Government of Malawi

Ministry of Energy

2022 Integrated Resource Plan (IRP) for Malawi

Main Report

Published September 2024

Executive Summaries

Developments in Malawi's power sector are currently guided by the Integrated Resource Plan (IRP) of 2017 which is a least-cost plan of investments in generation, transmission and some demand-side management measures up to 2037. In order to reflect the most recent information to maintain the country on a least-cost path, it was decided in 2022 to update the Plan. Among the important evolutions to take into account for the update of the optimum development plan, one can identify new assumptions for demand forecast and notably updated rural electrification plan, Expressions of Interests from Unsolicited Independent Power Producers (UIPP) for technologies which were not previously considered, development of the transmission and distribution grids, upcoming interconnection with Mozambique (MoMA interconnector) and therefore integration into the Southern African Power Pool network.

Building on the 2017 IRP, the revised IRP outlines optimal pathways of 'least cost, least risk, least carbon-emitting, reliable' project portfolios recommended for development in the next 5 to 15 year planning horizon. Against this background, the Malawi Government, through the Ministry of Energy, with support from the Global Energy Alliance for People and Planet (GEAPP) is embarking on a review of the IRP's generation and transmission expansion plans and the development of a distribution masterplan.

To achieve this objective, in close collaboration with the Ministry of Energy, ESCOM and the other Stakeholders and with the support of GEAPP, Economic Consulting Associates (ECA) studied the Demand Forecast, Loss Reduction and Energy Efficiency Strategies and Tractebel Engineering studied the development plans for Generation, Transmission and Distribution.

The results, conclusions and recommendations of the four studies constituting the IRP 2023 are presented in this document which aggregates the final reports. The structure of this global report is the following:

- Volume 0: Executive Summaries
- Volume 1: Demand Forecast, Loss Reduction and Energy Efficiency Strategies (ECA)
- Volume 2: Generation Development Plan (Tractebel)
- Volume 3: Transmission Development Plan (Tractebel)
- Volume 4: Distribution Development Plan (Tractebel)

The present document summarizes the take-aways of the complete study and is constituted by the executive summaries of the four reports. In addition, the first section of this report makes recommendations for the follow-up of the implementation of the IRP (monitoring and evaluation) and for the update of the IRP in the coming years.

1. Monitoring and evaluation of the implementation of IRP 2022

The update of the Integrated Resource Plan produced updated Demand Forecasts and defined the development plan for the generation, transmission, and distribution systems and the corresponding calendar of investment. In addition, thanks to the active participation and the capacity building of the Working Groups, the planning unit of the Ministry of Energy gained sufficient expertise and experience to effectively manage the roles and responsibilities assigned under the available regulation of the power sector. The results and recommendations of the IRP should be regularly monitored and evaluated. This involves updating or confirming the IRP based on a comparison between actual developments and the forecasted evolution of input data.

It is recommended that the Ministry and Single Buyer, with the assistance of the other Stakeholders of the Sector, will conduct this analysis and any necessary updates. These activities will enable the planning team to apply their newly acquired skills and enhance their experience. The monitoring and evaluation of sector developments, decision-making, and updating of the IRP results will be conducted annually, with the first iteration occurring one year after the IRP results are published.

Outside the IRP's implementation and update periods, the skills of the planning team members and other entities should be maintained and expanded through regular training sessions and exchanges within the Working Groups. The use of software should be sustained, and advanced training sessions can be organized based on specific needs. The unit should also keep track of technological and methodological advancements and their potential applications in Malawi.

In order for the Ministry to ensure an effective monitoring and evaluation of the implementation of the development plans, it is recommended to conduct regular reviews to assess progress and make necessary adjustments, and build capacity by training staff and stakeholders in monitoring and evaluation techniques. Transparency of the reporting is recommended: Ensure data quality through validation and verification protocols and communicate findings clearly and honestly to all stakeholders.

As highlighted here above, it is important to regularly monitor the implementation of the plans and the evolution of the input data. It is recommended that the Ministry organizes this activity in close collaboration with the relevant Stakeholders each year after the publication of the IRP. Based on the deviation on the measured input data such as the demand evolution and the progress of the project, a limited update of the IRP can be decided. This limited update will be based on the sensitivity analyses carried out around the base case scenario. In order to align the long-term development with the measured evolution of the system, the political vision and the technological evolutions, a complete update of the IRP is carried out every 5 years.

2. Executive summary of Demand forecast

Introduction

The main objective of the *Demand forecast, loss reduction and energy efficiency plan* was to develop a demand forecast for Malawi building on the *2017 IRP demand forecast* and incorporate a properly costed energy efficiency (EE) and loss reduction plan spanning 5-20 years. The forecast was developed in collaboration with the Utility Scale Working Group, which included experts from MERA, ESCOM, PML (before dissolution) and Ministry of Energy who validated all input assumptions, methodologies and outputs.

The demand forecast was developed for the next 20 years under three scenarios:

- a *Base case scenario* which reflects current projections on national economic development, as well as ongoing policy commitments and electrification targets;
- a *High case scenario* which forecasts rapid economic growth and a quick bounce-back from the economic shocks in the last few years, along with 100% electrification and rapid loss reduction actions; and
- a *Low case scenario* reflecting low economic growth and constrained capacity to implement policy targets and loss reduction measures.

The scope of this demand forecast is to be used as an input to the update of the Integrated Resource Plan (IRP) in Malawi. For least cost power development planning purposes, a forecast of sent-out energy (MWh or GWh) and sent-out maximum demand (MW) is required in the medium to long run. The geographical distribution of the demand is also necessary to assess capacity requirements by region for the transmission development plan. The forecast was prepared for the next 20 years (up to 2042) by economic activity, at national level and by region. It also accounts the impact of energy efficiency measures and loss reduction plans.

Base case demand forecast

The Base case demand forecast has been developed to reflect current policy targets, including the electrification targets set by the National Electrification Programme, the implementation of the 2021 Loss Reduction Roadmap, as well as the current long-term economic forecasts and industrial, agriculture and mining developments in the country. The annual energy and peak demand forecast results can be seen in **Error! Reference source not found.**.

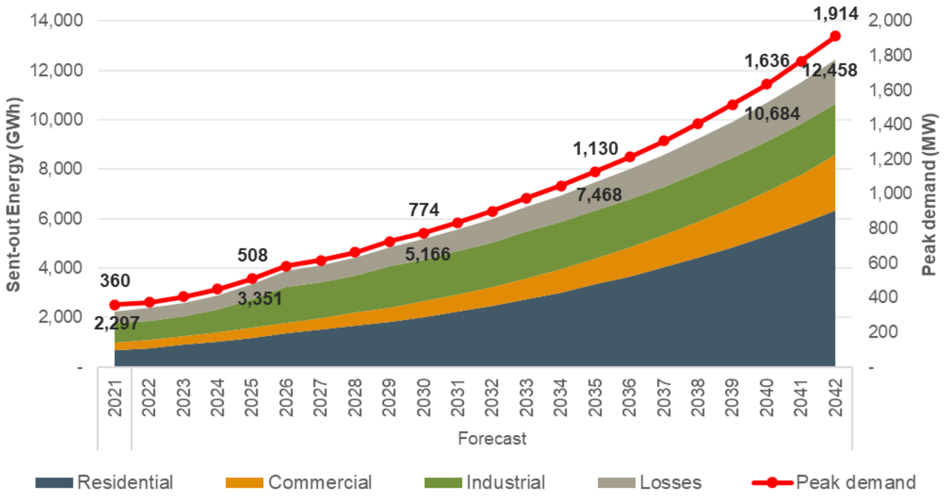


Figure 0.2.1: Base case updated demand forecast 2022-2042

Source: ECA analysis

It is estimated that the energy demand at the entry points of the grid (eg sent-out generation) will be 3,351 GWh by 2025, 5,166 GWh by 2030, 7,468 GWh by 2035, 10,684 by 2040 and 12,458 GWh by 2042. The peak demand is forecasted to be 508 MW in 2025, 774 MW in 2030, 1,130 MW in 2035, 1,636MW in 2040 and 1,914 MW in 2042. .This increase represents an average annual growth of 8%. The forecast growth rates in energy and peak demand are higher than the 4% average annual growth recorded between 2016 and 2021. The updated forecast considers suppressed demand from previous years as well as current electrification targets that foresee a rapid increase of residential connections compared to previous years.

It is estimated that the North region will increase its share of demand from 9% in 2021 to 13% in 2042 due to relatively high urbanisation and population growth rates compared to the other regions (see **Error! Reference source not found.**). Demand from all sectors (residential, commercial, and industrial) is expected to grow in the next 20 years, however, residential demand will increase more rapidly as rural households gain access to electricity, and all households increase their average consumption over time. As a result, residential sales are expected to account for 59% of total electricity sales by 2042, compared to 38% in 2021 (see **Error! Reference source not found.**).

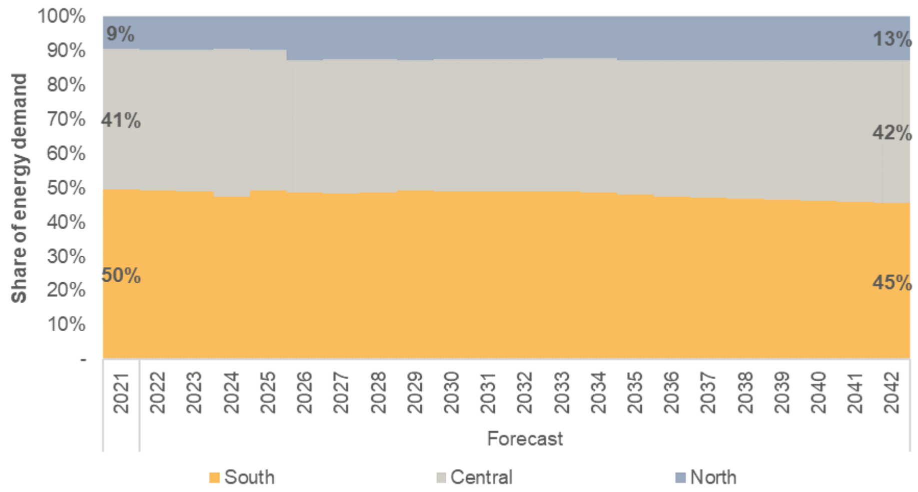


Figure 0.2.2 Regional demand split 2022-2042 – Base case Demand Forecast

Source: ECA analysis

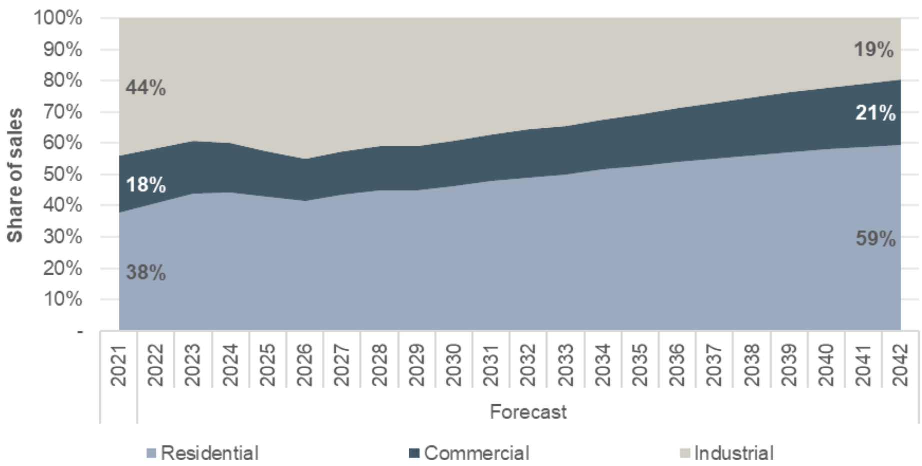


Figure 0.2.1 Sectoral sales split 2022-2042 – Base case Demand Forecast

Source: ECA analysis

Approach and key considerations

The table below summarises the approach taken for the update of the demand forecast.

Table 0.2.1 Approach used for the 2022-2042 demand forecast

Bottom-up approach that adds the demand by economic activity, losses and impact of DSM to derive energy and capacity that needs to be injected to the grid.

Residential sales	
Rural households	**Average consumption per household in rural areas** *(kWh/month * 12 months)* χ **Income elasticity** *(to estimate the increase in consumption relative to economic growth and efficiency improvements)* χ **Electrification rate of rural areas** *(% of rural households with access to electricity)* χ **Number of households in rural areas** *(=Population in rural areas / Persons per household in rural areas)*
Urban households	**Average consumption per household in urban areas** *(kWh/month * 12 months)* χ **Income elasticity** *(to estimate the increase in consumption relative to economic growth and efficiency improvements)* χ **Electrification rate of urban areas** *(% of urban households with access to electricity)* χ **Number of households in urban areas** *(=Population in urban areas / Persons per household in urban areas)*

Productive sector sales	
Commercial	**Econometric equation** linking sales with GDP per capita, tariff level and number of commercial consumers.
LV Industrial	**Econometric equation** linking existing LV industrial sales with GDP per capita.
MV Industrial	**Econometric equation** linking existing MV industrial sales with Industrial GDP.
New large projects *(Agriculture, Megafarms, Manufacturing, Mining, Water pumping)* **and Self-generation**	The demand of new large loads / expansions / shutdowns that cannot be identified in historical information (econometric equation) is identified separately and **added/subtracted to/from the demand forecast with a probability adjustment**. Self-generation is also accounted using a similar approach as with new step loads. *A survey was conducted to identify new industrial loads and plans for self-generation.*

Exports, losses and DSM	
Exports	Firm commitments for exports are added to the demand.
Losses	Sales are increased by forecast loss factors accounting the loss reduction roadmap to identify energy and capacity requirement at the entry points of the grid (eg generators sent out level).
DSM	The impact selected demand response and energy efficiency measures is subtracted from the demand forecast. Efficiency improvements of appliances are accounted in the income electricity of residential customers.
Peak demand	Peak demand is estimated from forecast energy demand using the system load factor.

Source: ECA analysis

The above approach incorporates the following key considerations from stakeholders:

- Step loads and self-generation from mining companies, various upcoming rock aggregate quarry plants, manufacturing firms, mega-farms, agriculture and water pumping projects.
- Population growth and urbanization rates from the 2018 Census
- Economic growth anticipated
- National electrification targets including universal access by 2030
- The fact that rural areas consume less electricity than urban areas and most of new customers that will be connected will be in rural areas
- Policy targets and national plans
- Technology improvements
- Expected tariff increases
- Firm commitments for exports
- System network losses (technical and commercial) and expected loss reductions

Low and high demand forecasts

The Low case and High case scenario follow a different set of input assumptions summarised in **Error! Reference source not found.** below. The low case scenario is structured to account for low economic growth, slow electrification, and lower probability for the development of new large loads. The high case scenario considers a positive outlook on economic growth, ambitious electrification and loss reduction rollouts, and high likelihood of new mines, manufacturing firms, mega-farms, agriculture and water pumping projects development.

Table 0.2.2 Summary of input assumptions for the 2022-2042 demand forecast

	Low scenario	Base scenario	High scenario
	Business as usual	*Market expectations and NEP electrification plan with current WB and MREP support supplementing ESCOM*	*High economic growth with universal access assuming no resource constraints*
Economic development	Assumes that economic growth in Malawi will be affected by global conflicts, other unforeseen events (eg cyclones, etc) and that Covid-19 pandemic has longer lasting impacts on economic growth. GDP growth is assumed to be closer to the average growth over the past 3 years (3.9%).	This scenario uses the IMF GDP growth projections up to 2028. For the 2028-2042 period, the long term GDP growth rate from IMF has been adopted (4.5%).	Assumes that from 2023, GDP growth will be higher than the IMF GDP growth projection (and closer to historical high GDP growth rates). This represents a quick recovery from COVID-19 pandemic as well as high economic growth conditions in Malawi.
Electrification targets	Applies ESCOM's historical new connection abilities (~35,000 per annum).	*National Electrification Policy (NEP)* targets by 2030 (32.4%) followed by linear increase of electrification by 2042 (56%).	Applies universal electricity access by 2030 following *SE4ALL Integrated Energy Plan for Malawi*
Average consumption per household	Unit, 2021, 2030, 2040 Urban kWh/month 160 172 203 Rural kWh/month 47 51 60	Unit, 2021, 2030, 2040 Urban kWh/month 160 188 252 Rural kWh/month 47 56 75	Unit, 2021, 2030, 2040 Urban kWh/month 160 203 309 Rural kWh/month 47 60 92
Network Losses	Slow implementation of the *Loss Reduction Roadmap* (LRR).	Base case implementation of the LRR.	Rapid implementation of the LRR and additional ESCOM measures.
Step load and self generation	Low probability of new projects to materialise and high probability of self-generation to be installed.	Moderate probability of new projects to materialise and low probability of self-generation to be installed.	High probability of new projects to materialise and low probability of self-generation to be installed.

Source: ECA analysis. ** For the base year (2021) the average consumption per household is based on ESCOM data, information from other countries in Southern Africa, and a bottom-up approach to alleviate suppressed demand. For the growth of the average demand per household an income elasticity of 1.2, 0.9 and 1.4 is assumed for the base, low and high scenarios, respectively, relative to the GDP per capita growth.*

The sent-out energy and peak demand forecasts for the Low, Base and High case scenarios were modelled following the above assumptions and approach, which have been developed with the support of the Utility Scale Working Group[1], chaired by the Ministry of Energy, and validated with stakeholders during the Final Workshop held in Lilongwe on 27 April 2023. The three scenarios developed for this demand forecast are illustrated in **Error! Reference source not found.**.

[1] The Utility Scale Working group included technical experts from MERA, ESCOM, PML (before dissolution) and the Ministry of Energy

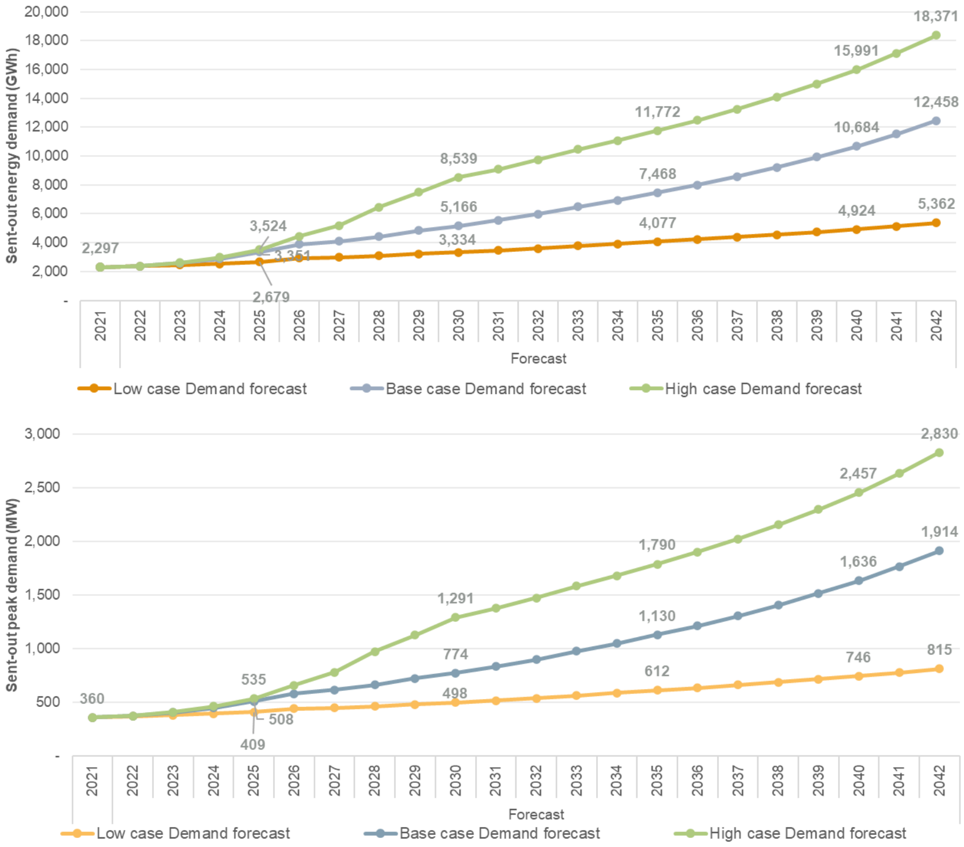


Figure 0.2.4 2022-2042 Updated demand forecast

Source: ECA analysis

Comparison with previous forecasts

Compared with previous forecasts, the updated demand forecast is lower than the 2017 IRP demand forecast (see **Error! Reference source not found.**). While the methodology used in the 2017 IRP demand forecast was satisfactory, the forecasted input assumptions varied significantly from outturn actual figures (mainly the forecasts of GDP growth, population growth, average household consumption, and electrification rates). These differences are also explained by the occurrence of socio-economic shocks due to the 2020 Covid-19 pandemic, load shedding, and recent natural disasters that have constrained demand growth. On the other hand, we find that World Bank's 2019 IRP Demand forecast update is in similar rage with the current update of the demand forecast.

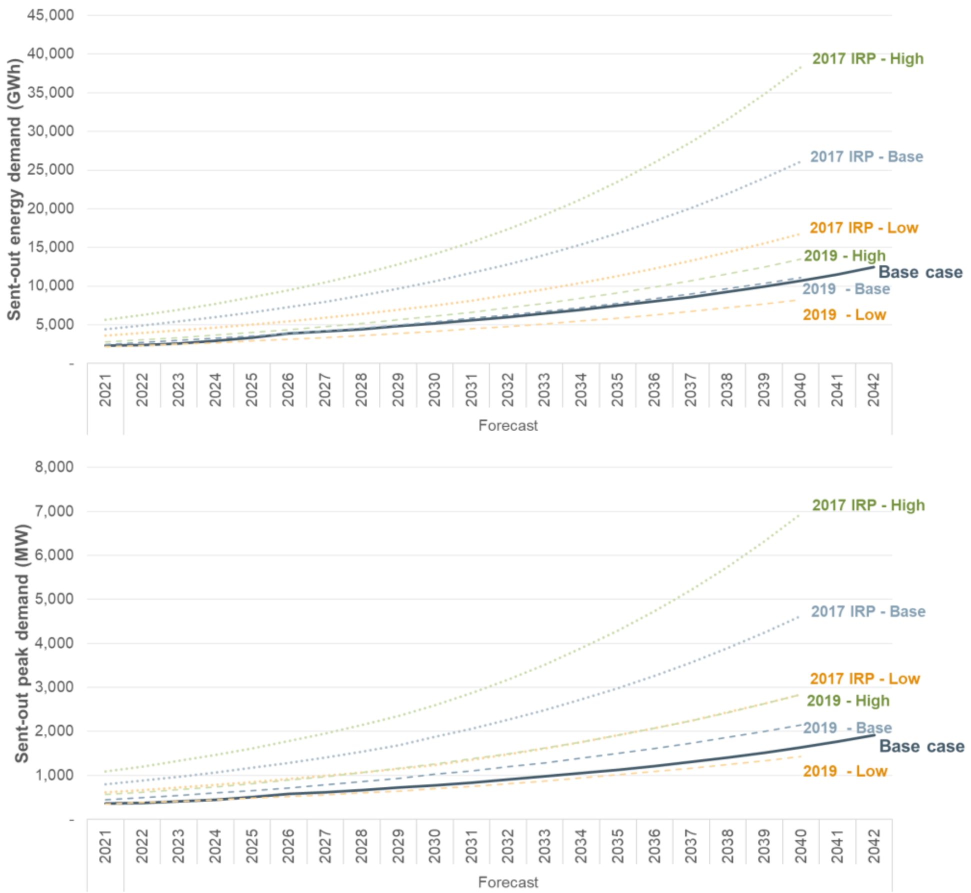


Figure 0.2.5 Base case updated demand forecast vs previous forecasts

Source: ECA Analysis, 2017 IRP, 2019 WB Update Note: The '2017 IRP' lies reflect the 2017 IRP demand forecast and the '2019' lines reflect the 2019 updated forecast prepared by the World Bank.

Loss reduction plan

As part of the assignment, 34 initiatives from ESCOM's 2021 Loss Reduction Roadmap (LRR) have been assessed in order to advice on its implementation. The initiatives from the LRR were found to be comprehensive, as they cover areas related to hardware, software, processes and personnel. The LRR also provides evaluations with respect to criteria such as budget and impact on losses.

For the purposes of this study, these initiatives have been ranked along three criteria: budget (low, mid, and high), impact on losses (low, mid, high, and very high), and dependency on other initiatives (0 if the initiative does not need any previous one to be implemented, up to 3). Prioritisation is then done through a combination of these three criteria and illustrated in **Error! Reference source not found.**, where the initiatives' priorities are higher in the top-left corner subject to any other initiative that is ought to be implemented before.

Table 0.2.3 Initiatives subject to budget, impact on losses, and dependence criteria

Budget	Impact on losses: Very high	High	Medium	Low
Low		2b. New Losses Calculation methodology	8b. Instructional Workshops with stakeholders	4 a. Improvements in the Meter Life Cycle
Low		4e. Strengthen the Customer Service processes	4b. Building a role for maintaining customer data	8 a. Round table with MERA
Low		5b. Acquisition of Mobile APPs	4 g. Written Procedure on Fraud Management	5f. Improve Free-Tokens process
Low		2e. Perform Regional Balances	8c. Periodic Regulatory Internal Committees	5 g. Convert “Suprima” customers
Low			6 a. Assessment for rehabilitating the grid	4f. Improve reporting and establish KPIs
Low			4c. Review the Debt Recovery process	7b. Smart Meter Regulation
Low			4h. Establish a Centralized Quality Control areas for key processes	5 d. Document management system
Low				8 d. Attraction of Private Investment
Medium	3c. Large customer and public institutions audit	3 a. Metering in Distribution Transformers	2c. Strengthen the EBM team	4 d. Review the current Organization of the Distribution Directorate
Medium	1 a. Establishing PMO	4i. Reorganization of the Revenue Protection area	5 a. Implementing a Meter testing laboratory	
Medium	2 a. Metering in Injection Points, Substations and Feeders	5e. Internal Training for CMS and Commercial Processes	6c. Technical Losses calculation process	
High	3b. End-customers audit	7 a. Smart metering for residential and commercial customer	6b. Piloting different technical configurations on the MV-LV grid	
High	3 a. Metering in Distribution Transformers	5c. Persons in Vulnerable Situations	7c. Establishment of a Metering Data Control Center	

Colour coding indicates initiative dependence on implementation of other initiatives, as follows:

No dependency	Depends on 1 initiative	Depends on 2 initiatives	Depends on 3 initiatives

Source: Loss Reduction Roadmap, ECA Analysis

The expected impact from the implementation of the LRR is listed below for three scenarios reflecting varying success rates of the same set of proposed interventions:

- **High Potential Scenario** with rapid implementation of the LRR and additional ESCOM measures: 1.2% average yearly reduction of losses, resulting to a total reduction of 6% in the fifth fiscal year.
- **Medium Potential Scenario** with the LRR implemented as planned: The annual loss reduction in this scenario is 1.1% resulting to a total loss reduction of 5.3% in the fifth fiscal year.
- **Low Potential Scenario** with a slow implementation of the LRR: losses reduce by 0.9% yearly, resulting to a total loss reduction of 4.5% in the fifth fiscal year.

Demand Side Measures (DSM) plan

The analysis of potential DSM measures, including Demand Response (DR) as well as Energy Efficiency (EE), has considered initiatives in the residential, commercial, and industrial sectors of Malawi. The analysis suggests that additional demand response measures such as (I/C) service and demand bidding/buyback programs could be considered by ESCOM, while others such as Ancillary Services market programs could not be applicable in Malawi with the current market structure.

With respect to Energy Efficiency, the main options considered are the introduction of MEPR as well as replacement/upgrading of appliances, including air conditioning (AC) units, solar water heaters, and lighting. The analysis describes the expected impacts of options that can be applied horizontally, thus the impact from additional measures for industrial users have not been assessed as their impact would vary depending on the customer. **Error! Reference source not found.** lists the measures to be considered as candidate options in the IRP and showcases the estimated potential impact and pay-back period of each measure.

Table 0.2.4: Shortlisted DSM measures and estimated impact and pay-back periods

Demand Side Measure (DSM)	Target Groups	Earliest year of implementation
Replacement of fluorescent bulbs with LED lights	Residential, Commercial, Public	2022
Replacement of AC units with high efficiency ones	Commercial	2023
Replacement of fans with high efficiency ones	Residential, Commercial	2023
Replacement of electric water heaters with solar	Residential, Commercial	2023
Introduction of Minimum Energy Efficiency Requirements	Residential, Commercial, Industrial	2025

Sector – end use	Total potential (GWh/year)	Capacity impact (MW)	CO2 savings (ton/year)	Pay-back period (years)
Domestic - Water heater	185.2	63.4	11,480.0	4.4
Commercial - Water heater	76.5	36.7	4,742.0	2.0
Domestic – CFL	24.0	9.2	1,487.3	1.1
Commercial – Fans	23.2	7.2	1,437.0	8.9
Commercial – FTL	19.7	6.3	1,219.0	1.1
Commercial – AC	7.7	3.9	476.0	2.7
Domestic – Fans	5.0	2.2	308.5	27.4
Commercial – CFL	4.4	1.4	273.0	0.4

Source: ECA calculations. Note: Measures highlighted in light orange indicate high pay-back period. For these measures, financial assistance for consumers might be needed to make these replacements.

3. Executive summary of the Generation development plan

The Malawian power sector is currently facing major challenges that will intensify in the coming years and needs to be prepared to sustain the increasing electric demand linked to the forecasted economic growth and the electrification of the population while ensuring the reliability of the supply and affordable electricity prices. The challenges encompass the reliance on an important share of hydro generation, the penetration of intermittent renewable energy generation (photovoltaic and wind), the need to diversify the energy mix and the integration into the SAPP regional network. Therefore, a precise vision of the optimal evolution of the power system and the related investment is critical.

The objective of the study is to define the generation, transmission and distribution expansion plans for the next 20 years. The generation development plan presented in this report constitutes the first Work Stream of the study. It aims at outlining the best possible pathway for meeting the electricity needs for Malawi from 2022 to 2042.

Approach

The optimum development plan relies on the combination of the definition of the **long-term vision** for the development of the electric sector and a **focus on the short- and medium-term required investment**.

- The definition of the **energy long-term orientations** for the country up to 2042 is based on a least cost optimization of new generation units for the next 20 years while respecting all planning and system operation constraints and the consideration of strategic projects. It uses a stochastic approach to build a robust plan against the hydrology uncertainties and its impact on the available generation.
- A **tangible investment plan for the next years** is obtained by additional analyses focusing on the minimum / no-regret investment in the next 5 years considering the national strategic projects and the constraints defined with the Stakeholders and the short-term reduced uncertainties.

The short- and medium- term evolution focuses on the period 2023-2029, when reliable forecasts of trends in river flows are available. Moreover, there are near-term strategies and projects which are about to be implemented and taking them into account allows to build a more realistic and tailored investment plan in the short, medium and long term. Furthermore, in order to provide the Stakeholders with a view on no-regret investments for the short and medium term, two optimizations are solved using two different demand scenarios.

The analysis of long-term requires instead the assessment of a wide range of options and realisations of the inputs. For this reason, uncertainty of river flows, playing a key role in electricity generation in Malawi, is now carefully integrated by means of a stochastic optimization. This allows to build an investment plan which is robust and climate resilient. The best system evolution is derived from the Least Cost (LC) optimization, where all technologies realistically available in the next future in Malawi are considered as possible investments. Additionally, the impact of including in the generation portfolio strategic projects selected by the Stakeholders is assessed in the Least Cost + Strategic Projects (LCSP) optimization.

The table below summarises the key aspects of each scenario.

Table 0.3.5: Different scenarios run for the development of the IRP

Horizon phase	Description	Sensitivities
Short- and medium-term evolution 2023-2029	Deterministic optimization considering good hydro availability and near-term committed projects	Main scenario (LC): Base case demand forecast (including DSM and EE measures)
		Sensitivity: Low case demand forecast
Long-term vision 2030-2042	Stochastic optimization based on 4 samples of hydro availability, Base case demand	Main scenario (LC): all available technologies and projects treated as candidates, hence all investments are optimized
		Alternative scenario (LCSP): key strategic projects are included in the investment plan

The demand forecast is an input from a previous study. The Base Case forecast is considered as reference and presents an average yearly growth of 8%. For the short-term detailed analysis, the Low Case forecast is also considered as a sensitivity analysis.

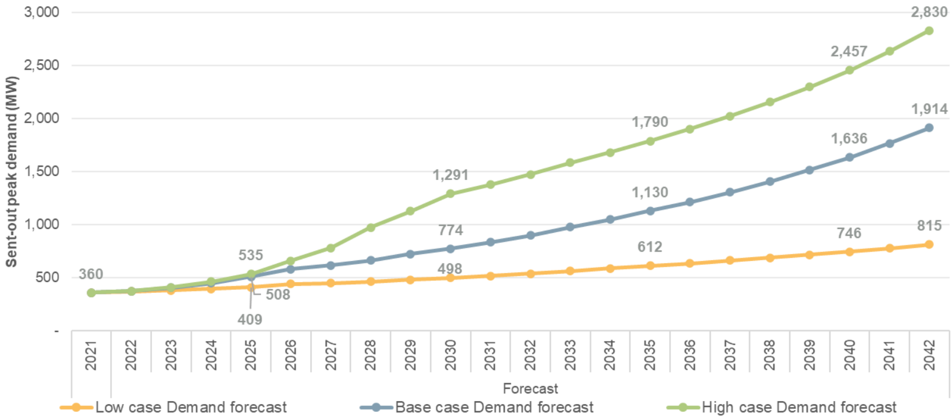


Figure 0.1: Peak demand scenarios [1]

Main results

Under the assumptions summarised in the table above, there is no need to install new power plants in the **short term**, besides the small addition of 23 MW of PV in 2026. The refurbishment of the existing diesel generators and the interconnection with Mozambique would be able to follow the demand growth, in a context where good availability of flows in the rivers leads to high shares of hydro generation. Starting from 2027, new technologies are integrated into the capacity mix: wind and biomass are installed, while the PV capacity keeps increasing. Moreover, the small hydro power plant of Wovwe 2 is installed in 2027.

If the **low demand scenario** is adopted for the short- and medium-term evolution, the growth rate falls from above 8% to around 4%, both in terms of total yearly demand and peak. Under this assumption, no additional capacity is needed in the short and medium term, besides the already planned installation of the run-of-river hydro power plant of Wovwe 2 (4.5 MW). Hence, the foreseen good availability of flows in the next few years, if combined with a more conservative projection of load growth, highlights that the current short-term plans would be sufficient to supply the demand in the next few years. In particular, the improvement of the availability of the existing assets (diesel gensets) and the start of the take-or-pay import contract would provide enough additional energy to accommodate a slower increase of the electricity demand.

The **long-term vision** builds on the outcomes of the short- and medium-term evolution analysis to develop a robust investment plan that can reliably supply the growing electricity demand from 2030 to 2042. The extension of the horizon under study and the peculiarities of the Malawian power system, i.e., high reliance on hydro generation, require particular attention in treating the vast uncertainty on the availability of resources: stochastic optimization based on four representative hydrology samples is adopted to provide a robust long-term investment plan.

In this context, the **Least Cost (LC) scenario** provides the unbiased evaluation of the most efficient path to reach security of supply while guaranteeing reliability at the lowest cost possible. As soon as their commissioning is possible, some large hydroelectric projects are selected (Mpatamanga from 2030 and Kholombidzo from 2033). Moreover, PV, wind and EE-DSM measures continue to grow and future interconnection lines to Zambia and Tanzania are selected. Towards the end of the horizon, the energy mix keeps diversifying with the addition of gas fired units. The need for imports is heavily dependent on the availability of river flows for hydro production: it maintains a key role in supplying the demand in case of low availability, while the end of the take-or-pay contract practically marks the almost total phase-out of imported energy, with a change in the trend over the last few years of the considered horizon, if water flows are highly available for energy production. In this last case, the excess energy from renewable sources and the availability of thermal plants would increase, creating consistent opportunities for export, reaching 4.6 TWh in 2042.

The development of a power system is subject to numerous constraints, including but not limited to availability of primary resources, need of diversification of the energy mix, geopolitical relationships and agreements with countries exporting fuels etc. For this reason, an additional scenario is run for the long-term vision, with the aim of assessing the impact of such plans and constraints. Such scenario, named **Least Cost + Strategic Projects (LCSP)**, considers the outcomes of multiple interactions between the Consultant and the Stakeholders, in order to accurately verify the implications of including the identified strategic projects in the Malawian power system. The list of strategic projects integrated in the optimization is provided in the table below.

Table 0.3.6: Strategic projects identified by the Stakeholders and integrated in the LCSP scenario

Project	Commissioning year
Gas power plant of 50 MW	2027
Hydro plant Wovwe 2	2027
Hydro plant Nyika	2027
Hydro plant Mbongozi	2028
Hydro plant Thyolo	2028
Coal power plant of 300 MW	2030
Hydro plant Mpatamanga	2030
Hydro plant Chasombo&Chizuma	2033
Hydro plant Dwambazi	2033
Hydro plant Fufu	2034
Hydro plant Kholombidzo	2034
Hydro plant Lower Songwe	2035

The integration of these power plants in the system allow to reach diversification in terms of river basin already in the medium term as the small hydro plants imposed before 2030 would not resort to the Shire river. Moreover, an overall diversification of the energy mix would derive from the integration of gas and coal units. The increased capacity of hydro units with respect to the Least Cost scenario, makes the system to rely even more on river flows. Overall, the share of yearly hydro production in the long term on the total is in the range 32-90% based on the hydrology sample; the range in the Least Cost scenario is instead 23-77%. Such a share grows as more plants are installed (until 2035), to then decrease in the last years because of the installation of new VRE and gas projects. Given the increased capacity available in the LCSP scenario, the system has a lower need to resort to import with respect to the LC scenario. Moreover, the export potential increases up to 5.6 TWh in 2042.

The Least Cost option obviously provides the most efficient plan cost-wise, but it does not take into account political and strategic visions which often influence the development of the generation portfolio of a country. Still, it provides valuable information in terms of long-term strategies and allows to challenge and adjust plans for the short and medium term. On the contrary, the alternative scenario including strategic projects reflects the current view of the Stakeholders and highlights the impacts of deviating from a least cost path. In particular, the inclusion of small hydro before 2030 allows to quickly diversify the resources for hydro production, which currently comes almost totally from the Shire river. The presence of these units, together with the selection of the coal power plant, leads to higher total investments, higher total domestic capacity, thus reducing the import needs and increasing the export potential.

For all the scenarios, **reserve requirements** have been taken into account, as primary and secondary reserves are needed to ensure the frequency stability of the system. Minimum primary and secondary reserve requirements are estimated for the current situation as well as for the considered evolution of the interconnected system. It is also highlighted that the assumptions made should be regularly revised in time based on the actual evolution of the Malawian system as well as the SAPP region as a whole.

In particular, for what concerns primary reserve, the requirements in the short term might be extremely challenging or easily fulfilled based on the integration of a second circuit on the interconnection with Mozambique (recommended option). Nevertheless, it has to be noted that, while allowing to respect the N-1 criterion for network planning, a second circuit on the interconnection line with Mozambique presents also important disadvantages:

- The two circuits will be on the same tower structure and structural default could lead to the unavailability of both circuits at the same time (structural vandalism, extreme wind speed etc.)
- Having both regional interconnections with the same country and at the same substation might lead to additional risks e.g. in case of unfavourable events within Matambo substation or the feeders of Matambo substation, or in case of geo or intra country politics which may affect the contract of power supply and limit the access to the regional market

Based on these considerations, it is recommended to maintain permanently the available primary reserve on the existing diesel and hydro units as well as BESS. This reserve (amounting to 20 to 50 MW depending on the availability of the units) is not sufficient to guarantee the stability of the isolated Malawian systemin case of sudden disconnection from the regional system and the loss of the 120 MW import. It should therefore by a properly sized SPS (Special Protection Scheme) triggering rapidly the shedding of the right amount of demand as soon as the loss of the interconnection is detected.

This situation will be resolved with the commissioning of an interconnection line with a second country of the SAPP regional system.

The need in the long term will be quite limited as Malawi will be fully integrated in the SAPP network. In case shortages arises, BESS proved to be the most efficient technology to fill the gap.

The secondary reserve requirement is based on the biggest unit in the control area, whose installed capacity currently amounts to 32 MW. As big hydro power plants are integrated in the system during the study period, this requirement evolves accordingly. If shortages occur, the key options to provide additional secondary reserve are the following: investing in additional peaking units; employing long-term storage; establishing agreements with neighbouring countries; define and implement on-demand DSM measures with large consumers.

Reference development plan

Following the presentation of the preliminary results, it was confirmed with the Stakeholders that, for the purpose of the planning exercise in the frame of this study, the **reference development plan** for the other tasks (transmission and distribution expansion planning) corresponds to the LC scenario. Therefore, the reference generation expansion plan combines the Least Cost investments of the short, medium and long term, and is shown in the figure below. The following table details the evolution of the installed capacity for key years.

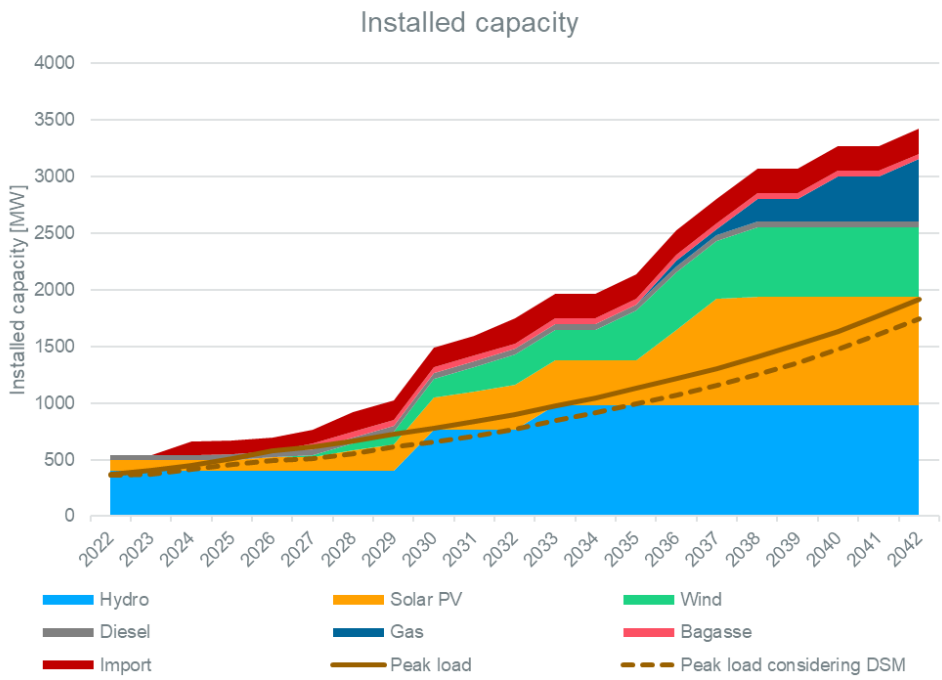


Figure 0.3.1: Installed capacity per technology for the Reference development plan

Table 0.3.7: Installed capacity per technology for the Reference development plan

Technology	Installed capacity [MW] 2023	2027	2032	2037	2042
Hydro	398	402	763	982	982
Solar PV	101	124	395	940	956
Wind	0	15	268	513	615
Diesel	42	52	52	52	52
Coal	0	0	0	0	0
Gas	0	0	0	50	550
Biomass	0	50	50	50	50
Geothermal	0	0	0	0	0
Total	**541**	**643**	**1527**	**2586**	**3204**
Import potential	0	120	220	220	220
Peak demand	405	617	900	1307	1914
Peak considering DSM	367	509	771	1159	1746

The figure below shows the investments linked to the Reference Plan, which amount to 4344 MUSD along the whole study period. As abovementioned, limited investment are foreseen in the short term (2024 – 2025), as the commissioning of the interconnection with Mozambique, together with the foreseen good availability of river flows, provides good resources to supply the demand. Moreover, the refurbishment of diesel units and the commissioning of 20 MW of BESS increase the flexibility of the system and its capability to cope with sudden variations. The only additional investment in this timeframe concerns the first adoption of DSM and EE measures (Demand Side Management and Energy Efficiency), costing around 10 MUSD until 2025. In the medium term (2026 – 2029), 433 MUSD of CAPEX are foreseen, as the demand growth requires rapid investments in the best technologies which are readily available, namely small hydro (Wowve 2), PV, wind and biomass, together with further penetration of DSM and EE measures. The two key investments of the horizon are the two big hydro power plants: Mpatamanga in 2030 and Kholombidzo in 2033, respectively 1418 MUSD and 675 MUSD. From 2035 to 2042, more than 1300 MUSD of additional investments are required, a third of which is for PV units, about 28% in wind and the remainder in gas units.

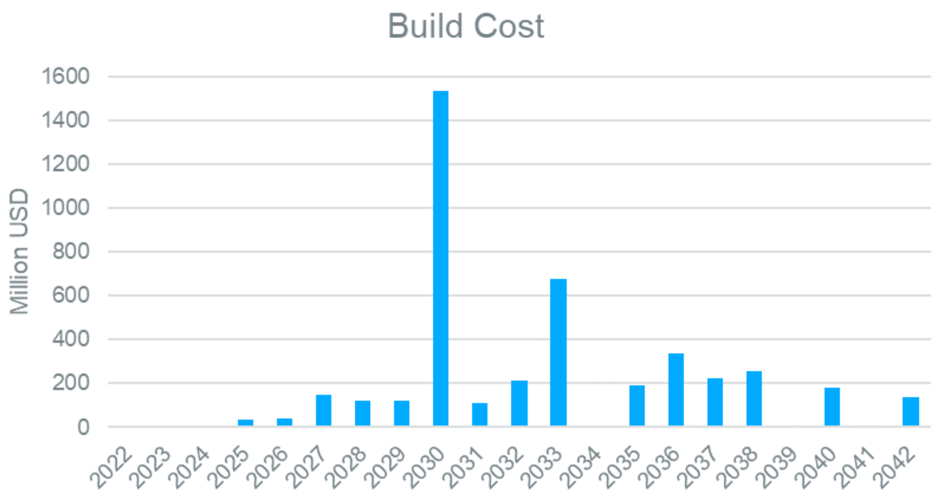


Figure 0.2.2: Yearly investment costs in the Reference scenario

Conclusions and recommendations

Given the role that hydro generation plays in the Malawian power system, assumptions on water availability are key in determining the trend of the investment plan. Indeed, the good water level forecasted for the next years, together with the establishment of the interconnection with Mozambique and the fixed import of 120 MW, determines a limited need to further invest in new power plants in the short and medium terms.

BESS and VRE represent the key addition to the existing portfolio. This is aligned with the type of projects under discussion at the Ministry of Energy. Indeed, a fairly long list of IPPs (mostly PV and wind) is under consideration, with different stages of the process being currently in place (PPA negotiation, waiting for financial close). In particular, a 20 MW BESS is foreseen to be commissioned in 2025 and this supports the integration of VRE allowing energy shifting and “filtering” of the VRE production while also representing a valuable resource for primary reserve provision, in case the second circuit on the MoMa interconnection is not readily available. The refurbishment of diesel units results strategic for the reliability of the system, as the existing plants will tend to be required less and less for supplying the demand (hydro, import and VRE will almost totally cover the needs) and could therefore be employed for the provision of secondary reserve. Finally, the adoption of DSM and EE measures is also recommended, as it reduces the peak demand and eases the dispatch of renewable resources.

Under a no-regret optimization, assuming a lower demand growth, the only investments that are kept in the short- and medium-term development are the decided small hydro Wowve 2 and the 20 MW of BESS along with the refurbishment of the existing diesel units. This would push forward the installation of new VRE power plants. Yet the addition of 10 MW of PV foreseen for mid-2025 would increase the robustness against uncertainty of the system in case the real availability of flow would not comply with the current optimistic forecasts, thus remaining a strategic investment to have a more reliable capacity mix. Hence, the trend in the economy, population and consequently electricity demand should be closely monitored in order to update accordingly the investment plan if needed.

In the long term, uncertainty grows and more comprehensive analyses are needed. Specifically, for Malawi, the quantity which heavily determines the operation as well as the required investments is the availability of water for hydro generation. For this reason, this stage of the optimization is performed using stochastic optimization, which builds an investment plan robust and reliable against any realization of the inputs while taking their respective probability of occurrence into consideration.

The key outcome of the results analysis is that the portfolio of hydro power plants should keep expanding, as it is a local, efficient and precious resource for the country. If provided with a reservoir (as in the case of Mpatamanga), flexibility and ability to accommodate increasing shares of VRE is an additional advantage of investing in hydro power plants. Once the strategic hydro power plants have been developed, another stable technology would be needed to follow the continuous growth of the demand. Gas is recommended over coal, given the lower environmental impact and the higher flexibility. An alternative to the development of new gas power plants, which would imply the import of fuel, would be to establish new agreements and contracts with the neighbouring countries to directly resort to import of electricity. Moreover, the integration in the SAPP market will allow to export excess energy from renewables as well as generation of thermal power plants and benefit from an efficient and coordinated exchange within the region.

In conclusion, the study provides comprehensive insights on the paths the investment plan may take and analyses the impacts of different strategies. The detailed development of the plan will also depend on the specific opportunities that will materialise in the next twenty years, namely the propositions from investors as well as the plans and subsidies that will be put in place during the period. In the context of an evolving landscape, this document will provide a robust reference path which can guide Stakeholders in the construction of a reliable and efficient generation infrastructure.

4. Executive summary of the Transmission development plan

The transmission development plan (TDP) presented in this study aims at providing a strategic blueprint for the future development and expansion of the Malawian transmission system over the next 20 years. The TDP has identified the necessary infrastructure upgrades and extensions to ensure reliable and efficient transmission operations while considering the demand growth and the integration of new power plants. The timeline and the costs of the investments are only indicative and will have to be revisited in due time in the scope of dedicated studies for each transmission project

A summary of the key features behind the recommended TDP is provided below. This TDP was referred to as the reference network structure in the study, which builds on the list of decided/proposed transmission projects shared by ESCOM.

Main description

As recommended by the preliminary analysis of the long-term development strategy, the proposed TDP aims to gradually phase out all existing 66kV assets and replace them with new 132kV ones by 2042. This transformation will result in a Malawian transmission system primarily composed of a main 400kV network integrating the national system to the regional network, supported by a 132kV system that connects to the distribution network. The main motivation behind this upgrade is that operating at a higher voltage level will reduce network losses and the hidden costs associated to them. Additionally, the upgrade to the 132kV level offers better prospects for future development. A higher voltage level not only facilitates the integration of long-distance transmission lines but also supports the installation of new power plants in remote locations.

List of reinforcements and costs estimates

A summary of the reinforcements foreseen in the TDP, on top of the decided/proposed transmission projects, is provided below:

Table 0.4.1: reinforcements foreseen in the TDP, on top of the decided/proposed transmission projects

Type	Quantity	Costs MUSD
HV substations	17	209
132kV lines	2950 km	386
33kV lines	24 km	4
3-winding transformers	6	18
Shunt inductors	185 Mvar	3
Shunt capacitors	-540 Mvar	10
	Total	**630**

These costs estimates should be treated as provisional. For the row in the table corresponding to the HV substations, the costs include the site opening for the new substations and the bays required to connect new transmissions lines and transformers at both existing and new substations.

When including the updated list of decided/proposed projects, the total costs estimates amount to **1306 MUSD**. An overview of the investment costs split by studied periods of 5-10 years and by reinforcement categories is shown in Figure.

From 2023 to 2027, most of the investment's costs (470 MUSD) are foreseen for implementing the decided/proposed projects, such as the Mozambique-Malawi interconnector, the Eastern Backbone, and other new 132kV lines across the country. The rest (118 MUSD) is needed to initiate the implementation of the reference network structure while ensuring the security of the Malawian power system.

From 2028 to 2032, the investments costs (206 MUSD) cover the remaining decided/proposed projects that include the Zambia-Malawi interconnector, the Tanzania-Malawi interconnector, the Western Backbone, and other new 132kV lines across the country. The rest (112 MUSD) is used to carry on the implementation of the reference network structure always while ensuring the security of the Malawian power system.

From 2033 to 2042, all the investments costs (400 MUSD) are intended for completing the implementation of the reference network structure defined for the study horizon.

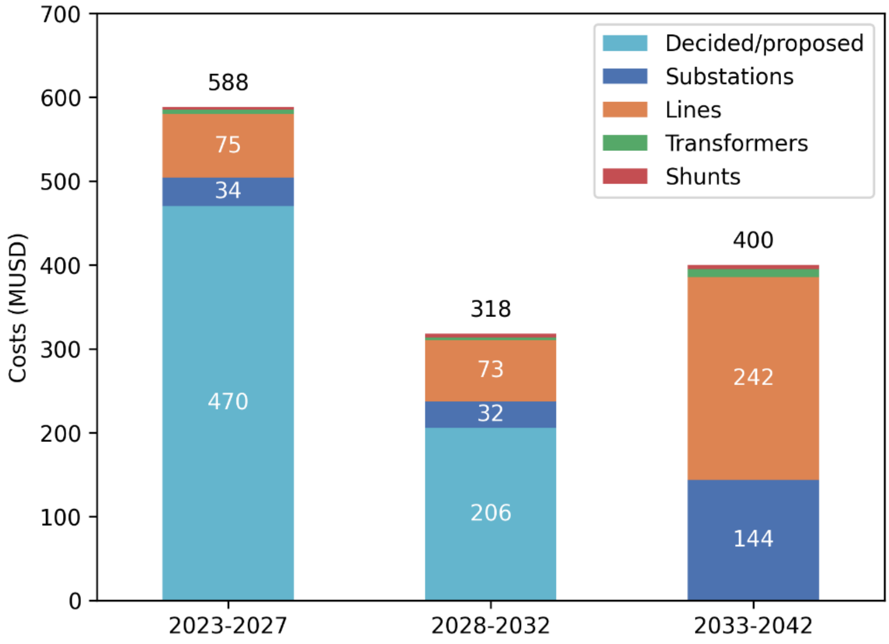


Figure0.4.1: Total costs estimates for the reference network structure split by periods and reinforcement categories.

Timeline of the reinforcements

Short term

By the year 2027, eight decided/proposed transmission projects in Malawi are expected to be operational:

Table 0.4.2: Decided/proposed transmission projects by 2027

Name	Voltage (kV)	Circuits (-)	In service by (year)
Mozambique – Malawi 400kV interconnector	400	2	2027
Eastern Backbone project	132	2	2027
Golomoti – Monkey Bay 132kV line	132	2	2027
Monkey Bay – Mangochi – Makanjira 132kV line	132	1	2027
Blantyre West – New Blantyre – Nkula B 132kV line	132	1	2027
New Blantyre – Phalombe 132kV line	132	1	2027
Nkhotakota – Serengeti – Chinyama – Kanyika 132kV line	132	1	2027
Lilongwe 132kV loop	132	1	2027

The system should be upgraded from 66 kV to 132 kV in the Southern Region up to Nkula B and from 33/66 kV to 132 kV in the Northern Region from Chintheche up to Telegraph Hill and Luwinga. Some of the 132/66kV transformers, decommissioned as a result of the upgrade, could be relocated to substations that remain at 66kV to optimize resource utilization and enhance network resilience.

The commissioning of the first interconnection with Mozambique and the integration into the SAPP regional system will mark a significant milestone for the Malawian power infrastructure. This development will enhance the overall system stability through shared reserves and inertia. However, the large import capacity of 120 MW relative to the national system size poses a significant risk in case of disconnection. Such an incident would lead to the largest instantaneous imbalance between demand and generation in Malawi and isolate the country from the larger regional system. Without appropriate preventive measures, it will be difficult to limit the impact on the Malawian consumers and avoid a complete black-out of the country.

Possible solutions to mitigate the aforementioned risk include the installation of a second circuit between Mozambique and Malawi (as foreseen in the list of decided/proposed transmission projects), keeping spinning reserve, the deployment of BESS dedicated to reserves, the implementation of SPS, or a combination of these measures.

Furthermore, the implementation of the Eastern Backbone project will strengthen the power supply to Mzuzu and the northern part of the country. The same can be said about the other 132kV projects that will improve the transfer capacity of the system around Blantyre and Lilongwe and add paths to new substations.

Medium term

By the year 2032, the remaining decided/proposed transmission projects in Malawi are expected to be operational:

Table 0.4.3: Decided/proposed transmission projects by 2032

Name	Voltage (kV)	Circuits (-)	In service by (year)
Zambia – Malawi 400kV interconnector	400/330	1	2032
Tanzania – Malawi 400kV interconnector	400	1	2032
Western Backbone project	400	1	2032
Phalombe – Zomba 132kV line	132	1	2032
Changalume – Zomba – Liwonde 132kV line	132	1	2032
Phombeya – Liwonde – Mangochi 132kV line	132	1	2032
Kanyika – Chatoloma 132kV line	132	1	2032
Mzimba – Dwangwa 132kV line	132	1	2032

The system upgrade from 66 kV to 132 kV should be completed in the Southern Region up to Chingeni and in the Central Region from Chingeni up to Tsabango. In addition, the study on the evolution of the geographical distribution of the demand has determined the need of new HV substations by 2032 at Chileka and Mponela. The recommended HV substations in Mangochi and Zomba are already included in the list of decided/proposed transmission projects.

The Western Backbone project and the new interconnectors with Zambia and Tanzania are seen as strategic expansions as they will significantly enhance the power infrastructure in Malawi, enable further integration within SAPP, and establish a connection with EAPP. The other 132kV projects will also increase the transfer capacity and the connectivity of the system. In particular, the Kanyika-Chatoloma and Mzimba-Dwangwa 132kV lines will establish two bridges between the Eastern and Western Backbones. These bridges will facilitate power exchange across the country and help distribute power to prevent overloads in the event of a contingency.

Long term

By the year 2042, the system upgrade from 66 kV to 132 kV should be finished across the whole country. Moreover, HV substations are expected to be operational and integrated in the transmission network at the following locations:

- Area 47
- Chirimba
- Chitipia
- City Center
- Limbe A
- Limbe B
- Michiru
- Sonda
- Thyolo A
- Thyolo B
- Thyolo C
- Namitete

The recommended HV substations in Chatoloma and Phalombe are already included in the list of decided/proposed transmission projects and should be in service by 2032.

At the end of process, the Malawian power system will be constituted by a main 400kV network, which interconnects the primary substations of country and the SAPP/EAPP regional systems, and a supporting 132kV network, which makes the links with the distribution system. Continuous reinforcement and extension of the 132kV network are essential to meet the increasing demand and support the expansion of the distribution system.

Transmission losses

The following table presents the yearly transmission losses for the studied years, expressed as a percentage of the total generated and imported energy in Malawi. Despite significant network expansion over the study period to enhance electricity access in remote areas, the relative amount of losses decreases. This reduction is attributed to grid reinforcement and the development of the 132 kV and 400 kV networks.

Table 0.4.4: yearly transmission losses

	2027	2032	2042
Transmission losses [%]	5.41	3.93	3.70

5. Executive summary of the Distribution development plan

The Malawi Government, through the Ministry of Energy, with support from the GEAPP is embarking on a review of the 2017 Integrated Resource Plan's (IRP) generation and transmission expansion plans and the development of a distribution masterplan. The objective of the current assignment is to produce a properly costed masterplan up to 2042. The project is organized into two work streams: Work stream 1 (WS1) focusing on generation and transmission, and Work stream 2 (WS2) on distribution.

The distribution master plan aims to update the IRP of 2017 with the latest developments and available information. The master plan outlines a path towards a least-cost and robust development of the distribution network. It integrates the IEP and MAREP studies that aim to provide full access to electricity by 2030. This target necessitates investments at every level of the electrical network to prepare for an increase in demand and newly connected regions. Furthermore, the master plan reinforces the already connected customer connections and gives room to continuous economic development.

A GIS (Geographic Information System) database has first been built to support the analysis and the simulations are carried out using the DIgSILENT software.

The current and future demand is identified in a geographical demand analysis. Starting from different data sources, a consolidated GIS database was developed as the basis for all further analyses. The country will experience a significant load growth in the next decades: The peak load is predicted to increase fivefold to reach 1,900 MW by 2042. This increase in demand should be accompanied by the necessary investments in distribution infrastructure.

The current MV network is analyzed to identify parts that need reinforcements in the short term. Several existing feeders are not adhering to the technical operational criteria, with the majority of the 11kV feeders supplying rural areas exceeding the technical operational limits. Most cases can be resolved by an upgrade to 33 kV of the feeders. In addition, all future feeders that supply rural areas should be developed in 33 kV. The network extensions in rural areas has been planned considering the optimal network extensions of MAREP and IEP.

Candidates for new primary and secondary substations are identified based on the geographical demand analysis. Eleven new primary substations will mainly supply the emerging load in rural areas. In addition, 15 secondary substations should be connected to the HV network to accommodate the increase in demand. This relieves the network in two ways: First, this will free some capacity at the HV/MV transformers of nearby primary substations. Second, it will increase the capacity of the secondary substation as larger transformers can be utilized. As a result, grid losses will reduce and additional loads can be connected to the distribution network.

Network reinforcements are proposed for rural areas. Here, the use of higher cross-sections will aid in reducing technical losses and accommodating the increasing demand. The backbone of rural networks should be considered in N-1 security where possible. Less critical parts of the rural distribution network can be implemented in N-1 depending on the preference and available budget at ESCOM side.

The analysis of the distribution network of urban areas is performed at a high level: In absence of urban development plans, it is not possible to predict the precise location of future load centers.

Therefore, the locations of new transformers, feeders, and secondary substations have not been identified. However, they are considered in an aggregated manner for the distribution and investment plan. N-1 security is systematically implemented in urban areas to be compliant with the planning standards.

The additional service transformers required to supply the load have been sized to optimize their loading at peak load. The inception report diagnosis revealed that the service transformers are currently underloaded, resulting in high transformer losses. The adopted structure in urban areas will ensure that technical losses in the feeders are maintained at an acceptable level.

The total investment required over the total duration of the project is approximately 3810 million USD, the majority of which is dedicated to service lines & meters and MV conductors.

Table of contets

List of Figures

LIST OF TABLES

Abbreviations and acronyms

ABOM	Agreement between Operating Members
AC	Alternating current
AGC	Automatic generation control
AVR	Automatic voltage regulator
BESS	Battery energy storage system
CAPEX	Capital expenditure
CAGR	Cumulative Average Growth Rate
DR	Demand Response
DSM	Demand-side management
PF	DIgSILENT PowerFactory
DC	Direct current
EAPP	Eastern Africa Power Pool
ECA	Economic Consulting Associates
ESCOM	Electricity Supply Corporation of Malawi Limited
EE	Energy efficiency
GIS	Geographic information system
GEAPP	Global Energy Alliance for People and Planet
GOV	Governor
GDP	Gross Domestic Product
GNI	Gross National Income
HV	High voltage
IEP	Integrated Energy Planning
IRP	Integrated Resource Plan
IEC	International Electrotechnical Commission
IMF	International Monetary Fund
KIA	Kamuzu International Airport
KPI	Key performance indicator
LC	Least-cost
LCSP	Least-cost + strategic projects
LV	Low voltage
MEAP	Malawi Electricity Access Project
MERA	Malawi Energy Regulatory Authority
MAREP	Malawi Rural Electrification Programme
MV	Medium voltage
OPEX	Operating expense
O&M	Operation and maintenance
OHL	Overhead line
PV	Photovoltaics

PPA	Power purchase agreement
PSS	Power system stabilizer
PMO	Project Management Organisation
QDS	Quasi-dynamic simulation
RMS	Root mean square
SADC	Southern Africa Development Community
SAPP	Southern Africa Power Pool
SPS	Special Protection Scheme
SVC	Static VAR compensator
SDG	Sustainable Development Goals
SEforALL	Sustainable Energy for All
TFO	Transformer
TDP	Transmission development plan
UFLS	Underfrequency load shedding
UG	UnderGround (cable)
USWG	Utility Scale Working Group
VRE	Variable renewable energy
WT	Wind turbine
WS	Workstream

VOLUME 1:Demand Forecast, Loss Reduction and Energy Efficiency Strategies Final Report

May,2023.

Introduction

The *Demand forecast, loss reduction and energy efficiency plan final report* has been prepared by Economic Consulting Associates (ECA) for the *Update of the 2017 IRP Demand Forecast for Malawi* study. The primary objective of the study was to develop a demand forecast for Malawi building on the *2017 IRP demand forecast* and incorporate a properly costed energy efficiency (EE) and loss reduction plan spanning 5-20 years. A secondary but equally important objective is to provide capacity building and validate work with stakeholders.

The *final report* discusses the updated electricity demand forecast for the power sector in Malawi under three scenarios. The scope of this demand forecast is to be used as an input to the update of the Integrated Resource Plan (IRP) in Malawi. For least cost power development planning purposes, a forecast of sent-out energy (MWh or GWh) and sent-out maximum demand (MW) is required in the medium to long run. The geographical distribution of the demand is also necessary to assess capacity requirements by region for the transmission development plan. The forecast was prepared for the next 20 years (up to 2042).

In previous steps, ECA and the Utility Scale Working Group (USWG) have agreed on a set of input assumptions (*Input assumptions report*) to be used for the development of the demand forecast and on the demand forecasting approach (*Inception report*). The USWG was composed by technical experts from MERA, ESCOM, PML (before dissolution) and Ministry of Energy.

The *Demand forecast draft report* is structured as follows:

- **Section 1** describes historical energy and peak electricity demand in Malawi and comments on the historical customer and sales mix. Historical data presented in this section were used for regression analysis and to set other input assumptions for the demand forecast.

- **Section 2** presents the most recent demand forecasts that were developed for Malawi for power system planning and comments on their performance to predict the demand.

- **Section 3** provides the agreed methodology for the update of the 2017 IRP demand forecast. It also presents the proposed methodology for the development of the EE measures and loss reduction plan.

- **Section 4** presents the input assumptions used for the development of the demand forecast and the EE and loss reduction plan, including socio-economic, technical, and demographic parameters, as well as policy targets.

- **Section 6** includes the results of the regression analysis that was conducted to estimate econometric equations that link the electricity demand with macroeconomic and other parameters.

- **Section 6** discusses the Loss Reduction Roadmap and ranks loss reduction projects for implementation by ESCOM.

- **Section 7** assesses potential Demand Side Measures for the power sector in Malawi and shortlists DSM to be analysed in the update of the IRP.

- **Section 8** presents the updated demand forecast in Malawi for the period 2022 to 2042. This includes aggregate sent-out energy and peak demand forecasts at a national and regional level. It also includes a demand forecast by economic activity. The impact of potential Demand Side Measures (DSM) on the demand forecast is also shown in the results.

1 Historical demand

This section analyses the evolution of the demand for electricity in Malawi and unravels key changes in the consumption and customer mix over the years. It presents historical data that were used for regression analysis, demand data for the base year of the forecast (2021) and information relevant to the preparation of the demand forecast.

1.1 System historical sent-out energy and peak demand

Over the past 10 years, served energy demand grew at an average rate of 2.3% per year and peak demand at an average rate of 3.1% per year. As can be seen in Figure 1.1, sent-out energy demand has increased from 1,906 GWh in 2012 to 2,297 GWh in 2021. Similarly, peak demand, has increased from 278 MW in 2012 to 360 MW in 2021, an overall 20.5% increase in ten years.

In contrary to the overall increasing trend of the demand over the 10-year period, from 2015 to 2018 served demand was decreasing. The drop in sent-out energy during those years was mainly the result of increased load shedding due to unavailable energy generation from hydro power plants. Malawi in that period had experienced droughts which resulted in low water levels in reservoirs of hydro power plants (see Annex A1 for more details). From 2017 an upward trend in energy demand was observed, but growth appeared to have slowed down again in 2020 impacted from the Covid-19 pandemic[2]. In 2021, economic growth rates rebounded from Covid-19, which coupled with negligible levels of load shedding, resulting in a higher increase in sent-out energy and peak demand by 12.5% and 5.9% respectively.

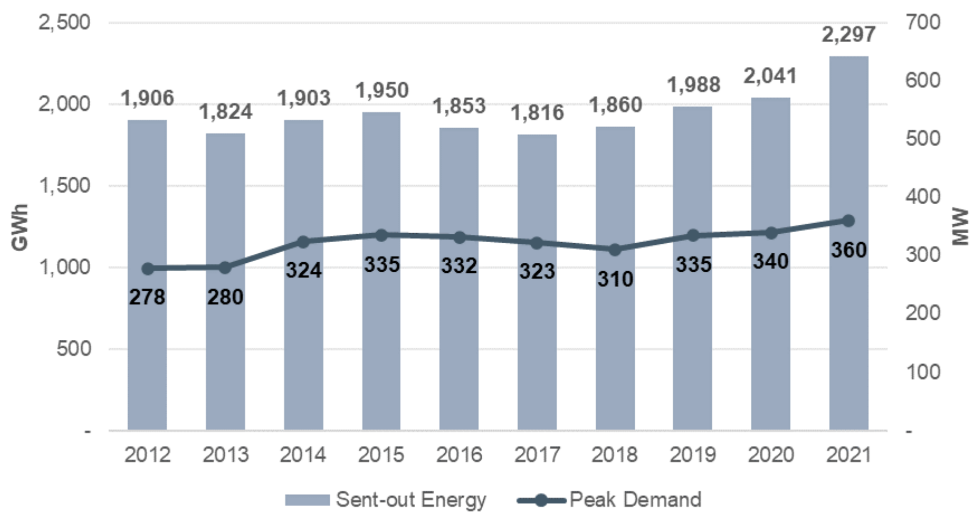


Figure 1.1.1 Sent-out energy (GWh) and peak demand (MW) in 2012-2021

Source: ESCOM data and 2017 IRP. Note: The demand shown is the actual demand served and does not include suppressed demand or load shed.

[2] GDP growth declined from 5% in 2019 to 1% in 2020 (*Source: Annual Economic Report 2022, National Accounts*)

Figure shows the evolution of economic growth (GDP growth) and energy demand growth (at generation sent-out level) over the past 10 years in Malawi. As can be seen in Figure , energy demand growth is aligned with GDP growth. A 1% increase in GDP growth was associated with an 0.3% increase in energy demand growth on average over the past 10 years. However, during the drought periods demand growth was not aligned with GDP growth due to the constraints imposed to the demand by unavailable supply[3].

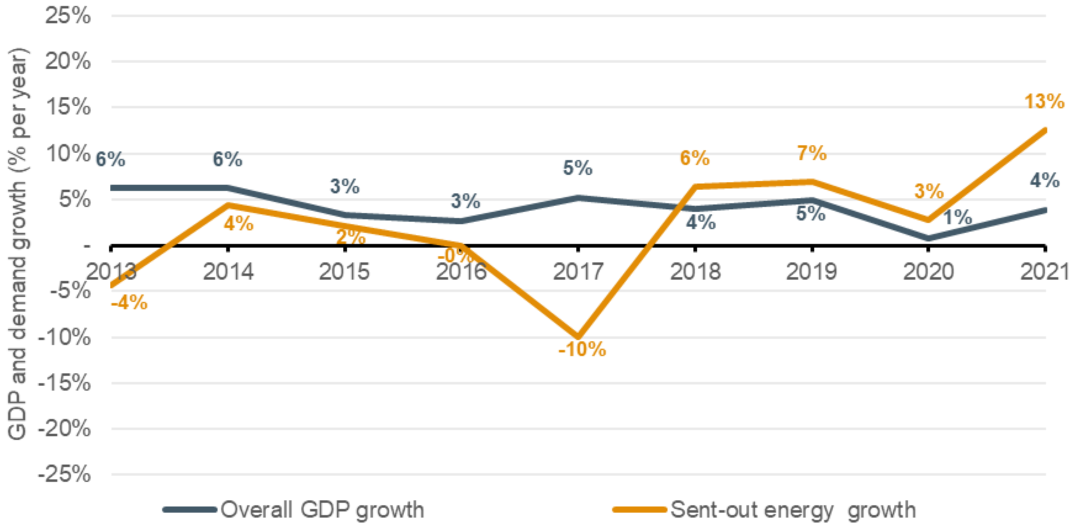


Figure 1.1.2 GDP growth rate vs sent-out energy demand growth rate in 2013-2021

Source: Annual Economic Report 2022, National Accounts 2010-2019, Sent-out energy growth calculated from ESCOM data

Excluding the years of drought (2013, 2016 and 2017 growth) from the data, the positive correlation between sent-out energy and GDP can be seen in Figure .

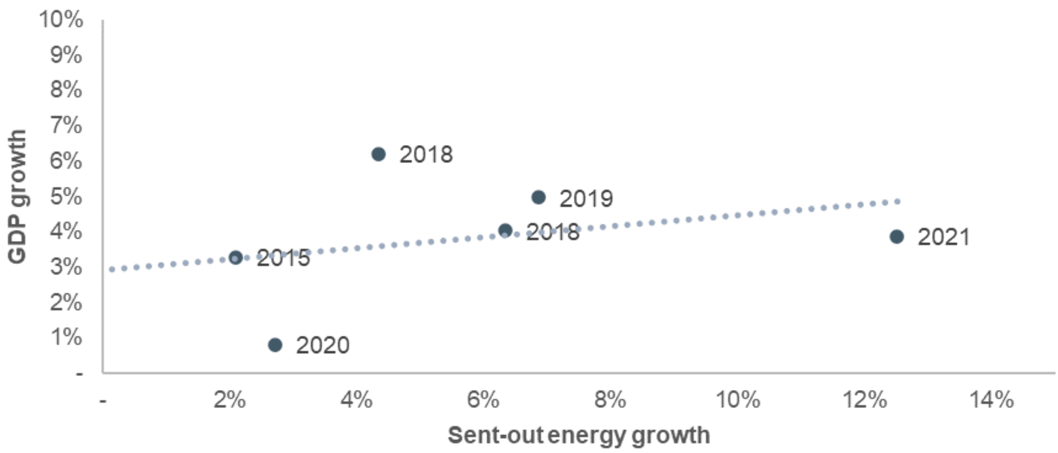


Figure 1.1.3 Sent-out energy growth vs. GDP growth 2013-2021

Source: Annual Economic Report 2022, National Accounts 2010-2019, ESCOM data

[3] The Guardian, 2017.The day the lights went out: the terrible toll of Malawi's power cuts

1.2 Historical system losses

Transmission losses have reduced over the past five years in comparison to the levels observed between 2012 and 2016. As can be seen in Figure , transmission losses have remained at around 5.5% since 2018 with a period of instability in 2016 and 2017. On average transmission losses were 5.7% between 2012 and 2021, which is high compared to less than 3% in most European countries[4] and less than 4% in other countries from the SADC region such as Botswana (3.7%), Namibia (3.2%) or South Africa (0.1%)[5].

Distribution losses fluctuated between 14% and 19% from 2012 until 2021. Distribution losses reached a maximum of 19% in 2015 and a minimum of 14% in 2018. A spike in distribution losses is also noticeable in 2021 reaching 18%, the highest level in five years. Distribution losses presented below cover both commercial and technical losses.

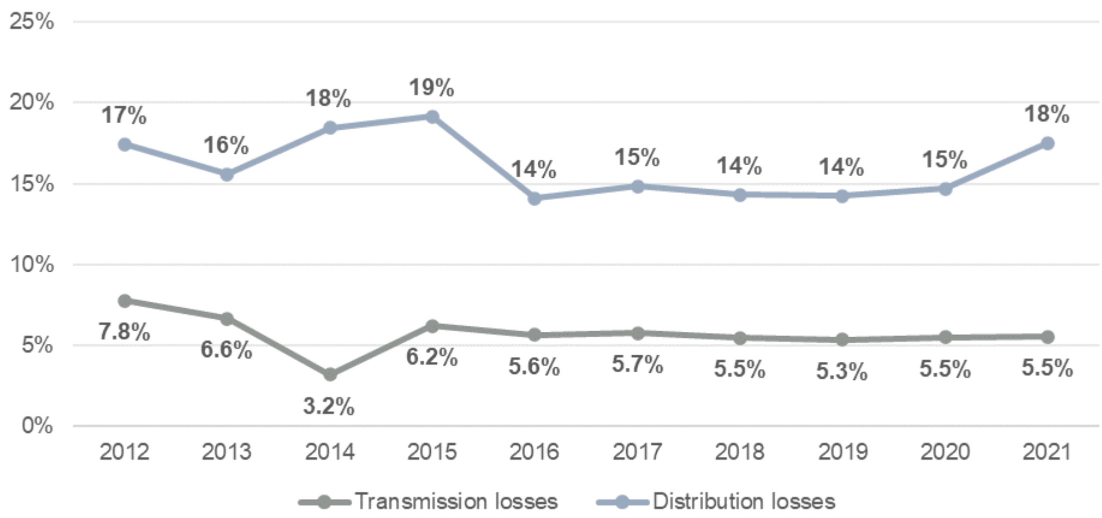


Figure 1.1.4 Transmission and distribution losses (% of incoming energy)

Source: ESCOM

1.2.1 Historical sales and number of customers

As of 2022, Malawi had 11 tariff categories which are presented in Table 1.1. below. ESCOM tariff categories were grouped by economic activity into four main groups – Residential (ET1, ET2, ET3, ET4), Commercial (ET5, ET6, ET7, ET8), Industrial (ET9, ET10, ET11 and large users with special tariffs).

Table 1.1.1 Current electricity tariff categories in Malawi

Groups by economic activity	Tariff Code	Description
Residential	ET1	Domestic, 1-Phase, Prepaid
	ET2	Domestic, 1-Phase, Postpaid
	ET3	Domestic, 3-Phase, Prepaid
	ET4	Domestic, 3-Phase, Postpaid
Commercial	ET5	General, 1-Phase, Prepaid

[4] Council of European Energy Regulators, 2020. 2nd report on Power Losses
[5] Southern African Power Pool, 2021. 2021 Annual Report

Groups by economic activity	Tariff Code	Description
	ET6	General, 1-Phase, Postpaid
	ET7	General, 3-Phase, Prepaid
	ET8	General, 3-Phase, Postpaid
Industrial	ET9	Maximum Demand, LV
	ET10	Maximum Demand, MV
	ET11	Essential Service, 3-Phase, Prepaid

Source: ESCOM Current Tariffs. Note: ESCOM is planning to phase out ET11 and incorporate ET11 customers to ET9 or ET10.

ESCOM total sales and number of customers by economic activity over the past 10 years is shown in the table below. The number of customers grew at a compound annual growth rate (CAGR) of 10% per year and sales grew at an average rate of 2% per year. In 2019, ET11 Essential Service category was introduced, incorporating users previously categorised as residential or commercial. Following discussions with the USWG it was agreed that these customers should be categorised as Industrial for the purpose of this analysis, resulting in a large increase in the number of customers in 2019 and 2020.

Table 1.1.2 Historical sales and number of customers 2012-2021

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average
Number of customers (‘000 customers)											
Residential	199.8	223.3	267.1	301.9	349.8	387.7	355.3	409.7	424.5	459.8	337.9
Commercial	30.5	28.4	22.9	18.8	9.6	7.3	67.2	78.2	77.3	83.8	42.4
Industrial	0.80	0.84	0.85	0.89	0.90	0.92	0.96	1.19	1.81	1.90	1.1
Total	**231.1**	**252.5**	**290.8**	**321.6**	**360.2**	**395.9**	**423.4**	**489.1**	**503.6**	**545.5**	**381.4**
Number of customers growth (% per year)											
Residential	-	12%	20%	13%	16%	11%	-8%	15%	4%	8%	10%
Commercial	-	-7%	-19%	-18%	-49%	-24%	822%	16%	-1%	8%	12%
Industrial	-	5%	1%	5%	1%	2%	4%	24%	52%	5%	10%
Total	**-**	**9%**	**15%**	**11%**	**12%**	**10%**	**7%**	**16%**	**3%**	**8%**	**10%**
Sales (GWh)											
Residential	589.9	583.6	664.3	721.2	755.5	745.5	544.9	551.1	598.2	663.6	641.8
Commercial	237.0	196.0	169.4	132.6	96.9	58.0	270.7	300.4	307.4	329.2	209.8
Industrial	602.6	634.4	645.7	602.6	627.2	633.3	672.0	742.3	722.3	777.0	665.9
Total	**1,429**	**1,414**	**1,479**	**1,456**	**1,480**	**1,437**	**1,488**	**1,594**	**1,628**	**1,770**	**1,517.5**
Sales growth (% per year)											
Residential	-	-1%	14%	9%	5%	-1%	-27%	1%	9%	11%	1%
Commercial	-	-17%	-14%	-22%	-27%	-40%	367%	11%	2%	7%	4%
Industrial	-	5%	2%	-7%	4%	1%	6%	10%	-3%	7%	3%
Total	**-**	**-1%**	**5%**	**-2%**	**2%**	**-3%**	**4%**	**7%**	**2%**	**9%**	**2%**

Source: ESCOM. Note: The large increases of the number of Industrial customers in 2019 and 2020 is the result of adding those categorised previously as "Essential services" to the Industrial category. The large increases/decreases of commercial and residential users are explained below

Number of connections

The aggregate number of connections has steadily increased annually from 231,116 customers in 2012 to 545,490 customers in 2021 (see Figure 1). Residential consumers remain the largest group in Malawi, accounting for 84% of current connections, whereas industrial consumers have remained consistently below 1% of total connections. In 2018 there was a sharp increase of commercial connections which coincided with a sharp decrease of residential connections. This was due to ESCOM moving commercial customers previously grouped under the residential category to the commercial category.

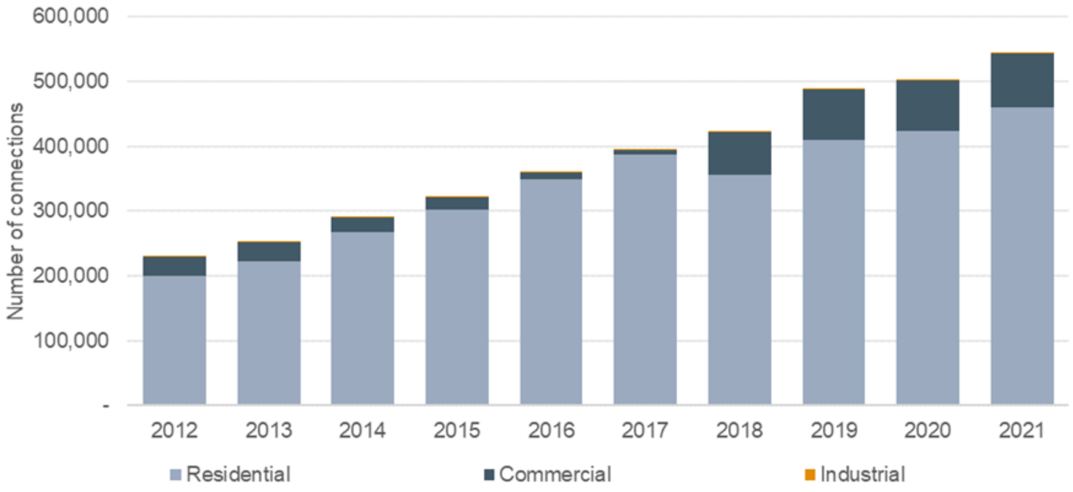


Figure 1.1.5 Number of connections by consumer group 2012-2022

Source: ESCOM

The average number of new connections between 2013 and 2021 was 34,390 customers per year, with the vast majority being new residential users (see Figure). Without taking into account the move of customers from the residential to the commercial category, each year an average of 33,992 residential connections were added, while 5,624 commercial users were added on average in 2020 and 2021.

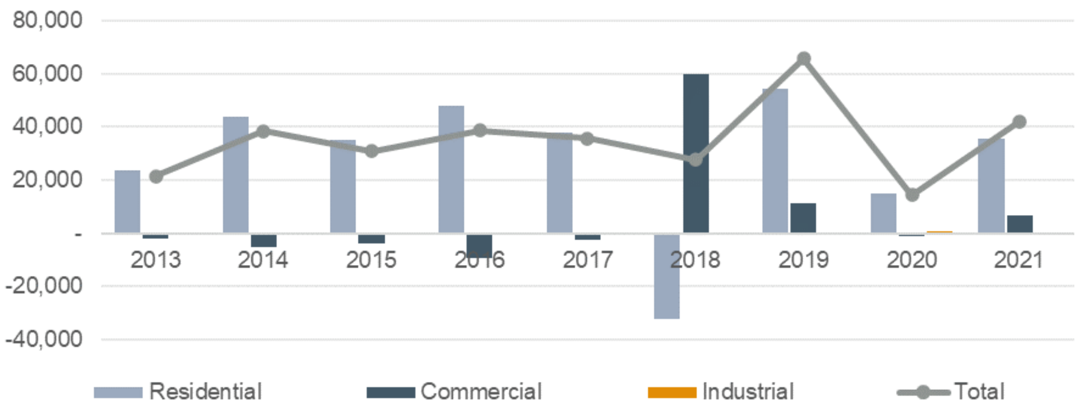


Figure 1.1.6 New connections by consumer group

Source: ESCOM Note: Negative new connections are due to ESCOM moving commercial customers previously grouped under the residential category to the commercial category and vice-versa.

Sales

In terms of energy sales, industrial consumers are, along residential consumers, the largest groups in the country (see Figure). In 2021, residentials sales accounted for 37% of total sales, industrial 44% of total sales and commercial 19% of total sales. The consumption mix has remained relatively stable over the past 4 years. The step change observed in 2018 is due to ESCOM moving commercial customers previously grouped under the residential category to the commercial category.

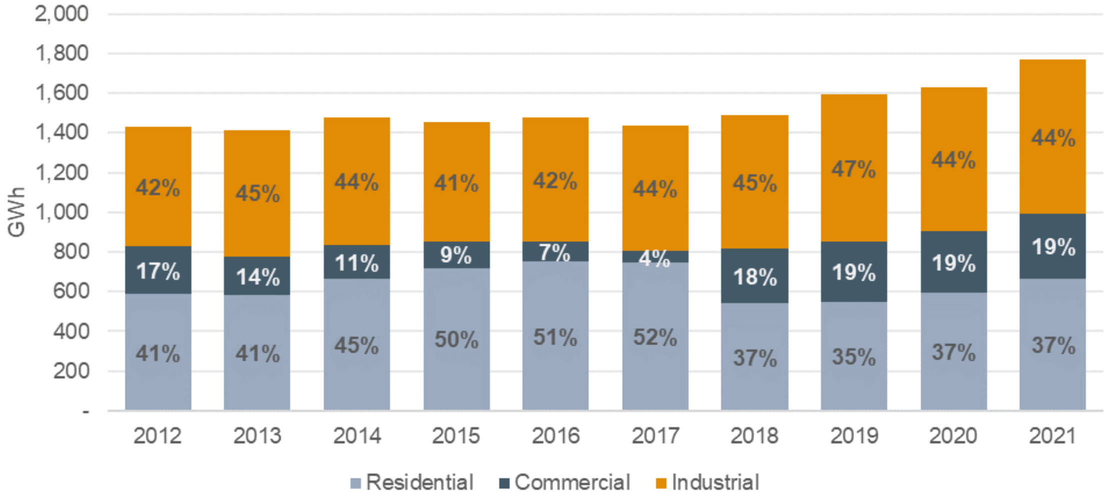


Figure 1.1.7 Sales by consumer group 2012-2021

Source: ESCOM

Consumption per connection varies widely depending on the type of customer as seen in the table below. For residential users, the average annual consumption per customer between 2012 and 2022 was 2,026 kWh per year (or 169 kWh per month). Commercial users consumed 6,549 kWh on average per year per customer and industrial consumers 645,574 kWh on average per year per customer. For all three consumer groups the average consumption per year per user was reducing from 2012 to 2021. This is a result of new customers connected to the grid, who used less electricity.

Table 1.1.3 Average annual consumption per customer by consumer group (MWh)

Consumer group	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average
Residential	3.0	2.6	2.5	2.4	2.2	1.9	1.5	1.3	1.4	1.4	2.0
Commercial	7.8	6.9	7.4	7.1	10.1	8.0	4.0	3.8	4.0	3.9	6.5
Industrial	751.3	753.5	758.8	674.0	694.5	686.9	701.4	625.8	399.5	410.0	645.6

Source: ESCOM

1.3 Historical load shedding

Load shedding has been a chronic problem in the Malawi's power sector. Energy lost from load shed ranged between 5 GWh and 248 GWh from 2012 to 2020 (see figure below). However, a positive trend with negligible load shedding was observed in 2021. The annual values of energy not served due to load shedding for the 2012-2021 period can be seen in Figure .

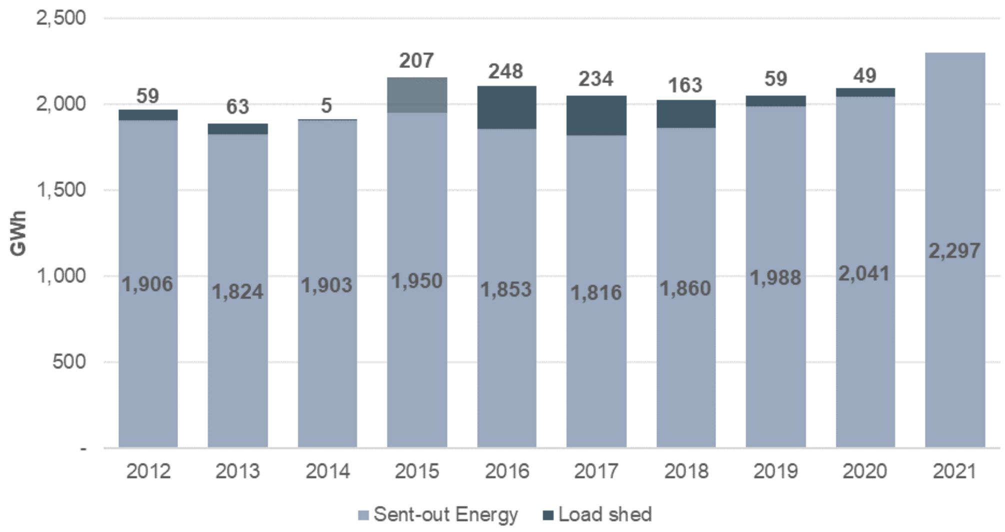


Figure 1.1.8 Lost load and sent-out energy served by year (GWh)

Source: ESCOM. Note: For 2015 the load shed value does not include the months of February-June

The years with the highest load shed were 2015, 2016, 2017 and 2018. This seems to confirm discussions with relevant stakeholders, who point to widespread load shedding between 2015 and 2017 as a result of low rainfall curtailing hydropower generation. Nonetheless, following discussions with ESCOM, it was agreed that 2021 experienced little to no load shedding and can be used as a representative base year for the demand forecast.

1.4 Historical geographical split of demand

Historically, most of the energy demand has come from the Southern region (more than 53% of total demand). The Central region accounts for around a third of energy demand and the Northern region accounts less than 10%. However, as seen in Figure, energy demand from the Central region has increased substantially, reaching 38% of the overall energy demand in 2021.

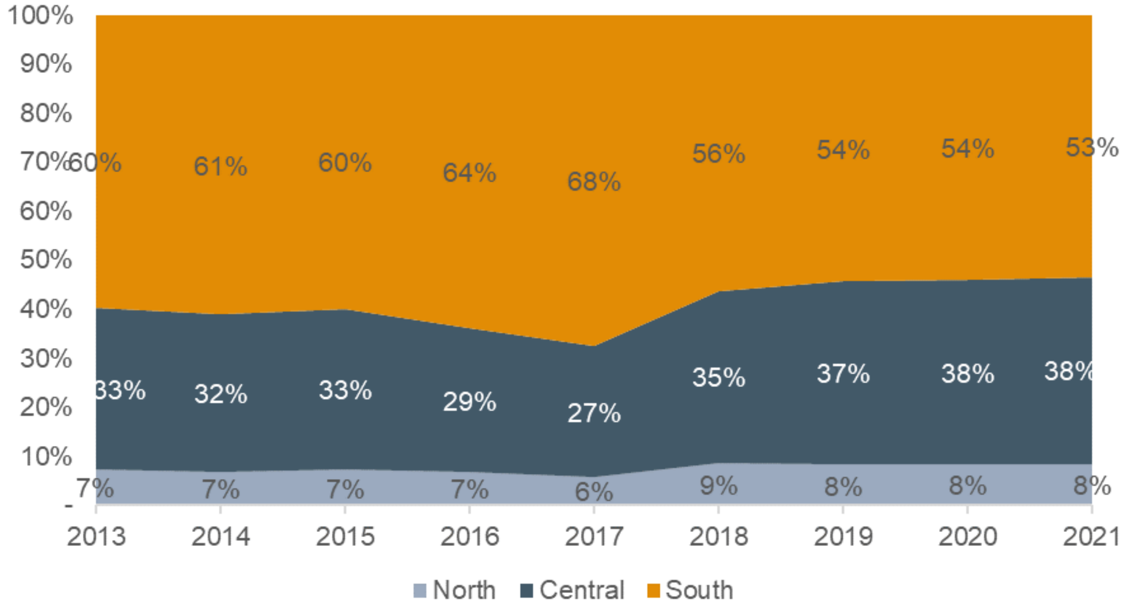


Figure 1.1.9 Energy sales by region 2012-2021

Source: ESCOM.

Industrial sales in the Northern region are lower compared to the other two regions, as shown in Figure . This is due to lower industrial activity in the Northern region and due to higher outages rates of the network. As of 2021, energy sales from industrial consumers accounted for 28% of the region's total sales, compared to 38% in the Central region and 50% in the Southern region. Residential share of consumption is similar across the three regions at around 34-42%. The share of commercial consumption in the Northern region (29% of total Northern region sales) is higher compared to the share of commercial consumption in the Central and Southern regions (20% and 16%, respectively).

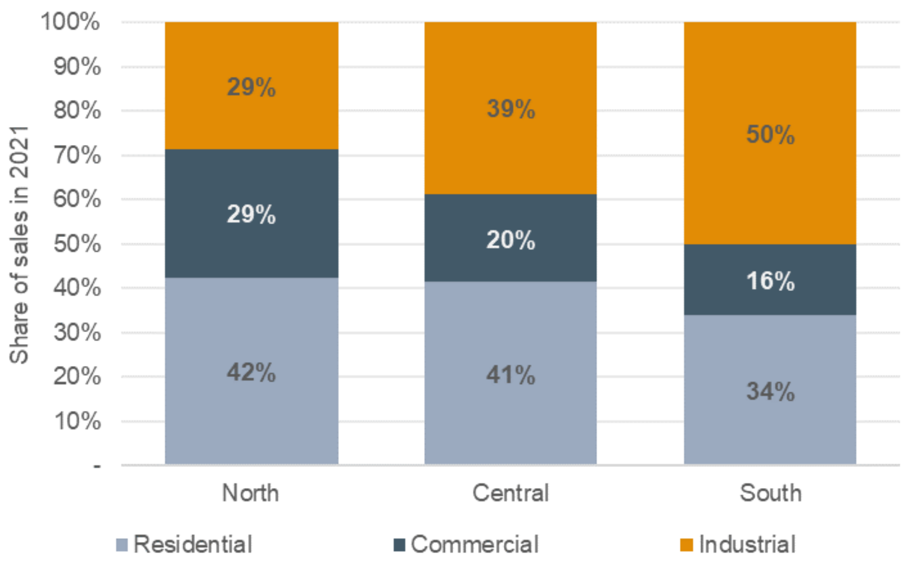


Figure 1.1.10 Energy demand composition by region in 2021

Source: ESCOM.

1.5 Energy balance

The following table presents the energy balance[6] for Malawi for 2012 to 2021.

Table 1.1.4 Malawi's historical energy balance

Item	Unit	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Energy (sent-out)	**GWh**	**1,906**	**1,824**	**1,903**	**1,950**	**1,853**	**1,816**	**1,860**	**1,988**	**2,041**	**2,297**
Transmission losses	GWh	148	121	60	121	104	104	101	106	112	127
Share	%	7.8%	6.6%	3.2%	6.2%	5.6%	5.7%	5.5%	5.3%	5.5%	5.5%
Energy exiting transmission network	GWh	1,758	1,703	1,843	1,829	1,749	1,712	1,758	1,882	1,930	2,170
Sales at transmission network	GWh	-	-	-	-	-	-	-	-	-	-
Energy entering distribution network	**GWh**	**1,758**	**1,703**	**1,843**	**1,829**	**1,749**	**1,712**	**1,758**	**1,882**	**1,930**	**2,170**
Distribution losses	GWh	306	265	340	350	246	254	252	268	283	380
Share	%	17%	16%	18%	19%	14%	15%	14%	14%	15%	18%
Distribution network sales	**GWh**	**1,452**	**1,437**	**1,502**	**1,478**	**1,502**	**1,458**	**1,507**	**1,614**	**1,646**	**1,789**
Export	GWh	22	23	23	22	23	21	19	20	18	20
Domestic	GWh	**1,429**	**1,414**	**1,479**	**1,456**	**1,480**	**1,437**	**1,488**	**1,594**	**1,628**	**1,770**
Residential	GWh	590	584	664	721	755	745	545	551	598	664
Commercial	GWh	237	196	169	133	97	58	271	300	307	329

[6] In this section, Energy Balance refers to the flow of electricity from generation to transmission and supply. The generated electricity should be balancing the electricity consumed or lost.

Historical demand

Item	Unit	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Industrial	GWh	603	634	646	603	627	633	672	742	722	777

Source: ESCOM and 2017 IRP. Note: In 2018 ESCOM identified that some commercial customers were included in the residential category in previous years, and they were allocated to the commercial category.

2 Review of previous demand forecasts

In the past few years, one demand forecast has been developed for the power sector in Malawi for planning purposes. This was developed in 2017 for the *2017 Malawi Integrated Resource Plan (IRP)*. In 2019, the *2017 Malawi Integrated Resource Plan (IRP)* demand forecast was updated by the World Bank, but this was for its internal usage. The *2017 Malawi Integrated Resource Plan (IRP)* demand forecast and the 2019 update of the Integrated Resource Plan demand forecast are discussed below.

2.1 2017 Malawi IRP demand forecast

The demand forecast developed for the 2017 Integrated Resource Plan follows a mix of forecasting approaches. For residential consumption, demand is determined by population growth, electrification rates and consumption per urban or rural user. Non-residential consumption is forecasted using an econometric equation linked to GDP growth. New Industrial step loads were identified separately and added to the demand forecast. Probabilities were assigned for the likelihood of this projects to materialise.

Some key assumptions of the 2017 IRP demand forecast are shown in the table below.

Table 1.2.1 2017 IRP demand forecast key input assumptions

Assumption	Low	Base	High
Population growth	Population growth rate was assumed to be 3.4% per year declining to 2.4% per year by 2050		
Electrification rate	2020 – 12.4% 2030 – 20.4% 2040 – 42.0%	2020 – 15.9% 2030 – 29.5% 2040 – 53.0%	2020 – 22.7% 2030 – 35.9% 2040 – 58.0%
Average consumption per household	Average monthly consumption per household was assumed to increase from 218 kWh in 2015 to 248 kWh in 2020, reaching 267 kWh in 2040		
GDP growth rate	0.5% p.a. lower than the base case up to 2021 1% p.a. lower than the base case after 2021	~4.0 – 4.5% p.a. up to 2021 5.0% p.a. up to 2030 4.5% p.a. up to 2040	0.5% p.a. higher than the base case up to 2021 1% p.a. higher than the base case after 2021
Losses	16% by 2020 12% by 2030	18% by 2020 15% by 2030	22% by 2020 18% by 2030
Suppressed demand (load shedding)	50 GWh	100 GWh	200 GWh
Step loads	130 GWh	200 GWh	260 GWh
Connection of existing loads (2016-2020)	147 GWh	147 GWh	147 GWh

Source: 2017 IRP

As can be seen in Figure , actual energy and peak demand served was lower than the demand projected in the 2017 IRP, with sent-out energy accounting for around a half of the projected value in 2021 (2,297 GWh vs. 4,426 GWh) and peak demand accounting for less than half (360 MW vs. 795 MW). The impacts of COVID-19 pandemic were not foreseen in the 2017 demand forecast which had assumed much higher GDP growth rates than actuals. Additionally, the 2017 IRP demand forecast had reflected policy targets for electrification rates of the country which did not materialise[7]. The luck of foreseen infrastructure improvements and developments failed to alleviate suppressed demand that was assumed that it would be served.

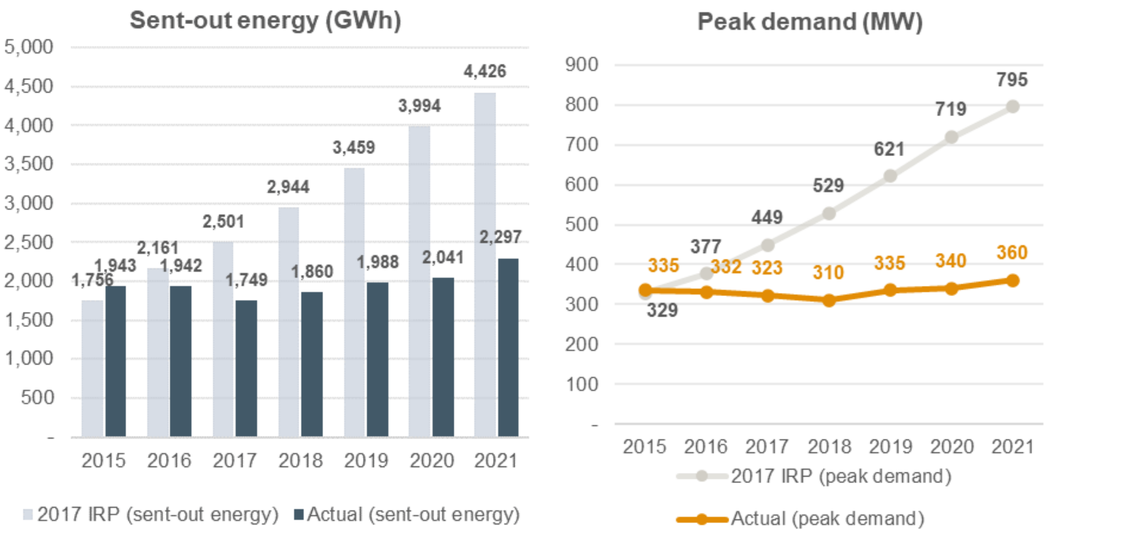


Figure 1.2.1 2017 IRP demand forecast (base case scenario) vs actual served demand

Source: 2017 IRP, ESCOM data

A comparison of the assumption used in the forecast with respect to the actual values for 2015-2021 is presented in Figure .

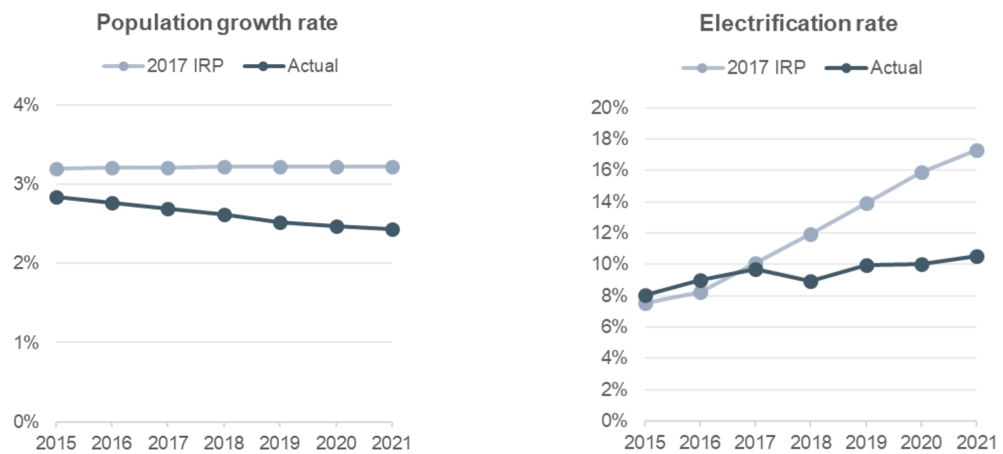


Figure 1.2.2 2017 IRP demand forecast assumptions vs actual values 2015-2021

[7] ESCOM reported that failure to connect new customers (both industrial and residential) is due to constrained supply chain management of materials needed for connections including transformers.

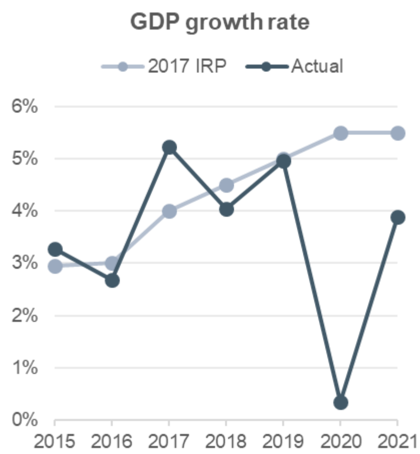


Figure 1.2.3: GDP growth rate

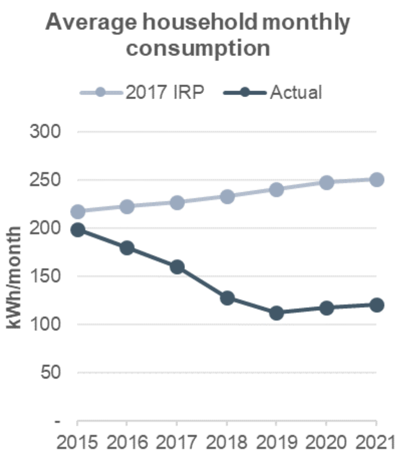


Figure1.2.4: Average household monthly consumption

Source: 2017 IRP Base case scenario

2.2 2019 Malawi IRP demand forecast update

The World Bank in 2019 updated the demand forecast of the IRP for its internal use. The updated demand forecast followed the same approach as the 2017 IRP but updated some assumptions as shown in Table 1.2. below.

Table 1.2.2: 2017 IRP vs 2019 IRP Update assumptions (base case scenarios)

Assumption	2017 IRP	2019 IRP Update
Electrification rate	• 15.9% in 2020 • 29.5% in 2030 • 53% in 2040	• 13.5% in 2020 • 30.0% in 2030 • 50.3% in 2040
GDP growth rate	• 4-4.5% per year until 2021 • 5% per year until 2030 • 4.5 per year until 2040	• 4.5% per year (2018-2040)
Losses	• 18% per year until 2020 • 15% per year until 2030	• 16% per year until 2020 • 15% per year until 2030
Suppressed demand	100GWh	400GWh

Source: 2019 Malawi IRP Update

The updated demand forecast is shown in Figure and is also compared with actual historical energy and peak demand recorded in the system. The updated demand forecast was much closer to the actual demand indicating that the input assumptions of the base case demand forecast of the 2017 IRP were probably overly optimistic.

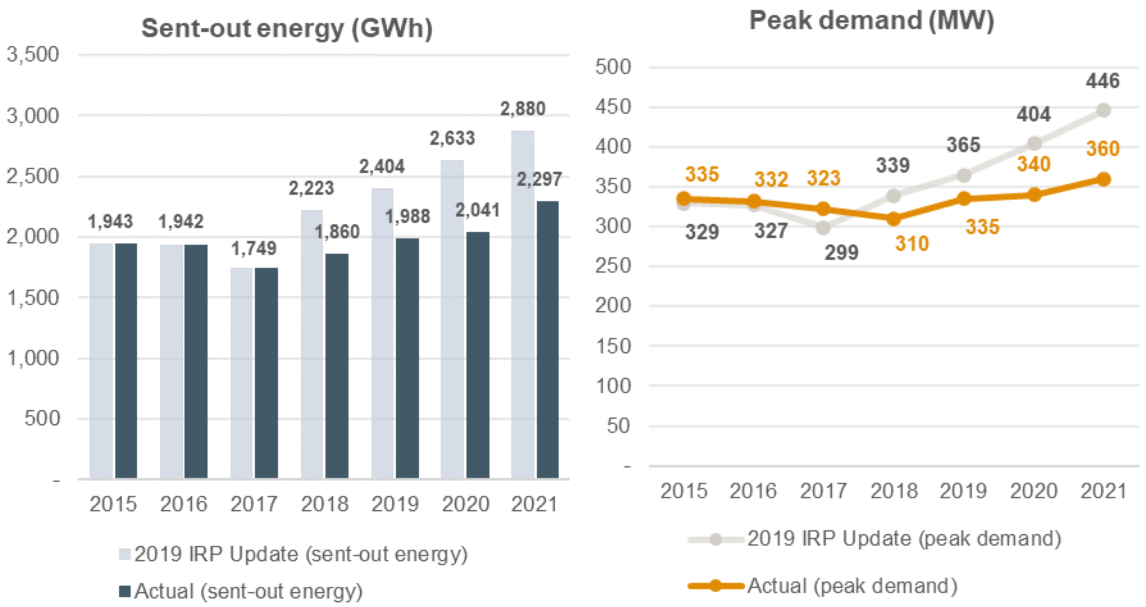


Figure 1.2.5: 2019 IRP demand forecast update (base case scenario) vs actual demand

Source: 2019 Malawi IRP Update

3 Forecasting approach

3.1 Demand forecasting approach

The demand forecast was developed for the following 20 years (2022 to 2042) and was prepared for a low, base and high scenario based on alternative assumptions relating to the key drivers such as GDP growth, electrification policies, industrial development, self-generation and others (see Section 4). The starting year of the forecast (base year) was proposed to be the most recent year with representative data. 2021 was considered by stakeholders as a year without significant load shedding, with minor impacts from COVID-19 pandemic and with available data to be considered as the base year for the forecast. However, it was noted that adjustments may have to be considered on the 2021 data to account for load shed or suppressed demand not reflected in the 2021 data.

The approach for the development of the demand forecast of each economic activity is summarised in the table below. The forecast of each economic activity is then aggregated to form the national demand forecast. Using locational information the national demand forecast is then disaggregated by region. More information regarding the demand forecast approach and the reasoning for the chosen methodologies are described in the *Inception report* and the *Input assumptions report*.

Table 1.3.1: Methodology for the demand forecast

Activity	Approach	Description

Domestic	Bottom-up	*Domestic energy demand is estimated separately for urban and rural households using the following equation:* ***Average consumption per urban or rural household per year x number of urban or rural domestic connections per year***
		• *Average consumption per household per year uses as a basis the average consumption of 2021.*
		• *The growth of the average consumption per household per year is estimated using the income elasticity of demand for residential customers. Thus, we quantify the relationship between GDP per capita and electricity consumption per household and adjust it to reflect the adoption of energy efficiency measures and the increasing efficiency of household appliances.*
		• *The number of connections is estimated as* ***Electrification rate x number of households***
		  – *The forecast electrification rate varies by scenario and seeks to incorporate policy targets, ESCOM's connection targets and the historical performance of ESCOM to achieve those targets.*
		  – *The number of households is estimated using population forecasts and the average number of persons per household forecast.*

Commercial	Econometric	*Econometric equation describing the relationship between commercial sales and independent variables. Combinations of several parameters were analysed for the independent variables*

Activity	Approach	Description
		(eg total GDP, services GDP, population growth, GDP per capita, etc) to identify the highest statistical significance.
Industrial LV	Econometric	*Econometric equation describing the relationship between Industrial LV sales and independent variables. Combinations of several parameters were analysed for the independent variables (eg total GDP, services GDP, population growth, GDP per capita, etc) to identify the highest statistical significance.*
Industrial MV	Econometric and bottom-up	*Econometric equation describing the relationship between Industrial MV sales and independent variables. Combinations of several parameters were analysed for the independent variables (eg total GDP, services GDP, population growth, GDP per capita, etc) to identify the highest statistical significance.* *The demand of new large industrial loads and shutdowns that cannot be identified in historical information (econometric equation) can be identified separately to be added/subtracted to/from the demand forecast. Probabilities were assigned to each new project for each year to obtain probability adjusted demand.* *Self-generation is also accounted using a similar approach as with new step loads.* *A survey was conducted to identify new industrial loads and plans for self-generation.*
Exports	Bottom-up	*No firm export commitments were identified to be considered in the demand forecast.*

Note: ESCOM specifies that the Maximum Demand LV and MV categories are intended to cover “Large power for industrial users”

3.2 Energy efficiency and loss reduction plan approach

The energy efficiency and loss reduction analysis focused on the identification and analysis of potential energy efficiency and loss reduction measures to reduce electricity consumption, the demand for electricity and losses in Malawi.

The approach for the examination of energy efficiency measures was planned along two axes:

- Measures that have been applied in the past in Malawi and their effectiveness could be considered ex post, based on actual changes to the load curve, and/or the level of annual or seasonal consumption.
- Measures that have not been applied in Malawi yet, and their effectiveness could be considered ex ante, in the context of this study.

Loss reduction measures have been extensively and exhaustingly reviewed in the context of the *Loss Reduction Roadmap 2021*. The proposed loss reduction measures were considered for implementation by ESCOM and were accounted in the demand forecast.

The impact of the identified energy efficiency and loss reduction measures were then added to the demand forecast in different combinations according to the scenario assumed.

4 Input assumptions for the forecast

Section 4 presents the input assumptions that were used for the development of the demand forecast and for the energy efficiency and loss reduction plan. These were also discussed in detail in the *Input assumptions report* which was subsequently validated by stakeholders. Annual values for all years in the forecasting period are presented in Annex A2.

4.1 Forecast period

The scope for the development of the demand forecast is to be used in the update of the Integrated Resource Plan for Malawi. For power sector assets that have lives of 25 years or more it is important to have a long-range demand forecast typically of 20 years or more to assess the investments throughout their lifetime.

The demand forecast will cover the period 2022-2042 with 2021 as the base year of the forecast. As indicated in Section 3.1 and 1.3, 2021 is considered a year without significant load shedding, with minor impacts from COVID-19 pandemic and with available data and could be considered as the base year for the forecast. However, adjustments were considered on the 2021 data to account for load shed or suppressed demand as indicated in the subsections below.

4.2 Forecast domestic customer connections

The 2018 Census provides historical and forecast (2018-2050) population in Malawi and the average number of persons per household. The information from the 2018 Census can be used to estimate the number of households in urban and rural areas by region. The number of connections is estimated combining information for the number of households and forecast electrification rates. The population forecast is assumed to be the same for the three scenarios and the key variance is the forecast electrification rate in each scenario. Historical domestic connections up to 2021 have been obtained from ESCOM.

4.2.1 Historical and forecast population growth

The following table presents the estimated urban and rural population growth used in the demand forecast for the period 2022-2042. According to the 2018 Census, the urbanisation rate has remained stable in the last few decades, with the share of urban population increasing by 0.7% between 2008 and 2018. Thus, we have assumed this trend will continue until 2042.

Table 1.4.1: Population forecast summary

	Unit	2021	2025	2030	2035	2040	2042
Urban population	million	3.1	3.4	3.9	4.4	4.9	5.2
Urban population growth	%*	2.8%	2.7%	2.5%	2.4%	2.3%	2.3%
Rural population	million	15.8	17.3	19.2	21.2	23.2	24.2

	Unit	2021	2025	2030	2035	2040	2042
Rural population growth	%*	2.3%	2.1%	2.0%	1.9%	1.8%	1.8%
Total population	million	**18.9**	**20.7**	**23.1**	**25.6**	**28.2**	**29.2**
Total population growth	%*	**2.4%**	**2.2%**	**2.1%**	**2.0%**	**1.9%**	**1.9%**

Source: 2018 Census. Note: * Average of the period starting from the indicated year and ending one year prior to the next indicated year.

4.2.2 Historical and forecast household size and number of households

As with the population forecast, there is no variation among the three demand forecast scenarios for the number of persons per household. The forecast of the average number of persons per household follows the 2018 Census and the trend observed between 2008 and 2018 for the growth of the number of average persons per household is assumed. An average annual reduction of 0.2 persons per household (from 4.6 to 4.4 persons per household) is assumed until 2042, where the household size is expected to be 3.9 persons per household. These values vary slightly between regions, with the North region household size starting at 4.7 persons per household in 2021 and decreasing to 4.1 persons per household in 2042; for the Central region, the household size is expected to fall from 4.3 to 3.9 persons per household in the same time period, while for the South region it will slightly decrease from 4.3 to 4.1 persons per household. The assumed household size and number of households is shown in Table below.

Table 1.4.2: Number of households and household size summary

	Unit	2021	2025	2030	2035	2040	2042
Household size	Average persons	4.3	4.3	4.2	4.1	4.0	3.9
Number of households	million	4.4	4.9	5.6	6.3	7.1	7.5

Source: Malawi Statistical Yearbook 2020 and 2018-2050 Population Projections

4.2.3 Electrification targets

Following discussions with members of the Utility Scale Working Group, the following assumptions for electrification targets by scenario were agreed:

- **Low scenario:** In this scenario electrification targets are constrained by ESCOM's historical capacity to connect new domestic consumers. Historically (from 2013 to 2021), ESCOM was connecting 35,000 domestic customers on average per year. The same number of new domestic connections is assumed for the forecast period per year reaching an electrification rate of 16.8% in 2042.

- **Base scenario:** This scenario is determined by the Ministry of Energy's Guidelines for Implementation of the National Electrification Programme. This includes a target electrification rate of 32.4% by 2030. From 2030 to 2042, it was assumed that the electrification rate will increase linearly to reach 55.5% by 2042, which reflects the trend from the 2022-2030 period.

- **High scenario:** This scenario uses the electrification targets set by the SE4ALL electrification plan, which aims to reach 100% electrification by 2030. However, as these estimates include households covered by off-grid solar PV and SHS, we have only used the estimates for grid expansion and grid intensification. These represent annual increases reaching over 900,000 in 2028, achieving 72.7% electrification (excluding off-grid) by 2030. For 2031-2042, we assume that every new household will represent a new grid connection.

The assumed domestic connections and electrification rates for each scenario of the demand forecast are shown in Table.

Table1.4.3: Electrification targets

Scenario	Item	2021	2025	2030	2035	2040	2042
Low	Total domestic connections	459,776	654,600	829,600	1,004,600	1,179,600	1,249,600
	New domestic connections per year	35,294	35,000	35,000	35,000	35,000	35,000
	Electrification rate	10.6%	13.4%	14.9%	15.9%	16.6%	16.8%
Base	Total domestic connections	459,776	999,600	1,669,600	2,563,072	3,647,650	4,140,081
	New domestic connections per year	35,294	150,000	130,000	193,219	233,225	240,656
	Electrification rate	10.6%	21.5%	32.4%	40.7%	51.3%	55.5%
High	Total domestic connections	459,776	1,122,441	4,038,622	4,784,978	5,594,908	5,937,678
	New domestic connections per year	35,294	256,894	475,330	154,056	167,171	172,884
	Electrification rate	10.6%	23.1%	72.7%	75.9%	78.7%	79.6%[8]

Source: Guidelines for Implementation of the National Electrification Programme, SE4ALL Electrification Plan

4.3 Average consumption per household

The average consumption per household was estimated separately for urban and rural consumers. Rural households consume on average less than the urban households and this needs to be captured in the demand forecast as most new connections are expected to be for rural households (as was the case historically). The increase of rural connections from 2012 has resulted in a decreasing trend on the average consumption per household per year and this is expected over the coming years as well.

In 2021, the billed average monthly consumption per household was 120kWh. However, consumption was higher for urban households than for rural households. Historical information on the average consumption per urban and rural household in Malawi was not available and the

[8] This refers to grid-connected households only. Full electrification achieved by 2030 with the remaining households expected to be electrified though off-grid systems.

following approach was adopted to estimate the average consumption per household separately for urban and rural consumers.

The average monthly consumption for rural households was assumed to be close to 50kWh in 2021 based on information of rural households in other countries (see Table).

Table 1.4.4 Monthly consumption per rural household in Ethiopia and Zambia

Country	Monthly electricity consumption
Ethiopia	45.1 kWh (rural), 149.7 kWh (urban)
Zambia	~50 kWh (rural, estimated based on reported affordability levels)

Sources: Ethiopia - Beyond Connections: Energy Access Diagnostic Report Based on the Multi-Tier Framework, World Bank, 2018; Zambia - Beyond Connections: Energy Access Diagnostic Report Based on the Multi-Tier Framework, World Bank, 2019

The indicated average monthly consumption for rural households (~50 kWh per month) was also supported by a bottom-up analysis on the amount of electricity rural households are likely to consume. Table below provides an overview of assumed rural household's electricity consumption while a full list of appliances considered is provided in Annex A2. 50 kWh per month would be adequate to cover lighting needs, sporadic operation of a small TV or a radio, ironing once per week, a small fridge and small power needs (ie mobile phone charging, computer charging, fan, etc.). The indicated level of consumption for rural households also aligns with observations of rural households in the region and falls within the ESMAP Tier 3 level of service.

Table 1.4.5: Indicative rural households' monthly electricity consumption

Item	No of items	Capacity *(W per month)*	Hours used *(h per day)*	Days used *(days per month)*	Energy used *(kWh per month)*
Light					
Fluorescent tube lamps	4	10	6	30	7.2
TV					
25" color TV	1	150	3	30	13.5
Other					
Radio	1	4	3	30	0.4
Iron	1	1,000	2	4	8
Kettle	1	2,200	0.1	10	2.2
Fridge (small)	1	100	4.7	30	14.3
Fan	1	10	3	10	0.3
Laptop	1	35	2	30	2.1
Phone charging	1	5	1	30	0.15
Total					**48.15**

Source: http://www.energuide.be/en/questions-answers/how-much-energy-do-my-household-appliances-use/71/, http://www.greatbowden.org/documents/TypicalEnergyUsageforHouseholdAppliances.pdf ,http://www.wholesalesolar.com/solar-information/how-to-save-energy/power-table

The average urban monthly consumption was then back-calculated from the total average monthly domestic consumption in 2021 in Malawi and the assumed average monthly consumption for rural households shown above. The results indicated that urban households consume a third more than the total average consumption per household (a ratio which was also used in the 2017 demand forecast), obtaining a monthly urban consumption around 160kWh. This consumption level is also similar to values observed in urban areas in Ethiopia and Zambia (see Table) and falls in the Tier 4 level of service as defined by the World Bank ESMAP Multi-tier Framework for Access to Household Electricity Supply.

