

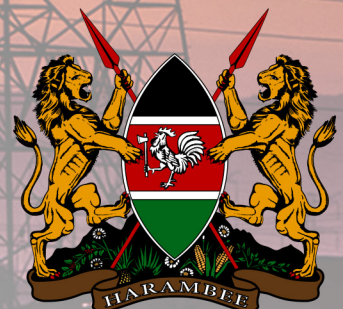
KETRACO

Kenya Electricity Transmission Company Limited

"Stable Power Grid – Mfumo Thabiti wa Umeme"

Transmission Master Plan

2026-2045



Disclaimer

The Transmission Master Plan (TMP) has been developed and published to provide stakeholders with a clear, comprehensive overview of the planned developments within KETRACO's transmission network. It serves as a strategic roadmap, outlining proposed expansions and upgrades aimed at enhancing grid reliability, enabling regional power trade, and integrating renewable energy sources.

The TMP is a dynamic document that will continue to evolve in response to new data, changing demand trends, and shifting sectoral priorities. It is intended solely for informational purposes and serves to enhance transparency, promote knowledge sharing, and facilitate stakeholder engagement across all phases of planning, design, construction, operation, and maintenance of high-voltage transmission infrastructure.

The contents of this document do not constitute legal, financial, or investment advice. KETRACO based its plans on the best available data at the time of publication of this document to ensure stakeholders are kept informed of developments across the transmission network.

Cost estimates provided in the TMP are indicative and subject to revision. These figures are sensitive to fluctuations in global economic conditions, including foreign exchange rates and commodity prices.

For future transmission network expansion, KETRACO will conduct the necessary feasibility studies and pursue development within the framework of its capital investment process. All such investments will be undertaken in accordance with the relevant public procurement laws and regulations of the Government of Kenya.



Executive Summary

The Transmission Master Plan (TMP) embeds inclusive stakeholder engagement and sustainability at its core. It provides a structured framework for transparent, continuous participation across government, communities, civil society, and the private sector tailored to the needs of programs, plans, and projects. Environmental, social, and climate change considerations are mainstreamed through the application of safeguards, promoting biodiversity, land stewardship, and socioeconomic inclusion. The TMP supports low-carbon development by facilitating renewable energy integration, reducing losses, and enhancing climate resilience through principles like redundancy and robustness. It also outlines strategies for climate finance, carbon markets, and resilient PPP models.

There were 30 active projects and 116 planned projects in the TMP 2025-2044. Since then, 5 projects have been completed. The new TMP 2026-2045 has 24 active projects and 116 planned projects.

The Transmission Master Plan (TMP) 2026-2045 serves as a strategic roadmap for the expansion and modernization of Kenya's high-voltage electricity transmission network. Developed by the Kenya Electricity Transmission Company Limited (KETRACO), this plan succeeds the TMP 2025-2044 and outlines a 20-year vision to enhance grid reliability, facilitate regional power trade, integrate renewable energy, and support national economic growth. The TMP is a dynamic document, designed to be reviewed and updated annually to remain responsive to changes in demand, generation, technology, and policy. It mainstreams sustainability, climate resilience, and inclusive stakeholder engagement at its core, moving beyond compliance to a strategic, risk-based approach that reduces project delays and strengthens the social license to operate.

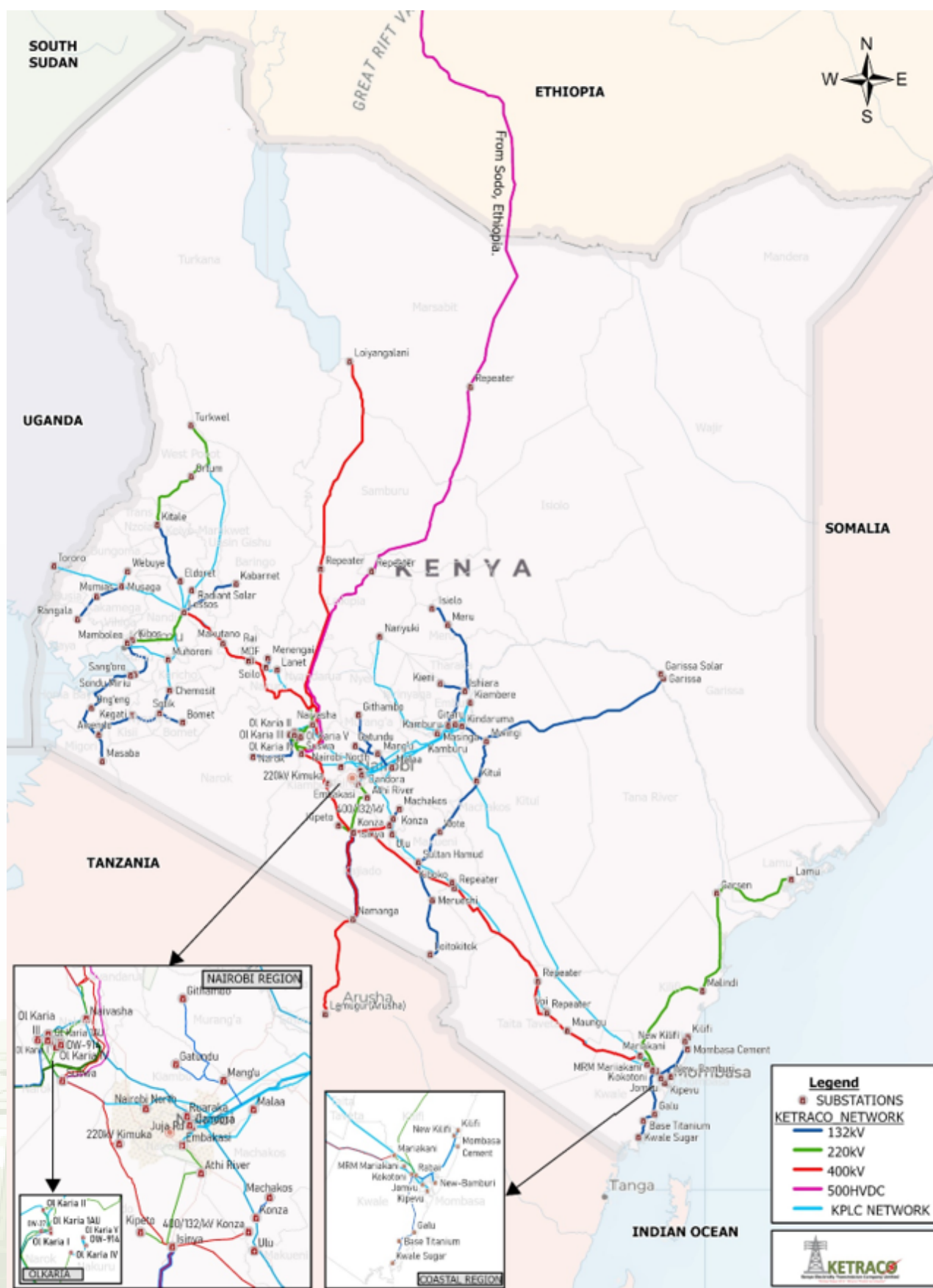
The Kenyan power sector is undergoing significant transformation, with peak demand rising from 2,177 MW in FY 2023/24 to a record 2,444 MW in January 2026, driven by manufacturing, agriculture, urbanization, and emerging loads like e-mobility and e-cooking. The number of connected households has surpassed 10 million, achieving an electricity access rate of over 76%. While the grid-interconnected capacity stands at 3,192 MW, the system faces persistent challenges, including technical losses, voltage instability, overloading of key corridors (especially in the western region), and integration complexities from variable renewable energy (VRE) sources.

to address these issues and meet future demand, the TMP projects system peak demand to grow at an average annual rate of 6.89%, from 2,439 MW in 2025 to 9,722 MW in 2045 under a reference scenario. The Vision scenario projects peak demand reaching 16,152 MW. Accordingly, effective generation capacity is expected to expand from 3,107 MW to over 18,000 MW by 2045, anchored by geothermal (40% of firm capacity), with significant contributions from Battery Energy Storage Systems (BESS), pumped storage, and a planned nuclear power plant by 2034. The transmission network, currently operating at 132kV, 220kV, 400kV, and 500kV DC, comprises approximately 9,718 km of circuit length, with KETRACO owning and operating 6,248 km.

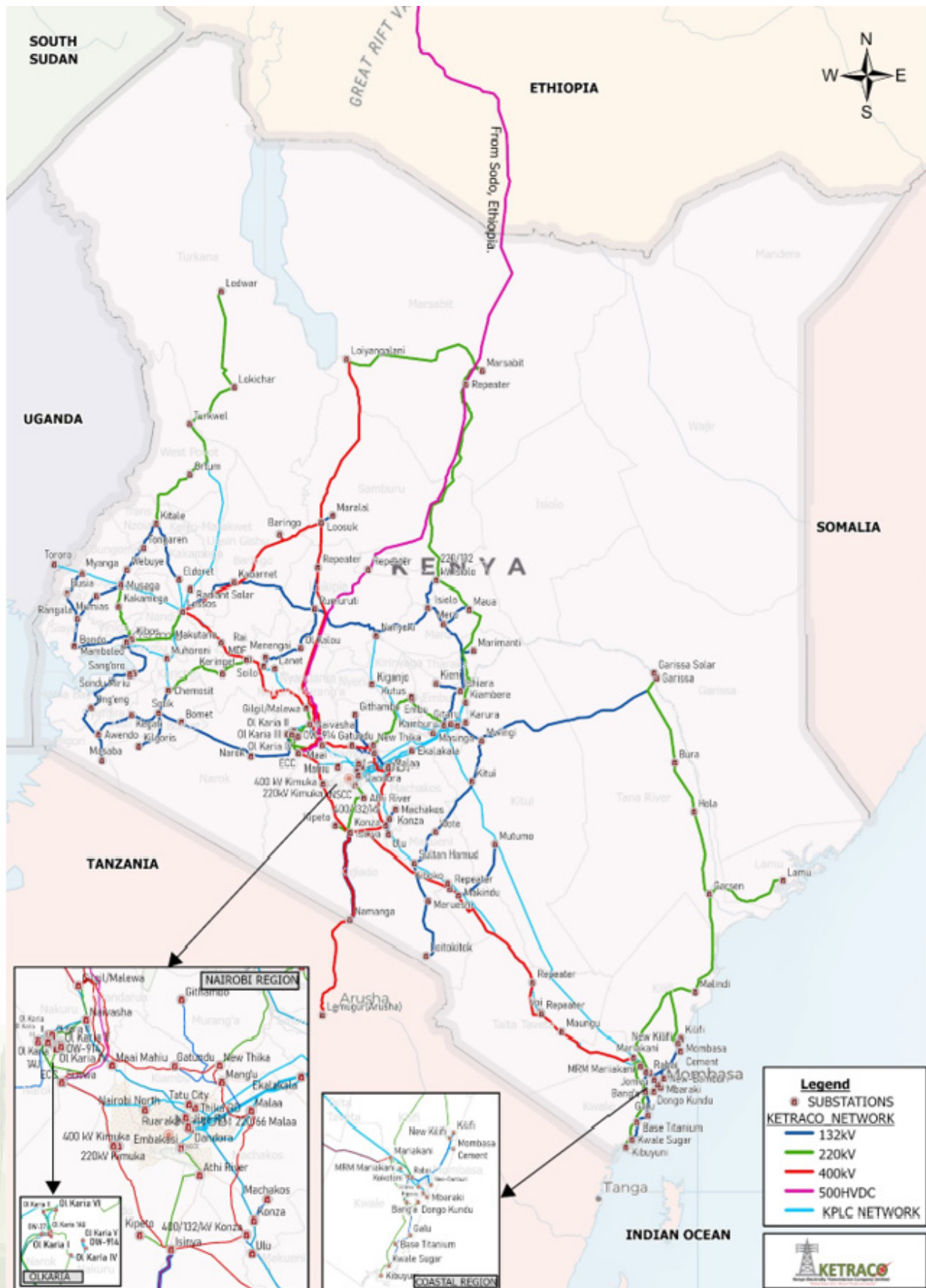
The TMP outlines a comprehensive expansion plan involving a total of 140 projects: 24 ongoing projects and 116 planned projects. These projects represent a total investment requirement of USD 5.3 billion, covering 6,851 km of new transmission line route length and 21,808 MVA of substation transformation capacity. Of this, only USD 350 million has been secured, leaving a significant financing gap of USD 4.95 billion. While the medium-term projects (through 2030) face a gap of USD 1.95 billion, the primary challenge remains mobilizing resources for long-term strategic investments. To bridge this gap, the plan recommends a multi-pronged approach, including increased government funding, private sector participation through Public-Private Partnerships (PPPs), and leveraging innovative climate finance mechanisms such as green bonds and carbon markets.

The maps in the next pages illustrate the national transmission grid network in 2026, and 2030 and 2045.

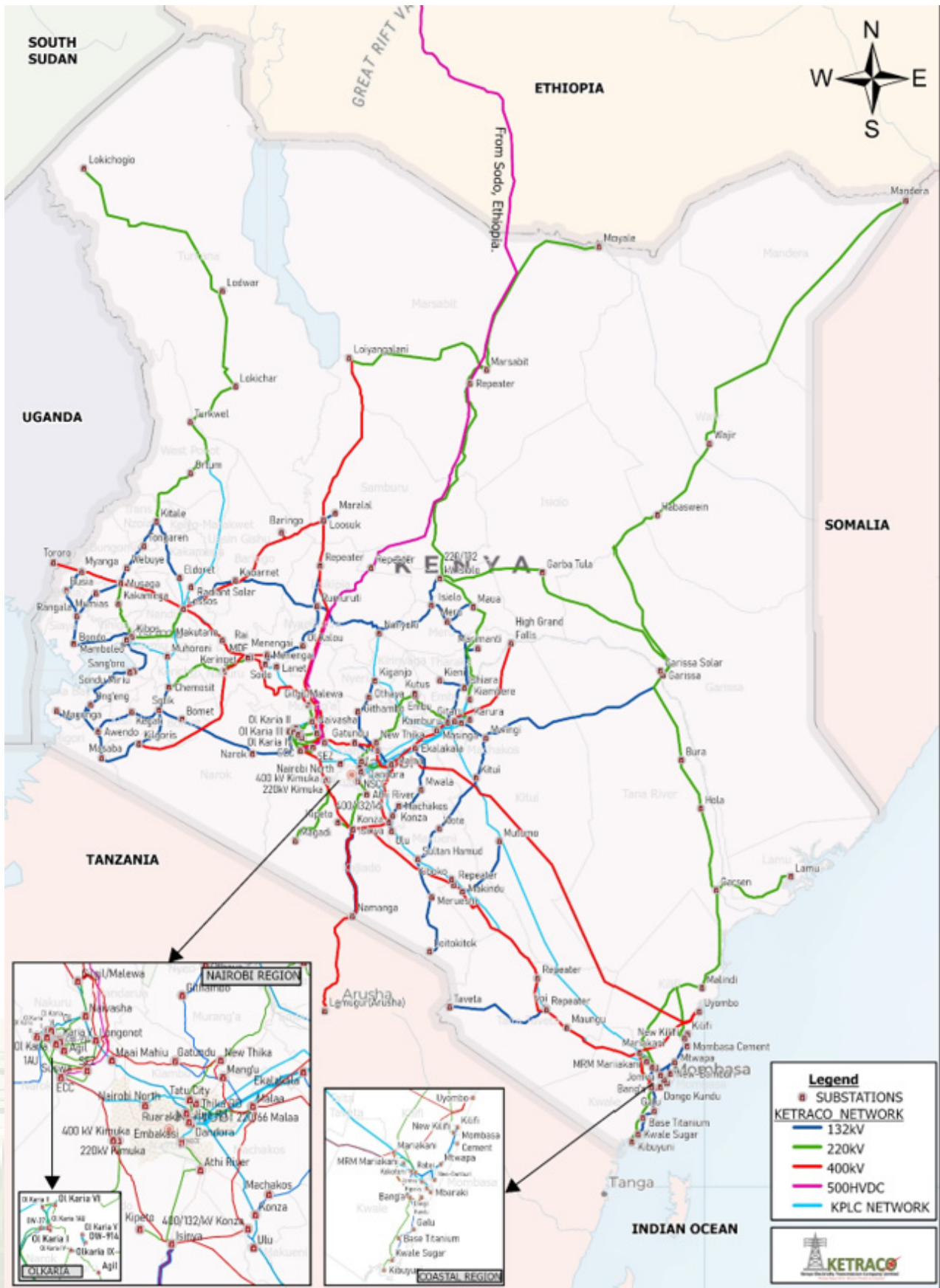
Current Transmission Network May 2026



2030 Projected Transmission Grid



2045 Projected Transmission Grid





Abbreviations & Acronyms

Abbreviations	Word
ACCC	Aluminium Conductor Composite Core
ACSR	Aluminium Conductor Steel Reinforced
ACSS	Aluminium Conductor Steel Supported
AI	Artificial Intelligence
APM	Asset Performance Management
BESS	Battery Energy Storage System
BETA	Bottom-Up Economic Transformation Agenda
BROP	Budget Review Outlook Paper
CIDP	County Integrated Development Plan
CIF	Climate Infrastructure Fund
CIM	Common Information Model
CMMS	Computerized Maintenance Management Systems
COD	Commercial Operation Date
COMFAR	Computer Model for Feasibility Analysis and Reporting
CS & GM LS	Company Secretary & General Manager Legal Services
CS MOE	Cabinet Secretary Ministry of Energy
DGE	Deemed Generated Energy
DOSH	Directorate of Occupational Health and Safety
DP	Development Partner
EAC	East African Community
EAPP	Eastern Africa Power Pool
EEHP	Eastern Electricity Highway Project
EHS	Environmental, Health & Safety
EMCA	Environmental Management and Coordination Act
EMS	Energy Management System
EMTDC	Electromagnetic Transients Direct Current
EPC	Engineering, Procurement & Construction
EPRA	Energy and Petroleum Regulatory Authority
ESIA	Environmental & Social Impact Assessment
FACTS	Flexible Alternating Current Transmission system
FIT	Feed in Tariff Policy
FOREX	Foreign Exchange
GCF	Green Climate Fund
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GEF	Grid Emission Factor
GIS	Gas Insulated Substation

GIS	Geographical Information Systems
GM D&C	General Manager, Design & Construction
GM F	General Manager Finance
GM HRAD	General Manager Human Resource and Administration
GM PDS	General Manager, Project Development Services
GM SO & PM	General Manager, System Operations & Power Management
GM SRC	General Manager, Strategy, Research & Compliance
GoK	Government of Kenya
GPOBA	Global Partnership on Output Based Aid
GT	Gas Turbine
GWh	Giga Watt hours
HFO	Heavy Fuel Oil
HTLS	High-Temperature Low-Sag
HVDC	High voltage direct current
ICNIRP	International Commission on Non
IEEE	Institute of Electrical & Electronics Engineers
ILIS	Integrated Location Intelligence Information System
INEP	Integrated National Energy Policy
IPP	Independent Power Producers
KenGen	Kenya Electricity Generating Company Limited
KESS	Kenya Electricity System Studies
KETRACO	Kenya Electricity Transmission Company Ltd
KLMCP	Kenya Last Mile Connectivity Program
KM	Kilometers
KPIs	Key Performance Indicators
KPLC	Kenya Power and Lighting Company Limited
kV	Kilo Volt
LCC	Line Commutated Converter
LCPDP	Least Cost Power Development Plan
LILO	Line In Line Out
LNG	Liquefied Natural Gas
LV	Low voltage
M KES	Million Kenya Shillings
MAED	Model for Analysis of Energy Demand
MEAL	Monitoring, Evaluation, Accountability and Learning
MECCF	Ministry of Environment, Climate Change, and Forestry
MoEP	Ministry of Energy and Petroleum
MOU	Memorandum of Understanding
MRV	Monitoring, reporting and verification
MSD	Medium Speed Diesel
MTEF	Medium Term Expenditure Framework
MTP	Medium Term Plan
MUSD	Million US Dollars
MV	Medium Voltage
MVA	Mega volt amp

NCCAP	National Climate Change Action Plan
NDC	Nationally Determined Contributions
NELSAP	Nile Equatorial Lakes Subsidiary Action Programme
NEMA	National Environmental Management Authority
NTEP	National Treasury and Economic Planning
ODPP	Office of Director of Public Prosecutions
PB	Parsons Brinckerhoff
PMU	Phasor Measurement Unit
PPA	Power Purchase Agreement
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PPRA	Public Procurement Regulatory Authority
PSCAD	Power System Computer Aided Design
PSSE	Power System Simulator for Engineering
PST	Phase Shifting Transformer
PST	Phase Shifting Transformers
RAP	Resettlement Action Plan
RAP	Resettlement Action Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPP	Southern Africa Power Pool
SCADA	Supervisory Control and Data acquisition
SDG	Sustainable Development Goals
SEA	Strategic Environmental Assessment
SIL	Surge Impedance Loading
SM IA	Senior Manager Internal Audit
SM SCM	Senior Manager Supply Chain Management
STATCOMS	Synchronous Static Compensators
SVCs	Static Var Compensators
tCO ₂ e	tonnes of carbon dioxide equivalent
TL	Transmission Line
TMP	Transmission Master Plan
ToC	Theory of Change
UNFCCC	United Nations Framework Convention on Climate Change
USD	United States Dollar
VRE	Variable Renewable Energy
VSC	Voltage Source Converter
WAMS	Wide Area Monitoring Systems
WHO	World Health Organization
ZTK	Zambia Tanzania Kenya



Glossary Of Terms

Term	Definition
Activities	The key actions undertaken to implement transmission projects e.g. securing financing, wayleave acquisition, engineering design and construction of transmission infrastructure.
Battery Energy Storage System (BESS)	A technology that uses rechargeable batteries to store electrical energy for later use. A BESS typically consists of multiple battery modules, a power conversion system (inverter), and sophisticated control software. It can absorb energy from the grid (charging) and discharge it back when needed.
Bay	A connection point to a busbar and comprising switchgear and measurement equipment.
Capacitor	An item of plant normally used on the electrical network to supply reactive power to loads (generally locally) and thereby support the local area voltage.
Captive Power	Electricity generation set up by a specific industrial or commercial entity (such as bagasse from sugar processing, or small hydropower from tea farms) primarily for its own use and consumption. It provides the user with energy independence, backup power, and a hedge against unreliable or expensive grid supply.
Circuit	A line or cable, including associated switchgear, which carries electrical power.
Circuit Breaker	A device used to open a circuit that is carrying electrical current.
Climate Change	It refers to long-term changes in the average state of the climate or its variability, typically measured over a period of 30 years or more. While climate change can result from natural processes, current changes are largely driven by human activities that increase greenhouse gas concentrations in the atmosphere.
Climate Change Adaptation	It is the process of adjusting natural or human systems in response to actual or expected climate change impacts in order to reduce harm or take advantage of potential opportunities.
Climate Change Mitigation	It refers to human interventions aimed at reducing greenhouse gas emissions or enhancing the removal of greenhouse gases from the atmosphere.

Climate Finance	It refers to local, national, or international financial resources mobilized from public, private, and alternative sources to support actions that address climate change, including mitigation of greenhouse gas emissions, adaptation to climate impacts, development of climate-resilient infrastructure, technology transfer, and capacity building.
Climate Infrastructure Fund	A multilateral climate fund established in 2008 to provide developing and middle-income countries with large-scale, concessional financing for climate change mitigation and adaptation. Its core purpose is to pilot innovative solutions, bridge financing gaps, and de-risk investments to unlock further funding from the private sector, governments, and other development partners. CIF works exclusively through six
Common Information Model	A standard data model used to represent electrical network components and their relationships in power systems, enabling consistent data exchange and interoperability between different power system applications.
Constraint	A change in the output of generators, scheduled in the market or not, due to transmission network limitations – specifically the overloading of transmission lines, cables and transformers.
Contingency	An unexpected failure or outage of a network component, such as a generation unit, transmission line, transformer or other electrical element.
Coupler	This is a device which can be used to either connect or disconnect sections of busbars. A coupler increases security of supply and flexibility under both fault and maintenance conditions. A coupler can also be known as a Sectionalising Circuit Breaker.
Demand	The amount of electrical power that is consumed by a customer and is measured in Megawatts (MW). In a general sense, the amount of power that must be transported from transmission network connected generation stations to meet all customers' electricity requirements.
Early Warning Systems	These are systems integrated monitoring, forecasting, risk assessment, and communication systems that provide timely information about potential hazards, enabling authorities and communities to take action to reduce risks and impacts.
Effective Capacity	The actual amount of power a plant can reliably produce under real-world conditions. It accounts for technical limitations, maintenance downtime, intermittent fuel supply (like sun or wind), and system losses, making it lower than the theoretical maximum (Installed Capacity). Also known as Firm Capacity.
Environmental Impact Assessment	This is a systematic a process used to identify, predict, and evaluate the environmental and social impacts of a proposed project before implementation and to recommend measures to mitigate adverse effects.

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1

INTRODUCTION AND BACKGROUND

The Transmission Master Plan (TMP) embeds inclusive stakeholder engagement and The establishment of KETRACO emanated from Sessional Paper No. 4 of 2004 and the subsequent enactment of the Energy Act of 2006. The company was incorporated in December 2008 under the Company Act Cap 486 as a state corporation wholly owned by the Government of Kenya.

The company was established to plan, design, construct, own, operate and maintain high voltage (132kV and above) electricity transmission grid and regional power interconnectors. This is aimed at increasing electricity access by expanding the transmission network, strengthening the national grid, protecting electricity consumers from high cost of power by absorbing capital cost of transmission infrastructure, evacuating generated power, and interconnecting with neighbouring countries. In addition, the Energy and Petroleum Regulatory Authority (EPRA) vide Kenya Gazette Notice No. 155 dated 21st December 2021, designated KETRACO as the System Operator (SO).

The transmission network developed by KETRACO serves multiple key objectives within the national and regional power system. These include enhancing electricity access; strengthening the national grid; evacuating renewable energy; and regional interconnection. The objectives of the TMP are anchored in Kenya's overarching development and energy policy architecture. The plan operationalizes the requirements of transmission infrastructure necessary to deliver the objectives of the Kenya Vision 2030, the Medium-Term Plans, and sector priority and strategic plans by ensuring timely provision of transmission capacity to support industrialization, universal access, and economic competitiveness. The plan harmonizes with the Integrated National Energy Planning Regulations which includes the Least Cost Power Development Plan (LCPDP), translating the projected demand growth and generation expansion pathways into optimised network investments. In addition, the plan supports the ambitions of the Kenya Energy Transition and Investment Plan and the National Energy Policy 2025-2034 by enabling large-scale integration of renewable energy, enhancing system flexibility, and promoting low-carbon development. Regionally, the plan underpins the role of Kenya within the Eastern Africa Power Pool (EAPP) by facilitating cross-border interconnections, strengthening trade corridors, and improving regional reliability and power market integration. Through this alignment,

the TMP ensures that transmission development remains policy-driven, economically justified, and responsive to both national priorities and regional opportunities.

Since inception, KETRACO has developed the transmission network from 50km in 2008 to 48 transmission lines of 6,248.5km circuit length and 69 high voltage substations and substation extensions with 6,978.2MVA of capacity as at February 2026. The rising electricity demand, the need for grid reinforcement, and expanding regional interconnection requires a long-term Transmission Master Plan to guide the implementation of grid development strategies.

The TMP 2026-2045 provides a rolling 20-year roadmap for prioritized transmission investments, financing options, and risk mitigation while supporting KETRACO's mandate. Anchored on national planning frameworks and LCPDP, the TMP will be reviewed, and if deemed necessary, updated annually to remain responsive to changes in demand, generation, technology, policy and emerging sector priorities and needs.

1.1. Objective of the Transmission Master Plan

The plan will guide the Company in:

- a. Aligning all the transmission investment requirements to electricity sub-sector priorities.
- b. Prioritization of the identified power transmission projects.
- c. Mobilizing/ sourcing for the financing of the identified projects and aligning with the budget process.

1.2. Scope of Work

The TMP covers the national transmission network at voltage levels of above 132kV for a 20-year planning horizon. The plan is designed as a living document, reviewed and updated periodically to reflect changes in demand, generation, policy, and technology.

The specific scope of work includes undertaking the following activities:

- i. Desktop review of the LCPDP 2024-2043 and the Medium Term LCPDP 2025-2029.
- ii. Updating forecasted demand and the generation expansion sequence over the planning period.
- iii. Updating planned transmission projects and those under implementation.
- iv. Identify investment requirements for the planning period.
- v. Preparing resilience and risk mitigation strategies, and a review of the pertinent legislative and compliance framework of the Transmission masterplan.

- vi. Identifying key emerging technologies in the power transmission realm.
- vii. Integrating sustainability and environmental considerations to the plan.
- viii. Integrating stakeholder engagement and public participation.
- ix. Institutionalizing a monitoring, evaluation, accountability and learning framework
- x. Prepare a 20-year Transmission Master Plan document.

1.3. Policy, legal and regulatory framework

In an increasingly complex and rapidly evolving regulatory landscape, organizations must navigate an intricate network of laws, regulations, and industry standards to ensure sustained compliance and operational integrity. KETRACO has established a comprehensive Regulatory and Compliance framework encompassing applicable Laws, Regulations, Policies, Procedures and Internal controls to guide its adherence to legal and sector-specific obligations while safeguarding the organization from compliance-related risks.

KETRACO remains unequivocally committed to upholding the highest standards of integrity, transparency, and accountability. By embedding compliance into our strategic and operational processes, KETRACO not only mitigates legal and regulatory risk but also reinforces the confidence of our stakeholders including government partners, regulators, development institutions, employees, and the public. Sustained regulatory compliance therefore serves as both a protective measure and a strategic enabler, positioning KETRACO to deliver its mandate efficiently, responsibly and with long-term credibility.

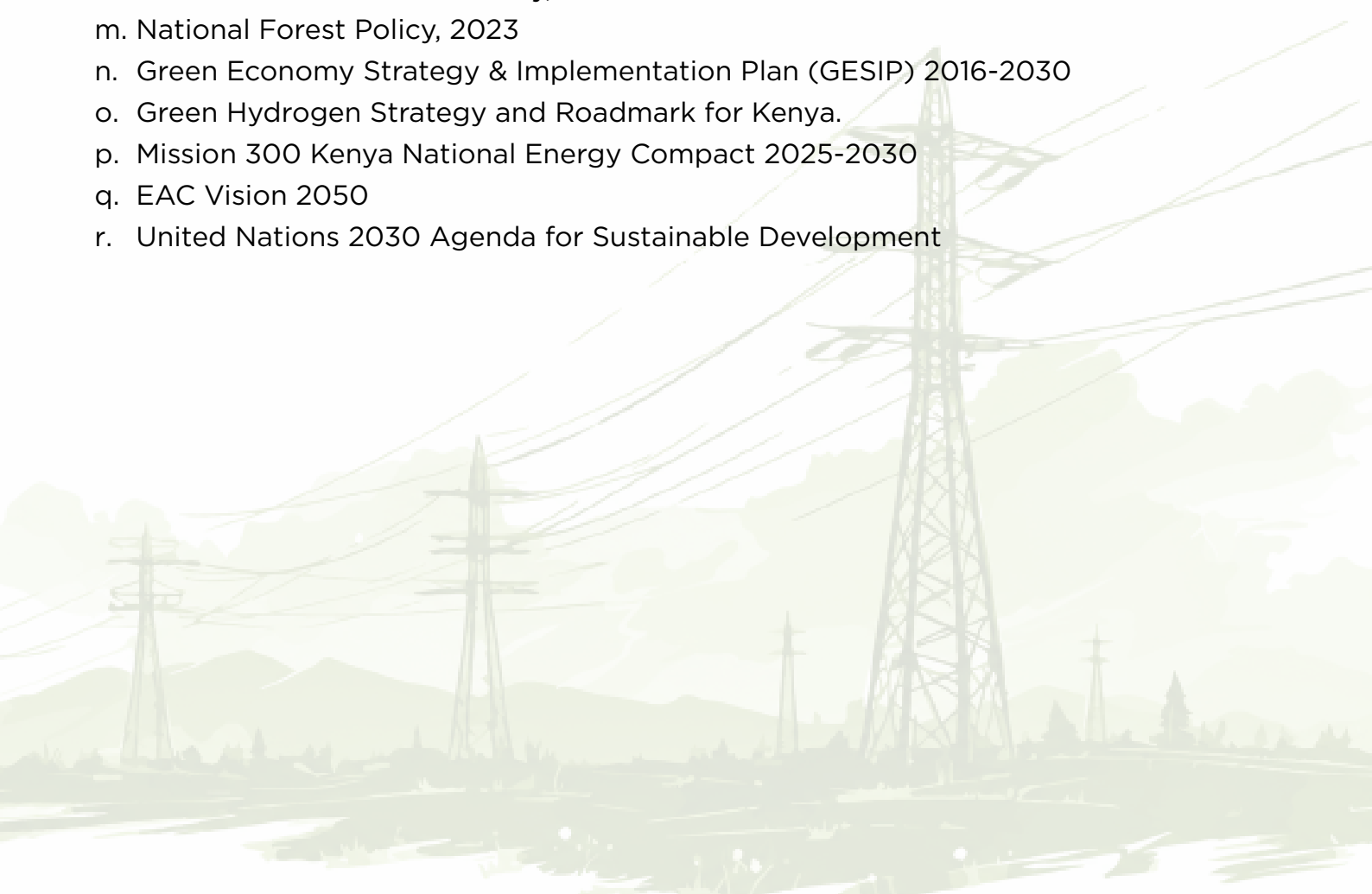
The legal instruments and institutional frameworks that will guide the implementation of this plan include but are not limited to:

- a. Kenya Constitution, 2010
- b. Energy Act, 2019
- c. Public Finance Management (PFM) Act, 2012
- d. Public Procurement and Asset Disposal Act, 2015
- e. Environmental Management and Coordination Act (EMCA), Cap 387
- f. Land Act, 2012
- g. Sustainable Waste Management Act, 2022
- h. Public Private Partnerships (PPP) Act, 2021
- i. National Land Commission Act, 2012
- j. County Government Act, 2012
- k. Data Protection Act, 2019

- l. Government Owned Enterprise Act, 2025
- m. National Infrastructure Fund Act, 2026
- n. Integrated National Energy Planning (INEP) Framework
- o. National and Regional Grid Codes
- p. Feed-in-Tariff Policy/Renewable Energy Auction Policy

Other Relevant Institutions and Policies include:

- a. Energy and Petroleum Regulatory Authority (EPRA)
- b. National Environmental Management Authority (NEMA)
- c. Public Procurement Regulatory Authority (PPRA)
- d. Communication Authority (CA)
- e. Directorate of Occupational Health and Safety (DOSH)
- f. Public Private Partnerships (PPP) Directorate
- g. Eastern Africa Power Pool (EAPP) Secretariat
- h. National Climate Change Action Plan (NCCAP) 2023–2027
- i. National Adaptation Plan (NAP)
- j. Clean Cooking Strategy (2024–2028)
- k. National E-Mobility Policy (2026)
- l. National Environmental Policy, 2013
- m. National Forest Policy, 2023
- n. Green Economy Strategy & Implementation Plan (GESIP) 2016-2030
- o. Green Hydrogen Strategy and Roadmap for Kenya.
- p. Mission 300 Kenya National Energy Compact 2025-2030
- q. EAC Vision 2050
- r. United Nations 2030 Agenda for Sustainable Development



2

CURRENT SITUATION OF THE POWER SECTOR

2.1. Electricity Demand & Access

In the last five years, Kenya has continued to experience a steady upward trajectory in electricity demand, with peak demand rising from 1,994 MW in the FY 2020/21 to 2,316 MW as of June 2025, a reflection of 16.18% increase. Notably, a new peak of 2,444 MW was recorded in January 2026 underscoring the sustainable growth of energy consumption. The trend in peak demand over the period 2020/21 to 2024/25 is illustrated in Figure 2.1 below:

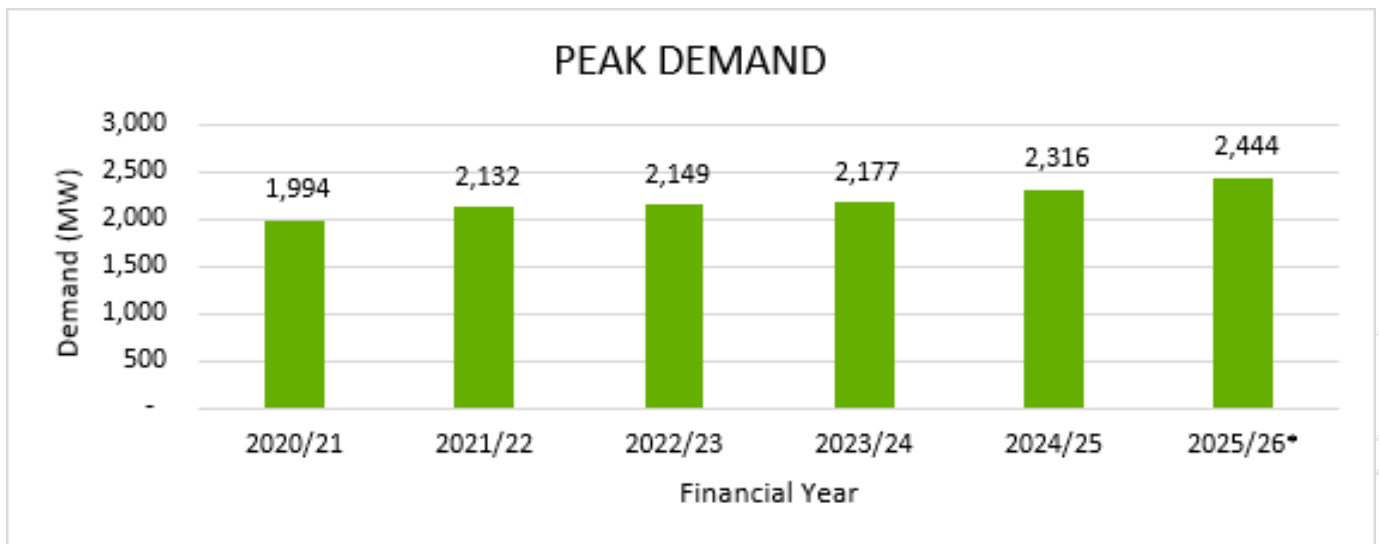


Figure 2 1: Historical Peak Demand (*Provisional peak demand for the financial year 2025/26)
Source: KPLC Annual report 2024/25

The annual surge in peak demand can be attributed to organic economic growth, industrial expansion, heightened investment, urbanization, and deliberate Government policies aimed at enhancing electricity access. Through the various Government-led initiatives like the Kenya Last Mile Connectivity Program (LMCP), that is aimed at achieving universal access by 2030, the number of consumers connected to the grid in the country increased significantly from 9,660,005 in the financial year 2022/23 to 10,045,978 in the financial year 2024/25, reflecting a 4.0% growth.

The total energy purchased increased from 13,684 GWh in the financial year 2023/24 to 14,472GWh in the financial year 2024/25, a 5.76% growth. Trends in energy purchased from different technologies are highlighted in Table 2 1 below and Figure 2 2.

Technology Type	2020/21	2021/22	2022/23	2023/24	2024/25
Hydro	4,141	3,349	2,569	3,396	3,503
Geothermal	5,034	4,953	6,035	5,708	5,718
Thermal	940	1,648	1,396	1,127	1,336
Cogeneration	0.33	0.38	0.21	0.11	0.00
Solar	88	313	444	474	473
Wind	1,700	2,052	2,202	1,781	1,908
Imports	197	338	644	1,199	1,534
Total	12,101	12,653	13,290	13,684	14,472

Source: KPLC Annual report 2024/25

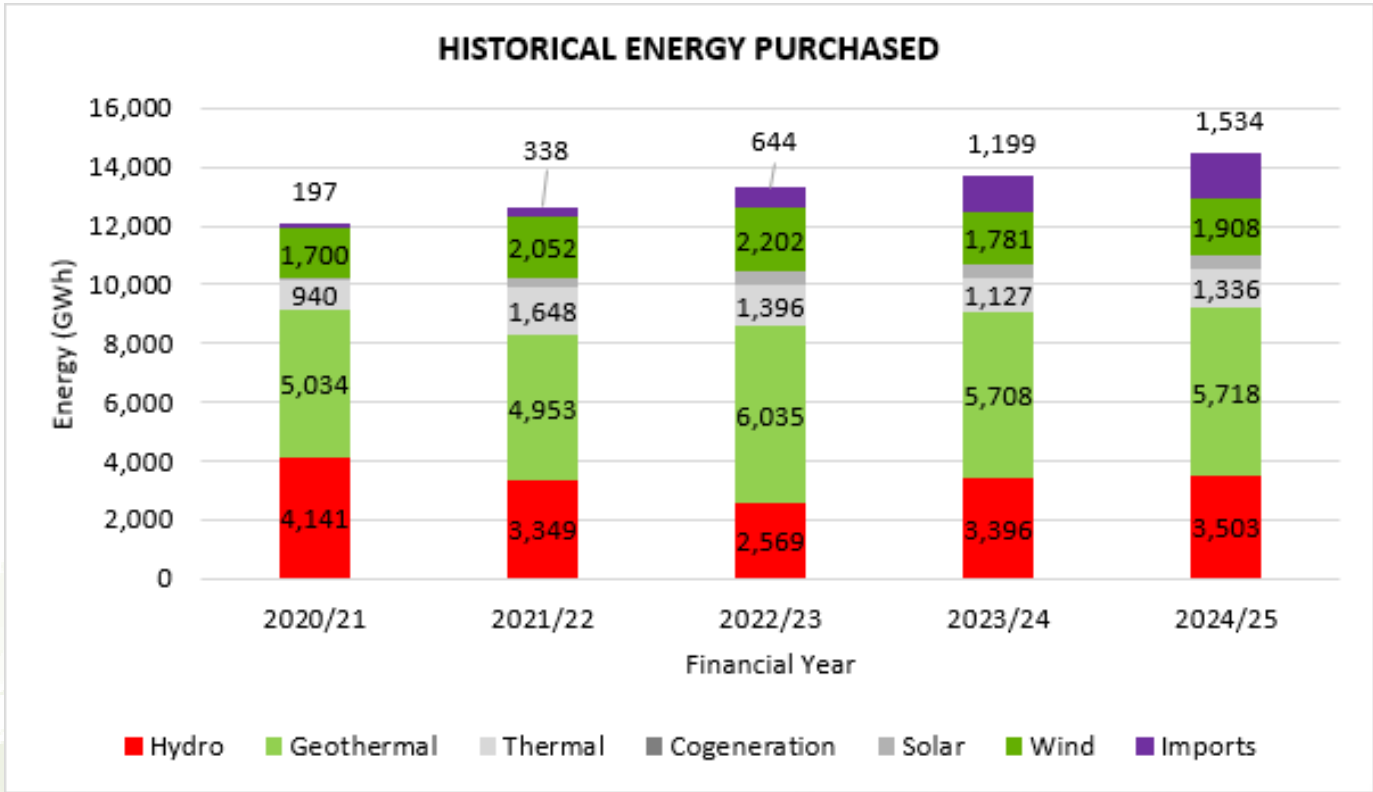


Figure 2 2: Historical Energy Purchased in GWh

In the financial year 2024/25, electricity consumption grew from 10,516GWh in 2023/24 to 11,403GWh, marking an 8.3%% rise. Figure 2 3 illustrates the trend in total electricity consumption over the five-year period.

