REPUBLIC OF KENYA

Report

of the

Presidential Taskforce on the Review of Power Purchase Agreements (PPAS)*

Chairperson

Mr. John Ngumi

Presented to

H.E. Uhuru Kenyatta, C.G.H.

President of the Republic of Kenya and Commander-in-Chief of the Kenya Defence Forces

29th September, 2021

NAIROBI

***THE REPORT CONTAINS REDACTED TEXT TO PRESERVE CONFIDENTIAL INFORMATION**

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Report

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Presidential Taskforce on the Review of Power Purchase Agreements (PPAS)*

IN ADDITION, ALL ANNEXURES HAVE BEEN REMOVED

REPUBLIC OF KENYA

TASKFORCE ON THE REVIEW OF POWER PURCHASE AGREEMENTS

LETTER OF TRANSMITTAL

28th September, 2021

HIS EXCELLENCY HON. UHURU KENYATTA, CGH
President of the Republic of Kenya and
Commander in Chief of the Kenya Defence Forces
Executive Office of the President
State House
NAIROBI

Through"

DR. JOSEPH K. KINYUA, EGH
Head of the Public Service
Executive Office of the President
State House
NAIROBI

TRANSMITTAL OF THE REPORT OF THE TASKFORCE ON REVIEW OF POWER PURCHASE AGREEMENTS

As part of Your Excellency's interventions geared towards reducing the cost of electricity, on the 29th March, 2021 Your Excellency constituted the Presidential Taskforce on Review of Power Purchase Agreements *vide* Gazette Notice 3076.

The **primary term of reference** of the Presidential Taskforce was to:

"undertake a comprehensive review and analysis of the terms of all Power Purchase Agreements (PPAs) entered into by the Kenya Power and Lighting Company Limited (KPLC)"

By dint of the same Gazette Notice, Your Excellency bestowed upon myself and fifteen of my colleagues the singular honour and privilege to serve in the Taskforce as the Chairperson and Members of the Taskforce respectively.

The Taskforce undertook its assignment diligently and we concluded our mandate on 27th September, 2021. In that regard, we now have the great pleasure and honour to submit our Report to Your Excellency.

We humbly and most sincerely thank you for according us the opportunity to make a contribution towards addressing the cost of electricity in Kenya.

Accept, Your Excellency, the assurances of our highest regard.

Yours Faithfully,

JOHN NGUMI
Chairperson of the Taskforce on Review of Power Purchase Agreements

Signature of the report by Taskforce members

Mr. John Ngumi

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Chairman

Dr. Elizabeth Muli

....

Vice Chairperson

Mr. Kennedy Ogeto, CBS

....

Member

(Rtd.) J. Aaron Ringera, EBS

....

Member

Dr. James Mcfie

....

Member

Mr. Mohammed Nyaoga, SC

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Member

Ms. Wanjiku Wakogi, EBS

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Member

Eng. Stanley Kamau

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Eng. Isaac Kiva, OGW

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Dr. Caroline Kittony

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Eng. Elizabeth Rogo

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Mr. Sachen Gudka

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Eng. James Mwangi, EBS

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Dr. John Mutua

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Member

Ms. Anne Eriksson

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Member

Mr. Yida Kemoli

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Member

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Acronyms

ADB	Asia Development Bank
CMFT	Contract Management Framework Tool
COD	Commercial Operation Date
CP	Conditions Precedent
DGE	Deemed Generated Energy
EAP&L	East Africa Power & Lighting Company Limited
EAPP	Eastern Africa Power Pool
ECG	Electricity Company of Ghana
EOI	Expression of Interest
EPC	Engineering, Procurement & Construction
EPIRA	Electric Power Industry Reform Act
EPP	Emergency Power Producer
EPRA	Energy and Petroleum Regulatory Authority
FCOD	Full Commercial Operation Date
FiT	Feed in Tariff
FM	Force Majeure
FY	Fiscal Year
GDC	Geothermal Development Corporation
GDC	Geothermal Development Company Limited
GOK	Government of Kenya
GSM	Government Support Measures
GT	Gas Turbine
HFO	Heavy Fuel Oil
INEP	Integrated National Energy Plan
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
KenGen	Kenya Electricity Generating Company Plc
KEPSA	Kenya Private Sector Alliance
KETRACO	Kenya Electricity Transmission Company
KPLC	Kenya Power and Lighting Company Plc
LCA	Land Control Act
LCOE	Levelised Cost of Electricity

LCPDP	Least Cost Power Development Plan
LNG	Liquefied Natural Gas
LOS	Letter of Support
MoE	Ministry of Energy
MSD	Medium Speed Diesel
MVA	Mega Volt Amp
MW	Mega Watts
NCC	National Control Centre
NEPC	Nuclear Electricity Project Company
NPC	National Power Corporation
NT	National Treasury
NuPEA	Nuclear Power and Energy Agency
O&M	Operation & Maintenance
OAG	Office of the Attorney General
OP	Office of the President
OTS	Open Tendering System
PISSA	Project Implementation and Steam Supply Agreement
PPA	Power Purchase Agreements
PPAD	Public Procurement and Assets Disposal
PPP	Public Private Partnership
PSALM	Power Sector Assets and Liabilities Management
RE	Renewable Energy
REAP	Reverse Energy Auctions Policy
REIPPPP	Renewable Energy Independent Power Producers Procurement Programme
RERAC	Renewable Energy Resource Advisory Committee
REREC	Rural Electrification & Renewable Energy Corporation
RES	Renewable Energy Sources
ToR	Terms of Reference
VRE	Variable Renewable Energy

Executive Summary

The PPA Taskforce was appointed by HE President Uhuru Kenyatta on 29th March 2021 against the backdrop of a sustained public outcry from consumers, businesses and individual Kenyans alike, about the high cost of power supplied by KPLC, especially when compared to the cost of power in neighbouring countries and in peer economies. The Taskforce's appointment was also recognition and acknowledgment of the risk posed by comparatively high power prices to Kenya's ambitions of becoming a globally competitive, newly industrialised, middle income and prosperous country by 2030. Government is also deeply concerned about KPLC's parlous financial state, significant blame for which has been attributed by many Kenyans to the cost of power procured from IPPs. Other features that the Kenyan public find inexplicable about Kenya's power situation include the paradox of cries that Kenya has too much power generation capacity amidst widespread under-served and frustrated demand, and unreliable supply of that power. This unwelcome mix of high costs, frustrated demand, unreliable supply and a financially challenged utility arguably finds expression in Kenya's per capita power consumption ranking extremely low among peer economies.

The cost of power purchased by KPLC for onward distribution to consumers is only one component of KPLC's total costs, but it is the largest one, accounting for 66% of total revenues for FY 2020. Understandably therefore, the Government felt it imperative that as it began addressing the causes of Kenya's relatively high power costs, it starts with a review of how this power is purchased, focusing initially on PPAs entered into between KPLC and IPPs. IPPs supply 25% of KPLC's power, but account for 47% of KPLC's power purchase costs. By way of comparison, KenGen supplies 72% of KPLC's power, but accounts for 48% of KPLC's power purchase costs. Purchases from REREC and imports from Uganda and Ethiopia account for the balance 2% that KPLC purchases. Seen from this perspective, the rationale for this initial focus on KPLC's PPAs with IPPs is clear, *prima facie* there is a misalignment between the share of IPPs' contribution into KPLC's power mix and the cost of that power.

Specifically, the Taskforce's Terms of Reference were to:

1. Undertake a comprehensive review and analysis of the terms of all PPAs entered into between KPLC and IPPs;

2. Probe the compliance of the PPAs and all associated agreements with Government policies, legislation and regulations and identify what appropriate actions should be taken, including the termination or renegotiation of the PPAs;

3. Review the sustainability and viability of all independent power generation projects that have been proposed, are under implementation, or in operation, and make appropriate recommendations;

4. Review the allocation of risk between the IPPs and KPLC under the PPAs, and make appropriate recommendations;

5. Review the Take-or-Pay approach applied under the PPA structure and recommend a viable Pay-when-Taken (merchant plant) approach, or any other viable payment structure, for use in independent power generation projects;

6. Develop a suitable strategy for engagement with the IPPs and lenders, in order to achieve relief for electricity consumers and ensure the long-term viability and sustainability of the energy sector;

7. Review the prevailing methods for sourcing of IPPs and recommend appropriate alternative sourcing frameworks, including energy auctions;

8. Recommend legislative, regulatory, policy or administrative interventions for the implementation of the recommendations and strategies of the Taskforce;

9. Develop a detailed action plan for implementing the recommendations made by the Taskforce; and

10. Perform any other function or tasks as the Task Force would find necessary in order to deliver on its mandate.

In carrying out its mandate, and in order to minimise duplication and repeat work, the Taskforce also reviewed recommendations from two previous official reports on PPAs, for 2018 and 2021. The Taskforce established that very few of these recommendations have been acted upon, and by all accounts not even the 2018 was made public. There were some useful and actionable recommendations in these reports, and it is impossible to avoid the conclusion that as a country we would have found ourselves in a far better position today had we acted on them. Accordingly, one of the Taskforce's recommendations is the expeditious implementation of these previous recommendations.

The Taskforce's methodology involved:

a. Four workstreams to focus on specific areas of review. These workstreams were Legal; Policy; Technical & Financial; and Strategy, Planning & Communications;

b. Structured engagements with stakeholders, including government entities such as MoE, KPLC, EPRA, KENGEN, National Treasury; and sector players including IPPs, industry groups, consumer groups (a full list of those with whom the Taskforce engaged is set out in Annexure 7, Schedule 3); and

c. Periodic reporting back and accountability to the Cabinet Sub-Committee on KPLC as stipulated in the Gazette Notice setting up the Taskforce. During its six-month lifespan the Taskforce submitted three interim reports to the Cabinet Sub-Committee, and was invited to make one presentation.

The Taskforce has come out with a detailed set of recommendations, which are summarised in the implementation framework in Chapter 13. This framework includes timelines, responsibilities, and the instruments required to effect the recommendations. Draft instruments have also been provided. We believe that this implementation framework and the tools provided by the Taskforce will differentiate this from previous Taskforces. Getting all these recommendations implemented will take time. Being acutely sensitive to Kenyans' desire for the authorities to get to grips with high power costs as soon as possible, the Taskforce has also come up with 10 priority recommendations which will have impact within the next six months. These recommendations are set out in this Executive Summary.

The Taskforce's recommendations, both priority and medium term, have as their organising impetus and objectives the reasons why the Taskforce was established in the first place:

We will reduce consumer tariffs from an average of KES 24 per kilowatt hour to KES 16 per kilowatt hour within four months following submission of the Taskforce Report.

Our analysis demonstrates that within this period KPLC should be able to generate annualised savings of USD 69 million-USD 77 million (KES 7.5 billion-8.3 billion), and in the medium-term savings of USD 114 million-USD 122 million (KES 12.4 billion-KES 13.2 billion) on power purchases from IPPs alone, which the company should be able to share with consumers. This does not include efficiency savings and increased income that a more commercially-minded and more efficient KPLC can generate.

These savings and tariff reductions are possible and doable. We have the data. We have the implementation tools. We have, or can obtain, the expertise to drive this process from Government's and KPLC's side.

Going forward, we will look to introduce tariff predictability and stability into PPAs.

Key to this will be:

i. Benchmarking proposed IPP tariffs against KenGen's tariffs for technologies where KenGen is present. In turn, pressure will be maintained on KenGen to keep working on efficiencies and adopt innovations that drive down costs and, therefore, tariffs; and

ii. Exploring the use of KES as the PPA currency.

In the drive to get to these lower tariffs, the Government of Kenya will fully adhere to contractual obligations and provisions.

We recognise fully that both Government and KPLC have entered into contracts with IPPs. We will work within the stipulations of these contracts.

Underpinning our recommendations is the goal of having a rational, fair, predictable, consistent and accountable PPA procurement and monitoring process.

We cannot afford a system that relies on investors having to spend copious amounts of time and resources divining who is/are the real power/s behind decision making, what will make him/her/they decide favourably, and when that will be. If we continue with what has been a capricious way of arriving at decisions, we will find ourselves forever constituting Taskforces to get us out of self-made problems. As it is, this is the fourth such Taskforce on PPAs in four years, including a short lived one earlier this year. We cannot go on like this. The uncertainty surrounding the PPA process is unfair to Kenyans and investors alike, and contributes to a "Kenya premium" being levied on IPP projects.

We must plan better for our power needs.

The paradox of power generation overcapacity amidst unmet or frustrated demand has its roots in how we plan for our power needs. Aspiration must be matched by realism regarding power demand patterns, with regular and frequent updates in order to avoid the kind of imbalances that we have today.

Institutional coordination among energy sector players is critical to our attaining sustainable, affordable and reliable power.

We have a multiplicity of players involved in IPPs/PPAs. It is critical that they work with clear objectives and mandates if we are to get the best out of IPPs/PPAs.

Right-fitting KPLC's organisational and operational structures is now a strategic imperative, and not only because of PPAs.

In the process of carrying out its assignment, and notwithstanding that its mandate was not to review KPLC, the Taskforce came to the firm conclusion that any recommendations it made would be redundant if not accompanied by comprehensive reforms to the organisational and operational structures of KPLC to make it fit-for-purpose, its purpose being to deliver affordable, accessible and reliable power while generating surpluses to fund its activities and deliver returns to shareholders.

Kenya has chosen the path of a commercially driven state owned entity to be the sole (for now) power utility. Like any other commercial enterprise, KPLC's vision ought to be driven towards maximising shareholder value by enhancing customer experience, business expansion, and managing operational costs. Based on submissions received, and also based on its own analysis, the Taskforce believes reforms are urgently needed at KPLC, and recommends the rapid commencement and conclusion of such reforms in the following areas:

i. Organisational Structure;

ii. Procurement Reform;

iii. Management of System/Technical Losses;

iv. Governance Reforms; and

v. Financial Restructuring.

Regarding PPAs specifically, the Taskforce experienced delayed or non-existent provision of critical information from KPLC, causing initial delays in the commencement of the Taskforce's work. While information did eventually trickle in following persistent follow ups with KPLC's management and, in some instances, engaging the KPLC Board to push KPLC's management to provide requested information, in the end there was information that the Taskforce simply did not receive. Such information includes some IPPs' audited financial models; tender evaluation reports for thermal plants, and data relating to the monitoring of PPAs, including fuel charges. This lack of cooperation forced the Taskforce to devise workarounds in order to overcome the information deficiency.

This experience is one that the Taskforce believes needs serious and urgent attention since it is reflective of broader problems at KPLC. There are two conclusions to be drawn to this inability or refusal to provide information:

i. KPLC does not have the information. This would be an extremely alarming situation. Power costs accounted for KES 87.5 billion or 66% of KPLC's total sales in FY 2020. Of this, IPPs accounted for KES 44.4 billion or 47% of total power costs. Given the amounts involved and their impact on both KPLC and consumer power prices, it is simply near inconceivable that KPLC would not adequately monitor the performance of suppliers to confirm that it is paying for what it gets; or

ii. KPLC has the information but refused to release it. This speaks to an attempt to defeat efforts aimed at streamlining the power sector in order to make power an effective enabler of economic development.

Either conclusion is extremely alarming in the extreme. In order to assist the KPLC Board get control of what appears to be a situation of management helplessness, incompetence or defiance, the Taskforce wrote formally to the Board pointing out these information deficiencies, and also recommending that the Board urgently institutes a forensic audit of:

i. How existing PPAs were entered into and how they are monitored; and

ii. An audit of KPLC’s key commercial customers in order to determine the causes and extent of system losses.

The following are priority recommendations to be implemented within 6 months.

1. Set up an Implementation Committee, reporting to the Cabinet Sub-Committee on KPLC, to commence implementation of the Taskforce’s recommendations, with an initial one-year mandate.
2. Within four months, enter into and conclude negotiations with IPPs on reductions in PPA tariffs. Such negotiations to be within existing contractual arrangements.
3. All unsigned PPAs to be cancelled. This will give room for any new PPAs to be aligned to the LCPDP as reviewed and, where necessary, revised under the new arrangements being recommended by the Taskforce.
4. Institute and intensify reforms at KPLC to refit it into a proper commercial entity, with the reform process being under the oversight of the PPA Taskforce Implementation Committee. This reform process to be undertaken by the KPLC Board.
5. KPLC to take the lead role in LCPDP formulation and related PPA procurement.
6. KPLC to institute Due Diligence and Contract Management frameworks for PPA procurement and monitoring. We have provided drafts of these tools.
7. KPLC to institute one and five-year rolling demand & generation forecasts and associated models.
8. KPLC to adopt standard PPAs and proposed Government LOS. We have provided drafts of these documents.
9. Forensic audit by KPLC on all PPAs’ procurement and monitoring and also an audit of system losses.
10. In line with the Constitutional stipulation for transparency in public sector dealings, KPLC’s annual reports to include the names and beneficial ownerships of IPPs with which it has contractual arrangements.

1. Introduction

1.1. The Taskforce

Kenya's long-term development blueprint, the Vision 2030, aims at transforming Kenya into a globally competitive, newly industrialised, middle income and prosperous country. Efficient, accessible, and reliable infrastructure is identified as an enabler to achieving sustained economic growth, development and poverty reduction by lowering the cost of doing business and improving the country's global competitiveness.

The energy sector is expected to play a critical role towards achievement of the Kenya's Vision 2030. Access to adequate, affordable, and reliable energy supply is necessary to reduce the cost of doing business, spur growth of enterprises and industries, and accelerate the realisation of "The Big Four" Plan. Consequently, the Government has allocated substantial resources for the development of energy infrastructure, including exploitation of renewable energy resources.

Unfortunately, Kenya continues to suffer from a significant energy over-supply, and consumer tariffs remain high. Current PPAs costs are perceived to be high, placing a large financial burden on both KPLC and consumers. It is for this reason that the Taskforce on Review of PPAs was established by H.E. Hon. Uhuru Kenyatta, President and Commander-in-Chief of the Kenya Defence Forces on 29th March 2021 vide Kenya Gazette Notice No. 3076.

The PPA Taskforce's mandate covers, in broad terms, the review and analysis of PPAs entered into between KPLC and power producers, and the review of the sustainability and viability of IPPs and the energy sector in Kenya. The analysis is geared towards assessing the terms, number and mix of PPAs, the aim being to secure reductions in the overall cost of power.

Mr. John Ngumi was appointed Chair of the Taskforce. The membership of the Taskforce comprised experts knowledgeable and experienced in diverse fields relevant to the assignment inter alia; Legal, Finance, Economics, Engineering, Public Policy and Public Private Partnerships (PPPs).

The Taskforce membership was as follows:

1. Mr. John Ngumi – Chairman
2. Mr. Kennedy Ogeto
3. (Rtd.) J. Aaron Ringera
4. Dr. James Mcfie
5. Mr. Mohammed Nyaoga

6. Dr. Elizabeth Muli
7. Eng. Stanley Kamau
8. Ms. Wanjiku Wakogi
9. Eng. Isaac Kiva
10. Dr. Caroline Kittony
11. Eng. Elizabeth Rogo
12. Mr. Sachen Gudka
13. Eng. James Mwangi
14. Dr. John Mutua
15. Ms. Anne Eriksson
16. Mr. Yida Kemoli

The Joint Secretaries were:

1. Mr. Jasper Mbiuki
2. Ms. Lillian Abishai
3. Ms. Elsie Mworia

The Taskforce co-opted the other members with the necessary technical expertise towards expeditious performance of its mandate. The resource persons were; Mr. Eric Mwangi, Mr. Robert Mahenia, Eng. Julius Micheni Mwathani, Dr. Grace Njeru, Eng. Patrick Idawo Mawala, Dr. Stephen Ikiki, Ms. Salome Karei Mwenda, Mr. Leonard Yegon, Mr. Tom Maruti, Mr. William Ngugi, Eng. Newton Orondoh, Eng. Christopher Shibuyanga, Mr. Owiti Awour, Ms. Naomi Githui, Ms. Maggie Campbell, Mr. Alex Mwaniki, Mr. Benedict Nzioki, Mr. Bramwel Ole Lekoroi, Mr. Muriuki Muriungi, Ms. Mary W. Murugu, Mr. Raphael Ngetich, Ms. Purity Njeri Wangigi, Ms. Yegon Linda Chelagat, Ms. Emily Mukami Njiru, Mr. Gabriel Mathenge Mwangi. Ms Joy Wanjugu Maina and Ms Mercy Wangui Mwaura

1.2. Terms of Reference

The Taskforce's terms of reference were:

a. Undertake a comprehensive review and analysis of the terms of all Power Purchase Agreements (PPAs) entered into by the Kenya Power and Lighting Company (KPLC);
b. Probe the compliance of the PPAs and all associated agreements with Government policies, legislation and regulations and identify what

appropriate actions should be taken, including the termination or renegotiation of the PPAs;

c. Review the sustainability and viability of all independent power generation projects that have been proposed, are under implementation, or in operation, and make appropriate recommendations;

d. Review the allocation of risk between the independent power producers and KPLC under the PPAs, and make appropriate recommendations;

e. Review the Take-or-Pay approach applied under the PPA structure and recommend a viable Pay-when-Taken (merchant plant) approach, or any other viable payment structure, for use in independent power generation projects;

f. Develop a suitable strategy for engagement with the independent power producers and lenders, in order to achieve relief for electricity consumers and ensure the long-term viability and sustainability of the energy sector;

g. Review the prevailing methods for sourcing of independent power producers and recommend appropriate alternative sourcing frameworks, including energy auctions;

h. Recommend legislative, regulatory, policy or administrative interventions for the implementation of the recommendations and strategies of the Taskforce;

i. Develop a detailed action plan for implementing the recommendations made by the Taskforce; and

j. Perform any other function or tasks as the Taskforce would find necessary in order to deliver on its mandate.

1.3. Methodology

The Taskforce established four specific workstreams among its members, namely Technical & Financial; Legal; Policy; and Strategic Planning & Communications. Working through workstreams ensured in-depth analysis and coverage of all issues enumerated in the ToR. A detailed work plan of the Taskforce was developed highlighting the procedures, timelines and processes to be adopted in accomplishing the tasks. The individual work streams' plans were based on the Taskforce Plan.

The respective work streams held weekly meetings to discuss their findings and offer progress updates. Thereafter chairpersons of the respective work streams also met weekly to discuss weekly reports of their activities and to ensure alignment of the same. The Taskforce held biweekly meetings to deliberate on the workstreams' weekly reports. The meetings were conducted both physically and online in observance of Ministry of Health Guidelines on Covid 19 Management.

The Taskforce examined various literature materials that included contracts, energy policies, the Constitution, energy laws and other statutes, regulations, standards, codes, reports, previous studies on different aspects in the electricity sub sector, financial statements and models. This exersice also included reviews of comparative jurisdictions to provide context.

Through newspaper advertisements, the Taskforce invited members of the public and other stakeholders to make submissions. Questionnaires were also used to capture some of the stakeholders' submissions. Other responses were provided in the form of presentations and oral interviews during stakeholders' meetings. The Taskforce also benefited from previous reports on PPAs, and recommendations thereof.

1.4. Interpretation of the ToR

The ToR were detailed and specific on the tasks the Taskforce was to undertake. The Taskforce assessed and analysed all the issues as follows:

i. Legal, technical and financial reviews of PPAs for IPPs projects both operational and in the pipeline;

ii. Reviewed key clauses of PPAs and whether these align with international best practices;

iii. Reviewed risk allocation criteria among the several parties to PPAs, and whether applicable risks were allocated prudently;

iv. Assessed IPPs procurement process ranging from the planning phase, feasibility, tendering, PPAs negotiation and approval, project construction, operation and maintenance;

v. Reviewed and analysed the mandates of various energy sectors institutions, highlighted duplication of roles and how they can perform their duties efficiently and effectively;

vi. Reviewed and analysed applicable laws, legislation, policies and proposed appropriate changes;

vii. The Taskforce held consultative forums with diverse stakeholders who provided valuable input; and

viii. The Taskforce has made appropriate recommendations necessary to improve the contracting process of IPPs; ensure energy security in the country; enhance the operational efficiency and financial viability of the off-taker; and derive balanced benefits to consumers, investors and other sector stakeholders.

1.5. Emerging experiences

The establishment of the Taskforce was variously received by different segments in the sector. Independent Power Producers (IPPs) had distinct perceptions about the purpose of establishment of the Taskforce and its outcomes. Various concerns were raised about the implications of the Taskforce's mandate on power purchase agreements, and in particular the Government's commitment to honoring its obligations.

From the outset, the Taskforce reached out to KPLC's management requesting information and documents critical to the Taskforce's work. Requests included financial and technical information relating to PPAs. The Taskforce's experience of KPLC's responses to these requests was one of disappointment. Documents and information did not come at all, came in very slowly, or contained scant/inadequate detail.

Specific requests for information on IPPs' compliance with laws and regulations, any breach or misrepresentation on the part of KPLC and/or the IPPs, or fraud on the part of IPPs, elicited curt answers without adequate supporting evidence. Critical agreements that must accompany PPAs such as direct agreements, EPC agreements, lease agreements, O&M agreements, PISSA, fuel supply agreements among others were not supplied. Notwithstanding these documentation and information challenges, the Taskforce determined it would work with what was available from KPLC, and with information in the public domain or from other stakeholders, to come up with its analyses, findings and recommendations. A summary of key information that was not availed to the Taskforce by KPLC is set out in annexure 1 under Schedule 1.

The Taskforce does, however, recognise and acknowledge that efforts were eventually made through the assisstance of the KPLC Board to avail PPAs in a data room for our perusal. The Taskforce was thus able to proceed with the information provided, as well as available published reports, and eventually make recommendations as captured herein.

2. Rationale for Power Purchase Agreements and the history of their renegotiations in other jurisdictions

2.1. What is a Power Purchase Agreement?

A PPA is generally the primary contract between the off-taker and a power producer. Parties come together and agree to buy and sell an amount of power to be generated from a renewable or non-renewable source.

PPAs are used as procurement and financing tools. Electricity sellers are project developers or independent power producers that own the technology or the project assets. The buyers range from state owned utility companies to private companies and individuals. PPAs are also critical tools for investors as they are used to pass on demand risk to off-takers. The PPA, in effect, reduces cash flow uncertainty and increases the security of returns on capital investment.

The PPA may require the IPP to make available to the purchaser an agreed level of capacity at the power plant and deliver the energy generated in accordance with its provisions. The pricing regime in the PPA typically has two components:

1. An availability or capacity charge, which is payable by the off-taker in consideration of the power plant operator making generation capacity available to the off-taker, whether or not the off-taker actually takes electricity from the power plant. This component is typically designed to provide a revenue floor for the project and is the primary channel through which each project proponent recovers its fixed costs; and
2. An output charge which is usually referenced to the volume of electricity actually delivered and is intended to cover the project company's variable costs.

Typically, private project proponents and lenders will require PPAs to run for a long term to guarantee investment recovery. PPAs are usually signed for a long-term period averaging 20 to 30 years.

PPAs are an increasingly common tool for funding renewable energy. For the utility company, they bring predictability in cost outlay. For the project developer, they ensure a secure, bankable revenue stream. The difficulty is in achieving a pricing model that works for all parties. The result needs to strike a balance between the financial needs of the buyer and the seller. If either party is significantly disadvantaged, then the long-term viability of the PPA will be put at risk.

2.2. The role of IPPs

There are several reasons, which make a country adopt the IPPs model in the generation segment of the electricity value chain.

The process and model of introducing IPPs in a country's power generation system may differ among different jurisdictions but the objectives tend to be similar including:

a. Attract private investment to meet rapidly growing electricity needs in a situation where the Government's budgetary resources are inadequate to meet the infrastructural investment necessary for power development;

b. Reduce electricity costs though competitive procurement of power projects;

c. Assign risks to the parties who are best placed to manage them; and

d. Bring into play off balance sheet financing.

Some jurisdictions prefer to have IPP participation though joint ownership. There are countries who opt to make all generation competitive and have subsequently sold all existing generation to IPPs.

The selected IPP programme in a country must fit with the nature of a country's overall electricity sector restructuring plans. In some countries, the restructuring results in new power generation being constructed by IPPs whilst in other jurisdictions, only some generation plants will be undertaken by IPPs. In Kenya, IPPs have invested in diverse technologies and accelerated the rate of power generation. The single buyer model is the one which exists in Kenya, and typically has the following features:

i. A single off-taker who buys all the power generated by the various generators;

ii. The single buyer has monopoly over transmission network and over sales to customers;

iii. Generation is subject to competitive bidding and is sold to the single buyer under a long-term contract;

iv. Customers remain captive and an independent regulatory authority is important for purposes of balancing the investor and the consumer interests. This is one of EPRA's functions;

v. The risk allocation criteria are critical and regulators are required to ensure that the same are properly allocated among the parties;

vi. The model relies on the financial viability of the underlying PPAs; and

vii. The creditworthiness of the off-taker is key, with different forms of credit enhancements being used as support.

2.3. Kenya's history with PPAs

Prior to the introduction of IPP, Kenya relied primarily on concessionary funding from multilateral and bilateral agencies to finance new power investments. Beginning in the 1990s, however, global donor trends shifted toward encouraging private sector participation in infrastructure with concessionary funding being targeted at health and social services.

In 1996, GoK in collaboration with the International Monetary Fund and the World Bank, developed the Economic Reforms for 1996-1998 Policy Framework to turn around the economy. The energy sector had stagnated due to lack of financing and, with the shift in donor trends towards private participation in infrastructure financing, injection of new investment from the private sector became a necessity. As a result, the Government prepared a rolling five-year least cost investment programme to attract urgent investments in power generation, transmission, and distribution as well as investments in other energy sector areas

In July 1996, GoK floated an international tender for a contract to Build, Own and Operate (BOO) a geothermal power facility using geothermal resources. This geothermal plant, Olkaria III, was an addition to two other geothermal facilities Olkaria I and Olkaria I1 which are owned and operated by KenGen. In November 1998, the KPLC signed the first IPP with Orpower 4 Inc. for an 8MW geothermal plant.

Since then, IPPs have increased their investments in various technologies ranging from thermal, solar, wind, cogeneration, hydro among others. The current number of PPAs between KPLC and power producers is tabulated under annexure 1 in Schedule 2.

2.4. IPP merits and challenges

The introduction of IPPs in a country's power generation system provides not only benefits but also has resultant challenges.

The advantages of IPPs include:

i. They facilitate resource mobilisation particularly funding from private investors;

ii. They have high levels of efficiency geared to maximising their returns;

iii. They are able to access the latest technology compared to public institutions;

iv. The diversification in different technologies improves the energy mix and overall energy security;

v. They assist in enhancing local capacity and expertise in certain technologies; and

vi. They are able to be deployed within a short period particularly where a country is experiencing power shortages.

Some of the challenges associated with IPPs include:

i. Forex risk disadvantages both the Government and the off-taker as most of the IPPs are denominated in foreign currencies, while off-taker revenue is in local currency;

ii. High costs associated with IPPs result in increased tariffs to end consumers;

iii. Guarantees required by investors and lenders in the form of Government Support Measures increases Government indebtedness;

iv. There are some IPPs which are incorporated and domiciled in certain jurisdictions to avoid tax obligations;

v. Some IPPs have been involved in corruption and other malpractices; and

vi. Due to their relatively strong financial positions, there are IPPs which tend to capture both the off-taker and associated government authorities, thus gaining the ability to extract certain favours.

To ensure optimal output from the IPPs, the Government has to ensure that appropriate measures are in place to guard against the negative aspects of IPPs.

Since 1996, the development of power generation capacity through IPPs using various technologies has evolved and accelerated, as will be demonstrated hereafter.

2.5. Analysis of renegotiation of PPAs in other jurisdictions

PPA reviews have been undertaken in other jurisdictions with varying results. The common parameters seem to be that initially a country, due to generation constraints and with limited financial resources, seeks private investors to hasten increases in power generation. In most cases, the country’s national distribution company is faced with two conflicting scenarios: the urgent need for power; and the very high costs that in most cases come as a consequence of meeting this urgency.

The Taskforce reviewed how other jurisdictions had gone about seeking renegotiations of PPAs, the purpose being to benefit from these jurisdictions’ experience and learnings therefrom. Selection of the specific countries for analysis was made was based on recent reviews undertaken in Africa, and comparable global regions. South Africa was moving towards energy auctions, while Ghana is of a comparable economic size and generation capacity to Kenya.

2.6. The review of PPAs in Ghana

In 2017 the Ministry of Energy, acting on the directive of the Office of the President of the Republic of Ghana, constituted a PPA Review Committee to review the fiscal and legal implications of PPAs executed between Electricity Company of Ghana (ECG) and IPPs for both thermal and renewable PPAs portfolios for the period 2018 – 2027. Ghana had an installed capacity of 5,288 MW as at December 2020. This comprised of thermal, hydro and other renewables.

Ghana's electricity sub sector had experienced challenges related to overcapacity, uncoordinated power planning, impeded competition among players, high debts attributed to utilities and opaque power procurement process. Some of these handicaps are akin to what is being experienced in Kenya's electricity sector.

There were 32 PPAs executed for the generation of power in Ghana. The Ministry of Energy had signed contracts with Emergency Power Producers (EPPs). Most of these PPAs were procured through unsolicited bids limiting competition, and resulting in high tariffs and were arranged with Take or Pay clauses placing a high financial burden on the offtaker. Moreover, there was non-disclosure of essential information to the public, which was vital in evaluation of project viability and the long-term aggregate cost of such IPPs. The parallel negotiations of PPAs by both the ECG and the Ghanaian Ministry of Enegry resulted in excess generation, which had to be paid for even if not utilised. The excess capacity charges, guaranteed by the Government, had resulted in enormous fiscal challenges that threatened the viability of the entire energy sector.

In order to avoid additional excess capacity costs, the Committee concluded that certain PPAs would need to be terminated and/or modified (deferred or downsized). The terminations and modifications themselves come at a cost and the Committee recommended various scenarios to terminate or modify these PPAs. The Committee concluded that:

a. Termination of 11 PPAs at a cost of $402 million, instead of maintaining them and paying an annual average capacity cost of $586 million over the subsequent 13 years.

b. Eight PPAs with a total capacity of 2,070 MW were to proceed uninterrupted.

c. Seven PPAs with a total capacity of 2,960 MW were to be postponed.

d. Rescheduling planned commercial operation dates, and in some cases reduced tariff charges, for "pipeline" projects (i.e., projects with executed PPAs but that have not yet reached financial close).

e. Restructuring of PPAs for those projects in operation or those that were expected to shortly reach commercial operation in an effort to minimise tariffs and/or "take-or-pay" obligations.

In August 2019, the Minister of Finance announced the commencement of a three-month collaborative process to restructure the PPAs.

A moratorium had been placed on signing new PPAs, and all future PPAs are to be conducted through open and transparent competitive procurement processes. It was noted that though renegotiation would save the country money, investor confidence was expected to dampen in a situation where contracts were subject to regular renegotiation. It is not clear how the renegotiation process hasprogressed.

2.7. Power Purchase Agreements review in South Africa

Eskom is a state owned entity with vertically integrated operations that generate, transmit and distribute power. Eskom generates 95% of the electricity used in South Africa. The company had entered into 20-year PPAs with IPPs procured under the first two bid rounds under the country's flagship programme, Renewable Energy Independent Power Producer Procurement Program (REIPPPP). In 2011 and 2012 a total of 47 generation projects were procured during the initial two bid windows.

In early 2019 the South African Government, through the Ministry of Public Enterprises and Ministry of Mineral Resources and Energy indicated that they proposed a renegotiation of contracts between IPPs and Eskom.

The stakeholders of IPPs reacted to the intended PPAs renegotiations with concerns relating to contract sanctity, certainty of the energy sector among others.

Several stakeholders sought formal communication, but the Government through the Public Enterprises Ministry clarified it had no plans to scrap costly contracts with renewable energy independent power producers but was trying to renegotiate the contracts down to more reasonable prices instead. No further information is available as to the conclusion of this renegotiation process.

2.8. The Philippines Independent Power Producers Contract Reviews

The Philippines geographical landscape, which comprises over 7,000 islands, presents formidable challenges in meeting power demand. The three largest islands; Luzon, Visayas and Mindanao account for 75% of all energy demand and 87% of the country's installed capacity.

The IPPs entered the Philippine power market in 1988, under Executive Order 215 of 1987 from President Aquino towards finding a solution for power shortages in the country. The Executive Order enabled the private generators to establish power plants and supply power to both National Power Corporation (NPC) and local distributors, thus ending NPC's monopoly in generation, though state monopoly on transmission continued.

The first contract for an IPP generation was executed in 1988 and subsequently the government of the Philippines had signed contracts with more than 40 IPPs, and by 1994 had more IPP contracts than the rest of the developing world combined.

The entry of IPPs into the Philippine power registered immediate benefits as the power shortages decreased within a short period. The rapid build-out of IPPs during the 1990s and the impact of the Asian financial crisis in 1998 led to the cost of electricity increasing dramatically due to a combination of the high fixed cost of the IPPs (capacity payments or minimum offtake) and the escalating foreign exchange liability stemming from heavy reliance on foreign capital.

Due to the power shortage crisis when the IPPs first came into the country, IPPs bargaining ability was higher than that of the government. To facilitate the immediate entry of IPPs, the government took on the following risks:

a. Market Risk: "Take or Pay" provisions that guaranteed payment for the contracted electricity regardless of whether or not these were fully generated;

b. Fuel Risk: the off-taker either was to provide the fuel or assume the fuel price and availability risks;

c. Foreign Exchange Risk;

d. Sovereign Guarantee; and

e. Tax exemption was also granted

The take-or-pay or capacity payments obligations provided in the PPAs became unsustainable. With progressive devaluation of the Peso, the price per kWh began to surge. The increased charges were passed directly to consumers.

During the period of financial crisis, the off-taker, though experiencing financial challenges, continued with its payment obligations as per the PPA terms until the 2001 electric industry reform law mandated an Inter-agency Review of the IPP Contracts. The review process of the PPAs resulted in a highly publicised renegotiations exercise of IPP contracts effort in the IPP sector. The renegotiations generated significant costs savings for the Philippine government. The actual modifications to specific contracts were minimal as only a few contracts necessitated the lender's approval to specific clauses of PPAs.

In addition to the burdensome Take or Pay requirements, the IPP contracting process had the following negative elements:

a. There was opaqueness in financing costs, rising foreign exchange liability, the offtake arrangements were not transparent and over time the IPPs became a financial burden to the economy.

b. There was political interference in setting tariffs and day-to-day management of the power sector. Corruption and management failure had been manifested in the IPPs procurement process resulting in excess capacity.

c. There was general sector mismanagement in procurement of power plants.

d. There was mounting currency mismatch since revenues are paid in Pesos and the IPPs payments were denominated in foreign currency.

e. There were delays in approving tariff increases for the off-taker.

f. IPP projects were procured on a fast-track basis without competitive bidding. Typically, the Government negotiated with unsolicited bidders, and agreements were reached hurriedly.

As the financial crisis raged on and the PPA review was under progress, the Philippines Government also embarked on restructuring the previous state-owned monopoly power sector into an unbundled, privatised merchant system where power is sold in the spot market.

Towards solving the financial crisis some of the measures adopted were as detailed below, and were anchored on Electric Power Industry Reform Act (EPIRA) No. 9136:

a. Power Sector Assets and Liabilities Management Corporation (PSALM) was created to own and manage the assets and liabilities of the off-taker NPC and National Transmission Corporation. The debt liabilities of NPC included payments due to IPPs.

b. To ease PSALM's financial burden, the Government exercised the option of assuming part of PSALM's long-term liabilities. A universal charge payable by consumers was introduced and utilised to defray some of PSALM's liabilities.

c. The country's Energy Regulatory Commission (ERC) also approved additional increases on tariff to cover generation costs, recovery for fuel costs and currency fluctuations.

d. A competitive market for electricity in the Philippines was introduced.

e. The establishment of an open-access transmission system needed to support a competitive wholesale market for electricity and also the establishment of open-access distribution systems to support competitive markets in electricity retailing.

f. Promotion of energy conservation and demand-side management to supplement efficiency gains from competitive markets.

g. The Philippine Electricity Market Corporation (PEMC) was created to supervise the establishment of the wholesale electricity spot market (WESM), which started commercial operations in June 2006.

h. The Department of Energy (DoE) was reorganised to perform its expanded mandate of power sector planning and supervision of power sector restructuring.

i. To ease PSALM's financial burden, the Government exercised the option of assuming part of PSALM's long-term liabilities, as provided for by EPIRA Act. The Government assumed a portion of PSALMs financial obligations, totaling around P200 billion.

j. Following EPIRA's mandate, PSALM had renegotiated substantially 20 of the 35 contracts that NPC had with IPPs, resulting in savings of about $1 billion in discounted present value terms.

The Asian Development Bank (ADB) supported three IPP projects with private sector loans and investments. The bank was a lender in some of the projects and it formulated some proposal that would mitigate the financial constrains that accrued from IPPs projects which included:

a. Funding programmes that increased transparency in the formulation, procurement, and implementation of ADB financed projects.

b. Promote the use of internationally accepted and transparent procedures for evaluating IPP bids.

c. Competitive bidding for the IPPs to guard against onerous, unsolicited bids.

d. Delays in project implementation to be reduced. ADB noted delays had occurred in all phases of the project cycle and the same situation continued to recur. The delays at the pre-qualification and tendering phase were approximately the same as delays during construction.