The exact values that resulted from the calculations were 47kWh on average per month for rural households and 160kWh on average per month for urban households in 2021.

To estimate the forecast growth of the average consumption per household, we calculated the income elasticity of residential demand as percentage change of GDP per capita over percentage change in average annual consumption per household. This resulted in an income elasticity of residential demand of 1.7, meaning that average consumption per household will increase by 1.7% for a 1% increase in GDP per capita. However, the income elasticity that was calculated was reduced to reflect:

- An increase in household disposable incomes will lead to higher electricity consumption from the purchase of new appliances.
- New appliances are expected to be more energy efficient; this includes the phasing out of incandescent lightbulbs that has been undergoing since 2011.

For the base case scenario, we assumed an income elasticity of 1.2, for the low case scenario an income elasticity of 0.9 and for the high scenario 1.4. The resulting average monthly consumption per urban and rural household is shown in Table .

Table 1.4.6: Average consumption per household (kWh per month)

Scenario		2021	2025	2030	2035	2040	2042
Low	**Urban**	160	163	172	187	203	211
	Rural	47	48	51	55	60	63
	Residential	**120**	**113**	**115**	**122**	**130**	**134**
Base	**Urban**	160	165	188	217	252	268
	Rural	47	49	56	64	75	79
	Residential	**120**	**96**	**99**	**108**	**121**	**127**
High	**Urban**	160	170	203	250	309	337
	Rural	47	51	60	74	92	100
	Residential	**120**	**93**	**94**	**114**	**140**	**153**

Source: ECA

4.4 Historical and forecast economic growth

Economic growth is considered a key driver of electricity demand. For the 2022-2042 period real GDP growth forecasts were used to capture the anticipated economic growth. For the development of the demand forecast the following economic growth scenarios were adopted:

- **Low scenario:** Assumes that economic growth in Malawi will be affected by global conflicts, other unforeseen events (eg cyclones, etc) and that Covid-19 pandemic has longer lasting impacts on economic growth. GDP growth is assumed to be closer to the average growth over the past 3 years (3.9%).

- **Base scenario:** This scenario uses the IMF GDP growth projections up to 2028. For the 2028-2042 period, the long-term GDP growth rate from IMF has been adopted (4.5%).

- **High scenario:** Assumes that from 2023, GDP growth will be higher than the IMF GDP growth projection (and closer to historical high GDP growth rates). This represents a quick recovery from COVID-19 pandemic as well as high economic growth conditions in Malawi.

The forecast GDP growth rates that were used for the development of the demand forecast are shown in Table .

Table 1.4.7 Real GDP forecast by sector (billion MWK) and forecast GDP growth (%)

Scenario	GDP	2021	2025	2030	2035	2040	2042
Low	Agriculture	1,696	1,815	2,047	2,341	2,678	2,826
	Industry	1,461	1,584	1,826	2,141	2,510	2,676
	Services	3,909	4,341	5,224	6,427	7,906	8,590
	Total	**7,499**	**8,260**	**9,799**	**11,866**	**14,367**	**15,510**
	Average growth*	**3.9%**	**3.1%**	**3.9%**	**3.9%**	**3.9%**	**3.9%**
Base	Agriculture	1,696	1,824	2,128	2,484	2,900	3,085
	Industry	1,461	1,593	1,912	2,296	2,758	2,968
	Services	3,909	4,373	5,544	7,036	8,929	9,823
	Total	**7,499**	**8,316**	**10,353**	**12,902**	**16,078**	**17,558**
	Average growth*	**3.9%**	**3.9%**	**4.5%**	**4.5%**	**4.5%**	**4.5%**
High	Agriculture	1,696	1,848	2,183	2,601	3,099	3,324
	Industry	1,461	1,617	1,971	2,425	2,983	3,241
	Services	3,909	4,461	5,767	7,549	9,881	11,005
	Total	**7,499**	**8,470**	**10,738**	**13,770**	**17,658**	**19,505**
	Average growth*	**3.9%**	**4.4%**	**5.1%**	**5.1%**	**5.1%**	**5.1%**

Source: Malawi National Accounts 2017-2022, 2022-2027 IMF real GDP growth forecast Note: * Average of the period starting from the indicated year and ending one year prior to the next indicated year.

4.5 Historical and forecast tariffs

Increases or decreases of tariff levels may have an impact on the level of consumption. The elasticity between historical electricity tariffs and consumption was estimated for each consumer category and if the identified relationship was significant then the electricity tariff forecasts was used to estimate the impact on the forecast demand. In this forecast only the commercial sector has been found to have a statistically significant relationship between demand and tariffs.

Historical tariff data, as well as forecasted tariffs by consumer category have been provided by ESCOM until the year 2027. ESCOM's forecasted tariffs are set to increase substantially in 2024, with a real term increase of 46%. For the demand forecast study, we have assumed a linear tariff increase between the nominal tariffs of 2022 and 2027.

Table 1.4.8 Average tariff (2017 real terms in MWK/kWh)

	2021	2025	2030	2035	2040	2042
Domestic	39.0	60.2	66.4	73.3	80.9	84.2
Commercial	85.3	95.1	106.1	117.1	129.3	134.5
LV Industrial	54.2	61.1	67.4	74.4	82.1	85.5
MV Industrial	47.6	55.1	60.7	67.0	74.0	77.0

Source: ESCOM forecasted tariffs, ECA assumptions

4.6 Large consumers new step loads or closures

New projects, expansions, closures, or self-generation plans from large customers will have a one-step impact on the overall energy and peak demand forecast in Malawi. These have to identified separately to be added/subtracted to/from the demand forecast as they occur once, in specific years, they are big loads, and they cannot be extrapolated from historical observations.

Following discussions with the USWG a list of 39 large customers was agreed including the Agro-Industrial sector, Water pumping boards, Manufacturing, and Mining companies. A questionnaire was drafted and sent to the identified large customers in order to understand their plans for expansions, closures or self-generation and the likelihood of these plans to materialise. The assumptions for large industrial loads that are used for the development of the demand forecast and are based on the survey results are presented in Table below.

Table 1.4.9 Large Industries' expansions and closures

Industry	Project	Status	Sector	Region	Incremental step load (MW)	Expected year of implementation	Low	Base	High
Agriculture and water pumping									
	Mangochi Expansion	Candidate	Water pumping	South	0.6	2023	25%	75%	100%

Industry	Project	Status	Sector	Region	Incremental step load (MW)	Expected year of implementation	Low	Base	High
Southern Region Water Board[9]	Projects under Indian Credit	Candidate	Water pumping	South	4.0	2024	25%	75%	100%
	Improvements in Liwonde and Balaka	Candidate	Water pumping	South	1.1	2024	25%	75%	100%
Lilongwe Water Board	Bunda Plant	Planned (Financial closure)	Water pumping	Central	0.6	2023	100%	100%	100%
	Treatment Works	Planned (Financial closure)	Water pumping	Central	1.5	2024	100%	100%	100%
	Malingunde Water Supply Project	Candidate (Feasibility)	Water pumping	Central	1.0	2025	25%	75%	100%
Illovo Sugar Ltd	SVTP Project	Candidate	Agriculture	South	-15.7	2026	0%	0%	50%
JTI Leaf Malawi	Line upgrade	Planned (Financial closure)	Agriculture	Central	0.1	2024	100%	100%	100%
Milambe water Users Association	Nkopola farm	Candidate	Agriculture	South	0.2	2023	50%	75%	100%
Chombe Foods Ltd	New building	Candidate	Agriculture	South	0.1	2024	25%	75%	100%
Greenbelt projects	North projects	Candidate	Agriculture	North	0.8	2025	25%	75%	100%
	Central projects	Candidate	Agriculture	Central	6.1	2025	25%	75%	100%
	South projects	Candidate	Agriculture	South	5.0	2025	25%	75%	100%
Manufacturing									
Bakhresaa Malawi Ltd	Processing facility expansion	Planned (Financial closure)	Manufacturing	South	3.0	2024	100%	100%	100%
PressCane Ltd	Liquid discharge plant and expansions	Planned (construction)	Manufacturing	South	0.8	2023	100%	100%	100%
	Processing mill	Candidate	Manufacturing	South	2.5	2024	25%	75%	100%
Chibuku Products Limited	Chibuku Super Line – Blantyre Brewery	Candidate (Concept)	Manufacturing	South	0.1	2023	25%	75%	100%
	Super Shake MAHEU –	Candidate (Feasibility)	Manufacturing	South	0.0	2023	25%	75%	100%

[9] No data has been provided for current demand

Industry	Project	Status	Sector	Region	Incremental step load (MW)	Expected year of implementation	Low	Base	High
	Blantyre Brewery								
	Chibuku Super Glass Line – Lilongwe Brewery	Planned (Financial closure)	Manufacturing	Central	0.1	2023	100%	100%	100%
	Project X – Lilongwe Brewery	Planned (Financial closure)	Manufacturing	Central	0.1	2023	100%	100%	100%
Raiply Malawi Limited	Factory expansion	Candidate	Manufacturing	North	4.4	2025	25%	75%	100%
Malawi Mangoes Operations Ltd	Despatch Cold Rooms	Candidate (Concept)	Manufacturing	Central	0.7	2025	25%	75%	100%
	Additional Mango Ovens	Candidate (Concept)	Manufacturing	Central	0.1	2025	25%	75%	100%
Shayona Cement Corporation	Expansion to operations	Candidate	Manufacturing	Central	5.5	2026	25%	75%	100%
O.G Plastic Industries Ltd	Expansions	Candidate	Manufacturing	South	0.2	2023	25%	75%	100%
Easy Pack Ltd	Printer machine	Candidate	Manufacturing	South	0.1	2024	25%	75%	100%
	Injection machine	Candidate	Manufacturing	South	0.1	2025	25%	75%	100%
	PVC pipe machine	Candidate	Manufacturing	South	0.1	2026	25%	75%	100%
Ethanol Company Ltd	Effluent Treatment Plant	Candidate	Manufacturing	Central	2.3	2024	50%	75%	100%
	MK3 and MK4 boiler closure	Candidate	Manufacturing	Central	-0.1	2024	50%	75%	100%
Mining									
Lotus (Africa) Limited – Kayelekera Uranium Mine	Kayelekera Restart	Candidate (Feasibility)	Mining	North	4.0	2026	50%	75%	100%
	Kayelera mine expansion	Candidate (Feasibility)	Mining	North	6.0	2029	50%	75%	100%
Malingunde Graphite and Kasiya Rutile	Mine expansion	Candidate (Feasibility)	Mining	Central	5.0	2026	0%	0%	50%
Globe Metals & Mining	Niobium mine opening	Candidate (Feasibility)	Mining	North	18.0	2026	50%	75%	100%

Industry	Project	Status	Sector	Region	Incremental step load (MW)	Expected year of implementation	Low	Base	High
	Niobium mine expansion	Candidate	Mining	North	6.0	2035	50%	75%	100%
Mkango Resources Ltd	Rare Earths mine opening	Candidate (Feasibility)	Mining	South	25.0	2026	50%	75%	100%
	Mine expansion	Candidate	Mining	South	8.0	2033	50%	75%	100%
Bwanje Cement Products	Mine opening	Planned (Financial closure)	Mining	Central	15.0	2024	20%	75%	100%
Mawei Heavy Mineral Sands	Mine opening	Planned (Financial closure)	Mining	South	40.0	2025	20%	75%	100%
Tengani Heavy Minerals Sands	Mine opening	Candidate (Feasibility)	Mining	South	40.0	2030	5%	20%	50%
Chambe and Lichenya Basins Bauxite	Mine expansion	Candidate (Concept)	Mining	South	50.0	2028	5%	20%	50%
Kangankunde Rare Earth	Mine expansion	Candidate (Feasibility)	Mining	South	30.0	2028	5%	20%	50%
Cement Products Limited	Mine opening	Candidate	Mining	South	5.0	2025	10%	50%	50%
	Njereza plant	Planned	Mining	South	7.0	2025	75%	100%	100%
	Limestone quarry	Planned	Mining	South	0.3	2023	75%	100%	100%
Other quarry projects	Quarry plants operation	Candidate (Concept)	Mining	Central	3.0	2025	10%	25%	50%

Source: From questionnaires sent to large customers

4.7 Self-generation

4.7.1 Domestic rooftop solar

While rooftop solar generation is not significant enough in areas reached by the grid in Malawi, this technology, among other Solar Home Systems (SHS), are present in the country. These are marketed to rural areas where grid connection is uncertain, however, the frequent need for load shedding might incentivise some households that are either electrified or about to be electrified to purchase one of these systems, reducing their electricity demand from the grid. Nonetheless, this effect is expected to be temporary and vastly reducing once households are connected to the main grid. For the purposes of this demand forecast, we assume that this temporary effect is insignificant for annual demand in all scenarios.

Nonetheless, given the expected introduction of a net-metering scheme, which allows power generated with rooftop solar systems to be exported to the grid at a given tariff, we expect that some users will install these systems. The assumed impact from the net-metering scheme and the installation of rooftop solar PV on the demand forecast is shown in Section 8.5.

4.7.2 Large industries self-generation

The plans of large industrial consumers for the development of self-generators and the assigned probabilities of occurrence which are accounted in the demand forecast are shown in the table below. These are based on the surveys conducted by the USWG.

Table 1.4.10: Large industries' self-generation plans

Industry	Project	Status	Sector	Region	Capacity (MW)	Expected year of implementation	Probability		
							Low	Base	High
Agriculture and water pumping									
Southern Region Water Board	Liwonde and Balaka Self-Generation	Candidate	Water pumping	South	1	2024	0%	0%	25%
Lilongwe Water Board	PV solar for pump stations	Candidate (Feasibility)	Water pumping	Central	10	2025	0%	0%	50%
Illovo Sugar Ltd	Nchalo Project	Candidate	Agriculture	South	28	2026	0%	0%	25%
JTI Leaf Malawi	Solar power plant	Candidate (Feasibility)	Agriculture	Central	0.4	2024	0%	0%	25%
Chombe Foods Ltd	Self-generator	Candidate	Agriculture	South	0.2	2023	0%	0%	25%
Manufacturing									
PressCane Ltd	Methane Self-Generation	Planned (financial close)	Manufacturing	South	3.2	2023	75%	100%	100%
	Steam Turbine Generator	Candidate	Manufacturing	South	3.0	2024	0%	0%	20%
Chibuku Products Limited	Generator – Lilongwe Brewery	Candidate (Concept)	Manufacturing	Central	0.7	2023	0%	0%	0%
Raiply Malawi Limited	Steam Engine Generator	Candidate	Manufacturing	North	10.0	2023	0%	0%	25%
Shayona Cements Corporation	2000KVA Diesel generator	Candidate	Manufacturing	Central	2.0	2023	0%	0%	25%

Industry	Project	Status	Sector	Region	Capacity (MW)	Expected year of implementation	Probability		
							Low	Base	High
Malawi Mangoes Operations Ld	Solar Plant	Candidate (Pre-feasibility)	Manufacturing	Central	0.7	2025	0%	0%	25%
Ethanol Company Ltd	Steam Turbine alternators	Candidate	Manufacturing	Central	1.8	2024	0%	25%	50%
Mining									
Lotus (Africa) Limited – Kayelekera Uranium Mine	Acid plant steam turbine	Candidate (Feasibility)	Mining	North	2.5	2024	0%	0%	25%
	Solar generator	Candidate (Feasibility)	Mining	North	7.4	2024	0%	0%	10%
	BESS	Candidate (Feasibility)	Mining	North	5.5	2024	0%	0%	25%
Cement Products Limited	Njereza Plant self-generator	Candidate	Mining	South	3.0	2025	0%	0%	25%
	Quarry self-generator	Planned	Mining	South	0.3	2023	0%	25%	50%
Globe Metals & Mining	Niobium mine self-generation	Candidate	Mining	North	5.0	2026	0%	0%	25%
Mawei Heavy Mineral Sands	HFO Generator	Candidate (Feasibility)	Mining	South	22	2025	0%	25%	50%

Source: From questionnaires sent to large customers

4.8 System losses

The assumptions for the determination of system losses to be considered in the demand forecast are based on the Loss reduction plan presented in Section 6 below. The forecast network technical and non-technical losses are shown in Table .

Table 1.4.11: Forecast losses

Scenario		2021	2025	2030	2035	2040	2042
Low	**Transmission**	5.5%	4.8%	4.3%	4.2%	4%	4%
	Distribution	16.7%	14.6%	12.9%	12%	11%	11%
	Total	**22.2%**	**19.4%**	**17.2%**	**16.1%**	**15%**	**15%**
Base	**Transmission**	5.5%	4.7%	4.2%	4.1%	4%	4%

Scenario		2021	2025	2030	2035	2040	2042
	Distribution	16.7%	14.2%	12.5%	11.7%	11%	11%
	Total	**22.2%**	**18.9%**	**16.6%**	**15.8%**	**15%**	**15%**
High	**Transmission**	5.5%	4.6%	3.8%	3.4%	3%	3%
	Distribution	16.7%	11.6%	11.7%	10.3%	9%	9%
	Total	**22.2%**	**16.6%**	**15.6%**	**13.8%**	**12%**	**12%**

Source: Loss Reduction Roadmap, ECA Assumptions

4.9 Exports

While ESCOM is a member of SAPP, the country's power system has remained mostly isolated from the other SAPP members with only minimal trade taking place. Malawi is now in the process of developing two interconnectors with Mozambique and Zambia, which will interconnect Malawi to other SAPP members. Additionally, *EU Malawi* is supporting EGENCO to become a member of SAPP. Once commissioned, these interconnectors will likely create new trade opportunities for Malawi, both bilaterally and through the Day Ahead Market. With enhanced connection to the SAPP, spare capacity from future Hydropower projects could be used to export electricity.

Currently there are no firm contracts for exports thus, no exports are included in the update of the demand forecast. Opportunities for exports should be analysed in the update of the IRP or regional studies.

4.10 System load factor

The historical system load factor is shown in the figure below. The average load factor over the past 10 years was 69.9%. However, the average load factor is affected by years with significant load shedding such as the 2015-2017 drought period and cannot be considered as a representative load factor for forward looking years. As it was discussed above, 2021 is considered as a representative year and the load factor of 2021 (72.8%) will be used to forecast the system peak demand from forecast sales and losses. Additionally, the consumption mix of the system is expected to remain similar to 2021. Thus, no significant variations on the load factor are expected.

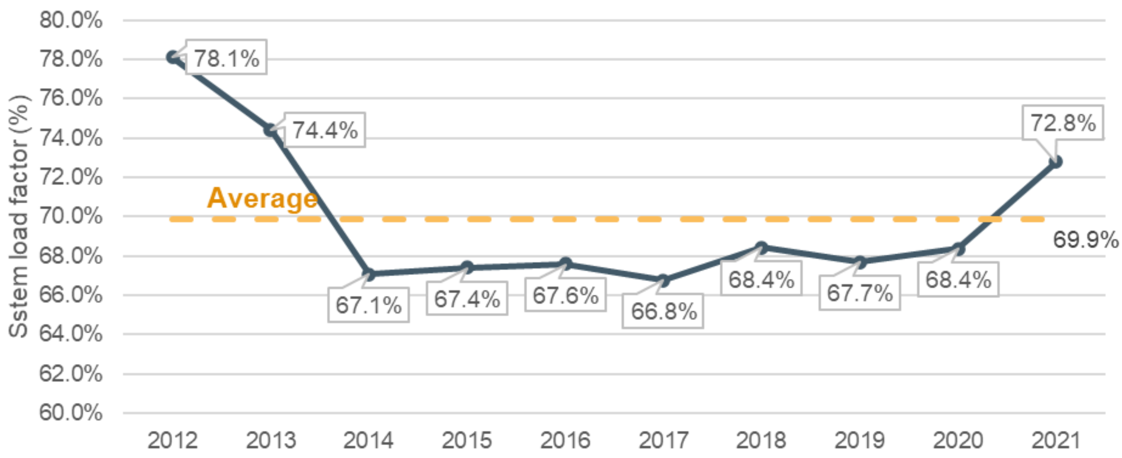


Figure 1.4.1: Historical system load factor

Source: ESCOM data

4.11 Geographical split of the demand

In aggregate, as shown in Figure, the trend from the last three years does not point towards significant regional shifts in demand, though some trends, such as the decreasing prominence of the South region, are expected to continue. The geographical split of demand in the forecast is estimated separately for residential users given each region's urbanisation rates and household size, as well as for large industrial customers from their location. Peak demand is derived using the regional load factors for 2021, this are found to be 42% for the North region, 70% for the Central region, and 48% for the South region.

Table 1.4.13: Historical share of sales by region

	2013	2014	2015	2016	2017	2018	2019	2020	2021	Avg
North	7%	7%	7%	7%	6%	9%	8%	8%	8%	**8%**
Central	33%	32%	33%	29%	27%	35%	37%	38%	38%	**34%**
South	60%	61%	60%	64%	68%	56%	54%	54%	53%	**54%**

Source: ESCOM data Note: The Avg is the average of the past three years

4.12 Summary of input assumptions

Table summarises the input assumptions for each scenario.

Table 1.4.14: Summary of input assumptions

Parameter			2021	2025	2030	2035	2040	2042
Population	As forecasted by the 2018-2050 population projections.							
	Urban growth		2.8%	2.7%	2.5%	2.4%	2.3%	2.3%
	Rural growth		2.3%	2.1%	2.0%	1.9%	1.8%	1.8%
	Total growth		**2.4%**	**2.2%**	**2.1%**	**2.0%**	**1.9%**	**1.9%**
Urbanization rate	16% in 2018, increasing by 0.07% each subsequent year.							
Household size	4.4 persons per household in 2018, decreasing by 0.02 each subsequent year. No distinction between urban and rural household sizes. Variation between regional household sizes							
	Average household size		4.3	4.3	4.2	4.1	4.0	3.9
Electrification rate (Grid connected only)	Low scenario follows ESCOM's historical new connection rates (on average 35,000 new connections per year), base scenario follows the Guideline of Implementation for the NEP (on average 135,000 new connections per year until 2030, followed by linear progression until 2042) and high scenario follows SE4ALL electrification targets (on average 260,000 new connections per year).							
	Low scenario		10.6%	13.4%	14.9%	15.9%	16.6%	16.8%
	Base scenario		10.6%	21.5%	32.4%	40.7%	51.3%	55.5%
	High scenario		10.6%	23.1%	72.7%	75.9%	78.7%	79.6%
Average consumption per household	Base year average consumption per household is based on information from similar countries and a bottom-up approach to alleviate suppressed demand included in historical data. For the growth of the average demand per household an income elasticity of 1.2, 0.9 and 1.4 is assumed for the base, low and high scenarios, respectively (relative to the GDP per capita growth).							
	Low scenario	**Urban**	160	163	172	187	203	211
		Rural	47	48	51	55	60	63
		Overall	**120**	**113**	**115**	**122**	**130**	**134**
	Base scenario	**Urban**	160	165	188	217	252	268
		Rural	47	49	56	64	75	79
		Overall	**120**	**96**	**99**	**108**	**121**	**127**
	High scenario	**Urban**	160	170	203	250	309	337
		Rural	47	51	60	74	92	100
		Overall	**120**	**93**	**94**	**114**	**140**	**153**
GDP growth rate	**Low scenario**		3.9%	3.1%	3.9%	3.9%	3.9%	3.9%
	Base scenario		3.9%	3.9%	4.5%	4.5%	4.5%	4.5%
	High scenario		3.9%	4.4%	5.1%	5.1%	5.1%	5.1%
Exports	No firm commitments for the 2022-2042 period.							
Losses	Assuming the implementation of the Loss Reduction Roadmap and historical losses							
	Low scenario	**Transmission**	5.5%	4.8%	4.3%	4.2%	4%	4%
		Distribution	16.7%	14.6%	12.9%	12%	11%	11%

Parameter			2021	2025	2030	2035	2040	2042
	Base scenario	**Transmission**	5.5%	4.7%	4.2%	4.1%	4%	4%
		Distribution	16.7%	14.2%	12.5%	11.7%	11%	11%
	High scenario	**Transmission**	5.5%	4.6%	3.8%	3.4%	3%	3%
		Distribution	16.7%	11.6%	11.7%	10.3%	9%	9%
System load factor	2021 is considered as a representative year and the load factor of 2021 (72.8%) will be used to forecast the system peak demand from forecast sales and losses. Additionally, the consumption mix of the system is expected to remain similar to 2021. Thus, no significant variations on the load factor are expected.							
Geographical split of demand	Based on the average consumption split of the past three years. Future deviations resulting from differences in urbanization rates, household size, and the location of large customers.							
	North	8% of total sales						
	Central	34% of total sales						
	South	54% of total sales						

Source: Input assumptions report

5 Regression analysis

5.1 Residential consumers

Several regression analyses were conducted with the average consumption per household growth as the dependant variable and combinations of GDP growth, GDP per capita growth, GDP by sector growth, population growth, inflation growth, GNI, electrification rate and tariffs as the independent variables.

All possible combinations of the above independent variable were examined including lagged variables (see Annex A4). No econometric equation with statistical significance and reasonableness was observed for the reasons analysed in the *Input assumptions* report.

5.2 Commercial consumers

Similarly to the analysis conducted for residential consumers, several regression analyses were performed with the commercial sales growth as the dependant variable and combinations of GDP growth, GDP per capita growth, GDP by sector growth, population growth, inflation growth, GNI, electrification rate and tariffs as the independent variables. All possible combinations of the above independent variable were examined including lagged variables (see Annex A4).

The econometric equation with the highest statistical significance and logical reasoning was:

$$\boldsymbol{ln(CommSales_i) = -0.05 + 1.05 * \ln(RealGDPpc_i) + 0.63 * \ln(CommConenctions_i) - 0.21 * \ln(CommTariff_i)}$$

Where:

$CommSales_i$ = Total electricity sales for the “General” tariff categories in kWh for year i.

$RealGDPpc_i$ = Real GDP per capita in MWK for year i.

$CommConenctions_i$ = Number of commercial connections at the end of year i.

$CommTariff_i$ = Average nominal tariff for commercial users in MWK/kWh for year i.

Real GDP per capita can be used as a measure for the purchasing power of commercial consumers, the number of commercial connections as the measure for the estimation of number of commercial consumers, and the electricity tariff as the measure to explain reductions in demand from tariff increases. The logical reasoning that follows the econometric equation shown above is:

- **Purchasing power of the population.** As income (and disposable income) increase, consumption of all goods and services also increase. As a response, businesses expand consuming more electricity.

- **Commercial connections.** As the density of commercial areas increase, the demand for office space also increases, increasing the overall use of office appliances.

- **Cost of electricity.** Lower electricity tariffs incentivise businesses to increase electricity consumption, while higher electricity tariffs discourage non-essential use of electricity. Effectively this is measured of the price elasticity of demand.

The resulting econometric equation implies a population income elasticity of demand of 1.05, with a 1% increase in real GDP per capita resulting in an 1.05% increase of aggregate electricity sales from the commercial sector. In terms of commercial densification of urban areas, we notice that a 1% increase in the number of commercial connections results in a 0.63% increase in total commercial sales. Finally, the price elasticity of demand for commercial users is found to be -0.21, implying that a 1% increase in the commercial electricity tariff would result in a 0.21% decrease of demand.

The statistical results of the econometric analysis for the chosen equations are sown in Annex A4.1 together with a comparison of a historical forecast using the econometric equation against actual sales.

5.3 LV Industrial consumers

The regression analysis for LV industrial sales explored the relationship between LV industrial sales growth and combinations of GDP growth, GDP per capita growth, GDP by sector growth, population growth, inflation growth, and tariffs as the independent variables. All possible combinations of the above independent variable were examined including lagged variables (see Annex A4).

The econometric equation with the highest statistical significance and logical reasoning was:

$$\boldsymbol{ln(IndLVSales_i) = 9.08 + 0.35 * \ln(RealGDP_i)}$$

Where:

$IndSalesLV_i$ = Total electricity sales for the “Maximum Demand LV” tariff category in kWh for year i.

$RealGDPpc_i$ = Real GDP in MWK for year i.

No significant relationship was identified between electricity prices and LV industrial consumption and the total GDP had a better explanatory power than Industrial GDP which includes larger consumers as well.

The resulting econometric equation implies an income elasticity of demand of 0.35, meaning that a 1% increase in Real GDP would lead to a 0.35% increase in the aggregate electricity sales of the Industrial LV category.

5.4 MV Industrial consumers

The regression analysis for MV industrial sales explored the relationship between MV industrial sales growth and combinations of GDP growth, GDP per capita growth, GDP by sector growth, population growth, inflation growth, and tariffs as the independent variables. All possible combinations of the above independent variable were examined including lagged variables (see Annex A4).

The resulting econometric equation with the highest statistical significance and logical reasoning was:

equation is:

$$\boldsymbol{ln}(\boldsymbol{IndMVSales_i}) = \mathbf{5.07} + \mathbf{0.53} * \mathbf{ln}(\boldsymbol{IndustrialGDP_i})$$

Where:

$IndSalesMV_i$ = Total electricity sales for the “Maximum Demand MV” tariff category in kWh for year i.

$IndustrialGDP_i$ = Real Industrial GDP in MWK for year i.

In this case, the energy intensity of these industries is 0.53, with a 1% increase in real Industrial GDP associated with a 0.53% increase in Industrial MV electricity sales.

6 Loss reduction plan

The loss reduction plan for Malawi reflects the findings and recommendations of the LRR, developed by ESCOM in 2021. The LRR is the outcome document prepared from the findings and conclusions obtained during the Losses Reduction Initiative project (LRI) developed and supported by IFC.

According to the Utility Scale Working Group (that has representation of the key power sector institutions), loss reduction measures have been extensively and exhaustingly reviewed in the context of the Loss Reduction Roadmap 2021 and need not be further analysed in the context of this study. Therefore, the objective was to single out which roadmap activities to implement and package them appropriately in readiness for that. The loss reduction measures identified are also considered in the demand forecast analysis for the impact they will have on the reduction of system losses and consequently on the amount of energy/capacity that is needed to be injected to the grid.

6.1 Loss reduction plan

The Loss Reduction Roadmap was developed based on the review and analysis of a long list of 71 potential projects, from which a total of 34 initiatives with differing complexity, budget, duration, and impact on losses were eventually included in the Roadmap.

The individual initiatives identified in the Roadmap are grouped in eight *Large Projects,* described in Table . *Large Projects* cannot be fully implemented in isolation as there are several interdependencies and synergies among projects and initiatives, shown along with the timing for implementation in

Figure . ESCOM has started implementing specific initiatives, as indicated in Table The total cost of the Loss Reduction Roadmap is estimated to USD 27.9 million and the expected revenues resulting from losses reduction to USD 34.8 million (ie the plan is expected to generate a net benefit of USD 6.8 million). To achieve this, an investment of around USD 10.5 million is needed.

Table 1.6.1: Initiatives included in the Loss Reduction Roadmap by Large Project

Initiatives	Description
1. Establishment of a Project Management Office (PMO) *The establishment of a PMO is needed in order to ensure that the different initiatives and activities are adequately executed. The project itself is not profitable (costing around USD 1.4 million) but is very useful at that the roadmap is implemented properly.*	
1 a.	Setting up a PMO's objectives will be facilitating the implementation of the roadmap,

Initiatives	Description
PMO	following up on the progress of the projects and guiding the efforts of the company towards accomplishing them in the most efficient way. The PMO will drastically increase the chances of success of the roadmap, and thus obtain the intended results of each of the projects within.
2. Network Metering & Losses Calculation	
The objective is to assess the losses in the system to target actions in network parts that have the highest losses. Many of the activities carried out in this project are key for the development of other activities and will lead to losses reduction, yielding a benefit of around USD 390,000.	
2 a. Metering in Injection Points, Substations and Feeders	Achieving the Metering of all injection points, substations and feeders will facilitate the control of energy flows and create accurate energy balances. This initiative aims to audit around 50 injection points, 64 substations and 311 feeders in order to understand their statuses and the need for meter installation. Additionally, the status of existing meters will be checked as well as their communication capabilities with the AMR systems. The metering in the HV-MV network will facilitate more accurate calculation of energy losses (technical and non-technical) in the network and determine hot points.
2b. New Losses Calculation methodology	To improve the calculation process using the "Baseline for losses" tool, as well as determine ways to make the information available to the entire organization. Calculating the losses with higher accuracy will allow ESCOM to better identify where the issues are (technical, non-technical) and establish actions to reduce them. Also, the appropriate calculation will facilitate the understanding of the impact and effectiveness of the ongoing Loss Reduction activities.
2c. Strengthen the EBM team	This initiative proposes the establishment of a dedicated team in charge of maintaining the EBM. If adequately maintained, the EBM can produce additional balances (per feeder, per substation, etc.). These balances will redirect the efforts to those areas where the losses are highest, increasing the productivity of the inspection teams.
2e. Perform Regional Balances	After consolidating the metering in the HV-MV network, ESCOM should start performing regional balances to identify the areas where the highest losses are and focus the effort on Loss Reduction activities. This initiative considers the installation of meters in the regional or administrative areas borders. Creating balances for smaller areas will facilitate the identification of key network sections where the losses are higher and focus the LR activities.
3. Feeder Based Loss Reduction Projects	
This project strives towards auditing ESCOM customers. The necessity of this project has been proven in the FBLR pilot already executed by ESCOM, which found many issues in just one feeder. Despite the large project cost (over USD 18 million), the estimated revenues obtained lead to a breakeven on the fifth fiscal year and total benefits at the end of the fiscal year of almost USD 5 million.	
3 a. Metering in Distribution Transformers	Installation of meters in the DTs. There are 5,132 distribution transformers. Approximately 10% are dedicated; therefore, there is a need to install meters in 4,619 DTs. However, when factoring in the future growth of the company, the number can increase to 5,000. Moreover, the installation must be followed by a validation of the communications and an update of the information into the system. Having balances on DT level, will allow ESCOM to identify the exact areas where the highest losses are and inspect more efficiently, focusing the limited resources on those areas where the monetary return is guaranteed.
3b. End-customers audit	This initiative considers a 4-year plan to visit all customers in a methodological way, prioritizing those areas with greater losses. It focuses on auditing and solving the issues from the customers (linking them with its DTs, removing illegal connections and fixing the sealing, improvement of PF and replacing faulty meters amongst others). A systematic inspection of all customers will allow elimination of fraud and issues that affect the Energy Losses.

Initiatives	Description
3c. Large customer and public institutions audit	ESCOM is advised to have personnel specifically deployed to monitor maximum demand customers and public institutions. During the inspections, ESCOM will fix all the potential issues found with these customers and link them with the DTs or Substations. Solving potential issues in these customers will facilitate the reduction of Non-technical losses and improve ESCOM's collection efficiency.
4. Distribution & Customer Services Operative Model Review *This project targets the Distribution & Customer Services area of ESCOM. focusing on improving and/or optimizing the different activities carried out by the area. It is estimated that it can derive a net benefit of over USD 4.4 million.*	
4 a. Improvements in the Meter Life Cycle	ESCOM should redefine the entire meter life cycle based on the enhancements identified. The new processes should be documented. It is worth highlighting the importance of following the procedures, the enhancements in the processes (sourcing, the distribution of goods and storing) and the functionalities that the system has, in order to boost the traceability of the meters. ESCOM has already established a plan for the set-up of the PMO under the Revenue Protection Department, to implement the relevant measures of the LRR.
4b. Building a role for maintaining customer data	The objective of the initiative is to maintain and update the required information in InCMS and Igea by creating a new role within the company. This role should clean up and update the database. (identify non-energy debts or contracts, and work orders that can be cancelled, erased or "put on hold" amongst others). Updating the information will result in better reports, balances, as well as a focus on the real problems of the operation. This initiative has already been implemented.
4c. Review the Debt Recovery process	This initiative aims to clarify the disconnection requirements (of customers that do not pay or are stealing energy) using a standard procedure that must be followed by all employees and taught in training sessions. Furthermore, ESCOM should update disconnection information in the system (disconnections and commercial agreements). The disconnection process must also consider periodic inspections to prevent or detect self-reconnections. The revenue protection process must segment ESCOM's debt and tackle them in different ways (ie sell the bad debt or follow up more often with large customers). The disconnection processes are an excellent tool to control losses and reduce the fraud. A more robust debt recovery process will prevent fraud and increase collection. The relevant procedures have been included in the Revenue Manual, developed by ESCOM in 2022.
4 d. Review the current Organization of the Distribution Directorate	ESCOM should redefine its operating model to better define the organization of the company. The structure should be homogeneous and incorporate the four different regions. The reorganization should improve productivity of the teams, which will in turn contribute to better performance in terms of loss reduction. A new structure implementing a zoning system was developed by ESCOM in 2023 and is now in place.
4e. Strengthen the Customer Service processes	The Customer Service processes should be reinforced, by increasing personnel and improving process efficiencies in order to reduce waiting times and improve the agility of the contracting process. This initiative aims to highlight the importance of customer service. ESCOM could benefit from a review and improvement of the current customer care services, especially related to issues found in the work request and contracting processes. Faster and accurate responses to user requirements should reduce fraud, particularly illegal connections.

Initiatives	Description
	The relevant procedures have been included in the Revenue Manual, developed by ESCOM in 2022.
4f. Improve reporting and establish KPIs	Different Key Performance Indicators should be defined and their progress tracked and publicized at regular intervals. The objective of this initiative is to add new ways to control the evolution of the different processes of the company, using control panels (ie different reports to identify fraud). The impact is not direct to the losses, but in the overall productivity of the teams. Better productivity will allow a focus on the problems arising. KPIs developed by MERA and submitted to the Ministry of Energy cover this requirement. In addition, customer service KPIs have been published.
4 g. Written Procedure on Fraud Management	ESCOM is encouraged to create procedures for disconnection, fraud invoice and reconnection, as this would help homogenize Fraud Management activities and develop a knowledge base to be shared throughout the company. The better the fraud is managed, the more fraudulent activities will be discovered and the faster the corrective measures will be applied. Additionally, a robust methodology will facilitate the detection of more cases and discourage customers from fraudulent activities. Part of the Revenue Manual, developed by ESCOM in 2022 and revised in 2023, provides procedures for handling fraud. In addition, an Audit Manual has been developed, to monitor implementation of the Revenue Manual. An actual audit was carried out in 2022.
4h. Establish a Centralized Quality Control areas for key processes	The utility should improve and document the reading and debt management processes as well the quality of data originating from these. This initiative should focus on improving the efficiency and productivity of the processes based on benchmarking and disseminating best practices. Improvement of the reading process will enhance billing productivity, resulting in a reduction of losses caused by internal inefficiencies. Improvement of the debt management process will reduce fraud and increase collection. This initiative comprises part of the Revenue Manual, developed by ESCOM in 2022.
4i. Reorganization of the Revenue Protection area	The Revenue Protection area should be upgraded, that is, given more competencies and capabilities and their influence on other operational areas such as, Fraud management, Incentives management, Inspections and a coordination office between regions increased. A strong Revenue protection area improves fraud reduction and optimizes the required resources. To that effect, reorganisation of authority among the Revenue Protection management and regional offices is required, to ensure that implementation of the relevant LRR measures is practicable.
5. Customer Service Supporting Projects *This project consists of enabler initiatives that can improve the operational efficiency of ESCOM. The net benefit from the implementation of the project is estimated to around USD 1.3 million.*	
5 a. Implementing a Meter testing laboratory	ESCOM should develop the facilities necessary to carry out meter testing, put in place a systematic approach, and acquire the appropriate equipment. This is key in order to mitigate the existence of faulty meters and ensure that the meters in the field function appropriately. ESCOM will improve the quality of the meters deployed, as well as reduce non-technical losses resulting from metering failure. Additionally, ESCOM will obtain accurate results on fraud cases investigated.
5b. Acquisition of Mobile APPs	The use of already existing tools will facilitate operational activities such as updating work orders, collections and reading & billing. Using the mobile applications will increase productivity and reduce data inconsistencies. Improvement in the reading process and the automation of the field activities will enhance productivity and the quality of InCMS data, resulting in a reduction of losses due to internal inefficiencies.

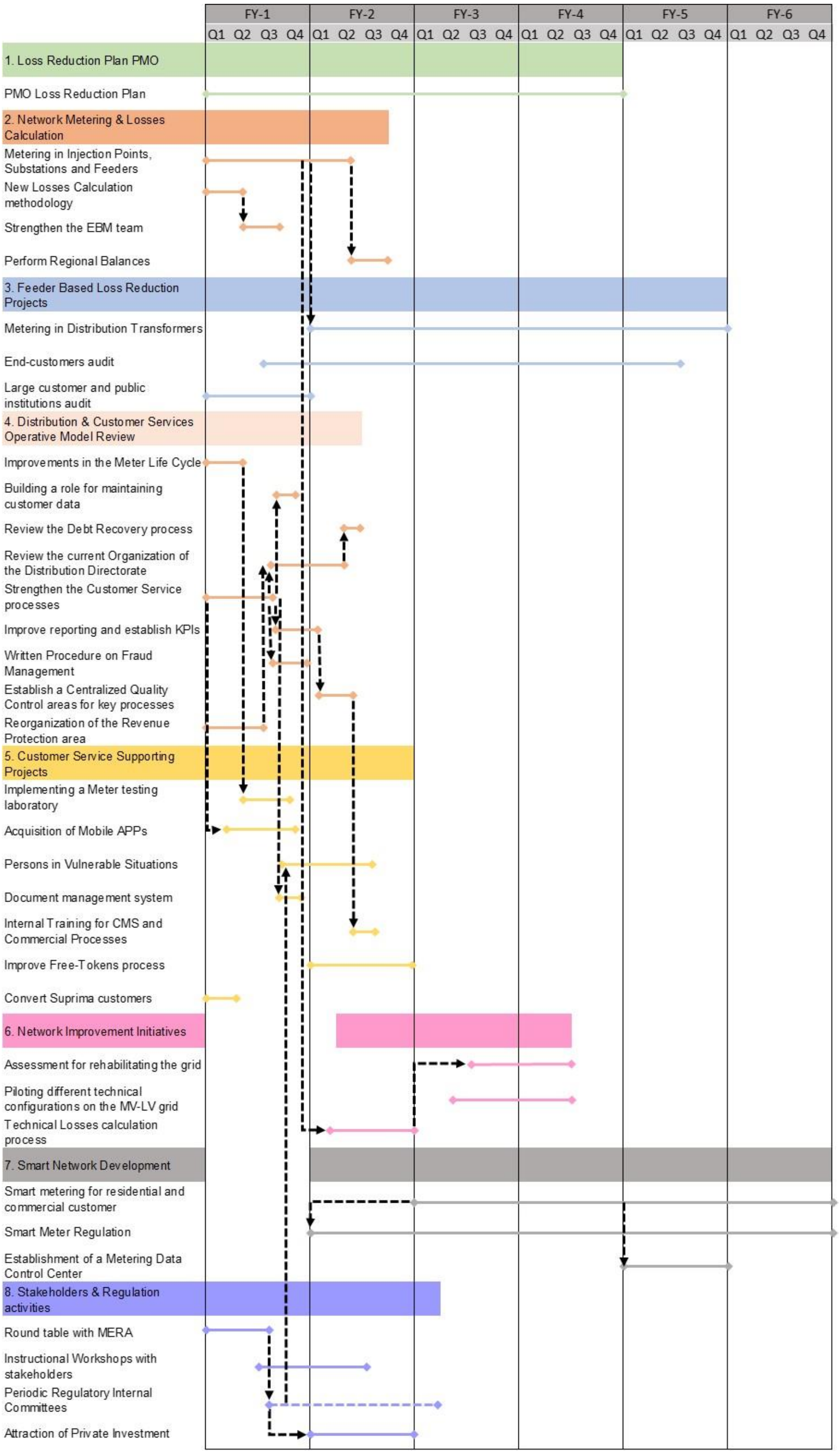
Initiatives	Description
5c. Persons in Vulnerable Situations	This initiative aims to engage with the national government to evaluate the creation of future programs that help reduce the impact of electricity costs to people in vulnerable situations. This initiative will facilitate the payment of energy, reduction of fraud and improved citizen perception of ESCOM.
5 d. Document management system	ESCOM should consider the use of a Document Management System (DMS) where all documentation (procedures and reports) will be stored in order to ensure that they are accessible to the pertinent people. This measure will enable homogeneity amongst the ESCOM's personnel and should help build a knowledge base that will improve ESCOM's processes and activities. The existence of a DMS will reduce workload and control fraud, if properly used in areas such as Work Requests and Contracting Processes.
5e. Internal Training for CMS and Commercial Processes	Various trainings should be carried out for ESCOM employees in order to impart knowledge on all the CMS functionalities, changes in procedures, available tools, etc. Creating user awareness on the procedures, capabilities and processes will have a positive impact on the Commercial activities such as, reducing customer frustration, improving the identification of abnormal behaviours and effectively managing fraud / illegal connections.
5f. Improve Free-Tokens process	The free-token process must be reviewed, not to alter the benefit but to increase the accuracy of determining the energy consumed by the employees. An adequate accountability of the free-tokens will facilitate obtaining accurate balances, and improve the identification of Energy Losses. The Revenue Manual, developed by ESCOM in 2022, includes information on Free-Tokens, as well as back-end financial reconciliation process.
5 g. Convert "Suprima" customers	Customers using "Suprima" meters must be converted to InCMS meters to standardize the commercial activities as well as improve the energy sales calculation.
6. Network Improvement Initiatives *This project aims to prepare ESCOM for a controlled and sustainable expansion of the grid while also targeting technical losses. It is estimated to have negative revenues of around USD 2.6 million, but its indirect impact in terms of present and future losses is estimated to be high.*	
6 a. Assessment for rehabilitating the grid	During the technical losses analysis, the need to assess the expansion plan in High Voltage, Medium Voltage and Low Voltage network arose. This initiative must evaluate the potential improvements in the network, for instance, increasing voltages for the transmission grid, installing capacitor banks and studying the expansion of lines amongst others. As a general rule, transmission should be carried out at 132 KV, avoiding 33 kV. A long-term plan for the grid expansion supported by network simulation results will help target the reduction of Technical Losses in the Transmission and Distribution network and result in a more adequate evolution of the network growth.
6b. Piloting different technical configurations on the MV-LV grid	It is recommended that ESCOM uses different LV configurations (network shielding, Internal Control Point) that could reduce the network's manipulation. This initiative aims to control the non-technical losses in areas with greater losses or key risky areas. Creating a protected LV network will reduce illegal connections or network tampering, eventually reducing losses.
6c. Technical Losses calculation process	ESCOM should Implement periodic process reviews of the Technical losses using DigSilent as the main tool. An accurate calculation of the energy flows impact on ESCOM's network should result in the identification of technical losses, which can then be targeted for reduction.
7. Smart Network Development *This project targets the development of a smart metering framework, infrastructure and deployment of smart metering for all ESCOM customers.*	

Initiatives	Description
7 a. Smart metering for residential and commercial customer	ESCOM should consider developing a full AMI for all customers. The initial execution must start an analysis of the standards and protocols to be used in the AMI. The AMI will provide knowledge in real time (or almost real time) of the energy flows through the network, receive alerts for any incident that could produce Energy Losses, and remotely act on those customers that require any action on their meters.
7b. Smart Meter Regulation	This initiative aims to encourage the development of a Smart Metering regulation in coordination with MERA. The regulation will allow progression of the smart network implementation.
7c. Establishment of a Metering Data Control Center	This initiative aims to create a Control Center to update the AMI assets: the meters and the communications infrastructure. This Control Center should be built within the company, backed by a combination of a strong organizational structure, an experienced team, the required software and hardware and the physical space. Additionally, this team must be responsible for updating the metering system sketch, the meters' information in between AMR, IGEA and the integration between AMR and MDM (that is, validating the measurements of MD customers and balancing readings of energy). The MDCC will ensure that the AMI is operational, so that any grid incident is controlled and managed within the required timeframe.
8. Stakeholders & Regulation activities *This project focuses on opening communication channels with the regulator and with local communities, with the aim of improving the legal framework and engaging in communication campaigns with different stakeholders.*	
8 a. Round table with MERA	The legislation should be reviewed by ESCOM and MERA. The objective is to align the disparities between the regulation and ESCOM's procedures: unpaid bills notification, segmentation of customers, amendments to "Revised Standards Administrative Charges", estimation of consumption for identified fraud, penal charges, reconnection fees and the non-disconnectable policy for some meters. Better regulatory support will help the Loss Reduction.
8b. Instructional Workshops with stakeholders	Creating an awareness campaign will facilitate the reduction of illegal connections and fraudulent activities. This initiative aims to target specific and relevant individuals to promote good behaviour and show the potential consequences of fraudulent activities (both administrative, penal and physical ie electrocuted individuals or burned-down constructions). Part of the losses are due to the lack of awareness of the citizens. This initiative will help in sensitization. An annual plan for implementation of campaigns in villages, the police, communities, etc is in place and is being implemented.
8c. Periodic Regulatory Internal Committees	This initiative aims to encourage monthly or quarterly meetings between the regulatory body and business operation departments. The goal of these frequent meetings is to facilitate communication between MERA and ESCOM, to help reveal the problems that each department may be facing (fraud, disconnection, debtors and reconnection), and to, in collaboration, find potential solutions backed by the legislation. Better regulatory support will help the Losses Reduction activities.
8 d. Attraction of Private Investment	This initiative aims to facilitate the attraction of private investment in Malawi, by improving the network, network regulations and renewable energy guidelines.

Source: Loss Reduction Roadmap, Loss Reduction Initiative, February 2021

Figure 1.6.2 Interrelations among and timing of initiatives included in the LRR

Loss reduction plan



Source: Loss Reduction Roadmap, Loss Reduction Initiative, February 2021

Considering that the implementation of the Roadmap requires significant investment and is a very complex exercise due to many interrelations and interdependence among many of the included 34 initiatives, Large Projects and initiatives were assessed looking at the following criteria:

- Budget – the amount of capital needed to implement the initiative. Budget variation are specified as Low, Medium, and High.
- Impact on losses – the level of the impact the implementation of the project will have on loss reduction. Impact on losses is classified as Low, Medium, High, and Very high.
- Complexity in terms of interdependence among initiative – the level of dependency of each project to other initiatives and the ease for implementation. The complexity is classified as 0 (no dependency in other initiatives), 1 (dependency in 1 initiative), 2 (dependency in 2 initiatives), 3 (dependency in 3 initiatives).

Ranking of initiatives by budget

In Table we provide an overview of the initiatives, ranked first in accordance with their budget and then their impact on losses and their interdependency. Assuming that the primary restriction is budget availability, then among initiatives with similar budget level, preference is for those with a higher impact on losses, and lower dependence from other initiatives. As the Table illustrates, there are 19 initiatives with a low budget. Among them seven have zero interdependency on other initiatives and could be implemented by ESCOM immediately. Among the seven initiatives, three have high or mid impact on losses reduction and could be prioritised, namely:

1. 2b. New Losses Calculation methodology
2. 4e. Strengthen the Customer Service processes
3. 8b. Instructional Workshops with stakeholders

There are also three initiatives with medium budget requirements, very high impact on losses, and no dependence on other initiatives, namely:

4. 1 a. Establishing PMO
5. 2 a. Metering in Injection Points, Substations and Feeders
6. 3c. Large customer and public institutions audit

These could also be developed in priority, given budget availability.

Table1.6.3 Ranking of initiatives by budget

Initiative	Budget			Impact on losses				Dependency on other initiatives			
	Low	Mid	High	Very high	High	Mid	Low	0	1	2	3
2b. New Losses Calculation methodology	Low				High			0			
4e. Strengthen the Customer Service processes	Low				High			0			

Initiative	Budget			Impact on losses				Dependency on other initiatives			
	Low	Mid	High	Very high	High	Mid	Low	0	1	2	3
8b. Instructional Workshops with stakeholders	Low					Mid		0			
4 a. Improvements in the Meter Life Cycle	Low						Low	0			
5f. Improve Free-Tokens process	Low						Low	0			
5 g. Convert “Suprima” customers	Low						Low	0			
8 a. Round table with MERA	Low						Low	0			
2e. Perform Regional Balances	Low				High				1		
5b. Acquisition of Mobile APPs	Low				High				1		
4b. Building a role for maintaining customer data	Low					Mid			1		
4 g. Written Procedure on Fraud Management	Low					Mid			1		
4h. Establish a Centralized Quality Control areas for key processes	Low					Mid			1		
8c. Periodic Regulatory Internal Committees	Low					Mid			1		
4f. Improve reporting and establish KPIs	Low						Low		1		
5 d. Document management system	Low						Low		1		
7b. Smart Meter Regulation	Low						Low		1		
4c. Review the Debt Recovery process	Low					Mid				2	
6 a. Assessment for rehabilitating the grid	Low					Mid				2	
8 d. Attraction of Private Investment	Low						Low			2	
1 a. Establishing PMO		Mid		Very high				0			
2 a. Metering in Injection Points, Substations and Feeders		Mid		Very high				0			
3c. Large customer and public institutions audit		Mid		Very high				0			
4i. Reorganization of the Revenue Protection area		Mid			High			0			
2c. Strengthen the EBM team		Mid				Mid			1		
5 a. Implementing a Meter testing laboratory		Mid				Mid			1		
6c. Technical Losses calculation process		Mid				Mid			1		
4 d. Review the current Organization of the Distribution Directorate		Mid					Low			2	
5e. Internal Training for CMS and Commercial Processes		Mid			High						3
3b. End-customers audit			High	Very high				0			
7 a. Smart metering for residential and commercial customer			High		High			0			
6b. Piloting different technical configurations on the MV-LV grid			High			Mid		0			
3 a. Metering in Distribution Transformers			High	Very high					1		
7c. Establishment of a Metering Data Control Center			High						1		
5c. Persons in Vulnerable Situations			High		High					2	

Source: ECA analysis based on the 2021 Loss Reduction Roadmap

Ranking of initiatives by impact on loss reduction

Table provides an overview of the initiatives, ranked first in accordance with their impact on losses and then their budget and interdependency. Assuming that the primary objective is to reduce losses, then among initiatives with the highest impact on loss reductions, preference is for those with a lower budget, and lower dependence on other initiatives. As the Table illustrates, there are five initiatives with very high impact on losses reduction. Among them four have zero interdependency on other initiatives and could be implemented by ESCOM immediately. Three out of the four have mid budget requirements and could be prioritised, namely:

1. 1 a. Establishing PMO
2. 2 a. Metering in Injection Points, Substations and Feeders
3. 3c. Large customer and public institutions audit

There is also 1 initiative with very high impact on loss reduction but with a high budget associated with it. Given availability of budget, this initiative could also be prioritised as it does not depend on any other initiatives:

4. 3b. End-customers audit

Finally there are three initiatives with high impact on losses and low to mid budget requirements which could be implemented immediately without the need to develop other initiatives:

5. 2b. New Losses Calculation methodology
6. 4e. Strengthen the Customer Service processes
7. 4i. Reorganization of the Revenue Protection area

These could also be developed in priority, given budget availability.

Table 1.6.5 Ranking of initiatives by impact on loss reduction

Initiative	Impact on losses				Budget			Dependency on other initiatives			
	Very high	High	Mid	Low	Low	Mid	High	0	1	2	3
1 a. Establishing PMO	Very high					Mid		0			
2 a. Metering in Injection Points, Substations and Feeders	Very high					Mid		0			
3c. Large customer and public institutions audit	Very high					Mid		0			
3b. End-customers audit	Very high						High	0			
3 a. Metering in Distribution Transformers	Very high						High		1		
2b. New Losses Calculation methodology		High			Low			0			

Initiative	Impact on losses				Budget			Dependency on other initiatives			
	Very high	High	Mid	Low	Low	Mid	High	0	1	2	3
4e. Strengthen the Customer Service processes		High			Low			0			
4i. Reorganization of the Revenue Protection area		High				Mid		0			
7 a. Smart metering for residential and commercial customer		High					High	0			
2e. Perform Regional Balances		High			Low				1		
5b. Acquisition of Mobile APPs		High			Low				1		
5c. Persons in Vulnerable Situations		High					High			2	
5e. Internal Training for CMS and Commercial Processes		High				Mid					3
8b. Instructional Workshops with stakeholders			Mid		Low			0			
6b. Piloting different technical configurations on the MV-LV grid			Mid				High	0			
4b. Building a role for maintaining customer data			Mid		Low				1		
4 g. Written Procedure on Fraud Management			Mid		Low				1		
4h. Establish a Centralized Quality Control areas for key processes			Mid		Low				1		
8c. Periodic Regulatory Internal Committees			Mid		Low				1		
2c. Strengthen the EBM team			Mid			Mid			1		
5 a. Implementing a Meter testing laboratory			Mid			Mid			1		
6c. Technical Losses calculation process			Mid			Mid			1		
7c. Establishment of a Metering Data Control Center			Mid				High		1		
4c. Review the Debt Recovery process			Mid		Low					2	
6 a. Assessment for rehabilitating the grid			Mid		Low					2	
4 a. Improvements in the Meter Life Cycle				Low	Low			0			
5f. Improve Free-Tokens process				Low	Low			0			
5 g. Convert “Suprima” customers				Low	Low			0			
8 a. Round table with MERA				Low	Low			0			
4f. Improve reporting and establish KPIs				Low	Low				1		
5 d. Document management system				Low	Low				1		
7b. Smart Meter Regulation				Low	Low				1		
8 d. Attraction of Private Investment				Low	Low					2	
4 d. Review the current Organization of the Distribution Directorate				Low		Mid				2	

Source: ECA analysis based on the 2021 Loss Reduction Roadmap

Ranking of initiatives by dependency on other initiatives

Table provides an overview of the initiatives, ranked first by projects that could be implemented without any dependency on other projects and then by budget and impact on loss reduction. Assuming that the primary restriction is budget availability, then among initiatives with similar dependency on other initiatives, preference is for those with a lower budget and then on the impact on losses.

There are 14 initiatives that do not depend on any other initiatives and could be implemented early on. Among the 14 initiatives, three have a low budget to implement and high to mid impact on loss reduction and could be prioritised:

1. 2b. New Losses Calculation methodology
2. 4e. Strengthen the Customer Service processes
3. 8b. Instructional Workshops with stakeholders

There are also 4 initiatives with very high impact or high impact on loss reduction but with a mid budget requirements. Given availability of budget, these initiatives could also be prioritised:

4. 1 a. Establishing PMO
5. 2 a. Metering in Injection Points, Substations and Feeders
6. 3c. Large customer and public institutions audit
7. 4i. Reorganization of the Revenue Protection area

Finally there are two initiatives with very high or high impact on losses but with high budget requirements:

8. 3b. End-customers audit
9. 7 a. Smart metering for residential and commercial customer

These could also be developed early on, given budget availability.

Table 1.6.6: Ranking of initiatives by dependency on other initiatives

Initiative	Dependency on other initiatives				Budget			Impact on losses			
	0	1	2	3	Low	Mid	High	Very high	High	Mid	Low
2b. New Losses Calculation methodology	0				Low				High		
4e. Strengthen the Customer Service processes	0				Low				High		
8b. Instructional Workshops with stakeholders	0				Low					Mid	
4 a. Improvements in the Meter Life Cycle	0				Low						Low
5f. Improve Free-Tokens process	0				Low						Low
5 g. Convert “Suprima” customers	0				Low						Low
8 a. Round table with MERA	0				Low						Low
1 a. Establishing PMO	0					Mid		Very high			

Initiative	Dependency on other initiatives				Budget			Impact on losses			
	0	1	2	3	Low	Mid	High	Very high	High	Mid	Low
2 a. Metering in Injection Points, Substations and Feeders	0					Mid		Very high			
3c. Large customer and public institutions audit	0					Mid		Very high			
4i. Reorganization of the Revenue Protection area	0					Mid			High		
3b. End-customers audit	0						High	Very high			
7 a. Smart metering for residential and commercial customer	0						High		High		
6b. Piloting different technical configurations on the MV-LV grid	0						High			Mid	
2e. Perform Regional Balances		1			Low				High		
5b. Acquisition of Mobile APPs		1			Low				High		
4b. Building a role for maintaining customer data		1			Low					Mid	
4 g. Written Procedure on Fraud Management		1			Low					Mid	
4h. Establish a Centralized Quality Control areas for key processes		1			Low					Mid	
8c. Periodic Regulatory Internal Committees		1			Low					Mid	
4f. Improve reporting and establish KPIs		1			Low						Low
5 d. Document management system		1			Low						Low
7b. Smart Meter Regulation		1			Low						Low
2c. Strengthen the EBM team		1				Mid				Mid	
5 a. Implementing a Meter testing laboratory		1				Mid				Mid	
6c. Technical Losses calculation process		1				Mid				Mid	
3 a. Metering in Distribution Transformers		1					High	Very high			
7c. Establishment of a Metering Data Control Center		1					High			Mid	
4c. Review the Debt Recovery process			2		Low					Mid	
6 a. Assessment for rehabilitating the grid			2		Low					Mid	
5c. Persons in Vulnerable Situations			2				High		High		
5e. Internal Training for CMS and Commercial Processes				3		Mid			High		

Source: ECA analysis based on the 2021 Loss Reduction Roadmap

Summary of ranked initiatives

The following table summarises the initiatives and puts together the three criteria discussed above. On the vertical axis initiatives are ranked by budget, on the horizontal axis by the impact on loss reduction and the blue scale colouring indicates which projects depend on other initiatives to be developed and which projects can be implemented irrespective of other initiatives.

Table 1.6.7 Initiatives subject to budget, impact on losses, and dependence criteria

Budget	Impact on losses: Very high	High	Medium	Low
Low		2b. New Losses Calculation methodology	8b. Instructional Workshops with stakeholders	4 a. Improvements in the Meter Life Cycle
Low		4e. Strengthen the Customer Service processes	4b. Building a role for maintaining customer data	8 a. Round table with MERA
Low		5b. Acquisition of Mobile APPs	4 g. Written Procedure on Fraud Management	5f. Improve Free-Tokens process
Low		2e. Perform Regional Balances	8c. Periodic Regulatory Internal Committees	5 g. Convert "Suprima" customers
Low			6 a. Assessment for rehabilitating the grid	4f. Improve reporting and establish KPIs
Low			4c. Review the Debt Recovery process	7b. Smart Meter Regulation
Low			4h. Establish a Centralized Quality Control areas for key processes	5 d. Document management system
Low				8 d. Attraction of Private Investment
Medium	3c. Large customer and public institutions audit	3 a. Metering in Distribution Transformers	2c. Strengthen the EBM team	4 d. Review the current Organization of the Distribution Directorate
Medium	1 a. Establishing PMO	4i. Reorganization of the Revenue Protection area	5 a. Implementing a Meter testing laboratory	
Medium	2 a. Metering in Injection Points, Substations and Feeders	5e. Internal Training for CMS and Commercial Processes	6c. Technical Losses calculation process	
High	3b. End-customers audit	7 a. Smart metering for residential and commercial customer	6b. Piloting different technical configurations on the MV-LV grid	
High	3 a. Metering in Distribution Transformers	5c. Persons in Vulnerable Situations	7c. Establishment of a Metering Data Control Center	

Colour coding indicates initiative dependence on implementation of other initiatives, as follows:

No dependency	Depends on 1 initiative	Depends on 2 initiatives	Depends on 3 initiatives

Source: Loss Reduction Roadmap, ECA Analysis

From the long list of 34 initiatives, the following projects have a relatively high impact on losses, low budget requirements and could be implemented immediately without the need to implement other initiatives first (as shown in the table below):

1. 1 a. Establishing PMO
2. 2 a. Metering in Injection Points, Substations and Feeders
3. 2b. New Losses Calculation methodology
4. 3c. Large customer and public institutions audit
5. 4e. Strengthen the Customer Service processes
6. 4i. Reorganization of the Revenue Protection area
7. 8b. Instructional Workshops with stakeholders

Table 1.6.8 Ranked initiatives by budget, impact on losses and dependency on initiatives

Criteria			Initiatives that fulfil the criteria
Budget	Impact	Dependency	
Low	Mid / High	0	2b. New Losses Calculation methodology 4e. Strengthen the Customer Service processes 8b. Instructional Workshops with stakeholders
Low / Mid	Very high	0	1 a. Establishing PMO 2 a. Metering in Injection Points, Substations and Feeders 3c. Large customer and public institutions audit
Low / Mid	High	0	2b. New Losses Calculation methodology 4e. Strengthen the Customer Service processes 4i. Reorganization of the Revenue Protection area
Mid	Very high / High	0	1 a. Establishing PMO 2 a. Metering in Injection Points, Substations and Feeders 3c. Large customer and public institutions audit 4i. Reorganization of the Revenue Protection area

Source: ECA analysis based on the 2021 Loss Reduction Roadmap

6.2 Forecast network losses

The LRR includes three scenarios illustrating the potential outcome from implementation of the LRR. The scenarios reflect varying expected success rates of the same set of proposed interventions, ie they do not comprise different sets of assumptions or parameters, or different sets of individual projects. The three scenarios are as follows:

- **High Potential Scenario**: This scenario anticipates rapid implementation of the LRR, assuming a 1.2% average yearly reduction of losses, resulting to a total reduction of 6% in the fifth fiscal year, as well as implementation of additional ESCOM measures.
- **Medium Potential Scenario**: This scenario reflects base case implementation of the LRR. The annual loss reduction in this scenario is 1.05% resulting to a total loss reduction of 5.25% in the fifth fiscal year.
- **Low Potential Scenario**: Based on this scenario, slow implementation of the LRR is assumed, by which losses are reduced by 0.9% yearly, resulting to a total loss reduction of 4.5% in the fifth fiscal year.

In the above scenarios the escalation of the total losses decrease compared to the maximum achieved in the 5th year, is assumed to be 34.53% in the first year, 28% in the second, 19% in the third, 13% in the fourth and 5.47% in the fifth.

Further possibilities for reduction of energy losses, beyond the horizon considered in the LRR will depend on the implementation and effectiveness of the measures included in the LRR, the expansion of the network and the actual operating conditions, which will need to be examined through further analysis of the sources of both technical and non-technical losses at the time. Based on the current level comparative to international network loss standards, losses may be further reduced over a 20 year planning period. It was assumed that losses could reach 12% in the High scenario, and 15% in the Low and Base scenarios by 2042. The measures implemented and the reduction achieved would depend on available financial resources and priorities set, considering also electrification targets.

Based on these assumptions, the forecast Transmission, Distribution, and total network technical and non-technical losses taken into consideration for the development of the demand forecast, are those presented in Table.

Table 1.6.9 : Forecast Losses

Scenario		2021	2025	2030	2035	2040	2042
Low	**Transmission**	5.5%	4.8%	4.3%	4.2%	4%	4%
	Distribution	16.7%	14.6%	12.9%	12%	11%	11%
	Total	**22.2%**	**19.4%**	**17.2%**	**16.1%**	**15%**	**15%**
Base	**Transmission**	5.5%	4.7%	4.2%	4.1%	4%	4%
	Distribution	16.7%	14.2%	12.5%	11.7%	11%	11%
	Total	**22.2%**	**18.9%**	**16.6%**	**15.8%**	**15%**	**15%**
High	**Transmission**	5.5%	4.6%	3.8%	3.4%	3%	3%
	Distribution	16.7%	11.6%	11.7%	10.3%	9%	9%
	Total	**22.2%**	**16.6%**	**15.6%**	**13.8%**	**12%**	**12%**

Source: Loss Reduction Roadmap, ECA Assumptions. Note: as a percentage of total energy injected in the transmission system.

7 Demand Side Management (DSM) measures

Demand Side Measures (DSM) includes everything that is done on the demand side of the power system. This can include such simple things as increasing efficiency of a light bulb by replacing an incandescent light bulb with fluorescent light bulb to using sophisticated controllers to dynamically change the load.

Demand Side Measures can be broadly categorised into two different categories:

- ***Energy Efficiency (EE) –*** This includes improve efficiency of the appliances or of the building, so that energy losses are reduced. This approach towards achieving DSM is related to technical features, rather than changes in the consumer's personal comfort and behaviour.

- ***Demand Response (DR) –*** DR gives an opportunity for consumers to take part in the operation of the electric grid by shifting or decreasing their electricity usage during peak time in response to some financial incentives (price based or incentive based).

  DR programs are typically used by electric operators and system planners as an option to balance the supply and demand. These programs are capable to decrease the electricity cost in the system. Both price and incentive based programs involve customers being incentivised to change their energy consumption patterns.

Today's electricity systems complement their operation with distributed energy resources, such that these provide flexibility in emergency or other grid congestion situations. In this context, demand side management raises as one of the most attractive solutions for an easy flexibility implementation in power systems.

7.1 Historical, existing and planned DSM measures in Malawi

ESCOM, the Ministry of Energy and Mining (MEM) and MERA have designed and implemented several DSM projects over the years. There are also plans from the same entities to implement further measures. Historical, existing and planned DSM measures by ESCOM, MEM and MERA in Malawi are described in the subsections below.

2012-2013 MEM Energy Efficient Lighting Project (EELP)

The Government of Malawi, through the MEM implemented in 2012/13 an Energy Efficient Lighting Project (EELP) with the aim of reducing the evening system peak demand.

MEM was the Executing Agency of the project while ESCOM was the Implementing Agency. The project involved procurement of 2 million compact fluorescent light (CFL) bulbs, of which 1.3 million were distributed nationwide for free to residential customers, small enterprises and public buildings. This was done by direct replacement of existing incandescent bulbs with CFL bulbs. Commercial and industrial customers were required to purchase the remaining 700,000 energy saver bulbs at subsidised prices via retail outlets owned by Malawi Post Corporation, Farmers World and Rab Processors. A maximum of 6 CFL bulbs was installed per house by electrical contractors hired by ESCOM.

The project achieved an estimated saving of approximately 50 MW in peak demand, resulting to reduction of blackouts/load shedding, and enabling ESCOM to connect some more customers who had been on the waiting list for some time.

The project was supported by the UK Government’s Department for International Development (DFID) with an amount in the order of £3 million.

2017-2019 ESCOM’s LED bulbs distribution programme

According to ESCOM reports, 1,200,000 LED bulbs were distributed to residential sector customers, and 400,000 LED bulbs sold, between 2017-2019, saving about 29 MW in the peak.

2022-2023 ESCOM’s Efficient Lighting (LED Tubes) project

Currently, ESCOM is implementing the Efficient Lighting (LED Tubes) project, for the period 2022-2023, which aims at reducing commercial lighting energy demand through the retrofitting of inefficient fluorescent tubes with modern Energy Efficient LED Tubes in commercial and public sector premises. Considering that a conventional fluorescent tube uses about twice as much energy as an efficient LED tube for the same output, ESCOM plans to replace 450,000 fluorescent tubes to achieve savings of over 9.4 MW at peak, ie about 21 W per bulb. The Project has already rolled out within ESCOM offices countrywide and public buildings.

In addition, the project will achieve a reduction of energy consumption, for the estimation of which we are making assumptions about the time that these lights are used. Malawi has a relatively long duration of daylight throughout the year, ranging from about 11:20 hours in June to about 13 hours in December, based on data about Lilongwe. Sunrise gets as late as about 06:10 in June, and sunset as early as about 05:25 in January. Considering that office hours are normally 8-12 and 13:30 to 16:30, and for most shops working hours are not further than 17:00, the artificial lighting requirements in the commercial and public sector seem rather limited to only a few hours per day. Apparently, the range of artificial lighting requirements is specific on the type of activity and the specific conditions in the premises. There are currently no statistics available to determine that range, and available international standards only refer to the required illumination per type of activity and cannot be readily translated into hours of required artificial lighting.

Existing Demand Response Measures (Time of Use charges)

ESCOM has implemented Time of Use tariffs for larger customers as it is depicted in the table below. The Time of Use energy charge provides signals to shift consumption from peak to off-peak periods and the demand charge provides signals to lower the peak demand on a monthly basis.

Table 1.7.1 ESCOM tariff design and time of use charges

Category		Type of charge					
		Fixed (per month)	Energy (per kWh)			Capacity charge (per kVA)	Demand charge (per MW)
			Blocks	Single rate	ToU	Fixed*	ToU**
ET1	Domestic, 1-Ph, Prepaid	x	√	x	x	x	x
ET2	Domestic, 1-Phase, Postpaid	√	√	x	x	x	x
ET3	Domestic, 3-Phase, Prepaid	x	x	√	x	x	x
ET4	Domestic, 3-Phase, Postpaid	√	x	√	x	x	x
ET5	General, 1-Phase, Prepaid	x	x	√	x	x	x
ET6	General, 1-Phase, Postpaid	√	x	√	x	x	x
ET7	General, 3-Phase, Prepaid	x	x	√	x	x	x
ET8	General, 3-Phase, Postpaid	√	x	√	x	x	x
ET9	Maximum Demand, LV	√	x	x	√	√	√
ET10	Maximum Demand, MV	√	x	x	√	√	√
ET11	Essential Service, 3-Ph, Prepaid	x	x	√	x	x	x

Source: ESCOM. Note: * Based on annual declared demand, ** Based on actual monthly demand reading.

MERA's Guidelines for promoting Energy Efficiency in Malawi

MERA has prepared guidelines for the promotion of energy efficiency in Malawi. The draft Guidelines include:

- Energy efficiency standards and appliance labelling
- Guidelines for the development of energy management strategies by all facilities
- Directions for energy audits
- Energy accounting principles
- Demand Side Management principles
- Energy saving tips

MERA has submitted the Guidelines to the Ministry of Energy for approval and setting in effect.

Further ESCOM plans

ESCOM has indicated that an efficient lightbulb plan is expected to be implemented with the support of the World Bank and mainly targeted at residential consumers.

7.2 Options for DSM in Malawi

As it was discussed above, Demand Side Measures can be broadly categorised into EE and DR measures. The following subsections discuss EE and DR options that could be considered for the power sector in Malawi and comment on the applicability of those measures in Malawi.

7.2.1 Demand Response options

DR gives an opportunity for consumers to take part in the operation of the electric grid by shifting or decreasing their electricity usage during peak time in response to some financial incentives. DR options include retail price based and incentive based programs.

The following table describes potential DR measures (both retail price and incentive based) and comments on their applicability in Malawi.

Table 1.7.2: DR measures

DR Measure	Descriptions / Comments
A. Retail price based DR	
1. ToU tariffs	Retail price based programmes mainly concern implementation of time of use tariffs, varying by hour or season, incentivising customers to use electricity during non-peak hours, or away from periods of energy shortages. Such programmes would require the introduction of meters capable of registering the consumption of electricity at different times. Such programmes are already in place for categories of industrial customers in Malawi. However, considering the cost of needed metering equipment and the priority for Malawi to extend electrification to the significant part of the population currently off the main grid, this option is not considered applicable at present.
B. Incentive based DR	
1. Direct load control	The utility or network operator may remotely shut down or cycle a customer's electrical equipment (eg air conditioner, water heater), on short notice, to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential and small commercial customers. Considering the very low average consumption in the domestic and commercial sector of Malawi, as well as the complexity of the operation and the increased capital cost requirements of such systems, they are not considered applicable in the country at this stage.
2. Interruptible / curtailable (I/C) service	This concerns programs integrated with the customer tariff providing a rate discount or bill credit for agreeing to reduce load, typically to a pre-specified firm service level during system contingencies. Customers that do not reduce load typically pay penalties in the form of very high electricity prices that come into effect during contingency events or may be removed from the program. Such arrangements could be examined by ESCOM with large industrial users. However, they will have to be considered carefully taking into consideration that ESCOM already sheds the load during some hours without any payments to consumers.
3. Demand bidding / buyback programs	These are programs targeted mainly to large customers, encouraging them to either bid into a wholesale electricity market and offer to provide load reductions at a price at which they are willing to be curtailed, or identify how much load they would be willing to curtail at a utility-posted price. Such tailor-made programs may be suitable for and of interest to certain large industrial customers, and should be further examined by ESCOM in the context of the development of a competitive wholesale electricity market.
4. Emergency demand	Programs that provide incentive payments to customers for measured load reductions during reliability-triggered events; emergency demand response

response programs	programs may or may not levy penalties when enrolled customers do not respond. The type of metering equipment required for this type of interventions might only concern certain large industrial customers in Malawi. Such arrangements could be examined by ESCOM with large industrial users. However, they will have to be considered carefully taking into consideration that ESCOM already sheds the load during some hours without any payments to consumers.
5. Capacity market programs	These programs are typically offered to customers that can commit to providing pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Given the current market structure in Malawi this measure is not applicable.
6. Ancillary Services Market Programs	These programs allow customers to bid load curtailments in open markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. Similarly, given the current market structure in Malawi this measure is not applicable.

Source: ECA analysis

7.2.2 Energy efficiency options

Domestic sector

According to the 2018 Malawi Population and Household Census, 453,592 households were using electricity for lighting, and 75,267 households for cooking and heating[10]. Moreover, 224,521 households owned a refrigerator, and 594,713 an iron, although there is no information regarding the percentage of those households connected to the distribution network. Households accounted for about 42% of electricity consumed in the country on the average during the period 2012-2021. Currently, there are no statistics concerning the average electricity consumption of households by end use.

For the purposes of this study, it is assumed that the main end uses of electricity in households are lighting, cooking, refrigeration, water heating, space heating/cooling, washing, vacuum cleaning, entertainment, information and education. It may be assumed that electricity is used for lighting in almost all domestic customers, whereas most other typical uses are less widespread.

Considering the very low average consumption in rural areas it may be assumed that the possibilities for energy savings are very poor in such connections. Even in urban areas electricity consumption in the order of 160 kWh/month (corresponding to use of an average of 222 W continuously on a daily basis) can be assumed to only cover basic needs of the household.

The following measures aimed at the domestic sector may be considered in the context of this study.

Table 1.7.3 Options for EE measures for the domestic sector

[10] As the census determines the use of electricity for these end uses distinctly from other energy sources (eg solar, battery, charcoal, firewood, etc), we are assuming that these numbers only concern households connected to the electricity distribution network of Malawi. We note though, that the total number of residential connections in 2018 was about 355,300, ie about 90,000 less than households using electricity for lighting. We are assuming that this may reflect multiple households using a single connection to the distribution network.

EE Measure	Descriptions / Comments
Domestic sector EE options	
1. Substitution of low efficiency lighting with LED bulbs	As already mentioned in section 7.1, considerable assistance has been provided for the substitution of incandescent with fluorescent lamps, and the introduction of LED lamps. There is still considerable potential for substitution of fluorescent lamps with LED lamps. Depending on the type and efficiency rating of lamps, savings may be in the order of 50% for the replacement of fluorescent lamps.
2. Introduction of Minimum Energy Efficiency Requirements (MEPR) and/or a labelling scheme	Minimum energy performance requirements and energy efficiency standards (MEPR) have been prepared by MERA and are in the process of approval by the Ministry of Energy. Such standards would incentivise the gradual phasing out of low energy efficiency appliances currently in use, and their gradual substitution by high energy efficiency ones. This impact is of interest for the purposes of this study, as it would affect the energy consumption needs of households. The introduction of such requirements would also apply in the construction of new or rehabilitation of existing buildings with high energy efficiency standards and would then have an effect on mainly the heating and cooling requirements of those buildings. However, considering the very low share of electricity currently used for heating and cooling purposes in Malawi, this effect is not considered significant for the purposes of this study. Depending on the type of appliances, the energy savings from the introduction of MEPR may be considerable (eg a A class refrigerator may save up to more than 50% of an older refrigerators' electricity consumption, and a A class washing machine may save up to 35% of the electricity consumption of a class D or E model). The introduction of strict MEPR for home appliances would have an impact on electricity consumption in the medium to long-term.
3. Provision of incentives for the installation of solar water heaters	According to the 2016 IRP for Malawi, solar water heating had been proposed in the SE4ALL Agenda Action and the World Bank had proposed a programme focusing on replacing electric heaters with 2.5 kW elements combined with ripple control, but no specific programme had been elaborated by any of the stakeholders for a solar water heating programme. Based on World Bank and Agenda Action estimates included in the 2016 IRP study, installed electric heaters were in the order of 30,000 to 40,000 in 2015. According to the project proposers, launching a programme for the installation of 16,000 partially subsidised solar hot water heaters for residential users, could be assumed to reduce peak demand by 21 MW within 5 years from implementation. Although the details for this estimate are not provided, it seems that coincident demand for water heating at peak was assumed to be approximately 50% of installed capacity for water heating. The annual reduction of electricity consumption would be 10,000 MWh at the end of programme implementation. The overall cost of the solar hot water heaters was estimated to about $11.2 million and would be partly covered by a subsidy.
4. Replacement of conventional technology fans with energy efficient ones	Although the number of households equipped with ceiling fans is not known, it may be estimated that there is a considerable number of fans in operation, which could be replaced with new technology units, capable of providing energy savings in the order of 60%.
5. Information dissemination and energy saving campaigns	An information dissemination programme, including an energy saving campaign should be complementary to any effort to improve the energy consumption pattern. However, the cost and benefit from the implementation of such programmes would depend on the specific characteristics and intentions of the programme, as well as

EE Measure	Descriptions / Comments
Domestic sector EE options	
	the specific economic and cultural conditions and consumer segments it is aimed at. Considering the low electrification and relatively low energy consumption in the residential sector, the effectiveness and priority of such a programme for Malawi at the moment seems low.

Source: ECA analysis

Commercial and industrial sectors

Electricity consumption in the commercial and the industrial sectors accounted for about 14% and 44%, on the average, respectively, in the period 2012-2021,

Incentives for the penetration of efficient machinery and other appliances used in commercial and industrial premises may have a positive effect on energy consumption, although the impact of specific measures would depend on the object of the commercial or industrial activity.

Energy saving potential can be assumed to be relatively low in the commercial sector, considering the relatively small share of the sector in total electricity consumption in the country, and the small average electricity consumption per commercial connection. The potential savings in industry may be higher, although a horizontal assessment of the potential in industry cannot be reliable, due to the specific characteristics of the particular premises, technology in place, and maintenance status.

The following options may be considered in the context of this study for the commercial and industrial sectors.

Table 1.7.4 Options for EE measures for the commercial and industrial sectors

EE Measure	Descriptions / Comments
Commercial and industrial sectors sector EE options	
1. Energy efficient lighting	As discussed in section 7.1, the Government of Malawi has already implemented programs for the replacement of incandescent lamps, and ESCOM is currently implementing the LED Tubes project, for the replacement of fluorescent with LED tubes in commercial and public buildings. It may be assumed that there is still untapped potential for the introduction of energy efficient lighting in these sectors, although it should also be assumed that competition drives owners of commercial and industrial premises to upgrading energy consuming equipment in line with technological innovation, more often than households. There is no information regarding the electricity consumption for street lighting in Malawi, or the relevant installed capacity, or the length of the street lighting network currently in use in the country. Based on the available statistics of ESCOM sales the share of electricity consumption for street lighting can be assumed to be negligible. Accordingly, the potential for energy savings through introduction of LED lamps in street lighting is unknown but can be assumed to be negligible for the purposes of this study. LED lights are 40% to 60% more energy efficient than traditional lighting technologies, therefore, savings could be in that order of

EE Measure	Descriptions / Comments
Commercial and industrial sectors sector EE options	
	magnitude relative to current electricity consumption for street lighting, if a replacement programme was implemented.
2. Introduction of Minimum Energy Efficiency Requirements (MEPR) and/or a labelling scheme	Minimum energy performance requirements and energy efficiency standards (MEPR) have been prepared by MERA and are in the process of approval by the Ministry of Energy. As in the domestic sector, the introduction of MEPR may have an effect mainly in some commercial activities. However, the scope for this type of investment is unknown in Malawi, due to the lack of statistics regarding the electricity consuming appliances in use in the commercial sector.
3. Replacement of electric water heaters by solar water heaters	For certain commercial activities solar water heaters may be applicable (eg in hotels), but there is no data to allow the estimation of the amount of electricity that might be saved by the installation of solar water heaters, or the estimation of the potential for such investment in Malawi. Hot water preparation in such premises is usually done using fossil fuels instead of electricity, therefore the impact on electricity consumption from the introduction of solar water heaters in commercial activities appears to be small.
4. Upgrading of AC units	There are AC units used, to some extent, in commercial customer premises. Although there is no specific information about the number and type of units in operation, it may be assumed that there is a certain potential for replacement of units with higher energy efficiency, inverter technology units.
5. Replacement of conventional technology fans with energy efficient ones	As in the domestic sector, it is also assumed that fans are also in use in the commercial sector, which could be replaced with high efficiency units.
6. Introduction of variable speed drives for the operation of motors in commercial and industrial activities.	This could also have a significant energy saving potential, but the current technical conditions in such premises is unknown and therefore a safe conclusion may not be drawn. Considering that such technological improvement are normally associated with clear economic benefits and competitive advantages for the investor, such opportunities are normally utilised without any additional incentives or interventions. Where such clear advantages are limited by price or other market distortions, the introduction of MEPR with or without additional incentive schemes may be effective.

Source: ECA analysis

7.2.3 Summary of DSM options in Malawi

The DSM measures considered as possible options to implement in Malawi are summarised in Table
.

Table 1.7.5 Summary of DSM options in Malawi

	Demand Side Measure (DSM)	Status	Unit	Capital costs ($/unit)	Impact on peak demand (kW/Unit)	Impact on energy demand (kWh/Unit/year)	Target groups	Earliest year for implementation (Year)
1	Replacement of Fluorescent bulbs with LED lights	Committed and candidate	Bulb	0.7-5	0.006	11 13-40	Residential Commercial Public	2022
2	Replacement of AC units with high energy efficiency ones	Candidate	AC unit	300	0.52	915	Commercial	2023
3	Replacement of fans with high efficiency ones	Candidate	Fans	100	0.036	66 92	Residential Commercial	2023
4	Replacement of electric water heaters with solar	Candidate	Solar water	750-900	2	3000 3650	Residential Commercial	2023
5	Introduction of Minimum Energy Efficiency Requirements	Candidate	All consumers	-	-	71	Residential Commercial Industrial	2025

Source: ECA

7.3 Assessment of potential DSM options

The design of a plan for the improvement of EE in electricity consumption concerns the identification of relevant end uses of electric energy, where EE improvements through technological or other interventions are technically and economically feasible.

The first step for the assessment of the identified DSM options is to identify the DSM potential by end use and customer category. The objective is to evaluate how much energy may be saved by satisfying the same end use, at an equivalent qualitative level, yet with higher energy efficiency appliances or procedures, compared to those currently in use, thus by consuming less electricity:

- *Domestic and commercial users* - The estimation of the potential for DSM improvement in the consumption of electricity by residential and commercial customers is normally based on a bottom-up calculation. Under this approach, the potential for a particular end use and customer group is estimated as the product of the average level of ownership of the relevant end use appliances among that customer group, the average utilisation (in hours) of these appliances and the average saving of end use appliance capacity (in W) from switching to a high efficiency alternative, compared to those currently in use. This product provides the total potential savings in electricity consumption for that use and customer group from the switch to high efficiency appliances.

- *Industrial users* – The approach to estimating DSM potential for industrial customers is rather different. Much of the DSM potential for these customers lies in the ability to replace motors, pumps, chillers and other installations which are specific to individual industrial processes and facilities regarding size, use, age and efficient alternatives. In addition, energy savings may be possible without replacing equipment by, for example, redesigning processes. Therefore, simple comparisons of the numbers of appliances owned by individual customers are not a reliable measure of aggregate DSM potential for industrial customers. Usually, this would be addressed by specific walk-through EE audits for a representative sample of industrial premises. These can be used to estimate overall DSM potential as a share of current consumption and, from this, to scale up to national-level estimates based on the number of similar facilities in the same industries.

Once the DSM potential is determined, the pay-back period to customers from different measures is also analysed. The pay-back period is the time taken for the savings from lower electricity bills, as a result of substituting an existing appliance with a high efficiency one, to fully offset the relevant investment cost. The resulting estimated pay-back periods for DSM measures reveals weather a consumer would have the incentive to implement it on his own (if benefits exceed costs) or if incentives should be considered to implement the measure (costs exceed benefits and consumers would not have an incentive to implement it on their own).

The analysis leads to a shortlist of EE and DR measures that should be considered for implementation in Malawi. The shortlisted DSM measures should be further assessed in the context of the IRP to determine which cases are the least cost options to be considered for implementation.

7.3.1 DSM potential in Malawi

Electricity consumption by sector in Malawi, in 2021, is presented in Table. The data illustrates the low level of average consumption in the residential sector, at 120 kWh/month per connection (reaching as low as 47 kWh/month on the average in rural connections), and the relatively low average consumption in the commercial sector, at 327 kWh/month per connection[11]. One may also observe that despite the relatively small number of industrial customers, industry accounts for about 44% of total electricity consumption in Malawi.

Table 1.7.6 Electricity consumption in Malawi, 2021

Sector	Number of customers	Annual sales (GWh)	Average consumption (kWh)	
			Annual	Monthly
Residential	459,800	663.6	1,443	120
Urban	297,600	571	1,919	160
Rural	162,200	92	567	47
Commercial	83,800	329.2	3,928	327
Industrial LV	1,743	270	154,905	12,909
Industrial MV	152	420	2,763,158	230,263

Source: ESCOM

DSM potential in the residential and commercial sectors

As detailed Information on current ownership of electric appliances by customer type in Malawi is not available, the estimation of the potential savings is based on assumptions, about the average

[11] For comparison, industry accounted for 36% in the EU(27) in 2021, ranging from 12% in Cyprus to 47% in Luxemburg. Also, the average monthly consumption per household in the EU(27) is about 300 kWh, ranging from about 160 kWh in Romania to 960 kWh in Sweden.

or typical size of appliances, the daily and annual use, the typical number of appliances per residential or commercial installation, and the penetration of appliances to the total of installations connected to the electric system of Malawi.

For example, it is assumed that the typical type of CFL lamps currently in place have a capacity of 15 W, and may be replaced by 9 W LED lamps. Average daily use in households is 5 hours, and such lamps are found in 90% of grid connected households. Considering there are about 298,000 urban and 162,000 rural residential connections, there are on the average about 5.4 CFL lamps per urban and 3.6 per rural household, respectively. The average capacity and energy savings by lamp are 6 W and 10.95 kWh/year respectively. Then, the total energy savings potential from the replacement of CFL by LED lamps in households is 23.99 GWh/year. Assuming an average CO2 emissions factor of 62 kg/MWh from existing power generation[12], the annual savings of CO2 emissions from the replacement of CFL by LED lamps is estimated at 1,487 ton.

Table and Table present the electricity and CO2 savings potential in the domestic and commercial sector of Malawi from the implementation of the identified EE measures. Within these, the replacement of electric water heaters by solar water heaters for residential and commercial customers has the greatest potential. The saving potential from the upgrading of AC systems in the commercial sector potential from upgrading of fans in the domestic sector are the lowest.

[12] Calculated using generation outputs from the 2017 IRP and assuming an emissions factor for diesel generators of 715kg/MWh, based on WAPP master plan.

Table 1.7.7 Electricity and CO_2 savings potential in the domestic sector

	Appliance capacity (W)		Operation	Penetration (% of customers owning)		Average no of units per connection		Savings per appliance		Customers (million)		Total potential	Capacity impact	CO2 saving	emissions
Appliance	Existing	New	h/day	Urban	Rural	Urban	Rural	W	kWh/year	Urban	Rural	GWh/year	MW	kg/MWh	Ton/year
Fans	60	24	5	20%	10%	0.20	0.10	36	65.7	0.298	0.162	4.98	2.18	62	308
CFL	15	9	5	90%	90%	5.40	3.60	6	11.0	0.298	0.162	23.99	9.20	62	1,487
Water heater	2,084	0	4	15%	10%	0.15	0.10	2,084	3,042.6	0.298	0.162	185.16	63.41	62	11,480
Total												214.13	74.79		13,276

Source: ESCOM, 2017 IRP, ECA assumptions and calculations

Table 1.7.8: Electricity and CO_2 savings potential in the commercial sector

	Appliance capacity (W)		Operation	Penetration (% of customers owning)	Average no of units per connection	Savings per appliance		Customers (million)	Total potential	Capacity impact	CO2 saving	emissions
Appliance	Existing	New	h/day			W	kWh/year		GWh/year	MW	kg/MWh	Ton/year
AC	1,200	680	8	5%	0.1	520	915	0.084	7.67	3.92	62	476
Fans	60	24	8	100%	3.0	36	92	0.084	23.17	7.24	62	1,437
FTL	35	18	6	42%	6.3	17	37	0.084	19.66	6.28	62	1,219
CFL	15	9	6	40%	4.0	6	13	0.084	4.41	1.41	62	273
Water heater	2,500	0	4	25%	0.3	2,500	3,650	0.084	76.48	36.67	62	4,742
Total									131.40	55.53		8,147

Source: ESCOM, 2017 IRP, ECA assumptions and calculations

The total estimated annual potential for each of the DSM options considered is as follows.

Table 1.7.9: Total energy and CO2 savings potential

	Energy potential *(GWh/year)*	**CO2 emissions potential** *(ton of CO2 per year)*
Households		
Replacement of fans by energy efficient ones in households	4.9	308
Substitution of CFL by LED lamps	23.9	1,487
Substitution of electric by solar water heaters	185.2	11,480
Commercial premises		
Replacement of AC units with high efficiency inverter units	7.7	476
Replacement of fans by energy efficient ones	23.2	1,437
Substitution of FTL by LED tubes	19.7	1,219
Substitution of CFL by LED lamps	4.4	273
Substitution of electric by solar water heaters	76.5	4,742

Source: ECA analysis

The total technical DSM potential for residential customers is estimated at approximately 215 GWh/year and for commercial customers at 131 GWh/year, and the respective CO2 savings at 13,300 ton/year and 8,147 ton/year.

As illustrated in Figure , the electricity savings potential as a share of sales, by customer class is highest for commercial customers, where almost 50% of consumption may be saved, mainly through investment in lighting and water heating. The type of DSM measures considered in the residential and commercial sectors could reduce total electricity consumption by 23%.

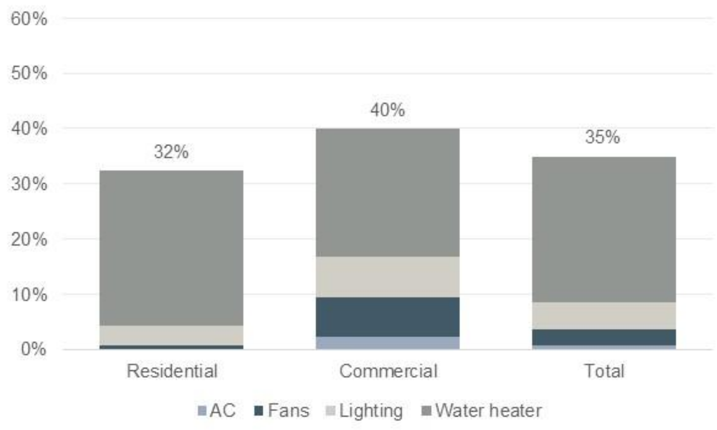


Figure 1.7,1: DSM potential as a share of sales by customer class (2021)

Source: ECA calculations

DSM potential in Industry

The information provided in Table confirms that, as discussed in section 7.2.2, generalisations on the average energy use of appliances, and the possibilities for their substitution by higher EE ones cannot be made for industrial premises. Instead, sound conclusions should only be drawn through audits, focusing on the specificities of each factory, or industrial process. Such audit data is not available for the industrial sector of Malawi, and the performance of such audits was not part of the scope of this project. Accordingly, relying on assumptions about the types of appliances and procedures used in industrial premises in Malawi would be unfounded and would defeat the purpose of the analysis for the preparation of an EE plan. Instead, it is proposed that a dedicated survey of the industrial sector through focused energy audits, is carried out, to feed the preparation of an EE plan for industry.

7.3.2 Pay-back period of DSM options

Further to estimates of the total EE potential, we have also prepared estimates of the pay-back period to customers from different measures. The pay-back period is the time taken for the savings from lower electricity bills, as a result of substituting an existing appliance with a high efficiency one, to fully offset the relevant investment cost. Pay-back periods provide a simple and rapid way of comparing different investments which is why they are used here. However, it should be noted that they are not the sole nor the best means of making investment decisions—better indicators are the internal rate of return (IRR) or the net present value (NPV) using cashflows discounted at the investor’s cost of capital.

The comparison only considers the costs and benefits to the customer. These are not the same as the costs and benefits to ESCOM or to Malawi as a whole. For example, if the tariff charged to a customer exceeds the marginal cost of supply to ESCOM, then an investment may well be profitable for the customer (the electricity bill saving exceeds the investment cost) but loss-making for ESCOM (the loss of electricity bill revenues exceeds the cost savings to ESCOM).

The assumptions used to calculate the change in investment costs and reduced electricity consumption are shown in the preceding tables. The calculation of the financial value of savings uses the consolidated retail tariffs for residential and commercial customers in 2021 (56.93 MWK/kWh and 124.52 MWK/kWh, respectively).

The resulting estimated pay-back periods for residential and commercial EE measures are shown in the following Table and Table .

These show that replacing current lighting with LED offers extremely rapid returns to customers, in both the residential and commercial sectors. The next most cost-effective EE measures from the perspective of customers are the replacement of water heaters with solar heaters and upgrading of AC units in the commercial sector. Replacement of electric water heaters with solar heaters in the domestic sector also has a low pay-back period. The replacement of fans in both sectors has high pay-back periods, in the residential sector exceeding the expected technical lifetime of the appliances.

Table 1.7.10: Estimated pay-back periods for residential EE measures

End use	Unit cost (USD)	Pay-back period (years)
Fans	100	27.4
CFL	0.7	1.1
Water heater	750	4.4

Note: Red indicates that the pay-back period exceeds the appliance lifetime (ie that the additional investment will never recover its cost).

Source: ECA calculations

Table 1.7.11: Estimated pay-back periods for commercial EE measures

End use	Unit cost (USD)	Pay-back period (years)
AC	300	2.7
Fans	100	8.9
FTL	5	1.1
CFL	0.7	0.4
Water heater	900	2.0

Source: ECA calculations

7.4 Conclusions for the DSM plan

Utility-based EE programs should be focused on those EE measures that offer the greatest potential and that are less likely to be implemented by customers without external support. This rationale directs resources to those measures which are likely to have the greatest effect.

The likelihood that customers will implement EE measures on their own initiative is proxied, in this report, by the estimated pay-back periods to customers. Where measures have longer pay-back periods, it is assumed that customers are less likely to implement these without external support and incentives.

Rankings of the individual EE measures identified are shown in Table, in order of potential electricity savings (from most to least) along with the respective estimated CO2 savings and pay-back periods. The proper way to assess the shortlisted measures would be through the IRP. The IRP should assess the economic efficiency of those measures against increasing generation capacity and should also indicate which measures to prioritise.

The analysis for potential DSM measures has highlighted the following:

- Substitution of electric water heaters by solar heaters in both the commercial and residential sectors accounts for over 75% of total potential savings of all considered measures.

- All lighting related measures in both sectors account for about 44% of the total electricity saving potential.

- Of the five measures with the largest potential, investments in energy efficient lighting in both sectors and replacement of electric water heaters with solar water heaters in the commercial sector have a rapid pay-back (<3 years in all cases), implying customers will make these investments if aware of the savings. The same holds for high efficiency AC in commercial premises, although the potential savings from this measure are relatively small, compared to lighting and water heating.

- Replacement of electric heaters with solar water heaters in the domestic sector has a relatively low pay-back period of 4.4 years, which, in combination with the relatively high cost of a solar water heater for a household, might require some assistance for the implementation of the measure.

- Investments for the replacement of fans with high energy efficiency ones have longer pay-back periods and customers would need financial incentives to make these replacements.

Based on this assessment, the proposed priorities for utility-based EE programs are encouraging residential customers to shift from electric to solar water heating, and both residential and commercial customers to switch to higher-efficiency fans.

It is noted that this conclusion does not include measures applicable to industry, due to the focus on electrical efficiency of standard appliances. Facility-specific energy audits will likely identify many additional opportunities to reduce electricity consumption in industry.

Table 1.7.12 Estimated EE potential and pay-back periods by measure

Sector – end use	**Total potential** *(GWh/year)*	**Capacity impact** *(MW)*	**CO2 savings** *(ton/year)*	**Pay-back period** *(years)*
Domestic - Water heater	185.2	63.4	11,480.0	4.4
Commercial - Water heater	76.5	36.7	4,742.0	2.0
Domestic – CFL	24.0	9.2	1,487.3	1.1
Commercial – Fans	23.2	7.2	1,437.0	8.9
Commercial - FTL	19.7	6.3	1,219.0	1.1
Commercial - AC	7.7	3.9	476.0	2.7
Domestic - Fans	5.0	2.2	308.5	27.4
Commercial - CFL	4.4	1.4	273.0	0.4

Source: ECA calculations. Note: Measures highlighted in light orange indicate high pay-back period. For these measures, financial assistance for consumers might be needed to make these replacements.

Based on the above analysis, the DSM that present benefits for the power sector in Malawi would comprise a set of DR and EE measures as shown in Table .

Table 1.7.13: DSM plan for Malawi

Measure	Average annual potential per connection			Average cost per connection	Earliest commissioning
	Peak demand reduction	Electricity savings	CO2 emission savings		
	(W)	*(kWh)*	*(ton)*	*(EUR)*	*(year)*
TOU tariffs in industry	Site specific				In place – may be further extended
Interruptible / curtailable (I/C) service with industrial users	Site specific, determined subject to system requirements				ESCOM to examine with large industrial users
Demand bidding / buyback programs for industry	Site specific, determined subject to system requirements				ESCOM to examine with large industrial users
Emergency demand response programs for industry	Site specific, determined subject to system requirements				ESCOM to examine with large industrial users
Energy efficient lighting in residential sector	24 – 36	44 - 66	2.7 - 4.1	2.8 – 4.2	2023
Energy efficient lighting in commercial sector	60 - 255	131 - 558	8.1 – 34.6	7 – 75	In place – could be further extended
Introduction of Minimum Energy Efficiency Requirements	Technology specific. Survey required				2025
Replacement of electric with solar water heaters in residential sector	2,084	3,042	188.6	750	2023
Replacement of electric with solar water heaters in commercial sector	2,500	3,650	226.3	900	
Replacement of conventional with EE fans in residential and commercial sectors	36 - 108	66 - 276	4.1 - 113	100 - 600	2023
Upgrading of AC units in commercial premises	1,040	1,830	113	600	2023
Variable speed drives in industry and commercial sector	Site specific. Survey required				2024

Source: ECA analysis

The plan will need to be further specified, following completion of the IRP for Malawi, when the economic feasibility of proposed measures will be possible, and financing plans can be drawn.

8 2022-2042 Demand forecast

This section presents the results of the 2022-2042 updated demand forecast for Malawi. It incorporates the lessons learned from previous approaches to demand forecasting in the country, including the one done in 2017 for the IRP, continuous engagement with the key stakeholders in the country represented by the USWG, as well as external stakeholders. The input assumptions and the methodology presented in Section 3 and Section 4 were validated by stakeholders and this represents the end deliverable of this project (eg the demand forecast).

Three scenarios have been developed, with variations centred around electrification plans, economic indicators, loss reduction initiatives, and probabilistic assessment. As a result, the following subsections are better understood as a range of energy and peak demand forecasts, rather than specific predictions. The full annual results are included in Annex A5.

The main outcomes from the results are:

- **Energy demand is expected to more than double in all scenarios until 2040.** When considering the entire forecasting period, the low case scenario forecasts annual growth rates higher to those in the last decade, including multiple occurrences of load shedding, at 4.1%; the base case scenario reflects the growth rate expected without load shedding and with the Ministry's electrifications targets at 8.4%; while the high case scenario forecasts annual growth rates of 10.4%, with many new connection up to 2030 to increase electrification to 100% by 2030, but slower increases in the second half of the forecasting period.

- **As with energy demand, peak demand is projected to more than double by 2042.** The low case scenario forecasts an increase of peak demand to 815 MW by 2042. The 2042 peak demand is projected to be 1,914 MW for the base case scenario, and 2,830 MW for the high case scenario.

- **High demand growth is expected in Malawi from the set electrification targets.** Given the low levels of access to electricity in the country and the commitment from the Ministry of Energy and development partners such as SE4ALL and the WB to accelerate electrification in Malawi, new connections are expected to increase substantially in the base and high case scenarios. While the low case scenario is based on ESCOM's historical performance to connect new customers, the existing support is expected to result in ambitious targets ranging from the Guidelines for Implementation of the National Electrification Programme, targeting 150,000 annual connections by 2025 (**base case**); to SE4ALL universal electrification target by 2030 (**high case**).

- **The geographical spread will slightly change, with the North region expanding faster than the South and Central regions.** While urbanization rates present a slower increase in the south, these are offset by the presence of the majority of large customers with expansion plans. Urbanization in the Central region (mainly towards Lilongwe) is expected to expand the regions' base of users with relatively high consumption. Nonetheless, most new connections are expected to occur in rural areas, which will also increase the size of residential demand in the North region.

The following subsections provide a detailed summary and analysis of each component of this demand forecast, followed by sectoral and geographical splits, as well as the expected impact of DSM in the forecasts.

8.1 Sent-out energy demand forecast

Energy demand is expected to more than double in all scenarios until 2040, as can be seen in

Figure 1. The low case scenario, with lower electrification rates and high use of self-generation, foresees a 133% increase in total sent-out energy demand between 2021 and 2042, reaching 5,362 GWh. The base case scenario, on the other hand, projects a 442% increase of sent-out energy demand by 2042 with respect to the 2021 level. In this scenario, self-generation becomes less widespread, and some large customers implement their expansion plans to reach 12,458 GWh. The high case scenario presents an optimistic view of the possibilities in each sector to increase energy demand. A rapid increase of demand before 2030 is expected due to the achievement of the SE4ALL electrification target of 100%. In the high case scenario, an overall increase of 700% in sent-out energy demand, reaching 18,371 GWh in 2042, is forecasted.

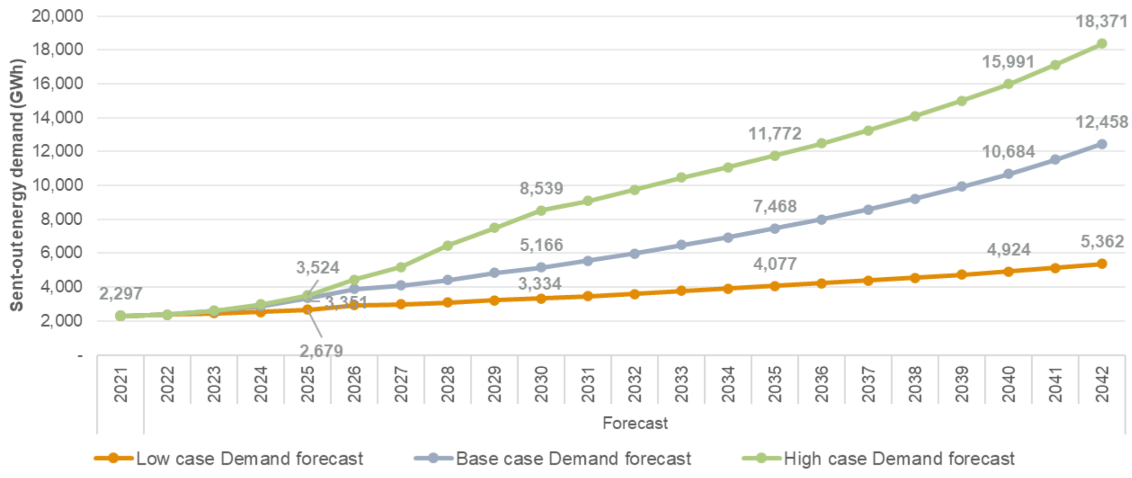


Figure 1.81 2022-2042 Energy demand forecast (sent-out level)

Source: ECA analysis

When considering the entire forecasting period, the low case scenario forecasts annual growth rates similar to those in the last few years at 4.1%; the base case scenario reflects the growth rate expected without frequent load shedding at 8.4%; while the high case scenario forecasts annual growth rates of 10.4%, with slower increases in the second half of the forecasting period (see Figure 1.8.2).

In the first 10 years of the forecast, growth in all scenarios is expected to be higher than after 2030. This is mainly due to electrification programmes and industrial expansions occurring before 2030. During the 2021-2025 period, energy demand is expected to grow at an annual rate of 3.9% for the low case scenario, 9.9% for the base case scenario, and 11.3% for the high case scenario. In the 2025-2030 period, the high case scenario projects annual energy demand growth rates of 19.4%, mainly driven by ambitious electrification targets that range between 200,000 to almost 900,000 each year.

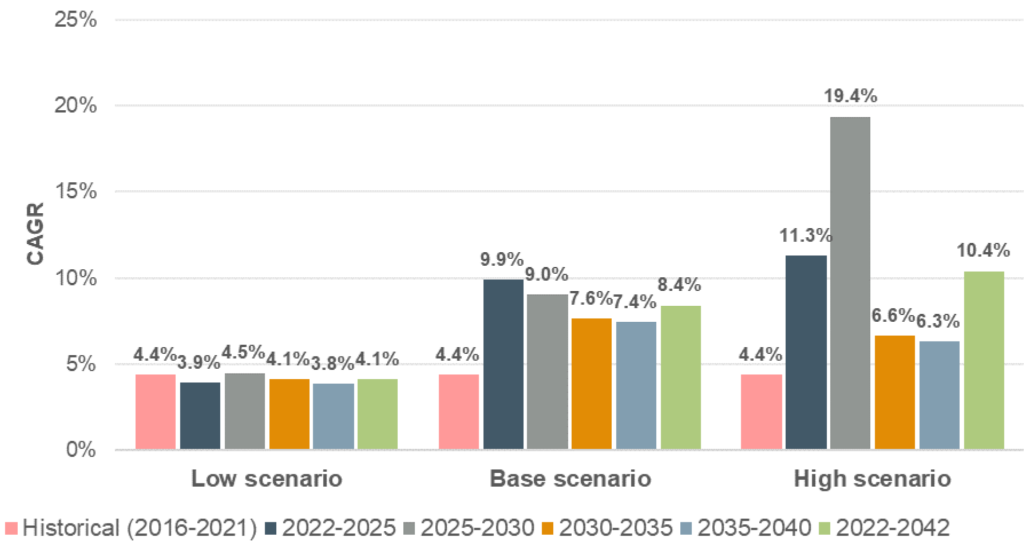


Figure 1.8.2 Sent-out energy demand annual growth

Source: ECA analysis

8.2 Sent-out peak demand forecast

As with energy demand, peak demand is projected to more than double by 2042 (see Figure). The low case scenario forecasts an increase of peak demand to 815 MW by 2042. For the base case scenario, the 2042 peak demand is projected to be 1,914 MW, reaching 2,830 MW in the high case scenario in 2042.

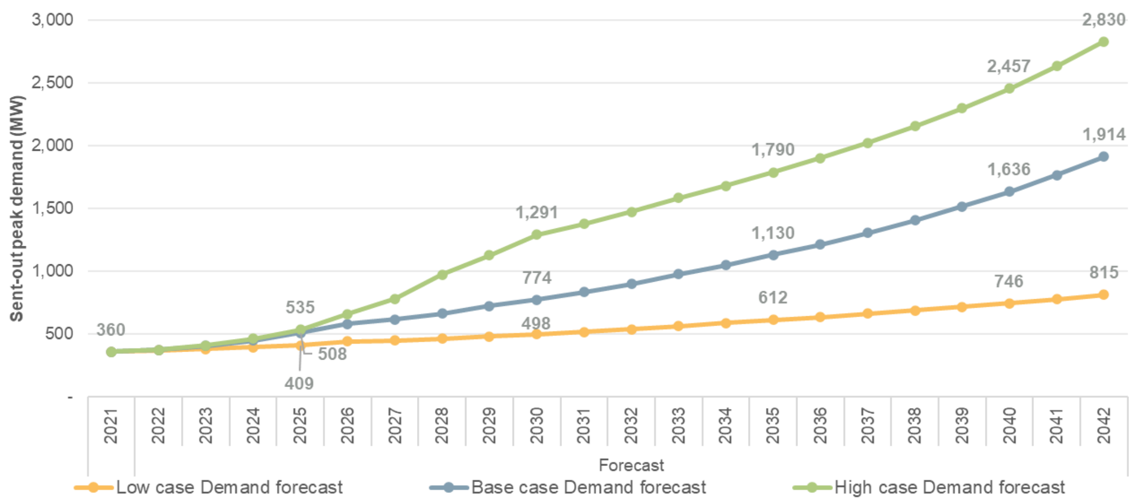


Figure 1.8.3: 2022-2042 Peak demand forecast

Source: ECA analysis

The dynamics of growth of peak demand are almost identical to those of energy demand as the consumers' mix is expected to remail relatively stable. The rapid projected peak demand increases in 2021-2030 for the base and high case scenarios would be a challenge for the transmission system and generation capacity in the country. Figure shows the growth rates of the peak demand by period and by scenario.

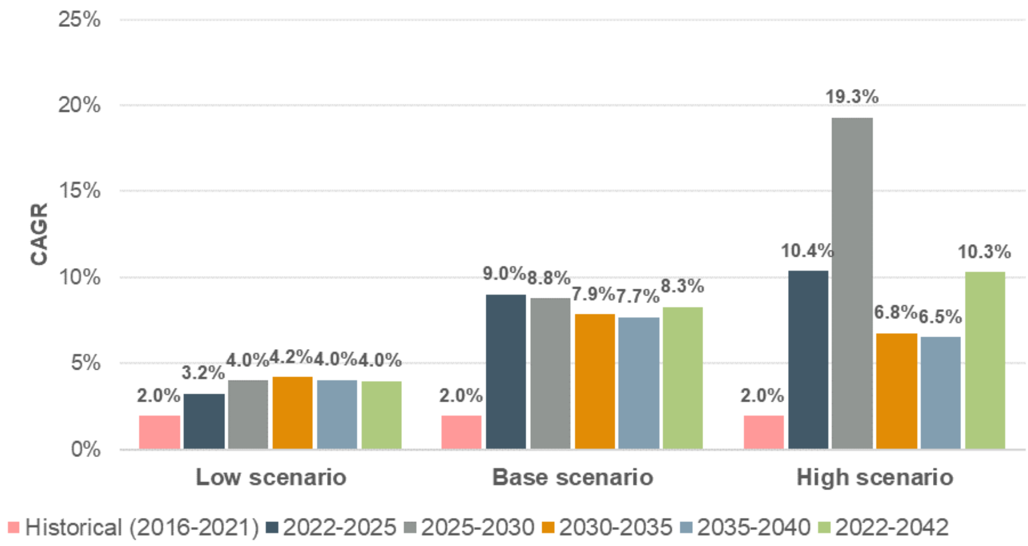


Figure 1.8.4 Peak demand annual growth

Source: ECA analysis

8.3 Demand forecast by economic activity

While the country-level results presented in Section 8.2 provide the aggregate demand for the power sector including losses, this section focuses on how this demand is formed. Electricity sales forecasts were developed for each economic activity[13] for each scenario. Economic activities were grouped in the following categories: Residential, Commercial, and Industrial (including agriculture). Figure showcases the increasing demand of the residential sector in the base and high case scenarios, resulting from electrification targets.

[13] Economic activities were grouped in the following categories three categories: Residential, Commercial, and Industrial (including agriculture) – see section 1.2.1.

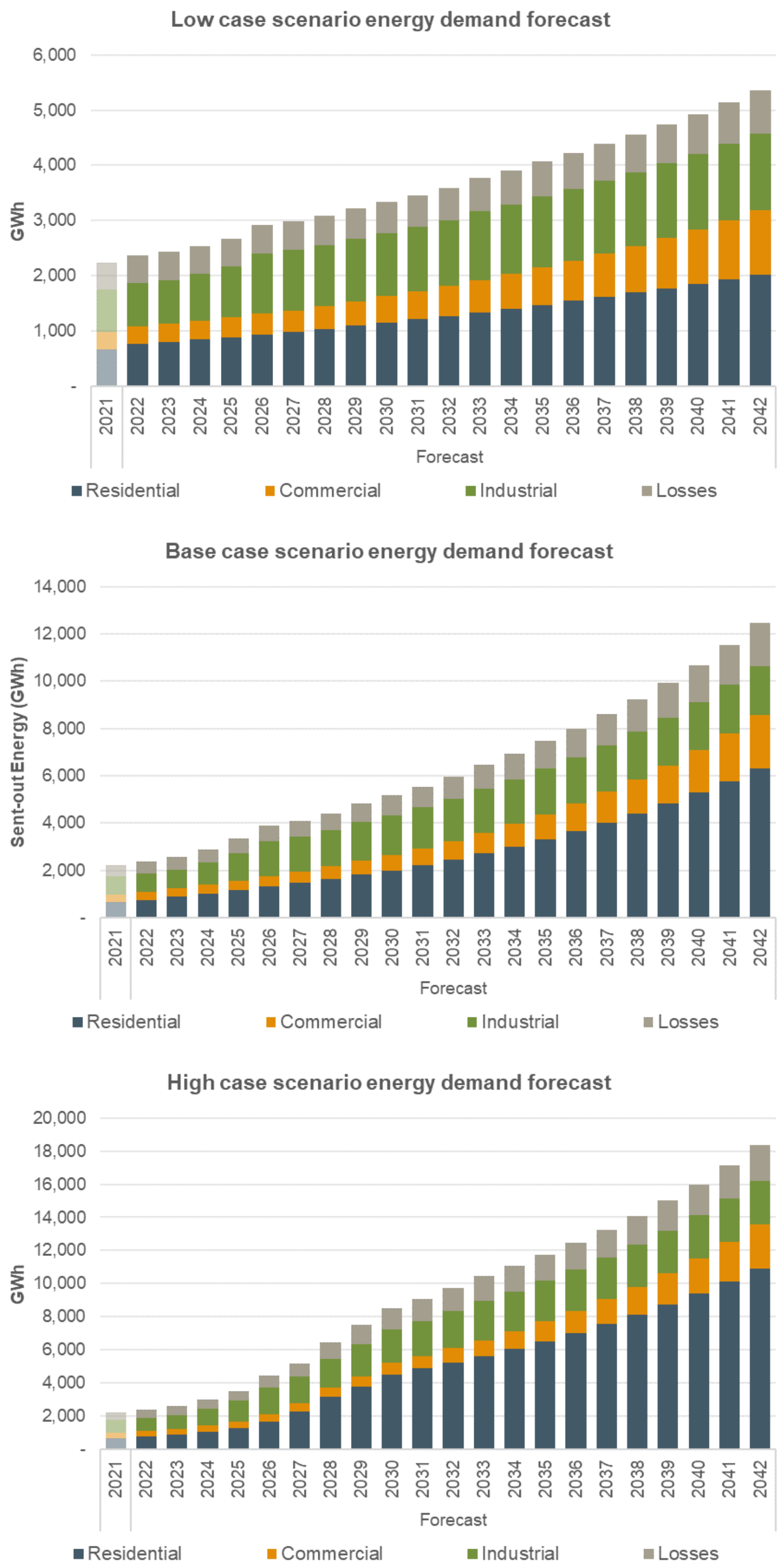


Figure1.8.5 Energy demand forecast by consumer category

Source: ECA Analysis

In the overall split of demand, the residential sector increases its share, as seen in Figure , while the industrial sector holds the second largest share of demand on average.

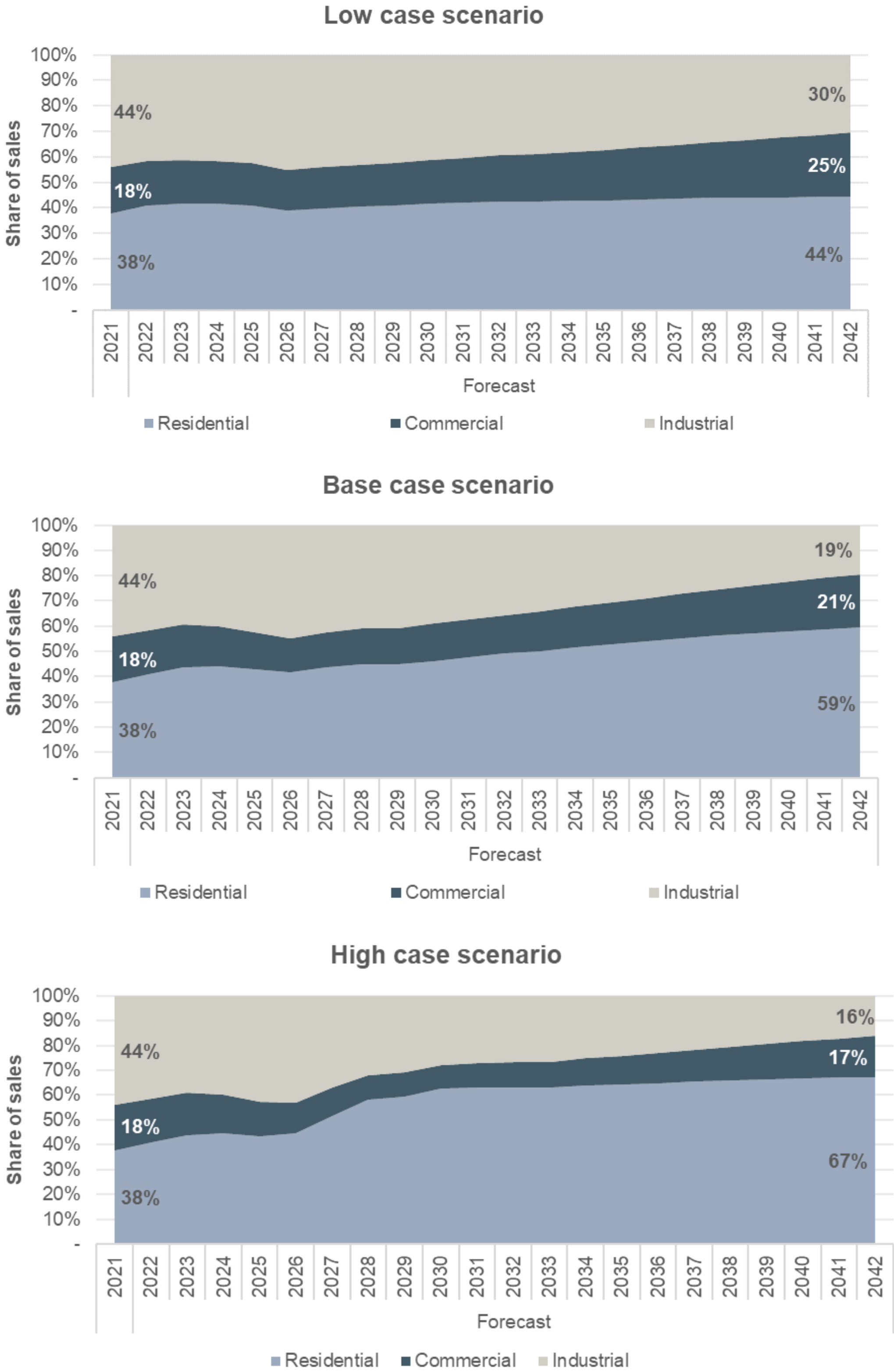


Figure 1.8.6: Split of energy demand by customer category

Source: ECA Analysis

8.3.1 Residential demand

Residential demand will reach between 44% and 67% of overall demand in the 2022-2042 period. Figure 1 showcases the energy demand forecast of domestic consumers compared to historical data as well as the 2017 IRP base case residential demand forecast. While the base case scenario contemplates a maximum 150,000 new connections being added annually, the high case scenario forecasts values reaching almost 900,000 new connections in 2028 driven by the 2030 100% electrification target. From 2030 onwards, the main determinant of growth for the residential sector is the increase in the average consumption per household driven by the assumed economic growth and increases in households purchasing power.

