Final Report

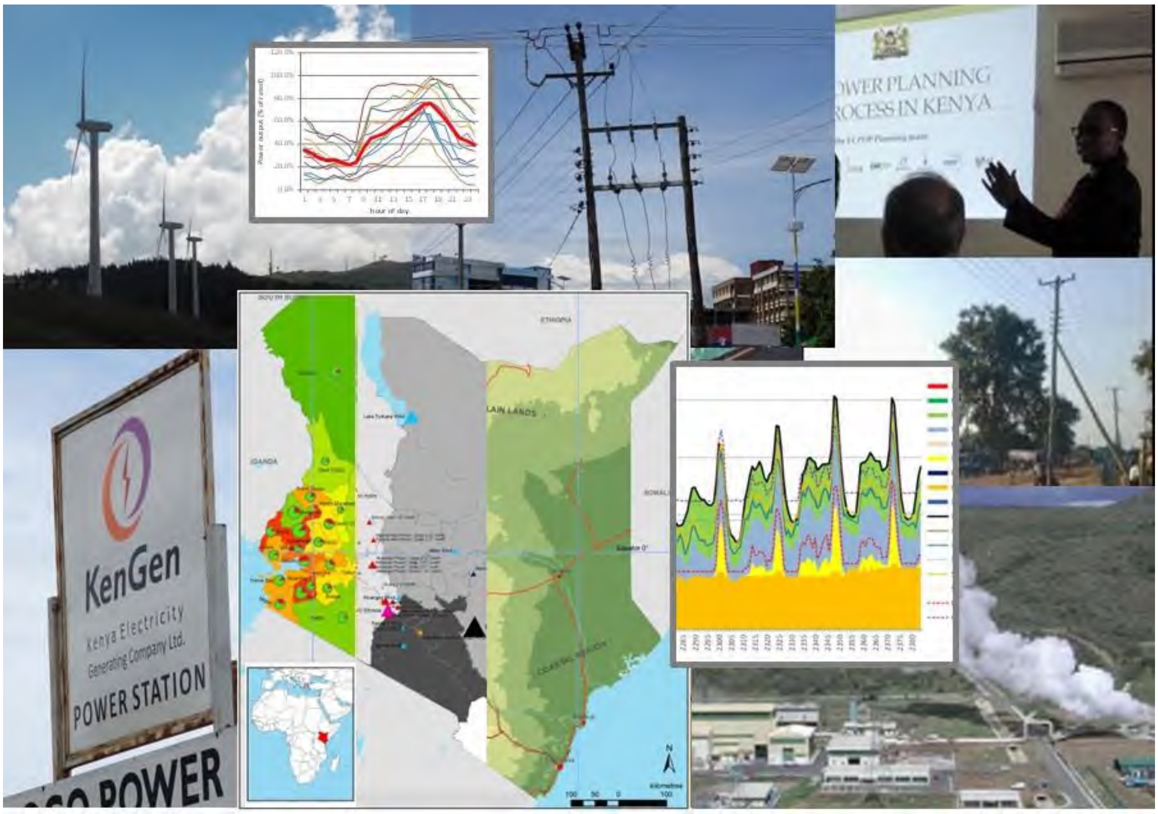
Development of a Power Generation and Transmission Master Plan, Kenya

Long Term Plan

2015 - 2035

Volume I – Main Report

October 2016



Ministry of Energy and Petroleum

- The photo on the title page shows a collection of photos from power generation and network assets in Kenya and figures from the planning process

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Table of Contents

List of Figures

List of Tables

Abbreviations and Acronyms

10YP	10 year plan
A	Ampere
AC	Alternating Current
ACSR	Aluminium Clad Steel/Reinforced
ADF	African Development Fund
AFD	Agence Française de Développement
AGO	Automotive Gas Oil
AIS	Air Insulated Switchgear
AVR	Automatic Voltage Regulation
BB	Busbar
BOO	Build Own Operate
BOOT	Build Own Operate Transfer
CAPEX	Capital Expenditure
CBS	Central Bureau of Statistics (predecessor KNBS)
CCGT	Combined Cycle Gas Turbine
CEEC	Committee for European Economic Cooper-ation
CHP	Combined Heat and Power
Cif	Cost Insurance Freight
COD	Commercial Operation Date
Cogen	Co-Generation
COMESA	Common Market for Eastern and Southern Africa
CPI	Corruption Perception Index
CPP	Coal Power Plant
CSP	Concentrating Solar Power
DANIDA	Danish International Development Agency
DC	Direct Current
DCR	Discount Rate
DIN	German Institute for Standardization
DNI	Direct Normal Irradiation
DUC	Dynamic Unit Cost
EAC	East African Community
EAPMP	East African Power Master Plan Study
EAPP	East African Power Pool
EE	Energy Efficiency
EECA	Energy Efficiency and Conversation Agency
EFLA	Company: Consulting Engineers
EGIS	Company: Engineering and Consulting
EIA	Environmental Impact Assessment
EIB	European Investment Bank
ENDSA	Ewasa Ng'iiro South River Basin Develop-ment Authority
ENS	Energy Not Served
EPC	Engineering Procurement Construction
ERB	Electricity Regulatory Board (predecessor ERC)
ERC	Energy Regulation Commission
ESIA	European Semiconductor Industry Associa-tion
ESRP	Energy Sector Recovery Project
EUE	Estimated Unserved Energy
EUR	Euro
FCC	Fuel Cost Charge
FERFA	Foreign Exchange Rate Fluctuation Adjust-ment
FGD	Flue gas desulphurisation
FiT	Feed in Tariff
Fob	Free on board
GAMS	General Algebraic Modelling System
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GE	General Electric
GEF	Global Environment Facility
GEO	Geothermal (energy)
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiation
GIS	Geographic Information System
GIS	Gas Insulated Switchgear
GIZ / GTZ	German Development Cooperation (Deut-sche Gesellschaft für International Zusammmenarbeit)
GJ	Gigajoule
GoK	Government of Kenya
GOV	Governor
GPOBA	Global Partnership Output Based Aid
GT	Gas Turbine
GW	Gigawatt
GWh	Giga Watt-hour
HDI	Human Development Index
HFO	Heavy Fuel Oil
HGFL	High Grand Falls
HPP	Hydro Power Plant
HSD	High Speed Diesel Engine
HV	High Voltage
HVDC	High Voltage Direct Current
Hz	Hertz
I&C	Instrument and Control System
IAEA	International Atomic Energy Agency
ICE	Internal Combustion Engine (here: MSD, HSD)

ICT	Information, Communication & Technology
IDO	Industrial Diesel Oil
IEA	International Energy Agency
IED	Innovation Energie Développement
IMF	International Monetary Fund
IPE	Indicator Power Efficiency
IPP	Independent Power Producer
IPS	Industrial Promotion Services
IR	Inception Report
ISO	International Organisation for Standardization
ITCZ	Intertropical Convergence Zone
JICA	Japan International Cooperation Agency
JKIA	Jomo Kenyatta International Airport
KAM	Kenya Association of Manufacturers
KenGen	Kenya Electricity Generating Company
KENINVEST	Kenya Investment Authority
KeNRA	Kenya National Resources Alliance
KEPSA	Kenya Private Sector Alliance
KES	Kenyan Shilling
KETRACO	Kenya Transmission Company
KfW	KfW Development Bank German development bank; was: Kreditanstalt für Wiederaufbau)
KISCOL	Kwale International Sugar Company Ltd
km	kilometre
km3	cubic kilometre
KNBS	Kenya National Bureau of Statistics
KNEB	Kenya Nuclear Electricity Board
KOSF	Kipevu Oil Storage Facility
KPC	Kenya Pipeline Company Limited
KPLC	Kenya Power and Lighting Company
KPRL	Kenya Petroleum Refineries Limited
KRC	Kenya Railways Corporation
KTDA	Kenya Tea Development Agency
kV	kilo Volt
Kvar	Kilo volt ampere reactive
KVDA	Kerio Valley Development Authority
KW	Kilowatt
kWh	kilowatt-hour
LAPSSET	Lamu Port, Southern Sudan and Ethiopia Transport
LCPDP	Least Cost Power Development Plan
LDC	Load Dispatch Center
LEC	Levelised electricity cost
LF	Load Flow
LFO	Light Fuel Oil
LI	Lahmeyer International GmbH
LIPS-OP/XP	Lahmeyer International Power System - Operation Planning / Expansion Planning
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas
LTP	Long Term Plan
LTWP	Lake Turkana Wind Park
LV	Low Voltage
m	metre
M&E	Mechanical & Electrical
MAED	Model for Analysis of Energy Demand (MAED-D for kWh, MAED-L for Kw)
MEWNR	Ministry of Environment, Water and Natural Resources
MIP	Mixed Integer Linear Optimization Problem
MJ	Megajoule
MOE	Ministry of Energy (changed in 2013 to Ministry of Energy and Petroleum)
MOEP	Ministry of Energy and Petroleum
MOIED	Ministry of Industrialization and Enterprise Development
MORDA	Ministry of Regional Development Authorities
MSD	Medium Speed Diesel Engine
MSW	Municipal Solid Wastes
MTP	Medium Term Plan
MUSD	Million USD
MV	Medium Voltage
MVA	Megavolt Ampere
Mvar	Megavolt Ampere Reactive
MW	Mega Watt (10^6 Watts)
MWh	Megawatt Hours
NBI	Nile Basin Initiative
NCC	National Control Center
NCV	Net calorific value
NELSAP	Nile Equatorial Lakes Subsidiary Action Program
NEMA	National Environment Management Authority
NG	Natural Gas
NGO	Non-Governmental Organization
NIB	National Irrigation Board
NPP	Nuclear Power Plant
NPV	Net Present Value
NSSF	National Social Security Fund
NTC	Net Transfer Capacity
NTP	Notice-to-Proceed

NWCPC	National |Water and Conservation and Pipeline Corporation
NWRMS	National Water Resources Management Strategy
O&M	Operation & Maintenance
ODA	Official Development Assistance
OECD	Organisation for Economic Co-operation and Development
OHL	Overhead Line
OPEX	Operational Expenditure
OPIC	Overseas Private Investment Corporation
P	Active Power
PB	Parsons and Brinckerhoff
PESTEL	Political, Economic, Social, Technical, Environmental and Legal criteria
PF	Power Factor
PGTMP	Power Generation and Transmission Master Plan
PPA	Power Purchase Agreement
PSS/E	Power System Simulator for Engineering
PV	Photovoltaic
Q	Reactive Power
Qc	Reactive Power Capacitive
QEWC	Qatar Water & Electricity Company
Ql	Reactive Power Inductive
QM	Quality Management
RAP	Resettlement Action Plan
RE	Renewable Energy
REA	Rural Electrification Authority
REP	Rural Electrification Programme
RES	Renewable Energy Sources
RfP	Request for Proposal
RMS	Root-Mean-Square Value
RMU	Ring Main Unit(s)
S/S	Substation
SBQC	Selection Based on Consideration of Quality and Cost
SC	Short Circuit
SCADA	Supervisory Control and Data Acquisition
SHPP	Small Hydro Power Plants
SHS	Solar Home Systems
SKM	Sinclair Knight Merz
SLA	Service Level Agreement
SLD	Single Line Diagram
SME	Small and Medium Sized Enterprises
SMP	System Marginal Price
SPP	Steam Power Plant
SPV	Special Purpose Vehicle
ST	Steam Turbine
SWERA	Solar and Wind Energy Resource Assessment
T/L	Transmission Line
TA	Technical Assistance
TARDA	Tana & Athi River Development Authority
TJ	Terra-joule
TNA	Training Need Assessment
TOR	Terms of Reference
TPP	Thermal Power Plant
TR	Transformer
TRF	Training Results Form
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
US	United States of America
USD	United States Dollar
VBA	Visual Basic for Applications
WACC	Weighted average cost of capital
WASP	Wien Automatic System Planning
WB	World Bank
WEO	World Energy Outlook
WTG	Wing turbine generators

1 EXECUTIVE SUMMARY

In 2013, the Ministry of Energy and Petroleum (MOEP) contracted Lahmeyer International (LI) to provide consultancy services for the development of the Power Generation and Transmission Master Plan (PGTMP) for the Republic of Kenya.

This report provides the respective Long Term Plan (LTP) for the period 2015 (base year) to 2035. This LTP is the identification and analysis of suitable expansion paths of the Kenyan power system for that period, complying with the defined planning criteria and framework. This encompasses:

- Analysis of past electricity demand and development of future demand scenarios,
- Analysis of suitable expansion candidate fuels and technologies, their optimal sizing, siting and scheduling,
- Modelling of their expected contribution to the future power generation and the probable operation of the generation system,
- Modelling of the transmission grid for the year 2030 and the analysis of its performance under several criteria,
- Investment analysis summarising financial implications of the expansion plans on the future investment needs and their expected schedule.

This executive summary focuses on the main results.

1.1 Demand forecast

The objective of the demand forecast is to provide a sound basis for the power system expansion planning. A critical analysis and a selection of suitable scenarios reduce the impact of the forecast uncertainty on the planning results. This will reduce the risk of costly over or underestimating the size of the power system. It is done by extensive analysis of i) input data (e.g. power sector, demography, economy), ii) frame conditions and interrelations in power sector, iii) the evaluation of desired and achievable targets and iv) a review of previous forecasts.

The forecast is developed for three scenarios and one sub-scenario:

1. <u>Reference scenario</u>: applying key assumptions for a probable development based on the historic development and actual plans (technical, demographic and economic issues diligently assessed).
2. <u>Vision scenario</u>: normative scenario; applying the wide range of largely ambitious government plans (e.g. 100% connectivity level by 2020; less challenged flagship project developments).
3. <u>Low scenario</u>: scenario for sensitivity and risk analyses; applying more conservative assumptions than reference scenario and similar to historic developments.
4. <u>Energy Efficiency</u> (reference sub-scenario): applying the EE potential to the reference scenario, as detailed in the separate EE report.

Besides the scenario analysis the forecast approach combines various other methodologies to address Kenya specific availability of data and needs (e.g. trend-projection and bottom-up).

Demand for electricity and annual peak load are expected to grow considerably for any scenario:

- Electricity consumption is forecasted to grow in the long term by an annual average of 7.3% per year (reference scenario). For the vision and low scenario the growth is expected to be at 9.6% and 5.6%, respectively. This would lead to consumption figures 50% above (vision) and 25% below (low) the values in the reference scenario towards the end of the study period. Thus, the three scenarios describe a range from a worst (low) case to a best (vision) case. This will help to analyse the economic and technical impact of demand uncertainty on mainly the generation expansion.

- Annual peak load is forecasted to grow at slightly higher rates. It is expected to more than quadruple from nearly 1,600 MW in 2015 to 6,700 MW in 2035 (vision: above 10,000 MW; low: nearly 5,000 MW). On average each year some 150 (low), 250 (reference), or 400 (vision) MW of capacity (plus reserve) have to be added to serve the growing peak load in the evening.

Table 1-1: Electricity consumption and peak load forecast – reference, vision, low scenarios (2015 – 2035)

Scenario		Unit	Growth LTP	2015[1]	2016	2020	2025	2030	2035
Reference with flagship projects	**Consumption gross**	**GWh**	**7.3%**	**9,453[1]**	**10,093**	**13,367**	**19,240**	**27,366**	**38,478**
	Growth	%		5.4%	7%	8%	9%	8%	7%
	Peak load	**MW**	**7.5%**	**1,570[1]**	**1,679**	**2,259**	**3,282**	**4,732**	**6,683**
	Growth	%		4%	7%	8%	9%	10%	7%
		MW		58	109	169	260	412	462
Vision with flagship projects	**Consumption gross**	**GWh**	**9.6%**		**10,592**	**16,665**	**25,469**	**39,260**	**58,679**
	Growth	%			12%	13%	10%	11%	8%
	Peak load	**MW**	**9.8%**		**1,770**	**2,845**	**4,431**	**6,833**	**10,219**
	Growth	%			13%	13%	12%	11%	8%
		MW			200	330	478	689	786
Low without flagship projects	**Consumption gross**	**GWh**	**5.6%**		**10,035**	**12,632**	**16,427**	**21,375**	**28,153**
	Growth	%			6%	6%	5%	6%	6%
	Peak load	**GWh**	**5.7%**		**1,669**	**2,116**	**2,769**	**3,618**	**4,788**
	Growth	%			6%	6%	5%	5%	6%

The assumed **electrification** targets considerably increase the number of connections for any scenario:

- More than 10 million additional domestic connections (to the existing 4 million) are needed throughout the study period for any scenario to compensate for population growth, shrinking household size, and provision of meters where currently several households share one and to reach electrification targets. During the medium term between half a million (low) and more

[1] Derived from latest available data (peak: NCC hourly load indicate 1,550 – 1,570 MW peak in October 2015; consumption: KPLC annual report 2014/2015 and preliminary half annual accounts 2015).

than 1 million (vision) new connections have to be realized each year. This is beyond the average number of new connections of the past years for any scenario.

- Connectivity level is forecasted to increase from currently around 50% to 70% (low), 80% (reference), and nearly 100% (vision) towards 2020. In the long term also for the reference scenario the level will reach nearly 100%. For any scenario, these figures can only be estimates due to the lack of solid data basis and the difficulty to realize electrification in particular in remote areas. In any case, to reach these very ambitious levels, the national grid based electrification has to be complemented by other means such as isolated grids and solar home systems.

- Previous electricity demand forecasts for Kenya (presented under the LCPDP) regularly overestimated demand (when compared to the actual demand growth in the medium term period). They also exceed by far the forecasted growth rates of similar African countries. They were also higher than actual growth of countries, which showed strong economic development in the past (similar to what Kenya is aiming at). Only very few countries in the world have shown such sustained high consumption growth rates as it has been forecasted for Kenya in the past.

- Policy targets for high demand were not reached for various reasons. This might have led to a situation where Kenya is currently one of the few African countries with sufficient available generation capacity to meet the demand and plenty of projects in the planning stage. However, the type of generation (e.g. mainly base load generation and import) might be more suitable for higher demand levels. Hence, policy targets should be reassessed more carefully and respective scenarios (including a conservative/pessimistic scenario) should be developed and considered to reduce risks and costs. The forecast scenarios within this study are in a more common range of growth rates with regard to the different benchmarks.

1.2 Generation planning

Energy sources for power generation in Kenya are assessed as follows:

- Coal is the only domestic fossil energy resource with proven availability for extraction and potential use in power generation[2]. Thus, besides renewable energy sources (RES) it is the only source to limit overall import dependency of power generation in Kenya. The dependency is however comparatively small due to the high share of RES. Further, coal leads to considerable environmental and social costs on a local, regional and international level. If run at base load with high capacity factors the pure generation costs can be comparatively low with little volatility. It should be assessed whether the benefits of coal based generation (low costs and domestic source) could materialize in Kenya against the high environmental and social costs.

- Natural gas (if available) should be developed due to its potential for flexible power generation, to diversify energy sources and to reduce import dependency with a lower environmental impact. However, besides general availability its availability for power generation has to be

[2] Petroleum extraction in Kenya may start in the near future but will most likely be used for export only.

assessed as it has to compete with other domestic demand (e.g. industry, residential sector). Liquefied Natural Gas (LNG) is an available option for diversification of energy sources and with limited environmental impact though at comparatively high costs.

- Renewable energy sources are vastly available for power generation in Kenya with different challenges (e.g. intermittent generation and social and environmental impact) and opportunities (flexible, base load, distributed generation). Generation costs vary, though compared to thermal generation the price fluctuation (and thus risk) is low due to the low or negligible variable cost share and still declining investment costs. Costs, opportunities and challenges have to be assessed within the national power system to identify and rank suitable RES.

- Petroleum based fuels are not recommended as a future fuel even if domestically available. This is due to high costs, strong price fluctuations, and the environmental impact. However, for back-up and peaking capacity (e.g. gas turbines) may remain necessary until it can be replaced in an economic way.

The key results with regard to **power generation expansion candidates** (based on qualitative and quantitative economic analysis) are as follows:

- For base load (with high capacity factors) geothermal power plants are ranked best in terms of generation costs, followed by the (generic) bagasse power plant (biomass cogeneration) and the HVDC (high voltage direct current) interconnection with Ethiopia. Nuclear power plants show the highest costs for all base load plants. Even at maximum availability they are less economical than coal and natural gas fuelled candidates. This stems from the high investment costs for a 600 MW nuclear unit. For any of the base load candidates the generation costs will strongly increase with decreasing capacity factors due to their high investment costs.

- For intermediate load plants coal power plants are cheaper than gas fuelled CCGT plants (domestic gas and LNG). For lower capacity factors (e.g. 50%) the Wajir NG-CCGT candidate appears to be the preferred option (if domestic gas is available), followed by Lamu "tender" coal, generic bagasse plant and Kitui coal power plant. If flexibility is required by the system CCGTs are the preferred option. The same is true for hydropower plants at even lower costs.

- For peaking units hydropower plants are the preferred option (with the lowest generation costs for Karura HPP). The alternatives are gasoil fuelled gas turbine and HFO fuelled MSD but at much higher generation costs though easier to develop. For assumed capacity factor of 20% the MSD engine is cheaper than the gas turbine but this ranking will change for capacity factors lower than 10%: due to the low investment costs this technology will be the preferred option in case of rare utilisation (e.g. reserve capacity).

- With regard to the volatile RE candidates, the analysis reveals that Lake Turkana wind farm has by far the lowest generation costs, followed by the generic wind farm and the generic PV power plant (with one third higher costs).

For the **generation expansion plan** (based on a two-step least cost generation system optimisation process considering also the transmission network) the key results and corresponding conclusions and planning recommendations are (see also tabularised principal generation expansion plan in Table 7-15 in Section 7.6.1.1):

- The energy mix of the generation expansion plan is diverse, secure with regard to supply and costs of fuel and "clean":
  - Main base load expansion is reached through geothermal capacity (geothermal will represent one third of the installed generation capacity providing more than half of the annual generated electricity in 2035), about half of the geothermal capacity will be located in the Olkaria area. In case of high demand developments, base and intermediate load capacity is supplemented by coal.
  - Second largest share in the long term energy mix is represented by hydropower (16% in 2035 in the reference scenario, down from a share of some 40% today). HPPs will also play a major role in the provision of flexible capacity to the system.
  - Back-up capacity expansion is about 1,890 MW (about 20% of the total system capacity in the reference expansion scenario). It is mainly providing the required cold reserve (in the plan as generic gas turbines which could also represent other means such as import (sharing) of reserve or storage, if available).
  - In the long term, more than 85% of the electricity demand will be covered by domestic renewable energy sources (56% by geothermal, 16% by hydropower, 11% by wind, 2% by biomass cogeneration and 2% by PV in the reference expansion plan). Imports and coal power will supplement the energy mix (7% and 6%, respectively).

  In this frame it is recommended

  - To continue development of geothermal capacities as in the past (considering a rescheduling as in this plan). However, the current and expected future dominance of geothermal capacity in Olkaria should be closely monitored in terms of security of supply, e.g. with regard to the geothermal source (which could decrease) or evacuation of power. This may include a partly shift of new geothermal capacities to other geothermal fields if they are sufficiently analysed,
  - To put more emphasis on the few hydropower candidates as essential and beneficial providers of flexibility. For instance, Karura should not be delayed. Even an earlier commissioning (scheduled by the optimisation for 2025 due to overcapacities) could be considered to allow for sufficient flexible capacity if other projects are delayed,
  - To develop a diverse mix of other RE sources: sustain implementation of wind and PV at moderate costs and support firm capacities of small hydro and biomass cogeneration throughout the country. Further, available RE such as wind and PV may be suitable in future to save geothermal energy (i.e. allow that the limited geothermal resources can be exploited in a sustainable way).
  - To further elaborate the position of coal within the power sector with regard to its particular benefits (due to low capacity factors in the simulation), environmental impact and to a lesser extent its import dependency. This could include a necessary link of the Lamu coal power plant to a large customer with demand for secure energy ("back to back"). This

would fit into the MOEP concept for Lamu as an anchor plant on the Coast supporting local development, supplying flagship projects, and replacing diesel engines. Further, the evaluation whether coal is necessary as a secondary expansion source (e.g. for higher demand growth) is recommended. This would be in particular the case if sufficient domestic natural gas supply for power generation were approved in future or the implementation of the committed Lamu plant could be adapted (see below).

- Some committed power supply projects (namely HVDC, Lake Turkana) will result in overcapacities and excess electricity during hours of low demand. This effect is strongest in the years 2019 to 2023 (up to 15%, 6% and 17% of generated energy for the reference, vision and low scenario, respectively). It will decrease to an acceptable level below 1% in the long term. There is further potential excess in the system due to regular reduced production from the geothermal plants towards there minimum capacity (probably resulting in venting of steam) and due to the low capacity factors of coal power plant units.

  It is recommended

  - To analyse the opportunity for exporting this energy to neighbouring countries (e.g. Rwanda, Tanzania, Uganda) for their demand or storage in their hydropower plants (since excess often appears during hours of low load).
  - To assess possibility for an amendment of the PPA with Ethiopia for a more flexible supply through the HVDC (e.g. instead of firm take or pay only a reduced base firm take or pay while adding flexible supply).
  - To carefully assess and continuously monitor implementation schedules of the plants committed for the medium term period to arrive at a suitable gradual commissioning (focussing on the most beneficial). A wrong signal to the market should be avoided which may indicate that these projects should be delayed or put on hold or are not necessary at all. However, if for committed plants the commissioning years are not fixed the simulation indicates that Lamu coal power plant would be only needed for the overall power system towards the end of the study period while geothermal plants would be brought forward to replace this capacity.

- In the generation modelling, sufficient reserve capacity is taken into account (mainly by consideration of the largest unit and average unavailability of generation capacity due to maintenance and forced outages). As a result, the LOLE is not critical in the long term. However, shortages in cold reserve capacity are expected in the years 2017 and 2018 which may lead to certain amounts of unserved energy in case of low hydrology or higher demand growth. Today, the Kenyan power system is running low on primary reserve provision[3].

  It is recommended

[3] Only Gitaru and Kiambere HPP contribute to reserve regulations

- To introduce the simulation reserve requirements – as practical – to the actual system as soon as possible.
- To conduct a separate practical study on the capability of existing and committed plants to provide reserve and other auxiliary services (e.g. see recommendation paper submitted to MOEP at the beginning of this project).
- Considering the strong wind expansion in the medium term as well as the increased unit sizes due to the commissioning of the first Lamu unit, it is essential to increase the primary reserve capacity in the generation system. In this context it is recommended to equip the existing hydropower plants Masinga, Kamburu, Kindaruma, and Turkwel with respective IT infrastructure enabling primary reserve provisioning (feasibility to be analysed). New installed large hydropower plants and large steam turbines should also be able to provide primary reserve.
- Geothermal expansion: flexibility of single-flash technology is very limited. Installation of binary systems may contribute to flexibility of supply (suitability to be analysed at design stage of respective geothermal power plant candidate).
- Flexible imports (see previous topic) and hydropower plants with dams may provide further flexible generation supply.
- Create incentives for provision of flexible capacity (reserve capacity) within contract structures (e.g. by means of capacity payments, load following compensation, frequency regulation).
- In case that a higher security of supply is aimed to be reached in the years 2017 and 2018 it is recommended
    - To analyse the opportunity to implement temporary geothermal wellheads utilising the steam from wells already drilled for future projects in the Olkaria and Menengai field. In this context also the absorption capacity of the grid in the respective area has to be taken into account. The wellheads would displace the existing diesel engines in the merit order, so that diesel engines would provide the required peaking and back-up capacity in this period.
    - To evaluate if a more flexible handling of power export to Rwanda is feasible, e.g. reduced export during hours of high demand. This option would reduce the capacity need by 30 MW[4].
    - In case that the above listed options are not sufficient, the installation of temporary back-up units (e.g. gas turbines) to provide the reserve capacity might represent an alternative for the period of concern.

- The principal generation expansion plan (along reference scenario, see also tabularised plan in Table 7-15 in Section 7.6.1.1) is robust with regard to changes of main assumptions (e.g. de-

[4] Due to the short-term nature of the need for measurements, Demand Side Management does not represent a feasible option.

mand, RE penetration, hydrology). Those changes may require a change of commissioning years for identified plants or additional capacity in the long term for any higher demand growth. Both is analysed and detailed below as part of the principal plan. Due to its focus on domestic and renewable sources the plan is considered very robust towards cost changes.

It is recommended that the responsible sector institutions (MOEP, ERC with among others KPLC, Ketraco, GDC and KenGen)

- Consider this plan as the blue print for the development of the power generation.
- Continuously monitor frame conditions to adapt implementation schedules of power plants as required (to avoid excess supply or deficits and financial implications). For instance if there are any delays for committed plants or demand increases beyond the reference forecast, geothermal plants with on-going production drilling could be brought forward. Hydropower projects (e.g. Karura) should not be delayed and even an earlier commissioning considered (see above). Further, the status of new hydropower projects in Ethiopia should be monitored in terms of availability to supply capacity and energy when the interconnector is operational.
- Reassess the plan as the regional market for power will emerge (which currently does not exist but shows high potential).

Below the generation expansion path and electricity generation is displayed.

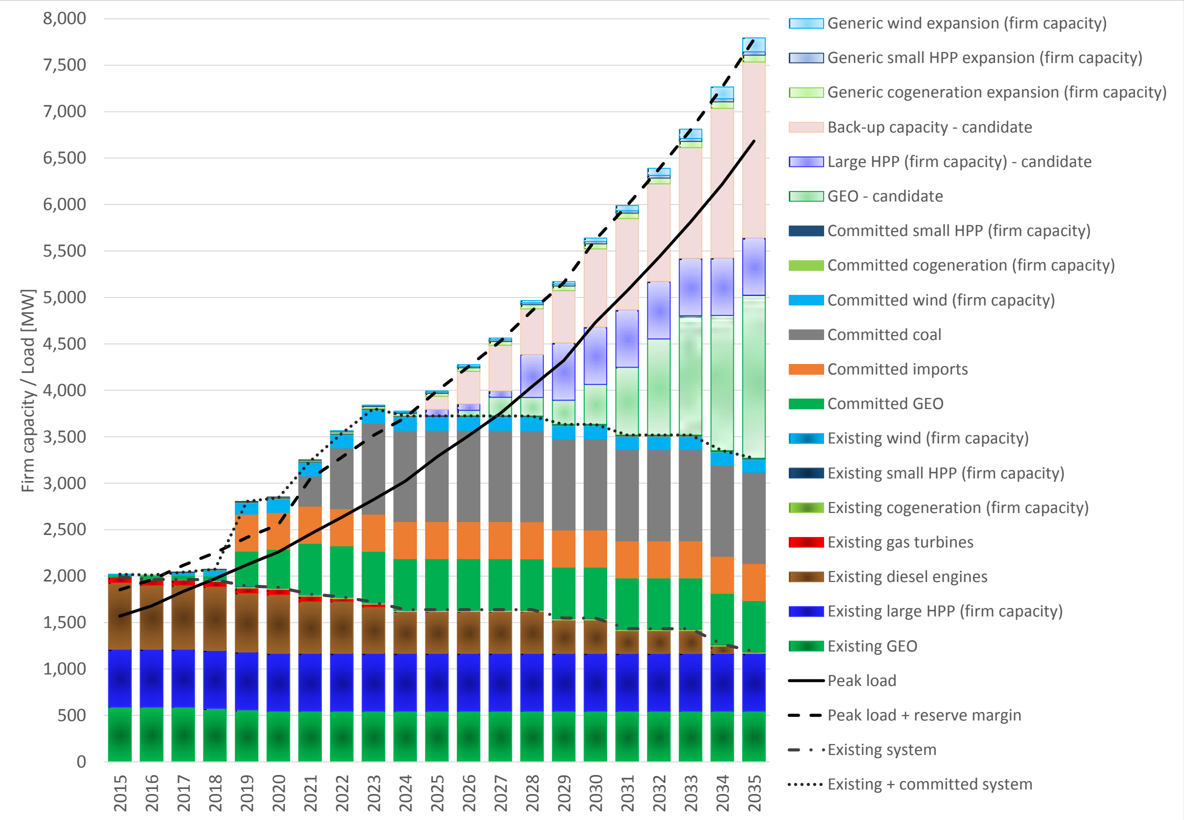

Figure 1-1: Reference expansion scenario – firm capacity versus peak demand

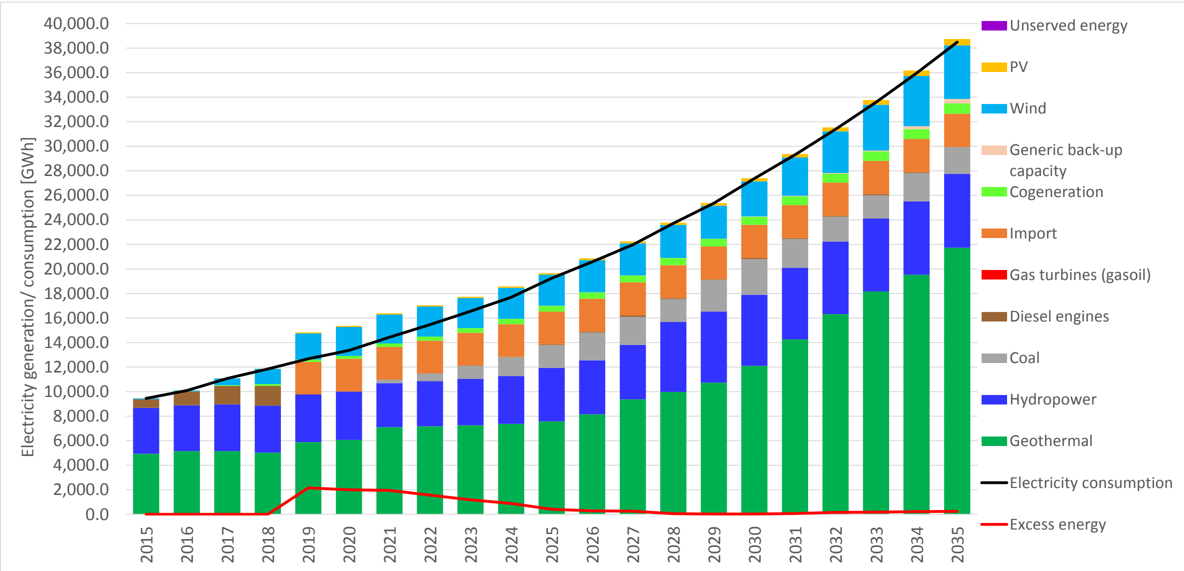

Figure 1-2: Reference expansion scenario – electricity generation versus electricity consumption

1.3 Transmission planning

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

For this the following tasks were conducted in an iterative approach:

1. A model of the future Kenyan transmission network was developed. It represents the target network for the long term period of this study up to 2035. For the below described simulations the year 2030 was chosen as a key year towards the end of this planning period. The model is based on the network model for the medium term (2020) as well as new projects for generation and transmission (including interconnections with neighbouring countries), identified by the client and the consultant.

2. Through simulations of the above described model of the target network the performance of the transmission network was analysed and bottleneck determined, focusing on the following aspects:

   - The reliability of the network and its compliance with the system requirements: It provides an assessment about how the Kenyan transmission system would extend with the implementation of new generation power plants (as developed in the generation system expansion) and rise of load in the long term. The analysis and its results focuses on a satisfactory, sustainable and reliable power supply.
   - The system behaviour and the interactions between its different parts of the core network at the high voltage level: No details at medium and low voltage levels are given since for the purpose of this study their structure was considered on an aggregated level only. Sole-

ly the elements prone to have an interaction at high voltage levels of the core network were modelled and analysed.

- The system behaviour on a static and dynamic level, i.e. load flow, short circuit studies and transient analysis, which are considered appropriate for the overall power system study.

The transmission system (target network) has been planned to comply with several criteria, as summarised in the following.

Transmission system target network observing voltage and loading limits under normal (N-0) and abnormal (N-1) conditions

- The topology of the target network is strong enough to cope with the growth of demand in the study period and is complying with the operational limits (in N-0 and N-1), as analysed in the load flow simulations.

- In the approach followed by the network analysis (Load Flow, Short Circuit), the sizing of equipment (lines, transformers) is based on the N-1 criterion, meaning for example that for double circuit lines, the ideal circuit loading condition will not exceed the 50% range of the circuit ampacity. Based on this assumption and considering a higher demand (15% increase compared to reference demand forecast), the transmission equipment proposed with the network extensions will not lead to unacceptable loadings, hence preserving the reliability of the system. In this context, the network can meet the N-1 security criteria since in case of any N-1 contingency event corresponding to the loss of any HV/MV transformer or HV overhead line the loading criteria are met. The "moderate" overloading levels observed in the contingency analysis are below 120% and are therefore considered to be resolvable either by anticipating system reinforcement projects or by activating corrective operational actions (overload under given limits is then resolved by manual de-loading measures e.g. load transfer or re-dispatching).

- All long term challenges for the network as indicated in the medium term plan (MTP network model) have been solved in the LTP target network. The identified and modelled investments in the network extension guarantee a global sustainability of the system (for instance the below described 400 kV and 220 kV rings).

- The calculated technical losses of about 3.2% are in an acceptable range for a transmission network. The implementation of improvement measures to reduce losses is in particular important for the Western and Coast areas.

- There is high reactive power transfer between load centres and generation feeding points. This leads to high reactive power losses and overload of transmission equipment especially in transformers and transmission lines.

Ability to withstand short circuit currents

- The results for the three-phases and single-phase-to-ground short circuit simulation show that the short circuit currents are under the switchgears limits (40 kA and 31.5 kA), indicating that their dimensioning is suitable.

- The circuit breakers of existing substations may not all cope with this threshold. Their replacement or other short circuit mitigation measures should be considered in separate studies.

Sufficient damping (steady state stability analysis)

- The results of the small signal stability analysis confirm that the operation of the system is stable and oscillations are sufficiently damped. For this the eigenvalues of the state matrix of the electrical transmission system relevant to the target network have been calculated. The damping ratio of each mode of the analysis have been analysed. In all the simulated cases the real part of the eigenvalues resulted to be on the negative axis and the minimum damping ratio resulted to be not lower than 5%.

- In terms of Transient Analysis, the sudden disconnection of the HVDC link with Ethiopia, with a pre-fault transfer power of about 400 MW (according to assumption in generation expansion plan, in direction Kenya) has been analysed.

  According to the transient analysis, the stability is considered verified for a sudden disconnection of the HVDC link:

  - Oscillatory trend of voltage and frequency have sufficient damping and the maximum and minimum values of the oscillations remain within the permissible limits complying with national grid code.
  - The maximum rotor angles of the synchronous generators during the transient period is about 82°, which is safely below of the limits (180°) and no out-of-step of generators is encountered.
  - The voltage at the 400 kV, 230 kV and 132 kV systems has also a stable profile, with maximum voltage variations well within the grid code requirements. A sufficient damping of oscillations is also evident in all the transient diagrams.

Expansion of the transmission system and recommendations for implementation

- Considerable expansion, reinforcement, and rehabilitation measures are required to reach the described stability of the target network which allows the stable transport of energy from the power plants to the load centres.

  - Based on the analysis necessary network expansion projects were identified to form the core network for the long term period. Depending on future electrification programs and subsequent identification of new local demand areas, additional actions on 220 kV and 132 kV levels will be necessary. The required system expansion and reinforcements needs to be individually analysed on a project-by-project level.

  - The highest rise in demand is expected for Nairobi and Western areas. Network development for transmission and distribution will continue to be of high importance in these regions as detailed in this study.

- The expansion of the necessary power generation capacity is limited to few sites and areas in Kenya (mainly in Western and Coast area) with long distances from the areas of growing demand. Recommendations to connect the power generation with the main load centres are provided.

- The implementation of the new 400 kV network and its extension are indispensable investments for the electrical network to be able to cope with the increasing demand. This includes the development of 400 kV and 220 kV rings: around the Nairobi Area (400 kV) and in the West Region (Western Area) at the 220 kV level. Otherwise the transmission system will experience serious loss of performance and partially collapse under the active and reactive power demand requirements.

- In order to allow for a secure operation of the transmission system in the medium and long-term and to avoid undesired impacts caused by the uncertainties of the demand growth, this plan has to be transferred into project specific implementation schedules and the development of new operational rules, based on the results of this study and operational requirements. These Important steps to follow are for instance:

  - Development and implementation of the 400 kV and 220 kV rings;

  - Implementation of reinforcements as detailed in the report for improving of the system reliability (N-1 contingency criteria), partly requiring project specific analyses.

  - New design and planning standards for development and rehabilitation of the network structure in close cooperation with the power system areas' chief engineers. As outcome, main design principles and element ratings (conductor cross-sections and transformer ratings) shall be reviewed as proposed and become the foundation of the network extensions and rehabilitation measures in the coming years.

  - The transmission system must be continuously monitored and the calculations (model) continuously updated in order to make required adjustments on time and to keep up with the actual load demand and project development in the system (if different than the load forecast and generation expansion). This process could be facilitated by the annual reviews by the LCPDP team which will allow for addressing the constraints and necessary measures to a wider audience in the power sector.

1.4 Investment plan

The key results and conclusions of the investment plan are as follows:

- The investment plan provides an overview of the expected costs and required capital. The required capital includes interest during construction according to a supported and commercial funding scenario. The supported funding scenario is the more favourable and less expensive one due to the lower interest rates. However, it is considered realistic that a mix of commercial and supported funding for the expansion of the Kenyan power sector will be achieved instead of applying either one or the other. Therefore, the investment plan results provide an indication on the probable range of capital requirements.

- The expansion plan to satisfy electricity demand until the year 2035 will result in overall investment in a range from 37 to 52 billion USD (37 billion USD for supported funding scenario, 2% inflation rate; 41 billion USD for supported funding scenario, 3% inflation rate; 52 billion USD for commercial funding scenario, 5% inflation rate). The supported funding scenario is subject to the ability of development banks for finance. The commercial funding scenario is more likely to materialise but results in higher capital requirements. The difference is not big with 4%. It however depends on achieving financing conditions that might constitute a deal breaker for the implementation of future expansion projects. The long term price increase for investments has the by far strongest impact on the overall amount, resulting in a difference of 13 billion USD between the inflation rates of 2% and 5%.

- It is recommended to investigate with lenders – both commercial and development banks – the availability of the required volume of funding in the short, medium and long term. In order to secure funding for the generation capacities, transmission projects and the extension of the distribution network at preferable conditions, thorough investigations and negotiations are suggested.

- The importance for securing and scheduling funding and investors for the expansion plan is also an outcome of the evaluation of power system's long run marginal costs. These costs (an indication of the future costs for additional power supply per kWh) are in a range of 8 to 9 USDcent / kWh. They are below the average generation costs (in terms of LECs) of the total generation system as well as below the LECs for all selected generation expansion candidates (thus, would not be sufficient to recover the necessary generation costs). The low cost may indicate underutilised existing or committed capacity or overcapacity as well as sufficient lower cost generation potential. From that point of view increased demand for electricity should be aimed at and slower demand growth than forecasted should be avoided. However, aiming for growth of demand did not materialise in the past. To avoid the present situation of overcapacity, expansion and securing of funding should be planned in a continuous way as the demand has grown in the past and is forecasted to grow in the future.

- Despite this positive impact of demand growth on levelised generation costs it could be beneficial to also consider the Energy Efficiency (EE) measures as outlined in the EE report: the EE induced benefits (i.e. reduction of generation costs) are considerably above the costs for the EE measures. This means for the same utilisation of electricity less costs apply. There are even further potential benefits such as environmental effects from fuel savings, technological edge and savings in the distribution network due to delayed load growth.

A distribution of the annual costs for generation, transmission and distribution under the commercial funding scenario is provided in Figure 1-3.

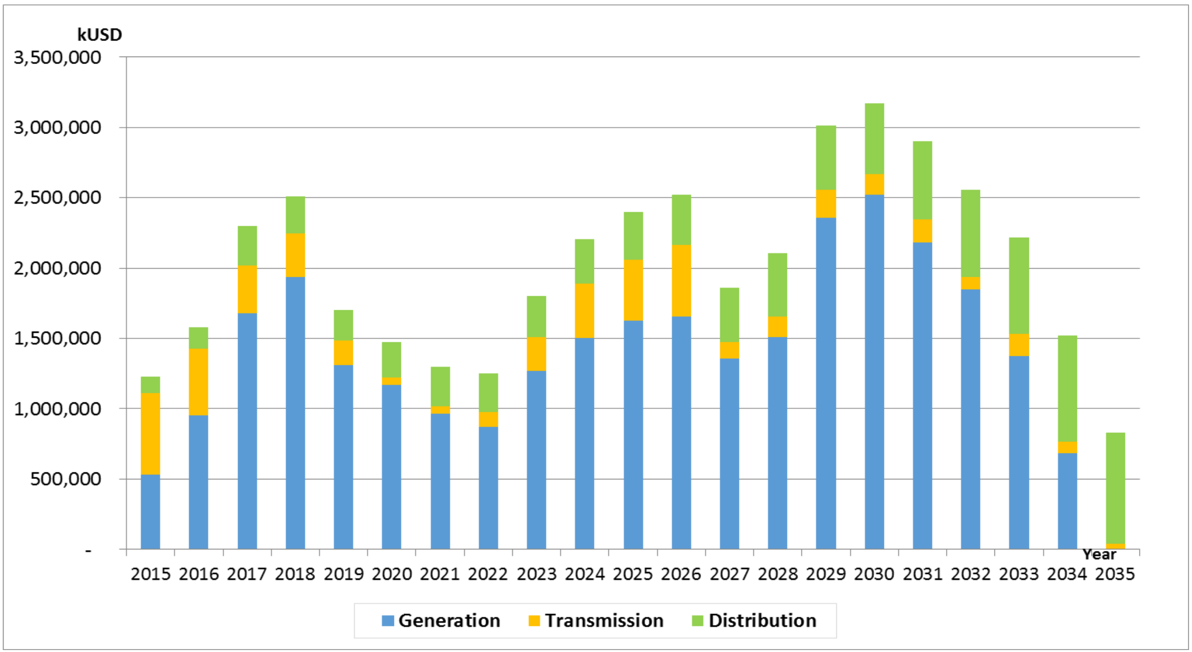

Figure 1-3: Investment costs (2015-2035) – commercial funding scenario, 3% inflation

2 INTRODUCTION

In 2013, the Ministry of Energy and Petroleum (MOEP, further also referred to as "the client") contracted Lahmeyer International (LI, further also referred to as "the consultant")[5] to provide consultancy services for the development of the Power Generation and Transmission Master Plan (PGTMP) for the Republic of Kenya.

This report provides the Long Term Plan for the period 2015 (base year) to 2035.

This chapter includes the following sections:

- The objectives of the report (section 2.1)
- The structure of the report (section 2.2)
- Introduction to the methodology and assumptions (section 2.3)

Note: The results provided in this report are not statements of what will happen but of what might happen, given the described assumptions, input data and methodologies.

In particular, given the very high uncertainty of the development of demand, its regional distribution and the actual electrification of new areas, the uncertainty of fuel price forecasts and the assessment of available and suitable fossil fuel resources the reader should carefully study the described assumptions before using any of the results. Further, the modelling and analysis of the electrical network is based on the technical information provided by the Client and the demand forecast with its own uncertainty. Any technical modifications or different development of demand could have a direct impact on the results.

Therefore, this critical review and regular update of the analysis of energy sources, fuel price and demand forecast is essential for any planning process based thereupon.

2.1 Objectives of report

The overall objective of this report is:

The identification and analysis of suitable expansion paths of the Kenyan power system for the long term period 2015 to 2035, complying with the defined planning criteria and framework.

This broad objective encompasses the following:

[5] Lahmeyer International conducts this project with Innovation Energie Développement (IED), France.

- To analyse past electricity demand and determine future demand scenarios,
- To analyse suitable expansion candidate fuels and technologies, their optimal sizing, siting and scheduling,
- To model their expected contribution to the future power generation and the probable operation of the generation system to meet the forecasted demand,
- To model the required expansion of the transmission grid to meet the forecasted demand in a secure and high-quality manner,
- To analyse the economic and financial implications of the expansion plans on the future investment needs and their expected schedule.

This report further provides recommendations on a range of alternative investment options depending on the actual realisation of potential future developments – such as fuel price or demand development or availability of domestic fuels.

These recommendations are meant to:

- Raise awareness for possible future developments,
- Provide guidance for monitoring the actual development in comparison with the expansion plans and to adapt the expansion plan continuously,
- Mitigate risks and increase benefits.

Hence, even with the suitable expansion plan identified, the Client is strongly recommended to continuously evaluate and update the assumptions and change the investment decisions, if necessary.

2.2 Structure of report

This report consists of the following main sections:

1) **Executive summary**, summarising the main results and recommendations of the report;
2) **Introduction,** providing the report's objectives and structure, and a general overview of the approach and assumptions and tools applied;
3) A description of **historic and current situation of Kenyan power sector** to establish the frame conditions for the forthcoming analysis;
4) A forecast of the future electricity demand;

5) A description of energy sources for **current electricity generation** and identification of possible **future energy sources for power generation**;

6) An evaluation of power generation expansion candidates;

7) The development of a power **generation expansion plan** with generation system optimisation;

8) The development of the **transmission expansion plan** with network analyses;

9) Presentation and evaluation of an **investment plan** for favourable expansion of generation and transmission capacity as identified earlier.

2.3 Methodology and assumptions

This chapter summarises the approach applied for the expansion planning of the power system and lists the most important planning tools and assumptions. It further highlights the changes compared to previous planning studies in Kenya, and refers to the data situation provided in Annex 2.A. Details on the methodology and assumptions are provided for each subject in the respective sections of this report.

2.3.1 Overall approach

The Consultant has prepared the approach in the following way:

- Using the generic approach, methodologies and tools for power sector planning, as well as renewable energy and energy efficiency programs & policies (proven in similar completed assignments);
- According to the requirements of the TOR considering any special needs of the client and distinctive features of the Kenyan energy sector;
- Considering lessons learned and results from previous projects in the country and region.

The methodology for the development of a power generation and transmission plan for Kenya is outlined in seven major steps:

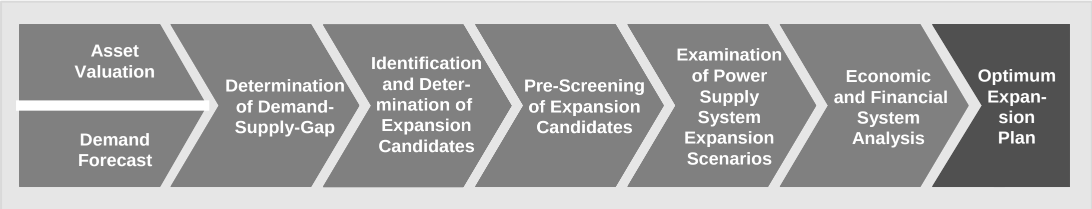

Figure 2-1: Methodology for development of a power generation and transmission plan

Although the report is based generally on this structure, there are sections of the report that address more than one steps of the methodology.

1) Asset valuation – historic and current situation of the power sector

As a first task, the study evaluates the current conditions of the power system concerning technical and economic parameters. During the asset valuation, all existing generation and transmission system components are analysed with regard to their current conditions and expected future development. For the development of an optimum expansion plan, a major contribution of the asset valuation is the identification of the total available generation capacity in the system throughout the considered period. The physical system constraints, regulatory requirements, and supply risk aspects identified in the course of this analysis are needed as modelling constraints.

2) Demand forecast

The study develops a number of scenarios to determine impacts of investment requirements for the development of the generation and transmission systems considering different demand growth assumptions. For each scenario, the total annual electricity demand and annual peak load are assessed. Furthermore synthetic load profiles are used to consider seasonal and daily variations of load requirements. As a basis various inputs were reviewed to develop achievable growth rates. These are for instance macroeconomic assumptions (e.g. gross domestic product and the population growth) along national and international sources and previous years' consumption tendencies.

3) Demand supply balance

The result of the asset evaluation and the demand forecast are combined to determine the demand-supply balance of the power system. For each year period peak demand and available capacity as well as total energy demand and possible total energy generation are matched. The determined net capacity and energy deficit constitutes the minimum amount of additional capacity needed in the system. This balance provides the framework for scheduling of generation capacity addition in the short to long term. Based on the development of the demand side on the one hand and expansion of generation facilities on the other hand, the requirements for the expansion of the transmission system are assessed as the basis for identification of adequate transmission system expansion projects.

4) Identification and short-listing of expansion candidates based on energy source assessments

From the above, a catalogue of power generation expansion candidates is established. This catalogue considers technical, economic, environmental and social parameters of all possible types of electricity supply such as hydropower generation, conventional thermal power generation, renewable energies as well as imports. It is based on an assessment of available and potential future primary energy sources and fuel price forecasts (where applicable).

5) Pre-screening and evaluation of expansion candidates

During the determination of the expansion candidates, their respective cost structure is analysed in detail. Based on generation estimates, the study determines the specific costs of the different expansion candidates in order to achieve a preliminary ranking of the candidate projects from an economic point of view. This determination may result in the elimination of candidates with significantly higher costs. This also takes into account the requirements for fuel supply to conventional thermal power plants and connection to the transmission system.

6) Examination of power supply expansion scenarios

The most promising expansion candidates (i.e. those that make it through the pre-screening) are further analysed during the examination of expansion scenarios. A number of sequences of hydro, thermal and renewable generation options for the planning period under consideration are defined. This presents options for decisions with regards to size, location and operational characteristics (base vs. peak load) of power plants.

7) Economic analysis and least cost / investment plan

The investment plans derived as a result of the foregoing process are subject to an economic analysis. By comparing the results of the economic analysis of different investment plans, the optimum (least cost) expansion plan from an economic point of view is determined. The least cost transmission network expansion plan provides the capital and operating costs for each development work package on a year-to-year basis. A range of realistic operation scenarios are assumed and the performance of the proposed future transmission network modelled and analysed. Finally, the derived investment plans for the Least Cost Generation and Transmission Expansion Plan is assessed within the framework of a financial analysis.

To combine all steps of the methodology, the following figure illustrates how the input data and accompanying analysis is used to derive a least cost plan.

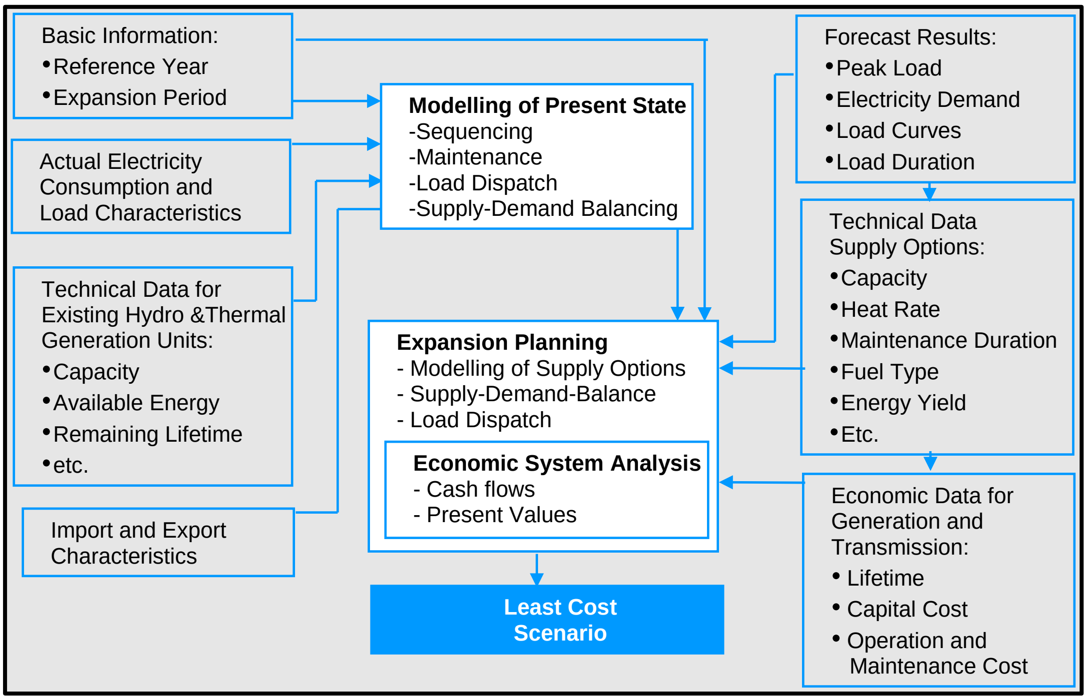

Figure 2-2: Work flow of the expansion planning process

2.3.2 Changes to previous studies

This study attempts to enhance previous efforts by making use of latest available information and incorporating modern modelling tools and software. It builds up on similar studies in the Kenyan energy sector and leverages the consultant's experience of such projects on an international level. The following highlight the changes in this report compared to previous similar studies:

- Collection and review of input data – in addition to collection of existing data in the form of annual reports and public databases, the Consultant also prepared questionnaires for collection of primary data. Furthermore, an internal filing structure has been developed and updated at regular intervals to provide a central database for information. The data situation is detailed in Annex 2.A.

- Within the review process the Consultant provides a third party point of view; bringing objectivity to the planning process. This is of importance with regard to the restricting impact of new policy targets and strategies on the planning approach (e.g. Vision 2030, flagship projects, organisations' own targets).

- Demand forecast – this study has enhanced the previously used tools for demand forecast by an in-house tailor-made tool. It is based on an extensive review of the previous approach, complemented by new assumptions and is designed especially for enabling detailed forecast analysis (by tariff groups and power system areas). Furthermore, this study provides demographic forecasts on a more detailed level and provides information for the major consumption areas and consumer groups in Kenya.

- Asset evaluation – key data bases for power system assets (e.g. power plants) were established bringing together information from various existing data sources (e.g. data files and system software such as WASP) from different organisations. This allows for a more comprehensive, consistent and less error-prone assessment of the power system assets.

- Energy and price forecasts – in addition to national studies, latest available international forecasts were used for forecast models to assess future energy sources and fuel prices.

- Evaluation of generation candidates – VBA (Visual Basic) based models and multi factor instruments have been developed for screening and ranking of power generation candidates.

- Generation expansion modelling – replacing the previously used WASP, in-house software, LIPS-OP and LIPS-XP, has been used for generation expansion planning and optimisation.

- Transmission expansion modelling – replacing system planning software Siemens PSS/E with DIgSILENT PowerFactory (converting PSS/E files to PowerFactory) to facilitate analysis, performance and data management of the network modelling and planning.

- Investment planning – for financial analysis of investment planning, another in-house software, LI Investment Implications Tool, has been used to update and upgrade the existing LCPDP model. This allows for the analysis and visualisation of the investment planning of both generation and network (which were previously analysed separately).

3 HISTORIC AND CURRENT SITUATION OF KENYAN POWER SECTOR

This chapter provides information and evaluation results on the historic development and presents the situation of the Kenyan power sector. An introduction to the geography, demography and economy of the country is provided in the annex, focusing on factors with an impact on the power sector, e.g. electricity demand and the planning framework.

3.1 Policy and institutional framework of the Kenyan power sector

This section provides an overview of the Kenyan energy and power sector with regard to policy and institutions.

3.1.1 Energy policies and strategies

Kenya is currently in a dynamic development phase with regards to its domestic energy requirements. Over the last two decades the country has been facing challenges in meeting its growing energy demands via unreliable and expensive means of energy generation and import. The fuels industry, commerce, transportation and agriculture are the backbones of the Kenyan economy and, therefore, provision of safe and reliable energy is a vital requirement for socio-economic development in the coming years. Furthermore, energy is a key enabler to achieve the country's future aspirations of "accelerated economic growth; increasing productivity of all sectors; equitable distribution of national income; poverty alleviation through improved access to basic needs; enhanced agricultural production; industrialisation; accelerated employment creation and improved rural-urban balance"[6], as captured in the development plan, Kenya Vision 2030.

The overall goal of Kenya's energy sector is to "ensure sustainable, adequate, affordable, competitive, secure and reliable supply of energy to meet national and county needs at least cost, while protecting and conserving the environment"[6].

<u>Main challenges</u> the Kenyan energy sector is facing are:

1. The need to improve competitiveness, reliability and quality of energy supply (in particular power generation and network are barely able to meet the growing demand leading to increasing supressed demand and economic losses),

2. Lack of major investments in the sector by the private sector versus high initial capital needs for new investments in the sector,

3. Long lead and implementation time for new infrastructure projects,

4. Lack of competitiveness of the country and negative impact on available household income and domestic wealth due to high energy costs and dependency on energy imports,

[6] Source: Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (16 June 2015)

5. Insufficient access to and quality of electricity supply due to low connectivity rates and a weak transmission and distribution network (leading to high losses and costs including theft of equipment and electricity).

In order to address these issues and to generally improve the energy sector, the Kenyan government has introduced a number of policies over the past years to govern the energy sector by different policies, institutions and legal framework. The country undertook fundamental liberalisation reforms in the energy sector after the mid-1990s following the enactment of the Electric Power Act of 1997. This was followed almost a decade later by the Energy Act of 2006. This act built the foundations for the unbundling of generation from transmission and distribution in the electricity subsectors as well as the liberalization of procurement, distribution and pricing of petroleum products in the country. The Energy Act consolidated all laws relating to the energy sector and provided for the establishment of the Energy Regulatory Commission (ERC) as a single sector regulator.

Some of the main strategic objectives of the energy sector are as follows:

1. Increase supply and security of supply by diversification of energy sources, in particular development of domestic energy sources (including upscaling of power generation capacity),

2. Increase affordable and reliable access and connectivity to electricity (and other energy sources), in particular in rural areas,

3. Provide an enabling framework for private investments and the provision of energy services with local content by various means such as supporting research and training, provision of necessary standards and legal regulations, proper planning, incentives, and international cooperation,

4. Limit environmental and social impacts including an increased use of renewable energy sources and promotion of energy efficiency.

Below the key[7] energy policy and strategy documents with focus on the power sector are listed:

1) **Kenya Vision 2030**

The Kenya Vision 2030 is the new long-term development blueprint for the country. It is motivated by the goal of a better society in Kenya by the year 2030. The aim of Kenya Vision 2030 is to create “a globally competitive and prosperous country with a high quality of life by 2030”. It aims to transform Kenya into “a newly industrialising, middle-income country providing a high quality of life to all its citizens in a clean and secure environment”. With reference to energy, the Vision 2030 acknowledges the currently high energy costs in Kenya compared to competitors in the region, especially in the face of growing energy demand. Therefore, it prioritises the growth of energy generation and increased efficiency in energy consumption. This is envisioned to be achieved through continued institutional reforms in the energy sector, including a strong regulatory framework, encouraging private generators of power, and separating generation from distribution, as well as securing new sources of energy through exploitation of geothermal power, coal, renewable energy sources, and connecting Kenya to energy-surplus countries in the region.

[7] Further legal documents are listed in the Draft National Energy and Petroleum Policy.

2) **Sessional Paper No. 4 of 2004**

The Sessional Paper No. 4 of 2004 is a policy document that stipulates the liberalisation reforms implemented in the energy sector in the mid-1990s. Its vision is to promote equitable access to quality energy services at least cost while protecting the environment. The paper therefore lays down the policy framework upon which cost effective, affordable and adequate quality energy services will be made available to the domestic economy on a sustainable basis over the period 2004-2023.

3) **Energy Act No. 12 of 2006**

One of the main proposals of the Sessional Paper was the enactment of an Energy Act to succeed the Electric Power Act No. 11 of 1997 and the Petroleum Act, Cap 116 of 1994 to facilitate a single platform for regulation and enhancement of all energy resources in the country. It further provides for the establishment of ERC, REA, KETRACO, and GDC. The Act also outlines the functions and powers of the two bodies. In addition, the Act established the Energy Tribunal whose purpose is to hear appeals from decisions of the ERC. The institutional setup situates the two bodies, namely the ERC and the Tribunal as overall regulatory bodies independent of state influence. Both institutions coordinate and advise the Ministry of Energy on policy and strategy.

4) **Proposed policy and law: Draft National Energy and Petroleum Policy[8] and Energy Bill 2015[9]**

The new constitution in 2010 and the Kenya Vision 2030 in 2008 necessitated a review of existing energy policy and its legal documents (e.g. Sessional Paper No. 4 of 2004 and Energy Act of 2006). The proposed (draft) energy policy document is the result of a comprehensive analysis and consultation process. It considers actual challenges and opportunities for the energy sector such as the discovery of domestic oil, gas and coal and high energy costs and capital needs. Its objective is "to ensure affordable, competitive, sustainable and reliable supply of energy to meet national and county development needs at least cost, while protecting and conserving the environment." The purpose of the draft Energy Bill 2015 is the consolidation of laws with regard to energy. It consists of various regulations for instance for renewable energy promotion and energy exploration. It further defines powers and functions of existing and various new entities for regulation and advisory of the energy sector. It also clarifies the respective functions for national and county governments.

5) **Least Cost Power Development Plans (LCPDPs)**

The Least Cost Power Development Plans (LCPDP) have been the Ministry of Energy and Petroleum (MOEP's) power implementation plan for delivering the power sector targets outlined in Vision 2030, prepared by the Planning Team. The main contents are demand forecast scenarios for electricity demand, assessment of energy resources and generation and transmission expansion plans for the respective study periods.

The following plans have been prepared in recent years, provided in chronological order:

- LCPDP 2011 – 2031 (March 2011)

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[8] Source: Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (16 June 2015)
[9] Source: Ministry of Energy and Petroleum, *The Energy Bill 2015* (August 2015)

- LCPDP 2013 – 2033 (May 2013)
- Power Sector Medium Term Plan 2014 – 2018 (April 2014)
- 10 Year Power Sector Expansion Plan 2014 – 2024 (June 2014)
- Power Sector Medium Term Plan 2015 – 2020 (June 2015)

The Power Generation and Transmission Master Plan of this report (including related reports on Energy Efficiency and Renewable Energy), the Medium Term Plan 2015 - 2020 and future Long and Medium Term Plans are the continuation of the LCPDPs, enhanced by additional topics and analyses towards comprehensive national master plans.

6) **Rural Electrification Master Plan**

This is the master plan for the electrification of rural areas through the rural electrification program. It is updated on an annual basis in order to respond to the most urgent needs of rural population regarding electricity connectivity. The main agency responsible for this is the Rural Electrification Authority (REA) which was established by the Energy Act of 2006, and operationalised in 2007 with the sole mandate of accelerating rural electrification in Kenya. The government of Kenya provides the main funding sources for REA projects (80%) and is supported by various development partners (20%). The projects completed by REA are handed to KPLC for operation and maintenance based on a Service Level Agreement (SLA). However, the projects continue to remain the property of REA and it does not pay KPLC operation and maintenance costs of the projects as this is recovered through the electricity retail tariff.

7) **Feed-in Tariff (FiT) Policy**

The Kenyan Government introduced feed-in tariffs (FiT) in 2008 to provide investment security to renewable electricity generators, reduce administrative and transaction costs and encourage private investors in establishment of Independent Power Production (IPPs). The FiT were reviewed in 2010 and 2012. The tariffs apply to grid-connected plants and are valid for a 20-year period from the beginning of the Power Purchasing Agreement (PPA), with approval of the PPAs granted by the ERC. The FiT Policy provides electricity purchase guarantees by the main power utility KPLC. It includes all power generation categories with the incentive for bigger projects, by providing a favourable tariff structure to both the investor and KPLC in such big projects.

3.1.2 Institutional and administrative framework

This paragraphs lists and briefly describes the institutional set-up with an influence on the power system planning. The institutional and political setup in Kenya is rather challenging for an effective and efficient planning in the power sector. This is for example due to:

- Numerous stakeholders on international, national and sub-national level representing overlapping and partly contradicting interests from different sectors (private, governmental, non-governmental, donors).
- Planning and implementation processes and responsibilities within Kenya are partly under discussion and not fully agreed and implemented (between different planning levels, e.g. county and central government institutions and among stakeholders on the same level,

e.g. KPLC and KETRACO for the transmission system as well as Ministry of Energy and Petroleum and Ministry of Environment, Water and Natural Resources for hydroelectric dams).

- The opportunities and challenges of an open power market and unbundled electricity sector consisting of national and international companies with various ownership structures.

A brief description of the relevant organisations is presented below. This descriptions' aim is solely to provide an initial understanding of the organisational set-up for the subsequent assessments which often refer to these organisations. The descriptions are not exhaustive with regard to an in-depth analysis of the organisational set-up and recommendations for organisational changes as this would be beyond the master plan's objectives.

3.1.2.1 National and sub-national level

Kenya's administration consists of the national level and 47 counties[10], displayed in the map below.

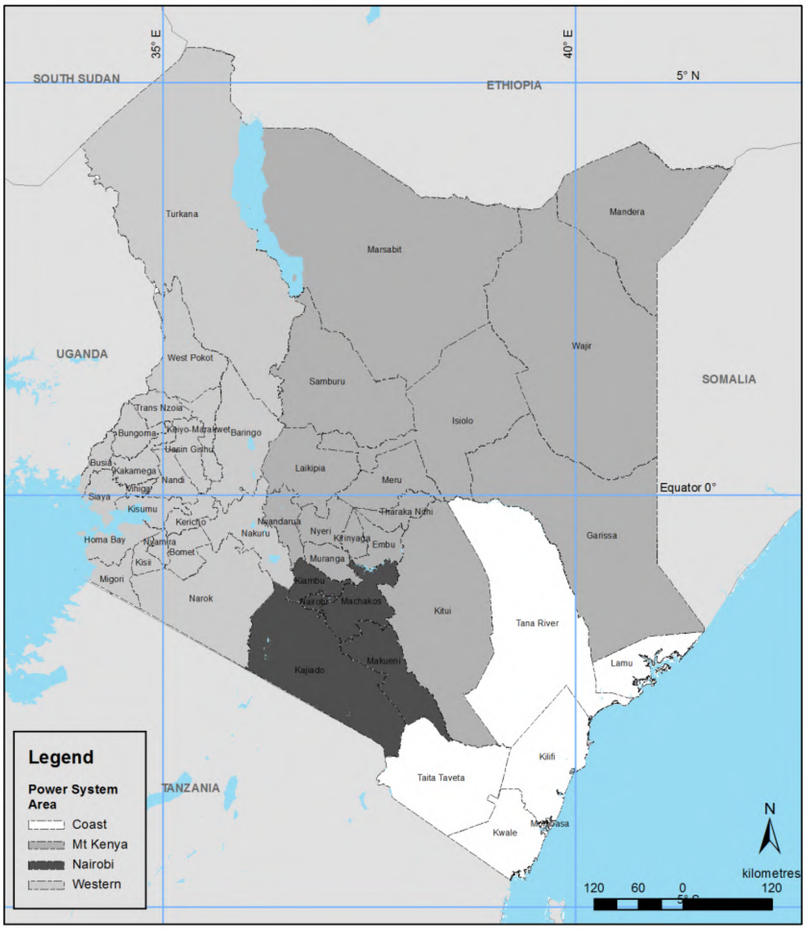

Figure 3-1: Map of Kenya – counties and power system areas

[10] Before the reform, Kenya was divided into 8 provinces (administered by a centrally appointed commissioner), districts (many similar to the current sub-counties) and divisions. This system is abolished though much data is only available along this structure. This limits the analysis on the sub-national level and provides some inaccuracy if data is transferred to the new structure.

In addition to this administrative layer, the four areas of the power system are considered in this study and displayed[11] along county boundaries in the map. They represent the split by KPLC of the national power system into four regions. Much of the power system data is not available below this level. Therefore, most demand analysis and provision of results is done for the four regions or the national level.

The counties are further divided in sub-counties and locations. This new administrative and political structure - under the so called devolution - was introduced with the new constitution in 2010. It is part of the transition from a centralised Kenyan administration and government to a more devolved structure with semi-autonomous status of the counties (e.g. election, budgets, and decisions). Though officially in place, it is still in implementation process with various issues under discussion which also effect power system planning (e.g. decision on local power generation and electrification budgets and plans). Planning and development of electricity supply, regulation and overall policy will continue to be the duty of the Government of Kenya (GoK).

During the time of this study planning processes at various county governments were already initiated, though they were still at an early stage (e.g. with regard to data collection, designation of staff and responsibilities). In this transition period, suitable processes, effective cooperation and responsibilities are still to be elaborated and agreed. Due to this uncertain environment this study could not cover the various planning efforts. However, the planning on county level should be included in future master plans once it is well defined and established.

3.1.2.2 International level

Kenya is member of various regional international organisations, which have an influence on energy and power planning. The most relevant for this study are:

- The Common Market for Eastern and Southern Africa (COMESA), which as a pillar of the African Economic Community is part of the African Union. Under COMESA the Eastern African Power Pool (EAPP) is a specialized institution for electric power to foster power system interconnectivity between its member countries. It facilitates planning of interconnections and a common power market, e.g. through regional master plans as well as the implementation of actual projects. There are two EAPP Master Plans submitted 2011 and 2014.

- The East African Community (EAC), which also includes a department dealing with energy matters. The latest EAC regional master plan is the East African Power Master Plan Study (EAPMP) submitted in 2005. Furthermore, it co-published the latest EAPP Master Plans.

- The Nile Basin Initiative (NBI) with its investment programme Nile Equatorial Lakes Subsidiary Action Program (NELSAP). It has the overall objectives of poverty reduction, promotion of economic growth, and the reversal of environmental degradation. It also consists of a program area for power exchange within the region and supports the study and implementations of interconnectors.

[11] Not all counties are connected to the national grid. For the purpose of this study and in coordination with KPLC, these areas were assigned to power system areas. This may change in future.

Besides governmental organisations there are around 14 international and national donor organisations from other countries with development interest in the energy and power sector, such as international and national development banks and organisations (World Bank, AfDB, AFD, KfW, JICA, GIZ, etc.). [12] They provide funding and oversight for studies and actual projects for numerous projects in the sector. The high number of projects and donors in addition to the numerous government organisations and private investors challenges coordination of overall sector planning. Hence, sufficient coordination is sometimes lacking and could be improved.

3.1.2.3 Power sector institutions

The Kenyan energy sector has been restructured in 1997 from a centralised organisation to an unbundled and distributed assignation of responsibilities and organisations. Since definition of this decentralisation process many steps have been taken to effectively promote a proper unbundling of responsibilities within the Kenyan power sector. However, this process is still on-going (e.g. with regard to the operation and expansion of the transmission network) and will take more time to be completed.

The chart below shows the institutional framework of the Kenyan energy sector. The subsequent table shows a list of most important institutions of the power sector. It indicates their representation in the Planning Team which conducts, among other tasks, power sector plans.

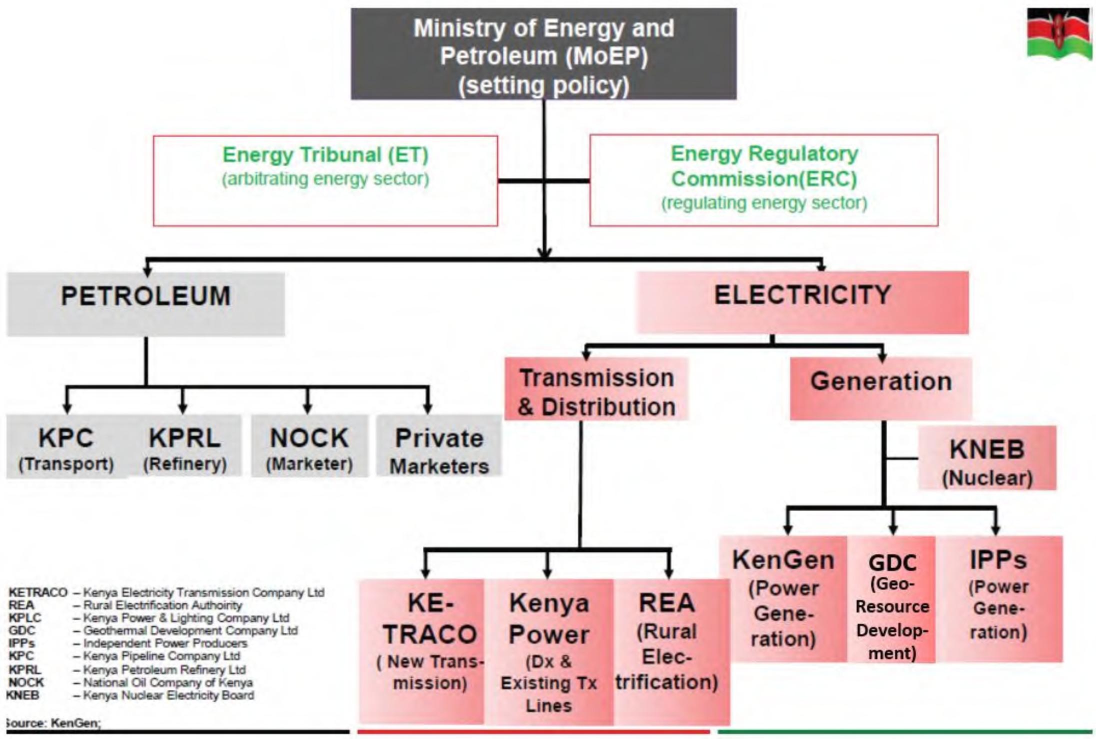

Figure 3-2: Kenya energy sector - institutional framework[13]

[12] EU - KENYA Cooperation, *11th EUROPEAN DEVELOPMENT FUND, NATIONAL INDICATIVE PROGRAMME 2014 – 2020 Ref. Ares(2014)2070433* - 24/06/2014 (Nairobi, 2014)
[13] Source: MOE

Table 3-1: Kenyan power sector - institutional framework

Abbreviation	Name of institution	Website	Represented in Planning Team
MOEP	Ministry of Energy and Petroleum	www.energy.go.ke/	Yes
ERC	Energy Regulation Commission	www.erc.go.ke	Yes (Lead)
Power sector institutions under MOEP and ERC			
	Energy Tribunal		No
KPLC	Kenya Power and Lighting Co. Ltd., recently re-branded "Kenya Power"	www.kplc.co.ke	Yes
Ketraco	Kenya Electricity Transmission Co. Ltd	www.ketraco.co.ke	Yes
KenGen	Kenya Electricity Generating Co. Ltd.	www.kengen.co.ke	Yes
GDC	Geothermal Development Company	www.gdc.co.ke	Yes
REA	Rural Electrification Authority	www.rea.co.ke	Yes
KNEB	Kenya Nuclear Electricity Board	www.nuclear.co.ke	Yes
IPPs	Independent Power Producers		On request
Institutions with an oversight role in the power sector			
Vision 2030	Kenya Vision 2030	www.vision2030.go.ke	Yes
KenInvest	Kenya Investment Authority	investmentkenya.com	Yes
KAM	Kenya Association of Manufacturers	kam.co.ke	No
KEPSA	Kenya Private Sector Alliance	www.kepsa.or.ke/	Yes
KNBS	Kenya National Bureau of Statistics	www.knbs.or.ke/	Yes
Donors	14 bilateral and multilateral donors active in energy sector and respective donor coordination group (chaired by MOEP)	-	No
MEWNR	Ministry of Environment, Water and Natural Resources	www.environment.go.ke/	No

A brief description of the relevant organisations is presented below. The aim is solely to provide an initial understanding of the organisational set-up for the subsequent assessment of the sector and policy framework which often refers to these organisations. The descriptions are not exhaustive with regard to an in-depth analysis of the organisational set-up and recommendations for organisational changes as this would be beyond the master plan's objectives.

1) **Ministry of Energy and Petroleum (MOEP)**

The MOEP is in charge of making and articulating energy policies to create an enabling environment for efficient operation and growth of the sector. It sets the strategic direction for the growth of the sector and provides a long term vision for all sector players. As the head of the energy sector it is also responsible for overall planning like other ministries within the Government. It is the Consultant's direct Client for this master plan. In 2013, MOEP has been restructured and in this course renamed from Ministry of Energy (MOE).

2) **Electricity Regulatory Commission (ERC)**

The ERC was established by the Energy Act of 2006 (with effect from 2007) by expanding the mandate of its predecessor, the Electricity Regulatory Board (ERB). The ERC is responsible for regulation of the energy sector. Its functions include tariff setting and oversight, coordination of the development of Indicative Energy Plans, monitoring and enforcement of sector regulations. Furthermore, its mandate is to provide information and statistics to the MOEP and to collect and maintain energy data. With its mandate to coordinate planning, it chairs the Planning Team and has a pivotal role within this project.

3) **The Energy Tribunal (ET)**

The Energy Tribunal was established by the Energy Act of 2006. It is an independent legal entity with the mandate to arbitrate disputes in the sector; in particular, appeals brought against the decisions of the Energy Regulatory Commission.

4) **Planning Team**

The Planning Team is responsible for developing the major power sector plans and deals with other power sector topics. The Planning Team is working under the supervision of the ERC and with policy and guiding input from the MOEP.

5) **Kenya Power & Lighting Company (KPLC, Kenya Power)**

KPLC is governed by the State Corporations Act and is responsible for existing transmission and distribution systems in Kenya. It is the off-taker in the power market buying power from all power generators on the basis of negotiated power purchase agreements for onward transmission, distribution and supply to consumers. KPLC is a listed company on the Nairobi Stock Exchange with the ownership structure being 50.1% by the National Social Security Fund (NSSF) and GoK while private shareholders own 49.9%.

6) **Kenya Electricity Transmission Company (KETRACO)**

KETRACO was established in 2008/2009 as a state corporation fully owned by the GoK. The mandate of the KETRACO is to plan, design, construct, own, operate and maintain new high voltage (132kV and above) electricity transmission infrastructure that will form the backbone of the national transmission grid & regional interconnections. It is expected that this will also facilitate evolution of an open-access-system in the country. KPLC is maintaining and operating the transmission lines in the name of KETRACO, due to its recent creation. A respective capacity building (e.g. organisational development & staffing, software introduction & training) with external funding is on-going through various projects so that KETRACO can handle all its responsibilities mandated at its establishment.

7) **Kenya Electricity Generating Company (KenGen)**

KenGen is the main player in electricity generation, with a current installed capacity of more than 1,500 MW. It is listed at the Nairobi Stock Exchange with the shareholding being 70% by the Government of Kenya and 30% by private shareholders. The Company accounts for around two thirds of the installed capacity from various power generation sources that include hydropower, thermal, geothermal and wind. Within the future generation expansion it will continue to compete with Independent Power Producers (IPPs).

8) **Geothermal Development Company (GDC)**

GDC is a fully government owned Special Purpose Vehicle (SPV) intended to undertake surface exploration of geothermal fields, undertake exploratory, appraisal and production drilling and manage proven steam fields and enter into steam sales agreements with investors in the power sector. Through this approach the risks for private investors should be reduced and overall investments in geothermal energy is expected to increase and speed up. For its mandate, it receives support from international development agencies. This is for instance the Japan International Cooperation Agency (JICA) which at the beginning of 2014 commenced the Geothermal Master Plan. The geothermal potentiality is still handled by both KenGen and GDC. Even though the power centres for each one are well defined, a better application of separation of areas of intervention can be achieved.

9) **Rural Electrification Authority (REA)**

REA was established in 2007 (Energy Act of 2006) with a mandate of implementing the Rural Electrification Programme (REP). Rural electrification is mainly implemented under the auspices of the REA, while KPLC complements this work by connecting customers and maintaining the network.

10) **Kenya Nuclear Electricity Board (KNEB)**

KNEB is charged with the responsibility of developing a comprehensive legal and regulatory framework for nuclear energy use in Kenya. This includes the mandate to undertake preparatory activities towards development and implementation of the Nuclear Power Programme in order to enhance the production of affordable and reliable electricity from nuclear power in Kenya.

11) **Independent Power Producers (IPPs)**

IPPs are private investors in the power sector involved in generation either on a large scale or for the development of renewable energy under the Feed-in-Tariff Policy. Current players comprise Iberafrica, Tsavo, OrPower 4, Rabai, Thika, Imenti, Power Technology Solutions, Gulf, Triumph, Mumias, Aggreko (as emergency power producer). Collectively, they account for about one third of the country's installed capacity from thermal, geothermal, small hydro and bagasse. Further IPP projects are under development and expected to commence operation in the medium term.

12) **Private Distribution Companies**

Private Distribution Companies (besides KPLC) are proposed under the draft Energy Act and are expected to improve the distribution function whose sole mandate rests with KPLC. It is envisaged that future power distribution will involve purchase of bulk power from the generators and with KETRACO facilitating the transmission; the power generators will be able to sell power directly to consumers. This is likely to enhance distribution competition and hence improve efficiency. No active plans are known to introduce private distribution companies though discussion is on-going.

3.2 Electricity demand

This section describes and analyses the historic consumption patterns of the electricity consumers in Kenya in order to identify key parameters for the demand forecast:

- Electricity consumption and the connections to the national grid, the two most important characteristics of the electricity demand;
- Specific consumption derived from the above,
- Load characteristics, suppressed demand and correlation among the parameters.

This is done by consumer groups (i.e. tariff groups) and power system areas. Definitions for the terms used in this chapter are provided in section 4.4. All data derive from KPLC annual reports[14] unless otherwise stated. Detailed figures are provided in Annex 3.D.

3.2.1 Customer / tariff groups

Data analysis and results for this study are provided along past and current KPLC tariff structure as detailed in tabularized way in Annex 3.D.1. It differentiates between the main categories:

- Domestic consumers;
- Small commercial consumers;
- Large commercial and industrial consumers;
- Street lighting.

All categories include customers of the normal (commercial) KPLC scheme (which have accounted for more than 80% of all customers) and the subsidized Rural Electrification Programme (REP). The data situation does not allow for the definition of other customer groups which could have been of benefit for this analysis due to their common consumption patterns (e.g. institutional public and private customers in education and health; large agricultural consumers). Besides the interconnected national electricity grid, there are 16 isolated grids[15] in Kenya. They serve areas and population far away from the grid. Compared to the interconnected grid, they only generate and supply less than 0.5% of the electricity. Therefore, they are negligible for the analysis which focusses on the national grid.

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[14] All figures provided for calendar years: connections according to KPLC annual accounts end of financial years (i.e. mid of calendar years), consumption (electricity) per calendar year derived from KPLC annual accounts financial years, 2015 figures extrapolated

[15] These off-grid stations are operated by KPLC. They are located in Wajir, Elwak, Takaba, Mandera, Marsabit, Moyale, Habaswein, Rhamu, Lodwar, Lokichoggio, Baragoi, Merti. 13 new isolated grids are under construction. Source: KPLC, *Annual Report 2013/2014* (2014)

3.2.2 Connectivity level and connections by consumer groups and by areas

At present, electricity only accounts for 9% of the total energy use in the country[16], petroleum products for 22%, and renewable energy (mainly biomass) for 69%. This low electricity share is mainly[17] due to a low and uneven connectivity level in the country. The underlying causes as well as the historic development of the connectivity level are summarized below.

1) Electrification definition, programs, status and connectivity rates

a) There is no definition on what qualifies a household to have 'access' and 'connectivity'. However, it has been successively applied (e.g. in previous LCPDP reports, National Energy Policy Draft) as actual connection and supply with electrical power (even with solar home systems) and not only the opportunity to access (e.g. a nearby transformer)[18].

b) There have been successful electrification measures[19] in the past, but mainly for institutional consumers. The below table summarises the main figures for electrification since 2009.

Table 3-2: Connectivity level and rate, households and population (2009 - 2015)

	Unit	2009	2010	2011	2012	2013	2014	2015
Population	Million	39.83	40.85	41.91	43.01	44.14	45.28	46.45
Households – total	Million	9.04	9.34	9.64	9.96	10.29	10.63	10.98
Need for new connections	Million	Na	0.29	0.31	0.32	0.33	0.34	0.35
Domestic connections	Million	1.08	1.26	1.53	1.79	2.06	2.48	3.31
Annual increase (rate of new connections)	Million	0.19	0.18	0.26	0.27	0.27	0.42	0.83
	%	21%	16%	21%	17%	15%	21%	33%
Households per connection[20]		1.83	1.79	1.76	1.73	1.70	1.67	1.62
Connectivity level	%	19%	21%	24%	27%	30%	35%	44%
theoretical: no population growth	%	19%	22%	26%	30%	33%	40%	51%

[16] Source: Ministry of Energy and Petroleum, Draft National Energy and Petroleum Policy (16 June 2015); electricity as a secondary energy is based on renewable energy sources (above two thirds) and petroleum.
[17] Other causes are insufficient power quality and security (see supressed demand below). The high share of renewable energy is mainly due to the traditional utilization of biomass for cooking. A change of this habit will be slow and rather towards gas than a substitution with electricity (according the Kenya Integrated Household Budget Survey KIBHS 2006, only 3% of households in Nairobi used electricity for cooking which is very low given the high electrification rate of more than 50%). The high share of petroleum products is mainly due to the exclusive use of petroleum products in the transport sector. The planned electrification of railway lines may change it to some extent (covered in this study under the flagship projects).
[18] Details on the definition for this master plan is provided in section 4.4.
[19] Information on current and planned electrification measures and targets are provided in Annex 4.D
[20] Known for 2009 only; for 2010 onwards reduction assumed to reach 1 household per connection in future

In mid-2015 there were some 3.6 million customers connected to the national power grid of which more than 90% (3.3 million) were domestic[21], reaching beyond 4 million at the end of 2015 and nearly 5 million mid of 2016[22]. The connectivity level for Kenya is estimated by the government with 32%[29] for mid-2014, 47%[22] for 2015, and 55%[22] for mid-2016. The analysis and calculation for this report revealed slightly different[23] levels of 35% (2014) and 44% (2015). During the past six years, the number of customers tripled (both total and domestic) with an annual average increase of 20% indicating the advances in electrification. Since financial year 2012/2013 the number of new connections nearly doubled every year. This strong increase includes an above average increases from slum electrification schemes and the provision of additional meters to existing customers (e.g. split of existing connections if more than one household is connected to one meter).

c) The connection rate by customer group has varied as shown in the figure below. Domestic customers increased slightly above average. Slower growth occurred for small commercial connections (9% per year for 2010 to 2015 with a tendency for slowdown in recent three years) and large[24] industrial and commercial customers (only 4.5% per year for 2010 to 2015). Street lighting connections increased by, on average, 19% during 2010 to 2015 (mainly due to the street lighting programme) with high fluctuations before 2004[25].

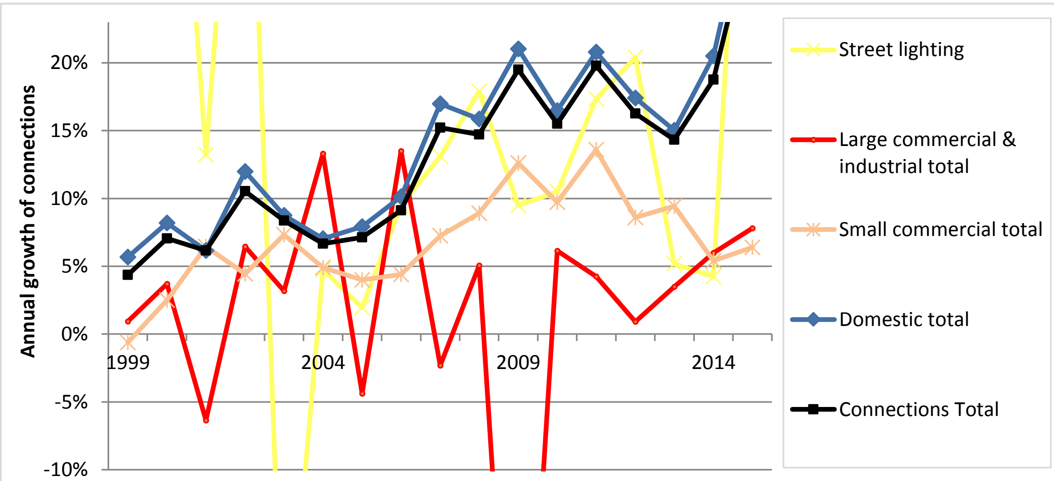

Figure 3-3: Connection growth by customer group (1999 - 2015)

d) There has been a strong correlation between the connection rates of domestic consumers, small commercial consumers and street lighting. This dependency shows a slightly decreas-

[21] Street lighting and large commercial and industrial consumers accounted for some 3,000 connections each, i.e. only 0.1% of total connections each.
[22] Source: KPLC webpage, *Special Achievements*, http://kplc.co.ke/ (accessed 7.1. 2016); *Milestones in Kenya's electricity access* http://kplc.co.ke/ (accessed 18.10. 2016)
[23] Since the latest available reliable figures for the official definition of the connectivity level date from census 2009, both figures are indicative. This is because the average number of households per connection are not known. Further, the assumed underlying demographic data may differ.
[24] Decline in 2009 due to change of tariff structure
[25] Not displayed in graph due to growth rates above 50%

ing growth for street lighting and small commercial connections in comparison with domestic connections (see figure in Annex 3.D.2)[26].

2) Uneven connectivity levels

a) Electrification of the country has been unbalanced for many years. A quarter of the national population (i.e. of Nairobi power system area) accounts for 50% of the access to the power supply and consuming half of the electricity[27]. This situation has barely changed within the past 15 years. Also, the Coast area accounts for an above average connectivity level and consumption in comparison to its population share.

b) The connectivity level on county level is also very uneven[28]. For the rural population, the situation has been even more serve throughout the country, with connectivity levels only a fraction of the overall county level. If the electrification figures are overlaid with the population density (second map in Annex 3.D.2) the areas close to the Lake Victoria stand out: millions of people who live comparatively close together (which should facilitate electrification) are still below national average in terms of electrification.

c) Regions not covered by the national grid rely on isolated grids (mainly fuelled by fossil fuels), small gasoil-fired generators or electricity substitutes such as kerosene lamps.

