mainly wind and solar power. Critical factors include price signals from electricity markets, which incentivize the development of new solutions and the attendant dispatchable capacity for a stable power system.

The Government's Bottom-Up Economic Transformation Agenda (BETA) outlines key interventions in the power sector. These interventions include the construction of new high-voltage transmission lines and associated substations. BETA also focuses on meeting Kenya's emission reduction commitments through the facilitation of electric vehicle (EV) charging infrastructure in urban areas and along highways. In addition, incentives to encourage the adoption of electric mass transit systems by public service vehicles and commercial transporters are being enhanced. It is anticipated that financial and tax incentives will also be offered to encourage the conversion of fossil oil-powered vehicles to EVs.

In developing the Least Cost Power Development Plan (LCPDP) 2024-2043, Kenya aims to scale up renewable energy sources in line with the medium-term clean energy goal for 2030 and the long-term net-zero aspiration for 2050. This plan also aims to address emerging challenges such as intermittency by deploying storage and hybrid projects to support grid stability and supply capacity. Strengthening the grid, which requires significant investment in both distribution and transmission, is a priority and essential for a robust and modernized power supply infrastructure. Key focus areas include harnessing geothermal power, improving last-mile access to electricity, reducing reliance on fossil fuel power plants, addressing regulatory lag to create a conducive environment for investors, and enhancing affordability and reliability for end users. A vital aspect of this effort will be the alignment of generation projects with the Energy and Petroleum Regulatory Authority's benchmark generation tariffs as gazetted in the latest notice of April 17, 2024. This alignment aims to enhance the affordability of power for end users by ensuring that generation tariffs remain competitive and transparent.

Thus, the LCPDP 2024-2043 is a crucial step in Kenya's journey toward a sustainable and resilient energy future. This plan underscores Kenya's commitment to scaling up renewable energy sources and addressing intermittency challenges through the strategic deployment of storage and hybrid projects. The plan presents Kenya's roadmap towards achieving a reliable, affordable, and environmentally friendly energy system.

DAVIS CHIRCHIR, EGH

Cabinet Secretary

ACKNOWLEDGEMENT

This update of Kenya's Least Cost Power Development Plan (LCPDP) was prepared by the Technical Committee of the power sector which comprises staff drawn from the Ministry of Energy and Petroleum, energy sector agencies, and the Energy and Petroleum Regulatory Authority. The report is intended to provide guidance for decision-making in the development of power generation and transmission capacity to enable the country meet its projected electricity demand in the medium to long term.

The Kenya Power and Lighting Company PLC (KPLC), the national electricity off-taker, distributor, and retailer, was responsible for coordinating the preparation of this report. An Oversight Committee chaired by the Chief Executive Officer of KPLC ensures quality assurance and overall leadership in this process. The Oversight Committee consists of senior management representatives from power sector organizations, representatives of private sector and other public institutions including Vision 2030 secretariat and the National Treasury, State Department of Planning.

We commend the Technical Committee and the Oversight Committee of the LCPDP for their unwavering commitment to the process. The various power sector Boards and representatives of the Ministry of Energy and Petroleum, Kenya Power, Geothermal Development Corporation (GDC), Kenya Electricity Transmission Company (KETRACO), Kenya Electricity Generation Company (KenGen), Nuclear Power and Energy Agency (NuPEA) and Rural Electrification and Renewable Energy Corporation (REREC) are also acknowledged for their contribution and guidance in this process.

The overall policy direction and guidance for the medium-term vision as espoused in the Bottom-Up Economic Transformation Agenda (BETA) was provided by the Cabinet Secretary through the Principal Secretary State Department for Energy. It is envisaged that the issues articulated in this report will be effectively implemented by the parties mentioned in the report, with continuous monitoring of results to ensure minimal deviation from the plans outlined herein and their implementation schedules.

EXECUTIVE SUMMARY

Part II section 5-8 of the Energy Act 2019 mandates the Cabinet Secretary responsible for Energy to prepare an integrated National Energy Plan (INEP). This function has not been fully actualized yet, however, the preparation of the electricity plan is realized through Biennial preparation of the 20 year Least Cost Power Development Plan (LCPDP) and the 5-year Medium Term Power Development Plan in alternate years. Currently, KPLC is coordinating this function while a multiagency technical team consisting of sector utilities, including the regulator, is responsible for the technical work. The sector periodically prepares a power master plan, which serves as a reference point for future updates of the LCPDP. The most recent power master plan was released in 2015 and is set to be updated from mid-2024.

This edition of the LCPDP is a long-term plan covering the period 2024 to 2043. It primarily builds up on the 2022-2041 plan but with special focus on emerging national and global issues. These include the adoption of clean cooking technologies, E-mobility and green hydrogen in the energy sector. These initiatives are part of the national strategies greenhouse gas emissions and enhancing climate change resilience in alignment with the Country's National Determined Contributions (NDC) target of reducing carbon emissions by 32% by 2030 and achieving carbon neutrality by 2050.

The plan outlines a demand forecast consisting of annualized peak and energy demand projections, as well as the recommended generation capacity expansion schedule alongside a corresponding transmission development plan. The electricity demand projection utilised a customized Excel tool based on the Model for Analysis of Energy Demand (MAED) principles. Generation modeling and optimization were conducted using the LahMeyer International Power System Short-Term Optimization and Long-term Expansion (LIPS-OP/XP) software, whereas the Power System Simulation for Engineering (PSS/E) software was employed for transmission planning.

Three demand forecast scenarios were developed based on projections of micro and macro-economic drivers, primarily demography, electrification and the national GDP. These scenarios are Reference, Low and the Vision forecast, which incorporates the country's economic flagship projects. Recommendations for capacity expansion are formulated based on the Reference demand forecast and average hydrology long term data. Additionally, sensitivity simulations were performed to assess the impact of a dry hydrology on the Reference case.

Improvements from the previous report

This report follows a similar structure as the previous one in terms of technical content, but specific additional considerations made in this report include:

a) Implementation of virtual demand applicable to battery storage (BESS) during off-peak hours. This is to allow for power storage considerations that have been modelled in the generation expansion plan and to give effect to ancillary services considerations articulated in the report to manage reliability and steam venting.
b) Consideration of emerging demand drivers of electric cooking and electric-mobility as areas of focus that could influence future demand trends.
c) Consideration of power system flexibility and stability through deliberate modeling of specific technologies including, pumped hydro and battery energy storage.
d) Future consideration of Modular Nuclear technology as part of the capacity mix for long term adequacy and diversity.
e) A section in the report is introduced to provide a strategy for project implementation, monitoring, and evaluation to enhance effectiveness.

Current status in the power sector

Over the past decade, there has been a significant increase in access to electricity from around 30% in 2012 to over 75% in 2023. The Bottom Up Economic Transformation Agenda (BETA) defines key intervention areas by the Government in the power sector. These include:

i. Construction of 2,930 Km of high voltage transmission lines and 37 associated substations;
ii. Rolling out electric vehicle (EV) charging infrastructure in all urban areas and along the highways and creating incentives for adoption of electric mass transit systems in all cities and towns; and
iii. Providing financial and tax incentives for public service vehicles and commercial transporters to convert to electric vehicles.

E-mobility and E-cooking are the key emerging technological adoptions in support of energy transition in the country both supporting efforts towards 100% renewable energy development in the country.

Over the last five years, installed generation capacity has expanded significantly by 18.3%, rising from 2,741MW in June 2019 to the current 3,243MW, inclusive of off-grid capacity. Between June 2019 and February 2024, the Peak demand increased from 1,882MW to 2,177MW, an average rise of 15.7%. The total effective capacity stands at 3,113MW with hydro, geothermal, and thermal sources providing the bulk of the power capacity. There are a further 92 licensed captive power generators in the country with a total installed capacity of 559.63MW.

Total length of the transmission and distribution network increased from 236,139 kilometers to 311,452 kilometers in the last 5 years attributed to the Government's continued effort to reinforce and expand the transmission and distribution network. The total transmission network (500kV, 400kV, 220kV, 132kV) as at June 2023 was 9,196 kilometers while the distribution network at the same period was 302,256 kilometers.

Demand forecast

Electricity demand forecasting takes into account different parameters that form the basis of applied assumptions. These include consumer behavior, population structure and dynamics, government priority projects and the national economic indicators. This demand forecast was conducted in 3 scenarios namely reference, Vision and low, each based on specific assumptions regarding the evolution of the related demand drivers. The main factors influencing demand growth that were considered in the forecast are Demographics, GDP growth and Vision 2030 Flagship projects. Additionally, future demand drivers such E-cooking, E-mobility and green hydrogen (ammonia) were also taken into consideration.

The Results of the forecast indicate that **peak demand** will grow from 2,170 MW in 2023 to 8,152MW, 13,495 MW and 4,996 MW in the Reference, Vision and Low scenarios respectively in 2043. **Energy purchased** is expected to grow at an annual average rate of 6.6% from 13,627GWh in 2023 to 48,499GWh in 2043 under the Reference scenario, and at a rate of 9.3% to 80,955GWh in 2043 in the Vision scenario. In the Low scenario, the energy purchased is expected to grow at an average rate of 4.0% to 29,742GWh over the same period.

Electricity sales on the other hand are expected to grow at an average rate of 6.1% from 10,488GWh in 2023 to 34,239GWh and 9.1% to 60,049GWh in 2043 in the Reference and Vision scenarios respectively. At the same time and based on the current connection trajectory of an average of 300,000 annually, **universal electricity access** is projected to be achieved by the year 2031 in the Reference scenario. However, in the vision scenario, accelerated connections at the rate of 500,000 annual connections could attain universal connectivity by 2028.

Generation Expansion Planning

The country is currently focused on increasing the share of renewable energy in the generation mix as part of its transition towards a green economy. Kenya has a range of renewable energy resources available including solar, hydro, wind, biomass and geothermal resources. The Government has given priority to the development of geothermal, wind and solar energy plants as well as solar-fed mini-grids for rural electrification. This generation expansion plan considered three demand scenarios: Reference, Vision, and Low with sensitivity analyses performed within the context of the reference demand and dry hydrology. The plan simulated both committed and potential projects taking into account the supply and demand balance.

To evaluate the various technologies necessary for the expansion planning of the system, a screening curve analysis was conducted. This technique assesses the competitiveness of different technologies at various utilization levels, based on their capital investment and variable costs at different discount factors. Accordingly, screening curves were prepared for selected candidate generation technologies that were considered in the plan to meet demand requirements.

A ranking was performed to compare the cost of generation among base load plants and peak power plants, considering their respective normal operating capacity factors and applying discount rates of 12.8% and 8%. The results of the ranking based on the screening curve data indicate that imports, geothermal and nuclear are the most appropriate electricity generation options at higher capacity factors. Solar PV is cheapest option at lower utilization levels of about 20%. For peaking duty, power imports from UETCL is the most attractive option, followed by MSDs. Sensitivity analysis shows that the large hydro become more attractive at lower discount

The expansion plan results are as follows: In the Reference case scenario, the total interconnected effective capacity 12,800 MW by 2043. Geothermal capacity is expected to contribute the most to the total firm capacity over the planning period. There will also be significant contribution from Battery Energy Storage Systems (BESS) and pumped hydro storage for grid stability by 2043. Notably, all diesel and gasoil power plants are expected to be decommissioned by 2035. In line with the Government target of achieving 100% clean energy by 2030, renewable sources, nuclear and imports will provide the required electricity generation mix by 2043, representing a full transition to clean energy.

The issue of low hydrology, which has historically been a challenge leading to load management, is well addressed in this plan. It is envisaged that geothermal production will be ramped up during this period with additional support from battery storage and the anticipated introduction of nuclear capacity as early as 2033 in the Vision case scenario.

Impact of the Expansion Plan on Climate Change

The plan proposes a significant reduction in the use of fossil fuels in both the medium and long term towards achieving the NDC emissions target of 31.14MtCO2e from electricity generation by 2030. By increasing the use of renewable energy sources, greenhouse gas (GHG) emissions are expected to remain below 0.5 MtCO2e across all scenarios outlined in the plan period.

Investment Costs of the Interconnected System and Evolution of Tariffs

The overall system cost is projected to increase from KSh. 234.9 billion in 2024 to KSh. 488 billion in 2033 in the reference expansion case. The expansion plan projects the end user retail tariff in nominal terms to evolve from KSh. 24.61/kWh in 2024 to KSh. 26.76/kWh in 2033. In real terms, the end user tariff decreases from KSh. 24.61/kWh to KSh. 17.66/kWh. This scenario could however be affected by low hydrology when more expensive power plants are deployed, hence increasing the resulting end user tariffs.

Transmission Planning

Outputs from demand forecast and generation expansion plan were used as an input in transmission planning. Power System Simulation for Engineering (PSS/E) software tool was used in modelling and analysis. The network model was simulated with analysis carried out against performance indices stipulated in the Kenya National Grid Code. The prioritized order of projects and investments required was then determined to generate the transmission system plan.

The simulations revealed that the 2023 power system, which serves as the base case in this study, is characterized by transmission constraints. Under normal system operating conditions, voltage violations (low voltages) were observed at nine 132kV substations particularly in the South Nyanza, Central Rift and North Rift Regions. Network overloads were also noted on 132kV Muhoroni-Chemosit (142.1%) and Kisumu-Muhoroni (123.4%) lines. During contingency conditions (N-1), more voltage and network loading violations were observed. Additionally, there were instances of loss of loads particularly in network sections served by radial lines or single transformers. The estimated instantaneous power losses at peak demand and annual energy losses at the transmission level (exclusive of 66kV network) are 96.96MW and

488.41GWh respectively. These power and energy losses account for approximately 4.47% and 3.58 % of the total injection from generation system respectively.

Based on these findings, the following measures were deemed necessary and urgent:

i. Construction of the 69km Ndhiwa-Sondu 132kV line to ensure adequate transmission capacity and resolve voltage issues in South Nyanza and Central Rift Region

ii. Construction of Narok-Bomet 132kV line to enhance supply reliability by providing alternative supply route to South Nyanza and parts of Central Rift Region

iii. Completion and commissioning of Kitale 220/132kV substation and Turkwel-Ortum-Kitale 220kV transmission line to enhance system reliability by providing alternative route for Turkwel generation evacuation

iv. Reconstruction and upgrade of Rabai-Kilifi 132 kV line to double circuit to enhance supply reliability and reduce network losses

v. Commissioning of Mariakani 400/2220kV substation to facilitate operation of Isinya – Mariakani lines at 400 kV to enhance grid reliability in coast region

vi. Commissioning of Kimuka 220/66kV 2X200MVA Substation and construction of the proposed 66kV feed-outs from Kimuka Substation to optimize network loading and reduce energy losses.

vii. Termination of Olkaria-Lessos-Kibos 220kV line at Lessos substation to enable operation of Olkaria-Lessos-Kibos lines as designed and therefore improve grid reliability.

viii. Completion of Isiolo-Nanyuki 132kV line to complete the Mt. Kenya Ring to enhance grid reliability and reduce network losses.

Summary of Recommendations

The following are the key conclusions and recommendations from the demand forecasting, generation and transmission planning:

i. Accelerate the implementation of flagship projects earmarked for economic growth, with the support of the government and all relevant stakeholders. Factor in key electricity demand drivers identified in this plan such as the electrification of the standard gauge railway, light rail and development of key industrial parks and economic zones.

ii. The Government to enhance incentives to support clean energy consumption and transition including adoption of EVs and e-cooking. Such incentives may be in the form of tax waivers to allow for competitive costs of electricity compared to alternatives such as diesel, kerosene and wood fuel.

iii. Increase investment in power system upgrade and reinforcement to improve system reliability and address weaknesses along the value chain that have increased system losses and constrained demand. High energy losses in the system have a bearing on end-user tariffs which together with system reliability issues encourage both captive power consumption and grid defection.

iv. Fast-track negotiations for 150MW under the regional power trade initiatives for peaking capacity and provision of system reserves required based on the reference demand scenario.

v. Process required approvals for all generation projects recommended in this plan starting with those that have had their PPAs renegotiated, and facilitate their commissioning and integration to the national power grid to avert supply shortfalls.

vi. Expedite development of 150MW BESS by 2026 through KenGen (100MW) and IPPs (50MW), to provide ancillary services, supplement peaking capacity, reduce venting of geothermal steam, enhance integration of variable renewables and support further greening of the grid.

vii. Fast-track approvals, PPA negotiations and issuance of support instruments for power generation projects scheduled in the medium term plan to avoid capacity shortfalls.

viii. The Ministry of Energy and Petroleum to undertake a study on adoption of flexible geothermal technologies in future projects to increase system flexibility, and geothermal energy uptake while managing venting of steam during low demand periods.

ix. Negotiate lower power purchase tariffs for the variable renewable energy projects in the medium term, considering that the costs of solar and wind power technologies have been declining in the recent past, to mitigate increase in electricity cost.

x. Finalize and implement the renewable energy auction policy to facilitate competition in the procurement of VRE projects in accordance with the policy, to enable achievement of lower generation tariffs.

xi. New capacity from variable renewable energy projects without PPA to be transitioned to the Renewable Energy Auctions program except small capacity projects of less than 20MW from small hydro, biomass, and biogas sources.

xii. Facilitate early approval of generation projects with long lead times, scheduled beyond the medium term in the LCPDP, to ensure they are commissioned in the long term as scheduled. These include large hydro, pumped storage and nuclear power plants.

xiii. Solar PV and wind energy power projects with storage scheduled in LCPDP should include sufficient storage capacity to resolve intermittency issues and provide at least one hour of peaking capacity at rated plant capacity to facilitate energy shifting, manage the risk of energy curtailment, and help meet peak power demand.

xiv. Construction of the 69km Ndhiwa-Sondu 132kV line to resolve voltage issues in South Nyanza and Central Rift Region and overloading of the Kisumu-Muhoroni and Muhoroni-Chemosit 132kV lines. It it will also facilitate decommissioning of the GTs in Muhoroni without adverse impact to the system.

xv. Construction of Narok-Bomet 132kV line to improve reliability by providing alternative route to supply South Nyanza and Central Rift Region.

xvi. Completion of 220/132kV Kitale substation on Turkwel-Ortum-Kitale 220kV route. This will provide an alternative evacuation route for Turkwel Hydro generation to North Rift and Western Kenya and improve the overall system security.

xvii. Reconstruction and upgrade of Rabai-Kilifi 132 kV line to double circuit to provide adequate supply capacity in North Coast sub-region, improve supply reliability and reduce network losses.

xviii. Commissioning of Mariakani 400/220kV substation to facilitate operation of Isinya-Mariakani system at 400kV to enable N-1 redundancy criteria for Coast region.

xix. Commissioning of Kimuka 220/66kV 2X200MVA Substation and construction of the proposed 66kV feed-outs from Kimuka Substation to reduce losses, improve voltages and security of supply on the 66kV network served from Nairobi North Substation and on Magadi feeder. This will also de-load the Suswa-Nairobi North 220kV lines.

xx. Termination of Olkaria-Lessos-Kibos 220kV line at Lessos to enable operation of Olkaria-Lessos-Kibos lines as designed. This will facilitate management of grid voltage and improve grid security by provide a complete parallel route to the North Rift and West Kenya load centers.

xxi. Installation/uprating of the 132/11kV transformer at Garissa Substation to provide adequate capacity.

xxii. Development of transmission line rings for areas currently served by radial networks especially where there is loss of substantial load upon occurrence of a contingency. Some of the projects expected to close key rings include Isiolo-Nanyuki 132kV line, Kamburu-Embu-Thika 220kV line, Kibos-Bondo-Rangala 132 Kv, Dongo Kund-Kibuyuni 220 kV, Githambo-Othaya –Kiganjo 132 kV, Kilgoris –Masaba 132kV, Machakos –Mwala 132kV and Weru-Kilifi 220kV line.

xxiii. Install additional transformers at Kibos, Bomet, Kyeni, Narok, Mwingi, Kitui and Wote substations among other with single transformers to facilitate compliance with n-1 reliability criteria.

xxiv. Construct Olkaria V-Olkaria 1AU double circuit line as an alternative evacuation path for Olkaria IV and Olkaria V geothermal power plants generation to ensure N-1 reliability criteria in Olkaria geothermal complex

xxv. Uprating of the Chemosit 132/33kV transformers from 23MVA to 45MVA.

xxvi. Fast-track construction of the Menengai-Olkalao-Rumuruti 132kV line and the associated substations to provide alternative evacuation path for Menengai geothermal field.

xxvii. Construct a 220Kv line from the proposed Thika 400/220 kV substation to Thika road 220/66 kV substation to establish alternative supply to the Nairobi North- Thika Road –Dandora 220kV corridor from the 400kV to improve security of supply

xxviii. Fast track installation of phase-shifting transformers on Nairobi North 220kV lines at Suswa to enhance grid reliability.

1 INTRODUCTION

Kenya's power sector has gone through a transformative experience over the last decade, supported by sustained investments and innovative and exploratory initiatives in the midst of situational complexities. The country maintains an open approach, eager to embrace change and emerging technologies, and adaptive to new business models. Kenya keeps abreast at the global arena, with underlying enthusiasm that catalyses building of strong bonds and partnerships across the divide. These attributes have often paid off, with outcomes from the preceding strategies laying a firm foundation to build on in the subsequent development cycles. For instance, restructuring of the power sector in the 1990s, outsourcing of electrification works, driving intensified electricity access across the country and committing substantive investments to geothermal development are among the key change drivers that have characterized Kenya since the onset of the new millennium. In the recent past, the country integrated a large proportion of variable renewable energy sources, largely developed through the public private partnership (PPP) model, placing Kenya high among peers and globally, as a leading light in the renewable energy space. Such are the moves that have collectively supported rapid access to clean energy and life changing socio-economic development in the country.

The Country's energy sector is expected to remain vibrant and dynamic in the coming years, chaperoned by emerging ideas and top themes shaping the global energy dialogue. Among them are energy transition, adoption of e-mobility, green hydrogen and energy storage. In addition, Kenya is determined to further the clean energy and clean cooking agendas in line with commitments made under the national determined contributions on climate change and safeguarding of human health and the environment. These prevailing discussions are the next likely frontiers of business growth and transformation into the future. Besides, the high global awareness with the advent of internet of things and changing consumer behaviour and evolving choices and markets, change is ultimately the constant characteristic going forward. Thus, it is no longer uncommon to see reversed roles in the service sector, with customers exerting more influence in the business landscape. This calls for regular self-evaluation in the market, and flexibility by the parties with a give-and-take interplay and adjustments.

Against this backdrop, updating of the Least Cost Power Development Plan (LCPDP) is necessary and timely. This plan covers the period 2024-2043, and is subsequent to a previous similar update released in mid-2022. The update aims to comprehensively capture the government's vision, renewed aspirations, pertinent initiatives and plans for the medium-term period ending 2028, and the goals for the period after, to the long-term relating to supply of adequate, reliable and affordable energy in a sustainable way.

The update comes soon after the Africa Climate Summit held in Kenya and attended by African leaders and opinion shapers at the global stage. During the summit, Kenya reiterated its commitment towards achievement of climate change goals, its journey towards 100% renewable energy and net-zero emissions. This aligns with the summit's African Leaders Nairobi Declaration on Climate Change and Call to Action, which inter alia, calls for accelerating of all efforts to reduce emissions in line with the Paris Agreement goals and climate-positive investments that facilitate a growth trajectory anchored in the industries poised to transform our planet and enable African countries to achieve stable middle-income status by 2050.

2 STATUS OF THE POWER SECTOR IN KENYA

2.1 Background

The power sector in Kenya is in a state of transition and is considered core in the Government's Energy Sector transition agenda. With the World currently consolidating its efforts towards climate change mitigation and building resilience towards negative impacts that come with it, Kenya is acutely attuned to the imperatives of this agenda and is fully demonstrating steadfast commitment to its realization.

E-mobility and E-cooking are among key emerging energy markets for countries in transition, supporting efforts towards 100% renewable energy development and adoption in the country. The resolve to reduce carbon emissions in the country by 32% by 2030, and achieving carbon neutrality by 2050, are heavily supported by the energy sector. The policy and legislative framework have consistently been reviewed to create and sustain an enabling environment to support interventions in the sector. To this end, the recent enactment of the Energy Act 2019 has come with significant institutional and operational reforms to align the sector with the country's energy needs. The Act introduced vital revisions to the core mandate of key sector institutions. The revisions were strategically designed to align the roles and responsibilities of these institutions with the evolving needs and the regulatory framework established by Kenya's Constitution of 2010. The legislative milestone reflects a commitment to adapt and modernize the energy sector to ensure it remains in harmony with Kenya's evolving socio-economic and constitutional landscape.

2.2 Sector Structure

The sector structure as per the Energy Act, 2019 is represented in Power Sector Institutional StructureFigure 2-1.

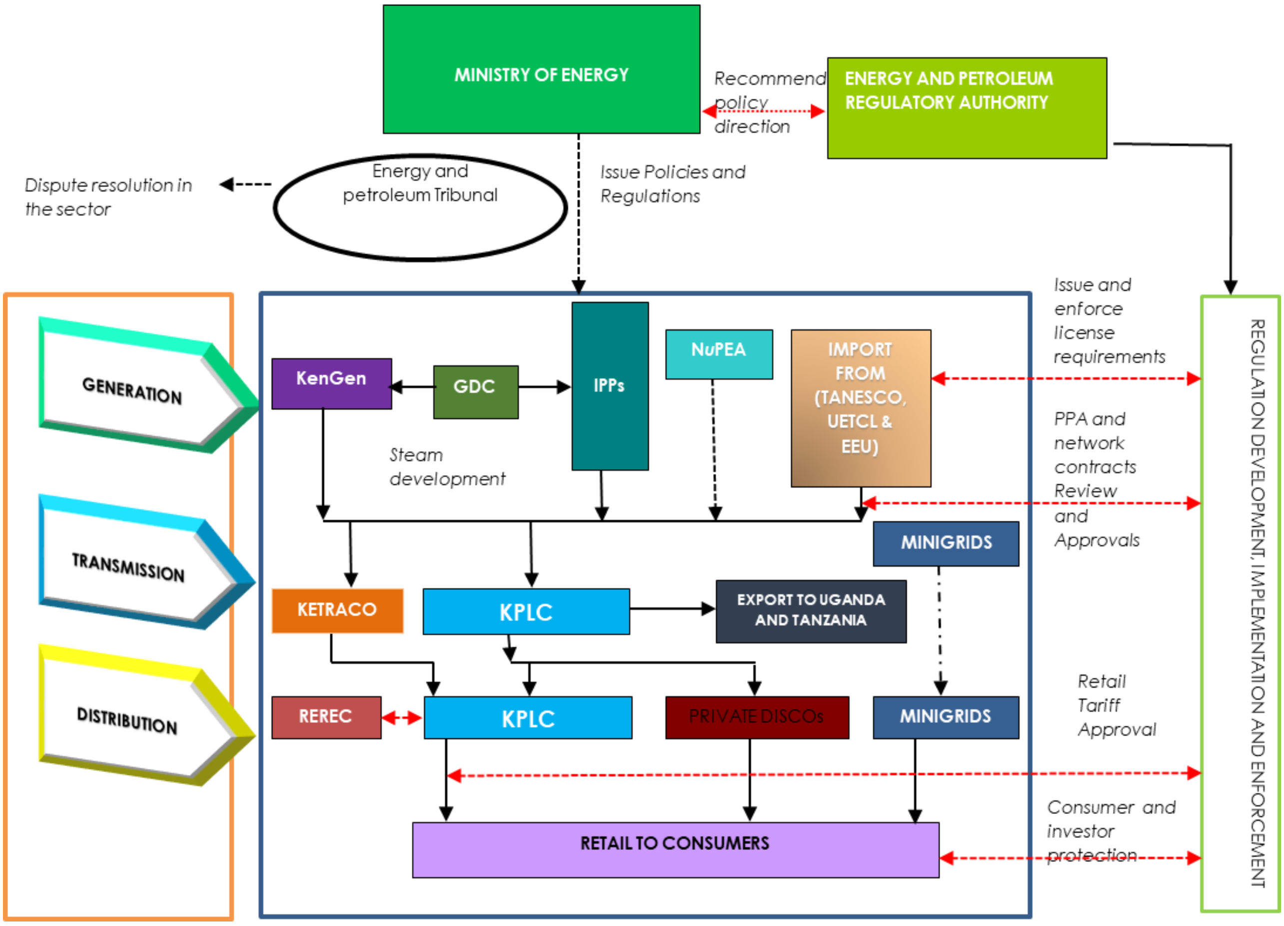


Figure 2-1: Power Sector Institutional Structure

The following section provides an overview of the key responsibilities of the energy sector organizations and other major stakeholders.

The Ministry of Energy and Petroleum (MOEP) is charged with the mandate to develop and implement policies that create an enabling environment for efficient operation and development of Kenya's energy sector. Additionally, it sets the strategic direction to facilitate the growth of the sector while providing long term vision for all sector players.

The Energy and Petroleum Regulatory Authority (EPRA) is mandated to guide and regulate technical and economic operations of the entire energy and petroleum sectors. It exists to protect interests of the consumer, investor and other stakeholders by enforcing the Energy Act 2019 and the Petroleum Act 2019.

Energy & Petroleum Tribunal is responsible for settling disputes and appeals in the energy sector in accordance with the Constitution of Kenya 2010, Energy Act 2019 and any other relevant law.

The Kenya Power and Lighting Company Plc (KPLC) has the mandate of transmission, distribution and retailing of electricity in the country. It is currently the sole power in Kenya, buying bulk energy from power producers based on negotiated Power Purchase Agreements (PPAs) for onward supply to consumers. KPLC is also coordinating electricity planning in the sector through the LCPDP.

Rural Electrification and Renewable Energy Corporation (REREC) is mandated to lead development of renewable energy resources except geothermal and large hydropower, in addition to its role of implementing rural electrification projects.

The Kenya Electricity Generating Company Plc (KenGen) is a public institution that has the mandate of generating power and is the leading generator in the country. The company utilizes various sources of energy to generate electricity ranging from hydro, geothermal, thermal and wind.

Kenya Electricity Transmission Company (KETRACO) is mandated to plan, design, construct, own, operate and maintain high voltage (132kV and above) electricity transmission lines. In addition, KETRACO has been designated the national power System Operator as well as the sole Transmission Operator as per provisions of the Energy Act, 2019.

Nuclear Power and Energy Agency (NuPEA) is mandated to promote the development of nuclear electricity generation in Kenya and carry out research, development and dissemination activities of energy related research findings.

Geothermal Development Company (GDC) is a wholly Government-owned Company with the mandate of derisking geothermal sites in the country through investing in exploration and appraisal and production drilling of geothermal steam fields. It is also expected to manage proven steam fields.

Independent Power Producers (IPPs) are private investors in the power sector involved in power generation.

Distribution Companies (DISCOs) are companies envisaged under the Energy Act 2019 with the role of purchase of power in bulk for the purpose of distribution to designated areas as may be approved by the regulator.

Mini-grids Generators – are involved in off-grid generation, storage and distribution networks that supply electricity to localized groups of customers not covered by the interconnected national power grid as approved by EPRA.

Solar Home Systems Companies –Are suppliers of solar home systems for households mainly those located far from the grid. They play a significant role in the attainment of universal access to electricity.

2.3 Policy Context

The energy sector plays a pivotal role in fostering socio-economic development by facilitating the provision of secure, affordable, and reliable energy at the least cost geared to meet both national and county requirements while protecting and conserving the environment. Over the past decade, there has been a remarkable rise in access to electricity from around 30% in 2012 to over 75% in 2023. This success is attributable to government-led initiatives, particularly spearheaded through specialized projects namely the Last Mile Electricity Connectivity Project, Global Partnership on Output-Based Aid (GPOBA) and the augmentation of street lighting infrastructure. These projects are social-economic in nature designed to connect as many consumers as possible to the grid and also to provide lighting and power services to urban areas particularly informal settlements.

The Bottom-Up Economic Transformation Agenda (BETA) has identified activities and sectors that have a strong impact and linkages in the economy. These include Agricultural Transformation, Micro, Small and Medium Enterprise (MSME), Housing and Settlement, Healthcare, Digital Superhighway and Creative Industry. In addition, BETA defines key intervention areas by the Government in the power sector including Construction of 2,930Km of high voltage transmission lines and 37 associated substations; meeting Kenya's emission reduction commitments; rolling out electric vehicle (EV) charging infrastructure in all urban areas and along the highways and creating incentives for adoption of electric mass transit systems in all cities and towns; and to provide financial and tax incentives for public service vehicles and commercial transporters to convert to electric vehicles.

In Article 5 of the Energy Act, 2019, provision is made for development and implementation of the Integrated National Energy Plan (INEP) covering coal, renewable energy and electricity. The INEP framework rollout is underway but, in the meantime, preparation of medium and long term Least Cost Power Development Plans continues.

The LCPDP process takes into account existing Government policies and guidelines to account for macroeconomic changes and national priorities among other factors, when carrying out electricity demand forecasting, generation and transmission planning. In addition, other national plans such as Kenya Vision 2030, Medium Term Plans and National Spatial Plan are considered.

The LCPDP Technical Committee reviewed the status of committed generation projects and scheduled retirements vis-à-vis the forecast demand and associated risks. It is anticipated that the Ministry of Energy and Petroleum will finalize the review of the National Energy Policy of 2018 to align it to the Energy Act 2019 with more emphasis on the following;

i. Further improvements of the policy to provide clear strategies and initiatives that will support exploitation of geothermal resources and the subsequent transformation to geothermal power.
ii. Ensuring that the proposed Consolidated Energy Fund is aligned to optimal energy requirements in the country.
iii. Incorporation of the recommendations of the Power Market Study regarding transition to open access which would lead to reduction of power supply interruptions and improvement in the quality of service. Also incorporation of recommendations of other studies such as battery energy storage among others.
iv. Incorporating more initiatives to cover all wayleave and compensation related issues to reduce risk of delays in project implementation;
v. Ensuring that the policy is updated to be consistent with the Energy Act; and
vi. Ensuring that the updated policy is well disseminated to create awareness on what the Government is proposing about energy planning and particularly the inter-linkages with Counties' energy plans.

The sector is required to continually address emerging policy challenges and enhance the effectiveness of the policy implementation tools to make them more responsive and efficient.

2.4 Reforms in the Power Sector

The Energy Act, 2019 has played a pivotal role in enabling transformation and enhancements aimed at improving service delivery within the power sector. These transformational interventions include:

i. Establishment of an inter-ministerial Renewable Energy Resources Advisory Committee (RERAC).
ii. KPLC to be responsible for procurement of power including from projects under the Feed in Tariff (FIT) Policy and negotiation of PPAs
iii. All new capacity of variable renewable energy to be procured through the Renewable Energy Auctions policy except for small capacity projects of less than 20MW from small hydro, biomass, and biogas sources that would be managed under the FIT policy.
iv. Reorganization of energy planning by creating an Integrated National Energy Plan framework consisting of coal, electricity and renewable energy plans that incorporate County Energy Plans.
v. A comprehensive review of the regulatory framework by reviewing existing and introducing new regulations aligned to the Energy Act 2019
vi. Providing for open access to the transmission and distribution networks, with EPRA mandated to designate a System Operator and encourage regional interconnections to enhance regional electricity trade. KETRACO has since been designated by EPRA as the System Operator.
vii. Establishment of the Energy Efficiency and Conservation Agency (EECA) as a fully-fledged national public entity to promote energy efficiency and conservation.
viii. Provision for county governments to set aside suitable land for development of energy infrastructure including but not limited to projects recommended in the Integrated National Energy Plans.
ix. Provision for national government to facilitate the development of a Resettlement Action Plan Framework for energy related projects, including livelihood restoration in the event of physical displacement of communities
x. Provision for development of a framework on the functional devolution of roles between the National government and County governments in consultation with all stakeholders to avoid overlap of functions.
xi. Provision for viable financing options from local and international sources for cost effective utilization of all its energy resources, to maintain a competitive fiscal investment climate in the country.

2.5 Regional Integration

EAPP Countries are becoming increasingly interconnected with significant investments in transmission and generation projects at national and regional levels underway. Kenya is presently connected asynchronously to Ethiopia via an HVDC link. The future 400kV Lessos – Tororo line with a capacity of 1600MW will strengthen the synchronized Kenya – Uganda network on completion, while the 400kV Isinya-Namanga Arusha transmission line which is under implementation will synchronize the Kenya and Tanzania power grids. Further, bidirectional energy transactions with SAPP will be enabled by the Kenya - Tanzania – Zambia interconnection. Benefits of national grids interconnections will be more evident when the share of intermittent renewable energy resources increases. It is also noteworthy that there have been power exchanges at consumption (distribution) level within border towns of the eastern African region. Transactions exist between Kenya and Ethiopia, Uganda and to a lesser extent Tanzania. EAPP is coordinating development of market rules and a trading platform, the soft infrastructure needed to operationalize a regional day ahead market with a target Go Live date the Mid 2025.

2.6 Existing Power System

2.6.1 Generation Capacity

Over the last five years, installed generation capacity has expanded significantly, rising from 2,741MW in June 2019 to 3,243MW in June 2023 inclusive of off-grid capacity, equivalent to a 18.3% increase over the period. Between June 2018 and February 2024, the Peak demand increased from 1,882MW to 2,177MW, an average rise of 15.7%.

KenGen, the largest power generator in the country, accounts for 1,685MW or 54.1% of the effective generation capacity. Independent Power Producers (IPPs) constitute 1,152MW (37%) of the effective capacity, while Off-grid generation under the Government's Rural Electrification Programme (REP) implemented under REREC accounts for about 0.8% and imports 6.4%. The total effective capacity stands at 3,113MW with hydro, geothermal, and thermal sources providing the bulk of the power as depicted in Table 2-1.

Table 2-1: Installed and Effective Capacity

	Installed	Effective*/ Contracted	% (effective)	% (Installed)
Hydro	838.6	809.8	26.50%	25.86%
Geothermal	940.0	876.1	28.67%	28.99%

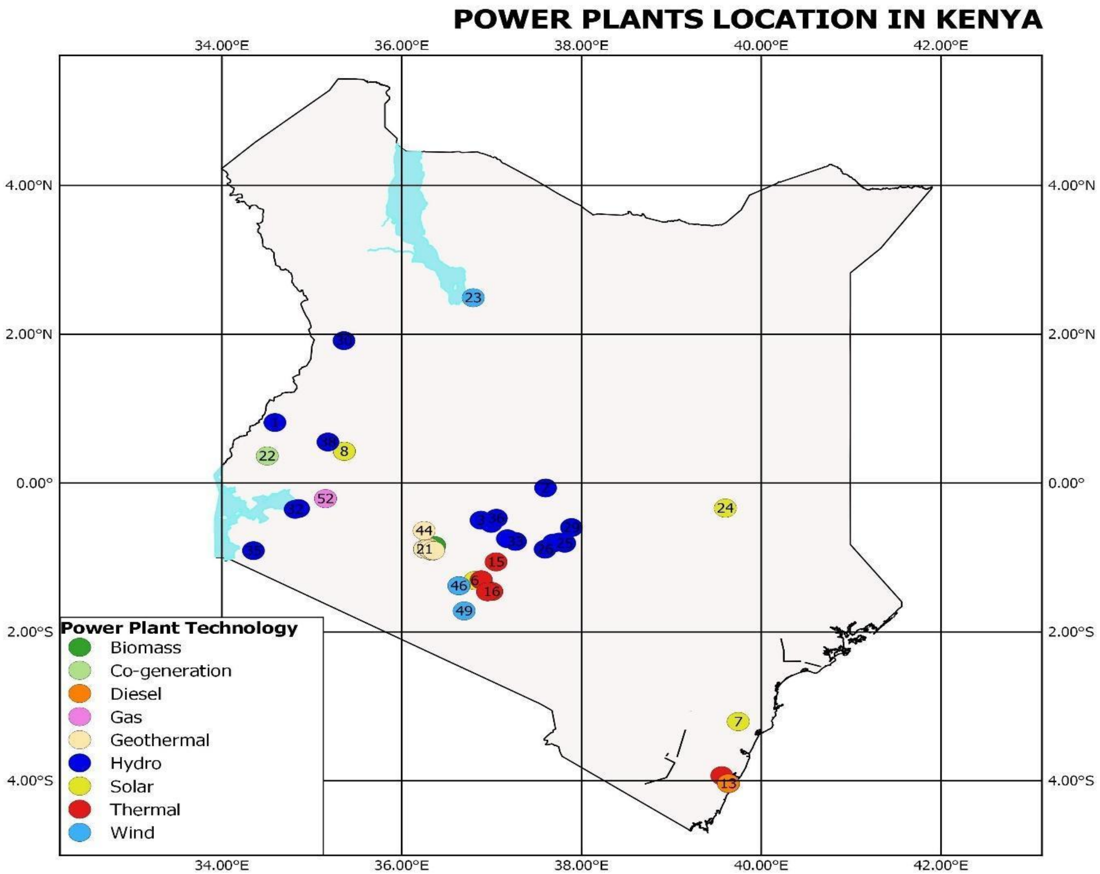
	Installed	Effective*/ Contracted	% (effective)	% (Installed)
Thermal (MSD)	512.8	506.4	16.57%	15.81%
Thermal (GT)	60.0	0.0	0.00%	1.85%
Wind	435.5	425.5	13.92%	13.43%
Biomass	2.0	2.0	0.07%	0.06%
Solar	210.3	210.3	6.88%	6.48%
Import	200	200	6.54%	6.17%
Interconnected System	**3,199**	**3,030**	**99.16%**	**98.7%**
Off grid thermal	40.96	24.15	0.79%	1.26%
Off-grid Solar	2.26	1.65	0.05%	0.07%
Off-grid Wind	0.55	0.00	0.00%	0.02%
Total Off-grid	**43.8**	**25.8**	**0.84%**	**1.35%**
Total Capacity MW	**3,243**	**3,056**	**100.0%**	**100.0%**

Source: Kenya Power

Additionally, there are 92 licensed captive power generators with a total installed capacity of 559.63MW. The technologies used for captive power generation include solar, hydro, diesel, biogas and biomass.

2.6.2 Power Plants Location in Kenya

Geothermal Power Plants are located within the rich Olkaria belt and Menengai crater in the Rift Valley, with main hydro plants primarily in the Tana Cascade. Over the recent years, the Country has diversified its energy mix by including solar and adding two large wind power plants. The wind farms are located in Kipeto and Ngong hills in Kajiado county, and Loiyangalani in Marsabit county. Solar PV plants are located in Garissa, Malindi and Eldoret. Figure 2-2 shows locations of power plants around the country while Annex A gives detailed description of the existing power plants.



S/N	PROJECT NA	INSTALLED	Technology	Eastings	Northings
1	GenPro, Shp	5	Hydro	0.812663	34.588565
2	Imenti Tea Factory, Shp	0.3	Hydro	-0.066806	37.599628
3	KTDA Gura	2	Hydro	-0.500292	36.881208
4	KTDA Ltd, River Chania	0.5	Hydro		
5	Power Technologies (Gikira Mini Hydro)	0.514	Hydro	-0.542846	36.994554
6	Strathmore University	0.25	Solar	-1.310165	36.813093
7	Malindi	40	Solar	-3.20709	39.7442
8	Selenkei	40	Solar	0.42597	35.3603
9	Eldosol	40	Solar	0.42597	35.3603
10	Biojoule Kenya Limited	2	Biomass	-0.842524	36.365392
11	Iberafrica I	56.346	Thermal	-1.30202	36.884354
12	Iberafrica II	52.5	Thermal	-1.30202	36.884354
13	Tsavo	74	Thermal	-4.039225	39.634028
14	Rabai Power	90	Thermal	-3.934151	39.560255
15	Thika Power	87	Thermal	-1.06094	37.04883
16	Gulf Power	80.32	Thermal	-1.45831	37.002262
17	Triumph Diesel	83	Thermal	-1.462457	36.953333
18	Orpower 4 Inc. I	63.8	Geothermal	-0.888644	36.253612
19	Orpower 4 Inc. II	39.6	Geothermal	-0.888644	36.253612
20	Orpower 4 Inc. III	17.6	Geothermal	-0.888644	36.253612
21	Orpower 4 Inc. IV	29	Geothermal	-0.888644	36.253612
22	Mumias Sugar Company Ltd.	26	Co-generation	0.362742	34.502822
23	Lake Turkana Wind Power	310	Wind	2.489546	36.795395
24	REA Garissa Solar	50	Solar	-0.338022	39.600022
25	Kindaruma	72	Hydro	-0.809966	37.812768
26	Masinga	40	Hydro	-0.889582	37.594499
27	Kamburu	94.2	Hydro	-0.806419	37.686117
28	Gitaru	225	Hydro	-0.794361	37.752322
29	Kiambere	168	Hydro	-0.599185	37.8884
30	Turkwel	106	Hydro	1.912874	35.356729
31	Sondu	60	Hydro	-0.343206	34.851267
32	Sangoro	21	Hydro	-0.353945	34.813128
33	Tana	20	Hydro	-0.785475	37.265444
34	Wanji	7.4	Hydro	-0.749279	37.174731
35	Gogo	2	Hydro	-0.909369	34.349244
36	Sagana	1.5	Hydro	-0.474453	37.052851
37	Mesco	0.433	Hydro		
38	Sosiani	0.4	Hydro	0.550432	35.178033
39	Olkaria 1	45	Geothermal	-0.893046	36.30903
40	Olkaria II	105	Geothermal	-0.864012	36.299186
41	Olkaria IV	150	Geothermal	-0.917744	36.334583
42	Olkaria V	165.4	Geothermal	-0.907081	36.321013
43	Olkaria 1 Unit 4&5	150	Geothermal	-0.887333	36.306947
44	Eburru Wellheads	2.4	Geothermal	-0.641099	36.248754
45	WellHeads	81.1	Geothermal	-0.908107	36.353186
46	Ngong 1 Phase I	5.1	Wind	-1.381111	36.635556
47	Ngong I Phase II	6.8	Wind	-1.381111	36.635556
48	Ngong II	13.6	Wind	-1.381111	36.635556
49	Kipeto I	100	Wind	-1.719361	36.69453
50	Kipevu 1 Diesel	73.5	Diesel	-4.03997	39.635604
51	Kipevu III Diesel	120	Diesel	-4.037753	39.632967
52	Gas Turbines (GT)	60	Gas	-0.210822	35.151119

Figure 2-2: Power Plants location in Kenya

2.6.3 Transmission and distribution

The total length of the transmission and distribution network increased from 236,139 kilometers to 311,452 kilometers between FY 2018/19 and FY 2022/23. This growth is attributed to the Government's continued effort to reinforce and expand the transmission and distribution network to increase electricity access, enhance system reliability and improve the quality of power. Table 2-2 provides a breakdown of lengths for different voltage levels over the past five years.

In the fiscal year 2022/23, a 500kV High Voltage Direct Current (HVDC) line spanning 1,282 kilometers, connecting Ethiopia to Kenya at the Suswa substation, was successfully commissioned. The total transmission network (500kV, 400kV, 220kV, 132kV) as at June 2023 was 9,196 kilometers while the distribution network at the same period was 302,256 kilometers. This expansive distribution network comprises 66kV feeder lines, as well as 33kV and 11kV medium-voltage lines, in addition to 415/240V Low Voltage (LV) lines strategically distributed across the nation.

Furthermore, the sector is actively engaged in the implementation of projects and programs specifically designed to mitigate system losses and enhance overall power system reliability. These concerted efforts underscore a commitment to fostering a robust and resilient electrical infrastructure in pursuit of sustainable and accessible energy services for all.

