

UNITED REPUBLIC OF TANZANIA



MINISTRY OF ENERGY

POWER SYSTEM MASTER PLAN 2020 UPDATE



2,115MW JNHPP



400 kV Transmission line



Renewables



Gas Fired Power Plant

FINAL REPORT

September ,2020
DODOMA

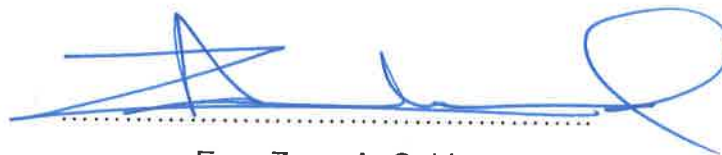
FOREWORD

The PSMP 2020 Update is the result of review of PSMP 2016. The overall objective of the review was to re-assess the short term (2020 – 2024), medium term (2025 – 2034) and long term (2035 – 2044) in terms of power generation and transmission plans requirement with primary goal of increasing access to modern energy, enhance power supply availability, reliability and affordability in the country. To achieve this goal the Government will continue to involve other stakeholders in the sector to implement least cost generation and transmission projects.

The PSMP 2020 Update reflects and accommodates Government policy guidelines and recent economic development experienced during the fifth Government phase, including development in electricity sub-sector. The Plan also reflects various regionals vision on energy. The PSMP 2020 Update is a joint effort by inter-governmental institutions which spent eight (8) months working hard and tirelessly to come up with this Plan. The entire work was carried out from February to September, 2020 by a team of experts from Ministry of Energy , Ministry of Finance and Planning, Tanzania Electric Supply Company, National Bureau of Statistics, Rural Energy Agency, Tanzania Petroleum Development Corporation and Energy and Water Utilities Regulatory Authority.

On behalf of the Ministry of Energy, I acknowledge the Task Force Team for their hard work and tireless efforts to ensure completion of PSMP 2020 Update. I also acknowledge Deputy Permanent Secretary, Eng. Leonard R. Masanja, Director for Policy and Planning, Mr. Haji Y. Janabi, Acting Commissioner for Electricity and Renewable Energy, Mr. Edward L. Ishengoma, Assistant Commissioner for Electricity, Eng. Innocent G. Luoga, Assistant Commissioner for Electricity Development, Eng. Styden Rwebangila for their close guidance during preparation of Plan. Moreover, I thank the Managing Director of TANESCO, Dr. Tito E. Mwinuka, Deputy Managing Director for Investment of TANESCO, Eng. Khalid James for their assistance and guidance provided to the Task Force Team.

Nevertheless, I extend my sincere appreciations to the MoFP, PO-RALG, TANESCO, ZECO, Regional Administrative Secretaries and District Administrative Secretaries for enabling collection of necessary and essential data of electricity demand of the entire country. The data provided were used as the critical input for PSMP 2020 Update. Furthermore, I thank all the public and private sector stakeholders and development partners for their valuable comments and contributions. Nevertheless, I thank all professionals from various institutions who were invited to contribute their inputs during PSMP 2020 Update preparation, their invaluable contribution is highly appreciated. I hereby once again thank Task Force Team members who participated in the preparation of PSMP 2020 Update and their names appended in appendix 1.



Eng. Zena A. Said
Permanent Secretary

Executive Summary

Introduction

The Power System Master Plan 2020 has been prepared using data on electricity demand gathered during industrial survey in the entire country. The PSMP also infers on methodology and procedures used in the previous PSMP of 2008 and its subsequent updates in 2009, 2012 and 2016. These reviews were necessary given the changes that were taking place or that were being anticipated in the Tanzanian economy and in the resulting electricity demand.

The Ministry of Energy (MoE) therefore decided to review the Power System Master Plan 2016 Update and prepare 2020 Update that will guide the next 25 years of its power development. The PSMP 2020 Update builds on previous update studies.

Load Forecast

The methodologies used in the load forecast were trend line analysis and econometric method. Trend line analysis considered the time series data of the past 25 years from 1995 to 2019, whereby 2019 was a base year for this Plan. An econometric forecast was reviewed to ensure the forecast is consistent with the growth pattern of other economic variables such as sectoral GDP in the Tanzania's economy. The key drivers for the forecast are: Electrification Program; Industrial load growth; Power losses; and Interconnection of Isolated Grid.

The Plan provides a forecast of the anticipated needs of the population and economy of Tanzania for the period to 2044 under base case assumptions. The projected average peak demand growth in MW for the total system, Grid and isolated System/Grids is projected to reach 17,611 MW (2044) from 1,120 MW in (2019) and in the year 2025 and 2030 the peak demand will be 2,677 MW and 4,878 MW respectively which is equivalent to an average growth of 11.7 percent per year. Similarly, the current system losses is 16.19 percent and the target is to reach 12 percent by 2026 to the end of

planning horizon. Furthermore, the rate of electrification (connection) grows from 30.1 percent in 2020 to 96.1 percent in 2044.

Generation Planning

Total installed capacity in the country is 1,602.32 MW which comprises of interconnected Grid System (1,565.72 MW) and isolated Grid System (36.60 MW). The National Grid System comprises of hydro and thermal generation units owned by TANESCO and IPP's with total capacity of 1,565.72 MW (base year 2019) out of which hydro 573.70 MW (36.64%), natural gas 892.72 MW (57.02%), liquid fuel, 88.80 MW (5.67%) and biomass 10.50 MW (0.67%). The highest system Maximum Demand (MD) recorded was 1,120 MW reached on 30th November 2019.

The generation plan criteria consider reserve margin, generation mix, loss of load expectation, outage rates, plant life span, operation & maintenance costs and lead time. It retained the base case scenario as a recommended power generation expansion plan for the country.

In order to meet the forecasted demand, the country requires a total installed generation capacity of 3,971.4 MW in the short term, 12,255.7 MW in the medium and 20,200.6 MW in the long term. The Plan indicates power generation mix which varies over the planning period and by 2044 the generation mix consist of 5,690.4 MW (28.15%) of hydro; 6,700 MW (33.18%) of natural gas; 5,300 MW (26.24%) of coal; 800 MW (3.96%) of wind; 715 MW (3.54%) of solar; and 995 MW (4.93%) of geothermal of power generation.

The National Grid system connected diesel/HFO plants have been phased out from 2021 and retained as reserve capacity for emergency through out the planning period. This Plan observes a reserve margin on firm capacity in the range of 15 - 20 percent.

The plan indicates that Julius Nyerere Hydropower Plant (2,115 MW) will be in operation by 2022 bringing a total installed capacity to 3,810.9 MW from which 2,001.9

MW is a surplus capacity. The surplus capacity may be traded with the neighbouring countries, enabling Tanzania to be a power hub.

Transmission Planning

An assessment of major power flows was conducted across the country over the planning horizon in order to plan for reinforcement and expansion of grid network to isolated and partially connected regions. The assessment was done by calculating the ranges of major interface flows for critical system conditions in short, medium and long term throughout the planning horizon.

In order to evacuate the generated power to the load centres, the transmission expansion plan determines new lines and required system upgrades. The planned lengths of power transmission projects includes 3,150.20 km of 400 kV, 1,833.70 km of 220 kV and 920.80 km of 132 kV in the short term; 2,444.45 km of 400 kV, 650.70 km of 220 kV and 192.00 km of 132 kV in the medium term; and 610.00 km of 400 kV, 1,180.30 km of 220 kV and 155.20 km of 132 kV in the long term.

Economic and Financial Analysis

The economic and financial analyses were done by taking into account ten (10) relevant basic economic and financial assumptions which are discounted rate, interest rate, debt to equity ratio, loan conditions, Interest During Construction (IDC), inflation rate on Capital costs, foreign exchange rate, depreciation rate, income rate and Return On Equity (ROE).

The proposed power expansion plan requires a total of USD 38,340.4 Million throughout the planning horizon, of which USD 9,526.4 Million will be required in the period of 2020-2025. When inflation and interest during construction are added, total investment required rises to USD 50,589.2 Million in the long run, about two third of this amount is earmarked for power generation projects over the planning horizon.

The financing of capital expenditure for new projects is based on 70 percent debt and 30 percent equity financing (except for Government fully funded projects) of the draw-downs capital expenditure. Therefore, when considering new projects only, the

additional unit cost of power supply is 13.7 UScents/kWh in 2021 and decreases sharply to a low value of 9.6 UScents/kWh in 2022 and reaching an average of 5.5 UScents/kWh from 2023 towards end of the planning period. The sharp decline is due to introduction of JNHPP.

The Long Run Marginal Cost of power projects was calculated on a year-by-year basis by examining the incremental cost over the base year. Nevertheless, the marginal costs of generation, transmission and distribution can be added to result in the overall cost of power supply after considering transmission and distribution losses. The planning horizon Marginal Costs for generation, transmission, distribution and supply in US cents/kWh are 6.7, 1.0, 2.2 and 9.6 respectively.

Conclusion and Recommendation

Tanzania has set the target to reach electricity consumption per capita of 490 kWh per annum by 2025 which is an indicator for middle income countries. Therefore, in order to meet this target, more investment is needed in power generation, transmission and distribution network.

The PSMP 2020 Update among other things considered the Government Industrialization Agenda which requires substantial power supply to meet demand growth. In this regard, power demand forecast was conducted as a base for generation, transmission and investment planning.

The key recommendations are:

- a) The Government to continue with concerted efforts to mobilize the huge financial resources required to implement the Plan including attracting private investment in the electricity sub-sector;
- b) The Government should fast track the short term plan which requires immediate decision and action;

- c) The Government to ensure that strategic power projects are studied to full feasibility so as to reduce project implementation lead time and cost during implementation;
- d) The Government to continue investing in the exploration and development of hydrocarbons to increase more discoveries;
- e) The Government to fast-track the implementation of interconnection transmission lines and negotiations to commence for possible power trading up to 1,500 MW within the SAPP and EAPP starting from 2023;
- f) There is need to prepare Implementation Strategies including capacity building on nuclear power generation; and
- g) The Government to prepare a comprehensive Power System Master Plan in 2025 as the last was conducted in 2008 and updated several times (2009, 2012, 2016 and 2020).

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LIST OF ABBREVIATIONS

AfDB	African Development Bank
AMR	Automatic Meter Reading
AU	African Union
BoT	Bank of Tanzania
CCGT	Combined Cycle Gas Turbine
DSM	Demand Side Management
EAC	East African Community
EAPP	Eastern African Power Pool
EPC	Engineering, Procurement and Construction
ESCOM	Electricity Supply Company of Malawi
EWURA	Energy and Water Utilities Regulatory Authority
FYDP	Five Years Development Plan
GIIP	Gas Initially In Place
GoT	Government of Tanzania
GWh	Gigawatt-hours = 1,000,000,000 watt-hours
IDC	Interest During Construction
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IGCC	Intergrated Gassification Combined Cycle
IPP	Independent Power Producer
JNHPP	Julius Nyerere Hydropower Project
kWh	Kilowatt-hours = 1,000 watt-hours
LTPP	Long Term Plan Perspective
MoE	Ministry of Energy
MoFP	Ministry of Finance and Planning
MVA	Mega Volt Ampere
MVA _r	Mega Volt Ampere Reactive
MW	Megawatt = 1,000,000 watts
MWh	Megawatt-hours = 1,000,000 watt-hours
NBS	National Bureau of Statistics
NDC	National Development Corporation

NGO	Non-Governmental Organisations
OCGT	Open Cycle Gas Turbine
PBPA	Petroleum Bulk Procurement Agency
PPA	Power Purchase Agreement
PPP	Public Private Partnership
PS	Permanent Secretary
PSMP	Power System Master Plan
PURA	Petroleum Upstream Regulatory Authority
R&D	Research and Development
REA	Rural Energy Agency
SADC	Southern African Development Community
SDG	Sustainable Development Goals
SAPP	Southern African Power Pool
SME	Small and Medium Enterprises
SNC	SNC-Lavalin International Inc.
SPP	Small Power Producer
STG	Steam Turbine Generator
SVC	Static Var Compensator
TANESCO	Tanzania Electric Supply Company Limited
TANWAT	Tanzania Wattle Company
TCF	Tonnes Cubic Feet
TFT	Task Force Team
TGDC	Tanzania Geothermal Development Company
TPC	Tanzania Plantation Company
TPDC	Tanzania Petroleum Development Corporation
TZS	Tanzanian Shillings
URT	United Republic of Tanzania
USD	United States Dollar
ZECO	Zanzibar Electricity Corporation
ZTK	Zambia – Tanzania – Kenya Interconnector

CHAPTER 1

1. INTRODUCTION

1.1. Background

The Power System Master Plan 2020 uses historical electricity data and new anticipated loads gathered during industrial surveys in the entire country. The PSMP also infers on the methodology and procedures used in the previous PSMP of 2008 and its subsequent updates in 2009, 2012 and 2016.

A consulting firm, ACRES International (Canada) prepared the first PSMP for Tanzania in 1985, which was followed by several updates until 2007. In 2008, SNC - Lavalin Consultant of Canada developed another new PSMP for the Government of Tanzania through TANESCO. The new plan provided a fundamentally new outlook to guide the development of the power sector in Tanzania. The study provided a detailed assessment of load demand projections, available options for meeting the demand and requirements for a new higher voltage backbone transmission system for the country.

Since then, the PSMP 2008 was firstly updated in 2009 by the then Ministry of Energy and Minerals and TANESCO with the technical support from the consultant SNC-Lavalin. The revision considered progress and challenges encountered during the implementation of the previous PSMP studies. PSMP 2012 was updated by a technical team which comprised of experts from the Ministry of Energy and Minerals, TANESCO, President's Office - Planning Commission, Ministry of Finance, TPDC, EWURA, REA and NBS. In order to cope with rapidly changing power requirements and the Government desire to restructure and drive the electricity sub-sector, the Team updated the power investment plan under the PSMP 2016 Update with technical and financial assistance from Japan International Cooperation Agency (JICA).

The PSMP 2020 Update builds on previous update studies and spearheaded by the Government Technical Team, again drawn from the Ministry of Energy, Ministry of Finance and Planning, TANESCO, EWURA, REA, TPDC, and NBS. The Plan

incorporates comments from various stakeholders, including Private Sector and Energy Development Partner Group.

1.2. Purpose of PSMP 2020 Update

The Power System Master Plan 2020 Update reflects and accommodates Government policy guidelines and recent economic development experienced during the Fifth Government Phase, including development in the electricity sub-sector . The Plan reflects also the visions of the Southern African Development Community , East African Community and African Union . The policy guidelines include, among others, the Government's desire to accelerate industrial and economic growth to attain the Vision 2025; the Government target to ensure 100 percent universal access to modern energy by 2030 ; construction of Standard Gauge Railway that demands reliable power supply; advancing the commissioning date of the Julius Nyerere hydropower project from 2035 as recommended by PSMP 2016 Update to 2022; the National Energy Policy 2015 that emphasise deliberate efforts to develop coal and renewable energy resources in the country for power generation; electrification aimed at achieving 50 percent connection rate by 2025; the Five Year Development Plan 2016 - 2021; and Electricity Supply Industry Strategy and Roadmap 2014 - 2025. Therefore, the PSMP 2020 underline the least-cost plan for additions of new power generation capacity, with the corresponding transmission requirements.

The overall objective is to re-assess the short term (2020 – 2024), medium term (2025 - 2034) and long term (2035 - 2044) in terms of power generation and transmission plans requirement for Tanzania. The goal of the Plan is to increase access to modern energy, enhance power supply availability, reliability and affordability in the country.

In order to achieve this goal, the Government will continue to involve other stakeholders in the power sector to implement the least-cost generation and transmission projects. Specifically, the implementation of the power investment plan will:

- a) facilitate early attainment of the Tanzanian Development Plan Vision 2025;
- b) accelerate rural electrification level and connection of new customers;

- c) facilitate power trading in the region such as Eastern African Power Pool and Southern Africa Power Pool ; and
- d) improve voltage levels and power supply reliability in the regional and National Grid.

For a sustainable power development, the short term investment plan in the PSMP 2020 requires immediate decisions and actions by the Government. The medium and long term plans require coordinated planning and project development studies. This approach ensures future power supply utilizes the least-cost projects that safeguard national interest in the planning horizon.

1.3. Scope of Work

The following five (5) primary components underlie the PSMP 2020 Update:

- a) Confirmation of planning criterion;
- b) Load forecast update including the collection of past and future power demand in all regions;
- c) Generation plan update, including updating and confirming data on all generation sources, existing, current under construction and future options;
- d) Transmission plan update, including ongoing additions and reinforcement to the existing system, plans for interconnecting presently isolated areas and options for export to neighbouring countries; and
- e) Investment plan update, economic and financial analysis on planned power projects.

1.4. Information Collected in the Plan

The following information were used for the PSMP 2020 Update:

1.4.1. Load Forecast Data

The historical records of 25 years (1995 – 2019) for the following information were used in load forecast:

- a) Peak demand at substation, region and national level;
- b) Energy sales by customer category and region;

- c) Level of losses, energy production, energy purchases and energy exports;
- d) Population number per region and household size;
- e) The information on the accelerated electrification programme and its implementation status;
- f) Current and recent electricity forecasts;
- g) Performance of the national economy up to the year 2019; and
- h) Information on expectations for the growth of the national economy and the individual sectors.

1.4.2.Generation Data

- a) Data on the existing generating plants maintained by TANESCO, SPPs and IPPs project developers;
- b) Data on the available and potential power generation resources, including gas, hydropower, coal and renewable power resources (wind, solar, biomass);
- c) Existing hydrological data adopted from previous PSMPs; and
- d) Data on hydrological characteristics of reservoirs, records of inflows, discharges, spills for the reservoirs maintained by TANESCO.

1.4.3.System Planning Data

- a) Existing system operating and maintenance data;
- b) Fuel types, prices, volume and characteristics;
- c) Generation and transmission expansion planning criteria;
- d) Inventory and characteristics of existing and committed units including hydro units, simple cycle gas turbine units, combined cycle units and others (solar, wind and geothermal);
- e) Inventory and characteristics of transmission facilities including transmission lines and substations;
- f) Transmission system current configuration and short term plans; and
- g) Previous study reports on identified new generation options and transmission.

1.5. Factors Considered in the Update Plan

The updated Plan has taken into account a broad spectrum of new information and planning criteria. The primary factors affecting the results, as compared with the PSMP 2016 Update, include:

1.5.1.Load Forecast

- a) The ongoing accelerated electrification program to connect 290,000¹ new customers annually for the first five years from 2020 to 2024, and to repeat or double the efforts in regions exhibiting low connectivity at the end of the first five years;
- b) The impact of the current level of electricity losses on the forecast;
- c) Program for interconnection of remaining isolated load systems by 2023;
- d) Emerging of high demands of power for industries and mining activities such as the construction of smelters;
- e) Construction of Standard Gauge Railway that demands reliable power supply; and
- f) Average household size of 8 persons.

1.5.2.Generation Options

- a) Availability of resources to meet projected demand (hydro, gas, coal, wind, solar and geothermal);
- b) The lead time of projects (fast-track hydro projects, which usually have very long lead time);
- c) End of Contracts or Retirement of projects; and
- d) The capital cost of the proposed projects.

1.5.3.Transmission Plan

- a) Concentrating on 400 kV and 220 kV backbone voltage;
- b) Developing transmission plans in the short, medium and long term while focusing on the introduction of 400 kV where necessary, instead of defining requirements for the whole horizon up to the year 2044; and
- c) The capital cost of the proposed projects.

¹ TANESCO Corporate Business Plan (2020/21)

CHAPTER 2

2. POWER DEMAND FORECAST

2.1. Background

This Chapter provides an estimate of the power demand in Tanzania over the study period from 2019 to 2044. The load forecast study provides a set of energy and power forecasts for Tanzania Interconnected Power System and the isolated systems in the short, medium and long term. The electricity forecast informs the planning of generation and transmission infrastructure. This forecast study explicitly accounts for changed economic background, Government development objectives in the power sector in addition to addressing specific issues concerning the power demand.

2.2. Factors Considered in the Load forecast

The load forecast study considered the following factors:

- (i) **System losses:** the level of losses in 2019 was 16.19 percent, split as 5.88 percent and 10.31 percent for transmission and distribution losses (technical and non-technical) respectively. The plans to reduce power losses and their treatment in the forecast will affect the overall generation requirements over the forecast period. Compared to power losses in 2015, there is a significant drop in losses due to an increase in the rate of inspecting customers and efforts to replace conventional electricity meters to smart meters (LUKU) and construction of high voltage transmission lines (400 kV) to connect significant power loads.

The system losses decreased from 17.47 percent in 2015 to 16.19 percent in 2019 due to the reinforcement of distribution and transmission systems. The Government target is to reduce the total power system losses to as low as 12 percent by 2026 onward. The PSMP 2020 adopted the Government target of attaining 12 percent of system losses from 2026 through the projection period.

Table 2-1 shows the actual and projected system losses.

Table 2-1: The Actual and Projected Power System Losses in Percentage

Years	2015	2019	2020	2021	2022	2025	2026	2044
Transmission	6.20	5.88	5.88	5.50	4.70	4.10	4.00	4.00
Distribution	11.27	10.31	10.31	9.90	8.90	8.20	8.00	8.00
Total	17.47	16.19	16.19	15.40	13.60	12.30	12.00	12.00

- (ii) **New significant power loads in Tanzania:** Currently, the demand forecast study shows that the industrial load growth continues to play a strong drive in the load growth in Tanzania. The Government policy for industrialization drives impacts on the industrial properties with consequent implications to the sudden addition of significant industrial loads. A significant issue in planning is the combination of the size, timing and uncertainty of these new loads. The load forecast will identify industrial loads and assess the likely impact on each regional load forecast.
- (iii) **Rate of electrification:** The Government committed to accelerating the level of its population with electricity supply in the country by connecting 50 percent of the households to electricity network by 2025. The National Energy Policy and the Tanzania Rural Electrification Expansion Program (TREEP) will serve to guide the levels of rural electrification. In this respect, the Government has a five-year electrification program whereby the target is to connect 290,000 new customers per annum from 2020 to 2025. The REA is actively involved in rolling out rural electrification mainly by grid extension to villages and load centers lacking electricity connection. Other initiatives include the densification program in all regions in Tanzania Mainland; the electrification of Ngorogoro from Loliondo Isolated Diesel power plant; and the electrification of villages that are in proximity to the Bulyanhulu-Geita, Geita-Nyakanazi, Makambako-Songea transmission lines and Tanzania – Kenya 400 kV transmission line corridor from Singida – Arusha – Namanga.
- (iv) **Interconnection of isolated systems:** The load forecast assessed the possibility and timing for the interconnection of the isolated regions into the National Grid System. These efforts are well in line with the forecast to accelerate

electrification in Tanzania by connecting the remaining two (2) regions (Kigoma and Katavi) by 2023. However, it is recognized that some districts in Kagera and Lindi regions receive power supply through the medium voltage lines. Other districts in the regions like Liwale and Mafia have isolated (off-grid) power generation and distribution systems. The prime drivers to interconnecting the isolated regions are mainly to provide adequate and reliable power and relieve the country from costly diesel-powered generation and importation of power.

- (v) **The number of persons per household:** Household size is critical in load forecast as it determines specific consumption and degree of electrification. The Plan has adopted the number of 8 persons per household as used in PSMP 2012 Update. In most urban Tanzania, it is common to observe one house with more than five households. Also, it is common to see small houses (huts) in one compound. In turn, a different household occupies each hut; however, households share one electricity connection (meter).
- (vi) **Tariffs:** Economic theory suggests that the consumption of goods or services will decrease as the selling price of the good or service increases. Therefore, this study assumes that electricity tariffs will decrease significantly after the completion of Julius Nyerere Hydropower Plant. Hence, the decrease in the tariff will lead to an increase in electricity consumption and stimulate investment in various sectors.
- (vii) **System load factor:** Figure 2-1 presents the records of load factors from 2000 to 2019. The graph indicates that the load factor has been quite steady from 2000 to about 2004. During that period, the load factor averaged about 64.6 percent, with variation between 65.1 percent and 65.5 percent. For the past ten years, the average load factor rose to about 67.4 percent, while the highest load attained was 76.0 percent in 2012. However, based on the best practices, this Plan has used a 70 percent load factor as the benchmark throughout the planning horizon.

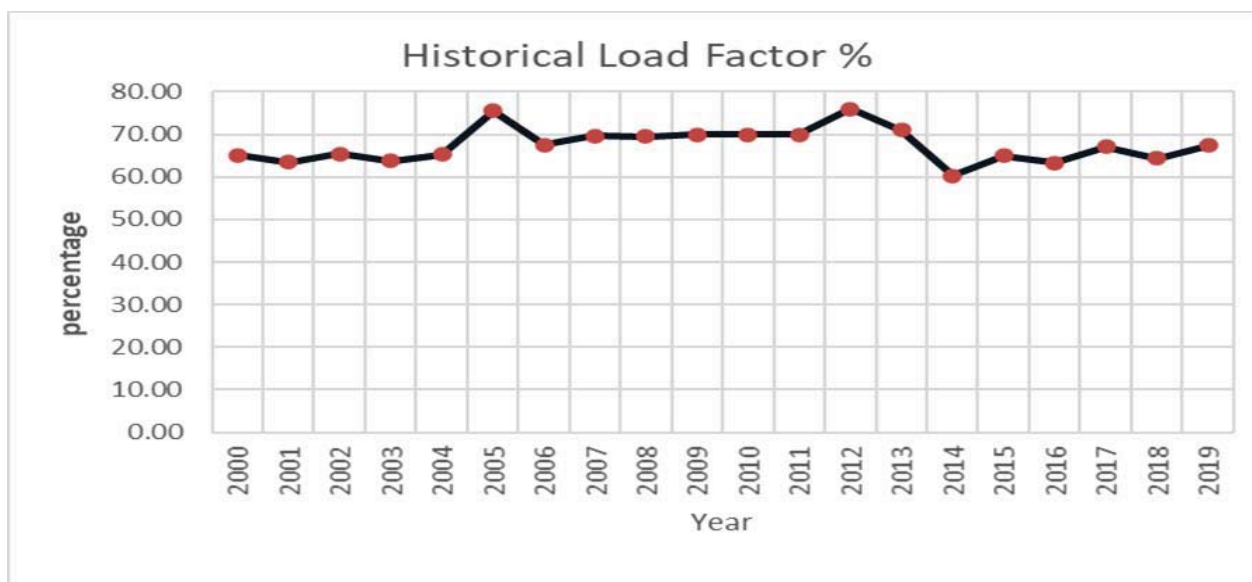


Figure 2-1: Historical Load Factor

2.3. National Economy

2.3.1. Highlights of the Economy

The real GDP has recorded an average growth rate of 6.4 percent over the period from 2008 to 2019. Growth slowed down in 2012 to 4.5 percent, lower than 7.7 percent recorded in 2011, on account of the negative impacts of the weather condition. However, the growth in real GDP bounced back to 6.8 percent in 2013, and it slowed down again in 2015 to 6.2 percent. According to Economic Survey Report 2019, the economy continues to grow consistently due to the rapid increase in Government spending in infrastructure development in the country. The economic activities which recorded higher growth in 2019 were Mining and quarrying (17.7 percent), construction (14.8 percent) and transport (8.7 percent). The economy is, however, expected to pick up in the medium term following Government initiative to stabilize power supply and implement development projects as outlined under FYDP II. **Figure 2-2** summarises the GDP growth over the period 2008 – 2019.

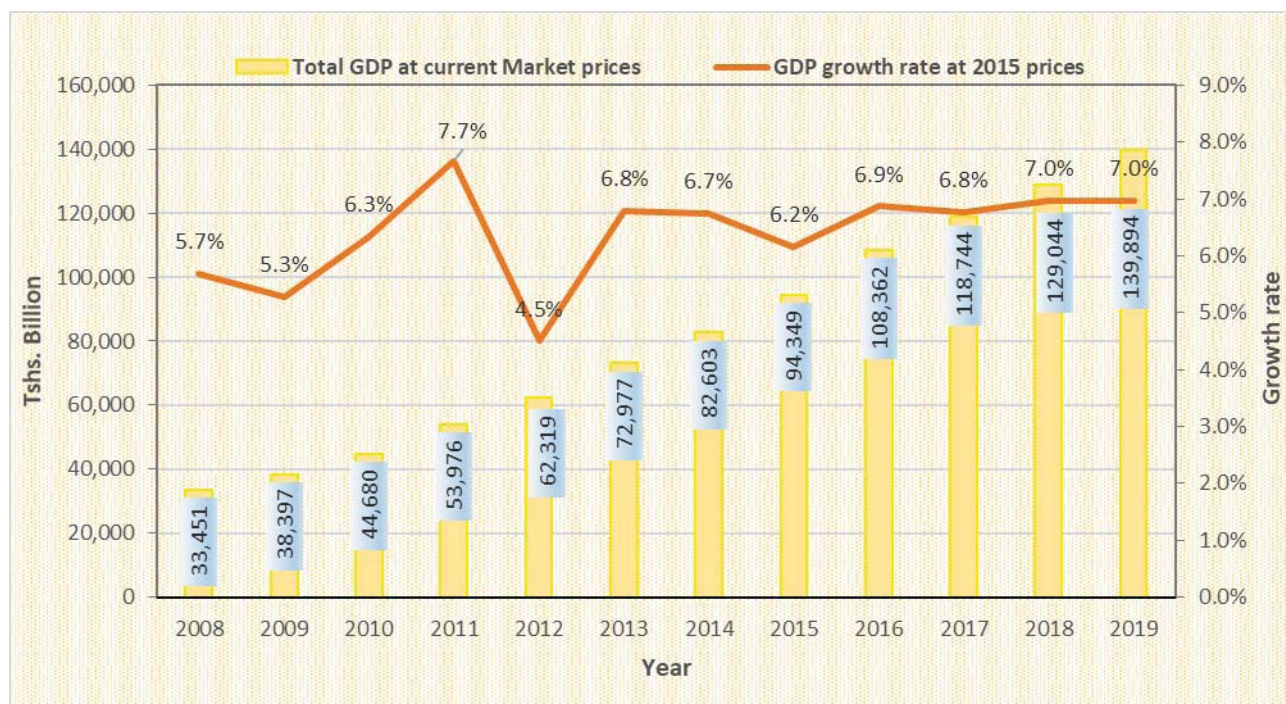


Figure 2-2: Historical Gross Domestic Product (GDP)

2.3.2. Inflation

The annual inflation rate in Tanzania has been at a single-digit averaging 7.8 percent over the period from 2008 to 2019. However, in 2011 and 2012, inflation reached double digits of 16.0 percent and 12.7 percent, respectively. These spikes of high inflation were due to global food and energy crises and drought in countries. The overall annual average inflation rate decreased to 3.4 percent in 2019 compared to 3.5 percent in 2018 on account of the high food supply in the country, low fuel price and a good supply of electricity for industrial production.

Food is the main contributor to Consumer Price Index (CPI), accounting for 37.1 percent of the total CPI basket, followed by transport (12.5 percent) and energy (8.7 percent). The high proportions of CPI show that food prices, fuel prices and energy are very significant in the determination of the inflation trend in the country. The variation of weather and energy supply has an impact on inflation.

2.3.3.Economic Outlook

The review of leading indicators for economic growth such as electricity generation, cement production and consumption-based tax revenues, credit to the private sector, and exports of manufactured, mineral and agricultural commodities have shown positive performance during 2019. The performance of those leading indicators, coupled with continued efforts to stabilize power supply and the implementation of on-going Government policy under FYDP II, the overall performance of the economy in 2020 and beyond is expected to increase to an average of 7.1 percent in the medium term. In the medium-term, growth is expected to pick up supported by continued implementation of infrastructure projects including roads, airports, ports, construction of central railways line into the standard gauge and construction of Julius Nyerere Hydropower Project for stable power supply in manufacturing industries, favourable weather conditions for agriculture production and other Government initiatives under place.

2.3.4.Long Term Perspective

Tanzania's long term growth potential is high, as the country begins to make full use of its resources and expands from a comparatively small market base. The availability of supporting infrastructure is a crucial factor in accelerating the pace of growth of new sectors of the economy. It is worth noting that Tanzania's infrastructure, such as railways, roads, water supply, power systems and telecommunication facilities, requires considerable capital investment for their rehabilitation and expansion to meet emerging demands. Tanzania has made a lot of progress in power development to meet demand growth.

The "Tanzania Development Vision 2025" articulates the long term development plan for Tanzania. The Vision 2025 projects a growth of 8 percent of the economy annually by 2025, but in 2019 the economy grew at 7 percent. The PSMP 2020 update has taken into consideration the "Vision 2025," which aims at increasing power capacity at a rate of 15 percent per annum in order to support the economic development envisaged in "Vision 2025". Likewise, the forecast of power demand considered the Tanzania Five Year Development Plan 2016/17 to 2020/21.

The Government aims to increase the value chain in agriculture products as agriculture employs the majority of Tanzanians, estimated at 67 percent of the employed population. In this regard, the Government plans to add value in agricultural products by forming agro-industries and agro-processing industries by revamping the textile, garment, clothing and leather industries.

The FYDP recognizes the challenges on resource mobilization and it has zeroed in on a few areas of prioritization, of which their implementation will unleash the country's growth potentials. These are in areas of industrial, agriculture, transport, energy, ICT and human resources. According to the FYDP, concerted and strategic measures will aim to accelerate annual economic growth of between 8 percent and 10 percent. Likewise, an overall investment will be raised to more than 30 percent of GDP per year in current prices.

The FYDP document recognizes that there are several challenges, which require the Government to address them to move Tanzania to a higher level of production. One of the critical challenges is the development of low-cost energy to make Tanzania a destination for producing efficient and competitive goods and services as well as a source for competitive energy supplies within the region. As such, Tanzania² is ranked medium in terms of its competitiveness in attracting investment in the country. The main objectives of the Plan are to improve infrastructure networks as well as to attain low-cost energy service that allows more inflow of investments into the country.

2.3.5. Population

Table 2-2 presents the human population estimates by region for the last four censuses as well as projections of the population from 2019 to the end of the forecast period. The growth rates assumed for each region correspond to the growth between the census of 2002 and the census of 2012. The population projections do not account for adjustments for the in and out-migration between census periods; the adjustments are assumed part of the census exercise.

² World Economic Forum: The Global Competitiveness Report, 2018-2019

Table 2-2: Regional Population Projection (in Thousand)

S/N	Mainland	1978 ¹	1988 ¹	2002 ¹	2012 ¹	2019	2025	2030	2035	2040	2044
1	Arusha	926	744	1,293	1,694	2,052	2,362	2,612	2,854	3,091	3,277
2	Dar es Salaam	843	1,361	2,498	4,365	5,275	5,995	6,529	7,062	7,647	8,146
3	Dodoma	972	1,235	1,699	2,084	2,569	3,082	3,578	4,117	4,693	5,183
4	Iringa	925	1,193	1,495	941	1,122	1,290	1,429	1,564	1,695	1,798
5	Kagera	1,010	1,314	2,034	2,458	3,128	3,848	4,552	5,341	6,214	6,975
6	Kigoma	649	857	1,679	2,128	2,707	3,312	3,892	4,531	5,220	5,800
7	Kilimanjaro	902	1,105	1,381	1,640	1,907	2,187	2,431	2,671	2,914	3,119
8	Lindi	528	646	791	865	1,004	1,138	1,258	1,381	1,505	1,604
9	Manyara	na	604	1,040	1,425	1,811	2,212	2,593	3,008	3,448	3,817
10	Mara	724	946	1,369	1,744	2,298	2,925	3,575	4,359	5,304	6,200
11	Mbeya	1,080	1,476	2,070	1,709	2,137	2,562	2,946	3,361	3,823	4,231
12	Morogoro	939	1,221	1,760	2,218	2,662	3,081	3,449	3,827	4,215	4,530
13	Mtwara	772	889	1,128	1,271	1,451	1,626	1,784	1,948	2,114	2,246
14	Mwanza	1,443	1,877	2,942	2,773	3,676	4,666	5,672	6,900	8,433	9,931
15	Pwani	517	636	889	1,099	1,295	1,486	1,654	1,829	2,010	2,158
16	Rukwa	452	699	1,142	1,005	1,232	1,484	1,741	2,030	2,340	2,604
17	Ruvuma	562	780	1,117	1,377	1,617	1,863	2,091	2,326	2,560	2,746
18	Shinyanga	1,324	1,764	2,805	1,535	1,934	2,297	2,600	2,900	3,194	3,425
19	Singida	614	792	1,091	1,371	1,658	1,967	2,271	2,600	2,940	3,215
20	Tabora	818	1,036	1,718	2,292	2,974	3,647	4,264	4,924	5,615	6,172
21	Tanga	1,038	1,280	1,642	2,045	2,392	2,766	3,127	3,513	3,910	4,239
22	Njombe	na	na	na	702	820	923	1,007	1,086	1,160	1,218
23	Katavi	na	na	na	565	771	1,001	1,242	1,544	1,926	2,304
24	Simiyu	na	na	na	1,584	2,196	2,934	3,736	4,761	6,103	7,489
25	Geita	na	na	na	1,740	2,335	2,993	3,658	4,441	5,368	6,224
26	Songwe	na	na	na	999	1,240	1,490	1,730	1,994	2,280	2,525
	MAINLAND TOTAL	17,038	22,455	33,583	43,625	54,265	65,140	75,422	86,872	99,723	111,177
	Zanzibar										
22	North Unguja	77	97	137	187	227	256	277	297	318	334
23	South Unguja	52	70	95	116	136	149	158	167	177	184
24	Urban West	142	209	391	594	717	810	879	944	1,008	1,058
25	North Pemba	106	137	186	212	283	355	420	488	559	618
26	South Pemba	99	128	176	195	262	326	381	437	495	543
	ZNZ TOTAL	476	641	985	1,304	1,626	1,897	2,115	2,333	2,556	2,737
	Country Total	17,514	23,096	34,568	44,929	55,891	67,036	77,537	89,205	102,279	113,914

NOTE:

1. Actual Population Census Results were 1978, 1988, 2002 and 2012.
2. "na" means that Manyara, Njombe, Katavi, Simiyu, Geita, and Songwe regions were not yet established.

2.4. The Energy Sector

2.4.1. Institution Framework

Tanzanian energy sector involves several stakeholders, which are Government and Non-Government institutions within and outside the country. The types of stakeholders in the energy sector of Tanzania vary significantly. They range from pro users of energy, production of energy equipment, financiers of energy projects, researchers, Non-Governmental organizations, policymakers and regulators of the energy sector. Key players, in the energy sector, include the Ministry of Energy, Tanzania Electric Supply Company, Tanzania Petroleum Development Corporation, the Rural Energy Agency, the Energy and Water Utilities Regulatory Authority Petroleum Upstream Regulatory Authority, Petroleum Bulk Procurement Agency, Tanzania Geothermal Development Company, National Environment Management Council (NEMC), Occupation Safety and Health Authority, Development Partners and Private Sector (Independent Power Producers).

2.4.2. Legal Framework

These are the Electricity Act of 2008, the Petroleum Act of 2015, Energy and Water Utilities Regulatory Authority Act of 2001 and the Rural Energy Act of 2005 and their amendments. The National Energy Policy, 2015, which is the overall guide in the energy sector development sustainably and supports the development of energy through Public and Private Partnership , utilization of natural resources and application of energy efficiency technologies.

2.4.3. Electricity Subsector

The Tanzanian power system (National Grid) comprises of hydro and thermal generation units owned by TANESCO and IPP's with a total nameplate (installed) capacity of 1,565.72 MW (as of December 2019) out of which 573.7 MW hydro and 892.72 MW natural gas, liquid fuel 88.8 MW and Biomass 10.5 MW. IPPs capacity constitutes 189 MW, equivalent to 12.07 percent of the total installed capacity. Thermal generators serve the isolated system with a total nominal capacity of 36.6 MW.

TANESCO has so far been the sole vertically integrated electricity supplier on Tanzania mainland, and supplies bulk electricity to Zanzibar. However, the National Energy Policy

of 1992 introduced the participation of the private sector in the electricity sub-sector. The independent power producers (IPP), include Songas 189 MW, which supplies power to TANESCO. Other Small Power Producers (SPP) include TPC 9 MW, TANWAT 1.5 MW, Tulila 5 MW, Mwenga 4 MW, Andoya 1 MW, Yovi 0.95 MW, Matembwe 0.59 MW and Darakuta 0.32 MW. These SPPs either sell power to TANESCO or/and distribute through their mini-grid networks. Tanzania also imports electricity through cross-border interconnections of 17 MW from Uganda, 8 MW Zambia and 1 MW from Kenya³. The distribution of electricity in Zanzibar is the sole responsibility of the Zanzibar Electricity Corporation (ZECO).

2.5. Performance of the Current Power System

The administrative regions of TANESCO, generally follow the political-administrative regions in Tanzania. However, Dar es Salaam region is composed of four TANESCO regions. The National Grid does not include two regions of Kigoma and Katavi, these regions are being served by isolated system. Four regions of Kagera, Rukwa, Lindi and Mtwara have a partial connection to the National Grid through medium voltage connection.

Table 2-3 shows that the system peak demand of Tanzania grew by 31.57 percent over the period 2012 to 2019. On the other hand, the units generated in the primary grid system grew by 35.82 percent. In comparison, electricity imports both locally and foreign declined by 35.63 percent in the same period.

Table 2-3: Units of Electricity Generated and Imports

Years	2012	2014	2016	2018	2019
Peak Demand – MW	851.35	934.62	1041.63	1116.58	1120.12
Units Generated – GWh	5537.8	6028.9	6788.9	7048.4	7521.2
Units Imported (Local) - GWh	2,564.10	2,149.40	1,819.50	1,512.40	1,576.50
Units Imported (foreign) - GWh	60.9	61	101.5	117.5	113.2

Source: TANESCO

Table 2-4 shows the coverage of the power transmission networks in Tanzania. A total of 670 km of new 400 kV lines were constructed and currently operated at 220 kV. By

³There is PPA between Tanzania and Kenya but currently Tanzania is not importing electricity from Kenya.

the end of 2019, approximately 1300.1 km of 220 kV lines or 15.7 percent of new lines were constructed annually from 2012 to 2019. Another 135 km of 132 kV lines were constructed over the same period, while the 66 kV lines remained at the current length of 543 km.

Table 2-4: Transmission Line Expansion Coverage

Years	2012	2014	2016	2018	2019
Lengths of 400 kV in km	0	0	670	670	670
Lengths of 220 kV in km	1710.69	2,227.85	2,745	2922.14	3,010.7
Lengths of 132 kV in km	1,538	1538.75	1626	1657.06	1672.57
Lengths of 66 kV in km	543	543	543	543	543

Source: TANESCO

Table 2-5 presents the units of electricity sales and the number of customers by regional loads of Tanzania in 2019. The table also shows the degree of electrification in each of the load centers considering that customers in tariff category T1 represent the households with electricity connections in the country. The table shows that the degree of electrification varies from one region to the other. The overall rate of population with access to electricity is 78.4 percent⁴ in Tanzania Mainland as a result of the on-going rural electrification programs in the country.

⁴ Energy Access and Use Situation Survey II in Tanzania Mainland 2019/20

Table 2-5: Electricity Sales and Number of Customers[illegible]

2.6. Recent Development in Electricity Sub-sector

The following are the major projects that have been implemented or under construction in electricity sub-sector since 2016:

- a) Construction of the Julius Nyerere Hydropower Plant (2,115 MW) at Rufiji River expected to be completed by 2022;
- b) Construction of Kinyerezi I extension (185 MW) expected to be completed by July 2021;
- c) Commissioning of Backbone Transmission Investment Project (BTIP – 400 kV) from Iringa to Shinyanga via Dodoma and Singida in 2016;
- d) Construction of 400 kV transmission line from Singida – Arusha – Namanga expected to be completed by 2021;
- e) Commissioning of 220 kV transmission line from Makambako – Songea in 2018;
- f) The on-going rural electrification program – REA phase III, Densification project, Peri-urban Project, and Result based electrification projects. The rural electrification program runs from 2020 over the next five years up to 2025. The electrification efforts will be rolled out for another five years, depending on the level of electrification in a given region;
- g) Extension of grid system (132 kV) from Tabora to Katavi via Inyonga and Kaliua as a parallel project under the Tabora – Kigoma via Urambo, Kaliua and Nguruka project by 2021;
- h) Construction of 400 kV transmission line from Nyakanazi to Kigoma and 220 kV transmission line from Bulyanhulu to Geita and Geita to Nyakanazi by 2022;
- i) Replacement of conventional meters with its subsequent smart metering system under the AMR system to large power users and medium customers and legalizing illegal customers;
- j) Development of Rusumo (80 MW), which is equally shared by Burundi, Rwanda and Tanzania and Murongo – Kikagati Hydropower (14 MW), which is equally shared by Tanzania and Uganda. All these projects will be commissioned by 2021; and

- k) Commissioning of 132 kV transmission line from Mtwara to Lindi (Mahumbika) with a total route length of 80 km in 2018.

2.7. Forecast Methodology

2.7.1. General

The current load forecast uses a similar approach and methodology as was developed and used for the 2008 forecast (PSMP 2008) and subsequent forecasts of 2009 and 2011. Initially, the forecast projects electricity sales – at the customer level, adding up for the implied distribution and transmission losses to arrive at the energy requirements and peak demand for each region; and then at each level aggregates to get total system energy and peak demand for the country.

The Forecast applied two methodologies, namely:-

- a) Trend line analysis – applied for regional forecasts and aggregated to arrive at total country forecasts; and
- b) Econometric analysis – this approach provided an overall check on the reasonableness of the forecast results obtained using the trend-line approach.

2.8. Approach Used for Forecasts

In achieving national load forecasts, regional load forecasts were performed individually based on the following steps:

- a) First, derived a forecast of sales for the regional loads using a trend-line approach in which the trends in the number of customers and the unit consumption in each category of load were studied. The objective was to establish the underlying trend and projection growth rates;
- b) Assessed the impact of specific factors for load forecast in the country;
- c) Estimated the load factors that would apply in the regional systems;
- d) Estimated the losses, both transmission, distribution-categorized as technical as well as non-technical losses and derive the energy required; and
- e) Derived a forecast of the energy and peak demand for the sector.

The forecasting approach also took into account Tanzania Development Vision 2025, Long Term Plan Perspective (LTPP: 2010-2025) and Five Year Development Plan II as a basis of judgment in applying future growth rates to the unit consumption of electricity.

Furthermore, the approach accounts explicitly for the expected new industries as obtained from the recent industrial surveys and a special program to accelerate electricity connection.

2.8.1.Data Validation

Data validation was carried out by tracing historical changes in a given data set. Graphs of the necessary input data (e.g customers and unit consumption) were assembled for each region for visual analysis and establishing historical trends. This examination permitted the selection of a historical period and appropriate growth rates for future load projections.

2.8.2.Assumptions

The assumptions employed are categorized into two groups, general and specific assumptions. General assumptions are summarised in **Table 2-6** while the specific ones were applied to specific regions.

Table 2-6: General Assumptions used in the forecast

High Case	Base Case	Low Case
Base Year Data 2019	Base Year Data 2019.	Base Year Data 2019
Target – Achieve 100% of the 290,000 new customers per annum for 5 years.	Target – Achieve 75% of the High Case target (217500).	Target – Achieve 50% of the High Case target (145,000)
Household size – 8 people	Household size – 8 people.	Household size – 8 people
Emerging of high demands of electricity (industrial survey Government industrialization policy and intention to reduce the price per unit due to low-cost power from Julius Nyerere hydropower plant in 2025)	Emerging of high demands of electricity (industrial survey): Assuming structural breaks – delays and shifts of projects. Further Government industrialization policy and intention to reduce the price per unit due to low-cost power from Julius Nyerere hydropower plant in 2025.	Historical growth rates and low unit price

High Case	Base Case	Low Case
By 2025 Tanzania is assumed to be a middle-income country according to the TDV 2025:	By 2025 Tanzania is assumed to be a middle-income country according to the TDV 2025	Business as usual, following historical trends
Regions connected to the National Grid from 19 to 23 in 2020/21 and 26 by 2025/26.	Regions connected to the National Grid from 19 to 23 in 2020/21 and 26 by 2025/26.	
Power losses from 19% in 2014/15 to 14% in 2020/21 and attain 12% by 2025/26	Power losses from 19% in 2014/15 to 14% in 2020/21 and attain 12% by 2025/26.	
Per capita consumption (kWh) from 108 observed during 2014/15 to 377 in 2020/21 and 490 for 2025/26	Per capita consumption (kWh) from 108 observed during 2014/15 to 377 in 2020/21 and 490 for 2025/26.	

Source: PSMP 2020 Update Team Compilation.

The specific assumptions used in the forecast for each region have considered the following factors:

- i. Population growth;
- ii. Number of people per household;
- iii. Rate of increase in customers under the electrification program (applied to T1 customers);
- iv. Rate of increase in customers in T2 and T3 as well as in T1 beyond the electrification program;
- v. Unit consumption for all three customer categories;
- vi. Amount and timing of new industrial loads; and
- vii. Amount and timing of significant expansions of existing T3 customers.

2.8.3.Projection of the Economic and Demographic Parameters

The load forecast study considers three periods of analysis. The short term from 2020 to 2024 – this period has a relatively high growth, during which 1.45 million customers will be connected. The medium term period covering 2025 to 2034 with moderate growth rate responding to LTPP. The long term that is 2035 to 2044, responding to characteristics of middle-income countries.

An assessment of historical GDP growth over the past 14 years reveals that the economic growth rate has been stable in all periods. The 25-year forecast study uses GDP growth rates availed by the Ministry of Finance and Planning. **Table 2-7** summarises the applicable GDP growth rates.

Table 2-7: GDP Growth Analysis

Analysis Period	High Case	Base Case	Low Case
2020 - 2025	7.20%	6.10%	5.30%
2026 - 2030	7.50%	6.60%	5.50%
2031 – 2035	7.30%	6.40%	5.20%
2036 - 2044	7.20%	6.10%	5.00%

Sources:

1. PSMP 2020 Update Team Compilation.
2. Ministry of Finance and Planning.

2.8.4.Loads from Potential Major Customers

The Government has been heavily promoting investment in extractive and other industries. Following these efforts, new potential significant customers have been identified, including mining and manufacturing industries, with their expected power needs and respective locations, as shown in **Table 2-8**. The identified load includes, 76.2 MW of power requirement in mining activities, 51 MW in sugar factories and 28 MW in cement factories and the rest of power required are for other industries. The new identified customers are explicitly considered in the forecast of the respective region.

Table 2-8: Identified Potential Loads

Major Loads	Capacity (MW)	Location	Expected Online
M/S Iron & Steel Ltd	6	Dar es Salaam	2020
M/S Tanzania Railways Corporation	20	Dar es Salaam	2020
Expansion of Mloganzila Referral Hospital	5	Dar es Salaam	2022
DUWASA	6	Dodoma	2025
Kagera Sugar	11	Kagera	2020
Mbeya Cement	5	Mbeya	2023
Mkulazi (Mbigiri) sugar Factory	10	Morogoro	2022
Mahenge Resources(Black Rock)	23.2	Morogoro	2025
Kilombero Sugar Company Limited	30	Morogoro	2022
Tanza Graphite Company Ltd	18	Morogoro	2020
MWAUWASA	6.8	Mwanza	2022
Tanzania Breweries Limited	9.9	Mwanza	2022
BUSOLWA Mining Co. Ltd	5	Mwanza	2020
Geita Gold Mining Limited	5	Geita	2020
Jielong Holding (T) Ltd	6	Shinyanga	2020
Kom Food Product	8	Shinyanga	2022
Jambo Food Product	5.9	Shinyanga	2020
M/S Kahama Mining Corp. Ltd	5	Shinyanga	2026
Williamson Diamond Ltd	7	Shinyanga	2023
Rhino Cement	18	Tanga	2021
Sparcoci International Ltd	8	Pwani	2021
Lodhia Steel 3	8	Pwani	2020
Rhino Cement Comp	5	Pwani	2020
Goodwill	5	Pwani	2020
Shungubwen Mining	8	Pwani	2020
Salt Industry (Processing, Grading, Packaging, an	5	Mtwara	2021
New Fertilizers Industry	10	Mtwara	2021
Makonde Plateau Water and Sanitation	5	Mtwara	2020
Fumba Uptown Living	18	Zanzibar	2020
Fumba Town Development	12	Zanzibar	2020
Maruhubi Port	5	Zanzibar	2021
Chumini Estate House	20	Zanzibar	2020
ZECO Reinforcement Line	7	Zanzibar	2020
Total	326.8		2020-2026

Source: PSMP 2020 Update Team Compilation.