3) **Demographic characteristics** (detailed in Annex 3.B):

a) The high share of rural (and thus often technically and economical difficult to connect) population has been a challenge in the past and is expected to continue. It is partly mitigated by a continuing urbanization. The recent National Electrification Strategy[29] confirms this challenge for Kenya with "high costs of supplying rural and peri-urban households", "lack of appropriate incentives", "weak implementing capacity", "population growth", and "cost of the internal wiring of consumer's premises".

b) The high population growth of about 2.4% is a big challenge for electrification. It requires some 300,000[30] new connections per year only to keep the connectivity level constant. The shrinking average household size will further severe this situation. Because of this the electrification ratio has increased at a slower rate than the number of connections. Figure 3-4 below and Table 3-2 above show this effect by comparing the actual calculated connectivity level during the past 6 years and the connectivity level if no population had occurred. The latter would have resulted in an electrification of about five percent higher.

[26]The connection rate of street lighting averaged in the range of 50 to 80% of the domestic connection rate in the past. For small commercial connections this relation was even more stable at around 50 to 60%. Only in the recent two years this ratio decreased to around 20%. This could derive from the advanced and partly subsidised electrification of households.
[27] Despite a similar number of households in Mt. Kenya and double amount of households in Western area.
[28] The map on connectivity level in Annex 3.D.2 highlights in red and dark orange the counties with very low connectivity level (below 10%) for the year 2009.
[29] Source: MOEP, *National Electrification Strategy* (2015). This document is closely linked to a recent study: MOEP, Fichtner, *Consultancy Services for Development of Electricity Connection Policy and Draft Regulations* (2014). Some of the study's assumptions and conclusions are to some extent taken over into this master plan (e.g. electrification scenarios) while some assumptions differ (e.g. household size).
[30] Expected to increase to some 500,000 in 20 years.

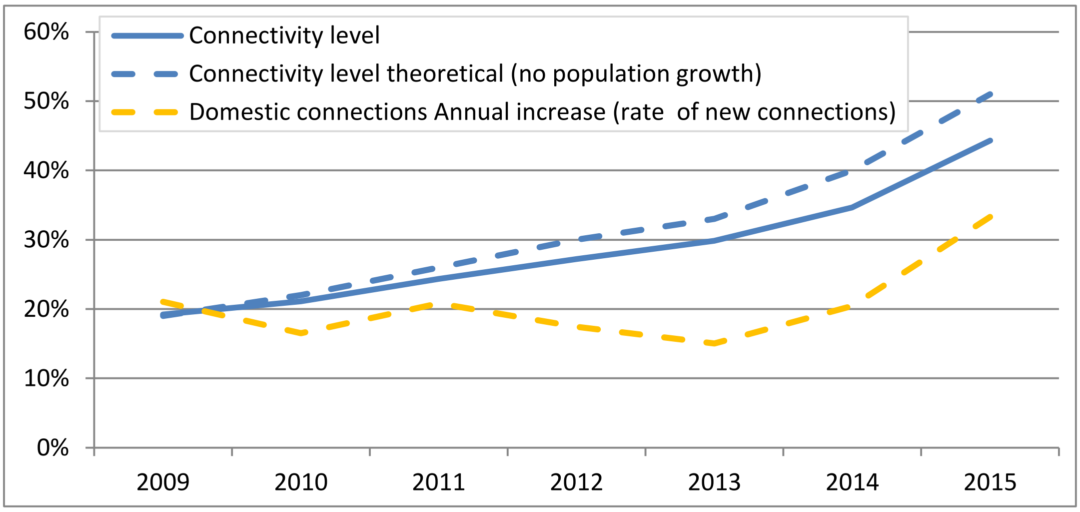

Figure 3-4: Connectivity level and rate of new connections (2009 - 2015)

4) Data situation

a) Lack of data to analyse and monitor official definition and target connectivity level: the available regular and recent statistics only cover actual connections (i.e. meters) but not actual households or population served by these connections. Only the census 2009 data allows to calculate average number of households or persons per connections and the actual connectivity level.

b) The information situation on the coverage of the national grid is very limited. Seven counties (out of 47) are probably not connected to the national grid[31]; the coverage of each county is not available[32]. Coverage of the national grid is estimated[33] with 70%.

c) Data on past electrification measures was not available for this study (e.g. average connection and consumption increase after rural electrification was initiated), to facilitate evaluation and planning of future electrification schemes as well as demand forecasts.

3.2.3 Electricity consumption by consumer group and area

The main characteristics for electricity consumption are:

1) Total consumption of electricity grew continuously by an average of 6% per year during the past 5 years. This is a considerable increase from the 4% during the preceding ten years[34].

2) Compared to the average of Sub-Saharan African countries[35], these growth rates are about twice as high for the period 2002 to 2012 and below average for the period before (1992 to

[31] Source: Parsons Brinckerhoff, *Kenya Distribution Master Plan* (2013); Lamu county assumed to be connected at the time of this study.
[32] Despite the existence of a Geographic Information System (GIS) displayed in Distribution Master Plan.
[33] No source for this often quoted 70% is available nor any information whether this relates to the area or population within reach of existing transformers or lines.
[34] Mainly caused by the 9% and 11% growth in financial years 2010/2011 and 2013/2014 respectively and a period of stagnant consumption from 1998 to 2002.
[35] Source: The World Bank, *World Development Indicators,* Electric power consumption (2015), for available countries and years (1991 – 2012)

2002). They are however below the growth rates of Ethiopia, Tanzania, Ghana, and Cote d'Ivoire. Per capita consumption is low at only one third of the average of Sub Sahara Africa but continuously increasing.

3) Consumption growth by consumer groups has been even throughout the years (see Figure 3-5 below), except for street lighting. For most years, domestic consumption increased above average while the consumption from large commercial and industrial consumers increased slightly below[36]. The growth rates for consumption are mostly below the rates for connections (previous section), leading to decreasing specific consumption (see 3.2.4 below).

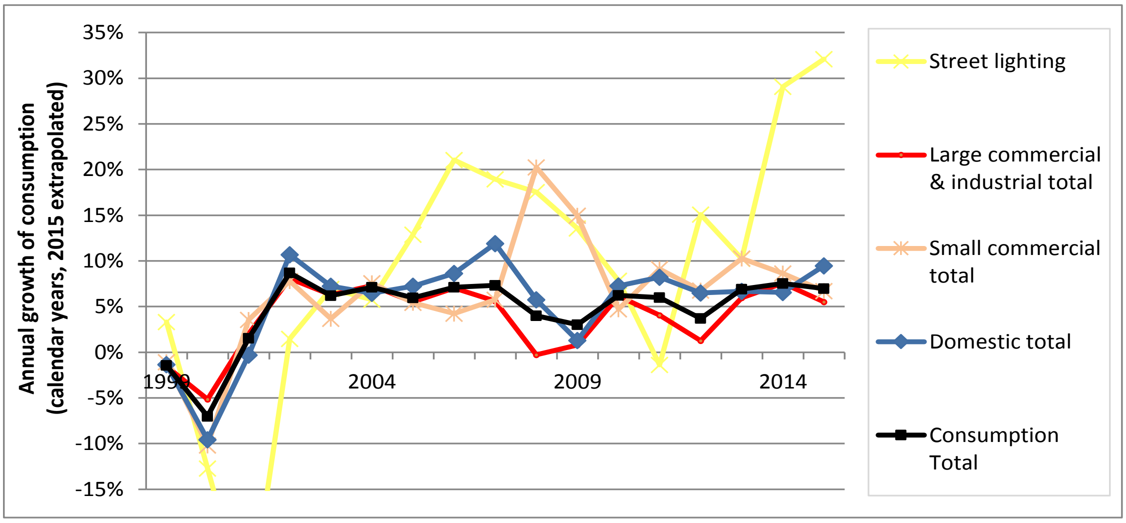

Figure 3-5: Consumption growth by customer group (1999 - 2015)

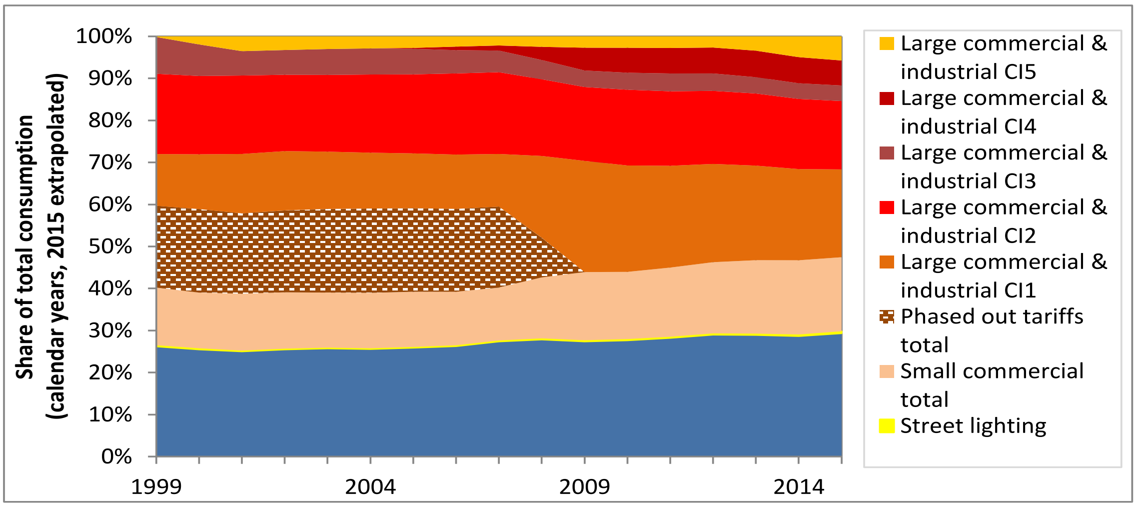

Figure 3-6: Consumption share by customer group (1999 - 2015)

4) The contribution of domestic consumers to total consumption is only about 30% although they account for 90% of the connections (the share has slightly increased by about two percent

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[36] The 2008/2009 decrease and the coincidental increase of small commercial consumers is assumed to derive from a transfer of consumers during the change in tariff groups during that period (see Annex 3.D.1).

since 1999 because of the above average connection rates). The remaining share is split among commercial and industrial consumers of which the small commercial consumers share has slightly increased[36].

5) The share by voltage level shows a strong increase for high voltage from no customers before 2000 to around 3% of total consumption until 2007 and to 11 to 12% today. Medium voltage consumers account for 20% down from 25% before 2008.

6) Few large consumers contribute to a large share of the overall electricity consumption. Their operation and planning has a strong influence on the present and future electricity demand. They also rely heavily on the planning and operation of the power system. The key characteristics are summarized below (see Annex 3.D.3 for details[37]):

   - Some 3,400 customers were registered under the large commercial and industrial tariff in 2015. They accounted for more than 50% of the total consumption. This share has continuously decreased from 61% in 2004.

   - Half of this (about 25% of total electricity) was consumed by 550 entities only (25 customers consumed 15% of which 14 consumed 10%, the 3 largest consumers took 5%).

   - There are nine sectors[38] - mainly manufacturing - each consuming in total 80 GWh per year or more. They make up 15% of the national electricity demand.

   - More than 50% of the analysed large consumers are located in Nairobi power system area, nearly 25% in Western area, and 15% in Coast area.

7) The consumption by consumer group differs by power system area[39]. This partly mirrors the economic structure of the country: Coast and Nairobi regions show a higher share of large commercial and industrial consumption due to a concentration of these consumers in Mombasa and Nairobi. In Western and Mt. Kenya regions, the share of small commercial consumption is higher. The share of domestic consumption is slightly smaller for Coast and Western area.

3.2.4 Specific consumption by consumer group and power system area

The main characteristics for electricity consumption are:

1) The overall annual specific consumption since 1999 decreased from about 8,000 kWh to about 2,200 kWh in 2015, with a longer period of stagnation at around 6,000 kWh (2001 and 2006). This is an average annual decrease of 7.5% for the whole period, 10% for the past ten years.

2) The specific domestic consumption decreased by 75% from 2,700 to 700 kWh per year, having the strongest effect on the total (as shown in the figure below). Small commercial consumers

[37] Figures based on a KPLC data set of some 700 large consumers for financial years 2007/2008 to 201372014
[38] According to KPLC classification: Cement, Lime & Plaster Plants, Other supplies in the Industry, Metal Products, Plastic Manufacturers, Tea Estate, Basic Metal Industry, Other Petroleum Supplies, Grain Mills, Industrial Chemical Plants
[39] The maps in Annex 3.D visualise these characteristics for the years 1999, 2004, 2009, and 2014.

have showed a stable specific consumption between 4,500 and 5,000 kWh with a slight increase in recent years. The specific consumption of large commercial and industrial consumers has been rather constant with a jump in 2009 probably due to the tariff reform.

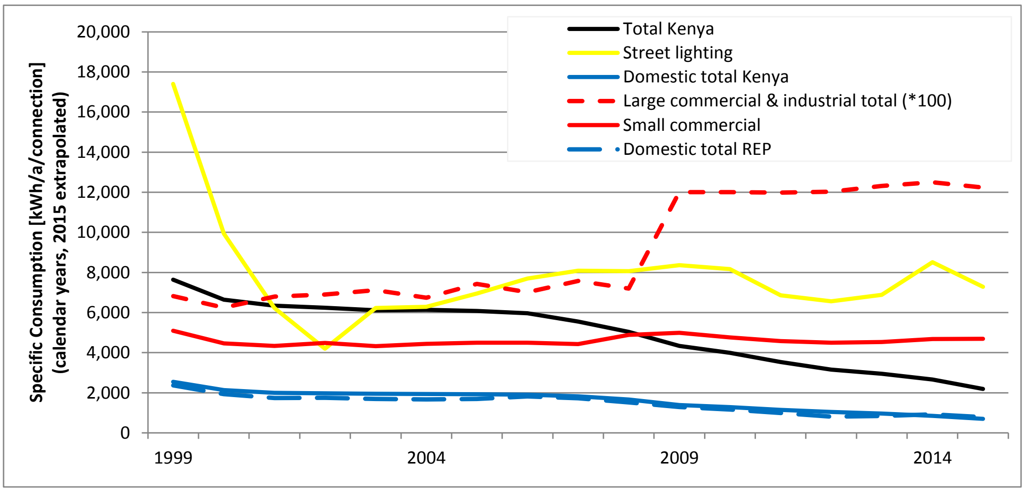

Figure 3-7: Specific consumption by customer group (1999 - 2015)

3) All <u>power system areas</u> show a reduction of specific total and domestic consumption (Figure 3-8). Nairobi - due to its dominance for connections and consumption - has been close to the national average. For Mt. Kenya, the percentage decrease was the slowest (only 50%). For Coast area, the specific consumption was the highest throughout the years at 150% of the national average. The lowest specific consumption appeared in Western and Mt. Kenya areas.

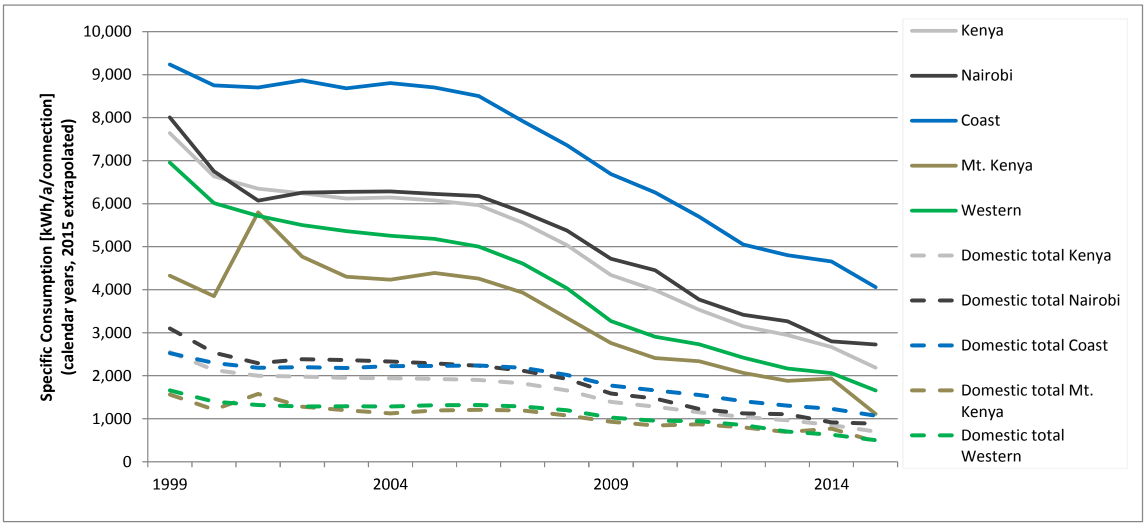

Figure 3-8: Specific domestic consumption by customer group and power system area (1999 - 2015)

4) <u>Electrification</u> causes the decreasing specific consumption in the domestic sector through the very low consumption of newly connected households. This more than offsets the on average expected increase of average consumption of connected households (assumed to be in the

range of 3% to 6%[40]). This effect is shown by a very strong non-linear correlation of specific consumption and electrification of domestic consumers (see Annex 3.D.4).

5) The rather constant specific consumption of small commercial and large consumers can be attributed to the lower consumption of newly connected consumers on average, which levels on an aggregated level, the consumption increase of the existing consumers.

6) For street lighting, the specific consumption has fluctuated throughout the years. No obvious cause for this development could be identified but temporary unavailability and load shedding or a changing numbers of lamps per typical connection might have had an influence. Based on recent information[41] from the street lighting project in Nairobi on the number of lamps (total and estimated 40% out of operation), an average number of 10 lamps per connection was estimated with an average rating of 260 Watt and 12 hours of operation for each lamp. This amounts to around 6,000 kWh per year per connection for the past years which will double in future if the street lighting project is implemented as planned and overall power system failures reduce.

3.2.5 Correlation between electricity consumption and economic growth

For most countries, there is a correlation between electricity consumption and economic growth[42]. For Kenya this correlation[43] is strong for GDP and the consumption of electricity in total and by tariff group as well as the connection rate. To utilize this correlation to support the demand forecast, it is necessary to thoroughly analyse the correlation and evaluate the economic development in the past and future (see Annex 3.C.2 and Annex 3.D.5). This is because the causal dependency and direction are not proven[44]. However, there are indications that in developing countries, the GDP growth is driving energy and electricity consumption, while with increasing income the causal-

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[40] Based KPLC customer specific billing data for only one year (2011/2012). The household survey 2012 revealed average annual electricity consumption for low consumption households of 487 and 270 kWh for urban and rural households respectively. The recent study, *Consultancy Services for Development of Electricity Connection Policy and Draft Regulations*[29], provides a lower estimate for the overall specific consumption of low income groups of 200 to 250 kWh per year, extrapolated from 2011 figures.

[41] Source: KPLC, *Government releases Shs.381 million for Nairobi street lights project* (13.10.2014); *Tender for the supply of materials for street lighting project* (October 2014) http://www.kplc.co.ke (accessed 15.6.2015)

[42] Measured as GDP or GNI

[43] A correlation analysis (Pearson product-moment correlation coefficient) for the period 2000 to 2014 revealed correlation coefficients of 0.95 and above for total, domestic, small commercial and overall large commercial and industrial consumption. The correlation for the tariff group large commercial and industrial consumers CI5 and street lighting is lower and not existent for interruptible off-peak consumers. The correlation is similarly strong for the respective connection rates. Linear correlation between absolute numbers of GDP and electricity consumption is strong with a correlation coefficient of above 0.99 and a ratio which indicates some two additional GWh consumption for every additional billion KES GDP. In comparison to that, growth rates of consumption and GDP follow each other on a general level but do not show any particular correlation. For the above correlations no time lag effect could be found, i.e. higher correlation if figures of different time series (e.g. shifted by one or two years) are analysed.

[44] „"causal dependence between the two focus variables has been a point of disagreement in the literature" Source: Economic Consulting Associates, *Correlation and causation between energy development and economic growth* (2014)

ity may turn[45]. This is in line with the assumptions applied for Kenya in the previous LCPDP reports and is supported by research on Kenya[46]. However, the evaluation of the previous approach and GDP elasticity coefficient[47] revealed the following:

- Coefficient is very high in comparison with other studies[48] and the analysis of historic data, it is questionable whether such a coefficient can be applied for high GDP growth rates beyond historic records (i.e. above 8%);

- Correlation between growth rates is much lower than for absolute numbers (figures are plotted in Annex 3.C). This indicates that a linear function of actual figures of GDP and electricity consumption is more accurate than the factor (or coefficient) for the growth rates.

- Saturation of electricity demand in the long-term (as observed in emerging and industrialised countries) is not considered.

This, in relation to the application of a single coefficient for the whole period, might result in considerable deviation of the forecasted demand if only one or two input parameters (e.g. GDP growth rates, coefficient) are slightly changed. It is recommended to use the linear correlation of actual values of electricity consumption and GDP (instead of growth rates) and to consider saturation effects e.g. by an energy efficiency scenario.

3.2.6 Ability and willingness to pay and price elasticity

The ability and willingness of consumers to pay for electricity have an impact on the actual and future consumption through the customer's sensitivity towards price changes, so called price elasticity of demand for electricity.

- Compared to other consumer goods, including other energy products, the <u>electricity price elasticity is rather low</u> in industrial countries and to a lesser extent in developing countries[49]. Price elasticity tend to be higher in the long term compared to short and medium term.

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[45] *"…upper middle and low middle income countries are more energy dependent than low income countries"* Source: Economic Consulting Associates, *Correlation and causation between energy development and economic growth* (2014)

[46] Onuonga, S., *The Relationship between commercial energy consumption and Gross Domestic Income in Kenya* (The Journal of developing Areas, 46(1), 2012). See Annex 3.C for the long-term comparison of the development of electricity consumption and GDP.

[47] The factor (also called GDP coefficient) determines the ratio of the growth rates of electricity consumption and GDP (future growth rate electricity consumption [%] = GDP coefficient x forecasted growth rate GDP [%]. The factor has been 1.5 since LCPDP 2013 and 1.3 before.

[48] *"…lower income countries, a 1% increase in GDP increases energy consumption by 0.73%"* (this would mean a factor of 0.73 compared to 1.5 in the LCPDP studies) Source: Economic Consulting Associates, *Correlation and causation between energy development and economic growth* (2014)

[49] As an example: studies on price elasticity exist which indicate factors of around -0.2, i.e. a decrease of the electricity price by 10% would result in a demand growth of 2%.

* This strongly depends on the national or local conditions such as the income situation, budget share for energy, consumption patterns or substitution opportunities. Conventional metering and billing (i.e. neither prepaid nor smart metres) - as common In Kenya - might have a dampening effect on elasticity since a change of price is more difficult for the consumers to recognize compared to, for instance, pump prices. The high tariffs in Kenya (in comparison to other countries in the region) probably have the opposite effect towards more sensitivity for the electricity price.

* Reliable information on the ability and willingness to pay in Kenya would require an in-depths analysis which would go beyond this master plan. In addition, this issue is uncertain for the domestic sector in Kenya since it strongly depends on the actual and perceived socio-economic situation of the consumers where reliable information does not exist and future developments are uncertain (see Annex 3.C.5 for data availability).

* Electricity tariffs in Kenya have fluctuated a lot during the past years with, for instance, domestic tariffs nearly doubling if particular months are compared. This is mainly caused by highly fluctuating Fuel Cost Charge (FCC) and, to a lesser extent, the Foreign Exchange Rate Fluctuation Adjustment (FERFA) which change every month. The range of average annual tariffs is much lower. Since the peak in mid-2014, average tariffs have decreased within one year (due to commissioning of new power generation plants but mainly due to the fall in oil prices) by about 20% to 30% from its peak in July 2014 but only 10% to 15% compared to the average 2014 tariffs. The government aims at further reducing the tariffs during the next years by the introduction of low cost new power generation sources. This should in return facilitate economic growth and increase the demand.

3.2.7 Load characteristics

This section describes the historic development of the load characteristics, e.g. the development of the load during the day and throughout the year. In combination with the electricity consumption, the analysis of load characteristics helps to identify periods of tight power supply (in particular the time of highest load) and define the needs and indirectly also the costs for power generation at any given time. Compared to electricity consumption, the information available on load is often much smaller as respective metres are often limited to the main sections of the transmission system (e.g. power plant sent-out and high voltage substations). This is also the case for Kenya[50].

1) Annual maximum load

* The national annual peak load in Kenya grew at around 4.5% per year during the past 15 years. Growth rates have increased so that for the recent 10 and 5 years they were on average at 5.5% and 6.5%, respectively. Exceptional growth rates of up to 10% appeared in 2012 and 2013. Between 1998 and 2001 peak load was stagnant or decreasing. This development is very similar to the growth of energy consumption with slightly higher growth rates for the peak load.

[50] Load is measured electronically (half-hourly basis) for all power generators, most of high voltage substations and some feeders to the distribution network. Various high voltage substations are not measured or measurement is done manually and not recorded electronically. Consumer group specific load data (e.g. for large customers) are not available or limited to the monthly peak. This limits detailed load analysis.

- The recent growth means on average more than 100 MW (+ reserve margin) additional capacity was needed per year. Earlier, it was only 20 to 70 MW per year.

- In 2015, the annual peak load of the system[51] was in the range of 1,550 to 1,570 MW; about double the peak load of the financial year 2002/2003 (786 MW).

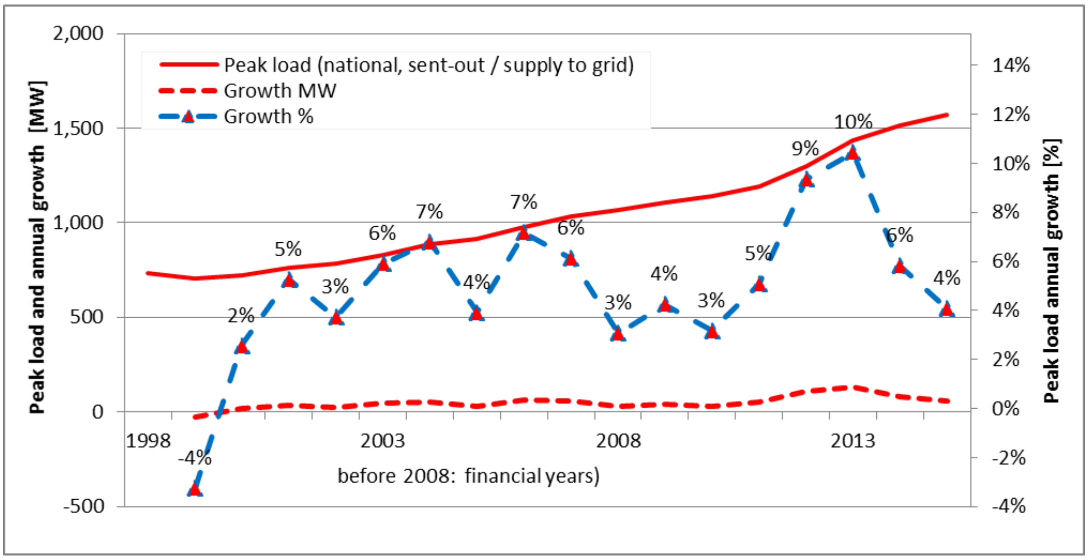

Figure 3-9: Annual peak load and annual growth rates (1998 - 2015)

2) Seasonal load characteristics

- Determined by continuous growth of demand throughout the year, the development of monthly peak loads shows one main maximum towards the end of the year, mainly occurring in November or December (see Figure 3-10 and Annex 3.D.6).

- There is no other significant seasonality of monthly peak loads but a stagnating peak demand at the beginning of most years until April (see red line in Annex 3.D.6).

- The peak of most other months is only about 2 to 10% (5 to 120 MW for 2015) below the annual peak[52].

[51] The annual peak load is the highest total simultaneous domestic (imports included, exports deducted) demand for a calendar year. There are different figures for the annual peak load depending on the definition: for 2014/2015 the KPLC annual report states for that financial year 1,512 MW. The annual peak load of the calendar year 2014 was also 1,512 if load shedding is considered (as measured on 26.11.2014 8pm considering in addition to the actual measured load estimated load shedding of 50 MW). As far as available the latter definition is applied for the analysis in this study. If not available the annual (served) peak load for the calendar year according to the hourly data of the National Control Center (system gross, at generator output) is assumed. For 2015, this was 1,560 – 1,569 MW measured 28 October 2015.

[52] Therefore, the required peak capacity of the year should be already available at the beginning of the year.

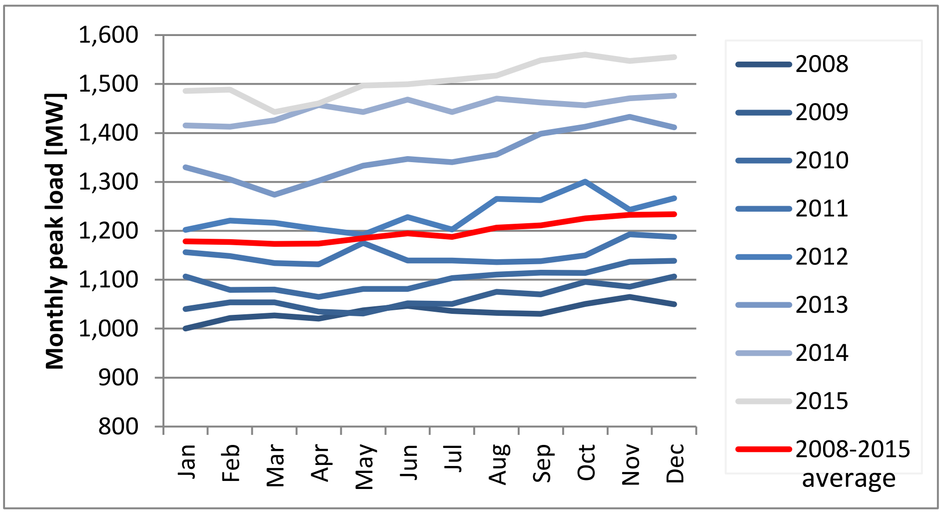

Figure 3-10: **Monthly peak load (2008 - 2015)**

3) Weekly and daily load characteristics

The daily load of the national grid is determined by

- A very distinctive evening peak between 7 pm and 11 pm. The highest peak mostly occurs between 8 pm and 9 pm with load on average 30% above the daily average load.
- A rather flat minimum between midnight and 6 am, 25% below the daily average load.
- A plateau between 8 am and 7 pm, during the second half of the year with a small maximum around 9 am slowly reducing until 7 pm.

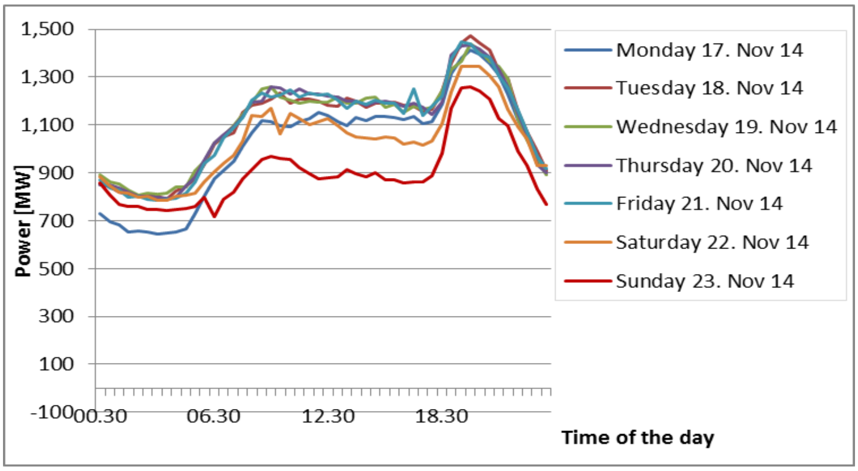

Figure 3-11: **Weekly exemplary daily load curves November 2014**

- Only minimal variation within a year and throughout the past years[53] with no long term trend.

- Variation by day of the week only for Sunday with overall reduced load. This reduction is most distinctive during the day (i.e. 8 a.m. to 7 p.m.) which leads to a relatively stronger evening peak. Saturday load curves are similar to Monday to Friday so that Saturday can also be categorized as a weekday. The highest daily electricity consumption on average is between Tuesday and Friday. It is slightly lower by about 5% on Mondays and Saturdays and 15% lower during Sundays.

- All in all a relatively stable shape of the load curve, which is only gradually growing throughout the year, is of benefit for the operation and expansion of the power system as no major seasonal fluctuations have to be considered. However, the distinctive evening peak requires the power system operation, for nearly each day of the week, to double the load during day and reduce it again by 50% (e.g. up to 800 MW in 2014) within few hours. This requires a high share of generation capacity to be capable for intermediate and peak operation. It is also an opportunity for measures to reduce this evening peak.

- The load factor, the average load faced by the Kenyan power system, varied in a relatively small range of 67% to 71% during the past decade (see Figure 3-12). In recent years the load factor was rather on the lower level because of the faster growth of peak load compared to consumption[54]. Below these key consumption characteristics are displayed.

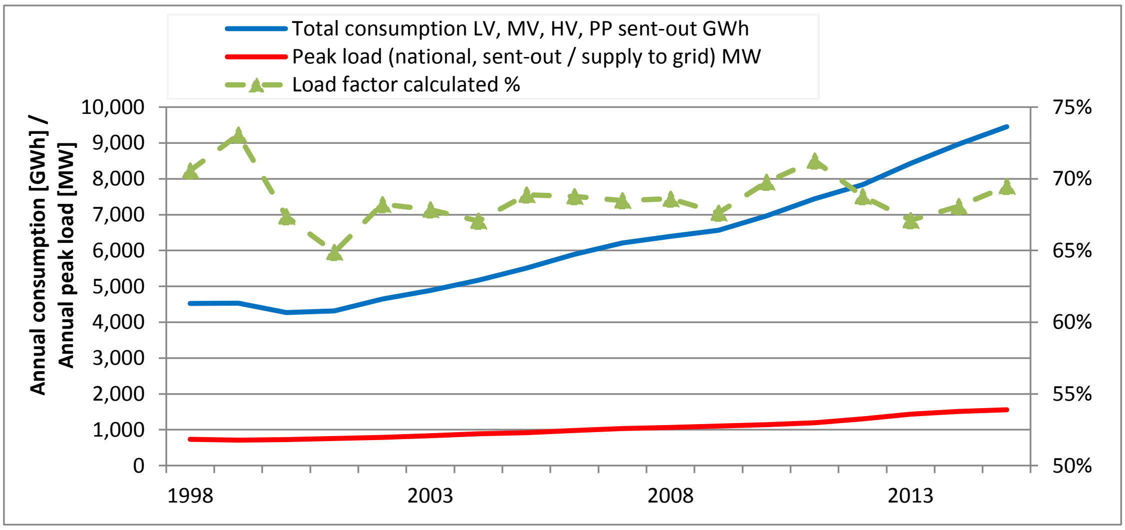

Figure 3-12: Annual generation, peak load and load factor (1998 - 2015)

[53] See Annex 3.D.6 for figure series of four weekly sets of exemplary load curves for each quarter of the years 2008 and 2014 and more detailed analysis of changes of load curve

[54] The reasons for variations of the year on year load factors are not known. They may be caused by a change or stop of load shedding (e.g. by adding sufficient capacity) or by extraordinary events. Consumption characteristics and the share of consumer groups (see sections above) may only change gradually and hence should rather have an effect on the load factor in the medium to long term.

4) Consumer group load characteristics

The analysis of the contribution of different consumer groups to the overall load curve can facilitate the forecast of demand if the share of consumption by consumer group is expected to change. This analysis however is strongly restricted due to the availability of data[55]. Hence, the below consumer group specific load factor and a responsibility factor (i.e. the customer group's contribution to system peak load) is only an indication which should be complemented if further data is available.

Table 3-3: Consumer group load characteristics

	Load factor	Source	Responsibility factor	Source
Domestic	56%	Nairobi North substation (mainly domestic) analysis	83%	Same as for load factor
Street lighting	50%	Calculation (in operation 12 hours, 365 days)	100%	In operation for whole evening peak
Small commercial	50% - 60%	Assumed to be similar to large consumers	67% - 90%	Same as for load factor
Large commercial & industrial	50% - 60%	Juja, Embakasi, Ruaraka, Eldoret (mainly industrial) substation analysis & power system area loads	50% - 90%	Same as for load factor

5) Power system area load characteristics

The load curves of the different power systems differ as illustrated in the selected load below:

- The load in Nairobi is several times the load of each of the other power system areas for the obvious reason of the high concentration of electricity consumption in this area.
- The evening peak in Mt. Kenya and Western area are more distinctive. This is also reflected in a lower load factor (58/59% in comparison to 65% and 69% for Nairobi and Coast, respectively). This is probably caused by the lower share of large industrial and commercial consumers which usually contribute a base load demand to the system. The envisaged further electrification of domestic consumers in these areas will further increase the evening peak and, as consequence, decrease the load factor.
- Compared to Mt. Kenya and Western, the evening peak of the Coast area is smaller. The overall load is more levelled with higher minimum load and the highest power system area load factor of 69%. This is caused by the high share of large commercial and industrial consumption and additional demand to power air conditioning due to the higher temperatures in the region.

[55] To analyse load characteristics by consumer group distinctive data sets for these consumer groups have to be available with certain level of detail (hourly load) and for a longer periods. This study and the below listed parameters rely solely on hourly data of few substations which serve areas where particular consumer groups dominate the consumption as well as power system area load data.

- The annual peaks in all areas occur in the evening at around 8 p.m., though at different times of the year. The peak in Nairobi and Western area occur in November, close to the power system peak. The peak in Mt. Kenya and Coast area are in May and March, respectively. However, the coincidence peak demand of the power system areas (i.e. the load during power system peak) is rather high (only 10 to 15% below their annual peaks).

- In conclusion, there is little effect of different load characteristics in the power system areas since the load curves do not differ much and the Nairobi area dominates the overall load characteristics. With growing consumption and electrification in West Kenya, the power system might be further challenged by an increasing evening peak, both in term of power generation and transmission links to these areas. The more balanced load of the Coast area with relatively high demand during the power system off-peak time in the night is expected to have a positive effect on the overall system, in particular if the industrial and commercial development in this area develop further and the transmission links are available.

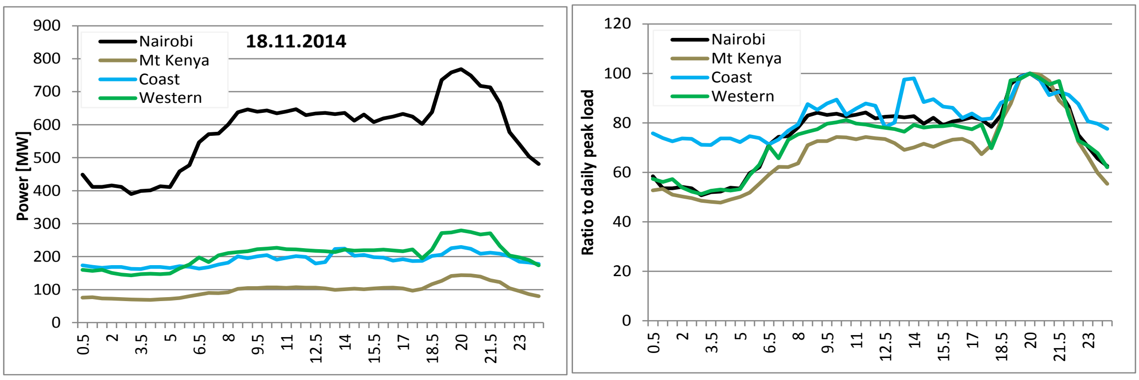

Figure 3-13: Power system area exemplary daily load curves (Tuesdays) November 2014[56]

3.2.8 Suppressed demand

Suppressed demand (also called non-served demand) is defined as demand for electricity which cannot be met by means of the national electricity supply due to various technical and economic limitations. Suppressed demand can only be estimated because of its wide range of interlinked causes and, in most cases, insufficient data basis. The following list provides estimates for different categories of suppressed demand in Kenya:

1) Load shedding due to insufficient power supply or transmission capacity (especially during peak hours): since sufficient power generation capacity exists in Kenya, there has been no load shedding with regard to insufficient generation capacity for some years. For transmission capacities, there are various restrictions e.g. for lines to and in Western area and Coast area. Available data for 2014/2015 show that load shedding focussed mainly on the Western area during evening hours indicating an overloaded network with a possible suppressed demand of

[56] The column on the left shows the actual connected half hourly load; the column on the right shows the half hourly load normalized by the daily power system area peak. Load curves for other periods of the year are provided in Annex 3.D.6.

only 0.1% of national electricity consumption[57]. New lines with higher capacity are under construction and should mitigate the adverse effect (see chapter on electrical network expansion).

2) Curtailed demand due to poor security and quality of power supply (in particular during peak hours): this leads to either self-supply of electricity and utilisation of energy substitutes or lack of connecting equipment or non-replacement of broken equipment. The quality and stability of power supply in Kenya greatly differs from area to area. The records of incidents available[57] clearly show that the grid in the Western area is the least stable. With more than 10 incidents per month on average, it can be expected that this has a strong effect on the consumption patterns in the region. Also for the other regions, widespread own supply is reported. On distribution level, low quality and lack of security of supply is more frequent. No comprehensive long-term statistics on system failures were available but various sources indicate a low quality and respective widespread curtailed demand due to lower quality or overloading of the distribution system. A recent World Bank survey[58] indicates, for the interviewed entities, outages during 4% of the time and 8% of generation from own generators. Based on this survey[59] and surveys conducted for this study, a curtailed demand caused by shortcomings of the electrical network of 10%[60] of the actual consumption is assumed (i.e. some 836 GWh for 2014). This estimate has to be considered as very vague.

3) Insufficient ability to pay for connection and electricity: though electricity is available in many areas, not all potential customers are connected. The main reason is the insufficient income to pay for connections and electricity (see Annex 3.C.5 for socio-economic details).

4) Insufficient coverage of power grid: currently, only a small portion of potential customers are connected to the grid since the electrical network does not cover all populated areas (see section 3.2.2). Together with the previous bullet point this causes the low connectivity level.

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[57] There are two statistics available:
i) Load shedding Summary 2013-08-01 to Date (Apr2015) - detailing system failure incidents and resulting load shedding: some 10 GWh lost (nearly 90% during evening hours) in 2 years and 300 incidents (12 per month), average shed load of 30 MW. This is, on average, less than 0.1% of the total national consumption.
ii) MD14-15 detailing load shed per power system area and day for the period July 2014 to May 2015 to calculate theoretical peak load: nearly only in Western area, on average 25 MW during evening hours, 11 times per month, maximum was 90 MW in March 2015, energy shed could amount to 50 MWh (assuming a duration of one hour) which is less than 0.001% of the 2014 total electricity consumption in Kenya

[58] Source: World Bank, *Doing Business 2015* (2014) www.doingbusiness.org (accessed 1.5.2015)

[59] Although, these figures derive only from one consumer group, they currently are the most comprehensive data available on suppressed demand from consumer perspective.

[60] In previous LCPDP reports, suppressed demand for load is assumed to be 100 MW. This is around 7% of the served peak load. With regards to electricity consumption the share would be less.

3.3 Electricity transmission and distribution

This section provides a brief description of the electrical network in Kenya with currently valid standards and planning criteria as well as the main challenges.

3.3.1 Existing power grid

This section briefly describes the Kenyan power system:

- The transmission network comprises of a 220 kV national grid[61] branching into 132 kV and 66 kV levels. The existing network was designed for an operating voltage level up to 220 kV, though a higher voltage level of 400 kV is under implementation[62]. The nominal fundamental system frequency is 50 Hz.

- The distribution network comprises the voltage levels of 33 kV and 11 kV and the low voltage system. Electricity is supplied to end consumers on different voltage levels up to 132kV.

- The transmission system is divided into four main areas. They are presented in the table below with further sub divisions for the larger areas in the network.

Table 3-4: Network[63] Areas / Power System Areas in the Kenyan system

Power System Areas	Nairobi	Mount Kenya	Coast	Western
Sub areas /	Nairobi South	Mt. Kenya North	Coast	North Rift
sub divisions	Nairobi North	Mt. Kenya South		Central Rift
	Nairobi West			West Kenya

- The interconnected system has been operated by KPLC which owns most of the network built in the past. The transmission company KETRACO established in 2008/2009 owns part of the high voltage lines and is developing the majority of new transmission lines (more than 4,000 km under construction or planned) and substations.

- Power generating plants are distributed in the country, some in far distance from the load centres; others support local load. The total installed capacity has increased to some 2,300 MW by the end of 2015 and 2016 with an effective capacity of some 2,200 MW to serve a peak load demand of around 1,600 MW.

Annex 3.E contains a map which provides an overview of the existing network and planned network extensions.

[61] This study focusses on the national grid. Besides the national grid there are isolated grids with own generation and local distribution (33 kV and 11 kV level). Some may be connected to the national grid in the future.
[62] Several 400 kV transmission lines and substations are under construction and in the planning phase.
[63] “Network Areas” » and “Power System Areas” have the same meaning in this report

3.3.2 Challenges to the network and committed / planned expansions

Although considerably expanded and strengthened in the past, the Kenyan electrical network faces various challenges in the medium and long term, for instance:

- Electricity supply from remote power plants (such as Turkwel Hydro Power Plant) which are located at relatively long distances from the large load centres (e.g. over 500 km from Nairobi which accounts for some 60% of the load). Several other production sites are also locally supporting the load demand, especially in the Central Rift and in the Western part of the country.

- Increase in load from the existing load centres through existing and partly overloaded network (in particular to Western and Coast area) thereby increasing losses, the risk of line tripping and increasing the need for reinforcements.

- The relatively high reactive power consumption: the supply of the largest consumers (i.e. Nairobi area) is achieved through line connections with relatively long electrical distances to the main generation feeding points.

- The government's plan to considerably increase the rate of electrification of the country both in terms of counties and households connected (in particular in remote areas in West and North): this requires a significant increase of investments in electrification projects across the whole the country and corresponding expansions of generation, transmission and distribution capacities.

- Levelling the seasonal fluctuation of hydro power generation and firm capacity with thermal generation at other generation sites (this may induce specific loading constraints on the grid).

- Integration of generation from intermittent renewable energy sources such as wind and solar energy: requiring an efficient monitoring and dispatch system.

To face these challenges, and supported by numerous planning studies for expansion and strengthening of the existing network, several projects are under construction and in the tendering phase. Some key observations are listed below (more detailed analysis and the projects are presented in chapter 8):

- The implementation of the planned generation plants (partly in remote areas) will require the extension of the transmission network, especially the 400 kV system (or even implementation of higher levels), in order to evacuate the power in a secure way and to cover all areas of the network.

- The analysis of alternatives with multiple circuit configurations and a division of large load centres into multiple substations e.g. 220 kV/400 kV with a defined firm capacity (e.g. 3x200 MVA – 2X350 MVA) will be indispensable.

- Achieving the expected high demand growth will also require a significant investment in electrification projects across the whole of the country with adequate expansions of transmission and distribution capacities.

- Failure to implement the envisaged generation projects, lower connection rates to the distribution networks, and inadequate network's expansion will inevitably lead to lower levels of served electricity demand, load supply constraints and load shedding.

3.3.3 Losses

This section details the historic development of technical and non-technical losses in the national power grid of Kenya and provides an outlook with regard to loss reduction measures and assumptions for the planning period.

3.3.3.1 Data availability and overview

Data on overall losses are available[64] for the financial years 1997/1998 to 2014/2015. Detailed data differentiating between transmission (high voltage: 132 kV and above), distribution medium voltage and low voltage are available for the financial years 2008/2009 to 2013/2014. An estimate on commercial losses is available only for the financial years 2012/2013 and 2013/2014. KPLC is currently the main organisation collecting and analysing losses (for distribution and transmission).

The table below indicates the evolution of losses by voltage level and as share of gross national electricity consumption[64].

Table 3-5: Losses in the Kenya electrical network 2010 to 2015[64]

	2010	2011	2012	2013	2014	2014/2015[64]
Total	**16.1%**	**16.8%**	**18.0%**	**18.3%**	**17.9%**	**17.6%**
HV	3.7%	4.0%	4.2%	4.3%	4.7%	4.9%
MV	5.1%	5.3%	5.6%	5.4%	5.0%	Not known
LV (including non-technical/commercial losses)	7.3%	7.5%	8.3%	8.6%	8.1%	

Information on loss reduction plans derive from a KPLC strategy paper[64] and targets set by ERC:

- For overall losses target: ERC set a declining maximum loss ceiling for KPLC at 16.8% for 2013/2014 down to 15.9% in 2015/2016 to encourage loss reduction within KPLC and Ketraco. Losses beyond that ceiling are not reimbursed through the tariffs. Total losses has have always been higher than these figures though KPLC reduced the losses (as percentage share) during the past year. KPLC states a target of 16% for overall losses in 2017/2018 (assuming an annual loss decrease by 0.5 percentage points).

[64] Source: KPLC annual reports / accounts; all loss figures for calendar years (derived from KPLC financial years annual accounts, see also definitions at 4.4) except for 2015 which represents 2014/2015 financial year's figures, source transmission losses: KPLC STRATEGIES TO REDUCE SYSTEM LOSSES (value until February 2015); KPLC data on losses also include losses for power exchange. For this study losses were estimated for the share of electricity which has been consumed in Kenya only (gross national consumption).

- For the transmission losses target: the KPLC sets the target to 3.5% after completion of the Nairobi -Mombasa 400kV line through measures like reactive compensation equipment and optimal dispatch of power plants with regard to losses.

- For the distribution losses target: KPLC is working on loss reduction within the Distribution System Reinforcement and Upgrade component of the World Bank financed Energy Sector Recovery Project (ESRP) through measures like new substations, intensified maintenance, reactive power compensation, improving MV network (extending MV network together with small distribution transformers to shorten LV lines). A loss reduction study within the above component is not available yet. It may provide further information for future updates.

Loss reduction is not an independent target. It should be a result of a cost benefit analysis of loss reduction measures, their costs and the cost of losses. The below estimates on future losses for the different voltage levels should be understood as assumptions (but not results) within this context. Overall losses are calculated in the demand forecast as they depend on the share[65] of LV, MV and HV consumers.

3.3.3.2 Technical losses in transmission

Transmission losses were 4.9% of gross national electricity consumption (power plant sent-out) for the financial year period until February 2015. The share of transmission losses have continuously increased from 3.7% in 2009, 4.2% in 2013, and 4.5% in 2014. This increase is partly due to the delay of some major transmission lines (e.g. Nairobi – Mombasa; Olkaria – Kisumu). Their commissioning will immediately reduce the losses.

For this study, it is assumed that the transmission losses will stay in the historic range:

- 4.5% in 2016;

- Towards the end of the medium term period (2020) they are expected to decrease to 4.0% mainly due to the commissioning of new transmission lines.

- In the long-term the losses are expected to increase again to 4.5% (2035).

These assumptions are above the official target (see above). 4 to 4.5% is assumed as a more realistic target for the medium and long term considering the continuously increasing load and the longer distances to evacuate power from committed and candidate power plants. This might outpace the effects of growing transmission capacity and loss reduction measures.

3.3.3.3 Technical losses distribution

Technical losses in the distribution grid (LV up to 66 kV) were estimated at 6.6% (5.2% for the MV level and 1.4% for LV lines) of gross national electricity consumption at the end of the financial year 2013/2014. The above stated decrease of overall losses (until 2014/2015) together with an increase of transmission losses means that either technical or non-technical distribution losses decreased. Detailed figures for 2014/2015 are not available. For technical losses this reduction could

[65] A further shift of consumption to HV consumers might reduce overall losses.

come from recently completed measures such as loss reduction substations, reduction of transformer distances, and network improvements in slum areas. The distribution company plans to further reduce the losses by several measures[66].

For this study, it is considered reasonable that the losses will stay at or slightly above the level of recent years (despite planned measures). For the MV a slight increase to 6.0% of electricity fed into MV network is assumed for the entire study period. This is a conservative assumption to account for the on-going and envisaged expansion of the distribution grid into less densely populated areas with longer line lengths causing higher losses. This may be partly offset by the loss reduction measures.

3.3.3.4 Non-technical losses

Non-technical[67] energy losses (also called commercial losses in Kenya) are estimated at 6.9%[68] of gross consumption for 2013/2014. Another estimate for 2012/2013 published in the LCPDP 10 year plan puts them at 4.6%. This variation shows the difficulty to assess the extent and causes of non-technical losses not to mention achieving a reduction. Compared to other African countries (e.g. Uganda) the level of non-technical losses is already on the lower side. Energy theft and defaulted payments probably contribute the highest share. Pre-paid meters accounted for about 25% of all connections (some 677,000) in 2014. This metering technology provides the opportunity to reduce non-technical losses through a further implementation. This is also foreseen by KPLC. However, there were considerable problems with previous efforts to introduce pre-paid meters.

For this study, it is assumed that the non-technical losses together with technical losses on the LV level will stay at 12.9% of electricity fed into LV network (about 8.4% of electricity fed into HV network through this share depends on the ratio of LV, MV and HV consumers). This is the level of the past years throughout the planning period. The split into technical and non-technical losses might vary depending on electrification and kind of reduction measures. However, this split is not needed and beyond the scope of this study.

3.4 Electricity supply (generation)

This section provides a brief introduction to the overall Kenyan electricity supply (generation) system, including the existing power plants and the historic development of installed capacity and electricity generation. Detailed information on existing power plants is provided in Annex 3.F.1 and – for power plants based on renewable energy sources - in the separate report on renewable energy sources (Long Term Plan – Renewable Energy) submitted with this report. Information on committed and planned power plants is provided in section 6. The section concludes with current and expected future challenges to the power supply.

[66] These are: Energy balance module to identify loss levels by region, voltage and feeders; Optimisation of assets to improve load factors of transformers; Distribution automation; Enhance informal settlements electrification under GPOBA; Data collection (e.g. GIS rollout, feeder and transformer metering) and analysis.
[67] Non-technical energy losses are understood as not billed energy that has been consumed by consumers (legally or illegally). Collection losses (which are billed) are assumed to be not included.
[68] Source: KPLC Infrastructure Development Division

The current Kenyan power supply system can be summarised as follows:

- It is one of the most well-established electricity supply systems in Sub-Saharan Africa.

- Most of the generated electricity is consumed domestically; exchange with neighbouring countries is negligible.

- Insufficient electricity generation capacity and an unreliable power supply have been perennial problems in the last decades. Also, a lack of integration between planning and implementation has plagued the Kenyan economy.

- Hydropower has long dominated Kenya's generating capacity. Its dependence on rainfall makes it unreliable. Severe droughts since the 1990s virtually paralysed the electricity supply system. Power cuts were widespread and commerce and industry suffered significant losses. To date, a large share of the electricity is still generated from hydropower. Poor hydrology has necessitated the use of expensive fossil fuel based and rented generation in recent years.

- As a consequence the government set the objective to reduce the country's dependence on hydropower as well as imported fossil fuels. One corresponding development is its geothermal procurement programme. Today, Kenya is Africa's largest producer of geothermal energy and continues to invest heavily in this sector. In recent years, electricity generation has been also given high political priority as a key macroeconomic enabler to boost the country's economic growth. Planning has been initiated for considerable new generation capacities based on renewable as well as fossil energy sources. In 2013, this was summarised under the 5000+MW generation plan which has been adapted in scope and scheduling various times.

- The fundamental reform of the electricity sector (see section 3.1) also affected electricity supply with successful unbundling of the power generation sub-sector and a small but successful independent power producer (IPP) procurement programme. It has been running since the mid-1990s, when KPLC started to procure power from IPPs. As a result, Kenya had been able to attract more IPPs than any other African country.

- Besides the interconnected national electricity grid, there are 16 isolated grids[69] in Kenya

3.4.1 Existing power plants

Table 3-6 gives an overview of the net generation capacity at the end of 2015. It can be seen, that in total 2,302 MW have been installed (excluding captive supply), out of which 2,213 MW can be accounted for effective power plant capacity. The values stated relate to the technically general effective capacity available to the grid. Concerning hydropower plants, their actual available capacity also depends on the hydrology. End of 2016 capacity is expected to slightly reduce to 2,294 MW and 2,205 MW (due to expiry of Aggreko Emergency Power and little capacity additions, see 3.4.2).

[69] For further information see 3.2. This study focuses on the supply through the national grid.

Table 3-6: Existing power generation facilities at the end of 2015

Source / Plant Name	Operator	COD	Fuel Type	Capacity [MW]	
				Installed	Effective
Hydro					
Tana	KenGen	1955	Water	20	20
Masinga	KenGen	1981	Water	40	40
Kamburu	KenGen	1974/1976	Water	94	90
Gitaru	KenGen	1978/1999	Water	225	216
Kindaruma	KenGen	1968	Water	72	71
Kiambere	KenGen	1988	Water	168	164
Turkwel	KenGen	1991	Water	106	105
Sondo Miriu	KenGen	2008	Water	60	60
Sang'oro	KenGen	2012	Water	21	20
Small hydropower	KenGen, IPP	until 2015	Water	15	14
Sub-Total				**821**	**800**
Thermal					
Kipevu 1	KenGen	1999	HFO	75	59
Kipevu 3	KenGen	2011	HFO	120	115
Embakasi Gas Turbine 1	KenGen	1987/1997	Kerosene	30	27
Embakasi Gas Turbine 2 (Muhoroni) [70]	KenGen	1999	Kerosene	30	27
Athi River Gulf	IPP	2014	HFO	80	80
Triumph	IPP	2015	HFO	77	77
Iberafrica 1	IPP	1997	HFO	56	56
Iberafrica 2	IPP	2004	HFO	53	53
Rabai Diesel	IPP	2009	HFO	90	90
Thika	IPP	2014	HFO	87	87
Tsavo	IPP	2001	HFO	74	74
Aggreko Emergency Power [71]	EPP	2008	AGO	30 [71]	30
Sub-Total				**802**	**775**
Geothermal					
Olkaria 1 - Unit 1-3 (= Olkaria 1)	KenGen	1981	Geothermal	45	44
Olkaria 1 - Unit 4-5 (= Olkaria 1AU)	KenGen	2014	Geothermal	140	140
Olkaria 2	KenGen	2003	Geothermal	105	101
Olkaria 3 - Unit 1-6 (OrPower4 Steam I)	IPP	2000	Geothermal	48	48
Olkaria 3 - Unit 7-9 (OrPower4 Steam II+III)	IPP	2013/2014	Geothermal	62	62
Olkaria 4	KenGen	2014	Geothermal	140	140
OrPower Wellhead 4	IPP	2015	Geothermal	24	24
Olkaria Wellheads (OW37, 43, 914-915)	KenGen	2012-2015	Geothermal	56	53
Eburru Hill	KenGen	2012	Geothermal	3	2
Sub-Total				**622**	**614**
Wind					
Ngong 1, Phase I-II	KenGen	2008/2015	Wind	26	26
Cogeneration					
Mumias [72]	IPP	2008	Bagasse	22	0
Kwale [73]	IPP	2015	Bagasse	10	0
Sub-Total				**32**	**0**
Total				**2,302**	**2,213**

[70] Relocated to Muhoroni in 2016

[71] 30 MW contracted until mid of 2016 (capacity replaced by relocated KenGen gas turbine); Aggreko Emergency Power once accounted to a total of 120 MW

[72] Due to fuel supply issues no supply of electricity to the grid for most of 2015 and 2016; recommissioning to the grid assumed for expansion planning from 2018 onwards

[73] Kwale power plant commissioned for own supply; power supply to the grid foreseen from 2017 onwards

Figure 3-14 shows the existing power plants in Kenya, categorised according to type and size of the plant. A zoomed in version is provided in Annex 3.E focusing on the area where most power plants are located. Annex 3.E also contains a brief description of the main power plant sites.

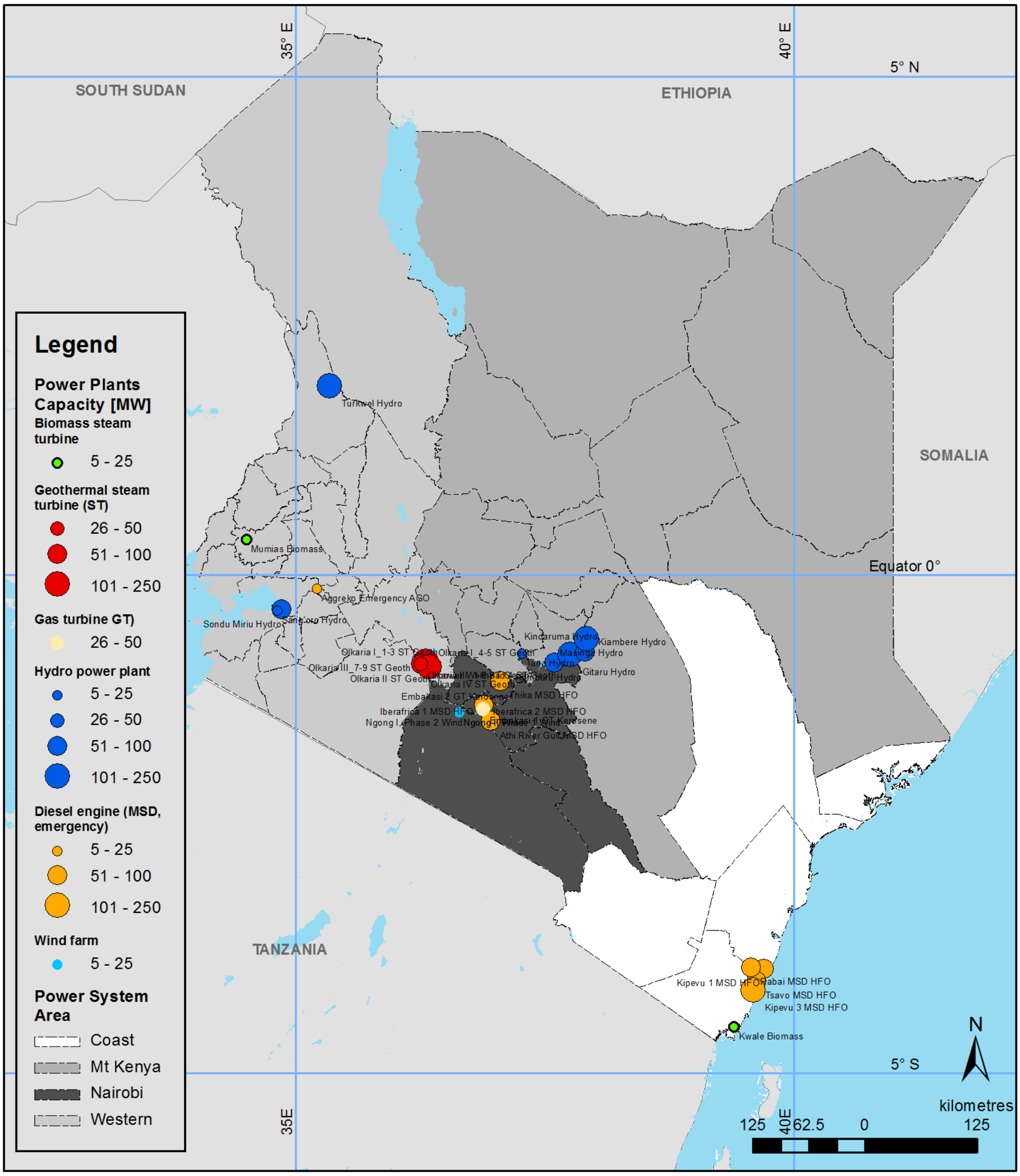

Figure 3-14: Map of Kenya – existing power plants (end of 2015)

3.4.2 Installed capacity – historic development

In the last 10 years the peak demand of the Kenyan power system grew from 830 MW in financial year 2003/2004 up to 1,500 MW in 2014 and nearly 1,600 MW in 2015. This represents an average annual increase of 6%. In the same time the available capacity grew with a similar rate from some 1,200 MW in 2004 up to the level of 2,213 MW by the end of 2015:

- In the period 2004 to 2007 no new capacity had been added to the power system
- In 2008 the 60 MW Sondo Miriu hydro power plant, the first phase of the wind farm Ngong Hills (5.1 MW) and the cogeneration biomass plant Mumias (21.5 MW) were commissioned and 120 MW of Aggreko rental diesel power plants were contracted for emergency purposes.
- In 2009, the combined-cycle MSD power plant Rabai became operational (90 MW).
- In 2011 the MSD plant Kipevu 3 was commissioned (115 MW) and the two Kipevu gas turbines were relocated to the site of Embakasi (54 MW).
- In 2012, Sang'Oro HPP (20 MW) got operational, downstream of Sondu Miriu HPP.
- In 2013 Olkaria 3 – Unit 7-9 (62 MW, Orpower4 Steam II and III) was added to system.
- In 2014, Athi River Gulf MSD TPP (80 MW), the combined-cycle MSD Thika TPP (87 MW) and the two geothermal power plants Olkaria 1 - Unit 4-5 (140 MW, "Olkaria 1AU") and Olkaria 4 (140 MW) were commissioned.
- In 2015, the geothermal plant OrPower Wellhead 4 (24 MW), further phases of the wind farm Ngong Hills (7 MW and 14 MW) and the cogeneration biomass plant Kwale[74] (18 MW of which 10 MW are foreseen for the national grid) were commissioned.
- In 2016, KenGen Olkaria Wellheads II (20 MW), Biojoule biomass (2 MW) and KTDA Chania small hydropower (1 MW) were commissioned (though during the third quarter of 2016 KTDA Chania was not connected to the grid yet). The contract with the Emergency Power Producer in Muhoroni, Kisumu (Aggreko, 30 MW) expired mid of 2016 after its capacity to support the network in Western Kenya was replaced by one gas turbine (relocated from Embakasi).

The development of the available capacity in Kenya is visualised in Figure 3-15. It can be seen that

- The dominance of hydropower capacity in the overall installed capacity (60% in 2004) has reduced over time to below 40% in 2015. Since 2004, only 80 MW of new hydropower capacity has been installed.

[74] According to the Kenya Sugar Board, at the end of 2015 Kwale co-generation plant was commissioned for own supply but has not been feeding into the grid. For this study it is assumed to feed into the grid from 2017 onwards.

- The share of fossil fuel based thermal power plants increased from 25% to more than 30% during the same time.

- Geothermal power plants showed the largest increase: they ramped up their capacity from 180 MW in 2004 to 622 MW in 2015. As a result, their share increased from 15.5% in 2004 to more than 26% in 2015.

- Renewable energy sources other than hydro and geothermal accounted for 3% in 2015 only.

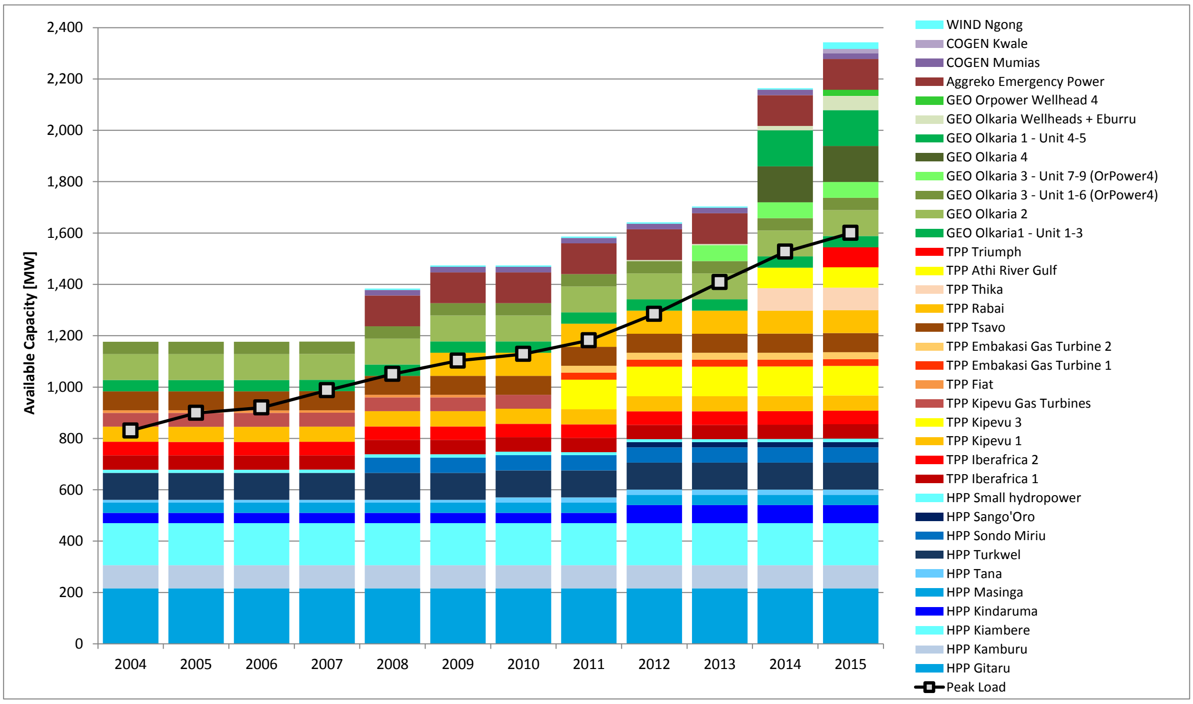

Figure 3-15: Development of annual available capacity and peak load (2004 to 2015)

3.4.3 Annual electricity production – historic development

In 2009, some 6,500 GWh of electricity were produced in Kenya. In 2014, the level of production raised up to above 9,000 GWh and is estimated with 9,500 GWh for 2015. This corresponds to an average annual increase of 6.5%. The main development to the energy mixes for the past years are shown in the figure below (details on the development of annual net generated electricity between 2009 and 2014 by power plant is given in Annex 3.F) and can be summarized as follows:

- Power generation relies on a multitude of power plants. However, some larger plants e.g. Olkaria II, Gitaru, Kiambere, Turkwel and Iberafrica alone provide about a third of electricity.

- Hydropower plants generated 2,110 GWh in 2009, increasing to 3,407 GWh in 2014. However, 2009 was a dry hydrological year. The average annual hydropower generation in the last six years was 3,359 GWh. If there is a large amount of water available that can be used for the production of hydroelectricity, the hydropower plants show large capacity factors - e.g. on monthly basis the capacity factor rose above 60% in 2013. However, when there is only limited water available for the generation of hydroelectricity, the capacity factor can get very low – e.g. in 2000 in some months it accounted only for less than 15% on monthly basis. In such situations, the Kenyan power system faces the challenge of finding alternate sources of power to meet its electricity demand. In the last 24 years the average capacity factor of hydropower accounted for 47%. In the most years, the hydropower output was close to this average. In good years, e.g. in 2013, the annual capacity factor went up to 61%. However in bad years, e.g. 2000, 2001 and 2009 the annual capacity factors were 24%, 30% and 30% respectively. The development of monthly and annual hydro capacity factors between 1991 and 2014 as well as the monthly development of generation by power plant and energy mix are depicted in Annex 3.F.

- Geothermal power plants produced 1,296 GWh in 2009 and 2,775 GWh in 2014. When comparing the combined generation of hydro power and geothermal power plants in 2013 and 2014, it can be seen, that its joint level remained constant at approx. 6,150 GWh. This is firstly due to the extraordinary good hydrology in 2013 and the average hydrology in 2014, and secondly due to the commissioning of Orpower4 Steam II and Orpower4 Steam III as well as of Olkaria IV and Olkaria I_4-5 (Olkaria 1AU). These newly built geothermal plants entirely compensated the loss of hydropower generation in 2014.

- Fossil fuel based thermal power generation accounted for 1,825 GWh in 2009 increasing up to 2,450 GWh in 2014.

- The share of emergency power (from rental Aggreko diesel plants) reduced from up to 20% of the entire Kenyan supply in 2009 to only a few percent until at the end of 2014 when it accounted for only 0.4% of the total generation

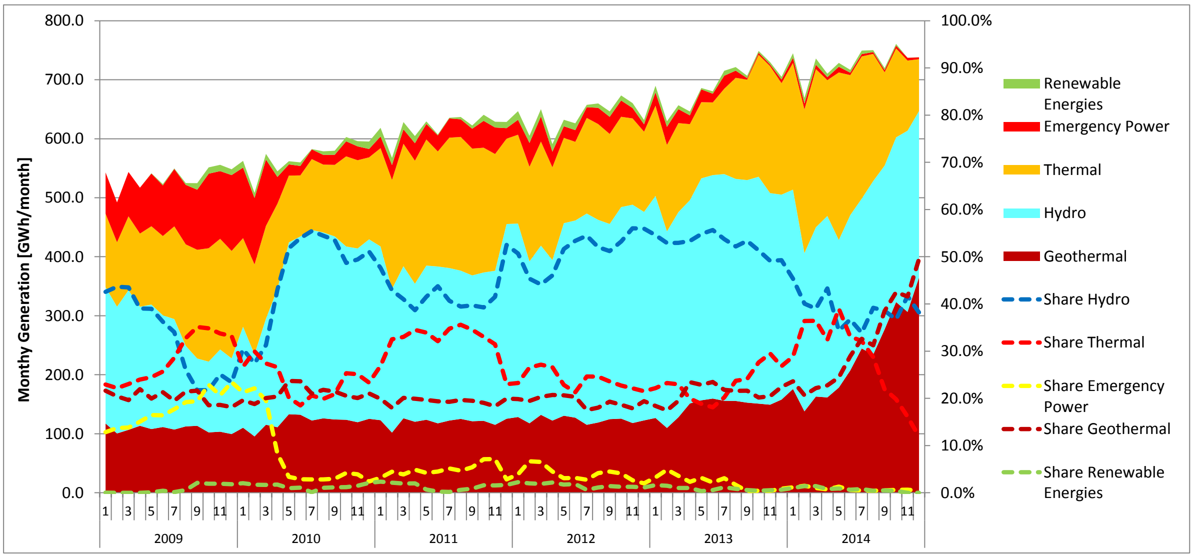

Figure 3-16: Seasonal energy mixes based on monthly generation (2009 to 2014)

3.4.4 Challenge to the future power system operation

The following characteristics and developments with regard to power generation pose a challenge for the current and future operation of the power system:

- The large share of hydropower generation capacity together with the potential for drought (and subsequent lower inflow of water) poses a risk to meet demand (both for energy and peak load). The share and thus the risk have been reduced considerably in recent years by adding geothermal and fossil fuelled power plants. However, short and long term hydrological changes are likely to increase since climate change is expected to affect East Africa adversely.

- The newly added large geothermal capacities are less flexible to meet peak load, load following and reserve power requirements than the medium speed diesel and hydropower plants. The reasons are technical and economic: they are designed and financed for continuous operation and hardly dispatchable. This challenge for the system will increase as more geothermal power plants are scheduled to be commissioned in the near future. However, they provide a secure, renewable base load energy source for reasonable costs.

- The addition of a large amount of wind power capacity in the near future will aggravate this: with no short run marginal cost and as a renewable energy source the power system should absorb wind power, whenever it is available. However, wind power is not dispatchable and intermittent. This increases the operational reserve requirements essentially.

- The main challenge for the system is thus meeting increasing reserve power requirements and growing peak load in the evening. The generation basis capable to provide this is limited, bearing in mind that even the current system can hardly provide sufficient primary reserve and often needs load shedding for frequency stabilisation. An interconnected system to neighbouring countries could support in these areas[75]. It is under implementation. But it is likely to take a longer time until a system is in place with all necessary technical and economic preconditions to exchange ancillary services such as reserve power.

[75] Including more flexible PPAs instead of "Take or Pay" clauses.

4 ELECTRICITY DEMAND FORECAST

This chapter provides the forecast for demand of electricity and power in the Kenyan national grid for the long term period 2015 to 2035. Further, the methodology is detailed and input parameters and assumptions are defined and summarised (e.g. demographics and demand characteristics as analysed and detailed in sections Annex 3.B and 3.2).

4.1 Key results and conclusions

The key results, corresponding conclusions and planning recommendations are:

- The objective of the demand forecast is to provide a sound basis for the power system expansion planning. A critical analysis and a selection of suitable scenarios reduces the impact of forecast uncertainty on the planning results. Considering the results will reduce the risk of costly over- or underestimating the size of the power system.

- The above objective is partly achieved by investigating a suitable range of scenarios:
    - Reference scenario: applying key assumptions for a probable development based on the historic development and actual plans (technical, demographic and economic issues diligently assessed).
    - Vision scenario: normative scenario; applying the wide range of largely ambitious government plans (e.g. 100% connectivity level by 2020; less challenged flagship project developments).
    - Low scenario: scenario for sensitivity and risk analyses; applying more conservative assumptions than reference scenario and similar to historic developments.

  The three scenarios describe a range from a worst (low) case to a best (vision) case. This range from 25% below (low) and 50% above (vision) of the reference scenario allows to analyse the economic and technical impact of demand uncertainty on mainly the generation expansion described in the successive chapters. The respective range of results should be carefully considered not focusing only on one scenario. Besides the scenario analysis the forecast approach combines various other methodologies to address Kenya specific availability of data and needs (e.g. trend-projection and bottom-up).

- Previous electricity demand forecasts for Kenya regularly overestimated demand (when compared to the actual demand growth in the medium term period). They also exceed by far the forecasted growth rates of similar African countries. They were also higher than actual growth of countries, which showed strong economic development in the past (similar to what Kenya is aiming at). Only very few countries in the world have shown such sustained high consumption growth rates as it has been forecasted for Kenya in the past.

- Policy targets for high demand were not reached for various reasons. This might have led to a situation where Kenya is currently one of the few African countries with sufficient available generation capacity to meet the demand and plenty of projects in the planning stage. However, the type of generation (e.g. mainly base load generation and import) might be more suitable for higher demand levels. Hence, policy targets should be reassessed more carefully and respective scenarios (including a conservative/pessimistic scenario) should be developed and considered to reduce risks and costs. The forecast scenarios within this study are in a more common range of growth rates with regard to the different benchmarks.

- Demand for electricity and annual peak load are expected to grow considerably for any scenario: electricity consumption is forecasted to grow in the long term by an annual average of 7.3% per year (reference scenario). Annual peak load is forecasted to more than quadruple from nearly 1,600[76] MW in 2015 to 6,700 MW in 2035 (vision: above 10,000 MW; low: nearly 5,000 MW). On average each year some 150 (low), 250 (reference), or 400 (vision) MW of capacity (plus reserve) have to be added to serve the growing peak load in the evening.

Table 4-1: Electricity consumption and peak load forecast – reference, vision, low scenarios (2015 – 2035)

Scenario		Unit	Growth LTP	2015[76]	2016	2020	2025	2030	2035
Reference with flagship projects	**Consumption gross**	**GWh**	**7.3%**	**9,453**[76]	**10,093**	**13,367**	**19,240**	**27,366**	**38,478**
	Growth	%		5.4%	7%	8%	9%	8%	7%
	Peak load	**MW**	**7.5%**	**1,570**[76]	**1,679**	**2,259**	**3,282**	**4,732**	**6,683**
	Growth	%		4%	7%	8%	9%	10%	7%
		MW		116	109	169	260	412	462
Vision with flagship projects	**Consumption gross**	**GWh**	**9.6%**		**10,592**	**16,665**	**25,469**	**39,260**	**58,679**
	Growth	%			12%	13%	10%	11%	8%
	Peak load	**MW**	**9.8%**		**1,770**	**2,845**	**4,431**	**6,833**	**10,219**
	Growth	%			13%	13%	12%	11%	8%
		MW			200	330	478	689	786
Low without flagship projects	**Consumption gross**	**GWh**	**5.6%**		**10,035**	**12,632**	**16,427**	**21,375**	**28,153**
	Growth	%			6%	6%	5%	6%	6%
	Peak load	**GWh**	**5.7%**		**1,669**	**2,116**	**2,769**	**3,618**	**4,788**
	Growth	%			6%	6%	5%	5%	6%

- The assumed electrification targets considerably increase the number of for any scenario: more than 10 million additional domestic connections (to the existing 4 million) are needed throughout the study period for any scenario. During the medium term between half a million (low) and more than 1 million (vision) new connections have to be realized each year. This is beyond the average number of new connections of the past years for any scenario. Connectivity level is forecasted to increase from currently around 45% to 70% (low), 80% (reference), and nearly 100% (vision) towards 2020. In any case, to reach these very ambitious levels, the national grid-based electrification has to be complemented by other means such as isolated grids and solar home systems.

[76] Derived from latest available data (peak: NCC hourly load indicate 1,550 – 1,570 MW peak in October 2015; consumption: KPLC annual report 2014/2015 and preliminary half annual accounts 2015).

4.2 Objectives and restrictions of the forecast

The purpose of the demand analysis and forecast as well as the successive demand supply balancing in later chapters is to provide a sound basis for the power system expansion planning by

- Identifying the driving and limiting factors for demand and consumption characteristics and their interrelations;
- Developing sound forecast scenarios for energy demand and peak demand; and
- Identifying supply gaps to determine optimal capacity, location, and technology for generation and transmission & distribution projects during the expansion planning process.

The official electricity demand forecast in Kenya has been crucial for the entire power sector because it has been applied for many sector studies (e.g. network studies, feasibility studies) and government plans. Hence, its accurateness will not only affect the master plan outcome but many other study results and policies in future. There has been an intensive discussion[77] among stakeholders in the power sector whether the selected demand scenarios are suitable and whether the forecasted demand can be achieved.

The following challenges are emphasised:

- Forecasts are uncertain per definition and experience;
- The reliability and completeness of data widely varies;
- It has to be differentiated between desired and economically and technically achievable targets for electricity supply;
- There are trade-offs between costs of under- and overestimating the size of the power system;
- The forecasts provided in this chapter are not statements of what will happen but of what might happen, given the described assumptions and methodologies[78];
- Given the high dynamics within the political and economic frame conditions and the power sector in particular the reader should carefully study the described assumptions and critically review the latest developments before using any of the results. This critical review and regular update of the demand forecasts is essential for any planning process based thereupon.

[77] E.g. kick-off and inception report presentation meeting for this study.

[78] In particular, the forecasts assume trends and plans that are consistent with historical and current developments with regard to population, economy, policy as well as the power sector. It relies on particular projects and expansions in the power sector to be realised with regard to generation as well as transmission and distribution/electrification. It is further based in part on general assumptions where no sufficient and reliable data was available.

4.3 General approach and demand scenarios

Demand analysis and forecast were conducted along the following overall approach:

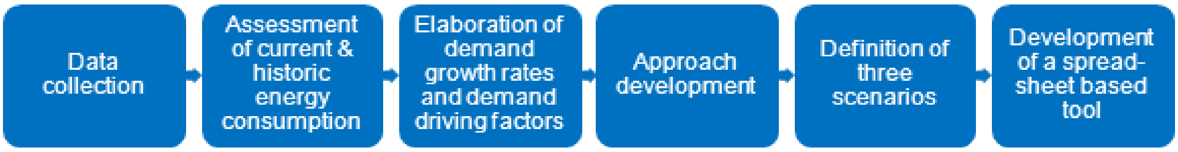

Figure 4-1: Approach demand analysis and forecast

1) Data collection and review and creation of data / assumption set (see Annex 4.A)

2) Assessment of frame conditions with impact on demand (geographic, political, institutional, demographic, (socio-) economic, see Annex 3.A, Annex 3.B, Annex 3.C, and section 3.1) and current and historic demand characteristics (see sections 3.2).

3) Elaboration of demand growth rates and demand driving and limiting factors e.g. developments and causalities for major consumer groups with demographic and economic parameters (see sections 3.2, 0 and Annex 4.C).

4) Review of previous demand forecasts and underlying models, data and assumptions (details in Annex 4.B) and adaption of suitable structure, methodologies and assumptions.

5) Development of methodologies based on i) experience from previous forecast models and approaches in Kenya, ii) experience from studies in similar countries, iii) data availability in Kenya iv) particular environment and requirements in Kenya, v) proven forecast methodologies and assumptions; combining:

    - Trend-projection (taking into account results from the correlation analysis, correction factors, and demographic parameters and forecasts). The assumptions are based largely on historic data analysis (e.g. for consumption and connections). Thereby, the analysis considers expansion potentials and limits within the power system mirrored in this data. This reduces the impact of information with a higher uncertainty (e.g. plans for power supply and economy).

    - Bottom-up approach; adding load from exceptional large projects (so called “flagship projects” which are beyond[79] the organic and typical development in Kenya) on top of the development of the existing (“without flagship projects”) consumer structure and new plans for particular consumer groups and areas (e.g. street lighting Nairobi).

    - Scenario definition, not limited to sensitivities (e.g. reference & low growth) but different views, i.e. the normative high vision scenario representing the largely ambitious governmental plans and the reference scenario based on a technical and economic assessment.

[79] By differentiating the two sources (flagship projects and organic growth) of future demand the transparency and clarity of the forecast is increased (e.g. uncertainty and realisation may differ considerably between these two sources).

- Distinction by voltage level: low, medium and high voltage analyses and forecasts allowing for the consideration of different assumptions for losses according to the level.

- Regional view by assessing demand and projects on a power system area level.

- Consumer group specific load characteristics (load factor, coincidence peak demand, responsibility factor) to provide indicative results for system load factor and peak load.

- Demographic forecasts for rural/urban population and households on power system area and county level.

- Consideration of all consumer groups (see section 3.2.1).

- Consideration of connection rates and specific consumption by consumer groups to arrive at total consumption (based on trend-projections and electrification assumptions).

6) Definition of three scenarios and one sub-scenario for the development of demand:

   a) **Reference scenario**: applying key assumptions established by the consultant in coordination with the client and stakeholders for a probable development based on the historic development and actual plans (technical, demographic and economic issues diligently assessed). The resulting grid-connected electrification has to be supplemented by off-grid electrification in rural areas to meet the governmental electrification targets.

   b) **Energy Efficiency**: sub-scenario to the reference scenario incorporating energy efficiency assumptions into the calculations (relevant for specific consumption by consumer group).

   c) **Vision scenario**: normative scenario applying the largely ambitious government plans (e.g. 100% mainly grid based connectivity level by 2020; less challenged flagship project developments).

   d) **Low scenario**: scenario for sensitivity and risk analyses applying more conservative assumptions than reference scenario and similar to historic developments.

7) Development of a spread-sheet based tool containing data and forecast formulas.

8) Reconstruction of the base year to calibrate the model to the specific situation of the country

9) Benchmarking of results with GDP forecasts and respective correlation with overall electricity consumption; historic developments (e.g. previous forecasts) in Kenya; forecasts of similar countries (e.g. in Africa); and historic demand development of countries, which had comparable characteristics (e.g. economic and demographic) in the past as Kenya has today.

4.4 Definitions

Below the most important definitions are provided (used in this chapter and the analysis of the frame conditions and historic demand). Abbreviations are listed at the beginning of this report.

Rate	Figure showing (rate of) change over time (i.e. not to be understood as a share), e.g. connectivity rate
Year / base year	Calendar year[80]; base year is 2015, the base year is the known reference point for the forecast as the most recent year where data is largely available
Areas (geographic)	Power system areas (Nairobi, Coast, Mt Kenya, Western) form main geographical partition of Kenya complemented by subdivision into counties for data analysis
Electrification	Definitions to be used as agreed in EAC (East African Community)
National connectivity (connection) level[81] (electrification rate; access)	Share (%) of population connected [to power supply][82]; also applied to areas below national level (i.e. power system areas). Internationally also called electrification rate; the National Electrification Strategy applies the wording 'access'.
Access to connectivity	Proportion of total national population in the proximity (600 metres) of low voltage transformer capable of providing connection

[80] The demand forecast is done for calendar years. KPLC data (the main input for past consumption and connection figures) is based on financial years (i.e. July to June). The connection status provided for end of the financial year is a good approximation for the average connections of the calendar year (the connection rate is assumed to be the same throughout the year). The consumption figures were transferred to calendar years considering that 2008 – 2014 on average 49.5% of total financial year consumption occurred July - December.
[81] Previously (agreed at EAC meeting but not valid anymore): connection level = persons (pax) per HH * No. of total domestic accounts / total national population
[82] No official definition is available on what qualifies households or people to "be connected" (e.g. in terms of quality and quantity such as minimum hours of supply per day, voltage level. available capacity). The National Electrification Strategy mentions isolated mini grids and standalone solar home systems as a solution to supply households "that cannot be economically supplied by national grid". Hence, 'be connected' within this master plan is understood "as actually connected to electricity supply system, i.e. people can utilize electricity in various ways" even if it is only for a few hours on low voltage solar home systems (solar lamps – as a single appliance - would not qualify as a system with various ways to utilize electricity). Monitoring of the connectivity level is restricted by the availability of data (only the 2009 census provides a complete set of information on whether households utilize electricity). In particular, data on the spread of solar systems since the census is important to measure this "off-grid" share of the connectivity level. However, only limited or not recent data is available (e.g. 2005/2006 2% of households indicated the use of solar panels in the Kenya Integrated Household Budget Survey (KIBHS); 2013 some 3.4 million people (approx. 8% of total) use solar lighting according to the Lighting Africa Kenya program of the World Bank, www.lightingafrica.org/).

Connectivity rate Rate of change of connection level with respect to time

$$\text{Connectivity rate or Electrification rate } \frac{\Delta CL}{\Delta t}$$

Where ΔCL = change in Connection Level
Δt = change in time over which the Connectivity rate is being determined

Connection rate Rate of change of connections (KPLC meters) to the electrical network with respect to time.

Meter connectivity level Ratio (%) of (KPLC) meters in comparison with total number of households.

Electricity penetration rate Rate at which the number of unconnected households are connected to the grid

$$Electrification\ Penetration\ Rate = \frac{(Total\ new\ households\ connected) \times (persons\ per\ households)}{(Total\ unconnected\ population)}$$

Specific consumption Average annual electricity consumption per tariff group / area

Suppressed demand Demand for electricity which cannot be met by the means of the national electricity supply due to various technical and economic limitations (also: non-served or unmet demand)

Annual peak load Highest total simultaneous national (imports included, exports deducted) demand for power, derived from half hourly load data actually measured at the National Control Centre

Weekdays Monday to Saturday (for load characteristics)

Weekend day(s) Sunday (for load characteristics)

Load factor Average load faced by a power system

$$\text{Load factor [\%]} = \frac{\text{System generation [MWh]}}{\text{(Peak load [MW]} \times \text{period hours [hrs])}}$$

(Load) **Responsibility factor** Area / group contribution to system peak load

$$\text{Responsibility factor [\%]} = \frac{Coincident\ peak\ demand\ [MW]}{Peak\ demand\ of\ group\ or\ area\ [MW]}$$

Coincident peak demand Area / group load at system peak load

4.5 Methodologies and assumptions

This section summarises in a clear step by step description the key assumptions and methodologies for the demand forecast. This is done along driving and limiting factors[83] for electricity demand (detailed in Annex 4.C). It further defines the forecast scenarios based thereupon. An overview of changes compared to previous forecasts are provided in Annex 4.B.

Calculation steps overview

The calculation steps of the demand forecast are visualises in the below figure. They are further detailed with formulas and input parameters.

[83] The actual and future demand for energy and electricity is the result of many factors which are often interrelated. They can be categorized as geographical, economic, technical, demographic and political factors. In order to prepare a plausible demand forecast it is not possible to model all factors and interrelations. Further it is also not reasonable to model every possible detail if the input data is incomplete or imprecise. However, the main underlying drivers should be analysed and understood. This could also facilitate the formulation and evaluation of policy measures. For this study, the main driving and limiting factors were identified. They provide the frame for defining the assumptions for each demand scenario.

