Lappeenranta University of Technology
LUT School of Energy Systems
Electrical Engineering

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POSSIBILITIES AND BARRIERS FOR INCREASING RENEWABLE POWER GENERATION IN KENYA AND TANZANIA

Master's Thesis, 2017

Examiners: Professor Samuli Honkapuro
D. Sc. Salla Annala

ABSTRACT

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The growing concerns about climate change, energy security, and the need for access to modern energy services in developing and emerging economies have heightened interest in harnessing renewable energy resources (RES) in recent years. The main objective of this Master's thesis is to examine the possibilities and barriers for Neo-Carbon Energy concept and related business in Kenya and Tanzania. The main idea in Neo-Carbon Energy ecosystem is a 100% renewable energy (RE) system where mainly solar, wind, and other renewables such as hydro, sustainable biomass, and geothermal are used as energy sources.

Kenya and Tanzania are both endowed with ample high quality renewable energy resources. The main source of energy services in both countries is the traditional biomass (firewood and charcoal). The electricity generation market in both countries is partly liberalized with moderate licenced power producers. Further, both governments have designed some regulatory tools (such as Feed-in tariff scheme, Standardized Small Power Purchase Tariffs, among others) in order to attract private capital investment in renewable power generation and accelerate the national electricity access rate. Yet, the level of investments in renewable electricity is presently not sufficient to meet the rapid growing

demand for electricity in the two countries. In 2014, the per capita electricity consumption was 100 kWh in Tanzania and 171 kWh in Kenya, compared to Mozambique at 463 kWh per capita (a similar low income economy), and South Africa at 4,240 kWh per capita. In the quest for quick expansion of energy access, Kenya and Tanzania have both planned to diversify their power generation sources and the bulk of the power generation capacities are expected to come from fossil fuels (coal, oil and natural gas). Of notable concern is the prominent role given to fossil fuels in their respective power expansion plan, which could possibly defer investment in RE technologies and at the same time put the countries in an unsustainable and carbon-intensive path.

In the end, a 100% RE scenario in the year 2050 is developed and simulated using EnergyPLAN simulation tools for Kenya and Tanzania. The scenario results suggest that an energy system based on 100% RE is possible in the two countries by 2050 and to achieve this goal, high share of solar PV, wind power and different storage technologies are needed.

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Ibrahim Olalekan Abdulganiyu
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LIST OF SYMBOLS AND ABBREVIATIONS

BAU	Business-As-Usual
CH_4	Methane
CO_2	Carbon Dioxide
COP21	21st Conference of Parties
CSP	Concentrated solar power
EPPs	Emergency Power Producers
ERC	Energy Regulatory Commission
EWURA	Energy and Water Utilities Regulatory Authority
FiT	Feed-in Tariff
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GHG	Greenhouse gas
GoK	Government of Kenya
H_2	Hydrogen
IEA	International Energy Agency
INDC	Intended Nationally Determined Contribution
IPPs	Independent Power Producers
KSh	Kenya Shillings
KENGEN	Kenya Electricity Generating Company
KPLC	Kenya Power and Lighting Company Ltd
LCOE	Levelised Cost of Energy
LCPDP	Least Cost Power Development Plan
PPAs	Power Purchase Agreements
PV	Photovoltaic
PtG	Power-to-Gas
RE	Renewable Energy
RES	Renewable Energy Resources
REP	Rural Electrification Programme
REB	Rural Energy Board

REF	Rural Energy Fund
SHS	Solar Home Systems
SNG	Synthetic Natural Gas
SPPA	Small Power Purchase Agreement
SPPs	Small Power Producers
SPPT	Standardized Small Power Purchase Tariff
TANESCO	Tanzania Electric Supply Company Limited
TWh	Terawatt-hours
TZS	Tanzanian Shilling
UNFCCC	United Nation Framework Convention on Climate Change

1 INTRODUCTION

1.1 Background

Today, nearly a fifth of the global population has no electricity connection at all, with the vast majority in the sub-Saharan Africa and Asia-Pacific region [1]. Countries in these region have quickly-growing populations, and are struggling to meet the rapid growing demand and need for access to modern energy services of its people. Simultaneously, global warming is threatening the fragile balance of our planet's ecosystems [59]. Therefore, in order to meet the target of keeping global warming below 2°C (as agreed upon at the 21st Conference of Parties (COP21)), while at the same time increasing access to modern energy services in developing countries, investment in clean energy solutions that are vital to reducing carbon emission worldwide will have to be scaled up dramatically. Today, renewable technologies notably solar photovoltaic (PV), wind and concentrated solar power (CSP) are increasingly becoming economically viable and environmentally preferable alternatives to fossil fuels [1], a trend that could potentially be a game-changer for market players pulling away from fossil fuels.

The Neo-Carbon Energy concept is a breakthrough solution for a new reliable energy system developed by VTT Technical Research Centre of Finland (coordinator), Lappeenranta University of Technology (LUT) and the University of Turku – Finland Futures Research Centre (FFRC) [2]. The main idea in Neo-carbon energy ecosystem is a 100% renewable energy (RE) system where mainly solar and wind, alongside other renewables, such as hydro, sustainable biomass and geothermal are used as energy sources. The goal is to launch a highly cost-effective, independent and zero-emission energy system for our planet by 2050. However, because of the intermittency of generation in the case of solar and wind, energy storages and bridges between energy forms are essential. In this case, the main proposed solution for the energy storage problem is the production of synthetic natural gas (SNG), methane (CH_4), from carbon dioxide (CO_2) and hydrogen (H_2) during times of excess electricity production from solar and wind.

1.2 Objective and research questions

The objective of this Master's thesis is to identify and provide key insight to the main drivers, possibilities, barriers, and potential for above described Neo-Carbon Energy ecosystem and related business in Kenya and Tanzania. This calls for the analyses about the energy and environmental policy, electricity market design, business and operational environment, and available energy resources in these two countries. Furthermore, energy system scenarios for Kenya and Tanzania are developed and their impacts on CO_2 emissions and costs are analysed using EnergyPLAN simulation tool.

This report will therefore addresses the following research questions:

1) What makes the case countries' an attractive investment opportunity for RE in sub-Sahara Africa?
2) How can the target countries' economies benefit from Neo-Carbon Energy experience and innovations?
3) What are the key policies, strategies and regulatory framework in the case countries' energy sector?
4) Are there any support mechanisms or incentives in place for renewable electricity generators in these two countries?
5) What are the main barriers to large-scale penetration of RE into case countries' power systems?

1.3 Structure of the thesis

The remaining part of this report is structured as follows:

- Chapter 2 gives a broad description of the case countries' energy sector, including the energy demand and supply trend, electricity market design as well as the players involved in the electricity generation and distribution business. The energy policies, strategies and regulatory conditions of the case countries are also provided.

- Chapter 3 examines the business opportunities for Neo-Carbon Energy concept and identifies the key barriers to renewable energy deployment in the target countries.

- Chapter 4 details the key principles that define how the energy system models (scenarios) were developed and simulated. The main input to the simulation tools (EnergyPLAN) including important assumptions and information are also outlined here.

- Chapter 5 discusses and analyses the results of all the simulations.

Based on these findings, conclusions and recommendations for future studies are provided in Chapter 6.

2 ENERGY STATUS IN KENYA AND TANZANIA

This section analyses the energy sector in Kenya and Tanzania. It details the development of the energy sector, electricity market, and reviews the energy demand and supply status of the case countries. Emphasis is given to private sector contribution, government response plan, and national policies and regulatory framework trend.

2.1 The Case of Kenya

Kenya is geographically located on the East coast of Africa. Between 2007 and 2013, Kenya has experienced an average annual gross domestic product (GDP) growth rate of 5% [3]. As of 2014, its GDP per capita stood at US$ 1370, and currently classified as lower-middle income economy by the World Bank [3]. Its long-term national development plan is anchored on the Kenya Vision 2030, which aims at transforming Kenya into a newly industrialized, middle-income economy by year 2030 [4]. Energy is one of the key pillars of its economic and social development, and its importance is fully recognized in the Vision 2030.

2.1.1 Energy sector description

The main source of energy in Kenya is the traditional biomass, followed by petroleum products, and electricity, as illustrated in figure 1.

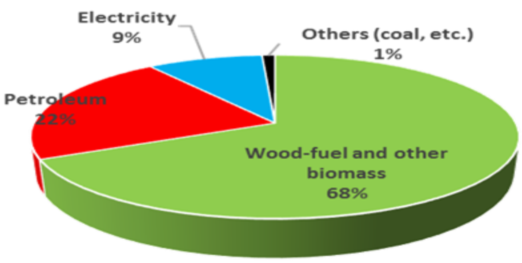

Figure 1. Primary energy supply in Kenya by source (2014) [5].

In 2014, wood fuel and other biomass accounted for about 68% of the 274.82 TWh of total primary energy supply [5]. The wood-based biomass are mainly used in the residential sector including rural communities and the poor urban for cooking and heating. The petroleum products are mainly consumed in the transport, industrial and commercial sectors. The flows of energy from fuel consumption to end-user demand in 2014 in the form of Sankey diagram for Kenya are illustrated in figure 2 below. The per capita electricity consumption was 171 kWh in 2014 [5]. The value is quite low when for instance, compared to Mozambique at 463 kWh per capita (a similar low income country), and South Africa at 4,240 kWh per capita (an upper middle income country).

Further, the per capita CO_2 emissions from fuel combustion in 2014 in Kenya were 0.28 tonnes/capita, compared 0.14 tonnes/capita and 8.10 tonnes/capita in Mozambique and South Africa respectively [5]. In 2015, Kenya like many other countries, submitted its Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change (UNFCCC), proposing a 30% reduction of its greenhouse gas (GHG) emissions by 2030 [6]. To achieve this target, the country plans to champion clean energy solutions and implement several climate change actions that are vital to reducing GHG emissions.

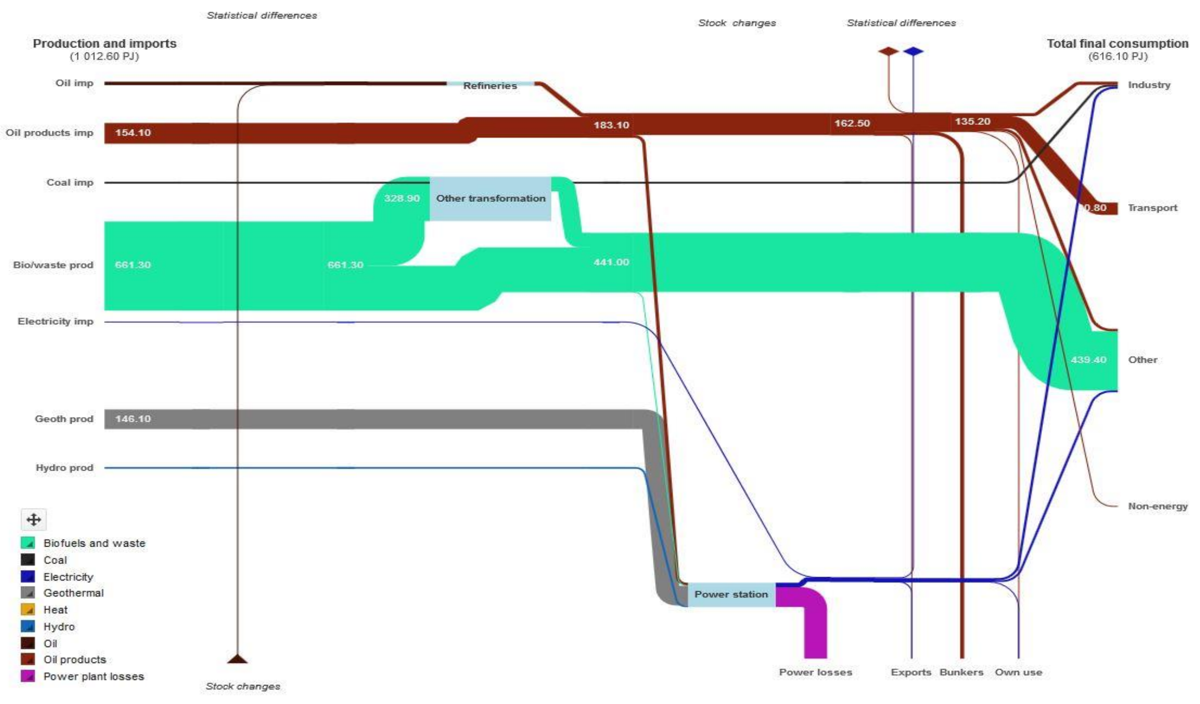

Figure 2. Kenya Energy Balance (2014) [15].

Kenya has abundant high quality renewable energy resources, alongside with regulatory tools (e.g. feed-in tariff scheme) designed by the government to attract private investment to the country. Despite these, its economic growth in the past few decades has been constrained by insufficient supply of modern energy services, frequent power interruptions, and increasing demand for electricity. In addition, the geographical dispersed nature of the remote towns and villages in Kenya has also made grid extension a very expensive option to electrify the rural communities [7–9].

The electricity access status at the national level in 2012 was estimated at 23% [10]. Further analysis of rural/urban electrification rate status shows that only 6.70% of the households in rural areas have direct access to electricity, compared to 58.20% of their urban counterparts [10]. With support from government, the state owned utility – Kenya Power and Lighting Company Ltd (KPLC) – was able to raise the national connectivity access rate to 55% in 2016 through its Last Mile Connectivity Project [11], [14]. The target is to achieve a national connection level of 70% by 2017, and universal access to electricity by 2020 [14].

2.1.2 Electricity Market Structure

The electricity market in Kenya is currently structured as a single buyer model, with KPLC being the sole off-taker of all the power generated by the generators [8], [11]. The Ministry of Energy and Petroleum (MoEP) under the Energy Act, is the government arm responsible for the design and formulation of energy policies to provide an enabling environment for all stakeholders. The energy sector is regulated by the Energy Regulatory Commission (ERC), which is operationally independent of MoEP [13]. The Energy Tribunal acts as the independent energy sector dispute resolution entity, mainly involved in settling disputes resulting from ERC decisions. The electricity trading is arranged in a way that KPLC buys power in bulk from the generators, through negotiated Power Purchase Agreements (PPAs) approved by ERC, for transmission, distribution and retail sales to the end-users [8]. The Government of Kenya has 50.1% ownership shares in KPLC with the rest coming from private investors. Figure 3 depicts the electricity market structure in Kenya.

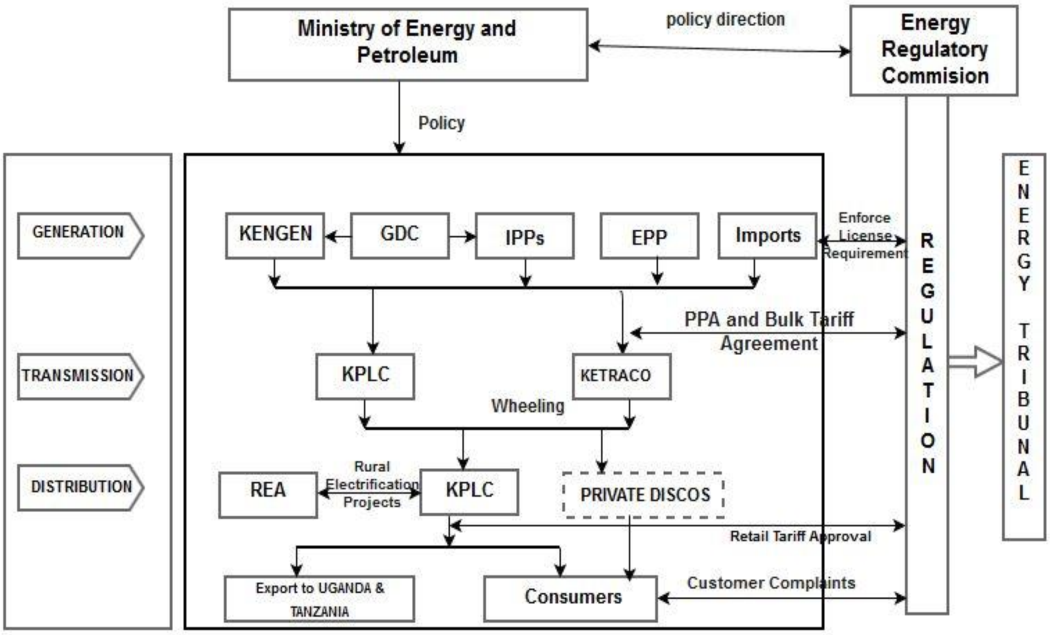

Figure 3. Electricity Market Structure in Kenya. [8]

The rural electrification projects (REP) are managed by the Rural Electrification Authority (REA), working in close cooperation with KPLC. The latter has a Mutual Co-operation and Provision of Services Agreement with the former to operate and maintain its lines (projects). In 2015, PowerHive East Africa Ltd (U.S based micro-grid firm), became the first private off-grid utility to be formally licensed by ERC for its 3 MW solar micro-grid, to sell electricity to the public within its reach [18]. Since then, quite a number of private off-grid entities have shown interest in obtaining electricity distribution license in Kenya.

The Kenya Electricity Transmission Company Limited (KETRACO) is fully owned by the Government [12]. It was established in 2008 to develop new high voltage electricity transmission network that will form the backbone of the National Transmission Grid, in line with Kenya Vision 2030. It is pertinent to know that both KPLC and KETRACO are licensed by ERC to provide transmission services [18]. Meanwhile, KPLC acts as the national system operator (SO) and is responsible for power plant dispatch through the National Control Centre (NCC) in Nairobi [11]. The Geothermal Development Company (GDC), which is also fully owned by the government, develops the geothermal steam field for subsequent use by the electricity generators [49].

The electricity generation market is partly liberalized with several licensed power producers and it is opened to competition [13]. The Kenya Electricity Generating Company (KENGEN) is the largest power producer in Kenya and it is state-owned. In times of drought, Kenya was forced to hire diesel-generated Emergency Power Producer (EPP) – Aggreko Power – to produce backup supply due to shortage of rainfall in parts of the country. Energy policies and regulation have changed significantly, which has triggered more private investors in the electricity generation business in Kenya. By the end of 2016, there are eleven Independent Power Producers (IPPs) operating in Kenya with cumulative installed capacity of 690 MW, compared to four IPPs in 2003 with collective capacity of 187 MW. The IPPs are Iberafrica, Tsavo, Thika Power, Rabai Power, Triumph Diesel, Gulf Power, OrPower, Mumias, Biojule Kenya Ltd, Imenti Tea factory, and Gikira small hydro [14]. The increased number of IPPs in recent years have helped partially to reduce the dependence on the costly diesel-generated EPP, as illustrated in figure 4.

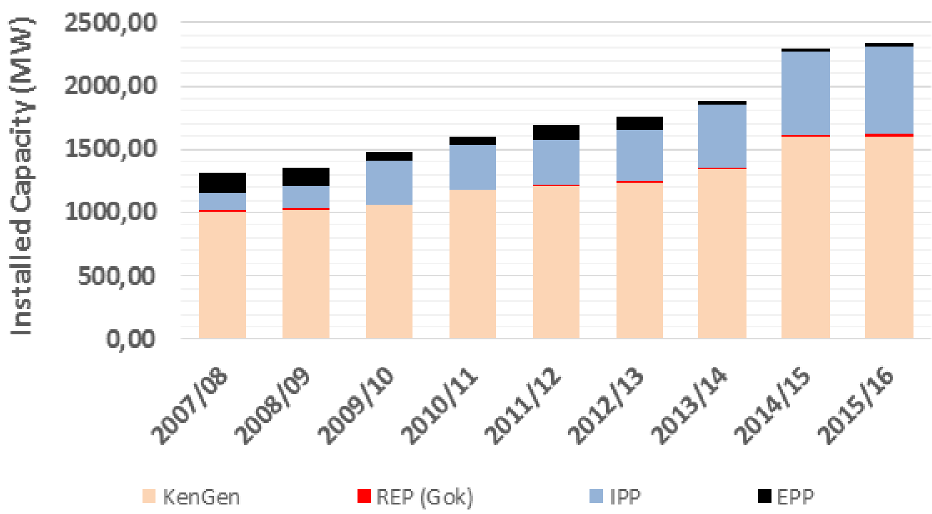

Figure 4. Evolution of the electricity generators in Kenya (2008 – 2016) [14].

2.1.3 Electricity Demand and Supply

The mainstay of the national electricity system in Kenya is currently hydropower and geothermal energy. As at June 2016, the total installed electricity generation capacity was 2,341 MW [14]. Renewables contributed to 65% of the installed capacity. The share of the intermittent RES (wind and solar) is just 1.74% of this installed renewable power capacity.

Thermal (diesel and gas fired) plants continue to provide backup and peaking capacity, as well as improve voltage levels in remote areas far from the generating plants. Table 1 details the contribution of each sources and electricity generators to power generation mix in Kenya.

Table 1. Electricity Generation Capacity in Kenya (June 2016). [14]

TECHNOLOGY	KENGEN (MW)	REP (GoK) (MW)	IPP (MW)	EPP (MW)	TOTAL INSTALLED CAPACITY (MW)	% SHARE (%)
Hydropower	820		0.81		820.81	35.06 %
Geothermal	493		139		632	26.99 %
Thermal	263	18	522.82	30	833.82	35.61 %
Biomass Cogeneration			28		28	1.20 %
Wind	25.5	0.55			26.05	1.11 %
Solar		0.57			0.57	0.02 %
Total (MW)	1601.5	19.12	690.63	30	2341.25	100%
% Share	68.40%	0.82%	29.50%	1.28%	100%	

The total electricity generated in 2016 was 9,816 GWh, while the total electricity consumption (including export to Uganda and Tanzania) was 7,912 GWh. The imbalance between the total electricity generated and consumption in this case is due to the high system (technical and non-technical) losses in Kenya. The peak electricity demand increased by 4.9% from 1,512 MW in 2015 to 1,586 MW in 2016 [14]. Figure 5 illustrates the trend of installed power capacity and peak demand in Kenya from 2010 to 2016.

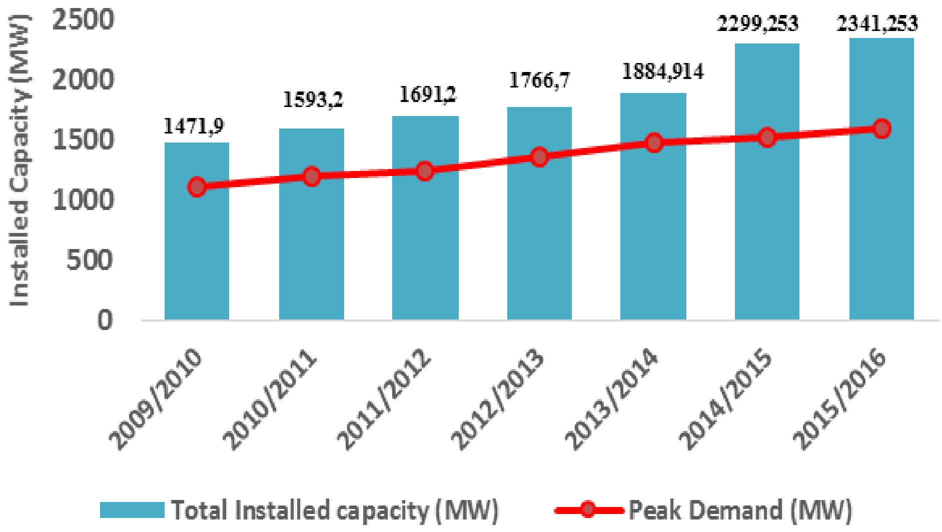

Figure 5. Installed power capacity and peak demand in Kenya (2010 – 2016) [14].

Power System Expansion Plan

The power system expansion plan in Kenya is guided by the Least Cost Power Development Plan (LCPDP) which covers 20-years period from 2011 – 2031 [16]. The reference scenario of the LCPDP anticipated that electricity production will increase to 61,490 GWh by 2031. Further, the peak demand is projected to rise to 10,612 MW, against an installed power capacity of 21,620 MW by 2031. In order to achieve this ambitious target, different electricity generation resources were evaluated by the energy planners based on their expected levelised cost of energy (LCOE), with the assumption of a reference discount rate of 8% for all plants. In the end, candidate resources with the lowest LCOE were selected for peak and base load operation (see Table 2). The resources considered to be the most economically attractive options are geothermal, wind, hydro, natural gas, coal, nuclear plants and imports (hydropower) from Ethiopia [16].

Table 2. Ranking of candidate projects in the LCPDP 2011 - 2031 [16].

Discount Rate – 8%			
Candidate projects	Technology	Load factor (%)	LCOE (USc/kWh)
Base load projects	1. Geothermal	93%	6.9
	2. Wind	40%	9.1
	3. Low Grand Falls (hydro)	60%	9.3
	4. Nuclear	85%	10.2
	5. Mutonga (hydro)	60%	11.1
	6. Gas Turbine (Natural gas)	55%	11.3
	7. Coal	73%	12.7
	Import from Ethiopia	70%	6.5
Peak load projects	1. Gas Turbine (Natural Gas)	20%	15.1
	2. Medium Speed Diesel	28%	21.7
	3. Gas Turbine Kerosene	20%	30.2

When compared the selected candidate resources in the LCPDP with the present situation in Kenya (see Figure 6 below), two important observations can be made. First, the prominent role given to fossil fuels whose over-consumption can lead to serious environmental issues such as air pollution. This is an indication that fossil fuels usage for power generation might increase dramatically in the future, despite Kenya’s pledge to limit its GHG emissions by 30% by 2030. Coal (which was recently discovered in Kenya), natural gas and medium speed diesel still account for significant amount (about 33% of installed capacity) of the proposed power generation mix. Following the contract agreement with the Korea Electric Power Corp (KEPCO) in 2016, Kenya plans to start the construction of its first 1,000 MW nuclear plant by 2021 [62]. The nuclear facility is estimated to come online by 2027.