   The construction phase of projects was delayed by about 20 months, mostly due to; land acquisition and resettlement challenge; contractors' financial problems of the contractors and lack of experienced labour. It noted that he reasons for delays in implementation were complex. ADB advised that the roles of the parties involved should be examined separately to find ways to minimise future project delays.

e. Executing agencies were required to improve their capabilities to administer and coordinate the implementation of complex projects. Procurement guidelines and procedures designed to facilitate fair competition and reduce corruption.

f. The ADB was not to approve loans or make it effective when necessary conditions for starting project implementation were not in place.

g. Project costs were to be controlled by improving governance and reducing corruption.

h. Transactional costs associated with heavy reliance on foreign consultants contributed to higher project costs in the Philippines' power sector and could be reduced by more participation and enhancing capacity of the off-takers technical staff. ADB proposed the adoption of the "Keep It Simple and Transparent" principle at all stages of the project cycle. The time required and the number of approvals needed to be reduced.

i. To address the currency mismatches local financing was one of the new financing instruments and modalities proposed as currency mismatches created major problems for power sector projects. The Philippines had borrowed heavily from different international financing agencies.

The Philippines' experience provides a good lesson, and benchmark from which Kenya can draw, and from which the Taskforce has been particularly guided.

2.9. Conclusion

This analysis of PPAs renegotiation in other jurisdiction reveals that reviews of PPAs is not exceptional, and that the same is usually guided by the need to address the mismatch of capacity and demand, and the resultant high cost of power. One critical learning from the Philippines' experience is need to accompany the review and renegotiation process with institutional restructuring actions. There is also need to focus on financial restructuring interventions and incorporation of transparent and accountable energy sourcing frameworks in order to facilitate fair competition and enhance good governance. This learning also reveals the need to delicately balance between government interests and responsibilities to its people, as against those of other stakeholders, particularly investors and lenders.

3. Previous Taskforces on Power Purchase Agreements in Kenya

3.1. Introduction

The need to review PPAs and electricity generation tariffs was first mooted in 2016 with the realisation that the country was still experiencing high cost of energy despite increase in uptake of renewables such as geothermal power. Retail tariffs remained high due to capacity payment obligations that have to be paid while the supply outlook was indicating possibility of having excess capacity in the system. At the same time, global prices for wind and solar power were declining drastically mainly driven by technology, innovation and economies of scale arising from increase in adoption. With this realisation, the Cabinet Secretary for Energy and Petroleum appointed a Taskforce to review PPAs on 3rd January 2017 vide Gazette Notice No. 862 of 2017. The Taskforce reviewed the PPAs entered between IPPs and KPLC and recommended appropriate policy action that would enable the Government achieve value for money on all PPAs in force as at 3rd January, 2017. The Taskforce submitted its final report to the Cabinet Secretary on 31st May 2018, making several recommendations. The details are attached in annexure 2 in Schedule 2.

The findings of the 2018 Taskforce were not made public, and several of its recommendations were not put in place for varied reasons outlined hereafter.

On 9th April 2020, the Cabinet Secretary for Energy appointed an Inter-agency Committee on Independent Power Producer' PPAs. The Committee's terms of reference were:

a. To review and update the recommendations of the Report of the Task Force on Independent Power Producers' (IPPs) Power Purchase Agreements (PPAs) dated 31st May, 2018; and

b. To align the Report of the Task Force on Independent Power Producers' Power Purchase Agreements with the provisions of the Energy Act, 2019.

The initial 2018 Taskforce was formed under the Energy Act 2006 whilst the Inter-agency Committee was formed following the enactment of the Energy Act No. 1 of 2019, which repealed the Energy Act 2006.

The Inter-agency Committee submitted its final report to the Cabinet Secretary on 26th January 2021. The recommendations of that report are attached in annexure 3 in Schedule 2.

The Taskforce assessed the extent of implementation of the previous two Committees' recommendations and noted their status of implementation as follows:

3.1.I mplemented Recommendations

According to submissions from the MoE, the following recommendations were implemented:

a. To harmoniously transition from the current Feed-in Tariffs Policy to the proposed Renewable Energy Auctions Policy it was necessary for the Government to:

   i. Stop receiving new applications and approval of any new EoIs for solar PV and wind projects under the FiT Policy.

   ii. Fast track the review of the FiT policy and adoption of the Renewable Energy Auction Policy.

   iii. Restructure the 2012 FiT policy such that:

      - Small hydroelectric, biomass and biogas projects remain under a revised FiT policy; and

      - All solar and wind projects are subjected to an Auction Policy.

b. Subject solar and wind projects without approved feasibility studies to the energy auction process.

c. Approve maximum transitional tariffs of US Cents 7.5/kWh for Solar PV and US Cents 7.00/kWh for wind, for all projects that have not yet reached financial close.

d. Adopt the FiT tariffs for Small Hydro, Biomass and Biogas technologies as proposed by the FiT Committee.

e. MOE/ERC to ensure that all renewable energy projects Commercial Operation Dates (COD) are aligned to the LCPDP.

f. A comparative analysis of Kenya's generation tariff with the others in the region revealed Kenya's generation tariff was not competitive and it was necessary for:

   i. The Government to apply legislative and policy intervention to reduce some project associated risks currently being borne by private investors in order to achieve a more reduced generation tariff; and

   ii. MoE should review the current FiT Policy to allow for competitive bidding process through an auction system.

g. The standardisations of PPAs Clauses.

h. To facilitate transition from the FiT Policy to the proposed Renewable Energy Auctions Policy it was recommended that the MoE stop receiving new applications and approval of any new EoIs for solar Photovoltaic (PV) and wind projects under the FiT Policy.

i. The 2012 FiT Policy be restructured as follows:

   i. Geothermal projects be subjected to the Energy Act 2019 and the Geothermal Policy.

   ii. Small hydroelectric, biomass and biogas projects remain under a revised FiT Policy.

   iii. Tariffs to be based on the time of implementation of the project, technology changes and market conditions.

j. MoE to complete the formulation of Renewable Energy Auction Framework, which had already been initiated and that all solar and wind projects be subjected to an Energy Auction Policy.

k. That all PPAs negotiations be aligned with the revised LCPDP 2020-2040 due to the drastic reduction in demand arising from the impact of COVID-19 pandemic on the energy sector and delayed investment that had been anticipated to increase demand.

l. The LCPDP Technical Committee to formulate a Plan that incorporated the recommendations of the Committee Report taking into account the prevailing market trends. MoE to ensure that the implementation of all generation projects was aligned to the revised LCPDP.

3.1.2 Recommendations Not Implemented

The MoE submissions confirmed that the following recommendations were not implemented:

a. The two 30 MW Gas Turbines, one at Muhoroni and the other at Embakasi be retired immediately. In the absence of the Narok-Bomet and the Olkaria - Lessos – Kisumu transmission lines whose construction had delayed, a temporary 60MW HFO power plant and in the medium-term, installation of a new 80MW gas turbine at Muhoroni to stabilise voltage in Western Kenya region.

b. The Kipevu I 60MW thermal plant whose term lapses in 2023 be terminated after commissioning of the Isinya – Mariakani – Rabai line expected in May 2017. The Iberafrica 1 plant and Tsavo Power plant with a capacity of 56MW and 74MW respectively be retired immediately.

c. Revoke EoIs and terminate all projects whose EoI were approved more than 3 years ago and have not met the requirements of the Implementation Guidelines.

d. Announcement by the Cabinet Secretary for Energy of a deadline by which solar and wind projects that have approved feasibility studies, must have signed PPAs. The suggested deadline was 6 months from the date of the announcement.

e. Require all solar and wind projects that execute PPAs within the deadline of 6 months reach financial close within 12 months after signing.

f. Launch the Renewable Energy Auction in line with the LCPDP.

g. The transmission projects should be implemented under a transparent and competitive PPP framework where appropriate. The MoE and KETRACO should work towards the implementation of a pilot project.

h. MoE to run a pilot renewable energy auction for solar and wind which was restricted to the approved solar and wind EoIs only.

i. MoE to finalize the Standard Technology–Specific PPAs for small hydro, biomass/biogas, solar and wind generation projects.

j. That the designation of a System Operator be made once EPRA does an analysis on which institution is better placed to be designated as a System Operator. During the transition period, EPRA in consultation with the MoE designates a project specific team of key experts from KPLC and KETRACO to work as the System Operator.

k. KPLC to relook at the obligations created by onerous clauses i.e., Deemed Generated Energy payments and find a mechanism to formulate clauses that are balanced in terms of risk transfer particularly on PPAs that have windows for reopening.

l. That the transmission projects be implemented under a competitive PPP framework to ensure realization of competitive tariffs. MoE and EPRA to fast track the development of a policy on transmissions charges and open access/wheeling regulations as provided in the Act. The National Treasury and MoE to prioritise funds to support the pilot PPP program including funds for right of way acquisition. MoE and KETRACO should identify and develop PPP on transmission lines only based on the optimized transmission expansion plan.

m. A study to be undertaken which would assess the role of grid energy storage system such as pumped storage hydro, battery storage and hybrid systems for grid stability purposes.

3.2 FindingsThe IPP PPA Taskforce Report, 2018

The Taskforce notes that the IPP PPA Taskforce Report, 2018 made very good recommendations, however many of them were not implemented at the time. With the lapse in time and the challenges facing KPLC with regard to financial sustainability and the anticipated excess capacity in the system, there is need to put in place deliberate measures and implement some of the good and viable recommendations from the report.

The Taskforce made the following findings with regards to the recommendations of the previous reports:

i. Immediate retirement of the Gas Turbines (2X30MW).

   The Task Force noted that Olkaria – Lessos - Kisumu line had been commissioned in June 2021 but the Narok- Bomet Line which was also a prerequisite for the retirement of the Gas Turbines had not been implement due to lack of financing. Consequently, the western part of the country still continues to experience unreliable supply of power. This has delayed the decommissioning of this Gas Turbine Power plant. There is therefore need for a system study to analyze the system needs in stabilizing the power supply to western Kenya in the medium term. The study should include a cost benefit analysis of the various options available for stabilizing the grid.

ii. The recommendation that a 6-month deadline by which solar and wind projects that have approved feasibility studies must have signed PPAs was considered to have been overtaken by events and also likely to aggravate the demand supply imbalance. Instead, the Taskforce recommends that all projects without signed PPAs cancelled and be subjected to the REAP policy. A reverse renewable energy auctions mechanism should be adopted to set maximum prices which are technically feasible.

iii. On the stoppage of approval of all feasibility study reports by the FiT Policy Committee, the Taskforce recommends that the FIT Committee be abolished. Expressions of interest and all aspects of procurement of PPAs to be undertaken by KPLC. It is evident that failure to implement these recommendations allowed for more projects to progress beyond feasibility study stage and being allocated CODs by the regulator. The Taskforce recommends that no feasibility study should be approved and that all projects should be migrated to the REAP.

iv. One of the recommendations made in the 2018 report was on revocation of EoIs and termination all projects whose EoI were approved more than 3 years ago and had not met the requirements of the Implementation Guidelines**.** This was a good recommendation and if it had been implemented it would have dealt with the issue of excess capacity and the challenge that is being experienced today. The MoE however failed to make a bold move and terminate these projects. The consequence was the continued variation of CoDs and commitment of more capacity by KPLC.

v. Fast track the review of the FiT policy and the adoption of the Renewable Energy Auction Policy. The review of the FiT Policy took a long time to implement. In essence, the MoE had undertaken a study on exploring possibilities to introduce renewable energy policy but this delayed. The taskforce observes that delay in the enactment of the National Energy Policy and Energy Act is also to blame for this problem. The FiT Policy and REAP should thereafter be released to the public.

vi. The 2018 report recommended that the Cabinet Secretary consider directing the LCPDP Technical Committee to formulate a Least Cost Power Development Plan. The Taskforce notes that this was partially implemented by the MoE. However, the estimates of the resultant LCPDP were not robust enough to manage scheduling of committed projects in the plan. The report prepared was therefore not implementable because of the many projects that were being committed as seen in Chapter 9.

vii. The 2018 report recommended that the MoE finalise the standard technology specific PPAs for small hydro, biomass/biogas, solar and wind generation projects. This particular recommendation was good but there was a delay in implementation and therefore exacerbated the problem. Very good projects for small hydropower have not been implemented because of this policy inertia. The Taskforce has prepared draft standard PPAs for these technologies.

viii. The 2018 report recommended the approval of a maximum transitional tariff of US Cents 7.49/kWh for Solar PV and US Cents 7.01/kWh for wind, for all projects that have not yet reached financial close. This particular recommendation was implemented for projects that have entered into a PPA with KPLC. It should however be observed that due to evolution of time, the respective technology costs have further come down globally. Recent bids in developed and developing countries have recorded lower tariffs of US Cents 6.00/kWh and US Cents 5.50/kWh for the two technologies respectively. This is an indication if a renewable energy auction was to be undertaken in Kenya today, it may record lower tariffs and therefore good in driving overall electricity tariffs down.

3.2.1 The Inter Agency Committee on IPP-PPA Report 2021

Analysis of the status of the implementations of the recommendations of the Inter-Agency Committee IPP-PPA Report, 2021 shows that just like in the case of the 2018 report, the recommendations from this committee have not been wholly implemented. Although it would appear most of the recommendations had been implemented or were under implementation, this is not the case. The Taskforce therefore has analysed and made certain observations:

i. A policy on licensing of geothermal Greenfields had been drafted in 2018. It was however noted that the issue of licensing of geothermal Greenfields had been covered in the Energy Act, 2019 and the National Energy Policy 2018, and was therefore not necessary anymore as a stand-alone policy. The Taskforce however opines that the MoE should have done much more, it should have published The National Energy Policy 2018 and disseminated it widely. Some of the energy sector stakeholders did not seem to have been aware that it had been finalized and still referred to it as a draft. The previous Sessional Paper No. 4 on Energy of 2004 had been formally adopted into a sessional paper and widely publicised and disseminated. There is need to publicise and disseminate the National Energy Policy 2018 to all stakeholders, including and especially Kenyans in general.

ii. The recommendation of the need for the Cabinet Secretary for Energy to consider directing a stoppage of approval of all feasibility study remains valid as above. This should be coupled with a pilot renewable energy auction for Solar and Wind aligned with the LCPDP and KPLC demand forecasts. The auctions should be subject to set maximum price which is technically feasible. Feasibility Studies of small hydroelectric, biomass and biogas projects that will remain under a revised FiT Policy should be aligned with the revised LCPDP 2020 – 2040 and KPLC demand forecasts.

iii. Conversion to use Liquefied Natural Gas (LNG) preceded by detailed feasibility studies to confirm the technical and financial viability. This recommendation has been progressed and KenGen is currently undertaking a study to explore the feasibility of converting HFO power plants to LNG.

iv. MoE should consider stopping receiving any new applications and approval of any new EoIs for Solar PV and Wind projects under the FiT Policy. This recommendation was in furtherance to what had been recommended in the 2018 report. Implementation of the Energy Auction process has however taken more time and the country has failed to take advantage of reduction from efficiencies in competitive bidding. We recommend the REAP is released immediately and a pilot energy auction carried out.

v. Run a pilot renewable energy auction for solar and wind restricted to the approved solar and wind EoIs only. This recommendation was delayed and consequently the economy did not benefit from technological innovation and associated cost reductions in generation costs. The energy auction should be open to all bidders/investors and should align to the LCPDP and KPLC demand forecasts.

vi. EPRA should fast track the appointment of the System Operator in line with the Energy Act, 2019, after due consideration of the associated risks. EPRA has commissioned a study with support from the World Bank and the MoE.

vii. PPAs negotiations be aligned with the revised LCPDP 2020-2040 due to the drastic reduction in demand arising from the impact of COVID-19 pandemic on the energy sector and delayed investment that had been anticipated to increase demand. EPRA at the request of KPLC extended PPA milestones but this was not consistent with the mandates as provided by the law. However, the demand risk arising from the impact of Covid 19 to the power sector negatively affected the power sector. Future variations in CoDs should be guided by provisions in PPAs and policies.

As has been observed in this analysis, the recommendations in the Inter-Agency Committee Report, 2021 mirrored those in the IPP PPA Taskforce Report, 2018, but, were more updated to reflect the developments in the sector. The updates included considerations for retired thermal plants that had previously been considered for early termination, incorporation of Energy Act, 2019 requirements for the designation of a system operator, ancillary services requirements for grid stability and developments in the market on hybrid storage systems.

3.3 Recommendations

The Taskforce after assessing and reviewing the implementation status of the previous two Committees' findings makes the following recommendations;

a. Cabinet Secretary for Energy to suspend the processing of all EoIs and feasibility study reports including those submitted during the tenure of Presidential Taskforce on PPAs.

b. KPLC in concert with the PPP to run a pilot renewable energy auction for Solar and Wind open to all bidders/investors, and that is aligned to the LCPDP and KPLC's demand forecasts. Auctions to be subject to set maximum price which, is technically feasible.

c. EPRA to fast track the procurement of consultants to undertake the following studies and implement the findings and recommendations of the studies:

    - Ancillary service study
    - Grid Tied Battery Storage.

d. EPRA to conclude the Power Market study and Operation and Dispatch Guidelines which will be the basis for appointment of the System Operator by 30th November 2021. In the meantime, KETRACO to suspend any work being undertaken on ISO infrastructure and KPLC to continue being the System Operator and running the National Control Centre. KPLC management to produce monthly reports to the KPLC Board and to EPRA that show the power purchase costs incurred under the merit order.

e. National Treasury to prioritise funding in FY22/23 for the stabilisation of the western Kenya power supply lines (Narok-Bomet)

f. EPRA should unbundle the transmission and distribution tariff to enhance transparency in pricing and ensure efficiency in risk allocation in the power system. It would also ensure cost recovery in line with the principle of prudently incurred costs.

g. Consider implementing PPP in transmission infrastructure development to reduce reliance on the already burdened exchequer. The implementation of the PPP transmission lines should be phased over time such that there is minimal impact to the end user tariff.

3.4 Implementation of the Presidential Taskforce Report

Noting that this is the fourth review process on Power of PPAs, the Presidential Taskforce has conceptualized and implementation strategy that will invariably secure implementation of the key proposals and ensure sustained action towards the anticipated reform objectives. These include:

a. Use of the Cabinet Sub-Committee on KPLC to take responsibility for assuring political support in the implementation of the Taskforce recommendations once Cabinet approval for the Taskforce Report has been obtained, with execution being the responsibility of relevant agencies.

b. Establishment of an Implementation Committee, reporting to the Cabinet Sub-Committee on KPLC. The Committee to consist of senior officials from the Office of the President (chairperson), National Treasury, Ministry of Energy, Attorney General, and relevant implementing agencies namely; EPRA, KPLC, KETRACO, REREC, KENGEN, and GDC and for a period of 1 year or as may be extended.

c. Creation of an Implementation Plan and accompanying draft implementation instruments to fastrack actions by respective actors.

d. National Treasury to ensure that adequate budgets and other resources to implement the key recommendations are factored into the annual budgets of respective agencies.

e. Ministry responsible for Public Service to ensure that the recommendations are incorporated as part of respective agency performance contract targets.

f. Presidential Delivery Unit (PDU) to monitor progress and prepare quarterly implementation reports to the National Development Implementation and Communication Cabinet Committee (NDICCC).

g. Performance contract targets and Budget plants to be aligned to the implementation framework.

4 Situational analysis of the relevant energy sector policy issues

The energy sector in Kenya has previously been guided by the Sessional Paper No. 4 of 2004 on Energy and governed by several legislation, principally the Energy Act, No. 12 of 2006 and the Geothermal Resources Act No. 12, of 1982 (now replaced by the Energy Act, 2019).

Adoption of the Kenya Vision 2030 (unveiled in 2008) and the promulgation of the Constitution on 27th August 2010, made it necessary to review both the Policy and the applicable legislation and regulations so as to align them with the Vision and the Constitution. The National Energy Policy 2018 was thus developed, which provides a comprehensive description of the current state of the energy sector, the policy framework and contains policy recommendations for various sub-themes: coal, renewable energy (including geothermal and hydro power), electricity, energy efficiency and conservation, land, environment, health and safety, energy services, energy financing, pricing, and socioeconomic issues.

This section seeks to analyse the relevant policies in the sector that have an impact on the PPAs and makes appropriate recommendations.

4.2 The National Energy Policy 2018

Energy is recognised as an enabler in the country's Vision 2030 and the Big 4 Agenda. Sustainable, affordable, and secure energy is key to the country's economic growth.

The Energy Policy 2018 was formulated and issued in October 2018 pursuant to the Constitutional requirements that necessitated enactment of new energy laws i.e., Energy Act 2019 and Petroleum Act 2019.

The Policy is comprehensive and has factored all matters relating to energy which include:

a. Energy Policy objectives;

b. Legal and regulatory framework in the energy sector;

c. Institutional arrangement in the energy sector;

d. Renewable Energy Resources and its sustainable use towards energy security;

e. Electricity generation from various forms of energy;

f. Electricity Transmission, distribution and retail;

g. Energy Efficiency and Conservation;

h. Land, Environment, Health and Safety on matters related to energy;

i. Devolution and Provision of Energy Services;

j. Energy Financing, Pricing and Socio-Economic Issues; and

k. Other Cross Cutting Issues.

4.2.1 Findings

A critical review of the National Energy Policy 2018 reveals that;

i. The Policy if implemented will transform the energy sector and particularly the electricity sector. The policy was finalised in 2018 and informed the enactment of the Energy Act 2019. These two documents are very transformative and progressive. One of the findings arising from the review however is that the National Energy Policy 2018 has neither been publicised nor disseminated to all stakeholders. Some of the institutions in the power sector have presumed that it had not been adopted as the official document and therefore up to now, most of the sector agencies have not uploaded it in their websites. There is need to ensure that the policy is well disseminated to create awareness on what the Government is proposing with regard to energy planning and particularly the interlinkages with Counties' energy plans. Other critical issues such as financing, pricing, electricity generation, renewable energy resources and environmental issues are very well articulated.

ii. With regard to exploitation of geothermal resources, the policy can be further improved to provide clear strategies and initiatives that will transform the geothermal sector on the country. The earlier Geothermal Policy was vacated and all related issues were assumed to have been incorporated in the Energy Policy of 2018. There is need to re-look at this energy policy and ensure that geothermal resources and exploitation issues are adequately covered.

iii. Some of the policy initiatives in the policy requires to be revised. For example, the policy asserts that in order to provide affordable and competitive electrical energy to transform Kenya's economy, a roadmap to raise the generation capacity by at least 5,000MW from 1,664MW as at October, 2013 to slightly over 6,700 MW by 2024 is proposed. This policy initiative has been overtaken by events as the proposal to deliver that capacity is not sustainable.

iv. The policy states that the Government shall set up a Consolidated Energy Fund to fund infrastructure development; energy sector environmental disaster mitigation, response and recovery; hydro risk mitigation; water towers conservation programmes; energy efficiency and conservation programmes as well as promotion of renewable energy initiatives. This issue needs to be re-looked at to ensure that the fund is aligned to optimal energy requirements in the country.

v. It also requires provision of incentives for the development of robust distribution networks to ensure efficient and safe provision of distribution services by duly licensed network service providers, so as to reduce power supply interruptions and improve the quality of supply and service. This needs to be revised to take into account the need to undertake a power market study and have clear timelines for transition to open access and system operations as provided for in the Energy Act. The Act was forward looking and proactive.

vi. Institution arrangements still reads the Ministry of Energy and Petroleum and the Energy Regulatory Commission, Rural Electrification Authority (REA). there is need to revise the policy to represent the existing energy organisations.

vii. Development of a National Resettlement Action Plan Framework for energy related projects; including livelihood restoration in the event of physical displacement of communities. More initiatives need to be introduced in the policy to cover all wayleave and compensation related issues to reduce risk of delay in project implementation.

viii. On cross cutting issues in renewable energy, the section on coordination of research and development in the Sector mandates NuPEA to coordinate. We recommend that each agency undertakes research and development, with the MoE providing coordinating role as detailed in this Report.

ix. The policy recommends the establishment of an inter-ministerial Renewable Energy Resources Advisory Committee (RERAC) to advise the Cabinet Secretary on matters relating to renewable energy resource. Renewable Energy Resources Advisory Committee (RERAC) has been established. However, we recommend the amendment of the Energy Act to include KPLC as a member of RERAC.

x. On the electric power distribution, we recommend that the finalisation of the necessary regulations under preparation to realise the Strategies

xi. On energy efficiency and conservation, we recommend the finalisation of the Action Plan whose development is in progress.

xii. On climate change mitigation, the Ministry of Environment appointed a taskforce to operationalise the Climate Change Act, 2016. Further, long-term emission strategy has been formulated.

xiii. Overall, the review of the National Energy Policy reveals that it still has several gaps and some of the initiatives require to be updated. The MoE should take advantage of the findings and recommendations of the Presidential Taskforce to revise it for sustainability and transformation of the sector to serve Kenyans better and enable them benefit from lower cost of power.

4.3 The Least Cost Power Development Plan (LCPDP)

The LCPDP is the energy sector multi-agency planning document intended to guide investment decisions in the power sector. The MoE and all its affiliate agencies namely: EPRA, NuPEA, GDC, KenGen, KETRACO, KPLC and REREC are involved in its formulation.

The planning process involves undertaking a demand forecast, identifying the generation plants to meet the projected demand, identifying a target transmission network and estimating the investments requirements and indicative tariffs from the planned generation and transmission network. The least cost optimisation process considers a comparison of the forecasted peak load with the expected available capacity in the existing and committed power plants. This helps to determine when supply gaps are going to occur and how much capacity is needed to fill the gaps. The least cost optimisation process also factors in the projects to meet the identified supply gaps, based on the system requirements (Baseload or peaking). The data used to identify the least cost projects includes: investment cost, O&M cost, fuel costs, imports price, power plant operation characteristics and expansion restrictions amongst others.

The Plan is updated every two years. The updates consider among others; changes in the demand drivers that could affect the demand forecast as well as changes in the planned generation and transmission projects. EPRA has been coordinating the LCPDP Committee. However, this is likely to change with the Energy Act, 2019 that places the mandate of preparation of the INEP with the MoE. The Taskforce has reviewed the Terms of Reference of the LCPDP which is attached as annexure 1 in Schedule 3. **Projects under the 2020-2040 LCPDP**

The Taskforce established that the LCPDP initially did not integrate all the projects approved under FiT Policy, geothermal concessions, regional power trade and other Government agencies such as KenGen, GDC, REREC, Kerio Valley Development Authority (KVDA) and Tana and Athi Rivers Development Authority (TARDA). The integration of Feed in Tariffs projects into the LCPDP started in 2016 when a few projects had already progressed beyond the PPA level or approved feasibility studies. Most these projects were Small hydro projects, Kwale Sugar Company Cogeneration project and three wind projects namely Prunus, Kipeto, and Kinangop Wind. Consequently, these were not in the LCPDP originally.

Lake Turkana Wind Power Project was integrated into the LCPDP as an unsolicited Privately Initiated Investment Proposal (PIIP) under the Public Procurement and Disposal Act of 2005. In addition, KenGen, being a state corporation received government directive to implement the Waste to Energy project in partnership with the Nairobi Metropolitan Services. The project is currently under feasibility study. These projects were subsequently integrated into the LCPDP. While we appreciate the importance of supporting parallel reform initiatives, as well as nurturing green innovative technologies, the LCPDP needs to remain sacrosanct, as a lack of fidelity distorts planning and can result in the current case of excess capacity.

The current LCPDP 2020-2040 generation sequence indicates that the approved renewable energy projects are sufficient in meeting the projected demand. Notably not all the projects have progressed to sign a PPA and therefore such projects can be transitioned into the proposed REAP to ensure they are aligned to the LCPDP and to also to derive competitive prices.

The LCPDP 2020-2040 include 50 committed generation projects with PPAs of which 13 are under construction. The total committed capacity is 2,838MW, capacity under construction totals to 533MW as detailed in the Table 1 below. It is expected that most of this committed generation capacity will be commissioned.

Table 1: List of Committed Projects

Description	Committed Capacity (MW)	Capacity Under-construction (MW)
Hydro	47	10
Biomass	39	20
Wind	340	100 (Kipeto Wind)
Solar	404	120
Geothermal	626	83
Import	400	200
Coal	981.5	0
Total	**2,837.5**	**533**

The remaining planned projects amounting to a capacity of 5,033MW are at various stages of development and are yet to execute a PPA with the offtaker. These projects will need to be monitored closely to determine their progress in implementation.

4.3.2 Power Imports

The Taskforce noted that Kenya imports/exports electrical energy from neighbouring countries through bilateral or cross-border agreements. The current cross-border agreements are between, Kenya and Tanzania, and Kenya and Ethiopia. There are two bilateral agreements at transmission level, that is, Kenya – Uganda (1955) and Kenya – Ethiopia (2012) currently.

The Kenya-Ethiopia PPA entered into in 2012 to import 400MW, became the anchor transaction to support the financing of the Eastern Electricity Highway project. The objective was to connect the power systems of Ethiopia and Kenya, to meet Kenya's increasing demand. As part of the Least-Cost Power supply options, the Kenya – Ethiopia PPA agreement was negotiated when the country experienced power shortages and it was meant to also diversify the energy mix away from unpredictable domestic hydropower and international fuel price-sensitive thermal power.

4.3.2.1 Imports Determination

The LCPDP process evaluates imports, similarly to other power generation candidates. This involves a review of the available and potential energy sources. The identified candidate generation projects are subjected to an optimisation process to arrive at the least cost solution.

In the case of Ethiopia – Kenya imports, a minimum of 150MW is technically required by the line, to ensure it remains charged.

The LCPDP 2020-2040 has identified the need to negotiate for firm 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term. Further, the report envisages capacity shortfalls in the period between 2022 and 2024 should the Ethiopia imports and the KenGen Olkaria I, Unit 6 fail to be realised as planned.

4.3.2.2 Future market under EAPP

The Eastern Africa Power Pool (EAPP) is being set up, with the assistance of the World Bank and the African Development Bank. The EAPP will comprise power utilities from eleven (11) member countries namely: Libya, Egypt, Sudan, Ethiopia, Djibouti, Kenya, Uganda, Rwanda, Democratic Republic of Congo, Burundi, and Tanzania. EAPP envisages a change from the current long-term bilateral contracts to a hybrid of bilateral contracts and short-term trading platforms. The proposed short-term trading platforms will therefore include a day ahead market, intra-day trade market and ancillary services market.

The Day Ahead market is an auction for the physical power delivery for the following day, run on every day of the year and the Intraday market is a continuous market where participants can buy and sell power every hour of the year. This market is designed to provide a possibility for participants to fine-tune their power balance and allow market participants to trade close to physical delivery.

4.3.3 Findings

The demand forecasts in the LCPDP are based on an approach that assumes largely status quo with incremental growth (linked to GDP forecasts). This approach may be satisfactory for demand forecasts in a fully developed economy with relatively slow economic growth. However, Kenya is a developing economy with relatively high economic growth and even higher economic growth ambitions. If Kenya is to have a power sector consistent with these economic ambitions, it must grow the sector and provide ample and reliable power to attract and retain the consumers who can drive the economy. The power sector leads, not follows, economic development, and if the power sector does not get ahead of economic development, then that economic development won't and can't happen.

For a power demand forecast to be relevant to an economic plan of strong growth, industrialization, and economic development it should be led by a vision of what that future economy looks like. This means that demand projections should be based on a plan for Kenya achieving its economic goals. Electricity demand projections for a developing economy like Kenya should be a top-down approach which is based on having a strong power sector meeting the future needs of power consumers derived from the country's economic development plans.

In practical terms, the starting point for demand projections should include an aggregation of new connection applications (300-400MW paid up – currently), a comprehensive analysis of suppressed demand, realistic system losses (the current version inexplicably expects system losses to drop from 23.5% in 2020 to 16.7% in 2025) as well as an *explicit* provision for new capacity to facilitate the country's economic growth agenda. Different scenarios can then be modelled so that the government-of-the-day can understand their implications on the investment required as well as the tariff progression, and plan accordingly.

While the installed capacity is 2,870MW, the available capacity is between 2,100-2300MW and could drop below 2,000MW in a sustained drought. Meanwhile, peak load is about 2,000MW, meaning the system doesn't currently have a prudent reserve margin, let alone room for growth (MoE aims for 30% - usually 15% minimum for mature systems).

Contrastingly, the LCPDP 2020-2040 generation sequence indicates that the approved renewable energy projects are sufficient in meeting the projected demand. Notably not all the projects have progressed to sign a PPA and therefore such projects can be transitioned into the proposed REAP to ensure they are aligned to the LCPDP and to also to derive competitive prices.

The LCPDP was previously guided by the Energy Act 2006 which gave EPRA the mandate to coordinate the plan on behalf of the sector. The process is a multi-sector in nature and has been applied since 2008 and has been working well. This has however changed with the Energy Act, 2019 that places the mandate of preparation of the INEP with the MoE. KPLC has been one of the key agencies in preparation of the Plan. It has however been observed that the MoE and EPRA may have dominated the outcomes in the formulation of the plan in the last thirteen (13) years.

KPLC engineers and economists have been represented and involved in all critical areas in preparation of the report but the challenge has been whether their views and technical opinion have always been adequately taken in account. As a result, demand forecasting, generation and transmission planning have been affected resulting in a skewed process that has worked against getting a feasible, viable and sound LCPDP.

The analysis of the experience in the implementation of the LCPDP shows that KPLC has had somewhat minimal influence compared to that of the policy makers and the regulator.

To cure this problem, the taskforce recommends the need to make KPLC central in the planning process and procurement of electricity in the country. While this may not go into perpetuity as a result of anticipated reforms to introduce open access and power market in the country, the utility should at least in the immediate and medium term play a leading role in the LCPDP process even as the MoE takes the lead role in the INEP.

Secondly, there is need to align the proposed INEP regulations with the new proposed role of KPLC for a clear implementation of the planning process.

Another key finding is that of the need for transparency in the preparation and publishing of the LCPDP including all the proposed projects and when they are proposed to be implemented. It has also been observed that despite the historical memory in the LCPDP process, there has been lack of clear coordination in the LCPDP implementation and it has not been sufficiently dynamic to consider the changing circumstances.

The other notable findings are including the need for individual utilities plans to fit into the LCPDP. This will ensure that we have a high-level approval of the plan. Further, the LCPDP had not indicated which projects are implemented outside the plan. This was highlighted by stakeholders during the stakeholder consultation process. Some projects developed by KenGen and some that have been done by IPPs were not initially aligned with the LCPDP. There is urgent need for close and effective monitoring of the LCPDP.

Other challenges likely to hamper the implementation of the LCPDP 2020-2040 include:

a. Delays in reaching financial close and other conditions precedent in the PPAs for committed projects.

b. The planned projects may fail to progress as sequenced due to various reasons including energy resource availability and assessment.

c. Slower than projected demand growth. Demand associated with Vison 2030 projects has been included. Delays in their implementation could result in the delay of some of the planned projects in the future updates of the Plan.

d. In the period between 2022 and 2024, there is a risk of firm capacity shortfalls if Ethiopia imports (200MW) and the KenGen Olkaria I unit 6 plant (83MW) are not realised as planned. Concerns regarding Ethiopia's project impact on the Nile, and the KenGen's Olkaria I Unit 6's readiness have already emerged. This may necessitate extension of the plants scheduled for retirement. Plants due for retirement in the period are the Gas turbines (56MW) and Tsavo power plant (74MW).

e. The LCPDP 2020-2040 recognises the need for a comprehensive study on ancillary services requirements for the system, including battery storage, pumped storage and reactive power compensation. A delay in undertaking this study could hamper the implementation of some of the planned projects due system operation associated issues in view of the increased levels of intermittent renewable energy sources. Towards system stability, the increment in intermittent generation needs to be in tandem with proportionate generation of firm capacity.

f. The LCPDP committee has identified challenges with the current generation optimisation software. The software lacks capabilities to simulate battery storage and optimize renewable energy technologies such as wind and solar. Several development partners have indicated interest in supporting the planning team to acquire more flexible planning tools. MoE is facilitating these engagements. It is likely a new planning tool will be available to the planning team in the financial year 2021/2022.

g. The LCPDP committee undertakes annual monitoring of Generation and Transmission projects under construction. There is however need for more stringent monitoring measures to ensure that all planned projects are progressing as planned and meeting all the milestones in the PPAs. The LCPDP committee should undertake an audit of all ongoing and planned projects to ascertain their status and progress. This is aligned to the Energy Act, 2019 that requires that monitoring of the implementation of the energy plans is done three months after the end of each financial year.

4.4 The Renewable Energy Auction Policy

The Renewable Energy Auctions Policy (REAP) has transparent and competitive mechanisms that enable procurement of clean energy at prices that reflect those prevailing in the market.

The auction schemes globally have benefited through the rapidly decreasing costs of renewable energy technologies, the increased number of project developers, the international exposure and know-how, and the considerable policy-design experience acquired over the last decade.

The successful implementation of auctions relies on an appropriate regulatory and institutional framework, relevant skills and adequate infrastructure to attract investors. Adapting the auction design to the country's conditions and priorities is one of the key steps of ensuring success in achieving auction policy objectives.

The MoE recognised the need to undertake a study before launching the Energy Auction Policy. A study with the support of the World Bank was undertaken and a draft REAP policy is ready for issuance once further revisions are done pursuant to the recommendations of the Taskforce. The draft REAP is attached in Schedule 3 as annexure 2. **Target Projects under the REAP**

The REAP outlines the approach to renewable energy procurement in Kenya based on competitive auctions. It is intended that draft REAP will be used to procure solar and wind power projects, as well as other renewable projects larger than 20MW. The draft REAP has already been reviewed by the National Treasury & Planning.

The policy will be applied, in the first instance, to all approved solar and wind EOIs under the FiT Policy that have not signed respective PPAs. This offers an opportunity to investors who may have made progress in preparing their projects to participate in the generation market through the renewable energy auction framework.

4.4.2 Renewable Energy Auction Mechanism

Auction volumes must be determined in relation to the capacity of the market to deliver. This is particularly so in markets with a limited number of local renewable energy developers and suppliers. Determining the optimal number of auction rounds and the volumes that would create greater competition is a challenge that requires learning by doing.

The energy auctions tend to favour large investors that are able to afford the associated administrative and transaction costs. The bidders face the risk of not being awarded the tender and absorbing the sunk costs of project predevelopment. There is the risk of underbidding, project non-completion, and discontinuous market development (stop-and-go cycles). There should be strong guarantees and penalties to prevent potential underbidding and minimising the risk of project delays and completion failure.

Penalties, backed by financial guarantees, can help mitigate these risks by ensuring the seriousness of bids and reducing the chance of project delays, underperformance, or non-completion. However, financial guarantees and penalties that are too high can deter participation, negatively impact competition in the auction, and lead to higher risk premiums and consequently bid prices.

South Africa's Renewable Energy Independent Power Producer Programme (REIPPPP) presents a model for a successful competitive bidding scheme. The programme was consultatively designed; standardized documentation was developed early and socialized with stakeholders (investors, lenders, development finance institutions, legal firms); institutional arrangements established to ensure independence (self-financing IPP Office staffed with world-class technical, financial and legal resources); and a transparent, well thought-through procurement process – these were the pillars of REIPPPP's success. The programme resulted in over $4.2 billion in direct investments and a 69% decline in tariffs over four bid rounds.

To prevent cartel like behaviour which has negative impact on the cost of power as it does not allow for effective price discovery, the following measures should be taken to minimise/eliminate the risk:

a. Promote procurement of power through transparent, open and accountable procurement processes;

b. Procurement to be open to all potential bidders.

c. Integrity of the procurement process to be enhanced through use of digital technology for ease of tracking and elimination of tempering of bids.

d. Procurement officers to be vetted and held to account.

e. Tender evaluation to carried out in a transparent manner with members of the tender evaluation committees being held personally accountable.

f. Tender bids to undergo due diligence to confirm credibility of documentation/information submitted.

g. Tender processes to be audited by an independent body after award of tender.

h. Tender opening to be public and tender results to be published on an electronic platform that is accessible to the bidders and members of the public.

i. Whistle blowing mechanism to be put in place for reporting of any unethical practices during and after the tendering process.

Streamlined administrative procedures, with communication and transparency provided equally to all bidders, are essential to the success of an auction scheme.

Policymakers should consider the transaction costs faced by bidders wishing to enter the market, as low volumes might lead some actors to opt against entering a market.

4.4.3 REAP vis-a-vis FiT

Unlike negotiated procurements or FiTs, auctions have the potential to enable price discovery, reduce windfall profits to power producers, and avail to cash-strapped utilities and consumers lower prices for power since companies compete against each other on the price. There could also be job creation opportunities as a result of the requirement for inclusion of local content.

REAP will allow the country to procure renewable energy capacity at competitive prices which is aligned to the LCPDP and INEP. The procurement will also be aligned to system needs such as voltage support, power quality and demand that could benefit from localised generation. This is because the terms of the bids will have outlined the requirements for site selection.

4.4.3.1 Findings

The Renewable Energy Policy preparation was supported by the undertaking of a study to assess the feasibility of the same and this was a good initiative of MoE with support from the World Bank. The policy will help streamline procurement of renewable energy projects and help curtail the vendor driven process that does not ensure optimal allocation of projects and the associated risks. It is the Taskforce's view that the new REAP policy should be adopted and publicised to create awareness and the new position of the country going forward. The policy will guide the highly anticipated energy auctions process and ensure predictability in procurement of power in the country.

4.5 The Feed in Tariff (FiT) Policy

The first FiT Policy for wind, biomass and small hydros was published in 2008. The Policy was first revised in 2010 which resulted in adjustment of the wind and biomass, and inclusion of geothermal, biogas and solar off-grid resources. The revision in 2010 was preceded by a study commissioned by MoE through the World Bank assistance on the, *Technical and Economic Study for Development of Small-Scale Grid Renewable Energy in Kenya*. The second revision was in 2012 which resulted in the current Policy. It reviewed the tariffs for different technologies and included the grid connected solar energy power plants into the Policy. The FiT values were based on the actual generation costs in Kenya and costs in other parts of the world. The tariffs in the Policy are applicable for twenty (20) years from the date of commissioning of the plants.