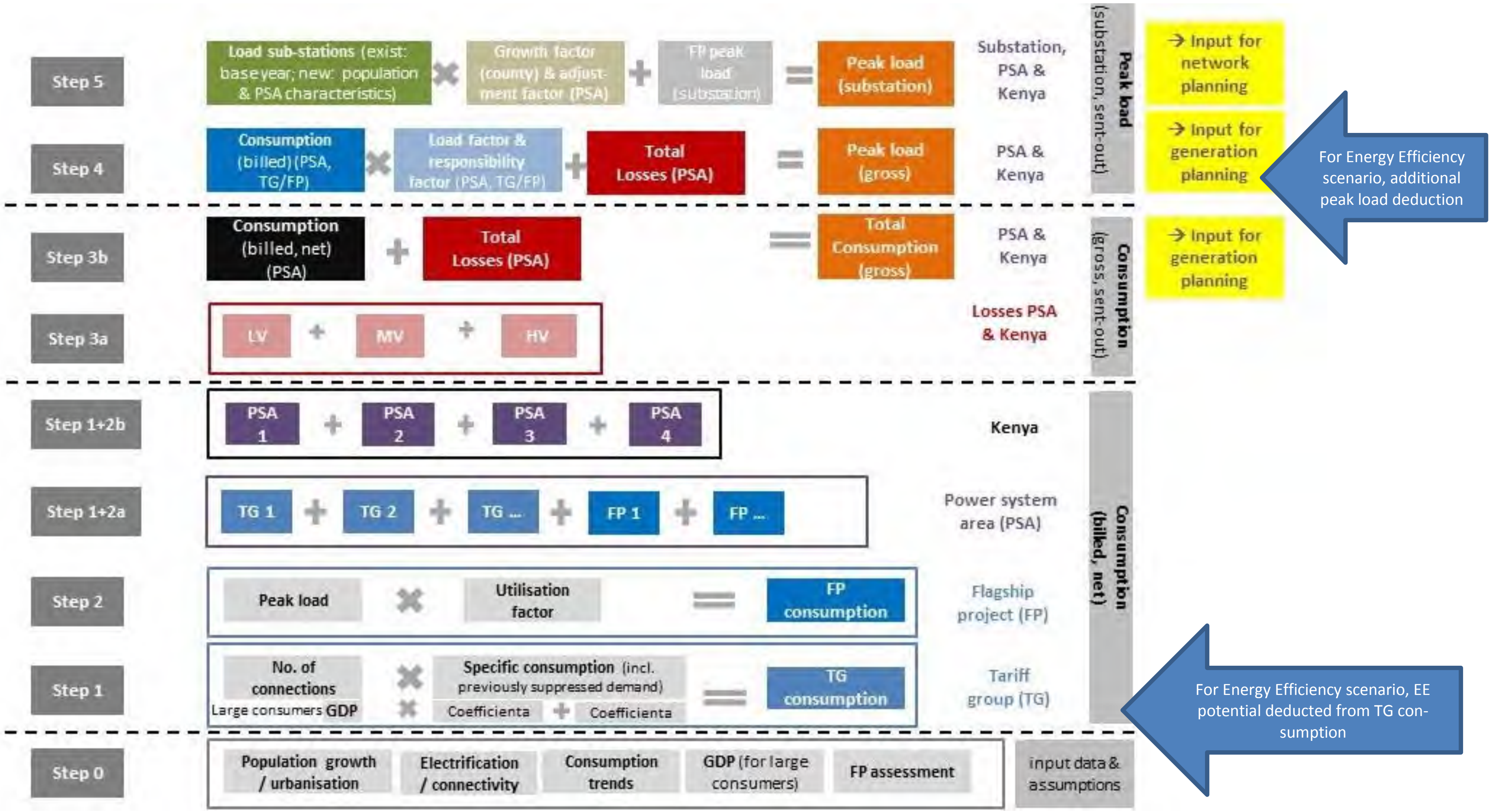

Figure 4-2: Calculation steps of demand forecast approach

The forecast is done along the following steps (numbered as in Figure 4-2):

1. Electricity (billed) consumption projections by tariff groups (domestic, street lighting, small commercial, large commercial / industrial) for four different geographic areas (power system areas: Nairobi, Coast, Mt Kenya, Western); applying the formulas[84] for each year of the study period:

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

   $$C_{B,TG,PSA}(y) = \left(SC_{TG,PSA,}(y) + SD_{TG,PSA}(y) \right) \times \#c_{TG,PSA}(y) \quad (1a)$$

   For tariff groups: large commercial / industrial

   $$C_{B,TG,PSA}(y) = GDP_{KE}\ (y) \times a_{PSA} + b_{PSA} \quad (1b)$$

#c	Number of connections
a, b	Coefficients of (past) linear correlation between consumption and GDP in absolute figures (C = a * GDP + b), by power system area
C_B	Consumption billed (net) in GWh
GDP_{KE}	Gross Domestic Product of Kenya in KES
PSA	Power system area
SC	Specific consumption in kWh/year
SD	Suppressed demand (which can be served in this particular year) in kWh/year
TG	Tariff group
y	Year

   For the Energy Efficiency (EE) scenario the saving potential per tariff group is deducted as identified under the EE task (for assumptions and results please refer to separate report "Long Term Plan – Energy Efficiency" submitted with this report).

   Below for each tariff group data sources and assumptions are detailed (differentiating by scenario where applicable).

[84] Similar to formula used in LCPDP forecasts for domestic consumption.

Table 4-2: Domestic consumption assumption and calculation

Determined by	Data sources	Assumptions, parameters
Demography	KNBS Census 2009 (county level) CBS Census 1999	<u>All scenarios</u>: Census 2009 forecast basis, Census 1999 for past long term developments
Population growth	UN medium fertility scenario forecast LCPDP 2013 population forecast	<u>Reference & low</u>: 2015: 46.7 million; 2020: 52.9 million; 2035: 73.7 million; growth: 2.4 – 2.5%/year <u>Vision</u>: 2015: 43.9 million; 2020: 49.7 million; 2035: 69.1 million; growth: 2.3 – 2.5%/year (impact of stronger economic growth of Vision 2030)
Household size	KNBS Census 2009, Census 1969, data industrialized countries	2015: 4.2 (urban: 3.6 rural: 4.7) persons / household 2020: 4.0 (urban: 3.6 rural: 4.5) persons / household2035: 3.6 (urban: 3.4 rural: 4.0) persons / household
Urbanisation rate, population density	UN World Urbanization Prospects - Urban Population 1950 - 2050 for Kenya: The 2011 Revision Vision 2030 Sessional Paper 2012 based on CBS 1999 projections	<u>Reference & low</u>: 2015: 34%; 2020: 37%, 2035: 48%; annual urbanisation rate: 4% /year <u>Vision</u>: 2015: 37%; 2020: 43%, 2035: 73%; annual urbanisation rate: 6% (representing impact of stronger economic growth of Vision 2030)
Electrification targets (connectivity level), connection rate	National Electrification Strategy; see also 4.4	<u>Reference</u>: 2017: 61%, 2020: 80%, 2028: 99%[85]; 2016: 0.8 million connections (=base year; 1% decrease / year until 2027) <u>Low</u>: 2017: 60% 2020: 72%; 2035: 78%; 2016: 0.8 million connections (=base year, 1% decrease / year until 2022) <u>Vision</u>: 2017: 70%, 2020 (onwards): 99%[85]; 1.04 million connections per year <u>All scenarios</u>: distribution of rural/urban connections according to historic split per power system area
Households per connection	KNBS Census 2009 Consultant assumption	Continuous reduction of households / connection from 1.8 (2009) to 1.6 (2015), 1.4 (2020), and 1 (2035) (all scenarios)
Annual consumption per connection (specific consumption) in kWh	KPLC annual reports 1989 – 2015 transferred to calendar years KPLC customer specific billing data for one year (2011/2012). Household survey 2012; Household survey 2015. Fichtner, Consultancy Services for Development of Electricity Connection Policy	<u>All</u>: specific consumption (kWh/year) 2015: 681 (2014: 851, 2010: 1,280, 2005: 1,928); link between new customers and specific consumption modelled to follow correlation with electrification: <u>Reference</u>: urban: 200, rural: 100, annual increase (connected): 4%; specific consumption 2020: 462, 2035: 473 <u>Low</u>: urban: 200, rural: 150, annual increase (connected): 4%; specific consumption 2020: 507, 2035: 543 <u>Vision</u>: urban: 400, rural: 200, annual increase (connected): 6%; specific consumption 2020: 613, 2035: 1,127
Suppressed demand	World Bank, *Doing Business 2015* (2014) survey; Consultant surveys and assumptions (predictions)	<u>All scenarios</u>: 10% of consumption in 2015 <u>Reference</u>: down to 7% in 2020 and 0% in 2034 <u>Low</u>: down to 8% in 2020 and 2% in 2034 <u>Vision</u>: down to 0% in 2020 <u>All scenarios</u>: No load shedding since this study will plan for sufficient supply and transmission capacity.

[85] There are technical and economic restrictions to extend the national grid to all rural areas. Therefore, off grid rural electrification has to be considered to supplement the extension of the national grid to reach in particular the high connectivity levels (see 4.4 for details).

Table 4-3: Small commercial consumption assumption and calculation

Determined by	Data sources	Assumptions, parameters
Electrification / connections	KPLC annual reports 1989 – 2015 transferred to calendar years	All scenarios: growth new connections 53% of growth new domestic connections (= historic correlation 2005 – 2015) Growth reduced by 60% for periods of high electrification (until 2019/2020)
Annual consumption per connection (specific consumption)	KPLC annual reports 1989 – 2015 transferred to calendar years	All: specific consumption 2015: 4,546 kWh/a (2014: 4,636 kWh/a, 2010: ,4,767 kWh/a, 2005: 4,501 kWh); Reference: annual increase: 1%; specific consumption 2020: 4,929 kWh/a, 2035: 6,194 kWh/a Low: urban: annual increase: 1%; specific consumption 2020: 4,876 kWh/a, 2035: 5,916 kWh/a Vision: annual increase: 2%; specific consumption 2020: 5,614 kWh/a, 2035: 7,537 kWh/a
Suppressed demand		See domestic consumption assumption Table 4-2

Table 4-4: Street lighting consumption assumption and calculation

Determined by	Data sources	Assumptions, parameters
Electrification / connections	KPLC annual reports 1989 – 2015 transferred to calendar years	All scenarios: growth new connections 80% of growth new domestic connections (= historic correlation)
Annual consumption per connection (specific cons.)	KPLC street lighting project tender documents and announcements KPLC annual reports 1989 – 2015 transferred to calendar years	All: specific consumption 2015: 7,281 kWh/a (2014: 8,516 kWh/a, 2010: ,8,168 kWh/a, 2005: 6,957 kWh); Specific consumption (including suppressed demand): 11,400 kWh/a (10 lamps each 260 Watt on 6pm to 6am)
Suppressed demand	KPLC street lighting project tender documents and announcements	All scenarios: see domestic consumption assumption Table 4-2 2014: 70% of urban areas not covered, 40% not in operation Reference & low: full coverage & repair of lamps until end 2020 Vision: full coverage and repair of lamps until end 2016

Table 4-5: Large commercial & industrial consumption assumption and calculation

Determined by	Data sources	Assumptions, parameters
Connections & consumption through **GDP growth**	KPLC annual reports 1989 – 2015 transferred to calendar years, KNBS GDP 2006 – 2015 (the 2015 GDP growth estimate was applied (5.5%), actual figures was slightly higher at 5.6% with limited effect on results), IMF GDP projection 2016 – 2020, Vision 2030 documents (see Annex 3.C for details)	All scenarios: by power system area for historic linear correlation based on 2009 – 2015 GDP and consumption data Nairobi: C = 0.44 x GDP + 449 Coast: C = 0.20 x GDP + 71 Mt Kenya: C = 0.09 x GDP - 59 Western: C = 0.17 x GDP - 9 Reference: GDP growth = IMF projection = 6.9% / year Low: GDP growth = average 2009 – 2015 = 5.1% / year Vision: GDP growth = Vision 2030 growth target 10% 2020 onwards (flagship projects (3-4%) deducted from this value)
Suppressed demand		See domestic consumption assumption Table 4-2

2. Demand from future flagship projects (exceptional, large projects are beyond the organic and typical development in Kenya) is added on top[86] of the existing ("without flagship projects") consumer structure, assessed based on expected peak load and load (utilisations) factors:

$$C_{B,FPs,PSA}(y) = \sum_{FP=1}^{x}(P_{FP}(y) \times LF_{FP}(y)) \qquad (2)$$

C_B	Consumption billed (net)
FP	Flagship project
LF	Load factor of tariff group / flagship project in %
P	Peak load in MW
PSA	Power system area
y	Year

Two scenarios represent a possible range of developments:

- Base scenario: rather conservative assumptions given the present status and outlook for the projects, frame conditions and considering typical time lags in such unique developments.
- High scenario: more optimistic assumptions close to the government plans, however applying latest information on status of the projects.

Below a summary for both scenarios is provided. Details are included in Annex 4.E.

Table 4-6: Electricity demand forecast of key flagship projects - Base scenario

		Peak demand [MW]					Energy demand [GWh]				
Projects	**COD**	**2015**	**2020**	**2025**	**2030**	**2035**	**2015**	**2020**	**2025**	**2030**	**2035**
LAPSSET oil pipeline and port	2025			50	100	150			325	650	975
LAPSSET refineries/industries	2028				46	100				346	745
Electrified railways											
Mombasa-Nairobi	2030				70	130				153	456
Nairobi-Kampala	2035					44					97
Rapid transit system Nairobi	2030				40	90				105	315
Konza Techno City	2017		33	66	138	190		104	334	603	832
Special Economic Zones	2019		12	44	77	110		41	170	317	482
Total			**45**	**180**	**471**	**814**		**145**	**829**	**2174**	**3901**

[86] By differentiating these general two sources of future demand the transparency and clarity of the forecast is increased (e.g. uncertainty and realisation may differ considerably between these two sources).

Table 4-7: Electricity demand forecast of key flagship projects - High scenario

Projects	COD	Peak demand [MW] 2015	2020	2025	2030	2035	Energy demand [GWh] 2015	2020	2025	2030	2035
LAPSSET oil pipeline and port	2020		50	100	150	150		325	650	975	975
LAPSSET refineries/industries	2023			93	200	200			691	1489	1489
Electrified railways											
Mombasa-Nairobi	2025			100	200	300			219	657	1314
Nairobi-Kampala	2030				63	189				138	662
Rapid transit system Nairobi	2025			40	90	140			105	315	613
LAPSSET railway	2033					14					49
Konza Techno City	2016		44	96	148	200		140	378	648	876
Special Economic Zones	2017		60	110	110	110		219	428	455	482
Integrated steel mill	2030				100	200				657	1314
Total			**154**	**539**	**1061**	**1503**		**684**	**2471**	**5334**	**7775**

3. Losses for respective voltage levels are added (LV, MV, HV) to arrive at gross consumption (power plant and transmission network sent-out):

$$C_{PP}(y) = \frac{C_B(y)}{(1 - L_{HV,MV,LV})} \tag{3.1}$$

$$C_{PP,PSA}(y) = \frac{C_{TN,PSA}(y)}{(1 - L_{HV})} \tag{3.2}$$

C_B;C_{PP};C_{TN}	Consumption billed (net); power plant sent-out (gross); transmission network sent-out (substation, incl. distribution losses) in GWh
HV	High voltage
L	Losses (share of corresponding voltage level) in %
LV	Low voltage
MV	Medium voltage
PSA	Power system area
y	Year

For the forecast it is assumed that losses (as percentage share) will largely prevail for the study period (slightly decreasing for HV, slightly increasing for MV and LV). Details on historic data and assumptions are provided in section 3.3.3 and the table below.

Table 4-8: Losses Kenyan electrical network 2010, 2014, 2015 and prediction[87]

	2010	2014	2015	2020	2035
Total	**16.1%**	**17.9%**	**17.6%**	Depending on scenario	
HV	3.7%	4.7%	**4.9%**	**4.0%**	**4.5%**
MV	5.8%	5.8%	**5.7%**	**6.0%**	**6.0%**
LV	11.1%	12.6%	**12.3%**	**12.9%**	**12.9%**

[87] Percentage of electricity of particular voltage level, LV including non-technical/commercial losses

4. System peak load estimate: conversion of gross consumption (by tariff group and area) to load at system peak by applying load factor and responsibility factor (factors are provided in section 3.2.7). Conversion of sum of power system area loads to arrive at simultaneous peak (system peak load in base year is about 99.7% of the sum of all power system area peaks).

$$P_{PP}(y) = \sum_{TG,FP=1,PSA=1} \left(C_{PP,TG/FP,PSA}(y) \times LF_{TG/FP,PSA}(y) \times RF_{TG/FP,PSA}(y) \right) \times \mathrm{SF} \qquad (4)$$

CC_{PP}	Consumption power plant sent-out (gross) in GWh
FP	Flagship project
LF	Load factor of tariff group / flagship project in %
P	Peak load in MW
PSA	Power system area
RF	Responsibility factor (share of peak load contributing to system peak) of tariff group / flagship project in %
SF	Simultaneous peak factor (of peak load power system area) = peak load system / sum peak loads power system areas in %
TG	Tariff group
y	Year

5. Substation load estimate (at system peak) are needed as an input for the network simulation. They are calculated by applying county growth rates (provided by KPLC) to estimated substation loads in base year. Load for new substations is derived from demographic characteristics of county and settlement as well as average characteristics of power system area and population. All substation loads for each power system area are adapted so that total power system loads reflect the general load forecast. Load or shares of load of flagship project loads are added on top. Annex 4.F contains details on data and approach.

$$P_{S/S}(y) = \mathrm{P}_{S/S\ base\ year} \times (c_{COUNTY})^{(y-base\ year)} \times CF_{PSA}(y) + P_{FP} \qquad (5)$$

c_{COUNTY}	County growth rates for peak load in %
CF_{PSA}	Correction factor to adjust total PSA substation loads to PSA peak load
FP	Flagship project
P	Peak load in MW
$P_{S/S}$	Load at substation (transmission network sent-out) at system peak in MW
PSA	Power system area
y	Year

4.6 Demand forecast results

This section provides the forecasted developments of peak load and power demand as well as connectivity for the long term period 2015 (base year) to 2035. Results are provided along the defined scenarios:

- Reference scenario
- Vision scenario
- Low scenario
- Energy efficiency (reference sub-scenario)

The following information is provided for all scenarios

a) Annual electricity consumption net (billed)

b) Annual electricity consumption gross (power plant sent-out)

c) Peak load gross (power plant sent-out)

d) Connectivity level (electrification)

e) Population and number of households

Some information is split for the following categories

- Consumer groups: domestic, small commercial, street lighting, large commercial/industrial
- Voltage level: HV, MV, LV
- Power system areas: Nairobi, Coast, Mt. Kenya, Western.

Details are provided in Annex 4.G. Annex 4.F contains future estimated loads at substation level.

4.6.1 Electricity consumption and peak load - reference, vision, low scenarios

Demand for electricity and annual peak load are expected to grow considerably for any scenario:

- <u>Electricity (gross consumption)</u> is forecasted to grow in the long term by an annual average of 7.3% per year for the reference scenario. By 2035 consumption would be four times the values of 2015.

- <u>For the vision and low scenario</u> the growth is expected to be at 9.6% and 5.6% respectively. This would lead to consumption figures 50% above and some 25% below the values in the reference scenario towards the end of the study period. Thus, the three scenarios describe a range from worst (low) case to a best (vision) case. This will help to analyse the economic and technical impact of demand uncertainty on mainly the generation expansion.

- These growth rates include flagship projects for the reference and vision scenarios which contribute around 0.5% and 0.9% additional annual demand growth, respectively.

- Annual peak load is expected to grow at rates about 0.2 percentage points above the electricity consumption rates. This leads to a slightly decreasing load factor.

- Annual peak load is forecasted to more than quadruple from nearly 1,600[88] MW in 2015 to 6,700 MW in 2035 (above 10,000 MW and nearly 5,000 MW for the vision and low scenario respectively). This means that on average each year some 150 (low), 250 (reference), or 400 (vision) MW of capacity (plus reserve) have to be added to serve the growing peak load in the evening.

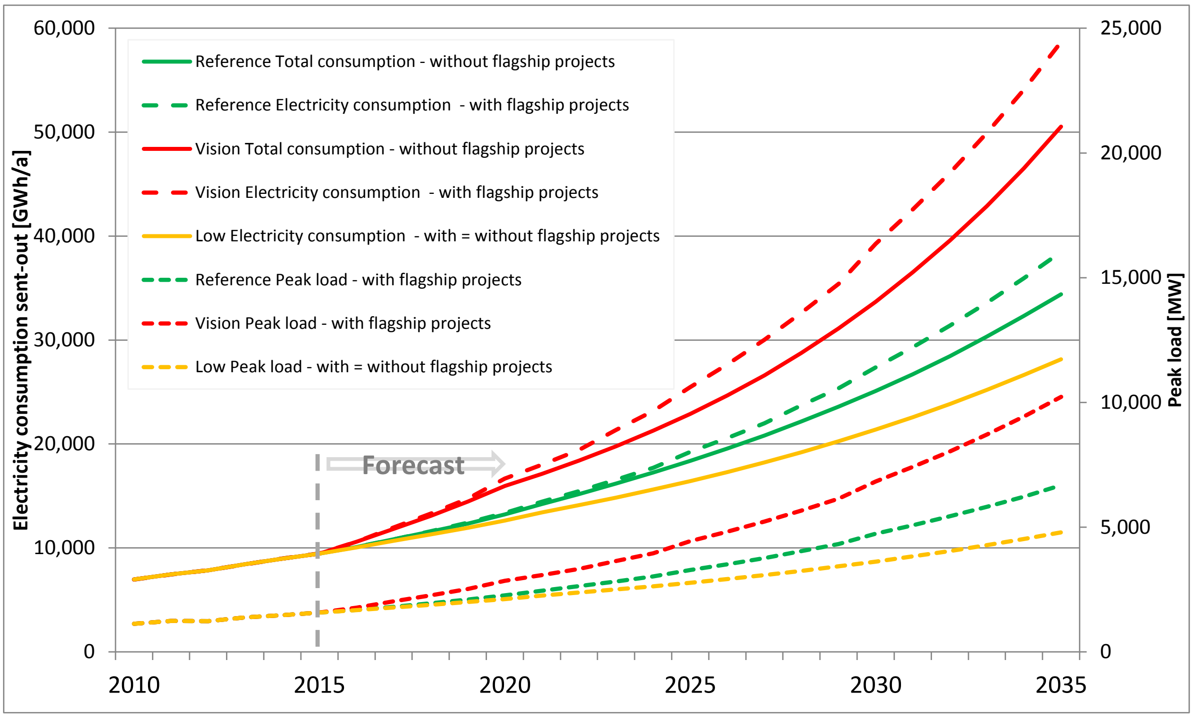

Figure 4-3: Electricity consumption and peak load forecast – reference, vision, low scenarios (2015 – 2035)

- While commercial and industrial consumption will continue to dominate overall demand, the share from domestic consumers is forecasted for the reference scenario to increase similar to the past trend, reaching a third from currently below 30% of total consumption. For the vision scenario the domestic share would be beyond 50% towards 2035.

Table 4-9: Electricity consumption and peak load forecast – reference, vision, low scenarios (2015 – 2035)

Sce-nario		Flagship projects	Unit	Average growth 2009-15	MTP	LTP	2013	2014	2015[88]	2016	2017	2018	2019	2020	2025	2030	2035
R	Consumption billed	without	GWh	5.9%	6.9%	6.6%	6,877	7,367	7,789[88]	8,311	8,905	9,516	10,154	10,881	15,085	20,567	28,145
E	Consumption gross	without	GWh	**6.3%**	**6.9%**	**6.7%**	8,423	8,969	9,453[88]	10,093	10,816	11,557	12,332	13,216	18,375	25,093	34,393
F	Growth		%				7.5%	6.5%	5.4%	7%	7%	7%	7%	7%	6%	6%	6%
E	**Consumption gross**	**with**	**GWh**		**7.2%**	**7.3%**	8,423	8,969	9,453[88]	10,093	10,821	11,594	12,421	13,367	19,240	27,366	38,478
R	Growth		%				7.5%	6.5%	5.4%	7%	7%	7%	7%	8%	9%	8%	7%
E	Peak load	without	MW	7.0%	7.1%	6.8%	1,433	1,512	1,570[88]	1,679	1,802	1,929	2,061	2,213	3,094	4,239	5,830
N	Growth		%				10%	6%	4%	7%	7%	7%	7%	7%	7%	6%	6%
C	**Peak load**	**with**	**MW**	**7.0%**	**7.6%**	**7.5%**	**1,395**	**1,485**	**1,570[88]**	1,679	1,804	1,942	2,090	2,259	3,282	4,732	6,683
E	Growth		%				10%	6%	4%	7%	7%	8%	8%	8%	9%	10%	7%
			MW				130	80	58[88]	109	125	138	149	169	260	412	462
V	Consumption billed	without	GWh	5.9%	10.8%	8.6%				8,699	9,694	10,711	11,813	13,031	18,633	27,307	40,791
I	Consumption gross	without	GWh	**6.3%**	11.0%	8.7%				10,586	11,819	13,077	14,442	15,952	22,891	33,684	50,538
S	Growth		%							12%	12%	11%	10%	10%	8%	8%	9%
I	**Consumption gross**	**with**	**GWh**		12.0%	9.6%				10,592	11,965	13,295	14,736	16,665	25,469	39,260	58,679
O	Growth		%					see above		12%	13%	11%	11%	13%	10%	11%	8%
N	Peak load	without	MW	7.0%	11.3%	8.9%				1,768	1,981	2,195	2,428	2,685	3,869	5,724	8,645
	Growth		%							13%	12%	11%	10%	10%	8%	8%	9%
	Peak load	**with**	**MW**	**7.0%**	12.6%	9.8%				1,770	2,026	2,261	2,515	2,845	4,431	6,833	10,219
	Growth		%							13%	14%	12%	11%	13%	12%	11%	8%
			MW							200	256	235	254	330	478	689	786
L	Consumption billed	without	GWh	5.9%	5.9%	5.5%				8,261	8,778	9,292	9,812	10,384	13,459	17,459	22,917
O	**Consumption gross**	**without**	**GWh**	**6.3%**	6.0%	5.6%				10,035	10,670	11,298	11,932	12,632	16,427	21,375	28,153
W	Growth		%					see above		6%	6%	6%	6%	6%	5%	6%	6%
	Peak load	**without**	**GWh**	**7.0%**	**6.1%**	**5.7%**				1,669	1,778	1,886	1,995	2,116	2,769	3,618	4,788
	Growth		%							6%	7%	6%	6%	6%	5%	6%	6%

[88] Derived from latest available data (peak: NCC hourly load indicate 1,550 – 1,570 MW peak in October 2015; consumption: KPLC annual report 2014/2015 and preliminary half annual accounts 2015).

4.6.2 Connectivity level - reference, vision, low scenarios

The assumed electrification targets will considerably increase the number of connections for any scenario:

- More than 10 million additional domestic connections (to the existing 4 million) are needed throughout the study period for any scenario to compensate for population growth, shrinking household size, and provision of meters where currently several households share one and to reach electrification targets.

- During the medium term between half a million (low) and more than 1 million (vision) new connections have to be realized each year. This is beyond the average number of new connections of the past years for any scenario.

- Connectivity level is forecasted to increase from currently around 45% to 70% (low), 80% (reference), and nearly 100% (vision) towards 2020. In the long term the level will reach nearly 100% also in case of the reference scenario. For any scenario, these figures can only be estimates due to the lack of solid data basis and the difficulty to realize electrification, particularly in remote areas. In any case, to reach these very ambitious levels, the national grid-based electrification has to be complemented by other means such as isolated grids and solar home systems.

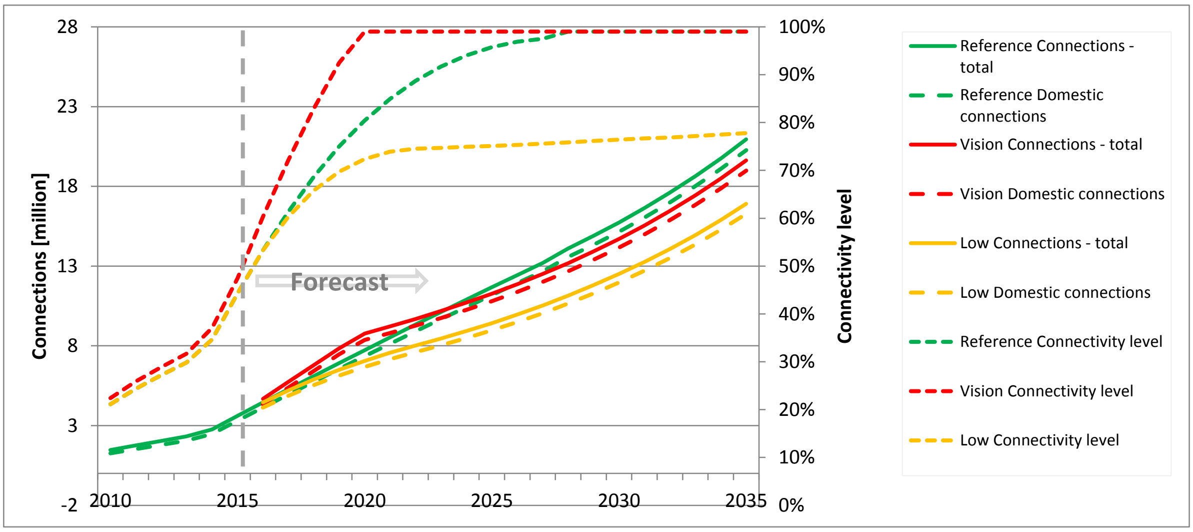

Figure 4-4: Electricity consumption and peak load forecast – reference, vision, low scenarios (2015 – 2035)

4.6.3 Energy efficiency (reference sub-scenario)

If EE potentials are realized as detailed in the EE report, demand beyond 2019 will gradually decrease against the development in the reference scenario. This difference is caused by the lead time which is necessary for EE measures to take effect. For the assumed EE scenario all measures are assumed to kick-off in the same year (2019) which causes the two scenarios to diverge from 2019 onwards. EE savings are accumulated throughout the years so that the highest savings with some 25% will be reached towards the end of the study period. The two scenarios only differ in specific and total consumption, connectivity and connection rate remain the same.

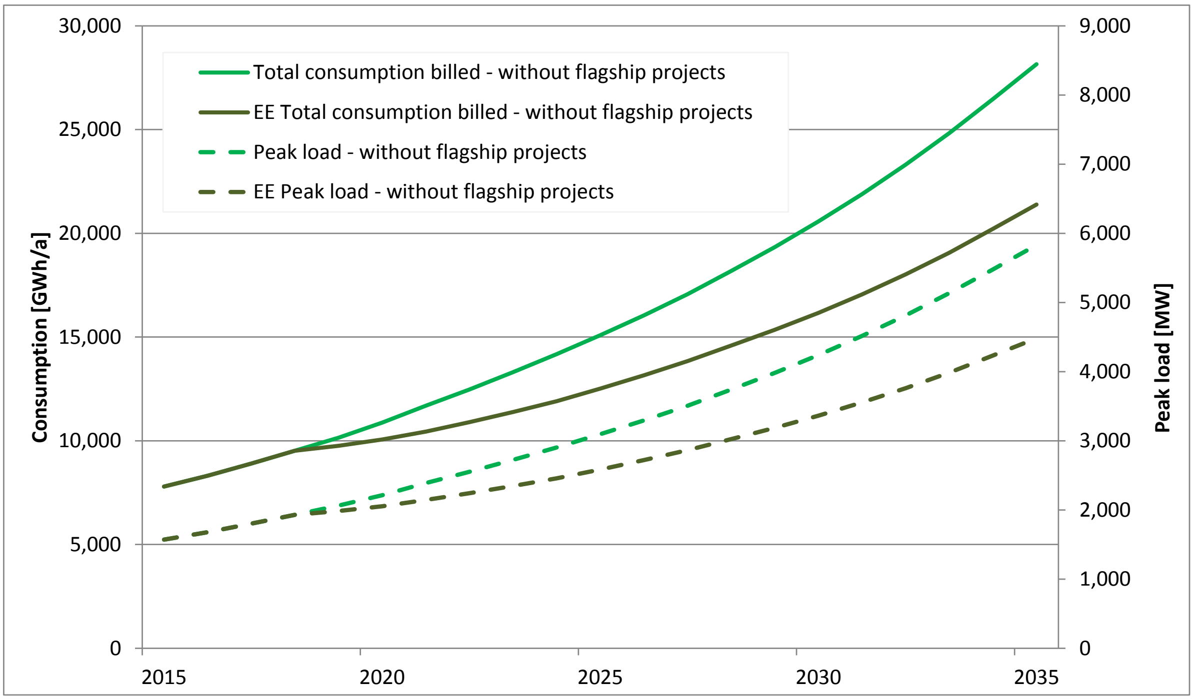

Figure 4-5: Electricity consumption and peak load forecast – reference and energy efficiency scenarios (2015 – 2035)

4.6.4 Benchmarking of demand forecast results

A comparison of previous forecasts with past and actual electricity demand growth in Kenya and other comparable countries (forecast of one other African country and past growth rates of various countries which showed strong economic development in the past) is provided below.[89] It shows for instance, that previously forecasted low and reference national consumption growth rates were by far not achieved for most of the years. Further, they exceed by far the forecasted growth rates of similar African countries. Only very few countries in the world have shown such sustained high

[89] A larger figure with more scenarios and countries is provided in the Annex. The sample country Ghana is considered similar to Kenya with regard to e.g. population, size, economy, location.

consumption growth rates as it has been forecasted for Kenya in the past (e.g. Vietnam and China). The forecast scenarios developed within this study are in a more common range of growth rates with regard to the different benchmarks.

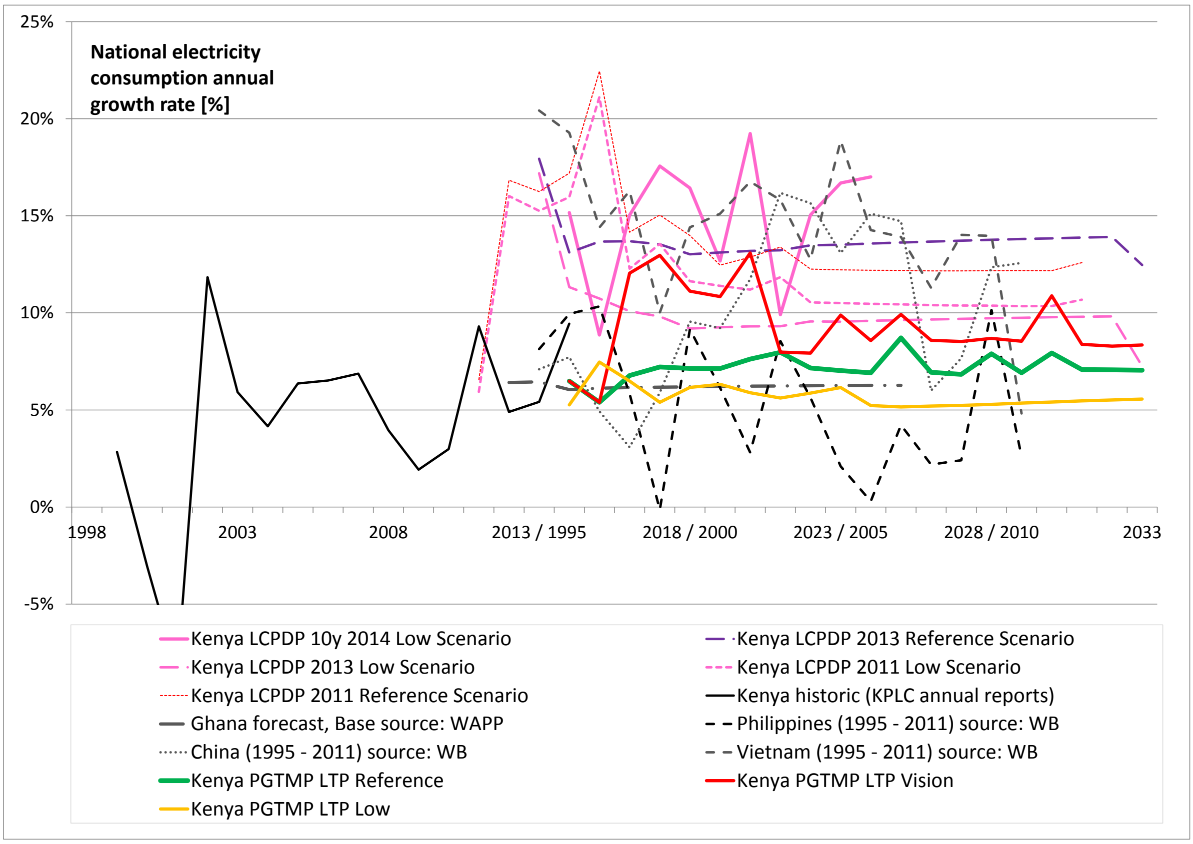

Figure 4-6: Comparison electricity demand forecast Kenya with other countries[89]

Policy targets for high demand were not reached in the past for various reasons. This might have contributed to a situation where Kenya is currently one of the few African countries with sufficient available generation capacity to meet the demand and plenty of projects in the planning stage. However, this type of generation (e.g. mainly base load generation and import) might be more suitable for higher demand levels. Hence, policy targets should be reassessed more carefully and respective scenarios (including conservative/pessimistic scenario) considered and developed to reduce risks and costs.

5 ENERGY SOURCES FOR CURRENT AND FUTURE ELECTRICITY SUPPLY

This chapter summarises the energy sources and fuels utilised for power generation in Kenya as well as the planned and potential energy sources for future electricity generation. The results are input for detailed analysis of generation candidate technologies in section 6 and 7. Characteristics of fossil fuels considering transport infrastructure and future fuel price developments are evaluated in section 5.2. Section 5.3 provides an overview[90] of renewable energy sources including hydropower, solar, wind, biomass, biogas, waste-to-energy and geothermal energy. Section 5.4 evaluates nuclear fuel and interconnections with neighbouring countries as potential future energy sources.

5.1 Key results and conclusions

The key results and corresponding conclusions and planning recommendations are:

- Coal is the only domestic fossil energy resource with proven availability for extraction and potential use in power generation[91]. Thus, besides renewable energy sources (RES) it is the only source to limit overall import dependency of power generation in Kenya. The dependency is however comparatively small due to the high share of RES. Further, coal leads to considerable environmental and social costs on a local, regional and international level. If run at base load with high capacity factors the pure generation costs can be comparatively low with little volatility. It should be assessed whether the benefits of coal based generation (low costs and domestic source) could materialize in Kenya against the high environmental and social costs.

- Natural gas (if available) should be developed due to its potential for flexible power generation, to diversify energy sources and to reduce import dependency with a lower environmental impact. However, besides general availability its availability for power generation has to be assessed as it has to compete with other domestic demand (e.g. industry, residential sector). Liquefied Natural Gas (LNG) is an available option for diversification of energy sources and with limited environmental impact though at comparatively high costs.

- Renewable energy sources are vastly available for power generation in Kenya with different challenges (e.g. intermittent generation and social and environmental impact) and opportunities (flexible, base load, distributed generation). Generation costs vary, though compared to thermal generation the price fluctuation (and thus risk) is low due to the low or negligible variable cost share and still declining investment costs. Costs, opportunities and challenges have to be assessed within the national power system to identify and rank suitable RES.

- Petroleum based fuels are not recommended as a future fuel even if domestically available. This is due to high costs, strong price fluctuations, and the environmental impact. However, for back-up and peaking capacity (e.g. gas turbines) may remain necessary until it can be replaced in an economic way.

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[90] Detailed information is provided in the separate report on renewable energy sources (Long Term Plan – Renewable Energy) submitted with this report.
[91] Petroleum extraction in Kenya may start in the near future but will most likely be used for export only.

- Nuclear fuel is a potential energy source for diversification of supply (though not domestic) with low fuel costs and high security of fuel supply. However, compared to fossil fuels and the technology and investment to build and operate a nuclear power plant, the fuel supply is of minor importance for the evaluation of nuclear power as an expansion candidate.

- Interconnections with neighbouring countries provide mutual benefits (sources of energy and power, the provision of ancillary services and overall higher security of supply). In this regard, it is recommended to further extend interconnections with neighbouring countries beyond the committed three interconnection projects.

Below the fuels used for power generation in Kenya today as well as for future plants are listed.

Table 5-1: Fuel characteristics and prices[92] of fossil and nuclear fuels

Fuel type	Existing / future power plants	Net calorific value[93]	Density[93]	Carbon emission factor[94]	Prices 2015/ 2040	Prices 2015 / 2040
		MJ/kg	kg/l	tCO_2/TJ	USD/ton	USD/GJ
Fossil fuels – liquid						
Crude	-	-	-	-	428 / 960	10.1 / 22.7
HFO (Heavy Fuel Oil)	Existing (candidate)	41.4	0.94	75.5	304 / 682	7.3 / 16.5
Kerosene / gasoil[95]	Existing, candidate	44.9	0.84	72.6	566 / 1,270	12.6 / 28.3
Fossil fuels – solid						
Coal – import (South Africa)	Committed , candidate	21.0	0.80	94.6	66 / 112	3.1 / 5.3
Coal – domestic (Mui Basin)	Candidate	18.0	na	94.6	51 / 90	2.8 / 5.0
Fossil fuels – gaseous						
Natural gas (exploration ongoing)	Candidate (if available)	46.5	0.0008	54.3	335 / 519	7.2 / 11.2
LNG	Candidate	46.5[96]	0.53[96]	54.3	573 / 757	12.3 / 16.3
Nuclear	Candidate	39,000	-	0	-	2.8 / 2.8

[92] cif basis: cost insurance freight, i.e. including international transport costs for imported fuels
[93] Source: Fuel Specifications – KPLC, KenGen
[94] For the carbon emission factors, official values provided by the Intergovernmental Panel on Climate Change (IPCC) are applied (lower values with 95% confidence interval). For natural gas, only one official factor is available which is applied to any gaseous fuel.
[95] Fuel characteristics are for Automotive Gasoil (AGO).
[96] NCV for regasified LNG, equal to natural gas; density for liquefied consistency

5.2 Fossil energy sources for future electricity generation

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

At present, coal is the only domestic fossil energy resource available for extraction and potential use in power generation. Exploration activities on crude oil and natural gas deposits are underway and for gas still in the appraisal stage. In 2014[97], national primary energy consumption was dominated by biomass (charcoal and wood fuel) accounting for 69%. This was followed by petroleum products (22%), electricity (9%, about a third based on the fossil fuels heavy fuel oil (HFO) and gasoil products, the remaining based on renewable energy sources), and coal (1%). Demand for petroleum products has been increasing steadily by 10% annually in the past.

5.2.1 Crude oil and liquid petroleum products

5.2.1.1 Crude oil

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

During the past 50 years, crude oil has been the major energy source in the world measured by energy content[98], being nearly 10% ahead of the second placed coal. This is due to its dominance in the transport sector. For electricity generation it plays a less dominant role, though it is still important for some petroleum products (such as gasoil and HFO) as well as for selected oil producing countries. In Kenya there are no power plants fuelled by crude oil but successive petroleum products from the local refinery and imports, such as HFO and diesel oil, are used for power generation.

Available resources in Kenya

Kenya's electricity sector relies considerably on imported crude oil and petroleum products fuelling nearly 40%[99] of the country's installed power generating capacity. With the commissioning of geothermal power plants this dependency has decreased in recent years. To this day all petroleum products used in Kenya are imported including crude oil as well as refinery products. Until its operation stop in 2013, imported crude oil was refined in the Kenya Petroleum Refineries Limited (KPRL) and processed into various petroleum products for use in domestic power generation. Crude oil imported into Kenya is sourced from Abu Dhabi (referred to as "Murban crude") and Saudi Arabia (referred to as "Arabian Medium") with corresponding quantity shares of 75% and 25% respectively. The Abu Dhabi crude oil variety is of higher quality as it produces more diesel, gasoline, kerosene and less heavy fuel oil than the Arabian Medium variety.

Kenya had a total of 46 onshore and offshore exploration blocks across the country and off the coast and a total of 43 exploratory wells which have been drilled in four basins (Lamu, Mandera,

[97] Source: Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (16 June 2015)
[98] Source: BP – Statistical Review of World Energy 2015, June 2015
[99] 36% in financial year 2014/2015 according to KPLC, *Annual Report 2014/2015* (2015)

Anza, Tertiary Rift) by 2015[97]. A corresponding number of 41 licences have been awarded to international oil firms (exploration and production companies) to carry out exploratory activities. Figure 5-1 below provides an overview of ongoing exploration activities in Kenya as from July 2015.

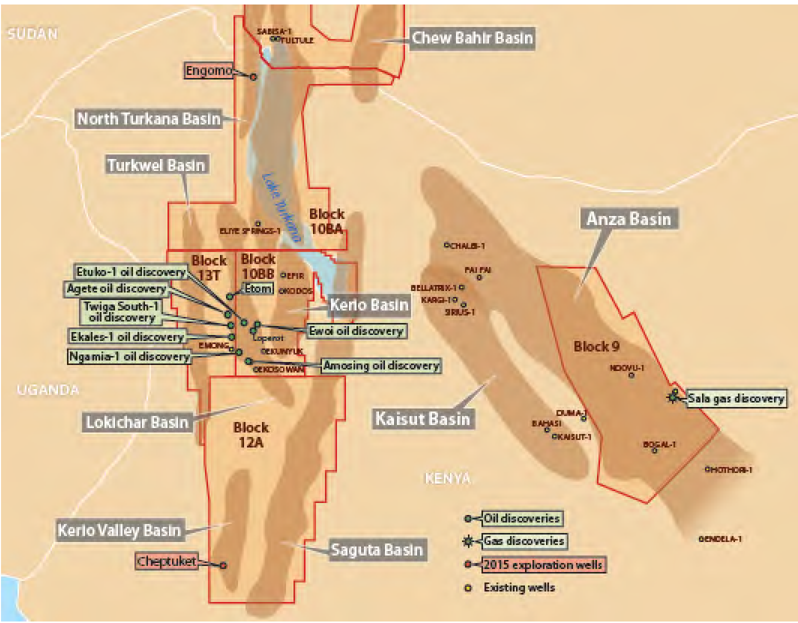

Figure 5-1: Exploration activities in Kenya[100]

Domestic crude oil deposits have been located in Turkana, the northern most county of Kenya bordering with Uganda. Extraction in Turkana may start in the near future[101]. There are plans to transport (as a pilot scheme for export) small amounts by road to Mombasa. It is planned to be replaced in the long term by large scale transport via a pipeline to Lamu for export. The idea for a refinery is also analysed (see Annex 4.E). Despite this progress it remains to be seen whether commercial viability of exploitation and export or domestic refining of the crude can be established.

<u>Assumptions for expansion planning</u>

Since no official information on a commercial supply of domestic crude oil is available, no conclusion could be drawn if domestic crude oil or domestically refined products will be available for electricity generation in the future. Thus, no domestic crude oil supply has been considered in the expansion planning.

5.2.1.2 Heavy fuel oil

Heavy fuel oil (HFO) or residual oil is a fraction at the lower end of the fractioning column obtained during the distillation process in the refinery. As a residual product, it is of low quality compared to most petroleum products. High viscosities require pre-heating for transport. HFO also includes a high share of impurities, such as water, soil and sulphur depending on the crude oil. It is mostly used as a relatively cheap but still liquid fuel for power generation and shipping. Its use brings

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[100] Source: Africa Oil Corporation (www.africaoilcorp.com), July 2015
[101] Tullow Oil plans for crude oil extraction in 2017 near Lokichar.

higher environmental risks than for other fuels through higher quantities combusted and a wider range of harmful substances (sulphur dioxide, soot, etc.) in the exhaust gases. As for every fraction, various kinds of HFO exist distinguished by their viscosity and net calorific value. For this study, HFO characteristics are based on fuel specifications provided by KPLC and KenGen.

Available resources in Kenya

In 2014, approximately 328,100 tonnes of HFO have been consumed which is roughly 8% of the total petroleum consumption by fuel category.[102] A large share of HFO used in Kenya is burned in diesel power plants, such as in the largest diesel plant in East Africa: the Kipevu Power Station in Mombasa. Besides power generation, the remaining share is used for industrial production. Until its operation stop in 2013, the domestic refinery in Mombasa met part of this consumption. At present all HFO is imported through Mombasa port and transported by road to the power plant sites.

Assumptions for expansion planning

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

5.2.1.3 Gasoil and kerosene

Gasoil[103] and kerosene are fractions at the middle of the fractioning column obtained during the distillation process in the refinery. Various kinds of gasoil exist distinguished by their viscosity and net calorific value. For this study, the fuel characteristics are based on fuel specifications provided by KenGen. Gasoil and kerosene are at the upper end of the cost range of generation fuels. It is only used if heavier fuels such as HFO cannot (e.g. some diesel engines do not run on HFO) or must not (for environmental reasons) be burned, if cheaper fuels are not available, or as a starter fuel. Kerosene is used in households (e.g. for lighting and generators), it powers jet engines of aircrafts, but also gas turbines in power stations.

Available resources in Kenya

In 2014 approximately 1,721,000 tonnes of gasoil have been consumed in total which is 44% of the total petroleum consumption by fuel category.[104] The transport sector accounts by far for the largest share of the total gasoil consumption in Kenya. The remaining share of gasoil consumption is typically used for power generation in emergency power generation units, such as Aggreko rented power, and large isolated grids. For power generation in Kenya, kerosene is used in gas turbines such as for the Embakasi Power Station in Nairobi and Muhoroni Power Station in Kisumu. In 2014,

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[102] Source: KNBS, Kenya Facts and Figures 2015

[103] Sometimes called distillate, diesel oil, or fuel oil number 2; in Kenya Automotive Gasoil (AGO), Industrial Diesel Oil (IDO)- a blend of HFO and diesel - and kerosene (dual purpose) are used for power generation. In Kenya Automotive Gasoil (AGO), Industrial Diesel Oil (IDO). Kerosene (as fuel for gas turbines) is the most relevant fuel among them for future candidates. AGO and IDO are mainly used for emergency generation, as a starter fuel, and at isolated grids.

[104] Source: KNBS, Kenya Facts and Figures 2015

approximately 300,300 tonnes of kerosene have been consumed in total which is below 8% of the total petroleum consumption by fuel category.[105]

Assumptions for expansion planning

Gasoil and kerosene are not recommended fuel options for expansion candidates given their high prices on the world market and, thus, high opportunity costs for Kenya. However, it could be an option to fuel backup and peaking capacity plants. Their low capacity factors lead to a lower share of fuel costs. Supply infrastructure is available and there are considerable environmental advantages compared to HFO. It is the aim of the expansion planning to compare this option with suitable alternatives as well as replacing its use at existing power plants where possible.

5.2.2 Gaseous fuels

5.2.2.1 Natural gas

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

During the past 50 years, natural gas has been the third important energy source in the world measured by energy content, behind crude oil and coal.[106] In this period, its share has continuously increased. Besides technical advances in the extraction and transport of natural gas as well as achieving a lower price than crude oil, the increased consumption is also due to its rather environmental-friendly characteristics: that is virtually no sulphur content and low carbon dioxide emissions. For these reasons, its already important role for electricity generation is further growing. However, the means of transport of natural gas are limited, i.e. in gaseous form in pipelines or as liquefied natural gas (LNG) in ships or trucks. These limitations restrict the use of natural gas to the vicinity of gas fields and an existing pipeline network with idle capacity; or it requires relatively high investment costs for constructing new pipelines or the transport in form of LNG.

Available resources in Kenya

Africa Oil Corporation, a Canadian oil and gas exploration and production company, has discovered gas in Block 9[107] onshore in north-eastern Kenya. An appraisal plan to follow up the gas discovery is currently being evaluated in consultation with the Government of Kenya. In addition, the Africa Oil Corporation is considering drilling an appraisal well on the crest of the large Bogal structure to confirm the large potential gas discovery which has closure over an area of up to 200 square kilome-

[105] Source: KNBS, Kenya Facts and Figures 2015
[106] Source: BP – Statistical Review of World Energy 2015, June 2015
[107] Africa Oil is the Operator with a 50% working interest. Marathon Oil Kenya has the remaining 50%.

tres. The gross best estimate of prospective resources for Bogal are 1.8 trillion cubic feet of gas based on a third-party independent resource assessment.[108]

Assumptions for expansion planning

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

5.2.2.2 Liquefied natural gas (LNG)

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

Available resources in Kenya

Due to the vast resources of natural gas worldwide, the potential for LNG is large in theory. It is restricted by required liquefaction and regasification facilities as well as competing demand on the world market. For Kenya, the large-scale import through an LNG terminal has been planned. Negotiations took place to import LNG from Qatar through the newly established Nebras Power Company which is the international investment arm of the Qatar Water & Electricity Company (QEWC). Government-to-government contracts have been underway to conclude favourable price terms for Kenya. However, the contract conclusion did not succeed, mainly because both parties were unable to agree on the LNG price. Moreover, the discovery of natural gas deposits resulted in a government shift in favour of developing the domestic resource instead.

Assumptions for expansion planning

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

[108] Source: Marketline Advantage – “Africa Oil discovers gas in Block 9 onshore Kenya” (www.marketline.com)

5.2.3 Solid fuels

5.2.3.1 Coal

Coal is a solid fossil fuel consisting mainly of carbon, i.e. organic matters, and differing quantities of other substances such as minerals, sulphur or water. It is found in and extracted from geological formations beneath the earth's surface. For utilisation in power plants, coal can be distinguished by the heating value and its composition ranging from lignite with a relatively low heating value to sub-bituminous coal. During the past 50 years, coal has been the second most important fossil energy source in the world measured by energy content, behind crude oil. It is the most important fuel for power generation worldwide due to its abundant reserves, which are distributed relatively evenly among many countries. However, the use of coal is accompanied by a strong environmental impact, such as high emissions of sulphur dioxide, heavy metals and harmful greenhouse gases.

Available resources in Kenya

Kenya avails of local coal reserves in the Mui Basin which runs across the Kitui county 200 km east of Nairobi. The coal basin stretches across an area of 500 square kilometres and is divided into four blocks: A (Zombe – Kabati), B (Itiku – Mutitu), C (Yoonye – Kateiko) and D (Isekele – Karunga). The MOEP in charge of drilling appraisal wells discovered coal seams of substantial depth of up to 27 meters in the said basin. 400 million tons of coal reserves were confirmed in Block C[109]. The MOEP has awarded the contract for mining of coal in Blocks C and D to the Chinese Fenxi Mining Industry Company. Coal mining – in particular open pit as planned for Mui - has a strong environmental and social impact. The mining will require large scale resettlement measures which have not started yet. Further, mining itself will produce considerable pollution. Exploitation of Blocks A and B has been recently awarded to China's HCIG Energy Investment Company and Liketh Investments Kenya Ltd. Coal characteristics are of much lower quality[110] than import coal from South Africa with regard to content of energy, ash, moisture and sulphur. The following table provides a comparison of the Kitui preliminary coal characteristics with characteristics of South African coal: possible import coal and low quality coal which is burnt locally.

Table 5-2: Coal characteristics in Kenya[111]

		Kenya (Mui Basin)	South Africa (Eskom general)	New Vaal (low quality coal)
Calorific value	MJ/kg	18.0	21.0	16.0
Ash content	%	37.0	30.0	40.0
Volatiles	%	25.0	23.0	16.0
Fixed carbon	%	40.0	44.0	36.0
Moisture content	%	8.0	4.0	6.0
Sulphur content	%	2.4	1.0	0.5

[109] Ministry of Energy and Petroleum, *Draft National Energy and Petroleum Policy* (16 June 2015)
[110] The fuel quality directly affects requirements for coal treatment, power plant design as well as the environmental impact such as ash disposal sulphur and carbon emissions.
[111] Source: LCPDP 2013

On a rather small scale, Kenya is importing coal in the range of half a million tonnes per year[112], mainly for use in cement production.

Assumptions for expansion planning

Due to its widespread deposits, production experience as well as relatively low costs, coal is an important fuel option for expansion planning but the negative environmental impact has to be factored in. The planned Lamu power plant would be the first coal power plant in Kenya. South African coal is used as reference fuel due to the sufficient quality and its rather short transport distance. The MOEP plans to later replace the imported coal with domestic coal from the Mui Basin. This might not be technically and economically feasible for the different coal characteristics. Instead coal power plant based on domestic coal could be developed directly near the Mui Basin in Kitui county once the mine is developed. This is also planned by MOEP for a second coal power plant.

5.2.4 Transport infrastructure for fossil fuels -implications for expansion planning

This section summarises potential means of transport as a restriction and cost factor for the use of conventional thermal electricity generation, mainly fired by fossil fuels. Details on different means of transport are provided in Annex 5.A. Fuel transport costs are provided in Annex 5.B.

In Kenya, fuel can be transported by pipeline, on road, rail or by ship. Locating thermal power stations close to its fuel source makes economic sense in terms of maximising the reliability of fuel supply as well as reducing transport cost despite incurring transmission cost due to required power evacuation. Reliable transport infrastructure is needed to facilitate proper access to power generation sites during construction as well as operation and to ensure an uninterrupted provision of fuels to thermal power generating plants.

Given the current state of Kenya's transport infrastructure, the following implications and assumptions should be taken into account when proposing new sites for thermal power generation facilities:

- Any power plant based on imported coal should be located near Mombasa, next to the country's existing port facilities and handling sites or - if available - near the planned Lamu port. It allows that imported coal can reach the power plant directly without intermediate means of transport, and a seawater intake is available for cooling purposes. This implication is subject to the feasibility of cost-effective power evacuation/installation of new transmission lines.

- For any natural gas fired power plant fuelled with imported LNG (e.g. from Qatar), the above implication applies as well.

- Any natural gas fired power plant fuelled with a domestic gas resource should be located near the gas well (e.g. in Wajir County) to reduce costs of required pipeline infrastructure. Howev-

[112] Source: KNBS, *Economic Survey 2014* (2014)

er, this implication is subject to the feasibility of cost-effective power evacuation/installation of new transmission lines.

- Any gasoil-fired power plant should be located along the existing fuel pipeline Mombasa – Nairobi; thus being closer to the country's largest load centre and its existing power transmission and distribution facilities or next to any refinery if operational in Kenya in future.

5.2.5 Fuel price forecast

The fuel price forecast has been conducted based on the most recent forecast published by the International Energy Agency (IEA), drawing on its World Energy Outlook 2015 (WEO 2015) under the "New Policies Scenario". The Consultant developed three scenarios:

a) Reference fuel price scenario, which is supposed to capture the long-term price trend from today's point of view.

b) High fuel price scenario, elevated by an all-in percentage of 20% on top of the reference scenario to capture a potential higher long term development similar to previous trends.

c) Low fuel price scenario, which is decreased by an all-in percentage of 20% deducted from the reference scenario prices to capture lower price levels for the long term.

Differences between market and forecast prices may occur in particular in the short term. This is due to the fact that forecasted values should be understood as averaged values which cannot show the often strong fluctuation of actual fuel prices. Any difference is expected to erode in the medium to long term. Details on the methodology and assumptions are provided in Annex 5.B.1.

Below the results of the reference fuel price forecast on a cif basis (cost insurance freight, i.e. including international transport costs for imported fuels) are provided. Prices exclude domestic transport costs for comparison purposes. Detailed forecast results are provided in Annex 5.B.

Although the forecast is developed with a medium to long term view the following can be said on fuel price development within the next years: fuel prices are expected to further recover from their low in 2015. For instance, crude prices are forecasted to continuously grow from an average of slightly above 50 USD / bbl in 2015, to nearly 60[113] USD / bbl in 2016 and 80 USD / bbl in 2020. Crude oil prices are important for the Kenya power system and the tariffs since they determine the prices of petroleum products – the only non-renewable fuel in the Kenyan power sector. However, the overall forecast or any deviation from actual prices in the short term and even in the medium to long term are not expected to have any considerable effect on the results and conclusions for the generation expansion. This is because (i) of the dominance of renewables in the present and even more in the future generation system, (ii) an alternative fuel (coal) is only introduced after 2020 and (iii) the medium term dispatch does not change with the costs of petroleum products (e.g. due to large price gap between petroleum products and coal).

[113] End of 2016 actual average price was below 50 USD / bbl. However, as stated in the text actual prices below (or above) forecasted values in the short term (e.g. 2016 and 2017) will not have an impact on the overall results. Only the calculated fuel costs for that years will be lower (or higher).

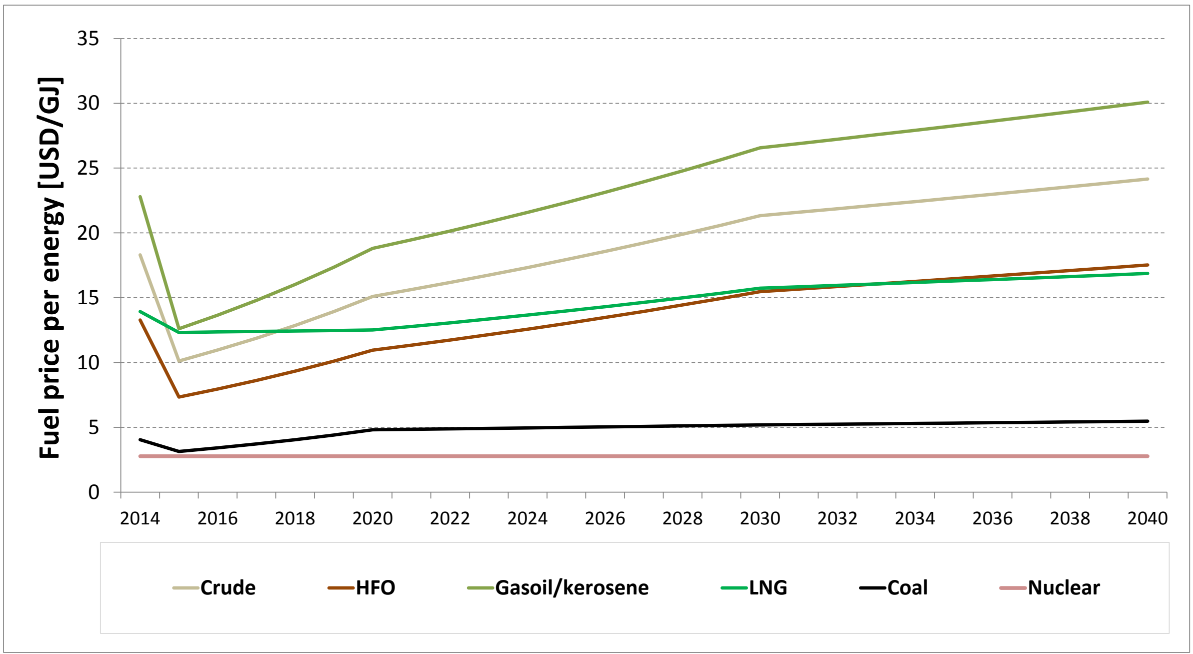

Figure 5-2: Price forecast results

Table 5-3: Fuel price forecast results – reference fuel price scenario

Fuel	Prices 2015 / 2035 [USD/ton]	Prices 2015 / 2035 [USD/GJ]
Crude oil	428 / 960	10.1 / 22.7
HFO	304 / 682	7.3 / 16.5
Gasoil / kerosene	566 / 1,270	12.6 / 28.3
Natural gas (domestic)	335 / 519	7.2 / 11.2
LNG	573 / 757	12.3 / 16.3
Coal – import (domestic[114])	66 / 112 (51 / 90)	3.1 / 5.3 (2.8 / 5.0)
Nuclear[115]	n/a	2.8 / 2.8

Coal and nuclear[116] are by far the cheapest fuels, whereas petroleum products are the most expensive ones except for HFO which is on a similar level as natural gas in the form of LNG. LNG is about three times as expensive as coal but cheaper than the petroleum products.

[114] Price domestic coal is equal to the price of import coal (on energy basis) but international transport costs deducted. Lower per ton prices for domestic coal derive from lower energy content.
[115] Based on the previous WEO 2014 (Outlook for Nuclear Power, p. 364), nuclear fuel costs about 10 USD/MWh. Being very robust to price fluctuations, nuclear fuel costs are assumed to remain fixed throughout the price forecast period.

5.3 Renewable energy sources for future electricity generation

This section provides an overview of renewable energy sources including hydropower, solar, wind, biomass, biogas, waste-to-energy and geothermal energy. Detailed information on resources, candidates, policies and recommendations on expansion paths are provided in the separate report on renewable energy sources (Long Term Plan – Renewable Energy).

5.3.1 Geothermal energy

Geothermal energy is a well-developed industry in Kenya. Projects have been implemented by both KenGen and large IPPs. Geothermal power is currently mainly being utilised in the Greater Olkaria Field located in the Hell's Gate National Park 120 km north-west of Nairobi[117]. In 2015, geothermal capacity provided nearly 50% of total power generation, up from 32% in 2014. Today, the total geothermal capacity amounts to nearly 650 MW. These power plants are equipped with single flash steam technology. The remaining capacity is owned and operated by independent power producers (IPP) using binary steam cycle technology. Due to the low short-run marginal costs, geothermal power plants generally run as base load.

Available resources in Kenya

Kenya is endowed with tremendous geothermal potential estimated at 8,000 to 12,000 MW along the Kenyan Rift Valley. A specific master plan for geothermal development of Kenya was announced by GDC with the support from JICA in 2015. This study will also provide the most recent status of geothermal resource potential in Kenya.

Today, geothermal power is only being harnessed in the Olkaria and Eburru field. In the medium and long term new geothermal reservoirs, such as Menengai, Suswa, Longonot, Akiira and Baringo Silali (comprising the fields Silali, Korosi and Paka) are planned to be developed. Other potential geothermal prospects within the Kenya Rift that have not been studied in great depth include Emuruangogolak, Arus, Badlands, Namarunu, Chepchuk, Magadi and Barrier. Geothermal studies are planned for these prospects until 2017.

The actually applicable medium and long term potential has been derived based on the current development status of the geothermal power plant pipeline. According to their achieved development stage by the time of the assessment under the present report, it is expected that an overall capacity of 539 MW of geothermal power could be implemented during the medium-term period since they are already at advanced stage of construction or planning. A breakdown of the project information is provided in the following table.

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[116] Based on the previous WEO 2014 (Outlook for Nuclear Power, p. 364), nuclear fuel costs about 10 USD/MWh. Being very robust to price fluctuations, nuclear fuel costs are assumed to remain fixed throughout the price forecast period.
[117] Besides a 2.5 MW binary plant in the Eburru field.

Table 5-4: Geothermal power plants at advanced development stage[118]

Project Name	Owner	Capacity [MW]	Project Status	Earliest year for system integration [119]	Project COD
Olkaria Well-heads	KenGen	20	Commissioned	2016	May 2016
Menengai 1 – Stage 1	Quantum, Or-Power 2020[120], Sosian Energy	103	Procurement and EPC contracting	2019	End 2018
Olkaria 1 (Unit 6)	KenGen	70	Production drilling completed; financial close	2019	Dec. 2018
Olkaria 5	KenGen	140	Production drilling completed; financial close	2019	Mid 2019
Olkaria topping unit[118]	KenGen	60	Steam available, study on-going	2019	End 2018
Olkaria 1 rehabilitation	KenGen	6	Financing committed, tendering in progress	2019 – 2020	End 2018, Mid / end 2019
Olkaria 6	KenGen	140	Production drilling completed	2021	2nd half 2020
TOTAL		**539**			

It is estimated that some further 2,400 MW geothermal capacity can be implemented during the LTP period until 2035. The following table provides an overview of the geothermal field development and potential considering the current status of the identified geothermal projects. In addition, the theoretical potential of each field is illustrated.

Table 5-5: Geothermal potential by field

Field	Existing capacity MW	Medium term potential[118] MW	Medium and long term potential[121] MW	Theoretical potential[122] MW
Olkaria	620	436	856	1,500
Menengai	0	103	763	1,600
Eburru	2	0	25	30
Longonot	0	0	140	700
Akiira	0	0	140	350
Suswa	0	0	450	600-750

118 Considering medium-term period until 2020; all plants considered as committed except for Olkaria topping unit which is scheduled as a candidate by the expansion optimisation considering system needs.
119 Estimated based on results of candidates assessment (see Chapter 6.5). Year considers full system integration; Project COD based on review / estimate consultant
120 Consortium consisting of Ormat, Civicon, Symbion
121 Estimates based on results of candidates assessment (see Chapter 6.5)
122 Estimated potential as presented in GDC strategic plan (April 2013) or additional information received

Field	Existing capacity MW	Medium term potential[118] MW	Medium and long term potential[121] MW	Theoretical potential[122] MW
Baringo Silali[123]	0	0	600	3,000
Emuruangogolak	0	0	no projects defined	650
Arus	0	0	no projects defined	200
Badlands	0	0	no projects defined	200
Namarunu	0	0	no projects defined	400
Chepchuk	0	0	no projects defined	100
Magadi	0	0	no projects defined	100
Barrier	0	0	no projects defined	450
Total	**622**	**539**	**2,974**	**9,880-10,030**

Assumptions for expansion planning

Already today, geothermal power contributes significantly to the Kenyan generation mix. Considering the tremendous potential of around 10 GW along the Kenyan Rift Valley, it can be expected that geothermal power will play an essential role in the future Kenyan power system. Deep knowledge and expertise in geothermal exploration, drilling, power plant implementation and operation is already present in the country today. However, drilling risks, high upfront costs and a rather long implementation period have to be taken into account in the planning.

Geothermal is considered as “conventional" renewable energy source which is already well developed in Kenya and can compete with other sources. In the expansion planning this is done through the fully identified candidates (see Chapter 6) which are drawn by the system according to their costs and plant characteristics (including earliest year of system integration).

Geothermal power provides reliable base load power at low operating cost. Single flash technology which is mainly being utilised in Kenya today, is restricted in providing flexible power due to technical reasons. Binary systems, however, are able to be operated very flexible. With regard to future geothermal expansion and considering the power system needs (load following, regulation control), it is thus recommended to analyse the opportunity for installing binary power plants. The possibility of implementing binary bottoming unit in a single flash plant should also be evaluated.

5.3.2 Hydropower

In the 1990s, the Kenyan power generation system was dominated by hydropower with a share of 70% of the total installed generation capacity and 80% of the total electricity generation. Due to several droughts in the past decade, the hydropower plants could, at times, not provide sufficient electricity any more. This resulted in an intensified construction of thermal power plants that are

[123] Comprising the fields Silali Korosi and Paka

independent of the fluctuations in hydrology. Only two large hydropower plants[124], namely Sondu Miriu (60 MW) and Sang'oro (21 MW) have been commissioned since then. Thus, the share of hydropower in the total installed system capacity has decreased to 36 to 37% until 2014 / 2015. In 2015 and 2016, the total effective capacity of large hydropower plants was 785 MW. Additionally, 14 MW of small hydropower capacity was available.

Available resources in Kenya

As defined by the National Water Resources Management Strategy (NWRMS), Kenya is divided into six catchment areas. The areas and the main rivers are summarised in the table below.

Table 5-6: Areas, major rivers and hydropower potential of the six catchment areas[125]

Catchment area	Area [km²]	Major Rivers	Identified hydropower potential [MW][126]
Lake Victoria North	18,374	Nzoia R., Yala R.	151
Lake Victoria South	31,734	Nyando R., Sondu R., Kuja (Gucha) R., Mara R.	178
Rift Valley	130,452	Turkwel R., Kerio R., Ewaso Ngiro South R.	305
Tana	126,026	Tana R.	790
Athi	58,639	Athi R., Lumi R.	60
Ewaso Ng'iro North	210,226	Ewaso Ngiro North R., Daua R.	0
TOTAL:	**575,451**		**1,484**

The figure below shows the major rivers of the six catchment areas and location of existing large hydropower plants in Kenya. As can be seen, six out of the nine large HPPs are located in the Tana catchment area, with the Tana River being the major source of water supply for the respective reservoirs.

[124] In the framework of the present study, hydropower plants with an effective capacity of at least 20 MW are defined as large hydropower plants.
[125] Source: NWMP – JICA based on data from WRMA
[126] Source: NWMP - JICA

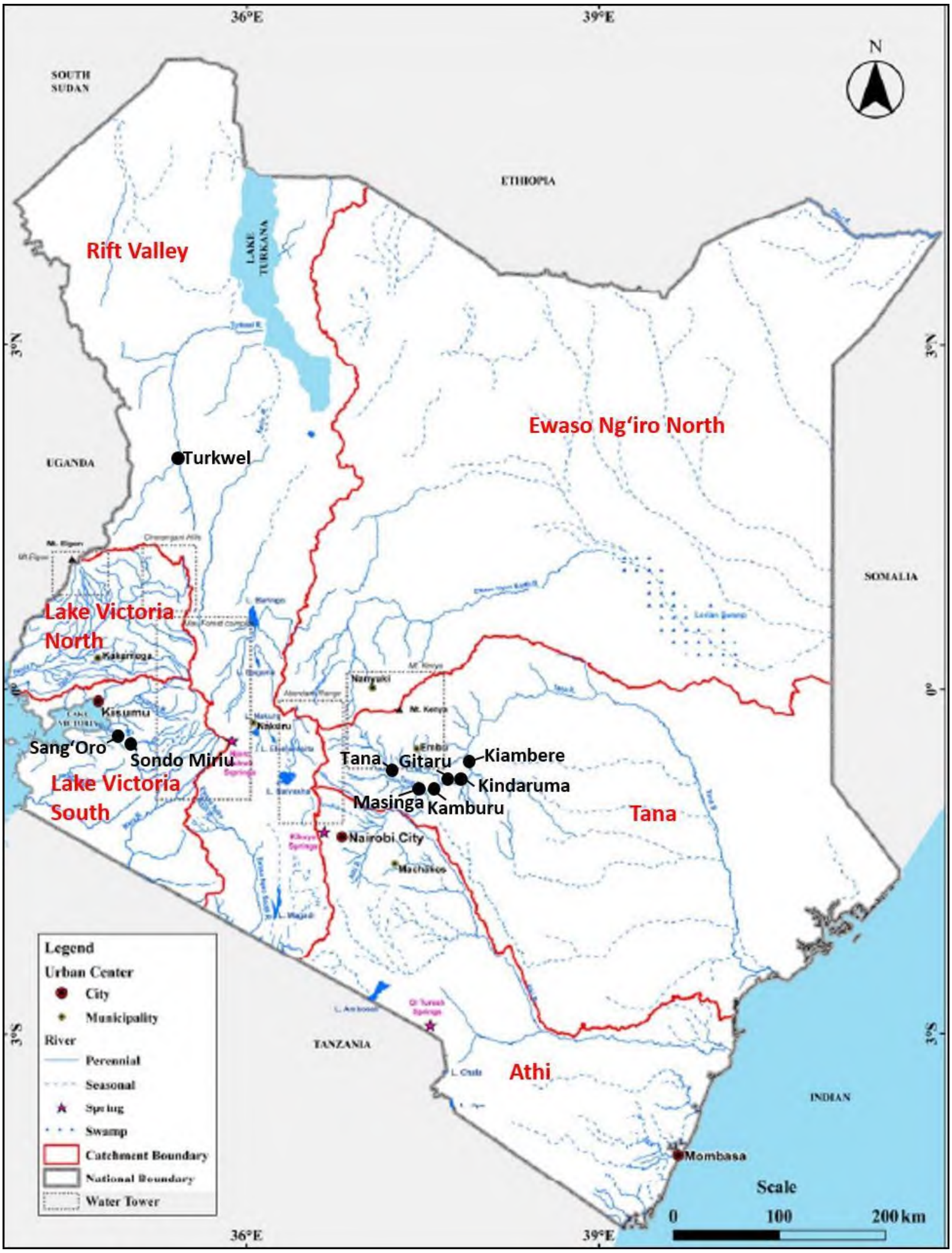

Figure 5-3: Areas and major rivers of the six catchment areas and location of existing large hydropower plants[127]

With regards to the location of hydropower plants in Kenya, there are four overall groups, namely

[127] Source of base map: National Water Master Plan

1) “Seven Forks” located in the Tana Catchment Area with Masinga HPP, Kamburu HPP, Gitaru HPP, Kindaruma HPP and Kiambere HPP (a total effective capacity of 581 MW)

2) “Upper Tana” HPPs located in the upper reach of the Tana River with Tana HPP, Wanjii HPP, Ndula HPP[128], Mesco HPP, Sagana HPP (total effective capacity of 29 MW)

3) Turkwel HPP located in the Rift Valley Catchment Area (effective capacity of 105 MW)

4) Lake Victoria South Catchment Area with Sondo Miriu HPP[129], Sang’oro HPP[130], Sosiani HPP and Gogo HPPs (total effective capacity of 82 MW)

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

There is a large pipeline of small hydropower projects promoted under the FiT scheme. Feasibility studies of 27 projects comprising a total capacity of 115 MW were already submitted end of 2016. PPA negotiations of thirteen of these projects with a total capacity of 37 MW are completed successfully, most of the PPAs signed. Four projects with a total capacity of 15 MW are under construction and four projects have been already completed in recent time (not all of them having a finalised PPA). Furthermore, feasibility studies of more than 20 small hydropower projects comprising a total capacity of more than 100 MW are on-going.

Assumptions for expansion planning

In the framework of the generation expansion planning only Karura HPP and High Grand Falls[163] is considered as “secured candidates”, which can be scheduled in the planning process. Karura HPP is within the responsibility of MOEP and the planning process of High Grand Falls is considered quite advanced. The remaining large hydropower plants are further assessed as potential future candidates. However, as multipurpose dams the responsibility for their scheduling and implementation is not solely within the power sector.

In addition, small hydropower projects which are under construction, commissioned or with completed PPA negotiations are considered to be implemented until 2020. Furthermore, projects whose feasibility studies were already approved end of 2015 are estimated to be commissioned until 2025. From 2025 onwards, linear extrapolation of small hydropower capacity is assumed (see section 7.3.4 for assumed expansion).

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[128] Ndula HPP has been phased out in 2011.
[129] Commissioning of Sondo Miriu HPP was in 2008.
[130] Commissioning of Sang’oro HPP was in 2012.

5.3.3 Wind energy

There are several types of wind turbines for generating electricity. However, in recent times, the horizontal axis three bladed turbine has become the most common configuration. Modern wind turbines vary in size with two market ranges:

- Small units rated at just a few hundred watts up to 50-80 kW in capacity, used mainly for rural and stand-alone systems; and

- Large units, from 150 kW up to 7 MW in capacity, used for large-scale, grid-connected systems.

However, in established markets, commercial proven utility scale wind turbine capacities (not considering off-shore applications) usually range from 1.5 MW up to 3.5 MW. As the small scale units are mainly used for off-grid applications, such as water pumping, they are not considered any further in this report.

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

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

<u>Available resources in Kenya</u>

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

At present (end 2015), the only grid connected wind power plant is the Ngong Wind Farm, operated by KenGen. The first two wind turbines of Ngong Wind Farm were commissioned back in 1993. The original two turbines have already retired. Their production data are not published, but the feasibility study determined the potential annual energy yield to be 14.9 GWh, which represents almost 3,000 full-load hours. The existing wind farm was developed and commissioned in stages (Ngong 1, Phase I (5.1 MW) in 2008, Ngong 1, Phase 2 (6.8 MW) and Ngong 2 (13.6 MW) in 2015). They are located in the northern part of the Ngong Hills, about 20 km south-east of Nairobi. Ngong 1 Phase I comprises of six Vestas V52 turbines rated at 850 kW each with an average capacity factor of 30% from 2012 to 2014. Ngong 1 Phase 2 and Ngong 2 consist of 24 Vestas V52 turbines.

In Kenya, the present pipeline under the FiT scheme of projects going through PPA negotiations shows an overall proposed capacity of 550 MW wind power distributed amongst 13 projects. However, additional sources of information suggest a much higher figure in the long term.

Taking into account the earliest CODs as a result of the generation candidates assessment (please see Chapter 6 of this report as well as Annex 6.D.5 for details), the wind power capacity could reach almost 2,500 MW in the long term. The potential wind expansion is visualised in the figure below.

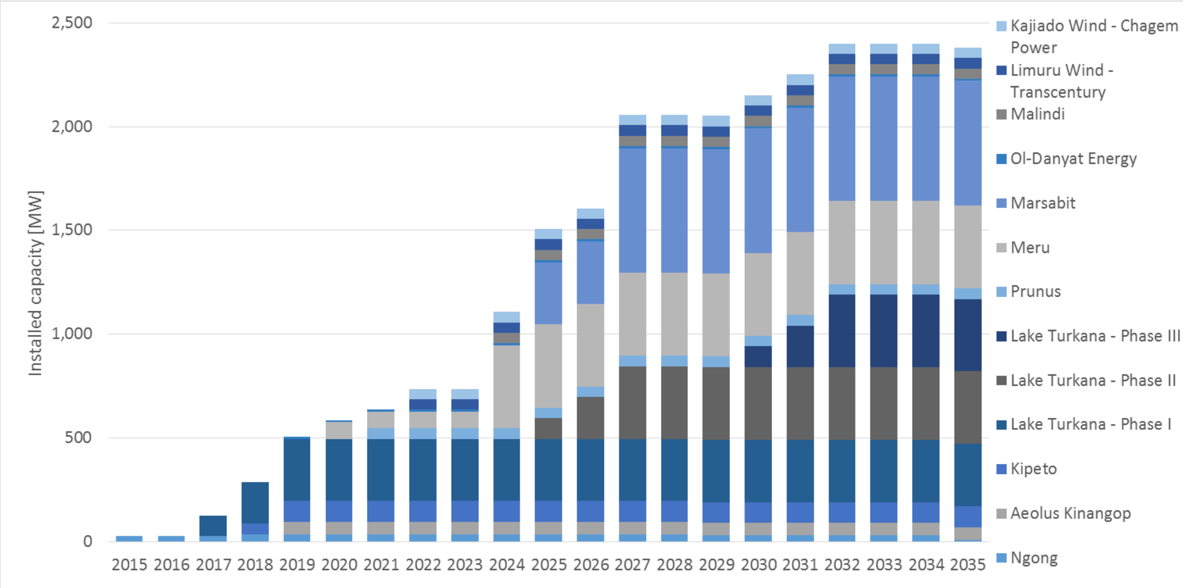

Figure 5-4: Potential wind capacity development in Kenya in the long term

The figures indicate the ambitious wind power project development efforts in Kenya. If all potential projects could indeed be realised until 2032, the total installed wind power capacity would reach roughly 50% of the identified theoretical potential in the country.

<u>Assumptions for expansion planning</u>

A considerable potential for wind power development exists in Kenya. Regardless of the economic implications, the utilisation of this potential might have significant impacts on the operation of the power system in future years. Depending on the generation characteristics of wind plants, additional reserve capacity might be required to safeguard the adequate operation of the power system. This might lead to substantial excess cost.

The expansion planning thus considers wind power development as a scenario parameter. Based on a reference case that reflects the pipeline of planned wind power projects, scenarios determine the impacts of an accelerated and slowed-down deployment of wind resources in Kenya (see section 7.3.4 for assumed expansion, in the medium term period roughly 550 MW is already committed which is respectively considered in the generation modelling). Results help to determine adequate development corridors and highlight potential excess cost due to the promotion of wind power.

5.3.4 Biomass, biogas and waste-to-energy

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

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

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

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

Available resources in Kenya

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

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

Biomass can appear as a rather modest potential at present, but could increase significantly with the agro industrial development and mainly through sugar mills revamping and future concentration of other agro industries. A specific survey of agro residues in the medium and long term, combined with the load centre and planned network could suggest lower investments in the power sector than conventional power supply and transmission. Since the government intends to increase sugar production, it might be useful for MOEP and ERC to collaborate more closely with the Ministry of Agriculture to locate the future sugar mills, with a view to optimise power (and ethanol) production in the long term.

In the long term, biomass cogeneration (also considered as industrial energy efficiency and could benefit from related support programmes) could represent a significant share of power production in rural areas. Compared to stand alone power production for the plant, the marginal investment to produce excess power for the grid is generally quite cost effective for the agro-industries. This is a major advantage from a macroeconomic point of view.

Assumptions for expansion planning

The future of successfully implemented biomass projects in Kenya will strongly depend on the development of the agricultural sector. The expansion planning considers the existing Mumias, Kwale, Cummins (under construction) and Biojoule (supply to the grid assumed for 2018, 2017, 2017, and 2016 respectively). Due to the uncertainty whether full capacity will be immediately available from these plants the total available biomass capacity is reduced by 10 MW in 2017 and 2018. No projects are at advanced development stage to be considered as additional committed capacity in the medium term. Generic expansion of biomass (mainly bagasse based) capacity (which will need some lead time to be developed) is assumed to start in 2020 with annually 11 MW (see section 7.3.4 for assumed expansion). Power generation from municipal solid waste are not expected to play a significant role in the future. Their profitable operation depends on benefits beyond the power sector such as waste collection and hygiene. Consequently, this option is not considered in the long-term planning as a candidate.

5.3.5 Solar energy – photovoltaic (PV)

Photovoltaics (PV) devices convert solar energy directly into electrical energy. The amount of energy that can be produced is proportional to the amount of solar energy available on a specific site. PV has a seasonal variation in electricity production, with the peaks generally following months with the highest solar irradiation. Due to the stable climate, PV systems operating along the equator typically have a fairly consistent exploitable solar potential throughout the year. Electricity production varies on a daily basis, with no generation when the sun has set. Short-term fluctuations of weather conditions, including clouds and rainfall, impact the hourly amount of electricity that is produced

Available resources in Kenya

Thanks to its latitude across the equator (4.5° South and 5° North), Kenya is endowed with very high solar resources, among the highest 10 of Sub-Saharan African countries. In favorable regions, the global horizontal irradiation (GHI) is up to 2,400 kWh/m²/year.

A publicly available Solar and Wind Energy Resource Assessment (SWERA) mapping exercise was completed and published by UNEP, with GEF funding in 2008. It compiles information relating to the solar and wind energy resource, including data capturing and analysis, computation and mapping using GIS and other technologies to produce national solar and wind atlases for Kenya. Moreover, a comprehensive report funded by the World Bank on Renewable Energy Resource Potential in Kenya, carried out by Economic Consulting Associates and Rambol in August 2012, provides useful background information on renewable energy, resources potential and current projects.

Republic of Kenya

IED LAHMEYER INTERNATIONAL

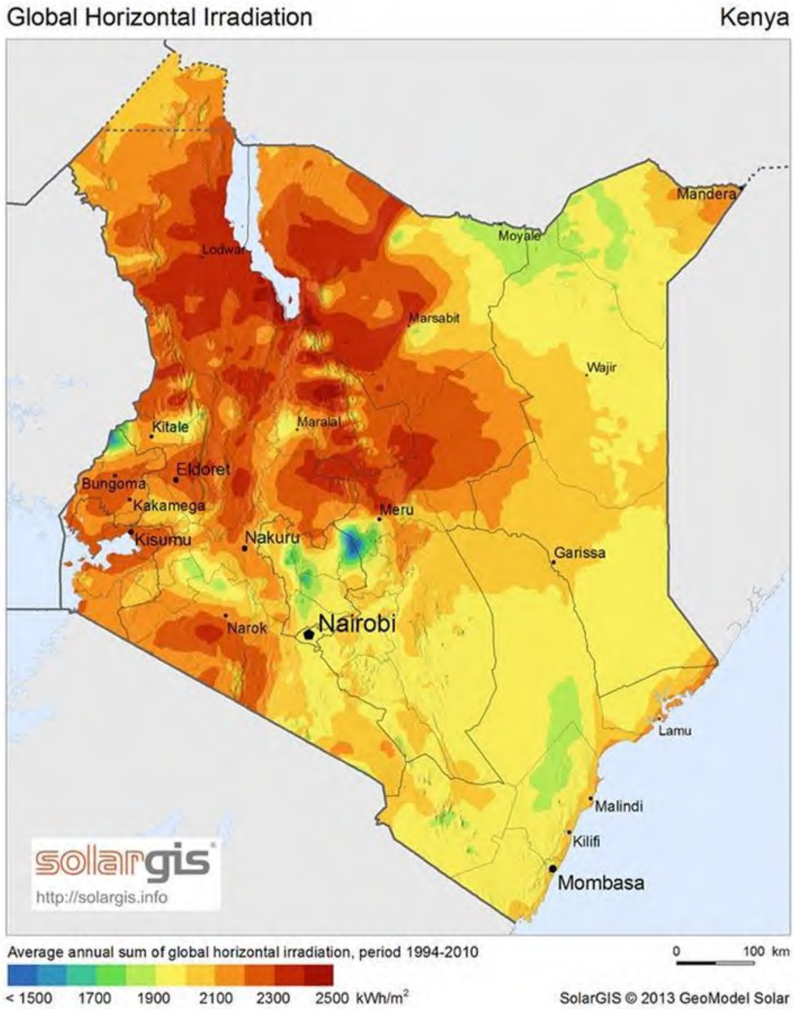

Figure 5-5: GHI map of Kenya

At present, there is a project pipeline under the FiT scheme with feasibility studies, amounting to an overall capacity of more than 500 MW distributed amongst some 20 projects. Eleven of these projects have finalised or ongoing PPA negotiations, amounting to an overall installed capacity of some 300 MW.

<u>Assumptions for expansion planning</u>

The total solar energy potential in Kenya is several thousand times the expected Kenyan electricity demand. Calculating the theoretical technical potential based on the resources is therefore not very meaningful. For long-term expansion planning potential solar PV development is analysed by a scenario analysis. Expansion pathways of generic PV projects are assessed regarding their technical and economic implications (see section 7.3.4 for assumed expansion). A committed 50 MW grid connected PV plant is considered to be available in 2019.

5.3.6 Solar energy – concentrated solar power (CSP)

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

The development of commercial CSP plants is still in its infancy with approximately 4 GW (compared to 150 GW of PV) of installed capacity worldwide up to 2014, with United States and Spain having about 1.5 GW and 2.3 MW of installed capacities respectively. However it is expected to grow in future as an additional 11 GW of capacity is in planning or under development for operation by 2020.

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

In Sub-Saharan Africa, South Africa leads the early development of CSP, having already allocated 400 MW towards CSP development with a potential pipeline of a further 1 GW over the next few years. Despite the large potential that this technology could have in some parts of Africa, a reduction in cost of electricity generation is essential to improve CSP competitiveness against some of the currently cheaper renewable alternatives.

<u>Available resources in Kenya</u>

CSP generation requires direct normal irradiation (DNI) to operate (i.e. a direct angle of incidence at clear skies without clouds). The map in Figure 5-6, shows the solar direct normal irradiance in the various regions of the country. As mentioned earlier, Kenya is endowed with very high solar resources and is among the highest 10 of Sub-Saharan African countries. Its solar direct normal irradiance is around 2,300 kWh/m²/year in favorable regions. However, there are presently no operational CSP plants in Kenya.

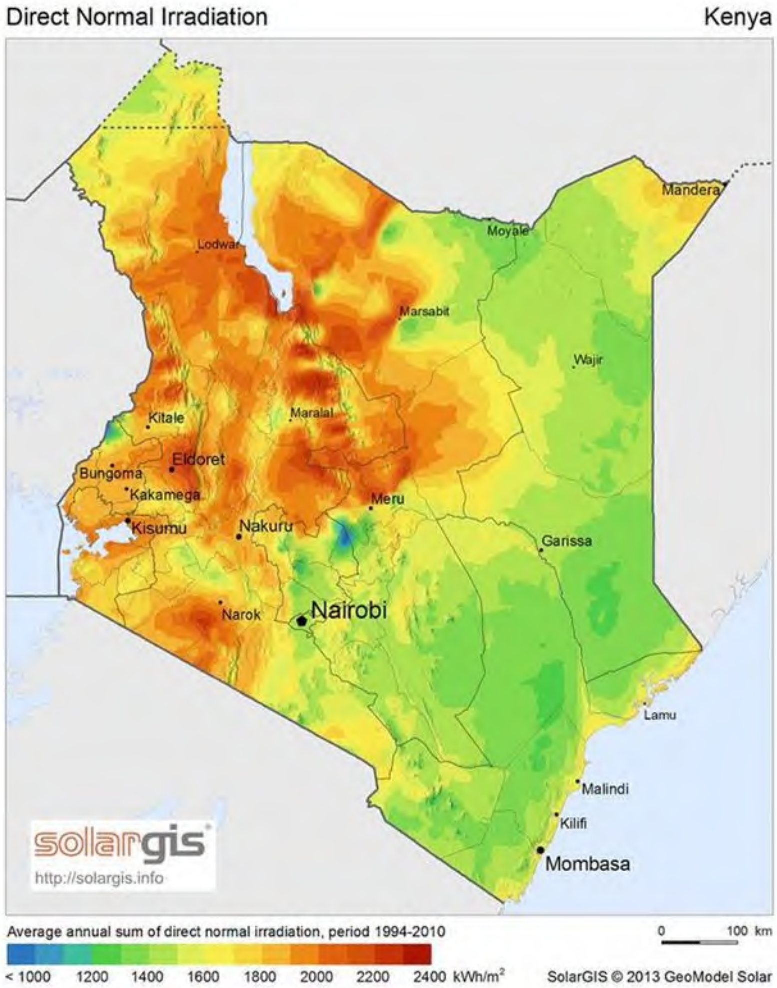

Figure 5-6: DNI map for Kenya

Between 2020 and 2030, CSP could become economically competitive with conventional base-load power due to reduced CSP costs and the increasing prices of fossil fuels and CO_2. The global installed capacity could reach about 350 GW by 2030. The United States, North Africa and the Middle East would be major producers of CSP electricity. In some specific areas of Kenya, CSP plants could be envisaged in 20 years from now.

Assumptions for expansion planning

Due to currently rather unclear development prospects of CSP projects and the considerable amount of more (cost-) competitive renewable alternatives (especially geothermal and wind) in Kenya, CSP is not addressed in the medium and long term expansion planning. However, it is strongly recommended to closely monitor the global development of the technology in future years.

5.4 Other energy sources for future electricity supply

Besides fossil fuels and renewable energy sources as a basis for power generation for a particular country, there is nuclear energy and energy imported from neighbouring countries through interconnections (which could be based on various types of energy sources) which might reduce the need for energy generation. They are detailed below.

5.4.1 Nuclear fuel

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

Available resources and assumptions for expansion planning

At present, only low levels of uranium oxide have been discovered in Kenya. However, exploration of uranium is still on-going.