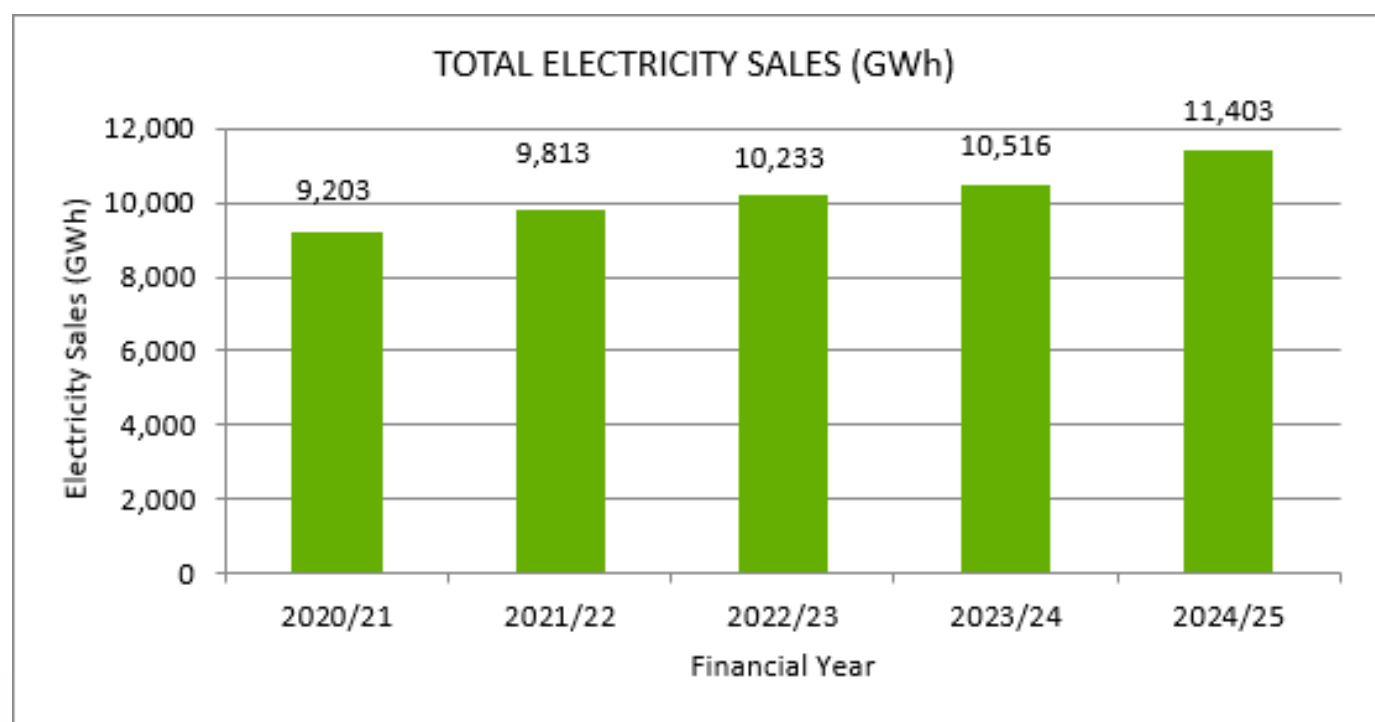


Figure 2 3: Electricity Sales (GWh)
Source: KPLC Annual report 2024/25

2.2. Electricity Generation

Kenya’s total installed capacity (including off grid) as of June 2025 stood at 3,236 MW while the grid installed capacity was 3,192 MW. The cumulative effective/contracted capacity stood at 3,108 for the same period. Table 2 2 shows the installed and effective capacity by technology type as of June 2025. Figure 2 4 and Figure 2 5 show the effective capacity by Source and the Installed and Effective Capacity by Technology as of June 2025 respectively.

Table 2 1: Historical Energy Purchased in GWh

Technology	Installed MW	Effective MW	Installed %	Effective %
Hydro	839.50	809.70	25.94%	26.05%
Geothermal	940.00	876.10	29.05%	28.19%
Thermal (MSD)	512.80	506.40	15.85%	16.29%
Thermal (GT)	52.00	52.00	1.61%	1.67%
Wind	435.50	425.50	13.46%	13.69%
Biomass	2.00	2.00	0.06%	0.06%
Solar	210.30	210.30	6.50%	6.77%
Import	200.00	200.00	6.18%	6.44%
Interconnected System	3,192.10	3,082.00	98.6%	99.2%
Off grid thermal	41.00	24.15	1.27%	0.78%
Off-grid Solar	0.60	-	0.02%	0.00%
Off-grid Wind	2.30	1.65	0.07%	0.05%
Total Off grid	43.90	25.81	1.36%	0.83%
TOTAL CAPACITY MW	3,236	3,108	100.00%	100.00%

Source: KPLC Annual Report 2024/25

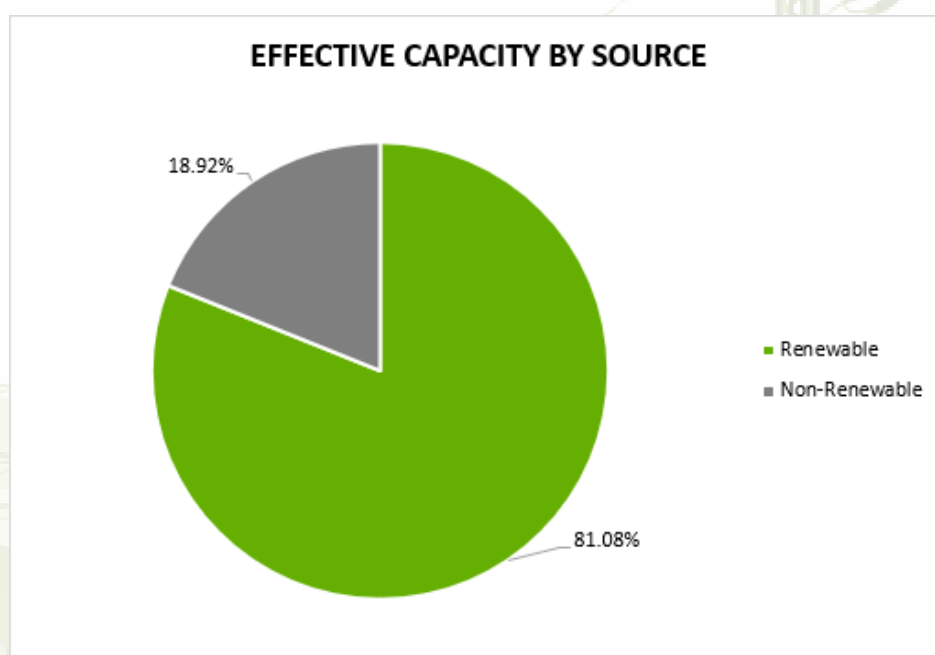


Figure 2 4: Effective Capacity by Source

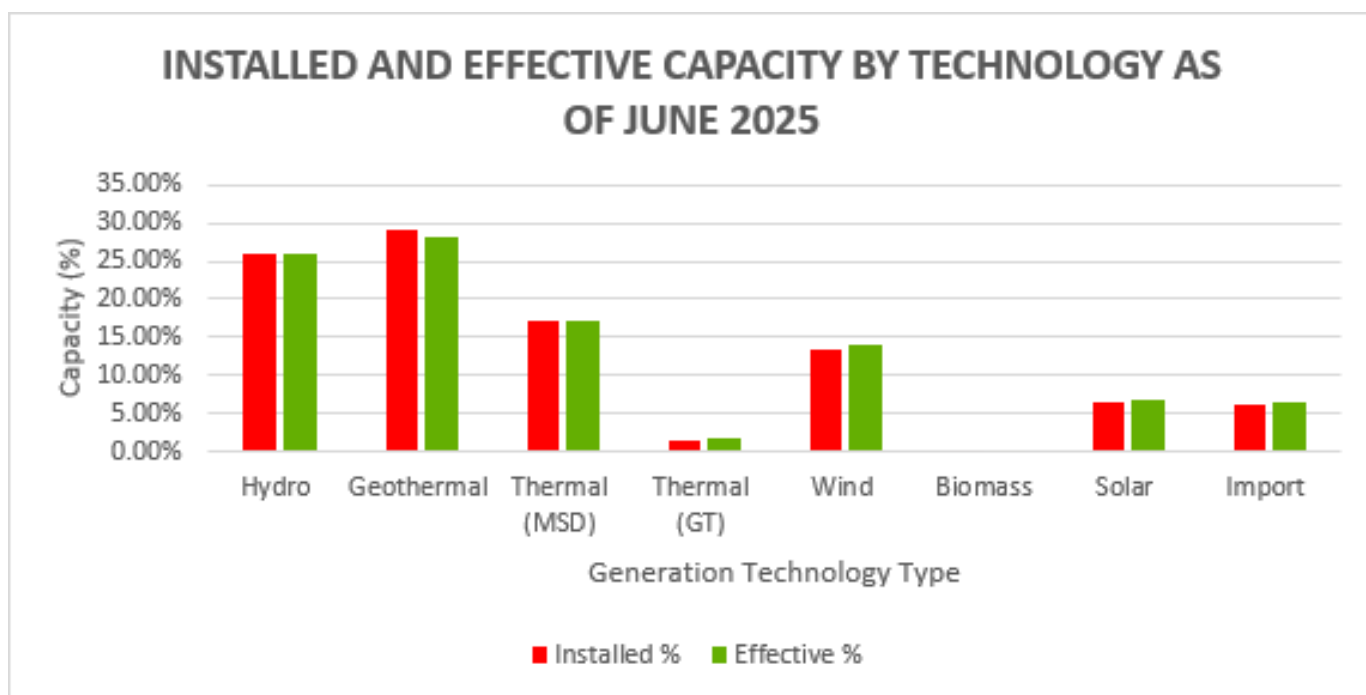


Figure 2 5: Installed and Effective Capacity by Technology as of June 2025

The Energy generation mix for the financial year ending June 2025 is 91% renewable energy, comprising of 39.5% of geothermal, 24.12% hydro, 9.23% fossil fuels, 13.18% wind, 3.27% solar and 8.76% imports. The evolution of the energy mix is given in Figure 2 6.

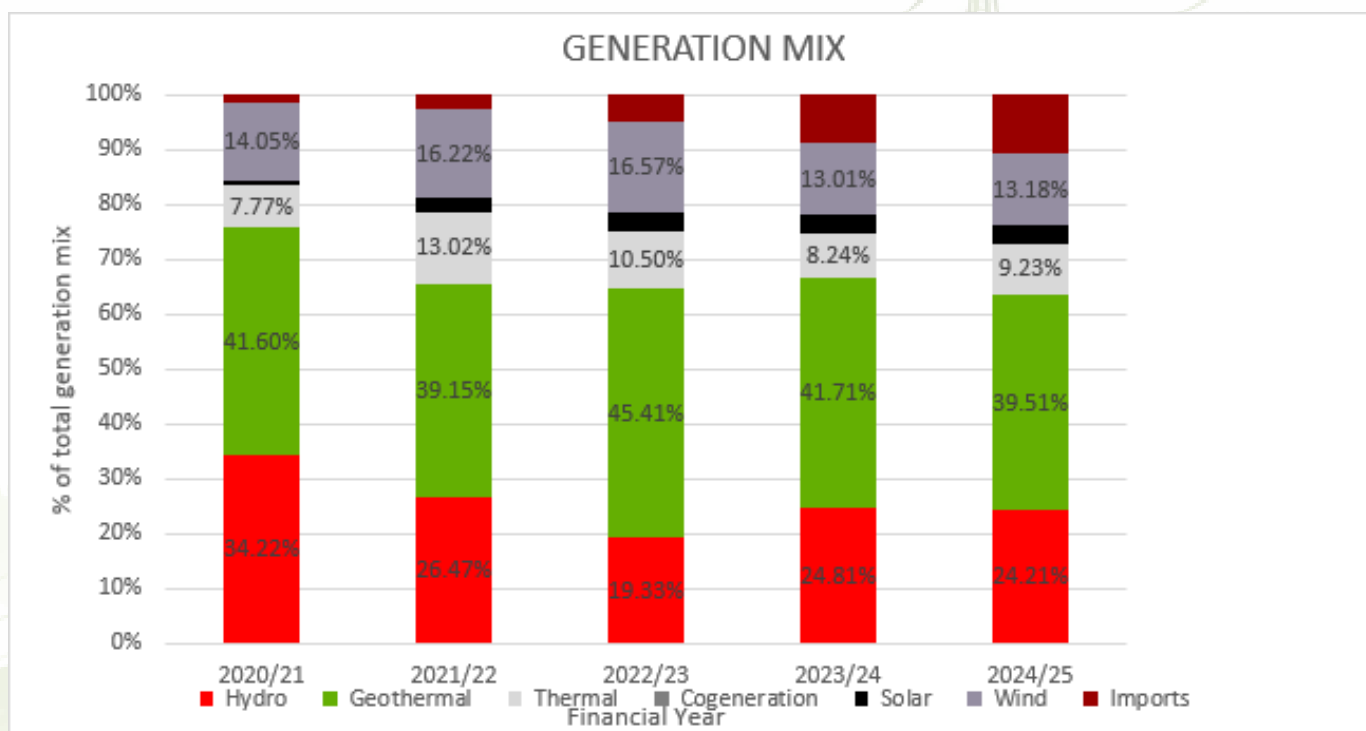


Figure 2 6: Historical Generation mix.
Source: KPLC Annual Report 2024/25

The distribution of power generators is as shown in Table 2 3.

Table 2 3: Distribution of power generators

Company	Installed	Effective/Contracted	% Installed	% Effective
KenGen	1,779	1,680	54.98%	54.05%
Off grid	44	26	1.36%	0.84%
IPP	1,163	1,152	35.94%	37.07%
REREC	50	50	1.55%	1.61%
Imports	200	200	6.18%	6.44%
TOTAL	3236	3,108	100.00%	100.00%

Figure 2 5: Installed and Effective Capacity by Technology as of June 2025

Additionally, Captive power generation as approved by EPRA have an installed capacity of 603.8 MW that use hydro, geothermal thermal, solar, bioenergy, and Waste Heat Recovery Cycle (WHRC) technology according to EPRA Energy and Petroleum Statistics Report FY 2024/25.

2.3. Transmission Network

As of March 2026, the power transmission network is operating at 132kV, 220kV, 400kV & 500kV DC. As of February 2026, the size of transmission network by circuit length is 9,717 km of which 6,248(64.30%) is owned and operated by KETRACO. This includes 1,542km of 132kV lines, 797km of 220kV lines, 2,627km of 400kV and 1,282km of 500kV lines. In addition, KETRACO has completed and commissioned 48 new substations with 6,978 MVA capacity and 30 bay extensions. Table 2 4 provides a list of KETRACO completed projects since inception while Figure 2 7 should the growth in completed transmission lines over the years.

Table 2 4: KETRACO Completed Projects as at February 2026

TRANSMISSION LINES				SUBSTATIONS			Date Completed
S. No	Name	Route Length (KM)	Circuit Length (KM)	S. No	Name	Transformation Capacity (MVA)	
1	Sonde - Kisumu (Mamboleo) 132kV	50	50	1	Sonde 132/33kV 1x23MVA	23	Jul-07
				2	Kisumu (Mamboleo) 132kV Bay Extension		
2	Chemosit - Kisii (Kegati) 132kV	62	62	3	Kisii (Kegati) 132/33kV 2x23MVA	46	Mar-10
				4	Chemosit 132kV Bay Extension		
3	Rabai-Galu 132kV	48	48	5	Galu 132/33kV 2x23MVA	46	Mar-10
				6	Rabai 132kV Bay Extension		
4	Kamburu-Meru 132 kV	122	122	7	Meru 132/33kV 2x23MVA	46	Sept-10
				8	Kamburu 132kV Bay Extension		
5	Sangoro- Sondu 132kV	5	5	9	Sangoro 132kV		Jun-12
6	Mumias-Rangala 132kV	34	34	10	Rang'ala 132/33kV 2x23MVA	46	Jun-12
				11	Mumias 132kV Bay Extension		
7	Kilimambogo-Mang'u 132kV	19	38	12	Mang'u 132/66kV 2x60MVA	120	Mar-13
8	Mang'u -Githambo 132kV	58	58	13	Githambo 132/33kV 1x23MVA	23	
9	Thika (Mang'u)-Gatundu 132kV	30	30	14	Gatundu 132/33kV 1x23MVA	23	Jun-13
10	Rabai-Malindi 220kV	128	128	15	Malindi (Kakuyuni) 220/33kV 1x23MVA	23	
				16	Rabai 220kV Bay Extension		Jun-13
11	Malindi-Garsen 220kV	104	104	17	Garsen 220/33kV 1x23MVA	23	
12	Garsen-Lamu 220kV	96	96	18	Lamu (Hindi) 132/33kV 1x23MVA	23	Jun-13
13	Meru-Isiolo 132kV	26	26	19	Isiolo 132/33kV 1x23MVA	23	Sept-15
				20	Meru 132kV Bay Extension		
14	Kindaruma-Mwingi 132kV	29	29	21	Mwingi 132/33kV 1x23MVA	23	May-16
				22	Kindaruma 132kV Bay Extension		
15	Mwingi-Garissa 132kV	204	204	23	Garissa 132/33kV 1x7.5MVA	7.5	May-16
				24	Garissa 132/11kV 1x7.5MVA	7.5	
16	Eldoret-Kitale 132kV	66	66	25	Kitale 132/33kV 2x23MVA	46	Jun-16
				26	Eldoret 132kV Bay Extension		
17	Suswa -Olkaria 1AU 220kV	25	51	27	Olkaria 1 AU 220/132kV 1x105MVA	105	Jun-16
18	Suswa- Olkaria IV 220kV	18	37	28	Suswa 220kV		Jun-16
19	Olkaria II- Olkaria 1AU 220kV	3	6	29	Olkaria IV 220kV		Aug-16
				30	Olkaria II 220kV Bay Extension		
20	Sotik-Bomet 132kV	26	26	31	Sotik 132kV		Aug-16
				32	Bomet 132/33kV 1x23MVA	23	
21	Machakos-Konza 132kV	13	13	33	Konza 132/33 kV 1x23MVA	23	Nov-16
				34	Machakos 132/33 kV 1x23MVA	23	
22	Ishiara - Kieni 132kV	33	33	35	Ishiara 132kV		Dec-16
				36	Kieni 132/33kV 1x23MVA	23	
23	Menengai-Soilo 132kV	13	13	37	Menengai 132kV		Dec-16
				38	Soilo 132kV Bay Extension		
24	Suswa-Isinya 400kV	103	206	39	Isinya 400/220 kV 4x200MVA	800	Jun-17
				40	Isinya 220/132 kV 1x110MVA	110	
				41	Isinya 132/33 kV 1x23MVA	23	
25	Athi river-Isinya 400kV	44	88	42	Rabai 220kV Bay Extension		Jun-17
26	Isinya-Mariakani 400kV	404	807				
27	Mariakani-Rabai 220kV	24	48				
28	Kisii (Kegati)-Awendo 132kV	44	44	43	Awendo 132/33kV 2x23MVA	46	Dec-17
				44	Kisii (Kegati) 132kV Bay Extension		
29	Awendo-Ong'eng 132kV	37	37	45	Ong'eng 132/33kV 1x23MVA	23	May-18
				46	Awendo 132kV Bay Extension		
30	Loiyangalani-Suswa 400kV	436	871	47	Loiyangalani 33/400kV		Aug-18
31	Embakasi-Athi River (Cable section repairs circuit I) 220kV	7	14	48	Embakasi 220kV Bay Extension		Dec-18
32	Embakasi-Athi River (Overhead section) 220kV	12	23				
33	Wote – Sultan Hamud 132kV	42	42	49	Wote 132/33kV 1x23MVA	23	Feb-19

TRANSMISSION LINES				SUBSTATIONS			Date Completed
S. No	Name	Route Length (KM)	Circuit Length (KM)	S. No	Name	Transformation Capacity (MVA)	
				50	Sultan Hamud 132/33 kV 1x23MVA	23	
34	Olkaria IV –Olkaria V 220kV	2	3	51	Olkaria V 220kV		Nov-19
35	Mwingi-Kitui 132kV	46	46	52	Kitui 132/33 kV 1x23MVA	23	Sept-20
				53	Nairobi North Bay Ext. 220/66kV 1x90MVA	90	Oct-20
36	Olkaria-Lessos-Kisumu 400/220/132kV	309	618	54	Kibos 220/132/33 1x150MVA, 2x 45MVA	240	Jun-21
				55	Olkaria II 220kV Bay Extension (Two Bays)		
				56	Kisumu (Mamboleo) 132kV Bay Extension (Two Bays)		
37	Olkaria- Narok 132kV	68	68	57	Narok 132/33 1x23MVA	23	Jul-22
				58	Athi River 220kV/66kV 2x200MVA	400	Oct-22
38	Ethiopia-Kenya Interconnector 500kV HVDC (from Suswa to Border)	641	1,282	59	Suswa 500/400kV 4x588.3MVA (196.1/Ph)	2353.2	Nov-22
				60	Suswa 400/220kV 3x350MVA (117/Ph)	1050	
39	Turkwel - Ortum 220kV	68	68	61	Ortum 220/33kV 1x23MVA	23	Dec-23
				62	Turkwel 220kV Bay Extension (One bay)		
40	Isinya (Kajiado) – Namanga 132kV	94	94	63	Namanga 132/33kV 1x23MVA	23	Feb-24
41	Ortum – Kitale 220kV	78	78	64	Kitale 220/132kV 1x90MVA	90	Sept-24
42	Sultan Hamud – Merueshi-Loitoktok 132kV	107.5	107.5	65	Loitoktok 132/33kV 1x23MVA	23	Oct-24
43	Kenya – Tanzania Interconnector 400kV	96	192				Dec-24
44	Kimuka LILLO 220kV	2	4	66	Kimuka 220kV/66kV 2x200MVA	400	Mar-24
45	Awendo- Masaba 132kV	29	29	67	Masaba 132/33kV 1x23MVA	23	Jun-25
				68	Mariakani 400/220kV 2x200MVA	400	Dec-25
46	Lessos – Kabarnet 132kV	65	65	69	Kabarnet 132/33kV 1x23MVA	23	Dec-25
47	Kitui – Wote 132kV	66	66				Jan-26
48	Sondu (Thuridibuoro) – Ongeng (Homa Bay/Ndhiwa) 132kV	69	69				Mar-26
TOTAL		4,105.50	6,248.50			6978.2	

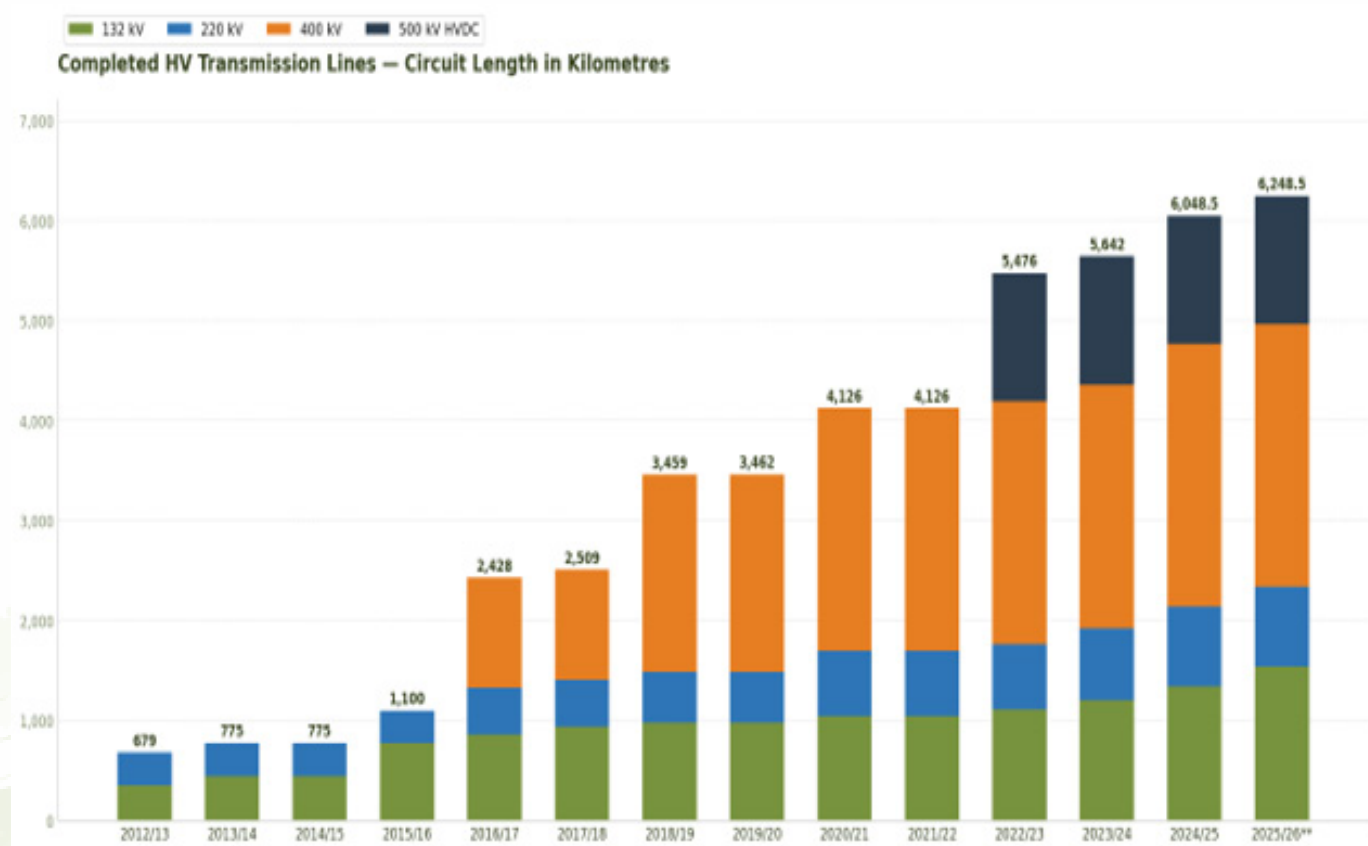


Figure 2 7: Completed Transmission Lines over the years.

The completed transmission lines have realized a range of desired objectives, ranging from power evacuation and supplying new load centres, connecting regions that initially were not connected to the grid, regional interconnection, reinforcing/ strengthening the existing transmission network for increased system reliability and transmission efficiency. The transmission network maintained a high level of operational reliability, with average availability recorded at approximately 99.9%.

KETRACO is currently developing additional transmission projects consisting of power evacuation projects, grid strengthening and regional interconnectors. The projects are at various stages of completion. Table 2 5 presents the on-going projects currently under implementation.

Table 2 5: KETRACO Ongoing Projects

S/n	Transmission Line Name	Length (km)	Circuit Length (km)	MVA/ Circuit	S/n	Substation Name	MVA	Estimated Total Cost (MUSD)	Outstanding Project Cost (MUSD)	With Financing	Without Financing	Financier
YEAR 2026												
					1	Malaa 220/66kV 2x200MVA	400	17.35	1.20	1.20		EIB, AFD, AFDB
1	Isinya-Konza 400KV	45	90	1600	2	Konza 400/132kV 2x350MVA	700	61.43	0.30	0.30		EXIM China, GOK
2	Rabai-Kilifi 132kV (with inter link to existing 132/33kV SS)	67	67	97	3	Kilifi 132/33kV 2x45MVA (new Site)	90	30.15	0.12	0.12		Gov of Spain
3	Rabai-Bamburi-Msa Cem-Vipingo- Kilifi 132kV	76	76	97								
4	Nanyuki – Isiolo 132kV	70	70	97				50.96	2.30	2.30		GOK
5	Nanyuki – Rumuruti 132kV 14.5 km Underground cable	14.5	29	100				17.82	3.60	3.60		African Development Bank, GoK
6	Nanyuki – Isiolo 132kV Underground cable	5	5	100								
7	Nanyuki – Rumuruti 132kV	79	79	97	4	Rumuruti 132/33kV 23MVA	23	41.23	0.95	0.95		African Development Bank, GoK
					5	Lessos Tx 3 220/132kV 75MVA	75	Cost borne by KPLC				
TOTALS 2026		356.5	416	2188			1,288.00	218.94	8.47	8.47	-	
YEAR 2027												
1	Narok – Bomet 132kV	88	176	97	1	Bomet 132/33kV 23MVA	23	27.07	10.86	10.86		GoK, AfDB
					2	Narok 132/33kV 23 MVA	23					
					3	Bomani 132/33kV 23MVA	23	Cost borne by KPLC				
					4	Kibos 20MVA reactor	20	Cost borne by KETRACO O&M				
TOTALS 2027		88	176	97			89.00	27.07	10.86	10.86	-	

S/n	Transmission Line Name	Length (km)	Circuit Length (km)	MVA/ Circuit	S/n	Substation Name	MVA	Estimated Total Cost (MUSD)	Outstanding Project Cost (MUSD)	With Financing	Without Financing	Financier
YEAR 2028												
1	Mariakani – Dongo Kundu 220kV Line	55	110	400	1	Dongo Kundu 220/33kV 2x75MVA	150	53.03	41.60	41.60		JICA& GoK
2	Garsen -Hola –Bura-Garissa 220kV	240	240	236.6	2	Bura 220/33kV 1x23MVA	23	94.99	52.34		52.34	EXIM China 'No finance'
					3	Hola 220/33kV 1x23MVA	23					
					4	Garissa 220/132kV 1x60MVA	60					
3	Makindu substation LILO - 400kV	1	4	1400	5	Makindu 400/132kV 2x90MVA	180	55.37	55.37	11.64	43.73	GoK, AFD
4	Makindu substation LILO - 132kV	1	4	97								
5	Rumuruti – Kabarnet 132kV	111	111	97	6	Rumuruti Tx2 132/33kV 1x23MVA	23	31.68	31.68	31.68		GoK, AfDB
					7	Kabarnet Tx2 132/33kV 1x23MVA	23					
6	Malindi – Kilifi 220kV	48.5	97	324	8	Kilifi 220/132kV 2x90MVA	180	82.80	82.80	82.80		GoK, AfDB
					9	Malindi 220/33kV 1x45MVA uprating	45					GoK, AfDB
					10	Olkaria I 11/132kV 1x25MVA (Unit 1and 2)	Cost to be borne by KenGen					
					11	Olkaria I 11/132kV 1x25MVA (Unit 3)						
7	Associated LILO for 132/33kV Maai Mahiu substation				12	Maai Mahiu 132/66kV 2x60MVA	120	12.06	12.06		12.06	EXIM China ' finance expired'
8	Olkaria 1 AU-Olkaria IV /V 220KV	8	16	324				14.76	14.76		14.76	No finance
					13	STATCOMs (Coast, Nairobi). Suswa 120MVA, 2x100MVA STATCOM/DR PC)	Suswa STATCOM 120, MSR 2x100MVA r	100.00	100.00	100.00		GoK, WB
9	400kV Kimuka - LILO on Suswa– isinya 400kV	2	4	1600	14	Kimuka 400/220kV 2x200MVA	400	28.59	9.96	9.96		GoK, WB
TOTALS 2028		466.5	586	4478.6	14		1,227.00	473.28	400.57	277.68	122.89	
YEAR 2029												
1	Loiyangalani – Marsabit 220kV	136	272	324	1	Loiyangalani 400/220 2x200MVA	400	126.81	122.46		122.46	EXIM China ' finance expired'
2	Kamburu-Embu 220KV	150	300	324	2	Embu 220/132 2x90MVA	180	40.50	17.25		17.25	EXIM China ' finance expired'
3	Isiolo - Marsabit 220kV	240	480	324	3	Marsabit 220/33kV 2x23MVA	46	127.72	120.63		120.63	EXIM China ' finance expired'
					4	Isiolo 220/132kV 1x90MVA	90		-		-	
4	National System Control Centre							94.62	53.08	53.08		GoK, AFD
TOTALS 2029		526	1052	972			716.00	389.65	313.42	53.08	260.34	
GRAND TOTAL		1437	2230	7735.6			3,320.00	1,108.94	733.31	350.08	383.23	

2.4. Distribution Network

The distribution network consists of Medium Voltage (MV) lines of 66kV, 33kV, and 11kV and low voltage (LV) lines of 415/240V and 433/250V. The circuit length of the MV network has grown from 79,310km in June 2021 to 88,548km by June 2025, representing a 10% increase. This includes 1,457km of 66kV lines, 41,029km of 33kV lines, and 46,062km of 11kV lines. The circuit length of the LV lines has grown from 168,595km in June 2021 to 234,120km by June 2025, representing a 28% increase. The total installed capacity of transformers in distribution substations grew from 8,778MVA in June 2021 to 10,786MVA in June 2025, representing an 8% increase.

The System Average Interruption Duration Index (SAIDI) improved from 120 hours in June 2024 to 113 hours by June 2025, while the System Average Interruption Frequency Index (SAIFI) improved from 47.5 in June 2024 to 44.07 in June 2025.

2.5. System Losses

The system losses, which include both technical and non-technical losses, reduced from 23.16% in June 2024 to 21.21% in June 2025 as indicated in Table 2 6. These losses were in part caused by constraints in the grid due to aging equipment, theft and vandalism of electricity infrastructure, distribution capacity limitations, inadequate supply of meters, faulty metering, and reduced reliability in power supply due to under-investment.

Table 2 5: KETRACO Ongoing Projects

	2020/21	2021/22	2022/23	2023/24	2024/25
Generation	12,100.87	12,652.55	13,289.75	13,684.36	14,472.00
Consumption	9,202.82	9,813.33	10,232.94	10,515.72	11,402.57
Losses	2,898.05	2,839.23	3,056.81	3,168.64	3,069.43
Losses Percentage	23.9%	22.4%	23.0%	23.2%	21.2%

Source: KPLC Annual report 2024/25

2.6. Distribution Network

2.6.1. Existing System Constraints and Challenges

Despite the significant transmission network reinforcements and expansion initiatives undertaken by Kenya Electricity Transmission Company Limited (KETRACO) over the years, the national grid continues to face several operational and structural challenges that affect system reliability, power quality, and the network's ability to accommodate growing electricity demand and increasing penetration of renewable energy sources.

These challenges are driven by evolving power flow patterns, increased integration of variable renewable energy, regional generation imbalances, and historical underinvestment in certain transmission corridors. Operational analyses such as the System Operations Daily Analysis (SODA) indicate increasing occurrences of voltage and frequency deviations, transmission congestion, and operational constraints that require targeted technical interventions.

The key operational and infrastructure challenges affecting the transmission system are summarized in Table 2 7

Table 2 7: Summary of Existing Transmission Line Challenges

System Challenge	Primary Causes	System Impact	Strategic Mitigation Measures	Key Projects addressing Challenge
Voltage instability and power quality issues	Long transmission distances; reactive power imbalance; low off-peak loading; intermittent renewables; overloaded network sections	Over/under voltages, increased losses, reduced power quality, instability risk	Reactive compensation (STATCOMs, SVCs, Capacitor banks, Reactors); BESS deployment; Line reinforcement and planned segmentation of long transmission lines; Improved voltage control.	STATCOMs at Suswa (120 MVar) and Coast/Nairobi (2x100 MVar); 20 Mvar Reactor at Kibos substation; Mobile 220kV reactor 1x20MVar and 132kV reactor 1x20MVar; BESS projects (Embakasi, Lessos, Kegati, Rabai); Loosuk 400kV switchyard, Gilgil-Thika-Malaa-Konza on Suswa-Loiyangalani TL; Makindu 400kV LILO and Voi 400/132kV for Isinya-Mariakani and Mutomo 220kV LILO for Rabai-Kiambere.

System Challenge	Primary Causes	System Impact	Strategic Mitigation Measures	Key Projects addressing Challenge
Transmission congestion and generation curtailment	Insufficient transmission capacity; weak regional infrastructure; growing renewable evacuation needs	Generation curtailment, inefficient asset utilization, reliability risks	Accelerated project completion of priority lines; Infrastructure uprating; Phase-shifting transformers; Improved power flow management	Narok-Bomet 132kV (ongoing); Nanyuki-Rumuruti & Nanyuki-Isiolo 132kV; Rabai-Bamburi-Mombasa Cement-Vipingo-Kilifi 132kV; Phase Shifting Transformers at Suswa; Reconductoring of KPTSIP second circuits
Renewable integration challenges	High variable renewable penetration without flexibility or reactive support	Frequency/voltage fluctuations, instability risks	Grid code enhancements; Forecasting tools; BESS deployment; WAMS/PMU rollout; operator training; reactive compensation; Increase of spinning reserves.	BESS_1 (Embakasi 100MW), BESS_2 (Lessos 100MW), BESS_3 (Kegati 50MW); PMU installation on interconnectors and backbone substations; National System Control Centre (NSCC) upgrade; STATCOMs (as above)
Regional imbalance in generation and transmission	Limited regional generation (Coast and West Kenya); Inadequate system redundancy (N-1)	Voltage instability, Outage risks, Constrained regional growth	Regional generation development; corridor reinforcement; Reactive compensation; Interconnection expansion	Lessos-Loosuk 400kV; Kisumu (Kibos)-Kakamega-Musaga 220kV; Kibos-Bondo-Rangala-Busia-Myanga 132kV; Mariakani-Dongo Kundu 220kV; Rabai-Kilifi 132kV
Insufficient transformation and evacuation capacity	Load growth; renewable expansion; historical underinvestment; high costs	Substation overloading; constrained electricity access; localized blackouts	Substation upgrades and new transformers; New transmission lines; Improved investment planning; Electrification alignment	Garissa 220/132kV 1x110MVA (second transformer); Ortum 220/33kV 45MVA addition; Rongai 400/220kV 2x200MVA; Soilo 132/33kV uprating; Lessos 132/33kV uprating; Malaa 220/66kV 2x200MVA (ongoing)

System Challenge	Primary Causes	System Impact	Strategic Mitigation Measures	Key Projects addressing Challenge
Inadequate system security and resilience	Limited redundancy; incomplete network meshing	Higher outage risk during contingencies; cascading failures	Completion of network loops; Backbone expansion; Contingency planning; Bi-polar HVDC operation	Olkaria IV/V–Olkaria I AU 220kV; 220kV Nairobi Ring (Malaa substation); 400kV Gilgil–Thika–Malaa–Konza ring; Narok–Bomet, Kabarnet–Rumuruti, Kitui–Wote loops; Lessos–Loosuk 400kV; HVDC Ethiopia–Kenya bi-polar mode completion
Infrastructure security risks	Vandalism, theft, external threats	Equipment damage, outages, increased maintenance costs	Infrastructure protection programs; security agency coordination; community engagement; emergency restoration capability	Emergency Restoration System (ERS) stocking of mobile substations and towers; Community sensitization programs (integrated into stakeholder engagement framework); Coordination with CIPU and Energy Police Unit (operational, not a project)
Metering and asset visibility deficiencies	Non-standard meters; incompatible equipment; calibration gaps	Poor energy accounting; limited visibility for planning and disturbance analysis	Standardized metering; centralized metering systems; meter upgrades; integration with digital monitoring	Centralized metering system (part of SAS Upgrade, SCADA, and KETRACO WAN); PMU rollout (Wide Area Monitoring System); Asset Performance Management (APM) system implementation at Isinya, Kimuka, Athi River, Suswa, Kakuyuni, Mangu, Kibos, Kegati

2.7. Review of the Implementation of the Previous Plan

This section reviews the status of implementation of the medium-term period of the 2025-2044 TMP. Therefore, the section will consider the actual timelines of the ongoing and planned projects.

Three (3) projects expected to be completed in 2025 were completed and energized as planned. These projects are Awendo-Masaba 132kV line and Masaba 132/33kV 1x23MVA substation to improve reliability and enhance electricity access in the South Nyanza region, Mariakani 400/220kV 2x200MVA substation to improve power transfer capacity for the Mombasa – Nairobi Transmission Line, reduce power losses and improve security of supply in the Coast region, and Lessos-Kabarnet 132kV line and Kabarnet 132/33kV 1x23MVA substation to Improve power supply quality, reliability and enhance access in the Central Rift region.

One (1) project expected to be completed in 2026 was completed and energized as planned. This project is Sondu (Thurdibuoro) – Ongeng (Homa Bay/Ndhiwa) 132kV line, to improve access and reliability of power to South Nyanza.

One (1) project expected to be completed in 2025 was completed and energized in 2026. This project is Kitui – Wote 132kV line, to connect load centres of Kitui, and Wote to high voltage grid for improved reliability and access.

Other projects have been deferred to the following year due to challenges in completion of construction activities, and delays in acquisition of right of way. Implementation of some projects experienced delays due to the long process of securing financing and long turnaround time in the project preparatory processes. A number of projects have been deferred by a year to allow for preparation, appraisal and sourcing of financing.

The expected completion dates for Rumuruti – Kabarnet and Malindi- Kilifi projects have been deferred to 2028 due to long project preparatory processes.

STATCOMs (Rabai and Suswa) and 400kV Kimuka substation projects have been deferred to 2028 to allow sufficient time for project procurement and implementation. However, earlier completion is targeted. Table 2 8 summarizes the implementation of projects in the 2026-2045 KETRACO TMP.

S/n	Transmission Line/ Substation Name	Projected Commissioning (TMP 2025- 2044)	Implementation Status (May 2026)	Remarks-Challenges affecting Project Implementation
1	Eastern Electricity Highway Project (EEHP) [Kenya - Ethiopia Interconnector]	2021	99%	Suswa Converter Station Lot 1. Operation in monopolar mode with metallic return currently ongoing. 2nd Pole not yet commissioned for the use of the electrode. Contractor already demobilized.
2	38km 400kV Double Circuit Isinya - Konza OHL	2025	93%	Funding by GoK required
3	220/66kV Malaa substation	2025	90.60%	Delay in procurement of CIO Modules for Malaa which are contained in addendum 12.
4	Nanyuki- Isiolo Overhead (Completion)	2025	100%	Pending commissioning and Energization.
5	14.5km 132kV Nanyuki - Rumuruti UG cable & 5km 132 kV Nanyuki-Isiolo UG cable	2025	91.40%	Payment for submitted invoices need to be paid as earliest possible to support site construction work.
6	132kV Nanyuki - Rumuruti OHL	2025	100%	Awaiting UG cable section
7	14.5km 132kV Nanyuki - Rumuruti UG cable & 5km 132 kV Nanyuki-Isiolo UG cable	2025	91.40%	Payment for submitted invoices need to be paid as earliest possible to support site construction work.
8	132kV Rabai – Bamburi - Mombasa Cement – Vipingo - Kilifi	2025	75%	Waiting for extension of funding and approval of revised completion date. Contractor to renew his bank guarantees. Demurrage incurring over goods at the CFS storage yard in Mombasa
				Addition of scope
				Court order on LILO section stopping works.
				Most of the Project Affected Persons (PAPs) are squatters hence difficult in compensation as a result lack of documents

S/n	Transmission Line/ Substation Name	Projected Commissioning (TMP 2025- 2044)	Implementation Status (May 2026)	Remarks-Challenges affecting Project Implementation
9	Narok -Bomet T/L and SS - Lot 2A&2B	2026	53%	Non- Availability of continuous wayleave to allow contractor to work in compliance with requirements in the financing agreement which requires work to be undertaken only at locations where 100% compensation has been done.
10	Garsen -HOLA –Bura- Garissa 220kV	2027	50%	No Finance
11	Makindu substation LILO - 400kV	2027	87%	Project Financing is less than the least evaluated bid price. Seeking additional financing- Request sent to National Treasury
12	Makindu substation LILO - 132kV	2027		
13	Malindi – Kilifi 220kV	2027	0%	Bidding in progress.
14	Malindi -Weru (Circuit II) 220kV	2027	0%	Bidding in progress.
15	Maai Mahiu LILO on Juja Rd. - Naivasha 132kV	2027	0%	No Finance
16	Olkaria 1 AU-Olkaria IV /V 220KV	2027	0%	No Finance
17	Kimuka LILO on Suswa– Isinya 400kV	2027	0%	Procurement ongoing
18	STATCOMs (Coast, Nairobi), Suswa 120MVar, 2x100MVar STATCOM/DRPC)	2027	0%	Procurement ongoing
19	Loiyangalani – Marsabit 220kV	2028	0%	No Finance
20	Kamburu-Embu 220KV	2028	0%	No Finance
21	Isiolo - Marsabit 220kV	2028	0%	No Finance





ELECTRICITY DEMAND PROJECTION AND GENERATION EXPANSION

Electricity demand projections and the generation expansion plan adopted in this TMP is in line with the forecast/projections in the following Electricity Sub-Sector plans.