2.8.5.Load Forecast Results

Table 2-9 provides a summary of load forecast results for each region from 2019 (base) to 2044. There is a noticeable increase of annual demand growth starting from 2022 to 2026. The growth is mainly due to identified additional power demands from existing customers, new customers (information obtained from power demand survey 2019) and a special electrification program which tallies with Government's policy statement of connecting 50 percent of the population by 2025.

The table also shows rate of electrification (connection) grows from 30.1 percent in 2020 to 96.1 percent in 2044. The derived rate of electrification does not include the population using private power sources such as a renewable solar systems, therefore the rate of electrification derived in the current forecast study is lower than 37.7 percent electrification rate reported by NBS (Energy Access and Use Situation Survey II, 2019/20).

Table 2-10 provides the corresponding peaks forecast for each region, and an evolution of the interconnected grid system, including all the isolated regions. **Table 2-11** presents projected total annual peak demand (MW) and energy generation (GWh) requirements. **Figures 2-3 to 2-5** visualize the sales, peak demand and generation forecasts for the three load forecast scenarios considered. The forecast is based on actual data of 2019 and data for the proceeding years from 2020 up to the year 2044 were estimated. Furthermore, the estimates were based on unconstrained demand consumption.

Table 2-9: Detailed Forecast Results - GWh

Sales, Generation and peak demand-Total country				BASE CASE								
Region	Unit	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040	2044
Arusha	GWh	406.4	439.8	495.1	557.1	625.1	700.6	811.5	1,519.3	2,615.5	4,458.2	6,808.9
Dares Salaam	GWh	2,600.6	2,732.9	3,038.3	3,460.8	3,964.2	4,542.0	5,272.3	10,279.6	16,249.4	23,376.4	29,140.3
Dodoma	GWh	180.0	223.5	240.2	216.7	240.2	270.3	303.7	438.3	736.3	1,154.3	1,462.5
Geita	GWh	53.0	56.3	61.9	72.7	89.8	111.6	150.0	336.8	720.7	1,631.3	3,048.0
Iringa	GWh	108.9	118.6	131.5	146.0	162.4	183.8	217.4	435.5	697.4	1,020.4	1,318.6
Kagera	GWh	80.4	80.9	87.8	105.3	126.3	150.2	172.1	355.6	741.7	1,478.6	2,673.7
Katawi	GWh	13.6	14.2	15.2	17.7	18.8	19.9	21.7	36.2	82.5	239.4	561.2
Kigoma	GWh	40.3	44.5	49.5	55.8	60.4	68.7	77.9	210.9	819.5	1,195.3	1,610.0
K'Manjaru	GWh	187.0	203.4	224.5	244.3	268.0	295.0	329.1	516.5	794.1	1,196.8	1,634.4
Lindi	GWh	29.8	31.5	36.1	43.4	54.4	67.9	84.7	159.2	318.2	638.6	786.7
Manyara	GWh	34.8	38.5	42.8	48.5	56.5	65.1	78.3	161.5	407.0	651.1	946.3
Mara	GWh	164.0	175.8	191.8	217.4	247.0	290.3	318.1	619.4	1,136.1	2,254.0	4,142.1
Morogoro	GWh	268.2	290.3	321.1	360.8	404.6	500.8	600.2	1,020.4	2,107.8	3,260.7	4,457.7
Mbeya	GWh	201.7	216.9	243.0	277.8	318.5	368.5	433.7	946.5	2,009.0	3,169.1	4,534.9
Mtwara	GWh	56.0	59.3	64.4	84.8	125.6	185.5	243.4	416.4	665.7	981.5	1,356.8
Mwanza	GWh	295.3	318.1	350.4	392.7	444.0	518.1	615.3	1,182.6	2,509.7	3,768.0	5,202.4
Pwani	GWh	450.9	474.5	509.8	625.6	758.7	979.1	1,087.1	1,644.0	2,484.9	3,624.5	4,910.5
Njombe	GWh	39.2	40.8	44.9	55.4	70.3	91.6	113.8	181.3	289.5	398.8	514.8
Rukwa	GWh	27.4	30.5	43.7	54.5	68.8	87.4	105.6	176.5	344.6	476.6	619.8
Ruvuma	GWh	50.4	53.8	61.9	73.8	90.9	113.6	143.3	286.6	674.3	1,027.8	1,442.7
Singida	GWh	49.5	55.0	62.4	72.7	84.6	100.6	121.3	244.8	558.4	839.5	1,118.6
Shinyanga	GWh	297.0	328.0	362.5	400.3	440.7	485.7	573.3	1,136.2	2,188.0	3,098.8	4,015.6
Simiyu	GWh	24.3	26.7	29.7	35.7	44.1	57.7	73.4	164.9	673.8	1,018.1	1,392.3
Songwe	GWh	33.2	34.4	37.8	46.5	58.1	73.7	88.5	145.5	290.5	406.6	529.0
Tabora	GWh	68.6	76.3	89.3	104.0	121.7	141.2	179.4	538.2	1,606.5	2,765.8	4,224.7
Tanga	GWh	351.9	378.7	408.4	440.4	487.3	537.7	640.2	1,250.9	2,560.2	3,875.2	5,169.1
Zanzibar_Pemba	GWh	43.3	49.2	55.5	62.2	69.6	77.9	87.2	151.8	231.3	290.2	345.4
Zanzibar_Unguja	GWh	458.6	488.2	453.8	485.0	519.8	560.9	595.5	738.3	898.0	1,092.1	1,258.0
Total (Grid + Isolated) - GWh		6,614	7,081	7,753	8,758	10,020	11,645	13,538	25,294	45,410	69,388	95,225
Growth rate			7.1%	9.5%	13.0%	14.4%	16.2%	16.3%	13.3%	9.5%	8.3%	8.3%
T1	GWh	3,368	3,688	4,181	4,795	5,473	6,226	7,180	14,742	28,676	43,934	60,431
T2	GWh	652	673	695	752	809	867	993	1,875	3,494	6,161	9,301
T3	GWh	2,594	2,719	2,851	2,996	3,139	3,284	3,619	6,126	10,198	15,569	21,135
Less New load	GWh	0	0	26	215	599	1,267	1,746	2,551	3,042	3,723	4,358
Total Sales	GWh	6,614	7,081	7,753	8,758	10,020	11,645	13,538	25,294	45,410	69,388	95,225
Distribution losses	GWh	783	822	857	919	997	1,110	1,226	2,294	4,092	6,206	8,481
Distribution loss rate	GWh	10.6%	10.4%	10.0%	9.5%	9.0%	8.7%	8.3%	8.3%	8.3%	8.2%	8.2%
Generation required at S/S	GWh	7,397	7,903	8,610	9,677	11,017	12,755	14,764	27,588	49,502	75,594	103,706
Recovered load shedding	GWh	0	0	0	0	0	0	0	0	0	0	0
Transmission Losses	GWh	435	435	439	455	474	510	591	1,104	1,980	3,024	4,148
Transmission Loss rate	GWh	5.9%	5.5%	5.1%	4.7%	4.3%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Net Generation	GWh	7,832	8,338	9,049	10,132	11,491	13,265	15,355	28,692	51,482	78,618	107,854
Station use	GWh	39	42	45	51	57	66	77	143	257	393	539
Fraction of Station use	GWh	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Gross Generation	GWh	7,861	8,028	9,098	10,176	11,470	13,240	15,271	28,663	51,496	78,657	107,937
Annual Growth rate			2.1%	13.3%	11.8%	12.7%	15.4%	15.3%	13.4%	9.5%	8.3%	8.3%
Sum of Peak Demands (MW)	MW	1,120	1,435	1,629	1,809	2,036	2,329	2,677	4,878	8,554	12,854	17,611
Coincident Peak (MW)	MW	1,120	1,425	1,533	1,702	1,914	2,189	2,514	4,573	7,958	11,867	16,111
Annual Growth rate			27.2%	7.5%	11.0%	12.5%	14.3%	14.8%	12.7%	8.9%	8.0%	7.9%
Overall electrification level	%	28.4	30.1	31.3	32.2	33.3	34.4	36.2	48.5	75.7	86.3	96.1

Source: PSMP 2020 Update Team Compilation

Table 2-10: Regional Peak Demand Forecast - MW

Non-coincidence Peak Demand Forecast					BASE CASE																							
MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044		
Arusha	58	71	84	94	105	118	134	156	182	205	230	259	292	327	366	409	458	513	574	642	718	802	897	1,003	1,121	1,257		
Dar es Salaam	581	644	734	818	916	1,030	1,181	1,353	1,532	1,733	1,970	2,171	2,369	2,577	2,793	3,019	3,246	3,483	3,722	3,960	4,197	4,430	4,655	4,872	5,078	5,380		
Dodoma	33	45	50	44	48	54	59	65	70	75	79	84	94	103	115	127	140	153	168	185	204	216	228	242	255	270		
Geita	13	14	16	19	22	27	35	42	48	54	61	74	88	101	116	130	147	176	207	240	274	310	348	411	479	563		
Iringa	19	22	25	29	32	35	41	48	55	63	71	81	89	98	106	118	129	142	155	167	177	188	198	210	225	244		
Kagera	8	9	11	13	15	18	21	24	29	34	41	48	57	68	80	95	111	130	153	180	213	251	296	350	416	494		
Katavi	7	8	8	8	8	8	8	8	9	9	9	10	13	14	15	17	20	24	28	34	41	49	58	71	84	103		
Kigoma	8	10	12	13	14	15	17	19	23	27	32	43	58	79	108	150	161	173	184	198	211	226	242	258	276	297		
K/Mwanjaro	42	49	55	59	64	69	75	80	88	95	102	110	120	129	139	150	160	173	185	199	214	229	246	263	281	302		
Lindi	3	4	4	5	7	8	11	13	15	17	20	23	26	30	35	42	50	59	71	85	102	111	120	129	140	145		
Manyara	7	8	10	11	12	14	16	18	21	24	26	32	39	48	58	72	79	86	95	103	114	124	135	148	161	175		
Mara	11	12	14	16	19	23	25	28	35	42	49	58	69	81	95	110	132	158	191	230	279	342	421	523	656	765		
Morogoro	45	52	59	67	74	90	107	125	136	148	160	183	215	250	289	332	381	419	459	501	547	595	653	705	759	823		
Mbeya	58	66	75	82	92	103	116	131	150	171	196	225	259	299	346	401	430	463	498	534	575	618	664	714	767	838		
Mtwara	11	12	14	17	25	37	48	58	63	68	74	81	89	97	107	119	127	138	148	159	171	185	200	216	233	251		
Mwanza	58	66	75	83	94	107	125	145	163	181	202	235	275	323	380	451	488	527	570	616	664	717	773	834	900	960		
Pwani	47	53	60	75	92	121	134	151	167	183	202	224	249	276	307	342	377	417	460	508	563	623	690	766	849	908		
Njombe	11	12	14	16	20	25	30	33	35	38	40	43	46	50	54	59	61	65	68	71	75	78	82	86	91	95		
Rukwa	8	9	14	17	20	25	29	31	33	35	39	46	51	58	67	76	80	83	88	92	96	100	105	110	116	123		
Ruvuma	11	12	14	17	20	25	30	35	40	45	50	58	70	84	101	123	133	144	155	168	180	195	210	228	246	267		
Singida	12	14	16	18	21	24	28	33	37	40	44	57	68	82	97	113	122	131	142	151	162	173	184	195	208	222		
Shinyanga	24	28	34	38	42	47	57	68	80	94	109	129	154	183	219	264	294	327	364	406	452	504	563	629	704	742		
Simiyu	11	11	12	14	16	20	24	27	30	32	34	44	57	76	104	146	155	164	173	183	194	204	217	228	241	257		
Songwe	3	4	4	5	6	8	10	11	14	15	16	19	23	27	32	40	43	47	52	57	63	69	76	83	92	98		
Tabora	11	12	15	18	21	24	30	38	47	57	72	93	120	154	197	253	284	320	358	402	450	503	564	630	704	780		
Tanga	77	88	97	103	113	122	142	164	180	200	221	264	309	359	414	473	514	556	600	646	694	743	794	847	901	954		
Znz Pemba	10	11	13	15	16	18	20	23	25	28	31	34	38	42	46	48	50	52	54	57	59	61	64	66	69	72		
Znz Unguja	86	87	90	96	102	114	121	127	133	138	143	149	154	160	167	173	180	187	194	193	200	208	216	223	231	227		
System Peak	1,120	1,435	1,629	1,809	2,036	2,329	2,677	3,053	3,439	3,850	4,323	4,878	5,488	6,177	6,951	7,851	8,554	9,309	10,116	10,968	11,885	12,854	13,897	15,042	16,283	17,611		
Growth	28.1%	13.5%	11.0%	12.5%	14.4%	14.9%	14.0%	12.6%	12.0%	12.3%	12.8%	12.5%	12.6%	12.5%	12.9%	9.0%	8.8%	8.7%	8.4%	8.4%	8.2%	8.1%	8.2%	8.3%	8.2%			

Source: PSMP 2020 Update Team Compilation.

Table 2-11: Peak Demand and Energy Generation Forecasts

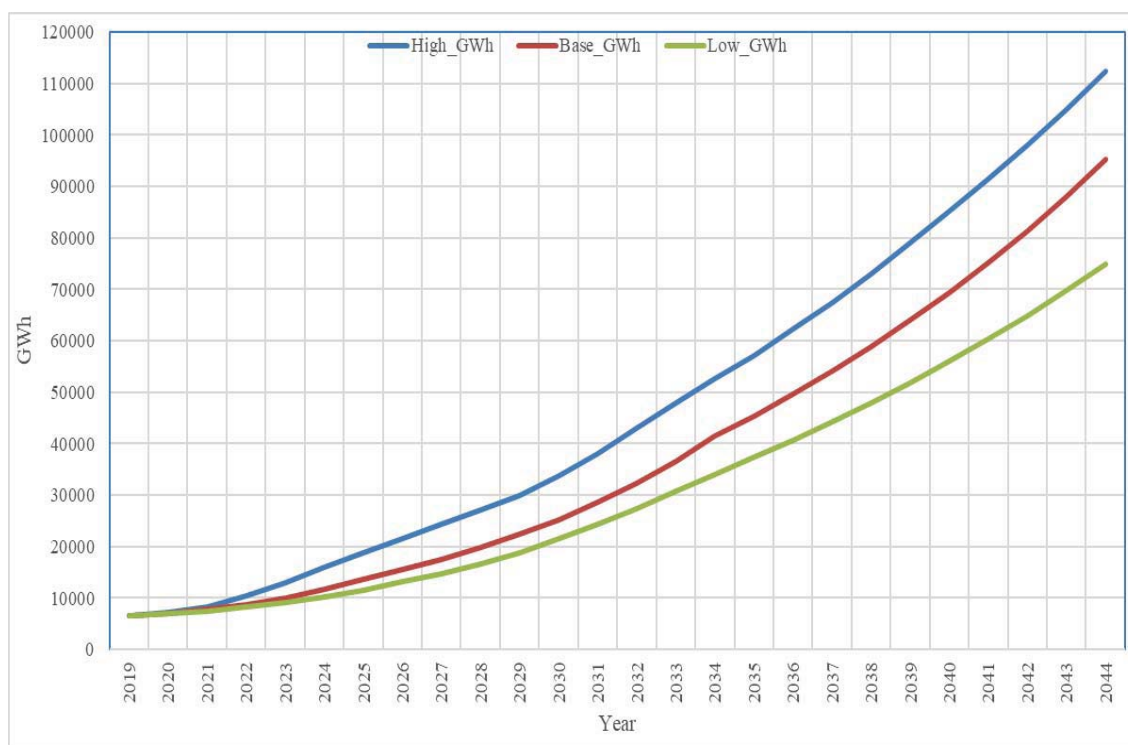
Year	Sum of Peak - MW	Coincidental Peak - MW	Gross Generation - GWh
2019-Unconstrained	1,120.12	1,120	7,861
2020	1,435.00	1,425	8,028
2021	1,629.00	1,533	9,098
2022	1,809.00	1,702	10,176
2023	2,036.00	1,914	11,470
2024	2,329.00	2,189	13,240
2025	2,677.00	2,514	15,271
2026	3,053.00	2,868	17,575
2027	3,439.00	3,229	19,880
2028	3,850.00	3,615	22,403
2029	4,323.00	4,059	25,271
2030	4,878.00	4,573	28,663
2031	5,488.00	5,137	32,413
2032	6,177.00	5,772	36,654
2033	6,951.00	6,485	41,475
2034	7,851.00	7,311	47,022
2035	8,554.00	7,958	51,496
2036	9,309.00	8,649	56,277
2037	10,116.00	9,386	61,376
2038	10,968.00	10,160	66,818
2039	11,885.00	10,992	72,601
2040	12,854.00	11,867	78,657
2041	13,897.00	12,806	85,136
2042	15,042.00	13,827	92,130
2043	16,283.00	14,927	99,627
2044	17,611.00	16,111	107,937

Source: PSMP 2020 Update Team Compilation.

Table 2-12: Comparison of Sum of Peak Demand in MW for Low, Base and High case

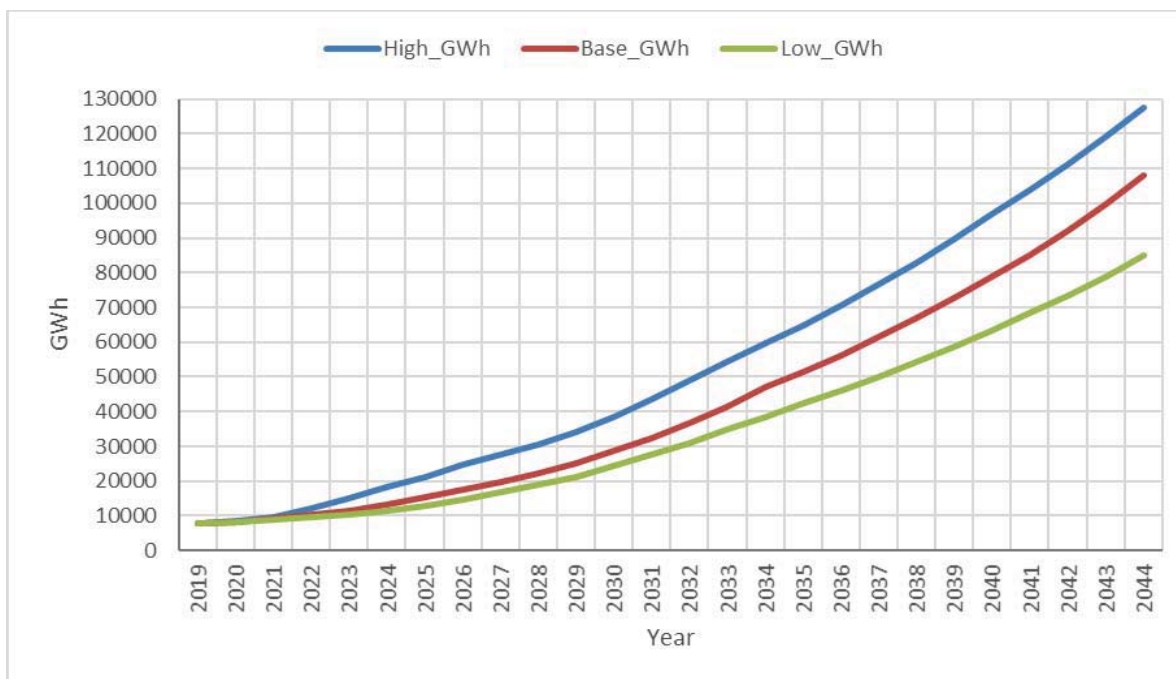
Year	Low Case	Base Case	High Case
2019	1,120	1,120	1,120
2020	1,405	1,435	1,549
2021	1,565	1,629	1,731
2022	1,702	1,809	2,129
2023	1,852	2,036	2,602
2024	2,043	2,329	3,134
2025	2,289	2,677	3,662
2026	2,581	3,053	4,212
2027	2,897	3,439	4,700
2028	3,246	3,850	5,212
2029	3,637	4,323	5,736
2030	4,147	4,878	6,469
2031	4,702	5,488	7,267
2032	5,246	6,177	8,146
2033	5,850	6,951	9,058
2034	6,456	7,851	9,890
2035	7,040	8,554	10,703
2036	7,642	9,309	11,608
2037	8,276	10,116	12,553
2038	8,939	10,968	13,546
2039	9,640	11,885	14,627
2040	10,379	12,854	15,762
2041	11,164	13,897	16,894
2042	12,008	15,042	18,139
2043	12,910	16,283	19,463
2044	13,862	17,611	20,804

Source: PSMP 2020 Update Team Compilation.



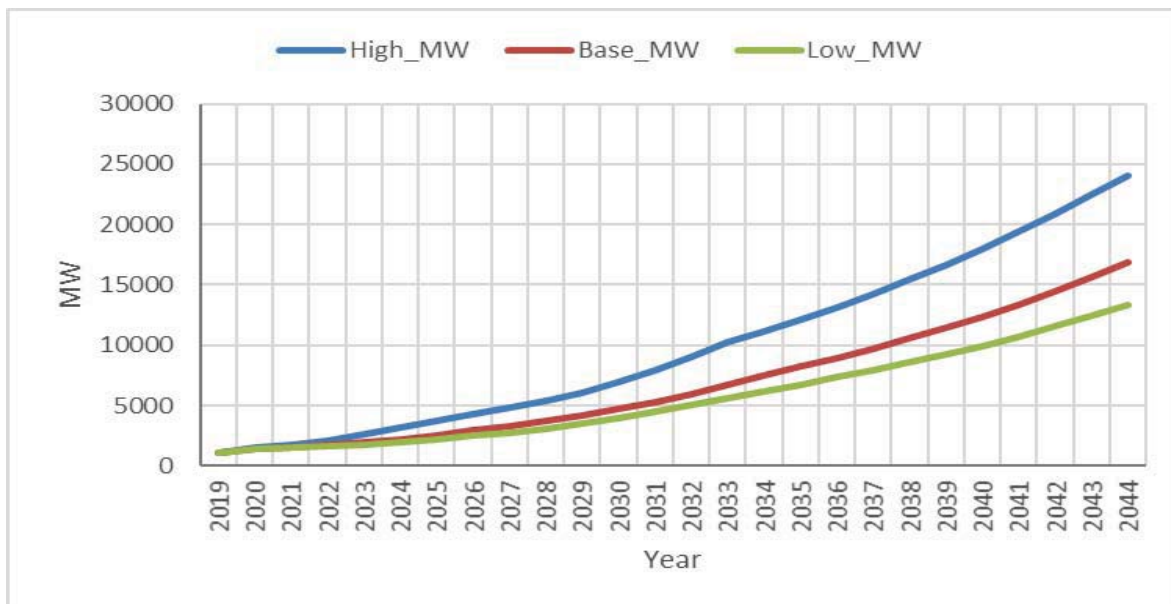
Source: PSMP 2020 Update Team Compilation

Figure 2-3: Electricity Sales Forecasts: 2019 – 2044



Source: PSMP 2020 Update Team Compilation

Figure 2-4: Gross Generation Forecast: 2019 – 2044



Source: PSMP 2020 Update Team Compilation

Figure 2-5: Peak Demand Forecast: 2019 – 2044

2.9. Derivation of Energy Sales Forecast – Econometric Analysis

2.9.1. Background

This sub-section derives forecasts of electricity at the national level using econometric principles and the results are compared with the forecast results obtained using the trend analysis approach described in the previous section.

The econometric method involves the estimation of causal relationships between energy sales or consumption (the dependent variable) and factors influencing consumption (the independent variables). From a conceptual point of view, there are three issues in a load electricity forecasting that need particular attention as described below:

- (i). Both sides of the equation need to be compatible: It is inappropriate to consider variables reflecting conditions in an entire nation with a variable reflecting only a part of the nation (e.g., sales for a region compared to GDP of the country as a whole);
- (ii). The use of an econometric analysis is only appropriate on large “populations”. It should not be used on consumer categories where there are a relatively small number of customers, each with very high consumption. In such a case,

- decisions by a small number of consumers can have a significant impact on the utility load. Econometric analysis is not equipped to handle such situations; and
- (iii). The past trend will continue in the future: It should be noted that this approach implicitly assumes that conditions in the past will prevail in the future. Significant changes such as accelerated electrification and rapid expansion of the mining activities, industries, and other identified loads must, therefore, be considered as additions to this method.

2.9.2.Econometric Method

The econometric method consists of two steps.

Step 1: Plot the Sales vs. economic and demographic indicators, i.e., fit – via a regression analysis – an equation of the form:

$$\text{Sales (t)} = \alpha + \beta \cdot (\text{demographic indicators, t}) + \gamma \cdot (\text{economic indicators, t})$$

Where at time t:

Sale = Sales in GWh (Sales could be T1 Sales, T2 Sales, T3 Sales or Country Sales),

Demographic indicators = Population, housing, etc.

Economic indicators = GDP, or a subset thereof, and α = constant, β , and γ are the (estimated) coefficients.

Step 2:

Assuming that in time, the relationship established in Step 1 between Sales and the other variables --demographic, economic-- will hold; and

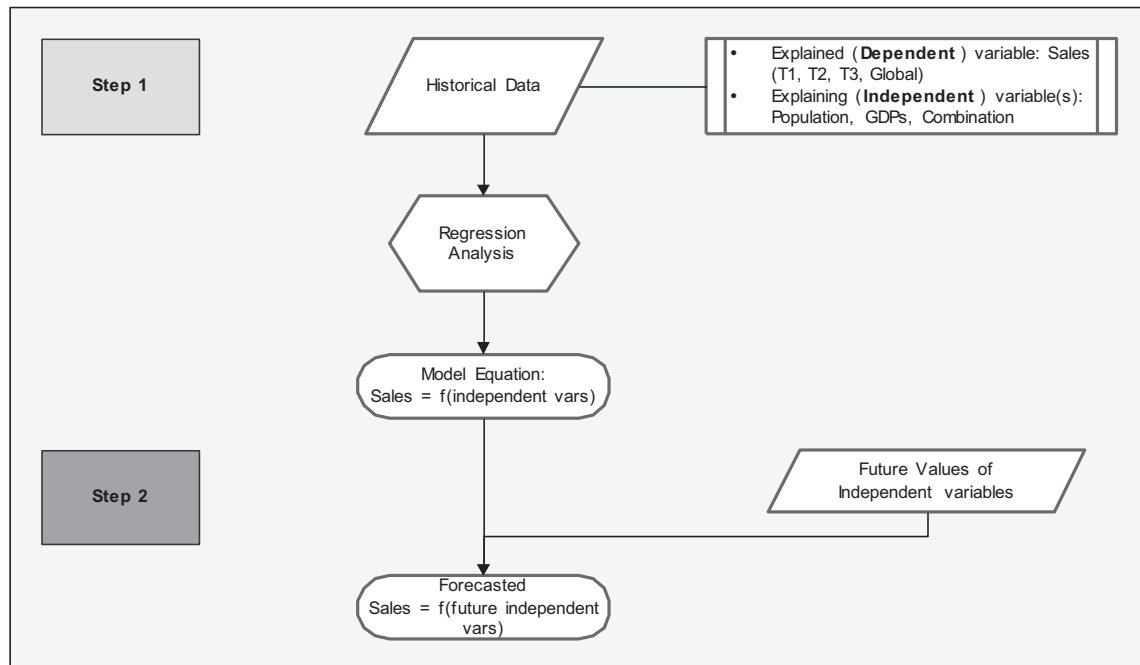
Based on reasonable assumptions as to the evolution in the future of these (independent⁵) variables, which evolution is usually measured in terms of growth rates⁶ (in percent), obtaining the forecast values of the Sales, at a future time t, by substituting the forecast values of the independent variables into the equation obtained in step 1.

The available historical data considered in the econometric forecast include, the GDP values by components (Agriculture, Industry, and Services sectors), and Demography (Population). These variables or a combination of them are the explaining variables or independent variables of the energy model. The explained or dependent variable is the

⁵The term “independent” variable is used to designate an explanatory factor as opposed to “explained” or forecasted variable—in this case, Sales or Consumption—which is also termed as the “dependent” variable.

⁶By way of Population and Economic forecasts

electricity Sales (global sales or sales by customer category). **Figure 2-6** illustrate the process of the econometric forecast modeling.



Source: PSMP 2008

Figure 2-6: Econometric Forecast Modelling

A vital element of the econometric process is the selection of the independent variables or combination of independent variables to be used in the equation “to explain” the dependent variables. A certain number of criteria are generally used to select the combination of independent variables.

In line with this method, T1, T2, T3, and the Total electricity Sales were each plotted against a series of combinations of independent variables or predictors. The ensuing results obtained after applying the above criteria are as follows:

(i) Forecast for Category T1

Category T1 is composed of residential, commercial, light industry, and street lighting customers. A series of relationships between sales to T1 customers and several

combinations of various economic and demographic parameters were examined. The regression equation is given by:

T1 Sales as a function of Total GDP

That is:

$$T1 = 268.1763071 + 0.022419789 \times \text{GDP}$$

Where T1 is expressed in GWh, and the Total GDP is in TZS Billion (constant 2015) prices.

The details of this relationship are as follows:

Table 2-13: Relation between T1 and GDP

<i>Regression Statistics</i>								
Multiple R	0.966929331							
R Square	0.93495233							
Adjusted R Square	0.931699947							
Standard Error	165.7448071							
Observations	22							
ANOVA								
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>			
Regression	1	7897099.01	7897099.01	287.4668181	2.46353E-13			
Residual	20	549426.8216	27471.34108					
Total	21	8446525.832						
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	268.1763071	97.17523986	2.759718499	0.012085024	65.47230873	470.8803054	65.47230873	470.8803054
GDP	0.022419789	0.001322323	16.95484645	2.46353E-13	0.019661471	0.025178107	0.019661471	0.025178107

(ii) Forecast for Category T2

Category T2 includes low voltage commercial, service, and industrial supply. A series of relationships between sales to T2 customers and several combinations of various economic and demographic parameters were examined. The equation is given by:

T2 Sales as a function of the sum of industry and services GDPs

That is:

$$T2 \text{ Sales} = 237.291439 + 0.005862273 \times (\text{Industry} + \text{Services GDPs})$$

Where T2 is expressed in GWh, and the Industry Plus Services GDP is in TZS Billion (constant 2015 prices).

The details of this relationship are as follows:

Table 2-14: Relation between T2 and GDP

<i>Regression Statistics</i>								
Multiple R	0.904151157							
R Square	0.817489314							
Adjusted R Square	0.80836378							
Standard Error	55.76278307							
Observations	22							
ANOVA								
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>			
Regression	1	278556.0943	278556.0943	89.58262471	7.9128E-09			
Residual	20	62189.75951	3109.487975					
Total	21	340745.8538						
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	237.291439	28.98007586	8.188088954	8.12532E-08	176.8400601	297.742818	176.8400601	297.742818
Industry & Services	0.005862273	0.000619376	9.464809808	7.9128E-09	0.004570278	0.007154268	0.004570278	0.007154268

(iii)Forecast for Category T3

Category T3 includes high voltage supply, agricultural, significant commercial buildings and Industries. A series of relationships between sales to T3 customers and several combinations of various economic and demographic parameters were examined.

The best relationship found was:

Sales to T3 customers as a function of a sum of Agriculture and Industry GDPs alone

That is:

$$T3 \text{ Sales} = -331.0222336 + 0.048372663 \times (\text{Agric} + \text{Industry GDPs})$$

Where T3 is expressed in GWh and the Agriculture plus Industry GDP is in TZS Billion (constant 2015 prices).

The details of this relationship are as follows:

Table 2-15: Relation between T3 and GDP

<i>Regression Statistics</i>								
Multiple R	0.969030267							
R Square	0.939019659							
Adjusted R Square	0.935970642							
Standard Error	177.7009468							
Observations	22							
ANOVA								
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>			
Regression	1	9725105.336	9725105.34	307.9745509	1.2891E-13			
Residual	20	631552.5297	31577.6265					
Total	21	10356657.87						
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>Lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	-331.0222336	105.7943945	-3.12892035	0.005286219	-551.7054734	-110.33899	-551.705473	-110.33899
Agriculture+Industry	0.048372663	0.002756402	17.5492037	1.2891E-13	0.042622909	0.05412242	0.04262291	0.05412242

(iv) Forecast of Total Sales Using the General Equation

The total sales can be derived by taking the sum of the sales to the individual categories or by directly regressing it by the socioeconomic variables. As in the preceding section, the (direct) fitting of the Total (or Global) Sales is carried out by examining a series of relationships between total sales and various economic and demographic variables.

Hence, the best relationship found was:

Total sales as a function of total GDP

That is:

$$\text{Global Sales} = -49.95291326 + 0.056231384 \times \text{GDP}$$

Where Total Sales is expressed in GWh and the Total GDP is in TZS Billion (constant 2015 prices).

The details of this relationship are as follows:

Table 2-16: Relation between Total Sales and GDP

<i>Regression Statistics</i>								
Multiple R	0.985946009							
R Square	0.972089533							
Adjusted R Square	0.97069401							
Standard Error	267.0523874							
Observations	22							
ANOVA								
	<i>df</i>	<i>SS</i>	<i>MS</i>	<i>F</i>	<i>Significance F</i>			
Regression	1	49677769.65	49677770	696.5770465	5.11978E-17			
Residual	20	1426339.553	71316.978					
Total	21	51104109.2						
	<i>Coefficients</i>	<i>Standard Error</i>	<i>t Stat</i>	<i>P-value</i>	<i>Lower 95%</i>	<i>Upper 95%</i>	<i>lower 95.0%</i>	<i>Upper 95.0%</i>
Intercept	-49.95291326	156.5712993	-0.319043	0.753002407	-376.5549206	276.6491	-376.5549	276.649094
GDP	0.056231384	0.002130562	26.392746	5.11978E-17	0.051787109	0.060676	0.0517871	0.060675658

2.10. Result of Electricity Forecast using Econometric

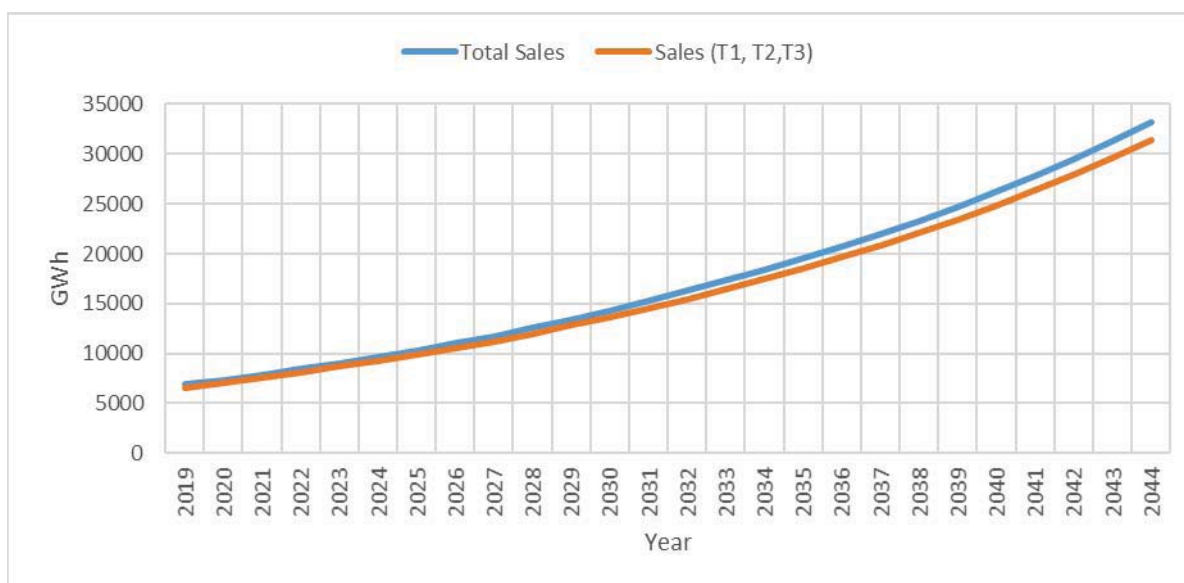
The best relationship found for each tariff category was used to forecast electricity sales for T1, T2, T3, and total electricity sales. **Table 2-17** presents the forecast for electricity sales for each tariff category.

Figure 2-7 visualizes the sum of the forecast results for the three load categories and the total country forecast, as detailed in **Table 2-17**. The figure indicates that a sum of forecast (T1+T2+T3) compares well with the total forecast (total sales vs. total DGP values).

Table 2-17: Sales Forecast (GWh) by Econometric Method

YEAR	T1	T2	T3	T1+T2+T3	Total
2019	3,029	721	2,831	6,581	6,875
2020	3,222	760	3,074	7,055	7,358
2021	3,427	801	3,332	7,560	7,872
2022	3,649	846	3,608	8,103	8,430
2023	3,891	895	3,907	8,692	9,035
2024	4,140	940	4,199	9,279	9,661
2025	4,399	987	4,501	9,887	10,310
2026	4,675	1,037	4,824	10,536	11,002
2027	4,973	1,091	5,173	11,237	11,749
2028	5,291	1,149	5,545	11,984	12,547
2029	5,635	1,212	5,948	12,795	13,411
2030	5,998	1,277	6,373	13,648	14,321
2031	6,380	1,347	6,819	14,546	15,279
2032	6,781	1,419	7,288	15,488	16,284
2033	7,202	1,496	7,781	16,478	17,340
2034	7,636	1,575	8,288	17,499	18,428
2035	8,081	1,656	8,810	18,547	19,547
2036	8,554	1,741	9,363	19,659	20,732
2037	9,056	1,832	9,950	20,838	21,990
2038	9,587	1,929	10,572	22,088	23,324
2039	10,151	2,031	11,232	23,414	24,738
2040	10,749	2,140	11,931	24,820	26,238
2041	11,383	2,255	12,673	26,312	27,829
2042	12,056	2,377	13,460	27,893	29,515
2043	12,769	2,506	14,295	29,570	31,305
2044	13,526	2,644	15,180	31,349	33,202

Source: PSMP 2020 Update Team Compilation.



Source: PSMP 2020 Update Team Compilation

Figure 2-7: Econometric Sales Forecast – Sum of Three Categories versus Total

Table 2-18 shows further results of the econometric approach as a trend of electricity share per customer tariff category. It is expected that the projections of electricity tariff decrease will stimulate the increase in electricity consumption of T2 and T3 customer categories and facilitate Tanzania to become a middle-income country. Notwithstanding, a significant contribution of the T1 category in overall sales, its share is gradually declining, reaching 43.15 percent in 2044 from the highest share observed in 2019. Similarly, T2 share shows a declining trend reflecting graduation of the T2 category into the T3 category (agriculture and Industry). Conversely, T3 categories, shows an increasing trend from 43.01 percent in 2019 to 48.42 percent, surpassing the T1 category. The increase in T3 sales is despite their lower share in the early years of projections. T3 Sales increased mainly on account of the expected increase and expansion of industrial and mining activities.

Table 2-18: Trend of Electricity Share per Customer Tariff Category in Percentage

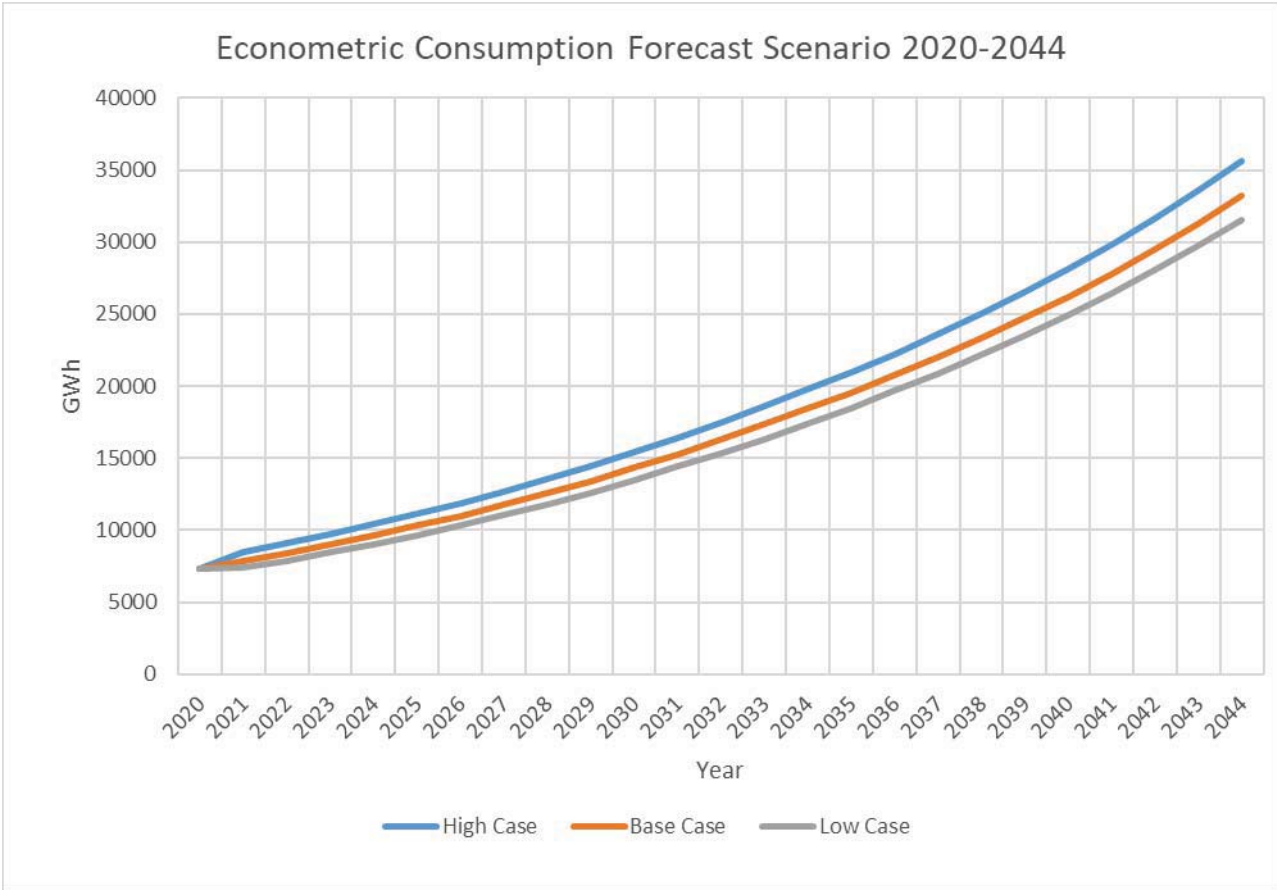
Year	T1 (%)	T2 (%)	T3 (%)
2019	46.03	10.96	43.01
2020	45.66	10.77	43.57
2021	45.33	10.60	44.07
2022	45.03	10.44	44.52
2023	44.76	10.29	44.95
2024	44.62	10.13	45.25
2025	44.49	9.98	45.53
2026	44.37	9.84	45.79
2027	44.25	9.71	46.04
2028	44.15	9.59	46.27
2029	44.04	9.47	46.49
2030	43.95	9.36	46.69
2031	43.86	9.26	46.88
2032	43.78	9.16	47.06
2033	43.70	9.08	47.22
2034	43.64	9.00	47.37
2035	43.57	8.93	47.50
2036	43.51	8.86	47.63
2037	43.46	8.79	47.75
2038	43.41	8.73	47.86
2039	43.36	8.68	47.97
2040	43.31	8.62	48.07
2041	43.26	8.57	48.17
2042	43.22	8.52	48.26
2043	43.18	8.48	48.34
2044	43.15	8.43	48.42

Source: PSMP 2020 Update Team Compilation.

2.11. Sensitivity Analysis

The uncertainties are commonly inherent in the forecast. Therefore, it is prudent to consider the load forecast results as a band of probable loads above and below a base forecast as opposed to a single value for each year. A range of values for various

components of GDP have been used to derive the forecast band using econometric principles. **Figure 2-8** illustrates the load forecasts for each set of assumptions. The graphs suggest that the low scenario grows about 1 percentage point less on average than the base case. Conversely, the high scenario grows at a 1.1 percentage point faster than the base case.



Source: PSMP 2020 Update Team Compilation

Figure 2-8: Econometrics Forecast Scenarios

2.12. Comparison of Load Forecast - Trend Line vs. Econometric Analyses

Table 2-19 provides a comparison of the forecast results obtained using an econometric and trend line analyses, respectively. The two forecasting methods gave comparable forecast results that exhibit a similar trend.

The table also shows that from 2022 the trend analysis approach projects relatively higher sales (GWh) forecasts than the counterpart econometric approach. As shown in **Figure 2-9**, the annual sales growth rates under the trend approach grows at a

sustainable rate necessary to achieve the overall objective of connecting 96.1 percent of the population by 2044. As such, the growth in electricity using the trend line approach averages 11.3 percent per annum while the growth using the econometric approach lag behind and averages 6.5 percent per annum.

The differences in the forecast results are primarily because of inclusion of the new industrial loads and the rural electrification initiative under the trend analysis. Furthermore, the trend line considers the government efforts to reduce electricity losses from 16.19 percent in 2019 to 12 percent by 2026. The interventions echo the Government industrialization drive and its desire to attain the status of a middle-income country.

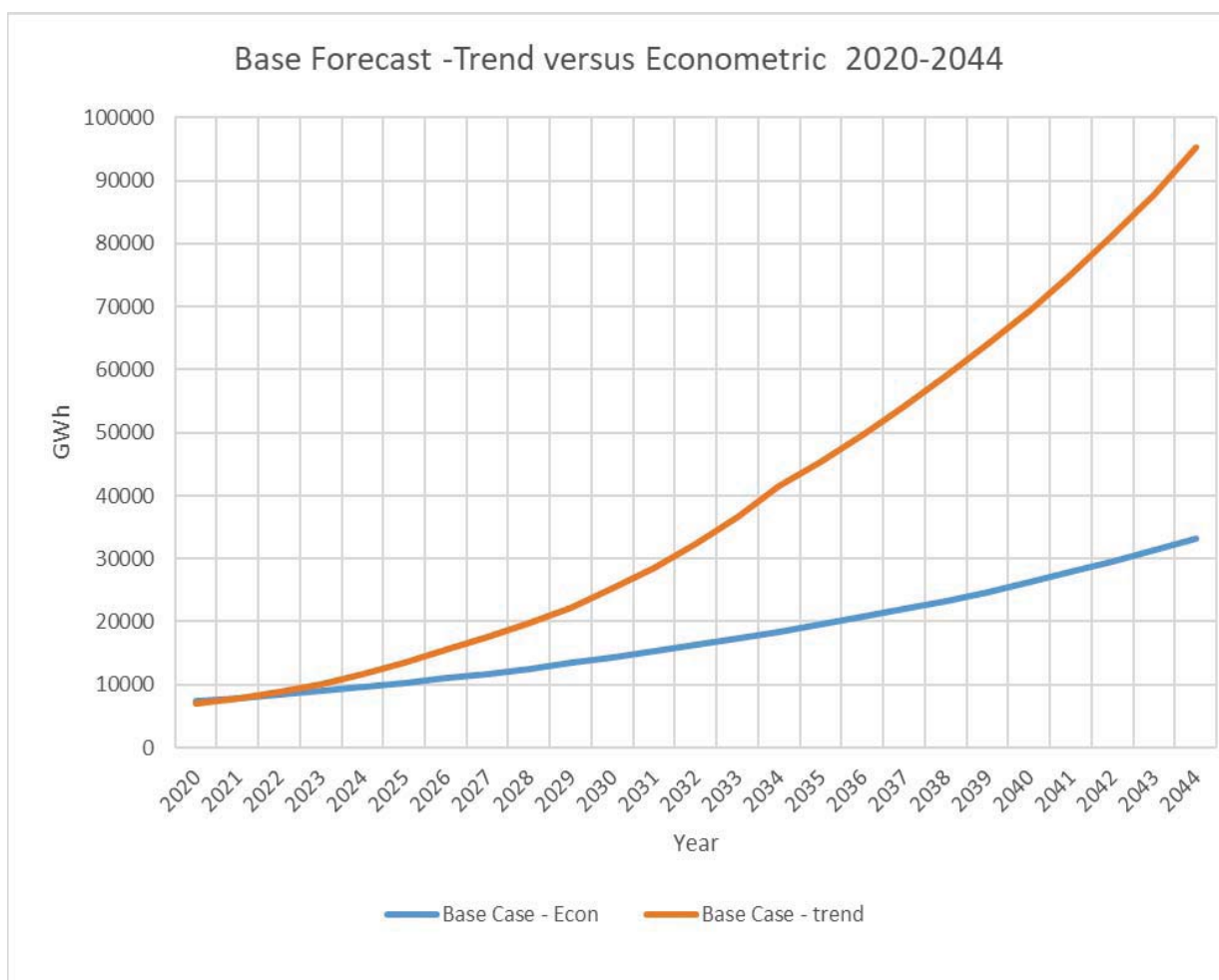
In contrast, the econometric analysis excluded the two exogenous variables. Furthermore, the trend analysis assumes that the past trend will repeat, implying that economic variables such as real GDP and electricity sales will behave the same way in the future.

Without such interventions under the trend line approach, the two approaches used in forecasting electricity would primarily suggest comparable forecast results.

Table 2-19: Energy Sales Forecast Comparison: Econometric Vs. Trend (in GWh)

Year	Econometric	Trend	Difference (Econometric Vs Trend)	Difference (Percent)
2020	7,358.04	7,081.00	-277.04	-3.77
2025	10,309.81	13,538.00	3,228.19	31.31
2030	14,321.30	25,294.00	10,972.70	76.62
2035	19,546.57	45,410.00	25,863.43	132.32
2040	26,237.85	69,388.00	43,150.15	164.46
2044	33,201.79	95,225.00	62,023.21	186.81

Source: PSMP 2020 Update Team Compilation.