Worldwide uranium reserves are estimated at 5 million tonnes[131]. At current consumption levels[132], these reserves would last more than 100 years as stated by official organisations[133]. Growing or diminishing future demand should affect the time taken for complete depletion of the resource. Nuclear energy is not a renewable energy. Compared to fossil fuels and the technology and investment to build and operate a nuclear power plant (NPP), the fuel supply is of minor importance for the evaluation of nuclear power as an expansion candidate. However, the relatively low costs for fuel as well as the considerably lower amounts of fuel to be replaced, stored and transported are advantages of nuclear power in terms of supply dependency and fluctuation of fuel cost.

Nuclear power is considered as an expansion candidate option in the long term only. A detailed analysis is provided in section 6 and Annex 6.D.8.

[131] Source: World Nuclear Association
[132] 563 million tonnes of oil equivalent nuclear energy consumption in 2013; source: BP Statistical Review of World Energy 2013
[133] Source: OECD Nuclear Energy Agency, International Atomic Energy Agency: Uranium 2011: Resources, Production and Demand

5.4.2 Interconnections with neighbouring countries

Interconnections with neighbouring countries provide mutual benefits. This may include additional sources of energy and power, the provision of ancillary services (e.g. reactive power, black start power) and an overall higher security of supply as well as lower costs from sharing of generation back-up capacity or combining complementary generation systems (e.g. hydro versus thermal based generation). Currently, the Kenyan national grid is interconnected with Uganda and with Tanzania via 132 kV transmission lines. The purpose of these interconnections is to mutually support system stability (with Uganda) and to supply isolated areas in borders areas (with Tanzania). The interconnection with Uganda is about to be utilised for power exchange to Rwanda.

With the objective to increase transfer capacities and flexibility of grid operation and to improve sustainable electricity supply in Kenya, various interconnection projects are in the planning and implementation stage.

<u>**Eastern African Power Pool**</u>

The Eastern African Power Pool (EAPP) is an intergovernmental organisation established in 2005 with the objective to provide an efficient framework for pooling electricity resources and to promote power exchanges in East Africa. So far, ten countries have joined EAPP, namely Burundi, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Libya, Rwanda, Sudan, Tanzania and Uganda. As part of the "Regional Power System Master Plan and Grid Code Study" published in 2011, major interconnection projects have been identified as well as planning criteria to support interregional power exchange and a phased interconnection plan for the EAPP countries has been developed. Additionally, a regional master plan study for the EAPP region has been carried out by EA (Energy Analysis) and Energinet.dk from June 2013 to 2014[134].

Three interconnection projects between Kenya and neighbouring countries are expected to be commissioned within the next years. More projects are in the planning stage. The actual status of implementation and planning of interconnections is described below. Interconnections are further analysed in the network studies.

1) **Interconnection with Ethiopia**

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

The Ethiopian Electric Power (successor of the restructured Ethiopian Electric Power Corporation EEPCo) will own the interconnection assets in Ethiopia. The interconnection assets on the Kenya site will be owned by Kenya Electricity Transmission Co. Ltd. (KETRACO). The Kenyan component of the project is financed by the African Development Bank (AfDB), World Bank (WB), Agence Française de Développement (AFD) and the Government of Kenya (GoK).

[134] The results of the study will be published after approval by EAPP.

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

Construction has started in 2015 and commercial operation of the HVDC is expected for 2019 (see 6.5.10 and Annex 6 for details).

2) **Interconnection with Uganda**

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

The project involves the construction of a 400 kV double circuit overhead line between Lessos in Kenya and Tororo in Uganda that will be financed by AfDB and GoK. The transmission line will be designed for a capacity of 1,700 MW and is expected to be commissioned by the end of 2016. The objective of this line is to support the market for power exchange within the EAPP. However, there is no PPA signed between Uganda and Kenya until now.

The existing interconnection with Uganda will be used for power export to Rwanda. A 5-year PPA from 31 July 2015 onwards was signed to export 30 MW from Kenya to Rwanda. The PPA will be reviewed after 2.5 years.

3) **Interconnection with Tanzania**

A 400 kV double circuit transmission line with a total length of 507.5 km between Tanzania and Kenya is in the implementation phase. 93 km of the line will be located in Kenya and 415 km in Tanzania. The overhead line will originate from Isinya substation in Kenya, pass Namanga and Arusha and terminate at Singida substation in Tanzania. The interconnector is designed for a capacity of 1,700 to 2,000 MW. On the Kenyan side, this project also includes the extension of the existing Isinya substation. The commercial operation is envisaged for March 2017. The objective of this line is to support the market for power exchange within the EAPP. However, there is no PPA signed between Tanzania and Kenya until now.

An additional interconnection from Rongai through Kilgoris to complete the Lake Victoria Ring (through Tanzania to Rwanda) is under investigation. At the time of this report, no information was available when or whether it is going to be built and how it relates to the above mentioned interconnection which is under implementation.

The following table provides an overview of the key characteristics of the planned interconnection projects.

Table 5-7: **Planned interconnectors and PPAs in the MTP period**

Parameter	Unit	Tanzania-Kenya	Uganda-Kenya	Ethiopia-Kenya
Head station (Kenya)		Isinya	Lessos	Suswa
Head station (neighbouring country)		Singida	Tororo	Welayta Sodo
Total distance	km	508	137	1,045
Length of T/L in Kenya	km	93	127	612
Technology		AC	AC	DC (bipolar)
Voltage level	kV	400	400	500
Number of circuits	#	2	2	na
Capacity	MW	1,700 to 2,000	1,700	2,000
PPA status		no PPA signed	no PPA with Uganda; 5-year PPA with Rwanda, 2015 onwards; reviewed after 2.5 years	25-year PPA signed
Contracted net transfer capacity (NTC)	MW	na	30 (with Rwanda)[135]	400
COD		2017	2016	2019
Financing		AfDB, JICA	AfDB, GoK	AfDB, IDA, AFD, GoK

Considerations for expansion planning and electrical network studies

The PPA with Rwanda through the already existing interconnection with Uganda is taken into account for the generation modelling conducted in the present study. The agreed purchase from Ethiopia is considered in both the generation and network expansion modelling with at least 300 MW (take or pay) and up to 400 MW maximum available capacity. Additional purchase of energy and capacity through the same line is possible though there are no terms yet, neither on price nor available energy and capacity nor possible flexibility of supply. The planned interconnections with Uganda and Tanzania are not taken into account in the energy balance, since no PPAs or other reliable information that would define power purchases with these countries are currently under discussion. However, the new lines are considered in the expansion analysis for potential exports of possible surplus generation (see chapter 7).

Interconnections with neighbouring countries provide mutual benefits such as purchasing energy from neighbouring countries at a lower price and receiving additional security of supply. In this regard, it is recommended to further extend interconnections with neighbouring countries in the long-term.

[135] Until commissioning of the planned 400 kV interconnector between Kenya and Uganda, electricity will be transferred via the existing 132 kV transmission line. At the time of this report export has not started yet; for the expansion planning it is assumed to start in 2017.

6 EVALUATION OF POWER GENERATION EXPANSION CANDIDATES

This section contains the evaluation of power generation candidates as a preselection and preparation for the subsequent expansion planning steps. It is partly based on the previous chapter of available and potential energy sources as well as a wide range of economic, technical and other criteria.

6.1 Key results and conclusions

The key results, conclusions and planning recommendations are:

- For base load (with high capacity factors) geothermal power plants are ranked best in terms of generation costs, followed by the (generic) bagasse power plant and the HVDC. Nuclear power plants show the highest costs for all base load plants. Even at maximum availability they are less economical than coal and natural gas fuelled candidates. This stems from the high investment costs for a 600 MW nuclear unit. For any of the base load candidates the generation costs will strongly increase with decreasing capacity factors due to their high investment costs.

- For intermediate load plants coal power plants are cheaper than gas fuelled CCGT plants (domestic gas and LNG). For lower capacity factors (e.g. 50%) the Wajir NG-CCGT candidate appears to be the preferred option (if domestic gas is available), followed by Lamu “tender” coal, generic bagasse plant and Kitui coal power plant. If flexibility is required by the system CCGTs are the preferred option. The same is true for hydropower plants at even lower costs.

- For peaking units hydropower plants are the preferred option (with the lowest generation costs for Karura HPP). The alternatives are gasoil fuelled gas turbine and HFO fuelled MSD but at much higher generation costs though easier to develop. For assumed capacity factor of 20% the MSD engine is cheaper than the gas turbine but this ranking will change for capacity factors lower than 10%: due to the low investment costs this technology will be the preferred option in case of rare utilisation (e.g. reserve capacity).

- With regard to the volatile RE candidates, the analysis reveals that Lake Turkana wind farm has by far the lowest generation costs, followed by the generic wind farm and the generic PV power plant (with one third higher costs).

6.2 Objectives and approach

The objective of this section is twofold: conducting a techno-economic evaluation of the power generation[136] expansion candidates for the 20-year long-term period from 2015 until 2035. It fur-

[136] This chapter deals with candidates for power generation. Power transmission candidates are identified and analysed in chapter 8 (transmission planning). The only exception is supply through interconnections with Ethiopia.

ther allows a prioritisation of committed and candidate projects for the medium-term period in order to harmonise their scheduling.

The evaluation enables the prioritisation and selection of suitable candidates for the subsequent power system expansion planning. It will allow for the harmonisation of the existing power generation plans with power system expansion needs for the medium and long term, e.g. for least cost planning, operational system requirements, changes in demand projections. Furthermore, the focus on relevant power generation scenarios by reducing successive expansion planning efforts (i.e. system simulations) for the long-term planning will be enabled.

The expansion candidates are evaluated according to quantitative and qualitative planning criteria, which involve the following two-step approach.

First, an **economic assessment** is carried out. Here, quantitate planning criteria are scrutinised by the screening curve method which plots the levelised electricity cost (LEC) of a generation unit as a function of either the capacity factor or the discount rate, where applicable.

Second, a **prioritisation assessment** bases on qualitative planning criteria and supplements the quantitative analysis. This task includes a PESTEL analysis, which covers **P**olitical, **E**conomic, **S**ocial, **T**echnical, **E**nvironmental and **L**egal criteria for the assessment of the expansion candidates. For each candidate (category) a brief introduction and a summary of results is provided in Annex 6.D.

6.3 Catalogue of expansion candidates

This section introduces suitable expansion candidates for the medium and long term period. It provides background information on their identification as well as basic data. It also provides a description of the candidates, which are categorised according to their primary energy source.

The sources and criteria applied for the identification of suitable candidates for the catalogue are:

- Recent power sector plans: the “10 Year Power Sector Expansion Plan 2014-2024” (10 YP) and the MTP 2015 – 2020 submitted by the Planning Team in 2014 and 2015 respectively served as basis for a first identification of the power system expansion candidates. The reports mirror recent government plans for a large-scale generation expansion (5000+MW generation plan) in the short to medium term. In addition, the Consultant considered other relevant planning documents, e.g. the National Water Master Plan, power generation projects based on renewable energy sources registered under the feed-in tariff scheme, and available status updates on the candidates of the above mentioned reports.

- Available energy sources for power generation in Kenya (i.e. already in use, already available, and potentially available in future) as analysed in chapter 5.

- Siting of plants: the siting of expansion candidates is in most cases determined by the availability of the primary energy source at the particular site. Contrary to renewable energy based plants that are attached to their geographic location by nature, thermal power plants typically represent a more flexible siting. The infrastructure needs for power evacuation, cooling as well as fuel supply have been considered in the analysis.

- Sizing of plants: regarding the sizing of expansion candidates, the installed capacities – if not available in official planning documents – are derived from:
  - Expansion requirements in terms of capacity and energy needs derived from the demand-supply gap for different demand forecast scenarios;
  - Restrictions on the size of the largest unit in the system in terms of technical limitations regarding system stability as well as economic criteria (e.g. cost for back-up capacity of cold and spinning reserve); and
  - Actual unit sizes commonly in use for the respective power plant technology in similar electricity systems in the region and worldwide.
- Industry standards and common practice: that is, available technologies for power generation worldwide and relevant hands-on experience in similar countries.

6.3.1 New candidates

This sub-chapter presents a summary table of the identified power plant candidates which are analysed in the economic assessment and in the prioritisation assessment. A map of the power plant sites is provided in Annex 6.A. For each candidate (category) a brief introduction and a summary of results is provided in Annex 6.D.

Table 6-1: New generation expansion candidates - catalogue

ID	Name	Net capacity [MW]	Economic assessment	Prioritisation assessment
1	**Coal ST (steam turbine) power plant**			
1.1	Lamu Coal ST		X	X
1.1.1	Lamu Coal ST 4x245 MW	982	X	
1.1.2	Lamu Coal ST 3x327 MW[141]	982	X	
1.1.3	Lamu Coal ST “tender” 3x327 MW[141]	982	X	
1.2	Kitui Coal ST		X	X
1.2.1	Kitui Coal ST 4x240 MW	960	X	
1.2.2	Kitui Coal ST 3x320 MW	960	X	
2	**(L)NG CCGT (Liquefied Natural Gas Combined Cycle Gas Turbine) power plant**			
2.1	Dongo Kundu LNG CCGT		X	X
2.1.1	Dongo Kundu LNG CCGT 2x(2+1)	751	X	
2.1.2	Dongo Kundu LNG CCGT 1x(2+1)	766	X	
2.1.3	Dongo Kundu LNG CCGT 1x(2+1), 3-pressure	789	X	

ID	Name	Net capacity [MW]	Economic assessment	Prioritisation assessment
2.2	Wajir NG CCGT		X	X
2.2.1	Wajir NG CCGT 2x(2+1)	727	X	
2.2.2	Wajir NG CCGT 1x(2+1)	752	X	
2.2.3	Wajir NG CCGT 1x(2+1), 3-pressure	698	X	
3	**Geothermal power plant**			
3.1	Olkaria 1 Unit 6	70	X	X
3.2	Olkaria 5	140	X	X
3.3	Olkaria 6	140	X	X
3.4	Olkaria 7	140		X
3.5	Olkaria 8	140		X
3.6	Olkaria 9	140		X
3.7	Olkaria Topping	60		X
3.8	Eburru 2	25	X	X
3.9	Menengai 1 Phase I – Stage 1	103	X	X
3.10	Menengai 2 Phase I – Stage 2	60		X
3.11	Menengai 2 Phase I – Stage 3	100		X
3.12	Menengai 2 Phase I – Stage 4	200		X
3.13	Menengai 3 Phase II – Stage 1	100		X
3.14	Menengai 4 Phase II – Stage 2	100		X
3.15	Menengai 4 Phase II – Stage 3	100		X
3.16	Menengai 4 Phase II – Stage 4	100		X
3.17	Menengai 5 Phase I – Stage 1	300		X
3.18	Menengai 5 Phase I – Stage 2	300		X
3.19	Suswa Phase I – Unit 1	50		X
3.20	Suswa Phase I – Unit 2	100	X	X
3.21	Suswa 2 Phase II – Stage 1	100		X
3.22	Suswa 2 Phase II – Stage 2	100		X
3.23	Suswa 2 Phase II – Stage 3	100		X
3.24	Suswa 2 Phase II – Stage 4	100		X
3.25	Suswa 2 Phase II – Stage 5	200		X
3.26	Baringo-Silali Phase I – Stage 1	100		X
3.27	Baringo-Silali Phase I – Stage 2	100		X
3.28	Baringo-Silali Phase I – Stage 3	200		X
3.29	Baringo-Silali Phase I – Stage 4	100		X
3.30	Baringo Silali Phase II – Stage 1	100		X
3.31	Baringo Silali Phase II – Stage 2	100		X

ID	Name	Net capacity [MW]	Economic assessment	Prioritisation assessment
3.32	Baringo Silali Phase II – Stage 3	300		X
3.33	Baringo Silali Phase II – Stage 4	300		X
3.34	Baringo Silali Phase II – Stage 5	300		X
3.35	Baringo Silali Phase III – Stage 1	300		X
3.36	Baringo Silali Phase III – Stage 2	300		X
3.37	Baringo Silali Phase III – Stage 3	300		X
3.38	Baringo Silali Phase III – Stage 4	300		X
3.39	Baringo Silali Phase III – Stage 5	200		X
3.40	Marine Power Akiira Stage 1	70		X
3.41	Marine Power Akiira Stage 2	70		X
3.42	AGIL Longonot Stage 1	70		X
3.43	AGIL Longonot Stage 2	70		X
4	**Hydropower plant (HPP)**			
4.1	High Grand Falls HPP Stage 1	495	X	X
4.2	High Grand Falls HPP Stage 2	198		X
4.3	Karura HPP	89	X	X
4.4	Nandi Forest HPP	50	X	X
4.5	Arror HPP	59	X	X
4.6	Magwagwa HPP	119	X	X
5	**Nuclear power plant (NPP)**			X
5.1	Generic nuclear power plant	600	X	
6	**Gas turbine power plant**			
6.1	Generic gas turbine (peaking plant)	70	X	
7	**Medium speed diesel power plant**			
7.1	Generic MSD (peaking plant)	80	X	
8	**Bagasse power plant (cogeneration)**			
8.1	Generic bagasse power plant (cogeneration)	25	X	
9	**Wind farm**			
9.1	Lake Turkana Phase I	300	X	X
9.2	Lake Turkana Phase II	350		X
9.3	Lake Turkana Phase III	350		X
9.4	Aeolus Kinangop	60		X
9.5	Kipeto	100		X
9.6	Prunus	51		X
9.7	Meru Phase I	80		X
9.8	Meru Phase II	320		X

ID	Name	Net capacity [MW]	Economic assessment	Prioritisation assessment
9.9	Ngong 1 – Phase III	10		X
9.10	Ol-Danyat Energy	10		X
9.11	Malindi	50		X
9.12	Limuru Wind – Transcentury	50		X
9.13	Kajiado Wind – Chagem Power	50		X
9.14	Marsabit Phase I	300		X
9.15	Marsabit Phase II	300		X
9.16	Generic wind farm	50	X	
10	**Solar (photovoltaic, PV) power plant**			
10.1	Generic PV power plant	10	X	X
11	**Interconnector (import)**			
11.1	HVDC Ethiopia-Kenya interconnector import – Stage 1	400	X	X
11.2	HVDC Ethiopia-Kenya interconnector import – Stage 2	400		X

6.3.2 Rehabilitation candidates

Under certain conditions rehabilitation of existing power plants can be profitable for instance if parts of the equipment are not at the end of their lifetime (i.e. civil works of hydropower plants typically have a longer lifetime than the mechanical and electrical equipment) or the fuel costs are very low compared to high investment costs required for a newly built power plant (i.e. geothermal power plants).

Since some of the power plants in the current Kenyan power system have already been commissioned many years ago, there are several potential rehabilitation candidates in the long-term study period until 2035 presented in the following table.

Table 6-2: Potential rehabilitation candidates in the long term

Power plant	Type	Net capacity [MW]	Commis-sioning year	Remark
Tana	Hydropower	20	1955/2010	
Masinga	Hydropower	40	1981	
Kamburu	Hydropower	90	1974/1976	
Gitaru	Hydropower	216	1978/1999	
Kindaruma	Hydropower	70.5	1968	
Kiambere	Hydropower	164	1988	

Power plant	Type	Net capacity [MW]	Commis-sioning year	Remark
Turkwel	Hydropower	105	1991	
Olkaria 1 Unit 1-3	Geothermal	45	1981	Step-wise rehabilitation scheduled for 2018-2019
Olkaria 2	Geothermal	105	2003	
Olkaria 3 Unit 1-6	Geothermal	48	2000	
Olkaria 3 Unit 7-9	Geothermal	62	2008	
Tsavo	MSD	77	2001	For fuel conversion
Rabai	MSD	90	2009	For fuel conversion
Kipevu 3	MSD	115	2011	For fuel conversion

The following will be analysed and considered in the expansion planning:

- All other power plants recently commissioned or to be commissioned soon are expected to be available throughout the study period or to be decommissioned after their useful lifetime.

- Based on international experience and due to the long lifetime of civil works of hydroelectric generating stations the rehabilitation of hydropower plants is profitable and feasible in most cases. As a result for the balancing of supply and demand hydropower capacity is assumed to remain in the framework of the present study. Thus, average costs for the rehabilitation mainly consisting of costs for hydro-mechanical and electro-mechanical equipment will be considered in the investment planning.

- For geothermal plants rehabilitation has to be decided on a case-by-case basis depending on the sustainability of the resource at a particular plant location. This may also include upgradation of the turbines resulting in a higher available capacity. For this study, a rehabilitation of geothermal plants and thus continued operation throughout the study period is assumed. For the sake of conservativeness, it is assumed that the power plant capacity will not change.

- Shut-down periods for rehabilitation are not considered.

Rehabilitation of diesel engines is possible from the technical point of view, but strongly depends on the condition of the plant at the end of its lifetime. This require plant specific case studies that serve as basis for the decision if rehabilitation is profitable or not. Within this study no rehabilitation of diesel engines is considered but for the power plants Tsavo, Kipevu 3 and Rabai with regard to fuel conversion to burn natural gas instead of heavy fuel oil[137].

[137] Power plants fuelled with heavy fuel oil and located in the Nairobi area are not considered in this analysis, because the construction of a natural gas pipeline from Mombasa to Nairobi is not foreseen. Kipevu 1 is also not considered in this analysis, since it is expected that the power plant will be phased out before LNG is available.

6.4 Economic assessment – screening curve analysis

6.4.1 Methodology and assumptions

In the context of the economic evaluation, the generation candidates are characterised and ranked by the so called screening curve analysis: calculating the cost per unit of electricity produced using the concept of Levelised Electricity Cost (LEC)[138] for a range of input parameters (i.e. capacity factor, discount rate),.

LEC is defined as the ratio of the present value of the projected costs of power production over the life of the project and the present value of such power production. Consequently, the LEC represent an accurate measure to reflect the real cost of the production per unit of electricity supposedly taking into account the average foreign and domestic cost of borrowing of the project executing agency (WACC: weighted average cost of capital, the discount rate).

The calculation of LEC ensures that the expected unit costs of electricity production of each candidate power plant are directly comparable and that an economic ranking of candidate plants can be established. The LEC also provides a generation tariff indication for the respective candidate.

6.4.1.1 Technical and economic input parameters

The following tables provide an overview of the technical and economic input parameters considered in the techno-economic assessment. Detailed explanations are illustrated in Annex 6.B (general and power plant transmission link assumptions) and in Annex 6.D (power plant technology specific) which contains description of all relevant candidates.

Table 6-3: General assumptions for the calculation of levelised electricity cost (1/2)

Parameters	
Prices expressed in	USD 2015 real
Discount rate	Range from 4-12%
Price escalation for investment and operation cost[139]	1.5%
First year of operation[140]	2022
Project horizon	Economic lifetime
Fuel prices	WEO 2015 fuel price forecast, reference and high scenario (see Chapter 5.2.5)

[138] Sometimes also referred to as Dynamic Unit Cost (DUC)
[139] Price escalation assumed based on recent (e.g. 2009-2015) average USD inflation (source: World Bank)
[140] The presented years do not reflect the actual feasible CODs of the respective technology, but are considered as working assumption in the economic analysis to ensure a uniform basis for the various technologies.

Table 6-4: General assumptions for the calculation of levelised electricity cost (2/2)

Economic parameters	Economic lifetime	Load coverage	Capacity factors (average lifetime, assumed)	Partial load (assumed)
Coal power plant	30	Base/intermediate	75%	100%
CCGT power plant	20	Base/intermediate/ peak	75%	100%
Nuclear power plant	40	Base	85%	100%
MSD engine	20	Peak	20%	100%
Gas turbine	25	Peak	20%	100%
Hydropower plant	Hydro-mechanical, electro-mechanical equipment: 40 years, civil works: 100 years	Base/intermediate/ peak	Equal to capacity factor for average energy (25 – 67%)	100%
Geothermal power plant	25	Base	90%	100%
Bagasse power plant	20	Base	80%	100%
Wind farm	20	Volatile	Equal to capacity factor for average energy	100%
Photovoltaic (PV) power plant	20	Volatile	Equal to capacity factor for average energy	100%
HVDC Ethiopia-Kenya interconnector	30	Base	75%	100%

Table 6-5: Techno-economic parameters of coal candidates (details in Annex 6.D.1)

Techno-economic parameters	Unit	Lamu coal 4x245 MW	Lamu coal 3x327 MW[141]	Lamu coal “tender” 3x327 MW[141]	Kitui coal 4x240 MW	Kitui coal 3x320 MW
Gross capacity	MW	1,062	1,062	1,062	1,059	1,059
Net capacity (sent-out)	MW	982	982	982	960	959
# of units		4	3	3	4	3
Capital Expenditure (CAPEX)	USDm	2,533	2,396	1,800	2,439	2,293
Specific CAPEX	USD/kW	2,619	2,478	1,833	2,542	2,388
Fixed O&M costs	USD/kW/a	69	66	80	75	69
Variable O&M costs	USD/MWh	1.4	1.3	1.3	1.2	1.4
Availability	%	87	87	87	87	87

[141] The candidates 1.1.2 (Lamu Coal ST 3x327 MW) and 1.1.3 (Lamu Coal ST “tender” 3x327 MW) are technically similar (number of units, capacity) but differ for CAPEX and OPEX assumptions: while for 1.1.2 average regional costs from similar projects are considered for 1.1.3 the actual costs according to the winning bid were taken. CAPEX and fixed OPEX are based on the tender document. The data could not be verified by the Consultant since related information (plant specifications) were not accessible.

Techno-economic parameters	Unit	Lamu coal 4x245 MW	Lamu coal 3x327 MW[141]	Lamu coal "tender" 3x327 MW[141]	Kitui coal 4x240 MW	Kitui coal 3x320 MW
Heat Rate at 100% load	kJ/kWh	8,745	8,695	8,978	9,647	9,625
Net calorific value (NCV)	MJ/kg	21	21	21	18	18
Fuel		Imported coal	Imported coal	Imported coal	Domestic coal	Domestic coal
Construction period	years	6	6	6	6	6

Table 6-6: Techno-economic parameters of CCGT candidates (details in Annex 6.D.2)

Techno-economic parameters	Unit	Dongo Kundu 2x(2+1) – 1pressure	Dongo Kundu 1x(2+1) – 1pressure	Dongo Kundu 1x(2+1) – 3pressure	Wajir 2x(2+1) - 1pressure	Wajir 1x(2+1) - 1pressure	Wajir 1x(2+1) - 3pressure
Gross capacity	MW	770	785	808	752	776	720
Net capacity (sent-out)	MW	751	766	789	727	752	698
# of units		2x(2+1)	1x(2+1)	1x(2+1)	2x(2+1)	1x(2+1)	1x(2+1)
Capital Expenditure (CAPEX)[142]	USDm	1,006	889	926	728	641	638
Specific CAPEX	USD/kW	1,339	1,159	1,174	1,002	913	913
Fixed O&M costs[143]	USD/kW/a	33	31	31	18	15	16
Variable O&M costs	USD/MWh	13.4	13.4	13.2	16.1	13.6	14.8
Availability	%	90	90	90	90	90	90
Heat rate at 100% load	kJ/kWh	7,033	6,478	6,295	7,448	6,949	6,718
Net calorific value (NCV)	MJ/kg	46.5	46.5	46.5	46.5	46.5	46.5
Fuel		Imported liquefied natural gas (LNG)	Imported liquefied natural gas (LNG)	Imported liquefied natural gas (LNG)	Domestic natural gas (NG)	Domestic natural gas (NG)	Domestic natural gas (NG)
Construction period	years	3	3	3	3	3	3

[142] For the Dongo Kundu options also proportional investment costs for the required LNG terminal are included in the CAPEX.
[143] For the Dongo Kundu options also proportional O&M costs for the required LNG terminal are included in the O&M costs.

Table 6-7: Techno-economic parameters of geothermal candidates (details in Annex 6.D.3)

Techno-economic parameters	Unit	Olkaria 1 Unit 6	Olkaria 5	Suswa Phase I Stage 1	Suswa Phase I Stage 2	Menengai 1 Phase I – Stage 1	Eburru 2
Gross capacity	MW	73	146	52	105	107	26
Net capacity (sent-out)	MW	70	140	50	100	103	25
# of units		1	2	2	3	3	1
Capital Expenditure (CAPEX)	USDm	236	471	191	344	352	98
Specific CAPEX	USD/kW	3,365	3,365	3,827	3,439	3,435	3,909
Total O&M costs	USD/kW/a	151.5	151.5	158.2	152.5	152.5	164.5
Availability	%	95	95	95	95	95	95
Implementation period	years	9	11	9	10	10	8

Table 6-8: Techno-economic parameters of hydropower candidates (details in Annex 6.D.4)

Techno-economic parameters	Unit	High Grand Falls HPP Stage 1	Karura HPP	Nandi Forest HPP	Arror HPP	Magwagwa HPP
Gross capacity	MW	500	90	50	60	120
Net capacity (sent-out)	MW	495	89	50	59	119
Average energy p.a.	GWh/a	1,213	235	185	190	510
Capacity factor	%	28	30	43	36	49
Capital Expenditure (CAPEX)	USDm	1,835	329	188	263	367
Specific CAPEX	USD/kW	3,708	3,687	3,791	4,431	3,087
Civil Cost share	%	94	68	83	83	78
Fixed O&M costs	USD/kW/a	16	15	19	20	28
Variable O&M costs	USD/MWh	0.5	0.5	0.5	0.5	0.5
Construction period	Years	9	5	7	7	7

Table 6-9: Techno-economic parameters nuclear, gas turbine, diesel engine, bagasse and HVDC candidates (details in Annex 6.D.6 – 6.D.9)

Techno-economic parameters	Unit	Nuclear unit	Gas turbine	MSD engine	Generic bagasse plant	HVDC Ethiopia-Kenya
Gross capacity	MW	630	71	18.3	32	400
Net capacity (sent-out)	MW	600	70	17.8	25	400
Average energy p.a.	GWh/a	4,244	123	31	175	2,628
Capacity factor	%	85	20	20	80	75
Capital Expenditure (CAPEX)	USDm	4,841	60	34.5	76	508
Specific CAPEX	USD/kW	8,068	848	1,935	3,045	1,269
Fixed O&M costs	USD/kW/a	7.5	21	32	152	25
Variable O&M costs	USD/ MWh	10	13	9	9	70[144]
Availability	%	90	90	92	90	100
Heat rate at 100% load	kJ/kWh	9,730	10,666	8,062	Not considered	n.a.
Net calorific value (NCV) of fuel	MJ/kg	39,000	44.9	41.4	Not considered	n.a.
Fuel		Imported Uranium	Imported gasoil	Imported HFO	Bagasse	n.a.
Construction period		10	1	2	3	3

Table 6-10: Techno-economic parameters of volatile renewable candidates (details in Annex 6.D.5 and 6.D.7)

Techno-economic parameters	Unit	Lake Turkana Wind	Generic wind farm	Generic photovoltaic (PV) power plant
Gross capacity	MW	300	50	10
Net capacity (sent-out)	MW	300	50	10
Average energy p.a.	GWh/a	1,495	157	28
Capacity factor	%	55	40	20

[144] Electricity procurement costs are considered in variable OPEX

Techno-economic parameters	Unit	Lake Turkana Wind	Generic wind farm	Generic photovoltaic (PV) power plant
Capital Expenditure (CAPEX)	USDm	609	102	17
Specific CAPEX	USD/kW	2,030	2,030	1,695
Fixed O&M costs	USD/kW/a	76	76	26
Variable O&M costs	USD/MWh	0	0	0
Construction period	years	3	2	1

6.4.1.2 Overview of expansion candidates ranking scenarios

Assessment of the most suitable generation expansion candidates to be used in the expansion modelling was done according to the following aspects:

- Generation costs for the range of
  - Discount rates; and
  - Capacity factors
- Transmission connection options;
- Fuel price scenarios.

In this regard, two overall ranking scenarios have been defined as presented in the following table.

Table 6-11: Overview of overall candidate ranking scenarios

Scenario ID	Scenario type	Scenario description	Remark
Sc1	Cost of each plant only as a function of various discount rates	No additional site specific cost (transmission links) accounted for each candidate	Reference (Sc1a) and high (Sc1b) fuel scenarios Range of discount rate
Sc2	Cost of each plant plus additional site specific infrastructure cost as a function of various discount rates and as a function of various capacity factors	Additional site specific cost for individual direct transmission link accounted for each candidate plant	Reference (Sc2a) and high (Sc2b) fuel scenarios Range of discount rate Range of capacity factor

A first scenario aims at establishing a first least cost ranking for the power plant candidates based on the full cost of each plant regardless of any incomplete or unclear determined site specific costs for power evacuation. At this point of the study the analysis of technical and cost implications of different network integration options (e.g. new substation or expansion) can be only preliminary.

A second scenario considers costs for site specific infrastructure. An example is transmission links with appropriate capacity to connect each plant to the nearest existing grid point able to absorb the power and where energy can be transferred to the load centre (assumed as being located in the Nairobi area). In comparison to the first scenario, candidates are more varied by additionally considering their network integration costs. However, as described above, there are higher uncertainties within these cost assumptions. The transmission link costs include both investment costs for the required overhead line and costs for transformers at the grid point should installation become necessary. Further costs related to the substation at the grid point (i.e. costs for additional switchgears, construction costs in case of loop in/loop out or T-connection) are neglected in the framework of this analysis, since the proportion is comparatively small. Cost for required transformers and switchgears at plant site are included in the overall investment cost of each plant candidate.

The grid connection measures undertaken in this section have been devised as abstract measures and are assumed for power plant ranking purposes only. They may not necessarily reflect the expansion plans of KPLC and KETRACO and do not constitute firm proposals for the expansion of the transmission system. However, the grid connection measures represent technically sensible proposals allowing for the techno-economic evaluation presented in this section.

The cost estimate assumptions for transmission lines and substations are provided in Annex 6.B.3. They are based on assumptions provided in the 10 year plan reviewed and adapted (where necessary) by the Consultant. Similar to the assumptions for required transmission line lengths, they may not reflect the exact costs for each candidate. However, they are sufficiently accurate to derive reliable and robust candidate plant rankings.

6.4.2 Economic ranking - results by technology

The following paragraphs present the results of the economic assessment considering cost for required transmission links and the reference fuel price scenario (scenario 2a). In a first step power plant options of the same technology (1. Coal power plants, 2. CCGT power plants, 3. Geothermal power plants, 4. Hydropower plants) are compared to each other which enables the identification of preferred options of one technology. In a second step LEC of selected candidates from different technologies are contrasted against each other.

The results of the remaining scenarios as well as the analysis of fuel conversion candidates are illustrated in Annex 6.C.

6.4.2.1 Coal power plant ranking scenarios

Considering the reference fuel price scenario and cost for required transmission links the results of the economic assessment on the five coal power plant options based in Lamu or Kitui can be summarised as follows:

- LEC of Lamu ST "tender" option are the lowest (between 3-10% below LEC of Lamu ST 3x327 MW option) due to assumed low investment cost estimated at 1,800 MUSD (see footnote 141).
- Neglecting Lamu ST "tender" option:
  - Options with smaller unit sizes are generally more expensive (by 3-4%) caused by higher specific investment costs.[145]
  - Considering same unit configurations Kitui appears cheaper than Lamu despite of its lower efficiency and lower net heating value of domestic coal. Essential reasons are the additional investment costs for the harbour infrastructure required for coal import at the Lamu plant site, higher cost for the grid connection as well as higher prices for imported coal utilised in Lamu.
- Cost for required transmission links leads to an increase in LEC by 3-7% at Lamu site. Since the Kitui site is located closer to the load centre, the Kitui options only show an LEC increase by 1-2% in case that grid integration cost are considered (please see Annex 6.C for comparison).

The results of scenario Sc2a are illustrated in the following table and graph.

Table 6-12: LEC for coal candidates, Sc2a: incl. transmission link, ref. fuel scenario

Discount Rate	Unit	Lamu-ST 4x245 MW	Lamu-ST 3x327 MW	Lamu-ST "tender" 3x327 MW	Kitui-ST 4x240 MW	Kitui-ST 3x320 MW
4%	USDcent/kWh	8.67	8.42	8.15	8.57	8.34
6%		9.54	9.25	8.78	9.34	9.07
8%		10.58	10.23	9.52	10.25	9.93
10%		11.78	11.36	10.38	11.31	10.92
12%		13.14	12.64	11.36	12.51	12.06
Ranking	#	5	3-4	1	3-4	2

[145] Nevertheless, smaller unit sizes are recommended from the system's point of view to ensure grid stability even if a unit trips. In addition, if this unit were the largest unit in the system, higher reserve margin requirement (which was not considered in the calculation) would reduce the cost advantage of the larger units.

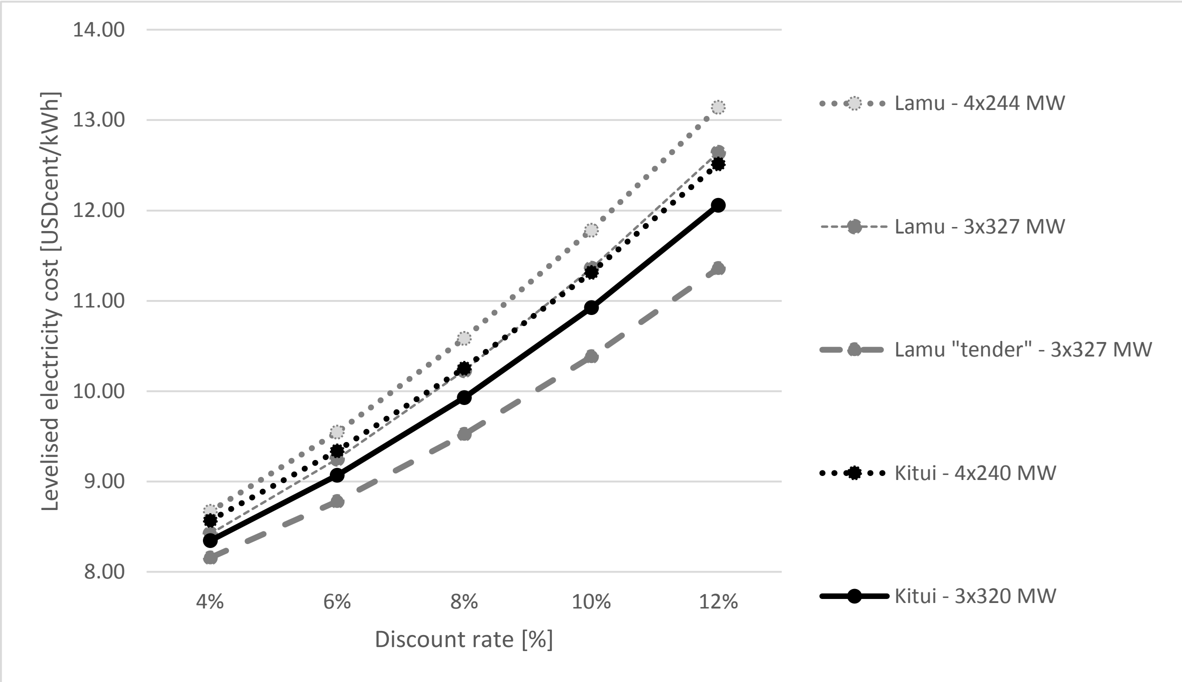

Figure 6-1: LEC for coal candidates, Sc2a: incl. transmission link, reference fuel scenario

6.4.2.2 CCGT power plant ranking scenarios

The economic assessment on the six natural gas fuelled CCGT options located in Dongo Kundu or in Wajir can be concluded as follows for scenario Sc2:

- Wajir power plant options are significantly cheaper than the Dongo Kundu options (between 24-31% when comparing same unit configurations). This stems from the Dongo Kundu plant options requiring high investment and O&M costs for the LNG terminal[146]. Furthermore, the fuel price of LNG is much higher than the price for domestic natural gas (though priced at international market level, see 5.2.5) used at Wajir site[147]. Thus, Wajir should be considered the preferred candidate for CCGT and gas based power generation once sufficiency of gas resources is confirmed.

- 2x(2+1) unit configurations are generally more expensive than 1x(2+1) unit configurations (between 8-10%) due to higher specific investment costs of smaller unit sizes.

- At Dongo Kundu site the triple pressure mode configuration is the preferred option. By the use of three pressure levels in the heat recovery steam generator, the efficiency is higher,

[146] Infrastructure costs for the pipeline at Dongo Kundu site are included in the investment costs of the power plant (LNG terminal is located next to the power plant).

[147] Though the underlying natural gas price is assumed to be the same (representing opportunity costs for domestic natural gas at Wajir) the liquefaction and transport costs – CIF (cost insurance freight) basis – are added for LNG.

so that the fuel savings throughout the plant lifetime surpasses the higher investment costs.

- At Wajir site, however, the one pressure mode configuration appears to be the preferred option. This is due to the lower cost for domestic natural gas used at this site, compared to LNG. The fuel savings which would be reached through a triple pressure technology will not surpass the higher investment costs.

Table 6-13: LEC for CCGT candidates, Sc2a: incl. transmission link, reference fuel scenario

Discount Rate	Unit	Dongo Kundu 2x(2+1) – 1pressure	Dongo Kundu 1x(2+1) – 1pressure	Dongo Kundu 1x(2+1) – 3pressure	Wajir 2x(2+1) - 1pressure	Wajir 1x(2+1) - 1pressure	Wajir 1x(2+1) - 3pressure
4%	USDcent /kWh	14.18	13.11	12.82	11.05	10.04	10.05
6%		14.42	13.31	13.03	11.28	10.24	10.28
8%		14.71	13.55	13.28	11.55	10.48	10.54
10%		15.03	13.83	13.56	11.86	10.75	10.84
12%		15.38	14.14	13.87	12.21	11.05	11.17
Ranking	#	6	5	4	3	1-2	1-2

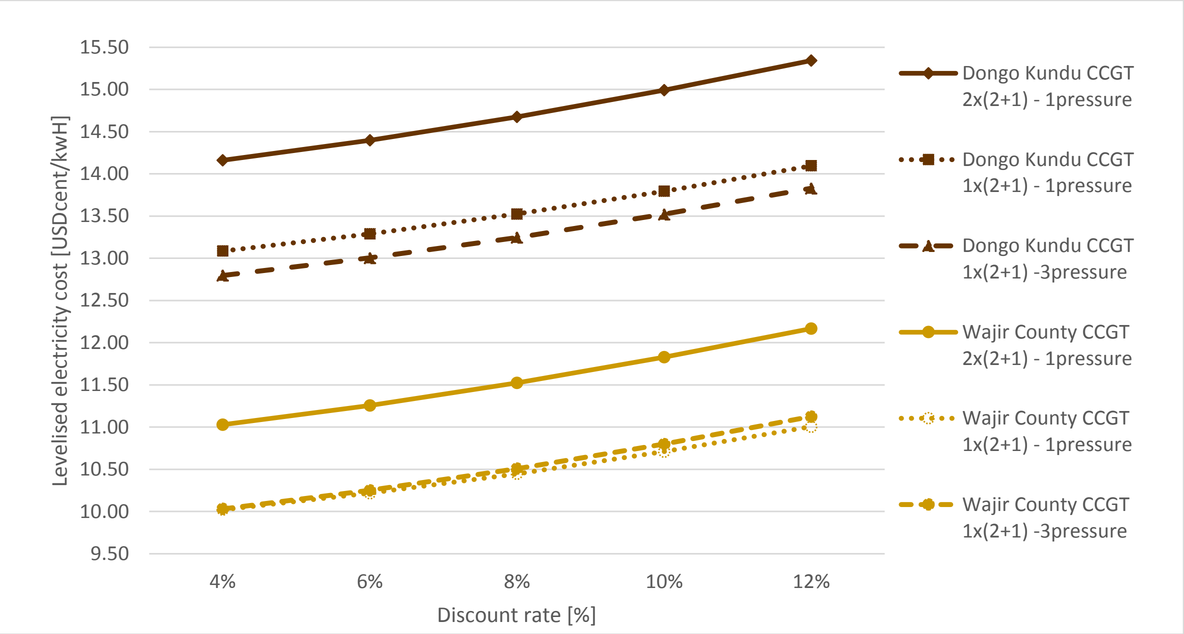

Figure 6-2: LEC for CCGT candidates, Sc2a: incl. transmission link, reference fuel scenario

6.4.2.3 Geothermal power plant ranking scenarios

Considering site specific cost for required transmission links the results of the economic assessment on selected geothermal power plant candidates can be summarised as follows:

- LEC of candidates with smaller unit sizes (e.g. Eburru with 25 MW and Suswa Phase I Stage 1 with 50 MW) are generally higher than the LEC of candidates with larger unit sizes (e.g. Olkaria 5 with 140 MW). For instance, the LEC of Suswa Phase I Stage 1 – 50 MW are 8% lower than the LEC of Suswa Phase I Stage 2 – 100 MW. This is mainly a result of the higher specific investment costs of smaller unit sizes.

- However, the candidates Suswa Phase I Stage 2 – 100 MW and Menengai Phase I Stage 1 – 103 MW appear to be cheaper than Olkaria 5 – 140 MW for discount rates above 8% (between 1-2%) due lower grid integration cost and the shorter implementation period.

- The impact of grid integration cost on the LEC of the selected geothermal power plant candidates is estimated as low. With an LEC growth of 2%, Eburru shows the highest LEC increase when transmission link costs are considered (please see Annex 6.C for scenario Sc1).

Table 6-14: LEC for geothermal candidates, Sc2: incl. transmission link

Discount Rate	Unit	Olkaria 1 Unit 6	Olkaria 5	Suswa Phase I Stage 1	Suswa Phase I Stage 2	Menengai 1 Phase I - Stage 1	Eburru 2
4%	USDcent /kWh	4.89	4.99	5.46	5.03	5.03	5.70
6%		5.70	5.87	6.41	5.89	5.89	6.67
8%		6.65	6.91	7.51	6.90	6.90	7.79
10%		7.72	8.12	8.76	8.06	8.06	9.06
12%		8.93	9.50	10.17	9.37	9.38	10.49
Ranking	#	1	2-4	5	2-3	3	6

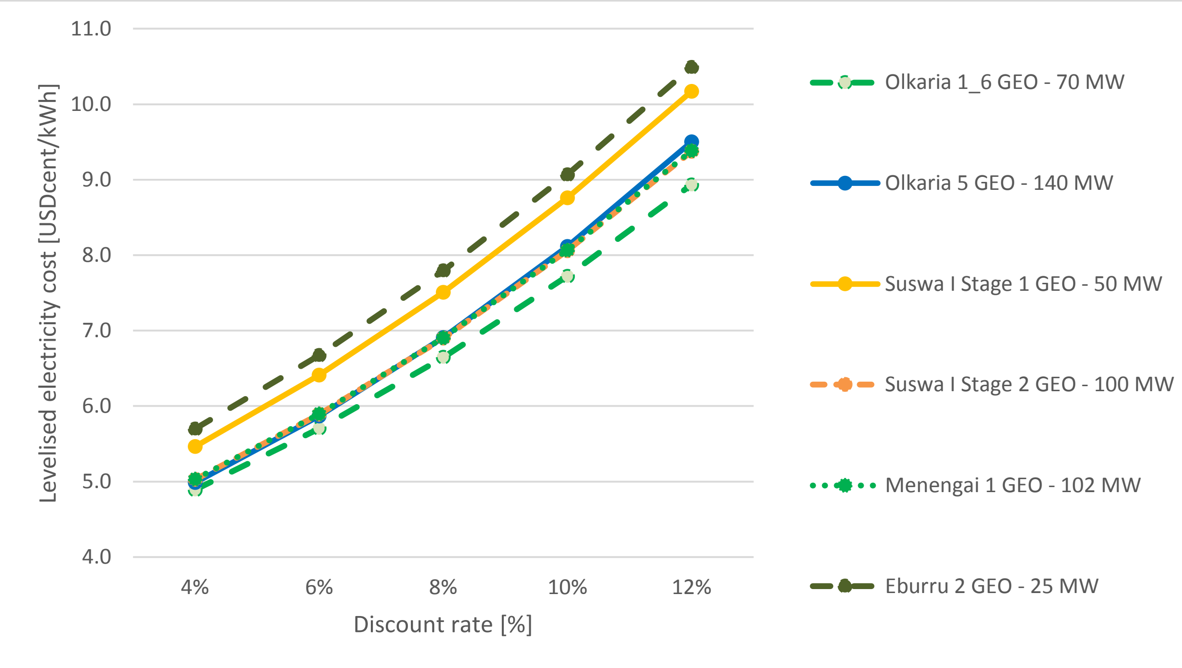

Figure 6-3: LEC for geothermal candidates, Sc2a: incl. transmission link

6.4.2.4 Hydropower plant ranking scenarios

The results of the economic assessment on hydropower plant candidates can be summarised as follows:

- With LEC ranging from 4.5 to 13.1 USDcent/kWh Magwagwa appears to be the least cost option, followed by Nandi Forest (LEC increased by 37-42%), Karura (LEC increased by 69-75%) and Arror (LEC increased 88-97%).

- High Grand Falls shows the highest LEC estimated at 9.3-32.0 USDcent/kWh. One reason is that the project will be located in a remote area resulting in comparatively high grid integration cost (6% of the total investments). Furthermore, the capacity factor with 28% is lower than capacity factors of the other projects (ranging from 30-49%). However, it should be noted that High Grand Falls would provide more than 400 MW of flexible generation capacity and would thus be very valuable for the power system.

Table 6-15: LEC for hydropower candidates, Sc2: incl. transmission link

Discount Rate	Unit	High Grand Falls (HGFL) HPP	Karura HPP	Nandi Forest HPP	Arror HPP	Magwagwa HPP
4%	USDcent/ kWh	9.33	7.78	6.12	8.34	4.48
6%		13.73	10.86	8.71	11.92	6.25
8%		18.93	14.31	11.67	16.03	8.27
10%		25.00	18.10	15.03	20.68	10.55
12%		32.02	22.22	18.79	25.88	13.12
Ranking	#	5	3	2	4	1

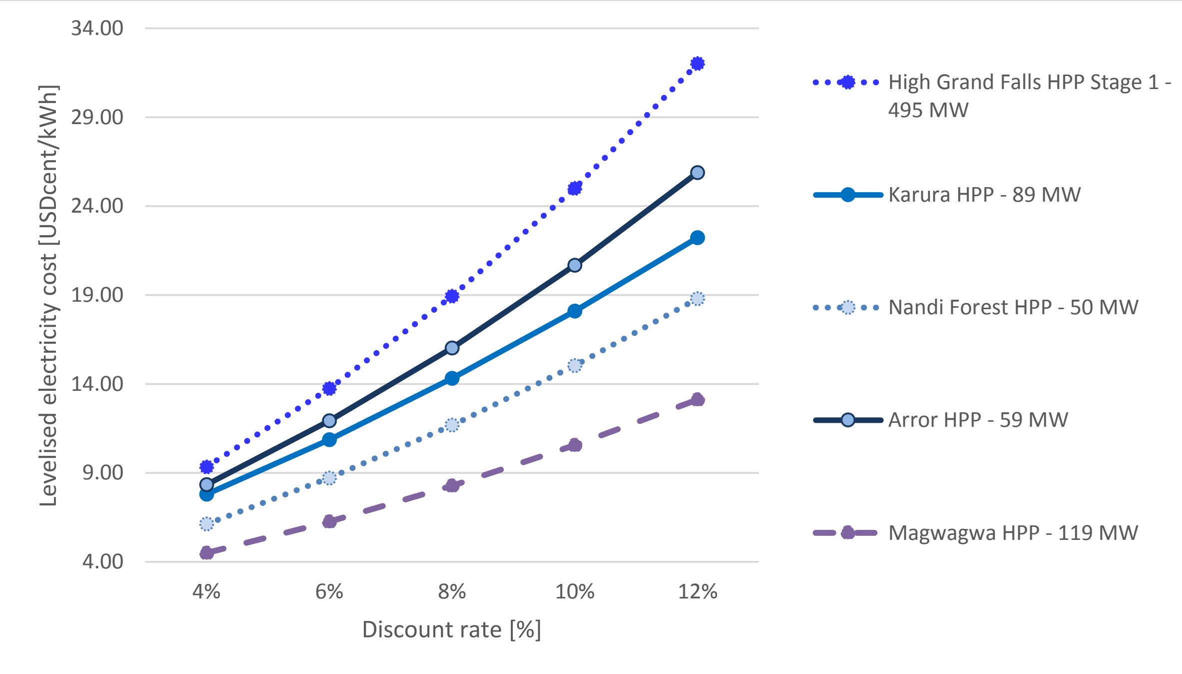

Figure 6-4: LEC for hydropower candidates, Sc2: incl. transmission link

6.4.3 Comparison of candidates of different technologies

This section presents selected screening curves for candidates representing diverse technologies whereby a direct comparison of the different technologies is reached. Based on the reference fuel price scenario and considering cost for required transmission links these candidates are evaluated as a function of varying discount rates and as a function of varying capacity factors.

6.4.3.1 Varying discount rates

Considering the reference fuel scenario and required grid integration cost the results of the economic assessment on selected candidates from different technologies is summarised as follows:

- When comparing traditional peaking units such as the generic gasoil fuelled gas turbine, the HFO fuelled MSD engine and the hydropower plants High Grand Falls and Karura, it can be seen that Karura has the lowest LEC (7.8-22.2 USDcent/kWh), followed by High Grand Falls (LEC increased by 20-44%) for discount rates up to 10%. Assuming a capacity factor of 20% for the gas turbine and MSD engine, the MSD engine is cheaper than the gas turbine (by between 21-50%). However, this ranking changes for capacity factors below 10%: due to the low investment costs of gas turbines, this technology shows lower LEC than the MSD engine and is thus the preferred option in case of rare utilisation (e.g. reserve capacity).

- When comparing traditional intermediate load plants such as the selected coal power plants and natural gas fuelled CCGT power plants, it can be seen that coal power plants are cheaper than gas fuelled CCGT plants for discount rates below 10%. Assuming a discount rate of 12% the Wajir CCGT plant fuelled with domestic natural gas is the preferred option due to the low investment and fuel costs. For all discount rates the Dongo Kundu candidate is the most expensive intermediate load candidate resulting from higher investment costs and higher fuel costs for LNG imports.

- The results clearly show that the geothermal power plant Suswa Phase I Stage 2 (100 MW)[148] is the preferred base load unit (LEC between 5.0-9.4 USDcent/kWh), followed by the generic bagasse power plant (LEC increased by 6-34%) and the HVDC (LEC increased by 8-71%). Nuclear power plants show the highest costs for all base load plants (actually only Dongo Kundu for low discount rates and peaking plants show higher costs for the reference fuel price forecast, a higher fuel price will not change this ranking considerably). This ranking is valid for all discount rates. Since coal and CCGT power plants are able to run as base load plants as well, it can be concluded that these options are also preferred to the nuclear unit from economic viewpoint.

- With regard to the volatile RE candidates, the analysis reveals that Lake Turkana wind farm has by far the lowest LEC for all discount rates, followed by the generic wind farm (LEC increased by 0-9%) and the generic PV power plant (LEC increased by 45-48%).

The following tables and graphs illustrate the result of the analysis.

[148] Suswa Phase I Stage 2 represents the various geothermal power plant candidates. As illustrated in Chapter 6.4.2.3 the LEC of the Olkaria power plant candidates are in the same range.

Table 6-16: Ranking of peaking, intermediate, base load and intermittent units, Sc2a incl. transmission link, reference fuel price

	Reserve units	Peaking units		Intermediate load units			Base load units	Intermittent capacity
Discount rate range	**4-12%**	**4-10%**	**12%**	**4-8%**	**10%**	**12%**	**4-12%**	**4-12%**
Ranking:								
1	Generic gas turbine (gasoil) – 70 MW	Karura HPP – 89 MW	Karura HPP – 89 MW	Lamu “tender” coal - 3x327 MW	Lamu “tender” coal - 3x327 MW	Wajir NG-CCGT 1 pressure – 698 MW	Suswa Phase I Stage 2 GEO – 100 MW	Lake Turkana wind farm – 300 MW
2	Generic MSD (HFO) – 18 MW	High Grand Falls HPP – 495 MW	Generic MSD (HFO) – 18 MW	Kitui coal - 3x320 MW	Wajir NG-CCGT 1 pressure – 698 MW	Lamu “tender” coal - 3x327 MW	Generic bagasse plant -25 MW	Generic wind farm – 50 MW
3		Generic MSD (HFO) – 18 MW	High Grand Falls HPP – 495 MW	Lamu coal - 3x327 MW	Kitui coal - 3x320 MW	Kitui coal - 3x320 MW	HVDC – 400 MW	Generic PV power plant – 10 MW
4		Generic gas turbine (gasoil) – 70 MW	Generic gas turbine (gasoil) – 70 MW	Wajir NG-CCGT 1 pressure – 698 MW	Lamu coal - 3x327 MW	Lamu coal - 3x327 MW	(intermediate load candidates)	
5				Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Nuclear unit – 600 MW	

Table 6-17: LEC as a function of discount factor for various candidates, Sc2a: incl. transmission link, reference fuel scenario

Discount Rate	Unit	Lamu coal ST - 3x327 MW	Lamu coal "tender" - 3x327 MW	Kitui coal - 3x320 MW	Dongo Kundu LNG CCGT 3pressure - 789 MW	Wajir NG CCGT 1pressure - 698 MW	Generic nuclear unit - 600 MW	Suswa Phase I Stage 2 GEO - 100 MW	Generic bagasse PP - 25 MW	Generic HFO MSD - 18 MW	Generic gas turbine (gasoil) - 70 MW	High Grand Falls HPP - 495 MW	Karura HPP - 89 MW	Lake Turkana Wind - 300 MW	Generic Wind farm - 50 MW	Generic PV - 10 MW	HVDC - 400 MW
4%		8.42	8.15	8.34	12.82	10.05	10.68	5.03	6.71	23.00	34.47	9.33	7.78	5.96	6.48	8.80	8.55
6%		9.25	8.78	9.07	13.03	10.28	13.60	5.89	7.39	24.50	34.72	13.73	10.86	6.87	7.30	10.14	8.87
8%	USDcent/kWh	10.23	9.52	9.93	13.28	10.54	17.18	6.90	8.15	26.16	35.07	18.93	14.31	7.87	8.19	11.59	9.23
10%		11.36	10.38	10.92	13.56	10.84	21.46	8.06	8.98	27.98	35.53	25.00	18.10	8.96	9.15	13.13	9.63
12%		12.64	11.36	12.06	13.87	11.17	26.48	9.37	9.88	29.94	36.10	32.02	22.22	10.15	10.16	14.75	10.06

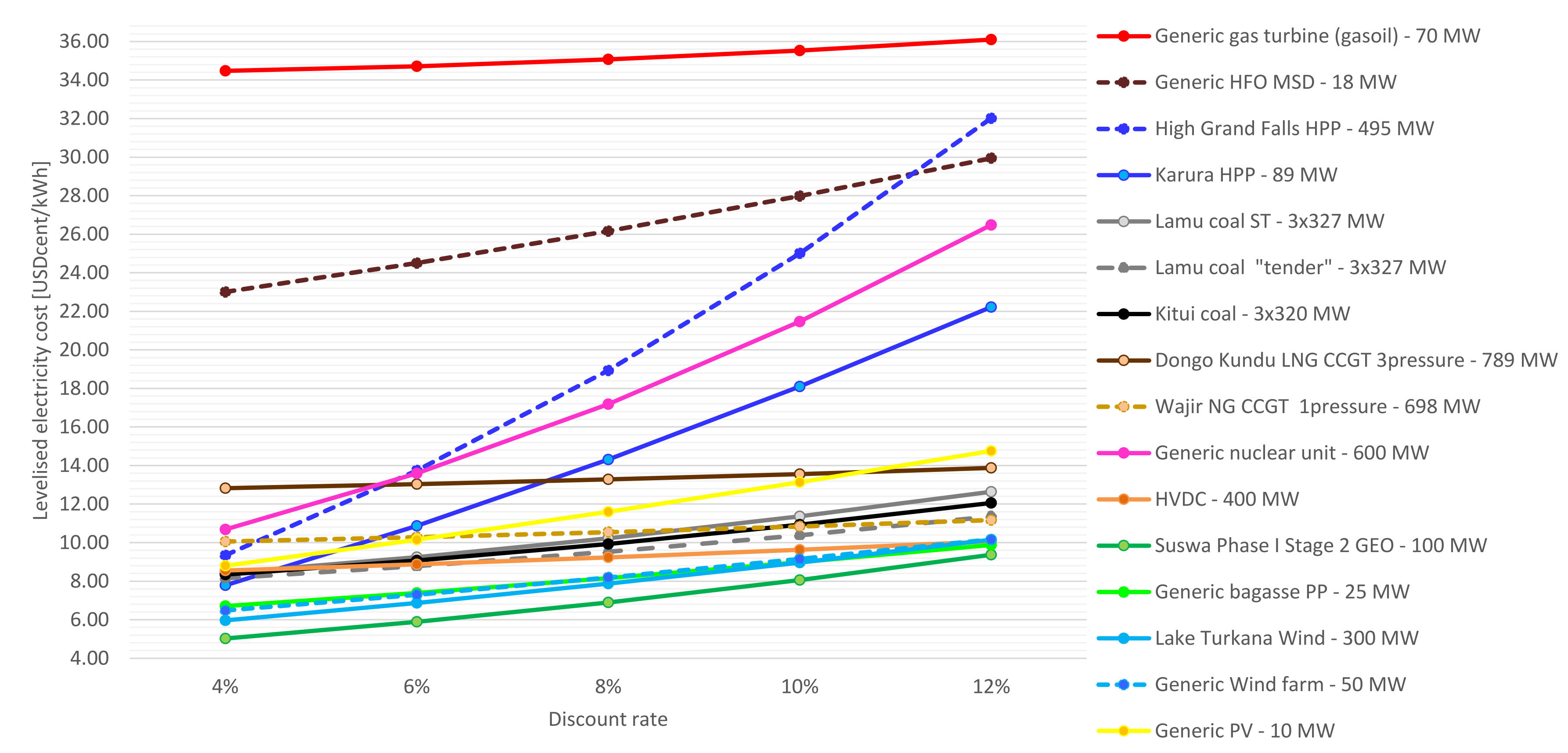

Figure 6-5: LEC as a function of discount rate for various candidates, Sc2a: incl. transmission link, reference fuel scenario

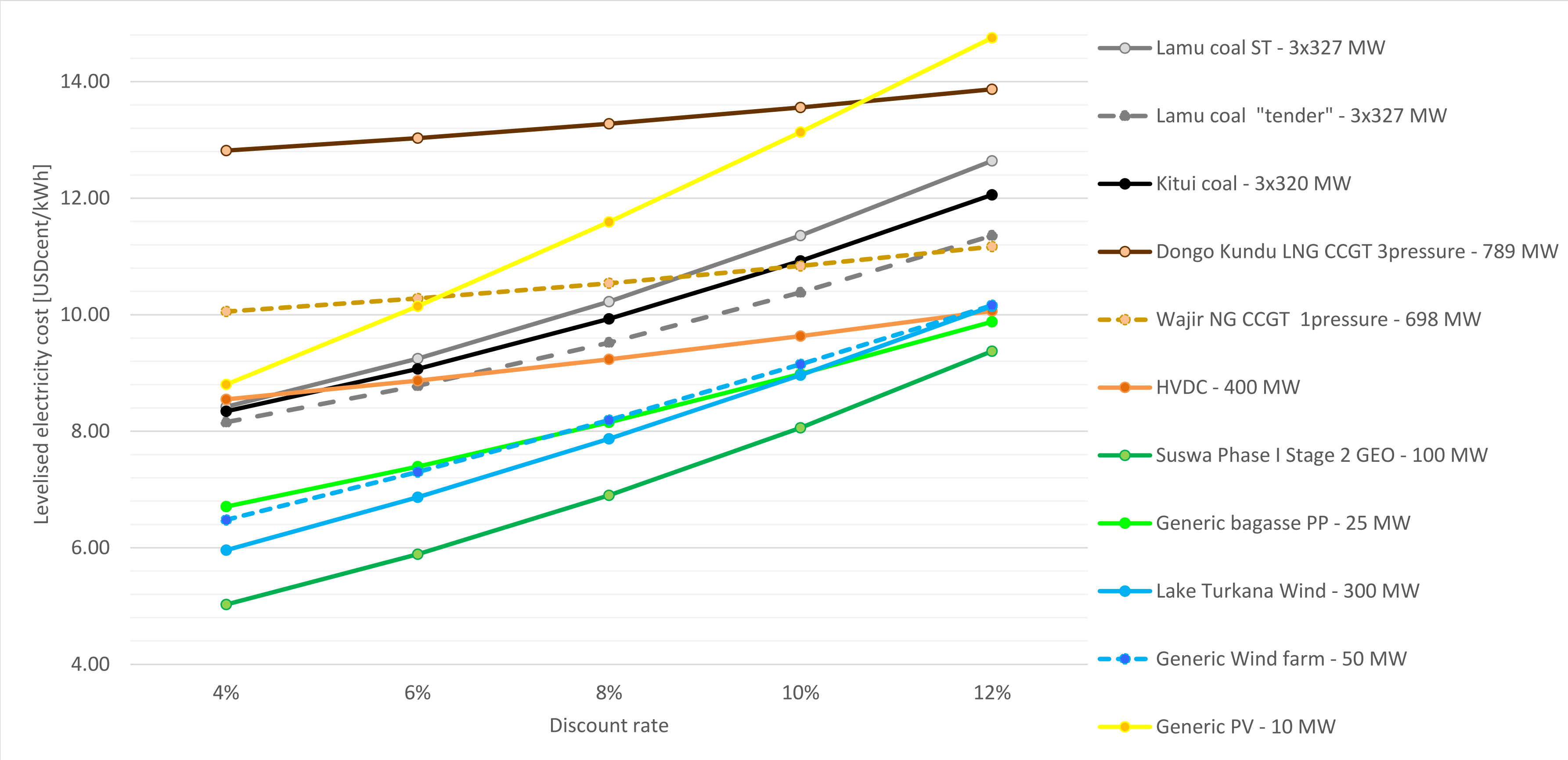

Figure 6-6: LEC as a function of discount rate for various candidates, extract, Sc2a: incl. transmission link, reference fuel scenario

6.4.3.2 Varying capacity factors

Based on the reference fuel scenario, a discount rate of 10% and assuming that the power plants operate at maximum load, LEC of selected candidates are calculated for varying capacity factors[149].

Table 6-18 provides an overview of the power plant ranking for different capacity factors.

- Suswa Phase I Stage 2[150] is the preferred option considering maximum utilisation, followed by the generic bagasse plant (LEC increased by 7%) and the HVDC (LEC increased by 18%). However, the LEC of these candidates will strongly increase with decreasing capacity factors due to their high investment costs.

- Even at maximum availability, the nuclear power plant is less economical than coal and natural gas fuelled candidates. This stems from the high investment costs for a 600 MW nuclear unit.

- Considering a capacity factor of 50%, the Wajir NG-CCGT candidate appears to be the preferred option, followed by Lamu “tender” coal (LEC increased by 10%), generic bagasse plant (LEC increased by 14%) and Kitui coal power plant (LEC increased by 15%).

- Assuming a capacity factor of 20% Wajir NG-CCGT is still the preferred option, followed by Dongo Kundu (LEC increased by 20%), Lamu “tender” coal (LEC increased by 45%) and Kitui coal power plant (LEC increased by 49%). However, further technical parameters (e.g. minimum uptime and downtime, efficiency at partial load) have to be taken into account for the selection of an accurate peaking unit in a power generation system. Despite of higher LEC of the MSD engine and the gas turbine, they may lead to lower system cost due to shorter minimum up- and downtimes compared to coal and CCGT power plants.

[149] Hydropower candidates in addition to volatile renewable power plant candidates (for instance wind farms and photovoltaic power plants) are not included in this analysis. Hydropower plants are designed and developed to utilise all available energy and run at full or partial capacity during plant availability times. Additionally they are capable of and required to adapt to varying loads within short spells of time (known as peaking capability). The generation of energy from wind farms and photovoltaic power plants is strongly influenced by the volatility of their resource. As a result, presenting LEC for these candidates as a function of varying capacity factors would not be meaningful.

[150] Suswa Phase I Stage 2 represents the various geothermal power plant candidates. As illustrated in Chapter 6.4.2.3 the LEC of the Olkaria power plant candidates are in the same range.

Table 6-18: Ranking of selected candidates for different capacity factors, Sc2a incl. transmission link, reference fuel scenario

Capacity factor	Maximum[151]	70%	50%	20%
1	Suswa Phase I Stage 2 GEO – 100 MW	Generic bagasse plant -25 MW	Wajir NG-CCGT 1 pres-sure – 698 MW	Wajir NG-CCGT 1 pres-sure – 698 MW
2	Generic bagasse plant - 25 MW	HVDC – 400 MW	Lamu “tender” coal - 3x327 MW	Dongo Kundu LNG-CCGT 3 pressure – 789 MW
3	HVDC – 400 MW	Suswa Phase I Stage 2 GEO – 100 MW	Generic bagasse plant -25 MW	Lamu “tender” coal - 3x327 MW
4	Lamu “tender” coal - 3x327 MW	Lamu “tender” coal - 3x327 MW	Kitui coal - 3x320 MW	Kitui coal - 3x320 MW
5	Kitui coal - 3x320 MW	Wajir NG-CCGT 1 pressure – 698 MW	HVDC – 400 MW	Generic MSD (HFO) – 18 MW
6	Wajir NG-CCGT 1 pres-sure – 698 MW	Kitui coal - 3x320 MW	Suswa Phase I Stage 2 GEO – 100 MW	Lamu coal - 3x327 MW
7	Lamu coal - 3x327 MW	Lamu coal - 3x327 MW	Lamu coal - 3x327 MW	Generic bagasse plant -25 MW
8	Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Dongo Kundu LNG-CCGT 3 pressure – 789 MW	Generic gas turbine (Kerosene) – 70 MW
9	Generic MSD (HFO) – 18 MW	Generic MSD (HFO) – 18 MW	Generic MSD (HFO) – 18 MW	HVDC – 400 MW
10	Nuclear unit – 600 MW	Nuclear unit – 600 MW	Generic gas turbine (Kerosene) – 70 MW	Suswa Phase I Stage 2 GEO – 100 MW
11	Generic gas turbine (Ke-rosene) – 70 MW	Generic gas turbine (Kerosene) – 70 MW	Nuclear unit – 600 MW	Nuclear unit – 600 MW

Detailed results are depicted in the following table and graph.

[151] Considering effective availability of the power plant candidates

Table 6-19: LEC as a function of capacity factor for various candidates, Sc2a: incl. transmission link, reference fuel scenario

Capacity factor	Unit	Lamu coal ST - 3x327 MW	Lamu coal "tender" - 3x327 MW	Kitui coal - 3x320 MW	Dongo Kundu LNG CCGT 3pressure - 789 MW	Wajir NG CCGT 1pressure - 698 MW	Generic nuclear unit - 600 MW	Suswa Phase I Stage 2 GEO - 100 MW	Generic bagasse PP - 25 MW	Generic HFO MSD - 18 MW	Generic gas turbine (gasoil) - 70 MW	HVDC - 400 MW
Maximum	USDcent/kWh	10.44	9.62	10.09	13.07	10.37	20.57	7.67	8.12	15.80	30.22	8.97
80%		10.94	10.03	10.54	13.38	10.66	22.57	9.06	8.98	16.32	30.40	9.47
70%		11.84	10.78	11.36	13.76	11.04	25.25	10.36	10.09	16.87	30.64	10.32
60%		13.04	11.78	12.45	14.27	11.53	28.84	12.09	11.57	17.61	30.97	12.04
50%		14.72	13.18	13.98	14.99	12.23	33.85	14.50	13.65	18.65	31.43	14.45
40%		17.24	15.28	16.28	16.06	13.27	41.37	18.13	16.75	20.20	32.11	18.06
30%		21.45	18.79	20.10	17.85	15.01	53.90	24.17	21.93	22.80	33.25	24.08
20%		29.85	25.79	27.75	21.44	18.48	78.97	36.26	32.29	27.98	35.53	36.12

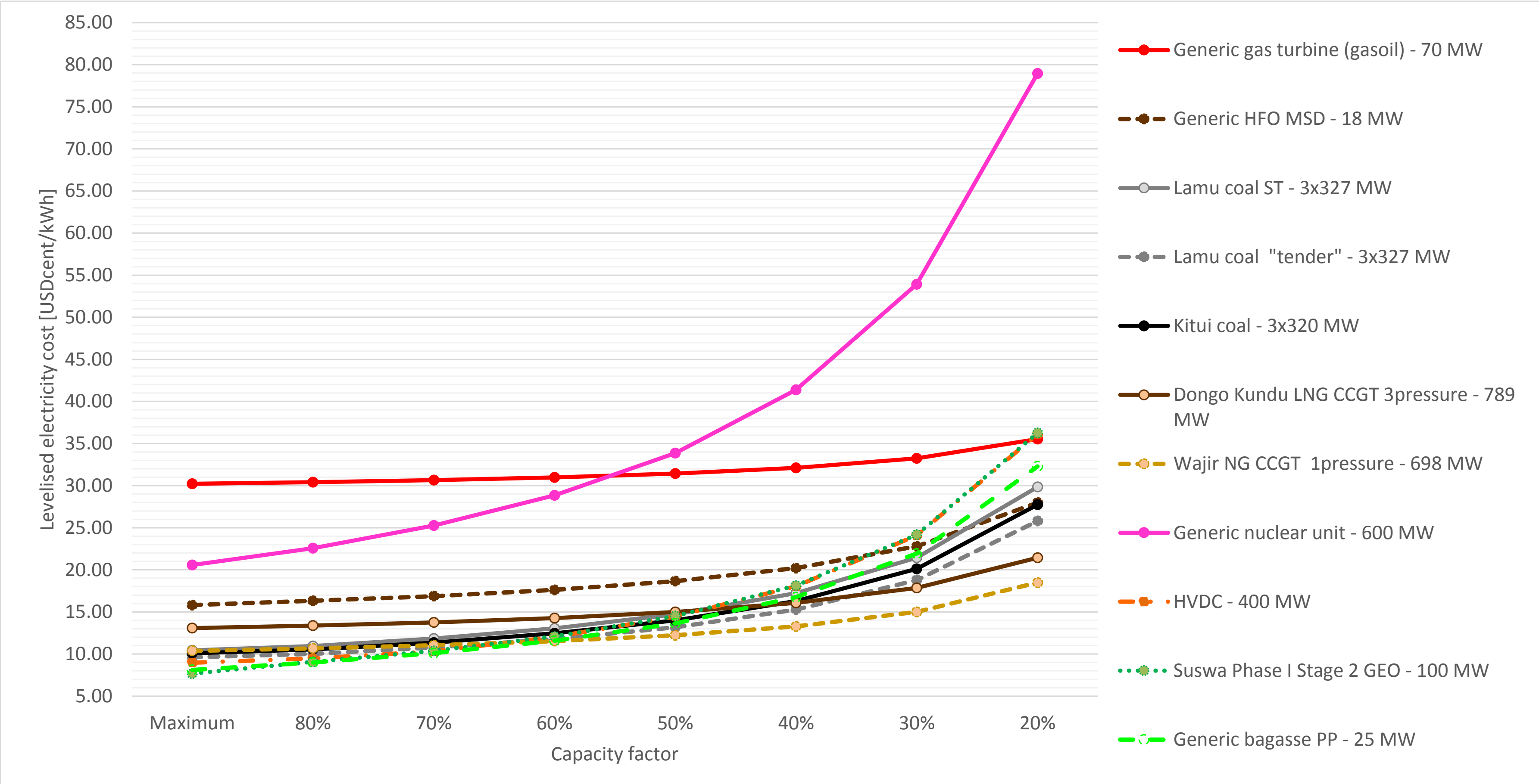

Figure 6-7: LEC as a function of capacity factor for various candidates, Sc2a: incl. transmission link, reference fuel scenario

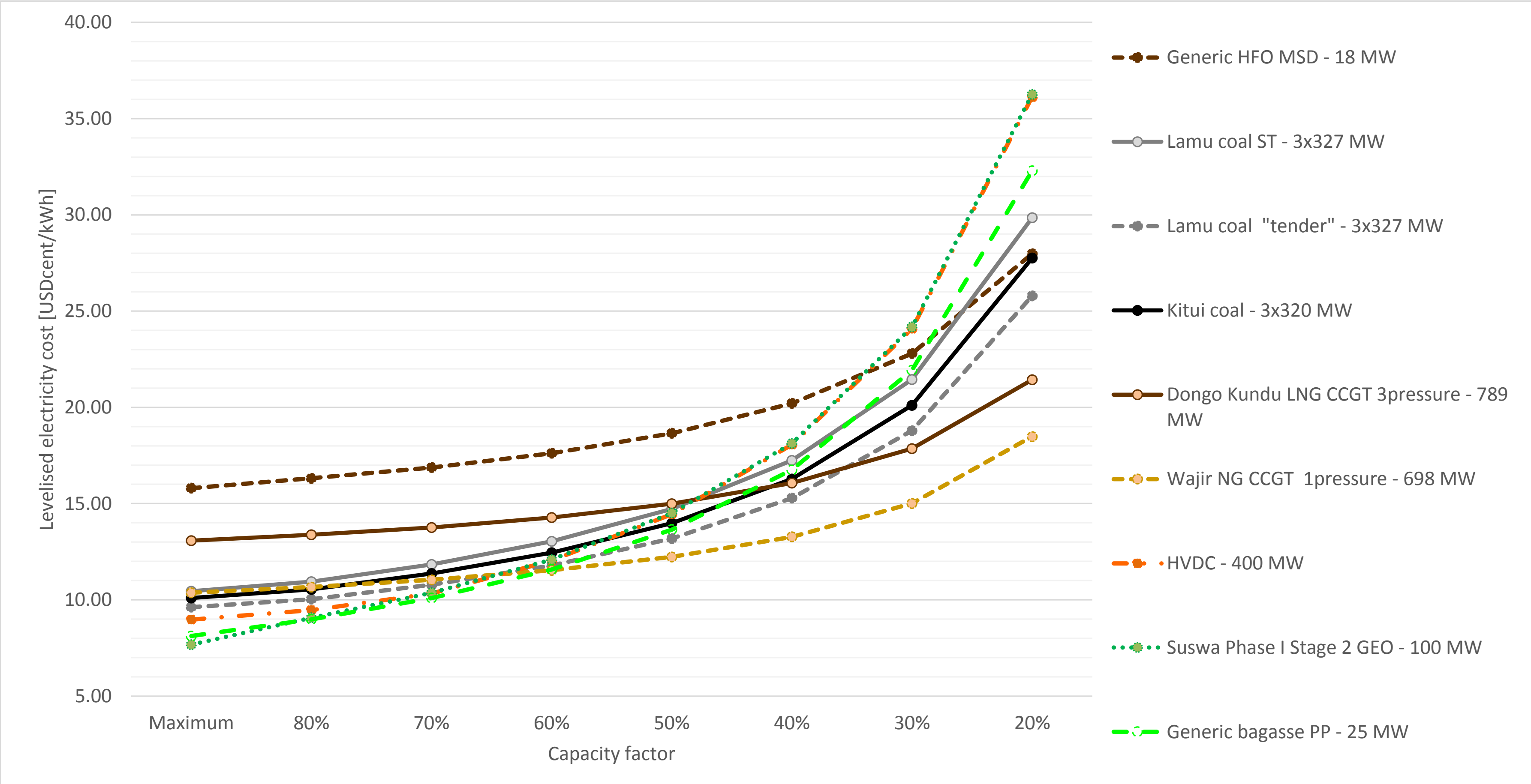

Figure 6-8: LEC as a function of capacity factor for various candidates, extract, Sc2a: incl. transmission link, reference fuel scenario

6.5 Prioritisation assessment – PESTEL analysis

This section provides the prioritisation assessment of candidates along the PESTEL approach. It contains an introduction to the methodology and provides the results for each candidate category (technology and energy) in a tabular form. The underlying detailed analysis is provided Annex 6.D together with a brief description of candidates.

6.5.1 Methodology and assumptions

The prioritisation assessment investigates the future capacity development regarding the medium and long term and provides an independent verification of the present status of the expansion candidates. It in particular facilitates a prioritisation of committed and candidate projects for the medium-term period in order to harmonise their scheduling.

Basically, the prioritisation assessment is carried out by means of a PESTEL analysis for which qualitative data for the assessment of the expansion candidates have been collected and analysed.

Market forces of the PESTEL analysis

The PESTEL analysis examines the projects' macro-environment, which covers the following market forces:

- P - Political forces
- E - Economic forces
- S - Social forces
- T - Technological forces
- E - Environmental forces
- L - Legal forces

Planning criteria / key drivers of the PESTEL analysis

The PESTEL framework provides a comprehensive list of influences on the possible success or failure of projects. Therefore, key drivers for evaluating the expansion candidates have been assumed according to the Consultant's experience in previous projects as well as particularities of the Kenyan power sector.

The table below lists the key drivers or planning criteria respectively, whose influence on the expansion candidates have been considered in the analysis.

Table 6-20: PESTEL criteria[152]

#	Key Planning Criteria	Remarks (where applicable)
1	**POLITICAL**	
1.1	Contributes to security of power supply?	Power plant's operating behaviour
1.2	Contributes to diversification of energy mix?	Consider potential fuel dependencies
1.3	Use of domestic resources?	Fossil or renewable resources
2	**ECONOMIC**	
2.1	Exploits economies of scale?	Size and number of generation units
2.2	Estimate of cost of required infrastructure?	Fuel supply (road, railway, port) and grid connection infrastructure
2.3	Site close to supply vs. load centre?	Effect on transmission line infrastructure
2.4	Overall capital needs	Effects financing / feasibility
3	**SOCIAL**	
3.1	Any social issues?	Compensation / resettlement
3.2	Conflicts in planning zones?	
4	**TECHNICAL**	
4.1	Suitable unit size for system integration?	Consider largest unit in system
4.2	Suitable for base / peak load operation?	Consider intermittent energy sources
4.3	Provision of reserve power?	
4.4	Construction / implementation schedule realistic?	Implementation time according to common industry practice
4.5	Fuel supply infrastructure?	Availability of road, railway, port
4.6	Grid connection feasible?	
5	**ENVIRONMENTAL**	
5.1	Compliance with national / international environmental standards?	Air pollution / direct environmental impact
6	**LEGAL**	
6.1	Status of contracts?	In particular PPA process
6.2	Status of processes?	In particular tendering process
6.3	Financial close / funding secured?	
6.4	Land use / rights secured?	In particular wayleave issues

[152] The PESTEL criteria have been the basis for verifying the expansion candidates. They were discussed and agreed with various project stakeholders during the site visits of the Consultant. Various data were collected and analysed, such as current regulations, maps, calculations, statistics, development strategies, project lists, tender documents, planning data as well as first-hand information from project participants. The data were been received by relevant ministries, the regulator, transmission system operator, generation companies and project developers, including the private sector.

Result structure and legend

To avoid lengthy and complex lists, the PESTEL analysis has been conducted in tabular form. It is structured into two levels i) the primary energy source / technology and ii) the power plant / candidate level. The result tables cover the qualitative evaluation of the PESTEL forces for each power plant technology or candidate, arranged by their earliest year for system integration.

The relevant legend for the evaluation of the PESTEL criteria is provided below. Detailed explanations are provided in the Annex, in particular for more advanced large-scale projects.

Legend for evaluation of PESTEL criteria	
++	very good
+	good
o	satisfactory
-	sufficient
--	insufficient

Candidates with commissioning years shifted beyond the medium term are greyed.

Earliest year for system integration / project COD

The analysis led to the Consultant's assumption on the earliest possible year to integrate the power plant into the power system. This considers the project's point of view but also estimates the impact of external factors of the overall system such as the capability of the system to absorb the energy and kind of generation (e.g. base load, intermittent). Hence, earliest year for system integration could be similar or later than project COD. For the medium term period project CODs are provided (were suitable) based on Consultant review and estimate.

6.5.2 Coal power plants

The PESTEL results of coal power plant projects are provided below (details in Annex 6.D.1).

Table 6-21: PESTEL evaluation – coal projects

No.	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Lamu Coal Plant – Unit 1	327	2021	+	+	--	o	--	-
2	Lamu Coal Plant – Unit 2	327	2022	+	+	--	o	--	-
3	Lamu Coal Plant – Unit 3	327	2023	+	+	--	o	--	-
4	Kitui Coal Plant – Unit 1	320	2025	+	o	--	-	--	o
5	Kitui Coal Plant – Unit 2	320	2026	+	o	--	-	--	o
6	Kitui Coal Plant – Unit 3	320	2027	+	o	--	-	--	o

6.5.3 Natural gas (CCGT) power plants

The PESTEL results of natural gas power plant projects are provided below (details in Annex 6.D.2).

Table 6-22: PESTEL evaluation – natural gas projects

No.	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Dongo Kundu CCGT	789	2021	o	+	o	++	+	o
2	Wajir CCGT	698	2025	+	+	o	++	+	o

6.5.4 Geothermal power plants

The PESTEL results of geothermal power plant projects are provided below (details in Annex 6.D.3).

Table 6-23: PESTEL evaluation – geothermal projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	Project COD	P	E	S	T	E	L
1	Olkaria topping unit	60	2019	End 2018	++	+	o	+	o	-
2	KenGen Wellheads Olkaria	20	2016	May 2016	++	+	o	+	o	-
3	Menengai 1 Phase I - Stage 1	103	2019	End 2018	++	+	o	+	o	-
4	Olkaria 1 - Unit 6	70	2019	Dec. 2018	++	+	o	+	o	-
5	Olkaria 5	140	2019	Mid 2019	++	+	o	+	o	-
6	Olkaria 6	140	2021	2nd half 2020	++	+	o	+	o	-
7	Olkaria 7	140	2021	beyond MTP	++	+	o	+	o	-
8	Olkaria 8	140	2022	beyond MTP	++	+	o	+	o	-
9	Olkaria 9	140	2023	beyond MTP	++	+	o	+	o	-
10	Menengai 2 Phase I - Stage 2	60	2021	beyond MTP	++	+	o	+	o	-
11	Menengai 2 Phase I - Stage 3	100	2023	beyond MTP	++	+	o	+	o	-
12	Eburru 2	25	2023	beyond MTP	++	+	o	+	o	-
13	Marine Power Akiira Stage 1	70	2024	beyond MTP	++	+	o	+	o	-
14	AGIL Longonot Stage 1	70	2024	beyond MTP	++	+	o	+	o	-
15	Suswa Phase I - Stage 1	50	2026	beyond MTP	++	+	o	+	o	-
16	Suswa Phase I - Stage 2	100	2027	beyond MTP	++	+	o	+	o	-
17	Baringo Silali Phase I, Stage 1	100	2025	beyond MTP	++	+	o	+	o	-
18	Baringo Silali Phase I, Stage 2	100	2026	beyond MTP	++	+	o	+	o	-
19	Menengai 2 Phase I - Stage 4	200	2028	beyond MTP	++	+	o	+	o	-
20	Menengai 3 Phase II - Stage 1	100	2029	beyond MTP	++	+	o	+	o	-
21	Suswa 2 Phase II - Stage 1	100	2029	beyond MTP	++	+	o	+	o	-
22	AGIL Longonot Stage 2	70	2030	beyond MTP	++	+	o	+	o	-
23	Marine Power Akiira Stage 2	70	2030	beyond MTP	++	+	o	+	o	-
24	Baringo Silali Phase I - Stage 3	200	2031	beyond MTP	++	+	o	+	o	-
25	Menengai 4 Phase II - Stage 2	100	2031	beyond MTP	++	+	o	+	o	-
26	Suswa 2 Phase II - Stage 2	100	2031	beyond MTP	++	+	o	+	o	-

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	Project COD	P	E	S	T	E	L
27	Baringo Silali Phase I - Stage 4	100	2033	beyond MTP	++	+	o	+	o	-
28	Menengai 4 Phase II - Stage 3	100	2034	beyond MTP	++	+	o	+	o	-
29	Suswa 2 Phase II - Stage 3	100	2034	beyond MTP	++	+	o	+	o	-
30	Baringo Silali Phase II - Stage 1	100	2035	beyond MTP	++	+	o	+	o	-
31	Baringo Silali Phase II - Stage 2	100	beyond LTP	beyond MTP	++	+	o	+	o	-
32	Baringo Silali Phase II - Stage 3	300	beyond LTP	beyond MTP	++	+	o	+	o	-
33	Baringo Silali Phase II - Stage 4	300	beyond LTP	beyond MTP	++	+	o	+	o	-
34	Baringo Silali Phase II - Stage 5	300	beyond LTP	beyond MTP	++	+	o	+	o	-
35	Baringo Silali Phase III - Stage 1	300	beyond LTP	beyond MTP	++	+	o	+	o	-
36	Baringo Silali Phase III - Stage 2	300	beyond LTP	beyond MTP	++	+	o	+	o	-
37	Baringo Silali Phase III - Stage 3	300	beyond LTP	beyond MTP	++	+	o	+	o	-
38	Baringo Silali Phase III - Stage 4	300	beyond LTP	beyond MTP	++	+	o	+	o	-
39	Baringo Silali Phase III - Stage 5	200	beyond LTP	beyond MTP	++	+	o	+	o	-
40	Menengai 4 Phase II - Stage 4	100	beyond LTP	beyond MTP	++	+	o	+	o	-
41	Menengai 5 Phase I - Stage 1	300	beyond LTP	beyond MTP	++	+	o	+	o	-
42	Menengai 5 Phase I - Stage 2	300	beyond LTP	beyond MTP	++	+	o	+	o	-
43	Suswa 2 Phase II - Stage 4	100	beyond LTP	beyond MTP	++	+	o	+	o	-
44	Suswa 2 Phase II - Stage 5	200	beyond LTP	beyond MTP	++	+	o	+	o	-

6.5.5 Hydropower plants

The PESTEL results of hydropower plant projects are provided below (details in Annex 6.D.4).

Table 6-24: PESTEL evaluation – hydropower projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Karura	89	2023	+	+	-	++	-	o
2	Arror	59	2024	+	+	-	++	-	o
3	Magwagwa	119	2024	+	+	-	++	-	o
4	Nandi Forest	49.5	2025	+	+	-	++	-	o
5	High Grand Falls -Stage 1	495	2026	+	+	-	++	-	o
6	High Grand Falls -Stage 2	198	2028	+	+	-	++	-	o

6.5.6 Wind power plants

The PESTEL results of wind power plant projects are provided below (details in Annex 6.D.5).

Table 6-25: PESTEL evaluation – wind projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	Project COD	P	E	S	T	E	L
1	Lake Turkana Phase I, Stage 1	100	2017	Mid 2017	++	+	o	-	+	+
2	Kipeto Wind - Phase I	50	2018	End 2017	++	+	o	o	+	+
3	Lake Turkana Phase I, Stage 2	100	2018	Mid 2017	++	+	o	-	+	+
4	Ol-Danyat Energy	10	2019	Na	++	+	o	o	+	+
5	Ngong 1 - Phase III	10	2019	End 2018	++	+	o	o	+	+
6	Aeolus Kinangop	60	2019	End 2018	++	+	o	o	+	+
7	Kipeto Wind - Phase II	50	2019	End 2018	++	+	o	o	+	+
8	Lake Turkana Phase I, Stage 3	100	2019	Mid 2017	++	+	o	-	+	+
9	Meru Phase I	80	2020	2nd half 2019	++	+	o	o	+	+
10	Prunus Wind	51	2021	beyond MTP	++	+	o	o	+	+
11	Limuru Wind – Transcentury	50	2022	beyond MTP	++	+	o	o	+	+
12	Kajiado Wind - Chagem Power	50	2022	beyond MTP	++	+	o	o	+	+
13	Malindi	50	2024	beyond MTP	++	+	o	o	+	+
14	Meru Phase II	320	2024	beyond MTP	++	+	o	o	+	+
15	Marsabit Phase I	300	2025	beyond MTP	++	+	o	-	+	+
16	Lake Turkana Phase II, Stage 1	100	2025	beyond MTP	++	+	o	-	+	+
17	Lake Turkana Phase II, Stage 2	100	2026	beyond MTP	++	+	o	-	+	+
18	Marsabit Phase II	300	2027	beyond MTP	++	+	o	-	+	+
29	Lake Turkana Phase II, Stage 3	150	2027	beyond MTP	++	+	o	-	+	+
20	Lake Turkana Phase III,Stage 1	100	2030	beyond MTP	++	+	o	-	+	+
21	Lake Turkana Phase III, Stage2	100	2031	beyond MTP	++	+	o	-	+	+
22	Lake Turkana Phase III, Stage3	150	2032	beyond MTP	++	+	o	-	+	+

6.5.7 Biomass power plants

The PESTEL results of biomass power plant projects are provided below (details in Annex 6.D.6).

Table 6-26: PESTEL evaluation – biomass projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Generic bagasse power plant (cogeneration)	25	2020	+	+	o	o	+	o

6.5.8 Solar (photovoltaic) power plants

The PESTEL results of solar power plant projects are provided below (details in Annex 6.D.7).