Second, is the exclusion of solar technologies (solar PV, and CSP) in the power expansion plan over the studied period. Research [17] indicates that the high upfront costs of solar power plants compared to the alternatives are possibly the reason why they were not selected in the power generation expansion plan for 2031. Figure 6 illustrates how the candidate resources considered in the LCPDP compare with the existing system.

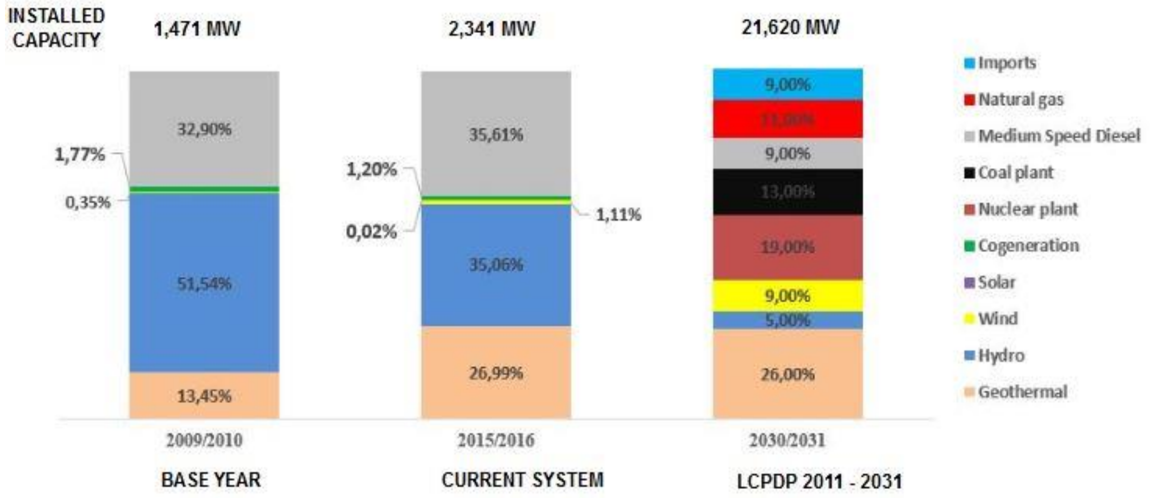

Figure 6. How the LCPDP 2011-2031 compares with the present situation [14], [16]

Today, RE technologies particularly solar PV and wind are now the least cost energy sources in many parts of the world [53].

Electricity Tariff in Kenya

As at 2013, the electricity price of different customer classes in Kenya are presented in table 3.

Table 3. Electricity tariff in Kenya as of 2013 [28].

Category	Price (US$ cents/kWh)
Domestic tariffs	19.78
Commercial/industrial tariffs	14.14

The retail electricity tariff in Kenya incorporates the combined cost of generation, transmission, and distribution, and it is based on the revenue-requirement of KPLC. The tariff components of the retail end-user include [26]:

- Energy charges, in KSh per unit of electricity consumed
- Fixed charge, in Kenya Shillings (KSh)
- Fuel cost charge (FCC) - which varies monthly depending on the quantity of thermal generation and the cost of fuel
- Foreign Exchange Rate Fluctuation Adjustment (FERFA)
- Inflation adjustment (IA) - which varies according to the domestic and international inflation on cost of supply
- Water levy for hydro-power generation of 1 MW and above
- ERC levy, currently set at 3 Kenya cents[1]/kWh
- Rural Electrification Programme (REP) levy at 5% of revenue from unit sales, and
- VAT, which is currently set at 16% and it is applicable to fixed charge, consumption, fuel cost charge and Forex Adjustment.

A web technology consultant based in Kenya – Regulus Ltd – has also developed a tool [27], to allow electricity consumers in country calculate their current and historic cost of electricity.

Rural electrification Scheme

As previously mentioned in section 2.1.2, the rural electrification schemes in Kenya are managed by the REA. The Authority has since its establishment by the Energy Act, 2006, tailored its goal to Vision 2030 [28]. The REA's electrification targets are classified into three phases as highlighted below [29]:

- Phase I: To raise the rural electrification rate to 22% between 2008 – 2012, by electrifying all public facilities such as health centres, secondary schools and market
- Phase II: The second phase aims to increase rural electricity access rate to 65% between 2013 and 2022, with focus on domestic households.

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[1] € 1 = 111.21 Kenyan Shilling (as of January 2017)

- Phase III: To achieve universal rural electrification rate by 2030, contrary to the 2020 universal target set by the Last Mile Connectivity Project in Kenya [14].

The REA was able to achieve about 90% of its target of electrifying major public facilities in the country by the end of 2013 [28].

Government Response Plan/Project

This sub-section highlighted few notable government's power project in Kenya.

(a) Kenya – Tanzania Inter-Connector Project: Kenya's transmission network is the backbone of its electricity distribution systems, providing linkage to the generation plants. In 2016, KETRACO signed a contract of Kenya – Tanzania interconnector project, which involves the construction of about 510 km of High Voltage Alternating Current (HVAC) transmission line from Kenya to Tanzania [12]. The interconnector is design to have a bi-directional configuration and will allow transfer of 2000 MW of electricity between the two countries. According to KETRACO, the interconnected system will facilitates the development of RES in both countries, and at the same time decrease the demands for power reserve capacity to be installed, as it will provide opportunities for power trade between East and Southern African Power Pool (SAPP) countries [12]. The project is expected to last for nearly 2 years from the commencement date. See [24] for broad overview of other completed, ongoing and planned transmission network projects in Kenya. Figure 7 shows the map of electricity transmission network in Kenya as of 2016.

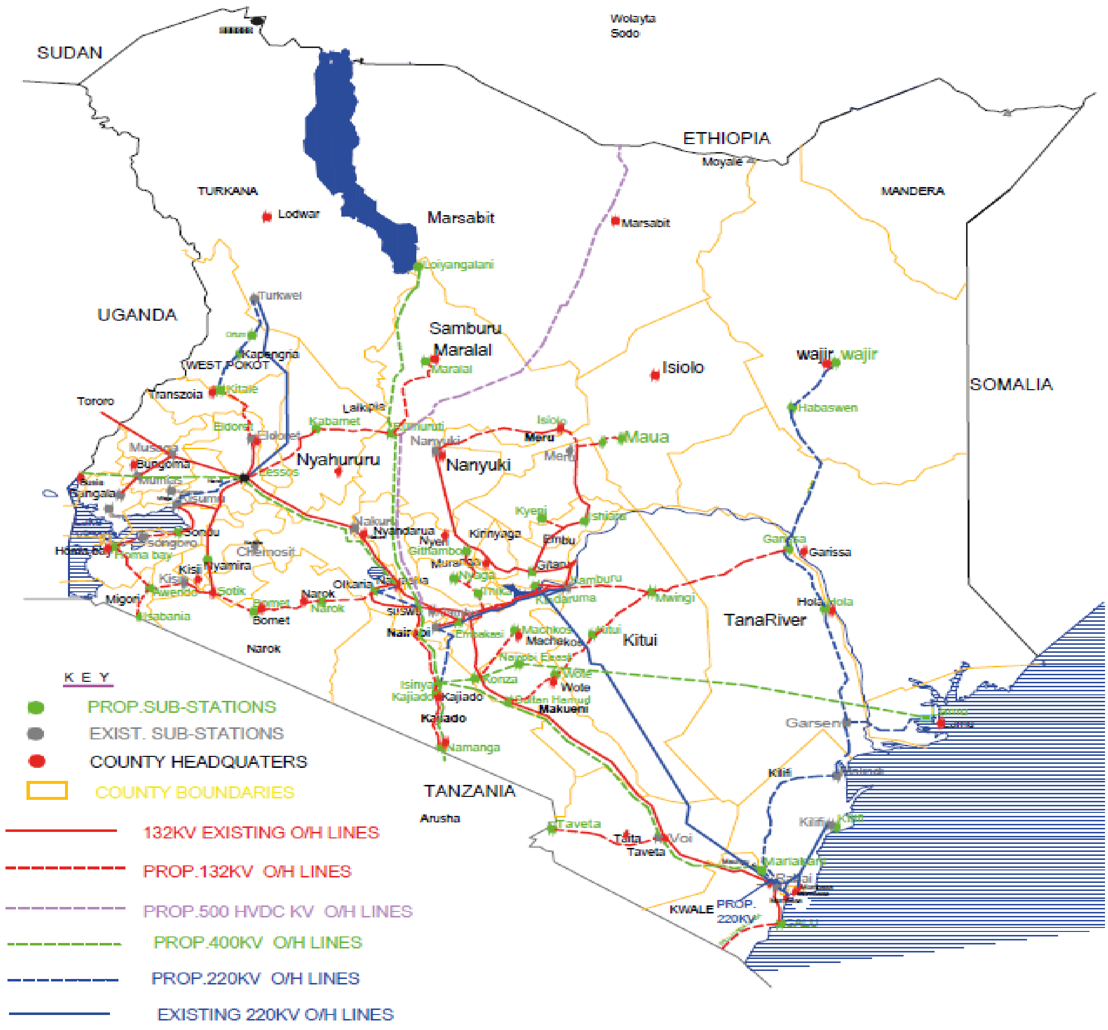


Figure 7. Kenya's Electricity Transmission Network [14].

(b) Toward Universal Connectivity: With support from the Government and other development partners, KPLC has implemented the Last Mile Connectivity Project [14]. The project aims to raise the country's connection level to 70% in 2017, and 100% by 2020. The target group of the Last Mile Connectivity Project are particularly the low income (rural and peri-urban) customers far from the existing line.

(c) National Public Lighting Project: In 2016, the government of Kenya initiated a National Public Lighting Projects worth of €68.34 million [25]. The aim of the project is to provide adequate public lighting to industrial/residential areas, public transport facilities, and commercial centres, among others. This is to create a conducive environment as envisioned in Kenya Vision 2030.

2.1.4 Energy Policy and Regulatory Framework

(a) Current and Proposed Energy Policies

The main energy policy documents in Kenya which complement each other are stated as follows [9], [19-21]:

- The Sessional Paper No. 4, 2004 on Energy
- The Energy Act, No. 12 of 2006
- The National Energy and Petroleum Policy
- The Energy Bill 2015

The **Sessional Paper No. 4, 2004 on Energy**: The main objectives of this policy is to set out the policy framework of the energy and petroleum sector over the study period of 2004 – 2023, in order to ensure equitable access to quality energy services in a cost effective, competitive, affordable and sustainable manner to everyone [19]. Some of the important themes highlighted in this policy document are the enactment of an Energy Act to replace the Electric Power Act No. 11 of 1997 and the Petroleum Act, Cap 116, creation ERC as an independent regulatory agency, creation of GDC, privatization of KENGEN, creation of REA, and to encourage high deployment of RE in the Kenya's energy mix, among others.

The **Energy Act, No. 12 of 2006**: The Energy Act established the ERC as an independent regulatory body, and the REA [20]. The Act clearly defined the objects, functions and power of these bodies. It succeeded the Electric Power Act No. 11 of 1997 and the Petroleum Act, Cap 116, in 2006.

The **National Energy and Petroleum Policy**: This policy paper was drafted in 2015 to govern the national policies and strategies for the energy and petroleum sector in Kenya, following the development of the Kenya Vision 2030 and the Constitution of Kenya in 2008 and 2010 respectively [9]. The policy document is in line with the policy lay out in the Sessional Paper No. 4 of 2004 and other statutes such as the Energy Act, No. 12 of 2006, the Geothermal Resources Act No. 12, of 1982, among others. The key objective to this document is to ensure the availability of sustainable, reliable cost-effective, and affordable energy supplies to meet the growing energy demand of Kenyans.

The **Energy Bill 2015**: The Energy Act, 2015 is expected to replace the Energy Act, No. 12 of 2006 when enacted by the Cabinet and gazette [21]. The Statute was under review, as of August 2016. The Energy Bill 2015 indicates some changes in energy regulation in Kenya. The Bill when approved by the Parliament, intends to make the electricity distribution market more competitive.

(b) Electricity Regulations

The **Kenya Electricity Grid Code**: A draft of the country's Electricity Grid Code was prepared in May 2016 by ERC, with NEXANT being part of the reviewing process. The Grid Code encompasses the main technical regulations related electricity generation, transmission, distribution and retail sales in Kenya [22]. The document has a renewable power plant chapter, developed to address the intermittency issues of solar and wind power plants.

The **Energy (Electricity Licensing) Regulations, 2012**: The document details the regulations (permit and license requirement) that are applied to any individual or entities undertaking or planning to engage in electricity generation, transmission, distribution, or retail supply business in Kenya [23]. A 'permit' as defined in the Energy Act, 2006 [20] is an authorisation granted to an individual or utility with a generation capacity less than 3 MW to enable undertake energy business. While, a license is required for undertakings involving a capacity above 3 MW. Table 4 highlights the requirement for electricity license/permit in Kenya.

Table 4. Requirement for electricity licence/permit in Kenya [13], [20].

Activity	Required Authorization	Applicable Regulation
Generation of electricity not exceeding 1,000 kW for own use (captive generation)	None	Energy (Electricity Licensing) Regulations, 2012
Generation and supply of electricity not exceeding 3,000 kW	Permit	
Generation, transmission, distribution and supply of electricity above 3,000 kW	Licence	
Electrical installation work at the premises of a customer	Electrician's license and Certificate of registration as an Electrical contractor	Electric Power (Electrical Installation Work) Rules, 2006

However, under the proposed Energy Bill 2015 [21], there is no capacity limit on licenses. This implies that license will be required for all generation capacities (regardless of size), repealing the Energy Act 2006 [20].

2.2 The Case of Tanzania

Tanzania is an East African nation. It shares border with Zambia, Malawi, Mozambique, Rwanda, Burundi, Zaire, Kenya, Uganda and the Indian Ocean. Between 2004 and 2014, the country has experienced sustained annual GDP growth rate of 6.8% [30]. In 2014, the GDP per capita stood at US$ 930, and currently classified by the World Bank as a low income economy [30]. Its long-term national development plan is anchored on the Tanzania's Development Vision (TDV) 2025 [31]. The country envisioned to become a middle income economy, with an annual GDP per capita of not less than US$ 3,000 by 2025 [31]. In order to achieve this target, the Government has instituted priority actions (such as energy market restructuring, power system expansion, financial recovery, etc.) to be undertaken from 2014 – 2025.

2.2.1 Energy sector description

The mainstream source of energy services in Tanzania is the traditional biomass (particularly firewood and charcoal) [32-33]. In 2014, they accounted for about 86% of 249.53 TWh of the final energy consumption in country [34]. Petroleum products, mainly used in transport sector and industry, represented 11% of the total energy consumption, followed by electricity with only 2% as shown in figure 8.

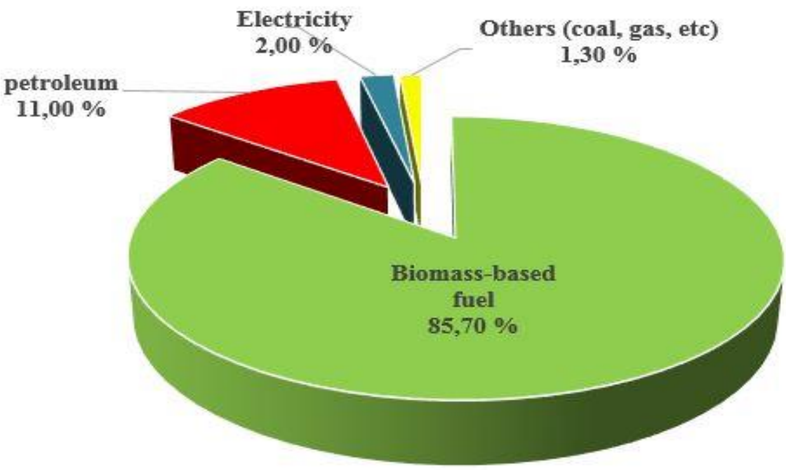


Figure 8. Primary energy consumption in Tanzania (2014) [34].

The per capita electricity consumption of Tanzania was approximately 100 kWh in 2014 [34]. By comparison, this is nearly five-times lower than the per capita electricity consumption of Mozambique (463 kWh), a similar low-income country in the East African region. Further, the per capita CO_2 emission from fuel combustion in Tanzania was 0.2 tonnes/capita in 2014. Figure 9 shows the flows of energy from fuel consumption to end-user demand in the form of Sankey diagram of Tanzania for 2014.

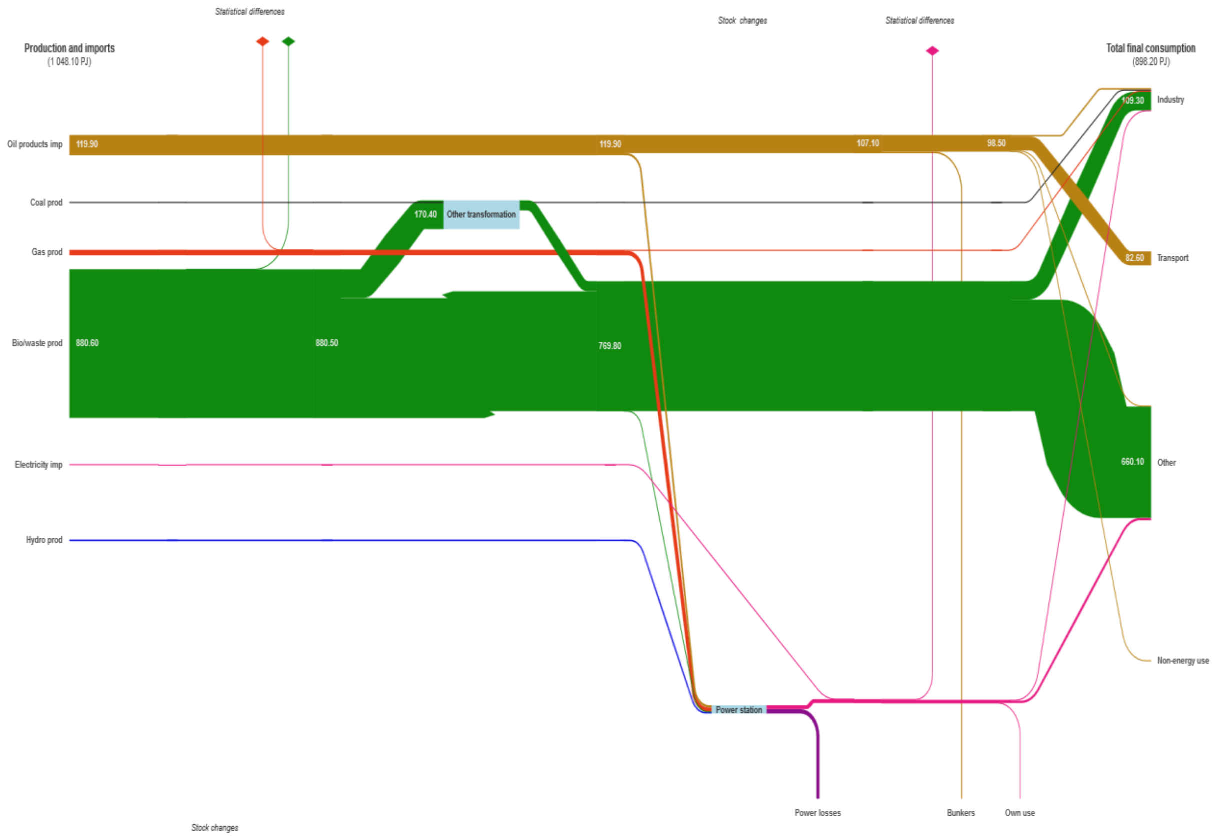


Figure 9. Tanzania Energy Balance (2014) [35].

Tanzania has huge high qualitity indigeneous energy resources ranging from solar to wind, hydropower, geothermal, natural gas, coal and Uranium which remain largely untapped [31-33]. Despite these, its economy has been constrained by low access to reliable energy services, frequent power interruption, increasing electricity demand, high system losses, and capacity shortage in the power sector, among others [31], [33]. The electricity access rate at the national level was estimated at 24% in 2014 [31]. Further analysis by [36], shows that only 16% of the rural households have direect access to electrcity compared to 41% of the urban counterparts. Meanwhile, about 70% of the country's population reside in the rural areas according to the 2012 National Population Census [31]. The geographical dispered nature of most of the settlements make the cost of electrifying the rural communities through grid extension relatively high [33]. As a result, the government's target is to accelerate the national electrification rate to 50% by 2025 and above 75% by 2033 [31].

2.2.2 Electricity Supply Industry

The electricity market model in Tanzania is in the form of a vertically integrated regulated monopoly with a number of IPPs. The Tanzania Electric Supply Company Limited (TANESCO), which is presently a vertically integrated state-owned utility, owns and operates most of the electricity generation, transmission and distribution facilities in the country [37]. The Ministry of Energy and Minerals (MEM) acts as the government arms responsible for the development and formulation of energy policies in Tanzania [32]. The energy sector is regulated by the Energy and Water Utilities Regulatory Authority (EWURA), which is operationally independent of MEM [38]. EWURA is responsible for the approval of PPA and initiation of procurement of power projects, tariff setting, issuing licences, and monitoring performance to ensure qualities and reliability of services. The rural electrification projects are being managed by the Rural Energy Agency (REA) [43]. Figure 10 represents the current structure of the electricity supply industry in Tanzania.

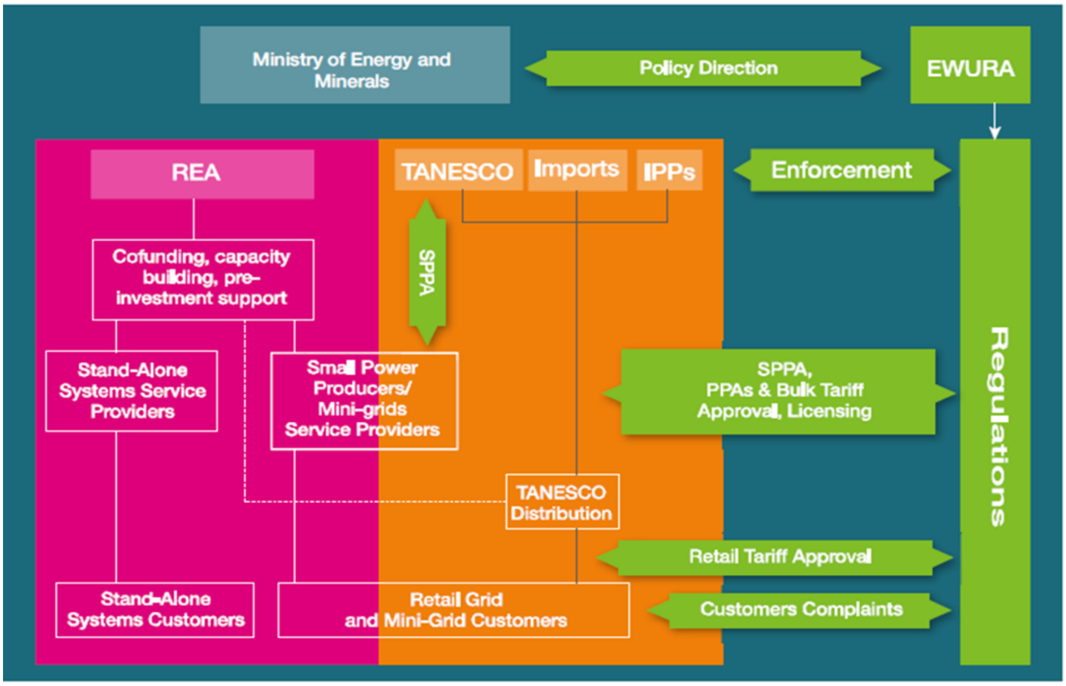


Figure 10. The Electricity Market Structure in Tanzania [33]

As illustrated in figure 10, electricity trading in Tanzania is arranged in a way that TANESCO deals with the generation, transmission, distribution and supply of electricity to the end users, within the grid-connected regions [37-38]. The utility acts as the sole off-taker of all the electricity generated by the IPPs, EPPs and the Small Power Producers (SPPs).The SPPs are the private investors with power plant capacity not exceeding 10 MW [33]. Furthermore, TANESCO sells bulk electricity through submarine cables (one 33 kV cables to Pemba and two 132 kV to Zanzibar) to Zanzibar Electric Company (ZECO) – an entity situated at the semi-autonomous part of Tanzania [38].

While, in the isolated grid regions, the SPPs are allowed (authorized by EWURA) to sell electricity directly to the consumers within their reach [33]. By the end of 2016, Mwenga Hydropower Limited (MHL), is the only entity apart from TANESCO actively carrying out electricity distribution and supply services in Tanzania [38]. The electricity generation market in Tanzania has been opened to private investors' participation for more than a decade [39]. Table 5 details the contribution of different power generators to the main grid in June 2013.