Source: PSMP 2020 Update Team Compilation

Figure 2-9: Base Forecast – Trend versus Econometric Analysis 2020-2024

CHAPTER 3

3. POWER GENERATION PLANNING

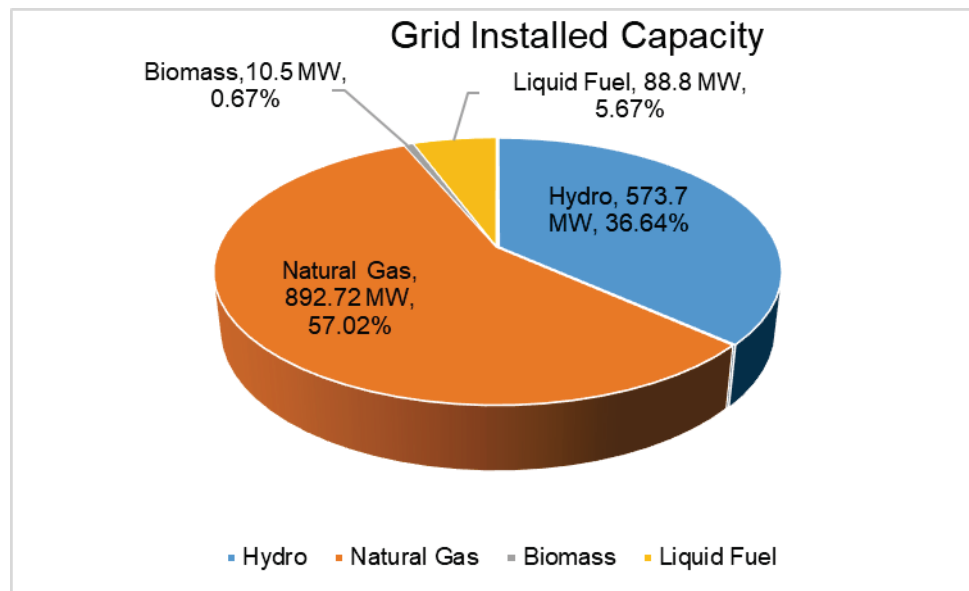
3.1. Introduction

This Chapter provides a comprehensive idea about generation systems and various planning strategies in general and the specific factors considered during power generation planning. Generation plan uses results from load forecast as criteria to determine the new capacity of generation required to meet the load demand. The power generation planning study first considers expanding the existing system, where feasible before planning for the future addition in the power generation system.

A comprehensive generation plan will enhance the security of power supply through the effective use of available energy resources in the country. The Plan considers various indigenous resources, including natural gas, coal, hydro and renewables (Geothermal, Wind and Solar). However, nuclear resources will be considered in future Plans.

3.2. Existing Generation system

Total installed capacity in the country is 1,602.32 MW which comprises of interconnected Grid System (1,565.72 MW) and isolated Grid System (36.60 MW). The National Grid System comprises of hydro and thermal generation units owned by TANESCO and IPP's with total capacity of 1,565.72 MW (base year 2019) out of which hydro 573.70 MW (36.64%), natural gas 892.72 MW (57.02%), liquid fuel, 88.80 MW (5.67%) and biomass 10.50 MW (0.67%) as provided in **Figure 3-1**. The highest system Maximum Demand (MD) recorded was 1,120.12 MW reached on 30th November 2019, which is a base year for this study. However, during the preparation of the Plan, the highest system Maximum Demand recorded was 1,151.66 MW on 27th February 2020.



Source: PSMP 2020 Update Team Compilation

Figure 3-1: Current Generation Mix

3.3. Existing Generation Plants

3.3.1. Hydropower Generation Plants

3.3.1.1. Hydroelectric Plants

Tanzania National Grid has 13 existing hydroelectric power plants with total installed capacity 573.7 MW **Table 3-1** shows the corresponding firm and average energy of the hydropower plants.

Table 3-1: Existing Hydropower Plants

S/N	Plant Name	Capacity (MW)	Average Energy (GWh)	Firm Energy (GWh)	Year Installed	Age in 2020 (Years)
1 .	Mtera	80.00	429.0	195	1988	33
2 .	Kidatu	204.00	1,111.0	601	1975	46
3 .	Hale	21.00	93.0	55	1967	54
4 .	Kihansi	180.00	694.0	492	2000	21
5 .	New Pangani Falls	68.00	341.0	201	1995	26
6 .	Nyumba ya Mungu	8.00	36.0	20	1968	53
7 .	Uwemba	0.84	7.3	2.3	1991	30
8 .	Mwenga	4.00	24.0	6	2012	9
9 .	Yovi	0.95	8.3	8.3	2012	9
10 .	Matembwe	0.59	0.4	0.565	2015	6
11 .	Darakuta	0.32	0.2	0.315	2013	8
12 .	Andoya	1.00	5.2	5.913	2015	6
13 .	Tulila	5.00	30.0	6.176	2015	6
	TOTAL	573.70	2,779.6	1,593.6		

Source: PSMP 2020 Update Team Compilation.

3.3.1.2. Characteristics of Hydropower Plants

Tanzania hydropower generation plants are in two groups namely: large Scale (above 10 MW) and small scale (below 10 MW). These categories consist of a reservoir and run-off river type, as shown in **Table 3-2** and **Table 3-3**. The Government owns the major hydropower plants through TANESCO, while the private sector (IPPs) owns the small power plants.

Table 3-2: Characteristics of the Existing Large Hydropower Plants

PROJECT NAME	Mtera	Kidatu	Nyumba ya Mungu	Hale	New Pangani Falls	Lower Kihansi
CHARACTERISTICS						
Owner	TANESCO	TANESCO	TANESCO	TANESCO	TANESCO	TANESCO
Location	Iringa	Morogoro	Kilimanjaro	Tanga	Tanga	Morogoro
Type	Reservoir	Reservoir	Reservoir	Run-off river	Run-off river	Run-off river
Max. supply level (m.a.s.l.)	698.50	450.00	688.91	342.44	177.50	1,146.00
Min. supply level (m.a.s.l.)	690.00	433.00	679.15	342.44	176.00	1,141.00
Recommended min. operational level (m.a.s.l.)	690.00	437.00	683.76	N/A	176.50	1,143.00
Storage vol. at max. level (mill. m ³)	3,750.00	167.00	1,118.11	0.00	1.31	1.62
Storage vol. at min. level (mill. m ³)	563.00	40.00	246.71	0.00	0.50	0.62
Active storage volume (mill. m ³)	3,200.00	125.00	600.00	0.00	0.80	1.00
Surface area at max. vol. (km ²)	604.96	9.62	148.52	0.00	0.75	0.27
Gross head at max. level (m)	101.0 (Francis)	175.0 (Francis)	25.2 (Francis)	70.0 (Francis)	169.7 (Francis)	852.75 (Pelton)
Gross head at min. level (m)	92.00	160.00	20.60	70.00	168.00	847.75
Energy equivalent (kWh/m ³)	0.23	0.42	0.05	0.13	0.42	2.06
Firm energy generation (GWh)	195.00	601.00	20.00	55.00	201.00	492.00
Average energy (GWh)	429.00	1,111.00	35.00	93.00	341.00	694.00
Avg. generation for each m ³ /s (MW/(m ³ /s))	0.85	1.50	0.20	0.50	1.50	7.40
Rated turbine discharge (total plant) (m ³ /s)	96.00	140.00	42.50	45.00	45.00	23.76

Table 3-3: Characteristics of the Existing Small Hydropower Plants

PROJECT NAME	Mwenga	Tulila	Andoya	Darakuta	Madope	Yovi	Ikondo	Matembwe	Diwale	Kikuletwa	Uwemba	Tosamaganga
CHARACTERISTICS												
Owner	IPP	IPP	IPP	IPP	IPP	IPP	IPP	IPP	IPP	IPP	TANESCO	TANESCO
Location	Iringa	Ruvuma	Ruvuma	Manyara	Njombe	Morogoro	Njombe	Njombe	Morogoro	Kilimanjaro	Njombe	Iringa
Type	Run-off river	Run-off river	Run-off river	Run-off river		Run-off river	Run-off River		Run-off River	Run-off River	Run-off River	Run-off River
Max. supply level (m.a.s.l.)	1,127.00	747.50	N/A	N/A	N/A	1,225.01	N/A	1,489.50	1,462.00	N/A	N/A	N/A
Min. supply level (m.a.s.l.)	1,127.00	746.50	N/A	N/A	N/A	1,224.30	N/A	1,480.00	1,460.00	N/A	N/A	N/A
Recommended min. operational level (m.a.s.l.)	1,127.00	746.50	N/A	N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A
Storage vol. at max. level (mill. m ³)	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Storage vol. at min. level (mill. m ³)	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Active storage volume (mill. m ³)	N/A - Run of River	0.60	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Surface area at max. vol. (km ²)	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gross head at max. level (m)	62.00	7.5 (Kaplan)	36 (Francis)	N/A	N/A	357.30	N/A	N/A	N/A	N/A	N/A	41.00
Gross head at min. level (m)	58.50	22.50	36.00	N/A	N/A	357.30	N/A	10.00	40.00	14.50	N/A	40.00
Energy equivalent (kWh/m ³)	N/A - Run of River	N/A	N/A	N/A	N/A	2,763.00	N/A	N/A	N/A	N/A	N/A	1.18
Firm energy generation (GWh)	6.00	6.18	5.91	0.32	N/A	8.30	N/A	0.57	16.60	N/A	N/A	0.10
Average energy (GWh)	24.00	30.00	5.25	0.20	N/A	8.30	N/A	0.40	N/A	N/A	7.30	0.12
Avg. generation for each m ³ /s (MW/(m ³ /s))	0.50	0.19	0.28	N/A	N/A	2.76	N/A	N/A	N/A	N/A	N/A	0.22
Rated turbine discharge (total plant) (m ³ /s)	8.00	26.60	3.60	N/A	N/A	0.36	4.30	N/A	10.00	12.00	N/A	22.74

Sources:

1. Small Hydro Mapping Report, "Renewable Energy Resource Mapping: Small Hydro – Tanzania" (2018) – REA/ the World Bank.
2. World Small Hydropower Development Report, UNIDO (2016).
3. Review of studies conducted for the potential sites.
4. Team survey to the potential sites, data collection and compilation, (2019).
5. PSMP 2020 Update Team Compilation.

3.3.2. Thermal Power Plants and their Characteristics

Table 3-4 shows that there are 19 thermal power plants in the National Grid System. These plants and their types of fossil fuel consists of eight (8) gas-fired plants, two (2) are biomass plants, seven (7) diesel-fired plants, one (1) industrial diesel oil (IDO) plant and one (1) Heavy Fuel Oil (HFO) plant. TANESCO's Diesel, IDO and HFO plants which are connected to the National Grid, currently operate as a reserve capacity.

The average economic life of thermal power plants is twenty-five (25) years. Through proper maintenance and interim replacement of major parts, the plant's economic life may reach about 30 years.

Table 3-4: Existing Thermal Power Plants

Plant	Technology	Fuel	Units	Installed Capacity (MW)	Available Capacity (MW)	Station Service (%)	Net Available Capacity (MW)	FOR (%)	Combined Outage Rate (%)	Maximum Plant Factor (%)	Available Energy (GWh)	Year Installed	Nominal Service Life Years	Retirement Year
IPP UNITS														
TANWAT	STG	Bagasse	1	1.5	1.0	2.0	1.5	5.0	13.0	50.0	6.1	2010	20	2030
TPC	STG	Bagasse	1	9.0	7.0	2.0	8.8	5.0	13.0	50.0	36.7	2011	20	2031
Subtotal				10.5	8.0		10.3				42.8			
TANESCO UNITS														
Ubungu I	GE	Gas	10	102.0	80.0	2.0	100.0	5.0	13.0	80.0	665.5	2007	20	2027
Songas	GT	Gas	6	189.0	189.0	2.0	185.2	5.0	13.0	80.0	1,233.1	2006	20	2026
Ubungu II	GT	Gas	3	129.0	86.0	2.0	126.4	5.0	13.0	80.0	841.7	2011	25	2036
Kinyerezi I	GT	Gas	4	150.0	105.0	2.0	147.0	5.0	13.0	80.0	978.7	2015	25	2040
Kinyerezi II	GT	Gas	8	248.2	203.0	2.0	243.3	5.0	13.0	80.0	1,619.5	2018	25	2043
Tegeta	GE	Gas	5	45.0	30.0	2.0	44.1	5.0	13.0	80.0	293.6	2009	20	2029
Mtwara I	GE	Gas	9	18.0	8.0	2.0	17.6	5.0	13.0	80.0	117.4	2007	20	2027
Mtwara II	GE	Gas	2	4.0	8.0	2.0	3.9	5.0	13.0	80.0	26.1	2017	20	2037
Somanga	GE	Gas	3	7.5	7.5	2.0	7.4	5.0	13.0	80.0	48.9	2010	20	2030
Subtotal				892.7	716.5		874.9				5,824.5			
TANESCO Reserve Capacity - Grid Connected														
Biharamulo	DG	Diesel	5	4.1	n/a	2.0	4.1	8.0	18.0	75.0	24.5	2015	20	2035
Zuzu	DG	Diesel	3	7.4	6.4	2.0	7.3	8.0	18.0	75.0	43.8	1980	20	2000
Nyakato	DG	HFO	10	63.0	36.0	2.0	61.7	8.0	18.0	75.0	373.2	2013	20	2033
Songea	DG	Diesel	3	7.7	n/a	2.0	7.5	8.0	18.0	75.0	45.4	2005	20	2025
Ludewa	DG	Diesel	3	1.3	n/a	2.0	1.2	8.0	18.0	75.0	7.5	2010	20	2030
Mbinga	DG	Diesel	2	2.0	n/a	2.0	2.0	8.0	18.0	75.0	11.8	2007	20	2027
Madaba	DG	Diesel	1	0.5	n/a	2.0	0.5	8.0	18.0	75.0	2.8	2010	20	2030
Namtumbo	DG	Diesel	1	0.3	n/a	2.0	0.3	8.0	18.0	75.0	2.0	2012	20	2032
Ngara	DG	Diesel	2	2.5	n/a	2.0	2.5	8.0	18.0	75.0	14.8	2015	20	2035
Subtotal				88.8			87.0				526.0			
TOTAL ON GRID				992.0			972.2				6,393.3			
Off-Grid														
Mafia	DG	Diesel	4	3.0	2.4	2.0	2.9	8.0	18.0	75.0	17.8	1970	20	1990
Mpanda	DG	Diesel	5	5.4	3.8	2.0	5.3	8.0	18.0	75.0	32.0	1992	20	2012
Kigoma	DG	Diesel	7	8.3	6.3	2.0	8.1	8.0	18.0	75.0	48.9	2010	20	2030
Inyonga	DG	Diesel	3	1.6	n/a	2.0	1.6	8.0	18.0	75.0	9.7	N/A	N/A	N/A*
Kasulu	DG	Diesel	2	2.5	2.5	2.0	2.5	8.0	18.0	75.0	14.8	2011	20	2031
Bukoba	DG	Diesel	4	2.6	2.2	2.0	2.5	8.0	18.0	75.0	15.2	1991	20	2011
Sumbawanga	DG	Diesel	4	5.0	5.0	2.0	4.9	8.0	18.0	75.0	29.6	2011	20	2031
Loliondo	DG	Diesel	4	3.8	2.5	2.0	3.7	8.0	18.0	75.0	22.2	2012	20	2032
Tunduru	DG	Diesel	4	2.1	n/a	2.0	2.0	8.0	18.0	75.0	12.2	1991	20	2011
Liwale	DG	Diesel	2	0.8	n/a	2.0	0.8	8.0	18.0	75.0	5.0	2013	20	2033
Kibondo	DG	Diesel	2	2.5	2.5	2.0	2.5	8.0	18.0	75.0	14.8	2010	20	2030
Subtotal (off grid)				37.5			36.8				222.2			
Grand Total				1,029.5			1,008.9				6,615.5			

Source: PSMP 2020 Update Team Compilation.

3.4. Existing Plants Retirement

In the scheduling of new generation plants, existing generating units were assumed to be retired at the end of their usual “economic” service life or end of plant contract. The hydroelectric plants, however, were assumed to remain in service throughout the planning period. The plants include Hale and Nyumba ya Mungu power plants which will undergo rehabilitation before 2022. Upon completion of rehabilitation, the plant life span will be extended, depending on the manufacturer's guidelines of each new component installed. Thus, these plants will not be retired after their normal economic service life. The economic life of power plants in **Table 3-5** will be re-estimated after major maintenance made based on the manufacturers' guidelines.

Table 3-5: Existing Plants Retirement Dates

Plant Name	Nominal Capacity (MW)	Normal Service Life (years)	Year Installed	Retirement Year
HYDRO				
Mtera	80	50	1988	2038
Kidatu	204	50	1975	2025
Hale	21	50	1967	2017
Kihansi	180	50	2000	2050
New Pangani Falls	68	50	1995	2045
Nyumba ya Mungu	8	50	1968	2018
Mwenga	4	15	2012	2027
Uwemba	0.843	50	1991	2041
Yovi	0.95	15	2016	2031
Tulila	5	20	2015	2035
Matembwe	0.59	10	2016	2026
Darakuta	0.32	20	2013	2033
Andoya	1	10	2015	2025
THERMAL				
Songas	189	20	2006	2026
Tegeta Gas Engine	45	20	2009	2029
Ubungo I	102	20	2008	2028
Ubungo II	105	20	2012	2032
Kinyerezi I	150	25	2015	2040
Kinyerezi II	248.22	25	2018	2043
Mtwara I	18.00	20	2007	2027
Mtwara II	4.00	20	2010	2030
Somanga	7.50	20	2010	2030
Zuzu Diesel	7.44	20	1980	2000
Nyakato	63	20	2013	2033
Biharamulo	4.14	20	2015	2035
Songea	7.67	20	2005	2025
Inyonga	1.636	N/A	N/A	N/A
Ludewa	1.27	20	2010	2030
Mbinga	2	20	2007	2027
Ngara	2.5	20	2015	2035
TANWAT	2.7	20	2010	2030
TPC	17	20	2011	2031

Note:

1. Rehabilitation of power plants (Thermal & Hydro) extends the life span by 50% to 80%.
2. Inyonga capacity (1.636 MW) comprises of original Inyonga Units (0.816 MW) and transferred units from Namtumbo (0.34 MW) and Madaba (0.48 MW).
3. N/A – Not Accessible.

Source: PSMP 2020 Update Team Compilation.

3.5. Power Generation Resources

3.5.1. Hydropower

Tanzania has abundant potentials of hydropower because its inland area is above sea level with precipitous rivers. Various studies, including feasibility studies, project proposals and consultation with project developers on hydropower potential in Tanzania, have been carried out over a long period. The reviewed studies revealed an increase of the potential hydropower capacity from 4,700 MW in 2012 to 7,491.2 MW in 2020 equivalent to an energy of 41,172 GWh and 65,622.91 GWh respectively. **Table 3-6** shows the capacity of hydroelectric power potential available in Tanzania. The Map showing river basins available in Tanzania is shown in **Appendix II**.

Table 3-6: Hydropower Potential in Tanzania

Range of Capacity (MW)	Total Range Capacity (MW)	Percentage (%)	Number of Potential Sites
0 – 9	602.31	8.0	450
10 – 49	396.6	5.3	22
50 – 199	2,453.3	32.7	21
200 – 500	1,924.0	25.7	7
500 and above	2,115.0	28.2	1
Total	7,491.2	100	501

Source:

1. Small Hydro Mapping Report, “Renewable Energy Resource Mapping: Small Hydro – Tanzania” (2018) – REA/ the World Bank.
2. World Small Hydropower Development Report, UNIDO (2016).
3. Review of studies conducted for the potential sites.
4. Team survey to the potential sites, data collection, and compilation, (2019).

3.5.1.1. Tanzania Hydrological System

In order to consider one or more hydroelectric power development options, it is imperative to have a clear assessment of the hydrology and hydroelectric power system capabilities. Historical river flow records spanning at least 30 years enables the determination of the capability of power generation of a hydroelectric system.

This study infers the studies of the ongoing hydroelectric power projects, datasets developed during the previous Power System Master Plans, following an intensive review and analysis of datasets.

Hydrological characteristics of the rivers flowing into reservoirs of existing and potential large hydropower plants is shown in **Table 3-7** and **Table 3-8** respectively with details of the gauging stations used for hydrological data collection.

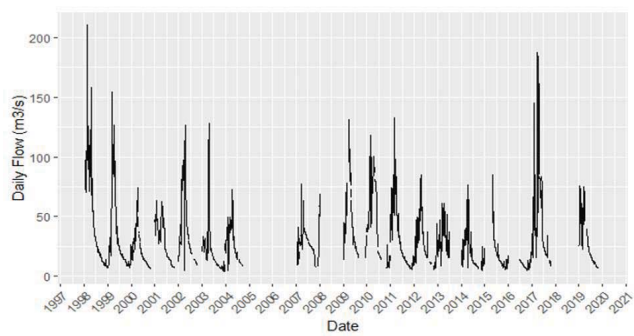
Table 3-7: Details of the Gauging Stations for Hydrological Data Monitoring for Existing Hydropower Plants

PLANT	GAUGING STATION(s)	START	FLOW (m ³ /s)			REMARKS
		(Year)	Max	Min	Mean	
Nyumba ya Mungu	Kikuletwa River at TPC (1DD1)	1959	247.2	3.86	10.32	Very high flow variability
	Ruvu River at Kifaru (1DC2A)	1959	58.55	1.2	5.09	High flow variability
Hale/Pangani	Pangani River at Korogwe(1D14)					No current data available
	Pangani River at Mnyuzi (1D17A)	1967	157.7	0.78	20.63	Very high flow variability, with very low flows during dry seasons
	Luengera River at Korogwe(1DA1)					No current data available
Mtera	Kizigo River at Chinugulu	1957	1805	0	34.33	High flows Dec -April, low flows Jul -Oct, experiences dry spells of zero flow
	Little Ruaha River at Mawande(1KA31)	1957	190.7	1.84	20.65	High flows Dec -April, low flows Jul -Oct with No zeros
	Great Ruaha River at Msembe (1KA59)	1963	1397	0	42.6	High flows Mar-May, low Aug-Nov , with some years of zero flows
Kidatu	Great Ruaha River at Msosa (1KA5)					No current data available
	Yovi River at Confluence (1KA38A)					No current data available
	Lukose River at Mtandika (1KA37)	1957	375.6	0	61.2	High variations of flow with dry spells
Kihansi	Kihansi River at Lutaki (1KB32)	1984	90.52	1.15	15.66	High flow variability

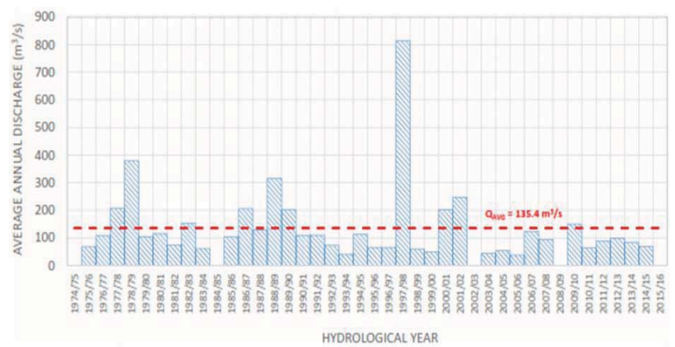
Table 3-8: Details of the Gauging Stations for Hydrological Data Monitoring for Planned Hydropower Plants

PROJECT	GAUGING STATION(s)	START (Year)	Flow (m ³ /s)			REMARKS
			Max	Min	Mean	
Julius Nyerere	Rufiji River at Stieglers Gorge(1K3B)	1960-80, 2018	2211	500	902	High variations of flow, data was extended using model to cover the missing period from 1980 - 2016
Malagarasi	Malagarasi River at Mbelagure(4A9)	1956	800	17.2	135.4	High flows Feb-Jun, low flows Sep-Nov, no record of zero flows
Kakono	Kagera River at Pumping Station	2013	500.2	100	213	Minor variations of flow
Ruhudji	Ruhudji River at Itipula (NC2)	1998	210.5	3.78	30.82	High variations of flow between wet and dry seasons
Rumakali	Rumakali River at Mwakautu(1RC11A)	1994	67.4	1	8.22	High variations of flow between wet and dry seasons
Masigira	Ruhuhu River at Masigira(1RB2)	1971	228.1	5.28	31.9	High variations of flow between wet and dry seasons
Kikonge	Kikonge (1RB3)	1971-73, 1991	1332	22.6	178.1	Good Hydrology, minor flow variations
Mpanga	Mpanga River at Mpanga Mission(1KB8)	1955	92.45	9.56	30.6	Moderate variations of flow
Mnyera	Mnyera River at Taveta					No current data available
Songwe	Songwe River at Kasumulu(1RD1)					No current data available

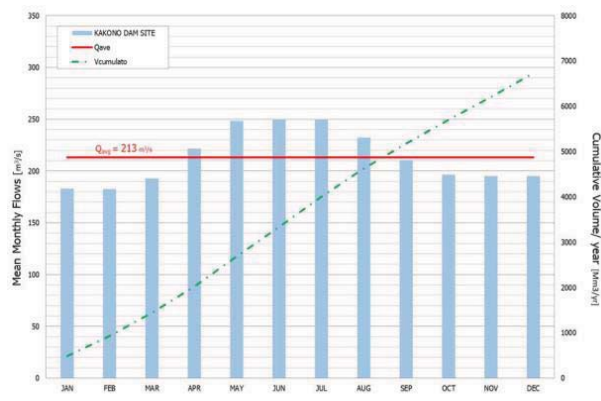
Source: PSMP 2020 Update Team Compilation.



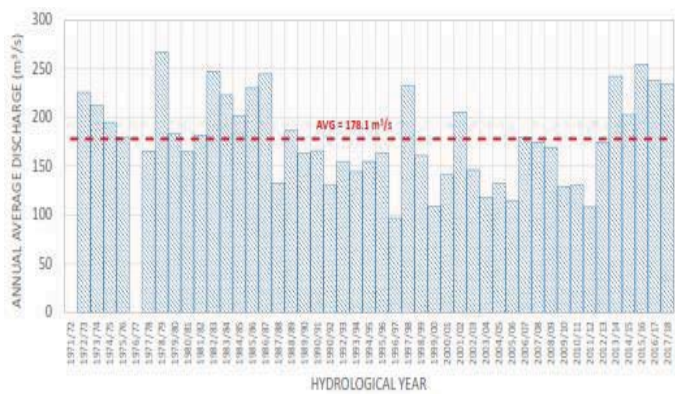
a) Ruhudji



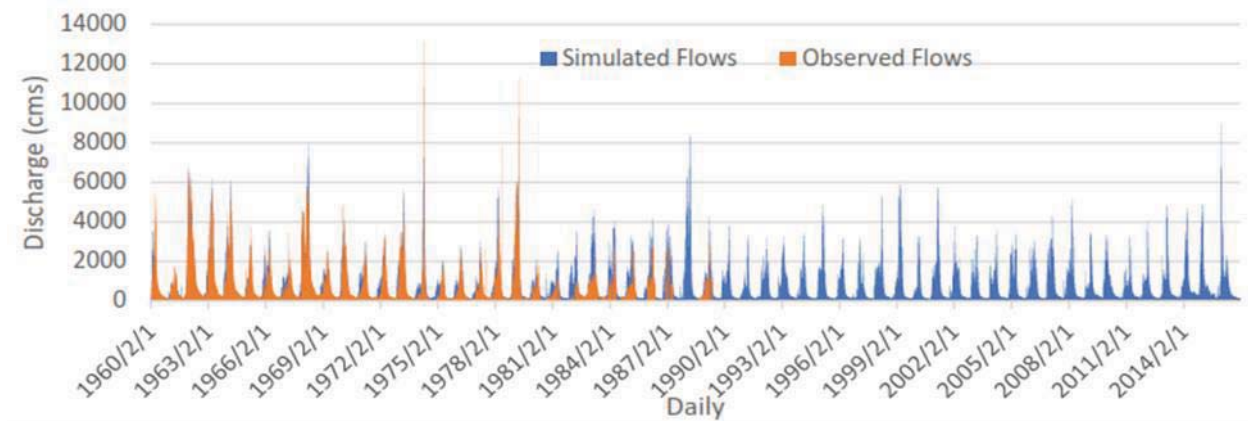
b) Malagarasi



c) Kakono



d) Kikonge



e) Julius Nyerere

Figure 3-2 (a) – (e): Discharge Variations of Selected Hydropower Potential Sites

3.5.2. Thermal Resources

Tanzania is endowed with huge potential thermal resources, including natural gas, coal and biomass. The Plan considers these resources as a fuel for power generation during planning period. However, this plan considers power generating plants operated by imported fuel such as Industrial Diesel Oil (IDO), Diesel Oil and Heavy Fuel Oil (HFO) as reserve capacity due to high operation and maintenance costs.

(i) Natural Gas

Tanzania has a significant amount of natural gas reserves of 57.54 TCF. According to the Natural Gas Utilization Master Plan (NGUMP) 8.3 TCF out of 57.54 TCF is allocated for electricity generation. The allocated natural gas can generate approximately 7,094.02 MW (177.35 GWyr) using Combined Cycle Gas Turbine (CCGT) technology.

Table 3-9 shows the natural gas discoveries.

Table 3-9: Natural Gas Discoveries

DISCOVERY BLOCK / LOCATION	YEAR DISCOVERED	CURRENT STATUS	GAS RESERVE PROVEN BY DECEMBER, 2018 - P50 (TCF)	RESOURCE - GIIP (TCF)
Songosongo	1974	Stated	0.729	2.500
Mnazi Bay	1982	Stated	0.482	5.000
Kiliwani North	2008	Stated - Gas production has been halted due to low reservoir pressure		0.070
Mkuranga	2007	Not yet developed		0.200
Ntorya	2012	Not yet developed		0.466
Mambakofi	2015	Not yet developed		2.170
Total Gas Onshore				10.406
Block 1	2011	Not yet developed		0.470
	2012	Not yet developed		3.530
	2012	Not yet developed		8.500
	2013	Not yet developed		0.600
	2014	Not yet developed		1.100
Block 2	2013	Not yet developed		6.000
	2012	Not yet developed		5.000
	2013	Not yet developed		5.400
	2013	Not yet developed		2.500
	2014	Not yet developed		3.000
	2014	Not yet developed		1.700
	2015	Not yet developed		1.800
Block 3	2012	Not yet developed		2.000
Block 4	2010	Not yet developed		1.800
	2010	Not yet developed		1.900
	2013	Not yet developed		0.800
	2014	Not yet developed		1.030
Total Gas Deep Sea				47.130
Total Gas in Deep Sea and Onshore				57.536

Source: TPDC

(ii) Coal

The coal demand in Tanzania has been growing mainly for industrial use, which drives the development of coal mining activities. According to reviewed studies, the coal reserves capacity has increased from 954.65 Mton in 2016 to 1,208 Mton in 2020, which is equivalent to 808.40 GWyr. The Songea Karoo belt in Southern Tanzania has the majority of discoveries of coal reserves in Tanzania. Coal fields exist in three regions of the country in Rukwa, Mbeya and the largest in Njombe as shown in **Table 3-10**. Intergrated Gasification Combined Cycle (IGCC) have been considered in the implementation of coal fired plants. IGCC plants use synthesis (syngas) to turn gas turbine to generate electricity. Syngas is obtained by converting coal through a process

called gasification. Technically, IGCC are more efficient than Open Cycle Gas Turbine (OCGT) and environmentally friendly.

Table 3-10: Areas with Potential Coal Resource in Tanzania

S/N	Coal Mine Name	Reserve (mil.t)
1 .	Mchuchuma	428
2 .	Katewaka	100
3 .	Ngaka	423
4 .	Kiwira (Ivogo Ridge)	90
5 .	Mbeya	109
6 .	Rukwa	58
Total		1,208

Source: STAMICO, NDC, PSMP 2016

3.5.3. Renewable Resources

The renewable resource available in Tanzania includes solar, wind, geothermal, biomass and tidal waves. Even though these resources have not yet been fully tapped for power generation, recently, the Government has been promoting investment in renewable energy projects in order to increase renewable energy share in power generation mix.

(i) Solar

During the development of this Plan, various studies on solar resources have been reviewed and indicated that the solar potential is estimated to be more than 670 MWp. The potential regions which are suitable for solar power generation have solar insolation ranging from 4.5 to 6.0 kWh per square meter per day about 10 hours from 0800hours to 1700hours. Some of these regions are Dodoma, Singida, Shinyanga, Iringa, Katavi, Rukwa, Tabora and Mara. The spatial distribution of annual solar radiation in Tanzania Map is shown in **Appendix III**.

(ii) Wind

Through various studies conducted in Tanzania revealed that the country has a potential of wind, which can generate more than 1,000 MW of power. The average wind

speed in a day which can generate power ranges from 3 to 10 m/s as indicated in **Table 3 – 11**. Tanzania Wind Map is shown in **Appendix IV**.

Table 3-11: Wind Potential Sites in Tanzania

S/N	Region	District	Average Wind Speed at 10m (m/s)	Average Wind Speed at 30m (m/s)
1.	Singida	Singida (Kititimo)	8.2	9.4
2.	Njombe	Njombe (Makambako)	7.6	8.7
3.	Iringa	Mufindi (Usokami)	7.5	>7.5
4.	Kilimanjaro	Mwanga (Mgagao)	3.75	4.85
5.	Tanga	Korogwe (Mkumbara)	4.14	4.9
6.	Arusha	Karatu	4.9	5.5
7.	Dar es Salaam	Kigamboni (Gomvu)	3.56	4.28
8.	Mtwara	Mtwara (Litembe)	3.21	4.47
9.	Pwani	Mafia	No Measurements	4.01
10.	Mwanza	Ukerewe	3.55	4.9

Source: TANESCO

(iii) Biomass

Primary energy consumption in Tanzania includes 85 percent biomass out of which, 75 percent is consumed in rural areas, heavily contributing to deforestation. Studies indicate that there are 10 biomass power plants with a total installed capacity of 105 MW as shown in **Table 3-12**. Most of these plants are operating in the isolated grid and are owned by IPP for their use.

Table 3-12: Existing Biomass Power Plants (IPP)

Power Plant Name	Fuel	Capacity (MW)	Grid Connection Status
Mufindi (Cogen)	Wood by products	27	Off-grid
Sao Hill (Cogen)	Wood by products	6	Off-grid
Kibena	Wood by products	3	Off-grid
Misenyi (Kagera)	Bagasse	4	Off-grid
Tanzania Plantation Company (TPC)	Bagasse	15	On-grid
Mkonge Energy System (I,II & III)	Sisal by products	2.8	Off-grid
Mkonge Energy System IV (Usambara)	Sisal by products	1.6	Off-grid
TANWAT	Wood by products	3	On-grid
Mgololo	Wood by products	40	Off-grid
Ngombeni (Mafia)	By products from coconut trees.	2.5	Off-grid
Total		105	

Source: Regulatory Performance Report on Electricity Sub-Sector for The Year Ended (2018), Tanzanian energy sector under the universal principles of the Energy Charter (2015).

(iv) Geothermal

Tanzania is endowed with substantial geothermal potential, which has not yet been utilized. Several reconnaissance surveys and few detailed studies on the potential of geothermal resources have provided essential information for the estimation of power generation from geothermal resources. As of 2020, the total potential of the geothermal resource is 5,000 MW as shown in **Table 3-13** and the Government plan is to generate 995 MW during the next 25 years from 2020, as shown in **Section 3.6.3**.

Table 3-13: Geothermal Potential Sites in Tanzania

S/N	GEOHERMAL SETTINGS / SYSTEMS	SITE	ESTIMATED CAPACITY (MW)	TOTAL CAPACITY (MW)
1 .	South-Western and Northern Volcanic Provinces (Mbeya, Songwe, Arusha, Manyara and Kilimanjaro).	Ngozi	1,000	2,300
		Kiejo-Mbaka	300	
		Songwe	100	
		Natron	250	
		Meru	250	
		Manyara	200	
		Eyasi	200	
2 .	Coastal basin geothermal systems (Coast Region, Morogoro, Tanga).	Kisaki	300	1,200
		Luhoi	300	
		Tagalala	200	
		Mtende	200	
		Utete	200	
3 .	Intra-cratonic geothermal systems (Mara, Shinyanga, Singida, Dodoma).	Takwa/Gonga	200	800
		Ibadakuli	100	
		Maji Moto-Mara	300	
		Kondoa	100	
		Msule/Mpondi	100	
4 .	Western rift geothermal systems (Kagera, Rukwa, Katavi).	Mtagata	200	700
		Maji moto-Rukwa	200	
		Mapyo	150	
		Kanazi	150	
TOTAL			5,000	5,000

Source: Tanzania Geothermal Development Company (TGDC)

In developing geothermal resource potential for power generation various challenges are encountered, these challenges are such as:

- (i). High upfront investment costs;
- (ii). Long lead time from conception to production of electricity;
- (iii). Capital intensive and high exploration cost and risk;
- (iv). Inadequate capital resource to undertake necessary studies; and
- (v). Remote location of the resources and limited infrastructures for accessing it.

Therefore, geothermal power projects included in the generation expansion plan are limited to the projects which have a high possibility of development potential.

(v) Uranium

The National Energy Policy of 2015 and the Mineral Policy of Tanzania of 2009 acknowledge the availability of uranium resource in the country. Tanzania confirmed to have Uranium resources of 58,500 ton discovered along Mkuju River at Namtumbo district, this potential resource is equivalent to 927.5 GWyr of energy. Studies have revealed that there are uranium prospects in different areas, including Singida, Tabora, and Dodoma, as indicated in **Table 3-14**. Therefore, further comprehensive studies should be carried out to explore and assess uranium resources in the country.

The plan has not considered the uranium resource for power generation due to the following reasons:

- (i) The Government is creating enabling environment for nuclear electricity generation including the policies, legal and regulatory framework on uranium resource and nuclear electricity generation; and
- (ii) Human Capacity building on nuclear power technologies and other related matters.

Table 3-14: Uranium Resources in Tanzania

Name	Region	Size (ton)/Status
Mkuju	Ruvuma	58,500
Kianju Mbuga	Singida	Study is ongoing
Ndala Mbuga	Tabora	Study is ongoing
Bahi Swamp	Dodoma	Study is ongoing

Source: Geological Survey of Tanzania (GST).

3.6. Power Projects Development

3.6.1. Hydropower Projects

3.6.1.1. Candidate Projects

Table 3-15 shows potential hydropower projects identified from various sites across the available water basins. The hydropower projects with more than 10 MW have a total generation capacity of 5,197.4 MW. The current update infers firm energy from previous PSMP 2008 and its Updates (2009, 2012, 2016) and review of various studies.

Table 3-15: Hydropower Project Candidates

S/N	Project Name	Capacity (MW)	Average energy (GWh)	Firm energy (GWh)	River
1	Julius Nyerere	2,115.0	9,264.0	6,307.0	Rufiji
2	Ruhudji	358.0	2,000.0	1,333.0	Ruhudji
3	Ikondo Mnyera	340.0	1,832.0	1,316.0	Mnyera
4	Kikonge	300.0	1,268.0	883.8	Ruhuhu
5	Rumakali	222.0	1,322.0	1,075.9	Rumakali
6	Mpanga	160.0	1,061.1	717.8	Mpanga
7	Songwe Sofre (163.2 MW)*	81.6	382.5	237.0	Songwe
8	Iringa Kilolo	150.0	994.8	672.9	Lukosi
9	Songwe Manolo (180.2 MW)*	90.1	471.7	295.1	Songwe
10	Mnyera Taveta	145.0	850.0	622.0	Mnyera
11	Mnyera Kwanini	143.9	693.8	617.3	Rufiji
12	Mnyera Mnyera	137.4	662.3	589.4	Rufiji
13	Mnyera Pumbwe	122.9	592.2	527.2	Rufiji
14	Upper Kihansi	120.0	69.0	99.0	Rufiji
15	Mnyera Kisingo	119.8	577.3	513.9	Rufiji
16	Masigira	118.0	664.0	492.0	Ruhuhu
17	Kakono	87.0	573.0	335.0	Kagera
18	Mnyera Ruaha	60.3	290.8	258.7	Rufiji
19	Iringa (Nginayo)	52.0	262.8	223.1	Rufiji
20	Malagarasi	49.5	181.0	21.4	Malagarasi
21	Mbarali	38.5	199.0	107.9	Kimani Falls
22	Iringa (Ibosa)	36.0	186.1	106.9	Little Ruaha
23	Songwe Bupigu (34 MW)*	17.0	76.5	50.5	Songwe
24	Njombe	32.0	165.4	123.9	Ruhuhu -1
25	Rusumo (80 MW)*	26.7	253.5	129.0	Rusumo
26	Mhanga	26.6	252.9	74.6	Lukosi
27	Songea	15.0	142.4	82.4	Ruhudji
28	Nakatuta (Liparamba)	15.0	140.8	29.7	Ruvuma
29	Kikuletwa	11.0	103.3	30.8	Kikuletwa
30	Kikagati (14 MW)*	7.0	43.8	33.0	Kagera
	Total	5,197.4	25,576	17,906	

Note: *These are a shared project with neighbouring countries.

Sources:

1. Small Hydro Mapping Report, "Renewable Energy Resource Mapping: Small Hydro – Tanzania" (2018) – REA/ the World Bank.
2. World Small Hydropower Development Report, UNIDO (2016).
3. Review of studies conducted for the potential sites.
4. Team survey to the potential sites, data collection, and compilation, (2019).

3.6.1.2. Hydropower Plant Characteristics

Table 3-16 shows the characteristics of the hydroelectric plants, which can generate more than 10 MW. The characteristics provide an overview of the plant in general, plant firm energy, and the capacity to be used during the development of the generation plan model.

Table 3-16: Characteristics of Hydropower Project Candidates

PROJECT NAME CHARACTERISTICS	Julius Nyerere	Rumakali	Ruhudji	Ikondo Mnyera	Kikonge	Mpanga	Songwe Sofre (163.2 MW)*	Iringa Kilolo	Songwe Manolo (180.2 MW)*	Mnyera Taveta	Mnyera Kwanini	Mnyera Mnyera	Mnyera Pumbwe
Generation													
Installed capacity (MW)	2,115	222	358	340	300	160	81.6	150	90.1	145	144	137	123
Average energy (GWh)	9,264	1,322	2,000	1,832	1,268	1,061	383	995	472	850	694	662	592
Firm energy (GWh)	6,307	1,076	1,333	1,316	884	718	237	673	295	622	617	589	527
Power house													
Number of units	4	3	4	4	N.A	2	3	N.A	3	2	2	2	2
Gross head at max. level (m)	100	1,295	765	405	N.A	374	315	N.A	253	155	N.A	N.A	N.A
Gross head at min. level (m)	99	1,265	765	400	N.A	350	285	N.A	173	150	160	155	130
Tailwater level (m.a.s.l)	59	N.A	N.A	N.A	N.A	N.A	825	N.A	527	N.A	N.A	N.A	N.A
Rated turbine discharge (total) (m3/s)	353	19	54	100	N.A	52	59	N.A	69	125	105	103	111
MW/(m ³ /s) based on calc Qmax	1	12	7	3	N.A	3	3	N.A	2	1	N.A	N.A	N.A
Reservoir													
Max. supply level (m.a.s.l.)	159	2,055	1,478	1,070	N.A	734	1,140	N.A	780	490	805	960	645
Min. supply level (m.a.s.l.)	158	2,025	1,440	1,030	N.A	710	1,110	N.A	700	490	805	960	645
Full supply level (m.a.s.l)	174	2,055	1,478	1,070	N.A	734	1,140	N.A	780	490	805	960	645
Recommended min. operational level (m.a.s.l.)	158	2,025	1,367	1,030	N.A	710	1,110	N.A	700	N.A	N.A	N.A	N.A
Storage vol. at max. level (mill. m ³)	13,000	280	300	800	N/A	75	440	N/A	260	N/A	N/A	N/A	N/A
Storage vol. at min. level (mill. m ³)	12,000	24	31	20	N/A	7	80	N/A	0	N/A	N/A	N/A	N/A
Active storage volume (mill. m ³)	1,000	256	269	780	N/A	68	360	N/A	260	N/A	N/A	N/A	N/A
Surface area at max. vol. (km ²)	1,250	13	14	38	N.A	3	15	N.A	11	N.A	N.A	N.A	N.A

PROJECT NAME CHARACTERISTICS	Upper Kihansi	Mnyera Kisingo	Masigira	Rusumo (80 MW)*	Mnyera Ruaha	Kakono	Iringa (Nginayo)	Malagarasi	Mbarali	Iringa (Ibosa)	Songwe Bipugu (34 MW)*	Njombe	Mhanga	Nakatuta (Liparamba)	Songea	Kikuletwa	Kikagati (14 MW)*
Generation																	
Installed capacity MW	120	120	118	27	60	87	52	49.5	39	36	17	32	27	15	15	11	7
Average energy GWH	69	577	664	254	290	573	263	181	199	186	76.5	165	250.1	141	141	103	44
Firm energy GWH	99	514	492	129	259	335	223	21	108	107	51	124	74.6	30	82	31	33
Powerhouse																	
Number of units	2	2	2	3	2	3	2	3	N.A	2	3	N.A	N.A	N.A	N.A	N.A	N.A
Gross head at max. level (m)	854	N.A	238	35	N.A	26	N.A	847	N.A	N.A	80	N.A	N.A	N.A	N.A	N.A	N.A
Gross head at min. level (m)	N.A	105	237	30	110	24	196	833	N.A	151	55	N.A	N.A	N.A	N.A	N.A	N.A
Tailwater level (m.a.s.l.)	N.A	N.A	N.A	1,290	N.A	1,156	N.A	N.A	N.A	N.A	1,165	N.A	N.A	N.A	N.A	N.A	N.A
Rated turbine discharge(total) (m3/s)	17	134	57	207	67	240	30		N.A	28	50	N.A	N.A	N.A	N.A	N.A	N.A
MW/(m ³ /s) based on calc Qmax	N.A	N.A	2	0	N.A	0	N.A	7	N.A	N.A	1	N.A	N.A	N.A	N.A	N.A	N.A
Reservoir																	
Max. supply level (m.a.s.l.)	1,146	415	938	1,325	1,070	1,182	977	N.A	N.A	1,212	1,245	N.A	N.A	N.A	N.A	N.A	N.A
Min. supply level (m.a.s.l.)	1,441	415	937	1,320	1,060	1,180	977	N.A	N.A	1,212	1,230	N.A	N.A	N.A	N.A	N.A	N.A
Full supply level (m.a.s.l.)	1,146	415	938	1,325	1,070	1,182	977	N.A	N.A	1,212	1,245	N.A	N.A	N.A	N.A	N.A	N.A
Recommended min. operational level (m.a.s.l.)	N.A	N.A	937	1,320	N.A	1,180	N.A	843	N.A	N.A	1,230	N.A	N.A	N.A	N.A	N.A	N.A
Storage vol. at max. level (mill. m ³)	N.A	N/A	24	1,250	N/A	27	N/A	457,000	N/A	N/A	350	N.A	N/A	N/A	N/A	N.A	N/A
Storage vol. at min. level (mill. m ³)	N.A	N/A	23	0	N/A	0	N/A	427,000	N/A	N/A	100	N.A	N/A	N/A	N/A	N.A	N/A
Active storage volume (mill. m ³)	1	N/A	2	1,250	288	27	N/A	457,000	N/A	N/A	250	N.A	N/A	N/A	N/A	N.A	N/A
Surface area at max. vol. (km ²)	N.A	N.A	3	390	N.A	14	N.A	169,000	N.A	N.A	30	N.A	N.A	N.A	N.A	N.A	N.A

Note:

- * These are a shared project with neighbouring countries.
- N.A – Not Accessible
- N/A – Not Applicable.

Source: PSMP 2020 Update Team Compilation.

3.6.2. Thermal Power Projects Characteristics

This section discusses the characteristics of thermal power projects (natural gas and coal), as detailed in **Table 3-17**.

Table 3-17: Characteristics of Thermal Power Project Candidates

Plant	Fuel	Technology	Installed Capacity (MW)	Station Service (%)	Net Available Capacity (MW)	Forced Outage Rate (%)	Combined Outage Rate (%)	Maximum Plant Factor (%)	Available Energy (GWh)	Nominal Service Life (Years)
GAS FIRED PLANTS										
Kinyerezi I ext	Natural Gas	CCGT	185	1.6	182	5	13	80	1,212	25
Mtwara I	Natural Gas	CCGT	300	2.0	294	5	11	80	1,957	25
Kinyerezi III	Natural Gas	CCGT	600	2.0	588	5	11	80	3,915	25
Somanga Fungu TANESCO	Natural Gas	CCGT	600	2.0	588	5	11	80	3,915	25
Tegeta New	Natural Gas	CCGT	320	2.0	314	5	11	80	2,088	25
Kinyerezi IV	Natural Gas	CCGT	330	2.0	323	5	11	80	2,153	25
Ubungo I New	Natural Gas	CCGT	320	2.0	314	5	11	80	2,088	25
Ubungo II New	Natural Gas	CCGT	470	2.0	461	5	11	80	3,066	25
Somanga Fungu PPP	Natural Gas	CCGT	320	2.0	314	5	11	80	2,088	25
Dodoma	Natural Gas	CCGT	600	2.0	588	5	11	80	3,915	25
Somanga Mtama	Natural Gas	CCGT	345	2.0	338	5	11	80	2,251	25
Mtwara II	Natural Gas	CCGT	300	2.0	294	5	11	80	1,957	25
Kinyerezi I New	Natural Gas	CCGT	320	2.0	314	5	11	80	2,088	25
Ubungo New	Natural Gas	CCGT	320	2.0	314	5	11	80	2,088	25
Mtwara III	Natural Gas	CCGT	600	2.0	588	5	11	80	3,915	25
Kinyerezi II New	Natural Gas	CCGT	470	2.0	461	5	11	80	3,066	25
Bagamoyo	Natural Gas	CCGT	300	2.0	294	5	11	80	1,957	25
Subtotal			6,700						43,719	
Coal Projects										
Kiwira I	Coal	STG	200	8.0	184	8	20	80	1,186	25
Kiwira II	Coal	STG	200	8.0	184	8	20	80	1,186	25
Mchuchuma I	Coal	STG	300	8.0	276	8	20	80	1,779	25
Mchuchuma II	Coal	STG	400	8.0	368	8	20	80	2,373	25
Mchuchuma III	Coal	STG	300	8.0	276	8	20	80	1,779	25
Ngaka I	Coal	STG	200	8.0	184	8	20	80	1,186	25
Ngaka II	Coal	STG	400	8.0	368	8	20	80	2,373	25
Rukwa I	Coal	STG	300	8.0	276	8	20	80	1,779	25
Mbeya I	Coal	STG	300	8.0	276	8	20	80	1,779	25
Rungwe	Coal	STG	600	8.0	552	8	20	80	3,559	25
Mbeya II	Coal	STG	600	8.0	552	8	20	80	3,559	25
Mbeya III	Coal	STG	600	8.0	552	8	20	80	3,559	25
Kiwira III	Coal	STG	300	8.0	276	8	20	80	1,779	25
Rukwa II	Coal	STG	600	8.0	552	8	20	80	3,559	25
Subtotal			5,300						31,437	
Total			12,000						75,156	

Source: PSMP 2020 Update Team Compilation.

3.6.3. Renewable Projects

Table 3-18 and **3-19** shows the potential candidates for renewable energy (solar, wind, geothermal, and hybrid) development in Tanzania.

Table 3-18: Renewable Energy Project Candidates

S/N	Plant Name	Location	Fuel Type	Capacity (MW/MWp)
SOLAR PROJECTS				
1 .	Shinyanga I (Kishapu)	Kishapu	Solar	150
2 .	Dodoma I	UDOM	Solar	55
3 .	Dodoma II	Michese	Solar	60
4 .	Manyoni	Monyoni	Solar	100
5 .	Same Kilimanjaro	Same	Solar	50
6 .	Kigoma	Kigoma	Solar	5
7 .	Singida	Singida	Solar	150
8 .	Shinyanga II	Sinyanga	Solar	150
	Total Solar Projects			720
WIND PROJECTS				
1 .	Singida I	Singida	Wind	100
2 .	Makambako	Makambako	Wind	300
3 .	Njombe I	Njombe	Wind	100
4 .	Singida II	Singida	Wind	100
5 .	Singida III	Singida	Wind	200
6 .	Njombe II	Njombe	Wind	200
	Total Wind Projects			1,000
HYBRID PROJECTS				
1 .	Loliondo Power Plant - TANESCO	Loliondo	Diesel-Solar	1
2 .	Mafia	Mafia	Diesel-Solar-wind	7
	Total Hybrid Projects			8
	Total Renewable Projects			1,728

Source: TANESCO.