Table 2-2: Transmission & Distribution Circuit Lengths (km) - FY 2018/19-2022/23

Voltage	2018/19	2019/20	2020/21	2021/22	2022/23
500kV HVDC Ketraco					1,282
400 kV Ketraco	2,020	2,020	2,479	2,479	2,479
220kv Ketraco & KenGen links	472	475	616	616	616
132kv Ketraco & kengen Links	985	985	1,049	1,049	1,117
KPLC					
220 kV	1,352	1,352	1,352	1,352	1,352
132 kV	2,350	2,350	2,350	2,350	2,350
66 kV	1,187	1,187	1,187	1,188	1,227
33 kV	35,177	35,703	36,570	38,051	39,168
11 kV	39,797	40,616	41,553	42,971	44,077
Total HV and MV	**83,339**	**84,688**	**87,156**	**90,056**	**93,667**

Voltage	2018/19	2019/20	2020/21	2021/22	2022/23
415/240V or 433/250V	152,799	158,527	168,595	200,050	217,784
Total	**236,139**	**243,215**	**255,751**	**290,106**	**311,452**
% Increase Per Annum	5%	3%	5%	13%	7%

Source; Kenya Power

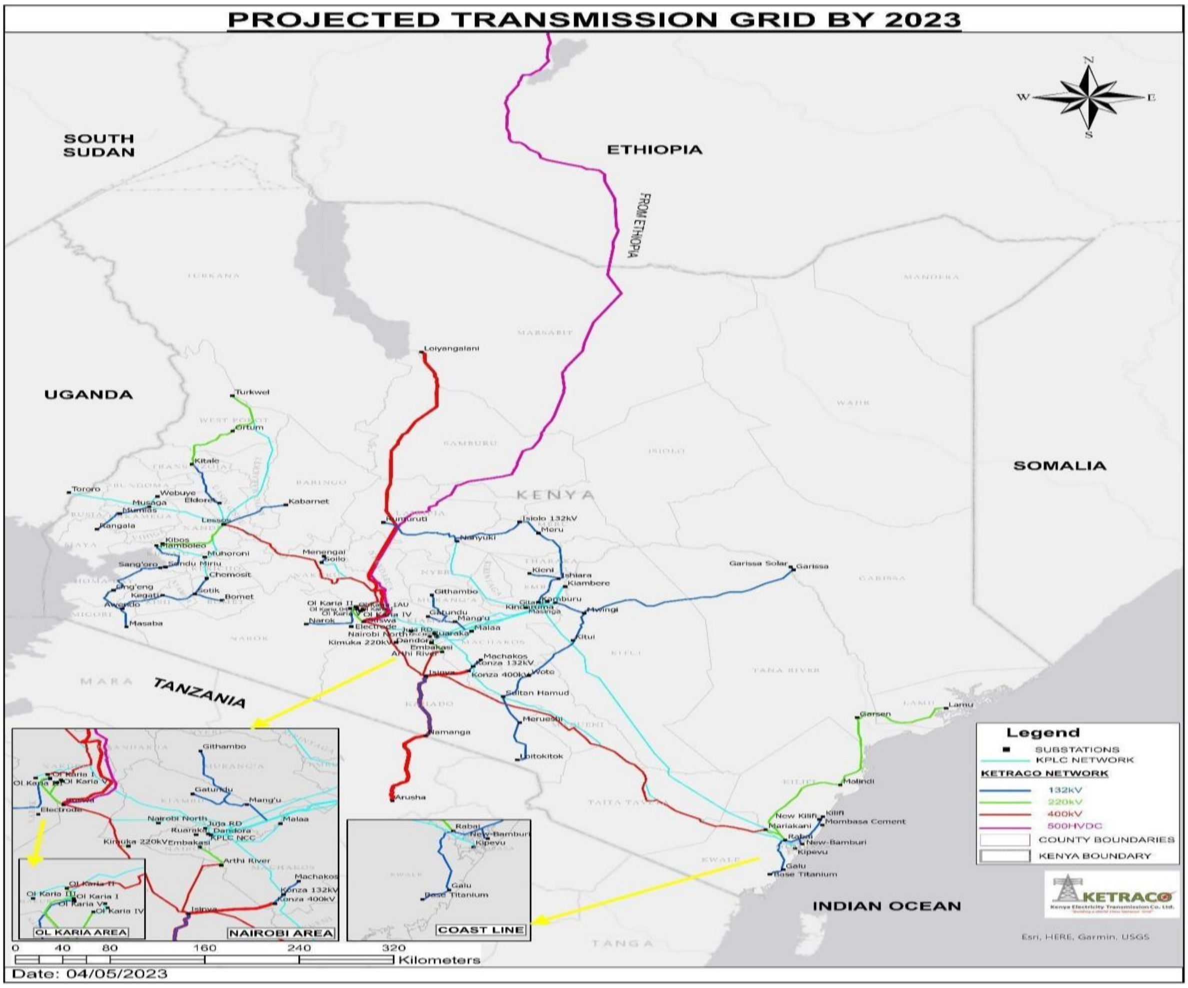


Figure 2-3: Transmission Network in Kenya 2023

The installed capacity of the generation substations increased from 3,720 MVA in 2018/19 to 4,093 MVA in 2022/23, transmission substations capacity from 4,942 MVA to 5,455 MVA and distribution substations capacity from 4,480 MVA to 4,847 MVA as shown in Table 2-3. Distribution transformer capacity significantly increased during the same period from 7,844 MVA to 9,444 MVA.

Table 2-3: Transformers in Service, total installed capacity in MVA as at 30th June, 2023

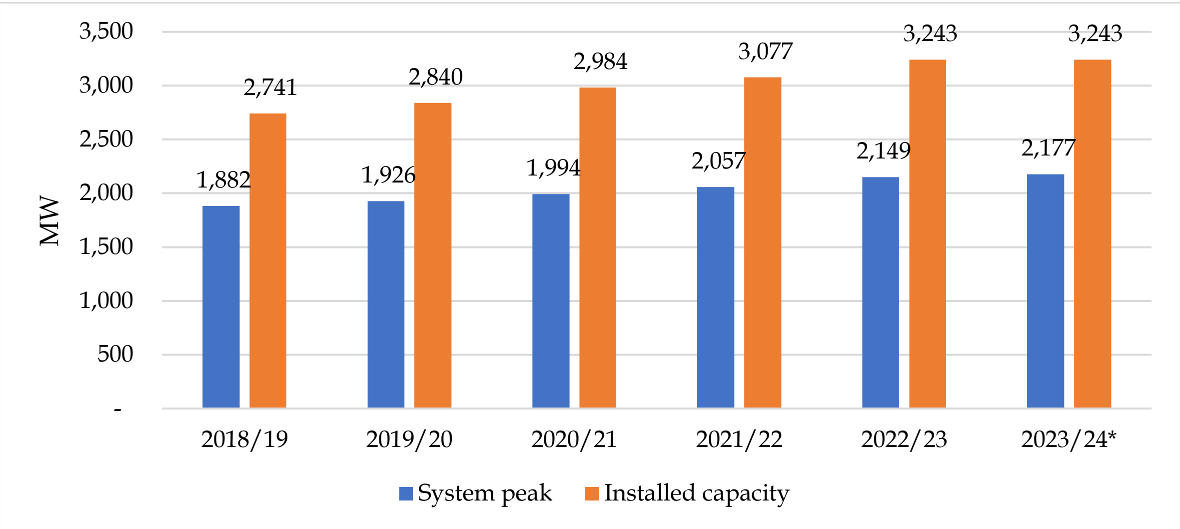
	2018/19	2019/20	2020/21	2021/22	2022/23
Generation Substations	3720	3818	3958	4118	4093
Transmission Substations	4942	4942	5455	5455	5455
Distribution Substations	4480	4563	4603	4669	4847
11/0.415kV and 33/0.415kV Distribution Transformers	7844	8174	8778	9170	9444

Source; Kenya Power

The transmission and distribution network issues facing the existing Kenya network include technical losses, over-voltages, overloading, and low voltages in some sections of the network, such as Kenya's western region. Diversifying power sources and their locations, building new transmission lines, installing reactors, and reinforcing transmission lines and substations are all necessary solutions proposed for rectifying all existing and future network issues.

2.6.4 Demand and Generation Mix

Kenya continues to record an upward trend in demand with peak demand increasing from 1,882 MW in FY 2018/19 to 2,149MW in FY 2022/2023. A new peak of 2,177MW was recorded in the month of February 2024. Trend in peak demand for the period 2018/19-2023/24 is shown in Figure 2-4.



2023/24 Provisional status for FY 2023/24*

Figure 2-4: Peak demand and Installed Capacity for last five years

Source: Kenya Power

The year-on-year increase in peak demand is attributed to organic economic growth, increased investments and deliberate policies to improve electricity access. Through the Last Mile Connectivity Program, the number of consumers connected to the grid in the country increased significantly, from 7,067,861 in FY 2018/19 to 9,212,754 in FY 2022/23, with rural connections accounting for 2,214,710 or 24.04% of the total connections. The expedited electrification programs around the country have resulted in an annual average growth rate of 6.9% in new customers over the five-year period.

The power generation mix for the financial year ending June 2023 comprised 45.41% of geothermal, 19.33% hydro, 10.50% fossil fuels, 16.57% wind, 3.34 % solar and 4.85% imports. Figure 2-5 shows the evolution of the generation mix from 2018/19 to 2022/23.

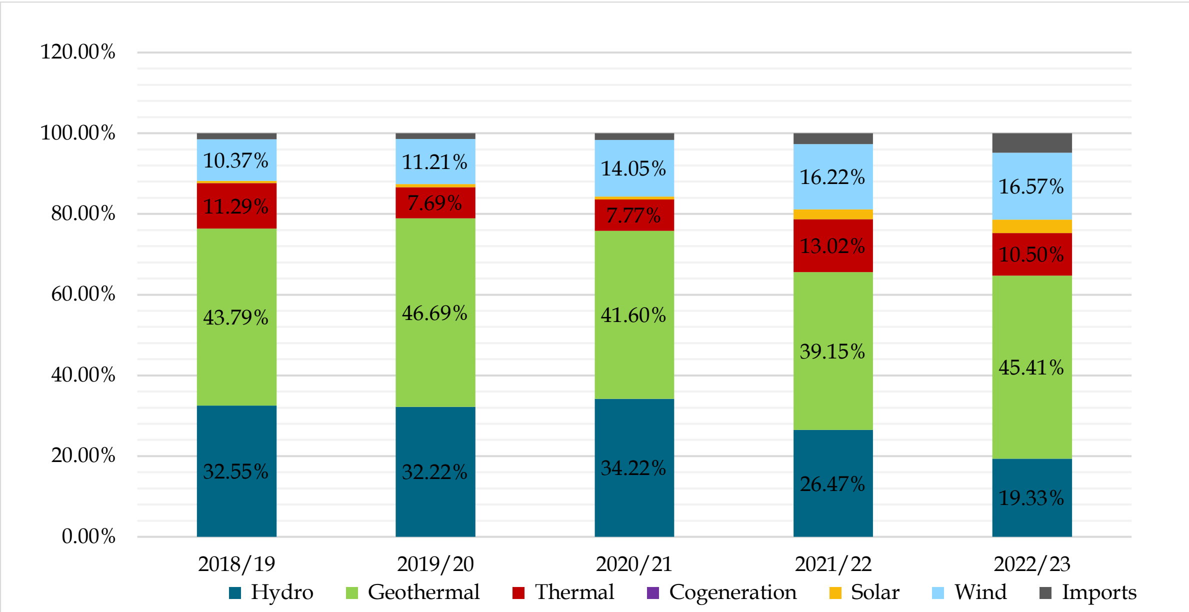


Figure 2-5: Generation Mix 2018/19-2022/23

Source: Kenya Power

Total energy purchased increased from 11,493 GWh in FY 2018/19 to 13,290 GWh in FY 2022/23. Hydropower generation decreased from 3,741 GWh to 2,569 GWh while geothermal generation increased from 5,033 GWh to 6,035 GWh for the same period. Wind generation increased from 1192 GWh in 2018/19 to 2202 GWh. Energy purchased from thermals increased from 1,298 GWh in 2018/19 to 1,396 GWh in FY 2022/23. These trends are summarized in Table 2-4.

Table 2-4: Energy Purchased in GWh

	2018/19	2019/20	2020/21	2021/22	2022/23
Hydro	3,741	3,693	4,141	3,349	2,569
Geothermal	5,033	5,352	5,034	4,953	6,035
Thermal	1,298	882	940	1,648	1,396
Cogeneration	0.27	0.29	0.33	0.38	0.21
Solar	60	91	88	313	444
Wind	1,192	1,284	1,700	2,052	2,202
Imports	170	161	197	338	644
Total	**11,493**	**11,462**	**12,101**	**12,653**	**13,290**

Source: Kenya Power

2.6.5 Electricity Consumption

The demand for electricity has been on an upward trend in the last 5 years, increasing by 17% from 8,769 GWh in 2018/19 to 10,233 GWh in 2022/23. This is primarily due to the government's commitment to attaining universal access to electricity. Table 2-5 and Table 2-6 provides a summary of electricity consumption by customer category and region respectively.

Table 2-5: Consumption in GWh among various categories 2018/19-2022/23

Customer Category	2018/19	2019/20	2020/21	2021/22	2022/23
Domestic-DC	2,366	2,508	2,630	2,728	2,798
Small Commercial-SC	1,250	1,262	1,326	1,474	1,504
Commercial and Industrial-CI	4,462	4,308	4,514	4,851	5,137
Street lighting-SL	68	76	84	95	99
R.E.P. Schemes	595	602	632	650	667
Export Sales	27	18	17	16	27
TOTAL	**8,769**	**8,773**	**9,203**	**9,813**	**10,233**
% INCREASE	4.07%	0.05%	4.90%	6.63%	4.28%

Source: Kenya Power

Table 2-6: Consumption in GWh by Region

REGION	2018/19	2019/20	2020/21	2021/22	2022/23
Nairobi	3,896	3,901	4,009	4,241	4,346
Coast	1,477	1,464	1,573	1,674	1,800
Central Rift	689	680	722	811	840
North Rift	288	302	317	357	349
South Nyanza	104	123	127	134	137
West Kenya	376	376	395	429	479
Mt Kenya	456	439	496	531	548
North Eastern	862	869	914	969	1,039
KPLC Sales	8,147	8,154	8,553	9,147	9,539
R.E.P. Schemes	595	602	632	650	667
Export Sales	27	18	17	16	27
TOTAL	**8,769**	**8,773**	**9,203**	**9,813**	**10,233**
%INCREASE P.A.	3.7%	0.05%	4.90%	6.63%	4.28%

Source: Kenya Power

In general, the expansion of the economy and other factors such as a growing population, urbanization, intensive electrification programs, and continued growth in the manufacturing, agricultural, and other sectors that drive GDP growth will drive commercial electricity sales growth in the medium to long term.

2.6.6 Electricity Retail tariffs

EPRA is mandated under section 11 (b) of the Energy Act 2019 to set, review and adjust tariffs and tariff structures and the terms of electrical supply in the country for both the interconnected and the Off-Grid Systems. The Retail electricity tariffs set as per customer category are illustrated in Table 2-7.

Table 2-7: Electricity Tariff Effective Date 1st April 2023

Code	Customer Type	Energy Limit kWh/month	Charge Method	Unit	2022/23	2023/24	2024/25	2025/26
					Yr 1	Yr 2	Yr 3	Yr 4
DC	Domestic Ordinary	0 - 100	Energy	KSh/kWh	-	-	-	
	Domestic Lifeline	0 - 30	Energy	KSh/kWh	12.22	12.24	12.23	12.14
	Domestic Ordinary 1	31-100	Energy	KSh/kWh	16.3	16.58	16.54	16.5
	Domestic Ordinary 2	> 100	Energy	KSh/kWh	20.97	20.58	19.08	18.57
SC	Small Commercial 1	0 - 100	Energy	KSh/kWh	-	-	-	
	"	0 - 30	Energy	KSh/kWh	12.22	12.24	12.23	12.28
	Small Commercial 2	31-100	Energy	KSh/kWh	16.4	16.36	16.34	16.30
	Small Commercial 3	> 100	Energy	KSh/kWh	20.18	20	19.4	19
	TOU	> 100	Energy	KSh/kWh	10.09	10	9.7	9.5
	Bulk Tariff	1,000-15,000	Energy	KSh/kWh	19.3	19.12	18.3	18
EM	E-mobility	200-15,000	Energy	KSh/kWh	16.00	16.00	16.00	16.00
		200-15,000	Energy	KSh/kWh	8.00	8	8	8
CI1	Commercial & Industrial 1	>15,000	Energy	KSh/kWh	14.7	14.5	13.74	13.44
	TOU	>15,000	Energy	KSh/kWh	7.35	7.25	6.87	6.72
	Bulk Tariff	>15,000	Energy	KSh/kWh	14.7	14.5	13.74	13.44
			Demand	KSh/kVA	1,100.00	1,100.00	1,100.00	1,100.00
CI2	Commercial & Industrial 2	No Limit	Energy	KSh/kWh	13.24	13.08	12.44	12.16
	TOU	No Limit	Energy	KSh/kWh	6.62	6.54	6.22	6.08
	Bulk Tariff	No Limit	Energy	KSh/kWh	13.24	13.08	12.44	12.16
			Demand	KSh/kVA	700	700	700	700
CI3	Commercial & Industrial 3	No Limit	Energy	KSh/kWh	12.66	12.51	11.93	11.67

Code	Customer Type	Energy Limit kWh/month	Charge Method	Unit	2022/23	2023/24	2024/25	2025/26
					Yr 1	Yr 2	Yr 3	Yr 4
	TOU	No Limit	Energy	KSh/kWh	6.33	6.26	5.96	5.84
	Bulk Tariff	No Limit	Energy	KSh/kWh	12.66	12.51	11.93	11.67
			Demand	KSh/kVA	370	370	370	370
CI4	Commercial & Industrial	No Limit	Energy	KSh/kWh	12.39	12.25	11.68	11.42
	TOU	No Limit	Energy	KSh/kWh	6.2	6.13	5.84	5.71
	Bulk Tariff	No Limit	Energy	KSh/kWh	12.39	12.25	11.68	11.42
			Demand	KSh/kVA	300	300	300	300
CI5	Commercial & Industrial	No Limit	Energy	KSh/kWh	12.12	11.97	11.41	11.15
	TOU	No Limit	Energy	KSh/kWh	6.06	5.99	5.7	5.58
	Bulk Tariff	No Limit	Energy	KSh/kWh	12.12	11.97	11.41	11.15
			Demand	KSh/kVA	300	300	300	300
CI6	Commercial & Industrial 6	No Limit	Energy	KSh/kWh	10	10	10	10
	TOU	No Limit	Energy	KSh/kWh	7.42	7.42	7.42	7.42
			Demand	KSh/kVA	200	200	200	200
CI7	Commercial & Industrial 6 (Special Economic Zone)	No Limit	Energy	KSh/kWh	10	10	10	10
		No Limit	Energy	KSh/kWh	7.42	7.42	7.42	7.42
			Demand	KSh/kVA	200	200	200	200
SL	Street Lighting	No Limit	Energy	KSh/kWh	9.22	9.24	9.23	9.15

Source: EPRA

In addition, EPRA approved new Time of Use thresholds in bid to promote manufacturing and industrial productions, and Kenya's goal to realising 24-hour economy. From the schedule of tariffs, Small Commercial and Commercial and Industrial 1 (CI1) who consume more than their average threshold, enjoy a 50%

discount on the applicable Energy Rate for the additional consumption. However, for Commercial and Industrial 2 (CI2) customers, Commercial and Industrial 3 (CI3), Commercial and Industrial 4 (CI4), Commercial and Industrial 5 (CI5) and Commercial and Industrial 6 (CI6) customers will enjoy 50% discount on energy charge within their consumption threshold but as per schedule of time of use. This discounted Time of Use Tariff is applicable during off-peak period as shown in Table 2-8.

Table 2-8: Time of Use Schedule

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

Source; EPRA

Electricity retail tariffs include monthly Pass-through Tariff Adjustments described below.

i. Fuel Energy Charge (FEC): This charge is designed to recover the costs associated with the fuel used in electricity generation. It fluctuates with monthly outputs from thermal power plants and changes in fuel prices. It is calculated based on the specific fuel consumption rate contracted for each power plant.
ii. Water Resource Management Authority Levy (WARMA Levy): This fee is paid to the Water Resource Management Authority for the use of water by hydro power plants in the generation of electricity. It is imposed on the energy purchased from hydroelectric plants with a capacity exceeding 1 megawatt.
iii. Inflation Adjustment: This charge accounts for the impact of both domestic and international inflation on the supply of electricity. It is adjusted semi-annually to reflect changing economic conditions.
iv. Foreign Exchange Rate Fluctuation Adjustment (FERFA): These adjustments are made to accommodate variations in foreign exchange-denominated utility costs, resulting from fluctuations in currency exchange rates and the volumes of foreign exchange-denominated payments. These adjustments help manage currency-related risks within electricity tariffs.

The future of Kenya's tariff policies lies in their ability to adapt, foster economic growth, and promote cooperation at regional and international levels. By doing so, Kenya can position itself as a vibrant and competitive player in the global marketplace while simultaneously ensuring economic development and prosperity for its citizens

3 ELECTRICITY DEMAND FORECASTING

3.1 Introduction

Electricity is considered a key enabler of economic development globally. It is an enabler for all economic and social interventions that facilitates development including manufacturing and industries, transport, agriculture, services & social sectors and households. Adequate and reliable supply of electricity is essential for the economic development of any Country. Accordingly, an assessment of electricity requirements over a given period needs to be undertaken as it informs the design of least-cost generation and transmission plans for the power sector, as well as in investment appraisals of individual power-generation projects.

The accuracy of electricity demand forecasts is key to policy making decisions. Inaccurate forecasts, can have adverse social and economic consequences. Underestimating demand results in supply shortages that cause forced power outages, affecting economic growth due to its impact on the various sectors of the economy. Overestimating demand can lead to overinvestment in generation and transmission capacity, and ultimately, higher cost of power supply to consumers.

Electricity demand forecasting is the first step towards development of an optimal power system expansion plan. The demand forecast considers various parameters that form the basis of applied assumptions. These parameters include; electricity consumer behavior, population structure and dynamics, identified government priority projects and the national economic indicators such as Gross Domestic Product (GDP) in the forecasting model. In addition, the demand forecast considers emerging technologies that spur electricity consumption including green fertilizer (ammonia), electric mobility and electric cooking. Lastly, the forecast considers policies on energy transition in the country and the impacts of climate change in the country as it relates to energy sector operations.

In consideration of these factors, and recent policy and socio-economic changes, an electricity demand forecast in Kenya for the period 2024-2043 is presented in this section.

3.2 Objectives of the forecast

The main objective of this demand forecast is to review and incorporate changes in macroeconomic and social indicators that influence electricity consumption. The forecast specifically focuses on:

i. Reviewing the current economic trends and future outlook;
ii. Updating key macroeconomic indicators and other key drivers affecting demand;
iii. Incorporating plans contained in the Vision 2030, the Fourth Medium-Term Plan IV (MTP IV) 2023-2027 and aligning them to the Bottom-up Economic Transformation Agenda (BETA) and Governments Manifesto;
iv. Considering the shift in demand in the year 2024, integrating the effect of emerging electricity demand drivers including electric motorization (e-mobility), Electric cooking (e-cooking); and
v. Updating the status of Kenya Vision 2030 flagship projects implementation progress and their impact on electricity consumption going forward.

3.3 Overview of the Domestic Economy

Real Gross Domestic Product (GDP) expanded by 4.8 per cent in 2022 compared to a revised growth of 7.6 per cent in 2021. The growth was spread across all sectors of the economy but was more pronounced in service-oriented activities. Agriculture, Forestry and Fisheries sectors contracted by 1.6 per cent in 2022 compared to a contraction of 0.4 per cent in 2021. This was attributed to drought conditions that characterized the period under review. Some of the key sectors that supported growth were Financial and Insurance (12.8%), Information and Communication (9.9%), and Transportation & Storage (5.6%). Nominal GDP increased from Ksh. 12,027.7 billion in 2021 to Ksh. 13,368.3 billion in 2022.

Despite slowing down markedly in 2022 in volume terms, agriculture remained the dominant single sector, accounting for about 21.2 per cent of the overall GDP in 2022. Industry-related activities accounted for 17.7 per cent, while service activities accounted for 61.1 percent of the total GDP in 2022. Figure 3-1 shows the historical GDP trend and 2023 projection.

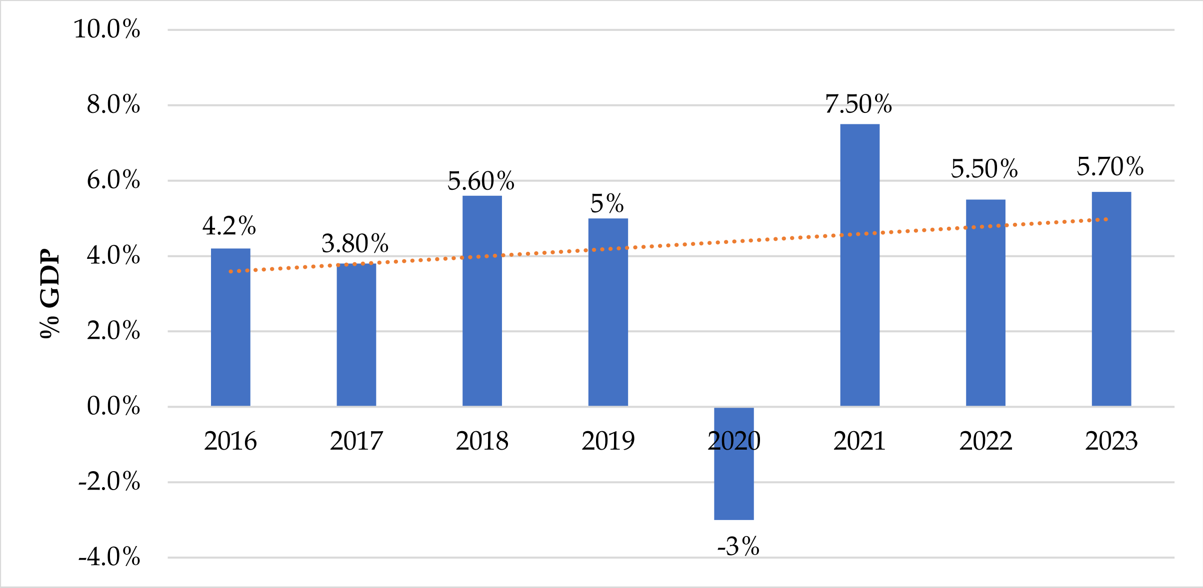


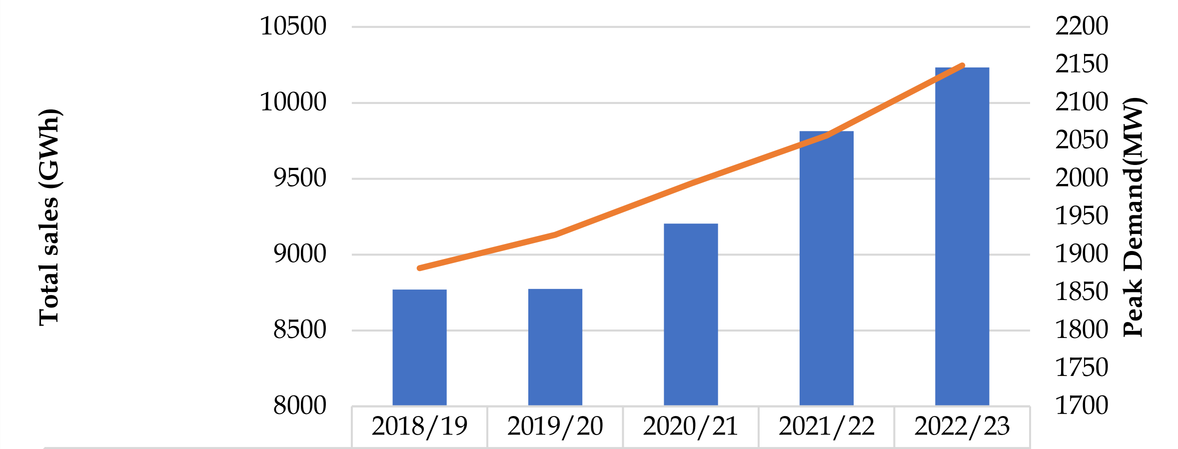
Figure 3-1: Kenya's GDP Growth

**Provisional GDP from BROP 2023*

GDP for the year 2023 is forecasted to grow to 5.7%, despite the weak global growth outlook, the economy is expected to remain resilient in the year 2023, supported by a robust performance in the services sector and expected recovery in agriculture. The agriculture sector is likely to rebound in 2023 from two consecutive annual contractions supported by favorable weather conditions and subsidized fertilizer from the Government. Economic performance in 2023 is likely to be reinforced by the Government's development agenda aimed at achieving economic turnaround and inclusive growth.

3.4 Performance of the Power Sector

Electricity peak demand and energy consumption continues to grow on account of the economic rebound from the adverse effects of COVID-19. The peak demand reported for the period grew to 2,149MW from the previous peak of 2,057MW as at June 2022 representing a 4.5% growth. The reported peak demand was 2,177MW as at February 2024, further cementing the economic recovery trajectory the country is taking. In the FY 2022/23, electricity sales grew to 10,233GWh from 9,813 GWh in 2021/22, a 4.3% growth which reflects a steady growth as shown in Figure 3-2.



	2018/19	2019/20	2020/21	2021/22	2022/23
Total Sales (GWh	8769	8773	9203	9813	10233
Peak Demand(MW)	1882	1926	1994	2057	2149

Figure 3-2: Peak Demand and Energy Sales trends 2018/19 to 2022/23

Source: Kenya Power

There was an increase of 4.28%in electricity consumption in FY 2022/23 which signifies a steady growth in the local economy despite the electioneering period in 2022. The number of customers connected to the national grid grew to 9,212,754 from 8,919,440 in 2021/22, a 3.3% growth. This growth was primarily due to targeted Government interventions towards universal access by 2028.

3.5 Future Economic Outlook and effect on electricity demand

Kenya's National Long-Term Low Emission Development Strategy (2022-2050) highlights a commitment to decarbonizing key economic sectors in pursuit of net zero emissions by 2050. This builds upon her previous commitment to achieve a 32% reduction in emissions by 2030 as set in the December 2020 updated NDC. Working towards net zero will involve decarbonizing the electricity system, shifting energy consumption from traditional carbon-based fuels towards conservation, hydrogen fuel and electricity, and through widespread adoption of low carbon mass transportation for passengers and freight cargo.

Sustained execution of diverse projects with a focus on expanding renewable energy and minimizing emissions in the energy mix in the country is poised to yield favorable outcomes towards net zero emissions while increasing the country's electricity demand. This segment outlines key proposals anticipated to exert a substantial influence on the net zero emission target and Kenya's electricity consumption patterns through targeted electricity consumption interventions.

3.6 Kenya Vision 2030 and Medium-Term Plan IV

The theme for the Medium-Term Plan IV (MTP IV) 2023-2027 is "accelerating socio-economic transformation to a more competitive, inclusive and resilient economy". The electricity sub-sector is set to play a pivotal role in realizing the objectives of the MTP IV by ensuring adequate, reliable, affordable and clean energy while protecting the environment.

The Kenya Vision 2030 and the MTP IV for the Energy Sector has set universal access to electricity by 2026 and adoption of modern clean cooking by the year 2028 as key economic growth drivers ahead of the Sustainable Development Goals (SDGs) target of 2030.

In line with the Government's vision of scaling up access to electricity services towards the attainment of Universal Access Coverage, various connectivity initiatives are proposed for implementation. The Energy Sector MTP IV envisages implementation of phase IV and V of the Last Mile Connectivity project. Some key interventions contained in the later phases of the Last Mile Connectivity Project include electricity connection of public facilities, 150 mini grids in off-grid areas, 50,473 standalone systems, and 380 solar pumps in 14 marginalized counties. Other proposals include the installation of 75,000 lanterns under the Public Lighting Project, retrofitting of diesel mini grids, the installation of 90,000 transformers across constituencies and maintenance of 2,500 solar systems. These projects will add to the number of customers connected to electricity by a further 2,300,000.

To promote adoption of renewable energy, the Energy Sector MTP IV commits to harness opportunities such as green financing and clean development mechanisms by implementing green projects including green hydrogen, e-mobility and clean cooking. These initiatives will affect electricity consumption in the medium to long term.

The government has committed to achieving 100% clean cooking by 2028. From a climate change mitigation perspective, the government through its updated NDC targets to abate at least 7.3 Mt C02eq per year by 2030, via the accelerated distribution and uptake of clean cooking alternatives. During the MTP IV, the Government will formulate Kenya National e-Cooking Strategy to provide implementable pathways towards access to electric cooking solutions.

Over the plan period the Government will formulate strategies and policies geared towards green hydrogen production and use. Further, it will prepare the regulatory framework to allow participation of the private sector in all aspects of green hydrogen production and use.

Specific Kenya Vision 2030 flagship projects are at various stages of implementation. The proposed Konza City, Dongo Kundu, Tatu City and Naivasha Industrial Parks are at an advanced stage of development. Completion of these flagship projects will positively impact electricity demand growth in the medium term. It is however noted that a number of projects earlier targeted for development and leading to significant electricity demand growth have been delayed and have new implementation timelines. These adjusted timelines have also been factored into this demand forecast

3.7 Government Priority Areas

The Kenya Kwanza manifesto has highlighted several measures that could have an effect on increasing electricity demand and reduce dependence on imports thus easing pressure on demand for foreign exchange. These include:

i. Affordable housing: There is a plan to increase supply of new housing units to 250,000 per annum increasing the percentage of affordable housing supply from 2-50%. The Jua Kali sector will be strengthened to produce high quality construction materials such as windows, doors among others

ii. Transportation: Adoption of electrical vehicles is expected to replace fossil fuel vehicles. Through its National Efficiency and Conservation Strategy, the Government will increase the adaptation of E-Mobility by targeting 5% of imported cars annually by 2025. Further, the Government plans to roll out electric vehicle (EV) charging infrastructure in all urban areas and along the highways; Provide financial and tax incentives for public service vehicles and commercial transporters to convert to electric vehicles. Leverage the financial support that will be provided to the boda boda sector, through the Hustler Fund, to develop the nascent electric vehicle (EV) and motorcycle assembly industries.

iii. Manufacturing: The government intends to enhance manufacturing through the value chain approach such as leather industry, building products, pharmaceutical and medical supplies, agro –processing, dairy and edible oils processing.

3.8 Budget Policy Statement and Electricity Demand

The Draft Budget Policy Statement (BPS) for FY 2023/24 is geared towards reduction to the cost of living and improving livelihoods, while at the same time fostering a sustainable inclusive economic transformation and aims to increase investment in at least five sectors envisaged to have the largest impact and linkage to the economy as well as household welfare. These include: Agricultural Transformation and Inclusive Growth, Micro, Small and Medium Enterprise (MSME) Economy, Housing and Settlement, Healthcare, Digital Superhighway and Creative Industry. The paper identifies electricity as an enabler and implementation of the programs will have a significant influence on electricity demand. The proposals that will directly influence electricity consumption are:

i. Setting up of leather cottage industries and the leather parks such as the Kenya Leather Industrial Park (KLIP), 18 County Aggregation and Industrial Parks (CAIPs), incentivizing e-mobility, installation of bulk milk coolers; and promotion of investment in the cold chains.
ii. Proposal to enhance transmission and distribution of power;
iii. Proposal to develop geothermal energy; and
iv. Electrification of new customers and public facilities.

3.9 Demand forecasting methodology

3.9.1 General approach

Electricity demand forecasting employed both parametric methods that integrate main variables and non-parametric methods such as pattern recognition. An Excel-based Demand Forecast Model customized to the Kenyan situation was used. This Model was developed specifically for electricity demand forecasting in Kenya. It is based on a set of consistent assumptions on medium to long-term socioeconomic, technological and demographic developments in Kenya.

The following steps were applied in developing the forecast:

i. A *bottom-up* approach was adopted in calculating the country's overall demand consisting of domestic and industrial consumers; street lighting; and flagship projects identified in the Vision 2030 long term plan.
ii. Trend projection was used for correlation analysis of the different factors affecting electricity demand growth in the country.

iii. Sensitivity analysis was carried out using three scenarios based on a realistic projected growth, optimistic and conservative perspectives; Reference, Vision and Low, respectively.
iv. Assumptions were made in assessing the electricity requirements for emerging technologies including E cooking and E-vehicles

3.9.2 Electricity demand structure

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

i. Domestic consumption: This includes KPLC and REREC consumers.
ii. Small commercial consumption: this includes KPLC and REREC consumers.
iii. Commercial and Industrial consumption: this represents large power consumers in tariff categories CI1 to CI5 where CI5 is a summation of CI5 & CI6.
iv. Street lighting consumption: These are the number of lamps installed for public lighting.

3.9.3 Electricity Demand Forecasting Procedure

The procedure adopted for demand forecasting is as detailed below:

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

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

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

$$C_{TG,PSA}(y) = \Theta C_{TG,PSA}(y-1) + \alpha SC_{TG,PSA}(y) + SD_{TG,PSA}(y)$$

For tariff groups: large commercial/industrial

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

Where:

α Number of new connections

θ Growth rate for existing consumption

a, b Coefficients of (past) linear correlation between consumption and GDP in absolute figures ($C = a \times GDP + b$), by power system area

C Projected electricity consumption in GWh

GDP_{KE} 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 a specific year) in kWh/year

TG Tariff group

y Year

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

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

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

Step 3: Electricity demand from future flagship projects is added to the existing consumer structure, assessed based on projected peak load and load (utilization) factors. This is computed for the reference and vision scenarios:

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

Where:

C Projected Consumption in GWh

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 system 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 sent out (energy purchased) is arrived at by a summation of the total projected consumption plus total losses. This has also been computed for each PSA:

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

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

Where:

C; C_{PP}; C_{TN}: are projected consumption; gross power plant sent-out (energy purchased); 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 a percentage of the units purchased will be decreasing in accordance with the target loss reduction path in the current electricity retail tariff.

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.

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

Where:

C_{PP} Consumption power sent-out (gross) in GWh

FP Flagship project

LF Load factor of tariff group divided by 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 divided by flagship project in %

SF Simultaneous peak factor (of peak load power system area) equals peak load system divided by sum peak loads power system areas in %

TG Tariff group

y Year

Hy Hours in a year.

3.10 Main drivers of the projected demand

The main factors influencing demand growth that were considered include the following:

i. **Demography**: This includes population and urbanization growth rates which have explicit effect on domestic, small commercial, street lighting consumption and connectivity levels. The distribution of the population in relation to rural and urban dwellings affects the demand growth through the different specific consumption for each. The population growth data is sourced from the World Population Prospectus 2022, and the urbanization rate from the Revised World Urbanization Prospectus 2018.

ii. **GDP growth:** This directly impacts on the activities of the productive sector which translates into electricity consumption of commercial and industrial consumers.

iii. **Specific Vision 2030 Flagship projects:** These projects have an impact on GDP growth under the reference and vision scenarios and contribute to demand growth based on their specific load requirements. The plan considers projects that are expected to be implemented within the medium-term period based on the progress status of the projects under development.

3.10.1 Future demand drivers

It is projected that other factors such as E-cooking and E-Vehicles will influence power demand in the near future.

Electric Cooking

The Kenya Cooking Sector Study of 2019 showed that over 75% of Kenyan households relied on woodstoves as either their primary or secondary cooking method, yet household electrification levels currently stand at over 75%. In line with Sustainable Development Goal number 7 (SDG 7), the country aims to achieve 100% access to clean cooking by 2028 to improve health and gender equity, whilst reducing deforestation and CO2 emissions to mitigate climate change. As of 2019, only about 3% of households owned electric appliances and still predominantly used charcoal, wood fuel, and LPG for cooking (Nuvoni, 2023).

In 2023, the Ministry of Energy and Petroleum commissioned the Kenya National e-Cooking Study (KNeCS), with technical assistance and funding from the Modern Energy Cooking Services (MECS), Climate Compatible Growth (CCG) and UK Partnerships for Accelerating Climate Transitions (UK PACT) programmes. The aim of the study was to analyze e-cooking status in Kenya with the view of supporting the development of Kenya National e-cooking Strategy. From the study, 68.9% of the households on the main grid were found to have electricity suitable for e-cooking with 25.2% owning at least one electric cooking appliance and 3.88% using e-cooking as their primary solution.

An analysis for transition to e-cooking was done based on typical cooking appliances. The assumptions for the analysis were as follows:

i. Four appliances were simulated for e cooking.

ii. The domestic customers are expected to fully transition to e cooking by 2044.
iii. The number of domestic customers that primarily use e-cooking as per the draft e-cooking strategy for MoEP was 3.88%. A percentage of the households use the simulated appliances.
iv. The growth in demand influenced by e-cooking is estimated at 4% per annum until 2030 and 10% until the end of the planning period, with the year of full load expected to be in 2044.

The results of the analysis assuming a complete transition to e-cooking are summarized in Table 3-1 and Table 3-2**.**

Table 3-1: Reference Scenario expected typical domestic customer e-cooking estimated consumption

Appliance	Typical power rating (Watts)	Kwh	Estimated usage/day (Hrs)	Kwh/day	Annual Usage kWh/year	No. of DC customers **	Annual potential consumption kWh	Annual potential demand-Base year MW	Annual Potential demand-2030 MW (4% growth)	Annual Potential demand-2044 MW (10% growth)
Induction Cooker	2,000	2	2	4.00	1,440	1,017	1,464,714	2.0	2.64	9.12
Electric Cooker	2,000	2	2	4.00	1,440	9,154	13,182,427	18.1	23.76	82.04
Air fryer	1,800	1.8	0.45	0.81	117	848	98,868	0.6	0.79	2.73
Electric Pressure Cooker	900	0.9	1	0.90	86	4,408	380,826	1.0	1.37	4.74
TOTAL		**6.7**		**9.71**	**3,083**	**15,427**	**15,126,835**	**21.7**	**28.57**	**98.63**

Table 3-2: Vision Scenario expected typical domestic customer e-cooking estimated consumption.

Appliance	Typical power rating (Watts)	Kwh	Estimated usage/day (Hrs)	Kwh/day	Annual Usage kWh/year	No. of DC customers	Annual potential consumption kWh	Annual potential demand-Base year MW	Annual Potential demand-2030 MW (6.1% growth)	Annual Potential demand-2044 MW (10% growth)
Induction Cooker	2,000	2	2	4.00	1,440	1,017	1,464,714	2.0	3.04	10.48
Electric Cooker	2,000	2	2	4.00	1,440	9,154	13,182,427	18.1	27.33	94.36
Air fryer	1,800	1.8	0.45	0.81	292	848	247,171	1.5	2.28	7.86
Electric Pressure Cooker	900	0.9	1	0.90	324	4,408	1,428,096	3.9	5.92	20.44
TOTAL		**6.7**		**9.71**	**3,496**	**15,427**	**16,322,408**	**25.5**	**38.57**	**133.15**

Electric Vehicles

Kenya's electric vehicle transport sector is gaining momentum, driven by supportive policies, infrastructure development, and a growing awareness of the benefits of EVs. While there are challenges to overcome, the transition to electric mobility holds promise for reducing pollution, promoting energy independence, and supporting economic growth. With continued investments and collaboration between the government, private sector, and international partners, Kenya is well-positioned to lead the way in sustainable transportation in Africa.

According to Long Term Emissions Strategy Report, 99% of the emissions recorded by the transport sector emanates from Road Transport. This therefore means that Air, Sea and Railway Transport modes contribute approximately 1% of the emissions which makes Road Transport a significant focus area towards reduction of carbon footprint.

The current demand for petroleum products resulting from the three modes of transport are significant in influencing the economy's balance of payments given that these products are imported.

Electric vehicles are a key tool in the fight against climate change due to their ability to reduce CO2 emissions, improve energy efficiency, and promote the transition to cleaner energy sources as shown in Figure 3-3. The adoption of EVs will enable Kenya to establish a clean and efficient transport network while creating demand for electricity. Key among the expected benefits resulting from development of EVs in Kenya include; Reduced CO2 emissions, energy independence, lower operating costs, local job creation, support for sustainable transportation system, reduced noise pollution and incentives for renewable energy.

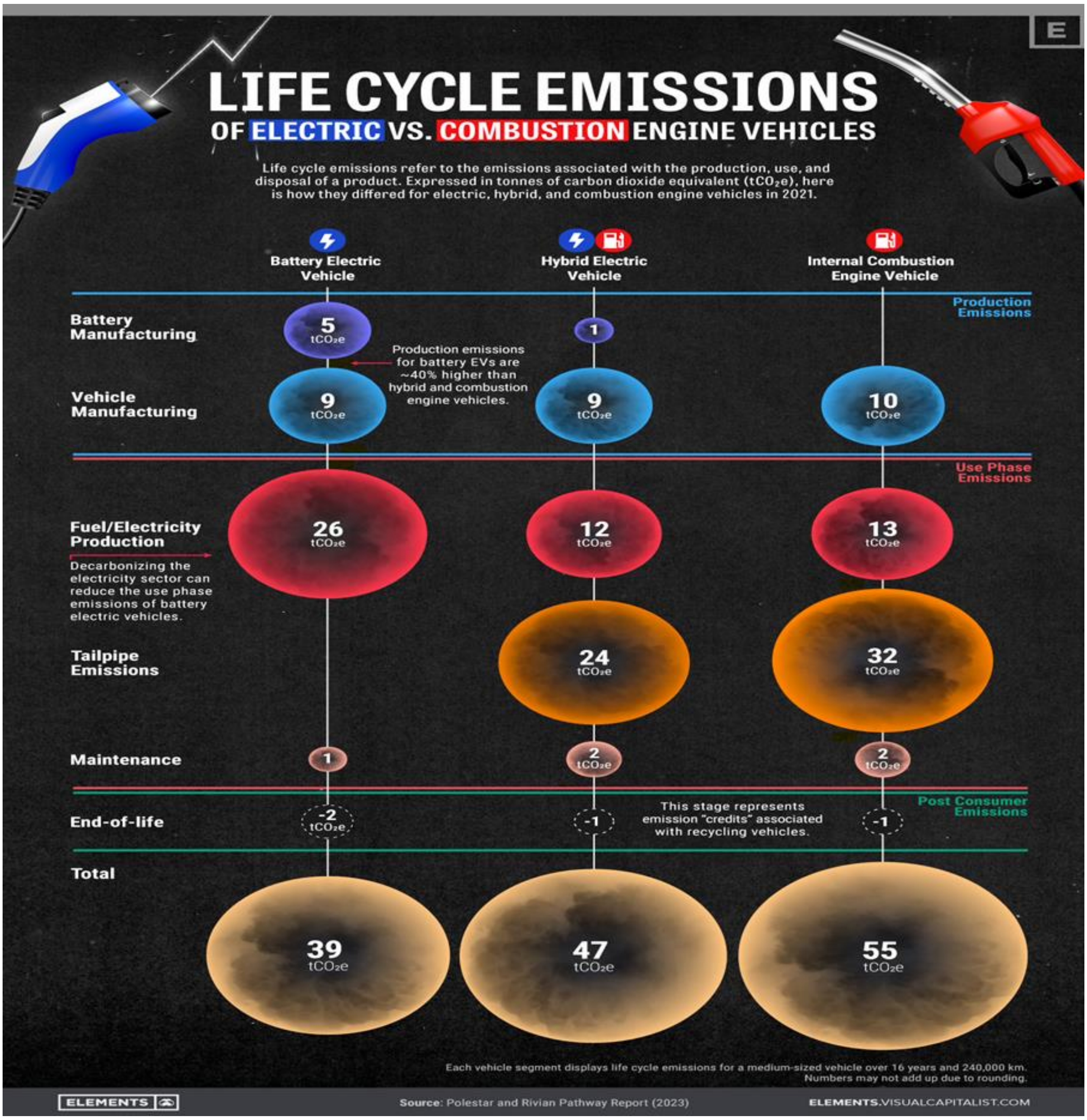


Figure 3-3: Lifecycle emissions of electric Vs Combustion engine vehicles.