The FiT Policy, 2012 responded to concerns from developers on the attractiveness of the tariffs to private investment. At the time of the review, only two projects had signed PPAs. The slow uptake of projects under the FiT Policy was attributed to low FiT tariffs. Developers were unable to undertake projects as the set tariffs were lower than the actual generation costs and tariffs in other jurisdictions. Table 2 provides a comparison of the tariffs in the 2010 and 2012 FiT Policies and against the range provided in the International Renewable Energy Agency (IRENA, 2012). This indicates the tariffs in the FiT Policy 2012 compared with other regions and hence cost effective. However, although the 2012 FIT tariffs were appropriate at that time, most of the approved plants have come in much later and could have higher than the competitive market tariff rates.

Table 2: Comparison of Tariffs: 2010 & 2012 FiT Policies

Technology	**FiT (2010)**	**FiT (2012)**	**IRENA (2012)**
Wind	0.12	0.11	0.06 - 0.14
Solar	-	0.12	0.15 - 0.31
Geothermal	0.085	0.088	0.09 - 0.14
Biomass/Bioenergy	0.08	0.10	0.06 - 0.15

In May 2018, the Taskforce on Review of IPPs' Power Purchase Agreements had recommended that solar, wind and Renewable energy projects above 20MW be transitioned to a Renewable Energy Auction and that during the transition period, the tariffs for solar and wind be 7.5 and 7 US cents per kWh respectively. A FiT tariffs policy for Small Hydro, Biomass and Biogas technologies below 20MW was proposed. The Taskforce has further reviewed the draft FiT Policy, 2021 attached in Schedule 3 as annexure 3. **Global Trends in FiT**

Globally, the technology costs have continued to decrease indicating the need for a review of the FiT Policy, 2012 to reflect the prevailing tariffs for different technologies. For example, IRENA (2019) estimates the levelised cost of solar PV to be USD 0.068/kWh and that of wind to be USD 0.053/kWh. In response to the declining costs associated with technology advancement in variable renewable energy, MoE has since proposed revisions to the FiT Policy, 2012. The draft FiT Policy, 2021 has excluded solar and wind power projects, as well as other renewable energy projects larger than 20MW including geothermal projects. The tariffs for small-scale biomass, biogas, and small hydro projects of up to 20MW compare well with those in other regions as detailed in the Table 3 below, an indication of the cost effectiveness of the draft FiT Policy, 2021.

Table 3: Cost effectiveness of the draft FiT Policy, 2021

Technology	FiT (2021)	IRENA (2019)
Small hydro	0.080 – 0.0920	0.038 – 0.13
Biomass	0.095	0.057 – 0.099
Biogas	0.095	

4.5.2 Installed Capacity under FiT Policy

The implementation of the FiT policy 2012 has resulted to an addition of 741.8MW generation capacity into the power system. The Policy has witnessed a huge proliferation of projections with about 300 hundred projects at different stages of development and with a total capacity of 5,044MW. Table 4 presents the status of the approved FiT projects.

Table 4: Status of FiT Projects

Description	Number	Capacity (MW)
Plants in Operation	8	18.80
Plants Under construction	11	250
Projects With Signed PPAs	18	473
Projects with Initialled PPAs	6	126.10
Projects with PPAs under Negotiations	26	603.10
Approved Projects with PPAs Negotiations Yet to Start	52	860.82
Projects with Feasibility Studies approved and sent to EPRA-LCPDP	25	641.19
Projects in Feasibility Study Stage	153	2,071.34
Total No. of Approved Projects	**299**	**5,044.35**

4.5.2.1 Findings

From the above analysis, it is clear that success in the development of the projects to commercial operation has been hampered by the long lead time for renewable energy projects that can take up to 10 years as has been the case with Kipeto Wind Project. This long lead has also made it difficult to limit the number of approved projects as it is not known how long the project would take to develop.

This delay in implementation impacts upon the cost of energy, as the PPAs signed over 10 years ago end up being implemented at higher tariffs compared to global prevailing rates for similar technologies.

The lack of timely review of the FIT policy has also had a negative impact on the sector. The policy anticipates a review of the tariff and terms every 3 years. However, since 2012, the latest review was conducted in 2021, and is yet to be approved. KPLC is thus constrained to continue contracting FiT based PPAs on the high tariffs of 2012.

A review of the draft FiT Policy, 2021 indicates a lack of flexibility to technological advancements that impact on the cost of generation. For example, according to IRENA (2019), solar PV module costs have reduced by over 70% in the last 10 years due to improved manufacturing processes, reduced labour costs and enhanced module efficiency. Such improvements are better realised through a competitive bidding as proposed in the Renewable Energy Auction policy.

The FiT Policy anticipates the establishment of a FiT Committee to review expressions of interest and feasibility studies for qualifying projects, stewarded by the MoE. As recommended elsewhere in this report, FiT Committee should be disbanded and KPLC should be responsible for procurement of PPAs.

4.6 Government Support Measures Policy, 2018

The main objective of the Government Support Measure (GSM) Policy, 2018 is to facilitate a predictable, stable, and transparent framework for private sector participation in public infrastructure development, while making various support measures available to implementers of public projects, in order for such investments to be more secure and bankable. The GSM Policy, 2018 applies to all public and private institutions in Kenya involved in public investment programmes, including their financiers.

GSMs are mechanisms for de-risking public investments in order for such investments to be more secure and bankable, in respect of private capital mobilisation for public investment and infrastructure developments. GSMs operate as credit-enhancement tools thereby enabling financing institutions to accept the financing risk profiles of public transactions. The GSMs impose various financial costs on public finance, and create varied forms of contingent liabilities on Government, with the risk that in the event such contingent liabilities crystallise, their financial impact on public finance may become substantially disruptive.

The National Treasury & Planning is the main agency in the implementation of GSMs within the framework of the PPP Act, and grants support for promoting and enhancing private sector participation in public investment programs. These measures enable financing institutions to willingly accept the risk associated with such huge investments.**Target Projects**

The Government undertakes many projects in several sectors of the economy. The projects come in different sizes and costs. Not all the projects qualify to be accorded GSM. A GSM should be granted in very exceptional circumstances for projects that are considered strategic and that are of public interest, as approved by Cabinet. In each GSM, the covered risks should be a closed list of risks, to the benefit of the project developers, their financiers, and the Government. Some power projects undertaken by IPPs are among projects that have been issued with GSM in the past.

4.6.2 Categories of GSM

The GSM Policy, 2018 has the following categories of GSMs in support of public investment:

a. Letter of Comfort;

b. Sovereign guarantees – used to guarantee borrowings by Government and its entities;

c. Letters of Support and Comfort – used variously to provide different forms of GoK undertakings, commitments and assurances in support of a project;

d. Project-based Guarantees usually undertaken or granted through contract provisions;

e. Partial Risk Guarantees (accompanied by Indemnity Agreements) – to backstop third party risks arising from various situations of project default;

f. Government Notes and Letters of Exchange – committing Government to a recognition of a bilateral or other government to government led transaction, and to the doing of specific tasks to actualise the undertakings of the parties under such instruments; Co-investments in public investment projects and programmes (whereby the GoK co-invests with the private party to enhance the credit rating of the project);

g. Letter of Support;

h. Non-sovereign Guarantees such as Minimum Revenue Guarantees, Market or Volume Guarantees, Partial Risk Guarantees, Credit Guarantees, Foreign Exchange Guarantees, Refinancing Guarantees, among other forms of guarantees;

i. Binding Undertakings;

j. Contract-based guarantees; and

k. Any other GSM, provided it is approved in principle by the Cabinet upon the recommendation of the Cabinet Secretary of the National Treasury & Planning.

The most popular GSM issued in Kenya are GoK LoS. The GSM covers the following fiscal risks:

i. Political risk, such as assurances of protection against expropriation and change in law, civil commotions, termination and similar state or country actions;

ii. Assurances on the commercial viability of state-owned enterprises (SOEs), or their successors, will be capable of performing the obligations under the contract;

iii. Repayment guarantees or obligations in support of state corporations or county government borrowings and undertakings;

iv. Direct undertakings by the Government to financiers that project finances made available in support of public investments will be repaid when due, and where necessary, that any counterpart funding on the part of GoK will be appropriated in timely manner for project execution success.

4.6.3 Findings

The Taskforce observed that:

a. One of the main challenges faced in the implementation of the GSM policy is the wide scope in the definition of Political Force Majeure Events. For example, in the Kinangop Wind Power Project, the IPP invoked the Political Force Majeure clause under the GOK issued Letter of Support. One of the recommendations, therefore, would be to limit the scope of Political Force Majeure Events under the GSM, the PPA and other related agreements. In addition, there ought to be a sector-specific closed list of Political Events to cure the mischief of issuance of tailor-made GSMs. Furthermore, GSMs ought to be a last resort, secondary to political risk insurance. The investor ought to demonstrate all earnest efforts to obtain Political Risk Insurance prior to issuance of any GSM which should only be issued for uninsurable political risks.

b. Despite the existence of the GSM Policy, there remains a lack of clear established criteria for identifying projects that are eligible for a GSM. In the absence of such framework, the process of issuance of GSMs will remain *ad hoc* and arbitrary. The GSM Policy acknowledges that there are increasing instances being observed where intending investors view guaranteed assurance that a GSM will be issued as a pre-requisite to their making of an investment decision, usually even before they have conducted preliminary project due diligence, thus establishing an "entitlement mentality". Some of the key considerations identified in the Policy and yet to be implemented are:

   i. Which projects qualify;

   ii. Who should submit an application for a GSM, and at what stage should an application request be lodged;

   iii. What are the roles of MDAs and county governments at the point of application;

   iv. What supporting documentation should be provided by the applicant; and

   v. What, when, by whom and how should assessment and approval actions be given.

c. In the past there were cases of assignment of GSMs to third parties without the consent of GoK. This is clearly noted in the current GSM Policy as one of the challenges. However, the Policy ought to clearly stipulate that any transfer or assignment of GSMs should be with the express approval and consent of GoK.

d. The Governing Law and Dispute Resolution clauses in issued Letters of Support, provide for arbitral tribunals in London, Paris and other jurisdictions outside Kenya. In the recent past, GoK has had to defend disputes at the International Chamber of Commerce, the London Court of International Arbitration, the International Center for Settlement of Investment Disputes and other tribunals, at steep costs to the Government of Kenya in the form of legal fees and other administrative costs. To enhance the capacity of the Nairobi Centre for International Arbitration (NCIA) as well as reduce high costs of arbitration, this GSM Policy ought to adopt NCIA Arbitration rules with Nairobi as the Seat of Arbitration.

e. The PPP Bill that is currently before Parliament and that anchors GSMs in law under section 28, ought to be enacted. In addition, the said Bill ought to include mandatory parliamentary approval for the issuance of GSMs. This is similar to the requirement for parliamentary approval for the issuance of sovereign guarantees under section 58 of the Public Finance Management Act, 2012.

f. The very existence of one off-taker creates market risk and the need for GSMs. This needs to be addressed, then gradually reduce the risks covered. It is noted that a power market study is currently being untaken to see how the power market can be opened up, including the option of having more than one off-taker among other related measures.

4.7 Local Currency Denominated PPAs

Most of the PPAs executed between the offtaker and IPPs in the country are denominated in foreign currency. Payments due to the IPPs from KPLC are either in US dollars or Euros. The government bears the responsibility to make dollars or euros available, while the offtaker covers any exchange rate fluctuation risks as well as inflation, bypassing the additional cost to the consumer.**Analysis of Local Currency Impact on KPLC's PPAs Payment Obligation**

The currency in which the offtaker pays the power producer for energy purchases is a key element in PPAs. Exchange rate risk makes the IPPs prefer to be paid in dollars, euros or other denominations over the local currency. Exchange rate movements which is a matter beyond the control of the parties to the PPAs have a financial impact on the project. The project could be funded in different form of currencies, but the revenue collected by the offtaker is usually in local currency.

The Taskforce analysed and reviewed PPAs based on the currency of payment and established that:

a. The subject projects have been undertaken in the country where the revenue generated by the offtaker for power sales is local currency. The offtaker is required to convert the local currency to either dollars or Euros in fulfilling the payment obligation. KPLC had contracted about 30 PPAs with IPPs and the payment obligation was denominated in either US dollars or Euros. Denominating the IPPs' tariffs in foreign currency is bound to weaken the Kenya shilling against the foreign currency in line with law of demand and supply.

b. KPLC as the offtaker will continue to incur significant foreign exchange losses given that the tariffs are agreed at the signing of the PPAs' and review of the foreign exchange losses has not been timely or has delayed at times beyond one year due to delays in the review of the retail tariffs. The life of a PPA averages 20 years and the exchange rates between the Kenya shilling and the US dollar/Euro are bound to change significantly over the twenty (20) years.

c. The analysis of some of the PPAs as detailed below revealed the high power costs occasioned by forex adjustments that are embedded in these foreign currency denominated PPAs. These costs are passed on to customers every month as pass through costs in the electricity bills i.e. KPLC passes the exchange rate risk to consumers. This has a high negative impact on the consumers.

i. The Tsavo Power plant:

Currency: US dollars

Life: September 2001 to September 2021

Exc rate 2001: **72**

Exc rate 2021: **109.93**

The analysis above implies that KPLC would require an extra Kes 9 today for each dollar it buys compared to what it would have spent for the same dollar in 2001.

ii. Rabai Power plant:

Currency: Euro

Life: May 2010 to May 2030

Exc rate 2010: 107.63

Exc rate 2021: 130.03

This implies, KPLC would require an extra Kes22.40 today for each Euro it buys compared to what it would have spent for the same Euro in 2010.

iii. Thika Melec Power Plant

Currency: Euro

Life: March 2014 to March 2034

Exc rate 2014: **Kes110.17**

Exc rate 2021: **Kes130.03**

This implies, KPLC would require an extra Kes19.90 today for each Euro it buys compared to what it would have spent for the same Euro in 2014.

iv. Iberafrica Power Plant

Currency: US dollar

Life: Oct 2009 to Oct 2029

Exc rate 2009: **Kes75.82**

Exc rate 2021: **Kes109.93**

This implies, KPLC would require an extra Kes34.10 today for each US dollar it buys compared to what it would have spent in 2009 for the same dollar.

v. Gulf Power plant

Currency: Euro

Life: Dec 2014 to Dec 2034:

Exc rate 2014. Kes110.17

Exc rate 2021: Kes130.03

This implies, KPLC would require to spend an extra Kes19.90 today for each Euro it buys compared to what it would have sent in 2014 to buy the same Euro.

vi. Triumph Power plant

Currency: USD

Life: July 2015 to July 2035

Exc rate 2015: Kes102.31

Exc rate 2021: Kes109.93

This implies that KPLC would require to spend an extra Kes7.60 today for each US dollar it buys compared to what it would have spent in 2015 for the same US dollar.

a. There are many multinational companies who have invested in Kenya and all their transactions are in Kenya shilling. These multinationals invoice their customers in Kenya shilling. These companies include: Diageo, Toyota and Vodafone among others.

4.7.2 Findings on local currency feasibility

In 2018, EPRA commissioned a feasibility study to test the viability of Kenya transitioning to PPAs denominated in local currency.

The study found that payments obligation in foreign currency had negative impacts on Kenyan consumers as they were vulnerable to external shocks and fluctuations in the value of the Kenyan shillings. These risks to consumers would be reduced under a local currency tariff structure. Additionally, broader economic requirements to support a local currency tariff structure setting should be considered including:

a. Increase of domestic investor participation / repatriation of returns;

b. Facilitating capital markets development;

c. Mobilize local resources such as pension funds to finance power projects;

d. Promoting growth of local developers; and

e. Promoting domestic manufacturing industry.

The Taskforce noted that a policy on local currency is yet to be developed. There is need for development of a policy on locally denominated PPAs to promote use and adoption in local power contracts. A concept note on Local Currency PPA Policy is attached in Schedule 3 as annexure 4.

The Taskforce recommends that all future PPAs should be denominated in Kenya Shillings. The monetary policy implementing agency will be required to ensure a stable macroeconomic stability to avoid fluctuations in the local currency and erosion of real value of money. Stability of local currency will enhance bankability of projects

4.8 Captive power

There are one hundred and six (106) candidate PPAs with an aggregate capacity of 3,784MW demonstrating that: (i) there is sufficient interest amongst developers and investors to participate in the Kenya power market; and (ii) there is significant resource potential (hydro, geothermal, wind, solar and biomass, together with imported fossil fuels) to be able to generate power. However, power demand is lagging the interest to supply.

A potential solution is to encourage players with interest to develop power generation to also participate in generating demand for this power such as:

i. Developing traditional industries that have demand for power e.g., bauxite processing;

ii. Participating in emerging industries that have high power demand e.g., data centres, battery storage solutions, agricultural urea manufacture;

iii. Developing industrial parks.

This could be particularly beneficial as a means to take advantage of Kenya's high potential across the renewables space and position the nation as an ideal location for industries that are seeking to demonstrate a commitment to using green energy.

This discussion is already being led by KenGen, who have expressed interest in supplying power to industries located near the Olkaria resource and should be further encouraged.

In addition, 145MW of captive power has been licensed in various parts of the country, an indication that investors and particularly large consumers are taking advantage of the declining costs of installing technologies as alternate to KPLC. Given the challenge observed above, there is need to insulate KPLC from obligations to purchase such capacity in future. The captive power owners therefore need to develop and enhance their demand to consume the power. Alternatively, they could negotiate with KPLC for better supply and lower tariffs.

There is no clear policy on captive power in the country but electricity licensing and minigrid regulations guide how these installations are to be regulated. There have been instances of investors installing captive power from dirty fuels such as coal at a time when Kenya has committed to reduce the emission levels in line with agreed protocols such as the Kyoto and COP21.

4.9 Recommendations

The Taskforce analysed and assessed the existing and proposed policies applicable to energy sector and makes the following recommendations:

4.9.1 National Energy Policy, 2018

Enhance to update as per Taskforce findings hereinabove, and thereafter publicise the National Energy Policy Least Cost Development Plan

4.9.2 Least Cost Power Development Plan

a. The contracting of 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term as per the 2020-2040 LCPDP.

b. In the future, Kenya participates in the market instead of long-term bilateral agreements as EAPP market evolves.

c. The conversion of bilateral agreements to power exchange agreements as opposed to take or pay agreements, to allow for flexibility in the management of the country's demand and supply balance.

Additional recommendations relating to the LCPDP are contained in chapter 5. However, in view of the long lead times that have been observed in the processing and completion of energy projects, the Taskforce recommends the procurement timelines in respect of procurement for large power projects other than FIT/REAP as detailed in Table 5 below;

Table 5: Procurement for Energy Projects not Under FiT Process

Milestone	Time Required	Party Responsible
Feasibility Study Approval	3 Months	KPLC
Bid Preparation	1 Month	KPLC
Tendering (EOI, RFI, RFP)	5 Months	KPLC
Negotiations*	6 Months	KPLC/Seller
Board Approval	6 Months (concurrent)	KPLC/Seller
Government Permits/Approvals (CPs)	6 Months (concurrent)	KPLC/Seller
Initialled PPA	6 Months (concurrent)	KPLC/Seller
PPP Unit Approval	6 Months (concurrent)	KPLC/Seller
EPRA Approvals (CPs)	6 Months (concurrent)	KPLC/Seller
The Attorney General Approval	6 Months (concurrent)	KPLC
Signing of PPA	6 Months (concurrent)	KPLC
GoK Letter of Support (CPs)	6 Months (concurrent)	Seller
Financial Close	6 Months	Seller
Mobilization	6 Months	Seller
Construction	24-36 Months	Seller

Recommended for Solar, Wind, Geothermal (de-risked) and hydro projects of over 20MW and not under FiT process as per LCPDP

4.9.3 Government Support Measures

a. Adoption of a standard letter of support for all projects going forward. A template GoK LoS is attached as annexure 5 in Schedule 3.

b. Ensure that GoK's financial risks and contingent liabilities under the LoS have been sufficiently addressed and are manageable.

c. GoK to establish from the outset, a clear definition of strategic projects.

d. GoK to include additional requirements for issuance of GSM, under minimum documentary requirements provided in paragraphs 3.1 and 4.5 [GSM Policy Statement Five] of the GSM Policy.

e. GSMs ought to be issued as a last resort after exhaustion of other options and only on an exceptional case by case basis.

f. Taking into account the revised risk allocation matrix, GOK to renegotiate the Government Letters of Support for committed projects;

g. Standardise the Government Letter of Support based on the risk allocation matrix for all new projects including those under FiT and REAP;

h. GOK to review the necessity of GSMs in the long-term, based on changes in the market.

4.9.4 FiT Policy

a. Small renewable capacities of below 20MW for small hydro, biomass and biogas continue to be facilitated through the revised FiT Policy, 2021.

b. Because of the recommendation to make KPLC the procuring entity of power, there is no need for FIT policy committee. Consequently, the same should be abolished.

c. The current advisory role played by FiT Committee will now be performed by the Renewable Energy Resource Advisory Committee (RERAC), who are mandated by the Energy Act, 2019 to provide an advisory role to the Cabinet Secretary for Energy on promotion of Renewable Energy in the country.

d. The proposed FiT Policy will be subjected to EPRA approval in line with the Energy Act, 2019.

e. The review/renegotiate PPAs for plants approved under FiT 2012 to review tariff to reflect price changes. This is based on the fact that some projects approved under FiT, 2012 ended up with lower tariffs than in the Policy following negotiations based on guidance from EPRA/MoE. It is noteworthy that a few PPAs were concluded with the same tariffs as in the Policy, but implementation delayed and occurred when prevailing equipment prices were much lower. This includes projects like Kipeto Wind (FiT, 2010), Selenkei Investments, Cedate Solar, Malindi Solar, Alten Solar, Chania Green Energy Generation (all FiT, 2012). In these PPAs, DGE payments are at the same rate as energy delivered to the grid.

f. The FiT Policy 2021 allows project sponsor to change shareholding as long as they retain a minimum of 30% shareholding without approval of Government. The PPAs should include the need for KPLC approval of such changes in the shareholding.

g. Review PPAs for power plants with installed capacity above that set in the FiT policy to ensure any deemed energy payments are based on the installed capacity stipulated in the policy.

h. There is need for price discovery from a competitive renewable energy auction for wind and solar to determine the optimal electricity tariffs.

i. Tariffs for small hydropower, Biomass and Biogas should remain as proposed in the revised draft FiT Policy of 2021.

j. There is need to ensure timely review of electricity tariffs as per the law.

k. The projects under FiT policy to be implemented under the milestone indicated in Table 6 below.

Table 6: FiT Procurement Processes and Roles of Different Parties

Role	Timeline	Party Responsible
Identification of the Project Site	12 Months	Project Sponsor
Submission of EoI	3 months	KPLC
Review of EoI	1 month (concurrent)	KPLC
Approval or Rejection of EoI	1 month (concurrent)	KPLC
Full Project Feasibility Study	6 months	Project Sponsor
Review of Feasibility Study	2 months (concurrently)	KPLC
Progression or Revocation of EoI	2 months (concurrently)	KPLC
Negotiation and finalization of PPA	3 months	KPLC
Approval of the PPA by the offtaker Board	1 month	KPLC
Submission of the PPA to EPRA	1 month	KPLC and Seller/Sponsor
PPA Review and Approval	2 months	EPRA
Project Construction, Operation & Maintenance	12 months	Seller/Project Sponsor
Monitoring of the project operations	Ongoing post-COD	KPLC
	Ongoing post-COD	EPRA
Decommissioning of the project	20 Years	Seller/Project Sponsor

4.9.5 REAP

a. Going forward, all new capacity of variable renewable energy to be procured through Renewable Energy Auctions, except for small capacity projects of less than 20MW from small hydro, biomass and biogas. The first round of Auctions, and the Capacity to be advised by the LCPDP Committee.

b. The finalisation and publishing of the draft REAP should be fast tracked, and thereafter a pilot programme launched. The Policy should be implemented in line with the 2020-2040 LCPDP. Auctions to be subject to set maximum price which is technically and economically feasible.

c. The existing draft policies on energy development including the REAP should be issued immediately after the Taskforce report is issued. A matrix on draft policies on energy developments is attached in Schedule 3 as annexure 6.

d. The penalties applied to non-conventional plants based on not meeting timelines:

   i. Provide Bid Security. This is meant to deter bidders from withdrawing their bids because they would otherwise forfeit the bid security amount to the Off-Taker. This recommendation is consistent with the draft REAP policy.

   ii. Amend the standard PPA to include provisions for termination if the PPA effectiveness is not achieved by the long stop date due to reasons attributable to the developer.

   iii. Amend the standard PPA to include provisions for termination if project construction does not start by the long stop date due to reasons attributable to the developer.

e. The projects under REAP to be implemented under the milestone indicated in Table 7: below.

Table 7: REAP projects procurement milestones

Milestone	Time Required	Party Responsible
Feasibility Study Approval	3 Months	KPLC
Bid Preparation	1 Month	KPLC
Tendering (EOI, RFI, RFP)	5 Months	KPLC
Negotiations*	6 Months	KPLC/Seller
Board Approval	6 Months (concurrent)	KPLC/Seller
Government Permits/Approvals (CPs)	6 Months (concurrent)	KPLC/Seller
Initialled PPA	6 Months (concurrent)	KPLC/Seller
PPP Unit Approval	6 Months (concurrent)	KPLC/Seller
EPRA Approvals (CPs)	6 Months (concurrent)	KPLC/Seller
The Attorney General Approval	6 Months (concurrent)	KPLC
Signing of PPA	6 Months (concurrent)	KPLC
GOK Letter of Support (CPs)	6 Months (concurrent)	Seller
Financial Close	6 Months	Seller
Mobilization	6 Months	Seller
Construction	24-36 Months	Seller

4.9.6 Local Currency

a. Denomination of PPAs in KES and a pass-through mechanism for foreign funding and inflationary risk adjustment.

b. Denominate all future projects into local currency to manage fluctuations and volatility in customer bills that results from forex adjustments.

c. The denomination of locally financed PPAs, or whose major components are from local materials and labour, into local currency PPAs to manage fluctuations and volatility in customer bills that results from forex adjustments.

4.9.7 Captive Power

a) The captive power owners need to develop and enhance their demand to consume the power.

b) All captive power approvals/licenses should be from renewable energy technologies only.

5 Institutional framework of the electricity subsector

The efficiency of the electricity subsector actors has an impact on the operational effectiveness of PPAs, the financial implications of the utilities including KPLC and the overall cost of power. The Taskforce therefore reviewed the institutional architecture of the critical actors who play a role in the PPA review, approval, procurement, generation, and transmission process as captured herein below.

5.2 The Evolution of the Sector

The East Africa Power and Lighting Company (EAP&L) was formed in 1922 following the merger of the private Mombasa Electric Power and Lighting Company with Nairobi Power and Lighting Syndicate. EAP&L later expanded geographically when it acquired controlling shares in the Tanganyika Electricity Supply Company (TANESCO) in Tanzania and obtained generation and distribution licenses in Uganda. However, in 1948 EAP&L exited Uganda when the national, vertically integrated Uganda Electricity Board was established. In 1964 EAP&L ceased operations in Tanzania.

EAP&L listed on the Nairobi Stock Exchange (now Nairobi Securities Exchange) in 1954 and in the same year started managing the state-owned KPLC Company which was established in 1954. EAP&L also managed the Tana River Development Company which was established in 1964, the Tana and Athi Rivers Development Company established in 1974 and the Kerio Valley Development Authority which was formed in 1979.

EAP&L was rebranded to Kenya Power and Lighting Company (KPLC) in 1983 and operated as a vertically integrated utility. The World Bank driven macroeconomic and financial reforms in the country of the 1990s were accompanied by energy sector reforms in power development projects.

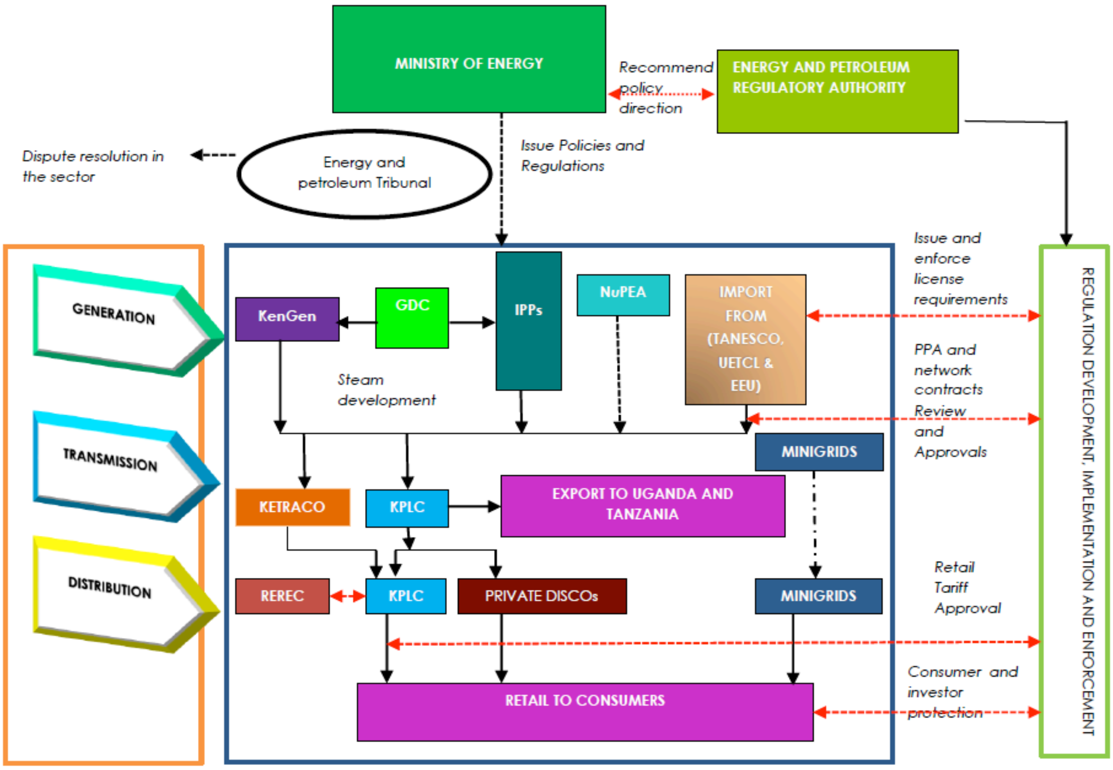
In 1997 the ownership and operation of all public sector generation assets was transferred to the Kenya Power Company (KPC), which had been established in 1954 but was hitherto under KPLC management. In 1998, KPC was rebranded as the Kenya Electricity Generating Company (KenGen). The World Bank funded the unbundling process of the generation segment from KPLC.

In 1997, the Electric Power Act was enacted. The 1997 Act established the Electricity Regulatory Board (ERB). The Ministry of Energy & Petroleum role was policy formulation whilst the ERB was vested with the regulatory function of the electricity sector.

Sessional Paper No. 4 of 2004 on Energy provided the policy road map that was necessary in reforming the energy sector. The policy proposed additional reforms targeted at further unbundling of the utilities through the establishment of a transmission company, a geothermal focused exploring company, and an energy and petroleum sector regulator. The proposed policy reforms were implemented towards the end of 2000.

The Energy Regulatory Commission (now Energy and Petroleum Regulatory Authority - EPRA), and the Energy Tribunal and Rural Electrification Authority (now Rural Electrification and Renewable Energy Authority - REREC) were established under the Energy Act, 2006. Nuclear Energy Project Committee (now Nuclear Power Energy Agency) was established in 2010 to support Kenya's nuclear ambitions. REREC was formed to implement the rural electrification programme, which was previously undertaken by KPLC. The Kenya Electricity Transmission Company (KETRACO) and Geothermal Development Corporation (GDC) were later established in 2008.

Chart 1: The Institutional Framework



5.3 Ministry of Energy (MoE)

The MoE is responsible for setting sector policies and overseeing the execution of such policies. The Ministry has no operational responsibilities. As a policy maker, its role is to create an enabling and conducive environment for the efficient operation and growth of the sector. Under Section 4 of the Energy Act 2019, the MoE is mandated, in consultation with other stakeholders, to publish a national energy policy that is to be reviewed every five years.

The MoE is required under Section 5 of the Energy Act to formulate and develop an Integrated National Energy Plan (INEP) in consultation with the stakeholders in respect of electricity, renewable energy and coal. In formulating the INEP, the ministry is to receive the plans from national energy service providers and county governments. Utilities and county governments are also required to submit to the MoE their plans for the provision of energy services and these plans are then to be consolidated into INEP.

The relevant powers of the Cabinet Secretary for Energy under the Energy Act include;

a. Assign NuPEA the research area to undertake related to a particular energy technology.

b. Undertake a countrywide survey of resource assessment of all renewable energy resources as per section 74 of the Energy Act.

c. Preparation of a renewable energy resources inventory and resource map in respect of each renewable energy resource area and thereafter prepare updates biennially which shall be published in the Gazette.

d. Promote the development and use of renewable energy technologies, including but not limited to biomass, biodiesel, bioethanol, charcoal, fuelwood, solar, wind, tidal waves, hydropower, biogas and municipal waste.

e. The Act under Section 76 establishes an inter-ministerial Committee known as the Renewable Energy Resource Advisory Committee (RERAC). The RERAC's advisory role to the Ministry is on —

    i. Criteria for allocation of renewable energy resource;

    ii. Licensing of renewable energy resource areas;

    iii. Management of water towers and catchment areas; and

    iv. Management and development of renewable energy resources.

f. RERAC may upon request advise County Governments on matters relating to renewable energy resources.

g. The Cabinet Secretary in consultation with RERAC is tasked with the issuance of geothermal licenses in regard to the exploration of the subject resource as per Section 80 of the Energy Act.

h. Section 93 of the Act confers the Cabinet Secretary with the powers to make regulations necessary for carrying out or giving effect to the provisions of the Energy Act.

5.3.1 Findings

The Taskforce established that the MoE was involved at various stages in the electricity procurement, generation and distribution value chain on issues that are beyond the policy spectrum, and cases where MoE's role in coordinating the sector could have been more effective. These include:

i. MoE is sometimes involved in various energy procurement aspects outside of its mandate. For example, MoE establishes and coordinates the FiT Committee pursuant to the provisions of the FiT Policy Application and Implementation Guidelines. The potential project developers submit their EoI to the MoE and the FiT Committee is in charge of the approval process;

ii. MoE was also been involved in the procurement of large energy projects such as coal and LNG through inviting and evaluating bids. KPLC is then required to commence PPA negotiations with the IPP, despite not having played its rightful role as the procuring entity in the invitation and evaluation of bids. MoE's policy mandate precludes it from participating (and in fact leading) procurement processes. This aspect of its current operations is an overreach of its functions;

iii. The MoE is involved in sourcing financing of Isolated Power Stations owned by REREC and various other schemes. The financing is however not channeled to the implementing agencies for direct utilisation, and is instead administered from MoE. This not only distorts the distinct status of the implementing agencies, but could likely impact upon accountability and transparency; and

iv. The Cabinet Secretary's approval of geothermal prospecting licenses comes with a guaranteed issuance of a PPA. In several cases, PPAs have been issued before establishment of viable geothermal resource, thereby compromising the integrity of the PPA terms (tariff, capacity charges etc).

As a result of the unbundling of the energy sector, the coordination of the energy sector projects and actors is a critical component of the sectors effectiveness. The MoE has not been effective in securing sector coordination to mitigate on the dependency challenges that arise. Energy planning was premised on ambitious demand projections that did not materialise.

This results in duplication of roles which are ordinarily vested in other utilities and institutions in the electricity sub-sector. There is need to eliminate these overlaps, and to have clear demarcation of each institutions' mandates for clear accountability and efficiency.

5.4 Energy & Petroleum Regulatory Authority (EPRA)

EPRA is an independent authority established under the Energy Act, 2019 following the repeal of the Energy Act 2006. EPRA is the successor of the Energy Regulatory Commission (ERC) which existed under the Energy Act, 2006. EPRA was formed pursuant to Sessional Paper No. 4 of 2004, which recommended for the establishment of an independent energy regulator. EPRA is responsible for regulating the entire energy sector, including the petroleum, electricity and renewable energy sub-sectors. EPRA's mandate and functions under Section 10 and 11 of the Energy Act are *inter alia to regulate*:

a. Importation, exportation, generation, transmission, distribution, supply and use of electrical energy;

b. Importation, exportation, transportation, refining, storage, and sale of petroleum products;

c. Production, distribution, supply and use of renewable & other forms of energy; and

d. Exploration, production, transportation, exportation, importation and sale of coal.

Toward the regulation of the energy sector, EPRA is empowered to:

a. Set, review and adjust electric power tariffs and tariff structures and investigate tariff charges; whether or not a specific application has been made for a tariff adjustment;

b. Approve electric power purchase and network service contracts for all persons engaging in electric power undertakings;

c. Make and enforce directions to ensure compliance with the Energy Act and with the conditions of licenses; and

d. Issue, renew, modify, suspend or revoke licences and permits.

As highlighted, EPRA sets the electric power tariff and tariff structures having reviewed the financial models, feasibility studies and accompanying proposals from IPPs. EPRA further approves PPAs and network service contracts. It collects and maintains the energy data. EPRA has substantial powers to supervise and monitor the activities of utilities particularly in approving contracts between the offtaker and IPPs, the issuance of associated generation licenses and the determination of the applicable tariffs.

5.4.1 Findings

The Taskforce established that EPRA participates in some roles, which would conflict with its mandate specified in Section 10 & 11 of the Energy Act as the energy sector regulator. We also noted situations where EPRA's role as a regulator should have been more effective. These include:

i. EPRA is a member of the FiT Committee; the Committee approves FiT projects at the EoI stage, yet as the regulator EPRA is required to review and approve the ensuing PPAs; and

ii. EPRA is required to schedule projects by planning their COD once the MoE approves FiT projects permitting PPA negotiations. Prior to 2018 the MoE used to communicate to KPLC directly to start negotiation on approved EoI. The MoE later revised this and directed EPRA to be responsible for scheduling CoD for projects with approved EoI. The directive was of an administration nature and was not based on any policy or legislation.

EPRA as a regulator is expected to be neutral and not be involved in the procurement process of generation projects. It is the view of the Taskforce that there appears to be no good reason why EPRA is a member of the FiT Committee, and it should not take part in project procurement process. The neutrality and objectivity of the regulator is paramount when approving contracts between the offtaker and the project developer.

Information that should have been held by EPRA as part of its regulatory function was not readily available. This information included financial models, annual reports of IPPs etc which are critical anchors of the PPA.

Submissions received by EPRA did not reveal any regulatory actions taken to mitigate the sector's challenges and in particular the challenges experienced by KPLC.

The Taskforce engaged the EPRA board of directors and management, where several regulatory gaps in the energy sector were highlighted. For example, KenGen commenced generating power in Olkaria V, Olkaria 1 unit VI without a generation license and subsequent power sales to KPLC without the applicable PPAs. REREC's Garissa Solar plant also begun operating without a generation license. Furthermore, EPRA is expected to regularly review tariffs but instances of unnecessary delays in tariff approval was noted. The Energy Act under Section 11 (c) mandates that the regulator set, review and adjust electric power tariffs and tariff structures and investigate tariff charges, whether or not a specific application has been made for a tariff adjustment. In view of the developments in the renewable energy technologies, the need for regular reviews of the tariffs applicable to respective technologies was paramount and has not been undertaken. This has resulted in projects being contracted at very high tariffs, resulting in high power costs. Further, EPRA has not mitigated the risks associated with delayed implementation of projects where tariffs had already been fixed, and where commissioning has occurred when prevailing rates have gone down.

The current difficulties experienced in KPLC, and in particular the challenges of PPA implementation, suggest a limitation in EPRAs effective monitoring of the sector. It appears that EPRA as a regulator has not effectively undertaken its mandate to mitigate the challenges at KPLC which is the sole utility distributor, and consequently exposed the consumers and the government to unsustainable power arrangements. The Taskforce established that EPRA had issued a Gazette Notice requiring KPLC to dispatch thermal plants to alledgedly keep the thermal plants in good condition, which decision was to the detriment of KPLC.

EPRA is expected to moderate the consumer tariffs and has consequently restrained itself from processing KPLC tariff review applications. It would be expected to therefore focus more on moderating the tariffs provided under the PPAs. The investor protection focus appears predominant over the consumer interest.

5.5 Rural Electrification and Renewable Energy Corporation (REREC)

REREC is a state-owned entity that is established under the Energy Act, 2019. REREC transitioned from REA which had been established in 2006. REA was formed pursuant to Sessional Paper No. 4 of 2004, which recommended the establishment of an Authority to accelerate the pace of rural electrification in the country. REREC is funded through monies from the Rural Electrification Programme Fund; monies appropriated by Parliament for that purpose, monies allocated from the consolidated energy fund for promotion and development of renewable energy initiatives among other sources.

According to the Energy Act, 2019, REREC's roles include, among others:

a. Develop and update the Rural Electrification Master Plans in consultation with County Governments, which master plan must take into account the Policy and the Energy Plans highlighted earlier;

b. Develop and update the Renewable Energy Master plan taking into account county specific needs and the principle of equity in the development of renewable energy resources;

c. Undertake feasibility studies and maintain data with a view to availing the same to developers of renewable energy resources;

d. Develop, promote and manage in collaboration with other agencies, the use of renewable energy and technologies, including biomass, municipal waste, solar, wind, tidal waves, small hydropower and co-generation but excluding geothermal; and

e. Formulate, in conjunction with the Nuclear Power and Energy Agency, a national strategy for coordinating research in renewable energy.

5.5.1 Findings

The Taskforce noted that the core mandate of REREC is the implementation of projects under the Rural Electrification Programme particularly in grid extension in rural areas. This mandate has been particularly important in bringing remote rural communities into the grid, and promoting development in these areas. These are the areas considered commercially unviable based on a profit focused offtaker. The Taskforce observed that:

Overlaps with KPLC: The Taskforce noted that the rural electrification is implemented by MOE, KPLC and REREC, which create overlaps and duplication. Further, there are several funding structures for the rural electricity programme including, GoK through the exchequer, Development Partners, 5% of electricity bills allocated to REREC, the Rural Electricity Scheme, Constituency Development Funds and the Petroleum Development Levy which situation poses a challenge in terms of accountability and prudent use of funds.