- i. LCPDP Medium Term Plan 2025-2029 for the period ending 2029.
- ii. LCPDP 2024-2043 for the period beyond 2029 to the end of the planning period.
- iii. Proposed Energy Sector National Infrastructure Fund (NIF) Priority Projects. This TMP, therefore, is aligned to the demand and generation projections from the LCPDP planning process. It's also aligned with the Mission 300 Kenya National Energy Compact 2025-20230.

3.1. Electricity Demand

According to the LCPDP 2024-2043 and the Least Cost MTP 2025-2029, Electricity demand growth in Kenya is principally influenced by demographic growth, increasing household-specific electricity consumption, sustained GDP growth, implementation of key Kenya Vision 2030 flagship projects, and the progressive electrification of end-use sectors such as e-cooking and electric mobility. Demand projections are therefore evaluated under three scenarios: a high (Vision) scenario reflecting accelerated economic transformation, a reference (business-as-usual) scenario representing continuation of prevailing trends and policies, and a low growth (constrained or worst-case) scenario capturing slower economic and sectoral expansion.

3.1.1. Kenya Vision 2030 Flagship Projects

Energy Plays a significant enabling role in achieving the goals as outlined in the Kenya Vision 2030. The vision highlights several flagship projects anticipated to significantly influence the country's electricity demand. The Government has since been implementing generation, transmission, and distribution projects with primary objectives of increasing electricity access, strengthening the grid, and enhancing power supply reliability and security of supply.

Flagship projects considered both in the reference and vision scenarios, years of consideration and load requirements are indicated in Table 3 1 below.

Table 2 4: KETRACO Completed Projects as at February 2026

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	2029	1	2044	50	2028	1	2035	50
Data Centre (IX Africa)	2026	40	2026	40	2026	40	2025	40
Oil Pipeline and Port Terminal (LAPSSET)	2026	1	2040	35	2026	1	2030	35
Special Economic Zones (Kedong, Dongo Kundu,)				***	2026	5	2039	60
Special Economic Zones (Tatu City, Athi River, Eldoret, Konza)	2025	5	2042	60	2026	5	2040	60
E-Mobility	2024	23.5	2030	219.2	2024	23.5	2030	273
Special Economic Zones (KenGen, Marathon Data Centre)	2026	30	2028	100	2026	30	2028	100
E-Cooking	2024	1.2	2030	34.7	2024	1.2	2030	45.7

Source: MTP 2025-2029

* The reference scenario did not consider any load for Special Economic Zones (Kedong and Dongo Kundu) due to limited data at the time of modelling

3.1.2. Government Priority areas

Electricity demand is projected to grow steadily, driven by government-led development initiatives aimed at accelerating economic transformation. Key drivers include the last-mile connectivity programme-mobility and e-cooking, alongside strategic programs in housing, industrialization, digitalization-data centres, and the energy transition.

3.1.3. Demand Forecast

3.1.3.1. Peak Demand

Demand in electricity consumption has been growing owing to the various demand drivers as discussed above. The projected growth in system peak demand over the planning period increases from 2,439 MW which was the recorded peak in 2025 to 3,406 in 2030 in the reference scenario and 9,272MW in 2045. In the vision and low scenarios, peak demand is forecasted to reach 16,152 MW and 5,431 MW by 2045 respectively as indicated in Figure 3 1 below. The average growth rates over the planning period for reference, vision and low scenarios are 6.89%, 9.40% and 4.26% respectively.

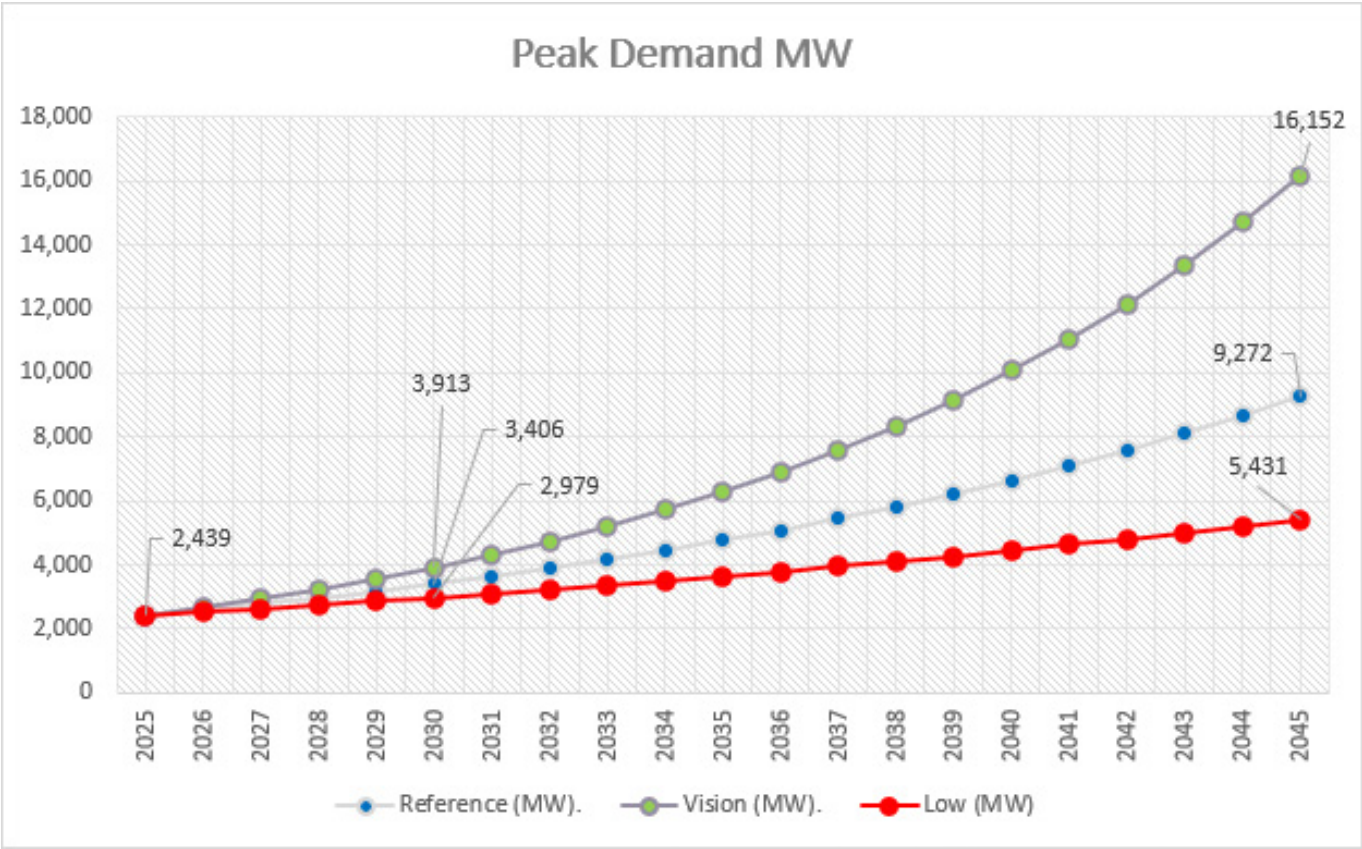


Figure 3 1: Electricity Peak Demand Forecast in MW
Source: LCPDP 2024-2043 and MTP 2025-2029

Electricity consumption is expected to rise from 11,403 GWh in 2025 to 15,530GWh in 2030 in the reference scenario, 18,044 GWh in the Vision scenario and 14,164 GWh in the low scenario by the same period, and 39,234 GWh, 71,501GWh and 27,145 GWh by 2045 as indicated in Figure 3 2.

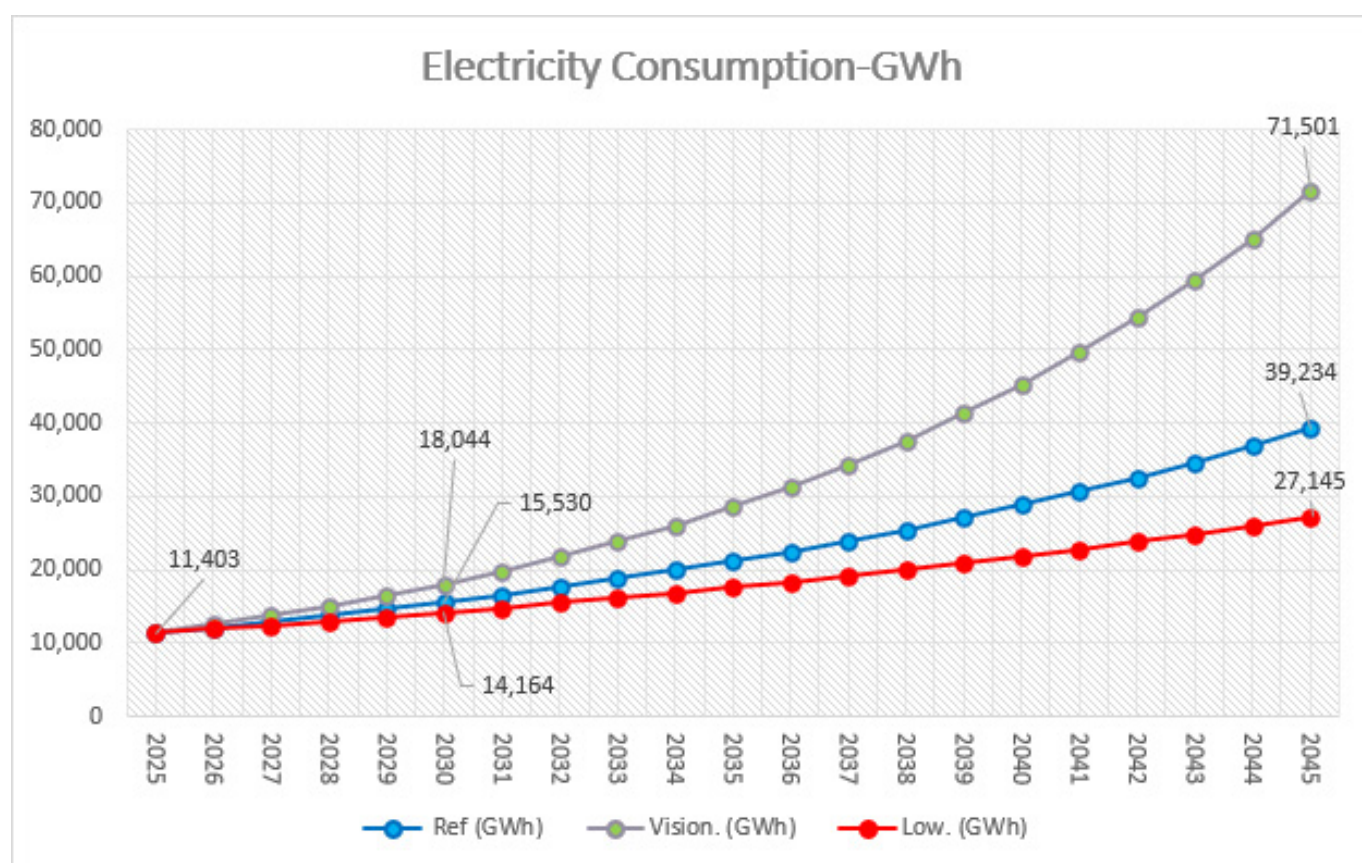


Figure 3 2: Electricity Consumption Forecast

Source: Least Cost Power Development Plan 2024-2043 and MTP 2025-2029

3.2. Generation Projection

Kenya's interconnected effective power capacity is expected to expand significantly—from 3,108 MW in 2025 to 12,898 MW by 2045—sufficient to meet the projected peak demand of 9,272 MW. Geothermal energy remains the backbone of firm capacity, contributing about 40% annually throughout the planning horizon. The realization of this planned generation expansion will be enhanced by various government initiatives such as the lifting of the moratorium on PPAs, RE auctions, private sector participation in BESS framework and the Kenya Energy Transition and Investment Plan (ETIP) among others.

However, the projected electricity supply is insufficient to fully meet the expected demand in the short term, resulting in a supply gap of 322 MW in 2026. To address these gap, key actions are recommended, including accelerating the planned 200 MW power import from Ethiopia, expected by December 2026, and commissioning an LNG power plant in 2027. Additionally, Battery Energy Storage Systems (BESS) and pumped storage will strengthen grid stability, together providing 18% of firm capacity by 2044.

The 1st Nuclear Power Plant is scheduled for 2034, eventually providing up to 9% of firm capacity. Overall, renewable sources will make up about 63% of the firm capacity mix, though variable renewable energy (such as wind and solar) will account for only 5% by 2045. All diesel power plants are set for retirement by 2035.

Furthermore, the lifting of the moratorium on new Power Purchase Agreements (PPAs) in Kenya in November 2025 is a strategic move designed to avert a looming electricity generation crisis and address a growing power supply deficit. Following the freeze, which was in place from 2018, the government is now focused on onboarding new, primarily renewable energy projects to meet rising demand.

The average reserve margin over the planning period is 13%, lower than the Ideal reserve margin of 20%-35% according to the International Energy Agency (IEA). Details of the reserve margin by year are in Volume II: Annex 5.

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2025			3,081.0	3,081.0	2,371	2,439					
2026	KTDA Nyambunde, Nyakwana	Small Hydro	0.5	0.5	0.13		Kegati 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Marco Borero Co Ltd.	PV	1.5	1.5	-		Kiganjo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	REA Vipingo Plantations Ltd (DWA Estates Ltd)	Biomass	1.44	1.44	0.72		Kiboko 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	KTDA Ltd, Lower Nyamindi	Small Hydro	0.8	0.8	0.2		Kutus132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	KTDA Ltd, South Maara (Greater Meru Power Co.)	Small Hydro	1.5	1.5	0.38		Kieni132/33kV (Marima33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	KTDA Ltd, Iruru	Small Hydro	1	1	0.25		Meru132/33kV (Kanyakine33/11)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Mt Kenya Community Based Organisation	Small Hydro	0.6	0.6	0.15		Meru 132/33kV (Meru 33/11)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Kleen Energy Limited	Small Hydro	6	6	1.5		Kutus 132/33kV (Embu 33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	Menengai 1 Phase I - Stage 1 (Quantum)	Geothermal	35	35	35		Menengai 132kV	Sufficient	Complete	N/A	Additional cost of connection will be borne by the developer
2026	Menengai 1 Phase I - Stage 1 (Orpower22)	Geothermal	35	35	35		Menengai 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2026	KPRL	Diesel	8.3	8.3	8.3		Awendo 33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2026	Kipevu I	Diesel	50	50	50		Hilltop 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2026	Gogo Existing small hydro	Small Hydro	-1.6		-0.4		Decommissioning	N/A	N/A	N/A	N/A
2026	Muhoroni GT 1	Gas turbines (gasoil)	-26		-26		Decommissioning	N/A	N/A	N/A	N/A
2026	Muhoroni GT 2	Gas turbines (gasoil)	-26		-26		Decommissioning	N/A	N/A	N/A	N/A
End of 2026			88.04	3,169.0	2,450	2,607					
2027	Tindinyo Falls Resort	Small Hydro	2.4	2.4	0.6		Cheptulu ex Kisumu 33kV feeder	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	20	20	20		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2027	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	20	20	20		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2027	Olkaria 1 - Rehabilitation	Geothermal	20	20	20		Olkaria I 132kV	Sufficient	Complete	N/A	The additional cost of connection will be borne by KenGen as part of the project
2027	Baringo Silali - Paka I&II	Geothermal	100	100	100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Loosuk-Baringo-Lessos 400kV line must be ready
2027	Menengai II-Stage I (Modular)	Geothermal	10	10	10		Menengai 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Prunus	Wind+ BESS	50	50	12.5		Kimuka 220/66kV	Sufficient	Complete	2024	Cost of connection will be borne by the developer
2027	Chania Green	Wind +BESS	50	50	12.5		Kimuka 220/66kV	Sufficient	Complete	2024	Cost of connection will be borne by the developer
2027	Aperture	Wind+ BESS	50	50	12.5		Limuru 66/11kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Tarita Green (Kaptagat)	PV+BESS	40	40	-		Lessos-Kabarnet132kVline	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Kisumu Solar One	PV+BESS	40	40	-		Kibos220/132/33kVsubstation		Complete	N/A	Cost of connection will be borne by the developer
2027	Kopere Solar Park Limited	PV+BESS	40	40			Lessos-Muhoroni 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	Kenergy Renewables Ltd- Rumuruti	PV+BESS	40	40	-		Rumuruti 132/33kV	Sufficient	Construction	2025	Additional cost of connection will be borne by the developer- Nanyuki-Rumuruti 132kV line must be ready
2027	Kibwezi One Energy Limited	PV+BESS	40	40	-		Kiboko 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]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2027	Hannan Arya Energy (K) Ltd	PV+BESS	10	10	-		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	42.5	-		Kamburu 220/132kV	Sufficient	Complete	N/A	cost of connection will be borne by KenGen
2027	HVDC Ethiopia2	Import	200	200	200		Suswa Converter Station	Sufficient	Installation of STATCOMS	2026	Installation of STATCOM required at Suswa as this necessitates switching of 2nd Filter
2027	BESS_1	BESS	100	100	50		Embakasi 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2027	BESS_3	BESS	50	50	25		Kegati 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2027			924.9	4,093.9	2,933	2,788					
2028	Raising Masinga	Hydropower	-	-	-						
2028	Gogo upgrade	Small Hydro	8.6	8.6	2.15		Awendo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2028	Olkaria 7	Geothermal	80	80	80		Olkaria 1AU 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	Olkaria 1 AU 4 & 5 uprating	Geothermal	20	20	20		Olkaria1AU220kV	Sufficient	Complete		No new investment
2028	Olkaria IV Upgrading	Geothermal	20	20	20		OlkariaIV220kV	Sufficient	Complete		No new investment
2028	Electrawinds Bahari	Wind+ BESS	50	50	12.5		Garsen-Lamu 220kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	BESS_2	BESS	100	100	50		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	40	-		Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2028	KenGen LNG and LNG Phase II	LNG	200	200	600						The additional cost of connection will be borne by KenGen as part of the project
2028	KenGen Olkaria Wellheads I	Geothermal	-44.6	-44.6	-44.6		Decommissioning	N/A	N/A	N/A	N/A
End of 2028			474	4,567.9	3,673	2,980					
2029	KTDA Chemosit	Small Hydro	0.25	0.25	0.06		Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Frontier Investment Management/ Nithi Hydro	Small Hydro	5.6	5.6	1.4		Kieni 132/33kV (Marima 33/11kV)	Sufficient	Construction	2024	Cost of connection will be borne by the developer
2029	Gem Gen Power Company Limited	Small Hydro	9.5	9.5	2.38		Rangala 132/33kV (Nyaminia 33/11kV)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Power Technologies (Gatiki Small Hydro Plant)	Small Hydro	9.6	9.6	2.4		Kiganjo 132/33kV Substation (Karatina-Mukurweini 33kV line)	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Rieke Ltd (Kaiuthi SHPP-Sagana I)	Small Hydro	20	20	5		Kutus-Kiganjo 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2029	Rieke Ltd (Ithari SHPP-Sagana II)	Small Hydro	20	20	5		Kutus-Kiganjo 132kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Global Sustainable-Kaptis	Small Hydro	14.7	14.7	3.68		Cheptulu ex 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	4.5	1.13		Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Mutunguru Hydroelectric Company Ltd	Small Hydro	7.8	7.8	1.95		Meru 132/33kV (Kanyakine 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	20	5		Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Ventus Energy Ltd	Small Hydro	7.7	7.7	1.93		Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Olkaria II Extension (Olkaria 6)	Geothermal	140	140	140		Olkaria II 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Ol-Danyat Energy	Wind+ BESS	10	10	2.5		LILLO on Matasia-Magadi 66kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2029	Marsabit Phase I - KenGen	Wind+ BESS	200	200	50		Loiyangalani Substation 400/220kV	Sufficient	Feasibility Study Stage	2029	Cost of connection will be borne by KenGen
2029	Kwale Int. Sugar Co. Ltd	Biomass	10	10	5		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
2029	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	Biomass	20	20	10		Garsen 220/33kV	Sufficient	Complete	N/A	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			398.65	4,966.6	3,810	3,186					
2030	Thika Way Investments (Homa Bay Biogas One)	Biomass	8	8	4		Sondu 132/33kV Substation	Sufficient	Under Construction-Stalled	2026	Cost of connection will be borne by the developer
2030	UETCL Import2	Import	150	150	150		Tororo 220/132kV Substation	Sufficient	Awaiting Settlement of Contractor by KETRACO/GoK before progressing the project further		Lessos-Tororo 220kV line and associated substations must be ready
2030	BESS_4	BESS	50	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	30	0		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	1.5	0.375		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	300		Ortun 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]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2030	Kenya Solar Energy	PV+BESS	40	40	-			Sufficient		N/A	Cost of connection will be borne by the developer
2030	Mwikhuo-Mwibale Hydro Power Kenya	Small Hydro	7	7	1.75		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	4.5	1.125		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	3.5	0.875		Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Western Hydro	Small Hydro	10	10	2.5		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	6.5	1.625		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	7	1.75		Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	KTDA R. Chemosit, Chemosit	Small Hydro	2.5	2.5	0.625			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	5.2	1.3		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	9.4	2.35		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	6	1.5		Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	VSHydro Kenya Ltd	Small Hydro	9.1	9.1	2.275		Kieni 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2030	Roadtech Solutions Ltd	Biomass	10	10	5		Kajiado 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2030			660.2	5,626.8	4,299	3,406					
2031	High Grand Falls Stage 1+2	Hydropower	700	700	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
2031	Karuga Gitugi Electrification Project	Small Hydro	2.7	2.7	0.68		Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	KTDA Chemosit, Kiptiget	Small Hydro	3.3	3.3	0.83		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	0.9	0.23		Chemosit 132/33kV	Complete	N/A	N/A	Cost of connection will be borne by the developer

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2031	KTDA R. Rupingazi, Rutune	Small Hydro	1.8	1.8	0.45		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	1.3	0.33		Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2031	KTDA, R. Yala, Taunet	Small Hydro	2.8	2.8	0.7		Cheptulu ex Kisumu 33kV feeder	Sufficient	Complete	N/A	
2031	Tridax Limited	Small Hydro	4.2	4.2	1.05		Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2031	Truck city ltd	Small Hydro	5.3	5.3	1.33		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		Decommissioning	Sufficient	N/A	N/A	N/A
End of 2031			633.7	6,260.5	4,766	3,641					
2032	Karura	Hydropower	90	90	70.68		Karura	Sufficient	Feasibility	2030	Cost of connection will be borne by the developer
2032	Eburru 2	Geothermal	25	25	25		Eburru/Naivasha	Sufficient	Concept/Complete	2032	Cost of connection will be borne by the developer
2032	Chevron Africa Limited	Small Hydro	7.8	7.8	1.95		Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Dominion Farms	Small Hydro	1	1	0.25		Rangala 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Webuye Falls-KenGen (Nabuyole)	Small Hydro	40	40	10		Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by KenGen
2032	Viability Africa (Northern Energy Limited)	Biomass	2.4	2.4	1.2		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	8.4	4.2		Kabarnet 132/33kV	Sufficient	2024	N/A	Cost of connection will be borne by the developer
2032	Baringo Silali Paka II	Geothermal	100	100	100		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	100		Suswa 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Electrawinds Bahari Phase 2	Wind+ BESS	40	40	10		Garsen-Lamu 220kV line	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	Meru Phase 1	Wind+ BESS	80	80	10		Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2032	BESS_5	BESS	150	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		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		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
End of 2032			502.1	6,762.6	4,994	3,892					
2033	Olkaria Rehabilitation II	Geothermal	105	105	105		Olkaria II 220kV Substation	Sufficient	Complete		Cost of connection will be borne by KenGen

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2033	Olkaria 8	Geothermal	140	140	140		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	60		Menengai 132kV	Sufficient	Complete		Cost of connection will be borne by the developer
2033	Njumbi Hydropower Plant Ltd (Hydroneo)	Small Hydro	9.6	9.6	2.4		Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2033	Hydel	Small Hydro	5	5	1.25		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	3	1.5		Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2033			322.6	7,085.2	4,891	4,161					
2034	Nuclear Unit 1	Nuclear	1000	1000	1000		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	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	22	5.5		Githambo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2034	West Kenya Sugar Company Limited	Biomass	6	6	3		Musaga 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2034	Biogas Holdings Ltd	Biogas	0.3	0.3	0.15			Sufficient			Cost of connection will be borne by the developer
2034	Generic PV	PV+BESS	40	40	-		Narok	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2034			1168.3	8,253.5	5,925	4,448					
2035	Menengai IV	Geothermal	100	100	100		Menengai 400kV	Sufficient	Feasibility	2033	Menengai 400kV Substation and Menengai-Rongai 400kV line required
2035	Baringo Silali - Korosi /Chepchuk I	Geothermal	100	100	100		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	35		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	35		Longonot/Olkaria II/Naivasha	Sufficient	Feasibility/Complete/Complete	2033	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 3	Geothermal	35	35	35		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	200	50		Loiyangalani Substation 400/220kV	Sufficient	Feasibility Study Stage	2029	Loosuk-Baringo-Lessos 400kV line must be ready
2035	Generic small hydro	Small Hydro	22	22	5.5		Kiganjo 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

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2035	Generic Wind	Wind+ BESS	50	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	40	0		Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2035	Generic Biomass	Biomass	18	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	100		Ethiopia-Kenya/ Kenya-Tanzania/ Kenya-Uganda	Sufficient	Complete/Under construction		N/A
2035	Regional Trade 1 B	Import	100	100	100		Ethiopia-Kenya/ Kenya-Tanzania/ Kenya-Uganda	Sufficient	Complete/Under construction		N/A
2035	Athi River Gulf	Diesel engines	-80.32		-80.32		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		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by the developer
2035	Thika (CC-ICE)	Diesel engines	-87		-87		Decommissioning	Sufficient	N/A	N/A	Cost of connection will be borne by the developer
End of 2035			615.18	8,868.7	6,287	4,755					
2036	Olkaria 9	Geothermal	140	140	140		Longonot/Olkaria II/Naivasha	Sufficient	Feasibility/Complete/Complete	2033	Cost of connection will be borne by KenGen
2036	Generic small hydro	Small Hydro	22	22	5.5		Webuye 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2036	Generic Biomass	Biomass	18	18	9		Malindi (Kakuyuni) 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2036	Generic PV	PV+BESS	40	40	-		Ndhiwa 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2036	Ngong I, Phase II	Wind	-20.4		-5.1		Decommissioning	N/A	N/A	N/A	Cost of connection will be borne by KenGen
2036	Triumph (Kitengela)	Diesel engines	-83		-83		Decommissioning	N/A	N/A	N/A	N/A
End of 2036			116.6	8,985.3	6,353	5,084					
2037	AGIL Longonot Stage 4	Geothermal	35	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	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	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	22	5.5		Cheptulu ex Kisumu 33kV feeder	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2037	Generic Wind	Wind+ BESS	50	50	12.5		Isiolo 132/33kV Substation	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2037	Generic Biomass	Biomass	18	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	40	-		Rumuruti 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
End of 2037			685	9,670.3	6,770	5,435					

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2038	Suswa II	Geothermal	100	100	100		Suswa 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2038	Generic small hydro	Small Hydro	22	22	5.5		Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2038	Generic Biomass	Biomass	18	18	9		Ruai 66kV	Sufficient	Complete	N/A	
2038	Generic PV	PV+BESS	40	40	-		Nanyuki 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2038	OrPower4 Plant 2	Geothermal	-39.6		-39.6		Decommissioning	N/A	N/A	N/A	N/A
End of 2038			140.4	9,810.7	6,845	5,810					
2039	Baringo Silali (Silali) II	Geothermal	100	100	100		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 6)	BESS	150	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	100		Menengai 400kV	Sufficient	Feasibility	2033	Menengai 400kV Substation and Menengai-Rongai 400kV line required
2039	Suswa III	Geothermal	100	100	100		Suswa 220kV	Sufficient	Complete	N/A	N/A
2039	Regional Trade 2	Import	200	200	200		Ethiopia-Kenya/Kenya-Tanzania/Uganda	Sufficient	Complete/Under construction		N/A
2039	Generic small hydro	Small Hydro	22	22	5.5		Kutus 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Generic Wind	Wind+ BESS	50	50	12.5		Meru 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Generic Biomass	Biomass	18	18	9		Meru/Thika	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	Generic PV	PV+BESS	80	80	-		Turkwel 220kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2039	BESS_1	BESS	-100		-25		Decommissioning	N/A	N/A	N/A	N/A
2038	BESS_3	BESS	-50		-12.5		Decommissioning	N/A	N/A	N/A	N/A
2039	REA Garissa	PV	-50		-		Decommissioning	N/A	N/A	N/A	
2039	Strathmore	PV	-0.25		-		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 1	Wind	-100		-25		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 2	Wind	-100		-25		Decommissioning	N/A	N/A	N/A	
2039	Lake Turkana - Phase I, Stage 3	Wind	-100		-25		Decommissioning	N/A	N/A	N/A	N/A
End of 2039			319.75	10,130.4	7,297	6,211					
2040	Olsuswa 70MW unit 1	Geothermal	70	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	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	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	100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer

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2040	Baringo (Paka) III	Silali Geothermal	100	100	100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	
2040	Baringo (Silali) III	Silali Geothermal	100	100	100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Sufficient	Finance Sourcing	2027	
2040	Arror	Hydropower	59	59	47.12		Proposed Kapsowar 132/33kV Substation	Sufficient	Feasibility Stage		Cost of connection will be borne by the developer
2040	Nandi Forest	Hydropower	50	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	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	300	75		Loiyangalani 400/220kV Substation	Sufficient	Complete	N/A	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Generic Biomass	Biomass	18	18	9		Kibos 220/132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2040	Generic PV	PV+BESS	80	80	-		Baragoi	Sufficient	Concept	TBD	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Olkaria I Unit 4-5	Geothermal	-140	-140	-140		Decommissioning	N/A	N/A	N/A	N/A
2040	Olkaria 4	Geothermal	-140	-140	-140		Decommissioning	N/A	N/A	N/A	N/A
2040	OrPower4 Plant 3	Geothermal	-17.6	-17.6	-17.6		Decommissioning	N/A	N/A	N/A	N/A
End of 2040			811.4	10,941.8	7,755	6,640					
2041	Generic Geothermal	Geothermal	400	400	400		TBD	TBD	0	0	Cost of connection will be borne by the developer
2041	BESS Generic 3 (BESS 7)	BESS	100	100	25		TBD	TBD	N/A	2041	Cost of connection will be borne by the developer
2041	Generic Biomass	Biomass	18	18	9		Kakamega 220kV	Sufficient	Finance Sourcing	2027	Cost of connection will be borne by the developer
2041	Generic Wind	Wind	200	200	50		Kipeto 220kV Extension	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2041	Generic PV	PV+BESS	80	80	-		Lodwar 220kV	Sufficient	Finance Sourcing	2041	Cost of connection will be borne by the developer Turkwel-Lokichar-Lodwar 220kV line required
2041	Generic small hydro	Small Hydro	22	22	5.5		Chemosit 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2041	BESS_2	BESS	-100	-100	-25		Decommissioning	N/A	N/A	N/A	N/A
End of 2041			720	11,661.8	8,220	7,099					
2042	Pumped hydro storage - Unit 3	Pumped storage	650	650	650		TBD	Sufficient	Concept	2042	Cost of connection will be borne by the developer
2042	Generic small hydro	Small Hydro	22	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	100	25		Kipeto 220kV Extension	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2042	Generic Biomass	Biomass	18	18	9		Muhoroni 132kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2042	Generic PV	PV+BESS	80	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	12,322.8	8,855	7,589					
2043	BESS Generic 2 (BESS 8)	BESS	50	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	300		TBD	TBD			Cost of connection will be borne by the developer
2043	Regional Trade 3	Import	200	200	200		Ethiopia-Kenya/Kenya-Tanzania/Kenya-Uganda	Sufficient	Complete/Under construction		Cost of connection will be borne by the developer
2043	Generic small hydro	Small Hydro	22	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	150	37.5		Bubisa/Marsabit 220kV	Sufficient	Finance Sourcing	2028	Cost of connection will be borne by the developer
2043	Generic Biomass	Biomass	18	18	9		Lanet 132/33kV	Sufficient	Complete	N/A	Cost of connection will be borne by the developer
2043	Generic PV	PV+BESS	80	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	N/A
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			666.2	12,989.0	9,344	8,113					
			0		0						
End of 2044			0	12,989.0	9,344	8,673					
			0		0						
End of 2044			0	12,989.0	9,344	9,272					

Source: LCPDP 2024-2043 and MTP 2025-2025

The National Infrastructure Fund (NIF) in Kenya, established in March 2026, is a KSh 5 trillion initiative designed to finance major, "bankable" projects through public-private partnerships, privatization proceeds, and institutional capital rather than traditional debt. The NIF priority projects in the energy and infrastructure sector aim to accelerate industrialization, increase power capacity, and enhance energy security in the country as indicated in Table 3-3.

Table 3-3: The proposed generation projects under the National Infrastructure Fund Act 2025.

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Connection Point (Substation)	Sufficient/ Insufficient Evacuation Capacity	Progress Status of Evacuation Point	Target Completion Date	Remarks
2028	KenGen LNG and LNG Phase II	LNG	600	600	600					The additional cost of connection will be borne by KenGen as part of the project
2031	High Grand Falls Stage 1+2	Hydropower	700	700	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
2031	LNG Phase III and IV	LNG	600	600	600	Dongo Kundu 400/220 kV	Sufficient	N/A	N/A	N/A
2034	Nuclear Unit 1	Nuclear	2000	2000	2000	Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by NUPEA (GoK)- Kilifi-Mariakani 400kV line required
2036	Nuclear Unit 2	Nuclear	2000	2000	2000	Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by the developer
2037	Pumped hydro storage - Unit 2	Pumped storage	300	300	300	Baringo 400kV (tied to Lessos-Loosuk 400kV line- PPP)	Sufficient	Finance Sourcing	2027	Loosuk-Baringo-Lessos 400kV line must be ready
2038	Nuclear Unit 3	Nuclear	2000	2000	2000	Kilifi 400kV	Sufficient	Feasibility	2034	Cost of connection will be borne by NUPEA (GoK)- Kilifi-Mariakani 400kV line required
TOTAL CAPACITY			8,200.00	8,200.00	8,049.70					

**some of the projects in the NIF were already in the Least Cost Table*





4

TRANSMISSION EXPANSION PLAN

Meeting growing electricity demand reliably and efficiently requires strategic expansion and modernization of transmission and distribution networks, with meticulous planning essential to ensure cost-effectiveness, system stability, and seamless integration of renewable energy sources given the complexity and capital-intensive nature of grid development. Transmission planning plays a pivotal role in shaping the future of power systems, particularly in the context of evolving power markets, cross-border electricity trade, and advanced grid technologies, and is categorized into medium-term and long-term planning, each addressing distinct objectives.

Long-term transmission planning focuses on strategic grid development, ensuring alignment with national and regional energy goals by identifying necessary investments to accommodate future generation, load growth, and cross-border interconnections particularly within the EAPP and SAPP. Short and medium-term planning evaluates immediate system needs, including generation evacuation, network reinforcement, and smart grid solutions to improve reliability and resilience, leveraging real-time data and advanced analytics to optimize grid performance under current and near-future conditions.

This section outlines the planning objectives and methodology used to develop a pipeline of transmission projects, including cost estimates for the period 2026–2045.

4.1. Objectives of transmission planning

The main objectives of the transmission-planning are:

- i. To identify and evaluate transmission network solutions up to the 2045 planning horizon, enabling the selection of an optimized target grid that will serve as the foundation for the transmission expansion plan.
- ii. To identify transmission development options/sequences for comparison and determination of the least cost option through detailed technical studies and economic analysis.
- iii. Support regional power trade and wheeling by strengthening interconnections with Ethiopia, Uganda, and Tanzania, in line with EAPP and SAPP frameworks.
- iv. To determine project cost estimates for the planned investments

4.2. Planning Methodology

The transmission expansion plan was developed using inputs from demand forecasts and generation expansion planning to ensure alignment with future power system requirements.

The planning process involved comprehensive transmission network modelling for existing and future scenarios, allocation of incremental demand based on distribution master plans, mapping of generation facility locations and regional demand-supply balances, and determination of inter and intra-regional power transfer requirements to establish a functional network model.

The project schedule was updated based on the current implementation status of ongoing transmission projects, updated demand forecasts, and planned/ongoing generation projects as detailed in Chapter 3.

The following models were developed:

- i. Existing transmission network model (base model for the target planning period)
- ii. End of 2026 model (existing network model with all ongoing projects with 2026 as target completion date)
- iii. End of year models for 2026, 2030, 2035, 2040 and 2045. These models included committed and planned projects expected in the respective years.
- iv. Target network model – the 2045 model (base model for long term planning) containing the planned projects building up on the medium-term model. This contained all the planned network expansions including the proposed reinforcements as planned in the previous planning period.

System simulations were conducted to verify compliance with the National Transmission Grid Code, with corrective measures (such as revised concepts or additional reinforcements) incorporated where deficiencies were identified, followed by confirmatory simulations.

Both the target network approach for long-term vision and the alternatives approach for flexible, scenario-based solutions, with both methods applied under the LCPDP framework to ensure cost-effective, optimal and coordinated grid development. In both approaches, the minimization of the costs was realized by comparing transmission system development options where required.

4.2.1. Alternatives approach:

Using PSS/E, the solution for the current network model was determined while introducing additional network segments required to resolve underlying network constraints and challenges and/or to meet a specific objective within the short to medium term.

4.2.2. Target network approach:

Given that no changes were proposed in the long term, only confirmatory simulations and analysis were conducted for long term, anti-chronologically, starting with target network 2045 and ending with 2035 model.

4.3. Grid Expansion Process

The process involved:

- i. Determining the location of future generation facilities and demand supply points. Starting from the schedule of generation investments described in chapter 3, the future plant locations were selected considering the nature of each generation plant and its basic requirements, its existing resource development plans and its established policies. Similarly, and where applicable, the location of government priority projects including BETA Legacy projects and key vision 2030 flagship projects were also considered.
- ii. Splitting the power network into regions, determining the regional power balances and estimating future potential flows between regions. In Kenya, six regions were defined as follows: -
 - a. Nairobi
 - b. Mt. Kenya
 - c. Coast
 - d. West Kenya
 - e. Central Rift
 - f. North Rift

Other regions such as Uganda, Tanzania and Ethiopia were also considered. These formed the external interconnected regions outside Kenya.

- iii. Estimating the number of transmission lines to plan within and between the regions. 220kV and 400 kV were adopted as the backbone transmission voltage in the short and medium terms. 400kV was adopted as the backbone for long term and for conformity with the current regional standards. Thermal rating and surge impedance loading were used to determine transfer capacity limits for transmission lines.

- iv. The transmission distances and level of system demand were also considered, and the power transfer capability of transmission lines was estimated as follows:
- a. For short transmission lines, the thermal capacity (IEEE Standards) was considered as the transfer limit.
 - b. For lines spanning lengths of over 500km, the transfer limit was much lower than the thermal limit and was assumed to be equal to SIL (Surge Impedance Loading), For instance the SIL for 400kV is estimated at 680 MW per circuit.
 - c. Medium length lines (spanning between 200 and 499) km were assumed to be capable of transmitting up to 1.5 SIL.
 - d. For EHV lines spanning between 80-199 km were assumed to transmit 2.0 times the SIL.

For the long term, network models for each of the snapshot years, i.e. 2030, 2035, 2040, 2044 were further optimized through load flow, contingency and short circuit studies to ensure transmission criteria was complied with at every stage. Any new project was included as part of the plan. Movement in scheduling where necessary was also affected.

Detailed studies were carried out for average hydrology peak load and minimum load, for each of the snapshot years. Whereas peak load studies were required to establish equipment and conductor ratings, minimum load studies confirmed voltage criteria and established reactive compensation requirements.

In case of alternative investment strategies, they were formulated based on the initial target network options. Each strategy, evaluated annually, accounted for reinforcing transmission lines and substations, determining reactive compensation needs, and assessing transmission losses.

Where required, and for comparison purposes, the cost of transmission losses calculated at the Long Run Marginal Cost (LRMC) of energy for each option was determined. 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 (2025) at a rate of 12.8% as gazetted by EPRA. Further, the Operation & Maintenance (O&M) cost was calculated as 2.5% of the Investment Cost.

The Present Value (PV) of cost for the investment strategy is then calculated by summing up these discounted annual investments. Where different investment strategies are involved, the strategy demonstrating the lowest PV of cost is recommended as the most economical option for expanding the transmission network.

be deployed as required and noted for consideration as new investments

4.4.2.2. Equipment Loading

Under normal conditions and at a steady state, all transmission equipment should not exceed 100% of their designed continuous rating. However, during contingency conditions loading was allowed to increase to 120%, which is a threshold justified by the fact that the equipment can withstand this level for about 20 minutes, assumed as the period within which the operator will be able to apply remedial actions and bring the system back to a normal or quasi normal condition.

4.4.2.3. Voltage Selection

Transmission development during the planning horizon was based on 132 kV, 220 kV and 400 kV. To enhance system operation and optimize wayleaves cost all future inter-regional transmission lines and regional interconnections were designed as 400 kV but may be initially operated at 220 kV. To limit corona losses and enhance transfer capacity, 400 kV and some 220 kV lines are designed with bundled conductors.

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

4.4.2.4. Reliability Criteria

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

4.4.2.5. Fault Levels

The system is planned to ensure maximum fault levels do not exceed 80% of the maximum rated fault current interrupting capacity of the circuit breakers. This criterion led to either the replacement of some breakers (i.e. upgrade) or to the identification of mitigation actions for limiting the fault levels.

4.4.2.6. Power Losses

The transmission system is planned to operate efficiently, with transmission power losses (technical losses) not exceeding 5% at the system peak and transmission energy losses not exceeding 2.5% at system peak.