According to a report done by the University of Nairobi Enterprise Service Limited (2024) on market assessment of electric mobility in Kenya, it is estimated that the electric vehicle fleet in Kenya consists of 3,753 vehicles distributed across the various existing categories. Two and three wheelers constitute of about 90% of the registered vehicles; this is because of the government intervention and promotion on electric mobility. Using Transport Industry sourced statistics, an analysis of electricity demand projections for EVs by 2043 indicate a demand of 1,083.18 MW for both the reference and vision scenarios. In estimating the demand for EVs, the following assumptions were applied:

i. 2-3-Wheeler cars consume approximately 1.8kWh per day and cover on average about 50kms per day.
ii. Passenger cars consume approximately 8.46kWh per day and cover on average about 61kms per day.
iii. Mini-buses and buses consume approximately 250kWh per day and cover on average about 250kms per day.
iv. Light Commercial Vehicles consume approximately 67.27kWh per day and cover on average about 82kms per day.
v. It is assumed that by 2043, all new registered vehicles in the country are expected to be EVs.
vi. The Share of EVs in relation to newly registered vehicles for the first 7 years from 2024 to 2030 is estimated at 5% annually, distributed according to the existing structure of motor vehicle categories for both Reference and Vision scenarios. This 5% is the estimated annual reduction of CO2 emissions towards realization of 32% CO2 emissions reduction by 2030 as provided in the Nationally Determined Contributions Report.
vii. The Share of EVs in relation to newly registered vehicles from the year 2031was assumed to grow from a share of 10% in tandem with the vision 2030 envisioned economic growth rate. This was then interpolated to ensure 100% by 2043 for both reference and vision scenario.
viii. Of this share, it was assumed that on an annual basis, only 80% of EVs would be charged from the grid while 20% accounted for under captive power.
ix. The Share of EVs in relation to newly registered vehicles as highlighted in (vi) and (vii), assumes a similar rate of reduction in CO2 emissions towards achieving Net Zero in 2050 for Vision Scenario and 2060 for Reference Scenario.
x. Daily average number of kms per vehicle category is based on; Updated Transport Data in Kenya 2018 Report.
xi. A typical electric car (passenger cars & motorcycles) takes just under 8 hours to charge from empty to full.
xii. Electric lorries and buses take just under 5 hours to fully charge
xiii. The analysis assumes an average of 6.6hours for all categories of vehicles to fully charge from zero and charging occurs daily for at least 2.2hours based on the computed charging cycles.
xiv. It takes on average 2 and ½ days for any motor vehicle category to discharge a fully charged battery from 100% - 0%. This therefore means you charge twice for usage in 5 days.

Demand from electric vehicles was factored in the base year as shown in Table 3-3 and is projected to grow from 37.94MW in 2024 to 1,083.18MW in 2043 for both the Reference and Vision Scenarios.

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Table 3-3: Electric vehicles power requirements analysis: Reference and Vision Scenarios

Vehicle Categories	Kms/yr	kms per day	Avg kWh	Avg. Range in kms	kWh/ km	kWh/ day	No. of Vehicle in 2018	Estd. No. of Vehicles in 2023	Share Proj. No. of Reg. E.Vehicles in 2030	Share Proj. No. of Reg. E.Vehicles in 2043	GWh-Current 2023	Proj. GWh-in 2043
Passenger Cars	22,223	61	50	360	0.14	8.46	135	200	1,469	32,664	0.61	99.44
Light Commercial Vehicles	29,862	82	185	225	0.82	67.27	31	148	59	1,307	3.58	31.64
Buses	43,815	250	384	250	1.54	384	16	21	154	3,430	2.90	474.13
Heavy goods Vehicles	63,205	173	185	225	0.82	142.38	3	10	73	1,633	0.51	83.71
Motorcycles	17,807	49	2.75	75	0.04	1.79	165	3,374	24,774	551,050	2.17	354.86
Total							**350**	**3,753**	**26,529**	**590,084**	**9.78**	**1,043.79**
Equivalent MW in a Year											**10.15**	**1,083.18**

3.11 Definition of the Scenarios

The forecast considers three scenarios:

Reference Scenario

This is the base case scenario with projection based on historical data trends and envisaged growth in the different demand drivers based on expected national economic development and selected committed flagship projects.

Vision Scenario

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

Low Scenario

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

3.12 Forecast assumptions.

3.12.1 Demography

Historically, population size and urbanization rate have shown a positive correlation with electricity usage in Domestic, small commercial and street lighting customer categories as shown in Figure 3-4**.** The demand forecasting model considers this correlation to perform trend analysis in estimation of future electricity demand within these classes.

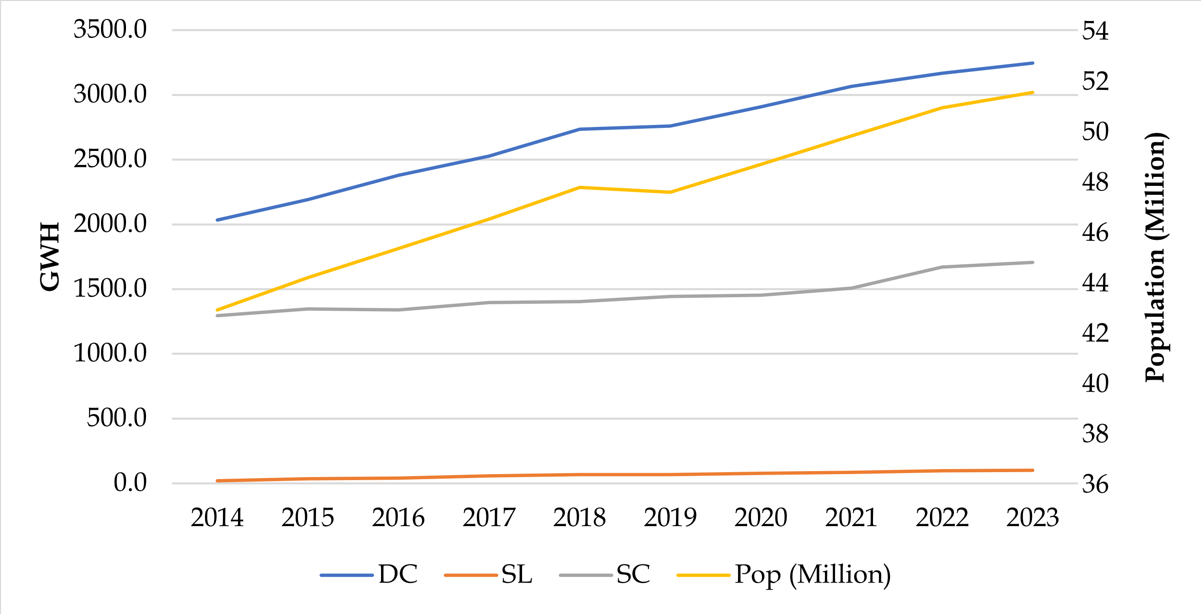

Figure 3-4: Historical trend between population, Domestic, Small Commercial & Street Lighting Consumption

Table 3-5 indicates the demographic assumptions adopted over the planning horizon.

Table 3-4: Demographic Assumptions

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
Population growth	KNBS 2019 KPHC-Analytical Report on Population Projections Vol XVI World Population Prospects 2022.	The population of 51.52 Million in 2023 based on KNBS 2019 KPHC-Analytical Report on Population Projections Vol XVI	Reference: Average annual growth rate of 1.73% from 2024 based on UN medium fertility scenario forecast. Vision: Average annual growth rate of 1.40% from 2024 based on UN low fertility scenario forecast. Low: Average annual growth rate of 2.03% from 2024 based on UN High fertility scenario forecast.
Household (HH) size	KNBS 1999 & 2019 Census.	2019 HH size of 3.92 persons/ household reduced annually by 0.029 to obtain 3.94 persons/household in the base year. The annual reduction (0.029) is obtained by:	For all scenarios, the household size has been reduced annually by 0.029 for the entire planning period.

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
Share of total urban population. Average Annual Urban growth rate	KNBS 2019 Census. World Urbanization Prospects: The 2018 Revision.	2019 Census, urban population of 14.8Million grown by an annual average urban growth rate of 4.12% to obtain 18.2Million representing an urban share of 35.4% in the base year. This is based on UN average annual urban growth rate projections.	For all scenarios, an average annual urban growth rate of 3.69% applied. This is based on UN average annual urban growth rate projections.

3.12.2 Domestic consumption

Over the last decade, there has been a notable surge in domestic connections and consumption as evident in Figure 3-5. Despite the overall increase in consumption, the specific consumption has actually decreased from 819 kWh per year in 2013/14 to 371 kWh per year in 2022/23.

This drop in specific consumption can be attributed to two main factors. Firstly, the government's push for universal access to electricity has led to a greater number of low-income households getting connected, and these households tend to use less electricity. Secondly, there have been significant improvements in the efficiency of consumer electronics and home appliances, which means lower consumption of power.

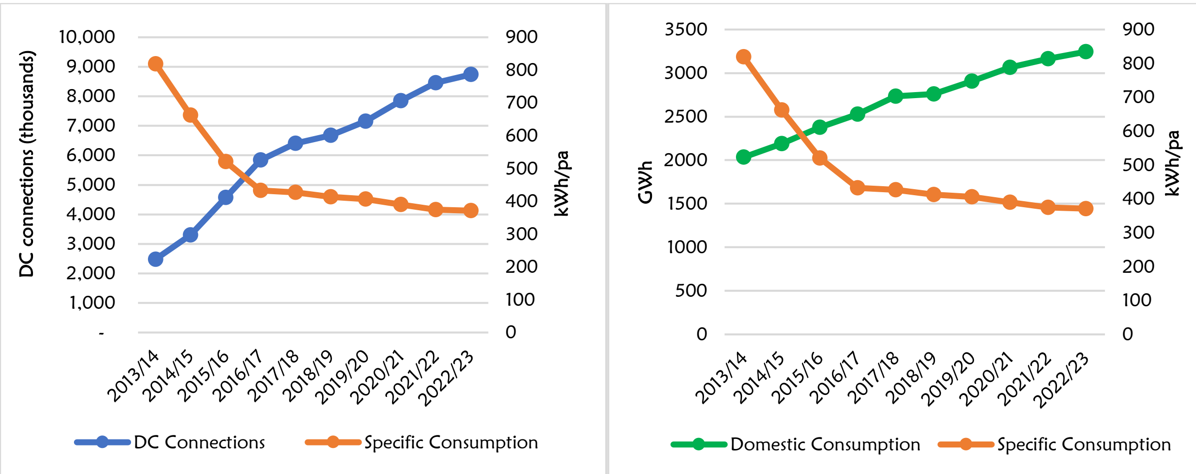

Figure 3-5: Historic Trend between Domestic Connections and Specific Consumption

Demography and electrification programs primarily drive domestic consumption. Alongside the demographic indicators detailed in Table 3-5, the assumptions outlined in Table 3-6 were considered when projecting future domestic consumption.

Table 3-5: Domestic Consumption Assumptions

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
Electrification targets (connectivity level), connection rate	KPLC Annual statistics 2022/2023. 2023-2028 Kenya Power Strategic Plan Vision 2030 MTP IV report	The number of domestic customers connected in the base year is 8,738,510	**Reference:** A total number of 271,278 new domestic customers to be connected annually over the planning period. This is based on average projected connections by Kenya Power over the period 2024-2028. The domestic customer connections are calculated as a 95% share of the total customers connected.
			Vision: A total number of 500,000 new domestic customers to be connected annually over the planning period. This is based on projected new connections by Kenya Power. Universal connectivity(99%) is expected by 2028.
			Low: A total number of 271,278 new domestic customers to be connected in 2024. This is based on average projected connections by Kenya Power over the period 2024-2028. Thereafter an annual reduction of 0.5% (from the masterplan 2015) applied over the planning period.
Specific Consumption	KPLC annual reports 2022/2023 Generation and Transmission Masterplan 2015	2022/2023 Domestic (DC) specific consumption was 371.36kWh/pa. Apportionment of specific consumption into urban and rural share was assumed to be the proportion of KPLC (76.1%) and REP (23.94%)	Specific consumption is applied for new customers connected over the planning period. **Reference:** Rural: 74.16kWh/pa: This is the specific consumption of customers in the 0-30kWh consumption band. Urban: 464.93kWh/pa: Calculated based on a weighted average of the rural specific consumption and urban specific consumption.

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
		customers respectively for all scenarios.	Annual increase in consumption of existing customers is 3.76% based on the average of the last 5 years.
			Vision: Rural: 111.45kWh/pa: Urban: 786.05 kWh/pa Calculated based on the apportionment adopted by the 2015 Masterplan. Annual increase in consumption of existing customers is 3.76% based on the average of the last 5 years.
			Low: Rural: 55.72 kWh/pa Urban: 393.02kWh/pa Calculated based on the apportionment adopted by the 2015 Masterplan. Annual increase in consumption of existing customers 2.26% being the worst recorded growth in DC sales in the last 5 years.

3.12.3 Small Commercial Consumption

Over the last five years, there has been a consistent increase in electricity sales within the Small Commercial (SC) customer category, marked by an average annual growth rate of 4.06%. Beyond the demographic assumptions outlined in Table 3-5, the assumptions detailed in Table 3-6 were applied to complement forecasting of small commercial consumption over the planning horizon.

Table 3-6: Small Commercial Assumptions

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
Electrification / Connections	2022/23 KPLC Annual accounts	Total small commercial connections in the base year: 449,148	For all scenarios, growth in new small commercial connections is assumed to be 36.16% of growth in new domestic connections.

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
			This is based on 26-year historic correlation between small commercial and domestic connections.
Specific Consumption	2022/23 KPLC Annual accounts	Specific Consumption as of June 2023: 3,800.49 kWh/pa	Overall increase in small commercial consumption is as follows:
			Reference: 4.06% based on an average growth in sales for the past 5yrs
			Vision: 10.73% based on the highest achieved growth in small commercial sales in the last 5 years.
			Low: 0.59% being the worst recorded growth in small commercial sales in the last 5 years.

3.12.4 Street lighting

Street lighting consumption is driven by number of lamps per meter, specific consumption of the lamps, demographics and the correlation with new domestic connections. In this forecast, it was assumed that there are 10 lamps per street light connection (meter) with each lamp rated 140 watts and operating from 6:00pm to 6:00am. In addition to the demographic assumptions presented in Table 3-5, the following assumptions shown in Table 3-7 were applied.

Table 3-7: Street Lighting Assumptions

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
Street Lighting (SL) Coverage	KPLC Street Lighting Data Sustainable Energy for All report MTP IV report	National street lighting coverage of 56.8% 13% streetlights not in operation due to disconnection	Target years for universal coverage of street lighting and 0% of streetlights disconnected.
			Reference: 7 years based on the SDG 7 SE4ALL target of universal access by 2030.
			Vision: 5 years based on MTP IV target of universal access
			Low: 13 years. This was obtained by growing the current national coverage of 56.8% by 4.60% (average growth rate for the past 2 years) to achieve 100% coverage in 2036.
Electrification / connections	2022/23 KPLC Annual accounts.	Number streetlight connections (meter): 10	For all scenarios, growth in streetlight connections is assumed to be 65.70% of growth in new domestic connections.

Category	Data sources	Base Year Assumption (2023)	Projection assumptions
			This is based on 25-year historic correlation between new street lighting and new domestic connections.
Specific Consumption	KPLC Street Lighting Data	6,132 kWh/pa - ((140*10*12*365)/1000) (10 lamps each 140 Watt on 6pm to 6am)	The base year specific consumption is maintained across all scenarios over the entire planning horizon.

3.12.5 Large Commercial and Industrial Consumption

Gross Domestic Product (GDP) is assumed to be the major driving factor for growth in commercial and industrial consumption. A regression analysis using the past seven years' records of GDP and large power consumption, shows that a 100% increase in GDP results into approximately 47% increase in large power consumption as shown in the equation below:

Based on the relationship above, GDP assumptions applied in the development of Large Commercial and Industrial forecast are as shown in Table 3-8**.**

Table 3-8: Large Commercial and Industrial Assumptions

Determined by	Data sources	Base Year Assumption (2023)	Projection assumptions
Connections & consumption through GDP growth	KNBS Quarterly GDP Report-First Quarter 2023 Draft Budget Review Outlook Paper (BROP) 2023 Vision 2030 Medium Term Plan (MTP) IV	GDP Growth of 5.3% assumed across the three scenarios This is based on GDP growth for 1st quarter 2023 reported by KNBS.	**Reference:** Adopted Draft BROP 2023 GDP projections for 2024 to 2027 and retained the growth rate of 2027 (6.3%) for the remainder of the planning period. **Vision:** Adopted Vision 2030 MTP IV GDP projections for 2024 to 2027 and 10% for 2030 (Vision 2030 Target) which is retained for the remaining planning period. **Low:** Average historic GDP growth for past 10yrs (2013-2022) at 5.10% Average injection of GDP by Flagship projects is 2%.

3.12.6 Suppressed Demand

Suppressed demand consists of system load outages (forced and planned) and load shed to ensure system stability when there is insufficient generation or a fault in part of the electric grid. In the forecast, this unmet load is added to the projected demand across all customer categories and scenarios.

The underlying equations used in computation of suppressed demand in the model are as follows:

$$SD=(O+LS)/CB$$

and;

$$O=C\times S\times P$$

Where:

SD Suppressed demand

O Outages in GWh for the base financial year

LS Load shed in GWh for the base financial year

CB 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.

The suppressed demand assumptions applied in the forecast are as shown in Table 3-9.

Table 3-9: Suppressed Demand Assumptions

Category	Data sources	Base Year Assumption (2022)	Projection assumptions
Suppressed demand	KPLC National Control Centre 2023-2028 Kenya Power Strategic Plan	**Outages** (Forced & Planned) as a percentage of 2022/23 sales (10,232.94GWh)	Target suppressed demand values;
		2.211% based on: CAIDI=2.25 hrs, SAIFI=44.90, Peak Demand=2,149.26MW	**Reference**: tends towards 0.826% in 2043
		Suppressed Demand as a percentage of 2022/23 sales (10,232.94GWh)	**Vision**: tends towards 0.826% in 2028 (MTP IV target for universal access)
		2.16% based on sum of outages (217.41 GWh) & Load shedding (3.91GWh)	**Low**: tends towards 0.826% beyond 2043 0.826% is obtained by reducing the current suppressed demand of 2.16% by an average growth rate of 4.70% (average growth rate in CAIDI over the period 2023-2028)

3.12.7 System loss reduction

System energy losses were projected to decrease gradually from 23.0% recorded in the base year by 1.80 percentage points annually in the period up to 2028.

3.13 Kenya Vision 2030 Flagship Projects

Energy is a key enabler for realization of the Kenya Vision 2030. The Vision identifies several flagship projects that are expected to have an impact on electricity demand in the country. It is assumed that the flagship projects contribute to electricity demand through:

i. A direct impact on the overall consumption in both reference and vision scenarios.
ii. A 2% average injection in GDP which affects large power consumption.

Details of the flagship projects considered are indicated in Table 3-10.

Table 3-10: Flagship Projects and their assumptions

Project	Reference scenario				Vision scenario			
	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	2035	50	2026	15	2031	50
Electrified Standard Gauge Railway-Mombasa-Nairobi					2030	98	2039	130
Oil Pipeline and Port Terminal (LAPSSET)	2024	1	2035	35	2024	1	2030	35
Special Economic Zones (Kedong, Dongo Kundu, Konza)	2024	5	2042	60	2024	5	2040	60
Special Economic Zones (KenGen)	2026	5	2045	151	2026	5	2035	151
E-Mobility	2024	37.94	2043	1,083.18	2024	37.94	2043	1,083.18
E-Cooking	2024	21.7	2044	98.6	2024	25.5	2044	133.2

3.14 Results of the forecast

This section presents the long-term national electricity demand forecast for the period 2024 – 2043. The section highlights the projections of energy purchases, electricity sales and peak demand. The section further provides a comparative analysis of the long-term plan forecast 2024-2043 and the actual sector performance over the period.

3.14.1 Energy purchased

Results of the forecast show that the energy purchased is expected to grow at an average annual rate of 6.5% from 13,627GWh in 2023 to 48,499GWh in 2043 under the reference scenario. In the vision scenario, it's expected to grow exponentially at an average annual rate of 9.1% to 80,955 GWh in 2043. This growth is mainly driven by a demand from emerging technologies such as electric vehicles and electric cooking as well as expected flagship projects.

In the low scenario, the energy purchased is expected to grow at an annual average rate of 4.0% to 29, 742GWh in the year 2043. The results are as shown in Figure 3-6.

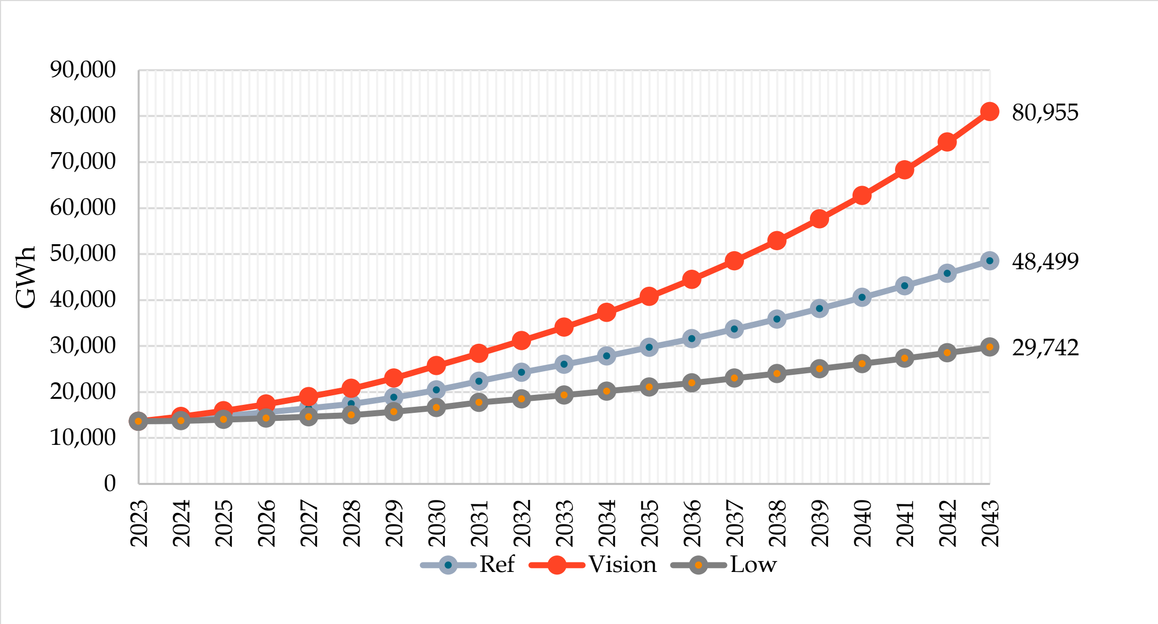

Figure 3-6: Energy Purchased

3.14.2 Electricity Sales

Electricity sales are expected to grow at an average of 6.1% from 10,488GWh in 2024 to 34,239GWh and 10.1% to 60,049GWh in 2043 in the reference and vision scenario respectively. In the vision scenario, the growth in sales is attributed to increased demand from emerging technologies such as electric vehicles and electric cooking as well as expected flagship projects. The results are as shown in Figure 3-7.

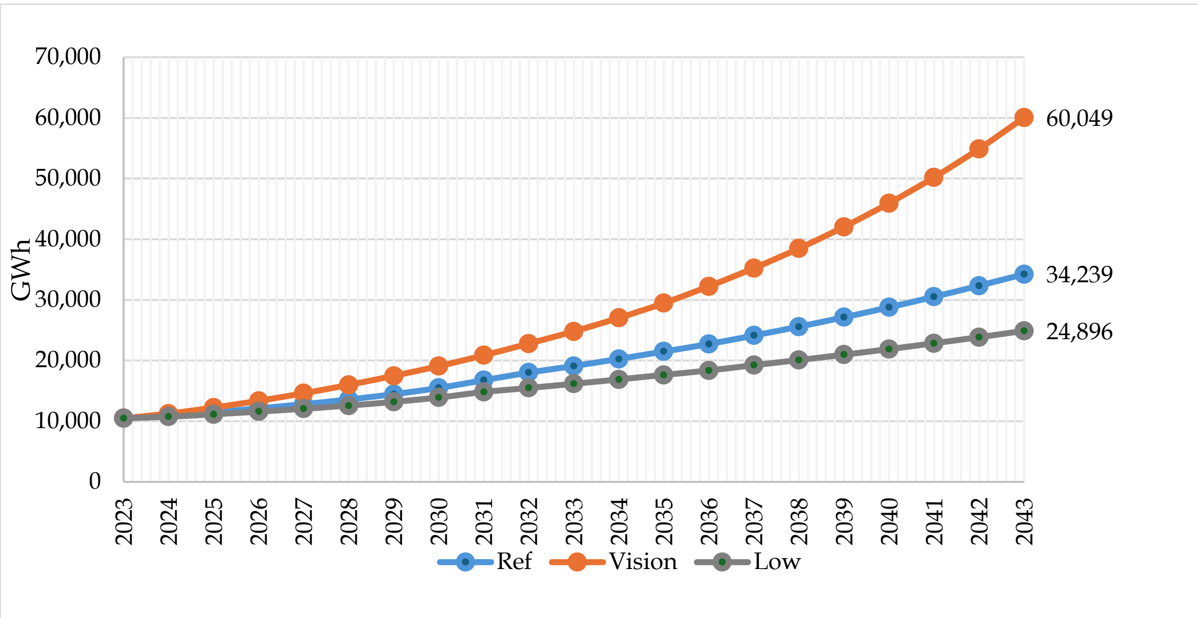

Figure 3-7: Electricity Sales

3.14.3 Peak Demand

Peak demand as projected in the long-term national electricity demand forecast for the period 2024 – 2043 is expected to grow from 2,170 MW in 2023 to 8,152 MW, 13,495 MW and 4,996 MW in 2043 in the reference, vision and low scenario respectively. In the vision scenario the growth in peak demand is primarily driven by emerging technologies such as electric vehicles and electric cooking as well as expected flagship projects. The results are as shown in Figure 3-8

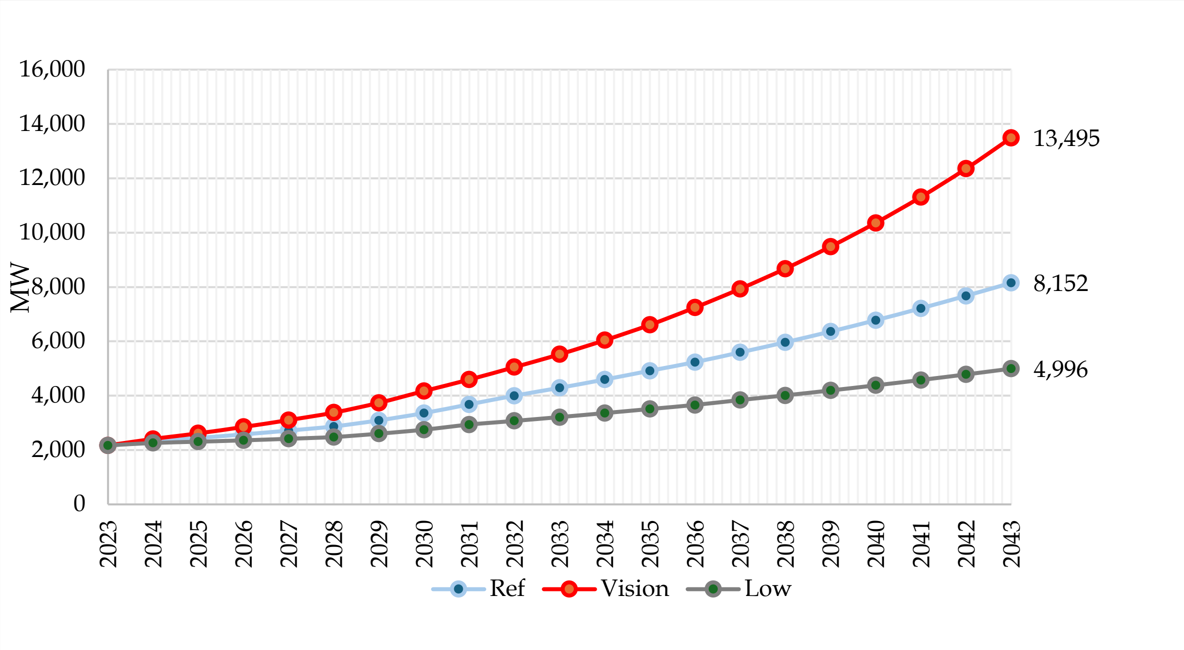

Figure 3-8: Peak Demand 2024 – 2043

3.14.4 Universal Access

Under the reference scenario, based on the current connection trajectory of an average of 300,000 annually, universal electricity access is projected to be achieved by the year 2031. In the vision scenario, universal access will be attained by the year 2028 by connecting an on average 500,000 customers annually.

3.15 Results Comparison

3.15.1 Actual versus projected peak demand

Peak demand forecast results from the 2015-35 PGTMP to the 2024-2043 LCPDP were compared against the actual recorded from 2016 to 2023 to verify the soundness of the forecasting methodology. The analysis shows a decline in deviations over time as shown in Table 3-11.

Table 3-11: Comparison of Actual Peak Demand Vs Projected, 2016-2023

Projected Reference Peak Demand, MW						Actual Peak Demand, MW	Variance from Actual Peak Demand, MW				
Year	PGTMP 2015-2035	LCPDP 2017-2037	LCPDP 2019-2039	LCPDP 2020-2040	LCPDP 2022-2041		PGTMP 2015-2035	LCPDP 2017-2037	LCPDP 2019-2039	LCPDP 2020-2040	LCPDP 2022-2041
2016	1,679					1,636	-43				
2017	1,804					1,754	-50				
2018	1,942	1,866				1,859	-83	-7			
2019	2,090	1,978				1,912	-178	-66			
2020	2,259	2,103	2,002			1,976	-283	-127	-26		
2021	2,451	2,234	2,063	2,029		2,036	-415	-198	-27	7	
2022	2,633	2,421	2,153	2,110	2,149	2,149	-512	-300	-39	11	0
2023	2,823	2,586	2,312	2,190	2,191	2,170	-653	-416	-142	-20	-21

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

A comparison of the reference scenario forecast results indicate a slight increase in the forecasted electricity sales, energy purchased and peak demand from the LCPDP 2024-2043 long-term plan over the period 2023 to 2028 as shown in Table 3-12.

The slight increase in the forecasted demand is due to increase in specific consumption, number of customers expected to be connected every year and GDP growth projected over the medium term.

Table 3-12: Comparison of the demand forecast results with previous forecast.

Reference Scenario	2023	2024	2025	2026	2027	2028
Peak Demand						
LCPDP 2022-2041	2,191	2,268	2,353	2,441	2,585	2,737
LCPDP 2024-2043	2,170	2,327	2,446	2,575	2,716	2,871
Deviation	-21	59	93	134	131	134
Energy Purchased						
LCPDP 2022-2041	13,304	13,760	14,257	14,780	15,632	16,538
LCPDP 2024-2043	13,627	14,133	14,806	15,596	16,475	17,434
Deviation	323	373	549	816	843	896
Electricity Sales						
LCPDP 2022-2041	10,531	11,098	11,720	12,382	13,080	13,822
LCPDP 2024-2043	10,488	12,382	13,497	14,737	16,097	17,687
Deviation	-43	1,284	1,777	2,355	3,017	3,865

4 ASSESSMENT OF NATURAL ENERGY RESOURCES IN KENYA

Kenya has abundant natural resources and predominantly relies on renewable energy for her energy needs. Extensive assessments have been conducted to ascertain the potential of various energy sources, identifying opportunities for their development. The nation prioritizes the promotion of renewable energy while also harnessing other forms of clean energy to provide essential services within its power grid. This chapter presents Kenya's electricity generation potential resources including ongoing interconnections with neighbouring countries under the regional power trade initiatives.

4.1 Renewable energy sources

Kenya possesses a diverse array of renewable energy sources such as solar, hydro, wind, biomass, and geothermal resources. With a strategic vision towards fostering a green economy, the nation is dedicated to increasing the proportion of renewable energy within its energy generation portfolio. The government has prioritized the development of geothermal, wind and solar energy plants as well as solar-fed mini-grids for rural electrification.

4.1.1 Geothermal energy

Kenya is endowed with abundant geothermal resources, poised to significantly contribute to the country's transition towards clean and renewable energy sources. Kenya was the first African country to build geothermal energy sources. Kenya has an estimated 10,000 MW potential mainly located in the Rift Valley (Annex C). Geothermal activity is widespread in many parts of the Kenyan Rift valley. Exploration of geothermal resources in Kenya started in 1956 with deep drilling commencing in 1973 and the first geothermal generator was commissioned in July 1981. Geothermal energy provides reliable base load power and has comparatively low electricity production costs. Currently geothermal power is only being harnessed in the Olkaria, Menengai and Eburru fields. In the medium and long term new geothermal reservoirs, such as Suswa, Longonot, Akiira and Baringo Silali will be developed. Other potential geothermal prospects within the Kenya Rift Valley yet to be exploited include Emuruangogolak, Arus, Badlands, Namarunu, Chepchuk, Magadi and Barrier. Geothermal installed capacity is at 940MW contributing 45.4% of the total annual electricity supplied in the country (2022/23 KPLC annual report).

Geothermal power plants have a prominent place in Kenya's overarching development plans. Geothermal power has the potential to provide reliable, cost-competitive, baseload power with a small carbon footprint, and reduces vulnerability to climate change by diversifying power supply as an alternative to hydropower. Kenya has set out ambitious targets for geothermal energy. It aims to continue expanding its geothermal power production capacity. The geothermal sector has both public and private players backed by various development finance institutions showcasing the confidence in the geothermal resource as a form of sustainable energy.

4.1.2 Hydropower

The national hydropower potential in Kenya is estimated to range between 3,000 to 6,000 MW. Currently over 800MW is exploited, mainly in large installations owned by KenGen. During the period from July 2022 to June 2023, hydropower plants contributed approximately 19.33% of the nation's annual electricity generation, marking the lowest hydro energy contribution in the past decade. There are 8 power stations with capacity of more than 10MW each that have reservoirs. At least half of the overall potential originates from smaller rivers that are key for small-hydro resource generated electricity. The Feed-in Tariffs (FiT) policy has spurred private sector interest to develop small-scale hydro plants. There is a large pipeline of small hydropower projects under the FiT scheme. Feasibility studies of smaller hydropower projects are also on-going under the same framework.

Given the lengthy lead-time associated with large hydropower projects, there is need to focus on developing small hydropower projects in the medium term. Besides meeting capacity requirements, small hydro plants play a pivotal role in supplying electricity at the distribution level, thereby minimizing losses and supporting system voltages.

Moreover, there is untapped potential for pumped storage hydropower generation, which involves storing energy in the form of water in an upper reservoir, pumped from a lower elevation reservoir. During periods of high electricity demand, stored water is released through turbines, functioning similarly to conventional hydro stations. Excess energy can be utilized to recharge the reservoir by pumping water back to the upper reservoir, creating a dual-functioning system. Preliminary studies identify suitable sites for pumped storage hydropower projects, including Lake Turkana, Samburu, Kapenguria, Kipcherere, Lomut, Sondu, and Homabay South.

4.1.3 Wind energy

The development costs associated with wind power have experienced a notable decline in recent years, marking a significant trend in the renewable energy landscape.

The prime wind sites in Kenya are located in Marsabit, Samburu, Laikipia, Meru, Nyeri, Nyandarua, and Kajiado counties, as identified in the Solar and Wind Energy Resource Assessment (SWERA) mapping exercise conducted in 2008. Additionally, areas such as Lamu, offshore Malindi, Loitokitok at the base of Kilimanjaro, and the Narok plateau are also of significant interest.

On average the country has an area of close to 90,000 square kilometres with excellent wind speeds of 6m/s and above. The potential capacity for wind energy in the country is about 1.073TW representing areas with wind speeds above 6m/s (Exploring Africa's Untapped Wind Potential, Sean Whittaker, IFC). For locations with wind speeds above 7.5m/s, the potential capacity is about 242.6 GW at a capacity factor (load factor) of 40.5% corresponding to an annual generation of 862 TWh/annum (P50). Taking only locations with average wind speeds of above 8.5m/s (exceptional wind speeds), the potential capacity for the country is estimated at 139.6 GW with a corresponding capacity factor of 43.6% which is the highest capacity factor in Africa. The total annual energy generation from these areas is approximately 533.2 TWh/annum. This analysis has excluded areas with elevation greater than 2000m, urban areas and airports, areas with population greater than 200 people/km2, water bodies and protected areas. This shows that the country has exceptional onshore wind resources in the Northern parts of the country and this potential coupled with the high capacity factor makes the resource very favourable for grid connected wind farms. The most recent investments in wind energy in Kenya are Lake Turkana 310 MW wind power plant which is the largest wind farm in Africa, and Kipeto 100 MW wind power plant. The two wind farms have registered exceptionally good capacity factors with LTWP having an average of 55% over the five years of operation while registering a CF of 64% in the period 2022/2023. This goes to confirm the excellent wind resource in the country. Wind power plants are intermittent in nature with capacity factors typically between 20% and 55%. The intermittency of wind power plants causes a challenge in the power network as their share on the grid rises. There is need to develop accurate forecasting capacity in the country to ease the effects the resource has on the network and other generating plants especially hydro units.

4.1.4 Solar Energy Resources

Kenya boasts significant potential for solar energy utilization year-round, owing to its strategic equatorial location and abundant insolation levels ranging from 4 to 6 kWh/m2/day (Annex D). A recent study conducted by the Kleinman Center for Energy Policy at the University of Pennsylvania reveals that Kenya has emerged as a global leader in solar energy generation — creating favorable conditions for harnessing solar power. The country's solar energy generation potential is estimated at approximately 15 GW. Presently, around 200,000 photovoltaic solar home systems are in operation across Kenya, predominantly rated between 10We and 20We and costing approximately KSh. 1,000/We. These systems collectively generate 9 GWh of electricity annually, primarily catering to lighting and powering television sets for about 1.2% of Kenyan households. Market penetration rates are expected to increase substantially, especially considering the untapped potential in rural areas where approximately four million households reside. With evolving rural electrification strategies and diminishing solar energy production costs, the deployment of solar systems is poised for significant growth, facilitating electricity supply to households, water heating, and telecommunications infrastructure in remote regions.

Forecasts by the International Energy Agency (IEA) suggest that solar photovoltaic energy will constitute the largest share (47%) of the technology mix for mini-grids and off-the-grid systems power generation in Sub-Saharan Africa by 2040. Solar PV system is a major cause of defections from power grid supply, posing a big threat to conventional utility supply market.

Currently, solar power plants connected to the grid are: The Rural Electrification and Renewable Energy Corporation (REREC) 50MW Garissa Solar PV, and Selenkei, Eldosol (in Eldoret) and Globeleq (in Malindi) each with 40MW solar PV power plants.

4.1.5 Biomass, biogas and waste-to-energy

Biomas are flexible renewable energy sources such as wood and wood residues, agricultural crops and residues; and animal and human wastes. Though biomass appears to have modest potential at present, this could significantly increase with the agro-industrial development. This is mainly through revamping sugar mills and future concentration of other agro industries.

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 cogenerate about 1 MW in the 100 factories using their own wood plantations for drying. Biogas is a mixture of methane and carbon dioxide with small amounts of other gases and needs a further cleaning step before it is usable. Biogas is similar to landfill gas, which is produced by the anaerobic decomposition of organic material in landfill sites.

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

4.2 Fossil energy sources

Coal and crude oil are the only domestic fossil energy resources available for extraction and potential use in power generation in the country while natural gas is imported.

4.2.1 Coal

Coal reserves in Kenya are concentrated in the Mui Basin, situated approximately 200 km east of Nairobi within Kitui County. 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 signifying a strategic move towards harnessing this resource for energy production.

Coal which has widespread deposits and relatively low production costs, can be used for power generation. However, it has strong environmental and social impacts as it requires large scale resettlement plans and will result in an increase in the amount of carbon emission.

4.2.2 Crude oil and liquid petroleum products

Domestic crude oil deposits have been located in Turkana and the initial plan is to transport the oil via a pipeline to Lamu for export. The commercial viability of exploitation and export or domestic refining of the crude is still being established.

Currently, the national primary energy consumption landscape is predominantly shaped by biomass sources such as charcoal and wood fuel, constituting 68% of the total. Petroleum products follow closely, accounting for 22%, while electricity contributes 9%, with approximately 8% sourced from fossil fuels like heavy fuel oil (HFO) and gasoil, with the remainder derived from renewable energy sources. Coal makes up a mere 1% of the energy mix. Demand for petroleum products has exhibited steady growth, increasing by approximately 10% annually.

Kenya relies entirely on imports for its petroleum products, with refined products sourced mainly from Abu Dhabi (referred to as "Murban crude") and Saudi Arabia (referred to as "Arabian Medium"). Murban crude boasts higher quality, yielding more diesel, gasoline, and kerosene, and less heavy fuel oil compared to Arabian Medium.

Kenya’s electricity sector previously relied heavily on imported crude oil and petroleum products fueling nearly 40% of the installed power generating capacity. With the commissioning of geothermal power plants, this dependency has decreased in recent years and fossil plants provide less than 10% of the annual electricity generated.

Heavy fuel oil (HFO) is deemed unsuitable for power generation expansion due to its adverse environmental impacts. Similarly, gasoil and kerosene are not recommended for expansion due to their high prices in the global market, resulting in elevated opportunity costs for Kenya. However, these fuels could serve as options for backup and peaking capacity plants.

4.2.3 Natural gas

Natural gas ranks as the third most significant energy source worldwide, measured by energy content, trailing behind crude oil and coal. Africa Oil Corporation, a Canadian oil and gas exploration and production company, discovered natural gas onshore deposits in north-eastern Kenya. An appraisal plan to follow up the gas discovery is currently being evaluated in consultation with the Government of Kenya. In addition, the Africa Oil Corporation is considering drilling an appraisal well on the crest of the large Bogal structure to confirm the large potential gas discovery which has closure over an area of up to 200 square kilometers. According to a third-party independent resource assessment, the gross best estimate of prospective resources for Bogal stands at a noteworthy 1.8 trillion cubic feet of gas. However, owing to the nascent stage of exploration, it is presumed that domestic natural gas will not emerge as a potential energy source for power generation in the medium term.

4.2.4 Liquefied natural gas (LNG)

Liquefied natural gas (LNG) is a relatively new option for large-scale power generation. 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. Importation of LNG would also provide economic benefits for other consumers, such as in industry, households or transport sectors. However, it's crucial to acknowledge that LNG is essentially natural gas liquefied at the country of origin, a process constrained by the existing transport infrastructure, which subsequently elevates the overall costs associated with imported LNG. Despite its potential advantages, the importation of LNG is tethered to logistical constraints imposed by the requisite liquefaction and regasification facilities, compounded by the presence of competing demands on the global market.

In light of these constraints, the Government of Kenya has embarked on initiatives to explore opportunities for developing domestic gas resources instead of relying solely on imports. If viable domestic gas resources were to become available, imported LNG would likely lose its competitive edge as a primary energy source.

4.3 Other energy sources

Besides the indigenous energy resources that form the basis for power generation, other energy sources and systems that are being considered include battery energy storage, nuclear energy, green hydrogen and energy imported from neighbouring countries through inter-connections (which could be based on various types of energy sources). These sources are discussed below.

4.3.1 Nuclear Power

Uranium ore serves as theprimary raw material essential for nuclear power production. Globally, the total identified recoverable resource of uranium reserves stood at an estimated 6.14 million tonnes [1]in 2017. At current consumption levels, these reserves are projected to last more than 130 years[2]. Growing or diminishing future demand should affect the time taken for complete depletion of the resource. In

[1] World Nuclear Association

[2] OECD Nuclear Energy Agency, International Atomic Energy Agency: Uranium 2018: Resources, Production and Demand

Kenya, low levels of uranium oxide have been discovered with exploration of uranium still ongoing[3].

Nuclear power is harnessed in 30 countries worldwide, with South Africa standing as the sole African nation with nuclear power capabilities. Across nations where nuclear electricity is generated, nuclear power capacity ranges from 2% to 71% of the total installed capacity. The escalating recognition of nuclear power's benefits, including its role in climate change mitigation and bolstering energy security, has sparked heightened interest in nuclear technology for electricity production globally, including in Kenya.

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.

4.3.2 Battery Storage

Grid battery energy storage is a rapidly maturing technology being used by utilities in improving security and reliability of supply especially for systems with constrained conventional generation and transmission systems. Advantaged by decreasing costs owing to ongoing research and increasing usage, the technology has potential to compete favourably with traditional thermal based frequency regulation and peaking technologies such as gas turbines and diesel plants.

The expected excess energy during off peak hours and increased intermittent capacity in the national grid present an opportunity for introduction of battery storage to balance demand and supply in the system. Additionally, its load shifting and potential to transform variable renewable energy to dispatchable sources capabilities can offer real solutions in off-grid systems as well as constrained grid areas.

Grid scale Battery Energy Storage Systems (BESS) can help in addressing grid reliability and provision of ancillary services to support integration of increased levels of intermittent renewable energy in the system.

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[3] Power Generation and Transmission Master Plan, Kenya, 2016

BESS 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 power system.
ii. Voltage instability in the grid 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.

The MoE&P in collaboration with The World Bank has completed a technical study on BESS integration into the national grid. The preliminary analysis indicates the need for BESS in the grid. The BESSs are expected to store excess energy from geothermal and VRE capacity in the national grid hence assist in load balancing while offering the much-needed ancillary services to the grid.

4.3.3 Green Hydrogen

Hydrogen is emerging as one of the leading options for storing energy from renewables with hydrogen-based fuels potentially transporting energy from renewables over long distances – from regions with abundant energy resources, to energy-deficient areas thousands of kilometers away. Green hydrogen is expected to play an important role in the energy transition. In Kenya it would complement the large shares of renewable, accelerate electrification by leveraging on low-cost renewable electricity. Additionally, it will serve as a pivotal tool in the endeavor to decarbonize industries traditionally resistant to conventional emissions reduction measures, such as heavy industry, long-haul freight, shipping, and aviation.

Kenya has started a green hydrogen programme. The purpose of this programme is to come up with a roadmap, strategy, policy and regulatory framework on the production of green hydrogen using the extra capacity in the grid, especially at night in the short to medium term. The country is in the process of developing a green hydrogen plant that will utilize geothermal energy to produce green ammonia to be used for manufacturing of fertilizers. The project will provide affordable fertilizer to the market, while also accelerating the phasing out of fossil fuels and reinforcing the position of Kenya as a global leader in renewable energy.

4.4 Interconnections with neighboring countries

Interconnections within the region present an opportunity to optimize the usage of clean energy resources available in the region to benefit the region's society with reduced cost of electricity production and increased rate of access. This may include additional sources of energy and power, the provision of ancillary services (e.g. reactive power, black start capability) and an overall higher security of supply as well as lower costs from sharing of generation back-up capacity or combining complementary power generation systems (e.g. hydro versus thermal based generation).

The Kenyan grid is interconnected with Uganda via 132 kV double circuit transmission line, Ethiopia via 500 HVDC line and the other neighbouring countries via medium voltage distribution lines. There are ongoing works to connect Kenya to Tanzania via 400kV double circuit line. These interconnections serve as critical conduits for regional energy collaboration, facilitating the exchange of resources and fostering a more resilient and sustainable energy landscape across the region.

5 GENERATION EXPANSION PLANNING

5.1 Introduction

This chapter provides the proposed 20-year plan for expanding generation from 2023 to 2043, outlining the process for planning for the expansion of power generation, scenarios and sensitivities, and discusses the results of multiple simulations conducted. It additionally presents the least cost generation plan while taking into account the best growth strategy for the Kenyan power system, considering various planning assumptions and limitations.

5.2 Expansion planning methodology

The LIPS-XP/OP tool was employed to simulate the generation system, with updates made to the respective input data for power plants, hourly electricity demand forecasts, and planning criteria. Key parameters considered in the modelling process include plant capacity, capital investment costs, fuel costs, fixed and variable operations and maintenance expenses, economic life, and planned commissioning and decommissioning dates for the plants.

Simulations were conducted using various planning assumptions and criteria, encompassing plant availability, generation, planning reserves, intermittent energy balancing, and hydrological forecasts. The generation expansion planning incorporated three demand scenarios: reference, vision, and low. Additionally, sensitivity analyses were performed focusing on hydrology and impact of green hydrogen on vented geothermal steam within the context of the reference case. Committed and potential projects were simulated, taking into account the supply and demand balance.

5.3 Planning Assumptions

Table 5-1 shows the generation expansion planning assumptions applied in the model for the plan period 2024-2043.