Table 6-27: PESTEL evaluation – solar photovoltaic projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Generic PV power plant	10	2019	+	+	+	+	o	o

6.5.9 Nuclear power plants

The PESTEL results of nuclear power plant projects are provided below (details in Annex 6.D.8).

Table 6-28: PESTEL evaluation – nuclear projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	P	E	S	T	E	L
1	Nuclear Power Plant	1,000/600	2030	o	o	--	o	--	--

6.5.10 Interconnectors

The PESTEL results of interconnector projects are provided below (details in Annex 6.D.9).

Table 6-29: PESTEL evaluation – interconnector projects

No	Power Plant Name	Net Capacity Addition [MW]	Earliest year for system integration	Project COD	P	E	S	T	E	L
1	HVDC Ethiopia-Kenya inter-connector import - Stage 1	400	2019	End 2018	+	+	o	++	o	o
2	HVDC Ethiopia-Kenya inter-connector import - Stage 2	400	2019	End 2018	+	+	o	++	o	o

7 GENERATION EXPANSION PLANNING

The section presents the inputs and results of the generation expansion planning of the Kenyan power system.

The objective of the this chapter is to

- Plan the least cost generation system for the years 2015 (base year) to 2035 considering the most probable operation of the Kenyan power system and observing the defined framework conditions.
- Identify solutions for possible shortcomings in generation planning.
- Provide inputs for the network expansion planning.

7.1 Key results and conclusions

The key results and corresponding conclusions and planning recommendations are (see also tabularised principal generation expansion plan in Table 7-15 in Section 7.6.1.1):

- The energy mix of the generation expansion plan is diverse, secure with regard to supply and costs of fuel and "clean":
  - Main base load expansion is reached through geothermal capacity (geothermal will represent one third of the installed generation capacity providing more than half of the annual generated electricity in 2035), about half of the geothermal capacity will be located in the Olkaria area. In case of high demand developments, base and intermediate load capacity is supplemented by coal.
  - Second largest share in the long term energy mix is represented by hydropower (16% in 2035 in the reference scenario, down from a share of some 40% today). HPPs will also play a major role in the provision of flexible capacity to the system.
  - Back-up capacity expansion is about 1,890 MW (about 20% of the total system capacity in the reference expansion scenario). It is mainly providing the required cold reserve (in the plan as generic gas turbines which could also represent other means such as import (sharing) of reserve or storage, if available).
  - In the long term, more than 85% of the electricity demand will be covered by domestic renewable energy sources (56% by geothermal, 16% by hydropower, 11% by wind, 2% by biomass cogeneration and 2% by PV in the reference expansion plan). Imports and coal power will supplement the energy mix (7% and 6%, respectively).

  In this frame it is recommended

  - To continue development of geothermal capacities as in the past (considering a rescheduling as in this plan). However, the current and expected future dominance of geothermal capacity in Olkaria should be closely monitored in terms of security of supply, e.g. with regard to the geothermal source (which could decrease) or evacuation of power. This may include a partly shift of new geothermal capacities to other geothermal fields if they are sufficiently analysed,

- To put more emphasis on the few hydropower candidates as essential and beneficial providers of flexibility. For instance, Karura should not be delayed. Even an earlier commissioning (scheduled by the optimisation for 2025 due to overcapacities) could be considered to allow for sufficient flexible capacity if other projects are delayed,
- To develop a diverse mix of other RE sources: sustain implementation of wind and PV at moderate costs and support firm capacities of small hydro and biomass cogeneration throughout the country. Further, available RE such as wind and PV may be suitable in future to save geothermal energy (i.e. allow that the limited geothermal resources can be exploited in a sustainable way).
- To further elaborate the position of coal within the power sector with regard to its particular benefits (due to low capacity factors in the simulation), environmental impact and to a lesser extent its import dependency. This could include a necessary link of the Lamu coal power plant to a large customer with demand for secure energy ("back to back"). This would fit into the MOEP concept for Lamu as an anchor plant on the Coast supporting local development, supplying flagship projects, and replacing diesel engines. Further, the evaluation whether coal is necessary as a secondary expansion source (e.g. for higher demand growth) is recommended. This would be in particular the case if sufficient domestic natural gas supply for power generation were approved in future or the implementation of the committed Lamu plant could be adapted (see below).

- Some committed power supply projects (namely HVDC, Lake Turkana) will result in overcapacities and excess electricity during hours of low demand. This effect is strongest in the years 2019 to 2023 (up to 15%, 6% and 17% of generated energy for the reference, vision and low scenario, respectively). It will decrease to an acceptable level below 1% in the long term. There is further potential excess in the system due to regular reduced production from the geothermal plants towards there minimum capacity (probably resulting in venting of steam) and due to the low capacity factors of coal power plant units.

  It is recommended

  - To analyse the opportunity for exporting this energy to neighbouring countries (e.g. Rwanda, Tanzania, Uganda) for their demand or storage in their hydropower plants (since excess often appears during hours of low load).
  - To assess possibility for an amendment of the PPA with Ethiopia for a more flexible supply through the HVDC (e.g. instead of firm take or pay only a reduced base firm take or pay while adding flexible supply).
  - To carefully assess and continuously monitor implementation schedules of the plants committed for the medium term period to arrive at a suitable gradual commissioning (focussing on the most beneficial). A wrong signal to the market should be avoided which may indicate that these projects should be delayed or put on hold or are not necessary at all. However, if for committed plants the commissioning years are not fixed the simulation indicates that Lamu coal power plant would be only needed for the overall power system towards the end of the study period while geothermal plants would be brought forward to replace this capacity.

- In the generation modelling, sufficient reserve capacity is taken into account (mainly by consideration of the largest unit and average unavailability of generation capacity due to maintenance and forced outages). As a result, the LOLE is not critical in the long term. However, shortages in cold reserve capacity are expected in the years 2017 and 2018 which may lead to certain amounts of unserved energy in case of low hydrology or higher demand growth. Today, the Kenyan power system is running low on primary reserve provision[153].

  It is recommended

  - To introduce the simulation reserve requirements – as practical – to the actual system as soon as possible.
  - To conduct a separate practical study on the capability of existing and committed plants to provide reserve and other auxiliary services (e.g. see recommendation paper submitted to MOEP at the beginning of this project).
  - Considering the strong wind expansion in the medium term as well as the increased unit sizes due to the commissioning of the first Lamu unit, it is essential to increase the primary reserve capacity in the generation system. In this context it is recommended to equip the existing hydropower plants Masinga, Kamburu, Kindaruma, and Turkwel with respective IT infrastructure enabling primary reserve provisioning (feasibility to be analysed). New installed large hydropower plants and large steam turbines should also be able to provide primary reserve.
  - Geothermal expansion: flexibility of single-flash technology is very limited. Installation of binary systems may contribute to flexibility of supply (suitability to be analysed at design stage of respective geothermal power plant candidate).
  - Flexible imports (see previous topic) and hydropower plants with dams may provide further flexible generation supply.
  - Create incentives for provision of flexible capacity (reserve capacity) within contract structures (e.g. by means of capacity payments, load following compensation, frequency regulation).
  - In case that a higher security of supply is aimed to be reached in the years 2017 and 2018 it is recommended

    - To analyse the opportunity to implement temporary geothermal wellheads utilising the steam from wells already drilled for future projects in the Olkaria and Menengai field. In this context also the absorption capacity of the grid in the respective area has to be taken into account. The wellheads would displace the existing diesel engines in the merit order, so that diesel engines would provide the required peaking and back-up capacity in this period.

    - To evaluate if a more flexible handling of power export to Rwanda is feasible, e.g. reduced export during hours of high demand. This option would reduce the capacity need by 30 MW[154].

[153] Only Gitaru and Kiambere HPP contribute to reserve regulations

[154] Due to the short-term nature of the need for measurements, Demand Side Management does not represent a feasible option.

- In case that the above listed options are not sufficient, the installation of temporary back-up units (e.g. gas turbines) to provide the reserve capacity might represent an alternative for the period of concern.

- The principal generation expansion plan (along reference scenario, see also tabularised plan in Table 7-15 in Section 7.6.1.1) is robust with regard to changes of main assumptions (e.g. demand, RE penetration, hydrology). Those changes may require a change of commissioning years for identified plants or additional capacity in the long term for any higher demand growth. Both is analysed and detailed below as part of the principal plan. Due to its focus on domestic and renewable sources the plan is considered very robust towards cost changes.

  It is recommended that the responsible sector institutions (MOEP, ERC with among others KPLC, Ketraco, GDC and KenGen)

  - Consider this plan as the blue print for the development of the power generation.
  - Continuously monitor frame conditions to adapt implementation schedules of power plants as required (to avoid excess supply or deficits and financial implications). For instance if there are any delays for committed plants or demand increases beyond the reference forecast, geothermal plants with on-going production drilling could be brought forward. Hydropower projects (e.g. Karura) should not be delayed and even an earlier commissioning considered (see above). Further, the status of new hydropower projects in Ethiopia should be monitored in terms of availability to supply capacity and energy when the interconnector is operational.
  - Reassess the plan as the regional market for power will emerge (which currently does not exist but shows high potential).

Below the generation expansion path and electricity generation is displayed.

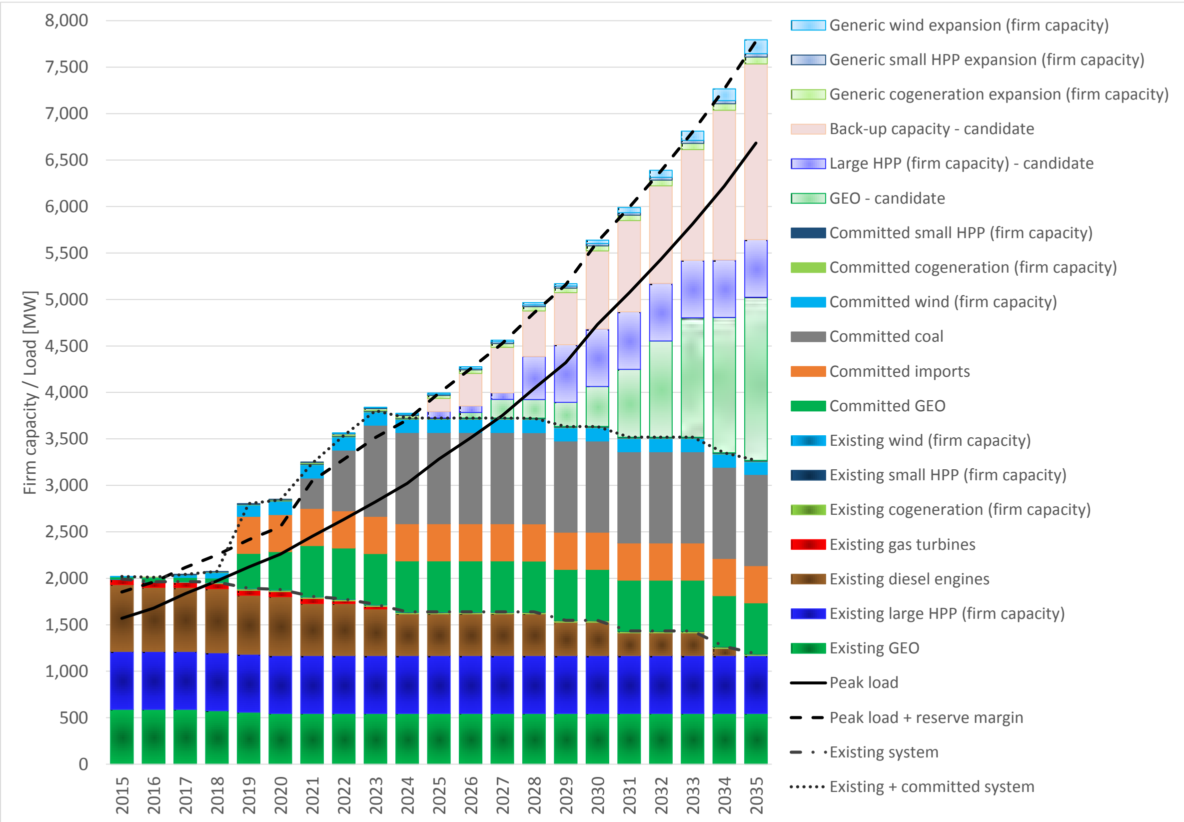

Figure 7-1: Reference expansion scenario – firm capacity versus peak demand

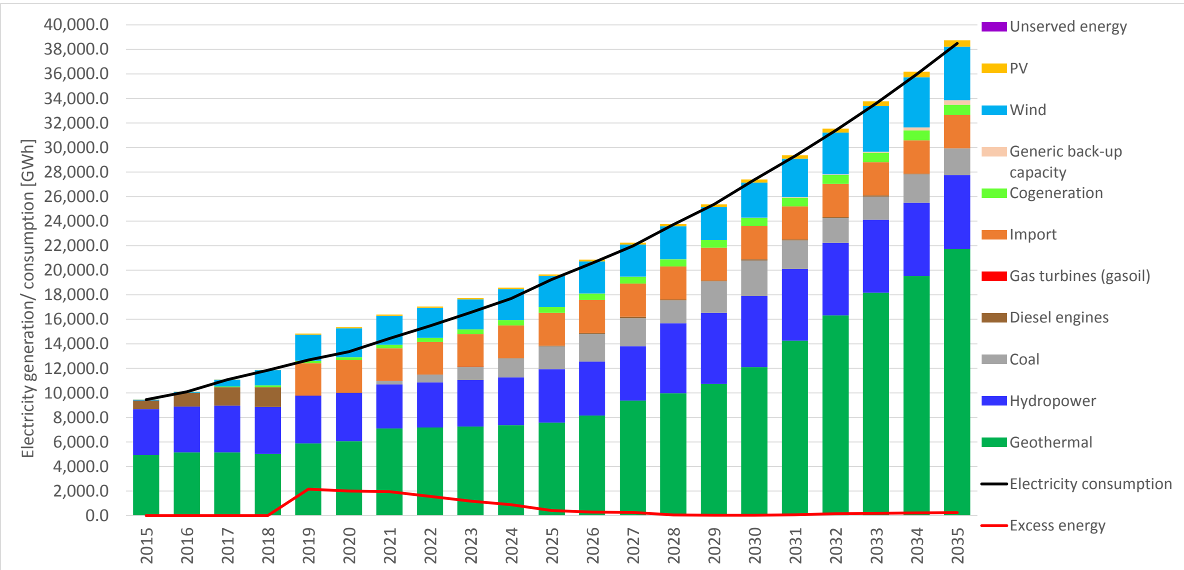

Figure 7-2: Reference expansion scenario – electricity generation versus electricity consumption

7.2 Generation expansion planning approach

In general, the generation expansion is done by means of an optimisation to arrive at the least cost solution for a given set of assumptions. These include among others demand scenarios, existing and committed generation system, and the network expansion (done in close coordination). For this, the generation expansion planning was done along the following steps:

1) Input processing for simulation and optimisation models (into Excel based data interface):

    a) Demand forecast hourly load curves for the study period (based on: generic load curves, annual demand for electricity and peak load);

    b) Existing generation system: configurations based on existing power plants (see 3.4);

    c) Renewable energy: potential expansion paths by energy source and for intermittent RE generic production curves (hourly, seasonal, representative sites);

    d) Pre-screened and prioritised generation candidates (see 6);

    e) Reliability requirements of the system (see below);

    f) Economic assumptions to calculate comparable cost streams.

2) Demand supply balancing: the demand supply balance of the power system is derived from the evaluation of the existing and committed power plants and the demand forecast scenarios. For each year of the study period, period peak demand and available capacity as well as total energy demand and possible total energy generation (as firm energy) are matched. The net capacity and energy deficit constitutes the minimum amount of additional capacity needed in the system. This balance will provide the framework for scheduling of generation capacity additions.

3) Scenario definition: the reference (base) scenario is based on the most probable or recommended projections of key developments in the future: demand (reference scenarios), the (previously analysed) RE expansion paths and available generation sources (committed power plants and candidates, hydrology, desired energy mix). This reference scenario is complemented by other (sub)scenarios which describe a potential range of developments (e.g. for demand or RE expansion).

4) Generation system optimisation: the optimisation follows a two steps approach which is done by two different generation system simulation and optimisation tools. The tools are interlinked.

    a) Identification of a long-list of preferable generation capacity expansion paths: (net present value costs) optimisation of the long-term capacity expansion by means of the software **LIPS-XP** (Lahmeyer International Power System Expansion Planning) considering power plant operation characteristics, hourly dispatch for the hourly load curves, candidates expansion restrictions (tunnels), general reserve requirements, (optimised) maintenance schedules, RE expansion paths, costs of energy not served, loss of load probabilities.

b) Identification of the optimum expansion path: optimisation (net present value costs) for the operational system configuration of the previously identified long-list (preferable expansion paths) by means of the software **LIPS-OP** considering same assumptions as for LIPS-XP (Lahmeyer International Power System Operation Planning)

5) Evaluation of the optimum expansion path in terms of energy mix, system reliability) and costs (levelised electricity costs).

7.3 Demand supply balancing

This section compares the forecasted peak load with the expected available capacity of the existing and committed power plants in order to determine when supply gaps are going to occur during the study period and how much capacity is needed to fill the gaps.

7.3.1 Demand forecast and load curve characteristics

The underlying annual demand for energy and power throughout the study period is based on the demand forecast presented in Chapter 4. Furthermore, the signed PPA for the export of 30 MW base load power (some 260 GWh per year) from Kenya to Rwanda is considered as additional demand in the generation modelling during the period from 2017 to 2019. The resulting peak load and electricity consumption of the four demand scenarios are reproduced in the table below.

Table 7-1: Forecast of peak load and electricity consumption (incl. export to Rwanda)

	Scenario	Unit	2015	2016	2017	2018	2019	2020	2025	2030	2035
Peak load	Reference	MW	1,570	1,679	1,834	1,972	2,120	2,259	3,282	4,732	6,683
	Vision		1,570	1,770	2,056	2,291	2,545	2,845	4,431	6,833	10,219
	Low		1,570	1,669	1,808	1,916	2,025	2,116	2,769	3,618	4,788
	EE		1,570	1,679	1,834	1,972	2,032	2,077	2,700	3,729	5,136
Consumption	Reference	GWh	9,453	10,093	11,084	11,856	12,683	13,367	19,240	27,366	38,478
	Vision		9,453	10,592	12,228	13,558	14,999	16,665	25,469	39,260	58,679
	Low		9,453	10,035	10,932	11,561	12,195	12,632	16,427	21,375	28,153
	EE		9,453	10,093	11,084	11,856	12,189	12,345	16,021	21,873	30,056

The following load characteristics are relevant for the demand supply balancing and later system optimisation (see 3.2.7 and Annex 3.D.6 for details):

- There is one main maximum towards the end of the year (mainly occurring in November or December), determined by continuous growth of demand throughout the year. There is no other seasonality of demand which would have an impact on the generation system. The peak of most other months is only about 2 to 5% below the annual peak (the impact of hydrological seasonality on the firm capacity is usually less). Generation expansion planning should be done by applying for the demand supply balancing the annual peak (which occurs at the end of the year) while scheduling new capacity additions at the beginning of the year.

- A very distinctive evening peak occurs 7 pm to 11 pm (highest mostly 8 pm to 9 pm) with load on average 30% above the daily average load. This requires the power system operation, for nearly each day of the week, to double the load during day and reduce it again by 50% (e.g. up to 800 MW in 2014) within few hours. It determines the capacity requirements, e.g. a high share of generation capacity to be capable for intermediate and peak operation and exclusion of solar to support the system.

- A rather flat minimum between midnight and 6 am, 25% below the daily average load will be crucial for the dispatch together with minimum capacity and up-/ downtime of the units.

- Load curve does not vary much within a year and throughout the past years with no long term trend (except for a slight decrease of the load factor).

This analysis allows to apply generic annual load curves (derived from most recent complete hourly load data set 2014) which are adapted to the different growth of demand for electricity and peak load. A different load curve shape is calculated for the Energy Efficiency scenario. Below the development of generic load curves is visualised.

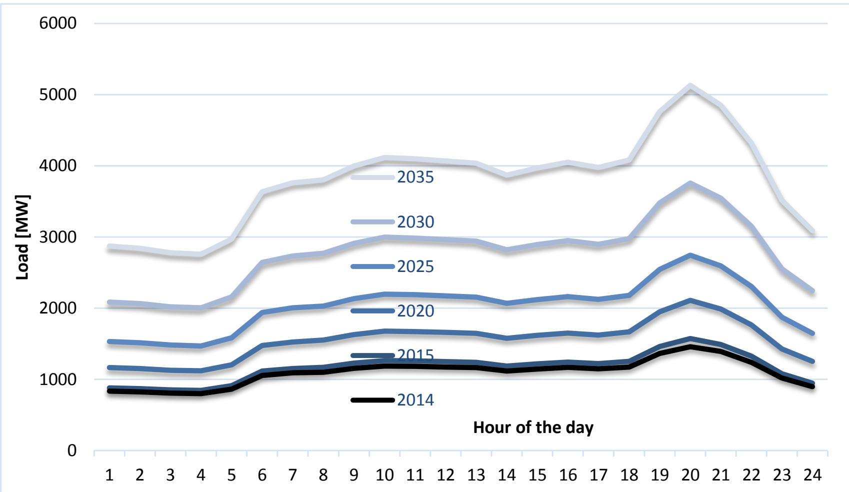

Figure 7-3: Generic load curves (last annual quarter) 2014, 2015, 2020, 2025, 2030, 2035

7.3.2 Existing power generation system

The overall net available capacity of the existing Kenyan power generation system end of 2016 amounts 2,205 MW (please see also Chapter 3.4).

In the generation modelling, it is assumed that existing hydropower and geothermal power plants will be rehabilitated after the end of their economic lifetime (see 6.3.2 for further information of rehabilitation). All other power plants recently commissioned or to be commissioned soon are expected to be phased out after their useful lifetime. The following table provides an overview of the assumptions in relation to decommissioning of existing power plants.

Table 7-2: Decommissioning of existing power plants

Power plant name	Type	Net capacity [MW]	COD	Phased out[155]	Remark
Tana	HPP	20	1955	beyond LTP	rehabilitation
Masinga	HPP	40	1981	beyond LTP	rehabilitation
Kamburu	HPP	90	1974/1976	beyond LTP	rehabilitation
Gitaru	HPP	216	1978/1999	beyond LTP	rehabilitation
Kindaruma	HPP	70.5	1968	beyond LTP	rehabilitation
Kiambere	HPP	164	1988	beyond LTP	rehabilitation
Turkwel	HPP	105	1991	beyond LTP	rehabilitation
Sondo Miriu	HPP	60	2008	beyond LTP	rehabilitation
Sang'oro	HPP	20	2012	beyond LTP	rehabilitation
Kipevu 1	MSD	59	1999	2023	decommissioning acc. to PPA
Kipevu 3	MSD	115	2011	2031	
Embakasi Gas Turbine 1	GT	27	1987/1997	2022	
Embakasi Gas Turbine 2[156]	GT	27	1999	2024	
Athi River Gulf	MSD	80	2014	2034	
Triumph	MSD	77	2015	2035	
Iberafrica 1	MSD	56	1997	2019	decommissioning acc. to PPA
Iberafrica 2	MSD	52.5	2004	2024	
Rabai Diesel	MSD	90	2009	2029	
Thika	MSD	87	2014	2034	
Tsavo	MSD	74	2001	2021	
Aggreko 1	HSD	30	2008	2016	

[155] Phased out assumed at the beginning of the year announced.
[156] Relocated to Muhoroni in 2016

Power plant name	Type	Net capacity [MW]	COD	Phased out[155]	Remark
Olkaria 1 - Unit 1-3	GEO	44	1981	beyond LTP	Step-wise rehabilitation in 2018-2019
Olkaria 1 - Unit 4-5	GEO	140	2014	beyond LTP	
Olkaria 2	GEO	101	2003	beyond LTP	rehabilitation
Olkaria 3 - Unit 1-6	GEO	48	2000	beyond LTP	rehabilitation
Olkaria 3 - Unit 7-9	GEO	62	2014	beyond LTP	
Olkaria 4	GEO	140	2014	beyond LTP	
KenGen Olkaria Wellheads I & Eburru	GEO	54.8	2015	beyond LTP	
Orpower Wellhead 4	GEO	24	2015	beyond LTP	
Ngong 1, Phase I	Wind	5.1	2008	2028	
Ngong 1, Phase II	Wind	6.8	2015	2035	
Ngong 2	Wind	13.6	2015	2035	
Mumias	COGEN	21.5	2008[157]	2033	
Kwale	COGEN	10	2015[157]	beyond LTP	
Small hydropower	HPP	14	various	beyond LTP	rehabilitation

7.3.3 Committed power supply candidates with fixed commissioning dates for system integration

The power supply projects illustrated in the table below are considered as committed as a result of the evaluation of power system expansion candidates (see PESTEL analysis in section 6.5). These projects are in a very advanced stage of implementation, e.g. financial close is almost/already reached. It is assumed that commissioning of these projects is not deferrable.

[157] Biomass assumptions: Mumias recommissioning to the grid assumed from 2018 onwards (no provision of electricity to the grid for most of 2015 and 2016); Kwale: power supply to the grid foreseen from 2017 onwards; Cummins: commissioning and supply to grid assumed for 2017. Temporary reduction of overall available biomass capacity by 10 MW in 2017 and 2018 due to uncertainty with regard to (re-)commissioning of full capacity of above existing and committed biomass plants.

Table 7-3: Committed power supply projects with fixed commissioning dates for system integration[158]

Power plant name	Type	Net capacity [MW]	Year for system integration[158]	Remark
Menengai 1 Phase I – Stage 1	GEO	102.5	2019	Construction of steam gathering system on-going
KenGen Olkaria Wellheads II	GEO	20	2016	Commissioned
Biojoule	Biomass	2	2016	Commissioned
Small hydro FIT	Hydro	17 7 11	2017 2018 2019	Accumulated expected commissioning of FIT list plants
HVDC Ethiopia-Kenya interconnector	Import	400	2019	Construction on-going
Cummins	Biomass	10	2017[157]	Under construction, step-wise commissioning possible
Lamu Unit 1	Coal	327	2021	Seeking financial close
Lamu Unit 2	Coal	327	2022	Seeking financial close
Lamu Unit 3	Coal	327	2023	Seeking financial close
Aelous Kinangop	Wind	60	2019	Project cancelled for location but assets assumed to be utilised in Kenya
Kipeto – Phase I	Wind	50	2018	Financial close reached
Lake Turkana – Phase I, Stage 1	Wind	100	2017	Financial close reached
Meru Phase I	Wind	80	2020	Financing committed
Kipeto – Phase II	Wind	50	2019	Financial close reached
Lake Turkana – Phase I, Stage 2	Wind	100	2018	Same as Stage 1 but step-wise system integration assumed
Lake Turkana – Phase I, Stage 3	Wind	100	2019	See above
Olkaria 1 Unit 6	Geo	70	2019	Financial close reached
Olkaria 5	Geo	140	2019	Financial close reached
Ngong Phase III	Wind	10	2019	Financial close reached
PV grid	PV	50	2019	Financial close reached
Olkaria 1 Unit 1,2,3 Rehabilitation	Geo	3x2	2019, 2020	Financing committed; each 15 MW unit to be replaced by 17 MW unit
Olkaria 6	Geo	140	2021[159]	Drilling in progress (financing for drilling secured)

[158] Years displayed for commissioning are years where the supply of respective plants is fully integrated into the power system. Project CODs may differ from these years (i.e. may be earlier). For details see Chapter 6.5

[159] Project COD assumed for 2nd half of 2020, within MTP period. Full integration into grid assumed for 2021 (i.e. beyond MTP period).

7.3.4 Demand supply balance

Based on the results of the load forecast and considering the existing and committed power supply projects, a demand and supply balancing has been carried out for the planning horizon of the LTP 2015-2035. The purpose of this analysis is to determine potential supply gaps which may occur during the study period. For this, the so-called firm generation capacity which can be guaranteed to be available at a given time has to be taken into account. For hydropower, wind, cogeneration and PV the following assumptions for the firm capacity are considered in the generation modelling (further details are presented in the Renewable Energy Report submitted with the present study as well as in Chapter 7.5.4 of this report):

- Large Hydropower: Percentile 90 (P90) exceedance probability value of the monthly maximum generation output of a hydropower plant based on half-hourly production data
- Small hydropower: 25% of the available net small hydropower capacity (reflecting minimum of monthly average available capacity considering low hydrology)
- Wind:
    - 2015-2018: 23% of the available net wind capacity
    - From 2019 onwards: 25% of the available net wind capacity (reflecting the P84 exceedance probability value during peak load hours)
- Cogeneration: 50% of the available net capacity
- PV: 0% of the available net capacity (no electricity production through PV plants during peak load hours)

The results of the demand & supply balancing can be summarised as follows:

- In the **reference expansion scenario**, peak load is met in all years until 2026. However, when considering reserve requirements, supply gaps occur from 2017 to 2018 (93 to 217 MW) and from 2025 onwards.
- In the **vision expansion scenario**, the firm system capacity will cover peak load in the years from 2015 to 2016, in 2019 and from 2021 to 2023. Considering peak load plus reserve margin, supply gaps occur from 2016 onwards.
- In the **Energy Efficiency (EE) expansion scenario**, peak load is met for all years until 2029. Taking into account reserve requirements, there will be a shortage between 93 and 217 MW in the medium term (during the years 2017 and 2018). Further gaps will occur from 2028 onwards. The commissioning of large capacities in the years 2019 to 2023 will lead to immense system overcapacities between 373 and 798 MW (in relation to peak demand plus reserve margin) in the years 2019 to 2025.

- The firm system capacity will cover peak load until 2030 in the **low expansion scenario**. Considering peak load plus reserve margin, the supply gap in the medium term is estimated at 64 to 155 MW (in the years 2017 and 2018). As expected, the commissioning of large capacities in the years 2019 to 2023 will result in large system overcapacities ranging from 297 to 681 MW until 2025.

- In the long-term, the supply gap is forecasted to be in the range of 2,400 to 8,500 MW (low and vision scenario).

In summary, the analysis reveals that supply gaps are not only expected in the long term, but may also occur until 2018 (depending on the demand scenario). In the years 2019 to 2023 large amounts of capacity will be added to the system resulting in strong overcapacities for the low and EE demand scenario. It is the objective of the generation expansion planning to identify suitable solutions for overcoming the detected supply gaps (both in the medium and long term) and to provide recommendations how to deal with the expected overcapacities. This will be further analysed in the following sections of the present chapter.

The following figure and Table 7-4 provide an overview of the forecasted demand and supply gaps for the four scenarios.

The figure compares (on annual basis)

- The development of peak demand (of the four demand scenarios);

- With the firm capacity throughout the study period.

The dotted lines indicate for each scenario the required capacities including a reserve margin considering the possible loss of the largest unit in the existing and committed system ("sizing incident") and in addition, a cold reserve margin of 10% for balancing occasional unavailability of power plants due to planned maintenance and forced outages[160].

[160] Please note that the reserve margin applied for the demand supply balancing only gives an indication and may deviate from the results of the generation expansion planning. The actual required reserve capacity depends on the actual system configuration (i.e. largest unit, power plant availability scheduling) and will thus be determined within the generation expansion simulation.

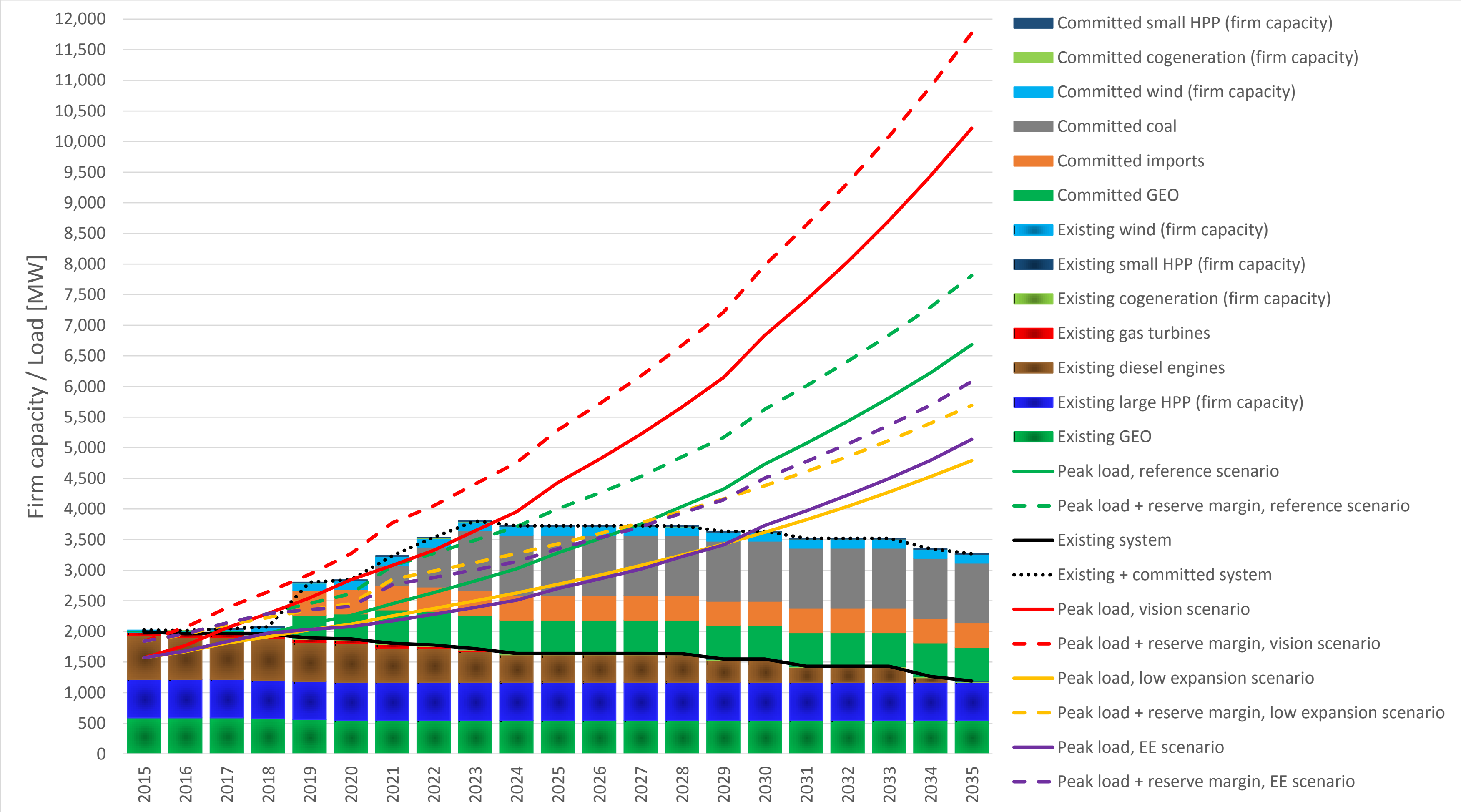

Figure 7-4: Demand supply balancing considering firm capacity of the existing and committed power generation system

Table 7-4: Demand supply balancing considering firm capacity of the existing and committed power generation system

	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Firm system capacity	MW	2,021	2,012	2,043	2,073	2,804	2,843	3,236	3,536	3,804	3,725	3,725	3,725	3,725	3,723	3,633	3,633	3,518	3,518	3,518	3,351	3,269
Peak load																						
Vision scenario	MW	1,570	1,770	2,056	2,291	2,545	2,845	3,077	3,325	3,643	3,953	4,431	4,811	5,218	5,665	6,144	6,833	7,414	8,031	8,710	9,432	10,219
Reference scenario	MW	1,570	1,679	1,834	1,972	2,120	2,259	2,451	2,633	2,823	3,022	3,282	3,511	3,751	4,040	4,320	4,732	5,071	5,431	5,813	6,220	6,683
EE scenario	MW	1,570	1,679	1,834	1,972	2,032	2,077	2,173	2,279	2,392	2,511	2,700	2,855	3,018	3,221	3,411	3,729	3,969	4,225	4,497	4,791	5,136
Low scenario	MW	1,570	1,669	1,808	1,916	2,025	2,116	2,253	2,373	2,497	2,629	2,769	2,917	3,076	3,245	3,426	3,618	3,822	4,041	4,276	4,528	4,788
Supply gap (firm capacity - peak load)																						
Vision scenario	MW	451	242	-13	-218	259	-2	159	211	161	-228	-707	-1,086	-1,493	-1,942	-2,511	-3,200	-3,896	-4,513	-5,191	-6,081	-6,949
Reference scenario	MW	451	333	209	102	683	584	785	903	981	703	443	214	-27	-317	-687	-1,099	-1,553	-1,913	-2,295	-2,869	-3,413
EE scenario	MW	451	333	209	102	772	766	1,063	1,257	1,412	1,214	1,024	869	706	502	222	-96	-451	-706	-978	-1,440	-1,867
Low scenario	MW	451	342	235	157	778	727	983	1,163	1,307	1,096	956	807	649	478	208	16	-304	-523	-758	-1,176	-1,519
Peak load plus reserve margin																						
Vision scenario	MW	1,840	2,064	2,385	2,648	2,932	3,268	3,773	4,051	4,407	4,754	5,290	5,715	6,171	6,672	7,209	7,980	8,631	9,322	10,082	10,891	11,772
Reference scenario	MW	1,840	1,962	2,136	2,290	2,457	2,612	3,073	3,276	3,488	3,711	4,003	4,259	4,529	4,852	5,165	5,627	6,006	6,410	6,838	7,294	7,812
EE scenario	MW	1,840	1,962	2,136	2,290	2,358	2,408	2,760	2,880	3,006	3,139	3,351	3,525	3,707	3,935	4,148	4,504	4,772	5,059	5,363	5,693	6,079
Low scenario	MW	1,840	1,952	2,107	2,228	2,350	2,452	2,851	2,984	3,124	3,271	3,428	3,594	3,772	3,962	4,164	4,379	4,608	4,853	5,116	5,398	5,690
Supply gap (firm capacity - peak load plus reserve margin)																						
Vision scenario	MW	180	-53	-342	-575	-128	-425	-537	-515	-603	-1,030	-1,565	-1,991	-2,446	-2,948	-3,575	-4,347	-5,112	-5,804	-6,563	-7,540	-8,503
Reference scenario	MW	180	49	-93	-217	347	231	163	260	316	13	-278	-535	-804	-1,129	-1,532	-1,994	-2,488	-2,891	-3,320	-3,943	-4,542
EE scenario	MW	180	49	-93	-217	446	435	476	656	798	586	373	200	17	-211	-514	-870	-1,254	-1,540	-1,845	-2,342	-2,810
Low scenario	MW	180	60	-64	-155	453	391	386	552	681	453	297	130	-48	-238	-530	-746	-1,090	-1,335	-1,598	-2,047	-2,421

7.4 Expansion scenario definition

This section defines the generation expansion scenarios to be analysed, based on

- Results of the demand forecast;
- Identification of suitable generation expansion candidates and analysis of committed plants;
- Analysis of renewable energy sources (including hydrology).

Various factors provide uncertainty to the future development of the power generation system. Their potential range might therefore be considered in separate scenarios or as sensitivity analyses of the scenario analysis results.

Table 7-5: Impact factors on power generation system development and resulting recommendations for scenario definition

Impact factor	Recommendations for generation expansion scenario definition
Development of demand	Consideration of demand scenarios developed (reference, vision, low, EE)
Impact of energy efficiency measurements	Consideration of EE measurements as sub-scenario
Penetration of generation from renewable energies	Consideration of different RE expansion paths which are analysed in sub-scenarios
Impact of drought periods on the reliability of the power generation system	Performing additional risk analysis of the detected optimal expansion path considering low hydrology conditions

The demand scenarios are defined and described in detail in Chapter 4 and reproduced in the previous section. The impact of energy efficiency measurements on the overall electricity demand are studied in the Energy Efficiency report. The resulting development of the future demand is illustrated in Chapter 7.3 as well.

In order to evaluate the impact of drought periods on the reliability of the power generation system, the operational behaviour of the detected optimal generation plan considering low hydrology conditions is analysed.

For the generation expansion optimisation, RE based generation is split into categories:

- “Conventional" RE: large scale generation which is already well developed in Kenya and can compete with other sources. These are fully identified candidates (see Chapter 6) based on geothermal energy and hydro. As normal candidates they are drawn by the system according to their costs and plant characteristics (including earliest CODs).

- “New” RE: generation which cannot fully compete in the optimisation with conventional sources (both, RE and fossil) due to
    - Their intermittent nature (wind and solar) with a strong interrelation between penetration level (i.e. different possible paths) and costs, or
    - Limitations with regard to their resources and plant characteristics which lead to a limit of the overall capacity and the implementation schedule. For this study and Kenya these are cogeneration (biomass) plants (mostly based on residuals) and small hydro. For both individual plant size and available information is limited so that only one aggregated probable expansion path is assumed.

The Renewable Energy report provides the reasonable RE paths in particular for the "new" RE considering the resources, the results of the generation candidates assessment (Chapter 6), the findings through the demand & supply balancing (Chapter 7.3) as well as the generation system characteristics (as detailed hereunder). They are summarised on the next page.

Summary generation expansion scenarios

The following table details the scenarios identified as worthwhile to be analysed in the generation expansion planning process.

Table 7-6: Overview of generation expansion scenarios

	Demand	Energy Efficiency (EE)	RE path	Hydrology
1 Reference expansion scenario	reference	non-EE	moderate	average
2 Low hydrology case	reference	non-EE	moderate	low
3 Accelerated RE scenario	reference	non-EE	accelerated	average
4 Slowed down RE scenario	reference	non-EE	slowed-down	average
5 Energy Efficiency scenario	reference	EE	moderate	average
6 Vision expansion scenario	vision	non-EE	moderate	average
7 Low expansion scenario	low	non-EE	moderate	average

Table 7-7: RE expansion paths: existing & committed capacity, generic expansion and total available capacity of RE sources

Existing & committed capacity:

		Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Small HPP	actual available for grid	MW	14	14	31	38	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
Cogeneration	installed for grid	MW	21	23	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	actual available for grid	MW	0	2	12	33	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
PV	actual available for grid	MW	1	1	1	1	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Wind	actual available for grid	MW	26	26	126	276	496	576	576	576	576	576	576	576	576	570	570	570	570	570	570	570	550

Generic expansion:

	RE scenario	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Small HPP	all	MW	0	0	0	0	0	9	18	27	36	45	54	63	72	81	90	99	107	116	125	134	143
Cogeneration	all	MW	0	0	0	0	0	11	22	33	44	55	66	74	83	91	99	108	116	124	132	141	149
PV	slowed down	MW	0	0	0	0	0	0	0	5	5	10	10	15	15	20	20	30	40	50	65	80	100
	moderate	MW	0	0	0	0	0	5	5	10	10	20	20	30	40	60	80	100	120	140	170	210	250
	accelerated	MW	0	0	0	0	0	10	10	20	20	40	40	60	80	120	160	200	240	280	340	420	500
Wind	slowed down	MW	0	0	0	0	0	0	0	25	25	25	50	50	50	75	75	100	100	125	150	175	200
	moderate	MW	0	0	0	0	0	0	0	25	25	50	50	75	75	100	100	150	225	300	400	500	600
	accelerated	MW	0	0	0	0	0	0	0	50	50	100	100	150	150	200	200	300	450	600	800	1,000	1,200

Total (available for grid):

	RE scenario	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Small HPP	all	MW	14	14	31	38	49	58	67	76	85	94	103	112	121	130	139	148	156	165	174	183	192
Cogeneration	all	MW	0	2	12	33	43	54	65	76	87	98	109	117	126	134	142	151	159	167	175	184	192
PV	slowed down	MW	1	1	1	1	51	51	51	56	56	61	61	66	66	71	71	81	91	101	116	131	151
	moderate	MW	1	1	1	1	51	56	56	61	61	71	71	81	91	111	131	151	171	191	221	261	301
	accelerated	MW	1	1	1	1	51	61	61	71	71	91	91	111	131	171	211	251	291	331	391	471	551
Wind	slowed down	MW	26	26	126	276	496	576	576	601	601	601	626	626	626	645	645	670	670	695	720	745	750
	moderate	MW	26	26	126	276	496	576	576	601	601	626	626	651	651	670	670	720	795	870	970	1,070	1,150
	accelerated	MW	26	26	126	276	496	576	576	626	626	676	676	726	726	770	770	870	1,020	1,170	1,370	1,570	1,750

7.5 Modelling assumptions

The assumptions and input data for the modelling and simulation of the generation system are detailed in this section.

7.5.1 Power supply options

Table 7-8 presents the power plant candidates which are considered in the generation expansion planning in addition to the existing and committed power supply options (see Table 7-2 and Table 7-3) as well as the defined RE expansion paths (see Table 7-7). The selection is based on the results of the assessment of defined generation candidates (please see Chapter 6). In addition, generic supply options are taken into account: generic coal power plants (with similar characteristics of the defined coal candidate Kitui in Chapter 6) and generic reserve/peaking units. The latter one are represented by generic gasoil fuelled gas turbines in the generation expansion modelling[161]. They are the least cost candidate for very low capacity factors according to the screening curve analysis (see Chapter 6) and generation system optimisation runs with gas turbines and medium speed diesel.

In contrast to committed projects, the commercial operational date of power plant candidates is not yet fixed and will be defined within the generation modelling process.

Table 7-8: Supply options for the generation expansion planning

Power plant name	Type	Net capacity [MW]	Earliest year considered for system integration[162]
Olkaria 7	GEO	140	2021
Olkaria 8	GEO	140	2022
Olkaria 9	GEO	140	2023
Olkaria Topping	GEO	60	2019
Eburru 2	GEO	25	2023
Menengai 2 Phase I – Stage 2	GEO	60	2021
Menengai 2 Phase I – Stage 3	GEO	100	2023
Menengai 2 Phase I – Stage 4	GEO	200	2028
Menengai 3 Phase II – Stage 1	GEO	100	2029
Menengai 4 Phase II – Stage 2	GEO	100	2031

[161] Due to low investment cost and short ramp-up times, gas turbines are traditionally used for peaking and cold reserve purposes. It is assumed that installation of this technology does not face any challenges which fall out of the sphere of influence of the MoEP, so that gas turbines are considered as secured candidates. However, the applied generic gas turbines may finally also be replaced by e.g. flexible imports from Ethiopia, Tanzania or Uganda or flexible hydropower plants as soon as implementation is assured.

[162] See Chapter 6.5

Power plant name	Type	Net capacity [MW]	Earliest year considered for system integration[162]
Menengai 4 Phase II – Stage 3	GEO	100	2034
Baringo Silali Phase I – Stage 1	GEO	100	2025
Baringo Silali Phase I – Stage 2	GEO	100	2026
Baringo Silali Phase I – Stage 3	GEO	200	2031
Baringo Silali Phase I – Stage 4	GEO	100	2033
Baringo Silali Phase II – Stage 1	GEO	100	2035
Suswa Phase I – Stage 1	GEO	50	2026
Suswa Phase I – Stage 2	GEO	100	2027
Suswa Phase II – Stage 1	GEO	100	2029
Suswa Phase II – Stage 2	GEO	100	2031
Suswa Phase II – Stage 3	GEO	100	2034
Marine Power Akiira Stage 1	GEO	70	2024
Marine Power Akiira Stage 2	GEO	70	2030
AGIL Longonot Stage 1	GEO	70	2024
AGIL Longonot Stage 2	GEO	70	2030
Kitui Unit 1	Coal	320	2025
Kitui Unit 2	Coal	320	2026
Kitui Unit 3	Coal	320	2027
Dongo Kundu CCGT	LNG	789	2021
Dongo Kundu CCGT small	LNG	375	2021
Nuclear Unit	Nuclear	600	2030
Karura HPP	HPP	89	2023
High Grand Falls Stage 1[163]	HPP	495	2026
High Grand Falls Stage 2[163]	HPP	198	2028
Generic back-up units	gasoil fuelled gas turbines	70 MW each	2019
Generic coal units	Coal	320 MW each	2028[164]

[163] High Grand Falls is the only multipurpose plant (i.e. other purposes than power generation) among the listed candidates. Its realisation therefore depends to a greater extent on decisions outside the power sector. As explained in section 5.3.2 it is however considered secured (compared to e.g. other multipurpose HPPs listed below). If this status and thus availability as expansion candidate changed alternatives would have to be considered to replace its purpose within the power system (largely peaking and provision of reserve). This could be pursuing development of other (currently not secured) HPPs or other peaking options (e.g. flexible import or MSD). Chapter 6.4.3.2 provides a cost comparison of High Grand Falls with other candidates.

[164] It is assumed that Kitui coal power plant is developed first (if coal capacity is required).

From the table above, the geothermal candidates Olkaria 7, Menengai 2 Phase I – Stage 2 and Olkaria topping are at advanced stage of implementation since production drilling is already on-going or (in case of Olkaria topping) steam is already available from existing wells. For this reason, these projects are considered as geothermal priority candidates which will be selected in the generation modelling before any other (non-priority) geothermal candidate will be selected. By this, the advanced stage of implementation of these projects can be taken into account. It is the objective to develop an achievable generation expansion plan based on "secured candidates". That means energy source and technology must be available and the implementation is either advanced or the responsibility lies solely within the power sector. As a result, the following power plant options are not considered in the analysis:

- Magwagwa HPP, a multipurpose dam under auspices of Ministry of Water and Irrigation,
- Arror HPP, a multipurpose dam under auspices of Ministry of Environment and Natural Resources,
- Nandi Forest HPP, a multipurpose dam under auspices of Ministry of Water and Irrigation,
- Wajir NG-CCGT, fuel resource of domestic gas not yet assured.

7.5.2 Technical parameters of thermal power plants

For the purpose of modelling the operation of the Kenyan power generation system, technical parameters of the thermal power plants are needed. The table below provides an overview of the data defined.

Table 7-9: Technical parameters of thermal power plants

TPP name	Technology	Fuel	Net Capacity [MW]	Minimum Capacity [% of net unit capacity]	Primary reserve provisioning	Must-run	Number of units [#]	Minimum Uptime [h]	Minimum Downtime [h]	Planned Maintenance [%]	Forced outage rate [%]	HR at max [kJth/kWhel]
Iberafrica 1	MSD	HFO	56	50%	no	no	10	1	1	5.8%	6.0%	9,358
Iberafrica 2	MSD	HFO	52.5	50%	no	no	7	1	1	3.8%	4.0%	9,275
Kipevu 1	MSD	HFO	59	50%	no	no	6	1	1	5.8%	6.0%	8,985
Kipevu 3	MSD	HFO	115	50%	no	no	7	1	1	3.8%	4.0%	8,675
Tsavo	MSD	HFO	74	50%	no	no	8	1	1	5.8%	5.0%	9,068
Rabai Diesel (CC-ICE)	MSD	HFO	90	50%	no	no	6	1	1	3.8%	4.0%	8,161
Thika (CC-ICE)	MSD	HFO	87	50%	no	no	6	1	1	3.8%	4.0%	8,240
Athi River Gulf	MSD	HFO	80	50%	no	no	10	1	1	3.8%	4.0%	8,903
Triumph (Kitengela)	MSD	HFO	77	50%	no	no	10	1	1	3.8%	4.0%	8,323
Aggreko	HSD	AGO	30	50%	no	no	38	1	1	3.8%	4.0%	10,015
Embakasi GT 1	GT	Gasoil	27	30%	no	no	1	3	1	7.7%	3.5%	11,485
Embakasi GT 2	GT	Gasoil	27	30%	no	no	1	3	1	7.7%	3.5%	11,485
Generic gas turbine	GT	Gasoil	70	30%	no	no	1	1	1	7.7%	3.0%	10,666
Lamu Unit 1	ST	Coal import	327	40%	yes	no	1	8	3	7.7%	5.0%	8,695
Lamu Unit 2	ST	Coal import	327	40%	yes	no	1	8	3	7.7%	5.0%	8,695
Lamu Unit 3	ST	Coal import	327	40%	yes	no	1	8	3	7.7%	5.0%	8,695
Kitui Coal Unit 1	GT	Coal domestic	320	40%	yes	no	1	8	3	7.7%	5.0%	9,625
Kitui Coal Unit 2	GT	Coal domestic	320	40%	yes	no	1	8	3	7.7%	5.0%	9,625
Kitui Coal Unit 3	GT	Coal domestic	320	40%	yes	no	1	8	3	7.7%	5.0%	9,625
Generic coal	ST	Coal domestic	320	40%	yes	no	1	8	3	7.7%	5.0%	9,625
Dongo Kundu CCGT	CCGT	LNG import	789	17%*	yes	no	3	4	2	3.8%	3.0%	10,657
Dongo Kundu CCGT sma	CCGT	LNG import	375	17%*	yes	no	3	4	2	3.8%	3.0%	7,033
Nuclear Unit	ST	Uranium	600	40%	yes	no	1	48	48	5.8%	5.0%	9,145
Olkaria 1 - Unit 1-3	GEO	Steam	44 (51 after rehab.)	75%	no	yes	3	1	1	3.8%	1.6%	10,500
Olkaria 1 - Unit 4-5	GEO	Steam	140	75%	no	yes	2	1	1	3.8%	1.6%	10,500
Olkaria 2	GEO	Steam	101	75%	no	yes	3	1	1	3.8%	1.6%	10,500
Olkaria 3 - Unit 1-6	GEO	Steam	48	75%	no	yes	6	1	1	3.8%	1.6%	10,500
Olkaria 3 - Unit 7-9	GEO	Steam	62	75%	no	yes	3	1	1	3.8%	1.6%	10,500
Olkaria 4	GEO	Steam	140	75%	no	yes	2	1	1	3.8%	1.6%	10,500

** % of total power plant net capacity*

TPP name	Technology	Fuel	Net Capacity [MW]	Primary reserve provisioning	Must-run	Minimum Capacity [% of net unit capacity]	Number of units	Minimum Uptime [h]	Minimum Downtime [h]	Planned Maintenance [%]	Forced outage rate [%]	HR at max [kJth/kWhel]
KenGen Olkaria Wellheads I & Eburru	GEO	Steam	54.8	no	yes	75%	14	1	1	3.8%	1.6%	10,500
KenGen Olkaria Wellheads II	GEO	Steam	20	no	yes	75%	4	1	1	3.8%	1.6%	10,500
Orpower Wellhead 4	GEO	Steam	24	no	yes	75%	6	1	1	3.8%	1.6%	10,500
Olkaria 1 - Unit 6	GEO	Steam	70	no	yes	75%	1	1	1	3.8%	1.6%	10,500
Olkaria 5	GEO	Steam	140	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Olkaria 6	GEO	Steam	140	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Olkaria 7	GEO	Steam	140	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Olkaria 8	GEO	Steam	140	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Olkaria 9	GEO	Steam	140	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Olkaria Topping	GEO	Steam	60	no	yes	75%	4	1	1	3.8%	1.6%	10,500
Eburru 2	GEO	Steam	25	no	yes	75%	1	1	1	3.8%	1.6%	10,500
Menengai 1 Phase I - Stage 1	GEO	Steam	103	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Menengai 2 Phase I - Stage 2	GEO	Steam	60	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Menengai 2 Phase I - Stage 3	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Menengai 2 Phase I - Stage 4	GEO	Steam	200	no	yes	75%	6	1	1	3.8%	1.6%	10,500
Menengai 3 Phase II - Stage 1	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Menengai 4 Phase II - Stage 2	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Menengai 4 Phase II - Stage 3	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Suswa Phase I - Stage 1	GEO	Steam	50	no	yes	75%	2	1	1	3.8%	1.6%	10,500
Suswa Phase I - Stage 2	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Suswa 2 Phase II - Stage 1	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Suswa 2 Phase II - Stage 2	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Suswa 2 Phase II - Stage 3	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Baringo Silali Phase I, Stage 1	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Baringo Silali Phase I, Stage 2	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Baringo Silali Phase I, Stage 3	GEO	Steam	200	no	yes	75%	6	1	1	3.8%	1.6%	10,500
Baringo Silali Phase I, Stage 4	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Baringo Silali Phase II - Stage 1	GEO	Steam	100	no	yes	75%	3	1	1	3.8%	1.6%	10,500
Marine Power Akiira Stage 1	GEO	Steam	70	no	yes	75%	1	1	1	3.8%	1.6%	10,500
Marine Power Akiira Stage 2	GEO	Steam	70	no	yes	75%	1	1	1	3.8%	1.6%	10,500
AGIL Longonot Stage 1	GEO	Steam	70	no	yes	75%	1	1	1	3.8%	1.6%	10,500
AGIL Longonot Stage 2	GEO	Steam	70	no	yes	75%	1	1	1	3.8%	1.6%	10,500

7.5.3 Technical parameters of hydropower plants

The actual available capacity and the annual generation of hydropower plants depend on the present hydrology. Average hydrology conditions are considered for modelling the operational dispatch in the main expansion scenarios. However, for the design of the power system sufficient back-up capacity has to be taken into account which is able to compensate the lacking hydropower capacity during drought periods. For this reason, the generation expansion modelling considers the firm capacity of hydropower plants for dimensioning the power system. The firm capacity of hydropower plants is defined as the P90 exceedance probability value determined based on historic half hourly production data.

In the low hydrology case, P95 hydrological conditions are taken into account for analysing the operational dispatch of the detected expansion plan of the reference expansion scenario.

An overview of the assumptions is provided in the following table (further details are provided in the Renewable Energy report).

Table 7-10: Available capacity and annual electricity generation of hydropower plants

Plant	Type	Net capacity [MW]	Firm capacity [MW]	Primary reserve provisioning	Average hydrology: Avg. available capacity [MW]	Average hydrology: Electricity generation [GWh/a]	Low hydrology: Avg. available capacity [MW]	Low hydrology: Electricity generation [GWh/a]
Tana HPP	RoR	20	7	no	16	106	7	47
Masinga HPP	Dam	40	24	yes	33	173	10	30
Kamburu HPP	Dam	90	76	yes	85	407	75	178
Gitaru HPP	Dam	216	169	yes	199	936	138	425
Kindaruma HPP	Dam	71	64	yes	68	331	60	142
Kiambere HPP	Dam	164	119	yes	149	883	85	423
Turkwel HPP	Dam	105	96	yes	100	373	91	125
Sondu Miriu HPP	RoR	60	52	no	58	364	45	97
Sang'oro HPP	RoR	20	16	no	19	117	14	31
Karura HPP	Dam	89	71	yes	83	235	60	95
High Grand Falls Stage 1	Dam	495	393	yes	459	1,213	331	493
High Grand Falls Stage 2	Dam	198	157	yes	184	57	132	23

7.5.4 Technical parameters of RE sources

The characteristics of RE based power generation and the RE expansion paths are described in the Renewable Energy report. The results of the analyses are applied in the generation modelling and are summarised below (please see Renewable Energy report for further explanations).

Wind generation curves & firm wind capacity

Hourly generation curves of the wind farms are based on the wind data measurement campaign of MOEP which was conducted from 2009 to 2014. For the determination of the power output, the respective planned wind turbine generator models have been taken into account. The achieved wind power production figures were then scaled up to the announced capacity factors[165].

Due to the volatile nature of wind power, the definition of **firm wind capacity** becomes necessary. It can be argued that an increased share of wind power generation (from an increasing number of separate and distributed wind farms) merits some balancing effects to the individual fluctuating generation patterns. This balancing effect, resulting in a rather stable base load generation, can then be regarded as firm capacity which could be supplied to the system at all times. In the generation expansion modelling, the firm wind capacity during system peak load hours is of interest[166]. The Percentile 84[167] (P84) exceedance probability value of the aggregated wind power output during peak load hours (occurring between 7 to 9 pm) is considered as firm wind capacity in the expansion planning. The analysis leads to the following definition of firm wind capacity during peak load hours:

- 2015-2018: 23% of installed wind capacity (6-61 MW)
- From 2019 onwards: 25% of installed wind capacity (124 MW in 2019, growing)

PV generation curves & firm PV capacity

The **hourly power output characteristics** of the generic PV capacity applied in the generation modelling are derived from measurement data of fifteen sites in Kenya.

Similar to the firm wind capacity, the **firm PV capacity** during system peak load is of interest. However, system peak typically occurs in the evening after sunset in the Kenyan power system. As a result the firm capacity of PV is defined as zero.

Cogeneration power output

Power generation from cogeneration power plants such as biomass, biogas and waste-to-energy are considered as non dispatchable in the generation modelling. It is assumed that 50% of the installed capacity are constantly available and provide power to the grid. This is a conservative[168] assumption not to overestimate their share of generation.

[165] This methodology had to be applied due to the lack of measurement data for the real sites. However, this methodology provides for a correct consideration of the electricity generation potential as well as a very good estimate of the hourly wind injection profile.
[166] Since the power system is dimensioned for the system peak
[167] This is a typical measure in statistics (in particular wind) were in a dispersed set of values only the values below one standard deviation from mean are excluded.
[168] Different from other countries, the sugar cane harvesting (the basis for bagasse as the main fuel) lasts the whole year. This would allow a much higher capacity factor. Further, technically the plants could be designed and operated to partly follow the load. However, experience in Kenya shows that actual generation falls short of expected generation for institutional reasons in the sector.

Small hydropower

Similar to cogeneration power plants, small hydropower plants are considered as non dispatchable. Their energy generation is fixed at their monthly capacity factor varying between 46 and 56% (assuming an average annual capacity factor of 50% which is similar to average generation in recent years). Considering low hydrology conditions, the monthly average capacity factor varies from 25 to 31%. Firm capacity is assumed with 25% of installed capacity.

The table below provides an overview of the average annual capacity factors applied in the generation modelling for the various RE sources.

Table 7-11: Annual average capacity factors of RE sources

Site/	Capacity factor [%]
Ngong wind farm	35%
Kinangop wind farm	34%
Kipeto wind farm	46%
Lake Turkana wind farm	55%
Meru wind farm	32%
Generic wind farm	40%
Generic PV power plant	20%
Generic bagasse power plant (cogeneration)	50%
Generic small HPP	50% considering average hydrology, 30% considering low hydrology

7.5.5 Interconnections with neighbouring countries

As described in Chapter 7.3, the signed PPA for the export of 30 MW base load power from Kenya to Rwanda is considered in the generation modelling as additional demand in the load forecast for the years of concern (2017 to 2019).

The HVDC interconnector between Kenya and Ethiopia (see also Chapter 6.5.10) is considered as a committed supply option. Following the signed PPA, the interconnector will provide 300 MW firm power to the Kenyan grid on take-or-pay basis at a cost of 7 USDcent/kWh. 100 MW are additionally taken into account for the provision of flexible power assuming that Ethiopia is able to provide this amount at all times during the year for the same price.

The interconnectors to Tanzania and Uganda (see also Chapter 6.5.10) are not taken into account in the energy balance, since no PPAs or other reliable information that would define power purchases with these countries are currently under discussion. However, they may be beneficial for export of excess energy and for the provision of flexible power.

7.5.6 Reliability of the power system

This section specifies the reliability requirements as considered for the simulation of the generation system. The reliability requirements with regard to the transmission system are provided in Chapter 8.

It has to be noted that the reliability specification in the simulation for the long term expansion of the generations system cannot fully mirror the reliability criteria set for the actual operation of the system. In the short term planning the representation of the actual reliability criteria makes sense to test and plan for a shorter period (e.g. day to day dispatch). The increasing uncertainty in the long term reduces the importance for an identical representation of reliability criteria for such expansion simulations. The increasing amount of data for a longer period restricts the number of possible criteria which can be processed in a simulation. Therefore, generation expansion tools in the past (e.g. WASP IV) included a trade-off between reliability criteria and practicability of the application (e.g. load duration curves instead of hourly dispatch). Changes to the power system operation in recent years – in particular the increasing penetration of intermittent generation based on RE (wind and solar) – have made a more thorough consideration of operational criteria necessary, also for the expansion planning, such as a differentiation of reserve requirements.

The approach and tools applied in this study are developed based on these considerations and the Consultant's respective experience. The main criteria are described below.

7.5.6.1 Reserve requirements

For the above reason, two tools are combined that deal with the reserve requirements in a different way:

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

As for any model it has to be kept in mind that it is not a replication of the actual power system but only a tool which allows the analysis of some topics (such as probable energy mix) while for other areas (such as hour to hour operation mode of particular plants and dispatch) the significance is lower.

Reserve margin for expansion planning purposes

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

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

Reserve margin for operational consideration purposes (operational considerations)

For operational considerations, reserve requirements are typically divided into two categories according to the delay acceptable in their availability:

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

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

The resulting reserve requirements applied for operational purposes are summarised in the table below.

Table 7-12: Reserve requirements for operational purposes

	Description	Considered in generation modelling
Primary reserve		
Sizing incident	Covering the loss of the largest unit	Determined by the maximum synchronised capacity of the largest unit in the system
Short-term wind fluctuations	Covering short-term gradients in wind power generation	15% of the installed wind capacity
Short-term PV fluctuations	Covering short-term gradients in PV power generation	15% of the installed PV capacity
Secondary reserve		
Load forecast errors	Deviations from the forecasted load	2.6% of hourly demand
Wind generation forecast errors[169]	Deviations from the forecasted wind generation	2015/2016: 55% of installed wind capacity 2020: 29% of installed wind capacity 2030: 26% of installed wind capacity 2035: 25% of installed wind capacity (requirements in interim years determined by linear interpolation)
PV generation forecast errors[170]	Deviations from the forecasted PV generation	For the entire study period PV forecast error (*fe*) determined based on the following equation: $fe = 0.05 \cdot PV\ power\ output(h) - 0.01$

Due to the unlikelihood of worst case wind & PV primary reserve provision and loss of the largest generator occurring simultaneously, the two events are considered as stochastically independent of each other. The total primary reserve demand is thus determined via their geometrical sum. In the modelling the introduction of a larger unit (in particular the great leap with the commissioning

[169] Further details are provided in Annex 7.
[170] Further details are provided in Annex 7.

of Lamu) could lead to an artificial inflation of the primary reserve and related unnecessary constraints for the providers of this reserve during the first years. To avoid this, the sizing incident has been defined at 85% of maximum capacity. This takes into account that the actual synchronised capacity is always 10% below maximum capacity due to the spinning reserve. The sizing incident is fully covered since the remaining gap of 5% is always less than the primary reserve for wind and PV fluctuations.

Similar to primary reserve provision, the amount of required secondary reserve is calculated by the geometrical sum of the respective components assuming that they are stochastically independent of each other.

The two different approaches for reserve requirement considerations help to bring more operational questions into the expansion planning. It has to be kept in mind that the results of the two tools may differ slightly due to the differing configuration. However, experience has shown that the overall results are in line and complementing each other.

7.5.6.2 Loss-of-Load-Probability (LOLP)

The Loss-of-Load-Probability (LOLP) is a common reliability indicator to determine the generation adequacy of a power system. The LOLP determines the probability that demand cannot be met entirely in a given period of time. In case of the LTP, the LOLP is calculated for all 8,760 hours in each year of the considered period.

A Monte-Carlo simulation determines the number of hours in which the system's hourly demand cannot be met due to a potential capacity shortfall. The simulation incorporates planned maintenance as well as forced outage characteristics of each individual power generation unit. The number of hours in which the entire demand cannot be served is called Loss-of-Load-Expectation (LOLE). Putting the LOLE in relation to the total number of hours of the entire evaluation period yields the LOLP.

The LOLP constitutes a probabilistic method of matching available capacity at every given hour of the year with the respective electricity demand for a multitude of cases by varying the event of forced outage of individual generation capacities.

In Kenya, the ERC has set a new target value, the Acceptable LOLP (referred as ALOLP in some documents), as being 24 hours per year, that is 0.274% of the time. This value is respectively considered in the generation modelling.

7.5.7 Surplus of energy

Due to operational system requirements and operational restrictions of power plants a potential surplus of energy may occur. In the generation expansion modelling and description of results of the Kenyan power system, this surplus energy is divided into the three groups

- Excess energy,

- Vented geothermal steam, and
- Spilled water.

This classification allows to identify the origin of surplus energy, to analyse (in separate detailed studies) in how far it can be utilised and to evaluate suitable measurements to reduce the surplus energy. The types are briefly described in the following.

1. Excess energy

Excess energy is defined as surplus energy (i.e. generated electricity beyond demand) that results from large amounts of must-run generators (based on technical as well as economic constraints) in the system:

- Must-run capacity of geothermal power plants (assumed as 75% of their available capacity[171]);
- Minimum capacity (outflow) of hydropower plants;
- Must-run capacity of cogeneration power plants[172];
- Take-or-pay condition of the import through the HVDC;
- Take-or-pay / priority dispatch of volatile RE (wind, PV);
- Surplus energy of hydropower plants which cannot be stored in the reservoirs;

There are mainly two ways in dealing with excess energy:

- In case that respective agreements exist, the generated excess energy may be exported to neighbouring countries (including storage in their hydropower plants).
- If this is not possible, then the system operator has to reduce the power output of some generators where technically feasible (e.g. wind/PV power rejection, reduce energy procurement through HVDC).

2. Vented geothermal steam

For the sake of conservativeness, geothermal power plants in the generation modelling are assumed to be equipped with the rather inflexible single-flash technology. Reduction of their power output can only be reached to a certain extent[171] through venting steam. This means that surplus

[171] This is based on the conservative assumption that geothermal power plants are equipped with single-flash technology (as the commonly applied technology today). Due to technical reasons, reduction of the power output below 70-80% (75% applied in the present study) of their available capacity is not feasible.
[172] For the sake of conservativeness, it is assumed that cogeneration plants are not dispatchable. A more flexible operation of cogeneration plants is technically possible and recommended for the benefit of the overall system. It is however often not foreseen in the PPAs.

energy occurs as soon as a geothermal power plant does not operate at its maximum. This is either lost (vented) with negative impact on the environment or represents a potential if demand for this additional energy can be found. Since this occurrence is based on the conservative assumption that only single-flash units are installed, this form of surplus energy is depicted separately and not included in the excess energy described above. Therefore, there are in general two options to mitigate this effect

- Energy export (as for excess energy); and
- The introduction of binary technology for future geothermal plants.

3. Spilled water for reserve provision

Not only today, but also in the future, hydropower plants with dams will play an essential role to provide primary reserve to the Kenyan power system. Due to the growing demand in primary reserve capacity resulting from larger unit sizes (sizing incident) and increasing volatile renewable resources, hydropower plants have to continuously maintain a considerable share of their available capacity for the provision of primary reserve. As a result, this capacity cannot be utilised to cover the electricity demand. In case that the reservoir of a hydropower plant reaches its maximum supply level, water has to be spilled. This form of energy cannot be utilised for power generation and is thus presented separately.

7.5.8 Fuel and fuel price development

The reference[173] fuel price scenario as elaborated within the fuel price forecast (see Chapter 5.2.5) is applied in the generation expansion simulation. Fuel prices are assumed at world market prices to account for actual costs of imported fuels and opportunity costs for domestic fuels. International transport costs are added for imported fuels. The fuel prices were also adapted to respective locations of the power plants. The table below summarises the relevant price projection for the applied fuels within the LTP period 2015 and 2035.

[173] The economic assessment of candidates showed that a different fuel price scenario does not affect the ranking of plants considerably.

Table 7-13: Development of fuel prices 2015 – 2035

	Fuel Prices [USD/GJ]										
	2015	2017	2019	2021	2023	2025	2027	2029	2031	2033	2035
HFO Nairobi	8.53	9.80	11.30	12.53	13.34	14.21	15.14	16.13	16.85	17.25	17.65
HFO Mombasa	7.34	8.62	10.11	11.34	12.15	13.02	13.95	14.95	15.67	16.06	16.47
AGO Eldoret	13.96	16.15	18.72	20.82	22.21	23.70	25.30	27.02	28.25	28.93	29.62
AGO Nairobi	13.44	15.63	18.20	20.30	21.69	23.19	24.78	26.50	27.73	28.41	29.11
Gasoil Nairobi	13.44	15.63	18.20	20.30	21.69	23.19	24.78	26.50	27.73	28.41	29.11
Coal imported	3.14	3.72	4.41	4.85	4.92	5.00	5.07	5.15	5.22	5.27	5.33
Coal domestic	2.81	3.39	4.08	4.51	4.59	4.66	4.74	4.82	4.88	4.94	5.00
Uranium	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78
LNG import	12.32	12.40	12.47	12.78	13.36	13.98	14.64	15.36	15.84	16.06	16.29
Crude [USD/GJ]	10.12	11.88	13.94	15.63	16.75	17.94	19.23	20.60	21.59	22.14	22.70
Crude [USD/bbl]	57	66	78	87	93	100	107	115	121	124	127
Crude fob [USD/bbl]	54	63	74	83	89	95	102	109	114	117	120

7.5.9 Assumptions for economic analysis

The following assumptions are applied for the net present value calculation for the least cost planning in the generation modelling:

- Prices in real terms (2015 prices);
- Base year: 2015;
- Discount rate: 12% (real, reflecting the time value of money);
- Investment cost will be considered as annuities (based on plants' lifetime, total investment cost as detailed in Chapter 6 and the discount rate).
- Cost for required rehabilitation measurements are taken into account as additional investment cost and will therefore be considered as annuities from the year of rehabilitation onwards. Details on the cost assumptions for rehabilitation are provided in Chapter 6.3.2.
- It is expected that investment of wind and PV technology will further decrease in the future (see Renewable Energy report for details). Therefore, the following degression of annual investment cost is considered:
    - Wind technology: -0.5% annually
    - PV technology: -1.5% annually

- O&M cost of power generation as occurring with the availability of the plants (fixed O&M cost) and actual electricity generation (variable O&M costs). The price for the purchased energy through the HVDC is subsumed under variable O&M cost as well.

- Fuel costs based on the respective kind of fuel, reference fuel price scenario, necessary national and international transport cost.

- Cost for expected unserved energy (EUE) (or energy not served, ENS) are set to 1.5[174] USD / kWh.

The following table depicts the cost & lifetime parameters of the expansion candidates and also shows the cost assumptions of the existing power plants.

Table 7-14: Cost & lifetime parameters of power plants

Plant	Type	Net capacity [MW]	CAPEX [MUSD]	Specific CAPEX [USD/kW]	Specific fixed OPEX [MUSD/(kW*a)]	Variable OPEX none fuel [USD/MWhel]	Life-time [a]	Rehab. cost (if rehab foreseen) [MUSD]
Iberafrica 1	MSD	56	90	1,604	31.5	8.8	20	
Iberafrica 2	MSD	53	84	1,604	31.5	8.8	20	
Kipevu 1	MSD	59	95	1,603	31.5	8.8	20	
Kipevu 3	MSD	115	163	1,421	31.5	8.8	20	
Tsavo	MSD	74	114	1,543	31.5	8.8	20	
Rabai Diesel (CC-MSD)	MSD	90	155	1,726	31.5	8.8	20	
Thika (CC-MSD)	MSD	87	150	1,725	31.5	8.8	20	
Athi River Gulf	MSD	80	128	1,604	31.5	8.8	20	
Triumph (Kitengela)	MSD	77	133	1,729	31.5	8.8	20	
Aggreko I	HSD	30	0[175]	0	193.8	8.8	20	
Embakasi GT 1	GT	27	34	1,241	20.9	12.5	25	
Embakasi GT 2 (Muhoroni)	GT	27	34	1,241	20.9	12.5	25	

[174] Previous national studies assumed 0.89 USD / kWh (LCPDP 2013) to 1 USD / kWh (MTP 2015-2020). It would require a separate study to calculate an actual and a more reliable figure. This is because the costs and weighting from different consumer groups and regions would have to be considered. However, a range of potential costs can be depicted: this could start from a floor value of substituting the electricity supply with gasoil based generator sets which could be valued at 0.5 USD / kWh. International comparison shows that figures up to 5 or 10 ÚSD / kWh can be justified. Surveys among large consumers in Kenya (within this study) provided feedback in the range of 1.5 to 3 USD / kWh for long and short power cuts, respectively. For this study 1.5 USD / kWh was chosen as a possible average of the depicted range. Further, much higher cost could lead to a not justified oversizing of the reserve. On the other hand the simulation showed that the assumed value does not allow much unserved energy. In other words the value could be even lower without adding much to the unserved energy. This effect might be caused by the diligent definition of reserve requirements in the previous chapter, e.g. to cover different failure incidents.

[175] Cost for mobilisation etc. considered in fixed OPEX.

Plant	Type	Net capacity [MW]	CAPEX [MUSD]	Specific CAPEX [USD/kW]	Specific fixed OPEX [MUSD/ (kW*a)]	Variable OPEX none fuel [USD/ MWhel]	Life-time [a]	Rehab. cost (if rehab foreseen) [MUSD]
Generic back-up units[176]	GT	70	60	857	20.9	12.5	25	
Lamu Unit 1	ST Coal	327	811	2,479	66.0	1.3	30	
Lamu Unit 2	ST Coal	327	811	2,479	66.0	1.3	30	
Lamu Unit 3	ST Coal	327	811	2,479	66.0	1.3	30	
Kitui Coal Unit 1	ST Coal	320	764	2,388	69.0	1.4	30	
Kitui Coal Unit 2	ST Coal	320	764	2,388	69.0	1.4	30	
Kitui Coal Unit 3	ST Coal	320	764	2,388	69.0	1.4	30	
Generic coal	ST Coal	320	764	2,388	69.0	1.4	30	
Dongo Kundu CCGT	CCGT	789	926	1,174	30.8	13.2	20	
Dongo Kundu CCGT small	CCGT	375	506	1,349	31.2	13.2	20	
Nuclear Unit 1	ST Nuclear	600	4,115	6,858	7.5	10.2	40	
HVDC Ethiopia-Kenya interconnector	Import	400	508	1,269	25.4	70.0[177]	30	
Olkaria 1 - Unit 1-3	GEO	44 (51 after rehab.)	175	3,980	151.9	0.0	25	106
Olkaria 1 - Unit 4-5	GEO	140	471	3,365	151.9	0.0	25	
Olkaria 2	GEO	101	313	3,095	153.2	0.0	25	84.4
Olkaria 3 - Unit 1-6 (Or-Power4)	GEO	48	210	4,365	104.5	0.0	25	56.6
Olkaria 3 - Unit 7-9 (Or-Power4)	GEO	62	266	4,294	104.5	0.0	25	
Olkaria 4	GEO	140	471	3,365	151.9	0.0	25	
KenGen Olkaria Well-heads I & Eburru	GEO	55	134	2,445	151.9	0.0	25	
Orpower Wellhead 4	GEO	24	91	3,775	104.5	0.0	25	
Olkaria 1 - Unit 6	GEO	70	236	3,365	151.9	0.0	25	
Olkaria 5	GEO	140	471	3,365	151.9	0.0	25	
Olkaria 6	GEO	140	471	3,365	151.9	0.0	25	
Olkaria 7	GEO	140	471	3,365	151.9	0.0	25	
Olkaria 8	GEO	140	471	3,365	151.9	0.0	25	
Olkaria 9	GEO	140	471	3,365	151.9	0.0	25	
Olkaria Topping	GEO	60	168	2,797	151.9	0.0	25	
Eburru 2	GEO	25	103	4,100	163.7	0.0	25	
Menengai 1 Phase I - Stage 1	GEO	103	352	3,417	151.7	0.0	25	
Menengai 2 Phase I - Stage 2	GEO	60	222	3,701	154.6	0.0	25	
Menengai 2 Phase I - Stage 3	GEO	100	344	3,439	151.8	0.0	25	
Menengai 2 Phase I - Stage 4	GEO	200	670	3,350	149.8	0.0	25	

[176] Represented by gasoil fuelled gas turbines
[177] Electricity procurement cost

Plant	Type	Net capacity [MW]	CAPEX [MUSD]	Specific CAPEX [USD/kW]	Specific fixed OPEX [MUSD/ (kW*a)]	Variable OPEX none fuel [USD/ MWhel]	Life-time [a]	Rehab. cost (if rehab foreseen) [MUSD]
Menengai 3 Phase II - Stage 1	GEO	100	344	3,439	151.8	0.0	25	
Menengai 4 Phase II - Stage 2	GEO	100	344	3,439	151.8	0.0	25	
Menengai 4 Phase II - Stage 3	GEO	100	344	3,439	151.8	0.0	25	
Suswa Phase I - Stage 1	GEO	50	191	3,827	157.5	0.0	25	
Suswa Phase I - Stage 2	GEO	100	344	3,439	151.8	0.0	25	
Suswa 2 Phase II - Stage 1	GEO	100	344	3,439	151.8	0.0	25	
Suswa 2 Phase II - Stage 2	GEO	100	344	3,439	151.8	0.0	25	
Suswa 2 Phase II - Stage 3	GEO	100	344	3,439	151.8	0.0	25	
Baringo Silali Phase II - Stage 1	GEO	100	344	3,439	151.8	0.0	25	
Baringo Silali Phase I, Stage 1	GEO	100	344	3,439	151.8	0.0	25	
Baringo Silali Phase I, Stage 2	GEO	100	344	3,439	151.8	0.0	25	
Baringo Silali Phase I, Stage 3	GEO	200	670	3,350	149.8	0.0	25	
Baringo Silali Phase I, Stage 4	GEO	100	344	3,439	151.8	0.0	25	
AGIL Longonot Stage 1	GEO	70	252	3,595	152.5	0.0	25	
AGIL Longonot Stage 2	GEO	70	252	3,595	152.5	0.0	25	
Marine Power Akiira Stage 1	GEO	70	252	3,595	152.5	0.0	25	
Marine Power Akiira Stage 2	GEO	70	252	3,595	152.5	0.0	25	
KenGen Olkaria Wellheads II	GEO	20	49	2,445	151.9	0.0	25	
Tana	HPP	20	69	3,430	27.4	0.5	40	
Masinga	HPP	40	137	3,430	27.4	0.5	40	16.1
Kamburu	HPP	90	309	3,431	27.4	0.5	40	19.9
Gitaru	HPP	216	741	3,431	27.4	0.5	40	59.4
Kindaruma	HPP	70	242	3,456	27.4	0.5	40	105.6
Kiambere	HPP	164	563	3,430	27.4	0.5	40	46.6
Turkwel	HPP	105	360	3,430	27.4	0.5	40	108.3
Sondo	HPP	60	206	3,430	27.4	0.5	40	69.3
Sang'oro	HPP	20	69	3,430	27.4	0.5	40	
Karura	HPP	89	328	3,691	14.9	0.5	40	
High Grand Falls Stage 1	HPP	495	1,835	3,708	15.5	0.5	40	
High Grand Falls Stage 2	HPP	198	63	317	15.5	0.5	40	
Ngong 1, Phase I	Wind	5	11	2,102	76.1	0.0	20	
Ngong 1, Phase II	Wind	6.8	14	2,030	76.1	0.0	20	
Ngong 2	Wind	13.6	28	2,030	76.1	0.0	20	
Aeolus Kinangop	Wind	60	121	2,000	76.1	0.0	20	
Kipeto - Phase I	Wind	50	100	2,010	76.1	0.0	20	

Plant	Type	Net capacity [MW]	CAPEX [MUSD]	Specific CAPEX [USD/kW]	Specific fixed OPEX [MUSD/(kW*a)]	Variable OPEX none fuel [USD/MWhel]	Life-time [a]	Rehab. cost (if rehab foreseen) [MUSD]
Lake Turkana – Phase I, Stage 1	Wind	100	201	2,010	76.1	0.0	20	
Meru Phase I	Wind	80	100	2,000	76.1	0.0	20	
Kipeto - Phase II	Wind	50	100	2,000	76.1	0.0	20	
Lake Turkana – Phase I, Stage 2	Wind	100	200	2,000	76.1	0.0	20	
Lake Turkana – Phase I, Stage 3	Wind	100	199	1,990	76.1	0.0	20	
Generic wind farm	Wind	n.a.	n.a	2,030 in 2015	76.1	0.0	20	
Generic PV power plant	PV	n.a.	n.a	1,695 in 2015	26.4	0.0	20	
Generic bagasse power plant (cogeneration)	Cogen-eration	n.a.	n.a	3,000	150	8.5	25	
Generic small HPP	HPP	n.a.	n.a	3,000	27	0.0	40	

7.6 Results of principal generation expansion plan

This section summarises the results for the principal generation expansion plan for this study. It further provides conclusions for the scenarios analyses where the robustness of the main generation expansion plan is tested by a variation of changes to the main assumptions (see section 7.3.4)

7.6.1 Principal generation expansion plan (reference scenario)

The principal generation expansion plan was developed along the assumptions for the reference scenario. The reference expansion scenario considers

- Reference demand forecast;
- Reference (moderate) RE expansion path; and
- Average hydrology conditions.

As the principal plan it should show robustness towards changes even of the key assumptions (e.g. demand). That means that the general path of generation expansion does not have to be overthrown but only adapted to changing circumstances (e.g. be rescheduling the same power plants or introducing additional capacity to complement the principal plan if needed). This robustness was tested and confirmed within this study. The results are summarised below and detailed in the next chapter (see 7.6.2)

7.6.1.1 Key results and recommendations

The key results of the reference expansion scenario are summarised in the following.

- The energy mix of the generation expansion plan is diverse, secure with regard to supply and costs of fuel and "clean".

- The forecasted need for new firm capacity until 2035 is about 6,500 MW (see Figure 7-5). This is more than three times the existing generation system. Hence, the generation system has to more than triple during the 20-year study period. About 32% (2.1 GW) of the needed firm capacity is already committed (i.e. commissioning dates are fixed).

- Main expansion through 1,695 MW base load geothermal capacity from 2026 onwards. Some 260 MW of this expansion capacity is already at an advanced development stage[178] but the capacity will probably only be needed from 2026 onwards in order to limit overcapacity. If there any considerable delays for committed plants in the medium term or demand increases beyond the reference forecast these geothermal plants could be brought forward. In 2035, geothermal capacity represents 30% of the total installed system capacity providing 56% of the annual generated electricity.

- Expansion of back-up and peaking capacity by 1,890 MW mainly providing the required cold reserve. In the generation modelling the capacity is represented by gasoil fuelled gas turbines. Flexible imports or peaking hydropower plants may constitute a favourable alternative.

- In the long-term, 86% of the electricity demand will be covered by renewable energy sources. 56% is generated by geothermal power plants (about half of the geothermal capacity in the Olkaria area), followed by hydropower with 16% and wind power with 11%. Cogeneration and PV contribute 4% to the annual energy needs. The remaining demand is mainly covered by imports (7%) and coal (6%).

- Due to the large amount of geothermal capacity with nearly zero operating costs as well as further must-run capacity (HVDC, RE sources) in the system, the utilisation of coal units is comparatively low during the entire study period. The capacity factor varies between 10 and 34%. If for committed plants the commissioning years are not fixed the simulation indicates that Lamu coal power plant would be only needed for the overall power system towards the end of the study period while geothermal plants would be brought forward to replace this capacity. This project and coal in general (as a fuel for future power generation) should be further evaluated amid this results and possibly adapted: for this large plant in Lamu consumers in the vicinity were foreseen (partly from flagship projects). Due to delays of flagship projects and probably also due to the impact of global economy on energy (intensive) projects the initial project setup might not be fully utilised for a period in the future until the development of planned projects and their demand catches up. The identification of additional or other large consumers and an implementation in suitable stages could mitigate this effect and would fit into the MOEP concept for Lamu as an anchor project for the region.

[178] This is the case for Olkaria 7, Menengai 2 Phase I - Stage 2 and Olkaria Topping for which production drilling has already started or (as for Olkaria Topping) steam is already available from existing wells. These projects are considered as priority geothermal candidates in the modelling (further explanations are given in Chapter 7.5.1).

- Since many large power supply projects (namely Lamu, Turkana, HVDC, geothermal power plants in Olkaria and Menengai) are already committed, considerable amounts of surplus energy occur in the medium term:
    - In the period from 2019 to 2023 excess electricity (which has to be dumped or exported) varies between 1,177 and 2,156 GWh (7-15% of the generated electricity).
    - In addition, 11-21% of the available geothermal steam (1,796 to 1,949 GWh/a) has to be vented in the period from 2019 to 2023[179].
    - Underused investments in this period are reflected by an increase in system LEC (up to 26% higher compared to 2015 LEC).
- High wind expansion and commissioning of larger units in the medium term will increase the need for primary reserve capacity (e.g. about 290 MW in 2021). Hydropower plants with dams thus have to continuously maintain a considerable share of their available capacity for the provision of primary reserve capacity which may result in spilling of water. This is especially the case in the period from 2021 to 2024 with an energy equivalent of up to 399 GWh which has to be spilled in the form of water (up to 13% of the potential generation from hydropower plants with dams). This situation will change with the commissioning of Karura in 2025 and High Grand Falls in 2028/2029 providing further valuable primary reserve capacity to the grid.
- The average costs of the generation system are expected to increase slightly from currently 9.3 USDcent per consumed kWh to 9.7 USDcent towards the end of the study period. Due to the temporary overcapacity from 2019 and 2023, system LEC will peak at nearly 11.7 USDcent in this period. The average levelised costs for the total period are 10.1 USDcent.

7.6.1.2 Generation expansion path and forecasted energy mix

The following table shows the determined years of commissioning and decommissioning of the various power supply projects in the reference expansion scenario. It further presents the installed and firm system generation capacity (to meet the demand peak in the evening), the annual peak load, the firm capacity additions and the resulting generation surplus/gap.