By 2042, energy sales in the low case scenario are expected to grow by over 200% to 2,028 GWh; for the base case scenario the increases surpass 850% to reach 6,319 GWh; whereas the high case scenario expects residential sales reach levels 16 times the 2021 value, reaching 10,892 GWh.

As can be seen, all scenarios remain at lower levels than the base case scenario of the 2017 IRP demand forecast. The target electrification rates in the 2017 IRP demand forecast are similar to the ones contemplated in the base case scenario. However, the electrification of customers foreseen in the 2017 IRP demand forecast did not materialise between 2016 and 2021. Additionally, economic growth had slowed down during the same period due to COVID-19 pandemic which was not foreseen in the 2017 IRP demand forecast study.

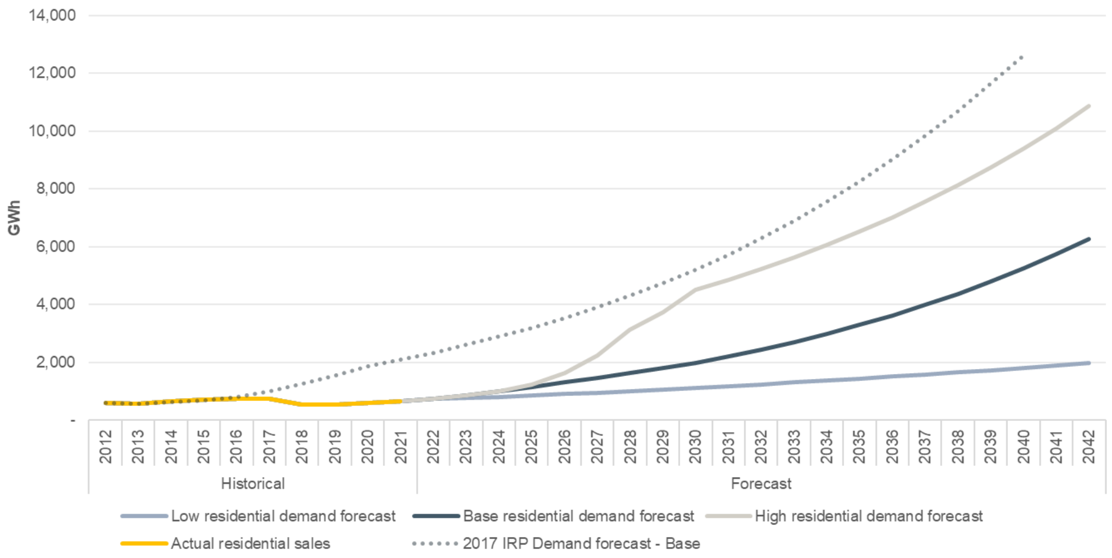


Figure 1.8.7: Domestic sales forecast

Source: ECA analysis

Similar to the overall demand forecast, domestic demand is expected to have higher growth rates in the first half of the forecasting period with annual growth expected to reach levels of between 7.8% and 18% in 2021-2025, and 5.2% and 28.6% in 2025-2030 (see Figure). Over the forecasting period, the annual growth rates for the three scenarios are 5.5%, 11.3%, and 14.3% respectively.

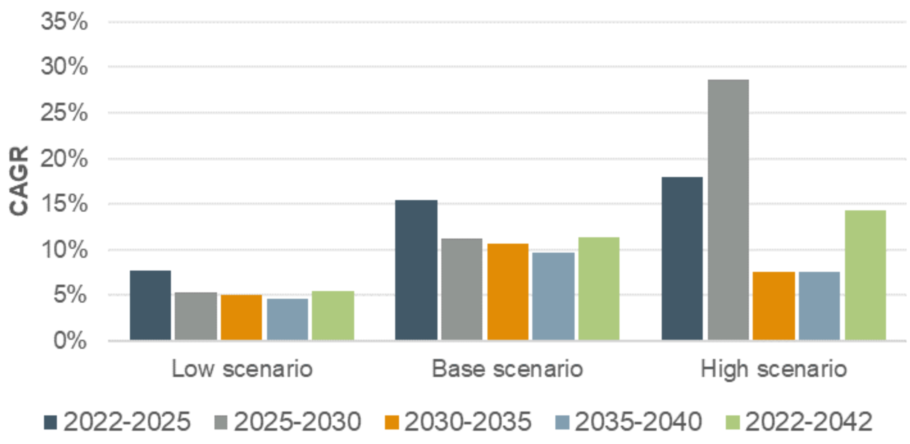


Figure 1.8.8: Residential sales average annual growth

Source: ECA analysis

8.3.2 Commercial demand

Commercial sales forecast is expected to surpass the expectations from the 2017 IRP base case demand forecast for commercial consumers. There are three key assumptions that define the commercial sales forecast:

- Anticipated economic growth – For all scenarios, GDP per capita is expected to increase over time.
- Urbanisation and business densification – For the base and the high case scenarios, the positive economic outlook is also expected to increase the demand for office space, resulting in an increase of commercial connections. In the low case scenario, this is increase in demand is expected to be limited, as the economic effect of the Covid-19 pandemic leaves long-lasting effects in the demand for office space in urban areas, thus limiting the overall energy demand growth for the sector.
- Commercial electricity tariffs – For all scenarios, the price elasticity of demand is expected to start at a relatively high level of -0.21, meaning that a 1% increase in tariff will decrease demand by 0.21%. It is expected that this effect will decrease over time as businesses adopt the use of electricity for their productive activities, reducing the incentive to reduce consumption if tariffs increase. Therefore, by 2042 the price elasticity of demand is assumed to decrease to -0.08, as seen in other countries with more developed commercial sectors, such as South Africa or Ethiopia.

Figure illustrates the commercial sector sales forecast for the 2022-2042 period. The low case scenario underperforms the 2017 IRP base case demand forecast, reaching 1,158 GWh by 2042. On the other hand, the base and high case scenarios reach levels of 2,249 GWh and 2,701 GWh, vastly outperforming the 2017 IRP demand forecast across the entire forecasting period.

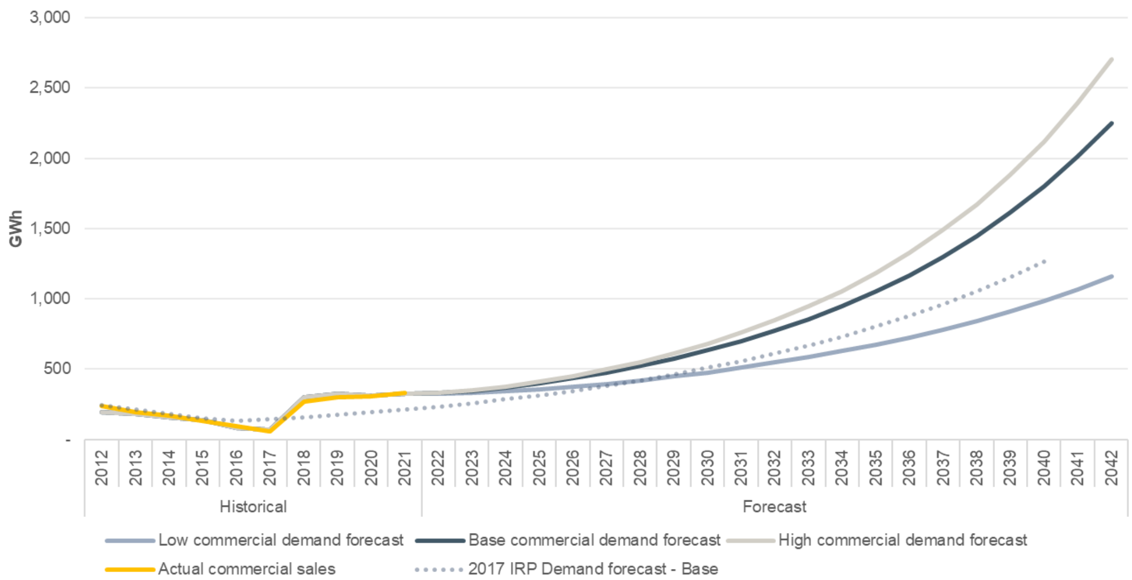


Figure 1.8.9 Commercial sales forecast

Source: ECA analysis

It is expected that growth will accelerate towards the end of the period with growth rates ranging from 2.6%-6.3% in 2021-2025, to 7.9%-12.4% in 2035-2040. As shown in Figure 1.8.10, the overall annual growth of the base case and high case scenarios (9.7% and 10.6% respectively) outpaces the growth expected in the low case scenario at 6.3%.

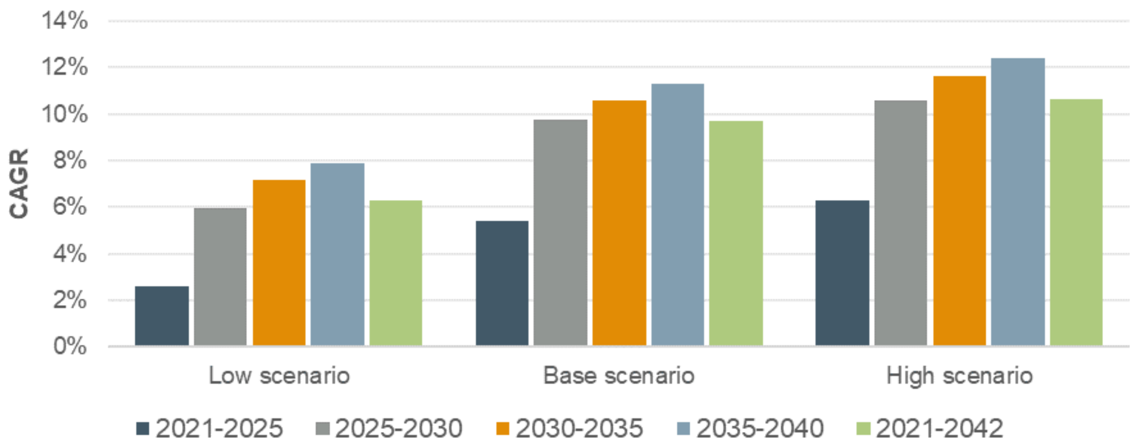


Figure 1.8.10 : Commercial sales average annual growth

Source: ECA analysis

8.3.3 Industrial sales

As can be seen in Figure , industrial sales are expected to reach 1,395 GWh, 2,075 GWh, and 2,623 GWh in the low, base, and high case scenarios respectively by 2042.

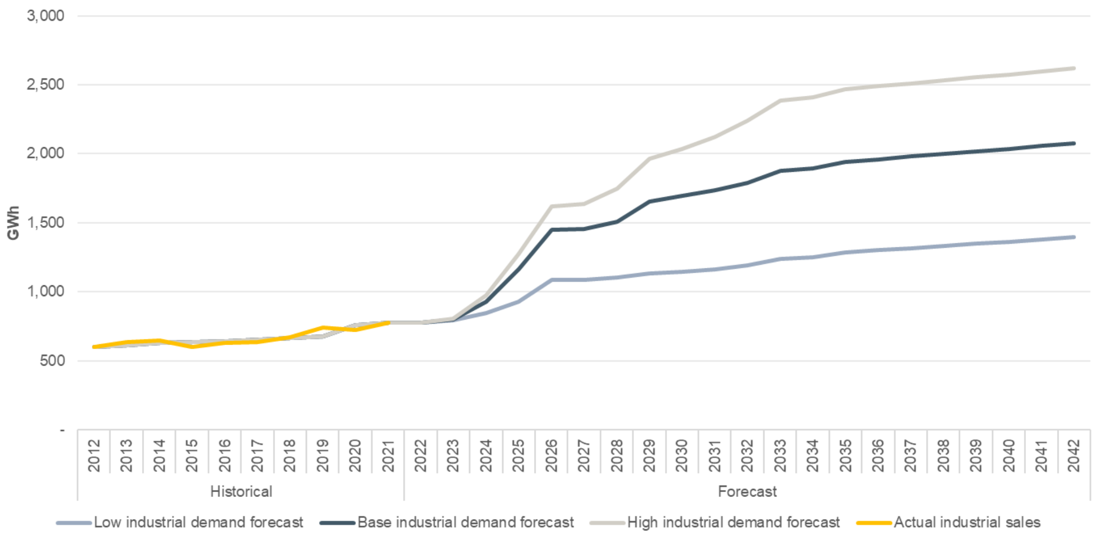


Figure 1.8.11: Industrial sales forecast

Source: ECA analysis

For all scenarios, the net impact (of New projects + Expansions – Closures - Self-Generation) of large customers is expected to be positive, reaching an extra 349 GWh, 974 GWh and 1,473 GWh in 2042 for the low, base and high case scenarios respectively.

The annual growth rates for the industrial sector, seen in Figure, are modest and mainly driven by large customers plans. During the 2021-2025 period, before most self-generation is expected to start, growth rates are considerably higher (4.6% to 13.2%) compared to the period immediately after (4.3%-9.8%), when self-generation is mostly adopted. In the long-term, growth becomes solely determined by GDP growth and a few expansion plans, reaching levels of less than 2% across scenarios. For the entire forecasting period, only the high case scenario results in an annual growth rate higher than 5%, compared to 2.8% and 4.8% for the base case and low case scenarios.

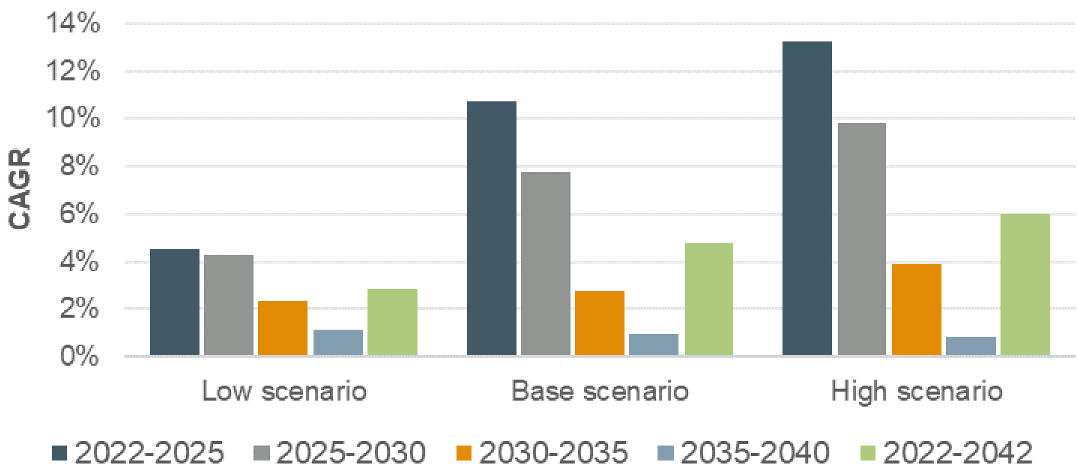


Figure 1.8.12: Industrial sales average annual growth

Source: ECA analysis

8.4 Demand forecast by region

One of the main trends that is expected to become relevant in the coming years, is the increasing share of demand by the North region (see Table), with no significant changes in the balance between the South and Central regions. The evolution of regional share in demand can be summarized as follows:

- North region – Expected to benefit from relatively high urbanisation rate growths, high initial share of new rural connections, as well as a rapidly increasing number of households from falling household sizes.
- Central region – While overall growth in the number of households is limited compared to the North region, increasing urbanization of the Lilongwe area results in higher average consumption.
- South region – Energy demand in this region is expected to benefit from the expansion plans of large customers, as well as from relatively stable household sizes and urbanization growth rates.

Table 1.8.1 Share of energy demand by region

Scenario	Region	2022	2025	2030	2035	2040	2042
Low case	**North**	10%	9%	12%	13%	13%	13%
	Central	41%	41%	40%	40%	41%	41%
	South	49%	50%	48%	47%	46%	46%
Base case	**North**	10%	10%	13%	13%	13%	13%
	Central	41%	41%	38%	39%	41%	42%
	South	49%	49%	49%	48%	46%	45%
High case	**North**	10%	10%	13%	13%	13%	13%
	Central	41%	41%	40%	40%	42%	42%
	South	49%	49%	47%	47%	45%	45%

Source: ECA analysis

8.4.1 North region

While the North region represents the smallest share of overall demand, it presents the largest growth rates in the forecasting period. As can be seen in Figure 1, energy demand is expected to grow from 213 GWh in 2021 to 676 GWh, 1,575 GWh, and 2,345 GWh for the low, base and high case scenarios respectively, representing annual increases of between 5.6% and 12.1%. Peak demand is also expected to grow rapidly from 58 MW in 2021, reaching 184 MW, 429 MW, and 638 MW by 2042 respectively.

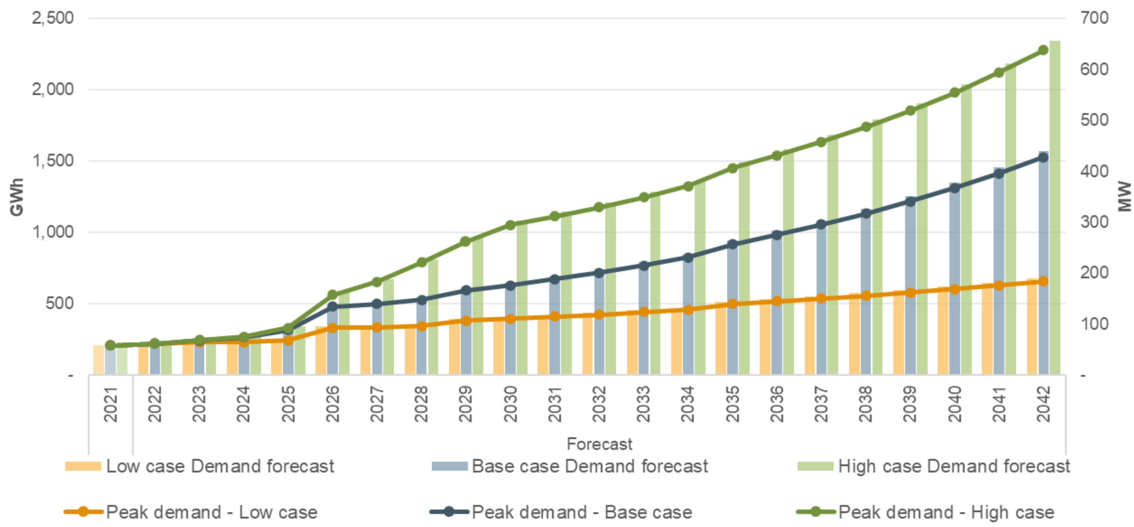


Figure 1.8.13: Demand forecast for the North region

Source: ECA analysis

8.4.2 Central region

Most of the growth expected in the Central region is a result of relatively rapid urbanization in the Lilongwe area, which increases average household consumption. Energy demand is expected to increase from 926 GWh in 2021, to 2,209 GWh, 5,215 GWh, and 7,789 GWh for each scenario by 2042, representing annual increases of between 4.2% and 10.7%. For peak demand, it is expected that it will increase from 151 MW in 2021 to 356 MW, 846 MW, and 1,268 MW for each scenario (see Figure 1).

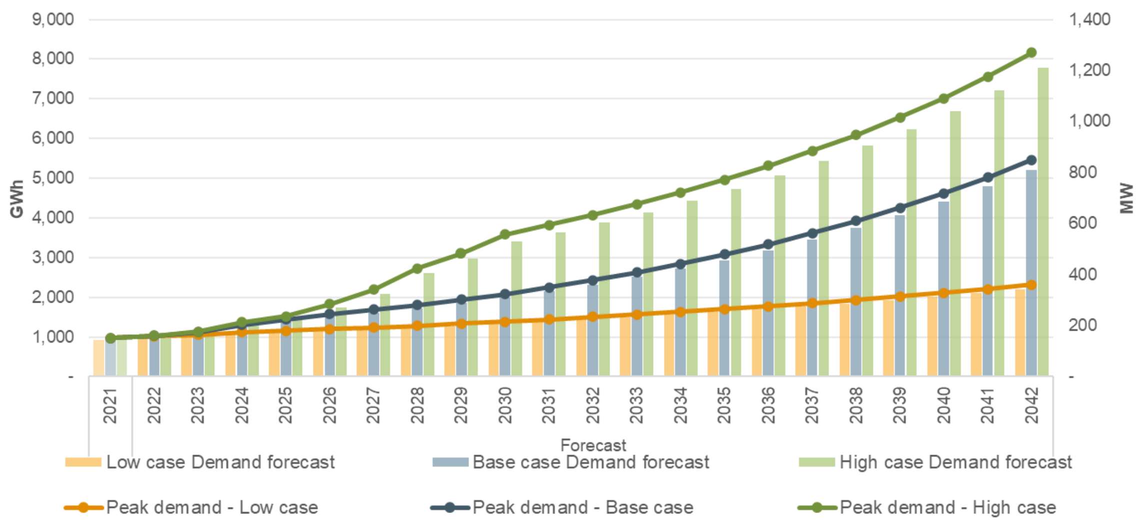


Figure 1.8.14: Demand forecast for the Central region

Source: ECA analysis

8.4.3 South region

The rate of the demand growth in the South region is expected to reduce over time, however, the South region is still expected to experience sustained growth in demand. As shown in Figure, energy demand in this region is expected to grow from 1,119 GWh in 2021, to 2,477 GWh, 5,668 GWh, and 8,237 GWh in the low, base, and high case scenarios respectively (with annual growth rates of between 3.9% and 10%). Similarly, peak demand is expected to grow from 264 MW in 2021, to 585 MW, 1,339 MW, and 1,946 MW for each scenario.

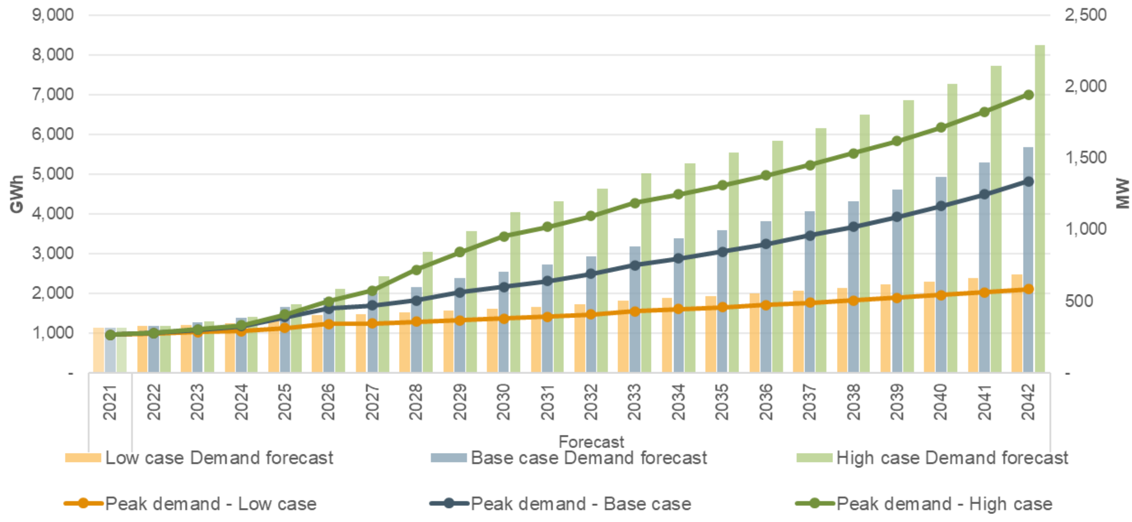


Figure 1.8.15: Demand forecast for the South region

Source: ECA analysis

8.5 Impact of DSM in the Demand Forecast

As mentioned in Section 7, we have incorporated the following DSM in this analysis:

- introduction of MEPR and/or labelling scheme,
- incentives for installation of solar water heaters,
- incentives for AC substitution,
- incentives for Fan substitution, and
- incentives for lightbulb substitution.

To model the impacts the above measures will have on the demand forecast, the following assumptions were considered (see Table). While the introduction of MEPR is expected to have a long-lasting impact after implementation, appliance substitution and the incentives for the adoption of solar water heaters will have a lasting impact if support is maintained above the scheduled implementation period. The share of new customers adopting these measures is expected to decrease after implementation, reducing the penetration rate over time.

Table 1.8.16 Assumptions for the modelling of DSM

Measure	Sector affected	Impact on energy and/or peak demand	Penetration rate
Introduction of MEPR and/or labelling scheme	All sectors	• 0.07 MWh per connection per year	• **Low:** 25% during the implementation period and beyond • **Medium:** 50% during the implementation period and beyond • **High:** 100% during the implementation period and beyond
Incentives for installation of solar water heaters	Residential Commercial	• 0.625 MWh per connection per year • 0.0013 MW per connection per year	• **Low:** increasing to 1.04% by 2027, decreasing to 0.36% by 2042 • **Medium:** increasing to 1.55% by 2027, decreasing to 0.70% by 2042 • **High**: increasing to 2.07% by 2027, decreasing to 1.22% by 2042
Lightbulb substitution	Commercial	• 0.004 MWh per connection per year • 0.03 MW per connection per year	• **Low:** increasing to 46% by 2027, decreasing to 11% by 2042 • **Medium:** increasing to 69% by 2027, decreasing to 34% by 2042 • **High:** increasing to 92.2% by 2023 and remaining at that level
AC unit substitution	Commercial	• 0.0915 MWh per connection per year • 0.000052 MW per connection per year	• **Low:** increasing to 4.6% by 2027, decreasing to 1.1% by 2042 • **Medium:** increasing to 6.9% by 2027, decreasing to 3.4% by 2042 • **High:** increasing to 9.2% by 2023 and remaining at that level
Fan substitution	Residential Commercial	• 0.00007 MWh per connection per year • 0.00003 MW per connection per year	• **Low:** 0% in the entire forecasting period • **Medium:** 0.1% in the entire forecasting period • **High:** 0.2% in the entire forecasting period

Source: ECA analysis

Under these considerations, and assuming the base case demand forecast, Figure 1 presents the expected energy and peak demand impact of all the measures under different penetration rates. As can be seen, under a low penetration rate annual savings amount to 113.9 GWh and 30 MW in

2042; with a medium penetration rate this savings increase to 256.3 GWh and 74 MW, while a high penetration rate would result in savings of 564 GWh and 168 MW.

Figure 1.8.17: DSM impact on the base case demand forecast

Source: ECA analysis

8.5.1 Net-metering scheme scenarios

A net-metering scheme has been proposed in Malawi, which allows the export of energy generated in solar rooftop systems to the grid. For the purpose of this analysis, we assume that these systems would be adopted by a small percentage of the residential population who can afford the relatively high initial capital costs.

Three scenarios were considered for potential penetration rates of rooftop solar PV under the net-metering scheme:

- **Low penetration rate:** Rooftop solar systems adopted by 0.1% of residential connections (1,000 per million connections), reaching this level in 2030 and remaining at that level until the end of the forecasting period.

- **Medium penetration rate:** Rooftop solar systems adopted by 0.25% of residential connections (2,500 per million connections), reaching this level in 2030 and remaining at that level until the end of the forecasting period.

- **High penetration rate:** Rooftop solar systems adopted by 0.5% of residential connections (5,000 per million connections), reaching this level in 2030 and remaining at that level until the end of the forecasting period.

Given that peak demand occurs during the late afternoon/early night, we expect no impact on peak demand. The savings for each scenario by penetration rate are presented in Table. Nonetheless, it is important to mention that these are just approximations, the real impact will depend on a deeper analysis on the number of beneficiaries, accessibility of the scheme, and the availability of suitable rooftop solar systems at an affordable price.

Table 1.8.2: Projected energy savings from rooftop solar systems (in GWh)

Scenario	Low penetration rate	Medium penetration rate	High penetration rate
Low case scenario	• 2025: 0.1 • 2030: 0.4 • 2035: 0.4 • 2042: 0.5	• 2025: 0.2 • 2030: 0.9 • 2035: 1.1 • 2042: 1.3	• 2025: 0.4 • 2030: 1.8 • 2035: 2.2 • 2042: 2.7
Base case scenario	• 2025: 0.1 • 2030: 0.7 • 2035: 1.1 • 2042: 1.8	• 2025: 0.3 • 2030: 1.8 • 2035: 2.8 • 2042: 4.5	• 2025: 0.6 • 2030: 3.6 • 2035: 5.5 • 2042: 8.9
High case scenario	• 2025: 0.1 • 2030: 1.7 • 2035: 2.1 • 2042: 2.6	• 2025: 0.3 • 2030: 4.3 • 2035: 5.2 • 2042: 6.4	• 2025: 0.7 • 2030: 8.7 • 2035: 10.3 • 2042: 12.8

Source: ECA analysis

Annexes

A1 Historical power shortages

The backbone of Malawi's power system was, for many years, a series of small hydropower plants on the Shire River at Nkula and Tedzani that were developed between the 1960s and 1990s. In the year 2000 the first phase of the Kapichira hydropower plant was commissioned, also on the Shire River, with a capacity of 64 MW. No other new generation plants were implemented in the country until 2013, when a second phase at Kapichira of another 64 MW was commissioned.

Since 2013 some of the units at Nkula and Tedzani have been refurbished and upgraded but, apart from some new diesel units, no other substantial capacity has been added.

Malawi's interconnected system has a total connected net available capacity of 503 MW (as of 2019). It comprises 379 MW of hydro plants and 123 MW of reciprocating engines operating on diesel fuel. Of the reciprocating engines, 45 MW are EGENCO owned and were installed in recent years and are therefore in good condition. The remaining 78 MW of reciprocating engines were rented under a three-year contract with Aggreko, which expired in 2020 but was extended. In addition, 20 MW is imported from Zambia to parts of Lilongwe and Mchinji as an island supply (which is temporarily disconnected from ESCOM's network) and is not included in Malawi's load discussed above.

The following figure shows the total net available capacity in 2019 and the actual peak demand of 2018 against the stock of the available capacity in 2019. Even though the available installed capacity was higher than the peak demand in the past decade, the generation fleet was unable to meet the demand for electricity in drought years. With the exception of the small Wovwe and Ruo-Ndiza micro hydro plants, all of the hydro capacity is sited along the Shire river in the south of country and the annual output is sensitive to hydrological conditions. On average, the annual capacity factor of ESCOM's hydro generation is approximately 67%, but this fluctuates very significantly from year to year.

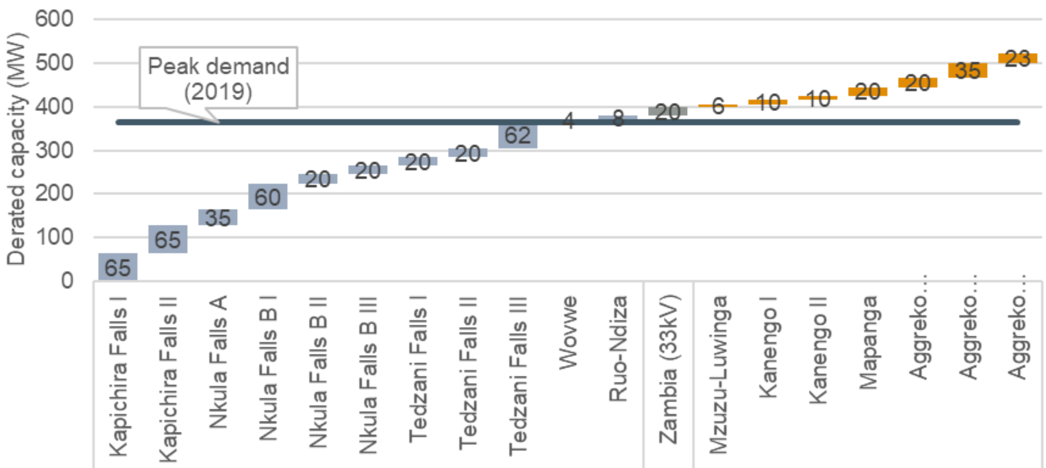


Figure 1.8.18 Total share of existing net available capacity, 2019

Source: ESCOM and the Integrated Resource Plan

From 2015 to 2019, Malawi has suffered chronic power shortages and electricity consumers have faced severe and frequent interruptions of power supply mainly due to very low water levels on Lake Malawi and low outflows on the Shire River following prolonged drought conditions. The following figure shows historical Lake Malawi water level variations from 2010 to 2019-20. Water levels have been at the lowest levels from 2015 to 2019.

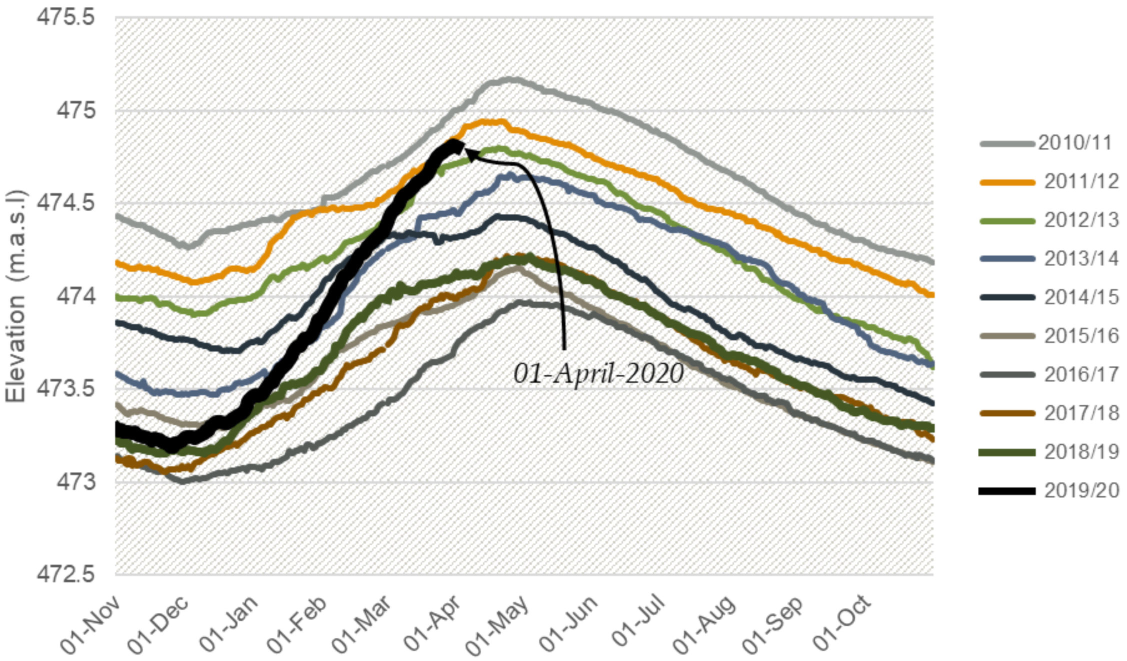


Figure 1.8.19: Lake Malawi mean levels from 2010 to 2019-20

Source: EGENCO Malawi, 2020

A2 Household appliance electricity usage

Table 1.A2.1: Consumption of household appliances

Item	No of items	Capacity *(W per month)*	Hours used *(h per day)*	Days used *(days per month)*	Energy used *(kWh per month)*
Light					
Incandescent bulbs	4	40	6	30	28.8

Item	No of items	Capacity *(W per month)*	Hours used *(h per day)*	Days used *(days per month)*	Energy used *(kWh per month)*
Fluorescent tube lamps	4	10	6	30	7.2
TV					
32” LED TV	1	41	3	30	3.6
25” color TV	1	150	3	30	13.5
19” color TV	1	70	3	30	6.3
12” black and white TV	1	20	3	30	1.8
Other					
Radio	1	4	3	30	0.4
Iron	1	1,000	2	4	8
Kettle	1	2,200	0.1	10	2.2
Hotplate	1	1,000	3	30	90
Fridge (small)	1	100	4.7	30	14.3
Fan	1	10	3	10	0.3
Laptop	1	35	2	30	2.1
Phone charging	1	5	1	30	0.15

Source: http://www.energuide.be/en/questions-answers/how-much-energy-do-my-household-appliances-use/71/, http://www.greatbowden.org/documents/TypicalEnergyUsageforHouseholdAppliances.pdf ,http://www.wholesalesolar.com/solar-information/how-to-save-energy/power-table

A3 Annual input assumptions

Table 1.A3.1: Population forecast summary

Population			
Year	**Urban**	**Rural**	**Total**
2021	3,063,437	15,835,004	18,898,441
2022	3,150,488	16,201,404	19,351,892
2023	3,238,855	16,570,656	19,809,511
2024	3,328,427	16,942,141	20,270,568
2025	3,419,080	17,315,182	20,734,262
2026	3,510,991	17,690,644	21,201,635
2027	3,604,351	18,069,436	21,673,787
2028	3,699,054	18,450,970	22,150,024

Population			
Year	Urban	Rural	Total
2029	3,794,994	18,834,667	22,629,661
2030	3,892,055	19,219,912	23,111,967
2031	3,990,434	19,607,638	23,598,072
2032	4,090,344	19,998,844	24,089,188
2033	4,191,696	20,393,031	24,584,727
2034	4,294,396	20,789,695	25,084,091
2035	4,398,336	21,188,261	25,586,597
2036	4,503,675	21,589,459	26,093,134
2037	4,610,593	21,994,099	26,604,692
2038	4,719,004	22,401,709	27,120,713
2039	4,828,815	22,811,796	27,640,611
2040	4,939,915	23,223,794	28,163,709
2041	5,052,453	23,638,364	28,690,817
2042	5,166,606	24,056,276	29,222,882

Source: 2018-2050 Population Projections

Table 1.A3.2: Number of households and household size

Year	Number of households	Household size	Household size – North	Household size – Central	Household size – South
		persons per household			
2021	4,354,479	4.34	4.7	4.3	4.3
2022	4,479,605	4.32	4.7	4.3	4.3
2023	4,606,863	4.30	4.7	4.3	4.3
2024	4,736,114	4.28	4.6	4.3	4.2
2025	4,867,198	4.26	4.6	4.3	4.2
2026	5,000,386	4.24	4.6	4.2	4.2
2027	5,135,968	4.22	4.5	4.2	4.2
2028	5,273,815	4.20	4.5	4.2	4.2
2029	5,413,794	4.18	4.5	4.2	4.2
2030	5,555,761	4.16	4.4	4.2	4.2
2031	5,700,017	4.14	4.4	4.1	4.2
2032	5,846,890	4.12	4.4	4.1	4.2
2033	5,996,275	4.10	4.4	4.1	4.2
2034	6,148,062	4.08	4.3	4.1	4.1

Year	Number of households	Household size	Household size – North	Household size – Central	Household size – South
		persons per household			
2035	6,302,117	4.06	4.3	4.1	4.1
2036	6,458,697	4.04	4.3	4.0	4.1
2037	6,618,083	4.02	4.2	4.0	4.1
2038	6,780,178	4.00	4.2	4.0	4.1
2039	6,944,877	3.98	4.2	4.0	4.1
2040	7,112,048	3.96	4.1	4.0	4.1
2041	7,281,933	3.94	4.1	3.9	4.1
2042	7,454,817	3.92	4.1	3.9	4.1

Source: Malawi Statistical Yearbook 2020 and 2018-2050 Population Projections

Table 1.A3.3: Average consumption per household (in kWh per month)

Scenario	Low scenario			Base scenario			High scenario		
	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural	Total
2021	160	47	120	160	47	120	160	47	120
2022	160	47	114	160	47	112	160	47	112
2023	160	48	113	160	48	103	162	48	103
2024	161	48	113	162	48	98	165	49	98
2025	163	48	113	165	49	96	170	50	93
2026	164	49	112	169	50	95	175	52	89
2027	164	49	112	174	52	96	181	54	86
2028	167	50	113	178	53	96	188	56	86
2029	169	50	114	183	54	97	195	58	88
2030	172	51	115	188	56	99	203	60	94
2031	175	52	116	194	57	100	212	63	97
2032	178	53	117	199	59	102	221	65	101
2033	181	54	119	205	61	104	230	68	105
2034	183	54	120	211	63	106	239	71	109
2035	187	55	122	217	64	108	250	74	114
2036	190	56	123	223	66	110	260	77	119
2037	193	57	125	230	68	113	272	81	124

Scenario	Low scenario			Base scenario			High scenario		
	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural	Total
2038	196	58	126	237	70	115	283	84	129
2039	200	59	128	244	72	118	296	88	134
2040	203	60	130	252	75	121	309	92	140
2041	207	61	132	259	77	124	322	96	146
2042	211	63	134	268	79	127	337	100	153

Source: ECA

Table 1.A3.4: Electrification targets

	Number of residential connections			Electrification rate		
Scenario	Low	Base	High	Low	Base	High
2021	459,776	459,776	459,776	11%	11%	11%
2022	549,600	549,600	549,600	12%	12%	12%
2023	584,600	699,600	699,600	13%	15%	15%
2024	619,600	849,600	890,547	13%	18%	19%
2025	654,600	999,600	1,122,441	13%	21%	23%
2026	689,600	1,149,600	1,541,637	14%	23%	31%
2027	724,600	1,279,600	2,161,668	14%	25%	42%
2028	759,600	1,409,600	3,056,398	14%	27%	58%
2029	794,600	1,539,600	3,563,292	15%	28%	66%
2030	829,600	1,669,600	4,038,622	15%	30%	73%
2031	864,600	1,834,001	4,182,878	15%	32%	73%
2032	899,600	2,005,426	4,329,751	15%	34%	74%
2033	934,600	2,184,004	4,479,136	16%	36%	75%
2034	969,600	2,369,853	4,630,922	16%	39%	75%
2035	1,004,600	2,563,072	4,784,978	16%	41%	76%
2036	1,039,600	2,763,913	4,941,557	16%	43%	77%
2037	1,074,600	2,972,666	5,100,943	16%	45%	77%
2038	1,109,600	3,189,464	5,263,039	16%	47%	78%
2039	1,144,600	3,414,425	5,427,738	16%	49%	78%

	Number of residential connections			Electrification rate		
Scenario	**Low**	**Base**	**High**	**Low**	**Base**	**High**
2040	1,179,600	3,647,650	5,594,908	17%	51%	79%
2041	1,214,600	3,889,426	5,764,794	17%	53%	79%
2042	1,249,600	4,140,081	5,937,678	17%	56%	80%

Source: ESCOM Fourth Base submission, SE4ALL Electrification Plan. Note the electrification targets of the base case scenario vary slightly due to differences in the reporting period in the Guidelines for Implementation of the National Electrification Programme

Table 1.A3.5: Real GDP forecast by sector (in billion MWK)

	Low scenario				Base scenario				High scenario			
	Total GDP	Agriculture GDP	Industry GDP	Services GDP	Total GDP	Agriculture GDP	Industry GDP	Services GDP	Total GDP	Agriculture GDP	Industry GDP	Services GDP
2021	7,499	1,696	1,461	3,909	7,499	1,696	1,461	3,909	7,499	1,696	1,461	3,909
2022	7,566	1,707	1,472	3,948	7,566	1,707	1,472	3,948	7,566	1,707	1,472	3,948
2023	7,755	1,737	1,503	4,055	7,755	1,737	1,503	4,055	7,808	1,745	1,511	4,085
2024	8,004	1,776	1,543	4,195	8,004	1,776	1,543	4,195	8,113	1,793	1,560	4,257
2025	8,260	1,815	1,584	4,341	8,316	1,824	1,593	4,373	8,470	1,848	1,617	4,461
2026	8,524	1,856	1,626	4,492	8,682	1,880	1,651	4,582	8,851	1,906	1,678	4,678
2027	8,737	1,888	1,659	4,614	9,072	1,939	1,712	4,805	9,249	1,966	1,740	4,907
2028	9,078	1,940	1,713	4,809	9,481	2,000	1,776	5,040	9,721	2,036	1,814	5,178
2029	9,432	1,993	1,769	5,012	9,907	2,063	1,843	5,286	10,217	2,108	1,891	5,465
2030	9,800	2,047	1,826	5,224	10,353	2,128	1,912	5,544	10,738	2,183	1,971	5,767
2031	10,182	2,103	1,885	5,445	10,819	2,195	1,983	5,815	11,286	2,261	2,054	6,086
2032	10,579	2,160	1,946	5,676	11,306	2,264	2,057	6,098	11,861	2,342	2,141	6,423
2033	10,992	2,219	2,009	5,916	11,815	2,335	2,134	6,396	12,466	2,425	2,232	6,778
2034	11,420	2,279	2,074	6,166	12,346	2,408	2,214	6,708	13,102	2,512	2,326	7,153
2035	11,866	2,341	2,141	6,427	12,902	2,484	2,296	7,036	13,770	2,601	2,425	7,549
2036	12,329	2,405	2,210	6,699	13,482	2,562	2,382	7,379	14,472	2,694	2,527	7,967
2037	12,809	2,471	2,282	6,982	14,089	2,643	2,471	7,740	15,210	2,790	2,634	8,408
2038	13,309	2,538	2,356	7,278	14,723	2,726	2,563	8,118	15,986	2,889	2,746	8,873
2039	13,828	2,607	2,432	7,586	15,386	2,812	2,659	8,514	16,801	2,992	2,862	9,364
2040	14,367	2,678	2,511	7,907	16,078	2,900	2,758	8,929	17,658	3,099	2,983	9,882
2041	14,928	2,751	2,592	8,241	16,802	2,991	2,861	9,365	18,559	3,209	3,109	10,429

	Low scenario				Base scenario				High scenario			
	Total GDP	Agriculture GDP	Industry GDP	Services GDP	Total GDP	Agriculture GDP	Industry GDP	Services GDP	Total GDP	Agriculture GDP	Industry GDP	Services GDP
2042	15,510	2,826	2,676	8,590	17,558	3,085	2,968	9,823	19,505	3,324	3,241	11,006

Source: Malawi National Accounts 2017-2022, 2022-2027 IMF real GDP growth forecast

Table1.A3.6: Forecast of average tariff (real terms in MWK/kWh)

Average tariffs (real terms in MWK/kWh)				
Year	Domestic	Commercial	LV Industrial	MV Industrial
2021	39.00	85.30	54.19	47.58
2022	32.94	87.74	45.77	40.19
2023	38.70	90.18	39.29	35.39
2024	56.65	92.63	57.52	51.80
2025	60.22	95.07	61.14	55.07
2026	61.31	97.51	62.25	56.07
2027	62.54	99.95	63.50	57.20
2028	63.79	101.95	64.77	58.34
2029	65.07	103.99	66.07	59.51
2030	66.37	106.07	67.39	60.70
2031	67.70	108.19	68.74	61.91
2032	69.05	110.35	70.11	63.15
2033	70.43	112.56	71.51	64.41
2034	71.84	114.81	72.94	65.70
2035	73.28	117.11	74.40	67.02
2036	74.75	119.45	75.89	68.36
2037	76.24	121.84	77.41	69.72
2038	77.77	124.28	78.96	71.12
2039	79.32	126.76	80.54	72.54
2040	80.91	129.30	82.15	73.99
2041	82.53	131.88	83.79	75.47
2042	84.18	134.52	85.47	76.98

Source: ESCOM forecasted tariffs, ECA assumptions

Table 1.A3.7: Forecast losses

	Low scenario		Base scenario		High scenario	
Year	**Transmission**	**Distribution**	**Transmission**	**Distribution**	**Transmission**	**Distribution**
2021	5.49%	16.71%	5.49%	16.71%	5.49%	16.71%
2022	5.49%	16.71%	5.49%	16.71%	5.49%	16.71%
2023	5.49%	16.71%	5.49%	16.71%	5.49%	16.71%
2024	5.11%	15.54%	5.04%	15.35%	4.98%	14.16%
2025	4.79%	14.59%	4.68%	14.24%	4.56%	11.60%
2026	4.58%	13.95%	4.43%	13.49%	4.28%	11.61%
2027	4.44%	13.51%	4.26%	12.97%	4.09%	11.62%
2028	4.38%	13.32%	4.19%	12.76%	4.01%	11.64%
2029	4.35%	13.13%	4.17%	12.61%	3.93%	11.65%
2030	4.32%	12.93%	4.16%	12.47%	3.84%	11.66%
2031	4.29%	12.74%	4.14%	12.32%	3.76%	11.39%
2032	4.25%	12.55%	4.13%	12.17%	3.67%	11.13%
2033	4.22%	12.35%	4.11%	12.03%	3.59%	10.86%
2034	4.19%	12.16%	4.10%	11.88%	3.51%	10.60%
2035	4.16%	11.97%	4.08%	11.73%	3.42%	10.33%
2036	4.13%	11.77%	4.06%	11.59%	3.34%	10.06%
2037	4.10%	11.58%	4.05%	11.44%	3.25%	9.80%
2038	4.06%	11.39%	4.03%	11.29%	3.17%	9.53%
2039	4.03%	11.19%	4.02%	11.15%	3.08%	9.27%
2040	4.00%	11.00%	4.00%	11.00%	3.00%	9.00%
2041	4.00%	11.00%	4.00%	11.00%	3.00%	9.00%
2042	4.00%	11.00%	4.00%	11.00%	3.00%	9.00%

Source: Loss Reduction Road Map

A4 Statistical results from the regression analysis

A4.1 Commercial sales econometric equation

The statistical results of the econometric analysis for the chosen equations for commercial sales together with a comparison of a historical forecast using the econometric equation against actual sales is shown in the table below.

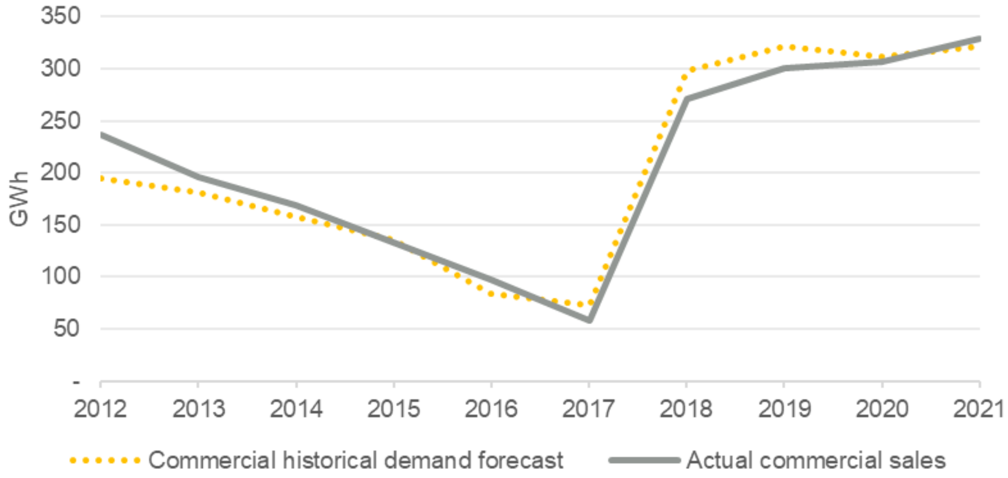
Table 1.A4.1: Statistical results for the commercial sales econometric equation

Regression Statistics	
Multiple R	0.973937
R Square	0.948554
Adjusted R Square	0.936682
Standard Error	0.111135
Observations	17

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2.960407	0.986802	79.89705	1.25E-08
Residual	13	0.160562	0.012351		
Total	16	3.120969			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-0.04651	7.832987	-0.00594	0.995352
LN(Real GDP per capita)	1.045044	0.638795	1.635962	0.125816
LN(Comm Connections)	0.633373	0.043497	14.56141	1.99E-09
LN(Commercial Tariff)	-0.21057	0.069718	-3.02034	0.009846



Source: ECA analysis using ESCOM data

A4.2 LV Industrial sales econometric equation

The statistical results of the econometric analysis for the chosen equations for LV Industrial sales together with a comparison of a historical forecast using the econometric equation against actual sales is shown in the table below.

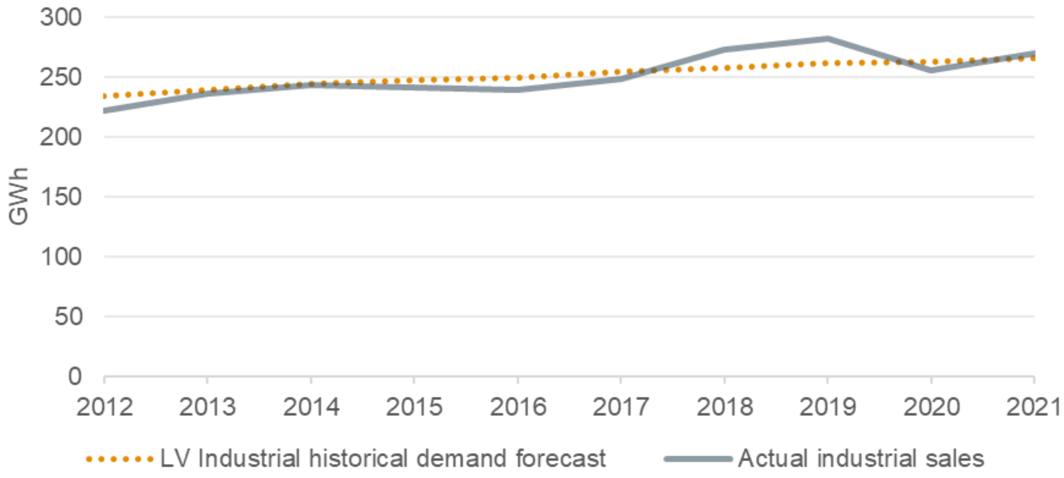
Tableb 1.A4.2 Statistical results for the LV Industrial sales econometric equation

Regression Statistics	
Multiple R	0.863506
R Square	0.745642
Adjusted R Square	0.728685
Standard Error	0.05229
Observations	17

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.120232	0.120232	43.97201	8E-06
Residual	15	0.041014	0.002734		
Total	16	0.161247			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	9.078276	1.539073	5.898535	2.92E-05
LN(Real GDP)	0.348131	0.052499	6.631139	8E-06



Source: ECA analysis using ESCOM data

A4.3 MV Industrial sales econometric equation

The statistical results of the econometric analysis for the chosen equations for MV Industrial sales together with a comparison of a historical forecast using the econometric equation against actual sales is shown in the table below.

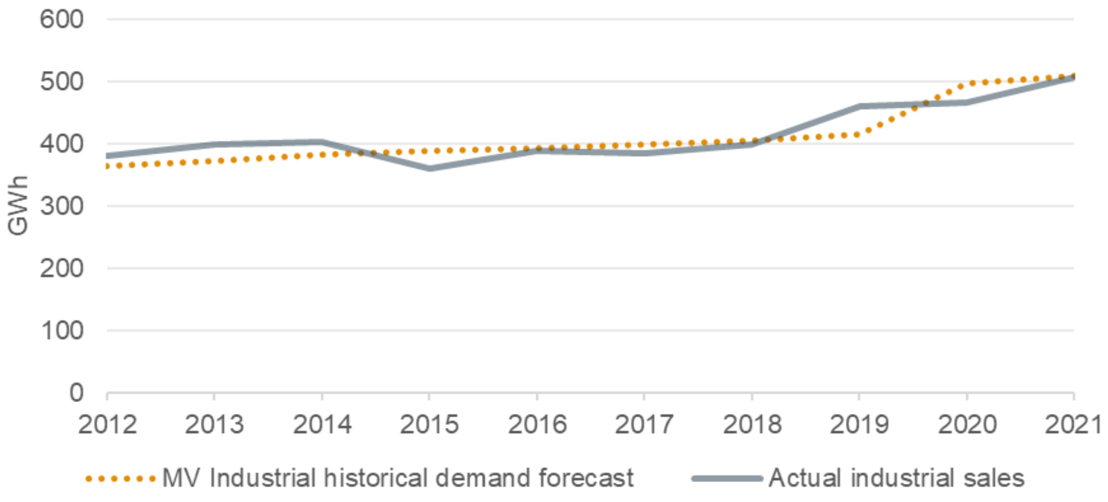
Table 1.A4.3: Statistical results for the MV Industrial sales econometric equation

Regression Statistics	
Multiple R	0.924297
R Square	0.854326
Adjusted R Square	0.844614
Standard Error	0.061564
Observations	17

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.33342	0.33342	87.96944	1.15E-07
Residual	15	0.056853	0.00379		
Total	16	0.390273			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
Intercept	5.074143	1.564504	3.243293	0.005458	1.739482
LN(Industrial GDP)	0.534582	0.056996	9.379202	1.15E-07	0.413096



Source: ECA analysis using ESCOM data

A4.4 Unsuccessful models considered in the analysis

Table 31 compiles the econometric model specifications tested for residential, commercial, and industrial users. In most cases, the specifications proved to have too little statistical significance (ie p-value above 10% for all variables in the equation). For others, highlighted in grey, the equation was deemed to be unreliable due to the inclusion of residential connection data.

Table 1.A4.4 Unsuccessful models considered in the analysis

Dependent Variable	GDP	Sector (Commercial, Agriculutral or Industrial) GDP	GDP per capita	Tariff (Residential, Commercial, or Industrial)	CPI	Lagged dependent variable	Connections (Residential, Commercial or Industrial)	Oil Price
Average consumption per household per year (kWh/year)	x							
			x					
				x				
					x			
						x		
							x	
	x			x				
	x				x			
	x					x		
	x						x	
			x	x				
			x		x			
			x			x		
			x				x	
			x	x		x		
			x	x			x	
			x		x	x		
			x		x		x	
			x			x	x	
				x		x		
				x			x	
				x		x	x	
Commercial sales (kWh)	x							
		x						
			x					
				x				
					x			

Dependent Variable	GDP	Sector GDP (Commercial, Agricultral or Industrial)	GDP or GDP per capita	Tariff (Residential, Commercial, or Industrial)	CPI	Lagged dependent variable	Connections (Residential, Commercial or Industrial)	Oil Price
						x		
							x	
	x			x				
	x				x			
	x						x	
		x		x				
		x			x			
		x				x		
		x					x	
		x		x		x		
			x	x				
			x		x			
			x			x		
			x	x		x		
			x		x		x	
				x	x	x		
				x		x	x	
Industrial LV sales (kWh)		x						
			x					
				x				
					x			
						x		
							x	
	x			x				
	x				x			
	x					x		
	x						x	
		x		x				
		x			x			

Dependent Variable	GDP	Sector GDP (Commercial, Agriculutral or Industrial)	GDP per capita	Tariff (Residential, Commercial, or Industrial)	CPI	Lagged dependent variable	Connections (Residential, Commercial or Industrial)	Oil Price
		x				x		
		x					x	
		x		x		x		
			x	x				
			x		x			
			x			x		
		x		x		x		
		x			x	x		
		x			x		x	
Industrial MV sales (kWh)	x							
			x					
				x				
					x			
						x		
							x	
	x			x				
	x				x			
	x							x
		x		x				
		x			x			
		x				x		
		x					x	
		x		x		x		
			x	x				
			x		x			
		x		x		x		x
		x			x	x		
		x			x		x	

Source: ECA analysis. Note: The lagged explanatory variables described in the table were also considered in all specifications, nominal and real tariffs were also considered

A5 Demand forecast 2022-2042

Table 1.A5.1: Sent-out energy and peak demand forecasts

	Low scenario		Base scenario		High scenario	
Year	**Sent-out Energy (GWh)**	**Peak demand (MW)**	**Sent-out Energy (GWh)**	**Peak demand (MW)**	**Sent-out Energy (GWh)**	**Peak demand (MW)**
2022	2,367	371	2,378	373	2,379	373
2023	2,447	383	2,587	405	2,610	409
2024	2,538	394	2,891	449	2,985	462
2025	2,679	409	3,351	508	3,524	535
2026	2,931	440	3,897	582	4,437	661
2027	2,985	449	4,111	617	5,199	781
2028	3,090	464	4,412	663	6,460	975
2029	3,219	481	4,847	725	7,495	1,129
2030	3,334	498	5,166	774	8,539	1,291
2031	3,462	518	5,551	834	9,101	1,378
2032	3,599	539	5,982	900	9,740	1,475
2033	3,771	565	6,485	976	10,458	1,583
2034	3,909	587	6,939	1,048	11,068	1,680
2035	4,077	612	7,468	1,130	11,772	1,790
2036	4,229	636	8,007	1,214	12,485	1,903
2037	4,389	662	8,593	1,307	13,258	2,025
2038	4,558	688	9,230	1,407	14,095	2,157
2039	4,736	716	9,927	1,516	15,004	2,301
2040	4,924	746	10,684	1,636	15,991	2,457
2041	5,137	779	11,531	1,768	17,129	2,635
2042	5,362	815	12,458	1,914	18,371	2,830

Source: ECA analysis

Table 1.A5.2: North region - Sent-out energy and peak demand forecasts

	Low scenario		Base scenario		High scenario	
Year	**Sent-out Energy (GWh)**	**Peak demand (MW)**	**Sent-out Energy (GWh)**	**Peak demand (MW)**	**Sent-out Energy (GWh)**	**Peak demand (MW)**

	Low scenario		Base scenario		High scenario	
2022	227	62	228	62	228	62
2023	236	64	252	68	254	69
2024	238	65	272	74	278	76
2025	252	68	326	89	343	93
2026	340	93	496	135	581	158
2027	345	94	514	140	674	183
2028	355	97	545	148	815	222
2029	392	107	614	167	961	261
2030	407	111	649	177	1,084	295
2031	422	115	693	189	1,146	312
2032	438	119	740	201	1,212	330
2033	454	124	792	216	1,285	350
2034	472	128	849	231	1,363	371
2035	514	140	945	257	1,493	406
2036	533	145	1,013	276	1,585	431
2037	553	151	1,086	296	1,685	458
2038	575	156	1,167	317	1,793	488
2039	597	163	1,254	341	1,910	520
2040	621	169	1,350	367	2,037	554
2041	648	176	1,457	397	2,184	594
2042	676	184	1,575	429	2,345	638

Source: ECA analysis

Table 1.A5.3 Central region - Sent-out energy and peak demand forecasts

	Low scenario		Base scenario		High scenario	
Year	Sent-out Energy (GWh)	Peak demand (MW)	Sent-out Energy (GWh)	Peak demand (MW)	Sent-out Energy (GWh)	Peak demand (MW)
2022	975	159	979	160	979	160
2023	1,009	165	1,070	174	1,078	176
2024	1,066	174	1,249	204	1,305	213

	Low scenario		Base scenario		High scenario	
2025	1,105	180	1,377	224	1,452	237
2026	1,147	187	1,509	246	1,747	285
2027	1,177	192	1,611	263	2,088	340
2028	1,223	199	1,726	281	2,602	424
2029	1,272	207	1,850	302	2,965	483
2030	1,323	216	1,983	323	3,418	557
2031	1,378	225	2,143	349	3,643	594
2032	1,435	234	2,317	378	3,885	633
2033	1,496	244	2,507	409	4,147	676
2034	1,559	254	2,714	442	4,431	722
2035	1,625	265	2,939	479	4,736	772
2036	1,695	276	3,185	519	5,067	826
2037	1,768	288	3,452	563	5,426	885
2038	1,845	301	3,743	610	5,815	948
2039	1,926	314	4,061	662	6,236	1,017
2040	2,012	328	4,407	718	6,694	1,091
2041	2,108	344	4,793	781	7,218	1,177
2042	2,209	360	5,215	850	7,789	1,270

Source: ECA analysis

Table 1.A5.4: South region - Sent-out energy and peak demand forecasts

	Low scenario		Base scenario		High scenario	
Year	Sent-out Energy (GWh)	Peak demand (MW)	Sent-out Energy (GWh)	Peak demand (MW)	Sent-out Energy (GWh)	Peak demand (MW)
2022	1,165	275	1,171	277	1,171	277
2023	1,201	284	1,266	299	1,278	302
2024	1,235	292	1,370	324	1,402	331
2025	1,321	312	1,649	390	1,729	408
2026	1,442	341	1,891	447	2,109	498
2027	1,461	345	1,986	469	2,437	576

	Low scenario		Base scenario		High scenario	
2028	1,511	357	2,142	506	3,043	719
2029	1,553	367	2,383	563	3,569	843
2030	1,602	379	2,534	599	4,036	954
2031	1,660	392	2,715	642	4,313	1,019
2032	1,724	407	2,925	691	4,642	1,097
2033	1,819	430	3,185	753	5,026	1,188
2034	1,877	443	3,377	798	5,275	1,246
2035	1,937	458	3,584	847	5,543	1,310
2036	2,000	473	3,810	900	5,833	1,378
2037	2,067	488	4,055	958	6,147	1,453
2038	2,137	505	4,321	1,021	6,488	1,533
2039	2,212	523	4,611	1,090	6,858	1,620
2040	2,291	541	4,927	1,164	7,260	1,716
2041	2,381	563	5,281	1,248	7,727	1,826
2042	2,477	585	5,668	1,339	8,237	1,946

Source: ECA analysis

Table 1.A5.5 Sales forecast by economic activity

GWh	Residential			Commercial			Industrial		
Year	Low case	Base case	High case	Low case	Base case	High case	Low case	Base case	High case
2022	763	763	763	322	330	332	778	778	778
2023	803	891	899	329	346	351	794	800	804
2024	848	1,027	1,084	341	368	378	844	929	972
2025	895	1,177	1,288	358	399	412	926	1,164	1,274
2026	942	1,339	1,682	376	436	452	1,088	1,447	1,620
2027	984	1,493	2,275	394	478	498	1,089	1,454	1,634
2028	1,039	1,655	3,177	420	525	552	1,102	1,508	1,750
2029	1,097	1,826	3,783	447	577	613	1,131	1,656	1,965
2030	1,155	2,005	4,536	477	636	681	1,144	1,693	2,036
2031	1,216	2,229	4,882	510	701	759	1,165	1,736	2,121
2032	1,279	2,471	5,254	546	775	846	1,188	1,792	2,238
2033	1,343	2,734	5,653	585	857	945	1,237	1,879	2,389
2034	1,410	3,019	6,083	628	949	1,056	1,251	1,897	2,409
2035	1,479	3,328	6,544	675	1,052	1,182	1,286	1,944	2,469
2036	1,550	3,662	7,040	726	1,168	1,325	1,301	1,961	2,489
2037	1,623	4,023	7,572	783	1,299	1,488	1,316	1,979	2,510
2038	1,699	4,414	8,144	844	1,446	1,672	1,331	1,998	2,532
2039	1,777	4,837	8,759	912	1,612	1,881	1,347	2,017	2,554
2040	1,858	5,294	9,419	986	1,799	2,120	1,363	2,036	2,576
2041	1,942	5,787	10,129	1,068	2,010	2,391	1,379	2,055	2,599
2042	2,028	6,319	10,892	1,158	2,249	2,701	1,395	2,075	2,623

Source: ECA analysis

VOLUME 2: Generation Development Plan – Final Report

1. Introduction

Malawi has one of the lowest electricity access rates in the world at about 20% if off grid systems are included in the estimation. Malawi, like all countries in sub-Saharan Africa, suffers from an acute Energy Poverty despite its endowment with an abundance of natural resources. The notables causes of Energy Poverty are poor governance, operational and financial performance, and the technical insolvency of state-owned power utilities.

Recently, Malawi has been suffering from insufficient foreign currency and could benefit from a focus on exporting its hydropower and solar potential as green energy, which is sufficient to attract foreign capital. The integration of the Malawi electrical power system into the SAPP and EAPP should inform policy makers that Malawi is no longer an electrical island and should leverage on the integration for its maximum benefit. Malawi's energy policies going forward must not adopt the concept of self-sufficiency in local power generation to comply with the integration drive of the SADC Vision 2050.

The Malawian power sector is already facing or will be facing major challenges in the coming years and needs to be prepared in order to be able to sustain the increasing electricity demand linked to the forecasted economic growth and the electrification of the population while ensuring the reliability of the supply and affordable prices for the electricity. The challenges encompass the reliance on an important share of hydro power plant subjected to potential important variations of early production, the penetration of intermittent renewable energy generation (photovoltaic and wind), the need to diversify the energy mix and the integration to the SAPP regional network. Therefore, a precise vision of the optimal evolution of the power system and the related investment is critical.

The objective of the study is to define the generation, transmission and distribution expansion plans for the next 20 years. The generation development plan presented in this report constitutes the first Work Stream of the study. It aims at outlining the best possible pathway for meeting the electricity needs for Malawi from 2022 to 2042.

The optimal generation plan is based on the output from the demand forecast, planned generation, and resource assessment. The plan integrates multiple objectives, ranging from least cost electricity generation to a high degree of reliability. It can serve as a guideline for policy makers and utilities deciding on the next steps for the Malawian power system.

The generation plan is designed using Energy Exemplar's PLEXOS®, a widely recognized software solution that is both capable of short-term (operational) and long-term (expansion) modelling and optimization.

A techno-economic modelling and optimization of the power generation system is performed for the planning horizon of 2022-2042. This model is used to compare and select the best economic options to supply the national power demand over the study period. Given that modelling the intermittency of renewables in generation planning often comes with a range of high-level assumptions, the Consultant complemented the generation expansion plan with an operational model (production cost model). This allows to properly capture realistic dispatch behaviour with hourly granularity while respecting the chronology. The latter is even more essential when considering flexibility resources (such as hydro and storage). The planning model allows finding which type of generating unit must be adopted, which size the generating unit should have, at which year it should be put into service. Given its importance for the power system of Malawi, a special attention was given to the modeling of the hydrology of the country and its impact on the uncertainty linked to the hydrogeneration. A tailored stochastic model and optimisation approach was developed for the purpose of the study using the long track of flows and hydro production records made available by the Stakeholders.

The first part of the report is constituted of the executive summary and the present global introduction. The third chapter presents the approach and the philosophy developed for the generation development plan. The two following chapters present the input data: respectively the demand forecast and existing and candidate generation units. Chapter 6 presents the assessment of the national VRE potential. The following chapter presents the analysis dedicated to the hydrology and the applied stochastic approach. Chapter 8 details the methodology and provides the results of the optimization process for the different studied scenarios. Chapter 9 details the reference development plan that will be considered in the other work stream of the study (Transmission and Distribution). Finally, the last chapter presents the conclusions of the analysis.

2. Approach and philosophy

The approach implemented to define the optimal development plan for the generation system of Malawi was tailored based on the initially proposed methodology in the inception report, the shared data, the characteristics of the system as well as the regular discussions within the Working Group dedicated to generation and during the presentation of the draft final report to the Stakeholders in Malawi.

The optimum development plan relies on the combination of the definition of the long-term vision for the development of the electricity sector and a focus on the short- and medium-term required investment.

- The definition of the energy long-term orientations for the country up to 2042 is based on a least cost optimization of new generation units for the next 20 years while respecting all planning and system operation constraints and the consideration of strategic projects.
- A tangible investment plan for the next years is obtained by additional analyses focusing on the minimum / no-regret investment in the next 5 years taking into account the constraints defined with the Stakeholders and the short-term reduced uncertainties.

The following figure presents the schematic diagrams of the methodology applied to define the optimum long term evolution for the generation system of the country. The input data used for the planning activity are detailed in the next sections of the present report and include the evolution of the demand over the study period, the definition of the technologies available in Malawi and their techno-economic characteristics and the results of the assessment of the Renewable Energy potential (wind and solar PV). Candidate technologies include Solar PV, wind, diesel, coal, gas GT& CC, Biomass (Waste to Energy (WtE) & bagasse), geothermal and HPP projects. A dedicated analysis was also carried out to take into account the uncertainty of the hydro resources in the long-term optimisation. These data are presented in the inception report. They were discussed and validated with the Stakeholders for the purpose of this analysis.

The long-term planning exercise optimises the least cost generation development plan under constraint, i.e., while respecting all planning and operation constraints for the future generation system. Two development scenarios are obtained with this approach: Least Cost scenario (LC) considers as candidate all technologies realistically available in the country and results in the definition of the unbiased optimal long-term least cost development pathway for the generation system of the country. In order to account for the strategic projects identified with the Stakeholders, a second scenario is studied: Least Cost + Strategic projects (LCSP). This scenario studies the impact of the generation projects identified as strategic for the development of the country on the costs and on the operation of the future generation system. The strategic projects include different small as well as major hydroelectric power plants and the development of a first gas and coal power plant.

In the frame of this long term planning study, the results of the LC scenario are considered as input for the next tasks: transmission planning and distribution planning.

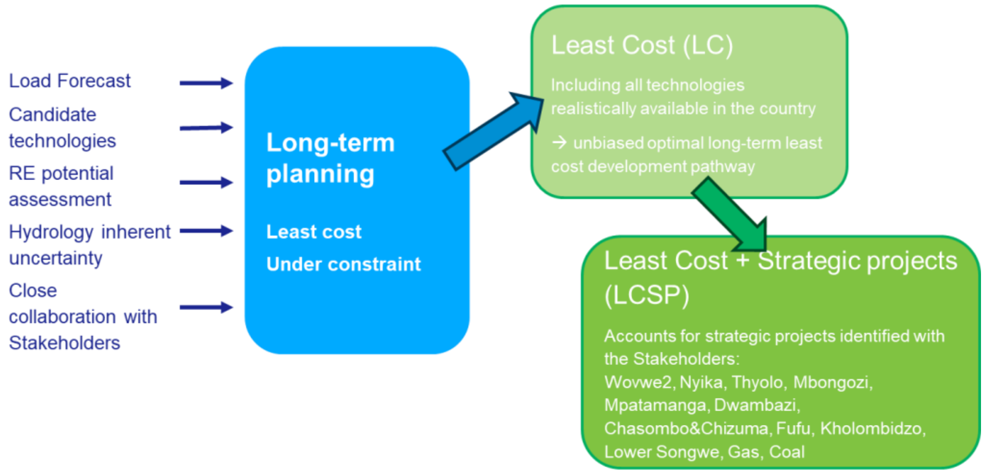


Figure 2.2.1: High level scheme of long-term vision definition

The Malawian generation system is characterized by its important share of hydro energy and the still untapped potential available to supply the growing national demand. This feature allows the country to rely on national and sustainable resources and enjoy a relatively cheap on the long term and low CO_2 emission electricity generation. On the other hand, the low diversity of the energy mix and the important reliance on an variable and only partially predictable resource constitute an important challenge for the country and the ongoing diversification of the mix notably with national RE resources such as wind, solar, geothermal and biomass is a key feature for the definition of the long-term vision for the country's energy mix.

The consideration of the uncertainties linked to hydrology and the difficulty to predict the energy available from hydro generation on the long-term is an important feature of the applied methodology. This probabilistic approach based on historical data is presented in details in Sections 6 and 7.1 and ensures that the recommended future generation system is resilient to wet and dry years and allows to supply the national demand with a sufficient reliability, i.e., the recommended generation system is the least cost option with a sufficient diversification of the energy mix allowing to withstand the variations of water availability and guarantee sufficient available resources to meet the demand.

This approach is well-suited to define a robust long-term development plan withstanding the uncertainties and variations linked to hydro-based resources and RE and ensuring a reliable supply of electricity under the possible hydrology evolution scenario. In the shorter term, such an approach can prove less adapted and lead to overinvestment recommendations. Indeed the uncertainty linked to hydro resources decreases as the studied horizon is getting closer and certain evolution scenarios can be privileged, therefore leading to a more accurate view on the future system's requirements and a more adapted investment plan. This is especially the case for Malawi as the existing hydro powerplants enjoy a very large and stable basin reservoir (Lake Malawi) and the Authorities have a long track record of the flows and related energy production.

Based on these considerations, a dedicated methodology was developed in close collaboration with the Stakeholders to define input assumptions as close as possible to the current evolution of the system and also to reflect the current national strategy, the ongoing projects and the short-term investment possibilities. Based on the recent track records for hydrology and the current level of Lake Malawi, it was concluded that a good hydro availability is to be expected at short- and medium-term on the Shire river. Therefore, the analysis focusing on this period considers in optimistic level for hydro generation to take into account the hydrology forecast and avoid overinvestment.

The schematic diagrams below illustrate the methodology applied to define the short- and medium-term optimum investment in the generation system to sustain the forecasted growth by ensuring reliable supply of the growing electricity demand. The methodology and the refined input assumptions are detailed in Section 7.3.1. The heart of the methodology remains the optimization of the least cost investment plan under constraints to ensure the respect of all planning and operation criteria while minimizing the investment and operation costs. Two demand scenarios are studied : Base case forecast and Low case forecast. Both these scenarios are an output of the recent Demand Forecast study [1]. The Base case scenario reflects the most likely evolution of the demand required to sustain the electrification rate improvement and the economic growth and is in line with the Stakeholder's expectations. The study of the Low Case Demand scenario provides the Stakeholders with an alternative development plan allowing to adapt the investment plan in the future based on the measured evolution of the load.

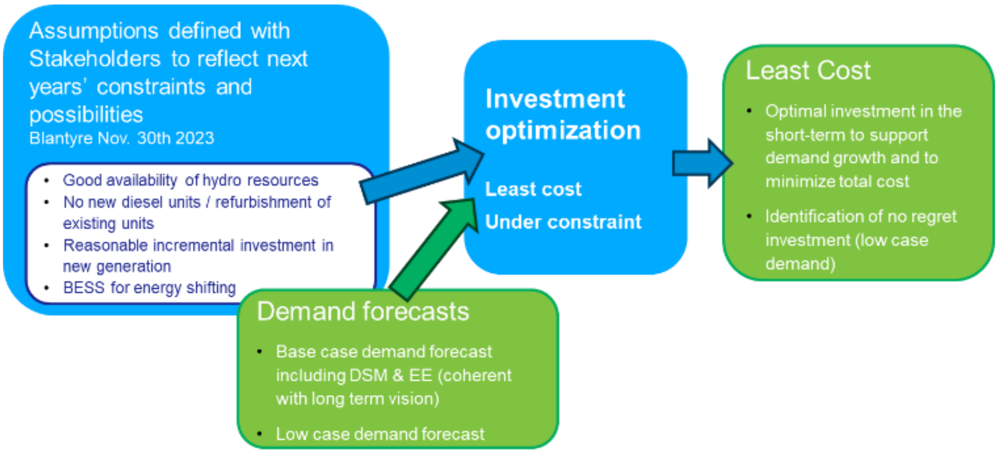


Figure 2.2.2: High level scheme of short- and medium-term investment definition

3. Demand

3.1 Forecast

The key document adopted as reference for the demand forecast until 2042 is the report issued by the Ministry of Energy in May 2023 [1]. The base case reflects the current policy targets, as well as the development forecasts in the country, which would lead to around 12.5 TWh of electricity demand, with an annual growth beyond 8%. In addition, low and high scenarios are proposed, with less or more ambitious underlying assumptions in terms of socio-economic development, electrification and loss reduction targets. The base case is adopted in this study as input to the capacity expansion plan.

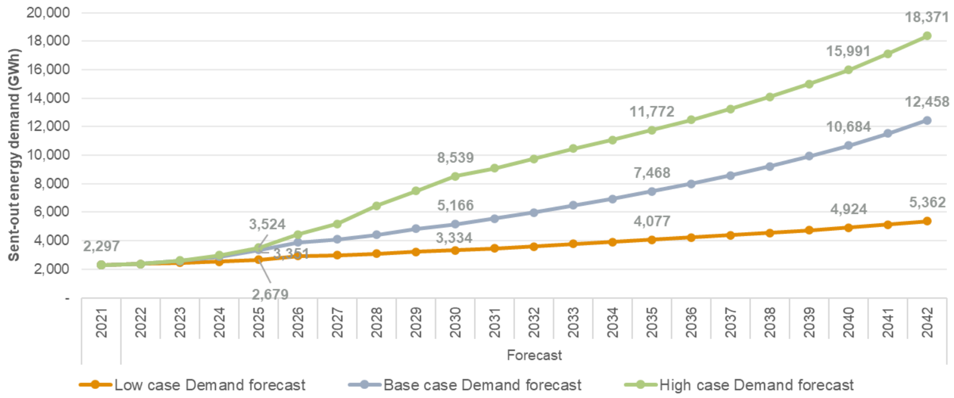


Figure 2.3.1: Demand forecast scenarios [1]

Similarly to total energy demand, the peak demand of the Base Case is also foreseen to grow at a yearly pace of around 8%, reaching 1914 MW in 2042. The three scenarios proposed in the demand forecast report are shown in the figure below.

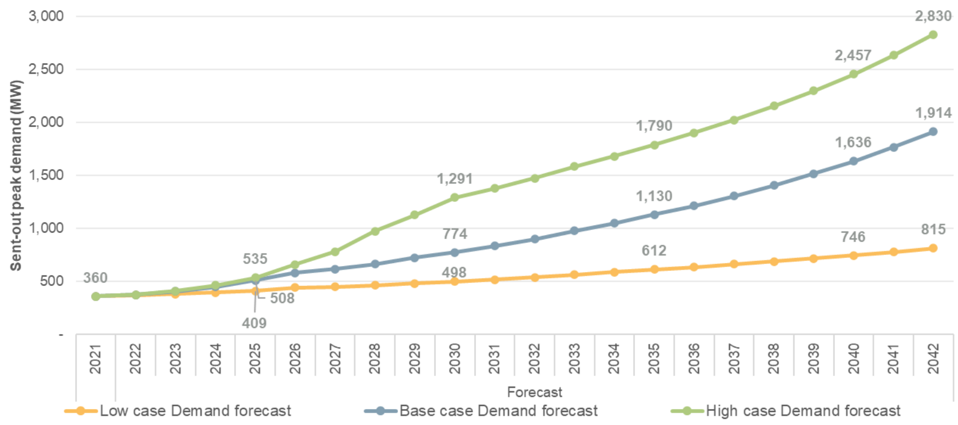


Figure 2.3.2: Peak demand scenarios [1]

3.2 Load curve

The demand forecast has a resolution of one year. This allows to size generation capacity in order to meet future demand. Furthermore, the intra-annual demand profiles are evaluated to find demand patterns on a monthly, daily or hourly basis.

The figure below presents the annual load profile of the Malawian electrical system in 2020. It is presented as the relative average daily load of each month: relative to the month with the highest average daily demand to ease the interpretation of the curve, and average daily demand in order to make it independent of the number of days[14]. Moreover, the load duration curve is shown in Figure .

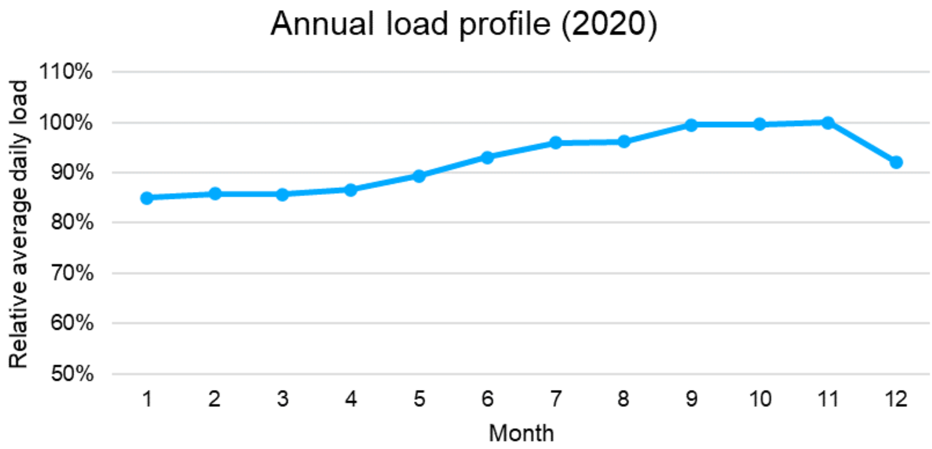


Figure 2.3.3: Annual load profile in 2020 (average daily load per month) [2]

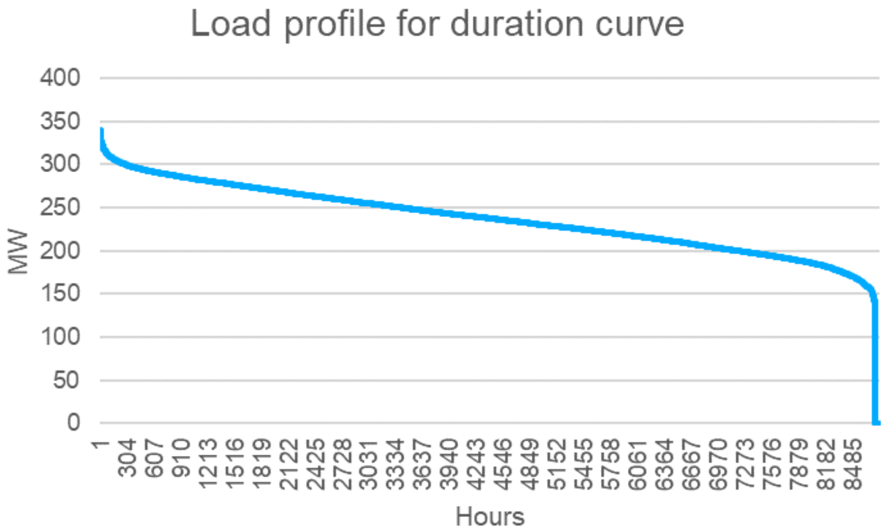


Figure 2.3.4: Load duration curve in 2020 [2]

---

[14] Otherwise, months with a lower number of days (e.g., February) could not be compared with months with a higher number of days (e.g., January)

The following could be concluded from the figures:

- The maximum demand occurs during the September-November period
- The minimum demand takes place during the first months of the year: January-April period
- Overall, the system shows a considerably flat curve, with a maximum average daily load deviation of 15% over the months

The following figure present the hourly demand for 2020. This confirms the low seasonality of the demand and the slight increase towards the end of the year. The Consultant used the 2020 hourly load profile as a reference for the next phases of the generation planning workstream given that it is the most recent shared data and the impact of curtailment and load shedding is limited for this year according to the national Stakeholders. Furthermore, the outliers have been excluded in order not to study exceptional cases (e.g., load shedding). It is worth noticing that the 2020 load will represent the reference only in terms of shape of the profile, while the absolute values will be derived from the ECA load forecast study [1] presented in the previous section.

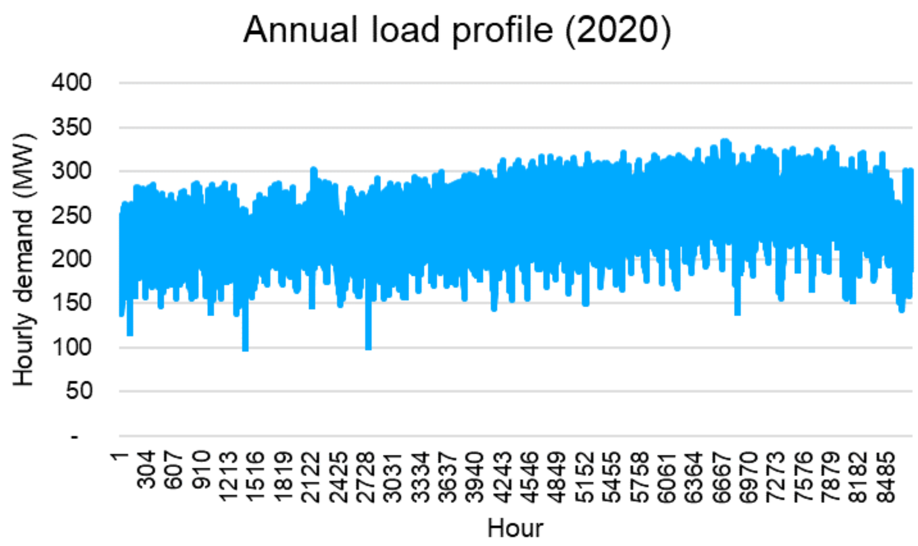


Figure 2.3.5: Annual load profile in 2020 (hourly load) [2]

With the purpose of detecting load variabilities along the day, some representative days are selected: on the one hand, one week day and one weekend day during the month with the lowest demand (i.e., January) and, on the other hand, one week day and one weekend day during the month with the highest demand (i.e., November).

The figure below presents the hourly demand for one week day and one weekend day for the month of January.

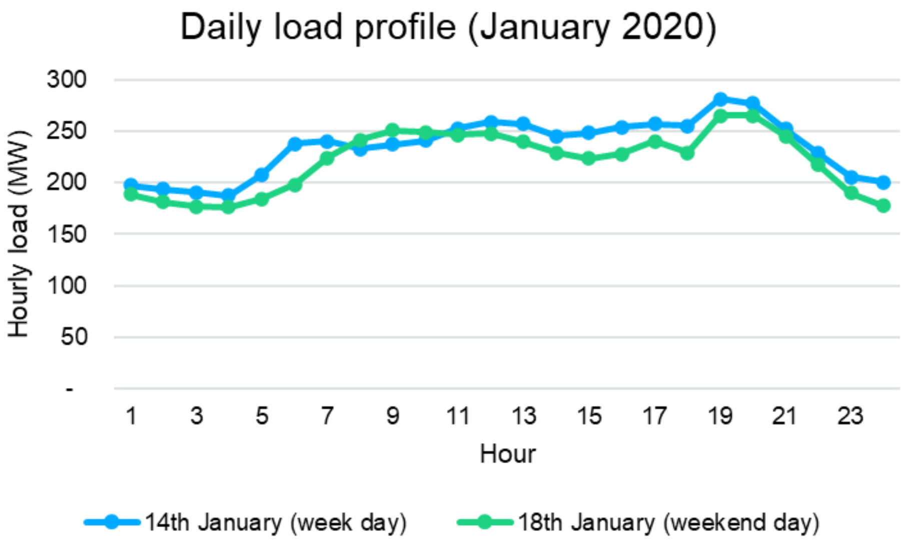


Figure 2.3.6: Daily load profile in a week and weekend day (January 2020) [2]

Here below, it is presented for the month of November:

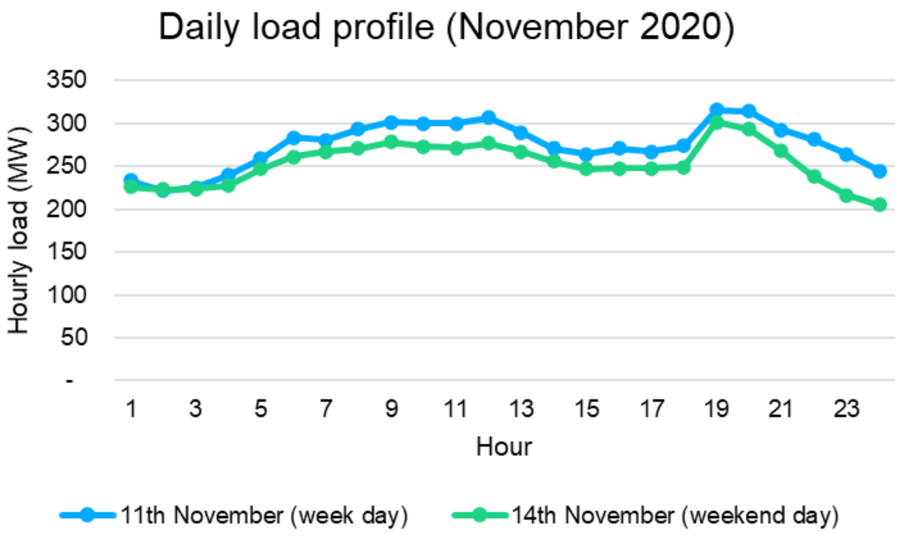


Figure 2.3.7: Daily load profile in a week and weekend day (December 2020) [2]

The following conclusions can be stated based on the previous two figures:

- The maximum hourly load deviation within one day is 30%
- The peak demand takes places during the evening, between 7 pm and 9 pm
- The minimum demand occurs during the night, between 11 pm and 5 am
- A lower peak and dip demand can be observed during the day
- No significant differences between the daily profiles of January and November are present
- Similar load behaviors in weekend and week days

4. Generation

The development of the generation expansion plan aims at identifying the most efficient options, but it also needs to consider what is already planned and decided, so that all contributions are correctly accounted for. Therefore, the Consultant developed the PLEXOS model considering the following categories:

- **Existing**: power plants already in operation at the beginning of this study;
- **Decided**: power plants with PPA signed and under construction or for which funding has been already secured;
- **Candidate**: additional investments to be considered during the planning horizon based on generic plants characteristics

By definition, existing and decided units are considered in the system from the beginning of the study period for the first category and from the defined date of commissioning for the second category and are not part of the optimization process.

Candidate units are the investment possibilities for the optimization exercise and represent the generation projects and technologies possible in Malawi to follow the demand increase and to minimize the overall investment and operation costs. During the data collection phase, many generation projects, mainly by IPP and through unsolicited proposals, were identified. As explained in Section 4.2 none of these projects is currently under construction or has reached financial closure. Therefore, for the purpose of the present planning study, generic projects in the different technologies have been considered as available in Malawi for the optimization of the development of the generation system. This approach allows to determine the optimum generation mix and the corresponding new production units requirements. Based on these results, critical analyses of unsolicited offers can be realized and possibly public procurement for future units can be organized.

Based on the most recent information in the PLEXOS model shared by the Client [3], the consultant considered a gas price of 27.778 USD/GJ and a coal price of 8.59 USD/GJ for future plants (these technologies are not currently used in the Malawian power system). A biomass price of 4.46 USD/GJ is considered. The study was conducted during a period (end of 2023) of particular instability in fuel and electricity prices[15]. Therefore, to ensure the validity of the results and avoid bias, reference values based on the Consultant's experience in similar context were used for Light Fuel Oil (LFO), whose cost is set to 32.12 USD/GJ.

4.1 Existing generation

The 2023 generation portfolio consists of 540 MW of grid-connected power plants, of which 398 MW are hydro power plants (73.6%). Around 18.7% of the installed capacity is PV plants, while diesel gensets represent the remaining 7.7%. Given that all the existing hydro power plants are run of river, the system presents limited flexibility and the share of renewable capacity exceeds 90%.

[15] In November 2023 the price of diesel was increased to 2734 kwacha per litre following a devaluation of the local currency.

For the list of power plants and their characteristics, please refer to the Appendix.

4.2 Future generation

Given the many challenges encountered by the stakeholders in finding guidance in the previous IRP, the Consultant pursued the goal of developing a generation master plan that could be a reference in a changing landscape. The technologies included as candidates are reflective of the portfolio of solutions that could realistically be implemented. As of now, multiple power plants have been taken into consideration, and different projects are in the pipeline in different stages (feasibility study, PPA negotiations, waiting for financial close,…). However, none of these plants is currently under construction nor with secured funding.

Based on this context, no *decided* plants are included in the model and a wide range of *candidate* plants are considered. Hydro projects for which a feasibility study has been conducted are explicitly represented among the *candidate* units, given the specificities of their conditions (not possible to define a generic unit). Data gaps have been filled by good-practice information derived from the Consultant's experience. Moreover, costs retrieved from feasibility studies have been updated based on US inflation rates [4], in order to take a conservative assumption on current investment required.

The rest of the technologies are represented by means of the so-called *generic* units, because they are less dependent on site-specific characteristics.

Taking these considerations into account, the generic candidates included in the PLEXOS model are: solar PV, wind, BESS, geothermal, CCGT, OCGT, biomass (bagasse and waste to energy), coal. Diesel was not included in the list of candidate technologies as the Stakeholders clarified that there is no plan to further invest in new diesel units, while refurbishment could be put in place to improve the availability of the existing ones.

The detailed techno-economic characteristics of all the plants considered are listed in the Appendix. The first possible year of installation is also listed in the table. This refers to the availability of the technology based on ongoing projects and future strategies. The actual adoption of the technology will be defined by the software based on the input techno-economic characteristics.

Once a technology is available (based on earliest date of commissioning agreed with the Client), capacity limits are set to high values in order to investigate the optimal techno-economic path. Limitations are only included for technologies relying on limited resources; in this case, future projects and interaction with stakeholders has led to specific limits, i.e. 50 MW for bagasse and 15 MW for geothermal.

Moreover, interconnection with other countries are also included in the study as additional possible sources of supply. These are discussed more in details in the next section.

4.3 Interconnections

The country's electricity network is currently isolated from the rest of the region. However, it will be soon integrated into the Southern Africa Power Pool (SAPP) through a 400 kV interconnection line with Mozambique, which is expected to come in operation in October 2024 , 29 years after the creation of the SAPP. The SAPP was created for members to pool their resources and assist each other in times of emergencies and very much in line with SADC Vision 2050. The SADC Vision 2050 envisages a peaceful, inclusive, competitive, middle- to high-income industrialised region, where all citizens enjoy sustainable economic well-being, justice, and freedom. It has three pillars (a) Industrial Development and Market Integration, (b) Infrastructure Development in Support of Regional Integration, and (c) Social and Human Capital Development. Thus, all regional interconnectors that support regional integration are taken by the SAPP as Priority 1 projects. The import of electricity in Malawi through this line is regulated by a Power Purchase Agreement (PPA), which sets a selling price of 0.10 USD/kWh and caps the transfer at 120 MW for this import contract. The Take-or-pay contract is modelled for the 5 years of contract already in place. Currently, no export agreement is foreseen. After October 2029, the use of the interconnection will be optimized based on the needs of the country. As it was confirmed by the Stakeholders during the Working Group sessions, the tie-line is currently constituted with one circuit with the possibility of adding a second circuit. This possibility is further discussed in Section 7.3.2.3 studying frequency stability reserves. Note that, as the study focuses on the supply of the national demand additional imports and the possibility to export are not considered in the frame of this study to avoid, on one side, a too important reliance to the regional market and, on the other side, the investment in plant dedicated to the export of energy outside of Malawi. Thanks to the SAPP energy market and the developing regional grid, import and export will be possible for Malawi but the available amount remains uncertain and should be determined by a dedicated study carried out at regional level.

A new 400 kV line is also foreseen to connect the country with Zambia, thus strengthening the interconnection with the SAPP area and the security of supply. In the absence of further information at the time of this report, a price of 0.10 USD/kWh for the import of energy will also be assumed. Based on the gathered information, a maximum import of 50 MW will be considered. Given the importance of a second interconnection for stability and reliability purposes, the line is considered to be commissioned during the first possible year, namely 2028.

A third interconnection project is also considered: 400 kV line to Tanzania in the North of the country as an extension of the Malawi Western Backbone. The first possible year of operation for this line is set at 2030 and its commissioning (if to be put in place and when) is decided by the techno-economic optimization. Again a maximum import of 50 MW and a price of 0.10 USD/kWh are considered.

Given that the focus of the study is on the supply of the local demand, import need is the key aspect considered in the study regarding the interconnections. Considerations are made about export potential when discussing the results in Section 7.4.

4.4 DSM measures

A further option to deal with increasing demand is to adopt Demand Side Management (DSM) and Energy Efficiency (EE). These aspects could support the development of the system and reduce the need to invest in generation assets. In particular, smoothening the peak would allow for reduced investments in peaking power plants, which are often the most expensive.

The adoption of DSM and EE measures was analysed in the ECA demand forecast study, along with the related costs [1]. The base case scenario, i.e., the demand scenario used in the PLEXOS model, is associated with the penetration and impact of DSM and EE measures listed in Table . Moreover, the Consultant explores the attractiveness for the system of such measures, by adding the possibility to further increase their penetration, as in the high penetration scenario of Table .

Table 2.4.1: DSM and EE measures – Impact on demand [1]

DSM and EE measures	Medium penetration scenario		High penetration scenario (incremental step)	
	Peak demand reduction (MW)	Energy savings (GWh)	Peak demand reduction (MW)	Energy savings (GWh)
2022	6	10	8	13
2027	45	97	63	128
2032	54	136	76	180
2037	62	186	87	246
2042	70	243	98	321

Based on the potential, cost and share of the different measures listed in the ECA study, the specific cost of these actions has been estimated at 290 USD/kW and 310 USD/kW for medium and high penetration steps respectively.

4.5 Planning criteria

Along the study period, the development of the generation is optimized taking into account the technical and economic characteristics of existing units and investment options with the objective of minimizing all the capital and operational costs to supply the national demand including from local generation and imports while respecting all defined constraints. As explained above, a probabilistic approach is taken. It relies on the definition of different samples associated with probabilities of occurrence. The investment required to supply the demand are determined to minimize the EENS (Expected Energy Not Served) considering all samples at the same time. To balance investment in new generation assets and probability of load shedding, a cost is associated to EENS. Such cost is the Value of Lost Load (VOLL) is set to 800 USD/MWh[16]. Detailed dispatch simulations on an hourly basis are carried out with the resulting development plan and the reliability indices are computed: LOLE (loss of load expectancy) and EENS. It is then verified that

[16] This value is based on the consultant's experience and is linked to the ratio of national wealth creation (GDP) with the electric consumption and to the LCOE of a peaking unit that could limit the ENS.

the LOLE remains under the defined limits for the different hydrology scenarios and for the whole study period. A maximum LOLE of 24 hours/year and 100 hours/year in a dry year are considered to ensure a minimum level of reliability for the system[17].

4.6 Reserves

An AC power system is characterized by a constant balance between power generation and consumption. Any disruption to this balance will result in a frequency deviation from the nominal frequency (50 Hz in the case of Malawi and Southern Africa). Typically, the tripping of a generation unit will force the other units to instantly supply extra power to cover demand, which has not changed. This instantly available power actually comes from the kinetic energy accumulated in all the rotating machines connected to the grid, which will slow down while supplying it, causing the system frequency to drop. If the system is unable to react to this disturbance, the frequency will continue to fall until frequency collapse and blackout occurs.

For this reason, the frequency stability of a system must be carefully studied to ensure that the system will be able to remain stable in the event of a plausible disturbance to the equilibrium. To achieve this, a certain amount of primary and secondary reserve must be maintained in the system at all times. The primary reserve or spinning reserve must be able to be released quickly to minimize the frequency drop and stabilize the system. The secondary reserve then acts to return the system to its initial state at nominal frequency, thus freeing the primary reserve. These principles are illustrated in the following figure.

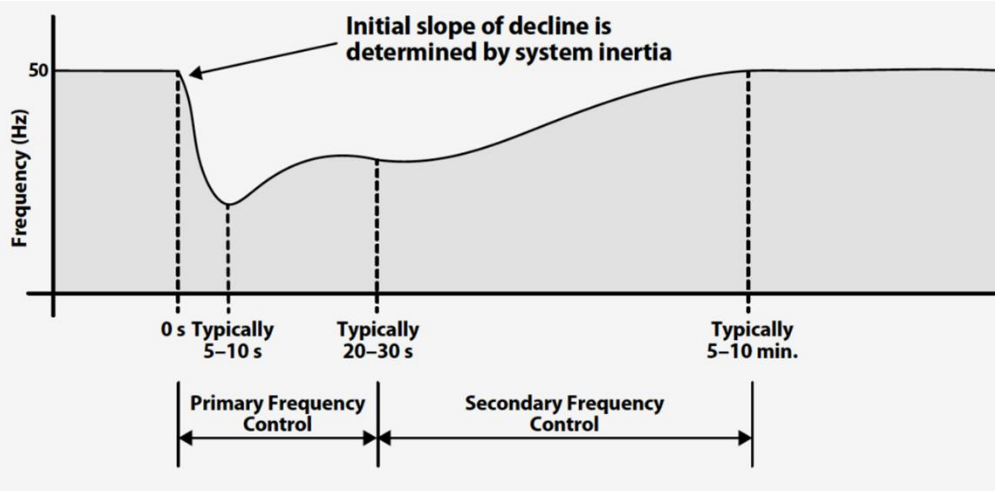


Figure 2.4.1: Frequency regulation and use of reserves18

In an interconnected network, resources and requirements in terms of frequency stability are common to all control areas and must therefore be distributed. The system's overall

[17] These values correspond to good practice value and are based on the consultant's experience. They allow to achieve a reasonable reliability level for the system under normal hydro conditions but also under extreme conditions (dry years) without leading to excessive investment driven by exceptional conditions only.

[18] Source : A Market for Primary Frequency Response? The Role of Renewables, Storage, and Demand, Thomas Lee

requirements are determined. The share of each country or control area is then calculated on the basis of distribution coefficients representing its electrical "weight".

The purpose of primary reserve is to limit the drop in frequency following an event on the network, such as the sudden loss of a generating unit. Primary reserve restores the balance between power generated and power consumed. Primary reserve does not restore the grid frequency to its nominal value (50 Hz), but stabilizes it at a lower value. It is activated automatically when the grid frequency exceeds a threshold value. The primary reserve calculation method for a control zone is deterministic and based on the definition of a dimensioning incident, generally corresponding to the loss of the largest unit connected to the network.

Once the primary reserve has limited the frequency drop and stabilized it at a value below the nominal value, the secondary reserve is automatically activated to bring the frequency back to its nominal value (50 Hz) and free the primary reserve to absorb future imbalances. Each control zone should maintain a secondary reserve corresponding to the largest unpredictable perturbation that can be caused within its system in order to be able to compensate this perturbation once the frequency is stabilized (action of the primary reserve) and restore the interarea exchanges. Typically the secondary reserve of a control zone corresponds to the largest unit of this control zone.

In case of isolated systems, primary reserves are sized to cater for the loss of the biggest generating unit. In 2023, the largest unit connected to the Malawian network has a capacity of 32 MW. This is the minimum amount of spinning reserve that should be available at all times.

As the frequency is shared across the interconnected system, the fast acting reserve (primary reserve) can be shared among all interconnected national networks. With the interconnection with Mozambique and SAPP, the frequency stability of the national network in normal operation will be importantly improved as Malawi power system will then benefit of the larger inertia and the slower ROCOF (Rate Of Change Of Frequency) of the much larger regional network of SAPP. Nevertheless, as seen from Malawi, the import through this only line with the rest of the SAPP regional grid will become the largest “generating unit” in Malawi and its loss will have to be rapidly compensated to avoid load-shedding or black-outs in Malawi. Therefore 120 MW of fast acting reserve to compensate the import on the tie-line with Mozambique in case of loss of the line as long as only one line connects the Malawian power system to the regional system.

With the commissioning of the second interconnection line, the loss of an interconnection line becomes less critical as the national system remains connected to the SAPP network. The reserve requirement can now be defined considering the sharing of the reserve needs of the whole system with the other SAPP countries. In this case, largest unit of the SAPP region to be considered would be the nuclear unit at the Koeberg nuclear power station in South Africa, having a gross power of 970 MW. In Europe, the primary reserve is shared between all countries of the same synchronous zone, in proportion to their load and their generation. According to the SAPP Pool Plan 2017, Malawi represents approximately 0.6% of the total SAPP load and generation combined [5]. Therefore, if a sharing methodology like the European one is adopted, the need of primary reserve is approximately 6 MW. Note that the electrical weight of Malawi within SAPP will evolve as a function of the national growth and the growth of all the interconnected countries. The coefficient should therefore be regularly reviewed and communicated by SAPP. For the purpose of the present study, this computed level of primary reserve will be considered for the whole period of study.

Based on these considerations, the evolution of primary reserve requirement can be summarized as follows:

- Current situation : 32 MW
- With the commissioning of first interconnection line : 120 MW
- After the commissioning of second interconnection line : 6 MW

As explained above, the secondary reserve requirement corresponds to the largest perturbation that can occur in the control area. In the current situation, it corresponds to the largest unit in Malawi i.e. one unit of Kapichira II HPP of 32 MW. Depending on the evolution of the generation system, the required secondary reserve will be adapted to the future largest unit of the country. The evolution of the reserve requirement will be highlighted in a dedicated section as well as the available or additional means to be considered to provide this reserve.

The primary and secondary reserves requirements and their evolution are depicted in the following figure. Note that two possible evolution of the minimum primary reserve are shown considering respectively one or two circuits for the upcoming Mozambique-Malawi interconnection. Once interconnected with at least two links to the SAPP system, the minimum reserve is considered constant. Similarly, the minimum secondary reserve is depicted as constant during the whole study period while it will have to be updated with the evolution of the generation system.

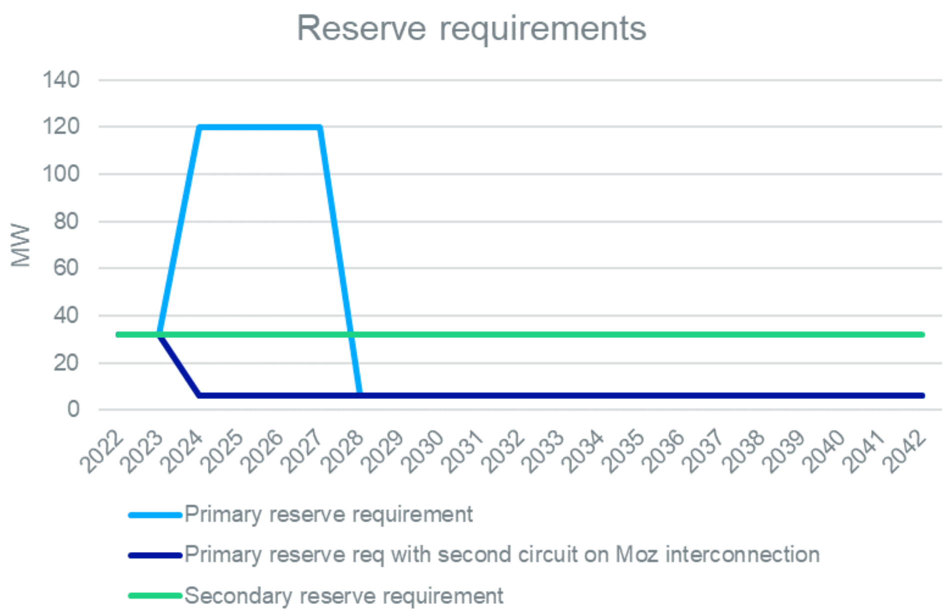


Figure 2.5.2: Evolution of reserve requirements in Malawi

5. VRE potential assessment

This chapter aims at estimating the potential of solar and wind resources in the country, by preliminarily identifying suitable areas for the installation of power plants, based on several exclusion criteria, and assessing the primary resource availability throughout the year. The key outcomes of this analysis are the production profiles to be integrated in PLEXOS and associated to the candidate PV and wind units.

5.1 Data collection

5.1.1 Reference documents collected

For the sake of the VRE potential assessment, the following documents have been collected during the data collection phase.

Table 2.5.1: Reference documents collected from the client

Document	Author	Year
Solar Resource Mapping in Malawi	ESMAP, World Bank	2018
Malawi Integrated Energy Plan	Sustainable Energy for All	2022
The Nationally Determined Contributions - Update	Government of Malawi	2016
Integrated Resource Plan (IRP) for Malawi	Ministry of Natural Resources, Energy and Mining	2017
Digest of Energy Statistics	Ministry of Energy	2023

5.1.2 GIS data collection

The following table presents the sources of the different data used for the site selection.

All the data used as input for the suitability analysis are provided in Geographic Information System (GIS) format and were imported into a GIS software.

Table 2.5.2: Input GIS data sources for suitability analysis

Input Data	Source	Available at	Last Access
Solar data	Global Solar Atlas	globalsolaratlas.info	17-01-2024
Wind data	Global Wind Atlas	globalwindatlas.info	
Protected areas	Protected Planet	protectedplanet.net	
Land use	Copernicus Global Land Service	https://lcviewer.vito.be/2019	

Input Data	Source	Available at	Last Access
Elevation	Shuttle Radar Topography Mission (SRTM)	https://srtm.csi.cgiar.org/srtmdata/	
Country boundaries Rivers Road network Railway network Airports	Humanitarian Data Exchange (HDX)	data.humdata.org (Malawi) https://data.humdata.org/dataset/hotosm_mwi_roads (2020) https://data.humdata.org/dataset/hotosm_mwi_railways (2020) https://data.humdata.org/dataset/ourairports-mwi (2020)	
Population density	WorldPop	https://hub.worldpop.org/geodata/listing?id=77 (2020)	
Transmission network Substations location Power Plants	ESCOM	-	
Existing RE Projects	ESCOM	-	

5.2 Software

The Geographic Information System (GIS) software used for this site selection is QGIS, a free, open source, cross-platform desktop geographic information system for viewing, editing, printing, and analysing geospatial data.

5.3 Methodology

The methodology comprises of several steps, starting with the analysis of GIS input layers, which is followed by the calculation of a weighted suitability score, allowing us to rank the most suitable sites for solar PV and wind projects in Malawi.

5.3.1 Solar potential

Malawi, situated in Southeast Africa, boasts a tropical climate that influences its solar resources. Malawi's abundant solar resources are at their peak in the Lower Shire Valley and parts of the Central Region, where solar irradiance averages between 5.5 to 6 kWh/m² per day, offering an excellent potential for solar energy generation. These areas, with their expansive, sun-drenched landscapes, are prime for both grid-connected and off-grid solar applications, essential for electrifying remote areas.

In contrast, the Northern Region, particularly the highlands, experiences slightly lower solar irradiance, around 4.5 to 5 kWh/m² per day, due to more prevalent cloud cover. Despite this, the region still maintains a viable level for solar energy projects, which can be tailored to the local climate, ensuring efficient energy harnessing across Malawi's diverse topographies.

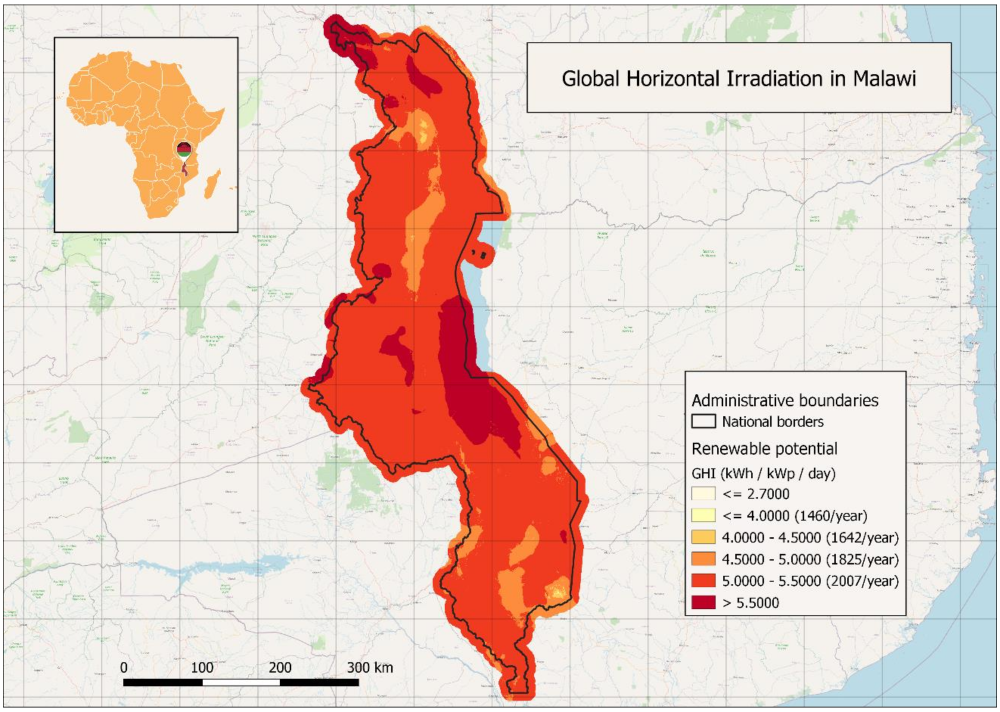


Figure 2.5.1: GHI map of Malawi – Source: ESMAP

5.3.2 Wind potential

Malawi, possesses noteworthy wind resources, featuring average wind speeds exceeding 7 m/s at a height of 100 meters above ground level in various regions. The elevated terrains in the central and north western parts of the country showcase particularly promising wind resources, with certain areas experiencing wind speeds surpassing 10 m/s.

The Southern Region, however, experiences lower wind speeds due to its generally flatter terrain and less pronounced climatic variations. Yet, the average wind speeds in the country still present opportunities for localized wind energy solutions, particularly for community-level wind power projects that can provide sustainable energy to off-grid areas.

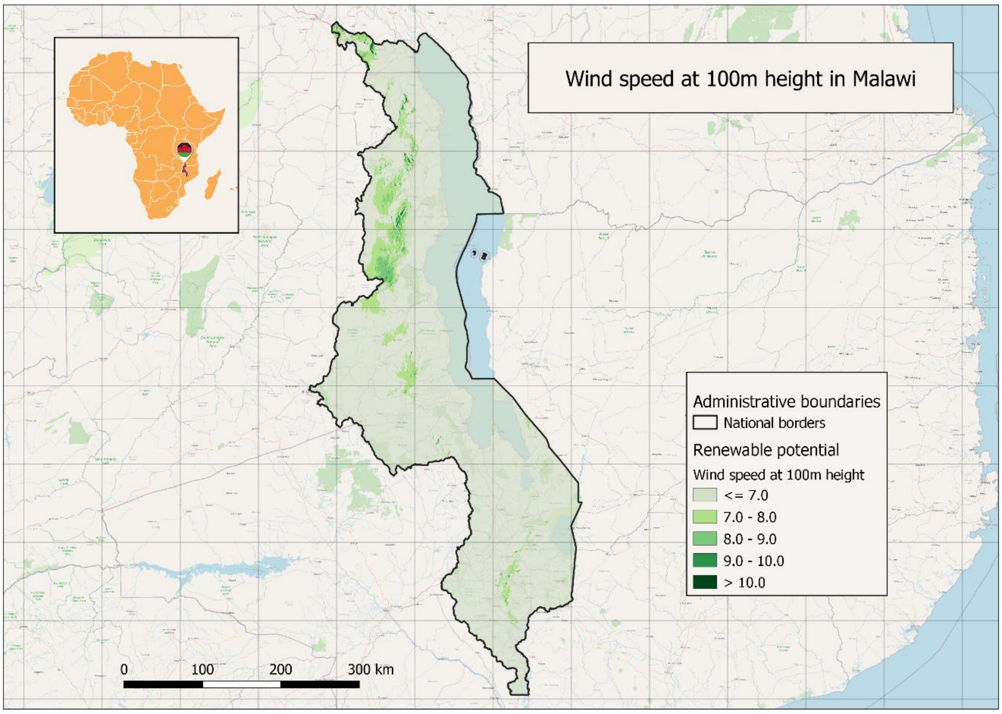


Figure 2.5.2: Wind speed map at 100 m height – Source: ESMAP

The site selection in this study was carried out with an emphasis on wind speed metrics. However, it is important to compare this with the wind capacity factor of the country to have a better understanding of the wind conditions. The capacity factor for wind turbines quantifies their actual energy output as a percentage of their potential maximum output, reflecting the efficiency of energy production. It is influenced by wind availability, turbine design, and operational factors such as maintenance. A higher capacity factor signifies a more effective use of the wind resource and consistent performance of the turbine.

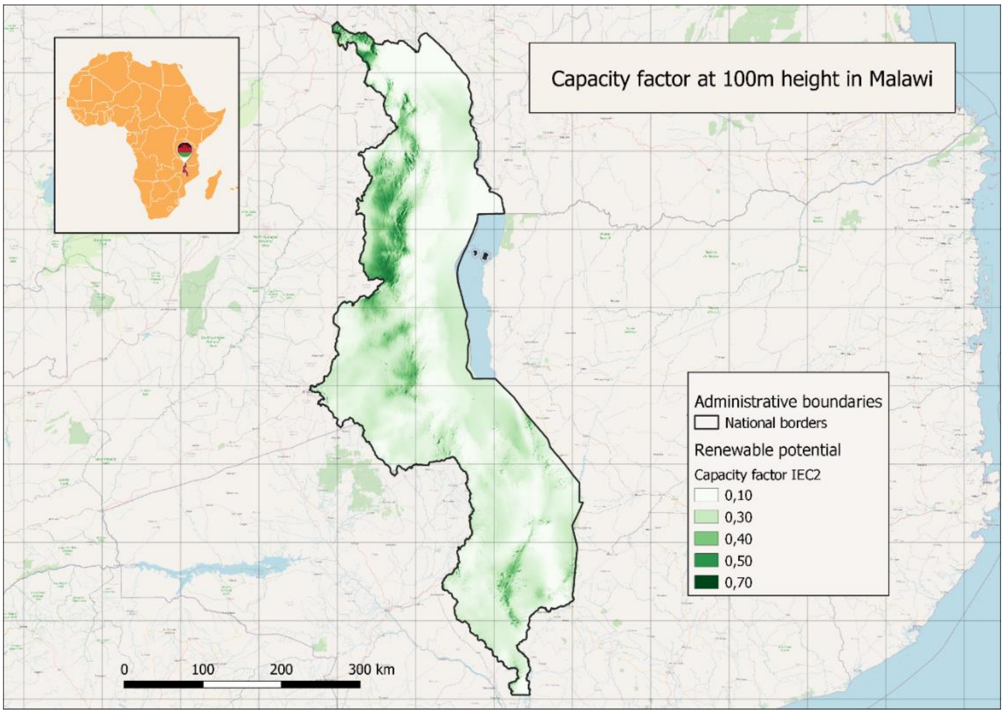


Figure 2.5.3: Capacity factor map at 100 m height – Source: ESMAP

The amount of electrical power a turbine can produce is greatly influenced by the incoming wind's consistency and speed. The amount of power produced decreases significantly at lower wind speeds. Power production drops eight times when the wind speed drops by half.