All the infrastructure developed under these varied initiatives is owned by REREC and then handed over to KPLC for operation and maintenance. However, the funds allocated for operation and maintenance are not adequate to compensate KPLC. Consequently, GoK currently owes KPLC significant amounts of funds. REREC also claims to be owed money by KPLC. This convoluted arrangement creates challenges in determining the exact financial status of each agency and the resultant implication on the cost of power to the consumer.

REREC constructs distribution lines and associated infrastructure in rural areas targeting to serve social amenities i.e., health centres, shopping centres or schools. This construction is predominately undertaken by sub-contractors. After the construction, the distribution lines constructed are then handed to KPLC for purposes of operation and maintenance. The consumers in the locality, including social institutions, then apply and contract with KPLC for power connection and metering.

Ordinarily there is no clear delineation on the areas which constitute 'rural' in that KPLC, in its role as distributor, performs the same function. In some instances, KPLC distribution system expands to areas that could be considered more remote compared to REREC's coverage.

Quality Standards: REREC and KPLC have entered into a service level agreement for implementation of its core projects. The Taskforce however received representations about concerns over the quality of projects undertaken by REREC.

Expanded Mandate: The operations of REREC have evolved to include generation i.e., the Garissa Solar plant for sale of power to the offtaker. The organization lacked capacity to construct, operate & manage such a project and had to initially outsource the operational aspect to KenGen before building its operation and maintenance capability. It is unclear to the Taskforce why the role of REREC has evolved into power generation for sale to the national grid as the same can efficiently be undertaken by either KenGen or IPPs, including use of the FiT programme.

5.6 Kenya Electricity Generating Company Plc (KenGen)

KenGen is a generation company which is partly owned by the government (70 percent shareholding) whilst 30% is owned by private investors. The company is listed on the Nairobi Securities Exchange. KenGen owns more than 70% of total installed capacity in Kenya. KenGen assumed the generation function after the vertical unbundling of KPLC in 1997. KenGen generates its electricity from diversified sources which include hydro, geothermal, thermal and wind. KenGen may also bid for projects initiated by GDC under the steam supply arrangement.

In the recent past, KenGen has expanded its scope and is implementing geothermal projects in neighbouring countries demonstrating its technical capacity to undertake additional projects within the country. In October 2019, the company secured a Ksh 5.8 billion contract to drill 12 geothermal wells in Ethiopia. In February 2021, the company secured a US$ 6,452,933 contract to drill 3 geothermal wells in Djibouti.

5.6.1 Findings

The Taskforce has established that the projects implemented by KenGen, which are of similar technology, scope and within same location, are less costly and yield lower tariffs compared to IPP projects.

It appears KenGen and GDC do not operate in tandem in exploring and utilising the geothermal resource. Their operational synergy in geothermal technology would accrue accelerated geothermal generation and at a lower tariff compared to that of IPPs.

Though KenGen's project derive better prices, the Taskforce found that some of the projects are implemented outside the scope of LCPDP resulting to alteration of the generation projections capacity. Some of KenGen projects are also commissioned before issuance of a generation license or execution of a PPA with the offtaker. This is indicative of lack of coordination and effective regulation of all players in the sector and will put further strain on the offtaker with the additional capacity.

5.7 Geothermal Development Company Limited (GDC)

GDC was incorporated in 2008 under the Companies Act as a fully government owned company, which was set up to accelerate development of geothermal resources. GDC's mandate is the development of geothermal steam fields and sale of steam for electricity production. The steam can be sold to KenGen or IPPs. There are no specific delineated geographic areas that are exclusively set aside for either GDC or KenGen to explore for geothermal.

In 2013, GDC awarded contracts to three IPPs to each construct a 35MW plant under the first phase of the 105MW Menengai Geothermal Project. GDC had completed the construction of the steam gathering system by end of 2019 while by end of 2018 KETRACO had constructed a 132 kilovolt (kV) substation that will transmit electricity from the three power plants. However, the IPPs are lagging behind. None of the IPP had commenced construction by August 2021as they are yet to reach financial close.

The formation of GDC, whose primary role of geothermal development is similar to that of KenGen, was apparently expected to accelerate development of the geothermal resource. This has not happened. IPPs prices for geothermal projects under GDC are higher compared to those of KenGen. Apparently, KenGen did not participate in, or failed to qualify for, bidding for the Menengai projects despite its expertise in the geothermal technology and its lower tariff in similar projects.

5.7.1 Findings

The Taskforce established that GDC concludes the Project Implementation and Steam Supply Agreement (PISSA) with IPPs without KPLC's input. Since the PISSA terms are subsequently factored in the respective PPA tariff KPLC should have access to these agreements before concluding these particular PPAs.

KPLC has entered into a Steam Supply Agreement with GDC for the steam supplied to IPPs. This contractual arrangement is not proper as KPLC does not buy steam from GDC. Even in thermal PPAs KPLC is not a party to the fuel supply agreement between the IPP and the fuel supplier. The steam tariff should be an element in PISSA.

The Taskforce found it inconceivable that KENGEN did not qualify for projects tendered by GDC for steam conversion.

5.8 Kenya Power & Lighting Company Limited Plc (KPLC)

KPLC is a transmission and distribution company in which the Government shareholding is 51% while private investors own 49% of the shares. KPLC is listed on the Nairobi Securities Exchange. KPLC also doubles as the grid operator.

After the establishment of KETRACO in 2008, KPLC focus is on distribution, supply and retail of electricity. It controls, owns and maintains the transmission lines that existed prior to formation of KETRACO. KPLC also operates the mini-grids owned by REREC.

KPLC acts as the single buyer in the electricity market where all generating companies sign respective PPAs with it.**Findings**

The Taskforce assessed and analysed KPLC's operational and management role particularly in; IPPs transactions, contract management, energy purchase, power distribution and customer focus parameters. It established that:

a. KPLC, whilst being a state corporation, is also a commercial enterprise listed in the Nairobi Securities Exchange and in this regard, the Board of Directors and the Company have obligations to all stakeholders in the business, including:

i. The customer base and their desire and need for affordable and consistent electricity;

ii. The company's direct lenders;

iii. The company's public equity investors;

iv. Suppliers; and

v. Employees.

b. Lack of complete and satisfactory information on IPPs' compliance with laws and regulations. The monitoring of IPPs contracts and performance has not been efficient. KPLC has executed contracts with IPPs in instances where the commerciality of the geothermal resource has not been assessed resulting in long lead times in project implementation; and

c. The KPLC management structure does not appear to be operating efficiently and optimally in overseeing the power purchase and subsequent distribution and retailing to consumers.

The Taskforce has made additional recommendations on the organisational structuring reforms at KPLC contained in Chapter 12 of this report.

5.9 Kenya Electricity Transmission Company Limited (KETRACO)

KETRACO is a state-owned utility incorporated under the Companies Act in 2008. The company is 100% Government owned. The Sessional Paper No. 4 of 2004 recommended the unbundling of KPLC into two entities, one for transmission which was to be 100% state owned and the other for distribution which will be private sector owned. The Policy envisaged that the transmission system would be vested under one entity, but it is silent on how to handle KPLC's transmission system that existed prior to the formation of KETRACO.

KETRACO is mandated to plan, design, construct, own, operate and maintain high voltage electricity transmission grids, as well as the regional interconnectors. It is responsible for high voltage lines and substations with 132kV and above. The company is also responsible for designing, building and maintaining interconnectors with neighbouring countries, which has allowed Kenya to sell to, buy from or transmit electricity between her neighbours and to participate in the Eastern Africa Power Pool. KPLC owns and operates the portion of the transmission system which existed prior to KETRACO formation. The transmission grid in a country power system is supposed to be a natural monopoly. The essence of natural monopolies in power systems arises due to unique circumstances where high start-up costs and significant economies of scale lead to only one firm being able to efficiently provide the service in a certain territory. **Findings**

The Taskforce established that the current setup where KPLC and KETRACO own and operate the transmission system results in duplication of both technical and human capital resources. Lack of information limited the Taskforce's analysis of the relative transmission costs by the two utilities. The Taskforce is led to conclude that the regulation of the two systems in terms of cost allocation and system losses monitoring may not be efficient. Further submissions are contained in section 4.12 (System Operator).

The Taskforce also observed the dependencies that exist between KETRACO/KPLC/KENGEN, and the need for strict alignment of project plans and implementation timelines to minimize disruptions.

5.10 The Nuclear Power and Energy Agency (NuPEA)

NuPEA is a State Corporation established under the Energy Act, 2019. NuPEA was initially Nuclear Electricity Project Committee (NEPC) prior to 2012 when it changed to the Nuclear Electricity Board through a Gazette Notice.

Under the Energy Act, 2019, NuPEA's mandate includes:

a. Promotion and implementation of Kenya's nuclear power programme;

b. Undertakes research and development for the nuclear form of energy;

c. Awareness creation and disseminate information on the efficient use of energy and its conservation;

d. Training and development in the field of energy and petroleum, research and technology development;

e. Train and upgrade human resource capacity in the energy sector; and

f. Promote local production of energy technologies.

5.10.1 Findings

According to the 2020-2040 LCPDP, it is unlikely that the country will go into nuclear power production in the foreseeable future. A separate entity to promote and implement a nuclear programme in Kenya is therefore not necessary at this point, and this high level non generation role could be played by MoE. The Taskforce established that the scope of NuPEA's mandate involves aspects not related to nuclear energy such as research in other forms of energy and capacity building in other utilities. The envisaged role, which is not nuclear related, can be performed efficiently by the respective entities. The cost implication of running NuPEA as a distinct entity cannot be justified.

5.11 Energy & Petroleum Tribunal

The Energy and Petroleum Tribunal is established under section 25 of the Energy Act, 2019. It replaced the Energy Tribunal which existed under Energy Act, 2006. The Sessional Paper No. 4 of 2004 recommended the establishment of an Appeals Tribunal to deal with complaints and grievances against regulators' decisions to replace the Minister who performed the function. The Tribunal was established for the purpose of hearing and determining disputes and appeals particularly on regulated issues within the energy sector. The Tribunal role is as follows:

a. A person aggrieved by a decision of the Authority may appeal to the Tribunal within thirty days of receipt of the decision.

b. The Tribunal has appellate jurisdiction over the decisions made by the Authority. The Tribunal has powers to grant equitable remedies including injunctions, penalties, damages, specific performance.

c. The Tribunal shall have original civil jurisdiction on any dispute between a licensee and a third party or between licensees. The jurisdiction of the Tribunal does not include the trial of criminal offences.

5.11.1 Findings

The Taskforce noted that the Tribunal does not have a substantive chairperson and is therefore not operational.

5.12 The Independent System Operator (ISO)

The ISO function is currently carried out by KPLC through its National Control Centre. The role and function of the System Operator are critical in ensuring optimal operation of the grid.

The Energy Act 2019, under Section 138 provides for EPRA to designate an ISO. This is so as to factor in a liberalised sector where more than one utility company is expected to be established. The system operator will be responsible for matching consumers' requirements or demand with electrical energy availability or supply, maintaining electric power system security and arranging for the dispatch process.

The system operator will be funded through levies and fees charged from the generating companies or other licensee engaged in electricity undertakings.

According to the Energy Act the functions of the system operator include; –

a. Managing and operating the National Control Centre (NCC) and other infrastructure established by the National Government for the purpose of carrying out system operations;

b. Giving directions, supervising and controlling the stability of network operations and for achieving the maximum economy and efficiency in the operation of the electric power system;

c. Optimal scheduling and dispatch of electrical energy and ancillary services throughout the country;

d. Keeping records of the quantity and quality of electrical energy supply on the national grid; and

e. Coordinating with system operators of the countries whose electric power systems are interconnected with the Kenyan system to ensure efficient operations.

5.12.1 Findings

The Taskforce observed that the proposed designation of a system operator has not been implemented. The law provides that the system operator shall not be involved in the direct or indirect buying or selling of electrical energy. This implies that KPLC as a distribution company cannot be designated as an ISO

The use of a system operator is also expected to enhance accountability in the merit order dispatch process. Taskforce was informed that power dispatch is done by the KPLC's NCC through the merit order mechanism where cheapest power is prioritized for dispatch. This could however not be verified.

The Taskforce established that KETRACO has obtained funding for the establishment of a system operator infrastructure although appropriate approvals have not been granted by EPRA. EPRA was undertaking a study to establish which utility was better placed to undertake the system operator role. This study is expected to be completed by December 2021.

5.13 Recommendations

In order to improve efficiency among sector institutions and deliver optimal services to all stakeholders in the industry the Taskforce recommends:

1. KPLC should play an active and effective role in energy planning, and the procurement processes that result into Power Purchase Agreements, with the following key components:

   i. The LCPDP development process, to include all relevant energy sector players, and incorporate in priority, demand forecast data from KPLC as the primary utility company at both the Technical and Oversight Committee levels;

   ii. The LCPDP components to incorporate:

      - The plan itself (demand forecast, generation and transmission plans).
      - An implementation matrix including actors, tentative budgets, timelines, and milestone events per project (Milestones Events

include: Feasibility Studies; Approvals; Procurement; Negotiation; Construction and Operation Dates);

- The Project Development Rights Criteria outlining the sequencing of projects, and identifying which agencies (public sector and IPPs) are to undertake which projects; and

- Sanctions/penalties and mitigation plans for non-performance, including step-in rights, performance tools and other guarantees to assure implementation as planned.

iii. The Boards of Directors of all participating public sector agencies to formally approve the LCPDP as part of the Oversight Committee approvals process. Evidence of Board resolutions to accompany the LCPDP submission to the MoE for endorsement, and thereafter concurrence by the Cabinet Sub-Committee on KPLC and/or its successor Committee.

iv. No projects to be implemented outside of the LCPDP. Any variations occurring as a result of non-performance, emergent considerations or other related circumstances are to follow the same procedure in (i) to (iii) above. Variation requests to the Cabinet Sub-Committee to include a comprehensive justification for the proposal.

v. The National Treasury to only approve relevant agency capital budgets and projects as per the LCPDP priorities. These include self-financed projects sourced independently by the agencies;

vi. Each public sector agency to thereafter be responsible for the procurement of agreements under their purview. The Boards of Directors of the respective agencies to be responsible for oversighting the procurement plans in assurance of the LCPDP priorities.

vii. KPLC to be responsible for the procurement and/or sourcing of all PPAs submitted through the FiT process, auctions, any privately initiated proposals, competitive procurements under the Public Procurement and Assets Disposal Act, PPAs arising out of concessions granted by Government, or other public private partnership initiatives from both public sector players i.e., KenGen, GDC, REREC, KETRACO as well as IPPs. KPLC to assure itself of the feasibility proposals accompanying any procured proposals.

viii. To secure consistent monitoring of project implementation of the LCPDP as well as approved PPAs/contracted services implementing the plan, the following structure to be adopted:

- The LCPDP Technical and Oversight Committees to meet quarterly, with a view to receiving reports on the status of the Implementation Matrix.
- The current MoE led sector meetings to be expanded to include:
    - The Cabinet Secretary (or his alternate) as Chairperson;
    - The Board Chairpersons and Chief Executive Officers of KPLC, KETRACO, KenGen, GDC, EPRA, REREC and any others;
    - The Principal Secretary, National Treasury or his alternate;
    - The Solicitor General, or his alternate.

ix. No indicative tariffs, or COD variations are to be done by EPRA. This should be done under the LCPDP oversight mechanism and should involve the formal approval of the Boards of the relevant utility companies.

x. The construction of projects should not begin before PPAs are negotiated and executed. Consequently, KPLC to issue a notice to proceed for all individual projects (public and private), prior to procurement of sub-contractor arrangements.

2. The MoE's role under the Energy Act should concentrate on the energy planning and policy setting at the National level as provided for under section 4 and 5 of the Act, and leave implementation of energy plans, policies and regulation to other designated players in the sector thus allow for efficient running of the energy sector. All donor funds for project implementation should be disbursed to the relevant implementing agency as is the case for Exchequer releases.

3. In setting and approving tariffs, EPRA should be guided to balance the interests of the generators, consumers and the utility.

4. EPRA should perform its regulatory functions as provided under Section 10 of the Energy Act and not get involved in procurement of projects to avoid conflict with its regulatory role. As such, EPRA should not be a member of the FiT committee or get involved with auction of power.

5. EPRA to undertake an immediate review within three (3) months, of all prevailing generation tariffs for the different technologies benchmarked against global tariffs and undertake regular reviews as provided for under the Energy Act.

6. EPRA to undertake the requisite legal, risk, technical and financial analysis before making the determination and designation of an Independent

System Operator (ISO). In the meantime, KETRACO to stop their undertaking infrastructure development of ISO until EPRA designates the ISO. In the meantime, KPLC to continue being the System Operator and running the National Control Centre. KPLC management to produce monthly reports to the board and to the LCPDP Oversight committee that show the power purchase costs incurred under the merit order.

7. Pursuant to its mandate for rural electrification as set out under Section 44 of the Energy Act, REREC to continue to perform its mandate of rural electrification by identifying areas of need. However, to mitigate costs and assure quality, REREC should contract out the implementation of rural electricity programme to KPLC, which has a better capacity.

8. The National Treasury to streamline the funding and disbursements of all financial arrangements surrounding rural electrification to ensure that REREC is the sole implementer of this programme and that funds allocated for this programme are allocated and disbursed to REREC who should be solely accountable for the utilization of these funds.

9. The administrator role for the Rural Electrification Scheme to immediately be transferred to REREC Chief Executive Officer to manage going forward, so as to synchronise and optimise the rural electrification objectives.

10. To avoid REREC's overexpansion on its mandate, and duplicating management costs, REREC should not be involved in power generation projects for sale to KPLC, but should focus on rural electrification through mini grid generation functions. The operation and maintenance function for the Garissa solar project to be handed over to KenGen which has the technical capacity to carry out these functions.

11. The operation and maintenance aspects of KPLC transmission system to be transferred to KETRACO in the short term through an operations and maintenance contract. In the medium to long term, assets to be transferred to KETRACO upon valuation.

12. NuPEA to be abolished. The mandate to be vested to a department within MoE to handle the general policy development of nuclear power. The capacity building mandate of the sector can be handled by the respective sector entities. This would require amendment of Section 56 of the Energy Act.

13. Due to the significant overlaps between GDC and KenGen there is need to align the roles of GDC and KenGen in harnessing the geothermal resource.

14. KenGen should be involved in bidding for all projects initiated by GDC. KenGen should have first right of refusal for GDC tenders, and as recommended in Chapter 11 (Proposed actions for operational PPAs). The

resulting tariff for IPPs in geothermal technology should always be bench marked with those of KenGen.

15. The terms & conditions of PISSA between GDC & IPPs terms and conditions to be input in PPAs. GDC should involve the offtaker and submit to them the draft agreements prior to execution of PISSA for KPLC concurrence. There should be no Steam Supply Agreement between KPLC and GDC since that tariff should be factored in the overall IPP tariff. The existing PISSA should be reviewed to have the steam tariff incorporated.

16. The KenGen projects to be simultaneously planned together with other IPPs generation and be incorporated within the LCPDP. No power generation should commence or payments or sale of the power generated prior to obtaining the applicable licenses and PPAs.

17. The award of PPAs to IPPs utilising geothermal resource would need to be subsequent to the assessment of the commerciality of the resource to reduce the delays associated with such projects that occur prior to commissioning of projects. Issuance of geothermal licensing to prospectors should not be accompanied by a guarantee of issuance of a PPA. The KPLC to negotiate PPAs with IPPs after confirmation of the commercial steam.

18. The Fit Committee to be abolished. As indicated, KPLC to take over responsibility for procurement of projects under the FIT as guided by the LCPDP. The LCPDP process to be modified accordingly. KPLC Board to approve FIT EoIs as they confer ownership of the project.

6 Stakeholder engagement

6.2 Introduction

Stakeholder involvement and consultation when undertaking activities that may impact on them is of paramount importance. It is a Constitutional requirement that relevant stakeholders should be consulted in making a decision that concerns them. Further, the Terms of the Reference on the review of PPAs required the Task Force to undertake consultations with stakeholders in the electricity sub-sector including industry players, large electricity consumers, associations and lobby groups, regulators and Government agencies, and any other person or entity deemed necessary.

The Taskforce, through local newspaper advertisements of 11th and 13th May 2021 invited the public to provide memoranda towards the review of PPAs. The Task force also held virtual stakeholder consultations between from 2nd of July 2021 to 10th September 2021.

6.3 Stakeholder Participation

The Taskforce received valuable responses from over Sixty-three (63) different stakeholders. There were local and international stakeholder who included:

a. Consumer protection other lobby groups;

b. Energy consultants;

c. Legal practitioners;

d. Lobby groups;

e. Development Finance Institutions (DFIs);

f. Agriculturalists;

g. Non-Governmental Organisations (NGOs);

h. Finance experts;

i. Pension fund managers;

j. Retail and industrial consumers;

k. Diplomatic corps/foreign governments;

l. Government agencies; and

m. Other individual members of the public.

In order to ensure a fair consultative and inclusive process in line with the Constitution, the Taskforce mapped out stakeholders from various industries and sectors depending on their interests and developed relevant questionnaires based on the Terms of Reference (ToRs).

The Taskforce held over Thirty-Two (32) stakeholder engagement sessions. The stakeholders were formally invited to the forums to make their presentations. They were also encouraged to submit written response that includes all the issues discussed in the forum.

There were over One Hundred and Thirty-two (132) individual stakeholders who appeared before the Taskforce to make their submissions, pooled from both local and international organizations and richly endowed with experience and expertise on matters of energy, investment and legal contracting among others. The list of stakeholders is attached in *annexure 7 under Schedule 3.*

6.4 Analysis

The Taskforce compiled all the submissions received from the stakeholders to facilitate detailed analysis. The analysis was done in accordance with the different recurring themes which included: legal and regulatory framework, procurement of power from IPPs, allocation of risk, take-or-pay vs take-and-pay PPA model, adequacy of the retail tariff structure, key considerations in funding electricity sector, generation mix and captive power.

While different stakeholders addressed different themes based on their respective interests, they generally maintained objectivity. This was evident in the common observations made about the various themes.

6.5 Findings

The Taskforce obtained the following summarised submissions:

a. On the Government Support Measures Policy (2018), stakeholder observed that changes in the market are inevitable and recommended review of GSM to facilitate future projects. The Central Bank of Kenya was in particular against continued issuance of GSM since they have the potential for creating contingent liabilities for the Government. Other stakeholders such as Development Finance Institutions (DFIs), investors and some development partners however affirmed that they are required given their importance in mitigating against a single off taker risk and political risk related events. The Taskforce concurs that GSMs are necessary for the bankability of energy projects; however, GSMs must align to the assessed risk matrix.

b. The preference of the local currency denominated PPAs over foreign denominated contracts. The exchange rate fluctuation risks as well as inflation left Kenyans vulnerable to external shocks and fluctuations in the value of the Kenyan shilling. There is need for broader economic analysis to support local currency denominated PPAs as well as the attendant policy for adoption in local currency.

c. The need to review the Feed-in-Tariff Policy. They highlighted the challenges faced in the energy sector particularly relating to the changing technology which had resulted to reduced production costs and proposed a structure to shield the FiT projects from becoming an unnecessary expense in the energy sector in Kenya.

d. They noted that the Least Cost Power Development Plan, was critical in ensuring that electricity generation matched the country's electricity demand. The LCPDP, which spans 20 years, was to be reviewed every two years, but had several implementation challenges.

e. The importation of electricity from neighbouring countries to complement the electricity demand gap foreseen under the LCPDP was noted to be critical. It was explained that Kenya can participate in the EAPP market through hybrid of trading platforms including short term trading platforms instead of long-term bilateral agreements.

f. Stakeholders indicated that the proposed Renewable Energy Auction Policy would provide a transparent and competitive mechanism for RE projects larger than 20MW. It was stressed that the policy be expedited, and a pilot program be launched.

g. With regard to reputational risk, it was noted that Kenya IPPs projects enjoy preferred access to debt financing terms and lenders are broadly comfortable with the current LoS. In a survey carried out by the Africa Infrastructure Development Association (AfIDA) which had 51 respondents, Kenya was ranked the most desirable investment destination for PPP projects in Africa.

The Taskforce assessed and analysed the risks that both the Government and KPLC would suffer in the event of termination of the IPPs. It was established that:

a. The management of the relationships with IPPs is a delicate matter – incidentally even in a 'do-nothing' scenario.

b. During the stakeholder engagements it was apparent that IPPs place significant reliance on the GoK LoS and would expect GoK to honour them. Most foreign investors view political risk as a key risk when it comes to the development of power in sub-Saharan Africa. However, it was positive to note that their recognition of the strides the government has made over the last decade in developing IPP structure in Kenya, allowing foreign investors to accept a LoS as opposed to a government guarantee.

c. The sanctity of agreed contractual terms and investment climate and approach to power purchase agreements are important to continuing to encourage and attract private investment (especially foreign private investment)

d. The IPPs tend to have development financial institutions as lenders, and they expect that the GoK would honour its commitments.

e. It is not always that large infrastructural projects are implemented without either technical or financial challenges and the DFIs are used to negotiating projects that are experiencing challenges.

f. Kenya's standing as a preferred investment destination of PPP projects in Africa will certainly change if any PPA termination process is not handled delicately.

g. Potential local investors (local banks, pension funds etc.) may however see the IPP space as an opportunity given that they risk appetite is slightly different in that they already mainly deal in local currency, and they are unlikely to require a LoS.

6.6 Recommendations

The Taskforce noted that most of the key issues concerning the stakeholders related to; the planning and legal and regulatory framework of the sector, procurement of power from IPPs, allocation of risk, Take-or-Pay vs Take and Pay PPA models, adequacy of the retail tariff structure and tariff making process, funding of the power projects, the GoK support measures, the power generation mix and need for captive power among others. Where deemed appropriate, stakeholder's recommendations have been included as part of the Taskforce's recommendations.

7 Review of contractual structure of Power Purchase Agreements (PPAs) and associated agreements

7.2 Introduction

The review of the contractual structure of PPAs and associated agreements was undertaken with the overarching goal of reducing the cost of electricity. The Taskforce was of the view that the goal could be achieved by reduction of transaction cost, minimisation of Government exposure, optimum allocation of risks, adoption of best global standards and efficient procurement and management of contracts. To that end, the Taskforce reviewed pertinent contract clauses as detailed below and developed standard templates for projects procured under the Feed in Tariff Policy (below 20MW) and those competitively procured. The clauses in those templates are non-negotiable. They embody among other items a Due Diligence Framework, a Balanced Risk Matrix and a Contract Management Framework.

The associated agreements vary depending on the technology and project structure and include the following:

a. Project Implementation Steam Supply Agreement

b. Fuel Supply Agreement;

c. Operation & Maintenance Agreement;

d. Engineering, Procurement & Construction Contract;

e. Project Agreement;

f. Escrow Account Agreement;

g. Direct Agreement;

h. Partial Risk Guarantee;

i. Indemnity Agreement;

j. Letter of Support;

k. Lease Agreement.

Regrettably, the said agreements, except for the Government Letter of Support, were not made available to the Taskforce at the time of the review. An appropriate reviewed Government Letter of Support is attached to the report in Schedule 3 in annexure 3.

7.3 Take and Pay Mechanism

Power Purchase Agreements are usually based on two payment models. The first one is Take or Pay and the second is Pay when Taken.

A take-or-pay clause is an agreement between the offtaker and the power producer guaranteeing that the offtaker will either 'take' power produced, 'or pay' for the power produced if it is not required. A take-or-pay requirement in a PPA assures the power generator a pre-determined amount of revenue on the condition that the power producer makes the power available to the offtaker under the agreement. The amounts guaranteed are in the form of Capacity Payments and Deemed Generation Energy Payments. This provision enables the power producer to cover its fixed costs.

Take or pay clauses are well established clauses commonly entrenched in PPAs and are critical for obtaining project financing, as they evidence certainty around project cashflows.

The alternative to avoid the guaranteed Capacity and Deemed Generated Energy Payments would be the Take and Pay option.

Take and Pay is a mechanism where payments are made to generators only when actual energy is purchased by the offtaker. The difference between the two mechanisms is that the offtaker is not obligated to pay for electricity that is not utilised or generated. The Take-or-Pay provision is usually the key contractual remedy available to an IPP when the offtaker fails to take delivery of power, which is generated or deemed to be generated.

The Taskforce was expected to review and consider the possibility of introducing a Pay when Taken mechanism to the current PPA structure. The main reason for this shift is financial in nature as the utility company will not be obliged to pay for electricity that is not used or delivered. Under a take and pay regime, utility companies are encouraged to conduct more careful due diligence on the volume of electricity that they will actually require.

7.3.1 Findings

The Taskforce established that:

a. PPAs by their very nature are long-term contracts averaging 20 to 30 years. This is the case for all the current energy projects and operational PPAs' in the country. Most of the PPAs provide for the Take or Pay mechanism and KPLC is financially obligated to make the respective payments for the entire term of the PPA, irrespective of any changes in power demand over the period.

b. The country has not developed a pay ahead market where generators compete in a free market and give offers of possible charge for electricity and capacity a day before off-taking.

c. The Take or Pay model has a knock-on impact on the consumer price of power and locally produced goods. This is because this cost of un-utilised power has to be passed on to domestic and industrial consumers resulting in high cost of manufacturing goods and other services.

d. Pay when taken is a model not exploited in Kenya and generally in Africa. Kenya and Ghana are some of the two countries in Africa exploring and considering the adoption of this power purchase model. The adoption of this model by KPLC may cause the following:

   - Power producers will be paid only for the power taken by KPLC and therefore the power producers will no longer be guaranteed of a certain income level.
   - Power producers will be required to undertake more strategic and futuristic due diligence based on power demand and supply before they undertake any power production project.
   - Potential investors may react negatively and hold back further investment in the sector. The operational IPPs may decide not to renew their PPAs or proceed to terminate them.
   - Lenders may also lack interest in financing the power generation project as the payments will no longer be guaranteed.

e. KenGen offers the country a good fallback alternative for IPPs. KenGen have proved to be cheaper in the various energy projects it has undertaken. The change would result in cheaper and reliable power, which will benefit the country and improve economic growth potential.

7.4 Change in Law and Change in Tax Clauses

The purpose of a Change in Law or Change in Tax clause in a PPA is to ensure that a party is not deprived of what it legitimately expected. By nature, PPAs are long term contracts of over 20 years and during their term, laws and tax regimes are bound to change. The potential changes are not intended to negatively impact on the parties particularly in regard to cost elements as they fulfil their contractual obligations. A change in law may significantly increase or decrease the obligations of the parties to a PPA and, therefore, impact their costs, expenses, or expected income. Some change in law events may also alter the very foundation of a PPA and may, in the absence of a clear and balanced change in law dispensation, render a project commercially unviable. **Findings**

The Taskforce established that:

a. Most of the reviewed PPAs have provision for Change in Law save for Tsavo Power Company Ltd, KenGen (Olkaria IV), and Kwale International Sugar

Company Limited (KISCOL). It was noted that even where the PPAs provided for the subject clause, the same was not exhaustive.

b. Some of the PPAs, such as for Akiira Geothermal Limited, have an elaborate provision specifying the amounts that the relevant Parties would be owed in the event of a Change in Law or Change in Tax, and within which period the amounts owing should be paid.

c. Most of the PPAs are long-term contracts, laws and taxes are bound to change within such a period. The clauses are wide in scope with far-reaching consequences for GOK under the respective GoK LoS.

d. There is need to limit GoK exposure under the respective PPAs and GoK LOS

7.5 Assignment and Novation Clause

Novation is the process by which the original contract is extinguished and replaced with another, under which a third party takes up rights and obligations duplicating those of one of the parties to the original contract. It involves the transfer of right and obligations to another party.

Assignment on the other hand is the transfer in whole or in part of some of the contractual rights in a contract. Novation clause differs from assignment clause in that an assignment clause regulates the extent to which a party's interest in a contract may be assigned to another party.**Findings**

The Taskforce established that:

a. Most of the PPAs have a clause on assignment, though the same is not adequate. It does not limit the period within which the assignment may occur, it excludes disclosure of consideration payable upon assignment, and there is no requirement of acquisition of fresh requisite approvals by the assignee.

b. Some of the existing PPAs have witnessed unnecessary transfer and assignments subsequent to the execution of PPAs and before commencement of construction as there is no limitation period for which an assignment can occur. This results in delays in the implementation of projects and total failure of other projects.

c. Consideration payable to the IPPs by the assignee are not to be disclosed.

d. There is need to limit the period within which an assignment may occur. This serves to discourage IPPs seeking PPAs purely for speculation purposes and with no intention to fully develop a project.

e. There is need for an assignee to undergo fresh due diligence and acquire requisite approvals from agencies such as, AG, parent Ministry, Cabinet, National Treasury, PPP Committee, where applicable.

f. The novation clause has not been incorporated in all the PPAs.

7.6 The Environment Clause

Environmental conservation and protection from degradation is crucial in mitigation of climate change and global warming. Project developers both locally and globally are required to adopt such measures in project implementation that address environmental sustainability for intergenerational benefits.

The Kenya Constitution under Article 42 provides for environmental rights and freedoms. It recognizes the right to a clean and healthy environment and requires the Government to ensure sustainable utilisation, management and conservation of the environment and natural resources. The Government is obligated to establish systems of environment impact assessment, environmental audit and monitoring. The processes and activities that are likely to endanger the environment are to be eliminated. Every person is constitutionally bound to cooperate with State organs and other persons in protection and conservation of the environment and ensure sustainable development of natural resources.

Section 96 of the Energy Act 2019 requires compliance with the applicable environmental, health, safety, planning, maritime legislation or guidelines, prior to the issuance of a license or permit.

Sessional Paper No. 4 of 2004 emphasises the importance of environmental conservation particularly in the execution of infrastructural energy projects ranging from generation, transmission and distribution.

Presently, most international organisations including multilateral lenders such as the World Bank, International Finance Corporation (IFC) and the African Development Bank (AfDB) have developed environmental guidelines that project developers must meet prior to financing of their projects. The International Renewable Energy Agency (IRENA), the Organization for Economic Co-operation and Development (OECD), United Nations Environment Programme (UNEP) promote adherence to environmental legislation including the applicable treaties.

One of the key goals towards use of clean energy in power generation is to mitigate environmental degradation associated with other forms of energy such us coal or thermal power. **Findings**

The Taskforce established that:

a. Most PPAs lack the necessary minimum environmental protection clauses and compliance with environmental law is only premised on expectations that the parties are obligated to adhere to public law.

b. Generally, investors including IPPs are required to comply with existing environmental national laws as well as international treaties to which Kenya is a party.

c. There is no provision in the PPAs clause on the formula and process of sharing environmental attributes such as carbon credits among the parties.

d. The risks associated with land acquisition and the environmental and social safeguards risks should be optimally allocated among the parties to the PPA.

e. There is need for the MoE to develop a carbon credit policy detailing the monetization and sharing process of carbon credits among other issues.

7.7 Force Majeure Clause

Force Majeure (FM) is a term often used in contracts to refer to events outside of a party's control which are unexpected and disruptive serving to excuse a party from its obligations under the contract without liability.

FM is often treated as a standard clause that cannot be changed. However, as the clause excuses a party from carrying out its obligations, it needs to be carefully thought through and tailored for the project in question.**Findings**

The Taskforce assessed and reviewed the Force Majeure clause and established that:

a. The existing PPAs between KPLC and power generators provide for FM relief extending beyond the PPA to other project agreements.

b. There is a risk that an event defined as a FM in one agreement affiliated to the PPA may not be reciprocated as a FM event under the PPA. On account of this misalignment such an event may not qualify a party for relief from its other contractual obligations.

c. The scope of what constitutes an FM event is too wide and does not cover circumstances that would reasonably be included as they are not foreseeable or within the control of either party.

d. It was important to draw a distinction between FM affecting the off-taker and the Seller respectively.

- Where the off-taker is affected by the FM, the PPA provides for continuation of capacity and energy payments to the Seller during the period of the FM e.g., if the FM event affecting the off-taker is to delay the COD, the Seller may be entitled to claim a deemed completion of the power plant. The Seller may then be entitled to deemed capacity payments that cover debt service; and

- Where the FM affects the seller, the impact on capacity or energy payments may depend on the specific type of FM.

e. A harmonised concept of FM clause across all the project agreements was necessary.

7.8 The Default Clause

A default clause in a contract provides for the actions the non-breaching party can take in the event of default by the other party. Default clauses are categorised together with provisions on Termination in the PPAs. Some of the events of defaults which may give rise to termination of PPA or other penalties are as follows:

a. Parties' failure to fulfil its obligations;

b. Producer's inability to provide average availability of power;

c. Breach of representations and warranties by the parties; and

d. Failure of any of the parties to comply with terms and conditions of the agreement.

Given the long-term nature of the PPAs typically between 20 to 25 years, there are several instances which could amount to breaches of the PPAs terms and conditions thus amounting to a default. Prior to termination, the PPAs provide for remedial measures to cure breaches and defaults by the Defaulting Party. These include extensions of time and payment of liquidated damages. In effecting the provisions on Default, the non-Defaulting Party is required to issue the relevant and appropriate Notice to the Defaulting Party. **Findings**

The Taskforce assessed and reviewed the Default Clause provisions of PPAs selected on the basis of mode of procurement (Competitive and Feed-in-Tariff); type of technology (thermal, renewable and hydros); size of the plants (Large, above 50MW and Small, less than 10MW). The selection largely represents all the signed PPAs. The following was established:

a. In order to balance the interests of the KPLC and the Seller the Default Clause provisions needed to be harmonised. The consequence of default should be proportionate and not excessive on either party depending on the extent of breach.

b. Misrepresentation by the IPP was only an event of default when made and not when deemed to have been made.

c. Failure by the IPP to provide Audited Financial Models to both EPRA and KPLC or Audited Financial Accounts to KPLC is not considered as an event of default.

d. Default on payment by either an IPP or KPLC is capable of remedy within 30 days.

7.9 The Termination Clause

A Termination Clauses in the PPA details how the contract may end and thereby extinguish the contractual relationship between the Parties. They also provide details on the liabilities of each Party to the other in the event of an exit from or termination of the PPA by the Parties. Termination can occur due to the power producer's default or the offtaker's default, violation of the terms and conditions of GoK LoS or following an occurrence of a Force Majeure event.**Findings**

The Taskforce assessed and reviewed the Termination clauses in PPAs between KPLC and power producers selected on the basis of mode of procurement (Competitive and Feed-in-Tariff); type of technology (thermal, renewable and hydros); size of the plants (Large, above 50MW and Small, less than 10MW). The selection largely represents all the signed PPAs. The following was established:

a. Termination may occur in case of a delay in achieving the Effective Date before the Long Stop Effective Date or such later date as the Seller (in its sole discretion) may decide.

b. PPAs provide for extensions of the Target Effective Date with no limitation resulting in PPAs taking an inordinate time from that initially envisaged to materialise into fully operational plants.

c. Termination only occurs at the default of either party and no party can terminate at their convenience.

d. Upon Termination the timelines for payment of the Transfer (compensation) Amounts varies from 30, 60 or 90 days depending on the specific PPA.

e. In the event of termination due to the Seller's default, the Seller is required to pay to KPLC only direct costs of procuring the capacity for the remainder of the Term.

f. KPLC is required to pay any termination payments in foreign currency.

g. The period within which the Audited Financial Models, after approval by the Financing Parties, should be submitted to KPLC by the Seller, is ambiguous.

h. Notice period for payment of agreed or determined Transfer Amount by KPLC is provided as seven (7). This is detrimental to KPLC taking into consideration approval processes within GoK that such payments have to be subjected to.

i. The option not to terminate the PPA but to suspend deliveries of electricity to KPLC and performance of its other obligations under this Agreement until KPLC has resumed full performance of its obligations under the PPA, is only at the discretion of the Seller and not KPLC.

j. In order to address the experience of the past, emerging challenges and the future, review of the provisions on Termination is advisable.

7.10 The Dispute Resolution Clause

Disputes between parties to a contract must always be anticipated. Contracts therefore provide for a dispute resolution clause laying out a mechanism for the resolution of disputes between the parties involved. This allows for formal and speedy resolution at mutually agreed terms. There is need to therefore have a dispute resolution mechanism that adequately addresses the needs of the parties.

The GoK in 2013 established the Nairobi Centre for International Arbitration (NCIA) to facilitate settlement of disputes through alternative dispute resolution mechanisms for local and international disputes. The NCIA (Arbitration) Rules, 2015 premised on the United Nation International Trade Law (UNCITRAL) Rules, incorporate best practices in international commercial arbitration and provide a flexible institute administered procedure.

The dispute resolution clause provides for both arbitration and Expert determination Arbitration should be conducted under the Arbitration Rules of the Nairobi Centre for International Arbitration, as the first option and the Rules of the London Court of International Arbitration as a second option, with the seat and location being Nairobi.**Findings**

The Taskforce reviewed the arbitration clause in PPAs and established as follows:

a. Dispute resolution in PPAs is undertaken by international arbitration centers and not by NCIA. This has resulted in huge financial exposure to KPLC in financing international arbitrations.

b. The seat and location of arbitration is in locations that have a negative impact on the cost of the arbitration and the applicable law of the arbitration.

c. Dispute resolution clause provides for arbitration and Expert determination.

7.11 Risk Allocation

The PPAs confer the Parties with various rights, obligations and liabilities. In undertaking power projects there are several risks involved which are to be shared among the parties to the PPA. As in other infrastructural transactions, the essence of risk allocation is to vest a particular risk with the party best placed to bear such risk. Imprudent risk allocation criteria result in higher project costs and thus a higher tariff to the end consumer.