Table 3-19: Geothermal Project Candidates

Forecasts Generation from 2025 - 2045						
S/N	Geothermal Projects	Capacity (MW) by 2025	Capacity (MW) by 2030	Capacity (MW) by 2035	Capacity (MW) by 2040	Capacity (MW) by 2045
1	(i) Ngozi phase I	30				
	(ii) Ngozi phase II	40				
	(iii) Ngozi phase III		30			
	(iv) Ngozi phase IV			30		
	(v) Ngozi phase V				30	
	(vi) Ngozi phase VI					30
2	Songwe	5		5	15	20
3	Kiejo- Mbaka	60		40	30	25
4	Luhoi	5		10	20	10
5	Natron	60	50	40	30	30
6	Kisaki		60	25	30	30
7	Meru		50	40	20	35
8	Ibadakuli		5	10	10	35
	Total	200	195	200	185	215

Source: Tanzania Geothermal Development Company (TGDC)

3.6.4. Project Development Costs

Capital costs for all candidate power projects are based on benchmarking of feasibility studies, Budget Speech 2020/21 from the Ministry of Energy, previous PSMPs Updates, International Atomic Energy Agency, U.S. Energy Information Administration and project developers. Construction costs for hydro, thermal and renewable projects are summarized in **Table 3-20** and **Table 3-21**.

Table 3-20: Hydropower Project Construction Costs

PLANT	Units	Capacity (MW)	Unit Capital Cost (\$/kW) 2019	Capital cost \$M no IDC / 2019 ^{1, 2 & 3}	Construction Period (months)	Pre-construction costs (% of total capital cost)	Annual expenditure as % of total capital cost						TOTAL (%)
							1	2	3	4	5	6	
Rusumo (80 MW)*	3	26.7	4,232.2	113	36**	4.5	55.5	35.0	5.0	0.0	0.0	0.0	100.0
Murongo/Kikagati (14 MW)*	2	7	2,071.4	29	24	4.5	75.5	20.0	0.0	0.0	0.0	0.0	100.0
Julius Nyerere	9	2115	1,348.3	2,852	36**	4.5	11.5	19.0	41.0	24.0	0.0	0.0	100.0
Malagarasi	3	49.5	2,911.9	144	48	4.5	5.5	40.0	30.0	20.0	0.0	0.0	100.0
Ruhudji	4	358	1,138.0	407	48	4.5	25.5	30.0	20.0	20.0	0.0	0.0	100.0
Songwe Manolo (180 MW)*	6	90	3,055.6	275	48	4.5	5.5	40.0	30.0	20.0	0.0	0.0	100.0
Kakono	2	87	3,223.0	280	51	4.5	5.5	40.0	30.0	15.0	5.0	0.0	100.0
Rumakali	3	222	1,690.2	375	48	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Upper Kihansi	2	120	1,840.0	221	45	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Masigira	2	118	2,214.0	261	54	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Kikonge	3	300	2,469.7	741	66	4.5	5.5	40.0	30.0	20.0	0.0	0.0	100.0
Mnyera Kwanini	2	144	1,141.0	164	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mpanga	2	160	1,865.6	298.50	48	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Mnyera Taveta	2	145	1,419.0	206	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songwe Sofre (163.2 MW)*	5	81.6	2,982.7	152	48	4.5	35.5	30.0	20.0	10.0	0.0	0.0	100.0
Iringa (Nginayo)	2	52	2,413.0	125	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Iringa (Ibosa)	2	36	3,418.0	123	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Mnyera	2	137	2,000.5	274	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Ikondo Mnyera	4	340	1,958.2	666	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Kisingo	2	119.8	2,621.4	314	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Ruaha	2	60	4,251.3	255	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mnyera Pumbwe	2	123	1,783.0	219	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Iringa Kilolo	3	150	2,000.0	300	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songwe Bupigu (34 MW)*	5	17	5,897.1	58	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mbarali	TBD	38.5	4,311.7	166	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Njombe	TBD	32	4,250.0	136	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Mhanga	TBD	27	3,518.0	95	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Songea	TBD	15	3,518.0	53	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Nakatuta (Liparamba)	TBD	15	3,518.0	53	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0
Kikuletwa	TBD	11	3,518.0	39	36	4.5	35.5	40.0	20.0	0.0	0.0	0.0	100.0

Note:

- * These are a shared project with neighbouring countries.
- ** These are candidate projects under construction.
- TBD – To Be Determined.

Sources:

- Budget Speech 2020/21– Ministry of Energy.
- PSMPs (2008, 2012 and 2016).
- Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (February, 2020).
(https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf).
- Tanzania Geothermal Development Company.
- Feasibility Studies.

Table 3-21: Thermal and Renewable Project Construction Costs

Plant	Fuel	Technology	Nominal Capacity MW	Unit Capital Cost (\$/kW) ³	Capital cost \$M no IDC / 2019 ^{1, 2, 3 & 4}	Annual expenditure as % of total capital cost					TOTAL
						1	2	3	4	5	
GAS FIRED PLANTS											
Kinyerezi I ext **	Natural Gas	OCGT	185	1,016.2	188	68	10	22	0	0	100
Mtwara I	Natural Gas	CCGT	300	1,213.0	363.9	2	58	40	0	0	100
Kinyerezi III	Natural Gas	CCGT	600	1,124.0	674	55	45	0	0	0	100
Somanga Fungu TANESCO	Natural Gas	CCGT	600	1,124.0	674	60	40	0	0	0	100
Tegeta New	Natural Gas	CCGT	320	1,124.0	360	70	30	0	0	0	100
Kinyerezi IV	Natural Gas	CCGT	330	1,213.0	400	50	50	0	0	0	100
Ubungo I New	Natural Gas	CCGT	320	1,124.0	360	55	45	0	0	0	100
Ubungo II New	Natural Gas	CCGT	470	1,124.0	528	70	30	0	0	0	100
Somanga Fungu PPP	Natural Gas	CCGT	320	1,062.5	340	20	50	30	0	0	100
Dodoma	Natural Gas	CCGT	600	1,124.0	674	20	50	30	0	0	100
Somanga Mtama	Natural Gas	CCGT	345	1,262.0	435	20	50	30	0	0	100
Mtwara II	Natural Gas	CCGT	300	1,113.0	334	60	40	0	0	0	100
Kinyerezi I New	Natural Gas	CCGT	320	1,062.5	340	20	50	30	0	0	100
Ubungo New	Natural Gas	CCGT	320	1,062.5	340	20	50	30	0	0	100
Mtwara III	Natural Gas	CCGT	600	1,124.0	674	20	50	30	0	0	100
Kinyerezi II New	Natural Gas	CCGT	470	1,262.0	593	20	50	30	0	0	100
Bagamoyo	Natural Gas	CCGT	300	1,200.0	360	20	50	30	0	0	100
COAL FIRED PLANTS											
Kiwira I	Coal	IGCC	200	2,186.0	437	40	40	20	0	0	100
Kiwira II	Coal	IGCC	200	2,186.0	437	40	40	20	0	0	100
Mchuchuma I	Coal	IGCC	300	2,185.7	656	40	40	20	0	0	100
Mchuchuma II	Coal	IGCC	400	2,185.7	874	40	40	20	0	0	100
Mchuchuma III	Coal	IGCC	300	2,185.7	656	40	40	20	0	0	100
Ngaka I	Coal	IGCC	200	2,186.0	437	40	40	20	0	0	100
Ngaka II	Coal	IGCC	400	2,344.4	938	40	40	20	0	0	100
Rukwa I	Coal	IGCC	300	2,344.4	703	40	40	20	0	0	100
Mbeya I	Coal	IGCC	300	2,185.7	656	40	40	20	0	0	100
Rungwe	Coal	IGCC	600	2,185.7	1311	40	40	20	0	0	100
Mbeya II	Coal	IGCC	600	2,319.3	1392	40	40	20	0	0	100
Mbeya III	Coal	IGCC	600	2,347.1	1408	40	40	20	0	0	100
Kiwira III	Coal	IGCC	300	2,319.3	696	40	30	30	0	0	100
Rukwa II	Coal	IGCC	600	2,185.7	1522	40	40	20	0	0	100
RENEWABLE PROJECTS											
A. SOLAR											
Shinyanga I (Kishapu)	Solar	PV	150	780.7	117	60	40	0	0	0	100
Dodoma I	Solar	PV	55	1,706.9	93.9	60	40	0	0	0	100
Dodoma II	Solar	PV	60	1,706.9	102.4	60	40	0	0	0	100
Manyoni	Solar	PV	100	1,785.0	178.5	60	40	0	0	0	100
Same	Solar	PV	50	1,785.0	89.3	60	40	0	0	0	100
Singida	Solar	PV	150	780.7	117	10	90	0	0	0	100
Shinyanga II	Solar	PV	150	780.7	117	10	90	0	0	0	100
B. WIND											
Singida I	Wind	Wind	100	1,265.0	126.5	100	0	0	0	0	100
Makamako	Wind	Wind	300	1,265.0	379.5	100	0	0	0	0	100
Njombe I	Wind	Wind	100	1,265.0	126.5	100	0	0	0	0	100
Singida II	Wind	Wind	100	1,265.0	126.5	100	0	0	0	0	100
Singida III	Wind	Wind	200	1,265.0	253.0	100	0	0	0	0	100
Njombe II	Wind	Wind	200	1,265.0	253.0	100	0	0	0	0	100
C. GEOTHERMAL											
Songwe	Geothermal	Geothermal	5	2,521.0	12.6	30	60	10	0	0	100
Ngozi (wellhead) & Ngozi I	Geothermal	Geothermal	30	2,521.0	75.6	30	60	10	0	0	100
Kiejo – Mbaka	Geothermal	Geothermal	60	2,521.0	151.3	30	60	10	0	0	100
Natron	Geothermal	Geothermal	60	2,521.0	151.3	30	60	10	0	0	100
Luhoi	Geothermal	Geothermal	5	2,521.0	12.6	30	60	10	0	0	100
Ngozi II	Geothermal	Geothermal	40	2,521.0	100.8	30	60	10	0	0	100
Geothermal Phase I	Geothermal	Geothermal	195	2,521.0	491.6	30	60	10	0	0	100
Geothermal Phase II	Geothermal	Geothermal	200	2,521.0	504.2	30	60	10	0	0	100
Geothermal Phase III	Geothermal	Geothermal	185	2,521.0	466.4	30	60	10	0	0	100
Geothermal Phase IV	Geothermal	Geothermal	215	2,521.0	542.0	30	60	10	0	0	100

Note:

1. ** These are Candidate Projects under Construction.

Sources:

1. Budget Speech 2020/21– Ministry of Energy.
2. PSMPs (2008, 2012 and 2016).
3. Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (February, 2020) – (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf).
4. Tanzania Geothermal Development Company (TGDC).
5. Feasibility Studies.

3.6.5.Fuel Costs

The fuel prices for generation planning were obtained from regulatory authorities (EWURA & PURA), Feasibility Studies, previous PSMPs, International benchmarking including U.S. Energy Information Administration and potential developers/suppliers.

Table 3-22 shows natural gas and coal prices in 2020.

Table 3-22: Natural Gas and Coal Price

Plant	Fuel	Installed Capacity MW	Fuel price \$/mmBTU	Plant heat rate BTU/kWh	Fuel cost \$/kWh	Fixed operating cost /kW-year	Variable operating cost \$/kWh
GAS FIRED PLANTS							
Kinyerezi I ext	Natural Gas	185	5.559	8,281	0.0460	16.3	0.0507
Mtwara I	Natural Gas	300	5.129	6,666	0.0342	12.2	0.0361
Kinyerezi III	Natural Gas	600	5.559	6,090	0.0339	12.2	0.0357
Somanga Fungu TANESCO	Natural Gas	600	5.206	6,666	0.0347	12.2	0.0366
Tegeta New	Natural Gas	320	5.559	6,090	0.0339	12.2	0.0357
Kinyerezi IV	Natural Gas	330	5.559	6,090	0.0339	12.2	0.0357
Ubungo I New	Natural Gas	320	5.559	6,090	0.0339	12.2	0.0357
Ubungo II New	Natural Gas	470	5.559	6,090	0.0339	12.2	0.0357
Somanga Fungu PPP	Natural Gas	320	5.206	6,666	0.0347	12.2	0.0366
Dodoma	Natural Gas	600	5.559	6,090	0.0339	12.2	0.0357
Somanga Mtama	Natural Gas	345	5.206	6,666	0.0347	12.2	0.0366
Mtwara II	Natural Gas	300	5.129	6,090	0.0312	12.2	0.0331
Kinyerezi I New	Natural Gas	320	5.559	6,090	0.0339	12.2	0.0357
Ubungo New	Natural Gas	320	5.559	6,090	0.0339	12.2	0.0357
Mtwara III	Natural Gas	600	5.129	6,090	0.0312	12.2	0.0331
Kinyerezi II New	Natural Gas	470	5.559	6,090	0.0339	12.2	0.0357
Bagamoyo	Natural Gas	300	5.559	6,090	0.0339	12.2	0.0357
COAL FIRED PLANTS							
Kiwira I	Coal	200	2.360	8,700	0.0212	40.58	0.0257
Kiwira II	Coal	200	2.360	8,700	0.0212	40.58	0.0257
Mchuchuma I	Coal	300	2.573	8,700	0.0231	40.58	0.0276
Mchuchuma II	Coal	400	2.573	8,700	0.0231	40.58	0.0276
Mchuchuma III	Coal	300	2.573	8,700	0.0231	40.58	0.0276
Ngaka I	Coal	200	2.100	8,700	0.0189	40.58	0.0234
Ngaka II	Coal	400	2.100	8,700	0.0189	40.58	0.0234
Rukwa I	Coal	300	2.360	8,700	0.0212	40.58	0.0257
Mbeya I	Coal	300	2.360	8,700	0.0212	40.58	0.0257
Rungwe	Coal	600	2.360	8,700	0.0212	40.58	0.0257
Mbeya II	Coal	600	2.360	8,700	0.0212	40.58	0.0257
Mbeya III	Coal	600	2.360	8,700	0.0212	40.58	0.0257
Kiwira III	Coal	300	2.360	8,700	0.0212	40.58	0.0257
Rukwa II	Coal	600	2.360	8,700	0.0212	40.58	0.0257

Sources:

1. The petroleum (Natural Gas Indicative Price) (Special Strategic Investment) Order 2017;
2. Feasibility Studies;
3. Project Developers; and
4. Indicative for large power plants (Above 10 MW) in Tanzania.

3.6.1. Project Screening

The development of alternative plans and their comparisons use comparative unit costs for alternative technology. The Screening tables for candidate power projects are shown from **Table 3-23 to 3-25**.

Table 3-23: Screening of Thermal Generation Projects

PROJECT	NAME	Unit	SOMANGA FUNGU TANESCO																															
			Kinyerezi I ext	Mtwara I	Kinyerezi II	Tegeta New	Kinyerezi IV	Ubungo I New	Ubungo II New	Somanga Fungu PPP	Dodoma	Somanga Mtwara	Mtwara II	Kinyerezi New	Ubungo New	Mtwara III	Kinyerezi II New	Bagamoyo	Kiwira I	Kiwira II	Mchuchuma I	Mchuchuma II	Mchuchuma III	Ngata I	Ngata II	Rukwa I	Mbeja I	Rungwe	Mbeja II	Mbeja III	Kiwira II	Rukwa II		
Capital Cost			188.0	363.9	674.4	674.4	358.7	400.3	359.7	528.3	340.0	674.4	435.4	333.9	340.0	340.0	674.4	583.2	360.0	437.2	437.2	655.7	674.3	655.7	437.2	937.8	703.3	655.7	1311.4	1391.6	1408.3	685.8	1522.0	
Installed capacity	MW		185	300	600	600	320	330	320	470	320	600	345	300	320	320	600	470	300	200	200	300	400	300	200	400	300	300	600	600	600	300	600	
Station service	%		1.6%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	
Net capacity	MW		182.04	294	588	588	313.6	323.4	313.6	460.6	313.6	588	338.1	294	313.6	313.6	588	460.6	294	184	184	276	368	276	184	368	276	276	552	552	552	276	552	
Unit availability																																		
Scheduled maintenance	hrs per unit		4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	6	6	6	6	6	6	6	6	6	6	6	6	6		
Forced outage rate	%		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	8	8	8	8	8	8	8	8	8	8	8	8	8		
Combined outage rate	%		13	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	20	20	20	20	20	20	20	20	20	20	20	20	20		
Net capacity available (after derating for outage)	MW		180	283	526	526	281	290	281	412	281	526	303	283	281	281	526	412	283	150	150	225	299	225	150	299	225	225	449	449	449	225	449	
Earliest on-power date	Yr		2021	2025	2028	2029	2029	2031	2032	2032	2034	2033	2037	2039	2041	2042	2043	2044	2040	2032	2034	2039	2038	2043	2032	2036	2036	2039	2034	2033	2039	2038	2044	
Service life	Yrs		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35	
O & M																																		
Fixed O & M	\$/kW		16.3	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58	40.58		
Variable O & M	\$/kWh		0.0507	0.0361	0.0357	0.0366	0.0357	0.0357	0.0357	0.0357	0.0366	0.0357	0.0366	0.0331	0.0357	0.0357	0.0331	0.0357	0.0357	0.0257	0.0257	0.0276	0.0276	0.0276	0.0234	0.0234	0.0257	0.0257	0.0257	0.0257	0.0257	0.0257		
Total capital cost with IDC																																		
Unit capital cost	US \$/kW		1016.2	1213.0	1240.0	1240.0	1213.0	1240.0	1240.0	1062.5	1240.0	1262.0	1113.0	1062.5	1062.5	1124.0	1262.0	1200.0	2186.0	2186.0	2185.7	2185.7	2185.7	2186.0	2344.4	2344.4	2185.7	2185.7	2319.3	2347.1	2319.3	2536.7		
Capital cost	USD Mil		185.0	356.6	660.9	660.9	352.5	382.3	352.5	517.7	333.2	660.9	426.7	327.2	332.3	333.2	660.9	581.3	352.8	402.2	402.2	603.2	604.3	603.2	402.2	862.7	647.1	603.2	1206.5	1280.2	1295.6	640.1	1400.3	
Avg capital cost per available capacity	\$/kW avail		1158.8	1353.0	1255.6	1255.6	1255.6	1255.6	1255.6	1186.9	1255.6	1409.8	1243.3	1186.9	1186.9	1255.6	1409.8	1340.5	2686.0	2686.0	2685.6	2685.6	2685.6	2686.0	2880.8	2880.8	2685.6	2685.6	2848.8	2848.0	2848.8	3188.9		
Annual fixed cost	\$/kW avail		30.2	27.2	26.2	26.2	26.2	27.2	26.2	26.2	25.5	26.2	27.7	25.1	25.5	25.5	26.2	27.7	27.0	76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.7	76.7	81.0		
Cashflow in year prior to on-power																																		
-7 % of capital																																		
-6 % of capital																																		
-5 % of capital																																		
-4 % of capital																																		
-3 % of capital																																		
-2 % of capital																																		
-1 % of capital																																		
0 % of capital																																		
Avg total cost at on-power	\$/kW avail		1203.9	1488.6	1295.1	1280.6	1280.0	1402.4	1295.1	1282.0	1280.0	1354.1	1520.4	1278.1	1280.0	1280.0	1354.1	1520.4	1445.7	2838.1	2838.1	2838.6	2838.6	2838.6	2838.6	2838.1	3044.8	3044.8	2838.6	2838.6	3012.2	3048.3	3012.2	3294.6
Annully over economic life (year-end)	\$/kW avail		103.3	127.7	111.1	110.8	110.0	120.3	111.1	110.0	108.9	116.2	130.5	109.7	109.8	108.9	116.2	130.5	124.1	219.3	219.3	219.2	219.2	219.2	219.3	235.2	235.2	219.2	219.2	232.6	235.4	232.6	254.5	
Total annual fixed cost	\$/kW avail		133.5	154.9	137.3	136.3	136.2	147.5	137.3	136.2	135.3	142.4	159.2	135.7	135.3	135.3	142.4	159.2	151.1	286.0	286.0	286.0	286.0	286.0	286.0	313.8	313.8	286.0	286.0	311.0	314.1	311.0	335.5	
Fuel cost calculation																																		
Fuel type			NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal		
Heat rate	kJ/kWh		8,281	6,666	6,090	6,666	6,090	6,090	6,090	6,090	6,666	6,090	6,666	6,090	6,090	6,090	6,090	6,090	6,090	8,216	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977		
Fuel cost	\$/kWh		0.0460	0.0342	0.0339	0.0347	0.0339	0.0339	0.0339	0.0339	0.0347	0.0339	0.0347	0.0312	0.0339	0.0339	0.0312	0.0339	0.0339	0.0212	0.0212	0.0221	0.0221	0.0221	0.0189	0.0189	0.0212	0.0212	0.0212	0.0212	0.0212	0.0212		
Total fixed cost	\$/kW avail		133.5	154.9	137.3	136.3	136.2	147.5	137.3	136.2	135.3	142.4	159.2	135.7	135.3	135.3	142.4	159.2	151.1	286.0	286.0	286.0	286.0	286.0	286.0	313.8	313.8	286.0	286.0	311.0	314.1	311.0	335.5	
Total variable cost	\$/kW avail		0.08677	0.07025	0.06958	0.07128	0.06958	0.06958	0.06958	0.06958	0.07128	0.06958	0.07128	0.06434	0.06958	0.06958	0.06434	0.06958	0.06958	0.04688	0.04688	0.05070	0.05070	0.05070	0.04220	0.04220	0.04688	0.04688	0.04688	0.04688	0.04688	0.04688		

No

te:

1. NG = Natural Gas

Table 3-24: Screening of New Hydropower Projects

PROJECT NAME		Table 3-24: Screening of New Hydropower Projects																													
CHARACTERISTICS		Rusumo (80 MW)*	Murongo/Kikagati (14 MW)*	Julius Nyerere	Malagarasi	Ruhwili	Songwe Manolo (180.2 MW)*	Kakono	Rumakali	Upper Kihansi	Masigira	Kikongo	Mnyera Kwanini	Mpanga	Mnyera Taveta	Songwe Sofie (163.2 MW)*	Iringa (Nginyayo)	Iringa (Ibosa)	Mnyera Myiera	Ikondo Myiera	Mnyera Kisingo	Mnyera Ruaha	Mnyera Pumbe	Iringa Kikolo	Songwe Bugipiga (34 MW)*	Mbarali	Njombe	Mhanga	Songea	Nakoluta (Uparamba)	Kikuletwa
Installed capacity MW		27.0	7.0	2,115.0	49.5	358.0	90.1	87.0	222.0	120.0	118.0	300.0	143.9	160.0	145.0	81.6	52.0	36.0	137.4	340.0	119.8	60.3	122.9	150.0	17.0	38.5	32.0	26.6	15.0	15.0	11.0
Average Energy GWh		253.5	43.8	9,263.7	181.0	2,000.0	471.7	573.0	1,322.0	69.0	664.0	1,268.0	693.8	1,061.1	850.0	382.5	262.8	186.1	662.3	1,832.0	577.3	290.8	592.2	994.8	76.5	199.0	165.4	250.1	140.8	140.8	103.3
Capital costs																															
Capital cost \$ Million		113.0	29.0	2,851.6	144.1	407.4	275.0	280.4	375.2	220.8	261.3	740.9	164.3	298.5	205.8	152.2	125.5	123.0	274.1	665.8	314.0	255.1	219.3	300.0	58.5	162.9	135.4	95.0	52.8	52.8	38.7
Year of estimate		2021	2021	2022	2024	2025	2028	2026	2026	2026	2028	2028	2036	2033	2034	2035	2035	2035	2029	2038	2039	2039	2039	2039	2040	2040	2040	TBD	TBD	TBD	TBD
IDC calculation																															
% cost year -6	6	0.666																													
% cost year -5	5	0.713						0.05																							
% cost year -4	4	0.763		0.24	0.20	0.20	0.20	0.15	0.10	0.10	0.10	0.20		0.10		0.10															
% cost year -3	3	0.816	0.050		0.41	0.30	0.20	0.30	0.20	0.20	0.20	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
% cost year -2	2	0.873	0.350	0.20	0.19	0.40	0.30	0.40	0.30	0.30	0.30	0.40	0.40	0.30	0.40	0.30	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
% cost year -1	1	0.935	0.555	0.76	0.12	0.06	0.26	0.06	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
% cost of pre-Construction	0	1.000	0.045	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total		1.000	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Cost with IDC, USD Mil.		178.2	46.2	4,284.7	217.6	622.3	415.1	422.6	579.6	341.1	403.6	1,118.5	255.6	461.1	320.1	235.1	195.2	191.4	426.4	1,035.8	488.6	396.8	341.2	466.7	91.0	253.4	210.6	147.8	82.1	82.1	60.2
Unit Capital Cost, USD/MW		6,598.2	6,593.9	2,025.8	4,385.8	1,736.3	4,607.5	4,857.3	2,610.8	2,842.2	3,420.0	3,728.2	1,776.3	2,881.8	2,207.8	2,881.2	3,754.0	5,317.6	3,103.2	3,046.5	4,076.2	6,581.1	2,776.2	3,111.5	5,352.7	6,581.1	6,581.1	5,555.4	5,473.1	5,473.1	5,473.1
Fixed annual cost																															
Fixed annual cost (capital + interest) UAP		12.91	3.34	310.47	15.77	45.09	30.08	30.62	42.00	24.71	29.24	81.04	18.52	33.41	23.19	17.04	14.14	13.87	30.90	75.06	35.40	28.76	24.72	33.82	6.59	18.36	15.26	10.71	5.95	5.95	4.36
Fixed O & M, USD Mil.	10	0.27	0.07	21.15	0.50	3.58	0.90	0.87	2.22	1.20	1.18	3.00	1.44	1.60	1.45	0.82	0.52	0.36	1.37	3.40	1.20	0.60	1.23	1.50	0.17	0.39	0.32	0.27	0.15	0.15	0.11
Total fixed annual cost		26.09	6.76	642.08	32.03	93.77	61.06	62.11	86.22	50.63	59.66	165.09	38.48	68.42	47.84	34.89	28.81	28.10	63.17	153.51	72.00	58.11	50.67	69.14	13.36	37.10	30.84	21.68	12.05	12.05	8.83
Unit cost of energy																															
Average energy \$/kWh		0.10	0.15	0.07	0.18	0.05	0.13	0.11	0.07	0.73	0.09	0.13	0.06	0.06	0.06	0.09	0.11	0.15	0.10	0.08	0.12	0.20	0.09	0.07	0.17	0.19	0.19	0.09	0.09	0.09	0.09

Note: *These are a shared project with neighbouring countries.
Source: PSMP 2020 Update Team Compilation.

Table 3-25: Screening of New Renewable Projects

PROJECT NAME	Unit	Shinyanga I (Kishapu)	Dodoma I	Dodoma II	Manyoni	Same	Singida	Shinyanga II	Singida I	Makambako	Njombe	Singida II	Njombe II	Singida III	Songwe	Ngosi (wellhead) & Ngosi I	Kiyo - Mbaka	Natron	Luhohi	Ngosi II	Geothermal Phase I	Geothermal Phase II	Geothermal Phase III	Geothermal Phase IV
Source		Solar	Solar	Solar	Solar	Solar	Solar	solar	Wind	Wind	Wind	Wind	Wind	Wind	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal
Capital Cost		117,098	93,8795	102,414	178.5	89.25	117,098	117,098	126.5	379.5	126.5	126.5	253	253	12,605	75.63	151.26	151.26	12,605	100.84	491.595	504.2	466.385	542.02
Installed capacity	MW	150	55	60	100	50	150	150	100	300	100	100	200	200	5	30	60	60	5	40	195	200	185	215
Station service	%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Net capacity	MW	148.5	54.45	59.4	99	49.5	148.5	148.5	99	297	99	99	198	198	4.9	29.4	58.8	58.8	4.9	39.2	191.1	196	181.3	210.7
Unit availability																								
Scheduled maintenance	hrs per unit	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4
Forced outage rate	%	5	5	5	5	5	5	5	5	5	5	5	5	5	7	7	7	7	7	7	7	7	7	7
Combined outage rate	%	11	11	11	11	11	11	11	11	11	11	11	11	11	15	15	15	15	15	15	15	15	15	15
Net capacity available (after derating for outage)	MW	132.9	48.7	53.2	88.6	11	132.9	132.9	88.6	265.9	88.6	88.6	177.2	177.2	4.2	25.2	50.5	50.5	4.2	33.7	164.1	168.3	155.6	180.9
Earliest on-power date	Yr	2027	2024	2031	2040	2042	2023	2041	2025	2037	2041	2036	180	2039	2023	2023	2024	2027	2027	2026	2030	2035	2040	2044
Service life	Yrs	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
O & M																								
Fixed O & M	\$/kW	15.25	15.25	15.25	15.25	15.25	15.25	15.25	26.34	26.34	26.34	26.34	26.34	26.34	128.544	128.544	128.544	128.544	128.544	128.544	128.544	128.544	128.544	128.544
Variable O & M	\$/MWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116
Total capital cost with IDC																								
Unit capital cost	US \$/kW	1,280.98	585.86	585.86	585.86	585.86	1,280.98	1,280.98	790.51	790.51	790.51	790.51	790.51	790.51	2,521.00	2,521.00	2,521.00	2,521.00	2,521.00	2,521.00	2,521.00	2,521.00	2,521.00	2,521.02
Capital cost	US \$ x 10 ⁶	192.15	32.22	35.15	58.02	28.01	192.15	192.15	79.05	237.15	79.05	79.05	158.10	158.10	12.61	75.63	151.26	151.26	12.61	100.84	491.60	504.20	466.39	542.02
Avg capital cost per available capacity	\$/kW avail	1,445.41	661.06	661.06	632.14	2,546.47	1,445.41	1,445.41	891.99	891.99	891.99	891.99	891.99	891.99	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.58	2,996.61
Annual fixed cost	\$/kW avail	31.49	23.65	23.65	23.36	94.09	31.49	31.49	38.34	38.34	38.34	38.34	38.34	38.34	179.70	179.70	179.70	179.70	179.70	179.70	179.70	179.70	179.70	179.70
Cashflow in year prior to on-power																								
-7 % of capital																								
-6 % of capital																								
-5 % of capital																								
-4 % of capital																								
-3 % of capital																								
-2 % of capital																								
-1 % of capital																								
0 % of capital																								
Avg total cost at on-power	\$/kW avail	1,533.224	687.502	687.502	657.421	2,648.332	1,575.494	1,575.494	891.986	891.986	891.986	891.986	891.986	891.986	3,229.303	3,229.303	3,229.303	3,229.303	3,229.303	3,229.303	3,229.303	3,229.303	3,229.303	3,229.333
Annulity over economic life (year-end)	\$/kW avail	165.607	75.741	75.741	72.427	291.762	173.569	173.569	98.269	98.269	98.269	98.269	98.269	98.269	356.868	356.868	356.868	356.868	356.868	356.868	356.868	356.868	356.868	356.871
Total annual fixed cost	\$/kW avail	197.097	99.387	99.387	95.784	385.851	205.059	205.059	136.612	136.612	136.612	136.612	136.612	136.612	636.571	636.571	636.571	636.571	636.571	636.571	636.571	636.571	636.571	636.575
Fuel cost calculation																								
Fuel type																								
Fuel price	\$/GJ																							
Heat rate	kWh/kWh																							
Fuel cost	\$/MWh																							
Total fixed cost	\$/kW avail	197.10	99.39	99.39	95.78	385.85	205.06	205.06	136.61	136.61	136.61	136.61	136.61	136.61	636.57	636.57	636.57	636.57	636.57	636.57	636.57	636.57	636.57	636.57
Total variable cost	\$/MWh avail	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116	0.00116

Note: Geothermal Phase I, II, III and IV sites are clarified in Table 3-31.

Source: PSMP 2020 Update Team Compilation

3.7. Generation Plan

3.7.1. Generation Plan Strategies and Criteria

3.7.1.1. Generation Plan Strategies

This update adopted and reviewed some strategies applied in the preparation of PSMP 2008 and its Updates (2009, 2012 and 2016). **Table 3-26** shows the overall power development strategies.

Table 3-26: Overall Power Development Strategies

Element	Reason
Base-Case load forecast	To take account of all identified new industrial loads, including background load growth, and to target a 96.1 percent electrification rate by 2044.
Interconnect isolated regions	To the extent that it is economic and feasible to do so, in order to promote social and economic development.
Install all new generation options that are feasible in the short term	To accommodate committed projects to meet the projected short term demand.
Use a judicious mix of hydro and non-hydro generation options	To avoid over-reliance on hydro with the attendant risk of power shortages during dry periods.
Accept limited amounts of firm exports	To balance demand and energy supply with an acceptable reserve margin.
Schedule new generation so that sufficient reserve margin is provided to allow for future pool power trading	To improve the economics of system expansion by developing revenue potential, while also providing improved security of energy supply

3.7.1.2. Generation Plan Criteria

- a. **Reserve Margin:** This Plan assumes a reserve margin of 15 to 20 percent of the system installed capacity.
- b. **Generation Mix:** This Plan considers an increase in the share of renewable energy and coal resources.

- c. Loss of Load Expectation:** The Plan maintains the use of a maximum loss of load expectation (LOLE) of 5 days per year as established in 2008 and its Updates (2009, 2012 and 2016). The LOLE values are based on a hydropower during a low flow period with a return period of 1:30 years, or 97 percent probability of exceedance.
- d. Outage rates:** The plan assumes that there will be planned and forced outages at the generating plants. The Combined Outage Rates per year is a result of scheduled maintenance and forced outages. **Table 3-27** outlines the selected outage rates based on different power generation technologies.

Table 3-27: Outage Rates for Power Generation

Generation Type	Schedule maintenance in weeks per year	Forced outage in percentage of time per year	Combined outage rate percent
Coal (IGCC)	6	8	20
Gas Turbine (GT)	4	5	13
Combined Cycle Gas Turbine (CCGT)	3	5	11
Hydroelectric	4	5	8
Geothermal	4	7	15

- e. Plant Life Span:** **Table 3-28** shows the plant life spans. The life span values inform the determination of average unit generation costs for preliminary comparisons, and for determining retirement dates for existing and future plants in the development of generation plan.

Table 3-28: Power Plants Life Span

Technology Type	Normal Service life (years)
Gas Turbines	25
Combined Cycle Gas Turbine	25
Medium Speed Diesel	20
Low Speed Diesel	25
Coal	35
Hydroelectric Plant	50
Renewable (Wind, Solar, Geothermal)	25

Note: The indicated generic economic life time is normally extended through proper maintenance and replacement of major equipment.

Source: PSMP 2020 Team compilation

- f. Operation, Maintenance (O&M), and other costs:** Unit generation costs include allowances for operation and maintenance. For thermal plants, the operation and maintenance costs are part of fixed and variable costs. In contrast, for hydroelectric plants, O&M cost is considered as a fixed cost. **Table 3-29** shows the Operation and Maintenance costs for various generation technologies.

Table 3-29: Selected Operation and Maintenance Costs for Generation Technologies

Plant Type	Unit size (MW)	Fixed O&M (US\$/kW-yr)	Variable O&M (US\$/kWh)
Coal	300	40.58	0.0258
Gas Turbine (GT)	60	16.30	0.0507
Combined Cycle Gas Turbine	300	12.2	0.0356
Hydroelectric	100	29.86	0
Geothermal	50	128.544	0.00116
Solar PV w/ Single Axis Tracking + Battery Storage	150 MWAC Solar 50 MW 200 MWh Storage	31.27	0
Solar PV w/ Single Axis Tracking	150 MWAC	15.25	0
Fixed-bottom Offshore Wind: Monopile Foundations	400 MW 10 MW WTG	110	0

Source: U.S. Energy Information Administration, Capital Cost, and Performance Characteristics Estimates for Utility-Scale Electric Power Generating Technologies (2020).

- g. Lead times:** A critical issue in determining the possible scheduling of new projects is the minimum lead-time that would be required to complete the project implementation process up to commercial operation date. Factors considered during the estimate of minimum lead-time are the level of preparation of the project (Pre-feasibility, feasibility, bankable document etc.).

This Plan considered that the earliest lead times will be January 2021. **Table 3-30** shows the time for each of the individual activities leading up to the implementation of the project and on-power, of which can be used to assess an appropriate minimum lead time of a project.

Table 3-30: Lead times for Power Generating Projects

Activity	Time (months)
Prefeasibility study, following a reconnaissance level project identification.	6-12
Feasibility study (including consultant selection).	12-24
Feasibility study update (where required).	6-12
Environmental study.	12
ESIA Approval/Certification.	3
Preparation of tender documents, access permit acquisition, resettlement and compensation.	12

Activity	Time (months)
Project financing.	12
Tendering.	6-12
Final design (including consultant selection) – depending on size/complexity.	12-18
Construction (depending on size/complexity).	24-72

Source: PSMP 2020 Update Team Compilation.

Several factors determine the overall lead time required for the construction of a given power plant. The factors are Government commitment, environmental approval process, private or public ownership, availability of funds, size and complexity of the project and the extent to which activities may be fast-tracked for instance carrying out activities in parallel, such as final design and preparation of the Environmental Impact Assessment (EIA).

3.7.2. Power Trading

Tanzania is a member of SAPP and EAPP, from which there is a possibility of power exchange with neighbouring countries and the regions as a whole. In respect to this, Tanzania is implementing regional interconnector projects which will enable power exchange, hence enhancing security of supply between Member States of the power pools.

Currently, the ongoing construction of strategic interconnector projects are from Tanzania to Kenya, Zambia, Burundi, and Rwanda. Other planned strategic interconnectors are from Tanzania to Uganda, Mozambique, Democratic Republic of Congo and Malawi. The ongoing interconnector projects have a total transfer capability of about 1,500 MW while planned strategic interconnectors shall have transfer capability of 1,200 MW. The detailed parameters for ongoing and planned interconnectors can be referenced from Chapter Four.

Moreover, the generation plan results will provide annual respective capacities available which Tanzania may exchange with other countries in the regions through out the planning horizon.

3.8. Generation Plan Results

The PSMP 2020 Update generation plan consider the load forecasted demand under Base Case Scenario to propose generation projects for future country's power

requirement. **Table 3-31** presents the details of the proposed projects over the planning horizon. In the period 2020 – 2044, Tanzania requires the total installed capacity of 20,200.6 MW. The Plan indicates power generation mix consisting of hydro (5,684 MW or 28.15%), natural gas (6,700 MW or 33.18%), coal (5,300 MW or 26.24%), wind (800 MW or 3.96%), solar (715 MW or 3.54%), geothermal (995 MW or 4.93%) and (0 MW or 0%) diesel/HFO by 2044.

Furthermore, **Table 3-31** shows that total installed generation capacity in the short term is 3,971.4 MW, medium term is 12,255.7 MW and long term is 20,200.6 MW. The installed power supply capacity satisfies the forecasted load demand of the respective terms, leaving adequate surplus capacity for reserve and trading needs.

The plan indicates that Julius Nyerere Hydropower Plant will come into full operation by 2022, bringing the total installed capacity to **3,810.9 MW** rendering a surplus power capacity of **2,001.9 MW**. However, due to limitation in transmission capacity, the power generation plan indicates that the maximum power to be traded is **1,000 MW** in 2023 and additional of **500 MW** by 2025 onwards.

Figures 3-3 and **3-4** illustrate the evolution of the installed power capacity and generation resource mix over the planning horizon to 2044. The figures show that the share of coal and renewable resources is increasing in the generation mix while oil (Diesel and HFO) connected to the National Grid will be phased out by 2021.

The utilization of the least cost generation sources like JNHPP will lead to economic dispatch of power generation plants and that suggest to non-utilization of some of thermal powered plants. However, under climatic consideration development of thermal power plants is inevitable. Furthermore, in order for the country to fully utilize thermal power plants and export the aforementioned surplus capacity, investment in short term for power interconnector projects to SAPP and EAPP is recommended. In this regard, it is further recommended that, arrangements to initiate bilateral and multilateral power exchange agreements have to start immediately.

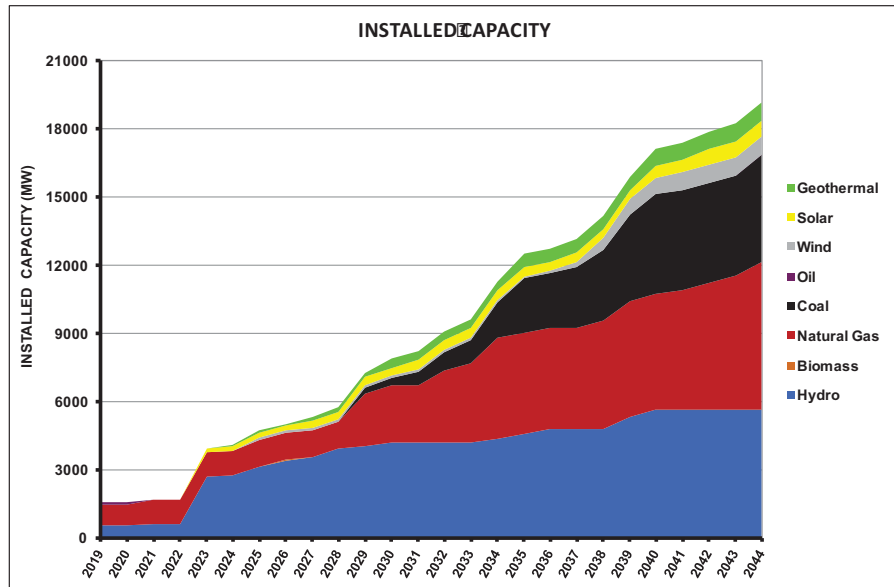


Figure 3-3: Installed Generation Capacity

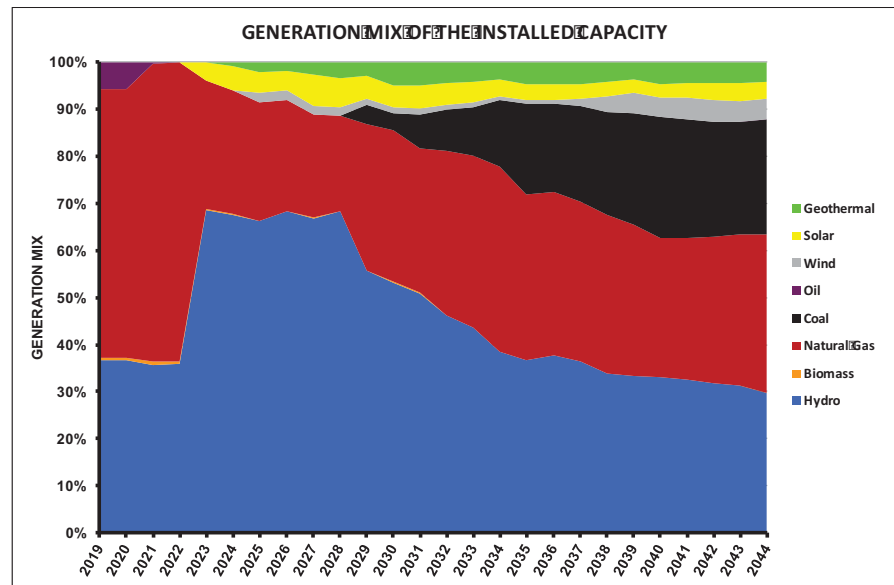


Figure 3-4: Generation Mix of the Installed Capacity

Table 3-31: Generation Plan

YEAR	PLANT	FUEL	TYPE	ADDITION		TOTAL SUPPLY		DEMAND		SURPLUS / DEFICIT		RESERVE MARGIN	
				CAPACITY (MW)	AVERAGE ENERGY (GWH)	CAPACITY (MW)	AVERAGE ENERGY (GWH)	CAPACITY (MW)	AVERAGE ENERGY (GWH)	CAPACITY (MW)	AVERAGE ENERGY (GWH)	CAPACITY (%)	ENERGY (%)
2019	All existing plants					1,565.7	9,172.9						
2020						1,565.7	9,172.9	1,120.1	7,861.0	445.6	1,311.9	39.8	16.7
	Kinyerezi I ext	Gas	SC	185.0	1,232.0	1,750.7	10,404.9						
	Rusumo (80 MW)*	Hydro	Hydro	27.0	253.5	1,777.7	10,658.4						
	Murongo/Kikagati - (14 MW)*	Hydro	Hydro	7.0	43.8	1,784.7	10,702.2						
	Biharamulo (Retire)**	Diesel	Diesel	(4.14)	(24.52)	1,780.6	10,677.7						
	Namitumbo (Retire)**	Diesel	Diesel	(0.34)	(2.01)	1,780.2	10,675.8						
	Madaba (Retire)**	Diesel	Diesel	(0.48)	(2.84)	1,779.8	10,672.8						
	Songwe (Retire)**	Diesel	Diesel	(7.67)	(45.43)	1,772.1	10,627.4						
	Ludewa (Retire)**	Diesel	Diesel	(1.27)	(7.52)	1,770.8	10,619.8						
	Zuzu (Retire)**	Diesel	Diesel	(7.40)	(43.83)	1,763.4	10,576.0						
	Mbinga (Retire)**	Diesel	Diesel	(2.00)	(11.85)	1,761.4	10,564.2						
	Nyakato (Standby)**	Diesel	Diesel	(63.00)	(373.18)	1,698.4	10,191.0						
	Ngara (Retire)**	Diesel	Diesel	(2.50)	(14.81)	1,695.9	10,176.2	1,629.0	9,098.0	66.9	1,078.2	4.1	11.9
2022	Julius Nyerere	Hydro	Hydro	2,115.0	9,263.7	3,810.9	19,439.9	1,809.0	10,176.0	2,001.9	9,263.9	110.7	91.0
	Singida	Solar	Solar	150.0	274.8	3,960.9	19,714.7						
	Songwe	Geothermal	Geothermal	5.0	39.4	3,965.9	19,754.1						
	Ngozi (wellhead) & Ngozi I	Geothermal	Geothermal	30.0	236.5	3,995.9	19,990.6						
	Export	Export	Export	(1,000.00)	(4,380.00)	2,995.9	15,610.6	2,036.0	11,470.0	959.9	4,140.6	47.1	36.1
	Malagarasi	Hydro	Hydro	49.5	181.0	3,045.4	15,791.6						
	Dodoma I	Solar	Solar	55.0	100.8	3,100.4	15,892.4						
2024	Kleje – Mbaka	Geothermal	Geothermal	60.0	473.0	3,160.4	16,365.4						
	Songas (Retire)	Gas	SC	(189.00)	(1,233.12)	2,971.4	15,132.2	2,329.0	13,240.0	642.4	1,892.2	27.6	14.3
	Ruhudji	Hydro	Hydro	358.0	2,000.0	3,329.4	17,132.2						
	Singida I	Wind	Wind	100.0	644.0	3,434.4	17,776.2						
	Mtwara I	Gas	CCGT	300.0	1,957.0	3,729.4	19,733.2						
2025	Export	Export	Export	(500.00)	(2,190.00)	3,229.4	17,543.2						
	Andoya (Retire)	Hydro	Hydro	(1.00)	(5.91)	3,228.4	17,537.3	2,677.0	15,271.0	550.5	2,265.7	20.6	14.8
	Matembwe (Retire)	Hydro	Hydro	(0.95)	(0.60)	3,227.5	17,536.7						
	Kakono	Hydro	Hydro	87.0	573.0	3,314.5	18,109.7						
	Rumakali	Hydro	Hydro	222.0	1,322.0	3,536.5	19,431.7						
	Upper Kihansi	Hydro	Hydro	120.0	69.0	3,656.5	19,500.7						
2026	Ngozi II	Geothermal	Geothermal	40.0	315.3	3,696.5	19,816.1						
	Darakuta (Retire)	Hydro	Hydro	(0.32)	(0.32)	3,696.2	19,815.7	3,053.0	17,575.0	643.2	2,240.7	21.1	12.7
	Mtwara (Retire)	Gas	GE	(18.00)	(117.00)	3,678.2	19,698.7						
	Shinyanga I (Kishapu)	Solar	Solar	150.0	327.0	3,828.2	20,025.7						
2027	Natron	Geothermal	Geothermal	60.0	473.0	3,888.2	20,498.7						
	Luhoi	Geothermal	Geothermal	5.0	39.4	3,893.2	20,538.2						
	Mwenga (Retire)	Hydro	Hydro	(4.00)	(24.00)	3,889.2	20,514.2	3,439.0	19,880.0	450.2	634.2	13.1	3.2
	Kikonge	Hydro	Hydro	300.0	1,268.0	4,189.2	21,782.2						
	Songwe Manolo (180.2 MW)*	Hydro	Hydro	90.1	471.7	4,279.3	22,253.9						
2028	Masinga	Hydro	Hydro	118.0	664.0	4,397.3	22,917.9						
	Kinyerezi III	Gas	CCGT	600.0	3,914.0	4,997.3	26,831.9						
	Ubungo I (Retire)	Gas	GE	(102.00)	(685.00)	4,895.3	26,146.9	3,850.0	22,403.0	1,045.3	3,743.9	27.1	16.7
	Somanga Fungu TANESCO	Gas	CCGT	600.0	4,228.0	5,495.3	30,374.9						
	Mbeya I	Coal	Steam	300.0	2,103.0	5,795.3	32,477.9						
2029	Mnyera Mnyera	Hydro	Hydro	137.4	692.3	5,932.7	33,140.2						
	Tegeta (Retire)	GE	GE	(45.00)	(290.10)	5,887.7	32,850.1						
	Tegeta New	Gas	CCGT	320.0	2,087.5	6,207.7	34,937.5	4,323.0	25,271.0	1,884.7	9,666.5	43.6	38.3
	Geothermal Phase I (Mbeya, Manyara, Morogoro, Arusha, Shinyanga)	Geothermal	Geothermal	195.0	1,537.3	6,402.7	36,474.8						
2030	Mtwara Additional (Retire)	Gas	GE	(4.00)	(26.00)	6,398.7	36,448.8						
	TANWAT (Retire)	Biomass	Biomass	(10.50)	(10.00)	6,397.2	36,438.8						
	Somanga (Retire)	Gas	GE	(7.50)	(48.93)	6,389.7	36,389.9	4,878.0	28,663.0	1,511.7	7,726.9	31.0	27.0
	Dodoma II	Solar	Solar	60.0	210.0	6,449.7	36,599.9						
2031	Mchuchuma I	Coal	Steam	300.0	2,103.0	6,749.7	38,702.9						
	Kinyerezi IV	Gas	CCGT	330.0	2,153.1	7,079.7	40,855.9						
	Yovi (Retire)	Hydro	Hydro	(0.95)	(8.30)	7,078.7	40,847.6						
	TPC (Retire)	Biomass	Biomass	(9.00)	(70.00)	7,069.7	40,777.6	5,488.0	32,413.0	1,581.7	8,364.6	28.8	25.8
	Kiwi I	Coal	Steam	200.0	1,186.3	7,269.7	41,963.9						
2032	Ubungo I New	Gas	CCGT	320.0	2,087.5	7,589.7	44,051.4						
	Ngaka I	Coal	Steam	200.0	1,314.0	7,789.7	45,365.4						
	Ubungo II (Retire)	Gas	SC	(129.00)	(842.00)	7,660.7	44,523.4						
	Ubungo II New	Gas	CCGT	300.0	3,066.0	8,130.7	47,589.4	6,177.0	36,654.0	1,953.7	10,935.4	31.6	29.8
	Mpanga	Hydro	Hydro	160.0	1,061.1	8,290.7	48,650.5						
2033	Dodoma	Gas	CCGT	600.0	3,914.0	8,890.7	52,564.5						
	Mbeya II	Coal	Steam	600.0	3,558.9	9,490.7	56,123.4	6,951.0	41,475.0	2,539.7	14,648.4	36.5	35.3
	Somanga Fungu PPP	Gas	CCGT	320.0	2,087.8	9,810.7	58,211.2						
2034	Kiwi II	Coal	Steam	200.0	1,289.0	10,010.7	59,500.2						
	Runzwe	Coal	Steam	600.0	3,558.9	10,610.7	63,059.2						
	Mnyera Taveta	Hydro	Hydro	145.0	850.0	10,755.7	63,909.2	7,851.0	47,022.0	2,904.7	16,887.2	37.0	35.9
	Songwe Sofre (163.3 MW)*	Hydro	Hydro	81.6	382.5	10,837.3	64,291.7						
2035	Geothermal Phase II (Mbeya, Manyara, Morogoro, Arusha, Shinyanga)	Geothermal	Geothermal	200.0	1,575.0	11,037.3	65,866.7						
	Ininga (Nganyo)	Hydro	Hydro	52.0	262.8	11,089.3	66,129.4						
	Ininga (Ibasa)	Hydro	Hydro	96.0	186.1	11,125.3	66,315.5						
	Tullia (Retire)	Hydro	Hydro	(5.00)	(6.18)	11,120.3	66,309.3	8,554.0	51,496.0	2,566.3	14,813.3	30.0	28.8
	Mnyera Kwanini	Hydro	Hydro	143.9	693.8	11,264.2	67,003.1						
	Rukwa I	Coal	Steam	300.0	276.0	11,564.2	67,279.1						
2036	Singida II	Wind	Wind	100.0	644.0	11,664.2	67,923.1						
	Ngaka II	Coal	Steam	400.0	2,804.0	12,064.2	70,727.1	9,309.0	56,277.0	2,755.2	14,450.1	29.6	25.7
	Makambako	Wind	Wind	300.0	1,932.0	12,364.2	72,659.1						
2037	Somanga Mtama	Gas	CCGT	345.0	2,250.9	12,709.2	74,910.1	10,116.0	61,376.0	2,593.2	13,534.1	25.6	22.1
	Mchuchuma II	Coal	Steam	400.0	2,804.0	13,109.2	77,714.1						
2038	Ikondo Mnyera	Hydro	Hydro	340.0	1,832.0	13,449.2	79,546.1						
	Kiwi II	Coal	Steam	300.0	1,779.5	13,749.2	81,325.5	10,968.0	66,818.0	2,781.2	14,507.5	25.4	21.7
	Mtwara II	Gas	CCGT	300.0	1,957.0	14,049.2	83,282.5						
	Singida III	Wind	Wind	200.0	1,288.0	14,249.2	84,570.5						
	Mnyera Kisingo	Hydro	Hydro	119.8	577.3	14,369.0	85,147.8						
2039	Mnyera Ruaha	Hydro	Hydro	60.3	290.8	14,429.3	85,438.6						
	Mnyera Pumbwe	Hydro	Hydro	122.9	592.2	14,552.2	86,030.8						
	Mbeya III	Coal	Steam	600.0	3,558.9	15,152.2	89,589.8						
	Ininga Kiloi	Hydro	Hydro	150.0	994.8	15,302.2	90,584.6	11,885.0	72,601.0	3,417.2	17,983.6	28.8	24.8
	Manyoni	Solar	Solar	100.0	175.0	15,402.2	90,759.6						
	Geothermal Phase III (Mbeya, Songwe, Manyara, Morogoro, Arusha, Shinyanga)	Geothermal	Geothermal	185.0	1,456.9	15,587.2	92,216.4						
2040	Songwe Bupiga (34 MW)*	Hydro	Hydro	17.0	76.5	15,604.2	92,292.9						
	Mbarali	Hydro	Hydro	38.5	199.0	15,642.7	92,491.9						
	Njombe	Hydro	Hydro	32.0	165.4	15,674.7	92,657.3						
	Bagamoyo	Gas	CCGT	300.0	1,957.0	15,974.7	94,614.3						
	Kinyerezi I (Retire)	Gas	SC	(150.00)	(1,034.00)	15,824.7	93,580.3	12,854.0	78,657.0	2,970.7	14,923.3	23.1	19.0
	Njombe I	Wind	Wind	100.0	644.0	15,924.7	94,224.3						
2041	Shinyanga II	Solar	Solar	150.0	274.8	16,074.7	94,499.1						
	Kinyerezi I New	Gas	CCGT	320.0	2,087.8	16,394.7	96,587.0						
	Uwemba (Retire)	Hydro	Hydro	(0.84)	(2.30)	16,393.9	96,584.7	13,897.0	85,136.0	2,496.9	11,448.7	18.0	13.4
	Ubungo New	Gas	SC	320.0	2,087.8	16,713.9	98,672.5						
2042	Same Kilimanjaro	Solar	Solar	50.0	175.0	16,763.9	98,847.5						
	Export (Retire)	Export	Export	1,500.0	6,570.0	18,263.9	105,417.5	15,042.0	92,130.0	3,221.9	13,287.5	21.4	14.4
	Mtwara III	Gas	CCGT	600.0	3,914.7	18,863.9	109,332.2						
2043	Mchuchuma III	Coal											

CHAPTER 4

4. TRANSMISSION EXPANSION PLAN

4.1. Introduction

This Chapter provides an update of transmission plan based on the load forecast and generation plan presented in previous chapters. Practically, the overall current logical planning process used for the conceptual primary transmission system is more or less similar to the PSMP 2008 and its Updates (2009, 2012 and 2016).