Table 5. Installed Grid Capacity and Import as of June 2013 [40].

Source	TANESCO (MW)	IPP (MW)	SPP (MW)	EPP (MW)	Total (MW)	% Share
Hydropower	561.8	-	4	-	565.8	37.0 %
Natural Gas	252	245	-	-	497	32.5 %
Oil (Jet-A1/diesel)	70.4	159	-	205	434.4	28.4 %
Biomass	-	-	19.5	-	19.5	1.3 %
Imports	14	-	-	-	14	0.9 %
Total	898.2	404	23.5	205	1530.7	100.0 %
% Share	59 %	26 %	2 %	13 %	100 %	

TANESCO is the largest power producer, accounting for 59% of the installed grid capacity. The share of the private investors (IPPs and SPPs) was significant, representing 29% of the installed capacity in 2013. Aggreko Power – an expensive diesel-fired EPP – was hired to bridge the electricity supply gap mainly due to the shortage of rainfall that have characterized the catchment areas in recent years [31], [40]. Between 2015 and 2016, the number of power generators in Tanzania increased from 8 to 11 (including TANESCO) [38], [41]. Table 6 present the service provided actively carrying electricity generation activities in Tanzania by the end of 2016.

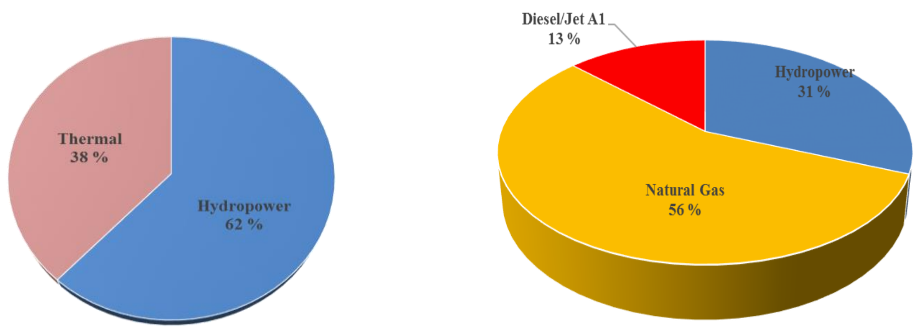
Table 6. Players involved in electricity generation activities (2016) [38].

Generators	Station	Sources
TANESCO	TANESCO Generation facilities	Hydro/Natural Gas/Diesel/Heavy Fuel Oil (HFO)
IPPs	Songas Tanzania Limited	Natural Gas
	Independent Power Tanzania Limited (IPTL)	HFO
SPPs	Tanganyika Planting Company Limited (TPC)	Biomass
	Tanzania Wattle Company (TANWAT)	Biomass
	Ngombeni Power Limited (1 MW)	Hydro
	Mwenga Hydropower Limited (MHL)	Hydro
	Darakuta Hydropower Development Company Limited	Hydro
	Yovi Hydropower Company Limited	Hydro
	Tulila Hydroelectric Power Company Limited (5 MW)	Hydro
	Andoya Hydro Electric Power Company Limited (1 MW)	Hydro

2.2.3 Electricity Generation Mix

The national installed power capacity drop slightly to 1442 MW in 2016 [38] from 1531 MW in 2013 (see table 5) and 1671 MW in 2014 (see table 9). The decline was due to the decommissioning of some oil-fired emergency power plants between 2015 and 2016. It should be kept in mind that 1358 MW of the total installed capacity in 2016 are from the main grid, while the rest were from the isolated mini-grids. Natural gas dominated the electricity generation mix, representing 56% of the total installed capacity in 2016. Hydropower, and liquid fuel (Diesel and Jet A1) constituted 31% and 13% respectively. The thermal power plant (natural gas and Oil) continued to provide the base-load capacity in the country to supplement the hydro generation, which has been affected by severe drought over the past few years [37-40].

As illustrated in figure 11, the contribution of hydropower to the electricity generation mix has declined dramatically from 62% in 2007 [39] to 31% in 2016 [38]. Since there is no major additional investment in hydropower generation in recent years. Consequently, the use of natural gas, coal and liquid fuels have created interest to some potential investors in power generation sector. In 2016, 150 MW Kinyerezi I gas-fired power plant was commissioned, following the completion of the gas pipeline from Mtwara to Dar es Salaam [38]. Construction works have also began during the year in review on the Kinyerezi II (240 MW gas-fired power project), and it is expected to be completed by 2018 [38].



(a) (b)

Figure 11. Power generation mix (% of installed capacity) in (a) 2007 [39] (b) 2016 [38].

The peak demand is also increasing significantly. It accelerated by nearly 25% from 831 MW in 2013 to 1026 MW in 2016 [38], [40]. The total electricity production in 2016 was 6,449 GWh. By comparison, it implies a 4% increase from 6,198 GWh in 2015 [41]. The electricity production and import in Tanzania from 2014 to 2016 is illustrated in figure 12.

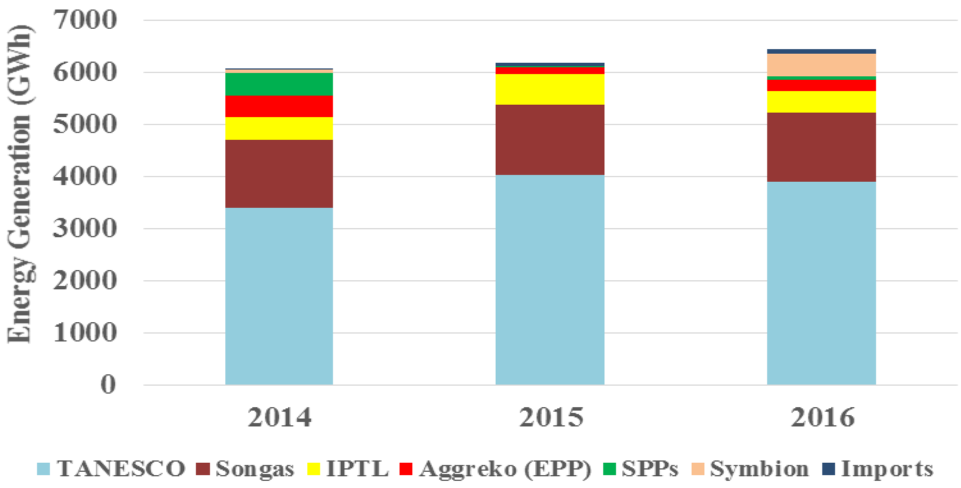


Figure 12. Electricity production and import in Tanzania from 2014 – 2016 [38], [41].

Electricity Tariff

The electricity tariff levels in Tanzania are classified as stated below [42]:

- Low Usage Tariff (D1) for domestic customers supplied at 230V with consumption less than 75 kWh per month. A higher rate is charged for any unit exceeding 75 kWh (see table 7).
- General Usage Tariff (T1) for residential, small commercial and light industry use, supplied at 230V (single phase) or 400V (three phase).
- Low Voltage Usage Tariff (T2), for three-phase customers with average consumption greater than 7,500 kWh per meter reading period and demand less than 500 kVA per meter reading period.
- Medium Voltage Usage Tariff (T3-MV), for customers connected to the medium voltage.
- High Voltage Usage Tariff (T4-HV) for consumers connected to the 11 kV supply and above.

As of 2016, the average electricity tariff for a General Usage Customer in Tanzania is 0.12 €/kWh with taxes inclusive[2] [42]. Table 7 details the approved electricity tariff for different customer groups in 2016.

Table 7. Approved Electricity Tariff for 2016 [42].

Customer Class	Approved Tariff for 2016		
	Service charge (€/month)	Energy charge (€/kWh)	Maximum demand charge (€/kVA/month
Low Usage Tariff (D1)			
• Consumption < 75 kWh/month	-	0.04	-
• Consumption > 75 kWh/month	-	0.15	-
General Usage Tariff (T1)	-	0.12	-
General Consumption >7,500 kWh per meter reading – (T2)	5.97	0.08	6.29
Medium Voltage (T3-MV)	7.03	0.07	5.53
High Voltage (T4 –HV)	-	0.06	6.94

Regulatory Framework – Energy Policy and Regulation

The regulation of the electricity sector in Tanzania is guided by the following main policy documents [33], [38-42]:

- National Energy Policy, 2003
- EWURA Act Cap 2001 and 2006
- Electricity Act 2008
- Electricity (General) Regulations GN 63
- Rural Energy Act 2005

[2] 0.12 € = 292 Tanzanian Shilling (TZS) as of February 2017

The **National Energy Policy, 2003**: The main objective of this policy document is to ensure equitable access to reliable and affordable energy services in a sustainable manner in order to support national development goals [33]. Importantly, the policy outlined the need to heighten the development of indigenous and renewable energy sources and technologies; accelerate energy efficiency and conservation in all sectors; and restructure the energy market to facilitate investment, efficient pricing mechanisms and other financial incentives.

The **EWURA Act 2001 and 2006**: This Act established EWURA as an independent regulatory authority, charged with the responsibility to regulate the electricity, water, natural gas and petroleum sectors in Tanzania [38-40].

The **Electricity Act 2008** set out a general framework for the powers of EWURA and the Ministry of Energy and Minerals [33]. The Act was enacted in 2008 to provide for the facilitation and regulation of generation, transmission, transformation, distribution, supply and use of electric energy, to provide for cross-border trade in electricity and the planning and regulation of rural electrification and to provide for related matters.

The **Rural Energy Act 2005** established the Rural Energy Agency (REA), Rural Energy Fund (REF), and Rural Energy Board (REB) [44]. The REA is charged with the responsibility to promote and facilitate provision of modern energy services in the rural areas Mainland Tanzania. The REB governs the REA and it is also entrusted to oversee the administration of the rural energy fund for the development of rural energy projects.

2.2.4 Ongoing Power Sector Reforms (2014 – 2025)

Following the consultation of the government with other key stakeholders in the energy sector in Tanzania, the Electricity Supply Industry (ESI) Reform Strategy and Roadmap for 2014 to 2025 was published in June 2014 [31]. The reform proposed a gradual transition of the existing electricity market model into a fully competitive market by 2025. Figure 13 provides a general overview to the evolution of power sector reform in Tanzania.

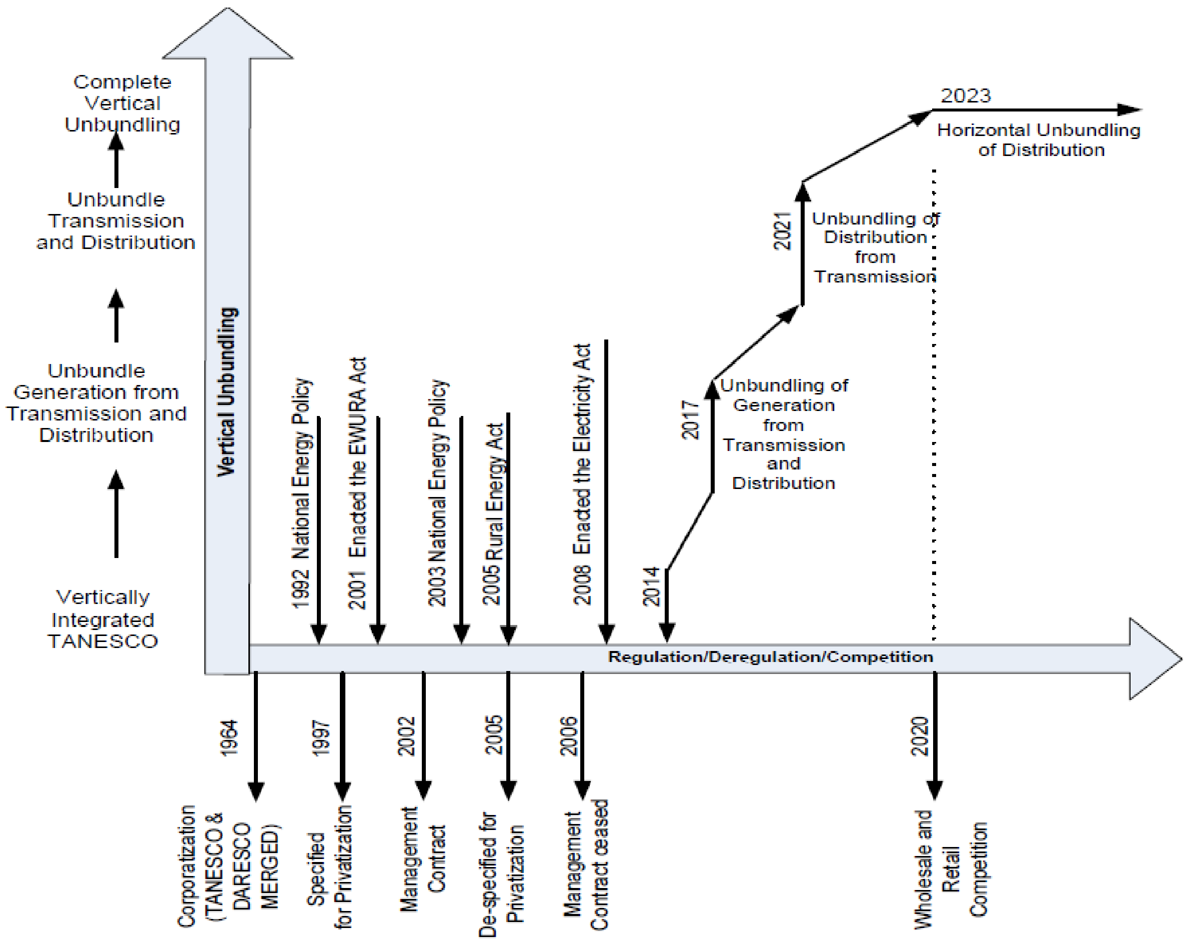


Figure 13. ESI Reform Path for Tanzania [31].

The underlying reasons for embarking on the ESI reform were to:

- enhance the operational and financial performance of TANESCO;
- attract private sector investment in the power sector;
- improve the reliability and efficiency of power supply in Tanzania;
- diversify the sources of power generation;
- accelerate the national electricity access rate; and
- limit the technical and non-technical losses.

The key activities planned to be implemented between 2014 and 2025, are divided into four (4) gradual stage process – intermediate, short, medium, and long term – as summarized in table 8.

Table 8. ESI Reform Roadmap (2014 – 2025) [31].

Immediate Term (July 2014-June 2015)	Short Term (July 2015 – June 2018)	Medium Term (July 2018 – June 2021)	Long Term (Jul 2021- Jun 2025)
Internal Turnaround	Partial Vertical Unbundling	Complete Vertical Unbundling	Full Vertical and Horizontal Unbundling
a) Establishment of a Task Force to monitor the implementation of the reform strategy b) Reducing the losses from 19% to 18% c) Accelerate the national electrification rate from 24% to 30% d) Improve TANESCO's financial performance e) Formulate technology based Model Power Purchase Agreement (PPA).	a) Unbundle the generation unit from transmission and distribution units b) Approval of electricity producers to sell electricity directly to bulk off-taker c) Continue to improve TANESCO's financial performance d) Raise the national electrification rate further to 33% e) Reduce system losses further to 16% f) EWURA to develop rules and mechanism for the operation of a retail electricity market	a) Unbundle the distribution unit from transmission unit b) Increase the electricity access rate further to 39% c) Develop rules and mechanisms for the operation of a retail electricity market d) Provide oversight role for the retail electricity market while prices are determined by the market forces e) Reduce system losses further to 14%	a) Unbundle the distribution unit into different zonal distribution utilities b) The generation and distribution utilities to be listed in Dar es Salaam Stock Exchange (DSE). c) achieve 50% electricity connection levels d) Establish ESI standards e) Reduce system losses to 12%

The intermediate term (July 2014 – June 2015) has already expired, and Tanzania is currently in the short-term phase. Some key achievements was recorded during the period under review. These include the development of technology based Model Power Purchase Agreement by EWURA, and initiation of Standardized Small Purchase Tariff for Small Power Projects to attract investment in renewable energy [38], [41]. Furthermore, as a result of extensive grid expansion of the distribution network funded by the rural energy fund in 2015, the national electrification rate also increased from 24% in 2014 to 36% [41]. This surpassed the Government target of 30% electricity connectivity rate (see table 8).

Future Power Supply Options

This ESI Reform Strategy and Roadmap was prepared in line with the Tanzania Development Vision 2025. The Roadmap estimated that at least 10,000 MW of installed power capacity will have to be on ground to transform Tanzania into a middle income economy by 2025 [31]. Table 9 compares the proposed power generation mix for 2025 with that of the base year.

Table 9. Comparison of proposed power generation mix for 2025 with the base year [31], [77].

Resources	**2014 [77]**		**2025 [31]**	
	Installed Capacity (MW)	% Share	Installed Capacity (MW)	% Share
Hydropower	608	36.4%	2090.84	19.4%
Solar	6	0.4%	100	0.9%
Wind	0	0	200	1.9%
Geothermal	0	0	200	1.9%
Biomass cogeneration	35	2.1%	0	0
Natural gas	527	31.5%	4469	41.4%
Liquid fuels (HFO/Diesel)	495	29.6%	438.40	4.1%
Coal	0	0	2900	26.9%
Interconnector	0	0	400	3.7%
Total	1,671	100%	10,798.24	100%

It was suggested that about 764.5 MW new power capacities will have to be installed annually till 2025 in order to meet up with the projected generation capacity [31]. As presented in table 9, natural gas and coal mainly dominate the future power generation mix, as the government attempts to partly displace the expensive, emergency oil-based power plants that stepped in to bridge the electricity supply gap, when drought scuppered its hydropower stations. The biggest concern is the prominent role given to fossil fuels particularly coal, which is the most carbon-intensive fuel and the single largest source of GHG emissions [59].

3 BUSINESS OPPORTUNITIES FOR NEO-CARBON ENERGY

This section will evaluates the viability and scalability of RE in Kenya and Tanzania. It will also examines the role of each country's RE support mechanisms in integrating renewables into their respective electricity market. The potential barriers to RE deployment in these countries are also provided in this section.

3.1 Prospects of Renewable Energy in Kenya

A) Renewable Energy Potential and Market

Kenya is blessed with abundant renewable energy resources [7-9], which still remain largely untapped as highlighted in table 10.

Table 10. Renewable Energy Potential in Kenya [7-9], [14].

Resources	Estimated potential	Cumulative Installed Capacity as of June 2016 (MW)
Large Hydro	3000 – 6000 MW	820
Small hydro (<10 MW)	3000 MW	0.814
Geothermal	5000 – 10000 MW	632
Wind	Wind speed of 8 – 14 m/s in certain of Kenya	26
Solar	Daily solar radiation of 4-6 kWh/m^2.	0.6
Bagasse cogeneration	193 MW	26

Solar Energy Market

The solar market is still relatively undeveloped, despite the ample availability of technically useful solar resources [7-9], [17]. A study [45] reveals that about 70% of Kenya's land area (581,309 km^2) has an annual average solar irradiation of 5 kWh/m^2/day, which implies that the country receives more than 743,000 TWh of solar energy per year[3]. Figure 14 depicts the world map of global direct normal irradiation. The first solar system with PPA to supply electricity to the national grid under the current feed-in tariff (FiT) scheme was realized in 2015 in the shape of the 600 kW project at Strathmore Business School in Nairobi. However, solar projects in the pipeline will see more of this resource injected to grid in next 1 – 2 years [46]. The Government of Kenya has also launched a programme to electrify institutions (such as primary and secondary schools, health centres, dispensaries and administrative buildings) located far away from the national grid, using solar PV system [9].

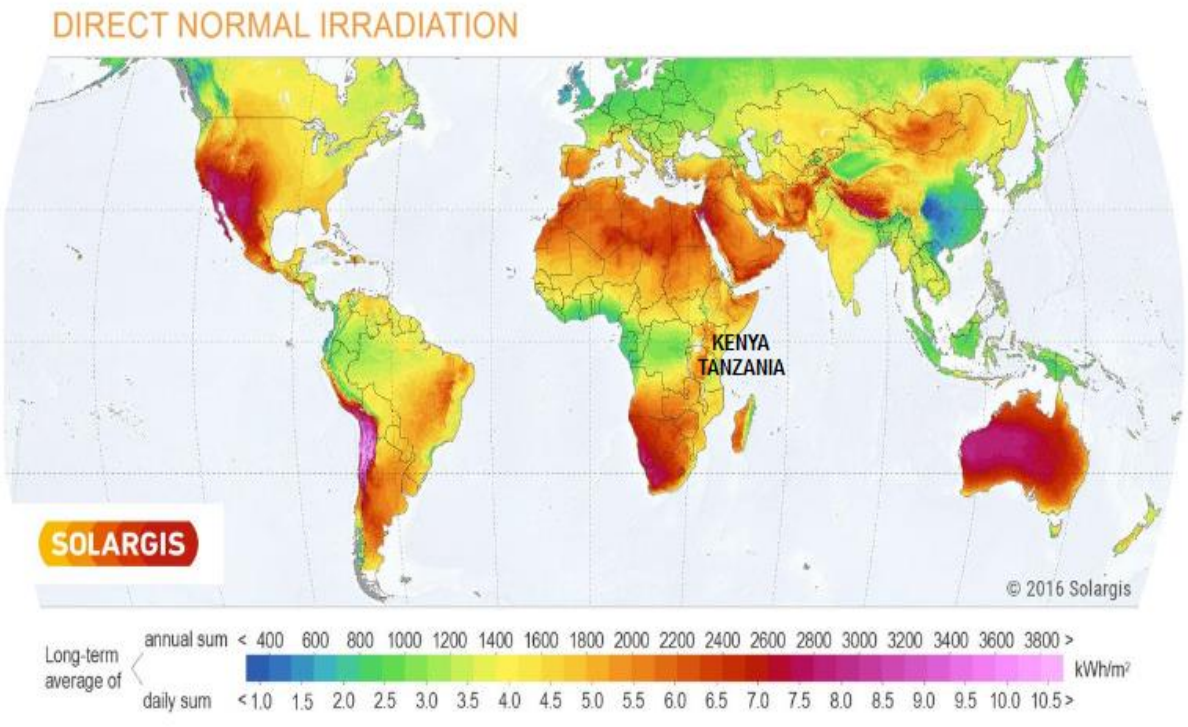


Figure 14. World Map of Global Direct Normal Irradiation [47].

[3] 70% * 581,309 ×10^6 m^2 * 5 kWh/m^2/day * 365 days = 742,622 TWh/year

There are quite a number of private operators running RE micro-grids in small but densely populated centres in Kenya. The most active players are Powerhive East Africa Ltd (with 3,000 kW solar PV technology), PowerGen, Solarjoule, and SteamaCo among others [51].

By the end of 2015, the sub-Saharan Africa was the largest market for off-grid solar applications, followed by South Asia [1]. It was estimated that about 15–20% of households in Kenya were using the off-grid solar lighting system in 2015 [1]. The pico-solar systems (1–10 W_P) in particular, are now replacing the use of candles, kerosene lamps and battery-powered flashlights, to power small lights bulbs and other low-power appliances in the country.

Another new investment vehicle in the East African region is the Solar Home Systems (SHS) market [1]. The SHS (with power capacity limit between 10 W and 500 W), mainly comprises of a solar module, battery and a charge control device, to supply electricity to the off-grid end-users for lightings, television, radios, or mobile phone charging stations among others. About 300,000 SHS were reportedly sold in Kenya, Tanzania and Uganda by M-KOPA between 2014 and 2015 [1].

Hydropower Market

For the past few decades, hydropower has been one of the mainstay of the national electricity system in Kenya [14]. But, low rainfall in the country over the years has affected and undermined its hydropower capacity. As a result, there is no significant additional investment in hydropower generation in Kenya in recent times. Between 2010 and 2016, only 62.21 MW of hydropower capacity (large hydro and small hydro) was added to the national grid from 758.60 MW to 820.81 MW [14]. Figure 15 illustrates the declining contribution of hydropower resources to national energy system. However, there are possibilities of constructing a micro- and pico-hydropower stations to provide affordable electricity to the local communities. The current IPPs in the small hydropower business in Kenya are Imenti Tea Factory (300 kW capacity), and Gikira small hydro (514 kW capacity) [14].

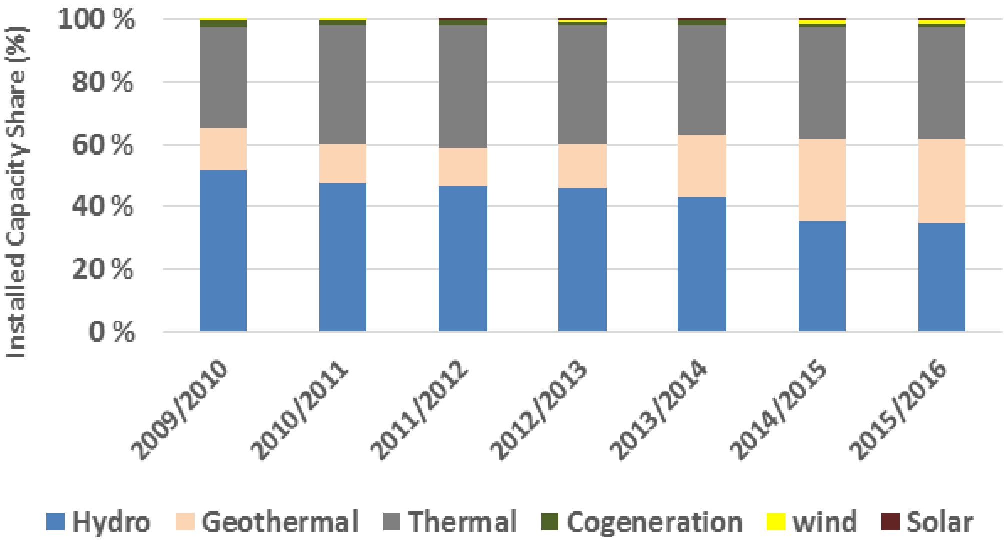


Figure 15. Installed power capacity by source from 2010 – 2016 [14].