[179] Assuming single-flash technology (no flexible steam handling)

Table 7-15: Reference expansion scenario – generation expansion overview

Commissioning year[180] Project COD (est.)	Year considered for system integration	Plant name Key plants (>20 MW) **bold font**	Status, comment	Type	Net capacity [MW]	Net capacity (year end) Installed effective [MW]	Firm [MW]	Firm additions [MW]	Peak load [MW]	Surplus/gap with reserve [MW]	without reserve, of peak load [MW]	[%]
	End 2015					**2,213**	2,021		**1,570**	168	451	29%
May 2016	**2016**	**KenGen Olkaria Wellheads II**	Commissioned, adds to well-heads total (75 MW)	Geo	20		20					
Beg. 2016	**2016**	Biojoule	Commissioned	Biomass	2		1					
Mid 2016	**2016**	Emergency Power Producer (Aggreko)	Contract terminated (capacity replaced by KenGen GT shifted from Nairobi)	Diesel Engine	-30		-30					
	End 2016					**2,205**	2,012	-9	**1,679**	51	333	20%
End 2015	**2017**	KTDA Chania Small hydro	Commissioned but delay of grid supply	Hydro	1		0.3					
End 2015	**2017**	Kwale cogeneration	Commissioned for own supply, supply to grid 2017 onwards	Biomass	10		5					
End 2016	**2017**	Cummins	Under construction, challenges due to new technology/fuel; stage wise commissioning with initial 2 MW possible	Biomass	10		5					
End 2016	**2017**	Small hydro FIT accumulated	RE expansion path: accumulated commissioning of FIT list plants	Hydro	16		4					
Mid 2017	**2017**	**Lake Turkana - Phase I, Stage 1**	Committed, total 300 MW to be available in financial year 2017/2018 but stages of 3x100MW for system integration	Wind	100		22					
	2018	**Lake Turkana - Phase I, Stage 2**		Wind	100		22					
	2019	**Lake Turkana - Phase I, Stage 3**		Wind	100		25					
	End 2017					**2,542**	2,043	31	**1,834**	-73	209	11%
End 2017	**2018**	Mumias (recommissioning)	Commissioned (2008) but out of service since 2015 for fuel / PPA issues	Biomass	21		11					
End 2017	**2018**	Small hydro FIT accumulated	RE expansion path, see above	Hydro	7		2					
End 2017	**2018**	**Kipeto - Phase I**	Committed, total 100 MW / stage wise implementation	Wind	50		11					
Mid 2018	**2018**	**Olkaria 1 Unit 1**	Decommissioning for rehabilitation	Geo	-15		-15					
	End 2018					**2,606**	2,073	31	**1,972**	-179	102	5%
End 2018	**2019**	**HVDC Ethiopia-Kenya interconnection**	Committed	Import	400		400					
Dec 2018	**2019**	**Olkaria 1 Unit 6**	Committed	Geo	70		70					
Mid 2019	**2019**	**Olkaria 5**	Committed	Geo	140		140					
End 2018	**2019**	**Menengai 1 Phase I - Stage 1**	Committed, open issues	Geo	103		103					
End 2018	**2019**	**Kipeto – Phase II**	Committed	Wind	50		12.5					
End 2018	**2019**	Ngong Phase III	Committed	Wind	10		3					
End 2018	**2019**	**Kinangop**	Project cancelled for location but assets assumed to be utilised; uncertainty with regard to project location, name and assets	Wind	60		15					
End 2018	**2019**	**PV grid**	Committed	Solar	50		0					
End 2018	**2019**	Small hydro FIT accumulated	RE expansion path, see above	Hydro	11		3					
Mid 2019	**2019**	**Iberafrica**	Decommissioning acc. to PPA, lifetime to be considered (beyond average economic lifetime)	Diesel Engine	-56		-56					
End 2018 / mid 2019	**2019**	**Olkaria 1 Unit 2 & 3**	Decommissioning for rehabilitation (successive for two units, each 15 MW)	Geo	-15		-15					
End 2018	**2019**	**Olkaria 1 Unit 1 Rehabilitation**	Committed, for unavailability of unit see above	Geo	17		17					
	End 2019					**3,446**	2,804	731	**2,120**	389	684	32%
Mid/end 2019	**2020**	**Olkaria 1 Unit 2 & 3 Rehabilitation**	Committed, for unavailability of units see above, capacity addition 17 MW (Unit 2) and 2 MW (balance rehab. Unit 3: 17 - 15 MW)	Geo	19 (17 + 17 - 15)		19					
2nd half 2019	**2020**	**Meru Phase I**	Committed	Wind	80		20					
End 2019	**2020**	PV generic	Generic (RE expansion path)	Solar	5		0					
End 2019	**2020**	Cogeneration generic	Generic (RE expansion path), average commissioning of FIT list & new bagasse projects	Biomass	11		6					
End 2019	**2020**	Small hydro generic	Generic (RE expansion path), average commissioning of FIT list	Hydro	9		2					
2nd half 2020	**2021**	**Olkaria 6**	Committed, full system integration in 2021	Geo	140		140					
	End 2020					**3,570**	2,851	47	**2,259**	296	592	26%
		with Olkaria 6 (commissioned 2nd half of 2020):				3,710	2,991	187	2,259	436	732	32%
	2021	**Lamu Unit 1**	Committed	Coal	327		327					
	2021	Cogeneration generic	Generic (RE expansion path)	Biomass	11		6					
	2021	Small hydro generic	Generic (RE expansion path)	Hydro	9		2.3					
	2021	**Tsavo**	Decommissioning after economic lifetime	Diesel Engine	-74		-74					
	End 2021					**3,983**	3,252	401	**2,451**	205	800	33%

[180] For decommissioning of power plants: year of decommissioning announced respectively (red colour)

Commissioning year[180] Project COD (est.)	Year considered for system integration	Plant name Key plants (>20 MW) **bold font**	Status, comment	Type	Net capacity [MW]	Net capacity (year end) Installed effective [MW]	Firm [MW]	Firm additions [MW]	Peak load [MW]	Surplus/gap with reserve [MW]	without reserve, of peak load [MW]	[%]
	2022	**Lamu Unit 2**	Committed	Coal	327		327					
	2022	PV generic	Generic (RE expansion path)	Solar	5		0					
	2022	Cogeneration generic	Generic (RE expansion path)	Biomass	11		6					
	2022	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2022	Wind generic	Generic (RE expansion path)	Wind	25		6					
	2022	**Embakasi GT1**	Decommissioning after economic lifetime	Gas turbine	-27		-27					
	End 2022					**4,333**	3,566	314	**2,633**	286	933	35%
	2023	**Lamu Unit 3**	Committed	Coal	327		327					
	2023	Cogeneration generic	Generic (RE expansion path)	Biomass	11		6					
	2023	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2023	**Kipevu 1**	Decommissioning acc. to PPA, lifetime to be considered (beyond average economic lifetime)	Diesel Engine	-59		-59					
	End 2023					**4,622**	3,841	276	**2,823**	326	1,019	36%
	2024	PV generic	Generic (RE expansion path)	Solar	10		0					
	2024	Cogeneration generic	Generic (RE expansion path)	Biomass	11		6					
	2024	Small hydro generic	Generic (RE expansion path)	Hydro	9		2.3					
	2024	Wind generic	Generic (RE expansion path)	Wind	25		6					
	2024	**Embakasi GT2**	Decommissioning after economic lifetime	Gas turbine	-27		-27					
	2024	**Iberafrica 2**	Decommissioning after economic lifetime	Diesel Engine	-53		-53					
	End 2024					**4,597**	3,776	-66	**3,022**	71	754	25%
	2025	**Karura**	Candidate	Hydro	89		71					
	2025	**Generic back-up capacity**	Generic candidate	Gas turbine	140		140					
	2025	Cogeneration generic	Generic (RE expansion path)	Biomass	11		6					
	2025	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	End 2025					**4,846**	3,994	218	**3,282**	2	712	22%
	2026	**Olkaria Topping**	Candidate (priority)	Geo	60		60					
	2026	**Generic back-up capacity**	Generic candidate	Gas turbine	210		210					
	2026	PV generic	Generic (RE expansion path)	Solar	10		0					
	2026	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2026	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2026	Wind generic	Generic (RE expansion path)	Wind	25		6					
	End 2026					**5,169**	4,277	283	**3,511**	21	766	22%
	2027	**Olkaria 7**	Candidate (priority)	Geo	140		140					
	2027	**Generic back-up capacity**	Generic candidate	Gas turbine	140		140					
	2027	PV generic	Generic (RE expansion path)	Solar	10		0					
	2027	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2027	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	End 2027					**5,475**	4,563	286	**3,751**	37	812	22%
	2028	**High Grand Falls Stage 1**	Candidate	Hydro	495		393					
	2028	PV generic	Generic (RE expansion path)	Solar	20		0					
	2028	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2028	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2028	Wind generic	Generic (RE expansion path)	Wind	25		6					
	2028	**Ngong 1, Phase I**	Decommissioning after economic lifetime	Wind	-5.1		-1					
	End 2028					**6,028**	4,967	404	**4,040**	107	927	24%
	2029	**Menengai 2 Phase I - Stage 2**	Candidate (priority)	Geo	60		60					
	2029	**High Grand Falls Stage 2**	Candidate	Hydro	198		157.0					
	2029	**Generic back-up capacity**	Generic candidate	Gas turbine	70		70					
	2029	PV generic	Generic (RE expansion path)	Solar	20		0					
	2029	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2029	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2029	**Rabai Diesel**	Decommissioning after economic lifetime	Diesel Engine	-90		-90					
	End 2029					**6,303**	5,171	203	**4,320**	14	851	20%
	2030	**Menengai 2 Phase I - Stage 3**	Candidate	Geo	100		100					
	2030	**Marine Power Akiira Stage 1**	Candidate	Geo	70		70					
	2030	**Generic back-up capacity**	Generic candidate	Gas turbine	280		280					
	2030	PV generic	Generic (RE expansion path)	Solar	20		0					
	2030	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2030	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2030	Wind generic	Generic (RE expansion path)	Wind	50		13					
	End 2030					**6,840**	5,640	469	**4,732**	19	908	19%
	2031	**Menengai 2 Phase I - Stage 4**	Candidate	Geo	200		200					
	2031	**Baringo Silali Phase I, Stage 1**	Candidate	Geo	100		100					

Commissioning year[180] Project COD (est.)	Year considered for system integration	Plant name Key plants (>20 MW) **bold font**	Status, comment	Type	Net capacity [MW]	Net capacity (year end) Installed effective [MW]	Firm [MW]	Firm additions [MW]	Peak load [MW]	Surplus/gap with reserve [MW]	without reserve, of peak load [MW]	[%]
	2031	**Generic back-up capacity**	Generic candidate	Gas turbine	140		140					
	2031	PV generic	Generic (RE expansion path)	Solar	20		0					
	2031	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2031	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2031	Wind generic	Generic (RE expansion path)	Wind	75		19					
	2031	**Kipevu 3**	Decommissioning after economic lifetime	Diesel Engine	-115		-115					
	End 2031					**7,277**	5,989	350	**5,071**	1	918	18%
	2031	**Olkaria 8**	Candidate	Geo	140		140					
	2032	**Olkaria 9**	Candidate	Geo	140		140					
	2032	**Eburru 2**	Candidate	Geo	25		25					
	2032	**Generic back-up capacity**	Generic candidate	Gas turbine	70		70					
	2032	PV generic	Generic (RE expansion path)	Solar	20		0					
	2032	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2032	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2032	Wind generic	Generic (RE expansion path)	Wind	75		19					
	End 2032					**7,764**	6,390	400	**5,431**	9	959	18%
	2033	**Baringo Silali Phase I, Stage 3**	Candidate	Geo	200		200					
	2033	**Suswa Phase I - Stage 1**	Candidate	Geo	50		50					
	2033	**Generic back-up capacity**	Generic candidate	Gas turbine	140		140					
	2033	PV generic	Generic (RE expansion path)	Solar	30		0					
	2033	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2033	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2033	Wind generic	Generic (RE expansion path)	Wind	100		25					
	End 2033					**8,301**	6,811	421	**5,813**	10	998	17%
	2034	**Baringo Silali Phase I, Stage 2**	Candidate	Geo	100		100					
	2034	**AGIL Longonot Stage 1**	Candidate	Geo	70		70					
	2034	**Generic back-up capacity**	Generic candidate	Gas turbine	420		420					
	2034	PV generic	Generic (RE expansion path)	Solar	40		0					
	2034	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2034	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2034	Wind generic	Generic (RE expansion path)	Wind	100		25					
	2034	**Thika**	Decommissioning after economic lifetime	Diesel Engine	-87		-87					
	2034	**Athi River Gulf**	Decommissioning after economic lifetime	Diesel Engine	-80		-80					
	End 2034					**8,882**	7,266	454	**6,220**	2	1,046	17%
	2035	**Menengai 3 Phase II - Stage 1**	Candidate	Geo	100		100					
	2035	**Suswa Phase I - Stage 2**	Candidate	Geo	100		100					
	2035	**Suswa 2 Phase II - Stage 1**	Candidate	Geo	100		100					
	2035	**Generic back-up capacity**	Generic candidate	Gas turbine	280		280					
	2035	PV generic	Generic (RE expansion path)	Solar	40		0					
	2035	Cogeneration generic	Generic (RE expansion path)	Biomass	8		4					
	2035	Small hydro generic	Generic (RE expansion path)	Hydro	9		2					
	2035	Wind generic	Generic (RE expansion path)	Wind	100		25					
	2035	**Triumph (Kitengela)**	Decommissioning after economic lifetime	Diesel Engine	-77		-77					
	2035	**Ngong 1, Phase II**	Decommissioning after economic lifetime	Wind	-20		-5					
	End 2035					**9,521**	7,795	529	**6,683**	16	1,112	17%

The figures below display the above listed key developments.

- The first figure shows the expansion of firm capacity in comparison with the forecasted peak load (with and without reserve margin).
- The second figure presents the annual generation mix contrasted with the forecasted electricity consumption. It further illustrates the annual excess electricity.
- The annual share by technology on the generation mix is depicted in the third figure.

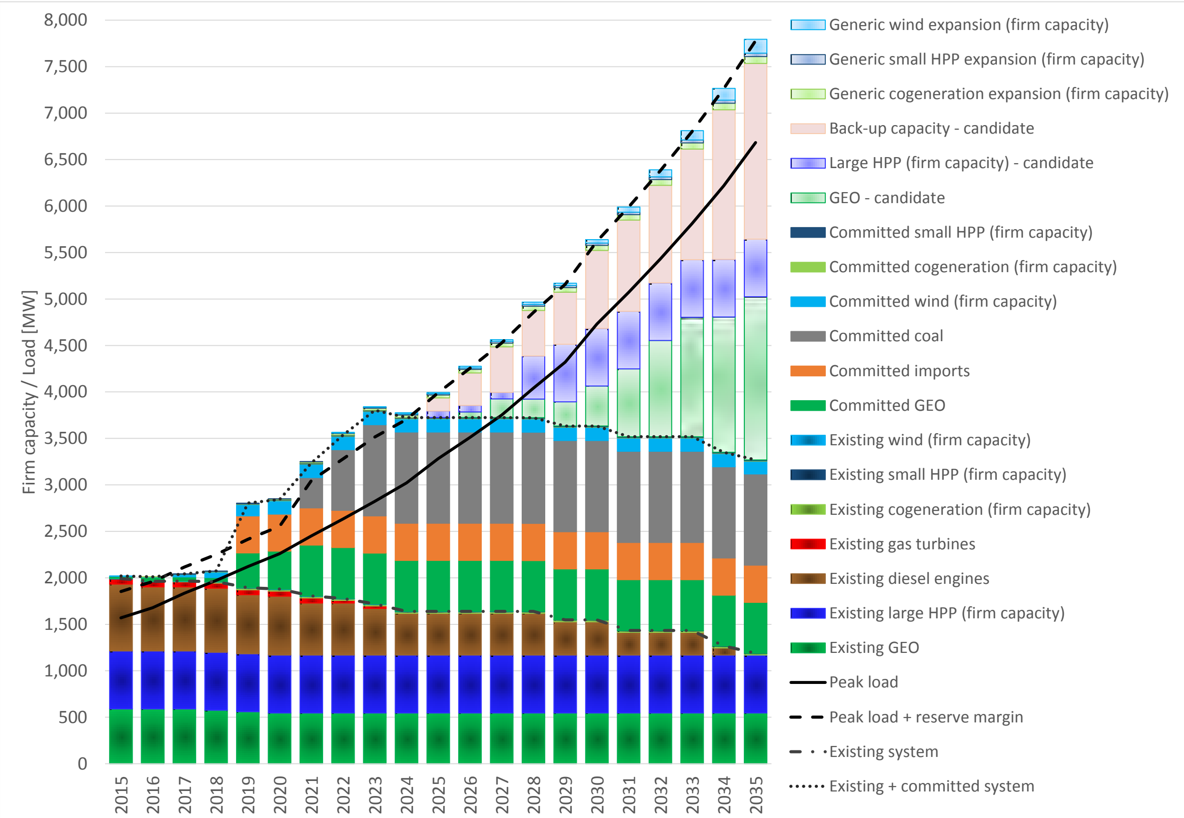

Figure 7-5: Reference expansion scenario – firm capacity versus peak demand

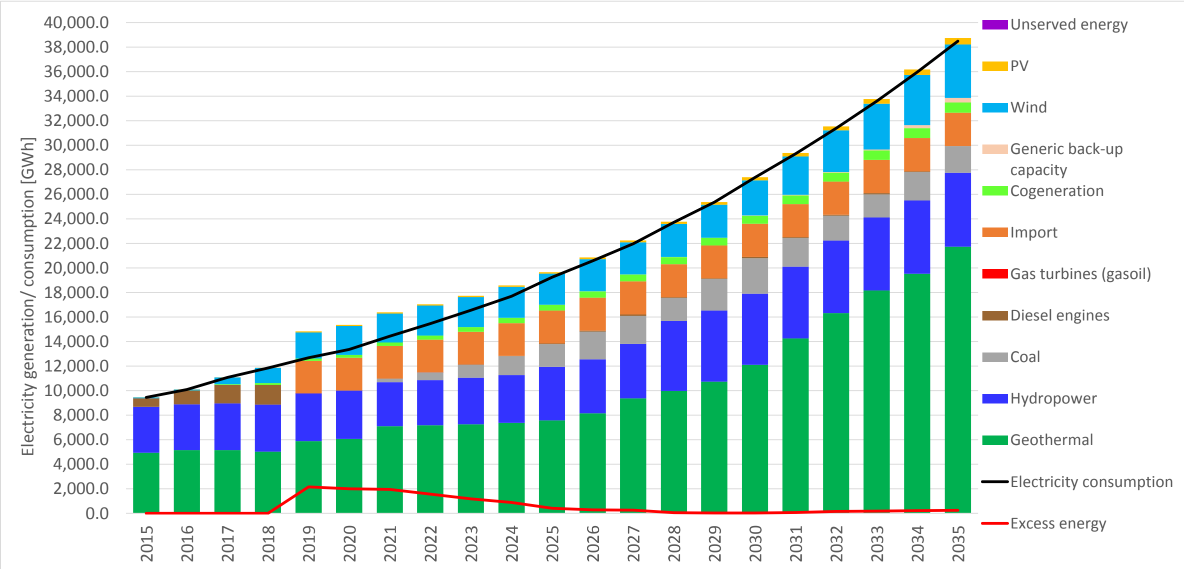

Figure 7-6: Reference expansion scenario – electricity generation versus electricity consumption

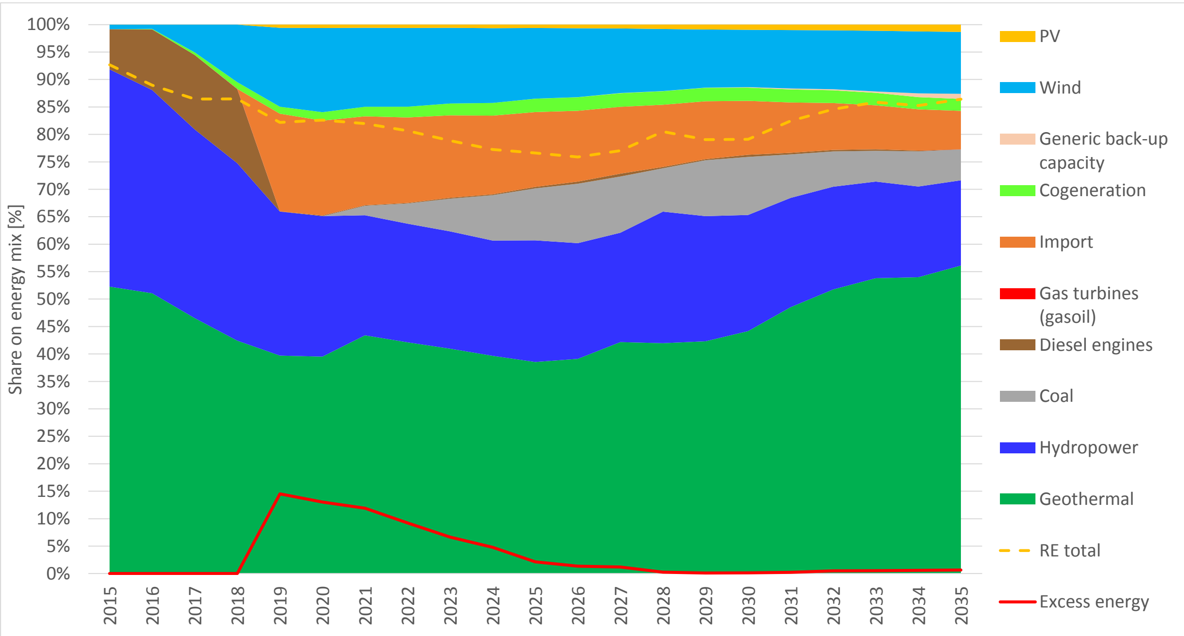

Figure 7-7: Reference expansion scenario – share on generation mix by technology

Figure 7-8 illustrates the development of the average capacity factors by technology.

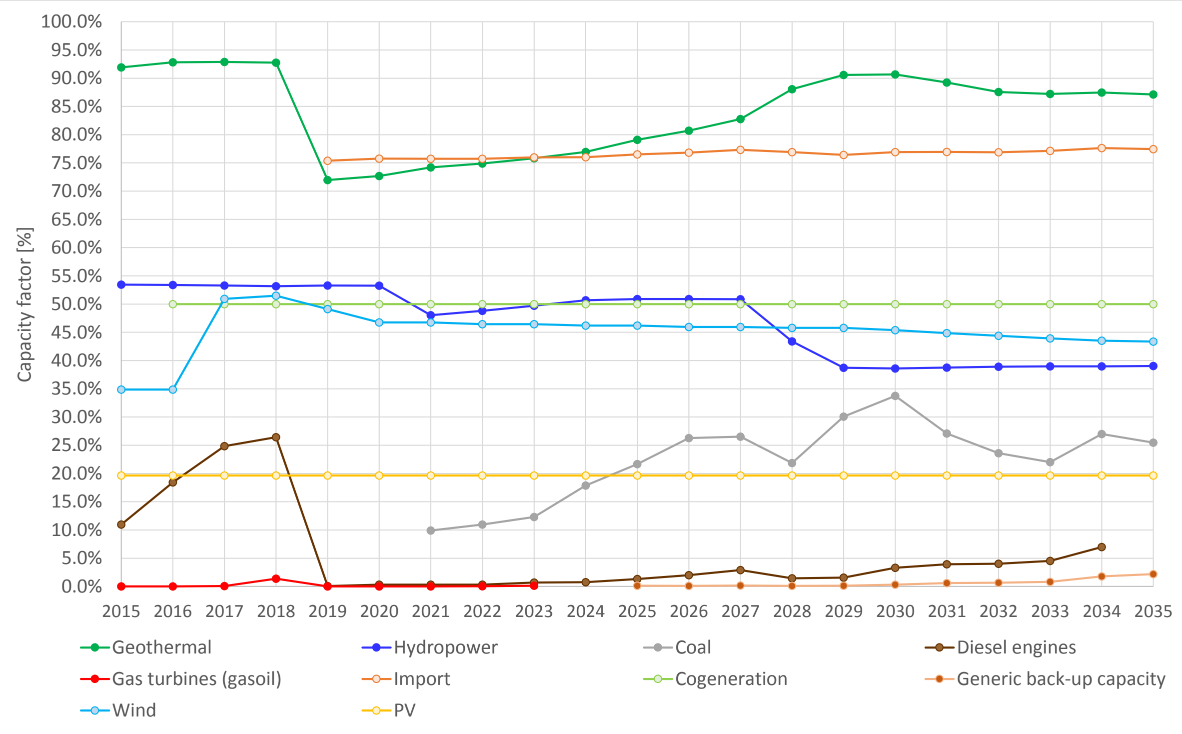

Figure 7-8: Reference expansion scenario – capacity factor by technology

An hourly dispatch of a sample week (21-27.06.2030) is presented in the figure below.

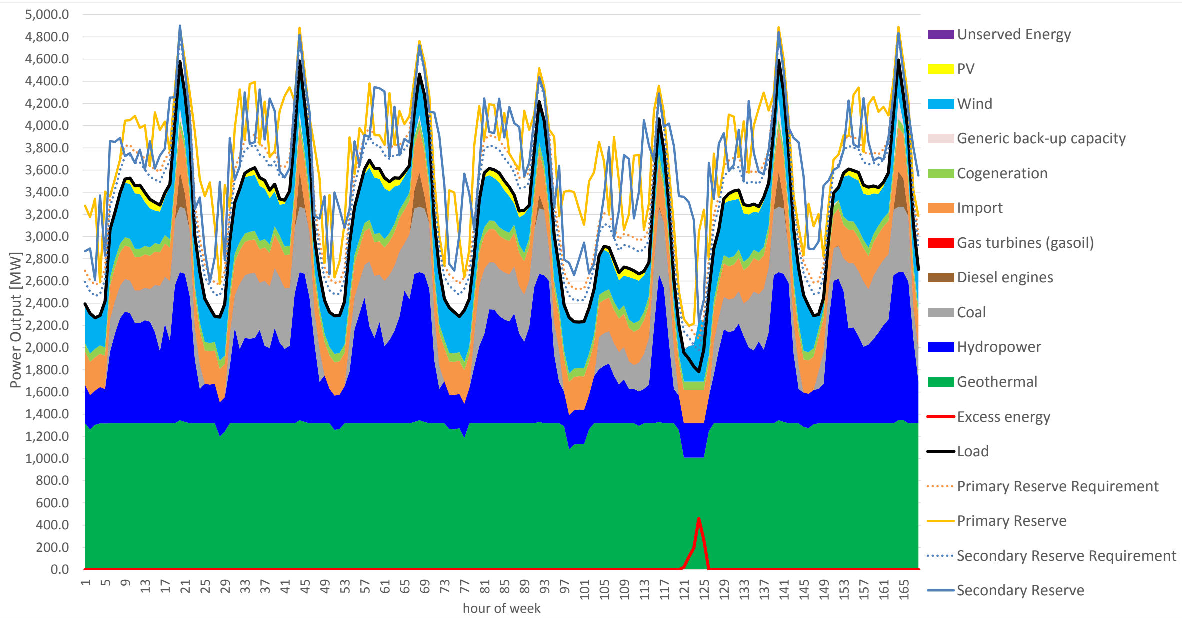

Figure 7-9: Reference expansion scenario – sample dispatch in the period 21.-27.06.2030

The daily patterns of the excess energy as monthly average for the year 2030 are illustrated in the following figure. As expected, excess energy mainly occurs at night when the demand is low. There are limitations to draw conclusions on seasonal patterns. This is because the variation of excess energy by months of the year probably derives from the generic wind production curves which differ by month but may vary in reality.

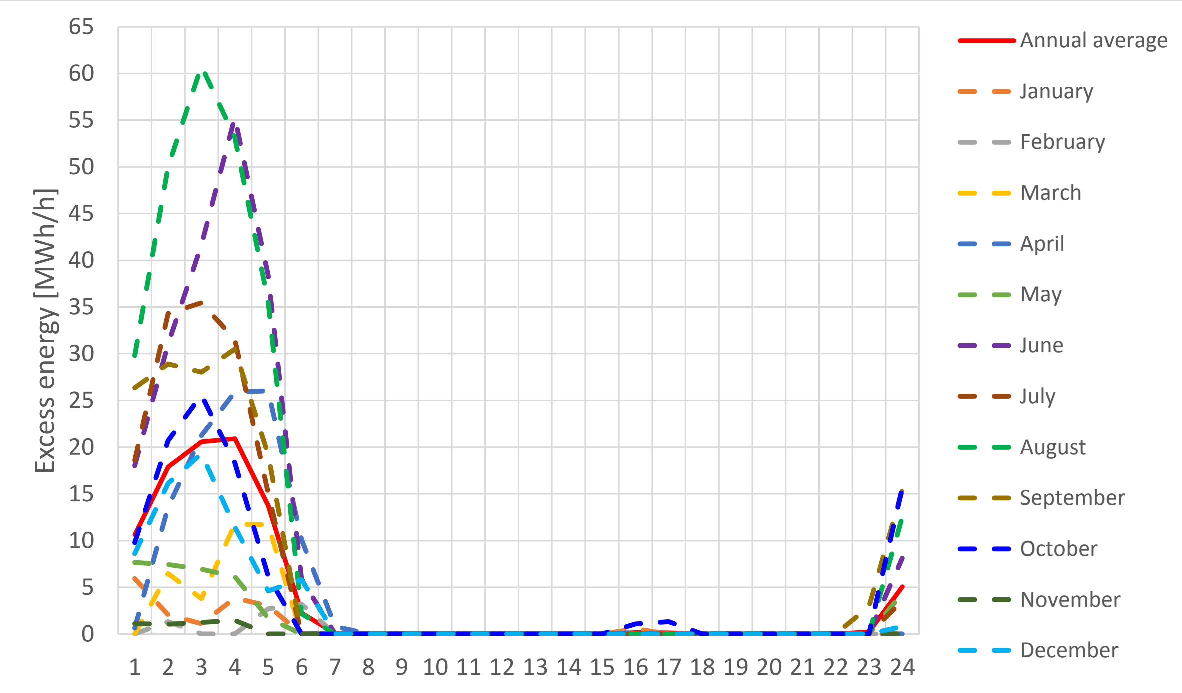

Figure 7-10: Reference expansion scenario – monthly average daily excess energy patterns for the year 2030

7.6.1.3 Annual generation and cost data of generation expansion path

The following tables summarise the results in terms of capacity, generation and cost data of the principal generation expansion plan.

Table 7-16: Reference expansion scenario – annual data demand, capacity, reliability criteria (LOLP)

	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak load	**MW**	**1,570**	**1,679**	**1,834**	**1,972**	**2,120**	**2,259**	**2,451**	**2,633**	**2,823**	**3,022**	**3,282**	**3,511**	**3,751**	**4,040**	**4,320**	**4,732**	**5,071**	**5,431**	**5,813**	**6,220**	**6,683**
Peak load + reserve margin	**MW**	**1,853**	**1,960**	**2,115**	**2,252**	**2,415**	**2,555**	**3,047**	**3,279**	**3,515**	**3,705**	**3,992**	**4,255**	**4,526**	**4,855**	**5,156**	**5,620**	**5,989**	**6,381**	**6,801**	**7,263**	**7,779**
Reserve margin		283	281	281	280	294	296	595	647	693	683	710	744	775	815	836	888	918	950	988	1,043	1,096
Share on peak load	*%*	*18%*	*17%*	*15%*	*14%*	*14%*	*13%*	*24%*	*25%*	*25%*	*23%*	*22%*	*21%*	*21%*	*20%*	*19%*	*19%*	*18%*	*17%*	*17%*	*17%*	*16%*
Installed capacity:																						
Geothermal	MW	614	634	634	619	934	954	1,094	1,094	1,094	1,094	1,094	1,154	1,294	1,294	1,354	1,524	1,824	2,129	2,379	2,549	2,849
Hydropower	MW	799	799	816	823	834	843	852	861	870	879	977	986	995	1,499	1,706	1,715	1,723	1,732	1,741	1,750	1,759
Coal	MW							327	654	981	981	981	981	981	981	981	981	981	981	981	981	981
Diesel engines	MW	721	691	691	691	635	635	561	561	502	449	449	449	449	449	359	359	244	244	244	77	
Gas turbines (gasoil)	MW	54	54	54	54	54	54	54	27	27												
Import	MW					400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Cogeneration	MW		2	12	33	43	54	65	76	87	98	109	117	126	134	142	151	159	167	175	184	192
Generic back-up capacity	MW											140	350	490	490	560	840	980	1,050	1,190	1,610	1,890
Wind	MW	26	26	126	276	496	576	576	601	601	626	626	651	651	670	670	720	795	870	970	1,070	1,150
PV	MW	1	1	1	1	51	56	56	61	61	71	71	81	91	111	131	151	171	191	221	261	301
Total	**MW**	**2,213**	**2,205**	**2,332**	**2,496**	**3,446**	**3,570**	**3,983**	**4,333**	**4,622**	**4,597**	**4,846**	**5,168**	**5,475**	**6,028**	**6,303**	**6,840**	**7,277**	**7,764**	**8,301**	**8,882**	**9,521**
Firm capacity:																						
Geothermal	MW	614	634	634	619	934	954	1,094	1,094	1,094	1,094	1,094	1,154	1,294	1,294	1,354	1,524	1,824	2,129	2,379	2,549	2,849
Hydropower	MW	627	627	631	633	635	638	640	642	644	647	720	722	724	1,119	1,278	1,280	1,283	1,285	1,287	1,289	1,291
Coal	MW							327	654	981	981	981	981	981	981	981	981	981	981	981	981	981
Diesel engines	MW	721	691	691	691	635	635	561	561	502	449	449	449	449	449	359	359	244	244	244	77	
Gas turbines (gasoil)	MW	54	54	54	54	54	54	54	27	27												
Import	MW					400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Cogeneration	MW		1	6	17	22	27	33	38	44	49	55	59	63	67	71	75	79	84	88	92	96
Generic back-up capacity	MW											140	350	490	490	560	840	980	1,050	1,190	1,610	1,890
Wind	MW	6	6	28	61	124	144	144	150	150	156	156	163	163	168	168	180	199	218	243	268	288
PV	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**MW**	**2,021**	**2,012**	**2,043**	**2,073**	**2,804**	**2,851**	**3,252**	**3,566**	**3,841**	**3,776**	**3,994**	**4,277**	**4,563**	**4,967**	**5,171**	**5,640**	**5,990**	**6,390**	**6,811**	**7,266**	**7,795**
LOLE	**h/a**	**0**	**3**	**12**	**28**	**0**	**0**	**0**	**0**	**0**	**1**	**1**	**1**	**1**	**1**	**2**	**2**	**2**	**2**	**1**	**1**	**1**

Table 7-17: Reference expansion scenario – annual data consumption and generation

	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Electricity consumption	**GWh**	**9,453**	**10,093**	**11,084**	**11,856**	**12,683**	**13,367**	**14,433**	**15,467**	**16,555**	**17,699**	**19,242**	**20,577**	**21,983**	**23,718**	**25,358**	**27,374**	**29,312**	**31,384**	**33,595**	**35,960**	**38,491**
Electricity generation:	GWh																					
Geothermal	GWh	4,941	5,154	5,158	5,031	5,892	6,073	7,111	7,177	7,264	7,372	7,577	8,158	9,381	9,979	10,740	12,104	14,257	16,326	18,172	19,531	21,739
Hydropower	GWh	3,741	3,737	3,810	3,832	3,894	3,934	3,584	3,681	3,788	3,902	4,356	4,396	4,432	5,698	5,786	5,798	5,850	5,903	5,943	5,976	6,015
Coal	GWh							283	628	1,058	1,536	1,863	2,258	2,279	1,879	2,584	2,900	2,328	2,027	1,892	2,319	2,189
Diesel engines	GWh	692	1,115	1,503	1,600	4	17	16	16	30	30	51	79	114	56	49	104	84	86	97	47	
Gas turbines (gasoil)	GWh	0	0	0	6	0	0	0	0	0												
Import	GWh					2,641	2,655	2,654	2,653	2,662	2,663	2,681	2,692	2,709	2,695	2,678	2,695	2,697	2,694	2,702	2,720	2,713
Cogeneration	GWh		9	53	145	188	237	285	333	382	430	478	515	551	587	623	660	696	732	768	805	841
Generic back-up capacity	GWh											1	3	8	5	6	24	52	60	85	249	361
Wind	GWh	78	78	560	1,243	2,132	2,357	2,357	2,444	2,444	2,531	2,531	2,618	2,618	2,689	2,689	2,863	3,124	3,386	3,734	4,082	4,368
PV	GWh	1	1	1	1	87	96	96	104	104	122	122	139	156	190	225	259	294	328	380	449	517
Total	**GWh**	**9,453**	**10,093**	**11,084**	**11,857**	**14,839**	**15,368**	**16,385**	**17,037**	**17,732**	**18,586**	**19,660**	**20,857**	**22,248**	**23,778**	**25,381**	**27,407**	**29,381**	**31,543**	**33,774**	**36,178**	**38,742**
Unserved energy	**GWh**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Excess energy	**GWh**	**0**	**0**	**0**	**1**	**2,156**	**2,001**	**1,952**	**1,570**	**1,177**	**887**	**418**	**280**	**265**	**60**	**24**	**34**	**69**	**159**	**179**	**217**	**251**
Share on total generation	*%*	*0%*	*0%*	*0%*	*0%*	*15%*	*13%*	*12%*	*9%*	*7%*	*5%*	*2%*	*1%*	*1%*	*0%*	*0%*	*0%*	*0%*	*1%*	*1%*	*1%*	*1%*
Spilled water	**GWh**	**10**	**14**	**15**	**24**	**10**	**10**	**399**	**341**	**274**	**199**	**19**	**18**	**22**	**7**	**15**	**42**	**30**	**16**	**14**	**20**	**21**
Share on potential generation of HPPs with dams	*%*	*0%*	*0%*	*0%*	*1%*	*0%*	*0%*	*13%*	*11%*	*9%*	*6%*	*1%*	*1%*	*1%*	*0%*	*0%*	*1%*	*1%*	*0%*	*0%*	*0%*	*0%*
Vented GEO steam*	**GWh**	**143**	**96**	**92**	**98**	**1,848**	**1,827**	**1,949**	**1,883**	**1,796**	**1,688**	**1,483**	**1,399**	**1,335**	**737**	**473**	**517**	**849**	**1,306**	**1,531**	**1,580**	**1,857**
Share on potential maximum GEO generation	*%*	*3%*	*2%*	*2%*	*2%*	*24%*	*23%*	*22%*	*21%*	*20%*	*19%*	*16%*	*15%*	*12%*	*7%*	*4%*	*4%*	*6%*	*7%*	*8%*	*7%*	*8%*

** assuming that all geothermal power plants are equipped with single-flash technology (no flexible handling of geothermal steam possible)*

Table 7-18: Reference expansion scenario – cost summary (1/2)

	Unit	NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
<u>**Capital cost (Investment & rehabilitation)**</u>																							
Geothermal	MUSD	3,127	249	256	256	256	395	404	464	464	464	464	445	466	526	497	525	601	730	864	973	1,049	1,181
Hydropower	MUSD	2,009	272	272	278	203	207	211	200	203	206	209	253	256	259	430	441	444	412	415	418	422	425
Coal	MUSD	910	0	0	0	0	0	0	101	201	302	302	302	302	302	302	302	302	302	302	302	302	302
Diesel engines	MUSD	880	149	149	137	137	124	124	109	109	109	98	98	98	98	98	77	77	55	55	55	18	0
Gas turbines (gasoil)	MUSD	42	9	9	9	9	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0
Import	MUSD	285	0	0	0	0	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Cogeneration	MUSD	182	0	1	5	13	16	21	25	29	33	38	42	45	48	51	54	58	61	64	67	70	73
Generic back-up capacity	MUSD	147	0	0	0	0	0	0	0	0	0	0	15	38	54	54	61	92	107	115	130	176	207
Wind	MUSD	861	7	7	34	74	133	154	154	160	160	167	167	173	173	178	178	191	210	229	254	278	298
PV	MUSD	84	0	0	0	0	11	12	12	13	13	15	15	17	19	22	26	30	33	37	42	49	56
Total	**MUSD**	**8,527**	**686**	**693**	**717**	**691**	**958**	**997**	**1,136**	**1,247**	**1,355**	**1,356**	**1,399**	**1,458**	**1,542**	**1,695**	**1,728**	**1,857**	**1,973**	**2,143**	**2,305**	**2,427**	**2,604**
<u>**O&M fixed**</u>																							
Geothermal	MUSD	1,089	87	90	90	88	131	134	156	156	156	156	156	165	186	186	195	221	266	313	351	376	422
Hydropower	MUSD	191	22	22	22	23	23	23	23	24	24	24	26	26	26	34	37	38	38	38	38	39	39
Coal	MUSD	385							22	43	65	65	65	65	65	65	65	65	65	65	65	65	65
Diesel engines	MUSD	139	28	22	22	22	20	20	18	18	16	14	14	14	14	14	11	11	8	8	8	2	
Gas turbines (gasoil)	MUSD	6	1	1	1	1	1	1	1	1	1												
Import	MUSD	72					10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Cogeneration	MUSD	80		0	2	5	6	8	10	11	13	15	16	18	19	20	21	23	24	25	26	28	29
Generic back-up capacity	MUSD	87											3	7	10	10	12	18	20	22	25	34	40
Wind	MUSD	246	2	2	10	21	38	44	44	46	46	48	48	50	50	51	51	55	61	66	74	81	88
PV	MUSD	11	0	0	0	0	1	1	1	2	2	2	2	2	2	3	3	4	5	5	6	7	8
Total	**MUSD**	**2,022**	**140**	**137**	**147**	**159**	**231**	**242**	**284**	**309**	**331**	**333**	**339**	**356**	**382**	**393**	**406**	**444**	**496**	**552**	**602**	**642**	**699**

Table 7-19: Reference expansion scenario – cost summary (2/2)

	Unit	NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
O&M variable (other than fuel)																							
Geothermal	MUSD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower	MUSD	15	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3
Coal	MUSD	14							0	1	1	2	2	3	3	2	3	4	3	3	2	3	3
Diesel engines	MUSD	33	6	10	13	14	0	0	0	0	0	0	0	1	1	0	0	1	1	1	1	0	
Gas turbines (gasoil)	MUSD	0	0	0	0	0	0	0	0	0	0												
Import	MUSD	1,331					185	186	186	186	186	186	188	188	190	189	187	189	189	189	189	190	190
Cogeneration	MUSD	20		0	0	1	2	2	2	3	3	4	4	4	5	5	5	6	6	6	7	7	7
Generic back-up capacity	MUSD	4											0	0	0	0	0	0	1	1	1	3	5
Wind	MUSD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	MUSD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**MUSD**	**920**	**8**	**12**	**16**	**17**	**188**	**190**	**190**	**191**	**193**	**194**	**197**	**198**	**200**	**199**	**199**	**202**	**202**	**202**	**203**	**206**	**207**
Fuel cost																							
Coal	MUSD	525							14	31	52	76	91	110	111	89	121	136	111	98	93	114	108
Diesel engines	MUSD	281	43	75	111	128	0	2	2	2	3	3	6	9	14	7	7	14	12	12	14	7	
Gas turbines (gasoil)	MUSD	1	0	0	0	1	0	0	0	0	0												
Generic back-up capacity	MUSD	98											1	1	3	2	2	8	18	21	29	83	118
Total	**MUSD**	**579**	**43**	**75**	**111**	**130**	**0**	**2**	**15**	**32**	**55**	**79**	**98**	**121**	**127**	**98**	**130**	**159**	**141**	**131**	**136**	**204**	**227**
Unserved energy cost	**MUSD**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total cost	**MUSD**	**12,048**	**876**	**916**	**990**	**997**	**1,378**	**1,430**	**1,626**	**1,780**	**1,935**	**1,962**	**2,032**	**2,133**	**2,251**	**2,386**	**2,463**	**2,661**	**2,812**	**3,028**	**3,246**	**3,479**	**3,737**
System LEC	**USDcent/kWh**		**9.26**	**9.08**	**8.93**	**8.41**	**10.86**	**10.70**	**11.26**	**11.51**	**11.69**	**11.08**	**10.56**	**10.37**	**10.24**	**10.06**	**9.71**	**9.72**	**9.59**	**9.65**	**9.66**	**9.67**	**9.71**

7.6.2 Scenario analysis for expansion plan

The robustness of the main generation expansion plan is tested by variation of changes to the main assumptions. The results of the scenarios are summarised in the following.

In general, the principal expansion plan is robust with regard to changes of main assumptions (e.g. demand, RE penetration, hydrology). Those changes may require a change of commissioning years for identified plants or additional capacity in the long term for any higher demand growth. The main changes concern

- The extent of excess energy which would be in range from some 18% of generated electricity for the low and EE scenario via a share of up to 15% for the reference scenario to a share of 6% for the vision scenario. Vented steam from geothermal plants would be very similar in the medium term for all scenarios. In the long term, it is still considerable for low and reference scenario while for the vision scenario generation from geothermal energy would be nearly fully used even if generated based on the inflexible single flash technology.

- Bringing forward or backward the main expansion capacities based on geothermal energy. In particular geothermal plants in an advanced development stage (i.e. production drilling ongoing) could be developed depending on the path of demand increase or in case committed plants are delayed or cancelled. For that reason also hydropower projects (e.g. Karura) should not be delayed and even an earlier commissioning be considered. Further, the status of new hydropower projects in Ethiopia should be monitored in terms of availability to supply capacity and energy when the interconnector is operational. This rescheduling will need careful monitoring of extrapolation progress and demand to avoid unused investments for a longer period or lag of supply.

- The need for temporary back up capacity or risk for unserved demand in the medium term: potential supply gaps may concern cold reserve only or also peak demand (see 7.3.4) depending on the demand and hydrology. There are measures to adapt to this uncertainty in a flexible way (both in terms of capacity and technology) such as temporary geothermal wellheads or gas turbines.

- The need for coal as a secondary base load expansion source which is low for the low, EE, and reference scenarios and higher for the vision scenario (though rather for the long term where alternative sources might be available).

- The development of costs with different demand scenarios. The annual levelised electricity costs (LEC) of the total generation system decrease with higher demand scenarios. This is due to reduced overcapacities and excess energy as well as an in general better utilisation of power plants (e.g. less vented steam) throughout the study period. This means that in particular in the medium term a higher demand growth would result in reduced per kWh costs (see also chapter 9.3.2). Only for the energy efficiency scenario the lower demand is beneficial despite slightly higher LECs. This is due to the fact that for the same use of electricity as in the reference scenario the total costs are lower.

7.6.2.1 Low hydrology case

The optimal generation expansion plan of the reference expansion scenario was simulated in a sub-case considering low hydrology conditions. By this, the robustness of the defined reference expansion plan is tested with regard to the impact of drought periods. It has to be noted that this sub-scenario is theoretical only since no drought throughout the whole study period is expected but only one or few occasional years. However, amid global climate change with the potential for negative impact on the hydrology in East Africa this scenario could provide an indication for long term impacts of such developments. The key results of this sub analysis can be summarised as follows:

- As expected, the LOLE values increase considering low hydrology conditions. With values ranging from 28 to 170 h/a, the target LOLE (1 day per year) is not met in the years 2016, 2017 and 2018.

- Due to the capacity shortage in 2017 and 2018 (firm capacity gap ranges from 73 to 179 MW in this period) unserved energy occurs in these years (2 to 16 GWh reflecting up to 0.1% of the annual electricity consumption). In the long term only small level of unserved energy may arise with values below 1 GWh representing less than 0.003% of the annual electricity consumption.

- Higher utilisation of fossil fuelled power plants leads to more than doubling of fuel cost over the entire study period. Considering low hydrology conditions the system LEC ranges from 10.3 to 11.9 USDcent/kWh (increase by 8% compared to scenario considering average hydrology conditions). The additional cost caused by low hydrology are particularly pronounced in the period until 2018 since the lacking hydropower energy is mainly compensated by the existing diesel engines with high short-run marginal cost. In this period LEC in the low hydrology case are about 20% higher compared to the reference scenario (with average hydrology conditions).

- Excess electricity in the years from 2019 to 2023 (period with largest excess energy in the reference scenario) is not as significant as in the reference scenario considering average hydrology. With 363 to 806 GWh about 2 to 5% of the generated electricity are considered as excess electricity. However, assuming that all geothermal power plants are equipped with single-flash technology[181], additional 1,255 to 1,655 GWh of geothermal energy is not utilised during that period (15-18% of the available geothermal steam has to be vented).

- Potential shortages in the period 2017 and 2018 may be overcome by implementation of additional temporary geothermal wellheads in the Olkaria and Menengai field utilising steam from wells already drilled but not yet utilised (feasibility to be checked). Taking into account rather small amounts of unserved energy from 2019 onwards (below 0.003% in relation to electricity consumption) despite low hydrology conditions, the detected generation expansion plan of the reference expansion scenario is considered as sufficient. However, if higher security of supply (lower values for LOLE and unserved energy) is aimed to be reached in the long term, further back-up capacity should be taken into account in the planning process (in the long-term around 150 to 200 MW).

[181] Thus, adjustment of the power output is limited and only feasible through venting steam.

The following figure shows the annual energy mix contrasted with the forecasted annual electricity consumption. The second figure depicts again the generation mix by technology, however, as percentage of the overall electricity generation. Further details of the results (in relation to capacity, generation, reliability and cost) as well as a direct comparison with the reference expansion plan is provided in Annex 7.B.

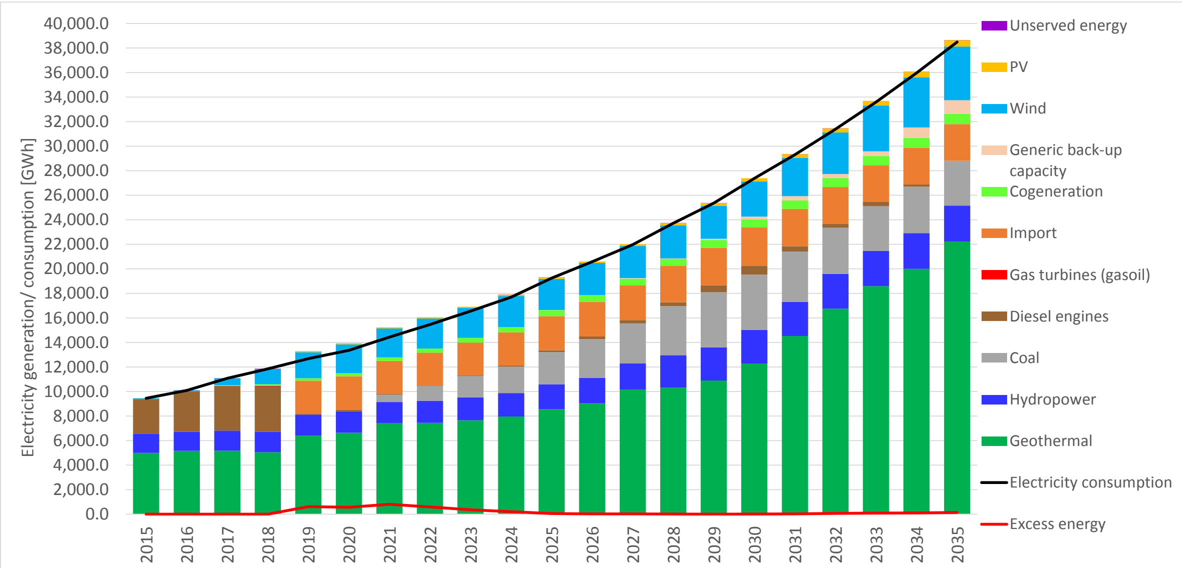

Figure 7-11: Low hydrology case – electricity generation versus electricity consumption

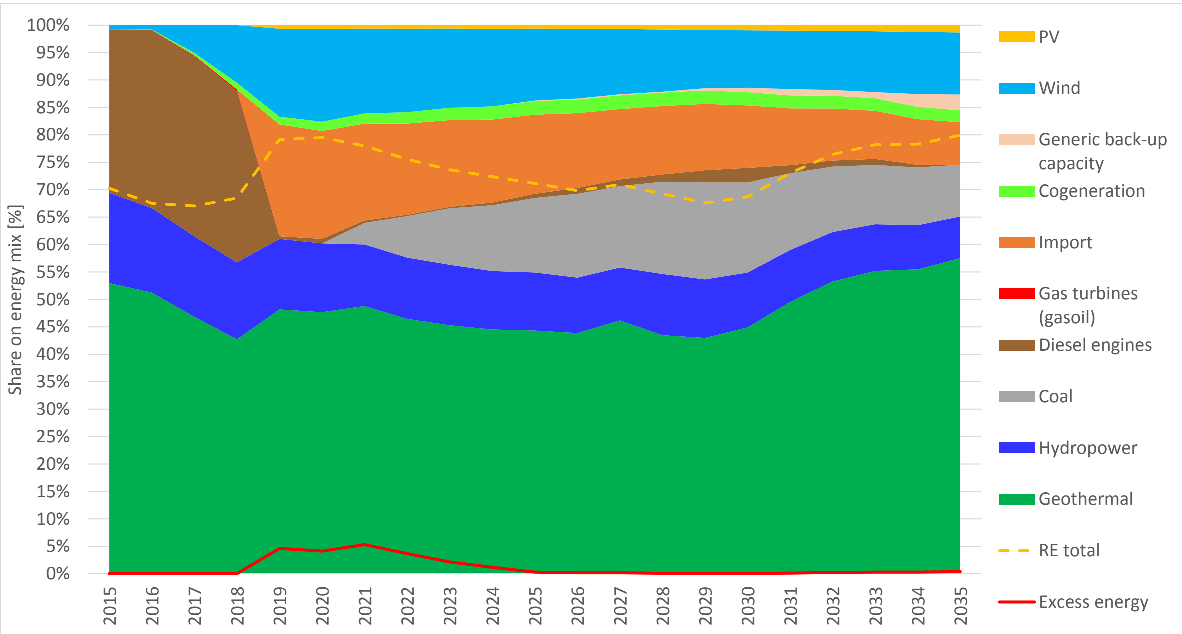

Figure 7-12: Low hydrology case – share on generation mix by technology

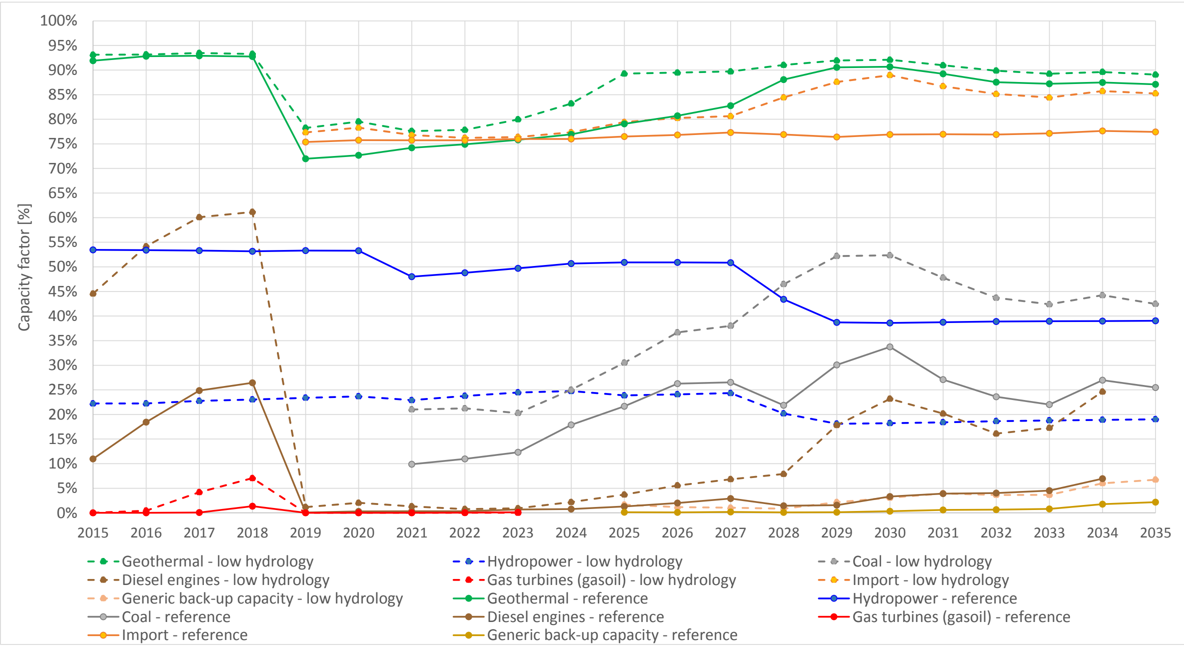

Figure 7-13: Low hydrology case – comparison of capacity factors of dispatchable generation types with reference scenario

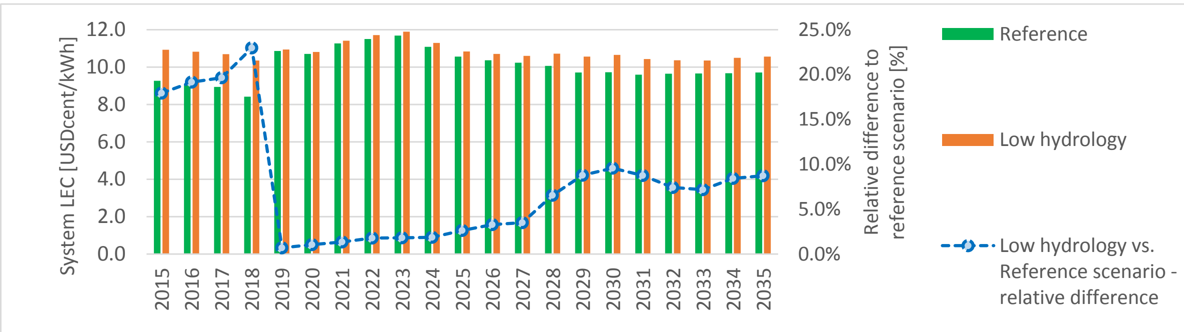

Figure 7-14: Low hydrology case – comparison of system LEC with reference scenario

7.6.2.2 Renewable energy scenario

Deriving adequate expansion pathways for power generation from renewable energy requires a detailed analysis of the techno-economic implications of RE deployment. The analysis will be based on different scenarios as defined in Section 7.4. These are:

- The reference scenario (as described in Section 7.6.1)

- An accelerated RE scenario: This scenario mimics intensified efforts to develop wind and solar (PV) resources in Kenya. Regarding large and small hydropower, geothermal pro-jects and co-generation projects from biomass the assumptions of the moderate RE scenario hold. In case of wind power, the development of new projects is intensified after 2020 to reach an additional capacity of 1,200 MW until 2035 (600 MW more than assumed for the moderate RE scenario). Also solar PV efforts are intensified (doubling to 500 MW in 2035 compared to moderate RE scenario).An accelerated RE Scenario: This scenario mimics intensified efforts to develop wind and solar (PV) resources in Kenya. The scenario builds on the main assumptions of the reference scenario. However, wind and solar generation is increased.

- A slowed down RE scenario: The scenario also builds on the main assumptions of the moderate RE scenario, however, wind and solar development is less ambitious. Addition-al wind capacity amounts to 200 MW (a third of the moderate RE scenario wind expansion), and solar PV capacity to 100 MW until 2035 (40% of the moderate RE scenario PV expansion).

A detailed description of wind and solar expansion pathways under the three different scenarios is provided in Table 7-7.

The three scenarios create a bandwidth of possible wind and solar PV development until 2035. The following analysis identifies the impacts of these different development path-ways. Results provide a valuable basis for future decision-making regarding the development of wind and solar PV. The resulting expansion of the generation system in the accelerated and slowed down RE scenario is provided in Annex 7.C.

The following figures depict a more comprehensive evaluation of the differences between the three RE scenarios. The moderate RE scenario serves as a benchmark in order to highlight the relative differences between the three expansion pathways. The figures display for the relevant period 2020 to 2035 the differences in the

1. Fuel-specific power generation (Figure 7-15 and Figure 7-16): changes of annual power generation of the accelerated and the slowed down RE scenarios versus the moderate RE scenario – measured in absolute terms (GWh)

2. Shares of RE generation in total power generation (Figure 7-17): changes of annual RE shares in total generation versus the moderate RE scenario – measured in percentage point changes of the share (%), and

3. Changes to excess energy (Figure 7-18): changes of total annual excess energy versus the moderate RE scenario – measured in relative terms (%).

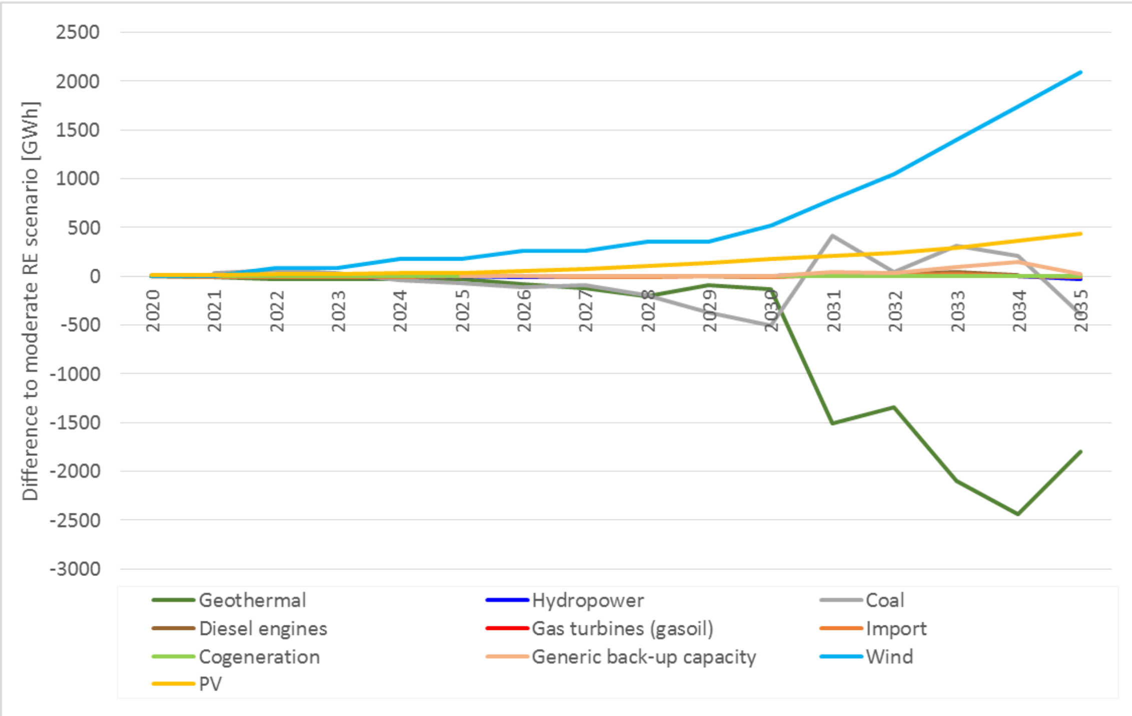

Figure 7-15: Power generation – accelerated RE vs. moderate RE scenario 2020–2035

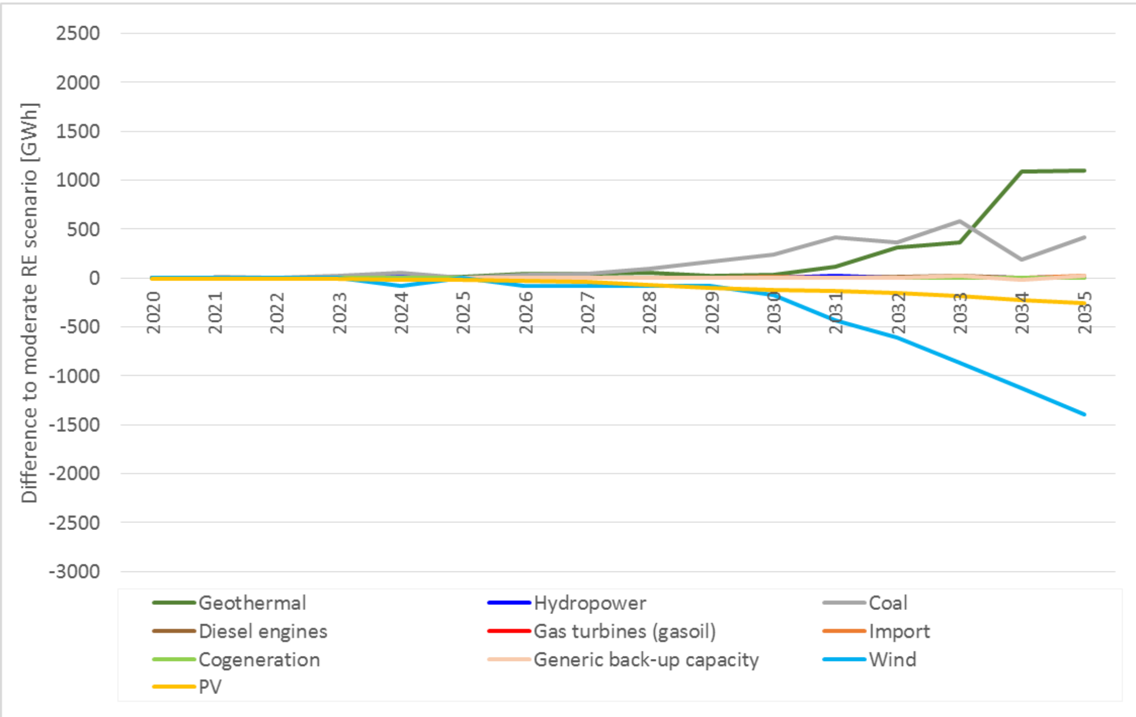

Figure 7-16: Power generation – slowed down RE vs. moderate RE scenario 2020–2035

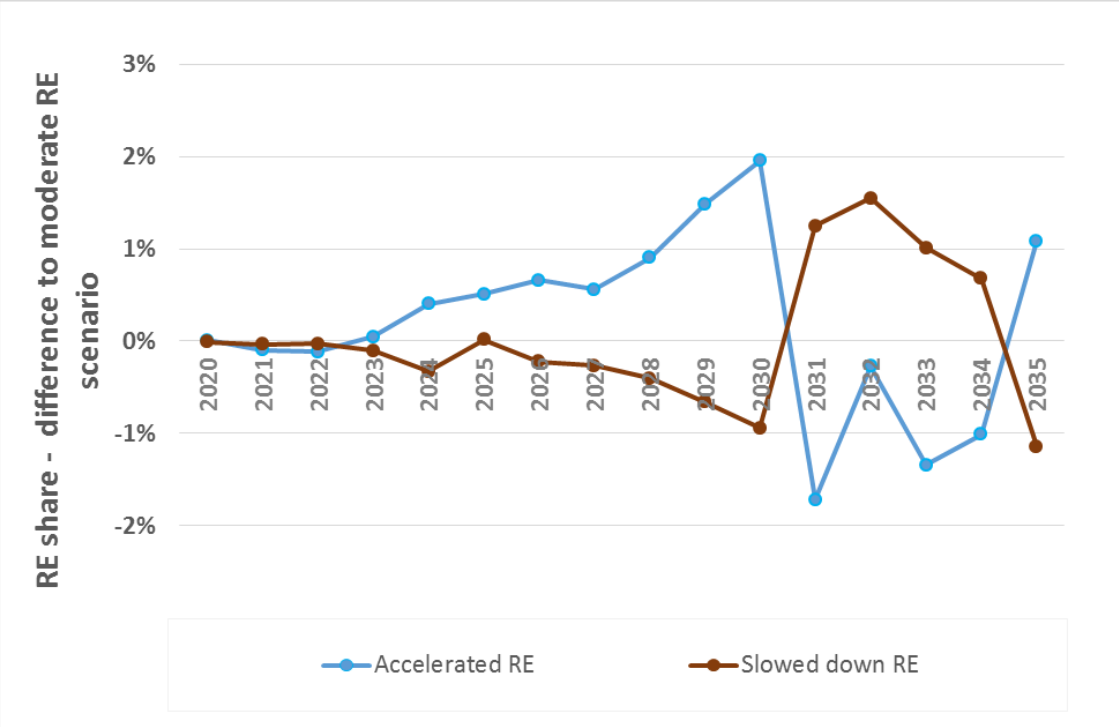

Figure 7-17: Change of RE generation share – difference to moderate RE scenario

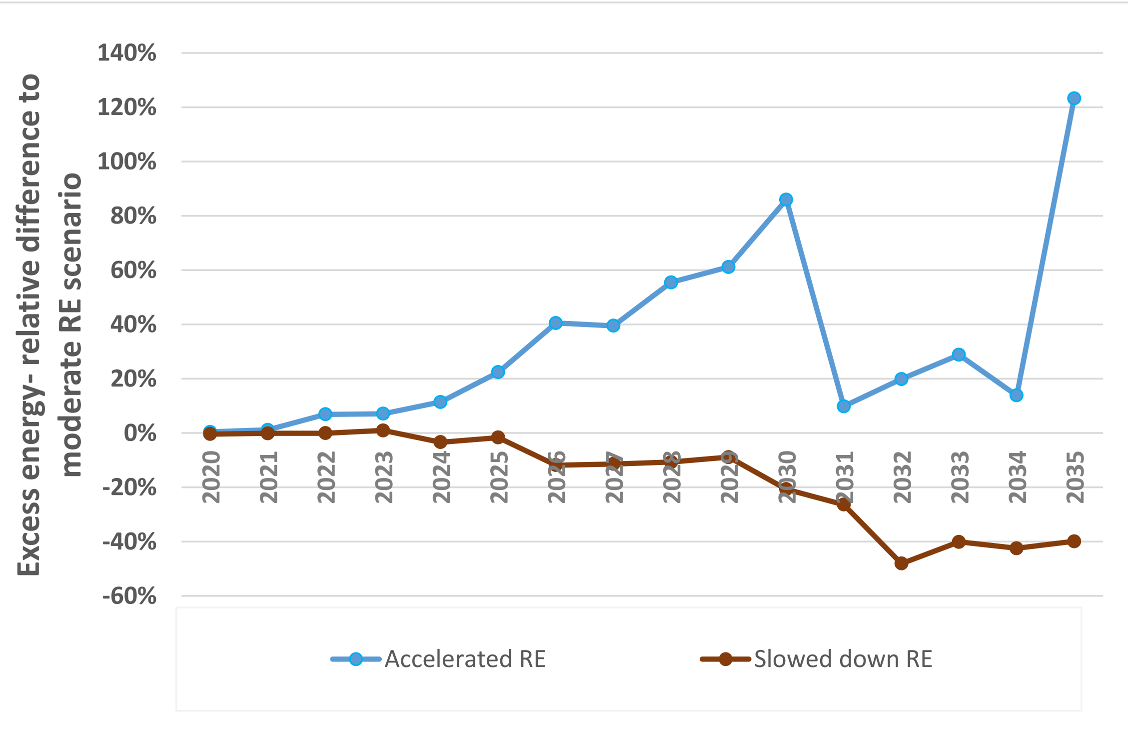

Figure 7-18: Excess energy – difference to moderate RE scenario

Not surprisingly, the accelerated RE scenario leads to higher power generation based on wind and solar resources than the moderate RE case. From 2020, the first year of the accelerated RE development, power generation from wind exceeds developments of the moderate scenario (see blue line in the figure). In 2035, wind-based generation is roughly 2,100 GWh higher than in the moderate scenario. Also generation from solar PV is higher than in the moderate RE scenario (see yellow line in the figure). In 2035 solar PV capacity is twice as high as in the moderate case, which also doubles PV-based power generation. At the end of the planning period solar generation in the accelerated RE scenario exceeds the one in the moderate case by approximately 430 GWh.

For the whole study period the increased wind and solar development comes almost entirely at the expense of geothermal generation (see the dark green line in the figure). Coal based generation is decreased to a much lesser extent (only 7% of the reduction of geothermal generation) and only for particular periods. In other words: Increasing the contribution of one renewable resource (e.g. wind) directly crowds out another renewable source (i.e. geothermal). On the one hand, additional wind and solar generation substitutes the utilisation of existing geothermal plants. On the other hand, and of higher relevance, it delays investments in new geothermal power stations. Obviously this delays their contribution to total, geothermal and RE based generation. This effect explains the strong shift from increased RE share to reduced RE share (compared to moderate RE scenario) in 2031 (Figure 7-17) where the delay of one large geothermal plant results in a reduced geothermal generation by more than 1,000 GWh per year. Table 7-20 shows the impacts of the RE scenarios on the CODs of considered geothermal expansion candidates. After 2030 the accelerated RE scenario delays CODs of geothermal candidates by one or two years compared to the CODs in the moderate RE case.

Table 7-20: Changes in CODs due to different RE developments

	COD	COD - difference to moderate RE	
	Moderate RE	Accelerated RE	Slowed down RE
Olkaria 9	2032	delayed by 1 year	
Eburru 2	2032	delayed by 2 years	
Menengai 2 Phase I - Stage 4	2031	delayed by 1 year	
Menengai 4 Phase II - Stage 2	na		additional 2035
Suswa Phase I - Stage 1	2033	delayed by 2 years	
Suswa Phase I - Stage 2	2035		advanced by 1 year
Suswa 2 Phase II - Stage 1	2035	delayed by 1 year or more	
Baringo Silali Phase I, Stage 3	2033	delayed by 2 years	
AGIL Longonot Stage 1	2034	delayed by 1 year	

As a consequence, the accelerated RE scenario does not substantially increase the share of RE generation in Kenya's total power generation. The RE share in generation is only slightly higher (by on average less than half a percentage point for the period 2020 to 2035) compared to the moderate RE scenario (see Figure 7-17). For the years 2031 to 2034 the RE share in total generation is even lower than in the moderate RE case. The increased utilisation of volatile wind and solar resources induces additional reserve requirements. In the simulation this can be observed in the reduced hydropower generation that need to run below their minimum to utilise all water (minimum outflow) more often compared to the moderate RE case. This leads to not utilised (spilled) water.

Thus, increased wind and solar development would not only substitute geothermal generation but also reduce hydropower generation (however to a much lower extent).

The accelerated RE scenario increases excess energy since more must take generation is included in the system. This increase can be enormous, even doubling excess energy for some years (the Figure 7-18).

Evidently, the effects of the slowed down RE scenario point to the opposite direction. If less wind and solar generation capacity is introduced to the system (compared to the moderate case), the emerging supply gap is covered by advanced commissioning of geothermal power plants (see again Table 7-20). Again, the simulation results emphasise the relationship between different renewable energy sources in the Kenyan power supply system. Volatile renewable sources (complemented with conventional thermal capacity) and geothermal resources appear as substitutes. This outcome is backed by the development of total RE shares in generation: Compared to the moderate case the slowed down RE scenario does not induce a substantial reduction of the overall RE shares. Between 2031 and 2034 the overall RE shares are even higher than in the moderate RE case caused by advanced realisation of geothermal projects and less reserve requirements due to lower wind and PV development targets. This leads to a lower utilisation of coal-fired plants vis-à-vis the moderate case. A reduced expansion of must take RE capacity in the slowed down RE scenario reduces excess energy.

The three considered RE scenarios do not distinctly differ in the share of renewable energy in the Kenyan power system. As shown in the moderate RE scenario already leads to a rather large share of renewables in total generation and consumption – calculated as the average shares in the period from 2015 to 2035. On average, the accelerated RE case increases the RE share in generation by roughly 0.2%, as compared to the moderate scenario. Even a less ambitious development of wind and solar re-sources – as stipulated by the slowed down RE scenario – does not lead to decreasing shares of all RE generation in total generation in Kenya. Reduced development of wind and PV is compensated by advanced utilisation of geothermal resources.

Table 7-21: RE shares in generation (average 2015-2035)

	Moderate RE	Accelerated RE		Slowed down RE	
		share	*Difference to Moderate RE*	share	*Difference to Moderate RE*
RE share in total generation	82.4%	82.6%	*0.2%*	82.4%	*0.0%*

As a first important result the analysis revealed the potential of wind and solar power to substitute a portion of the huge geothermal contribution to the Kenyan power supply system. The simulation shows that the Kenyan generation system can be well suited to include a substantial amount of volatile power generation from wind and solar resources. Such resources can be interpreted as an alternative option to maintain large RE shares in the Kenyan system. Although Kenya disposes of considerable geothermal resources as well as an adequate project pipeline to exploit them, wind and solar power can serve as an insurance. Wind and solar resources can help:

- To slow down the depletion of the geothermal resources in Kenya. They are able to save parts of the resource for future use – beyond the current planning horizon. However, the actual depletion of geothermal fields and the future value of (saved) geothermal sources are difficult to estimate. Therefore, this reason may not be sufficient to justify solar and wind development alone.

- To diversify the Kenyan fuel mix – thereby reducing the dependency on the geothermal resource and on other, mostly conventional fossil fuels. As wind and solar potentials are available in different regions of the country, this can also contribute to a more decentralised structure of power supply.

- To introduce new opportunities for the Kenyan manufacturing and service sectors – thereby enabling creation of added value and job opportunities on a regional level.

Notwithstanding the potential benefits of increased wind and solar generation in Kenya, the accelerated development induces excess cost.

The following table gives an overview on the cost implications. The table provides information on the development of annual capital and O&M cost, as well as fuel cost and resulting system-wide power generation cost (LEC) for the years 2020 to 2035. The column labelled ‘Present value’ reflects the sum of the discounted annual cost figures over the whole planning horizon from 2015 to 2035[182].

As compared to the moderate case, the accelerated RE scenario increases annual capital cost by 0.1% in 2020 up to 6% in 2035. Over the period from 2015 to 2035 the present value of all annual capital cost is 1% higher than in case of the moderate scenario. The impact on fixed and variable O&M cost is lower with an increase of 0.5% for the present value. The present value of the fuel cost is higher by about 1%. For half of the years in the period 2020 to 2035 the fuel costs decrease with the accelerated development of wind and PV. However, in a few years the fuel consumption increases considerably due to the delay of geothermal capacity and the resulting higher dis-patch of coal units and generic back-up units (which are assumed to run on gasoil) during that years.

Total cost are higher in the accelerated RE case than in the moderate scenario: cumulated and discounted cost are 1% higher than in the moderate scenario. Total cost development is dominated by the increase in capital cost, mainly in the later years. On average, specific generation cost are as well 1% higher, reflected by a system LEC of 10.2 USD/MWh compared to 10.1 USD/MWh in the moderate case.

Total cost are higher in the accelerated RE case than in the moderate scenario: cumulated and discounted cost are 1% higher than in the moderate scenario. Total cost development is dominated by the increase in capital cost, mainly in the later years. On average, specific generation cost are as well 1% higher, reflected by a system LEC of 10.2 USD/MWh compared to 10.1 USD/MWh in the moderate case.

[182] Only annual values as of 2020 are reported since both considered RE scenarios fully enfold after this year. Values from 2015 to 2019 are (almost) similar in all scenarios. For the sake of comparability present values include also the first years.

Table 7-22: Cost implications of RE scenarios

	Unit	Present Value*	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Capital cost (Investment & rehabilitation)																		
Moderate RE	MUSD	**8,527**	997	1,136	1,247	1,355	1,356	1,399	1,458	1,542	1,695	1,728	1,857	1,973	2,143	2,305	2,427	2,604
Accelerated RE	MUSD	**8,612**	998	1,137	1,256	1,364	1,373	1,416	1,483	1,569	1,733	1,769	1,915	1,991	2,188	2,337	2,472	2,748
Difference to Moderate RE		***1.0%***	*0.1%*	*0.1%*	*0.7%*	*0.6%*	*1.3%*	*1.2%*	*1.8%*	*1.8%*	*2.2%*	*2.4%*	*3.1%*	*0.9%*	*2.1%*	*1.4%*	*1.9%*	*5.5%*
Slowed down RE	MUSD	**8,471**	996	1,134	1,246	1,354	1,347	1,397	1,448	1,530	1,681	1,710	1,831	1,934	2,090	2,230	2,366	2,521
Difference to Moderate RE		***-0.7%***	*-0.1%*	*-0.1%*	*-0.1%*	*-0.1%*	*-0.6%*	*-0.1%*	*-0.7%*	*-0.7%*	*-0.8%*	*-1.0%*	*-1.4%*	*-2.0%*	*-2.5%*	*-3.2%*	*-2.5%*	*-3.2%*
O&M cost (fixed and variable)																		
Moderate RE	MUSD	**2,942**	432	475	501	524	527	536	555	582	593	605	645	697	753	805	848	906
Accelerated RE	MUSD	**2,958**	432	475	502	525	531	540	561	589	601	614	658	695	758	806	850	941
Difference to Moderate RE		***0.5%***	*0.0%*	*0.0%*	*0.3%*	*0.2%*	*0.7%*	*0.7%*	*1.1%*	*1.1%*	*1.4%*	*1.5%*	*2.0%*	*-0.4%*	*0.7%*	*0.1%*	*0.2%*	*3.8%*
Slowed down RE	MUSD	**2,930**	432	475	501	524	525	535	552	580	589	602	641	688	740	786	835	889
Difference to Moderate RE		***-0.4%***	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*-0.4%*	*-0.1%*	*-0.4%*	*-0.4%*	*-0.5%*	*-0.5%*	*-0.7%*	*-1.3%*	*-1.8%*	*-2.3%*	*-1.5%*	*-1.9%*
Fuel cost																		
Moderate RE	MUSD	**579**	2	15	32	55	79	98	121	127	98	130	159	141	131	136	204	227
Accelerated RE	MUSD	**587**	2	16	35	56	77	94	116	123	89	113	134	179	147	187	265	224
Difference to Moderate RE		***1.4%***	*-0.1%*	*7.2%*	*6.9%*	*0.9%*	*-3.3%*	*-3.9%*	*-3.8%*	*-3.0%*	*-9.3%*	*-12.8%*	*-15.6%*	*27.0%*	*11.7%*	*37.4%*	*30.0%*	*-1.0%*
Slowed down RE	MUSD	**597**	2	16	33	56	82	98	122	129	102	137	170	160	149	170	204	251
Difference to Moderate RE		***3.1%***	*0.1%*	*2.0%*	*0.9%*	*2.0%*	*3.5%*	*-0.1%*	*1.3%*	*1.7%*	*4.1%*	*5.6%*	*7.0%*	*14.1%*	*13.6%*	*24.5%*	*0.3%*	*10.9%*
Total cost																		
Moderate RE	MUSD	**12,048**	1,430	1,626	1,780	1,935	1,962	2,032	2,133	2,251	2,386	2,463	2,661	2,812	3,028	3,246	3,479	3,737
Accelerated RE	MUSD	**12,157**	1,432	1,628	1,792	1,945	1,980	2,049	2,160	2,281	2,423	2,497	2,707	2,864	3,093	3,330	3,587	3,913
Difference to Moderate RE		***0.9%***	*0.1%*	*0.1%*	*0.7%*	*0.5%*	*0.9%*	*0.9%*	*1.3%*	*1.3%*	*1.5%*	*1.4%*	*1.7%*	*1.9%*	*2.1%*	*2.6%*	*3.1%*	*4.7%*
Slowed down RE	MUSD	**11,997**	1,429	1,625	1,779	1,934	1,954	2,029	2,123	2,240	2,373	2,449	2,642	2,783	2,979	3,186	3,405	3,661
Difference to Moderate RE		***-0.4%***	*-0.1%*	*-0.1%*	*0.0%*	*0.0%*	*-0.4%*	*-0.1%*	*-0.5%*	*-0.5%*	*-0.6%*	*-0.6%*	*-0.7%*	*-1.0%*	*-1.6%*	*-1.9%*	*-2.1%*	*-2.0%*
System LEC																		
Moderate RE	USD/MWh	**10.07**	10.70	11.26	11.51	11.69	11.08	10.56	10.37	10.24	10.06	9.71	9.72	9.59	9.65	9.66	9.67	9.71
Accelerated RE	USD/MWh	**10.16**	10.71	11.28	11.59	11.75	11.19	10.65	10.50	10.38	10.21	9.85	9.89	9.77	9.85	9.91	9.98	10.17
Difference to Moderate RE		***0.9%***	*0.1%*	*0.1%*	*0.7%*	*0.5%*	*0.9%*	*0.9%*	*1.3%*	*1.3%*	*1.5%*	*1.4%*	*1.7%*	*1.9%*	*2.1%*	*2.6%*	*3.1%*	*4.7%*
Slowed down RE	USD/MWh	**10.03**	10.69	11.26	11.50	11.68	11.04	10.55	10.32	10.19	10.00	9.66	9.65	9.49	9.49	9.48	9.47	9.51
Difference to Moderate RE		***-0.4%***	*-0.1%*	*-0.1%*	*0.0%*	*0.0%*	*-0.4%*	*-0.1%*	*-0.5%*	*-0.5%*	*-0.6%*	*-0.6%*	*-0.7%*	*-1.0%*	*-1.6%*	*-1.9%*	*-2.1%*	*-2.0%*

*Discount rate: 12%

In contrast, slowing down the development of wind and solar resources may reduce cost. Annual capital cost would be up to 2% lower than in the moderate scenario. In total, cumulated and discounted annual capital cost are 1% lower. Fixed and variable O&M cost are lower (by 0.7% of the present value). The slowed down RE scenario increases fuel consumption and cost. This is mainly caused by higher dispatch of coal units in the last years of the study period. The fuel cost effect of the advanced commissioning of additional geothermal projects (in comparison to the moderate scenario) is apparently not as strong as between the accelerated and moderate scenario. Total costs of the slowed down RE scenario are lower as compared to the moderate case. Over the whole planning horizon savings of about 50 MUSD could be realised, which represents a reduction in total cost of roughly 0.4% versus the moderate case.

The results show that scope and timing of wind and solar development markedly affects cost of the Kenyan power supply system. Results indicate that cost of adding an amount of renewable generation keeps at a similar level for different shares of already existing renewable generation in the system. This effect is further evaluated by calculation of incremental cost between the three scenarios. For each year (absolute) differences in total cost are related to differences in wind and solar generation. Furthermore annual differences in cost and generation are discounted and cumulated for the entire period (2015-2035). Relating cumulated and discounted cost to cumulated and discounted generation yields the expected long-run marginal cost (LRMC) for in-creasing the development of wind and solar power (from one scenario to another). Results of this analysis are presented in Figure 7-19.

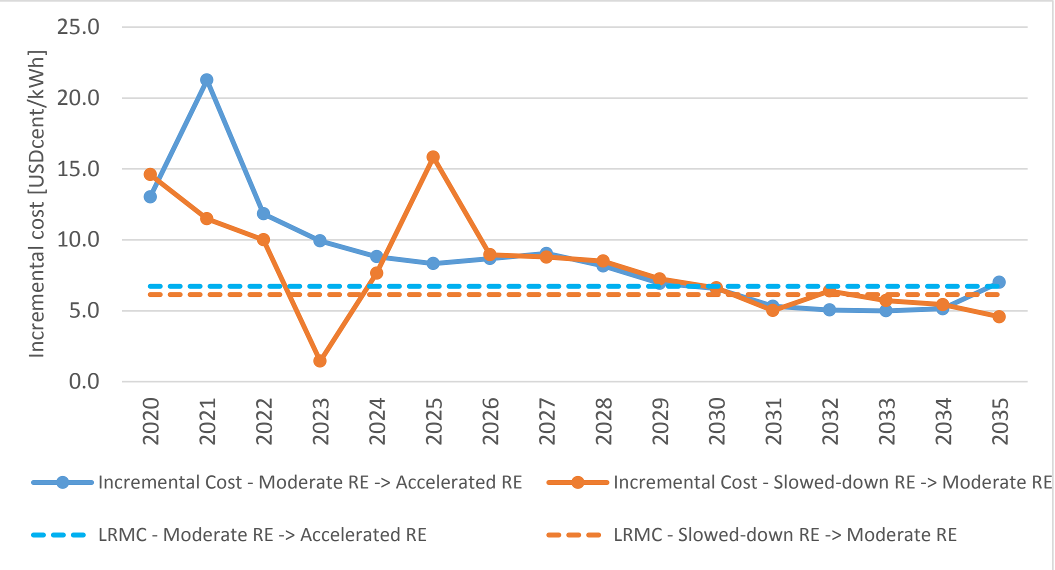

Figure 7-19: Incremental cost and LRMC of RE expansion

In general, the development of incremental costs is very similar for both increases of wind and PV capacities (from slowed down RE to moderate RE and from moderate to accelerated RE).

Increasing the share of wind and solar is slightly more costly in the early years compared to the later years. The higher incremental costs in 2020 and 2021 derive from the development of solar PV in these years while wind generation remains the same. Thus, the observed high specific incremental cost are caused by the deployment of a relatively costly technology. In the long term the two cost curves converge to a lower cost level. This is caused by an increasing utilisation of wind power in all scenarios as well as the assumed cost degradation for specific costs of newly installed PV and wind plants. Annual incremental cost range between 8 USDcent/kWh and 21 USDcent/kWh in the beginning and 5 to 7 USDcent/kWh in the long term.

When comparing the cost implications of the two switches between different PV and wind development scenarios the following can be observed. The switch from slowed down to moderate scenario appears to be less costly (on a per kWh basis) than the switch from moderate to accelerated scenario. The overall LRMC for the first amount to roughly 6 USDcent/kWh (indicated by the dotted orange line in Figure 7-19). The overall LRMC for latter case are higher and amount to roughly 7 USDcent/kWh (indicated by the dotted blue line in Figure 7-19). Concluding, increasing the share of wind and solar power generation will be more costly (in specific terms) when the share of already existing generation such kind gets higher. This is well reflected by the simulation results.

The analysis of different RE expansion pathways revealed several important implications regarding the development of the Kenyan power generation system and the associated cost. First and foremost, a more ambitious development of wind and solar potentials in Kenya does not necessarily lead to an increased share of renewables in generation. This is mainly caused by two reasons: (i) Additional wind and solar capacities postpone the commissioning of geothermal projects. So, wind and solar generation directly crowds out another renewable energy source, and (to a much lesser extent) (ii) volatile wind and solar generation increases the reserve requirements in the system. Results also revealed the potential to include wind and solar power: The generation system may well be operated when larger wind and solar capacities exist. Against this background, wind and solar generation might be interpreted as a long-term alternative to the geothermal resource in Kenya. Despite the additional cost of an over-ambitious development, these resources may contribute to the future generation in Kenya:

- They can slow down the depletion of the geothermal resources in Kenya and are thus able to save parts of the resource for future use – beyond the current planning horizon. However, the actual depletion of geothermal fields and the future value of (saved) geo-thermal sources are difficult to estimate. Therefore, this reason may not be sufficient to justify solar and wind development alone.

- They enable a diversification of the Kenyan fuel mix and thereby reduce the dependency on the geothermal resource and on other, mostly conventional fossil fuels. As wind and solar potentials are available in different regions of the country, this can also con-tribute to a more decentralised structure of power supply.

- To introduce new opportunities for the Kenyan manufacturing and service sectors – thereby enabling creation of added value and job opportunities on a regional level.

However, the results underpin the important role of the geothermal resource as an available, cost-effective and emission-free energy source for Kenya.

7.6.2.3 Energy Efficiency scenario

In this scenario, the impact of energy efficiency measurements is taken into account (based on the assumptions and results presented in the Energy Efficiency report).

The key results are summarised below.

- Energy efficiency measurements lead to a reduction in electricity demand on sent-out level. As a result less generation capacity is required to satisfy the costumers' needs. In the long-term, the lower demand growth leads to delayed commissioning of some geothermal power plant candidates. Furthermore, less back-up capacity (910 MW in 2035) is required.

- Compared to the reference scenario, energy efficiency measurements lead to a reduction of total generation costs by 7% (roughly a NPV of USD 800 million). This means that for the same output (i.e. benefit of electricity utilisation such as same GDP growth, industrial production and use of household appliances) only a reduced input (consumption of electricity) is needed (i.e. for lower supply costs). If costs for EE measures are added to the total costs the reduction for the EE scenario is still 6%.

- However, the LEC of the system (including costs for EE measures) may increase by 7%. This is obvious since the LECs are calculated for a considerably lower electricity consumption (reduced by 10%, discounted) which exceeds the net reduction of costs. The costs are not expected to decrease to the same extent as the consumption because more excess electricity will be generated (for export or to be dumped) due to system requirements (such as minimum capacity and reserve requirements). For the total study period, some 100% more excess electricity is estimated. This appears mainly during the period 2019 to 2024 where an overcapacity of committed plants may occur. If EE measures are applied to a higher demand scenario this excess electricity is expected to decrease and the EE scenario will be even more beneficial. The same is true if excess energy is lower (e.g. due to a delay of generation projects).

- Concluding, despite slightly higher LECs the recommended EE measures and the assumed effect would be beneficial: overall system costs would be reduced while the utilisation of electricity would remain the same. Further potential benefits such as environmental effects from fuel savings, technological edge and savings in the distribution network due to delayed load growth are not included in this calculation.

The figure below presents the firm capacity expansion contrasted with the forecasted peak demand (without and with reserve margin). The second figure displays the annual generation mix by technology. Further details are provided in Annex 7.D.

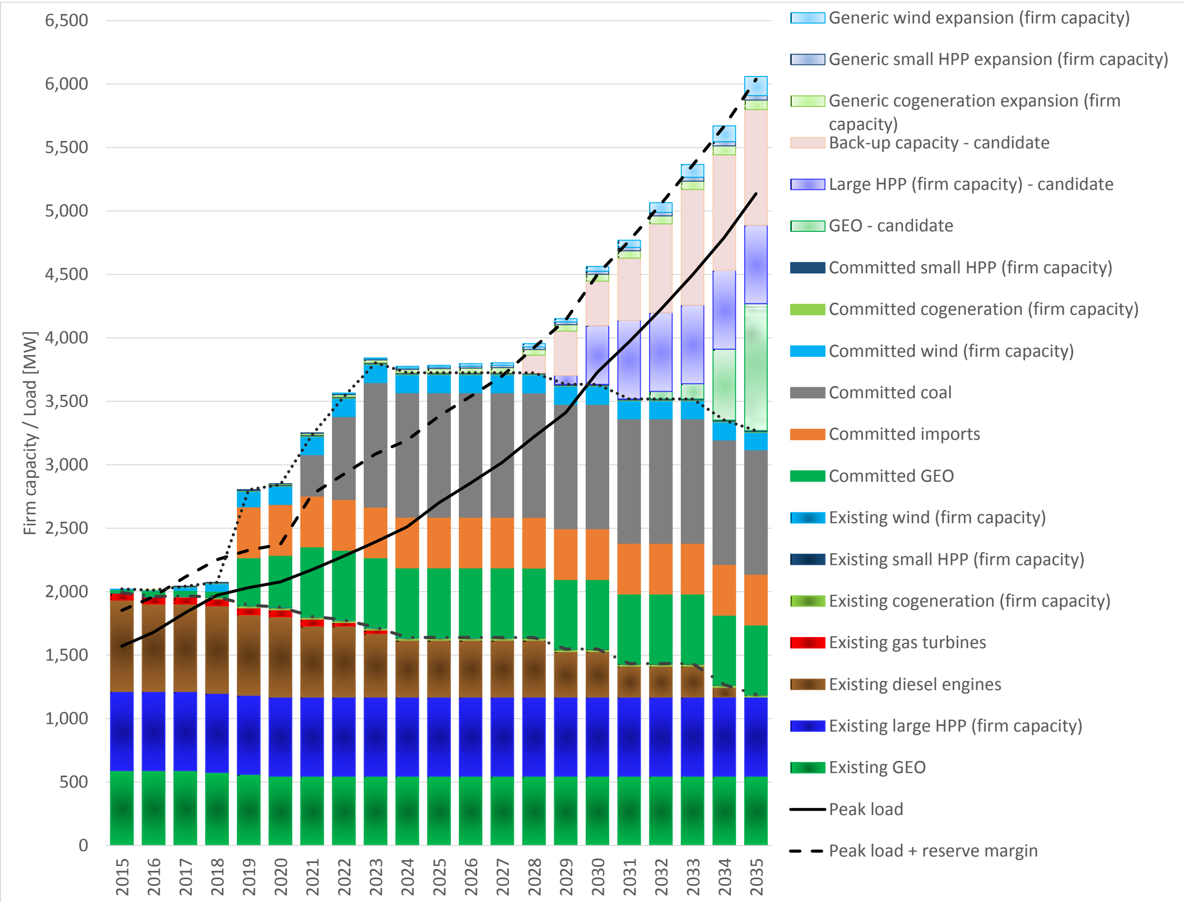

Figure 7-20: Energy Efficiency scenario – firm capacity versus peak demand

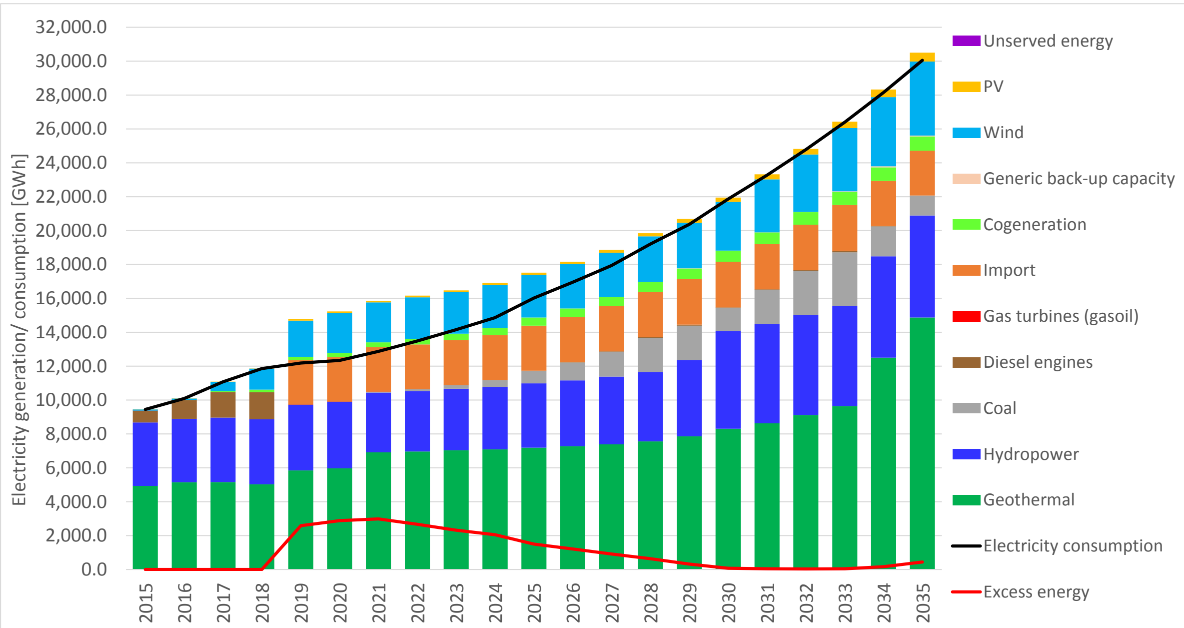

Figure 7-21: Energy Efficiency scenario – electricity generation versus consumption

7.6.2.4 Vision expansion scenario

This scenario considers

- Vision demand forecast;
- Reference (moderate) RE path; and
- Average hydrology.