Optimal risk allocation is vital in IPPs contracts. This supports the structure, bankability, operations and intended contractual relationship of Parties in the PPA. It also avoids assigning certain obligations to the wrong or unintended Party that would only serve to unreasonably burden such Party and make the PPA unviable. The revised Risk Allocation Matrix informed the review of pertinent clauses in the PPA and the development of the standard PPA template.**Findings**

The Taskforce reviewed the risk allocation criteria in most PPAs and established that:

a. A Study conducted in Kenya in May 2020 by Synergy Consulting to *inter alia* compare present practices with globally accepted risk allocation mechanisms for renewable energy PPAs, showed that to a significant extent, the existing risk allocation matrix was in line with global standards though there were a few imbalances.

b. Conditions Precedents that relate to the standard governmental approvals for energy projects were not similar in all the PPAs.

c. IPPs are not familiar with land economics to inform the appropriate land for projects resulting in unnecessary delays and increased project costs.

d. Controls to guard against the risk of power plant producing more or less after declaring the expected output had not been properly captured in the PPAs.

e. The dispute settlement mechanism provided in most PPAs does not adopt a local dispute resolution mechanism thus resulting in huge international arbitration costs.

f. The Force Majeure clause exposes the Government to excessive risk based on the definition of Political Events that needs to be reviewed.

7.12 Contract Management Framework

Contract Management is the process of managing contract creation, execution, and analysis so that operational and financial performance can be maximised while reducing business risk. An effective contract management framework helps improve the company's performance and reduces exposure to unwarranted litigation. A proper contract management mechanism enables the transacting parties to maintain a cordial relationship in meeting respective obligations, reduces risks and enables quick solutions in case of disputes.

In view of their intricate nature, PPAs require constant review and monitoring after execution to secure contract performance and ensure smooth implementation of the projects. Both the Public Procurement and Assets Disposal (PPAD) Act 2015 and Public Private Partnership Acts 2013 are explicit on the essence of Contract Management. The PPAD Act under Sections 151 and 152 *inter alia* provides for:

a. Constitution of a contract implementation team for complex and specialised contracts.

b. Appointment of a contract implementation team which includes members from the procurement function, the requisitioner, the relevant technical department and a consultant where applicable. In managing complex and specialised procurement contracts, the contract implementation team shall be responsible for:

i. Monitoring the performance of the contractor, to ensure that all delivery or performance obligations are met or appropriate action taken by the procuring entity in the event of obligations not being met;

ii. Ensure that the contractor submits all required documentation as specified in the tendering documents, the contract and as required by law;

iii. Ensure that the procuring entity meets all its payment and other obligations on time and in accordance with the contract;

iv. Ensure that there is right quality and within the time frame, where required;

v. Review any contract variation requests and make recommendations to the respective tender awarding authority for considerations;

vi. Manage handover or acceptance procedures as prescribed;

vii. Make recommendations for contract termination, where appropriate;

viii. Ensure that the contract is complete prior to closing the contract file including all handover procedures, transfers of title if need be and that the final retention payment has been made;

ix. Ensure that all contract administration records are complete, up to date, filed and archived as required;

x. Ensure that the contractor acts in accordance with the provisions of the contract; and

xi. Ensure discharge of performance guarantee where required.

The PPAD Act under Section 138 provides for a contract management framework with specific reports to be reviewed periodically. The contract review is to consider the following elements:

a. The timeliness of contract performance;

b. Cost and quality performance;

c. Risk analysis;

d. Operational effectiveness; and

e. Appropriateness of the procedure of delivery;

A risk register is to be maintained to monitor all identified contract risks.

The PPP Act under Section 65 on contract management provides that a contracting authority that is a party to a project agreement shall, together with sector regulators, where applicable ensure that the project agreement is properly implemented by—

a. Monitoring the implementation of the project agreement;

b. Measuring the output of the project;

c. Liaising with the private party, users of the facility or service and other relevant stakeholders;

d. Overseeing the management of the project agreement;

e. Preparing periodic reports on the project agreement implementation; and

f. Submitting reports on the project agreement implementation to the Committee in June and December in each year of the project.

7.12.1 Findings

The Taskforce assessed and reviewed the contract monitoring mechanism applied by KPLC and established that:

a. KPLC currently undertakes some form of contract management for the PPAs. It however lacks a comprehensive tool for the identification and remedying of challenges in the implementation of PPAs.

b. Contract Management Teams for each PPA have not been constituted as required under the law.

c. There is no clear framework for undertaking contract management.

The Taskforce has formulated a Contract Management Framework Tool (CMFT) to be applicable to both existing and future contracts. The proposed CMFT is attached as Annexure 1 in Schedule 4.

7.13 The Due Diligence Process

Commercial transactions of any kind confer certain rights and obligations to the parties. The ability of all parties to fulfill their respective obligations is vital. A party is obligated to conduct the necessary due diligence to assure itself that the counterpart has the required resources to discharge its contracted obligations.

It is therefore imperative for the offtaker to conduct a comprehensive appraisal of the legal, technical and financial position of the project sponsors and its associated SPVs. The due diligence should extend to analysing the developer's financial statements, the proposed technology, previous projects undertaken, and the litigation history among other parameters.

The PPP Act and the PPAD Act require a procurement entity to conduct the requisite due diligence prior to contracting.

The due diligence is not only limited to the procurement process, but the regulator is legally mandated to appraise the IPPs competence during the PPA review process prior to approval of a particular IPP projects. **Findings**

The Taskforce assessed whether the offtaker conducted any due diligence when contracting with power producer and established that:

a. Adequate due diligence was not undertaken both at the offtaker level and regulatory approval stage for some IPPs projects. This failure could have led to delayed project implementation. Delays in project execution leads to increased costs, which in most cases are ultimately borne by the consumers.

b. Conducting due diligence on current IPPs would be part of the monitoring process on their performance and assessment of these utilities as a going concern. The Taskforce has formulated a Due Diligence Framework which needs to be applied to both existing and future IPPs. The proposed Due Diligence Framework is attached as Annexure 2 in Schedule 4.

7.14 Amendments to the Energy Act

PPAs are drafted and signed pursuant to various laws. These include the Energy Act, 2019, and the Public Private Partnerships Act, 2013. The former sets out the law regarding technical and operational aspects incorporated in the PPAs while the latter provides the framework under which procurement of generation is carried out.

The Taskforce undertook a review of the Energy Act and noted the following:

7.14.1 Findings:

a. Section 76 of the Act establishes Rural Energy Resource Advisory Committee (RERAC) that includes key energy sector players with the exception of KPLC. RERAC has the mandate to advice on the allocation, licensing, management and developments of renewable energy resources.

b. The Fifth Schedule of the Act mandates County Governments to undertake county energy planning, county energy regulation and county operations and development. Contemporaneously, the Constitution, 2010 provides in the Fourth Schedule that Counties are responsible for County planning and developing electricity and gas reticulation and energy regulations. Currently, there is no national legal framework guiding the process and some counties such as Busia have developed County Reticulation legislation.

The proposed amendments are attached as annexure 3 under Schedule 4.

7.15 Acquisition of Land for Energy Projects

Land is a resource that is required in projects in all sectors including in the energy sector. Acquisition of land for energy projects is a risk borne by the developer. There has been a challenge in the acquisition process due to the restrictions set by the Land Control Act (LCA).

The Constitution of Kenya, 2010 provides in Article 65 that non-citizens may only own land on a leasehold basis for a term not exceeding 99 years. The LCA on the other hand in section 9(1)(c) read together with section 6, restricts the sale, transfer, lease, charge, partition or exchange of land by non-citizens of agricultural land or land within land control areas.

The LCA in Section 8 gives the Land Control Board, the power to refuse or grant consent to '*controlled transaction*' and its decision shall be final and binding and not subject to questioning by any court of law.

Section 2 as read with section 6(1) of the LCA define controlled transactions as:

> ***"(a) the sale, transfer, lease, mortgage, exchange, partition or other disposal of or dealing with any agricultural land which is situated within a land control area;***
>
> ***(b) the division of any such agricultural land into two or more parcels…unless the land control board for the land control area or division in which the land is situated has given its consent in respect of that transaction in accordance with this Act."***

In making a determination, the Land Control Board as provided in section 9 (1), must give regard to the effect which the grant or refusal of consent is likely to have on the economic development of the land concerned or on the maintenance or improvement of standards of good husbandry within the land control area.

Section 8 (2) provided that the decision of the Land Control Board is final and cannot be questioned by any court.

The LCA however provides a solution to the problem in the event consent is not granted. Section 24 of the LCA gives the President the power to grant exemptions to any person with regard to controlled transactions from all or specific provisions of the Act.

Regulation 2A of the Land Control Regulations, 1967 (Revised 2012), provides for the process of application for exemption. It provides that an application shall be made to the Commissioner of Lands with payment of the prescribed fee.

The President may then either grant or refuse to grant an exemption in accordance with section 24 of the Act. The use of the word 'may' in that section means that it is discretionary upon the President to make a decision.

It is noted that in the past, the President in 2002 granted an exemption of all controlled transactions entered into by mobile telecommunication licensees for the purpose of taking leases or subleases of land for erecting towers, guided masts, or buildings for the installation of equipment and generators from the application of the Act.

7.16 Over securitisation of IPPs

Government Support Measures (GSMs) issued pursuant to the GSM Policy, 2018, are mechanisms for de-risking public investments in order for such investments to be more secure and bankable, in respect of private capital mobilisation for public investment and infrastructure developments. GSMs operate as credit-enhancement tools thereby enabling financing institutions to accept the financing risk profiles of public transactions.

There are several GSMs that are issued pursuant to the GSM Policy, 2018 to serve as credit enhancement tools thereby enabling financing institutions to accept the financing risk profiles of public institutions. The GSMs include:

i. Political risk cover, such as assurances of protection against expropriation and change in law, civil commotions, termination and similar state or country actions;

ii. Assurances on the commercial viability of state-owned enterprises (SOEs), or that their successors, where they are replaced, will be equally capable of performing the obligations of the SOE under contract;

iii. Repayment guarantees or obligations in support of state corporations or county government borrowings and undertakings;

iv. Direct undertakings by the Government to financiers that project finances made available in support of public investments will be repaid when due, and where necessary, that any counterpart funding on the part of GoK will be appropriated in timely manner for project execution success.

v. Sovereign guarantees – used to guarantee borrowings by Government and its entities;

vi. Letters of Support and Comfort – used variously to provide different forms of GoK undertakings, commitments and assurances in support of a project;

vii. Project-based Guarantees usually undertaken or granted through contract provisions;

viii. Partial Risk Guarantees (accompanied by Indemnity Agreements) – to backstop third party risks arising from various situations of project default;

ix. Standby Letter of Credit - Secures payments due to an IPP if not made within the 30 days period as provided in a PPA. The PRG provider then covers the payments due to the developer (considered as a loan to the GoK).

x. Government Notes and Letters of Exchange – committing Government to a recognition of a bilateral or other government to government led transaction, and to the doing of specific tasks to actualize the undertakings of the parties under such instruments;

xi. Co-investments in public investment projects and programmes (whereby the GoK co-invests with the private party to enhance the credit rating of the project).

7.16.1 Findings:

a. GSMs secure the IPP in the event of failure by KPLC to meet any payment obligations and protects the IPP from any political risk events as defined in the Government Letter of Support.

b. This level of fiscal comfort to third parties to a transaction has negative implication on the Government of Kenya due to their attendant financial implications.

c. In one project, some IPPs benefit from more than one GSM mostly Letters of Support with an addition of two or more other GSMs in addition to Political Risk Insurance taken out by the IPP to cover for non-fulfillment of payment obligations and political events under the GoK Letter of Support.

7.17 Recommendations

In order to improve the key provisions of the PPAs entered between the offtaker and power producers towards optimal risk allocation among the parties in terms of rights and obligations, the Taskforce recommends as follows:

1. The following amendments be made on Take or Pay Clause:

a. KPLC to maintain the Take-or-Pay model but ensure that there is a balance between demand and supply allowing for a reasonable energy reserve which can be achieved with improved demand and supply forecasting tools and capabilities.

b. Renegotiation of the current PPAs where practical, to Pay-when-Taken upon evolution to a spot market.

c. In the event that the one year and 5-year demand forecast indicates the need for thermal power capacity in the short term, KPLC should explore the use of pay when taken provisions for expired PPAs such as Tsavo Power. However, full assessment should be made of the quality and viability of such old plants.

2. The following amendments be made on Change of Law/ Change of Tax Clause:

a. The Change in Law/Change in Tax clauses in respective PPAs need to be aligned for uniformity and the same to provide those remedies are applicable only in instances where the changes affect the financial position of the Seller rather than a blanket cover.

b. The amounts payable by the GoK under a PPA in the event there is change of Law/Tax should be capped.

3. **The following amendments be made on Assignment and Novation Clauses:**

a. There should be disclosure of consideration payable to an IPP subsequent to an assignment under the PPA.

b. There should be further/fresh approvals by the relevant government agencies i.e., NEMA, AG, PPP Committee subsequent to an assignment.

c. The assignments of PPAs to be only permitted at least five years after Full Commercial Operation Date.

d. In the event of an assignment or novation, due diligence should be undertaken by KPLC on the new parties.

e. Include a novation clause.

4. **The following amendments be made on Environmental Clause:**

a. The inclusion of environmental protection clauses in all PPAs.

b. Considering most projects are situated in conservation areas, appraisal and valuation of the land should take into consideration the value of the ecosystem and the prevailing rate applied in the valuation of any compensation due to the affected persons or community.

c. The provision of a clause in the PPAs on the formula and process of sharing environmental attributes such as carbon credits among the parties and other stakeholders who could be entitled.

d. NEMA should ensure that the Environmental and Social Impact Assessment (ESIA) or Environmental Impact Assessment (EIA) report for all energy projects adequately provides for appropriate compensation where the resources valuation is in accordance with international best practices.

e. In risk allocation matrix, the developer to bear the risks associated with land acquisition and the environmental and social safeguards risks be prudently allocated among the parties.

f. The National Treasury should expedite finalisation of the policy on carbon credit.

5. **The following amendments be made in relation to Risk Allocation;**

a. Optimal allocation of risks be as provided in the Risk Allocation Matrix attached as annexure 4 in Schedule 4.

b. The Conditions Precedents clauses to be harmonised across the PPAs.

c. The economics of the land should inform the power producers on suitable site for location of their plant(s).

d. To safeguard the risk that the Plant produces more or less than the expected amount after declaring expected output, the Seller should install predictive forecasting systems; introduce inverter-based controls to increase the Plant's ability to modulate unexpected output fluctuations and KPLC should penalise the Seller for under-delivery.

e. Alignment of Political Force Majeure risk in Government Support Measures to limit GOK's exposure. Each Party should bear its own financial exposure in case of termination due to natural force majeure.

f. Losses that are above the allowed loss rate should be allocated to individual parties based on each party's contribution. This will require that the regulator sets the loss target rates at High Voltage, Medium Voltage, Low Voltage and commercial losses.

g. Acknowledging the importance of flagship projects that will drive economic growth of the nation, demand risk of power consumption of large projects (e.g., SGR, new satellite towns, large private industries) should be borne by the developer of those projects. This will require EPRA to designate a system operator and operationalise open access so that the flagship projects are also able to directly procure their power directly from generators should they opt not to take on the grid associated demand risk.

h. The regulator should monitor the technical performance of all sector utilities and ensure unavailability of the system is borne by the right parties. KETRACO, KPLC, KenGen, REREC and IPPs should enter into interconnection agreements. This will provide a mechanism of allocating the risk of unavailability of the system to the right party.

i. The designation of a system operator should be followed by the appropriate risk-sharing agreements between all parties.

j. Need to unbundle transmission and distribution tariff from the total retail electricity tariff. This will enhance transparency in pricing and ensure efficiency in risk allocation in the power system.

6. The following amendments be made on the Dispute Resolution Clause

a. Adoption of a local dispute resolution mechanism with the Rules of the Nairobi Centre for International Arbitration as the first option and the Rules of the London Court of International Arbitration as a second option, and in either case, the seat and location be Nairobi.

b. The Arbitration and Expert dispute resolution clause to be maintained in the PPAs.

7. **The following amendments be made on Force Majeure Clause;**

   a. The primary form of relief in the case of FM may be the suspension of certain contractual obligations, though, other forms of specific remedies for FM may be provided.

   b. The event or circumstance giving rise to force majeure must have ***"**a material and adverse impact**"*** on a party. This modifies the current wording of the phrase which only refers to any event "*which affects*" a party without making reference to the nature in which a party is affected-which may well be either positive or negative/adverse.

   c. The inclusion of the following statement in the definition of a Force Majeure Event, *"is not a consequence of the fault or negligence of the party affected or its employees or agents"* which clause is absent in the current force majeure clause. This proposed statement is important as it helps avoids instances where a party instigates events or circumstances amounting to force majeure in a bid to be excused from performing their contractual obligations as happened in the Kinangop Wind Power Project.

   d. The event or circumstance must not be one that can be avoided *"by the exercise of reasonable diligence"* in addition to *"through Prudent Operating Practice*" given that it is common phraseology employed in contractual clauses and may also be more universally understood.

   e. The limitation of the events or circumstances giving rise to force majeure to those listed/enumerated therein in place of the earlier phraseology which read "*shall include without limitation the following events or circumstances…*". This is meant to provide a closed list of force majeure events or circumstances thus avoiding ambiguity and limiting Government's exposure by providing for a narrow definition of what qualifies to be force majeure.

   f. Exclude *riots and civil commotion instigated by a party* as events or circumstances giving rise to force majeure.

   g. The addition of *"pandemics, outbreaks of infectious disease or any other public health crisis necessitating quarantine or other employee restrictions***"** to the epidemics and plagues as events or circumstances giving rise to force majeure, in light of the Covid-19 pandemic and the associated difficulties.

   h. The deletion of the wording "*change in Law other than where the affected Party has been fully compensated for the effect of such Change in Law*" as an event or circumstance giving rise to a force majeure event. This to be replaced with;

      "*any legal prohibition on the Contractor's ability to conduct the Contractor's Business, including passing of a statute, decree, regulation or order by a Competent Authority prohibiting the Contractor from conducting the Contractor's Business, other than as a result of the Contractor's failure to* *comply with the law or any order, Consent, rule, regulation or other legislative or judicial instrument passed by a Competent Authority."*

i. The inclusion of the following additional events or circumstances as giving rise to force majeure:

> *"failure or inability of the Contractor to obtain or renew any Consent, on terms and conditions as favourable in all material respects as those contained in the original Consent relating to the Contractor's business (other than due to a breach by the Contractor of any of such terms and conditions).*

8. The following amendments be made on Default Clause:

a. The deletion of payment as a Default deemed capable of remedy within 30 days.

b. On Seller's Default –

- To introduce a new clause being failure to provide Audited Financial Models to both KPLC and EPRA within 7 days of approval by the Seller's Financiers/Lenders.
- Failure by the IPP to provide Audited Financial Models to both EPRA and KPLC or Audited Financial Accounts to KPLC within one month after completion of the audits be considered as an event of default.
- Amend to include that the statement, representation etc. may have been incorrect when made or deemed to have been made.

c. To introduce new clause for renewable energy projects (wind and solar) to provide that variation of forecasted output 20% below the given threshold shall amount to an event of default that attract penalties including reduction of Tariff.

d. On the part of KPLC, align provisions on payment with proposals of extension to 120 days and in instalments.

9. The following amendments be made on Termination Clause:

a. The need to introduce a new clause on Termination by either Party for convenience.

b. Termination payments should be in local currency.

c. To introduce a maximum number of extensions of the PPAs as 2 for a total period of no more than 12 months after which the PPA terminates automatically. This is in order to avoid extended delays in materialisation of the Project, and, tariffs that have been held for several years from Signature Date when circumstances have altered.

d. The need to harmonise the payment process of the Transfer or Compensation amounts as 120 days in receding instalments by KPLC to the Seller and 60 days by the Seller to KPLC.

e. Failure of IPPs to submit the Audited Financial Model to KPLC and EPRA no later than 7 days upon the Model's approval by the Seller's Financiers/ Lenders, results in an event of default that can lead to termination of PPA.

10. The following action be taken to improve contract management processes:

a. A contract management team be established with clear roles and responsibilities. The existence of a project management team will not only comply with the law, but also ensure that compliance and performance by IPPs is monitored regularly and any bottlenecks or setbacks are arrested early to ensure smooth running of energy projects.

b. The members of the contract management team should be comprised of KPLC experts from different fields with the technical know-how on matters regarding the PPA such as finance, legal, engineering, environment and such other relevant fields as may be deemed necessary by KPLC. The team should be comprised of not less than five people but not exceeding ten people.

c. The contract management team should review implementation of PPAs on a quarterly basis using the proposed Contract Management Framework Tool as provided in annexure 1 Schedule 4.

d. There ought to be a proper record of all PPAs, addenda and all accompanying documentation, including reports of all reviews made at appropriate intervals. The custodian of all relevant documentation is the Board Secretary and Head of Legal, KPLC.

e. The contract implementation team shall on a quarterly basis prepare reports and submit to the Company Secretary for submission to the Board.

f. There should be a provision in the PPA for a contract implementation team and requiring parties to PPAs to provide relevant information as may be requested by KPLC, to assist with contract monitoring and implementation.

g. KPLC should develop a Contract Management Policy.

11. The following steps be taken to improve the KPLC's due diligence procedures when contracting with power producers or procuring similar services:

a. That KPLC adopts the proposed Due Diligence Framework as a tool in appraising the generation and other associated projects.

b. That there ought to be proper authentication and verification of information and documentation received during a due diligence exercise.

c. That due diligence be conducted in all instances where there is change of control or the structure of the project company, including a change in beneficial ownership.

d. That due diligence be conducted on an assignee or a new party in case of novation of contract.

12. The following amendments be made to Energy Act 2019:

a. Develop Grid-Defection Regulations to provide for switches by consumers to other service providers or to own-generation. The Grid-Defection Regulations to also provide for the handling and re-allocation of risks and obligations when such defection occurs.

b. Amend section 166(4) of the Act to allow for the implementation of the provisions on compensation to consumers for power outages until such time as the Country achieves an appreciable N-1 Grid Reliability status.

c. Amend section 76 to include KPLC to the membership of the RERAC given that it signs the PPAs, bears the Demand and System Operation Risks in the PPAs

d. Develop separate Regulations for procurement of power with a unified framework for it under the Public Private Partnerships Act, 2013.

e. The MoE to develop a policy and regulations to guide electricity and gas reticulation by the Counties.

f. Amend section 76 to disband NuPEA and to transfer its functions to a department within the MoE.

13. In relation to land acquisition for renewable projects:

The IPPs through their representatives should, pursuant to Section 24 of the Land Control Act and Regulation 2A of the Land Control Regulations, make an application to the President for exemptions from the application of the Land Control Act.

14. In relation to over securitisation of IPPs, the following are recommended:

a. GSM should only be issued in exceptional circumstances for strategic projects of national interest, after Cabinet approval.
b. The National Treasury should assess and recommend GSMs that have the lowest financial risk exposure to Government.
c. IPPs should only benefit from one GSM issued in accordance with the GSM Policy, 2018.

8 The power generation mix and dispatch procedure

8.2 Background and context

The overall cost of generated power is essentially the weighted average tariffs of the plants with which KPLC has entered into power purchase arrangements. These arrangements are largely long-term in nature (at least 20 years) and so decisions made in the present time have implications for long periods into the future.

To determine the appropriate power generation installed capacity mix, the following factors are taken into account:

(i) *The demand curve:* Power consumption by consumers will vary during a 24-hour period arising from their activity levels and due to this a decision has to be made on the proportion of base load plants versus peaking plants. Base load plants operate constantly at near full capacity and tend to have limited capability to operate at significantly below capacity or are inefficient at those levels. As such the proportion of these plants operating in the grid is the constant power consumption in a 24-hour period. Peaking plants are able to adjust to surges and declines in power demand efficiently and so are applied to power consumption above the base load. The same analysis is also considered on an intra-year basis, as demand patterns can change due to weekdays, public holidays and traditional holiday periods (e.g., Christmas).

(ii) *Energy security, expressed as the reserve margin:* The grid has to maintain a margin of security to cater for expected and unexpected breakdowns, as well as demand growth rates that are higher than expected. Generally, the planners attempt to keep a reserve of the capacity of the largest machine in the grid as the minimum reserve margin. Given all installed capacity comes with a cost, an excessive caution adds cost to the system.

(iii) *Electricity as a key driver of economic growth:* All sectors of the economy are dependent on electricity and an appropriate tariff, in order to maintain global competitiveness. Given the long lead-time of developing power plants and the economic growth expectations of the nation, the planners need to forecast increased capacity significantly ahead of the actual consumption. However, excess capacity will result in uncompetitive tariffs as the unused capacity comes with a cost.

(iv) *Access to energy resources and the tariffs offered by each technology:* This will vary country by country. Kenya is blessed with an abundance of hydro and geothermal and to some extent wind and solar. However, the nation currently has to import fossil fuels. Each of these technologies is offered at a different tariff and so a balance has to be struck between access, cost and reliability.

(v) *Availability and reliability:* Whilst Kenya has an abundance of hydro potential, given the climatic conditions, this resource requires reservoir storage to have predictable availability. Similarly, whilst the nation has abundant solar radiation and wind in certain parts of the country, these plants' output needs to be matched with actual intra-day demand. Additionally, wind and solar plants in Kenya have demonstrated periods of fluctuating output (high intermittency) on an intra-day basis. As such, wind and solar require the grid to maintain spinning reserve (spare) capacity at added cost, to cater for declines in output. An alternative would be to have wind or solar energy provide electricity into storage facilities (e.g., pumped hydro or batteries), again at added cost, so that steady power can be utilised at a more convenient time.

(vi) *Contracting arrangements:* Presently Kenya's contracts protect the IPP from market risk for periods of at least 20 years, with IPPs indicating this is necessary due to the absence of a wholesale market. These contracts range from Take-or-Pay contracts (where a capacity charge is incurred even if power is not dispatched) to Take-and-Pay contracts where the utility is obligated to procure the power to the extent it is available, as is the case with wind, solar and mini-hydro.

(vii) *Grid stability:* The further a particular point of the grid is from the generation sources, the less stable the grid in that area is, and a localised generation solution is required.

Based on this, the country ends up with a power generation installed capacity mix. On a continual basis, the National Control Centre (NCC) issues dispatch orders to plants to meet the power demand at that point in time. As such, the overall power purchases mix (measured in KWh) varies continually and with it the weighted average tariff.

Therefore, understanding and managing the factors indicated above with diligence contributes significantly to the appropriate power tariffs for the nation. Conversely, inappropriate levels of diligence will have a negative impact on power generation tariffs.

8.3 Kenya Power National Control Centre (NCC)

The NCC manages the real-time dispatch of power from producers through the transmission system to the regional control centres and large power consumers (e.g., steel and cement producers). The regional control centres in turn feed the distribution network connected to residential, commercial and industrial areas.

The NCC is managed through the Supervisory Control and Data Acquisition (SCADA) System which is real time and provides the Centre with visibility over the grid. To facilitate effective communication between NCC and the generators, any generating power plants has to be connected to the NCC through SCADA. The Taskforce established that there are plants (particularly those on the distribution network) that have not been connected to the SCADA. Further, there was no clear communication channel between NCC and the commercial team and between the commercial team and customers. Consequently, the dispatch is not advised by accurate forecasts, availabe capacity, and is likely to dispatch technologies that are not the most attuned to the merit order.

The NCC dispatches plants on the basis of a merit order (codified in an operating manual) that is expected to deliver the lowest cost tariff and has been established using the following priorities:

i. Plants that 'must-run' for technical and legal reasons – the dams have to maintain a minimum flow rate and the renewable plants are on take-and-pay contracts, which require KPLC to take the output or face deemed charges.

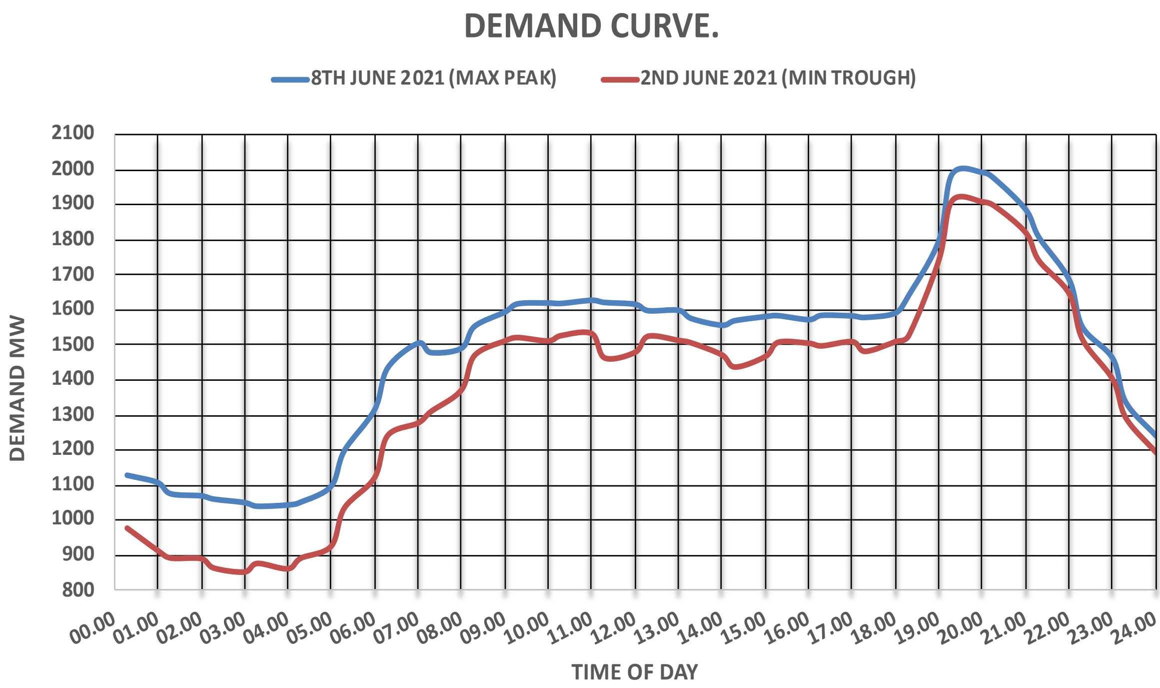
ii. Remaining plants (that have capacity charge payments) and dispatched on the basis of their variable costs (fuel and O&M), considering that the capacity charges (take-or-pay) are sunk costs. This is largely the thermal plants.

8.3.1 Daily Demand Curve

The shape of the demand curve is essentially the same every day, but consumption varies between weekdays, weekends and public holidays.

The lowest demand occurs between 1am and 5am, when the most significant consumption is associated with the over-night shift of industries that operate 24 hours per day. Thereafter, demand increases sharply as the bulk of retail customers wake up and prepare for the day. As people and industries engage in their daily activities, there is a plateau around 7am to 6pm, following which, there is a sharp increase that culminates in a peak demand at around 7:30pm, that lasts for about an hour, driven by domestic consumption. Demand falls off rapidly thereafter back to the base load.

Graph 1: Illustration of the Demand Curve pattern.



8.3.2 Overall Capacity vs Consumption

The Taskforce assessed the supply and demand dynamics impacting on KPLC and established that the impact of the daily demand curve is a challenge in managing the grid, as there are three power demand levels to be catered for *(as described above)*.

- Pure base load power planned to run continuously, and which cannot be stored (e.g., geothermal) is most effective within the lower demand state (c1,000MW).
- Peaking plants are required to meet the surges in demand to the two higher demand levels.
- Hydro power, which has both peaking power (or load-following) and base power characteristics due to its (i) storage capacity; and (ii) speed of spinning up to meet demand can manage the sharp increases in power, to the extent there is sufficient capacity and hydrology.

Large hydros contribute to the stability of the grid by being a reliable provider of spinning reserve. Wind and solar generation increase the need for spinning reserve due to their intermittency (or lower reliability).

The grid then has to contend with the renewables on Take-and-Pay contracts as it has to dispatch the power, to the extent the power is available, or provide power from other sources to meet shortfalls. The overall impact therefore, is the venting of geothermal steam at night and the availability of wind power when there is low power demand. Ideally, this would be an opportunity for KPLC's commercial team to innovate on storage and/or incentivize demand during low power demand times.

Additionally, the HFO thermal stations are providing peaking power during periods of high demand and low reliability of renewables, in the absence of hydro capacity. It should be noted that thermal/diesel plants have higher tariffs compared to the other technologies.

Table 8: Analysis of Installed Capacity vs the Consumption

Installed Capacity	**2,854 MW**
Available Capacity-*Amount of power that can actually be dispatched. Varies day-to-day due to machine outages and prevailing hydrological conditions.*	2,416 MW
Available Firm Capacity (excluding wind and solar) *Wind and solar excluded due to intermittency (or lower reliability)*	2,153 MW
Maximum power consumption – *recorded 08 June 2021*	1,994 MW
Minimum power consumption *Average minimum for weekdays, but can go lower during weekends and public holidays*	1,014 MW *(854 MW recorded on 28 June)*
Daily peak-to-trough variance	c900 MW – 1,150 MW
Must-run power generation *Comprises (i) small hydros; (ii) geothermals; and (iii) wind; that have to run as the resource/power cannot be stored. Additionally, a minimum of 240 MW of large hydro and 35 MW of Coast thermals required to support spinning reserve voltage*	1,297 MW
Curtailment/Compromised power generation *Wasted power due to must-run generation, without corresponding demand at low peak times. Manifested as by-passing of turbines by the resources – hydro, vented steam, wind.*	c 400 MW

8.3.3 Generation Mix

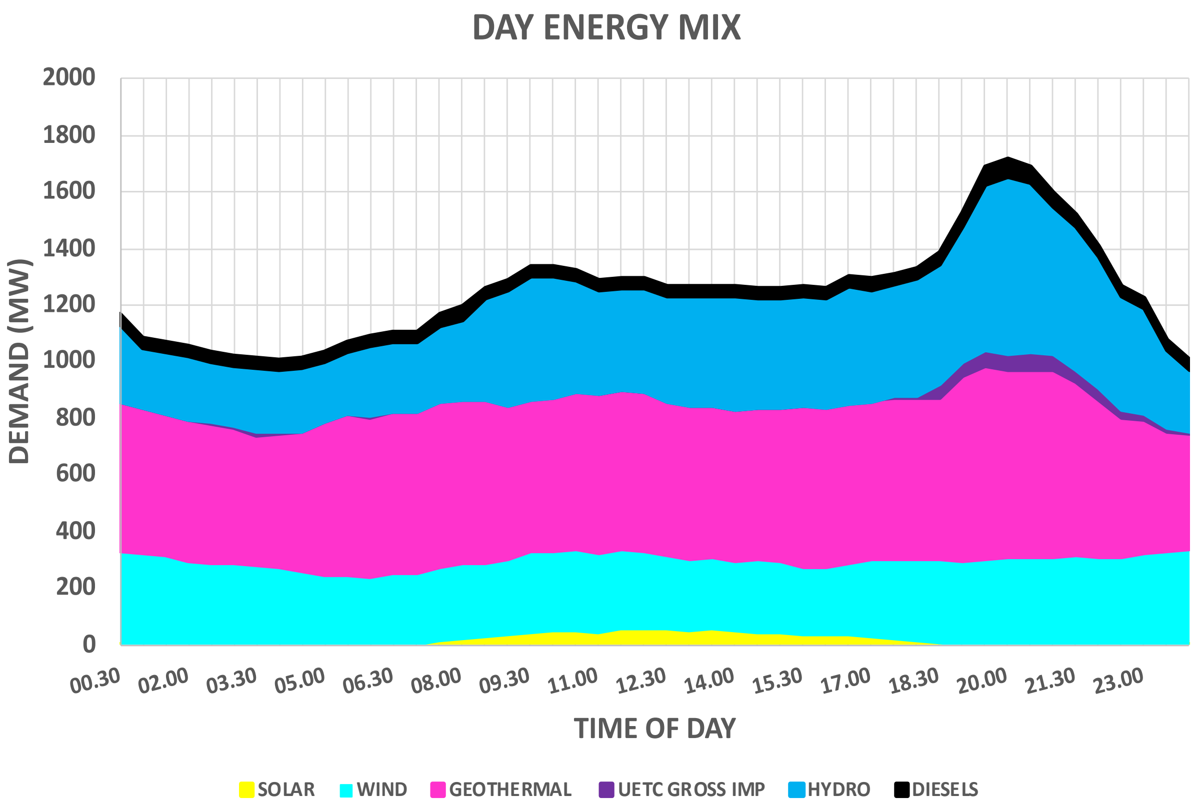
The following table shows the share of installed capacity compared to actual dispatched power.

Table 9: Analysis of Installed Capacity vs the Actual Dispatch

Technology	**Actual Installed Capacity - MW (01 July 2021)**	**Share of Installed Capacity (01 July 2021)**	**Actual Available Capacity – MW (01 July 2021)**	**Share of Available Capacity (June 2021)**	**Share of dispatched power (2020)**
Hydro	825	29%	753	31%	37%
Geothermal	787	28%	685	28%	44%
Thermal/diesel	756	26%	635	26%	6%
Wind	436	15%	263	11%	12%
Solar	50	2%	30	1%	1%
UETCL			50	2%	1%
Total	**2854**	**100%**	**2416**	**100%**	**100%**

The Graph 2 below represents a day's energy mix on a day when wind has high availability and so (i) the thermal plants are largely not running (c50 MW dispatched).

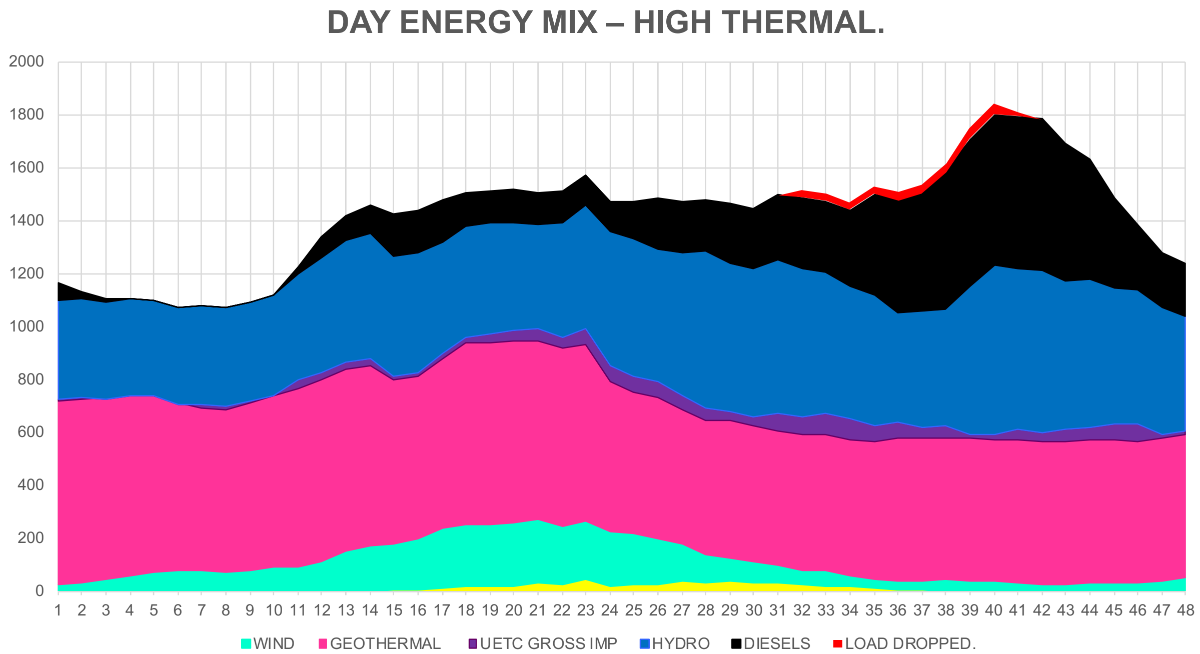
Graph 2: Generation Mix on a High Reliability Day for Renewables



Source: National Control Centre in Kenya Power and Lighting Company Limited

When wind and/or solar availability are low due to climatic conditions, then the thermal/diesel plants are dispatched at full or near-full capacity. According to KPLC, this occurs about 5 days annually.

Graph 3: Generation Mix on a High Reliability Day for Thermals.