Significant power flows assessment was conducted across the country throughout the planning horizon in order to plan for reinforcement and new transmission lines. The assessment was done by calculating ranges of major interface flows for critical system conditions at intervals for short, medium and long term throughout the planning horizon. These ranges of major interface power flow between geographic subsystems follow a generation planning sequence, grid station load forecast, ranges of load levels and known operating constraints. This information led to a conceptual update design of the transmission additions or changes where necessary. Likewise, the information will provide early feedback of transmission costs associated with the least cost generation plan.

Load flow simulations were carried out in short, medium and long term using generation data as an input to transmission plan. The result provides detailed information for transmission system expansion, reinforcement and addition.

4.1.1. Objective

The main objective is to identify definitive near to medium term and an indicative long term plan for the transmission system expansion, reinforcement and addition. More specifically, transmission expansion plan objectives are:

- a) To ensure security of supply in the short term by coordinating electricity supply and demand;
- b) To ensure security of supply in the medium and long term by developing the National Grid;
- c) To ensure accessible transmission routes using good maintenance practices;

- d) To determine the location, capacity and type of the required power transmission development and upgrades over the planning horizon by 2044;
- e) To establish the timing of the transmission upgrades across years 2024, 2034 and 2044; and
- f) To estimate the capital cost in investment plan associated with the transmission system development and upgrades.

In the context of this Plan, the transmission expansion plan determines the system upgrades that will allow the planned generation to serve the forecasted load. Additionally, a corresponding investment plan is developed to estimate the cost of the transmission expansion plan associated to the generation and sub-transmission plans which provide the basic input to financial and economic analysis.

The transmission plan identifies the most economical system additions while satisfying a pre-defined set of technical criteria. Such criteria composes a set of rules that measure the system performance and compare several scenarios on a common technical basis, ensure the adequate operation of the power system under both normal and emergency conditions, once the infrastructure has been built.

4.1.2.Existing Grid System

There are transmission lines of different voltage capacities all over the country. The transmission system comprises of 670 km of 400 kV, 3,010.7 km of 220 kV, 1,672.57 km of 132 kV, and 543 km of 66 kV. The isolated centers away from the grid have generating units with an aggregate nominal capacity of 36.598 MW. TANESCO imports power from Uganda through 132 kV, Zambia through 66 kV lines and Kenya through 33 kV line. **Figure 4-1** shows the existing grid network, and **Table 4-1** shows the existing transmission line system with line parameters.

Simulation of the existing power system under peak load conditions revealed that there is a constrain in the Dar es Salaam and Pwani Grid Network including the following portions of lines: Kinyerezi – Ubungo 220 kV; Kinyerezi – Gongo la Mboto – Mbagala – Kurasini 132 kV; Chalinze – Hale – Arusha 132 kV; and Ubungo – Makumbusho 132 kV which had exceeded their thermal limits. Therefore, these lines could not transmit all demanded power. This lead to introduction of new lines such as: 414 km of 400 kV Singida –

The proposed increase of power generation in Mbeya, Iringa, Pwani and Dar es Salaam regions has necessitated the reinforcement of the 220 kV lines in these areas so that power can be evacuated to the load centres. Following this, 400 kV transmission lines of 253 km JNHPP – Chalinze – Kinyerezi; 345 km of 400 kV Chalinze – Dodoma; and 616 km Iringa – Kisada – Mbeya – Tunduma – Sumbawanga, to mention the few, are planned for construction as per **Tables 4-8, 4-9 and 4-10**.



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Table 4-1: Parameters of the Existing Transmission Line System

NO.	FROM - TO SUBSTATION	VOLTAGE (KV)	ROUTE LENGTH (KM)	NO. OF TOWERS	No. OF CIRCUITS	TYPE OF SUPPORT	TOWER CONFIG	TYPE & NO. OF INSULATORS/PHASE	CONDUCTOR TYPE AND SIZE (Nominal Al)	YEAR COMMISSIONED	CURRENT RATING*1 (AMPS)	FULL RATING (MVA)	NORMAL RATING (MVA)
1	MOROGORO-UBUNGO 1st	220	172	456	1	GUYED	HORIZONTAL	15/16 STANDARD TYPE	BLUEJAY 565.5 sq mm ACSR	1975	1092	416	333
2	KINYEREZI - MOROGORO	220	180	499	1	SELF SUPPORT LATTICE		15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	1975	1092	416	365.7984
	Section I (Kinyerezi - Kimara)	220	8	37	1	SELF SUPPORT LATTICE	VERTICAL	15/16 GLASS	2 x BLUEJAY 565.5 sq mm ACSR	1975	2*1092	2*416	2*365.7984
	Section II (Kimara - Morogoro)	220	172	462	1	SELF SUPPORT LATTICE	TRIANGULAR	15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	1995	1092	416	333
3	KINYEREZI - UBUNGO	220	15	36	1	SELF SUPPORT LATTICE		15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	1995	1092	416	365.7984
	Section I (Kinyerezi - Kimara)	220	8	23	1	SELF SUPPORT LATTICE	VERTICAL	15/16 GLASS	2 x BLUEJAY 565.5 sq mm ACSR	1995	2*1092	2*416	2*365.7984
	Section II (Kimara - Ubungo)	220	7	13	1	SELF SUPPORT LATTICE	TRIANGULAR	15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	1993	1092	416	333
4	KIDATU-MOROGORO 1ST	220	128	320	1	GUYED	HORIZONTAL	15/16 STANDARD TYPE	BLUEJAY 565.5 sq mm ACSR	1975	1092	416	333
5	MOROGORO- KIDATU 2nd	220	130	328	1	SELF SUPPORT	TRIANGULAR	15/16 STANDARD TYPE	BLUEJAY 565.5 sq mm ACSR	1993	1092	416	333
6	KIDATU- IRINGA	220	163	441	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
7	IRINGA- MUFINDI	220	130	336	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
8	IRINGA- MTERA	220	107	297	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
9	MTERA- DODOMA	220	130	303	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
10	DODOMA- SINGIDA	220	214.3	528	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
11	SINGIDA- SHINYANGA	220	205	532	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
12	SHINYANGA - MWANZA (NYAKATO)	220	140	336	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
	Shinyanga - T-Point	220	84.4	202	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
	T-Point - MWANZA (NYAKATO)	220	55.8	134	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
	T-Point - MABUKI	220	416m	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1988	679	259	207
13	MUFINDI- MBEYA	220	220	544	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
	MUFINDI - T-Point	220	60.3	149	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
	T-Point - MBEYA	220	159.7	395	1	SELF SUPPORT	HORIZONTAL	15/16 STANDARD TYPE	BISON 350 sq. mm ACSR	1985	679	259	207
	T-Point - MAKAMBAKO	220	404m	n/a	1	n/a	n/a	n/a	33kv CU/XPLE/5WA/PVC 3X240 sq.mm single	1985	679	259	207
14	UBUNGO - MLANDIZI	132	48.8	168	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1963	406	93	74
15	MLANDIZI-CHALINZE	132	48.2	166	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1963	406	93	74
16	CHALINZE- MOROGORO	132	82	288	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1967	406	93	74
17	CHALINZE- HALE	132	175	534	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1963	406	93	74
18	HALE-TANGA	132	60	389	1	WOODEN H-POLE	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1971	406	93	74
	HALE-MAWENI	132	53	344	1	WOODEN H-POLE	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1971	406	93	74
	MAWENI -TANGA	132	7	45	1	WOODEN H-POLE	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1971	406	93	74
19	HALE- SAME	132	173	561	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1975	406	93	74
	SAME-T-point	132	99.3	322	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1975	406	93	74
	T-Point - HALE	132	73.7	239	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1975	406	93	74
	T-Point - Kasiga	132	308m	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1975	406	93	74

NO.	FROM - TO SUBSTATION	VOLTAGE (KV)	ROUTE LENGTH (KM)	NO. OF TOWERS	No. OF CIRCUITS	TYPE OF SUPPORT	TOWER CONFIG	TYPE & NO. OF INSULATORS/PHASE	CONDUCTOR TYPE AND SIZE (Nominal Al)	YEAR COMMISSIONED	CURRENT RATING*1 (AMPS)	FULL RATING (MVA)	NORMAL RATING (MVA)
20	SAME- KIYUNGI	132	102	291	1	GUYED	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1975	406	93	74
21	UBUNGO- ILALA 1st	132	9.5	25	2	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1963	962	440	352
22	NYAKATO (MWANZA)-MUSOMA	132	210	628	1	SELF SUPPORT	HORIZONTAL	9/ 10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	NYAKATO (MWANZA)-T-Point	132	133.4	399	1	SELF SUPPORT	HORIZONTAL	9/ 10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	T-Point - MUSOMA	132	76.2	228	1	SELF SUPPORT	HORIZONTAL	9/ 10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	T-Point - BUNDA	132	326m	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	9/ 10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
23	SHINYANGA - TABORA	132	203	587	1	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	SHINYANGA - Lusu	132	60	174	1	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	Lusu-Tabora	132	143	413	1	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
	T-Point - LUSU	132	345m	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	9/10 STANDARD TYPE	1 x WOLF 150 sq. mm ACSR	1989	406	93	74
24	NYM - KIYUNGI	66	53	463	1	WOODEN POLES	TRIANGULAR	5/ 6 STANDARDTYPE	RABBIT 50 sq. mm ACSR	1968	197	23	18
25	KIYUNGI - ARUSHA	66	78	625	1	WOODEN POLES	TRIANGULAR	5/ 6 STANDARDTYPE	RABBIT 50 sq. mm ACSR	1967	197	23	18
26	BABATI- KONDOA	66	85	251	1	SELF SUPPORT	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 150 sq. mm ACSR	1999	406	46	37
27	BABATI- MBULU	66	85	192	1	SELF SUPPORT	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 150 sq. mm ACSR	1999	406	46	37
28	MBULU- KARATU	66	65	172	1	SELF SUPPORT	TRIANGULAR	7/ 7 STANDARD TYPE	WOLF 150 sq. mm ACSR	1999	406	46	37
29	KIHANSI- IRINGA	220	96.9	279	1					1998	1,092	416	333
	Section I: Kihansi - Escapment	220	1.67	2	1	SELF SUPPORT	TRIANGULAR	15/ 16 STANDARD TYPE	PHEASANT 645.1 sq. mm ACSR	1998	1,187	452	362
	Section II: Escapement - Iringa	220	95.23	277	1	SELF SUPPORT	TRIANGULAR	15/ 16 STANDARD TYPE	BLUEJAY 565.5 sq mm ACSR	1998	1,092	416	333
30	KIHANSI - KIDATU	220	180	529	1	SELF SUPPORT	TRIANGULAR	15/ 16 STANDARD TYPE	BLUEJAY 565.5 sq mm ACSR	1999	1,092	416	333
31	UBUNGO- ILALA 2nd	132	9.5	25	1	SELF SUPPORT	VERTICAL DOUBLE CKT	11/ 12 STANDARD TYPE	WOLF 150 sq. mm ACSR	1999	962	440	352
32	UBUNGO- KIPAWA (FZIII)	132	11	35	1	SELF SUPPORT	VERTICAL DOUBLE CKT	11/ 12 STANDARD TYPE	WOLF 150 sq. mm ACSR	2000	406	93	74
33	PANGANI FALLS-TANGA	132	63.5	223	1	SELF SUPPORT		10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR	1995	659	301	241
	Section I - (Pangani-Songa)	132	8.5	33	1	SELF SUPPORT	VERTICAL DOUBLE CKT	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR	1995	659	301	241
	Section II - (Songa - T-point)	132	45	155	1	SELF SUPPORT	TRIANGULAR	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR	1995	659	301	241
	Section III - (T-point - Tanga)	132	10	35	1	SELF SUPPORT	TRIANGULAR	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR	1995	659	301	241
	KANGE -T-point	132	285m	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR	1995	659	301	241
34	PANGANI FALLS - HALE	132	13.5	33	2					1995	659	301	241
	- Section I	132	8.5	33	1	SELF SUPPORT	VERTICAL	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR		659	301	241
	- Section II	132	5	10	1	SELF SUPPORT	TRIANGULAR	10/12 STANDARD TYPE	HAWK 241.6 sq. mm ACSR		659	301	241
35	SINGIDA-BABATI	220	150	424	1	SELF SUPPORT	TRIANGULAR	15/16 STANDARD TYPE	RAIL 483.8 sq. mm ACSR	1996	993	378	303
36	BABATI- NJIRO (ARUSHA)	220	162	433	1	SELF SUPPORT	TRIANGULAR	15/16 STANDARD TYPE	RAIL 483.8 sq. mm ACSR	1996	993	378	303
37	KYAKA - MTUKULA (Line to the border with UGANDA) Off Grid	132	30	85	1	SELF SUPPORT	HORIZONTAL	10/12 STANDARD TYPE	TIGER 125 sq. mm ACSR	1992	361	83	66
38	KYAKA - KIBETA (BUKOBA) Off Grid	132	54.5	157	1	SELF SUPPORT	HORIZONTAL	10/12 STANDARD TYPE	TIGER 125 sq. mm ACSR	1992	361	83	66
39	SHINYANGA - BULYANHULU	220	129.5	277	1	SELF SUPPORT	HORIZONTAL	POLYMERIC TYPE	BISON 350 sq. mm ACSR	2000	679	259	207
40	SUMBAWANGA - KASESYA	66	93	569	1	MONOPOLE STEEL	TRIANGULAR	COMPOSITE TYPE	WOLF 150 sq. mm ACSR	2002	406	46	37

NO.	FROM - TO SUBSTATION	VOLTAGE (KV)	ROUTE LENGTH (KM)	NO. OF TOWERS	No. OF CIRCUITS	TYPE OF SUPPORT	TOWER CONFIG	TYPE & NO. OF INSULATORS/PHASE	CONDUCTOR TYPE AND SIZE (Nominal Al)	YEAR COMMISSIONED	CURRENT RATING**1 (AMPS)	FULL RATING (MVA)	NORMAL RATING (MVA)
41	BUNDA-KIBARA	66	50	300	1	WOODEN POLES	HORIZONTAL	5/6 STANDARD TYPE	WOLF 150 sq. mm ACSR	2007	197	23	18
42	MUSOMA-NYAMONGO	132	90	238	1	SELF SUPPORT	TRIANGULAR	POLYMERIC TYPE	WOLF 150 sq. mm ACSR	2011	406	93	74
43	SHINYANGA-BUZWAGI	220	108	237	1	SELF SUPPORT	TRIANGULAR	POLYMERIC TYPE	BISON 350 sq. mm ACSR	2000	679	259	207
44	UBUNGO - MAKUMBUSHO	132	7	37	1	SELF SUPPORT - MONOPOLE	VERTICAL	PORCELAIN	HAWK 241.6 sq. mm ACSR	2010	659	151	121
45	KIYUNGI - MAKUYUNI	66	34	172	1	SELF SUPPORT LATTICE	VERTICAL	PORCELAIN	WOLF 150 sq. mm ACSR	2012	406	46	37
46	UBUNGO - KUNDUCHI (I)	132	12	50	1	SELF SUPPORT LATTICE	HORIZONTAL	9/10 GLASS	HAWK 241.6 sq. mm ACSR	1980	406	93	74
47	KIYUNGI - NIRO (ARUSHA) - 1	132	71.6	208	1	SELF SUPPORT LATTICE	TRIANGULAR	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	1983	406	93	74
	I. KIYUNGI - KIA	132	35		1	SELF SUPPORT LATTICE	TRIANGULAR	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	1983	406	93	74
48	KIYUNGI - NIRO (ARUSHA) - 2	132	36.6		1	SELF SUPPORT LATTICE	TRIANGULAR	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	1983	406	93	74
	II. KIA - NIRO (ARUSHA)	132	70	207	1	SELF SUPPORT LATTICE	TRIANGULAR	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	2015	406	93	74
49	KIYUNGI - KIA	132	35	85	1	SELF SUPPORT LATTICE	TRIANGULAR	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	2015	406	93	74
	II. KIA - NIRO (ARUSHA)	132	35	122	1	SELF SUPPORT LATTICE	HORIZONTAL	9/10 PORCELAIN	HAWK 241.6 sq. mm ACSR	2015	406	93	74
50	KINYEZEI - FZII	132	3	16	1	SELF SUPPORT LATTICE	VERTICAL	9/10 GLASS	HAWK 241.6 sq. mm ACSR	2016	406	93	74
51	UBUNGO - KUNDUCHI (II)	132	12	65	1	MONOPOLE STEEL	VERTICAL	POLYMERIC TYPE	HAWK 241.6 sq. mm ACSR	2012	406	93	74
52	KUNDUCHI - ZANZIBAR (I)	132	64	96	1					1980	286	65	52
	Section I : Overhead (Kunduchi - Ras Kilomoni)	132	4	16	1	SELF SUPPORT LATTICE	HORIZONTAL	9/10 GLASS	HAWK 241.6 sq. mm ACSR	1980	286	65	52
	Section II : Submarine cable (Raskilomoni - Ras Fumba)	132	38	n/a	1	n/a	n/a	n/a	XLPE Type (X -Linked Polyethylene) Submarine	1980	286	65	52
	Section III: overhead (Ras Fumba - Zanzibar(mtoni))	132	22	80	1	SELF SUPPORT LATTICE	HORIZONTAL	9/10 GLASS	HAWK 241.6 sq. mm ACSR	1980	286	65	52
53	KUNDUCHI - ZANZIBAR (II)	132	63.6	132	1					2013	640	146	117
	Section I : Overhead (Kunduchi - Ras Kilomoni)	132	4.6	23	1	MONOPOLE STEEL	VERTICAL	POLYMERIC TYPE	HAWK 241.6 sq. mm ACSR	2013	640	146	117
	Section II : Submarine cable (Raskilomoni - Ras Fumba)	132	37	n/a	1	n/a	n/a	n/a	XLPE Type (X -Linked Polyethylene) Submarine cable, 94 sq.mm CU	2013	640	146	117
	Section III: overhead (Ras Fumba - Zanzibar(mtoni))	132	22	109	1	MONOPOLE STEEL	VERTICAL	POLYMERIC TYPE	HAWK 241.6 sq. mm ACSR	2013	640	146	117
54	IRINGA-DODOMA 1	220 (400)	224.6	590	1	SELF SUPPORT LATTICE	VERTICAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
55	IRINGA-DODOMA 2	220 (400)	224.6	590	1	SELF SUPPORT LATTICE	VERTICAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
56	DODOMA SINGIDA 1	220 (400)	216.5	563	1	SELF SUPPORT LATTICE	VERTICAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
57	DODOMA SINGIDA 2	220 (400)	216.5	563	1	SELF SUPPORT LATTICE	VERTICAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
58	SINGIDA SHINYANGA 1	220 (400)	228.9	594	1	SELF SUPPORT LATTICE	VERTICAL/HORIZONTAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
59	SINGIDA SHINYANGA 2	220 (400)	228.9	594	1	SELF SUPPORT LATTICE	VERTICAL/HORIZONTAL	POLYMERIC TYPE	2 X BLUEJAY 565.5 sq mm ACSR	2016	2*1092	416	2*365.79
60	MTWARA - MAUMBIKA (LINDI)	132	80	487	1	WOODEN POLE	HORIZONTAL	9/10 GLASS	HAWK 241.6 sq. mm ACSR	2017	286	65.38	54.8
61	KURASINI - MBAGALA	132	15.1	44	1	Lattice tower (38), Steel	vertical	Toughned glass 9/11	HAWK 241.6 sq. mm ACSR	2017	659	151	120.8
62	MBAGALA - FZII	132	16.2	65	1	Lattice tower (48), Steel	vertical	Toughned glass 9/12	HAWK 241.6 sq. mm ACSR	2017	659	151	120.8
63	FZII - KIPAWA(FZIII)	132	7.4	57	1	Steel Poles	vertical	Toughned glass 9/13	HAWK 241.6 sq. mm ACSR	2017	659	151	120.8
64	ILALA - New City Center	132	3.1		1								
	Section I: Overhead Line	132	1.3	5	1	Lattice Tower	TRIANGULAR	Toughned glass 9/13	HAWK 241.6 sq. mm ACSR	2016	659	151	120.8
	Section II:Underground cable	132	1.8	n/a	1	n/a	n/a	n/a	XLPE/CWS/HOPE (IEC60840) core:1x 1000sq.mm; Overall dia:83mm; 766A single conductor/phase	2016	659	151	120.8

NO.	FROM - TO SUBSTATION	VOLTAGE (KV)	ROUTE LENGTH (KM)	NO. OF TOWERS	No. OF CIRCUITS	TYPE OF SUPPORT	TOWER CONFIG	TYPE & NO. OF INSULATORS/PHASE	CONDUCTOR TYPE AND SIZE (Nominal Al)	YEAR COMMISSIONED	CURRENT RATING**1 (AMPS)	FULL RATING (MVA)	NORMAL RATING (MVA)
64	New City Center - MAKUMBUSHO	132	6.67	n/a	1	n/a	n/a	n/a	XLPE/CWS/HDPE (IEC60840) core:1x 1000sq.mm; Overall dia:83mm; 766A single conductor/phase	2016	659	151	120.8
65	MAKAMBAKO - MADABA	220	110	317	1	SELF SUPPORT LATTICE	HORIZONTAL	Toughened glass insulators are proposed	The recommended conductor is an aluminium steel reinforced conductor (ACSR) Bluejay 565.5 mm² single conductor	2018	1092	416	332.8
66	MADABA-SONGEA	220	140	403	1	SELF SUPPORT LATTICE	HORIZONTAL	Toughened glass insulators are proposed	The recommended conductor is an aluminium steel reinforced conductor (ACSR) Bluejay 565.5 mm² single conductor	2018	1092	416	332.8
67	UBUNGO-UGP1	220	1.5	n/a	1	n/a	n/a	n/a	XLPE/CWS/HDPE (IEC60840) core:3 x single core 500sq.mm Aluminium cable	2008	1092	416	332.8
68	UBUNGO 220 - UBUNGO 132 (I) (T4)	132	0.1	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	2008	1092	416	332.8
69	UBUNGO 220 - UBUNGO 132 (II) (T5)	132	0.1	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	2008	1092	416	332.8
70	UBUNGO 220 - SONGAS	132	0.05	2 Gantry towers	1	SELF SUPPORT	HORIZONTAL	15/16 GLASS	BLUEJAY 565.5 sq mm ACSR	2004	1092	416	332.8
71	UBUNGO 220 - UGP2	132	0.05	n/a	1	n/a	n/a	n/a	145kv XLPE/CWS/HDPE (IEC60840) core:1x 630sq.mm Aluminium conductor	2012	1092	416	332.8
72	KUNDUCHI - WAZO	132	5	15	1	Concrete poles	Triangular	10&9	HAWK 241.6 sq. mm ACSR		659	151	120.8
73	KUNDUCHI - TEGETA GAS PLANT	132	0.3	n/a	1	n/a	n/a	n/a	XLPE/CWS/HDPE (IEC60840) core:1x 300sq.mm Aluminium cable	2009	659	151	120.8
74	NYAKATO 220 KV - NYAKATO HFO PLANT	220	0.2	n/a	1	n/a	n/a	n/a	A2XS(F)L3YsR(AL)2Y-GC 1x300RM/50 127/220(245)kV acc.to IEC 62067 note:300 sq.mm	2013	659	151	120.8

Note: Normal Rating = Full Rating * 80%

Voltage	Total Length (Above Table)	No. of Lines (Above Table)	Comments
400kV	670	3	
220kV	3010.7	21	
132kV	1672.57	32	2 x Submarine Cables Included
66kV	543	8	
Total	5896.27	64	

VOLTAGE (KV)	ROUTE LENGTH (KM)							
	2020	2019	2018	2017	2016	2015	2014	2013
400kV	670	670	670	670	670	0	0	0
220kV	3010.7	3010.7	2,922.14	2,833.57	2,745	2,745	2,227.85	1,710.69
132kV	1672.57	1672.6	1657.06	1641.53	1,626	1,626	1,583.75	1,543.59
66kV	543	543	543	543	543	543	543	543
Total	5896.27	5896.3	5792.2	5688.1	4,914	4914	4354.6	3795.19

Source: TANESCO (December 2019)

4.1.3. Development of New Interconnectors

Power interconnection between countries is essential to increase the exchange capacity within the regions, to ensure reliability and security of power supply through power trading. The operational experienced in recent years lead to necessary adjustments of the plans for establishing new interconnectors. These interconnectors are:

- i. **Tanzania (Singida – Arusha – Namanga) – Kenya (Isinya) 400 kV interconnection project:** The project is under construction and is expected to be commissioned in 2021;
- ii. **Tanzania – Zambia 400 kV interconnection project:** The construction of the project is expected to commence in April 2021 and commissioned by 2023;
- iii. **Tanzania (Nyakanazi – Kyaka) – Uganda (Masaka) 400 kV interconnection project:** The project is planned to be commissioned by 2025;
- iv. **Tanzania – Mozambique 400 kV interconnection project:** Inter-Utility Memorandum of Understanding (IUMOU) for Construction of Tanzania-Mozambique Interconnector between Electricidade de Mozambique (EDM) and TANESCO was extended in June 2018;
- v. **Tanzania, Rwanda, and Burundi Interconnection Project:** The project has been driven by the construction of 80 MW hydropower project at Rusumo border. The project will enable the National Grids of the three countries to interconnect through the 220 kV transmission line, which is expected to be commissioned in 2021;
- vi. **Tanzania – Malawi 400 kV interconnection project:** Tanzania completed a pre-feasibility study up to the border of Malawi, while Malawi has completed a feasibility study to the border of Tanzania. TANESCO and ESCOM (Malawi) are on discussion of developing the project;
- vii. **Tanzania (Shinyanga – Mwanza – Musoma) – Kenya (Kilgories) 400 kV interconnection project:** The project is under the planning stage, with initial proposals for its commissioning in 2025; and

viii. **Tanzania (Kigoma) – Burundi (Itaba) 220 kV Interconnection Project:** The project is under planning stage.

ix. **Tanzania (Rukwa) – DRC (Katanga Province) 400 kV Interconnection Project:** The project is under planning stage.

Figures 4-2, 4-3 and 4-4 show the grid network of 400 kV, 220 kV and 132 kV lines in short, medium and long term plan.

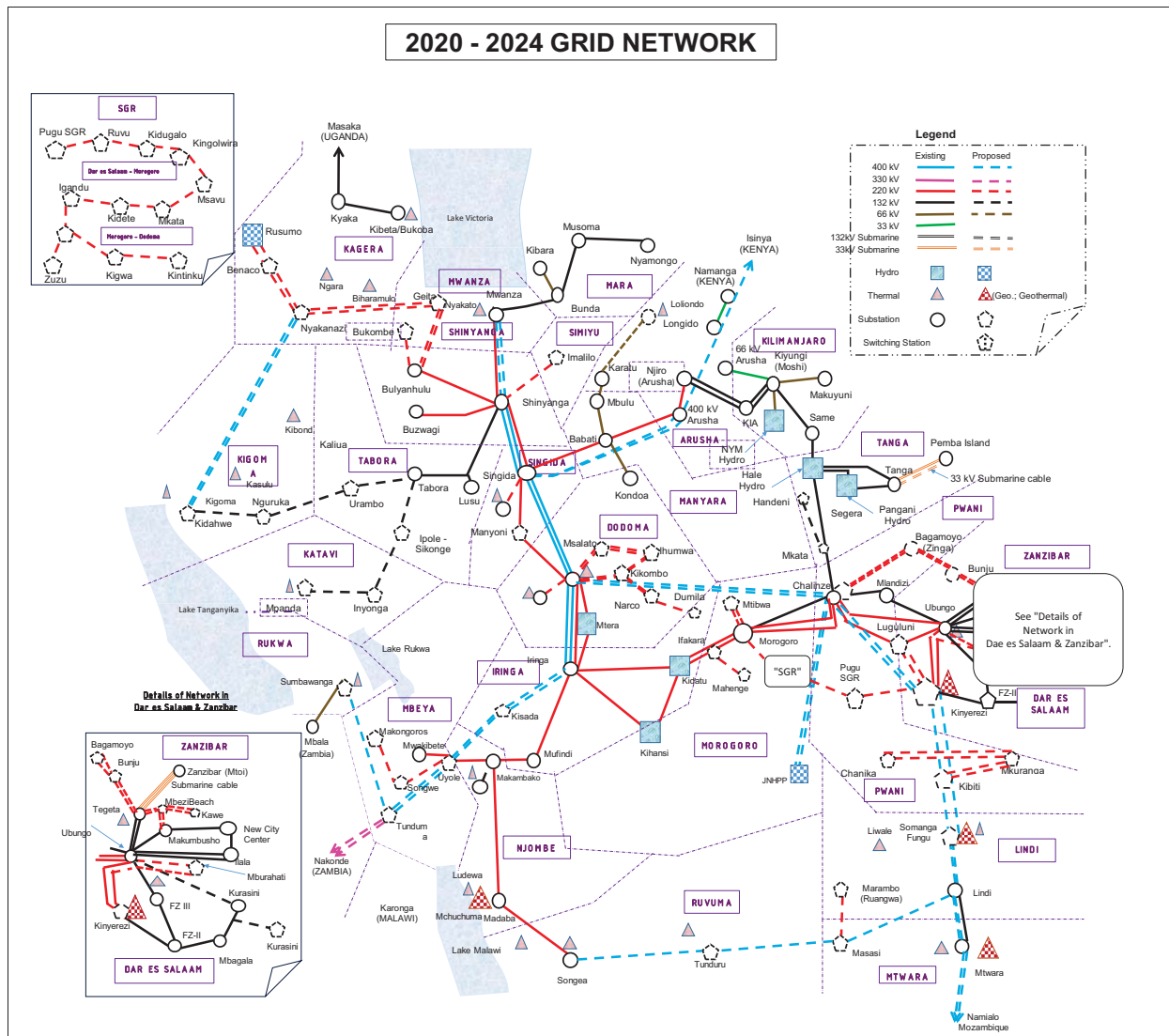


Figure 4-2: Generation and Transmission Plan – Year 2020 – 2024

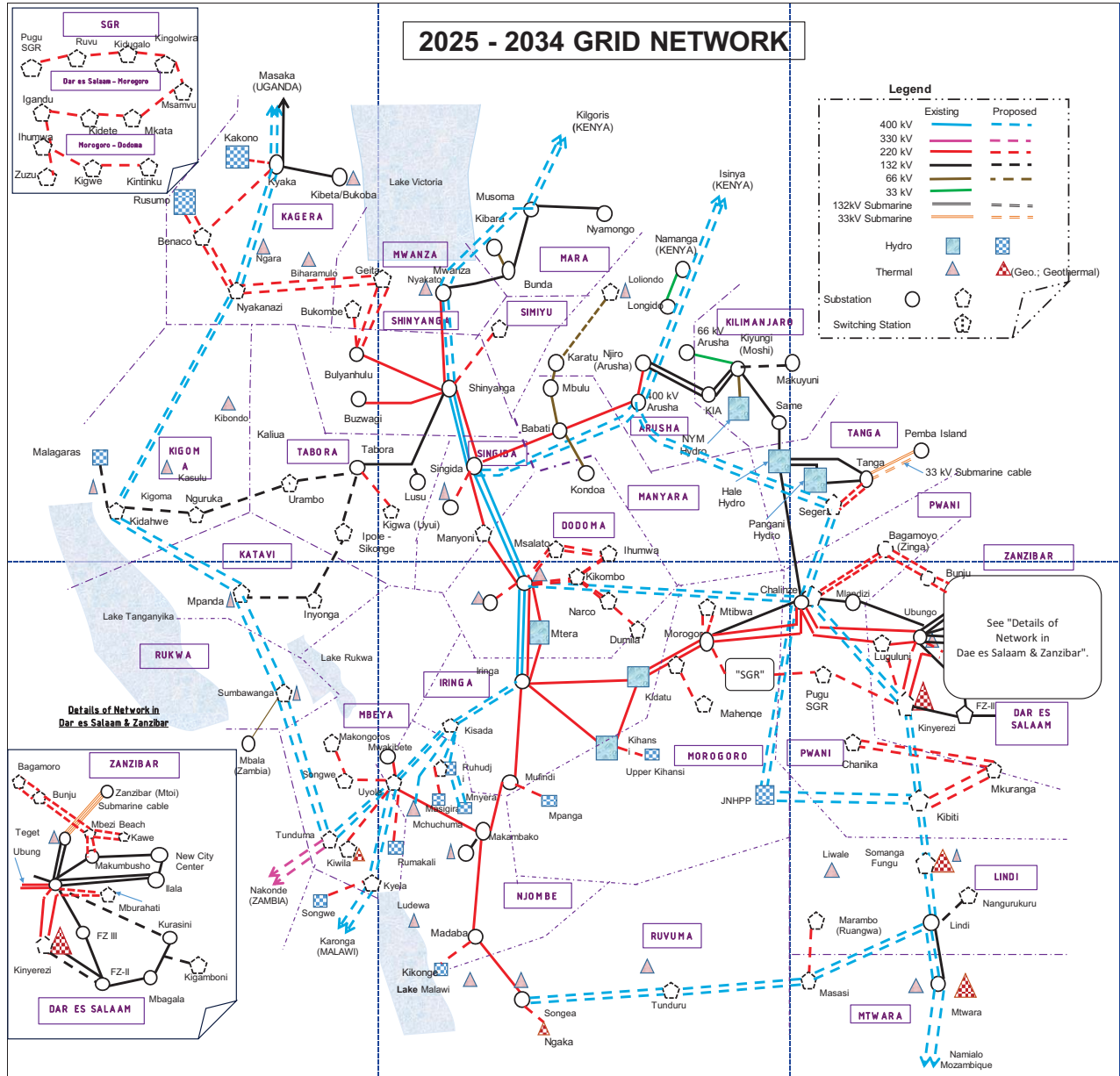


Figure 4-3: Generation and Transmission Plan – Year 2034

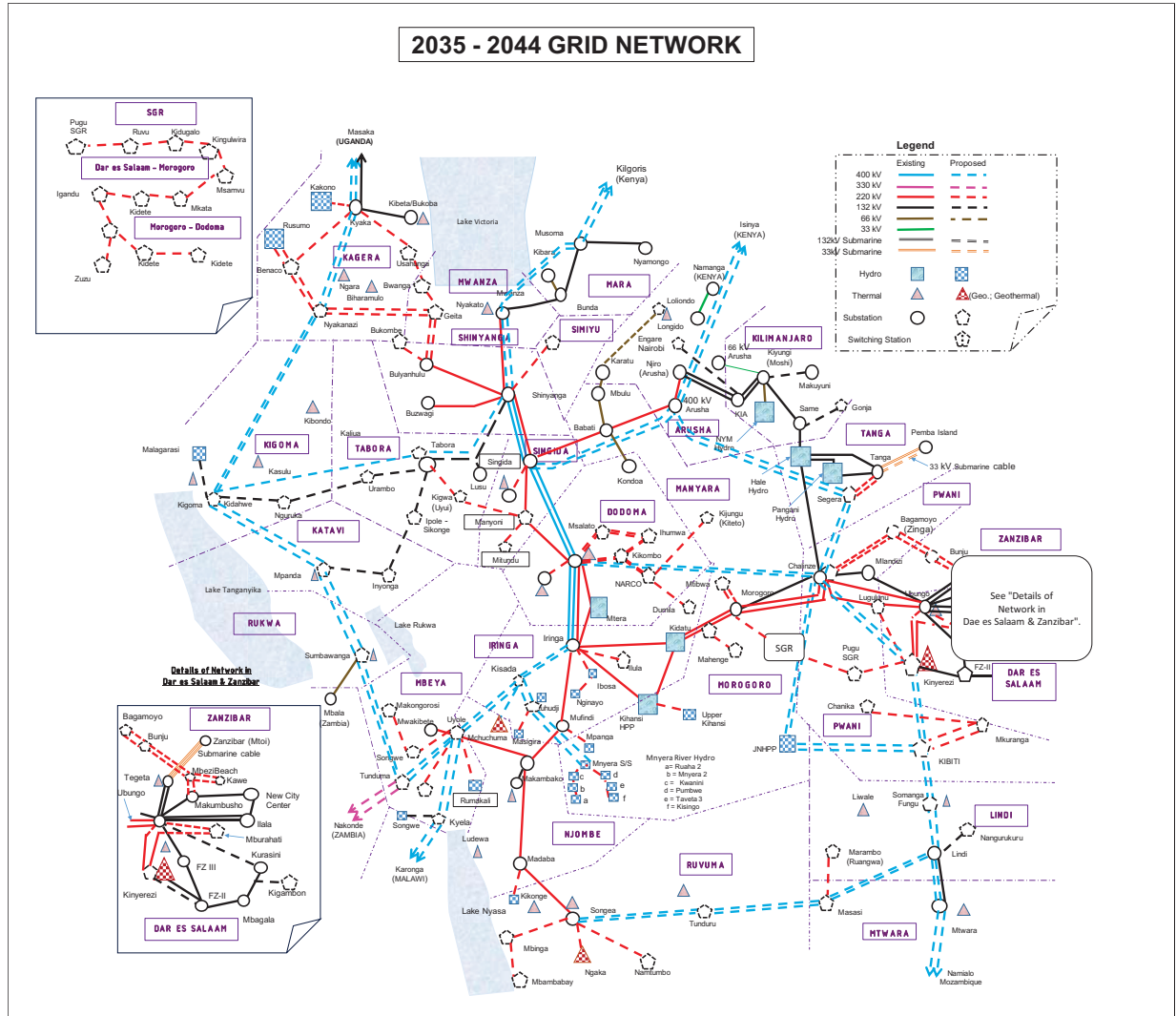


Figure 4-4: Generation and Transmission Plan – Year 2044

4.1.4. Drivers for Grid Development

4.1.4.1. Reinforcement of Grid Security

The Government intend to connect all isolated grid and reinforce the National Grid in order to ensure grid reliability and security of power supply in the country. In this regard, the Western, Northern and Lake Zones need new transmission capacity addition. Similarly, the South-West and Coast Zone areas need transmission reinforcement to supply power to the load centers.

The Government has initiated several projects to reinforce Grid security and reliability, particularly in the short term. These projects include: 400 kV Singida – Arusha – Namanga; 400 kV transmission lines for evacuation of power in JNHPP (JNHPP –

Chalinze, Chalinze – Dodoma and Chalinze – Kinyerezi, 220 kV Chalinze – Bagamoyo); 400kV Iringa – Mbeya – Tunduma – Sumbawanga; 220 kV Kinyerezi – Ubungo – Mburahati; 220 kV Kibiti – Mkuranga – Chanika; 400 kV Mtwara – Somanga; Somanga – Kibiti – Kinyerezi and JNHPP – Kibiti; and 400 kV Nyakanazi – Kigoma – Mpanda – Sumbawanga.

4.1.4.2. Grid Expansion to Explore Renewable Energy Resources

Development of renewable energy requires a stable grid to the point where renewable energy sources are available. An increase in the generation from renewable energy will further increase variations in the grid power system between years with low precipitation and years with high precipitation. Therefore, to accommodate renewable energy sources to the grid it requires stability of the National Grid. Initiatives are in place to motivate renewable power generation through the procurement of wind and solar project developers to a maximum of 200 MW and 150 MW, respectively, as a first round.

4.1.4.3. Reliable Grid Creates Value

The load forecast shows that there will be high growth of power demand mainly due to the increase of industrial, agricultural, construction and extractive activities. The growth in these activities will lead to higher levels of energy consumption. It is anticipated that the grid system needs to be reinforced for a more reliable connection between regions and contribute to uniform electricity prices across the country.

4.1.4.4. The Future of Tanzania is Electric

The Government's policy is to attain access rate to electricity of more than 75 percent by 2025 and 100 percent by 2030. In addition to that, the electricity demand in transport and industrial sectors is expected to grow hence there is need to strengthen grid capacity.

4.2. Transmission Planning Criteria

Planning methodologies and criteria used in PSMP 2016 Update were reviewed and used in this Update. Transmission planning considers the operation of the power system under two possible criteria, which are: Normal operating conditions (N-0) and Contingency operating conditions (N-1).

4.2.1.Operating Conditions

(i) Normal operating conditions (N-0)

Under normal operating conditions, the transmission infrastructure is assumed to be entirely available (no equipment has been forced out of service).

(ii) Contingency Operating Conditions (N-1)

The principle is that the National Grid will be operated and scheduled based on the so called N-1 criterion. This means that under normal system conditions a fault in one single component (line or transformer) will have no influence on the general power supply. This criterion establishes security of supply as a stronger driving force in grid development.

In this Chapter, the Plan has set a target to rectify all known breaches of the planning criteria by 2044. The deadline has been predetermined to ensure that there is a capacity to carry out investment projects related to additional priorities. Therefore, only outages of equipment rated at 220 kV or above will be considered under the N-1 criteria.

It should be noted that in most cases for voltage class of 220 kV and above, the line thermal capability is not the main limiting factor for the amount of power transferred. Transfer limits are usually dictated by steady state stability, dynamic stability and voltage stability.

4.2.2.System Voltage Criteria

The acceptable voltage range for operating the system is based on factors such as equipment limitations and motor operation under normal and contingency conditions as shown in **Table 4-2**

Table 4-2: Acceptable Operating Voltage Range

Condition	Acceptable Voltage Range
Normal System Conditions	95% – 105%
Contingency Conditions	90% – 110%

Note: Healthy systems usually target a minimum voltage close to 1.0 per unit (p.u) in the bulk system.

4.2.3. Equipment Thermal Loading Criteria

The transmission system must be planned/designed to allow all transmission lines and equipment to operate within the following limits as indicated in **Table 4-3**.

Table 4-3: Thermal Loading Criteria

Condition	Thermal Loading Limit
Normal System Conditions	Defined Normal Load Capacity
System Design Contingencies of Long Duration (i.e. an outage involving the failure of a transformer)	Defined Normal Load Capacity
System Design Contingencies of Short Duration (i.e. not involving a transformer)	Defined Emergency Load Capacity (120% of normal rating for 10 hours per year)

4.2.4. Grid Substation Load Forecast

The grid substation load forecast updates are shown in **Tables 4-4, 4-5** and **4-6** in short, medium and long term respectively. Individual existing and future grid substations were modelled in the load flow simulations in short, medium and long term so that the corresponding total updated load forecasts in all regions were used as one of the inputs.