Geothermal Power Market

As illustrated in figure 16, the geothermal power market in Kenya is developing quite dynamically, with KENGEN taking the leading role. Ormat Technologies (owner of OrPower geothermal power plant) is the sole IPP engaged in geothermal energy generation and has been contributing significantly to growth of geothermal energy in the country [14]. In 2014, Kenya contributed more than half of the total 640 MW geothermal power capacity installed globally [48]. By the end of 2015, the country was ranked among the top 10 largest geothermal power producers in the world [1], with a total installed capacity of 598 MW [14]. Further, an additional 34 MW was added to the national grid between 2015 and 2016.

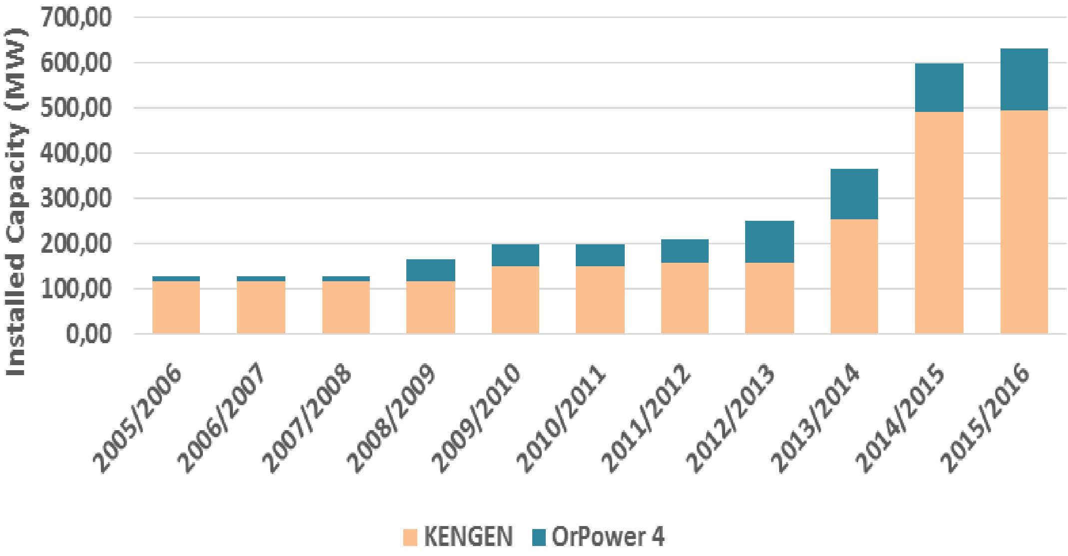


Figure 16. Geothermal energy growth in Kenya [14]

Kenya's long term target is to add 5,530 MW of geothermal resources to its generation mix by 2031 [8]. For this reason, the Government of Kenya and other development partners have been financing risks associated with the exploration and drilling of the geothermal steam at its Olkaria field [49]. Having signed a PPA with KPLC for its output, drilling works started on the first phase of the 140 MW Akiira Geothermal Limited Project in Naivasha near Nairobi in 2015 [1]. When completed in 2017, the project is expected to become the first private sector greenfield geothermal development in Sub-Saharan Africa.

Wind Energy Market Development

In recent years, the wind energy market in Kenya has been attracting different local and multinational investors. The notable ongoing wind power projects in the country are:

- The 310 MW Lake Turkana Wind Power project
- The 100 MW Kipeto Wind Farm
- The 60 MW Kinangop Wind Park

The Lake Turkana Wind Power (LTWP) project, will be largest wind farm in Africa when completed in 2017 [50]. The 310 MW wind farm is expected to produce 1,440 GWh of electricity annually, which is equivalent about 18% of the total electricity consumption in 2016. The power produced will be bought by KPLC at a fixed price (0.075 €/kWh) over a 20 years period, according to the PPA signed with the utility [50]. The wind farm project is led by a consortium of KP&P Africa BV, Aldwych International Limited, Danish Investment Fund for Developing Countries (IFU), Norwegian Investment Fund for Developing Countries (Norfund), Finnish Fund for industrial Cooperation (Finnfund), Vesta, and Sandpiper limited.

The LTWP comprises of 365 Vesta V52 wind turbines rated at 850 kW each, overhead electric grid connection system and high-voltage sub-station. The reasons for selecting smaller size turbine (V52-850 kW) for the wind farm project according to chief technical officer[4] of the project include:

- The project concept/idea was initiated when the ratio of intermittent RES (wind and solar) to the conventional energy sources was low. Thus, installing many turbines was considered for smooth control during dispatch (more stable since they didn't require large capacity plants as reserve in case of failure of small group of turbines
- The wind regime in the area favoured design of V52 maximum power outputs
- As that time of project development, investors were not sure that the infrastructure (roads, tracks, cranes, off tarmac roads, bridges etc.) to transport and erect bigger turbines will be available
- Furthermore, V52 turbines were already tested in Kenya. The 2 MW and 3 MW taller turbines were not yet fully commercial in Africa, and
- Finally, V52-850 kW turbine is robust and can survive the unstable African grid system.

As of March 2017, out of the 365, V52-850 kW turbines, a total of 347 have already been erected [50].

Further, the **100 MW Kipeto wind power project**, which is financed by the Kipeto Energy Limited Company (KEL), is also expected to start operation by the end of 2017 [76]. Therefore, when all the above-mentioned projects are completed, they will play a crucial role in enabling Kenya to achieve its Vision 2030 objectives, and at the same time

[4] Onesmus Odhiambo. [email interview on 22.12.2016]

significantly increase the share of wind energy to the national energy mix. A number of other wind power projects in the pipeline under the current feed-in tariff scheme can be found in [46].

Biomass-Based Electricity Market in Kenya

Biomass resources are mainly extracted in traditional and unsustainable ways in Kenya, but the potential of generating electricity from bagasse, and biogas co-generation are high [7-9]. By the end of 2016, the two active IPPs involved in biomass-based, grid-connected electricity generation activities are [14]:

- Mumias Sugar Company, with installed grid capacity of 26 MW (via bagasse cogeneration)
- Biojule Kenya Limited: 2 MW installed grid capacity (biogas-fired plant)

B) Incentives for RES-Electricity Generators in Kenya

Kenyan Feed in-Tariff Scheme

Kenya developed its first feed in-tariff (FiT) scheme in March 2008 [9], [52]. The first FiT scheme covers small hydro, biomass and wind power generated electricity, for plants with capacities not exceeding 10 MW, 40 MW and 50 MW respectively [52]. The 2008 FiT was revised in January 2010 and December 2012. The revised version of the FiT policy contained revised tariffs for biomass and wind. New tariffs for biogas, solar and geothermal resources were also included. The aim of this scheme is to facilitate resource mobilization by providing investment security and stability for RES-E generators.

The scheme allows generators to sell and obligates the distributors (KPLC) to buy on a priority basis all the RES-E at a pre-defined fixed tariff [7]. The tariffs are guaranteed for 20-years period from the time the PPA is sign with KPLC. Meanwhile, the operations and maintenance (O&M) component of the FiT are adjusted for inflation each year by certain percentage known as the escalation percentage. This varies according to the US Consumer Price Index [52]. Table 11 details the revised FiT scheme for RE project within and above 10 MW capacity.

Table 11. FiT values for renewable projects in Kenya. [9], [52].

<table>
<tr><th>Technology</th><th>Project Size (MW)</th><th>Standard FiT (US $/kWh)</th><th>Escalation Percentage[5] (%)</th></tr>
<tr><td rowspan="3">Hydro[6]</td><td>0.5</td><td>0.105</td><td rowspan="3">8%</td></tr>
<tr><td>10</td><td rowspan="2">0.0825</td></tr>
<tr><td>10.1-20</td></tr>
<tr><td rowspan="2">Wind</td><td>0.5 – 10</td><td rowspan="2">0.11</td><td rowspan="2">12%</td></tr>
<tr><td>10.1 – 50</td></tr>
<tr><td rowspan="2">Solar (Grid)</td><td>0.5 – 10</td><td rowspan="2">0.12</td><td>8%</td></tr>
<tr><td>10.1-40</td><td>12%</td></tr>
<tr><td>Solar (Off-grid)</td><td>0.5 – 10</td><td>0.20</td><td>8%</td></tr>
<tr><td rowspan="2">Biomass</td><td>0.5 – 10</td><td rowspan="2">0.10</td><td rowspan="2">15%</td></tr>
<tr><td>10.1-40</td></tr>
<tr><td>Biogas</td><td>0.2 – 10</td><td>0.10</td><td>15%</td></tr>
<tr><td>Geothermal</td><td>35 – 70</td><td>0.088</td><td>20% for first 12 years and 15% after</td></tr>
</table>

The FiT has been effective to some extent in attracting investors to promote the development of RE projects in the country. Between 2012 and 2016, about 90 MW of renewable power capacity have been added to the national grid by private investors (IPPs) [14]. Also see [46] for proposed RE projects approved by ERC under the FiT policy. A

[5] How much the FiT increases every year (%).

[6] For values between 0.5 – 10 MW, interpolation shall be to determine tariff for hydro.

combined wind power capacity of 160 MW are expected to come online by the end of 2017, under the FiT scheme.

Proposed Renewable Energy Auction Scheme in Kenya

At the time of writing this Master's thesis report (January 2017), Kenya is working on the introduction of competitive auction system for awarding RE projects – a policy shift from the existing FiT scheme. RE auctions are increasingly becoming a popular regulatory instrument for government in industrialized and developing countries to procure renewable electricity at moderate cost. By the end of year 2016, not less than 67 countries have adopted the auction scheme compared to six (6) in 2005 [53]. The main motivation of adoption of this scheme globally has been its potential to achieve low price.

It is therefore anticipated that when the proposed auction model in Kenya is implemented, it will likely bring down the cost of solar from the current FiT of US 12 cent/kWh, given the drop in cost of materials, availability of funds from financiers, and use of refined technology. However, unlike the FiT schemes, the auction schemes benefit only the selected project developers, and the tariff level is based on the prices indicated by the developers in their bids during the auction process [54].

3.2 Prospects of Renewable Energy in Tanzania

A) Energy Resources Availability

Just like Kenya. Tanzania also has abundant forms of energy resources which have not been optimally utilized [31-33]. Table 12 presents the energy resources potential in Tanzania.

Table 12. Overview of potential of different energy resources in Tanzania [32-33],[40]

Resource	Estimated potential	Cumulative Installed Capacity (2013) (MW)
Large Hydropower	4.0 - 4.7 GW	562
Small hydro (< 10 MW)	480 MW	4
Geothermal	650 MW	-
Wind	average wind speed of 9.9 m/s at Kititimo and 8.9 m/s at makambako, at height of 30m.	-
Solar	Global horizontal irradiation of 4 -7 kWh/m^2 per day.	6
Bagasse cogeneration	500 MW	19.5
Coal	Coal reserve of about 1200 million tons	-
Natural gas	57.25 trillion standard cubic feet	497

Energy Resource Market development

Over the past few years, Tanzania has faced shortage of rainfall resulting in low water levels in the hydropower reservoirs, which has consequently lowered its energy and capacity contribution into the grid. The regional mismatch between main demand centres and the hydropower sites in Tanzania is also one of key constraints to hydropower market development. The existing hydropower sites are primarily situated in the southwest of the country, while the main demand centres are in the east, north and northwest [33]. Therefore, the weak and ageing transmission system must be strengthened in order to fully realise the hydropower development.

Interestingly, there has been an increasing interest during the year for opportunities in the RE based electricity, especially in the off-grid and isolated towns [40]. The combined 6 MW capacity of solar PV installed in Tanzania were utilized for various applications in public schools, health centres, street lighting, and households [33]. The geothermal potential has not yet been fully quantified [33]. Surface assessment are been carried out in some prospect zones (Kilimanjaro, Arusha, Mara, Mbeya and Rukwa regions).

Further, Tanzania also has a promising wind energy market. By the end of 2017, the privately owned 100 MW Singida wind farm project is expected to start operation. The project will not only provide clean and reliable source of electricity to Tanzanian, but also, a blueprint to wind developers eyeing Tanzania. Biomass is the country's main source of energy, although mainly extracted in a traditional and unsustainable ways [33]. Small-scale uses of biomass for electricity generation especially in the rural area are taking off [33], [38].

As of March 2016, about 57.25 trillion standard cubic feet of natural gas reserves (equivalent to 16,780 TWh of electricity) have been proven in Tanzania [55]. The four (4) active players in the midstream and downstream natural gas activities are Songas Limited, Tanzania Petroleum Development Corporation (TPDC), Maurel & Prom (M&P), and Pan African Energy Tanzania Limited (PAET).

B) Incentives for RES-Electricity Generators in Tanzania

The Standardized Small Power Projects Tariff

In 2008, the government adopted a standardized mechanism known as the 'SPP Framework' for the development of Small Power Projects, using renewable sources with capacity ranging from 100 kW to 10 MW [56]. The framework includes a Standardized Small Power Purchase Agreement (SPPA), and the associated Standardized Small Power Purchase Tariffs (SPPT) for projects connected to either the national grid or isolated min-grids. The main motivation is to attract investment in renewable power generation and accelerate the national electricity access status.

In 2015, EWURA reviewed the 2008 SPP Framework, and came up with the 'Second Generation SPP Framework' to respond to the challenges identified during implementation of the former, and thereby further improves the conditions for small power project investments in Tanzania [41]. The Second Generation SPP Framework is based on two approaches: 1) a Renewable Energy Feed-in Tariffs (REFiTs) approach for small hydro and biomass power plant between 100 kW to 10 MW capacity [41], [57]; and 2) a competitive bidding process for wind and solar projects with capacity of up to 1 MW [38], [41]. Table 13 presents the standardized small power projects tariff for small hydro and biomass power plant.

Table 13. Standardized Small Power Projects Tariff [57].

Mini hydro Power Plant		**Biomass Power Plant**	
Size	Tariff (US$/kWh)	Size	Tariff (US$/kWh)
100 kW	0.155	-	-
150 kW	0.146	200 kW	0.179
200 kW	0.141	300 kW	0.169
250 kW	0.140	400 kW	0.161
500 kW	0.134	500 kW	0.157
750 kW	0.129	750 kW	0.149
1 MW	0.123	1 MW	0.147
2 MW	0.115	2 MW	0.138
3 MW	0.108	3 MW	0.128
4 MW	0.102	4 MW	0.126
5 MW	0.098	5 MW	0.123
6MW	0.095	6 MW	0.120
7 MW	0.091	7 MW	0.118
8 MW	0.088	8 MW	0.115
9 MW	0.087	9 MW	0.114
10 MW	0.085	10 MW	0.112

The applicable tariffs for wind and solar power projects with capacity of up to 1 MW connected to either the main gird or isolated grid as of April, 2016 is shown in table 14.

Table 14. Wind and solar connection Tariff [38].

Description	Approved Tariff (US$/kWh)
Standardized Small Power Purchase Tariff for Wind and Solar plants of up to 1 MW connected to the mini grid	0.181
Standardized Small Power Purchase Tariff for Wind and Solar projects of up to 1 MW connected to the main grid	0.165

Model PPAs for Projects larger than 10 MW capacity

As earlier mentioned in section 2.2.4, one of the key milestones in the Electricity Sector Reform Strategy and Roadmap for the 2014 – 2025, is the development of a technology based Model Power Purchase Agreements (PPAs) in 2015 [38], [41], [58]. The Model PPAs is used as guide between power off-taker and the project developers, when negotiating power projects with capacity exceeding 10 MW [58]. The technologies covered in the Model PPAs are hydropower, solar, wind, geothermal, natural gas, coal and oil.

Rural Energy Fund

The Rural Energy Fund (REF) provides capital subsidies to rural energy project developers (private individual, public entities, co-operatives and local communities) in Tanzania [43-44]. The Fund is intended to draw down the capital costs of investing in modern rural energy projects. It helps to reduce investors’ risk and improve their returns on rural energy projects investment, also lowering the final cost of electricity supplied to rural customers. The REF are derived from the following sources [43-44]:

- 5% levies on commercial generation of electricity to the grid

- Government's annual budgetary allocation
- Interest or return on investment
- Contribution from development partners, among others.

The Rural Energy Board (through the REA) assigned a "Trust Agent", whose responsibility is to evaluate the qualified developers and disburse the payment grant to such developers to co-finance their equity contributions and loans procured from banks and donors [44]. Therefore, the Trust Agent as of June 2015 was M/s Tanzania Investment Bank Limited (TIB).

3.3 Barriers to High RE deployment in Kenya and Tanzania

Despite the regulatory tools designed by the respective government of Kenya and Tanzania to attract private investment in the country, the investment level in renewable electricity is presently not sufficient to meet the rapid growing demand for electricity in the two countries [41]. The potential barriers to renewable energy deployment in Kenya and Tanzania include:

a) Political will of decision makers

The key barriers to RE deployment in Kenya and Tanzania is the political will of the decision makers. Kenya through the LCPDP 2011 – 2031, is determined to increase the use of fossil fuels for its electricity generation [8]. The reason is the country's pursuit of least-cost power generation options to meet the anticipated demand for electricity in the future. Similarly, Tanzania has also planned to diversify the sources of electricity generation to include mainly natural gas and coal, complemented with small portion of renewable energy resources (see table 9) [31]. Tanzania is trying to wean itself off the expensive oil-powered power plants.

b) Economic and financial issues

Renewable energy projects have high capital cost [9]. Finding long term financing at favourable rates is a major hurdle. The local banking sector seems not to have adequate knowledge about renewable energy projects compared to their familiar customer base such as construction projects, and as such, often view the former as a high risk sector. In Tanzania, TANESCO's late payments to the SPPs which sell electricity to the former, is also reported to have make it difficult for the SPPs to operate and obtain finance for new projects [33], [41].

c) Ageing electricity facilities

A number of the existing transmission and distribution lines in Kenya and Tanzania are old, and do not have adequate capacity to effectively manage the present demand [14], [38-41]. Meanwhile, RE projects often require strong network development so that power system can access high-quality solar, wind and geothermal resources, which are often remote from existing lines.

d) Other barriers

Another challenge that project developers have faced in recent times in Kenya and Tanzania is in form of resistance from local communities especially over land issues. Few years ago, the Lake Turkana wind project, and Kinangop wind park (combined power capacity of 370 MW) were initially given up before they later resumed construction operation, due to delays and hostility from the local communities over land and compensation issues [1], [60]. It was also reported that KENGEN, the state-owned generation company, faced similar protests for its Olkaria geothermal project in 2012. Similarly, a number of REA's projects in Tanzania have been stalled due to compensation demands from the local communities [44].

Table 15 highlights the key constraints associated with different renewable energy resources in Kenya and Tanzania.

Table 15. Barriers to RE deployment in Kenya and Tanzania [9], [61]

<table>
<tr><th rowspan="2">Renewable Energy Resources</th><th colspan="2">Barriers/challenges</th></tr>
<tr><th>Kenya</th><th>Tanzania</th></tr>
<tr><td>Solar Energy</td><td>• High upfront capital cost for solar power plant.
• Frequent theft of solar PV panels, which in turn discourages its installation
• Proliferation of sub-standard solar energy technologies and equipment</td><td>• high initial cost
• Inadequate credit and financing mechanisms.</td></tr>
<tr><td>Wind Energy</td><td>• High initial costs of wind power generation equipment
• Strong investment in transmission and distribution facilities due geographically disperse nature of this resource
• Land constraints and limited area for wind turbine and transmission lines installation
• Insufficient wind regime data.</td><td>• High investment costs of wind technologies
• Integration and compatibility to the grid system
• Long-distance transmission
• Inadequate wind regime data</td></tr>
<tr><td>Hydropower</td><td>• Vulnerability to variations in hydrology and climate change, leading to drop in water levels in the reservoirs, which has consequently reduced the contribution of hydro power in the energy mix.
• No sufficient storage capacity in current power generating reservoirs.
• Water levies that have a direct effect on the cost of hydro generated electricity.
• Competing and conflicting interest in land and water use
• Vandalism of electric power infrastructure</td><td>• Vulnerability to variations in hydrology and climate change
• Regional mismatch between main demand centres and the hydropower sites</td></tr>
</table>

Geothermal Energy	• High upfront investment costs. • High investment in transmission and other support infrastructure due to the geographical disperse of these resources. • High resource exploration and development risks. • Land use conflict. • The resources are site specific.	• High investment costs • High exploration risks • Remote location of geothermal fields • Undeveloped infrastructures
Biomass	• Biomass resources are used in an unsustainable manner. • Weak enforcement of the legal and regulatory framework to support sustainable production, distribution and marketing of biomass	• No strong legal and institutional framework to support sustainable production, distribution, supply and use of wood fuel • Low conversion and end-use efficiency

4 ENERGY SYSTEM MODEL OF CASE COUNTRIES

The way electricity is produced and consumed today is gradually changing, and there is uncertainty regarding how this could evolve in the future [80]. In this chapter, energy system scenarios for Kenya and Tanzania are developed and simulated using EnergyPLAN model to outline possible pathways to a highly cost-effective, independent and emission free energy system for these two countries by 2050. The energy scenarios should not be viewed as a prediction of what will happen in the future, but as an “if-then” analysis [63]. Energy scenarios provide energy ministries, society and other stakeholders with an indication of how they can shape the future energy system, by outlining the implications of various options.

4.1 The EnergyPLAN simulation tool

The EnergyPLAN simulation model was employed for this study. The model is a deterministic, input/output simulation model that assists in the design of energy systems on a regional, national or multi-national level, on the basis of different technical regulation and market-economic optimization strategies [64], [71-72]. The energy system analysis is carried out in hourly steps throughout the year. The feasibility of this simulation tool for energy system modelling has been widely reported and verified in literature. The tool has been used successfully to simulate energy systems with high shares of RE for several countries [65-70], including Finland [71]. The advantages of EnergyPLAN have been well documented in [64].

The model may include the entire energy system with all consumption sectors, all energy carriers and a variety of energy resources including fossil fuels, RE and nuclear power. It has been developed with particular attention to high RE systems which are crucial to achieve high penetration of low carbon energy resources in the energy mix [70]. It is on the other hand also an aggregated model, where different kinds of generation, conversion and consumption units are aggregated into fewer units. Figure 17 illustrates the general structure of the EnergyPLAN simulation model.

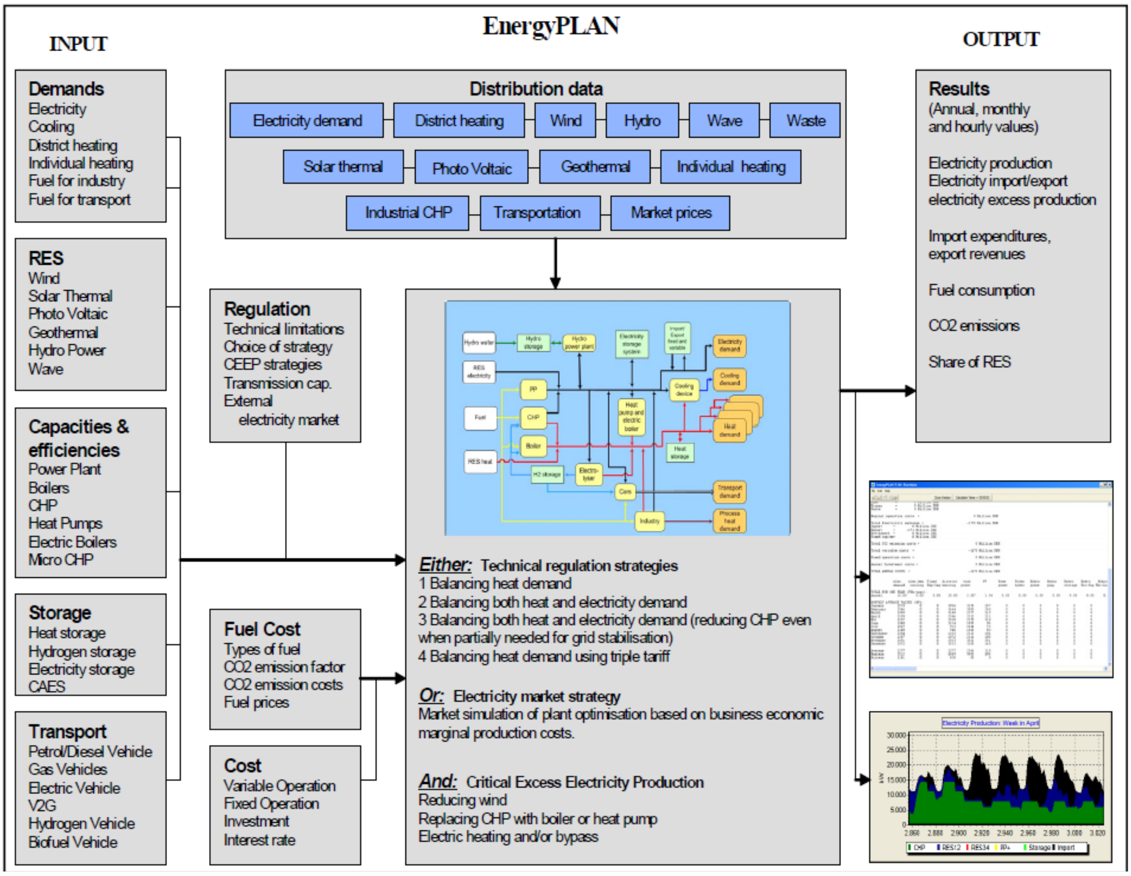


Figure 17. The Structure of the EnergyPLAN tool [72].