Source: National Control Centre in Kenya Power and Lighting Company Limited

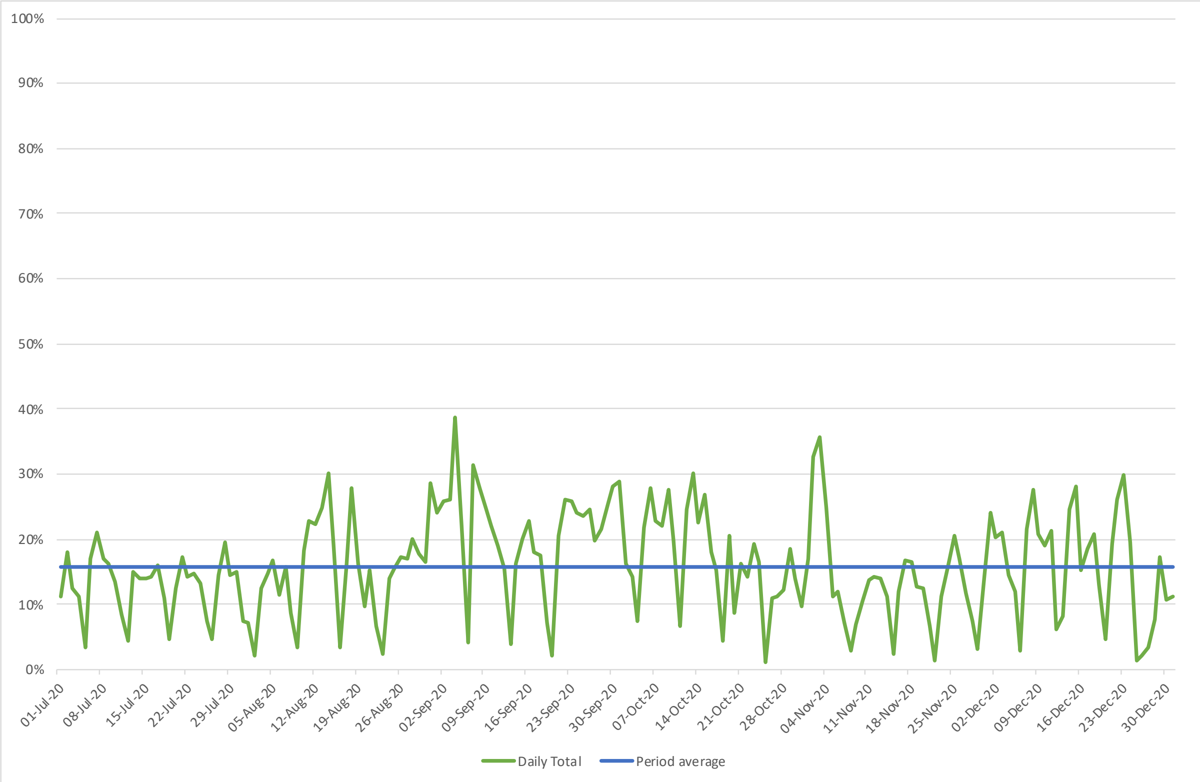
8.3.4 Dispatch of HFO thermal plants

Observing the dispatch patterns of the HFO thermal plants answers the query of the extent of peaking capacity required on the grid and the extent to which this peaking capacity could be provided for through other means such as (i) transferring loads to other times in the day; and (ii) other technologies e.g., hydro and batteries. Additionally, given the plants are already in operation, are there ways of reducing their operational costs such as (i) improved fuel procurement procedures; (ii) changing to lower cost fuels e.g., natural gas; and (iii) improved dispatch procedures.

In the 6 months ended December 2020, the aggregate Load Factor for HFO thermal IPPs peaked at 39% and averaged 16%. It is only 2 days in the half-year, that the Load Factor for thermal IPPs exceeded 160MW (approximately 2 plants at full capacity).

The following Chart 2 highlights the dispatch of HFO thermal l IPPs from July to December 2020.

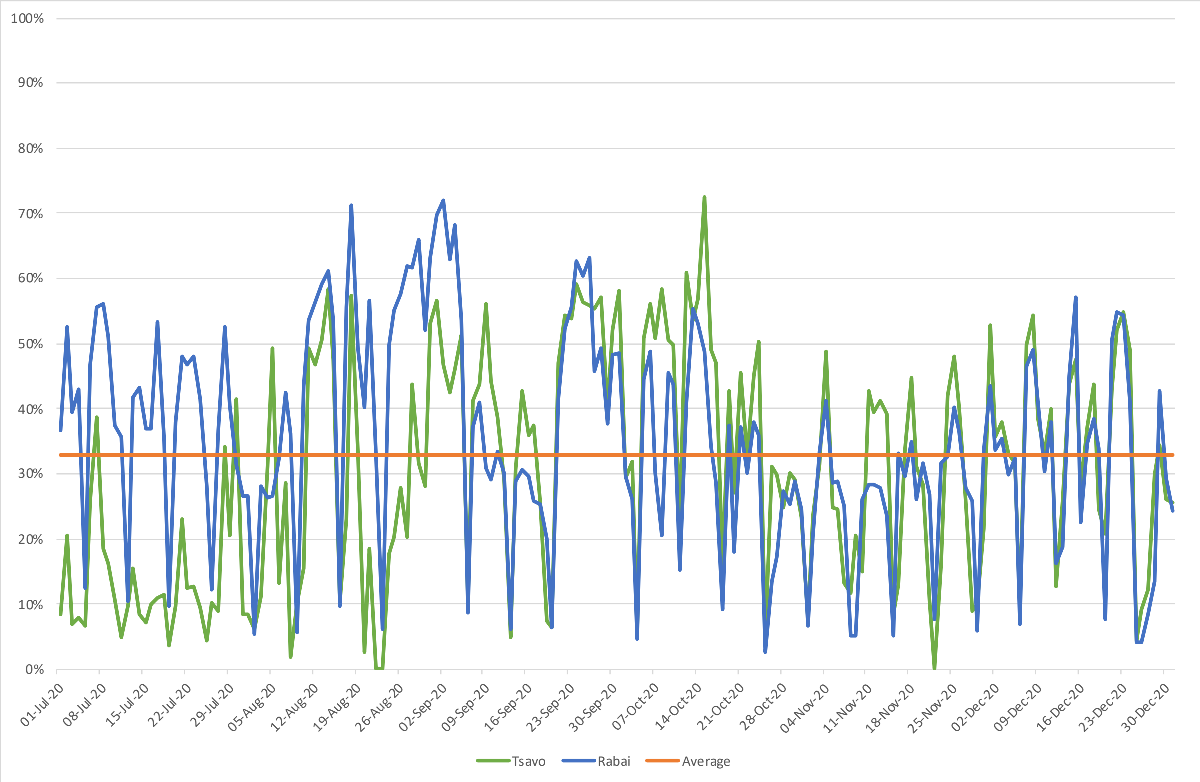
Chart: 2: Dispatch of the thermal/diesel IPPs (July-December 2020)



The Mombasa area HFO thermal IPPs (Tsavo and Rabai) have operated at comparatively higher Load Factors, due to the need to provide voltage support to the local grid, given its distance from the main power generation areas of the Seven Forks dams, the Rift Valley and Northern Kenya.

The following Chart 3 highlights the dispatch from June to December 2020 for HFO thermal IPPs located in the Mombasa area.

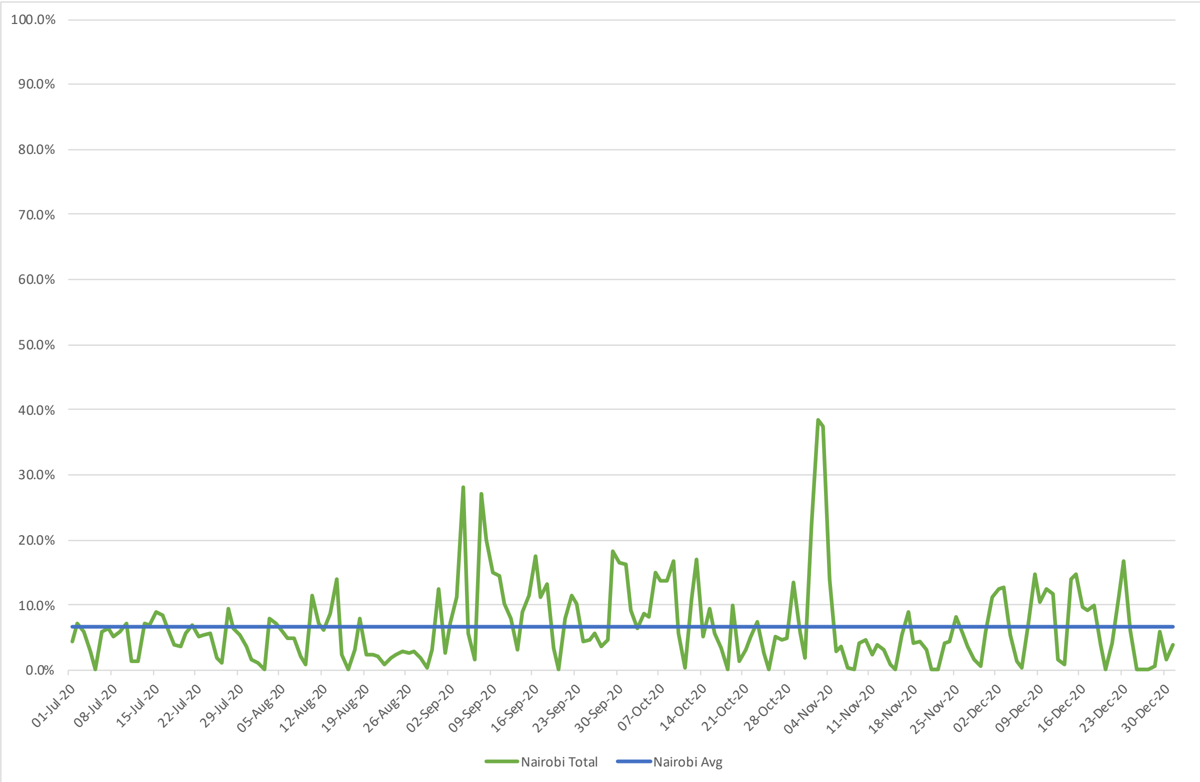
Chart 3: Dispatch of the Mombasa area HFO thermal IPPs (June – December 2020)



The Nairobi area thermal HFO IPPs (Iberafrica, Thika Melec, Athi River Gulf and Triumph) with an aggregate 303MW of capacity reported an average dispatch of 7% during the same period and a maximum of 39%. Only 4 days in the six-month period was 80MW exceeded (the capacity of each Thika, Athi River and Gulf).

The following Chart 4 highlights the dispatch of HFO thermal IPPs from July to December 2020 in the Nairobi area.

Chart 4: Dispatch of the Nairobi area thermal/diesel IPPs



8.3.5 Opportunity to switch the thermal plants from HFO to natural gas

There is an increasing consensus that the dual-fuel engines would have a lower fuel cost, if run on natural gas. There were two stakeholders, both international IPP developers with experience in natural gas who indicated potential savings of as much as 40% of the fuel cost, with the developer taking on the cost of conversion, in exchange for a higher tariff and/or tenor extension.

The main issue appears to be the source of the natural gas and its distribution around Kenya. The various options presented include:

a. Piped gas from Tanzania, which is already the subject of engagement by the Ministry of Petroleum & Mining.

b. Liquified Natural Gas (LNG) through Mombasa. KenGen is undertaking a study on this option.

c. Compressed Natural Gas (CNG) by truck from Dar es Salaam.

The key point is that KPLC needs to undertake its own review of the:

(i) Appropriate source of natural gas and the cost;

(ii) The cost of conversion of the plants; and

(iii) The logistics within Kenya.

There are additional benefits that could accrued for Kenya in that the natural gas could be used in various other industries such as cement, steel and glass.

8.3.6 The KPLC's Demand-Supply Forecasts

KPLC had computed the projections of demand and supply, in comparison with the LCPDP as these are illustrated in Chart 5.

Chart 5: KPLC forecasts for power generation compared to the LCPDP

LCPDP 2021: Peak demand vs capacity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Peak load (MW)	2,078	2,158	2,233	2,315	2,404	2,544	2,717	2,872	3,038	3,220
Peak load + reserve margin (MW)	2,361	2,433	2,509	2,594	2,685	2,832	3,015	3,208	3,380	3,560
Reserve margin %	*13.6%*	*12.7%*	*12.4%*	*12.1%*	*11.7%*	*11.3%*	*11.0%*	*11.7%*	*11.3%*	*10.6%*
Installed system capacity (MW)	**2,807**	**3,043**	**3,212**	**3,361**	**3,629**	**3,925**	**4,091**	**4,455**	**4,667**	**4,847**
Firm system capacity (MW)	**2,321**	**2,473**	**2,560**	**2,630**	**2,869**	**3,011**	**3,156**	**3,435**	**3,558**	**3,579**
Supply - demand gap (MW)	(40)	40	51	36	184	180	141	226	178	19

Kenya Power 2021 Plan capacity	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Installed capacity (MW)	2,655	2,965	3,144	3,310	3,591	3,854				
% kenya Power / LCPDP	*94.6%*	*97.4%*	*97.9%*	*98.5%*	*99.0%*	*98.2%*				

KPLC's projections are marginally lower as they are based on:

a. Projected annual average energy demand growth rate of 4% and 7% per year for the Reference and High scenarios, respectively, compared to 5% and 8% respectively for the LCPDP.

b. Peak demand projected to grow at an average annual growth rate of 4.8 % and 8.0% per year for the Reference and High scenarios respectively. LCPDP projects 5% and 8%.

The Taskforce assessed the KPLC projections and noted that the analysis, which did not reference the commercial team's view, was reflective of KPLC's view of which plants would come online as per the commercial operation dates (and any expected delays) as opposed to the actual underlying demand drivers.

The Taskforce has reservations in respect of this approach due to the following reasons:

a. There is anecdotal evidence of customers who have engaged KPLC to be connected to the grid, but the connections have not been made and so demand could be under-stated.

b. Opportunity for a commercial team to engage with existing customers to manage their consumption to take advantage of low demand times (particularly when geothermal steam is being vented), including by offering tariffs that are acceptable mutually. This has been attempted before, but with limited uptake from existing industrial customers as the terms were not attractive. Going forward, a more consultative and commercial approach would be expected.

c. Drive engagement with existing large customers to plan power consumption together (including down-time), with a view to reducing the redundancy required by the system. As such more power demand could be satisfied without necessarily requiring additional power generation.

d. Opportunity to identify and on-board new customers who are well placed to absorb power at low demand times and can be on-boarded quickly e.g., the data centre industry, agricultural ammonia industry

e. The understanding of the daily demand curve is a critical input to the planning of generation mix – base load capacity versus peaking capacity and the extent to which the grid can absorb intermittent energy. This impacts the reverse auctions and/or FiT projects by adjusting the terms to suit KPLC's needs. Additionally, this will impact the potential around on-boarding power projects that provide for storage e.g., hydro pump storage, batteries

f. Critical to understand the localised demand (county and smaller level) and not just aggregate national demand as different parts of the country are likely to be experiencing differential growth rates. Additionally, the solution may not always be generation, but could be transmission and distribution.

g. With economic shifts that the country (and the world in general) is experiencing the traditional linkages between economic growth and power demand growth may be changing. For example, growth in financial services and IT may require more distributed power as opposed to centralised power. Additionally, the per capita power demand requirements for service industries are likely to be lower than manufacturing. Even within the manufacturing space, there are continual efforts to energy efficiency.

h. Historically, power plants have been developed to address localised grid issues e.g., the grid stability issues in Western Kenya has necessitated the continued use of the Muhoroni gas turbine, whereas an upgrade of the

Olkaria – Lessos - Kisumu and Olkaria Narok lines could have resolved the issue and provided for a lower tariff (considering the thermal plants have higher tariffs than the rest of the technologies on the grid).

8.4 Relationship between KPLC and KETRACO

There appears to be some areas of conflict in the relationship, including:

i. Indications by KPLC that KETRACO capex programme is not aligned with the needs of KPLC e.g., the Olkaria – Lessos - Kisumu - line in Western Kenya and the Suswa - Lyongalani line. Key outcome of this:

   a. KPLC suffers penalties for failure of a transmission line, but this penalty is not shared with the transmission line operator, KETRACO.

   b. A transmission line could be a better solution than adding generation capacity, particularly considering the available steam at Olkaria and Menengai.

ii. Indications by KPLC that KETRACO still uses KPLC's technical support to manage breakdowns.

8.5 Recommendations

The Taskforce assessed and reviewed the energy mix and dispatch procedure requirements and make the following recommendations:

1. KPLC to undertake an organisational restructuring to strengthen and empower the following Departments/Sections among others:

   - Commercial; (with the capacity to forecast demand with reference to the issues discussed in this chapter under *'Kenya Power's Demand-Supply Forecasts)'.*
   - Generation Planning & Contracting;
   - Finance; and
   - Legal (including contract management and compliance monitoring).

   Each of these Departments/Sections to report to the KPLC Board at each meeting of the Board.

2. KPLC to produce a 1-year and 5-year forecast of demand and generation immediately including bringing in external expertise to assist the team. The forecast should:

   i. Include information on unmet requests for power connections.

   ii. Be conducted annually.

iii. Make reference to the ideal power generation mix and ideal tariff, in the context of the resources available to the country.

iv. Make specific reference to the extent intermittent sources (wind and solar) can be absorbed onto the grid, taking cognisance that with hydro and geothermal, Kenya already has a high proportion of renewables on the grid with high availability and reliability. Additionally, biomass (e.g., biogas, bagasse, wood, agricultural waste and municipal waste) should have lower levels of intermittency.

v. Make specific reference to the need for the existing HFO thermal stations, including their capability to provide base load power at an appropriate tariff, if converted to natural gas.

vi. In respect of Tsavo, examine the opportunity of retaining the plant (whose PPA has expired) at improved terms (e.g., significantly lower tariff based on a cost-plus model and one-year or shorter tenors.

3. Subject to the 1-yr and 5-yr power forecast and guided by the least cost criteria:

   i. Negotiate a 12–24-month delay for Commercial Operation Dates for PPAs where construction will start imminently, and CPs have been met;

   ii. Negotiate new Commercial Operation Dates for PPAs in default, if the capacity is required; otherwise terminate the engagement; and

   iii. Refer unsigned PPAs to the Taskforce Implementation Committee.

4. KPLC to conduct studies on the meteorological conditions of existing large wind and solar sites to determine the reliability of these plants during the year.

5. KPLC to require future IPPs with high intermittency (wind, solar, mini hydro) to take financial risk for predicting their daily/weekly/monthly dispatch of power. The penalty for under-producing of power would be to compensate the grid at the cost of the thermal plants or the highest peaking plant on the grid as an alternative to the under-generation compared to the forecast. Alternatively, the projects could themselves take on the cost of providing energy storage and presumably adjust the tariff accordingly. Production beyond the forecast would be on a Pay-when-Taken (merchant) basis.

6. KPLC to require in future PPAs, that after a reasonable period (2-3 years) the commercial terms of PPAs with high intermittency (e.g., wind, solar and

mini hydro) can be renegotiated downwards to take into account any material underperformance of the plant compared to the feasibility study.

7. As a solution to the intermittency of existing wind and solar projects and the excess power at night, KPLC to undertake a comprehensive review of energy storage options (including batteries and pump storage of existing and new hydro), including but not limited to:

    i. Technical fit for the Kenya grid and KPLC;

    ii. Actual capex and operational costs, even if they are to be incurred by a third-party under a PPA; and

    iii. Appropriate financing methods e.g., via PPA or via direct procurement and debt financing.

8. KPLC to undertake its own review of the switch to natural gas, which based on stakeholder engagements, could result in fuel cost savings exceeding 40%. This review should include, but not be limited to:

    i. Cost of conversion of the existing plants;

    ii. Sources and cost of natural gas;

    iii. Import logistics; and

    iv. In-country logistics:

    Based on this, coherent negotiations with the IPPs can be held on conversion and the appropriate economies they can achieve; and

9. Align the activities of KPLC and KETRACO where KPLC is part of the approval process of capex and maintenance programmes of KETRACO, in line with the ongoing initiatives to create electricity regulatory accounts regulations that create an asset register for each utility.

9 Analysis of PPAs for committed and pipeline projects

9.2 Background and context

Kenya has attracted significant interest into the power generation space arising from:

a. Good reputation of all the power players in the sector.

b. Declared route toward unbundling of the sector.

c. Attractive commercial terms, including tariffs, tenors and government support measures.

d. High forecast demand for power based on the Big 4 and Vision 2030 flagship projects e.g., an electrified standard gauge rail, LAPSSET programme among others.

e. Varied resource base – geothermal, hydro, solar, wind, biomass – offering a broad range of participants opportunities based on their areas of expertise and choice.

f. Favourable investment climate with a long history of domestic and international investment across all sectors and the power sector in particular.

As such, there has been significant interest in entering into PPAs with KPLC. The utility has signed an additional 35 PPAs with an aggregate capacity of 1,938.45 MW beyond the current 32 live operational PPAs whose aggregate capacity is 2,854 MW and is in various stages of negotiation for a further 113 PPAs with an aggregate capacity of 4,306.07 MW. KPLC has forecasted the need for an additional 4,847 MW by 2030. Additionally, as explained in the previous chapter, lack of diligence in on-boarding new capacity can result in:

a. Higher tariffs if the power generation is growing significantly faster than demand, as the contracts will either be Take-or-Pay or Take-and-Pay.

b. Risk of not supporting economic growth if demand out-strips supply or if the power on-boarded is not at globally competitive tariffs.

c. Challenges in managing the grid (and higher tariffs) if the appropriate mix is not planned. As an example, the high intermittency renewables (wind and solar) require additional spinning reserve or storage as back-up, which comes at an additional cost.

It should be noted that the delay in the large flagship projects and limited manufacturing, points to potentially muted demand and challenges in absorbing all of these new projects.

9.3 Introduction

The Taskforce reviewed the existing PPAs and placed them into two broad categories; those in operation and those in the pipeline. The PPAs for both IPPs and KenGen projects are categorized in the table below. The classification provides specific information provided by KPLC on; plant technology, the number of plants and the term of the PPA as at March 2021.

9.4 IPPs' Projects – existing operational PPA

There are 18 PPAs with a contracted capacity of 1029.57MW for the IPPs' 21 power plants which are operational as detailed in Table 10.

Table 10. IPPs Power Plants in Operation

Plant Technology	**No. of Plants**	**Capacity (MW)**	**Project status as at March 2021**
Hydro	6	11.9	The power plants were operational and active. The PPA term for Tsavo Power, a 74 MW thermal plant was to expire in September 2021.
Wind	2	400	
Solar	1	0.25	
Thermal	6	465.42	
Biogas	1	2	
Geothermal	4	150	
Other (UETCL)	1		
Total	**21**	**1029.57**	

9.5 Signed PPAs, with CPs effective and under construction

There are 14 signed PPAs with projects in various stages of construction and commissioning with a contracted capacity of 233.85 MW. Additionally, there are 4 PPAs with a contracted capacity of 185.6 MW, in respect of which construction has not commenced.

Table 11: Signed PPAs with CPs effective and under construction

<table>
<tr><th>Plant Technology</th><th>No. of Plants</th><th>Capacity (MW)</th><th>Project status as at March 2021</th></tr>
<tr><td>Hydro</td><td>7</td><td>10.91</td><td rowspan="5">- Of the 14 plants, seven (7) plants are under Construction and awaiting commissioning with a capacity of 216.51 MW.

- Three (3) plants, with a capacity of 12.94MW are reported as under construction or construction has completed, but the PPAs have lapsed as the commercial operation dates have passed. These include DWA Estates Ltd (Res Vipingo), Kwale International Sugar Limited (KISCOL) & Marco Borero Co Ltd.

- Of the plants under construction, five (5) plants, with a capacity of 4.4MW are reported as having PPAs under default, in addition to commercial operation dates have passed. These are;

(i) KTDA Ltd, Nyambunde/Nyakwana;
(ii) Kirinyaga Power Company Ltd & KTDA Power Company Ltd (Lower Nyamindi),
(iii) Greater Meru Power Company Ltd (South Mara) & KTDA Power Company Ltd;
(iv) Settet Power Company Ltd (Kipsanoi) & KTDA Power Company Ltd;
(v) Greater Meru Power Company Ltd (Iraru) & KTDA Power Company Ltd.</td></tr>
<tr><td>Wind</td><td>1</td><td>50</td></tr>
<tr><td>Solar</td><td>4</td><td>161.5</td></tr>
<tr><td>Biogas & Co-gen</td><td>2</td><td>11.44</td></tr>
<tr><td>Total</td><td>14</td><td>233.85</td></tr>
</table>

9.6 Signed PPAs, with CPs effective and construction has not commenced

The Table 12 below details illustrates signed PPAs where CPs are effective and the construction has not commenced.

Table 12: Signed PPAs with CPs effective and construction has not commenced

Plant Technology	No. of Plants	Capacity (MW)	Project status as at March 2021
Geothermal	2	175	There are 4 PPAs for plants where construction is yet to commence. These are: (i) Quantum/QPEA GT Menengai Limited (Menengai); (ii) Africa Geothermal International (Kenya) Ltd – AGIL; (iii) Hannan Arya Energy (K) Ltd; (iv) Mt Kenya Community Based Organisation.
Hydro	1	0.6	
Solar	1	10	
Total	**4**	**185.6**	

9.7 Signed PPAs, without CPs effective (construction has not commenced)

The Table 13 below details signed PPAs where CPs are not effective and the construction has not commenced.

Table 13: PPAs with not effective CPs and the construction has not commenced

Plant Technology	No. of Plants	Capacity (MW)	Project status as at March 2021
Geothermal	1	35	- Eight (8) projects have signed PPAs, but not effective and construction has not started. These are: Sosian Menengai, Aperture, Kenergy Renewable, Thika Way, Kopere Solar, Makindu Solar, Bahari Winds, & Greenmillenia Energy.
Wind	2	140	
Solar	4	150	
Biogas	1	8	
Total	**8**	**333**	

9.8 Signed PPAs, now lapsed

The Table 14 below details signed PPAs which have lapsed.

Table 14: Signed PPAs which have lapsed

<table>
<tr><th>Plant Technology</th><th>No. of Plants</th><th>Capacity (MW)</th><th>Project status as at March 2021</th></tr>
<tr><td>Geothermal</td><td>2</td><td>102.5</td><td rowspan="5">- Six (6) projects have signed PPAs that have since lapsed.
- These are: Gatiki Small Hyddro, OrPower 22, Tindinyo Falls, Roadtech Solutions, Akiira Geothermal & Amu Power.</td></tr>
<tr><td>Coal</td><td>1</td><td>981.5</td></tr>
<tr><td>Small Hydro</td><td>2</td><td>12</td></tr>
<tr><td>Biogas</td><td>1</td><td>10</td></tr>
<tr><td>Total</td><td>6</td><td>1,106</td></tr>
</table>

9.9 Unsigned PPAs

The Table 15 below details unsigned PPAs.

Table 15: Unsigned PPAs

<table>
<tr><th>Plant Technology</th><th>No. of Plants</th><th>Capacity (MW)</th><th>Project status as at March 2021</th></tr>
<tr><td>Wind</td><td>5</td><td>202.5</td><td rowspan="5">- 6 projects have initialed PPAs.
- 28 PPAs are under negotiation with no commitment.
- 58 projects are awaiting PPA negotiation.</td></tr>
<tr><td>Solar</td><td>44</td><td>1093.1</td></tr>
<tr><td>Hydro</td><td>35</td><td>900.72</td></tr>
<tr><td>Biogas</td><td>8</td><td>148.75</td></tr>
<tr><td>Total</td><td>92</td><td>2,345.07</td></tr>
</table>

9.10 KenGen's Projects

There are 14 PPAs with 34 power plants entered between the offtaker and KenGen with a total capacity of 1,694.32MW where the power plants were operational and active.

Table 16: KenGen's Operational and Active PPAs

Plant Technology	**No of Plants**	**Capacity (MW)**	**Remarks as at March 2021**
Hydro	14	796.72	- All the PPAs are active. - 2 PPAs to expire within one year.
Wind (Ngong has 3 Units with each being considered as a separate plant)	3	25.5	
Thermal	3	231	
Geothermal	14	641.1	
Total	**34**	**1694.32**	

KenGen is currently undertaking an 80MW geothermal plant at Olkaria, with expected completion by the end of 2021.

As part of KenGen's growth strategy, the company has planned to undertake 21 power projects with 26 plants whose cumulative capacity is 1,961.20 MW by the year 2028.

Table 17: Proposed KenGen Projects

Plant Technology	**No of Plants**	**Capacity (MW)**	**Remarks as at March 2021**
Hydro	3	402	The plants are proposed to be operational by 2028
Wind	4	491	
Biogas/Waste	1	30	
Geothermal	13	690.7	
LNG Gas Turbine	1	200	
Solar	1	42.5	
Well-Heads	2	105	
Total	**26**	**1961.2**	

9.11 XYZ Power

Tsavo Power's (74MW thermal plant located in Mombasa) PPA lapsed in September 2021. The IPP indicated to the Taskforce (during stakeholder engagements) that the plant still has at least another ten years of operational life and they would be interested in seeking a continuing relationship and fully acknowledge the plant has been fully depreciated and so there should be improved economics for KPLC. The Taskforce was however informed that the Board of KPLC has made a decision that the plant should be decommissioned (as per the PPA) with the attendant decommissioning costs borne by Tsavo Power. Additional recommendation on this is in Chapter 7.

9.12 Findings

The following observations are based on a review of the IPPs and PPAs as at March 2021:

a. The PPA for Bahari Winds (90MW) procured under the FiT mechanism are larger than the maximum capacity specified in the FiT Policy.

b. There were several instances of extension of Full Commercial Operation Date and/or Long Stop Date - Kleen Energy, Alten, Kianthumbi; Selenkei, Cedate, Malindi Solar, Kipeto; Chania Green, Makindu, Greensmillenia; Thika Way; Akiira; Roadtech, Kwale Sugar, Quantum, AGIL, Hannan, Mt Kenya Community Based Organisation, Akiira Geothermal & Marine Power Generation Company Ltd.

c. Kwale Sugar (10MW) was placed under receivership after completion of construction but before commissioning.

d. There were instances of signed PPAs that were not effective as conditions precedent had not been met with no construction including Sosian-Menengai Geothermal Power Ltd, Aperture Green Ltd, Bahari Winds (Electrawinds Kenya), Kenergy Renewables Ltd (Rumuruti), Kopere Solar Park (Subuiga), Makindu Solar - Rareh Icon Solar Limited, Greenmillenia Energy Ltd (Isiolo) and Thika Way Investments.

e. There were instances of signed PPAs with inactive plants whose PPAs had lapsed with no construction including OrPower 22 (Menengai), Akiira Geothermal Ltd & Marine Power Generation Company Ltd, Roadtech Solutions Ltd, Amu Power, Gatiki, and Tindinyo Falls Resort.

9.13 Recommendations

The Taskforce recommends as follows;

a. KPLC need to formulate a 1-year and 5-year electricity demand and generation forecast. This is described in Chapter 8.

b. Treatment of PPAs in respect of which construction is complete, but PPA has lapsed or there is an event of default:

   i. Negotiate new commercial operation dates, if the capacity is required per the 1-year and 5-year forecast.

   ii. Terminate if the capacity is not required.

c. Treatment of plants with effective PPAs but construction has not commenced:

   i. Subject to the 1-year and 5-year forecast, negotiate a 12-24-month delay of commercial operation dates.

d. Treatment of plants with signed PPAs without CPs effective:

a. Subject to the 1-year and 5-year forecast, negotiate a 12-24-month delay of commercial operation dates.

e. Treatment of plants with unsigned PPAs:

   i. Refer unsigned PPA to the post Taskforce regime of FiT and reverse auctions.

f. Treatment of plants under receivership:

   i. Terminate the plant pursuant the bankruptcy provision of the PPA, subject to the 1-year and 5-year forecast.

g. Implement the contract management framework to manage this large number of counterparties and contractual relationships as provided in this report.

10 Financial implication of PPAs

10.2 Background and context

KPLC entered into its first PPA on 3rd November 1998 with the 74 MW Tsavo Power whose COD was September 2001, and since then is now the counterparty of 61 PPAs for a total of 2,854MW of installed capacity as at June 2021. As such this is an opportune time to take stock of the successes and potential areas for improvement.

The key successes include:

a. The development of a power generation industry that now includes 6 active players and judging by the 113projects being considered, a sector that more players – domestics and international – find attractive.

b. Finance has been crowded into the sector from development financial institutions, commercial banks, private equity and family office investors. Noting that KPLC and KenGen provide public investors with exposure to sector through public equity and debt.

c. KenGen has emerged as an important player in geothermal, including providing services to other nations to develop their resources.

d. KenGen through its diversity of generation sources – geothermal, hydro, wind, thermal – provides the country with an important benchmark for the sector. As should the IPPs, in respect of providing competition to KenGen.

e. The unbundling has reduced the systemic risk of having only one player in the industry, as well has creating opportunity to achieve more success by having companies that focus on various aspects of the power value chain – generation, geothermal exploration, transmission and distribution.

f. KPLC has developed a system that is able to integrate these various counterparties, which provides confidence that the journey to continued unbundling of the sector is indeed viable.

When viewed through the prism of KPLC's financials several queries emerge that could guide the sector to more success:

a. In FY 2019 and FY 2020, KPLC incurred net losses of KES 0.904 billion and KES 1.335 billion, respectively. Additionally, the net debt as at FY 2020 was KES 114.85 billion, which is a concern in the context of losses and strained cashflows.

b. IPPs accounted for 47% of power procurements costs in FY2020, but only 25% of power volumes, whilst KenGen accounted for 48% of costs and 72% of volumes. This raises questions in respect of the (i) tariffs paid to IPPs; (ii) appropriateness of the capacity that was procured; and (iii) the nature of the contractual terms. KenGen routinely charges lower tariffs than the IPPs and clarity is required as to why Kenya should accept projects pricing higher than KenGen. In the wind space, pricing the two live projects at the same tariff as KenGen, could result in annual savings exceeding USD15 million in aggregate. Whilst in the geothermal space, the saving could be USD 10 million annually.

c. The HFO thermal IPPs, which were initially built as base load plants, have low load factors (less than 10% in the Nairobi area alone in 2020) raising the question of the quantity of this capacity that is actually required, bearing in mind these plants are on a Take-or-Pay basis. Even idling these plants cost USD 20 million to USD 25 million annually.

d. HFO, which costs KPLC KES 12 billion annually, requires close supervision of the procurement as there are significant unexplained variances in pricing between stations of between 10% and 60%.

e. The HFO thermal plants can be converted to natural gas and initial reviews suggest there could be fuel savings of 40%.

f. The Kenya government provides credit support to these plants and a credit event at KPLC could expose the government to KPLC's IPP payments, which exceed USD 400 million annually. Additionally, KenGen, the bulk of whose revenues are from KPLC, would be exposed.

10.3 Contributions to KPLC purchases by generator type

The Taskforce analysed and assessed the contributions to KPLC's power purchases by generator type and established:

a. KenGen dispatches the bulk of electricity (70%+), whilst accounting for 48% of KPLC's purchase costs. In comparison the IPPs, account for a third of KenGen's power dispatch and bill KPLC almost equal amount as KenGen.

b. KenGen is able to charge a lower tariff, whilst being profitable due to:

   i. High technical capacity to undertake projects.

   ii. Lower cost of debt due to access to funding from development partners.

   iii. Lower cost of equity due to access to lower cost and long-term public equity on the Nairobi Securities Exchange as opposed to purely private equity which tends to be more expensive.

   iv. Legacy dam assets in the portfolio, which have been largely amortised.

   v. Limited exposure to HFO, which carries a high fuel cost that is dependent on the international oil prices.

The complete breakdown of power purchases by KPLC from KenGen and IPPs is detailed in Table 18 below.

Table 18: Breakdown of power purchase by KPLC

Power purchase costs (USD mm)	**Jun-18**	**Jun-19**	**Jun-20**
KenGen	457	468	435
% of total	*50.8%*	*48.3%*	*48.1%*
IPPs	390	442	426
% of total	*43.4%*	*45.6%*	*47.0%*
REREC	16	21	26
% of total	*1.8%*	*2.2%*	*2.8%*
Imports - Uganda and Tanzania	36	38	19
% of total	*4.0%*	*4.0%*	*2.1%*
Total	**898**	**969**	**906**
% growth		*7.9%*	*(6.6%)*

Power purchase volumes (GWh)	**Jun-18**	**Jun-19**	**Jun-20**
KenGen	7,990	8,275	8,238
% of total	*74.6%*	*72.0%*	*71.9%*
IPPs	2,496	2,930	2,913
% of total	*23.3%*	*25.5%*	*25.4%*
REREC	47	118	151
% of total	*0.4%*	*1.0%*	*1.3%*
Imports - Uganda and Tanzania	171	170	161
% of total	*1.6%*	*1.5%*	*1.4%*
Total	**10,703**	**11,493**	**11,463**
% growth		*7.4%*	*(0.3%)*

Source: Compiled from KPLC Annual Reports

The scale of the contribution of KenGen to KPLC's power procurement calls for continued oversight to ensure that KenGen continues in its effort to drive efficiency and generate shareholder value, as well as opportunities for tariff savings to be passed on to consumers. For instance, if KenGen and KPLC worked together to generate efficiencies of 10% on the FY2020 invoices, this could reduce the procurement costs by USD44 million

10.4 KPLC's Power Purchases from KenGen and IPPs

The power purchased from power producers by the offtaker is illustrated in Table 19 below. The Kipeto Wind (100MW) and Malindi Solar (40MW) came online after June 2020 and KenGen is in the process of expanding Olkaria I Unit 6 by 80MW.

Table 19: Power Purchases Breakdown by Power Generator

USD millions			Jun-18	Jun-19	Jun-20	Jun-20 %
			102.2	*101.2*	*103.7*	
KenGen (incl steam)	1	Various	457	468	435	*48.1%*
OrPower 4	2	Geo	112	124	120	*13.3%*
Lake Turkana Wind Powe	3	Wind	0	109	118	*13.0%*
Iberafrica	4	*HFO*	51	39	25	*2.8%*
Rabai	5	*HFO*	79	38	46	*5.1%*
Thika	6	*HFO*	46	35	26	*2.9%*
Tsavo	7	*HFO*	41	36	38	*4.2%*
Gulf	8	*HFO*	35	28	21	*2.3%*
Triumph	9	*HFO*	22	29	25	*2.8%*
Uganda Electricity	10	Import	35	38	19	*2.0%*
Regen-Terem	11		2	2	3	*0.3%*
Gura	12		1	1	2	*0.2%*
Ethiopia Electricity	13	Import	1	0	0	*0.0%*
Power Technology	14		0	0	0	*0.0%*
Chania	15	Mini Hydro	0	0	0	*0.0%*
Biojule	16	Biomass	0	0	0	*0.0%*
Imenti Tea	17	Mini Hydro	0	0	0	*0.0%*
REA Garissa Solar	18	Solar	0	3	5	*0.6%*
Strathmore University	19	Solar	0	0	0	*0.0%*
Tanzania Electricity	20	Import	0	0	0	*0.0%*
REA Off-grid	21	Diesel	16	18	20	*2.3%*
Mumias Sugar	22	Biomass	0	0	0	*0.0%*
Gikira	23	Mini Hydro	0	0	0	*0.0%*
Aggreko	24	Diesel	0	0	0	*0.0%*
Total - Gross			**898**	**969**	**906**	***100.0%***

Source: Compiled from KPLC Annual Accounts

10.5 The Tariffs for different technologies

Generation tariffs is computed by considering the investment costs and a reasonable return on the investment. The investment cost is amortised over the entire useful life of the project. Tariffs for different technologies vary due to the various cost drivers including direct capex, tax incentives, land wayleaves, grid interconnection, term of PPA, capacity of the power plant, financing among others.

The Taskforce reviewed the tariffs applicable to different technologies and established thermal/diesel plants had higher tariffs compared to the other technologies.

The experienced higher tariffs (in USD per KWh) for the HFO thermal plants result from the fact that these plants invoice a fixed capacity charge (irrespective of the quantity of power dispatched) and over the last 3 years the plants have operated at low Load Factors, including below 10% in the Nairobi metropolitan area. Table 20 below illustrates the tariffs charged by generators based on different technologies.

Table 20: Power Tariffs by IPP / Supplier

Total Tariff (Non Fuel + Fuel) - USD c / KWh			**Jun-18**	**Jun-19**	**Jun-20**
F/X			*102.2*	*101.2*	*103.7*
KenGen (incl steam)	1	Various	5.7	5.7	5.3
OrPower 4	2	Geo	9.4	9.7	11.2
Lake Turkana Wind Powe	3	Wind	0.0	9.7	9.5
Iberafrica	4	HFO	27.4	53.3	45.8
Rabai	5	HFO	14.1	31.4	18.4
Thika	6	HFO	21.2	32.4	52.7
Tsavo	7	HFO	21.1	27.7	25.2
Gulf	8	HFO	43.1	74.2	117.2
Triumph	9	HFO	79.3	179.5	166.8
Uganda Electricity	10	Import	20.7	22.7	11.9
Regen-Terem	11	???	9.7	9.6	9.4
Gura	12	???	7.9	7.8	8.1
Ethiopia Electricity	13	Import	26.7	7.8	6.9
Power Technology	14	???	14.4	11.5	8.8
Chania	15	Mini hydro	6.5	13.5	11.9
Biojule	16	Biogas	10.1	9.1	3.0
Imenti Tea	17	Mini hydro	0.0	0.0	0.0
REA Garissa Solar	18	Solar	0.0	5.5	5.7
Strathmore University	19	???	0.0	13.8	0.0
Tanzania Electricity	20	Import	0.0	0.0	0.0
REA Off-grid	21	Diesel	34.8	30.7	34.0
Mumias Sugar	22	Biomass	0.0	0.0	0.0
Gikira	23	Mini hydro	0.0	0.0	0.0
Aggreko	24	Diesel	0.0	0.0	0.0
"Not in Use"	25		0.0	0.0	0.0
Total - Gross			**8.4**	**8.4**	**7.9**

The Taskforce further noted the dispatch rates of the larger plants as illustrated in Table 21 below.

Table 21: Plant Dispatch Rates

Plant Load Factors %	**Jun-18**	**Jun-19**	**Jun-20**
Iberafrica	*20.7%*	*8.2%*	*12.0%*
Thika	*28.2%*	*14.0%*	*6.6%*
Gulf	*11.5%*	*5.4%*	*2.6%*
Triumph	*3.9%*	*2.2%*	*2.1%*
Rabai	*71.3%*	*15.5%*	*32.5%*
Tsavo	*30.2%*	*20.2%*	*23.4%*
KenGen HFO	*44.1%*	*37.3%*	*13.8%*
KenGen Geothermal	*87.4%*	*84.2%*	*74.5%*
OrPower Geothermal	*90.2%*	*97.8%*	*81.9%*
KenGen Wind	*21.3%*	*30.2%*	*20.9%*
Lake Turkana Wind Power	-	*42.8%*	*47.1%*
KenGen Hydro	*45.6%*	*53.1%*	*52.1%*

10.5.1 The tariffs for the IPP thermal plants

The Table 22 illustrates the key invoicing terms under thermal power plants. It indicates that Triumph power pricing is higher compared to Gulf Power and Thika Power though it is the same technology and all the plants are located within the Nairobi metropolitan area.