Table 5-1: Generation expansion planning assumptions

Description	Assumption	Basis for the assumption
Firm capacity		
Large	P90*	Exceedance probability value of monthly maximum output based on
Small	25%	Minimum of the monthly average capacity factor for low hydrology
Wind	25%	Sum of the P90 available capacity of existing wind power plants at peak
Solar PV	0%	Solar not available during peak
Biomass	50%	The assumption is based on the possibility of challenges in availability
BESS	25%	Mainly due to assumed discharging over a period of four hours at peak.
Other assumptions		
Load curve	2022 annual	Maintained over the planning period as it is assumed that the profile
Reserve Margin	13% (average	Calculated considering the largest unit in the system plus 10% of peak
Discount rate	12.8%	Based on gazetted applicable discount rate for public institutions
Hydrology	Average	Second quartile of the monthly hydropower output values based on
	Low hydrology:	First Quartile of the monthly energy output values based on historical

**P90 – 90% probability that the value will be equal to or greater than the stated value*

5.4 Hydrology

The available capacity and the annual generation of hydropower plants depend on the present hydrology. For this LTP, the half-hour dispatch data and monthly large hydropower plants production for a period of the 10 years was considered. For the months of January to September, the years 2014 to 2023 were considered while for the months October to December, the years 2013 to 2022 were considered. This is because of data unavailability for the base year 2023 for the three months. The period and data are considered representative as they cover all the upgrades that had been carried out in various hydropower plants such as Tana, Masinga, Gitaru, Kindaruma and Kiambere and includes drought periods in 2017 and prolonged drought from 2021 through 2023.

The plan considers average and low hydrology cases. For the average hydrology case, the second quartile (median) was considered for projections. In the low hydrology case, the lower quartile of the monthly large hydropower plants production for the ten-year period was considered, which is equivalent to the worst-case scenario observed. The generation expansion modelling considers the firm capacity of hydropower plants, which is defined as the P90 exceedance probability value determined based on historic half hourly production data.

5.5 Energy Storage

Battery Energy Storage Systems (BESS) were introduced in this LCPDP plan to cater for peaking capacity gaps in the medium term as well as manage vented geothermal steam during hours of low demand. Additionally, battery storage will help in provision of primary reserves for frequency regulation as penetration of Variable Renewable Energy Sources (VRES) in the energy mix increases. Further, it is expected that energy from BESS will reduce the need for utilization of thermal energy through energy shifting thus reducing GHG emissions.

BESS plants were modelled as peaking plants in addition to operating as load during charging for four hours during periods of off-peak demand thereby minimizing venting of geothermal steam. Furthermore, the expansion of Variable Renewable Energy Sources (VRES) in the energy mix is set to bolster the role of battery storage in supplying primary reserves for frequency regulation. The proposed total BESS capacity for this period is 500MW. This, in turn, is expected to curtail the demand for thermal energy utilization, leading to a decrease in greenhouse gas (GHG) emissions.

Pumped hydro storage plants were included in the model to offer long-term peaking capacity. Pumped Storage Plants (PSP) further enhance the system by providing ancillary services, even while in pumping mode. They are characterized by their cost-effective operation and maintenance, resilience to drought, and the potential to substitute more costly thermal plants.

Similar to BESS, PSP were assumed to utilize the excess energy from geothermal to pump the water to the upper reservoir during off peak hours. The water would be turbined back into the lower reservoir and potential energy then transformed into power during peak. 600MW capacity pumped hydro storage plants with four hours of pumping during hours of off-peak demand have been considered in the model.

5.6 Green Hydrogen

Kenya has taken a significant step forward in its commitment to sustainability and environmental responsibility. The country is to develop green energy and fertiliser facility in Naivasha. This monumental initiative is set to not only usher in a new era of renewable energy for Kenya but also serve as a critical component in the nation's quest to decarbonize its industrial and agricultural sectors and contribute to a greener, more sustainable future. The envisioned facility is poised to harness the substantial potential of geothermal energy for the purpose of producing the much-needed green hydrogen.

5.7 Energy resources

5.7.1 Hydropower modelling

The available capacity and the annual generation of hydropower plants depend on the present hydrology. For this LTP, the half-hour dispatch data and monthly large hydropower plants production for a period of the 10 years was considered. For the months of January to September, the years 2014 to 2023 were considered while for the months October to December, the years 2013 to 2022 were considered. This is because of data unavailability for the base year 2023 for the three months. The period and data are considered representative as they cover all the upgrades that had been carried out in various hydropower plants such as Tana, Masinga, Gitaru, Kindaruma and Kiambere and includes drought periods in 2016/17 and the current 2022/23 financial years.

The plan considers average and low hydrology cases. For the average hydrology case, the second quartile (median) was considered for projections. In the low hydrology case, the lower quartile of the monthly large hydropower plants production for the ten-year period was considered, which is equivalent to the worst-case scenario observed. The generation expansion modelling considers the firm capacity of hydropower plants, which is defined as the P90 exceedance probability value determined based on historic half hourly production data.

5.7.2 Generation expansion candidates

The various candidate power generation projects considered in this planning process are discussed in this section. The availability and potential of the energy resources and the techno economic parameters relating to the generation technologies were used in the preliminary economic assessment using the screening curves methodology. The projects evaluated included several committed projects expected to be commissioned in the medium to long term. This is shown in Table 5-2.

Table 5-2: Summary on generation expansion candidates

Description	Description	Assumptions/Remarks
Large hydropower	• Karura 90MW hydro • High Grand Falls, 693MW • Nandi Forest 50 MW • Western hydro 40 MW	• The system requires more hydropower with storage, large units for system inertia, and additional peaking capacity • Two large hydro projects have feasibility studies completed • Developer for the High Grand Falls project has been identified
Small hydropower	• Generic generation of 22MW annually	• A number of candidate small hydro projects are proposed under the FiT policy • National potential is over 3000MW • They can contribute to firm capacity at peak • Distributed generation supports the system
Wind	• Specific projects and generic wind power plants.	• National potential is over 1.073TW • A number of candidate wind projects are proposed under the FiT policy • Wind units can contribute to capacity at peak • Distributed generation supports the power system • Wind power cost has been decreasing over time
Solar PV	• Specific and generic 40MW solar power projects.	• National potential is over 15W. • A number of candidate solar projects proposed under the FiT policy. • Priority for new candidates based on proposal to add Battery storage to solar plants at no or minimal additional cost to smoothen output and contribute to peaking capacity. • Distributed generation supports the power system. • Solar power cost has been decreasing over time.
Biomass	• Individual biomass projects	• National potential is about 131 MW. • Several candidate biomass projects proposed under the FiT policy. • Distributed generation supports the power system.
Geothermal	• Specific projects proposed by KenGen, GDC or private sector.	• Available steam and ongoing exploration, appraisal and production drilling for generation capacity enhancement. • Several committed projects at Olkaria and Silali fields. • Low-cost generation for baseload energy

Description	Description	Assumptions/Remarks
Nuclear	• Projects proposed by NuPEA based on engagements with identified technology providers/manufacturers.	• Potential low-cost energy sources in the long term • Technology vendors indicate reduced costs for this competitive baseload capacity. • Projected vision demand requires more capacity than may be available from locally available sources
Pumped Storage Hydro	• Greenfield project with two reservoirs. • About 300MW of PSH recommended.	• A prefeasibility study done. Full feasibility to be done soon. • Surplus energy from must-run renewable power plants is available and more is projected from geothermal, nuclear wind and solar PV. • Enhance flexible generation and provide peaking capacity

5.8 Fuel cost forecast

According to the Statistics Review World Energy 2023, global energy consumption is likely to increase by almost 50% by 2050, primarily due to economic and population growth, particularly in Asia. In this regard, liquid fuels will continue to be the main energy source, but the use of renewable energy is forecasted to grow to a similar level. The increase in renewable energy use is driven by decreasing technology costs and government policies, and it will become the primary source for new electricity generation. Renewables' (excluding hydroelectricity) share of primary energy consumption reached 7.5%, an increase of nearly 1% over the previous year. However, batteries and pumped storage will be used to meet demand and stabilize the grid. The push for net-zero emissions will have a significant impact on fossil fuels, furthermore recent political incidences have shown the volatility of the fossil fuel prices. Governments will aim to anticipate and counteract potential drivers of significant price increases and ensure that energy services remain accessible and affordable for all households. Possible actions to support this include promoting energy efficiency and incentivizing the switch to renewable energy sources.

Below is an overview of some of the fuels considered in this forecast:

5.8.1 Crude Oil

The Statistics Review World Energy 2023 anticipates a gradual decline in the demand for oil. The long-term trajectory of global oil demand is significantly influenced by factors such as evolving lifestyles, technological advancements, consumer preferences, and policy changes in transportation and petrochemicals. Projections suggest that between 2030 and 2050, the demand for oil in road transportation will decrease by over 2 million barrels per day on a global scale. By 2050, approximately 30% of passenger cars worldwide are expected to be electric, and nearly 5% of heavy trucks will either be electric or powered by fuel cells. The shift towards green energy is also noticeable in the electricity generation and building sectors. Nevertheless, these reductions in demand are expected to be counterbalanced by increased oil use in aviation, shipping, and the petrochemical industry.

5.8.2 Nuclear/Uranium

Uranium has a very high energy density, 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, must be processed, enriched, and fabricated into fuel elements. This constitutes half the total fuel cost.

The world's power reactors with a combined capacity of approximately 392 GW (10% of global production) require 65,000 tons of uranium each year. The uranium fuel requirement is increasing but the factors increasing fuel demand are offset by the trend for higher burnup of fuel and other efficiencies, so demand is steady.

The World Nuclear Association (as of March 2021) cites prices of about US$ 1,163 per kilogram of uranium as Uranium dioxide (UO_2) reactor fuel which works out to a fuel cost of US$ 0.00429 /kWh. The fuel's contribution to the overall cost of the electricity produced is relatively small, so even a large fuel price escalation will have relatively little effect. Uranium prices are stable and not affected by market fluctuations.

The fuel prices forecasted, and the assumptions made therein for the planning period 2024-2043 are as shown in Table 5-3.

Table 5-3: Fuel Forecast assumptions

Product	Data sources	Assumptions & parameters
Crude oil	EPRA Historical data on Murban crude prices West Texas Intermediate Crude Price forecast:	Historical correlation exists between Murban and WTI Crude prices.

Product	Data sources	Assumptions & parameters
	Link: WTI Crude Oil Forecast 23 to 34	Adopted WTI crude forecast between 2023 &2033.
		An average growth rate of -2.55% is used to forecast for the period 2034-2043. This is derived as the average growth rate in WTI crude prices between 2030 -2033.
Gasoil	2015-2035 Electricity Masterplan by Lahmeyer International	A historical high correlation (99%) between gasoil and crude prices has been observed. The price of gasoil was assumed to be 135% of the crude price as per the Master Plan.
HFO	2015-2035 Electricity Masterplan by Lahmeyer International	A historical high correlation (98%) between gasoline and crude prices has been observed. The price of HFO was assumed to be 75% of the crude price as per the Master Plan.
Uranium	www.world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx	Adopted historical world Uranium at CIF for the period 2014 to 2022
	https://fred.stlouisfed.org/series/PURANUSDM	Adopted a 8yr average growth rate of 0.977% between 2014 & 2022 to forecast the prices for the period between 2024 & 2043.

5.9 Assumptions on transport costs

International shipping costs are considered in calculation of the fuel costs at the national border. Local transport costs are also considered to reflect the actual fuel prices at the respective power plants. Table 5-4 shows the International shipping costs assumptions.

Table 5-4: International shipping cost assumptions

Fuel	Assumption	Data Source
Crude oil	5% mark-up on FOB	2015-2035 Master Plan Assumptions by Lahmeyer International
HFO	13% mark-up on FOB	
Gasoil	4% mark-up on FOB	

Domestic Shipping cost assumptions

As per the EPRA petroleum pump price model, 100% of gasoil received at the port of Mombasa is transported via pipeline while HFO is trucked via the road. In 2022, EPRA approved a multi-year pipeline rate of KSh. 5.03 m^3/km for the period 2022/2023, KSh. 5.12 m^3/km for the period 2023/2024, KSh. 5.44m^3/km for the period 2024/2025.

A pipeline rate of KSh. 5.12 m^3/km was adopted for the base while a rate of KSh. 5.44m^3/km was adopted for the year 2024 and grown by an average growth rate of 0.62%. This is the average growth rate in the pipeline tariff between 2017/18 and 2024/25

Similarly, a constant trucking cost of 9.12 (KSh./m3/km) has been adopted over the planning period. The distance considered between Mombasa and Nairobi is 487 km and 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.

5.10 Fuel Forecast Results

HFO and Gasoil fuel prices are projected to decrease gradually over the planning period by average annual rates of 2.55% and 5.49% respectively. Uranium prices are forecasted to slowly grow over the planning period by an average annual rate of 0.97% as shown in Figure 5-1.

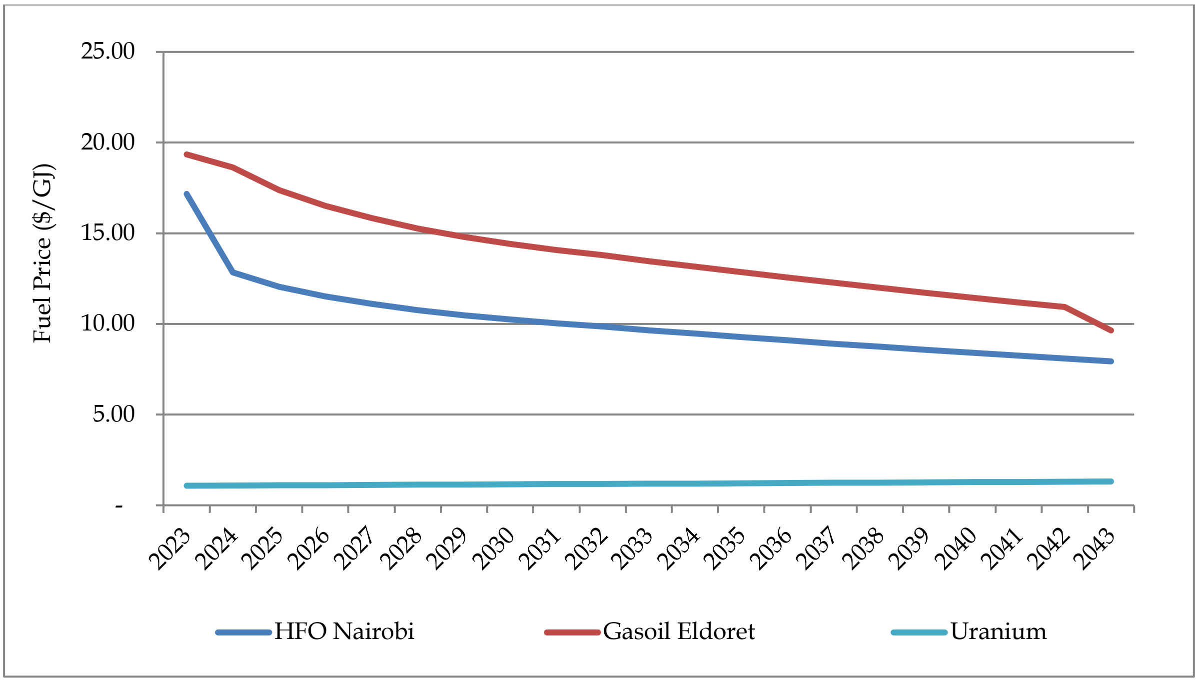


Figure 5-1: Fuel Price forecast for selected products

5.11 Screening curve analysis

Screening curves were prepared for selected candidate generation technologies listed in Table 5-5 to provide an illustration of annualized costs of electricity generation for different candidate technologies at various levels of dispatch. The screening curve technique is an approximate method that captures major tradeoffs between capital costs, operating costs and utilization levels for various types of generating capacity in the system. The screening curve method expresses the total annualized electricity production cost for a generating unit, including all capital and operating expenses, as a function of the unit capacity factor. This approach is especially useful for quick comparative analyses of relative costs of different electricity generation technologies. A discount rate of 12.8% and an exchange rate of KSh/$ 139.8 were used in the screening model. Table 5-6 shows the techno-economic data for the various candidate generation plants screened while Figure 5-2 shows the screening curves.

The results of the screening curve analysis indicate that nuclear, combined cycle and geothermal are the most economical electricity generation options at higher capacity factors. Solar PV is cheapest from 5% to 20% utilization while wind is cheapest at 20-50% capacity factor. But as the penetration level of these intermittent technologies increases, there are significant additional costs that are not included in this analysis. These include required ancillary services. Combined cycle and MSD plants are cheapest at very low-capacity factors.

Table 5-5: List of screened candidates

Item	Candidate	Technology/Type	Unit size (No. x	Capacity (MW)
1.	Silali Paka I- GDC	Geothermal	2 x 50	100
2.	Olkaria 7 – KenGen	Geothermal	2 x 40	80
3.	MSD	Heavy fuel oil ICE	7 x 16.4	114.8
4.	Karura Hydro plant	Hydro	2 X 45	90
5.	High Grand Falls Hydro plant	Hydro	7 X 99	99
6.	Solar plant	Solar PV	1 X 40	40
7.	Wind Plant	Wind	1 x 100	100

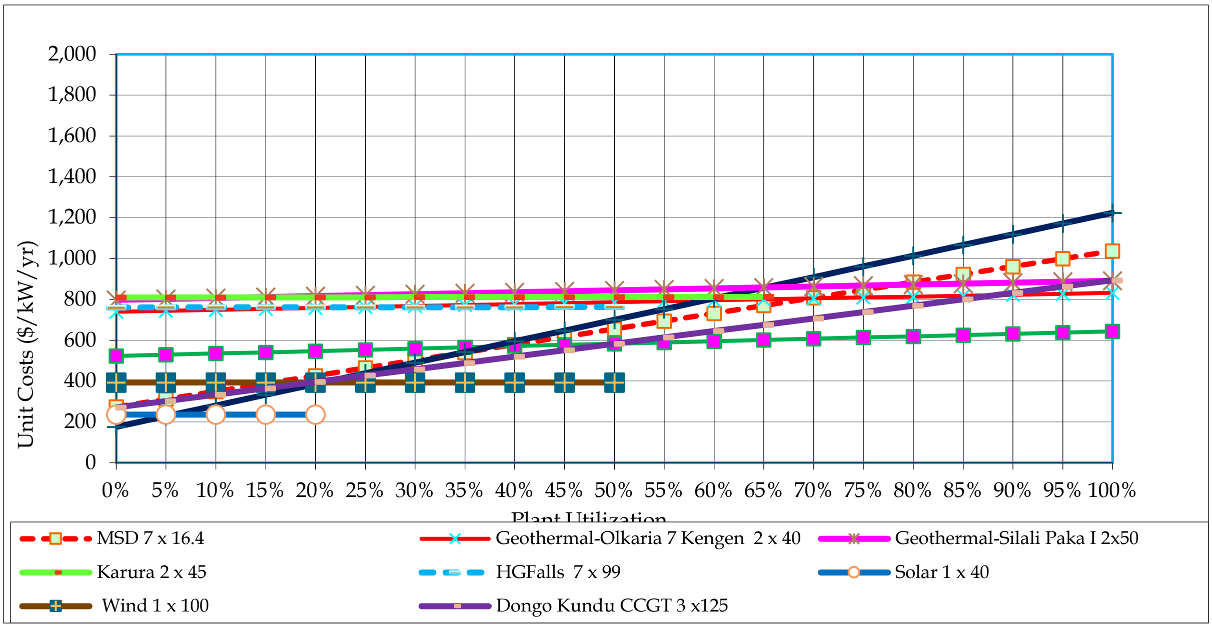


Figure 5-2: Screening Curves for Selected Candidates

Table 5-6: Techno-economic data for candidate projects

		Geothermal-Olkaria 7 Kengen	Geothermal-Silali Paka I	Nuclear 1	MSD- Diesel	Karura	High Grand Falls	Solar	Wind
Configuration (n x MW)		2 x 40	2x50	(4 X 72.8)	7 x 16.4	2 x 45	7 x 99	1 x 40	1 x 100
Total Capacity (MW)		80	100	291.3	114.8	90	693	40	100
Fixed Cost									
Capital ($ x 10^6)		280	381	840	163	350	2570	51	189
Capital ($/kW)		3500	3808	2882	1421	3889	3708	1277	1886
IDC Factor		1.21	1.21	1.21	1.06	1.31	1.31	1.06	1.12
Annuity Factor (or C.R.F.)		0.14	0.14	0.13	0.14	0.13	0.13	0.14	0.14
Interim Replacement		0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.00
Fixed Annual Capital		627.66	682.89	494.78	220.32	719.08	685.63	197.99	307.62
Fixed O&M Costs ($/kW/yr)		71.45	71.45	7.50	31.50	27.40	15.50	26.40	76.10
Total Fixed Annual Cost		**699.11**	**754.34**	**502.28**	**251.82**	**746.48**	**701.13**	**224.39**	**383.72**
Total Outage Rate		0.05	0.05	0.04	0.08	0.08	0.08	0.05	0.02
Outage Adjustment		1.06	1.06	1.04	1.09	1.08	1.08	1.05	1.02
Annual Fixed Cost		739	798	523	273	809	760	236	393

		Geothermal-Olkaria 7 Kengen	Geothermal-Silali Paka I	Nuclear 1	MSD- Diesel	Karura	High Grand Falls	Solar	Wind
Annual Fixed Cost ($/kWh)		0.08	0.09	0.06	0.03	0.09	0.09	0.03	0.04
Variable Cost									
Fuel Price ($/GJ)		0.00	0.00	1.14	9.26	0.00	0.00	0.00	0.00
Heat Rate (kJ/kWh)		10700.00	10700.00	11593.89	8470.00	0.00	0.00	0.00	0.00
Fuel Cost ($/kWh)		0.00	0.00	0.01	0.08	0.00	0.00	0.00	0.00
CO_2 Tax ($/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Variable O&M ($/kWh)		0.01	0.01	0.001	0.01	0.00	0.00	0.00	0.00
Total Variable ($/kWh)		0.01	0.01060	0.01	0.09	0.00	0.00	0.00	0.00
Total Variable ($/kW/yr)		**93**	**93**	**121**	**764**	**4**	**4**	**0**	**0**
		Geothermal-	Geothermal-	Nuclear 1	MSD	Karura	HGFalls	Solar	Wind
Unit Cost ($/kW/yr)		2 x 40	2x50	(4 X 72.8)	7 x 16.4	2 x 45	7 x 99	1 x 40	1 x 100
Plant Factor............	0%	739	798	523	273	809	760	236	393
Plant Factor............	5%	744	802	529	311	810	760	236	393

		Geothermal-Olkaria 7 Kengen	Geothermal-Silali Paka I	Nuclear 1	MSD- Diesel	Karura	High Grand Falls	Solar	Wind
Plant Factor............	10%	749	807	535	350	810	761	236	393
Plant Factor............	15%	753	812	541	388	810	761	236	393
Plant Factor............	20%	758	816	547	426	810	761	236	393
Plant Factor............	25%	763	821	553	464	810	761	236	393
Plant Factor............	30%	767	826	559	502	811	762	236	393
Plant Factor............	35%	772	830	565	541	811	762	236	393
Plant Factor............	40%	777	835	571	579	811	762	236	393
Plant Factor............	45%	781	840	577	617	811	762	236	393
Plant Factor............	50%	786	844	583	655	812	762	236	393
Plant Factor............	55%	790	849	589	693	812			
Plant Factor............	60%	795	854	595	732	812			
Plant Factor............	65%	800	858	601	770	812			
Plant Factor............	70%	804	863	607	808				
Plant Factor............	75%	809	867	613	846				

		Geothermal- Olkaria 7 Kengen	Geothermal- Silali Paka I	Nuclear 1	MSD- Diesel	Karura	High Grand Falls	Solar	Wind
Plant Factor............	80%	814	872	619	884				
Plant Factor............	85%	818	877	625	923				
Plant Factor............	90%	823	881	631	961				
Plant Factor............	95%	828	886	637	999				
Plant Factor............	100%	832	891	643	1037				
Unit Cost ($/kWh)									
Plant Factor............	5%	1.70	1.83	1.21	0.71	1.848	1.736	0.538	0.898
Plant Factor............	10%	0.85	0.92	0.61	0.40	0.924	0.868	0.269	0.449
Plant Factor............	15%	0.57	0.62	0.41	0.30	0.616	0.579	0.179	0.299
Plant Factor............	20%	0.43	0.47	0.31	0.24	0.462	0.434	0.135	0.224
Plant Factor............	25%	0.35	0.37	0.25	0.21	0.370	0.348	0.108	0.180
Plant Factor............	33%	0.27	0.29	0.19	0.18	0.280	0.263	0.082	0.136
Plant Factor............	35%	0.25	0.27	0.18	0.18	0.264	0.248	0.077	0.128

		Geothermal-Olkaria 7 Kengen	Geothermal-Silali Paka I	Nuclear 1	MSD- Diesel	Karura	High Grand Falls	Solar	Wind
Plant Factor............	40%	0.22	0.24	0.16	0.17	0.231	0.217	0.067	0.112
Plant Factor............	45%	0.20	0.21	0.15	0.16	0.206	0.193	0.060	0.100
Plant Factor............	50%	0.18	0.19	0.13	0.15	0.185	0.174	0.054	0.090
Plant Factor............	55%	0.16	0.18	0.12	0.14	0.168			
Plant Factor............	60%	0.15	0.16	0.11	0.14	0.154			
Plant Factor............	65%	0.14	0.15	0.11	0.14	0.143			
Plant Factor............	70%	0.13	0.14	0.10	0.13				
Plant Factor............	75%	0.12	0.13	0.09	0.13				
Plant Factor............	80%	0.12	0.12	0.09	0.13				
Plant Factor............	85%	0.11	0.12	0.08	0.12				
Plant Factor............	90%	0.10	0.11	0.08	0.12				
Plant Factor............	95%	0.10	0.11	0.08	0.12				
Plant Factor............	100%	0.10	0.10	0.07	0.12				

5.11.1 Ranking of candidate projects.

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

The load factor chosen is the highest one attainable for each type of candidate. It takes into account schedule and unscheduled outages and also takes into account the availability of water for hydro candidates and wind and solar availability for candidates. The candidates are categorized according to the type of supply they are designed for; either base load or peak load. Two discount rates are considered, 12.8% for base case and 8% for sensitivity analysis. The results are shown in Table 5-7,

Table 5-8, Table 5-9 and Table 5-10.

Ranking of base load projects

Table 5-7: Ranking of Base Load Generation Candidate Projects (12.8%)

Candidate Project	Load Factor	LCOE US cts /kWh at 12.8% Discount rate	Index
EEP Import	70%	7.9	100%
Nuclear	85%	8.3	106%
Solar	20%	8.5	107%
Geothermal	93%	10.0	127%
High Grand Falls hydro	60%	10.6	135%
Wind	40%	11.0	139%
Lamu Coal	73%	14.7	187%
Karura Hydro	60%	14.9	189%
CCGT	85%	27.7	351%

Table 5-8: Ranking of Base Load Generation Candidate Projects (8%)

Candidate Project	Load Factor	LCOE US cts /kWh at 8% Discount rate	Index
Nuclear	85%	5.7	100%
Solar	20%	6.2	108%
High Grand Falls hydro	60%	6.7	116%
Geothermal	93%	7.4	129%
EEP Import	70%	7.9	137%
Wind	40%	8.4	146%
Karura	60%	9.3	162%
Lamu Coal	73%	11.6	202%
CCGT	85%	26.8	466%

Ranking of Peak Load Candidates

Table 5-9: Ranking of Peak Load Generation Candidate Projects (12.8%)

Candidate Project	Load Factor	LCOE US cts /kWh at 12.8% Discount rate	Index
UETCL Import	17%	9.0	100%
MSD	28%	29.2	324%

Table 5-10: Ranking of Peak Load Generation Candidate Projects (8%)

Candidate Project	Load Factor	LCOE US cts /kWh at 8% Discount rate	Index
UETCL Import	17%	9.0	100%
MSD	28%	26.4	293%

The results of the ranking based on the screening curve data indicate that imports, geothermal and nuclear are the most appropriate electricity generation options at higher capacity factors. Solar PV is cheapest at lower utilization of about 20%. For peaking duty, power imports from UETCL is the most attractive followed by MSDs. Sensitivity analysis shows that the large hydro become more attractive at lower discount.

6 GENERATION EXPANSION SIMULATION RESULTS

This section provides the long-term generation expansion results for the electricity demand scenarios simulated.

6.1 Reference demand scenario

The total interconnected effective capacity grows from 3,110 MW in 2024 to 4,654MW in the medium term (2028) and reaches 12,800MW by the end of the planning horizon as shown in Figure 6-1.The annual average vented steam- share of potential maximum geothermal generation is expected to grow from the current 18% in 2024 to 25% in 2027 and remain constant over the planning period as indicated in Table 6-1. The increase in vented steam is attributed to the projected addition of Imports capacity as well as new geothermal projects in the system increasing the baseload capacity.

Table 6-1. This growth in installed capacity is to meet the projected three-fold growth in peak demand plus reserve margin reaching 9,130 MW by 2043. From the results shown in Figure 6-2, geothermal capacity is expected to contribute the highest to the total firm capacity at an annual average of 40% over the planning period. There is contribution from BESS and pumped storage for grid stability, amounting to a total of 18% of the firm capacity mix from both technologies by 2043. All existing diesel and gasoil power plants are expected to be decommissioned by 2035 while capacity from nuclear is projected to come in from 2034, contributing up to 9% of the total firm capacity mix by 2043. In 2043, RE resources contributes 63% of the firm capacity mix with capacity from VRE representing 5% within these.

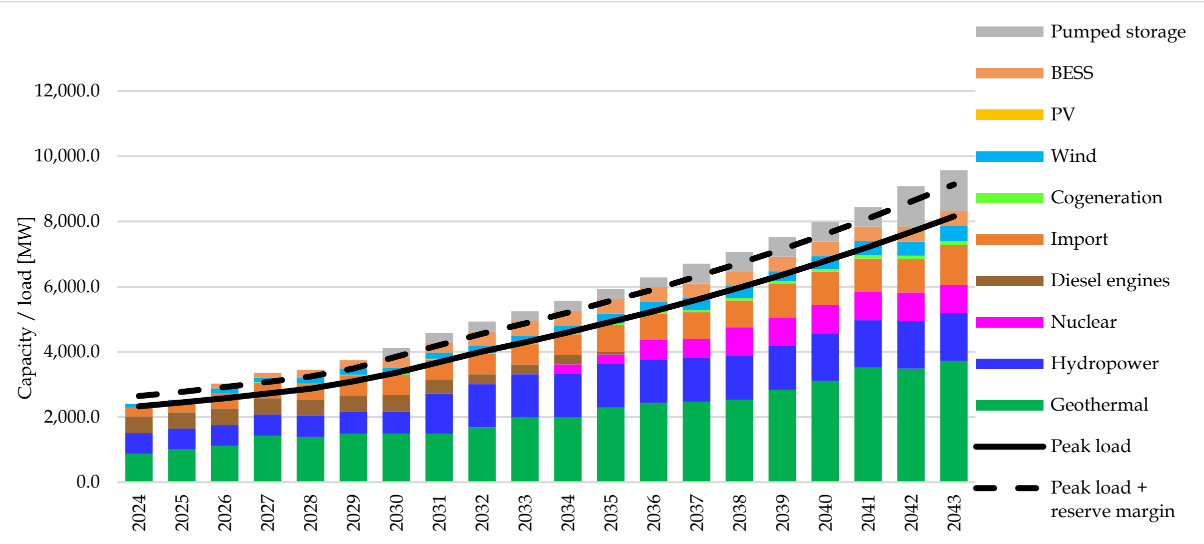


Figure 6-2: Firm capacity vs peak load – Reference demand scenario

The annual average vented steam- share of potential maximum geothermal generation is expected to grow from the current 18% in 2024 to 25% in 2027 and remain constant over the planning period as indicated in *Table 6-1*. The increase in vented steam is attributed to the projected addition of Imports capacity as well as new geothermal projects in the system increasing the baseload capacity.

Table 6-1: Demand - Supply balance – Reference demand scenario

Peak demand versus generation capacity		2024	2025	2026	2027	2028	2029	2030	2031	2032	2035	2038	2040	2043
Peak load	MW	2,327	2,446	2,575	2,716	2,871	3,093	3,361	3,682	4,001	4,919	5,969	6,778	8,152
Peak load + reserve margin	MW	2,643	2,774	2,916	3,071	3,241	3,486	3,780	4,133	4,485	5,560	6,715	7,606	9,117
Reserve margin	% of peak load	14%	13%	13%	13%	13%	13%	12%	12%	12%	13%	13%	12%	12%
Installed system capacity	MW	3,110	3,308	3,952	4,401	4,654	5,079	5,492	6,275	6,609	8,086	9,481	10,762	12,800
Firm system capacity	MW	2,394	2,545	2,909	3,201	3,257	3,551	3,797	4,310	4,490	5,582	6,778	7,639	9,182
Supply - demand gap	MW	-248	-229	-8	130	16	64	16	177	5	22	63	33	64
Electricity consumption	GWh	13,364	13,987	14,921	15,764	16,717	17,697	19,358	21,158	23,033	28,242	34,289	38,748	46,681
Electricity generation	GWh	13,494	14,240	16,133	18,184	18,652	20,042	20,658	22,192	23,457	31,135	36,827	42,135	48,446
Excess energy	GWh	129	317	1,277	2,485	2,000	2,410	1,429	1,164	555	3,022	2,668	3,517	1,894
Excess energy - share on generation	%	1%	2%	8%	14%	11%	12%	7%	5%	2%	10%	7%	8%	4%
Vented GEO steam	GWh	1,065	1,412	1,863	2,490	2,492	2,721	2,731	2,687	2,932	4,425	5,209	6,269	7,728
Vented GEO steam - share of potential max. GEO flash steam generation	%	18%	20%	24%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%

Output from renewable energy plants is projected to account for 82.3% of the electricity generation mix by 2043. In the same year, geothermal energy is projected to have the highest contribution accounting for 47.3% of the total electricity generation mix. In this scenario, generation from nuclear is realized from 2034 and grows from 6.2% to 10.8% of the electricity generation mix in 2043 as shown in Figure 6-3.

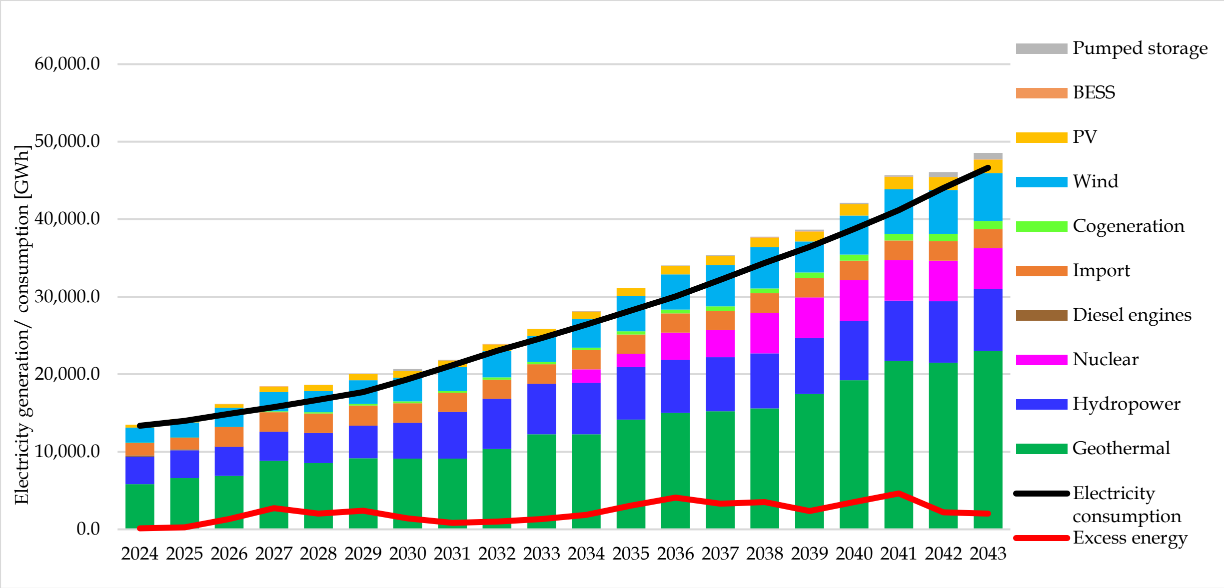


Figure 6-3: Annual generation balance – Reference demand scenario

The resultant recommended generation expansion path based on the reference electricity demand scenario is as shown in Table 6-2.

6.1.1 Generation Tariff

In accordance with Section 163(3) of the Energy Act, 2019, the Energy and Petroleum Regulatory Authority (EPRA) has established guidelines for calculating the allowed return on investment for generation, transmission, and distribution projects in Kenya. As part of this process, EPRA has published indicative tariffs based on various generation technologies, with the most recent publication issued on April 17, 2024 (Gazette Notice No. 6421, 6422, 6423 and 6424). These indicative tariffs serve as a critical reference for the Kenya Power and Lighting Company (KPLC) in aligning tariffs for generation projects with the benchmark generation tariffs set by EPRA. This alignment is intended to enhance the affordability of power for end users by ensuring that generation tariffs remain both competitive and transparent.

Table 6-2: Recommended 20-year Generation Expansion Plan for 2024-2043

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
End of 2023				**3,113**	**2,393**	**14%**							
2024	KTDA Ltd, Lower Nyamindi	Small Hydro	0.8		0.2		2014	20-Mar-14	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2024	KTDA - Nyambunde, Nyakwana	Small Hydro	0.5		0.13		2013	17-Feb-14	Kegati 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2024	KTDA Ltd, South Maara (Greater Meru Power Co.)	Small Hydro	1.5		0.38		2014	20-Mar-14	Kieni 132/33kV(Marima 33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2024	KTDA Ltd, Iraru	Small Hydro	1		0.25		2014	20-Mar-14	Meru 132/33kV (Kanyakine 33/11)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2024	Marco Borero Co Ltd.	PV	1.5		-		2013	14-Aug-14	Kiganjo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2024	REA Vipingo Plantations Ltd (DWA Estates Ltd)	Biomass	1.44		0.72		2015	24-Jun-15	Kiboko 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2024			**6.74**	**3,120**	**2,395**	**14%**							
2025	Mt Kenya Community Based Organisation	Small Hydro	0.6		0.15		2011	17-Feb-14	Meru 132/33kV (Meru 33/11)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2025	Tindinyo Falls Resort	Small Hydro	2.4		0.6		2013	04-Feb-13	Cheptulu ex Kisumu	Sufficient	Complete	N/A	Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
									33kV feeder				by the developer
2025	Kleen Energy Limited	Small Hydro	6		1.5		2013	07-Jun-13	Kutus 132/33kV(Embu 33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2025	Kaptagat Solar Park (Tarita Green)	PV+BESS	40		-		2015	04-Aug-16	Lessos - Kabarnet 132kV line	Sufficient	Construction	2024	Lessos-Kabarnet line which is projected to be energized this year needs to be ready
2025	Menengai 1 Phase I - Stage 1 (Quantum)	Geothermal	35		35		2010		Menengai 132kV	Sufficient	Complete	N/A	Additional cost of connection will be borne by the developer
2025	Menengai 1 Phase I - Stage 1 (Orpower22)	Geothermal	35		35		2010		Menengai 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2025	Wellhead leasing	Geothermal	58.64		58.64		2016		Olkaria 1AU 220kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2025	Imenti Factory Limited	Small Hydro	-0.3		-0.08		2009	26-Jan-09	Decommissioning	N/A	N/A	N/A	N/A
End of 2025			**177.34**	**3,297**	**2,525**	**13%**							
2026	Olkaria IV Uprating	Geothermal	20		20		2020		Olkaria IV 220kV	Sufficient	Complete	N/A	No new investment
2026	HVDC Ethiopia2	Import	100		100				Suswa Converter Station	Sufficient	Construction	2026	Installation of STATCOM required at

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													Suswa as this necessitates switching of 2nd Filter
2026	HVDC Ethiopia3	Import	100		100				Suswa Converter Station	Sufficient	Construction	2026	Installation of STATCOM required at Suswa as this necessitates switching of 2nd Filter
2026	Olkaria 1 AU 4 & 5	Geothermal	20		20		2020		Olkaria 1AU 220kV	Sufficient	Complete	N/A	No new investment
2026	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	21		21		2014		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2026	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	21		21		2014		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2026	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	21		21		2014		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2026	KTDA Chemosit	Small Hydro	0.25		0.06		2012	10-Aug-12	Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Frontier Investment Management/ Nithi Hydro	Small Hydro	5.6		1.4		2013	09-Oct-15	Kieni 132/33kV(Marima 33/11kV)	Sufficient	Construction	2024	Cost of connection will be borne by the developer
2026	Gem Gen Power Company Limited	Small Hydro	9.5		2.38		2018	28-Nov-19	Rangala 132/33kV (Nyamninia 33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Prunus	Wind+BESS	50		12.5		2010	12-Apr-09	Kimuka 220/66kV	Sufficient	Construction	2024	Cost of connection will be borne by the developer
2026	Chania Green	Wind +BESS	50		12.5		2012	2015-02-02 Reviewed on 2016-12-22	Kimuka 220/66kV	Sufficient	Construction	2024	Cost of connection will be borne by the developer
2026	Aperture	Wind+ BESS	50		12.5		2009	12-Nov-14	Limuru 66/11kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Kopere Solar Park Limited	PV+BESS	40		-		2013	10-Sep-14	Lessos-Muhoroni 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	BESS_1	BESS	100		25		2023		Embakasi 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2026	BESS_3	BESS	50		12.5				Kegati 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Power Technologies (Gatiki Small Hydro Plant)	Small Hydro	9.6		2.4		2015	02-Jun-16	Kiganjo 132/33kV Substation (Karatina - Mukurweini 33kV line)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Gogo upgrade	Small Hydro	8.6		2.15		2023	N/A	Awendo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2026	Gogo Existing small hydro	Small Hydro	-2		-0.5				Decommissioning	N/A	N/A	N/A	N/A
End of 2026			**674.55**	**3,972**	**2,911**	**13%**							
2027	Baringo Silali - Paka I	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Loosuk-Baringo-Lessos 400kV line must be ready
2027	Olkaria II Extension (Olkaria 6)	Geothermal	140		140		2014 (initially conceptualized as Olk6 PPP)		Olkaria II 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Olkaria 7	Geothermal	80		80		2024		Olkaria 1AU 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	KTDA, Kipsonoi (Settet Power Co.)	Small Hydro	0.6		0.15		2013	17-Feb-14	Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													by the developer
2027	Kenergy Renewables Ltd-Rumuruti	PV+BESS	40		-		2013	24-Jun-15	Rumuruti 132/33kV	Sufficient	Construction	2025	Additional cost of connection will be borne by the developer-Nanyuki-Rumuri 132kV line must be ready
2027	Kibwezi One Energy Limited	PV+BESS	40		-		2013	22-Mar-16	Kiboko 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Hannan Arya Energy (K) Ltd	PV+BESS	10		-		Concept under development	04-Oct-16	Kajiado 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Seven Forks (Kamburu) Solar Power Plant	PV	42.5		-		2017		Kamburu 220/132kV	Sufficient	Complete	N/A	cost of connection will be borne by KenGen
2027	Kwale Int. Sugar Co. Ltd	Biomass	10		5		2009	12-Apr-09	Kwale Sugar 132kV Substation	Sufficient	Was under Construction-Stalled	2027	Cost of connection will be borne by the developer-Base Titanium-Kwale Sugar 132kV line must be completed
2027	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	Biomass	20		10		2016	19-Dec-17	Garsen 220/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2027	Ngong 1, Phase I	Wind	-5.1		-1.28				Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by KenGen
End of 2027			**478.00**	**4,450**	**3,245**	**13%**							
2028	Reike Ltd (Kaiuthi SHPP-Sagana I)	Small Hydro	20		5			22-Jun-20	Kutus-Kiganjo 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	BESS_2	BESS	100		25				Lessos 220/132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	Isiolo Power (Greenmillenia Energy) Limited	PV+BESS	40		-		2013	09-Feb-16	Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	Raising Masinga	Hydropower	-		-		2018		N/A	Sufficient	2028	N/A	N/A
2028	Ngong 1 - Phase III	Wind	11		2.75		Concept under development		Kimuka 220/66kV	Sufficient	Under Construction	2024	Cost of connection will be borne by the developer
2028	Ol-Danyat Energy	Wind+BESS	30		7.5		2011	23-Jan-13	LILO on Matasia-Magadi 66kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	Electrawinds Bahari	Wind+BESS	50		12.5		2012	17-Feb-14	Garsen-Lamu 220kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	Thika Way Investments (Homa Bay Biogas One)	Biomass	8		4		2014	06-Oct-16	Sondu 132/33kV Substation	Sufficient	Under Construction-Stalled	2026	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2028	KenGen Olkaria Wellheads I	Geothermal	-44.6		-44.6				Decommissioning	N/A	N/A	N/A	
End of 2028			**214.40**	**4,664**	**3,257**	**13%**							
2029	Baringo Silali - Silali I	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk line-PPP)	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2029	UETCL Import2	Import	150		150				Tororo 220/132kV Substation	Sufficient	Awaiting Settlement of Contractor by KETRACO /GoK before progressing the project further		Lessos-Tororo 220kV line and asspociated substations must be ready
2029	Reike Ltd (Ithanji SHPP-Sagana II)	Small Hydro	20		5			22-Jun-20	Kutus-Kiganjo 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Marsabit Phase I - KenGen	Wind+BESS	100		25		2020		Loiyangalani 400/220kV Substation	Sufficient	Feasibility Study Stage	2029	Cost of connection will be borne by Kengen
2029	Global Sustainable-Kaptis	Small Hydro	14.7		3.68		2011	12-Nov-14	Cheptuluex Kisumu 33kV feeder	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Global Sustainable Ltd-Buchangu	Small Hydro	4.5		1.13		2011	30/03/2015	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2029	Mutunguru Hydroelectric Company Ltd	Small Hydro	7.8		1.95		2015	15-Dec-15	Meru 132/33kV (Kenyakine 33/11)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Khalala Hydro Power Kenya Limited (Coastal Energy Ltd, Navakholo)	Small Hydro	20		5		10-Jul-05	28-Nov-19	Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Ventus Energy Ltd	Small Hydro	7.7		1.93		2015	13-Jun-18	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Menengai III	Geothermal	100		100		2010		Menengai 400kV	Sufficient	Feasibility	2030	Cost of connection will be borne by the developer
2029	Olkaria 2	Geothermal	-101		-101				Decommissioning	N/A	N/A	N/A	N/A
End of 2029			**423.70**	**5,088**	**3,550**	**13%**							
2030	BESS_4	BESS	50		12.5				Rabai 220/132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Makindu solar ltd	PV+BESS	30		0		2013	14-Feb-14	Makindu 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Greenlight Holdings/ Rianjue/Gichuki Ventures	Small Hydro	1.5		0.375		2013	09-Oct-15	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Pumped hydro storage - Unit 1	Pumped storage	300		300		Prefeasibility conducted is 2018		Ortum 220kV/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2030	Kenya Solar Energy	PV+BESS	40		-		2013	23-Mar-16		Sufficient		N/A	Cost of connection will be borne by the developer
2030	Mwikhupo-Mwibale Hydro Power Kenya	Small Hydro	7		1.75		2018	19-Jun-19	Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Virunga Power Holdings Ltd, R. Sossio, Kaptama	Small Hydro	4.5		1.125		2017	28-Nov-19	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2030	Njega/Rukenya Hydro Power Limited (Rights transfer)	Small Hydro	3.5		0.875		2010	25-Feb-19	Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Western Hydro	Small Hydro	10		2.5		2011	14/08/2014	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Kibisi Kinetic Energy Limited/Virunga Power Holdings	Small Hydro	6.5		1.625		2014	16-Aug-19	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer-More 220/132kV Transformers required at Kitale and the Kitale-Webuye 132kV line
2030	Kirogori Electrification Project	Small Hydro	7		1.75		2015	16-Aug-19	Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2030	KTDA R. Chemosit, Chemosit	Small Hydro	2.5		0.625		2012	10-Aug-12		22-Jul-05	Pumped hydro storage - Unit 1	Pumped storage	Cost of connection will be borne by the developer
2030	Rareh Nyamindi Hydro Ltd-Mbiri	Small Hydro	5.2		1.3		2013	09-Oct-15	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Rareh Nyamindi Hydro Ltd-Kiamutugu	Small Hydro	9.4		2.35		2013	09-Oct-15	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Rareh Nyamindi Hydro Ltd-Gitie	Small Hydro	6		1.5		2013	09-Oct-15	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	VSHydro Kenya Ltd	Small Hydro	9.1		2.275		2015	16-Aug-19	Kieni 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Roadtech Solutions Ltd	Biomass	10		5		2015	04-Oct-16	Kajiado 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2030			**502.20**	**5,590**	**3,886**	**14%**							
2031	High Grand Falls Stage 1+2	Hydropower	693		549.7				High Grand Fall then 400kV line to Malaa Substation	Sufficient	Feasibility	2030	Cost of connection will be borne by the developer. High Grand Falls-Malaa 400kV line and Malaa 400kV Substation required