The EnergyPLAN simulation tool is an input/output model as illustrated in figure 17. The model uses demands, RES, energy station capacities, costs, and different kinds of regulation strategies as inputs, and calculates energy balances and associated annual productions, CO_2 emissions, fuel consumption, as well as the total costs including income from the exchange of electricity as outputs. A full description of EnergyPLAN tool and its uses can be found at [72].

The newest version (EnergyPLAN 12.5) was released in October 2016 and it contains some new additional features [72]. These include the MultiNODE Help tool that allows user to link multiple EnergyPLAN scenarios, among others. However, the model has some few limitations related to its ability to simulate Kenyan and Tanzanian energy system. First, it does not accurately model today's energy systems due to emphasis on future, low-carbon technologies. Second, the entire generation plant capacity are treated as single process for entire area. Consequently, this aggregation does not enable easy inclusion of plants of different age, size, efficiencies, etc. Generally, it assumes the nominal and peak capacity to be the same, which might not always be true, but correction factors can be used to adjust energy output if necessary [71].

4.2 Energy scenarios overview

Using EnergyPLAN, a reference model for 2014 for Kenya and Tanzania will first be established and verified for accuracy based on 2014 data, to ensure the model is valid for further use. After validating the reference models, three (3) future scenarios are developed for each country and discussed in details to show possible pathways to a highly cost-effective, independent and emission free energy system for these two countries by 2050. The main inputs to the EnergyPLAN tool, including important assumptions and sources of information are outlined in the subsequent sections. The modelling details of Kenyan energy system will be presented first, followed by that of Tanzania.

4.2.1 Kenyan Energy System Model

a) 2014 reference scenario and verification

In a similar manner to other studies [65], [70-71], a reference model of Kenyan energy system for year 2014, which is the most recent year with complete data was created and the accuracy of the results were verified. The basic input data to EnergyPLAN such as the annual electricity demand, fuel consumption of different sectors and generation capacities were based on information available from the International Energy Agency (IEA) statistics database of energy balance [5] and some local data [8], [79], unless otherwise stated. The hourly load distribution profile was computed based on the available synthetic load data for Kenya.

According to IEA [5], the total electricity demand of Kenya in 2014 was defined as 7.69 TWh. The total demand in industry, transport and other sectors for year 2014 were also derived from the [5]. On the supply side, the total installed generation capacity in

2014 was 1885 MW [79], composed of wind onshore 5.9 MW, solar PV 0.7 MW, hydropower 817.81 MW, geothermal 363 MW, biomass cogeneration 26 MW and condensing (diesel and gas-fired) power plant 671.50 MW. The distribution profile for solar PV, hydropower, and wind was created to represent the hourly production of each of these technologies in Kenya.

These parameters are implemented in EnergyPLAN model, and results are compared with the actual data from the IEA data [5]. This stage is necessary to validate the method and models created in EnergyPLAN simulation tool. Table 16 presents the results of the electricity production in Kenya in 2014.

Table 16. Comparison of EnergyPLAN power production results and actual data in 2014 for Kenya

Production mode	Actual 2014 [5] (TWh)	EnergyPLAN 2014 (TWh)	Difference (TWh)
Hydropower	3.31	3.31	0.00
Wind power	0.04	0.04	0.00
Solar PV power	0.00	0	0.00
Condensing power	1.71	1.73	0.02
Geothermal	4.06	4.06	0.00
Biomass Cogeneration	0.14	0.13	-0.01
Total production	9.26	9.27	0.01
Import	0.08	0.06	-0.02
Export	-0.04	-1.64	-1.60
Domestic Supply	9.30	7.69	-1.61

It will observed from table 16, that the EnergyPLAN results agree to an extent with the actual data from the IEA. Further, the values of the total fuel consumption and CO_2 emissions obtained from EnergyPLAN model were also compared with the actual data from IEA [5]. The results are compiled in table 17.

Table 17. Comparison of EnergyPLAN fuel consumption results and actual data in 2014 for Kenya

Consumption parameter	Actual 2014 [5] (TWh)	EnergyPLAN 2014 (TWh)	Difference (TWh)
Coal	3.81	3.81	0.00
Oil	39.25	40.91	1.66
Natural gas	0.00	0.00	0.00
Biomass	122.05	122.5	0.45
Total fuel consumption	165.11	167.22	2.11
Annual CO_2 emissions (Mt)	12.35	12.20	-0.15

As displayed in table 17, the simulation results are quite close to the actual data. Thus, the accuracy of the EnergyPLAN results is assumed to improve significantly as the simplications and generalizations of parameters of future energy systems become an inherent part of the scenario design [71]. Therefore, the simulation will be employed in the future scenarios to represent the energy system performance for 2030 and 2050 respectively.

b) Planning future energy system scenarios for Kenya

This section will briefly describes the three (3) future energy system scenarios developed for Kenya in this report, and outline the key scenario parameters and assumptions used in modelling Kenyan energy system. The future energy system scenarios developed for Kenya in this report are highlighted below.

The **BAU scenario for 2030 (2030 BAU).** In this scenario, the fuel mix for power generation proposed by the government of Kenya in the LCPDP 2011-2031 [8], was taken into account. The government has planned to increase the use of fossil fuels, following the recent discoveries of oil and coal deposits few years ago in Kenya. The aim of this scenario is to analyse the impact of such proposal on energy, environment (CO_2 emission) and total annual cost of the energy system. The average energy growth rate collected from the LCPDP report [8], was used to estimate the annual electricity demand forecast for the 2030 and 2050 scenarios. The transport and industrial fuel demand projections in this scenario are based on the historical trend from IEA [5]. A technical simulation was performed using EnergyPLAN, where EnergyPLAN balanced both heat and electricity demands within the domestic energy system when possible. Further, the interconnections with the neighbouring countries allow for regional power trading.

Second, the **RE scenario for 2030 (2030 RE)**. This scenario was designed, in order to achieve the targeted carbon emission reduction level proposed by the government of Kenya in [6] by 2030. As a result, some scenario parameters were changed in the BAU scenario. These include a significant reduction in coal consumption in all sectors and an obvious increase in RE utilization particularly in the power sector. However, the total consumption level for different sectors in this scenario was set at almost the same level as that of 2030 BAU scenario. This is to facilitate comparison between the two scenarios developed for 2030.

Lastly, the **100% RE scenario for 2050 (2050 100% RE)**. The aim of the 2050 100% RE scenario is to build a functional and highly independent energy system for Kenya by 2050. The scenario was modified through several steps of iteration to eliminate the import of either electricity or natural gas from neighbouring countries. Similar to the assumption was made in the Tanzanian's 2050 scenario, the inefficient use of traditional biomass in the residential sectors will be replaced by alternatives such as solar cookers, improved biomass cooking stoves and small-scale biogas and digester. This development process will provide business opportunities for many players [74]. The industrial sector is assumed to have improved energy use by 2050. Coal and oil fuels usage in industrial sector will also be phased out and replaced by synthetic grid gas and sustainable biomass. The scenario also assumed a shift to electric vehicle and biofuel in the transport sector by 2050.

Electricity demand

The key scenario parameters and assumptions made in modelling Kenyan energy system scenarios for 2030 and 2050 are outlined below. First, the population growth projections of

Kenya from 2012 to 2050 are given in table 18.

Table 18. Projected population growth in Kenya [73].

	2012	2014	2030	2040	2050
Population (million)	43.01	45.01	56.55	64.06	70.76
Population Growth rate (% per year)	2.40%	1.9 %	1.2%	1.2%	0.8 %

The population projections and economic growth rate are important parameters in designing energy system model, as they affect the size and composition of energy demand [63], [74]. As estimated in the LCPDP [8], the average energy growth for the period 2010-2031 for the country's low and medium growth scenario is 11.9% and 13.4% respectively. These estimates was used to forecast the electricity demand in buildings and industry for 2050 in this report. Table 19 presents the electricity demand projections for Kenya. Today, there is no demand for electricity in the transport sector in Kenya [5], but electric vehicles offer the opportunity for the sector to significantly reduce dependence on oil products consumption. The projection for the electricity demand in transport are cross checked towards those found in literature for developed countries [81].

Table 19. Electricity demand forecast for Kenya

	2014 [5] (TWh)	**2030 BAU (TWh)**	**2030 RE (TWh)**	**2050 RE (TWh)**
Electricity demand in household and industry	7.69	69.84	69.84	131.63
Electricity demand for transportation	0	4	4	16
Electricity demand for Power-to-Gas (PtG) process	0	0	0	69.16[7]
Total annual electricity demand	7.69	73.84	73.84	216.85

[7] The electricity demand for the PtG process was generated from EnergyPLAN output based on estimates of needed capacity to prevent any need for the conventional natural gas.

The transport demands are defined in terms of passenger kilometre. It was assumed about 25% and 90% of transport demand are powered by electricity for the 2030 and 2050 scenario respectively.

Other energy consumption/fuel use

The projections for the industrial fuel demand are presented in table 20. The forecast for the 2030 BAU scenario was based on the historical trend from IEA statistics for Kenya [5]. This decision is similar to the one made in [70]. In the case of the 2030 and 2050 RE scenarios, the values are defined based on the scenario assumptions to gradually phase out fossil fuel usage by 2050.

Table 20. Industrial fuel use in Kenya (excluding the demand for electricity)

Source	**Industrial Fuel Use (TWh)**			
	2014 [5]	**2030 BAU**	**2030 RE**	**2050 100% RE**
Coal/peat	3.81	10.5	5.5	0
Oil	6.23	16.5	8.0	0
Natural gas/Grid gas	0	4.0	8.50	20
Biomass	0	7.0	16	35
Total	10.04	38	38	55

A summary of the transport demand forecast used excluding the demand for electricity in Kenya formulated in this report is provided in table 21. The assumptions are similar to one made for the industrial sector. It was assumed that biofuels (biodiesel, biopetrol and biojetfuel) will account for 10% of the transport demand by 2050, with rest coming from electricity. Excluding air travel, transport demands represent 36 billion passenger km/year in 2014, 76 billion passenger km/year in 2030, and 88 billion passenger km/year in year 2050.

Table 21. Transport fuel use in Kenya, excluding demand for electricity

Source	Transport Fuel Use (TWh)			
	2014 [5]	**2030 BAU**	**2030 RE**	**2050 100% RE**
Diesel	13.86	19.00	13.50	0
Petrol	10.30	14.00	10.30	0
Natural gas	0	0	0	0
Jet Fuel	0.02	0.50	0.50	0
Biofuel	0	4.00	13.20	6.50

The energy demand projections of other sectors (residential, commercial, agriculture etc.) excluding demand for electricity is given table 22.

Table 22. Fuel use in other sectors (excluding demand for electricity)

Source	Fuel consumption in other sectors (TWh)			
	2014 [5]	**2030 BAU**	**2030 RE**	**2050 100% RE**
Coal	0	2.00	0	0
Oil products	4.91	10.00	7.00	0
Biomass	122.05	141.60	119.80	98

Power generation capacity

Furthermore, the installed generation capacities for each of the scenarios are highlighted in table 23. The electricity generation mix in the 2030 BAU scenario was designed to represent the proposed power generation mix in [8]. The condensing power plant is powered by coal, natural gas and diesel. As previously mentioned in section 2.1.3 of this report, Kenya is seeking to add a 1000 MW nuclear plant to it energy mix by 2027 [62] and a cumulative capacity of 4000 MW by 2033 [8]. Therefore, the capacity of the nuclear power plant was set at 1000 MW for the 2030 BAU scenario.

Table 23. Installed power generation capacities in Kenya

	Installed Capacity in MW			
Technology	**2014 [79]**	**2030 BAU [8]**	**2030 RE**	**2050 RE**
Wind onshore	5.9	2036	4500	24000
Solar PV	0.70	0	7000	65000
Hydropower	817.81	1039	1100	2000
Geothermal	363	5530	5530	6900
Biomass cogeneration	26	50	50	50
Condensing PP	671.50	7015	3080	13500
Nuclear power	0	1000	0	0
PtG (CH_4)	0	0	0	18904
Total	1885	16670	21260	130000

In the RE scenario for 2030, the generation mix was developed to accommodate more RE utilization in the government's proposed power mix for 2030. The coal power plants was eliminated and the existing condensing power plant in this scenario uses natural gas and a little of oil as fuel. It is assumed that a minimum capacity of 115 MW of condensing power plant capacity, must run at all times to provide grid stability. This decision is similar to the one made in [69, 71]. Another important distinction made in the 2030 RE scenario is the total elimination of the nuclear power plant, which in turn remove public fears and worries about nuclear plant accident.

In the 2050 100% RE scenario, the installed power capacity in Kenya is estimated to reach 111 GW by 2050 (excluding the capacity for the PtG process). Solar PV capacity was set at 65 GW in this scenario. It is assumed that half of the solar PV capacity would be located on residential or commercial rooftops and other half in larger, ground-mounted plants. Assume that a ground-mounted solar arrays can be installed at a density of 0.02 km^2/MW [71], the land area needed for such solar panels would be about 1300 km^2 - which is equivalent to about 0.22% of total Kenyan land mass (581,309 km^2).

The onshore wind power capacity was set at 24 GW. According to [8], Kenya has a land area of about 90,000 km^2 with very excellent wind speeds of 6 m/s and above. It was estimated further that less than 150,000 households reside in the those areas considered to have excellent wind speeds, which offers possibilities for large scale wind farms as there would be minimal human interference [8]. The geothermal energy is currently the most promising local energy resources in Kenya for power generation [8], and the capacity was set at 6900 MW in this scenario. The hydropower capacity was set at 2000 MW. The limiting factors to hydropower development in Kenya are already highlighted in chapter 3. Other RE technologies (tidal, CSP solar power, wave power and offshore wind) were available as tools within the EnergyPLAN model. However, these technologies were not considered in this scenario for some reasons. The feasible potential of these resources are rather low [7-9] and the cost of these technologies may need serious consideration [71].

1 TWh of synthetic methane was created in a CO_2 hydrogenation facility of 12,000 MWgas capacity. This facility consists of an electrolyser operating at 73% conversion efficiency and a methanation unit that required 0.289 TWh per TWh of CO_2 recycled from air. In addition, it was assumed that 0.252 Mt of CO_2 would be needed per TWh of synthetic methane produced. The synthetic grid gas produced is used as fuel for the existing condensing power plant in the power sector and industry as the use of fossil fuels was totally eliminated in the 2050 scenario.

Battery and Gas storage

Next, 20 GWh of stationary electric battery (lithium ion) storage was introduced. Battery storage was also made available from the electric vehicles. 2 million vehicles were assumed to each have a 50 kWh lithium ion battery, which is equal to 100 GWh of capacity. It was assumed that the maximum share of cars during the peak demand would be 20%, the share of parked cars that were grid connected would be 70% and that capacity of connection between the grid and batteries would be 6250 MW, giving an energy-to-power ratio of 8. About 75% of the transport demand was classified as a one-way, dump charge, and the other 25% was classified as having the capacity to be a two way, smart charge.

Therefore, only three-quarter of the battery capacity was available for Vehicle-to-Grid (V2G) services. Lastly, the grid gas storage was set at 7 TWh, an estimated capacity needed to prevent any need for import.

These parameters are then implemented in EnergyPLAN tool and a series of iteration were undertaken to find a least-cost solution. A technical simulation was performed using EnergyPLAN, whereby EnergyPLAN balanced both heat and electricity demands within the domestic energy system when possible. The interconnections with the neighbouring countries allow for regional power trading of the excess electricity generated. Electricity market data created for the 2014 was used to represent the 2050 market.

4.2.2 Tanzanian Energy System Model

a) 2014 reference scenario and verification

In a similar manner to the case of Kenya discussed in section 4.2.1, a reference model of Tanzanian energy system for year 2014, which is the most recent year with complete data was designed and the accuracy of the results were verified. The hourly electricity demand distribution profile is derived based on the available synthetic load data for Tanzania. The basic input data to EnergyPLAN such as the annual electricity demand, and fuel consumption of different sectors were based on information available from the IEA statistics database of energy balance [34], unless otherwise stated.

The annual electricity demand for 2014 was defined as 5.21 TWh for Tanzania [34]. The annual fuel demands for industry, transport and other sectors were then specified as obtained from the IEA statistics [34]. On the supply side, the total installed power generation capacity was 1671 MW as at 2014 [77] and the breakdown is provided in table 24 below. The distribution profile for solar PV, hydropower, and wind were also created to represent the hourly production of each of these technologies in Tanzania.

Table 24. Tanzania's installed generation capacities as of 2014 [77].

Technology	**Installed Capacity (MW)**
Wind onshore	0
Solar PV	6
Hydropower	608
Geothermal	0
Biomass cogeneration	35
Condensing PP	1022
Power-to-Gas (PtG) - (CH_4)	0
Total	1,671

These above-mentioned data are then simulated in EnergyPLAN model, and the results are compared with actual data as presented in table 25-26. This stage is very important to ensure that the simulation tool is capable of generating accurate simulation results of Tanzanian energy system. The EnergyPLAN simulation model automatically generates some results (for example, the primary energy supply, CO_2 emissions), and few need manual calculations based on the results. Table 25 compares the EnergyPLAN output values with actual production data for Tanzania.

Table 25. Comparison of EnergyPLAN power production results with actual data for Tanzania 2014

Production mode	Actual 2014 [34] (TWh)	EnergyPLAN 2014 (TWh)	Difference (TWh)
Hydropower	2.59	2.59	0.00
Wind power	0	0	0.00
Solar PV power	0.02	0.02	0.00
Condensing power	3.59	2.45	-1.14
Biomass Cogeneration	0.02	0.27	0.25
Total production	6.22	5.33	-0.89
Import	0.06	0.00	-0.06
Export	0.00	-0.11	-0.11
Domestic Supply	6.28	5.22	-1.06

As shown in table 25, difference between actual data and the simulation results for the electricity production are quite small. This implies that the EnergyPLAN model is able to provide an accurate representation of the power production in Tanzania for 2014. The largest difference occurs in the case of condensing power plant. The reason is that EnergyPLAN have difficulties representing, in an aggregated manner, all the thermal power plants (oil, natural gas, and diesel-fired plant) of the current heterogeneous Kenyan and Tanzanian energy system as previously mentioned. The efficiency of the condensing power plant (30%) used is a combined value of all thermal plants due to the aggregation in EnergyPLAN, and is calculated based on the total fuel consumed and total electricity generated. However, such difficulties will disappear when the thermal power plant are replaced with RE plants in the future energy system scenarios.

Subsequently, other outputs were examined to determine the accuracy of the EnergyPLAN model, including total fuel consumption and CO_2 emissions. These results were compiled in table 26.

Table 26. Comparison of EnergyPLAN fuel consumption results with actual data for Tanzania 2014

Consumption parameter	Actual 2014 [34] (TWh)	EnergyPLAN 2014 (TWh)	Difference (TWh)
Coal	1.77	1.77	0.00
Oil	28.31	30.91	2.60
Natural gas	4.51	5.76	1.25
Biomass	213.74	214,64	0,90
Total fuel consumption	248.33	253.08	4.75
CO_2 emissions (Mt)	10.37	10.01	-0.36

It will be observed that the simulation results for the annual fuel use and CO_2 emission are quite close to the actual data. The accuracy of the EnergyPLAN results is assumed to improve significantly as the simplications and generalizations of parameters of future energy systems become an inherent part of the scenario design [71]. Therefore, the simulation tool will be employed in the future scenarios to represent the energy system performance for 2030 and 2050 respectively.

b) Planning future energy system scenarios of Tanzania

This section briefly describes the future scenarios modelled for the Tanzanian energy system, and outlines the key scenario parameters and assumptions used for the modelling. The scenarios include:

First, the **Business-as-usual scenario for 2030 (2030 BAU).** This scenario is based on the country's Electricity Supply Reform Strategy and Roadmap 2014-2025 projections for the power sector [31]. In this scenario, the fuel mix for power generation proposed by the government of Tanzania was taken into account.

Second, the **renewable energy scenario for 2030 (2030 RE scenario)**. This scenario was designed to provide energy stakeholders in Tanzania with an indication of how they can shape the future energy system by outlining the implications of various options. This scenario focuses on increasing the RE share in the government's proposed power generation mix, and dramatically reducing the use of fossil fuels across different sectors in Tanzania. As a result, a number of scenario parameters was changed in 2030 BAU scenario for Tanzania. However, the total demand of each sector in the 2030 RE scenario are kept almost at the same level as that of the 2030 BAU scenario. This approach was used to facilitate comparison with the BAU scenario in term of energy, environmental, and economic impact.

Lastly, the **100% RE scenario for year 2050 (2050 100% RE)**: The aim of this scenario is to build a functional and highly independent energy system for Tanzania by 2050. It is assumed that the inefficient use of traditional biomass in the residential sector, will be replaced by alternatives such as solar cookers, improved biomass cooking stoves and small-scale biogas and digester. This development process will provide business opportunities for many players. Further, the industrial sector is assumed to have improved energy use by 2050. Coal and oil fuels use in industrial sector will also be phased out and replaced by synthetic grid gas and sustainable biomass. The scenario envisions a shift to biofuel and electric vehicle in the transport sector by 2050. Domestic biofuel production will provides huge business potential for new players, and the electrification of transport sector will leads to significant gains in efficiency [80-81].

Electricity demand

In planning future energy system scenarios, many factors including sociological, technological, demographic, economic and regulatory changes are considered [81]. For example, population and economic growth, consumer behaviour, change in energy prices, gain in efficiency and process improvements. The reason is that they affect the size and composition of energy demand. Table 27 presents the projected population growth of Tanzania from 2012 to 2050 according to [73].

Table 27. Projected population growth in Tanzania [73].

	2012	2014	2030	2040	2050
Population (million)	49.91	49.64	76.07	96.40	118.59
Population Growth rate (% per year)	2.80 %	2.80 %	2.50 %	2.20 %	1.90 %

Due to the forecasted population increase, GDP growth and improved standard of living in Tanzania by 2050, the energy demand of different sectors in Tanzania is expected to increase significantly from the present situation. In this study, the electricity demand forecast in building (residential, commercial and industry) for 2030 and 2050 scenarios are calculated based on the average energy growth rate projections derived from [74], and these values are presented in table 28. Although there is presently no demand for electricity in the transport sector in Tanzania [34], electric vehicles offer the opportunity for the sector to significantly reduce dependence on oil products consumption. The estimates of electricity demand for transportation in Tanzania was based on projection from developed countries [81]. It was assumed electricity will account for about 10% of the transport demand in the 2030 BAU scenario, 50% of the transport demand in the 2030 RE scenario, 90% of the transport demand in the 2050 RE scenario.

Table 28. Electricity demand forecast for Tanzania

	2012 [33] (TWh)	2014 [34] (TWh)	2030 BAU (TWh)	2030 RE (TWh)	2050 RE (TWh)
Electricity demand in household and industry	4.27	5.21	18.44	18.44	79.78
Electricity demand for transportation	0	0	1.5	6	13
Electricity demand for PtG process	0	0	0	0	70.89[8]
Total annual electricity demand	4.27	5.21	19.94	22.44	163.67

Other energy consumption/fuel use

The energy consumption pattern of different sectors (industrial, transport and others) in Tanzania differs, and each sector is modelled based on its demand for final services using the historical trend from IEA [34] to form the basis for the model. A summary of the key scenario parameters used in modelling the Tanzanian energy system scenarios for 2030 and 2050 are provided in the following table 29-31.

Table 29. Industrial fuel use in Tanzania (excluding the demand for electricity)

Source	Industrial Fuel Use (TWh)			
	2014 [34]	2030 BAU	2030 RE	2050 100% RE
Coal/peat	1.77	6.08	2.00	0
oil	2.38	7.60	3.50	0
Natural gas/Grid gas	1.69	7.60	14.50	25
Biomass	30.38	54.72	56.00	65
Total	36.22	76.00	76.00	90

[8] The electricity demand for the PtG process was obtained from the EnergyPLAN output based on estimates of needed capacity to prevent any need for the conventional natural gas.

The forecast for the transport fuel use is presented in table 30. The transport demands are defined in terms of passenger kilometre. Excluding air travel, transport demands represent 34 billion passenger km/year in 2014, 60 billion passenger km/year in 2030, and 70 billion passenger km/year in year 2050. It was assumed that electricity will account for about 90% of the transport demand in 2050, with the rest coming from biofuels (biodiesel, biojetfuel, and bioethanol).