5.3.3 Exclusion areas

5.3.3.1 Protected areas

Malawi comprises national parks and wildlife reserves dedicated to preserving its natural legacy. Liwonde National Park and Majete Wildlife Reserve showcase successful initiatives in wildlife conservation, while Lake Malawi National Park, a UNESCO World Heritage Site, stands as a guardian for diverse aquatic life and underscores Malawi's commitment to environmental stewardship. Nyika National Park, with its expansive grasslands, and other areas like Kasungu National Park and Nkhotakota Wildlife Reserve contribute significantly to the nation's conservation narrative.

The presented map delineates regions exempted from the implementation of solar and wind projects, emphasizing their exclusion to support and safeguard the country's protected areas. These designated zones are excluded from the site selection process.

A buffer of 1 km has been applied around the polygons representing the protected areas to prevent construction in close proximity to these areas.

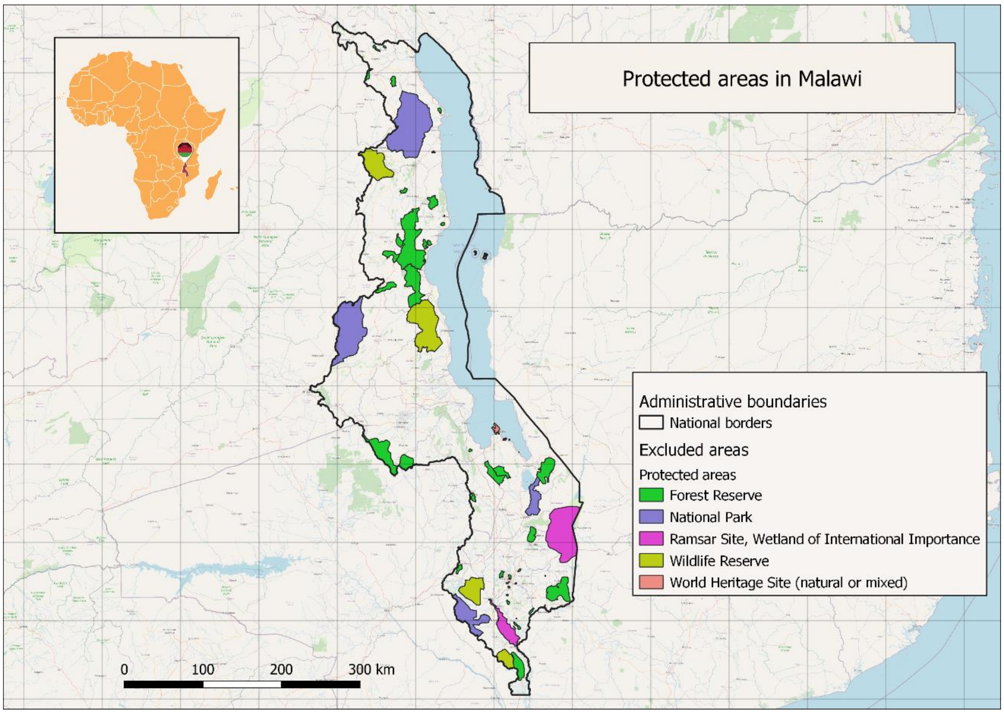


Figure 2.5.4: Protected areas map in Malawi - Source: Protected Planet

5.3.3.2 Land use

Based on the Copernicus Global Land Service, the land use of Malawi is shown in Figure .

As with the protected areas, some other areas are also considered not to be suitable for solar and wind project development. These areas are:

- Urban areas;
- Permanent water bodies;
- Wetlands;
- Closed forests.

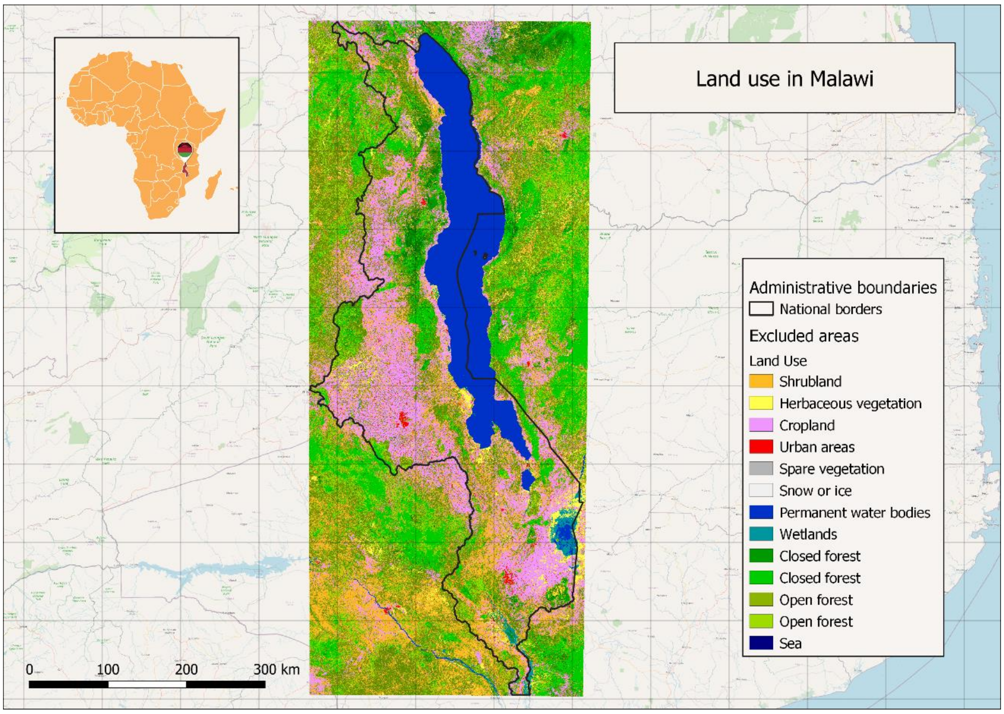


Figure 2.5.5: Land use in Malawi – Source: Copernicus Global Land Service

5.3.3.3 Topography

Malawi's topography is diverse, featuring Lake Malawi along the eastern border and elevated terrain in the central and western regions. Hills, plateaus, and the granite peak of Mount Mulanje contribute to the country's varied landscape. The Great Rift Valley influences the terrain, creating a dynamic mix of highlands and low-lying plains. This topographical diversity shapes Malawi's scenery and impacts its climate, ecosystems, and agriculture.

Figure represents the topology of Malawi. The data to create this map originates from the Shuttle Radar Topography Mission (SRTM). This is an international research effort from NASA that obtained digital elevation models.

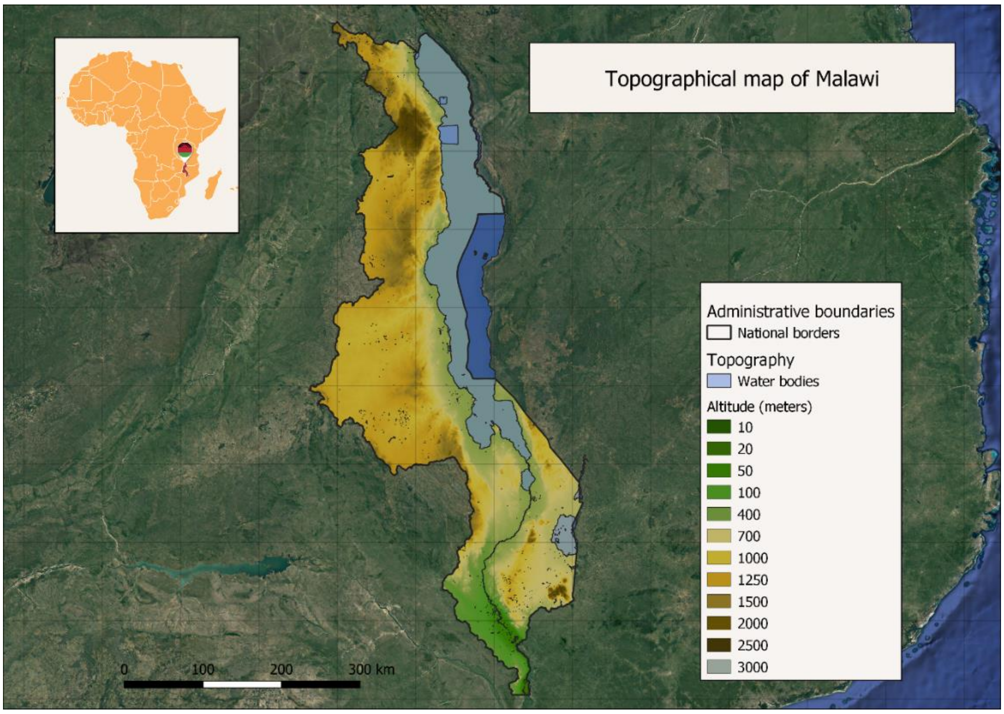


Figure 2.5.6: Topographical map of Malawi – Source: SRTM

For the creation of this map, the SRTM program provided raster data with values of terrain elevation per pixel. By comparing the elevation values of adjacent pixels, it is possible to calculate the slope of the terrain, as is shown in Figure .

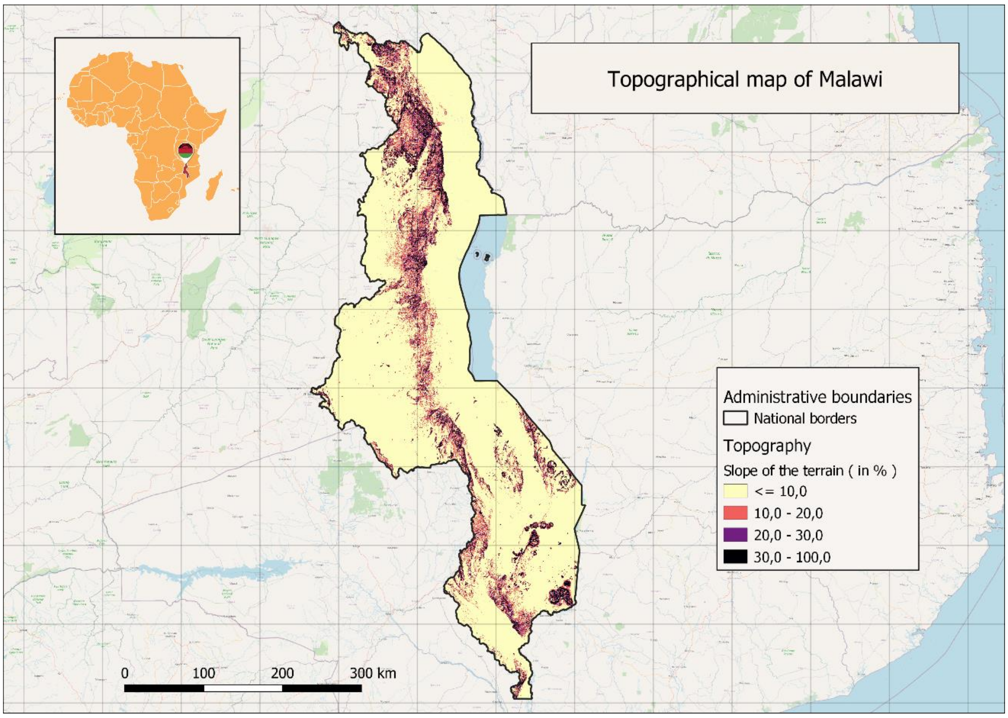


Figure 2.5.7: Slope of the terrain map – Calculated based on data from SRTM

As slope gradients in the topography of a site increases the complexity and related costs for civil and installation works, some areas with steep slopes are excluded from the site selection process:

- **Solar PV assessment: a maximum slope gradient of 10%** is considered as a limit for standard civil and installation works;
- **Wind assessment: a maximum slope gradient of 30%** is considered as the transportation of large wind turbine components, such as the blades, limits the maximum gradient of the access roads.

5.3.4 Distance to the road and network

The distance of a potential solar or wind power site from established roads is pivotal for the initial setup and ongoing maintenance of the facility. Sites easily accessible by road allow for more straightforward and cost-effective transportation of heavy equipment, materials, and personnel, both during the construction phase and for routine operations thereafter.

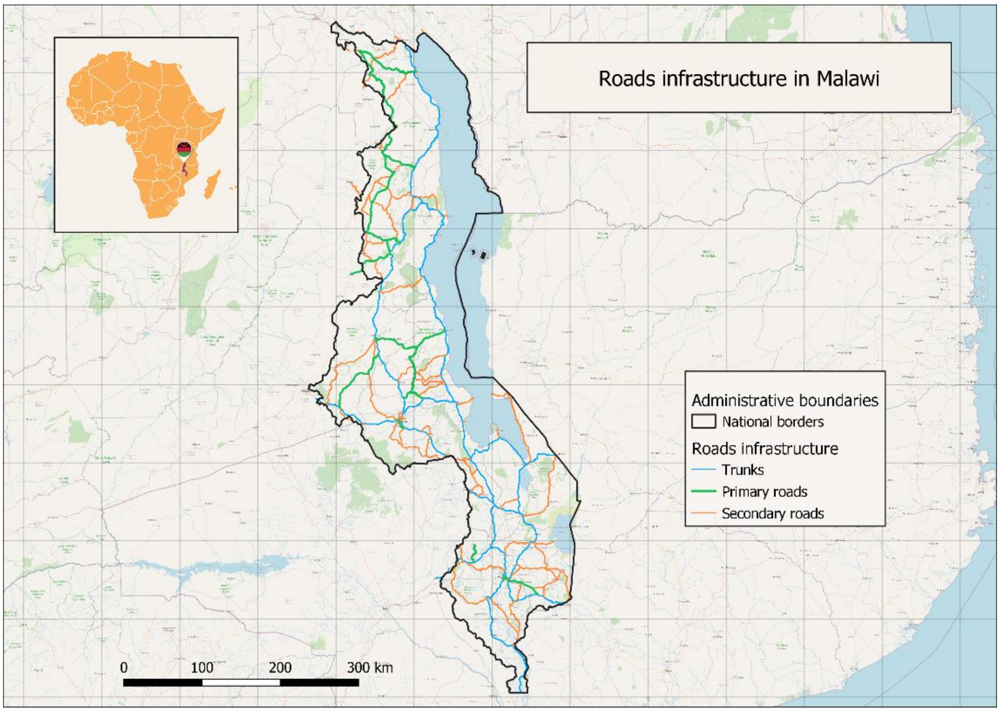


Figure 2.5.8: Roads infrastructure map – Source: HDX

The proximity of a potential solar or wind power site to the electric grid infrastructure is crucial for the feasibility and economics of a renewable energy project, even if the project would probably need its own substation. Closer distance reduces the costs and energy losses associated with transmitting electricity to end-users. It also simplifies the logistical challenges of connecting the renewable energy source to the existing infrastructure, potentially accelerating project timelines and reducing impacts on the environment.

Conversely, sites far from the grid may necessitate significant additional investments in transmission infrastructure, potentially affecting the overall viability of the project.

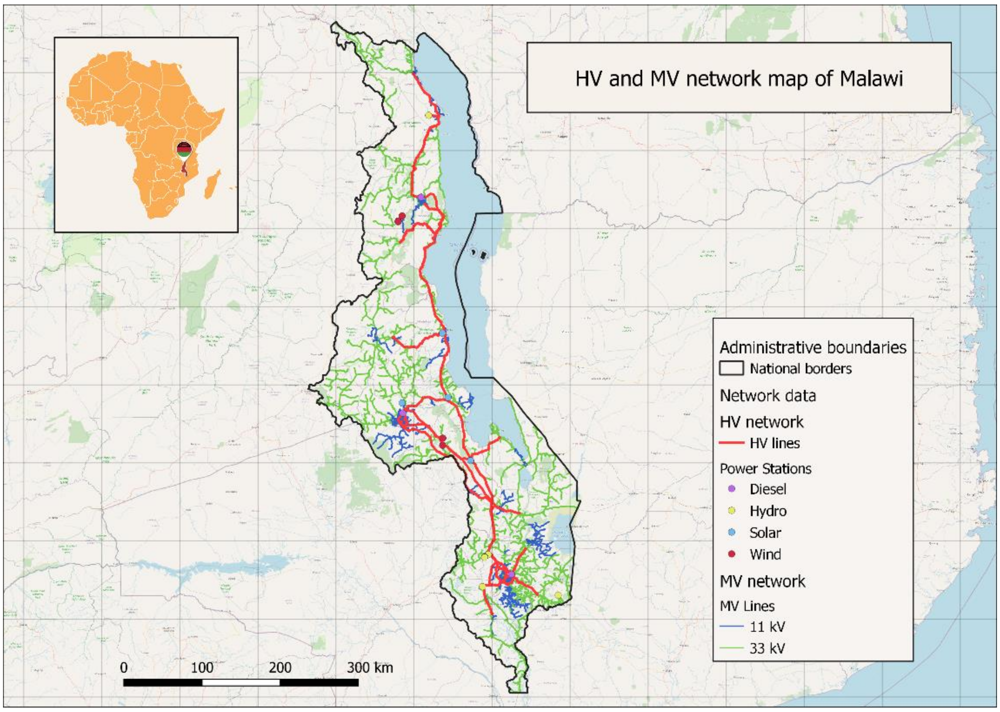


Figure 2.5.9: Electric network map of Malawi – Source: World Bank

5.4 Results

5.4.1 Excluded areas

As outlined in the methodology, specific areas of the country have been excluded from consideration for the installation of solar or wind power plants. This exclusion takes into account both the size of the areas being excluded and the buffer zones surrounding them. For example, water bodies account for a substantial 34% (31,483 km²) of the land, with a surrounding buffer zone of 50 meters applied.

Malawi's total land area is recorded as 93,272 km². From this total, areas have been methodically excluded to ensure the most suitable locations are selected for renewable energy development. The excluded areas and their respective details are presented in the table below:

Table 2.5.3: Exclusion criteria of the VRE potential assessment

	Area (km2)	Buffer	Share of land area
Total area	93,272		100%
Total area with lake	118,029		
Protected wind	24,077	1 km	26%
Protected solar	21,923	0.5 km	24%
Aero ways wind	284	1 km	0.3%
Aero ways solar	114	0.5 km	0.1%

	Area (km2)	Buffer	Share of land area
Rivers and streams	2,663	50 m	3%
Water bodies	31,483	50 m	34%
Railways	92	50 m	0.1%
Built-up	2,812	100 m	3%
Forests	46,588	100 m	50%
Permanent water bodies	41.201	100 m	0%
Herbaceous wetland	649.588	100 m	1%
Low wind (less than 7 m/s)	83,954	200 m	90%

In the assessment of potential sites for solar photovoltaic (PV) installations, the Global Horizontal Irradiation (GHI) is utilized as a key indicator of solar energy potential.

In the methodology, the data indicate that the majority of the country experiences an average daily GHI in excess of 4.5 kWh/m²/day, which equates to an annual irradiation of approximately 1,643 kWh/m²/year. It is recognized by IRENA, that solar PV installations become economically viable at average GHI values surpassing the threshold of 2.7 kWh/m²/day, or 1,000 kWh/m²/year. Based on this criterion, the evaluation concludes that there are no regions within the country that fall below this threshold of solar PV resource potential.

Consequently, and in contrast with the wind assessment, no areas have been excluded on the basis of low solar PV resources in the geographical scope of this study.

5.4.2 Solar PV potential

Upon exclusion of the specified lands from the total landmass of the country, the resulting land deemed suitable for the development of solar photovoltaic (PV) installations encompasses an approximate 39,200 square kilometers. This figure represents about 40% of the country's entire area. Distribution of this area across the regions is as follows:

- 19% is located within the Northern region;
- 47% is in the Central region;
- 34% falls within the Southern region.

An analysis based on satellite imagery of the existing solar PV power plants yields an average capacity density of 39.2 MW per square kilometer (see Table 2.5.4 for detailed information). Taking into account this data, the Consultant recommends adopting an average power density of 40 MW/km² for planning purposes. It is also important to note that the theoretically available area is often not fully utilizable due to various local constraints, such as the presence of roads and power lines.

Consequently, a more realistic net available area, accounting for such constraints, is estimated to be 60% of the identified suitable land (based on the Consultant experience).

Table 2.5.4: Example of existing power plants and their install capacity

Power plants	Area [km²]	Installed capacity [MW]	Capacity density [MW/km²]
Golomoti	0.62	20	32.2
Nkhotakota / Serengeti	0.55	21	38.0
Salima	1.41	60	42.7
Total	**2.58**	**101**	**39.2 (average)**

Taking into account the available land after excluding unsuitable areas and applying the proposed capacity density, the estimated solar photovoltaic (PV) potential for Malawi stands at a substantial 940 gigawatts (GW).

When we dissect these figures by region, we find that the Northern region contributes 180 GW to the total potential, the Central region offers the highest potential with 440 GW, and the Southern region accounts for 320 GW of the solar PV potential.

Table illustrates that out of an estimated solar power potential of 941 GW, only 505 GW are situated within a distance of less than 25 kilometers from existing grid infrastructure. However, should forests be considered viable for development, the assessable potential increases substantially to 1,640 GW.

The 25 km distance represents a threshold beyond which these factors (losses, cost, efficiency, regulatory concerns) become increasingly impactful. This number is based on the consultant's experience.

Table 2.5.5: Total solar PV area and capacity (in GW) with different sensibilities

Criteria	Total Area (km²)	Area within < 25 km network (km²)	Area beyond > 25 km network (km²)	Total Capacity (GW)	Capacity within < 25 km network (GW)	Capacity beyond > 25 km network (GW)
Forest Excluded	39,218	21,062	18,156	941	505	436
Forest Included	68,242	37,715	30,527	1,638	905	733

5.4.3 Solar PV profiles

Figure represents the hourly photovoltaic (PV) production profiles for selected sites in Malawi, segmented by region. These profiles have been meticulously derived from the PVsyst software, which is dedicated to the simulation of photovoltaic systems. By utilizing this software, we can gain insights into the hourly solar energy generation potential. Additionally, to facilitate energy modelling and forecasting, one distinct profile per region has been incorporated into the PLEXOS simulation software, ensuring a comprehensive analysis of the solar energy distribution across different parts of Malawi.

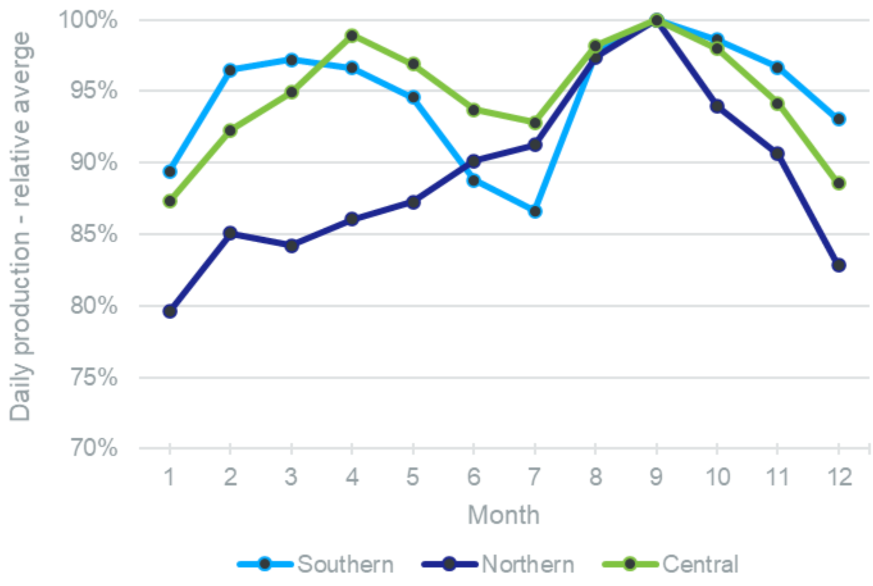


Figure 2.5.10: Daily PV production in average per region

The graph displayed here depicts the variance in daily solar PV production relative to the annual average, broken down by the Southern, Northern, and Central regions of Malawi.

Notably, there are observable trends and differences in solar production across the regions throughout the year. For instance, the Northern region does not show a first peak in April and May, while the other regions do. This suggests seasonal variability and potential regional influences on solar energy generation.

5.4.4 Wind potential

Taking into account the exclusion of certain lands from Malawi's total area for wind energy potential, approximately 4,000 square kilometers remain viable for development, which constitutes about 4% of the country's land area. This assessment uses a baseline wind speed criterion of 7 meters per second.

The distribution of the available area for wind development across the regions of Malawi is notably uneven, with the Northern region holding the majority at 62%, followed by the Central region at 33%, and the Southern region having the smallest share at just 5%.

As of the current status, Malawi has not yet established any wind parks. To project the potential capacity density for future installations, the Consultant has proposed a set of hypotheses based on turbine spacing:

- The optimal spacing between turbines should range from three to five times the rotor diameter laterally, and five to nine times the rotor diameter longitudinally.
- Utilizing the specifications of the SIEMENS Gamesa SG 3.4-145 turbine, which has a nominal power of 3.5 MW and a rotor diameter of 145 meters, the calculated capacity density spans from 8 MW/km² to 25 MW/km² over an area of 5 km² for various configurations at these optimal distances.

- For a conservative estimate and to accommodate potential spatial constraints, the Consultant recommends adopting the lower threshold of 8 MWp/km² for capacity density calculations.

Table 2.5.6: Total wind area and capacity (in GW) with different sensibilities

Wind Speed	Area with Forest Exclusion (km²)	Area with Forest Included (km²)	% of Total Land Area	Capacity with Forest Exclusion (GW)	Capacity with Forest Included (GW)
7 m/s	3,893	6,788	4%	31.1	54
6.5 m/s	6,945	11,319	7%	56	91

Taking into account the previously suggested capacity density, the estimated wind energy potential in Malawi stands at 31 gigawatts.

When dissected by region, the Northern region accounts for the majority with 19.5 gigawatts, followed by the Central region with 10 gigawatts. The Southern region has the least potential, contributing 1.5 gigawatts to the national estimate.

From the total potential of 31 GW, only 10 GW are located less than 25 km far from the network. Two additional sensitivities are studied:

- If forests were included as suitable areas, the total potential would be 54 GW
- If the wind speed criteria were 6.5 m/s, the total potential would be 56 GW

5.4.5 Wind profiles

Figure 2.5.11 provides an analytical view of the monthly wind production profiles for Malawi, categorized by the Northern, Central, and Southern regions. These profiles are generated from the MERRA-2 database, a sophisticated meteorological collection that offers high-resolution weather data.

Each regional profile has been singularly integrated into the PLEXOS modelling software, which is instrumental in simulating and optimizing the energy market operations.

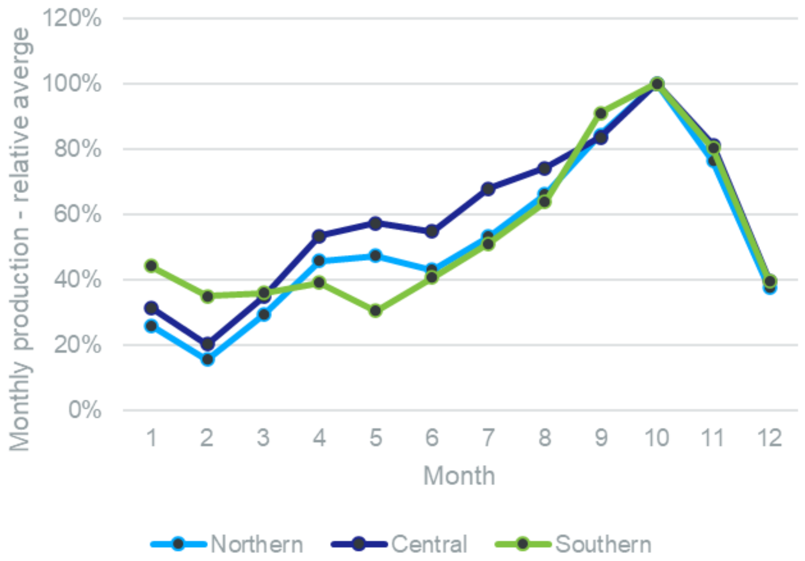


Figure 2.5.11: Monthly wind production per region – relative average

In the graph, we observe the monthly wind production for each of the three regions as a percentage relative to the annual average.

It is evident that all regions follow a remarkably similar trend throughout the year. Each region experiences a gradual increase in production from the beginning of the year, peaking around the latter months. The most notable peak occurs in November, where wind production for all regions dramatically exceeds the annual average. This consistent pattern suggests a uniform influence affecting wind production across the different regions within Malawi.

6. Hydrology analysis

Hydro power plants currently supply the vast majority of the electricity demand. Moreover, hydro power plants are almost exclusively built on the Shire river. Hydro provides a cheap electricity source for the country but comes with some additional risks. Most prominent for a generation master plan is the impact of the climate on the hydro generation. A high level of detail is needed to correctly represent the impact of different levels of precipitation and the resilience of the generation mix to droughts.

Forecasting the flow of rivers for planning purposes, i.e., throughout a long-lasting period, is a challenging task that could hardly result in robust and reliable predictions. However, in a system like the Malawian one, this plays a crucial role in determining the vision of a generation plan. It is thus of key importance to identify a way to correctly model the availability of flows and their uncertainty. This aspect will be tackled in the next subsections. The social and environmental impact of large hydropower projects is out of scope for this project, but should be treated with care in any subsequent studies.

As abovementioned, the purpose of this section is to explain how the uncertainty related to river flows is modelled in the PLEXOS simulation of the capacity expansion plan for the horizon 2022-2042. The figure below shows the key steps of the methodology which are detailed in the following subsections.

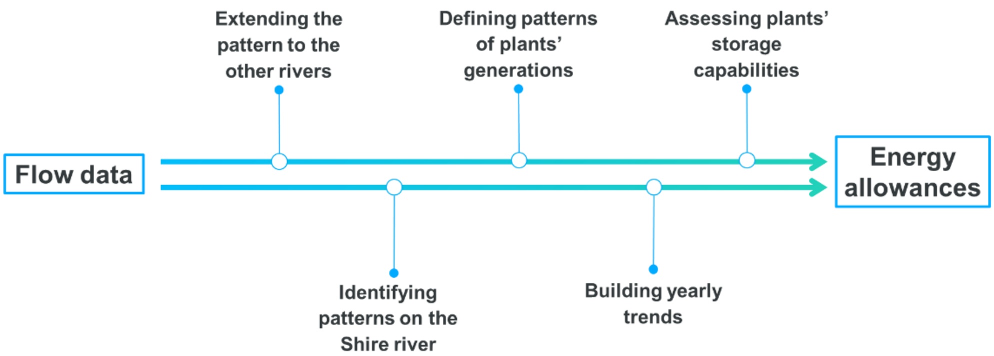


Figure 2.6.1: Methodology to model river flows uncertainty

The hydrology data are derived from the feasibility studies of the candidate power plants [6] [7] [8] [9] [10] [11] [12] [13], and present different sizes of datasets, ranging from 22 to 45 years of measured flows. In particular, information on flows of the rivers Shire, Bua, Songwe, South Rukuru, North Rumphi were collected.

The specific information provided in the different studies is not always the same: data measured could be the flow measured at project site, the annual runoff or other type of information in the same domain. For the purpose of this study, all these are equivalent, as the key information to be conveyed is the variability of the flow (relative changes) rather than the quantities themselves. Hence, the methodology has been designed to be flexible and allows to take the most out of the available data.

6.1 Identifying patterns on the Shire river

Given the role of the Shire river in the hydro production of the country, the purpose of this first step is to analyse the Shire river flow data and derive a reference pattern for probability scenarios that will be then extended to the other rivers. In other words, as the availability of flows on the Shire river heavily weights on the overall hydro production, this aspect will represent the reference for the definition of the samples to be used in PLEXOS to represent flows uncertainty.

The flow data on the Shire river are derived from the Kholombidzo feasibility study [9]. The observations are performed at project site for 60 years, but only the ones starting in 1992 are considered for the analysis, because this is when the outflows of the Lake Malawi started to be regulated by the existing Kamuzu (Liwonde) Barrage.

It can be observed in the figure below that the flow of the Shire river changed quite consistently during the period of observation, with the minimum value equal to only 30% of the maximum value.

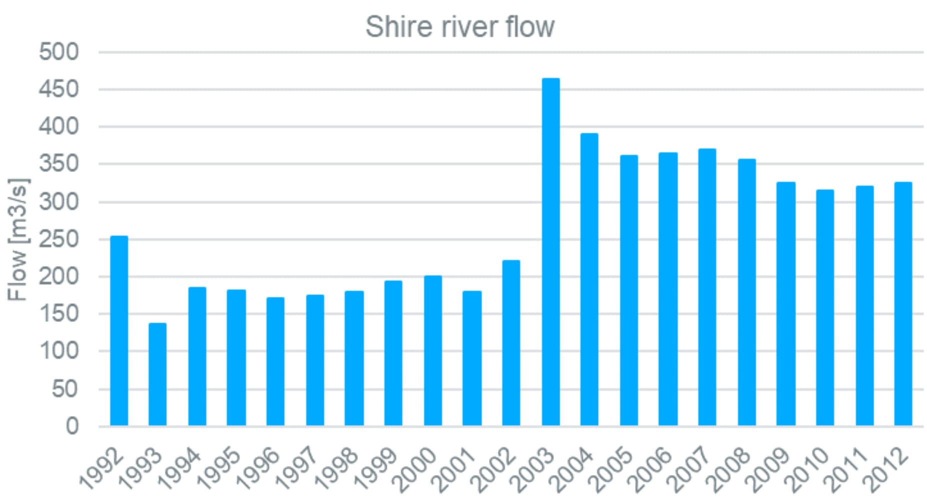


Figure 2.6.2: Shire flows

In order to assess the variability of flows on a certain river and the frequency of each flow level, the flow duration curve should be built. This allows to visualize the full interval of variability of the flow in the collected data and to define representative samples to model such variability in PLEXOS.

If the flows are ranked, the flow duration curve shown in Figure is obtained. By visual inspection, four main levels can be identified and selected to derive the representative samples to be included in PLEXOS, which have been nominated “dry” sample, “average low” sample, “average high” sample and “wet” sample.

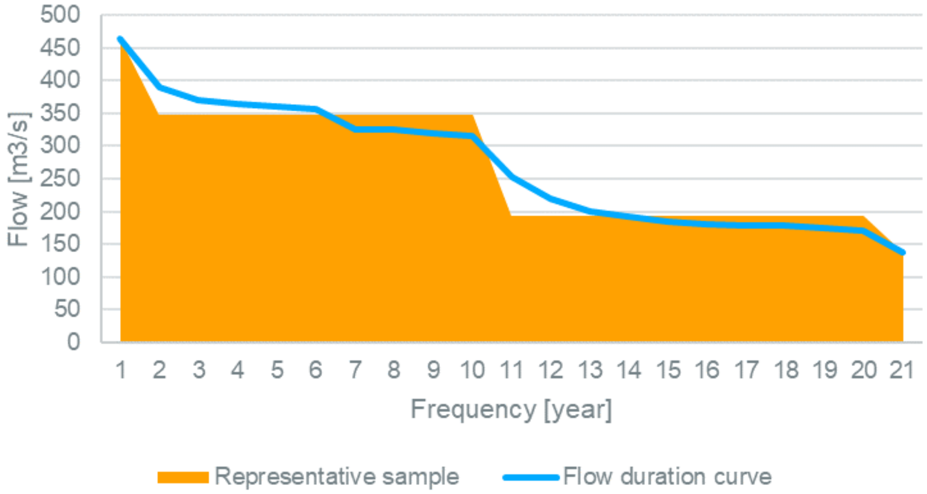


Figure 2.6.3: Shire flow duration curve and representative samples

Based on the number of representative samples and on the number of data falling within each sample, the probabilities listed in Table can be computed, providing information on the occurrence of the different levels. Moreover, the table shows the average values across all elements falling in a specific sample computed and used as representative values.

Table 2.6.1: Samples representing Shire river flows

Sample	Probability	Representative value [m^3/s]
Wet	4.76%	463.29
Avg high	42.86%	347.34
Avg low	47.62%	193.42
Dry	4.76%	137.08

These four values will be used in PLEXOS, together with their respective probabilities, to represent the uncertainty on the Shire river flow and derive a robust capacity expansion plan.

6.2 Extending the pattern to the other rivers

Once the samples for Shire river have been formulated, the same probability distribution is applied to the datasets of the other rivers, to derive an homogenous set of samples to be included in PLEXOS.

6.2.1 Songwe river

The feasibility study of the Lower Songwe provides 45 years of discharge data at Mwandenga gauging station [11]. The data are shown in the figure below. The minimum value is only 23% of the maximum, thus showing great variability in time.

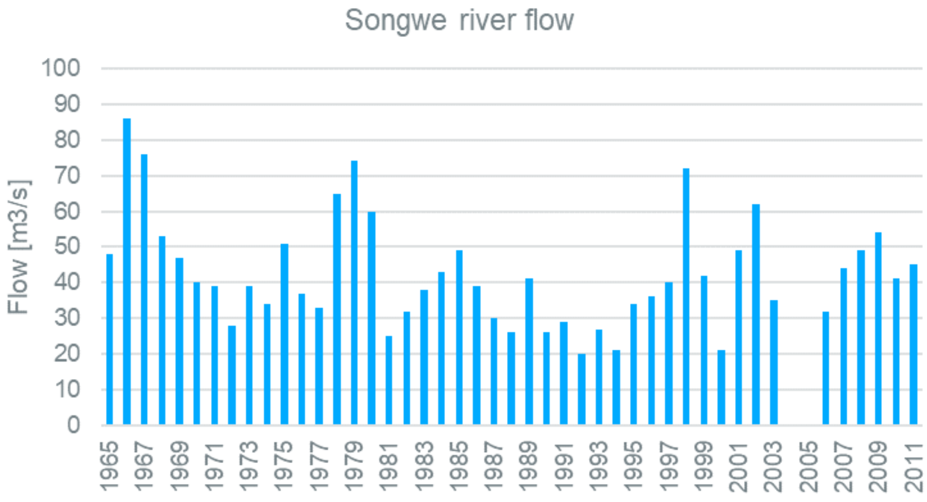


Figure 2.6.4: Songwe river flow

The flow duration curve is built and the four samples probabilities identified for the Shire river are here adopted to split the duration curve into four samples. The resulting representative values are shown in Figure and Table.

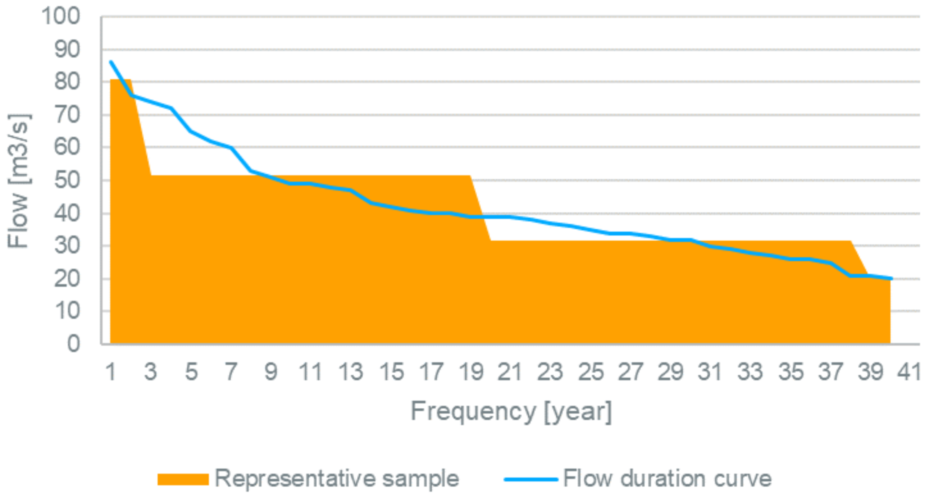


Figure 2.6.5: Songwe flow duration curve and representative samples

Table 2.6.2: Samples representing Songwe river flows

Sample	Probability	Representative value [m^3/s]
Wet	4.76%	81.00
Avg high	42.86%	51.47
Avg low	47.62%	31.63
Dry	4.76%	20.50

6.2.2 Bua river

The dataset retrieved from the feasibility study of Chasombo and Chizuma power stations consists in 31 years of annual runoff at the 5C1 station [7] (see Figure). As mentioned before, the difference in terms of type of data does not affect the quality of the analysis as the variability in the overall water availability is what is of interest, and this can be derived from different types of information. The trend is shown in the figure below, highlighting high variability.

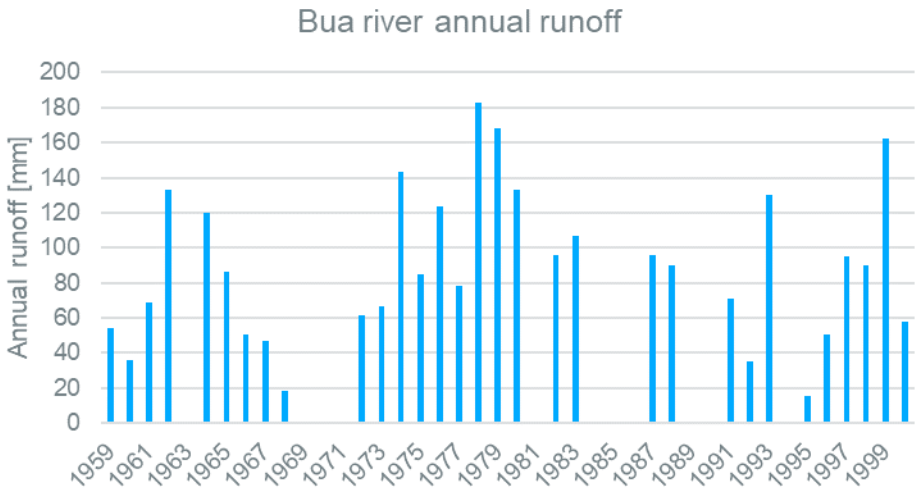


Figure 2.6.6: Bua river annual runoff

The flow duration curve is built and the four samples probabilities identified for the Shire river are here adopted to split the duration curve into four samples. The resulting representative values are shown in Figure and Table .

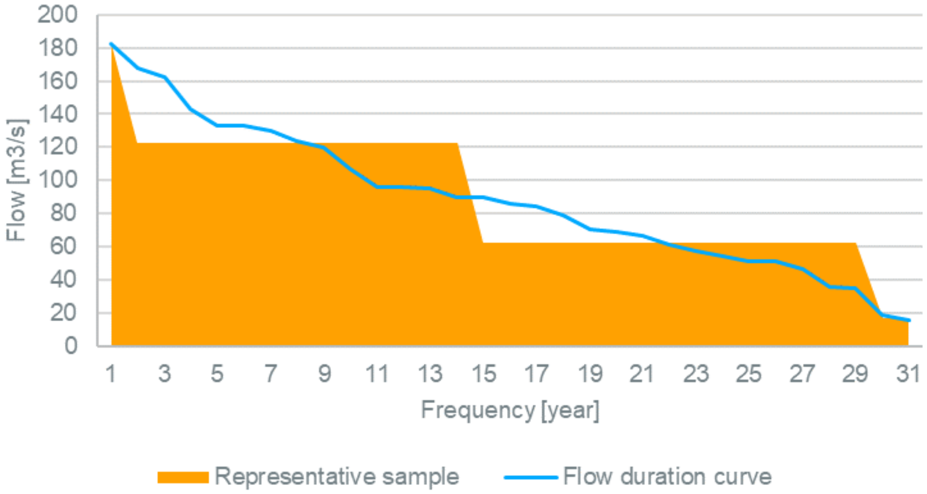


Figure 2.6.7: Bua flow duration curve and representative samples

Table 2.6.3: Samples representing Bua river flows

Sample	Probability	Representative value [m^3/s]
Wet	4.76%	182.44
Avg high	42.86%	122.83
Avg low	47.62%	62.49
Dry	4.76%	16.97

6.2.3 South Rukuru river

The Fufu feasibility study provides 39 years of mean annual discharge of South Rukuru river at Fufu dam site [8], which are shown in the figure below.

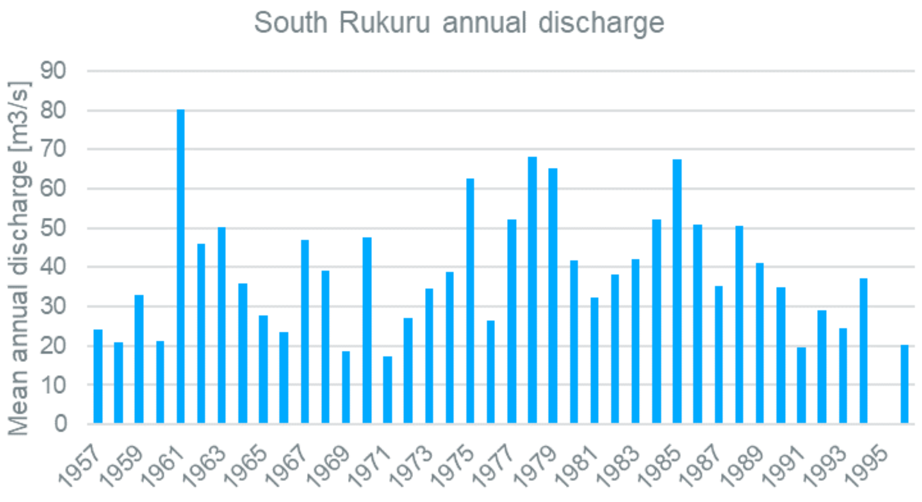


Figure 2.6.8: South Rukuru annual discharge

The flow duration curve is built and the four samples probabilities identified for the Shire river are here adopted to split the duration curve into four samples. The resulting representative values are shown in Figure and Table.

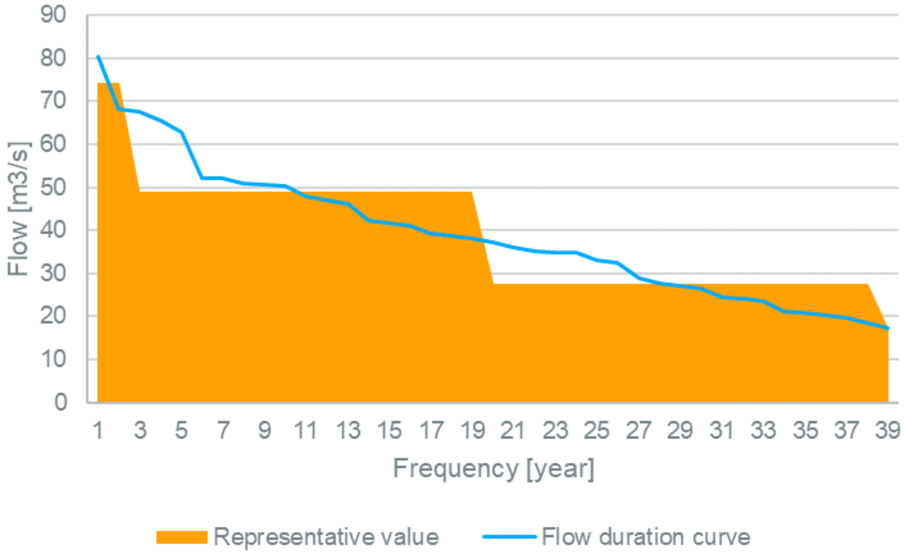


Figure 2.6.9: South Rukuru flow duration curve and representative samples

Table 2.6.4: Samples representing South Rukuru river flows

Sample	Probability	Representative value [m^3/s]
Wet	4.76%	74.17
Avg high	42.86%	49.04
Avg low	47.62%	27.72
Dry	4.76%	17.19

6.2.4 North Rumphi river

The Fufu feasibility study provides 40 years of mean annual discharge of North Rumphi river at the water intake location [8], which are shown in the figure below.

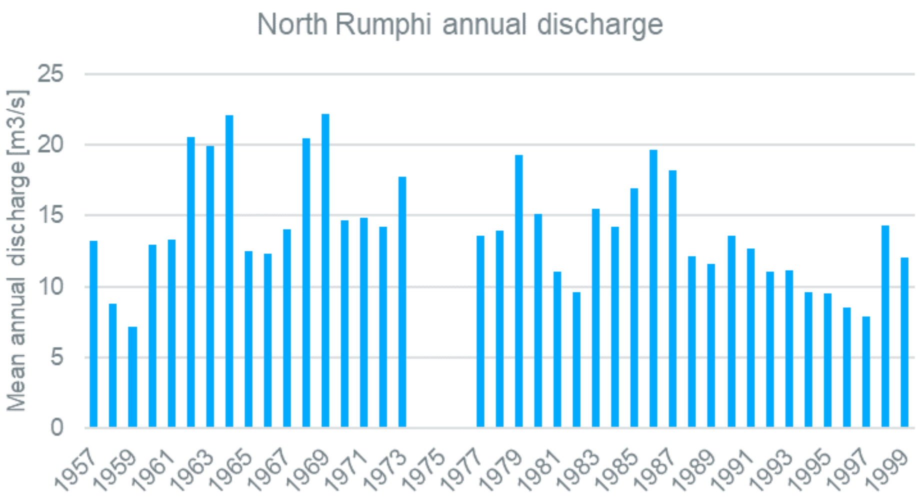


Figure 2.6.10: North Rumphi annual discharge

The flow duration curve is built and the four samples probabilities identified for the Shire river are here adopted to split the duration curve into four samples. The resulting representative values are shown in Figure and Table .

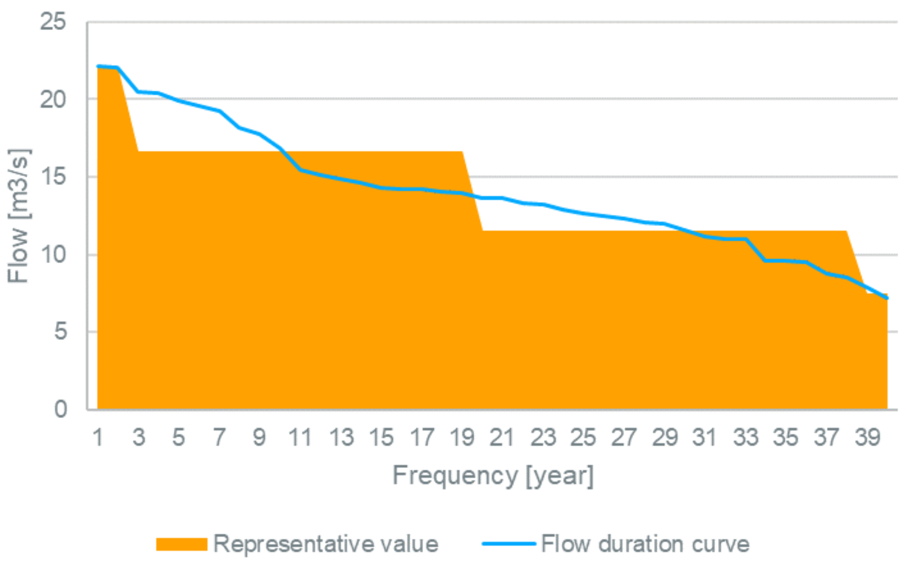


Figure 2.6.11: North Rumphi flow duration curve and representative samples

Table 2.6.5: Samples representing North Rumphi river flows

Sample	Probability	Representative value [m^3/s]
Wet	4.76%	22.13
Avg high	42.86%	16.66
Avg low	47.62%	11.53
Dry	4.76%	7.52

6.3 Defining patterns of plants' generation

In order to translate the flow data into generation data, the average annual production of the different plants is used. A unitary plant productivity is computed as the ratio between the average annual production and the average river flow.

Given that the power produced is proportional to the turbine inflow, this information is used to scale the production to each of the four samples, to obtain the "dry", "average low", "average high" and "wet" annual production of each plant, which is in any case limited by the maximum power of the plant.

6.4 Building yearly trends

Once the annual generation is computed, it needs to be distributed across the year. When available, monthly generation data have been retrieved from the feasibility studies. As an alternative, trends have been derived from the Water Resources Investment Strategy report [14], showing the monthly variability of flows on the different rivers. This information is shown in the picture below.

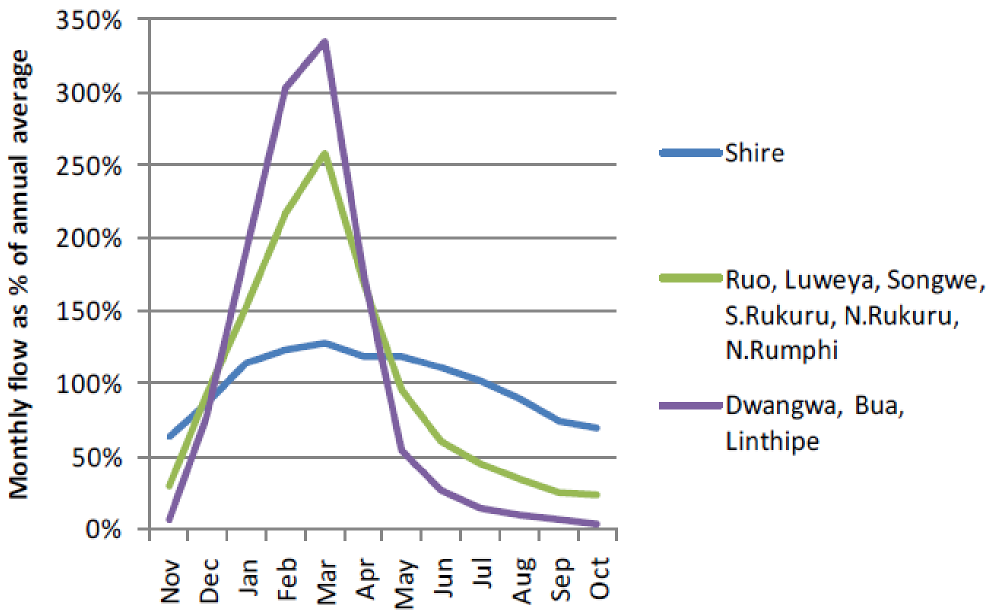


Figure 2.6.12: Monthly flows

It is worth noting that the Shire river is subject to lower monthly variability, being a more robust source of energy throughout the year.

6.5 Assessing plants storage capabilities

The final step consists of translating generation samples into information that PLEXOS can use for the optimization of the system. The approach adopted in this study consists in using energy allowances, i.e. maximum energy producible during a certain period of time, to capture the different degrees of flexibility of the plants. Indeed, hydro power plants are modelled in one of three types, namely run of river, small reservoir, and large reservoir hydro power plants.

Run of river hydro power plants have little to no energy storage. At most, a small pond is present to shift generation throughout the day. They are modelled with a daily generation allowance in PLEXOS.

Small reservoir hydro power plants allow for a higher level of flexibility. They can store the energy equivalent of several weeks up to several months of generation at full capacity. They are modelled with a monthly generation allowance in PLEXOS. This allows to shift generation over short time periods, but not between seasons.

Large reservoir hydro power plants allow for full flexibility of their dispatch. They can store enough energy during the wet season to generate at a constant level throughout the year, including the dry season. They are modelled with a yearly generation allowance, allowing to shift generation between seasons.

Table lists the type of each power plant (existing and candidate). More information about the storage capacities can be found in Appendix B.

Table 2.6.6: Energy allowance per plant

Plant	Energy allowance type
Kapichira I	daily
Kapichira II	daily
Muloza RoR	daily
Nkula A	daily
Nkula B	daily
Tedzani I & II	daily
Tedzani III	daily
Tedzani IV	daily
Wovwe	daily
Mulanje	daily
Chasombo/Chizuma	yearly
Lower Songwe	monthly
Mpatamanga	monthly
Kholombidzo	daily
Fufu	monthly
Mbongozi	monthly
Nyika	daily
Dwambazi	daily
Thyolo	daily
Wovwe 2	daily

7. Optimal generation plan

As mentioned in Section 2, this optimal generation plan is a composite exercise which combines a short- and medium-term strategy based on robust inputs and committed projects, with a long-term vision considering a wide range of investment opportunities as well as uncertainty of river flows. This methodology has been developed to reflect the Working Group discussions, held throughout the whole task development, and the outcomes of the in-person meeting held in Blantyre on the 30th of November 2023, where the Consultant presented the draft generation master plan to key stakeholders and collected comments and feedback for further alignment with the country's interests and strategies.

As uncertainty of hydro resources plays a key role in determining investments in the long term, Section 7.1 provides an overview of the methods available in PLEXOS to deal with uncertain inputs; then, it justifies the choice of a specific approach and establishes the link with the hydrology analysis presented in Section 6. Section 7.2 lists the scenarios analysed in this study for the short, medium and long term, which will be then detailed in dedicated sections. In particular, Section 7.3 describes the approach and the results of the optimization for the short and medium term; two demand scenarios are studied, in order to provide Stakeholders with alternative development plans to be able to adapt the investments based on the measured evolution of the load. Section 7.4 focuses on the long-term vision, by analysing two key scenarios: Least Cost, including as candidate options all technologies and plants realistically available in the country, and Least Cost + Strategic Projects, imposing the commissioning of strategic projects identified with the Stakeholders.

7.1 Modelling flows uncertainty in PLEXOS

As discussed in Section 6, river flows are highly variable. Given that the vast majority of energy production in Malawi relies on hydro power plants and that the availability of the resource in the long term in highly uncertain, variability of flows is one of the key aspects to be modelled in PLEXOS for the formulation of the robust development plan.

The software provides three ways to deal with uncertainty:

1. **Deterministic optimization**: the expected value is used. Hence, there is no explicit modelling of uncertainty and one single solution (capacity expansion and system operation) is the outcome of the optimization.
2. **Monte Carlo simulation**: the *n* scenarios based on the *n* input samples are run separately (using deterministic optimization) and the results consist in one full long-term plan (capacity expansion and system operation) per sample.
3. **Stochastic optimization**: Single optimization incorporating all *n* samples and their probabilities, resulting in one capacity expansion output and *n* operating strategies.

As the modeller moves from deterministic to stochastic optimization, complexity and computational burden grow, together with the robustness of the results. Intermediate options like Monte Carlo simulation allow for more sophisticated solutions with respect to deterministic optimization, but they require interpretation and post-processing of results, given that multiple solutions are provided. On the contrary, stochastic optimization reflects the uncertainty of inputs and uses it to derive the best plan possible; then, the actual operation of the system will depend on the real-time realization of the uncertain inputs, and this is why multiple operating strategies are proposed by the solver.

As discussed in Section 2, there is limited uncertainty concerning the hydro resources of the next few years, given the availability of historical data and the slow pace of change of the flows, particularly for the Shire river, thanks to the stabilizing action performed by lake Malawi. Hence, the short- and medium-term evolution is studied using a deterministic optimization that accounts for the near-term forecasts, which envision good availability of resources.

The Consultant uses instead the stochastic optimization option in order to cope with uncertainty in the long term, when reliable forecasts cannot be formulated, as it allows for a complete assessment of the variability of river flows, which heavily affect the operation and the performances of the system. Hence, the resulting long-term capacity expansion plan will consider the costs and the risks associated to each sample and define the most convenient and robust solution.

Each sample included in the stochastic optimization is characterized by a specific flow availability and its related probability. Hence, the optimization is composed by the 4 samples and probabilities presented in Section 6 (dry, avg low, avg high, wet). The outcome of the optimization is a long-term expansion plan that accounts for all the possible representative flows and defines the best compromise solution considering all costs and risks.

7.2 Scenarios

With the purpose of providing a comprehensive analysis that could capture all the different aspects and constraints guiding the future evolution of the generation system in Malawi, different scenarios are studied and presented in this report.

As mentioned in Section 2, a key distinction is made between short and medium term on one side, long term on the other side. The short- and medium- term evolution focuses on the period 2023-2029, when reliable forecasts of trends in river flows are available. Moreover, there are near-term strategies and projects which are about to be implemented and taking them into account allows to build a more realistic and tailored investment plan in the short, medium and long term. Furthermore, in order to provide the Stakeholders with a view on no-regret investments for the short and medium term, two optimizations are solved using two different demand scenarios.

The analysis of long-term requires instead the assessment of a wide range of options and realisations of the inputs. For this reason, uncertainty of river flows, playing a key role in electricity generation in Malawi, is now carefully integrated by means of a stochastic optimization. The best system evolution is derived from the Least Cost (LC) optimization, where all technologies realistically available in the next future in Malawi are considered as possible investments. Additionally, the impact of including in the generation portfolio strategic projects selected by the Stakeholders is assessed in the Least Cost + Strategic Projects (LCSP) optimization.

The table below summarises the key aspects of each scenario, which are then detailed in the dedicated sections 7.3 and 7.4.

Table 2.7.1: Different scenarios run for the development of the IRP

Horizon phase	Description	Sensitivities
Short- and medium-term evolution 2023-2029	Deterministic optimization considering good hydro availability and near-term committed projects	Main scenario (LC): Base case demand forecast (including DSM and EE measures)
		Sensitivity: Low case demand forecast
Long-term vision 2030-2042	Stochastic optimization based on 4 samples of hydro availability, Base case demand	Main scenario (LC): all available technologies and projects treated as candidates, hence all investments are optimized
		Alternative scenario (LCSP): key strategic projects are included in the investment plan

7.3 Short- and medium-term evolution

7.3.1 Context and input assumptions

In order to identify the robust investments to be surely performed in the near future, a run focusing on the period 2023-2029 and accounting for short- and medium- term forecasts and strategies is performed. The purpose of this simulation is twofold: on the one hand, to collect feedbacks and assess impacts of strategies and projects of Malawi in the short term; on the other hand, to include realistic forecasts and to test conservative assumptions that would avoid overinvestments and highlight the plants that would be strategic under any circumstances. The features of this short- and medium-term focus are listed below.

- Short term strategy and plans:
    - No investment in new diesel capacity but rather preference for refurbishment of existing diesel units (total available capacity growing from 41.7 MW to 51.4 MW and maximum capacity factors reaching 80%).
    - BESS for energy shifting (20 MW-30 MWh) decided from 2025.
    - Small hydro power plant Wowve 2 (4.5 MW) decided from 2027.
- Realistic forecasts and conservative assumptions to avoid overinvestments:
    - Good availability of hydro resources in the coming years (corresponding to avg high sample).
    - Sensitivity analysis on demand forecasting. Two cases are simulated: Base case demand forecast including DSM & EE (consistent with long term vision) and Low case demand forecast (allowing to eventually review the investment plan on basis of the measured demand growth).

The following sections present the results of the simulations performed under the list of inputs listed above. In particular, Section 7.3.2 describes in the details the outcomes of the main short- and medium-term evolution, i.e. the one using the Base case demand forecast. Section 7.3.3 discusses the impact of a lower demand and Section 7.3.4 draws the conclusions of these analyses.

7.3.2 Least cost scenario

7.3.2.1 Installed generation capacity

Under the assumptions listed in the previous section, there is no need to install new power plants in the short term, besides the small addition of 23 MW of PV in 2026. The refurbishment of the existing diesel generators and the interconnection with Mozambique would be able to follow the demand growth, in a context where good availability of flows in the rivers leads to high shares of hydro generation. During this period, the number of hours with unserved energy remains limited and reached an acceptable maximum of 200 hours/year at the end of the dry season of 2026 (period of the year with highest demand).

Starting from 2027, new technologies are integrated into the capacity mix: wind and biomass are installed, while the PV capacity keeps increasing. Moreover, the small hydro power plant of Wovwe 2 is installed in 2027. Details about the capacities are provided in Table .

It can be noted that the selection of the biomass project to be realised will be based on the opportunities taking into account the availability of the primary resource and the production costs. These projects can be agricultural waste or culture e.g. bagasse, or waste to energy.
The following figure presents the evolution of the installed capacity over the period 2023-2029 along with the import potential and the peak demand.

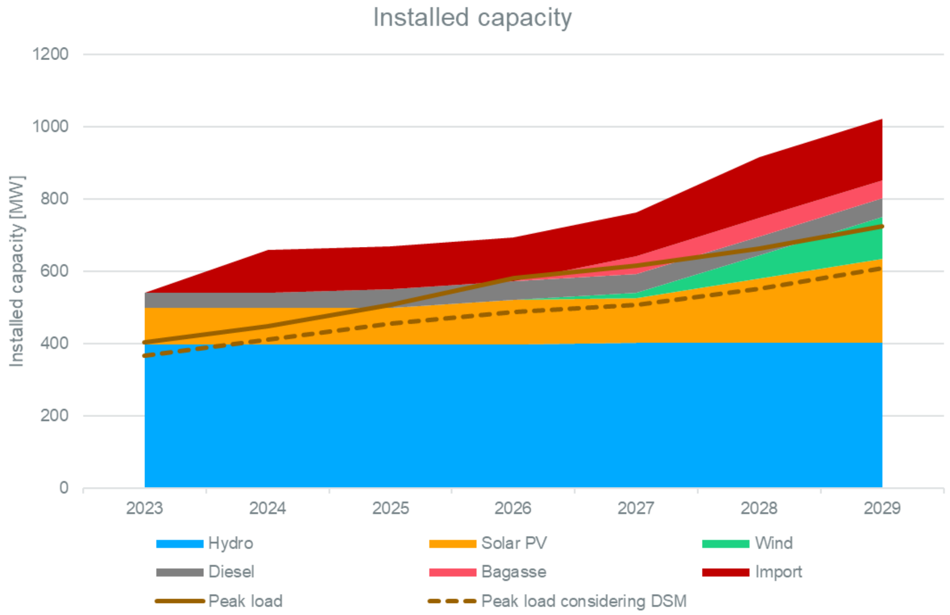


Figure 2.7.1: Installed capacity per technology in Least Cost short-term focus

The margin of the system, computed as the ratio of the dispatchable generation (hydro and thermal) and peak demand taking into account DSM and EE measures, is 22.3% in 2022. It quickly decreases in the following years, when the interconnection with Mozambique is given a key role in supplying the demand, up to a point where the total installed dispatchable capacity is below the peak demand (from 2025 on).

The following table details the installed capacity per technology and for selected years.

Table 2.7.2: Installed capacity per technology in Least Cost short-term focus

	Installed capacity [MW]			
Technology	**2023**	**2025**	**2027**	**2029**
Hydro	398	398	402	402
Solar PV	101	101	124	233
Wind	0	0	15	116
Diesel	42	52	52	52
Coal	0	0	0	0
Gas	0	0	0	0
Biomass	0	0	50	50
Geothermal	0	0	0	0
Total	**541**	**551**	**643**	**853**
Import potential	0	120	120	170
Peak demand	405	508	617	725
Peak considering DSM	367	456	509	610

7.3.2.2 Generation

The activation of the take-or-pay import contract from Mozambique alters significantly the energy mix of the country, as fixed import of 120 MW ends up covering around one third of the total demand. This rules out almost completely diesel generators (not even visible in the figure below): they support the system mostly at the end of the dry season/beginning of the wet season (between October and December), when the demand is higher and the hydro availability is lower.

Energy from PV panels is fully exploited and the increasing capacity allows for its share in the energy mix to stay stable around 6% in spite of the increasing demand.

In 2027, new technologies are included in the system, namely wind turbines and biomass plants. Hence, the energy mix diversifies, while keeping a heavy reliance on hydro power plants (more than 60% of the total).

The following figures present the energy mix for the years 2025 and 2027. The yearly production by technologies are expressed in GWh.

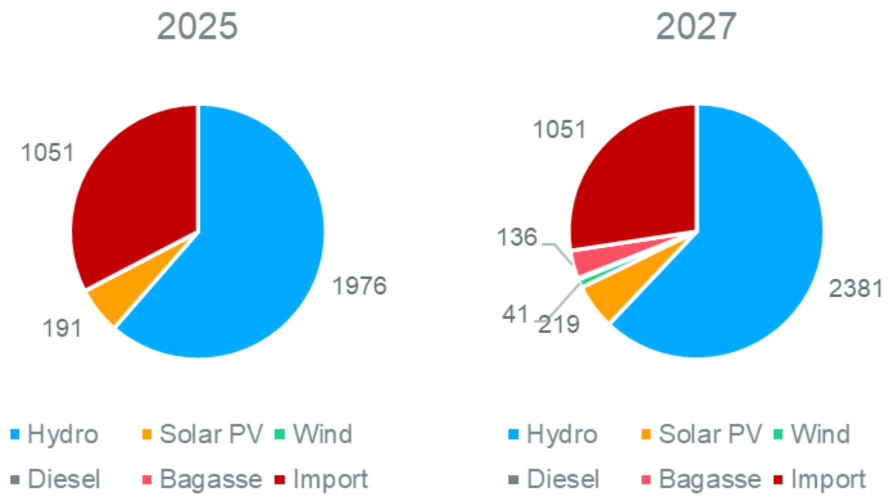


Figure 2.7.2: Generation mix in 2025 and 2027 in Least Cost short-term focus [GWh]

The capacity factors shown in Table further highlight the evolution in the use of the different technologies. Currently, the system is isolated and hydro and PV are used as much as possible to reduce the consumption of fuel and the significant operating costs of diesel generators.

The full import capacity of the interconnection with Mozambique is exploited starting from October 2024, thus bringing to almost zero the use of diesel gensets in 2025. In the same year, the potential hydro production is not totally exploited, yet the increase of the demand brings about the new increase in the hydro capacity factor in 2027. Moreover, in 2027, wind energy is introduced in the system, together with biomass production. Finally, diesel units are used in moments of need, hence being characterized by an overall almost-null capacity factor.

Table 2.7.3: Weighted capacity factors per technology in Least Cost scenario

	Yearly capacity factor [%]		
Technology	**2023**	**2025**	**2027**
Hydro	65	57	68
Solar PV	21	22	20
Wind	0	0	32
Diesel	11	0	2
Biomass	0	0	31
Import	0	100	100

In terms of reliability of the system, the abundance of hydro resources and the availability of thermal units lead to the ability of the system to fully supply the load. The only exception happens in 2026, when the demand keeps increasing with the only addition of 23 MW of PV. In particular, towards the end of the year, when the load is higher and hydro flows are lower, almost 200 hours of unserved energy occur. Still, this is within acceptable reliability levels and acceptable costs for the system, also considering that new technologies become available in 2027 and restore full load supply under all circumstances.

7.3.2.3 Reserves

Primary and secondary reserves are needed to ensure the frequency stability of the system. The reserve requirements and their evolution along the study period are defined in section 4.6.

This section presents the results of the analyses regarding the reserve provision. This analysis is based on the detailed simulation of the hourly dispatch of the generating units of the optimum generation development plan.

7.3.2.3.1 Primary reserve

The assessment of the dispatch of the units on an hourly basis allows to verify if sufficient fast acting reserve can be provided under the different operation conditions. Given the evolution of the reserve requirements shown in Figure , the most challenging years to provide reserve are between 2025 and 2027, i.e., when the interconnection with Mozambique is the only connection with the SAPP system and the take-or-pay contract enforces a fixed import of 120 MW. Hence, the analysis is focused on these three years, when the primary reserve requirement is 120 MW (see Section 4.6 for detailed explanations).

In these first years of the horizon, the newly installed capacity is fairly limited and the existing hydro and thermal units are responsible for reserve provision. As discussed in Section 7.3.2.1, between 2025 and 2027 there is no margin of dispatchable generation with respect to the peak, as the system heavily relies on the imported energy from Mozambique. Hence, it is very challenging for the system to provide such a large amount of reserve in case of loss of the interconnection. Indeed, a partial shortage would always be present and the system needs to be integrated with additional units in order to be able to satisfactorily comply with the reserve requirements. To reach percentile 90% of reserve fulfilment, 100 MW of additional reserve capacity is required i.e. the reserve requirements are totally covered 90% of time leading to a very small probability of experiencing an incident larger than the reserve available at this moment. It is therefore recommended to add to the system new features dedicated to the provision of reserve and able to inject rapidly up to 100 MW into the network to complement the reserve that can provided by existing hydro and diesel units.

7.3.2.3.2 Primary reserve fulfilment – Technology selection

Once the limits of the system to fully provide the needed reserve are assessed, the cheapest technology for the provision of such service needs to be identified. In order to do this, the Levelized Cost Of Reserve (LCOR) of the suitable options is computed.

First of all, the technologies to be involved in the analysis need to be selected. Considering that the most critical years are between 2025 and 2027 (as discussed in the previous section), only the options readily available to quickly tackle the issue and with the needed technical characteristics to provide the service should be taken into account.

In particular, both BESS and diesel generators could be available in 2025 and would have the responsiveness and flexibility required to provide reserve. Hence, these two options are included in the analysis. OCGT would also represent a technically suitable technology, but the fact that it could only be available starting from 2027, makes it less interesting for the purpose of providing the missing reserve in the period 2025-2027.

The Working Group discussions put forward the additional option of stringing a second circuit on MOMA to offer N-1 security on the loss of the main circuit. Even if this solution would be less robust then adding generating units (a problem on the line infrastructure would affect both circuits), it is still considered as a good option bearing acceptable level of risk. Moreover, this solution could already be available from 2024. A last option would be the recourse to a Special Protection Scheme (SPS) associated to the tie-line: in case of the trip of the line, an automatic protection will rapidly trigger the shedding of an amount of load corresponding to the import through the line minus the available reserve. This solution is not recommended as it leads to the disconnection of consumers but can be considered as a temporary solution to avoid wider loadshedding and the black-out of the isolated system.

In terms of techno-economic features of the options under analysis, the diesel unit considered is the same as the generic diesel generator included in the list of candidates (see Section 4.1). For what concerns the battery, as the unit considered as candidate is more suitable for demand shifting purposes (duration of 4 hours, as per Section 4.2), a BESS with different characteristics is considered, namely with capacity-to-energy ratio equal to 1. The specific CAPEX (USD/kW and USD/kWh) are the same used for the demand shifting battery. Finally, the cost of the second circuit is derived from the offer received by a contractor who is willing to undertake the second stringing: a supply and installation cost of 20.4 MUSD is proposed. On top of that, 1% O&M costs are considered.

The way these three options provide reserve is quite different: on the one hand, a diesel unit would need to be active and working at its minimum stable level in order to be readily available when needed; on the other hand, the BESS system only needs to be charged once and the line only needs to be commissioned in order to effectively provide the service. Hence, the diesel genset would need to continuously consume fuel, while the batteries and the line would only cause limited fixed costs. This leads to a very wide difference of the LCORs, as shown in the table below.

Table 2.7.4: LCOR of diesel generator, BESS and second circuit

Technology	LCOR [USD/kW]
Diesel generator	812
BESS	72
Second circuit	20

Hence, giving the important cost difference, it is clear that diesel generators represent the least convenient choice in order to effectively tackle reserve shortages. The installation of 100 MW of BESS dedicated to reserve would instead be quite efficient but identifying a developer and commissioning the project by 2025 might prove challenging. Moreover, the least expensive option is actually the commissioning of a second circuit on the interconnectors.

In conclusion, stringing a second circuit is the recommended solution, also based on the discussions with the Stakeholders during the Working Group meetings and during the presentation of the draft final report in Blantyre on the 30th of November 2023. Besides lower cost and faster implementation, this option, directly covering the full 120 MW requirement, would also reduce the need to keep an available margin for dispatchable units, which potentially represents an additional economic advantage of such a choice.

7.3.2.3.3 Secondary reserve

In the short and medium term, the secondary reserve requirement is foreseen to be 32 MW, which is the size of the biggest unit in the system (see Section 4.6). Given that the existing diesel units are rarely used after the commissioning of the MoMa line, they could be employed for the provision of secondary reserve.

This could become challenging in 2026, when the demand keeps increasing with the only addition of 23 MW of PV. In particular, towards the end of the year, when the load is higher and hydro flows are lower, diesel generators are used frequently to supply the demand, thus reducing the available margin to provide reserve. As this higher use of diesel units happens at the end of the dry season (and because of the dry season), existing hydro is also not available to provide the secondary reserve. Hence, alternative solutions should be investigated.

One option would be to invest in additional peaking units; as gas would hardly be available before 2027, diesel would be the most suitable technology, which would however go against the current strategy of the country, not willing to further invest in diesel units. Long-term storage could be integrated in the system for this purpose, or agreements with neighbouring countries could also be established in order for them to provide the service. Finally, an additional option would be to define and implement on-demand DSM measures with large consumers.

It is worth mentioning that in 2027 new capacity would be installed (biomass, wind and small hydro) and diesel units utilization would again fall down drastically, making them available again for secondary reserve provision. Moreover, in case the second circuit is implemented on the MoMa interconnection, more capacity would be available for secondary reserve provision already since 2024.

7.3.2.4 BESS

Batteries can support a system in multiple ways and play a key role especially for energy shifting and reserve provision. This last function is particularly efficient, if compared to traditional technologies, e.g. diesel gensets (see previous section).

Energy shifting is normally another very interesting service provided by BESS, especially in case of high penetration of VRE. Nevertheless, the case of Malawi is quite unique as the massive presence of hydro power plants, as well as the plan to install new ones, provides the system with the flexibility that would normally be performed by BESS. Indeed, the existing and future run-of-river power plants are considered to be able to provide daily flexibility. Moreover, a 30 MW battery is foreseen to be installed in 2025, to improve further the use of renewable energy, whose share in the capacity mix increases to reach around 35% in 2029, as shown in the figure below.

7.3.2.5 Operational feasibility

Detailed dispatch analysis is performed throughout the studied period, in order to guarantee the operational feasibility of the system. The years 2025 and 2027 are shown in the figure below to highlight the evolution of the system in the short and medium term. Two different periods of the year are shown, namely a low load period (January/February), also characterized by high hydro availability, and a high load period (October/November), coming at the end of the dry season, hence characterized by limited hydro resources.

In both 2025 and 2027, when the load is low, the take-or-pay import energy and the renewable sources (hydro and PV) are sufficient to fully supply the load and part of the renewable energy gets curtailed. The DSM and EE measures allow to flatten the evening peak and smoothen the load curve. Similar behavior can be spotted in 2025 in the period of high load, while the same period in 2027 is characterized by a more varied mix of sources (wind and biomass are installed). Wind resource is more available towards the end of the year (see Section Figure), which couples well with the higher demand in the same period. Moreover, thermal generation is also dispatched, with priority to the newly available biomass plants, characterized by lower O&M costs with respect to the existing diesel gensets.

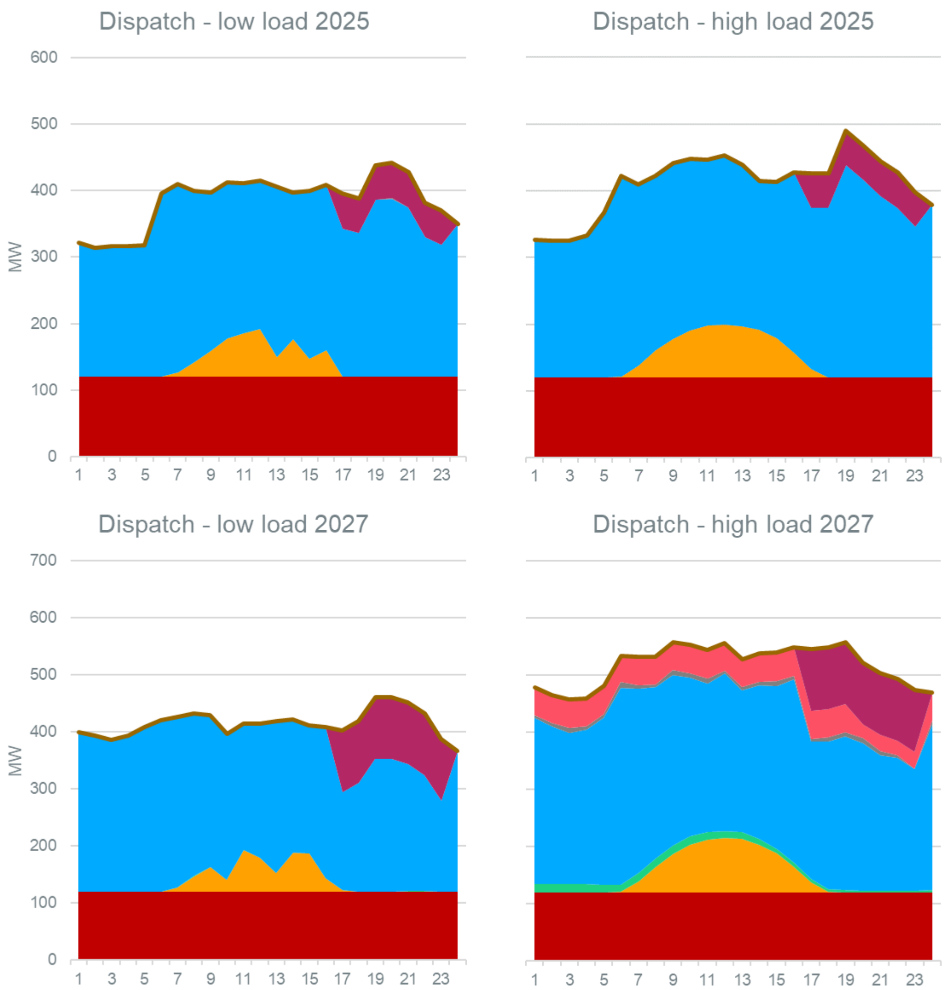


Figure 2.7.3: 1-day dispatch in 2025 and 2027 for dry and avg low samples in Least Cost short-term focus

7.3.3 Sensitivity analysis – Low demand scenario

If the low demand scenario of the ECA demand forecast study is adopted (see Figure and Figure), the growth rate falls from above 8% to around 4%, both in terms of total yearly demand and peak.

Under this assumption, no additional capacity is needed in the short and medium term, besides the already planned installation of the run-of-river hydro power plant of Wovwe 2 (4.5 MW). Hence, the foreseen good availability of flows in the next few years, if combined with a more conservative projection of load growth, highlights that the current short-term plans would be sufficient to supply the demand in the next few years. In particular, the improvement of the availability of the existing assets (diesel gensets) and the start of the take-or-pay import contract would provide enough additional energy to accommodate a slower increase of the electricity demand.

Under the present low demand scenario, the possibilities of provision of reserve are similar to the situation presented above for the base case scenario: sufficient primary reserve can be provided by the available thermal, hydro and BESS units most of the time depending on the demand level and the availability of the units. The availability of reserve is highly improved with the commissioning of the first interconnection and same recommendations are made for the commissioning of a second circuit as soon as possible and implement a SPS to rapidly decrease the national demand in case of loss of the interconnection(s).

Figure shows that the fixed amount coming from Mozambique would cover between 35% and 40% of the total load, while solar PV would supply around 6-7% of the demand, and hydro power plants would generate most of the electricity needed.

If compared with the generation mix in case of Base case demand scenario (see Figure), the contribution of hydro appears lower, as the fixed import and the energy coming from PV are enough to cover a larger share of the demand. Hence, more hydro energy gets curtailed.

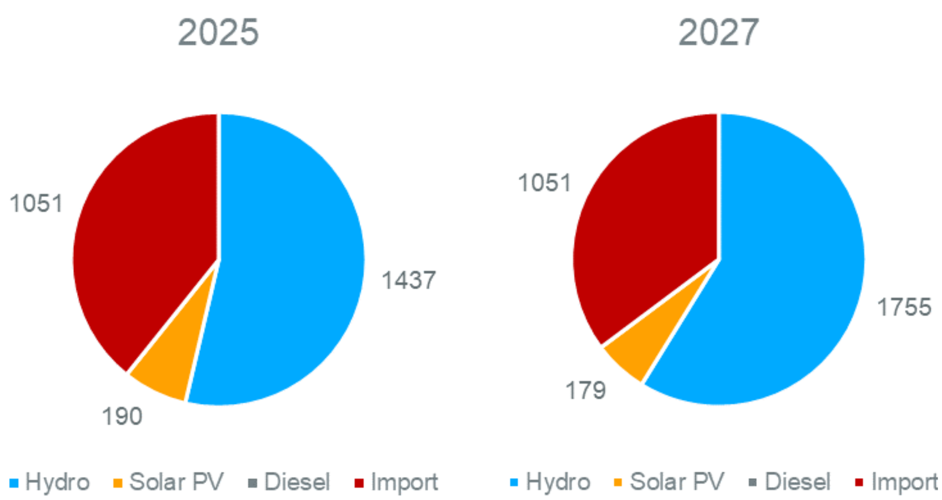


Figure 2.7.4: Generation mix in 2025 and 2027 in Least Cost short-term focus - Low demand alternative

7.3.4 Conclusions on short- and medium-term evolution

When formulating the optimal generation masterplan for the short and medium term, robust inputs concerning strategies, projects as well as forecasts on the availability of resources can be used. Hence, the first investments can be planned considering solid information and tailoring the plan to the most recent discussions and vision about the development of the country.

In the case of Malawi, this led to the several key assumptions, including the investment in BESS and small hydro, the removal of diesel generators from the options for new investments (refurbishment of existing units has been considered), the forecast of good hydro flow availability for the next few years.

Given the role that hydro generation plays in the Malawian power system, this last assumption is key in determining the trend of the investment plan. Indeed, the good water level forecasted for the next years, together with the establishment of the interconnection with Mozambique and the fixed import of 120 MW, determines a limited need to further invest in new power plants in the short and medium term.

BESS and VRE represent the key addition to the existing portfolio. This is aligned with the type of projects under discussion at the Ministry of Energy. Indeed, a fairly long list of IPPs (mostly PV and wind) is under consideration, with different stages of the process being currently in place (PPA negotiation, waiting for financial close,…).

In particular, a 20 MW BESS is foreseen to be commissioned in 2025 and this supports the integration of VRE while also representing a valuable resource for primary reserve provision, in case the second circuit on the MoMa interconnection is not readily available.

The refurbishment of diesel units results strategic for the reliability of the system, as the existing plants will tend to be used less and less for supplying the demand (hydro, import and VRE will almost totally cover the needs) and could therefore be employed for the provision of secondary reserve.

Finally, the adoption of DSM and EE measures is also recommended, as it reduces the peak demand and eases the dispatch of renewable resources. For all the scenarios, **reserve requirements** have been taken into account, as primary and secondary reserves are needed to ensure the frequency stability of the system. Minimum primary and secondary reserve requirements are estimated for the current situation as well as for the considered evolution of the interconnected system. It is also highlighted that the assumptions made should be regularly revised in time based on the actual evolution of the Malawian system as well as the SAPP region as a whole.

In particular, for what concerns primary reserve, the requirements in the short term might be extremely challenging or easily fulfilled based on the integration of a second circuit on the interconnection with Mozambique (recommended option). Nevertheless, it has to be noted that, while allowing to respect the N-1 criterion for network planning, a second circuit on the interconnection line with Mozambique presents also important disadvantages:

- The two circuits will be on the same tower structure and structural default could lead to the unavailability of both circuits at the same time (structural vandalism, extreme wind speed etc.)
- Having both regional interconnections with the same country and at the same substation might lead to additional risks e.g. in case of unfavourable events within Matambo substation or the feeders of Matambo substation, or in case of geo or intra country politics which may affect the contract of power supply and limit the access to the regional market

Based on these considerations, it is recommended to maintain permanently the available primary reserve on the existing diesel and hydro units as well as BESS. This reserve (amounting to 20 to 50 MW depending on the availability of the units) is not sufficient to guarantee the stability of the isolated Malawian systemin case of sudden disconnection from the regional system and the loss of the 120 MW import. It should therefore by a properly sized SPS (Special Protection Scheme) triggering rapidly the shedding of the right amount of demand as soon as the loss of the interconnection is detected.

This situation will be resolved with the commissioning of an interconnection line with a second country of the SAPP regional system.

The need in the long term will be quite limited as Malawi will be fully integrated in the SAPP network. In case shortages arises, BESS proved to be the most efficient technology to fill the gap.

The secondary reserve requirement is based on the biggest unit in the control area, whose installed capacity currently amounts to 32 MW. As big hydro power plants are integrated in the system during the study period, this requirement evolves accordingly. If shortages occur, the key options to provide additional secondary reserve are the following: investing in additional peaking units; employing long-term storage; establishing agreements with neighbouring countries; define and implement on-demand DSM measures with large consumers.

Under a no-regret optimization, assuming a lower demand growth, the only investments that are kept in the short- and medium-term development are the decided small hydro Wowve 2 and the 20 MW of BESS. This would push forward the installation of new VRE power plants. Hence, the trend in the economy, population and consequently electricity demand should be closely monitored in order to update accordingly the investment plan if needed.

7.4 Long-term vision

7.4.1 Context and input assumptions

The long-term vision aims at building on the outcomes of the short- and medium-term evolution analysis to develop a robust investment plan that could reliably supply the growing electricity demand from 2030 to 2042. The extension of the horizon under study and the peculiarities of the Malawian power system, i.e., high reliance on hydro generation, require particular attention in treating the vast uncertainty on the availability of resources. In particular, river flows and their probabilities have been analysed in Section 6 and represent a key input of the long-term vision, based on a stochastic optimization which adopts the four representative hydrology samples identified in Section 6 to provide a robust investment plan. Hence, this aspect is only included in the long-term vision, as the current flow level and the stability of the resource given the presence of Lake Malawi suggest good water availability in the coming years, and stochastic optimization with all the samples would lead to unnecessary overinvestments in the short and medium term. It is instead pivotal to include this aspect in the long-term plan, to be able to capture this inherent uncertainty of hydro resources for power production and security of supply in Malawi.

The aim of this optimization is to define the least-cost path to reliably supply the demand during the studied horizon. For this purpose, Working Group discussions identified the list of possible technologies and plants that could be realistically integrated in the Malawian power system in the next 20 years. As mentioned in Section 4.2, hydro power plant characteristics are strictly related to their geographical location. Hence, new investments in hydro generation are related to existing projects, for which techno-economic characteristics could be collected. On the contrary, VRE and thermal units are represented by means of generic units and it is then up to PLEXOS to define the optimal sizes. The detailed characteristics of all the candidate units are presented in Appendix B.

This Least Cost (LC) scenario provides the unbiased evaluation of the most efficient path to reach security of supply while guaranteeing reliability at the lowest cost possible. The development of a power system is however subject to numerous constraints, including but not limited to availability of primary resources, need of diversification of the energy mix, geopolitical relationships and agreements with countries exporting fuels etc. For this reason, an additional scenario is run for the long-term vision, with the aim of assessing the impact of such plans and constraints, as anticipated in Section 2. Such scenario, named Least Cost + Strategic Projects (LCSP), considers the outcomes of multiple interactions between the Consultant and the Stakeholders, in order to accurately verify the implications of including the identified strategic projects in the Malawian power system. The detailed list of strategic projects integrated in the optimization is provided in Section 7.4.3.1.

The results of the LC and LCSP scenarios are presented in Sections 7.4.2 and 7.4.3, respectively. Finally, conclusions are drawn in Section 7.4.4.

7.4.2 Least cost scenario

This section presents the optimum development plan corresponding to this scenario: the evolution of installed capacity by technology and the operation of the generation system to supply the demand along the study period. Considerations about the provision of reserve and storage are also provided.

7.4.2.1 Installed generation capacity

The evolution of the capacities per technology over the study period is presented in Figure 2.7.5. The values of installed capacities for key years are given in Table . The main features of the generation system evolution are the following:

- In the long term, as soon as their commissioning is possible, some large hydroelectric projects are selected (Mpatamanga from 2030 and Kholombidzo from 2033). PV, wind and EE-DSM measures continue to grow. One additional interconnection line is selected
- Towards the end of the horizon, the energy mix keeps diversifying with the addition of gas fired units

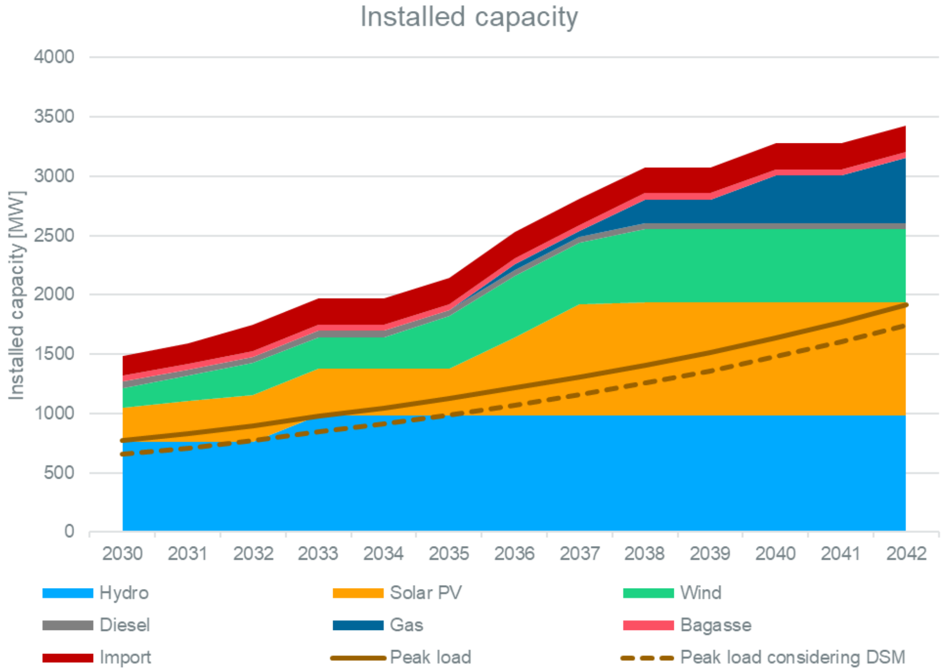


Figure 2.7.5: Installed capacity per technology in Least Cost scenario

The following table provides the installed capacities per type of unit for key years over the study period as per the outcome of the least-cost scenario. The total installed capacity evolves from 540 MW in 2022 to 1638 MW in 2032 and 3342 MW in 2042 (not considering import). An important share of the capacity is constituted by VRE (PV and wind). The penetration rate of VRE in terms of installed capacity is already 18.7% in 2022. The penetration rate reaches 40.5% in 2032 and 47% in 2042.

Storage is discussed in a dedicated section (see Section 7.4.2.4). It is interesting to note that possible DSM and EE measures identified in the load forecast study are selected as optimum to reduce the energy demand and most of all the demand during the peak.

Another interesting parameter is the margin of the system which is computed as the ratio of the dispatchable generation (hydro and thermal) and peak demand taking into account DSM and EE measures. The margin is 22.3% in 2022. It decreases greatly in the short and medium term (see Section 7.3.2.1), to then increase with the new hydroelectric projects starting from 2030. As the demand and the VRE penetration keep increasing, the margin decreases again to reach 1.5% in 2042. Such a small margin is sufficient to achieve the targeted level of reliability thanks to the diversification of the mix (less impact from hydrology), the integration into the SAPP regional network with several interconnection lines (possibility of import and export, limited reserve to be maintained by each interconnected system), deployment of wind plants (possible contribution to the supply of the peak demand contrarily to PV generation).

Table 2.7.5: Installed capacity per technology in Least Cost scenario

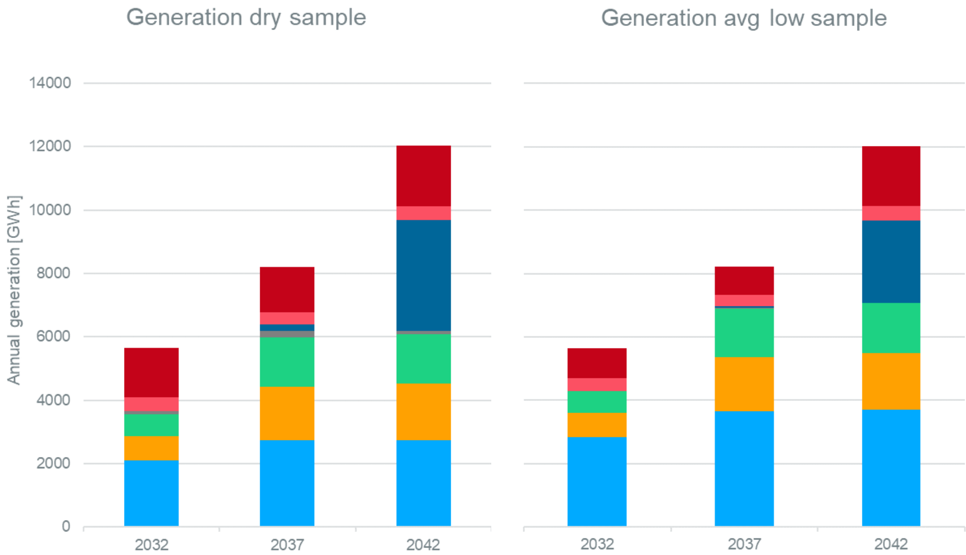
	Installed capacity [MW]		
Technology	**2032**	**2037**	**2042**
Hydro	763	982	982
Solar PV	395	940	956
Wind	268	513	615
Diesel	52	52	52
Coal	0	0	0
Gas	0	50	550
Biomass	50	50	50
Geothermal	0	0	0
Total	**1527**	**2586**	**3204**
Import potential	220	220	220
Peak demand	900	1307	1914
Peak considering DSM	771	1159	1746

7.4.2.2 Generation

As mentioned in Section 7.1, the applied stochastic optimization produces one single capacity expansion plan (presented in the previous section), while the operation of the system is scenario dependent. Hence, the four different input samples translate into four different optimal ways to manage the installed units (optimal dispatch of the units). In this way, the stakeholders can derive insights on what would be the best resource allocation in case of dry, average or wet year. It is to be borne in mind that the extreme scenarios (*dry* and *wet*) would normally occur only about once every 20 years. Hence, the *avg low* and *avg dry* results would correspond to the most representative optimal ways to operate the system.

The figure below shows the annual generation by technology for each sample, highlighting that the cases characterized by low availability of hydro resources (*dry* and *avg low*) heavily relies on import also after the end of the take-or-pay contract with Mozambique in 2029. Moreover, biomass plants (bagasse) would operate at very high capacity factor (80-100%) for the whole time they are available, while gas units would only come online later on, in order to cope with the demand growth towards the end of the horizon.

The figure shows that the energy mix varies greatly when higher river flows allow for more hydro production (*avg high* and *wet* samples). Hydro production is used to accommodate the load which cannot be supplied by VRE (solar PV and wind). Thermal units are rarely used to cover the peaks.



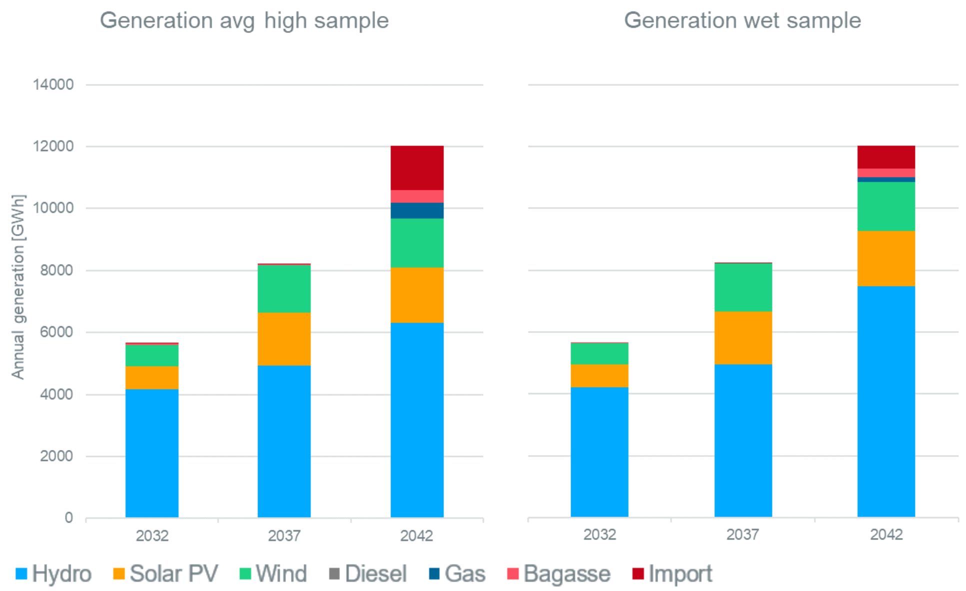


Figure 2.7.6: Annual generation per sample in Least Cost scenario

As highlighted in Figure , the availability of river flows can significantly impact the operation of the system. It is worth noticing that the extreme scenarios (*dry* and *wet*) are included in the simulation together with their probability of occurrence to build a robust expansion plan; however, their probability of occurrence is low and the corresponding system operation is not representative of a "normal" year.

For this reason, a weighted average of the results of the different samples is used to compute representative capacity factors of the different technologies and to derive all-encompassing insights.

Overall, Table 2.7.6 shows that renewable resources (hydro, PV, wind) present quite a stable capacity factor, mostly based on the availability of the resource itself. On average, capacity factor of hydro is normally above 50%, while for PV and wind they are around 21 and 30% respectively.

For what concerns thermal units, diesel is the only option available in the first years to support RES and it is highly employed to supply the load; its capacity factor falls considerably as soon as import and VRE are available. Given the high operating costs, diesel units are then rarely used throughout the rest of the horizon. On the contrary, biomass (bagasse) units are installed as soon as they are available and always used at high annual capacity factor, rapidly increasing towards the end of the horizon and exceeding 90%. Finally, the installation of gas units starting from 2036 aims at supporting the existing RES-based plants to supply the growing demand and provide the needed flexibility: as the load increases, the capacity factor grows. A similar use is shown for import, whose use drops dramatically after the end of the take-or-pay with Mozambique, but gains momentum again towards the end of the horizon, ending up reaching almost full use.

Table 2.7.6: Weighted capacity factors per technology in Least Cost scenario

	Yearly capacity factor [%]		
Technology	**2032**	**2037**	**2042**
Hydro	52	49	58
Solar PV	22	21	21
Wind	29	34	29

Diesel	0	1	0
Gas	0	7	34
Biomass	55	45	94
Import	27	26	86

7.4.2.3 Reserve

The reserve requirements in the long term are discussed in Section 4.6. Minimum primary and secondary reserve requirements are estimated for the current situation as well as for the considered evolution of the interconnected system. It is also highlighted that the assumptions made should be regularly revised in time based on the actual evolution of the Malawian system as well as the SAPP region as a whole.

In particular, for what concerns primary reserve, the need in the long term will be quite limited as Malawi will be fully integrated in the SAPP region and its contribution, based on its current share in the network in terms of yearly generation and peak load, has been estimated to 6 MW. As abovementioned, the electrical weight of Malawi within SAPP will evolve as a function of the national growth and the growth of all the interconnected countries. The coefficient should therefore be regularly reviewed and communicated by SAPP. For the purpose of the present study, this computed level of primary reserve will be considered for the whole period of study. This quantity is easily maintained by the system and does not lead to shortages. It has to be mentioned that this situation is valid as soon as the national system is connected to the regional grid through two independent interconnections as explained in section 7.3.4.

Given the considerations made in Section 7.3.2.3.2 about the LCOR (Levelized Cost Of Reserve) of the different possible technologies, BESS would be the preferred option in case the reserve needs would change substantially and shortages of primary reserve would occur in the long term.

Analogously, the secondary reserve requirement is currently based on the biggest available unit, whose installed capacity amounts to 32 MW. As big hydro power plants are integrated in the system during the study period, this requirement evolves accordingly, reaching almost 55 MW in 2033 with the commissioning of Kholombidzo hydro power plant. If shortages occur, the key options to provide additional secondary reserve are the following: investing in additional peaking units; employing long-term storage; establishing agreements with neighbouring countries for them to provide the service; define and implement on-demand DSM measures with large consumers.

7.4.2.4 BESS

As mentioned in Section 7.3.2.4, batteries can support a system in multiple ways and play a key role especially for energy shifting and reserve provision. As detailed above, one existing and one decided project BESS are considered in the present study. They will participate to the integration of the VRE generation. Additional candidate BESS for energy shifting were considered as candidate for the investment optimization but not selected to be integrated into the least cost generation mix.

As discussed in section 7.3.2.3.2, BESS constitutes one of the best solution for reserve provision i.e. with the lowest LCOR, the recommended solution being the commissioning of a second circuit on the future Mozambique-Malawi interconnection line. See also in section 7.3.4, the discussions on the advantages and disadvantages for reserve associated to the implementation of a second link on the same infrastructure. If that latest solution is not implemented, the integration of a 100

MW BESS dedicated to fast acting reserve is recommended. Along with the existing generation participating to reserve (diesel and hydro), the BESS will maintain the stability of the isolated system in case of tripping or unavailability of the MoMa line. As explained in the previous section, such amount of reserve will be required until a second connection with the SAPP system will be commissioned in order to respect the N-1 rule and be considered as always connected to the regional system for planning purposes. After that, the required primary reserve is drastically reduced and the BESS can be either used for energy shifting to ease VRE integration, reduce system operation cost and potentially provide export possibility outside of the solar production period or decommissioned.

Indeed the energy shifting capacity of hydro grows greatly in 2030, when Mpatamanga is installed, as it is provided with a reservoir that can regulate flows across months. For this reason, the increase of the share of PV and wind in the capacity mix does not lead to the installation of additional energy shifting BESS. On the contrary, decided 20 MW BESS is decommissioned as the other existing batteries after their economic lifetime of 15 years and the hydro plants provide enough flexibility to efficiently manage the available resources.

7.4.2.5 Unserved energy

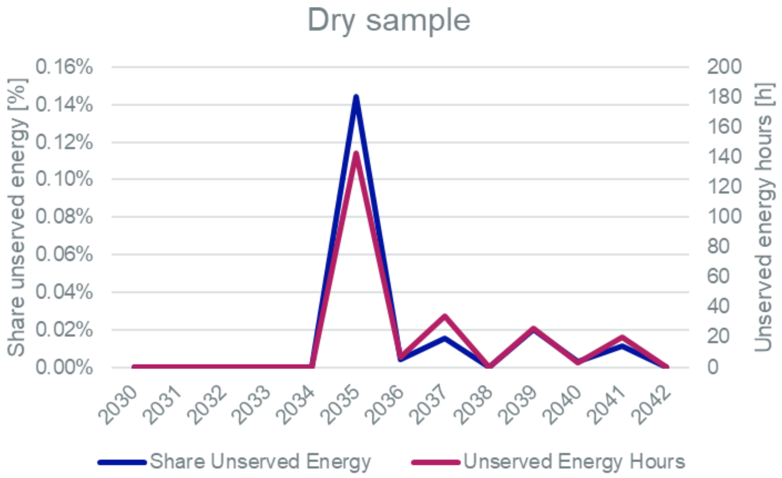
The assessment of the reliability of the system is done by looking at the *dry* and *avg low* samples, as the other two samples would be characterized by higher availability of hydro resources and thus better reliability.

The criteria to assess the system reliability are discussed in Section 4.5. It is worth noting that the two subfigures below are characterized by a different scale in terms of unserved energy hours, to ease a correct interpretation of the results.

The share of unserved energy remains very low (below 0.15%) for the whole horizon also in the *dry* scenario, while the unserved energy hours (LOLE) oscillates around the reference value of 100 hours/year. Some limited spikes can be identified when the detailed modelling of the ST module in PLEXOS (detailed system operation) reveals that the variability of RES leads to the inability to fully sustain the load growth without installing further units.

It is worth noting that the *dry* scenario has very low probability and the system is still able to guarantee satisfying levels of reliability. Indeed, the *avg low* scenario sees a fall to zero of the unserved energy in most years, with very few sparse unserved energy hours across the horizon.

The recommended generation development plan therefore respect the defined planning criteria and ensure a sufficient reliability level under the different possible hydrology levels.



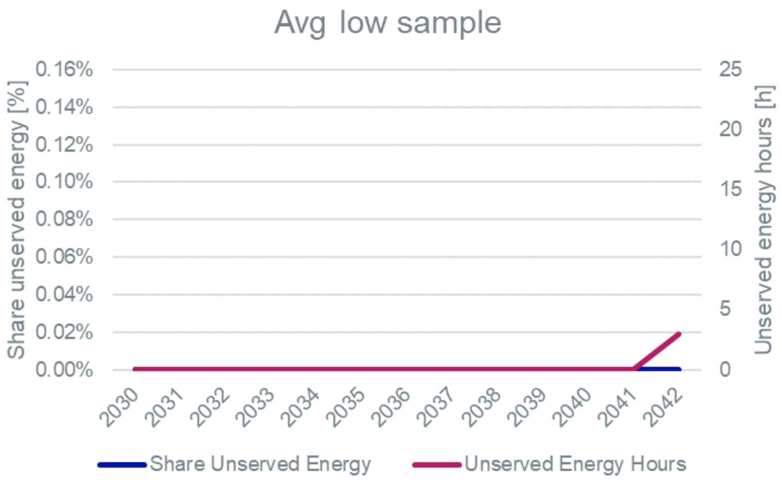


Figure 2.7.7: Reliability indicators of dry and avg low sample in Least Cost scenario

7.4.2.6 Import and export potential

Based on the input data discussed in Section 4.3, the possibility to import represents a very interesting option in the Least Cost scenario, where the cheapest available solution is recommended.

Figure presents the yearly import in GWh for selected years in the long term and clearly shows how the need for imports is heavily dependent on the availability of river flows for hydro production. In particular, in the *dry* scenario and *avg low* case, import needs fall thanks to the installation of new hydro power plants (Mpatamanga HPP in 2030, Kholombidzo HPP in 2033); however, the installed units are not able to keep up with load growth and import maintains a key role in supplying the demand.

In the *avg high* and *wet* scenarios, the end of the take-or-pay contract practically marks the almost total phase-out of imported energy, with a change in the trend over the last few years of the considered horizon.

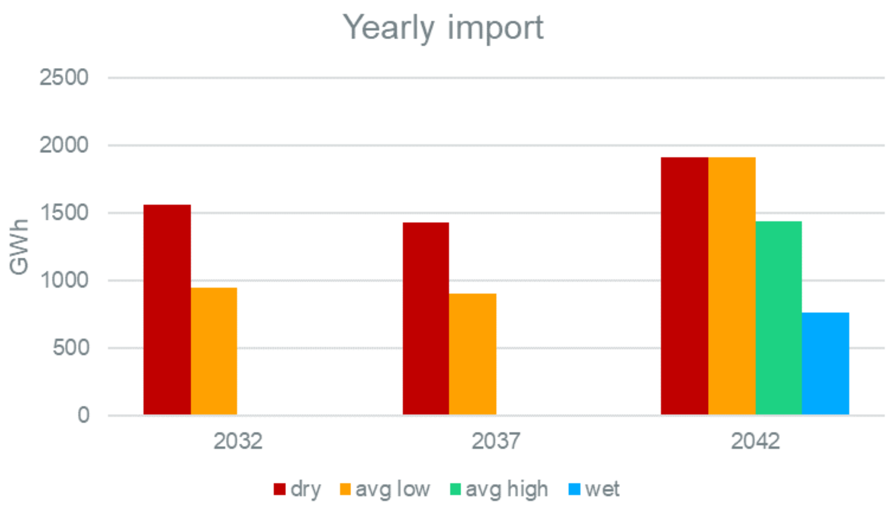


Figure 2.7.8: Yearly import per sample in Least Cost scenario

By looking at the total excess energy from PV, wind and hydro, it can be derived that export is particularly interesting when there is high availability of river flows, as this determines higher excess from renewables, which is easily available at almost no cost. The excess energy from RES sees peaks when new big hydro power plants are installed, with a maximum value beyond 3.5 TWh in the *wet* scenario as presented at the next figure.

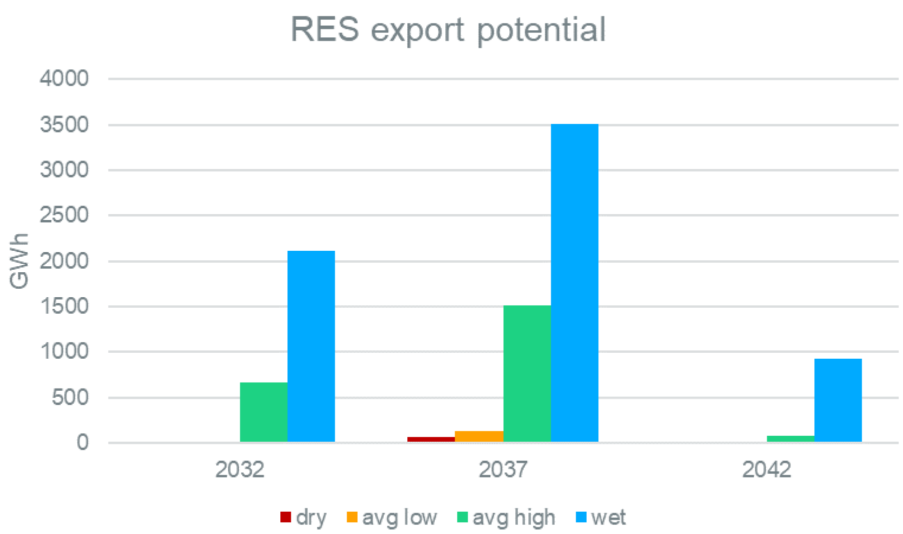


Figure 2.7.9: Total yearly RES export potential per sample in Least Cost scenario

If the available energy from thermal units is also considered, the total export potential can be derived. In scenarios with high availability of hydro resources, the need for thermal plants to supply the domestic load is reduced and the availability for export increases.

The weighted average trend of the total export potential, considering the probabilities of the different samples, is shown in Figure , together with minimum and maximum levels. In case of high availability of hydro, the export potential could double with respect to the weighted average case (around 4 times the potential in the *dry* case). The potential grows steadily during the horizon studied, to reach 4.6 TWh with the installation of gas power plants in the last years.

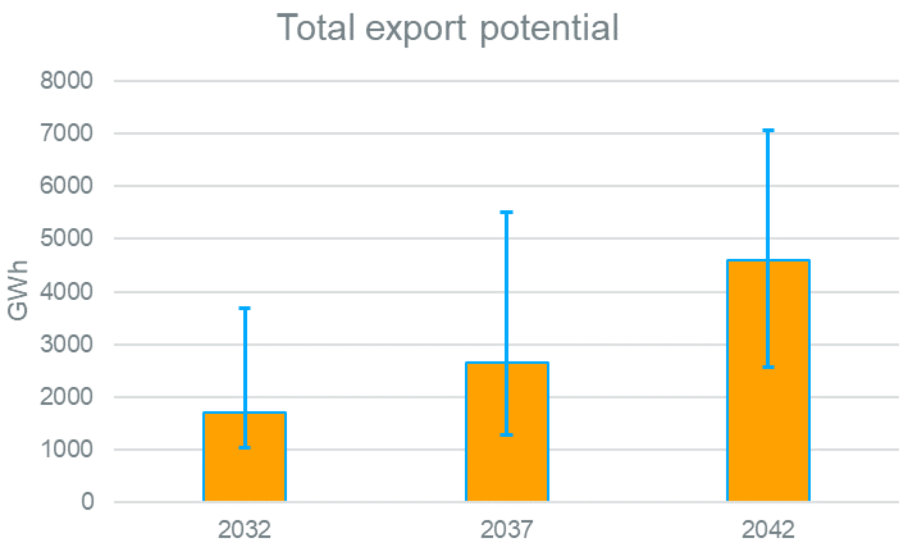


Figure 2.7.10: Weighted average, min and max export potential in Least Cost scenario

In order to assess in detail the export opportunities, a dedicated study at regional level would be necessary, so that the simultaneity of excess generation with the import needs of the neighbouring countries as well as the outcomes of the electricity markets could be thoroughly assessed.

7.4.2.7 Operational feasibility

In order to test the operational feasibility of the expansion plan, the Consultant complemented the long term modelling by an operation or production cost model (unit commitment model run with the ST module of PLEXOS). In such model the operation of the system is further refined with the highest possible level of detail. The objective is to make sure that the final long term generation expansion model proposes adequate power units to answer to all constraints.

The model is run on all samples. For the sake of brevity, key years and scenarios are here presented in order to provide meaningful insights. In particular, the dispatch in 10 years (2032) from the beginning of the study period is analysed. A typical day in a low load period (January/February) and a typical day in the high load period (October/November) are shown.

Only *dry* and *avg low* scenarios are shown here, as they represent the most challenging situations for the system, and proving the operation feasibility in these two scenarios entails the operational feasibility of the other two. Hence, the *dry* and *avg low* scenarios in low and high load periods are shown in the figure below. In 2032, the presence of Mpatamanga and more wind units allow to fully supply the demand while limiting the use of diesel generators. In the beginning of the year, availability of wind is usually lower (see Section 5.4.5). The increased load towards the end of the year requires higher use of thermal power plants, but higher presence of wind allows to limit these quantities.

Even after the end of the take-or-pay contract, import keeps contributing to a considerable share of the total production, being less expensive than increasing the generation of diesel units.

The reservoir of Mpatamanga provides enough flexibility for the system; hence, the existing batteries are rarely used throughout the whole year.

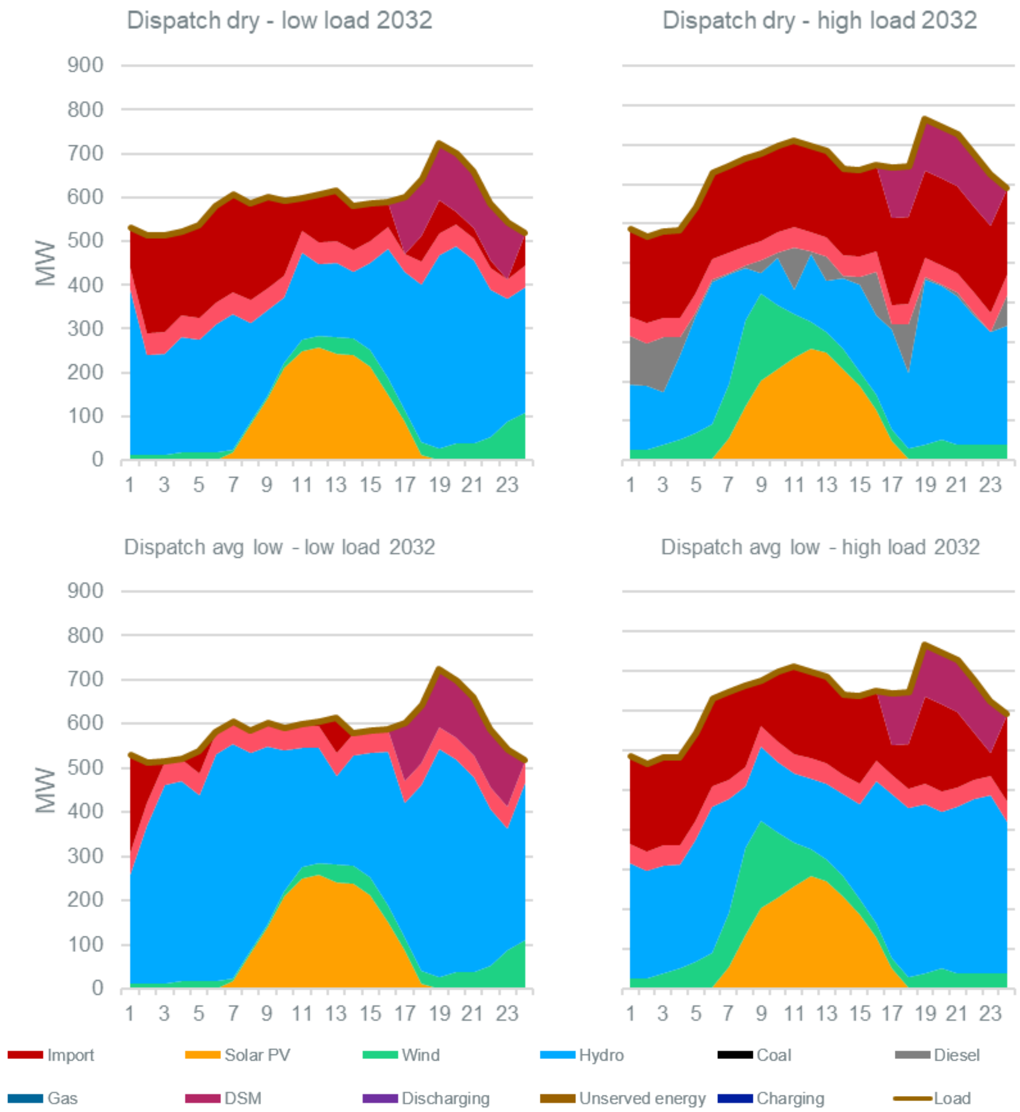


Figure 2.7.11:1 -day dispatch in 2032 for dry and avg low samples in Least Cost scenario

7.4.3 Least Cost with strategic projects scenario (LCSP)

Based on the discussions with the Stakeholders during the Working Group sessions organized to present the preliminary results and notably the Least Cost scenario (Section 7.4.2), the need for an alternative scenario was highlighted taking into account the latest decisions, constraints and strategic project at national level identified by the Stakeholders in Malawi. The features, constraints and strategic projects were discussed and validated with the Stakeholders during the presentation of the preliminary results on November 30th in Blantyre. The features of this scenario are defined in the next section.

The purpose of the LCSP scenario is to determine the optimal development plan considering these constraints. The long-term optimal trend was identified with the Least Cost scenario. The impact of the modifications and constraints in the short-term are highlighted with the analysis of the

LCSP scenario. In order to provide a broader view on evolution possibilities, sensitivity analyses to assess the impact of one additional constraint are carried out.

7.4.3.1 Strategic projects

The table below lists key project identified by the Stakeholders during the Working group meetings and during the presentation of the draft generation masterplan in Blantyre. These have been considered as strategic for the development of the power sector in the country; hence, they are considered as decided, i.e., imposed in the investment plan. The integration of these power plants in the system allow to reach diversification in terms of river basin already in the medium term as the small hydro plants imposed before 2030 would not resort to the Shire river. Moreover, an overall diversification of the energy mix would derive from the integration of gas and coal units.