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2031	Karuga Gitugi Electrification Project	Small Hydro	2.7		0.68		2015	16-Aug-19	Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	KTDA Chemosit, Kiptiget	Small Hydro	3.3		0.83		2012	10-Aug-12	Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	KTDA Ltd, Yurith, Chemosit	Small Hydro	0.9		0.23		2014	17-Feb-14	Chemosit 132/33kV	Complete	N/A	N/A	Cost of connection will be borne by the developer
2031	KTDA R. Rupingazi, Rutune	Small Hydro	1.8		0.45		2015	25-Feb-19	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	KTDA, R. Itare, Chemosit	Small Hydro	1.3		0.33		2014	17-Feb-14	Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2031	KTDA, R. Yala, Taunet	Small Hydro	2.8		0.7		2015	25-Feb-19	Cheptulu ex Kisumu 33kV feeder	Sufficient	Complete	N/A	
2031	Tridax Limited	Small Hydro	4.2		1.05		2016	25-Feb-19	Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	Truck city ltd	Small Hydro	5.3		1.33		2018	16-Aug-19	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	Rabai Diesel (CC-ICE)	Diesel engines	-88.6		-88.6		N/A		Decommissioning	Sufficient	N/A	N/A	N/A
End of 2031			**626.70**	**6,217**	**4,352**	**14%**							

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2032	Karura	Hydropower	90		70.68		2023		Karura	Sufficient	Feasibility	2030	Cost of connection will be borne by the developer
2032	Eburru 2	Geothermal	25		25		Concept under development		Eburru/ Naivasha	Sufficient	Concept/Complete	2032	Cost of connection will be borne by the developer
2032	Chevron Africa Limited	Small Hydro	7.8		1.95		2016		Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Dominion Farms	Small Hydro	1		0.25			N/A	Rangala 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Webuye Falls-KenGen	Small Hydro	40		10			N/A	Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2032	Viability Africa (Northern Energy Limited)	Biomass	2.4		1.2		2014	25-Feb-19	Garissa 132/33/11kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Cummins Cogeneration Kenya Limited	Biomass	8.4		4.2		2010	04-Oct-12	Kabarnet 132/33kV	Sufficient	2024	N/A	Cost of connection will be borne by the developer
2032	Baringo Silali Paka II	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2032	Suswa I	Geothermal	100		100		2012		Suswa 220kV	Sufficient	Complete	N/A	Cost of connection

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													will be borne by the developer
2032	Electrawinds Bahari Phase 2	Wind+BESS	40		10		2012	17-Feb-14	Garsen-Lamu 220kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Meru Phase 1	Wind+BESS	80		10				Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	BESS_5	BESS	150		37.5				Weru 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Kipevu 3	Diesel engines	-115		-115		N/A		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
2032	KenGen Olkaria Wellheads II & Eburru	Geothermal	-27.5		-27.5		N/A		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
End of 2032			**502.1**	**6,719**	**4,581**	**14%**							
2033	Olkaria II Rehabilitation	Geothermal	105		105		Concept under development		Olkaria II 220kV Substation	Sufficient	Complete		Cost of connection will be borne by KenGen
2033	Olkaria 8	Geothermal	140		140		Concept under development		Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by the developer
2033	Menengai I Stage II	Geothermal	60		60		2010		Menengai 132kV	Sufficient	Complete		Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													by the developer
2033	Njumbi Hydropower Plant Ltd (Hydroneo)	SmallHydro	9.6		2.4		2015	28-Dec-19	Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2033	Hydel	Small Hydro	5		1.25		2010	3-Aug-10	Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2033	VR Holding AB-Local Trade Ltd	Biomass	3		1.5		2015	25-Feb-19	Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2033			**322.60**	**7,041**	**4,891**	**13%**							
2034	Nuclear Unit 1	Nuclear	291.3		291				Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by NUPEA (GoK)-Kilifi-Mariakani 400kV line required
2034	Meru Phase II	Wind+BESS	100		25				Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2034	Generic small hydro	Small Hydro	22		5.5				Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2034	West Kenya Sugar Company Limited	Biomass	6		3		2016	17-Aug-18	Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2034	Biogas Holdings Ltd	Biogas	0.3		0.15		2012	20-3-2013		Sufficient			Cost of connection will be borne by the developer
2034	Generic PV	PV+BESS	40		-				Narok	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2034			**459.60**	**7,501**	**5,215**	**13%**							
2035	Menengai IV	Geothermal	100		100		2010		Menengai 400kV	Sufficient	Feasibility	2033	Menengai 400kV Substation and Menengai-Rongai 400kV line required
2035	Baringo Silali - Korosi /Chepchuk I	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 1	Geothermal	35		35		N/A		Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 2	Geothermal	35		35		N/A		Longonot/Olkari	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
									a II/ Naivasha				by the developer
2035	AGIL Longonot Stage 3	Geothermal	35		35		N/A		Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by the developer
2035	Marsabit Phase II - KenGen	Wind+BESS	200		50		To be done upon completion of Marsabit 1		Loiyangalani 400/220kV Substation	Sufficient	Feasibility Study Stage	2029	Loosuk-Baringo-Lessos 400kV line must be ready
2035	Generic small hydro	Small Hydro	22		5.5				Kiganjo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2035	Generic Wind	Wind+BESS	50		12.5				Kipeto 220kV Extension	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2035	Generic PV	PV+BESS	40		0				Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2035	Generic Biomass	Biomass	18		9				Sondu-Ndhiwa-Awendo 132kV line	Sufficient	Construction	2026	Cost of connection will be borne by the developer
2035	Regional Trade 1 A	Import	100		100		N/A		Ethiopia-Kenya/Kenya-Tnzania/ Kenya-Uganda	Sufficient	Complete/ Under construction		N/A

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2035	Regional Trade 1 B	Import	100		100		N/A		Ethiopia-Kenya/Kenya-Tnzania/ Kenya-Uganda	Sufficient	Complete/ Under construction		N/A
2035	Athi River Gulf	Diesel engines	-80.32		-80.32		N/A		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
2035	Iberafrica 2	Diesel engines	-52.5		-52.5		N/A		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
2035	Thika (CC-ICE)	Diesel engines	-87		-87		N/A		Decommissioning	Sufficient	N/A	N/A	Cost of connection will be borne by the developer
End of 2035			**615.18**	**8,116**	**5,578**	**13%**							
2036	Olkaria 9	Geothermal	140		140		Concept under development		Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by KenGen
2036	Nuclear Unit 2	Nuclear	291.3		291.3				Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by the developer
2036	Generic small hydro	Small Hydro	22		5.5				Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2036	Generic Biomass	Biomas	18		9				Malindi (Kakuyuni) 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2036	Generic PV	PV+BESS	40		-				Ndhiwa 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2036	Ngong 1, Phase II	Wind	-20.4		-5.1		N/A		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by KenGen
2036	Triumph (Kitengela)	Diesel engines	-83		-83		N/A		Decommissioning	N/A	N/A	N/A	N/A
End of 2036			**407.90**	**8,524**	**5,935**	**13%**							
2037	AGIL Longonot Stage 4	Geothermal	35		35				Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by the developer
2037	Pumped hydro storage - Unit 2	Pumped storage	300		300				Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Loosuk-Baringo-Lessos 400kV line must be ready
2037	Meru Phase III	Wind+BESS	220		55				Isiolo 220kV Substation	Sufficient	Feasibility Study Stage	2037	Cost of connection will be borne by the developer
2037	Generic small hydro	Small Hydro	22		5.5				Cheptulu ex Kisumu 33kV feeder	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2037	Generic Wind	Wind+BESS	50		12.5				Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2037	Generic Biomass	Biomas	18		9				Sultan Hamud 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2037	Generic PV	PV+BESS	40		-				Rumuruti 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2037			**685.00**	**9,209**	**6,352**	**13%**							
2038	Suswa II	Geothermal	100		100		2012		Suswa 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2038	Nuclear Unit 3	Nuclear	291.3		291.3				Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by NUPEA (GoK)-Kilifi-Mariakani 400kV line required
2038	Generic small hydro	Small Hydro	22		5.5				Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2038	Generic Biomass	Biomas	18		9				Ruai 66kV	Sufficient	Complete	N/A	
2038	Generic PV	PV+BESS	40		-				Nanyuki 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													by the developer
2038	OrPower4 Plant 2	Geothermal	-39.6		-39.6		N/A		Decommissioning	N/A	N/A	N/A	N/A
End of 2038			**431.70**	**9,641**	**6,719**	**13%**							
2039	Baringo Silali (Silali) II	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Loosuk-Baringo-Lessos 400kV line must be ready
2039	BESS Generic 1	BESS	150		37.5				Embakasi 220kV/Lessos 132kV/Kegati 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Menengai V	Geothermal	100		100		2010		Menengai 400kV	Sufficient	Feasibility	2033	Menengai 400kV Substation and Menengai-Rongai 400kV line required
2039	Suswa III	Geothermal	100		100		2012		Suswa 220kV	Sufficient	Complete	N/A	N/A
2039	Regional Trade 2	Import	200		200				Ethiopia-Kenya/Kenya-Tnzania/Kenya-Uganda	Sufficient	Complete/ Under construction		N/A
2039	Generic small hydro	Small Hydro	22		5.5				Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
													by the developer
2039	Generic Wind	Wind+BESS	50		12.5				Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Generic Biomass	Biomass	18		9				Meru/ Thika	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Generic PV	PV+BESS	80		-				Turkwel 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	BESS_1	BESS	-100		-25		N/A		Decommissioning	N/A	N/A	N/A	N/A
2038	BESS_3	BESS	-50		-12.5		N/A		Decommissioning	N/A	N/A	N/A	N/A
2039	REA Garissa	PV	-50		-		N/A		Decommissioning	N/A	N/A	N/A	
2039	Strathmore	PV	-0.25		-		N/A		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 1	Wind	-100		-25		N/A		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 2	Wind	-100		-25		N/A		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 3	Wind	-100		-25		N/A		Decommissioning	N/A	N/A	N/A	N/A
End of 2039			**319.75**	**9,960**	**7,171**	**12%**							

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2040	Olsuswa 70MW unit 1	Geothermal	70		70				Loiyangalani-Suswa 400kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2040	Marine Power Akiira Stage 1	Geothermal	70		70				Longonot/Olkaria II/ Naivasha	Sufficient	Feasibility/ Complete/ Complete	2033	Cost of connection will be borne by the developer
2040	Generic Geothermal Unit 2	Geothermal	140		140				Loiyangalani-Suswa 400kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2040	Baringo Silali (Korosi/Chepchuk) II	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2040	Baringo Silali (Paka) III	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	
2040	Baringo Silali (Silali) III	Geothermal	100		100		2010		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	
2040	Arror	Hydropower	59		47.12				Proposed Kapsowar 132/33kV	Sufficient	Feasibility Stage		Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
									Substation				
2040	Nandi Forest	Hydropower	50		39.27				Proposed Chavakali 132/33kV Substation	Sufficient	Feasibility Stage	N/A	Cost of connection will be borne by the developer
2040	Generic small hydro	Small Hydro	22		5.5				Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2040	Generic Wind	Wind+BESS	300		75				Loiyangalani 400/220kV Substation	Sufficient	Complete	N/A	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Generic Biomass	Biomass	18		9				Kibos 220/132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2040	Generic PV	PV+BESS	80		-				Baragoi	Sufficient	Concept	TBD	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Olkaria I Unit 4-5	Geothermal	-140		-140		N/A		Decommissioning	N/A	N/A	N/A	
2040	Olkaria 4	Geothermal	-140		-140		N/A		Decommissioning	N/A	N/A	N/A	
2040	OrPower4 Plant 3	Geothermal	-17.6		-17.6				Decommissioning	N/A	N/A	N/A	N/A

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
End of 2040			**811.40**	**10,772**	**7,629**	**12%**							
2041	Generic Geothermal	Geothermal	400		400				TBD	TBD	0	0	Cost of connection will be borne by the developer
2041	BESS Generic 3	BESS	100		25				TBD	TBD	N/A	2041	Cost of connection will be borne by the developer
2041	Generic Biomass	Biomass	18		9				Kakamega 220kV	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2041	Generic Wind	Wind	200		50				Kipeto 220kV Extension	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2041	Generic PV	PV+BESS	80		-				Lodwar 220kV	Sufficient	Finance Sourcing	2041	Cost of connection will be borne by the developer Turkwell-Lokichar-Lodwar 220kV line required
2041	Generic small hydro	Small Hydro	22		5.5				Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2041	BESS_2	BESS	-100		-25		N/A		Decommissioning	N/A	N/A	N/A	N/A
End of 2041			**720.00**	**11,492**	**8,093**	**12%**							

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2042	Pumped hydro storage - Unit 3	Pumped storage	650		650				TBD	Sufficient	Concept	2042	Cost of connection will be borne by the developer
2042	Generic small hydro	Small Hydro	22		5.5				Kegati 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2042	Generic Wind	Wind+BESS	100		25				Kipeto 220kV Extension	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2042	Generic Biomass	Biomass	18		9				Muhoroni 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2042	Generic PV	PV+BESS	80		-				Magadi	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2042	Orpower 4 Plant 4	Geothermal	-29		-29				Decommissioning	N/A	N/A	N/A	N/A
2042	Kipeto - Phase I	Wind	-50		-12.5				Decommissioning	N/A	N/A	N/A	N/A
2042	Kipeto - Phase II	Wind	-50		-12.5				Decommissioning	N/A	N/A	N/A	N/A
2042	Selenkei (Radiant)	PV	-40		-				Decommissioning	N/A	N/A	N/A	N/A
2042	Eldosol (Cedate)	PV	-40		-				Decommissioning	N/A	N/A	N/A	N/A
End of 2042			**661.00**	**12,153**	**8,729**	**12%**							

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2043	BESS Generic 2	BESS	50		12.5				Rabai 220/132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2043	Generic Geothermal Unit 3	Geothermal	300		300				TBD	TBD			Cost of connection will be borne by the developer
2043	Regional Trade 3	Import	200		200				Ethiopia-Kenya/Kenya-Tnzania/ Kenya-Uganda	Sufficient	Complete/ Under construction		Cost of connection will be borne by the developer
2043	Generic small hydro	Small Hydro	22		5.5				Kieni 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2043	Generic Wind	Wind+BESS	150		37.5				Bubisa/ Marsabit 220kV	Sufficient	Finance Sourcing	2028	Cost of connection will be borne by the developer
2043	Generic Biomass	Biomass	18		9				Lanet 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2043	Generic PV	PV+BESS	80		-				North Horr	Sufficient	Concept	TBD	Cost of connection will be borne by the developer
2043	BESS_4	BESS	-50		-12.5				Decommissioning	N/A	N/A	N/A	

Year considered for system integration	Plant name	Type	Net capacity [MW]	Installed Effective [MW]	Firm (MW)	Reserve Margin (%)	EOI Application Dates	Date of Feasibility Study Approval	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status	Target Completion Date	Remark
2043	Malindi Solar Ltd	PV	-40		-				Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
2043	Orpower 4 Plant 1 (Expanded)	Geothermal	-63.8		-63.8				Decommissioning	N/A	N/A	N/A	N/A
End of 2043			**666.20**[4]	**12,819**	**9,217**	**12%**							

[4] All small hydro power plants will be prioritised for implementation based on readiness.

6.2 Reference demand scenario - low hydrology

Figure 6-4 shows the effects on generation due to a reduction in the output from the hydro power plants in the event of a low hydrology scenario. This is based on the reference demand forecast.

Given low hydrological conditions output from geothermal power plants over the planning period is expected to increase to 269,699 GWh in comparison to 261,931 GWh under average hydrology conditions. Likewise, production from nuclear is expected to increase to 41,983 GWh compared to 41,967 GWh between the two scenarios.

Due to over planting of base load capacity over the planning period, the projected output from geothermal and nuclear technologies is quite similar across the two scenarios. During periods of low hydrology, in the medium term, the system utilizes, already existing geothermal generation capacity thus reducing on vented steam from an annual average of 23% in the average hydrology scenario to about 20% in this scenario. In the long term however it remains the same for the two scenarios. It is also noted that total output from BESS is expected to increases by 45% when output from the hydro power plants decreases

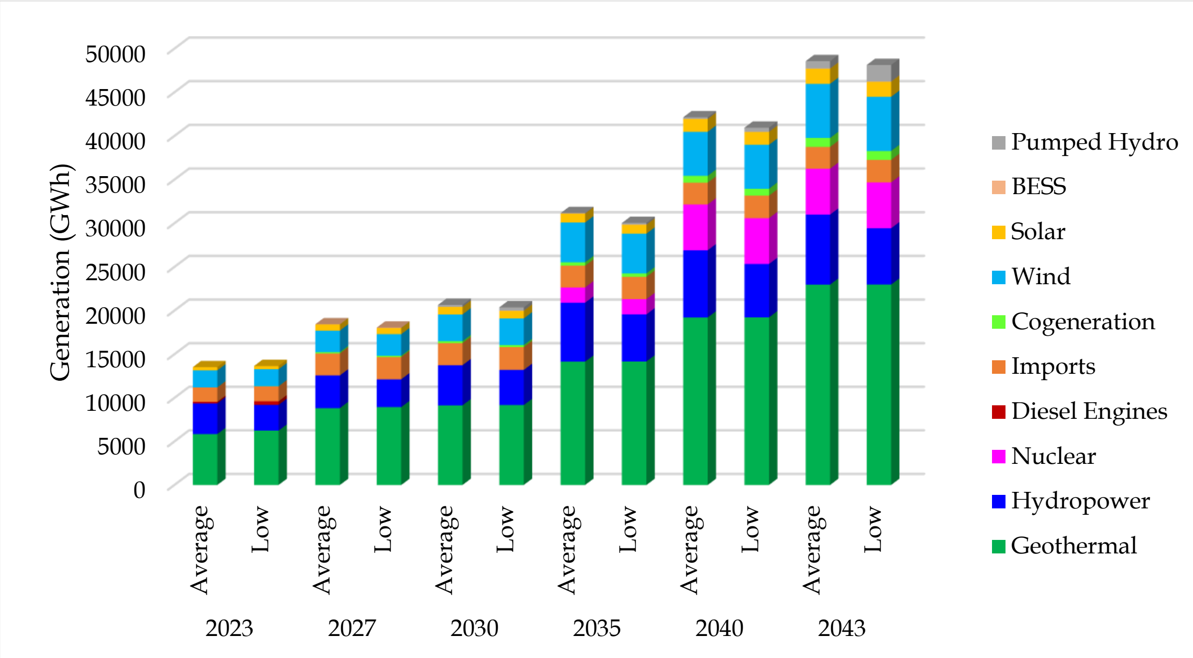


Figure 6-4: Comparison between average and low hydrology under reference demand scenario

6.3 Vision demand scenario

The total installed capacity in this scenario is projected to grow at a higher rate compared to the reference and low demand scenarios reaching 18,630 MW in 2043. To meet higher electricity demand in this scenario, electricity from geothermal is projected to increase to 56,094 GWh in 2043, while energy from nuclear power is projected to come online earlier in 2032 increasing to 5,245 GWh in 2043. Pumped hydro storage is also projected to come online earlier in 2028, to manage excess energy from geothermal, nuclear and VRE technologies. Electricity generated from RE accounts for about 88.5% of the total electricity mix in 2043 with geothermal contributing 67.7% of this energy. This is illustrated in Figure 6-5.

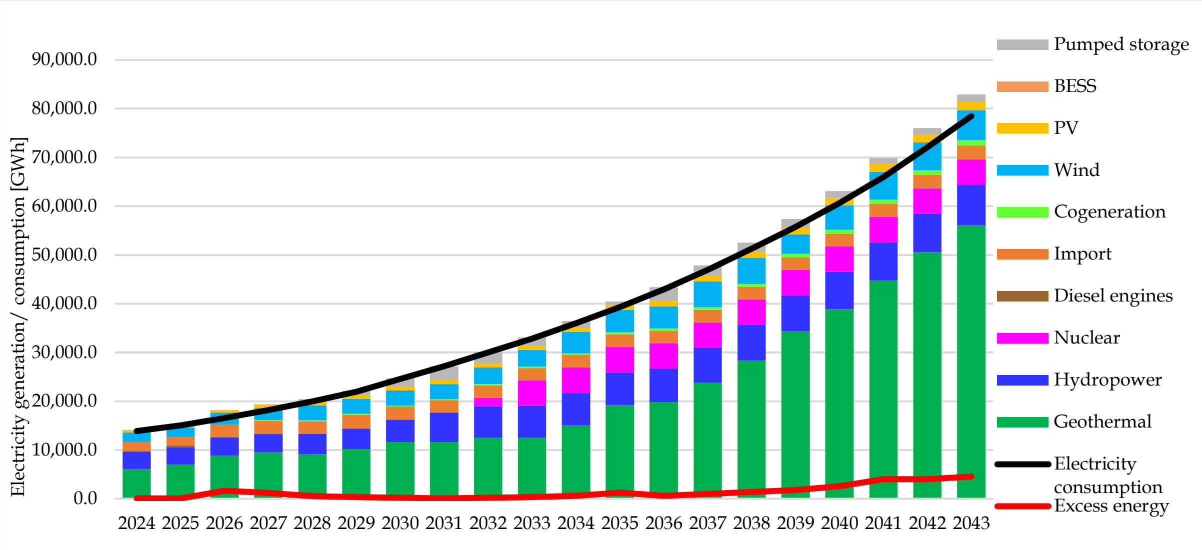


Figure 6-5: Annual generation Balance - Vision demand scenario

From the results, the annual average net vented steam share on the potential maximum geothermal generation decreased to 21% in the medium term, from 23% in the reference demand scenario. The projected annual average excess energy share on generation similarly decreases to 3% from 7% in the reference scenario for the entire plan period. This is due to increase in projected demand in this scenario.

6.4 Low demand scenario

This scenario presents the long-term expansion path as projected under the low demand growth forecast. The interconnected installed capacity is projected to grow to 9,048MW compared to 12,810MW in the reference demand scenario by 2043. Due to lower demand, the total generation from geothermal plants over the plan period is projected to be 180,552GWh compared to 261,930GWh in the reference demand scenario. Table 6-3 gives the demand supply balance for the low demand scenario.

Table 6-3: Demand - Supply balance – Low demand scenario

		2024	2025	2026	2027	2028	2030	2035	2040	2043
Peak load	MW	2,264	2,310	2,361	2,418	2,483	2,606	2,754	3,542	4,450
Peak load + reserve margin	MW	2,573	2,624	2,680	2,743	2,815	2,950	3,179	4,047	5,045
Reserve margin	% of peak	14%	14%	14%	13%	13%	13%	15%	14%	13%
Installed system capacity	MW	3,110	3,288	3,689	3,870	4,189	4,558	4,850	6,575	7,985
Firm system capacity	MW	2,394	2,525	2,790	2,843	2,895	3,030	3,193	4,206	5,123
Supply - demand gap	MW	-179	-99	110	100	81	80	13	159	78
Electricity consumption	GWh	12,875	13,124	13,590	13,896	14,288	14,659	15,603	19,969	25,031
Electricity generation	GWh	13,160	13,813	15,001	15,633	16,177	16,757	18,089	24,170	31,352
Excess energy	GWh	285	754	1,476	1,802	1,953	2,163	2,616	4,331	6,450
Excess energy - share on generation	%	2%	5%	10%	12%	12%	13%	14%	18%	21%
Vented GEO steam	GWh	1,167	1,495	1,731	1,742	1,806	1,647	1,940	2,670	3,877
Vented GEO steam - share on	%	20%	21%	24%	24%	25%	25%	25%	25%	25%

In this scenario, the optimization process results in the selection of two units of nuclear capacity from 2040 in the planning period, in contrast to the three units chosen in the reference demand scenario from 2034. Electricity generated from RE accounts for about 83.7% of the total electricity mix in 2043 with geothermal contributing 37.7% of this energy. This is illustrated in Figure 6-6.

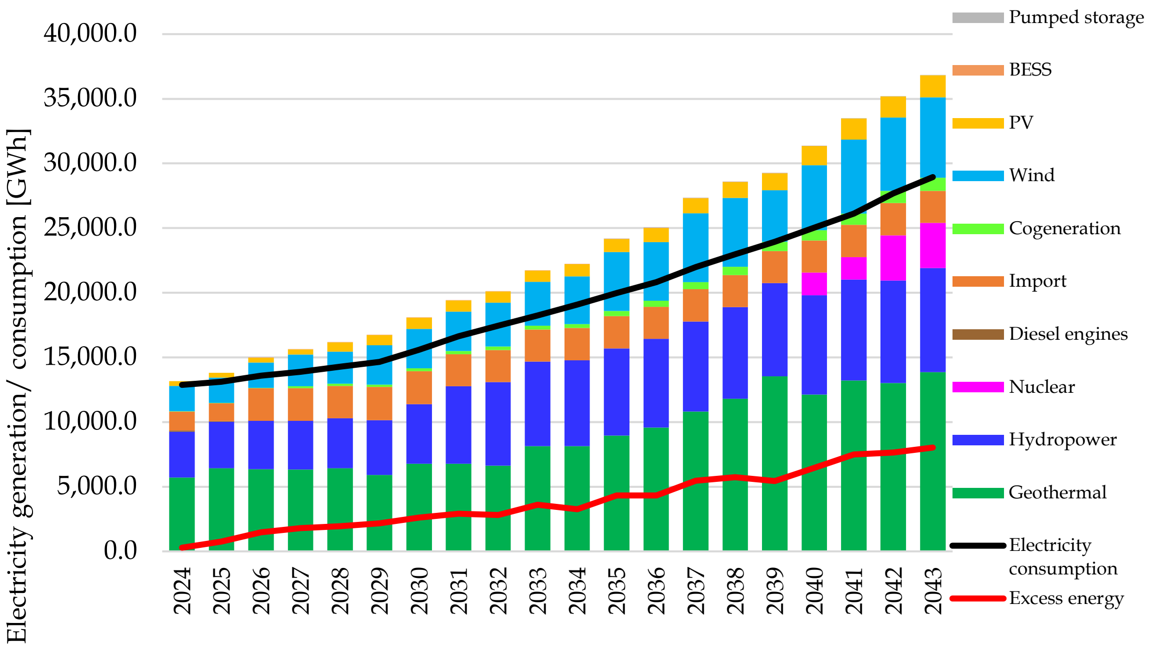


Figure 6-6: Annual generation Balance - Low demand scenario

The committed generation from geothermal and imports in the medium term is projected to increase the excess energy to 9% from the 8% in the reference demand scenario. In the long term, with lower demand generation from geothermal and nuclear resources are projected to increase the excess energy. This increases to an annual average of 18% compared to the forecasted 7% in the reference demand scenario for the entire plan period.

7 TRANSMISSION PLANNING

Transmission planning process can be classified into long term, medium-term and short-term; it forms the blueprint guiding the development of the national electricity grid. Long term transmission plan determines the long-term strategic development of the transmission system. It highlights the transmission system investments required to meet the long-term plan for all generators and loads. In addition, the plan aims to achieve power system stability while meeting the Grid Code requirements. Optimized short and medium-term transmission plans are used for evaluation of the proposed options for improved system performance. They also provide requirements for evacuation of the generated power and reinforcement of distribution systems.

7.1 Objective of transmission planning

The objective of transmission planning is to develop a network expansion sequence that is least cost through detailed technical and economic analysis. It is used to determine the transmission system requirements, evaluate performance of the expected transmission system expansion including reinforcements against the adopted planning criteria to ensure system adequacy during the 20-year planning period.

7.2 Transmission Planning Approach and Expansion Planning Process

The transmission planning process involves the following:

i. Modelling the current as built network and developing annual transmission networks based on revised target dates for ongoing and planned transmission projects in the simulation and analysis software tool for the Medium Term.
ii. Carrying out system studies to assess impact of the ongoing/planned projects as well as identify critical and new projects that are required to ensure adequacy, reliability and efficiency of the power system.
iii. Developing a set of transmission network solutions for the target year, which is the final year of the plan.
iv. Selecting and recommending an optimized target network for the transmission plan from the identified network solutions,
v. Identifying the target network development sequence options for comparison and determination of the least cost network development option through detailed technical studies and economic analysis,
vi. Developing and presenting cost estimates for the planned investments and recommending prioritization of the identified critical projects.

Outputs from demand forecast and generation expansion plan were used as inputs in transmission planning. The plan employed the annual network expansion concept for the Medium Term and Target Network Concept for the Long Term to ensure a coordinated investment strategy and optimal network development using the least cost planning concept. In addition, alternative schemes approach was used in selection of appropriate reinforcements required to alleviate network challenges within the period. Power System Simulation for Engineering (PSS/E) software tool was used in modelling and analysis. The network model was simulated, and analysis carried out against performance indices stipulated in the Kenya National Grid Code. Investment's analysis was undertaken on the developed target networks having capitalized the transmission losses to select the least cost option. The schedule (Annualized order) of projects and investments required was then determined to generate the transmission system plan.

7.3 The Annual Network Expansion Concept

The annual network expansion concept is aimed at addressing the short-term network expansion challenges beginning from the first year of the planning period. Planning starts with developing a solution for the current network, by first considering the committed projects and later introducing additional network elements as required for solving network challenges within the short term.

The analysis was carried out annually from 2023-2028 based on the scheduled commissioning dates of the projects under construction and those planned in the Medium Term. Network violations were identified and appropriate solutions proposed.

The process ensures development of an efficient transmission system in the short term as the target network is implemented for the long term.

7.4 Target Network concept

Target network concept starts with developing a network solution beginning with the final year of the planning period and then working backwards to identify network solutions required for earlier period at defined time intervals.

This ensures that any network investments in the short term are not rendered obsolete in the long term. The process therefore ensures a coordinated development of an efficient and economical transmission system.

In both approaches, the minimization of costs is carried out by comparing costs of development sequence variants.

7.5 Transmission expansion process

The process of developing target network options begins with development of the medium term (2024-2028) transmission system model considering projects that have secured financing and/or are under construction. Alternative functional network models for the remainder of the planning horizon are developed having taken into consideration the demand forecast and planned generation for the years up to 2043.

The process of developing a target network thus involves:

i. Considering future plants' locations and characteristics of each generation technology, existing resource development plans and its established policies;
ii. Splitting the power network into several regions, determining the regional power balances and estimating future potential flows between regions;
iii. Estimating the number and capacities of transmission lines required between regions.

220kV and 400 kV are adopted as the backbone transmission voltages in conformity with the current regional standards, transmission distances and level of system demand. In addition, the transfer capacities, limited by both the thermal rating and the surge impedance loading (for long EHV lines), are considered.

7.6 Planning Assumptions

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

i. The demand and generation planning data are as reported in chapters 3 and 5 respectively. In both cases, recommended reference scenarios were adopted.
ii. Regional demand was assumed to grow at the same rate as the national demand. The point loads expected at various locations were also considered as part of the national load.
iii. Firm power imports will be available only from Ethiopia as provided in the generation planning chapter. However, surplus power exchange and trans-border wheeling within the region are envisaged hence regional interconnections with Uganda and Tanzania were considered in the transmission development plan.

iv. Exports to Tanzania from Ethiopia via Kenya were also considered starting with 100MW in 2024 and scaled up to 200MW in 2025.
v. Due to anticipated right of way challenges and demand growth, major transmission lines will be designed as double circuits (and at higher system voltages) for higher transmission capacity, with a possibility of initially operating them as single circuits and at lower voltage levels.
vi. Off-peak demand was assumed to be 50% of the peak demand, this being the average recorded based on historical data.

7.7 Planning Criteria

In compliance with the Kenya National Transmission Grid Code, the planning process considered the following:

7.7.1 System Voltage

Under normal conditions, all system voltages from 132 kV and above (i.e. 132kV, 220kV, and 400kV) should be within ± 5% of the nominal values.

Voltage magnitude should not exceed ±10% at steady state following a single contingency for 132kV and 220kV. For 400kV system, the voltage magnitude should not exceed ± 5%.

In order to maintain a satisfactory voltage profile both static and fast acting dynamic reactive power compensation equipment are deployed as required and noted for consideration as new investments.

7.7.2 Equipment loading

Under normal operating conditions (and at steady state following single contingencies) no transmission equipment should exceed 100% of the rated continuous rating. However, in some instances during operations at contingency conditions, loading may be allowed to exceed the rated continuous equipment rating subject to confirmed ability of the equipment to withstand the overloading stress for short duration of time.

7.7.3 Voltage Selection

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

7.7.4 Reliability criteria

Some transmission network segments are planned to operate satisfactorily under the condition of a single element contingency, N-1 for generators, transmission lines and transformers, N-2 reliability criteria may be considered for critical transmission network segments. In assessing system reliability, a double circuit line was be considered as two separate circuits.

7.7.5 Fault levels

The system is planned to ensure maximum fault levels do not exceed 80% of the maximum rated short circuit current of the substation equipment. This criterion may lead to either replacement of switchgear (i.e. upgrade) or identification of other actions for limiting the fault levels.

7.7.6 Power losses

The transmission system is planned to operate efficiently with transmission power losses (technical losses) not exceeding 5% and transmission energy losses not exceeding 2.5% at system peak. The economic comparison of variants will take the cost of losses into account and identify the least (global) cost variant. For economic comparison of alternative transmission development plans, power losses at peak are converted to corresponding energy losses and cost at the Long Run Marginal Costs (LRMC) of energy (15 US cents/kWh). The targets are indicative considering normal system operating conditions. The planning process endeavors to maintain optimal network losses.

7.8 Catalogue of Equipment and Materials

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

i. They offer economic and monetary value due to bulk purchase.
ii. They are easily stocked for replacement in cases of failure and redundancy: standardization allows reduction of the amount of spare parts.

iii. It offers ease of operation and maintenance owing to its uniformity and commonality.
iv. It makes it easier for the utility to train its technical staff on the standard equipment
v. It makes it easier to uprate certain equipment by substituting them with others that maybe recovered.

The updated catalogue of equipment and materials used in development of the transmission plan and their estimated unit costs is summarized in Annex G. These costs were used as the basis for preparing project cost estimates and comparison provides the least cost scenarios where required. The costs data will be updated, expanded/revised in future to include equipment made available in the market and installed in the system.

7.9 Generation and load data

7.9.1 Generation data 2024 – 2043

The future generation plants considered in this plan are provided in Table 6-2.

7.9.2 Load data

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

i. Uniform load growth rate in individual KPLC regions as per the reference demand forecast shown in Figure 3-8.
ii. Flagship projects as indicated in Table 3-11.

7.9.3 Distributed load forecast 2024 -2043

The forecast for the regional peak loads in Kenya is distributed as indicated in Table 7-1. It is assumed that peak demand occurs simultaneously in all regions.

Table 7-1: Peak Load Distribution in Regions

Region	2023		2028		2035		2040		2043	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Nairobi	1055.5	347.1	1224.0	401.3	2176.3	440.4	2886.6	436.3	3454.8	440.4
Coast	291.4	96.5	434.8	143.7	738.2	155.2	967.2	155.2	1134.3	169.7
Mt. Kenya	211.2	69.4	269.4	88.4	477.8	96.9	642.8	96.9	763.7	96.9
C Rift	209.0	68.0	305.9	98.6	367.2	74.6	491.2	74.6	603.2	81.6
N Rift	107.6	35.9	134.1	44.7	210.6	41.0	283.9	41.0	510.5	65.2
Western	196.4	62.3	267.6	84.3	324.5	65.2	438.8	65.2	337.7	41.0
Grand Total	2071.1	679.2	2635.8	861.0	4294.6	873.3	5710.5	869.2	6804.2	894.8

7.10 Simulations and Network Analysis

7.10.1 Load flow studies

Load flow studies were carried out iteratively with further network reinforcements included in the model to ensure that all system buses meet the ± 5% voltage criteria and no system equipment are overloaded at steady state. The load flow study forms the basis for all other network studies. The system losses and the impact of target network elements on system losses was determined from load flows.

7.10.2 Contingency studies

Contingency studies are an extension of load flow studies carried out to check whether the target network options meet the loading and voltage criteria following a defined contingency. This informs the requirement of further network reinforcements to meet the redundancy criteria. For critical transmission network segments, N-1 criterion was investigated.

7.10.3 System Fault Studies

Fault level computations were carried out to estimate fault levels at the substations, taking note of substations with fault levels exceeding 80% of the maximum rated short circuit current of the equipment. This informs the need for corrective actions such as replacement of switchgear and reconfiguration of transmission lines.

7.10.4 Power imports

200MW from Ethiopia was considered in 2023 then increased to 300MW (400MW considering 100MW export to Tanzania) in 2024 and 400MW (600MW considering 200MW export to Tanzania) from 2025. Imports from UETCL (Uganda) were restricted to a maximum of 50MW at system peak.

7.10.5 Calculation of Network Losses

Losses in series elements are related to the square of the current flow. It is possible to establish a relationship between peak demand on a system and the average technical losses through consideration of load factors and loss load factors.

i. Load Factor (LF) is defined as the ratio of the average demand over a period of time to the maximum demand within that period for the particular network.
ii. Loss Load Factor (LLF) is defined as average power losses over a period of time to the losses at the time of peak demand.

Where demand recordings exist such as 15 minutes' readings (or half hour readings), LF and LLF can be expressed using standard formulae as follows;

i. LF = Sum of 15 min demands / (maximum demand * number of 15min periods)
ii. LLF = Sum of squares of 15min demands / (square of maximum demand * number of 15min periods)

As historical demand recordings are not available, empirical formulae are available that can be used to estimate the LLF from a LF.

$$LLF = k * LF + (1 - k) * LF^2$$

Where k = a constant, typically 0.1, 0.2 or 0.3

Typically;

K =0.3 for sub transmission systems (Mixed commercial/residential loads with 2 dominant peaks) and

K= 0.2 for medium voltage feeders and distribution substations (Mixed commercial/residential loads with 1 dominant peak)

The formula to calculate energy loss is:

> Energy Loss (KWh) = kW * LLF * 8760 is calculated from the load flow modeling.

The formula adopted is $LLF = 0.3 * LF + 0.7 * LF^2$ as the basis for loss calculations, because the network considered is mainly transmission and sub-transmission.

A load factor of 0.706 (the KPLC Statistics for 2022-23 FY) was used for the existing system. Load factors for the years 2024 to 2043, were derived from the demand forecast results.

7.11 Simulation Results-Medium Term (2023-2028)

7.11.1 Current System Constraints

The 2023 power system, which is the base case in this study, has constraints as shown in Table 7-2 as per the daily reports from the National Control Centre.

Table 7-2: Current System Constraints

Equipment/ Substation/Lines	Constraints	Cause
Juja-Dandora lines	Highly loaded at Peak.	Lack of alternative supply to support Juja Dandora line, Increasing demand and high number of feeders originating from Juja SS.
Suswa-N/North lines	Highly loaded normally.	Suswa – Nairobi North being electrically shorter than existing alternative. Increasing demand and high number of feeders originating from Nairobi North SS
Muhoroni-Chemosit line	Highly loaded at Peak.	Lack of alternative supply to support the radial network from Kisumu (Mamboleo – Muhoroni-Chemosit-Sotik-Kisii- Awendo) absence of capacity injection at Muhoroni exacerbates the constraint
Kisumu-Muhoroni line	Highly loaded at peak.	
Masinga-Kamburu line	Highly loaded at Peak (during low hydrology seasons).	Lack of alternative supply to support the radial network from eastern Hydros to Nanyuki
Masinga-Kutus line	Highly loaded at Peak.	Lack of alternative supply to support the radial network from eastern Hydros to Nanyuki

Equipment/ Substation/Lines	Constraints	Cause
Kibos substation voltages	Normally very high with no reactive power control equipment especially at night and low demand days	Long 220kV line between Olkaria and Kibos
System Frequency	Regulation challenges due to integration of Variable Renewable Energy generation	Inadequate spinning reserve as a result of poor/low hydrology
Severe voltage swings in Athi River and Coast Region	Caused by System disturbances, especially during low demand periods, and operation of static reactors.	Long transmission lines that are lightly loaded during low peak periods
Low Voltages at Nanyuki Substation	Very low in the evenings and at high demand periods	Lack of alternative supply to support the radial network from eastern Hydros to Nanyuki

7.11.2 Existing System-Year 2023

The existing power system was modelled and simulated based on the current peak demand of 2170MW. During normal system operating conditions, voltage violations (low voltages) were noted on nine 132kV buses notably in South Nyanza, Central Rift and North Rift Regions. Branch over-loads were also noted on 132kV Muhoroni-Chemosit (142.1%) and Kisumu-Muhoroni (123.4%) lines. During contingency conditions (N-1) more voltage and branch violations were noted, additionally, there is loss of loads in network sections served by radial lines or single transformers. Simulation output and results are as indicated in Annex K.

Estimated instantaneous power losses at peak and annual energy losses are 96.96MW and 488.41GWh respectively at the transmission level (without 66kV). Comparing power and energy losses with peak demand of 2170MW and the projected energy purchased in the year 2023 of 13,627GWh, the power and energy losses translate to approximately 4.47% and 3.58 % in that order.

To mitigate the above violations, several simulations were carried out and the following projects, which have been delayed beyond their initial scheduled commissioning dates, were identified for fast tracking:

i. Construction of the 69km Ndhiwa-Sondu 132kV line to resolve voltage issues in South Nyanza and Central Rift Region and overloading of the Kisumu-Muhoroni and Muhoroni-Chemosit 132kV transmission lines. It also makes it possible to decommission the GTs in Muhoroni without adverse impact to the system.

ii. Construction of Narok-Bomet 132kV line to provide alternative supply to South Nyanza and Central Rift Region.
iii. Completion and commissioning of 220/132kV transformer at Kitale substation and Turkwel-Ortum-Kitale 220kV transmission line. This will provide an alternative evacuation route for Turkwel Hydro generation to North Rift & Western Kenya. Furthermore, completion of Turkwel-Ortum-Kitale 220kV will improve System Security.
iv. Reconstruction and upgrade of Rabai-Kilifi 132 kV line to double circuit to provide adequate supply capacity in North Coast sub-region and improve supply reliability.
v. Commissioning of Mariakani 400/220kV substation to enable operation of Isinya-Mariakani at 400kV and facilitate N-1 redundancy criteria supply reliability at Coast.
vi. Commissioning of Kimuka 220/66kV 2X200MVA Substation and construction of the proposed 66kV feed-outs from Kimuka Substation to reduce losses, improve voltages and security of supply on the 66kV network served from Nairobi North Substation and on **the** Magadi feeder. This will also de-load Suswa-Nairobi North 220kV lines.
vii. Termination of Olkaria-Lessos-Kibos 220kV line at Lessos substation to enable operation of Olkaria-Lessos-Kibos lines as designed. This will provide a complete parallel route to the North Rift and West Kenya load centers.
viii. Completion of Isiolo-Nanyuki 132kV line to complete the Mt. Kenya Ring and deload Kamburu-Masinga and Masinga-Kutus 132kV lines.

7.11.3 Year 2024 Transmission Expansion Plan

At the end of the year 2024, Eight (8) projects consisting of 562km of lines (route length), 6589km (circuit length) and transformation capacity of 1692MVA are expected to have been completed and operational as per the Table 7-5 at an estimated cost of USD 455 Million. With the expected network as at end of 2024, voltage violations in 10 buses were recorded in South Nyanza, Central Rift and the North Coast Regions. Chemosit-Muhoroni 132kV line was notably highly loaded at 152% of rated capacity.

During N-1 contingency conditions, loss of the following lines led to non-convergence of the system and are therefore considered system wide critical contingencies:

i. Loss of the HVDC
ii. Loss of Embakasi-City Centre 220kV line
iii. Loss of Suswa-Kimuka 220kV line
iv. Loss of Suswa-Isinya 400kV line

v. Loss of Isinya-Tanzania 400kV line
vi. Loss of Isinya-Mariakani 400kV line
vii. Loss of sections of Juja-Rabai 132kV line between Top Steel (Mariakani) and Rabai
viii. Loss of Mariakani-Rabai 220kV line
ix. Loss of Olkaria 1AU-Naivasha 132kV line
x. Loss of Olkaria II-Kibos 220kV line
xi. Loss of Kisumu-Muhoroni 132kV line
xii. Loss of Lessos-Muhoroni 132kV line
xiii. Loss of Sondu-Kisumu 132kV line
xiv. Loss of Olkaria II-Lessos 220kV line (Second line)

There were six (6) instances of branch overloading violations excluding Muhoroni-Chemosit 132kV line which was over loaded in the Base Case ranging from 102% to 139% (Suswa-Nairobi North 220kV lines upon loss of one circuit) resulting from six (6) resulting from loss of one circuit on the double circuit lines.

Voltage violations of 0.6966p.u. to 0.89p.u. were noted in the meshed part of the network. All radial segments of the network were lost upon loss of preceding section(s).

Ninety-four (94) loss of load violations ranging from 0.27MW to 31.59MW are observed in different stations when sections of radial systems are put out of service at different sections. The affected radial systems include Masinga-Kutus-Kiganjo-Nanyuki, Musaga-Mumias-Rangala, Rabai-Malindi -Garsen Lamu, Mwingi-Garissa, Muhoroni-Chemosit-Sotik-Kisii-Awendo-Ndhiwa and Bomet, Rabai-Galu-Base Titanium and all substations with single transformers. Detailed simulation output and results are given in the Annex K.

By end of 2024, the instantaneous power losses and annual energy losses are estimated at 97.64MW and 468.55GWh respectively. Comparing power and energy losses with peak of 2313MW and the projected energy purchased in the year 2024 of 14,101GWh, this translates to approximately 4.22% and 3.32 % respectively.

Fault levels at the monitored buses were determined to be within the maximum equipment short circuit ratings.

To resolve the network issues identified at the end of the year 2024, especially during contingency conditions, the following projects are recommended in addition to the ones in the Base Case Scenario:

i. Development of transmission line rings for areas currently served by radial networks especially where there is loss of substantial load. Some of the projects expected to close the rings are Isiolo-Nanyuki 132kV line scheduled for completion in 2024 and Weru-Kilifi 220kV line.
ii. Install second transformers in Kibos, Bomet, Kyeni, Narok, Mwingi, Kitui and Wote substations among others.
iii. Development of an alternative evacuation path for Olkaria IV and Olkaria V geothermal power plants

7.11.4 Year 2025 Transmission Expansion Plan

At the end of the year 2025, seven (7) projects consisting of 626.5km (route length), 906km (circuit length) of lines and transformation capacity of 957MVA are expected to have been completed and operational as per Table 7-5 at an estimated cost of USD 298 Million.

Simulation of the planned 2025 transmission system returned voltage violations (under voltages) in 132kV buses in the substations in South Nyanza i.e. Kisii, Awendo, Masaba and Ndhiwa. There were no loading violations in the normal operating system.

During N-1 contingency conditions, 51 contingencies led to non-convergence of the system and are therefore considered system wide critical contingencies.

There are six cases of branch over loadings for various contingencies including Muhoroni-Kisumu 132kV line after loss of Olkaria-Lessos 220kV line (2nd line), Olkaria II-Olkaria I 132kV line after loss of Kisumu-Muhoroni-132kV line and Olkaria II-Lessos 220kV line, Muhoroni-Chemosit 132kV line after loss of Bomet-Sotik 132kV line and Olkaria IV-Suswa 220kV line after loss of one of the circuits. There were 88 voltage range violations in the meshed part of the network during contingency conditions. Forty-eight (48) loss of load violations ranging from 2.68MW to 32.25MW (Kisii) are observed in different stations when sections of radial systems were put out of service at different sections. The affected radial systems include Musaga-Mumias-Rangala, Konza-Machakos, Isinya-Namanga, Rabai-Malindi–Garsen-Lamu, Mwingi-Garissa, Rabai-Galu, Kisii-Awendo-Ndhiwa,Lessos-Kabarnet among others and all substations with single transformers. Detailed simulation output and results are given in the Annex K.

By end of 2025, the estimated instantaneous power losses and annual energy losses are estimated at 83.47MW and 400.65GWh respectively. Comparing power and energy losses with peak of 2405MW and the projected energy purchased in the year 2025 of 14,664.68GWh, this translates to approximately 3.47% and 2.73% respectively.