Table 22: The tariffs for IPP thermal plants

Plant	Capacity (MW)	Start date / Tenor (years)	Capacity Charge at signing (USD / KW) [1]	Energy Charge (USD / KWh) [1]	Fuel efficiency (Kg / KWh)
Tsavo Power	74.0	Sep-01 / 20.0	USD274.4	USD0.011	[TBC]
Iberafrica 2	52.5	Oct-09 / 25.0	USD 299.3	USD0.012	0.224
Rabai Power	88.6	May-10 / 20.0	EUR221.7 *(USD270.4)*	USD0.010	0.197 – 0.208
Gulf Power	80.3	Dec-14 / 20.0	EUR205.4 *(USD250.5)*	USD0.009	0.215
Thika Power	87.0	Mar-14 / 20.0	EUR199.1 *(USD242.8)*	USD0.010	0.199 – 0.215
Triumph	83.0	Jul-15 / 19.6	USD290.0	USD0.011	0.201 – 0.210
Total thermal/diesel	**465.4**				

[1] *Post signing there is escalation indexed at the USD or EUR consumer prices index, as applicable*

10.5.2 Fuel management by thermal plants

The results derived from the audited annual reports in respect of the cost of fuel per KWh, indicated the need for deeper oversight by KPLC going forward. The fuel charge (on a USc / KWh) basis of Gulf and Triumph were nearly double the comparable power plants in the Nairobi area in FY2019. The fuel charge for Gulf Power was almost double compared to similar plants within the same locality in FY2018. Table 23 below highlights the cost of fuel per unit of power generated.

Table 23: The Cost of fuel per unit of power generated

Fuel Charges (Usc / KWh)		Jun-18	Jun-19	Jun-20
Iberafrica	Nairobi Met	10.8	13.3	12.0
Thika	Nairobi Met	10.5	12.6	12.6
Gulf	Nairobi Met	17.3	22.3	12.8
Triumph	Nairobi Met	11.5	19.8	12.4
Rabai	Mombasa Met	9.0	10.9	8.4
Tsavo	Mombasa Met	9.6	11.2	10.5
REA Off-grid	Various	34.8	30.7	34.0
Average - simple		*14.8*	*17.3*	*14.7*
Highest		*34.8*	*30.7*	*34.0*
Lowest		*9.0*	*10.9*	*8.4*

Source: Compiled from KPLC Annual Reports

The Taskforce was able to derive the HFO cost (USD/tonne) incurred historically. The result is that in the Nairobi Area, where the price differential should be limited, as the transport cost should be the same, there are considerable differences during the same financial period. In FYE June 2020, Iberafrica was the lowest at USD534 and Gulf the highest at USD594, with the remainder of the cohort still pricing at a significant premium. More significantly in FY 2019, Gulf and Triumph priced in excess of 60% higher than the lowest of the Nairobi cohort. Gulf and Triumph were similarly expensive in 2018. Table 24 below highlights derived HFO prices.

Table 24: Derived HFO prices

Fuel invoices amounts (USD mm)	Jun-18	Jun-19	Jun-20
Iberafrica	20.0	9.8	6.6
Thika	22.6	13.5	6.3
Gulf	14.0	8.5	2.3
Triumph	3.2	3.2	1.9
Rabai	50.4	13.1	21.1
Tsavo	18.9	14.7	16.0
HFO price (USD/tonne)	*Jun-18*	*Jun-19*	*Jun-20*
Iberafrica	480.3	593.5	533.9
Thika	489.6	584.7	587.1
Gulf	806.0	1,037.6	593.6
Triumph	545.9	944.3	588.4
Rabai	431.5	526.0	403.1
Tsavo	*n/a*	*n/a*	*n/a*

An indicative and informal quote from a fuel transporter suggests the transport rate from Mombasa to Nairobi inclusive of VAT is in the region of USD40-USD50 per tonne. If this is the case, then based on the Rabai price, Nairobi should have priced at USD450 per tonne area in FY 2020 and USD575 per tonne area in FY 2019, noting that even Rabai includes a transportation cost.

An analysis of the May 2021 invoices suggests that this issue is still continuing. The variance in pricing is a significant cause for concern and a potential breach of the undertakings of the PPA. It is difficult to explain the USD 60 premium that Thika is paying over Triumph and Iberafrica, let alone the USD331 premium of Gulf. Note this pricing is taken from invoices for pricing for May 2021. Table 25 below highlights the May 2021 fuel invoices.

Table 25: May 2021 fuel invoices

	Nairobi Area				Mombasa Area	
	Gulf	Thika	Triumph	Iber	Tsavo	Rabai
Opening stock (tonnes)	296.5	2,540.4	1,176.1	1,354.6	8,379.3	6,774.0
Delivered (tonnes)	0.0	3,832.1	0.0	500.8	3,692.4	7,499.0
Consumed (tonnes)	223.1	4,683.8	509.9	564.4	1,153.3	8,209.0
Closing stock (tonnes)	**73.4**	**1,688.8**	**666.3**	**1,282.0**	**10,918.3**	**6,099.0**
Required Minimum Fuel Stock – PPA			4,500.0			
% compliance	*n/a*	*n/a*	*(85.2%)*	*n/a*	*n/a*	
Weighted average fuel price (USD/tonne)	**838.2**	**563.8**	**507.1**	**507.4**	**494.8**	**426.7**
Contractual fuel consumption (<35MW) Kg/KWh	**0.215**	**0.215**	**0.201**	**0.224**		**0.208**
Contractual uel consumption (>35MW) Kg/KWh	**0.215**	**0.199**	**0.210**	**0.224**		**0.197**
Lowest Contractual fuel consumption	0.197	0.197	0.197	0.197		0.197
Fuel differential - 100% dispatch of 80 MW (tonnes)	2,697.0	265.0	1,898.5	4,222.7		0.0
Fuel differential @ USD600/tonne - USDmm	**1.6**	**0.2**	**1.1**	**2.5**		**0.0**

Meanwhile, the lower fuel consumption rate of Thika, suggests this plant should be prioritised for dispatch with closer supervision of the HFO purchase price.

10.6 The Comparison between wind IPPs and KenGen's wind plants

Benchmarking the IPPs against KenGen pricing raised key queries:

a. KPLC reports that in FY2020, Lake Turkana had a Load Factor of 47%, compared to KenGen Ngong's 21%, yet the more efficient Lake Turkana enjoys a higher tariff. Additionally, Lake Turkana is situated further from the power demand centres and required the government (through KETRACO) to build a 400Km transmission line.

b. The Kipeto power plant which is located in the same vicinity as KenGen's Ngong power plant has a tariff which is 40% higher.

c. Kipeto power plant enjoys the higher FiT tariff, which leads to a suggestion that IPPs should not be allowed to price above the KenGen's price, unless an acceptable justification is provided.

The comparative analysis of the wind tariff for different power projects is detailed in Table 26 below:

Table 26: The Tariff for Different Wind Plants

Plant	Capacity (MW)	Actual Tariff per KWh[1]	Tariff equivalent (USD/ KWh)
KenGen			
Ngong 1	20.4	KES7.33 fixed KES1.5481 escalable	0.086
IPPS – operational			
Lake Turkana	300	EUR0.065 fixed EUR0.0125 escalable	0.095
Kipeto Wind Plant	100	USD0.120	0.120

IPPs – proposed			
Chania Green	50	USD0.110	0.110
Aperture Green	50	USD0.070	0.070
Bahari Winds	90	USD0.070	0.070

[1] *Post signing there is escalation indexed at the USD or EUR consumer prices index, as applicable*

10.7 The comparison between geothermal IPPs and KenGen's geothermal plants

This technology within Kenya benefits from having two experienced operators and increasing competition, which should create appropriate pricing benchmarks.

However, to the extent that Akiira and Africa Geothermal are still prospecting, it would not be prudent to offer a Capacity Charge, before KPLC knows the actual potential of their resources. Table 27 below illustrates the tariff for different geothermal plants.

Table 27: The Tariff for Different Geothermal Plants

Plant	**Capacity (MW)**	**Actual Tariff per KWh**[1]	**Tariff equivalent (USD/ KWh)**[2]
KenGen			
Weighted Average including steam costs	656.1		0.085
Weighted Average utilising GDC steam			0.042
IPPS – operational			
OrPower – weighted average across 4 PPA	300	Capacity (Fixed): USD270.4 per KW Capacity (Escalable): USD323.7 per KW **Capacity (Total): USD594.1 per KW** Energy (Escalable): USD0.0259 per KWh	0.096
IPPs – proposed			
Sosian – Menengai (excl steam)	35.0	0.049	0.049
Sosian Menengai			0.02

Steam cost			
Quantum – Menengai (excl steam)	35.0	0.050	0.050
Quantum Menengai steam cost			0.02
OrPower 22 (excl steam)	32.5	0.050	0.050
Or Power 22 steam cost			0.02
Africa Geothermal (incl steam)	140.0	Capacity (Fixed): USD263.0 per KW Capacity (Escalable): USD290.0 per KW **Capacity (Total): USD553.0 per KW** Energy (Fixed): USD0.0240 per KWh	0.089
Akiira (incl steam)	70.0	Capacity (Fixed): USD263.0 per KW Capacity (Escalable): USD290.0 per KW **Capacity (Total): USD553.0 per KW** Energy (Fixed): USD0.0240 per KWh	0.089

[1] *Post signing there is escalation indexed at the USD or EUR consumer prices index, as applicable.*

[2] *Assuming 97.5% Load Factor, due to priority dispatch and high geothermal availability.*

10.8 Financial impact of PPAs on GoK

The Taskforce assessed and analysed the impact of PPAs on KPLC, the Energy Sector and GoK and noted that PPAs, both KenGen and IPPs represent a significant financial burden to KPLC with a direct impact on the company's negative cashflow and threatens its going concern status.

Whilst the GoK Letters of Support are meant to limit the commitment of GoK to exclude commercial challenges that a project could experience (as opposed to political risk events) and are not meant to be guarantees. The Taskforce established that in the event of non-payment by KPLC (for commercial reasons), GoK may be compelled to honour KPLC's commitments.

KPLC's negative cashflows, where the net debt only changed marginally from KES120.63 billion in FY2018 to KES114.85 billion in 2020 and continues to increase, then the risk of such guarantee crystallising is imminent.

The Taskforce noted that in 2020, KPLC's total power procurement costs payable to both KenGen and IPPs was USD906 million. Additionally, a credit event of KPLC will have a material adverse impact on KenGen, as the generator is dependent on KPLC for the bulk of its revenues.

10.9 Recommendations

The Taskforce recommends:

1. KPLC to take steps aimed at reducing tariffs charged by the IPPs.
2. KPLC to conduct a forensic audit on the PPAs and Independent Power Producers (IPPs) to cover the following, *noting that the Taskforce was not able to receive this information comprehensively from KPLC*:
    i. The procurement processes that were used;
    ii. Identification of beneficial owners;
    iii. Selection criteria used to identify the eventual operator;
    iv. An analysis of IPPs' audited accounts for at least the last 5 years to ascertain whether key parameters are in line with the audited financial models in the PPAs and the PPA; and
    v. Technical audit to ascertain the capacity discharged by the various plants' *vis a vis* respective PPAs.
3. Improvements in HFO management -
    i. KPLC to conduct a forensic audit of HFO purchases over the preceding five years;
    ii. KPLC to review the dispatch orders to consider the benefits of running the HFO thermal plants on a rotational basis for longer periods to take advantage of fuel efficiency during longer runs; and
    iii. KPLC to institute a joint tender for fuel purchases, modelled on the refined product open tendering system (OTS).
4. KPLC to use KenGen's prices as the pricing benchmark for FiT and Reverse Auction, with very clear justification required to exceed the KenGen prices.
    i. Similarly, KenGen to be driven to continually seek efficiencies so that tariffs can be lowered in the future.
5. In respect of Akiira Geothermal Limited and Africa Geothermal International (Kenya) Limited:
    i. As they are still in the exploration phase, it is not prudent to offer a Capacity Charge, before KPLC knows the actual potential of their resources;
    ii. Considering the length of period of execution, there should be mechanisms to adjust tariffs to take advantage of (a) improving

technologies; and (ii) better than expected results of the exploration phase; and

iii. Clarity, from MoE, in respect of progress being made by these licencees and the extent to which they are meeting milestones and action taken if they are not.

6. KPLC to develop financial modelling capacity to be able to analyse (a) individual PPAs; and (b) the impact of individual PPAs on KPLC income statement, balance sheet and cashflows. This capacity would include in-depth understanding of capex costs and operations and maintenance costs, across technologies.

11 Proposed action for operational PPAs

11.2 Background and context

Based on the financial analysis in Chapter 10, it is clear that various changes need to be made for the sustainability of KPLC and the power sector in general and to improve the tariff structure that consumers experience.

The potential savings that can accrue if certain actions are taken are highlighted in table 28 below.

Table 28: Potential Savings

Action	Potential annual reduction in KPLC IPP costs
Near-term	
Pursue the HFO thermal plants for breaches of the PPA, resulting in a 40% decline in capacity charge. *Athi River Gulf, Thika Melec and Triumph analysed as only this information was provided. Further potential savings with a deep-dive analysis of Iberafrica Power and Rabai Power.*	USD27 million – USD35 million
Improved fuel management across the HFO thermals – 10% reduction. *Closer oversight of fuel tenders and eventual centralised procurement of HFO, adopting the open tendering system used for refined products*	USD12 million
Renegotiate Lake Turkana Wind Farm to the KenGen tariff *Current performance date is showing high intermittency and an average dispatch of 150MW compared to contracted capacity of 300MW.*	USD12 million
Renegotiate Kipeto to the KenGen tariff. *Assumes same long-term load factors as KenGen Ngong.*	USD6 million
Renegotiate OrPower geothermal to the KenGen tariff. *Pursue capital structure refinancing given the maturity of the project, including tenor extension and interest coupon reduction.*	USD12 million
Sub-total	**USD69 million – USD77 million**
Medium term	
Pursue switch to natural gas. *Natural gas potentially lowers fuel costs by 40%.*	USD45 million
Total	**USD114 million to USD122 million**

(1) Based on KPLC's 2020 power procurement costs per the audited annual report

(2) Using a conversion of KES110 to the USD1

The proposed near-term actions could reduce the on-going power procurement costs by USD 69 million to USD 77 million annually, which corresponds to USc 2.3 to USc 2.6 per KWh of the average IPP tariff. The switching of the HFO thermal stations to natural gas (assuming that all be converted with an acceptable logistics solution) could add another USD45 million of annual savings. Additionally with the four new solar plants coming online, there could be opportunity to rationalise these tariffs towards international benchmarks.

11.3 IPPs analysis

The Taskforce began by conducting financial analysis of the IPPs impact on KPLC, in order to determine which would have the most impact in respect of improving KPLC's position. The analysis highlighted HFO thermal IPPs collectively made up 20% of power procurement costs in FY2020, whilst Lake Turkana and OrPower contributed 13% each. Kipeto Wind and Malindi Solar come online in FY2021 and so whilst not appearing in the FY2020 reporting, will have a material impact going forward, given their relative size.

It should be noted, that the Taskforce's work was hampered by incomplete information – including no access to the complete suites of audited financial models (that are required to be an appendix of the PPA) and audited annual reports of the IPPs. However, the team was able to piece together a way forward based on the available information. Key missing models that were not made available are Rabai Power and OrPower. Annexure 1 under Schedule 5 indicates the requested information that was not made available. As such a key contributor to the analysis was public information from the annual reports of the sector.

11.4 Thermal IPPs

The following areas were identified as potential areas that would constitute a default of the HFO thermal IPPs: These potential areas are specifically analysed in Chapter 9 on financial implications of the PPAs and in the two tables below.

a. *Misrepresentation of the total project cost*: This would have caused KPLC to:

   (i) Agree to a higher capacity charge;

   (ii) Obtain government support measures that are over-stated;

   (iii) Come to the view erroneously, that the minimum cash equity test had been achieved; and

   (iv) Be exposed potentially to an inflated termination cost.

b. *Failure to meet the minimum cash equity contribution*: A minimum cash equity contribution of 25% of the total project costs is required per the PPAs.

c. *Failure to operate the plant per the agreement in respect of fuel purchases*: The lack of correlation in fuel prices could be an indication that the operator had failed to obtain the lowest possible fuel prices.

In the event of a default of an IPP, the only payment that would be due to the IPP would be the value of the third-party debt outstanding, with no penalty for loss of profit. At termination, the ownership of the plant would transfer to KPLC.

11.5 Misrepresentation of Total Project Cost and Minimum Cash Equity

The information was restricted to Athi River Gulf, Thika Melec and Triumph, due to a lack of record-keeping at KPLC. Rabai and Iberafrica would need to undergo similar analysis. Tsavo was retired in September 2021. Table 29 below indicates the total project costs analysis.

Table 29: Total project costs analysis

	Athi River Gulf	**Thika Melec**	**Triumph**
Capacity (MW)	80.3	87	83
Direct capex (USD)	78.7	124.3	106.5
Direct capex / MW (USD)	*1.0*	*1.4*	*1.3*
Total Uses (USD)	**119.0**	**154.0**	**149.3**
Total uses / MW (USD)	*1.5*	*1.8*	*1.8*
Equity requiring verification (USD millions)	**12.7**	**42.5**	**24.2**
Adjusted Total Uses	106.3	111.5	125.1
Adjusted Cash Equity	17.3	(4.1)	17.1
% Adjusted cash equity	*16.3%*	*(3.6%)*	*13.7%*
Financiers	Standard Bank IFC OPEC Fund	Absa AfDB IFC	Standard Bank ICBC

Source: Audited financial models attached to the respective PPAs

The Adjusted Total Uses and Adjusted Cash Equity reflect the reduction by the equity requiring verification. Details of the determination of the above are presented within the Annexure 1 under Schedule 5.

There are several areas for verification, which can be determined by requesting the IPPs to provide further information to demonstrate the numbers presented in the audited financial model are indeed correct:

i. *Variation in the Direct Capex:* The three plants are all located in the Nairobi area and should be expected to have similar direct capex costs. Rather Gulf's capex is USD1.0 million per MW, whilst Thika Melec and Triumph are 30%-40% more expensive. It should be noted that the fuel consumption rates across the plants are not materially different at 0.2 Kg/KWh and so it would be expected that one could not make the argument that the higher capex was compensating for improved fuel consumption.

ii. *Equity requiring variation:*

(a) Gulf has USD 6.3 million of shareholder costs that have been capitalised and unexplained, together with at least USD 3.0 million of advisor costs that are covered in other areas of the Total Uses.

(b) *Thika Melec:* The bulk of the equity requiring variation, refers to the significantly higher direct capex (USD 1.4m per MW).

(c) *Triumph:* In the audited financial model of Triumph, there is USD 24.2 million that has been recognised on the balance sheet and has not been identified as having any use, including having been cash on the balance sheet at the closing of the transaction. There is a further variation relating to the comparatively high direct capex per MW of USD 1.3 million, which using Gulf at USD 1.0 million per MW as benchmark, could be an additional USD 25 million.

11.6 Failure to operate the plant per the agreement in respect of fuel purchases

The lack of correlation of fuel prices is covered in Chapter 10 under financial implications of PPAs. Essentially the significant variations in HFO fuel prices (in USD/tonne) between plants in the same vicinity during the same financial period, suggest that the plants with the highest HFO prices did not take the due care required in conducting their fuel tenders. Given the price of HFO is indexed on Platts, the only variation should be the cost of transport. Furthermore, there are significant variations between the Mombasa and Nairobi plants that appear beyond the typical transportation costs between Mombasa and Nairobi.

11.7 Gazette Notice regarding operation of thermal generation plants

On 19 April 2016, a Gazette Notice No. 2826 was published, where EPRA provided approvals in respect of:

i. Lowering the HFO minimum fuel stock holding levels; and

ii. Operating the HFO thermal stations outside of the merit order to allow for the equipment to be run to keep the machines in good working order.

This benefitted the HFO thermal plants as follows:

a. Reduced minimum stock holdings (and the consequent release in working capital) without facing liquidated damages (penalties) for doing so. The working capital released would be worth approximately USD 3 million to USD 7 million per plant.

b. Giving the IPPs the opportunity to run the equipment even though there was no demand for the power. This allowed the IPPs to maintain their equipment in good working order, which should have been at their cost and not KPLC's. It should be noted it is the obligation of the IPP to maintain the plant at the agreed availability, for which the capacity charge is paid. There is no minimum dispatch obligation in respect of KPLC.

In this event, KPLC made significant concessions to the benefit of the HFO thermal plants and it is not clear what concessions were provided to KPLC in turn. It is also unclear how EPRA approved the same. Gazette Notice No. 2826 is attached as Annexure 2 in Schedule 5.

11.8 Cost-benefit analysis

At termination, the ownership of the plant would transfer to KPLC per the PPA. As such, the cost-benefit analysis is treated as the impact of KPLC buying the plant from the IPP at the cost of termination. Given in the event of a seller default, this does not include loss of profit compensation but only the outstanding debt, this is attractive financially for KPLC. As KPLC would continue to meet the debt obligations, lenders interests should not be harmed.

Based on this the Taskforce believes that when the benefits are passed on to consumers the tariff could reduce by as much as 40% for each station and potentially even more. There is also the added benefit of being able to take advantage of the government's long-term USD cost of borrowing (c 6.5%) compared to the IPPs costs in excess of 7.5% Table 30 below indicates the potential termination payments and revised tariffs.

Table 30: Potential termination payments and revised tariffs

	Athi River Gulf	**Thika Melec**	**Triumph**
Capacity charge at signing – per MW per year	EUR 205	EUR 199	USD290
Revised capacity charge – per KW per year	**EUR 123**	**EUR 120**	**USD174**
Average annual cash savings to consumer	**EUR 7 million**	**EUR 7 million**	**USD 10 million**

11.9 Wind and solar

As has been indicated, wind and solar experience high intermittency due to the exposure to the:

i. Real-time-climatic conditions (e.g., cloudy days impacting radiation levels and wind speeds that are higher or lower than the design capacity); and

ii. Lack of storage, so if the resource (wind or solar) is not converted and the power dispatched, then the opportunity to use the power generated is lost.

This causes some challenge in respect of integration onto the grid, including:

i. Requiring back-up solutions at an additional cost (e.g., pump storage hydro, thermal generation batteries) to step-in when the resource is not available.

ii. The Take-and-Pay contracts require KPLC to absorb the power regardless of the prevailing demand and during periods of low demand (such as night-time) when the wind is prevalent, the grid is forced to vent geothermal steam, as the supply outstrips the demand.

As such the sizing of the projects relative to the grid is critical and continuous analysis must be undertaken, particularly in respect of on-boarding new capacity of this type and the FiT policy guidelines should evolve in the context of this for the following reasons:

a. The larger the project, the more challenging it is to manage the intermittency;

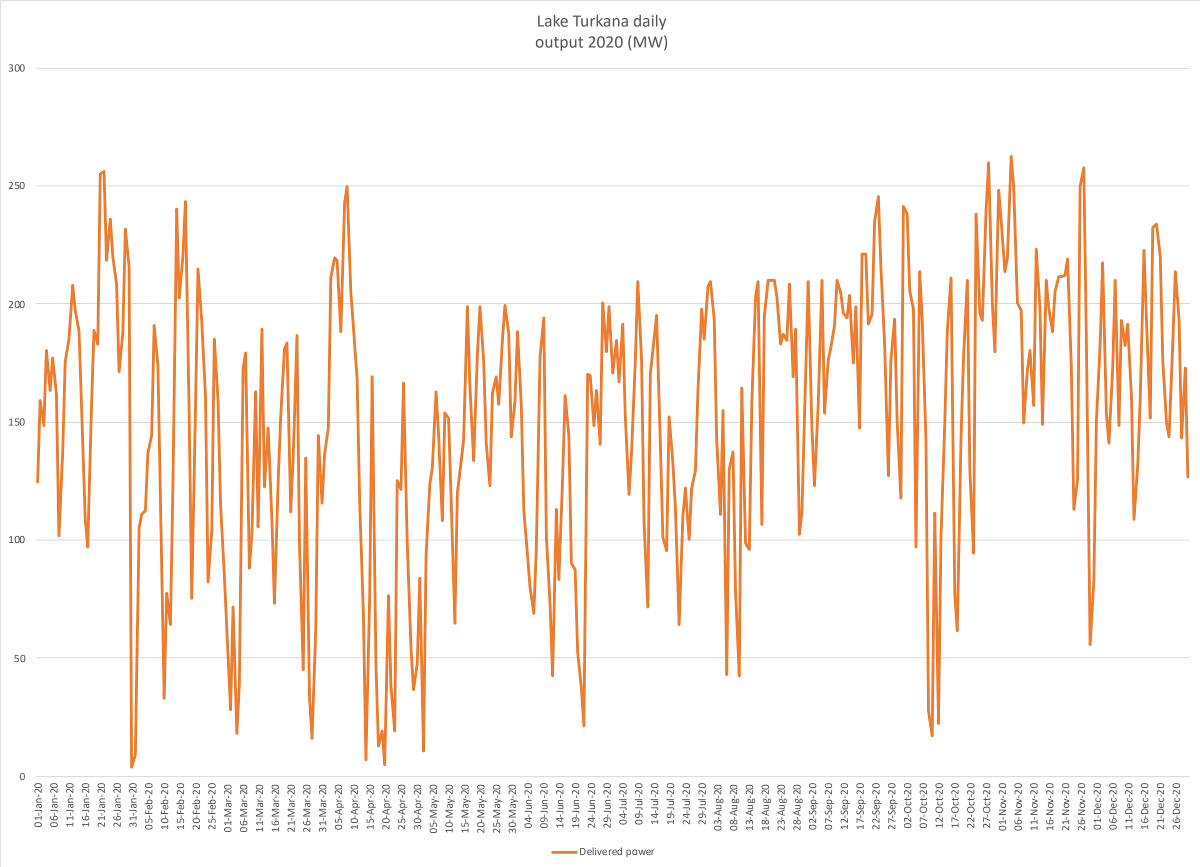
b. The country has been left open to tariffs that were higher than KenGen's offering; and

c. More financial risk should be placed on developers that are keen to on-board large plants that are beyond the FiT policy guidelines. Certainly, there is an argument that in the future Take-or-Pay tariffs (where applicable) should be set on lower more predictable (high availability) capacities and merchant (Pay-when-Taken) tariffs offered for the production in excess of those capacities.

11.9.1 XYZ Power

Lake Turkana Wind Power, with its 300MW of installed capacity is illustrative of the point above. A key question is why the tariff is USD 0.095 (EUR equivalent) compared to the KenGen Ngong project at USD 0.086. Given the higher load factor at Lake Turkana (47% in FY2020) compared to Ngong Wind (21% in FY2020), it would be expected that the higher output and efficiency of Lake Turkana would have resulted in a lower tariff. If Lake Turkana would have priced at the lower tariff, this would have reduced KPLC's costs by USD 12 million in FY 2020.

Chart 6: Daily output of Lake Turkana Wind during the year-ended 2020



The Chart 6 above (which illustrates the intermittency point above) shows the daily output of Lake Turkana Wind during the year-ended 2020, when:

a. The project did not achieve the nameplate 300 MW capacity for a sustainable period on any day;

b. The minimum average daily output was 4 MW and the maximum 262 MW: during only 5 days of the year was output in excess of 250MW;

c. During 67 days, (18% of the year) daily output was less than 100MW; and

d. The bulk of the year (225 days or 62%) experienced production of between 100 MW and 200 MW and hence an average daily output for the year of 150 MW.

The Taskforce was not able to view the feasibility reports that led to the approval of Lake Turkana, but certainly the performance of the project should be reviewed in the context of those reports to determine if there were gaps in the procurement process. Certainly, there is a question in respect of the sizing of the project and the extent to which a smaller project would have resulted in a project with (i) less intermittency; and (ii) a lower tariff arising from higher load factors.

This exercise requires further in-depth analysis, taking into account that the plant is gathering more performance data continually. Comparing this experienced actual data to the feasibility study (which was not made available to the Taskforce) could address any queries in respect of any gaps in the procurement process and the appropriate sizing of the plant.

11.9.2 XYZ Wind

Kipeto Wind began full commercial operation in February 2021 and as the data set grows, the discussion above (in respect of Lake Turkana) is also contextual for Kipeto. Kipeto is in the same vicinity as KenGen's Ngong and it is assumed that the wind conditions should be similar. If that is the case, then there is a question in justifying the FiT based tariff of USD 0.120, which is 40% higher than KenGen's. If this project's tariff was the same as KenGen's Ngong and had the same load factors, the annual savings could be USD 6 million.

11.9.3 XYZ Plants

Currently there is one operational solar project (REREC's 50MW Garissa Solar) which is experiencing high intermittency. An additional 4 plants: Malindi Solar (40MW), Alten Kenya (400, Selenkei (40MW) and Eldosol (40MW) are under construction and will bring an aggregate (160) MW of capacity on stream by January 2022.

A similar exercise as per the Lake Turkana Wind Power analysis will need to be undertaken as the data set develops.

11.10 XYZ Plant

The OrPower plants have been operating at Olkaria since23rd July 2000, during which significant data has been gathered in respect of the plants' performance, the OrPower steam-field concession and the Olkaria geothermal potential in general. Based on these facts, this would be an opportune time to engage the IPP on routes to achieve a tariff reduction, including refinancing the capital structure (to achieve longer tenors and lower interest coupons). Reducing the tariff to match that of KenGen would achieve annual cost savings of USD 12 million.

11.11 Deemed generated energy versus installed capacity

Deemed Generation means the energy which a generating station was capable of generating but could not generate due to grid/power system conditions beyond the control of generator in the case of renewable energy PPAs such as wind and solar. The payments made by the offtaker to the generator is referred to as Deemed Generated Energy Payments (DGE).

The DGE is computed on the basis of the energy threshold of the electrical output from the power plant and is based on the number of units generated but the offtaker was not able to take it. units generated from a power plant is based in the capacity factor. For example, a power plant of 100MW which has a capacity factor of 50% is able to deliver 50MW. However, in terms of energy generated, the units produced in one year will be 100*1000*8760*50% which translates to 438,000,000kWh or 438GWh in year. The energy threshold can be set at the 438 million kWh per year. If the offtaker is not able to take up the entire units generated during the year, the utility will have to pay for the energy deemed to have been generated at the agreed price. The formula is provided in the PPAs to guide on how the parties will cure the problem. Many of the big power plants such as Lake Turkana Wind Power, Kipeto Power etc have DGE threshold agreed by the parties based on the units generated at the agreed capacity factors.

11.12 Recommendations

1. KPLC to establish a team (that will comprise senior members from KPLC, the Attorney General and the National Treasury):

i. HFO thermal IPPs

a. Renegotiate or terminate the PPAs (with reference to the material breaches identified in this chapter) within a timeline of 4 months. This applies to Athi River Gulf, Thika Melec and Triumph.

b. Conduct similar analysis for termination or renegotiation for Rabai and Iberafrica, as the appropriate information was not made available to the Taskforce. If the situation is similar, pursue termination or renegotiation.

c. Gazette Notice No 2826 dated 19th April 2016 provided the power plants with significant benefits. KPLC should receive benefits from this through these renegotiations or consider having the notice rescinded.

ii. Wind IPPs

a. Renegotiate the Lake Turkana Wind Power tariff downwards to the KenGen pricing benchmark. Part of the reduction in tariff could be achieved via a refinancing of the plant (given it is now operational and mature) by extending the tenor and reducing the interest coupon.

b. In respect of Lake Turkana, the implementing team will need to review the feasibility report (which was not made available) to determine if there is a material gap between the actual experienced performance and the analysis presented in the report. To the extent there is, then a reduction in contracted capacity (with the aim of reducing the impact of intermittency) should be a negotiation position.

c. KPLC and Lake Turkana to enter into discussions led by the appropriate technical and finance persons with a view to optimising the dispatch procedures and with that KPLC's average annual tariff.

d. Similarly renegotiate the Kipeto Wind tariff (as per Lake Turkana).

iii. Geothermal IPPs (OrPower)

a. Renegotiate the tariff downwards to the KenGen benchmark, including through a refinancing of the capital structure (interest coupon and tenor) taking advantage of the maturity of the plants.

iv. To take this forward, KPLC will need to appoint:

i. Legal counsel with experience in PPAs and possibly termination of PPAs or infrastructure concessions; and

ii. Corporate finance transaction advisor with experience in PPAs or infrastructure.

2. KPLC engineering teams to review the dispatch procedures in the context of the new 1-year and 5-year plan to determine a dispatch procedure that would deliver the lowest average tariff for the financial year, including:

   i. Optimising fuel efficiency – HFOs

   ii. Reducing the impact of intermittency on the grid

   iii. Using meteorological data to have a dispatch plan for the year

3. Improved fuel management:

   i. Closer supervision of the HFO tender and supply processes and acting on anomalies as they occur; and

   ii. Implement centralised procurement (similar to the refined product open tender system).

4. KPLC to review potential storage solutions e.g., pump storage and batteries;

5. KPLC to undertake a review of the natural gas conversion options as described in this Report.

6. Gazette Notice No 2826 of 19th April 2016: KPLC to investigate the circumstances that led to the issuance of the Gazette Notice and to come to a determination if the arrangement should be continued.

12 Concurrent operational reform proposals of KPLC to support the PPA review process

12.2 Background

In undertaking this assignment, the Taskforce recognised that the review of PPAs as a reform strategy of its own would be redundant if not accompanied by comprehensive reforms to the organizational and operational structures of KPLC. This would involve a re-orientation of the organizational structure of KPLC to reflect its commercial status and operate as a typical commercial entity responsible to its shareholders.

A company's business model has been argued to be the most important factor in its success or failure in the marketplace—more so than other factors. State owned utility companies like KPLC are established to offer public goods. Like many other state-owned enterprises, their establishment by governments is for the purpose of pursuing economic, social, and political objectives alongside their commercial objectives. KPLC has indeed been the Government of Kenya's main vehicle driving the universal electricity access programme.

These multiple objectives often pose several governance and management challenges for utility companies such as KPLC. The mixed objectives can lead to an obscuring of accountability, exacerbate principal-agent challenges, and weaken incentives for performance. It is the Taskforce's observation however, that these objectives should not preclude the company from operating a business model that pursues commercial ideals. Like any other commercial enterprise, KPLC's vision ought to be driven towards enhancing customer experience, business expansion, and managing operational costs. The Taskforce received varied submissions on the procurement, governance and other related challenges at KPLC, whose unresolved status would undermine the recommendations herein. These include:

a. Organisational Structure
b. Procurement Reform
c. Management of System/Technical Losses
d. Governance Reforms
e. Financial Restructuring

The Taskforce reviewed the following elements that will contribute to this objective:

12.3 Organizational Structure:

The KPLC Board of Directors has recently proposed and received GoK's approval for a revised organisational structure that seeks to prioritise transformation in its core departments of Commercial Services, Infrastructure Development and Finance. KPLC Management provided the Taskforce a summary of this structure:

a. Commercial Services Department: The department is responsible for developing norms and standards that govern meter reading, billing, commercial loss reduction, disconnection and reconnection and provision of quality assurance of these activities. The department was re-organised to also incorporate energy purchase and development of alternative business for revenue diversification.

b. Infrastructure Development Department: The Infrastructure Development Department is responsible for the management and development of power network infrastructure and standards to allow expansion of the network, effective management of projects, design power systems and enhance electricity connectivity.

c. Finance Department: The reorganisation of Finance included the realignment of the revenue collection function under Revenue Collection and Financial Control Division. Previously, the revenue collection and debt control functions were under Commercial Services. The revenue collection function has been moved to Debt Control and Finance from Commercial Services. The function will be responsible for follow up and collection of company debt for both running and finalised accounts.

d. Risk Assurance Treasury Middle Office: This function is a new introduction to the structure. The mandate of this function will be to provide assurance to the Board of Directors on the company's resources appropriation, fund utilisation and Enterprise Risk Management process.

e. Managing Director and CEO's Office: The Service Delivery Department has been formed under the MD & CEO's office. This role was previously premised under Regional Coordination, a function that has been abolished under the new structure. The mandate of the Service Delivery Department is to ensure compliance with the Customer Service Charter, efficiency in compliance management, enlighten customers on new products and services and conduct market research to attain quality customer service to all customers. The Managing Director's office includes the Field Services Division, Customer Experience Division and Treasury and Investment.

    - Field Services is also a new introduction that is resident in the Managing Director's office and the role was split to have Regional Managers provide oversight and shared resources to the counties and provide Quality Assurance in Network, Infrastructure and Commercial Service Operations. In addition, the County Business Management function is established to oversee the infrastructure development, operations and maintenance and commercial services at the county. It is also the interface with the customers in delivery of excellent customer experience. Previously the County Business Managers reported to Regional Co-ordination.

- Experience: This division was premised in Commercial Services Department but has been moved in the MD's Office. The mandate of the Department will be to ensure compliance with the Customer Service Charter, efficiency in complaint management, enlighten customers on new products and services and conduct market research to attain quality customer service to all customers.

- Treasury and Investment: The Treasury and Investment portfolio is responsible for maintaining stewardship of financial assets including cash and investment management functions of the Company. It is aimed at ensuring the maintenance of corporate liquidity and financial stability as well as development and revision of financial policies for capital structure, working capital, treasury operations and foreign exchange interest rate risk management.

12.3.1 Recommendations:

The Taskforce observed that the proposed changes in the organisational structure will, if implemented fully, enable the company to focus on the customer and improve efficiency that will help deliver KPLC's mandate. The Taskforce however recommends the following additional actions:

a. The establishment of critical offices:

   i. An IPP office, responsible for all aspects of PPAs including procurement, management, monitoring, record keeping, risk management. This office would be the PPP node for KPLC, and should report to the Managing Director's office comprising officers with skills in finance, legal, technical and economics. This would incorporate the contract management team and framework as recommended in Chapter 7.

   ii. The establishment of a meteorological office. In light of KPLC's reliance on renewable energy sources that are dependent on weather patterns, and whose impact on intermittency are high, KPLC should establish capabilities to monitor weather trends and make appropriate dispatch decisions based on weather patterns and climatic changes. Linkages should be made to acquire data and capabilities from the national metrological offices.

iii. Demand Planning and Forecasting division to assure preparation of relevant LCPDP projections, as well as one year and five-year forecasts.

b. While noting the comprehensive restructuring of the organisation's departments that should be fully enforced, KPLC should nevertheless undertake a comprehensive business process review of its operations, focusing on automating critical citizen centric services such as billing, metering and payments, and outsourcing of functions that are not critical to core mandate.

c. Focus on a performance-based framework supported by a balance scorecard system aligned to the strategic plan, to assure performance management objectives at organisational, departmental and individual level.

d. Specific metrics to be established to ensure fastrack outstanding connection applications with a prescribed timeline for completion.

e. Undertake a suitability vetting of staff, assuring itself of the qualifications, competencies and integrity of officers and staff working in the organization. Use of wealth declarations to verify unexplained wealth should be initiated through the Ethics and Anti-Corruption Commission to secure assurance of this value ideal.

f. Introduce a shift system and rationalise staff numbers.

g. To enhance specialised skills within the company, such as structuring and negotiation of international transactions (legal), Financial Modelling, Treasury operations, new innovations, talent management, etc., KPLC to outsource and secure external experts, from both local and international segments.

12.4 Procurement Reform

Observations of the Taskforce buttressed by stakeholder submissions allude to the fact that procurement at KPLC has been riddled with accusations of corruption. Ambitious connection targets resulted in KPLC increasing its outsourced grid construction projects, and unfettered purchases of poles, meters and transformers whose quality was questionable. In 2018, two managing directors of KPLC and 19 officials faced prosecution for procuring low-quality transformers and outsourcing line construction and other related services to non-qualified, unregistered firms. Reports of procurement of substandard metering equipment and transformers have been reported. The company is reported to be holding obsolete and slow-moving stock worth over Kshs. 5 billion, which is likely to go to waste as in some cases procured items are now obsolete.

12.4.1 Recommendations

In spite of the robust reforms that have been undertaken in public procurement regulation, corruption remains a distinct challenge. The Taskforce observed that

KPLC will need to put in place robust procurement reform actions, distinctly customised to the organisation in order to secure its noble objectives. The Taskforce therefore recommends:

a. KPLC Board replace (redeploy, redesignate) all the staff in the entire procurement department and recruit new staff. In the interim, KPLC to outsource procurement to other government agencies with demonstrated experience in procurement of certain high quality engineering equipment and machinery.

b. KPLC Board of Directors to approve a policy on strategic procurement items and their specifications, and as part of the procurement planning approval process, require accompanying justifications for procurements to be undertaken especially for high value goods and services. This would include power purchases through PPAs.

c. KPLC to adopt framework agreement procurements for fast moving consumable goods and equipment. This will not only manage the company's liquidity position, but also prevent the holding of large stocks that could be susceptible to pilferage, and deterioration.

d. Implementation of end-to-end enterprise resource management systems to manage procurement, warehousing and storekeeping functions.

e. KPLC to undertake a forensic audit of the current procurement systems, staff and stocks, and introduce robust contract management systems.

f. KPLC to engage appropriate expertise on management of obsolete assets and undertake maintenance of KPLC's distinct parts for engineering equipment and supplies already procured.

g. KPLC to designate specific goods of a high value/critical to sustainable service (e.g., transformers, sub-station equipment, meters, cables) to be procured from Original Equipment Manufacturers (OEMs) only and not assemblers.

12.5 Management of System Losses

The Taskforce noted that system loss reduction remains a key focus area for KPLC. System losses comprise of the following elements:

a. Technical losses, which occur during transmission and distribution of power from generation sites to the customer; and

b. Commercial losses which are the result of theft of power at the end-user point.