If needed, additional investment are determined with the optimization routine based on the available candidate units (same techno-economic characteristics as in the Least Cost scenario).

Table 2.7.7: Strategic projects identified by the Stakeholders and integrated in the LCSP scenario

Project	Commissioning year
Gas power plant of 50 MW	2027
Hydro plant Wovwe 2	2027
Hydro plant Nyika	2027
Hydro plant Mbongozi	2028
Hydro plant Thyolo	2028
Coal power plant of 300 MW	2030
Hydro plant Mpatamanga	2030
Hydro plant Chasombo&Chizuma	2033
Hydro plant Dwambazi	2033
Hydro plant Fufu	2034
Hydro plant Kholombidzo	2034
Hydro plant Lower Songwe	2035

The techno-economic characteristics of these plants are presented in Section 4.2.

7.4.3.2 Installed generation capacity

The evolution of the available capacities per technology in the long term is presented in Figure . The values of installed capacities for key years are given in the Table. The main features of the generation system evolution are the following. The differences compared to the Least Cost scenario are also highlighted.

- As in the short and medium term multiple strategic projects are included in the generation portfolio, there is limited need to add further capacity in the first years analysed (2030 already sees the integration of Mpatamanga in the system as well as the addition of 300 MW of coal).
- In the long term, as soon as their commissioning is possible, some more large hydroelectric projects are added to the system (Chasombo and Chizuma and Dwambazi in 2033, Kholombidzo and Fufu in 2034 and Lower Songwe in 2035).
- Towards the end of the horizon, the energy mix keeps diversifying with the addition of wind plants and the increase of capacity of PV plants and gas fired units, required for ensuring flexibility and following the demand growth.

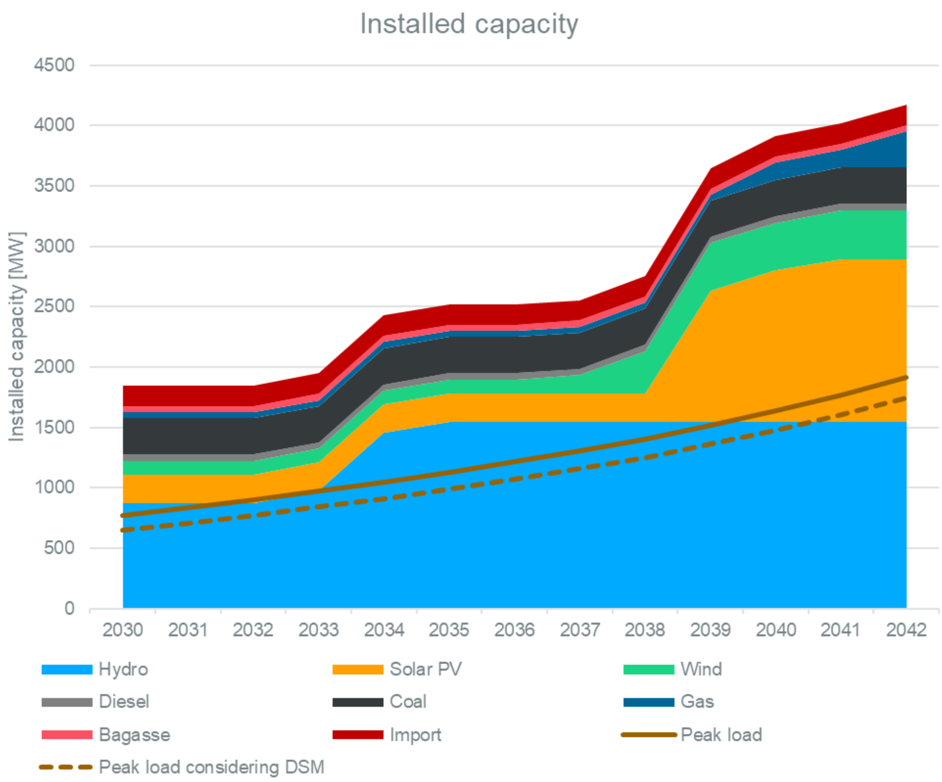


Figure 2.7.11: Installed capacity per technology in LCSP scenario

The following table provides the installed capacities per type of technology for key years over the study period. The total installed capacity evolves from 540 MW in 2022 to 1845 MW in 2032 and 4171 MW in 2042. An important share of the capacity is constituted by VRE (PV and wind). The penetration rate of VRE is 18.7% in 2022, 18.9% in 2032 and 42% in 2042.

The margin, computed as the ratio of the dispatchable generation (hydro and thermal) and peak demand taking into account DSM and EE measures is 22.3% in 2022. The margin increases with the new hydroelectric projects and the coal power plant, being 72% in 2032. As the demand and the VRE penetration keep increasing, the margin decreases again to reach 29% in 2042. The share of hydro in the capacity mix is 73.6% in 2022, 47% in 2032 and 37% in 2042.

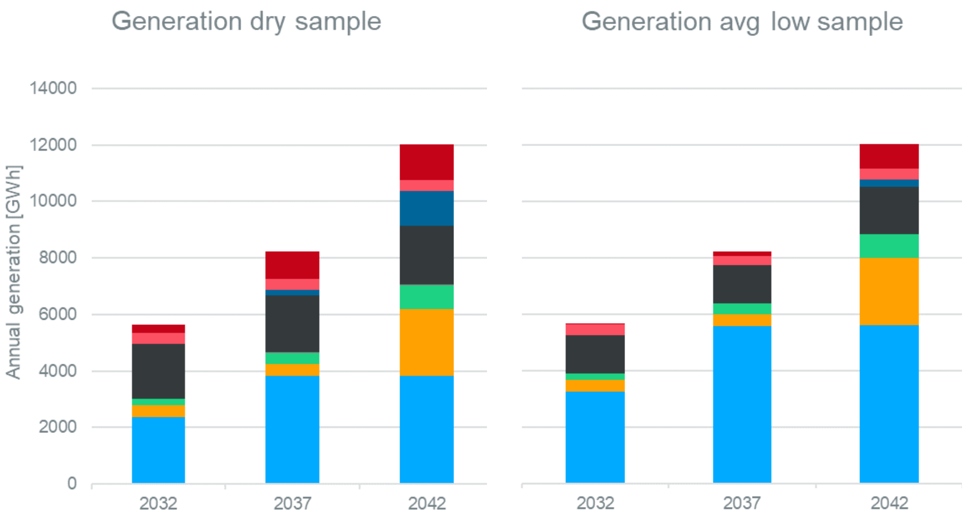
Table 2.7.8: Installed capacity per technology in LCSP scenario

	Installed capacity [MW]		
Technology	**2032**	**2037**	**2042**
Hydro	875	1547	1547
Solar PV	233	233	1348
Wind	116	154	405
Diesel	52	52	52
Coal	300	300	300
Gas	50	50	300
Biomass	50	50	50
Geothermal	0	0	0
Total	**1676**	**2386**	**4002**
Import potential	170	170	170
Peak demand	900	1307	1914
Peak considering DSM	771	1159	1746

Analogously to the Least Cost scenario, no additional energy shifting BESS is integrated in the system, besides the already foreseen project of 20 MW coming in operation in 2025. Same considerations as elaborated for LC scenario apply for possible BESS dedicated to reserves.

7.4.3.3 Generation

The increased capacity of hydro units with respect to the Least Cost scenario, makes the system to rely even more on river flows. Overall, the minimum share of yearly hydro production in the long term on the total is 32% in the *dry* scenario and grows up to 90% in the *wet* scenario; the range in the Least Cost scenario is instead 23-77%. Such a share grows as more plants are installed (until 2035), to then decrease in the last years because of the installation of new VRE and gas projects. The following figures present the yearly production and the energy mix for the different hydrology samples.



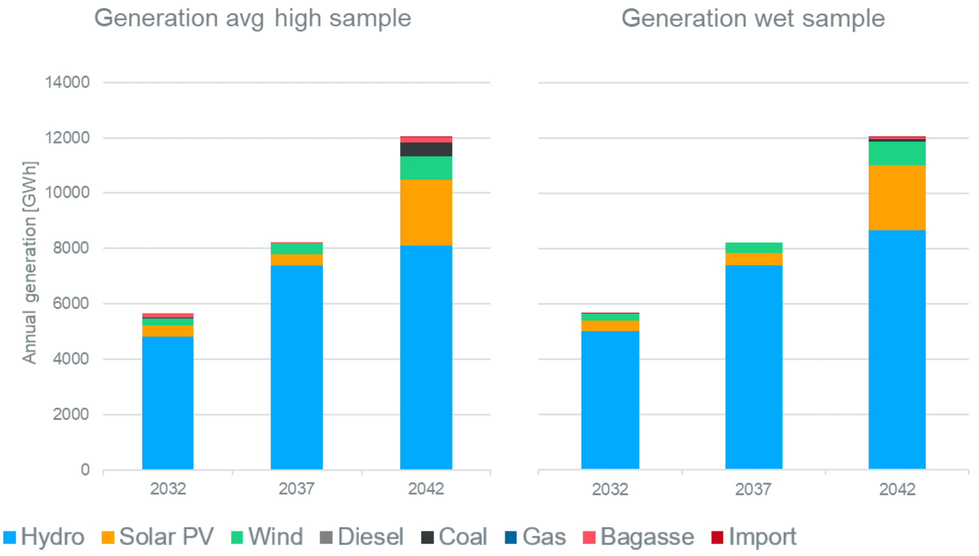


Figure 2.7.12: Annual generation per sample in LCSP scenario

The table below shows the weighted average capacity factors across all samples, in order to provide an overview of the use of the different technologies in a system characterized by highly variable primary resources.

As in the Least Cost scenario, renewable resources (hydro, PV, wind) present quite a stable capacity factor, mostly based on the availability of the resource itself. The existing diesel units stop being interesting as soon as other technologies are available, because of their high operation costs and their yearly generation is reduced to almost zero. Nevertheless, these peaking units remain interesting to provide primary and secondary reserve as highlighted in the dedicated sections.

While biomass has high utilization rates across the whole horizon, coal units maintain a capacity factor which is quite low for the type of technology: this is because all the installed strategic projects exceed the actual needs of the country. Gas units work as peaking plants to avoid load shedding in the most challenging situations. Finally, the higher availability of domestic production with respect to the Least Cost scenario makes import drastically decrease after the end of the take-or-pay contract.

In terms of reliability of the system, the overcapacity in the system leads to its ability to fully supply the load.

Table 2.7.9: Weighted capacity factors per technology in LCSP scenario

	Yearly capacity factor [%]		
Technology	**2032**	**2037**	**2042**
Hydro	52	47	50
Solar PV	20	21	20
Wind	24	29	24
Diesel	0	0	0
Coal	28	28	42
Gas	0	2	7
Bagasse	61	42	66
Import	1	8	32

7.4.3.4 Reserve

The reserve requirements in the long term are discussed in Section 4.6. More detailed considerations are made in the case of the LC scenario (see Section 7.4.2.3) and are equally valid for this scenario. It is also mentioned that the assumptions made should be regularly revised in time based on the evolution of the Malawian system as well as the SAPP region as a whole.

In addition, it is worth mentioning that, for both primary and secondary reserves, the presence of additional installed capacity with respect to the LC scenario reduces the risk of shortages, reducing risks and increasing the reliability of the system.

7.4.3.5 Import/export potential

The increased available capacity with respect to the Least Cost scenario leads to reduced import needs. Indeed, connection with Tanzania is not considered interesting for supplying the load, and import basically disappears after the end of the take-or-pay contract with Mozambique in the scenarios with high availability of hydro production. Note that an additional interconnection line with a new country such as Tanzania furthermore located in another power pool might present other benefits for Malawi such as a diversification of the import possibilities, local increased voltage stability, potential wheeling revenues. This will be further discussed in the frame of the transmission development analysis.

As shown in Figure , in the *dry* and *avg low* samples, import provides an important support to domestic production to supply the load in the last years of the horizon, but at a much lower rate with respect to the Least Cost scenario. Indeed, considering a weighted average of all samples, in 2042 import provides 14% of the total production in the Least Cost scenario, while only 4% of the total comes from import in the LCSP scenario.

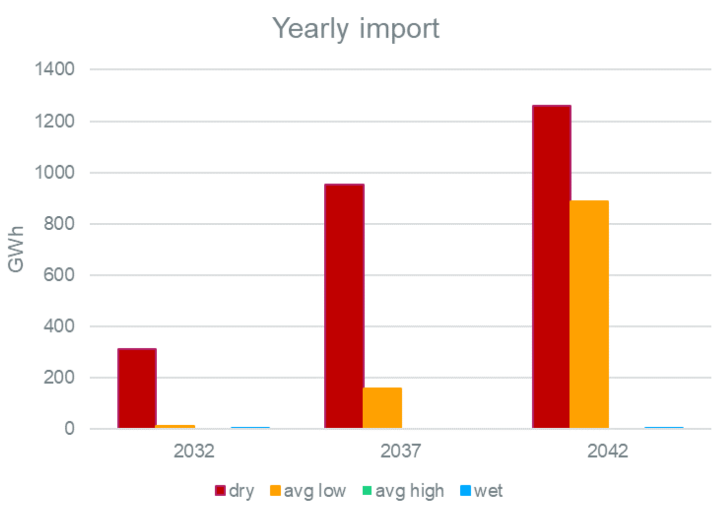


Figure 2.7.13: Yearly import per sample in LCSP scenario

More hydro power plants get installed in the LCSP scenario, which leads to higher total RES export potential, mainly driven by hydro excess generation. The export potential grows dramatically between 2030 and 2035, when multiple big hydro power plants come into operation (Mpatamanga, Chasombo and Chizuma, Dwambazi, Fufu, Kholombidzo and Lower Songwe), reaching around 7 TWh in 2035 and being twice as much the value of the Least Cost scenario.

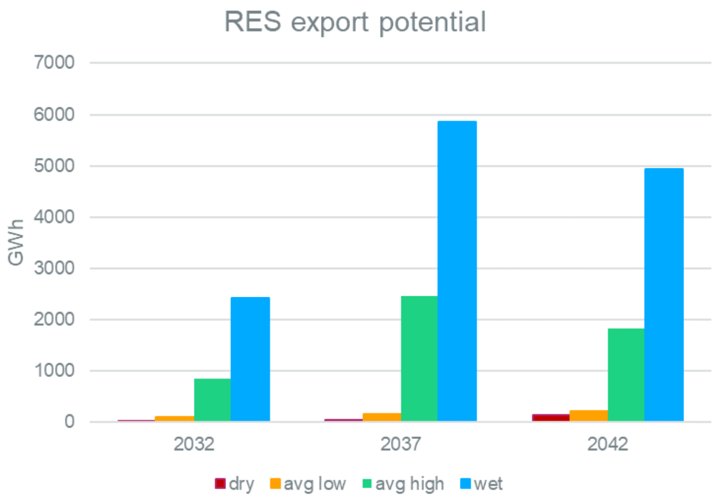


Figure 2.7.14: yearly RES export potential per sample in LCSP scenario

Analogously to the Least Cost scenario, if thermal units are also taken into account, the export potential significantly increases. Again in the last years of the horizon, further installations of gas units cause an increase of the annual export potential up to a weighted average of 5.6 TWh, as shown in the Figure below, which illustrates the weighted average across all samples as well as the minimum and maximum levels.

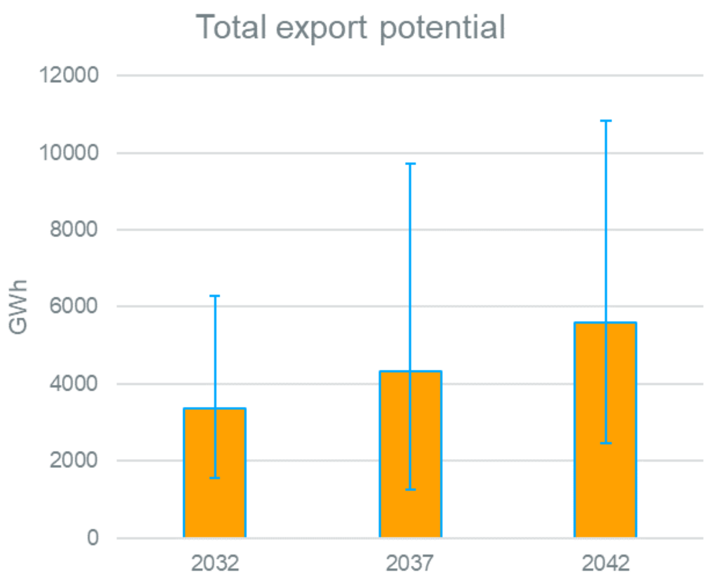


Figure 2.7.15: Weighted average, min and max export potential in LCSP scenario

7.4.3.6 Operational feasibility

The same approach of the Least Cost scenario (see Section 7.4.2.7) is here adopted to analyse the operational feasibility of the plan.

The presence of 300 MW of coal allows to almost totally cover the load which cannot be supplied by PV and hydro units, together with the use of the biomass units at high capacity factor. In particular, the coal plant supplies the demand only during the night in the periods of low load, while in high load periods it provides almost one third of the total energy.

Only in the high load period of the *dry* case a small share of import is needed to further support renewable generation. This is very different from the dispatch shown for the Least Cost plan in Figure , where import, in the absence of the coal power plant, would provide most of the energy needed to cover the gap between the demand and the generation from hydro, PV and wind units.

At this stage, as for the Least Cost case, the presence of many hydro power plants (including Mpatamanga with large reservoir) provides the needed flexibility to handle the availability of PV production, reducing the need to resort to BESS.

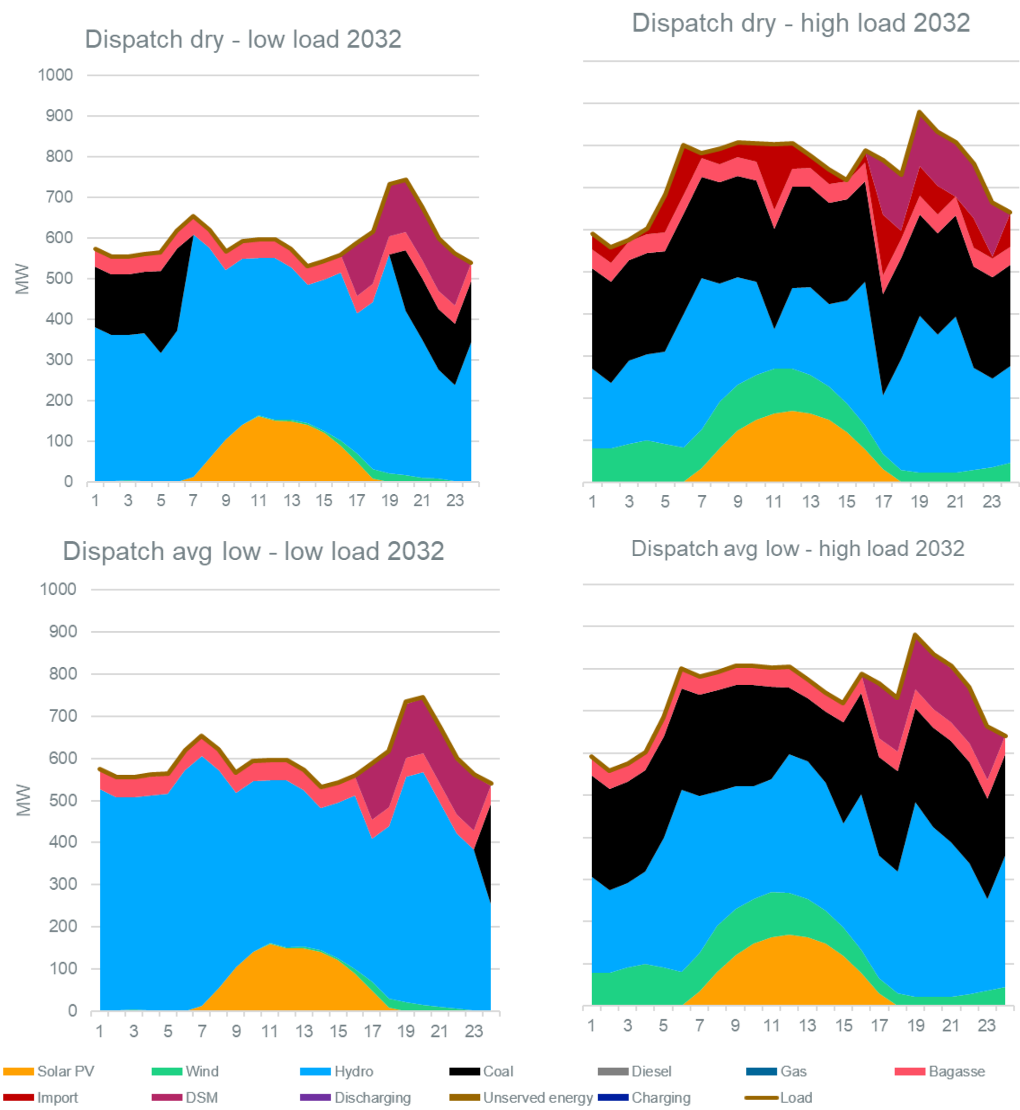


Figure 2.7.16: 1-day dispatch in 2032 for dry and avg low samples in LCSP scenario

7.4.4 Conclusions on long-term vision

This analysis aims at defining the optimal long term vision for the development of the generation sys/tem and identifying the investment plan required to ensure the support of the demand growth, the security of supply and the diversification of the energy mix while respecting a least cost approach and all planning and operational constraints.

The long-term optimal plan focuses on the period 2030-2042 and builds on the first investments defined in the short and medium term. As the years under study get further in the future, uncertainty grows and more comprehensive analyses are needed. Specifically for Malawi, the quantity which heavily determines the operation as well as the required investments is the availability of water for hydro generation. For this reason, this stage of the optimization is performed using stochastic optimization, which includes four different samples of hydrology inputs and builds an investment plan which is robust and reliable against any realization of the inputs while taking their respective probability of occurrence into consideration. This allows to develop a climate-resilient investment plan which would guarantee reliability and security of supply under unfavourable conditions.

The key outcome of the results analysis is that the portfolio of hydro power plants should keep expanding, as it is a local, efficient and precious resource for the country. If provided with a reservoir (as in the case of Mpatamanga), flexibility and ability to accommodate increasing shares of VRE is an additional advantage of investing in hydro power plants.

Once the strategic hydro power plants have been developed, another stable technology would be needed to follow the continuous growth of the demand. Gas is recommended over coal, given the lower environmental impact and the higher flexibility.

An alternative to the development of new gas power plants, which would imply the import of fuel, would be to establish new agreements and contracts with the neighbouring countries to directly resort to import of electricity. Moreover, the integration in the SAPP market will allow to export excess energy from renewables as well as generation of thermal power plants and benefit from an efficient and coordinated exchange within the region.

8. Reference development plan

8.1 Introduction

The generation system long term optimal development plan study presented in this report constitutes the first task of the development study of the electricity sector which also covers the development of the transmission grid and the distribution networks over the same period. For the sake of coherency, clear links between the different tasks should be defined and respected for all tasks. The results of this task are one of the main input of the transmission development plan task while the decided and potential interconnection lines with neighbouring countries of the SAPP regional grid are an input of the generation analysis.

In order to provide to the Stakeholders a complete view of the possible development of the system and the impact on the reliability of the supply and the investment costs, different scenarios and sensitivity analyses were carried out. For each of the studied cases, a least cost approach was used including different features defined in close collaboration with the Stakeholders during the working group sessions and the presentation of the intermediate results in Blantyre. The Least Cost scenario (LC) defines the optimal development plan considering standard candidate units representing all technologies available in Malawi and define an unbiased optimal long-term least cost development pathway. The Least Cost + Strategic projects scenario (LCSP) accounts for strategic projects for the country identified with the Stakeholders and illustrates the impact of the selection of these projects on the least cost development plan.

Following the presentation of the preliminary results, it was confirmed with the Stakeholders that, for the purpose of the planning exercise in the frame of this study, the reference development plan for the other tasks (transmission and distribution) corresponds to the LC scenario. The recommended evolution of the generation system over the complete study period for the LC scenario is detailed in the next sections.

8.2 Reference development plan

8.2.1 Installed capacity

As explained in the introduction of the present section, the reference plan corresponds to the least cost scenario over the whole study period. Therefore the recommended generation expansion plan combines the Least Cost investments of the short, medium and long term, and is shown in the figure below. The following table details the evolution of the installed capacity for key years. The complete table is provided in appendix.

Considerations made in Sections 7.3.2.1 and 7.4.2.1 stand for this plan as well as the conclusions that were developed in sections 7.3.4 and 7.4.4 respectively for the medium-term and the long-term horizon, remain valid for the reference plan defined here.

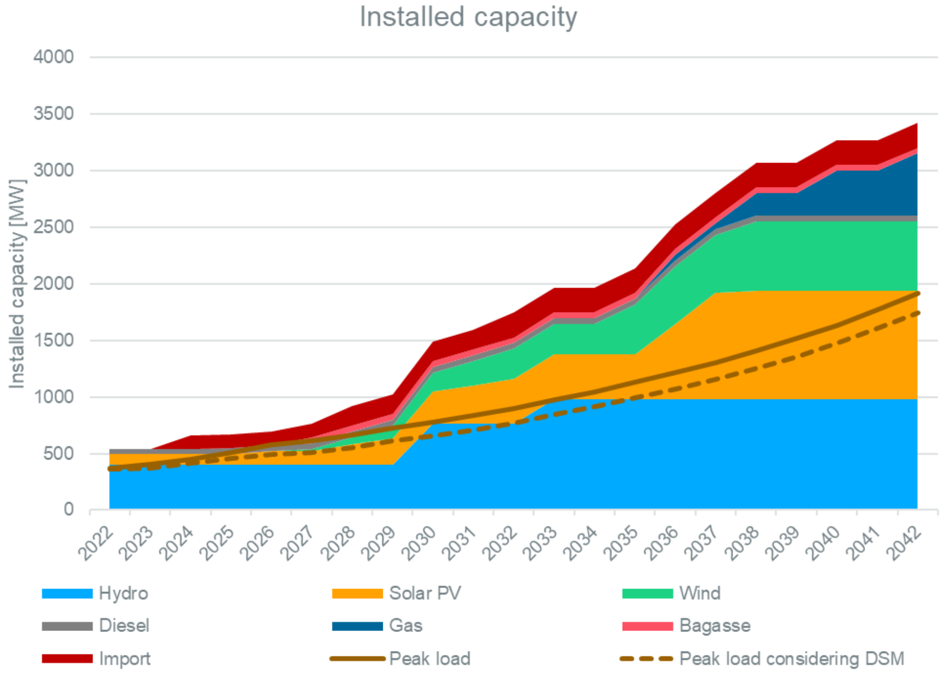


Figure 2.8.1: Installed capacity per technology for the Reference development plan

Table 2.8.1: Installed capacity per technology for the Reference development plan

	Installed capacity [MW]				
Technology	**2023**	**2027**	**2032**	**2037**	**2042**
Hydro	398	402	763	982	982
Solar PV	101	124	395	940	956
Wind	0	15	268	513	615
Diesel	42	52	52	52	52
Coal	0	0	0	0	0
Gas	0	0	0	50	550
Biomass	0	50	50	50	50
Geothermal	0	0	0	0	0
Total	**541**	**643**	**1527**	**2586**	**3204**
Import potential	0	120	220	220	220
Peak demand	405	617	900	1307	1914
Peak considering DSM	367	509	771	1159	1746

8.2.2 Investments costs

Figure shows the investments needed to install new units and have new solutions available, which amount to 4344 MUSD along the whole study period. The total CAPEX is modelled in PLEXOS by means of the annualised build cost, which spreads the investment considering the discount factor and the lifetime of the plant. For the sake of simplicity, the total investment cost of each plant is here shown for the year when the investment first occurs.

Limited investment are foreseen in the short term (2024 – 2025), as the commissioning of the interconnection with Mozambique, together with the foreseen good availability of river flows, provides good resources to supply the demand. Moreover, the refurbishment of diesel units and the commissioning of 20 MW of BESS increase the flexibility of the system and its capability to cope with sudden variations. The only additional investment in this timeframe concerns the first adoption of DSM and EE measures, costing around 10 MUSD until 2025. DSM and EE measures represents a very efficient way to reduce the cost of the power system by acting on the demand side. Given that the perspective of the current study is the Malawian system as a whole (economic study), the costs of these measures (most of which should be borne by consumers) are here included.

In the medium term (2026 – 2029), 433 MUSD of CAPEX are foreseen, as the demand growth requires rapid investments in the best technologies which are readily available, namely small hydro (Wowve 2), PV, wind and biomass, together with further penetration of DSM and EE measures.

The two key investments of the horizon are the two big hydro power plants: Mpatamanga in 2030 and Kholombidzo in 2033. The cost of Mpatamanga, set to 670 MUSD during the inception phase of the project and execution of the study, has been updated to 1418 MUSD in the final version of the current report based on the latest estimates shared by the Client. The total investment costs of Kholombidzo amounts to about 675 MUSD. From 2035 to 2042, more than 1300 MUSD of additional investments are required, a third of which is for PV units, about 28% in wind and the remainder in gas units.

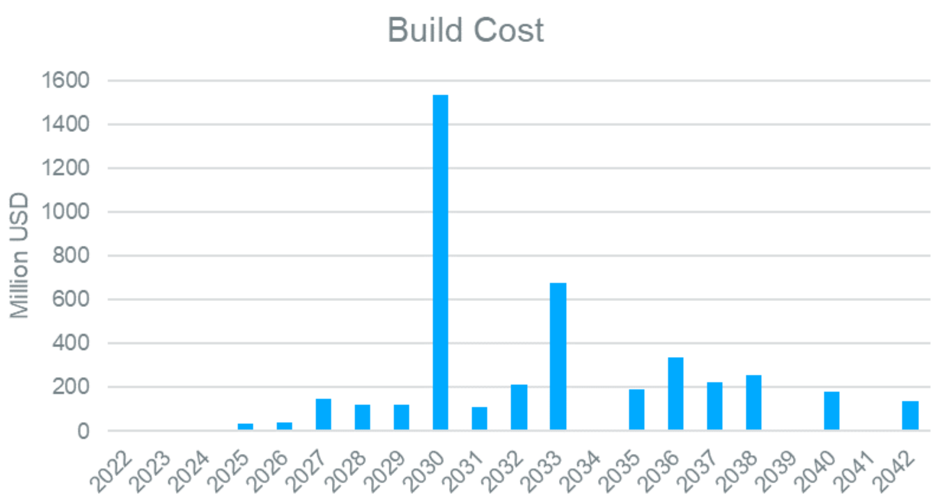


Figure 2.8.2: Yearly investment costs in the Reference scenario

8.2.3 Operating costs

The figure below illustrates the total operating costs of the system for key years. In 2027, a good river flow availability is foreseen and more than 60% of the generation is from hydro power plants (see Figure). Besides limited contribution of PV, wind and biomass plants, most of the remaining demand is supplied by the take-or-pay contract with Mozambique. Hence, almost all the domestic production has very limited operating expenses and more than 70% of the total OPEX is the cost of import (shown in Figure as variable O&M cost, being expressed as a cost per MWh).

In the long term, big investments in hydro power plants and distributed investments in VRE allow to keep low operating costs, with a higer share of fixed O&M over variable O&M (mostly related to import). Fuel costs remain very limited for most of the horizon, biomass keeps a high capacity factor while diesel and gas units are rarely used when renewables and import are not sufficient to supply the demand.

This pattern changes rapidly in the last years of the horizon, when the further installation of gas plants, needed to provide further flexibility and the satisfy increasing demand, lead to a higher diversification of the energy mix (see Figure). In 2042, OPEX are more than three times the operating costs of 2037, compensated by rarer and less substantial investment costs (yet with a continuously increasing demand), as described in the previous section.

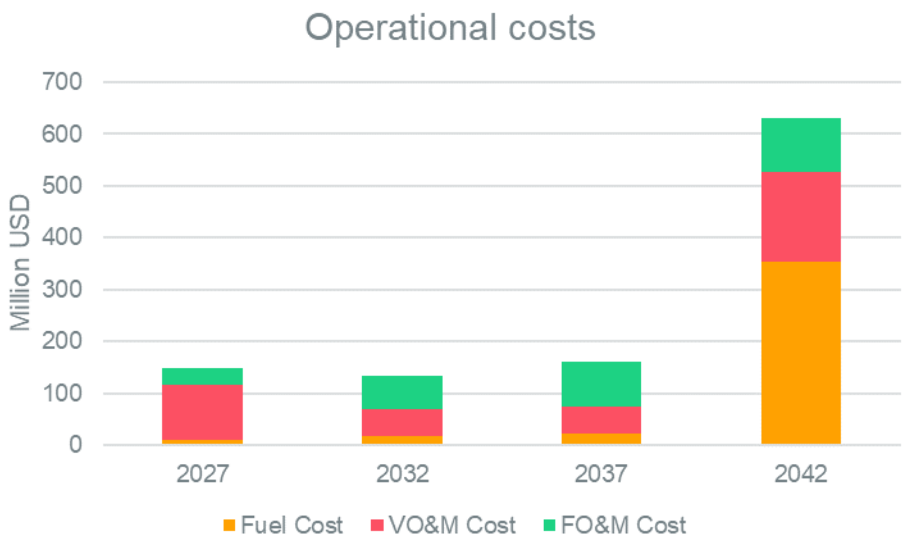


Figure 2.8.3: Total OPEX in key years of the Reference scenario

9. Legal and Regulatory Framework for Generation, Transmission, and Distribution Projects in Malawi

9.1 Introduction

This section provides an overview of the legal and regulatory framework governing generation, transmission, and distribution projects in Malawi, with a particular focus on the Environmental and Social Impact Assessment (ESIA) requirements.

9.2 Relevant Malawi Policies and Legislation.

9.2.1 Malawi Vision 2063

Malawi Vision 2063 is a comprehensive blueprint that envisions transforming Malawi into a wealthy, self-reliant, industrialized, and middle-income country by 2063. This vision is built on three key pillars: Agricultural Productivity and Commercialization, Industrialization, and Urbanization. Each pillar is supported by enablers that include Human Capital Development, Economic Infrastructure, and Environmental Sustainability. The vision emphasizes the need for sustainable and inclusive economic growth driven by innovation, technology, and a robust energy sector. Malawi Vision 2063 places significant emphasis on the development of the energy sector as a critical enabler for industrialization and urbanization. The vision outlines specific goals for energy generation, transmission, and distribution to support Malawi's economic transformation:

- Expansion of Energy Generation Capacity
  - Increase the installed electricity generation capacity to meet the growing demand from industrial, commercial, and residential sectors.
  - Promote the diversification of energy sources, including the development of renewable energy projects such as solar, wind, and hydropower.
  - Encourage the adoption of clean and sustainable energy technologies to reduce the carbon footprint and mitigate the impacts of climate change.
- Enhancement of Transmission and Distribution Networks
  - Upgrade and expand the transmission and distribution infrastructure to ensure reliable and efficient delivery of electricity across the country.
  - Reduce transmission and distribution losses through the adoption of modern technologies and best practices.
  - Strengthen the grid's resilience to withstand environmental challenges and improve energy security.
- Universal Access to Electricity
  - Achieve universal access to electricity by 2063, with a focus on connecting rural and underserved areas.
  - Implement the Malawi Rural Electrification Program (MAREP) to accelerate the electrification of remote communities.
  - Foster public-private partnerships to mobilize resources and expertise for expanding access to electricity.

Implications for Generation, Transmission, and Distribution Projects

The goals outlined in Malawi Vision 2063 have profound implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Strategic Goals
  - Projects must align with the strategic goals of increasing generation capacity, diversifying energy sources, and enhancing grid infrastructure.
  - Long-term planning should incorporate the vision's targets, ensuring that projects contribute to the overarching objectives of industrialization and urbanization.
- Sustainability and Environmental Considerations
  - Projects should prioritize sustainability by integrating renewable energy sources and adopting environmentally friendly technologies.
  - Conduct comprehensive ESIAs to mitigate adverse impacts and ensure compliance with national and international environmental standards.
- Capacity Building and Technological Innovation
  - Invest in capacity building and training for local stakeholders to ensure the successful implementation and maintenance of energy projects.
  - Embrace technological innovations such as smart grids, energy storage solutions, and digital monitoring systems to improve efficiency and reliability.
- Public-Private Partnerships
  - Leverage public-private partnerships to mobilize investment, technical expertise, and innovative solutions for energy projects.
  - Create an enabling environment for private sector participation by ensuring transparent regulatory frameworks and attractive investment incentives.
- Focus on Rural Electrification
  - Prioritize projects that support rural electrification to bridge the energy access gap and promote inclusive development.
  - Implement off-grid and mini-grid solutions in remote areas to provide reliable and sustainable electricity to underserved communities.
- Monitoring and Evaluation
  - Establish robust monitoring and evaluation mechanisms to track progress towards the vision's energy sector goals.
  - Use data and analytics to inform decision-making, optimize project performance, and ensure accountability.

9.2.2 Environmental Policy (2004)

Environmental Policy (2004) is a critical framework that guides the integration of environmental considerations into the planning and implementation of development projects in Malawi. The policy aims to promote sustainable development by ensuring that environmental protection is a fundamental part of economic and social planning. It emphasizes the importance of preserving natural resources, reducing pollution, and fostering a healthy and productive environment for current and future generations. The Policy outlines several key elements that are essential for the sustainable development of Malawi:

- Sustainable Resource Management

- Promote the sustainable use and management of natural resources, including land, water, forests, and wildlife.
  - Implement measures to prevent resource depletion and degradation, ensuring their availability for future generations.
- Pollution Control and Waste Management
  - Establish and enforce standards for controlling pollution from industrial, agricultural, and domestic sources.
  - Develop efficient waste management systems to minimize environmental pollution and health hazards.
- Environmental and Social Impact Assessment
  - Mandate the conduct of ESIA for all major development projects to evaluate potential environmental impacts.
  - Ensure that mitigation measures are implemented to address any adverse effects identified during the ESIA process.
- Conservation of Biodiversity
  - Protect and conserve Malawi's biodiversity, including endangered species and critical habitats.
  - Promote reforestation and afforestation programs to restore degraded ecosystems and enhance biodiversity.
- Public Awareness and Participation
  - Enhance public awareness of environmental issues and promote community involvement in environmental conservation activities.
  - Encourage stakeholder participation in the decision-making process for environmental management and development planning.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Policy (2004) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to Environmental Standards
  - Projects must comply with the environmental standards and best practices outlined in the policy.
  - Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.
- Integration of ESIA Process
  - Conduct thorough ESIA for all projects to identify potential environmental impacts and develop mitigation strategies.
  - Ensure that ESIA findings are incorporated into project design and implementation to minimize negative environmental effects.
- Sustainable Resource Utilization
  - Utilize natural resources efficiently and sustainably to prevent depletion and environmental degradation.
  - Adopt technologies and practices that enhance resource conservation, such as renewable energy sources and energy-efficient systems.
- Pollution Prevention and Waste Management
  - Implement measures to control pollution from project activities, including emissions, effluents, and waste.

- Develop and maintain effective waste management systems to handle project-related waste in an environmentally responsible manner.
- Biodiversity Conservation
  - Incorporate biodiversity conservation into project planning by protecting critical habitats and endangered species.
  - Engage in reforestation and habitat restoration activities to offset any environmental disturbances caused by project activities.
- Stakeholder Engagement and Public Participation
  - Engage local communities and stakeholders in the planning and implementation of projects to ensure their concerns and suggestions are addressed.
  - Promote transparency and accountability by keeping stakeholders informed about project progress and environmental management efforts.
- Long-term Environmental Sustainability
  - Focus on long-term environmental sustainability by adopting practices that reduce the ecological footprint of projects.
  - Invest in technologies and processes that support environmental resilience and adaptation to climate change.

9.2.3 National Energy Policy (2018)

National Energy Policy (2018) is a strategic framework designed to enhance access to reliable, affordable, and sustainable energy services in Malawi. The policy underscores the importance of diversifying energy sources and promoting renewable energy to reduce reliance on biomass, which is a significant contributor to deforestation and environmental degradation. The policy aims to address the low electrification rate, mitigate climate change impacts, and support sustainable economic development.

Key Elements of the National Energy Policy (2018)

The National Energy Policy (2018) outlines several key elements that are crucial for the development of the energy sector in Malawi:

- Diversification of Energy Sources
  - Promote the development and use of various energy sources, including hydropower, solar, wind, and biomass.
  - Encourage investment in renewable energy projects to reduce dependence on traditional biomass and fossil fuels.
- Enhancement of Energy Access
  - Increase the electrification rate, particularly in rural and underserved areas, to ensure equitable access to energy services.
  - Implement the MAREP to extend the electricity grid and provide off-grid solutions where grid extension is not feasible.
- Energy Efficiency and Conservation
  - Promote energy efficiency measures and technologies to reduce energy consumption and improve the overall efficiency of the energy sector.
  - Encourage the use of energy-efficient appliances and industrial processes to lower energy demand and reduce environmental impacts.

- Climate Change Mitigation and Adaptation
  - Integrate climate change considerations into energy planning and project implementation.
  - Support the development of low-carbon technologies and practices to mitigate greenhouse gas emissions and enhance climate resilience.

Implications for Generation, Transmission, and Distribution Projects

The National Energy Policy (2018) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Policy Goals
  - Projects must align with the policy's goals of promoting renewable energy and ensuring energy sustainability.
  - Long-term planning should incorporate the policy's targets, ensuring that projects contribute to the overall objectives of increasing energy access and reducing reliance on biomass.
- Integration of Renewable Energy Sources
  - Developers should consider integrating renewable energy sources such as solar, wind, and hydropower into their projects.
  - The adoption of renewable energy technologies can help reduce greenhouse gas emissions and mitigate climate change impacts.
- Enhancement of Energy Access
  - Projects should focus on extending energy access to rural and underserved areas, in line with the goals of the MAREP.
  - Implementing off-grid and mini-grid solutions can provide reliable and sustainable electricity to remote communities.
- Energy Efficiency Measures
  - Incorporate energy efficiency measures into project design and implementation to reduce energy consumption and operational costs.
  - Promote the use of energy-efficient technologies and practices in both residential and industrial sectors.
- Climate Change Considerations
  - Integrate climate change mitigation and adaptation measures into project planning and execution.
  - Develop and implement low-carbon technologies and practices to enhance the sustainability and resilience of energy projects.
- Regulatory Compliance and Institutional Strengthening
  - Ensure compliance with the regulatory framework and engage with relevant institutions for project approvals and oversight.
  - Strengthen the capacity of local institutions to manage and regulate energy projects effectively.

The National Energy Policy (2018) provides a comprehensive framework for enhancing energy access, promoting renewable energy, and ensuring sustainable development in Malawi. Projects must align with the policy's goals and integrate renewable energy sources, energy efficiency measures, and climate change considerations into their planning and implementation.

9.2.4 Forest Policy (2016)

Forest Policy (2016) is a pivotal framework aimed at promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. The policy seeks to address the challenges of deforestation, forest degradation, and unsustainable use of forest resources, which are critical issues affecting the environment and livelihoods in the country. The Forest Policy underscores the importance of conserving forest ecosystems, enhancing carbon sequestration, and promoting the sustainable use of forest products.

The Forest Policy (2016) outlines several key elements essential for the sustainable management of forest resources in Malawi:

- Sustainable Forest Management
  - Promote practices that ensure the sustainable management and utilization of forest resources.
  - Implement forest management plans that balance environmental, economic, and social objectives.
- Reforestation and Afforestation
  - Encourage reforestation and afforestation initiatives to restore degraded forest lands and increase forest cover.
  - Support community-based reforestation projects and agroforestry practices that enhance livelihoods and biodiversity.
- Protection of Forest Resources
  - Enforce regulations to protect forest resources from illegal activities such as logging, encroachment, and charcoal production.
  - Establish protected areas and conservation zones to preserve critical habitats and biodiversity.
- Charcoal Production and Trade Regulation
  - Regulate the production and trade of charcoal to reduce its impact on forest resources.
  - Promote alternative energy sources to reduce dependency on charcoal and mitigate deforestation.
- Community Participation and Capacity Building
  - Engage local communities in forest management and conservation efforts.
  - Build the capacity of communities and stakeholders to effectively participate in sustainable forest management practices.

Implications for Generation, Transmission, and Distribution Projects

The Forest Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources
  - Projects involving land use changes must assess the impact on forest resources and implement measures to mitigate adverse effects.
  - Conduct ESIAs to evaluate the potential impacts on forests and develop appropriate mitigation strategies.
- Compliance with Reforestation and Sustainable Management Requirements

  - Projects must comply with reforestation and sustainable management requirements as outlined in the Forest Policy.
  - Implement reforestation initiatives to compensate for any forest loss due to project activities, ensuring no net loss of forest cover.
- Regulation of Charcoal Production and Forest Protection
  - Adhere to regulations regarding charcoal production and trade to avoid legal penalties and support forest conservation efforts.
  - Promote the use of alternative energy sources to reduce the reliance on charcoal and mitigate deforestation.

The Forest Policy (2016) provides a robust framework for promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and sustainable management requirements, and adhere to regulations regarding charcoal production and forest protection.

9.2.5 National Climate Change Management Policy (2016)

National Climate Change Management Policy (2016) is a strategic framework designed to guide Malawi in addressing the impacts of climate change through effective adaptation and mitigation measures. The policy aims to enhance resilience to climate change, reduce greenhouse gas emissions, and promote sustainable development practices. It emphasizes the integration of climate change considerations into all sectors of the economy, including energy, to ensure a coordinated and comprehensive response to climate challenges. The Policy outlines several key elements essential for addressing climate change impacts in Malawi:

- Climate Change Adaptation
  - Implement measures to increase resilience to climate change impacts, particularly in vulnerable sectors such as agriculture, water resources, and infrastructure.
  - Promote the development and use of climate-resilient technologies and practices to minimize the adverse effects of climate change.
- Climate Change Mitigation
  - Develop and implement strategies to reduce greenhouse gas emissions across all sectors, including energy, transportation, and industry.
  - Encourage the adoption of renewable energy sources and energy-efficient technologies to lower carbon emissions.
- Capacity Building and Public Awareness
  - Enhance the capacity of institutions and stakeholders to effectively address climate change through training, research, and knowledge dissemination.
  - Raise public awareness about climate change impacts and the importance of adaptation and mitigation measures.
- Policy and Institutional Coordination
  - Strengthen the coordination and integration of climate change policies and actions across different sectors and levels of government.
  - Establish and support institutions responsible for overseeing the implementation of climate change policies and strategies.
- Funding and Resource Mobilization

- Mobilize resources from domestic and international sources to finance climate change adaptation and mitigation initiatives.
- Promote public-private partnerships to leverage additional funding and expertise for climate action projects.

Implications for Generation, Transmission, and Distribution Projects

The National Climate Change Management Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Integration of Climate Change Adaptation Measures
  - Projects should incorporate climate change adaptation measures to enhance resilience to climate impacts such as extreme weather events, temperature variations, and changing precipitation patterns.
  - Design infrastructure and systems that can withstand climate-related stresses and ensure continuous and reliable energy supply.
- Implementation of Climate Change Mitigation Strategies
  - Projects must implement strategies to reduce greenhouse gas emissions, including the adoption of renewable energy sources such as solar, wind, and hydropower.
  - Promote energy efficiency measures to reduce energy consumption and minimize the carbon footprint of energy projects.
- Compliance with National Climate Goals
  - Ensure that projects comply with the national climate goals and targets set forth in the policy, contributing to Malawi's overall efforts to combat climate change.
  - Monitor and report on greenhouse gas emissions and climate change impacts associated with project activities.
- Capacity Building and Stakeholder Engagement
  - Enhance the capacity of project teams and stakeholders to understand and address climate change issues through training and knowledge sharing.
  - Engage local communities and stakeholders in climate change adaptation and mitigation efforts, ensuring their participation and support.
- Policy and Institutional Coordination
  - Collaborate with relevant government agencies and institutions to ensure the alignment of project activities with national climate change policies and strategies.
  - Contribute to the development and implementation of coordinated climate action plans that integrate sectoral efforts.

The National Climate Change Management Policy (2016) provides a comprehensive framework for addressing climate change impacts and promoting sustainable development in Malawi. Generation, transmission, and distribution projects must integrate climate change adaptation and mitigation measures, comply with national climate goals, and engage stakeholders in climate action efforts.

9.2.6 National Water Policy (2005)

National Water Policy (2005) aims to guide the sustainable management, development, and use of water resources in Malawi. This policy is comprehensive, addressing various aspects of water resource management, including conservation, utilization, and service delivery, to support socio-economic development and environmental sustainability. The National Water Policy (2005) outlines several key elements essential for effective water resource management and development:

- Integrated Water Resources Management (IWRM):
  - Promotes IWRM principles to ensure the coordinated development and management of water, land, and related resources.
  - Aims to maximize economic and social welfare without compromising the sustainability of vital ecosystems.
- Water Quality and Pollution Control:
  - Ensures water of acceptable quality for various needs by setting standards and guidelines for water quality and pollution control.
  - Implements measures to prevent and control water pollution, protecting both surface and groundwater resources.
- Water Utilization:
  - Addresses the provision of water supply and sanitation services for urban, peri-urban, and rural areas.
  - Promotes the efficient and equitable use of water resources for agriculture, irrigation, hydropower, fisheries, navigation, and eco-tourism.
- Disaster Management:
  - Establishes preparedness and contingency plans for water-related disasters, such as floods and droughts.
  - Aims to mitigate the impact of such disasters on communities and infrastructure.
- Institutional Roles and Linkages:
  - Defines the roles and responsibilities of various stakeholders, including government ministries, water utilities, local governments, NGOs, and the private sector.
  - Encourages collaboration and coordination among these stakeholders to ensure effective water management.

Implications for Generation, Transmission, and Distribution Projects

The National Water Policy (2005) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to IWRM Principles:
  - Projects must integrate IWRM principles into their planning and implementation processes to ensure sustainable water resource management.
  - Coordinated development and management of water, land, and related resources should be prioritized.
- Ensuring Water Quality and Pollution Control:

  - Projects must comply with the standards and guidelines for water quality and pollution control set forth in the policy.
  - Implementing effective pollution prevention and control measures is essential to protect water resources from contamination.
- Efficient and Equitable Water Utilization:
  - Projects should promote the efficient and equitable use of water resources, ensuring that water supply and sanitation services are accessible to all.
  - Consideration of water needs for various sectors, including agriculture, hydropower, and eco-tourism, is crucial for balanced water use.
- Disaster Management and Preparedness:
  - Incorporating disaster management and preparedness measures into project planning can mitigate the impact of water-related disasters.
  - Developing contingency plans and infrastructure to cope with floods and droughts is essential for project resilience.

The National Water Policy (2005) provides a comprehensive framework for the sustainable management, development, and use of water resources in Malawi. Generation, transmission, and distribution projects must adhere to the policy's principles and guidelines to ensure sustainable water resource management, compliance with water quality standards, efficient utilization, disaster preparedness, and stakeholder collaboration. By aligning with the National Water Policy, developers can contribute to the sustainable development of Malawi's water resources, supporting socio-economic growth and environmental conservation.

9.3 Relevant Malawi Legislative Framework

9.3.1 Constitution of the Republic of Malawi (1994)

Constitution of the Republic of Malawi (1994) serves as the supreme law of the land, laying the foundation for all legal and regulatory frameworks within the country. It enshrines principles of environmental protection and sustainable development, reflecting Malawi's commitment to fostering a balanced relationship between development and environmental stewardship. The Constitution ensures that all developmental activities, including energy projects, adhere to fundamental environmental principles to safeguard the well-being of its citizens and the natural environment. The Constitution outlines several key principles and provisions that are pertinent to environmental protection and sustainable development:

- Environmental Protection
  - Mandates the state to adopt and implement policies and measures designed to protect and sustain the environment for present and future generations.
  - Requires that environmental considerations be integrated into national development plans and policies.
- Sustainable Development
  - Emphasizes the need for sustainable use of natural resources to ensure that development meets the needs of the present without compromising the ability of future generations to meet their own needs.

- Supports economic development that is environmentally sustainable and socially inclusive.
- Public Participation and Rights
  - Ensures the right of citizens to participate in environmental decision-making processes.
  - Protects the rights of individuals and communities to access information regarding environmental matters and to seek redress for environmental harm.
- Legislative and Institutional Framework
  - Provides the basis for enacting environmental laws and establishing institutions to oversee environmental management and enforcement.
  - Encourages the development of laws and regulations that promote environmental justice and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Constitution of the Republic of Malawi (1994) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Constitutional Provisions
  - Projects must comply with constitutional provisions related to environmental protection, ensuring that all activities align with the principles of environmental sustainability and stewardship.
  - Regular audits and environmental impact assessments should be conducted to ensure ongoing compliance with constitutional mandates.
- Integration of Environmental Considerations
  - Integrate environmental considerations into all stages of project planning and implementation, from initial design through to operation and maintenance.
  - Develop and implement ESIAs to identify potential impacts and develop mitigation strategies.
- Upholding Constitutional Rights and Principles
  - Uphold the constitutional rights of citizens by ensuring transparent and inclusive decision-making processes.
  - Provide opportunities for public participation and access to information, allowing communities to engage meaningfully in project planning and implementation.
- Sustainable Resource Management
  - Utilize natural resources in a manner that ensures their sustainability, preventing over-exploitation and degradation.
  - Adopt practices that promote the efficient use of resources, reducing waste and minimizing environmental impacts.
- Establishing Accountability and Enforcement Mechanisms
  - Establish mechanisms for monitoring and enforcing compliance with environmental laws and regulations.
  - Ensure that project developers are held accountable for any environmental harm caused and that appropriate remedial actions are taken.

The Constitution of the Republic of Malawi (1994) provides a foundational legal framework that mandates the integration of environmental protection and sustainable development into all aspects of national development. Generation, transmission, and distribution projects must comply with constitutional provisions, uphold the rights and principles enshrined in the Constitution, and integrate environmental considerations into their planning and implementation processes.

9.3.2 Environmental Management Act (2017)

Environmental Management Act (2017) is a comprehensive legal framework designed to ensure environmental protection and sustainable management in Malawi. The Act mandates the conduct of ESIAs for all significant development projects to evaluate and mitigate potential environmental and social impacts. It establishes clear requirements and procedures for environmental protection, reflecting Malawi's commitment to sustainable development and environmental stewardship. The Environmental Management Act (2017) outlines several key elements essential for effective environmental protection and management:

- Environmental and Social Impact Assessments
  - Mandates the conduct of ESIAs for all significant development projects to assess potential environmental and social impacts.
  - Requires public participation in the ESIA process, ensuring that stakeholders' views and concerns are considered.
- Environmental Standards and Regulations
  - Establishes standards and regulations for pollution control, waste management, and the sustainable use of natural resources.
  - Provides guidelines for the management of hazardous substances and the protection of biodiversity.
- Institutional Framework
  - Establishes the Malawi Environment Protection Authority (MEPA) as the primary agency responsible for overseeing environmental management and enforcement.
  - Creates mechanisms for coordination and collaboration among various stakeholders, including government agencies, private sector entities, and local communities.
- Compliance and Enforcement
  - Sets out penalties and sanctions for non-compliance with environmental regulations.
  - Provides for regular environmental audits and inspections to ensure adherence to environmental standards.
- Public Participation and Access to Information
  - Ensures public access to environmental information and promotes transparency in environmental decision-making processes.
  - Encourages community involvement in environmental management and conservation initiatives.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Management Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Conducting Comprehensive ESIAs
  - Projects must conduct thorough ESIAs to identify and assess potential environmental and social impacts.
  - The ESIAs should include detailed mitigation measures to address identified impacts and ensure environmental sustainability.
- Compliance with Environmental Standards and Regulations
  - Projects must comply with the environmental standards and regulations established under the Act.
  - Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.
- Engagement with the MEPA
  - Engage with the MEPA throughout the project lifecycle to ensure compliance with regulatory requirements and obtain necessary approvals.
  - Collaborate with the MEPA to address any environmental concerns and implement best practices in environmental management.
- Public Participation and Transparency
  - Ensure active public participation in the ESIA process, allowing stakeholders to provide input and express concerns.
  - Maintain transparency by providing access to environmental information and keeping stakeholders informed about project developments and environmental management efforts.
- Mitigation of Environmental and Social Impacts
  - Develop and implement effective mitigation measures to minimize adverse environmental and social impacts.
  - Monitor the effectiveness of mitigation measures and adjust them as necessary to achieve desired outcomes.
- Institutional Coordination and Collaboration
  - Coordinate with relevant government agencies, private sector entities, and local communities to ensure a holistic approach to environmental management.
  - Leverage the expertise and resources of various stakeholders to enhance the effectiveness of environmental protection efforts.

The Environmental Management Act (2017) provides a robust legal framework for ensuring environmental protection and sustainable management in Malawi. Generation, transmission, and distribution projects must conduct comprehensive ESIAs, comply with environmental standards and regulations, and engage with the MEPA to obtain necessary approvals.

9.3.3 Energy Regulation Act (2004)

Energy Regulation Act (2004) is a pivotal framework that establishes the Malawi Energy Regulatory Authority (MERA), the key regulatory body responsible for overseeing the energy sector in Malawi. The Act provides a comprehensive structure for licensing, setting tariffs, and ensuring compliance with energy laws, promoting the efficient use and development of energy resources. It aims to create a stable and transparent regulatory environment conducive to investment and sustainable energy development. The Energy Regulation Act (2004) outlines several key elements essential for effective energy sector regulation and management:

- Establishment of MERA
  - MERA is established as the principal regulatory body for the energy sector, with the authority to issue licenses, set tariffs, and enforce compliance with energy laws.
  - MERA's mandate includes the regulation of electricity, gas, and petroleum sectors to ensure efficiency, reliability, and sustainability.
- Licensing and Tariff Setting
  - MERA is responsible for issuing licenses for the generation, transmission, distribution, and supply of electricity, as well as other energy-related activities.
  - The authority sets and reviews tariffs to ensure that they are fair, reasonable, and reflective of the cost-of-service delivery.
- Regulatory Compliance and Enforcement
  - MERA ensures that all licensed entities comply with the relevant energy laws, regulations, and standards.
  - The authority has the power to impose penalties and take corrective actions against entities that violate regulatory requirements.
- Promotion of Efficient Energy Use
  - The Act promotes the efficient use and development of energy resources, encouraging the adoption of energy-efficient technologies and practices.
  - MERA supports initiatives aimed at enhancing energy conservation and reducing wastage.
- Consumer Protection and Public Involvement
  - The Act includes provisions to protect consumer rights and ensure that consumers have access to reliable and affordable energy services.
  - MERA facilitates public involvement in the regulatory process, ensuring transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Energy Regulation Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Necessary Licenses
  - All energy projects must obtain the necessary licenses from MERA before commencing operations. This includes licenses for generation, transmission, distribution, and supply activities.

  - The licensing process involves submitting detailed project proposals and compliance with regulatory requirements set by MERA.
- Compliance with MERA's Regulations
  - Projects must adhere to all regulations, standards, and guidelines established by MERA. This includes compliance with technical, safety, and environmental standards.
  - Regular audits and inspections may be conducted by MERA to ensure ongoing compliance and identify areas for improvement.
- Tariff Setting and Financial Viability
  - Projects must work with MERA to set appropriate tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.
  - Financial viability and sustainability of the projects are essential, as tariffs must be fair and reflective of operational costs.
- Promotion of Efficient Energy Use
  - Incorporate energy-efficient technologies and practices in project design and operation to enhance overall efficiency and reduce energy consumption.
  - Support initiatives and programs that promote energy conservation and the efficient use of resources.
- Consumer Protection and Public Engagement
  - Ensure that project operations align with consumer protection regulations, providing reliable and affordable energy services.
  - Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.
- Enforcement and Penalties
  - Be aware of the enforcement mechanisms and penalties for non-compliance with MERA's regulations. This includes potential fines, suspension of licenses, and other corrective actions.
  - Maintain thorough documentation and records to demonstrate compliance and facilitate regulatory oversight.

The Energy Regulation Act (2004) establishes a robust regulatory framework for the energy sector in Malawi, emphasizing the importance of licensing, tariff setting, compliance, and efficient energy use. Generation, transmission, and distribution projects must obtain the necessary licenses from MERA, comply with all regulatory requirements, and promote energy efficiency and consumer protection.

9.3.4 Electricity Act (2004) and Electricity Amendment Act (2016)

Electricity Act (2004) and the Electricity Amendment Act (2016) are key legislative frameworks that regulate the generation, transmission, and distribution of electricity in Malawi. These acts aim to ensure the efficient and reliable supply of electricity while promoting competition and enhancing the overall efficiency of the energy market. The amendments introduced in 2016 are particularly significant as they allow for multiple licenses beyond the previously sole holder, the Electricity Supply Corporation of Malawi (ESCOM), thereby fostering a more competitive environment. The Electricity Act (2004) and the Electricity Amendment Act (2016) outline several key elements essential for the regulation and management of the electricity sector:

- Regulation of Electricity Generation, Transmission, and Distribution
  - The Acts provide a comprehensive legal framework for regulating the generation, transmission, and distribution of electricity.
  - They establish standards and procedures for the development, operation, and maintenance of electrical infrastructure.
- Licensing and Competition
  - The original act centralized licensing with ESCOM as the sole license holder. The 2016 amendment, however, introduced provisions for multiple licenses, allowing other entities to enter the electricity market.
  - This shift aims to encourage competition, improve service delivery, and provide more choices for consumers.
- Standards and Compliance
  - The Acts set technical, safety, and environmental standards for all electricity-related activities.
  - Compliance with these standards is mandatory for obtaining and maintaining licenses.
- Tariff Regulation
  - The Acts empower regulatory authorities to set and review tariffs to ensure they are fair, reasonable, and reflective of the cost of electricity supply.
  - Tariff regulation aims to balance the interests of consumers and service providers, ensuring affordability and financial sustainability.
- Consumer Protection and Public Involvement
  - Provisions are included to protect the rights of electricity consumers and ensure they have access to reliable and affordable electricity services.
  - The Acts encourage public participation in the regulatory process, enhancing transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Electricity Act (2004) and the Electricity Amendment Act (2016) have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Application for Multiple Licenses
  - Project developers can apply for multiple licenses for generation, transmission, and distribution activities. This facilitates more integrated and efficient operations.
  - The ability to hold multiple licenses encourages vertical integration, allowing developers to streamline processes and reduce operational costs.
- Enhanced Competition and Market Efficiency
  - The introduction of multiple licenses fosters competition in the electricity market. This can lead to improved service delivery, better pricing, and increased innovation.
  - Developers must be prepared to operate in a competitive environment, focusing on efficiency, reliability, and customer satisfaction.
- Compliance with Standards and Regulations

- Projects must comply with all technical, safety, and environmental standards set forth in the Acts. This includes adherence to construction, operation, and maintenance guidelines.
  - Regular audits and inspections by regulatory authorities ensure ongoing compliance and identify areas for improvement.
- Tariff Setting and Financial Sustainability
  - Developers must work with regulatory authorities to set tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.
  - Financial planning should consider the regulatory framework for tariffs to ensure the long-term sustainability of projects.
- Consumer Protection and Public Engagement
  - Projects must align with consumer protection regulations, ensuring reliable and affordable electricity services.
  - Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.
- Promoting Competition and Innovation
  - The Acts encourage developers to adopt innovative technologies and practices to enhance service delivery and efficiency.
  - Competitive dynamics in the market can drive continuous improvement and adoption of best practices.

The Electricity Act (2004) and the Electricity Amendment Act (2016) establish a regulatory framework for the electricity sector in Malawi, emphasizing the importance of licensing, competition, standards compliance, and consumer protection. Generation, transmission, and distribution projects must navigate this regulatory landscape by applying for the necessary licenses, adhering to standards, and embracing competition.

9.3.5 Rural Electrification Act (2004)

Rural Electrification Act (2004) is a legislative framework designed to support the development of energy infrastructure in rural areas of Malawi. The Act aims to increase electrification rates and support socio-economic development by ensuring that rural communities have access to efficient, sustainable, and affordable energy. It establishes the necessary structures, funding mechanisms, and regulatory provisions to promote rural electrification initiatives. The Rural Electrification Act (2004) outlines several key elements essential for promoting rural electrification:

- Establishment of the Rural Electrification Management Committee
  - A Rural Electrification Management Committee is established to oversee the planning, implementation, and management of rural electrification projects.
  - The Committee is responsible for developing and updating a rural electrification master plan, setting selection criteria for projects, and ensuring the efficient and effective implementation of rural electrification programs.
- Creation of the Malawi Rural Electrification Fund

  - The Act establishes the Malawi Rural Electrification Fund, which finances the capital costs of rural electrification projects, operational and maintenance costs, and other related expenses.
  - The Fund is sourced from government appropriations, levies on energy sales, grants, donations, and other financial contributions.
- Licensing and Regulation
  - Rural electrification activities, including grid extension and off-grid electrification, must be licensed by the MERA.
  - The Act sets forth regulations for safety, tariffs, and concession agreements, ensuring that rural electrification projects meet established standards and provide reliable services.
- Promotion and Support of Rural Electrification
  - The Act mandates the promotion of rural electrification through public awareness campaigns, market research, and the provision of technical, commercial, and institutional advice.
  - It encourages the use of renewable energy resources and technologies, such as solar home systems and micro-hydropower stations, to enhance rural energy access.
- Monitoring and Reporting
  - The Committee is tasked with monitoring the implementation and operation of rural electrification projects to ensure compliance with the Act and related regulations.
  - Concessionaires are required to submit regular reports on the progress and performance of their projects, including annual plans, progress updates, and post-completion evaluations.

Implications for Generation, Transmission, and Distribution Projects

The Rural Electrification Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Access to Incentives and Support
  - Projects targeting rural areas can benefit from the incentives and support provided under the Act, including funding from the Malawi Rural Electrification Fund.
  - Developers can leverage these resources to reduce capital costs, improve project viability, and ensure sustainable operations.
- Integration of Rural Electrification in Project Planning
  - Developers should consider rural electrification as an integral part of their project planning, aiming to extend energy access to underserved rural communities.
  - Incorporating off-grid and mini-grid solutions can enhance energy access in remote areas where grid extension is not feasible.
- Compliance with Licensing and Regulatory Requirements
  - All rural electrification activities must obtain the necessary licenses from MERA and comply with the regulatory provisions set forth in the Act.
  - Ensuring adherence to safety standards, tariff regulations, and concession agreements is crucial for project approval and operation.

- Promotion of Renewable Energy Technologies
  - Projects should promote the use of renewable energy technologies, such as solar home systems and micro-hydropower stations, to support sustainable rural electrification.
  - Emphasizing renewable energy can help reduce reliance on traditional biomass and fossil fuels, contributing to environmental sustainability.
- Engagement with Local Communities and Stakeholders
  - Active engagement with local communities and stakeholders is essential for the successful implementation of rural electrification projects.
  - Developers should involve communities in project planning and implementation, ensuring their needs and concerns are addressed.

The Rural Electrification Act (2004) provides a comprehensive framework for promoting rural electrification and supporting socio-economic development in Malawi. Generation, transmission, and distribution projects must leverage the incentives and support provided under the Act, integrate rural electrification into their planning, and comply with licensing and regulatory requirements.

9.3.6 Forestry Act Amendment (2019)

Forestry Act Amendment (2019) is a critical legislative update that introduces stricter penalties for illegal activities, enhances regulation of charcoal production, and increases transparency and accountability in the forestry sector. This amendment aims to address the significant deforestation and forest degradation challenges in Malawi, driven by the demand for natural resources such as charcoal and firewood. The Act is designed to promote sustainable forest management and conservation efforts, ensuring the protection of forest resources for future generations. The Forestry Act Amendment (2019) outlines several key revisions and provisions essential for effective forestry management and conservation:

- Stricter Penalties for Illegal Activities
  - The amendment introduces harsher penalties for deforestation, encroachment, illegal logging, and other unlawful activities within forest reserves and protected areas.
  - Penalties include significant fines and long-term imprisonment, reflecting the seriousness of forest crimes.
- Enhanced Regulation of Charcoal Production
  - Charcoal is now classified as a forest product, and its production, distribution, sale, possession, import, and export are regulated.
  - Permits for charcoal production can only be granted by the Department of Forestry and must be accompanied by an approved reforestation or forest management plan.
- Increased Transparency and Accountability
  - The Department of Forestry is mandated to improve information systems, providing the public with easy access to forestry-related data.
  - The amendment promotes greater stakeholder participation in forestry-related decision-making processes, ensuring inclusive and transparent governance.
- Strengthened Law Enforcement
  - Forestry officers are empowered to carry firearms in the line of duty to enforce forestry laws effectively.

- The amendment increases penalties for a range of offences, including bribery, obstruction of justice, falsification of documents, and illegal trade in forest products.

- Promotion of Sustainable Forest Management
  - The amendment supports initiatives like the "Modern Cooking for Healthy Forests" program, which aims to promote sustainable cooking technologies and reduce reliance on charcoal and firewood.
  - It encourages public-private partnerships to enhance sustainable forest management and conservation efforts.

Implications for Generation, Transmission, and Distribution Projects

The Forestry Act Amendment (2019) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources
  - Projects involving land use changes must assess their impact on forest resources and comply with reforestation and sustainable management requirements.
  - ESIAs should include detailed evaluations of potential impacts on forests and outline mitigation strategies.
- Compliance with Charcoal Production Regulations
  - Projects must adhere to regulations regarding charcoal production, ensuring that any activities related to charcoal are properly licensed and managed.
  - Failure to comply with these regulations can result in severe legal penalties, including fines and imprisonment.
- Adherence to Stricter Penalties and Law Enforcement
  - Developers must be aware of the stricter penalties for illegal activities outlined in the amendment and ensure compliance with all forestry laws.
  - Regular audits and monitoring should be conducted to prevent illegal logging, encroachment, and other unlawful activities within project areas.
- Promotion of Sustainable Practices:
  - Projects should incorporate sustainable forest management practices to minimize environmental impacts and support conservation efforts.
  - Engaging in reforestation initiatives and promoting the use of alternative energy sources can help mitigate the effects of deforestation and forest degradation.

The Forestry Act Amendment (2019) provides a robust framework for addressing deforestation and promoting sustainable forest management in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and charcoal production regulations, and adhere to the stricter penalties and enforcement measures outlined in the amendment.

9.3.7 National Parks and Wildlife Act (2017)

National Parks and Wildlife Act (2017) provides the legislative framework for the protection and management of national parks and wildlife in Malawi. The Act includes provisions for the conservation of biodiversity, the regulation of activities within protected areas, and the sustainable use of wildlife resources. It emphasizes the need to balance development with environmental conservation, ensuring that natural habitats and wildlife populations are preserved for future generations. The National Parks and Wildlife Act (2017) outlines several key elements essential for the protection and management of national parks and wildlife:

- Protection of National Parks and Wildlife Reserves
  - Establishes and manages national parks, wildlife reserves, and other protected areas to conserve biodiversity and natural habitats.
  - Prohibits activities that may harm wildlife or degrade habitats within these protected areas, including hunting, logging, and mining.
- Conservation of Biodiversity
  - Promotes the conservation of biodiversity through the protection of endangered and threatened species.
  - Implements measures to restore and maintain ecological integrity and the natural processes within ecosystems.
- Regulation of Activities within Protected Areas
  - Regulates activities such as tourism, research, and resource extraction within national parks and wildlife reserves to ensure they do not negatively impact the environment.
  - Requires permits for activities that may affect wildlife or their habitats, ensuring that such activities are conducted sustainably.
- Community Involvement and Benefit Sharing
  - Encourages the involvement of local communities in the management and conservation of wildlife and protected areas.
  - Promotes benefit-sharing arrangements to ensure that communities derive economic benefits from conservation activities, such as eco-tourism and sustainable resource use.
- Enforcement and Compliance
  - Strengthens law enforcement capabilities to combat wildlife crime, including poaching and illegal trade in wildlife products.
  - Imposes penalties and sanctions for violations of the Act, including fines and imprisonment for illegal activities.
- Public Awareness and Education
  - Promotes public awareness and education on the importance of wildlife conservation and the sustainable use of natural resources.
  - Supports initiatives to educate communities and stakeholders about conservation laws and the benefits of protecting biodiversity.

Implications for Generation, Transmission, and Distribution Projects

The National Parks and Wildlife Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Conservation and Management Requirements
  - Projects located near or within protected areas must comply with conservation and management requirements outlined in the Act.
  - Conduct ESIAs to identify potential impacts on national parks, wildlife reserves, and biodiversity, and develop appropriate mitigation measures.
- Minimizing Impact on Wildlife and Biodiversity
  - Ensure that project activities have minimal impact on wildlife and biodiversity by adopting best practices for environmental management.
  - Implement measures to protect endangered and threatened species and their habitats, avoiding any activities that could cause harm.
- Obtaining Necessary Permits and Approvals
  - Obtain the necessary permits and approvals from relevant authorities for any activities within or near protected areas.
  - Engage with the Department of National Parks and Wildlife (DNPW) to ensure compliance with regulatory requirements and secure project approvals.
- Enhancing Law Enforcement and Compliance
  - Support law enforcement efforts to combat wildlife crime by collaborating with authorities and providing resources for monitoring and enforcement.
  - Ensure that project personnel are aware of and comply with all legal requirements related to wildlife protection and conservation.

The National Parks and Wildlife Act (2017) provides a comprehensive framework for the protection and management of national parks and wildlife in Malawi. Generation, transmission, and distribution projects must comply with conservation and management requirements, minimize their impact on wildlife and biodiversity, and obtain necessary permits and approvals.

9.3.8 Water Resources Act (2013)

Water Resources Act (2013) provides a comprehensive legal framework for the management, conservation, use, and control of water resources in Malawi. The Act aims to promote the sustainable use of water resources, ensure equitable access, and protect the environment from pollution and over-exploitation. It establishes regulatory mechanisms and institutional frameworks to support the effective management of water resources, addressing the needs of various stakeholders, including domestic, agricultural, industrial, and environmental users. The Water Resources Act (2013) outlines several key elements essential for effective water resource management:

- National Water Resources Authority (NWRA):
  - Establishes the NWRA as the primary agency responsible for regulating and managing water resources in Malawi.
  - The NWRA is tasked with developing principles, guidelines, and procedures for the allocation and sustainable use of water resources.
- Water Abstraction and Use:
  - Defines the processes for obtaining licenses for water abstraction and use, ensuring that all water use is regulated and sustainable.
  - Requires the reservation of water resources to meet domestic needs and protect aquatic ecosystems.

- Groundwater Conservation:
  - Provides regulations for the protection and sustainable use of groundwater resources, including the issuance of permits for borehole drilling and groundwater extraction.
  - Establishes conservation areas and guidelines for preventing groundwater pollution and over-exploitation.
- Catchment Management:
  - Establishes catchment management committees to oversee the sustainable management of water resources within designated catchment areas.
  - Requires the development of catchment management strategies that align with the National Water Resources Master Plan.
- Control and Protection of Water Resources:
  - Implements measures to prevent and control water pollution, including the regulation of effluent discharge and the prohibition of harmful substances.
  - Promotes the safe storage, treatment, and disposal of waste to protect water quality and public health.
- Dams and Flood Management:
  - Establishes guidelines for the construction, operation, and safety of dams, including the registration of dams with safety risks.
  - Provides measures for flood mitigation and control, ensuring the protection of communities and infrastructure.
- Water Charges and Financial Provisions:
  - Introduces charges for water use and services, with the revenue used to support the management and conservation of water resources.
  - Establishes a Water Resources Trust Fund to finance water management projects and initiatives.
- Public Participation and Consultation:
  - Ensures public participation in water resource management through consultations, stakeholder engagement, and access to information.
  - Promotes transparency and accountability in decision-making processes related to water resources.

Implications for Generation, Transmission, and Distribution Projects

The Water Resources Act (2013) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Water Abstraction Licenses:
  - Projects must obtain licenses from the NWRA for the abstraction and use of water resources. This includes providing detailed information on the intended use, location, volume, and impact on existing water users and the environment.
  - Compliance with licensing requirements ensures that water use is sustainable and aligned with national water management goals.

- Compliance with Groundwater Regulations:
  - Projects involving groundwater extraction must comply with the regulations for borehole drilling and groundwater use. This includes obtaining permits and adhering to conservation guidelines.
  - Proper management of groundwater resources is essential to prevent over-exploitation and ensure long-term availability.
- Integration of Catchment Management Strategies:
  - Projects located within designated catchment areas must align with catchment management strategies and contribute to the sustainable management of water resources.
  - Engaging with catchment management committees and incorporating local water management plans into project design can enhance sustainability and community support.
- Environmental Protection and Pollution Control:
  - Projects must implement measures to prevent water pollution and ensure the safe disposal of effluents and waste. This includes adhering to effluent discharge permits and maintaining high standards of water quality.
  - Protecting water resources from pollution is critical for maintaining ecosystem health and public safety.

The Water Resources Act (2013) provides a robust framework for the sustainable management and protection of water resources in Malawi. Generation, transmission, and distribution projects must comply with the Act's licensing, conservation, and pollution control requirements to ensure sustainable and responsible use of water resources. Integrating the Act's provisions into project planning and implementation, developers can contribute to the long-term sustainability of Malawi's water resources, support environmental conservation, and enhance community well-being.

9.3.9 Independent Power Producer (IPP) Framework

Independent Power Producer (IPP) Framework provides a structured approach for private sector participation in Malawi's power sector. It outlines the roles, responsibilities, and processes necessary for project evaluation, approval, and procurement. The framework is designed to attract private investment, enhance competition, and ensure the efficient and reliable supply of electricity in Malawi. The IPP Framework aims to streamline the development of power projects and support the country's energy goals. The IPP Framework outlines several key elements essential for the successful involvement of independent power producers in Malawi's energy sector:

- Roles and Responsibilities
  - Defines the roles and responsibilities of key stakeholders, including the government, regulatory authorities, and private sector participants.
  - Clarifies the obligations of IPPs regarding project development, financing, construction, operation, and maintenance.
- Project Evaluation and Approval
  - Establishes criteria and procedures for the evaluation and approval of power projects proposed by IPPs.
  - Ensures that projects meet technical, financial, and environmental standards before receiving approval.
- Procurement Processes

- Details the procurement processes for selecting IPPs, including competitive bidding and direct negotiations.
- Aims to ensure transparency, fairness, and competitiveness in the selection of power projects.

- Regulatory and Licensing Requirements
  - Outlines the regulatory and licensing requirements that IPPs must comply with to operate in Malawi.
  - Includes provisions for obtaining generation licenses, environmental permits, and other necessary approvals.
- Financial and Contractual Arrangements
  - Provides guidelines for financial and contractual arrangements, including power purchase agreements (PPAs), financing structures, and risk mitigation measures.
  - Ensures that contracts are fair, balanced, and provide adequate protection for all parties involved.
- Monitoring and Compliance
  - Establishes mechanisms for monitoring and ensuring compliance with the terms and conditions of licenses and contracts.
  - Includes provisions for regular reporting, audits, and performance reviews.

Implications for Generation, Transmission, and Distribution Projects

The IPP Framework has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Facilitating Private Investment
  - Clear guidelines and streamlined processes facilitate private investment in power projects, attracting local and international investors.
  - By providing a predictable and transparent regulatory environment, the framework reduces uncertainties and encourages long-term investment.
- Following the IPP Framework for Project Approvals
  - Developers must follow the IPP Framework's procedures for project evaluation and approval to ensure compliance with regulatory standards.
  - Adhering to the framework increases the likelihood of obtaining necessary approvals and licenses in a timely manner.
- Ensuring Competitive and Transparent Procurement
  - Developers must participate in competitive bidding processes or direct negotiations as outlined in the IPP Framework.
  - Ensuring transparency and fairness in procurement processes enhances the credibility and integrity of project selection.
- Complying with Regulatory and Licensing Requirements
  - Projects must comply with all regulatory and licensing requirements, including obtaining generation licenses, environmental permits, and other approvals.
  - Regular audits and monitoring are essential to maintain compliance and address any regulatory issues promptly.

- Establishing Financial and Contractual Arrangements
  - Developers must negotiate and finalize power purchase agreements (PPAs) and other financial contracts in accordance with the IPP Framework's guidelines.
  - Adequate risk mitigation measures should be incorporated to protect the interests of all parties involved.
- Monitoring and Ensuring Compliance
  - Implement mechanisms for ongoing monitoring and compliance with the terms and conditions of licenses and contracts.
  - Regular reporting and performance reviews help identify and address any issues that may arise during project implementation and operation.

The IPP Framework provides a comprehensive structure for private sector participation in Malawi's power sector, outlining clear guidelines for project evaluation, approval, and procurement. Generation, transmission, and distribution projects must follow the IPP Framework to facilitate private investment, ensure compliance with regulatory requirements, and promote transparency and competitiveness in the power market.

9.4 Guidelines and Regulations.

9.4.1 EIA Guidelines

EIA Guidelines provide detailed procedures for conducting ESIAs in Malawi. These guidelines are essential tools for project developers to ensure that environmental and social impacts are thoroughly assessed and managed throughout the project lifecycle. The guidelines cover key stages such as project screening, scoping, baseline data collection, impact assessment, and the development of Environmental and Social Management Plans (ESMPs). The EIA Guidelines outline several key stages and elements essential for the effective assessment and management of environmental and social impacts:

- Project Screening
  - The screening process determines whether a project requires a full ESIA based on its type, size, and potential environmental impact.
  - Projects that are likely to have significant environmental impacts are subjected to a detailed ESIA.
- Scoping
  - Scoping identifies the key environmental and social issues that need to be addressed in the ESIA.
  - It involves consultations with stakeholders to gather input on potential impacts and concerns.
- Baseline Data Collection
  - Baseline data collection involves gathering information on the existing environmental and social conditions of the project area.
  - This data serves as a reference point for assessing the potential impacts of the project.

- Impact Assessment
  - The impact assessment evaluates the potential environmental and social impacts of the project, both positive and negative.
  - It considers the magnitude, extent, duration, and reversibility of the impacts.
- Mitigation Measures
  - Mitigation measures are developed to avoid, reduce, or offset significant adverse impacts.
  - These measures are integrated into the project design and implementation plan.
- Environmental and Social Management Plans
  - ESMPs outline the specific actions and responsibilities for managing and monitoring environmental and social impacts throughout the project lifecycle.
  - They include measures for impact mitigation, monitoring, and reporting.
- Public Consultation and Participation
  - Public consultation and participation are critical components of the ESIA process, ensuring that stakeholders' views and concerns are considered.
  - The guidelines provide methods for effective public engagement and information dissemination.
- Monitoring and Reporting:
  - Ongoing monitoring and reporting are required to ensure that mitigation measures are effectively implemented and that environmental and social impacts are managed.
  - Regular audits and inspections are conducted to assess compliance with ESMPs and regulatory requirements.

Implications for Generation, Transmission, and Distribution Projects

The EIA Guidelines have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Thorough Assessment and Management of Impacts:
  - Developers must follow these guidelines to ensure a thorough assessment and management of environmental and social impacts.
  - Conducting comprehensive ESIAs helps identify potential issues early in the project lifecycle, allowing for effective mitigation and management.
- Regulatory Compliance:
  - Compliance with EIA guidelines is critical for obtaining regulatory approval for projects.
  - Proper ESIA documentation, including baseline studies, impact assessments, and ESMPs, is essential for demonstrating compliance with environmental regulations.
- Stakeholder Engagement:
  - Effective stakeholder engagement is crucial for the successful implementation of projects.
  - Developers should actively involve stakeholders in the ESIA process, addressing their concerns and incorporating their input into project planning and decision-making.

- Sustainability and Long-term Success:
  - Ensuring environmental and social sustainability is key to the long-term success of projects.
  - Implementing robust ESMPs and ongoing monitoring helps mitigate adverse impacts and promotes positive outcomes for communities and the environment.
- Transparency and Accountability:
  - The ESIA process promotes transparency and accountability by involving stakeholders and providing access to information.
  - Regular reporting and public disclosure of ESIA findings and management measures enhance trust and credibility with stakeholders.
- Integration into Project Planning:
  - Integrating ESIA findings into project planning and design helps optimize project outcomes and minimize negative impacts.
  - Developers should use ESIA results to inform decision-making and improve project sustainability.

The EIA Guidelines provide a comprehensive framework for assessing and managing the environmental and social impacts of generation, transmission, and distribution projects in Malawi. Developers will ensure thorough impact assessment, regulatory compliance, effective stakeholder engagement, and long-term project sustainability. Integrating ESIA findings into project planning and implementation helps optimize project outcomes and contributes to the overall well-being of communities and the environment.

9.5 REFERENCES

GoM, (1995). Constitution of the Republic Malawi, Government of Malawi (1994)

GoM, (1997). Guidelines for Environmental Impact Assessment (EIA) in Malawi, Government of Malawi (1997)

GoM, (2004). Electricity Act, Government of Malawi (2004)

GoM, (2004). Energy Regulation Act, Government of Malawi (2004)

GoM, (2004). National Environmental Policy, Government of Malawi (2004)

GoM, (2005). National Water Policy, Government of Malawi. Lilongwe, 2005.

GoM, (2008). Environment Management (Chemicals and Toxic Substances Management) Regulations, Government of Malawi. Lilongwe, 2008.

GoM, (2013). Water Resources Act, Government of Malawi (2013)

GoM, (2016). Electricity Amendment Act, Government of Malawi (2016)

GoM, (2016). National Climate Change Management Policy, Government of Malawi (2016)

GoM, (2016). National Forestry Policy, Government of Malawi. Lilongwe, 2016.

GoM, (2016). Physical Planning (Amendment) Act, Government of Malawi. Lilongwe, 2022.

GoM, (2017). Environmental Management Act, Government of Malawi (2017)

GoM, (2017). National Parks and Wildlife Act, Government of Malawi (2017)

GoM, (2018). National Energy Policy, Government of Malawi (2018)

GoM, (2019). Forestry Act Amendment, Government of Malawi (2019)

GoM, (2021). The Malawi 2063 First 10 Year Implementation Plan (2021 – 2030, Government of Malawi. Lilongwe, 2021.

10. Conclusions

This study aims at updating the Integrated Resource Plan of Malawi, by providing efficient and reliable solutions to supply the national demand in the horizon 2022-2042 i.e. defining the least cost generation development over the period and providing the Stakeholders with sufficient information to adapt the optimal plan to measured deviations to the base case evolution thanks to the study of alternative scenarios

The first presented capacity expansion plan is the Least Cost scenario, which includes all the technologies that could realistically be implemented in Malawi in the next future and accounts for their techno-economic characteristics to identify the optimal capacity mix. This scenario allows to have an unbiased view on the best strategy to develop the generation system in Malawi in the long-term.

An alternative scenario including considerations about the diversification of the resources and the current strategic views of the Stakeholders is also tested and presented. In particular, in this scenario, a 50 MW gas unit and a 300 MW coal power plant are considered as decided. Analogously, small hydro plants are considered as decided and available in the system before 2030, while bigger hydro power plants come online between 2030 and 2035.

The Least Cost option obviously provides the most efficient plan cost-wise, but it does not take into account political and strategic visions which often influence the development of the generation portfolio of a country. Still, it provides valuable information in terms of long-term strategies and allows to challenge and adjust plans for the short and medium term.

On the contrary, the alternative scenario including strategic projects reflects the current view of the stakeholders and highlights the impacts of deviating from a least cost path. In particular, the inclusion of small hydro before 2030 allows to quickly diversify the resources for hydro production, which currently comes almost totally from the Shire river. The presence of these units, together with the selection of the coal power plant, leads to higher total investments, higher total domestic capacity, thus reducing the import needs.

Therefore, the study provides comprehensive insights on the paths the investment plan may take and analyses the different aspects that would be impacted. The detailed development of the plan will depend also on the opportunities that will realise in the next twenty years, namely the IPP as well as the plans and subsidies that will be put in place during the period.

As confirmed by the Stakeholders after the presentation of the preliminary results, the reference development plan for the global planning exercise of this study corresponds to the Least Cost scenario. This plan that will be the base for the Transmission and Distribution development plan studies in the frame of the other tasks of the present study.

11. References

[1] Ministry of Energy, "Demand Forecast, Loss Reduction and Energy Efficiency Strategies Final Report," 2023.

[2] "System Profile 2020.xlsx".

[3] WSP, "RAPID COST BENEFIT ANALYSIS FOR DIESEL GENERATOR REPLACEMENT OPTIONS AND MODELLING OF GRID-INTEGRATED BESS," 2022.

[4] [Online]. Available: https://www.bls.gov/data/inflation_calculator.htm.

[5] SAPP, [Online]. Available: https://www.sapp.co.zw/demand-and-supply.

[6] "Volume 1-CHASOMBO Feasibility Report 15-04-2013".

[7] "29-04-2013_Chizuma Feasibility Report".

[8] "Part 1_Fufu_Phase III_Report & appendices_2018-04-17".

[9] "40251-FS-21-0101-MDJ Kholombidzo feasibility study".

[10] "Volume I - FS_Report_Mpatamanga," 2018.

[11] "02 SRBDP Final Project Report".

[12] "Appendix 7 - Feasibility Study Main Report - FINAL (1) Nyika".

[13] "Volume I MBONGOZI".

[14] Government of Malawi, "Water Resources Investment Strategy," 2011.

[15] IRENA, "Renewable Power Generation Costs in 2021," 2022.

[16] NREL, "Annual Technology Baseline," 2023.

[17] Danish Energy Agency, "Technology data," 2022.

Appendix A: Existing generation

Table 2.A.1: List of existing hydro power plants

Power plant name	Technology	Total net capacity [MW]	# of units	Average generation [GWh/y]	Minimum stable level [%]	Min up time [h]	Min down time [h]	Max ramp rate [%/min]	VO&M cost [USD/MWh]	Fixed O&M cost [USD/kW/y]	Forced outage rate [%]	Planned outage rate [%]
NKULA A	RoR	34.7	3	17784	60	1	1	20	0.003	40.738	3	7
NKULA B	RoR	99.7	5	50666	60	1	1	20	0.003	40.738	3	7
TEDZANI I & II	RoR	39.8	4	17256	60	1	1	20	0.003	40.738	3	7
TEDZANI III	RoR	60.5	2	26747	60	1	1	20	0.003	40.738	3	7
TEDZANI IV	RoR	19.1	1	8240	60	1	1	20	0.003	40.738	3	7
KAPICHIRA I	RoR	64.6	2	37920	60	1	1	20	0.003	40.738	3	7
KAPICHIRA II	RoR	63.8	2	37450	60	1	1	20	0.003	40.738	3	7
WOVWE	RoR	4.3	3	2820	60	1	1	20	0.003	40.738	3	7
Mulanje	RoR	8.0	3	4117	60	1	1	20	0.003	40.738	3	2
Muloza	RoR	3.0	1	1745	60	1	1	20	0.003	40.738	3	2

Table 2.A.2: List of existing thermal power plants

Power plant name	Technology	Fuel	Total net capacity [MW]	# of units	Minimum stable level [%]	Max capacity factor [%]	Heat rate [GJ/MWh]	Min up time [h]	Min down time [h]	Max ramp rate [%/min]	VO&M cost [USD/MWh]	Fixed O&M cost [USD/kW/y]	Forced outage rate [%]	Planned outage rate [%]
KANENGO I	Diesel	Diesel LFO	7.5	5	20	78	9.919	0.083	0.083	15	5.58	46.55	5	7
KANENGO II	Diesel	Diesel LFO	8.0	5	20	78	9.919	0.083	0.083	15	5.58	46.55	5	7
MAPANGA	Diesel	Diesel LFO	16.0	10	20	80	9.919	0.167	0.067	15	5.58	46.55	5	7
LUWINGA	Diesel	Diesel LFO	4.5	3	20	75	9.919	0.067	0.067	15	5.58	46.55	5	7
LILONGWE A 1	Diesel	Diesel LFO	3.0	1	20	56	9.919	0.017	0.083	15	5.58	46.55	5	7
LILONGWE A 2	Diesel	Diesel LFO	1.3	1	20	56	9.919	0.017	0.083	15	5.58	46.55	5	7
LILONGWE A 3	Diesel	Diesel LFO	1.1	1	20	56	9.919	0.017	0.083	15	5.58	46.55	5	7

Table 2.A.3: List of existing renewable power plants.

Power plant name	Technology	Total net capacity [MW]	Total storage capacity [MWh]	Total storage power [MW]	Minimum stable level [%]	Fixed O&M cost [USD/kW/y]	Forced outage rate [%]	Planned outage rate [%]
Golomoti	Solar PV	20.0	10.0	5.0	0	116	1	3
Salima	Solar PV	60.0	-	-	0	108	1	3
Serengeti	Solar PV	21.0	-	-	0	16	1	3

Appendix B: Candidate generation plants

Table 2.B.1: List of candidate thermal and hydro power plants.

Power plant name	Technology	Fuel	Total net capacity [MW]	Storage capacity [Mm³]	# of units	Minimum stable level [%]	Heat rate [GJ/MWh]	Min up time [h]	Min down time [h]	Max ramp rate [%/min]	VO&M cost [USD/MWh]	Fixed O&M cost [USD/kW/y]	CAPEX [USD/kW]	Forced outage rate [%]	Planned outage rate [%]	Technical lifetime [y]	Earliest COD
Chasombo	Hydro reservoir	-	40.4	963	2	50		1	1	20	0.5	39.716	10407	3	7	50	2033
Chizuma	Hydro reservoir	-	40.4	28.8	2	50		1	1	20	0.5	39.716	4021	3	7	50	2033
Lower Songwe	Hydro reservoir	-	90	165	3	50		1	1	20	0.5	39.716	2650	3	7	50	2035
Mpatamanga	Hydro reservoir	-	309	261	6	50		1	1	20	0.5	39.716	1861	3	7	50	2030
Mpatamanga regulating dam	Hydro RoR	-	52		1	100		1	1	20	0.5	39.716	1861	3	7	50	2030
Kholombidzo	Hydro RoR	-	219		4	50		1	1	20	0.003	39.716	3082	3	7	50	2034
Fufu	Hydro reservoir	-	261	138	3	50		1	1	20	0.5	39.716	3276	3	7	50	2034
Mbongozi	Hydro reservoir	-	41		4	50		1	1	20	0.5	40.738	4829	3	7	50	2028
Nyika	Hydro RoR	-	51		3	50		1	1	20	0.003	40.738	6965	3	7	50	2027
Dwambazi	Hydro RoR	-	22		1	50		1	1	20	0.003	40.738	4021	3	7	50	2033
Thyolo	Hydro RoR	-	20		1	50		1	1	20	0.003	40.738	4021	3	7	50	2028
Wovwe 2	Hydro RoR	-	4.5		3	50		1	1	20	0.003	40.738	3380	3	7	50	2027

Generic geothermal unit	Geothermal	-	5		1	50		1	1	5	0.0012	98.48	9355	7	8	25	2031
Generic WtE	Steam turbine	Was te	10		1	20	14.243	1	1	5	28.18	447	10770	1	3	25	2027
Generic biomass unit	Steam turbine	Bag asse	10		1	50	14.243	-	-	5	0	66.6	2258	1	10	25	2027
Generic gas unit	CCGT	Gas	50		1	40	7.122	4	2	10	5.58	20	900	5	6	25	2027
Generic coal unit	Coal	Coal	100		1	50	10.266	8	4	4	6.5	66	2497	8	12	30	2028
Generic OCGT	OCGT	Gas	25		1	40	10.7953329	2	1	10	4.5	5.7	1076	5	8	20	2027

Table 2.B.2: List of candidate RES and storage plants.

Power plant name	Technology	Total net capacity [MW]	Total storage capacity [MWh]	Initial SOC [%]	Min SOC [%]	Max SOC [%]	Charge efficiency [%]	Discharge efficiency [%]	VO&M cost [USD/MWh]	Fixed O&M cost [USD/kW/y]	CAPEX [USD/kW]	Forced outage rate [%]	Planned outage rate [%]	Technical lifetime [y]	Earliest COD
Generic PV unit	Solar PV	1	-	-	-	-	-	-	-	15.79	variable	1	3	25	2025
Generic wind unit	Wind	1	-	-	-	-	-	-	-	27.57	variable	1	3	25	2027
Generic storage unit	BESS	1	4	90	10	98	95	95	-	5	variable	1	2	15	2025

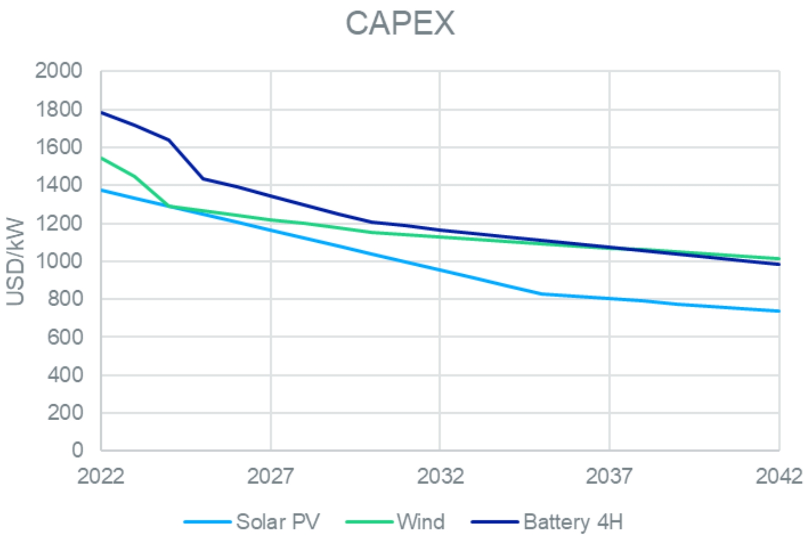


Figure 2.B.1: CAPEX trends for RES and BESS unit

Appendix C: Yearly capacity in the Reference development plan

Table 2.C.1: Yearly installed capacity in Reference development plan

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Hydro	398	398	398	398	398	402	402	402	763	763	763	982	982	982	982	982	982	982	982	982	982
Solar PV	101	101	101	101	124	124	179	233	287	341	395	395	395	395	660	940	956	956	956	956	956
Wind	0	0	0	0	0	15	65	116	167	217	268	268	268	444	513	513	615	615	615	615	615
Diesel	42	42	42	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	200	200	400	400	550
Biomass	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total installed capacity	**540**	**540**	**540**	**550**	**574**	**643**	**748**	**852**	**1318**	**1422**	**1527**	**1746**	**1746**	**1922**	**2307**	**2586**	**2854**	**2854**	**3054**	**3054**	**3204**
Import potential	0	0	120	120	120	120	170	170	170	170	220	220	220	220	220	220	220	220	220	220	220
Total available generation	**540**	**540**	**660**	**670**	**694**	**763**	**918**	**1022**	**1488**	**1592**	**1747**	**1966**	**1966**	**2142**	**2527**	**2806**	**3074**	**3074**	**3274**	**3274**	**3424**
Peak Demand	373	405	449	508	582	617	663	725	774	834	900	976	1048	1130	1214	1307	1407	1516	1636	1768	1914
DSM & EE potential	14	38	38	52	93	108	110	115	120	124	129	132	136	141	144	148	153	156	160	163	168

VOLUME 3: Distribution network planning — Final report

1. Introduction

1.1 Project background

Developments in Malawi's power sector are currently guided by the Integrated Resource Plan (IRP) of 2017 which is a least-cost plan of investments in generation, transmission and some demand-side management measures up to 2037. The plan must be updated every five years to reflect the most recent information to maintain the country on a least-cost path. The first update of the Plan falls due in 2022 and it has already been confirmed by key stakeholders that most of the underlying assumptions that formed the basis of developing the 2017 IRP generation and transmission plans have changed. Moreover, no investment plan was developed for the distribution network in the 2017 IRP.

Building on the 2017 IRP, the revised IRP is expected to outline optimal pathways of 'least cost, least risk, least carbon-emitting, reliable' project portfolios recommended for development in the next 5 to 15 year planning horizon. Against this background, the Malawi Government, through the Ministry of Energy, with support from the GEAPP is embarking on a review of the IRP's generation and transmission expansion plans and the development of a distribution masterplan.

The objective of the current assignment is to produce a properly costed masterplan up to 2042. It is intended to produce a reliable, risk-weighted, least-cost investment roadmap for the generation, transmission and distribution networks that ensures access to energy for all whilst respecting the network operating criteria and optimizing the grid losses.

1.2 Overview of the complete methodology

The project is organized into two work streams: Work stream 1 (WS1)focusing on generation and transmission, and Work stream 2 (WS2) on distribution. In addition, a Work stream 0, common for all tasks, deals with the inception phase of the project. It consists of the kick off, data collection and review of the existing situation.

Moreover, Work stream 1 is split in two parts, of which the first part focuses on the generation master plan. After the generation planning exercise, the transmission planning and distribution planning start in parallel. It allows iterations and exchanges between the transmission and distribution planning.

The second workstream is interlinked with the first one, as the development of the distribution masterplan will be partially built on the findings of Work stream 1 and, in turn, the optimal planning of the distribution network will provide insights for the transmission development plan (e.g. siting of substations, capacity of substations given the local load).

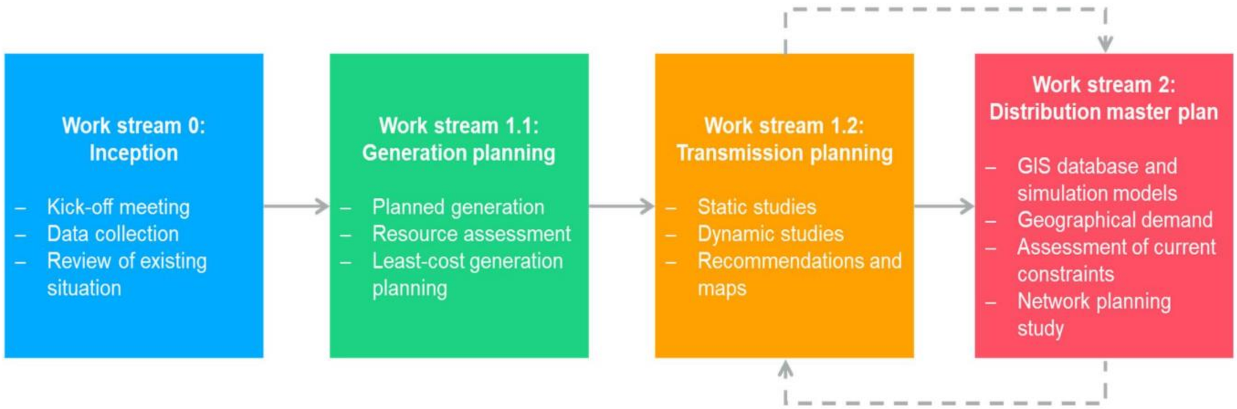


Figure 3.1.1. Overall project methodology. Source: ENGIE Impact

In the context of WS 2, a GIS (geographic information system) database has been built to support the analysis and the simulations are carried out using the DIgSILENT software.

This work stream 2 is conducted in a four-step approach:

- Step 1: Preparation of GIS database and simulation models
- Step 2: Geographical demand assessment
- Step 3: Assessment of the current constraints
- Step 4: Distribution network planning study

1.3 Working Group Distribution

It is worth mentioning that Working Groups have been set from the beginning of the project for the 2 workstreams. In the context of WS 2, a great part of the report has been discussed remotely with the local stakeholders through direct exchanges and recurrent meetings. Especially, the Working Group Distribution has discussed about the next topics:

- Gaps and assumptions regarding collected data: GIS data, models, reports, tables, costs assumptions, etc.
- Data clarifications
- Energy access data from IEP and MAREP
- Geographical demand analysis
- Planning standards
- Planning methodology
- Needs in terms of new primary and secondary stations

1.4 Organization of the report

The present report consists in the second deliverable of the Workstream 2. It follows the Inception report issued in the first phase of the project. The aim of the report was to present the main collected data and to highlight data gaps and assumptions. The report also aimed at presenting the methodology and main hypotheses.

This report corresponds to the final version of the distribution master planning (workstream 2).

The report is organized in five chapters as follows:

- Chapter 1: presentation of the project and the report
- Chapter 2: description of the preparation of the GIS database
- Chapter 3: geographical demand analysis
- Chapter 4: analysis of current network constraints
- Chapter 5: distribution network planning study
- Chapter 6: Legal and Regulatory Framework for Generation, Transmission, and Distribution Projects in Malawi
- Chapter 7: synthesis of the distribution development plan
- Chapter 8: report's appendixes
- Chapter 9: References

2 Preparation of the GIS database

A consolidated GIS database is the basis for all analysis performed during the development of the distribution master plan. The database consists of inputs from multiple sources and is updated throughout the project to have a most accurate representation of the existing and planned Malawian distribution network. The focus of the distribution master plan is on the medium voltage level. The high voltage level is the subject of Workstream 1.2 (transmission) but is also included in the GIS database. The development of the MV network affects the future needs of the HV network, and vice versa, making data on the HV network crucial for consistent distribution network planning. LV network samples are also available in the GIS database.

2.1 Available databases

Two databases are available in GIS format: the ESCOM GIS database contains information about the existing network, while the IEP GIS database contains information about planned network. The received data have been complemented with additional information from open-source databases:

- Administrative boundaries (https://gadm.org/): national and regional boundaries will be used for map creation as well as to link administrative information with the network assets (e.g., breakdown of current regional demand between service transformers)
- Protected areas (https://www.protectedplanet.net/en): environmentally sensible areas will be taken into consideration when planning future network extensions
- Average solar irradiation (https://globalsolaratlas.info/) and wind speed (https://globalwindatlas.info/en).

The following table summarizes the main data and sources:

Table 3.2.1: Available databases for the distribution workstream

Database	Available in GIS format	Content
ESCOM	Yes	MV feeders, service transformers, LV network, HV network
IEP	Yes	Planned MV feeder extensions, planned service transformers (electrification)
MAREP	No	Planned load centers (electrification)
Direct clients	No	Location of direct transformers (incl. rating or demand)
Open-source data	Yes	Administrative boundaries, protected areas, solar and wind resources

2.1.1 Existing high voltage network

The ESCOM database contains the existing HV network (line location, voltage) and MV network (feeder location, voltage, underground/overhead), as well as the existing service transformers (name, rating, feeder).

ESCOM's HV network roughly covers 2,700 km. As shown in the figure, the voltage levels are 400 kV, 132 kV, and 66 kV. The 132-kV and 66-kV voltages are predominant, with 51.6% and 48% of the total conductors' length, whereas the 400-kV network only represents 0.4%. Substations were not shared in GIS format and were manually added to the database.

2.1.2 Existing medium voltage network

ESCOM's MV network roughly covers 12,500 km. ESCOM's medium-voltage levels are 11 and 33 kV, the latter being the main one with 75% of the total MV network length. Whereas the 11-kV feeders are limited to urban areas, the 33-kV feeders cover long distances to serve rural communities. Nevertheless, some long 11-kV feeders are also present; they mostly serve rural communities.

Most of the existing MV conductors are OHL (Overhead Lines), while underground cables are barely employed (mainly present in urban settlements): 99% of the existing MV lines are OHL.

Demand is served by two MV/LV transformer types: service and direct transformers. Service transformers are connected to a LV public network, while direct transformers serve a specific customer directly from the MV network.

ESCOM currently operates more than 7,000 service transformers. Most of them are installed in the Southern and Central regions (47% and 39%, respectively), whereas only 14% are located in the Northern region.

Direct transformers are not included in the ESCOM database. Data on direct transformers was received in multiple tables from the three regions and added to the GIS database.

2.1.3 Electrification

Two electrification programs exist in parallel and are considered in the distribution master plan: the Integrated Energy Planning (IEP) Tool and the Malawi Rural Electrification Programme (MAREP).

2.1.3.1 IEP

The IEP database (2022) contains the planned MV feeder extensions and service transformers under the SEforALL initiative, targeting universal electricity access in Malawi by 2030.

A great network development is expected to reach the electrification objectives, with a total length of 27,684 km of new MV lines. The following table presents the breakdown between voltage level, conductor's type, and conductor's phase:

- 75% of these extensions are planned to be at 33 kV
- Similar share of 3-phase and 1-phase extensions
- The main employed conductor is AAAC 50 mm²

Table 3.2.2: Length of expected grid-connected MV lines for electrification purposes

Voltage		Phase		Conductor	
33 Kv	**11 kV**	**3**	**1**	**AAAC 100 mm²**	**AAAC 50 mm²**
20,732	6,952	14,770	12,914	7,969	19,715

Regarding the future electrification transformers, more than 48,000 new transformers are envisaged for rural electrification, with a total peak demand of 530 MW. The following table shows the split between voltage level, phase, and nominal capacity:

- 75% of these new transformers are expected to be 33kV/LV
- Most of them will be 1-phase (95%)
- These transformers will present a low nominal capacity. Indeed, 80% of them will be either 15-kVA or 25-kVA transformers

Table 8.2.3: Number of expected grid-connected transformers and their peak demand in the IEP database

Criteria	Type	Number	Peak demand (MW)
Voltage	33 kV	36,380	400.4
	11 kV	12,096	129.2
Phase	3-phase	2,744	58.7
	1-phase	45,732	470.9
Nominal capacity	10 kVA	6,871	42.0
	15 kVA	20,390	185.1
	25 kVA	18,471	243.8
	50 kVA	2,717	57.6
	100 kVA	25	1.0
	200 kVA	2	0.1
Total	**-**	**48,476**	**529.7**

2.1.3.2 MAREP

The MAREP is a database that contains the location and estimated demand of villages in non-electrified regions of Malawi. 2800 locations have been identified with an average demand of 104 kW. Missing data has been added based on averages of the available data. Each location has been included in the GIS database as a transformer with the relevant peak load. No plans for feeders or network extensions are at disposal from the MAREP.

As the MAREP study was ongoing at the time of writing of this report, more locations will be selected in the future. This study considers all MAREP data that was available by the end of February 2024.

2.1.3.3 Integration of marep and IEP in the gis database

Both databases cover most of Malawi with considerable overlap. To avoid double counting, the MAREP has been selected as the principal database. All transformers of the IEP database that are closer than 1 km to a MAREP transformer have been excluded from the further analysis.

It is important to note that the MAREP and IEP have a different approach to electrification. The MAREP targets more centralized MV/LV transformers, approximately one per village. At the same time, the IEP foresees multiple small MV/LV transformers, even within small villages. As a result, the average size between the two differs significantly: Table 8 shows that the average transformer rating in the IEP is 15–25 kVA, whereas the average peak demand in the MAREP is 100 kW.

2.1.4 New industrial loads

The following new industrial loads are identified based on interactions with ESCOM. Other lists of new industrial customers such as the one published in the ECA report [1] did not include any information on location and could not be included in the analysis.

No detailed information on project timelines was available, but all projects are modeled to be commissioned by 2030.

Table3.2. 9: Planned industrial loads (substations indicated with an asterisk have a dedicated feeder to the substation)

Name	Region	Peak demand (MW)	Substation
Chigumula industrial parc	South	5	Chigumula
Lunzu (Matindi)	South	1	Chileka
Area 55	Center	10	Kanengo
Shayona Cement	Center	7.5	Chinyama*
Kanyika mining	North	10	Chinyama*
Kasiya	Center	15	Nkhoma*
Malingunde	Center	10	Nkhoma*

2.2 Data processing and issues

The processing of the various databases has been successfully completed, during which several types of errors were identified and rectified. These errors include naming errors, misaligned network objects, location mismatches of the normal open points (NOPs), and missing data.

It is important to note that transformers located more than 1 km from the Medium Voltage (MV) network were excluded from consideration. This exclusion applied to some of the direct transformers that were added to the database based on the received tables.

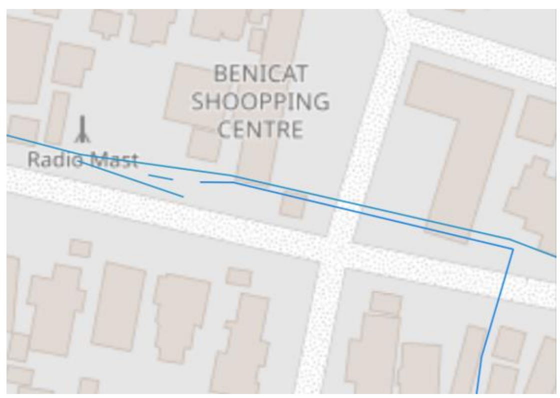
2.2.1 MV feeders

The MV network is modeled in great detail in the ESCOM database. Two recurring issues are identified and resolved:

- Naming inconsistencies: the name of a feeder is not always consistent with reality. This has been resolved in the updated GIS database.
- The network elements were not physically attached to each other, making network analysis impossible. The updated GIS database has all feeders, substations, and transformers connected to allow for power flow simulations.

Figure shows examples of these two types of issues in the ESCOM database. In Figure A, the red feeder is named 20F LUWINGA, while the green feeder is named 20F TELEGRAPH HILL. Figure B shows the 2LF AREA 48 feeder in blue with several disconnected parts.

A: inconsistent naming of feeders



B: Feeders not connected in the GIS database

Figure 3.2.1: ESCOM database issues for MV feeders

2.2.2 Service transformers

The ESCOM database of service transformers is of high quality and it is adjusted in three aspects:

- Some transformers were not physically connected to their MV feeder. This has been resolved in the updated GIS database.
- The rating of transformers with missing data is estimated at 100 kVA (rural areas) or 200 kVA (urban areas) in accordance with the average rating of service transformers.
- The feeder attribute of some transformers was incorrect. This has been resolved in the updated GIS database.

2.2.3 Direct transformers

Approximately half of the direct transformers data did not include any identification of location (coordinates) and was disregarded from the study. Transformers that are located more than 1 km from the MV network are also excluded. For the remaining transformers, none or any of the following data was available: rating, peak load, annual demand.

The transformer rating is a key input for the geographical demand analysis in chapter 3. Where missing, the rating is approximated based on the declared peak load or demand. Transformers without any disclosed information have an estimated rating of 400 kVA, equal to the average of the direct transformers with known ratings.

In total, 270 direct transformers are considered in the study.

3 Geographical demand analysis

A critical step in the planning of the distribution network is the repartition of the future demand. Depending on the location of new load centers, the future electrical network should be planned to accommodate the new demand in the best way possible. Furthermore, the location of new load centers also impacts the planning of the transmission network.

The geographical demand analysis starts from the top-down demand forecast that predicts the electricity demand for Malawi up to 2042. Next, the demand is split over different load centers to estimate the location of the future demand.

3.1 Methodology

The GIS data used for the demand decoupling is listed in chapter 2. This database contains the location and rating of all MV/LV transformers. In addition, the demand forecast, as prepared by ECA and published in 2023 [1], is a key input. Section 3.1.1 summarizes the ECA demand forecast study. Next, the methodology for the geographical demand analysis is detailed in three steps:

First, the current demand per transformer is calculated, taking 2021 as a reference year. This is the last year with measured demand data, following the ECA demand forecast report.

Second, a demand increase is modeled in accordance with the reference scenario of the ECA study. Results are presented for the key years 2027, 2032, and 2042.

Third, the peak load per transformer is calculated based on their demand, using estimates for the respective load factors. Additionally, values are calculated at feeder, substation, and zonal level.

Figure 3.3.1 and Figure 3.3.2 visualize the methodology of the geographical demand analysis.

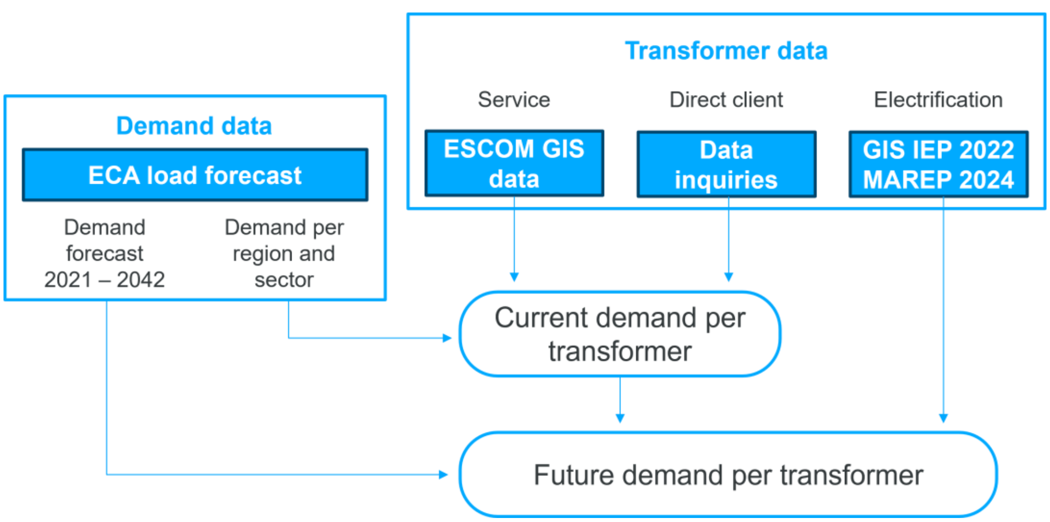


Figure 3.3.1: Methodology for the geographical demand analysis (1)

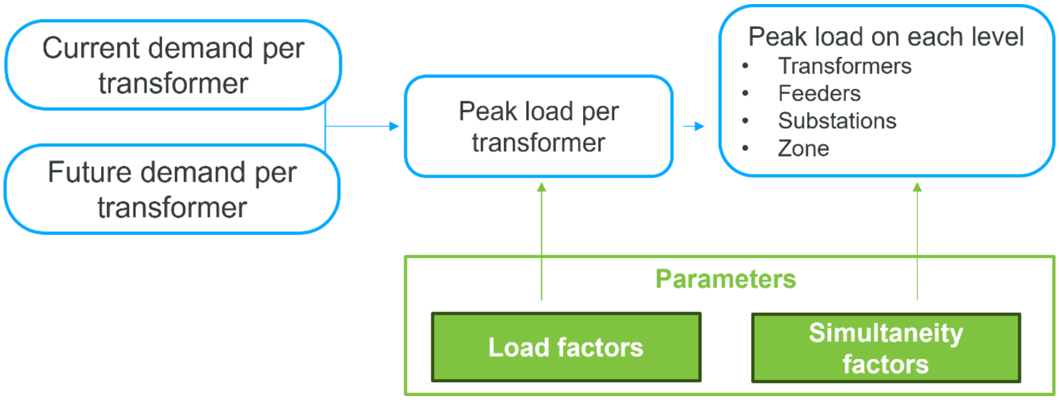


Figure 3.3.2: Methodology for the geographical demand analysis (2)

3.1.1 Summary of the ECA demand forecast study

The demand forecast, as prepared by ECA and published in 2023 [1], studies the load growth between the last year with measured data, 2021, and the final year in the planning horizon, 2042. Figure and Figure summarize the results of the study. The *base case* demand forecast is used as the basis for the distribution master plan.

The national energy demand in 2021 reached 2.3 TWh, with a peak demand of 360 MW. By 2042, this would increase fivefold to 12.5 TWh and 1,900 MW.

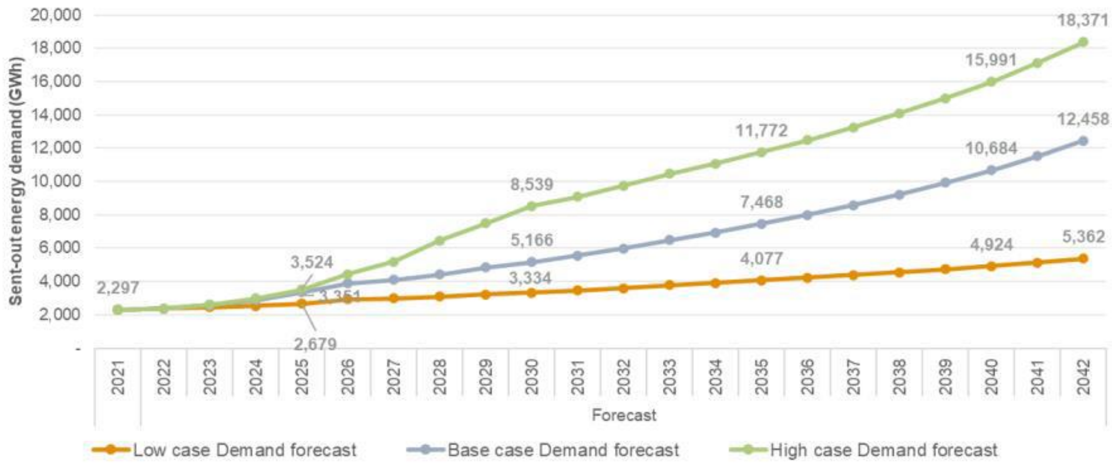


Figure 3.3.3: ECA demand forecast results (energy) [1]

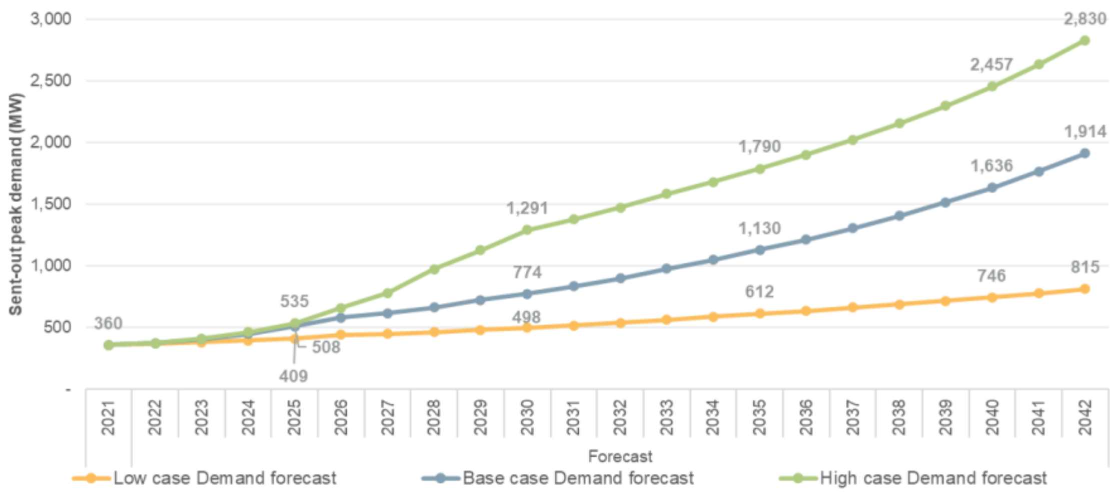


Figure 3.3.4: ECA demand forecast results (power) [1]

In 2021, industrial demand represented the large share of the national demand at 44%, more than residential (38%) and commercial (18%) demand. Residential demand will become more important in the future, representing 59% of the national demand by 2042.