4.4.3. Catalogue of Equipment

Standard equipment and materials (e.g. transformers, conductors, capacitors, substation diameters and bays etc.) were recommended for electricity transmission grid infrastructure development for the following reasons:

- i. They offer economic and monetary value due to bulk purchase for future developments using established designs.
- ii. These equipment and materials are easily stocked for replacement in cases of failure and redundancy: standardization allows a large degree of interchangeability and a reduction of the number of spare parts holding.
- iii. It offers ease in operation and maintenance owing to its uniformity and commonality.
- iv. It makes it easier for KETRACO to train and build capacity for its technical staff on the standard equipment.
- v. Lower costs could be incurred due to there being a reduced level of design input and no obligation to undertake type testing.
- vi. It makes it easier to up-rate certain equipment by substituting them with others that may be recovered for deployment elsewhere.

The updated catalogue of equipment and materials used in the development of the transmission plan and their estimated unit costs are summarized in Volume II Annex 8. The standardization principle was based on the 2012 Kenya Electricity System Studies (KESS) Report by Parsons Brinckerhoff (PB) for ERC (now EPRA). The equipment selection was based on the prevailing KETRACO practice and is compliant with industry standards.

These costs will be used as basis for preparing project cost estimates. The unit costs are reviewed and updated in every planning period to include equipment made available in the market and installed in the system. The wayleaves costs assume a highly populated and built-up area that represents the worst-case scenario

i. 4.5. Simulations Result for Network Planning

ii.

iii. 4.5.1. Load Data

- iv. In disaggregating the national load forecast to individual substations in the regions, the following assumptions were made:
- v. Load distribution and growth rates in Kenya power system regions as projected in the reference scenario of the forecast.
- vi. Vision 2030 flagship projects as detailed in Table 4 1, and with their indicative

points of connections given in Table 3 2.

vii. Uniform load growth rate in individual regions as per the demand forecast.

Table 4-1: Key Flagship Projects and their points of connection

S/n	Project	First year of operation	Max Initial load [MW]	Year of total load	Max Total load [MW]	Remarks and Point of Connection
1	Electrified Mass rapid transit system for Nairobi	2028	1	2035	50	Distribution Network
2	Data Centre (IX Africa)	2025	40	2025	40	TBA
3	Oil Pipeline and Port Terminal (LAPSSET)	2025	1	2030	35	LAPPSET Corridor Power Supply Projects (Isiolo-Garba Tula-Garissa)
4	Special Economic Zones (Tatu City, Athi River, Eldoret))	2025	5	2039	60	Tatu City: Malaa-Tatu City-Thika Rd/Dandora LILO Athi River: Athi River 220/66kV Eldoret: TBA
5	Special Economic Zones (Kedong, Dongo Kundu, Konza)	2025	5	2040	60	Kedong: Maai Mahiu, Suswa, Dongo Kundu: 220/33kV Dongo Kundu SS Konza: Konza 400/132/66kV and Konza 132/33kV
6	E-Mobility	2024	23.5	2030	273	TBA
7	Special Economic Zones (KenGen, Marathon Data Centre)	2026	30	2028	100	KenGen: Olkaria Complex Marathon Data Centre: TBA
8	E-Cooking	2024	1.2	2030	45.7	Organic Growth incorporated in regional SS loads.

The forecast for the peak load was distributed per region as indicated in Table 4-2. In developing the distributed forecast, it was assumed that peak demand occurs simultaneously in all regions.

Table 4-2: Peak Load as Distributed Per Region

Region	2026		2030		2035		2040		2045	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Nairobi	1031.9	340.1	1551.7	493.7	2187.7	440.4	2934.3	965.8	4066.2	512.8
Coast	359.5	123.5	513.5	169.5	741.8	155.2	155.2	155.2	1305.4	175.7
Mt. Kenya	351.4	115.5	335.8	106.9	480.4	96.9	641.8	96.9	886.6	112.8
C Rift	237.5	78.1	267.9	85.3	369.2	74.6	490.4	74.6	695.6	93.4
N Rift	116.2	102.2	568.3	-295	211.8	41	283.5	41	392.1	47.8
Western	222.8	73.2	158.3	19.7	326.2	65.2	438.2	65.2	607	76
Grand Total	2319.3	832.6	3395.5	580.1	4317.1	873.3	4943.4	1398.7	7952.9	1018.5

4.5.2. Generation Data 2026 -2046

The dispatch for system generation plants as described in Table 3-2 were distributed into the Kenya power system regions as given in Volume II Annex 5. Detailed distributed forecast by substation is provided in Volume II Annex 4. This also includes the tentative evacuation substation (point of connection).

4.5.3. Regional Power Balance Statement

As per the load and generation plan, it is noted that Coast, Central Rift, North Rift, Mt Kenya regions continue to dominate as generation and remain net exporters, while Nairobi and West Kenya dominate as net importers. The regional power balance as simulated for the year 2044 is given on Table 4-3. The regional power exchange as per simulations is given on Table 4-4.

Table 4-3: Year 2045 Regional Power Balances (MW)

Power Balance			
Region	Generation Dispatch	Demand (Peak Load)	Surplus/ Deficit ¹
NAIROBI	253.33	4032.11	-3,778.77
COAST	2,182.05	1,367.35	814.7
MT KENYA	1,648.81	862.01	786.80
C RIFT	1,858.64	925.34	933.30
W REGION	292.80	707.96	-415.16
N RIFT	1,830.46	390.26	1,440.2
ETHIOPIA(Imports)	600.7	-	-
EKT(Exports)	-200	200	-
Totals	8,710	8,448.7	

² As per assumed dispatch

Table 4 4: Year 2045 Regional Power Exchange (MW)

REGION		NAIROBI	COAST	MT KENYA	C RIFT	W KENYA	N RIFT	UGANDA	ETHIOPIA	TANZANIA
NAIROBI	MW	-	-842	-1347	-1377	0	-	-	-590	200
	MVAr	-	243	61	236	0	-	-	268	-21
COAST	MW	842	-	-6	-	-	-	-	-	-
	MVAr	-243	-	-29	-	-	-	-	-	-
MT KENYA	MW	1347	6	-	-386	-	-236	-	-	-
	MVAr	-61	29	-	-113	-	37	-	-	-
C RIFT	MW	1347	-	386	-	-80	-922	-	-	-
	MVAr	-236	-	113	-	11	155	-	-	-
W KENYA	MW	0	-	-	-80	-	-208	-30	-	-
	MVAr	0	-	-	-11	-	76	-12	-	-
N RIFT	MW	-	-	236	922	208	-	30	-	-
	MVAr	-	-	-37	-155	-76	-	-16	-	-
UGANDA	MW	-	-	-	-	30	-30	-	-	-
	MVAr	-	-	-	-	12	16	-	-	-
ETHIOPIA	MW	590	-	-	-	-	-	-	-	-
	MVAr	-255	-	-	-	-	-	-	-	-
TANZANIA	MW	-200	-	-	-	-	-	-	-	-
	MVAr	-21	-	-	-	-	-	-	-	-

Source: Authors

4.5.4. Target network Candidates for 2026-2045

In the 2022 – 2041 planning period, candidate projects were selected to resolve challenges in the network. These projects aimed at: de-loading 132kV Dandora – Juja line by providing alternative supply to Juja Road substation; reducing reliance on 220kV Suswa – Nairobi North lines; providing alternative supply to Maralal and Mtwapa; and de-loading Soilo 132/33kV substation.

In the 2024-2043 planning period, target network candidates were identified to: assist in decongesting the Suswa Complex; mitigate the risk of increasing the short circuit fault level of equipment at Suswa; evacuate planned generation at Agil and Olkaria IX; and provide an alternative evacuation path from Olkaria complex.

In the current planning period, there were no new emerging targeted objectives beyond what was assessed in the previous planning period. The evacuation for nuclear power plant expected in Siaya County³ shall be studied in detail and reported in the next planning phase.

4.5.5. Establishment of Sequence of Investments

For the medium term, the investment sequence considered all ongoing projects, projects with committed financing and any other project that compliments the transmission of bulk power to and from 220 /400kV ring for increased efficiency and system reliability in the short and medium term.

Additional Projects in the medium term included:

- i. Additional 23MVA at Ortum Substation
- ii. 23MVA at Ishiara Substation
- iii. 20MVAR Reactor at Kibos

Detailed investment analysis for the plan is given in Chapter 5.

³The development of nuclear power plant is subject to final decision to develop the power plant is received

4.5.6. Transmission System Expansion Plan 2026-2045

Table 4-5 gives the list of planned transmission projects and gives the details of the transmission investment required within the planning period 2026-2045. .

Table 4-5: Planned Transmission Projects

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
YEAR 2027								
1	Intertie between Konza 400/132 and Konza 132/33kV	5.5	11	97	-		-	KPLC
2					Isinya 220/132kV 1x90MVA additional	90		
3					Isinya 132/33 2x45MVA, 1 uprating and 1 additional	90		
4					Ortum 220/33 45MVA	45	3.87	Ketraco
TOTALS 2027		5.50	11.00	97.00	0.00	225.00	3.87	
YEAR 2028								
1	Kipevu - Mbaraki 132kV	6.5	13	97	Mbaraki 132/33kV 2x45MVA	90	-	KPLC
2	Rongai Substation 132/33kV	1.5	6	97	Rongai 132/33kV 2x45MVA	90	17.56	KfW and GoK
3	LILO on Juja/Naivasha 132kV- Maai Mahiu	1.5	3	97	Maai Mahiu 132/66kV 2x60MVA	120	12.06	EXIM China
4	400kV Kimuka - LILO on Suswa- Isinya 400kV	2	4	1600	Kimuka 400/220kV 2x200MVA	400	28.59	GoK, WB
5	Musaga- Webuye Tongaren - Kitale 132kV	91	91	97	132/33kV 2X23MVA Tongaren Substation	46	26.78	TBC

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
6	Suswa - Naivasha SEZ 220kV	18	36	324	Naivasha SEZ 220kV	-	43	TBC
7	Olkaria 1 AU-Olkaria IV /V 220KV	8	16	324			14.76	TBC
8	Juja Rd-Ruaraka 132KV conversion to steel towers including associated substation extension and modification	6.5	6.5	97			11.21	KBC Belgium & GoK
9	Installation of Phase Shifting Transformers (PST) at Suswa						9.8	CIF considered
10					Mobile 220/33kV 1x30MVA and 132/33kV 1x30MVA	60	15	KfW and GoK
11					Mobile 220kV reactor 1x20MVA and 132kV reactor 1x20MVA.	-	11.6	KfW and GoK
12					Garissa 132/11kV 23MVA	23	3.2	KfW and GoK
13					Kisii 132/33kV 2x45MVA	90	3.3	KfW and GoK
14					SAS Upgrade, CCTV& Access Control, SCADA Upgrade, new Metering System, KETRACO WAN	-	16	KfW and GoK
15					Kibos 220/132kV 1x150MVA	150	5.6	TBC
16					SS Ext. Garsen 220/33kV 1x23MVA	23	3.9	TBC
17					Kitale 220/132kV 1x110MVA	110	5.2	TBC
18					Machakos 132/33kV 1x23MVA	23	2.89	TBC
19					Kyeni 132/33kV 1x23MVA	23	2.89	TBC
20					Kutus 132/33kV 2x45MVA	90	3.78	TBC
TOTALS 2028		117.00	139.50	2409.00		1338.00	237.12	
YEAR 2029								
1	Gilgil-Thika-Malaa-Konza 400kV	205	410	1600	Thika 400/220 or 400/132 2x400MVA	800	262.59	TBC
					Malaa/Nairobi East 400/220 2x400MVA	800		TBC
					Gilgil 400/220 2x400MVA	800		TBC
2	LILO at Tatu City on Dandora/Thika Road 220kV to Malaa	30	60	324	Switch Station at Tatu City	-	30.11	TBC
3	Sotik – Kilgoris 132kV	50	100	97	Kilgoris 132/33kV 2x23MVA	46	22	Eol PIP
4	Lessos -Loosuk (Loiyangalani/Suswa LILO) 400kV	180	360	1600	Loosuk Switch 400kV substation	-	166	PIP
					Lessos 400/220kV 2x400MVA	800		PIP

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
5	Kisumu (Kibos) - Kakamega – Musaga 220kV	73	146	324	Kakamega 220/33 2x45MVA	90	71.17	PIP
					Musaga 220/132 2x90MVA	180		PIP
6	Rongai 400/220 LILO	2	8	1600	Rongai 400/220 2x200MVA	400	34.05	TBC
7	Kamburu-Embu 220KV	150	300	324	Embu 220/132 2x90MVA	180	40.5	EXIM China
8	Rongai 220/132 LILO	2	8	97	Rongai 220/132 2x90MVA	180	18.85	TBC
9	Kibos - Bondo-Rangala-Busia-Myanga 132kV	141	141	97	Bondo 132/33 2x23MVA	46	28.35	EXIM India
					Busia 2x23MVA 132/33kV	46	47.67	TBC
					SS Ext Rangala 132/33kV Additional Line Bays	0		
					Myanga 132kV Switch Station	0		
10	Rongai - Keringet - Chemosit 220kV	96	192	324	Keringet 220/33 2x60MVA	120	100	TBC
					Chemosit 220/132kV 2x90MVA	180		TBC
11	400/220kV SS at Baringo and LILO to Loosuk/Lessos line	3	12	1400	Baringo 400/220kV 2x400MVA	800		Developer/GDC
13					Chemosit 132/33kV 2x45/60MVA	90	2.178	TBC
14					Garissa 220/132kV 1x110MVA - second TX	110	5.2	
15					Githambo 132/33kV 23MVA - second TX	23	2.89	EXIM India
16					Mwingi 132/33kV 23MVA	23	2.89	TBC
17					Wote 132/33kV 23MVA	23	2.89	TBC
18					Thuridibuoro 132/33kV 23MVA	23	10.08	TBC
19					Kitui 132/33kV 23MVA	23	2.89	TBC
TOTALS 2029		932.00	1737.00	7787.00		5783.00	850.31	
YEAR 2030								
1	Meru - Maua 132kV	35	70	97	Maua 132/33kV 2x23MVA	46	25.63	Solicited PPP
2	Kiambere - Maua – Isiolo 220kV	145	290	324	Maua 220/132kV 2x90MVA	180	120.94	Solicited PPP
3	Menengai - Olkalou – Rumuruti 132kV	70	140	97	Olkalou 132/33kV 2x23MVA	46	34.34	TBC
4	Rumuruti - Maralal/Loosuk 132kV	148	296	97	Loosuk 132/33kV 1x23MVA	23	48.84	Eol PIP
5	Ishara - Meru LILO - Marimanti 132kV	13	26	97	Marimanti 132/33kV 2x23MVA	23	13.35	TBC

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
					Ishiara 132/33kV 1x23MVA	23	2.89	GoK
6	220kV Kiambere/Rabai LILO – Mutomo	1.5	3	324	Mutomo 220/132kV 2x90MVA	180	36.86	Eol PIP
7	132kV Mutomo- Makindu	69	138	97	Mutomo 132/33kV 2x23MVA	46		Eol PIP
8	Turkwel – Lokichar – Lodwar 220kV	120	240	324	Lokichar 220/66kV 2x23MVA	46	100	TBC
					Lodwar 220/33kV 2x23MVA	46		
9	Kwale LILO (Mariakani/Dongo Kundu) - Kibuyuni (including switch station at Bang'a) and 132kV intertie to existing network	77	154	324	Shimoni/Kibuyuni 220/132kV 2x90MVA	180	84.9	Solicited PPP
10	Second Circuit LILO Nakuru West –Lanet 132KV	1.5	3	97			5	KfW and GoK
TOTALS 2030		680.00	1360.00	1878.00		839.00	472.75	
YEAR 2031								
1	Kenya -Uganda Interconnector	132	264	1400	Lessos 220/132kV 75MVA	75	161.83	AfDB & GoK
2	Ndhiwa (Ongeng) - Magunga (Karungu Bay/Sindo) 132kV	50	50	97	Magunga 132/33 1x23MVA	23	21.24	TBC
3	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	78	156	97	Mwala 132/33 2x23MVA	46	33.21	TBC
4	Mtwapa 132/33kV off Rabai-Kilifi 132kV	1.5	3	97	Mtwapa 132/33 2x45MVA	90	10.63	TBC
5	Githambo - Othaya-Kiganjo 132kV	72	144	97	Othaya 132/33 2x23MVA	46	28.03	Solicited PPP
6	LILO on Nairobi – Mombasa 400kV system -New Voi 400/132kV ss	3	12	1400	Voi 400/132kV 2x150MVA	300	18.24	Eol PIP
7	Reinforcement of Nairobi – Mombasa 132kV system at Voi 132kV intertie	7	14	97	New Voi 132/33kV 2x23MVA	46	10.91	Eol PIP
8					Habaswein 220/33 2x23MVA	46	176.18	TBC
	Garissa – Habaswein/Dadaab – Wajir 220kV	330	330	324	Wajir 220/33 2x23MVA	46		TBC
9	Isiolo – Garba Tula – Garissa 220kV	320	640	324	Garba Tulla 220/33 2x60MVA	120	177.99	TBC
10	Embu-Thika 220kV	75	150	324	Thika 220/132 2x90MVA	180	48.96	TBC
11	Reconductoring of KPTSIP lines with second circuit: i. 132kV Olkaria - Narok ii. 132kV Sotik-Bomet iii. 132kV Sultan Hamud- Wote-Kitui-Mwingi iv. 132kV Ishiara- Kieni v. 132kV Nanyuki-Rumuruti		353		Substation Extension of KPTSIP SS to accommodate second circuits: i. 132kV Olkaria - Narok ii. 132kV Sotik-Bomet iii. 132kV Sultan Hamud- Wote-Kitui-Mwingi iv. 132kV Ishiara- Kieni v. 132kV Nanyuki-Rumuruti	-	31.4	TBC
12	Voi - Taveta 132kV	110	220	97	Taveta 132/33 2x23MVA	46	34.76	Eol PIP
13	Thika/Malaa – HG Falls 400kV	200	400	800			134.84	Developer

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
14	Kiambere/Malaa LILO-Karura 220kV	10	20	324			10.44	Developer
15					-200MVA, +150MVA STATCOM/DRPC at Western Kenya region, Nairobi Region and Coast region	-200 and +150 MVA	135	TBC
TOTALS 2031		1388.50	2756.00	5478.00		1064.00	1,033.66	
YEAR 2032								
1	Supply to Mandera County and environs (220kV Wajir-Mandera or link from Ethiopia)	250	500	324	Mandera 220/33kV 1x23MVA	23	161.1	TBC
2					Garissa 132/33kV 23MVA (second tx)	23	2.89	TBC
TOTALS 2032		250.00	500.00	324.00		46.00	163.99	
YEAR 2033								
1	Olkaria VIII 220KV Evacuation (through Olkaria VI)	5	10	324			13.34	TBC
2	NPP TI 1	80	160	1600	Div 1 SS 3x350MVA	1050	110.23	TBC
3	NPP TI 2	418	836	1600	Div 2 SS 3x350MVA	1050	316.10	TBC
4	Rongai - Kilgoris (Part of Lake Victoria Ring) 400kV	235	470	1600	Kilgoris 400/132 2x150MVA	300	219	TBC
5	220kV Marsabit-Moyale	180	360	324	Moyale 220/33 1x23	23	119.94	TBC
TOTALS 2033		918.00	1836.00	5448.00		2423.00	778.61	
YEAR 2034								
1	Menengai – Rongai 400kV	45	90	1600	Menengai 400/132 2x150	300	76.08	TBC
TOTALS 2034		45.00	90.00	1600.00		300.00	76.08	
YEAR 2035								
1					SS Ext Dandora 220/66kV 2x200MVA	400	13.62	TBC
2					SS Ext Voi 132/33 2x45MVA uprating	90	3.09	TBC
3					SS Ext Galu 132/33 2x45MVA uprating	90	3.09	TBC
4					SS Ext Jomvu 132/33 2x45MVA uprating	90	3.09	TBC
5					SS Ext Rabai 132/33 1x45MVA additional	45	5.87	TBC
6					SS Ext Webuye 132/33 1x23MVA additional	23	5.23	TBC
7					SS Ext Naivasha 132/33 1x45MVA additional	45	5.87	TBC

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
TOTALS 2035		0.00	0.00	0.00		783.00	39.86	
YEAR 2036								
1	Longonot Substation including LILO on Gilgil Thika 400kV line	40	80	1600	Longonot 400/220kV 2x400MVA	400	58.03	TBC
2	New Thika - Ruaraka 220kV UG cables	27	54	324	Ruaraka 220/132kV 2x150MVA	180	81.06	TBC
3	NPP TI 1	80	160	1600	Div 1 SS 3x350MVA	1050	110.23	TBC
4	NPP TI 2	418	836	1600	Div 2 SS 3x350MVA	1050	316.10	TBC
5	Kilgoris – Masaba (Isebania/Kehancha) 132kV	45	90	97			13.37	TBC
6	Olkaria IX - Longonot 220kV (Evacuation)	25	50	324			13.69	TBC
7					Myanga or Musaga 400/132kV 2x150MVA	300	30.39	TBC
8					New Bamburi 132/33 45MVA upgrade	45	1.79	TBC
TOTALS 2036		635.00	1270.00	5545.00		3025.00	624.66	
YEAR 2037								
TOTALS 2037		0.00	0.00	0.00		0.00	-	
YEAR 2038								
1					Namanga 132/33 1x23MVA additional	23	5.23	TBC
2					Rabai 132/33 1x45MVA additional	45	5.87	TBC
3					Thika 132/66 1x60MVA additional	60	5.97	TBC
4					Gatundu 132/33 1x23MVA additional	23	5.23	TBC
5					Soilo 132/33 2x45MVA uprating	90	3.09	TBC
6					Chemosit 132/33 1x45MVA additional	45	5.87	TBC
7					Eldoret 132/33 1x45MVA additional	45	5.87	TBC
8					Kitale 132/33 2x90 uprating	180	3.09	TBC
9					Isiolo 132/33 1x23MVA additional	23	5.23	TBC
TOTALS 2038		0.00	0.00	0.00		534.00	45.45	
YEAR 2039								

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
1	400kV Mariakani-Dongokundu	60	120	1600	Dongo Kundu 400/220kV 4x200MVA	800	86.16	TBC
2					Lessos 132/33 2x45MVA uprating	90	3.16	TBC
TOTALS 2039		60.00	120.00	1600.00		890.00	89.32	
YEAR 2040								
1	Agil 220KV Evacuation	8.5	8.5	324	Agil SS (by Developer)	-	4.66	TBC
2	Agil - Olkaria IX	25	25	324	Agil SS (by Developer)	-	13.69	TBC
TOTALS 2040		33.50	33.50	648.00		-	18.35	
YEAR 2041								
1	132kV Kwale Sugar-Titanium reconductoring	31.5	31,5	165			0.95	TBC
2	132kV Webuye-Musaga reconductoring	18	18	135			1.8	TBC
3					City Centre 150MVar Capacitor	150MVar	4.612	TBC
4					City Centre 220/66 1x200MVA additional	200	9.92	TBC
5					Isinya 400/220kV 2x200MVA	400	14.5	TBC
6					Nanyuki 132/33 2x45MVA uprating	90	3.09	TBC
7					Meru 132/33 2x45MVA uprating	90	3.09	TBC
8					Kisii 132/33 1x45/60MVA additional	45	3.09	TBC
9					Kitale 220/132 1x90MVA additional	90	5.01	TBC
TOTALS 2041		49.50	18	300		915	46.06	
YEAR 2042								
1	Lokichar/Lodwar – Lokichoggio 220kV	190			Lokichoggio 220/33 1x23 MVA	23		TBC
2					Loosuk 400/132 2x90MVA	180	12.77	TBC
TOTALS 2042		190	0	0		203	12.77	
YEAR 2043								
TOTALS 2043		0	0	0		0	-	
YEAR 2044								

S/n	Transmission Line Name	Length (KM)	Circuit Length (KM)	MVA/ Circuit	Substation Name	MVA	Estimated Total Cost (MUSD)	Financier
TOTALS 2044		0	0	0		0	-	
YEAR 2045								
1	Ngong (Kimuka) – Magadi 220kV	88	88	324	Magadi 220/66 2x60MVA	120	60.1	TBC
TOTALS 2045		88	88	324		120	60.10	
GRAND TOTAL		5,392	9,959	33,438		18,488	4,552.96	





5

INVESTMENT AND FINANCING PLAN

5.1. Ongoing projects

The ongoing transmission projects comprises approximately 1,459 km of route length (equivalent to 2,252 km of circuit length) of transmission lines and about 3,320 MVA of substation capacity, all currently under construction and expected to be completed by 2030.

The total estimated cost of these ongoing projects is USD 1,109 million, with an outstanding investment requirement of USD 733 million. Out of the remaining investment requirement, USD 350 million has already been secured or committed through a combination of development partner financing and Engineering, Procurement and Construction (EPC). Despite these commitments, there remains a financing gap of approximately USD 383 million.

Figure 5-1 illustrates the yearly breakdown of the funding gap.

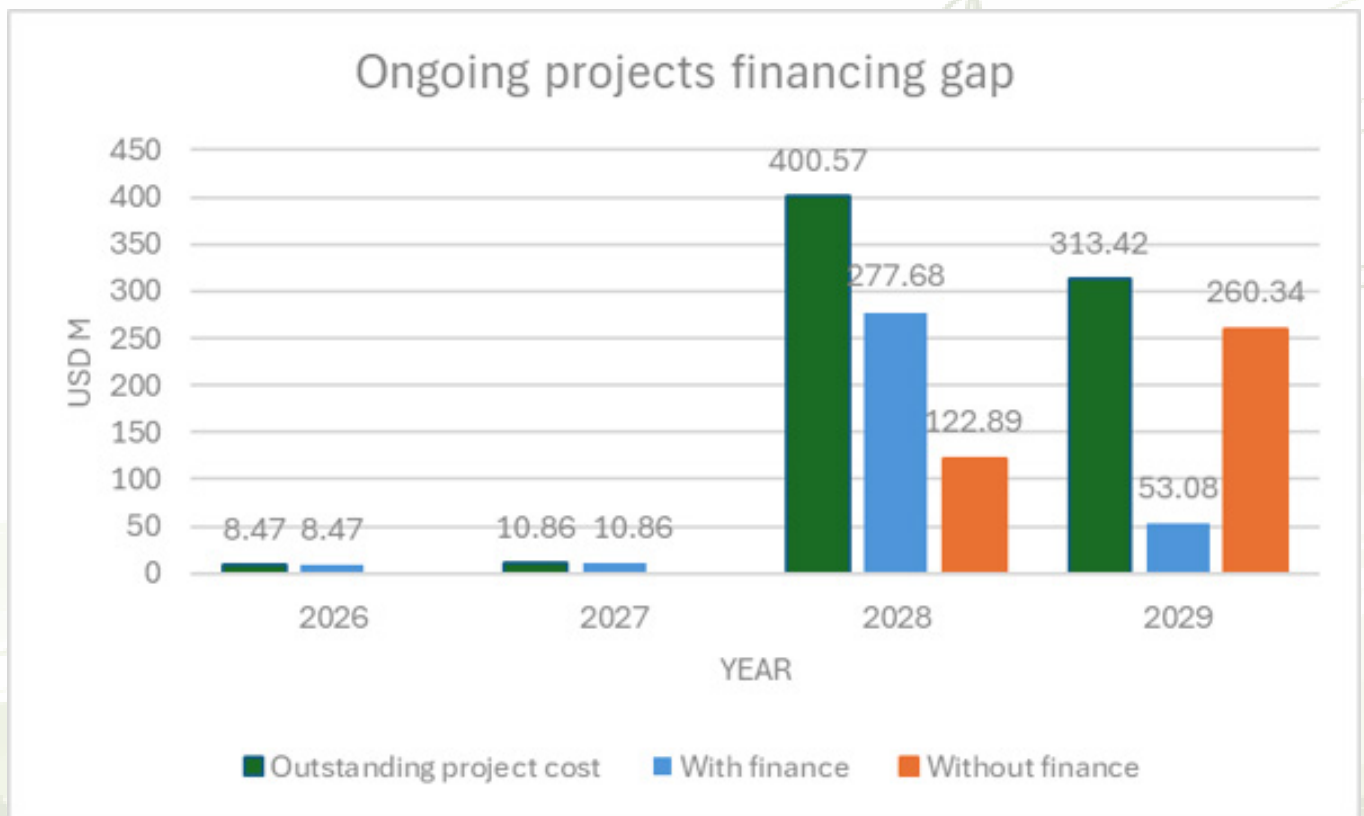


Figure 5-1: Ongoing projects financing gap.

This funding gap is associated with several key transmission projects that are critical for strengthening the national grid and supporting power evacuation and regional reliability. These projects include the 220 kV Garsen-Hola-Bura-Garissa transmission line, Makindu Substation, 86 132/33kV Maai Mahiu substation and associated LILO, Olkaria I AU – Olkaria IV/V 220 kV, 220 kV Loiyangalani-Marsabit, 220 kV Kamburu-Embu-Thika, and 220 kV Isiolo-Marsabit.

Comparatively the ongoing projects have reduced from 30 in 2025-2044 TMP to 24 in the current TMP as a result of completion of the following projects.

- i. 29 km Awendo-Masaba 132kV and its associated Masaba 132/33kV 1x23 substation
- ii. 65 km Lessos – Kabarnet 132kV and its associated Kabarnet 132/33kV 1x23MVA
- iii. substation
- iv. 66 km Kitui – Wote 132kV
- v. 69 km Sondu (Thurdibuoro) – Ongeng (Homa Bay/Ndhiwa) 132kV
- vi. Mariakani 400/220kV substation
- vii. Restoration of Longonot Towers

Notably, the funding gap for ongoing projects remains unchanged from the 2025-2044 Transmission Master Plan (TMP). This is because the financing requirements continue to be linked to the same set of projects identified in the previous planning cycle.

5.2 Planned Projects

Between the period 2026 - 2045, about 5,410 km in route length (10,406 km in circuit length) of transmission lines and 18,442 MVA of substation capacity are planned. The investment requirement is approximated at USD 4,553 million without funding commitment.

Comparatively, the planned projects have remained at 116 in the current TMP.

5.3 Medium term projects

Medium term projects refer to ongoing and planned projects expected to be completed by the year 2030. The company has planned to implement 3,193 km in route length (5,499 km in circuit length) of transmission lines and 11,459 MVA of substation capacity.

The total cost of medium-term transmission projects is USD 2,673 million, categorized into ongoing USD 1,109 million and planned projects of USD 1,564 million.

Out of the total investment requirement in the short term of USD 2,673 million, USD 376 million has been settled and USD 350 million has secured funding leaving a financing gap of USD 1,947 million. 87 Ongoing projects outstanding balance account for USD 733 million, with USD 350 million funded and USD 383 million still requiring financing. This indicates that several projects already under implementation may face delays without additional funding support. These projects include the 220 kV Garsen-Hola-Bura-Garissa transmission line, Makindu Substation, 132/33 kV Maai Mahiu substation and associated LILO, Olkaria I AU - Olkaria IV/V 220 kV, 220 kV Loiyangalani-Marsabit, 220 kV Kamburu-Embu, and 220 kV Isiolo-Marsabit.

Planned projects represent investment pipeline of USD 1,564 million in the medium term which is not funded. However, there is potential of funding for USD 381 million only highlighting the need for proactive resource mobilization.

Table 5-1 summarizes the investment requirements and funding gaps for transmission projects during the medium-term period and the overall Transmission Master Plan (TMP) period.

Table 5-1: Investment requirements and funding for medium term and overall TMP

Project Status	Medium-Term Estimated Cost (USD Million)	Medium-Term Funding Gap (USD Million)	Overall TMP Estimated Cost (USD Million)	Overall TMP Funding Gap (USD Million)
Ongoing Projects	733	383	733	383
Planned Projects	1,564	1,564	4,553	4,553
Total	2,297	1,947	5,286	4,936

Figure 5-2 illustrates the overall TMP funding gap in the last five years.

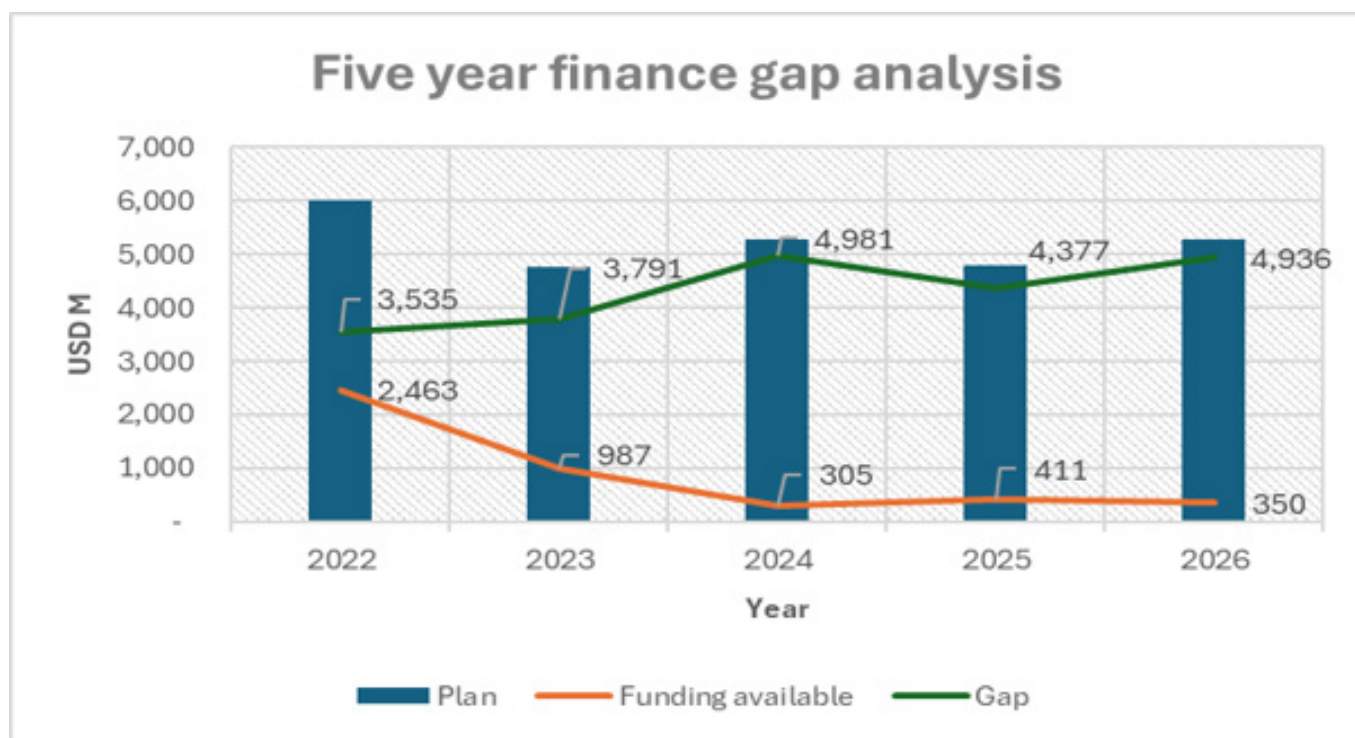


Figure 5-2: Historical five-year funding gap analysis.

5.3.1 Planned Projects with Potential Financing

The following planned transmission infrastructure projects have potential funding by development partners.

- i. Substations upgrade; Garissa, Kisii and phase shifting transformers at Suswa.
- ii. Mobile substations
- iii. 73 km Kisumu (Kibos) - Kakamega - Musaga 220kV
- iv. 180 km Lessos -Loosuk (Loiyangalani/Suswa LILO) 400kV
- v. Design, supply and installation of 220kV Phase Shifting Transformers
- vi. 13 Substation Extensions, Supply and installation of new power transformers
- vii. Reconductoring of second circuits for the 6 KPTSIP lines
- viii. SAS Upgrade, CCTV& Access Control, SCADA Upgrade, new Metering System, PMUs, KETRACO WAN.

5.3.2. PPP Projects

Among the projects with potential financing, the following projects have been considered for possible procurement through solicited PPP.

- i. 77 km Kwale LILO (Mariakani/Dongo Kundu) -Kibuyuni (including switch station Bang'a) and 132kV intertie to existing network.
- ii. 145 km Kiambere-Maua-Isiolo 220 kV
- iii. 35 km Meru- Maua 132kV
- iv. 72 km Githambo - Othaya-Kiganjo 132kV
- v. 91 km Musaga- Webuye Tongaren - Kitale 132kV
- vi. 141 km Kibos-Bondo-Rangala-Busia-Myanga 132kV

In addition, the company has received expression of interest on the following projects which are at various stages of PIP4.

- i. 1.5 km 220kV Kiambere/Rabai LILO-Mutomo and 69km 132kV Mutomo-Makindu
- ii. 148 km Rumuruti - Maralal/Loosuk 132kV
- iii. 50 km Sotik-Kilgoris 132kV
- iv. 3 km LILO on Nairobi - Mombasa 400kV system -New Voi 400/132kV ss and 7km Reinforcement of Nairobi - Mombasa 132kV system at Voi 132kV intertie
- v. 110 km Voi - Taveta 132kV

⁴As of January 2026







STAKEHOLDER ENGAGEMENT AND PUBLIC PARTICIPATION

6.1. Introduction

6.1.1. Context and Stakeholder Landscape in Transmission Development

Transmission infrastructure development has the potential to disrupt existing social, environmental, and economic systems within a community setup. These impacts vary depending on project location, scale, and design. However, the fundamental essence of infrastructure development is to address critical socio-economic challenges by enabling reliable electricity supply, facilitating economic activity, improving livelihoods, and supporting national development goals. The development of these infrastructure interfaces with a diverse range of stakeholders, both affected and interested, whose interests, influence, and actions can significantly shape project feasibility, cost, schedule, and long-term performance. These stakeholders possess varying degrees of power, influence, and interest in the project and may affect or be affected by project decisions and outcomes. They include directly affected groups such as landowners and local communities, as well as institutional stakeholders including county governments, national ministries, departments and agencies, regulators, development partners, civil society organizations, and private sector actors.

6.1.2. Role of Stakeholder Engagement and Public Participation

Stakeholder engagement and public participation provide a structured and systematic approach for managing the interfaces between transmission infrastructure development and the diverse stakeholders involved. Within the previous Transmission Master Plan (2025–2044), stakeholder engagement was largely undertaken to meet compliance requirements. While this approach fulfilled regulatory obligations, the scale and ambition of future transmission expansion require a more structured, strategic, and risk-based approach to stakeholder engagement.

Consistent with the Constitution of Kenya (2010) and applicable environmental and land governance frameworks, stakeholder engagement promotes transparency, accountability, and inclusiveness in infrastructure planning and implementation. When applied early and proportionately, it supports evidence-based decision-making, strengthens the social license to operate, and reduces non-technical risks that may otherwise translate into cost escalation, project delays, or operational constraints.

Accordingly, the essence of stakeholder engagement and public participation in the 2026 2045 Transmission Master Plan is to ensure that transmission expansion is planned and implemented in a socially inclusive, environmentally responsible, and institutionally coordinated manner, thereby enhancing project acceptability (social license to operate), reducing implementation risks, and strengthening the long-term sustainability and resilience of Kenya’s power transmission system.

The image below presents a social framework approach indicating the centrality of people’s wellbeing in project for planning and development shown in Figure 6-1



Figure 6-1: Social framework approach in management of social impacts in projects.
Source: Intersocial consulting group

6.2 Stakeholder mapping

Stakeholder mapping is an essential part of planning and implementing transmission projects. Knowing who is affected, who has influence, and who can contribute is crucial for projects success and sustainability. Mapping focuses on three main aspects: interest, influence, and impact.

In the planning and development of transmission infrastructure, this process involves.

- **Stakeholder identification:** All relevant stakeholders are identified, including government agencies, regulatory bodies, local communities, non-governmental organizations, financiers, and contractors. Each group has different concerns, priorities, and expectations.
- **Assessing Influence:** Stakeholders are evaluated based on their ability to affect the project. For example, regulatory authorities can approve or delay projects; local communities can affect access to land and social acceptance; financiers and development partners influence financing; and environmental organizations may shape design decisions through advocacy.
- **Assessing Interest:** Stakeholders are also evaluated based on their interest in project outcomes. Such as communities are concerned with land use, safety, and livelihoods; contractors focus on timelines, costs, and technical requirements; and government agencies emphasize compliance with policies and socio-economic objectives.

Based on influence and interest, stakeholders are usually grouped into four categories as shown in Figure 6-2 .

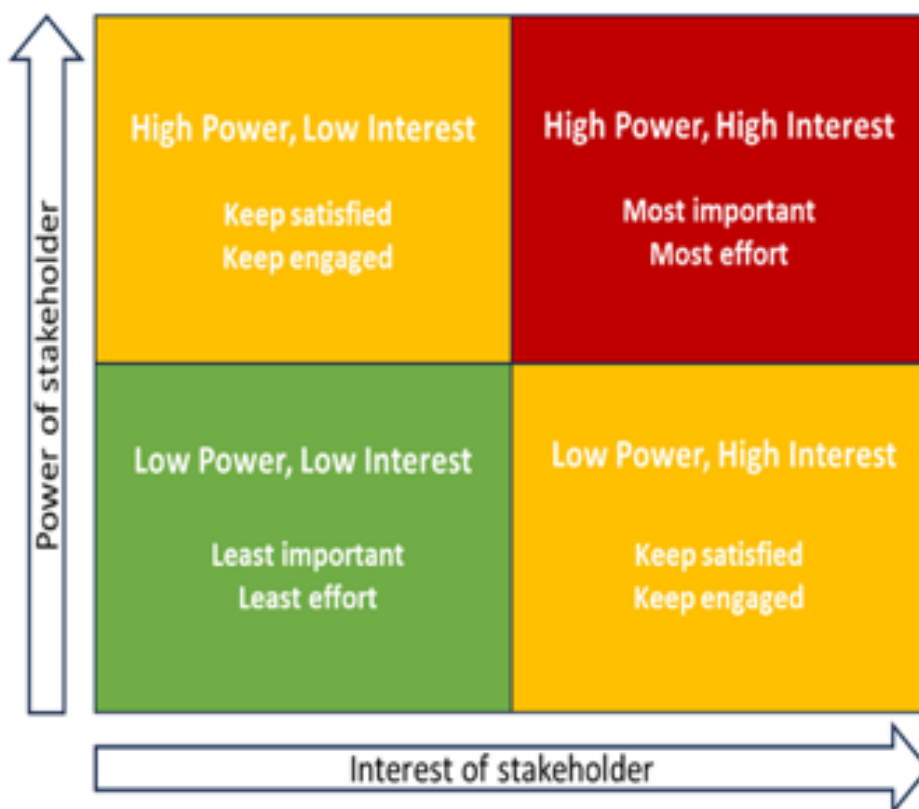


Figure 6-2: Stakeholder mapping framework.

6.3 Stakeholder Management

Stakeholder engagement and management currently occur across several stages of transmission project development. Key practices include:

- Public participation during ESIA and RAP processes
- Community meetings during wayleave acquisition and land valuation
- Community grievance handling during construction
- In addition to these activities, stakeholder consultation and public participation also occur, though to varying degrees, at other critical project stages, including:
- Project feasibility studies, where initial high-level consultations help identify potential social, environmental, and technical constraints.
- Development of appraisal documents, ensuring stakeholder perspectives inform project design and risk assessment.
- Route firming, to gather input on preferred corridors and reduce potential conflicts with communities or sensitive areas.
- Substation land scoping, engaging local stakeholders on land availability, ownership, and potential impacts.
- Environmental and Social monitoring during construction, though current practice is limited and requires strengthening.
- Environmental and Social audits, where systematic engagement is essential to validate mitigation measures and compliance.