Table 30. Transport fuel use in Tanzania, excluding demand for electricity

Source	Transport Fuel Use (TWh)			
	2014 [34]	**2030 BAU**	**2030 RE**	**2050 100% RE**
Diesel	14.57	18.20	5.80	0
Petrol	8.37	12.50	4.00	0
Natural gas	0	0.20	0.20	0
Jet Fuel	0	1.00	1.00	0
Biofuel	0	4.00	10.00	4.30

The fuel consumption in households for cooking and heating as well as in other sectors (commercial, public services, agriculture etc.) in Tanzania excluding demand for electricity is given in table 31

Table 31. Fuel use in other sectors (excluding demand for electricity)

Source	Fuel consumption in other sectors (TWh)			
	2014 [34]	**2030 BAU**	**2030 RE**	**2050 100% RE**
Coal	0	0	0	0
Oil products	1.52	3	0	0
Biomass	183.37	231	186	98

Power generation capacity

On the supply side, the installed power capacities for major generation technologies in

Tanzania are summarized in table 32. In the 2030 BAU scenario, the power generation mix is designed to represent the proposed fuel mix in [31] which is mainly dominated by fossil fuels.

Table 32. Installed power capacity in Tanzania.

	Installed Capacity in MW			
Technology	**2014 [77]**	**2030 BAU [31]**	**2030 RE[9]**	**2050 RE**
Wind onshore	0	200	2975	25000
Solar PV	6	100	5500	70000
Hydropower	608	2108	2100	2900
Geothermal	0	200	350	650
Biomass cogeneration	35	67	50	50
Condensing power	1022	9800	1500	9950
PtG (CH_4)	0	0	0	17754
Total	1,671	12,475	12,475	126,304

In the 2030 RE scenario, the power generation mix was created by modifying the government proposed fuel mix [31] in order to accommodate more RE particularly solar and wind. The use of coal for power generation is phased out in this period. The existing condensing power plant in the 2030 RE scenario uses natural gas (60%) and oil (40%) as fuel.

In the 2050 scenario, the installed power capacity in Tanzania is estimated to reach 108 GW (excluding the capacity for PtG process) from 1.67 GW in 2014. The solar PV capacity was set at 70 GW in this scenario. It is assumed that half of the solar PV capacity would be located on residential or commercial rooftops and other half in larger, ground-mounted plants. Assume that a ground-mounted solar arrays can be installed at a density of 0.02 km^2/MW [71], the land area needed for such solar panels is calculated to be 1400 km^2 - which is equivalent to about 0.15% of total Tanzanian land mass (945,087 km^2). The

[9] author's estimate is based on [31]).

onshore wind power capacity was set at 25 GW. Though Tanzania has some range of sites (e.g. Kititimo and makambako) with excellent wind resources [32-33]. Other factors considered include the overall cost of electricity generation, social acceptance and possible competing interest in land use with other activities [61].

The hydropower capacity for 2050 was defined as 2900 MW, a slight increase from the 2100 MW capacity [31] proposed by the government for year 2025. It is assumed that the existing plants during this period will be renovated and modernized, so some increase in efficiency and capacity is assumed. Further, the geothermal capacity was set at 650 MW, the feasible potential quantified till date with resources assessment still under preliminary surface studies [33]. Other RE technologies (tidal, CSP solar power, wave power and offshore wind) were available as tools within the EnergyPLAN model. However, these technologies were not considered in this scenario for some reasons. According to [71], CSP was considered as an economically uncompetitive options to solar PV electricity production combined energy storage solutions.

A 2 TWh/year of synthetic methane was created in a CO_2 hydrogenation facility of 11,270 MWgas capacity. This facility consists of an electrolyser operating at 73% conversion efficiency and a methanation unit that required 0.289 TWh per TWh of CO_2 recycled from air. In addition, it was assumed that 0.252 Mt of CO_2 would be needed per TWh of synthetic methane produced. The synthetic grid gas produced is used as fuel for the existing condensing power plant for power generation as well as in industry as the use of fossil fuels are phased out by the end of 2050.

Battery and Gas storage

Battery storage was made available from the electric vehicles. 1 million vehicles were assumed to each have a 50 kWh lithium ion battery, which is equal to 50 GWh of capacity. It was assumed that the maximum share of cars during the peak demand would be 20%, the share of parked cars that were grid connected would be 70% and that capacity of connection between the grid and batteries would be 6250 MW, giving an energy-to-power ratio of 8. About three-quarter of the transport demand was classified as a one-way, dump charge, and the other one-quarter was classified as having the capacity to be a two way, smart charge. Therefore, only three-quarter of the battery capacity was available for Vehicle-to-Grid (V2G) services. Lastly, 16 TWh of natural gas storage was assumed based on estimates of needed capacity to prevent any need for import of gas.

These parameters are implemented in EnergyPLAN simulation tool, and a series of iteration were undertaken to find a least-cost solution. A technical simulation was performed using EnergyPLAN, whereby EnergyPLAN balanced both heat and electricity demands within the domestic energy system when possible. The interconnections with the neighbouring countries allow for regional power trading of the excess electricity generated. Electricity market data created for the 2014 was used to represent the 2050 market.

4.3 Cost Assumptions

The EnergyPLAN model contains broad overview of different costs such as investments, operation and maintenance, fuels, and lifetimes for 2020, 2030, and 2050 [75]. The most recent cost database was updated in January 2016 [75]. In this study, the EnergyPLAN cost distributions developed for 2020 was employed for the 2014 reference scenarios, as data could not be obtained for 2014. The cost distributions for 2030 and 2050 were employed for the 2030 (BAU and RE) scenarios and 2050 RE scenarios respectively. In many case, the EnergyPLAN cost database were used directly, and for those cost assumption that were not originally part of the EnergyPLAN cost database, assumption was made based on [71], [78]. The details of the cost parameters used in this analysis are presented in the Appendix A. The interest rate for annual investment cost was set at 7% for all the scenarios.

In the case of the cost estimate for the power trading, the hourly price data for 2014 for the East African Power Pool are not made available. Therefore, an estimate for the external market price (resulting in an average price of 35 €/MWh) was made based on the electricity price in the region. In the case of all import and export of electricity, the constructed market price was used.

5 SIMULATION RESULTS AND DISCUSSION

This section presents and discuss the results of all the energy system scenarios simulated in the EnergyPLAN model. The scenario results of the Kenyan energy systems will be presented first, followed by that of Tanzania. The full details of the results can be found in Appendix B and C for Kenya and Tanzania respectively.

5.1 Scenario Results of Kenya

Total Primary Energy Supply (TPES)

According to the EnergyPLAN output, the annual primary energy supply of Kenya for each of the scenarios is shown in figure 18. The total primary energy supply (TPES) was 175 TWh in 2014, with biomass (70%) and oil (23%) consumption dominating the primary supply mix.

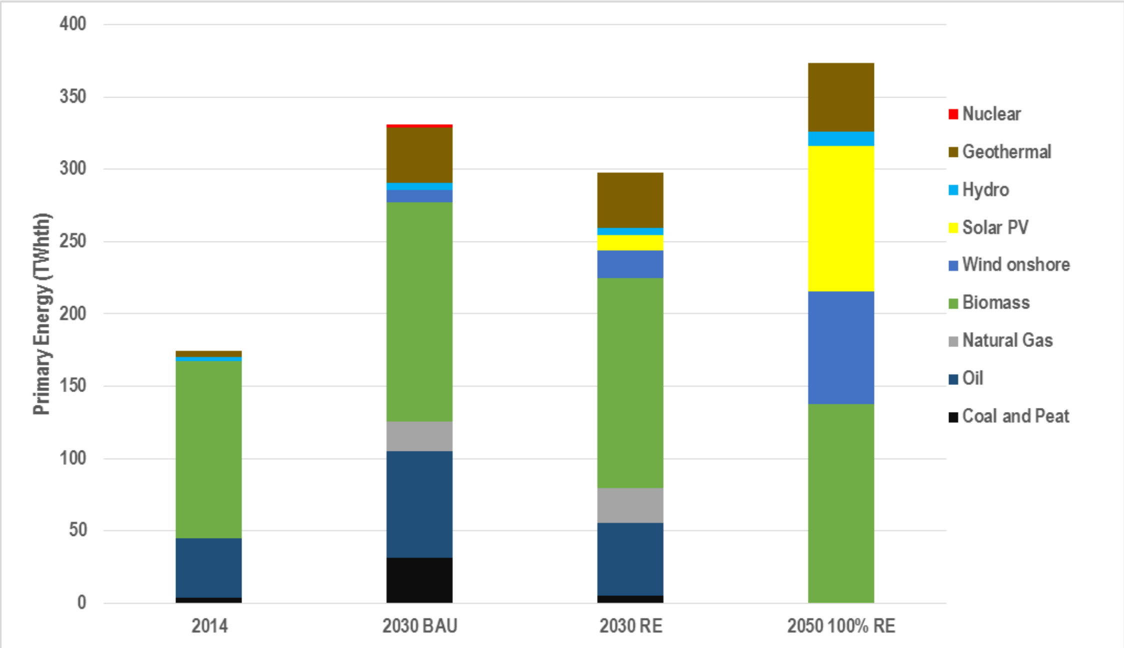


Figure 18. Primary Energy Supply for all scenarios for Kenya. (See Appendix B for numerical values)

The TPES is 331 TWh in the BAU scenario for 2030, 298 TWh in the RE scenario for 2030, and 373 TWh in the 2050 RE scenario. It will be observed in figure 18 that the 2030 RE scenario exhibits a lower energy than in the BAU scenario, due to the fuel transition. There is a significant decrease in the coal consumption in the 2030 RE scenario when compared with the 2030 BAU scenario as the use of coal as fuel in industry as well as for power generation is reduced dramatically. On the other hand, there is an increase in gas consumption in the 2030 RE scenario in order to replace the coal-fired power plants during this period.

In the 2050 scenario, the energy supply is diversified through a mix of different RES. A significant contribution of solar and wind energy is noted in this scenario, alongside with other RES to compensate for lower usage of woody biomass. Biomass contributes about 37% of the primary energy in 2050 compared to 70% share in the 2014 reference scenario. The RE share of primary energy and the associated carbon emissions resulting from the EnergyPLAN simulation for each of the scenarios are presented in table 33.

Table 33. Carbon emissions and shares of RE for all scenarios.

Category	2014	2030 BAU	2030 RE	2050 100% RE
CO_2-equivalent emissions (Mt)	12.20	34.58	20.10	0
Renewables share of primary energy (%)	74.4	61.4	73.3	100

As shown in table 33, the 2030 BAU scenario has the highest CO_2 emission, as the share of conventional fossil fuels increase significantly in this scenario. On comparing the total CO_2 intensity in the 2030 RE and BAU scenarios, a 42% decrease in CO_2 will be observed in the RE scenario, which can meet the government's carbon emission reduction target by 2030 in [6].

The 2050 scenario results in a 100% RE system and the CO_2 emission from the energy system is equal to zero. The increased use of renewable electricity for cooking and heating in residential, electric vehicle in transport sector, and improved use of energy in industry and efficiency gains significantly reduced the emissions in the energy sector. This result indicates that a 100% renewable energy system is technically possible in Kenya by 2050 by unleashing actions and investments toward low carbon and sustainable future.

Annual Electricity Production by Sources

The annual electricity production of Kenya in each of the scenarios is shown in figure 19. The results indicate that generation capacities of solar PV, geothermal and wind are significantly increased in order to eliminate the fossil fuels usage for power generation. In the 2030 BAU scenario, the electricity production from geothermal is 37.85TWh, from wind 8.57 TWh, from hydro 4.88 TWh, from nuclear 2.07 TWh and from the condensing PP 22.08 TWh. In the case of the 2030 RE scenario, electricity generated from geothermal is 37.85 TWh, from wind 18.99 TWh, from hydro 5.23 TWh, from solar PV 10.84 TWh and from the condensing PP 11.82 TWh. Higher production of electricity from wind energy is noticed in the 2030 RE scenario, despite the low installed capacity of wind power compared to solar PV in this scenario. This suggests wind onshore as a promising renewable energy in Kenya.

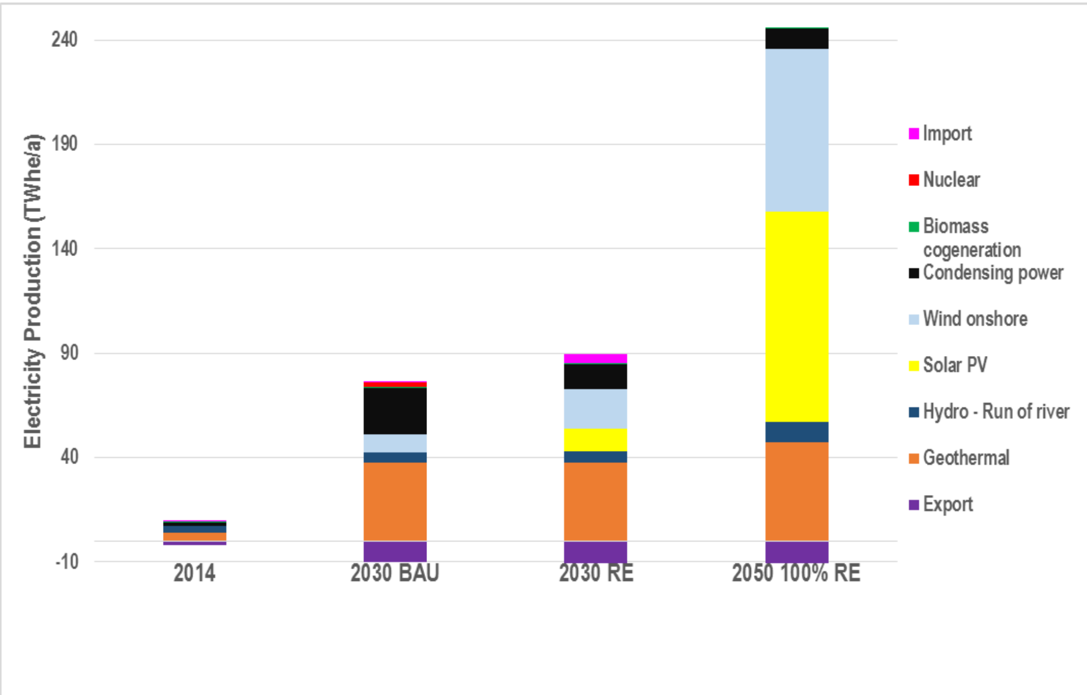


Figure 19. Total electricity production by source in scenarios (export indicated as negative)

The role of RE are expanded in the 2050 scenario, with wind, solar and geothermal energy providing the backbone of Kenyan energy system. Solar PV generates 101 TWh of the electricity production in 2050, which represents 47% of the total electricity production on 2050. Production of electricity from hydropower 9.73 TWh, from geothermal 47.23 TWh and from wind 77.62 TWh. With the huge geothermal energy potential in Kenya, it is capable of providing base load power for the national electricity system by 2050. Table 34 summarizes the numerical values of the total electricity production by different technologies for each of the scenarios in Kenya.

Table 34. Total electricity production by different technologies in Kenya

Technology	Electricity Production (TWh_e)			
	2014	**2030 BAU**	**2030 RE**	**2050 100% RE**
Hydro - Run of river	3.31	4.88	5.23	9.23
Wind onshore	0.04	8.57	18.99	77.62
Solar PV	0	0	10.84	100.96
Geothermal	4.06	37.85	37.85	47.23
Condensing PP	1.73	22.08	11.82	9.88
Biomass cogeneration	0.13	0.42	0.44	0.11
Nuclear power	0	2.07	0	0
Import	0.06	0.78	4.16	0
Export	-1.64	-9.97	-15.49	-28.65
Total	7.69	66.78	73.84	216.88

Total electricity consumption

The total electricity consumption for each of the scenarios in Kenya is shown in figure 20. There is a much closer relationship between the total electricity production and electricity consumption in all the scenarios. The electricity consumption in household and industry dominate the total consumption all the scenarios. In the 2050 100% RE scenario, there is a large demand for electricity in the PtG process, mostly in the case when synthetic methane is the end product.

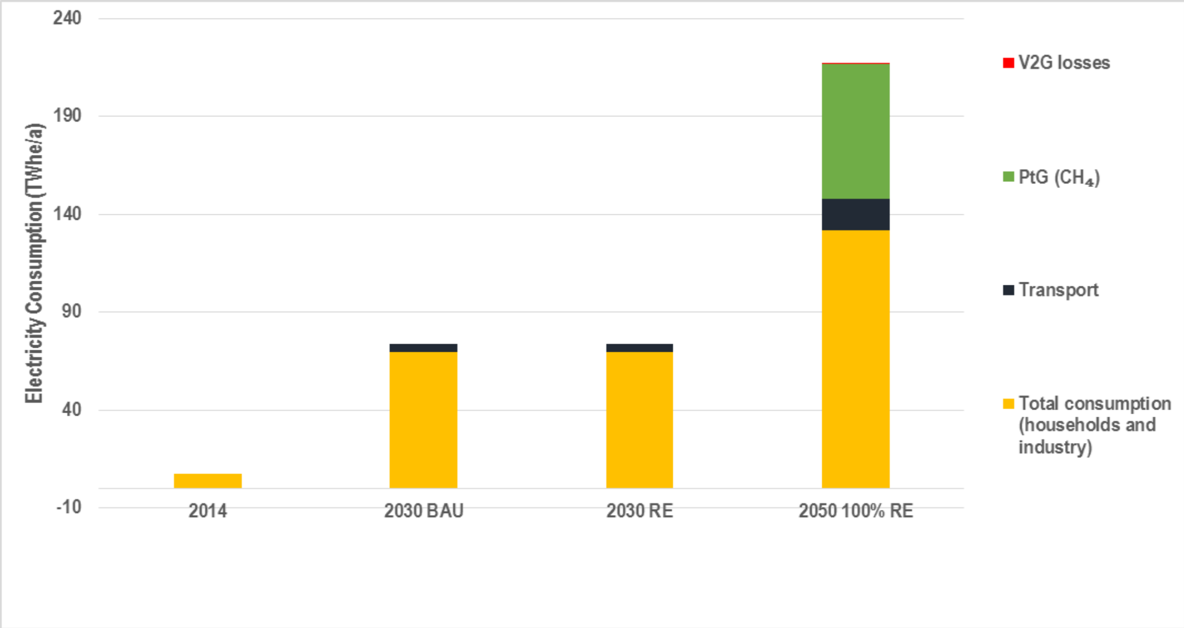


Figure 20. Total electricity consumption in all scenarios.

Total Annual Cost of the energy system scenarios

The total annual cost for each of the energy system scenarios in Kenya is illustrated in figure 21. A full disclosure of cost parameters used in this analysis is found in appendix A. Based on this cost assumptions, the total annual cost of the 2014 reference scenario is 9.51 b€/a. In this scenario, the total annual cost is mainly dominated by the costs of fuel. The 2030 BAU scenario seems to have the highest annual cost of 21.5 b€/a, due to high consumption of fossil fuels and CO_2 emissions. Comparatively, annual cost for the 2030 RE scenario is 18.9 b€/a. The biggest savings in RE scenario are from the costs of fuel and CO_2.

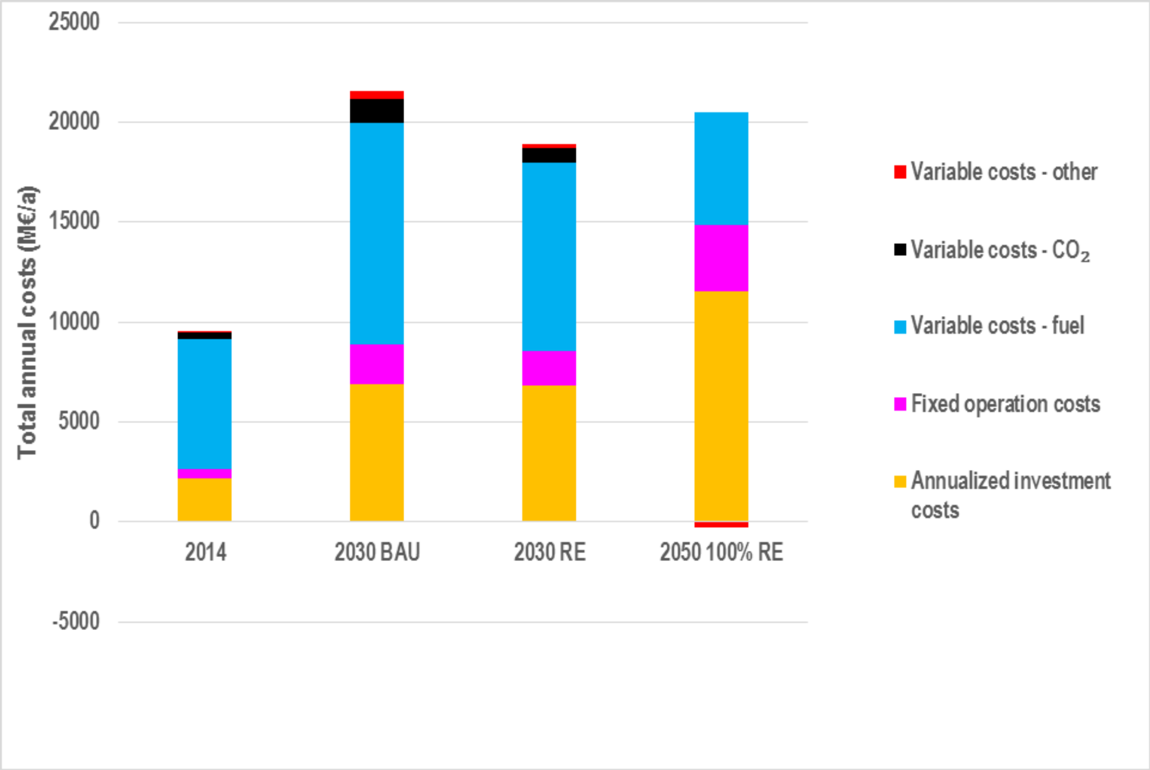


Figure 21. Total annual costs of energy system scenarios in Kenya

The 2050 100% RE scenario results in an overall annual cost of 20.2 b€/a. This scenario has the highest annualized investment costs and fixed operational costs, due to relative investment in clean energy technologies and energy savings, but again the fuel cost is lowest than in all other scenarios. In addition, the per capita electricity consumption in this scenario is about 3000 kWh, which is of several magnitude higher than the present situation. This implies that with wider use of renewable energy resources, the Government of Kenya can achieve increased energy access and emission-free energy system simultaneously in a highly cost-effective manner. Thus, the scenario results suggest that an energy system based on 100% renewables is not only technically possible in Kenya, but also competitive in term of cost.

5.2 Scenario Results of Tanzania

Total Primary Energy Supply (TPES)

In 2014, the total primary energy supply (TPES) in Tanzania was 256 TWh. About 84% of this energy is supplied by traditional biomass (charcoal, wood and agriculture residues). While oil (petroleum products) accounted for about 12% of the TPES in 2014, with remaining coming from natural gas, coal and other renewables (hydropower and solar PV). Figure 22 illustrates the primary energy supply of Tanzania obtained from the EnergyPLAN output for each of the scenarios.

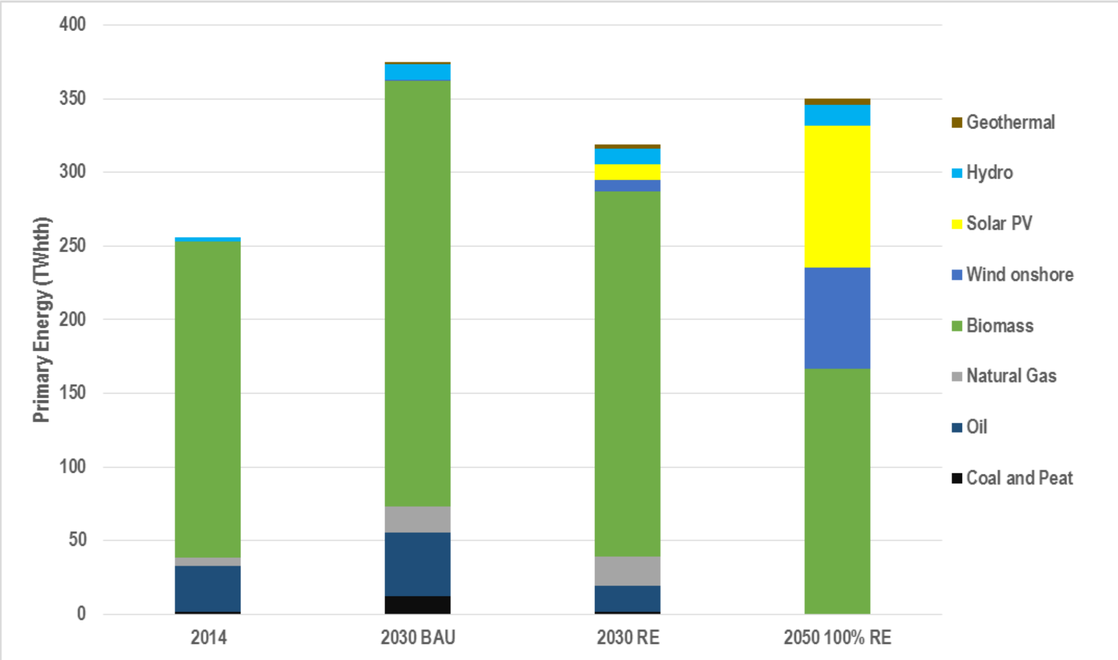


Figure 22 Primary Energy Supply for all scenarios in Tanzania.