50% of the 2021 demand was in the southern region, while 41% was in the central region and only 9% in the northern region. This distribution will slowly change towards 2042: by then, the regional demand would be 45%, 42%, and 13% for the southern, central, and northern regions respectively.

Following the *Loss Reduction Plan*, distribution losses would decrease from 16.7% in 2021 to 11% by 2042. The share of distribution losses in the LV network is not specified in the ECA report. The calculations below assume that 75% of the distribution losses occur at the LV side. In 2021, the domestic sales at distribution level are 1,770 GWh. Including the LV losses, the total demand at distribution level is 1,992 GWh.

Clean cooking

Clean cooking technologies will become more important in Malawi in the next years. Multiple technologies such as biogas, electricity, and liquid petroleum gas (LPG) can provide solutions to the health issues and other challenges associated with wood and charcoal alternatives. Electrical clean cooking technologies should be considered in the planning of the distribution (and transmission) networks: they have a high peak load per appliance and can alter load patterns and average load factors. The OnStove initiative of SEforALL puts biogas and biomass forward as the optimal clean cooking technologies for most rural areas in Malawi (Figure).

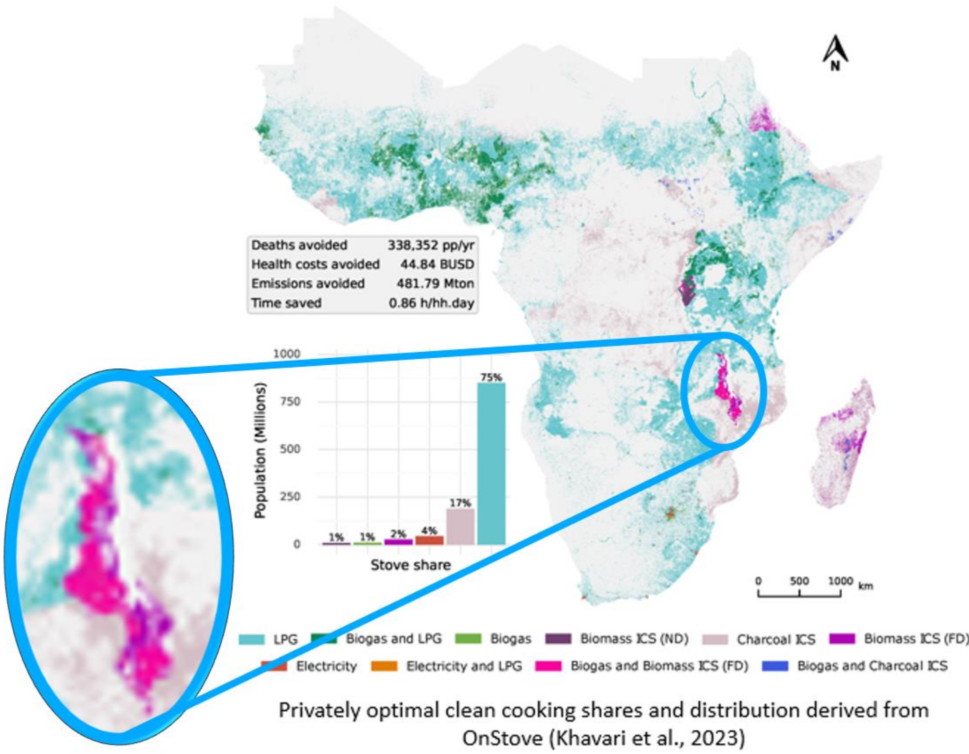


Figure 3.3.5: Optimal clean cooking technologies (OnStove)

The ECA study accounts for the electricity consumption of household appliances, including electrical cooking appliances such as stoves and kettles [1]. The study uses the current trends to predict future electricity consumption of electric cooking. The same assumptions are retained in the development of the distribution master plan to remain consistent with the ECA demand forecast.

3.1.2 Current demand per transformer (2023)

This demand is allocated to the MV/LV transformers in three steps. First, the demand is split per region and sector. Second, the demand is recalculated, this time per region and transformer type (service or direct). Third, the demand is distributed among the transformers in the database based on their respective rating.

The total demand attributed to the MV/LV transformers includes the domestic sales and the losses at LV side. Table represents the 2021 demand for MV/LV transformers, per region and sector. These values are calculated using the data of the ECA study for the last year with available data — 2021 [1].

Table 3.3.1: Demand for MV/LV transformers in 2021 per region and sector (values in GWh)

Sector \ Region	North	Center	South
Residential	75	310	359
Commercial	52	151	169
Industrial	52	295	528

This demand is recalculated per transformer type — service or direct. Assuming that 60% of the industrial demand is served by direct transformers, as well as 20% of the commercial demand and 0% of the residential demand, the values from Table can be converted to a demand per region and transformer type:

Table 3.3.2: Demand for MV/LV transformers in 2021 per region and transformer type (values in GWh)

Type \ Region	North	Center	South
Service TFO	138	549	705
Direct TFO	42	207	350

The values of 2021 are then extrapolated to the years 2023 and beyond based on the ECA forecast. Finally, the demand is distributed proportionally among the transformers in the GIS database: The higher the rating of a transformer, the larger its share in the demand. The demand for some direct transformers is known for current or future years. This information is accounted for in the calculations.

3.1.3 Future demand per transformer

3.1.3.1 Existing transformers

The 2021 demand at the distribution level is 1,992 GWh following section 3.1.1. This increases to 11,500 GWh by 2042, almost a six times increase. The demand growth per sector and region is detailed in the ECA report [1], allowing to calculate the load growth per transformer based on its type (service or direct) and location (north, center, or south).

3.1.3.2 planned transformers (iep and MAREP)

Electrification targets are adjusted to align with the SEforALL initiative to reach a 100% electrified population by 2030. This translates to 73% of the consumers connected to the national grid. Off-grid solutions such as mini-grids and solar home systems would supply the remaining customers.

From the IEP and MAREP databases, the location, rating, and estimated peak load of the 48,000 planned transformers is known. Estimating their load factor at 30%, the 2032 demand for these planned transformers is estimated at 1.3 TWh or 24% of the national demand. The 2042 demand of these planned transformers is estimated using the same load growth as existing service transformers.

The electrification (i.e., the construction of the feeders and 48,000 transformers) takes place between 2023 and 2030. 43% of the efforts would be accomplished by 2027 [2]. The goal is to ensure a balanced distribution of efforts across all regions, with each aiming to achieve the 43% target by 2027.

The demand per year, region, and transformer type is listed in Table . The columns S, D, and E represent the demand for service, direct, and electrification (planned) transformers, respectively.

Table 3.3.3: Future demand decoupling (values in GWh)

Year	North			Center			South			Total
	S	D	E	S	D	E	S	D	E	
2023	179	44	0	716	228	0	772	350	0	2,290
2027	360	103	12	818	378	293	954	593	288	3,800
2032	532	122	29	996	458	687	1,256	769	676	5,525
2042	1,247	141	68	2,496	606	1,721	2,700	1,088	1,454	11,521

3.1.4 Peak load calculations

The expansion of the distribution network depends on the peak load on different parts of the network, rather than the energy demand itself. For example, circuit breakers and lines are sized to withstand a certain current during a predefined time window.

The peak load per transformer is calculated from the demand per transformer as follows (with LF representing the load factor):

$$\text{Peak load} = \frac{\text{Demand}}{8760 \cdot \text{LF}} \quad (1)$$

Next, the peak load is calculated at the different levels in the distribution network. The peak load per feeder is calculated as follows (with SF representing the simultaneity factor and TFO the transformer):

$$\text{Peak feeder} \quad (2)$$

$$= \mathrm{SF}_{\mathrm{electr}} \cdot \sum_{\mathrm{electr\ TFOs}} \mathrm{Peak\ electr\ TFO}$$

Similarly, the peak load of each substation is calculated as the sum of the peak load of the connected feeders, again taking into account a simultaneity factor:

$$\mathrm{Peak\ substation} = \mathrm{SF}_{\mathrm{feeder}} \cdot \sum_{feeders} \mathrm{Peak\ feeder} \qquad (3)$$

Table lists the load factors and simultaneity factors. They are estimated based on standard values, then adjusted to yield results that accurately represent Malawi. One of the checks was the calculated load factor at national level. Using the bottom-up approach as detailed above, the national load factor is 72%, in line with the findings of the ECA demand forecast.

Table 3.3.4: Peak load assumptions for transformers and feeders

Parameter	Value	Symbol
Load factor (service TFOs in the north)	40%	LF
Load factor (service TFOs in the center and south)	50%	LF
Load factor (direct TFOs)	60%	LF
Load factor (service TFOs for rural electrification)	20–30%	LF
Simultaneity factor (service TFOs)	90%	$\mathrm{SF}_{service}$
Simultaneity factor (direct TFOs)	70%	SF_{direct}
Simultaneity factor (service TFOs for rural electrification)	35–50%	SF_{electr}
Simultaneity factor (MV feeders)	95%	SF_{feeder}

3.2 Current demand (2023)

The total demand in 2023 is 2280 GWh. This includes losses on the LV network, but not the losses on the MV and HV network. The demand growth is distributed between the existing load centers, while respecting the regional and sectoral forecasts.

Service transformers account for 73% of the total demand, the remaining 27% is allocated to direct transformers. Detailed results are provided in the GIS database per transformer and per zone.

Northern region

The largest load center in the northern region is Mzuzu with a synchronous peak load of 16 MW. Other load centers include Karonga, Chitipa, Rumphi, Nkhata Bay, and Mzimba. The demand in the north is small compared to the other regions, only representing 10% of the total demand.

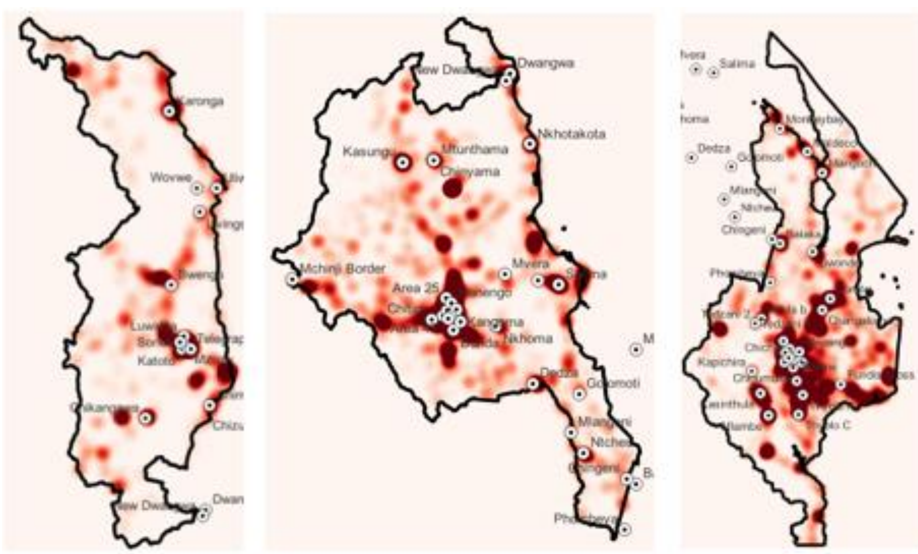
Central region

The capital of Lilongwe is the largest load center in the central region and in the country in general. The synchronous peak demand is 90 MW, and this increases further when accounting for the suburbs. Besides Lilongwe, there are other (smaller) load centers around Kasungu, Dwangwa, Salima, and Mchinji.

Southern region

Blantyre is the largest load center of the south with a synchronous peak demand of 66 MW. The city surroundings and suburbs also have a significant load. Notably, the district of Chileka substation and Chileka international airport has another 8 MW synchronous peak demand.

Other load centers are visible in the vicinity of Monkeybay, Liwonde, Zomba, Kapichira, and the regions southeast of Blantyre.



Southern region Northern region Central region

Figure 3.3.6: Load centers in 2023 per region

3.3 Future demand

The demand is expected to increase fivefold in the next 20 years and reach 1,900 MW in 2042. A significant part of the demand growth is attributed to electrification. This represents 22% of the total demand by 2042. In addition, there are plans for new industrial loads for a total of 60 MW by 2030.

Starting from the demand distribution in 2023, the load growth is modeled at existing load centers, new electrified regions, and new industrial load centers. The demand is calculated for the target years 2027, 2032, and 2042. Figure displays the load density of the districts, expressed as the synchronous peak load density (in kW/km²). Lilongwe, Blantyre, and Mzuzu are the most dense load centers of the country. Besides the large cities, most areas will experience a significant load growth. This is particularly true for the central and southern region where most of the electrification efforts are foreseen. Most of the areas around Lilongwe and Blantyre will be fully electrified by network extension by 2032.

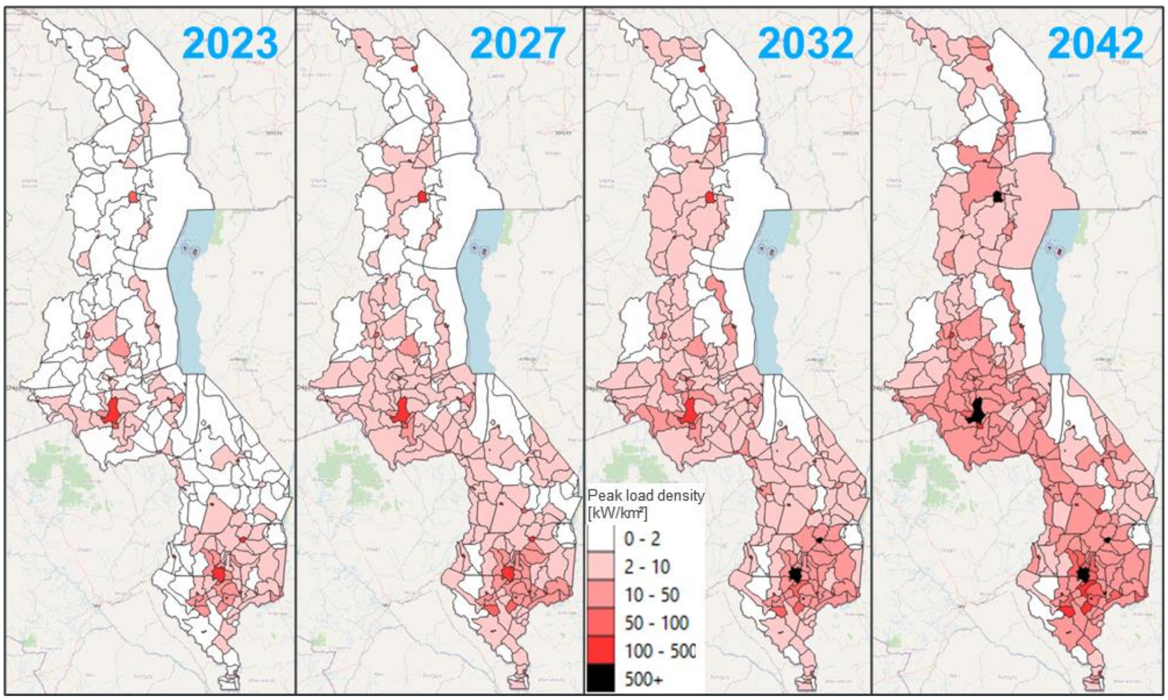


Figure 3.3.7: Evolution of the electricity demand between 2023 and 2042

Table lists the demand in the major cities for each target year. The demand is expected to increase 4 times in Lilongwe and Blantyre and 6 times in Mzuzu. While still representing a small share of the national demand, the northern region will expect the highest demand growth in the next 20 years.

Table 3.3.5: Demand growth in the major cities between 2023 and 2042 (synchronous peak load expressed in MW)

City	2023	2027	2032	2042
Lilongwe	91	118	142	354
Blantyre	66	89	121	265
Mzuzu	12	23	32	71

4 Current network constraints

Simulations of the distribution network has been achieved in order to have a good overview of the current operational challenges. The detection of overloading, voltage profiles and technical losses in the distribution network have been performed considering the existing MV infrastructure.

Given that the shared DIgSILENT models date from 2020, the Consultant used the following approach to assess the current network's constraints:

- Update the DIgSILENT models from the 2020 network: the investments in the distribution network during the past years (2020-2023) have been included in the models, as well as the missing substations' networks have been modelled from scratched based on the shared GIS database and other information shared by ESCOM.
- Update of the peak demand: given that the demand in the existing DIgSILENT models corresponds to the 2020 peak demand, the feeders' demand has been increased to reach the 2023 peak demand
- Once the models are complete and the peak demand is increased to reach the current peak load, load-flow simulations could be launched to perform the diagnosis of the current network's constraints

The following diagram displays the used methodology to assess the current network's constraints:

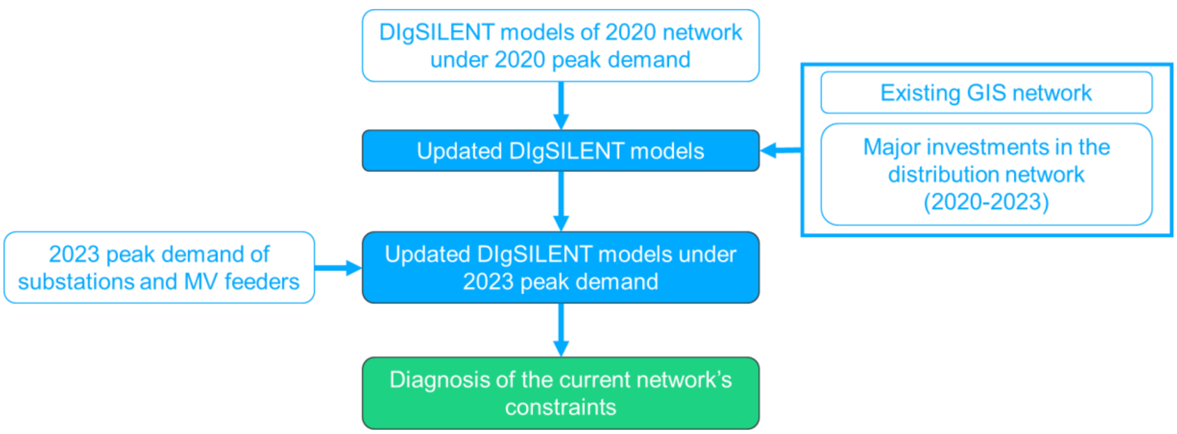


Figure 3.4.1. Methodology to perform the diagnosis of the current network's constraints

A power flow analysis (AC load flow) has been performed to verify that the MV network can satisfy all the operating conditions of the electrical network:

- Voltages limits
- (Over)loading of feeders
- Technical losses level
- Check compliance with operation & planning criteria

Simulations are based on measured peak loads (Measurements taken in spring season 2023).

The operational limits for 11kV and 33kV network which have been considered here are the one presented in the Inception report:

- Normal operating conditions: -6% and +1% of nominal voltage
- Contingency operating conditions: -11% and +1% of nominal voltage
- Overload is considered when feeder is higher than 100% in N situation and 110% in N-1 situation

4.1 Northern Region

In the Northern Region, 31 feeders have been studied. The results are as follows:

- 4 feeders with voltages < 0.94 pu (i.e., 13% of the feeders)
- 0 feeder with loading > 100% (i.e, 0% of the feeders)
- 3 feeders with losses > 4% (i.e., 10% of the feeders)

The mean values and calculated ranges in terms of voltage, loading and losses are summarized in the next table.

Table 3.4.2: Summary of the minimum voltage, maximum loading and losses in the Northern region

Mean values

Min voltage	Max loading	Losses
0.97 pu	21.17%	1.85%

Ranges

Min voltage	Max loading	Losses
[0.88 – 1] pu	[2.51 – 47.76] %	[0.03 – 8.49] %

The list of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% are summarized in the next table.

Table 3.4.1: List of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% - North Region

Feeder	TFO capacity (MVA)	Peak load (MW)	Power factor (-)	Min voltage (pu)	Max loading (%)	Losses (%)
10F CHIKANGAWA (33 kV)	9.130	4.70	0.93	0.88	42.37	8.49
10F CHINTECHE (33 kV)	14.705	3.25	0.98	0.93	28.87	5.68
20F KARONGA (33 kV)	15.005	1.70	0.96	0.91	13.47	5.91
1LF ULIWA (11 kV)	8.041	1.30	0.96	0.92	23.14	3.02

The Northern Region is mainly characterized by rural areas with long feeders. In such feeders, the voltage limit is reached before the loading which is still within the limits. The high losses are also representative of such long feeders. Voltage regulators on the line are a solution to step-up the voltage for such feeders.

4.2 Central Region

In the Central Region, 71 feeders have been studied. The results are as follows:

- 20 feeders with voltages < 0.94 pu (i.e., 28% of the feeders)
- 3 feeders with loading > 100% (i.e, 4% of the feeders)
- 20 feeders with losses > 4% (i.e., 28% of the feeders)

The mean values and calculated ranges in terms of voltage, loading and losses are summarized in the next table.

Table 3.4.2: Summary of the minimum voltage, maximum loading and losses in the Central region

Mean values

Min voltage	Max loading	Losses
0.96 pu	38.49%	2.73%

Ranges

Min voltage	Max loading	Losses
[0.79 – 1] pu	[1.49 – 304.57] %	[0.00 – 12.74] %

The list of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% are summarized in the next table.

Table 3.4.3: List of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% - Central Region

Feeder	TFO capacity (MVA)	Peak load (MW)	Power factor (-)	Min voltage (pu)	Max loading (%)	Losses (%)
3LF AREA 47 (11 kV)	16.60	2.73	0.82	0.91	71.63	6.28
4LF AREA 48 (11 kV)	13.55	5.76	0.96	0.94	119.02	3.62
5LF AREA 48 (11 kV)	11.95	4.70	0.94	0.93	85.76	4.40
1LF BARRACKS (11 kV)	6.77	3.80	0.95	0.91	68.40	5.80
3LF BARRACKS (11 kV)	6.00	3.98	0.95	0.93	71.66	5.04
1LF BUNDA (11 kV)	10.72	1.54	0.95	0.85	23.67	6.94
2LF BUNDA (11 kV)	13.28	1.99	0.95	0.83	30.64	10.42
3LF BUNDA (11 kV)	13.89	4.52	0.95	0.91	69.64	5.82
40F CHINYAMA (33 kV)	19.62	3.96	0.95	0.88	36.30	8.69
3LF CHITIPI (11 kV)	10.09	4.48	0.96	0.86	79.80	9.59

2LF DWANGWA (11 kV)	1.80	4.75	0.95	0.99	130.56	1.31
5LF KANENGO (11 kV)	8.27	2.17	0.95	0.92	39.22	6.13
8LF KANENGO (11 kV)	5.99	1.32	0.95	0.94	23.85	4.21
10F KANENGO (33 kV)	18.57	5.43	0.95	0.91	32.57	5.57
20F KANENGO (33 kV)	21.17	9.77	0.95	0.79	88.25	12.74
2LF KANG'OMA (11 kV)	6.36	3.62	0.95	0.91	99.51	7.25
5LF LILONGWE A (11 kV)	9.58	4.80	0.95	0.88	304.57	8.13
10F NANJOKA (33 kV)	29.97	6.08	0.90	0.88	42.78	8.07
20F NANJOKA (33 kV)	10.38	2.49	0.95	0.93	14.95	4.06
30F NANJOKA (33 kV)	15.41	2.71	0.96	0.92	18.59	4.90
2LF NKHOTAKOTA (11 kV)	8.75	1.46	0.86	0.82	44.24	6.38
2LF SALIMA (11 kV)	11.28	1.81	0.95	0.90	42.84	4.86

The Central Region is characterized by rural areas, small cities and one big city (Lilongwe). That region present the worst results in terms of respect of the technical limits. Generally speaking, when analyzing the list given hereabove, the losses are relatively high and the drop voltage as well. The thermal loading is rarely a concern. Most of the 11kV feeders of the list are long feeders that supply rural areas and present high drop voltage.

Please note finally that the abnormal value on feeder 5LF LILONGWE A is probably due to a mismatch in the measurement.

4.3 South Region

In the South Region, 86 feeders have been studied. The results are as follows:

- 8 feeders with voltages < 0.94 pu (i.e., 9% of the feeders)
- 5 feeders with loading > 100% (i.e, 6% of the feeders)
- 6 feeders with losses > 4% (i.e., 7% of the feeders)

The mean values and calculated ranges in terms of voltage, loading and losses are summarized in the next table.

Table 3.4.4: Summary of the minimum voltage, maximum loading and losses in the South region

Mean values

Min voltage	Max loading	Losses
0.97 pu	34.93%	1.83%

Ranges

Min voltage	Max loading	Losses
[0.59 – 1] pu	[0.44 – 158.25] %	[0.00 – 26.68] %

The list of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% are summarized in the next table.

Table 3.4.5: List of feeders with voltages < 0.94 pu, loading > 100%, and/or losses > 4% - South Region

Feeder	TFO capacity (MVA)	Peak load (MW)	Power factor (-)	Min voltage (pu)	Max loading (%)	Losses (%)
40F CHICHIRI (33 kV)	42.30	12.88	0.98	0.99	114.43	1.11
1LF CHILEKA (11 kV)	?	6.80	0.98	1.00	158.25	0.13
1LF LIMBE B (11 kV)	18.34	5.54	0.97	0.93	138.25	5.36
2LF LIMBE B (11 kV)	4.32	1.85	0.97	1.00	104.22	0.28
10F MAPANGA (33 kV)	16.51	6.83	0.98	0.93	53.05	2.92
2LF MLAMBE (11 kV)	4.51	2.90	0.95	0.59	79.62	26.68
10F MLAMBE (33 kV)	20.70	2.71	0.95	0.91	16.31	4.93
30F MLAMBE (33 kV)	21.02	3.26	0.95	0.92	26.09	3.84
10F MONKEYBAY (33 kV)	34.87	8.78	0.96	0.80	78.79	14.12
1LF ZOMBA (11 kV)	10.61	1.99	0.95	0.68	121.78	15.00
4LF ZOMBA (11 kV)	14.98	2.71	0.95	0.86	86.71	6.11

Similarly to the Central Region, the South Region is characterized by rural areas, small cities and a big city (Lilongwe).

Generally speaking, when analyzing the list given hereabove, the losses are relatively high and the drop voltage as well. The thermal loading is a concern in urban areas. Most of the 11kV with a high drop voltage have been extended too much.

5 Distribution network planning study

5.1 Global distribution network planning process

The global distribution network planning process aims to design the future network for a defined period, such as the next 15 or 20 years. The goal is to determine the optimal network arrangements, the network extensions for electrification of new regions, the investments required, and the timing of the implementation.

The network planning aims to ensure that the future load can be supplied cost-effectively, with good service quality and acceptable voltage drops and losses.

The electricity supply systems are strictly regulated to ensure proper operation for the benefit of the region, ensure safety and balance the tariffs and costs of the network. To enforce these guidelines, planning objectives or criteria are defined, typically concerning the quality of supply, tariff price levels, and stable employment. It is then the responsibility of the utility to plan their network to meet these criteria.

The starting point for the planning process is the existing network, where the need for investments is prompted by load growth, aged assets that need replacement or an increase in operational criteria that must be met. The existing network must be analyzed to assess its performance and identify weak spots, requiring short-term actions. Then follows the load forecast to assess how the power will flow through the network. This information is then used in future network planning where the future network design is made, respecting the criteria for power quality and reliability. The investments required are then summarized and longer-term costs of developing the network must be compared to more short-term needs. These investments may be modified as the time passes and future changes in such factors as the precise load growth in different areas become clear. The environmental and social assessment concludes the planning process and reports on the impacts that the project has on its environment.

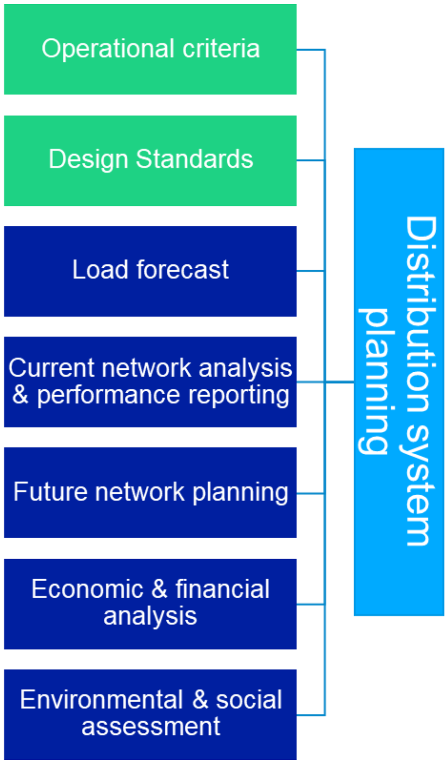


Figure 3.5.1: The global planning process with the entry requirements (green) and the required studies (dark blue) required

5.2 Definition of network development guidelines

When restructuring and planning distribution networks, a set of criteria and standards must be met. The objective of this section is therefore to identify, analyze and define relevant planning criteria. This section reviews and updates the current technical options or basic criteria for network planning and operation regarding voltage level, permissible voltage drops, ampacity, feeders topology and type of line/cable structure.

The current standards used for the planning and operation of the distribution network are first analyzed. More specifically, the structure used, the operating rules, the standard conductor cross-sections as well as the standards at substation level are analyzed.

On the basis of the data collected concerning the existing medium-voltage network structures and based on the diagnosis done in the Inception phase, we then study the best way to structure the network to ensure the backup of outgoing feeders, avoid overloads in transformers and primary stations and optimize investments. A coherent development of the infrastructure and appropriate reinforcements are indeed crucial to limit outage times and improve reliability.

The elements presented here have been discussed through meetings end e-mails exchanges (Working Group Distribution) in order to capture the current practices and to identify the required updates also considering the significant load growth up to 2042 and the increase of the network through network extension.

5.2.1 Planning standards - General considerations

Several criteria must be considered when planning a distribution network:

- Economic criteria: Optimal design standards minimize both capital (equipment investment) and operating cost (technical losses)
- Operating criteria: technical constraints
- Reliability criteria: N-1 for which loads and in which conditions? Which topology for the networks?
- Other criteria: environmental constraints, political decisions, …

In terms of economic criteria, the optimal design standards minimize both capital (equipment investment) and operating cost (technical losses), ensure the quality of service, with coherent standards (considering the existing structure). The optimal design standards allow to define the future network. Some examples of design standards are:

- Conductors' cross-section for each voltage level (LV and MV) and for each type of area (rural, urban)
- Maximum feeder's length for each voltage level and area type. This depends on the type of load that is on the feeder in question.
- Nominal capacity of distribution transformers for each area type. Oversized transformers will lead a high level of losses.
- LV networks can be standardized based on the type of area, whereas MV networks may need dedicated considerations
- Other considerations: It must be pointed out that the initial determinant is the availability of a feeder close to the load that has been applied for. In a situation where the existing feeder cannot supply the load in question, alternative means are weighed out whether to supply the customer on a dedicated feeder on a higher voltage or at the existing voltage level

  The operating criteria which are applied currently in the distribution network are as follows and are considered for the network development. In terms of voltage deviations, the next boundaries are considered:

- LV (0.23 kV and 0.4 kV)
  - Normal operating conditions: -6% and +6% of nominal voltage
  - Contingency operating conditions: -11% and +6% of nominal voltage
- MV (11 kV and 33 kV)
  - Normal operating conditions: -6% and +6% of nominal voltage
  - Contingency operating conditions: -11% and +6% of nominal voltage

The maximum loading of the different network assets are as follows:

- Transformers HV/MV and MV/MV and MV/LV
  - Normal operating conditions: 100%
  - Contingency operating conditions: 110%
- Overhead lines and underground cables

- Normal operating conditions: 100%
- Contingency operating conditions: 110%

The voltage drop can be controlled by installing voltage regulators that primarily are installed to increase the voltage drop at a long MV feeder. These voltage regulators must ensure that the voltage is put back to a magnitude slight above 100% to take care of the following voltage drop on the feeder. Network studies are required to determine the exact placement of voltage regulators.

A capacitor bank can improve the power factor along a distribution feeder, which results in the following benefits:

- Lowers the current in the feeder, which increases the loading capacity. This is the case when the voltage drop or thermal current rating is currently restricting the loading capacity;
- Reduction of feeder losses and losses in upstream components;
- Slight reduction of the voltage drop, due to the lower current in the feeder.

Customers with large reactive power consumption can be requested to install power factor compensation equipment themselves, making the consumers responsible for the power factor of their load. Capacitors connected to the MV side of the primary stations should be installed as standard practice.

In order to achieve the right level of reliability, and once the operating limits are respected in normal operation, the N-1 security must be achieved. However, N-1 for all the distribution networks has a cost. For that reason, the required level of reliability often defers from one area to another area. The level of service in a capital city or in a main city is the highest level to be reached. In secondary cities, a lower level of reliability might be accepted. Finally, in rural areas, N-1 is often not required for long laterals to the main feeders which often presents a very low load density.

For the above reasons, and also to limit the costs of the networks, several topologies of network (structure of the network) have been developed. They are presented in Appendix (8.2). The proposed topology for each type of area can be found in the next sections.

5.2.2 Planning and design standards for the largest cities with internal MV feeders

The cities are currently predominantly supplied by overhead lines of 11 kV. Part of the network can be underground cables, but this is generally not the case for entire feeders. In some areas in the cities, undergrounding can be considered. According to ESCOM, there have been projects suggesting to have an underground network for reliability It is the option which is followed in our planning approach. N-1 shall be considered as mandatory for all the customers in urban areas by adopting a meshed network for MV network.

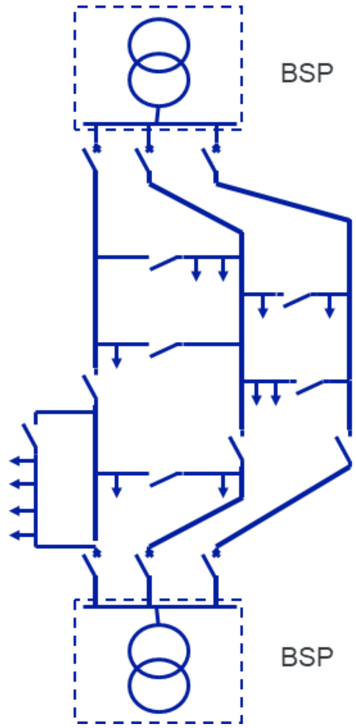


Figure 3.5.2: Meshed network in urban areas

Cities have dedicated MV feeders that go mainly within the city. However, there can also be feeders exiting the cities Primary Station at 33 kV, that serve more dispersed customers with low load density at city outskirts as well as other cities and towns of the operation area outside of the city. These 33 kV feeders fall in the standards proposed in section 5.2.3.

Industrial zones are mostly located in the periphery of the cities. Depending on the size of the load, it can be supplied from one or several 11kV feeders. If the load is consequent, a secondary station supplied in 33 kV shall be considered. The 11 kV feeders are thus leaving the secondary station. It avoids long 11 kV lines within the city.

The next tables summarizes the planning criteria considered for urban areas distribution network planning.

Table 3.5.1: Planning and design criteria for primary 33/11 kV substation

Planning parameter	Value
Transformer rating	Several possible configurations: 10, 15, 20 MVA
MV feeders per transformer	Average of 3 feeders per transformer

Table 3.5.2: Planning and design standards for the largest cities with internal MV feeders – 11 Kv

Planning parameter	Value
MV feeder length	Max 11 km (max 10km crow fly distance between primary station and service transformer)
Main cross section	UG: 120 mm2 underground (for smaller towns) UG: 185 mm2 underground (for biggest cities) OHL: 100 mm² OAK (by default for smaller towns) OHL: 150 mm2 OHL (for biggest cities)
Maximal loading of the feeder	100% of the nominal capacity in N; 110% in N-1 (but maximum 55% to allow the N-1 backup in the “Open loop configuration” circuit arrangement) UG: 120 mm² at 55% (110%/2): 3.2 MVA UG: 185 mm² at 55% (110%/2): 4.1 MVA OHL: 100 mm² at 55%: 3.2MVA OHL: 150 mm² at 55%: 4.1MVA
Voltage limits	Normal operating conditions: **-6% and +6%** of nominal voltage Contingency operating conditions: **-11% and +6%** of nominal voltage
Losses	No criteria: Max 55% loading capacity is ensuring an acceptable level of losses

Table 3.5.3: Planning and design criteria for 11/0.4 substations (urban areas)

Planning parameter	Value
Transformer rating	3-phase ground mounted: 1000, 800, 630, 400 kVA 3-phase pole mounted: 200, 100, 50 kVA
Substation type	Ground and pole mounted
Transformer maximum loading	80% for losses optimization
LV feeders by transformer	2 to 10 maximum

Table 3.5.4: Planning and design criteria for LV network (urban areas)

Planning parameter	Value
Feeder length	Maximum 500 m
Main cross section	4 x 95 mm² Al Bundle (OHL)
Loading of the LV feeder	Up to 150kVA per feeder These limits correspond to a 80% loading of the feeders to minimize the losses

5.2.3 Planning and design standards for smaller cities, rural towns and dispersed customers

The MV network of 33 kV lines has as main purpose to connect the different smaller cities and towns in a rural area and therefore the length, cross-section of these lines and the connected power primarily depend on the geography of that area and the location of the load. These geographies and load distribution can differ greatly from area to area. These lines should be sized per feeder to ensure the specific situation of that feeder is captured. The loading should be kept limited to approximately 40%-55%. This allows to respect the N-1 criteria that in case of a primary station loss, the feeder can take over the load of the residual network as illustrated below.

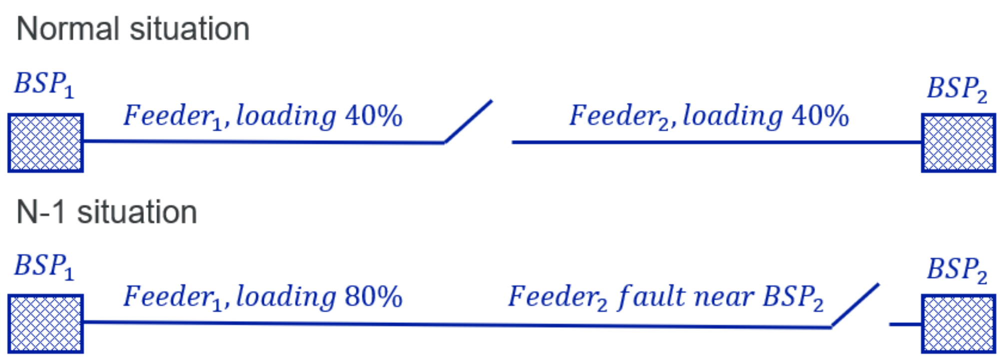


Figure 3.5.3: Illustration of the normal and contingency situation in case of a fault of the feeder near the BSP

The rural towns and other areas are considered as areas with a low load density. The population and load density are not homogeneous, and the area is very small, the internal distribution network is nearly exclusively radial and very limited in size. For these areas the planning guidelines such as transformer ratings and line cross-sections should be predominantly decided by the specific geographic and loading characteristics of that area, instead of optimization and standardization. The substation transformers must be of smaller sizes such as 15, 25, 50, 100, and 200 kVA, except for specific cases with a local high load. The LV network must be constructed with small section lines. The small rural towns are mainly along the laterals and often do not present N-1. The backbone of the feeder shall present an N-1 as it is illustrated at Figure 3.5.4.

Overall, for any feeder, the cross-section of the feeder conductor should depend on the type of branch that the conductor is part of. The first branch, or principal branch, must have the biggest section and secondary and even tertiary branches must have a smaller section as these branches conduct less current.

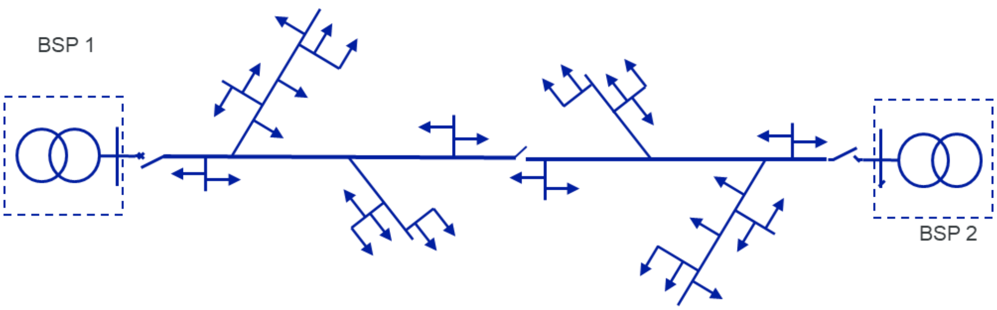


Figure 3.5.4: Two radial network feeders with N-1 supply from another BSP. Laterals do not present N-1

The considered standards for rural towns and dispersed customers are in line with the GIS layers from the IEP platform (2022) which contains a first route of the future MV lines extensions and transformers for electrification. MAREP transformers are also considered.

In terms of voltage, only 33kV networks must be considered for rural feeders due to the characteristics of the load: dispersed load/ low load density and long distance between the loads. According to IEP, about 75% of the extension in rural areas are 3-phase extension. The laterals with low loading are 1-phase extensions and represents 25% of the extensions in terms of length as it has been identified in the Inception Report.

Regarding the future electrification transformers, and according to IEP, 75% of these new transformers are expected to be 33kV/LV and most of them will be 1-phase (95%). These transformers will present a low nominal capacity. Indeed, 80% of them will be either 15-kVA or 25-kVA transformers. Other transformers will be 50 kVA, 100 kVA and 200 kVA depending on the load. The transformers list which has been shared by MAREP consider bigger transformers (not smaller than 50 kVA) covering an higher area, with longest LV feeders.

The next tables summarizes the planning criteria considered for rural areas distribution network planning.

Table 3.5.5: Planning and design standards for the smaller cities and rural towns – 33 kV

Planning parameter	Value
MV feeder length	Between 35 and 100 km (max 70km crow fly distance between primary station and service transformer)
Main cross section	OHL: 50 mm² (for laterals only, depending on the load), 1 phase or 3 phase OHL: 100 mm² OAK (main part of the feeder)

Planning parameter	Value
	OHL: 150 mm2 OHL(main part of the feeder)
Maximal loading of the feeder	100% of the nominal capacity in N; 110% in N-1 (but maximum 55% to allow the N-1 backup of the main part of the feeder) OHL: 50 mm² at 100%: 3.9 MVA (3 phase) OHL: 100 mm² at 100%: 17.5MVA (9.7 MVA at 55%) OHL: 150 mm² at 100%: 22MVA (12.3 MVA at 55%)
Voltage	33kV Normal operating conditions: **-6% and +6%** of nominal voltage Contingency operating conditions: **-11% and +6%** of nominal voltage
Losses	Limited by definition of the maximal loading

Table 3.5.6: Planning and design criteria for 33/0.4kV substations in rural areas

Planning parameter	Value
Transformer rating	3-phase pole mounted: 200, 100, 50 kVA 1-phase pole mounted: 15, 25 kVA
Substation type	Pole mounted
Transformer maximum loading	80% for losses optimization
LV feeders by transformer	2 to 10 maximum

Table 3.5.7: Planning and design criteria for LV network (rural areas)

Planning parameter	Value
Feeder length	Maximum 1000 m
Main cross section	4 x 50 mm² Al/Bundle (OHL)
Loading of the LV feeder	Up to 20 kVA per feeder These limits correspond to a 80% loading of the feeders to minimize the losses

5.2.4 Feeders upgrade from 11 kV to 33 kV

The load-flow simulations achieved for the existing situation (section 4) have shown that some 11kV feeders already present a drop voltage which is outside the limits, especially in rural areas.

Existing 11kV feeders have been extended in rural areas outside the planning standards. The high length of those feeders and the planned significant rural connections (IEP and MAREP) will worsen the situation. For that reason, and according to the developed planning criteria all those feeders must be upgraded to 33 kV at short term horizon. Only the city centers and the close surrounding must be operated in 11 kV, respecting the defined standards. Around the city centers, secondary stations will continue to be supplied in 33kV.

5.2.5 Losses reduction

There is a Loss Reduction Initiative which is based on the Loss Reduction Roadmap report that was made available in February 2021. This Loss Reduction Roadmap (LRR) is the outcome document prepared from the findings and conclusions obtained during the Losses Reduction Initiative project (LRI) developed and supported by IFC. The roadmap is a set of related projects that aims at helping ESCOM gradually reduce the current losses, from 17.36% to 12.11% within a six-year period (a total reduction of 5.25%).

The recommendations highlighted in that document are necessary to achieve that important target. The losses reduction process is complex and requires well-coordinated activities in various areas. In the planning phase, thus in this Distribution Master Plan, the losses considerations are the next ones:

- Losses assumptions are the ones of the load forecast done by ECA
- Proposed planning standards through the maximal loading of feeders and of transformers are chosen to optimize the level of losses.
- Specific meters are recommended. They are included in this study.

Especially, the estimate of additional service transformers to supply the load is done using the optimal loading at peak load. Indeed, the diagnosis made in the Inception report has shown that the service transformers are currently lowly loaded, leading to a high level of losses in transformers. Regarding the technical losses in the feeders, the adopted structure in urban areas will ensure the losses are kept at an acceptable level. In rural areas, the use of higher cross-sections will also contribute to the reduction of technical losses.

5.3 Definition of the target distribution network (2042)

In this section, a target distribution network is proposed for 2042, for the medium load growth scenario, respecting the network development guidelines as presented here above and considering the existing infrastructure in the areas already electrified.

Based on the diagnosis of the distribution network carried out in the Inception Phase of the study, a target distribution network is determined for 2042, taking into account the geographical demand forecasting. Planning is therefore based on the projection of demand, the existing network and planned projects to define the extensions and reinforcements of the network necessary to supply the load while respecting planning standards and operating criteria. ESCOM GIS database provides the most accurate representation of today's network and is used as starting point. IEP and MAREP data are used as inputs for the rural electrification.

The methodology used to determine the target network depends on the density of the demand, but also on the available information. For that reason, section 5.3.1 and 5.3.2 presents the dedicated approaches which have been followed.

All DIgSILENT and GIS models used during the study are shared separately. Detailed results such as voltages and load per feeder in 2042 can be found in the models.

5.3.1 Methodology to determine the distribution network development for urban areas

Only the major cities will follow the methodology described in this section: Blantyre, Lilongwe, Mzuzu, Zomba. The smaller cities will follow the methodology described in the section 5.3.2.

The proposed approach discussed in this section must first consider the fact that no recent Urban Master Plan is available. There is thus a significant long-term incertitude in terms of densification level of the existing urbanized area and of the city surface extension. From the load decoupling activity prepared in the chapter 3, we however have a good estimate of the load growth at the scale of the region, then at the scale of the local district, and finally at the scale of the cities. This has been done considering that the current trends in terms of urbanization of the existing cities will be similar in the future, but considering the differences from one region to another.

Load increase in the urban areas can be split in two: the load increase in the area already covered by the network and the new load in extension zone of the city (network extension). The network in the main cities is planned globally in order to obtain an estimate of the number of feeders, feeders lengths, service transformers type and length and thus, finally the investment needs up to the end of the study period. Generally speaking, big cities require their own dedicated Distribution Master Plan study to be done based on the Urban Master Plan and other city development plans.

ESCOM GIS database provides the most accurate representation of today's network and is used as starting point. In the area already covered by the network, the demand increase is allocated to the existing load centers (densification) considering the existing trends will continue in the future. In the city's outskirts and sub-urban areas, the planning done by IEP will be considered and extended up to 2042. For those areas, the followed approach is described in the next section.

The requirements of new infrastructure are determined per geographical zone considering the increase of the load to determine the number of new feeders. As their locations are unknown, they are not represented in the GIS database. An average length per feeder is used, according to the planning standards. That methodology will allow us to capture the needs in terms of new conductors and thus the required investment needs in the city.

By following the planning standards, the N-1 security is always ensured as the feeders are loaded at maximum 55% (so max 110% in N-1 when one feeder supplies in other one in emergency situation). That loading level also ensures a limited level of technical losses.

Finally, it is also considered that the replacement of existing infrastructure will be done depending on the age of the assets. The conductors will be systematically replaced by the default standard conductor, respecting the network development guidelines presented in the section 5.2.

5.3.2 Methodology to determine the distribution network development for small towns and in rural areas

The target network in small towns and rural areas is developed considering the least-cost electrification option in rural settlements identified by IEP (Malawi Electricity Access Project[19]) and in MAREP. It constitutes the starting point for the analysis, also considering the geographical load growth at 2042 horizon.

Starting from ESCOM, IEP and MAREP database, a geographical analysis is done with the following objectives:

- Create a coherent dataset between IEP, MAREP and ESCOM GIS database
- Include the load growth up to 2042
- Consider the planning standards
- Respect the operational constraints (thermal capacity and drop voltage)
- Include new primary stations
- Improve the reliability
- Reduce the losses

In order to reach those objectives, MV networks developments are necessary as compared to the existing situation (ESCOM GIS) and planned situation (IEP and MAREP). It includes the next considerations:

- Connection of the feeders to the new primary stations
- Analysis of the needs of additional secondary stations or voltage regulators
- Analysis of the needs in terms of new transformers
- Replacement of existing conductors with a higher cross-section
- Reconfiguration of existing feeders
- Analysis of the needs of new feeders

[19] https://projects.worldbank.org/en/projects-operations/project-detail/P164331

- Ensure N-1 of backbones of feeders also in rural areas

Thanks to the IEP database, the MV network extension to connect villages are clearly identified, as it can be seen in Figure .

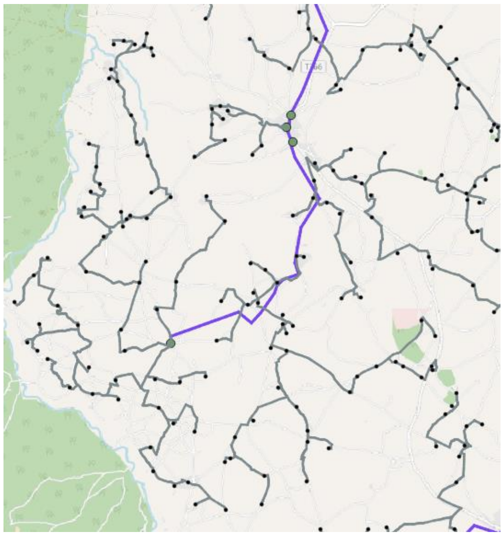


Figure 3.5.5: MV network extension in rural area (IEP)

Regarding smaller cities and their outskirts, the needs in terms of network extension have been covered by the IEP and the MAREP. The example for the network around Salima is given at Figure (part of the network in black). On top of the MV network extension, additional services transformers will be required to supply the load and are estimated in section 7.1.5. The load increase of the direct transformers is also considered when planning the network.

Figure 3.5.6: Salima network in 2042 – IEP, MAREP, ESCOM

In the existing situation, some 11kV feeders have been extended far away from the cities center in order to electrify rural areas. This lead however to a high level of losses and a high drop voltage. Those network must be upgraded to 33 kV in order allow the supply of the load increase and to respect the technical limits, as explained in Planning Standards section.

5.3.3 Determination of the needs in terms of primary and secondary stations

The planning of transmission and distribution networks must be carried out jointly. A geographical analysis has been undertaken considering the results of the load decoupling (Section 3) and the diagnosis of the current situation.

This exercise is critical to determine the needs for new substations. New primary substations mainly target rural areas that will expect a significant demand growth and are located far from the HV network. This avoids multiple long MV feeders in parallel and reduces the overall grid losses.

New secondary substations allow to supply concentrated load in a given area while avoiding numerous long 11kV feeders. Instead, one or two 33kV feeders are installed up to the secondary stations in which one or several 33/11kV transformers will supply 11kV feeders to supply the surrounding area. This reduces the total investment cost and considers possible space constraints to install additional new distribution lines or cables within the city. This is typically used in order to supply a new industrial zone developed at the city border.

As a result of the load increase across the country, a significant amount of secondary stations will require to be upgraded to primary stations. This will allow to supply the load in the city outskirts. In addition, this reduces the load at the primary substation where the secondary substation was initially connected.

For example, the demand at Chichiri is expected to reach 120 MW by 2042. Chichiri supplies multiple secondary substations in the city of Blantyre. One of the secondary substations, Limbe A, will become a primary substation by 2042. This will reduce the load at Chichiri: It will no longer supply Limbe A at MV level, thus reducing the demand by 35 MW in 2042.

The section below details the proposed new substations and substation upgrades. The needs in terms of additional transformer capacity can be found in the Equipment Plan section 7.1.

The determination of new substations is based on the results of the demand at MV level. However, this has a profound impact on the HV network. Therefore, interaction between the transmission and distribution planning is critical during the analysis. The analysis also aligns with the latest information from ESCOM, such as the MEAP 2 study.

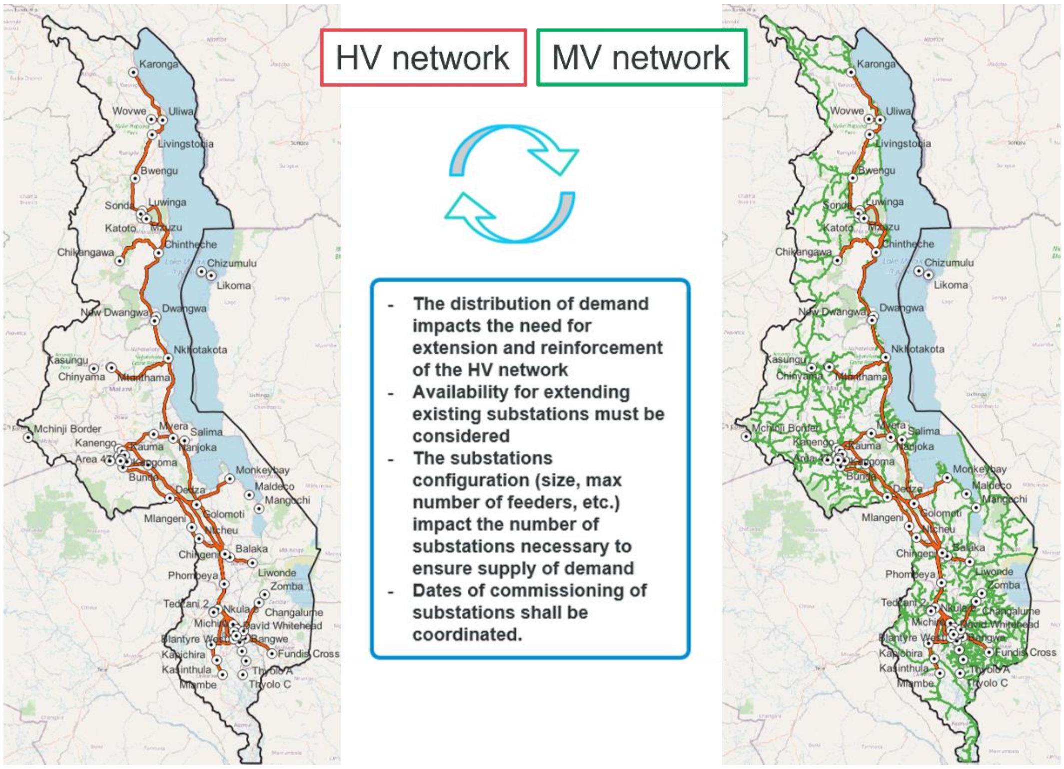


Figure 3.5.7: Integrated HV and MV planning

5.3.3.1 results of the geographical analysis

Section 3.3 discusses the results of the geographical demand analysis between 2023 and 2042. This analysis determines the future demand per existing and planned MV/LV transformer. From there, the peak load per substation is calculated by summing all synchronous peak loads per transformer and per feeder.

This results allow to identify substations where the peak demand will experience a significant growth in the next years. The maximum capacity of a substation mainly depends on the capacity of the installed transformers and the voltage level the substation is connected to. As a general rule, an upgrade of secondary substations to primary substations is recommended when the peak demand exceeds 20 MW, although this can be lower depending on the specific situation in the region. Appendix 8.1 lists the results per substation and indicates the substations that need an upgrade to a primary substation, including the proposed timeline. The peak load per substation already accounts for all reinforcements that are discussed below.

Results for 2027

In the short-term, no reinforcements of substations are needed. Zomba substation will experience a high demand growth and reach an estimated peak load of 22 MW in 2027. As a result, it should be among the first substations that ESCOM connects to the HV network. The analysis foresees this upgrade between 2027 and 2032 (see below).

Results for 2032

The following secondary substations are in need for an upgrade to primary before 2032: Chileka, Mangochi, and Zomba. Chileka and Zomba substations will have a peak demand in 2032 that exceeds the 20 MW threshold. Notably, Zomba should be a priority as the demand is expected to reach 32 MW by 2032 and a substation upgrade should be planned for as soon as possible.

Mangochi substation has an estimated peak demand of 18 MW by 2032. However, this substation also supplies the eastern side of Lake Malawi up to Makanjira. The connection of Mangochi to the HV network will reduce voltage drops and grid losses and allow for a more robust supply of that region. Mangochi can be connected to the HV network in Monkeybay. This route passes through Maldeco, making this another candidate for an upgrade to primary substation. However, this upgrade is not critical as the demand of Maldeco substation remains low.

The following new primary substations are proposed for the 2032 horizon:

- Mponela: The region north of Lilongwe is generally far from the HV network and experiences a high load growth, mostly due to electrification. The new substation is proposed in Mponela, north of Lilongwe. This substation would take over part of the load of the Nanjoka and Kanengo substation and supply a peak load of 24 MW in 2032.
- Chitipa: The northern part of the country is currently supplied from Karonga substation with long 33 kV feeders. ESCOM faces operational challenges and the load growth in the region will require reinforcement of the network. The substation will supply 8 MW in 2032.
- Bangula: Similar to Chitipa, this substation will reinforce the network in a region far from existing substations. The far south is currently supplied by 10F MLAMBE, with significant operational challenges such as voltage drop. The new substations will resolve these issues and improve the region's access to electricity.
- KIA: A new substation at Kamuzu International Airport is proposed to offload the Kanengo substation and supply the north of Lilongwe, where a high demand growth is expected. The substation will supply 9 MW in 2032.

Results for 2042

The following secondary substations are proposed to be upgraded to primary substations between 2032 and 2042:

- Area 47
- Chirimba
- Chitipi
- City Center
- Kasungu
- Limbe A
- Limbe B
- Michiru
- Sonda
- Thyolo A
- Thyolo B
- Thyolo C

In addition, new primary substations are proposed:

- Namitete: Rural electrification will lead to a high demand growth in the region. The estimated demand is 28 MW by 2042.
- Phalombe: The substation will supply a region that is located far from existing substations and that will see significant electrification. The estimated peak demand is 30 MW by 2042.
- Euthini: The region that is currently supplied by 20F LUWINGA will be underserved when the demand quickly increases. If the load growth continues as expected, a new substation will be needed to serve 18 MW of demand by 2042.
- Luwelezi: The region around Luwelezi is currently supplied from Chikangawa and Chinyama substation. If the demand growth is as high as expected, a new substation will be needed to solve emerging issues in the MV network. The substation would supply 14 MW by 2042. If demand grows slower than expected, this substation may only be necessary after 2042.
- Makanjira: The region east of the lake is currently supplied from Mangochi. The load is low and expected to reach 5 MW by 2042. This load could be fully supplied from Mangochi substation, given the foreseen connection to the HV network in Mangochi. The new substation of Makanjira is already planned by ESCOM and thus integrated in the IRP update to align with the latest developments.

Other new primary substations can be avoided by upgrading the existing secondary substations to primary substations, especially if an HV line is close. Chitipi (19 MW peak load in 2042) substation will be connected to the HV line that extends west from Lilongwe to the new primary substation in Namitete. Kasungu will become an essential HV substation that connects to the planned 400 kV backbone and the planned 132 kV line to Dwangwa. Although the peak load at MV level will only reach 12 MW in 2042, the substation will still be an important reinforcement of the HV network.

5.3.4 List of planned big clients and planned network development

The planned industrial loads are listed in section 2.1.4. Most of them will be supplied by dedicated feeders; these are not included in the distribution master plan and investment plan. The planned industrial loads that will connect to the MV network are considered in the geographical demand analysis and the distribution master plan.

Direct feeders to large industrial clients are not modeled, but their demand is considered to size the substations.

5.3.5 Other proposed network reinforcements

The following future network reinforcements and refurbishments have been shared in the Submitted to World Bank to seek financing for ESCOM Projects (2021) report:

- Substation at Area 49 in Lilongwe: a 33/11 kV substation with a 15 MVA transformer. The cost is estimated at 4 MUSD
- A new 132/33 kV substation at Monkey-bay, with a 40-50 MVA transformer

Additionally, the concept paper of the following projects have been shared:

- Project to improve access to electricity in peri-urban areas within cities of Malawi (Lilongwe, Blantyre, Zomba and Mzuzu): this project envisages 238 km and 964 km of new MV and LV lines, respectively, to supply 482 sites, each one served by a 200-kVA transformer. The total project cost is estimated at 33.54 MUSD
- Matindi 132/66/33 substation: the project consists of a new 132/66/33 kV substation in the north of Blantyre as well as new HV and MV lines to link Blantyre's existing substations. The total project cost is estimated at 20.4 MUSD. The following transformers are proposed:
  - One 50-MVA 132/66 kV transformer
  - One 50-MVA 132/33 kV transformer
  - One 10-MVA 33/11 kV transformer at Lunzu site

Besides, the implementation progress report of Senga-bay in Salima has been shared. This area is currently supplied by the 11-kV 2LF Salima feeder, which is fed from Salima 33/11 kV substation. In order to reduce losses and improve the voltage profile in the area, a new 2x7.5 MVA 33/11 kV substation is envisaged with 2 incoming feeders and 4 outgoing feeders. Due to the availability of equipment, the budget is estimated at 832,548,666 K (767,509 USD). According to ESCOM, the land has been acquired, the designs have been created, and funds have been allocated.

The following substations are considered to reinforce the transmission network and align with the plans detailed in the MEAP 2:

- Matindi
- Tsabango
- Bunda T

The substations will offload neighboring substations in the cities and are detailed in the transmission master plan.

5.3.6 Northern region

This section present the proposed network developments in the Northern region. This analysis is done by capitalizing on the GIS database as the development of network in rural areas must considered the directions of the existing feeders and the location of the load development.

5.3.6.1 Rural areas

The two next figures present the existing distribution grid in the Northern region. The feeders operated in 11kV are in green and the feeders operated in 33kV are in orange.

Figure 3.5.8: Upper part of the Northern region (33kV feeders are in brown – 11kV feeders are in green)

Figure 3.5.9: Downer part of the Northern region (33kV feeders are in brown – 11kV feeders are in green)

Several 11kV feeders are operated in the Northern Region. As mentioned in the Planning Standards, long 11kV feeders in rural areas must be avoided.

Two 11kV feeders are operated from Karonga station:

- 1LF KARONGA: remain in 11 kV to supply the city of Karonga
- 2LF KARONGA: the part supplying the city and the region just under will be kept in 11kV. The end will be upgraded to 33kV and will be extended to 1LF ULIWA which will be operated in 33kV for N-1 security purpose.
- Note also that 2 additional 11kV feeders will be necessary in the city, due to the load increase.

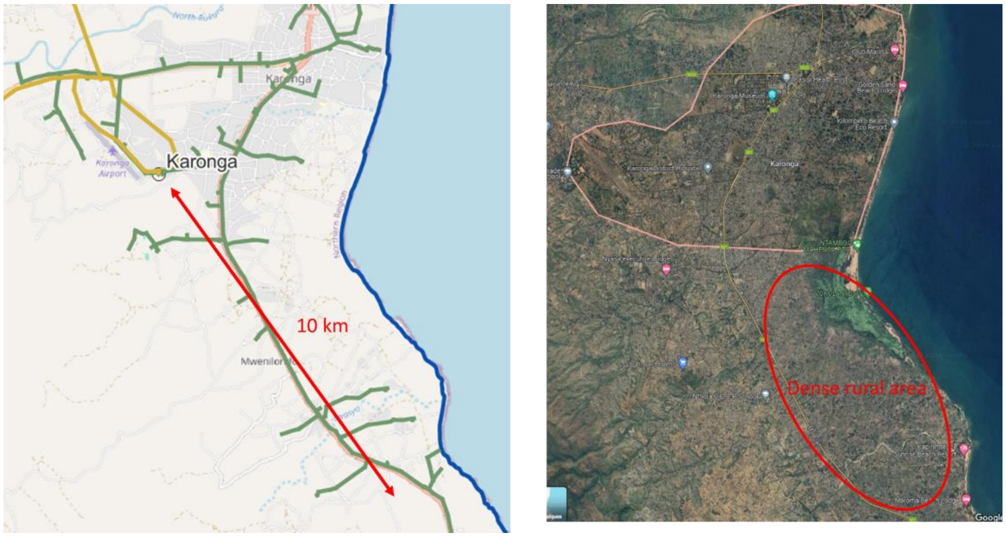


Figure 3.5.10: Karonga area: upgrade to 33kV to supply the areas outside the city

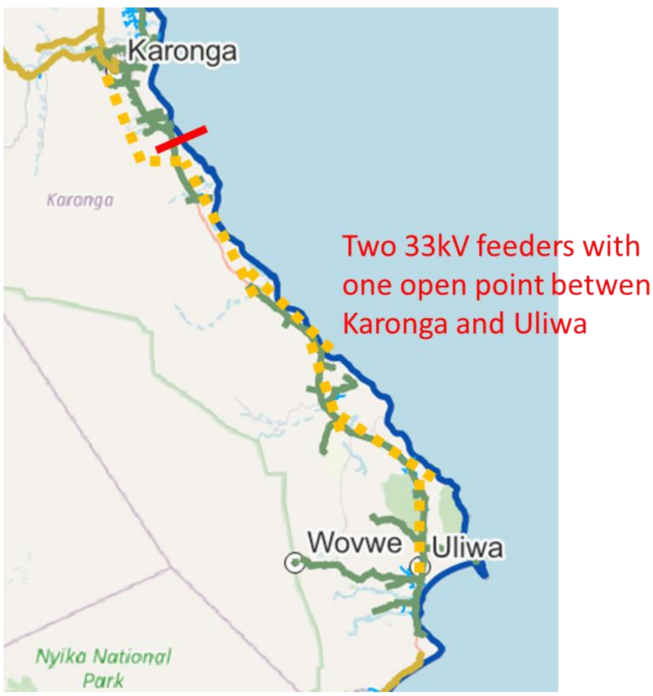


Figure 3.5.11: Proposed 33kV line between Karonga and Uliwa

The simulation analysis of the current situation have shown that the feeder 1LF ULIWA, operated in 11kV, present a drop voltage which is outside the limits. The level of losses is also important.

The feeder part of the feeder 1LF ULIWA (11 kV) which supply Uliwa city and the close surroundings can be kept in 11kV. However, all the other parts of the feeders will be upgraded to 33 kV to supply the rural areas and also to join the stations of Karonga and of Bwengu for N-1 security. For that reason, we propose to upgrade the entire feeder to 33kV.

Figure 3.5.12: Upgrade to 33kV of the feeder supplying Uliwa

At Bwengu station, the feeder 20F BWENGU is going to the South will see its load multiplied by two to reach 5.2MW. It will stay within the thermal limits, as operated in 33kV.

Regarding the 33kV 10F BWENGU, the load is expected to significantly increased as it will increase from 2.9 MW to 19 MW in 2042. For that reason, it is proposed to split the feeder in two as shown at Figure . The first part of the feeder will remain as currently, while the second part going to the north will be split and supplied by a new 150mm² OHL (40F BWENGU). The 10F BWENGU feeder is connected south to add N-1 security.

Similarly, the 30F BWENGU feeder going to the north and east will be split in two. The second half of the feeder (50F BWENGU) still experiences voltage drops due to its length, requiring a step-up transformer to stay within the voltage limits. The connection is made to ULIWA for N-1 security.

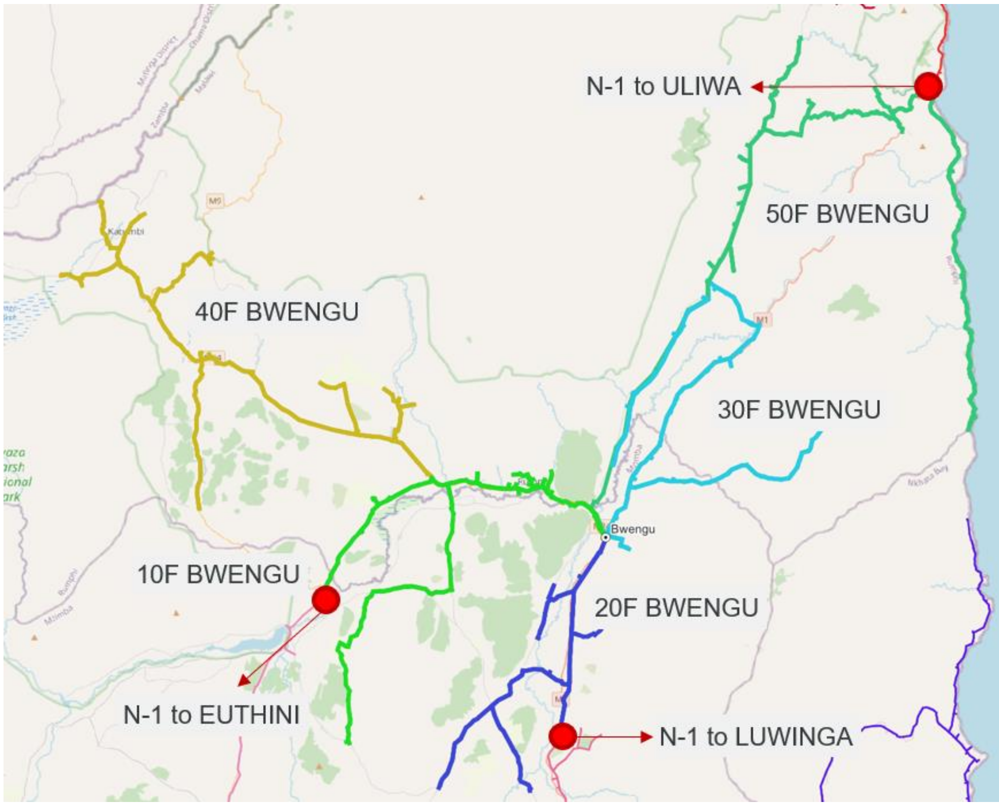


Figure 3.5.13: 33kV feeders leaving Bwengu station

The feeders supplying the Mzuzu are currently operated in 11kV and it will remain the case in 2042. However, there is a long 11kV feeder (5LF KATOTO) leaving Katoto to up to 24 km in the South. This feeder currently respects the technical limits as the load is limited. In 2042, the load is expected to grow up to 5.3MVA. It can be extended to 10F CHINTHECHE to have an N-1.

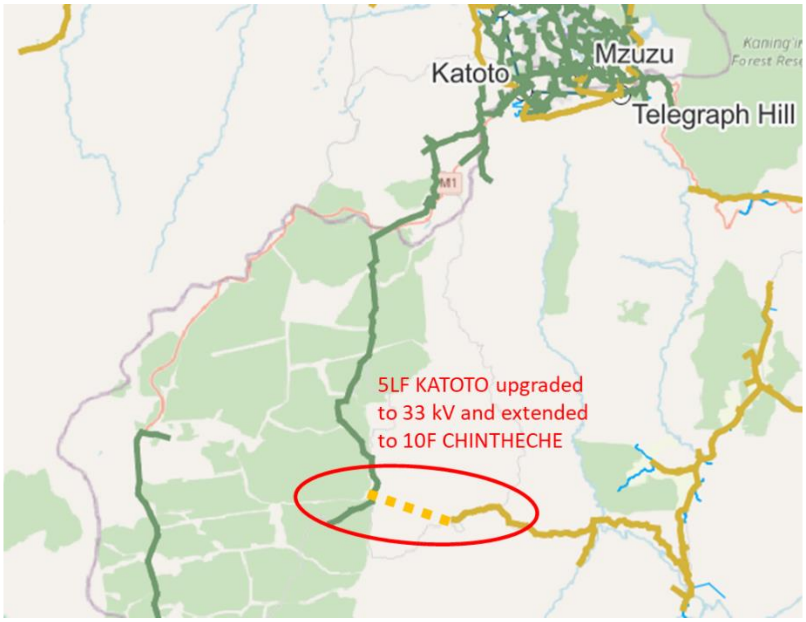


Figure 3.5.14: 5LF KATOTO upgraded to 33 kV and extended to 10F CHINTHECHE

Similarly, feeder 1LF CHIKANGAWA is currently operated in 11kV and supply a large rural area. It is recommended to upgrade in to 33kV in order to accept the load growth in the area and to reduce the losses. In order to have an N-1 security of that feeder, it is proposed to extend it to feeder 20F LUWINGA.

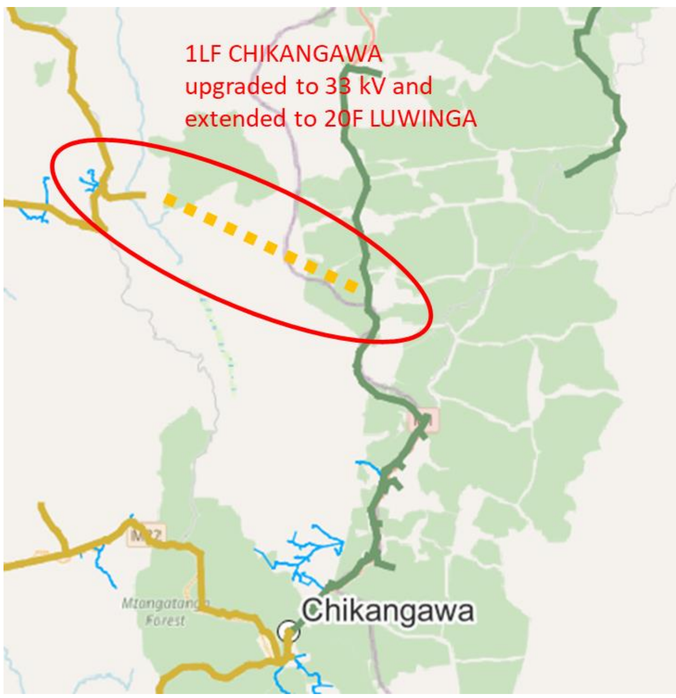


Figure 3.5.15: 1LF CHIKANGAWA upgraded to 33 kV and extended to 20F LUWINGA

There are smaller 11kV feeder existing in the north supplying partly city areas and rural areas:

- 1LF LIVINGSTONIA: remain in 11kV
- 1LF WOVWE: remain in 11kV
- 1LF CHINTHECHE: remain in 11kV

Those feeder are currently lowly loaded and the remaining margin is sufficient in terms of capacity.

Regarding Karonga station, two feeders are leaving to supply the upper north (30F KARONGA) and the north-west (20F KARONGA).

Considering the electrification of the villages in this area (from IEP and MAREP), the load of 30 F KARONGA will increase from 1.5MW to 10.2 MW. No N-1 is here foreseen. A step-up transformer is needed to limit the voltage drop.

Regarding the feeder 20F KARONGA, the load will increase from 3 MW to 22.3MW mainly due to the connection of additional villages in this area and also the load increase in Chitipa. Furthermore, the feeder already presents a too high drop voltage due to its significant length.

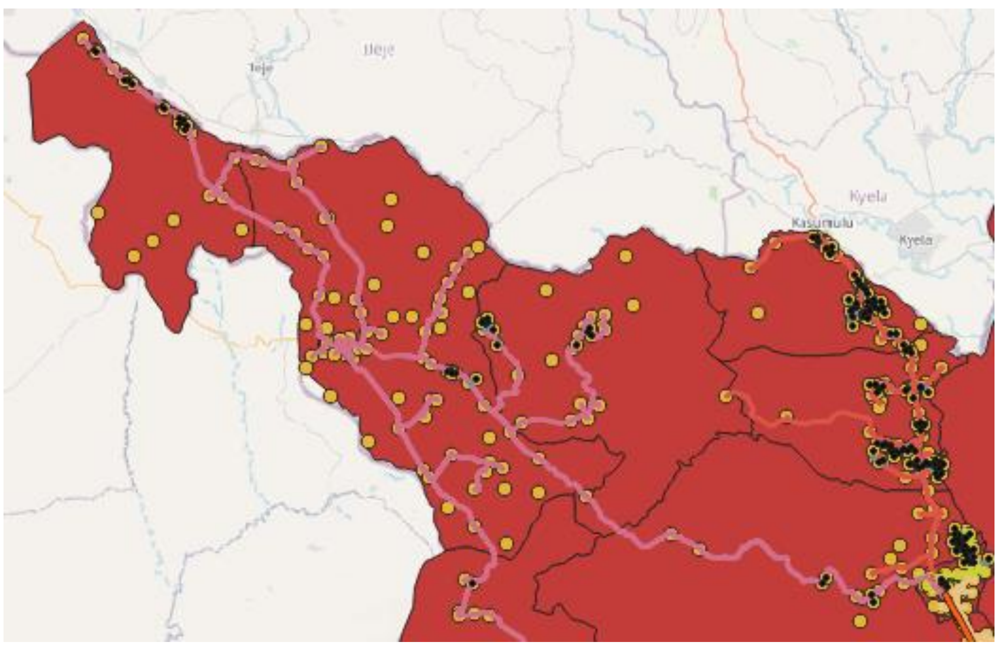


Figure 3.5.16: Transformers in the North-West of Karonga

In the short and medium term, these issues can be rectified by upgrades of the medium voltage network. Due to operations challenges and the long-term load growth, a new substation is proposed in Chitipa. The new substation will have 3 33 kV feeders with a cross section of 150 mm². Normal open points increase reliability in N-1 situations between 20F CHITIPA – 20F KARONGA, 10F CHITIPA – 50 F KARONGA, and 20F CHITIPA – 30F CHITIPA.

The 20F KARONGA feeder is split in two, with a new trajectory that connects to the loads in the southwest (50F KARONGA). Both the 20F and 50F KARONGA feeders are upgraded to 150 mm² to limit voltage drops and accept higher loads.

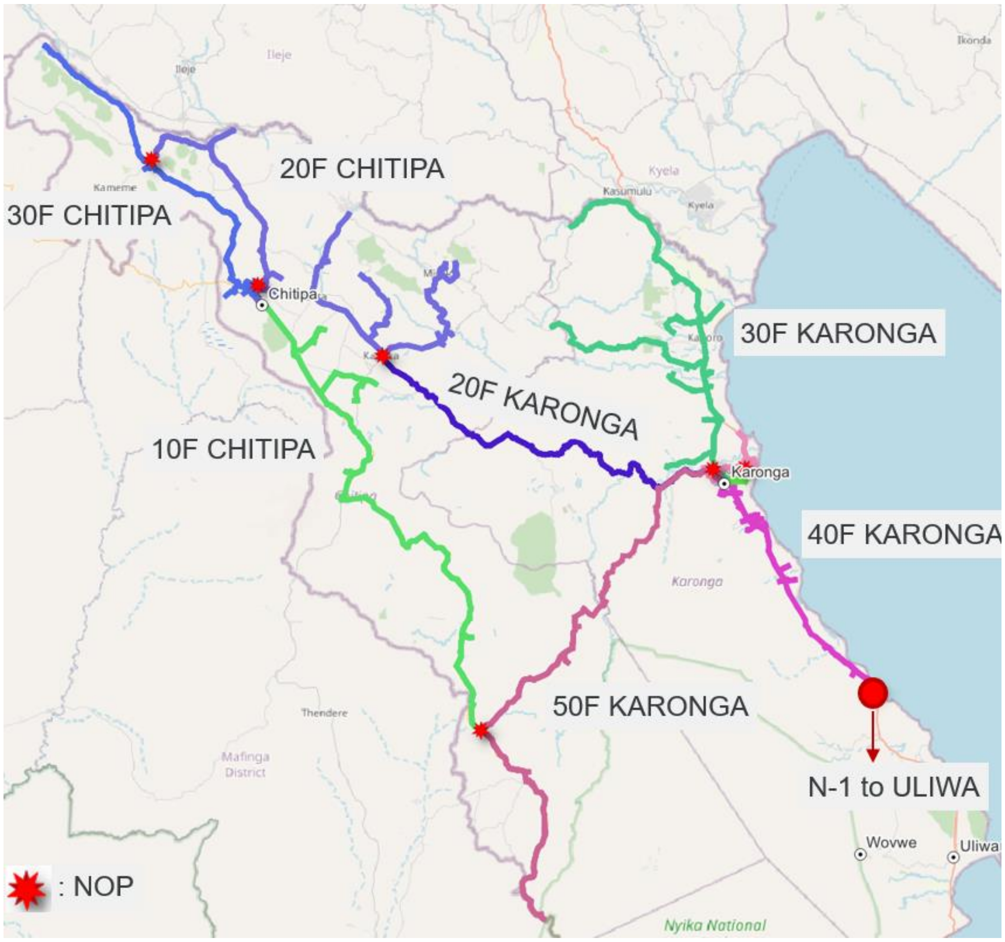


Figure 3.5.17: Feeder 20F KARONGA upgraded and doubled

On top of the two 11kV feeders suppling the northern area of Mzuzu, Luwinga station also presents 3 33kV feeders. The feeder 30F LUWINGA supplies Sonda secondary station. The feeder 10F LUWINGA is currently lowly loaded. There is space for additional load. It is not the case for the feeder 20F LUWINGA which will see a dramatic load increase mainly due to electrification in that area.

Depending on the future load growth, the issues can be addressed in MV (adding more MV feeders) or HV (adding an HV substation). It is proposed that only the first part of the feeder will remain considered as 20F LUWINGA. All parts to the west would be supplied by a new substation, Euthini. Four new 33 kV feeders supply the region, with additional normal open points to allow for N-1 operation. The 20F EUTHINI feeder will be converted to 150 mm² conductors, and a trajectory of 16 km of new feeder will be constructed to connect the 30F EUTHINI feeder to the substation.

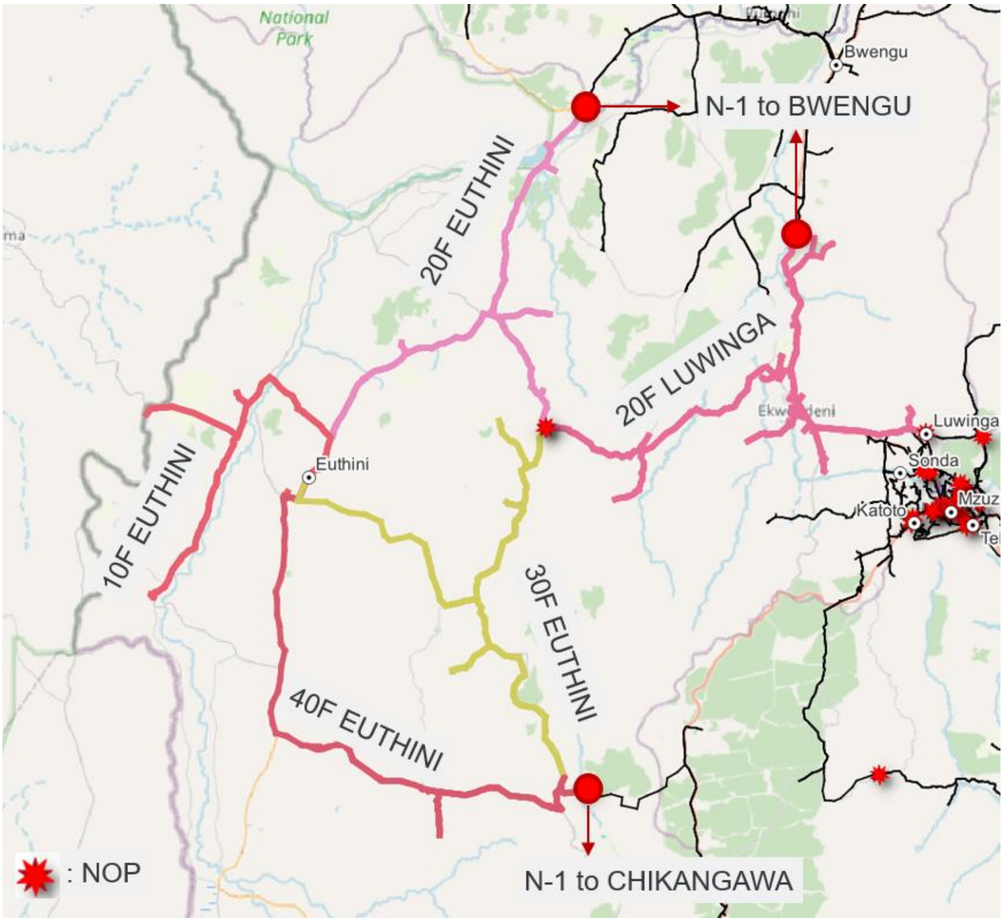


Figure 3.5.18: New Euthini substation and 20F LUWINGA

At Sonda, the 33kV feeder 20F SONDA will also increase due to the electrification in this area (IEP and MAREP transformers), passing from 2.4 MW to an expected load of 15.8MW in 2042. It is proposed to upgrade the feeder main section to 150mm².

The 10F LUWINGA feeder will be reinforced with a step-up transformer. A normal open point in the south will allow operation in N-1 situations.

The feeder 20F CHINTHECHE is more than 50 km and is oriented to the South. It presents an N-1 from New Dwangwa (20F NEW DWANGA). The existing feeder is enough to host the additional load.

The other feeder 10F CHINTHECHE already present high losses and a high drop voltage. The situation will continue to worsen in the future, considering the significant increase of the load on the feeder from 5MW in the current situation. It will reach 37 MW in 2042, considering a significant electrification through network extension in that area. For that reason, the feeder structure will be totally rearranged in order to create N-1. This is illustrated in Figure . The feeder will be split in 3: north, west and east. The northern part will be supplied using the existing 10F CHINTHECHE. The western part will be supplied with the 30F CHINTHECHE feeder in 150 mm². The eastern part will be supplied with the 40F CHINTHECHE feeder.

A significant demand increase is projected for Nkhata Bay. Therefore, a new substation would be constructed with a 33 kV feeder supplying the bay. This substation would initially be supplied from

Chintheche in medium voltage, but can be upgraded to a primary substation when the demand exceeds the capacity of the medium voltage network.

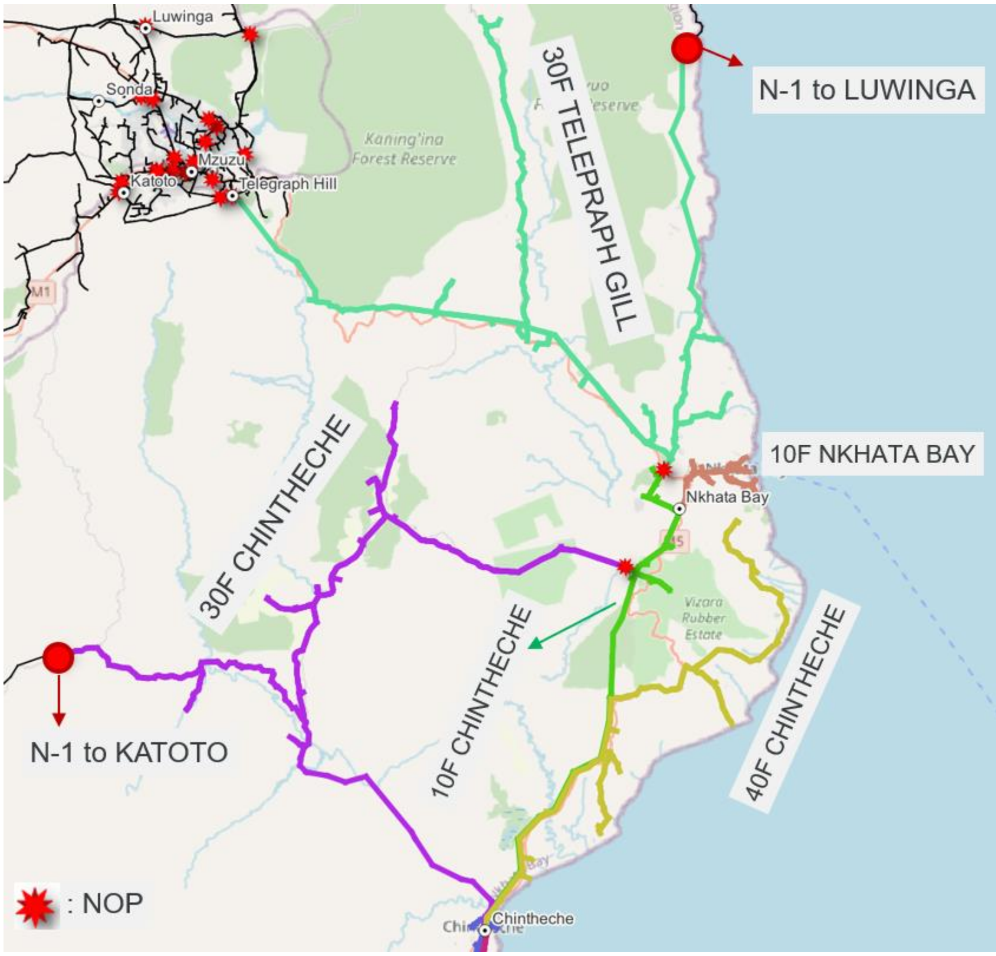


Figure 3.5.19: Rearrangement of 33kV feeder 10F CHINTHETCHE

The feeder 10F CHIKANGAWA presents a too high drop voltage in the current situation and does not respect the standards. Given the expected load at 2042 horizon and given the length, significant reinforcements are needed.

The feeder will be doubled, with a new 40F CHIKANGAWA feeder supplying the west. The 10F CHIKANGAWA supplies the loads closer to the substation, as well as part of the load to the south up to the town of Vibangalala. Both feeders require a step-up transformer to limit voltage drops.

The loads further to the south will be supplied from a new substation Luwelezi. This substation is foreseen between 2032 and 2042 to accommodate the rural electrification that is located far from existing substations. Solutions in MV are an alternative if the load grows slower than expected.

Four feeders in 33 kV leave Luwelezi to offload the previous 40F CHINYAMA and 10F CHIKANGAWA feeders in the central and northern region, respectively. A step-up transformer on the 30F LUWELEZI feeder limits the voltage drops to comply with the planning standards.

The 1LF CHIKANGAWA feeder going to the north is upgraded to 33 kV and extended with 14 km to the west to create a loop with the new 40F EUTHINI feeder.

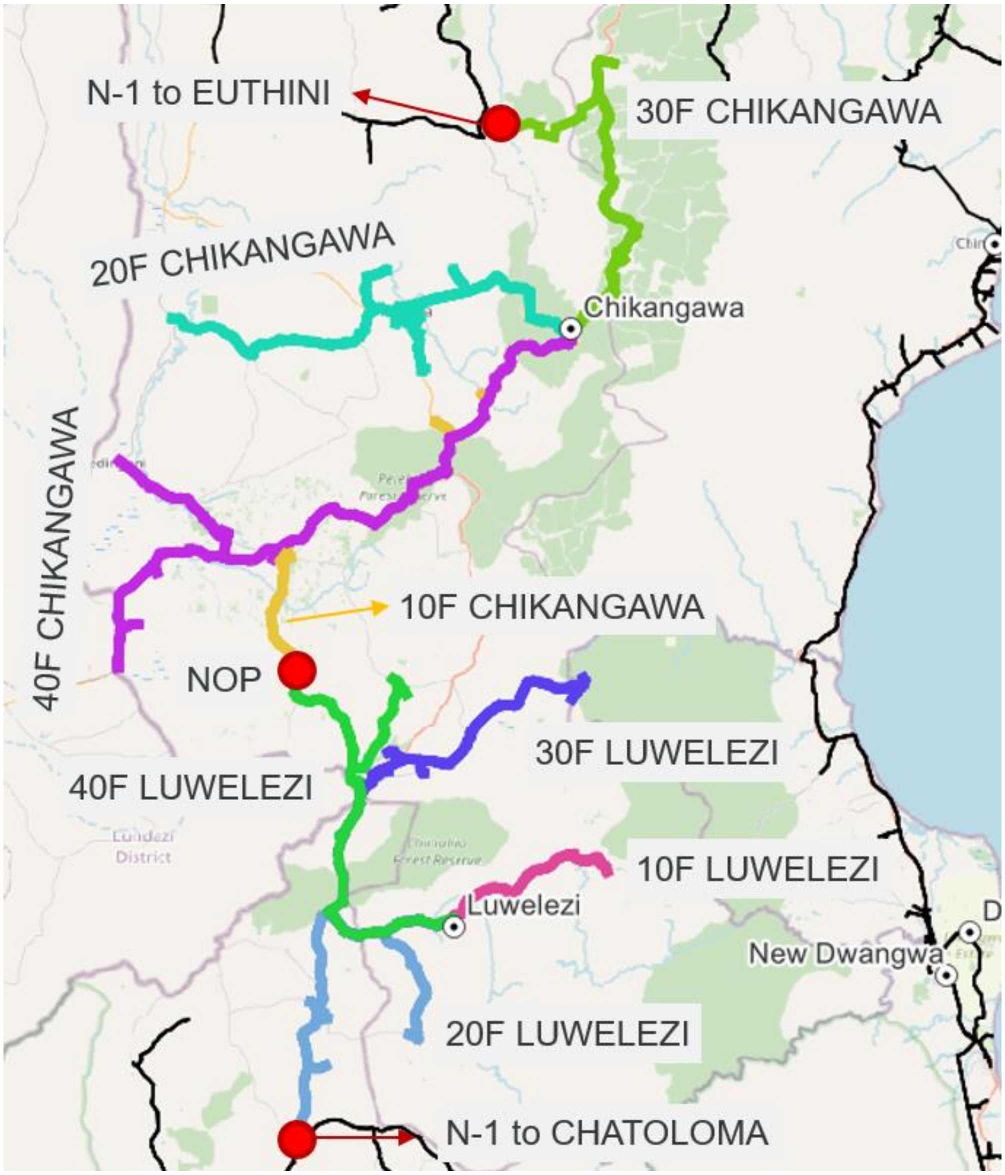


Figure 3.5.20: Luwelezi substation and Chikangawa feeders

5.3.6.2 Mzuzu city

Currently the city of Mzuzu (Figure) is supplied from the several primary/secondary stations:

- Katoto
- Sonda
- Telegraph Hill
- Luwinga

Currently, the city is supplied through several 11 kV feeders:

Table 3.5.8: Feeders supplying the city of Mzuzu

feeder	substation
1LF MZUZU	MZUZU
2LF LUWINGA	LUWINGA
1LF LUWINGA	LUWINGA
2LF TELEGRAPH HILL	TELEGRAPH HILL
1LF KATOTO	KATOTO
2LF MZUZU	MZUZU
2LF SONDA	SONDA
1LF SONDA	SONDA
3LF MZUZU	MZUZU
2LF KATOTO	KATOTO
4LF MZUZU	MZUZU

/

n

Figure 3.5.21: Mzuzu city – current supply in 11 Kv

The needs in terms of transformers and feeders have been estimated globally. It is expected that the demand of Mzuzu city will rapidly grow, growing from a peak load of about 12 MW to 70 MW.

New feeders are necessary in order to connect the transformers in the city. The city is currently supplied in 11kV and it shall remain the same in the future, according to the defined planning standards.

Currently, the 11kV feeders still offer remaining room for load increase, but not for such a high increase. The number of feeders have been estimated based on the methodology explained in section 5.3.1. Depending on the assumption considered, between 10 and 12 new feeders will be required to supply the city. We have considered 11 new 120 mm² underground feeders with an average length of 10 km to supply the city.

5.3.7 Central Region

5.3.7.1 Rural areas

Several 11kV feeders are operated in the Central Region, mainly in the cities. However, long 11kV feeders in rural areas are also present and must be avoided.

The long 11kV feeders supplying the rural areas are the following ones:

- 2LF NKHOTAKOTA
- 2LF KASUNGU
- 3LF KASUNGU

- 2LF SALIMA
- 1LF BUNDA
- 2LF BUNDA
- 1LF NTCHEU
- 5LF KANENGO
- 8LF KANENGO
- 1LF CHITIPI

Several existing 11kV are also already either overloaded or either present a drop voltage outside the limits. We can see that the long feeders supplying the rural areas are almost all in that table, presenting a too high drop voltage.

- 3LF AREA 47 (11 kV)
- 4LF AREA 48 (11 kV) - overloaded
- 5LF AREA 48 (11 kV)
- 1LF BARRACKS (11 kV)
- 3LF BARRACKS (11 kV)
- 1LF BUNDA (11 kV)
- 2LF BUNDA (11 kV)
- 3LF BUNDA (11 kV)
- 3LF CHITIPI (11 kV)
- 2LF DWANGWA (11 kV) - overloaded
- 5LF KANENGO (11 kV)
- 8LF KANENGO (11 kV)
- 2LF KANG'OMA (11 kV)
- 5LF LILONGWE A (11 kV)
- 2LF NKHOTAKOTA (11 kV)
- 2LF SALIMA (11 kV)

In order to solve the drop voltage problem and also to be able to host the significant increase of the load in the area due to network extension, all the long 11kV will be upgraded to 33kV in the target 2042 network.

The next upgrades are thus proposed:

- 2LF NKHOTAKOTA: Feeder upgrade to 33kV 150 mm²
- 2LF KASUNGU: Feeder upgrade to 33kV 150 mm²
- 3LF KASUNGU: Feeder upgrade to 33kV 150 mm²
- 1LF BUNDA: Feeder upgrade to 33kV 150 mm²
- 2LF BUNDA: Feeder upgrade to 33kV 150 mm² and creation of a new feeder (Figure)
- 3LF BUNDA: Feeder upgrade to 33kV 150 mm
- 1LF NTCHEU: Feeder upgrade to 33kV 150 mm²
- 5LF and 8LF KANENGO: Feeder upgrade to 33kV 150 mm²
- 1LF CHITIPI Feeder upgrade to 33kV 150 mm²
- 3LF CHITIPI Feeder upgrade to 33kV 150 mm²

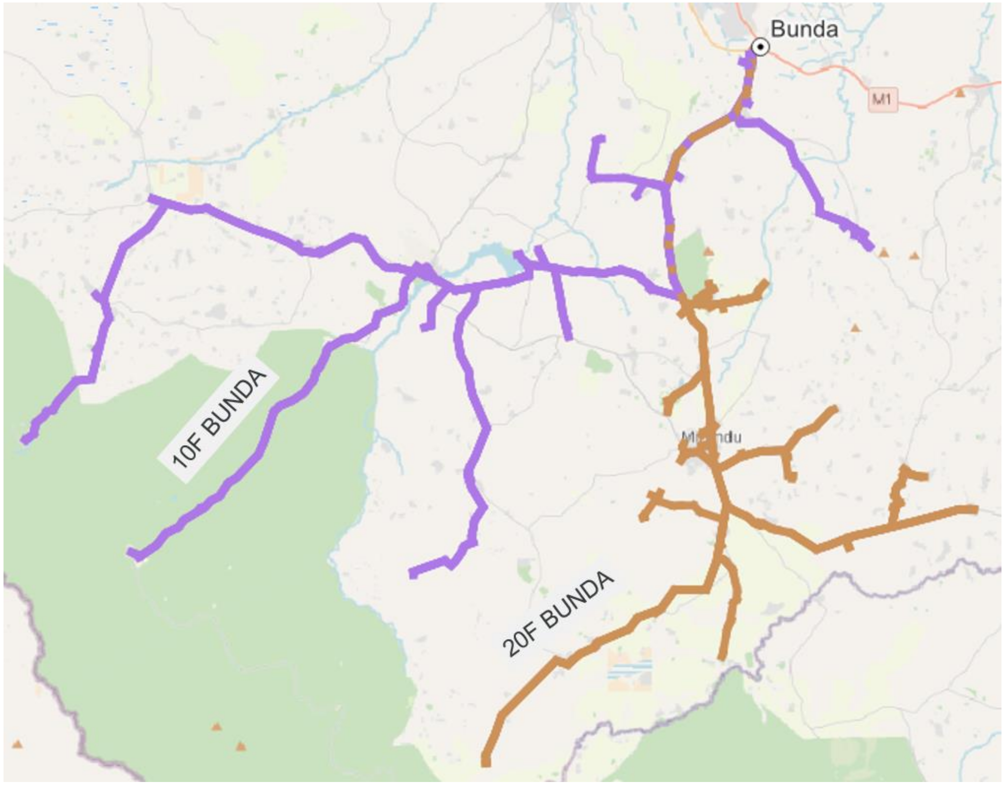


Figure 3.5.22: 2LF BUNDA upgrade to 33 kV + second 33 kV feeder

The 2LF SALIMA feeder will be replaced by two new 33 kV feeders. They will connect Salima substation to a new secondary substation in Senga-bay. This substation is planned by ESCOM with the funds and land already secured (see section 5.3.5). Four 11 kV feeders will connect the load in Senga-bay to the new substation.

Most of the remaining 11kV feeders in the Central area supply Lilongwe city and are analyzed in section 5.3.7.6.

Some other 11kV remains to supply small urban areas and surroundings. No reinforcements are required there, only the connection of new transformers.

- Dwanga: 2 LF DWANGA and 3LF DWANGA
- Salima: 1LF SALIMA
- Mvera: 1LF MVERA
- Mtunthama: 1LF MTUNTHAMA and 2LF MTUNTHAMA
- Nkhotakota: 1LF NKHOTAKOTA

The feeder 20F NKHOTAKOTA goes up to Dwangwa in the north and supplies rural areas. No new feeder is required as the existing feeder can still host additional load.

Kanengo station supplies currently the north of Lilongwe and also rural areas. It has already been mentioned that 5LF KANENGO and 8LF KANENGO will be upgraded to 33kV as they already present very high drop voltage and are not respecting the planning standards.

Regarding the existing 33kV feeders, the load will increase mainly due to the network extension in rural areas. At the target horizon, the feeder 10F KANENGO and 20F KANENGO will only supply the first part of the feeders, while the second part of the feeders will be supplied by the future primary stations of Namitete and Mponela.

Regarding 40F KANENGO, it shall be noted that a second feeder is necessary to supply the secondary station Area 25 from Kanengo.

Also due to increase of rural electrification, several 33kV feeders around Dedza will have to be updated:

- 10 DEDZA: Feeder split in 3 parts and 2 new outgoing feeders from the station
- 40F DEDZA: the feeder will be split in two: west and east. N-1 with feeder 10F DEDZA C
- 20F DEDZA and 30F DEDZA feeders will be added an N-1

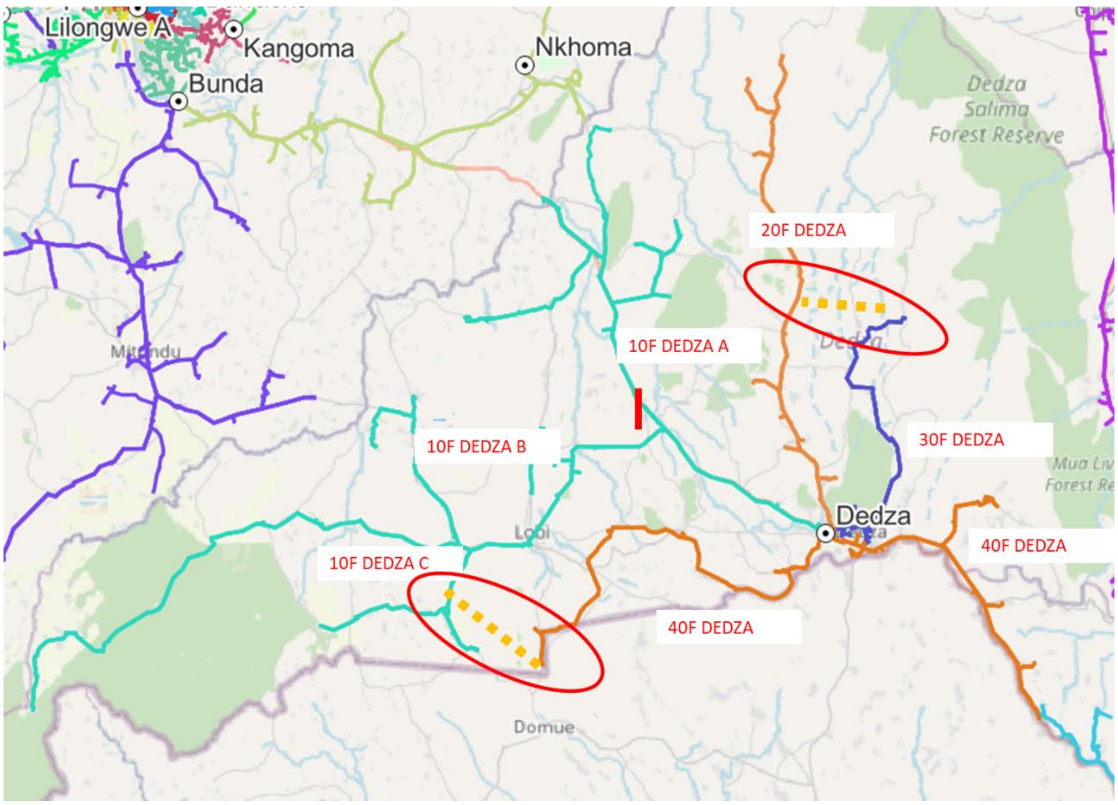


Figure 3.5.23: Feeders update around Dedza

In Golomoti, the existing feeders can host the increase of the load. It is however proposed to extend by 4.3km the feeder 40F Golomoti to 30F CHINGENI in order to ensure N-1 security .

The feeders Mlangeni present enough hosting capacity for additional load.

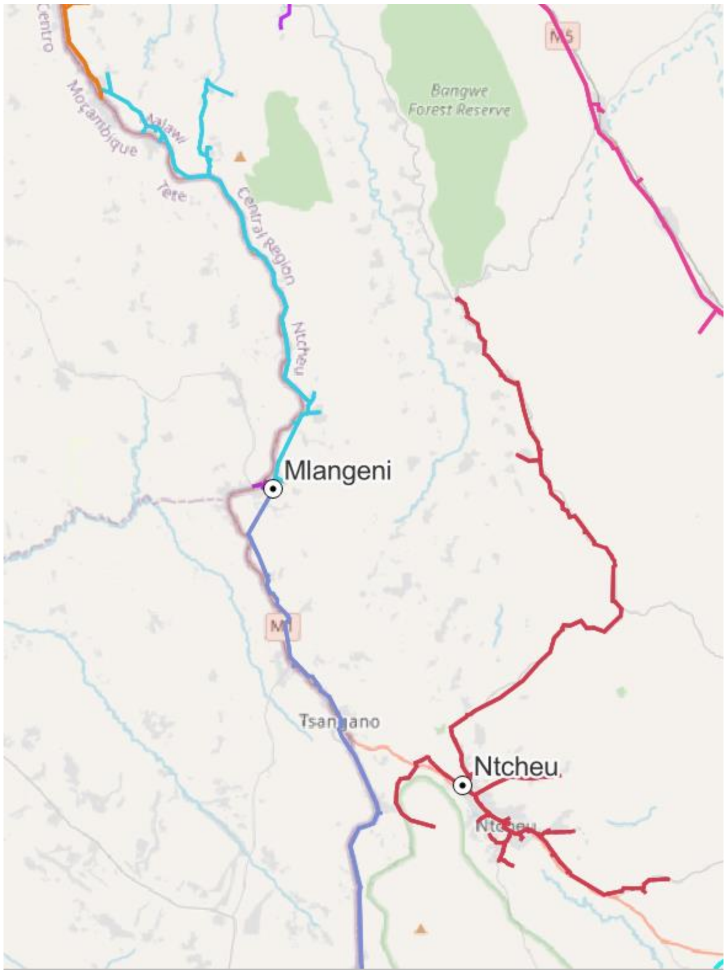


Figure 3.5.24: Mlangeni and Ntcheu stations

Currently, the 3 feeders from station Nanjoka (Figure) are presenting too high drop voltage. This is due to the high length of those feeders:

- 10F NANJOKA: going to the north at 45 km
- 20F NANJOKA: Nanjoka-Golomoti: 85 km
- 30F NANJOKA going to Mvera at 20 km and continuing to the north at 100 km

All the feeders will see a significant increase in the load mainly driven by rural electrification.

The feeder 10F NANJOKA will be reinforced. Two dedicated feeders 150 mm² feeders will supply the secondary station of Salima (10F NANJOKA SALIMA A; 10F NANJOKA SALIMA B). A third new feeder (10F NANJOKA B) will take part of the load that supply the feeder.

The feeder 20F NANJOKA will also be reinforced with a second 20F NANJOKA B feeder that will take the second part of the feeder.

Regarding the feeder 30F NANJOKA, all the part after Mvera, when the feeder is going to the North will be disconnected to be supplied from new station Mponela (Lilongwe North) as explained in section 5.3.7.4.

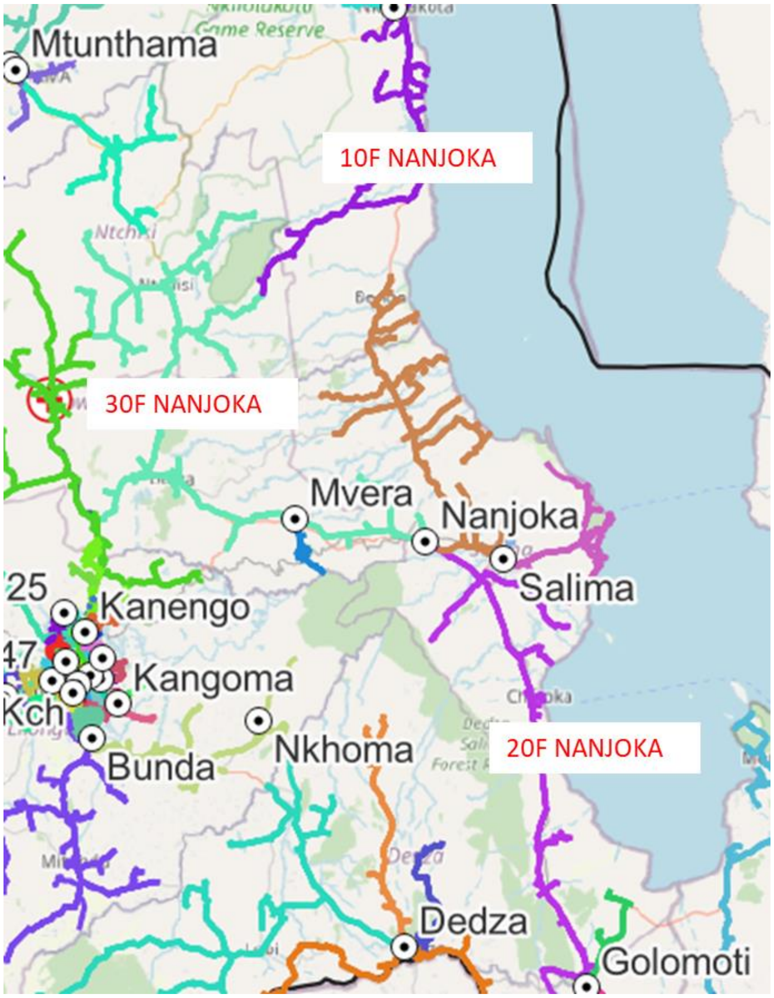


Figure 3.5.25: Current outgoing feeders from Nanjoka

The secondary station of Mchinj Border is far from the other stations. Due to the increase of the load for network extension, a new primary station is proposed between Chitipi and Mchiniji Border in Namitete. More information about that new primary station can be found in section 5.3.7.3. There, it is explained that the 10F MCHINJI BORDER feeder is split in two, with one part supplied from the new station. Thanks to the load transfer to the new station, the existing backbone of the feeder 10F MCHINJI BORDER is sufficient to host the extra load expected for the rural electrification.

Regarding the 33kV 20F MCHINJI BORDER, as the load is expected to significantly grow, the feeder will be doubled: the new 30F MCHINJI BORDER feeder (150 mm²) will supply the western part with a new 10 km trajectory along the S118 road. Due to the considerable load and distance, multiple step-up transformers are needed on the feeders.

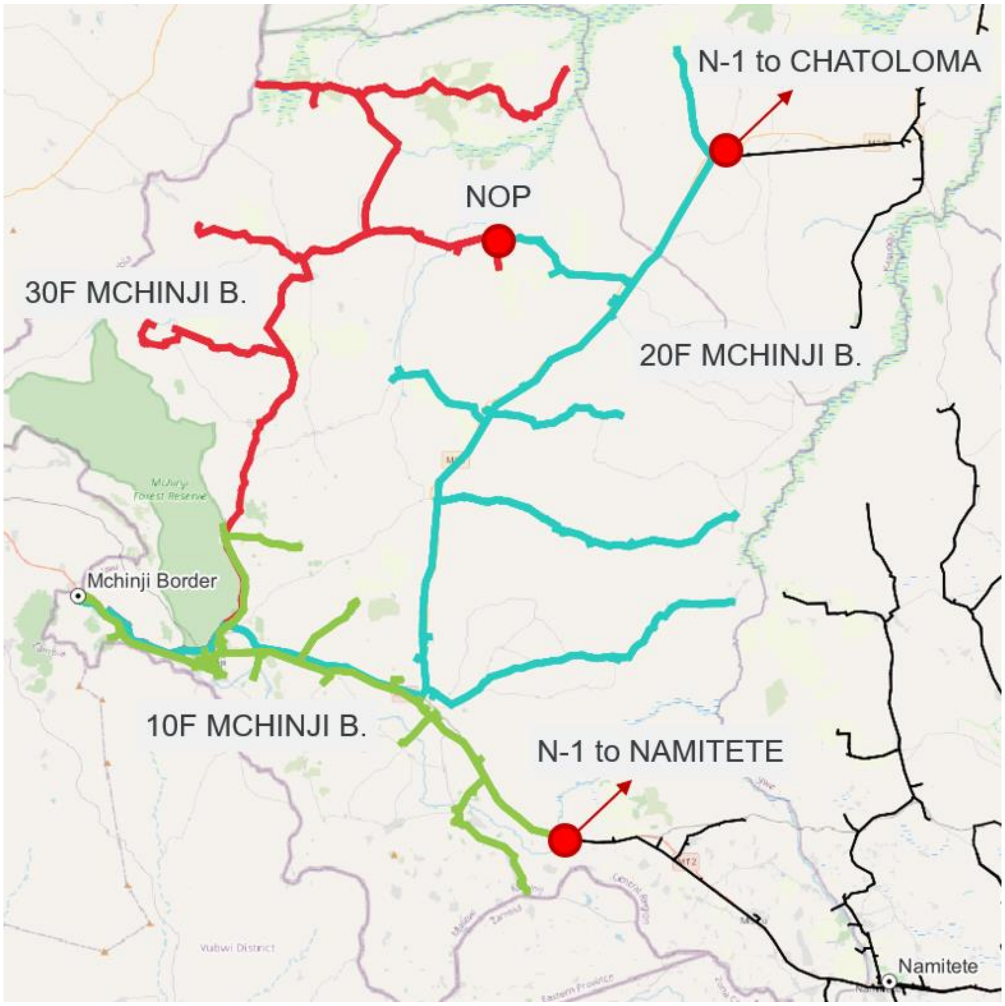


Figure 3.5.26: Proposed modification around Mchinji Border substation

5.3.7.2 Zone around the new Primary Station of Chatoloma (KASUNGU)

The area located at the north of Kasungu is supplied with the 33kV feeder 40F CHINYAMA. As the new 400/132/33kV station will be installed at horizon 2042, the actual feeder will be split in two and supplied from the new substation (10F CHATOLOMA and 20F CHATOLOMA).

40F CHINYAMA will only supply the load between Kasungu secondary station and the 132/33kV primary station of Chinyama and part of the load immediately north of the city. It will also be useful for N-1 security in 33kV between the two primary stations.

2LF KASUNGU and 3LF KASUNGU will be upgraded to 33kV 100 mm² as they supply rural areas.

The feeder 20F CHINYAMA is operated in 33kV. In order to accommodate the load increase, the feeder is required to be double.

The feeder 30F CHINYAMA is very long and supplies a growing demand expected to reach 17.2 MW in 2042. The feeder will be split in two: 30F CHATOLOMA and 40F CHATOLOMA.

50F CHINYAMA has enough space for additional load.

Finally, it must be noted that 20F CHINYAMA supplies the secondary station of Mtunthama.