These activities have enabled KETRACO to meet regulatory requirements and facilitate project implementation. However, engagement has largely been project-specific and concentrated during the initial appraisal and approval stages of the project viewed as a critical process towards project approvals.

The Master Plan therefore proposes strengthening stakeholder engagement through earlier, structured, and continuous participation across the entire project lifecycle. Effective stakeholder management ensures that all relevant parties are appropriately informed, consulted, and involved, thereby reducing project risks, enhancing acceptance, and supporting sustainable project outcomes.

6.4 Engagement Strategy Development

Stakeholders are prioritized based on their influence and interest, and engagement strategies are tailored accordingly. Error! Reference source not found. summarizes the main stakeholder groups for transmission projects, their relevance to the project,

potential impact exposure, level of influence, and the corresponding engagement modalities. This structured approach enables the project team to implement a targeted and effective stakeholder engagement program that aligns with the project lifecycle and regulatory requirements.

Table 6-1: Stakeholder Categories and Engagement Modalities

Stakeholder Group	Relevance	Impact Exposure	Influence	Engagement Mode
Ministries Departments and Agencies	Policy and approvals	Low–High	High	Inform, Consult, Collaborate
Sector Agencies and Utilities	System integration	Low–High	High	Inform, Consult, Collaborate
Regulatory Authorities	Compliance certainty	Low	High	Consult, Collaborate
County Governments	Land and local approvals	Medium	Medium	Inform, Consult, Involve
Development Partners	Capital and risk oversight	Low	High	Collaborate
Affected Communities	Land and livelihood impacts	High	Low– Medium	Inform, Consult, Involve, Empower
Civil Society	Oversight and reputation	Medium	Medium	Consult, Collaborate
Private Sector (including PPPs)	Delivery and O&M	Medium	High	Collaborate, Involve
Media	Public perception	Medium	High	Inform, Monitor
Power Consumers	Service reliability	Medium	Low	Inform, Consult

6.5 Process Improvements

6.5.1. Full public participation spectrum implementation

The Master Plan integrates a full spectrum of public engagement, from informing stakeholders to empowering them appreciatively through its implementation period. Stakeholders are first informed about project objectives, timelines, and potential impacts. They are then consulted to provide feedback, involved in decision-making, collaborated with on solutions, and ultimately empowered to influence project outcomes, particularly in communities directly affected by transmission activities.

While stakeholder engagement remains a critical component of current practices, there is room for improvement, with empowerment representing the pinnacle of engagement. Fully empowering stakeholders fosters a sense of ownership, strengthens trust, and enhances the project’s social license to operate. Furthermore, applying engagement consistently across the entire project lifecycle ensures that stakeholder perspectives actively inform decisions at every stage, promoting sustainable and equitable project outcomes.

Refer to Figure 6-3 for a visual representation of the full spectrum of public engagement across the transmission project lifecycle.

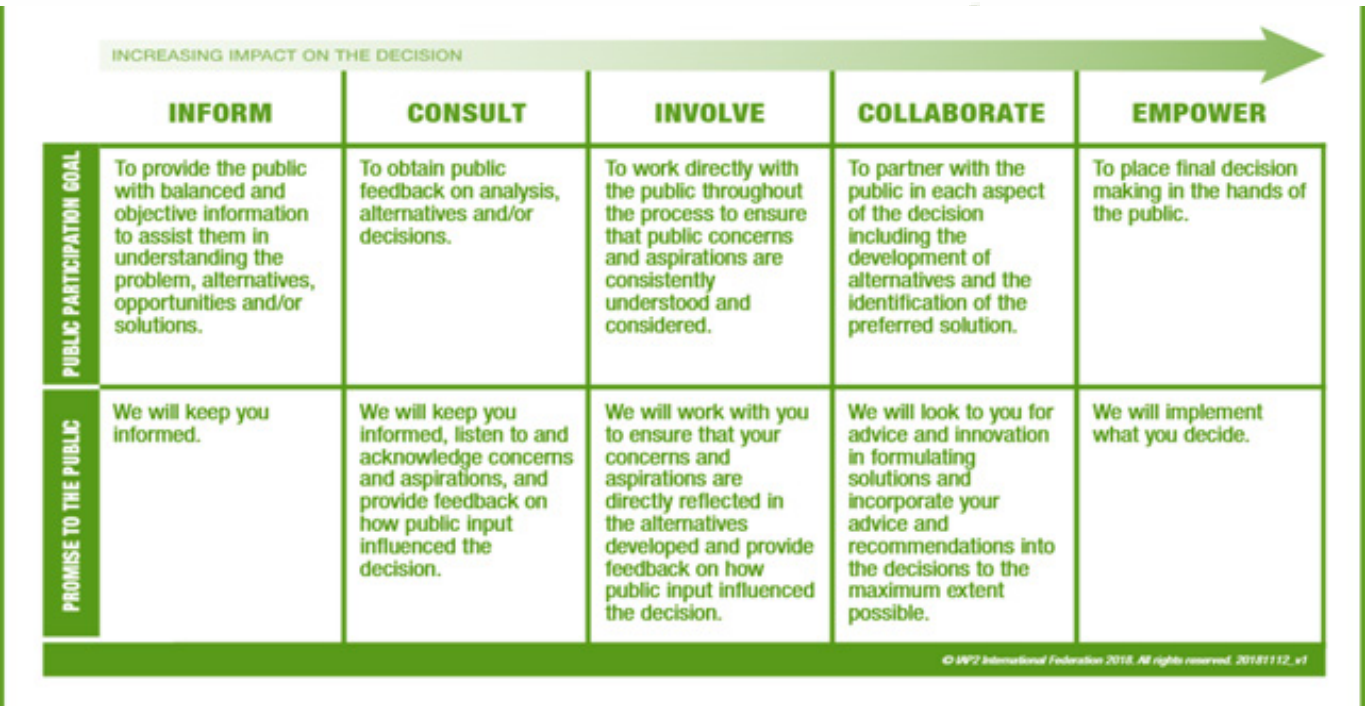


Figure 5-1: Ongoing projects financing gap
Source: International Association public participation .

6.5.2. Stakeholder Engagement Across the Project Lifecycle

Stakeholder engagement and disclosure will be embedded at defined decision points across the project lifecycle, with scope and intensity aligned to project risk profiles as shown in Table 6-2.

Table 6-2: Stakeholder Engagement Across Project Lifecycle

Project Stage	Engagement Objective	Key Instruments
Project initiation and concept development	Identify material risks and inform option selection	Concept briefs, targeted meetings, public notices
Feasibility and design development	Manage environmental and social risks; optimize routing	Draft safeguard instruments, hearings, disclosures
Approvals and financing	Resolve residual issues; support investment decisions	Final safeguard documents, consultation summaries
Construction and commissioning	Control implementation risks; manage grievances	Construction schedules, GRMs, liaison meetings
Operation and maintenance	Monitor long-term impacts and performance	Monitoring reports, surveys, feedback platforms

This lifecycle integration reduces the likelihood of late-stage risk emergence and strengthens implementation predictability.

6.5.3. Engagement Framework and Risk-Based Approach

Stakeholder engagement will be implemented as a risk-based, proportionate, and performance-oriented process, aligned with project scope, scale, complexity, and impact profile. Engagement activities will be integrated into project planning, construction, and operations.

The framework commits to early identification and proactive management of social, environmental, land, and governance risks through structured stakeholder engagement. It emphasizes targeted and inclusive participation, timely and transparent information disclosure, and documented consultations that inform project decisions. The framework also establishes accessible grievance redress mechanisms and prioritizes the avoidance, minimization, and mitigation of adverse impacts on communities, the environment, and project delivery.

6.5.4. Sensitization and Capacity-Building for Stakeholder Management

To strengthen this approach, the Master Plan emphasizes sensitization and capacity-building on stakeholder management for all project actors, including project implementation units, the management, and operational staff. Key measures include:

- Enhancing institutional capacity to design contextual messaging tailored to specific projects and stakeholder groups based on detailed stakeholder mapping.
- Building skills on effective stakeholder communication techniques, ensuring clearculturally appropriate, and responsive information exchange
- Equipping project teams to manage stakeholder interactions proactively, anticipate concerns, and resolve conflicts efficiently.

6.6 Grievance Redress Mechanisms

This TMP strengthens the role of Grievance Redress Mechanisms (GRMs) by positioning them as a practical, frontline tool for managing stakeholder concerns throughout the project lifecycle.

A well-designed GRM ensures grievances are captured systematically, addressed promptly, and resolved transparently.

Key components include:

- Clear reporting and access channels
- Defined response timelines (not exceeding five days where possible)
- Escalation procedures
- Documentation and tracking
- Oversight and accountability arrangements.

The operational steps of the grievance handling process are illustrated in Figure 6-4.

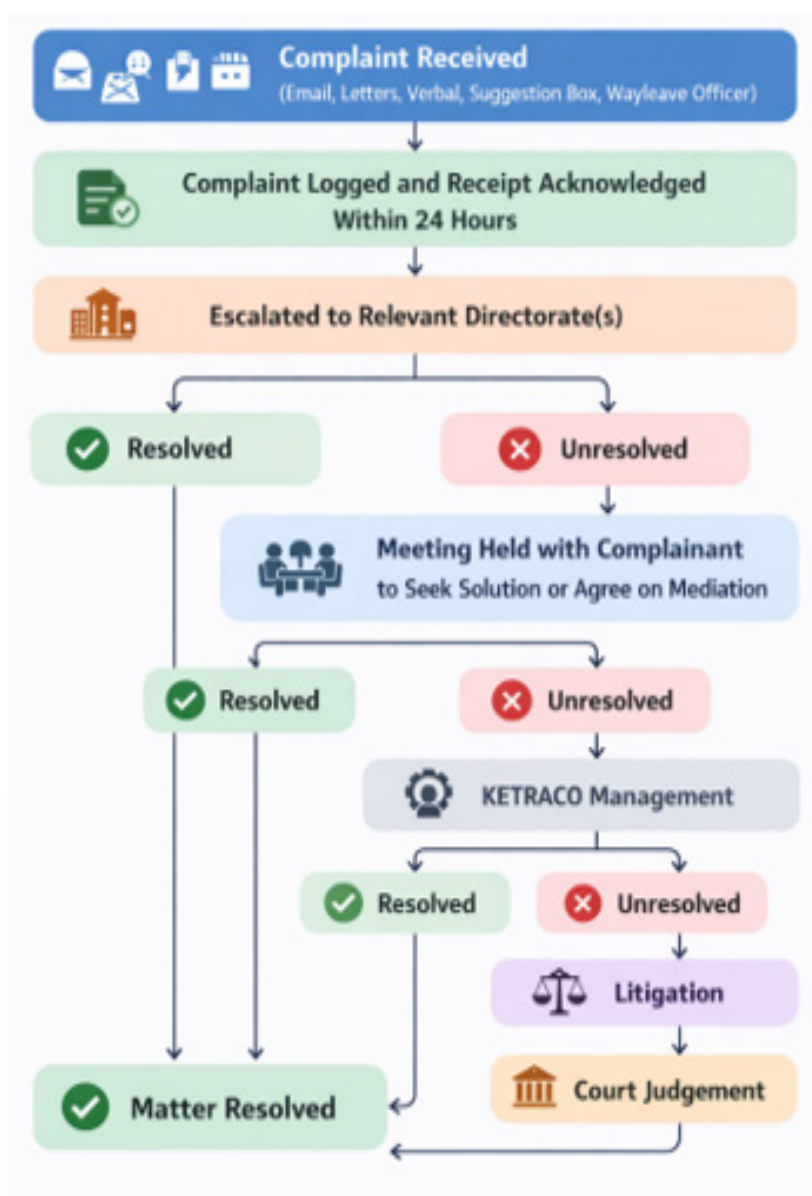


Figure 6-4: Grievance Redress Mechanism (GRM) Procedure.
Source: KETRACO RPF

Effective GRMs enable issues to be resolved early at community or project level before they escalate into disputes or disruptions that impact construction or operations.

6.7. Stakeholder Engagement as a Risk Mitigation Mechanism

Transmission projects involve translation of technical designs into physical infrastructure, requiring extensive interaction with land, communities, and existing social systems. Improper management of stakeholder interactions may give rise to non-technical risks such as land disputes, regulatory objections, grievances, political intervention, or litigation. These risks can directly result in schedule overruns, cost escalation, financing delays, and revenue impacts.

Structured stakeholder engagement operates as risk control measures, reducing the likelihood and severity of such outcomes by addressing concerns early and systematically as illustrated in Figure 6-5.

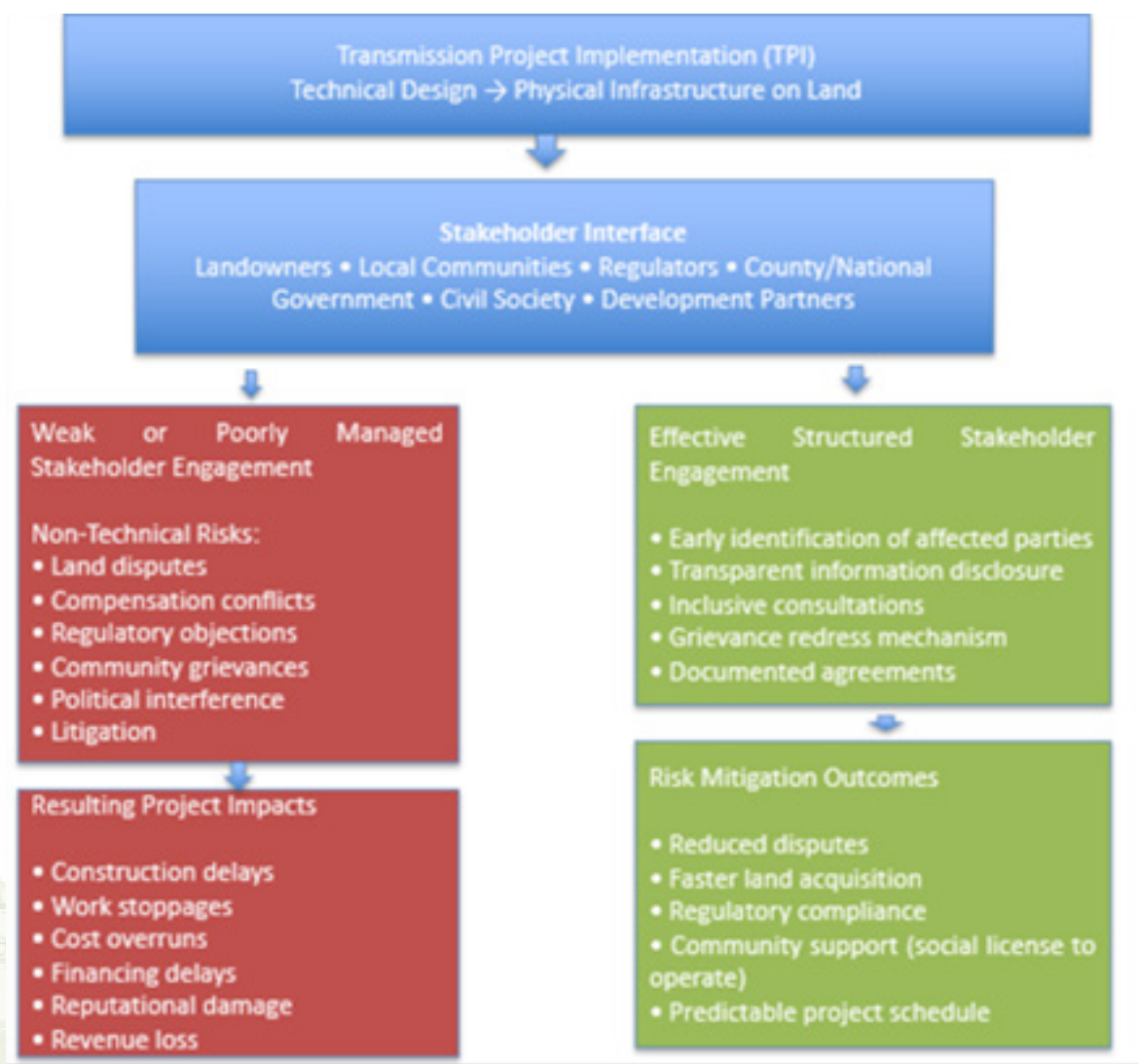


Figure 6-5: Visual conceptual illustration for the Stakeholder Risk Control Framework

The conceptual framework illustrates how proactive stakeholder engagement reduces non technical risks, enabling smoother project implementation, faster land acquisition processes, and stronger community support.

6.9. Stakeholder Engagement Approach: Current Practice vs Vision to 2045

Stakeholder engagement in transmission development has traditionally been undertaken primarily during project planning and environmental assessment stages, with public participation largely driven by regulatory compliance requirements. Engagement activities have typically focused on consultation meetings facilitated through local administration structures, while information disclosure has mainly occurred during formal consultation forums or project announcements. Grievance management mechanisms have generally been project-based, and coordination with government agencies has often taken place during approval and permitting stages. In many cases, stakeholder engagement reduces significantly after project commissioning.

The Transmission Masterplan 2026-2045 proposes a more proactive and integrated stakeholder engagement framework that spans the entire project lifecycle. Under this approach, stakeholder mapping will begin at the project concept and planning stages to ensure early identification and engagement of affected communities and institutions before route design and feasibility studies commence. Public participation will transition from a compliance driven activity to a continuous engagement process supported by structured feedback mechanisms, expanded communication channels, and proactive information disclosure. The framework also introduces a strengthened Grievance Redress Mechanism (GRM) with defined response timelines and centralized tracking to ensure timely resolution of concerns. In addition, early coordination with government agencies, regulators, and infrastructure partners will be emphasized to improve project alignment and reduce approval delays, while clear engagement arrangements will be established for projects involving Public-Private Partnerships (PPPs) and EPC+F delivery models. Stakeholder engagement will also extend beyond project commissioning through mechanisms integrated into operations and maintenance activities to sustain long-term community relations.





SUSTAINABILITY AND ENVIRONMENTAL CONSIDERATIONS

The integration of environmental, socio-economic safeguards, and climate change considerations into this Master Plan reflects a commitment to the sustainable and responsible development of electricity transmission infrastructure. By embedding these considerations into planning and decision-making processes, the Master Plan enhances long-term system resilience, minimizes environmental and social risks, and strengthens the sustainability of transmission investments. This approach also reinforces investor confidence while contributing to the realization of Kenya's broader sustainable development and climate objectives.

The regulatory and policy framework guiding this Masterplan with regards to sustainability is informed the Constitution of Kenya, 2010; Environmental Management and Coordination Act (EMCA), CAP 387; the Climate Change Act, 2016 (and 2023 amendments); the Land Act 2012, among others. The plan is aligned with Kenya's international and national climate commitments, particularly the Nationally Determined Contributions (NDCs) (2026 to 2030 and 2031 to 2035) and the current National Climate Change Action Plans (NCCAPs), which operationalize these commitments through successive medium-term plans.

7.1. Environmental, Social and Governance framework

Environmental, Social and Governance (ESG) considerations are recognized as essential components of sustainable infrastructure planning and implementation as shown in Figure 7-1

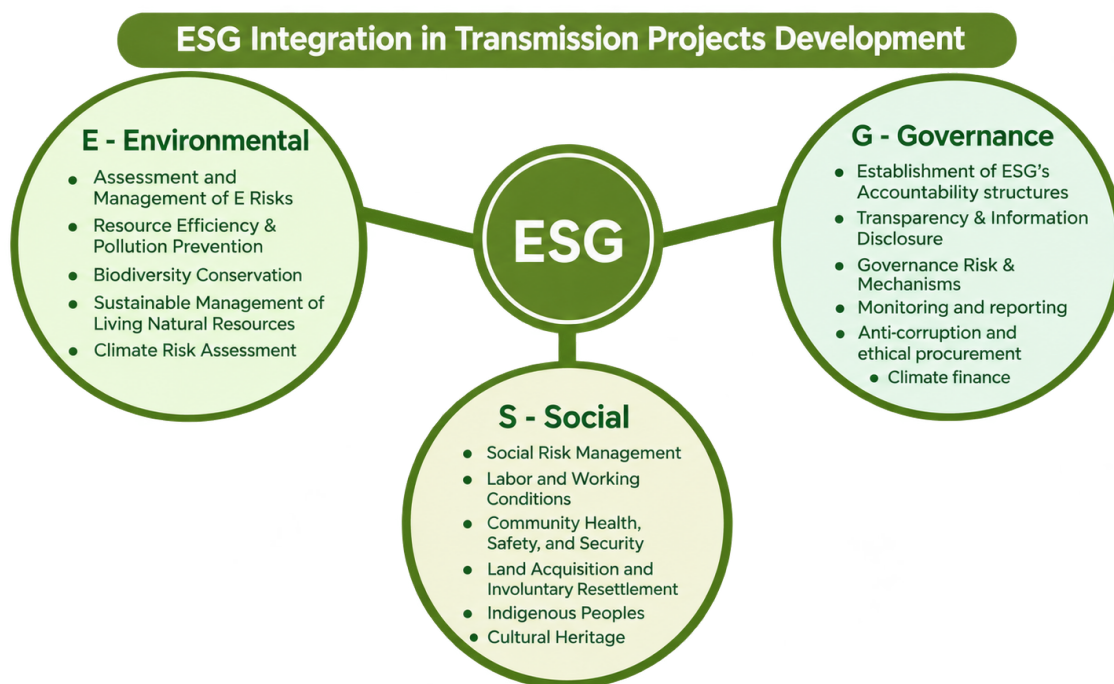


Figure 7-1: ESG Considerations in infrastructure development.

At the project level, the practice involves mainstreaming environmental and social considerations throughout the entire project lifecycle as follows: -

7.1.1. Project Concept and Planning Stage

Early integration of ESG considerations helps minimize adverse impacts and enhance positive outcomes for communities, ecosystems, and other stakeholders. During the feasibility and design phases, risks are assessed through structured safeguards, which include Environmental and Social Impact Assessments Resettlement Action Plans, Stakeholder Engagement Plans, Environmental and Social Management Plans, Biodiversity Management Plans, and other project-specific instruments. These safeguards ensure compliance with national legislation, including the EMCA, Cap 387, as well as the policies of project financiers, including multilateral development banks and other development partners.

7.1.2. Route Mapping and Site Selection

Transmission line alignments and substation sites are planned to minimize environmental and social impacts while ensuring technical and economic feasibility. Climate-related risks such as flooding, landslides, extreme winds, and coastal impacts are incorporated using historical climate data from the Kenya Meteorological Department and other relevant sources. Geographic Information Systems and elevation models are applied to optimize route selection and identify suitable sites.

7.1.3. Transparency and Stakeholder Engagement

Transparency and stakeholder engagement are central to ESG implementation. Environmental and social assessment reports and project information are disclosed in accordance with EMCA and international best practice. Information is shared through multiple channels, including the company website, project sites, and community forums such as public barazas. Structured mechanisms are provided to enable stakeholder feedback and participation throughout the project lifecycle.

7.1.4. Creation of Public Rights of Way

The creation of transmission corridors requires land acquisition, easements, or restrictions on land use to guarantee safe operation and maintenance. While compensation frameworks exist for land acquisition and resettlement, gaps remain regarding compensation for the creation of rights of way, sometimes resulting in disputes and litigation. Strengthening the regulatory framework is necessary to improve project implementation efficiency.

7.1.5. Project Construction and Monitoring

All approved Environmental and Social Management Plans, Resettlement Action Plans, and Biodiversity Management Plans are implemented and monitored throughout the construction phase. Environmental performance indicators including biodiversity conservation, emissions management, and responsible resource use are tracked alongside social performance metrics, such as resettlement outcomes, community satisfaction, and stakeholder engagement quality. Governance oversight is maintained through regular monitoring, evaluation, reporting, and grievance redress mechanisms to ensure accountability. Monitoring extends beyond internal mechanisms to include external oversight by project financiers, and relevant national lead agencies.

7.1.6. Post-Construction Audits

Post-construction audits are conducted to verify the effective implementation of mitigation measures and to identify any residual impacts. These include project completion audits as required by financiers, which assess compliance with safeguard instruments and ESG commitments, as well as annual environmental audits statutory audits mandated by NEMA. There is need for stronger and more systematic post-construction environmental and social audits. Strengthening these audits ensures lessons are captured, residual risks are addressed, and continuous improvement is promoted for subsequent projects. Figure 7-2 shows the ESG integration across project phases.

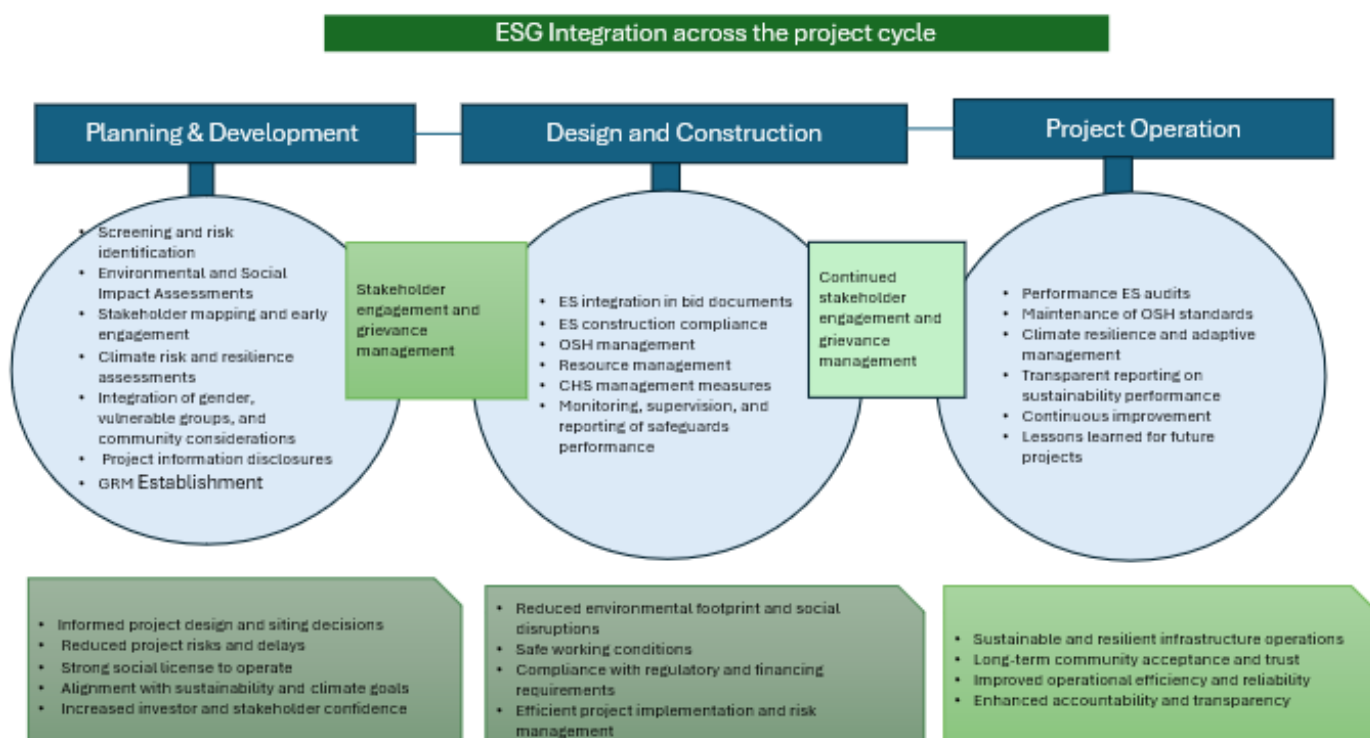


Figure 7-2: ESG integration across project phases

7.2. Climate Change and Transmission Infrastructure

7.2.1. Transmission Infrastructure as an enabler for mitigation

7.2.1.1. Low-Carbon Transition Support

Transmission infrastructure serves as the critical link between Kenya's abundant renewable energy generation and demand centres, anchoring the country's low-carbon transition and climate ambitions. Kenya's grid already over 90% her share of its electricity from renewable sources of total supply in recent years.

Under its NDCs, Kenya targets a 100% transition to renewable energy by 2035. In addition, the country aims to achieve 32% greenhouse gas abatement by 2030 and 35% abatement by 2035 relative to business-as-usual scenarios. Both the NDCs and the National Adaptation Plan (2015-2030) emphasize enhanced climate adaptation in the energy sector, highlighting the importance of resilient and low-carbon electricity infrastructure.

For the financial year ending June 2025, renewable energy accounted for 91% of total electricity generation, comprising 39.5% geothermal, 24.12% hydropower, 13.18% wind, and 3.27% solar, while 9.23% was generated from fossil fuels and 8.76% from electricity imports as discussed in Section 2.2. As renewable generation continues to expand, often located far from major load centres, transmission infrastructure

becomes increasingly critical for evacuating power from generation sites, integrating variable renewable energy into the national grid, and ensuring reliable electricity supply across the country. In this context, the development and reinforcement of the transmission network play a strategic role in enabling the continued growth of renewable energy while maintaining system stability and reliability.

7.2.1.2. Enhancing System Reliability and Grid Stability

To support increased renewable integration and grid resilience, the Master Plan prioritizes:

- Grid reinforcement and expansion of transmission corridors to connect renewable generation zones with major load centres.
- Deployment of grid-support technologies STATCOMs, shunt reactors, additional transformers and reconductoring to improve voltage stability and reduce the risk of outages.
- Network modernization, including digital monitoring and smart grid systems, to enhance operational flexibility and system responsiveness.

These measures create redundancy and flexibility in the grid, allowing multiple pathways for power flow and improved handling of variable renewable generation. System reinforcement also supports the accommodation of growing electricity demand.

7.2.1.3. Expanding Access and Enabling Inclusive Growth:

Transmission expansion supports equitable access by strengthening connectivity to underserved and historically less-electrified regions. Planned projects will enhance grid coverage throughout the country enhancing inclusive economic development.

7.2.1.4. Contribution to Low-Carbon Economic Pathways:

By enabling high renewable penetration and stable grid operations, the transmission network supports national low-carbon economic initiatives. A resilient transmission system enhances investor confidence in renewable projects, facilitates private sector participation, and attracts climate finance.

7.2.1.5. Tree growing

Acknowledging the impacts of transmission infrastructure wayleaves on natural ecosystems, including forests, KETRACO has taken proactive steps to enhance tree cover and offset lost carbon sinks. As of 2025, the company has planted 760,000 trees across diverse forests throughout the country with an 85% survival rate. In line with its corporate responsibility to strengthen national tree cover and mitigate

ecological impacts from wayleave creation, the company has incorporated tree-growing obligations into bidding documents for all transmission projects, with each project targeting the planting of 30,000 to 50,000 trees. This requirement has already been implemented in several major initiatives, including the KTNIP projects, the 220 kV Mariakani-Dongo Kundu Transmission Line, and the GREEN projects, demonstrating commitment to sustainability.

7.2.2. Climate Infrastructure Resilience

Climate infrastructure resilience is a function of adaptation. It is guided the principles of resilience, redundancy, rapidity, resourcefulness, and robustness. These principles ensure that transmission infrastructure can withstand and recover from climate-induced disruptions.

Current climate adaptation practices involve on reducing infrastructure exposure to climate related hazards. This is done during route selection, transmission corridors optimized to avoid flood-prone areas, steep terrains, and other high-risk zones, thereby minimizing vulnerability to extreme weather events. In cases where avoidance is not possible, structural protection measures such as elevated towers and reinforced foundations are employed to safeguard critical infrastructure.

Design and operational decisions rely primarily on historical climate data, complemented by the integration of structural resilience measures, including wind and seismic design factors within engineering specifications. To ensure system reliability, regular inspection and maintenance schedules are implemented, keeping transmission lines and towers robust against weather-related stresses. In addition, personnel are trained and equipped for response, retrofitting, and maintenance of infrastructure following climate-related events, supporting timely restoration and minimizing disruptions. Community and stakeholder engagement is also conducted to incorporate local knowledge of climate hazards, improving situational awareness and informing adaptive planning. Through these measures, KETRACO is progressively reinforcing network redundancy and robustness.

To safeguard the long-term operability of transmission infrastructure in the context of current and unprecedented future climate conditions, the following strategies are proposed:

- Integrate systematic climate risk assessments early in project planning, from feasibility studies and route selection through to detailed engineering designs.

- Incorporate climate modelling and downscaled climate projections into transmission planning to inform adaptive infrastructure designs.
- Continuously strengthen internal technical capacity in climate risk assessment, climate modelling, cost-benefit analysis, and adaptive engineering practices.
- Revise technical design manuals to incorporate climate-informed parameters, including wind loading, temperature thresholds, corrosion risk, and hydrological stress on account of modelled climate data.
- Enhance disaster risk management and emergency response plans to ensure rapid restoration of transmission services following climate-related events, as part of comprehensive asset management.
- In areas with high vulnerability and infrastructure exposure, early warning systems are integrated into transmission project design to enhance grid climate resilience and reduce operational risks. These systems enable the network to anticipate hazards, take preventive measures, and maintain reliable electricity supply during extreme events.

Key EWS applications for transmission systems include but not limited to:

- Partnerships with the Kenya Meteorological Department ensure access to accurate meteorological data and forecasts, supporting Early Warning Information and integration into grid operations.
- Real-time tracking of rainfall, wind, temperature, and storms, with alerts sent to control centres.
- River gauges and runoff models detect rising water levels, triggering pre-emptive shutdowns or isolation of vulnerable equipment.
- Lightning sensors along corridors to forecast high-risk periods and activate protective measures for sensitive equipment.
- Ground vibration and slope stability sensors provide alerts for inspections or temporary line shutdowns in the event of seismic and land destabilizations.
- Satellite imagery and terrain analysis to identify flood-, landslide-, and fire-prone areas to guide maintenance and emergency response.
- Hazard data can be linked to the SCADA-systems to trigger automated load shedding or rerouting protocols to prevent cascading failures.

A phased-out approach for climate-resilience integration for the 2026-2045 TMP is shown in Volume II Annex 9.

7.2.3. Climate Financing

The company has already secured financing for Phase 2 of the Green and Resilient Expansion of Energy (GREEN) Program, supported through joint financing from the International Development Association (IDA) and the Green Climate Fund (GCF). This program is designed to strengthen the resilience of Kenya's energy infrastructure, facilitate the integration of renewable energy into the grid, and enhance the reliability and sustainability of electricity transmission systems. In addition, consideration is being given by the Climate Investment Funds to finance phase-shifting transformers at the Suswa Substation, further supporting grid stability and optimal power flow management.

- **Multilateral, Bilateral, and Blended Finance:** Access climate-aligned funding from international and regional institutions; blend with private capital or concessional loans.
- **Green Bonds and Sustainable Finance:** Issue green or sustainability-linked bonds to finance low-carbon and climate-resilient transmission projects.
- **Carbon Market Opportunities:** Develop carbon credit-generating projects through improved grid efficiency, transmission loss reduction, and renewable energy integration; participate in voluntary and compliance markets.
- **Carbon Projects Feasibility Studies:** Conduct technical and financial assessments to evaluate carbon revenue potential and investment viability.
- **Capacity Building for Carbon Projects:** Develop institutional frameworks and technical skills for designing, implementing, and managing carbon-credit projects.
- **Climate-Resilient PPP Models:** Structure availability-based PPPs tied to climate resilience outcomes (e.g., line availability during extreme weather or post-disaster recovery timelines).

Table 7-1 shows prevailing gaps and opportunities while Figure 7-3 shows a phased-out approach to climate financing within the master plan period and

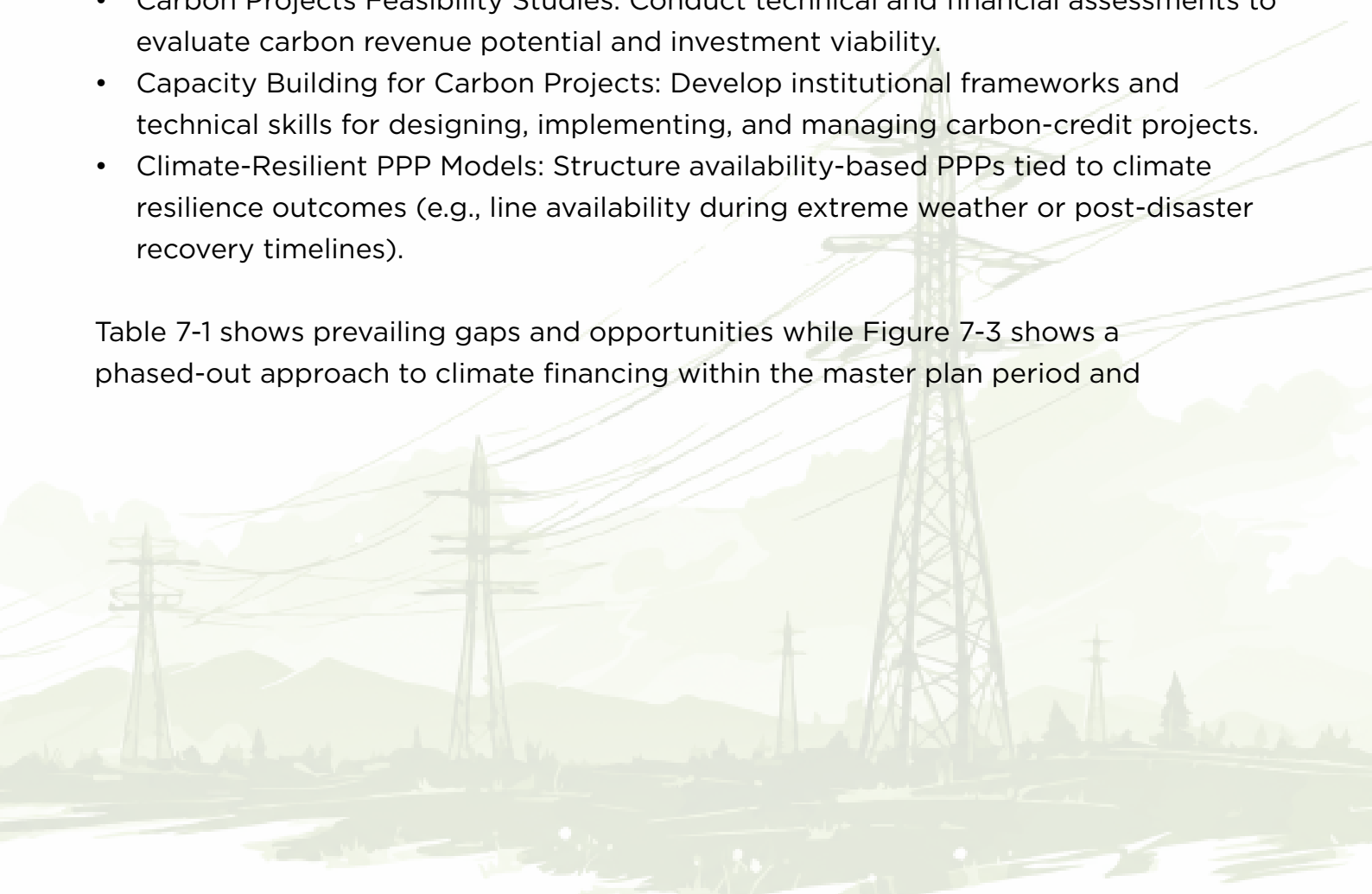


Table 7-1: Climate financing gaps and opportunities

Challenge / Gap	Description	Proposed Solutions
Limited internal capacity to develop climate finance proposals	Insufficient technical expertise in preparing bankable climate project concepts, climate finance proposals, and carbon finance documentation.	Build internal capacity through training on climate finance and proposal development; establish a dedicated climate finance unit; partner with development partners and accredited entities (e.g., MDBs) to support proposal preparation.
Limited experience with climate finance instruments	Insufficient familiarity available climate financing mechanism and markets.	Build staff capacity on climate finance instruments; engage specialized transaction advisors; develop internal guidelines for identifying climate finance opportunities in transmission projects.
Difficulty demonstrating climate additionality and impact	Climate funds require clear evidence of mitigation or adaptation benefits, which can be challenging to quantify for transmission projects.	Develop standardized methodologies for calculating emission reductions, resilience benefits, and avoided losses; integrate climate indicators into project appraisal frameworks.
Fragmented institutional coordination	Limited inter-agency coordination can slow project development and approval.	Strengthen coordination with regards to climate financing opportunities between Ministry of Environment and Climate Change, National Treasury, and the designated national authority (NEMA); establish inter-agency working groups for climate finance.
Limited pipeline of climate-ready projects	Projects are often conceptualised from a technical perspective without integrating climate finance.	Develop a pipeline of climate-aligned transmission projects during project concept development.
Limited monitoring and reporting systems for climate impacts	Difficulty tracking and reporting climate mitigation and adaptation benefits required by climate financiers.	Establish robust monitoring, reporting, and verification (MRV) systems aligned with international climate finance standards. Build climate-aligned MRV capacity

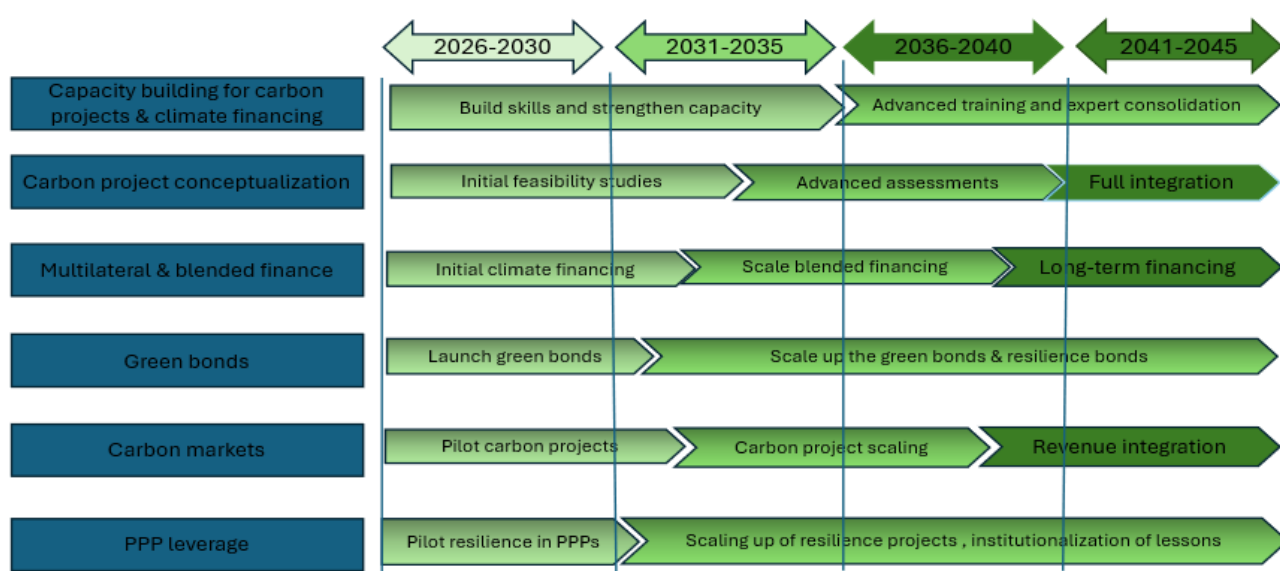


Figure 7-3: Climate opportunities under TMP.