The key results of the vision expansion scenario are summarised in the following.

- The forecasted need for new firm capacity until 2035 is about 10,675 MW (see Figure 7-22). Thus, the generation system would have to more than quadruple during the 20-year study period. About 20% (2.1 GW) of the needed firm capacity is already committed (i.e. commissioning dates are fixed).

- Major expansion is reached through 2,435 MW base load geothermal capacity from 2020 onwards. Compared to the principal generation expansion plan, geothermal plants in an advanced development stage (at Olkaria and Menengai) have to be brought forward close to their earliest possible COD. In 2035, geothermal capacity represents 26% of the total installed system capacity providing 50% of the annual generated electricity. Due to the high demand, coal power plants become more important but only in the long-term. From 2030 onwards, further 1,920 MW coal capacity is added to the generation system. In 2035, coal power capacity amounts 2,901 MW (21% of the installed system capacity) generating 23% of the annual electricity.

- Expansion of back-up and peaking capacity by 2,520 MW mainly providing the required cold reserve. In the generation modelling the capacity is represented by gasoil fuelled gas turbines. Flexible imports or peaking hydropower plants may constitute a favourable alternative.

- Despite the higher demand growth (compared to the reference expansion scenario) considerable amounts of excess electricity would occur in the years 2021 and 2022 ranging between 864 and 1,179 GWh (4 to 6% of the total electricity generation). Similar to the reference scenario this is due to several committed must-run capacities (HVDC, geothermal capacity, Lake Turkana). In addition, advanced geothermal projects have to be brought forward (in comparison to the principal generation expansion plan) in order to supply the load. These projects further represent must-run capacity as well resulting in higher excess energy. However, this amount is less than for the reference scenario. Taking into account that implementation schedule may change during development of a power plant, the amount of excess energy during this period is considered as acceptable because it provides higher security of supply with respect to such potential delays.

- The annual levelised electricity costs (LEC) of the total generation system vary between 8.9 and 10.4 USDcent/kWh during the study period. On average LECs are 3% lower compared to the reference expansion scenario. This derives from lower overcapacities and excess energy from 2019 to 2023 and in general better utilisation of power plants (e.g. less vented steam) throughout the study period.). This means that in the medium term a higher demand growth would result in reduced per kWh costs (see also chapter 9.3.2). Due to higher costs for required additional fossil fuelled capacity (coal, natural gas) in the long term (when all lower cost geothermal candidates' potential is used) the LEC in the vision scenario will exceed the LEC in the reference scenario with an increasing trend towards the end of the study period (by about 2% in 2035).

Annex 7.E provides an overview of the generation expansion considering the vision scenario. It provides the annual commissioning and decommissioning of generation projects, the installed and firm system capacity as well as annual firm capacity additions, the annual peak demand and the resulting generation capacity gap/surplus.

The forecasted key developments are visualised in the following figures. The first figure below shows the expansion of firm capacity in comparison with the forecasted peak load (with and without reserve margin). The second figure presents the annual generation mix contrasted with the forecasted electricity consumption.

Annex 7.E provides further details of the simulation results as well as a direct comparison with the results of the reference and low expansion scenario.

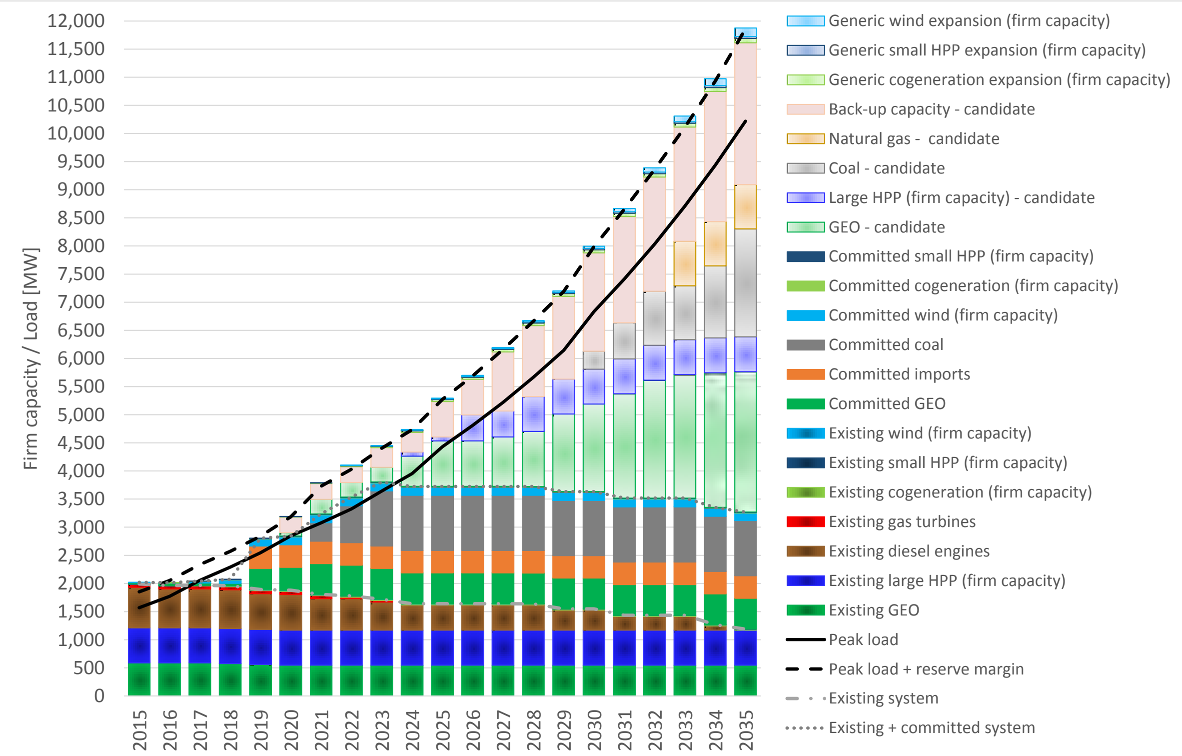

Figure 7-22: Vision expansion scenario – firm capacity versus peak demand

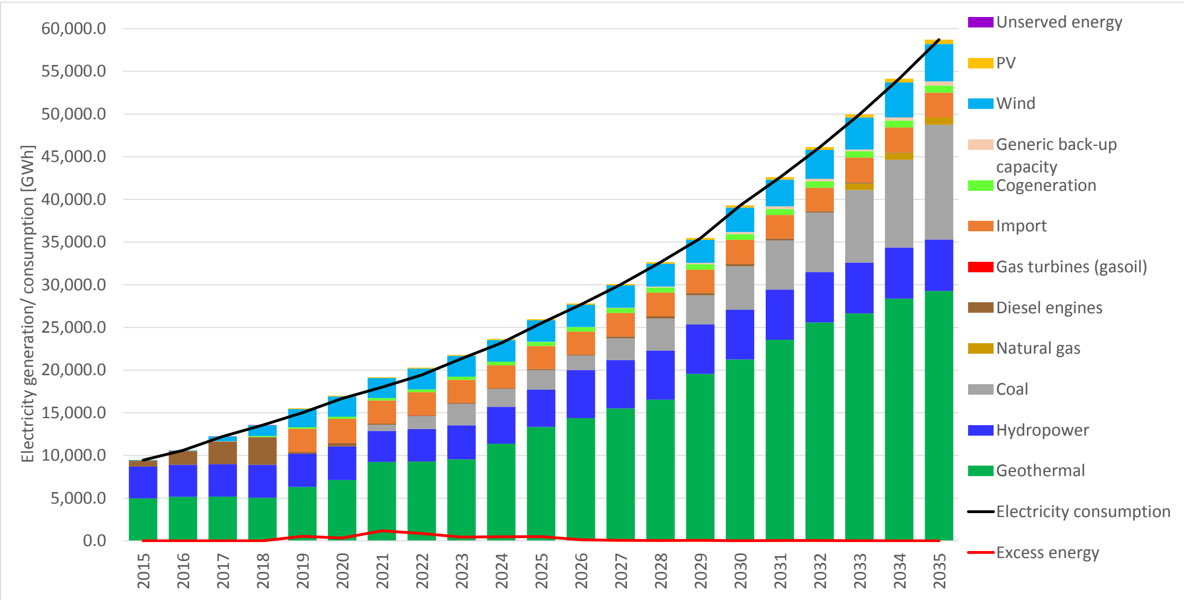

Figure 7-23: Vision expansion scenario – electricity generation versus electricity consumption

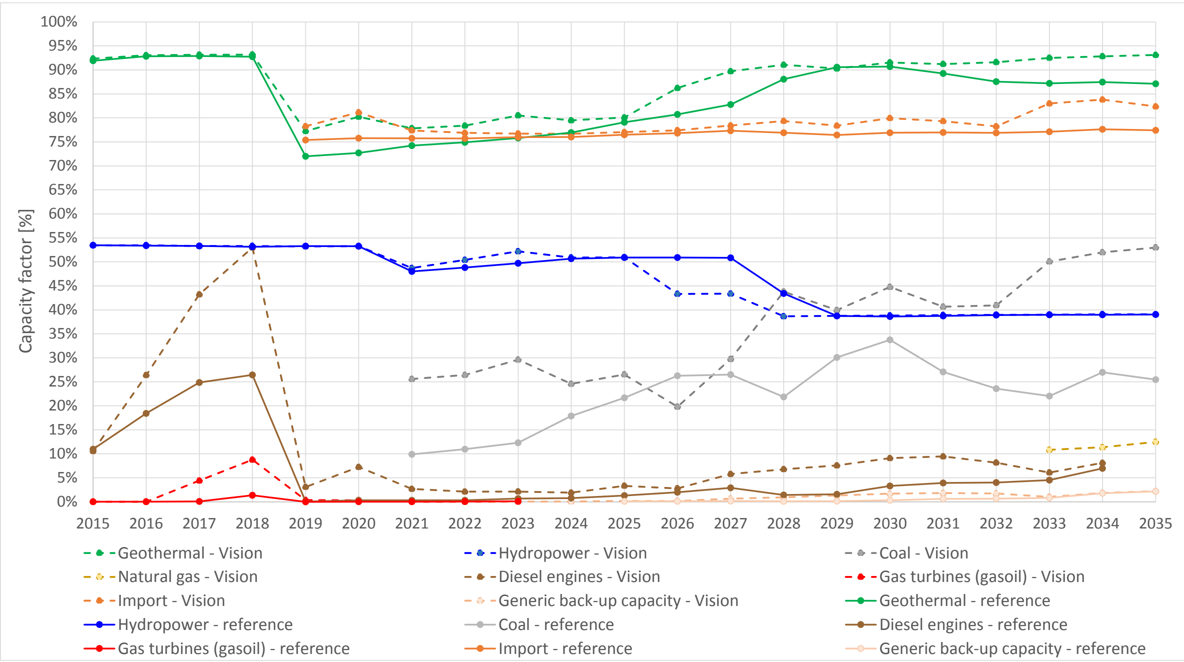

Figure 7-24: Vision expansion scenario – comparison of capacity factors of dispatchable generation technologies with reference scenario

7.6.2.5 Low expansion scenario

This scenario considers

- Low demand forecast;
- Reference (moderate) RE expansion path; and
- Average hydrology.

The results of the analysis are summarised in the following.

- The forecasted need for new firm capacity until 2035 is about 4,468 MW (see Figure 7-25). This is more than two times the existing generation system. About 47% (2.1 GW) of the needed firm capacity is already committed (i.e. commissioning dates are fixed).
- Due to the large amount of committed capacity, further expansion of the system is not needed until 2028. From 2028 onwards, base load expansion is reached through geothermal capacity (additional 670 MW until 2035).
- Expansion of back-up capacity amounts to 840 MW until 2035 mainly providing the required cold reserve.
- Despite of the low demand growth, the hydropower plants Karura and both stages of High Grand Falls are commissioned during the study period. This result clearly emphasises the need for flexible peaking power in the Kenyan generation system even if demand increases more slowly compared to the reference scenario. They are however required some years later than scheduled in the principal expansion plan. However, an earlier commissioning may provide (at higher costs) higher security of supply through more flexible operation.
- Since the committed power plants with must-run capacity (HVDC, geothermal power plants in Olkaria and Menengai, Lake Turkana) are the same as for the reference and vision scenario the excess electricity is considerably higher during the whole study period (up to 2,624 GWh representing 17% of the generated electricity in 2020).
- The annual levelised electricity costs (LEC) of the total generation system vary between 8.4 and 12.8 USDcent/kWh during the study period. On average LECs are 5% higher compared to the reference expansion scenario. This derives from higher overcapacities and excess energy throughout the study period. The result highlights a higher demand growth would result in reduced per kWh costs (see also chapter 9.3.2).

Annex 7.E provides the determined years of commissioning and decommissioning of the various power supply projects in the low expansion scenario. It further presents the installed and firm system generation capacity, the annual peak load, the firm capacity additions and the resulting generation surplus/gap.

The figures below display the above listed key developments. The first figure shows the expansion of firm capacity in comparison with the forecasted peak load (with and without reserve margin). The second figure presents the annual generation mix contrasted with the forecasted electricity consumption. In Annex 7.E further details of the scenario analysis as well as a direct comparison with the reference and vision expansion scenario are provided.

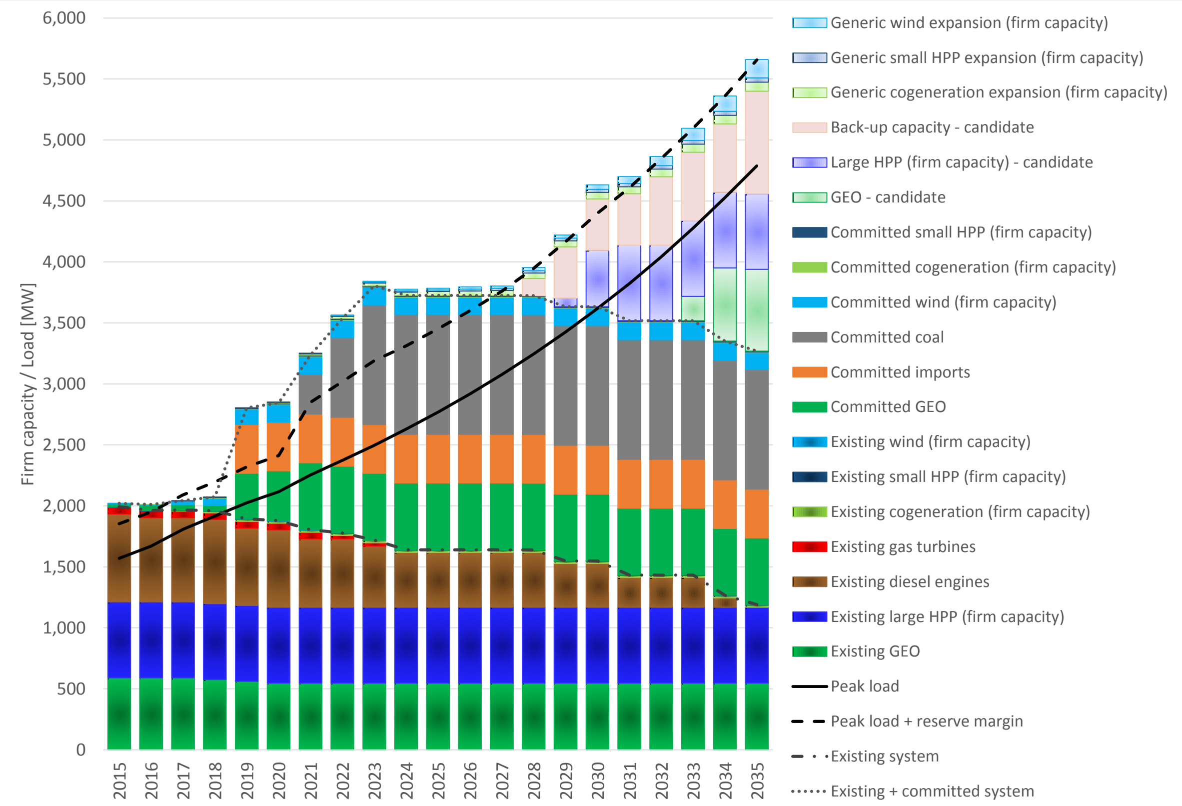

Figure 7-25: Low expansion scenario – firm capacity versus peak demand

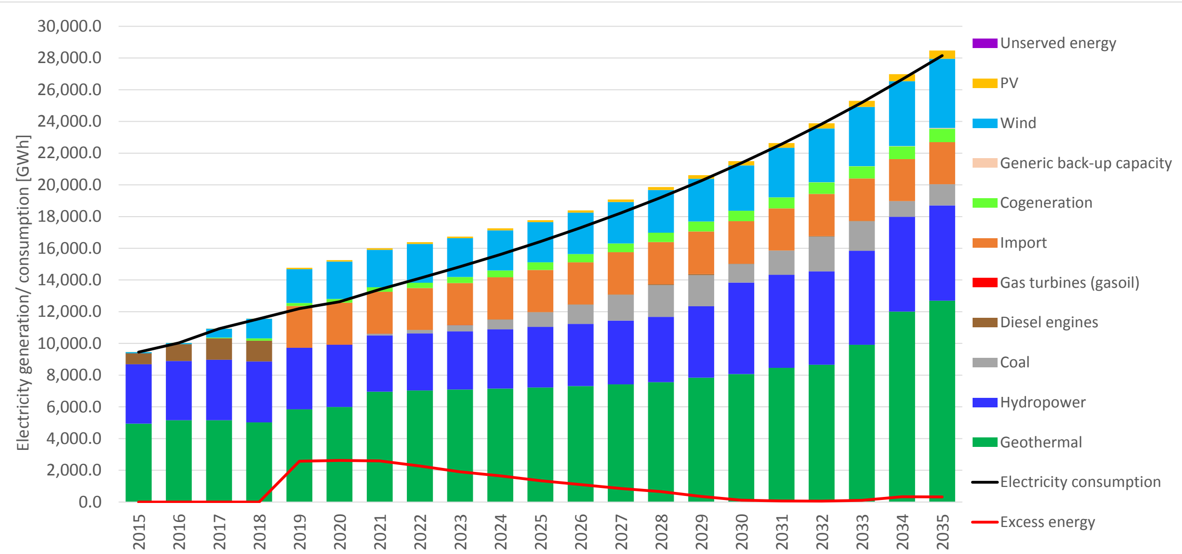

Figure 7-26: Low expansion scenario – electricity generation versus consumption

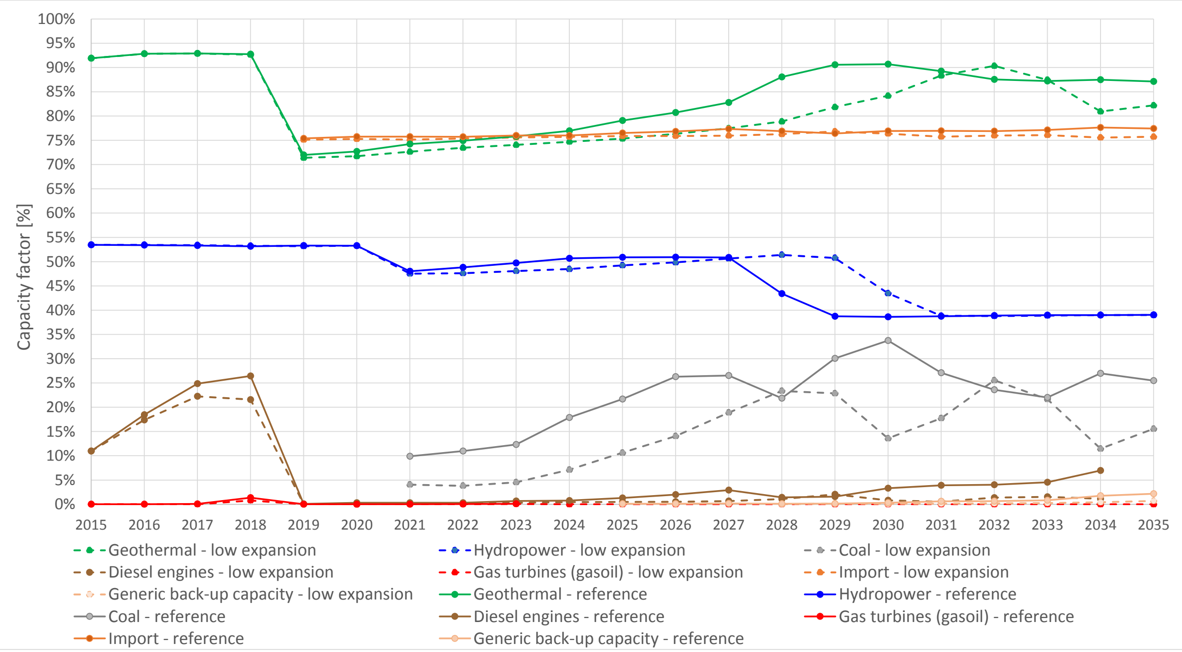

Figure 7-27: Low expansion scenario – comparison of capacity factors of dispatchable generation technologies with reference scenario

8 TRANSMISSION EXPANSION PLANNING

This chapter contains the analysis of the electrical network system in the long term, based on the results of the demand forecast and scheduled generation capacity expansion[183].

Its objective is to plan the system assets in a way that a reliable, secure and cost-effective transmission of power between generation and load centres is ensured.

8.1 Key results and conclusions

The transmission system (target network) has been planned to comply with several criteria, as summarised in the following.

Transmission system target network observing voltage and loading limits under normal (N-0) and abnormal (N-1) conditions

- The topology of the proposed target network is strong enough to cope with the growth of demand in the study period and is widely complying with the operational limits (in N-0 and N-1) as analysed in the load flow simulations.

- In the approach followed by the network analysis (load flow, short circuit), the sizing of equipment (lines, transformers) is based on the N-1 criterion, meaning for example that for double circuit lines, the ideal circuit loading condition will not exceed the 50% range of the circuit ampacity. Based on this assumption and considering a higher demand (15% increase compared to reference demand forecast), the transmission equipment proposed with the network extensions will not lead to unacceptable loadings, hence preserving the reliability of the system. In this context, the network can meet the N-1 security criteria since in case of any N-1 contingency event corresponding to the loss of any HV/MV transformer or HV overhead line the loading criteria are met. The "moderate" overloading levels observed in the contingency analysis are below 120% and are therefore considered to be resolvable either by anticipating system reinforcement projects or by activating corrective operational actions (overload under given limits is then resolved by manual de-loading measures e.g. load transfer or re-dispatching).

- All long term challenges for the network as indicated in the medium term plan (MTP network model) have been solved in the LTP target network. The identified and modelled investments in the network extension guarantee a global sustainability of the system (for instance the below described 400 kV and 220 kV rings).

[183] The generation expansion plan presented in this report considers updated information which were incorporated in the modelling. The network analysis was not part of this revision, so that the underlying assumptions in terms of generation capacity considered in the network simulations may deviate from the revised generation plan presented in chapter 7 of this report. However, in order to derive a most recent investment plan, the scheduling of transmission investments has been updated based on the revised generation expansion plan.

- The calculated technical losses of about 3.2% are in an acceptable range for a transmission network. The implementation of improvement measures to reduce losses is in particular important for the Western and Coast areas.

- There is high reactive power transfer between load centres and generation feeding points. This leads to high reactive power losses and overload of transmission equipment especially in transformers and transmission lines.

Ability to withstand short circuit currents

- The results for the three-phases and single-phase-to-ground short circuit simulation show that the short circuit currents are under the switchgears limits (40 kA and 31.5 kA), indicating that their dimensioning is suitable.

- The circuit breakers of existing substations may not all cope with this threshold. Their replacement or other short circuit mitigation measures should be considered in separate studies.

Sufficient damping (steady state stability analysis)

- The results of the small signal stability analysis confirm that the operation of the system is stable and oscillations are sufficiently damped. The eigenvalues of the state matrix of the electrical transmission system relevant to the target network have been calculated. The damping ratio of each mode of the analysis have been analysed. In all the simulated cases the real part of the eigenvalues resulted to be on the negative axis and the minimum damping ratio resulted to be not lower than 5%.

- In terms of transient analysis, the sudden disconnection of the HVDC link, with a pre-fault transfer power of about 400 MW (according to assumption in generation expansion plan, in direction Kenya) has been analysed.

  According to the transient analysis, the stability is considered verified for a sudden disconnection of the HVDC link:

  - Oscillatory trend of voltage and frequency have sufficient damping and the maximum and minimum values of the oscillations remain within the permissible limits complying with national grid code.

  - The maximum rotor angles of the synchronous generators during the transient period is about 82°, which is safely below of the limits (180°) and no out-of-step of generators is encountered.

  - The voltage at the 400 kV, 230 kV and 132 kV systems has also a stable profile, with maximum voltage variations well within the grid code requirements. A sufficient damping of oscillations is also evident in all the transient diagrams.

Expansion of the transmission system and recommendations for implementation

- Considerable expansion, reinforcement, and rehabilitation measures are required to reach the described stability of the target network which allows the stable transport of energy from the power plants to the load centres.

  - Based on the analysis necessary network expansion projects were identified to form the core network for the long term period. Depending on future electrification programs and subsequent identification of new local demand areas, additional actions on 220 kV and 132 kV levels will be necessary. The required system expansion and reinforcements needs to be individually analysed on a project-by-project level.

  - The highest rise in demand is expected for Nairobi and Western areas. Network development for transmission and distribution will continue to be of high importance in these regions as detailed in this study.

  - The expansion of the necessary power generation capacity is limited to few sites and areas in Kenya (mainly in Western and Coast area) with long distances from the areas of growing demand. Recommendations to connect the power generation with the main load centres are provided.

  - The implementation of the new 400 kV network and its extension are indispensable investments for the electrical network to be able to cope with the increasing demand. This includes the development of 400 kV and 220 kV rings: around the Nairobi Area (400 kV) and in the West Region (Western Area) at the 220 kV level. Otherwise the transmission system will experience serious loss of performance and partially collapse under the active and reactive power demand requirements.

- In order to allow for a secure operation of the transmission system in the medium and long-term and to avoid undesired impacts caused by the uncertainties of the demand growth, this plan has to be transferred into project specific implementation schedules and the development of new operational rules, based on the results of this study and operational requirements. These important steps to follow are for instance:

  - Development and implementation of the 400 kV and 220 kV rings;

  - Implementation of reinforcements as detailed in the report for improving of the system reliability (N-1 contingency criteria), partly requiring project specific analyses.

  - New design and planning standards for development and rehabilitation of the network structure in close cooperation with the power system areas' chief engineers. As outcome, main design principles and element ratings (conductor cross-sections and transformer ratings) shall be reviewed as proposed and become the foundation of the network extensions and rehabilitation measures in the coming years.

  - The transmission system must be continuously monitored and the calculations (model) continuously updated in order to make required adjustments on time and to keep up with the actual load demand and project development in the system (if different than the load forecast and generation expansion). This process could be facilitated by the annual reviews by the LCPDP team which will allow for addressing the constraints and necessary measures to a wider audience in the power sector.

8.2 Methodology, model architecture and assumptions

This section summarises the methodology applied for all network simulations conducted in the present study. It provides an overview of the underlying assumptions, input data and definitions applied in the analysis. Further details are provided in Annex 8.A.

8.2.1 Network system state and analysis for long term expansion planning

The analysis deals with the future Kenyan transmission network. Its objective is to identify suitable transmission expansion and reinforcement projects so that a reliable, secure and cost-effective transmission of power between determined generation projects and forecasted demand of the load centres is ensured.

For this the following tasks were conducted in an iterative approach:

1. A model of the future Kenyan transmission network was developed. It represents the target network for the long term period of this study. For the below described simulations the year 2030 was as agreed with the client as a key year towards the end of this planning period. The model is based on the network model for the medium term (2020). A summary of the MTP network modelling results is provided in Annex 8.A.4. Based on this network model new projects for generation and transmission (including interconnections with neighbouring countries) were added and analysed (as identified by the client and the consultant) to allow for stable
   - Evacuation of supply from generators,
   - Overall transmission through the network, and
   - Supply to the load centres.

2. For various reasons (e.g. lack of detailed data to support local load forecast) this target network model consists of the future core transmission network, i.e. mainly 400 kV and 220 kV as well as 132 kV to support the above mentioned objective. That means that not all projects from the candidates list (e.g. as defined by KETRACO) are included as they do not form part of this core network but may be needed for purposes beyond this core network. This approach highlights the importance of the listed and analysed projects within the Master Plan. It however does not provide any implications on other projects which are not listed in the PGTMP. These projects are for instance the project lists of KETRACO which formed part of the input for the analysis (where connected to the core network and not to the regional detailed expansion of the network).

3. Through simulations of the above described model of the target network the performance of the transmission network was analysed and bottleneck determined, focusing on the following aspects:

- The reliability of the network and its compliance with the system requirements: It provides an assessment about how the Kenyan transmission system would extend with the implementation of new generation power plants (as developed in the generation system expansion) and rise of load in the long term. The analysis and its results focuses on a satisfactory, sustainable and reliable power supply.
- The system behaviour and the interactions between its different parts of the core network at the high voltage level: No details at medium and low voltage levels are given since for the purpose of this study their structure was considered on an aggregated level only. Solely the elements prone to have an interaction at high voltage levels of the core network were modelled and analysed.
- The system behaviour on a static and dynamic level, i.e. load flow, short circuit studies and transient analysis, which are considered appropriate for the overall power system study.

4. The expansion plan was developed for the period up to 2030 based on the target network (consisting of the scheduling of transmission projects by power system area)[184].

Below the main methods and general assumptions are listed, which were applied for the overall approach:

The following analyses are conducted in order to detect the target network of the year 2030:

1. Load flow analysis (N-0)
2. Contingency analysis (N-1)
3. Short circuit analysis
4. Small signal stability analysis
5. Transient stability analysis (disconnection of HVDC line)

The set-up for the load flow study 2030 is defined by:

- Peak load and off-peak load demand in 2030 (reference demand forecast as per chapter 4, converted into substation[185] loads of the four power system area as per Annex 4F)

[184]For investment planning purposes, additional transmission investments which might be required after 2030 are determined based on an assessment for further needs such as for evacuation of power plants to be commissioned during the period 2031 to 2035. These additional investments are depicted in Chapter 9.
[185] The substation loads are estimates adjusted to fit the national demand forecast. They are based on actual substation loads and local load growth rates prepared by KPLC. They are complemented by load from future flagship projects and identified future substations. It is assumed that the connection of additional new load centres will follow the actual needs of the electrical distribution systems in relation to the capability of the new and existing substations. These future needs as well as underlying local load developments are not known.

- Generation projects in 2030 based on reference expansion plan (see Chapter 7)
- Network topology 2030 (network expansion):
    - New line constructions
    - New substations

The above defined set-up was then simulated in order to assess the impact of the peak load demand on the following parameters:

- Loading condition of network elements;
- Active and reactive power flow and losses;
- Voltage profile;
- Compensation requirements for the reactive power, if any.

As a result of the increasing demand and new generation projects after the medium term period, new transmission expansion projects become necessary. Reaching the limits of the transmission system at a certain loading condition level means that if a higher total load level has to be supplied in that area either the active power regime or the reactive power balance need has to be re-established by introducing other investments in the network structure. Such investments can be:

- Upgrade of existing transmission equipment (transformers);
- Additional measurements for reactive power compensation;
- New lines (single or double circuit) in the area;
- New substations for transmission and relating distribution.

This is respectively considered in the network modelling.

8.2.2 Operation criteria and network characteristics, quality and security of supply

This section summarises the main operation and planning criteria and standards for the network.

8.2.2.1 Voltage and frequency

At present, the national electrical system of Kenya operates on the transmission level with standard voltages of 66 kV, 132 kV, 220 kV and 400 kV. Furthermore, the standard voltages of 11 kV and 33 kV have been implemented in the networks scheme on the distribution levels. The nominal fundamental system frequency is 50 Hz.

The range of variation (long duration) for system voltage during normal conditions at any connection point are required to be in the limits of 95% and 105% of the nominal voltage at its root-mean-square value (RMS).

In terms of frequency, the limits are 49.5 Hz and 50.5 Hz (i.e. +/- 1% around the nominal frequency) under normal conditions. The electricity authorities foresee that system voltage and frequency are and will remain under the monitoring and control of the grid owner / system operator, i.e. KETRACO/KPLC.

8.2.2.2 Redundancy criterion (N-1)

Transmission networks have to be distinguished from distribution networks, however similarities are sometimes present, as it is the case for the following issues.

Distribution networks are typically operated in radial configuration, so that in case of a line tripping, the load is not instantaneously transferred to a neighbouring line. By this, tripping of the neighbouring line is avoided.

Transmission networks are often radial in the early years of development and are later meshed so that each line contributes to provide a redundancy path when any other line trips. This redundancy is achieved as far as the N-1 criteria is fulfilled: any single component tripping does not lead to overload another component. If not fulfilled, then a cascade of overloads would occur, possibly bringing the system to a black out[186].

The approach proposed for this study is to gradually reinforce the transmission network so that the meshed structure that will be present at the end of the planning period will enjoy the N-1 security criteria with a meshed (parallel) operation of the network, i.e. insuring redundancy on every loop in the grid, since such redundancy cannot be provided by the current radial operation.

In its present status, the transmission network is operated:

- In radial operation in areas where the N-1 could not be fulfilled;
- In meshed operation in areas where the N-1 can be fulfilled.

This operation mode can be called “hybrid” in the sense that some areas are in meshed operation, but other areas are in radial operation.

In the long term, the transmission planning criteria are the following:

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[186] In some countries, the transmission has a meshed structure but is operated in radial topology because the fulfilment of the N-1 criteria cannot be reached in meshed operation with the present levels of loads. This is partly the case of Kenya, but also Nigeria and likely several other countries in Africa.

- This situation of "hybrid operation of the network" will continue, extending the areas that can be operated in meshed operation while fulfilling the N-1 criteria.

- The transmission network is extended in the way that the generated electricity of future power plants can be evacuated through corridors that fulfil the N-1 criteria. This is usually done on the basis of double circuit lines fitted with circuits rated each at the maximum power level to be evacuated or higher.

Generally speaking:

The redundancy criterion "N-1" is targeted, but its implementation during the MTP period (2015-2020) is limited, partly because the investments would be too costly, nonetheless for the LTP period (2020 – 2035) the necessary grid extension shall be able to comply with the redundancy criterion "N-1".

As a result some areas in the transmission network topology provide redundancy and sufficient transmission capacity to avoid the loss of supply. The development of the transmission system for new projects is concentrated on the application of the N-1 redundancy criterion so that there is no loss of supply in the event of a planned or unplanned outage, hence avoiding during operation the risk of overloading any transmission circuit.

A redundancy criterion (N-1) for transmission and distribution schemes is targeted in Kenya for the long term. The N-1 redundancy criterion is particularly relevant for the evacuation of new generation projects thereby avoiding a loss of supply in case of a line outage.

8.2.2.3 Steady state stability

For this study, the system will be planned in such a way that it can adequately manage at least one of the outage conditions listed below without any load shedding or alteration in the generation at the power stations:

a) Outage of any tower in a double circuit transmission line,

b) Two circuits of 66 kV or 132 kV or 220 kV electric supply lines,

c) One circuit of 400 kV electric supply line,

d) One interconnecting transformer,

e) One largest capacity generator, or

f) One inter-connecting line with neighbouring grid,

The above contingencies shall be planned taking into account the assumption of a pre-contingency system depletion (planned outage) of another 220 kV double circuit line or 400 kV single circuit electric supply line occurs in another corridor and not from the same substation. All the generating plants shall operate within the limits defined by their reactive capability curves. Network voltage profile shall also be maintained within the specified voltage limits.

In line with the stability requirements mentioned above, the following planning criteria are applied to the analyses:

Table 8-1: Network planning criteria to meet steady state requirements

Planning criteria	Condition	Acceptable Range
System Voltage	Normal conditions (N-0)	+5% -5%
	Contingency conditions (N-1)	+10% -10%
Loading of equipment	Normal conditions (N-0)	100%
	Contingency conditions (N-1)	120%
System frequency		50 Hz
Load power factor		0.95 (targeted)

The planned range of acceptable voltage variations for each voltage level are shown Table 8-2.

Table 8-2: Voltage variations limits

Nominal system voltage kV - rms	Maximum kV - rms	Minimum kV – rms
66	72.5	60
132	145	120
220	245	200
400	420	360

It is important to note that from an operational standpoint, healthy systems usually target a set point at 105 % (420 kV) and a minimum voltage close to 100% in the bulk system.

8.2.2.4 Fault levels

The minimum design short circuit ratings[187] for the transmission network in Kenya are as follows:

- 25 kA (2,900 MVA) for 66 kV
- 31.5 kA (7,200 MVA) for 132 kV
- 40 kA (15,250 MVA) for 220 kV
- 40 kA (27,720 MVA) for 400 kV

The minimum breaking capacity for circuit breakers in any given substation is required to be no less than 120% of the maximum fault levels at the substations. The additional margin of 20% serves to manage increases in short circuit levels that are expected in the future as the system will expand.

[187] The circuit breakers of existing substations may not all cope with this threshold. Their replacement or other short circuit mitigation measures should be considered in separate studies.

8.2.2.5 Substation planning criteria

For this study, the ideal number of transformers (EHT (extra high tension) and interconnecting) required will be planned and reviewed in order to effectively manage contingencies of forced or planned outages. Once more, a 20% margin in the breaking capacity of the circuit breakers is required to handle increases in short circuit levels as the system grows.

The size and number of HT (high tension) or EHT transformers shall be adequately dimensioned so that in the event of outage of any single unit, the remaining HT or EHT transformers can still supply 80% of the load. In accomplishing said guideline and taking into consideration the connection between adjacent substations, the load exceeding the capacity of the available transformers may be transferred onto the adjacent substations, using reconfigurations in the distribution network.

Load transfer issues and planning new substations

When an existing substation is overloaded in n-1, corrective actions (load transfer, re-dispatching strategies) have to be taken into account. Considering that standardisation studies indicate that the optimal number of transformers is between two and three, the following measurements may be applied:

1. In case that less than three transformers are installed, investing a third one (reinforcement) may then solve the problem at the condition that enough space and spare feeders are available (first solution).

2. If three transformers are already installed in the substation, a new substation has to be built in the same area/state in order to supply a part of the load of the old one through lines rerouting and/or investment of new lines (second solution).

3. The replacement of low rating transformers (MVA) by adequate transformers of higher rating can be considered as an efficient way to increase the transmission capacity of overloaded transformers (third solution).

4. A fourth solution is investing new lines and/or cable re-routing between existing substations, as well as network configuration modification (switch open/close) in order to transfer some existing feeders of a substation to another existing one, allowing to reduce the load demand in the first substation (fourth solution).

New 220/132/33 kV substations are already under construction or planned for the next years. With 220 kV and 132 kV lines/cables re-routing, this corresponds to the second solution presented above.

Additionally, load transfer at 33/11 kV can be realised not only between the new 220, 132-HV/MV substations and the other existing substations (second solution), but also between existing 33/11 kV substations supplied by the new 220/132 kV substations and the other 33/11 kV ones that stay connected to existing 220/132 kV substations (third/forth solution). Such a load transfer planning can be performed without consideration of 11 kV/33 kV network constraints but by checking plausibility from available network drawings on maps. Nevertheless, 66 kV / 33 kV / 11 kV network constraints are not considered and needs to be separately analysed in close cooperation with the medium voltage operator.

The objective of load transfer is to distribute the load optimally between 220/132kV substations in case that N-1 condition occurs. The best solution is obtained when every 220/132 kV substations in the same area can afford N-1 contingency reliability up to 2030, with the minimum number of 220/132 kV transformers. The achieved solution then corresponds to the optimal distribution of the forecasted load in an area/state up to 2030 between existing and planned HV/MV substations.

8.2.2.6 Reactive compensation

With a view to meet the reactive power requirement of load, series or shunt capacitors reactive compensation shall be provided in 132 kV systems close to the load.

Switchable shunt reactors are to be provided at 400 kV substations for maintaining the voltages within the limits. The step changes should not cause a voltage variation of more than 5%. Suitable line reactors (switchable/fixed) should be provided for energising the 400 kV lines without exceeding the specified voltage limits.

8.3 Transmission expansion projects

In this section, the transmission projects proposed to be installed in the period from 2020 to 2030 are presented by power system area[188]. The selection of projects was done along the above described approach. It considers the most recent planning documents provided by KETRACO, KPLC and KenGen. In addition, further reinforcements and extensions are recommended.

For the planning approach of the target network consisting of the core network not all projects as defined by the various institutions are included:

- The network planning was done with the so called target network approach. It defines for future key years the status of the network to allow for a stable operation of this network; the overall objective so that supply can meet demand.

- For various reasons this target network consists of the future core network, i.e. mainly 400 kV and 220 kV as well as 132 kV for supporting the above mentioned objective. The lack of detailed data (e.g. to support a detailed local load forecast) is one of the reasons for this approach.

- Therefore, such projects are included in the network model and analysis which contribute to achieve this objective. That means that not all projects from the candidates list (e.g. planned

[188] As already stated in Chapter 8.2.1, the network model for the year 2030 is based on the network model 2020 (presented in the MTP report 2015-2020). For the sake of simplicity, the proposed transmission expansion and reinforcement projects of the MTP model are not repeated. Instead, the following sub-sections focus on additional transmission projects proposed to be implemented from 2020 onwards in order to cope with the forecasted demand in 2030. A summary of the MTP model is provided in Annex 8.A.3.

for) are included as they do not form part of this core network but may be needed for purposes beyond this core network.

- This approach highlights the importance of the listed and analysed projects. It however does not provide any implications on other projects which are not listed in the PGTMP. These projects are for instance the project lists of KETRACO[189] which formed part of the input for the analysis (where connected to the core network and not to the regional detailed expansion of the network).

Typically the decision and implementation of projects outside this core network is done on a project by project basis, e.g. feasibility studies which consider the detailed frame conditions of the projects which were not fully available for the overall network planning (e.g. detailed local load forecast based on a consistent data basis). The network planning results (for the core network) may complement such project focussed studies.

8.3.1 Power plant projects considered in the network analysis

The network analysis is based on the results of the principal (reference) generation expansion plan. This includes the HVDC interconnection associated with mostly base-load imports from Ethiopia. The power plants (existing, committed and candidates) planned to be available in 2030 are listed in the table below. They are sorted by power system area, type and commercial operation date. Existing plants are marked grey. Currently existing power plants not listed in the table will be decommissioned by 2030. This list already indicates that with regard to geographical distribution (with potential constraint for the network) the main generation expansion will happen in Western area. However, a large share of the geothermal expansion and the HVDC inverter station will be rather close to the main load centre and power system area Nairobi. Mt. Kenya will remain the area with by far the largest hydropower capacity and its potential to balance the system operation.

[189] An overview of transmission candidate projects defined by KETRACO is provided in Annex 8.A.4.

Table 8-3: Planned generation power capacity [190, 191]

Power plant	Type	Net capacity [MW]	COD	Power system area
Kipevu 3	MSD	115	2011	Coast
Lamu Unit 1	Coal	327	2020	Coast
Lamu Unit 2	Coal	327	2021	Coast
Lamu Unit 3	Coal	327	2022	Coast
Generic back-up units 2	GT	70	2026	Coast
Generic back-up units 4	GT	140	2029	Coast
Tana	HPP	20	1955	Mt Kenya
Kindaruma	HPP	70.5	1968	Mt Kenya
Kamburu	HPP	90	1974/1976	Mt Kenya
Gitaru	HPP	216	1978/1999	Mt Kenya
Masinga	HPP	40	1981	Mt Kenya
Kiambere	HPP	164	1988	Mt Kenya
Karura	HPP	89	2023	Mt Kenya
High Grand Falls Stage 1+2	HPP	693	2028/2029	Mt Kenya
Meru Phase I	Wind	80	2018	Mt Kenya
Athi River Gulf	MSD	80	2014	Nairobi
Thika (CC-MSD)	MSD	87	2014	Nairobi
Triumph (Kitengela)	MSD	77	2015	Nairobi
Generic back-up units 1	GT	140	2025	Nairobi
Generic back-up units 3	GT	140	2027	Nairobi
Generic back-up units 5	GT	210	2030	Nairobi
Ngong 1, Phase II, Ngong 2	Wind	20	2015	Nairobi
Kipeto - Phase I	Wind	50	2017	Nairobi
Kipeto - Phase II	Wind	50	2018	Nairobi
Turkwel	HPP	105	1991	Western
Sondo Miriu	HPP	60	2008	Western
Sang'oro	HPP	20	2012	Western
Olkaria 1 - Unit 1-3	GEO	44	1981	Western
Olkaria 3 - Unit 1-6 (OrPower4)	GEO	48	2000	Western
Olkaria 2	GEO	101	2003	Western
Olkaria 3 - Unit 7-9 (OrPower4)	GEO	62	2014	Western
Olkaria 1 - Unit 4-5	GEO	140	2014	Western
Olkaria 4	GEO	140	2014	Western

[190] The table presents the power plants as considered in the network simulation (see chapter 8.4). They are based on the results of the generation expansion plan of the earlier master plan version (please see footnote 183). However, for scheduling of transmission investments the revised generation expansion plan (presented in chapter 7 of this report) is taken into account.

[191] Required back-up capacity is represented by generic gas turbines in the generation modelling. Please see Chapter 7 for further details.

Power plant	Type	Net capacity [MW]	COD	Power system area
Orpower Wellhead 4	GEO	24	2015	Western
KenGen Olkaria Wellheads I & Eburru	GEO	54.8	2015	Western
KenGen Olkaria Wellheads II	GEO	20	2016	Western
Menengai 1 Phase I - Stage 1	GEO	103	2018	Western
Olkaria 1 - Unit 6	GEO	70	2024	Western
Olkaria 5	GEO	140	2024	Western
Menengai 2 Phase I - Stage 2	GEO	60	2025	Western
Olkaria 6	GEO	140	2025	Western
Olkaria 7	GEO	140	2026	Western
Menengai 2 Phase I - Stage 3	GEO	100	2027	Western
Eburru 2	GEO	25	2029	Western
AGIL Longonot Stage 1	GEO	70	2030	Western
Marine Power Akiira Stage 1	GEO	70	2030	Western
Baringo Silali Phase I, Stage 1	GEO	100	2030	Western
HVDC Ethiopia-Kenya interconnector	Import	400	2019	Western
Aeolus Kinangop	Wind	60	2018	Western
Lake Turkana - Phase I, Stage 1	Wind	100	2017	Western
Lake Turkana - Phase I, Stage 2	Wind	100	2018	Western
Lake Turkana - Phase I, Stage 3	Wind	100	2019	Western
Generic bagasse power plant (cogeneration) including Mumias and Kwale	Cogeneration	156	until 2030	Western and Coast
Small HPP	HPP	148	until 2030	Western and Nairobi
Generic PV power plant	PV	100	until 2030	various
Generic wind farm	Wind	150	until 2030	various

For the integration of generation from intermittent renewable energy into the power grid and the respective network simulation the following aspects have to be considered.

Intermittent renewable energy technologies provide power only when the resource is available (e. g. wind, sunlight). These resources are classified as "must-take" generators, where their output is usually used when it is available. It cannot be dispatched but curtailed if the system requires. Due to these characteristics the integration of a large amount of "must-take" generation into the grid requires special care on control and dispatch management and for the network planning:

- In the worst (or most conservative) case the system has to be capable to operate without these renewable energy sources. For the long term network expansion and the respective modelling this means that there are limitations to consider these sources as dependable supply. Since the network analysis focuses on a high reliability of generation the system is modelled without contribution of the intermittent renewable energy during peak load. This will allow the conclusion whether the network can be operated in a stable way even without these sources supporting the load.

- The system must be capable to absorb a change of generation from these volatile resources. The required control for this depends on the renewable resource being used, the detailed technology of the plant and essentially on the power system design in each area of the grid. The impact on the network topology needs to be evaluated individually on a project by project basis according to the operation characteristics and network reliability criteria at each particular site (designed component redundancy, plant control, capacity on line for transmission and distribution). This is for instance done for project feasibility.

8.3.2 Recommendations for equipment replacement and upgrade

The following proposal for equipment replacement and upgrade is based on standard design and rating provided by KETRACO. The measurements become necessary to improve the transmission capacity of the system and to overcome the overloaded cases due to the increased demand in 2030 and is thus implemented in the network model. In general it is recommended to define main design principles and element ratings as the foundation of the network extensions and rehabilitation measures.

Table 8-4: Equipment replacement/upgrade recommendation for target network model

Voltage level	Transformers	
kV	Installed equipment	Proposed equipment for 2030
400	MVA rating: 100 MVA Voltage ratio: 400/220 kV	MVA rating: 350 MVA Voltage ratio: 400/220 kV
220	MVA rating: 90 MVA Voltage ratio: 220/132 kV MVA rating: 100 MVA Voltage ratio: 220/66 kV	MVA rating: 200 MVA Voltage ratio: 220/132 kV MVA rating: 200 MVA Voltage ratio: 220/66 kV
132	MVA rating: 23 MVA Voltage ratio: 132/33 kV	MVA rating: 75 MVA Voltage ratio: 132/33 kV MVA rating: 150 MVA Voltage ratio: 132/33 kV
Voltage level	**Overhead line (OHL) conductors**	
kV	Installed equipment	Proposed equipment for 2030
132	ACSR LYNX conductor ACSR WOLF conductor	ACSR HAWK conductor ACSR CANARY conductor
220	ACSR STARLING conductor ACSR 300/50 DIN	ACSR CANARY conductor
400	ACSR 3xCONDOR conductor	ACSR 3XCONDOR conductor ACSR 3XCANARY conductor

The analysis of alternatives with multiple circuit configurations and a division of large load centres into multiple substations e.g. 220 kV/400 kV with a defined firm capacity (e.g. 2x350 MVA –

3x250 MVA) is essential and requires attention according to the characteristics at site[192]. In order to cope with the increased demand, significant investments in electrification projects across the whole country with adequate expansions of transmission and distribution capacities are required for the long term planning period.

Tower layout and trends in technology

Due to increasing difficulties in building new lines, there is a tendency to maximise the utilisation of the existing lines using new technologies and advanced methods of maintenance engineering.

Moreover, an optimum design can minimise or reduce the impact of overhead lines on the environment and can ensure a maximum reliability in the face of meteorological events.

Thus, the future technical specifications for the planned overhead line shall include the loadings for which a line has to be designed, above-ground clearances, the performance of towers/poles, foundations and fittings. An overview of potential tower silhouettes is provided in Annex 8.E.

Additional proposed network upgrade, extensions and modifications 2030

The proposed measures are stated under following conditions to be observed:

- The proposed investments for network upgrade, extension and modification are the result of a conceptual network study. Consequently, all investments must be subjected to a more detailed verification and equipment data specification. The specific conditions at site must be checked (e.g. rating of parallel transformer, tap changer range and control, switchgear short-circuit rating, nominal currents of existing bays and CTs, especially if existing transformer are replaced by larger sizes, station supply demands, in case of substation extension: space requirements, switchgear extension works). The final design to be specified and implemented must be adjusted accordingly.

- Further on, remote end modifications, telecommunication & signalling requirements have to be taken into consideration.

After implementing the investments up to the year 2030, the transmission system shows reliable conditions in terms of loading of network elements. All extreme cases of overload endangering the supply reliability are consequently eliminated by implementing the proposed transmission expansion and reinforcement projects. The element loading under (N-1) outage condition is generally reduced to moderate levels which can be resolved gradually step by step by system reinforcement projects.

[192] A more detailed verification and analysis by substation and equipment data specification is required. The specific conditions at site must be monitored (e.g. rating of parallel transformer, tap changer range and control, switchgear short-circuit rating, nominal currents of existing bays and CTs, especially if existing transformer are replaced by larger sizes, station supply demands, in case of substation extension: space requirements, switchgear extension works). The final design to be specified and implemented must be adjusted accordingly.

8.3.3 Nairobi area

The following tables list transmission projects for the Nairobi area planned to be implemented in the period 2021 to 2030 (transmission projects expected to be commissioned during the MTP period until 2020 are listed in Annex 8.A.3).

Table 8-5: New transmission lines in Nairobi area until 2030

#	Project	from	to	Topology	Length km	COD[193]
1	Lne 400 ISINYA - KONZA	BB 400 ISINYA (PSS/E 1403)	BB 400 KONZA (LTP)	2x(3XCONDOR)-400kV-2.4kA	45	2025
2	Lne 132 DANDORA - JUJA	BB 220 DANDORA (PSS/E 1221)	BB 132 JUJA RD (PSS/E 1117)	1XCANARY_132kV_0.72kA	2	2025
3	Lne 400 NBEAST - THIKA	BB 400 THIKA (LTP)	BB 400 NBEAST (LTP)	2x(3XCONDOR)-400kV-2.4kA	35	2025
4	Lne 400 NBEAST-KONZA	BB 400 NBEAST (LTP)	BB 400 KONZA ICT (LTP)	2x(3XCONDOR)-400kV-2.4kA	52	2027
5	Lne 220 THIKA - MANGU	BB 220 MANGU (LTP)	BB 220 THIKA RD(PSS/E 1282)	2XCANARY_220kV_0.72kA	10	2026
6	Lne 220 NBNORTH - LONGONOT	BB 220 NBNORTH (PSS/E 1224)	BB 220 LONGONOT (LTP)	2XCANARY_220kV_0.72kA	50	2027
7	Lne 132 RUARAKA - RUARAKA	BB 132 RUARAKA TEE (PSS/E 1150)	BB 132 RUARAKA (PSS/E1151)	1XCANARY_132kV_0.72kA	1.5	2027
8	Lne 400 THIKA - GILGIL	BB 400 THIKA (LTP)	BB 400 GILGIL (LTP)	2x(3XCONDOR)-400kV-2.4kA	85	2027
9	Lne 132 THIKA - RUARAKA TEE	BB 132 THIKA (PSS/E 11160)	BB 132 RUARAKA TEE (PSS/E 1150)	1XCANARY_132kV_0.72kA	30	2026

Table 8-6: New transformers in Nairobi area until 2030

	Project	No. of TR / Rated Capacity	Connected		COD[193]
#	Name	MVA	from	to	
1	TR KONZA 400/220 kV	2x350	BB 400 KONZA (LTP)	BB 220 KONZA (LTP)	2025
2	TR KONZA 220/132 kV	2x200	BB 220 KONZA (LTP)	BB 132 KONZA (LTP)	2025
3	TR DANDORA 132/11 kV	2x75	BB 132 DANDORA (PSS/E 1121)	BB 11 1DAND11 (PSS/E 1921)	2025
4	TR KAJIADO 132/33 kV	2x75	BB 132 KAJIADO (PSS/E 1170)	BB 33 KAJIADO (PSS/E 1395)	2026
5	TR MATASIA 220/66 kV	2x100	BB 220 MATASIA (PSS/E 1204)	BB 66 MATASIA BSP (PSS/E 1756)	2026
6	TR MACHAKOS 132/33 kV	1x75	BB 132 MACHAKOS (PSS/E 1192)	BB 33 MACHAKOS (PSS/E 1394)	2026
7	TR NBEAST 400/220	2x350	BB 400 NBEAST (LTP)	BB 220 NBEAST (LTP)	2025
8	TR THIKA RD 400/220	2x350	BB 400 THIKA (LTP)	BB 220 THIKA RD (PSS/E 1282)	2025

[193] Please note that the presented CODs are only indicative and shall be considered as qualitative estimates.

Project		No. of TR / Rated Capacity	Connected		COD[193]
#	Name	MVA	from	to	
9	TR RUARAKA 132/66 kV	2x120	BB 132 RUARAKA (PSS/E 1151)	BB 66 RUARAKA (PSS/E 1601)	2026
10	TR MANGU 220/132	2x200	BB 220 MANGU (LTP)	BB 132 MANGU (PSS/E 1116)	2026
11	TR KOMOROCK 220/66 kV	2x200	BB 220 KOMOROCK (PSS/E 1222)	BB 66 KOMOROCK (PSS/E 1703)	2027
12	TR MANGU 132/66 kV	2x120	BB 132 MANGU (LTP)	BB 66 MANGU1 (PSS/E 1673)	2024
13	TR THIKA 220/132 kV	2x150	BB 132 THIKA (PSS/E 11160)	BB 132 THIKA (PSS/E 11160)	2026

The development and implementation of the high-voltage transmission ring around the Nairobi area at 400 kV level is one essential action during the analysed period. The implementation of four new substations to 400 kV/220 kV voltage level is indispensable; the development of the 400 kV ring foresees the construction of the new 400/220 kV S/S Nairobi East, Thika S/S, Gilgil S/S and Konza ICT S/S. Complementary, the 400 kV double circuit line connections between S/S Isinya - S/S Konza and the 400 kV double circuit connecting the new 400 kV S/S Nairobi East with the 400 kV S/S Konza ICT will support the reliability of the Nairobi region, especially with the direct supply of the load increase linked with the development of the Techno City in Konza. The new 400 kV circuits supports the de-loading of several transmission lines at the 132 kV level like the connections adjacent to the S/S Juja, S/S Juja Rd., S/S Dandora, S/S Thika keeping the voltage within its permissible voltage range. With the implementation of the 400 kV double circuit connecting the S/S Nairobi East with the S/S Konza ICT, the reliability for the 400 kV system increase considerably providing security to the Nairobi area in case of disconnection of the 400 kV connection Suswa – Isinya.

The installed transformer capacity for the S/S Dandora, S/S Ruaraka, S/S Kajiado and S/S Machakos on 132 kV level cannot afford the foreseen load increase in the region. Similarly, S/S Matasia (220 kV level) needs a reinforcement /replacement of transformer-capacity. The proposed transformer capacity is provided in the list of future projects here above.

The foreseen realisation of the new hydropower plant High Grand Falls in the Mount Kenya area with an approx. nominal power of 500 MW (first stage) requires the extension of the 400 kV network in order to provide the necessary reliability of power supply of this power plant. The proposed implementation of the new corridor connecting directly the new 400 kV Thika S/S and the 400 kV High Grand Falls power plant will provide the required security and reliability.

The main power bulk supply for Nairobi area will be supported with the direct connection from 400 kV S/S Thika with the 400 kV S/S Nairobi East as well as the power supply from the Central Rift region to Nairobi trough the new 400 kV double circuit S/S Gilgil – S/S Thika.

The implementation of the new 220/132 kV S/S Mangu increases the access und improves the connectivity in the Nairobi north region supporting the de-loading of the 220/132 kV transformer capacity at Dandora S/S as well as the 132 kV corridors like Dandora – Juja Road, Ulu– Juja Rd., Juja Rd. – Mangu.

8.3.4 Coast area

The following tables list transmission projects for the Coast area planned to be implemented in the period 2021 to 2030 (transmission projects expected to be commissioned during the MTP period until 2020 are listed in Annex 8.A.3).

Table 8-7: New transmission lines in Coast area until 2030

#	Project Name	from	to	Topology	Length km	COD[193]
1	Lne 220 LAMU - GARSEN	BB 220 GARSEN (PSS/E 1255)	BB 220 LAMU (PSS/E 1256)	1XOHL\300/50-RMGL_220kV_0.62kA.	108	2025
2	Lne 132 RABAI - MARIAKANI	BB 132 RABAI (PSS/E 1126)	BB 132 MARIAKANI (PSS/E 1148)	1XCANARY_132kV_0.72kA	21	2024
3	Lne 220 GARSEN - MALINDI	BB 220 MALINDI (PSS/E 1254)	BB 220 GARSEN (PSS/E 1255)	1XCANARY_220kV_0.72kA	117	2025
4	Lne 132 MALINDI - KILIFI	BB 132 MALINDI (LTP)	BB 132 KILIFI (PSS/E 1134)	1XCANARY_132kV_0.72kA	50	2026
5	Lne 132 MALINDI - BAMBURI	BB 132 MALINDI (LTP)	BB 132 BAMBURI (PSS/E 1136)	1XCANARY_132kV_0.72kA	105	2026
6	Lne 220 RABAI - MARIAKANI	BB 220 RABAI (PSS/E 1226)	BB 220 MARIAKANI (PSS/E 1250)	2XCANARY_220kV_0.72kA	24	2026

Table 8-8: New transformers in Coast area until 2030

#	Project Name	No. of TR / Rated Capacity MVA	Connected at from	to	COD[193]
1	TR RABAI 220/132 200MVA (N3,N4)	2x200	BB 220 RABAI (PSS/E 1226)	BB 132 RABAITRF (PSS/E 1727)	2024
2	TR MARIAKANI 400/220 kV	2x200	BB 400 MARIAKANI (PSS/E 1401)	BB 220 MARIAKANI (PSS/E 1250)	2026
3	TR LAMU 220/33 kV	2x75	BB 220 LAMU (PSS/E 1256)	BB 33 LAMU (PSS/E 1380)	2025
4	TR GALU 132/33 kV	2x75	BB 132 GALU (PSS/E 1156)	BB 33 GALU (PSS/E 1346)	2024
5	TR BAMBURI 132/33 kV	2x75	BB 132 BAMBURI (PSS/E 1136)	BB 33 BAMBURI (PSS/E 1364)	2026
6	TR MALINDI 220/132kV	2x150	BB 220 MALINDI (PSS/E 1254)	BB 132 MALINDI (LTP)	2025
7	TR KILIFI 132/33 kV	2x75	BB 132 KILIFI (PSS/E 1134)	BB 33 KILIFI (PSS/E 1345)	2026
8	TR LAMU 400/220 kV	1x350	BB 400 LAMU CPP	BB 220 LAMU (PSS/E 1256)	2027

The regional increase of power demand requires the reinforcement of the transformer capacity at the existing S/S Rabai and S/S Mariakani at the 132 kV, 220 kV and 400 kV levels in order to guarantee the N-1 compliance and consequently the reliability of power supply in the Coast area.

Several preliminary simulations and analyses have been conducted in order to improve the performance and voltage sustainability of the region including the 132 kV substations Mariakani S/S, Samburu S/S, Voi S/S, Mtito Andei S/S, Taveta S/S, Loitokitok S/S. The planned single circuit from 132 kV S/S Rabai to 132 kV Mariakani leads to de-loading of the 132 kV circuits Rabai-Kokotoni and Kokotoni – Mariakani. Additionally, the reliability (N-1) is improved.

The single circuit at 220 kV level connecting the S/S Lamu and S/S Garsen needs to be reinforced in order to reduce the loading condition of this circuit and to improve the reliability of this connection foresees to supply the south part of the Coast region. The second circuit 220 kV Lamu-Garsen with 108 km is planned to be implemented for the LTP strengthening the direct corridor for power supply for the counties Tana River, Kilifi and Mombasa from the Lamu coal power plant.

Special care is needed in relation to the county Kilifi which is considerably growing in terms of power demand. As a result, the 132 kV S/S Kilifi and 132 kV S/S Bamburi need to be supplied in an improved and reliable way. The existing connections outgoing from the 132 kV S/S Rabai are high loaded in terms of its electrical ampacity. Resolute reinforcement actions are needed. For this reason, a new corridor has been created in order to cope with the electricity demand at the Coast area. The corridor foresees the direct connection at the new 132 kV voltage level at S/S Malindi (now as a S/S 220/132/33 kV) with the S/S Kilifi, and with a second corridor from the S/S Malindi to the S/S Bamburi likewise on 132 kV level. On this manner the reliability at the Coast area can be reached.

8.3.5 Mt Kenya area

The following tables list transmission projects for the Mt. Kenya area planned to be implemented in the period 2021 to 2030 (transmission projects expected to be commissioned during the MTP period until 2020 are listed in Annex 8.A.3).

Table 8-9: New transmission lines in Mt Kenya area until 2030

	Project	from	to	Topology	Length	COD[193]
#	Name				km	
1	Lne 400 HGFALLS - THIKA	BB 400 HGFALLS (LTP)	BB 400 THIKA (LTP)	2x(3XCONDOR)-400kV-2.4kA	200	2027
2	Lne 220 KARURA HPP - KIAMBERE	BB 220 KIAMBERE (PSS/E 1205)	BB 220 KARURA HPP (LTP)	2XCANARY_220kV_0.72kA	20	2024
3	Lne 220 HGFALLS - KAMBURU	BB 220 KAMBURU (PSS/E 1203)	BB 220 HGFALLS HPP (LTP)	2XCANARY_220kV_0.72kA	35	2027
4	Lne 220 KAMBURU - KIGANJO	BB 220 KAMBURU (PSS/E 1203)	BB 220 KIGANJO (LTP)	2XCANARY_220kV_0.72kA	100	2026
5	Lne 132 KAMBURU - MERU	BB 132 KAMBURU (PSS/E 1103)	BB 132 MERU (PSS/E 1163)	1XCANARY_132kV_0.72kA	130	2027

	Project	from	to	Topology	Length	COD[193]
#	Name				km	
6	Lne 132 KAMBURU - KUTUS	BB 132 KAMBU-RU (PSS/E 1103)	BB 132 KUTUS (PSS/E 1162)	1XCANARY_132kV_0.72kA	70	2024
7	Lne 132 KIGANJO - NANYUKI	BB 132 KIGANJO (PSS/E 1132)	BB 132 NANYUKI (PSS/E 1133)	1XCANARY_132kV_0.72kA	51.5	2025

Table 8-10: New transformers in Mt Kenya area until 2030

	Project	No. of TR / Rated capacity	Connected at		COD[193]
#	Name	MVA	from	to	
1	TR HGFALLS 400/220	2x350	BB 400 HGFALLS (LTP)	BB 220 HGFALLS HPP (LTP)	2027
2	TR KIGANJO 132/33 kV	2x150	BB 132 KIGANJO (PSS/E 1132)	BB 33 KIGA33 (PSS/E 1352)	2025
3	TR KIGANJO 220/132	2x150	BB 220 KIGANJO (LTP)	BB 132 KIGANJO (PSS/E 1132)	2026
4	TR GITHAMBO 132/33 kV	1x75	BB 132 GITHAMBO (PSS/E 1182)	BB 33 GITHAMBO (PSS/E 1357)	2026
5	TR KUTUS 132/33 kV	2x75	BB 132 KUTUS (PSS/E 1162)	BB 33 KUTUS (PSS/E 1392)	2024
6	TR KYENI 132/33 kV	1x75	BB 132 KYENI (PSS/E 1158)	BB 33 KYENI (PSS/E 1389)	2026
7	TR NANYUKI 132/33 kV	1x75	BB 132 NANYUKI (PSS/E 1133)	BB 33 NANYU33 (PSS/E 1353)	2026

According to the generation expansion plan new hydropower plants will be erected in the Mount Kenya area with an overall installed capacity of nearly 800 MW (namely High Grand Falls stage 1 and 2 as well as Karura). The extension of the 220 kV network foreseen for the connection of the new hydropower plant High Grand Falls (new double circuit between the 220 kV High Grand Falls power plant and the 220 kV S/S Kamburu) ensures secure power supply of the Mount-Kenya area. In order to provide a reliable transport of electricity from the Mount Kenya area to the Nairobi region, the implementation of the new corridor connecting directly the new 400 kV Thika S/S and the 400 kV High Grand Falls power plant is recommended.

The implementation and grid connection of the new hydropower plant Karura has been planned with a direct connection through the new double circuit between the 220 kV Karura and the 220 kV S/S Kiambere. By this, the bulk power supply will flow to Nairobi area and the Coast area through the existing connection between Kiambere S/S and the 220 kV Rabai S/S respectively.

The implementation of the new 220/132 kV S/S Kiganjo increases access und the connectivity in the region supporting the de-loading of the 132 kV corridors like Kamburu – Masinga, Masinga – Kutus, Kiganjo – Nanyuki and providing a better permissible range for the 132 kV level. A new line connection 132 kV Kamburu - Kutus with a distance of approx. 70 km is needed in order to de-load and provide reliability for the existing 132 kV Masinga – Kutus S/S.

The installed transformer capacity for the S/S Ghitambu, S/S Kutus, S/S Nanyuki and S/S Kyeni at the 132 kV level cannot afford the foreseen load increase in the region. The listed points for transmission and distribution of power supply in this area need a reinforcement of transformer-capacity, the planned transformer capacity is illustrated in the list of future projects here above.

8.3.6 Western area

The following tables list transmission projects planned to be implemented in the period 2020 to 2030 for the Western area which comprises the Central Rift -, North Rift - and West regions (transmission projects expected to be commissioned during the MTP period until 2020 are listed in Annex 8.A.3).

Table 8-11: New transmission lines in the Western area until 2030

	Project	Sub-Region	from	to	Topology	Length	COD[193]
#	Name					km	
1	Lne 220 MENENGAI II - LESSOS	N Rift	BB 220 LESSOS (PSS/E 1240)	BB 220 MENENGAI II (LTP)	2XCANARY_220kV_0.72kA	110	2024
2	Lne 132 LESSOS - LESSTRF	N Rift	BB 132 LESSOS (PSS/E 1140)	BB 132 LESSTRF (PSS/E 1740)	2XCANARY_132kV_0.72kA	1	2027
3	Lne 220 LESSOS - ELDORET	N Rift	BB 220 LESSOS (PSS/E 1240)	BB 220 ELDORET (LTP)	2XCANARY_220kV_0.72kA	30	2026
4	Lne 220 ELDORET – BARINGO GEO	N Rift	BB 220 ELDORET (LTP)	BB 220 BARINGO GEO (LTP)	2XCANARY_220kV_0.72kA	95	2030
5	Lne 220 BARINGO GEO – KIGANJO	N Rift	BB 220 BARINGO GEO (LTP)	BB 220 KIGANJO (LTP)	2XCANARY_220kV_0.72kA	150	2030
6	Lne 220 GILGIL - MENENGAI II	C Rift	BB 220 GILGIL (LTP)	BB 220 MENENGAI II (LTP)	2XCANARY_220kV_0.72kA	50	2028
7	Lne 132 NAIVASHA - OLKARIA I	C Rift	BB 132 OLKARIA 1 (PSS/E 1108)	BB 132 NAIVASHA (PSS/E 1142)	1XCANARY_132kV_0.72kA	23	2024
8	Lne 220 LONGONOT - NAROK	C Rift	BB 220 LONGONOT (LTP)	BB 220 NAROK (LTP)	2XCANARY_220kV_0.72kA	25	2027
9	Lne 220 OLKARIA IV - LONGONOT	C Rift	BB 220 OLKARIA IV (PSS/E 1243)	BB 220 LONGONOT (LTP)	2XCANARY_220kV_0.72kA	75	2029
10	Lne 220 THIKA - GILGIL	W Region	BB 220 THIKA RD (PSS/E 1282)	BB 220 GILGIL (LTP)	2XCANARY_220kV_0.72kA	120	2028
11	Lne 220 MENENGAI II - KISII	W Region	BB 220 KISII (LTP)	BB 220 MENENGAI II (LTP)	2XCANARY_220kV_0.72kA	150	2025
12	Lne 132 MENENGAI - CHEMOSIT	W Region	BB 132 CHEMOSIT (PSS/E 1130)	BB 132MENENGAI	1XCANARY_132kV_0.72kA	105	2026
13	Lne 220 KISII - NAROK	W Region	BB 220 NAROK (LTP)	BB 220 KISII (LTP)	2XCANARY_220kV_0.72kA	140	2027
14	Lne 220 KISUMU - KISII	W Region	BB 220 KISII (LTP)	BB 220 KISUMU (PSS/E 1288)	2XCANARY_220kV_0.72kA	80	2027
15	Lne 132 ELDORET - MUSAGA	W Region	BB 132 ELDORET (PSS/E 1127)	BB 132 MUSAGA (PSS/E 1139)	1XCANARY_132kV_0.72kA	65	2027
16	Lne 132 SOTIK - KILGORIS	W Region	BB 132 SOTIK (PSS/E 1173)	BB 132 KILGORIS (LTP)	1XCANARY_132kV_0.72kA	48	2027
	Lne 132 MUSAGA - RANGALA	W Region	BB 132 RANGALA (PSS/E 1178)	BB 132 MUSAGA (PSS/E 1139)	1XCANARY_132kV_0.72kA	60	2027

	Project	Sub-Region	from	to	Topology	Length	COD[193]
#	Name					km	
	Lne 132 KISII - HOMABAY	W Region	BB 132 HOMABAY (PSS/E 1194)	BB 132 KISII (PSS/E 1167)	1XCANARY_132kV_0.72kA	35	2027

Table 8-12: New transformers in Western area until 2030

	Project		No. of TR / Rated Capacity	Connected at		COD[193]
#	Name	Area	MVA	from	to	
1	TR ELDORET 220/132 kV	N Rift	2x150	BB 220 ELDORET (LTP)	BB 132 ELDORET (PSS/E 1127)	2030
2	TR ELDORET 132/33 kV(1)	N Rift	2x150	BB 132 ELDORET (PSS/E 1127)	BB 33 ELD33 (PSS/E 1328)	2026
3	TR KITALE 132/33 kV	N Rift	1x75	BB 132 KITALE (PSS/E 1179)	BB 33 KITALE (PSS/E 1382)	2026
4	TR BARINGO 220/11 kV	N Rift	2x180	BB 220 BARINGO GEO (LTP)	BB 220 BARINGO GEO (LTP)	2030
5	TR LANET 132/33 kV	C Rift	2x150	BB 132 LANET (PSS/E 1141)	BB 33 LANET33 (PSS/E 1341)	2026
6	TR NAKURU 132/33 kV	C Rift	2x75	BB 132 NAKURU WEST (PSS/E 1172)	BB 33 NAKURU WEST (PSS/E 1359)	2026
7	TR NAIVASHA 132/33 kV	C Rift	2x75	BB 132 NAIVASHA (PSS/E 1142)	BB 33 NAIVA33 (PSS/E 1343)	2024
8	TR GILGIL 220/132 kV	C Rift	2x150	BB 220 GILGIL (LTP)	BB 132 GILGIL (LTP)	2028
9	TR LONGONOT 220/11 kV	C Rift	2x90	BB 220 LONGONOT (LTP)	BB 220 LONGONOT (LTP)	2027
10	TR MENENGAI II 220/11 kV	C Rift	2x180	BB 220 MENENGAI (LTP)	BB 220 MENENGAI (LTP)	2024
11	TR KISUMU 220/132 kV	W Kenya	2x200	BB 220 KISUMU (PSS/E 1288)	BB 132 KISUMU (PSS/E 1129)	2027
12	TR KISUMU 132/33 kV	W Kenya	2x200	BB 132 KISUMU (PSS/E 1129)	BB 33 KISU33 (PSS/E 1329)	2026
13	TR LESSOS 132/33 kV	W Kenya	2x75	BB 132 LESSOS (PSS/E 1140)	BB 33 LESSO33 (PSS/E 1340)	2026
14	TR KISII 132/33 kV	W Kenya	2x150	BB 132 KISII (PSS/E 1167)	BB 33 KISII33 (PSS/E 1356)	2027
15	TR KISII 220/132 kV	W Kenya	2x150	BB 220 KISII (LTP)	BB 132 KISII (PSS/E 1167)	2027
16	TR CHEMOSIT 132/33 kV	W Kenya	2x100	BB 132 CHEMOSIT (PSS/E 1130)	BB 33 CHEMO33 (PSS/E 1350)	2026
17	TR MUSAGA 132/33 kV	W Kenya	2x75	BB 132 MUSAGA (PSS/E 1139)	BB 33 MUSAGA (PSS/E 1339)	2027
18	TR RANGALA 132/33 kV	W Kenya	1x75	BB 132 RANGALA (PSS/E 1178)	BB 33 RANGALA (PSS/E 1376)	2027
19	TR MUHORONI 132/33 kV	W Kenya	2x75	BB 132 MUHORONI (PSS/E 1128)	BB 33 MUHORONI (PSS/E 1375)	2026
20	TR BOMET 132/33 kV	W Kenya	1x75	BB 132 BOMET (PSS/E 1164)	BB 33 BOMET (PSS/E 1386)	2027

	Project		No. of TR / Rated Capacity	Connected at		COD[193]
#	Name	Area	MVA	from	to	
21	TR KILGORIS 132/33 kV	W Kenya	1x75	BB 132 KILGORIS (LTP)	BB 33 KILGORIS (LTP)	2027
22	TR NAROK 220/132 kV	W Kenya	2x150	BB 220 NAROK (LTP)	BB 132 NAROK (PSS/E 1185)	2027

Until 2031, 100 MW geothermal capacity will be commissioned in the Baringo field. The generation capacity requires the extension of the 220 kV system in the Western area. The implementation of the new S/S 220 kV Baringo is crucial in terms of power evacuation. Taking into account that further stages of the Baringo geothermal field may be commissioned after 2030, the future upgrade of the S/S Baringo to 400 kV is recommended. By this, the development and implementation of the 400 kV high-voltage transmission network in Kenya may be supported.

Reciprocally to the grid connection of the power plants in the Baringo geothermal field, the grid connection of the capacity extensions in the Menengai and Olkaria geothermal fields require the implementation of the new 220 kV S/S Menengai II (point for power evacuation for the new geothermal power plant Menengai II), S/S Longonot and S/S Narok. With the implementation of these new 220 kV S/S the reliability of power evacuation can be secured providing a considerable support in terms of voltage criterion and balance of reactive power in the northern part of the Western area. By the year 2035, the amount of installed power on this exemplary site is expected to further increase. As a result, based on long-term horizons view, the future upgrade of the S/S Menengai II to 400 kV is strongly recommended.

Upon the necessary installation/and commissioning of additional transmission and distribution substations in the Western area, especially in the West region, the supply of local demand through transmission from the North Rift and Central Rift regions will be necessary. This estimated transmission reaches almost 80% of its total load demand (West region). This includes the implementation of at least three new (also upgrade from 132 kV) substations 220/132/33 kV with sufficient transmission capacity to support the remaining 220 kV supply-corridors and especially to cope with the local rise of load demand in the Western region. The new S/S 220/132/33kV Eldoret, S/S 220/132kV Kissii and S/S 220/132 kV Narok are required and will primarily supply the growth of local load demand in the Western region, providing a considerable support in terms of voltage criterion and de-loading of several 132 kV corridors as for Lessos – Kitale.

The extension of the 220 kV grid for power transmission and evacuation is crucial. Two new corridors need to be realised through the direct connection of the new substation Menengai-II- with the substation Kisii [194](new 220 kV S/S by 2030) with an approx. distance of 150 km. The new S/S Kisii 220/132 kV has been planned to have a direct connection with the new 220 kV S/S Menengai-II point for power evacuation for the new geothermal capacity in the Menengai field. This direct connection increases considerably the reliability of the Western area system. It further provides the

[194] The direct connection 220 kV Line Menengai II – Kisii shows a better option in terms of distances and technical aspects (e.g. elec. losses) in comparison to the previous planned 220 kV line Rongai – Kilgoris.

basis for forthcoming electrifications projects in the Counties Homa Bay, Migori, Siaya with the electrification of prospective load centres e.g. Bondo, Sindo, Karungo Bay.

In order to support and secure the connectivity to the Kenya counties Narok, Bomet Kisii a new 220 kV corridor is proposed. This 220 kV corridor bonds the new 220 kV S/S Longonot in a direct way with the 220kV S/S Narok. The prolongation of the corridor foresees the connection of Narok S/S with the new 220 kV S/S Kisii closing the ring with the connection of Kisii with the existing 220 kV S/S Kisumu.

The 220 kV ring in the Western region is proposed to be completed with the new connection 220 kV Lessos – Eldoret with approx. 30 km. This new corridor improves the reliability in the region and provides a better connectivity of several 132 kV substations like S/S Muhoroni, S/S Musaga, S/S Chemosit.

The new S/S 220 kV Longonot is foreseen as the point of connection for the future geothermal power plants Agil and Marine Power. The evacuation of generated power will be realised through new 220 kV double circuits connecting S/S Longonot with the S/S Nairobi North (with a distance of approx. 50 km).

Furthermore, the 132 kV System in the Western area requires the realisation of transmission lines projects like:

- The new line 132 kV Menengai – Chemosit with approx. 105 km which is needed to de-load the existing 132 kV circuits Lessos –Muhoroni and Muhoroni – Chemosit.

- The Naivasha – Olkaria I 132 kV line which is required to provide reliability and support for power evacuation in Olkaria to Naivasha S/S.

The new 220 kV line connection between S/S Olkaria IV and the new S/S Longonot provides a much better reliability and security in relation to power evacuation of Olkaria IV and Olkaria V with the OW 914/915/905 Wellheads.

8.3.7 Reactive power projects

New capacitive/inductive shunt, banks are necessary to appease the reactive power demand in the Nairobi and Western area. Reactors will be required for the 400 kV circuits to prevent over-voltages during energising. Transmission lines and transformers demand reactive power to support their magnetic fields which is dependent on the magnitude of the current flow in the line and the line's natural inductive reactance (X_L). Additional actions need to be taken into account to establish a balance of reactive power flow of the foreseen grid expansion according to its implementation schedule. On these terms, a more detailed verification and analysis by substation and equipment data specification is required. The specific conditions at site must be monitored. The final design to be specified and implemented must be adjusted accordingly. The following table provides an overview of the proposed reactive power compensation facilities in the country including years of plant commissioning as well as installed and available capacity parameters.

Table 8-13: Reactive power compensation projects until 2030

Name	Voltage[195] kV	Area	Fixed Compensation Mvar	Cap. /React.	COD[196] Year
KAJIADO	33	Nairobi	12 (3X4)	Capacitor	2025
VOI	132	Coast	60 (4X15)	Capacitor	2024
KILIFI	33	Coast	24(3X8)	Capacitor	2024
LUNGA	33	Coast	24(3X8)	Capacitor	2026
MERU	132	MT Kenya	40(4X10)	Capacitor	2026
LESSOS	220	N Rift	60 (3x20)	Reactor	2026
NAROK	220	N Rift	60 (3x20)	Reactor	2026
KITALE	33	C Rift	24(3X8)	Capacitor	2026
GILGIL	220	C Rift	60 (3x20)	Reactor	2027
RUMURUTI	132	C Rift	60 (3x20)	Reactor	2027
CHEMOSIT	33	W Kenya	12(3X4)	Capacitor	2025
RANGALA	33	W Kenya	24(3X8)	Capacitor	2026
MUSAGA	33	W Kenya	24(3X8)	Capacitor	2026
MUHORONI	33	W Kenya	24(3X8)	Capacitor	2027
KISUMU	220	W Kenya	40(4X10)	Capacitor	2027
KAJIADO	33	Nairobi	12 (3X4)	Capacitor	2025

Annual reviews of the existing transmission system and the implementation status of new investments are essential in order to ensure reliable, secure and cost-effective power transfer. These reviews shall also outline any changes of economic environment dynamics such evolving county development plans, government projects and other primordial aspects which provides essential information for all involved institutions. This process could be facilitated by the annual reviews by the LCPDP team which will allow for addressing the constraints and necessary measures to a wider audience in the power sector.

[195] Note that the given medium voltage level can be considered as indicative, generally the proposed compensation is foreseen to be installed at the 132 kV and 220 kV level.
[196] Please note that the presented CODs are only indicative and shall be considered as qualitative estimates.

8.4 Network analysis for the long term (2030)

The following section presents the results of the conducted transmission system analyses for the long term plan. The main outcome of the analyses is the identification and description of suitable transmission projects and additional implementation of mitigation measures to cope with the forecasted demand, as listed in the previous section.

In the first sub section the results of the load flow analysis are presented. The proposed topology of the transmission network in 2030 is provided in the list of substations and single line diagram in Annex 8.B and Annex 8.C respectively.

The results of the load flow calculations for the proposed topology of the transmission network in 2030 – are shown in the load flow reports in the Annex 8.D. Short circuit calculations are presented in tabulated form and attached in Annex 8.G and Annex 8.H.

8.4.1 Load flow analysis

In the following section, the results of the load flow analyses for the year 2030 are presented.

The results can be summarised as follows:

- The net[197] technical losses are around 3.2%. This is an acceptable range for a transmission network. The Western[198] and Coast areas show a prospective increase of losses due to the extension in the transmission network (especially long distance connections between new generation sites in the Mount Kenya and Central Rift areas and the main load centres like Nairobi and Coast).
- Considering implementation of the additionally proposed transmission projects and reinforcement measures up to the year 2030, the transmission system is able to cope with the demand. Only moderate overload conditions of few network elements are present and these are considered as not critical, because they still comply the planning criteria. All critical and extreme cases of overload, endangering the system reliability are mitigated by the implementation of necessary measures. These measures are illustrated in Chapter 8.3.
- As mentioned above, the approach applied for the expansion period until 2030, is focusing on the planned and necessary changes on the network's topology. The expansion analyses show that the main changes and electrical infrastructure's developments will be concentrated in three areas
  - Coast Area (comprising the counties Lamu, Tana River, Kilifi, Kwale),
  - Nairobi Area,
  - Western Area (comprising the counties Narok, Bomet, Homa Bay, Kisumu, Siaya).

[197] The net technical losses (active power) are based on the net produced power excluding power production for power plants consumption.
[198] The Western Area includes the Central Rift, North Rift and West Kenya regions

- The transmission capability of the Coast, Western and Nairobi areas sets the focus of the necessary grid expansion in order to cope with expected growth in electricity demand. The demand development in these areas requires resolute actions in the long term. Therefore the expansion plan for the analysed period focuses on the development/implementation of the high-voltage transmission ring 220 kV / 400 kV in the mentioned areas.

The following tables display a summary of the load flow analyses during peak and off-peak load in 2030.

Table 8-14: System summary results 2030 – Peak Load

Load Flow Calculation			Total System Summary	
AC Load Flow, balanced, positive sequence			Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	Yes		Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	Yes		Nodes	1.00 kVA
			Model Equations	0.10 %

Total System Summary				Study Case: Study Case MTP/LTP		Annex: LF.001	/ 1
No. of Substations	2	No. of Busbars	569	No. of Terminals	27	No. of Lines	286
No. of 2-w Trfs.	275	No. of 3-w Trfs.	0	No. of syn. Machines	62	No. of asyn.Machines	7
No. of Loads	80	No. of Shunts	56	No. of SVS	1		

Generation	= 4242.77 MW	401.26 Mvar	4261.70 MVA	
External Infeed	= 402.00 MW	-176.18 Mvar	438.91 MVA	
Load P(U)	= 4510.10 MW	1701.24 Mvar	4820.29 MVA	
Load P(Un)	= 4510.10 MW	1701.24 Mvar	4820.29 MVA	
Load P(Un-U)	= 0.00 MW	0.00 Mvar		
Motor Load	= 0.00 MW	0.00 Mvar	0.00 MVA	
Grid Losses	= 134.67 MW	-1535.04 Mvar		
Line Charging	=	-2849.68 Mvar		
Compensation ind.	=	618.59 Mvar		
Compensation cap.	=	-559.71 Mvar		
Installed Capacity	= 7328.86 MW			
Spinning Reserve	= 1674.03 MW			
Total Power Factor:				
Generation	= 1.00 [-]			
Load/Motor	= 0.94 / 0.00 [-]			

Table 8-15: System summary results 2030 – Off-Peak Load

Load Flow Calculation			Grid Summary	
AC Load Flow, balanced, positive sequence			Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	Yes		Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No		Nodes	1.00 kVA
			Model Equations	0.10 %

Grid: 1 KENYA		System Stage: 1 KENYA		Study Case: Study Case MTP/LTP		Annex: A01	/ 1
Grid: 1 KENYA		Summary					
No. of Substations	0	No. of Busbars	549	No. of Terminals	0	No. of Lines	273
No. of 2-w Trfs.	263	No. of 3-w Trfs.	0	No. of syn. Machines	63	No. of asyn.Machines	0
No. of Loads	80	No. of Shunts	56	No. of SVS	0		

Generation	= 1531.73 MW	-773.08 Mvar	1715.76 MVA	
External Infeed	= 304.96 MW	-96.00 Mvar	319.72 MVA	
Inter Grid Flow	= 0.00 MW	0.00 Mvar		
Load P(U)	= 1804.04 MW	680.50 Mvar	1928.12 MVA	
Load P(Un)	= 1804.04 MW	680.50 Mvar	1928.12 MVA	
Load P(Un-U)	= -0.00 MW	-0.00 Mvar		
Motor Load	= 0.00 MW	0.00 Mvar	0.00 MVA	
Grid Losses	= 32.65 MW	-2255.55 Mvar		
Line Charging	=	-2833.00 Mvar		
Compensation ind.	=	1180.32 Mvar		
Compensation cap.	=	-474.35 Mvar		
Installed Capacity	= 7295.85 MW			
Spinning Reserve	= 4480.47 MW			
Total Power Factor:				
Generation	= 0.89 [-]			
Load/Motor	= 0.94 / 0.00 [-]			

The graphic below depicts the estimated balance of peak load and power generation during peak load hour in 2030. The highest demand is concentrated in the Nairobi area, where the focus for infrastructure development for transport and distribution of electrical power is of importance. The Central Rift area and the Coast area constitute the centres of power generation.

The load forecast also shows a relative high growth of load demand in the West Region area. This load can only partly be covered by power supply in this area. Therefore, power transfer from the northern and central Rift will continue to be necessary or even increase. This transfer requires to be secured with at least N-1 contingencies.

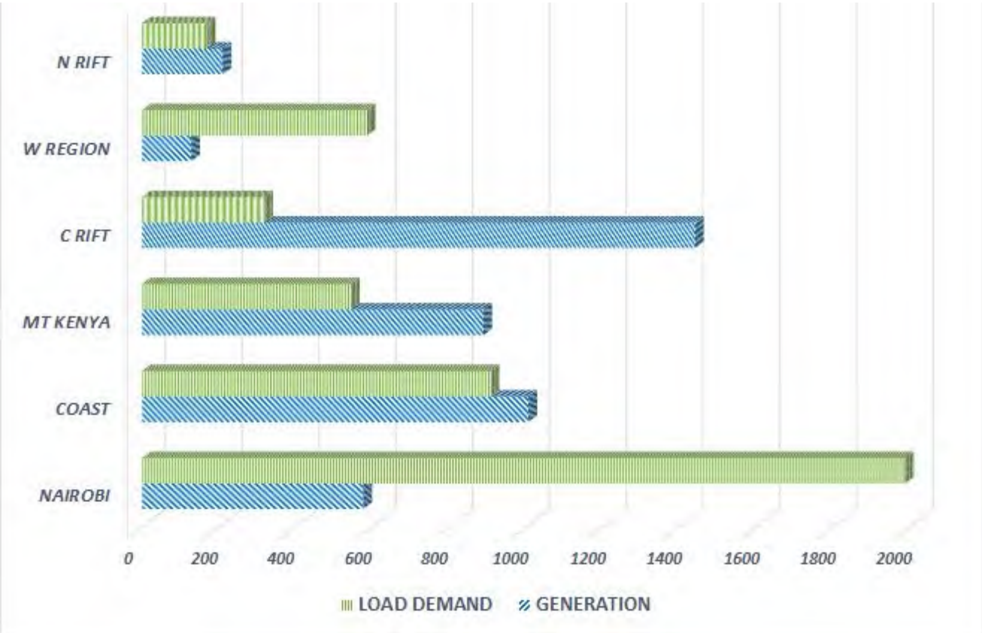


Figure 8-1: Generation / demand balance by area 2030 [MW]

The figure below shows schematically the topology-2030 load flow through the different network areas in Kenya. It provides an overview of load demand, power generation and inter-area power transfer.