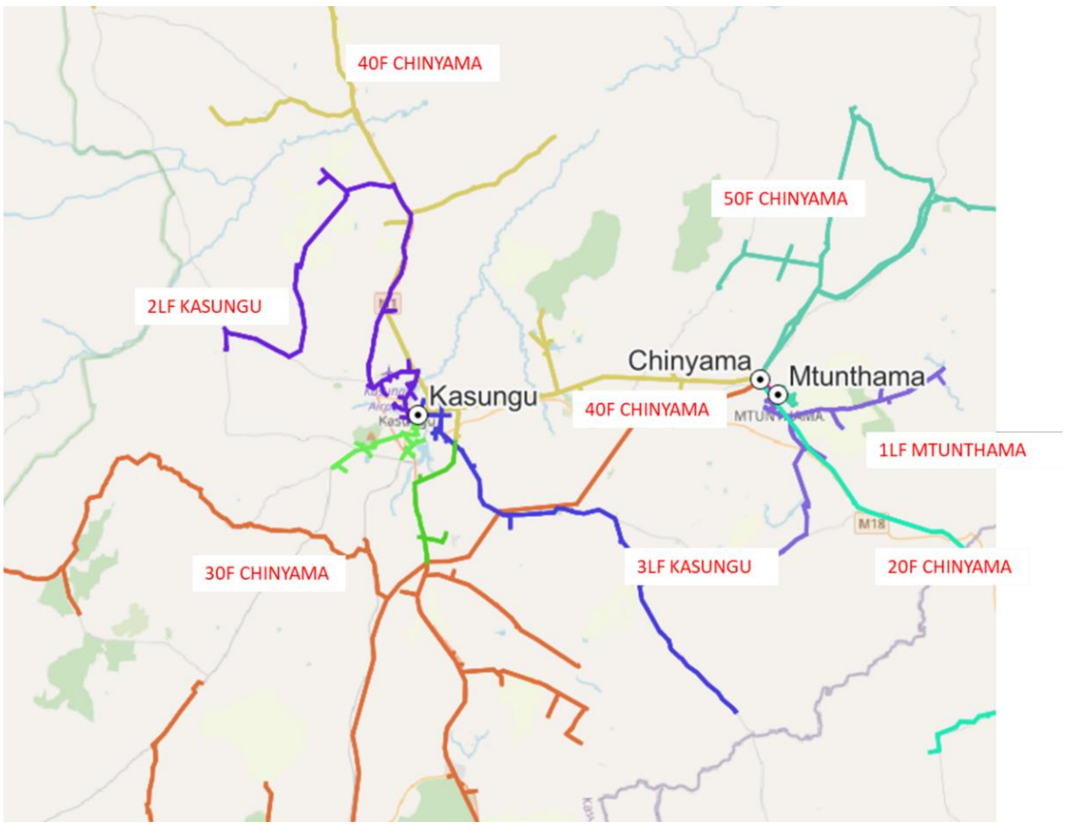


Figure 3.5.27: Current supply of Kasungu areas with the 33kV feeder 40F CHINYAMA starting at Chinyama

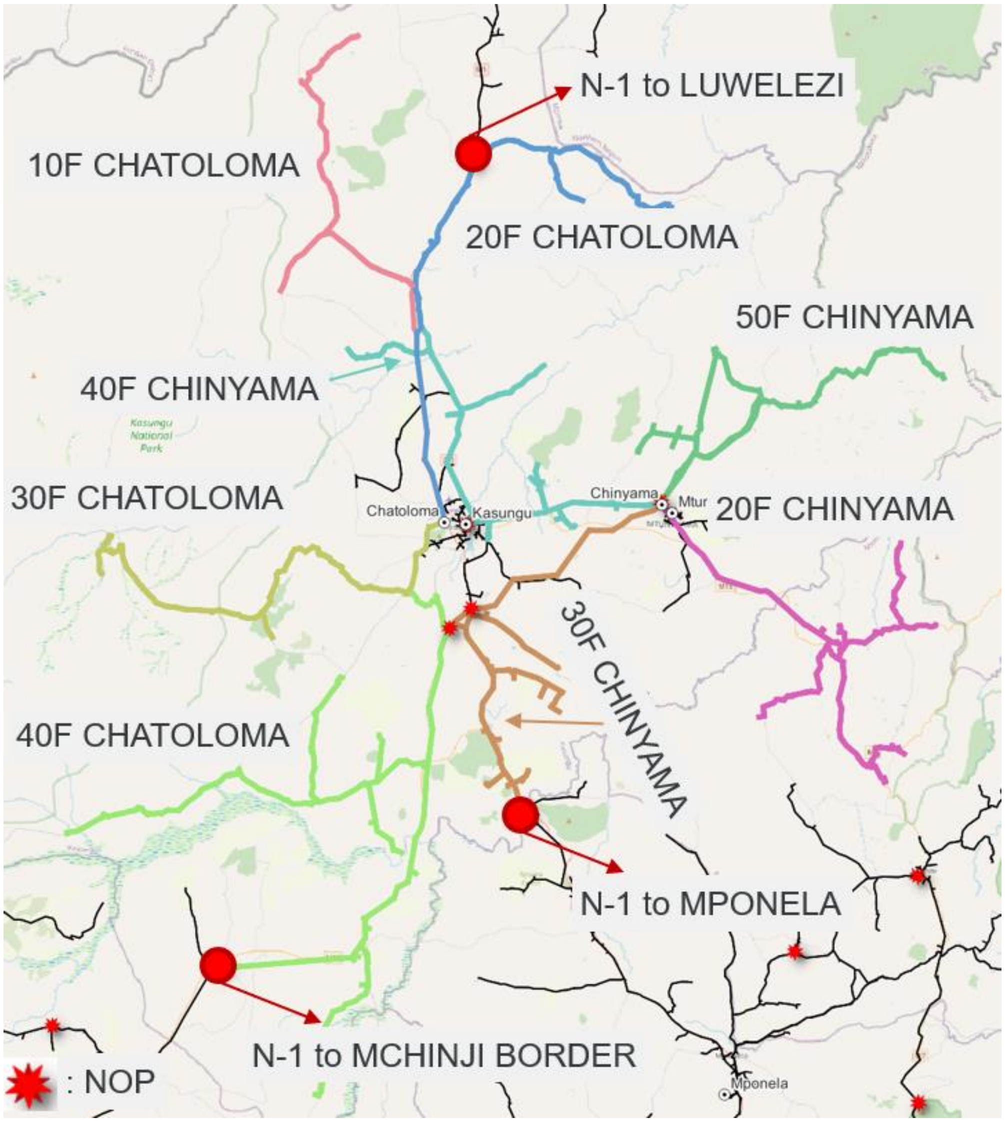


Figure 3.5.28: Proposed feeders around Chatoloma and Kasungu

5.3.7.3 Zone around the new Primary Station of Namitete (Lilongwe west)

The substations will be operating in 2042 and will be necessary to supply the growing demand in the region which driven by energy access increase. Four 33kV feeders will be necessary to supply the load in the area:

- 10F NAMITETE
- 20F NAMITETE (upgrade to 150 mm² and need for step-up transformer)
- 30F NAMITETE (need for 2 step-up transformers)
- 40F NAMITETE (need for step-up transformer)

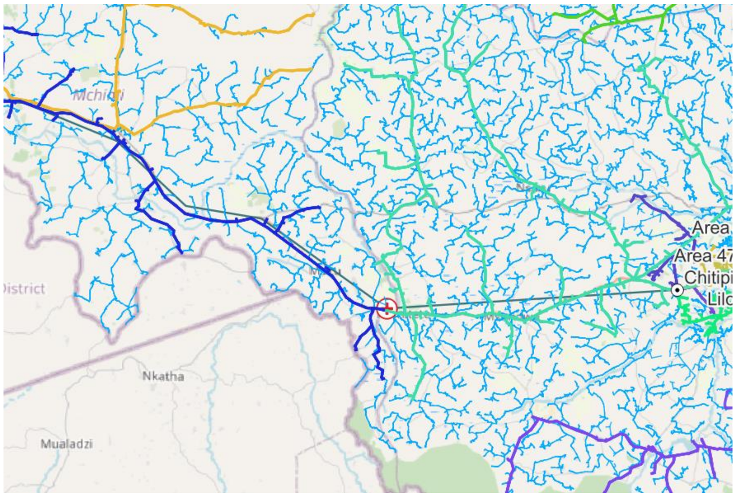


Figure 3.5.29: Energy access through network extension around future Namitete primary station

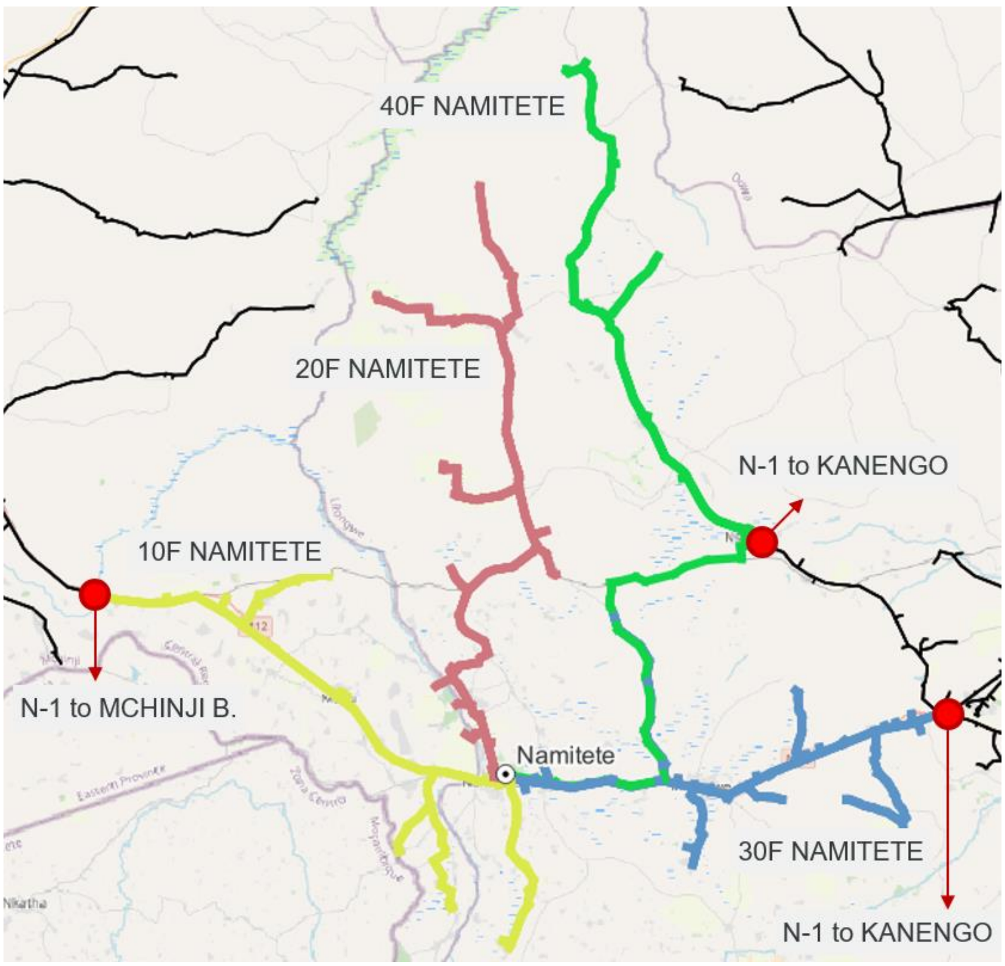


Figure 3.5.30: Namitete substation and new feeders

5.3.7.4 Zone around the new Primary Station of Mponela (Lilongwe North)

The substation will be operational in 2032.

The feeders 30F NANJOKA (18.1 MW) and of 10F KANENGO (36.9 MW) will see a tremendous increase of the load due to the rural electrification foreseen by network extension in this area (see blue part in Figure). 7 new 150mm² feeders will be necessary to supply the load in the area.

All feeders except for 10F and 70F MPONELA require step-up transformers to maintain adequate voltage levels. The feeders 40F, 50F, 60F, and 70F are reinforced to 150 mm^2 conductors.

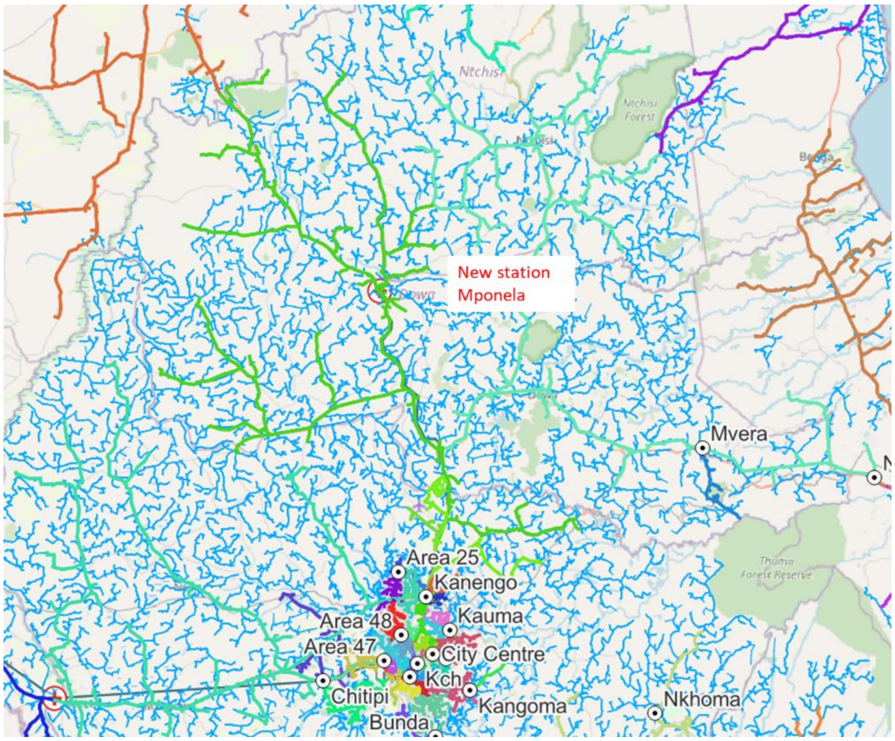


Figure 3.5.31: Significant increase of rural electrification around future Mponela primary station

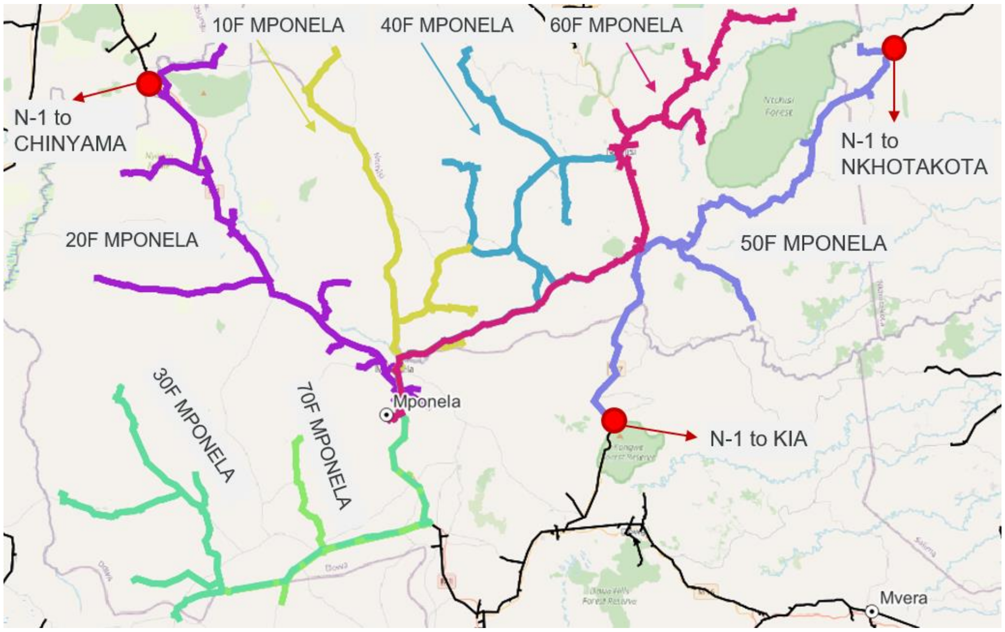


Figure 3.5.32: Mponela substation

5.3.7.5 Kasungu city

Kasungu city is currently supplied in 11kV from the secondary station 33/11kV. At 2042 horizon, it will be the same. That secondary station of Kasungu will not anymore be supplied via the 33kV feeder 40F CHINYAMA, but by a new dedicated feeder coming from the new 400/132/33 kV primary station which is foreseen at 2042 time horizon.

City center of Kasungu is supplied by 1LF KASUNGU. It is expected that the load will grow from 0.6MW to 3 MW. Even if theoretically, no other feeder will be required for such a load, it is recommended to add a second OHL 100 mm² in the city in order to create an open loop with the existing feeder. It will be used in order to supply new areas in the growing periphery of the city.

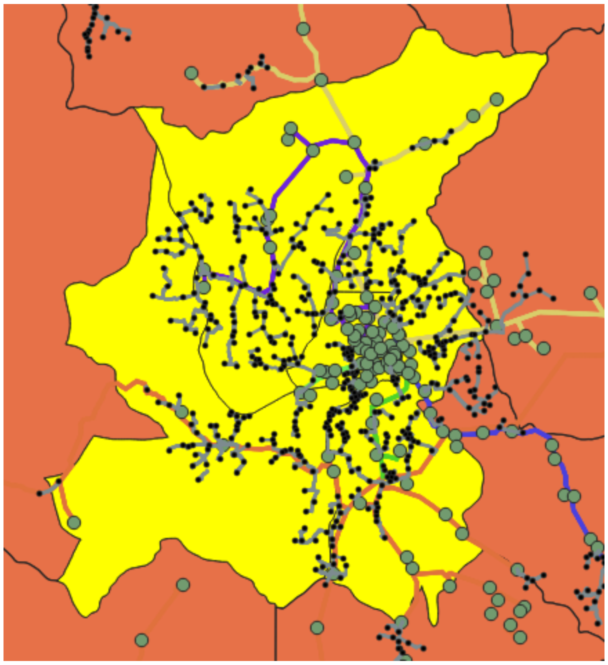


Figure 3.5.33: Existing and foreseen transformers around Kasungu

5.3.7.6 Lilongwe city

Currently the city of Lilongwe and its periphery (Figure) is supplied from the several primary/secondary stations:

- Area 25
- Area 47
- Area 48
- Chitipi
- City Centre
- Kch
- Kanengo
- Kauma
- Barracks
- Linlongwe A
- Kangoma
- Bunda

Currently, the city is supplied through 38 11 kV feeders. Some 33kV feeders are also present in the city but only to supply secondary stations from another primary station. Some 11kV feeders are also leaving the city to supply rural areas. As explained hereabove, it is recommended to upgrade those feeder in 33kV.

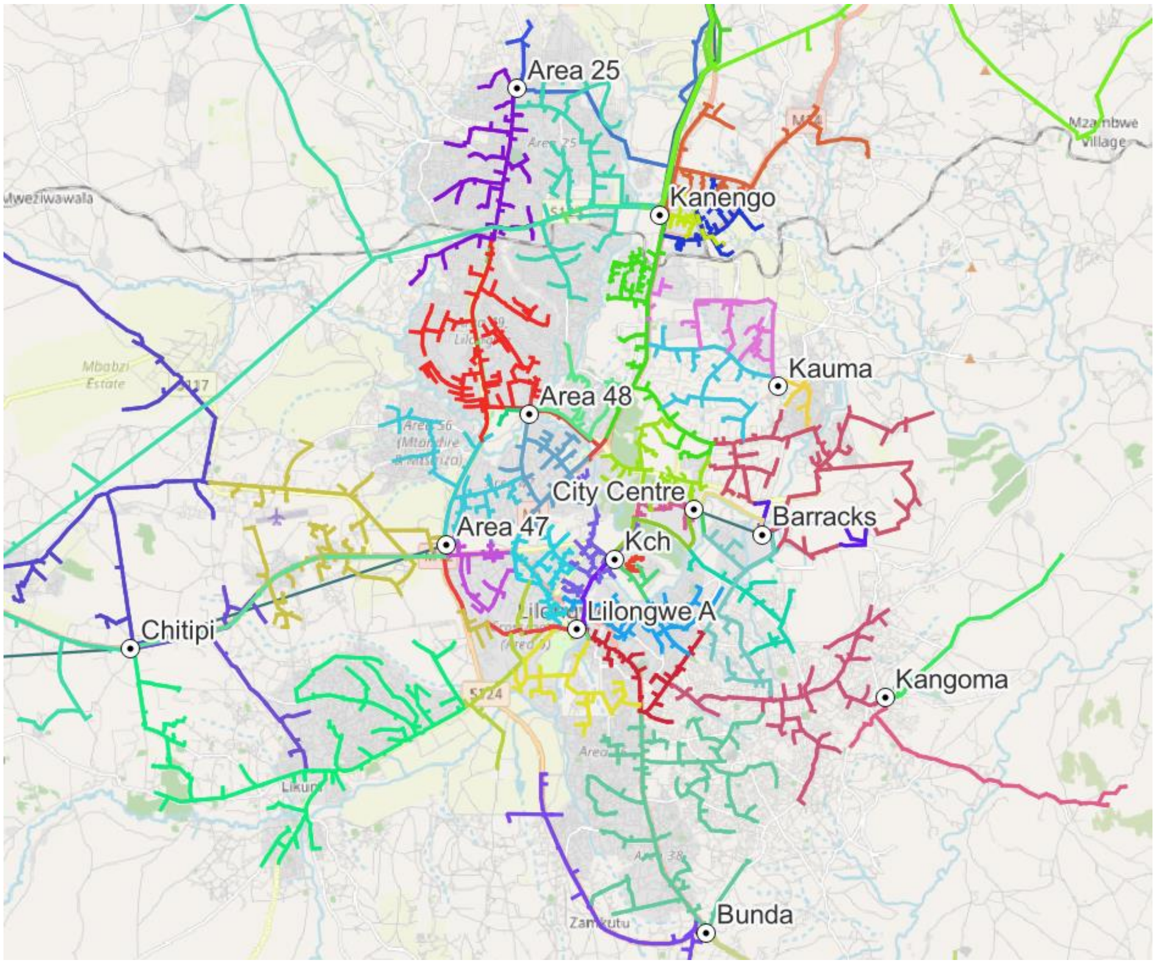


Table 3.5.34: Feeders 11kV supplying the city of Lilongwe

Globally, the peak load for the feeders will increase from 86 MW to 330 MW in 2042. Both network reinforcement and new feeders will be required in order to host the additional load.

There is no existing Urban Master Plan and the needs in terms of transformers and feeders have thus been estimated globally.

Currently, the 11kV feeders still offer remaining room for load increase, but not for such a high increase. Also, part of the existing feeders will reach their lifetime and would need to be replaced. They won't be replaced identically, but considering an upgrade of section. By respecting the defined standards, the existing feeders will be replaced at long term to 185 mm² underground feeders within the city.

As not all feeders are charged equally everywhere due to different load density from one area to another, a coefficient of 0.80 is used as localization factor. A cos phi of 0.95 is also used.

Considering the upgrade of all the existing feeders to 185 mm² UG, our analysis has shown that 68 additional feeders operated in 11kV will be required at 2042 horizon. On top of that, the 38 existing feeders will have to be renewed (life time end) and also upgraded to 185 mm² UG. In total, 106 UG 185 mm² will thus supply the city of Lilongwe and the close periphery.

This estimate includes a full respect of the planning standards, ensuring the respect of the technical limits both in N and N-1. By loading the feeders at a maximum of 55% (4.1 MVA for 185 mm² UG), closing the loop is always possible. Also, the respect of a length of maximum 11km will ensure the drop voltage remains also within the acceptable limits in N-1.

The new KIA substation will partially offload the Kanengo substation. KIA will supply the region around the airport, including some rural areas that were previously served by 30F NANJOKA and 10F KANENGO.

The new feeders 10F KIA and 20F KIA will serve rural areas, while 11 kV feeders will serve the areas to the south of the substation.

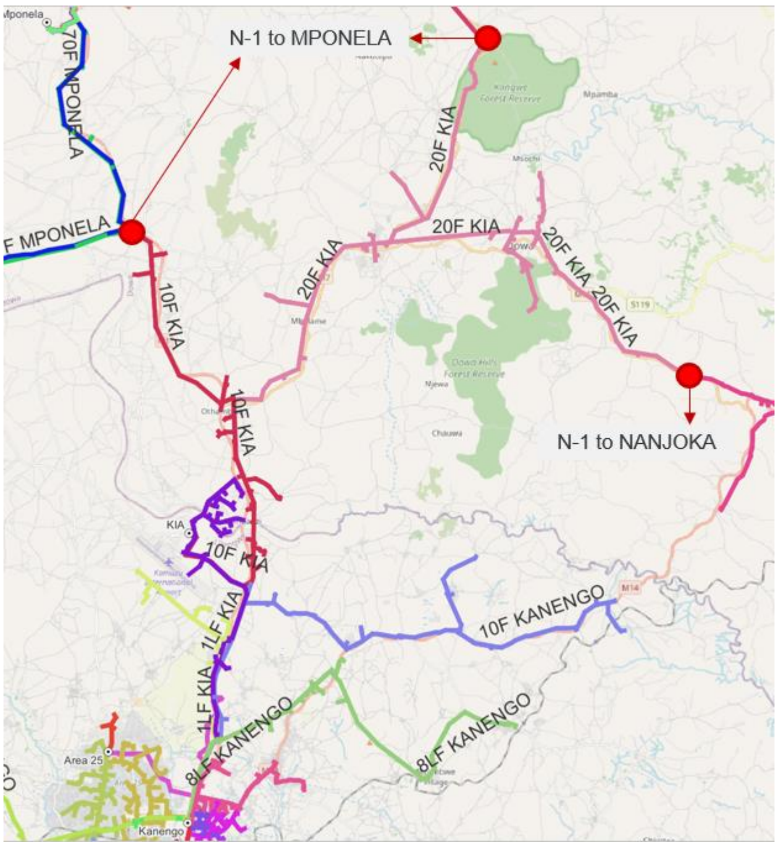


Figure 3.5.35: KIA substation

5.3.8 Southern region

5.3.8.1 Rural areas

According to the analysis of the current situation, several 11kV feeders in the Southern region do not respect the technical constraints.

- Southern region
  - 1LF CHILEKA (11 kV): overloaded
  - 1LF LIMBE B (11 kV): overloaded and high drop voltage
  - 2LF LIMBE B (11 kV): overloaded

- 2LF MLAMBE (11 kV): very high drop voltage
- 1LF ZOMBA (11 kV): very high drop voltage and overloaded
- 4LF ZOMBA (11 kV): high drop voltage

In the area of Zomba, the first part of the 11kV feeder 4LF ZOMBA supplies part of the city of Zomba. However, the feeder has been extended to the rural areas, which is against the defined standards. An upgrade is foreseen to 33 kV, using 150 mm² conductors. In addition, the feeder is doubled, creating the 30F and 40F ZOMBA feeder.

Similarly, the 1LF feeder extends to the north of the city and is upgraded to two 33 kV feeders with 150 mm² conductors: 10F and 20F ZOMBA.

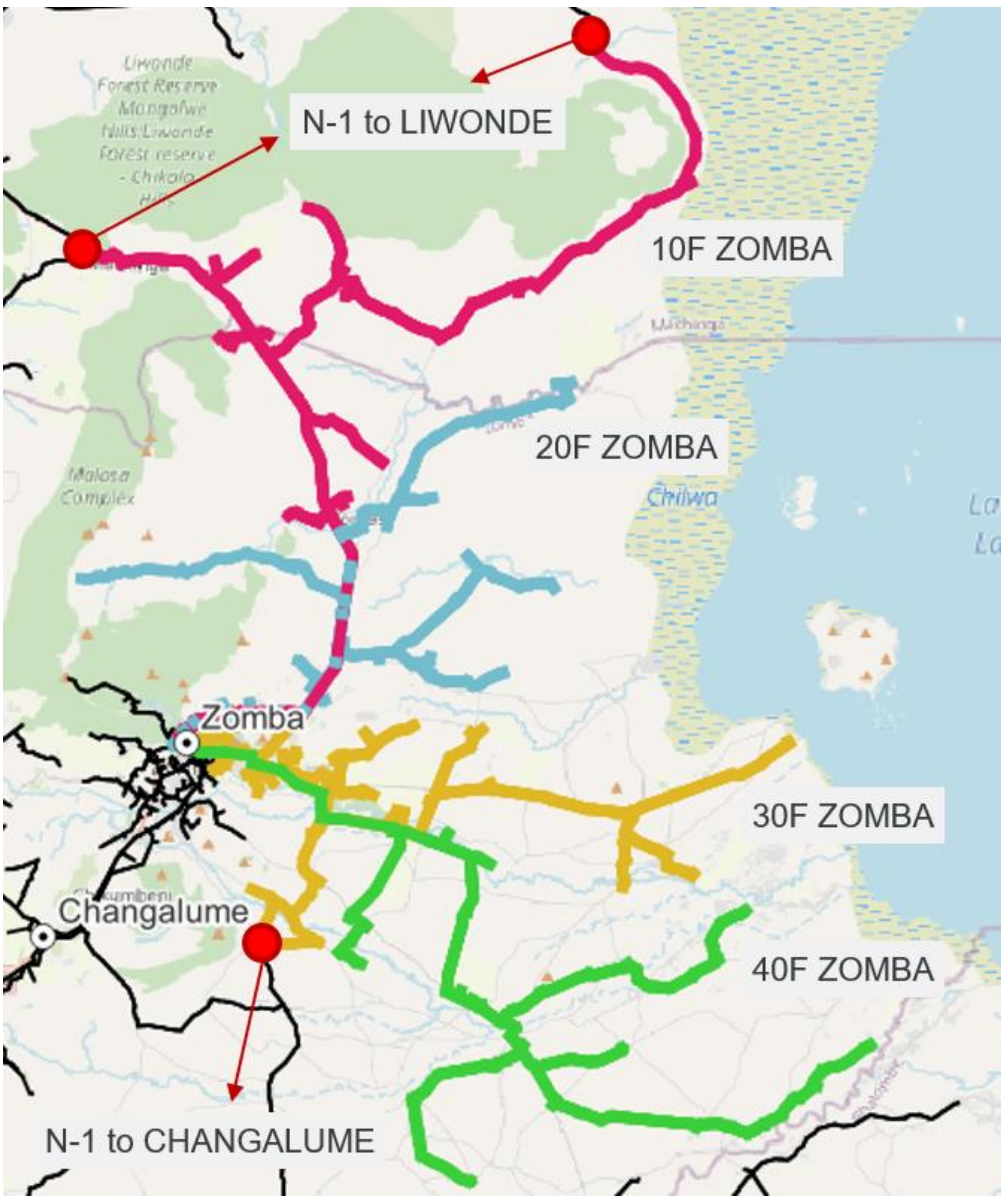


Figure 3.5.36: Upgrade of 1LF and 2LF ZOMBA feeders to 33 kV

The feeder 2LF ZOMBA mainly supplies the city. However, one part of the feeder is leaving the city to supply the rural areas located at the western part. The first part of the feeder will continue to supply the city, while a new 33kV feeder will be created to supply the rural areas.

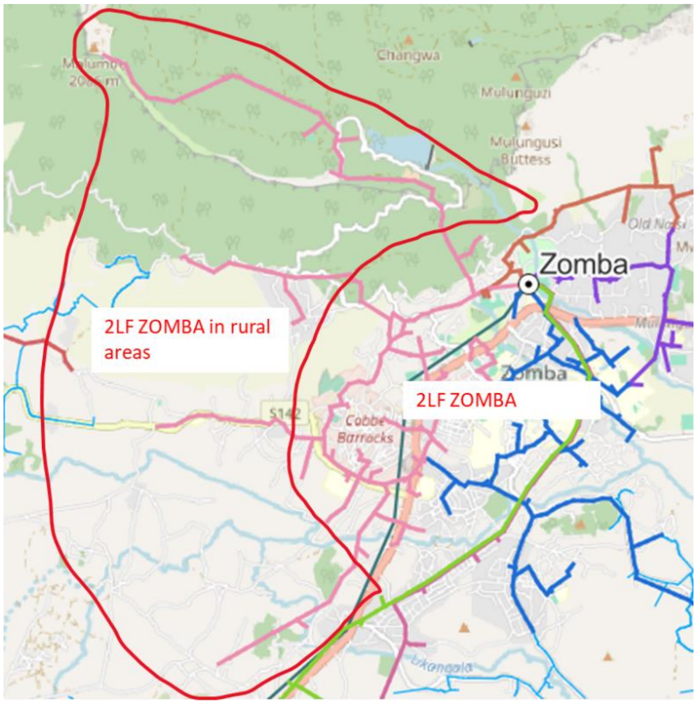


Figure 3.5.37: 2LF ZOMBA currently supplies both the city and rural areas

Balaka is supplied from a primary station. The peak load at the station will grow from 2.7 to 13.5 MW.

Feeders 1LF BALAKA and 2LF BALAKA present enough capacity to host additional load up to 2042. The feeder 3LF BALAKA is going in the rural areas in the north of the city. Due to the connection of additional load for rural electrification, the current 11kV feeder will not be enough. For that reason and regarding the length of the feeder (40 km), it is recommended to upgrade the feeder in 33kV 150 mm² OHL.

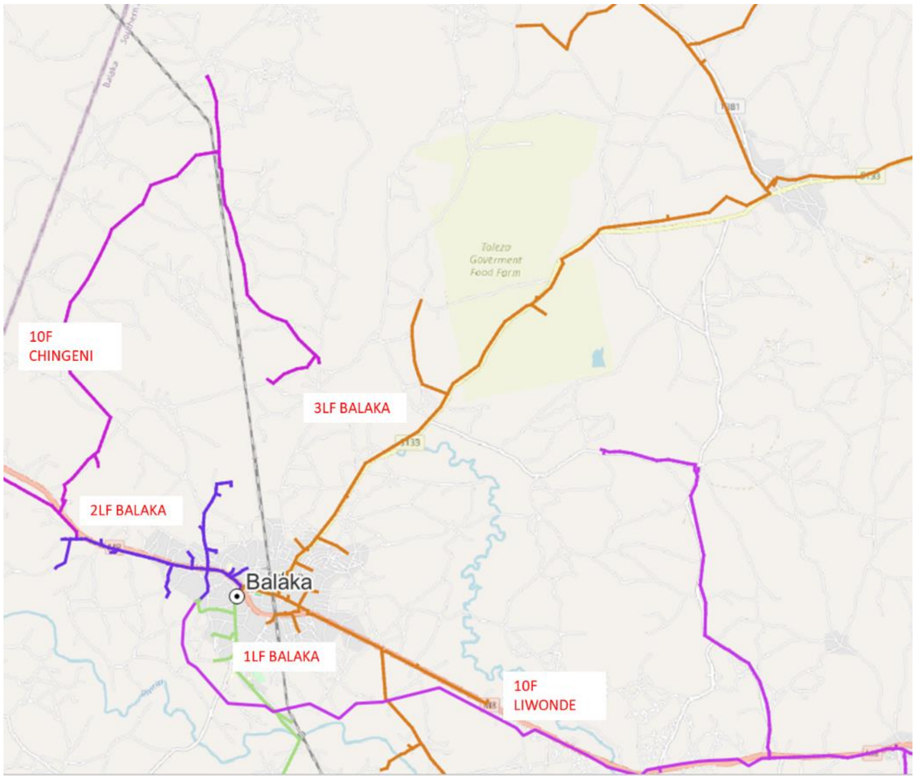


Figure 3.5.38: Situation in Balaka

Chileka secondary station supplies several feeders in 11kV and 33kV. The feeders that supply Blantyre are studied in a dedicated section (5.3.8.5). The feeders supplying rural areas are the next ones:

- 20F CHILEKA: feeding the rural areas in the north. It presents enough remaining capacity up to 2042.
- 4LF CHILEKA: feeding the rural areas in the west. That feeder in 11kV is already very loaded. It must be upgraded to 33kV

Figure 3.5.39: Situation around Chileka station

The load of the primary station Mlambe is expected to grow from 17 MW to 85 MW. Three outgoing feeders supply the rural areas: one 11kV feeder 2LF MLAMBE and two 33kV feeders 10F MLAMBE and 30F MLAMBE. All of them present a too high drop voltage, and especially, feeder 2LF MLAMBE (11 kV).

The next recommendations can be done to solve the issues and host the additional load in the area

- 10F MLAMBE. The southern part of the region will be supplied by the new substation of Bangula, offloading this feeder
- 2LF MLAMBE. Upgrade to 33 kV
- 30F MLAMBE. The feeder supplies area at the west, north and east of Mlambe. The feeder will be divided in 2 to cover the 2 areas with an acceptable load for 150 mm² feeders. Due to the long distances, voltage regulators will be installed to correct the voltage issues in the area. The southern part of the feeder will be supplied from the new substation of Bangula.

Around Blantyre, several feeders are going outside to supply rural areas. From Blantyre West, the feeder 20F BLANTYRE WEST will see its load increasing mainly due to rural areas . A new feeder will be to take the load increase. It will be looped with the existing one.

In Chigumula, one long 11kV feeder is supplying the rural areas. It must be upgraded to 33kV 150 mm² given the expected load growth.

The feeder 10F MAPANGA is a long 33kV feeder supplying the eastern area from Blantyre. The load is expected to grow from 2.3 MW to 29 MW at 2042 horizon. This is due to the expected significant rural electrification in the area. Additionally, it is worth mentioning that the feeder already present a drop voltage higher than 5%. It is recommended to divide the feeder in 3, each one to cover one direction as illustrated in Figure . The feeder 20F MAPANGA will also be divided in two.

The eastern part of 10F MAPANGA is located far from the substation and will be supplied from the new Phalombe substation (see section 5.3.8.3).

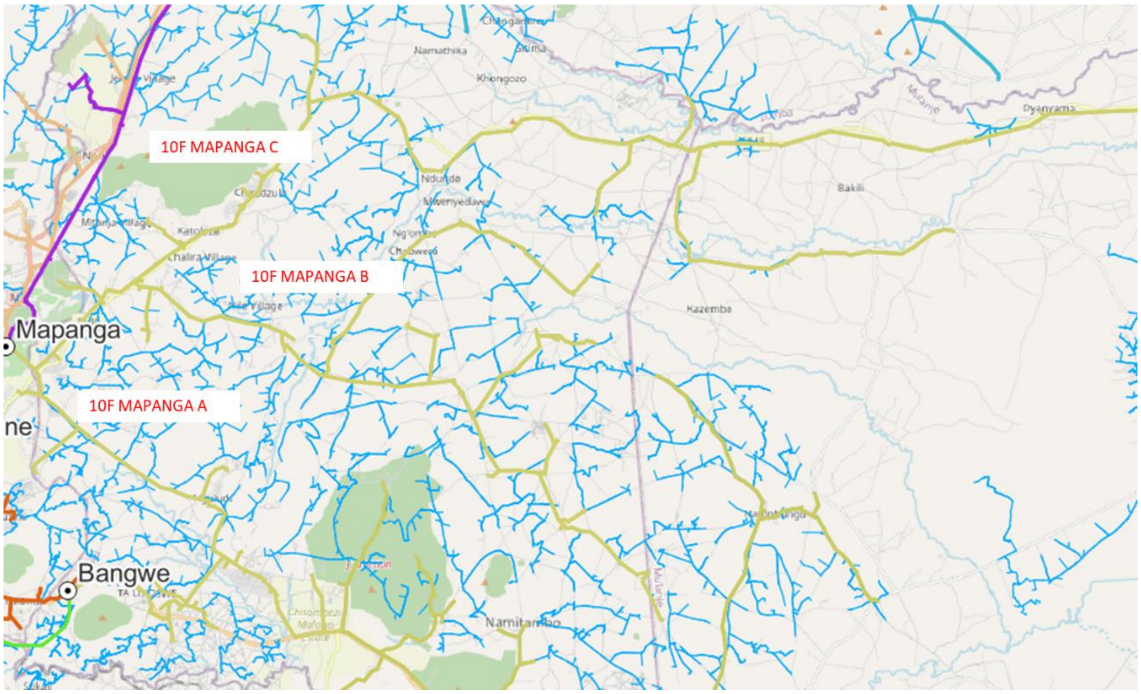


Figure 3.5.40: Proposed modifications at 10F MAPANGA feeder

Finally, some 33kV feeders across the south region must be reinforced due to the load increase:

- 10F CHANGALUME (from 4.6 MW to 19.7MW): One new 150 mm² OHL feeder
- 10F CHICHIRI (from 5.7MW to 23.2 MW): One new 150 mm² OHL feeder
- 10F LIWONDE (from 3.2MW to 17.2MW): One new 150 mm² OHL feeder
- 11F NKULA B (from 5.5MW to 27.6MW): Two new 150 mm² OHL feeders
- 30F LIWONDE (from 3 MW to 17.5 MW): One new 150 mm² OHL feeder

5.3.8.2 Zone of Monkey Bay, Maldeco, Mangochi, AND MAKANJIRA

Due to the load increase of the area of Monkey Bay, Maldeco and Mangochi, the next modifications are proposed:

- Currently, Monkeybay is a primary station 66/33 kV supplying Maledco and Mangochi secondary stations.
- Mangochi secondary station will be upgraded to secondary station at 2032 horizon and moved out of the city

Currently the feeder 10F MONKEYBAY is overloaded and present a high drop voltage. A new 150 mm² feeder is thus required waiting the upgrade of Mangochi stations.

Regarding the feeder 20F MONKEYBAY, it supplies two different directions (north and west) directly after leaving the primary station. It is recommended to divide in two distinct feeders to supply both directions.

The feeder 20F MANGOCHI will see a significant load increase (from 3 MW to 29 MW). New feeders and voltage compensation are the cheapest solution and do not require a new HV substation. However, the Makanjira substation is already planned at the eastbank of the lake. From here, one feeder will supply the coastline (plus a direct feeder to an industrial client). In addition, the 20F MANGOCHI is split in three parts, including 30F MANGOCHI and 40F MANGOCHI. Both the 20F and 40F feeders have a reinforced backbone in 150 mm² and require voltage compensation along the lines.

Figure 3.5.41: Mangochi and Makanjira substations

Finally, several 11kV feeders are present in Maldeco and Mangochi stations:

- 1LF MALDECO can host load increase up to 2042
- 1LF MANGOCHI will be doubled to supply the growing load in the small city and to have an N-1 within the city. One new 100 mm² OHL feeder will be constructed.
- 2LF MALDECO can host load increase up to 2042

5.3.8.3 Zone around the new Primary Station of Phalombe

A new primary station must be in place in Phalombe at 2042 horizon in order to host the demand in the area. Currently, the area of Phalombe is supplied from Fundis Cross via 30F FUNDIS CROSS and via 10F FUNDIS CROSS. The feeders 10F MAPANGA and 10F CHANGALUME supply also the north of this area. At term, the station will supply about 28 MW in this area. The situation can be seen at Figure 3.5.42.

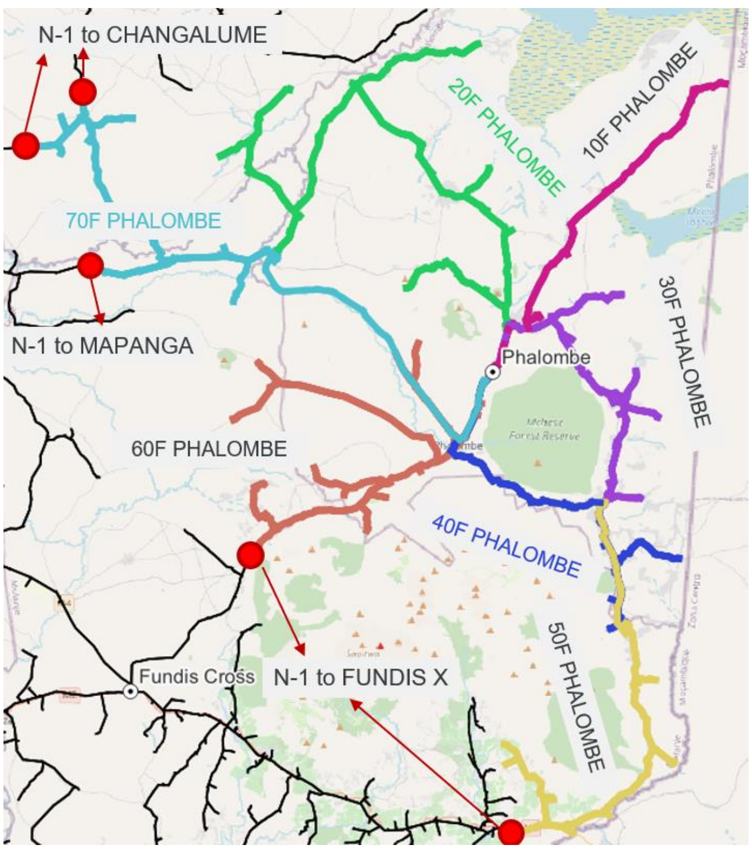


Figure 3.5.42: Phalombe substation

The East part of the feeder 30F FUNDIS CROSS will be supplied from new station Phalombe (10F PHALOMBE). A new 150 mm² feeder will be necessary to take the load at the east of Mulanje forest: 20F PHALOMBE.

Regarding the part of the feeder going to the West, the existing feeder 30F FUNDIS CROSS will be upgrade to 150 mm² and will be double with another 150 mm² OHL.

The other outgoing feeders of Fundis Cross will also see their load increasing significantly from 10 MW to 60 MW in 2042. Four new 150 mm² OHL feeder will take the load increase.

5.3.8.4 Zone of Tyolo

Three secondary stations currently supplies a big area in the south of Blantyre: Tyolo A, Tyolo B, and Tyolo C. Due to the load increase in this area, the 3 stations will be upgraded in Primary Station at 2042 horizon. The existing 11b/n kV feeders of that area are most of the time very long.

Table 3.5.9: Total length of n/ the feeders of Tyolo A, Tyolo B, Thyolo C

feeder	Total length of the feeder (km)
1LF THYOLO A	36.19
1LF THYOLO B	87.21
1LF THYOLO C	31.75
2LF THYOLO A	30.68
2LF THYOLO B	29.22
2LF THYOLO C	13.61
3LF THYOLO A	12.68
4LF THYOLO A	68.89

Due to the load increase, 12 new 100 mm² OHL feeders will be required to supply the area. The significant length is mainly due to the number of laterals of each feeder. With the new foreseen feeders, each one will serve a smaller angle in a given direction. It will allow to stay within the limits.

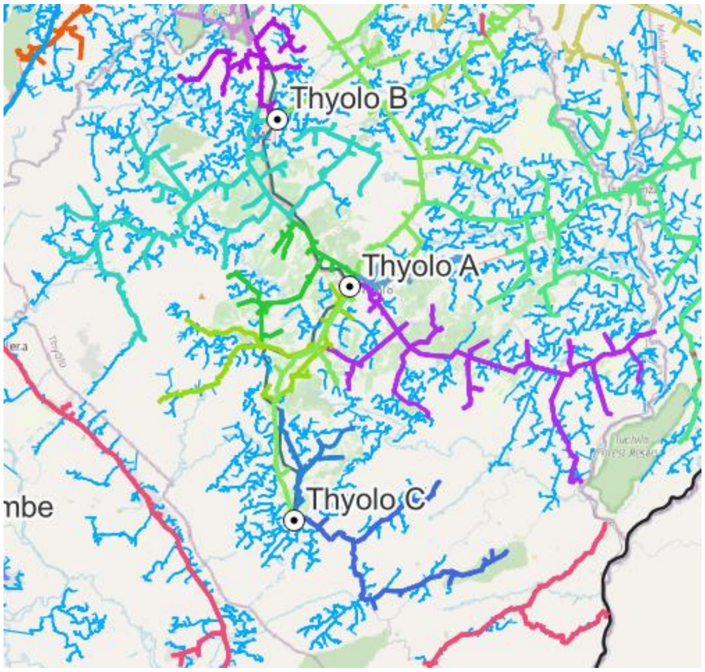


Figure 3.5.43: Area around Thyolo A, Tyolo B and Tyolo C

5.3.8.5 Blantyre city

Currently the city of Blantyre and its periphery is supplied from the several primary/secondary stations:

- Blantyre Main
- Blantyre West
- Chileka
- Chichiri
- Chigumula
- Chirimba
- Customs
- David Whitehead
- Kwatcha
- Limbe A
- Limbe B (supplied from Mapanga)
- Michiru
- Ntdonda
- Queens
- Mapanga 33kV

Note that for Bangwe and Maone, we have no data regarding those substations. They are thus not considered.

Blantyre and its periphery is supplied by 47 feeders operated in 11kV.

Several 11kV feeders are going outside Blantyre and are thus not supplying the city:

- 1LF BLANTYRE WEST
- 3LF CHIGUMULA

- 3LF CHILEKA
- 4LF CHILEKA

The area around the stations of Thyolo A and Thyolo B (see dedicated chapter) will see a significant increase of the load, but there are not considered as part of Blantyre.

Globally, the asynchronous peak load for the feeders supplying Blantyre will increase from 77 MW to 304 MW in 2042. Both network reinforcement and new feeders will be required in order to host the additional load.

Here again, the needs in terms of transformers and feeders have been estimated globally considering the remaining capacity of existing feeders for load increase.

When feeders will reach their life time, they will be upgraded by respecting the defined standards, the existing feeders will be replaced at long term to 185 mm² underground feeders within the city. As not all feeders are charged equally everywhere due to different load density from one area to another, a coefficient of 0.80 is used as localization factor. It is worth mentioning that a cos phi of 0.95 is also used.

Considering the upgrade of all the existing 11kV feeders to 185 mm² UG, our analysis has shown that 47 additional feeders operated in 11kV will be required at 2042 horizon. On top of that, the 51 existing feeders will have to be renewed (life time end) and also upgraded to 185 mm² UG. In total, 98 UG 185 mm² will thus supply the city of Blantyre and the periphery.

This estimate includes a full respect of the planning standards, ensuring the respect of the technical limits both in N and N-1. By loading the feeders at a maximum of 55% (4.1 MVA for 185 mm² UG), closing the loop is always possible. Also, the respect of a length of maximum 11km will ensure the drop voltage remains also within the acceptable limits in N-1.

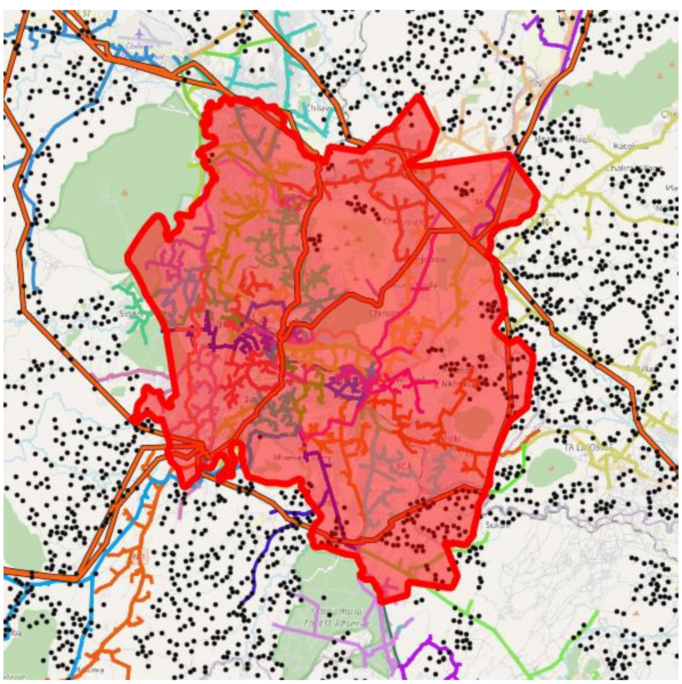


Figure 3.5.44: Blantyre city

5.3.8.6 Zomba

A secondary station 33/11 kV is present in Zomba. However, due to the expected load increase, the secondary station will be upgraded by a primary station. The current infeed of that secondary station is done through two 33kV feeders: 20F CHANGALUME and 30F CHANGALUME. They will be kept as (partial) N-1.

The city of Zomba is supplied in 11kV by feeders:

- 1LF ZOMBA (only some transformers in the city)
- 2LF ZOMBA (most of the load)
- 4LF ZOMBA (first part only)
- 5LF ZOMBA (most of the feeder)
- End of 30F CHANGALUME (only some transformers)

The feeders 2LF ZOMBA and 4LF ZOMBA will be split in two and upgraded in 33kV to supply the rural areas. Indeed, the surrounding of Zomba will see a lot of network extensions to increase the energy access.

Regarding the 11kV feeders inside the city, the withdrawal of part of the load towards 33kV (feeders 1LF ZOMBA, 2LF ZOMBA and 4LF ZOMBA), and the fact that feeder 3LF ZOMBA is currently lowly loaded gives some space for additional load. However, the analysis has shown that 4 new feeders 120 mm² underground will be necessary.

5.3.8.7 Zone around the new primary substation of BANGULA

The southern part of the country is located far from existing substations and will experience significant load growth in the next decades. As ESCOM is already facing operational challenges due to the load and long distances, a new substation is planned in Bangula before 2032.

Three feeders in 33 kV supply the area, each requiring voltage regulators to cope with the long distances. In addition, the 10F and 30F BANGULA feeders are reinforced to 150 mm² to limit losses and voltage drops.

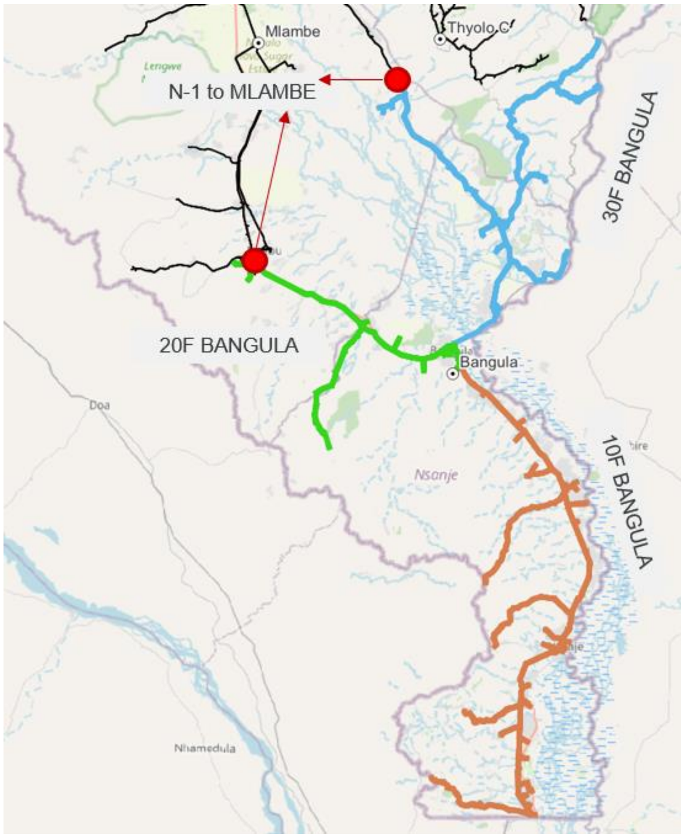


Figure 3.5.45: Bangula substation

5.3.8.8 Chizumulu and Likoma

The islands of Chizmululu and Likoma are supplied by11kV feeders Chizmulu is supplied by 1LF CHIZMULULU and 2LF CHIZUMULU and Likoma is supplied by 1LF LIKOMA and 2LF LIKOMA.

Even if the load is expected to increase significantly (x 6), the existing feeders will be enough to supply the load. Some additional conductors will be required for connected additional transformers.

Figure 3.5.46: Islands of Chizmululu and Likoma

5.4 Prioritization of distribution projects – analysis of the intermediate years

The adequacy of the proposed reinforcements regarding capacity/size and expected load at regional scale have been verified at the intermediate horizons.

Using the knowledge about current situation and the target network on the 20-year horizon, network development must be planned to respect at any moment the demand evolution and the operation and security constraints.

5.4.1 Criteria for network investments prioritization

The distribution planner must foresee investments on the distribution network so that the infrastructure can meet the current and future demand, while respecting the defined network criteria. When planning with a long-term time horizon, numerous investment may be required, particularly for networks facing a continuously-growing demand.

Therefore, the distribution planner must be capable of prioritizing and spreading the investments over the planning timescale. This process can be done based on prioritization criteria:

1. The first priority must be ensuring the security of supply of the current network's demand. Therefore, investments that will solve current issues with power quality and equipment's loading (i.e., conductors and transformers) network criteria must be envisaged first;
2. The second priority must be to investment on reinforcements that will allow the network to fulfill the remaining network criteria under the current demand: technical losses and reliability;
3. The third priority must be to ensure the future security of supply. That is to say, to invest on meeting the power quality and equipment's loading criteria under the future expected load;
4. Finally, the fourth priority must be to fulfill the technical losses and reliability criteria under the future forecasted demand.

5.4.2 Planned development and actual weaknesses

The existing network has been analyzed in the chapter 4 to assess its performance and identify weak spots, requiring short-term actions.

The actual weaknesses and the cases when the technical limits are not respected. All the feeders flagged in the above mentioned chapter must be reinforced in priority (see Table , Table , and Table).

5.4.3 Feeder upgrade from 11 kV to 33kV

As part of the actual weaknesses, ESCOM currently operates long 11kV in rural areas. This is not in line with the defined planning standards. As most of them are currently not respecting the technical constraints, they must be upgraded to 33kV as presented in the next table, for 2027.

Table 3.5.10: 11kV feeders to be upgraded to 33 kV at 2027 horizon

Feeder	Substation	Cross section (mm^2)
1LF BLANTYRE WEST	BLANTYRE WEST	150
1LF BUNDA	BUNDA	150
1LF CHIKANGAWA	CHIKANGAWA	150
1LF CHITIPI	CHITIPI	100
1LF NTCHEU	NTCHEU	100
1LF ULIWA	ULIWA	150
1LF ZOMBA	ZOMBA	150
2LF BUNDA	BUNDA	150
2LF CHILEKA	CHILEKA	150
2LF KARONGA	KARONGA	150
2LF KASUNGU	KASUNGU	100
2LF MLAMBE	MLAMBE	150
2LF NKHOTAKOTA	NKHOTAKOTA	150
2LF SALIMA	SALIMA	100
2LF ZOMBA	ZOMBA	150
3LF BALAKA	BALAKA	150
3LF CHIGUMULA	CHIGUMULA	150
3LF CHILEKA	CHILEKA	150
3LF CHITIPI	CHITIPI	150
3LF KASUNGU	KASUNGU	100
4LF CHILEKA	CHILEKA	150
4LF ZOMBA	ZOMBA	150
5LF KANENGO	KANENGO	100
5LF KATOTO	KATOTO	150
8LF KANENGO	KANENGO	100

5.4.4 Progress to Universal access by 2030

On top of the 33kV backbones to supply rural areas (as identified hereabove), additional MV network (laterals) will connect the villages to the existing or future backbone. This has been done by directly considering inputs from IEP rural electrification study which reflects the ambition of the Malawi Energy Sector at the distribution level.

However, if the pace of electrification is slower than anticipated, the development of the backbone network, as presented in the hereabove sections, should continue unaffected, although investments in last-mile electrification can be delayed.

The next table presents the needs in 50 mm² OHL (for the laterals) for the different periods of the study. As the universal access is targeting 2030, it is considered that 100% of the laterals will be installed in 2030.

Table 3.5.11: MV network extension in rural areas (IEP)

	Efforts in the time period	Needs in 50 mm² OHL (km)	Needs in 100 mm² OHL (km)
2023-2027	43%	8477	3427
2028-2030	57%	11238	4542

5.5 DER integration in the distribution network

This chapter provides an overview of the integration of Distributed Energy Resources (DER) in distribution networks, while also setting the stage for more detailed analyses in the future. It aims to give a clear understanding of the potential impacts and benefits of integrating distributed generation into MV networks.

While this report does not include specific simulations of ESCOM's feeders, it is important to note the value such simulations can bring to the understanding of DER integration. Therefore, a section has been included in appendix, providing a demonstration of a simulation for one DER connection. This demonstration aims to serve as an example guide for such an analysis to be carried out and how the results may look.

5.5.1 Potential impacts of DER integration and Hosting capacity studies

Currently, only few DER (Distributed Energy Resources) are connected to the distribution network of ESCOM, whether in MV or in LV. Hosting capacity studies can first be achieved in order to evaluate the capacity of DG (Distributed Generation) that can be connected.

The main objective of that kind of analysis is to determine the possible integration level of DG powers into the Malawian distribution networks considering the current infrastructure, status and configuration and to identify the limiting factors that should be corrected/removed in order to increase the integration level of DG powers. HC studies must first be done for the current situation and then can be done considering the planned development of the network in order to analyze how the planned infrastructure can handle with DER accommodation.

The process can be summarized as follows:

1. Evaluate how much (new) capacity from renewable-based DG units can be integrated into the current existing distribution networks without having adverse impacts on the technical limits.
2. Identify the barriers that do not allow increasing of DG integration
3. Prioritize the investment needs to relieve the constraints while considering the planned investments to supply the future load increase (what has been done in this Master Plan).

5.5.1.1 Definition of the hosting capacity

Distribution networks were designed to meet the maximum load demands. In other words, the integration of DG power was not foreseen in the planning stage of the distribution systems. Consequently, this can lead to overload of the network equipment including system conductors, cables and transformers as shown in Figure .

Moreover, the injected powers from DG units can create voltage problems such as overvoltage issues, particularly, in the long feeders when the load demand is low. Protection issues can also arise from the injected powers of DGs since the latter changes the direction of power flow from unidirectional to bidirectional and increases the fault level of the system. Finally, the power quality problems such as harmonic distortion and voltage flicker are produced due to the power electronic-based converters of DGs and their rapid power variations.

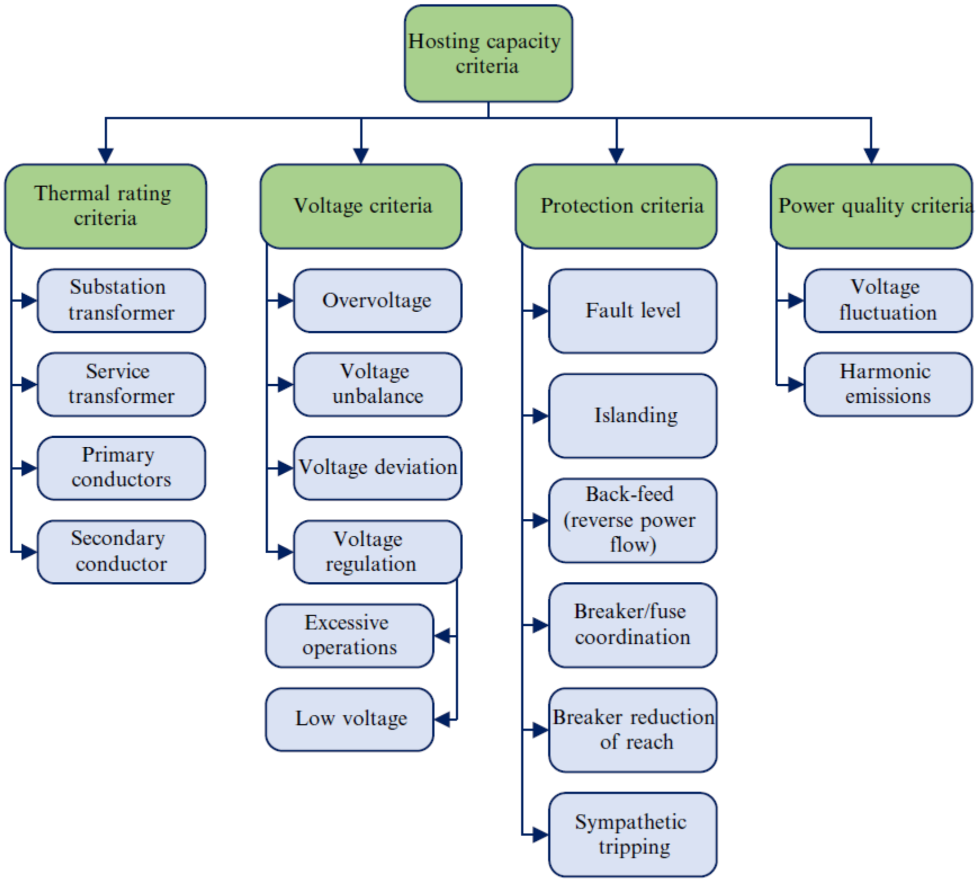


Figure 3.5.47: Hosting capacity criteria[20]

Hosting capacity analysis quantifies the possible integration level of DG power into the distribution system. The analysis is carried out through evaluating impacts of the injected DG powers on the technical performance of the studied system by doing the multiple power flow calculations. The satisfactory technical performance of the system is evaluated by verifying the parameters and factors such as voltage limit, loading of equipment and protection while power quality issues are more rarely considered at the stage of HC analysis. Figure shows the important technical factors that are usually taken into account when evaluating the hosting capacity of the studied network.

Importance of the hosting capacity analysis

Determination of the possible amount of DG power to be connected to the existing network is not a straightforward task since it depends on the size and location of DG units as well as the considered technical constraints. The hosting capacity analysis takes into account all these aspects and provides us a range of possible integration level of DG power in function of the location of DGs to be installed and the studied constraints.

[20] Reference: Smart Power Distribution Systems, Chapter 23, Distribution systems hosting capacity assessment: Relaxation and linearization, 2019.

All the criteria that are mentioned in Figure can be considered in the hosting capacity analysis. For a specific value of the injected power, it is possible to have all the limits within their predefined range for some locations of DG while for other locations, some or all the limits are violated. Figure depicts three regions of hosting capacity where in the zone A, for any value and location of DG injected power, all limits are respected. In the zone B, some of the limits are respected and the rest are violated in function of the location of injected power. Finally, for any power injection within the zone C in all the locations, all the limits are violated.

Based on the three regions shown in Figure , one can define the minimum and maximum hosting capacity levels of the studied network. Accordingly, the minimum hosting capacity corresponds to the border of the zones A and B. The maximum hosting capacity relates to the border of the zones B and C.

Finally, it can be concluded that the hosting capacity of the studied network is not a unique value, but it is a range of possible integration of DG powers, which is obtained in function of location and the studied technical constraints.

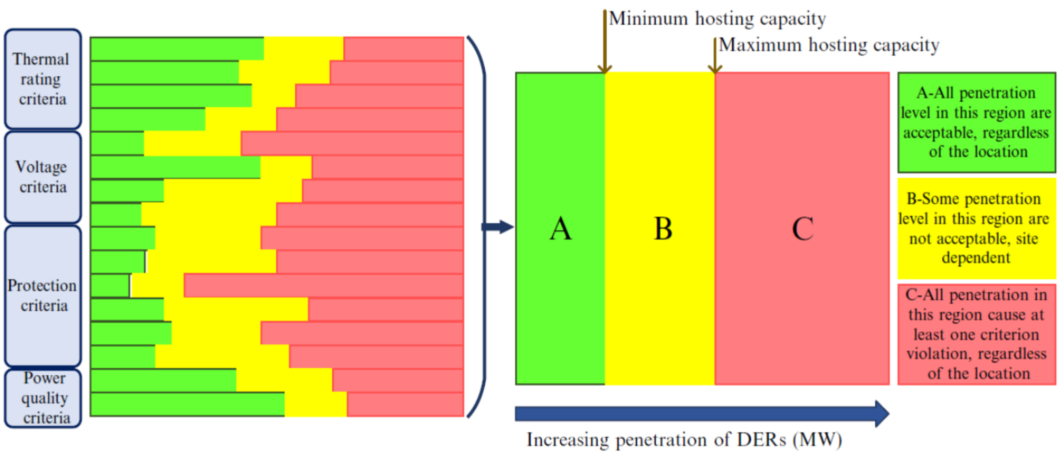


Figure 3.5.48: Minimum and maximum levels of hosting capacity (DERs: Distributed Energy Resources)21

Hosting capacity as a function of DG location - Example

Figure shows how the DG location can affect the hosting capacity of the network considering the voltage limit as the studied technical criterion. As it can be seen, the voltage rise created by injection of 18 MW DG power at 3 km away from the substation is equal to that of the 4.9 MW DG power injection at 15 km from the substation or 2.5 MW injection from a DG located 30 km from the substation. Therefore, it can be concluded that the further is DG from the substation, the smaller hosting capacity can have the studied network at that point (node) considering the voltage limit.

[21] Reference: Smart Power Distribution Systems, Chapter 23, Distribution systems hosting capacity assessment: Relaxation and linearization, 2019.

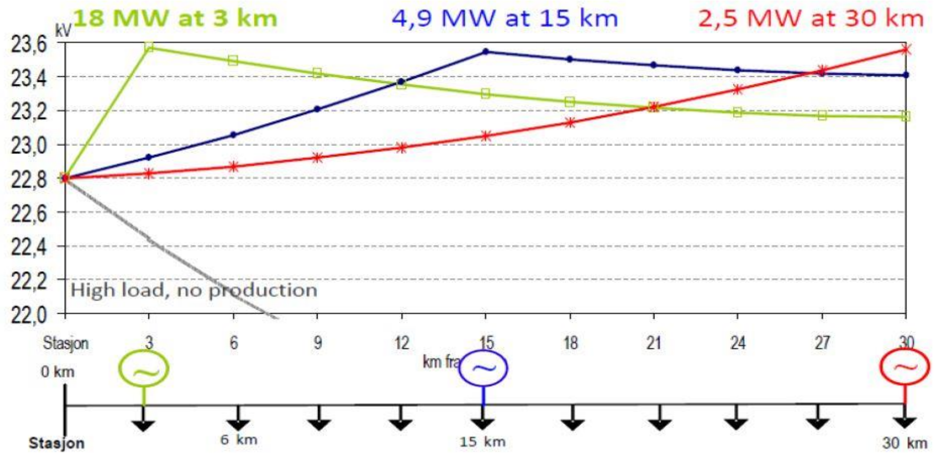


Figure 3.5.49: Impact of DG location on the feeder voltage – example 22

5.5.1.2 Quantification of the hosting capacity

The distribution system operators evaluate the hosting capacity of their networks/feeders through the following ways:

- Approach based on predefined rules;
- Analytical approach.

The **first approach is based on predefined rules** and gives a high-level estimation of the hosting capacity of the studied network taking into account factors such as the rated power of substation transformer, minimum load demand of the feeder or fault level of the feeder. One of the known examples of this approach is the useful rule of thumb named ''15% rule'' which indicates that the DG power integration up to 15% of the feeder nominal load is permitted in the feeder. The advantage of this approach is that it does not require a detailed model of the network. However, the output of this method does not provide an exact quantification of the hosting capacity. The hosting capacity evaluation based on the predefined rules is more and more replaced by the analytical approach with the increase of the penetration rate.

The **second approach is to achieve an hosting capacity analysis which is analytically determined** by doing sets of load flow calculations in deterministic or stochastic way. The detailed network model is needed in order to quantify analytically the hosting capacity of the studied network. Currently, there are some simulation tools that can determine the hosting capacity of feeders (for instance, NEPLAN, CYME, and PowerFactory). The simulation tools usually represent the hosting capacity of the studied network either in tabular format or graphically within the geographical or single line diagram by applying different colouring modes. Figure depicts, for instance, the graphical-geographical representation of hosting capacity analysis obtained by the PowerFactory software.

[22] Reference: Capacity of Distribution Feeders for Hosting DER, CIGRE Working Group, 2014.

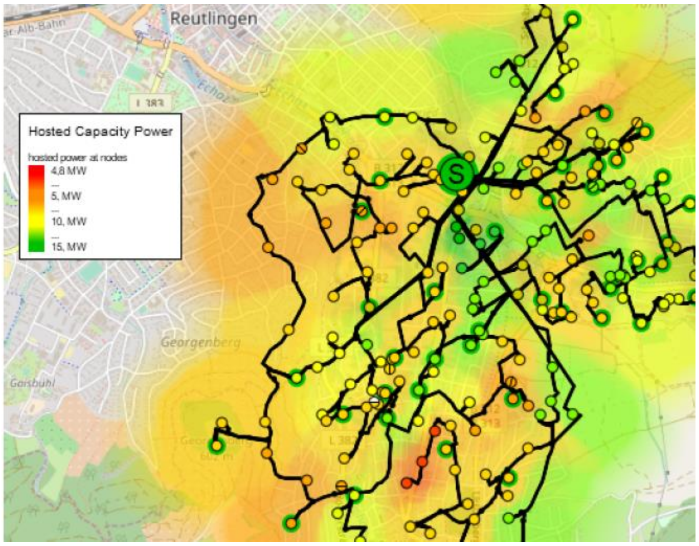


Figure 3.5.50: Geographical representation of hosting capacity results by PowerFactory

5.5.1.3 Identification of the limiting factors

Based on the computer simulations and relevant analyses performed in the previous stage, **limiting factors of DG integration in different studied zones can be determined**. As a result, investment needs can be prioritized in order to increase the share of renewable-based generations. For instance, if it is seen that the overload of equipment is the most important limiting factor, feeder reinforcement is prioritized or in the case that the voltage rise is found to be of a high importance, the voltage regulator utilization and/or feeder reinforcement can be envisaged.

5.5.1.4 Enhancement of the network hosting capacity by investment

Hosting capacity of one studied network increases if the barriers limiting it are mitigated/removed. The technical factors limiting integration of DG powers are the voltage, current, power quality and protection issues as mentioned before. Considering the origin of the technical problems arisen from the integration of the DGs, different enhancement methods can be applied. Figure shows the hosting capacity enhancement techniques.

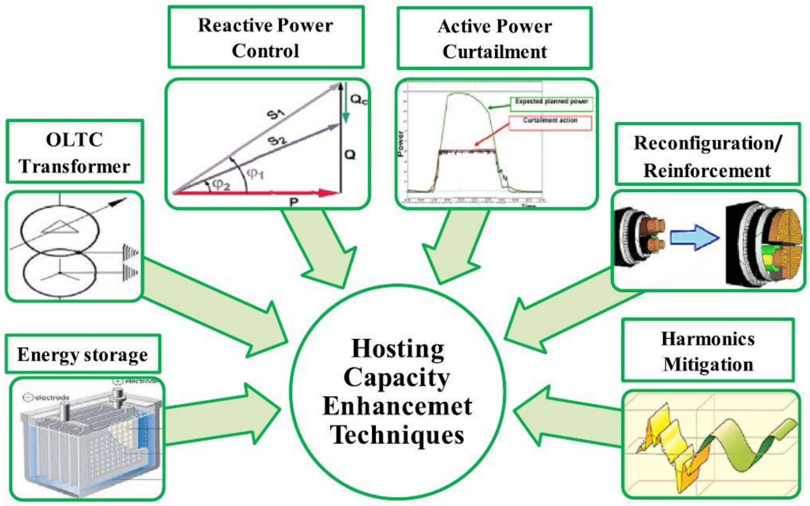


Figure 3.5.51: Hosting capacity enhancement techniques23

In Figure , in order to tackle the voltage-related issues, methods such as generation curtailment, control of on-load tap changer (OLTC) and reactive power control are used while options like feeder reinforcement, energy storage equipment can address both voltage and overloads issues. Therefore, the enhancement methods should be applied considering their investment cost and their efficiency.

As mentioned, the mitigation of limiting factors of DG integration requires some extra investments. Figure depicts the hosting capacity as a function of the investment. As it is seen, the hosting capacity nonlinearly evolves with respect to the increase of investment, which defines that the efficiency of investments is not always identical. Therefore, it is necessary to consider both technical and economic aspects in the hosting capacity evaluation. To make it clearer, one feeder located in the urban zone can have already an acceptable hosting capacity level and the investment on that feeder can lightly increase its current possible integration level while the same investment on one feeder in rural zone can bring a big increase of the hosting capacity.

Qualitatively, from the knee point of the curve shown in Figure , the investment on the feeder equipment to increase the hosting capacity will not be any more efficient. In such a case, it would be economically more optimal to connect the extra DG generation to a network in higher voltage level.

[23] **Reference: State-of-the-art of hosting capacity in modern power systems with distributed generation, Renewable Energy Journal, 2019.**

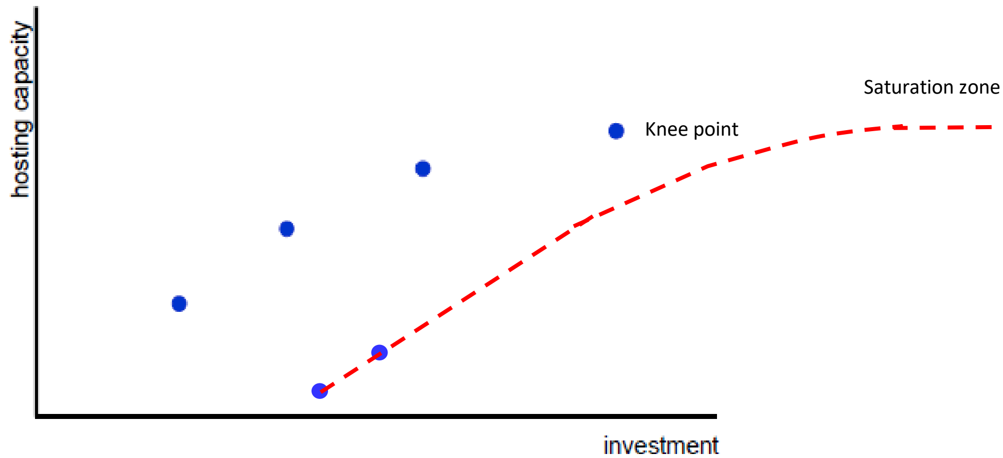


Figure 3.5.52: Hosting capacity as a function of investment24

The outcomes of analysis of the section can be used in order to direct the needed investments through the most optimal options, bringing higher hosting capacity to the network at the country-level.

5.5.1.5 Most adequate areas for decentralized generation

As seen in the sections here above, the size and the location and of the decentralized generation has a significant o the hosting capacity of the distribution network. Most of the time, size and location are an unknown and cannot be chosen.

However, incentives and rules can be put in place in order to attract investments for DER in some given areas in order to relieve constraints and reduce losses. From the hosting capacity analysis, it is possible to determine the most relevant areas for interconnection of distributed generation sources for optimal network operation efficiency in the distribution network. Dedicated feasibility studies must then follow in order to confirm the detailed technical feasibility of the projects in the selected areas.

The connection of decentralized generation in some MV feeders will relieve their technical losses in hours of available resources. Consequently, their annual energy losses share will reach lower values. However, decentralized generation projects are not expected to fully support technical issues on the network for both peak and off-peak situations, as by definition these sources will be intermittent.

[24] Reference: Power quality: interactions between distributed energy resources, the grid, and other customers, 2005.

5.5.2 Typical analysis for connecting DER

Several studies must be achieved for connecting DER into the grid. While DER connection in LV does not cause major impacts for low penetration rates, dedicated studies are necessary for connecting DER on MV feeders.

For that reason, a grid impact study is required to evaluate if the connection of the renewable plants does not violate network constraints. Once the Point of Connection (PoC) is determined, the concerned 11kV or 33 kV feeders need to be fully modelled. Most of the time, static analysis of the network are enough to verify the grid impact.

When analyzing several plants, all plants must be added simultaneously in the network.

An example of analysis for DER connection is given hereunder.

<u>Loading of conductors and voltage constraints both in N and N-1</u>

The analyses are performed at the connection nodes to ensure that the DER plants do not cause any issue in the network. Voltage profile in the zone of the point of connections as well as line loadings are studied in normal condition (N) and in N-1 condition and in on-peak and off-peak conditions, according to some critical contingencies applied to the network. The presence of reverse flows in the MV feeders is also highlighted.

Regarding N-1, only contingencies with a direct impact on the PoC must be studied. Specifically, it is the complete loss of a feeder which is considered (i.e. the worst case). It thus corresponds to the loss of the first leg feeder between the primary substation and the first RMU.

<u>Short-circuit analysis</u>

The three phase short-circuit (SC) current levels (in line with the IEC 60909 norm) in the immediate vicinity of the DER plants are compared with the rated capacity of the existing circuit breakers.

For PV, a voltage factor (C factor) of 1.1 is often assumed for this analysis. Furthermore, it is verified that the short-circuit ratio (SCR) at the studied nodes are sufficiently high to ensure a stable operation of the inverters in case of a perturbation. The SCR is an indication of the system strength with respect to the rated power of the power plant. As inverters need a certain short-circuit ratio to be able to operate, this is an important parameter for the inverter selection and the plant design in a later phase of the project. The SCR can be computed by the ratio between the short-circuit power of the system at the PoC (SCC, in MVA) and the nominal power of the considered plant (P_{PV} in MW).

$$SCR = \frac{SCC}{P_{PV}}$$

One typical SCR threshold to be considered is SCR > 3, which is a conservative assumption: most modern inverters can accommodate lower SCR. However, below SCR = 3, some additional verifications with EMT simulation tools must be performed to ensure a smooth operation of the inverters.

For the connection of synchronous generators, the step-up transformer with its short-circuit reactance must also be modelled in order to compute the short-circuit contribution of the complete DER.

An example of analysis is given in appendix 8.3.

6 Legal and Regulatory Framework for Generation, Transmission, and Distribution Projects in Malawi

6.1 Introduction

This section provides an overview of the legal and regulatory framework governing generation, transmission, and distribution projects in Malawi, with a particular focus on the Environmental and Social Impact Assessment (ESIA) requirements.

6.2 Relevant Malawi Policies and Legislation

6.2.1 Malawi Vision 2063bn

bMalawi Vision 2063 is a comprehensive blueprint that envisions transforming Malawi into a wealthy, self-reliant, industrialized, and middle-income country by 2063. This vision is built on three key pillars: Agricultural Productivity and Commercialization, Industrialization, and Urbanization. Each pillar is supported by enablers that include Human Capital Development, Economic Infrastructure, and Environmental Sustainability. The vision emphasizes the need for sustainable and inclusive economic growth driven by innovation, technology, and a robust energy sector. Malawi Vision 2063 places significant emphasis on the development of the energy sector as a critical enabler for industrialization and urbanization. The vision outlines specific goals for energy generation, transmission, and distribution to support Malawi's economic transformation:

- Expansion of Energy Generation Capacity
  - Increase the installed electricity generation capacity to meet the growing demand from industrial, commercial, and residential sectors.
  - Promote the diversification of energy sources, including the development of renewable energy projects such as solar, wind, and hydropower.
  - Encourage the adoption of clean and sustainable energy technologies to reduce the carbon footprint and mitigate the impacts of climate change.
- Enhancement of Transmission and Distribution Networks
  - Upgrade and expand the transmission and distribution infrastructure to ensure reliable and efficient delivery of electricity across the country.
  - Reduce transmission and distribution losses through the adoption of modern technologies and best practices.
  - Strengthen the grid's resilience to withstand environmental challenges and improve energy security.
- Universal Access to Electricity
  - Achieve universal access to electricity by 2063, with a focus on connecting rural and underserved areas.
  - Implement the Malawi Rural Electrification Program (MAREP) to accelerate the electrification of remote communities.

- Foster public-private partnerships to mobilize resources and expertise for expanding access to electricity.

Implications for Generation, Transmission, and Distribution Projects

The goals outlined in Malawi Vision 2063 have profound implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Strategic Goals
  - Projects must align with the strategic goals of increasing generation capacity, diversifying energy sources, and enhancing grid infrastructure.
  - Long-term planning should incorporate the vision's targets, ensuring that projects contribute to the overarching objectives of industrialization and urbanization.
- Sustainability and Environmental Considerations
  - Projects should prioritize sustainability by integrating renewable energy sources and adopting environmentally friendly technologies.
  - Conduct comprehensive ESIAs to mitigate adverse impacts and ensure compliance with national and international environmental standards.
- Capacity Building and Technological Innovation
  - Invest in capacity building and training for local stakeholders to ensure the successful implementation and maintenance of energy projects.
  - Embrace technological innovations such as smart grids, energy storage solutions, and digital monitoring systems to improve efficiency and reliability.
- Public-Private Partnerships
  - Leverage public-private partnerships to mobilize investment, technical expertise, and innovative solutions for energy projects.
  - Create an enabling environment for private sector participation by ensuring transparent regulatory frameworks and attractive investment incentives.
- Focus on Rural Electrification
  - Prioritize projects that support rural electrification to bridge the energy access gap and promote inclusive development.
  - Implement off-grid and mini-grid solutions in remote areas to provide reliable and sustainable electricity to underserved communities.
- Monitoring and Evaluation
  - Establish robust monitoring and evaluation mechanisms to track progress towards the vision's energy sector goals.
  - Use data and analytics to inform decision-making, optimize project performance, and ensure accountability.

6.2.2 Environmental Policy (2004)

Environmental Policy (2004) is a critical framework that guides the integration of environmental considerations into the planning and implementation of development projects in Malawi. The policy aims to promote sustainable development by ensuring that environmental protection is a fundamental part of economic and social planning. It emphasizes the importance of preserving natural resources, reducing pollution, and fostering a healthy and productive environment for current and future generations. The Policy outlines several key elements that are essential for the sustainable development of Malawi:

- Sustainable Resource Management
  - Promote the sustainable use and management of natural resources, including land, water, forests, and wildlife.
  - Implement measures to prevent resource depletion and degradation, ensuring their availability for future generations.
- Pollution Control and Waste Management
  - Establish and enforce standards for controlling pollution from industrial, agricultural, and domestic sources.
  - Develop efficient waste management systems to minimize environmental pollution and health hazards.
- Environmental and Social Impact Assessment
  - Mandate the conduct of ESIA for all major development projects to evaluate potential environmental impacts.
  - Ensure that mitigation measures are implemented to address any adverse effects identified during the ESIA process.
- Conservation of Biodiversity
  - Protect and conserve Malawi's biodiversity, including endangered species and critical habitats.
  - Promote reforestation and afforestation programs to restore degraded ecosystems and enhance biodiversity.
- Public Awareness and Participation
  - Enhance public awareness of environmental issues and promote community involvement in environmental conservation activities.
  - Encourage stakeholder participation in the decision-making process for environmental management and development planning.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Policy (2004) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to Environmental Standards
  - Projects must comply with the environmental standards and best practices outlined in the policy.
  - Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.
- Integration of ESIA Process
  - Conduct thorough ESIA for all projects to identify potential environmental impacts and develop mitigation strategies.
  - Ensure that ESIA findings are incorporated into project design and implementation to minimize negative environmental effects.
- Sustainable Resource Utilization
  - Utilize natural resources efficiently and sustainably to prevent depletion and environmental degradation.

- Adopt technologies and practices that enhance resource conservation, such as renewable energy sources and energy-efficient systems.

- Pollution Prevention and Waste Management
  - Implement measures to control pollution from project activities, including emissions, effluents, and waste.
  - Develop and maintain effective waste management systems to handle project-related waste in an environmentally responsible manner.
- Biodiversity Conservation
  - Incorporate biodiversity conservation into project planning by protecting critical habitats and endangered species.
  - Engage in reforestation and habitat restoration activities to offset any environmental disturbances caused by project activities.
- Stakeholder Engagement and Public Participation
  - Engage local communities and stakeholders in the planning and implementation of projects to ensure their concerns and suggestions are addressed.
  - Promote transparency and accountability by keeping stakeholders informed about project progress and environmental management efforts.
- Long-term Environmental Sustainability
  - Focus on long-term environmental sustainability by adopting practices that reduce the ecological footprint of projects.
  - Invest in technologies and processes that support environmental resilience and adaptation to climate change.

6.2.3 National Energy Policy (2018)

National Energy Policy (2018) is a strategic framework designed to enhance access to reliable, affordable, and sustainable energy services in Malawi. The policy underscores the importance of diversifying energy sources and promoting renewable energy to reduce reliance on biomass, which is a significant contributor to deforestation and environmental degradation. The policy aims to address the low electrification rate, mitigate climate change impacts, and support sustainable economic development.

Key Elements of the National Energy Policy (2018)

The National Energy Policy (2018) outlines several key elements that are crucial for the development of the energy sector in Malawi:

- Diversification of Energy Sources
  - Promote the development and use of various energy sources, including hydropower, solar, wind, and biomass.
  - Encourage investment in renewable energy projects to reduce dependence on traditional biomass and fossil fuels.
- Enhancement of Energy Access
  - Increase the electrification rate, particularly in rural and underserved areas, to ensure equitable access to energy services.

- Implement the MAREP to extend the electricity grid and provide off-grid solutions where grid extension is not feasible.
- Energy Efficiency and Conservation
  - Promote energy efficiency measures and technologies to reduce energy consumption and improve the overall efficiency of the energy sector.
  - Encourage the use of energy-efficient appliances and industrial processes to lower energy demand and reduce environmental impacts.
- Climate Change Mitigation and Adaptation
  - Integrate climate change considerations into energy planning and project implementation.
  - Support the development of low-carbon technologies and practices to mitigate greenhouse gas emissions and enhance climate resilience.

Implications for Generation, Transmission, and Distribution Projects

The National Energy Policy (2018) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Policy Goals
  - Projects must align with the policy's goals of promoting renewable energy and ensuring energy sustainability.
  - Long-term planning should incorporate the policy's targets, ensuring that projects contribute to the overall objectives of increasing energy access and reducing reliance on biomass.
- Integration of Renewable Energy Sources
  - Developers should consider integrating renewable energy sources such as solar, wind, and hydropower into their projects.
  - The adoption of renewable energy technologies can help reduce greenhouse gas emissions and mitigate climate change impacts.
- Enhancement of Energy Access
  - Projects should focus on extending energy access to rural and underserved areas, in line with the goals of the MAREP.
  - Implementing off-grid and mini-grid solutions can provide reliable and sustainable electricity to remote communities.
- Energy Efficiency Measures
  - Incorporate energy efficiency measures into project design and implementation to reduce energy consumption and operational costs.
  - Promote the use of energy-efficient technologies and practices in both residential and industrial sectors.
- Climate Change Considerations
  - Integrate climate change mitigation and adaptation measures into project planning and execution.
  - Develop and implement low-carbon technologies and practices to enhance the sustainability and resilience of energy projects.
- Regulatory Compliance and Institutional Strengthening
  - Ensure compliance with the regulatory framework and engage with relevant institutions for project approvals and oversight.

- Strengthen the capacity of local institutions to manage and regulate energy projects effectively.

The National Energy Policy (2018) provides a comprehensive framework for enhancing energy access, promoting renewable energy, and ensuring sustainable development in Malawi. Projects must align with the policy's goals and integrate renewable energy sources, energy efficiency measures, and climate change considerations into their planning and implementation.

6.2.4 Forest Policy (2016)

Forest Policy (2016) is a pivotal framework aimed at promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. The policy seeks to address the challenges of deforestation, forest degradation, and unsustainable use of forest resources, which are critical issues affecting the environment and livelihoods in the country. The Forest Policy underscores the importance of conserving forest ecosystems, enhancing carbon sequestration, and promoting the sustainable use of forest products.

The Forest Policy (2016) outlines several key elements essential for the sustainable management of forest resources in Malawi:

- Sustainable Forest Management
  - Promote practices that ensure the sustainable management and utilization of forest resources.
  - Implement forest management plans that balance environmental, economic, and social objectives.
- Reforestation and Afforestation
  - Encourage reforestation and afforestation initiatives to restore degraded forest lands and increase forest cover.
  - Support community-based reforestation projects and agroforestry practices that enhance livelihoods and biodiversity.
- Protection of Forest Resources
  - Enforce regulations to protect forest resources from illegal activities such as logging, encroachment, and charcoal production.
  - Establish protected areas and conservation zones to preserve critical habitats and biodiversity.
- Charcoal Production and Trade Regulation
  - Regulate the production and trade of charcoal to reduce its impact on forest resources.
  - Promote alternative energy sources to reduce dependency on charcoal and mitigate deforestation.
- Community Participation and Capacity Building
  - Engage local communities in forest management and conservation efforts.
  - Build the capacity of communities and stakeholders to effectively participate in sustainable forest management practices.

Implications for Generation, Transmission, and Distribution Projects

The Forest Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources
  - Projects involving land use changes must assess the impact on forest resources and implement measures to mitigate adverse effects.
  - Conduct ESIAs to evaluate the potential impacts on forests and develop appropriate mitigation strategies.
- Compliance with Reforestation and Sustainable Management Requirements
  - Projects must comply with reforestation and sustainable management requirements as outlined in the Forest Policy.
  - Implement reforestation initiatives to compensate for any forest loss due to project activities, ensuring no net loss of forest cover.
- Regulation of Charcoal Production and Forest Protection
  - Adhere to regulations regarding charcoal production and trade to avoid legal penalties and support forest conservation efforts.
  - Promote the use of alternative energy sources to reduce the reliance on charcoal and mitigate deforestation.

The Forest Policy (2016) provides a robust framework for promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and sustainable management requirements, and adhere to regulations regarding charcoal production and forest protection.

6.2.5 National Climate Change Management Policy (2016)

National Climate Change Management Policy (2016) is a strategic framework designed to guide Malawi in addressing the impacts of climate change through effective adaptation and mitigation measures. The policy aims to enhance resilience to climate change, reduce greenhouse gas emissions, and promote sustainable development practices. It emphasizes the integration of climate change considerations into all sectors of the economy, including energy, to ensure a coordinated and comprehensive response to climate challenges. The Policy outlines several key elements essential for addressing climate change impacts in Malawi:

- Climate Change Adaptation
  - Implement measures to increase resilience to climate change impacts, particularly in vulnerable sectors such as agriculture, water resources, and infrastructure.
  - Promote the development and use of climate-resilient technologies and practices to minimize the adverse effects of climate change.
- Climate Change Mitigation
  - Develop and implement strategies to reduce greenhouse gas emissions across all sectors, including energy, transportation, and industry.
  - Encourage the adoption of renewable energy sources and energy-efficient technologies to lower carbon emissions.
- Capacity Building and Public Awareness

- Enhance the capacity of institutions and stakeholders to effectively address climate change through training, research, and knowledge dissemination.
- Raise public awareness about climate change impacts and the importance of adaptation and mitigation measures.

- Policy and Institutional Coordination
  - Strengthen the coordination and integration of climate change policies and actions across different sectors and levels of government.
  - Establish and support institutions responsible for overseeing the implementation of climate change policies and strategies.
- Funding and Resource Mobilization
  - Mobilize resources from domestic and international sources to finance climate change adaptation and mitigation initiatives.
  - Promote public-private partnerships to leverage additional funding and expertise for climate action projects.

Implications for Generation, Transmission, and Distribution Projects

The National Climate Change Management Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Integration of Climate Change Adaptation Measures
  - Projects should incorporate climate change adaptation measures to enhance resilience to climate impacts such as extreme weather events, temperature variations, and changing precipitation patterns.
  - Design infrastructure and systems that can withstand climate-related stresses and ensure continuous and reliable energy supply.
- Implementation of Climate Change Mitigation Strategies
  - Projects must implement strategies to reduce greenhouse gas emissions, including the adoption of renewable energy sources such as solar, wind, and hydropower.
  - Promote energy efficiency measures to reduce energy consumption and minimize the carbon footprint of energy projects.
- Compliance with National Climate Goals
  - Ensure that projects comply with the national climate goals and targets set forth in the policy, contributing to Malawi's overall efforts to combat climate change.
  - Monitor and report on greenhouse gas emissions and climate change impacts associated with project activities.
- Capacity Building and Stakeholder Engagement
  - Enhance the capacity of project teams and stakeholders to understand and address climate change issues through training and knowledge sharing.
  - Engage local communities and stakeholders in climate change adaptation and mitigation efforts, ensuring their participation and support.
- Policy and Institutional Coordination
  - Collaborate with relevant government agencies and institutions to ensure the alignment of project activities with national climate change policies and strategies.
  - Contribute to the development and implementation of coordinated climate action plans that integrate sectoral efforts.

The National Climate Change Management Policy (2016) provides a comprehensive framework for addressing climate change impacts and promoting sustainable development in Malawi. Generation, transmission, and distribution projects must integrate climate change adaptation and mitigation measures, comply with national climate goals, and engage stakeholders in climate action efforts.

6.2.6 National Water Policy (2005)

National Water Policy (2005) aims to guide the sustainable management, development, and use of water resources in Malawi. This policy is comprehensive, addressing various aspects of water resource management, including conservation, utilization, and service delivery, to support socio-economic development and environmental sustainability. The National Water Policy (2005) outlines several key elements essential for effective water resource management and development:

- Integrated Water Resources Management (IWRM):
  - Promotes IWRM principles to ensure the coordinated development and management of water, land, and related resources.
  - Aims to maximize economic and social welfare without compromising the sustainability of vital ecosystems.
- Water Quality and Pollution Control:
  - Ensures water of acceptable quality for various needs by setting standards and guidelines for water quality and pollution control.
  - Implements measures to prevent and control water pollution, protecting both surface and groundwater resources.
- Water Utilization:
  - Addresses the provision of water supply and sanitation services for urban, peri-urban, and rural areas.
  - Promotes the efficient and equitable use of water resources for agriculture, irrigation, hydropower, fisheries, navigation, and eco-tourism.
- Disaster Management:
  - Establishes preparedness and contingency plans for water-related disasters, such as floods and droughts.
  - Aims to mitigate the impact of such disasters on communities and infrastructure.
- Institutional Roles and Linkages:
  - Defines the roles and responsibilities of various stakeholders, including government ministries, water utilities, local governments, NGOs, and the private sector.
  - Encourages collaboration and coordination among these stakeholders to ensure effective water management.

Implications for Generation, Transmission, and Distribution Projects

The National Water Policy (2005) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to IWRM Principles:
  - Projects must integrate IWRM principles into their planning and implementation processes to ensure sustainable water resource management.

- Coordinated development and management of water, land, and related resources should be prioritized.
- Ensuring Water Quality and Pollution Control:
  - Projects must comply with the standards and guidelines for water quality and pollution control set forth in the policy.
  - Implementing effective pollution prevention and control measures is essential to protect water resources from contamination.
- Efficient and Equitable Water Utilization:
  - Projects should promote the efficient and equitable use of water resources, ensuring that water supply and sanitation services are accessible to all.
  - Consideration of water needs for various sectors, including agriculture, hydropower, and eco-tourism, is crucial for balanced water use.
- Disaster Management and Preparedness:
  - Incorporating disaster management and preparedness measures into project planning can mitigate the impact of water-related disasters.
  - Developing contingency plans and infrastructure to cope with floods and droughts is essential for project resilience.

The National Water Policy (2005) provides a comprehensive framework for the sustainable management, development, and use of water resources in Malawi. Generation, transmission, and distribution projects must adhere to the policy's principles and guidelines to ensure sustainable water resource management, compliance with water quality standards, efficient utilization, disaster preparedness, and stakeholder collaboration. By aligning with the National Water Policy, developers can contribute to the sustainable development of Malawi's water resources, supporting socio-economic growth and environmental conservation.

6.3 Relevant Malawi Legislative Framework

6.3.1 Constitution of the Republic of Malawi (1994)

Constitution of the Republic of Malawi (1994) serves as the supreme law of the land, laying the foundation for all legal and regulatory frameworks within the country. It enshrines principles of environmental protection and sustainable development, reflecting Malawi's commitment to fostering a balanced relationship between development and environmental stewardship. The Constitution ensures that all developmental activities, including energy projects, adhere to fundamental environmental principles to safeguard the well-being of its citizens and the natural environment. The Constitution outlines several key principles and provisions that are pertinent to environmental protection and sustainable development:

- Environmental Protection
  - Mandates the state to adopt and implement policies and measures designed to protect and sustain the environment for present and future generations.
  - Requires that environmental considerations be integrated into national development plans and policies.
- Sustainable Development

- Emphasizes the need for sustainable use of natural resources to ensure that development meets the needs of the present without compromising the ability of future generations to meet their own needs.
- Supports economic development that is environmentally sustainable and socially inclusive.

- Public Participation and Rights
  - Ensures the right of citizens to participate in environmental decision-making processes.
  - Protects the rights of individuals and communities to access information regarding environmental matters and to seek redress for environmental harm.
- Legislative and Institutional Framework
  - Provides the basis for enacting environmental laws and establishing institutions to oversee environmental management and enforcement.
  - Encourages the development of laws and regulations that promote environmental justice and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Constitution of the Republic of Malawi (1994) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Constitutional Provisions
  - Projects must comply with constitutional provisions related to environmental protection, ensuring that all activities align with the principles of environmental sustainability and stewardship.
  - Regular audits and environmental impact assessments should be conducted to ensure ongoing compliance with constitutional mandates.
- Integration of Environmental Considerations
  - Integrate environmental considerations into all stages of project planning and implementation, from initial design through to operation and maintenance.
  - Develop and implement ESIAs to identify potential impacts and develop mitigation strategies.
- Upholding Constitutional Rights and Principles
  - Uphold the constitutional rights of citizens by ensuring transparent and inclusive decision-making processes.
  - Provide opportunities for public participation and access to information, allowing communities to engage meaningfully in project planning and implementation.
- Sustainable Resource Management
  - Utilize natural resources in a manner that ensures their sustainability, preventing over-exploitation and degradation.
  - Adopt practices that promote the efficient use of resources, reducing waste and minimizing environmental impacts.
- Establishing Accountability and Enforcement Mechanisms
  - Establish mechanisms for monitoring and enforcing compliance with environmental laws and regulations.
  - Ensure that project developers are held accountable for any environmental harm caused and that appropriate remedial actions are taken.

The Constitution of the Republic of Malawi (1994) provides a foundational legal framework that mandates the integration of environmental protection and sustainable development into all aspects of national development. Generation, transmission, and distribution projects must comply with constitutional provisions, uphold the rights and principles enshrined in the Constitution, and integrate environmental considerations into their planning and implementation processes.

6.3.2 Environmental Management Act (2017)

Environmental Management Act (2017) is a comprehensive legal framework designed to ensure environmental protection and sustainable management in Malawi. The Act mandates the conduct of ESIAs for all significant development projects to evaluate and mitigate potential environmental and social impacts. It establishes clear requirements and procedures for environmental protection, reflecting Malawi's commitment to sustainable development and environmental stewardship. The Environmental Management Act (2017) outlines several key elements essential for effective environmental protection and management:

- Environmental and Social Impact Assessments
  - Mandates the conduct of ESIAs for all significant development projects to assess potential environmental and social impacts.
  - Requires public participation in the ESIA process, ensuring that stakeholders' views and concerns are considered.
- Environmental Standards and Regulations
  - Establishes standards and regulations for pollution control, waste management, and the sustainable use of natural resources.
  - Provides guidelines for the management of hazardous substances and the protection of biodiversity.
- Institutional Framework
  - Establishes the Malawi Environment Protection Authority (MEPA) as the primary agency responsible for overseeing environmental management and enforcement.
  - Creates mechanisms for coordination and collaboration among various stakeholders, including government agencies, private sector entities, and local communities.
- Compliance and Enforcement
  - Sets out penalties and sanctions for non-compliance with environmental regulations.
  - Provides for regular environmental audits and inspections to ensure adherence to environmental standards.
- Public Participation and Access to Information
  - Ensures public access to environmental information and promotes transparency in environmental decision-making processes.
  - Encourages community involvement in environmental management and conservation initiatives.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Management Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Conducting Comprehensive ESIAs
  - Projects must conduct thorough ESIAs to identify and assess potential environmental and social impacts.
  - The ESIAs should include detailed mitigation measures to address identified impacts and ensure environmental sustainability.
- Compliance with Environmental Standards and Regulations
  - Projects must comply with the environmental standards and regulations established under the Act.
  - Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.
- Engagement with the MEPA
  - Engage with the MEPA throughout the project lifecycle to ensure compliance with regulatory requirements and obtain necessary approvals.
  - Collaborate with the MEPA to address any environmental concerns and implement best practices in environmental management.
- Public Participation and Transparency
  - Ensure active public participation in the ESIA process, allowing stakeholders to provide input and express concerns.
  - Maintain transparency by providing access to environmental information and keeping stakeholders informed about project developments and environmental management efforts.
- Mitigation of Environmental and Social Impacts
  - Develop and implement effective mitigation measures to minimize adverse environmental and social impacts.
  - Monitor the effectiveness of mitigation measures and adjust them as necessary to achieve desired outcomes.
- Institutional Coordination and Collaboration
  - Coordinate with relevant government agencies, private sector entities, and local communities to ensure a holistic approach to environmental management.
  - Leverage the expertise and resources of various stakeholders to enhance the effectiveness of environmental protection efforts.

The Environmental Management Act (2017) provides a robust legal framework for ensuring environmental protection and sustainable management in Malawi. Generation, transmission, and distribution projects must conduct comprehensive ESIAs, comply with environmental standards and regulations, and engage with the MEPA to obtain necessary approvals.

6.3.3 Energy Regulation Act (2004)

Energy Regulation Act (2004) is a pivotal framework that establishes the Malawi Energy Regulatory Authority (MERA), the key regulatory body responsible for overseeing the energy sector in Malawi. The Act provides a comprehensive structure for licensing, setting tariffs, and ensuring compliance with energy laws, promoting the efficient use and development of energy resources. It aims to create a stable and transparent regulatory environment conducive to investment and sustainable energy development. The Energy Regulation Act (2004) outlines several key elements essential for effective energy sector regulation and management:

- Establishment of MERA
  - MERA is established as the principal regulatory body for the energy sector, with the authority to issue licenses, set tariffs, and enforce compliance with energy laws.
  - MERA's mandate includes the regulation of electricity, gas, and petroleum sectors to ensure efficiency, reliability, and sustainability.
- Licensing and Tariff Setting
  - MERA is responsible for issuing licenses for the generation, transmission, distribution, and supply of electricity, as well as other energy-related activities.
  - The authority sets and reviews tariffs to ensure that they are fair, reasonable, and reflective of the cost-of-service delivery.
- Regulatory Compliance and Enforcement
  - MERA ensures that all licensed entities comply with the relevant energy laws, regulations, and standards.
  - The authority has the power to impose penalties and take corrective actions against entities that violate regulatory requirements.
- Promotion of Efficient Energy Use
  - The Act promotes the efficient use and development of energy resources, encouraging the adoption of energy-efficient technologies and practices.
  - MERA supports initiatives aimed at enhancing energy conservation and reducing wastage.
- Consumer Protection and Public Involvement
  - The Act includes provisions to protect consumer rights and ensure that consumers have access to reliable and affordable energy services.
  - MERA facilitates public involvement in the regulatory process, ensuring transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Energy Regulation Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Necessary Licenses
  - All energy projects must obtain the necessary licenses from MERA before commencing operations. This includes licenses for generation, transmission, distribution, and supply activities.
  - The licensing process involves submitting detailed project proposals and compliance with regulatory requirements set by MERA.
- Compliance with MERA's Regulations
  - Projects must adhere to all regulations, standards, and guidelines established by MERA. This includes compliance with technical, safety, and environmental standards.
  - Regular audits and inspections may be conducted by MERA to ensure ongoing compliance and identify areas for improvement.

- Tariff Setting and Financial Viability
  - Projects must work with MERA to set appropriate tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.
  - Financial viability and sustainability of the projects are essential, as tariffs must be fair and reflective of operational costs.
- Promotion of Efficient Energy Use
  - Incorporate energy-efficient technologies and practices in project design and operation to enhance overall efficiency and reduce energy consumption.
  - Support initiatives and programs that promote energy conservation and the efficient use of resources.
- Consumer Protection and Public Engagement
  - Ensure that project operations align with consumer protection regulations, providing reliable and affordable energy services.
  - Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.
- Enforcement and Penalties
  - Be aware of the enforcement mechanisms and penalties for non-compliance with MERA's regulations. This includes potential fines, suspension of licenses, and other corrective actions.
  - Maintain thorough documentation and records to demonstrate compliance and facilitate regulatory oversight.

The Energy Regulation Act (2004) establishes a robust regulatory framework for the energy sector in Malawi, emphasizing the importance of licensing, tariff setting, compliance, and efficient energy use. Generation, transmission, and distribution projects must obtain the necessary licenses from MERA, comply with all regulatory requirements, and promote energy efficiency and consumer protection.

6.3.4 Electricity Act (2004) and Electricity Amendment Act (2016)

Electricity Act (2004) and the Electricity Amendment Act (2016) are key legislative frameworks that regulate the generation, transmission, and distribution of electricity in Malawi. These acts aim to ensure the efficient and reliable supply of electricity while promoting competition and enhancing the overall efficiency of the energy market. The amendments introduced in 2016 are particularly significant as they allow for multiple licenses beyond the previously sole holder, the Electricity Supply Corporation of Malawi (ESCOM), thereby fostering a more competitive environment. The Electricity Act (2004) and the Electricity Amendment Act (2016) outline several key elements essential for the regulation and management of the electricity sector:

- Regulation of Electricity Generation, Transmission, and Distribution
  - The Acts provide a comprehensive legal framework for regulating the generation, transmission, and distribution of electricity.
  - They establish standards and procedures for the development, operation, and maintenance of electrical infrastructure.

- Licensing and Competition
  - The original act centralized licensing with ESCOM as the sole license holder. The 2016 amendment, however, introduced provisions for multiple licenses, allowing other entities to enter the electricity market.
  - This shift aims to encourage competition, improve service delivery, and provide more choices for consumers.
- Standards and Compliance
  - The Acts set technical, safety, and environmental standards for all electricity-related activities.
  - Compliance with these standards is mandatory for obtaining and maintaining licenses.
- Tariff Regulation
  - The Acts empower regulatory authorities to set and review tariffs to ensure they are fair, reasonable, and reflective of the cost of electricity supply.
  - Tariff regulation aims to balance the interests of consumers and service providers, ensuring affordability and financial sustainability.
- Consumer Protection and Public Involvement
  - Provisions are included to protect the rights of electricity consumers and ensure they have access to reliable and affordable electricity services.
  - The Acts encourage public participation in the regulatory process, enhancing transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Electricity Act (2004) and the Electricity Amendment Act (2016) have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Application for Multiple Licenses
  - Project developers can apply for multiple licenses for generation, transmission, and distribution activities. This facilitates more integrated and efficient operations.
  - The ability to hold multiple licenses encourages vertical integration, allowing developers to streamline processes and reduce operational costs.
- Enhanced Competition and Market Efficiency
  - The introduction of multiple licenses fosters competition in the electricity market. This can lead to improved service delivery, better pricing, and increased innovation.
  - Developers must be prepared to operate in a competitive environment, focusing on efficiency, reliability, and customer satisfaction.
- Compliance with Standards and Regulations
  - Projects must comply with all technical, safety, and environmental standards set forth in the Acts. This includes adherence to construction, operation, and maintenance guidelines.
  - Regular audits and inspections by regulatory authorities ensure ongoing compliance and identify areas for improvement.

- Tariff Setting and Financial Sustainability
  - Developers must work with regulatory authorities to set tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.
  - Financial planning should consider the regulatory framework for tariffs to ensure the long-term sustainability of projects.
- Consumer Protection and Public Engagement
  - Projects must align with consumer protection regulations, ensuring reliable and affordable electricity services.
  - Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.
- Promoting Competition and Innovation
  - The Acts encourage developers to adopt innovative technologies and practices to enhance service delivery and efficiency.
  - Competitive dynamics in the market can drive continuous improvement and adoption of best practices.

The Electricity Act (2004) and the Electricity Amendment Act (2016) establish a regulatory framework for the electricity sector in Malawi, emphasizing the importance of licensing, competition, standards compliance, and consumer protection. Generation, transmission, and distribution projects must navigate this regulatory landscape by applying for the necessary licenses, adhering to standards, and embracing competition.

6.3.5 Rural Electrification Act (2004)

Rural Electrification Act (2004) is a legislative framework designed to support the development of energy infrastructure in rural areas of Malawi. The Act aims to increase electrification rates and support socio-economic development by ensuring that rural communities have access to efficient, sustainable, and affordable energy. It establishes the necessary structures, funding mechanisms, and regulatory provisions to promote rural electrification initiatives. The Rural Electrification Act (2004) outlines several key elements essential for promoting rural electrification:

- Establishment of the Rural Electrification Management Committee
  - A Rural Electrification Management Committee is established to oversee the planning, implementation, and management of rural electrification projects.
  - The Committee is responsible for developing and updating a rural electrification master plan, setting selection criteria for projects, and ensuring the efficient and effective implementation of rural electrification programs.
- Creation of the Malawi Rural Electrification Fund
  - The Act establishes the Malawi Rural Electrification Fund, which finances the capital costs of rural electrification projects, operational and maintenance costs, and other related expenses.
  - The Fund is sourced from government appropriations, levies on energy sales, grants, donations, and other financial contributions.

- Licensing and Regulation
  - Rural electrification activities, including grid extension and off-grid electrification, must be licensed by the MERA.
  - The Act sets forth regulations for safety, tariffs, and concession agreements, ensuring that rural electrification projects meet established standards and provide reliable services.
- Promotion and Support of Rural Electrification
  - The Act mandates the promotion of rural electrification through public awareness campaigns, market research, and the provision of technical, commercial, and institutional advice.
  - It encourages the use of renewable energy resources and technologies, such as solar home systems and micro-hydropower stations, to enhance rural energy access.
- Monitoring and Reporting
  - The Committee is tasked with monitoring the implementation and operation of rural electrification projects to ensure compliance with the Act and related regulations.
  - Concessionaires are required to submit regular reports on the progress and performance of their projects, including annual plans, progress updates, and post-completion evaluations.

Implications for Generation, Transmission, and Distribution Projects

The Rural Electrification Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Access to Incentives and Support
  - Projects targeting rural areas can benefit from the incentives and support provided under the Act, including funding from the Malawi Rural Electrification Fund.
  - Developers can leverage these resources to reduce capital costs, improve project viability, and ensure sustainable operations.
- Integration of Rural Electrification in Project Planning
  - Developers should consider rural electrification as an integral part of their project planning, aiming to extend energy access to underserved rural communities.
  - Incorporating off-grid and mini-grid solutions can enhance energy access in remote areas where grid extension is not feasible.
- Compliance with Licensing and Regulatory Requirements
  - All rural electrification activities must obtain the necessary licenses from MERA and comply with the regulatory provisions set forth in the Act.
  - Ensuring adherence to safety standards, tariff regulations, and concession agreements is crucial for project approval and operation.
- Promotion of Renewable Energy Technologies
  - Projects should promote the use of renewable energy technologies, such as solar home systems and micro-hydropower stations, to support sustainable rural electrification.
  - Emphasizing renewable energy can help reduce reliance on traditional biomass and fossil fuels, contributing to environmental sustainability.

- Engagement with Local Communities and Stakeholders
  - Active engagement with local communities and stakeholders is essential for the successful implementation of rural electrification projects.
  - Developers should involve communities in project planning and implementation, ensuring their needs and concerns are addressed.

The Rural Electrification Act (2004) provides a comprehensive framework for promoting rural electrification and supporting socio-economic development in Malawi. Generation, transmission, and distribution projects must leverage the incentives and support provided under the Act, integrate rural electrification into their planning, and comply with licensing and regulatory requirements.

6.3.6 Forestry Act Amendment (2019)

Forestry Act Amendment (2019) is a critical legislative update that introduces stricter penalties for illegal activities, enhances regulation of charcoal production, and increases transparency and accountability in the forestry sector. This amendment aims to address the significant deforestation and forest degradation challenges in Malawi, driven by the demand for natural resources such as charcoal and firewood. The Act is designed to promote sustainable forest management and conservation efforts, ensuring the protection of forest resources for future generations. The Forestry Act Amendment (2019) outlines several key revisions and provisions essential for effective forestry management and conservation:

- Stricter Penalties for Illegal Activities
  - The amendment introduces harsher penalties for deforestation, encroachment, illegal logging, and other unlawful activities within forest reserves and protected areas.
  - Penalties include significant fines and long-term imprisonment, reflecting the seriousness of forest crimes.
- Enhanced Regulation of Charcoal Production
  - Charcoal is now classified as a forest product, and its production, distribution, sale, possession, import, and export are regulated.
  - Permits for charcoal production can only be granted by the Department of Forestry and must be accompanied by an approved reforestation or forest management plan.
- Increased Transparency and Accountability
  - The Department of Forestry is mandated to improve information systems, providing the public with easy access to forestry-related data.
  - The amendment promotes greater stakeholder participation in forestry-related decision-making processes, ensuring inclusive and transparent governance.
- Strengthened Law Enforcement
  - Forestry officers are empowered to carry firearms in the line of duty to enforce forestry laws effectively.
  - The amendment increases penalties for a range of offences, including bribery, obstruction of justice, falsification of documents, and illegal trade in forest products.

- Promotion of Sustainable Forest Management
  - The amendment supports initiatives like the "Modern Cooking for Healthy Forests" program, which aims to promote sustainable cooking technologies and reduce reliance on charcoal and firewood.
  - It encourages public-private partnerships to enhance sustainable forest management and conservation efforts.

Implications for Generation, Transmission, and Distribution Projects

The Forestry Act Amendment (2019) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources
  - Projects involving land use changes must assess their impact on forest resources and comply with reforestation and sustainable management requirements.
  - ESIAs should include detailed evaluations of potential impacts on forests and outline mitigation strategies.
- Compliance with Charcoal Production Regulations
  - Projects must adhere to regulations regarding charcoal production, ensuring that any activities related to charcoal are properly licensed and managed.
  - Failure to comply with these regulations can result in severe legal penalties, including fines and imprisonment.
- Adherence to Stricter Penalties and Law Enforcement
  - Developers must be aware of the stricter penalties for illegal activities outlined in the amendment and ensure compliance with all forestry laws.
  - Regular audits and monitoring should be conducted to prevent illegal logging, encroachment, and other unlawful activities within project areas.
- Promotion of Sustainable Practices:
  - Projects should incorporate sustainable forest management practices to minimize environmental impacts and support conservation efforts.
  - Engaging in reforestation initiatives and promoting the use of alternative energy sources can help mitigate the effects of deforestation and forest degradation.

The Forestry Act Amendment (2019) provides a robust framework for addressing deforestation and promoting sustainable forest management in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and charcoal production regulations, and adhere to the stricter penalties and enforcement measures outlined in the amendment.

6.3.7 National Parks and Wildlife Act (2017)

National Parks and Wildlife Act (2017) provides the legislative framework for the protection and management of national parks and wildlife in Malawi. The Act includes provisions for the conservation of biodiversity, the regulation of activities within protected areas, and the sustainable use of wildlife resources. It emphasizes the need to balance development with environmental conservation, ensuring that natural habitats and wildlife populations are preserved for future generations. The National Parks and Wildlife Act (2017) outlines several key elements essential for the protection and management of national parks and wildlife:

- Protection of National Parks and Wildlife Reserves
  - Establishes and manages national parks, wildlife reserves, and other protected areas to conserve biodiversity and natural habitats.
  - Prohibits activities that may harm wildlife or degrade habitats within these protected areas, including hunting, logging, and mining.
- Conservation of Biodiversity
  - Promotes the conservation of biodiversity through the protection of endangered and threatened species.
  - Implements measures to restore and maintain ecological integrity and the natural processes within ecosystems.
- Regulation of Activities within Protected Areas
  - Regulates activities such as tourism, research, and resource extraction within national parks and wildlife reserves to ensure they do not negatively impact the environment.
  - Requires permits for activities that may affect wildlife or their habitats, ensuring that such activities are conducted sustainably.
- Community Involvement and Benefit Sharing
  - Encourages the involvement of local communities in the management and conservation of wildlife and protected areas.
  - Promotes benefit-sharing arrangements to ensure that communities derive economic benefits from conservation activities, such as eco-tourism and sustainable resource use.
- Enforcement and Compliance
  - Strengthens law enforcement capabilities to combat wildlife crime, including poaching and illegal trade in wildlife products.
  - Imposes penalties and sanctions for violations of the Act, including fines and imprisonment for illegal activities.
- Public Awareness and Education
  - Promotes public awareness and education on the importance of wildlife conservation and the sustainable use of natural resources.
  - Supports initiatives to educate communities and stakeholders about conservation laws and the benefits of protecting biodiversity.

Implications for Generation, Transmission, and Distribution Projects

The National Parks and Wildlife Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Conservation and Management Requirements
  - Projects located near or within protected areas must comply with conservation and management requirements outlined in the Act.
  - Conduct ESIAs to identify potential impacts on national parks, wildlife reserves, and biodiversity, and develop appropriate mitigation measures.
- Minimizing Impact on Wildlife and Biodiversity
  - Ensure that project activities have minimal impact on wildlife and biodiversity by adopting best practices for environmental management.

- Implement measures to protect endangered and threatened species and their habitats, avoiding any activities that could cause harm.

- Obtaining Necessary Permits and Approvals
  - Obtain the necessary permits and approvals from relevant authorities for any activities within or near protected areas.
  - Engage with the Department of National Parks and Wildlife (DNPW) to ensure compliance with regulatory requirements and secure project approvals.
- Enhancing Law Enforcement and Compliance
  - Support law enforcement efforts to combat wildlife crime by collaborating with authorities and providing resources for monitoring and enforcement.
  - Ensure that project personnel are aware of and comply with all legal requirements related to wildlife protection and conservation.

The National Parks and Wildlife Act (2017) provides a comprehensive framework for the protection and management of national parks and wildlife in Malawi. Generation, transmission, and distribution projects must comply with conservation and management requirements, minimize their impact on wildlife and biodiversity, and obtain necessary permits and approvals.

6.3.8 Water Resources Act (2013)

Water Resources Act (2013) provides a comprehensive legal framework for the management, conservation, use, and control of water resources in Malawi. The Act aims to promote the sustainable use of water resources, ensure equitable access, and protect the environment from pollution and over-exploitation. It establishes regulatory mechanisms and institutional frameworks to support the effective management of water resources, addressing the needs of various stakeholders, including domestic, agricultural, industrial, and environmental users. The Water Resources Act (2013) outlines several key elements essential for effective water resource management:

- National Water Resources Authority (NWRA):
  - Establishes the NWRA as the primary agency responsible for regulating and managing water resources in Malawi.
  - The NWRA is tasked with developing principles, guidelines, and procedures for the allocation and sustainable use of water resources.
- Water Abstraction and Use:
  - Defines the processes for obtaining licenses for water abstraction and use, ensuring that all water use is regulated and sustainable.
  - Requires the reservation of water resources to meet domestic needs and protect aquatic ecosystems.
- Groundwater Conservation:
  - Provides regulations for the protection and sustainable use of groundwater resources, including the issuance of permits for borehole drilling and groundwater extraction.
  - Establishes conservation areas and guidelines for preventing groundwater pollution and over-exploitation.

- Catchment Management:
  - Establishes catchment management committees to oversee the sustainable management of water resources within designated catchment areas.
  - Requires the development of catchment management strategies that align with the National Water Resources Master Plan.
- Control and Protection of Water Resources:
  - Implements measures to prevent and control water pollution, including the regulation of effluent discharge and the prohibition of harmful substances.
  - Promotes the safe storage, treatment, and disposal of waste to protect water quality and public health.
- Dams and Flood Management:
  - Establishes guidelines for the construction, operation, and safety of dams, including the registration of dams with safety risks.
  - Provides measures for flood mitigation and control, ensuring the protection of communities and infrastructure.
- Water Charges and Financial Provisions:
  - Introduces charges for water use and services, with the revenue used to support the management and conservation of water resources.
  - Establishes a Water Resources Trust Fund to finance water management projects and initiatives.
- Public Participation and Consultation:
  - Ensures public participation in water resource management through consultations, stakeholder engagement, and access to information.
  - Promotes transparency and accountability in decision-making processes related to water resources.

Implications for Generation, Transmission, and Distribution Projects

The Water Resources Act (2013) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Water Abstraction Licenses:
  - Projects must obtain licenses from the NWRA for the abstraction and use of water resources. This includes providing detailed information on the intended use, location, volume, and impact on existing water users and the environment.
  - Compliance with licensing requirements ensures that water use is sustainable and aligned with national water management goals.
- Compliance with Groundwater Regulations:
  - Projects involving groundwater extraction must comply with the regulations for borehole drilling and groundwater use. This includes obtaining permits and adhering to conservation guidelines.
  - Proper management of groundwater resources is essential to prevent over-exploitation and ensure long-term availability.
- Integration of Catchment Management Strategies:
  - Projects located within designated catchment areas must align with catchment management strategies and contribute to the sustainable management of water resources.

- Engaging with catchment management committees and incorporating local water management plans into project design can enhance sustainability and community support.
- Environmental Protection and Pollution Control:
  - Projects must implement measures to prevent water pollution and ensure the safe disposal of effluents and waste. This includes adhering to effluent discharge permits and maintaining high standards of water quality.
  - Protecting water resources from pollution is critical for maintaining ecosystem health and public safety.

The Water Resources Act (2013) provides a robust framework for the sustainable management and protection of water resources in Malawi. Generation, transmission, and distribution projects must comply with the Act's licensing, conservation, and pollution control requirements to ensure sustainable and responsible use of water resources. Integrating the Act's provisions into project planning and implementation, developers can contribute to the long-term sustainability of Malawi's water resources, support environmental conservation, and enhance community well-being.

6.3.9 Independent Power Producer (IPP) Framework

Independent Power Producer (IPP) Framework provides a structured approach for private sector participation in Malawi's power sector. It outlines the roles, responsibilities, and processes necessary for project evaluation, approval, and procurement. The framework is designed to attract private investment, enhance competition, and ensure the efficient and reliable supply of electricity in Malawi. The IPP Framework aims to streamline the development of power projects and support the country's energy goals. The IPP Framework outlines several key elements essential for the successful involvement of independent power producers in Malawi's energy sector:

- Roles and Responsibilities
  - Defines the roles and responsibilities of key stakeholders, including the government, regulatory authorities, and private sector participants.
  - Clarifies the obligations of IPPs regarding project development, financing, construction, operation, and maintenance.
- Project Evaluation and Approval
  - Establishes criteria and procedures for the evaluation and approval of power projects proposed by IPPs.
  - Ensures that projects meet technical, financial, and environmental standards before receiving approval.
- Procurement Processes
  - Details the procurement processes for selecting IPPs, including competitive bidding and direct negotiations.
  - Aims to ensure transparency, fairness, and competitiveness in the selection of power projects.
- Regulatory and Licensing Requirements
  - Outlines the regulatory and licensing requirements that IPPs must comply with to operate in Malawi.
  - Includes provisions for obtaining generation licenses, environmental permits, and other necessary approvals.

- Financial and Contractual Arrangements
  - Provides guidelines for financial and contractual arrangements, including power purchase agreements (PPAs), financing structures, and risk mitigation measures.
  - Ensures that contracts are fair, balanced, and provide adequate protection for all parties involved.
- Monitoring and Compliance
  - Establishes mechanisms for monitoring and ensuring compliance with the terms and conditions of licenses and contracts.
  - Includes provisions for regular reporting, audits, and performance reviews.