7.2.4. Greenhouse Gas Emissions from Transmission

The analysis below indicates that emissions avoided through Kenya's high share of renewable energy generation significantly exceed emissions associated with transmission losses, resulting in a net climate benefit. Transmission investments under the Transmission Master Plan therefore constitute climate-positive interventions, as they enable the evacuation and integration of renewable energy, reduce reliance on thermal generation, and support the delivery of low-carbon electricity to demand centres. Table 7-2 shows the assumptions while

Table 7-3 shows the calculations made.

Table 7-2: Assumptions made in calculating GHG in Transmission

Parameter	Value	Source / Note
Total electricity consumption	11,329,000 MWh	KPLC, 2025
Transmission losses (technical)	4%	Standard technical assumption
Grid emission factor (GEF)	0.4087 tCO ₂ /MWh	UNFCCC, 2020 – expired Dec 2023
Avoided emissions factor	0.733 tCO ₂ /MWh	Fossil fuel (HFO) counterfactual
Thermal (HFO) generation	1,247,928 MWh	EPRA, 2025
Life cycle analysis of transmission has not been factored to include lost sink potential due to creation of wayleave and SF ₆ emissions		

Table 7-3: Recalculated key results for GHG in transmission

Parameter	Energy (MWh)	CO ₂ (tCO ₂)	Notes
Total transmission losses (4%)	453,160	185,200	Emissions using UNFCCC GEF (0.4087)
CO ₂ avoided – total grid losses	453,160	332,166	Avoided using HFO baseline (0.733)
Net CO ₂ benefit	–	146,966	Avoided minus loss-related emissions
Thermal (HFO) transmission losses	49,917	20,407	Emissions from losses attributable to HFO share
CO ₂ avoided – thermal losses	49,917	36,590	Avoided if HFO-based grid
Net CO ₂ benefit (thermal portion)	–	16,183	Avoided minus emissions

7.2.1.6. Explanations and Observations

Transmission losses are estimated at about 4% of the electricity transported, equivalent to 453,160 MWh per year. Using the grid emission factor of 0.4087 tCO₂/MWh, these losses correspond to approximately 185,000 tCO₂ annually, since additional electricity generation is required to compensate for the lost energy.

However, when compared with a fossil fuel (HFO) baseline, the emissions that would have occurred are significantly higher. Under this counterfactual scenario, the same amount of electricity would have resulted in approximately 332,000 tCO₂, meaning that the renewable based grid results in a net climate benefit of about 147,000 tCO₂ per year.

Thermal generation represents only about 10% of total electricity supply, but its associated transmission losses still contribute approximately 20,000 tCO₂ annually. This highlights that even a relatively small share of fossil generation can influence the carbon intensity of the electricity system.

Kenya's transmission system mainly uses air-insulated lines and substations, with only limited use of gas-insulated switchgear (GIS). As a result, SF₆ emissions from the transmission sector are expected to be very low, likely less than 1% of total grid-related greenhouse gas emissions.





MONITORING, EVALUATION, ACCOUNTABILITY AND LEARNING (MEAL) FRAMEWORK

81. Introduction

KETRACO's investments in transmission lines and substations play a critical role in strengthening Kenya's national grid and ensuring reliable bulk power supply across the country. Reliable electricity transmission supports key economic sectors such as manufacturing, mining, agribusiness, and commercial services, and contributes to the achievement of national development priorities including Kenya's Vision 2030 and the Bottom Up Economic Transformation Agenda (BETA).

While transmission infrastructure is often assessed based on construction progress and commissioning milestones, it is equally important to understand how these investments perform once operational. Project-level monitoring and evaluation provides an opportunity to assess changes in system reliability, power quality, electricity consumption, and other outcomes following the energization of transmission projects.

To support this, KETRACO has incorporated a Monitoring, Evaluation, Accountability and Learning (MEAL) framework within the Transmission Master Plan (TMP). The framework draws on evidence generated through project monitoring activities, including baseline data collected prior to project energization and follow-up monitoring after commissioning. It provides a structured approach for tracking the performance of transmission investments, measuring their technical and socio-economic outcomes, and capturing lessons that can inform future transmission planning.

As part of this approach, data on power quality and reliability is often collected from large electricity consumers such as industrial and commercial facilities. These consumers typically maintain detailed operational records, including information on power outages, voltage fluctuations, and the use of backup diesel generators. Such records provide more consistent and verifiable data compared to household-level reporting. In addition, industries closely track their expenditure on diesel fuel used to operate standby generators during power

interruptions. This information provides useful evidence for assessing the operational and economic impacts of improvements in transmission reliability following project energization.

The sections that follow describe how the Monitoring, Evaluation, Accountability and Learning (MEAL) framework is applied within the Transmission Master Plan, including the logical framework used to track results, lessons emerging from project implementation, mechanisms for integrating learning into project preparation, and approaches for communicating results to stakeholders.

8.2. Institutionalizing Results Through the Logical Framework

While project-level assessments demonstrate the impact of individual transmission investments, KETRACO has adopted a Logical Framework under the TMP to support consistent tracking of results across the national transmission program.

The Logical Framework links transmission of investments to broader development outcomes by establishing a clear relationship between project inputs, activities, outputs, and the expected outcomes and impacts. This framework helps demonstrate how transmission infrastructure contributes to improvements in system performance and national energy development.

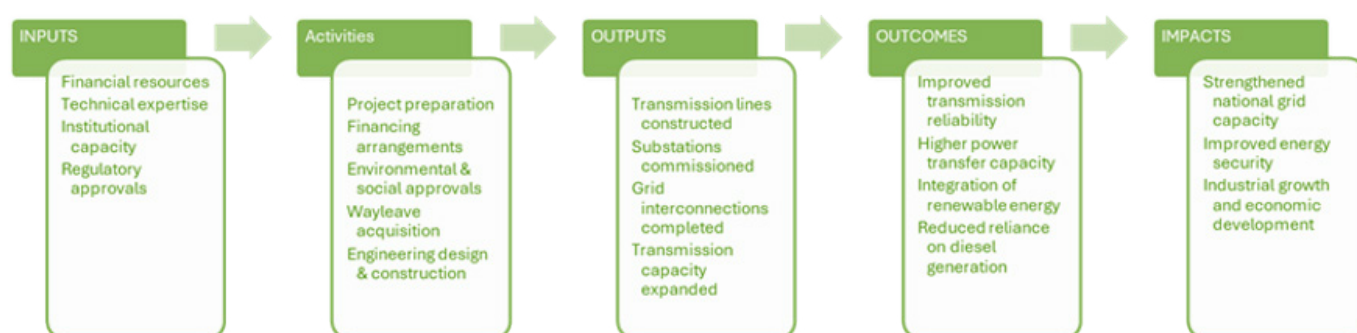
Through this approach, KETRACO can monitor key areas such as:

- Expansion of national bulk power transmission capacity
- Improved reliability and stability of the transmission network
- Integration of renewable energy generation into the national grid
- Increased electricity supply and consumption in emerging load centres
- Reduced reliance on diesel-based electricity generation in areas newly connected to the grid.

The framework also identifies indicators, data sources, and means of verification used to monitor progress, together with assumptions that may influence the achievement of results. This approach supports accountability and strengthens the link between transmission expansion and national energy sector objectives, including Kenya's energy policy priorities, Vision 2030, regional power interconnection initiatives, and development partner reporting requirements.

8.3. Logical Framework Structure for the Transmission Master Plan

The Logical Framework applied in the Transmission Master Plan follows a results chain that links transmission investments to sector outcomes and national development impacts. The framework connects project inputs and activities to infrastructure delivery, improved system performance, renewable energy integration, and broader socio-economic benefits. A simplified representation of the results chain applied in the Transmission Master Plan is presented in Figure 8-1.



The full Logical Framework matrix, including indicators, data sources, verification mechanisms, and assumptions, is presented in Volume II Annex 10.

8.4. Incorporating Learning to Improve Transmission Project Implementation

Experience of the implementation of transmission projects has shown that delays often arise during the early stages of project preparation, particularly when key pre-construction requirements are not completed in time. Some projects included in earlier planning cycles were completed later than anticipated or experienced implementation challenges due to delays in meeting critical preparatory milestones. For example, the 220 kV Garsen-Hola and 220 kV Kamburu-Embu transmission projects experienced delays because financing agreements were not effective within the expected timeframe. In other cases, such as the 220 kV Marsabit-Isiolo and Loiyangalani-Marsabit projects, challenges arose around the validity and extension of government guarantees required to secure project financing.

These experiences highlight the importance of closely tracking pre-construction milestones that determine whether projects are ready to proceed to construction. Under the Monitoring, Evaluation, Accountability and Learning (MEAL) framework of the Transmission Master Plan, greater emphasis is placed on monitoring indicators that reflect early project readiness.

Key pre-construction indicators include:

- Status of financing commitments and execution of loan agreements
- Approval of Environmental and Social Impact Assessments (ESIA) and Resettlement Action Plans (RAP)
- Availability of cadastral mapping and land ownership data
- Availability and timely disbursement of funds for wayleave acquisition and compensation

Regular monitoring of these milestones enables KETRACO to identify potential challenges early, address bottlenecks, and support informed decision-making during project preparation and implementation.

Further details are provided in the Volume II Annex 10.

8.5. Lessons Learned from Transmission Project Implementation

Experience from project implementation has provided several important lessons that can strengthen the delivery of transmission infrastructure under the Transmission Master Plan.

8.5.1. Timely Mobilization of Financing

Delays in the effectiveness of financing agreements have slowed the start of some projects. Monitoring indicators related to financing commitments and loan agreement effectiveness helps ensure that projects included in the Transmission Master Plan are financially ready to proceed.

8.5.2. Adequate Financing for Wayleave Acquisition and Construction

Projects implemented with financing arrangements covering both construction and wayleave compensation tend to progress more smoothly. Where wayleave compensation relies solely on Government budget allocations, delays in the release of funds can interrupt implementation. Financing approaches that cover both

infrastructure development and wayleave compensation, such as in the 132 kV Narok–Bomet transmission line, help reduce implementation interruptions and minimize contractor idle claims.

8.5.3. Strengthening Project Management Capacity

Effective project delivery requires strong project management and coordination. Continued capacity building, adequate staffing, and regular supervision of project activities are essential for improving implementation efficiency.

8.5.4. Timely Completion of Environmental and Social Safeguards

Processes Delays in the approval of ESIA and RAP studies can significantly affect project timelines. Tracking safeguards approval milestones and initiating these processes early helps reduce implementation risks.

8.5.5. Strengthening

Community Engagement and Wayleave Management

Transmission projects require extensive wayleave acquisition across multiple communities. Early engagement with affected communities and continuous monitoring of wayleave acquisition processes help minimize disputes and delays.

8.6. Integrating Lessons into the MEAL Framework

The lessons emerging from project implementation are incorporated into the MEAL framework of the Transmission Master Plan. By tracking milestone indicators and documenting implementation experiences, KETRACO can strengthen project preparation, improve coordination across technical and financial processes, and better manage implementation risks.

These lessons also inform the selection of project readiness indicators included in the Transmission Master Plan Logical Framework, ensuring that risks related to financing, safeguards approvals, and wayleave acquisition are systematically monitored. This learning process enables more realistic planning, improved project readiness, and more effective delivery of transmission infrastructure investments.

8.7. Results Communication and Knowledge Management Framework

To strengthen accountability, transparency, and stakeholder confidence, KETRACO has established a Results Communication and Knowledge Management Framework that transforms baseline and post-energization MEAL findings into evidence-based products for diverse audiences. Integrated within the Transmission Master Plan, this

framework positions communication as a strategic M&E function, linking technical performance to development impact. By validating data, analysing trends, and sharing outcomes such as increased transmission capacity, higher electricity consumption in new load centres, renewable energy integration, and reduced diesel dependence. KETRACO shows how infrastructure investments drive industrial growth, energy security, climate resilience, and socio-economic transformation. Through policy briefs, impact reports, stakeholder forums, digital dashboards, and strategic briefings, the framework elevates communication into a core governance tool, supporting accountability, adaptive management, and sustainable national development.

Further details are provided in Volume II Annex 10





9 RESILIENCE AND RISK MITIGATION STRATEGIES.

Kenya's transmission network is facing increasing demand, greater integration of renewable energy, and growing climate-related risks, which present significant challenges to the implementation of the KETRACO Transmission Master Plan (2026–2045). These challenges include technical losses, network overloading, voltage instability, variable renewable energy intermittencies (VRE), and climate vulnerabilities that require strengthened grid infrastructure.

To address this, a comprehensive risk assessment has been undertaken to identify, evaluate, and prioritise potential risks across all the project phases, including Planning, Funding, Feasibility Studies, Pre-Construction Activities, Construction, Commissioning, and Operations and Maintenance.

The risk matrix outlines these risks, assigns mitigation measures, and identifies responsible offices to support proactive risk management and ensure the successful, resilient, and sustainable implementation of the Transmission Master Plan.

The details of the risks assessment and mitigation measures are outlined in Table 9-1.

Table 9-1: Risk Matrix and Mitigation Measures

No.	Risk Description	Cause	Potential Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
1.	Strategic Risks Risks arising from limited ability to fully implement the Transmission Master Plan	- Shifts in government or sector priorities and policies. - Inadequate Projects funding and Delayed disbursement of funds from National Treasury - Unanticipated regulatory changes which may affect the feasibility and implementation of the plan. - Market volatility impacting projects financing and costs estimates. - Limited availability of real-time or historical data necessary for accurate stability assessments.	- Reduced investor and stakeholder confidence. - Inefficient operations resulting to sub optimal operations of the transmission grid. - Project Cost Overruns - Security threats to the transmission infrastructure - Missed opportunities for innovation, renewable energy integration. - Loss of revenue due to delays in project completion.	High	- Develop and implement a centralized KRI dashboard to monitor the Transmission Master Plan KPIs in real time and enable early identification of implementation risks. - Establish periodic stakeholder engagements and policy reviews with key upstream and downstream actors with documented decisions to maintain confidence.	GM-PDS CS, & GM LS

No.	Risk Description	Cause	Potential Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		- Health and Safety Risks - Lack of stakeholder goodwill - Destruction of habitat through deforestation during clearing land for TL corridors. - Noncompliance with sustainability standards and regulatory requirements.	- Potential conflicts with indigenous communities or local stakeholders over land use and rights - Regulatory penalties.		- with a detailed implementation roadmap. - Develop and operationalize strong health and safety policies. - Strengthen Stakeholder engagement through involvement in planning and regular communication and delivering on commitments. - Conduct regular workplace risk assessments to identify potential hazards. - Deploy heavy-lift helicopters for supply drops and utilize specialized stringing drones for initial line-pulls to minimize environmental footprint.	GM SOPM GM LEGAL GM SOPM
4.	Operational Risks Risk arising from failures in internal processes, systems, people, or external operational factors that directly affect the execution of the Transmission Master Plan.	- Rapid changes in technology - Cyber Security Risks - Vandalism & Terrorism of transmission infrastructure - Supply chain disruptions resulting to delays or shortages affecting project timelines. - Disruptions caused by grid interconnectors. - Global transformer lead-time fluctuations and theft of conductors or steel towers during transit in high-risk corridors. - High technical complexity of maintaining a specialized Airwing, aging high-cost vehicles and transitioning to a 60% decarbonized Green Fleet.	- Obsolescence of equipment due to new technologies, exposing the network to potential attacks. - Disruption of grid operations or system outages - Damage or destruction of transmission assets such as towers and substations. - Project delays affecting implementation of transmission projects. - Cost overruns due to scarcity or increased prices of materials - Rapid asset depreciation	High	- Periodic technology reviews and upgrades to align infrastructure development with global transmission technology trends. - Continuous staff training and capacity building on modern grid technologies and systems. - Develop and implement a robust cybersecurity framework including network monitoring, intrusion detection systems, and regular vulnerability assessments. - Develop and test cyber incident response and recovery plans response to cyberattacks affecting grid operations. - Strengthen physical security of transmission assets through surveillance systems, fencing, security patrols, and remote monitoring technologies. - Enhance collaboration with security agencies and local communities to improve intelligence sharing and early detection of threats.	GM-D&C

No.	Risk Description	Cause	Potential Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
					- Strengthen procurement planning and maintain buffer stocks of critical components. - Improve supplier risk assessment and monitoring to identify potential disruptions early and implement contingency plans. - Operationalize the KETRACO Airwing for helicopter-led stringing and utilize the Port of Lamu as the primary entry point for Northern Grid projects. - Implement an IoT-based Global Logistics Tracker integrated into SAP/ERP and standardize Smart Convoys with GPS-enabled locks and real-time drone surveillance.	
5.	Human Resources Risks Risks arising from workforce planning, skills availability, skills gaps, compliance with labour regulations, attrition, and loss of critical institutional knowledge jeopardizing the continuity, development and implementation of the Transmission Master Plan.	- Talent attrition and constraints in attracting and retaining critical skills. - Shortage of certified airwing pilots, drone operators and EV technicians - Loss of skilled employees to competing organisations or international markets - Workplace accidents and injuries due to hazardous working environments associated with high-voltage infrastructure. - Weak Institutional Knowledge Management.	- Delays in transmission projects and infrastructure expansion - Increased reliance on external consultants and contractors - Reduced technical capacity for managing complex infrastructure. - Legal liabilities and reputational damage	High	- Develop and implement succession planning and mentorship programmes. - Establish knowledge management systems and documentation frameworks. - Develop competitive compensation and retention strategies. - Leverage on collaborations and partnerships for knowledge sharing and access best practices. - Implement strong health and safety management systems	GM-HRA

No.	Risk Description	Cause	Potential Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
6.	Legal and Compliance Risks Arising from noncompliance with applicable laws, regulations, and statutory requirements;	- Legal disputes arising from poorly structured contracts, ineffective contract management or contractor non-performance. - Failure to comply with laws, regulations, licensing requirements, and regulatory directives. - Legal disputes arising from land acquisition, compensation, or access to transmission corridors. - Exposure to legal disputes involving contractors, employees, communities, or regulatory bodies.	- Project implementation delays. - Fines and Penalties - Project Cost overruns - Reputational damage - Increases in contingent liabilities. - Financial losses due to legal costs and compensation	High	- Strengthen contract management and procurement oversight frameworks. - Periodic monitoring and evaluation of contracts implementation. - Conduct periodic compliance audits and regulatory reviews. - Strengthen legal due diligence, land documentation and dispute resolution mechanisms	CS & GM-LEGAL SERVICE S
7.	Project Risks Inability to deliver project scope on time and to quality due to delays in acquisition of Right of Way, design changes, technology interfaces, and procurement issues.	- Ineffective Project and contract management processes. - Inadequate risk assessments exposing the projects to unforeseen risks and uncertainties. - Design flaws/changes or technical failures in transmission infrastructure within the life of the projects. - Inability/delays to acquire wayleaves for transmission infrastructure. - Lack of year-round O&M access and failure to secure a social license to operate within host communities.	- Increased project costs - Increased legal disputes/litigation. - Reputational damage.	High	- Develop and implement a project and contract management framework. - Monitor procurement performance, delivery timelines and contractual obligations to mitigate procurement risks. - Institutionalize the Road Asset Model to build substation access roads to Type B Rural Road standards in collaboration with KeNHA and County Governments.	GM-PDS, GM-D&C
8.	New and Emerging Risks The risk that newly developing or evolving internal and external factors may create unforeseen threats to the organization due to limited historical data, uncertainty, and rapidly changing conditions.	- Geopolitical and global supply-chain disruptions for critical transmission equipment. - AI assisted cyber-attacks targeting grid control systems. - Data protection violation through data privacy breaches /failure to adequately protect data. - New Technologies such as Smart grids AI, blockchain and other technologies that may disrupt current systems.	- Power Transmission disruptions - Reduced grid reliability and increased operational costs. - Regulatory Penalties and fines. - Service disruptions due to unauthorized access and data breaches.	High	- Establish systems to continuously monitor global trends in technology, climate regulations and energy markets to identify the emerging risks early. - Conduct regular stress tests to assess how emerging risks could affect the transmission network and operations. - Developing and implement strong cyber security frameworks to protect grid control systems from evolving cyber threats.	GM SOPM, GM SRC

No.	Risk Description	Cause	Potential Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
					- Establish Strategic partnerships and collaborations with industries and research bodies to share knowledge on emerging risks and best practices. - Continuous staff training and capacity building on emerging technologies, cybersecurity and evolving risk management practices.	







TECHNOLOGY AND INNOVATION ROADMAP

10.1. Introduction

Transmission technology is no longer limited to physical lines and substations. Modern transmission systems are complex cyber-physical infrastructures that integrate power electronics, digital communications, advanced analytics, and human decision-making.

10.2. Strategic Context and Technology Objectives

Between 2026 and 2045, KETRACO intends to enhance its transmission infrastructure by adopting technology to a digitally enabled transmission system operator capable of managing a complex, interconnected power system.

The technology strategy is designed to achieve five executive-level objectives:

- Maximise utilisation of existing and new transmission assets.
- Reduce system risk and outage exposure.
- Enable large-scale renewable energy and cross-border trade.
- Improve transparency and confidence for financiers.
- Build long-term internal technical capacity.

10.3. Recent implementations in Kenya (2020–2026)

- i. Ethiopia-Kenya HVDC interconnector (EEHP / Eastern Electricity Highway Project): Completed in 2021; a bipolar 500 kV HVDC overhead transmission corridor designed to transmit up to ~2,000 MW and connect the two systems for large-scale regional trade.
- ii. Regional wheeling & trial operations: Kenya participated in energy-wheeling trials involving Ethiopia and Tanzania to test cross-border dispatch and settlement arrangements, demonstrating operational capability for multilateral trade corridors.

10.4. Planning Technologies

Transmission planning decisions have long-term implications for system reliability, financial sustainability, and network performance. Investment errors made during the planning stage are often the costliest to correct. Therefore, modern transmission planning relies heavily on advanced data management systems, analytical tools, and digital modelling platforms.

10.4.1. Data Collection, Integration and Governance

Effective transmission planning begins with accurate and high-quality data. The required datasets include:

- Network topology and equipment parameters.
- Protection system settings
- Historical outage and maintenance records
- Asset condition data
- High-resolution demand and generation profiles

Modern utilities increasingly adopt Common Information Model (CIM) framework to ensure consistency between planning studies, operational and asset management databases.

10.4.2. Power System Studies and Simulation Platforms

Transmission system analysis relies on specialized simulation platforms capable of modelling complex network behaviour under a wide range of operating conditions. KETRACO currently utilizes Siemens PSS®E and DIgSILENT PowerFactory which are globally recognized software. For detailed electromagnetic transient analysis of HVDC and inverter based resources, PSCAD/EMTDC are used. These tools enable planners to quantify thermal limits, voltage stability margins, frequency response, and system strength under high renewable scenarios.

10.4.3. GIS, Survey and Feasibility Technologies

Geographical Information Systems (GIS) are essential in developing transmission line master plans. By integrating spatial data with technical, economic, and environmental parameters, GIS offers a robust framework for optimizing transmission infrastructure planning. Currently, the company uses the following technologies.

- KETRACO Integrated Location Intelligence Information System (ILIS) is a centralized, web-enabled enterprise system for Wayleave Management and Engineering Construction.

- AutoCAD Civil 3D / Bentley OpenUtilities – engineering design integration.
- Comfar Computer models for feasibility analysis and reporting.

There is a need to leverage the use of drones in:

- i. Feasibility Studies: Drones can be used to acquire high resolution satellite imagery, Lidar data to create precise 3D data for GIS based route optimization to minimize environmental and social impacts.
- ii. Asset Inspection and Maintenance: Drones can be equipped with thermal sensors for thermographic inspections and UV cameras to detect corona discharge.
- iii. Construction: Real Time Project monitoring and tracking

10.5. Transmission Infrastructure Technologies

Design and construction technologies translate planning decisions into physical assets. The choice of materials, equipment and construction methods directly affects capacity, reliability, environmental footprint, and long-term operating costs.

10.5.1. Advanced Conductors and Line Technologies

While Aluminium Conductor Steel Reinforced (ACSR) remains widely used. However, modern systems increasingly employ High-Temperature Low-Sag (HTLS) conductors, such as: Aluminium Conductor Composite Core (ACCC) and Aluminium Conductor Steel Supported (ACSS). These conductors can operate at significantly higher temperatures while maintaining reduced sag characteristics, enabling the uprating of existing transmission corridors. KETRACO will employ the use of HTLS conductor in the upcoming Dongo Kundu- Mariakani 220kV Transmission Line.

10.5.2. Power Electronics, FACTS and HVDC

Flexible AC Transmission Systems (FACTS), including STATCOMs and Static Var Compensators (SVCs), provide fast reactive power support, voltage control and oscillation damping. Line Commutated Converter High Voltage Direct Current (LCC-HVDC) technology enables efficient long-distance bulk power transfer and cross-border electricity trading. Kenya's successful implementation of the Ethiopia-Kenya HVDC interconnector demonstrates KETRACO's capability to manage and operate advanced power transmission network.

10.6. Digitalization of Operations and Asset maintenance

Operations and maintenance technologies ensure that transmission assets deliver their intended performance throughout their service life. The global trend is a shift from time-based maintenance to condition-based and predictive maintenance, supported by digital monitoring and analytics.

10.6.1. Asset Performance Management Systems (APM)

As part of its commitment to modernizing transmission network operations and enhancing system reliability, KETRACO is implementing an Asset Performance Management (APM) system. This initiative forms a key component of the Company's broader digital transformation strategy aimed at improving asset visibility, optimizing lifecycle costs, and strengthening data driven investment planning across the transmission network.

The APM system is currently under implementation in the following substations: Isinya, Kimuka, Athi River, Suswa, Kakuyuni, Mang'u, Kibos and Kegati substations. KETRACO intends to achieve full implement APM By 2027. The preliminary outputs and asset data will support transmission planning processes, particularly in asset refurbishment prioritization, risk management, maintenance optimization, and long-term infrastructure development.

10.6.2. Strategic Role in Transmission Network Modernization

The APM system supports the transition toward a more intelligent, resilient, and efficient transmission grid by integrating advanced analytics, digital monitoring technologies, and centralized asset information platforms. This enhances operational awareness and enables proactive asset management aligned with evolving grid demands, renewable integration requirements, and emerging electricity market developments.

The initiative complements other digital utility systems such as SCADA, Geographic Information Systems (GIS), and Computerized Maintenance Management Systems (CMMS), strengthening overall network operational efficiency and planning accuracy.

10.6.3. Integration with Operational Planning

As system maturity improves, the APM platform will increasingly support transmission planning and operational decision-making as shown in Table 10-1.

Table 10 1: Integration with Operational Planning

Integration with Operational Planning	
Asset Refurbishment and Replacement Planning	Condition-based insights will guide decisions on refurbishment, reinforcement, or replacement of existing infrastructure prior to new capital expansion.
Reliability and Risk Management	Enhanced asset performance data will improve identification of critical asset vulnerabilities, failure risks, and system resilience requirements.
Maintenance Optimization	The transition from time-based to predictive maintenance is expected to reduce forced outages, improve asset availability, and optimize operational expenditures.
Investment Prioritization	Evidence-based asset condition information will support balanced capital allocation considering asset health, system demand growth, financial constraints, and network security needs.

10.7. National System Control Centre (NSCC) and Emergency Control Centre (ECC)

Modern system operation requires highly resilient control facilities equipped with redundant communications, power supply, and computing systems. The establishment of a new National Control Centre and Emergency Backup Control Centre provides critical operational resilience.

These facilities are designed to meet the highest global standards for redundancy, situational awareness, and decision support.

10.7.1. Core Control Room Technology Stack

These includes:

- Integrated EMS/SCADA platform with real-time and study environments
- HVDC and FACTS control modules. Advanced alarm management and decision-support systems.
- Large-format visualization walls and operator dashboards.

10.7.2. Energy Management and Control Systems

The control centres host fully integrated (EMS) incorporating SCADA, state estimation, contingency analysis, optimal power flow, automatic generation control, and HVDC and FACTS control modules. Systems support both real-time operation and offline study modes, ensuring consistency between planning and operations.

10.7.3. Wide-Area Monitoring, Visualization and Decision Support

Full integration of PMU and WAMS data enables real-time monitoring of angular stability, oscillations, and system stress. Advanced visualization tools, large-format display walls and decision-support dashboards support effective operator response under both normal and emergency conditions.

10.7.4. Cybersecurity, Resilience and Business Continuity

The NSCC and ECC are geographically separated and designed for high availability, with redundant power, communications, and data replication. Comprehensive cybersecurity controls, regular disaster recovery testing and business continuity planning are essential to protect critical national infrastructure.

10.8. Technology Implementation Roadmap (2026–2045)

Table 10 2: Technology Implementation Roadmap (2026-2045)

Phase	Technology Focus	Strategic Outcome
2026–2030	SCADA/EMS upgrade, PMU rollout, APM deployment, HTLS pilots,	Improved visibility, reduced outages, initial capacity uplift

Phase	Technology Focus	Strategic Outcome
2028–2035	STATCOM deployment and HVDC increased capacity. Solarization of substations	Regional trade support, renewable stability, predictive operations. Enhanced power supply reliability and reduced restoration time.
2038–2045	Advanced automation, forecasting AI-based analytics.	Fully digital, resilient, smart transmission network

10.9. Regulatory gap

The increasing penetration of inverter-based renewable energy sources, particularly solar photovoltaic (PV) and wind generation, introduces new operational challenges. As their share in the generation mix increases, the overall system inertia declines, potentially leading to faster frequency deviations during disturbances. To enhance grid resiliency, the grid code should be reviewed to include inverter technical standards for synthetic inertia requirements, and market products for flexibility.

10.10. Monitoring & Key Performance Indicators

Suggested KPIs (monitoring frequency in parentheses):

- VRE curtailment rate (%): annual
- MW of controllable transfer capacity added (HVDC/FACTS): annual.
- PMU coverage (% of substations): annual
- Transmission SAIDI/SAIFI linked to transmission faults: annual.
- Number of cyber incidents detected / mitigated: quarterly.

10.11. Voltage Stabilization and Reliability Enhancement Measures

This section summarizes ongoing and proposed national interventions aimed at strengthening voltage stability, frequency control, system strength and reliability of Kenya's transmission network. It includes generation-side flexibility, reactive power support, storage deployment, and future firm capacity technologies.

Table 10 3: Summary of Stability and Reliability Interventions

Intervention	Technical Purpose	Application to Transmission Stability	Lead Entity	Implementation Status (2026)
HVDC Interconnection (Ethiopia–Kenya)	Controlled bulk power transfer	Improves controllability and regional reliability	KETRACO	Operational
Liquefied Natural Gas (LNG) Generation	Dispatchable thermal generation for peak and reserve support	Provides inertia, spinning reserve and voltage stability during renewable variability	Government / Private Sector	Policy-level discussions; no large-scale plant operational
Battery Energy Storage Systems (KenGen)	Fast frequency response and peak shaving	Provides synthetic inertia, FCR, voltage support	KenGen	feasibility study stage
STATCOM Installations	Dynamic reactive power compensation	Improves voltage profile and transient stability	KETRACO	procurement
Phase Shifting Transformers (PST)	Active power flow control	Reduces congestion and loop flows	KETRACO	sourcing for finance
Nuclear Power (Proposed Programme)	Firm baseload generation with high inertia contribution	Enhances system inertia, voltage stability and long-term reliability	KenGen	pre-feasibility stage

Table 10 4: Stability Gap Analysis – Current vs 2045 Requirements

STABILITY METRIC	ESTIMATED CURRENT CAPACITY (2026)	INDICATIVE REQUIREMENT BY 2030	INDICATIVE REQUIREMENT BY 2045	GAP ASSESSMENT
GRID-SCALE BESS (MW)	≈ 0–50 MW (pilot scale)	300–500 MW	800–1200 MW	Significant scaling required
DYNAMIC REACTIVE COMPENSATION (STATCOM/SVC) (MVAR)	≈ 200–300 MVAR	800–1000 MVAR	1500–2000 MVAR	Reactive capacity deficit in renewable zones
FIRM INERTIA CONTRIBUTION (EQUIVALENT MW)	Hydro + Thermal dominant	Additional 500–800 MW support	1000–1500 MW firm support (incl. nuclear/storage)	Long-term firm capacity expansion required
PHASE-SHIFTING TRANSFORMERS (STRATEGIC CORRIDORS)	1–2 key locations	3–5 corridors	5–8 corridors	Congestion management enhancement needed
WIDE-AREA MONITORING (PMU COVERAGE %)	Partial deployment	≈70% backbone coverage	≈100% backbone coverage	Monitoring expansion required





CONCLUSION AND RECOMMENDATIONS

11.1. Conclusion

This Transmission Master Plan 2026-2045 provides a robust, data-driven framework for guiding KETRACO's medium and long-term transmission infrastructure investments. Based on the demand and generation scenarios from the Least Cost Power Development Plan (LCPDP) 2024-2043, the simulated network using PSSE software confirms that the planned transmission expansions will adequately meet projected peak loads, evacuate new generation, and comply with the National Transmission Grid Code's N-1 reliability and voltage criteria. The plan successfully addresses existing system constraints, such as overloading and voltage instability, while enabling the integration of up to 63% renewable energy in the firm capacity mix by 2045.

A key conclusion is that the role of transmission extends beyond mere infrastructure delivery; it is a critical enabler of Kenya's low-carbon transition. By facilitating the evacuation of geothermal, wind, and solar power, and by reducing reliance on thermal generation, the TMP directly supports Kenya's Nationally Determined Contributions (NDCs) and climate resilience goals. However, the analysis also highlights that technical transmission losses, though unavoidable, present a climate cost that must be actively managed, while the net climate benefit from renewable integration remains overwhelmingly positive.

The plan successfully integrates cross-cutting themes essential for project success. The institutionalization of a Monitoring, Evaluation, Accountability, and Learning (MEAL) framework will ensure that investments translate into tangible improvements in power quality, reliability, and socio-economic benefits. Furthermore, the shift from a compliance-based to a strategic, risk-based stakeholder engagement framework is critical for mitigating non-technical risks, expediting wayleave acquisition, and reducing project delays. Ultimately, the most significant challenge to realizing the TMP's vision is the substantial financing gap. With a total investment requirement of USD 5.3 billion and an unfunded gap of USD 4.95 billion, the timely implementation of 138 projects is at risk. Addressing this will require a concerted and innovative financing strategy that moves beyond traditional exchequer funding and development partner support to fully engage private capital and climate finance instruments.

11.2. Recommendations

To ensure the successful and timely implementation of the Transmission Master Plan 2026-2045 and to secure Kenya's electricity transmission future, the following actions are recommended:

11.2.1. Mobilize Innovative Financing to Close the Investment Gap

- i. Continue to advocate for financing Right of Way (RoW) costs through alternative sources beyond the exchequer, such as retail tariffs or development assistance, to prevent project delays related inadequate budget for land acquisition and compensation.
- ii. Continuously promote and structure bankable transmission projects for development through the PPP framework, prioritizing solicited and unsolicited proposals for the planned projects.
- iii. Build dedicated institutional capacity to develop bankable climate project proposals and actively pursue concessional loans, green bonds, and carbon credit revenues by quantifying the emission reductions enabled by transmission investments.
- iv. Maintain continuous engagement with the National Treasury and development partners to secure and accelerate the disbursement of committed funds, especially for critical projects with existing financing gaps.

11.2.2. Enhance Project Implementation and Risk Management

- i. Strengthen the monitoring of pre-construction indicators (e.g., ESIA/RAP approvals, financing effectiveness) to identify bottlenecks early. Initiate safeguard processes and land surveys concurrently with feasibility studies.
- ii. Systematically integrate climate risk assessments, downscaled climate projections, and GIS-based vulnerability mapping into route selection and engineering designs. Update technical manuals to include climate-informed parameters for wind, temperature, and flooding.
- iii. Implement the comprehensive risk matrix as a living tool, assigning clear ownership for each risk and conducting regular reviews of mitigation strategies, particularly for strategic, financial, and operational risks.

11.2.3. Accelerate Technology Adoption and Grid Modernization

- i. Fast-track the procurement and installation of STATCOMs, Phase-Shifting Transformers (PSTs), and additional BESS to provide dynamic reactive power support, manage congestion, and enhance system inertia in response to growing VRE penetration.

- i. Increase Phasor Measurement Unit (PMU) coverage across the backbone network to enable Wide-Area Monitoring (WAMS) and improve real-time visibility of system stability and oscillations.
- ii. Initiate a review of the National Transmission Grid Code to establish technical standards for inverter-based resources, including requirements for synthetic inertia and frequency response, and to create market products for grid flexibility.

11.2.4. Strengthen Institutional Frameworks and Capacity

- i. Establish a dedicated multi-disciplinary team within KETRACO to identify, develop, and manage climate-financed projects, including building expertise in Monitoring, Reporting, and Verification (MRV) systems.
- ii. Fully operationalize the MEAL framework by ensuring baseline data collection before project energization and conducting post-commissioning impact evaluations to capture lessons and demonstrate socio-economic returns.
- iii. Implement the full IAP2 spectrum of public participation, empowering affected communities and moving from simple consultation to collaborative decision-making to build lasting social license and reduce project friction.





12 APPENDICES AND SUPPORTING DOCUMENTATION

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12.1. Generation Statistics

Table 12 1: Capacity and Energy Purchased from various power producers

COMPANY	Capacity (MW) as at 30.06.2025		Energy Purchased (GWh)				
	Installed	Effective ¹ / Contracted ²	2020/21	2021/22	2022/23	2023/24	2024/25
KenGen							
Hydro:							
Gitaru	225	216	884	709	456	806	777
Kamburu	94.2	90	443	368	236	407	399
Kiambere	168	164	977	796	516	806	802
Kindaruma	72	70.5	184	165	102	188	187
Masinga	41.2	40	176	154	77	116	161
Tana	25.7	20	123	87	82	118	109
Turkwel	106	105	715	539	486	413	574
Sondu Miriu	60.7	60	431	339	375	280	235
Sang'oro	21.2	20	144	110	122	126	128
Small Hydros	12.27	11.26	16	34	67	75	75
Hydro Total	826	797	4,091	3,300	2,520	3,335	3,448
Thermal:							
Kipevu Diesel Power I	0	0	55	141	93	0	0
Kipevu Diesel Power III	120	115	147	399	231	365	461
Muhoroni GT	52	52	43	40	35	0	15
Thermal Total	172	167	245	580	360	365	476
Geothermal:							
Olkaria I (Units 1,2&3)	0	0	70	204	113	0	0
Olkaria II	104.5	101	500	488	730	627	688
Eburru	2.4	2.1	8	4	8	9	4
OW37 - WellHead 37 ³	22	17.5	101	65	70	56	91
OW 43 - WellHead 43	14	10	55	40	29	44	0
OW 914 - WellHead 914 ⁴	52.5	42.5	231	215	211	161	177
Olkaria IV	149.9	140	960	1,007	1,013	970	993
Olkaria I AU (Units 4&5)	150.5	140	861	774	1,042	1,020	786
Olkaria V	172.3	158	1,268	1,066	1,266	1,164	1,183
Olkaria I (Unit 6)	86.9	80		113	607	583	586
Geothermal Total	755	691	4,053	3,977	5,089	4,633	4,509
Wind:							
Ngong	25.5	25.5	53.6	53.6	57	50	48
KenGen Total	1,779	1,680	8,443	7,911	8,027	8,383	8,482
Government of Kenya (Rural Electrification Programme)							
Off-grid Diesel	41	24.2	64.8	71	74	85	88
Off-grid Solar	2.3	1.7	0.26	0.25	0.34	0.28	0.26
Off-grid Wind	0.6	0	0	0	0	0	0
Total Offgrid	44	26	65	71	75	85	88
Independent Power Producers (IPP) - Thermal & Geothermal							
Thermal:							

¹ PPA Effective Capacity - Contracted Capacity for the Power Plant on Energy PPA

² PPA Contracted Capacity – Contracted Capacity for the Power Plant on Capacity PPA

³ Includes OW37, OW 37 kwg 12, OW 37 kwg 13 and OW 39 Olkaria Mobile Wellheads centrally metered at OW 37

⁴ Includes OW905,OW914 ,OW915 and OW 919 Olkaria Mobile Wellheads centrally metered at OW 914

COMPANY	Capacity (MW) as at 30.06.2025		Energy Purchased (GWh)				
	Installed	Effective ¹ / Contracted ²	2020/21	2021/22	2022/23	2023/24	2024/25
Off-grid Solar	2.3	1.7	0.26	0.25	0.34	0.28	0.26
Off-grid Wind	0.6	0	0	0	0	0	0
Total Offgrid	44	26	65	71	75	85	88
Independent Power Producers (IPP) - Thermal & Geothermal							
Thermal:							
Iberafrica	52.5	52.5	45	86	116	38	60
Rabai Power	90	88.6	266	502	446	441	489
Kipevu II (Tsavo)	0	0	183	48	0	0	0
Thika Power	87	87	93	211	194	121	133
Gulf Power	80.3	80.3	21	81	170	53	42
Triumph Power	83	83	22	70	35	26	47
Thermal Total	393	391	630	997	961	678	772
Geothermal:							
OrPower 4 -Geothermal (1st plant)	63.8	63.8	390	392	399	332	371
OrPower 4 -Geothermal (2nd plant)	39.6	39.6	269	265	245	210	240
OrPower 4 -Geothermal (3rd plant)	17.6	17.6	128	128	116	104	117
OrPower 4 -Geothermal (4th plant)	29	29	194	190	180	147	155
Sossian Menengai Geothermal	35	35			6	282	326
Geothermal Total	185	185	981	976	946	1,075	1,209
Wind:							
Lake Turkana Wind Power	310	300	1,559	1,573	1,678	1,326	1,437
Kipeto Energy PLC	100	100	88	426	466	404	423
Wind Total	410	400	1,647	1,999	2,144	1,730	1,859
Small Hydro:							
Imenti Tea Factory	0	0	0.4	0.2	0.3	1	0
Gikira small hydro	0.5	0.5	1.8	0.9	1	2	1
Regen-Terem	5	5	22	15	20	23	22
Gura KTDA	2.8	2.8	11.3	20	11	14	13
Chania KTDA	0.5	0.5	1	1	0.2	1	1
North Mathioya (Metumi) KTDA	3.6	3.6	13.8	9.9	14	17	15
Kianthumbi Small hydro	0.5	0.5	0.36	2	1.5	3	3
Small Hydro Total	12.9	12.9	50.3	48.5	48.9	60.7	55.2
Cogeneration:							
Biojoule Biogas	2	2	0.3	0.4	0.2	0.1	0
Cogeneration Total	2	2	0.3	0.4	0.2	0.1	0
Solar:							
Strathmore Solar	0.3	0.3	0.09	0.05	0.08	0.08	0.07
Selenkei Solar Farm	40	40	1.5	89	86	94	94
Cedate Solar Farm	40	40		88	94	96	92
Malindi Solar Group	40	40		54	99	99	97
Alten Kenya SolarFarm	40	40			79	100	108
Solar Total	160.3	160.3	1.6	230.4	357.8	389	390.2
IPP Total	1,163	1,152	3,310	4,251	4,458	3,933	4,285

COMPANY	Capacity (MW) as at 30.06.2025		Energy Purchased (GWh)				
	Installed	Effective ^{1/} Contracted ²	2020/21	2021/22	2022/23	2023/24	2024/25
REREC							
Garissa Solar Plant	50	50	86	82	86	84	83
REREC Total	50	50	86	82	86	84	83
Imports							
UETCL			192	332	275	217	226
TANESCO			0	0	0	0	0
EEU (MOYALE)			4.8	5.5	5.5	5.5	6.5
EEP 500 HVDC	200	200			364	977	1,268
TANESCO- 400kV							33.8
Total Imports	200	200	197	338	644	1,199	1,534
SYSTEM TOTAL							
	3,236	3,108	12,101	12,653	13,290	13,684	14,472

Table 12 2: Summary of Key Power System Statistics over the past 5 years

SUMMARY OF KEY STATISTICS							
Sales							
KPLC System (GWh)			8,553	9,147	9,539	9,813	10,570
REP System (GWh)			632	650	667	660	760
Export to Uganda (GWh)			17	16	27	43	42
Export to Tanesco (GWh)			0	0	0	0	0
Export to Tanesco 400kV (GWh)							30.16
TOTAL SALES (GWh)			9,203	9,813	10,233	10,516	11,403
System Losses (GWh) ¹			2,898	2,839	3,057	3,169	3,069
System Peak Demand (MW)²			1,994	2,057	2,149	2,177	2,316
System Load Factor			69.30%	70.20%	70.60%	71.80%	71.30%
Sales % of Energy Purchased			76.10%	77.60%	77.00%	76.80%	78.80%
Losses as % of Energy Purchased			23.95%	22.44%	23.00%	23.16%	21.21%
Annual Growth							
Energy Purchased			5.57%	4.56%	5.04%	2.97%	5.76%
Total Sales			4.90%	6.63%	4.28%	2.76%	8.43%
KPLC Sales			4.90%	6.94%	4.28%	2.87%	7.71%
REP Sales			5.02%	2.89%	2.58%	-1.06%	15.17%
System Peak Demand			3.51%	3.18%	4.49%	1.30%	6.36%

¹ System losses comprise of technical and non-technical losses.