Table 4-4: 2024 Grid Substation Load forecast

LOAD DISTRIBUTION FOR 2024				
AREA	BusBar No.	Busbar Name	MW	MVAR
Arusha	505001	Tarusha_3B1 33.000	43.68	14.36
	505281	Tnjiro_3B1 33.000	34.16	11.23
	505282	Tnjiro_3B2 33.000	34.16	11.23
	Total		112.00	36.81
Manyara	505091	Tbabati_3B1 33.000	2.34	0.77
	505092	Tbabati_3B2 33.000	2.34	0.77
	505681	Tkaratu_3B1 33.000	3.21	1.05
	505721	Tmbulu_3B1 33.000	0.70	0.23
	505701	Tkondoa_3B1 33.000	1.60	0.53
	505701	Tkondoa_3B1 33.000	0.37	0.12
	506093	Tbabati_7B3 11.000	0.90	0.30
	506094	Tbabati_7B4 11.000	0.90	0.30
	506701	Tkondoa_7B1 11.000	0.64	0.21
Dar es Salaam	Total		13.00	4.27
	502182	Tkinye1_2B2 220.00	112.76	37.06
	503024	Pug_220.00	13.27	4.36
	503181	Tkinye1_1B1 132.00	132.66	43.60
	503311	Tubu220_1B1 132.00	66.33	21.80
	503461	Tkipawa_1B1 132.00	66.33	21.80
	503651	Twazo_1B1 132.00	6.63	2.18
	505321	Tubu110_3B1 33.000	26.53	8.72
	505322	Tubu110_3B2 33.000	26.53	8.72
	505391	Tilala_3B1 33.000	9.12	3.00
	505391	Tilala_3B1 33.000	9.12	3.00
	505392	Tilala_3B2 33.000	9.12	3.00
	505392	Tilala_3B2 33.000	9.12	3.00
	505461	Tkipawa_3B1 33.000	66.33	21.80
	505462	Tkipawa_3B2 33.000	66.33	21.80
	505481	Tkunduc_3B1 33.000	10.28	3.38
	505482	Tkunduc_3B2 33.000	10.28	3.38
	505511	Tmkumbu_3B1 33.000	26.53	8.72
	505512	Tmkumbu_3B2 33.000	26.53	8.72
	505571	Tncc_3B1 33.000	8.29	2.73
	505572	Tncc_3B2 33.000	8.29	2.73
	505732	Tfzii_33B1 33.000	26.53	8.72
	505733	Tmbgl_33B1 33.000	26.53	8.72
	505734	Tkurs_33B1 33.000	6.63	2.18
	505735	Tlemugur_3B133.000	19.90	6.54
	505799	Tubungo_3B1 33.000	106.13	34.88
	505801	Mbhat_1_33.000	26.53	8.72
	505803	Lugulun_33.000	39.80	13.08
	505811	Kunduch_33.000	6.63	2.18
	505815	Chanik_33.000	19.90	6.54
	Total		989.00	325.07
Coast	503025	Ruvu_220.00	1.82	0.60
	503026	Kidugal_220.00	1.82	0.60
	505551	Tmlandi_3B1 33.000	2.73	0.90
	505552	Tmlandi_3B2 33.000	2.73	0.90
	505761	Tchali_3B1 33.000	4.55	1.50
	505762	Tchali_3B2 33.000	4.55	1.50
	505812	Kawe_33.000	0.91	0.30
	505813	Bunju_33.000	0.91	0.30
	505814	Zinga_33.000	0.91	0.30
	505816	Mkurang_33.000	7.28	2.39
	505817	Kibit_33.000	7.28	2.39
	507666	Tchali_3B3 33.000	9.10	2.99
Dodoma	Total		44.60	14.66
	502022	Tdodoma_2B2	15.76	5.18
	505021	Tdodoma_3B1 33.000	3.50	1.15
	505022	Tdodoma_3B2 33.000	5.25	1.73
	505781	Tdodoma_3B1 33.000	7.00	2.30
Iringa	Total		31.51	10.36
	505031	Tiringa_3B1 33.000	6.41	2.11
	505032	Tiringa_3B2 33.000	6.54	2.15
	505171	Tkihanah_3B1 33.000	3.25	1.07
	505251	Tmufind_3B1 33.000	10.66	3.51
	505738	Tkisada_3B1 33.000	1.06	0.35
Njombe	506251	Tmufind_7B1 11.000	5.08	1.67
	Total		33.00	10.85
	505221	Tmkamba_3B1 33.000	24.00	7.89
Total			24.00	7.89

LOAD DISTRIBUTION FOR 2024 (Continues)				
AREA	BusBar No.	Busbar Name	MW	MVAR
Kagera	501070	Tkaronga 4B	4.78	1.57
	501081	Tz-Ug 400.00	9.55	3.14
	504005	Tkyaka 1B 132.00	0.96	0.31
	505754	Tnyaka 3B 33.000	0.14	0.05
	505758	Tnickel 3B 33.000	1.43	0.47
	505800	Ngara 33.000	0.14	0.05
		Total	17.00	5.59
Kigoma	505809	Kigoma 33.000	14.00	4.60
		Total	14.00	4.60
K'Manjaru	505441	Tkia 3B1 33.000	9.43	3.10
	505442	Tkia 3B2 33.000	9.43	3.10
	505471	Tkiyung 3B1 33.000	28.29	9.30
	505601	Tsame 3B1 33.000	3.51	1.15
	505711	Tmakuyu 3B1 33.000	7.67	2.52
	505712	Tmakuyu 3B2 33.000	7.67	2.52
		Total	66.00	21.69
Lindi	504002	Tlindi 1B1 132.00	0.44	0.14
	505746	Tsomanga 3B133.000	2.67	0.88
	505747	Tsomanga 3B233.000	2.67	0.88
	505748	Tlindi 3B1 33.000	2.67	0.88
		Total	8.00	2.63
Mara	505361	Tbunda 3B1 33.000	0.26	0.08
	505362	Tbunda 3B2 33.000	2.33	0.77
	505561	Tmusoma 3B1 33.000	2.60	0.85
	505562	Tmusoma 3B2 33.000	2.60	0.85
	505581	Tnyamon 3B1 33.000	10.77	3.54
	505581	Tnyamon 3B1 33.000	1.86	0.61
	505691	Tkibara 3B1 33.000	1.59	0.52
		Total	22.00	7.23
Mbeya	505051	Tmbeya 3B1 33.000	10.14	3.33
	505052	Tmbeya 3B2 33.000	10.14	3.33
	505739	Tmbeya 3B1 33.000	5.07	1.67
	505740	Tmbeya 3B2 33.000	5.07	1.67
	505759	Tkyela 3B 33.000	13.52	4.44
	505760	Tkyela 3B2 33.000	13.52	4.44
	507002	Ttundu 33B2 330.00	40.55	13.33
		Total	20.28	6.66
Songwe	505741	Ttundu 3B1 33.000	4.00	1.31
	505742	Ttundu 3B2 33.000	4.00	1.31
		Total	8.00	2.63
Morogoro	502231	Tmorogo 2B1 220.00	21.45	7.05
	503027	Kinglwir 220.00	7.15	2.35
	503231	Tmorogo 1B1 132.00	7.15	2.35
	505151	Tkidath 3B1 33.000	0.84	0.28
	505152	Tkidath 3B2 33.000	0.81	0.27
	505231	Tmorogo 3B1 33.000	7.15	2.35
	505232	Tmorogo 3B2 33.000	21.45	7.05
	505820	Mtibw 33.000	20.02	6.58
		Total	86.00	28.27
Mtwara	504003	Tmtwara 3B1 132.00	11.67	3.83
	505751	Tmtwara 1B2 33.000	23.33	7.67
		Total	35.00	11.50
Mwanza	505261	Tmwanza 3B1 33.000	8.73	2.87
	505261	Tmwanza 3B1 33.000	9.85	3.24
	505262	Tmwanza 3B2 33.000	9.85	3.24
	505201	Tmabuki 3B1 33.000	6.57	2.16
		Total	35.00	11.50
Geita	505753	Tgeita 3B 33.000	26.00	8.55
		Total	26.00	8.55
Rukwa	504732	Tsumb 6B1 66.000	10.91	3.59
	505806	Mpanda 33.000	13.09	4.30
		Total	24.00	7.89
Ruvuma	505736	Tmadaba 3B1 33.000	14.77	4.85
	505737	Tsongea 3B1 33.000	9.23	3.03
		Total	24.00	7.89
Shinyanga	505071	Tshinya 3B1 33.000	3.65	1.20
	505071	Tshinya 3B1 33.000	3.65	1.20
	505071	Tshinya 3B1 33.000	3.65	1.20
	505111	Tbulyan 3B1 33.000	4.45	1.46
	505112	Tbulyan 3B2 33.000	3.82	1.25
	505121	Tbuzwag 3B1 33.000	18.83	6.19
	505501	Tlusu 3B1 33.000	6.94	2.28
		Total	45.00	14.79
Simiyu	505810	Simiyu	19.00	6.24
		Total	19.00	6.24
Singida	505081	Tsingid 3B1 33.000	11.50	3.78
	505082	Tsingid 3B2 33.000	11.50	3.78
		Total	23.00	7.56
Tabora	505621	Ttabora 3B1 33.000	0.95	0.31
	505622	Ttabora 3B2 33.000	0.16	0.05
	505804	Ipole 33.000	4.23	1.39
	505805	Inyonga 33.000	2.85	0.94
	505807	Urambo 33.000	3.17	1.04
	505808	Nguruka 33.000	11.63	3.82
		Total	23.00	7.56
Tanga	503421	Tkange 1B1 132.00	27.29	8.97
	504008	Tsegera 1B1 132.00	39.93	13.12
	505381	Thalehy 3B1 33.000	2.33	0.77
	505381	Thalehy 3B1 33.000	2.33	0.77
	505421	Tkange 3B1 33.000	3.33	1.09
	505432	Tkasiga 3B2 33.000	7.19	2.36
	505531	Tmaweni 3B1 33.000	2.00	0.66
	505631	Ttanga 3B1 33.000	3.33	1.09
	505632	Ttanga 3B2 33.000	3.33	1.09
	505633	Ttanga 3B3 33.000	4.99	1.64
	505818	Handen 33.000	9.98	3.28
	505819	Mkat 33.000	9.98	3.28
		Total	116.00	38.13
Zanzibar - Pemba	503661	Tzanz1 1B1 132.00	18.35	6.03
Zanzibar - Unguja	503671	Tzanz12 1B1 132.00	113.89	37.43

Source: PSMP 2020 Update Team Compilation

Table 4-5: 2034 Grid Substation Load forecast

LOAD DISTRIBUTION FOR 2034				
AREA	Bus No.	Bus Name	MW	MVAR
Arusha	51211	Nji132Mb 132.00	393.00	129.17
	51501	Isi400Mb 400.00	200.00	65.74
	Total		593.00	194.91
Manyara	50116	Bab066Mb 66.000	22.35	7.35
	50716	Kar066Mb 66.000	43.60	14.33
	50916	Mbu066Mb 66.000	3.05	1.00
	Total		69.00	22.68
Dar es Salaam	10311	Ubu132Mb 132.00	917.44	301.55
	11507	Chanik 220.00	170.40	56.01
	11508	Pug 220.00	59.64	19.60
	11510	Kidugal 220.00	55.38	18.20
	11519	Mburah 220.00	299.70	98.51
	11601	Kawe 132.00	149.10	49.01
	11803	Kin132Mb 132.00	649.94	213.63
	12002	Bunj 33.000	51.12	16.80
	12202	Sds1132Mb 33.000	438.78	144.22
	12302	Kunduchi 33.000	106.50	35.00
	Total		2,898.00	952.53
Pwani	10411	Cha132Mb 132.00	71.22	23.41
	10611	Mla132Mb 132.00	51.88	17.05
	11402	Bag220Mb 220.00	94.73	31.14
	11509	Ruv 220.00	11.24	3.69
	12102	Mkurang 132.00	30.33	9.97
	20402	Kibit 220.00	28.15	9.25
	91201	Kib132Mb 132.00	40.45	13.29
	Total		328.00	107.81
Dodoma	50816	Kon066Mb 66.000	13.42	4.41
	80212	Dod220Mb 220.00	108.58	35.69
	Total		122.00	40.10
Iringa	40112	Muf220Mb 220.00	48.78	16.03
	60412	Iri220Mb 220.00	64.22	21.11
	Total		113.00	37.14
Njombe	40115	Makmbko 220.00	56.91	18.71
	Total		56.91	18.71
Kagera	11513	Benac 220.00	2.23	0.73
	11514	Kabang 220.00	10.05	3.30
	20501	Mas400Mb 220.00	30.19	9.92
	90701	Rus220Mb 220.00	24.26	7.97
	91002	Kya132Mb 132.00	24.26	7.97
	91301	Mas220Mb 220.00	200.00	65.74
	Total		291.00	95.65
Katavi	90301	Mpa400Mb 400.00	16.00	5.26
	Total		16.00	5.26
Kigoma	11617	Tz -Bur 220.00	28.04	9.22
	90402	Kig220Mb 220.00	79.41	26.10
	90602	Nya220Mb 220.00	36.54	12.01
	Total		144.00	47.33
K'Manjaró	50311	Kiy132Mb 132.00	100.36	32.99
	50313	Kia132Mb 132.00	36.36	11.95
	51011	Sam132Mb 132.00	7.27	2.39
	Total		144.00	47.33
Lindi	501	Kilw 220.00	10.43	3.43
	20201	Som400Mb 400.00	14.79	4.86
	20301	Lin400Mb 400.00	14.79	4.86
	Total		40.00	13.15
Mara	11516	Tk-Kilgoris 400.00	200.00	65.74
	30201	Bun220Mb 220.00	17.91	5.89
	30301	Mus220Mb 220.00	32.04	10.53
	30316	Nyamo220Mb 220.00	56.05	18.42
	Total		306.00	100.58

LOAD DISTRIBUTION FOR 2034 (Continues)				
AREA	Bus No.	Bus Name	MW	MVAR
Mbeya	40212	Mbe220Mb 220.00	310.17	101.95
	49101	Karonga 220.00	74.83	24.59
	Total		385.00	126.54
Songwe	42001	Nak400Mb 400.00	200.00	65.74
	90102	Tundum 400.00	38.00	12.49
	Total		238.00	78.23
Morogoro	11511	Kingolwir 220.00	12.40	4.07
	60112	Kid220Mb 220.00	56.16	18.46
	60212	Kih220Mb 220.00	7.97	2.62
	80111	Mor132Mb 132.00	185.20	60.87
	80401	Mti132Mb 220.00	57.27	18.83
	Total		319.00	104.85
Mtwara	20401	Mtw400Mb 400.00	19.74	6.49
	21001	Moz400Mb 400.00	94.26	30.98
	Total		114.00	37.47
Mwanza	30112	Mwa220Mb 220.00	324.52	106.66
	51302	Seg220Mb 220.00	108.48	35.66
	Total		433.00	142.32
Geita	11519	Bukomb 220.01	12.13	3.99
	30401	Gei220Mb 220.00	112.87	37.10
	Total		125.00	41.09
Rukwa	90101	Sum400Mb 400.00	73.00	23.99
	Total		73.00	23.99
Ruvuma	20701	Tun400Mb 220.00	39.50	12.98
	20902	Son220Mb 220.00	39.50	12.98
	40601	Mad220Mb 220.00	39.00	12.82
	Total		118.00	38.78
Shinyanga	70112	Bul220Mb 220.00	126.50	41.58
	70312	Shi220Mb 220.00	75.90	24.95
	71010	Buzw220 220.00	50.60	16.63
	Total		253.00	83.16
Simiyu	11520	Simiy 220	140.00	46.02
	Total		140.00	46.02
Singida	80312	Sin220Mb 220.00	108.00	35.50
	Total		108.00	35.50
Tabora	70201	Lus220Mb 220.00	85.05	27.95
	70401	Tab220Mb 220.00	157.95	51.92
	Total		243.00	79.87
Tanga	51111	Tan132Mb 132.00	454.00	149.22
	Total		454.00	149.22
Zanzibar _Pemba			47.95	15.76
Zanzibar _Unguja			173.16	56.91
Grid System Peak			7,545.00	2,479.92

Source: PSMP 2020 Update Team Compilation

Table 4-6: 2044 Grid Substation Load forecast

LOAD DISTRIBUTION FOR 2044				
AREA	Bus No.	Bus Name	MW	MVAR
Arusha	51211	Nji132Mb 132.00	1,207.00	396.72
	51501	Isi400Mb 400.00	200.00	65.74
	Total		1,407.00	462.46
Manyara	50116	Bab066Mb 66.000	54.42	17.89
	50716	Kar066Mb 66.000	106.15	34.89
	50916	Mbu066Mb 66.000	7.42	2.44
	Total		168.00	55.22
Dar es Salaam	10311	Ubu132Mb 132.00	1,635.12	537.44
	11507	Chanik 220.00	303.70	99.82
	11508	Pug 220.00	106.29	34.94
	11510	Kidugal 220.00	98.70	32.44
	11519	Mburah 220.00	534.14	175.56
	11601	Kawe 132.00	265.74	87.34
	11803	Kin132Mb 132.00	1,158.37	380.74
	12002	Bunj 33.000	91.11	29.95
	12202	Sds1132Mb 33.000	782.02	257.04
	12302	Kunduchi 33.000	189.81	62.39
	Total		5,165.00	1,697.65
Pwani	10411	Cha132Mb 132.00	189.33	62.23
	10611	Mla132Mb 132.00	137.93	45.34
	11402	Bag220Mb 220.00	251.85	82.78
	11509	Ruv 220.00	29.89	9.82
	12102	Mkurang 132.00	80.63	26.50
	20402	Kibit 220.00	74.84	24.60
	91201	Kib132Mb 132.00	107.52	35.34
	Total		872.00	286.61
Dodoma	50816	Kon066Mb 66.000	28.49	9.36
	80212	Dod220Mb 220.00	230.51	75.76
	Total		259.00	85.13
Iringa	40112	Muf220Mb 220.00	101.02	33.20
	60412	Iri220Mb 220.00	132.98	43.71
	Total		234.00	76.91
Njombe	40115	Makmbko 220.00	56.91	18.71
	Total		56.91	18.71
Kagera	11513	Benac 220.00	11.64	3.83
	11514	Kabang 220.00	52.37	17.21
	20501	Mas400Mb 220.00	157.25	51.69
	90701	Rus220Mb 220.00	126.37	41.54
	91002	Kya132Mb 132.00	126.37	41.54
	91301	Mas220Mb 220.00	200.00	65.74
	Total		674.00	221.53
Katavi	90301	Mpa400Mb 400.00	99.00	32.54
	Total		99.00	32.54
Kigoma	11617	Tz -Bur 220.00	55.50	18.24
	90402	Kig220Mb 220.00	157.18	51.66
	90602	Nya220Mb 220.00	72.32	23.77
	Total		285.00	93.67
K'Manjaru	50311	Kiy132Mb 132.00	202.12	66.43
	50313	Kia132Mb 132.00	73.23	24.07
	51011	Sam132Mb 132.00	14.65	4.81
	Total		290.00	95.32
Lindi	501	Kilw 220.00	36.24	11.91
	20201	Som400Mb 400.00	51.38	16.89
	20301	Lin400Mb 400.00	51.38	16.89
	Total		139.00	45.69
Mara	11516	Tk-Kilgoris 400.00	200.00	65.74
	30201	Bun220Mb 220.00	123.98	40.75
	30301	Mus220Mb 220.00	221.87	72.92
	30316	Nyamo220Mb 220.00	388.15	127.58
	Total		934.00	306.99
Mbeya	40212	Mbe220Mb 220.00	647.74	212.90
	49101	Karonga 220.00	156.26	51.36
	Total		804.00	264.26

LOAD DISTRIBUTION FOR 2044 (Continues)				
Area	Bus No.	Bus Name	MW	MVAR
Songwe	42001	Nak400Mb 400.00	200.00	65.74
	90102	Tundum 400.00	94.00	30.90
	Total		294.00	96.63
Morogoro	11511	Kingolwir 220.00	30.70	10.09
	60112	Kid220Mb 220.00	139.08	45.71
	60212	Kih220Mb 220.00	19.74	6.49
	80111	Mor132Mb 132.00	458.64	150.75
	80401	Mti132Mb 220.00	141.84	46.62
	Total		790.00	259.66
Mtwara	20401	Mtw400Mb 400.00	41.73	13.71
	21001	Moz400Mb 400.00	199.27	65.50
	Total		241.00	79.21
Mwanza	30112	Mwa220Mb 220.00	691.01	227.12
	51302	Seg220Mb 220.00	230.99	75.92
	Total		922.00	303.05
Geita	11519	Bukomb 220.01	52.39	17.22
	30401	Gei220Mb 220.00	487.61	160.27
	Total		540.00	177.49
Rukwa	90101	Sum400Mb 400.00	118.00	38.78
	Total		118.00	38.78
Ruvuma	20701	Tun400Mb 220.00	85.70	28.17
	20902	Son220Mb 220.00	85.70	28.17
	40601	Mad220Mb 220.00	84.60	27.81
	Total		256.00	84.14
Shinyanga	70112	Bul220Mb 220.00	356.00	117.01
	70312	Shi220Mb 220.00	213.60	70.21
	71010	Buzw220 220.00	142.40	46.80
	Total		712.00	234.02
Simiyu	11520	Simiy 220	247.00	81.18
	Total		247.00	81.18
Singida	80312	Sin220Mb 220.00	212.00	69.68
	Total		212.00	69.68
Tabora	70201	Lus220Mb 220.00	262.15	86.16
	70401	Tab220Mb 220.00	486.85	160.02
	Total		749.00	246.18
Tanga	51111	Tan132Mb 132.00	916.00	301.07
	Total		916.00	301.07
Zanzibar_Pemba			71.90	23.63
Zanzibar_Unguja			227.16	74.66
Grid System Peak			16,917.00	5,560.35

Source: PSMP 2020 Update Team Compilation

4.3. Projects under Implementation

The Plan also considers the transmission projects under implementation. These projects are:-

- 400 kV Singida – Arusha – Namanga transmission line and associated Substations at Singida and Arusha and Interconnection at Namanga;
- 220 kV Transmission Line Project for Electrification of Dar es Salaam – Morogoro Standard Gauge Railway Line Phase I and associated traction Substations at Pugu, Ruvu, Kidugalo and Kingolwira;
- 220 kV Morogoro – Dodoma Transmission Line Project for Electrification of Morogoro – Makutupora Standard Gauge Railway Line Phase II and

- associated traction Substations at Mkata, Kidete, Godegode, Igandu, Ihumwa, Kigwe and Kintiku;
- iv. 220 kV Bulyanhulu – Geita Transmission Line Project and associated Substations at Geita and Bulyanhulu;
 - v. 220 kV Geita – Nyakanazi Transmission Line Project and associated Substations at Nyakanazi;
 - vi. 220 kV Rusumo – Nyakanazi Transmission Line Project and associated Substations at Benako;
 - vii. 220kV Shinyanga - Simiyu Transmission Line Project and associated Substations at Imalilo;
 - viii. 220kV Kinyerezi - Luguluni transmission Line and associated substation at Luguruni.
 - ix. 400 kV Nyakanazi – Kigoma Tansmission Line Project and associated Substation at Kigoma (Kidahwe);
 - x. 132 kV Tabora – Kigoma Transmission Line Project and Associated Substations at Urambo, Nguruka and Kidahwe;
 - xi. 132 kV Tabora – Katavi Transmission Line Project and Associated Substations at Ipole, Inyonga and Mpanda; and
 - xii. 132 kV Kurasini – Kigamboni Transmission Line Project and Associated Substations at Kigamboni.

4.4. Planned Transmission Line Projects

The following are some of the planned 400 kV and 220 kV transmission line projects that are under different implementation stages:

The 400 kV Transmission Line Projects are:-

- i. Iringa – Kisada – Mbeya – Tunduma – Sumbawanga and interconnection with Zambia at Tunduma and associated Substations at Kisada, Mbeya, Tunduma and Sumbawanga,
- ii. JNHPP – Chalinze, Chalinze - Dodoma, Chalinze – Kinyerezi, JNHPP Kibiti, Chalinze – Segera – Arusha,
- iii. Mtwara – Songea and associated substation at Masasi, Tunduru and Songea;

- iv. Mtwara – Lindi – Somanga. Somanga – Kinyerezi,
- v. Northwest Grid: Sumbawanga – Mpanda and Kigoma – Nyakanazi and
- vi. Shinyanga – Tabora – Kigoma.

The 220 kV Transmission Line Projects are:

- i. Segera – Tanga, Chalinze – Bagamoyo,
- ii. Morogoro – Mtibwa,
- iii. Mbeya – Songwe – Chunya,
- iv. Dodoma City Ring Circuit (Zuzu – Msalato – Ihumwa – Kikombo, Ihumwa – NARCO),
- v. NARCO – Dumila, Ifakara – Mahenge,
- vi. Shinyanga – Simiyu,
- vii. Kibiti – Mkuranga – Chanika,
- viii. Kinyerezi – Ubungo – Mburahati,
- ix. Bulyanhulu – Bukombe,
- x. Songea – Mbambabay,
- xi. NARCO – Kijungu (Kiteto),
- xii. Manyoni – Kigwa (Uyui),
- xiii. Manyoni – Mitundu (Manyoni) and
- xiv. Songea – Namtumbo.

4.5. Transmission System Additions - Least Cost Expansion Plan

Following the result of transmission planning analysis PSMP 2020 Update recommends an addition transmission system that includes transmission lines, substations and compensators in short, medium and long term plan which fulfill transmission planning criteria.

4.5.1. Transmission System Parameters

In designing and recommending transmission line addition various parameters were used as indicated in **Table 4-7**.

Table 4-7: Transmission line assumed parameters

Voltage (kV)	Conductor	Name	Size (mm²)	*Normal Rating (MVA)
400	ACSR	Sorbus	659.4	626.31
		Blue jay	564	605.25
220	ACSR	Sorbus	659.4	344.47
		Blue jay	564	332.89
132	ACSR	Wolf	150.	74
		Hawk	241	121
	XLPE	—	300/400	143
		—	95	52
66	ACSR	Wolf	150	37
		Rabbit	50	18

Note: * 80% of current rating.

4.5.2. Transmission Lines Additions

The recommended transmission line addition results are shown in **Tables 4-8, 4-9 and 4-10.**

Table 4-8: Transmission System Additions from 2020 to 2024

RATED VOLTAGE (KV)	FROM	TO	REMARKS	ROUTE LENGTH (KM)	NO. OF CIRCUITS	CONDUCTOR			YEARS TO BE COMMISSIONED	CURRENT RATING (Amps)	FULL RATING (MVA)	NORMAL RATING (MVA)
						CODE NAME	No. OF CONDUCTOR'S PER PHASE	ALLUMINIUM SECTIONAL AREA (mm ²)				
400	Singida	Kisongo (Arusha)		300	2	Bluejay	2	564	2020	1092	3,026.24	2,420.99
400	Arusha	Isinya (Kenya)	Up To Kenya border	114	2	Bluejay	2	375	2020	1092	3,026.24	2,420.99
220	Morogoro	Mtibwa		88	1	Bluejay	1	564	2023	1092	416.11	332.89
220	Wind project	Singida	Evacuation of Singida Wind farm	10	1	Bluejay	2	564	2023	1092	832.22	665.77
400	Iringa	Kisada		106	2	Bluejay	2	564	2023	1092	3,026.24	2,420.99
400	Kisada	Mbeya		285	2	Bluejay	2	564	2023	1092	3,026.24	2,420.99
400	Mbeya	Tunduma		122	2	Bluejay	2	564	2023	1092	3,026.24	2,420.99
400	Tunduma	Sumbawanga		203	2	Bluejay	2	564	2023	1092	3,026.24	2,420.99
220	Solar 1	Dodoma	Evacuation of Dodoma Wind farm	10	1	Bluejay	1	242	2023	1092	416.11	332.89
132	Wind project	Makambako	Evacuation of Makambako Wind farm	10	1	Hawk	1	242	2023	659	150.67	120.53
400	JNHPP	Chalinze	2 X 1,048 MW	160	2	Sorbus	3	659.4	2022	1274	5,295.92	4,236.73
400	Chalinze	Kinyerezi		93	2	Sorbus	3	659.4	2022	1274	5,295.92	4,236.73
400	Chalinze	Dodoma		345	2	Sorbus	3	659.4	2022	1274	5,295.92	4,236.73
220	Chalinze	Bagamoyo (Zinga)		60	1	Sorbus	2	659.4	2022	1274	970.92	776.73
220	Bagamoyo (Zinga)	Chalinze		60	1	Sorbus	2	659.4	2022	1274	970.92	776.73
400	Mtwara	Lindi (Mahumbika)		60	2	Sorbus	2	564	2024	1130	3,131.55	2,505.24
400	Lindi (Mahumbika)	Somanga		210	2	Sorbus	2	564	2024	1130	3,131.55	2,505.24
400	Somanga	Kibiti		79.56	2	Sorbus	2	659.4	2024	1130	3,131.55	2,505.24
400	Kibiti	Kinyerezi		110.56	2	Sorbus	2	659.4	2024	1130	3,131.55	2,505.24
220	Narco	Dumila		117	1	Sorbus	1	659.4	2024	1130	430.59	344.47
400	Mtwara	Mozambique	MOTA Interconnector	100	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
132	Tabora	Ipole		127	1	Hawk	1	242	2024	659	150.67	120.53
132	Ipole	Inyonga		138	1	Hawk	1	242	2024	659	150.67	120.53
132	Inyonga	Mpanda (Katavi)		140	1	Hawk	1	242	2024	659	150.67	120.53
132	Tabora	Urambo		131	1	Hawk	1	242	2024	659	150.67	120.53
132	Urambo	Nguruka (Uvinza)		185	1	Hawk	1	242	2024	659	150.67	120.53
132	Nguruka	Kigoma (Kidahwe)		79	1	Hawk	1	242	2024	659	150.67	120.53
220	Bulyanhulu	Geita		55	2	Bluejay	1	564	2020	1092	832.22	665.77
220	Geita	Nyakanazi		144	2	Bluejay	1	564	2021	1092	832.22	665.77
220	Rusumo	Nyakanazi	Evacuation of Rusumo HPP	94	2	Bluejay	1	564	2021	1092	832.22	665.77
400	Nyakanazi	Kigoma		280	2	Sorbus	2	659.4	2022	1130	3,131.55	2,505.24
400	Uyole (Mbeya)	Kyela		80.66	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
400	Kyela	Karonga (Malawi)		39.79	2	Sorbus	2	659.4	2023	1130	3,131.55	2,505.24
220	Mbeya	Songwe		41	2	Sorbus	1	659.4	2024	1130	861.18	688.94
220	Songwe	Chunya (Makongoros)		73	2	Sorbus	1	659.4	2024	1130	861.18	688.94
132	Mkata	Handeni		46.8	1	Hawk	1	242	2024	659	150.67	120.53
220	Zuzu	Msalato		32	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
220	Msalato	Ihumwa		12	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
220	Ihumwa	Kikombo		52	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
220	Kikombo	Zuzu		47	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
220	Kikombo	Narco		50	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
400	Songea	Tunduru		230	2	Sorbus	2	659.4	2024	1130	3,131.55	2,505.24
400	Tunduru	Masasi		194	2	Sorbus	2	659.4	2024	1130	3,131.55	2,505.24
400	Masasi	Lindi		141	2	Sorbus	2	659.4	2024	1130	3,131.55	2,505.24
220	Masasi	Marambo (Ruungwa)		65	1	Sorbus	1	659.4	2024	1130	430.59	344.47
220	Ifakara	Mahenge		68	1	Sorbus	1	659.4	2024	1130	430.59	344.47
220	Shinyanga (libadakuli)	Simiyu (Imalilo)		113	2	Sorbus	2	659.4	2023	1130	1,722.35	1,377.88
220	Pugu (SGR SS)	Chanika (Buyuni)		16	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Chanika (Buyuni)	Mkuranga		60	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Kinyerezi	Ubungo		17	1	Bluejay	2	564	2023	1130	861.18	688.94
220	Kinyerezi	Mburahati (Mabibo)		2	1	Bluejay	2	659.4	2023	1130	861.18	688.94
220	Zinga	Bunju		18	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Bunju	Kunduchi		14	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Kunduchi	Mbezi Beach		6	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Mbezi Beach	Makumbusho		11	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
220	Mbezi Beach	Kawe		8.7	2	Sorbus	2	659.4	2024	1130	1,722.35	1,377.88
132	Malagalasi	Kigoma (Kidahwe)	Evacuation of Malagalasi	74	1	Hawk	1	242	2024	659	150.67	120.53
220	Kishapu Solar P	Shinyanga	Evacuation of Power from Kishapu Solar Farm	10	1	Bluejay	1	659.4	2024	1092	416.11	332.89

Source: PSMP 2020 Update Team Compilation

Table 4-9: Transmission System Additions from 2025 to 2034

RATED VOLTAGE (kV)	FROM	TO	REMARKS	ROUTE LENGTH (KM)	NO. OF CIRCUITS	CONDUCTOR			YEARS TO BE COMMISSIONED	CURRENT RATING (Amps)	FULL RATING (MVA)	NORMAL RATING (MVA)
						CODE NAME	No. OF CONDUCTOR'S PER PHASE	ALLUMINIUM SECTIONAL AREA (mm²)				
400	JNHPP	Kibiti	Evacuation of JNHPP	172	2	Sorbus	3	659.4	2025	1274	5,295.92	4,236.73
220	Kibiti	Mkuranga		60	2	Sorbus	2	659.4	2025	1274	1,941.84	1,553.47
400	Chalinze	Segera		175	2	Sorbus	2	659.4	2025	1274	3,530.61	2,824.49
400	Segera	Arusha		366	2	Sorbus	2	659.4	2025	1274	3,530.61	2,824.49
220	Segera	Tanga		64	2	Sorbus	2	659.4	2025	1274	1,941.84	1,553.47
400	Kigoma	Mpanda		290	2	Sorbus	2	659.4	2026	1130	3,131.55	2,505.24
400	Mpanda	Sumbawanga		119	2	Sorbus	2	659.4	2026	1130	3,131.55	2,505.24
400	Shinyanga	Mwanza		140	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
400	Mwanza	Musoma		210	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
400	Musoma	Kilgoris (Kenya)		179	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
220	Kakono P/S (Hydro)	Kyaka	87MW	39	1	Bluejay	1	564	2025	1092	416.11	332.89
400	Nyakanazi	Kyaka	Interconnection project to Uganda	30	2	Sorbus	2	564	2025	1130	3,131.55	2,505.24
400	Kyaka	Masaka (Uganda)		30	2	Sorbus	2	564	2025	1130	3,131.55	2,505.24
220	Bulyanhulu	Bukombe		66.5	1	Sorbus	1	659.4	2030	1130	430.59	344.47
132	Kiyungi	Makuyuni		34	1	Hawk	1	242	2025	659	150.67	120.53
220	Tabora	Kigwa - Uyui	Initially the line to be charged in 132kV	42	1	Sorbus	1	659.4	2026	1130	430.59	344.47
132	Lindi	Nangurukuru (Kilwa)		158	1	Hawk	1	242	2026	659	150.67	120.53
132	Kiyungi	Makuyuni		34	1	Hawk	1	242	2026	659	150.67	120.53
400	Ruhudji	Kisada	Evacuation of Hydro Project	140	2	Sorbus	2	659.4	2025	1130	3,131.55	2,505.24
220	Rumakali PP	Mbeya (Uyole)	Evacuation of HPP	70	1	Sorbus	1	659.4	2026	1130	430.59	344.47
220	Dodoma Solar	Dodoma	Evacuation of Dodoma Solar	12	1	Bluejay	1	564	2025	1092	416.11	332.89
220	Ngozi (wellhead) & Ngozi I	Mbeya	Evacuation of Geothermal	35	1	Bluejay	1	564	2025	1092	416.11	332.89
220	Masigira	Ruhudji	Evacuation of Masigira Power	100	1	Bluejay	1	564	2027	1092	416.11	332.89
220	Kikonge	Madaba	Evacuation of Kikonge HPP	49	1	Bluejay	1	564	2027	1092	416.11	332.89
220	Mnyera	Ruhudji	Evacuation of Mnyera HPP	50	1	Bluejay	1	564	2027	1092	416.11	332.89
220	Kwanini P/S	Mnyera S/S - Ruaha 2	T- branch	10	2	Bluejay	2	564	2028	1092	1,664.43	1,331.55
220	Mnyera S/S (new)	Taveta 3 P/S	(119.8+83.9+122.9)MW	26	1	Bluejay	2	564	2034	1092	832.22	665.77
220	Ruaha 2 P/S (Hydro)	Mnyera S/S (new)	(60.3+137.4+143.9)MW	33	2	Bluejay	2	564	2028	1,092	1,664.43	1,331.55
220	Ngaka	Songea	Evacuation of Power	37	1	Bluejay	1	564	2032	1092	416.11	332.89
400	Mchuchuma P/s	Kisada	Evacuation of Mchuchuma	200	1	Sorbus	2	659.4	2025	1130	1,565.77	1,252.62
220	Mpanga P/S (Hydro)	Mufindi	160MW	65	1	Bluejay	1	564	2031	1092	416.11	332.89
220	Uyole	Kiwira		35.6	1	Sorbus	1	659.4	2032	1130	430.59	344.47
220	Kihansi P/S (Hydro)	Upper Kihansi P/S (Hydro)	47 MW	10	1	Bluejay	1	564	2034	1092	416.11	332.89
400	Somanga Fungu S/S	Future CGT3 -1	648 MW	20	1	Bluejay	1	564	2028	1092	756.56	605.25

Source: PSMP 2020 Update Team Compilation

Table 4-10: Transmission Additions from 2035 to 2044

RATED VOLTAGE (kV)	FROM	TO	REMARKS	ROUTE LENGTH (KM)	NO. OF CIRCUITS	CONDUCTOR			YEARS TO BE COMMISSIONED	CURRENT RATING (Amps)	FULL RATING (MVA)	NORMAL RATING (MVA)
						CODE NAME	No. OF CONDUCTOR	ALLUMINIUM M				
220	Songea	Mbinga		92.5	1	Sobber	1	659.4	2037	1130	430.59	344.47
220	Mbinga	Mbambabay		53.8	1	Sobber	1	659.4	2037	1130	430.59	344.47
132	KIA	Engare Nairobi		40.1	1	Hawk	1	242	2036	659	150.67	120.53
132	Same	Gonja		49.1	1	Hawk	1	242	2038	659	150.67	120.53
220	NARCO	Kijungu (Kiteto)		157	1	Sobber	1	659.4	2037	1130	430.59	344.47
220	Manyoni	Kigwa (Uyui)		200	1	Sobber	1	659.4	2037	1130	430.59	344.47
220	Manyoni	Mitundu (Manyoni)		106	1	Sobber	1	659.4	2037	1130	430.59	344.47
220	Geita	Bwanga		61	1	Sorbus	1	659.4	2041	1130	430.59	344.47
220	Bwanga	Usahunga		62	1	Sorbus	1	659.4	2041	1130	430.59	344.47
220	Usahunga	Kyaka		228	1	Sorbus	1	659.4	2041	1130	430.59	344.47
2202	Songea	Namtumbo		70	2	Sorbus	1	659.4	2036	1130	8,619.59	6,895.67
400	Shinyanga	Tabora		195	2	Sorbus	2	659.4	2040	1130	3,131.55	2,505.24
400	Tabora	Kigoma		415	2	Sorbus	2	659.4	2040	1130	3,131.55	2,505.24
132	Songwe B S/S	Kyela	(79.5+88.1)MW	7	1	Hawk	2	242	2035	659	301.34	241.07
132	Songwe A S/S	Songwe B S/S		40	1	Hawk	2	242	2035	659	301.34	241.07
132	Songwe Sofwe P/S (Hydro)	Songwe A S/S	79.5MW	16	1	Hawk	1	242	2035	659	150.67	120.53
220	Iringa (Ibosa)	Iringa (Tagamenda)	Evacuation of Ibosa and Nginayo HPP	81	1	Bluejay	1	564	2035	1092	416.11	332.89
220	Ibosa P/s (Hydro)	Nginayo P/S (Hydro)	52 MW	10	1	Bluejay	1	564	2035	1092	416.11	332.89
220	Iringa (Kilolo-Ilula)	Iringa (Tagamenda)	evacuation of Kilolo HPP	39	1	Bluejay	1	564	2039	1092	416.11	332.89
220	Pumbwe P/S (Hydro)	Mnyera S/S - Taveta 3 T/L		10	1	Bluejay	2	564	2039	1092	832.22	665.77
220	Mnyera 2 P/S	Mnyera S/S - Ruaha 2 T/L	T- branch	10	2	Bluejay	2	564	2035	1092	1,664.43	1,331.55
220	Pumbwe P/S (Hydro)	Mnyera S/S - Taveta 3 T/L		10	1	Bluejay	2	564	2030	1092	832.22	665.77

Source: PSMP 2020 Update Team Compilation.

4.5.3.Reactive Compensation

It was assumed that each 400 kV line would be compensated by two line-connected reactors located at the two line ends. The magnitude of each reactor was taken as 35 percent of the full line charging value, which is equivalent to a total of 70 percent compensation. These line-connected reactors would be switched on and off based on the system operation requirements. However, for line switching (or energization), these reactors must be switched on to avoid high voltages at the open line ends (Ferranti Effect). These factors are subject of a detailed dynamic study performed at design stage.

Variable reactors were sized to ensure the adequacy of the system operating conditions as given in the planning criteria.

4.5.4.Substation Additions

The numbers of circuit breakers for the 400 kV and 220 kV systems are based on the breaker and a half scheme, as shown in **Figure 4-5**. Each bay is composed of three (3) breakers and provides two positions for transmission line, transformer or compensation equipment. Sub-transmission switchgear has not been considered as it depends greatly on how many positions will be needed, which in turn, depends on the local area planning.

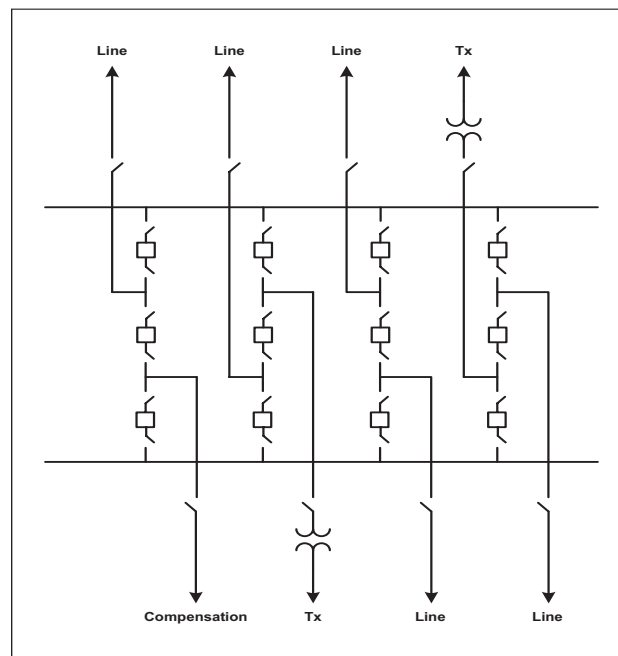


Figure 4-5: Breaker and Half Scheme

4.6. Load Flow Analysis

The proposed transmission system is based on the load forecast and the new power plants as presented in the Chapter Two and Three. The short, medium and long term study was considered as follows:

- a) Year 2019 existing peak load case;
- b) Year 2024 peak load case;
- c) Year 2034 peak load case; and
- d) Year 2044 peak load case.

Each case has been analyzed under both normal (N-0) and contingency (N-1) conditions. System reinforcement including transmission lines, transformers/ substations and reactive power compensations were defined as appropriate.

4.6.1. Year-2019 case

In year 2019, simulation of existing peak load revealed that the Kinyerezi – Ubungo 220 kV line, the Chalinze – Hale 132 kV line, Kinyerezi – Gongolamboto – Mbagala – Kurasini 132 kV line, Ubungo – Makumbusho 132 kV line had exceeded their thermal limit. Therefore, they could not transfer all the demanded power. This has resulted in the introduction of Kurasini – Kigamboni (Dege) project 132 kV, Kinyerezi – Ubungo – Mburahati 220 kV line, stringing of Chalinze Hale 132 kV line and Kinyerezi - Gongolamboto – Mbagala – Kurasini 132 kV line and the reinforcement of power network in Dar es Salaam and Pwani.

4.6.2. Year-2024 case

The major short term plan lines addition will consist of 400 kV double Circuit Lines: JNHPP – Chalinze – Kinyerezi and Chalinze – Dodoma; Singida – Arusha – Namanga; Iringa – Mbeya – Tunduma – Sumbawanga; Mtwara – Somanga – Kibiti – Kinyerezi; and Lindi – Masasi – Tunduru Songea.

220 kV transmission line addition includes: Shinyanga – Simiyu; Morogoro – Mtibwa; Bulyanhulu – Geita; Geita – Nyakanazi; Rusumo – Nyakanazi; Mbeya – Songwe – Chunya; Dodoma City (Zuzu – Msalato – Ihumwa – Kikombo – Zuzu, Ihumwa – NARCO)

Ring Circuit; Ifakara – Mahenge; Shinyanga – Simiyu; Kibiti– Mkuranga– Chanika; Kinyerezi – Ubungo –Mburahati; and Zinga – Kunduchi – Makumbusho.

These lines will carry amount of power generated at each plant to maintain the load/generation balance. Contingency analysis (N-1) for this case was performed and no voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 p.u) limits and the loading was based of the transmission line/transformer emergency capacity (rating B).

4.6.3.Year 2034 case

The major lines addition by the year 2034 are divided into two categories. The first is the expansion of the 400 kV network composed of: Chalinze – Segera – Arusha; Northern West Grid (Kigoma – Mpanda – Sumbawanga); Shinyanga – Mwanza Musoma; and the JNHPP – Kibiti. The second is the expansion of 220 kV network in Dar es Salaam area composed of: Chalinze Bagamoyo; Bagamoyo – Bunju – Kunduchi – Makumbusho; and Kinyerezi – Luguluni. Other 220 kV additions are Segera – Tanga; Bulyanhulu – Bukombe; Kibiti – Mkuranga; Kakono – Kyaka; and NARCO (Dodoma) – Dumila.

Under normal conditions (N-0), all bus voltages are within the limits (0.95 -1.05 pu), as defined in the planning criteria. No voltage violations are recorded in the bulk system (220 kV and above.). Transmission line power flows are also below the line normal capacity (rating A).

Contingency analysis (N-1) for this case was performed and no voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 pu) limits and the loading was based of the transmission line/transformer emergency capacity (rating B).

4.6.4.Year 2044 case

This case represents the ultimate load flow case for the power system. Generally, the importance of such a case is to plan the system in the early years ie 2024 and 2034 with an eye on the foreseen ultimate configuration. Both the 400 kV and 220 kV networks were expanded as many power plants were considered. Since the generation is mostly concentrated in the South and coastal areas and there are substantial load centers at North,

reactive power compensation played an important role in reaching satisfactory operating conditions for the system developed.

Under normal conditions (N-0), all bus voltages are within the limits (0.95 -1.05 pu), as defined in the planning criteria. No voltage violation is recorded in the bulk system (220 kV and above). Transmission line power flows are also below the line normal capacity (rating A).

Contingency analysis (N-1) for this case was performed and no voltage or overloading problems were encountered in the bulk system. Under contingency conditions the voltage check was based on the (0.9-1.1 pu) limits and the loading was based of the transmission line/transformer emergency capacity (rating B).

4.7. Short Circuit Study

A Short circuit study was performed only on the bulk system (220 kV and above) and results are given in **Table 4-11**.

A typical equivalent machine reactance of 15 percent and step-up transformer reactance of 10 percent were assumed for short circuit current calculations. Classical assumptions (flat conditions) were assumed and all bus voltages were set to 1.05 pu.

All fault currents for 400 kV and 220 kV substations are within the practical switchgear ratings for these levels. The minimum switchgear short circuit rating is in the range of 63 kA for 400 kV level and 40 kA for 220 kV level. Therefore, the year 2044 case with the overall 400/220 kV transmission system does not experience any switchgear short circuit rating problems.

Table 4-11: Year 2044 Short Circuit Results

BUS			3 - ph Short Circuit Currents		
No.	Name	kV	kA	MVA	X/R Ratio
400 kV Buses					
10401	Chalinze	400	41.26	11,106	14.8
11504	Rumakali	400	30.32	7,643	50.3
11506	JNHPG	400	30.17	8,181	13.7
11515	Mara	400	8.26	2,313	10.1
11516	TK Kilgoris	400	5.03	148	7.2
11517	Kyaka	400	8.33	2,295	11.7
11801	Kiny	400	57.86	15,118	22.0
20201	Somanga	400	47.78	12,878	14.6
20227	Dom CCGT	400	16.38	5,973	1.6
20232	Kisada Wind	400	19.83	7,756	1.1
20234	CCGT II	400	20.75	7,086	2.1
20235	CCGT I	400	20.39	7,016	2.0
20301	Lindi	400	29.28	8,586	7.3
20401	Mtwara	400	30.43	8,874	7.6
20601	ST I	400	30.25	8,200	13.7
20611	JNHPP PGI	400	30.13	8,172	13.6
21001	Mozambique	400	15.65	4,361	10.6
21002	Kibiti	400	48.80	12,989	16.9
30101	Mwa	400	11.86	3,181	15.3
40210	Mbeya	400	39.04	10,314	24.9
40605	Taveta	400	21.03	5,549	19.0
40701	Masa	400	9.09	2,362	24.3
41301	Ruh	400	14.29	3,618	43.5
41401	Mnyera	400	20.43	5,308	24.2
41501	Kwanini	400	22.68	5,895	23.9
41601	Ruhudji	400	34.88	8,984	28.4
41701	Ikonda	400	25.76	6,661	26.4
42001	Nak	400	18.71	5,127	12.3
42101	Kis	400	45.90	11,839	27.7
42501	Mnyera	400	34.65	8,903	30.0
51301	Segera	400	18.91	4,956	20.9
51401	Arusha	400	13.92	3,677	18.6
51501	Isinya	400	9.38	2,485	18.0
60401	Iringa	400	32.68	8,537	22.1
70301	Shinyanga	400	15.42	4,176	13.8
70402	Tabora	400	15.38	4,113	15.9
80201	Dodoma	400	27.94	7,701	11.7
80301	Singida	400	20.53	5,437	18.0
90101	Sumbawanga	400	24.64	6,540	17.5
90102	Tunduma	400	27.95	7,631	12.7
90301	Mpanda	400	20.31	5,369	18.6
90401	Kigoma	400	16.74	4,450	17.1
90601	Nya	400	11.28	2,973	19.2
91301	Masaka	400	6.78	1,860	12.2
91501	Ruk	400	22.87	6,021	19.6

BUS		3 - ph Short Circuit Currents			
No.	Name	kV	kA	MVA	X/R Ratio
220 kV Buses					
501	Kilwa	220	5.53	839	11.5
10312	Ubungo	220	32.13	9,537	18.2
10411	Chalinze	220	5.66	37,888	13.4
11402	Bagamoyo	220	4.52	30,384	14.2
11503	Lindi	220	39.56	6,466	8.2
11507	Chanika	220	31.57	4,669	15.0
11508	Pugu	220	28.64	7,124	16.8
11509	Ruvu	220	19.60	2,933	13.1
11510	Kidugalo	220	14.82	2,241	11.9
11511	Kingoluwira	220	15.11	2,311	10.7
11513	Benaco	220	13.48	1,962	18.1
11514	Kabanga	220	7.43	1,098	15.0
11518	Bukombe	220	6.70	1,002	12.2
11519	Mburahati	220	16.79	7,811	16.2
11601	Kawe	220	14.13	2,408	5.4
11617	TZ - Bur	220	11.43	1,591	44.1
11802	Kiny	220	25.54	10,887	26.0
12001	Bunju	220	28.49	3,993	7.4
12101	Mkuranga	220	19.59	2,887	15.6
12301	Kunduchi	220	28.96	4,444	10.5
20219	Ubu 1 New	220	35.07	5,926	16.0
20220	Ubu New	220	17.38	6,622	16.0
20221	Mbeya Coal	220	34.18	5,403	19.3
20228	Makambako wind	220	3.87	560	19.5
20229	CCGT IPP	220	20.89	3,272	4.2
20230	Kilol	220	24.19	4,511	2.1
20231	Sing solar	220	18.36	3,129	3.0
20233	Simiyu	220	6.47	976	12.2
20402	Kibiti	220	28.38	3,990	33.9
20511	Masaka	220	21.08	3,087	16.9
20701	Tund	220	17.73	2,528	25.3
20801	Nga	220	35.36	4,853	78.3
20802	Songwe	220	21.28	3,090	18.9
20803	Sing Wind	220	20.00	2,977	13.9
20804	Kishap	220	17.03	2,573	12.0
20805	Solar Dom	220	21.00	3,076	16.8
20902	Son	220	30.27	4,208	46.4
30112	Mwa	220	17.19	2,519	16.6
30201	Bund	220	12.77	1,909	13.3
30301	Muso	220	14.15	2,168	10.6
30316	Nyamongo	220	9.33	1,397	13.1
30401	Geita	220	10.68	1,567	16.3
40112	Mufindi	220	13.20	2,087	8.3
40115	Makambako	220	13.90	2,203	8.2
40212	Mbeya	220	30.06	8,566	26.3
40214	Uyole	220	20.20	6,647	12.6
40215	Kiwira	220	28.82	7,241	36.8
40601	Madaba	220	16.51	2,393	19.2
40801	Kik	220	19.12	2,678	37.1
41001	Rum	220	14.43	2,051	26.9

BUS		3 - ph Short Circuit Currents			
No.	Name	kV	kA	MVA	X/R Ratio
220 kV Buses (Continues)					
41101	Geo	220	29.06	4,284	15.5
41201	Mpa	220	10.66	1,583	14.3
42801	Kyak	220	12.82	1,843	22.0
49101	Karonga	220	10.20	1,474	20.2
50112	Babati	220	7.39	1,173	8.1
51101	Tanga	220	9.81	1,485	11.8
51212	Njiro	220	18.66	2,705	19.3
51302	Segeera	220	19.97	2,838	26.7
51402	Arusha	220	18.76	2,718	19.4
60112	Kid	220	19.62	3,001	10.8
60212	Kih	220	16.78	2,481	15.0
60312	Mtera	220	12.10	1,924	8.0
60412	Iringa	220	35.98	5,252	17.6
60501	Ibosa	220	11.85	1,712	20.2
70112	Bulyanhulu	220	11.28	1,701	12.2
70201	Lusu	220	10.89	1,665	10.8
70312	Shinyanga	220	22.71	3,059	11.9
70401	Tabora	220	17.28	2,489	21.2
71010	Buzwagi	220	10.89	1,582	15.6
80112	Morogoro	220	21.27	3,358	8.4
80212	Dodoma	220	24.82	3,629	17.2
80312	Singida	220	25.31	3,209	13.3
90402	Kigoma	220	11.43	1,591	44.1
90602	Nya	220	16.16	2,323	21.8
90701	Rusumo	220	11.88	1,733	17.8
91001	Kyaka	220	14.30	2,189	10.7

BUS		3 - ph Short Circuit Currents			
No.	Name	kV	kA	MVA	X/R Ratio
330 kV Bus					
401402	Taza	330	16.55	4,785	3.1

Source: PSMP 2020 Update Team Compilation.