The TPES is 375 TWh in the BAU scenario for 2030, 319 TWh in the RE scenario for 2030, and 350 TWh in the 2050 RE scenario. It will be observed from figure 18 that the RE scenarios resulted in a much lower energy than in the BAU scenario, due to the fuel transition. Comparatively, there is a significant decrease in the coal consumption in the 2030 RE scenario as the use of coal as fuel in industry and for power generation is reduced dramatically. Conversely, there is an increase in gas consumption in the 2030 RE scenario in order to replace the coal-fired power plants during this period. This in turn contributes to the CO_2 emission reduction in the 2030 RE scenario as the carbon content of natural gas is quite less than that of coal [70].

The energy supply mix in the 2050 scenario differs from the 2014 reference scenario mainly by the absence of fossil fuels and reduced consumption of biomass. The energy supply in 2050 scenario is diversified through a mix different RES to help reduce the pressure on biomass consumption. In the 2050 RE scenario, biomass share in the TPES decreases to 48% from 84% in 2014. The role of RES are expanded in this scenario with biomass, solar PV and wind energy providing the mainstay of the Tanzanian energy system. The RE share of primary energy and the associated carbon emissions resulting from the EnergyPLAN simulation for each of the scenarios are presented in table 35.

Table 35. Carbon emissions and shares of RE for all scenarios

Category	**2014**	**2030 BAU**	**2030 RE**	**2050 100% RE**
CO_2 -equivalent emissions (Mt)	10.01	19.27	9.38	0
Renewables share of primary energy (%)	85	80.6	87.7	100

The 2030 BAU scenario has the highest CO_2 emission (19.27 Mt.) followed by the 2014 reference scenario (10.01 Mt.). The power, industrial, and transport sector - dominated mainly by fossil fuels such as coal, oil products and natural gas – are the largest source of emissions from energy in the BAU scenario. Compared to the 2030 BAU scenario, the decrease of CO_2 emissions will be 51% in the 2030 RE scenario. The decrease in the TPES in the 2030 RE scenario lead to a significant reduction of CO_2 in this scenario.

The 2050 scenario resulted in a net zero CO_2 emissions and a 100% renewable energy systems as presented in table 35. The improved use of energy in households and industry, as well as the increased use of renewable electricity in vehicles and efficiency gains in the transport sector have positive impact on the CO_2 emission reduction. The results indicate that a 100% renewable energy system is technically achievable in Tanzania by 2050 by unleashing actions and investments toward low carbon and sustainable future.

Annual Electricity Production

The electricity production by source in Tanzania in the each of the scenarios is shown in figure 23. The total domestic electricity supply in the 2014 reference scenario was 5.22 TWh, in the 2030 BAU scenario it is 19.99 TWh, in the 2030 RE scenario it is 24.33 TWh, and in the 2050 100% RE scenario the total electricity supply is 163.75 TWh.

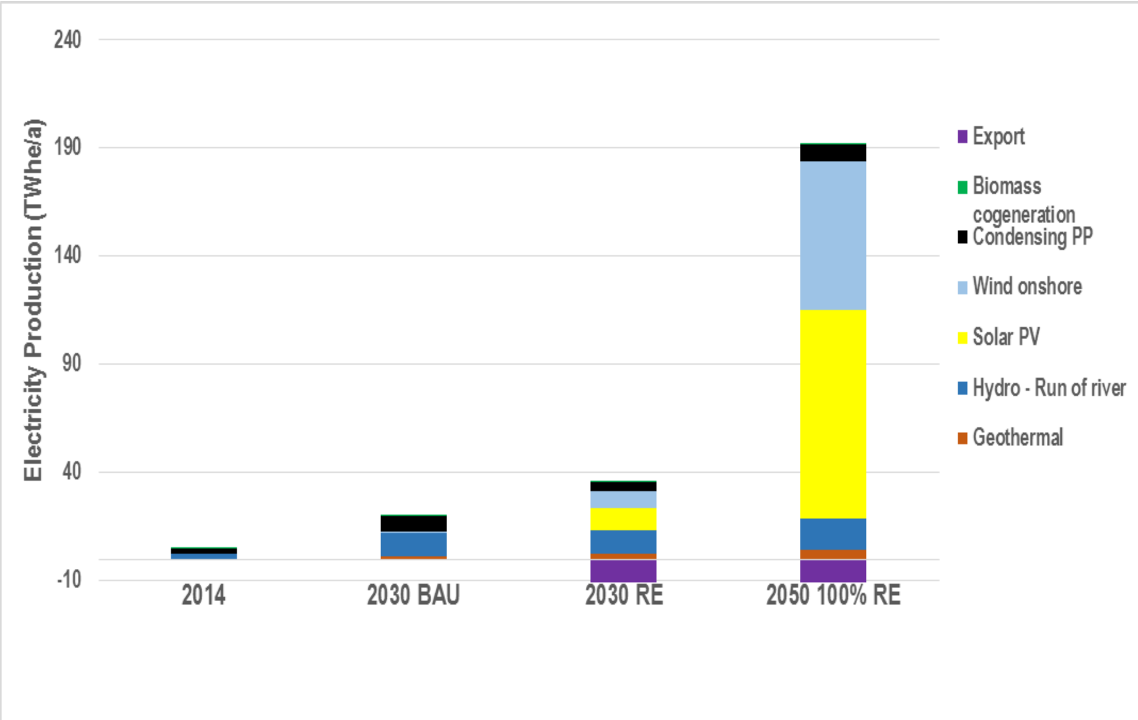


Figure 23. Total electricity production by technologies for different scenarios (see table 36 for numerical values)

The results indicate that the overall electricity production increases significantly as the share of RE in the national energy system increases. Higher production of electricity is noticed in the 2030 RE scenario than the BAU scenario due higher share of solar PV and wind power needed to compensate for lower use of fossil fuels for power generation. In 2050 scenario, the generation capacities of solar PV, wind and hydro are increased significantly in order to replace the fossil fuel powered technology. The existing the condensing power plant in the 2050 scenario uses the synthetic gas produced by the PtG process as fuel. Table 36 summarizes the numerical values of the total electricity production by different technologies for each of the scenario in Tanzania.

Table 36. Total electricity production by different technologies in Tanzania

Technology	**Electricity Production (TWh_e)**			
	2014	**2030 BAU**	**2030 RE**	**2050 100% RE**
Hydro - Run of river	2.59	10.53	10.49	14.49
Wind onshore	0	0.55	8.13	68.36
Solar PV	0.02	0.18	10.49	96.24
Geothermal	0	1.41	2.47	4.58
Condensing PP	2.45	7.52	3.7	8.1
Biomass cogeneration	0.27	0.59	0.44	0.11
Import	0	0	0.1	0
Export	-0.11	-0.79	-11.49	-28.13
Total	5.22	19.99	24.33	163.75

Total electricity consumption for all scenarios

Figure 24 depicts the total electricity consumption for each of the energy scenarios in Tanzania. A much closer relationship between the total electricity production and electricity consumption is noticed in all the scenarios. The total consumption in household and industry continue to increase significantly in all the scenarios. In the 2050 100% RE scenario, there is a large demand for electricity in the PtG process, mostly in the case when synthetic methane is the end product.

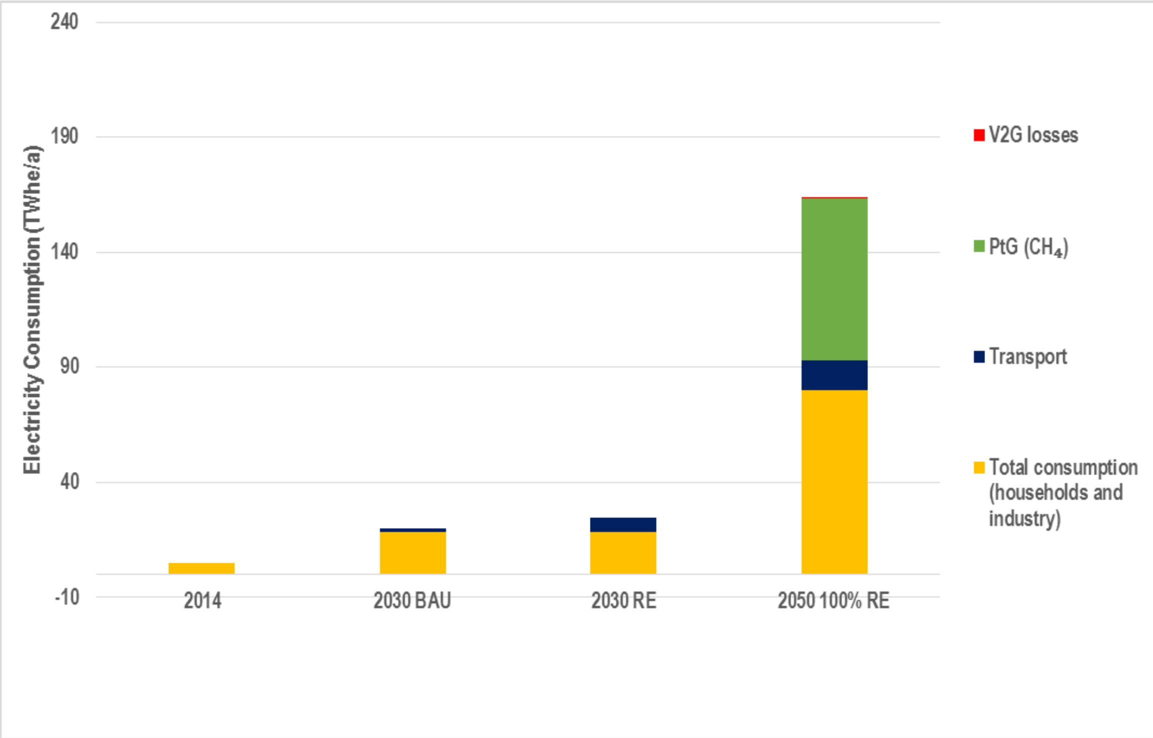


Figure 24. Total electricity consumption in all scenarios.

Economic evaluation of the energy scenarios

Figure 25 shows the total annual costs of each of the Tanzanian energy system scenarios. A full disclosure of cost parameters used in this analysis is found in appendix A. Based on the cost assumptions used in this study, the total annual cost of the 2014 reference scenario is 12.3 billion Euros per annum (b€/a) and its mainly dominated by variable cost (cost of fuel and CO_2). The 2030 BAU scenario seems to have the highest annual cost of 19.7 b€/a, due to high consumption of fossil fuels and CO_2 emissions. On the other hand, the 2030 RE scenario amounted to 16 b€/a. The biggest savings in RE scenario are from the costs of fuel and CO_2. When compared with the BAU scenario for 2030, it will be observed the 2030 RE scenario exhibit a higher annualized investment cost but again a lower variable cost (cost of fuel and CO_2) due to relative investment in clean energy technologies and energy savings.

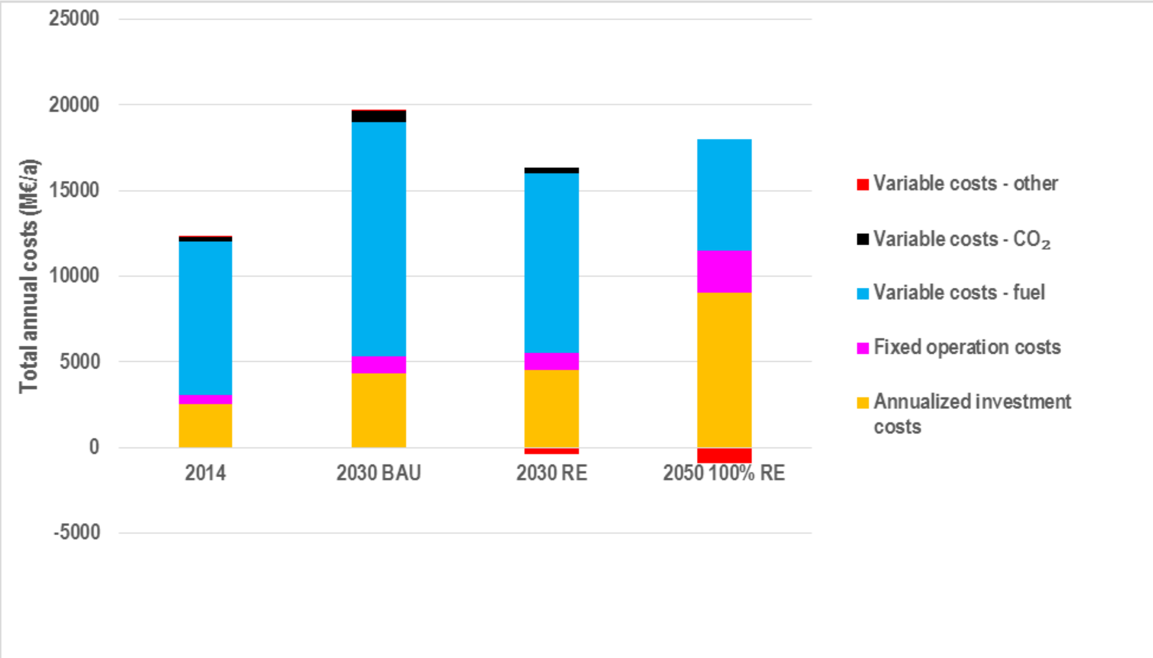


Figure 25. Total annual costs of Tanzanian energy system for all scenarios

The 2050 100% RE scenario results in an overall annual cost of 17.1 b€/a. This scenario has the highest annualized investment costs and fixed operational costs, whereas the fuel cost is lowest in this scenario than in all other scenarios. The variable costs-other is calculated as the summation of the marginal operational costs and the electricity exchange costs (costs derived from the electricity export). A negative value was obtained due to assumed average electricity and gas exchange price. In addition, the per capita electricity consumption is highest in this scenario. This indicates that the Government of Tanzania can increase the energy access of its people while at the same time reducing CO_2 emission in a highly cost-effective manner with wider use of renewable energy resources. It can therefore be concluded that an energy system based on 100% renewables is not only technically achievable in Tanzania, but also competitive in term of cost.

5.3 Limitation of the scenario results

There are some limitations and uncertainties associated with the energy scenario results presented in section 5.1 and 5.2. It should be kept in mind that the energy system scenarios developed in this report are by means a prognosis of what will happen in the case countries' energy sector. But, should rather be seen as an option for debate on the impact of different technologies to attain a 100% RE system in the future. The scenarios focused on the energy (PES), CO_2 emissions, and cost implications of a possible path to a sustainable and low carbon energy system for Kenya and Tanzania. Policies or measures to be implemented to enable these countries achieve the scenario's target were not discussed in this study.

The scenario results are highly dependent on the assumptions and input parameters (provided in chapter 4) such as the energy demands, generation capacities, and costs variables simulated using the EnergyPLAN simulation tool. A large number of alternatives could be obtained by adjusting any of the input parameters to test the sensitivity of the results. For this reason, great care was taken in relation to the methodology used to estimate the input parameters in order to ensure that the scenario results are as reliable as possible.

Further, the EnergyPLAN cost database was used directly in most cases for the cost analysis, due to the wide variety of opinions about different cost assumptions [80]. While, for other costs that were not originally part of the EnergyPLAN cost database, assumptions were based on the available literature. A full disclosure of the cost parameters employed in this study is found in Appendix A.

6 CONCLUSION AND FUTURE OUTLOOK

6.1 Conclusions

This study will be concluded by summarising the main results of the analysis under the following sub-headings:

- Energy sector overview of Kenya and Tanzania
- Energy system scenarios of Kenya and Tanzania

Energy sectors overview of Kenya and Tanzania

In Sub-Sahara Africa, Kenya and Tanzania offer one of the largest and dynamic market, but again there are challenges, to renewable energy. Both countries have abundant forms of energy resources ranging from hydropower to geothermal, biomass, wind, solar, uranium, coal and natural gas. The main source of primary energy in these two countries is the traditional biomass, followed by petroleum products and electricity. Further, the per capita electricity consumption in both countries are quite low compared to other part of the world. At the same time, the electricity access rate at the national level in Tanzania is estimated at 36% in year 2015, and 55% in Kenya as of 2016. Due to the geographical dispersed nature of the remote towns and villages in both countries, electrifying the rural communities through grid extension is considered as a very expensive option.

The electricity generation market in both countries is partly liberalized with moderate licenced power producers. Though the market is dominated by the state-owned utility (KENGEN in the case of Kenya, and TANESCO in Tanzania), the contribution of private investors – IPPs and SPPs – to the national installed power capacity is significant in both countries. It is important to know that the power sector in Tanzania is currently undergoing some transitional market reforms. The reform process envisioned a gradual transformation from the existing electricity market model to a fully competitive wholesale market by 2025. The main rationale for the reforms includes, but not limited to, accelerate the electricity connectivity level to 75% by 2033, attract private capital investment to the power sector, diversify the power generation mix, and improve the financial performance of TANESCO, among others. In both countries, the government has designed some regulatory tools (such as Feed-in tariff scheme, Standardized Small Power Purchase

Tariffs, among others), in order to attract capital investment from local and multinational investors in renewable power generation, and at the same time accelerate the national electricity access rate. Yet, the level of investments in renewable electricity is presently not sufficient to meet the rapid growing demand for electricity in the two countries.

If business continue as usual, Kenya planned to raise its power generation capacity from 2,341 MW in 2016 to 21,620 MW by 2031. Similarly, Tanzania is also expecting its power generation capacity to increase from 1,671 MW in 2014 to a minimum capacity of 10,000 MW by 2025. However, the bulk of the proposed generation capacity in both countries is expected to come from fossil fuels (coal, oil products, and natural gas), and geothermal, wind, and nuclear (precisely in Kenya). The countries' strategy is to develop low-cost generation options to meet both the present and future demand of electricity.

Of notable concern is the prominent role given to fossil fuels in their future power expansion plan, which could possibly defer investment in RE technologies and at the same time put the countries in an unsustainable and carbon-intensive path. Despite the ample availability of renewable energy resources in both countries, capable of providing lower-cost of electricity, and also, Kenya's INDC goal of reducing its GHG emissions by 30% by year 2030. Theoretically, Kenya receives nearly 743,000 TWh of solar energy per year, which is about 76,000 times higher its electricity production in 2016. Of course, several factors (sustainability aspects, storages, etc.) need to be considered so that it can be used.

The high initial cost of RE technologies possibly is the biggest barrier to RE development in Kenya and Tanzania, coupled with poor credit and financing mechanisms, ageing and weak electricity transmission and distribution system to take advantage of the geographically diverse RE resources in the countries, and regional mismatch between main demand centres and hydropower sites (especially in Tanzania). Although these challenges might appear to be enormous, the individual government are increasing their policy commitment in the power sector to foster the development of RE in their countries.

Energy System scenarios of case countries

In this Master's thesis report, a reference energy system scenario based on actual 2014 data, which is the most recent year with complete data, was developed and simulated using EnergyPLAN simulation model for Kenya and Tanzania respectively. In addition, three future scenarios were developed and analysed for each of the countries: the 2030 BAU scenario, 2030 RE scenario, and finally, the 2050 100% RE scenario. The scenario results of each country are summarized as follows:

Scenario results of Kenya

The total primary energy supply (TPES) is 175 TWh in 2014, 331 TWh in the BAU scenario for 2030, 298 TWh in the RE scenario for 2030, and 373 TWh in the 2050 RE scenario. Due to the fuel transition in the 2030 RE scenario, this scenario results to a lower energy than in the BAU scenario. In the 2050 scenario, a significant contribution of solar and wind energy is noted in this scenario, alongside with other RES to compensate for lower usage of woody biomass. Biomass contributes about 37% of the primary energy in 2050 compared to 70% share in the 2014 reference scenario.

Furthermore, the 2030 BAU scenario has the highest CO_2 emission (34.58 Mt.). On the other hand, a 42% decrease in CO_2 intensity was observed in the 2030 RE scenario, which can meet the government's carbon emission reduction target for 2030. The 2050 scenario results in a 100% RE system and the CO_2 emission from the energy system is equal to zero. Further, the scenario results indicate that the overall electricity production increases significantly as the share of RE in the national energy system increases. Higher production of electricity from wind energy is noticed in the 2030 RE scenario, despite the low installed capacity of wind power compared to solar PV in this scenario. This suggests wind onshore as a promising RE in Kenya. In addition, with the huge geothermal energy potential in Kenya, it is capable of providing base load power for the national electricity system by 2050.

In relation to the economic evaluation of the scenarios, the 2030 BAU scenario seems to have the highest annual cost of 21.5 b€/a (based on the cost assumptions employed for this analysis), due to high consumption of fossil fuels and CO_2 emissions. Compared to annual cost of 18.9 b€/a in the 2030 RE scenario. The 2050 100% RE scenario results in an overall annual cost of 20.2 b€/a. This scenario has the highest annualized investment costs and fixed operational costs, due to relative investment in clean energy technologies and energy savings but again the fuel cost is lowest in this scenario than in all other scenarios. This suggests that a 100% RE system is not only technically possible in Kenya, but also competitive in term of cost.

Scenario results of Tanzania

The TPES was 256 TWh in 2014, 375 TWh in the BAU scenario for 2030, 319 TWh in the RE scenario for 2030, and 350 TWh in the 2050 RE scenario. A much lower energy were noticed in the RE scenarios compared to the BAU scenario due to the fuel transition. This in turn contributed to the CO_2 emission reduction in the 2030 RE and 2050 scenario respectively. The 2030 BAU scenario has the highest CO_2 emission (19.27 Mt.) followed by the 2014 reference scenario (10.01 Mt.), and the 2030 RE scenario (9.38 Mt.). The 2050 scenario resulted in a net zero CO_2 emissions and a 100% renewable energy systems. In relation to the electricity production, the results indicate that the overall electricity production increases significantly as the share of RE in the national energy system increases. Higher production of electricity is noticed in the 2050 RE scenario than in other scenarios due higher share of solar PV and wind power needed to compensate for displaced fossil fuels power plants.

In term of annual cost evaluation, the BAU scenario also exhibits the highest cost. The annual cost is 19.7 b€/a in the 2030 BAU scenario, 16 b€/a in the 2030 RE scenario and 17.1 b€/a in the 2050 scenario. The 2050 RE scenario has the highest annualized investment costs and fixed operational costs, but again the lowest fuel costs than in all other scenarios. This indicates that an energy system based on 100% renewables is not only technically achievable in Tanzania, but also highly cost-effective with wider use of RES.

6.2 Recommendation and future research

In the planning of the power system expansion, it is important that the interests of preserving the environment are equally important as well as the present economic and energy interests. Due to the serious environment issues associated with the over-consumption of fossil fuel resources, increasing their usage for power generation is not the ultimate solution. Instead, RE can be a long-term sustainable solution as indicated by the scenario results presented in chapter 5. It is therefore recommended that policymakers in Kenya and Tanzania develop appropriate policies, rules and procedures to encourage more RE investment in the power sector. Today, RE technologies particularly solar PV and wind are now the least cost energy sources in many parts of the world.

Expansion of the transmission and distribution lines, including cross-border interconnection can be an important measures to enable electricity generators take advantage of the geographically diverse RE resources, reduce grid congestion, and allow lower-cost of electricity and RES-E produced flows to the end-users. Therefore, there is a need to foster the development of innovative mechanisms such as grants, challenge funds to help KETRACO and TANESCO finance their proposed transmission projects. This approach will not only improve the utilization of RES, but also potentially defer the need for network refurbishment.

As identified in section 3.3, another challenge that RE project developers have faced in recent times in Kenya and Tanzania was in form of resistance from local communities especially over land and compensation issues. Therefore, feasibility study and integration of large scale RE in Kenya and Tanzania should be addressed in future research.

In addition, a more investigation on how these case countries can attain the RE and CO_2 emission reduction target presented in the RE scenarios, should be conducted in the future studies. Further, a more reliable and accurate information on energy demand and supply projections for different sectors in both countries as well as the sustainable level of biomass available for future energy system, and the cost estimate of electricity and gas transmission and distribution grids are important for future modelling. Finally, the role of energy storage technologies in transition to a 100% RE system is crucial as illustrated by the scenario results, therefore, feasibility study of different storage solutions should be considered in future work.

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APPENDIX A. Main Cost Assumptions

The cost assumed for the energy system components in the analysis are outlined in the tables below.