² The peak demand shown includes export to Uganda.

12.1. 12.2. List of GoK owned off-grid stations

Table 12 3: GoK Offgrid and Minigrids

Government of Kenya Off-grid and Minigrid Stations				
Station Name	Installed Capacity (MW)	Effective*/Contracted Capacity (MW)		
Off-Grid				
Wajir Diesel	4.8	2.98		
Mandera Diesel	0.8	0.2		
Mandera Aggreko Diesel	2.6	2.1		
Mandera Solar	0.33	0.23		
Marsabit Diesel	2.8	1.5		
Marsabit Wind	0.5	0		
Lodwar Diesel	0.4	0.3		
Lodwar Solar	0.06	0		
Lodwar Aggreko Diesel	2.6	2.4		
Merti Diesel	0.52	0.4		
Merti Solar	0.01	0.01		
Habasweni Diesel	1.8	1.36		
Habasweni Solar	0.03	0		
Habasweni Wind	0.05	0		
Elwak Diesel	1.36	0.52		
Elwak Solar	0.06	0.03		
Baragoi Diesel	0.24	0.129		
Mfangano Diesel	0.64	0.33		
Mfangano Solar	0.01	0.01		
Lokichogio Diesel	1.085	0.6		
Eldas Diesel	0.92	0.28		
Eldas Solar	0.03	0.024		
Takaba Diesel	0.8	0.55		
Takaba Solar	0.03	0.03		
Rhamu Diesel	1.1	0.84		
Rhamu Solar	0.06	0.03		

Government of Kenya Off-grid and Minigrid Stations

Station Name	Installed Capacity (MW)	Effective*/Contracted Capacity (MW)
Laisamis Diesel	0.584	0.47
Laisamis Solar	0.08	0
North Horr Diesel	0.584	0.4
Lokori Diesel	0.6	0.44
Moyale Diesel	2.252	1.34
Dadaab Diesel	0.784	0.54
Faza Diesel	1.72	1.02
Lokitaung Diesel	0.184	0.15
Kiunga Diesel	0.27	0.2
Hulugo Diesel	0.24	0.18
Banisa Diesel	0.48	0.32
KAMOLIRIBAN Diesel	0.402	0.08
KOTULO Diesel	0.36	0.28
Kakuma Diesel	1.6	0.961
LOKIRIAMA	0.464	0.05
KHORONDILE	0.6	0.5
Sololo	0.64	0.52
Maikona	0.304	0.05
REREC Mini-Grids		
Ashabito Diesel	0.04	0.04
Ashabito Solar	0.06	0.06
Kiliwaheri Diesel	0.04	0.04
Kiliwaheri Solar	0.06	0.06
Gari Diesel	0.04	0.04
Gari Solar	0.06	0.06
Burduras Diesel	0.04	0.04
Burduras Solar	0.06	0.06
Lafey Diesel	0.04	0.04
Lafey Solar	0.06	0.06

Government of Kenya Off-grid and Minigrid Stations

Station Name	Installed Capacity (MW)	Effective*/Contracted Capacity (MW)
Shibir Fatma Diesel	0.04	0.04
Shibir Fatma Solar	0.06	0.06
Ambalo Diesel	0.04	0.04
Ambalo Solar	0.06	0.06
Illaut Diesel	0.04	0.04
Illaut Solar	0.06	0.06
Balesa Diesel	0.04	0.04
Balesa Solar	0.06	0.06
Basir Diesel	0.04	0.04
Basir Solar	0.06	0.06
Sarman Diesel	0.04	0.04
Sarman Solar	0.06	0.06
Sarif Diesel	0.04	0.04
Sarif Solar	0.06	0.06
Gurar Diesel	0.04	0.04
Gurar Solar	0.06	0.06
Hadado Diesel	0.04	0.04
Hadado Solar	0.06	0.06
Riba Diesel	0.04	0.04
Riba Solar	0.06	0.06
Biyamadhow Diesel	0.04	0.04
Biyamadhow Solar	0.06	0.06
Sangailu Diesel	0.04	0.04
Sangailu Solar	0.06	0.06
Eldera Diesel	0.04	0.04
Eldera Solar	0.06	0.06
Garsweno Diesel	0.04	0.04
Garsweno Solar	0.06	0.06
Liboi Diesel	0.04	0.04
Liboi Solar	0.06	0.06

Government of Kenya Off-grid and Minigrid Stations		
Station Name	Installed Capacity (MW)	Effective*/Contracted Capacity (MW)
Napeleleilim Diesel	0.04	0.04
Napeleleilim Solar	0.06	0.06
Letea Diesel	0.04	0.04
Letea Solar	0.06	0.06
Ilowareng Diesel	0.04	0.04
Ilowareng Solar	0.06	0.06
Eliye Diesel	0.04	0.04
Eliye Solar	0.06	0.06
Kangangipur Diesel	0.04	0.04
Kangangipur Solar	0.06	0.06
Lopeduru Diesel	0.04	0.04
Lopeduru Solar	0.06	0.06
TOTAL		
Off-grid Diesel	41	24.2
Off-grid Solar	2.3	1.9
Off-grid Wind	0.55	0
Total Off-grid	43.8	26.1

12.3. Demand Drivers

The main factors influencing demand growth considered were demography, GDP growth, Specific Vision 2030 Flagship projects, E-cooking, and Electric vehicles.

12.3.1. Demography

Historically, population size and urbanization rate have shown a positive correlation with electricity usage. As shown below, domestic commercial (DC), small commercial (SC), and street lighting (SL) show positive correlations with population growth. This correlation is used to perform trend analysis in estimating future electricity demand within the named classes.

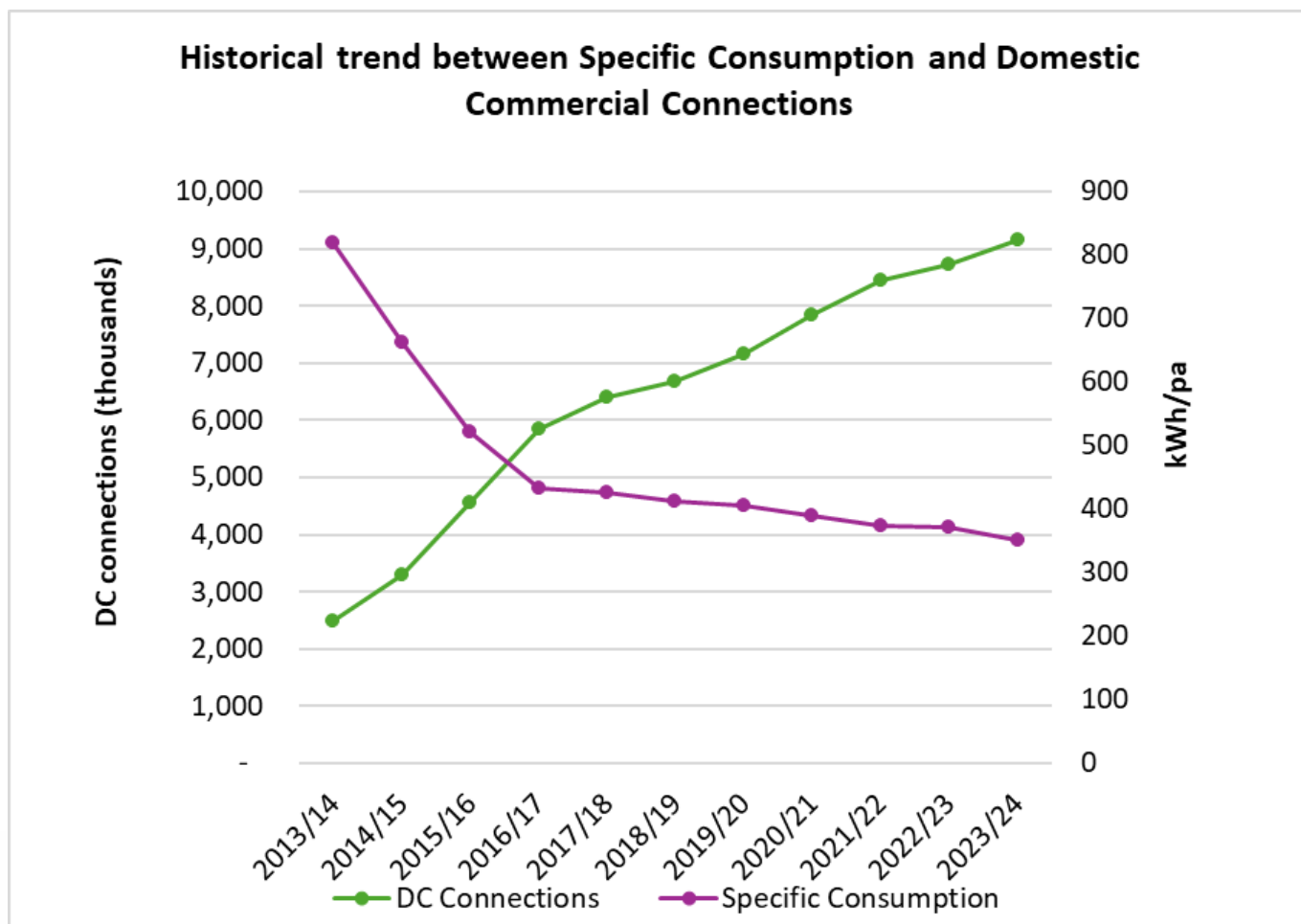
The demand for more electricity is mainly due to economic activities and household needs. Currently, the inadequacy of individual consumer data makes forecasting power demand a challenge, thus requiring the utilization of aggregated data for system load predictions. Population growth and urbanization are essential elements to the demand rise, as is the growth of GDP, which has an immediate result on household earnings and thus electrical consumption. Additionally, key government priority projects through the Bottom-up Economic Transformation Agenda (BETA) and Vision 2030 flagship projects have a bearing on GDP growth in both the reference and high scenarios.

The methodology used to undertake the forecast is similar to that used in the previous updates of the LCPDP plans. The methodology follows Model for Analysis of Energy Demand (MAED) principles for the domestic consumers, whereby a simple correlation factor between GDP growth and consumption for the commercial & industrial consumers and a correlation between street lighting consumers and domestic consumers is formulated. 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.

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

12.3.2. Domestic Consumption

In the past decade, domestic connections has significantly increased; however, annual specific consumption has declined from 819kWh in 2014/15 to 351kWh in 2023/24 as shown in the table below. The decrease is due to two factors: universal electricity access leading to more low-income households being connected yet they consume less power, and advancements in energy-efficient appliances and electronics.



An analysis of power demand as a result of e-mobility and e-cooking was undertaken to assess the impact on overall future electricity demand.

12.3.3. E-Mobility

Kenya's electric vehicle (EV) sector is steadily progressing, supported by favourable government policies, expanding charging infrastructure, and rising public awareness of environmental and economic benefits. To support the government initiatives, Kenya Power and Lighting Company (KPLC) has introduced a special tariff for this category of consumers, offering off-peak rates for those connected under the tariff categories C11-C15. The sector also plays a significant role in the country's energy transition and Vision 2030 goals especially in reducing greenhouse gas (GHG) emissions and enhancing energy security. According to National E-Mobility Policy Kenya, 2024, road transport accounts for 94% of transport emissions. The National Climate Change Action Plan (NCCAP)

2023-2027 identifies the uptake of EVs as one of the climate actions in the transport and energy sectors as they significantly cut CO₂ emissions, improve energy efficiency, and build a clean transport network.

According to the bi-annual EPRA statistic report 2024/25, cumulative number of registered EVs stood at 5,294 as of December 2024, a rise from 3,753 registered in 2023. The growth is attributed to various government initiatives such as introduction of special electric mobility tariff of 16 Kshs/kWh, reduction in excise duty on electric vehicles from 20% to 10%, exemption of fully electric cars from VAT, the expansion of charging infrastructure, and declaration by the Kenyan government to the COP26 to transition to 100% zero-emission cars by 2035. Besides, according to National Energy Efficiency and Conservation Strategy 2020, 5% of the target newly registered vehicles will be EVs by 2030. With all these initiatives, it is expected that the level of EV's adoption in Kenya will increase substantially. It is therefore expected that modelling the demand for EVs will be improved as more data becomes available. Using the projections in the MTP 2025-2029, electricity demand from EVs is expected to increase from 23.51MW in 2024 to 219.2MW and 273MW in 2030 for both reference and vision scenarios and subsequently to 397.87MW in 2045, assuming a growth rate of 4.35%.

12.3.4. E-Cooking

According to Kenya National e-Cooking Baseline Study Report 2023 done by Nuvoni, 0.58% of the population who own electric appliances primarily use electric appliances for cooking while 3.9% of households use these appliances for cooking, reheating food and preparing beverages. Ownership and usage of the appliance is influenced by gender, wealth, and urban-rural divide. Besides, 74.6% of the Kenyan households, believed that traditionally cooked food tastes better. Kenya aims to achieve 100% access to clean cooking by 2028, a strategy that is aligned with Sustainable Development Goal 7 (SDG7). The milestone also aligns with reducing deforestation, indoor air pollution, and greenhouse gas emissions.

An assessment of the transition to e-cooking was conducted, focusing on a typical residential customer. Currently, 0.58% of the household primarily rely on electricity for cooking. Projected demand growth

attributed to e-cooking is anticipated to be 10% by 2028, according to the Kenya National Cooking Transition Strategy (2024-2028) which outlines a five-year plan to establish a sustainable eCooking marketing place. The value will be escalated to 15% by 2030.

Further, a diversity factor of 22% from a study done in Malawi, was employed to account for the variation in uses of the appliance. The estimated demand of 1.16MW in 2024 is projected to increase to 28.2MW and 37.43MW by 2029 and 38.57 MW by 2030 and 141.14 MW by 2044 for reference and vision scenario, respectively.

12.3.5. Government Priority Areas

Electricity demand in Kenya is expected to grow steadily in the coming years driven by various government-led development initiatives that aim to transform and sustain the economy. Strategic programs target housing, industrialization, digitalization, and energy transition, which intend to significantly increase Kenya's energy consumption.

- i. Affordable housing and urban development: as per the National Housing Corporation Strategic Plan 2023-2027, the Kenyan government has identified housing as one of its development priorities and targets to facilitate the construction of at least 1,000,000 affordable houses by 2027.
- ii. Industrialization and MSME Growth: MTP IV has proposed a 5.9% annual industrial growth by 2027.
- iii. Digital superhighway and creative economy: the Kenya National Digital Master Plan 2022-2032 aims at expanding Kenya's fibre network coverage countrywide by connecting 100,000 KM of fibre optic cable to provide internet to schools, government institutions/offices, health facilities, and public spaces among others. The facilities will require electricity to support data centers and ICT operations. Coupled with the Last Mile connectivity program, this effort will empower the creative digital sectors while reducing the digital divide.
- iv. Green Energy Transition and Electric Cooking: Kenya is accelerating its shift towards clean energy, focusing on electric mobility and electric cooking. These trends underscore the need for grid expansion and investment in green infrastructure.
- v. Social services and healthcare: the Universal Health Coverage initiative

- i. indirectly increases electricity demand through hospitals and clinics construction and upgrades. Increased use of medical equipment especially in rural areas connected through the Last Mile Connectivity program will contribute towards rising energy needs.
- ii. Green hydrogen development: Kenya has positioned itself as a pioneer in green hydrogen, a clean energy carrier capable of transforming energy storage and transport. In a major step, Kenya has published a Green Hydrogen Strategy and Roadmap and Guidelines on Green Hydrogen and its Derivatives in September 2023 and May 2024 respectively. Green hydrogen policy framework is also underway. A notable project includes the development of a geothermal-powered green hydrogen plant to produce green ammonia for local fertilizer manufacturing, reducing fossil reliance and boosting energy innovation.

12.3.6. 2025 Budget Policy Statement

The 2025 BPS is built on the Government's Bottom-Up Economic Transformation Agenda with a strong emphasis on inclusive green growth. This approach recognizes the energy sector as a foundational enabler for economic transformation, job creation, and sustainable development. The energy agenda is aligned with the national goals such as reducing the cost of living, supporting manufacturing, expanding infrastructure, and transitioning to clean energy. Some of the proposals in the BPS that will influence energy consumption include the following:

- i. Expansion of electricity generation and access: the government plans to connect 1.44 million new electricity customers and 1,080 public facilities and develop infrastructure to enhance energy resilience and meet the growing electricity demand, especially in industrial, residential, and institutional sectors.
- ii. Green energy and E-mobility Transition: BPS promotes clean energy technologies by installing solar PV systems, promote clean cooking technologies and energy-efficient appliances, expand energy centers to all counties, and electrify schools, boreholes, and public institutions. BPS also highlights E-mobility as a key intervention to reduce emissions and fuel dependence. In collaboration with BasiGo and Kenya Vehicle Manufacturers (KVM), the Kenyan government has begun a local assembly of electric buses, aiming for 1,000 units over three years. The aim is to support the target of a fully electric bus fleet by 2027.

- i. Green Hydrogen and climate adaptation: Kenya is developing green hydrogen strategy to leverage excess renewable energy for hydrogen and ammonia production and support fertilizer production and export capability. Climate resilience and emission reduction is also key in the document with the ongoing integration of climate data and environmental accounting into economic planning.
- ii. Infrastructure for economic growth: infrastructure expansion includes electrification of transport (Bus Rapid Transit and Mass Rapid Transit System) using electric vehicle buses signaling a demand shift in electricity usage towards public transit systems. Cooling demand from new data centers and creative digital economy also contributes to the projected rise in electricity consumption.

12.4. Demand Forecast Results

Table 12 4: Peak Demand Forecast Results

Peak Demand Forecast Results			
Year	Reference (MW)	Vision (MW)	Low (MW)
2025	2,439	2,439	2,439
2026	2,607	2,681	2,539
2027	2,788	2,947	2,642
2028	2,980	3,239	2,750
2029	3,186	3,560	2,863
2030	3,406	3,913	2,979
2031	3,641	4,301	3,101
2032	3,892	4,727	3,228
2033	4,161	5,196	3,360
2034	4,448	5,711	3,497
2035	4,755	6,277	3,639
2036	5,084	6,899	3,788
2037	5,435	7,583	3,943
2038	5,810	8,335	4,104
2039	6,211	9,161	4,271
2040	6,640	10,069	4,446
2041	7,099	11,067	4,627
2042	7,589	12,164	4,816
2043	8,113	13,370	5,013
2044	8,673	14,696	5,218
2045	9,272	16,152	5,431
Average Growth rate	6.89%	9.40%	4.26%

Table 12 5: Electricity Consumption Forecast Results

Electricity Consumption Forecast Results			
Year	Reference (GWh)	Vision (GWh)	Low (GWh)
2025	11,403	11,403	11,403
2026	12,119	12,499	11,908
2027	12,880	13,701	12,436
2028	13,689	15,018	12,987
2029	14,548	16,462	13,563
2030	15,462	18,044	14,164
2031	16,432	19,779	14,792
2032	17,464	21,681	15,447
2033	18,561	23,765	16,132
2034	19,726	26,050	16,847
2035	20,965	28,554	17,594
2036	22,281	31,299	18,374
2037	23,680	34,308	19,188
2038	25,167	37,606	20,038
2039	26,747	41,222	20,926
2040	28,426	45,185	21,854
2041	30,211	49,529	22,822
2042	32,108	54,290	23,834
2043	34,124	59,509	24,890
2044	36,266	65,230	25,993
2045	38,544	71,501	27,145
Average Growth rate	0	0	0

Source: LCPDP 2024-2043 and MTP 2025-2029

12.5. Generation Dispatch

Table 12 6: Medium Term System Summary (Generation, Load & Losses)

Medium Term System Summary (Generation, Load & Losses)							
ZONE		2026			2030		
		Generation	Load	Losses	Generation	Load	Losses
Ethiopia	MW	289.2	0	1.1	600.7	0	10.8
	MVAr	-128.7	0	129.6	-244.6	0	471.7
Nairobi	MW	217.6	1031.9	28.4	273.8	1551.7	46
	MVAr	44.7	340.1	220.1	166.3	493.7	375.9
Uganda	MW	73	0	0	150	0	0
	MVAr	-19	0	0	-19	0	0
Coast	MW	212.8	359.5	7.4	284.2	513.5	13.3
	MVAr	85.8	123.5	62	-50.3	169.5	105.4
Mt. Kenya	MW	645.2	351.4	26.9	388.4	335.8	11
	MVAr	114.5	115.5	166.6	-9.6	106.9	97.7
Central Rift	MW	807.9	237.5	25.4	1089.3	267.9	15.6
	MVAr	-91.9	78.1	250.1	20.1	85.3	262.9
Western Region	MW	78.5	222.8	7.7	158.3	232.1	3.6
	MVAr	59.6	73.2	44.1	-19.7	73.9	23.2
North Rift	MW	225	116.2	8	568.3	151.7	7.7
	MVAr	-15	102.2	78.5	-295	48.3	96.8
Tanzania	MW	0	33.6	0.1	0	200	0.4
	MVAr	0	0	1.5	0	90	4
Active Power	MW	2,549.20	2,352.90	105	3,513.00	3,252.70	108.4
Reactive Power	MVAr	50	832.6	952.50	-451.8	1067.6	1,437.60

Long Term System Summary (Generation, Load & Losses)										
ZONE		2035			2040			2045		
		Gen	Load	Losses	Gen	Load	Losses	Gen	Load	Losses
Nairobi	MW	245.4	2187.7	64.3	175.5	2,934.3 0	126.3	217.7	4,066.2 0	237
	MVA r	51.4	440.4	626.9	193.7	965.8	1,159.5 0	280.9	512.8	2,377.6 0
Coast	MW	513.3	741.8	14.1	1412.5	155.2	35.1	2,306.3 0	1,305.4 0	70.3
	MVA r	-69.9	155.2	138	-273.4	155.2	323.8	123.5	175.7	657.8
Mt. Kenya	MW	1,101.3 0	480.4	18.3	1,101.1 0	641.8	23.7	1372.3	886.6	43.4
	MVA r	-79.2	96.9	209.4	54.7	96.9	269.7	176.7	112.8	440.4
Central Rift	MW	1,351.0 0	369.2	26.4	1,652.6 0	490.4	47.4	1,982.9 0	695.6	81.1
	MVA r	-41.6	74.6	214.5	-75.8	74.6	361.3	93.9	93.4	574.2
Western Region	MW	182	326.2	4.2	207	438.2	10.9	272	607	20.6
	MVA r	0.3	65.2	32	72.5	65.2	71.1	174.6	76	110.9
North Rift	MW	621.9	211.8	10.3	1,080.0 0	283.5	18.8	1,914.5 0	392.1	48.2
	MVA r	-52	41	102.9	-150.5	41	230.1	8.3	47.8	501
Ethiopia	MW	590	0	10.8	600.7	0	10.8	600.7	0	10.8
	MVA r	-250.9	0	471.7	-244.6	0	455	-251.2	0	487.1
Tanzania	MW	-200.8	0	0	0	200	0.8	0	200	0.5
	MVA r	-140	0	0	0	90	8.3	0	90	5.4
Uganda	MW	-0.1	0	0	0	0	0	0	0	0
	MVA r	28.4	0	0	0	0	0	0	0	0
Active Power	MW	4,404.0 0	4,317.1 0	148.40	6,229.4 0	5,143.4 0	273.80	8,666.4 0	8,152.9 0	511.90
Reactive Power	MVA r	-553.5	873.3	1,795.4 0	-423.4	1,488.7 0	2,878.8 0	606.7	1,108.5 0	5,154.4 0

12.6. Peak Load Distribution by Regions

Table 12 7: Peak Load Distribution by Regions

Peak Load Distribution by Regions					
Load in MW					
REGION	2026	2030	2035	2040	2045
NAIROBI	1031.9	1551.7	2187.7	2,934.30	4,066.20
COAST	359.5	513.5	741.8	155.2	1,305.40
MT KENYA	351.4	335.8	480.4	641.8	886.6
C RIFT	237.5	267.9	369.2	490.4	695.6
W REGION	222.8	232.1	326.2	438.2	607
N RIFT	116.2	151.7	211.8	283.5	392.1
TOTALS	2319.3	3052.7	4317.1	4943.4	7952.9

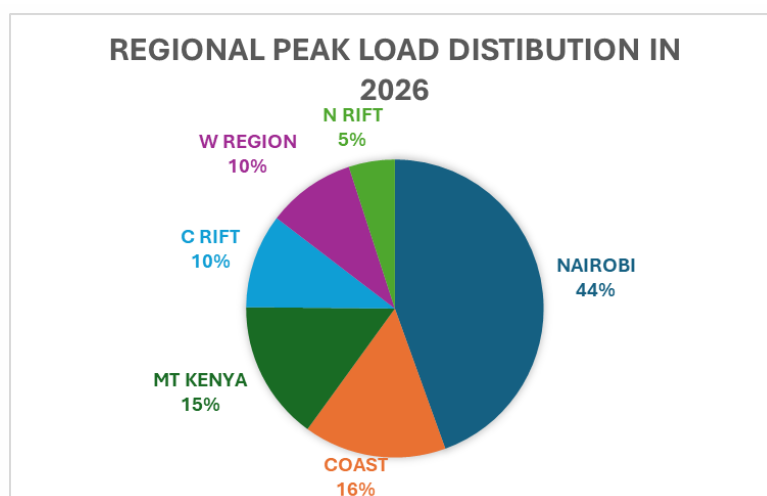


Figure 12 2: Regional Peak Load Distribution in 2026

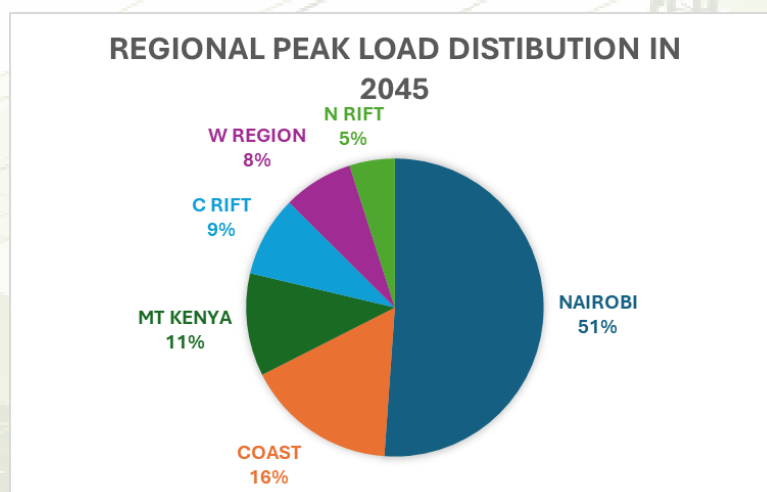


Figure 12 3: Regional Peak Load Distribution in 2045

12.7. Simulation Findings

Table 12 8: Year 2026 Three Phase Short Circuit Current

YEAR 2026 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
LOIY1	220	18.44	31.5	58.5
LOIY2	220	18.44	31.5	58.5
SUS1	220	2.54	40	6.4
7FORKS_SLR	132	10.78	31.5	34.2
ULU11	132	3.14	31.5	10
JUJA RD11	132	17.67	31.5	56.1
DANDORA11	132	17.95	31.5	57
SULTAN HA1	132	2.85	31.5	9
KIBOKO11	132	2.13	31.5	6.7
MTITO AND1	132	1.63	31.5	5.2
RUARAK TE1	132	14.33	31.5	45.5
RUARAKA11	132	14.11	31.5	44.8
MAKINDU	132	1.93	31.5	6.1
KONZA	132	3.22	31.5	10.2
MACHAKOS11	132	2.65	31.5	8.4
RUARAKAT12	132	14.33	31.5	45.5
NEW SULTAN	132	2.94	31.5	9.3
ISINYA	132	4	31.5	12.7
NAMANGA	132	1.47	31.5	4.7
MERUWESHI	132	1.49	31.5	4.7
LOITOKTOK	132	1	31.5	3.2
KONZANEW	132	8.21	31.5	26.1
UPLANDS	132	11.33	31.5	36
WOTE	132	2.68	31.5	8.5
NRB NORTH	220	12.71	31.5	40.4
DANDORA21	220	13.9	31.5	44.1
EMBAKASI21	220	13.34	31.5	42.4
ISINYA21	220	12.88	31.5	40.9
MALAA220	220	6.68	31.5	21.2
KIMUKA 220	220	9.91	31.5	31.5
ATHI RIVER	220	12.76	31.5	40.5
CABLE-OHL	220	12.66	31.5	40.2
CBD	220	12.42	31.5	39.4
KIPETO 220	220	9.75	31.5	30.9
THIKA RD21	220	12.39	31.5	39.3
ISINYA	400	7.07	31.5	22.4
SUSWA	400	7.72	40	19.3
KONZA4	400	6.04	31.5	19.2
KIMUKA	400	7	31.5	22.2
LOYAN	220	2.54	31.5	8.1
KIPEVU11	132	7.35	31.5	23.3
MANYANI11	132	1.65	31.5	5.2

YEAR 2026 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
SAMBURU11	132	2.94	31.5	9.3
KIPEVUDII1	132	4.62	31.5	14.7
KOKOTONI11	132	6.87	31.5	21.8
RABAI11	132	8.21	31.5	26.1
KILIFI11	132	3.55	31.5	11.3
BAMBURI11	132	5.44	31.5	17.3
VOI11	132	1.78	31.5	5.6
MAUNGU11	132	1.98	31.5	6.3
MARIAKANI1	132	4.89	31.5	15.5
GALU11	132	2.59	31.5	8.2
RABAITRF11	132	8.21	31.5	26.1
RABTRF12	132	8.21	31.5	26.1
VIPINGO31	132	3.9	31.5	12.4
MSCEMTEE31	132	3.61	31.5	11.4
MSACEM31	132	3.55	31.5	11.3
MSACEMTEE3	132	3.5	31.5	11.1
TITANIUM11	132	2.16	31.5	6.9
JOMVU	132	6.95	31.5	22.1
BAMB TEE	132	5.18	31.5	16.4
RABAITR 13	132	8.21	31.5	26.1
NEW KILIFI	132	3.61	31.5	11.5
TOP STEEL	132	4.34	31.5	13.8
NEWMMAUNGU	132	2.08	31.5	6.6
MTWAPA	132	4.36	31.5	13.9
WAPA TEE	132	4.36	31.5	13.9
WPA TEE2	132	4.36	31.5	13.9
DEVK SMBUR	132	3.39	31.5	10.8
RABAI21	220	5.13	31.5	16.3
MALINDI21	220	1.94	31.5	6.1
GARSEN21	220	1.15	31.5	3.6
LAMU21	220	0.83	31.5	2.6
WERU	220	2.22	31.5	7.1
MLDI SOLAR	220	2.22	31.5	7.1
MARIAKANI4	400	2.92	31.5	9.3
KINDARUMA1	132	8.66	31.5	27.5
GITARU11	132	12.56	31.5	39.9
KAMBURU11	132	14.86	31.5	47.2
MASINGA11	132	6.94	31.5	22
NANYUKI11	132	1.78	31.5	5.7
KYENI11	132	3.47	31.5	11
ISHIARA11	132	4.79	31.5	15.2
MERU11	132	2.06	31.5	6.5
GITHAMBO11	132	2.17	31.5	6.9
KIGANJO11	132	1.91	31.5	6.1
KAMBTRF11	132	14.86	31.5	47.2
KUTUS11	132	2.42	31.5	7.7

YEAR 2026 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
KUTUSTEE1	132	2.14	31.5	6.8
THIKA NEW	132	6.3	31.5	20
MWALA	132	4.39	31.5	13.9
KAMBURU21	220	9.93	31.5	31.5
KIAMBERE21	220	7.44	31.5	23.6
GITARU21	220	8.13	31.5	25.8
MUTOMO	220	2.45	31.5	7.8
MUTOMO	220	2.45	31.5	7.8
MUTOMO	220	2.45	31.5	7.8
GATUNDU11	132	2.78	31.5	8.8
MWINGI11	132	4.22	31.5	13.4
GARISSA11	132	0.87	31.5	2.8
ISIOLO11	132	1.87	31.5	5.9
KITUI11	132	3.15	31.5	10
THIKA11	132	7.3	31.5	23.2
THIKA12	132	7.26	31.5	23.1
GARISA PV1	132	0.84	31.5	2.7
OLKARIA1 1	132	8.97	31.5	28.5
NAIVASHA11	132	8.63	31.5	27.4
OLKARIAIAU	132	9.08	31.5	28.8
LANET11	132	5.91	31.5	18.8
SOILO11	132	5.27	31.5	16.7
OLKARIA II	132	8.72	31.5	27.7
KABARNET11	132	2.22	31.5	7.1
MAKUTANO11	132	3.76	31.5	11.9
NAROK11	132	2.08	31.5	6.6
MENENGAI11	132	4.74	31.5	15.1
RUMURUTI11	132	1.08	31.5	3.4
WELLHED37-	132	7.82	31.5	24.8
RONGAI_NC	132	4.02	31.5	12.8
RONGAI 132	132	4.26	31.5	13.5
CHEMOSIT11	132	2.85	31.5	9.1
BOMET11	132	1.56	31.5	5
OLKARIAIAU	220	17.3	31.5	54.9
OLK V	220	13.41	31.5	42.6
OLKARIA II	220	17.34	31.5	55
SUSWA21	220	18.44	40	46.1
OLKARIA IV	220	14.02	31.5	44.5
OLK IX	220	12.62	31.5	40.1
OLK III	220	13.52	31.5	42.9
SUSWA GEN	220	15.71	31.5	49.9
MUHORONI11	132	4.69	31.5	14.9
KISUMU 132	132	4.41	31.5	14
WEBUYE11	132	3.33	31.5	10.6
MUSAGA11	132	4.98	31.5	15.8
MUMIAS11	132	2.94	31.5	9.3

YEAR 2026 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
SONDU11	132	2.85	31.5	9
SANGORO11	132	2.69	31.5	8.5
KISII11	132	1.63	31.5	5.2
SOTIK	132	2.07	31.5	6.6
AWENDO11	132	1.19	31.5	3.8
RANGALA11	132	2.02	31.5	6.4
ONGENG	132	0.99	31.5	3.1
MASABA	132	0.89	31.5	2.8
MUSAGATEE	132	4.98	31.5	15.8
KIBOS 132	132	4.36	31.5	13.8
ANGA TEE1	132	3.72	31.5	11.8
ANGA TEE2	132	3.63	31.5	11.5
KIBOS 220	220	2.61	31.5	8.3
ELDORET11	132	4.06	31.5	12.9
LESSOS11	132	8.11	31.5	25.7
KITALE11	132	2.76	31.5	8.8
LESSTRF11	132	8.11	31.5	25.7
KOPERE	132	5.11	31.5	16.2
TURKWEL21	220	2.48	31.5	7.9
KITALE	220	1.84	31.5	5.8
ORTUM21	220	2.07	31.5	6.6
LESSOS	220	4.71	31.5	15
KAINUK21	220	2.47	31.5	7.9
TEE SLR	220	3.79	31.5	12
SLR PARK	220	3.74	31.5	11.9
LESSOS TEE	220	4.71	31.5	15
LESSOS TEE	220	3.07	31.5	9.8

Table 12-9: Year 2045 Three Phase Short Circuit Current

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
SUSWA	400	20.16	40	50.39
7FORKS_SLR	132	13.49	31.5	42.83
MAKINDUSLR	132	7.19	31.5	22.83
BSS_EMBA	220	22.6	31.5	71.75
TOTAL SLR	132	9.46	31.5	30.05
GT_COAST1	220	12.85	31.5	40.81
ULU11	132	4.29	31.5	13.61
JUJA RD11	132	29.92	31.5	94.97
DANDORA11	132	29.71	31.5	94.32
SULTAN HA1	132	5.34	31.5	16.97
KIBOKO11	132	7.19	31.5	22.83

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
MTITO AND1	132	3.75	31.5	11.9
RUARAK TE1	132	24.99	31.5	79.34
RUARAKA11	132	25.37	31.5	80.55
MAKINDU	132	14.26	31.5	45.26
KONZA	132	4.3	31.5	13.67
MACHAKOS11	132	3.37	31.5	10.71
RUARAKAT12	132	24.99	31.5	79.34
NEW SULTAN	132	5.33	31.5	16.91
ISINYA	132	4.52	31.5	14.33
NAMANGA	132	1.59	31.5	5.03
MERUWESHI	132	1.94	31.5	6.15
LOITOKTOK	132	1.2	31.5	3.8
KONZANEW	132	11.66	31.5	37.01
MAHI MAHIU	132	20.25	31.5	64.29
WOTE	132	3.74	31.5	11.87
SUNPOWER	132	3.74	31.5	11.88
NRB NORTH	220	19.44	31.5	61.71
DANDORA21	220	23.73	31.5	75.34
EMBAKASI21	220	22.6	31.5	71.75
ISINYA21	220	23.92	31.5	75.93
MALAA220	220	22.91	31.5	72.73
KIMUKA 220	220	13.34	31.5	42.34
MAGADI	220	4.95	31.5	15.73
ATHI RIVER	220	20.71	31.5	65.73
CABLE-OHL	220	20.62	31.5	65.44
CBD	220	19.97	31.5	63.41
KIPETO 220	220	14.69	31.5	46.65
THIKA RD21	220	22.86	31.5	72.56
RUARAKA21	220	16.39	31.5	52.03
ISINYA41	400	18.93	40	47.34
SUSWA	400	20.16	40	50.39
KONZA4	400	17.79	40	44.48
KIMUKA	400	18.11	40	45.29
NAMANGA	400	9.9	40	24.75
MALAA 400	400	19.3	40	48.26
MAKINDU400	400	11.77	40	29.41
KIPEVU11	132	11.01	31.5	34.95
MANYANI11	132	3.89	31.5	12.35
SAMBURU11	132	4.27	31.5	13.55
KIPEVUDI11	132	5.95	31.5	18.9
KOKOTONI11	132	10.5	31.5	33.34
RABAI11	132	13.79	31.5	43.79
KILIFI11	132	9.35	31.5	29.68
BAMBURI11	132	7.44	31.5	23.61
VOI11	132	6.43	31.5	20.4
MAUNGU11	132	4.29	31.5	13.63

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
MARIAKANI1	132	6.84	31.5	21.72
GALU11	132	4.85	31.5	15.4
KIBUYUNI	132	5.99	31.5	19.01
KWALE SC	132	5.11	31.5	16.21
RABAITRF11	132	13.79	31.5	43.79
RABTRF12	132	13.79	31.5	43.79
VIPINGO31	132	5.85	31.5	18.57
MSCEMTEE31	132	6.16	31.5	19.56
MSACEM31	132	6.55	31.5	20.8
MSACEMTEE3	132	7.07	31.5	22.46
TITANIUM11	132	4.61	31.5	14.63
JOMVU	132	10.37	31.5	32.93
TEE OFF	132	11.06	31.5	35.12
BAMB TEE	132	7.26	31.5	23.06
RABAITR 13	132	13.79	31.5	43.79
NEW KILIFI	132	13.51	31.5	42.89
TOP STEEL	132	6	31.5	19.06
NEWMAUNGU	132	4.06	31.5	12.88
NEW_VOI	132	11.8	31.5	37.45
MBARAKI	132	10.39	31.5	32.97
MTWAPA	132	6.21	31.5	19.71
MTWAPA TEE	132	6.21	31.5	19.71
MTWPA TEE2	132	6.21	31.5	19.71
DEVK SMBUR	132	4.78	31.5	15.17
RABAI21	220	11.51	31.5	36.54
MALINDI21	220	5.08	31.5	16.13
GARSEN21	220	2.66	31.5	8.43
LAMU21	220	1.45	31.5	4.61
MARIAKANI2	220	14.8	31.5	47
WERU	220	5.77	31.5	18.3
KILIFI	220	5.55	31.5	17.62
MLDI SOLAR	220	5.77	31.5	18.3
MTWAPA	220	2.27	31.5	7.21
HOLA	220	2.26	31.5	7.17
BURA	220	2.19	31.5	6.97
KWALE TEE	220	13.28	31.5	42.16
DONGO_KU	220	14.62	31.5	46.42
KIBUYUNI2	220	6.07	31.5	19.28
KENSEN	220	1.91	31.5	6.05
MARIAKANI4	400	10.82	40	27.06
VOI 400	400	9.92	40	24.8
KILIFI NPP	400	10.11	40	25.29
DONGO KUND	400	9.23	40	23.07
KINDARUMA1	132	9.96	31.5	31.62
GITARU11	132	15.07	31.5	47.85
KAMBURU11	132	19.43	31.5	61.69