4.8. Transmission and Substation Costs

4.8.1. Transmission Voltage Options

It is expected that 132 kV, 220 kV and 400 kV system voltage levels will be the main transmission technology choice for the transmission expansion. Variable Shunt Reactor and Line Shunt Reactor are used to improve the receiving end voltages on long and

heavily loaded lines. These devices are still considered to delay or replace the need for new transmission lines where they appeared to be economical and practical.

4.8.2. Cost Estimates

Cost estimate was investigated for transmission lines, transformers, substations and compensation. The cost estimate of the bulk system was based on unit costs for transmission lines, substation switchgears, transformers and reactive power compensation (SVR and LSR), as given in **Tables 4-12, 4-13 and 4-14**.

4.8.3. Transmission Unit Costs

Transmission line and substation costs have been benchmarked from recent TANESCO studies and transmission line projects under implementation in Tanzania based on international competitive bidding. **Table 4-12** shows transmission line unit costs that were used in this plan. Unit costs for various substation components are summarized in **Table 4-13**. Costs for new switching substations include circuit breakers, disconnectors, switches, current and voltage transformers, relay buildings, structures and site preparation.

Table 4-12: Unit Cost of Transmission Lines⁷

Rated Voltage (kV)	Unit Cost (1,000 USD/km)	
	Single Circuit	Double Circuit
400	300 – 400	380 - 450
220	185 – 270	230 - 320
132	155 – 195	165 - 210

Source: PSMP 2020 Update Team Compilation.

Table 4-13: Unit Cost of Substation per Bay

Substation Cost MUSD/bay		
132 kV	220 kV	400 kV
3.49	5.89	9.68

Source: PSMP 2020 Update Team Compilation

Table 4-14: Unit cost of transformers and reactive compensation

	kUSD/MVA	MUSD /100 MVA _r
Transformer	11.56	
Variable Shunt Reactor (SVR)		3.56
Line Shunt Reactor (LSR)		2.74

Source: PSMP 2020 Update Team Compilation.

⁷ One bay means the designated compartment where switchgear and buses are configured to interconnect a transmission line or a transformer. The costs include the switchgear, the buses, the structures, Control/Protection devices and site preparation. (Building is not included)

4.9. Transmission System Project Costs

The major 400 kV and 220 kV, transmission additions required for the above Least Cost Expansion Plan are illustrated in **Figures 4-2, 4-3 and 4-4**, the costs of the transmission additions are listed in **Tables 4-15, 4-16 and 4-17**, those for transformers are listed in **Tables 4-18, 4-19 and 4-20**, substation additions are listed in **Tables 4-21, 4-22 and 4-23** and reactive compensation are listed in **Table 4-24**.

The total transmission system costs in the Least Cost Expansion Plan from 2020 up to 2024 are approximately **USD 3,187.46 million** and from 2025 up to 2034 is **USD 1,936.06 million** while from 2035 up to 2044 are **USD 813.38 million**. Accounting to the total amount from 2020 up to 2044 will be **USD 5,936.90 million**.

Table 4-15: Phased Transmission Lines Cost Estimates 2020-2024

From	To	Rated Voltage (kV)	No. of Circuits	No. of Conductor per phase	Route Length (km)	Unit Cost k\$/km	Total Cost M\$	Year of Commissioning
Bulyanhulu	Geita	220	2	1	55	230	12.65	2020
Singida	Kisongo (Arusha)	400	2	2	317	415	131.555	2021
Arusha	Isinya (Kenya)	400	2	2	114	415	47.31	2021
Rusumo	Nyakanazi	220	2	1	94	230	21.62	2021
Geita	Nyakanazi	220	2	1	144	230	33.12	2021
Nyakanazi	Kigoma	400	2	2	280	415	116.2	2021
Dar es salaam	Msamvu	220	1	1	160	185	29.6	2021
Msamvu	Ihumwa	220	1	1	236	185	43.66	2020
Ihumwa	Kitinku	220	1	1	174	185	32.19	2020
Kinyerezi	Ubungo	220	2	1	17	230	3.91	2022
Kinyerezi	Mburahati (Mabibo)	220	1	2	2	230	0.46	2022
JNHPP	Chalinze	400	2	3	160	450	72	2022
Chalinze	Kinyerezi	400	2	3	93	450	41.85	2022
Chalinze	Dodoma	400	2	3	345	450	155.25	2022
Chalinze	Bagamoyo (Zinga)	220	1	2	60	230	13.8	2022
Zuzu	Msalato	220	1	1	32	185	5.92	2023
Msalato	Ihumwa	220	1	1	12	185	2.22	2023
Ihumwa	Kikombo	220	1	1	52	185	9.62	2023
Kikombo	Zuzu	220	1	1	47	185	8.695	2023
Kikombo	Narco	220	1	1	50	185	9.25	2023
Morogoro	Mtibwa	220	1	2	88	228	20.02	2023
Shinyanga (libadakuli)	Simiyu (Imalilo)	220	1	2	113	228	25.7075	2023
Iringa	Kisada	400	2	2	106	415	43.99	2023
Kisada	Mbeya	400	2	2	285	415	118.275	2023
Mbeya	Tunduma	400	2	2	122	415	50.63	2023
Tunduma	Sumbawanga	400	2	2	203	415	84.245	2023
Somanga	Kibiti	400	2	2	79.6	415	33.034	2024
Kibiti	Kinyerezi	400	2	2	110.6	415	45.899	2024
Tabora	Ipole	132	1	1	127	155	19.685	2024
Ipole	Inyonga	132	1	1	138	155	21.39	2024
Inyonga	Mpanda (Katavi)	132	1	1	140	155	21.7	2024
Tabora	Urambo	132	1	1	131	155	20.305	2024
Urambo	Nguruka (Uvinza)	132	1	1	185	155	28.675	2024
Nguruka	Kigoma (Kidahwe)	132	1	1	79	155	12.245	2024
Chanika (Buyuni)	Mkuranga	220	2	2	60	275	16.5	2024
Kibiti	Mkuranga	220	2	2	60	275	16.50	2025
Mkata	Handeni	132	1	1	46.8	155	7.254	2024
Mbeya	Songwe	220	1	2	41	228	9.3275	2024
Songwe	Chunya (Makongorosi)	220	1	2	73	228	16.6075	2024
Mtwara	Lindi (Mahumbika)	400	2	2	60	415	24.9	2024
Lindi (Mahumbika)	Somanga	400	2	2	210	415	87.15	2024
Mtwara	Mozambique	400	2	2	100	415	41.5	2024
Songea	Tunduru	400	2	2	230	415	95.45	2024
Tunduru	Masasi	400	2	2	194	415	80.51	2024
Masasi	Lindi	400	2	2	141	415	58.515	2024
Masasi	Marambo (Ruagwa)	220	1	1	65	185	12.025	2024
Ifakara	Mahenge	220	1	1	68	185	12.58	2024
Narco	Dumila	220	1	1	117	185	21.645	2024
Zinga	Bunju	220	2	2	18	275	4.95	2024
Bunju	Kunduchi	220	2	2	14	275	3.85	2024
Kunduchi	Mbezi Beach	220	2	2	6	275	1.65	2024
Mbezi Beach	Makumbusho	220	2	2	11	275	3.025	2024
Mbezi Beach	Kawe	220	2	2	8.7	275	2.3925	2024
Malagalasi	Kigoma (Kidahwe)	132	1	1	74	155	11.47	2024
Karatu	Loliondo	66	1	1	200	120	24	2024
Total						1,888.48		

Table 4-16: Phased Transmission Lines Cost Estimates 2025 - 2034

From	To	Rated Voltage (kV)	No. of Circuits	No. of Conductor per phase	Route Length (km)	Unit Cost k\$/km	Total Cost M\$	Year of Commissioning
Chalinze	Segera	400	2	2	175	415	72.63	2025
Segera	Arusha	400	2	2	366	415	151.89	2025
Segera	Tanga	220	2	2	64	275	17.60	2025
Uyole (Mbeya)	Kyela	400	2	2	80.7	415	33.47	2025
Kyela	Karonga (Malawi)	400	2	2	39.8	415	16.51	2025
Nyakanazi	Kyaka	400	2	2	253	415	105.00	2025
Kyaka	Masaka (Uganda)	400	2	2	30	415	12.45	2025
JNHPP	Kibiti	400	2	3	172	450	77.40	2025
Shinyanga	Mwanza	400	2	2	140	415	58.10	2025
Mwanza	Musoma	400	2	2	210	415	87.15	2025
Musoma	Kilgoris (Kenya)	400	2	2	179	415	74.29	2025
Kakono P/S (Hydro)	Kyaka	220	1	1	39	185	7.22	2026
Ruhudji	Kisada	400	2	2	140	415	58.10	2025
Kinyerezi	Luguruni	220	2	2	22.6	275	6.22	2025
Kigoma	Mpanda	400	2	2	290	415	120.35	2026
Mpanda	Sumbawanga	400	2	2	119	415	49.39	2026
Lindi	Nangurukuru (Kilwa)	132	1	1	158	155	24.49	2026
Kiyungi	Makuyuni	132	1	1	34	155	5.27	2026
Rumakali PP	Mbeya (Uyole)	220	1	1	70	185	12.95	2026
Masigira	Ruhudji	220	1	1	100	185	18.50	2028
Tabora	Kigwa - Uyui	220	1	1	42	185	7.77	2028
Kikonge	Madaba	220	1	1	49	185	9.07	2028
Songwe B S/S	Kyela	132	1	2	10	175	1.75	2028
Songwe A S/S	Songwe B S/S	132	1	2	40	175	7.00	2028
Songwe Sofwe P/S (Hydro)	Songwe A S/S	132	1	1	16	155	2.48	2028
Mnyera	Ruhudji	400	1	1	50	185	9.25	2029
Bulyanhulu	Bukombe	220	1	1	66.5	185	12.30	2030
Uyole	Kiwira	220	1	1	35.6	185	6.59	2032
Ngaka	Songea	220	1	1	37	185	6.85	2032
Mchuchuma P/s	Kisada	400	1	2	200	350	70.00	2031
Mpanga P/S (Hydro)	Mufindi	220	1	1	65	185	12.03	2033
Total							1,154.03	

Table 4-17: Phased Transmission Lines Cost Estimates 2035 - 2044

From	To	Rated Voltage (kV)	No. of Circuits	No. of Conductor per phase	Route Length (km)	Unit Cost k\$/km	Total Cost M\$	Year of Commissioning
Iringa (Ibosa)	Iringa (Tagamenda)	220	1	1	81	185	14.99	2035
Ibosa P/s (Hydro)	Nginayo P/S (Hydro)	220	1	1	10	185	1.85	2035
KIA	Engare Nairobi	132	1	1	40.1	155	6.22	2036
Songea	Namtumbo	220	1	1	70	185	12.95	2036
Same	Gonja	132	1	1	49.1	155	7.61	2037
NARCO	Kijungu (Kiteto)	220	1	1	157	185	29.05	2037
Manyoni	Mitundu (Manyoni)	220	1	1	106	185	19.61	2037
Songea	Mbinga	220	1	1	92.5	185	17.11	2037
Mbinga	Mbambabay	220	1	1	53.8	185	9.95	2037
Ilula (Kilolo)	Iringa (Tagamenda)	220	1	1	39	185	7.22	2039
Mnyera 2 P/S	Ruaha 2	220	1	2	10	228	2.28	2039
Pumbwe P/S (Hydro)	Mnyera Taveta	220	1	2	10	228	2.28	2039
Manyoni	Kigwa (Uyui)	220	1	1	200	185	37.00	2040
Shinyanga	Tabora	400	2	2	195	415	80.93	2040
Tabora	Kigoma	400	2	2	415	415	172.23	2040
Geita	Bwanga	220	1	1	61	185	11.29	2041
Bwanga	Usahunga	220	1	1	62	185	11.47	2041
Usahunga	Kyaka	220	1	1	228	185	42.18	2041
Total						486.18		

Table 4-18: Phased Transformer Cost Estimates 2020 – 2024

Substation	Region	HV/LV (kV)	Rating (MVA)	No. of T.x	Total Cost (M\$)	Commissioning Year
Bulyanhulu	Shinyanga	220/33	30	1	0.35	2020
Geita	Geita	220/33	50	2	1.16	2020
Lemugul (Kisongo)	Arusha	400/220	250	2	5.78	2020
Lemugul (Kisongo)	Arusha	220/33	125	2	2.89	2020
Iringa	Iringa	400/220/33	250/250/85	2	8.67	2021
Iringa	Iringa	220/33	125/125/37.5	2	4.34	2021
Dodoma	Dodoma	400/220/33	250/250/85	2	8.67	2020
Dodoma	Dodoma	220/33	125/125/37.5	2	4.34	2020
Singida	Singida	400/220/33	250/250/85	2	8.67	2020
Singida	Singida	220/33	125/125/37.5	2	4.34	2020
Shinyanga	Shinyanga	400/220/33	315/315/105	2	10.92	2021
Shinyanga	Shinyanga	220/33	125/125/37.5	2	4.34	2021
Rusumo (BENACO)	Kagera	220	30	2	0.69	2021
Nyakanazi	Kagera	400/220/33	120/120/45	2	4.16	2021
Kigoma	Kigoma	400/132/33	120/70/50	2	3.58	2021
Mburahati (Mabibo)	Dar es Salaam	220/132/33	200/200/45	2	6.94	2022
Buzwagi	Shinyanga	220/33	30	1	0.35	2022
Zegereni	Dar es Salaam	220/33	60	2	1.39	2022
Chalinze	Pwani	400/220/33	250/250/85	4	14.45	2022
Kinyerezi	Dar es Salaam	400/220/33	250/250/85	4	14.45	2022
Bagamoyo	Pwani	220/33	125	2	2.89	2022
Msalato	Dodoma	220/33	50	2	1.16	2023
Kikombo	Dodoma	220/33	100	2	2.31	2023
Ihumwa	Dodoma	220/33	30	2	0.69	2023
NARCO	Dodoma	220/33	45	2	1.04	2023
Simiyu	Simiyu	220/33	45	2	1.04	2023
Luguluni	Dar es Salaam	220/33	45	2	1.04	2023
Chanika	Dar es Salaam	220/33	45	2	1.04	2024
Mkuranga	Coast	220/33	120	2	2.77	2024
Mtibwa	Morogoro	220/33	45	2	1.04	2023
Mbeya	Mbeya	400/220/33	200/200/70	2	6.94	2023
Tunduma	Mbeya	400/330/33	250/250/85	2	8.67	2023
Kisada	Iringa	400/220/33	150/150/45	2	5.20	2023
Sumbawanga	Rukwa	400/66/33	100/100/35	2	3.47	2023
Somanga	Lindi	400/220	125	2	2.89	2024
Somanga	Lindi	220/33	85	2	1.97	2024
Kibiti	Lindi	400/220	125	2	2.89	2024
Kibiti	Lindi	220/33	85	2	1.97	2024
Ipole	Tabora	132/33	15	1	0.17	2024
Inyonga	Tabora	132/33	15	1	0.17	2024
Mpanda	Katavi	132/33	35	1	0.40	2024
Urambo	Tabora	132/33	35	1	0.40	2024
Nguruka	Tabora	132/33	15	1	0.17	2024
Dumila	Dodoma	220/33	30	2	0.69	2024
Mtwara	Mtwara	400/132	100	3	3.47	2024
Mtwara	Mtwara	400/220	125	2	2.89	2024
Mtwara	Mtwara	220/33	85	2	1.97	2024
Lindi	Lindi	400/132	100	2	2.31	2024
Mkata	Tanga	132/33	30	2	0.69	2024
Handeni	Tanga	132/33	30	2	0.69	2024
Songwe	Songwe	220/33	45	2	1.04	2024
Makongolos (Chunya)	Mbeya	220/33	45	2	1.04	2024
Masasi	Mtwara	400/33	45	2	1.04	2024
Tunduru	Ruvuma	400/33	45	2	1.04	2024
Ruangwa	Lindi	400/33	30	2	0.69	2024
Songea	Ruvuma	400/33	125	2	2.89	2024
Ifakara	Morogoro	220/33	20	2	0.46	2024
Mahenge	Morogoro	220/33	60	2	1.39	2024
Makumbusho	Pwani	220/132	150	2	3.47	2024
Mbezi Beach (Bunju)	Dar es Salaam	220/33	50	2	1.16	2024
Kunduchi	Dar es Salaam	220/33	60	1	0.69	2024
Kawe	Dar es Salaam	220/33	50	2	1.16	2024
Malagalasi	Kigoma (Kidahwe)	11/132	60	2	1.39	2024
Loliondo	Arusha	66/33	25	1	0.29	2024
Total					191.26	

Table 4-19: Phased Transformer Cost Estimates 2025 - 2034

Substation	Region	HV/LV (kV)	Rating (MVA)	No. of T.x	Total Cost (M\$)	Commissioning Year
Segera	Tanga	400/220/33	150/150/45	2	5.20	2025
Tanga	Tanga	220/132/33	150/150/45	2	5.20	2025
Kyela	Mbeya	400/220/33	180/180/45	2	6.24	2025
Kyaka	Kagera	400/220	125	2	2.89	2025
Kyaka	Kagera	220/33	85	2	1.97	2025
Makutuni	Knjaro	132/33	30	2	0.69	2026
Nangulukulu	Lindi	132/33	30	2	0.69	2025
Mwanza	Mwanza	400/220/33	250/125/85	2	7.23	2026
Musoma	Mara	400/132/33	250/125/85	2	7.23	2026
Kigoma	Kigoma	400/132/33	120/70/50	2	3.58	2026
Mpanda	Katavi	400/132/33	120/70/50	2	3.58	2026
Rujewa (Mbalali)	Mbeya	220/33	30	2	0.69	2028
Same	Knjaro	132/33	30	1	0.35	2028
Manyoni	Singida	220/33	30	2	0.69	2029
Kigwa	Iyui	132/33	30	2	0.69	2030
Bukombe	Geita	220/33	30	2	0.69	2030
Total					47.63	

Table 4-20: Phased Transformer Cost Estimates 2035-2044

Substation	Region	HV/LV (kV)	Rating (MVA)	No. of T.x	Total Cost (M\$)	Commissioning Year
Mbinga	Ruvuma	220/33	30	2	0.69	2035
Mbambabay	Ruvuma	220/33	30	2	0.69	2036
Engare Nairobi	Knjaro	132/33	30	2	0.69	2036
Namtumbo	Ruvuma	220/33	45	2	1.04	2036
Gonja	Knjaro	132/33	30	2	0.69	2037
Kijungu	Kiteto Manyara	220/33	30	2	0.69	2037
Mitundu	Singida	220/33	30	2	0.69	2040
Tabora	Tabora	400/132	250	2	5.78	2040
Tabora	Tabora	132/33	125	2	2.89	2040
Bwanga	Geita	220/33	45	2	1.04	2041
Usahunga	Kagera	220/33	45	2	1.04	2041
Total					15.95	

Table 4-21: Phased Substation Cost Estimates 2020 – 2024

Substation	Region	Switchgear (kV)	No. of Bays	Unit Cost M\$/bay	Total Cost M\$
Bulyanhulu	Shinyanga	220	2	5.25	10.51
Geita	Geita	220	3	5.25	15.76
Rusumo	Kagera	220	3	5.25	15.76
Nyakanazi	Kagera	400	3	6.83	20.48
Kigoma	Kigoma	400	4	6.83	27.31
Singida	Singida	400	2	6.83	13.65
Arusha	Arusha	400	6	6.83	40.96
Arusha	Arusha	220	4	5.25	21.01
Morogoro	Morogoro	220	2	5.25	10.51
Mtibwa	Morogoro	220	4	5.25	21.01
Iringa	Iringa	400	2	6.83	13.65
Kisada	Iringa	400	6	6.83	40.96
Mbeya	Mbeya	400	6	6.83	40.96
Tunduma	Mbeya	400	5	6.83	34.13
Tunduma	Mbeya	330	4	6.83	27.31
JNHPP	Pwani	400	11	6.83	75.09
Chalinze	Pwani	400	9	6.83	61.44
Chalinze	Pwani	220	7	5.25	36.77
Bagamoyo (Zinga)	Pwani	220	6	5.25	31.52
Somanga	Lindi	400	6	6.83	40.96
Kibiti	Pwani	400	8	6.83	54.61
Kibiti	Pwani	220	4	5.25	21.01
Tabora	Tabora	132	3	4.04	12.12
Ipole	Tabora	132	3	4.04	12.12
Inyonga	Katavi	132	2	4.04	8.08
Urambo	Tabora	132	2	4.04	8.08
Nguruka	Tabora	132	3	4.04	12.12
Mkata	Pwani	132	4	4.04	16.16
Handeni	Tanga	132	2	4.04	8.08
Mtwara	Mtwara	400	6	6.83	40.96
Mtwara	Mtwara	400	6	6.83	40.96
Mtwara	Mtwara	400	6	6.83	40.96
Lindi	Lindi	400	7	6.83	47.79
Msalato	Dodoma	220	5	5.25	26.27
Ihumwa	Dodoma	220	6	5.25	31.52
Kikombo	Dodoma	220	3	5.25	15.76
Songea	Ruvuma	400	3	6.83	20.48
Tunduru	Ruvuma	400	4	6.83	27.31
Masasi	Mtwara	400	4	6.83	27.31
Masasi	Mtwara	220	2	5.25	10.51
Ifakara	Morogoro	220	3	5.25	15.76
Simiyu	Simiyu	220	3	5.25	15.76
Kibiti	Lindi	220	1	5.25	5.25
Mkuranga	Pwani	220	4	5.25	21.01
Chanika (Buyuni)	Pwani	220	4	5.25	21.01
Ubungo	Dar es Salaam	220	2	5.25	10.51
Mburahati	Dar es Salaam	220	4	5.25	21.01
Zinga	Pwani	220	4	5.25	21.01
Bunju	Pwani	220	4	5.25	21.01
Kunduchi	Dar es Salaam	220	4	5.25	21.01
Mbezi Beach	Dar es Salaam	220	5	5.25	26.27
Kawe	Dar es Salaam	220	3	5.25	15.76
Makumbusho	Dar es Salaam	220	4	5.25	21.01
Total (2020 - 2024)				1,318.32	

Table 4-22: Phased Substation Cost Estimates 2025 -2034

Substation	Region	Switchgear (kV)	No. of Bays	Unit Cost M\$/bay	Total Cost M\$
Segera	Tanga	400	4	6.83	27.31
Tanga	Tanga	220	2	5.25	10.51
Uyole	Mbeya	400	2	6.83	13.65
Kyela	Mbeya	400	4	6.83	27.31
Kyela	Mbeya	220	2	5.25	10.51
Nyakanazi	Kagera	400	2	6.83	13.65
Kyaka	Kagera	400	4	6.83	27.31
Kyaka	Kagera	220	2	5.25	10.51
Lindi	Lindi	220	3	5.25	15.76
Nangulukulu	Lindi	132	2	4.04	8.08
Songwe	Songwe	220	4	5.25	21.01
Uyole	Mbeya	220	2	5.25	10.51
Mwanza	Mwanza	400	4	6.83	27.31
Musoma	Mara	400	2	6.83	13.65
Kigoma	Kigoma	400	1	6.83	6.83
Kigoma	kigoma	220	2	5.25	10.51
Mpanda	Katavi	400	6	6.83	40.96
Rujewa (Mbalali)	Mbeya	220	4	5.25	21.01
Kiyungi	Kilimanjaro	220	2	5.25	10.51
Makuyuni	Kilimanjaro	132	3	4.04	12.12
Same	Kilimanjaro	220	3	5.25	15.76
Manyoni	Singida	220	4	5.25	21.01
Tabora	Tabora	220	3	5.25	15.76
Kigwa	Iyui	220	3	5.25	15.76
Kigwa	Iyui	132	2	4.04	8.08
Bukombe	Geita	220	3	5.25	15.76
Total				431.12	

Table 4-23: Phased Substation Cost Estimates 2035 - 2044

Substation	Region	Switchgear (kV)	No. of Bays	Unit Cost M\$/bay	Total Cost M\$
Songea	Ruvuma	220	1	5.25	5.25
Mbinga	Ruvuma	220	4	5.25	21.01
Mbambabay	Ruvuma	220	3	5.25	15.76
KIA	Kilimanjaro	132	1	4.04	4.04
Engare Nairobi	Kilimanjaro	132	3	4.04	12.12
Same	Kilimanjaro	132	1	4.04	4.04
Gonja	Kilimanjaro	132	3	4.04	12.12
NARCO	Dodoma	220	1	5.25	5.25
Kijungu (Kiteto)	Dodoma	220	3	5.25	15.76
Kigwa (Uyui)	Tabora	220	3	5.25	15.76
Manyoni	Singida	220	6	5.25	31.52
Mitundu (Manyoni)	Singida	220	3	5.25	15.76
Geita	Geita	220	1	5.25	5.25
Bwanga	Geita	220	4	5.25	21.01
Usahunga	Geita	220	4	5.25	21.01
Kyaka	Kagera	220	1	5.25	5.25
Songea	Ruvuma	220	1	5.25	5.25
Namtumbo	Ruvuma	220	3	5.25	15.76
Shinyanga	Shinyanga	400	1	6.83	6.83
Tabora	Tabora	400	4	6.83	27.31
Kigoma	Kigoma	400	1	6.83	6.83
Total					272.90

- (1) Cost estimate is based on “a breaker and a half” scheme.
- (2) Switchgear associated with the power plants is not included.
- (3) Subs transmission or distribution switchgear is not included.
- (4) Expansion of existing substation is not included.

Table 4-24: Phased Reactive Compensation Cost Estimate

Substation	SVR			LVR		
	MVAr	Total No	Cost	MVAr	Total No	Cost
Iringa	40/60	2	4.27	60	2	3.29
Singida				60	6	9.86
Shinyanga				60	4	6.58
Mwanza				60	4	6.58
Musoma				40	4	4.38
Chalinze				90	6	14.80
Dodoma				90	2	4.93
Kinyerezi				40	2	2.19
Kibiti				60	6	9.86
Mtwara				40	4	4.38
Tunduru				30	4	3.29
Chalinze				90	2	4.93
Segera				90	2	4.93
Tanga				30	2	1.64
Segera				90	2	4.93
Arusha				90	2	4.93
Mbeya	50/90	2	6.41	30	4	3.29
Tunduma	30/50	1	1.78	30	5	4.11
Sumbawanga	30/50	2	3.56			
Nyakanazi	30/-30	2	2.14			
Kigoma	70/-70	3	7.48			
Sumbawanga				60	2	3.29
Mpanda				60	2	3.29
Kigoma				60	2	3.29
Geita				30	1	0.82
Benaco (Ngara)	10/-10	1	0.36			
	Total - SVR			Total - LVR		
		Total	25.99			109.60
			135.59	MUSD		

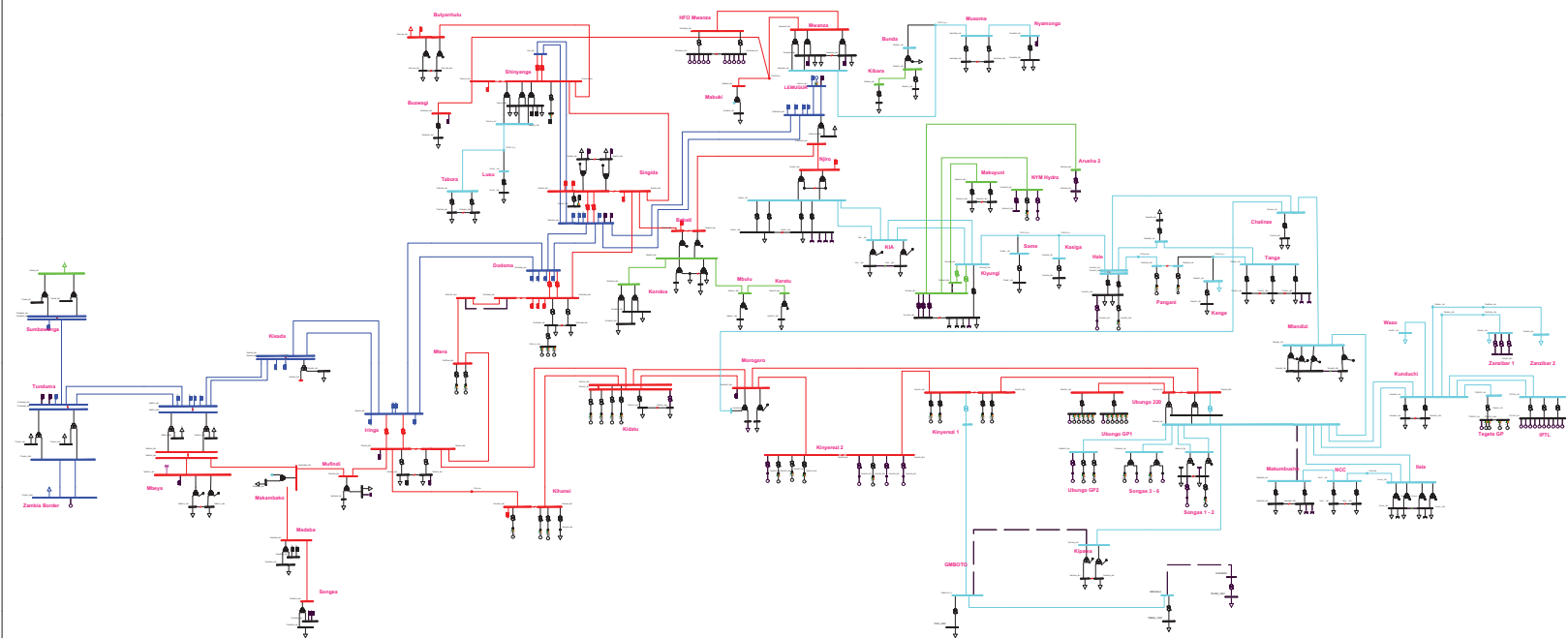
4.9.1. Summary of Cost Estimates

The overall phased costs for the transmission lines, transformers, substations and reactive power compensation over the planning horizon (2020-2044) are summarized in **Table 4-25**.

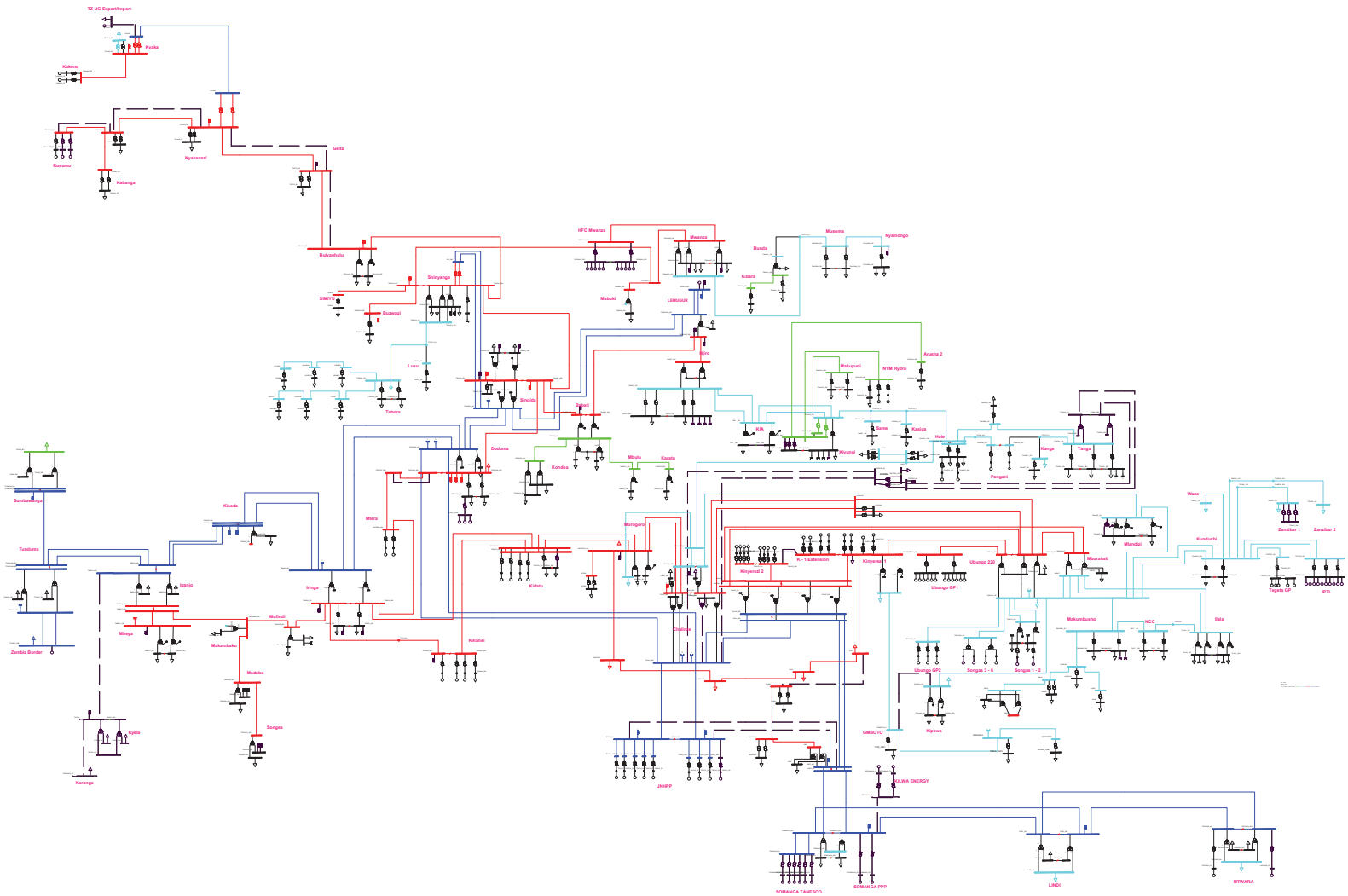
Table 4-25: Cost Estimates Summary

Cost of	Option, MUSD			Total
	2020-2024	2025-2034	2035-2044	
Transmission Lines	1,888.48	1,154.03	486.18	3,528.69
Transformers	191.26	47.63	15.95	254.84
Substation	1,318.32	431.12	272.90	2,022.33
Compensation	61.01	47.46	27.12	135.59
Total	3,459.08	1,680.23	802.15	5,941.46
% of Each Phase	58.22%	28.28%	13.50%	100%

Tanzania Existing Grid Network - 2019

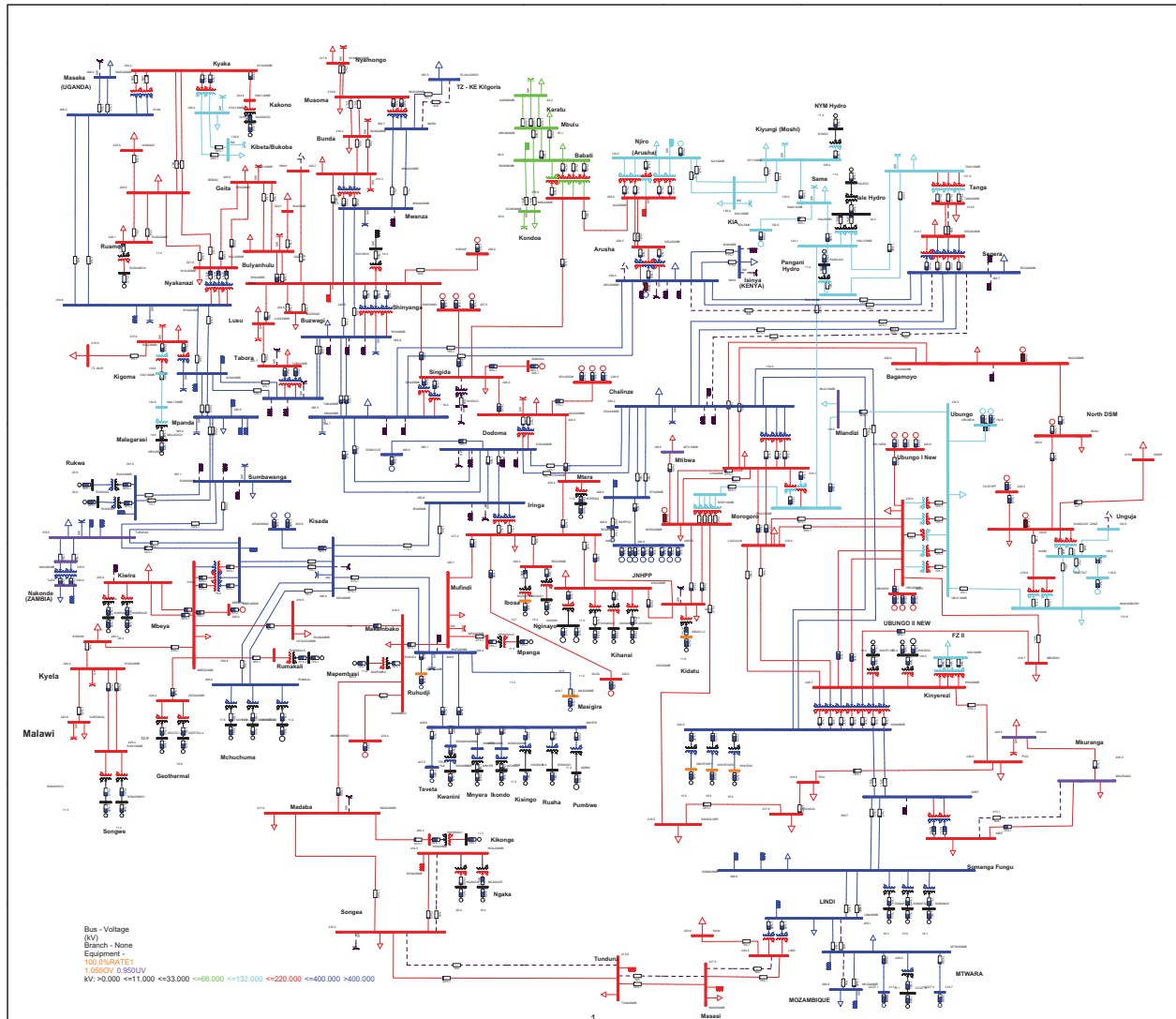


Tanzania Grid Network in 2024



Bus - Voltage (kV)
 Branch - None
 Equipment -
 100.00kV
 1.0000V 0.9500V
 kV: >0.000 <=11.000 <=33.000 <=66.000 <=132.000 <=220.000 <=400.000 >400.000

Load Flow for the Tanzanian Grid Network - Year 2044



CHAPTER 5

5. ECONOMIC AND FINANCIAL ANALYSIS

5.1. Introduction

Economic and Financial concepts are essentially used to determine the costs to be incurred and the resulting benefits from investing in the proposed power projects. They both involve ascertaining the net present value of a project based on its estimated present and future cash flows, appropriately discounted.

The economic and financial analysis on the proposed power investment plan identifies planning criteria used in the analysis that covers two major sub-chapters, namely:

- (a) A financial analysis of the proposed generation and transmission expansion plans; and
- (b) An estimate of the long-run marginal cost of generation, transmission and distribution.

It also spells out the required cost to implement the proposed power expansion plan so that players can identify projects to be implemented either independently or in partnership. The modality of implementing these projects can be either purely Government or Private or in partnership between the Public and Private Sector (PPP).

In this respect, the Government will have two roles to play as follows:

- (i) To mobilize financial resources in order to implement some of the earmarked projects; and
- (ii) To continue creating a conducive environment for attracting private investors in the electricity sub-sector.

Generally, all strategic power generation, transmission lines and substations upgrades projects will be implemented by Government while the remaining generation and related power evacuations projects may be implemented by Private Sector.

However, it is important to note that the analysis done under this Chapter does not cover the economics of interconnecting the isolated load centres. This is due to the fact that the Government is implementing two transmission projects with a capacity of 132 kV to connect the remaining two regions of Kigoma and Katavi to the National Grid by 2023.

5.2. Basic Assumptions

The economic and financial analyses were done by taking into account some relevant basic economic and financial assumptions, which are described hereunder:

5.2.1. Discount Rate

The Plan considers discount rate as the time value of money which is used to calculate present values of a series of future costs. An appropriate discount value has to be selected by taking into account the reflection of opportunity cost of capital; and normally tends to be higher in regions where capital is relatively scarcer. Thus, the choice of discount rate is discretionary. Nevertheless, some studies might use the Weighted Average Cost of Capital as the method for calculating the discount rate but this does not provide the perfect value in every situation.

Typically, the use of a higher discount rate tends to favour thermal power projects in cost comparisons with hydropower projects due to their lower initial costs, but higher yearly operating costs. In contrast, lower discount rates would favour hydro plants, where most of the expenditures are at the beginning of the project cycle. By considering the previous PSMPs, a discount rate of 10 percent (which excludes inflation) was used in converting capital costs into equivalent annual costs over the life of a project and for comparisons of unit generation costs for initial screening of options.

5.2.2. Interest Rate

Interest rate is also considered as the cost of the loan, and it usually varies from one Financier to the other. This implies that different sources of finance have a different cost of loans to be offered. Basing on experience, the interest rate for commercial loans in the long term borrowing varies from 4.4 percent for Government lending and 7 percent for private investor. However, for the purpose of this Plan, a weighted average interest rate of 5.8 percent has been considered to represent the required return for the Financiers. This rate represents an average cost of debt in Tanzania.

5.2.3. Debt Equity Ratio

Most Financiers and Banks prefer to use the standard debt equity ratio of 70:30 to finance infrastructural projects including power generation and transmission. Therefore, this ratio has been adopted in this Plan.

5.2.4.Loan Condition

For the purpose of this Plan, loan tenure for financing power projects is set at fifteen (15) years of which two (2) years being grace period for all power projects except hydropower projects which is assumed to be four (4) years.

5.2.5.Interest During Construction (IDC)

This is interest incurred directly as the result of investment cost obtained as loan during construction. This has impact on the overall project cost as it is added on the project cost by capitalizing them. In this Plan, 5.8 percent per annum which is equal to the interest rate has been assumed in calculating IDC of projects based on the Investment Plan.

5.2.6.Inflation Rate on Capital Cost

The analysis made in this Plan is based on constant prices of the year 2019. The Constant Price Method avoids the assumption of the price escalation, as forecasting inflation rate in long term is not reliable. Also, price escalation of benefit and cost will be balanced out if the escalation rate is the same for both of them in the Investment Plan. Therefore, price escalation is not priced in the Investment Plan but it will only be shown to highlight figures which could have been involved.

5.2.7.Foreign Exchange Rate

An exchange rate of **TZS 2,316.4** against **1 USD** has been used for this Plan as provided in the Government guidelines for the Preparation of Plans and Budgets for the Financial Year 2019/20 – 2021/22.

5.2.8.Depreciation Rate

The depreciation rates applied in this Plan are calculated basing on the economic life of various power projects to be implemented. Thus, the following depreciation rates have been applied:

- (i). Hydropower projects – 2% per annum;
- (ii). Gas fired and Renewable energy power projects – 4% per annum;
- (iii). Coal fired power projects – 3% per annum; and
- (iv). Transmission projects – 3% per annum.

5.2.9. Income Tax

Tanzanian Corporate Income Tax (CIT) rate is 30 percent. This implies that benefit exceeding cost is subject to deduction of 30 percent tax value in Investment Plan.

5.2.10. Return On Equity

Return On Equity (ROE) is a measure of financial performance calculated by dividing net income by shareholders' equity. Usually, utilities have many assets and debt on the balance sheet compared to a relatively small amount of net income. A normal ROE in the utility sectors is about 10 to 12.5 percent. For the purposes of this Plan, the ROE is assumed to be 12 percent.

5.3. Financial Analysis

The financial analysis of projects under this Plan follows from the analysis done on its economic perspective and long run marginal costs. Likewise, this section presents the approach and results of the financial analysis. The financial analysis takes into consideration the previous PSMPs from the financial point of view and focuses on the financing of the power projects and the total amount of required debt and equity. During financial forecasting period the annual interest costs, repayment of debt and income taxes were presented.

5.3.1. Summary of Financial Analysis

For the purposes of aligning with the Tanzania Development Vision 2025, the financing requirement to implement the PSMP in the short run (2020 – 2025) is about **USD 9,526.4 Million**, of which debt financing will be USD 4,516.1 Million and equity will be USD 5,010.3 Million. **Table 5-1** shows the breakdown of projections of the annual financing requirement in the short run.

Table 5-1: Short Run Financing Requirement

US\$ Million									
Investments	Capacity MW	Online Year	2020	2021	2022	2023	2024	2025	Project Total
Generation									
Julius Nyerere HPP 2,115 MW	2,115.0	2022	550.0	1,169.2	684.4	-	-	-	2,403.5
Rusumo HPP 80 MW	26.7	2021	39.6	5.7	-	-	-	-	45.2
Ruhudji HPP 358 MW	358.0	2025	-	-	122.2	122.2	81.5	81.5	407.4
Kakono HPP 87 MW	87.0	2026	-	-	28.0	112.2	84.1	42.1	266.4
Rumakali HPP 222 MW	222.0	2026	-	-	-	150.1	112.6	75.1	337.7
Kikonge HPP 300 MW	300.0	2028	-	-	-	-	-	74.1	74.1
Malagarasi HPP 49.5 MW	49.5	2024	-	14.4	57.7	43.2	28.8	-	144.1
Murongo-Kikagati HPP 14 MW	7.0	2021	23.2	5.8	-	-	-	-	29.0
Lower Songwe HPP (Manolo) 180.2 MW	90.1	2028	-	-	-	-	-	27.5	27.5
Kihansi II - Upper Kihansi HPP 120 MW	120.0	2026	-	-	-	88.3	66.2	44.2	198.7
Masigira HPP 118 MW	118.0	2028	-	-	-	-	-	104.5	104.5
Kinyerezi - I Extension 185 MW	185.0	2021	18.8	41.4	-	-	-	-	60.2
Mtwara I 300 MW	300.0	2025	-	-	-	7.3	211.1	145.6	363.9
Singida - I (wind) 100 MW	100.0	2025	-	-	-	-	-	126.5	126.5
Singida (solar) 150 MW	150.0	2023	-	-	11.7	105.4	-	-	117.1
Dodoma Solar - I 55 MW	55.0	2024	-	-	-	56.3	37.6	-	93.9
Ngozi (wellhead) & Ngozi - I 30 MW	30.0	2023	-	22.7	45.4	7.6	-	-	75.6
Kiejo - Mbaka 60 MW	60.0	2024	-	-	45.4	90.8	15.1	-	151.3
Natron 60 MW	60.0	2027	-	-	-	-	-	45.4	45.4
Ngozi - II 40 MW	40.0	2026	-	-	-	-	30.3	60.5	90.8
Songwe 5 MW	5.0	2023	-	3.8	7.6	1.3	-	-	12.6
Luhoi 5 MW	5.0	2027	-	-	-	-	-	3.8	3.8
Total Generation Investments	19,639.7		631.6	1,262.9	1,002.3	784.6	667.2	830.6	5,179.2
Transmission	Voltage Level (kV)	Online Year	2020	2021	2022	2023	2024	2025	Project Total
Rufiji-Chalinze-Dodoma (400kV)	400	2022	67.3	235.6	33.7	-	-	-	336.5
Kinyerezi-Chalinze (400kV)	400	2022	24.0	84.0	12.0	-	-	-	119.9
Ruhudji-Kisada (400kV)	400	2025	-	-	-	34.9	20.3	2.9	58.1
Rusumo-Nyakanazi (220kV)	220	2021	-	38.4	-	-	-	-	38.4
Malagarasi-Kidahwe (Kigoma) (132kV)	132	2024	-	-	3.9	7.7	1.3	-	12.9
Kakono-Kyaka (220kV)	220	2026	-	-	-	-	-	6.5	6.5
Rumakali-Mbeya (Uyole) (220kV)	220	2026	-	-	-	-	-	11.7	11.7
JNHPP-Kibiti (400kV)	400	2025	-	-	-	-	52.4	34.9	87.3
Singida-Arusha-Namanga (400kV)	400	2021	92.1	13.2	-	-	-	-	105.3
Bulyankulu-Geita (220kV)	220	2020	7.1	-	-	-	-	-	7.1
Geita-Nyakanazi (220kV)	220	2021	29.3	19.6	-	-	-	-	48.9
"North West Grid" Iringa-Mbeya-Tunduma-Sumbawanga-Mpanda-Kigoma-Nyakanazi (400kV)	400	2026	55.4	129.4	129.4	129.4	138.6	92.4	674.5
Tabora-Urambo-Nguruka-Kidahwe (Kigoma) (132kV)	132	2024	8.2	8.2	24.6	32.8	8.2	-	82.0
Tabora-Ipole-Inyonga-Nsimbo (Katavi) (132kV)	132	2024	4.8	9.6	28.8	43.1	9.6	-	95.9
Ibadakuli (Shinganya)-Imalilo (Simiyu) (220kV)	220	2023	-	-	8.5	34.0	-	-	42.5
Tanzania (Nyakanazi)-Kyaka-Uganda (Masaka) (400kV)	400	2025	-	-	34.8	69.5	52.1	17.4	173.8
Chalinze-Segera (400kV); Segera-Tanga (220kV)	400; 220	2025	-	-	15.0	60.0	45.0	30.0	150.0
Chalinze-Bagamoyo (220kV)	220	2022	-	51.0	34.0	-	-	-	85.0
Segera-Arusha (400kV)	400	2025	-	-	16.2	64.7	48.5	32.4	161.8
Morogoro-Mtibwa (220kV)	220	2023	-	-	31.5	21.0	-	-	52.6
Tanzania-Mozambique (MOTA)									
Interconnection (400kV)	400	2024	-	-	-	24.9	16.6	-	41.5
Tanzania-Malawi (TAMA)									
Interconnection (400kV)	400	2025	-	-	-	21.5	53.9	32.3	107.7
Mbeya-Songwe-Chunya (Makongoros) (220kV)	220	2024	-	-	5.6	14.0	8.4	-	28.0
Mkata-Handeni (132kV)	132	2024	-	-	-	-	32.9	-	32.9
Dodoma City Ring Circuit (220kV)	220	2023	-	22.9	57.2	34.3	-	-	114.5
NARCO (Dodoma)-Dumila (220kV)	220	2024	-	-	-	13.4	8.9	-	22.3
Songea-Tunduru-Masasi-Lindi (400kV); Masasi-Ruangwa (220kV)	400; 220	2024	-	-	69.1	172.7	103.6	-	345.4
Ifakara-Mahenge (220kV)	220	2024	-	-	-	-	30.2	-	30.2
Tanzania (Mwanza)-Kenya (Kilgoris) Interconnection (400kV)	400	2025	-	-	-	57.2	143.0	85.8	285.9

Transmission	Voltage Level (kV)	Online Year	2020	2021	2022	2023	2024	2025	Project Total
Lindi-Nangurukuru (Kilwa) (132kV)	132	2026	-	-	-	-	9.8	24.5	34.3
Zinga-Kunduchi-Makumbusho (220kV)	220	2024	-	-	-	89.1	59.4	-	148.4
Karatu-Loliondo (66kV)	220	2024	-	-	4.9	12.1	7.3	-	24.3
Chanika-Mkuranga-Kibiti (220kV)	220	2024	-	-	-	-	84.1	-	84.1
Kinyerezi-Ubungo-Mburahati (220kV)	220	2022	-	-	42.8	-	-	-	42.8
Dar-Moro-Dodoma SGR-TL (220kV)	220	2020	48.5	20.0	-	-	-	-	68.5
Kinyerezi-Luguruni (220kV)	220	2025	-	-	-	1.0	-	6.2	7.3
Mtwara-Somanga Fungu (400kV)	400	2024	-	-	29.3	146.7	117.3	-	293.4
Somanga-Kibiti-Kinyerezi (400kV)	400	2024	-	-	-	123.1	82.1	-	205.2
Iringa-Dodoma-Singida-Shinyanga (Existing TL - 400kV) - Transformers & Compesators (TL Upgrade)	400	2021	37.6	40.7	-	-	-	-	78.3
Shinyanga-Buzwagi (Existing TL-220kV) - Buzwagi Substation (TL Upgrade)	220	2022	-	-	0.4	-	-	-	0.4
Morogoro-Ubungo (Existing TL - 220kV) - Zegereni Substation (TL Upgrade)	220	2022	-	-	1.4	-	-	-	1.4
Total Transmission Investments			374.4	672.4	582.9	1,207.2	1,133.4	376.9	4,347.2
Total Investments			1,005.9	1,935.3	1,585.2	1,991.8	1,800.7	1,207.5	9,526.4
Cumm. Investments			1,005.9	2,941.2	4,526.4	6,518.2	8,318.9	9,526.4	
Investments subjected to Debt:Equity			375.6	686.9	804.2	1,723.3	1,671.4	1,190.1	
Financing	Contribution Ratio								
Govt Fully Financed Investments	100% Equity		630.3	1,248.3	781.0	268.5	129.3	17.4	
Debt	70%		262.9	480.8	562.9	1,206.3	1,170.0	833.1	
Equity	30%		112.7	206.1	241.3	517.0	501.4	357.0	
Total Debt/Year			262.9	480.8	562.9	1,206.3	1,170.0	833.1	4,516.1
Total Equity/Year			743.0	1,454.4	1,022.3	785.5	630.7	374.4	5,010.3
CAPITAL NEEDED	\$ Million								
Short Term (2020 - 2025)	9,526.4								

Note: Project costs marked with red colour are partial cost since construction of these projects goes beyond 2025.