Fault levels were determined to be less than 80% of maximum equipment short circuit ratings

To resolve the network issues identified at the end of the year 2025, especially during contingency conditions, the following projects are recommended for fast-tracking:

i. Weru-Malindi-Kilifi 220kV line
ii. Sondu-Ndhiwa 132kV line
iii. Rumuruti-Kabarnet 132kV line
iv. Installation of second transformers in all substations with single transformers.

7.11.5 Year 2026 Transmission Expansion Plan

At the end of the year 2026, thirteen (13) projects consisting of 469.5km (route length), 752km (circuit length) of lines and transformation capacity of 3696MVA are expected to have been completed and operational as per Table 7-5 at an estimated cost of USD 707 Million.

The simulation of the planned 2026 transmission system returned over voltages in Turkwel and Lessos 220kV buses, Makindu 132kV after commissioning of the 400kV and Gilgil 400kV bus. Chemosit 132/33kV 2X23MVA transformers and Garissa 132/11kV 7.5MVA transformer are overloaded during normal system operating conditions.

During N-1 contingency conditions, loss of the section of the Juja-Rabai 132kV line between Rabai and Kokotoni leads to non-convergence of the system and is therefore considered a system wide critical contingency. There were ten (10) instances of branch overloading violations ranging from 100% to 143% (Suswa-Nairobi North line upon loss of one of the circuits) resulting from five (5) contingencies. Voltage violations of 0.7665p.u. to 0.8997p.u. were noted in the meshed part of the network. All radial segments of the network lost voltages. Thirty (30) loss of load violations ranging from 2.71MW to 28.14MW are observed in different stations when sections of radial systems were put out of service at different sections. The affected radial systems included Awendo-Masaba, Malindi-Garsen-Lamu, Sultan-Hamud-Loitoktok, Mwingi-Garissa, Musaga-Mumias-Rangala, Rabai-Galu-Base Titanium among others and all substations with single transformers. Detailed simulation output and results are given in the Annex K.

By end of 2026, the estimated instantaneous power losses and annual energy losses were 70.11MW and 337.86GWh respectively. Comparing power and energy losses with peak of 2506MW and the projected energy purchased in the year 2026 of 15,315.69GWh, the power and energy losses translate to approximately 2.8% and 2.21% respectively. Fault levels were determined to be less than 80% of maximum equipment short circuit ratings.

To resolve the network issues identified at the end of the year 2026, especially during contingency conditions, the following projects are recommended:

i. Uprating of the 132/33kV 2X23MVA transformers in Chemosit to 2X45MVA and the Garissa 132/11kV 7.5MVA transformer to 23MVA.
ii. Finding an alternative 220kV supply to Nairobi North, Thika Road and Dandora from the 400kV ring. The proposed Thika 400/220kV substation to Thika Road or Ruaraka by KETRACO is recommended for fast-tracking.
iii. Installation of the phase-shifting transformers on Nairobi North 220kV lines at Suswa.

7.11.6 Year 2027 Transmission Expansion Plan

At the end of the year 2027, Eleven (11) projects consisting of 811.5km (route length), 1285.5km (circuit length) of lines and transformation capacity of 842MVA are expected to have been completed and operational as per as per Table 7-5 at an estimated cost of USD 589 Million.

The simulation of the planned network model in 2027 did not return voltage and loading violations under normal system operating conditions.

During N-1 contingency conditions, loss of the section of the Juja-Rabai 132kV line between Rabai and Kokotoni, HVDC and Garsen-Hola-Bura 220kV line lead to non-convergence of the system and are therefore considered a system wide critical contingency. There were fifteen (15) instances of branch overloading violations ranging from 104.8% to 152.09% (Suswa-Nairobi North line upon loss of one of the circuits) resulting from nine (9) contingencies. Nineteen (19) voltage violations of 0.7021p.u. to 0.8995p.u. were noted in the meshed part of the network. All radial segments of the network lost voltages. Twenty one (21) loss of load violations ranging from 2.71MW to 28.15MW were observed in different stations when sections of radial systems were put out of service at different sections. The affected radial systems included Garsen-Lamu, Sultan-Hamud-Loitoktok, Konza-Machakos, Mangu-Gatundu, Musaga-Mumias-Rangala among others. Detailed simulation output and results are given in the Annex K.

By end of 2027, the estimated instantaneous power losses and annual energy losses were 77.68MW and 376.46GWh respectively. Comparing power and energy losses with peak of 2615MW and the projected energy purchased in the year 2027 of 16,041.42GWh, the power and energy losses translate to approximately 2.97% and **2.35 %** respectively.

Fault levels were determined to be less than 80% of maximum equipment short circuit ratings.

To resolve the network issues identified at the end of the year 2027, especially during contingency conditions, the following projects are recommended in addition to the previous ones:

- Alternative evacuation path out of the Menengai geothermal field is recommended after commissioning of the three Menengai plants. Fast-tracking of the Menengai-Olkalou-Rumuruti 132kV line and the associated substations is therefore recommended.

7.11.7 Year 2028 Transmission Expansion Plan

At the end of the year 2028, twenty-four (24) projects consisting of 514km (route length), 925km (circuit length) of lines and transformation capacity of 1,425MVA are expected to have been completed and operational as per Table 7-5 at an estimated cost of USD 367.328 Million.

No voltage or loading violations were observed during normal system operating conditions.

During N-1 contingency conditions, loss of the section of the Juja-Rabai 132kV line between Rabai and Kokotoni, HVDC and Garsen-Hola-Bura 220kV line lead to non-convergence of the system and are therefore considered a system wide critical contingency. There were no instances of branch overloading violations if the projects recommended in the previous years are implemented.

15 buses suffer voltage range violations during contingency conditions with the voltage ranging from 0.664p.u. to 0.8993p.u. for the meshed part of the network. All

radial segments of the network lost voltages when preceding sections were put out of service.

Twenty-four (24) loss of load violations ranging from 2.80MW to 29.02MW were observed in different stations when sections of radial systems were put out of service at different sections. The affected radial systems included Garsen-Lamu, Sultan-Hamud-Loitoktok, Konza-Machakos, Mangu-Gatundu, Musaga-Mumias-Rangala, Mangu-Githambo, Meru-Maua, Ishiara-Kyeni-Chogoria, Kisumu-Bondo, Awendo-Masaba among others. Detailed simulation output and results are given in the Annex K.

By end of 2028, the estimated instantaneous power losses and annual energy losses were 64.39MW and 313.65GWh respectively. Comparing power and energy losses with peak power demand of 2737MW and the projected energy purchased in the year 2028 of 16,839.62GWh, the power and energy losses translate to approximately 2.35% and 1.86 % respectively.

Fault levels at Suswa 220kV substation were notably above 50% (22kA out of 31.5kA) and those at Juja Road 132kV substation at 18kA, the short circuit levels for other buses were within 50% of the respective maximum equipment short circuit ratings.

A summary of fault level evolution for assorted substations in the medium term are given in Figure 7-1.

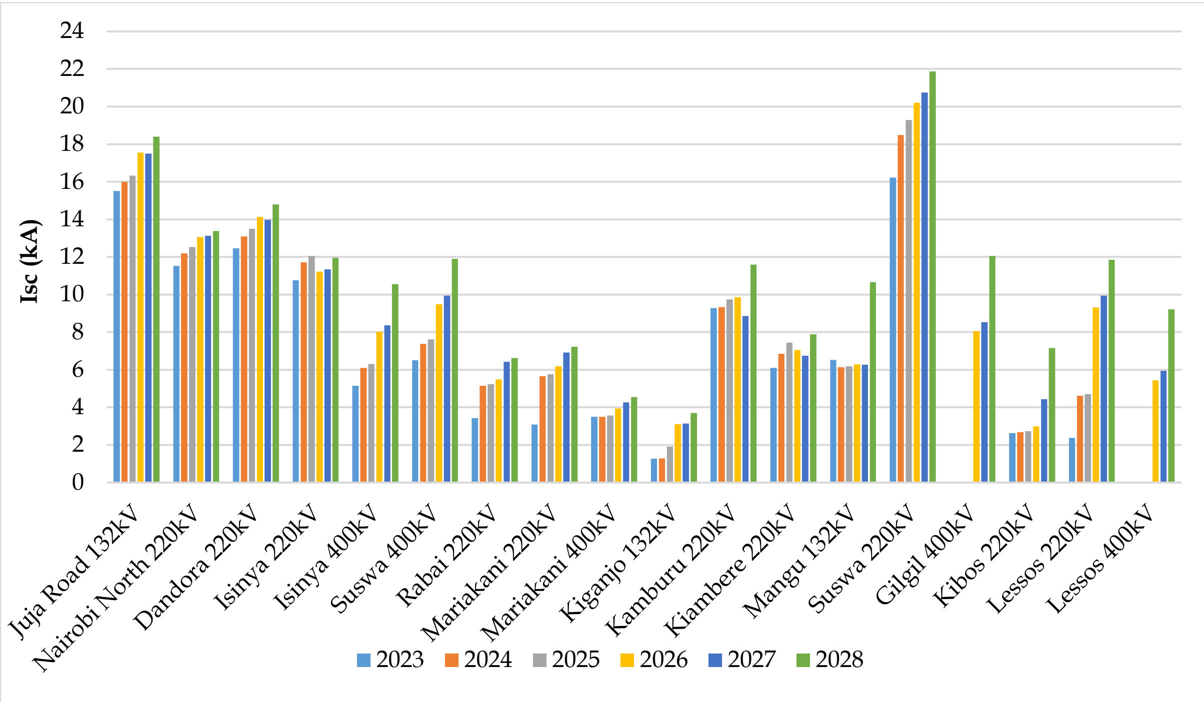


Figure 7-1: Fault Level Evolution 2023 - 2028

To resolve the network issues identified at the end of the year 2028, especially during contingency conditions, the following projects are recommended in addition to the previous ones:

i. Githambo-Othaya-Kiganjo 132kV line and associated substations to create 132kV ring.
ii. Bondo-Rangala 132kV line to close the 132kV ring.
iii. Kilgoris-Masaba 132kV line to create the 132kV ring.
iv. Machakos-Mwala 132kV line and associated substation to close the 132kV ring

The transmission projects expected to address the network challenges in the medium term were identified and scheduled annually according to priority and advancement in network development.

7.11.8 Long Term Plan 2029-2043

7.11.8.1 Overview of the Target Network Elements

In the current planning period, the options for target network (TN) elements required to resolve challenges are given in Table 7-3. These options aim to:

i. Assist in decongesting Suswa Complex and reduce risk of increasing the short circuit fault level of equipment.
ii. Evacuation path for Agil and Olkaria IX and providing alternative evacuation path from Olkaria Complex.

7.11.9 Developing Target Networks Options

The network models for the target year (2043) were developed by determining selected combinations of the target network elements as shown in Table 7-3.

Table 7-3: Target Network elements

Target Network Option	TN Element	Description	Objective	Length (Km)	Cost (MUSD)	Year
1	1.1	Naivasha 220/132kV substation	Alternative evacuation path from Olkaria Complex	-	23.43	2035
	1.2	Naivasha–Olkaria IX 220kV double circuit line and installation of Phase Shift Transformers on the lines to Ruaraka		25	16.69	2035
	1.3	Agil-Olkaria IX 220kV double circuit line		25	13.69	2039
	1.4	Naivasha–Agil 220kV double circuit line		23	12.6	2039
2	2.1	Agil-Olkaria IX 220kV double circuit line	Alternative evacuation path from Olkaria Complex	25	13.69	2039
	2.2	Olkaria IX-Longonot 220kV double circuit line		25	13.69	2035
	2.3	Agil–Longonot 220kV double circuit line	Decongest Suswa Complex	8.5	4.66	2039
	2.4	Gilgil-Thika LILO - Longonot 400kV double circuit line		40	32.37	2035
	2.5	Longonot 400/220kV substation		-	25.66	2035
	2.6	Reconductoring of 132kV Olkaria I AU - Naivasha	Resolve overloading issues	22	15	2040

7.11.10Target Network Selection

The result of the investment analysis of the two target networks is given in Table 7-4.

Table 7-4: Results of the Investment analysis

Target Network	TN1	TN2
Total Cost (EPC_RAP+O&M + Losses) [MUSD]	7,142	7,129
Total PV of Costs [MUSD]	3,342.69	3,343.28

Based on the analysis, Target Network 2 emerges with a lower total cost, while Target Network 1 boasts a lower present value (PV) of costs in achieving the transmission expansion objective, rendering it more economical. However, considering the projected medium and long-term outcomes, both networks display a decrease in transmission energy losses.

By the end of 2028, simulated results for both networks predict a reduction in losses from 3.58% in 2023 to 1.86%. Over the long term, losses are expected to further decrease to 2.28% by 2043. Notably, from 2035 onward, Target Network 2 demonstrates marginally lower energy losses compared to Target Network 1, signifying its superior long-term efficiency. The specifics of the energy loss differences between the two networks are detailed in Annex K.

Project costs and losses guided the selection of target networks, aligning transmission investments with technical criteria. PSS/E load flow models and results for both target networks are found in the Appendices. Cost estimates for network elements informed the investment analysis detailed in the next section of this report.

The alternative investment strategies were formulated based on the initial target network options using a specific methodology. Each strategy, evaluated annually, accounted for reinforcing transmission lines and substations, determining reactive compensation needs, and assessing transmission losses.

For comparison purposes, the cost of transmission losses calculated at the Long Run Marginal Cost (LRMC) of energy was factored in. This cost was added to the total investment expenses. To establish the most cost-effective transmission plan, the annual costs of each investment sequence were discounted back to the base year (2023) at a rate of 12.8%. Further, the Operation & Maintenance (O&M) cost calculated as 2.5% of the Investment Cost was included. The Present Value (PV) of cost for each strategy was then calculated by summing these discounted annual investments. The strategy demonstrating the lowest PV of cost emerged as the most economical option for expanding the transmission network.

Ultimately, based on these comprehensive assessments, Target Network 2 is selected as the optimal option for implementation, owing to its superior efficiency in the long run. Notably, Target Network 2 is recommended for implementation. The present value of investments for this option is estimated at MUSD 3,343.28.

Detailed investment analysis for the two options is given in Annex K.

7.12 Long Term Projects

7.12.1 Year 2029 Transmission Expansion

At the end of year 2029, five (5) projects consisting of 337 km of lines (route length), 674km (circuit length), line transformation capacity of 1166MVA per circuit, five (5) substations, and 498MVA substation transformation capacity are expected to have been completed and operational at an estimated cost of 262.8 MUSD.

7.12.2 Year 2030 Transmission Expansion

At the end of year 2030, ten (10) projects consisting of 1,054 km of lines (route length), 1,783 km (circuit length), line transformation capacity of 3,884 MVA per circuit, eight (8) substations, 740 MVA substation transformation capacity, and one (1) Dynamic Reactive Power Compensation (DRPC) equipment are expected to have been completed and operational at an estimated cost of 677.97 MUSD.

7.12.3 Years 2031 - 2035 Transmission Expansion

To increase capacity, reduce congestion, maintain voltage stability, and enhance reliability of the grid in the long term, the following reinforcement projects are planned for implementation by the year 2034:

i. Transfer of loads from Limuru 220/66kV substation to Kimuka 220/66kV substation to reduce loads at the transformer at Nairobi North 220/66kV substation.
ii. Installation of a second 23MVA transformer at Namanga 132/33kV substation.
iii. Installation of a third 45MVA transformer at Rabai 132/33kV substation.
iv. Installation of a second 60MVA transformer at Thika 132/33kV substation.
v. Installation of a second 23MVA transformer at Gatundu 132/33kV substation.
vi. Installation/uprating of the two (2) 23MVA transformers at Soilo 132/33kV substation to 45MVA.
vii. Installation of a third 45MVA transformer at Chemosit 132/33kV substation.
viii. Transfer of 10MW load from Rangala 132/33kV substation to Bondo 132/33kV substation.
ix. Installation of a third 45MVA transformer at Eldoret 132/33kV substation.
x. Installation/uprating of the two (2) 23MVA transformers at Kitale 132/33kV substation to 45MVA.
xi. Installation of a second 23MVA transformer at Isiolo 132/33kV substation.

Between 2031- 2035, twenty (20) projects consisting of 1,220 km of lines (route length), 2,440km (circuit length), line capacity of 8,214 MVA per circuit, eighteen (18) substations, and 3,969 MVA substation transformation capacity are expected to have been completed and operational at an estimated cost of 1,058.1 MUSD.

7.12.4 Year 2036 - 2040 Transmission Expansion Plan

Between 2036 - 2040, twenty-three (23) projects consisting of 200 km of lines (route length), 228.5 km (circuit length), line capacity of 2645MVA per circuit, twenty-one (21) substations, and 2204MVA substation transformation capacity are expected to have been completed and operational at an estimated cost of 214.12 MUSD.

To increase capacity, reduce congestion, maintain voltage stability, and enhance reliability of the grid in the long term, the following reinforcement projects are planned for implementation by the year 2040:

i. Installation of a 150MVAr capacitor bank at City Centre 220/66kV substation to inject reactive power to Dandora-Embakasi 220kV transmission line.
ii. Installation of a third 200MVA transformer at City Centre 220/66kV substation.
iii. Installation of two (2) additional (third and fourth) 200MVA transformers at Isinya 400/220kV substation.
iv. Transfer one third (1/3) of loads from Kilifi 132/33kV substation to New Kilifi 220/132kV substation
v. Reconstruction and upgrade of Kwale Sugar-Titanium 132kV line from Lynx to Canary to provide adequate supply capacity in South Coast sub-region and improve supply reliability.
vi. Installation/uprating of the two (2) 23MVA transformers at Nanyuki 132/33kV substation to 45MVA.
vii. Installation/uprating of the two (2) 23MVA transformers at Meru 132/33kV substation to 45MVA.
viii. Transfer loads from Meru 132/33kV substation to Maua 132/33kV substation.
ix. Construction of several 33/11kV substations at Garissa to reduce overloading at Garissa 132/11kV substation.
x. Reconstruction and upgrade of Webuye-Musaga 132kV line from Lynx to Goat to provide adequate supply capacity in West Kenya region and improve supply reliability.
xi. Installation/uprating of the two (2) 45MVA transformers at Kisii 132/33kV substation to 45/60MVA.
xii. Installation of a second 90MVA transformer at Kitale 220/132kV substation to accompany the installation of Pumped Hydro storage at Ortum.

xiii. Connection of Baringo, Silali and Paka geothermal generation to the grid through the 400kV bus at Baringo 400/220kV substation.

7.12.5 Year 2041 -2043 Transmission Expansion Plan

Between 2041 - 2043, five (5) projects consisting of 357 km of lines (route length), 592 km (circuit length), line capacity of 1697MVA per circuit, four (4) substations, and 540MVA substation transformation capacity are expected to be completed and operational as per Table 7-5 at an estimated cost of 346.1 MUSD.

The evolution of short circuit current levels in the long term is given in Figure 7-2.

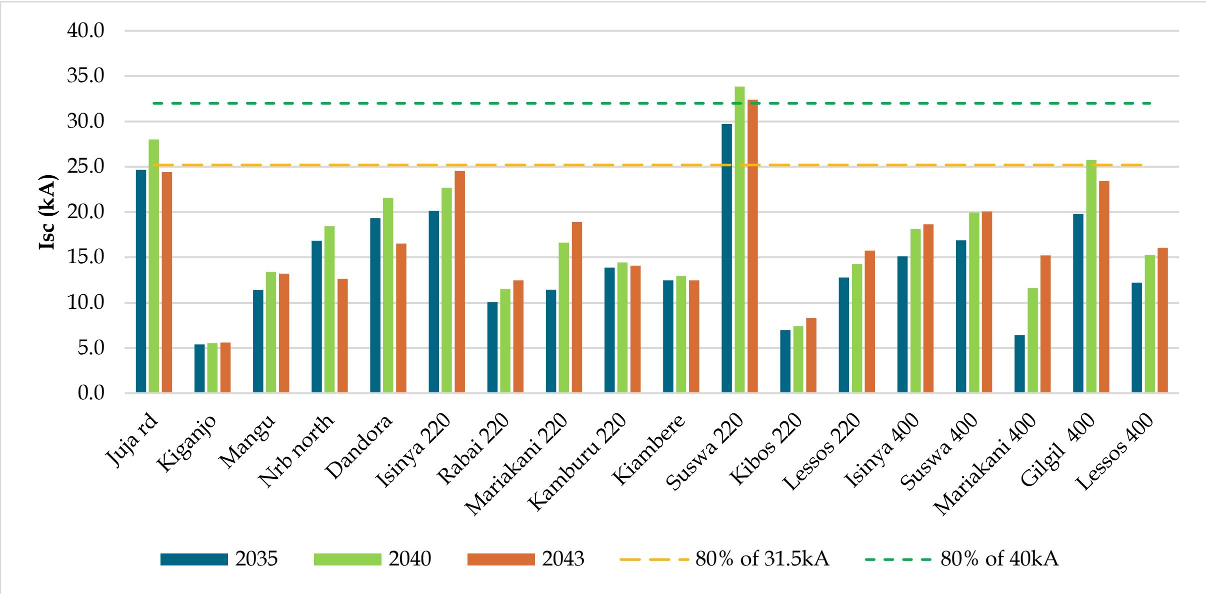


Figure 7-2: Fault Level Evolution 2035-2043

The evolution of transmission system energy losses in the long term is given in Figure 7-3.

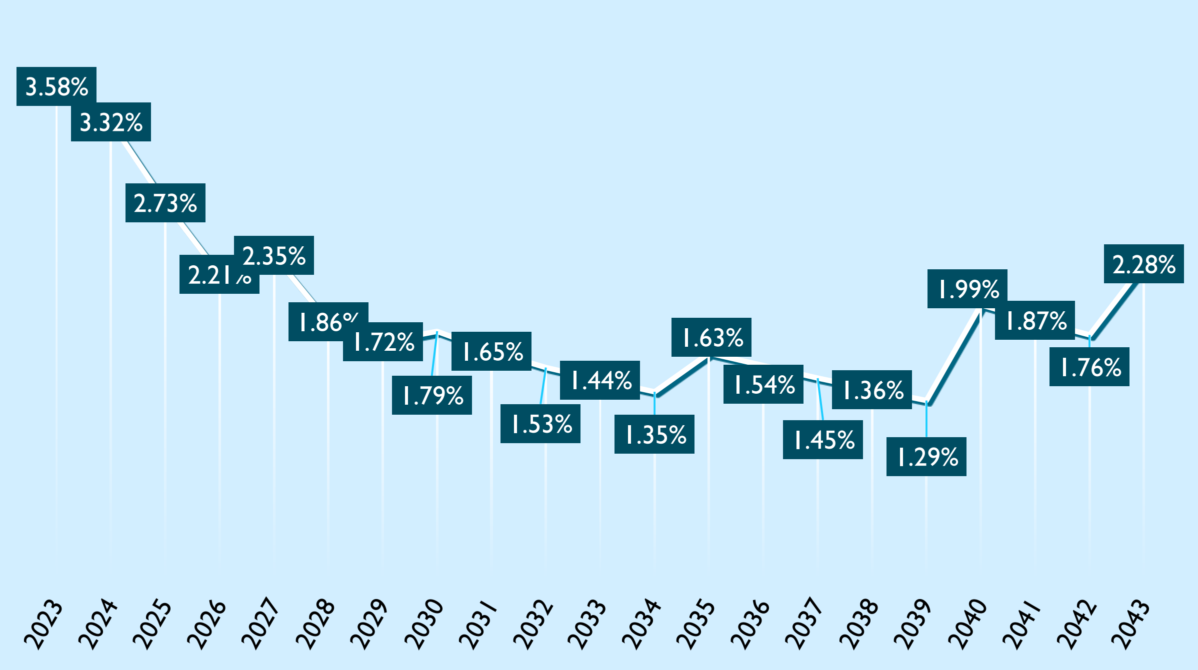


Figure 7-3: Evolution of Transmission System Energy Losses

Table 7-5 provides the network reinforcements and expansion projects required in the planning period.

Table 7-5: Investment Schedule (Ongoing and Planned Projects)

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
YEAR 2023							
1					Olkaria IAU or Olkaria II 220/132 90MVA	90	5.2
TOTALS 2023		**0**	**0**	**0**		**90**	**5.2**
YEAR 2024							
1	Nairobi Ring substations (Isinya, Athi River, Kimuka, Malaa)	-	-	-	Kimuka 220/66 2x200MVA	400	47.76
					Malaa 220/66 2x200MVA	400	
2	Isinya (Kajiado) – Namanga 132kV	80	80	97	Namanga 132/33 23 MVA	23	42.57
3	Mariakani 400/220kV substation	-	-	-	Mariakani 400/220 4x200MVA	800	27
4	Sultan Hamud – Meruesh i- Loitoktok 132kV	120	120	97	Loitoktok 132/33 23MVA	23	129.69
					Merueshi 132/33 23MVA	0	
5	Turkwel – Ortum – Kitale 220kV	135	135	270	Ortum 220/33 23MVA	23	45.95
6	Lessos – Kabarnet 132kV	65	65	97	Kabarnet 132/33 1x23MVA	23	109.59
7	Kitui – Wote 132kV	66	66	97			
8	Kenya - Tanzania (Namanga Border)	96	192	1600			52.01
TOTALS 2024		**562**	**658**	**2258**		**1692**	**454.57**
YEAR 2025							
1	Nanyuki – Rumuruti 132kV	79	79	97	Rumuruti 132/33 23MVA	23	50.96
2	Nanyuki – Isiolo 132kV	70	70	97			
3	Awendo- Isebania	50	50	97	Isebania 132/33 1x23	23	Included in year 2024 TL item no. 6
4	Isinya-Konza 400KV including step down to 66kV and 132kV intertie between Konza 400/132 and Konza 132/33	45	90	1600	Konza 400/132 2x350MVA	700	
5	Lessos – Tororo 400kV	132	264	1400	Lessos 220/132kV 75MVA	75	161.83

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
6	Narok – Bomet 132kV	88	176	97	Bomet 132/33 23MVA	23	27.07
					Narok 132/33 23 MVA	23	
7	Rabai-Kilifi 132kV (with inter link to existing 132/33kV SS)	67	67	97	Kilifi 132/33 2x45MVA (new Site)	90	30.15
8	Rabai-Bamburi-Msa Cem-Vipingo- Kilifi 132kV	76	76	97			
9					Mobile 220/33 1x30MVA and 132/33 1x30MVA	60	15
10					Mobile 220kV reactor 1x20MVAr and 132kV reactor 1x20MVAr.		
11	Nanyuki – Rumuruti 132kV 14.5 km UG cable	14.5	29	100			17.82
12	Nanyuki – Isiolo 132kV 5 km UG cable	5	5	100			
TOTALS 2025		**626.5**	**906**	**3782**		**1017**	**302.83**
YEAR 2026							
1	Kamburu-Embu-Thika 220KV	150	300	324	Embu 220/132 2x90MVA	180	130.96
					Thika 220/132 2x90MVA	180	
2	Maai Mahiu/Uplands (Limuru) substation	1	4	97	Maai Mahiu 132/66 2x60MVA	120	
3	Sondu (Thurdibuoro) – Ongeng (Homa Bay/Ndhiwa)	69	69	97	Thurdibuoro 1x23MVA	23	28.92
4	Makindu substation LILO - 400kV	1	4	1400	Makindu substation 400/132kV 2x90MVA	180	32.05
	Makindu substation LILO - 132kV	1	4	97			
5	400/220kV SS at Baringo and LILO to Loosuk/Lessos line	3	12	1400	Baringo 400/220kV 2x400MVA	800	35.24
6	Rumuruti – Kabarnet 132kV	111	111	97	Rumuruti Tx2 132/33kV 1x23MVA	23	31.68
					Kabarnet Tx2 132/33kV 1x23MVA	23	
7	Rongai Substation 132/33kV	1.5	6	97	Rongai 132/33 2x45MVA	90	12.83

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
8	Kipevu - Mbaraki 132kV	6.5	13	97	Mbaraki 132/33 2x45MVA	90	14.44
9	Weru – Kilifi 220kV	48.5	97	324	Kilifi 220/132 2x90MVA	180	52.89
10	Malindi -Weru (Circuit II) 220kV	22	22	324	Malindi 220/33 45MVA	45	27.13
11	TX Upgrade Olkaria I	-	-	-	Olkaria I 1x45/60MVA (Unit 1and 2) Olkaria I 1x45/60MVA (Unit 3)	120	2
12	Olkaria II Ext - Olkaria VII - Fertilizer Plant	45	90	324	Fertilizer Plant Substation	-	47.3
13	Olkaria II - Olkaria II Extension (and relocation of Olkaria III to Olkaria II extension	2	4	324	Olkaria II Extension	-	12.67
	Olkaria 1 AU-Olkaria IV /V 220KV	8	16	324	-		14.76
14	Installation of Phase Shifting Transformers (PST) on Suswa- Nairobi North lines at Suswa	39	78	600	-	-	9.8
15					Garissa 132/11 23MVA	23	2.89
16					Kimuka 400/220 2x200MVA	400	28.59
17					Kibos 220/132 150MVA	150	5.6
18	-				Fast acting reacting power and voltage control devices at various regions for improved power quality (Coast, Nairobi).Suswa 120MVAr ,2x100MVAr STATCOM/DRPC)	Suswa STATCOM 120, MSR 2x100MVAr	100
19					Lessos 400/220 2x400MVA	800	32.16
20					SS Ext. Garsen 220/33 23MVA	23	3.9
21					Kitale 220/132 110MVA	110	5.2
22					Machakos 132/33 23MVA	23	2.89
23					Kyeni 132/33 23MVA	23	2.89
24					Kisii/Kegati 132/33 2x45MVA	90	3.779

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
25					SAS Upgrade, CCTV& Access Control, SCADA Upgrade, new Metering System, KETRACO WAN	-	16
TOTALS 2026		**508.5**	**830**	**5926**		**3696**	**656.569**
YEAR 2027							
1	Mariakani – Dongo Kundu 220kV Line	55	110	400	Dongo Kundu 2x75MVA	150	53.03
2	Garsen -Bura-Hola –Garissa 220kV	240	240	236.6	Bura 220/33 1x23MVA	23	94.99
					Hola 220/33 1x23MVA	23	
					Garissa 220/132 1x60MVA	60	
3	Kwale LILO (Mariakani/Dongo Kundu) - Kibuyuni (including switch station at Bang'a)	77	154	324	Shimoni/Kibuyuni 220/132 2x90MVA	180	84.9
4	Kisumu (Kibos) - Kakamega – Musaga 220kV	73	146	324	Kakamega 220/33 2x45MVA	90	71.17
					Musaga 220/132 2x90MVA	180	
5	Sotik – Kilgoris 132kV	50	100	97	Kilgoris 132/33 2x23MVA	46	22
6	Lessos-Loosuk 400kV	179	358	1600	Lessos Ext 400kV substation	-	202
					Loosuk 400kV Substation		
7	Lessos/Loosuk LILO - Baringo 400kV	40	80	1600	Baringo 400kV substation	-	50.49
8					Kutus 132/33 2x45MVA	90	3.779
9	Webuye – Kitale 132kV	73	73	97			17.73
10	Juja-Ruaraka 132KV	6.5	6.5	97			1.71
11	Musaga-Webuye 132KV	18	18	97			2.79
TOTALS 2027		**811.5**	**1285.5**	**4872.6**		**842**	**604.589**
YEAR 2028							
1	Gilgil-Thika-Malaa-Konza	205	410	1600	Thika 400/220 2x400MVA	800	262.59

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
					Malaa/Nairobi East 400/220 2x400MVA	800	
					Gilgil 400/220 2x400MVA	800	
2	Loiyangalani – Marsabit 220kV	136	272	324	Loiyangalani 400/220 2x200MVA	400	126.81
3	Rongai 400/220 LILO	2	8	1600	Rongai 400/220 2x200MVA	400	34.05
4	Rongai 220/132 LILO	2	8	97	Rongai 220/132 2x90MVA	180	18.85
5	Meru –Maua 132kV	35	70	97	Maua 132/33 2x23MVA	46	25.63
6	Kibos - Bondo 132kV	61	61	97	Bondo 132/33 2x23MVA	46	23.53
7	Kieni – Chogoria 132kV	23	46	97	Chogoria 132/33 1x23MVA	23	18
8	Rumuruti – Maralal/Loosuk 132kV	148	296	97	Loosuk 132/33 1x23MVA	23	48.84
9	Rongai – Keringet-Chemosit 220kV	96	192	324	Keringet 220/33 2x60MVA	120	100
					Chemosit 220/132kV 2x90MVA	180	
		-	-		Chemosit 132/33kV 2x45/60MVA	90	2.178
10	Menengai - Olkalou – Rumuruti 132kV	70	140	97	Olkalou 132/33 2x23MVA	46	34.34
11	-	-	-		Garissa 220/132 1x110MVA - second TX	110	5.2
12	Myanga – Busia 132kV	27	54	97	Busia 132/33 2x23MVA	46	23.91
13	Ndhiwa (Ongeng) - Magunga (Karungu Bay/Sindo) 132kV	50	50	97	Magunga 132/33 1x23MVA	23	21.24
14	Isiolo-Marsabit	240	480	324	Marsabit 220/33 2x23MVA	46	127.72
					Isiolo 220/132 1x90MVA	90	
15					Githambo Tx2 132/33 23MVA	23	2.89
16					Mwingi 132/33 23MVA	23	2.89
17					Wote 132/33 23MVA	23	2.89
18					Kitui 132/33 23MVA	23	2.89

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
TOTALS 2028		**1095**	**2087**	**4948**		**4361**	**884.448**
YEAR 2029							
1	220kV Kiambere/Rabai LILO -– Mutomo and establishment of 220/132/33kV substation including 33kV switchyard.	1.5	3	324	Mutomo 220/132kV 2x90MVA	180	36.86
2	132kV Mutomo- Makindu	69	138	97	Mutomo 132/33 2x23MVA	46	
3	Turkwel – Lokichar – Lodwar 220kV	120	240	324	Lokichar 220/66 2x23MVA	46	100
					Lodwar 220/33 2x23MVA	46	
4	Kiambere - Maua – Isiolo 220kV	145	290	324	Maua 220/132 2x90MVA	180	120.94
5	Second Circuit LILO Nakuru West –Lanet 132KV	1.5	3	97			5
TOTALS 2029		**337**	**674**	**1166**		**498**	**262.8**
YEAR 2030							
1	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	80	160	97	Mwala 132/33 2x23MVA	46	29.28
2	Mtwapa 132/33 off Rabai-Kilifi 132kV	1.5	3	97	Mtwapa 132/33 2x45MVA	90	13.42
3	Githambo - Othaya-Kiganjo 132kV	72	144	97	Othaya 132/33 2x23MVA	46	34.9
4	Reinforcement of Nairobi – Mombasa 132kV system LILO on Isinya– Mariakani 400kV and Establishment of Voi 400/132/33kV ss including 33kV switchyard	3	12	1400	Voi 400/132 2x150MVA	300	36.57
5	LILO on Nairobi – Mombasa 132kV system at Voi	7	14	97	New Voi 132 132/33 2x23	46	
6	Garissa – Habaswein/Dadaab – Wajir 220kV	330	330	324	Habaswein 220/33 2x23MVA	46	188.32
					Wajir 220/33 2x23MVA	46	

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
7	Isiolo – Garba Tula – Garissa 220kV	320	640	324	Garba Tulla 220/33 2x60MVA	120	160.43
8					-200MVAr, +150MVAr STATCOM/DRPC)	-200 and +150 MVAr	111
9	Malaa –Tatu City 220kV line with LILO on 220kV Thika Rd /Nairobi North or LILO on 220kV Thika Rd-Dandora and establishment of a Switch station at Tatu City.	30	60	324	-		24.5
10	Thika/Malaa – HG Falls 400kV	200	400	800	-	-	180.34
11	Kiambere/Malaa LILO-Karura 220kV	10	20	324	-	-	10.21
TOTALS 2030		**1053.5**	**1783**	**3884**		**740**	**677.97**
YEAR 2031							
1	220kV Wajir-Mandera	250	500	324	Mandera 220/33 1x23MVA	23	161.1
2					Garissa 132/33 23MVA	23	2.89
TOTALS 2031		**250**	**500**	**324**		**46**	**163.99**
YEAR 2032							
1	220kV Marsabit-Moyale	180	360	324	Moyale 220/33 1x23	23	119.94
2	Voi - Taveta 132kV	110	220	97	Taveta 132/33 2x23MVA	46	34.76
TOTALS 2032		**290**	**580**	**421**		**69**	**154.7**
YEAR 2033							
1	Olkaria VIII 220KV Evacuation (through Olkaria II Ext)	5	10	324			13.34
2	Menengai – Rongai 400kV	45	90	1600	Menengai 400/132 2x150	300	76.08
TOTALS 2033		**50**	**100**	**1924**		**300**	**89.42**
YEAR 2034							
1					Dandora 220/66kV 2x200MVA	400	13.62

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
2					Voi 132/33 2x45MVA uprating	90	3.09
3					Galu 132/33 2x45MVA uprating	90	3.09
4					Jomvu 132/33 2x45MVA uprating	90	3.09
5					Rabai 132/33 1x45MVA additional	45	5.87
6					Webuye 132/33 1x23MVA additional	23	5.23
7					Naivasha 132/33 1x45MVA additional	45	5.87
TOTALS 2034		**0**	**0**	**0**		**783**	**39.86**
YEAR 2035							
1	NPP TI 1	80	160	1600	Div 1 SS 3x350MVA	1050	110.23
2	NPP TI 2	418	836	1600	Div 2 SS 3x350MVA	1050	316.1
3	New Thika - Ruaraka 220kV UG cables	27	54	324	Ruaraka 220/132kV 2x150MVA	180	81.06
4	Kilgoris – Masaba (Isebania/Kehancha) 132kV	40	80	97	Isebania/Kehancha 132/33 2x23MVA	46	29.2
5	Longonot Substation including LILO on Gigil Thika 400kV line	40	80	1600	Longonot 400/220kV 2x200MVA	400	58.03
6	TX Upgrade Bamburi				New Bamburi 132/33 45MVA	45	1.79
7	Olkaria IX - Longonot 220kV (Evacuation)	25	50	324			13.69
TOTALS 2035		**630**	**1260**	**5545**		**2771**	**610.10**
YEAR 2036							
1	Rangala – Bondo 132kV	57	57	97			16
TOTALS 2036		**57**	**57**	**97**		**0**	**16**
YEAR 2037							
1					Namanga 132/33 1x23MVA additional	23	5.23
2					Rabai 132/33 1x45MVA additional	45	5.87

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
3					Thika 132/66 1x60MVA additional	60	5.97
4					Gatundu 132/33 1x23MVA additional	23	5.23
5					Soilo 132/33 2x45MVA uprating	90	3.09
6					Chemosit 132/33 1x45MVA additional	45	5.87
7					Eldoret 132/33 1x45MVA additional	45	5.87
8					Kitale 132/33 2x45MVA uprating	90	3.09
9					Isiolo 132/33 1x23MVA additional	23	5.23
TOTALS 2037		**0**	**0**	**0**		**444**	**45.45**
YEAR 2038							
1		-	-		Lessos 132/33 2x45MVA	90	3.16
2	400kV Mariakani-Dongokundu	60	120	1600	Dongo Kundu 400/220kV 4x200MVA	800	86.16
TOTALS 2038		**60**	**120**	**1600**		**890**	**89.32**
YEAR 2039							
1	Agil 220KV Evacuation	8.5	8.5	324	Agil SS (by Deveeloper)	-	4.6554
2	Agil - Olkaria IX	25	25	324	Agil SS (by Deveeloper)	-	13.69
TOTALS 2039		**33.5**	**33.5**	**648**		**0**	**18.35**
YEAR 2040							
1	132kV Kwale Sugar-Titanium reconductoring	31.5	31,5	165		-	0.95
2	132kV Webuye-Musaga reconductoring	18	18	135			1.8
3					City Centre 150MVAr Capacitor	150MVAr	4.612
4					City Centre 220/66 1x200MVA additional	200	9.92
5					Isinya 220/66kV 2x200MVA	400	13.44
6					Nanyuki 132/33 2x45MVA uprating	90	3.09

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
7					Meru 132/33 2x45MVA uprating	90	3.09
8					Kisii 132/33 2x45/60MVA uprating	90/120	3.09
9					Kitale 220/132 1x90MVA additional	90	5.01
TOTALS 2040		**49.5**	**18**	**300**		**870**	**45.002**
YEAR 2041							
1	Suswa - Naivasha SEZ				Naivasha SEZ 220kV	-	43
2	Rongai - Kilgoris (Part of Lake Victoria Ring) 400kV	235	470	1600	Kilgoris 400/132 2x150MVA	300	219
3	Ngong (Kimuka) – Magadi 220kV	88	88		Magadi 220/66 2x60MVA	60	60.1
4					Loosuk 400/132 2x90MVA	180	12.77
5	Rangala – Busia 132kV	34	34	97	-	-	11.21
TOTALS 2041		**357**	**592**	**1697**		**540**	**346.08**
	GRAND TOTAL	**4229**	**6911**	**22016.6**		**11483**	**3278.59**

8 IMPACT OF THE EXPANSION PLAN ON CLIMATE CHANGE

8.1 Background

Kenya, a signatory to the United Nations Framework Convention on Climate Change (UNFCCC), initially submitted its intended Nationally Determined Contribution (NDC) in July 2015, committing to combating climate change by aiming for a 30% reduction in emissions from the Business as Usual (BAU) scenario of 143 MtCO2eq. In 2020, Kenya reaffirmed its dedication by revising its NDC submitted to the UNFCCC.

This revision revealed heightened ambition with a commitment to reduce greenhouse gas (GHG) emissions by 32% compared to the BAU scenario, aligning closely with its sustainable development goals. The Kenya Climate Change Act of 2016 mandates all government institutions and agencies to incorporate climate change action plans into sectoral strategies, action plans, and other implementation frameworks for their legislative and policy functions. The Kenya Climate Change (Amendment) Act of 2023 further establishes a structure for overseeing carbon trading in Kenya and outlines the necessary steps for the country to meet its obligations under the Paris Agreement.

Although Kenya's electricity generation mix features relatively low emissions intensity, the existing medium-speed diesel plants and proposed non-renewable facilities contribute to GHG emissions. The combustion of fossil fuels for power generation remains a significant factor in emitting GHGs, a primary driver of climate change.

8.2 Projected GHG Emissions

Kenya relies on renewable energy sources, making up 82% of its installed capacity, predominantly from geothermal, hydro, wind, and solar power. These sources contribute approximately 90% of the energy generated, positioning Kenya's electricity grids among the most environmentally friendly globally. The nation aims to achieve complete reliance on clean energy generation by 2030.

Increased installation of renewable energy technologies such as hydropower, wind, solar PV and geothermal, enables the electricity sub sector to make major contributions towards the global net zero emissions goal and the national targets as contained in the Updated NDC. Projections indicate that greenhouse gas (GHG) emissions will remain below 1.2 MtCO2e across all scenarios in the 2024-2043 LCPDP (Least Cost Power Development Plan). This reduction is attributed to the planned decommissioning of inefficient medium-speed diesel plants and the incorporation of renewable energy sources. Additionally, the strategy involves support intermittent renewable energy generation. The LCPDP outlines a substantial decrease in the use of fossil fuels in both the medium and long term.

This plan represents a significant contribution towards the global goal of achieving "net zero GHG emissions by 2050." Implementing the LCPDP 2024-2043 is expected to have a notably positive impact on Kenya's national GHG emissions target

8.3 Mitigation

The LCPDP projections provide significant mitigation options in the electricity subsector. Emissions from the electricity sub sector are expected to remain fairly low if more renewable energy technologies are implemented as proposed in the LCPDP 2024-2043. The expansion plan indicates that, for the electricity sub sector to achieve the target towards the net zero emissions target, installation and use of fossil fuels power plants capacity should be curtailed. This can be achieved through balanced expansion of renewable energy technologies options and making energy efficiency improvements. Annual emissions from the electricity subsector between 2025 and 2030 are expected to remain below the maximum allowed in the target as defined in the NDC (32% by 2030), for the three expansion scenarios. Table 8-1 shows the projected emission levels for selected years in the LCPDP.

Table 8-1: Projected GHG emissions under different scenarios

Milestone Years	Scenario emissions ($MtCO_2e$)		
	Vision	Reference	Low
2025	0.18	0.08	0.03
2030	0.00	0.000	0.0000
2035	0.00	0.000	0.0000
2040	0.00	0.000	0.0000
2043	0.00	0.00	0.0000

Based on the projected emissions under the three simulated scenarios, LCPDP 2024-2043 offers a good climate change mitigation measure for both the medium term and long-term expansion plan. The GHG emissions depend entirely on the rate of the utilization of the installed natural gas capacities in the system.

The National Climate Change Action Plan (NCCAP) 2018-2022 projected baseline emissions of 41MtCO2e from electricity generation by 2030. The total emissions in the LCPDP 2024-2043 plan for each of the three demand scenarios would be 0.453 MtCO2e for the vision scenario, 0.30 MtCO2e for the reference scenario and 0.2 MtCO2e for the low scenario as shown in Figure 8-1, Figure 8-2 and Figure 8-3. This shows that the highest total emissions of 0.453 MtCO2e in the vision demand scenario by 2043 are below the NDC emissions target of 31.14MtCO2e from electricity generation by 2030. This is calculated from a reduction contribution of 9.93MtCO2e towards the 32% target in the same year. The higher GHG emissions in the vision demand scenario of the planning period is due to the dispatch from the Diesel and Gas turbines power plants.

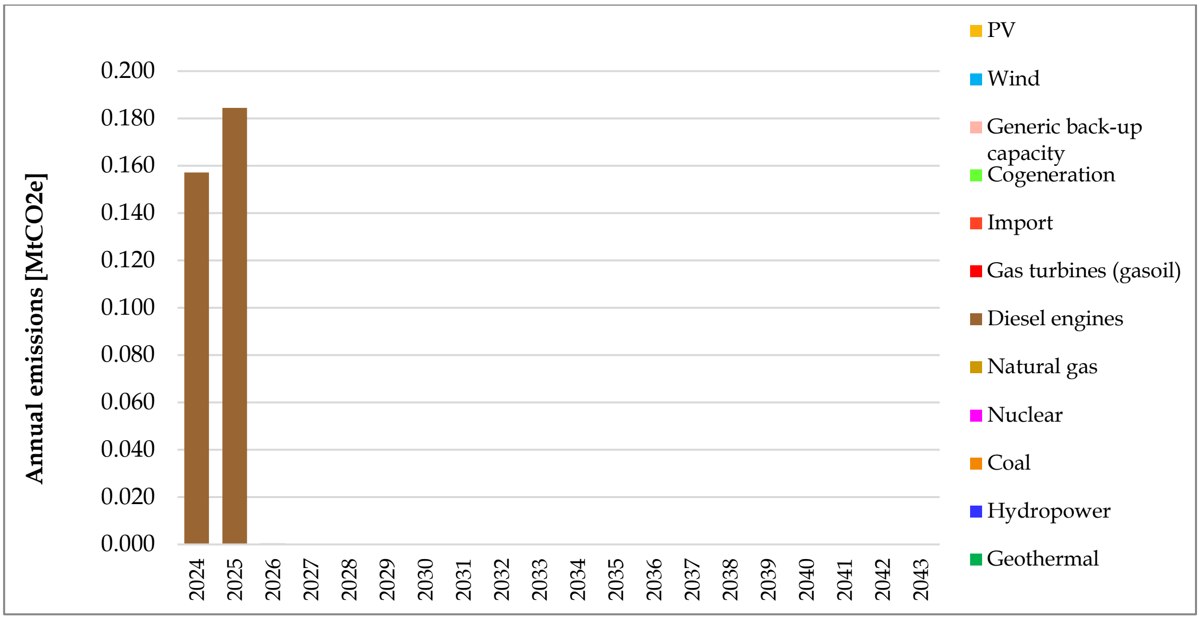


Figure 8-1: Projected GHG emissions under vision scenario

Figure 8-2: Projected GHG emissions under reference scenario

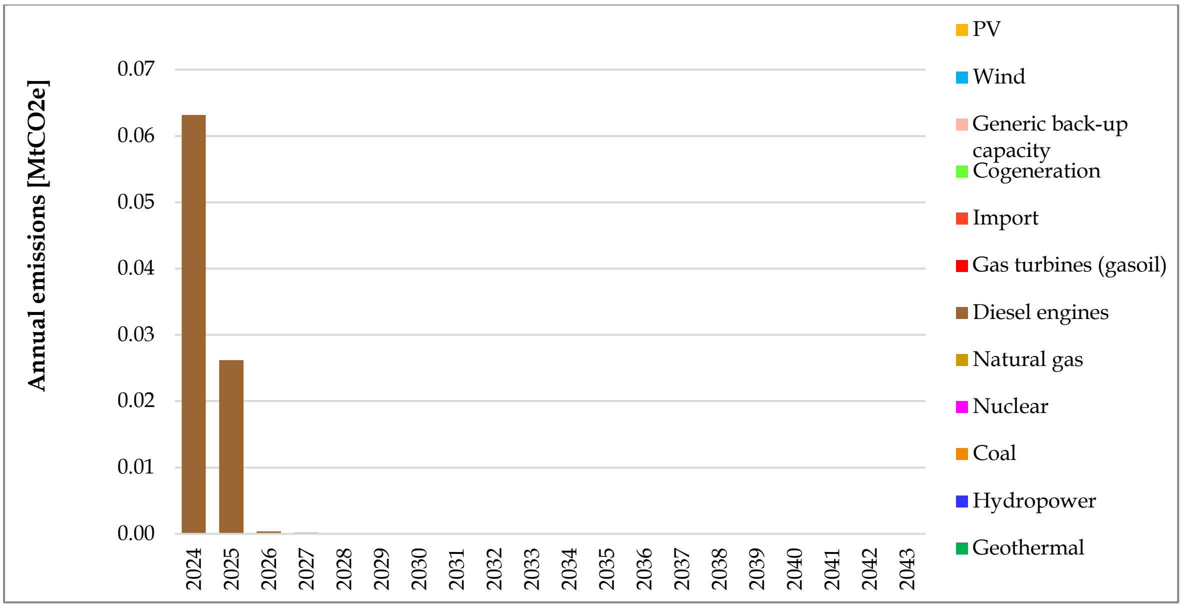


Figure 8-3: Projected GHG emissions under low scenario

Achievement of climate change mitigation objectives and the NDC targets for 2025 and 2030 in the electricity sub-sector is possible with the implementation of LCPDP 2024-2043, targeting integration of more renewable and clean energy technologies.