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
MASINGA11	132	8.56	31.5	27.16
NANYUKI11	132	5.71	31.5	18.14
KYENI11	132	4.28	31.5	13.59
ISHIARA11	132	6.21	31.5	19.73
MERU11	132	6.26	31.5	19.89
GITHAMBO11	132	4.29	31.5	13.63
MAUA11	132	6.16	31.5	19.54
KIGANJO11	132	5.6	31.5	17.77
KAMBTFR11	132	19.43	31.5	61.69
KUTUS11	132	9.11	31.5	28.91
KUTUSTEE1	132	5.88	31.5	18.67
TEE 2	132	5.98	31.5	18.99
EMBU13	132	9.26	31.5	29.4
THIKA NEW	132	12.89	31.5	40.93
CHOGORIA	132	3.38	31.5	10.73
MWALA	132	4.97	31.5	15.79
OTHAYA	132	4.05	31.5	12.85
MUTOMO	132	5.43	31.5	17.24
KAMBURU21	220	15.54	31.5	49.33
KIAMBERE21	220	12.64	31.5	40.13
GITARU21	220	10.82	31.5	34.34
MAUA 220	220	5.41	31.5	17.19
ISIOLO 220	220	6.22	31.5	19.75
THIKA 220	220	19.73	31.5	62.64
KARURA	220	8.05	31.5	25.57
EMBU	220	13.28	31.5	42.14
TI_KARURA	220	7.53	31.5	23.91
T_2_KARURA	220	8.82	31.5	28.01
WAJIR	220	0.72	31.5	2.3
GARBATULA	220	3.26	31.5	10.35
HABASWEIN	220	0.95	31.5	3.01
MANDERA	220	0.46	31.5	1.47
MUTOMO	220	3.79	31.5	12.04
T1 MUTOMO	220	3.79	31.5	12.04
MUTOMO	220	3.79	31.5	12.04
GATUNDU11	132	3.65	31.5	11.58
MWINGI11	132	5.18	31.5	16.43
GARISSA11	132	2.8	31.5	8.9
ISIOLO11	132	9.66	31.5	30.67
KITUI11	132	3.81	31.5	12.11
ISIOLO NEW	132	9.53	31.5	30.27
THIKA11	132	12.41	31.5	39.4
GARISA PV1	132	2.53	31.5	8.03
THIKA 400	400	19.85	40	49.63
HG FALL 40	400	13.19	40	32.98
OLKARIA1 1	132	18.36	31.5	58.29

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
NAIVASHA11	132	20.21	31.5	64.17
OLKARIAIAU	132	18.13	31.5	57.56
LANET11	132	13.04	31.5	41.39
SOILO11	132	18.07	31.5	57.37
OLKARIA II	132	16.99	31.5	53.94
KABARNET11	132	4.42	31.5	14.05
MARALAL11	132	13.52	31.5	42.93
MAKUTANO11	132	5.74	31.5	18.24
NAROK11	132	4.3	31.5	13.65
MENENGAI11	132	18.48	31.5	58.68
RUMURUTI11	132	9.24	31.5	29.33
WELLHED37-	132	14.73	31.5	46.76
RONGAI_NC	132	10.92	31.5	34.66
OLKALOU132	132	11.57	31.5	36.73
RONGAI 132	132	17.13	31.5	54.37
MENE_NEW	132	17.67	31.5	56.08
CHEMOSIT11	132	9.26	31.5	29.41
BOMET11	132	5.05	31.5	16.04
KENERGY	132	9.23	31.5	29.31
OLKARIAIAU	220	27.14	31.5	86.14
OLK V	220	24.55	31.5	77.94
OLKARIA II	220	27.04	31.5	85.83
SUSWA21	220	40	31.5	126.98
RONGAI220	220	15.61	31.5	49.56
GILGIL 220	220	19.89	31.5	63.16
OLKARIA IV	220	23.95	31.5	76.02
LONGONOT	220	14.94	31.5	47.42
OLK IX	220	22.09	31.5	70.11
OLK III	220	16.22	31.5	51.5
AGIL 220	220	9.89	31.5	31.4
NIP 220	220	16.56	31.5	52.57
KERINGET20	220	7.13	31.5	22.65
OLK VIII	220	21.9	31.5	69.52
SUSWA GEN	220	26.26	40	65.65
OLK VII	220	13.25	31.5	42.05
OLKII EXT	220	24.32	31.5	77.2
FERTILIZER	220	9.04	31.5	28.69
MENENGAI40	400	17.12	31.5	54.35
GILGIL	400	22.61	31.5	71.78
RONGAI 400	400	19.41	31.5	61.62
MUHORONI11	132	7.83	31.5	24.84
KISUMU 132	132	9.02	31.5	28.65
WEBUYE11	132	8.94	31.5	28.39
MUSAGA11	132	11.31	31.5	35.9
MUMIAS11	132	5.2	31.5	16.49
SONDU11	132	4.68	31.5	14.86

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
SANGORO11	132	4.21	31.5	13.37
KISII11	132	5.62	31.5	17.84
SOTIK	132	9.34	31.5	29.64
AWENDO11	132	4.63	31.5	14.69
RANGALA11	132	4.41	31.5	14.01
ONGENG	132	3.73	31.5	11.83
MASABA	132	4.04	31.5	12.83
MUSAGATEE	132	11.31	31.5	35.9
KIBOS 132	132	9.54	31.5	30.27
BONDO	132	2.32	31.5	7.35
KILGORS132	132	11.77	31.5	37.36
MAGUNGA	132	1.83	31.5	5.82
BUSIA	132	5.81	31.5	18.45
MYANGA	132	7.2	31.5	22.85
MYANGA T 1	132	7.2	31.5	22.85
MYANGA T 2	132	7.2	31.5	22.85
KIBOS 220	220	8.56	31.5	27.16
KAKMEGA220	220	6.7	31.5	21.27
MUSAGA220	220	6.16	31.5	19.57
CHEMOSIT 2	220	6.19	31.5	19.64
KILGORIS	400	6.55	31.5	20.79
ELDORET11	132	6.34	31.5	20.14
LESSOS11	132	15.86	31.5	50.36
KITALE11	132	8.95	31.5	28.4
LESSTRF11	132	15.86	31.5	50.36
KOPERE	132	7.26	31.5	23.04
TARITA	132	5.83	31.5	18.5
TURKWEL21	220	5.96	31.5	18.91
KITALE	220	5.2	31.5	16.51
LOKICHAR	220	3.1	31.5	9.83
ORTUM21	220	7.87	31.5	24.99
LESSOS	220	16.34	31.5	51.88
BARINGO21	220	26.53	31.5	84.21
LOYAN	220	9.55	31.5	30.31
KAINUK21	220	5.96	31.5	18.93
TEE	220	8.33	31.5	26.46
SLR PARK	220	8.11	31.5	25.75
LESSOS TEE	220	16.34	31.5	51.88
LESSOS TEE	220	16.34	31.5	51.88
MARSABIT	220	5.97	31.5	18.94
LODWAR	220	2.3	31.5	7.32
MOYALE	220	1.35	31.5	4.3
BARINGO	400	16.04	40	40.11
MARAL/LOOS	400	15.21	40	38.02
LESSOS 400	400	15.71	40	39.29
LOYAN 400	400	7.99	40	19.98

YEAR 2045 THREE PHASE SHORT CIRCUIT CURRENT				
Bus Name	Voltage Level (kV)	Maximum Fault Current (kA)	Breaker Capacity (kA)	% of Breaker Capacity
GARISSA	220	2.81	40	7.02
SIDE_A	400	16.33	40	40.82
WOLAYTA	400	16.33	40	40.82
TARUSHA41	400	6.32	40	15.8

12.8. Catalogue of Equipment, Substation Land and Wayleave Compensation

Table 12-10 : Catalogue and Unit Cost of Power Transformers

POWER TRANSFORMERS							
MAXIMUM CAPACITY/RATING	Unit Costs (MUSD)						
	132/33kV	220/33kV	220/66kV	220/132kV	400/132kV	400/220kV	500/400kV
23MVA	0.5	0.62	0.7	-	-	-	-
45/60MVA	0.75	0.8	0.9				
90MVA	-	-	-	0.98	1.5	-	-
150MVA	-	-	-	1.15	2	-	-
200MVA (3-ph units for 220/66 rest 1-ph)	-	-	1.5	-	1.8	2.2	-
400MVA (1-ph units x3)	-	-		-	-	3	4.11

Table 12-11: Catalogue and Unit Cost of Reactor Banks

REACTOR BANKS					
MAXIMUM CAPACITY/RATING	UNIT COST (MUSD)				
	33kV	66kV	132kV	220kV	400kV
7.5 MVar	0.25	0	0.3	0.37	-
10-15MVar	0.38	0	0.508	0.685	-
50 MVar	-	-	-	-	0.75
100 MVar	-	-	-	-	1.4

Table 12-12: Catalogue and Unit Cost of Capacitor Banks

CAPACITOR BANKS					
MAXIMUM CAPACITY/RATING	UNIT COST (MUSD)				
	33kV	66kV	132kV	220kV	400kV
7.5 MVar	-	-		-	-
10-15 MVar	0.54			0.75	-
50 MVar	-	-	-	0.85	8.7
100 MVar	-	-	-	1.3	1.4

Table 12-13: Catalogue and Unit Cost of STATCOMs

STATCOMS					
MAXIMUM CAPACITY/RATING	UNIT COST (MUSD)				
	33kV	66kV	132kV	220kV	400kV
– 50Mvar inductive and 50Mvar capacitive 1x-/+50Mvar.	-	-	18.5	-	-
–100Mvar Inductive and 50Mvar capacitive (-/+1x50Mvar DRPC and 1x-50Mvar MSR)	-	-	-	22	-
–200Mvar Inductive and 100Mvar capacitive (-/+2x50Mvar DRPC and 2x-50Mvar MSR)	-	-	-	-	37

Table 12-14: Catalogue and Unit Cost of Other Equipment

Catalogue & Unit Cost of Other equipment						
PARTICULARS	UNIT COST (MUSD)					
	33kV	66kV	132kV	220kV	400kV	500kV DC
Line Terminal Equipment	0.02	0.045	0.1	0.23	0.34	15.13 (per pole)
Transformer Terminal Equipment	0.02	0.045	0.1	0.24	0.36	
Diameter/Bay	0.1	0.13	0.22	1	1.7	inc
Partial Diameter	-	-	-	0.5	0.85	-
Bus Coupler	0.025	0.05	0.22	0.34	-	-
Power Transformer (see table above)	-	-	-	-	-	-
Reactor/Capacitor banks (see table above)	-	-	-	-	-	-
Bus Bars	inc	inc	inc	inc	inc	
Protection & Control	inc	inc	inc	inc	inc	
Telecom	inc	inc	inc	inc	inc	
Control Room building			0.9	1	1.2	2
SS Extension			0.2	0.35	0.4	-
Civil Structural Works	35% of cost of equipment					
Design & Installation	27% of cost of equipment and civil-structural works					
PM and Supervision	5% of total EPC cost					
Contingency	15% of Total EPC + Supervision					

Table 12-15: Catalogue and Unit Cost of Transmission Lines

Transmission Lines				
VOLTAGE (KV)	EPC+PM COSTS (MUSD/km)			
	OHL DC	OHL SC	Mono Pole DC	UG CABLE DC
132kV	0.156	0.1	0.244	0.445
220kV	0.3124	0.2	0.488	-
400kV	0.456	0.292	0.713	-

Table 12-16: Unit Cost of Substation Land

Substation Land			
PRIMARY VOLTAGE (kV)	TYPICAL SIZE (ACRES)	COST (MKES)	COST (MUSD)
132	5	12.5	0.1202
220	10	25	0.2404
400	15	37.5	0.3606

Table 12-17:Wayleave Compensation Costs

WAYLEAVE COMPENSATION COSTS						
TL Voltage (kV)	SIZE (m)	SIZE Sqm/km	SIZE ACRES/km	COST/KM (MUSD)		
				Sparsely Populated Areas	Medium Populated Areas	Densely Populated Areas
132	30	30,000	7.413	0.064904	0.086538	0.173077
220	40	40,000	9.884	0.086538	0.115385	0.230769
400	60	60,000	14.826	0.129808	0.173077	0.346154



12.9. Climate Resilience Strategies

Table 12 18: Phased Implementation of Climate Resilience Strategies (2026–2045)

Strategy / Principle	2026–2032	2033–2037	2038–2042	2043–2045
Institutionalizing Climate Risk Assessments	Conduct risk assessments in pilot projects and priority corridors. Expand risk assessments to all major new projects and retrofits of existing lines.	Integrate standardized climate risk assessment protocols across the entire transmission network.		Fully embedded climate risk assessments in all planning and engineering processes.
Integrate Climate Modelling & Downscaled Projections	Apply climate projections to high-priority renewable integration zones and climate-sensitive corridors.	Extend use of downscaled climate projections to additional corridors, including northern and western regions.	Use projections for adaptive design of all new transmission lines and major upgrades.	Institutionalize climate-informed planning as standard practice for the entire grid.
Technical Capacity Building	Train core KETRACO teams in climate risk, adaptive engineering, and cost-benefit analysis.	Expand training to project teams; develop internal climate resilience experts.	Maintain knowledge-sharing, incorporate lessons learned into engineering standards and operations.	Fully institutionalized capacity building, integrated into routine operations and asset management.
Update Technical Design Manuals	Revise manuals to include climate-modelled parameters: wind loading, temperature thresholds, hydrological stress, among others	Apply updated design standards to all planned projects and network expansions.	Continuous refinement of manuals based on operational experience and modelled climate data.	Fully climate-informed technical manuals for all transmission design and upgrade projects.
Disaster Risk Management & Emergency Plans	Develop emergency response plans for pilot projects and key corridors.	Expand plans across all regions, incorporating coordination with local authorities.	Integrate disaster response into network-wide asset management, with simulations and drills.	Standardize and optimize disaster management protocols across the transmission system.
Early Warning Systems	Deploy early warning systems in high-risk areas with high infrastructure exposure.	Expand coverage to additional vulnerable regions and integration with national meteorological services.	Integrate early warning data into real-time operations and automated response systems.	Full-scale integration of early warning systems across all high-risk corridors, with predictive analytics for proactive response.

12.10. MEAL Framework and Matrix

The Logical Framework (Logframe) presented in this annex provides a summary results framework for the Transmission Master Plan. It outlines the logical linkages between planned interventions, expected outputs, outcomes, and long-term impacts, while identifying key performance indicators, means of verification, assumptions, and risks. The Logframe serves as a reference tool for monitoring, evaluation, and reporting on the implementation and achievement of the Master Plan objectives, ensuring that transmission infrastructure investments contribute effectively to national energy, economic, and sustainable development goals.

	Indicator	Data Source/ Methodology	Means of Verification	Assumptions
Goal (Impact)	Impact indicator 1 % increase in national bulk transmission capacity (MW transfer capability)	KETRACO system planning data	Transmission Master Plan reports	Generation capacity grows concurrently
	Impact indicator 2 Growth in electricity consumption in newly connected load centers (MWh/year)	KPLC load data	Billing & load reports	Demand growth sustained

	Indicator	Data Source/ Methodology	Means of Verification	Assumptions
Purpose (Outcomes)	Outcome indicator 3 Average energy (MWh) transmitted through the substation (before and after energization)	SCADA system energy reports, System Operations energy dispatch records and load flow and system planning studies.	SCADA system generated reports, substation energy meter readings and transmission/ substation performance reports	Downstream distribution network can absorb increased energy supply; adequate generation capacity is available to supply increased transmission capacity and industrial/ commercial consumers connected as projected.
	Outcome indicator 4 Total MW peak demand absorbed at project- connected substations (annual average)	SCADA system, substation meters, system operation load dispatch records, monthly peak demand reports from System Operations, load flow studies and power system analysis reports	SCADA system reports, System Operator monthly/ annual operational reports, substation load logs, Transformer loading reports and annual transmission performance reports	Connected load centers have adequate downstream distribution capacity, economic growth drives increased electricity demand, no prolonged outages affecting demand absorption and tariffs remain stable and affordable.
	Outcome indicator 5 % reduction in reliance on isolated diesel generation in connected areas	KPLC generation dispatch records (diesel plants), off grid/ isolated station fuel consumption records, Independent Power Producer (IPP) diesel generation reports (if applicable), System Operations dispatch logs, EPRA energy statistics reports, KPLC annual reports, fuel procurement records for diesel plants and SCADA system data (post-grid interconnection)	KPLC diesel plant generation reports, Fuel purchase and consumption records, system dispatch records, EPRA energy statistics publications, independent technical audits and GHG emissions monitoring reports (if linked to climate reporting)	The isolated area is fully integrated into the national grid, transmission capacity is adequate to replace diesel generation, no persistent grid outages forcing fallback to diesel, and policy direction continues to favor least cost generation.
	Outcome indicator 6 Maximum MW transferred through newly constructed transmission lines (Transmission capacity utilization)	SCADA system real-time and historical power flow, Energy Management System (EMS) reports, System Operator dispatch records, Substation transformer loading data, and Power Purchase Agreement (PPA) declared capacity records	SCADA power flow reports, Substation load logs, line loading reports, Transmission network performance reports, and independent system audit reports.	Generation plants are operational and dispatchable, no persistent curtailment due to downstream bottlenecks, grid stability allows full evacuation of available generation, adequate demand exists to absorb generated power, no major outages on associated transmission infrastructure and generation availability is not constrained by fuel, hydrology, or maintenance issues.
	Indicator	Data Source/ Methodology	Means of Verification	Assumptions
	Outcome indicator 7 Installed MW of renewable generation capacity connected to the national transmission grid through project infrastructure (Integration of renewable energy into the national grid)	Generation interconnection agreements, grid connection approval records, commissioning certificates for renewable plants, System Operator generator register, EPRA generation licensing database, SCADA/ EMS plant registration data, Power Purchase Agreements (PPA) capacity data and project completion reports.	Generator commissioning certificates, grid interconnection approval letters, EPRA generation licenses, Signed PPA documentation, System Operator plan registry, SCADA/ EMS registration reports, project completion and	Renewable projects reach financial close and are constructed on schedule, Transmission Infrastructure is completed before or alongside generation plants, grid stability allows safe integration of intermittent resources and adequate demand exists to absorb additional renewable capacity.

	Indicator	Data Source/ Methodology	Means of Verification	Assumptions
			energization reports and annual energy sector statistical reports.	
	Outcome indicator 8 % reduction in frequency of power outages	Reports from KPLC Control Centre and consumer feedback	SCADA logs, outage analytics reports, feedback logs from consumers	Assumes full operationalization of new lines and accurate data logging
	Outcome indicator 9 Reduction in duration of power outages	Reports from KPLC Control Centre and consumer feedback	System downtime logs, Consumer complaints data	Assumes improved maintenance and fault response
	Outcome indicator 10 Reduction in diesel fuel use	Energy cost and fuel use reports from consumers	Purchase receipts, plant logs, cost tracking forms	Assumes truthful reporting and willingness of industries to share data
	Outcome indicator 11 Reduction in voltage fluctuations	KPLC voltage records, consumer data	Voltage monitoring reports, event logs from substations	Assumes consistent voltage logging and consumer feedback
	Output indicator 4 MW capacity of green energy added	Reports from KETRACO, KenGen & GDC	Interconnection agreements, dispatch records	Assumes timely generation project completion
Expected Results (Outputs)	Output indicator 3 Number of IPPs connected to the grid	Reports from KETRACO, KenGen & GDC	PPA records, grid interconnection documents	Assumes regulatory approval and infrastructure readiness
	Output indicator 2 Km of transmission line constructed (by voltage level)	Reports from KETRACO	Completion certificates, inspection reports	Assuming timely construction and reporting
	Output indicator 1 Total MVA capacity of new substations commissioned	Reports from KETRACO & KPLC	Commissioning reports and spatial data	Assuming availability of funding and equipment
Activities (pre-construction milestones-critical determinants of timely project execution and risk mitigation)	% of priority projects with signed loan agreements	Finance Dept	Signed loan agreements	Government & DP financing remains available
	% of projects with approved ESIA & RAP	Safeguards Dept	NEMA approvals, RAP clearance	Regulatory approvals granted within expected timelines
	% of projects with complete cadastral mapping	Wayleave Unit	Survey reports	Land records accurate and accessible
	% of projects with secured funds for wayleave compensation	Finance & Treasury	Budget approvals, disbursement records	Budget allocations released on time
	Input indicator 2 Finances disbursed for constructions	KETRACO finance systems	Financial disbursement reports, audit records	Assuming transparent financial management
Inputs	Input indicator 1 Finances disbursed for compensation	KETRACO finance systems	Payment schedules, signed receipts	Assumes no delays in approval or disbursement

What Needs to be Monitored	Expected Result (Output)	Indicator (How it will be monitored)	Measurement Period	Data Source / Collection Method	Baseline	Milestones	Planned Progress (Yr 1-3)	Planned Progress (Yr 4-5)	Planned Progress (Yr 6-8)	Actual Progress	End-of-Project Target	Project Performance Rating (Quality / Time)	Responsible
Financing readiness	Loan agreement signed and effective	Status of loan agreement effectiveness	Quarterly	Financing agreements, Treasury records	No financing secured	Loan negotiated	Loan signed	Loan effective			Loan fully effective	Good / Delayed	GM, Finance & GM, D&C
ESIA approval	Environmental approval obtained	Status of ESIA approval	Quarterly	NEMA approval letters	ESIA not approved	ESIA submitted	ESIA under review	ESIA approved			ESIA approved	Good / Delayed	GM, PDS-Wayleave
RAP approval	Land acquisition framework approved	Status of RAP approval	Quarterly	RAP approval documents	RAP not approved	RAP submitted	RAP review ongoing	RAP approved			RAP approved	Good / Delayed	GM, PDS-Wayleave
Cadastral mapping	Wayleave boundaries defined	% of cadastral mapping completed	Quarterly	Survey reports	No mapping completed	Surveys initiated	Mapping ongoing	Mapping completed			100% completed	Good / Delayed	GM, PDS-Wayleave
Wayleave compensation	Land access secured	% of compensation completed	Quarterly	Compensation records	No compensation	Valuation completed	Compensation ongoing	Compensation completed			100% compensation	Good / Delayed	GM, PDS-Wayleave
Procurement readiness	Contractor selected	Status of procurement process	Quarterly	Procurement records	No procurement initiated	Tender issued	Tender evaluation	Contract signed			Contractor mobilized	Good / Delayed	Procurement

Logframe Level	Key Indicators	Strategic Message	Communication Product	Target Audience	Frequency
Impact	% increase in national bulk transmission capacity	Transmission expansion is strengthening Kenya's national grid and supporting economic development	Policy Briefs	National Treasury, Ministry of Energy, Regulators	Annual
	Growth in electricity consumption in newly connected load centers	Transmission investments are enabling industrial growth and expanding electricity demand	Sector Impact Reports	Development Partners, Government Agencies	Annual
Outcome	Increase in average MWh transmitted through substations	Improved power flow capacity is enabling increased electricity delivery	Technical Impact Briefs	System Operators, Energy Planners	Annual
	MW peak demand absorbed at project-connected substations	Increased demand absorption reflects economic growth in connected regions	Infographics and Data Dashboards	Policy makers, investors	Quarterly
	Reduction in reliance on diesel generation	Grid connectivity is lowering energy costs and reducing emissions	Impact Stories / Case Studies	Media, Public, Climate partners	Semi-Annual
	Renewable MW integrated into the national grid	Transmission infrastructure is enabling renewable energy integration	Climate and Energy Transition Briefs	Climate finance institutions	Annual
	Reduction in outage frequency and duration	Grid reliability and service quality are improving	Public Information Campaigns	Consumers, businesses	Quarterly
	MVA capacity of new substations commissioned	Transmission infrastructure is expanding system capacity	Commissioning Briefs	Media, local communities	At commissioning
Outputs	Km of transmission lines constructed	Expansion of the national transmission backbone	Project Fact Sheets	Public, government stakeholders	At completion
	Number of IPPs connected to the grid	Transmission investments are enabling private sector power generation	Investment Briefs	Investors, development partners	Annual
	MW of renewable energy added	Infrastructure supports green energy development	Renewable Integration Reports	Climate partners	Annual
	Projects with approved ESIA and RAP	Environmental and social safeguards are implemented	Compliance Updates	Regulators, development partners	Quarterly
Activities	Loan agreements signed	Financing arrangements supporting project delivery	Financing Updates	Treasury, financiers	Annual
	Wayleave compensation secured	Land acquisition processes supporting project implementation	Stakeholder Engagement Reports	Local communities	Quarterly
Inputs	Financial disbursements for construction and compensation	Resources are mobilized and deployed efficiently	Financial Transparency Reports	Treasury, development partners	Annual

TRANSMISSION NETWORK AS OF 2008.

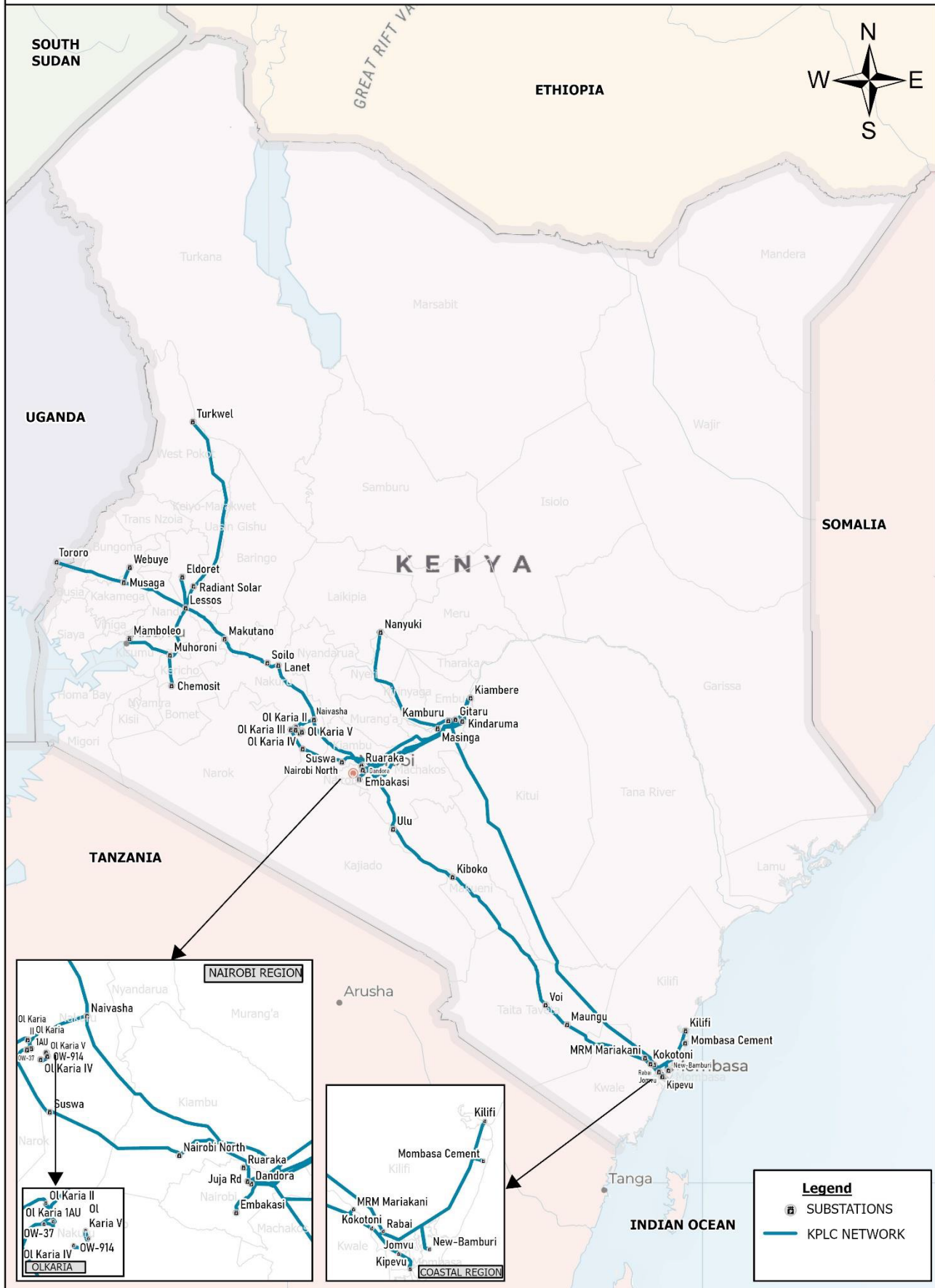


Figure 12 4: Transmission Network as of 2008

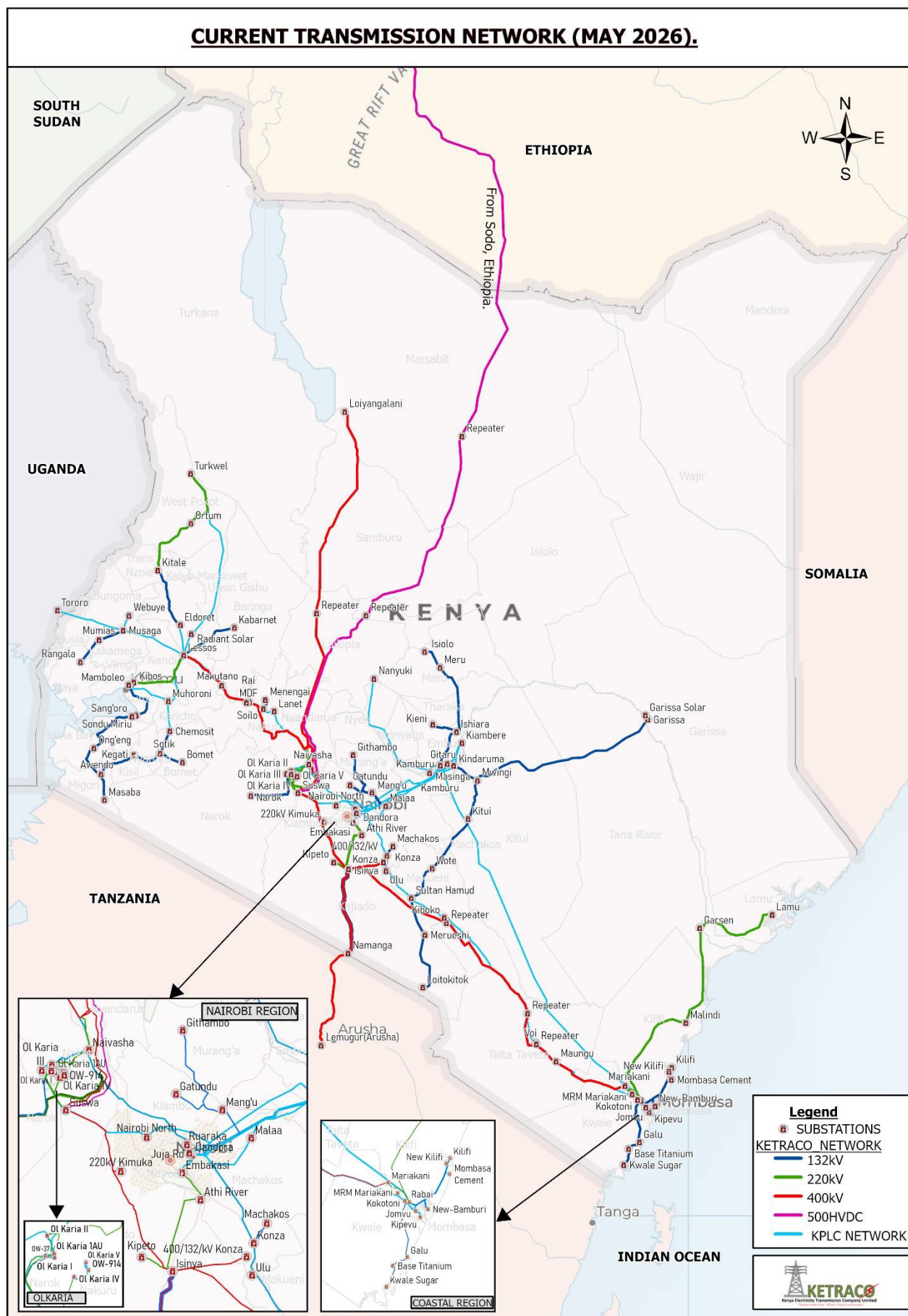


Figure 12 5: Current Transmission Network (May 2026)

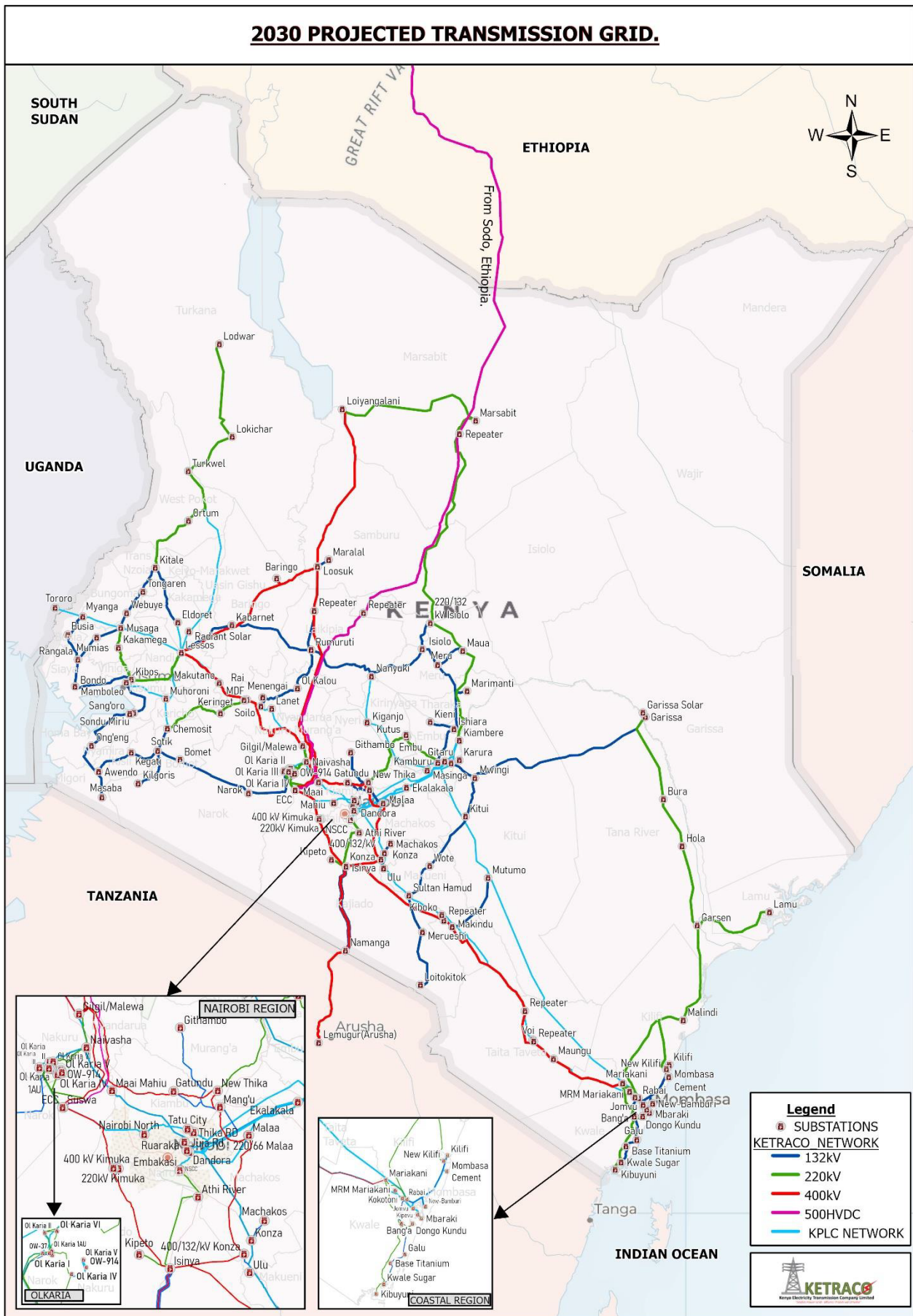


Figure 12 6: 2030 Projected Transmission Grid

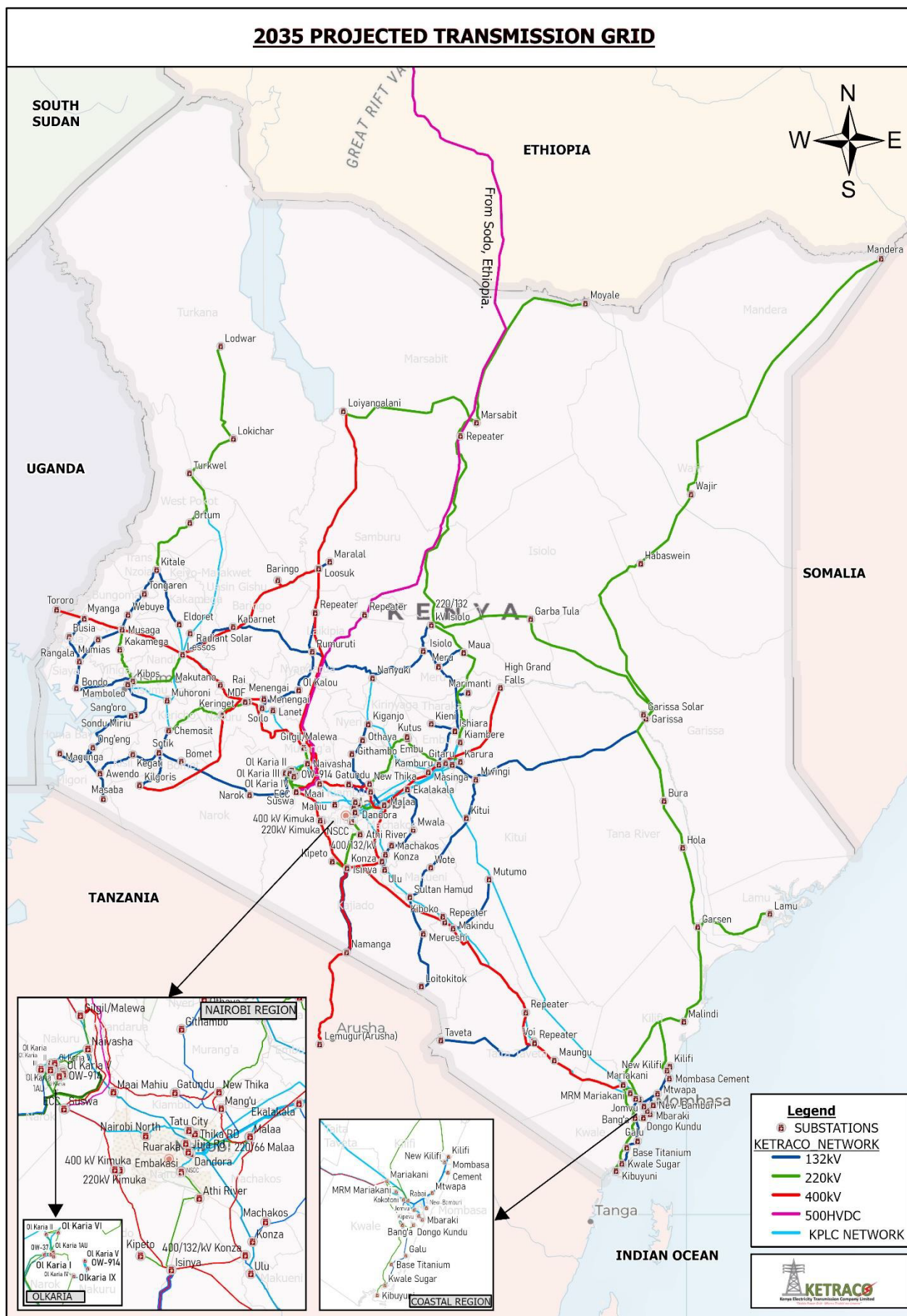


Figure 12 7: 2035 Projected Transmission Grid

2040 PROJECTED TRANSMISSION GRID.

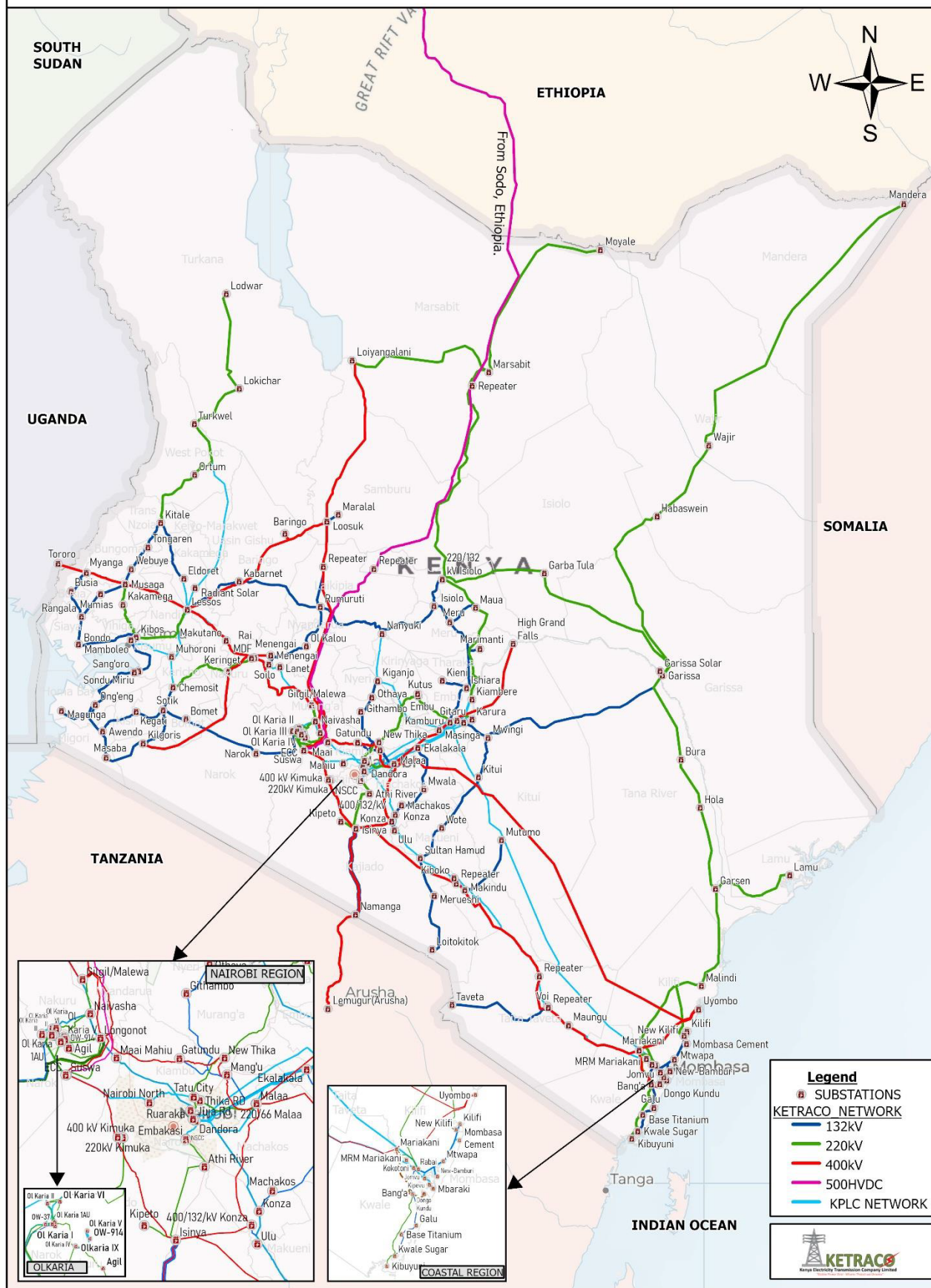


Figure 12 8: 2040 Projected Transmission Grid

2045 PROJECTED TRANSMISSION GRID

SOUTH SUDAN

UGANDA

TANZANIA

ETHIOPIA

SOMALIA

INDIAN OCEAN

Legend

- SUBSTATIONS
- KETRACO NETWORK 132kV
- 220kV
- 400kV
- 500HVDC
- KPLC NETWORK

KETRACO
Kenya Electricity Transmission Company Limited

Figure 12 9: 2045 Projected Transmission Grid



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