Similarly, in order to implement this Plan for the entire planning horizon (2020 – 2044) approximately **USD 38,340.4 Million** is required as capital cost for generation and transmission projects, as detailed in **Appendix V**.

However, after including the distribution projects, drawdown of capital financing and IDC, the total required capital expenditures for financing the power projects increases to USD 58,377 Million as shown in **Table 5-2**.

Impact of Financing Capital Expenditure: The financing of capital expenditure given in **Table 5-2** is based on the 70 percent debt and 30 percent equity financing (except for the Government fully funded projects) the inclusion of IDC amounting to USD 9,173 Million changes the debt to equity ratio to be 71 percent and 29 percent respectively of the drawdowns for capital expenditure.

Table 5-2: Breakdown of Capital Costs Requirement over the Plan Horizon (2020-2044)

Capital Costs and Financing Items		(Mill. USD)	%
1) Capital Costs without Inflation and IDC			
Generation		32,612	
Transmission		5,728	
Distribution		10,864	
Total Capital Cost (excl. Inflation & IDC)		49,204	
2) Drawdowns for Financing Capital Expenditures			
Debt financed		32,290	66%
Equity financed		16,914	34%
Total Financing without IDC		49,204	100%
3) Overall Financing including IDC			
IDC	9,173		
Debt	<u>32,290</u>		
Total Debt (Drawdown + IDC)		41,463	71%
Equity		16,914	29%
Total Financing including IDC		58,377	100%

5.3.2. Financed by Debt

Optimal capital structure is the mix of debt and equity financing. Debt financing often requires the borrower to adhere to rules regarding financial performance. Usually, there is a short and long term debt financing. However, power investment requires long term financing that is fifteen (15) to twenty (20) years.

5.3.3. Interest During Construction

The Interest During Construction (IDC) for the generation and transmission over the period of 2020 to 2044 amounts to **USD 9,173 Million**, which increases the overall cost of capital expenditure by 18.6 percent. The IDC is added to the debt principal resulting to increase in total debt obligation, which is recovered together with the principal debt over the planning horizon.

5.3.4. Inflation

The projects will be implemented one after another during the planning horizon, hence the inflation will have impact on the total cost of implementing this Plan. In this case, inflation rate of 1.8 percent per year has been assumed, which is a combination of USA

and TZ CPI indexes. Based on annual inflation of 1.8 percent, the overall capital costs will increase by **USD 3,076 Million** (accumulation) an increase of 5 percent.

The breakdown of total capital expenditure, inflation and Interest During Construction for power projects over the planning horizon is shown in the **Table 5-3**.

Table 5-3: Breakdown of Overall Financing Requirements for Capital Costs⁸

Cost Item	(Mill. USD)	(Mill. USD)	(%)
1) Capital Costs without Inflation and IDC			
Generation	32,612		66.3
Transmission	5,728		11.6
Distribution	10,864		22.1
Total Capital Cost (excl. Inflation & IDC)	49,204		100.0
		Inflation	
		(Mill. USD)	
2 Capital Costs with Inflation			
Generation	35,386	2,774	90.2
Transmission	6,031	302	9.8
Distribution	10,864	-	-
Total Capital Cost (incl. Inflation)	52,280	3,076	100.0
3) Capital Costs with Inflation and IDC			
Interest During Construction	9,173		
Capital Cost incl. Inflation	52,280		
Total Capital Costs (incl Infl & IDC)	61,453		

5.3.5. Unit Cost of Power Supply for Proposed Projects

The unit cost of power supply derived on a financial basis for the new power projects was calculated for each year of the planning horizon by dividing the Annual Revenue Requirements (ARR) by the energy supplied. The financial cost of power supply is derived on an accounting basis and includes the depreciation expense, financing costs and net income for the Utility. Likewise, the financial unit cost of supply is obtained by

⁸ Transmission cost of USD 5,728 Million excludes costs incurred before 2019 for the projects under construction.

dividing the ARR by the energy supplied for that particular year. **Table 5-4** presents the ARR, energy supplied and the computed unit cost of annual power supply.

According to the information on the **Table 5-4**, the unit cost of power supply decreases sharply from 13.7 UScents/kWh in 2021 to a low value of 9.6 UScents/kWh in 2022 and reaching an average of 5.5 UScents/kWh from 2023 towards end of the planning period. The sharp decline of the unit cost of power supply is due to introduction of JNHPP. Nevertheless, the ARR considered in this analysis caters for the new investments only and not for the overall ARR of the power utility.

Table 5-4: Annual Revenue Requirements, Energy Supplied and Unit Cost of Supply

Year	Annual Rev. Requirement (Mill. USD)	Energy Supply (GWh)	Unit Cost of Supply (USc/kWh)
2020	-	-	-
2021	106	778	13.7
2022	346	3,623	9.6
2023	478	10,848	4.4
2024	642	11,588	5.5
2025	906	15,658	5.8
2026	1,015	18,173	5.6
2027	995	18,956	5.3
2028	1,348	24,956	5.4
2029	1,792	33,925	5.3
2030	1,842	35,401	5.2
2031	2,152	39,882	5.4
2032	2,646	48,056	5.5
2033	3,162	57,148	5.5
2034	3,646	65,690	5.6
2035	3,766	68,717	5.5
2036	4,196	74,785	5.6
2037	4,522	78,150	5.8
2038	5,018	84,795	5.9
2039	5,597	93,955	6.0
2040	5,985	98,008	6.1
2041	6,340	100,816	6.3
2042	6,704	103,089	6.5
2043	7,360	109,335	6.7
2044	8,188	118,508	6.9

5.4. Long Run Marginal Costs

Generally, the Long Run Marginal Cost (LRMC) is the incremental cost incurred by a firm in producing one (1) additional unit of electricity when all inputs are variable. In particular, it is an extra cost incurred by the firm as it increases the scale of its operations by not only adding more workers to a given factory but also by building a larger factory/plant.

The LRMC under this Plan is considered as the cost of supplying an incremental unit of electricity (kWh) to the system at a future date. It is used as a base for electricity pricing

due to the rationale that it directs customer through the price charged for electricity towards the most efficient use of resources available. Theoretically, if price is equal to marginal cost of supply, an optimal allocation of resources takes place and economic efficiency will result.

Usually, the Marginal Cost is one among factors considered during the development of electricity tariffs. The LRMC of electricity supply are computed to satisfy the criterion of economic efficiency. Similarly, Marginal Costs are usually adjusted to arrive at an appropriate tariff structure that meets various other goals and constraints, including, the financial viability of the power projects, social objectives, metering and billing constraints. Nevertheless, this Plan focuses exclusively on the estimate of Long Run Marginal Costs and does not address the financial viability or tariff structure issues.

5.4.1.Approach Used to Estimate Marginal Costs

The computation of Marginal Costs focuses into two broad cost categories namely: demand or capacity-related costs and energy-related costs. Marginal capacity costs (also referred to as marginal demand costs) are taken as the costs of investment in generation, transmission and distribution to supply additional units plus the fixed costs of operation and maintenance.

The projected capital investment cost of power generation, transmission and distribution projects forms the demand costs. Marginal energy costs are the costs of fuel, energy purchases and the variable operating and maintenance costs needed to provide additional kilowatt-hours.

It is important to note that, the mandate for this Plan considered only the expansion of the generation and transmission system. It does not include the estimate of capital costs for the expansion of distribution system to meet the system needs at the end of this Plan (2044). Thus, an estimate of the distribution investments is required, even though it is not part of the mandate for the Plan.

Investment in distribution networks are capital intensive systems. Timely investments are crucial for long term reliability of their service. In coming years, many networks will need extensive investments idue to their aging. Also, energy efficiency, Demand Side

Management (DSM), network energy loss reduction, quality of service standards, and security of power supply require active, flexible, and smart networks thus intensive investments.

Unreliable and inadequate power supply infrastructure have significant adverse effects on the public and the economy as a whole. An appropriate planning process is essential to ensure ongoing efficient and reliable power supply. To determine this, a tool to identify and assess the investment requirements of distribution networks has to be available.

However, based on various study including PSMP 2008, it is assumed that the distribution costs will amount to about twice (200 percent) of the investment costs in transmission. According to Tanzania Development Vision 2025, it's expected that villages electrification will reach 100 percent by 2025, hence the distribution investment cost during the short run (2020-2025) is expected to be above 200 percent of transmission investment cost and slightly below 200 percent of the transmission cost in the medium and long term (2026-2044).

On the other hand, Operation and Maintenance costs are expected to be minimum during the short term, higher during the medium and long term due to planned and unplanned maintenance carried out on the aged distribution infrastructure. Therefore, total distribution costs during the short term will be lower compared to medium and long term.

5.4.2. Summary of Results

The Long Run Marginal Cost of power projects was calculated on a year-by-year basis by examining the incremental cost over the base year. This approach is closer to the robust definition of Long Run Marginal Cost.

From the analyses, the unit cost of generation, transmission and distribution were calculated for each year as presented in **Table 5-5**.

Table 5-5: Long Run Marginal cost (US cents per kWh) for the period 2020-2044

Period	Marginal cost of Generation	Marginal cost of Transmission	Marginal cost of Distribution	Marginal cost of Supply
2020-2025	14.9	3.9	7.2	24.9
2026-2034	6.5	0.6	1.4	8.3
2035-2044	5.2	0.6	1.4	7.0
2020-2044	6.7	1.0	2.2	9.6

The marginal costs of generation, transmission and distribution cannot simply be added to result in the overall marginal cost of power supply since there are transmission losses ranging from 5 to 4 percent as well as distribution losses in the order of 15 to 12 percent short, medium and long term periods.

CHAPTER 6

6. CONCLUSION AND RECOMMENDATIONS

6.1. Conclusion

Tanzania has consistently identified that inadequate, expensive, unreliable and limited access to power are critical constraints to economic growth of the country. To address these challenges, there is a need of robust power infrastructure that supports the economic and social development agenda of the country. The Government has set the target to reach electricity consumption per capita of 490 kWh per annum by 2025 equally the Government intend to build an industrial led economy to support its desire to attain a status of a higher middle income country by 2025. Therefore, in order to meet these targets, more investment is required in power generation, transmission and distribution network.

The PSMP 2020 Update details a least cost power generation plan for the country in immediate to long term up to 2044 that satisfies the forecasted demand over the planning horizon. The Plan also include an associated transmission expansion plan to evacuate power from generation sources to the respective load centres across the country.

The Generation Plan considered the available energy resources in the country which includes hydro, natural gas, coal, solar, wind and geothermal for power generation. Generated power will be used domestically as well as export while ensuring that the country has adequate, affordable, reliable and security of power supply over the planning horizon.

In order to meet the forecasted demand, the country requires a total installed generation capacity of 3,966 MW in the short term, 12,257 MW in the medium and 20,200.6 MW in the long term. The Plan indicates power generation mix which varies over the planning period and by 2044 the generation mix consist of 5,690.4 MW (28.15%) of hydro; 6,700 MW (33.18%) of natural gas; 5,300 MW (26.24%) of coal; 800 MW (3.96%) of wind; 715 MW (3.54%) of solar; and 995 MW (4.93%) of geothermal of power generation.

Power generation from diesel/HFO has been phased out from 2021 and retained as reserve capacity for emergency through out the planning period. This Plan observes a reserve margin on firm capacity in the range of 15 - 20 percent.

In order to evacuate the generated power to the load centres, the transmission expansion plan determines new lines and required system upgrades. The planned lengths of power transmission projects includes 3,150.20 km of 400 kV, 1,833.70 km of 220 kV and 920.80 km of 132 kV in the short term; 2,444.45 km of 400 kV, 650.70 km of 220 kV and 192.00 km of 132 kV in the medium term; and 610.00 km of 400 kV, 1,180.30 km of 220 kV and 155.20 km of 132 kV in the long term.

By the end of the planning period the generation and transimsion plans provides sufficient energy to meet the country needs in the National Grid system as well as connecting all isolated loads.

Moreover, the Plan provides export capacity of 1,500 MW, however due to limitation of transmission capacity in the short term only 1,000 MW may be traded within EAC and SADC regions from 2023 and the remaining 500 MW may be traded from 2025. The country's available surplus power capacity and its cross border infrastructure enables power trading within EAC and SADC regions and thus will enable Tanzania to be the power hub in the SAPP and EAPP.

The proposed power expansion plan requires a total of USD 38,340.4 Million throughout the planning horizon, of which USD 9,526.4 Million will be required in the period of 2020-2025. When inflation and interest during construction are added, total investment required rises to USD 50,589.2 Million in the long run, about two third of this amount is earmarked for power generation projects over the planning horizon.

6.2. Recommendations

The Task Force Team recommends the following:

- a) Most of the planned power projects have no full feasibility study reports. Therefore, the Government to ensure that strategic power projects are studied to full feasibility level before implementation of the respective projects so as to reduce project

implementation lead time and cost. Particularly, to speed up feasibility studies for geothermal resources in order to enhance the implementation of identified geothermal projects;

- b) The Government to continue investing in the exploration and development of hydrocarbons to increase more discoveries. Further, investment in processing and transportation infrastructure is required to satisfy projected high demand of natural gas for power generation. Extension of the natural gas pipeline network from Dar es Salaam to other regions including Dodoma and Pwani (Bagamoyo) to be fast-tracked to allow its use for the proposed gas-fired power plants;
- c) Implementation of this Plan requires huge financial resources thereby needs concerted efforts in mobilizing financing for both power generation and transmission projects. The Government to continue with efforts of attracting private investment in the electricity sub-sector;
- d) The Government to fast-track the implementation of interconnection transmission lines and negotiations to commence for possible power trading up to 1,500 MW within the SAPP and EAPP starting from 2023;
- e) Uranium resources has not been considered for power generation in this Plan. The National Energy Policy of 2015 and the Mineral Policy of Tanzania 2009 acknowledge the availability of uranium resource in Tanzania. There is need to prepare Implementation Strategies including human capacity building on the use of nuclear for power generation. Such strategies will ensure future utilization of nuclear resource for power generation by 2045;
- f) The Government through the Ministry of Energy to consider establishing a monitoring and evaluation Task Force responsible for preparation of the Implementation Strategy for effective implementation of PSMP 2020 Update; and
- g) The Government to conduct a comprehensive Power System Master Plan in 2025 as the last was conducted in 2008 and updated several times (2009, 2012, 2016 and 2020). Preparation to start on January, 2023.

APPENDICES

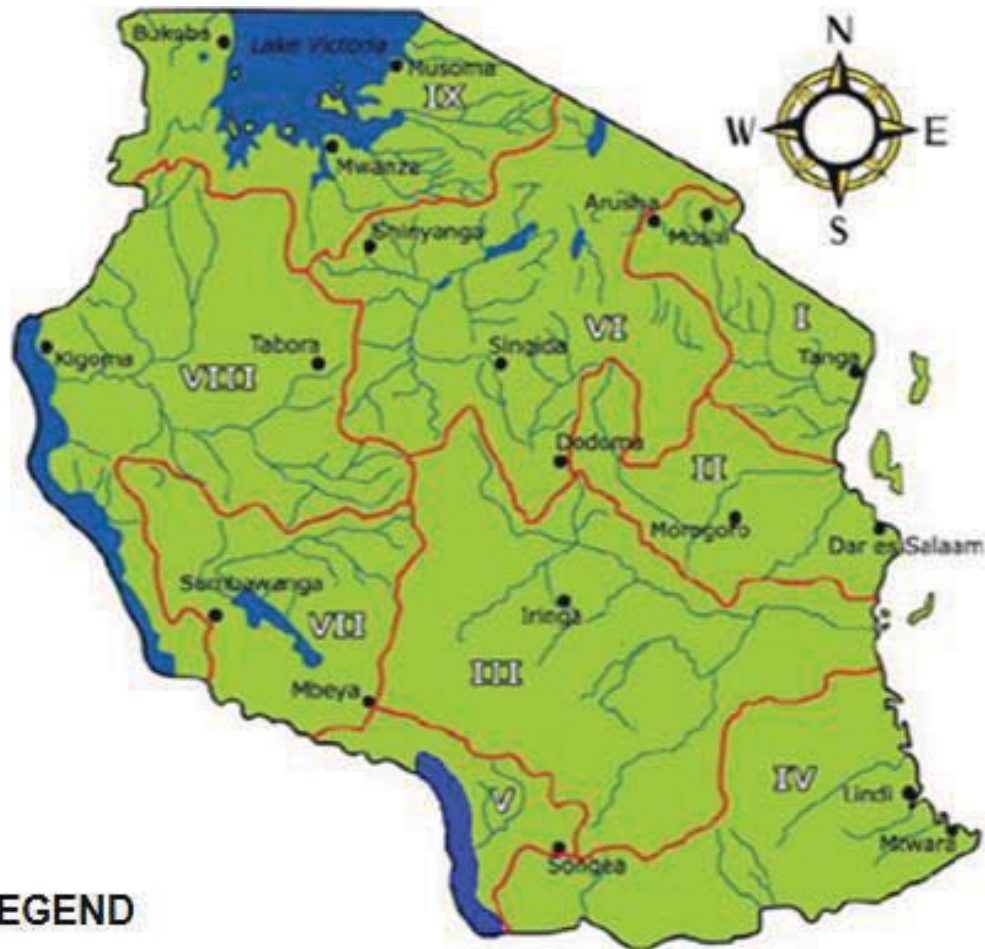
APPENDIX I: Task Force Team Involved In Preparation of PSMP 2020 Update

S/N	NAME	ORGANIZATION	RESPONSIBILITIES
1.	Juma F. Mkobya	MoE	Team Leader + Generation Planning
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4.	John F. Kitonga	EWURA	Load Forecast
5.	Marianus I. Mgendera	TANESCO	Load Forecast
6.	Abdallah M. Chikoyo	TANESCO	Generation Planning
7.	Elias R. Kajiru	TANESCO	Generation Planning
8.	Ahmed M. Chinemba	MoE	Generation Planning
9.	Godson C. Bisansaba	MoE	Generation Planning
10.	Fokas Daniel	TANESCO	Transmission Planning
11.	Jensen G. Mahavile	REA	Transmission Planning
12.	Zuvena B. Nkwanya	MoE	Transmission Planning
13.	Lusajo K. Mwakaliku	MoE	Economic + Financial Analysis
14.	Oliver F. Mtatifikolo	TPDC	Economic + Financial Analysis
15.	Jesca E. Mugyabuso	MoFP	Economic + Financial Analysis
16.	Mathew D. Maduhu	TANESCO	Economic + Financial Analysis

INVITEES

S/N	NAME	ORGANIZATION	RESPONSIBILITIES
1.	Elineema Mkumbo	REA	Hydrology Expert
2.	James Kirahuka	TANESCO	Hydrology Expert
3.	Rasmus Hyera	TGDC	Geothermal Expert
4.	Patricia Nguliule	TANESCO	Documentation

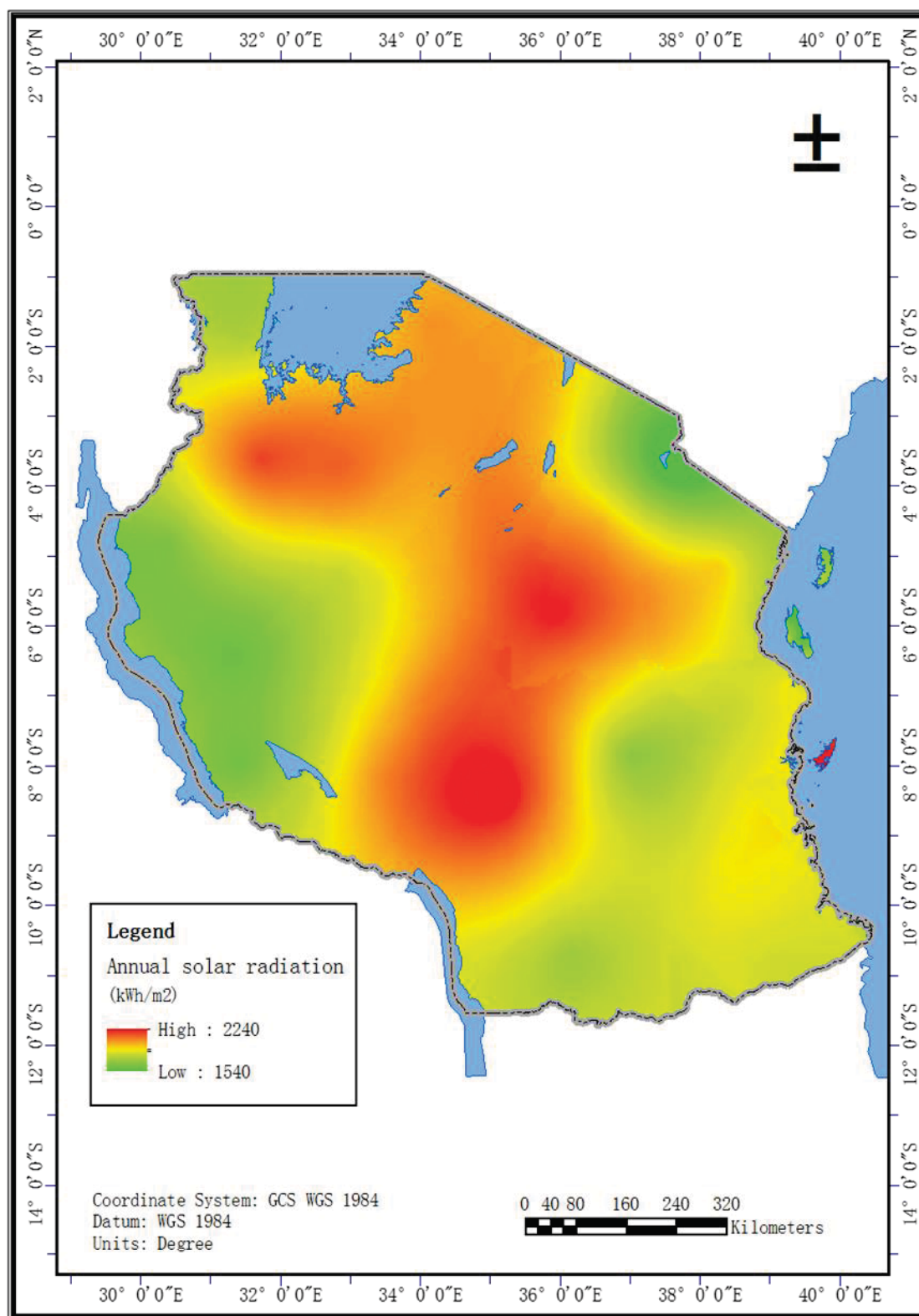
APPENDIX II: River Basins in Tanzania



LEGEND

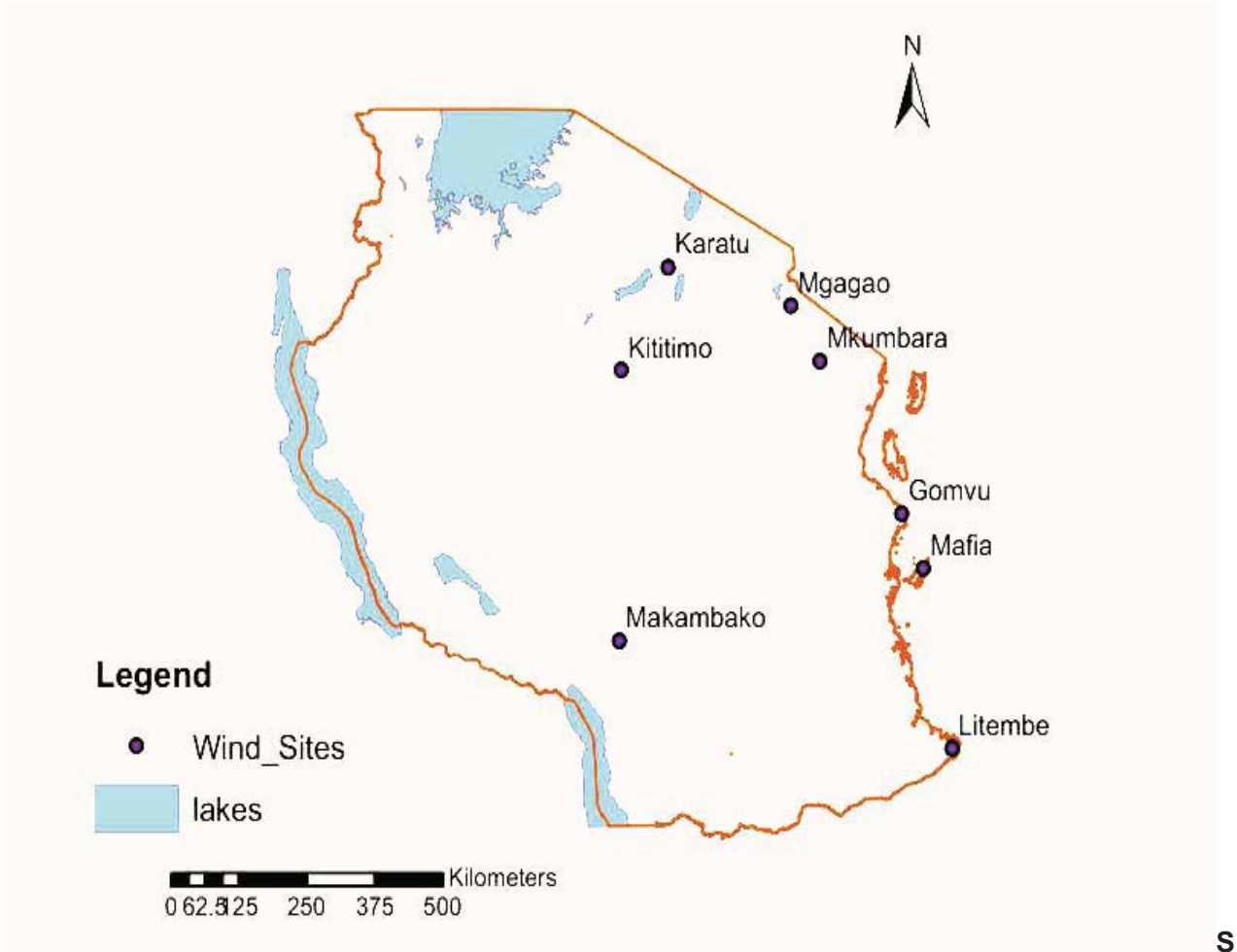
I – Pangani Basin	IV – Ruvuma and Southern Coast Basin	VII – Lake Rukwa Basin
II – <u>Wami Ruvu</u> Basin	V – the Lake Nyasa	VIII – Lake Tanganyika Basin
III – <u>Rufiji</u> Basin	VI – The internal drainage basin	IX – Lake Victoria Basin

APPENDIX III: Spatial distribution of Annual Solar Radiation in Tanzania



Source: Report on the Assessment of Solar Energy Potential Resources and Development of Solar Map of Tanzania, (2014).

APPENDIX IV: Tanzania Wind Map



ource:

TANESCO

APPENDIX V: Financing Requirements of the Entire Plan

																										US\$ Million		
Investments	Capacity MW	Online Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Project Total
Generation																												
Julius Nyerere HPP 2,115 MW	2,115.0	2022	550.0	1,169.2	684.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,403.5
Rusumo HPP 80 MW	26.7	2021	39.6	5.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45.2
Ruhudji HPP 358 MW	358.0	2025	-	-	122.2	122.2	81.5	81.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	407.4
Kakono HPP 87 MW	87.0	2026	-	-	28.0	112.2	84.1	42.1	14.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280.4
Rumakali HPP 222 MW	222.0	2026	-	-	-	150.1	112.6	75.1	37.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	375.3
Kikonge HPP 300 MW	300.0	2028	-	-	-	-	-	74.1	296.4	222.3	148.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	740.9
Malagarasi HPP 49.5 MW	49.5	2024	-	14.4	57.7	43.2	28.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	144.1
Murongo-Kikagati HPP 14 MW	7.0	2021	23.2	5.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.0
Lower Songwe HPP (Manoko) 180.2 MW	90.1	2028	-	-	-	-	-	27.5	110.0	82.5	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	275.0
Kihansi II - Upper Kihansi HPP 120 MW	120.0	2026	-	-	-	88.3	66.2	44.2	22.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	220.8
Masigira HPP 116 MW	116.0	2028	-	-	-	-	-	104.5	78.4	52.3	26.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261.3
Mipanga HPP 160 MW	160.0	2033	-	-	-	-	-	-	-	-	-	-	119.4	89.5	59.7	29.8	-	-	-	-	-	-	-	-	-	-	-	298.5
Songwe Sofre HPP 163.2 MW	81.6	2035	-	-	-	-	-	-	-	-	-	-	-	-	60.9	45.7	30.4	15.2	-	-	-	-	-	-	-	-	-	152.2
Songwe Bupigu HPP 34 MW	17.0	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.4	23.4	11.7	-	-	-	-	58.5
Mnyera Kwanini HPP 143.9 MW	143.9	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65.7	65.7	32.9	-	-	-	-	-	-	-	-	164.3
Mnyera Taveta HPP 145 MW	145.0	2034	-	-	-	-	-	-	-	-	-	-	-	-	82.3	82.3	41.2	-	-	-	-	-	-	-	-	-	-	205.8
Iringa (Ngirayo) HPP 52 MW	52.0	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	50.2	50.2	25.1	-	-	-	-	-	-	-	-	-	125.5
Iringa (Ibosa) HPP 36 MW	36.0	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	49.2	49.2	24.6	-	-	-	-	-	-	-	-	-	123.0
Mnyera Mnyera HPP 137.4 MW	137.4	2029	-	-	-	-	-	-	-	109.6	109.6	54.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	274.1
Kiondo Mnyera HPP 340 MW	340.0	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	266.3	266.3	133.2	-	-	-	-	-	-	665.8
Mnyera Kisingo HPP 119.8 MW	119.8	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	125.6	125.6	62.8	-	-	-	-	-	314.0
Mnyera Ruaha HPP 60.3 MW	60.3	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102.0	102.0	51.0	-	-	-	-	-	255.1
Mnyera Pumbwe HPP 122.9 MW	122.9	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87.7	87.7	43.9	-	-	-	-	-	219.3
Iringa Kilolo HPP 150 MW	150.0	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120.0	120.0	60.0	-	-	-	-	-	300.0
Mbarali HPP 38.5 MW	38.5	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66.4	66.4	33.2	-	-	-	-	166.0
Njombe HPP 32 MW	32.0	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54.4	54.4	27.2	-	-	-	136.0
Kinyerezi - I Extension 185 MW	185.0	2021	18.8	41.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.2
Mtwara I 300 MW	300.0	2025	-	-	-	7.3	211.1	145.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	363.9
Kinyerezi - II 600 MW	600.0	2028	-	-	-	-	-	-	-	370.9	303.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	674.4
Somanga Fungu TANESCO 600 MW	600.0	2029	-	-	-	-	-	-	-	-	404.6	269.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	674.4
Ubungo New 320 MW	320.0	2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.0	170.0	102.0	-	-	340.0
Somanga Fungu PPP 320 MW	320.0	2034	-	-	-	-	-	-	-	-	-	-	-	-	68.0	170.0	102.0	-	-	-	-	-	-	-	-	-	-	340.0
Somanga Mtema 345 MW	345.0	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87.1	217.7	130.6	-	-	-	-	-	-	-	435.4
Ubungo - I New 320 MW	320.0	2032	-	-	-	-	-	-	-	-	-	-	-	197.8	161.9	-	-	-	-	-	-	-	-	-	-	-	-	359.7
Tegeta New 320 MW	320.0	2029	-	-	-	-	-	-	-	-	251.8	107.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	359.7
Dodoma (Gas) 600 MW	600.0	2033	-	-	-	-	-	-	-	-	-	-	-	-	134.9	337.2	202.3	-	-	-	-	-	-	-	-	-	-	674.4
Ubungo - II New 470 MW	470.0	2032	-	-	-	-	-	-	-	-	-	-	-	-	369.8	158.5	-	-	-	-	-	-	-	-	-	-	-	528.3
Kinyerezi - IV 330 MW	330.0	2031	-	-	-	-	-	-	-	-	-	-	200.1	200.1	-	-	-	-	-	-	-	-	-	-	-	-	-	400.3
Mtwara I 300 MW	300.0	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200.3	133.6	-	-	-	-	-	333.9
Kinyerezi - I New 320 MW	320.0	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.0	170.0	102.0	-	-	-	340.0
Kinyerezi - I New 470 MW	470.0	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118.6	296.6	177.9	593.2

Investments	Capacity MW	Online Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Project Total
Mwara II 600 MW	600.0	2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134.9	337.2	202.3	-	674.4
Bagamoyo 300 MW	300.0	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72.0	180.0	108.0	-	-	-	-	380.0
Singida - I (wind) 100 MW	100.0	2025	-	-	-	-	-	126.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	126.5
Singida - II (wind) 100 MW	100.0	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	126.5	-	-	-	-	-	-	-	-	126.5
Singida - III (wind) 200 MW	200.0	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	253.0	-	-	-	-	-	253.0
Makambako 300 MW	300.0	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379.5	-	-	-	-	-	-	-	379.5
Njombe I 100 MW	100.0	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	126.5	-	-	-	126.5
Singida (solar) 150 MW	150.0	2023	-	-	11.7	105.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117.1
Shinyanga - I (solar) 150 MW	150.0	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.7	105.4	-	-	-	117.1
Dodoma Solar - I 55 MW	55.0	2024	-	-	-	56.3	37.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93.9
Shinyanga - I (Kishapu) 150 MW	150.0	2027	-	-	-	-	-	-	70.3	46.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117.1
Dodoma Solar - I 60 MW	60.0	2031	-	-	-	-	-	-	-	-	-	-	61.4	41.0	-	-	-	-	-	-	-	-	-	-	-	-	-	102.4
Manyoni Solar 100 MW	100.0	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107.1	71.4	-	-	-	-	178.5
Same Kilimanjaro Solar 50 MW	50.0	2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53.6	35.7	-	-	89.3
Ngaoz (wellhead) & Ngaoz - I 30 MW	30.0	2023	-	22.7	45.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75.6
Kiyo - Mtaka 60 MW	60.0	2024	-	-	45.4	90.8	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151.3
Natron 60 MW	60.0	2027	-	-	-	-	-	45.4	90.8	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151.3
Ngaoz - I 40 MW	40.0	2026	-	-	-	-	30.3	60.5	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.8
Songwe 5 MW	5.0	2023	-	3.8	7.6	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.6
Luhor 5 MW	5.0	2027	-	-	-	-	-	3.8	7.6	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.6
Geothermal - I (Mbeya, Manyara, Morogoro, Anushe, Shinyanga) 195 MW	195.0	2030	-	-	-	-	-	-	-	-	147.5	295.0	49.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	491.6
Geothermal - II (Mbeya, Manyara, Morogoro, Anushe, Shinyanga) 200 MW	200.0	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	151.3	302.5	50.4	-	-	-	-	-	-	-	-	-	504.2
Geothermal - III (Mbeya, Songwe, Manyara, Morogoro, Anushe, Shinyanga) 185 MW	185.0	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139.9	279.8	46.6	-	-	-	-	466.4
Geothermal - IV (Mbeya, Manyara, Morogoro, Anushe, Shinyanga) 215 MW	215.0	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	162.6	325.2	54.2	542.0
Mbeya I 300 MW	300.0	2029	-	-	-	-	-	-	-	262.3	262.3	131.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	655.7
Kiwira II 300 MW	300.0	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	278.3	208.7	208.7	-	-	-	-	-	-	665.8
Kiwira - I 200 MW	200.0	2032	-	-	-	-	-	-	-	-	-	-	174.9	174.9	87.4	-	-	-	-	-	-	-	-	-	-	-	-	437.2
Ngaka - I 200 MW	200.0	2032	-	-	-	-	-	-	-	-	-	-	-	174.9	174.9	87.4	-	-	-	-	-	-	-	-	-	-	-	437.2
Ngaka - I 400 MW	400.0	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	375.1	375.1	187.6	-	-	-	-	-	-	-	-	937.8
Mchuchuma - I 300 MW	300.0	2031	-	-	-	-	-	-	-	-	-	262.3	262.3	131.1	-	-	-	-	-	-	-	-	-	-	-	-	-	655.7
Mchuchuma - I 400 MW	400.0	2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	349.7	349.7	174.9	-	-	-	-	-	-	874.3
Mbeya II 600 MW	600.0	2033	-	-	-	-	-	-	-	-	-	-	-	556.6	556.6	278.3	-	-	-	-	-	-	-	-	-	-	-	1,391.6
Kiwira - I 200 MW	200.0	2034	-	-	-	-	-	-	-	-	-	-	-	-	174.9	174.9	87.4	-	-	-	-	-	-	-	-	-	-	437.2
Mchuchuma - II 300 MW	300.0	2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	262.3	262.3	131.1	-	655.7
Rukwa I 300 MW	300.0	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	281.3	281.3	140.7	-	-	-	-	-	-	-	-	703.3
Rungwe 600 MW	600.0	2034	-	-	-	-	-	-	-	-	-	-	-	-	524.6	524.6	262.3	-	-	-	-	-	-	-	-	-	-	1,311.4
Mbeya II 600 MW	600.0	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	563.3	563.3	281.7	-	-	-	-	-	1,408.3
Rukwa II 600 MW	600.0	2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	608.8	608.8	304.4	1,522.0
Total Generation Investments	19,639.7		631.6	1,262.9	1,002.3	784.6	667.2	830.6	737.0	1,163.1	1,708.6	1,120.9	1,042.2	2,070.7	2,399.4	1,758.6	1,647.4	924.6	1,599.6	2,333.6	2,071.9	1,665.0	547.8	954.6	1,627.2	1,564.1	536.6	32,812.0

Transmission	Voltage Level (kV)	Online Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Project Total
Rufji-Chalirze-Dodoma (400kV)	400	2022	67.3	235.6	33.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	336.5
Kinyerezi-Chalirze (400kV)	400	2022	24.0	84.0	12.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	119.9
Ruhudji-Kisada (400kV)	400	2025	-	-	-	34.9	20.3	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58.1
Rusumo-Nyakaza (220kV)	220	2021	-	38.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.4
Kikonge-Madaba (220kV)	220	2028	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1
Malagarasi-Kidahwe (Kigoma) (132kV)	132	2024	-	-	3.9	7.7	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.9
Kwirizi-Ujole (220kV)	220	2032	-	-	-	-	-	-	-	-	-	-	-	-	38.1	-	-	-	-	-	-	-	-	-	-	-	-	38.1
Kakono-Kiyaka (220kV)	220	2026	-	-	-	-	-	6.5	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.2
Mchuchuma-Kisada (400kV)	400	2031	-	-	-	-	-	-	-	-	-	-	42.0	28.0	-	-	-	-	-	-	-	-	-	-	-	-	-	70.0
Ngaka-Songea (220kV)	220	2032	-	-	-	-	-	-	-	-	-	-	-	-	6.9	-	-	-	-	-	-	-	-	-	-	-	-	6.9
Rumakali-Mbeya (Ujole) (220kV)	220	2026	-	-	-	-	-	11.7	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0
Masigira-Ruhudji (220kV)	220	2028	-	-	-	-	-	-	-	-	16.7	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.5
Mnyera-Mnyera-Ruhudji (220kV)	220	2029	-	-	-	-	-	-	-	-	-	9.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.3
Mnyera Ruaha-Mnyera Mnyera (220kV)	220	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	-	-	-	-	-	2.3
Mnyera Pumbwe-Mnyera Mnyera (220kV)	220	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	-	-	-	-	-	2.3
Mpanga-Mulindi (220kV)	220	2033	-	-	-	-	-	-	-	-	-	-	-	-	-	12.0	-	-	-	-	-	-	-	-	-	-	-	12.0
Iringa (Nginyo-Bosa)-Iringa (Tagamenda) (220kV)	220	2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.2	1.7	-	-	-	-	-	-	-	-	-	16.8
Iringa (Kilolo)-Iringa (Tagamenda) (220kV)	220	2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.2	-	-	-	-	-	7.2
Lower Songwe (Marozio)-Kyela (132kV)	132	2028	-	-	-	-	-	-	-	-	11.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.2
JN-PP-Kibiti (400kV)	400	2025	-	-	-	-	52.4	34.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87.3
Singida-Arushi-Namanga (400kV)	400	2021	92.1	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105.3
Bulyankulu-Gela (220kV)	220	2020	7.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.1
Gela-Nyakaza (220kV)	220	2021	29.3	19.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48.9
"North West Grid" Iringa-Mbeya-Tunduma-Sumbawanga-Mpanda-Kipoma-Nyakaza (400kV)	400	2026	55.4	129.4	129.4	129.4	138.6	92.4	249.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	924.0
Tabora-Urambo-Ngunika-Kidahwe (Kigoma) (132kV)	132	2024	8.2	8.2	24.6	32.8	8.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82.0
Tabora-Ipole-hyonga-Nsimbo (Katavi) (132kV)	132	2024	4.8	9.6	28.8	43.1	9.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95.9
badakuli (Shinganya)-malilo (Simiyu) (220kV)	220	2023	-	-	8.5	34.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42.5
Tanzania (Nyakanazi)-Kyaka-Uganda (Masaka) (400kV)	400	2025	-	-	34.8	69.5	52.1	17.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	173.8
Chalirze-Segera (400kV); Segera-Tanga (220kV)	400; 220	2025	-	-	15.0	60.0	45.0	30.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150.0
Chalirze-Bagamoyo (220kV)	220	2022	-	51.0	34.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85.0
Segera-Arusha (400kV)	400	2025	-	-	16.2	64.7	48.5	32.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	161.8
Morogoro-Mitwa (220kV)	220	2023	-	-	31.5	21.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52.6
Tanzania-Mozambique (NOTA)	400	2024	-	-	-	24.9	16.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41.5
Interconnection (400kV)	400	2025	-	-	-	21.5	53.9	32.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107.7
Interconnection (400kV)	400	2025	-	-	-	21.5	53.9	32.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107.7
Mbeya-Songwe-Chunya (Makongoro) (220kV)	220	2024	-	-	5.6	14.0	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.0
Mtata-Handeni (132kV)	132	2024	-	-	-	-	32.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32.9
Dodoma City Ring Circuit (220kV)	220	2023	-	22.9	57.2	34.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	114.5
NARCO (Dodoma)-Dumila (220kV)	220	2024	-	-	-	13.4	8.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22.3
Songea-Tunduru-Masasi-Lindi (400kV);	400; 220	2024	-	-	69.1	172.7	103.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	345.4
Masasi-Ruangwa (220kV)	220	2024	-	-	-	-	30.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.2
Tanzania (Mwanza)-Kenya (Kigoris)	400	2025	-	-	-	57.2	143.0	85.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285.9
Interconnection (400kV)	400	2025	-	-	-	57.2	143.0	85.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285.9
Bulyankulu-Bukombe (220kV)	220	2030	-	-	-	-	-	-	-	-	-	-	28.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.8
Tabora-Kigwa (Ujui) (220kV)	220	2028	-	-	-	-	-	-	-	-	48.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48.1

Transmission	Voltage Level (kV)	Online Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	Project Total
Lindi-Nangurukuni (Kilewa) (132kV)	132	2026	-	-	-	-	9.8	24.5	14.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49.0
Kijungu-Makuyuni (132kV)	132	2026	-	-	-	-	-	-	28.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28.6
Songea-Mbinga-Mbambabay (220kV)	220	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42.3	28.2	-	-	-	-	-	-	-	70.5
KIA-Ergara Nairobi (132kV)	132	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.1	-	-	-	-	-	-	-	-	23.1
Same-Gorija Gorija (132kV)	132	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.5	-	-	-	-	-	-	-	24.5
NARCO (Dodoma)-Kijungu (Kilele) (220kV)	220	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.5	20.3	-	-	-	-	-	-	-	50.8
Manyoni-Kigwa (Ujui) (220kV)	220	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.6	26.4	15.8	-	-	-	-	52.8
Manyoni-Mitundu (Manyoni) (220kV)	220	2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.8	6.8	-	-	-	-	-	-	-	67.6
Shinyanga-Tabora-Kipoma (400kV)	400	2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.1	30.3	60.6	90.8	90.8	15.1	-	-	-	-	302.8
Zinga-Kunduchi-Makumbusho (220kV)	220	2024	-	-	-	89.1	59.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148.4
Geita-Bwanga-Ushahunga-Kyaka (220kV)	220	2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.0	47.8	35.9	23.9	-	-	119.6
Songea-Namtumbo (132kV)	132	2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
Karatu-Lolondo (69kV)	220	2024	-	-	4.9	12.1	7.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.3
Chamika-Mkuranga-Kibiti (220kV)	220	2024	-	-	-	-	84.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84.1
Kinyerezi-Ubungu-Mburahai (220kV)	220	2022	-	-	42.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42.8
Dar-Moro-Dodoma SGR-TL (220kV)	220	2020	48.5	20.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5
Kinyerezi-Luguruni (220kV)	220	2025	-	-	-	1.0	-	6.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.3
Mtwara-Somanga Fungu (400kV)	400	2024	-	-	29.3	146.7	117.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	293.4
Somanga-Kibiti-Kinyerezi (400kV)	400	2024	-	-	-	123.1	82.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	205.2
Hinge-Dodoma-Singida-Shinyanga (Existing TL - 400kV) - Transformers & Compensators (TL Upgrade)	400	2021	37.6	40.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78.3
Shinyanga-Buzwagi (Existing TL - 220kV) - Buzwagi Substation (TL Upgrade)	220	2022	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4
Morogoro-Ubungu (Existing TL - 220kV) - Zagereni Substation (TL Upgrade)	220	2022	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4
Mufindi-Mbeja (Existing TL - 220kV) - Rujewa Substation (TL Upgrade)	220	2028	-	-	-	-	-	-	-	-	21.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.7
Dodoma-Singida (Existing TL - 220kV) - Manyoni Substation (TL Upgrade)	220	2029	-	-	-	-	-	-	-	-	-	21.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.7
Hale-Same-Kiyungu (Existing TL - 132kV) - Same Substation (TL Upgrade)	132	2028	-	-	-	-	-	-	-	-	16.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.1
Total Transmission Investments			374.4	672.4	582.9	1,207.2	1,133.4	376.9	294.8	16.7	108.0	31.0	70.8	28.0	45.0	12.0	15.2	16.8	221.9	140.3	113.3	176.8	66.8	23.9	-	-	-	5,728.4
Total Investments			1,005.9	1,935.3	1,585.2	1,991.8	1,800.7	1,207.5	1,031.8	1,179.7	1,816.6	1,151.8	1,112.9	2,098.7	2,404.4	1,770.6	1,662.6	941.4	1,821.5	2,473.8	2,185.2	1,841.8	614.7	978.5	1,627.2	1,564.1	536.6	38,340.4
Cumm. Investments			1,005.9	2,941.2	4,526.4	6,518.2	8,318.9	9,526.4	10,558.2	11,737.9	13,554.6	14,706.4	15,819.3	17,918.0	20,322.4	22,093.0	23,755.5	24,696.9	26,518.5	28,992.3	31,177.5	33,019.3	33,634.0	34,612.5	36,239.8	37,803.8	38,340.4	
Investments subjected to Debt/Equity			375.6	686.9	804.2	1,723.3	1,671.4	1,190.1	1,031.8	1,179.7	1,816.6	1,151.8	1,112.9	2,098.7	2,404.4	1,770.6	1,662.6	941.4	1,821.5	2,473.8	2,185.2	1,841.8	614.7	978.5	1,627.2	1,564.1	536.6	
Financing	Contribution Ratio																											
Govt Fully Financed Investments	100% Equity		630.3	1,248.3	781.0	268.5	129.3	17.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt	70%		262.9	480.8	562.9	1,206.3	1,170.0	833.1	722.3	825.8	1,271.6	806.3	779.1	1,469.1	1,683.0	1,239.4	1,163.8	659.0	1,275.1	1,731.7	1,529.7	1,289.3	430.3	685.0	1,139.1	1,094.8	375.6	
Equity	30%		112.7	206.1	241.3	517.0	501.4	357.0	309.6	353.9	545.0	345.5	333.9	629.6	721.3	531.2	498.8	282.4	546.5	742.1	655.6	552.6	184.4	293.6	488.2	469.2	161.0	
	Total Debt/Year		262.9	480.8	562.9	1,206.3	1,170.0	833.1	722.3	825.8	1,271.6	806.3	779.1	1,469.1	1,683.0	1,239.4	1,163.8	659.0	1,275.1	1,731.7	1,529.7	1,289.3	430.3	685.0	1,139.1	1,094.8	375.6	24,685.9
	Total Equity/Year		743.0	1,454.4	1,022.3	785.5	630.7	374.4	309.6	353.9	545.0	345.5	333.9	629.6	721.3	531.2	498.8	282.4	546.5	742.1	655.6	552.6	184.4	293.6	488.2	469.2	161.0	13,654.5
	USD Million																											
CAPITAL NEEDED	Total	Debt	Equity																									
Short Term (2020 - 2025)	9,526.4	4,516.1	5,010.3																									
Medium Term (2026 - 2034)	14,229.2	9,960.4	4,268.7																									
Long Term (2035 - 2044)	14,584.9	10,209.4	4,375.5																									
Total Plan (2020 - 2044)	38,340.4	24,685.9	13,654.5																									