8.4 Adaptation

Most renewable energy sources provided are inherently variable depending on the prevailing climate and weather conditions. Thus, they have the innate potential of causing instability in the electricity supply system. Storage systems such as battery storage systems and pumped storage hydropower projects (PSP) need to be fast-tracked in the system as adaptation actions to support the system's stability.

9 INVESTMENT PLAN AND TARIFF EVOLUTION

This chapter covers investment plan and tariff evolution for the tariff projection period beginning 2024 to 2033. The base year (2023) end user tariff inclusive of tariffs and levies is estimated at Ksh. 28.03/kWh. The tariff projection considers the system requirement costs for all the generation expansion planning scenarios namely, reference, vision, and low demand scenarios. Sensitivity analysis is also undertaken on the reference demand scenario to investigate the impact of low hydrology on the tariff.

9.1 Reference Demand Scenario

The reference scenario projects peak demand to grow from 2,327MW in 2024 to 8,152MW in 2043, an annual growth rate of 6.8%. In 2033, peak demand is projected at 4,289MW. The overall system cost in the Tariff Projection Period (2024 – 2033) is expected to increase from KSh. 234.9 billion in 2024 to KSh. 488 billion in 2033 as shown in Figure 9-1.

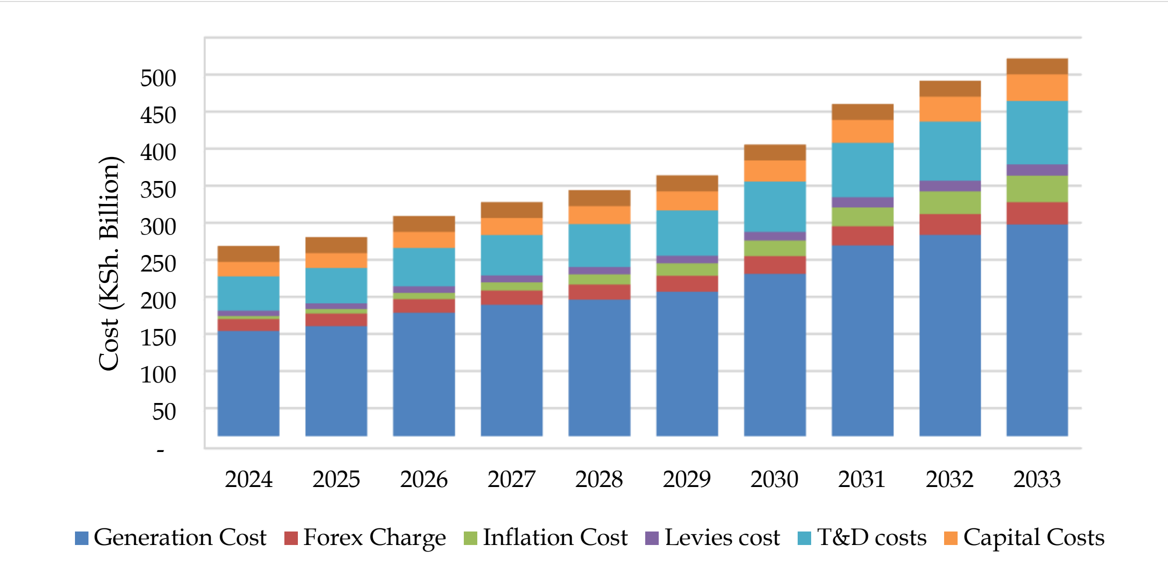


Figure 9-1: System Cost- reference demand scenario

The tariff projection indicates that the end user retail tariff will evolve from KSh. 24.61/kWh in 2024 to KSh. 26.76/kWh in 2033. The generation unit cost over the tariff projection period averages KSh 13.46/kWh as illustrated in Figure 9-2. The projected tariff trajectory indicates a slight marginal increase over the same period primarily attributed to generation capacity additions from the year 2026. Notably, the construction of the 693 MW high Grand Falls hydropower plant is scheduled for completion in 2031.

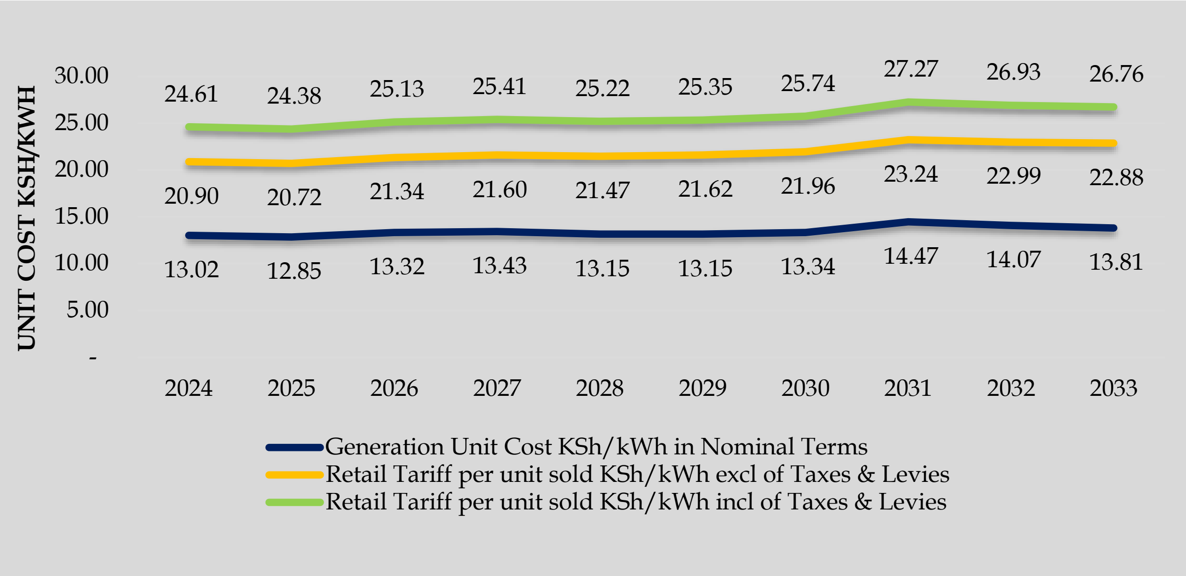


Figure 9-2: Tariff Evolution - Reference Demand Scenario

The tariff projection indicates that the Generation tariff in real terms after factoring the time value of money will evolve from KSh. 13.02/kWh in 2024 to KSh. 9.11/kWh in 2033. This projection has used a discounting factor of 4.73% which is the average annual underlying inflation rate for the period 2010 – 2022. Figure 9-3 presents a projected tariff trajectory indicating a significant decrease over the same period.

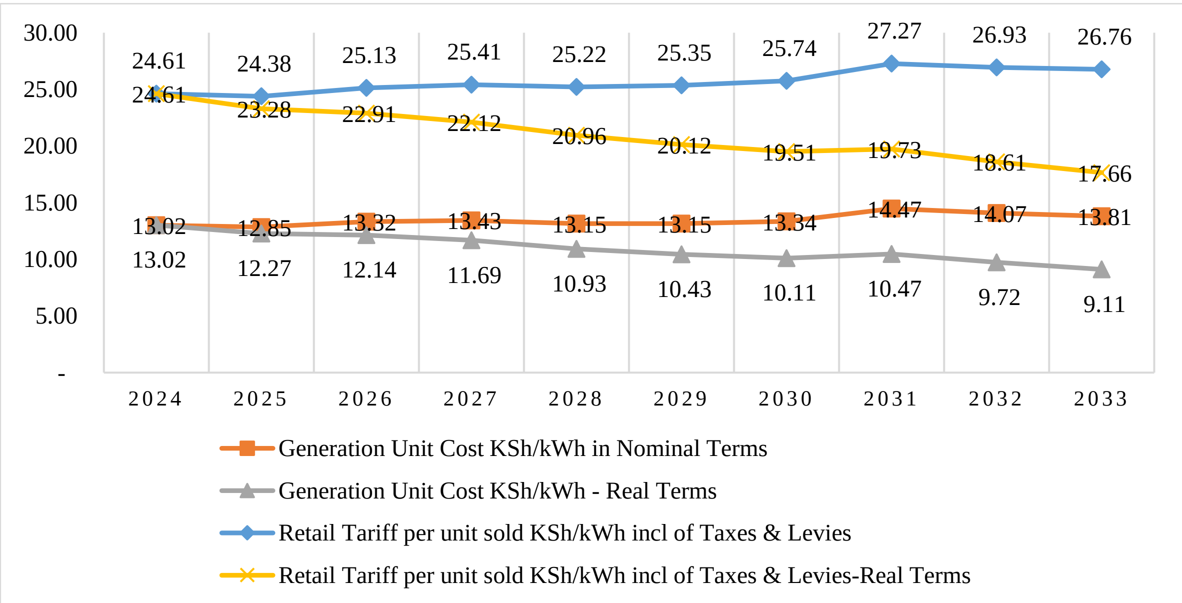


Figure 9-3: Comparison between Gen. Tariff - Nominal & Real Terms- Reference Demand Scenario

9.2 Low Hydrology Scenario

Low hydrology is a sensitivity assessment of the reference demand scenario characterized by reduced generation output from hydro power plants. The scenario is aimed at presenting the impact on the tariff and investment costs due to low output from the hydro plant. Figure 9-4 below presents the tariff evolution under this scenario.

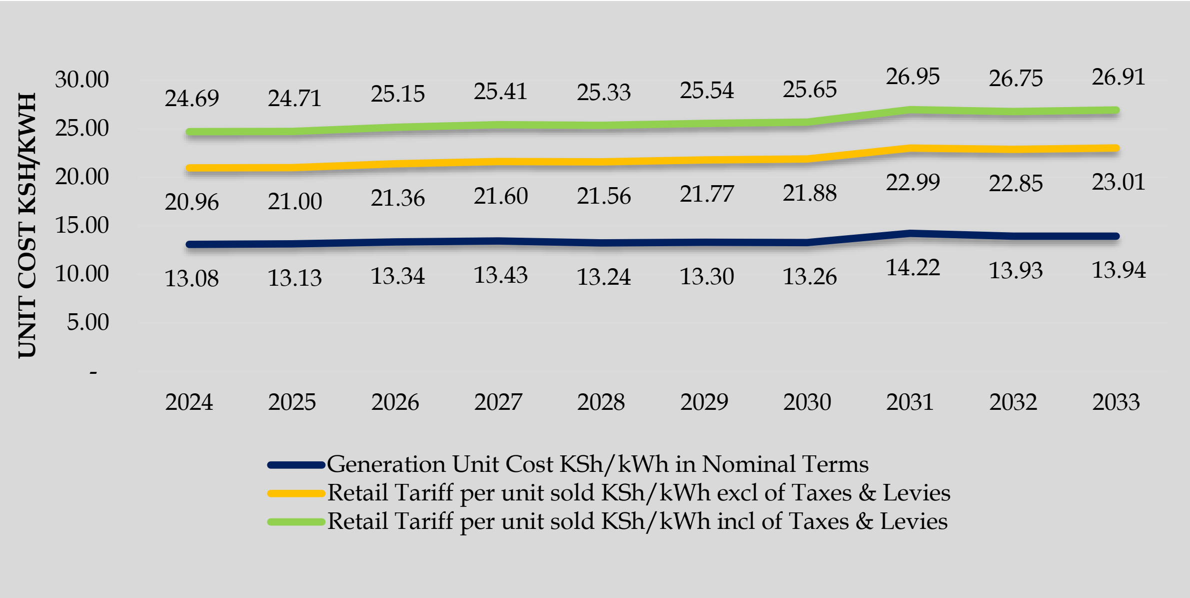


Figure 9-4: Tariff evolution under Reference Low Hydrology Scenario

The expansion plan under low hydrology projects the end user retail tariff to evolve from KSh. 24.69/kWh in 2024 to KSh. 26.91/kWh in 2033. The generation unit cost over the period averages KSh.13.49/kWh. In comparison to the base reference scenario, the low hydrology scenario presents slightly higher tariff over the planning period as illustrated in Figure 9-5.

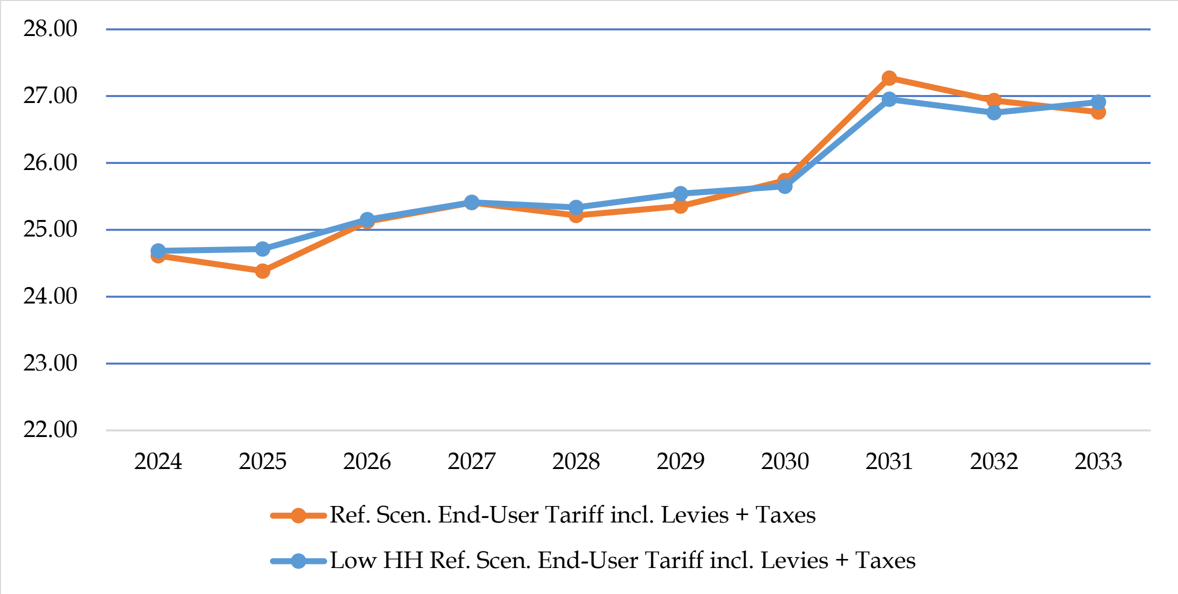


Figure 9-5: End User Tariff Comparison between reference and Low Hydrology

From the simulations, the low hydrology scenario averages KSh. 25.71/kWh compared to KSh.25.68 /kWh for the reference scenario over the tariff projection period. This is attributed to the increased fuel costs arising from increased thermal generation, to mitigate the reduced hydro power output.

9.3 Vision Demand Scenario

The vision scenario projects peak demand to grow by an average of 9.3% in line with the Vision 2030 GDP growth rate from 2,409MW in 2024 to 5,522MW by 2033 and reaching 13,495MW by the end of the planning period. The overall system cost in the tariff projection period (2024 – 2033) is expected to increase from KSh. 239.5 billion in 2024 to KSh. 627.8 billion in 2033 as shown in Figure 9-6.

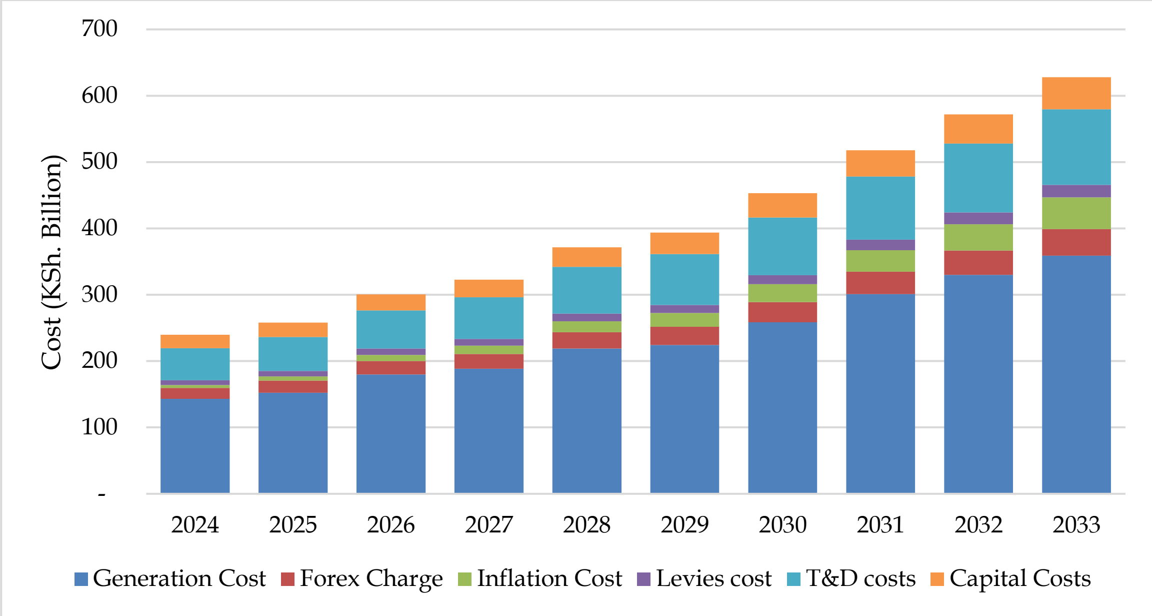


Figure 9-6: Total System Cost - Vision Demand Scenario

The end-user tariff is expected to evolve from KSh. 24.16/kWh in 2024 to KSh. 25.82 /kWh in 2033. The generation unit cost over the tariff projection period averages KSh 12.68/kWh. This is illustrated in Figure 9-7.

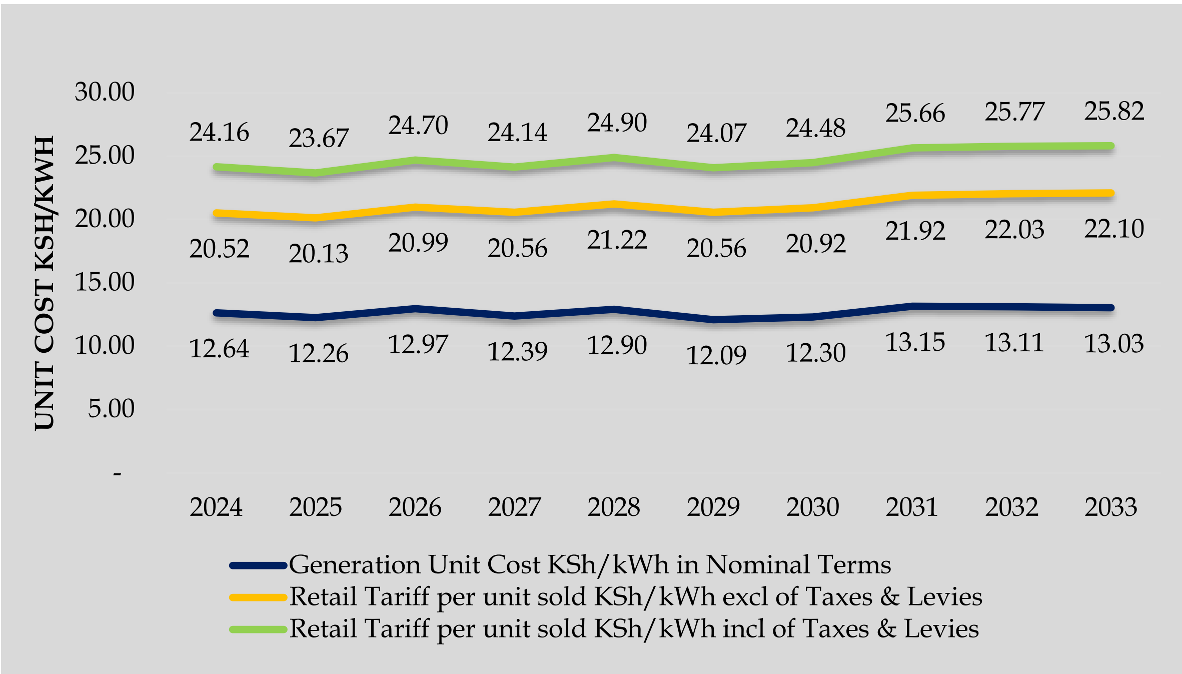


Figure 9-7: Tariff Evolution - Vision Demand Scenario

The tariff projection indicates that the Generation tariff in real terms factoring in the time value of money will evolve from KSh. 12.64/kWh in 2024 to KSh. 8.59/kWh in

2033 as shown in Figure 9-8. This projection has used a discounting factor of 4.73% which is the average annual underlying inflation rate for the period 2010 – 2022.

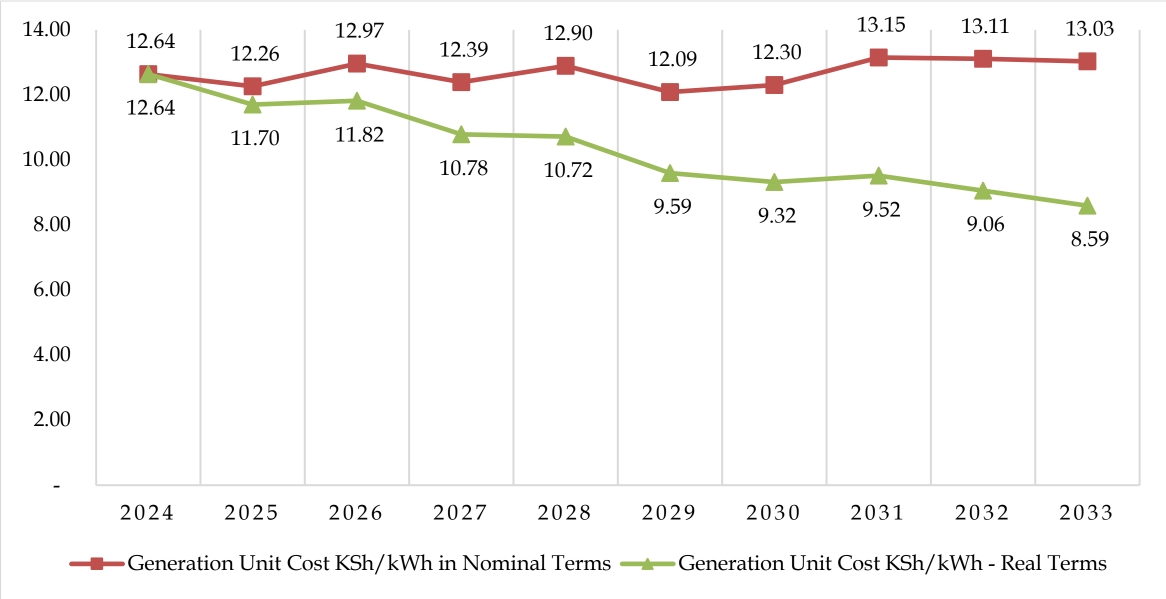


Figure 9-8: Comparison between Gen. Tariff - Nominal & Real Terms- Vision Scenario

9.4 Low Demand Scenario

The low demand scenario projects peak demand to grow from 2,264MW in 2024 to 4,996MW in 2043, a growth rate of 4.3%. In 2033, peak demand is projected at 3,213MW. The overall system cost is projected to increase from KSh. 234.9 billion in 2024 to 445.6 billion in 2033 as shown in **Error! Not a valid bookmark self-reference.**.

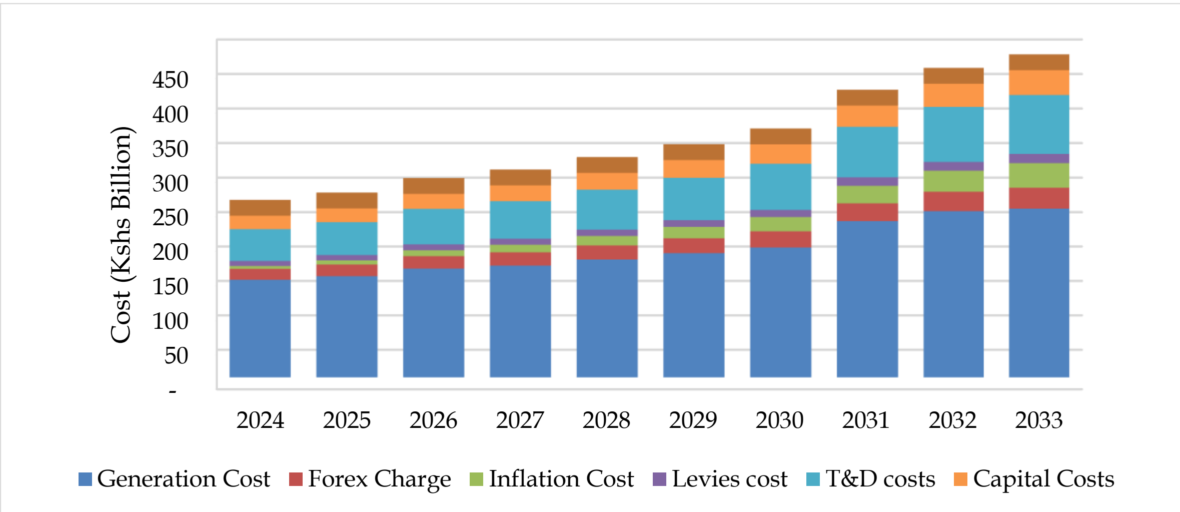


Figure 9-9: System cost – Low Demand Scenario

In the Tariff Projection Period, the end-user tariff is expected to evolve from KSh. 24.61/kWh in 2024 to KSh. 24.45/kWh in 2033. The generation unit cost over the tariff projection period averages KSh 12.80/kWh. This is illustrated in Figure 9-10:

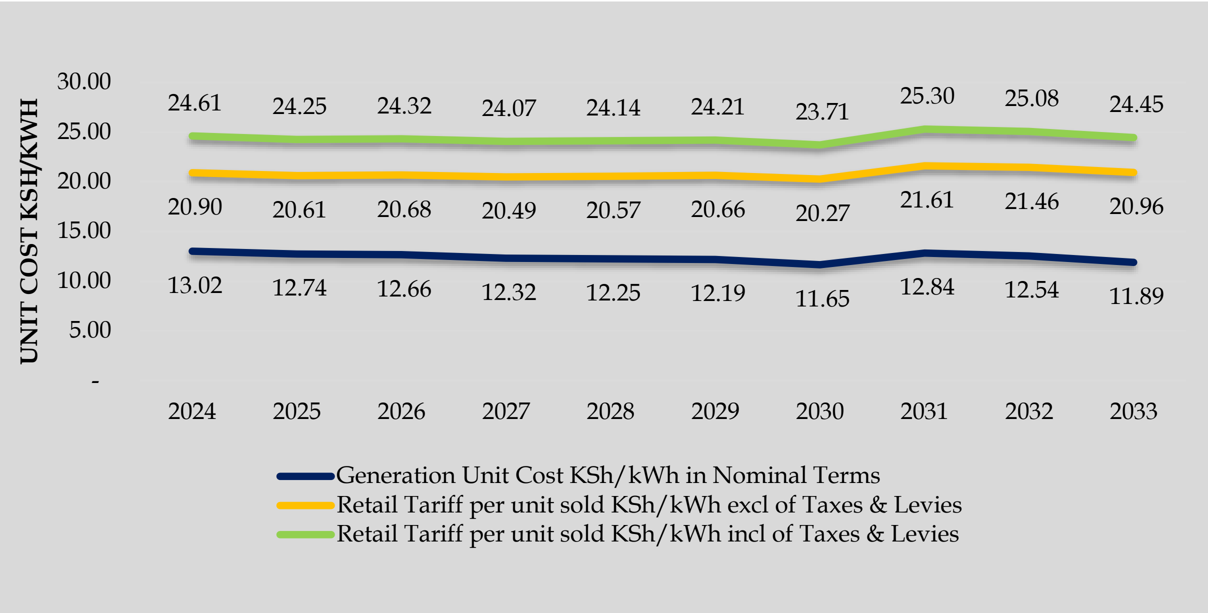


Figure 9-10: Tariff Evolution - Low Demand Scenario

9.5 Comparison of the Retail tariff scenarios

The general trend across all the three demand scenarios in terms of nominal and real terms and the sensitivity scenario, shows a marginal decline in the end-user retail tariff for the period 2024-2033. The expected lower end user tariffs in Vision compared to other scenarios is due to higher generation capacity utilization. This is illustrated in Figure 9-11 and Figure 9-12.

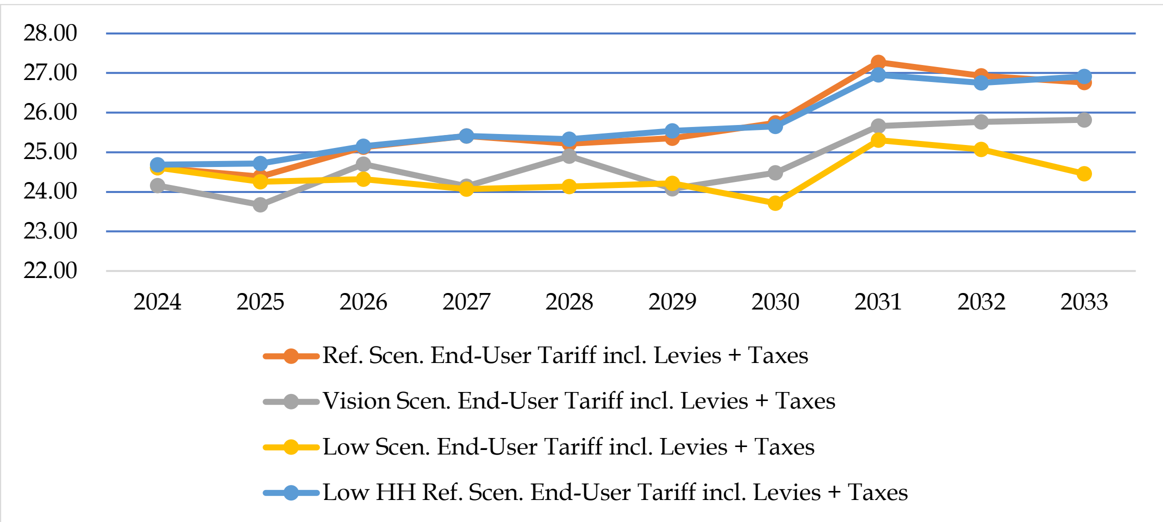


Figure 9-11: Retail tariff Comparison across the Scenarios – in Nominal Terms

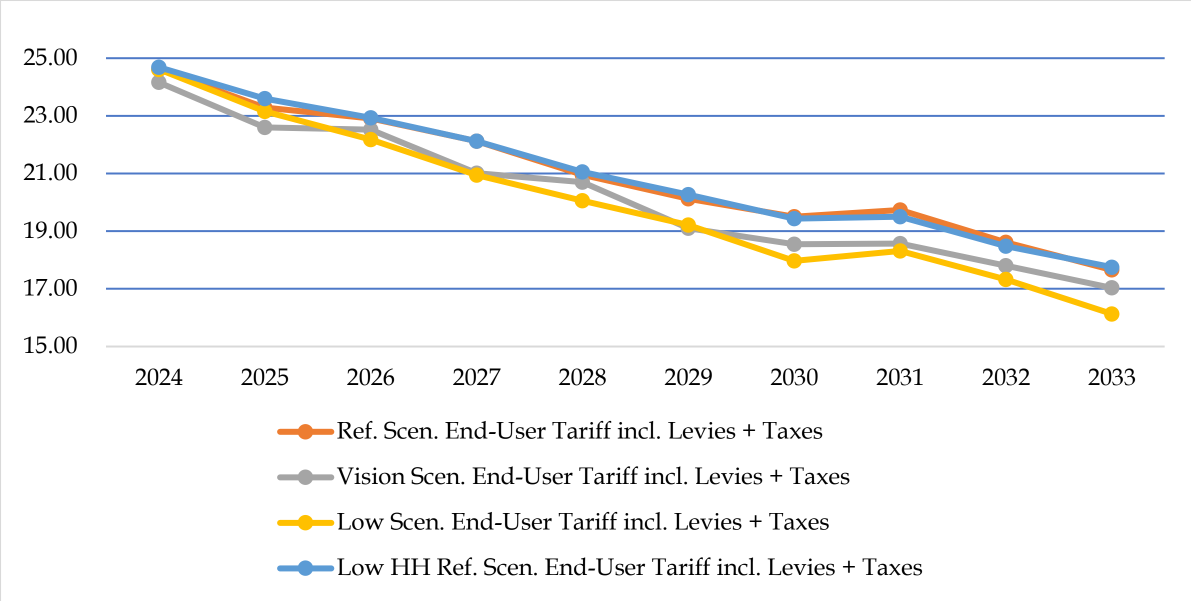


Figure 9-12: Retail tariff Comparison across the Scenarios – Real Terms assuming 4.73% Discounting Factor

10 IMPLEMENTATION PLAN

The implementation plan of this report (given in Annex M) will be dependent on realization of the various assumptions on medium to long-term socioeconomic, technological and demographic developments in Kenya. It is evident that the success of the plan hinges on the growth in demand, which will subsequently bolster the anticipated expansion of generation and transmission, along with the resulting evolution of tariffs. Nonetheless, there are anticipated challenges and risks that could hinder the effective execution of the plan. This chapter outlines the assumptions made during development, implementation strategies, as well as the challenges and risks involved.

The key milestone activities considered in this implementation plan are project preparation, procurement and construction. Project preparation includes surface studies, feasibility studies, conceptual design, safeguards studies, finance, surveys, wayleave and land acquisition and permitting and licenses. Procurement timelines considered procurement methods in the PPAD Act 2015 and PPP Act 2021, and included finalization of financiers' Project Concepts Notes, preparation of bidding documents and preparation and issuance of procurement notices, evaluation of bids, negotiations, commercial and financial close. Construction timelines include design, installation, pre-commissioning, capacity testing and commissioning.

The following assumptions were made in the developing the implementation plan:

i. Availability of timely finance (both GoK and Development partners for GoK financed projects.
ii. No delays in reaching financial close and other conditions for PPP projects.
iii. Social stability and political goodwill.
iv. Efficient land rights and wayleaves acquisition process.
v. Zero delays in acquisition of permits and licenses.
vi. Candidate generation projects meet the assumed resource viability levels.

10.1 Implementation Strategies

Generation projects fall under different categories, based on the selection and scheduling process. The projects considered are identified through the Least Cost Power Development Plan, Feed in Tariffs Policy, privately initiated renewable projects or Regional Integration Initiatives aimed at resource optimization within the region. All power generation projects are approved by the Government through the Ministry of Energy and Petroleum and the National Treasury, and EPRA which provides regulatory approvals such as licensing, commercial operation date and PPA approval.

Generation projects implemented through public institutions use concessional loans and balance sheet as well as government funding which, for example, is used for early developmental activities for projects such as geothermal. Implementation of these projects involves competitive procurement process for contracts under EPC or Turnkey modes. On the other hand, projects under IPPs are implemented through SPVs created for the sole purpose. These include Feed-in Tariff Projects and privately initiated renewable projects which receive government approval. Implementing the project under the LCPDP involves careful consideration of various factors such as technology options, resource availability, environmental impact, regulatory frameworks, and financial considerations.

10.1.1 Strategies for fast-tracking Geothermal Projects

To enhance the contribution of geothermal energy in Kenya and for the realization of the geothermal projects in the LCPDP, the following strategies are proposed;

i. Alignment of the proposed projects to the implementing agencies' work plans and business plans.
ii. Development of new or updated strategy for fast tracking geothermal exploration and development in Kenya and achievement of the LCPDP geothermal Projects over the planning period.
iii. Enforcing adherence to license provisions: Government has so far issued letters of authorization to search geothermal resources to over 18 Independent Power Producers (IPPs) to undertake greenfield geothermal projects having recognized the potential role that could be played by private investors in expediting geothermal development. According to licensing conditions, after demonstrating their ability to undertake full steam field development, the private developers are required to drill exploration wells within three years of license issuance. However, private companies undertaking the greenfield geothermal projects have recorded limited success, with few being able to progress past the surface study stage due to their inability to attract financing for field development. There is now, therefore, limited capacity for the government to deploy its full ability to facilitate geothermal development through the capacity that it has built over the years, effectively reducing the rate of geothermal development in the country. There is a need for the Ministry of Energy to, therefore, relook at the geothermal licensing process that would allow the government to strictly follow the license provisions for private

developers to record developmental progress made in their geothermal concessions in order to expedite geothermal development in the country. Deviation from the license provisions should lead to license revocation.

iv. Streamline the issuance of government support measures policy and instruments (Government of Kenya Letter of Comfort, Sovereign guarantees, Letters of Support and Comfort, Partial Risk Guarantees, etc.) for geothermal investments to be more secure and bankable, in respect of private capital mobilization for public investment and infrastructure developments.
v. Government to seek and allocate adequate funding to GDC to allow for nationwide geothermal resource assessment.
vi. Closely monitoring, supervision and regular reporting LCPDP geothermal projects progress by Independent Power Producers (IPPs) and government agencies with clear milestones and deliverables.
vii. Government and utility to fast-track in meeting part of its bargain in the closure of conditions precedent under the Project Implementation and Steam Supply Agreement (PISSA), and power purchase agreement (PPA).
viii. Proper coordination of the energy sector to eliminate overlaps of roles and mandates among the state agencies.

Delivery of geothermal projects will be realized through phased development by developer(s) depending on the business model adopted. The general milestones for geothermal projects are shown in Table 10-1.

Table 10-1: Geothermal Development Milestones

No	Project Phase	Project Activities	Milestone/Deliverable
1	Project Preparation	• Surface Studies • Obtain land rights • Obtain permits and Licenses • Infrastructure development (Water, roads, well pads) • Project funding • Procurements	• Well targets • Land agreements • Permits and Licenses • Contracts • Water system commissioning certificates • Handing over certificates • Financing agreements
2	Exploration and appraisal drilling	• Drilling exploration and appraisal wells depending on the size of the project • Well logging and testing	• No. of Wells
3	Feasibility Study	• Carry reservoir simulation • Develop bankable feasibility documents	• Feasibility Study Report
4	Production and re-injection drilling	• Drilling production and reinjection wells depending on the size of the project	• No. of Wells

No	Project Phase	Project Activities	Milestone/Deliverable
		• Well logging and testing	
5	Steam Gathering System	• Design, financing, and construction of the steam gathering system	• Contracts • Completion certificates • Commissioning reports
6	Power Plant construction	• Procurement of power producers where applicable • Project contracting – Project Implementation Steam Sale Agreement (PISSA) where applicable • Project contracting – Power Purchase Agreement (PPA)	• Contracts • Financial closure date • Completion certificates • Commissioning reports • Closure of CP's
7	Substation and Transmission	• Construction of transmission infrastructure by KETRACO in sync with power plant completion	• Contracts • Completion certificates • Commissioning reports

10.1.2 Strategies for fast-tracking Nuclear Power Generation

To fast track the contribution of nuclear energy in Kenya and for the realization of the nuclear projects, NuPEA has developed a road map (Figure 10-1) detailing milestones required to be achieved before construction of the nuclear power plant. The significance of having a nuclear implementation road map lies in its ability to provide a clear and strategic plan for the successful integration of nuclear power. The roadmap serves as a guiding framework, outlining key steps, milestones, and considerations throughout the development process. It enhances transparency, aids in resource allocation, and facilitates effective decision-making, ultimately contributing to the efficient and secure deployment of nuclear plants.

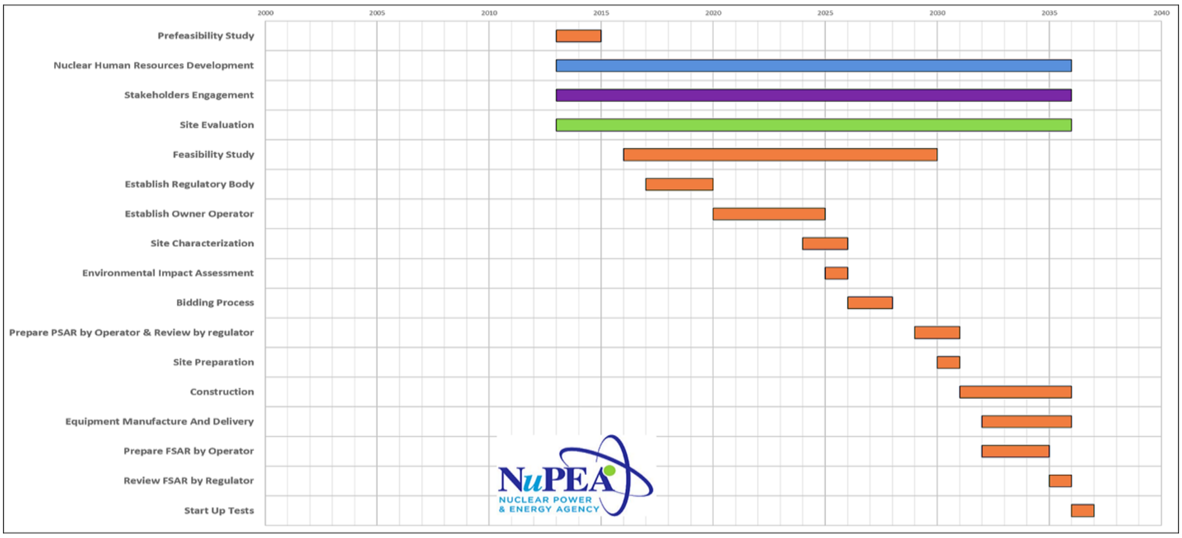


Figure 10-1: Kenya Roadmap to Deployment of the First Nuclear Power Plant (NPP)

The implementation of nuclear power will occur through a gradual development process as detailed in NuPEA roadmap. The general milestones under the road map are detailed in Table 10-2.

Table 10-2: Nuclear Power Generation Milestones

Activities	Start	End	Explanation
Nuclear Human Resources Development	2013	2036	The knowledge and skills necessary to safely purchase, construct, license, operate, maintain, and regulate an NPP spread across most scientific and engineering disciplines. Additional knowledge and appreciation of the increased attention to detail to assure operational safety and radiation protection are vital and require a heightened attention to quality assurance for major systems and equipment. Operation and maintenance require this same special attention and differentiate nuclear plant operation from conventional power plants. Even if much of the initial knowledge and skills are to be provided by foreign sources of manpower, the need for the knowledge and skills to manage and oversee the project should exist within Kenya.
Feasibility Study	2016	2030	Project decision-making stage starts with the initiation of a feasibility study which looks at the introduction of nuclear energy as a reliable and economical source of energy to meet the demand of the national energy system and ends with the closure of a contract for the purchase of a NPP. This stage includes preparatory activities to create a national infrastructure to support the launching of the project and lead to the decision-making to go forward with it. It is essential to clearly understand the specific aspects of nuclear power, and to have a thorough knowledge of the tasks and activities to be performed along with the requirements, responsibilities, commitments, problems, and constraints involved.
Establish Regulatory Body	2017	2020	The legal framework establishes the duties and responsibilities of the various organizations necessary for a successful program especially focusing on safety, security, safeguards, and liability for nuclear damage. It should also implement any international instruments to which the nation is a party. The legislation should provide for complete Independence of the regulatory body. The regulatory body has already been established and it is now supposed to come up with regulations. Independent and competent regulatory organization provides the confidence of the public and the international community. The technical training, knowledge and capabilities of the regulator need be adequate for competent interaction with the owner/operator.
Establish Owner Operator	2020	2025	The owner-operator is the entity that will be responsible for constructing and operating and maintaining the NPP. A good example of an owner operator in Kenya is KenGen, LTWP et cetera.
Site Characterization	2024	2026	The main safety objective in site evaluation is protecting the public and the environment from the impact of normal and accidental releases of radioactive material.

Activities	Start	End	Explanation
			Site evaluation should determine how site characteristics influence design and operation and demonstrate suitability of the site from a safety viewpoint.
Environmental Impact Assessment	2025	2026	EIA is a systematic process to identify, predict and evaluate the environmental effects of proposed actions and projects. Particular attention is given in EIA for preventing, mitigating and offsetting the significant adverse effects of proposed undertakings The unique concern with nuclear power production is the release of radioactive effluents during normal plant operation. Large releases of radiation are low probability events which are more appropriately treated through the nuclear safety program. Land use, water use, and quality and other more conventional environmental impacts are also to be considered. The overall impact will vary depending on the facilities needed as determined by the fuel cycle strategy adopted. Environmental studies should be performed for the potential or selected site for nuclear facilities and particular environmental sensitivities identified. Environmental sensitivities should be addressed in the bid specification where unique plant design provisions or construction techniques are necessary to address those sensitivities.
Prepare PSAR by Operator	2026	2027	The Preliminary Safety Analysis Report, or PSAR, presents design criteria and preliminary design information for the proposed reactor. It also gives detailed data on the proposed site. The report discusses hypothetical accident situations and describes the safety features that will be provided in the plant to prevent such conditions. It also details the features provided to mitigate the effects of an accident if one should occur. A prerequisite if a two-stage licensing process is adopted by the regulator. The operator must provide a safety analysis report covering each aspect and component of the NPP explaining the nature of the facility and its intended use and that the facility can be built and operated without any undue risk to the health and safety of the public. A preliminary report detailing the above should be prepared and submitted to the regulator before license to construct the NPP is granted.
Review PSAR by Regulator	2029	2031	The regulator should review the PSAR and once convinced that the facility can be safely constructed and will not compromise the health and safety of the public, it can grant a construction license.
Construction	2031	2036	Construction of a nuclear power plant takes an average of 4.5 Years.
Prepare FSAR by Operator	2032	2035	A prerequisite if a two-stage licensing process is adopted by the regulator. The operator must provide a safety analysis report covering each aspect and component of the NPP explaining the nature of the facility and its intended use and that the facility can be operated without any undue risk to the health and safety of the public. A final report detailing the above should be prepared and submitted to the regulator before license to operate the NPP is granted.
Review FSAR by Regulator	2035	2036	The regulator should review the FSAR and once convinced that the facility can be safely operated and will not compromise the health and safety of the public, it can grant an operation license.

Activities	Start	End	Explanation
Start Up Tests	2036	2037	This includes the first hot trial run, first criticality, trial operation tests and final handover.