Table 37. Cost assumptions for energy system components [71], [75], [78]

Production type		**Unit**	**2020**	**2030**	**2050**
Onshore wind	Capex	€/kW$_e$	1100	1000	900
	Lifetime	Years	20	25	30
	Opex fixed	% of investment	2.97 %	3.06%	3.21 %
Offshore wind	Capex	€/kW$_e$	2400	2100	1800
	Lifetime	Years	20	25	30
	Opex fixed	% of investment	2.09 %	1.38%	1.15 %
Solar PV - ground-mounted	Capex	€/kW$_e$	1150	625	350
	Lifetime	Years	30	35	30
	Opex fixed	% of investment	0.6 %	1%	2.00 %
Solar PV - rooftop	Capex	€/kW$_e$	1200	813	400
	Lifetime	Years	30	35	40
	Opex fixed	% of investment	1 %	1.48%	1.00 %
Hydropower - Run of the river	Capex	€/kW$_e$	2750	3300	3030
	Lifetime	Years	50	50	50
	Opex fixed	% of investment	1.5 %	1.5%	1.5 %
Geothermal Electricity	Capex	€/kW$_e$	4550	4030	4030
	Lifetime	Years	20	20	20
	Opex fixed	% of investment	3.48%	3.48%	3.48%
Biomass gasification plant	Capex	€/kW$_e$	420	320	320
	Lifetime	Years	15	15	15
	Opex fixed	% of investment	15.79 %	17.65%	18.75 %
		Efficiency	80 %	80%	80 %
	Capex	€/kW$_{th}$	3420	2530	1890

Biodiesel plant	Lifetime	Years	20	20	20
	Opex fixed	% of investment	3.00 %	3.00%	3.00 %
		Efficiency	60 %	60%	60 %
Biopetrol plant	Capex	€/kW$_{th}$	790	580	440
	Lifetime	Years	20	20	20
	Opex fixed	% of investment	7.70 %	7%	7.70 %
		Efficiency	40 %	40%	40 %
Biojetpetrol plant	Capex	€/kW$_{th}$	790	580	440
	Lifetime	Years	20	20	20
	Opex fixed	% of investment	3.00 %	3.7%	3.70 %
		Efficiency	40 %	40%	40 %
CO_2 Hydrogenation plant (P2G)	Capex	€/kW$_{th}$	900	600	400
	Lifetime	Years	20	15	15
	Opex fixed	% of investment	2.5 %	3.00%	3.00 %
		Efficiency	63 %	63%	70 %
SOEC Electrolyser	Capex	€/kW$_{e}$	590	350	280
	Lifetime	Years	20	15	15
	Opex fixed	% of investment	2.50 %	3.00%	3.00%
		Efficiency	73 %	73%	73 %
Biogas plant	Capex	€/kW$_{th}$ input	240	240	240
	Lifetime	Years	20	20	20
	Opex fixed	% of investment	7.00 %	7.00%	7.00 %
Biogas upgrading	Capex	€/kW$_{th}$	300	300	300
	Lifetime	Years	15	15	15
	Opex fixed	% of investment	15.80 %	17.6%	18.80 %
Gasification gas upgrading	Capex	€/kW$_{th}$	300	300	300
	Lifetime	Years	15	35	35
	Opex fixed	% of investment	3.7 %	3.7%	3.7%
Large Power plant	Capex	€/kW$_{th}$	990	980	950
	Lifetime	Years	20	25	30
	Opex fixed	% of investment	3.05%	2.97%	3.2%

Condensing power plant (average)	Capex	€/kW$_e$	1000	1000	1000
	Lifetime	Years	27	27	30
	Opex fixed	% of investment	3.00%	3.00%	2.00%
	Variable costs	Efficiency	2.654	2.654	0
Nuclear	Capex	€/kW$_{th}$	5500	6000	6500
	Lifetime	Years	40	40	40
	Opex fixed	% of investment	3.5%	3.5%	3.5%

Table 38. Cost assumptions for energy storage [71], [75]

Energy storage		**Unit**	**2050**
Gas storage	Capex	€/kWh$_{th}$	0.081
	Lifetime	Years	50
	Opex fixed	% of investment	1.00 %
Oil storage	Capex	€/kWh$_{th}$	0.023
	Lifetime	Years	50
	Opex fixed	% of investment	0.6%
Hydro storage	Capex	€/kWh$_{th}$	7.5
	Lifetime	Years	50
	Opex fixed	% of investment	1.5%
Lithium ion stationary battery	Capex	€/kWh$_e$	75
	Lifetime	Years	20
	Opex fixed	% of investment	3.30 %
Lithium ion BEV	Capex	€/kWh$_e$	100
	Lifetime	Years	12
	Opex fixed	% of investment	5.00 %

Table 39. Cost assumptions for fuel and CO_2 [75]

Fuel and CO_2	**Unit**	**2020**	**2030**	**2050**
Oil	USD/bbl	107.4	118.9	142.0
Natural Gas	€/MWh_{th}	32.8	40.3	43.9
Coal/Peat	€/MWh_{th}	11.2	11.5	12.2
Fuel Oil	€/MWh_{th}	42.8	47.9	58.0
Diesel	€/MWh_{th}	54.0	59.8	70.6
Petrol	€/MWh_{th}	54.7	60.1	70.9
Jet fuel	€/MWh_{th}	58.0	63.4	74.2
Biomass (weighted average)	€/MWh_{th}	18.0	21.6	27.4
Uranium (including handling)	€/MWh_{th}	5.4	5.4	5.4
CO_2	€/t $CO_{2\ eq}$	28.6	34.6	46.6

Table 40. Energy to power ratio of energy storage technologies [78].

Storage Technology	**Energy/Power Ratio (h)**	**Self-Discharge (%/h)**
Battery	6	0
Gas Storage	80*24	0
PHS	8	0

Input Kenya_2050_100%_RE_scenario.txt

The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	113,71	Fixed imp/exp.	0,00
Electric heating + HP	18,00	Transportation	16,00
Electric cooling	0,00	Total	147,71

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	0,00	0,00	0,00
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	0,00	0,00	0,00

Wind	24000	MW	77,62	TWh/year	0,00	Grid
Photo Voltaic	65000	MW	100,96	TWh/year	0,00	stabili-
River Hydro	2000	MW	9,73	TWh/year	0,00	sation
CSP Solar Power	0	MW	0	TWh/year	0,00	share
Hydro Power	0	MW	0	TWh/year		
Geothermal/Nuclear	6900	MW	47,23	TWh/year		

	Capacities MW-e	Capacities MJ/s	Efficiencies elec.	Efficiencies Ther	COP
Group 2:					
CHP	0	0	0,40	0,50	
Heat Pump	0	0			3,00
Boiler		0		0,90	
Group 3:					
CHP	0	0	0,40	0,50	
Heat Pump	0	0			3,00
Boiler		0		0,90	
Condensing	50		0,45		

Heatstorage: gr.2: 0 GWh gr.3:0 GWh
Fixed Boiler: gr.2:0,0 Per cent gr.:0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,00
Gr.3:	0,00	0,00

Regulation Strateg	Technical regulation no. 2	
CEEP regulation	87100000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	0,50	
Maximum import/export	5000	MW

Distr. Nar	Electricity Market Price.txt	
Addition factor	0,00	EUR/MWh
Multiplication factor	1,00	
Dependency factor	0,00	EUR/MWh pr. MW
Average Market Price	35	EUR/MWh
Gas Storage	7000	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	3333	20	0,97	
Hydro Turbine:	3333		0,97	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	0,00	0,00	0,00
Household	0,00	0,00	0,00	98,00
Industry	0,00	0,00	20,00	35,00
Various	0,00	0,00	0,00	0,00

Output

	District Heating: Demand Distr. heating MW	Production Solar MW	Waste-CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW	Electricity Consumption: Elec. demand MW	Flex.& Transp MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Production: Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste-CSHP MW	CHP MW	PP MW	Balance: Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Exchange Payment Imp Million EUR	Exp Million EUR
January	0	0	94	0	0	0	0	0	0	-94	12814	1821	0	7766	2028	35	33	18700	0	7162	0	0	1642	100	2	3074	0	3074	0	80
February	0	0	94	0	0	0	0	0	0	-94	12912	1823	0	8383	2044	8	7	21706	0	6834	0	0	342	100	0	3719	0	3719	0	91
March	0	0	94	0	0	0	0	0	0	-94	12965	1821	0	7396	2052	63	60	19552	0	5406	0	0	2181	100	4	2906	0	2906	0	76
April	0	0	94	0	0	0	0	0	0	-94	12982	1819	0	7193	2055	22	21	20159	0	5063	0	0	1508	100	0	2679	0	2679	0	68
May	0	0	94	0	0	0	0	0	0	-94	12996	1826	0	7419	2057	29	27	20082	0	4988	0	0	1906	100	0	2676	0	2676	0	70
June	0	0	94	0	0	0	0	0	0	-94	12966	1819	0	7708	2052	12	11	22871	0	4312	0	0	609	100	0	3246	0	3246	0	82
July	0	0	94	0	0	0	0	0	0	-94	12896	1821	0	7947	2041	7	6	24891	0	3283	0	0	338	100	0	3807	0	3807	0	99
August	0	0	94	0	0	0	0	0	0	-94	12967	1826	0	8249	2053	6	6	24898	0	3769	0	0	285	100	0	3856	0	3856	0	100
September	0	0	94	0	0	0	0	0	0	-94	13056	1814	0	8432	2067	8	7	23895	0	4831	0	0	399	100	0	3756	0	3756	0	95
October	0	0	94	0	0	0	0	0	0	-94	13051	1826	0	8295	2066	17	16	22857	0	4803	0	0	923	100	0	3345	0	3345	0	87
November	0	0	94	0	0	0	0	0	0	-94	12927	1825	0	7518	2046	22	21	18852	0	6861	0	0	1567	100	0	2963	0	2963	0	75
December	0	0	94	0	0	0	0	0	0	-94	12815	1816	0	8193	2029	28	26	18812	0	7293	0	0	1876	100	0	3126	0	3126	0	81
Average	0	0	94	0	0	0	0	0	0	-94	12945	1821	0	7874	2049	22	20	21438	0	5377	0	0	1137	100	1	3261	0	3261	Average price	
Maximum	0	0	94	0	0	0	0	0	0	-94	19803	3731	0	19778	3136	3333	3333	46082	0	22542	0	0	13550	100	1617	5000	0	5000	(EUR/MWh)	
Minimum	0	0	94	0	0	0	0	0	0	-94	7397	500	0	138	1170	0	0	1667	0	0	0	0	0	100	0	0	0	0	35	35
TWh/year	0,00	0,00	0,83	0,00	0,00	0,00	0,00	0,00	0,00	-0,83	113,71	16,00	0,00	69,16	18,00	0,19	0,18	188,31	0,00	47,23	0,00	0,00	9,99		0,00	28,65	0,00	28,65	0	1003

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV	Hydro	CSP	Solar.Th	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
N.Gas	-	-	-	-	-	21,95	-	-	-	-	-	-41,96	-	-	-	-	-	-	-	20,00	-0,02	0,00	-0,02	0,00	0,00
Biomass	-	-	-	-	-	0,25	-	-	-	-	4,55	-	-	-	-	-	-	-	98,00	35,00	137,79	-63,65	74,14	0,00	0,00
Renewable	-	-	-	-	-	-	47,23	-	-	-	-	-	77,62	100,96	9,73	-	-	-	-	-	235,54	0,00	235,54	0,00	0,00
H2 etc.	-	-	-	-	-	0,00	-	-	-	-48,26	-	48,26	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-6,50	-	-	-	-	-	-	6,50	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	-	-	-	-	22,19	47,23	-	-	-48,26	-1,95	6,29	77,62	100,96	9,73	-	-	6,50	98,00	55,00	373,32	-63,65	309,67	0,00	0,00

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Output specifications Kenya_2050_100%_RE_scenario.txt The EnergyPLAN model 12.4

District Heating Production

	Gr.1 District heating MW	Gr.1 Solar MW	Gr.1 CSHP MW	Gr.1 DHP MW	Gr.2 District heating MW	Gr.2 Solar MW	Gr.2 CSHP MW	Gr.2 CHP MW	Gr.2 HP MW	Gr.2 ELT MW	Gr.2 Boiler MW	Gr.2 EH MW	Gr.2 Storage MW	Gr.2 Balance MW	Gr.3 District heating MW	Gr.3 Solar MW	Gr.3 CSHP MW	Gr.3 CHP MW	Gr.3 HP MW	Gr.3 ELT MW	Gr.3 Boiler MW	Gr.3 EH MW	Gr.3 Storage MW	Gr.3 Balance MW	RES1 Wind MW	RES2 Photo MW	RES3 River MW	RES 4-7 MW	Total MW
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	6089	11313	1297	0	18700
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	8450	12010	1245	0	21706
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	6787	11968	796	0	19552
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	7340	11526	1293	0	20159
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	7597	10932	1552	0	20082
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	11051	10980	840	0	22871
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	13023	11181	687	0	24891
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	11914	11922	1062	0	24898
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	11084	11638	1173	0	23895
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	9877	11804	1176	0	22857
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	6278	11212	1361	0	18852
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	6535	11451	826	0	18812
Average	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	8836	11494	1108	0	21438
Maximum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	21896	45314	1976	0	46082
Minimum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	-94	0	0	501	0	1667
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00	0,00	0,00	0,83	0,00	0,00	0,00	0,00	0,00		-0,83	77,62	100,96	9,73	0,00	188,31

Own use of heat from industrial CH0,00 TWh/year

ANNUAL COSTS (Million EUR)

Total Fuel ex Ngas exchange = 5592
Uranium = 0
Coal = 0
FuelOil = 0
Gasoil/Diesel= 26
Petrol/JP = 15
Gas handling = 176
Biomass = 5374
Food income = 0
Waste = 0

Total Ngas Exchange costs = -1

Marginal operation costs = 735

Total Electricity exchange = -1002
Import = 0
Export = -1003
Bottleneck = 0
Fixed imp/ex= 0

Total CO2 emission costs = 0

Total variable costs = 5323
Fixed operation costs = 3376

Annual Investment costs = 11501

TOTAL ANNUAL COSTS = 20200

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	0	0	3613	0	0	2277	5890	0	0	4712	0	0	1180	-2	0	2
February	0	0	745	0	0	2277	3022	0	0	5086	0	0	-2062	-2	0	2
March	0	0	4808	0	0	2277	7084	0	0	4488	0	0	2599	-2	0	2
April	0	0	3310	0	0	2277	5586	0	0	4364	0	0	1224	-2	0	2
May	0	0	4194	0	0	2277	6471	0	0	4501	0	0	1971	-2	0	2
June	0	0	1330	0	0	2277	3607	0	0	4677	0	0	-1068	-2	0	2
July	0	0	738	0	0	2277	3014	0	0	4821	0	0	-1805	-2	0	2
August	0	0	622	0	0	2277	2899	0	0	5005	0	0	-2104	-2	0	2
September	0	0	870	0	0	2277	3147	0	0	5116	0	0	-1967	-2	0	2
October	0	0	2025	0	0	2277	4302	0	0	5033	0	0	-729	-2	0	2
November	0	0	3445	0	0	2277	5722	0	0	4562	0	0	1162	-2	0	2
December	0	0	4135	0	0	2277	6412	0	0	4971	0	0	1443	-2	0	2
Average	0	0	2498	0	0	2277	4775	0	0	4777	0	0	0	-2	0	2
Maximum	0	0	30000	0	0	2277	32277	0	0	12000	0	0	32196	-2	0	2
Minimum	0	0	0	0	0	2277	2277	0	0	84	0	0	-9721	-2	0	2
Total for the whole year TWh/year	0,00	0,00	21,95	0,00	0,00	20,00	41,95	0,00	0,00	41,96	0,00	0,00	0,00	-0,02	0,00	0,02

RES Share: 100,0 Percent of Primary Energy 112,7 Percent of Electricity 235,5 TWh electricity from RES 15-toukokuu-2017 [01:53]

Input Tanzania_2050_100%_RE_scenario.txt The EnergyPLAN model 12.4

Electricity demand (TWh/year):		Flexible demand	0,00
Fixed demand	69,84	Fixed imp/exp.	0,00
Electric heating + HP	10,00	Transportation	13,00
Electric cooling	0,00	Total	92,84

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0,00	0,00	0,00	0,00
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	0,00	0,00	0,00	0,00

Photo Voltaic	70000	MW	96,24	TWh/year	0,00	Grid
Wind	25000	MW	68,36	TWh/year	0,00	stabili-
River Hydro	2900	MW	14,49	TWh/year	0,00	sation
River Hydro	0	MW	0	TWh/year	0,00	share
Hydro Power	0	MW	0	TWh/year		
Geothermal/Nuclear	650	MW	4,58	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	0	0	0,40	0,50	
Heat Pump	0	0			3,00
Boiler		0		0,90	
Group 3:					
CHP	0	0	0,40	0,50	
Heat Pump	0	0			3,00
Boiler		0		0,90	
Condensing	50		0,45		

Heatstorage: gr.2: 0 GWh gr.3:0 GWh
Fixed Boiler: gr.2:0,0 Per cent gr.:0,0 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0,00	0,00
Gr.2:	0,00	0,00
Gr.3:	0,00	0,00

Regulation Strateg	Technical regulation no. 2	
CEEP regulation	87100000	
Minimum Stabilisation share	0,00	
Stabilisation share of CHP	0,00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	0,50	
Maximum import/export	5000	MW

Distr. Nar	Electricity Market Price.txt	
Addition factor	0,00	EUR/MWh
Multiplication factor	1,00	
Dependency factor	0,00	EUR/MWh pr. MW
Average Market Price	35	EUR/MWh
Gas Storage	16000	GWh
Syngas capacity	0	MW
Biogas max to grid	0	MW

Fuel Price level: Basic

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0,97	
Hydro Turbine:	0		0,97	
Electrol. Gr.2:	0	0	0,80	0,10
Electrol. Gr.3:	0	0	0,80	0,10
Electrol. trans.:	0	0	0,80	
Ely. MicroCHP:	0	0	0,80	
CAES fuel ratio:	0,000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	0,00	0,00	0,00
Household	0,00	0,00	0,00	98,00
Industry	0,00	0,00	25,00	65,00
Various	0,00	0,00	0,00	0,00

Output

District Heating

	Demand: Distr. heating MW	Production: Solar MW	Waste-CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW
January	0	0	72	0	0	0	0	0	0	-72
February	0	0	72	0	0	0	0	0	0	-72
March	0	0	72	0	0	0	0	0	0	-72
April	0	0	72	0	0	0	0	0	0	-72
May	0	0	72	0	0	0	0	0	0	-72
June	0	0	72	0	0	0	0	0	0	-72
July	0	0	72	0	0	0	0	0	0	-72
August	0	0	72	0	0	0	0	0	0	-72
September	0	0	72	0	0	0	0	0	0	-72
October	0	0	72	0	0	0	0	0	0	-72
November	0	0	72	0	0	0	0	0	0	-72
December	0	0	72	0	0	0	0	0	0	-72
Average	0	0	72	0	0	0	0	0	0	-72
Maximum	0	0	72	0	0	0	0	0	0	-72
Minimum	0	0	72	0	0	0	0	0	0	-72
TWh/year	0,00	0,00	0,64	0,00	0,00	0,00	0,00	0,00	0,00	-0,64

Electricity / Exchange

	Consumption: Elec. demand MW	Flex.& Transp MW	HP MW	Elec-trolyser MW	EH MW	Hydro Pump MW	Production: Tur-bine MW	RES MW	Hy-dro MW	Geo-thermal MW	Waste-CSHP MW	CHP MW	PP MW	Balance: Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Exchange: Payment Imp Million EUR	Exp Million EUR
January	7849	1479	0	7561	1124	0	0	17607	0	695	0	0	2113	100	1	2403	0	2403	0	63
February	7842	1484	0	7755	1123	0	0	18616	0	663	0	0	1495	100	0	2570	0	2570	0	63
March	7882	1484	0	7644	1129	0	0	18504	0	525	0	0	1816	100	1	2706	0	2706	0	70
April	7905	1480	0	7860	1132	0	0	19675	0	491	0	0	1017	100	0	2807	0	2807	0	71
May	7956	1485	0	7868	1139	0	0	20216	0	484	0	0	823	100	0	3074	0	3074	0	80
June	7960	1485	0	7834	1140	0	0	20341	0	419	0	0	684	100	0	3025	0	3025	0	76
July	7937	1476	0	8583	1136	0	0	22706	0	319	0	0	154	100	0	4048	0	4048	0	105
August	7983	1485	0	8324	1143	0	0	22312	0	366	0	0	150	100	0	3892	0	3892	0	101
September	8037	1478	0	8812	1151	0	0	23104	0	469	0	0	103	100	0	4198	0	4198	0	106
October	8055	1479	0	8620	1153	0	0	22742	0	466	0	0	222	100	0	4124	0	4124	0	107
November	8040	1484	0	8167	1151	0	0	20395	0	666	0	0	823	100	0	3043	0	3043	0	77
December	7967	1484	0	7803	1141	0	0	18377	0	708	0	0	1819	100	4	2513	0	2513	0	65
Average	7951	1482	0	8070	1138	0	0	20387	0	522	0	0	935	100	0	3203	0	3203	Average price	
Maximum	12400	6477	0	18575	1776	0	0	38913	0	2188	0	0	10000	100	1730	5000	0	5000	(EUR/MWh)	
Minimum	4527	-50	0	325	648	0	0	1316	0	0	0	0	0	100	0	0	0	0	35	35
TWh/year	69,84	13,02	0,00	70,89	10,00	0,00	0,00	179,08	0,00	4,58	0,00	0,00	8,21		0,00	28,13	0,00	28,13	0	985

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	PV	Wind	Hydro	Hydro	Solar.Th	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
N.Gas	-	-	-	-	-	18,00	-	-	-	-	-	-43,01	-	-	-	-	-	-	-	25,00	-0,01	0,00	-0,01	0,00	0,00
Biomass	-	-	-	-	-	0,25	-	-	-	-	3,49	-	-	-	-	-	-	-	98,00	65,00	166,74	-62,51	104,23	0,00	0,00
Renewable	-	-	-	-	-	-	4,58	-	-	-	-	-	96,24	68,36	14,49	-	-	-	-	-	183,67	0,00	183,67	0,00	0,00
H2 etc.	-	-	-	-	-	0,00	-	-	-	-49,46	-	49,46	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Biofuel	-	-	-	-	-	-	-	-	-	-	-4,30	-	-	-	-	-	-	4,30	-	-	0,00	0,00	0,00	0,00	0,00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0,00	0,00	0,00	0,00	0,00
Total	-	-	-	-	-	18,25	4,58	-	-	-49,46	-0,81	6,45	96,24	68,36	14,49	-	-	4,30	98,00	90,00	350,39	-62,51	287,88	0,00	0,00

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District Heating Production

	Gr.1				Gr.2										Gr.3										RES specification				
	District heating MW	Solar MW	CSHP MW	DHP MW	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW	RES1 Photo MW	RES2 Wind MW	RES3 River MW	RES 4-7 MW	Total MW
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	12179	2871	2557	0	17607
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	11894	4445	2277	0	18616
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	11618	4235	2650	0	18504
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10851	6214	2611	0	19675
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10339	7571	2306	0	20216
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10560	7886	1895	0	20341
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	9284	11889	1533	0	22706
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10489	10672	1151	0	22312
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10032	12225	847	0	23104
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10359	11696	687	0	22742
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	11552	8197	646	0	20395
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	12349	5379	649	0	18377
Average	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	10956	7782	1649	0	20387
Maximum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	34456	22462	2742	0	38913
Minimum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0	0	-72	0	196	506	0	1316
Total for the whole year TWh/year	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00		0,00	0,00	0,00	0,64	0,00	0,00	0,00	0,00	0,00		-0,64	96,24	68,36	14,49	0,00	179,08

Own use of heat from industrial CH0,00 TWh/year

ANNUAL COSTS (Million EUR)

Total Fuel ex Ngas exchange = 6545

Uranium = 0
Coal = 0
FuelOil = 0
Gasoil/Diesel= 15
Petrol/JP = 10
Gas handling = 207
Biomass = 6313
Food income = 0
Waste = 0

Total Ngas Exchange costs = -1

Marginal operation costs = 90

Total Electricity exchange = -985
Import = 0
Export = -985
Bottleneck = 0
Fixed imp/ex= 0

Total CO2 emission costs = 0

Total variable costs = 5650
Fixed operation costs = 2474

Annual Investment costs = 9016

TOTAL ANNUAL COSTS = 17139

NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	0	0	4643	0	0	2846	7489	0	0	4588	0	0	2903	-1	0	1
February	0	0	3277	0	0	2846	6123	0	0	4705	0	0	1419	-1	0	1
March	0	0	3990	0	0	2846	6836	0	0	4638	0	0	2200	-1	0	1
April	0	0	2227	0	0	2846	5073	0	0	4769	0	0	306	-1	0	1
May	0	0	1800	0	0	2846	4646	0	0	4774	0	0	-127	-1	0	1
June	0	0	1490	0	0	2846	4336	0	0	4753	0	0	-415	-1	0	1
July	0	0	334	0	0	2846	3180	0	0	5207	0	0	-2026	-1	0	1
August	0	0	323	0	0	2846	3169	0	0	5051	0	0	-1880	-1	0	1
September	0	0	221	0	0	2846	3067	0	0	5346	0	0	-2277	-1	0	1
October	0	0	486	0	0	2846	3332	0	0	5230	0	0	-1896	-1	0	1
November	0	0	1800	0	0	2846	4646	0	0	4955	0	0	-307	-1	0	1
December	0	0	3992	0	0	2846	6838	0	0	4734	0	0	2105	-1	0	1
Average	0	0	2049	0	0	2846	4895	0	0	4896	0	0	0	-1	0	1
Maximum	0	0	22111	0	0	2846	24957	0	0	11270	0	0	24761	-1	0	1
Minimum	0	0	0	0	0	2846	2846	0	0	197	0	0	-8422	-1	0	1
Total for the whole year TWh/year	0,00	0,00	18,00	0,00	0,00	25,00	43,00	0,00	0,00	43,01	0,00	0,00	0,00	-0,01	0,00	0,01

RES Share: 100,0 Percent of Primary Energy 119,5 Percent of Electricity 183,7 TWh electricity from RES

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