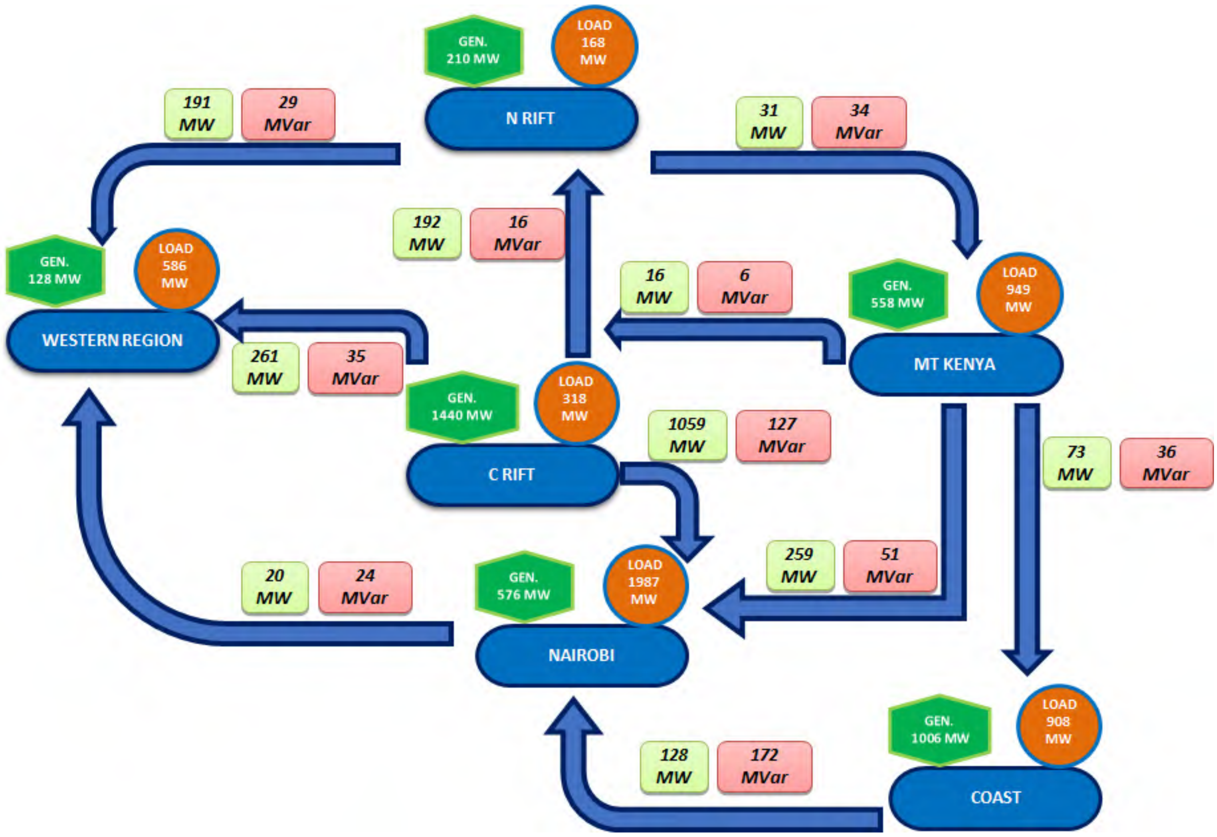


Figure 8-2: Schematic inter- area-network load flow 2030

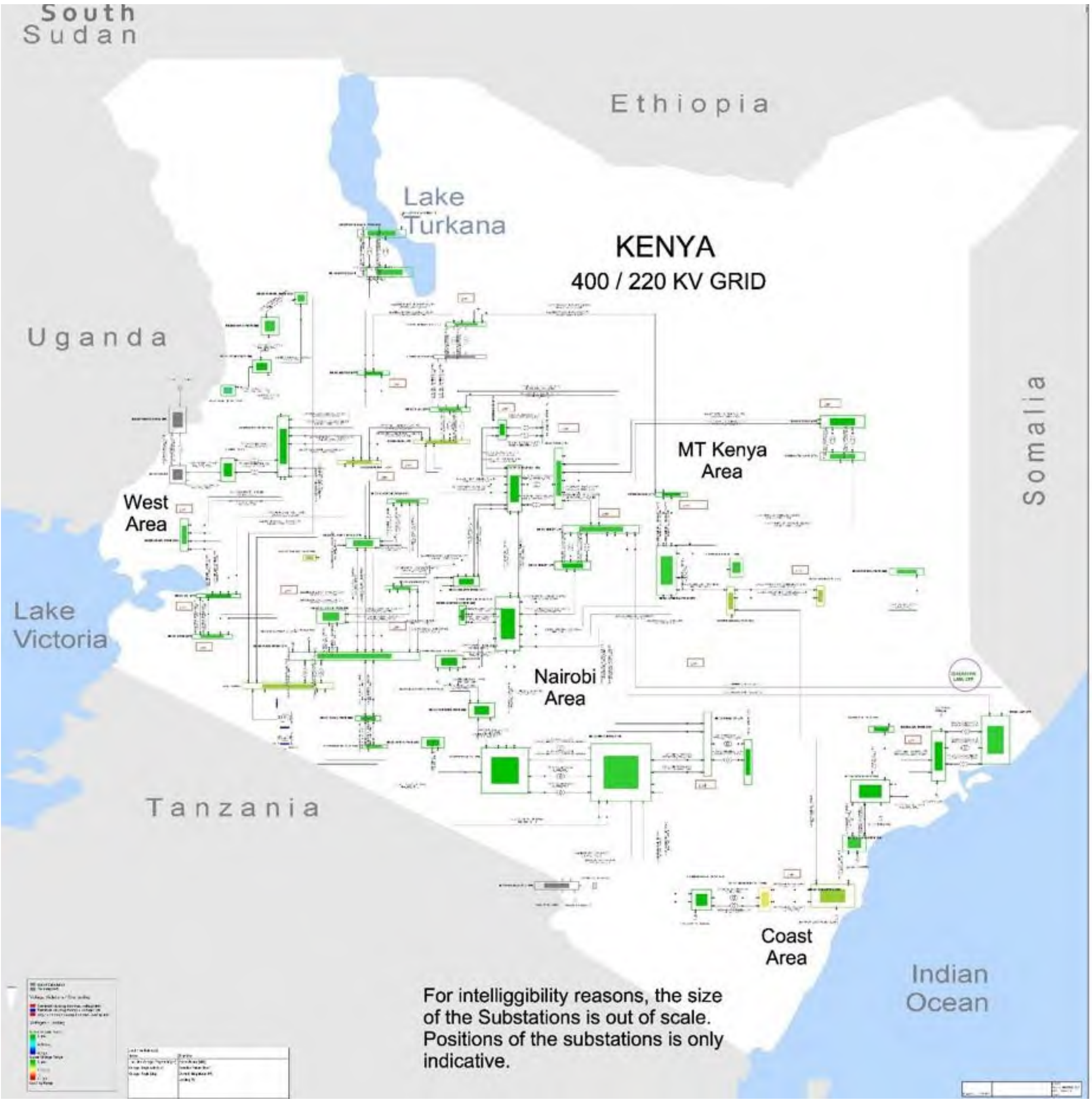


Figure 8-3: Network structure in 2030

8.4.2 Contingency analysis

A N-1 contingency analysis has been conducted in order to determine power transfer margins, detect the risk inherent in changed loading conditions of transmission equipment and evaluate (loading and voltage-wise) post-fault load flows; each of which reflect the "outage" of a single element (such as transformers, transmission line.).

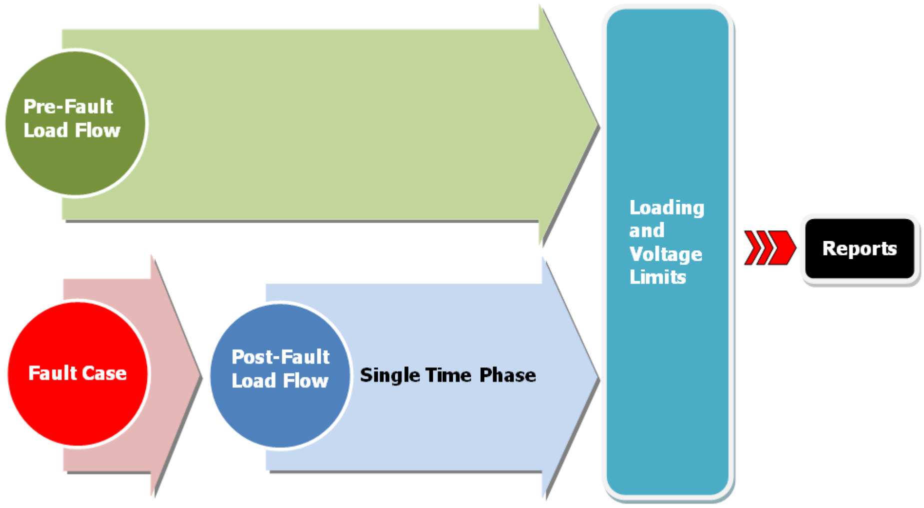


Figure 8-4: Single Time Phase Contingency Analysis Method applied by PowerFactory[199]

The performed static analysis covers the disconnection of all transmission branches (lines and transformers) in the Kenyan transmission system.

For the analysis, the lines and transformers that are considered for contingency are all connected at high voltage, from 132 kV to 400 kV. In case that a branch is lost, two types of problems may appear, caused by the new power flows in the network when it has reached its new steady state (dynamic behaviour is not taken into account for the static security analysis): branch overloads and voltage variations (either under-voltage or over-voltage). The following criteria have been defined:

Branch overloads criteria

- Initial load flow, before contingency, should not show any loading above 100%
- After contingency, the following overloading are accepted[200]:
  - Transmission Lines : 120%
  - Transformers : 120%

[199] DigSILENT Power Factory 15, User Manual „Contingency analysis“
[200] These limits are acceptable, since corrective actions (e.g. load transfer) are available.

Voltage variations criteria

- In the initial voltage profile, the voltage of every node in the network is between 0.95 pu and 1.05 pu;
- After contingency, the range tolerated is 0.9 pu to 1.1 pu.

Conclusions and Results

The performed analysis shows that N-1 contingency reliability of connecting element (OHL's, transformers) is for the long term plan widely satisfied.

In this context, the network may comply any N-1 contingency event corresponding to the loss of any HV/MV transformer or HV overhead line, but in certain cases (where the N-1 loading is between 100% and 120%) with some transfer of power supply by switching operations and rearrangement of couplers in the S/S.

Indeed, "moderate" loadings' levels (100% to 120%) in case of N-1 contingency incident, can be resolved (overload is then resolved by manual de-loading measures e.g. load transfer, re-dispatching or interrupting interruptible loads).

CONTINGENCY ANALYSIS REPORT LTP MASTER PLAN: Loading Violations

Study Case: Study Case MTP/LTP
Result File: Contingency Analysis AC

Loading Limit: 80.0
Overloading Limit: 100

	Component	Branch, Substation or Site	Loading Continuous [%]	Loading Short-Term [%]	Loading Base Case [%]	Contingency Number	Contingency Time Phase [min.]	Contingency Name	Base Case and Continuous Loading [0.0 % - 125.9 %]
1	TR MATASIA 220/66 kV		118.2	118.2	59.1	336	3	TR MATASIA 220/66 kV(1)	
2	TR MATASIA 220/66 kV(1)		118.2	118.2	59.1	335	3	TR MATASIA 220/66 kV	
3	TR KISUMU 132/33 kV(1)		117.5	117.5	56.8	284	3	TR KISUMU 132/33 kV	
4	TR KISUMU 132/33 kV		117.5	117.5	56.9	285	3	TR KISUMU 132/33 kV(1)	
5	TR MUHORONI 132/33 kV(1)		115.0	115.0	56.2	341	3	TR MUHORONI 132/33 kV	
6	TR MUHORONI 132/33 kV		115.0	115.0	56.2	342	3	TR MUHORONI 132/33 kV(1)	
7	TR ELDORET 132/33 kV(1)		115.0	115.0	55.2	235	3	TR ELDORET 132/33 kV	
8	TR ELDORET 132/33 kV		115.0	115.0	55.3	236	3	TR ELDORET 132/33 kV(1)	
9	TR KIPEVU 132/33 kV		112.6	112.6	73.3	279	3	TR KIPEVU 132/33 kV(2)	
10	TR KIPEVU 132/33 kV		112.6	112.6	73.3	278	3	TR KIPEVU 132/33 kV(1)	
11	TR KIPEVU 132/33 kV(2)		112.6	112.6	73.3	278	3	TR KIPEVU 132/33 kV(1)	
12	TR KIPEVU 132/33 kV(2)		112.6	112.6	73.3	277	3	TR KIPEVU 132/33 kV	
13	TR KIPEVU 132/33 kV(1)		112.6	112.6	73.3	279	3	TR KIPEVU 132/33 kV(2)	
14	TR KIPEVU 132/33 kV(1)		112.6	112.6	73.3	277	3	TR KIPEVU 132/33 kV	
15	Lne 132 SONDU - HOMABAY		111.6	111.6	26.5	42	3	Lne 132 KISUMU - SONDU	
16	TR MUSAGA 132/33 kV		111.2	111.2	45.1	344	3	TR MUSAGA 132/33 kV(1)	
17	TR RABAI 132/33kV (1) (LTP)		109.6	109.6	52.6	365	3	TR RABAI 132/33kV (2) (LTP)	
18	TR RABAI 132/33kV (2) (LTP)		109.6	109.6	52.7	364	3	TR RABAI 132/33kV (1) (LTP)	
19	Lne 132 ELDORET - KITALE		106.1	106.1	41.9	205	3	Lne 220 TURKWEL - KAINUK	
20	TR NBNORTH 220/66 kV(2)		104.6	104.6	70.9	358	3	TR NBNORTH 220/66 kV(1)	
21	TR NBNORTH 220/66 kV(2)		104.6	104.6	70.9	357	3	TR NBNORTH 220/66 kV	
22	TR NBNORTH 220/66 kV		103.9	103.9	66.4	359	3	TR NBNORTH 220/66 kV(2)	
23	TR NBNORTH 220/66 kV(1)		103.9	103.9	66.4	359	3	TR NBNORTH 220/66 kV(2)	
24	TR RABAI 220/132 200MVA (N1)		101.1	101.1	53.1	367	3	TR RABAI 220/132 200MVA (N2)	
25	TR RABAI 220/132 200MVA (N2)		101.1	101.1	53.1	366	3	TR RABAI 220/132 200MVA (N1)	
26	TR CHEMOSIT 132/33 kV(1)		101.1	101.1	49.3	230	3	TR CHEMOSIT 132/33 kV	
27	TR CHEMOSIT 132/33 kV		101.0	101.0	49.4	231	3	TR CHEMOSIT 132/33 kV(1)	
28	TR NBNORTH 220/66 kV		99.9	99.9	66.4	358	3	TR NBNORTH 220/66 kV(1)	
29	TR NBNORTH 220/66 kV(1)		99.9	99.9	66.4	357	3	TR NBNORTH 220/66 kV	
30	TR RUARAKA 132/66 kV		99.6	99.6	49.0	370	3	TR RUARAKA 132/66 kV(1)	
31	TR RUARAKA 132/66 kV(1)		99.6	99.6	49.0	369	3	TR RUARAKA 132/66 kV	
32	Lne 33 CHEMO33 - CHEMO33		97.4	97.4	54.3	230	3	TR CHEMOSIT 132/33 kV	
33	TR KONZA 220/132kV (2)(LTP)		95.5	95.5	57.8	293	3	TR KONZA 220/132kV (1)(LTP)	
34	TR KONZA 220/132kV (1)(LTP)		95.5	95.5	57.8	294	3	TR KONZA 220/132kV (2)(LTP)	
35	TR NAKURU 132/33 kV(1)		94.1	94.1	45.5	348	3	TR NAKURU 132/33 kV	
36	TR NAKURU 132/33 kV		94.1	94.1	45.5	349	3	TR NAKURU 132/33 kV(1)	
37	Lne 132 LANET - NAIVASHA(1)		94.1	94.1	61.6	49	3	Lne 132 LANET - NAIVASHA	
38	Lne 132 LANET - NAIVASHA		94.1	94.1	61.6	50	3	Lne 132 LANET - NAIVASHA(1)	
39	Lne 132 ELDORET - KITALE		93.9	93.9	41.9	146	3	Lne 220 KAINUK - 0RTUM	
40	Lne 220 GARSEN - LAMU		93.2	93.2	56.6	163	3	Lne 220 LAMU - GARSEN (LTP)	
41	TR LANET 132/33 kV		92.2	92.2	60.9	307	3	TR LANET 132/33 kV(1)	

Figure 8-5: N-1 contingency results Kenya 2030 peak-load

An extensive contingency analysis (n-1) report as per PowerFactory can be found in Annex 8.F "Contingency Analysis LTP".

8.4.3 Short circuit analysis

Short circuit calculation is conducted according the IEC 60909 (2001) std. in order to verify the with-standing of the substation equipment and the new OHLs in comparison with the calculated 3-phase and single-phase-to-ground short circuit currents. The results of the computer simulations include the following electrical parameters:

- Initial short circuit current I"k: The (50 Hz) RMS fault current flowing immediately after the occurrence of the short circuit;
- Peak current Ip: The highest instantaneous value of fault current after fault occurrence.
- Breaking fault current Ib: The RMS value of the symmetrical fault current flowing through the first phase to open when contact separation occurs in the circuit breaker. In our case, the calculation considers 55 ms as minimum break time for any current below the rated breaking current capacity.
- Steady-state short circuit current Ik: RMS value of the short circuit current which remains after decay of the transient phenomena.

A complete short circuit calculation report as per PowerFactory can be found in Annex 8.G, and Annex 8.H "Short Circuit Results LTP" for 3-phase and single-phase-to-ground short circuit currents respectively. In the present paragraph, the calculated short circuit currents (sub-transient values) are graphically summarised and compared with the reference withstand currents of the substation equipment. These should be checked against existing switchgear fault break ratings. For new switchgear at 132 kV/220 kV/400 kV voltage levels the minimum rating is likely to be 31.5 kA and switchgear with the standard IEC fault ratings of 40 kA, 50 kA or 63 kA are also available as re-quired. In particular, the short circuit currents for the 400 kV, 220 kV and 132 kV voltage level are respectively presented in the following figures.

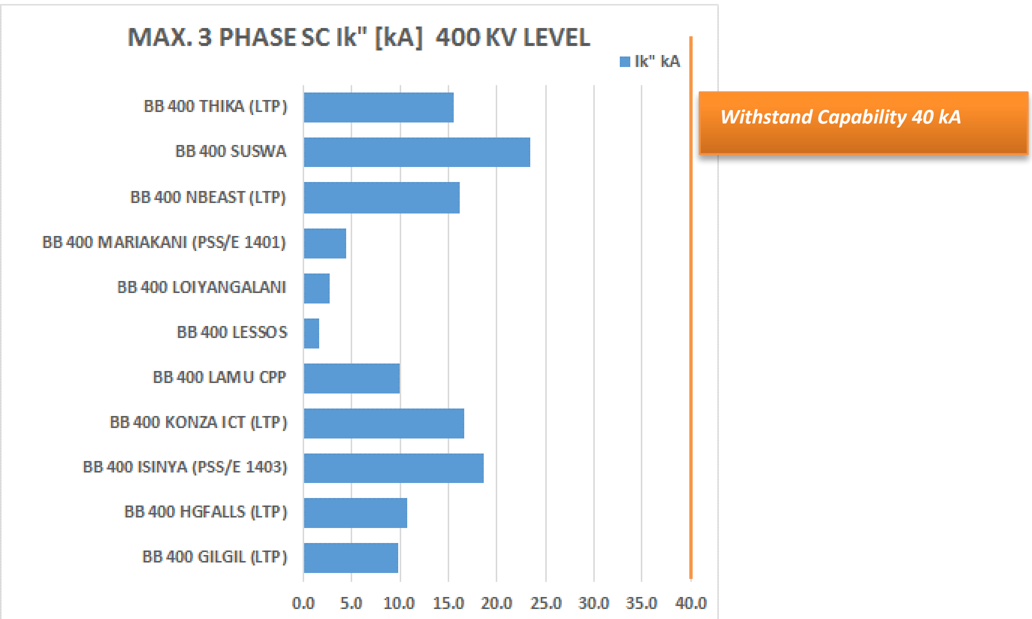


Figure 8-6: Max 3-Ph short circuit currents at 400 kV

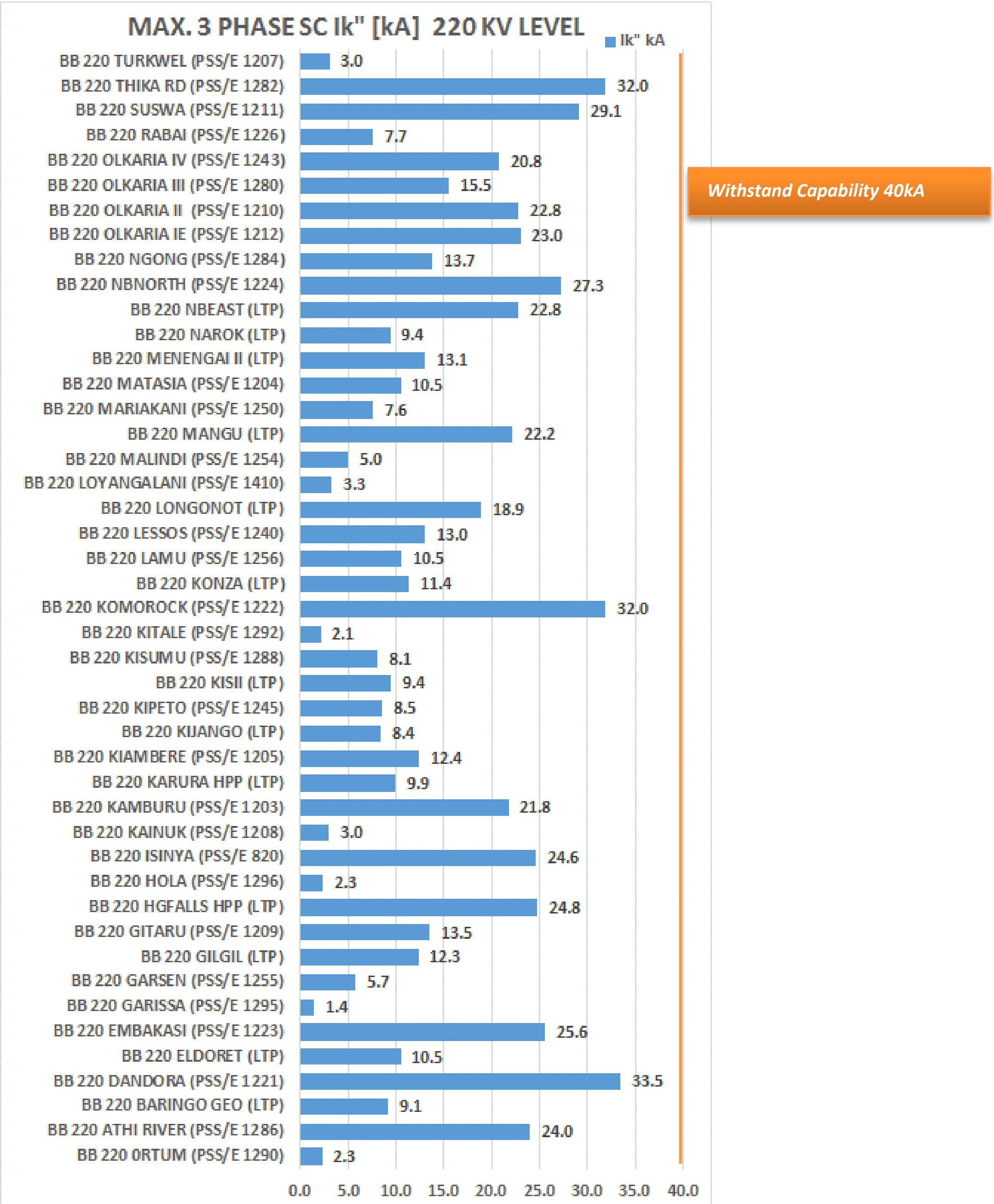


Figure 8-7: Max 3-Ph short circuit currents at 220 kV

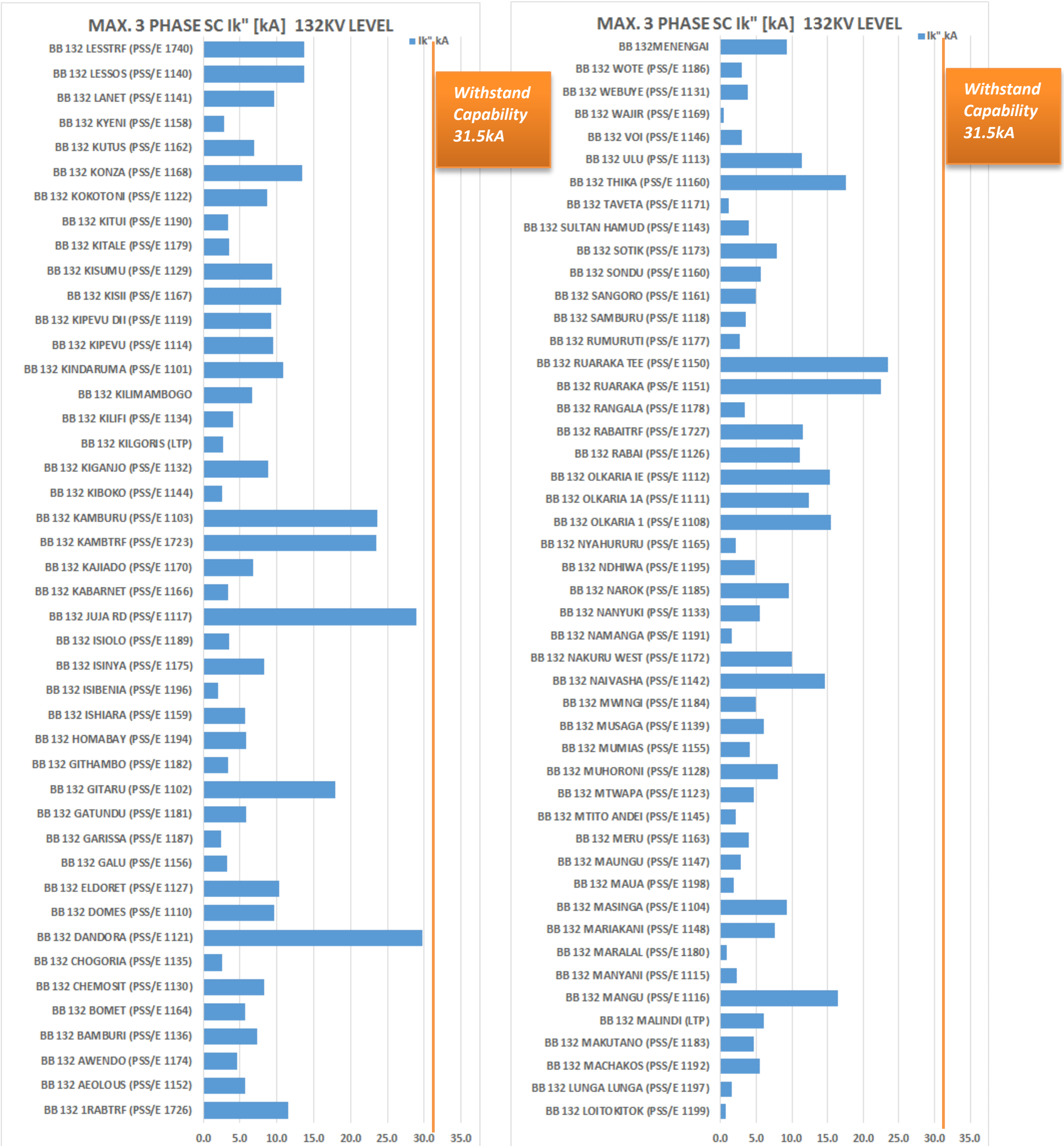


Figure 8-8: Max 3-Ph short circuit currents at 132 kV

The aim of the short circuit analysis is the identification of potential problems due to symmetrical fault current phenomena on the high voltage network in 2030. This analysis has been conducted to evaluate and to compare the obtained results with the design capacity, and rated-data-values for short circuit at all busbars locations in the high voltage network.

The results for the three-phases short circuit simulation shows that the short circuit currents are under the switchgears limits (40 kA and 31.5 kA), indicating that their design is suitable. However, the circuit breakers of existing substations may not all cope with this threshold. Their replacement or other short circuit mitigation measures should be considered in separate studies.

The scope of the present study is focused on the transmission part. The necessary extension replacement and upgrade of transmission equipment considered in the long term plan may require validation of equipment design on medium voltage level (switchgears and its short circuit current capacities). A re-design/upgrade of equipment's' rating (11 kV, 33 kV and 66 kV) on the medium voltage may be required.

8.4.4 Modal analysis – small signal stability

Small signal stability is relevant to the ability of the power system to maintain synchronism when subjected to small disturbances. In this context, a disturbance is considered to be small if the equations that describe the resulting response of the system may be linearised.

The analysis is based on the calculation of the eigenvalues of the state matrix of the electrical system: the real component of the eigenvalues gives the damping and the imaginary component gives the frequency of oscillations. A negative real part represents a damped oscillation whereas a positive real part represents oscillation of increasing amplitude.

To each eigenvalue relates a degree of damping and an oscillation frequency. The whole forms a "specific operating mode".

As a first approximation, the specific operating modes can be classified into four groups:

- The inter-area modes: their frequency is generally comprised between 0.1 and 1 Hz, they relate to the natural oscillations between set of units forming together coherent electrical areas;
- The electromechanical modes: their frequency is around 1 Hz and they relate to the natural oscillations of the generating units;
- The modes relating to the damper windings: they are highly damped;
- The modes relating to control systems (speed or voltage): these can be found within the entire frequency range, depending on the characteristics of the systems;
- The other modes: they cannot be related directly to any precise cause.

Small signal stability is verified when all the eigenvalues have negative real component and sufficient damping. The "Task Force 07" of CIGRE Committee (Final Report 111 – Dec. 1996), about analysis and control of power system oscillations, recommends a minimum damping of 5%.

A damping threshold of 5% will be also considered in the present analysis as minimum level to be respected.

Similarly to load flow analysis, the assessment of small signal stability is conducted considering an arbitrary point of operation close to the voltage stability limits calculated with V-P curve method.

<u>Conclusions and Results</u>

The eigenvalues of the state matrix of the electrical transmission system relevant for the Kenyan transmission network in 2030 have been calculated and plotted in a complex plane. Hence, the damping ratio of each mode of the analysis has also been calculated.

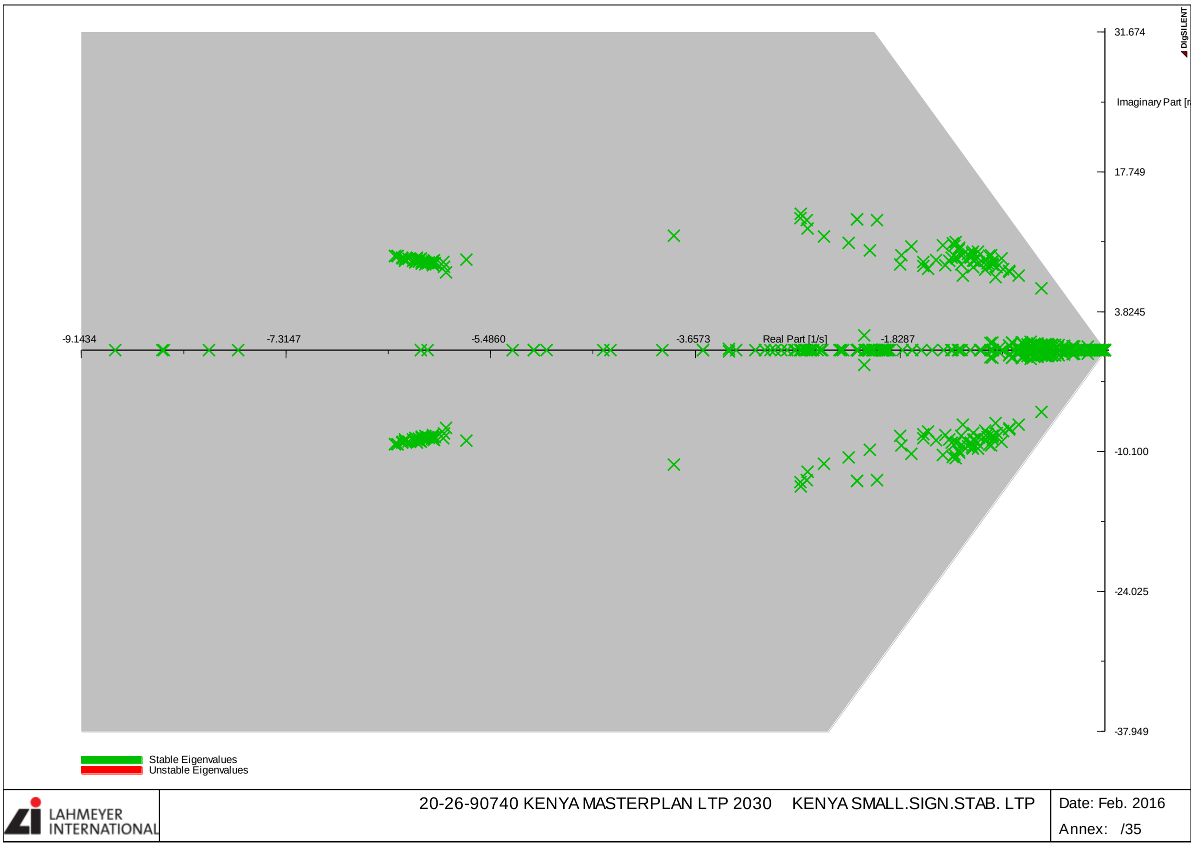


Figure 8-9: Eigenvalue plot for the Kenyan transmission system

In all simulated cases the real part of the eigenvalues resulted to be on the negative axis and the minimum damping ratio resulted to be not lower than 5%.

The results of the small signal stability analysis confirm that the operation of the system is stable and oscillations are sufficiently damped.

SMALL SIGNAL STABILITY LTP 2030										
Name	Real part	Imaginary part	Magnitude	Angle	Damped Frequency	Period	Damping	Damping Ratio	Damping Time Const	Ratio A1/A2
	1/s	rad/s	1/s	deg	Hz	s	1/s		s	
Mode 00005	0	0	0	0	0	0	0	0	0	0
Mode 00727	0	0	0	0	0	0	0	0	0	0
Mode 00734	0	0	0	0	0	0	0	0	0	0
Mode 00735	0	0	0	0	0	0	0	0	0	0
Mode 00736	0	0	0	0	0	0	0	0	0	0
Mode 00737	0	0	0	0	0	0	0	0	0	0
Mode 00738	0	0	0	0	0	0	0	0	0	0
Mode 00022	-21.63378	331.8391	332.5435	93.73004	52.81383	0.0189344	21.63378	0.06505548	0.04622401	1.50625
Mode 00023	-21.63378	-331.8391	332.5435	-93.73004	52.81383	0.0189344	21.63378	0.06505548	0.04622401	1.50625
Mode 00722	-0.00000004	0.00000055	0.00000055	94.14598	0.00000009	11520674	0.00000004	0.07229793	25294970	1.576888
Mode 00723	-0.00000004	-0.00000055	0.00000055	-94.14598	0.00000009	11520674	0.00000004	0.07229793	25294970	1.576888
Mode 00407	-0.5681064	6.151363	6.177541	95.27656	0.9790198	1.02143	0.5681064	0.09196321	1.760234	1.78654
Mode 00408	-0.5681064	-6.151363	6.177541	-95.27656	0.9790198	1.02143	0.5681064	0.09196321	1.760234	1.78654
Mode 00341	-0.9241487	9.118176	9.164889	95.7873	1.451203	0.6890836	0.9241487	0.1008358	1.082077	1.890451

Figure 8-10: Eigenvalue List for the Kenyan Transmission System LTP

The analysis shows few eigenvalues in where the damping ratio are in the range of 6% range, but well damped. The mode phasor plot of these eigenvalue shows that these 6% damped values can be explained to the lack of detailed information needed to model the interconnection to Ethiopia. Therefore, detailed information about modelling parameters e.g. acceleration time constant beyond others (action of power system stabilisers at the Ethiopia power plants), may support the accuracy of the calculations and achieved results.

A small signal stability analysis is based on a linearisation process of the solutions around the selected operating points, the above verification cannot be extended to a different operating point, as well as to large disturbance events. A complete report of the above results is provided in Annex 8.I "Small Signal Stability LTP".

8.4.5 Transient stability

The transient stability analysis is related to the dynamic behaviour of the electrical system when subjected to abrupt changes in load or generation and short circuit faults.

The subsequent recovery of the electro-mechanical parameters within an acceptable state of operating equilibrium is calculated and analysed.

As first approximation, according to the well-known theory of equal-area criterion, the worst case for a simulation scenario in terms of power system stability is represented by peak load demand.

In this case, the operating point of the synchronous machine rotor angle is closer to the upper part of the power-angle curve, where the stable areas of deceleration kinetic energy are smaller. This condition could lead to unstable response of the generators during severe changes in active power, when high values of deceleration kinetic energy are requested. Hence, as conservative assumption, peak load demands are considered in the present stability analyses.

The present transient stability analysis focuses on the behaviour of the Kenyan transmission system after faults at the HVDC connection to the Ethiopian network.

Loading conditions are considered as per peak load, which reflect the worst case scenario for transient stability for the year 2030.

The dynamic response of the HVDC system is strongly affected by the selected technology and the specific characteristics of the control system that will be implemented in the converter stations.

At the time of the present writing, the above information is not available in detail and therefore a detailed response of the HVDC system under fault conditions could not be simulated with the same accuracy expected during the implementation phase of the HVDC itself. Additional information about the applied HVDC model has been attached in Annex 8.K.

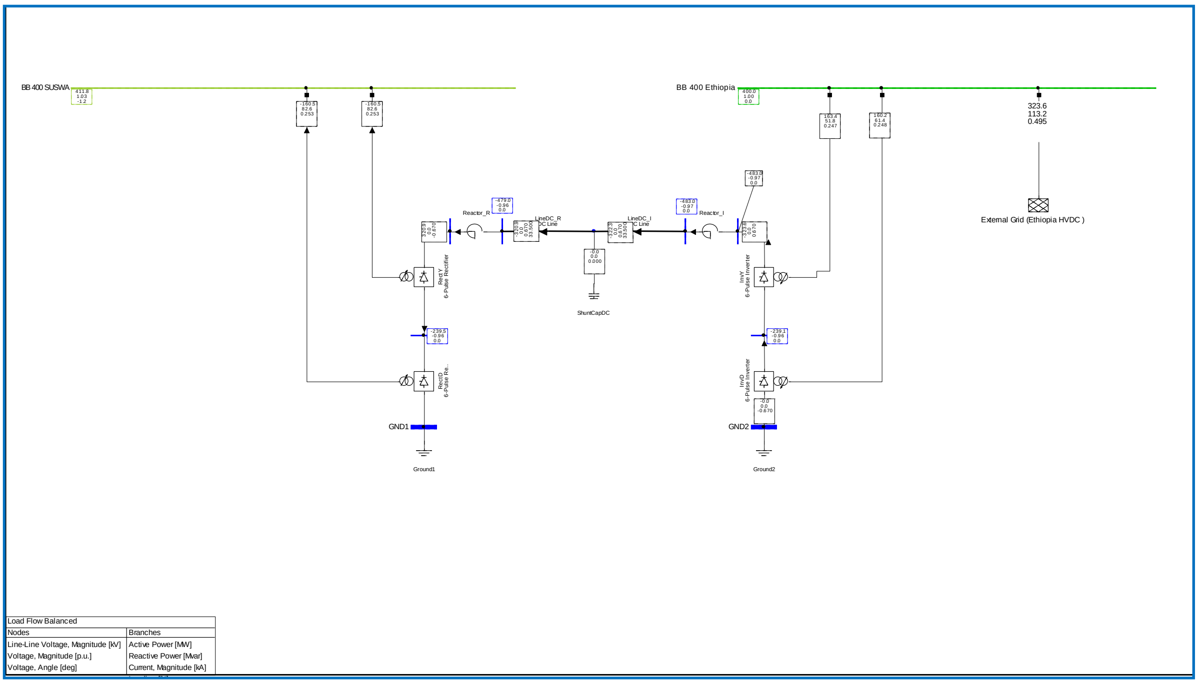


Figure 8-11: HVDC Ethiopia-Kenya interconnector model

However, as a conservative assumption, the sudden disconnection of the whole HVDC link, with a pre-fault transfer power of 400 MW (according to generation plan 2030, in direction Kenya) has been analysed.

The above simulation scenario is a conservative assumption, as during common fault conditions, the HVDC systems are generally still able to transfer a portion of the design rated power, depending on the characteristics of the control and switching equipment and on the type of fault.

After the disconnection of the HVDC, following parameters are calculated:

- Voltage at selected key buses (400 kV, 220 kV and 132 kV);
- Frequency at selected key buses (400 kV, 220 kV and 132 kV);
- Mechanical torque of the synchronous generator;

- Rotor angle of synchronous generators;
- Speed of synchronous generators.

The stability is considered verified when the oscillatory trend of voltage and frequency have sufficient damping and the maximum and minimum values of the oscillations remain within the permissible limits requested by the EAPP Interconnected Transmission Systems (see Figure 8-13).

In particular, during fault conditions shall remain within 48.75 Hz and 51.25 Hz.

The minimum value of 48.75 Hz is also matching with the technical requirements of interconnected parties of Figure 8-12, even if in this case the same value of frequency is allowed for a maximum period of 30 seconds.

6.1.10 Technical Requirements for the Interconnected Parties

Protection measures are required to be taken by *EAPP* and *TSOs* to isolate a *National System* or part of such system from the *EAPP Interconnected Transmission System* in case of uncleared faults or the malfunctioning of *Plant* or *Apparatus* which could lead to a System Emergency condition.

Each *TSO* shall make the necessary arrangements to disconnect its *National System* from the *EAPP Interconnected Transmission System* under the circumstances stated below.

Area Separation by Frequency Deviation

The cross-border connections to *Neighbouring Systems* shall be tripped when frequency measured at the border falls below 48.75 Hz for more than thirty (30) seconds.

Area Separation by Abnormal Transient Conditions

The cross-border connections to *Neighbouring Systems* shall be tripped when an Out of Step pole slipping condition or when sustained inter-area oscillations with amplitudes exceeding an agreed limit are observed.

Area Separation by Transmission Line Overloading

The cross-border connections to *Neighbouring Systems* shall be tripped when overloading of the connections occurs. The overload values for the connections shall be agreed between the respective *TSOs* and *EAPP Sub-Committee on Operations*

Figure 8-12: Kenya Grid Code reference for interconnected parties

Operating Conditions	Frequency Limits
Under Normal Operation	49.50Hz to 50.50Hz
Under System Disturbance	49.00 Hz to 51.00 Hz
Maximum band under system fault	48.75 Hz to 51.25 Hz
Under extreme System operation or fault conditions	f<47.50 Hz or f>51.50 Hz for up to 20 seconds

Figure 8-13: Frequency limits in the EAPP Interconnected Transmission System

Moreover, it has been verified that rotor angle of the synchronous machines remain with sufficient margin within 180°, which is a necessary conditions to avoid out-of-step conditions and the consequent tripping of the machines.

Conclusions and results

As stated before, due to lack of detailed information on the HVDC system, the simulation results are based on a basic model of the HVDC link (benchmark model) including all available known parameters (line parameters, configuration, power), which is however providing a sufficient assessment of the stability problems within the purposes of the present master plan.

It is also expected that during the implementation phase of the HVDC system, additional and updated analysis will be executed by the EPC, in order to take into account the more accurate models of the converter stations, the complexity of the dynamic response of the control devices at the converter stations and the reactive power compensation/harmonic filters, according to Vendor data.

For the analysis of the simulation results, reference is made to the results presented from Figure 8-14 to Figure 8-19.

The present analysis also consider that a sufficient spinning reserve in the Kenya generation system is present to cope with sudden disconnection of the HVDC link, which is a necessary conditions to avoid load shedding.

In the simulated cases, the voltage and frequency curves at selected nodes of the HV Kenyan grid, as well as the speed and rotor angle of synchronous generators resulted having a stable trend.

According to the latest version of the Kenyan Grid Code, under chapter "6.1.10 Technical Requirements for the Interconnected Parties" a tripping of the interconnected part shall be executed when the measured frequency at the border falls below 48.75 Hz for more than thirty seconds. After the disconnection of the HVDC link and the consequent import of 400 MW, the frequency had a minimum transient value of 49.655 Hz, which is well within the minimum grid code requirements.

The maximum rotor angles of the synchronous generators during the transient period is about 82° (Olkaria VI), which is safely below of the limits (180°) and no out-of-step of generators is encountered.

The voltage at the 400 kV, 230 kV and 132 kV system has also a stable profile, with maximum voltage variations well within the grid code requirements.

A sufficient damping of oscillations is also evident in all the transient diagrams. For what above, transient analysis for a sudden disconnection of the HVDC link can be considered verified.

In Figure 8-14, the list of the monitored generators is included and refers to the units having an actual dispatched power above 10 MW. Hence, the calculated speed and rotor angle values of these generators during the HVDC disconnection events have been included in the successive diagrams of Figure 8-15 and Figure 8-16.

Sym LAMU CPP G1	Sym KARURA HPP
Sym LAMU CPP G2	Sym THIKA PP -11 kV- G1
Sym LAMU CPP G3 (LTP)	Sym THIKA PP -11 kV- G2
Sym KIAMBERE -11 kV-	Sym EPZ MSD -11 kV- G2
Sym AKIIRA GEO 11kV (LTP)	Sym MSA RD -11 kV- G2
Sym LONGONOT GEO 11kV (LTP)	Sym EMBAKASIGT1 -11 kV-
Sym OLKARIA 1E -11 kV- G3	Sym EMBAKASIGT2 -11 kV-
Sym OLKARIA IV -11 kV- G1	Sym MASINGA -11 kV-
Sym OLKARIA IV -11 kV- G2	Sym KAMBURU -11 kV-
Sym OLKARIA IV -11 kV- G3	Sym MENENGAI -11 kV- STG1
Sym OLKARIA IV -11 kV- G4	Sym OLKNEG1 -11 kV-
Sym OLKARIA VI -11 kV- G1(N)	Sym OLKNEG2 -11 kV-
Sym OLKARIA VI -11 kV- G2(N)	Sym OLKNEG3 -11 kV-
Sym HGFALLS GEN -STAGE 1-(LTP)	Sym SONDU -11 kV-
Sym KONZA -11 kV- G1-G2(LTP)	Sym SONDU1 -11 kV-
Sym KIPEVU III -11 kV- G1	Sym OLKARIA OW914/915/905
Sym KIPEVU III -11 kV- G2	Sym AEOLUS W -11 kV-
Sym MENENGAI -11 kV- G2	Sym 1KINDAG -11 kV- G2
Sym DOMES -11 kV-	Sym EBUURU -11 kV- G1(N)
Sym BARINGO -11 kV- STG1	Sym MUHORONI EG -11 kV- G2
Sym BARINGO -11 kV- STG2	Sym OLK WELLHEADS II -11 kV (LTP)
Sym MENENGAI -11 kV- STG2	Sym CHEMOSIT BIOM -11 kV (LTP)
Sym KIPETO -11 kV- G1	Sym KISII BIOM -11 kV (LTP)
Sym KIPETO -11 kV- G2	Sym OLKARIA III -11 kV- G4(N)
Sym OLKARIA -11 kV- G1	Sym OLKAIII -11 kV- G3

Figure 8-14: List of monitored generators

Key simulation diagrams are included in the following figures.

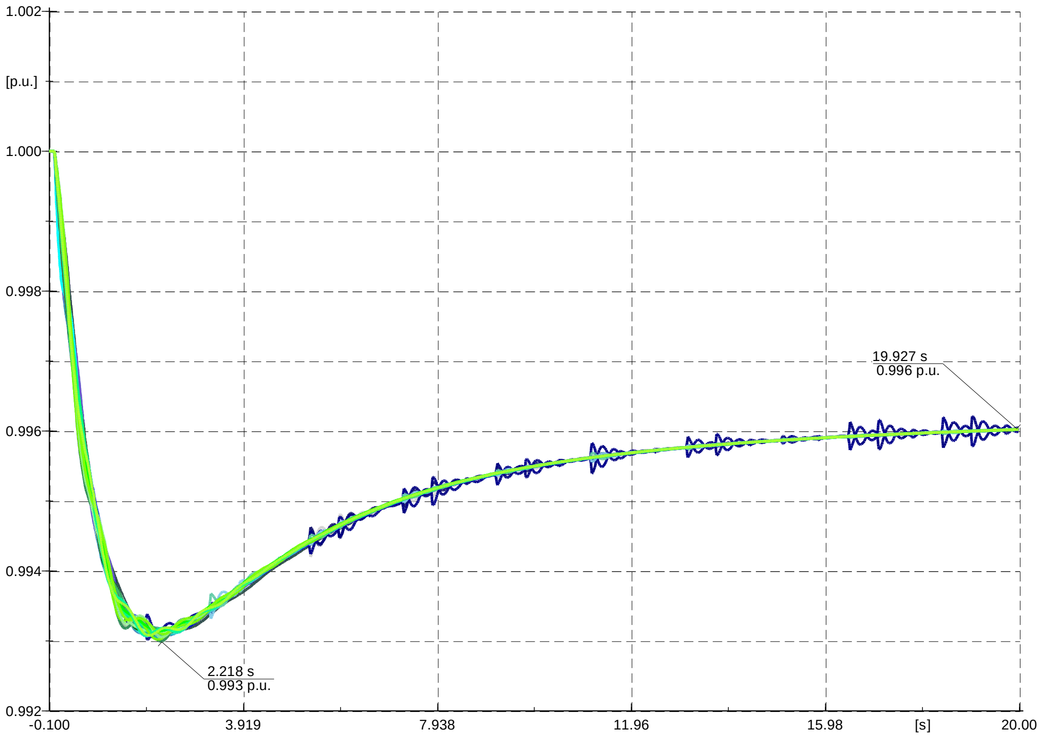


Figure 8-15: Speed of synchronous generators

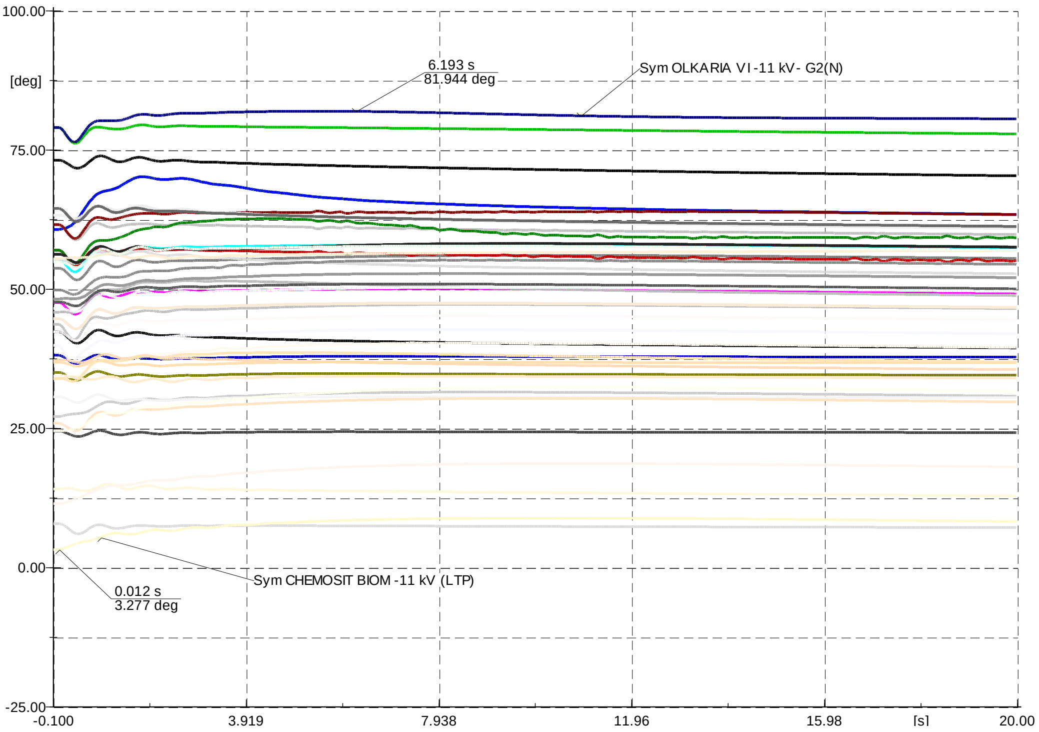
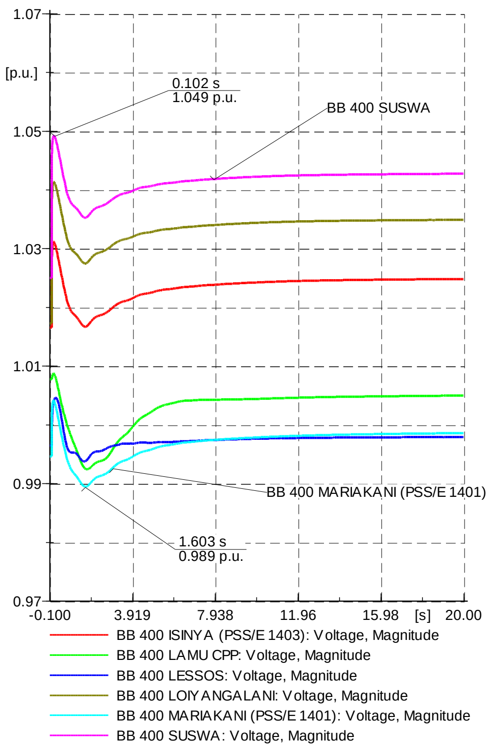


Figure 8-16: Rotor angle of synchronous generators



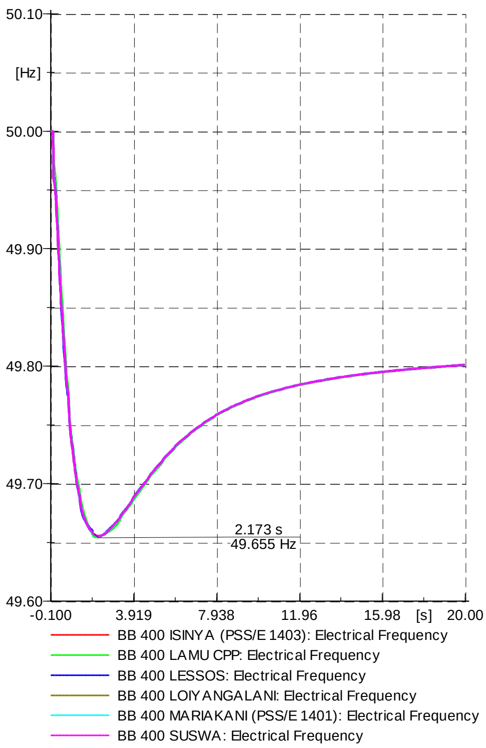


Figure 8-17: Voltage and frequency at 400 kV system

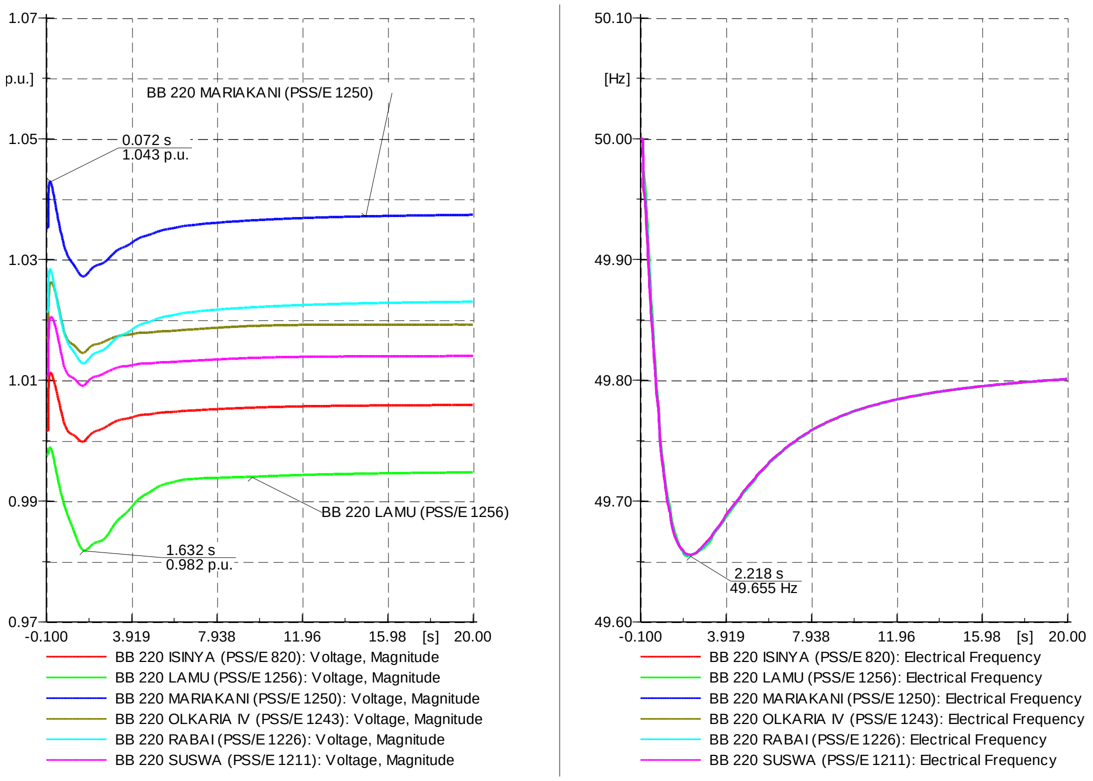


Figure 8-18: Voltage and Frequency at 220 kV system

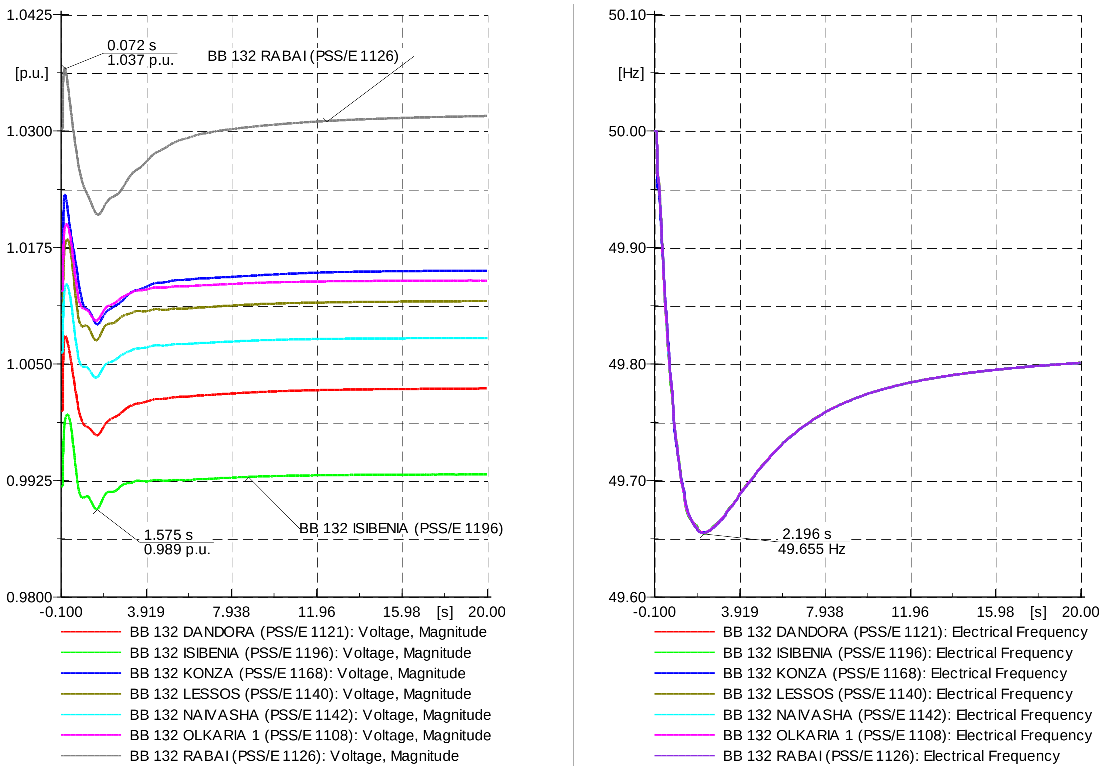


Figure 8-19: Voltage and Frequency at 132 kV system

9 INVESTMENT PLAN FOR FAVOURABLE EXPANSION PLAN

This chapter describes the methodology and assumptions for the determination of the investment plan of the generation and transmission expansion planning as outlined in chapter 7 and 8. Results are provided in section 9.3 which also contains an evaluation of the cost development of the power system applying the long run marginal costs. Key results are presented below.

9.1 Key results and conclusions

The key results and conclusions of the investment plan are as follows:

- The investment plan provides an overview of the expected costs and required capital. The required capital includes interest during construction according to a supported and commercial funding scenario. The supported funding scenario is the more favourable and less expensive one due to the lower interest rates. However, it is considered realistic that a mix of commercial and supported funding for the expansion of the Kenyan power sector will be achieved instead of applying either one or the other. Therefore, the investment plan results provide an indication on the probable range of capital requirements.

- The expansion plan to satisfy electricity demand until the year 2035 will result in overall investment in a range from 37 to 52 billion USD (37 billion USD for supported funding scenario, 2% inflation rate; 41 billion USD for supported funding scenario, 3% inflation rate; 52 billion USD for commercial funding scenario, 5% inflation rate). The supported funding scenario is subject to the ability of development banks for finance. The commercial funding scenario is more likely to materialise but results in higher capital requirements. The difference is not big with 4%. It however depends on achieving financing conditions that might constitute a deal breaker for the implementation of future expansion projects. The long term price increase for investments has the by far strongest impact on the overall amount, resulting in a difference of 13 billion USD between the inflation rates of 2% and 5%.

- It is recommended to investigate with lenders – both commercial and development banks – the availability of the required volume of funding in the short, medium and long term.

- The importance for securing and scheduling funding and investors for the expansion plan is also an outcome of the evaluation of power system's long run marginal costs. These costs (an indication of the future costs for additional power supply per kWh) are in a range of 8 to 9 USDcent per kWh. They are below the average generation costs (in terms of LECs) of the total generation system as well as below the LECs for all selected generation expansion candidates (thus, would not be sufficient to recover the necessary generation costs). The low cost may indicate underutilised existing or committed capacity or overcapacity as well as sufficient lower cost generation potential. From that point of view increased demand for electricity should be aimed at and slower demand growth than forecasted should be avoided. However, aiming for growth of demand did not materialise in the past. To avoid the present situation of overcapacity, expansion and securing of funding should be planned in a continuous way as the demand has grown in the past and is forecasted to grow in the future.

- Despite this positive impact of demand growth it could be beneficial to also consider the Energy Efficiency (EE) measures as outlined in the EE report: the EE induced benefits (i.e. reduction of generation costs) are considerably above the costs for the EE measures. This means for the same utilisation of electricity less costs apply. There are even further potential benefits such as environmental effects from fuel savings, technological edge and savings in the distribution network due to delayed load growth.

9.2 Methodology and Assumptions

Based on the generation and transmission expansion projects as identified within the previous analyses, the Consultant developed an investment plan for the study period. The following information has been compiled:

- Overview of investments according to identified power generation projects;
- Estimation of transmission cost based on the network study and forecast;
- Determination of distribution cost in accordance with the latest distribution master plan[201] and reference demand forecast;
- Proposed implementation schedules; and
- Total investment costs in the consideration period.

Two scenarios of the investment plan have been elaborated to reflect different funding scenarios, i.e. a commercial and a supported funding scenario. The latter considers the achievement of favourable funding conditions through funding from development banks. The investment plan will facilitate decision-making along the expansion of the Kenyan power sector to allow for sustainable growth and demand-responding development. It will enhance the information on the requirements to secure financing for the future growth of the electricity sector.

In order to achieve the expansion of the Kenyan electricity system with the objective to satisfy the electricity demand and to respect the implementation of the planned projects within the study period, the following measures are required:

- **On generation level:** Planned power plants need to be implemented according to the determined commissioning.

- **On transmission level:** In accordance with the determined commissioning of the power plants, also their grid connections need to be accomplished.

- **On distribution level:** The distribution infrastructure to connect the customers to the grid along the study period needs to be considered as indicated in the demand forecast.

The investment plan therefore consists of generation, transmission and distribution and outlines the respective costs for each component.

[201] Parsons Brinckerhoff, Kenya Distribution Master Plan (prepared for KPLC), Final Report, Volume I, April 2013

9.2.1 General assumptions

For the sake of consistency, the cost assumptions applied in previous chapters have also been utilised for the investment plan. Furthermore, a range of assumptions have been applied which were discussed based on first-hand information of the Kenyan power sector and checked for plausibility by the Consultant.[202]

9.2.1.1 Currency and markets

In consistency with previous work tasks, the currency applied for the investment plan is US dollar (USD). Therefore, all assumptions are denominated in USD.

The investment plan is based on a price level of the base year 2015 provided in USD. The investment plan is based on nominal terms. This means that according fees and inflation are included along the timeline.

9.2.1.2 Contingencies

For generation and transmission investment costs, the following cost components are deemed to be included in the base cost assumptions:

- EPC costs (engineering, procurement and construction);
- Physical contingencies;
- Engineering supervision; and
- Owner's costs.

The assumed costs are based on the regional EPC price. Physical contingencies amount to 5% of the EPC price estimate. An appropriate share of owner's cost (e.g. for third-party construction supervision) has been taken into consideration per power plant. Moreover, import fees of 3% of the investment costs are considered on top. In addition to this price basis, the escalation of prices to reflect inflation and interest during construction (IDC) are considered.

9.2.1.3 Inflation

In order to cater for the probable case that prices will increase over the study period, inflation has been taken into account. Inflation rates determine the amount of costs that needs to be added to the base costs and physical contingencies to implement the project. In this context, estimations for the expected inflation for the underlying currency USD of 2 to 3% have been foreseen based on historic range of USD GDP deflator[203]. A sensitivity analysis of 5% is also applied.

[202] Based on the investment planning workshop with relevant members of the LCPDP team and other representatives of the Kenyan power sector in July 2014.
[203] Source: International Monetary Fund, World Economic Outlook Database, April 2016

9.2.1.4 Financing requirements and funding conditions

Depending on the funding conditions, additional costs on the investment of the financed energy infrastructure components accrue. Since the investment plan is considered in nominal terms, the respective financing costs during construction are taken into consideration. They depend on the applied funding conditions, which have been chosen according to the applicable funding conditions within the Kenyan power sector.[204]

Besides governmental entities and utilities being partly private and partly governmentally owned, there are also a couple of IPPs active on generation level. The private sector is well established but there is also sufficient public share amongst the players. Funding of the various assets for sector expansion can be achieved on a commercial basis or in cooperation with development banks, resulting in more favourable conditions compared to commercial funding. For the two funding scenarios, the conditions assumed for financing are presented in Table 9-1.

Table 9-1: Financing conditions

Financing	Commercial Scenario	Supported Scenario
Gearing	70%	75%
Interest	8%	5%
Interest During Construction (IDC)	8%	5%

To demonstrate the impact of either the one or the other funding scenario, the assumptions have been considered for all expansion assets.

9.2.1.5 Disbursement

To derive the investment costs for the generation capacities according to their timing in the expansion plan, the foreseen COD as well as the construction period are considered in the disbursement schedule. All assumptions in terms of timing (i.e. first year of operation, construction period, project lifetime) for the different generation and transmission assets have been adopted from chapter 6 and 8. The disbursement for the capital drawdown during the construction period of the generation assets is distributed in an S-shaped curve.[205]

The disbursement schedules according to power plant technologies and corresponding construction periods are provided in Table 9-2. There are technologies where different construction periods and disbursement schedules occur due to the power plant size (e.g. geothermal plants).

[204] Based on discussions with LCPDP team members during the investment planning mission in July 2014
[205] Based on the assumptions derived from the Consultant's expertise

Table 9-2: Disbursement schedules of power plants[206]

Technology	Capacity [MW]	Construction Period	Disbursement (years before commissioning)											
			11	10	9	8	7	6	5	4	3	2	1	TOTAL
Geo-ST (flash)	30	8				2%	5%	1%	1%	19%	30%	17%	25%	100%
Geo-ST (flash)	70	9			1%	3%	1%	1%	12%	17%	26%	13%	26%	100%
Geo-ST (flash)	100	10		1%	2%	1%	1%	10%	14%	8%	15%	20%	28%	100%
Geo-ST (flash)	140	11	1%	2%	1%	1%	5%	12%	10%	9%	13%	18%	28%	100%
Geo-ST (binary)	30	6						2%	4%	2%	9%	37%	46%	100%
GT		2										60%	40%	100%
MSD		1											100%	100%
MSD (CC)		1											100%	100%
SHPP		4								10%	30%	40%	20%	100%
ST	600	6						5%	15%	35%	25%	15%	5%	100%
ST	960	6						5%	15%	35%	25%	15%	5%	100%
Grid		3									15%	65%	20%	100%
HPP (RoR)		7					5%	7%	18%	35%	20%	10%	5%	100%
HPP (dam)		9			2%	6%	12%	18%	25%	20%	10%	5%	2%	100%
Wind		2										25%	75%	100%
Wind	300	3									15%	65%	20%	100%
Bagasse		3									15%	65%	20%	100%
Solar PV		1											100%	100%

For the transmission infrastructure, the disbursement schedule depends on the type. The construction period for transmission line projects in Kenya is assumed to be 100 km per year. Thus, the disbursement schedule is derived according to the length of the respective transmission line. Since the investment plan is developed on an annual basis, the assumptions for the disbursement schedule are rounded up. It foresees an equal distribution of costs over the disbursement period. For substations, a general construction period of two (2) years per substation is assumed, considering as well an equal distribution of the cost.

Along the considered investments, the final year of construction is set to be the year before the first commercial operation year. If necessary, construction periods are rounded up to full years.

9.2.2 Assumptions on generation

The power plants considered in the investment plan comprise the candidates identified under the reference expansion scenario as the principal generation expansion scenario. The cost assumptions are in accordance with the economic analysis of the expansion candidates based on their levelised electricity cost (see chapter 6.4) as well as the analysis of the least cost expansion path. For any power plants already under construction, only the remainder of the investment cost as accruing during the study period is taken into account.

An overview of the power plants to be constructed during the study period including their base investment costs is listed in Annex 9.A. For all committed plants – especially the ones already under construction – the remaining disbursed investment costs are considered as available. The upfront investments already accomplished prior to the start of the consideration period (i.e. before the year 2015) are indicated in the table as upfront investments. The information provided in the table refers to base cost assumptions.

For the implementation of the power plants, it is assumed that construction is executed directly prior to the first year of commercial operation. The grid connections of the different plants are

[206] GEO: geothermal, ST: steam turbine, GT: gas turbine, MSD: medium speed diesel engine, CC: combined cycle, HPP: hydro power plant, RoR: run of river

considered in the network analysis. They are assumed to be implemented and operational one year before the COD of the corresponding power plants.

During the study period, some power plants will reach the end of their operational lifetime. A reinvestment to account for rehabilitation of the power plants considered suitable for rehabilitation as detailed in chapter 7.3.2 is included. An overview of the power plants of concern with their rehabilitation cost and start of rehabilitation (i.e. year) is provided in Annex 9.A. The rehabilitation period takes place in the years before recommissioning the respective power plant. The rehabilitation costs are expected to accumulate in an S-shaped curve over the rehabilitation period in accordance with Table 9-2.

9.2.3 Assumptions on transmission

The transmission expansion planning in chapter 8 has been executed to determine the transmission system by the end of the study period. The following costs for the expansion of the transmission infrastructure have been derived:

- New overhead transmission lines which are under construction, committed or planned; [207]
- Grid connections becoming operational during the consideration period;
- Substations; and
- Reactive power compensation.

The required investments for transmission components have been estimated according to Kenyan market conditions.[208] Costs for way-leave and related costs are not included in the overall investment costs as their share may greatly differ from project to project. This does not allow the identification of reliable general representative costs. An overview of the transmission lines to be constructed during the long term including their base investment costs is presented in Annex 9.A.

To further allow for a continuous expansion of the transmission system in particular to connect or reinforce connection of load centres, a generic transmission line expansion for the period 2019 onwards has been assumed leading to constant annual investments.[209]

Since the network analysis focuses on the state of the transmission system in the year 2030, the network has not been simulated for each year of the period 2015-2035. It is assumed that the transmission assets are implemented in the final year prior to commercial operation. No costs for the upgrade and/or rehabilitation of the National Control Centre (NCC) are considered. The CODs of the transmission line projects have been assumed one year before COD of the generation expansion. In doing so, the future transmission system will be capable to evacuate the electricity generated in the planned power plant projects. No rehabilitation or replacement measures are taken into account for transmission or distribution assets.

[207] The HVDC link between Kenya and Ethiopia is regarded as generation capacity and covered under the generation part. However, relevant technical aspects are considered in the network study. Costs for the electrification of railway lines, i.e. flagship projects, are not considered as they are going to be defined within a separate railway electrification project (see Annex 4.E).
[208] Based on KETRACO cost assumptions and plausibility checks by the Consultant. For each voltage level, one representative configuration was selected and the cost estimate developed.
[209] A constant transmission line expansion of 200 km per year on the 132 kV level is assumed.

9.2.3.1 Cost estimates of overhead lines

The types of transmission lines and related costs during the consideration period are summarised in Table 9-3. Technical details of the transmission network expansion are provided in chapter 8.

Table 9-3: Cost of transmission lines

Type of OHL	Cost [mUSD/km]
132 kV d/c TL	0.18
220 kV d/c TL	0.24
400 kV d/c TL	0.48

For each voltage level, a representative configuration was selected and the corresponding cost assumption developed. The cost assumptions include as well reactive power compensation measures, which are mainly required due to the length of the installed overhead lines. The cost for reactive power compensation amounts to roughly 1% of the specific cost for transmission lines per kilometre.

9.2.3.2 Cost estimates of HV substations

In the study period, several HV substations will be connected to the new overhead transmission lines. Their construction period has been estimated based on the implementation of the new transmission lines. The substation types and costs are presented in Table 9-4.

Table 9-4: Cost of HV substations

Substation Configuration		Cost [mUSD]
132/33 kV TR	2 x 60 MVA	6.00
220/132 kV TR	2 x 150 MVA	10.95
400/220 kV TR	2 x 350 MVA	18.20

For each of the above types of substation, a standard design has been considered to facilitate an adequate cost estimate. This standard design includes cost for the automation system, substation building, auxiliaries and civil works. The final substation design has to be decided from case to case. However, the approach is adequate for the investment plan to result in reliable cost estimates.

9.2.4 Assumptions on distribution

In order to satisfy the increasing electricity demand by expanding the infrastructure on generation and transmission level, according distribution infrastructure will be required. It is an objective to consider these distribution costs within the investment plan as well.

To determine cost estimates for the investment plan, a suitable approach is to assume specific investment costs for characteristic distribution expansion in typical areas and relate them to the annual electricity demand growth. This approach has been pursued in the latest distribution master plan for Kenya.[210] Thus, the long-term incremental cost from the distribution master plan are considered for the investment plan. They are linked with the reference demand forecast of the present report to derive the costs on distribution level. An overview of the applied cost assumptions is provided in Table 9-5.

Table 9-5: Specific distribution cost related to electricity demand growth

Region	Specific distribution cost [USD/kW demand growth]
Nairobi	829
Urban	1,366
Rural	1,930

For the investment plan, only the distribution profiles for Nairobi, urban and rural regions are considered. The demand growth in these regions has been derived according to the results of the demand forecast in chapter 4. For each region, the demand growth is based on the delivered load at the different voltage levels (as defined in the distribution master plan) of the distribution system. It is derived from billed consumption and the load factors by consumer groups connected to the distribution system. This approach considers consumer group specific peak loads by area, which have an impact on the necessary capacity of the distribution equipment. The forecasted load from consumption beyond MV level (including flagship projects) is excluded for these costs since it is not connected to the distribution system. For these reasons the shown peak loads differ from the national peak load.

The below figure and table show the development of this load for the different regions of Kenya. It also indicates the split between the urban and rural share of the load in the Coast Region, Western Region and Mount Kenya. For the Nairobi region, the entire peak load is linked to the according urban distribution cost. The demand forecast does not differentiate between urban and rural consumption but respective connections. Therefore the split into urban and rural share is derived from the ratio of rural and urban connections. This approach can be also seen as a proxy for the expected higher distribution costs related to the foreseen enhanced rural electrification.

Table 9-6: Peak load development at substation level

Power system area	Urban / rural share	Unit	2015	2020	2025	2030	2035
Nairobi	Urban	MW	669	889	1,189	1,591	2,151
Coast	Urban	MW	199	178	249	352	504
Mt. Kenya	Urban	MW	83	74	104	155	237
Western	Urban	MW	235	225	265	384	583
Coast	Rural	MW	14	121	152	190	233
Mt. Kenya	Rural	MW	110	220	316	430	590
Western	Rural	MW	70	248	457	638	839
Total		**MW**	**1,380**	**1,954**	**2,732**	**3,740**	**5,137**

[210] Parsons Brinckerhoff, Kenya Distribution Master Plan (prepared for KPLC), Final Report, Volume I, April 2013

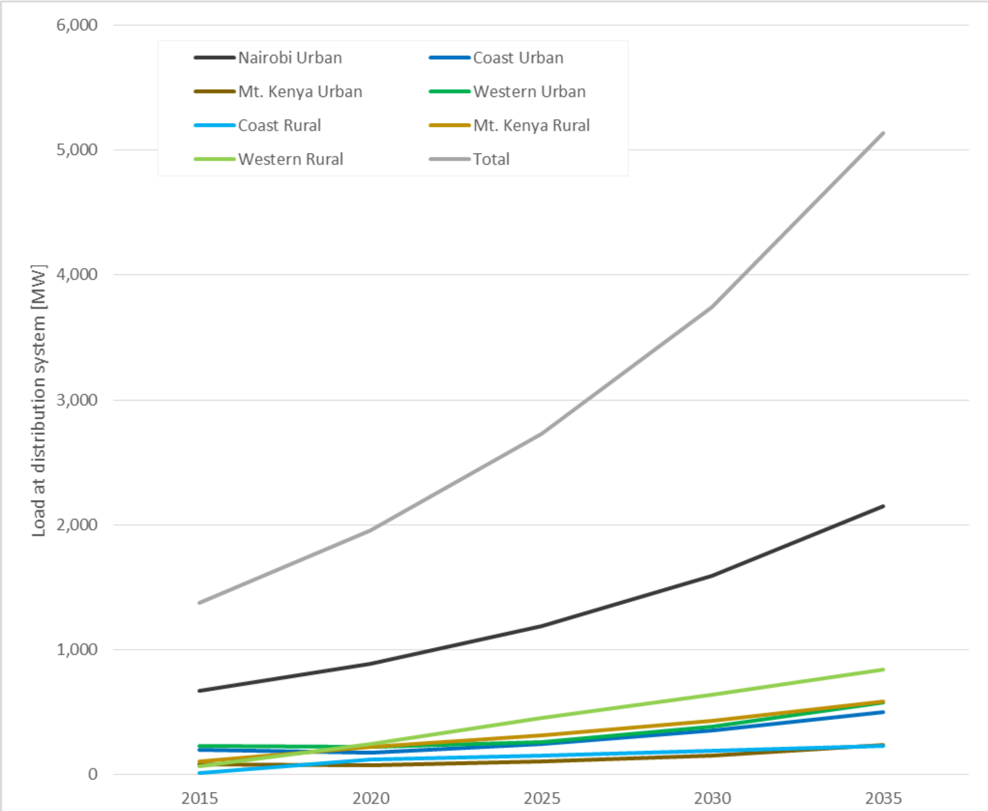


Figure 9-1: Peak load development at substation level

9.3 Results investment planning

This section provides the results for the investment plan as well as for the evaluation of the long run marginal costs of the power system.

9.3.1 Investment plan with total financing needs

Depending on assumptions for funding and inflation the investment plan results in overall investments in a range from 37 to 52 billion USD (37 billion USD for supported funding scenario, 2% inflation rate; 41 billion USD for supported funding scenario, 3% inflation rate; 52 billion USD for commercial funding scenario, 5% inflation rate). The values are expressed in nominal terms and comprise inflation, financial fees and IDC. The inflation (through the price increase of future investments compared to the base year cost estimate) has the by far strongest impact on the overall amount, resulting in a difference of 13 billion USD between the inflation rates of 2% and 5%.

A distribution of the annual costs for generation, transmission and distribution under the commercial funding scenario for 3% inflation is provided in Figure 9-2. It shows that the highest annual investments of more than 3 billion USD occur in year 2030. Investment costs for generation are also peaking in the year 2030 but are at a similar level between 2029 and 2031. Investment costs for transmission see their highest amount in the year 2026 with similar levels in the two years before

(2024 – 2025). In the years 2020/2021 the lowest investment costs occur, except for 2035. Investments in that year are only covering the distribution and transmission expansion because the generation expansion plan does not cover the period beyond 2035 which would be relevant for disbursements in 2035.

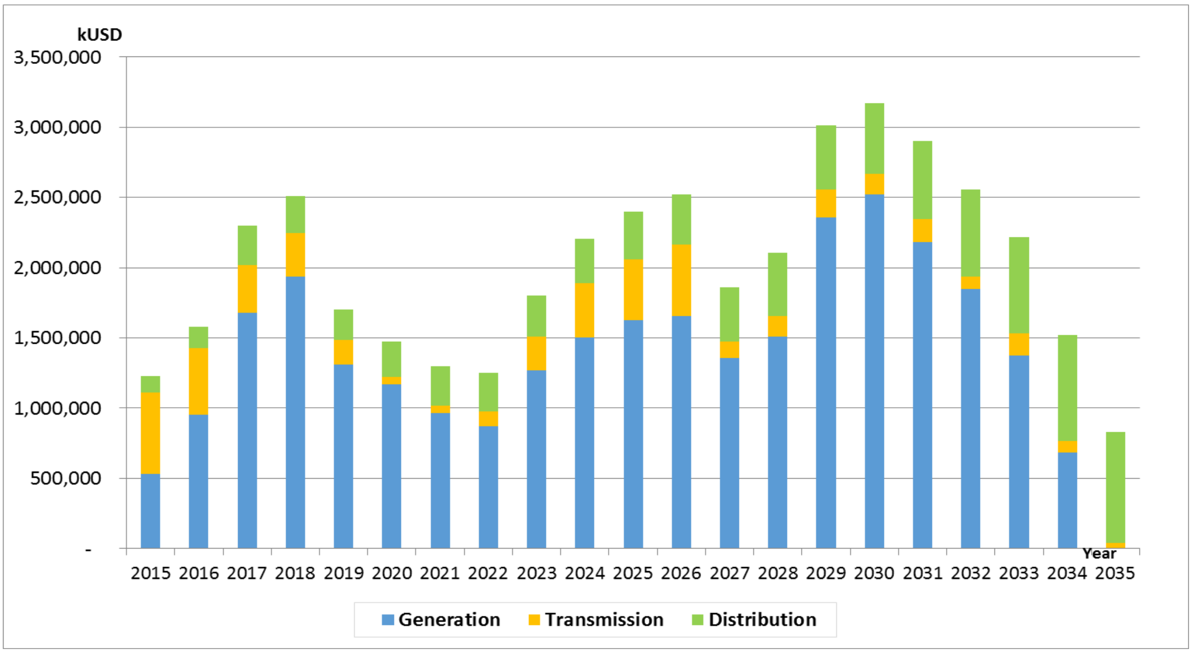


Figure 9-2: Investment costs (2015–2035) – commercial funding scenario, 3% inflation

The supported funding scenario is not presented since it provides comparable result at lower costs.

A breakdown of the costs by generation, transmission and distribution is provided in the tables below according to the considered funding scenarios and for different inflation rates. Annual figures are provided in Annex 9.B.

Table 9-7: Investment Plan – commercial funding scenario (in kUSD)

	Inflation	3%		2%		5%	
Cost Item		**Total**		**Total**		**Total**	
Generation	Expansion	28,343,064		25,710,702		34,638,205	
	Rehabilitation	960,200		883,035		1,137,571	
	Total	29,303,264		26,593,737		35,775,776	
Transmission	T/L	3,249,292		3,017,343		3,796,833	
	S/S	1,562,400		1,452,805		1,818,653	
	Total	4,811,692		4,470,148		5,615,485	
Distribution		8,328,953		7,369,327		10,699,253	
OVERALL INVESTMENT		**42,443,909**		**38,433,212**		**52,090,514**	
Present Value	(PV)	**15,972,012**	**kUSD**	**14,982,858**	**kUSD**	**18,266,678**	**kUSD**
@ Discount Factor		12%		12%		12%	
Extreme Investment	MAX	3,172,282	2030	2,745,553	2030	4,218,262	2030
	MIN	833,014	2035	685,365	2035	1,223,695	2035

Table 9-8: Investment Plan – supported funding scenario (in kUSD)

Cost Item	Inflation	3% Total		2% Total		5% Total	
Generation	Expansion	27,021,882		24,498,191		33,061,680	
	Rehabilitation	929,120		854,407		1,100,864	
	Total	27,951,002		25,352,598		34,162,544	
Transmission	T/L	3,156,991		2,930,383		3,691,949	
	S/S	1,521,683		1,414,829		1,771,534	
	Total	4,678,674		4,345,212		5,463,483	
Distribution		8,183,039		7,240,224		10,511,814	
OVERALL INVESTMENT		**40,812,714**		**36,938,034**		**50,137,840**	
Present Value	(PV)	**15,365,017**	**kUSD**	**14,409,487**	**kUSD**	**17,582,640**	**kUSD**
@ Discount Factor		12%		12%		12%	
Extreme Investment	MAX	3,045,996	2030	2,634,761	2030	4,054,631	2030
	MIN	817,773	2035	672,820	2035	1,188,970	2015

Due to the lower interest rate the supported funding scenario always leads to lower capital requirements, for absolute figures and for the present values for any discount rate. A present value expresses the current worth of a future stream of cash flows. In order to discount the investments along the future timeline to the present, a discount rate of 12% is applied. This value is in accordance with official planning figures of Kenyan utilities.[211] As a result, the present value of the investment costs of the supported funding scenario remains below the one of the commercial funding scenario. That is, 15.4 billion USD compared to approximately 16.0 billion USD for an inflation rate of 3% (constituting a difference of 4%). The difference between the supported funding and commercial scenario is for any assumed discount and inflation rate around 4%.

Hence, the supported funding scenario is the more favourable and less expensive one. However, it is considered realistic that a mix of commercial and supported funding for the expansion of the Kenyan power sector will be achieved instead of applying either one or the other. Therefore, the investment plan results provide an indication on the probable range of capital requirements also for different assumptions for price increases.

Based on this overall calculation and specific project evaluations the availability of the required volume of funding in the short, medium and long term should be investigated with lenders – both commercial and development banks.

9.3.2 Cost development of power system - long run marginal cost

There are different approaches to estimate and evaluate future costs of power systems. That is, levelised electricity costs (LEC) of the expansion path (see chapter 7), LECs of candidate technologies for different capacity factors, and short and long run marginal costs. This section applies the long run marginal costs for the evaluation of the identified expansion plan but also provides a comparison with the previously calculated LECs.

[211] The discount rate has been discussed during the investment planning mission in July 2014.

Marginal cost is the cost increase for an incremental change of output (either an increase or decrease). Here it is understood as USD per generated kWh. Marginal costs are further distinguished by their time frame: Short Run Marginal Costs (SRMC) versus Long Run Marginal Costs (LRMC). The differentiation by time frame considers to what extent capacity for output can be changed. While the capacity is assumed to be inflexible in the short term, for the long term any factor of production is assumed to be flexible. That means that LRMC represent the cost estimate for a capacity expansion scheduled earlier than initially planned, due to a change in demand.

For the present Long Term Plan (LTP) of the power system, the following applies:

- The LRMC are calculated and provided to give an indication of the cost of power supply. They answer the question "how much would it cost if in addition to the expansion plan one more kWh has to be produced". LRMC also play a role for electricity markets since they indicate costs for investments to expand the system. For instance, if wholesale prices align with LRMC, it would provide a justification that additional investments into the expansion of the market are feasible for the investors.

- Among different concepts to estimate the LRMC, the perturbation approach is considered the most suitable for this study (the same as used for LCPDP reports in the past). LRMC are calculated based on different demand scenarios. The difference of the present value of total costs between two scenarios is divided by the difference of the present value of total demand.

- Here, the critical issue is the actual difference between the two scenarios, since it should only be incremental. Towards the end of the study period the scenarios differ by 20% (i.e. low scenario below reference scenario), and 40% (i.e. vision scenario above reference scenario) respectively. However, by comparing the LRMC for various transitions between the scenarios a suitable indication should be possible. Due to the definition of the demand scenarios the focus is laid on the increase from reference to vision (the low scenario defined as a rather conservative development for risk analyses).

- The LRMC are calculated based on the generated electricity (power plant sent-out) including excess energy. This is above national electricity consumption for some years but both figures align in the long term[212]. The applied discount rate is 12%.

The table below contains the calculated LRMC for two steps between different demand scenarios.

Table 9-9: LRMC of expansion plan

Compared Demand Scenarios	LRMC for generated electricity (power plant sent-out) [USDcent/kWh]
Reference increase to Vision	9.1
Low increase to Reference	7.9

[212] The LRMC based on consumed electricity are below the LRMC based on generated electricity. This difference reflects the excess electricity as kind of "free" electricity if demand is increased. Therefore, the LRMC based on generated electricity give a more meaningful picture of the actual costs.

The average costs to increase electricity generation beyond the reference demand are 9 USDcent per kWh. This is very close to the average costs for increasing generation from low to reference demand scenario of 8 USDcent per kWh. This means that increasing electricity supply from the low to the reference scenario is done with less than increasing from reference to vision (or the other way round, reducing demand from the reference to low scenario will "only" save this amount). Both figures are below the power generation LECs for the study period, i.e. the average total costs of the power generation systems. Concluding, the similar figures indicate that the long term expansion for any scenario is done on a lower cost basis than the existing system is representing.

This indicates the following:

- Overcapacity and underutilised capacity (including sunk costs), which is already in the system or committed (the capacity factors of the generation expansion simulation partly show the underutilisation of specific power plants), will be used to expand the production in future.

- Sufficient lower cost generation potential (e.g. geothermal potential) and little need for the expansion with costly technology and fuels.

- A positive correlation between cost development and demand: the larger the demand growth the lower the average levelised costs. The marginal costs represent the reduction.

- The LRMC would not be sufficient to recover the necessary generation costs of the expansion candidates. For a discount rate of 12%, they are below any LECs calculated in chapter 6. Only geothermal and generic biomass candidates have LECs close to this value.

From this point of view, it is recommended to consider the following options:

- Increase demand[213] for electricity to reduce – in theory – average costs for all consumers.

- Avoid a slower demand growth than forecasted since this would mean an increase of costs for all consumers even in the long term. Energy efficiency is an exception because the output ("the use of electricity") remains the same, though with lower consumption at lower total costs.

[213] As experience in Kenya has shown, there are limitations to considerably increase the demand of electricity in the short and medium term through external measures. This is at least in part due to the fact that other and often more important factors influence the decision to increase consumption or production (e.g. electricity supply and costs are only one production factor for industry and commerce; higher residential electricity consumption require that the households can afford the appliances). A more actually available additional demand is the currently suppressed demand. It is estimated with some 10% of the currently served demand (see section 3.2.8). It could be tapped by improving security and quality of supply. This would probably decrease the levelised costs for power generation by utilizing the existing and committed plants in a more efficient way. However, it would require large investments mainly into the distribution grid to replace malfunctioning equipment, reinforce overloaded equipment, and extend the network. These costs could easily exceed the lower generation costs. However, these investments are necessary in the medium to long term anyway. In addition, organisational and structural challenges in the power sector (mainly in KPLC) have to be addressed to increase the quality and security of supply. This would be also necessary to connect the vast amount of potential customers which are not connected to the grid yet. This is addressed in section 3.2.2 and Annex 4.D.

- <u>Duly consider this risk when planning for the power sector</u>, in particular since past efforts to considerably increase demand from households or commerce/industry have not brought outstanding effects.

- <u>Plan and implement capacity expansion in a continuous way as the demand has grown in the past and is forecasted to grow in the future</u>. In particular, periods of high overcapacity should be avoided as they might give wrong signals to the market. Likewise, periods of a lack of capacity should be avoided as well due to the high costs of unserved energy.

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