Table 10-3 shows risk matrix summarizing the risks arising, consequences and their proposed mitigations during the implementation of the nuclear plant.

Table 10-3: NPP Risk Analysis

No	Risk	Consequences	Mitigation measure
1.	Stakeholder engagement	Lack of acceptance by the local community. No stakeholder buy-in may paralyze all future operations starting with site characterization.	Regional office in Mombasa to reach out to the relevant stakeholders.
2.	Regulatory process is very slow	We have a clear roadmap to commission our first NPP by 2036. For this to be achieved, we need to commence construction by 2026 (& years for construction, 3 years catering for the average construction delay of nuclear plants). This means that by 2024, we need a well-developed regulatory system that can review our PSAR and give us the construction license. This implies that the regulator has less than 3 years to establish regulations that will govern the construction, operation, and decommissioning of the NPP.	Higher intervention from the CEO, Board, PS and CS of Energy to ensure that MoH and KNRA execute their mandate within the set timelines.

10.1.3 Strategies for fast-tracking BESS Projects

Kenya is facing the challenge of a mismatch between her power generation mix and load requirements. The system lacks flexibility with geothermal, wind and solar PV making up close to half of total generation capacity. Hydropower reservoirs and Diesel engines are currently the only flexible options that can accommodate ramp up or ramp down of generation. Both are sub-optimal due to the exposure to seasonal and/or meteorological conditions (hydro) and their high cost (diesel). KenGen conducted a prefeasibility study on the installation of utility scale battery storage and the MoE&P through The World Bank conducted a technical analysis on BESS. The technical analysis indicates the need for Battery Energy Storage Systems (BESS) in the grid. The BESS is expected to store excess energy from geothermal and VRE capacity in the national grid hence assist in load balancing while offering ancillary services to the grid.

The project is in line with the sector plans. The project will help reduce geothermal venting and reduce generation from thermal sources during the peak period leading to a reduction in fuel costs. The results from the technical assessment confirm the critical role BESS assets will play in the Kenyan power system. This is mainly focused on load shifting but there is also a key role for BESS provision of ancillary services. As confirmed in our least-cost generation plan, a 1-hr or 2-hr battery will be well suited to meet the energy shifting requirements for the system. For this reason, KenGen is proposing to develop a 100MW/200MWh battery storage system as the initial capacity for the project.

Other expected benefits of BESS include:

i. Frequency regulation reserves especially due to the relatively large proportion of VRE in the system;
ii. Voltage stability in the power system;
iii. Management of geothermal resources through reduction of steam venting;
iv. Increased integration of VRE into the grid;
v. Provide peaking capacity, deferment of new generation capacity and displacement of thermal generation;
vi. Enhanced system security by supplying energy during shortages in electricity generation, and Transmission and distribution expansion deferrals by reducing loading on the lines during peak times.

KenGen is planning to conduct a detailed feasibility study on BESS based on the outcome of the technical assessment and other industry planning documents. The study is expected to be completed in June 2024 as shown in Table 10-4 and will also include an environmental and Social Impact Assessment (ESIA) study. Implementation of the technical solution will be undertaken by KenGen and will include procuring a supervision consultant for the implementation, an EPC contractor, and a component of technical assistance for the KenGen team on critical areas of capacity building requirement.

Table 10-4: BESS Implementation Schedule

No	Activity	Responsibility	Actions	Date
1	Approval for KenGen to implement the project.	KenGen & MoE&P	KenGen to seek approval from MoE&P to implement the BESS project. MoE&P to grant KenGen the approval for the project	September 2023
2	Feasibility study financing and procurement	KenGen	KenGen to seek financing and procurement of consultant to carry out the feasibility study	Sep 2023 - Dec 2023
3	Feasibility study	KenGen	KenGen to conduct the FS and ESIA studies	Jan 2024 - June 2024
4	Approval of the FS	MoE&P	KenGen to submit the FS to MoE&P for approval to develop the project.	July 2024
5	Storage Agreement	KenGen & KPLC	KenGen and KPLC to develop and sign the Storage Agreement	July 2024 – Dec 2024
6	Procurement of owner's engineer	KenGen	KenGen to procure owner's engineer to develop the detailed design of the project	August 2024 – Dec 2024
7	Procurement of EPC contractor	KenGen	KenGen to procure the EPC contractor	Jan 2025 - June 2025
8	Project construction	KenGen	Constriction of the project and all requisite works.	July 2025 – Dec 2026

10.1.4 Strategies for Pumped Storage Projects

KenGen conducted a pre-feasibility study for a pumped hydro power plant. The main objective of the study was to appraise the viability of a pumped hydro in the country and propose possible locations for such a power plant. The study identified potential locations for further analysis during the feasibility study and proved the necessity of the pumped hydro power plant. Services brought by Pumped Storage Projects (PSP) include:

i. Peaking capacity
ii. Energy shifting / peak shaving: the pumping/generating cycle (also called "Energy Arbitrage") described above has three main functions.
   - It saves peak-load generation at the expense of increased off-peak generation,
   - It reduces the number of thermal units starts/stops,
   - It displaces competitive peak generation units (typically MSD or GT).
iii. Ancillary services: in addition to energy shifting, a range of services can be provided by a PSP.
   - Frequency regulation.
   - Operating reserves and flexibility.
   - Capacity reserve.

- Congestion mitigation
- Voltage support.
- Black start capabilities.
- Improved grid stability (inertia)

Key advantages of a PSP are;

i. It has the dynamic performances of a hydro plant, which are superior even to a Gas Turbine
ii. It can provide nearly around the clock Ancillary Services, even in pumping mode (spinning and secondary reserve)
iii. It is hydrology-proof, as the same water travels from one reservoir to the other.

The major risk for the project was the regulations governing storage. As of today, the Kenyan Energy framework does not provide clear conditions for the development of storage in general and PSP in particular. In the short term, it is recommended:

i. To develop pumped storage hydro projects in Kenya as "Balancing and Ancillary Service Capacity" Project to specifically respond to operational and security purposes. For its financial viability and sustainability, and to provide appropriate incentive to private investors for such "Balancing and Ancillary Services" Pumped Storage Project,
ii. To adopt a financing arrangement based on a Capacity payment to cover the operation & maintenance costs plus the debt service of the project. The project could be developed by KenGen with a PPA signed between KenGen and the KPLC.

For this reason, KenGen is proposing to proceed with the project as follows; carry out the Feasibility Study, commence procurement of the owner's engineer for detailed design, and procure an EPC contractor.

10.1.5 Strategies for fast-tracking Wind Projects

Several wind projects have been identified in this plan. The country has three wind farms in operation:

i. Ngong Wind Farm – Ngong Town
ii. Lake Turkana Wind Farm – Marsabit Northern Kenya
iii. Kipeto wind farm – Kajiado County

The potential capacity for wind energy in the country is about 1.073TW representing areas with wind speeds above 6m/s (Exploring Africa's Untapped Wind Potential, Sean Whittaker, IFC). For locations with wind speeds above 7.5m/s, the potential capacity is about 242.6 GW at a capacity factor (load factor) of 40.5% corresponding to an annual generation of 862 TWh/annum (P50). Taking only locations with average wind speeds of above 8.5m/s (exceptional wind speeds), the potential capacity for the country is estimated at 139.6 GW with a corresponding capacity factor of 43.6% which is the highest capacity factor in Africa. The total annual energy generation from these areas is approximately 533.2 TWh/annum. It is for this reason that a strategy is required for development of wind energy. The most critical issue relating to wind energy is the availability of land for these large wind farms. Most of the resource lies in community land as defined by the constitution of Kenya. Acquiring community land for projects is very difficult except for community land that is already registered. Even so, it is an uphill task for land that transverses different communities. Most of the community land in northern Kenya has not been registered which makes it extremely difficult to for project access. Land access and accompanying community agitations have resulted in the delay and failure of noticeable wind projects in the country. A good strategy for wind farms would be to develop guidelines on how land can be accessed for wind projects. This will streamline the process of wind project development and help in protecting the rights of indigenous landowners and communities.

Another challenge is that the wind resources are found in remote areas, far from the operating ports and require extensive logistical support measures. The current wind turbines have long hub heights, long blades, and heavy nacelles to improve efficiency. The designs of the ports and transport corridors should be in such a way that the transport of such abnormal cargo is not hindered as much bigger turbines gain preference.

Table 10-5 shows the key challenges for implementation of wind project.

Table 10-5: Key Challenges for Wind Projects

No	Challenge	Way Forward	Responsibility
1	Lack of resource data	Install wind masts for wind resource assessment	MoE&P, KenGen, IPPs
2	Land Acquisition	1. Allocate areas with good wind resources for wind projects. 2. Register community land.	GoK

No	Challenge	Way Forward	Responsibility
		3. Provide laws and regulations for revenue sharing with the community. 4. Provide mechanisms for social license and regulations on free prior and informed consent (FPIC)	
3	Transport and logistics	1. Enhance the lifting and storage capacity of the ports especially the Port of Lamu 2. Identify specific corridors for transport of turbines and related infrastructure from the port to areas of good wind resource. 3. Standardize road infrastructure, specifically turning radiuses, culvert loading capacity, bridge loading capacity, heights of road furniture (signage, power lines, overpasses, and bridges), and gradient of the corridor. 4. Create bypasses for corridors passing through cities and towns.	GoK (Ministry of Transport)

10.1.6 Strategies for Hydro Storage Projects

Hydropower continues to expand globally as the power sector transitions away from carbon-intensive fossil fuels. New dam sites vary widely in the magnitude of their adverse effects on natural ecosystems and human livelihoods. Advances in data availability and computational analysis now enable accounting for an increasing array of social and environmental metrics at ever-larger spatial scales. In turn, expanding the spatial scale of planning yields more options in the quest to improve both economic and socio environmental outcomes. There remains a pressing need to incorporate climate change into hydropower planning. Ultimately, these innovations in evaluating prospective dam sites should be integrated into strategic planning of the entire energy system to ensure that social and environmental disruption of river systems is minimized. Globally, hydropower developers are increasingly expected to share benefits with people living in project-affected areas. Nevertheless, hydropower benefit-sharing has not found sufficiently widespread application, and the concept is not yet widely understood. For a sustainable development strategy, the image in Figure 10-2 indicates interest and risks faced by the major stakeholders for hydro power development

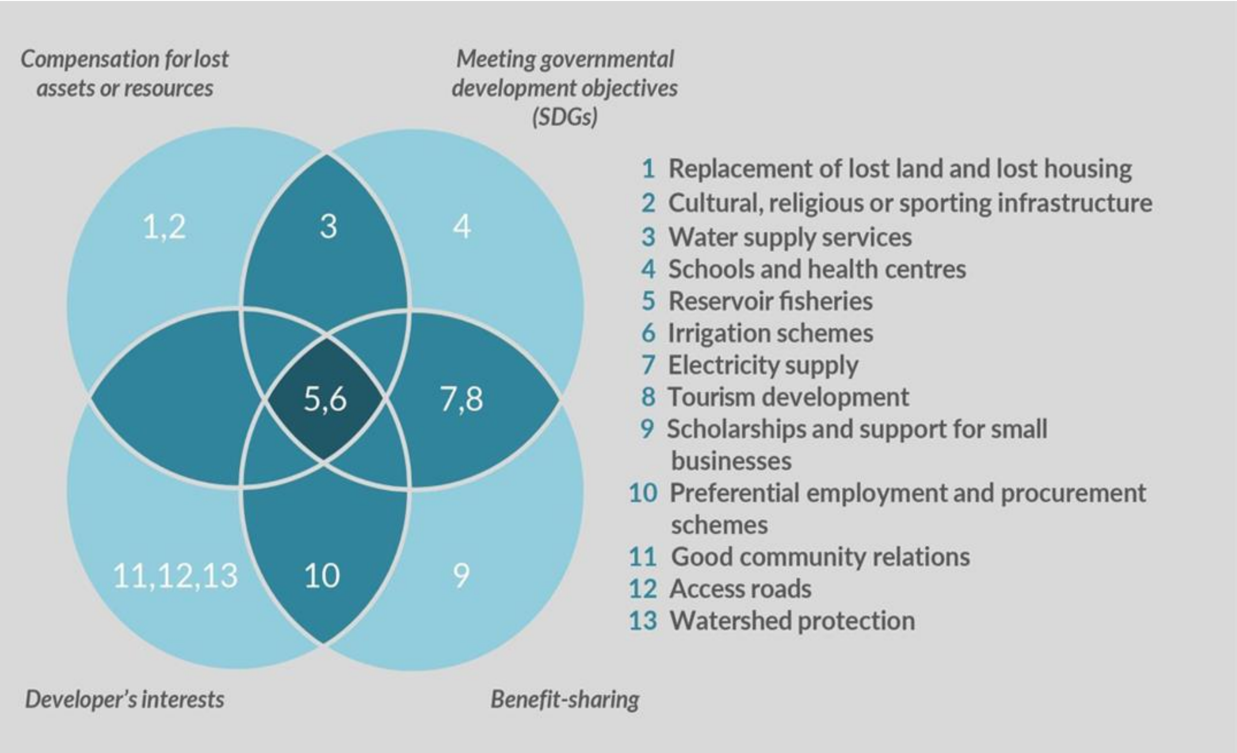


Figure 10-2: Risks Faced by Hydro Power Development. (Hydropower benefit-sharing and resettlement: A conceptual review. Christopher Schulz, Jamie Skinner)

From this assessment, hydro power development has tremendous opportunities for the economy as well as great risks for the environment and local community. Large dams offer great opportunities for irrigation and electricity supply but risk the flora and fauna as well as displace large populations. Proper analysis should be done at feasibility study level to determine the cost benefit analysis for such projects and proper risk management should be identified.

There is an estimated national hydropower potential of between 3,000-6,000 MW. Currently over 800MW is exploited, mainly in large installations owned by KenGen. During the period July 2022 to July June 2023 the existing hydropower plants contributed about 19.33% of annual electricity generation in the country which is also the lowest contribution of hydro energy in the country. There are 8 power stations with capacity of more than 10 MW each that have reservoirs. At least half of the overall potential originates from smaller rivers that are key for small-hydro resource generated electricity. The Feed-in Tariffs (FiT) policy has spurred private sector interest to develop small-scale hydro plants. There is a large pipeline of small hydropower projects under the FiT scheme. Feasibility studies of smaller hydropower projects are also on-going.

The key challenges faced in implementing hydropower projects are discussed in Table 10-6.

Table 10-6: Key Challenges for Hydro Projects

No	Challenge	Way Forward	Responsibility
1	Lack of accurate resource assessment	Carry out a comprehensive resource assessment	MoE&P, WARMA, KenGen, IPPs
2	Land acquisition problems	1. Allocate land for hydro power development in areas identified as having good resources. 2. Register community land. 3. Provide laws and regulations for revenue sharing with the community. 4. Provide mechanisms for social license and regulations on Free Prior and Informed Consent (FPIC)	GoK
3	Resettlement and rehabilitation	1. Ensure ESIA is conducted as stipulated in the regulations 2. Enforce monitoring of EMP to conform to recommendations identified in the ESIA. 3. Enhance laws relating to compensation of communities	GoK, NEMA
4	Poor economic benefit	1. Ensure feasibility studies are conducted professionally and all opportunities and risks are identified 2. Enhance cooperation between different GoK agencies to ensure the economic benefits of the projects is realized (irrigation, power generation, fishing and tourism)	MoE&P
5	High capital costs	Assist in securing affordable financing for hydro projects.	GoK

Table 10-7 shows the current and planned hydro power projects.

Table 10-7: Hydro Power Projects

Project	Capacity (MW)	LCPDP COD	Status/ Challenge	Way Forward	Responsibility
Major Hydros	792.7		PPA expiring in 2028 Rehabilitation of power plants is required and unrecovered costs	Carry out FS on the rehabilitation of the power plants negotiate new PPA including Karura and Raised Masinga	KenGen KenGen & KPLC
Karura Hydro	90	2031	FS completed, high tariff	Include Karura in new hydro PPA after expiry of current PPA in 2028	KenGen, KPLC, MoE&P, EPRA
High Grand Falls Stage 1+2	693	2031	FS completed	The HGF project is a multipurpose project that requires a multi-stakeholder approach. FS was completed more than 10 years ago. To	KenGen, Tana and Athi Development Authority (TARDA),

Project	Capacity (MW)	LCPDP COD	Status/ Challenge	Way Forward	Responsibility
				put this project on track, it is recommended to put in place a multi stakeholder team of all key stakeholders to spearhead the following: High level review of the feasibility study completed in February 2011, Prepare implementation structure and Implementation plan	National Irrigation Authority, Tanathi Water Services Board and Northern Water Services Board
Webuye Falls- KenGen	40	2032	Planning phase, lack of adequate data, land acquisition challenges	Carry out resource assessment campaigns. Avail land to KenGen for implementation	KenGen, KPLC
Pumped hydro storage - Unit 1	300	2034	Pre-feasibility study completed, FS about to commence, lack of regulations for storage	Conduct Feasibility Study Get approval to implement the project.	KenGen MoE&P
Pumped hydro storage - Unit 2	300	2043	Pre-feasibility study completed, FS about to commence, lack of regulations for storage	Conduct Feasibility Study Get approval to implement the project	KenGen MoE&P

10.2 Challenges Identified in the Implementation of LCPDP 2024-2043

i. The successful implementation of the Vision 2030 and Bottom-up Economic Transformation Agenda Initiatives projects is crucial for driving electricity demand and achieving the goals of the plan. However, historical delays in their execution have resulted in an imbalance between demand and supply. Therefore, the recommended scenario in this plan, which optimizes the outcomes, takes into account the limited success of the Vision 2030 flagship and the Bottom-up Economic Transformation Agenda Initiatives projects. The plan's success hinges significantly on the synchronized progress of major flagship projects alongside the phased deployment of generation plants.

ii. The plan has several committed and planned intermittent renewable generation projects which creates a challenge of system operations. However, the ancillary services study has faced significant delays due to financing constraints. The successful implementation of this plan will depend on the development and implementation of ancillary services framework and projects.

iii. The System operator is likely to face challenges in management of secondary reserves associated with ancillary services highlighted in (c). Automatic Generation Control (AGC) systems need to be implemented to improve on system frequency control.

iv. Delay in the implementation of projects under the FiT Policy project pipeline has led to approval of many projects which are at various stages of development. The generation plan recommends Solar and Wind FiT Projects that do not have PPAs be migrated to renewable energy auctions.

v. High system losses. Measures to address commercial and technical losses need to be enhanced. The plan assumes 1.5% reduction in system losses annually.

vi. Delay in approval of retail tariffs leads to adoption of pass-through mechanism to generate revenues for new capacity additions. This mechanism does not factor in the system costs subsequently leading to revenue shortfall for the off-taker. Cost reflective tariff needs to be maintained to ensure sustainability of the sector.

vii. Waste of geothermal resources through venting due to a lack of appropriate balance in the development of geothermal plants and intermittent renewable energy. Need to use planning tools that are able to optimize the generation expansion mix to ensure a balanced capacity mix in the system.

viii. Increasing trend in the development of captive generation especially among the industrial and commercial customers. This will have a negative impact on the achievement of demand projections in the plan. There is need to enhance power supply reliability to meet customer expectations.

ix. The tools used in the development of the LCPDP 2024-2043 have limitations that could significantly impact on the outcomes of the plan. The demand forecasting tool does not incorporate the effects of price on energy consumption. The generation expansion planning software does not allow for the optimization of renewable energy projects, except geothermal, and for the modeling of storage and imports. The Ministry of Energy is working towards acquiring a more flexible planning tool.

10.3 Risks in the Implementation of LCPDP 2024-2043

Table 10-8 presents a risk matrix summarizing the risks arising from the challenges and their proposed mitigations.

Table 10-8: Risk Matrix on Implementation of the LCPDP 2024-2043

No	Area of Risk	Risk	Cause	Mitigation
1	Demand	Failure to attain the projected demand growth.	a) Unreliability of the network b) Captive power generations c) Cost of power d) Universal access target not achieved. e) Delay in implementation of transmission projects. f) Delayed Implementation of Vision 2030 flagship and Big Four Agenda Projects. g) Low economic growth (GDP)	a) Monitor the progress in demand growth and adjust the generation and transmission plan accordingly. b) Review policy intervention that can enhance specific consumption of electricity. c) Finalize development of captive power policy d) Maintain a record of all captive power generators and integrate that into the overall planning process. e) Strengthen and facilitate the interagency demand creation committee coordinated by the Ministry of Energy, to coordinate demand creation initiatives. f) Monitor and fast track implementation of transmission projects and missing links.
2	Power Purchase	Risks of Contingent Liability and Litigation risks on project rescheduling as per the plan and migration to auction policy.	a) Implementation of the proposed plan omits a number of approved and projects with initialed PPAs leading to a high risk of litigation b) Many projects approved at feasibility study stage with developer having legitimate expectations for their development	a) Prioritize approved projects and projects with initialed PPAs in the renewable energy auctions b) Develop contingency plan for projects with PPAs and prioritize projects with Letters of Support (LoS). c) Pursue to renegotiation of PPAs with due considerations for prioritization, financial risk management and investor expectations. d) Cabinet secretary to approve both the revised FIT Policy for biomass/biogas and Small Hydro projects, and to transition to the Auctions framework for Geothermal, Wind and Solar projects.
3	Resource sustainability	a) Risk of increased curtailment of energy b) Resource Risk	a) High capacity of must-run energy sources in the mix leading to curtailment b) Unsustainable exploitation of the resource.	a) Introduction of storage solutions to ensure optimal utilization of resources. b) Introduction of incentives to shift loads to off-peak periods c) Adopt flexible geothermal technologies for future plants

No	Area of Risk	Risk	Cause	Mitigation
			c) Inadequate resource assessment by developers d) Climate Change e) Natural Disasters f) Supply chain disruptions g) Displacement of cheaper energy sources by must-run plants due to contractual obligations h) Unpredictable (high) prices of fossil fuels	d) Continuous resource monitoring and update of resource assessment. e) Continuous studies on the impact and mitigation measures for climate change on energy resources. f) Strategic forecasting and creation of reasonable stocks. g) Prioritize indigenous resources. h) Improve project approval procedure to ensure adequate resource assessment
4.	Project Management	a) Projects delay b) High tariffs	a) Slow disbursement of project finance b) Lack of project financing c) Procurement delays d) Complex challenges in wayleave acquisition e) Non-performing contractors f) Change in Law and Change in Tax g) Delays in providing government support instruments for projects. h) Expensive take or pay projects	a) Align project planning with budget availability. b) Enhance the macro environment and provide clarity on government support measures c) Enhance contract planning, design and supervision. d) Strengthen community engagement and stakeholder consultation during project conceptualization and implementation. e) Lobby National Treasury and other government agencies to stabilize taxes, levies and other laws in the power sector. f) Develop framework for competitive and transparent procurement of IPPs g) Blacklisting non-performing contractors
5.	Network	a) Increased system Losses. b) Reduced grid reliability	a) Delayed transmission and distribution projects b) Internal inefficiencies at distribution and retail level. c) Expansive rural electrification network. d) Vandalism e) Terrorism f) Illegal connections	a) Consider off-grid supply options in far to reach areas such as standalone units and mini-grids options. b) Strengthen/ fix resource hemorrhages recovery measures and in the long run consider other power market structures such as competitive power markets/trading. c) Preventive maintenance d) Enhanced security on critical installations e) Enhance penalties and declare power theft an economic crime

No	Area of Risk	Risk	Cause	Mitigation
6.	System Operation	System operation risks in management of generation reserves.	a) Disproportionate intermittent capacity (Wind and Solar) in the system. b) Lack of adequate ancillary services. c) Lack of Automatic generation control system for management of secondary reserves. d) Inadequate provision in the PPA and the Grid Code to address ancillary service requirements. e) Inadequate/inaccurate forecasting for intermittent technologies	a) Funding for the ancillary services study which is critical as a result of significant addition of intermittent renewable energy projects to the national grid. b) Introduce an ancillary market framework during the market restructuring and allocate costs to parties as appropriate c) Installation of Automatic Generation Control (AGC) systems to improve on system frequency control. d) Restructure PPAs and the grid code to capture and align emerging issues on system operations. e) Implement accurate forecasting for all intermittent projects.
7.	Excessive captive generation approvals	Risk of crowding out committed power Purchase Agreements leading to stranded public sector investments by utilities from prosumers and other solar investors.	a) Reliability of power supply b) Perceived high electricity tariffs c) Delays in connecting consumers to the grid	a) Make grid connected power more competitive including reducing system costs (including end-user tariffs), enhance system efficiencies and focus on demand side management b) Going forward, entrench different power purchase principles including "Take and Pay" c) Consider introducing power markets once a system operator is in place to introduce competition at retail/distribution level d) Leverage on the interconnected network to increase export of interconnected power e) Awareness creation on tariffs f) Streamline new customer connection process to enhance efficiency
8.	Demand-Supply Balance	a) Risk of reduced system reserves b) Load shedding c) Risk of firm capacity shortfalls	a) Large baseload capacity and inadequate flexible/peaking capacity plants b) Delay in development of envisaged peaking plants including large hydro-plants. c) Delayed implementation of generation projects in the medium term.	a) Introduction of battery storage to absorb excess energy during off-peak hours. b) FastTrack development of peak load projects particularly hydro plants. c) Critically analyze needs against the decommissioning programme to forestall shortages before new capacity is commissioned. d) Expedited decision making on projects required in the medium term to avoid delays

No	Area of Risk	Risk	Cause	Mitigation
9.	Political risk	a) Delay in projects b) Shifting priorities	a) Change of government priorities b) Change in laws, policies, and regulation c) Political instability	a) Development and implementation of strong legal and regulatory frameworks b) Sustained entrenchment of good ethics and governance strategies

11 CONCLUSIONS AND RECOMMENDATIONS

11.1 Demand forecasting

The following are the key conclusions and recommendations from the demand forecast:

i. The Government should enhance incentives to support clean energy consumption and transition including adoption of EVs and e-cooking; Such incentives may be in the form of tax waivers to allow for competitive costs of electricity compared to alternatives such as diesel, kerosene and wood fuel.
ii. Investment in power system upgrade and reinforcement to be enhanced to help improve system reliability and address weaknesses along the value chain that have increased system losses and constrained demand. High energy losses in the system have a bearing on end-user tariffs which together with system reliability issues encourage both captive power consumption and grid defection.
iii. Leverage on County programmes to promote demand creation through the inter-governmental relation processes, noting that counties have a role in electricity reticulation. This would enable synergies between National and County Governments in electrification of unserved areas.

11.2 Generation capacity expansion

The generation plan developed from the reference demand forecast scenario to be adopted as the 2024-2043 expansion pathway with the following recommendations:

i. Process required approvals for all generation projects recommended in this plan starting with those that have had their PPAs renegotiated, and facilitate their commissioning and integration to the national power grid.
ii. Expedite development of 150MW BESS by 2026 through KenGen (100MW) and IPPs (50MW), to provide ancillary services, supplement peaking capacity, reduce venting of geothermal steam, enhance integration of variable renewables and support further greening of the grid.
iii. Fast-track negotiations for 150MW under the regional power trade initiatives for peaking capacity and provision of system reserves required based on the reference demand scenario.
iv. New capacity from variable renewable energy projects without PPA to be transitioned to the Renewable Energy Auctions program except small capacity projects of less than 20MW from small hydro, biomass, and biogas sources.

v. Fastrack approvals, PPA negotiations and issuance of support instruments for power generation projects scheduled in the medium-term plan to avoid capacity shortfalls;
vi. The Ministry of Energy and Petroleum to undertake a study on adoption of flexible geothermal technologies in future projects to increase system flexibility, and geothermal energy uptake while managing venting of steam during low demand periods;
vii. Negotiate lower power purchase tariffs for the variable renewable energy projects in the medium term, considering that the costs of solar and wind power technologies have been declining in the recent past, to mitigate increase in electricity cost;
viii. Finalize and implement the renewable energy auction policy to facilitate competition in the procurement of VRE projects in accordance with the policy, to enable achievement of lower generation tariffs;
ix. Facilitate early approval of generation projects with long lead times, scheduled beyond the medium term in the LCPDP, to ensure they are commissioned in the long term as scheduled. These include large hydro, pumped storage and nuclear power plants;
x. Solar PV and wind energy power projects with storage scheduled in LCPDP should include sufficient storage capacity to resolve intermittency issues and provide at least one hour of peaking capacity at rated plant capacity to facilitate energy shifting, manage the risk of energy curtailment, and help meet peak power demand.
xi. The Ministry of Energy and Petroleum to undertake a study on adoption of flexible geothermal technologies in future projects to increase system flexibility, and geothermal energy uptake while managing venting of steam during low demand periods.

11.3 Transmission planning

To provide adequate network capacity and improve transmission reliability and efficiency in the short term, prioritization and fast tracking of the following projects is recommended:

i. Construction of the 69km Ndhiwa-Sondu 132kV line to resolve voltage issues in South Nyanza and Central Rift Region and overloading of the Kisumu-Muhoroni and Muhoroni-Chemosit 132kV lines. It it will also facilitate decommissioning of the GTs in Muhoroni without adverse impact to the system.

ii. Construction of Narok-Bomet 132kV line to improve reliability by providing alternative route to supply South Nyanza and Central Rift Region.
iii. Completion of 220/132kV Kitale substation on Turkwel-Ortum-Kitale 220kV route. This will provide an alternative evacuation route for Turkwel Hydro generation to North Rift and Western Kenya and improve the overall system security.
iv. Reconstruction and upgrade of Rabai-Kilifi 132 kV line to double circuit to provide adequate supply capacity in North Coast sub-region, improve supply reliability and reduce network losses.
v. Commissioning of Mariakani 400/220kV substation to facilitate operation of Isinya-Mariakani system at 400kV to enable N-1 redundancy criteria for Coast region.
vi. Commissioning of Kimuka 220/66kV 2X200MVA Substation and construction of the proposed 66kV feed-outs from Kimuka Substation to reduce losses, improve voltages and security of supply on the 66kV network served from Nairobi North Substation and on Magadi feeder. This will also de-load the Suswa-Nairobi North 220kV lines.
vii. Termination of Olkaria-Lessos-Kibos 220kV line at Lessos to enable operation of Olkaria-Lessos-Kibos lines as designed. This will facilitate management of grid voltage and improve grid security by provide a complete parallel route to the North Rift and West Kenya load centers.
viii. Installation/uprating of the 132/11kV transformer at Garissa Substation to provide adequate capacity.
ix. Development of transmission line rings for areas currently served by radial networks especially where there is loss of substantial load upon occurrence of a contingency. Some of the projects expected to close key rings include Isiolo-Nanyuki 132kV line, Kamburu-Embu-Thika 220kV line, Kibos-Bondo-Rangala 132 Kv, Dongo Kund-Kibuyuni 220 kV, Githambo-Othaya –Kiganjo 132 kV, Kilgoris –Masaba 132kV, Machakos –Mwala 132kV and Weru-Kilifi 220kV line.
x. Install additional transformers at Kibos, Bomet, Kyeni, Narok, Mwingi, Kitui and Wote substations among other with single transformers to facilitate compliance with n-1 reliability criteria.
xi. Construct Olkaria V-Olkaria 1AU double circuit line as an alternative evacuation path for Olkaria IV and Olkaria V geothermal power plants generation to ensure n-1 reliability criteria in Olkaria geothermal complex
xii. Uprating of the Chemosit 132/33kV transformers from 23MVA to 45MVA.

xiii. Fast-track construction of the Menengai-Olkalao-Rumuruti 132kV line and the associated substations to provide alternative evacuation path for Menengai geothermal field.

xiv. Construct a 220kV line from the proposed Thika 400/220 kV substation to Thika road 220/66 kV substation to establish alternative supply to the Nairobi North- Thika Road –Dandora 220kV corridor from the 400kV to improve security of supply

xv. Fast track installation of phase-shifting transformers on Nairobi North 220kV lines at Suswa to enhance grid reliability.

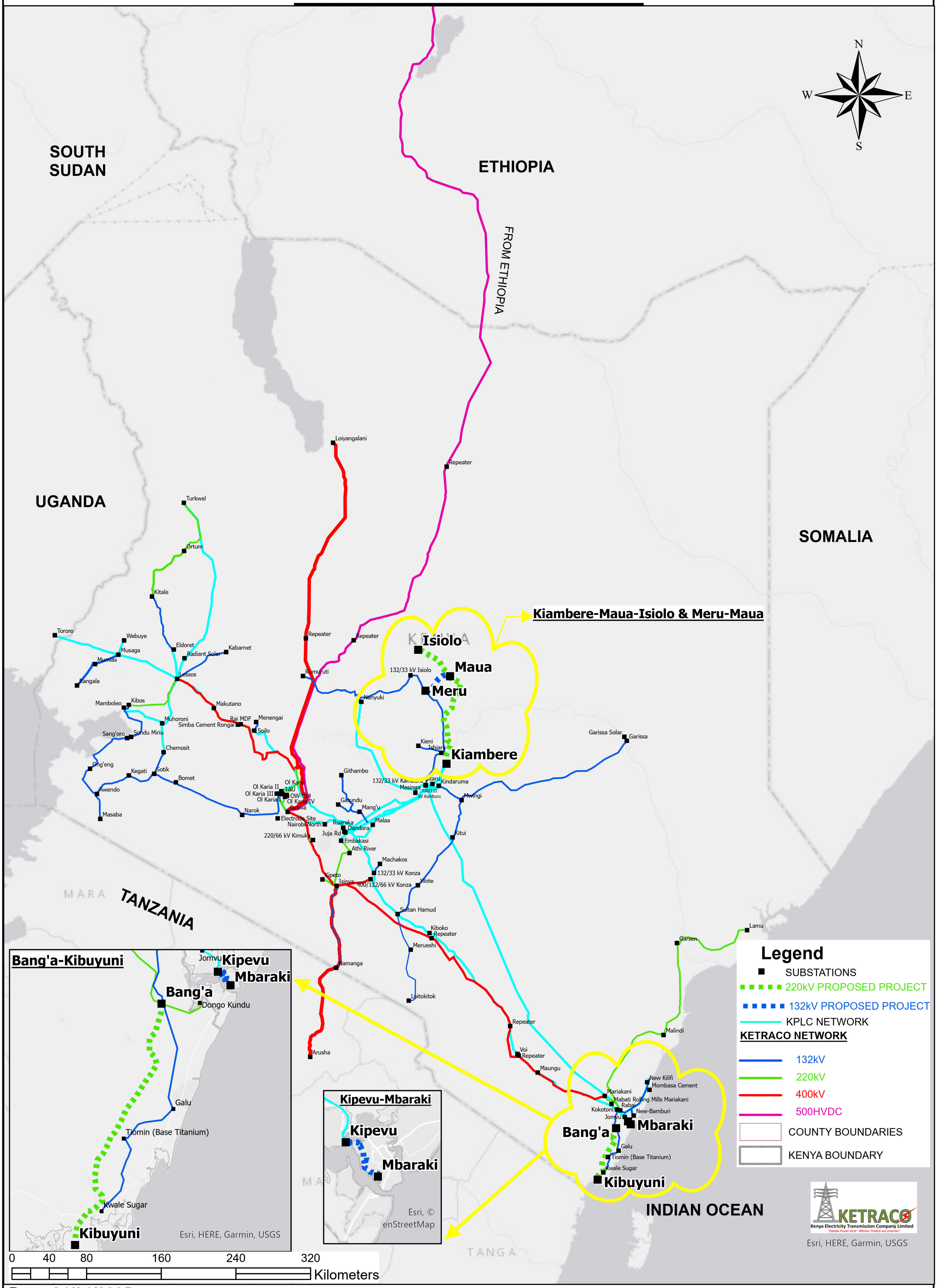
ANNEX 3: PROJECT DESCRIPTION

Project name	Brief Description	Objective	Estimated Cost (USD Mn)
Approx. 80km 220kV Kwale - Shimoni (Kibuyuni) and intertie to existing 132kV system	220 kV Kwale -Shimoni (Kibuyuni) double circuit line from off 220kV Dongo Kundu Mariakani via a LILO at Bang'a including establishment of new 220kV switching station at Bang'a, new 220/132/33kV at Shimoni (Kibuyuni) 132kV intertie to existing 132kV system in the area.	Extend 220kV network to Kibuyuni for increased adequacy of supply required for projected ship recycling and new port at Shimoni, including reinforcing 132kV in South Coast networks	84.9
Approx. 7km 132 kV Kipevu-Mbaraki	132 kV Kipevu – Mbaraki double circuit line including establishment of new 132/33kV substation station at Mbaraki and 132kV bay extension at Kipevu. Due to space constraint, the underground cable and GIS system may be considered.	Extend high voltage network to Mbaraki for increased adequacy, improved security of supply by renforcing the medium voltage network	14.4
Approx. 145 km 220 kV Kiambere-Maua-Isiolo	220 kV Kiambere-Maua-Isiolo double circuit line including establishment of new 220/132/33 substation at Maua, 220kV bay extensions at Isiolo and Kiambere substations	Provide alternative supply/evacuation path for Isiolo and hydro, wind and solar resources	120
Approx. 34km 132kV Meru-Maua	132 kV Meru – Maua double circuit line including establishment of new 132/33kV substation at Maua and 132kV bay extension at Meru.	Extend 132kV network to Maua for increased supply adequacy and reinforcing medium voltage networks	26.63
TOTAL			**245.93**

****These are estimated EPC and RAP cost prepared for KETRACO Transmission Master Plan and may not be reflective of the prevailing market rates. The consultant is expected to undertake independent feasibility to determine project cost(s).***

The map of Kenya showing the geographical location of the projects above is given in the next section.

PROJECT LOCATION MAP



Date: 24/04/2025

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Ref: PPPD/O&S/RFP/05/2024-2025 **2nd May, 2025**

REF: REQUEST FOR PROPOSALS (RFP) FOR PROVISION OF CONSULTANCY SERVICES FOR TRANSACTION ADVISORY SERVICES FOR DEVELOPMENT OF TRANSMISSION LINES PROJECTS THROUGH SOLICITED PUBLIC PRIVATE PARTNERSHIPS PROJECTS.

RFP NO. PPPD/O&S/RFP/05/2024-2025

ADDENDUM I

The National Treasury and Economic Planning, has issued an addendum to the request for proposals (RFP) for provision of consultancy services for Transaction Advisory Services for Development of Transmission Lines' Projects through Solicited Public Private Partnerships Projects.

Annex 1 – Updated Remuneration schedule and disbursement arrangements
Annex 2 – Updated Deliverables table
Annex 3 – Updated Project Description and Map
Annex 4 – Least Cost Power Development Plan

All other terms and conditions remain the same.

HEAD, SUPPLY CHAIN MANAGEMENT SERVICES
FOR: PRINCIPAL SECRETARY/THE NATIONAL TREASURY

S/No	Query	Clarification
1.	Can electronic submission be accepted?	Please note that electronic submission is not permitted for this RFP. Bidders are required to submit hard copies in accordance with Clause 17.5. • Binding of Documents Tender documents must be securely and firmly bound. The use of spring files, box files, or loose-leaf binding is not permitted. • Table of Contents Each submission must include a clear and comprehensive Table of Contents, appropriately referencing the sections and page numbers of the bid. • Pagination/Serialization All pages of the bid document must be paginated or serialized in continuous ascending order from the first page to the last in this format; (i.e. 1, 2, 3…n where n is the last page) using indelible ink **(Mandatory)**
2.	In reference to the local partnership requirement, in which proof of involvement of local staff in the assignment is required. Please advise on the number of staff needed to score the full marks	The requirement is for 4 Key Experts
3.	"There are four lines—please confirm whether these	The decision on whether to procure one private party

S/No	Query	Clarification
	are intended to be covered under a single concession agreement or if multiple concession agreements are anticipated."	through a single concession agreement or several shall be informed by the feasibility study outcome of Phase 1. The Transaction Advisor shall justify and advise on the most effective procurement strategy whether the projects are to be procured as a single lot through one concession agreement or separate concession agreements. This advice shall be taken into consideration.
4.	Kindly confirm if the Master Transmission Plan and the associated Least Cost Power Development Plan available for review	We confirm that the 2024-2043 Least Cost Power Development Plan is a published document available publicly. A copy is attached as **Annexure 3.**
5.	Kindly clarify the designated signatories to the transaction advisory contract, and outline the approval process for consultant deliverables and corresponding payments.	The contract will be between the National Treasury and the awarded consultant. Regarding milestone approval, we have a joint process in place between The National Treasury and KETRACO. In the final contract, the contact address and communication details will be provided for the contracting authority, who is the recipient of the consultancy services. Once the milestones are delivered, the Project Implementation Team (PIT) will convene to review and approve them. Subsequently, KETRACO will communicate with the National Treasury to confirm the

S/No	Query	Clarification
		completion of the milestones, and payment will be processed by The National Treasury. Milestones linked to PPP Committee approvals shall be paid upon receipt of the approval.
6.	Could you please clarify the expected scope and deliverables associated with Milestone 7 listed under Phase Two- ***Completion of RAP, Social Audit and VMGP Plan***	A clarification has been provided through **Annexure 2** where the undertaking of RAP, Social Audit and VMGP Plan has been removed from Phase I. Undertaking of RAP, Social Audit and VMGP plan shall be done under Phase 2. ESIA undertaken under Phase 1 is as per the scope described in the TOR.
7.	The RFP indicates that the fee structure should be broken down between Phase One and Phase Two, with the fees for Phase One not exceeding 50% of the total contract value. Could you please confirm this requirement Should we submit separate forms for Phase One and Phase Two, or is a single consolidated form required for both phases?	The evaluation of proposals will be based on the total cost presented in the Financial Submission Form. To facilitate clarity and effective allocation, bidders are kindly requested to indicate the resources assigned to Phase I and Phase II within the relevant sections of the Technical and Financial Forms. The disbursement criteria for fees is amended as per attached ***Annexure 1*** to provide clarity.
8.	Kindly clarify the nature of the existing studies related to these transmission lines and the dates of their	We confirm that the projects are distinct and are not part of the Adani and Africa50 privately initiated

S/No	Query	Clarification
	completion. We also understand that these lines are separate from the privately initiated proposals submitted by Adani and Africa 50 Corporation.	proposals that have been received. Response on existing studies is as per clarification 9.
9.	Kindly confirm the nature of the studies currently available for these transmission lines, and clarify whether these documents will be made available at this stage or only to the successful bidder.	The existing studies are limited to technical and economic feasibility including preliminary assessment of environmental and social aspects. The existing studies may not be not be current. The transaction advisor is expected to conduct their independent feasibility study including project cost estimate as per the TOR. However, available studies will be provided for reference, to the successful bidder.
10.	Will there be any penalties for not including the non-key experts in our proposal? Additionally, should the non-key experts be considered part of the required submissions as outlined in the RFP?	The provision of non-key experts is not intended to be prescriptive, but rather a guidance based on the expected outputs from the transaction advisors. The absence of any non-key experts will not result in penalization; however, we would appreciate their inclusion if you choose to provide them. While the CVs of non-key experts are expected, their non-availability will not lead to any penalties.
11.	We need further clarification on the financial closure aspect. There is a task element that outlines the financial closure of the projects. It would be helpful if you could provide more details on the expectations for this.	Between commercial close and financial close it is expected that there will be conditions precedent (CPs) to be fulfilled. The Transaction Advisor is expected to assist with any CPs on government side. Additionally, the last payment is linked to financial close

S/No	Query	Clarification
		to ensure that the Transaction Advisor structures bankable projects.
12.	confirm whether the task involves only reviewing the reports already prepared by the KETRACO team, or if a complete feasibility study is expected to be conducted.	The transaction advisor is expected to conduct their independent feasibility study including project cost estimate as per the TOR. However, any necessary information related to previous feasibility studies will be provided for reference, though the responsibility for conducting the study lies with the advisor. While an estimate is provided in the published least cost power development plan, we expect you to develop your own cost estimate, including a detailed breakdown. This will be part of the financial model you will create, as outlined in the TOR, for evaluating bids by consortiums.
13.	The expected commencement date for the services will be determined upon the signing of the contract with the selected firm. Do you have any indication of when this might take place?	The Client plans to award and commence services in July 2025.
14.	Kindly consider extending the bidding period by an additional two weeks to allow for the submission of a comprehensive bid.	The RFP closing date has been extended to 30th May 2025.

7. DELIVERABLES OF THE ASSIGNMENT

The general deliverables[1] of the project are as represented in the table below.

No.	Deliverable	Target Timeline (Time from contract signing)
Phase I		
1	Inception Report	3 weeks
2	Draft Feasibility Study Phase Deliverables including: • Feasibility Study Report • Site selection and suitability assessment • Preliminary ESIA report • Land acquisition plan, • Market sounding report • Project Financial Model	5 months
3	Updated Feasibility Study Phase Deliverables including: • Feasibility Study Report • Detailed ESIA report • Land acquisition plan, • Market sounding report • Project Financial Model • Communication Strategy and Plan	6 months
Phase II		
4	RFQ stage procurement documentation and completion of the RFQ process	7 months
5	RFP bidding stage documents, including RFP, draft PPP project agreements, Design Criteria and Performance Specifications, evaluation criteria, including any other relevant bid documents	8 months
6	Completion of the RFP bidding process and evaluation of bids, and delivery of the evaluation report	9 months
7	Completion of RAP, Social Audit and VMGP Plan	11 months
8	Negotiated Project Agreement & Negotiation Report	12 months

1 Completion of approved capacity building workshop(s) shall be part of the package of a listed deliverable where the workshop's completion timelines fall within the completion timeline for any of the listed deliverables.

9	Commercial Close, Project's contract management framework and case study	14 months
10	Financial close, delivery of the close-out report and final case study	20 months

* ***Undertaking of RAP, Social Audit and VMGP plan shall be done under Phase 2 and not under Phase 1. Scope of RAP, Social Audit and VMGP remains as detailed under Task 1.6 of the TOR.***

9. REMUNERATION SCHEDULE AND DISBURSEMENT ARRANGEMENTS

The Transaction Advisor contract will be a lump sum contract and will be paid on the basis of timely and acceptable deliverables over an envisaged contract period of 20 calendar months. The appointed TA is expected to sign a contract for 24 months, extendable at no extra cost for a further one year in the event that Financial Close has not been reached within 24 months. An extension at extra cost would however be considered for inflation adjustments where delays have not arisen as a result of the performance of the TA.

Bidders must submit bids in the formats prescribed in the RFP. The remuneration schedule is as set out below:

- Phase 1 (the "Phase 1 Amount") - 45% of the lump sum contract amount
- Phase 2 (the "Phase 2 Amount") - 55% of the lump sum contract amount

The following disbursement schedule is set for each phase of the contract. Bidders should keep these in mind in writing their proposals.

For Phase 1:

- 5% of the lumpsum contract amount upon delivery of the inception report;
- 15% of the lumpsum contract amount upon delivery of the draft Feasibility Study Phase Deliverables including Feasibility Study Report, draft ESIA report. The Communication Strategy and Plan should also be delivered at this point;
- 15% of the lumpsum contract amount upon delivery of the final Feasibility Study Phase Deliverables including Feasibility Study Report, ESIA report. This shall also include presentation of the findings and recommendations; and
- 10% of the Phase 1 Amount upon acceptance of the final feasibility study by KETRACO and the PPP Committee.

If KETRACO elects to proceed to Phase 2:

- 7% of the lumpsum contract amount upon delivery of Resettlement Action Plan, Social Audit and Vulnerable and Marginalized Group Plan (VMGP);
- 8% of the lumpsum contract amount upon delivery of the RFQ stage procurement documentation and completion of the RFQ process;
- 15% of the lumpsum contract amount upon delivery of the RFP bidding stage documentation, including RFP, draft PPP project agreements, Design Criteria and Performance Specifications, evaluation criteria, including any other relevant bid documents and completion of the RFP bidding process and evaluation of bids, and delivery of the evaluation report;
- 10% of the lumpsum contract amount upon execution of the PPP agreements, delivery of Project's contract management framework and case study; and
- 15% of the lumpsum contract amount upon financial close and delivery of the close-out report and final case study.

After Phase 1, KETRACO will decide whether to proceed with Phase 2. If KETRACO decides not to proceed with Phase 2, the contract with the TA will be terminated. There shall be proportional reduction of payments in case fewer number of project(s) are taken up from the four projects and/ or if one of the project fails during the transaction process.