Technical losses accrue as a result of deficiencies in transmission line management, including the lack of readiness for offtake of energy/distribution to KPLC, poor maintenance, theft and vandalism. Commercial losses accrue due to theft of electricity at end user points, particularly large power consumers and SMEs. Illegal connections especially within informal settlements also contribute to commercial losses.

The Taskforce observed that the KPLC continues to operate above the approved system loss benchmark of 15%. The rapid increase of KPLC's customer base from 2.3M to 6.6M (between 2013 and 2019) should have brought a rise in sales of electricity, hence more revenue. However, this rapid rise is accompanied with an increase in *Total System Losses* (18.7% to 23.5%) – i.e., technical and commercial losses.

12.5.1 Recommendations

a. Technical Losses

    i. KETRACO projects should be perfectly aligned to KPLC's priority programmes as proposed in chapter 4. This is to ensure that there are no delays in project implementation and/or redundant lines.

    ii. The rehabilitation of the distribution network by KETRACO/KPLC to be fast-tracked.

    iii. As recommended previously in this report, KPLC transmission lines to be transferred to KETRACO, to ensure that transmission infrastructure and accompanying operating cost elements are streamlined in a coherent manner. Specific recommendations are outlined in chapter 4.

b. Commercial Losses

    i. KPLC to review metering policy for large power consumers and ensure all meters are placed outside customer premises or accessible to KPLC staff.

    ii. Meter transformers around industrial areas and other heavy consumers, and theft prone areas to be metered from the transformers.

    iii. Institute a forensic audit of key commercial consumers to confirm that the power delivered is consistent with the metered power, and that there is no power leakage.

    iv. Focus to be undertaken to crackdown on all illegal connections, arrest and prosecute offenders including staff and contractors. National Police and NYS staff to support KPLC as is currently the case.

12.6 Governance Reforms

The Taskforce recognises that the newly appointed reform Board of Directors of

KPLC has begun implementing far reaching governance related actions geared towards restoring the company to a path of profitability. The Taskforce noted that the Board of Directors has initiated a business turnaround and transformation strategy to expeditiously improve the financial and operational aspects of the business, while balancing social responsibilities to enhance business sustainability. The turnaround strategy is geared towards improving overall business performance by meeting customer expectations, growing sales, ramping up revenue collection to improve cash flow, managing costs, and enhancing system efficiency.

12.6.1 Recommendations

As part of governance reforms, and in keeping with the Taskforce recommendation of having KPLC operate as a commercial corporation, the Taskforce recommends that:

a. The National Treasury to enhance its shareholder responsibility in KPLC, and (i). Set clear expectations on return on equity, (ii) pursue its social and public good mandate in line with sector policy.

b. That the Board of Directors takes responsibility to secure the competitive recruitment and hiring of a Chief Executive Officer of the company, or a management company, and sets the requisite performance targets to guide their function.

c. KPLC's Board of Directors to provide strategic leadership and oversight to the Company including driving a performance culture and holding management to account for results.

12.7 Financial Restructuring

KPLC has over the years been implementing a fast paced and high capital consuming investment program intended to increase connectivity in the country and improve coverage, capacity and quality of the distribution network. This investment activity was financed entirely with KPLC's resources – cash from operations and debt. Although highly beneficial for the country, the result of this effort has been a material deterioration of KPLC's financial position. This has resulted in a substantial debt increase, lack of liquidity, and difficulties in honoring its payment obligations.

12.7.1 Recommendations:

a. KPLC budgets be premised at all times on the current financial position of the Company. The business expenditure be streamlined and reduced to the minimum amount in order to ensure that the Company operates within its means without compromising on service delivery and safety.

b. Government of Kenya moratorium for on-lent loans to KPLC be extended by a further period (say 2 years).

c. KPLC to renegotiate and restructure commercial debts, and where possible convert debt to equity (KENGEN/GoK).

d. KPLC to review RES agreements on the compensation, operations and maintenance and the GoK last mile subsidy costing for CAPEX.

e. KPLC to enhance revenue collection through improving commercial cycle activities, focusing on revenue collection and reduction of the debt age and utilising government support in relation to the payment of Government related institutions electricity pending bills.

f. National Treasury to provide resources to reimburse KPLC under the rural electrification scheme.

g. EPRA to formulate and publish a realistic benchmark on return on equity and cost of funds to guide PPAs going forward.

13 Implementation Framework for the Taskforce Recommendation

The Taskforce has suggested the actions to be taken to make sure that all recommendations are implemented within the proposed timelines as detailed below:

13.2 Previous Taskforces on PPAs in Kenya

No	ISSUE	RECOMMENDATIONS (*Under Chapter 3, 3.3*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
1.	Implementation of recommendations arising from studies on ancillary services, storage, and grid stability	1. Procure Consultants and implement the findings and recommendations of the ancillary service and grid tied battery studies. 2. Undertake a system study to analyze the system needs in stabilizing the power supply to western Kenya for possible retirement of the Gas Turbines.	EPRA	By 30th October 2021	EPRA to prepare a tender document.
2.	Appointment of the System Operator	EPRA to implement the recommendations of the Power Market study and Operation and Dispatch Guidelines and designate a system operator. In the meantime, KETRACO to suspend their undertaking on infrastructure of	EPRA	30th November 2021	Gazette notice by Director General EPRA Letter by EPRA to KETRACO

No	ISSUE	RECOMMENDATIONS (*Under Chapter 3, 3.3*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		ISO and KPLC to continue being the System Operator and running the National Control Centre. KPLC management to produce monthly reports to the Board and to EPRA that show the power purchase costs incurred under the merit order.			
3.	The recommendations of the Task Force	a. Use of the Cabinet Sub-Committee on KPLC, to take responsibility for assuring policy support in the implementation of the Taskforce recommendations. The Taskforce Report will be approved by Cabinet with necessary action to be taken by the relevant agencies; b. Establishment of an Implementation Committee, reporting to the Cabinet Sub-Committee on KPLC. The Committee will comprise of senior officials from the Office of	Cabinet Sub-Committee. Head of Public Service PDU Ministry of Public Service National Treasury.	By 30th October 2021	Cabinet Directive A letter to be issued by the Head of Public Service to the appointed public officers of the implementation committee. Implementation Plan Budget FY22/23 Performance Contract Quarterly Reports

No	ISSUE	RECOMMENDATIONS (*Under Chapter 3, 3.3*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		the President (chairperson), National Treasury, Ministry of Energy, Attorney General, and relevant implementing agencies namely; EPRA, KPLC, KETRACO, REREC, KENGEN, and GDC and for a period of 1 year or as may be extended; c. Creation of an Implementation Plan and, accompanying draft implementation instruments to fastrack actions by respective actors; d. National Treasury to ensure that adequate budgets and other resources to implement the key recommendations are factored into the annual budgets of respective agencies; e. Ministry responsible for Public Service to ensure that the			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 3, 3.3*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		recommendations are incorporated as part of respective agency performance contract targets. f. Presidential Delivery Unit (PDU) to monitor progress and prepare quarterly implementation reports to the National Development Implementation and Communication Cabinet Committee (NDICCC).			
4.	Transmission infrastructure and tariff	1. The Authority should unbundle the transmission and distribution tariff for transparency in the supply of electricity and ensure cost recovery in line with the principle of prudently incurred costs. 2. Consider implementing PPP in transmission infrastructure development to reduce reliance on the already burdened	EPRA KETRACO/PPP Unit	31st October 2021	Legal notice Proposal to PPP unit

No	ISSUE	RECOMMENDATIONS (*Under Chapter 3, 3.3*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		exchequer. The implementation of the PPP transmission lines should be phased over time such that there is minimal impact to the end user tariff.			

13.3 Situational analysis of the relevant energy subsector policy issues

No	ISSUE	RECOMMENDATIONS (*Under Chapter 4, 4.9*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
1.	GSMs	Adoption of a standard letter and amendment to include additional requirements for issuance of GSM.	Cabinet secretary for National Treasury and the Attorney General	30th November 2021	GSM Policy, marked up version [see annex] GoK Letter of Support, draft of the proposed standard LoS attached [See Schedule 3, Annexure 5]
2.	FiT Policy	Amended to include only Small renewable (Biomass, Biogas & Small Hydros) capacities of up to 20MW and a reconstituted FiT Policy Committee.	Cabinet Secretary for Energy	30th November 2021	FiT Policy, marked up version attached [See Schedule 3, annexure 3]
3.	REAP	All new capacity of variable renewable energy to be procured through Renewable Energy Auctions, except for small capacity projects of less than 20MW from small hydro, biomass, and biogas.	Cabinet Secretary for Energy	30th November 2021	REAP, marked up version attached [See See Schedule 3, annexure 2]
4.	Local Currency	The denomination of PPAs in Kenya shillings targeting for power plants for all future PPAs.	Cabinet Secretary for Energy,	30th November 2021	National Energy Policy
5.	Power Imports	Determine imports based on the LCPDP and in the future get into power exchange agreements or markets in place of bilateral	Cabinet Secretary for Energy,	30th November 2021	LCPDP, marked up version attached [See AFFECT Schedule 3, annexure 1]

No	ISSUE	RECOMMENDATIONS (*Under Chapter 4, 4.9*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		agreements.			
6.	National Energy Policy, 2018	Cabinet secretary for Energy to publish the National Energy Policy.	Cabinet Secretary for Energy	30th November 2021	National Energy Policy
7.	Captive Power	c) The captive power owners need to develop and enhance their demand to consume the power. d) All captive power approvals/licenses should be from renewable energy technologies only.	Cabinet Secretary for Energy	By 31st October 2021	Captive Power Policy
8.	LCPDP	e) Refer to recommendation (1) in section 13.3.			

13.4 Institutional framework of the electricity subsector

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
1.	KPLC is a commercial enterprise with obligations to all stakeholders including; customers, investors, lenders, employees, suppliers and GoK.	1. KPLC should be the lead utility in the formulation and development of the LCPDP and the procurement of PPAs. 2. LCPDP development to include all key stakeholders. 3. The LCPDP to include: i. KPLC's demand forecast demand forecast, generation and transmission plans; ii. An implementation matrix including actors, tentative budgets, timelines, and milestone events per project. iii. The Project Development Rights Criteria outlining the sequencing of projects. iv. Sanctions/penalties and mitigation plans for non-performance.	Cabinet sub-Committee.	15th October 2021	A letter to be issued by the Head of Public Service to effect these recommendations has been produced. Amended LCPDP

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		4. The Boards of Directors of all participating public sector agencies to formally approve the LCPDP. The LCPDP to be endorsed by the Cabinet Sub-Committee on KPLC and/or its successor committee. 5. There shall be no projects implemented outside the LCPDP. Any variations to be approved by the Cabinet Sub-Committee on KPLC. 6. The National Treasury shall only approve relevant agency capital budgets and projects as per the LCPDP priorities. Each public sector agency shall be responsible for the procurement of agreements under their purview. 7. KPLC shall be responsible for the procurement of all projects and respective PPAs submitted through any of the proposed mechanism in this Report. 8. In monitoring the implementation			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		of the LCPDP and associated projects the following to be adopted: i. The LCPDP Technical and Oversight Committees to meet quarterly. ii. The MoE led sector meetings to be expanded to include: -The Cabinet Secretary (or his alternate) as Chairperson; -The Board Chairpersons and CEOs of KPLC, KETRACO, KenGen, GDC, EPRA, REREC; -The Principal Secretary, National Treasury or his alternate; -The Solicitor General, or his alternate; 9. There shall be no indicative tariffs, or CODs variations issued by EPRA. This should be done under the LCPDP oversight mechanism 10. The construction of projects should not begin before PPAs are negotiated and executed. Consequently, KPLC to issue a			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		notice to proceed for all individual projects (public and private), prior to procurement of sub-contractor arrangements.			
2.	The energy sector needs to be properly coordinated to eliminate overlaps and the EPRA to be more effective in its role.	1. The MoE's role should be focused on national energy planning policy setting and allow for independence of the sector. 2. Donor funds for project implementation should be disbursed to the relevant implementing agency and not be administered by MoE. 3. EPRA should independently regulate the sector without directions from MoE or other entities. 4. EPRA should balance the interests of the generators, consumers and utility. 5. EPRA to undertake an immediate review of all	CS - Ministry of Energy EPRA EPRA EPRA	1st Nov 2021	CS MoE to promulgate the various changes and advice all parties accordingly.

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		prevailing generation tariffs for the different technologies benchmarked against global tariffs and undertake regular reviews as provided for under the Energy Act.			
3.	The unbundling of the energy sector resulted to formation of several entities. There appear to be significant overlap of mandates amongst these entities and for some, it is unclear if their scope warrants a separate entity.	1. REREC should focus on its core mandate of Rural Electrification Programme particularly in areas considered not commercially viable for KPLC.	CS - Ministry of Energy	By 1st Nov 2021	CS MoE letter to REREC
		2. To mitigate costs and assure quality, REREC should contract out the implementation of rural electricity programme to KPLC, which has a better capacity.	REREC/KPLC	By 1st Nov 2021	
		3. To avoid REREC's overexpansion on its mandate, and duplicating management costs, REREC should not be involved in power generation projects for sale to KPLC, but should focus on rural	REREC/KENGEN	By 1st Nov 2021	

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		electrification through mini grid generation functions. The operation and maintenance function for the Garissa solar project to be taken over to KenGen which has the technical capacity.			
		4. The National Treasury to streamline the funding and disbursements of all financial arrangements surrounding rural electrification to ensure that REREC is the sole implementer of this programme and that funds allocated for this programme are allocated and disbursed to REREC who should be solely accountable for the utilization of these funds.	National Treasury		FY2022/23 Budget
		5. The administrator role for the Rural Electrification Scheme to immediately be transferred to REREC Chief Executive Officer to manage going forward, so as to synchronise and optimize the	CS National Treasury		CS National Treasury appointment letter

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		rural electrification objectives 6. NuPEA to be abolished and the mandate transferred to a Department within MoE. The capacity building mandate of the sector to be handled by the respective sector entities. 7. The roles of GDC and KenGen in harnessing of the geothermal resource should be aligned to obtain synergy. The resulting tariff for IPPs in geothermal or other technology should always be bench marked with those of KenGen. KenGen should have first right of refusal for GDC tenders.	CS MoE GDC KenGen EPRA	1st July 2022 1st November 2021	Energy Act Amendment Bill CS MoE letter to the agencies EPRA policy
4.	The generation of Power by KenGen and sale to KPLC without issuance of generation licenses and PPAs approval.	-All the KenGen projects to be captured under the LCPDP. There should be no generation of power or power purchases without respective generation license and PPA.	KenGen, LCPDP Oversight Committee EPRA	31st October 2021	Amended LCPDP EPRA letter to KENGEN
5.	The designation of Independent System	1. EPRA shall undertake legal, technical and financial analysis	EPRA KETRACO	By 31 December	Gazette Notice

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
	Operator (ISO).	prior to designating the ISO upon completion of the relevant Study. 2. KETRACO to stop commencement of any infrastructural works related to ISO and KPLC to continue being the System Operator and running the National Control Centre. KPLC management to produce monthly reports to the board and to LCPDP that show the power purchase costs incurred under the merit order.		2021 15th October 2021	EPRA letter to KETRACO (Immediately)
6.	The ownership, operation and maintenance of KPLC and KETRACO transmission lines.	-The operation and maintenance aspect of KPLC transmission system to be transferred to KETRACO in the short term through an operations and maintenance contract subject to SLA. In the medium/long term transmission system to be transferred to KETRACO upon valuation.	KPLC KETRACO National Treasury	Short term, by 31st December 2021 Long term, by 1st July 2022	O&M contract Vesting Order
7.	The Geothermal PPAs between KPLC and IPPs issued prior to establishment of the commerciality of the geothermal resources.	1. The award of PPAs to IPPs utilizing geothermal resource should be after the assessment of the commerciality of the resource. 2. Issuance of geothermal licensing to prospectors should not be	KPLC	15th October 2021	KPLC Board Resolution.

No	ISSUE	RECOMMENDATIONS (*Under Chapter 5, 5.12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		accompanied by a guarantee of issuance of a PPA. 3. The KPLC to negotiate PPAs with IPPs after confirmation of the commerciality of steam.			
8.	The key terms and conditions of Project Implementation and Steam Supply Agreement (PISSA) are negotiated outside the PPA framework.	1. The terms and conditions of PISSA between GDC and IPPs should be incorporated in PPAs. The existing PISSA should be reviewed to have the steam tariff incorporated. 2. There should be no Steam Supply Agreement between KPLC and GDC since that tariff should be factored in the overall IPP tariff. GDC sells steam to IPP and not KPLC.	KPLC GDC	15th October 2021.	Revised PISSA
9.	The composition of FiT Committee which approves EoIs for FiT Projects include EPRA as a member.	The FiT Committee to be abolished and KPLC to take over responsibility for procurement of projects under the FIT as guided by the LCPDP. The LCPDP process to be modified accordingly. KPLC Board to approve FIT EoIs as they confer ownership of the project.	CS MoE KPLC	15th October 2021	Revised FIT policy

13.5 Review of contractual structure of Power Purchase Agreements and associated agreements

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
1.	Take or Pay	KPLC to maintain the Take-or-Pay model but ensure that there is a balance between demand and supply allowing for a reasonable energy reserve which can be achieved with improved demand and supply forecasting tools and capabilities. Renegotiation of the current PPAs where practical, to Pay-when-Taken upon evolution to a spot market. In the event that the one year and 5-year demand forecast indicates the need for thermal power capacity in the short term, KPLC should explore the use of pay when taken provisions for expired PPAs such as Tsavo Power. However, full assessment should be made of the quality and viability of such old plants	KPLC	31st January 2021 Ongoing (future PPAs)	Reviewed clause in Standard PPA template
2.	Need to review Change in Law/Tax clauses	-Revise to limit it to change in financial position of seller.	KPLC	15th October 2021	Reviewed clause in Standard PPA template

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		-Cap the potential liability that may accrue to indemnify the Seller.			
3.	Assignment and Novation	-Revise to cap it to five (5) years after Commercial Operation Date. -Disclose Consideration. -Assignments to require fresh due diligence and approvals. -Include a novation clause.	KPLC	15th October 2021	Reviewed clause in Standard PPA template
4.	Minimum environmental protections	-Harmonize all PPAs to provide minimum environmental protection clauses. -Valuation of land and compensation should include value of ecosystem. -PPA to provide formula and process of sharing environmental attributes. -ESIA/EIA provide for appropriate compensation. -Developer bear risk of acquisition of land. -National Treasury to FastTrack development of Carbon Credit Policy.	KPLC	15th October 2021	Reviewed clause in Standard PPA template
5.	Termination Clause	- Right to terminate at convenience. - Termination costs to be payable in local currency for KPLC default.	KPLC	15th October 2021	Reviewed clause in Standard PPA template

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		Two (2) Maximum extension for a total period of 12 months after which PPA terminates. - Failure to submit Audited Financial Model to KPLC and EPRA and Audited Financial Statements seven (7) days after approval by financiers is a ground for termination.			
6.	Force Majeure Clause	- The event or circumstance giving rise to force majeure : ✓ must have *"a material and adverse impact"* on a party. ✓ the events limited to those listed/enumerated therein. ✓ Delete '*change in* - The definition of a FM Event: ✓ "*is not a consequence of the fault or negligence of the party affected*". ✓ Exclude *riots and civil commotion instigated by a party* as events or circumstances giving rise to force majeure. ✓ Add *"pandemics, outbreaks of infectious disease or any other*	KPLC	15th October 2021	Reviewed clause in Standard PPA template

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		public health crisis necessitating quarantine or other employee restrictions". - Proposed increase of the FM duration from 6 months to 1 year, after which a party may be at liberty to terminate the Agreement.			
7.	Dispute Resolution Clause	-Adoption of a local dispute resolution mechanism with the Rules of the Nairobi Centre for International Arbitration as the first option and the Rules of the London Court of International Arbitration as a second option, and in either case, the seat and location be Nairobi. -The Arbitration and Expert dispute resolution clause to be maintained in the PPAs.	KPLC	15th October 2021	Reviewed clause in Standard PPA template
8.	Default Clause	- The deletion of payment as a Default deemed capable of remedy within 30 days. - On Seller's Default – ✓ To introduce a new clause being failure to provide Audited Financial Models to both KPLC and EPRA within 7 days of	KPLC	15th October 2021	Reviewed clause in Standard PPA template

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		approval by the Seller's Financiers/Lenders. ✓ Failure by the IPP to provide Audited Financial Models to both EPRA and KPLC or Audited Financial Accounts to KPLC within one month after completion of the audits be considered as an event of default. ✓ On the incorrect statement, representation clause, amend to include that the statement, representation etc. may have been incorrect when made or deemed to have been made. - For renewable energy projects (wind and solar) variation of forecasted output 20% below the given threshold shall amount to an event of default and attract penalties including reduction of Tariff. - On the part of KPLC, align provisions on payment with proposals of extension to 120 days			

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		and in instalments.			
9.	Termination Clause	- Introduce a new clause on Termination by either Party for convenience. - Termination payments should be in local currency. - Maximum number of extensions of Target Effective Date of the PPAs at 2 for a total period of no more than 12 months after which the PPA terminates automatically. - Harmonise payment process of the Transfer or Compensation amounts as 120 days in receding instalments by KPLC to the Seller and 60 days by the Seller to KPLC. - Failure of IPPs to submit the Audited Financial Model to KPLC and EPRA no later than 7 days upon the Model's approval by the Seller's Financiers/ Lenders, results in an event of default that can lead to	KPLC	15th October 2021	Reviewed clause in Standard PPA template

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		termination of PPA.			
10.	Risk Allocation	There is need to review the existing Risk Allocation Matrix to be more favourable to GoK.	KPLC	15th October 2021	Revised Risk Allocation Matrix
11.	Review GSMs (Letter of Support) and make recommendations	-Process of issuance GSMs does not comply with the GSM Policy. - GoK ought to establish from the outset, a clear definition of strategic projects. - Adoption of standard template of Letter of Support for energy projects. - Ensure that GoK's financial risks and contingent liabilities under the Letters of Support have been sufficiently addressed and are manageable - Include additional requirements for issuance of GSM, under minimum documentary requirements provided in paragraphs 3.1 and 4.5 [GSM Policy Statement Five] of the GSM Policy.	National Treasury	30th November 2021	- Standard Template Letter of Support - Proposed definition of Strategic Projects to be included in GSM Policy. - Additional minimum documentary requirements for issuance of a GSM to be included in GSM Policy.
12.	Review current standard PPAs	Review PPA in line with proposed amended clauses.	KPLC	15th October 2021	Standard PPA template
13.	Comprehensive legal, technical and financial due diligence is not undertaken on IPP	Need to assess technical, financial and legal capacity of IPPs in undertaking any project and continuously during the life of the project.	KPLC	15th October 2021	Due Diligence Framework

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
14.	Energy Act, 2019 as drafted curtails the operation of KPLC	- Develop Grid-Defection Regulations to provide for switches by consumers to other service providers or to own-generation. The Grid-Defection Regulations to also provide for the handling and re-allocation of risks and obligations when such defection occurs. - Amend section 76 to include KPLC to the membership of the RERAC given that it signs the PPAs, bears the Demand and System Operation Risks in the PPAs. - Develop separate Regulations for procurement of power with a unified framework for it under the Public Private Partnerships Act, 2013. - The Ministry of Energy should	MOE	31st December 2021	Proposed amendments to the Energy Act, 2019

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		develop a policy and regulations to guide electricity and gas reticulation by the Counties. - Amend section 76 to disband NuPEA and make it a department within the Ministry of Energy.			
15.	Acquisition of project land	- The IPPs through their representatives should, pursuant to Section 24 of the Land Control Act and Regulation 2A of the Land Control Regulations, make an application to the President for exemptions from the application of the Land Control Act. - Expedite review of the Land Control Act Regulations.	IPPs	15th October 2021	S.24 Land Control Act & Regulation 2A Land Control Regulations
16.	Over securitization of IPPs	- Government Support Measures should only be issued in exceptional circumstances for strategic projects of national interest, after Cabinet approval. - The National Treasury should assess and recommend GSMs that have the	National Treasury	15th October 2021	GSM Policy, 2018

No	ISSUE	RECOMMENDATION (Under Chapter 7, 7.16)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		lowest financial risk exposure to Government. - IPPs should only benefit from one GMS issued in accordance with the GSM Policy, 2018.			

13.6 The Power Generation Mix and Dispatch Procedures

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
1.	Organisational Structure	a. KPLC to undertake an organizational restructuring to strengthen and empower the following Departments/Sections among others: ○ Commercial (with the capacity to forecast demand with reference to the issues discussed in this chapter under *'KPLC's Demand-Supply Forecasts;* ○ Generation Planning & Contracting; ○ Finance; and ○ Legal (including contract	KPLC Board	31st December 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		management and compliance monitoring). **b.** Each of these Departments/Section to report to the KPLC Board at each meeting of the Board.			
2.	1-year and 5-year forecast of demand and generation	**a.** KPLC to produce a 1-year and 5-year forecast of demand and generation immediately including bringing in external expertise to assist the team. The forecast should: (i) Include information on unmet requests for power connections; (ii) Be conducted annually; (iii) Make reference to the ideal power generation mix and ideal tariff, in the context of the resources available to the country; (iv) Make specific reference to the extent intermittent sources (wind and solar) can be absorbed onto the grid, taking cognisance that with hydro and geothermal, Kenya already has a high proportion of renewables	KPLC Board	15th October 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		on the grid with high availability and reliability. Additionally, biomass (e.g., biogas, bagasse, wood, agricultural waste and municipal waste) should have lower levels of intermittency; (v) Make specific reference to the need for the existing HFO thermal stations, including their capability to provide base load power at an appropriate tariff, if converted to natural gas. (vi) In respect of Tsavo, the opportunity to retain the plant (whose PPA has expired) at improved terms (e.g., significantly lower tariff based on a cost-plus model and one-year or shorter tenors.			
		a. Subject to the 1-yr and 5-yr power forecast and guided by the least cost criteria: (i) Negotiate a 12–24-month delay for Commercial Operation Dates for PPAs where construction will start imminently and CPs have	KPLC Board	31st December 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		been met; (ii) Negotiate new Commercial Operation Dates for PPAs in default, if the capacity is required, otherwise terminate the engagement; and (iii) Refer unsigned PPAs to the post Taskforce regime.			
3.	Meteorological studies	**a.** KPLC to conduct studies on the meteorological conditions of existing large wind and solar sites to determine the reliability of these plants during the year	KPLC	31st December 2021	KPLC Board Resolution
4.	IPPs with high intermittency	a. KPLC to require future IPPs with high intermittency (wind, solar, mini hydro) to take financial risk for predicting their daily/weekly/monthly dispatch of power. The penalty for under-producing of power would be to compensate the grid at the cost of the thermal plants or the highest peaking plant on the grid as an alternative to the under-generation compared to the forecast. Alternatively, the projects could themselves take on the cost of providing energy storage and	KPLC Board	31st December 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		presumably adjust the tariff accordingly. Production beyond the forecast would be on a Pay-When-Taken (merchant) basis.			
		b. KPLC to require in future PPAs, that after a reasonable period (2-3 years) the commercial terms of PPAs with high intermittency (e.g., wind, solar and mini hydro) can be renegotiated downwards to take into account any material underperformance of the plant compared to the feasibility study.	KPLC Board	31st December 2021	KPLC Board Resolution
		c. As a solution to the intermittency of existing wind and solar projects and the excess power at night, KPLC to undertake a comprehensive review of energy storage options (including batteries and pump storage of existing and new hydro), including but not limited to: (i) Technical fit for the Kenya grid and KPLC; (ii) Actual capex and operational	KPLC Board	31st December 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		costs, even if they are to be incurred by a third-party under a PPA; and (iii) Appropriate financing methods e.g., via PPA or via direct procurement and debt financing.			
5.	Switch to natural gas	**a.** KPLC to undertake its own review of the switch to natural gas, which based on stakeholder engagements, could result in fuel cost savings exceeding 40%. This review should include, but not be limited to: (i) Cost of conversion of the existing plants; (ii) Sources and costs of natural gas; (iii) Import logistics; and (iv) In-country logistics: ▪ Based on this, coherent negotiations with the IPPs can be held on conversion and the appropriate economies they can achieve; and (v) Align the activities of KPLC and KETRACO with KPLC being part of the approval process of capex	KPLC Board	15th October 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 8, 8.4)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		and maintenance programmes of KETRACO, in line with the ongoing initiatives to create electricity regulatory accounts regulations that create an asset register for each utility.			

13.7 Analysis of PPAs for committed and pipeline projects

No	ISSUE	RECOMMENDATION (Under Chapter 9, 9.13)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
1.	**1-year and 5-year forecast**	KPLC need to formulate a 1-year and 5-year electricity demand and generation forecast.	KPLC Board	15th November 2021	KPLC Board Resolution
2.	Action on PPAs where construction is complete but PPA has lapsed or have had an event of PPA default.	Subject to the 1-yr and 5-yr power forecast: i. Negotiate new Commercial Operation Dates if the capacity is required; ii. Terminate if the capacity is not required;	KPLC Board	31th December 2021	KPLC Board Resolution
3.	Action on plants with effective PPAs but	Subject to the 1-yr and 5-yr power forecast:	KPLC Board	15th Novemb	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 9, 9.13)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
	construction yet to commence.	▪ Negotiate a 12- to 24-month delay for Commercial Operation Dates (CODs), for plants where construction will start imminently and CPs have been met.		er 2021	
4.	Action on plants with signed PPAs without CPs effective.	Subject to the 1-year and 5-year forecast: ▪ egotiate a 12-24-month delay of commercial operation dates, subject to the 1-year and 5-year forecast.		31^{st} December 2021	
5.	Action on plants under receivership.	Subject to the 1-yr and 5-yr power forecast: Terminate the PPA pursuant to the bankruptcy provision of the PPA.	KPLC Board	31 December 2021	KPLC Board Resolution
6.	Action on plants with unsigned PPAs.	Refer unsigned PPAs to the post Taskforce regime of revised FiT and reverse auctions.	KPLC Board	15^{th} October 2021	(i) Revised Fit Policy (ii) Reverse Auctions Policy

13.8 Financial implications of PPAs

No	ISSUE	RECOMMENDATION (Under Chapter 10, 10.8)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
1.	Forensic audit of on the Power Purchase Agreements (PPAs)	a. KPLC to conduct a forensic audit of on the Power Purchase Agreements (PPAs) and Independent Power Producers (IPPs) to cover the following, *noting that the Taskforce was not able to receive this information comprehensively from KPLC*: (i) The procurement processes that were used; (ii) Identification of beneficial owners; (iii) Selection criteria used to identify the eventual operator; (iv) An analysis of IPPs' audited accounts for at least the last 5 years to ascertain whether key parameters are in line with the audited financial models in the PPAs and the PPA; and (v) Technical audit to ascertain the capacity discharged by the various plants' vs respective PPAs.	KPLC Board	31st October 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 10, 10.8)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
2.	Improvements in HFO management	a. KPLC to conduct a forensic audit of HFO purchases over the preceding five years. b. KPLC to review the dispatch orders to consider the benefits of running the HFO thermal plants on a rotational basis for longer periods to take advantage of fuel efficiency during longer runs. c. KPLC to institute a joint tender for fuel purchases, modelled on the refined product Open Tendering System (OTS).	KPLC Board	31st October 2021	KPLC Board Resolution
3.	KenGen's prices as the pricing benchmark for FiT and Reverse Auction	a. KPLC to use KenGen's prices as the pricing benchmark for FiT and Reverse Auction, with very clear justification required to exceed the KenGen prices. (i) Similarly, KenGen to be driven to continually seek efficiencies so that tariffs can be lowered in the future.	KPLC Board / Treasury / MoE /	15th October 2021	(i) Revised Fit Policy (ii) Reverse Auctions Policy
4.	Action on Akiira and Africa Geothermal	a. In respect of Akiira Geothermal Limited and Africa Geothermal International (Kenya) Limited: i. Renegotiate in respect of the	KPLC Board	30th November 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 10, 10.8)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		tariff as it is not prudent to offer a Capacity Charge, before KPLC knows the actual potential of their resources; ii. Considering the length of period of execution, there should be mechanisms to adjust tariffs to take advantage of (a) improving tehnologies; and (ii) better than expected results of the exploration phase; iii. EPRA to inspect progress being made by the licencees and to the extent to which they are meeting milestones and action taken if they are not.	EPRA		
5.	KPLC Financial Modelling and structuring.	7. KPLC to develop financial modelling capacity to be able to analyse (a) individual PPAs; and (b) the impact of individual PPAs on KPLC income statement, balance sheet and cashflows. This capacity would include depth of understanding of capex costs and operations and maintenance costs,	KPLC Board	15th October 2021	KPLC Board Resolution

No	ISSUE	RECOMMENDATION (Under Chapter 10, 10.8)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		across technologies.			

13.9 Proposed action on operational PPAs

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
1.	Termination and/or Renegotiation	a. KPLC to establish a team (that will include senior members from the National Treasury & Attorney General): 1. HFO thermal IPPs a. Renegotiate or terminate with reference to the material breaches identified in Chapter 9), within a timeline of 4 months. Applies to Athi River Gulf, Thika Melec and Triumph. b. Conduct similar analysis (for termination or renegotiation for Rabai and Iberafrica, as the	KPLC CEO National Treasury Attorney General	30th November 2021	KPLC Board Resolution CS National Treasury

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		appropriate information was not made available to the Taskforce. If the situation is similar, pursue termination or renegotiation. c. The Gazette Notice provided the power plants with significant benefits. KPLC should receive benefit from this through these renegotiations or consider having the notice rescinded. 2. Wind IPPs i. Renegotiate the Lake Turkana Wind Power tariff downwards to the KenGen pricing benchmark. Part of the reduction in tariff could be achieved via a refinancing of the plant		30th October 2021	

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		(given it is now operational and mature) by extending tenor and reducing interest coupon. ii. In respect of Lake Turkana, the implementing team will need to review the feasibility report (which was not made available) to determine if there is a material gap between the actual experienced performance and the analysis presented in the report. To the extent there is, then a reduction in contracted capacity (with the aim of reducing the impact of intermittency) should be a negotiation position.			

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		iii. Similarly renegotiate the Kipeto Wind tariff (as per Lake Turkana). 3. Geothermal IPPs (OrPower) i. Renegotiate the tariff downwards to the KenGen benchmark, including through a refinancing of the capital structure (interest coupon and tenor) taking advantage of the plants' maturity. 4. To take this forward, KPLC will need to appoint; i. Legal counsel with experience in PPAs and possibly termination of PPAs or infrastructure concessions; and ii. Corporate finance transaction			

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		advisor with experience in PPAs or infrastructure. b. KPLC engineering teams to review the dispatch procedures (in the context of the new 1-year and 5-year plan to determine a dispatch procedure that would deliver the lowest average tariff for the financial year, including; i. Optimising fuel efficiency – HFOs; ii. Reducing the impact of intermittency on the grid; and iii. Using meteorological data to have a dispatch plan for the year. c. Improved fuel management; i. Closer supervision of the HFO tender and supply processes and acting on			

No	ISSUE	RECOMMENDATION (Under Chapter 11, 11.11)	WHO SHOULD TAKE ACTION	TIME-LINE	INSTRUMENT REQUIRED TO EFFECT THE RECOMMENDATION
		anomalies as the occur; and ii. Implement centralised procurement (similar to the refined product open tender system). d. KPLC to review potential storage solutions e.g., pumped storage and batteries; e. KPLC to undertake a review conversion of HFO plants to LNG.			

13.10 Concurrent operational reform proposals of KPLC to support the PPA review process

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
1.	KPLC's organizational structure to reflect its commercial entity status.	1. Establishment of an IPP office, responsible for all aspects of PPAs including procurement, management, monitoring, record	KPLC Board	By 30th November 2021	Human Resource Instruments (Staff establishment, HR Policy, Organizational Structure).

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		keeping, risk management. This office would be the PPP node for KPLC, and should report to the Managing Director's office comprising officers with skills in finance, legal, technical and economics. This would incorporate the contract management team and framework. 2. The establishment of a meteorological office. In light of KPLC's reliance on renewable energy sources that are dependent on weather patterns, and whose impact on intermittency are high, KPLC should establish capabilities to monitor weather trends and make appropriate dispatch decisions based on weather patterns and climatic changes; Linkages should be made to acquire data and capabilities from the national metrological offices. 3. Establishment of Demand Planning and Forecasting Division to assure			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		preparation of relevant LCPDP projections, as well as one year and five-year forecasts. 4. KPLC to undertake a comprehensive business process review of its operations, focusing on automating critical citizen centric services such as billing, metering and payments, and outsourcing of functions that are not critical to core mandate. 5. Focus on a performance-based framework supported by a balance scorecard system aligned to the strategic plan, to assure performance management objectives at organizational, departmental and individual level. - Specific metrics to be established to ensure fastrack ffast-track outstanding connection applications with a prescribed timeline for			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		completion;			
2.	KPLC to entrench values of integrity, transparency and accountability in operations, staffing and business processes.	KPLC to: 1. Undertake a suitability vetting of staff, assuring itself of the qualifications, competences and integrity of officers and staff working in the organization. Use of wealth declarations to verify unexplained wealth should be initiated through the Ethics and Anti-Corruption Commission to secure assurance of this value ideal. 2. Introduce a shift system and rationalize staff numbers. 3. To enhance specialized skills within the Company, such as structuring and negotiation of international transactions (legal), Financial Modelling, Treasury operations, new innovations, talent management, etc., KPLC to outsource and secure external experts, from both local and	KPLC Board Chief Executive Officer	30th November 2021	Wealth Declaration Forms Staff Performance Appraisal System (SPAS)

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		international segments.			
3.	Procurement Reform	1. KPLC Board to replace (redeploy, redesignate, redundancy) all the staff in the entire procurement department and recruit new staff. In the interim, KPLC to outsource procurement to other government agencies with demonstrated experience in procurement of certain high quality engineering equipment and machinery. 2. KPLC Board of Directors to approve a policy on strategic procurement items and their specifications, and as part of the procurement planning approval process, require accompanying justifications for procurements to be undertaken especially for high value goods and services. 3. KPLC to adopt framework agreement procurements for fast	KPLC Board of Directors Chief Executive Officer	30th October 2021	Human Resource Instruments. Board Procurement Policy

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		moving consumable goods and equipment. This will not only manage the company's liquidity position, but also prevent the holding of large stocks that could be susceptible to pilferage, and deterioration. 4. Implementation of end-to-end enterprise resource management systems to manage procurement, warehousing and storekeeping functions. 5. KPLC to undertake a forensic audit of the current procurement systems, staff and stocks, and introduce robust contract management systems. 6. KPLC to engage the Numerical Machining Corporation on management of obsolete assets and the role to manufacture and undertake maintenance of KPLC's distinct parts for engineering equipment and supplies already			

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		procured. 7. KPLC to designate specific goods of a high value/critical to sustainable service (e.g., transformers, sub-station equipment, meters, cables) to be procured from manufactures only (not assemblers).			
4.	Management of System Losses	Technical Losses 1. KETRACO projects to be perfectly aligned to KPLC's priority programmes. This is to ensure that there no delays in project implementation and/or redundant lines. 2. The rehabilitation of the distribution network by KETRACO/KPLC to be fast-tracked. 3. As recommended previously in this report, KPLC transmission lines to be transferred to KETRACO, to ensure that transmission infrastructure and accompanying operating cost elements are	KETRACO KPLC Board Chief Executive Officer National Treasury	As per Chapter 8	KETRACO and KPLC Boards Resolution.

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		streamlined in a coherent manner. Commercial Losses 4. KPLC to rreview metering policy for large power consumers and ensure all meters are placed outside customer premises or accessible to KPLC staff. 5. Meter transformers around industrial areas and other heavy consumers, and theft prone areas to be metered from the transformers. 6. Focus to be undertaken to crackdown on all illegal connections, arrest and prosecute offenders including staff and contractors. National Police and NYS staff to support KPLC as is currently the case.	KPLC Board National Police Service/NYS		CS Interior directive
5.	Governance Reforms	1. The National Treasury to enhance its shareholder responsibility in KPLC, and set clear expectations on return on equity.	National Treasury Board of KPLC	30th October 2021	N/A Employment Contract

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		2. The Board of Directors takes responsibility to secure the competitive recruitment and hiring of a Chief Executive Officer of the company or a management company and sets the requisite performance targets to guide their function. 3. KPLC's Board to provide strategic leadership and oversight to the Company including driving a performance culture and holding management to account for results.			HR Instruments
6.	Financial Restructuring	1. KPLC budgets be premised at all times on the current financial position of the Company. The business expenditure be streamlined and reduced to the minimum amount in order to ensure that the Company operates within its means without compromising on service delivery and safety. 2. National Treasury moratorium for on-lent loans to KPLC be extended	National Treasury Board of Directors Chief Executive Officer	30th November 2021	Board Policy Paper National Treasury letter

No	ISSUE	RECOMMENDATIONS (*Under Chapter 12*)	WHO SHOULD TAKE ACTION	TIMELINE	INSTRUMENTS REQUIRED TO EFFECT THE RECOMMENDATION
		by a further period (2 years). 3. KPLC to renegotiate and restructure commercial debts, and where possible convert debt to equity (KENGEN/GoK). 4. KPLC to enhance revenue collection through improving commercial cycle activities, focusing on revenue collection and reduction of the debt age and utilising government support in relation to the payment of Government related institutions electricity pending bills. 5. National Treasury to provide resources to reimburse KPLC under the rural electrification scheme.			KPLC Performance Contract Y2022/23 Budget
7.		EPRA to formulate and publish a realistic benchmark on return on equity and cost of funds to guide PPAs going forward.	EPRA	31st December 2021	Gazette Notice