Implications for Generation, Transmission, and Distribution Projects

The IPP Framework has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Facilitating Private Investment
  - Clear guidelines and streamlined processes facilitate private investment in power projects, attracting local and international investors.
  - By providing a predictable and transparent regulatory environment, the framework reduces uncertainties and encourages long-term investment.
- Following the IPP Framework for Project Approvals
  - Developers must follow the IPP Framework's procedures for project evaluation and approval to ensure compliance with regulatory standards.
  - Adhering to the framework increases the likelihood of obtaining necessary approvals and licenses in a timely manner.
- Ensuring Competitive and Transparent Procurement
  - Developers must participate in competitive bidding processes or direct negotiations as outlined in the IPP Framework.
  - Ensuring transparency and fairness in procurement processes enhances the credibility and integrity of project selection.
- Complying with Regulatory and Licensing Requirements
  - Projects must comply with all regulatory and licensing requirements, including obtaining generation licenses, environmental permits, and other approvals.
  - Regular audits and monitoring are essential to maintain compliance and address any regulatory issues promptly.
- Establishing Financial and Contractual Arrangements
  - Developers must negotiate and finalize power purchase agreements (PPAs) and other financial contracts in accordance with the IPP Framework's guidelines.
  - Adequate risk mitigation measures should be incorporated to protect the interests of all parties involved.
- Monitoring and Ensuring Compliance
  - Implement mechanisms for ongoing monitoring and compliance with the terms and conditions of licenses and contracts.
  - Regular reporting and performance reviews help identify and address any issues that may arise during project implementation and operation.

The IPP Framework provides a comprehensive structure for private sector participation in Malawi's power sector, outlining clear guidelines for project evaluation, approval, and procurement. Generation, transmission, and distribution projects must follow the IPP Framework to facilitate private investment, ensure compliance with regulatory requirements, and promote transparency and competitiveness in the power market.

6.4 Guidelines and Regulations.

6.4.1 EIA Guidelines

EIA Guidelines provide detailed procedures for conducting ESIAs in Malawi. These guidelines are essential tools for project developers to ensure that environmental and social impacts are thoroughly assessed and managed throughout the project lifecycle. The guidelines cover key stages such as project screening, scoping, baseline data collection, impact assessment, and the development of Environmental and Social Management Plans (ESMPs). The EIA Guidelines outline several key stages and elements essential for the effective assessment and management of environmental and social impacts:

- Project Screening
  - The screening process determines whether a project requires a full ESIA based on its type, size, and potential environmental impact.
  - Projects that are likely to have significant environmental impacts are subjected to a detailed ESIA.
- Scoping
  - Scoping identifies the key environmental and social issues that need to be addressed in the ESIA.
  - It involves consultations with stakeholders to gather input on potential impacts and concerns.
- Baseline Data Collection
  - Baseline data collection involves gathering information on the existing environmental and social conditions of the project area.
  - This data serves as a reference point for assessing the potential impacts of the project.
- Impact Assessment
  - The impact assessment evaluates the potential environmental and social impacts of the project, both positive and negative.
  - It considers the magnitude, extent, duration, and reversibility of the impacts.
- Mitigation Measures
  - Mitigation measures are developed to avoid, reduce, or offset significant adverse impacts.
  - These measures are integrated into the project design and implementation plan.
- Environmental and Social Management Plans
  - ESMPs outline the specific actions and responsibilities for managing and monitoring environmental and social impacts throughout the project lifecycle.
  - They include measures for impact mitigation, monitoring, and reporting.

- Public Consultation and Participation
  - Public consultation and participation are critical components of the ESIA process, ensuring that stakeholders' views and concerns are considered.
  - The guidelines provide methods for effective public engagement and information dissemination.
- Monitoring and Reporting:
  - Ongoing monitoring and reporting are required to ensure that mitigation measures are effectively implemented and that environmental and social impacts are managed.
  - Regular audits and inspections are conducted to assess compliance with ESMPs and regulatory requirements.

Implications for Generation, Transmission, and Distribution Projects

The EIA Guidelines have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Thorough Assessment and Management of Impacts:
  - Developers must follow these guidelines to ensure a thorough assessment and management of environmental and social impacts.
  - Conducting comprehensive ESIAs helps identify potential issues early in the project lifecycle, allowing for effective mitigation and management.
- Regulatory Compliance:
  - Compliance with EIA guidelines is critical for obtaining regulatory approval for projects.
  - Proper ESIA documentation, including baseline studies, impact assessments, and ESMPs, is essential for demonstrating compliance with environmental regulations.
- Stakeholder Engagement:
  - Effective stakeholder engagement is crucial for the successful implementation of projects.
  - Developers should actively involve stakeholders in the ESIA process, addressing their concerns and incorporating their input into project planning and decision-making.
- Sustainability and Long-term Success:
  - Ensuring environmental and social sustainability is key to the long-term success of projects.
  - Implementing robust ESMPs and ongoing monitoring helps mitigate adverse impacts and promotes positive outcomes for communities and the environment.
- Transparency and Accountability:
  - The ESIA process promotes transparency and accountability by involving stakeholders and providing access to information.
  - Regular reporting and public disclosure of ESIA findings and management measures enhance trust and credibility with stakeholders.
- Integration into Project Planning:
  - Integrating ESIA findings into project planning and design helps optimize project outcomes and minimize negative impacts.

- Developers should use ESIA results to inform decision-making and improve project sustainability.

The EIA Guidelines provide a comprehensive framework for assessing and managing the environmental and social impacts of generation, transmission, and distribution projects in Malawi. Developers will ensure thorough impact assessment, regulatory compliance, effective stakeholder engagement, and long-term project sustainability. Integrating ESIA findings into project planning and implementation helps optimize project outcomes and contributes to the overall well-being of communities and the environment.

6.5 Références

GoM, (1995). Constitution of the Republic Malawi, Government of Malawi (1994)

GoM, (1997). Guidelines for Environmental Impact Assessment (EIA) in Malawi, Government of Malawi (1997)

GoM, (2004). Electricity Act, Government of Malawi (2004)

GoM, (2004). Energy Regulation Act, Government of Malawi (2004)

GoM, (2004). National Environmental Policy, Government of Malawi (2004)

GoM, (2005). National Water Policy, Government of Malawi. Lilongwe, 2005.

GoM, (2008). Environment Management (Chemicals and Toxic Substances Management) Regulations, Government of Malawi. Lilongwe, 2008.

GoM, (2013). Water Resources Act, Government of Malawi (2013)

GoM, (2016). Electricity Amendment Act, Government of Malawi (2016)

GoM, (2016). National Climate Change Management Policy, Government of Malawi (2016)

GoM, (2016). National Forestry Policy, Government of Malawi. Lilongwe, 2016.

GoM, (2016). Physical Planning (Amendment) Act, Government of Malawi. Lilongwe, 2022.

GoM, (2017). Environmental Management Act, Government of Malawi (2017)

GoM, (2017). National Parks and Wildlife Act, Government of Malawi (2017)

GoM, (2018). National Energy Policy, Government of Malawi (2018)

GoM, (2019). Forestry Act Amendment, Government of Malawi (2019)

GoM, (2021). The Malawi 2063 First 10 Year Implementation Plan (2021 – 2030, Government of Malawi. Lilongwe, 2021.

7 Synthesis of the distribution development plan

Based on the above analysis, we have elaborated a list of all the reinforcements in lines, substations, transformers, as well as the schedule of work and a high level budget estimation.

7.1 Equipment plan

7.1.1 Primary stations

In the Transmission Master Plan, two main options have been studied for the development of the network. The analysis have shown that developing the network in 132 kV and not in 66 kV is the most economical solution and will also allow load increase after 2042.

Note that the plans and the cost linked to the development of the network in 132 kV and of the 400/132 kV substations are available in the Transmission Master Plan.

The next needs in terms of investments can be identified in the context of the Distribution Master Plan:

- Existing 66/11 kV and 66/33 kV stations and transformers upgraded to 132/11 kV and 132/33 kV. In this report, only the cost linked to the transformations from HV to MV is considered.
- Upgrade of 33/11 kV secondary stations to 132/11kV or 132/33/11 primary stations.
- New 132/11 kV and 132/33/11 kV substations (Phalombe, Namitete and Mponela

Due to the increase of the load in the peripheries of the main cities, or due to network extension in rural areas, several existing secondary stations will be upgraded to primary stations, 132/11kV, as summarized in Table . It can be seen that it is between 2033 and 2042 that the main effort of upgrade will be done.

Table 3.7.1: Evolution of the number of existing secondary stations upgraded to primary stations

	2027	2032	2042
Number of Secondary stations upgraded to primary stations (132/11kV)	0	4	16

New 132/11 kV and 132/33kV substations are also foreseen across the country, as summarized in the next table.

Table 3.7.2: Evolution of the number of new primary stations

	2027	2032	2042
New primary stations - cumulated	0	4	11

Table 31 summarises the evolution of the tolal number of primary stations in Malawi supplying disribution networks. It can be observed that from 38 existing primary stations, 26 additional ones are foreseen to be developped between today and 2042.

Table 3.7.3: Evolution of the number of primary stations

	2023	2027	2032	2042
Existing 132kV/MV	38	31	24	7
Existing 66kV primary stations upraded132 kV	0	7	14	31
New primary stations - cumulated	0	0	4	11
Number of Secondary stations upgraded to primary stations	0	0	3	15
Total - Evolution of the number of primary stations	38	38	45	64

The new primary stations will be equipped with transformers between HV and 11kV/33kV, as detailed on the next table.

Table 3.7.4: HV/MV Transformers to be installed in the new primary stations

Station	2027-2032	2033-2042	Total cumulated
	132/33kV 30 MVA	132/33kV 30 MVA	132/33kV 30 MVA
Phalombe	0	2	2
Mponela	2	1	3
Namitete	0	2	2
Euthini	0	1	1
Chitipa	1	0	1
Luwelezi	0	1	1
Bangula	1	1	2
Makanjira	0	1	1
Kia	2	0	2
Matindi	2	0	2
Chatoloma	1	0	1

New 132/11kV, 132/33kV and 132/33/11kV transformers will be necessary to follow the load growth. In the intermediate period of upgrading the 66kV network to 132 kV, additional 66/33/11kV transformers will have to be installed.

Table 3.7.5: presents the needs in terms of additional transformers in secondary stations upgraded to primary stations at 2032 and 2042 horizon. All transformers are 132/33/11 kV at 20/25/30 MVA.

Station	Additional transformers 2024-2027	Additional transformers 2028-2032	Additional transformers 2033-2042
Area 48	/	/	2 x 132/11kV 30 MVA
Balaka	/	1 x 66/33/11 kV 5 MVA	1 x 132/33/11 kV 30 MVA
Barracks	/	/	1 x 132/33/11 kV 30 MVA
Blantyre West	/	/	/
Bunda/Tsabango	/	/	3 x 132/11kV 30 MVA
Bwengu	/	/	2 x 132/33kV 40 MVA
Changalume	2 x 66/33kV 20 MVA	/	2 x 132/33kV 40 MVA
Chichiri	/	/	3 x 132/33/11kV 50 MVA
Chigumula	2 x 66/33/11 kV 30 MVA	/	2 x 132/33/11kV 40 MVA
Chikangawa	/	/	2 x 132/33/11kV 40 MVA
Chingeni	/	/	2 x 132/33kV 30 MVA

Station	Additional transformers 2024-2027	Additional transformers 2028-2032	Additional transformers 2033-2042
Chintheche	/	/	2 x 132/33/11kV 40 MVA
Chinyama	/	2 x 132/33kV 40 MVA	1 x 132/33kV 40 MVA
Dedza	1 x 132/33kV 40 MVA	/	1 x 132/33kV 40 MVA
Fundis Cross	/	2 x 66/33kV 20 MVA	3 x 132/33kV 40 MVA
Golomoti	/	/	/
Kanengo	/	/	4 x 132/33kV 40 MVA
Kangoma	/	/	1 x 132/11kV 15 MVA
Kapichira	/	/	/
Karonga	1 x 66/33/11 kV 15 MVA	/	2 x 132/33/11kV 40 MVA
Kauma	/	/	1 x 132/11kV 15 MVA
Lilongwe A	/	/	3 x 132/33/11kV 30 MVA
Livingstonia	/	/	1 x 132/11kV 15 MVA
Liwonde	1 x 66/33 kV 15 MVA	1 x 66/33 kV 15 MVA	2 x 132/33kV 40 MVA
Luwinga	/	1 x 132/33/11kV 30 MVA	1 x 132/33/11kV 30 MVA
Mapanga	2 x 132/33kV 30 MVA	1 x 132/33kV 30 MVA	/
Mchinji Border	/	1 x 132/33/11kV 30 MVA	1 x 132/33/11kV 30 MVA
Mlambe	/	1 x 132/33/11kV 50 MVA	/
Mlangeni	/	2 x 132/33kV 15 MVA	/
Monkeybay	/	/	2 x 132/33kV 20 MVA
Nanjoka	1 x 132/33kV 40 MVA	1 x 132/33kV 40 MVA	1 x 132/33kV 40 MVA
New Dwangwa	/	/	/
Nkhotakota	/	/	2 x 132/33/11kV 30 MVA
Nkula b	2 x 132/33/11kV 30 MVA	/	/
Ntcheu	/	2 x 132/11kV 15 MVA	/
Telegraph Hill	1 x 132/33/11kV 30 MVA	/	1 x 132/33/11kV 30 MVA
Uliwa	/	/	1 x 132/33/11kV 15 MVA
Wovwe	/	/	3 x 132/11kV 15 MVA

Table 3.7.610: Needs in terms of additional 132/33/11 kV transformers in secondary stations upgraded to primary stations at 2032 horizon

Substation	2032	2042	Total
Chileka	2	1	3
Mangochi	2	0	2
Zomba	2	1	3

Table 3.7.7 11: Needs in terms of additional transformers in secondary stations upgraded to primary stations at 2042 horizon

	132/11kV 15 MVA	132/33/11 kV 15MVA	132/11kV 30 MVA	132/33/11kV 30 MVA
Area 47	0	0	2	0
Chirimba	0	0	2	0
Chitipi	0	0	0	2
City Centre	0	0	2	0
Kasungu	0	2	0	0
Limbe A	0	0	2	0
Limbe B	0	0	2	0
Michiru	2	0	0	0
Sonda	0	0	2	0
Thyolo A	0	0	2	0
Thyolo B	0	0	2	0
Thyolo C	2	0	0	0

7.1.2 Secondary stations

In the existing secondary stations, additional transformers are required due to the load increase. Most of them will need one extra transformer to supply the additional load.

Table 3.7.8 12: Needs in terms of additional transformers in the secondary stations

	2032		2042		Total cumulated	
Station name	33/11 kV 10/15 MVA	33/11 kV 20 MVA	33/11 kV 10/15 MVA	33/11 kV 20 MVA	33/11 kV 10/15 MVA	33/11 kV 20 MVA
Area 25	0	0	1	0	1	0
Blantyre Main	0	0	1	0	1	0
Customs	0	0	1	0	1	0
David Whitehead	0	0	1	0	1	0
Dwangwa	0	0	0	0	0	0
Kasinthula	0	0	0	0	0	0
Katoto	0	0	1	0	1	0
Kch	0	0	1	0	1	0
Kwacha	0	0	1	0	1	0
Maldeco	0	0	0	0	0	0
Mtunthama	0	0	0	0	0	0
Mvera	0	0	0	0	0	0
Mzuzu	0	0	1	0	1	0
Salima	0	0	1	0	1	0
Queens	1	0	0	0	1	0

A new secondary substation is foreseen in Senga-Bay before 2027. Two 33/11 transformers of 7.5 MW each will connect the new substation to Salima with a double 33 kV feeder. More information on the substation is provided in section 5.3.5.

Additional secondary substations will be needed as the load evolves. Their location and size depends on the exact location of future load centers. Notably, new industrial parcs quickly require a secondary substation to limit grid losses and increase the available capacity for enterprises and factories. The specific location and size of additional secondary substations has not been identified in absence of the required urban master plans. They should be identified when the exact location of new demand becomes clear or when new city districts are developed. Instead, the need for secondary substations is calculated at a high level in the investment plan by accounting for sufficient 33 kV equipment to supply the load.

7.1.3 MV network equipment plan

This section presents the needs in terms of 11kV and 33 kV network infrastructure. They are classified by type.

7.1.3.1 Network extension in main cities

An estimate of the network development needs has been done globally for the cities of Blantyre, Lilongwe, Mzuzu, Zomba. The needs in network investments can be found in the next tables by studied period. The second column presents the reinforcements with new cables, while the last column presents the upgrade of existing feeders.

Table 3.7.9 13: Estimate 11kV network development in Mzuzu city

	120 mm² UG - new (km)	120 mm² UG - upgrade (km)
2023-2027	40	22
2028-2032	30	27.5
2032-2042	40	60.5
Total	110	110

Table 3.7.1014: Estimate 11kV network development in Lilongwe city

	185 mm² UG - new (km)	185 mm² UG - upgrade (km)
2023-2027	70	76
2028-2032	80	95
2032-2042	530	209
Total	680	380

Table 3.7.11 15: Estimate 11kV network development in Blantyre city

	185 mm² UG - new (km)	185 mm² UG - upgrade (km)
2023-2027	90	94
2028-2032	130	117.5
2032-2042	290	258.5
Total	510	470

Table 3.7.12 16: Estimate 11kV network development in Mzuzu city

	120 mm² UG - new (km)	120 mm² UG - upgrade (km)
2023-2027	10	10
2028-2032	10	10
2032-2042	20	20
Total	40	40

7.1.3.2 Feeders Voltage upgrade (11 kV to 33 kV feeders)

It is foreseen to upgrade all the 11kV feeders of that list for 2027 as most of them do not respect the technical limits and none of them respect the planning standards. It is an investment priority!

Table 3.7.1317: 11kV feeders to be upgraded to 33 kV at 2027 horizon

feeder	substation	Total length of the feeder (km)	Cross section (mm²)
1LF BLANTYRE WEST	BLANTYRE WEST	32.8	150
1LF BUNDA	BUNDA	84.8	150
1LF CHIKANGAWA	CHIKANGAWA	41.1	150
1LF CHITIPI	CHITIPI	31.2	100
1LF NTCHEU	NTCHEU	62.9	100
1LF ULIWA	ULIWA	101.2	150
1LF ZOMBA	ZOMBA	128.9	150
2LF BUNDA	BUNDA	212.7	150
2LF CHILEKA	CHILEKA	32.6	150
2LF KARONGA	KARONGA	42.1	150
2LF KASUNGU	KASUNGU	48.7	100
2LF MLAMBE	MLAMBE	46.8	150
2LF NKHOTAKOTA	NKHOTAKOTA	142.2	150
2LF SALIMA	SALIMA	76.8	100
2LF ZOMBA	ZOMBA	33.7	150
3LF BALAKA	BALAKA	69.9	150
3LF CHIGUMULA	CHIGUMULA	20.5	150
3LF CHILEKA	CHILEKA	51.4	150
3LF CHITIPI	CHITIPI	42.6	150
3LF KASUNGU	KASUNGU	36.4	100
4LF CHILEKA	CHILEKA	76.2	150

feeder	substation	Total length of the feeder (km)	Cross section (mm²)
4LF ZOMBA	ZOMBA	147.2	150
5LF KANENGO	KANENGO	24.2	100
5LF KATOTO	KATOTO	46.4	150
8LF KANENGO	KANENGO	51.5	100

7.1.3.3 33kV backbones development in 33 kV

The 33kV network represents the backbone of the rural electrification and of the supply of secondary stations. Massive investments in the 33kV is required in order to remove ongoing weak points, to improve the reliability and to support the rural electrification. This is done by the installation of new feeders and by the upgrade of the backbone of 33kV voltage grid to OHL 150 mm².

Table 3.7.1418: 33kV MV– backbone network development

	2024-2027	2028-2032	2033-2042
OHL 150 mm² 33kV (km)	1123.7	1474.9	1667.9

7.1.3.4 Network extension in rural areas

On top of the 33kV backbones to supply rural areas (as identified hereabove), additional MV network (laterals) will connect the villages to the existing or future backbone. That information is an output of the IEP study dedicated to the rural electrification.

The next table presents the needs in 100 mm² OHL and 50 mm² OHL (for the laterals) for the different periods of the study. As the universal access is targeting 2030, it is considered that 100% of the laterals will be installed in 2030.

The next table presents the needs in 50 mm² OHL (for the laterals) for the different periods of the study. As the universal access is targeting 2030, it is considered that 100% of the laterals will be installed in 2030.

Table 3.7.1519: MV network extension in rural areas (IEP)

	Efforts in the time period	Needs in 50 mm² OHL (km)	Needs in 100 mm² OHL (km)
2023-2027	43%	8477	3427
2028-2030	57%	11238	4542

7.1.4 Voltage regulators

The simulations have shown that the first technical constraints in rural areas is not the loading of the conductors, but the low voltage. This is due to the length of the feeder which lead to a high voltage drop and high level of technical losses.

For that reason, voltage regulators will be installed on the longest feeders in order to step-up the voltage. 60 voltage regulators will be installed on the longest 33kV feeders.

7.1.5 Services Transformers equipment plan

For calculating the necessary quantity of transformers needed in the future, it's important to study the current transformation capacity and the location of existing transformers.

Currently, in Malawi, there are almost 7.4 thousands transformers, according to the information received in GIS, this number includes only direct and service transformers. Yet, in the coming years this number is expected to increase a big deal due to the installation of smaller transformers for rural electrification.

The actual peak, according to the information shared by ESCOM is around 470 MW. By 2042, the national peak power is expected to significantly increase, exerting pressure on the transformation network, which will need to be reinforced both in the rural and urban areas.

In order to strengthen transformer capacity, it is crucial to identify the types of transformers currently in use in the country and propose a similar rating for future installations. The table below illustrates the types of service transformers most commonly used in the present and the percentage (%) of the total power they would represent in 2042:

Table 3.7.16 20: Observed current transformers rates for service transformers

Transformers rating power (kVA)	Number of transformers per rating type in 2023	Ranking per type of transformer	% of the power they would represent in 2042
10	208	6	1.6%
15	22	12	6.9%
25	104	8	8.9%
50	1137	4	4.2%
100	2537	1	10.4%
200	1610	2	12.8%
315	1167	3	14.5%
400	79	10	2.5%
500	380	5	7.4%
800	108	7	3.3%
1000	96	9	6.0%

We have to distinguish between when a transformer requires reinforcement and when it needs resizing. Since the information gathered in GIS originates from various sources, we will also differentiate between different types of transformers, namely:

- Direct: transformers used by private consumers, such as factories
- Services: transformers set by ESCOM for public use
- MAREP & IEP: rural transformers for electrification

Those transformers considered as "direct" will not be taken into account in the following steps, as the private owner is responsible for their upgrade.

For those considered as "service", we will calculate the reinforced capacity needed for 2042. For example, if a transformer of 315 kVA is expected to have twice as much power in the coming years, it will be necessary to install a second one.

For MAREP and IEP transformers, we will size them as new, based on the input data of IEP and MAREP and considering the load increase up to 2042.

7.1.5.1 Size of transformers

To size a transformer, we will take the actual rating in (kVA) and compare it with the power peak in the area around it. To compare it with power units, we have considered:

- A coefficient of 0.95 as power factor
- A coefficient of 0.80 as transformers should not be charge over 80%
- A coefficient of 0.80 as localization factor (not all are charged equally everywhere)

This results in a total coefficient of 0.608 for comparing the current rating of each transformer with the estimated peak power within its operational zone.

Now, for each service transformer, we can compare the projected power for 2042 with its current rating to determine the additional power required. If the difference between these values is positive, indicating the need for reinforcement, we will select the minimum value from Table 3.7.16 20 to address this disparity. This process is repeated for all service transformers.

For a better understanding, here there is an example:

If an actual service transformer has a rating of 315 kVA, and the estimated power peak in 2042 in its operational zone is 362 kWp, this is divided by the total coefficient 0.608, getting 595 kVA. Then the transformer is the minimum one in the list that has a rating power above: 595 – 315 = 280. So the transformer chosen to reinforce the actual one, will be a second one of 315 kVA.

7.1.5.2 Results of the anaylisis

Below are the results obtained regarding the number of transformers required by 2042 to accommodate the significant growth in energy demand:

Table3.7.17 21: Number of new transformers needed for 2042 categorized by rating

Rating (kVA)	MAREP	Service	IEP	Total
15	28	319	4120	4467
25	139	42	20620	20801
50	327	972	12756	14055
100	465	2252	426	3143
200	726	2427	1	3154
315	514	715	0	1229
400	192	239	0	431
500	151	224	0	375
800	208	253	0	461
1000	55	62	0	117
Total	**2805**	**7505**	**37923**	**48233**

The results provided in the list above indicate that the total number of transformers required for 2042 will need to double to meet the demand. However, it's important to note that this is a collective figure. Upon closer examination, it becomes apparent that the majority of these new transformers are intended for Integrated Energy Platform (IEP) and electrification purposes. These transformers are typically small, designed to serve remote consumers situated far from the existing network.

The quantity of large transformers is comparatively less significant, with ratings of 100, 200, and 315 kVA being the most commonly utilized.

The requirement for transformers is expected to evolve from now until 2042. The ones scheduled by IEP & MAREP are set to be installed by 2030. However, the service transformers will be gradually implemented, with the process continuing steadily until 2042. The table below illustrates this progression across significant years:

Table 3.7.1822: Evolution of the number of transformers, categorized by rating

Rating (kVA)	Actual transformers (Direct & Service)	Additional transformers 2024-2027	Additional transformers 2028-2032	Additional transformers 2033-2042
15	22	1837	2506	4467
25	104	8933	11851	20801
50	1155	5788	7889	14055
100	2562	758	1509	3143
200	1620	717	1493	3154
315	1169	340	611	1229
400	143	122	216	431
500	384	102	186	375
800	108	132	231	461
1000	125	34	59	117
Total	**7392**	**18764**	**26551**	**48233**

Following discussions with ESCOM about the smaller transformers and the unitary costs, it has been decided to not install 15kVA transformers and to use 25 kVA as the minimal size. It will allow to benefit of an economy of scale and to simplify for procurements and spare.

7.1.6 LV network and public lighting equipment plan

To estimate the length of the low-voltage (LV) network, it is customary to make an approximation based on the type of transformer. Depending on their ratings, cable lengths are determined using geospatial data and insights from previous consulting projects.

In the following table, it can be found a list of transformers along with their ratings and the corresponding proposed lengths of LV network cables in meters.

Table 3.7.19 23: Low voltage average cable length per type of transformer

Rating (kVA)	LV network (meters)	Additional LV lines (km) 2024-2027	Additional LV lines (km) 2028-2032	Additional LV lines (km) 2033-2042
15	100	187.9	241.2	17.5
25	100	914.1	1163.7	2.3
50	500	2960.9	3799.3	267.3
100	500	387.4	564.8	619.3
200	1000	732.5	1086.7	1334.9
315	1500	521.6	732.1	589.9
400	1500	187.7	261.7	197.2
500	1500	156.8	220.9	184.8
800	2000	269.1	374.6	278.3
1000	2000	69.5	96.3	68.2

After correlating these estimations with the findings from the preceding section regarding the anticipated number of transformers required by 2042, we arrive at the total kilometers of low-voltage cable needed for that year.

These results can be found in the following table, where the number of transformers to be installed is multiplied by the number of meters of cable per associated transformer:

Table 3.7.20 24: Km of LV cable needed by type of transformer

Rating (kVA)	Number of transformers	LV cable (km)
15	4467	447
25	20801	2080
50	14055	7028
100	3143	1572
200	3154	3154
315	1229	1844
400	431	647
500	375	563
800	461	922

1000	117	234
Total	**48233**	**18488**

The average length of cable required for small transformers is significantly less than that needed for medium or large transformers. This discrepancy arises because small transformers, such as those with ratings of 15 kVA, serve specific clients where only a short line is necessary from the transformer to the location. Conversely, large transformers are intended to serve expansive areas with numerous clients, necessitating much longer cables.

7.1.7 Service lines and meters equipment estimate

Following the 2022 Electrification Report by IEP, we know that ESCOM and off-grid providers serve approximately 750,000 households, including about 550,000 grid-connected consumers and 200,000 off-grid consumers.

New clients will require service lines and meters. According to the 2023 Demand Forecast, Loss Reduction, and Energy Efficiency Strategies Final Report by ECA and the Ministry of Energy of Malawi, the number of clients is expected to grow significantly, reaching 4.14 million by 2042 (base scenario).

Considering that each new client will need one service line and one meter, we estimate a total requirement of 3.59 million units for each. For the service lines, 95% of the installations will be single-phase, and the remaining 5% will be three-phase.

The cost of these units will be detailed in the next section.

7.2 Investment plan

Based on the proposed network reinforcements (conductor, distribution substations, transformers, etc.) in the distribution network, we have established a high level budget estimate after presenting the assumptions considered in terms of unitary costs.

7.2.1 Unitary costs

The unitary costs for every part of the network is display in here:

The average cost of the transformers proposed, based on previous experience of the consultant in similar projects, is the following:

Table 3.7.21 25: Cost of MV transformers based on consultant experience

Nominal power (kVA)	Unitary cost (k$USD)
15	2.4
25	3.0
50	5.4
100	8.2
200	15.1
315	19.3
400	23.0
500	33.1
800	50.1
1000	63.2

For the costs of the lines ($USD), the information source for the 33 kV lines and the LV lines is ESCOM, found in the Electrification Report by IEP in 2022. For the 11 KV lines the price is proposed by the consultant based on previous experience:

Table 3.7.22 26: Cost of MV and LV lines per km – Source: ESCOM and consultant experience

Voltage (kV)	Section (mm2)	Type	Cost (k$USD) per km
11	50	AAAC	25.9
11	100	AAAC	33.0
11	120	XLPE	49.5
11	150	XLPE	59.4
33	50	AAAC	37.0
33	100	AAAC	43.0
Low voltage		AAC	23.0

The cost for the High-Voltage transformers in $USD is presented in the following table, based on information both from the consultant and from ESCOM.

Table 3.7.23 27: Cost of HV transformers - Source: ESCOM and consultant experience

HV transformers	Unitary cost k$USD
132/11 kV 10/15 MVA	573.1
132/33 kV 10/15 MVA	667.5
132/33 kV 25/30 MVA	1,146.2
132/11 kV 25/30 MVA	1,335.0

132/33 kV 40/50 MVA	2,115.5
132/11 kV 40/50 MVA	2,464.0
132/33/11 kV 10/15 MVA	801.0
132/33/11 kV 25/30 MVA	1,375.4
132/33/11 kV 40/50 MVA	2,538.6
66/33 kV Transformers	**k$USD**
66/33 kV 20/25 MVA	835.5
66/33/11 kV 20/25 MVA	1002.6
33/11 kV Transformers	**k$USD**
33/11 kV 20 MVA	557.0
33/11 kV 10/15 MVA	371.3

The cost for the primary and secondary stations needed in the transmission study, were proposed by the consultant and agreed by the client during the inception report. The costs can be found in the following table:

Table 3.7.24 28: Cost of primary and secondary stations

Primary stations	k$USD
132kV Station with bays	3,083
Secondary stations	**k$USD**
33/11 with bays	750

In case of voltage drop due to the long MV lines that feeds across the cities distant localities, it's possible that voltage regulator are needed to compensate the drop. The cost of these instruments are shown in the following table:

Table 3.7.2529: Cost of voltage regulators

Voltage regulators	$ USD
Open Delta (+10%)	32,700
Closed Delta (+15%)	40,330

The cost of the Services Lines are found as well in the Electrification Report by IEP, while the price of the meters are found in the Loss Reduction Roadmap done by Minsait. Both costs are in $USD and are shown in the following table:

Table 3.7.26 30: Cost of service lines & meters - Source: IEP and ESCOM

Instrument	$ USD	Type
Service lines - Cost ($)	150	Single phase
	433	Three phase
Meters	200	Price per unity

7.2.2 Budget estimates

7.2.2.1 Primary stations

The investment budget for the primary station is composed of the next breakdown:

- Investment in the substations, HV/HV transformers and bays: this budget is included in the Transmission Master Plan
- Investment in transformation capacity to the Medium Voltage (HV/33, HV/11 and HV/33/11). This is included in the next table.

Table 3.7.2731: Cost of HV transformers in Millions of $USD

	2024-2027	2028-2032	2033-2042	Total MUSD
66/33kV 20/25/30 MVA	2.51	3.34	0.00	5.85
66/33/11kV 20/25/30 MVA	3.01	0.00	0.00	3.01
132/33/11 kV 10/15 MVA	0.00	0.00	3.20	3.20
132/11kV 20/25/30 MVA	0.00	1.34	14.69	16.02
132/33kV 20/25/30 MVA	2.29	2.29	5.73	10.32
132/33/11kV 20/25/30 MVA	4.13	23.38	52.27	79.77
132/33kV 40/50 MVA	4.23	6.35	33.85	44.43
132/33/11kV 40/50 MVA	0.00	0.00	35.54	35.54
Total MUSD	**16.16**	**36.70**	**145.27**	**198.14**

7.2.2.2 Secondary stations

The investment budget required for the additional transformation capacity in the existing secondary stations is given in the next table.

Table 3.7.2832: Cost of 33/11 transformers in Millions of $USD

33/11 kV Transformers	2024-2027	2028-2032	2033-2042	Total
33/11 kV 10/15 MVA	0.00	0.37	3.34	3.71

7.2.2.3 MV network

The investment budget for MV network has been done by category and is presented in the next tables.

Table 3.7.2933: Total cost of MV network for rural electrification (in Millions of $USD)

MV network - electrification	2024-2027	2028-2032	2033-2042	Total cost (M$USD)
OHL 50 mm² 33 kV	219.6	291.1	0.0	510.6
OHL 100 mm² 33 kV	113.1	149.9	0.0	263.0
Total cost (M$USD)	332.6	440.9	0.0	773.6

Table 3.7.3034: Total cost of MV network for cities (in Millions of $USD)

MV network - cities	2024-2027	2028-2032	2033-2042	Total cost (M$USD)
UG 3x120 mm² 11 kV	4.1	3.8	7.0	14.9
UG 3x185 mm² 11 kV	19.6	25.1	76.5	121.2
Total cost (M$USD)	23.7	28.9	83.5	136.1

Table 3.7.3135: Total cost of MV network for 11kV to 33kV upgrade (in Millions of $USD)

	2024-2027	2028-2032	2033-2042	Total cost (M$USD)
OHL 100 mm² 33kV	15.31	0	0	15.31
OHL 150 mm² 33kV	72.40	0	0	72.40
Total cost (M$USD)	87.71	0	0	87.71

Table 3.7.3236: Total cost of MV network for 33kV backbone development (in Millions of $USD)

	2024-2027	2028-2032	2033-2042	Total cost (M$USD)
OHL 150 mm² 33kV (km)	57.98	76.10	86.06	220.15

7.2.2.4 Voltage regulators

The total cost for voltage regulators needs has been estimated using the unitary cost presented in the previous section.

Table 3.7.3337: Total cost of voltage regulators in Millions of $USD

Voltage regulators				
	2024-2027	2028-2032	2033-2042	Total
Voltage regulators	1.78	0.44	0.00	2.22

7.2.2.5 Services Transformers

The unitary cost of each transformer presented in the previous section, multiplied by the number of transformers needed gives us the total cost of the new transformers until 2042:

Table 3.7.3438: Total cost of MV transformers in Millions of $USD

Nominal power (kVA)	**Total cost (M$USD)**

15	10.9
25	62.4
50	76.2
100	25.7
200	47.7
315	23.7
400	9.9
500	12.4
800	23.1
1000	7.4
Total	**299.3**

Following discussions with ESCOM about the smaller transformers and the unitary costs, it has been decided to not install 15kVA transformers and to use 25 kVA as the minimal size. It will allow to benefit of an economy of scale and to simplify for procurements and spare.

7.2.2.6 LV network and public lighting

The low voltage lines total cost has been calculated as the number of km of LV lines needed multiplied by the cost of the LV lines per km. The result of this calculation can be seen in the following table:

Table 3.7.3539: Total cost of LV lines in Millions of $USD

Transformers rating (kVA)	Number of transformers	LV lines in km	Total cost (M$USD)
15	4467	447	10.3
25	20801	2080	47.8
50	14055	7028	161.6
100	3143	1572	36.1
200	3154	3154	72.5
315	1229	1844	42.4
400	431	647	14.9
500	375	563	12.9
800	461	922	21.2
1000	117	234	5.4
Total	**48233**	**18488**	**425.2**

Table 3.7.3640: Total cost of LV lines in Millions of $USD per period of investment

LV lines	2024-2027	2028-2032	2033-2042	Total	Cost (M$USD)
LV lines	6387.4	8541.3	3559.7	18488.3	425.2

7.2.2.7 Services lines and meters

The cost of the Services Lines and meters has been calculated together, as both refer to the number of new clients ESCOM will have to furnish electricity in 2042, multiplied by the unitary cost of the previous section. The total cost can be seen in the following table:

Table 3.7.3741: Service lines and meters per period of investment

Service lines / meters	2024-2027	2028-2032	2033-2042	Total
Number of new connections (millions)	1.5	2.1	0.9	4.6
Cost per period (Millions USD)	544	781	339	1664

7.2.2.8 Summary of the investments

In the previous sections, total costs are calculated by type of equipment and by year have been estimated. By summing these total costs per equipment, we can calculate the total cost of the additional infrastructure project and therefore the investment necessary.

Table 3.7.3842 shows the spread of investments required for additional infrastructure.

Table 3.7.3842: Breakdown of investments per category and per time

	2024-2027	2028-2032	2033-2042	Total MUSD
Transformers HV/MV	16.2	36.7	145.3	198.1
Transformers MV/MV	0.0	0.4	3.3	3.7
MV network & voltage regulators	503.8	546.4	169.5	1219.7
Service Transformers	103.5	138.4	57.5	299.3
LV network and public lighting	146.9	196.4	81.9	425.2
Services lines and meters	543.8	781.0	339.4	1664
Total MUSD	1314.2	1699.3	796.9	3810.3

The total investment required over the total duration of the project is approximately 3810 million USD, the majority of which is dedicated to service lines & meters and MV conductors.

It appears that the largest investments will be devoted to services lines and meters, followed by medium voltage lines, while the lowest investments will concern the additional transformers in secondary stations.

By analyzing the distribution of investments by periods, it appears that the first two periods are notably more expensive than the third one. This can be explained by the important projects for correcting the weaknesses in the grid, upgrading long 11kV feeders to 33kV and also the ongoing rural electrification with the 2030 target for energy access.

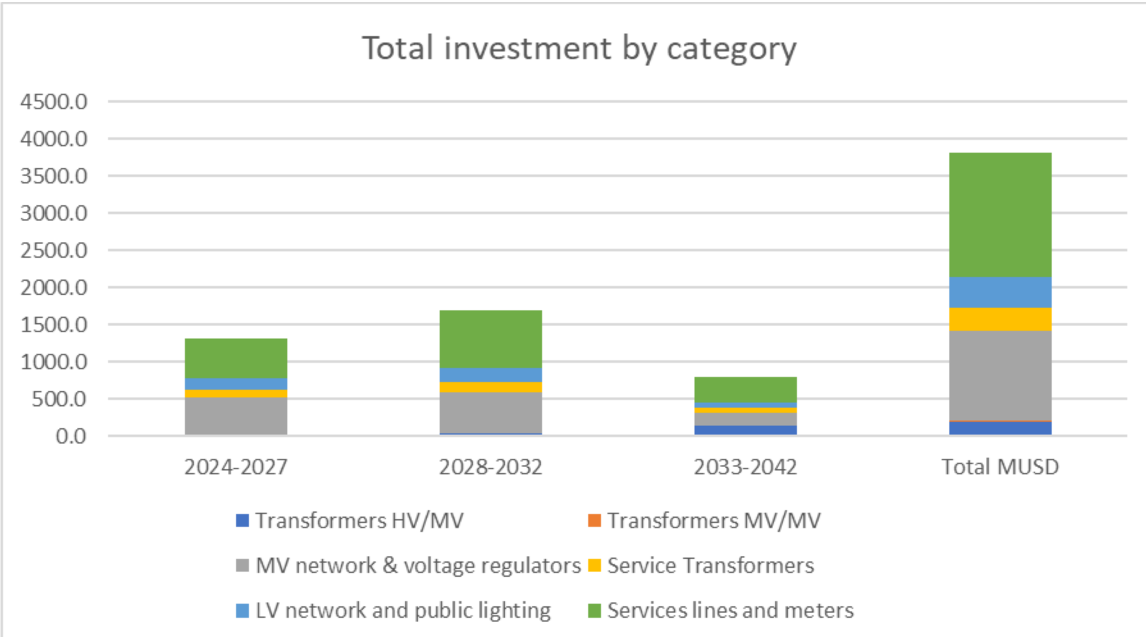


Figure 3.7.1: Total investment by category and period

8 Appendix

8.1 Needs in terms of primary and secondary substations

Table 3.8.143: Peak load per substation considering network reinforcements

Substation	Primary substation	2023 peak load (MW)	2027 peak load (MW)	2032 peak load (MW)	2042 peak load (MW)
Area 25		4.0	4.8	5.8	16.5
Area 47	After 2032	9.1	10.9	13.1	35.3
Area 48	Yes	7.0	8.4	10.2	28.1
Balaka	Yes	2.7	4.3	6.5	13.7
Bangwe	Yes	No data			
Barracks	Yes	11.7	14.1	17.0	16.2
Blantyre Main		2.8	3.7	5.0	11.1
Blantyre West	Yes	16.9	23.2	32.1	30.0
Bunda	Yes	11.4	17.9	26.9	62.6
Bwengu	Yes	5.5	11.1	16.1	37.2
Changalume	Yes	23.0	37.2	22.1	38.4
Chichiri	Yes	30.3	40.6	55.2	86.9
Chigumula	Yes	21.5	36.8	51.8	40.7
Chikangawa	Yes	4.4	10.0	14.7	29.4
Chileka	Before 2032	11.7	16.8	23.6	44.2
Chingeni	Yes	2.4	4.8	8.2	17.2
Chintheche	Yes	5.9	12.8	19.1	41.0
Chinyama	Yes	13.4	22.2	49.4	73.1
Chirimba	After 2032	6.1	8.2	11.2	24.8
Chitipi	After 2032	4.2	5.6	7.4	18.8
Chizumulu	Yes	0.1	0.1	0.2	0.5
City Centre	After 2032	7.5	9.2	11.1	27.2
Customs		5.2	6.9	9.4	20.8
David Whitehead		2.8	3.8	5.2	11.5
Dedza	Yes	5.0	12.4	22.7	46.2
Dwangwa		2.5	3.2	4.0	7.1
Fundis Cross	Yes	16.9	32.4	53.2	75.7
Golomoti	Yes	0.7	2.3	4.5	8.8
Kanengo	Yes	50.7	79.9	93.5	138.3
Kangoma	Yes	1.9	2.5	3.4	8.9
Kapichira	Yes	0.8	1.3	1.9	4.0
Karonga	Yes	7.0	13.7	19.3	44.4
Kasinthula		0.9	1.2	1.7	3.7
Kasungu	After 2032	2.5	3.5	4.9	12.3
Katoto		2.1	4.1	5.7	13.5
Kauma	Yes	2.6	3.2	3.9	10.7

Substation	Primary substation	2023 peak load (MW)	2027 peak load (MW)	2032 peak load (MW)	2042 peak load (MW)
Kch		4.2	5.1	6.1	15.8
Kwacha		3.5	4.7	6.4	14.3
Likoma	Yes	0.3	0.5	0.7	1.6
Lilongwe A	Yes	18.5	22.2	26.8	69.4
Limbe A	After 2032	8.6	11.6	15.9	34.6
Limbe B	After 2032	6.4	8.6	11.6	24.4
Livingstonia	Yes	0.4	0.8	1.2	2.2
Liwonde	Yes	6.3	11.4	18.4	36.3
Luwinga	Yes	11.1	23.3	33.9	52.0
Maldeco	Before 2032*	0.8	1.1	1.6	3.4
Mangochi	Before 2032	3.7	9.7	18.2	34.6
Maone		No data			
Mapanga	Yes	26.2	39.4	57.5	69.1
Mchinji Border		5.1	10.6	18.4	39.4
Michiru	After 2032	9.9	13.4	18.4	15.8
Mlambe	Yes	17.1	30.6	47.1	85.1
Mlangeni	Yes	1.4	3.1	5.4	11.5
Monkeybay	Yes	9.0	17.4	9.7	20.6
Mtunthama		0.9	1.1	1.4	3.3
Mvera		0.4	0.7	1.1	2.6
Mzuzu		3.4	6.5	8.8	19.8
Nanjoka	Yes	14.7	24.6	29.7	69.8
New Dwangwa	Yes	3.5	4.9	6.6	13.3
Nkhoma	Yes	No data			
Nkhotakota	Yes	3.6	6.3	10.0	22.5
Nkula b	Yes	6.0	9.7	14.6	28.4
Ntcheu	Yes	1.1	2.8	5.1	10.6
Ntonda	Yes	0.0	0.2	0.5	0.9
Phombeya	Yes	0.0	0.0	0.0	0.0
Queens		4.5	6.1	8.2	18.3
Salima		3.7	4.7	6.0	15.9
Sonda	After 2032	3.7	7.3	10.0	22.1
Tedzani 1	Yes	0.0	0.0	0.0	0.0
Tedzani 2	Yes	0.0	0.0	0.0	0.0
Telegraph Hill	Yes	4.7	9.1	12.4	27.8
Thyolo A	After 2032	6.4	10.0	14.3	25.7
Thyolo B	After 2032	4.4	6.8	10.0	18.8
Thyolo C	After 2032	2.7	4.4	6.2	10.1
Uliwa	Yes	1.7	3.5	5.2	11.8
Wovwe	Yes	0.0	0.1	0.1	0.3
Zomba	Before 2032	13.4	21.7	32.3	61.5

Table 3.8.143 lists all substations together with their estimated peak load between 2023 and 2042. The peak load of primary substations already includes the peak load of connected secondary substations. The second column indicates the substations that are connected to the HV network (primary substations) and indicates the substations that should be upgraded in the future. A split is made between secondary substations that should be upgraded to primary substations before or after 2032. No substation upgrades are foreseen before 2027.

*The upgrade of Maldeco to a primary substation is optional as the peak load remains small. The HV line foreseen between Monkeybay and Mongochi passes right beside Maldeco substation, thus limiting the cost of a potential upgrade to primary substation.

8.2 Network configuration

The network configuration, how the MV feeders are structured in the service are, is a first planning choice that must be made. The feeder topology and the switching equipment locations determine load distribution and can create an open point that can be closed in case of contingency. The switching equipment provides increased reliability and network operation flexibility.

Different network structures can be deployed and are selected based on the:

- Load density (following the load forecast)
- Load distribution and distance to the HV/MV substations
- The chosen level of reliability for the service area.

Three configurations, with the advantages and disadvantages are discussed:

- Radial network;
- Open loop network;
- Meshed network.

8.2.1 Radial network configuration

The radial network; illustrated below, follows an outward structure from the HV/MV substation, primary station or BSP, towards the customers. A single path connects the customers to the source substation, with multiple branches to cover the service area. Generally these are overhead networks and prone to faults (lightning strikes), thus often feature an automatic reclosure to improve reliability.

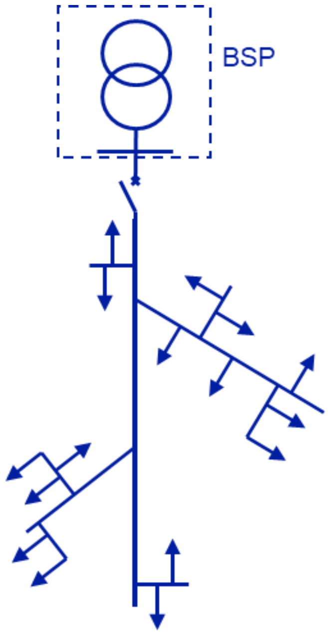


Figure 3.8.1: Radial network configuration

The main advantage of the configuration is the simplicity of design and construction. Feeders move outwards to the service area and can easily connect all customers and the configuration is very well suited to serve low demand density areas. The configuration only requires a single BSP substation and the least amount of conductors and is thus the least-cost configuration. Conductor sections can be reduced as the feeder serves more distant customers, further reducing costs. The disadvantage is the poor performance of the configuration during faults, in case of a fault in the BSP or on the feeder, all downstream customers are disconnected and no alternative supply path can be created.

The disadvantage can be mitigated if an emergency supply conductor interconnects two radial feeders, yet this is only possible if multiple BSPs are available and the feeders are located near one another. This is shown in Figure below. In this case the common conductor section needs to be increased to allow to supply both feeder loads in case of an outage.

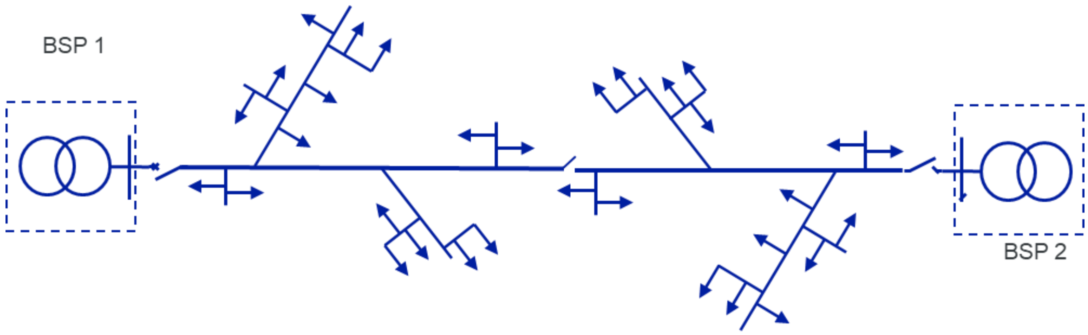


Figure 3.8.2: Two radial network feeders with an emergency conductor to interconnect the feeders

8.2.2 Open loop network configuration

The second configuration is an open loop network or a ring main network. As the title indicates, the network feeders are structured into one or multiple loops, such that in case of a fault an alternative path can be made to supply all the MV/LV substations. Each feeder leaving the BSP serves multiple MV/LV substations and connects to:

- Another feeder from the same substation (a loop);
- A feeder from another substation (inter-injector);
- An emergency cable.

During normal operation the MV/LV substations are supplied by two switches in series (S1 and S2), that are normally closed, except for one switch in the loop which is open and called the open point. If a fault occurs on a section, it is isolated by opening the two switches adjacent to the fault. Then the open point is closed and the MV/LV substations between the previous open point and the fault are again energized.

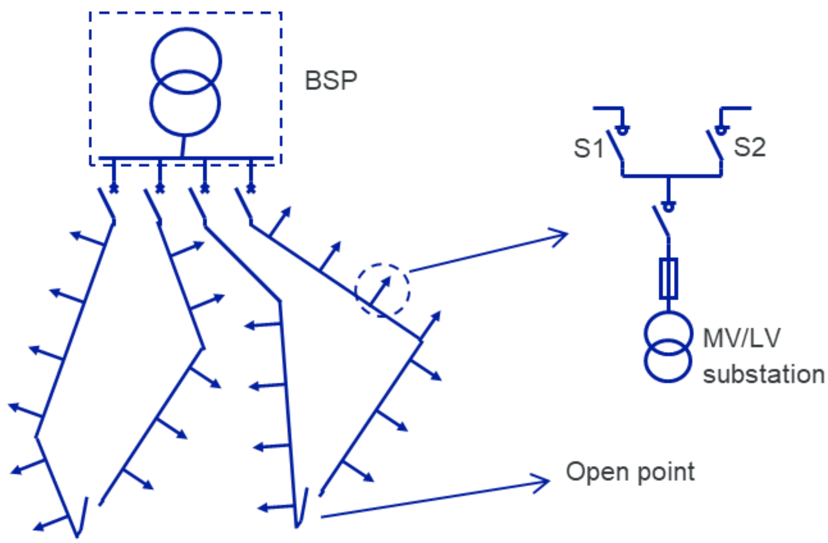


Figure 3.8.3: Open loop network configuration with a single BSP

The advantage of the system is the good reliability and flexibility it offers. The downside is that is requires a larger investment in conductors and a greater planning effort. The configuration is suited for higher load density areas, such as primary cities with an internal distribution network to supply just the city. When the feeder can connect to another substation, supply can be guaranteed even in case of a BSP fault, offering great performance in contingency situations.

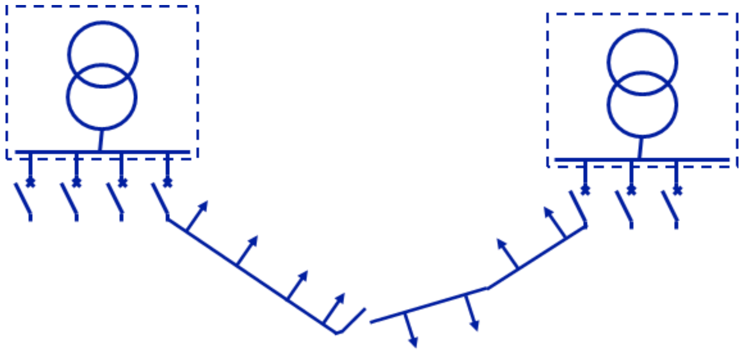


Figure 3.8.4: Open loop network configuration with multiple BSP's

8.2.3 Meshed network configuration

In the meshed network configuration, all feeders are composed of several branches looped together or to other branches. The feeders coming from the BSP ensure to transport the power into the network while the different branches and loops distribute the power to the different MV/LV substations. Multiple conductive paths, or parallel operation of the conductors; are avoided with opening points placed at each network intersection.

All the branch conductors are designed to also be capable of providing emergency power supply to adjacent branches. This allows this structure to have a very high load rate provided that the network operation is well managed.

The development of a meshed network is flexible and easily scalable according to the load growth in the area, simply by installing a new branch line. Since the distance of the loads from the HV/MV substation can be optimized by the switches, this structure is suitable for low and medium densities.

The main disadvantage of this structure is the network management, which is more difficult as the acquisition of the network status requires to know the status of the opening points and of the loads in the different branches. The configuration also requires significant investments in conductors and switches, making the configuration the most expensive out of the three.

As for the other configurations the reliability of the network can be further increased in case the meshed network is supplied by multiple BSP’s.

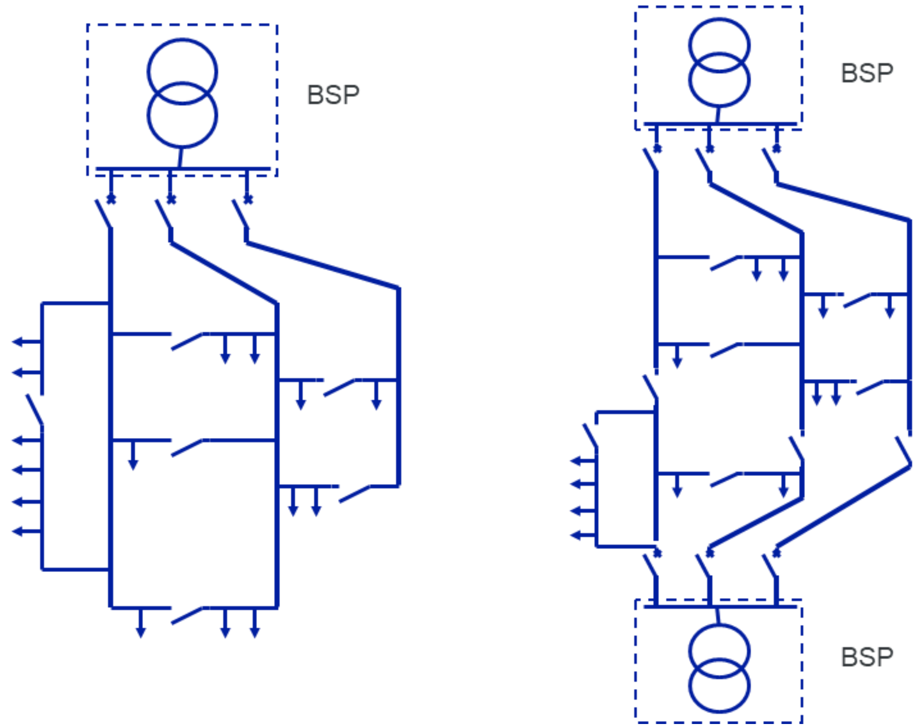


Figure 3.8.5: Meshed network configuration with one (left) or two (right) BSP's

8.3 Example of DER grid connection analysis

8.3.1 Description of the example

A PV generation of 4.4 MW is expected to be connected to one 11kV grid. The point of connection is first identified in a GIS model. Supply in N and N-1 situations are then analyzed.

For that given example, the peak and off-peak loads data of 11kV feeders have permitted to determine the load in both situations. The consumption at the peak is 0.7MW and 0.4MW during off-peak.

The 4.4MW are modelled as **one generator connected to the 11kV studied feeder.** The internal installation of the customer/producer is not modelled. Practically, the plant is divided into several sets of inverters.

8.3.2 Load flow analyses results in normal condition (N)

In that example, Figure shows that the voltage is not significantly impacted by adding PVs to the connection point, voltage is stable both in peak and off-peak cases.

Table 3.8.244 shows that reverse flows occur when PV are connected caused by the fact that the load is low compared to the generation. But the line loading remains below the thermal limit.

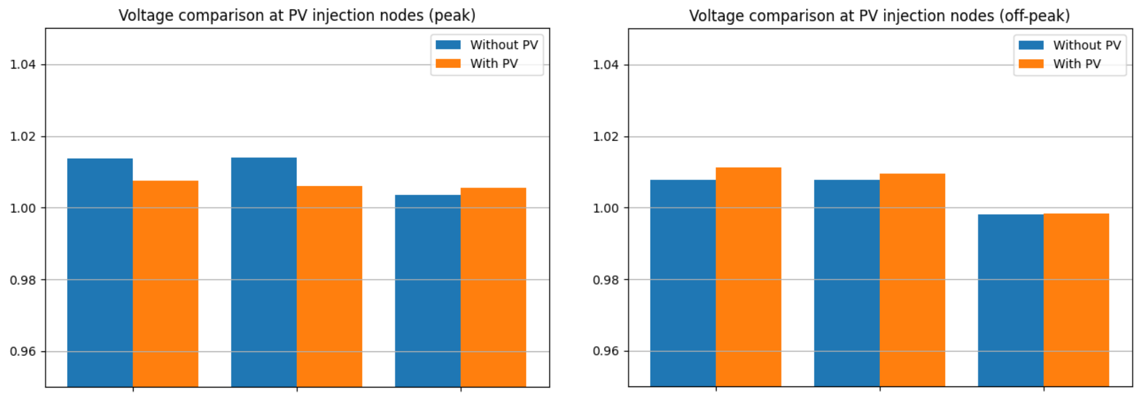


Figure 3.8.6: Comparison of voltage at the injection node and nearby nodes before and after connecting the PV plant (left: peak; right: off-peak).

Table 3.8.244: Equipment loading related to the PV plant connection (left: peak; right: off-peak).

			LINE LOADING [%]			
			Peak		Off-peak	
BUS 1	**Bus 2**	**Voltage level [kV]**	**No PV**	**PV**	**No PV**	**PV**
BUS 1	**BUS2**	11	12%	-61%	6%	-66%

8.3.3 Load flow analyses results in contingency (N-1) condition

Figure shows that connecting the N-1 does not impact neither the voltage at the connection point nor the voltage of the new buses at which it is connected.

It does not create either loading problem as shown in Table 3.8.345. It just changes the direction of the power in these lines.

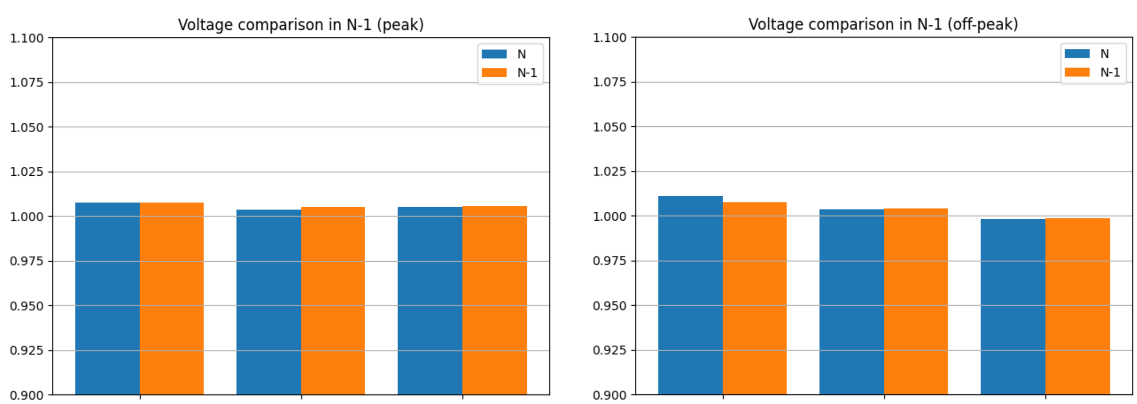


Figure 3.8.7: Comparison of voltage at the injection node and nearby nodes before and after connecting the PV plant 3 – N-1 situation (left: peak; right: off-peak).

Table 3.8.345: Equipment loading related to the PV plant connection in N-1 situation (left: peak; right: off-peak).

			Line loading [%]			
			Peak		Off-peak	
BUS 1	BUS 2	Voltage level [kV]	N	N-1	N	N-1
LINE 1-B1	**LINE 1-B2**	11	/	-59%	/	-66%
LINE 2-B1	**LINE 2-B2**	11	19%	-47%	15%	-53%
LINE 3-B1	**LINE 3-B2**	11	41%	-29%	29%	-41%

8.3.4 Short-circuit analyses

Table 3.8.446 shows that the SC currents are below the breakers rating. This plant does not cause unacceptable SC currents. The SC currents are not higher than the breakers ratings.

The SCR is equal to 65.4 which is much higher than 3.

$$SCR = \frac{286.34}{4.38} = 65.4$$

Table 3.8.446: Short-circuit current at the injection node of PV plant connection (left: peak; right: off-peak)

		Short-circuit current [kA]				Breaker rating [kA]
		Peak		Off-peak		
BUS	Voltage [kV]	No PV	PV	No PV	PV	
BUS 1	11	16.5	17.5	16.3	17.3	20
BUS 2	11	18.1	19.3	17.8	19.0	20
BUS 3	66	19.0	19.3	18.1	18.4	31.5 – 40

8.3.5 Conclusions

The power plant studied in this example has no harmful impact on the network. It respects the voltage limits; it does not cause overloading of any lines and the SC currents are not higher than the breakers ratings.

9 References

[1] Economic Consulting Associates Limited, "Demand Forecast, Loss Reduction and Energy Efficiency Strategies Final Report," Ministry of Energy, Republic of Malawi, 2023.

[2] Sustainable Energy for All, "Malawi Integrated Energy Plan, Electrification Report: An Overview," 2022.

VOLUME 4: Transmission Development

1. Introduction

Malawi has one of the lowest electricity access rates in the world at about 20% if off-grid systems are included in the estimation. Malawi, like all countries in sub-Saharan Africa, suffers from an acute Energy Poverty despite its endowment with an abundance of natural resources. The characteristics of Energy Poverty are poor governance, operational and financial performance, and the technical insolvency of state-owned power utilities.

Malawi also suffers from insufficient foreign currency and could benefit from a focus on exporting its hydropower and solar potential as green energy, which is sufficient to attract foreign capital. The integration of the Malawi electrical power system into the Southern African Power Pool (SAPP) and Eastern Africa Power Pool (EAPP) should inform policy makers that Malawi is no longer an electrical island and should leverage on the integration for its maximum benefit. Malawi's energy policies going forward must not adopt the concept of self-sufficiency in local power generation to comply with the integration drive of the SADC Vision 2050.

The Malawian power sector is already facing or will be facing major challenges in the coming years and needs to be prepared in order to be able to sustain the increasing electric demand linked to the forecasted economic growth and the electrification of the population while ensuring the reliability of the supply and affordable prices for the electricity. The challenges encompass the reliance on an important share of hydropower plants potentially subjected to important variations of yearly production, the penetration of intermittent renewable energy generation (photovoltaic and wind), the need to diversify the energy mix and the integration to the SAPP regional network. Therefore, a precise vision of the optimal evolution of the power system and the related investment is critical.

The objective of the study is to define the generation, transmission and distribution expansion plans for the next 20 years. The transmission development plan presented in this report constitutes the continuation of the first Workstream of the study. It aims at outlining the best possible way for strengthening the transmission system in Malawi from 2022 to 2042 while accounting for the outcomes of the generation development plan.

1.1 Methodology

Overview of the complete methodology

The project is organized into two workstreams: Workstream 1 (WS1) focusing on generation and transmission, and Workstream 2 (WS2) on distribution. In addition, a Workstream 0, common for all tasks, deals with the inception phase of the project. It consists of the kick-off, data collection and review of the existing situation.

Moreover, Workstream 1 is split in two parts, of which the first part focuses on the generation master plan. After the generation planning exercise, the transmission planning and distribution planning start in parallel. It allows iterations and exchanges between the transmission and distribution planning.

The second workstream is interlinked with the first one, as the development of the distribution master plan will be partially built on the findings of Workstream 1 and, in turn, the optimal planning of the distribution network will provide insights for the transmission development plan (e.g., siting of substations, capacity of substations given the local load).

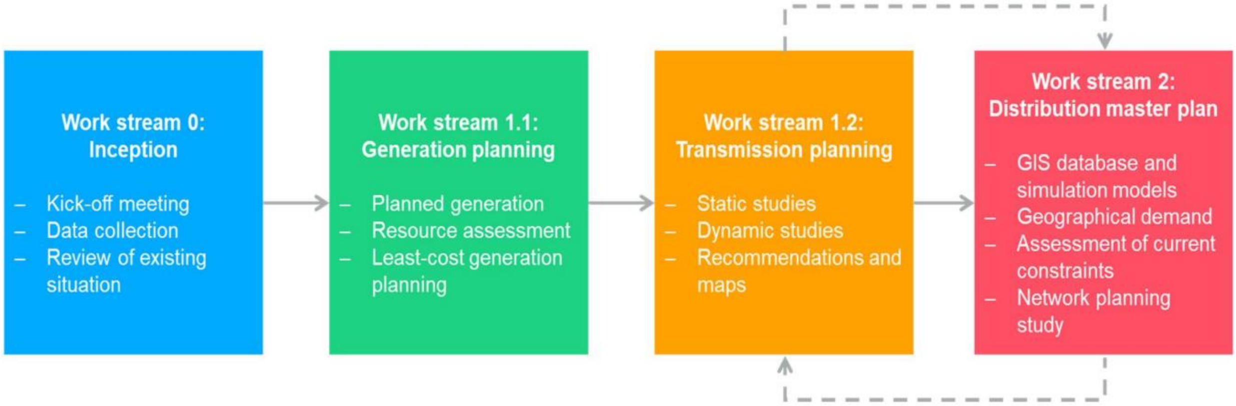


Figure 4.1.1: Overall project methodology. Source: ENGIE Impact.

- Approach for the transmission development plan

The design of the transmission development plan is essentially based on the five-step approach presented in Figure . This approach relies on the simulation model representing the current transmission system in Malawi, the results of the Workstream (WS) Generation and Distribution, and the list of decided/proposed transmission projects. The overall idea is to integrate as much known information as possible over the evolution of the power sector in Malawi inside the initial model and to run simulations in order to identify the weaknesses and propose some grid reinforcements.

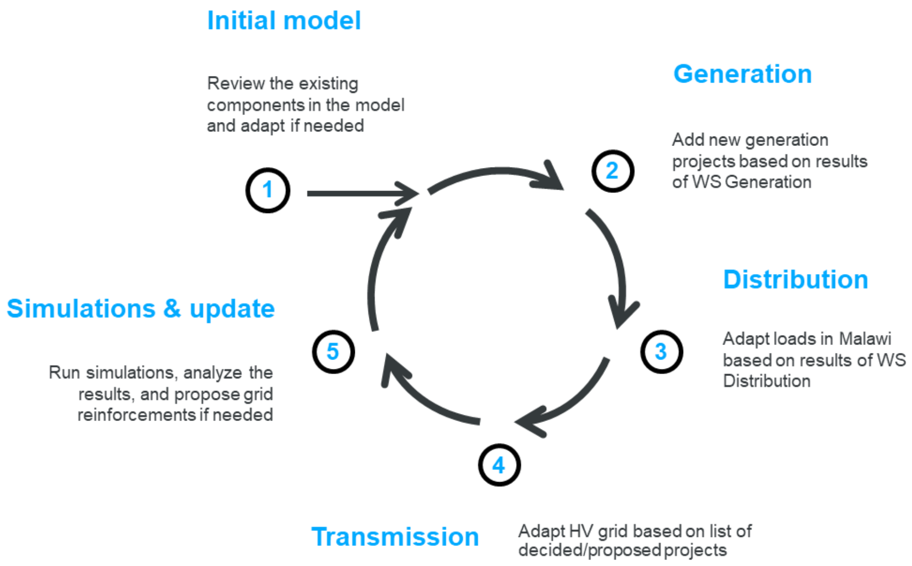


Figure 4.1.2: Five-step approach for designing the transmission development plan.

1.2 Working Group

It is worth mentioning that Working Groups have been set from the beginning of the project for the two workstreams. In the context of WS 1, an important part of the report has been discussed remotely with the local stakeholders through direct exchanges and recurrent meetings. Specifically, the **Working Group Transmission** has discussed the next topics:

- Data clarifications
- Planning standards
- Planning methodology
- Geographical location of the future generation by 2042
- Geographical demand analysis
- New transmission substations and connection to the existing and future network
- Presentation of the network development options for the target horizon and selection of the reference network structure

1.3 Outline of the report

The present report is the third deliverable of Workstream 1. It follows the inception report issued in the first phase of the project and the generation development plan report. The aim of the inception report was to present the main collected data and to highlight data gaps and assumptions. The report also aimed at presenting the methodology and main hypotheses. The present report incorporates the conclusions of the generation report and was developed in close collaboration with Workstream 2 and the distribution development plan.

This report corresponds to the final version of the transmission master planning (Workstream 1.2).

The report is organized in nine chapters as follows:

- Chapter 1: Presentation of the project and the report
- Chapter 2: Description of the existing transmission system
- Chapter 3: Results of the generation development plan
- Chapter 4: Results of the load distribution forecast
- Chapter 5: Transmission development planning study
- Chapter 6: Assessment of system performance in intermediate years
- Chapter 7: Overview of legal and regulatory framework in Malawi
- Chapter 8: Conclusions
- Chapter 9: References

2 Existing transmission system

The transmission system in Malawi consists of 400kV, 132kV, and 66kV overhead lines and is managed by the Electricity Supply Corporation of Malawi Limited (ESCOM). It has an elongated shape that covers the entire country from the South to the North and passes through the cities with the highest population densities. The 132kV system forms the backbone of the system, which ensures that electricity can flow across Malawi. The 66kV system is composed of auxiliary branches that extend the reach of the power system. As for the 400kV level, it is currently limited to a section between Phombeya and Nkhoma. The Malawian transmission system is at this moment operated as an isolated system with no possibility of exchanging power or ancillary services with the neighboring countries. However, it should be noted that the Mozambique-Malawi 400kV interconnector is currently under construction and will be commissioned in the short term.

Despite the wide area covered by its electrical infrastructure, Malawi is still suffering from a low electrification rate and is unable to address the growing demand for electricity. As the population increases and the economic activities expand, the existing infrastructure needs to be upgraded to handle a higher share of electrical load. New investments will have to be made to alleviate the strain on the overloaded lines and enhance the security of supply. This situation calls for a long-term coordination to address the future challenges, which is the purpose of the current transmission development plan.

In this context, the first step is to obtain a better insight into the characteristics and performances of the existing transmission system because a sound development plan starts with understanding the present limitations. The reference source for this task is the DIgSILENT PowerFactory (PF) model shared by ESCOM on June 26, 2023 [1]. The analysis consists in checking the available generation and transmission assets, investigating the initial dispatch, and assessing the impact of not being interconnected with the Southern African Power Pool (SAPP).

2.1 Initial PowerFactory model

2.1.1 Configuration

The PF model shared by ESCOM is a representation of the Malawian transmission system which has been divided into five main grids:

- Generation
- Malawi Grid
- Trans Centre
- Trans North
- Trans South

Generation and **Malawi Grid** regroup the models of all generating units in Malawi, as well as the associated terminals, step-up transformers, and the transmission lines between generation sites.

Trans Centre, **Trans North**, and **Trans South** contain the main load centers in Malawi and the remaining transmission lines found in the country. The allocation of the elements to a certain grid is based on its belonging to one of three eponymous regions, which can either be the Central Region, the Northern Region, or the Southern Region.

The PF model corresponds to the current state of the Malawian transmission system in **2024** and has been configured to represent the **peak load conditions**. There exists no readily available operation scenario that enables a switch to the off-peak load conditions or any other loading conditions.

In the following model description, the comments made during the working group sessions have been taken into account. These comments address the correction of inaccuracies identified after the initial version of this chapter was shared.

2.1.2 Generation assets

The generation assets found in the PF model consists of several synchronous machines and PV systems. An exhaustive list of the assets is provided for the current situation in the table hereunder.

In PowerFactory, one single network element can be used to model multiple elements in parallel. The total installed capacity stated in the table corresponds to the rated active power per machine times the number of parallel machines. The table also indicates if the generating units include a dynamic model in the form of a composite frame with controllers (AVR, GOV, and/or PSS).

Color legend for the table

	Dispatched generating units
	Undispatched generating units

Situation in 2024 – Generating units

Exhaustive list of generation assets in the current situation:

Table 4.2.1: List of generating units represented in the PF model for the situation in 2024.

Type	Power plant / Location	PF name	Total installed capacity (MW)	Number of machines	Dynamic model (Yes/No)
Hydro	Kapichira	Kapichira G1	32.4	1	Yes
		Kapichira G2	32.4	1	Yes
		Kapichira G3	32.4	1	Yes
		Kapichira G4	32.4	1	Yes
	Tedzani I and II	Tedzani I & II G1 2023	10.0	1	Yes
		Tedzani I & II G2 2023	10.0	1	Yes
		Tedzani I & II G3 2023	10.0	1	Yes
		Tedzani I & II G4 2023	10.0	1	Yes
	Tedzani III	Tedzani III G5	31.4	1	Yes
		Tedzani III G6	31.4	1	Yes
	Tedzani IV	Tedzani IV G7	19.1	1	Yes
	Nkula A	Nkula A G1	11.7	1	Yes
		Nkula A G2	11.7	1	Yes
		Nkula A G3	11.7	1	Yes
	Nkula B	Nkula B G4	20	1	Yes
		Nkula B G5	20	1	Yes
		Nkula B G6	20	1	Yes
		Nkula B G7	20	1	Yes
		Nkula B G8	20	1	Yes
	Wovwe	Wovwe G1 2023(1)	4.5	3	Yes
		Wovwe G3	1.4	1	No
	Ndiza	Ndiza G1	6.0	3	Yes
Diesel	Luwinga	Luwinga_G1	6.0	3	No
		Luwinga_G2	30.0	15	No
	Mapanga	Mapanga_G1	20.0	10	No
		Mapanga_G2(1)	30.0	15	No
	Kanengo	Kanengo Diesel(1)	10.0	1	No
PV	Golomoti	JCM Golomoti Plant(1)	20.0	1	Yes
	Nanjoka	JCM Plant 1(1)	60.0	3	Yes
	Serengeti	Serengeti (1)	21.0	1	Yes

2.1.3 Transmission assets

The transmission assets found in the PF model include some lines and transformers operated at 400 kV down to 33 kV. An overview of the number of lines and transformers is provided per grid and voltage level in the tables hereunder.

2.1.3.1 Transmission lines

Summary of the transmission lines in the current situation:

Table 4.2.2: Summary of the transmission lines represented in the PF model for the situation in 2024.

Grid	Voltage level (kV)	Number of connected lines	Number of disconnected lines
Generation	132	2	0
	66	1	0
	33	1	0
Malawi Grid	132	6	0
	66	6	0
Trans Centre	400	1	0
	132	16	3
	66	8	2
	33	1	0
Trans North	132	2	0
	66	7	0
	33	1	0
Trans South	66	13	0
Total		**67**	**5**

In the 132kV system, the three disconnected lines are:

- Nkhotakota – Dwangwa
- Dwangwa – Chintheche
- Chipata – Bunda

In the 66kV system, the two disconnected lines are:

- Kangoma – Barracks
- Dedza – Tsabango

These lines are assumed to be part of future transmission projects that should/could be in service in the future. In particular, there are currently two parallel paths in the model between Nkhotakota and Chintheche with different parameter values. One is operational whereas the other one is disconnected as mentioned before. The unavailable path should belong to the Eastern Backbone project that are set to replace the existing one installed on wooden poles.

2.1.3.2 Transformers

Summary of the transformers[25] in the current situation:

[25] Some of the 3-winding transformers are represented as 2-winding ones in the model. To avoid any confusion, both categories of transformers have been grouped together.

Table 4.2.47: Summary of the transformers represented in the PF model for the situation in 2024.

Grid	High voltage level (kV)	Number of connected transformers	Number of disconnected transformers
Generation	132	5	0
	66	3	0
	33	5	0
Malawi Grid	132	12	0
	66	13	0
Trans Centre	400	2	2
	132	11	0
	66	18	0
Trans North	132	4	0
	66	14	0
Trans South	132	5	0
	66	15	0
Total		**107**	**2**

In the 400kV system, the two disconnected transformers are:

- Nkhoma 400/132/33kV
- Phombeya 400/132/33kV

Each of these two transformers has been inserted in parallel with an identical transformer and could be seen as reinforcements for the future.

2.1.4 Initial dispatch

The initial dispatch shared by ESCOM is expected to represent a realistic way to operate the generation assets in order to meet the peak load conditions in 2024. Analyzing this specific scenario should enable to grasp the current situation in Malawi and to identify the potential bottlenecks if any. The study is based on a regular load flow calculation and verifies whether the system state is compliant with the operational and planning criteria described in the grid code issued by the Malawi Energy Regulatory Authority (MERA) in 2026 [2].

More specifically, in the **normal state**,

- The voltages at all connection points are within 0.95 and 1.05 of the nominal value
- The loading levels of all transmission lines and substation equipment are below 100% of the maximum continuous ratings

2.1.4.1 Generation and load per grid

The repartition of the produced active power per grid is shown in Figure . Since all the generating units have been included in the same **Generation** grid, the only information that can be retrieved from this graph is that the total generation amounts to 406.9 MW. This value includes the import of 38.9 MW from SAPP, which is modelled as an equivalent generator inside the **Generation** grid. If this value is subtracted from the total generation, the actual generation in Malawi would amount to 368 MW.

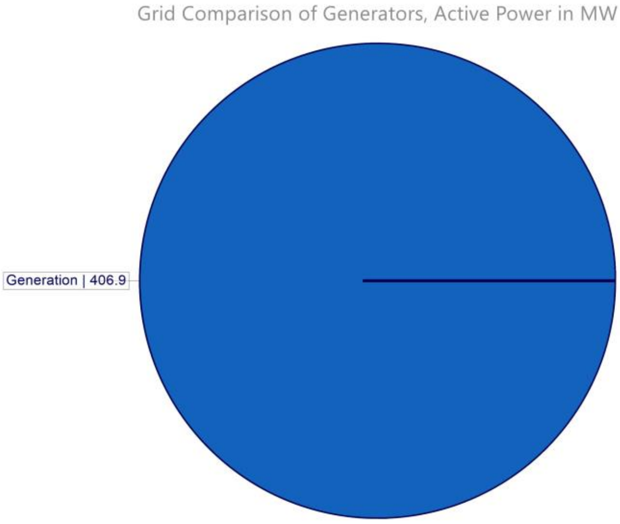


Figure 4.2.3: Repartition of the produced active power (MW) per grid for the initial dispatch in 2024.

The repartition of the consumed active power per grid is shown in Figure . Trans South is the grid with the largest consumption as the load amounts to 209.9 MW. It is followed by Trans Centre with a load of 135.4 MW and Trans North with a load of 31.3 MW. The Generation grid contains a load of 7.2 MW connected in Nkula that should belong to Trans South. The total load in Malawi is therefore equal to 383.8 MW.

By confronting the total generation with the total load, it can be deduced that the total losses amount to 23.1 MW or 5.68%.

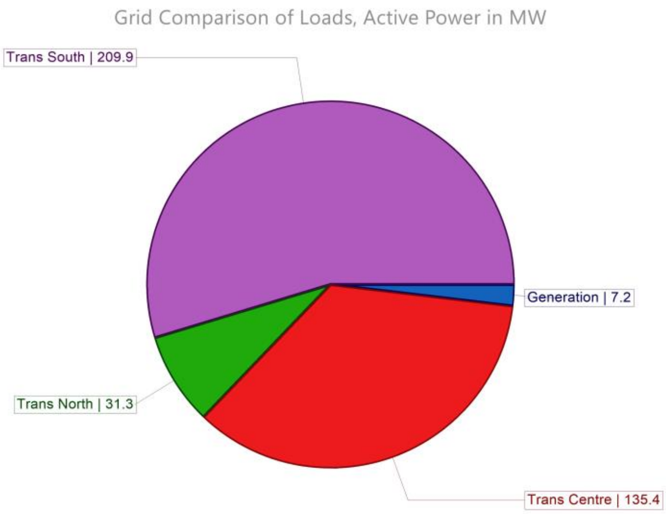


Figure 4.2.4: Repartition of the consumed active power (MW) per grid for the situation in 2024.

An overview of the active power interchanges from the Generation grid and the remaining grids is available in Figure . A large amount of active power is seen to be transiting through Malawi Grid before being distributed to Trans Centre, North, and South. Malawi Grid includes the step-up transformers of the Kapichira, Tedzani, and Nkula hydropower plants.

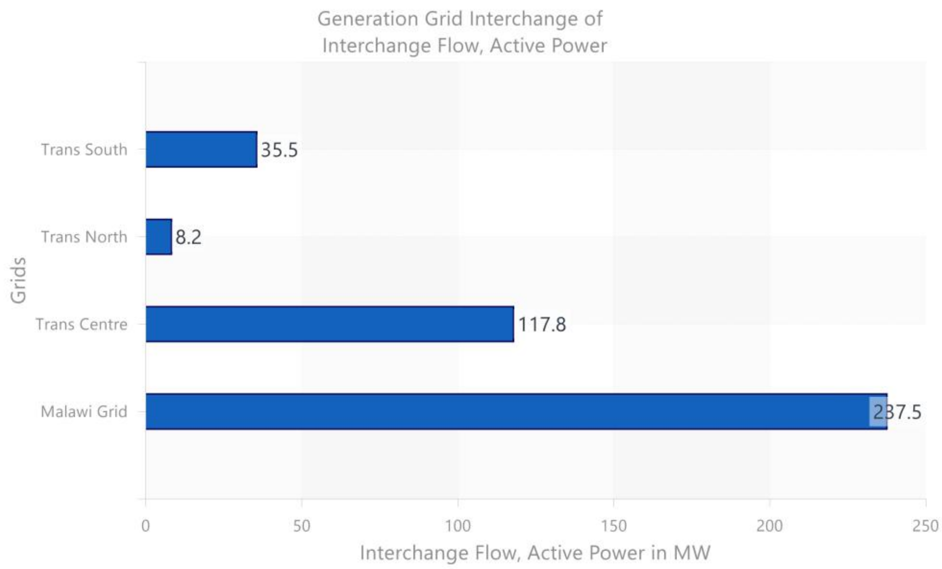


Figure 4.2.5: Active power interchanges (MW) from the Generation grid to the other grids for the initial dispatch in 2024.

2.1.4.2 Voltage values

The maximum and minimum voltage values per grid are shown in Figure . Without any adjustments, the voltage in Malawi can fall as low as 0.786 pu and rise as high as 1.156 pu across all voltage levels. 1 per unit (pu) corresponds to 100% of the nominal voltage. None of the five grids has a voltage distribution that strictly remains inside the recommended normal operating range set between 0.95 and 1.05 pu in the grid code.

Figure 4.2.6: Maximum and minimum voltage values per grid for the initial dispatch in 2024.

Most of the extreme voltage values are in fact related to LV buses below 33 kV. The situation appears to be slightly better for HV buses above 66 kV as the operational voltage varies between 0.814 and 1.106 pu.

Table 4.2.48 reveals that only two HV buses are operated below 0.95 pu. The busbar in Chinyama is supplied in antenna by a 66kV line of 70 km that starts at the busbar of Serengeti. The situation is similar in Fundis Cross where the busbar is supplied in antenna by a 66kV line of 44 km that starts at the busbar in Mapanga. The two low voltages are caused by the large amounts of power flowing across long 66kV lines and the lack of reactive power compensations.

Table 4.2.48: List of HV buses operated below 0.95 pu for the initial dispatch in 2024

Busbar	Grid	Voltage (pu)	Voltage (kV)
Chinyama 66kV	Trans Centre	0.814	53.7
Fundis Cross 66kV	Trans South	0.926	61.1

.

Table 4.2.49 contains the list of the 13 HV buses operating above 1.05 pu. Most of them are located just beyond the step-up transformers of a generating unit. This is namely the case for the busbars in Tedzani, Nkula, Kapichira, and Golomoti. The remaining busbars in Phombeya and BT West are connected to the previous ones through transmission lines. These high voltages could be improved by setting the generating units in voltage control and adding more reactive power compensations in the system.

Table 4.2.49: List of HV buses operated above 1.05 pu for the initial dispatch in 2024.

Busbar	Grid	Voltage (pu)	Voltage (kV)
Tedzani IV 66kV	Generation	1.106	73.0
Tedzani 66kV	Malawi Grid	1.105	72.9
Nkula B 66kV	Generation	1.103	72.8
Nkula A 66kV	Generation	1.102	72.8
Tedzani 132kV	Malawi Grid	1.085	143.3
Nkula B 132kV	Malawi Grid	1.079	142.5
Kapichira 132kV	Malawi Grid	1.078	142.3
Phombeya 132kV	Trans Centre	1.068	140.9
BT West 132kV	Trans South	1.067	140.9
Phombeya 400kV	Trans Centre	1.056	422.5
Golomoti 132kV	Trans Centre	1.052	138.9
JCM Golomoti 132kV	Generation	1.052	138.8
BT West 66kV	Trans South	1.051	69.4

2.1.4.3 Line and transformer loadings

The maximum line and transformer loadings per grid are shown in Figure 4.2.7. Apart from **Trans South**, all remaining grids appear to have at least one branch element loaded above 100%.

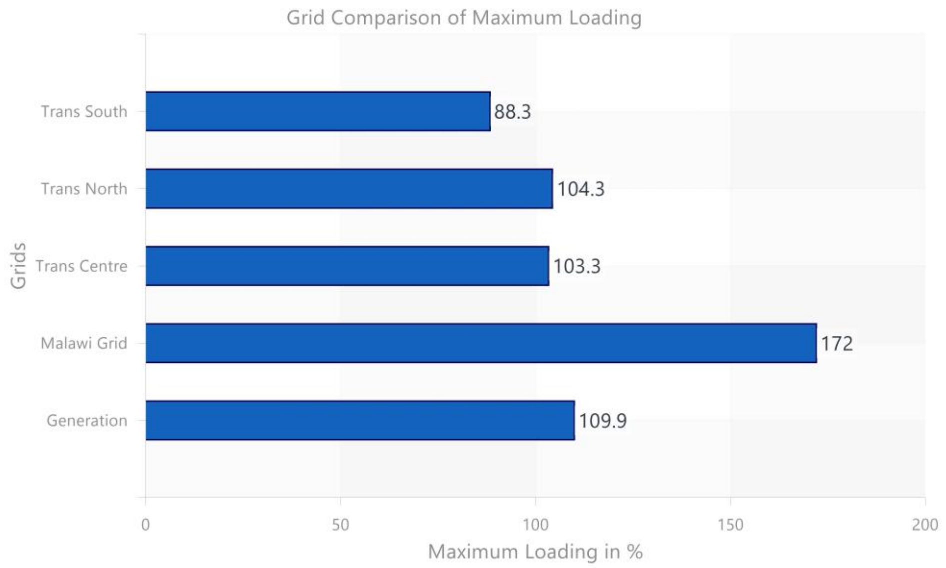


Figure 4.2.7: Maximum line and transformer loadings per grid for the initial dispatch in 2024.

A total of four branch elements are overloaded in the system as displayed in Table 4.2.50 and all of them are transformers. The one in Mlangeni is a step-down transformer supplying a load of 8.01 MW. It was confirmed by ESCOM that the load in Mlangeni has been overestimated in the model and should be revised down to 1.5 MW instead, which is a power level that can be handled by the transformer. The one in Ndiza corresponds to the step-up transformer of the hydropower plant of Ndiza. Additional transformers will need to be installed next the existing one in order to handle the full capacity of the three generating units. The small overload in the 3-winding transformer of Chintheche comes from the installation of a 5 Mvar shunt capacitor at the LV side, which has a rated power of 5 MVA. Finally, the step-down transformer of Chinyama must supply a load of 13 MW at the same location as well as an additional load of 7.5 MW belonging to Shayona. The combination of these two loads is slightly above the rated power of the transformer which amounts to 20 MVA.

Table 4.2.50: List of overloaded branch elements for the initial dispatch in 2024.

Element	Type	Grid	Loading (%)
Mlangeni 66/33kV	2-winding	Malawi Grid	172.0
Ndiza 33/0.4kV	2-winding	Generation	109.9
Chintheche 132/66/33kV	3-winding	Trans North	104.3
Chinyama 66/33kV	2-winding	Trans Centre	103.3

2.1.5 Interconnection with SAPP

The future interconnection with Mozambique and, by extension, SAPP will bring at least two significant benefits to Malawi. The first one is naturally the ability to engage in bilateral and regional power trade. Malawi will be able to export any surplus of power and import power when it is economically justified. The second one is the possibility to benefit from the large inertia and the primary reserves of the regional network of SAPP. Upon the occurrence of a sudden power imbalance inside Malawi, all the generators of SAPP participating in the primary reserves can quickly respond to the frequency deviations. This role will no longer be assumed by the generators of Malawi only.

The benefits of the interconnection with SAPP on the frequency stability is assessed by simulating the loss of a generating unit on the initial PF model. The selected generating unit for the test is Kapichira G4 and the frequency signal is taken from the bus Nkhoma 400kV A (see Figure 4.2.8). A first simulation is run without the equivalent SAPP generator (in blue) and a second simulation is run by keeping the equivalent SAPP generator in service (in red).

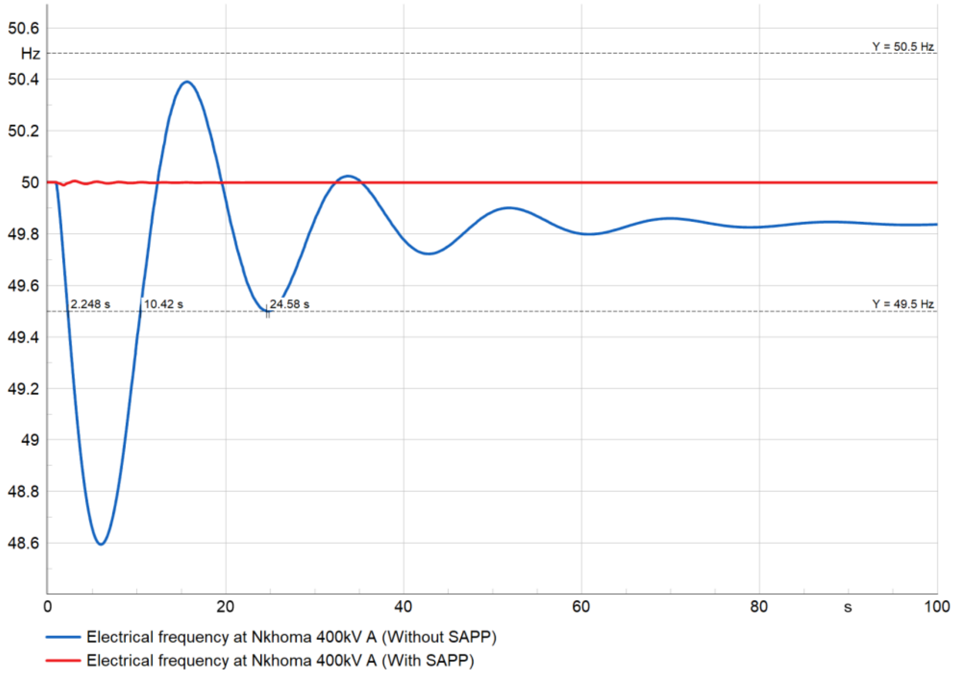


Figure 4.2.8: Time evolution of the frequency at Nkhoma 400kV A after losing Kapichira G4 for the initial dispatch in 2024.

When the Malawian transmission system operates as an isolated system without any support from SAPP, the frequency nadir reaches 48.6 Hz upon the loss of Kapichira G4. The first simulation highlights a lack of inertia in the initial dispatch as the frequency falls below the acceptable limit of 49.5 Hz. When the equivalent SAPP generator is connected, the frequency always stays close to 50 Hz upon the loss of the same Kapichira G4 unit. The second simulation is implicitly considering that the Mozambique-Malawi interconnector is in service and shows the advantage of sharing inertia with SAPP.

2.1.6 Conclusions

The initial DIgSILENT PowerFactory (PF) model shared by ESCOM has served as a basis to understand the characteristics and performances of the existing transmission system in Malawi as of 2024. The analysis consists in checking the available generation and transmission assets, investigating the initial dispatch, and assessing the impact of not being interconnected with the Southern African Power Pool (SAPP).

The main conclusions that can be drawn from the analysis are the following:

Generation and load

- Under the peak load conditions, the generation and load levels amount to 406.9 MW and 383.8 MW, respectively. The imported power from SAPP is 38.9 MW and the total losses is equal to 23.1 MW or 5.68%.
- The load level is significantly lower than the estimated peak of 1850 MW reached in 2042, which almost represent a fivefold increase.

Voltage values

- The voltage magnitude of some busbars fall outside the normal operating range between 0.95 pu and 1.05 pu.
- Some remedial actions include the installation of reactive power compensation devices and the switching of some generating units to voltage control.

Line and transformer loadings

- The loadings of the lines and transformers can be high and even go beyond 100% in the case of some transformers.
- Network reinforcements would certainly be needed to stay compliant after the loss of a highly loaded element in N-1 conditions.

Interconnection with SAPP

- Frequency stability is not guaranteed when the Malawian transmission system is operated as an isolated system.
- The interconnection with SAPP offers an access to a larger inertia and more primary reserves, which limits the frequency deviations.

In the next two decades, the Malawian transmission system is poised to undergo significant changes in view of tackling the current shortcomings. New projects will be installed across the country to enhance access to electricity and improve the security of supply. Some of these projects are already planned, such as the interconnection with Mozambique whose benefits have been demonstrated in this chapter. Others will need to be proposed in the scope of the present transmission development plan while accounting for the expected evolutions in terms of generation capacity and load distribution.

The next chapter recalls the generation development plan derived during the first phase of Workstream 1, which will serve as a reference for the transmission development plan. Besides the combined installed capacities per technology, a new focus is set on proposing a realistic way to split the MW among projects as this choice will also affect the outcomes of the transmission development plan.

3 Generation development plan

The generation system long-term optimal development plan study, presented in a previous report, formed the first task of the development study of the electricity sector which also covers the development of the transmission grid and the distribution networks over the same period. For the sake of coherency, clear links between the different tasks should be defined and respected for all tasks. The results of the generation development plan are parts of the main inputs of the transmission development plan task while the decided and potential interconnection lines with neighboring countries of the SAPP regional grid were inputs of the generation analysis.

In order to provide a complete view on the possible developments of the system, the impacts on the reliability of supply, and the investment costs to the Stakeholders, different scenarios and sensitivity analyses were carried out. For each of the studied cases, a least-cost approach was used including different features defined in close collaboration with the Stakeholders during the working group sessions and the presentation of the intermediate results in Blantyre. The Least-Cost scenario (LC) defines the optimal development plan considering standard candidate units representing all technologies available in Malawi and forms an unbiased optimal long-term least cost development pathway. The Least-Cost + Strategic projects scenario (LCSP) accounts for strategic projects for the country identified with the Stakeholders and illustrates the impact of the selection of these projects on the least-cost development plan.

Following the presentation of the preliminary results, it was confirmed with the Stakeholders that, for the purpose of the planning exercise in the frame of this study, the reference development plan for the other tasks (transmission and distribution) would be the LC scenario. The recommended evolution of the generation system over the complete study period for the LC scenario is recalled in the next sections.

The outcomes of the generation development plan is completed with a list of candidate generation projects, which are characterized by specific rated powers and point of connections. Such information was not required, and therefore not available, during the generation planning phase where the focus was set on sizing the combined generation capacity needed to meet the future demand. In the scope of the transmission planning phase where the focus is on defining the infrastructure needed to connect the generation to the loads, it becomes necessary to translate the combined installed capacities per technology into actual generation projects spread across the country. The proposed generation splitting has been validated by the Stakeholders through email exchanges.

3.1 Reference development plan

3.1.1 Installed capacity

As explained in the introduction, the reference plan corresponds to the least-cost scenario over the whole study period set from 2022 and 2042. Therefore the recommended generation expansion plan combines the Least-Cost investments of the short-, medium- and long-term, and is shown in Figure . In addition, Table 4.3.1 details the evolution of the combined installed capacity for multiple key years.

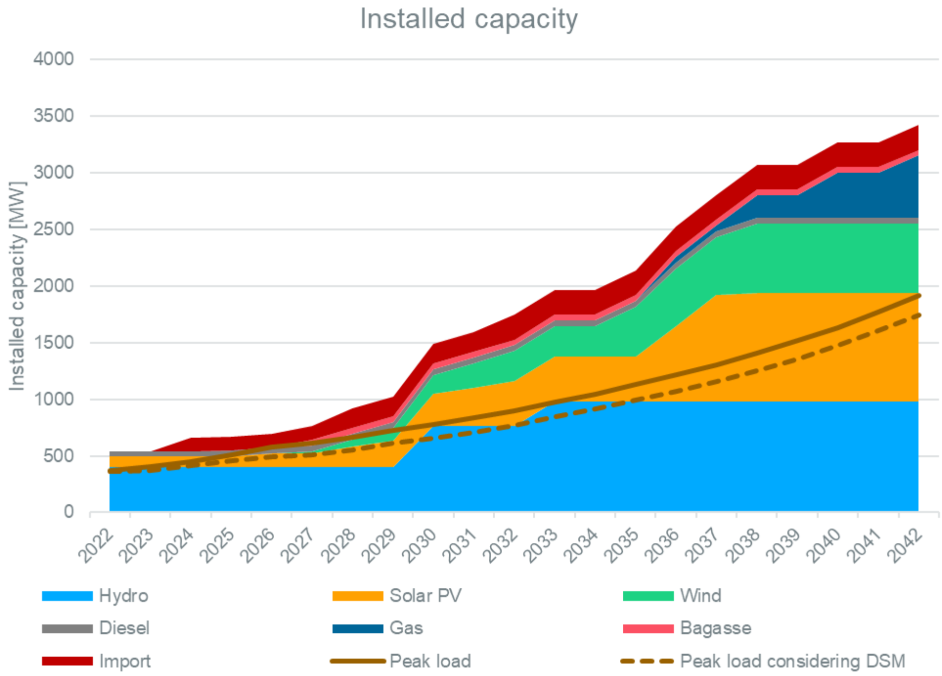


Figure 4.3.1: Installed capacity per technology for the Reference development plan.

Table 4.3.1: Installed capacity per technology for the Reference development plan.

	Installed capacity (MW)				
Technology	**2023**	**2027**	**2032**	**2037**	**2042**
Hydro	398	402	763	982	982
Solar PV	101	124	395	940	956
Wind	0	15	268	513	615
Diesel	42	52	52	52	52
Coal	0	0	0	0	0
Gas	0	0	0	50	550
Biomass	0	50	50	50	50
Geothermal	0	0	0	0	0
Total	**541**	**643**	**1527**	**2586**	**3204**
Import potential	0	120	220	220	220
Peak demand	405	617	900	1307	1914
Peak considering DSM	367	509	771	1159	1746

3.1.2 Investments costs

Figure shows the investments needed to install new units and have new solutions available, which amounts to a total of 4344 MUSD along the whole study period.

Limited investments are foreseen in the short term (2024-2025), as the commissioning of the interconnection with Mozambique, together with the foreseen good availability of river flows, provides good resources to supply the demand. Moreover, the refurbishment of diesel units and the commissioning of 20 MW of BESS increase the flexibility of the system and its capability to cope with sudden variations. The only additional investment in this timeframe concerns the first adoption of demand-side management (DSM) and energy efficiency (EE) measures, costing around 10 MUSD until 2025. DSM and EE measures represents a very efficient way to reduce the costs of the power system by acting on the demand side. Given that the perspective of the current study is the Malawian system as a whole (economic study), the costs of these measures (most of which should be borne by consumers) are here included.

In the medium term (2026-2029), 433 MUSD of CAPEX are foreseen, as the demand growth requires rapid investments in the best technologies which are readily available, namely small hydro (Wowve 2), PV, wind and biomass, together with further penetration of DSM and EE measures.

The two key investments of the horizon are the two big hydro power plants: Mpatamanga in 2030 and Kholombidzo in 2033. The cost of Mpatamanga, set to 670 MUSD during the inception phase of the project and execution of the study, has been updated to 1418 MUSD in the final version of the generation development plan based on the latest estimates shared by the Client. The total investment costs of Kholombidzo amounts to about 675 MUSD. From 2035 to 2042, more than 1300 MUSD of additional investments are required, a third of which is for PV units, about 28% in wind and the remainder in gas units.

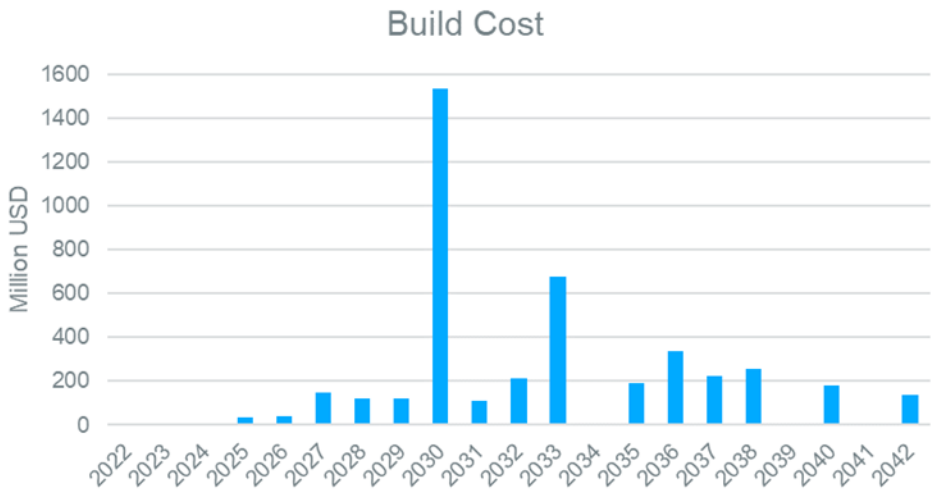


Figure 4.3.2: Yearly investment costs in the Reference scenario

3.1.3 Operating costs

Figure illustrates the total operating costs of the system for key years. In 2027, a good river flow availability is foreseen and more than 60% of the generation is coming from hydropower plants. Besides limited contribution from PV, wind and biomass plants, most of the remaining demand is supplied by the take-or-pay contract with Mozambique. Hence, the domestic production has very limited operating expenses (OPEX) and the costs of import amount to more than 70% of the total OPEX (shown in Figure as variable O&M cost, being expressed as a cost per MWh).

In the long term, big investments in hydropower plants and distributed investments in variable renewable energy (VRE) sources allow to keep low operating costs, with a higher share of fixed O&M than variable O&M (mostly related to import). Fuel costs remain very limited over most of the studied horizon, biomass keeps a high capacity factor while diesel and gas units are rarely used when renewables and import are not sufficient to supply the demand.

This pattern changes rapidly in the last years of the horizon, when the additional gas-fired power plants, needed to provide more flexibility and to satisfy increasing demand, lead to a higher diversification of the energy mix. In 2042, OPEX amounts to more than three times the operating costs of 2037. This difference is nevertheless compensated by rarer and less substantial investment costs (yet with a continuously increasing demand), as described in the previous section.

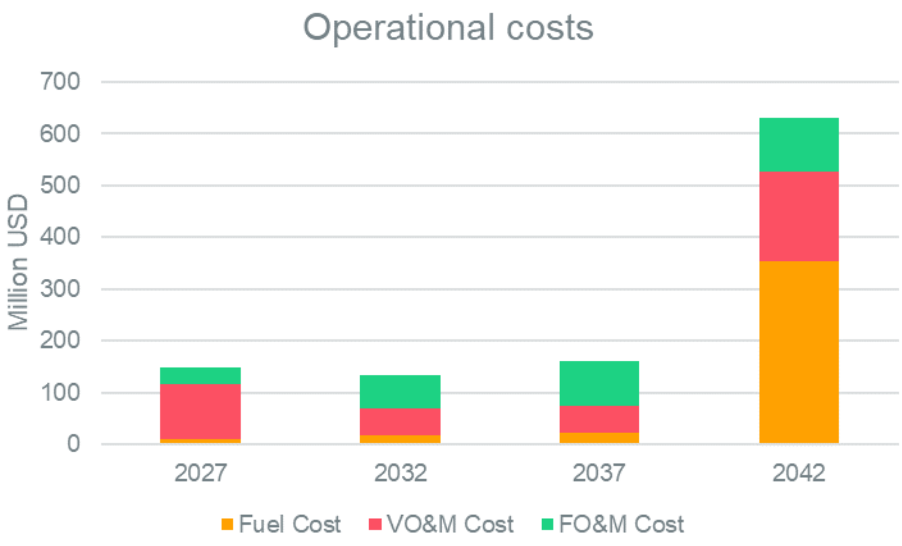


Figure 4.3.3: Total OPEX in key years of the Reference scenario.

3.2 List of candidate generation projects

In view of the transmission development plan, the combined installed capacities per technology presented in Table 4.3.1 for multiple key years must be split into several generation projects. Each additional MW with respect to the current situation needs to be assigned to a connection point in order to evaluate the ability of the transmission system to accommodate new power plants and to identify the needs for reinforcements. The connection points can either be an existing substation or a new one foreseen through the planned transmission projects.

In this framework, Table provides a suggested list of candidate generation projects to be installed over the next 20 years. The candidates are for most derived from a pipeline of projects at different stages of development (i.e., feasibility study, power purchase agreement (PPA) negotiations, waiting for financial close, …). The others are proposed to top the combined installed capacities of Table 4.3.1. The objective of this exercise was to come up with a realistic list of projects which is broad enough to implement the yearly generation dispatches obtained during the first part of Workstream 1. This list of candidate generation projects is therefore a means to proceed with the transmission development plan and should not be seen as the final list of projects that will be implemented in reality.

The elements in the column "First target year for consideration" only take one of the following values: 2027, 2032, 2042. These values correspond to the target years for which a model needs to be develop in the scope of the transmission development plan. The column is thus providing the first model version in which the candidate generation projects start to appear. The values should not be interpreted as the commissioning years which can take place earlier, in between the target years.

In the special case of Mpatamanga, the project is composed of a 309 MW peaking plant and a 52 MW regulating downstream plant that are connected at different points, i.e., Mpatamanga 132kV and Regulation Dam 132kV, respectively

Table 4.3.2: List of candidate generation projects with their installed capacity and connection point

Name	Region	Installed capacity (MW)	Type	First target year for consideration	Connection point	Comments
Kholombidzo	South	219	Hydro	2042	Kholombidzo 132kV	New substation connected to Phombeya 132kV through a double-circuit line of 16 km
Mpatamanga	South	361	Hydro	2032	1) Mpatamanga 132kV 2) Regulation Dam 132kV	1) New substation connected to Phombeya 400kV through a step-up transformer and single-circuit line of 64 km 2) New substation installed after a loop-in loop-out of the Tedzani – Kapichira 132kV double-circuit line
Wovwe 2	North	4.5	Hydro	2027	Wovwe 66kV or 132kV	Existing 66kV substation potentially replaced with a 132kV one
Dwangwa	Center	22	Bagasse	2027	Dwangwa 132kV	Existing 132kV substation
Nchalo	South	33	Bagasse	2027	Mlambe 132kV	Existing 132kV substation
Phalula	South	300	Gas	2042	Phalula 132kV	New substation connected to Phombeya 132kV through a double-circuit line of 6 km
Salima	Center	250	Gas	2042	Salima 132kV	New substation connected to Nanjoka 132kV through a double-circuit line of 16 km
Chingeni	Center	20	Solar	2032	Chingeni 66kV or 132kV	Existing 66kV substation potentially replaced with a 132kV one
Monkey Bay	South	20	Solar	2032	Monkey Bay 132kV	New 132kV substation replacing the 66kV one
Balaka	South	40	Solar	2032	Chingeni 66kV or 132kV	Existing 66kV substation potentially replaced with a 132kV one
Phombeya	South	125	Solar	2042	Phombeya 132kV	Existing 132kV substation
Chatoloma	Center	75	Solar	2042	Chatoloma 132kV	New 132kV substation
Dwangwa	Center	55	Solar	2032	Dwangwa 132kV	Existing 132kV substation
Zomba	South	34	Solar	2032	Zomba 132kV	New 132kV substation
Mangochi	South	20	Solar	2042	Mangochi 132kV	New 132kV substation
Lilongwe	Center	50	Solar	2032	Nkhoma 132kV	Existing 132kV substation
Nanjoka	Center	50	Solar	2042	Nanjoka 132kV	Existing 132kV substation
Chintheche I	North	50	Solar	2032	Chintheche 132kV	Existing 132kV substation
Chintheche II	North	50	Solar	2042	Chintheche 132kV	Existing 132kV substation
Bwengu I	North	50	Solar	2027	New Bwengu 132kV	Existing 132kV substation
Bwengu II	North	50	Solar	2042	New Bwengu 132kV	Existing 132kV substation
Luwinga	North	125	Solar	2042	Luwinga 132kV	Existing 132kV substation

Telegraph Hill	North	50	Solar	2042	Telegraph Hill 66kV or 132kV	Existing 66kV substation potentially replaced with a 132kV one
Mzimba I	North	50	Wind	2027	New Bwengu 132kV	Existing 132kV substation
Mzimba II	North	100	Wind	2042	Mzimba 132kV	New 132kV substation
Dedza	Center	109.5	Wind	2032	Nkhoma 132kV	Existing 132kV substation
Rumphi	North	120	Wind	2032	New Bwengu 132kV	Existing 132kV substation
Zomba	South	120	Wind	2042	Zomba 132kV	New 132kV substation
Lilongwe	Center	120	Wind	2042	Nkhoma 132kV	Existing 132lV substation

Figure presents the geographic distribution of the candidate generation projects on a map. The new projects can be seen to be well-spread across the country. Such a distribution should be beneficial to limit power congestion on the transmission system as each load center could then be supplied by the closest active generating unit.

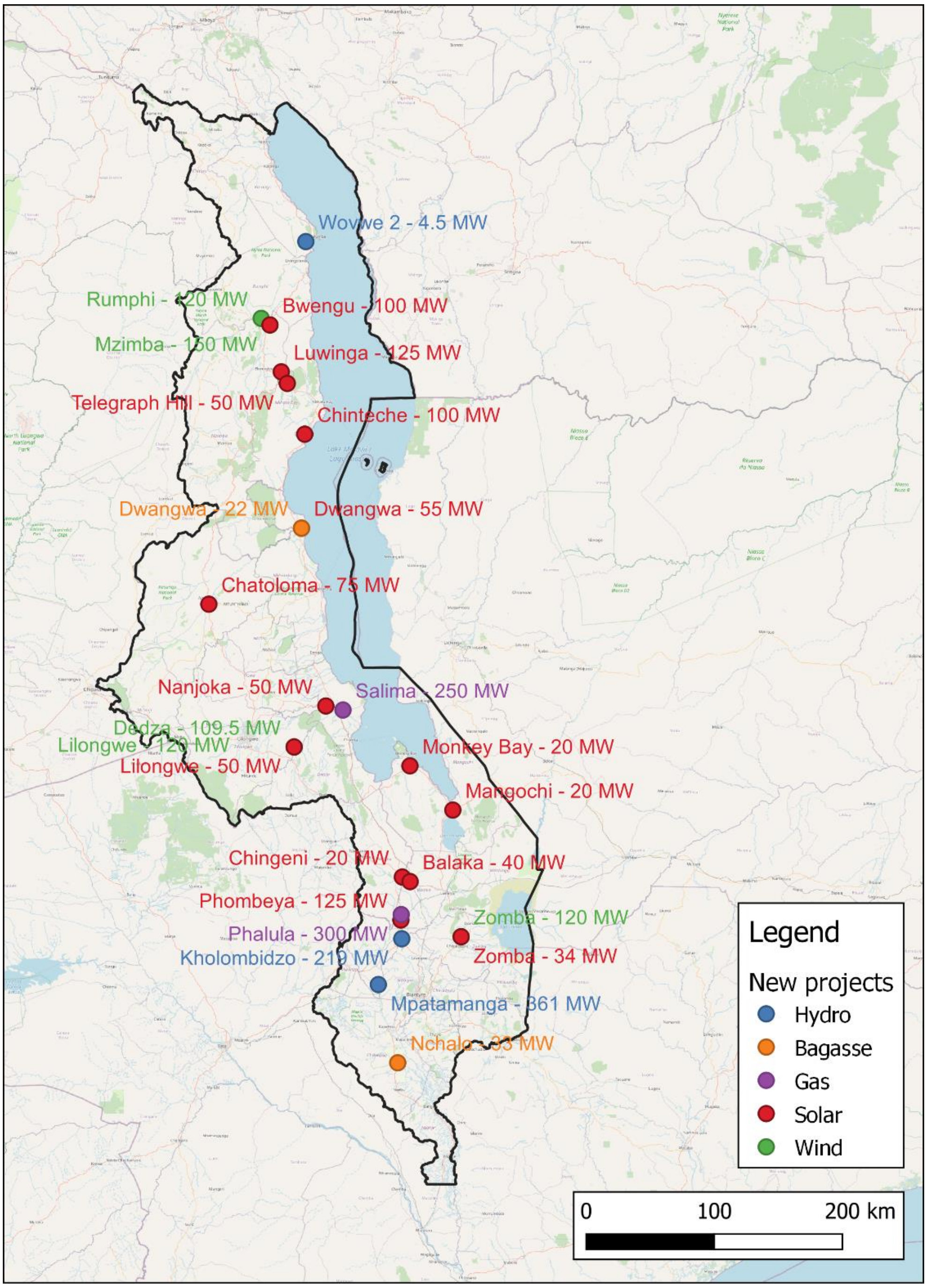


Figure 4.3.4: Map with the candidate generation projects sorted per technology.

In the DIgSILENT PowerFactory model, the candidate generation projects are modeled as generating units (i.e, synchronous machines, wind turbines, or PV systems) that are connected to a HV substation via adequate step-up transformers.

4 Load distribution

The location and size of the demand is calculated in the scope of the distribution workstream. Multiple databases are used as inputs:

- ESCOM database: existing service transformers and MV network
- Data inquiries: location and demand of direct customers
- Integrated Energy Planning (IEP) Tool: electrification network and demand up to 2030
- Malawi Rural Electrification Programme (MAREP): electrification demand up to 2030
- Data inquiries: location and expected demand of future industrial load centers

All data are combined into a consolidated GIS database. Next, the demand is divided among the known load centers for the following target years: 2023, 2027, 2032, and 2042. The demand is divided proportionally to the size of the transformers, while considering the demand forecasts at regional and sectoral levels as calculated by ECA [3]. This process is visualized in Figure 4.4.1:

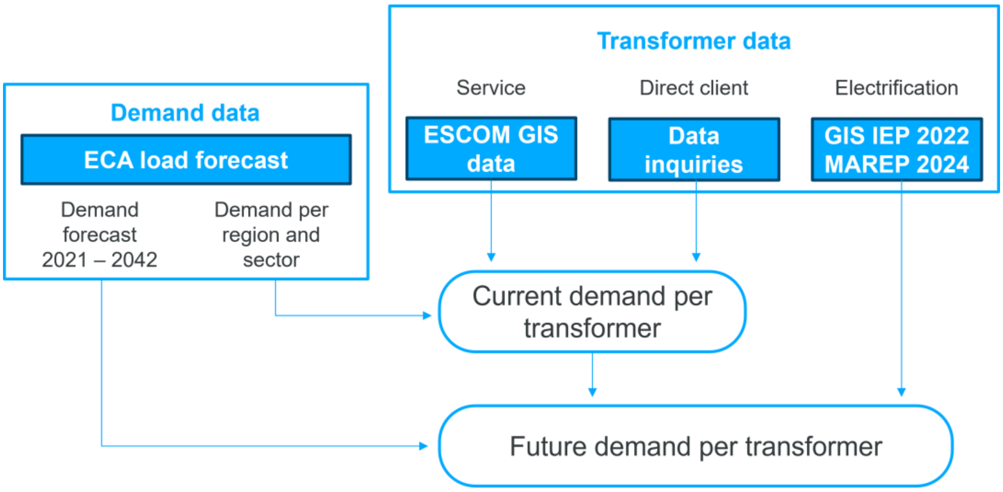
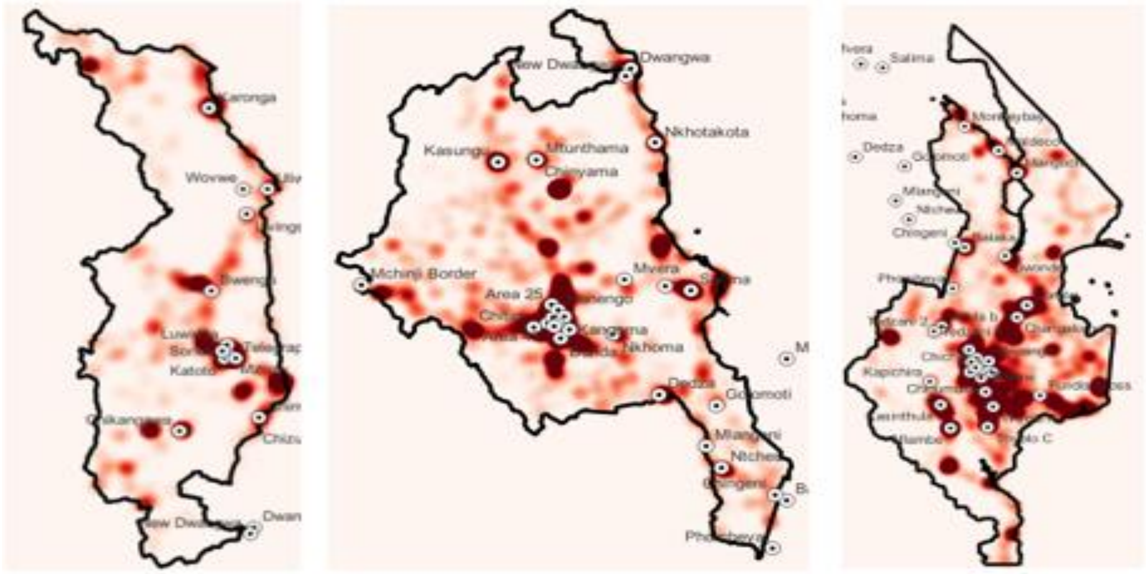


Figure 4.4.1: Methodology for the geographical demand analysis.

4.1 Current demand (2023)

The total demand in 2023 is 2280 GWh. This includes losses on the LV network, but not the losses on the MV and HV networks. The demand growth is distributed between the existing load centers, while respecting the regional and sectoral forecasts.

Service transformers account for 73% of the total demand, the remaining 27% is allocated to direct transformers. **Error! Reference source not found.** visualizes the load centers in 2023 per region.



Northen region **central region** **southern region**

Figure 4.4.2: Load centers in 2023 per region.

Northern Region

The largest load center in the Northern Region is Mzuzu with a synchronous peak load of 16 MW. Other load centers include Karonga, Chitipa, Rumphi, Nkhata Bay, and Mzimba. The demand in the north is small compared to the other regions, only representing 10% of the total demand.

Central Region

The capital of Lilongwe is the largest load center in the Central Region and in the country in general. The synchronous peak demand is 90 MW, and this value increases further when accounting for the suburbs. Besides Lilongwe, there are other (smaller) load centers around Kasungu, Dwangwa, Salima, and Mchinji.

Southern Region

Blantyre is the largest load center in the Southern Region with a synchronous peak demand of 66 MW. The city surroundings and suburbs also have a significant load. Notably, the district of Chileka substation and Chileka international airport has another 8 MW synchronous peak demand.

Other load centers are visible in the vicinity of Monkey Bay, Liwonde, Zomba, Kapichira, and the regions southeast of Blantyre.

4.2 Future demand

The demand is expected to increase fivefold in the next 20 years and reach 1900 MW in 2042. A significant part of the demand growth is attributed to electrification. This process represents 22% of the total demand by 2042. In addition, there are plans for supplying new industrial loads for a total of 60 MW by 2030.

Starting from the demand distribution in 2023, the load growth is modeled at existing load centers, new electrified regions, and new industrial load centers. The demand is calculated for the target years 2027, 2032, and 2042. Figure displays how the load density of the districts, expressed as the synchronous peak load density (in kW/km²), is expected to evolve between 2023 and 2042. Lilongwe, Blantyre, and Mzuzu will remain the most dense load centers of the country. Besides the large cities, most areas will experience a significant load growth. This is particularly true for the Central and Southern Regions where most of the electrification efforts are expected. Most of the areas around Lilongwe and Blantyre will be fully electrified by 2032.

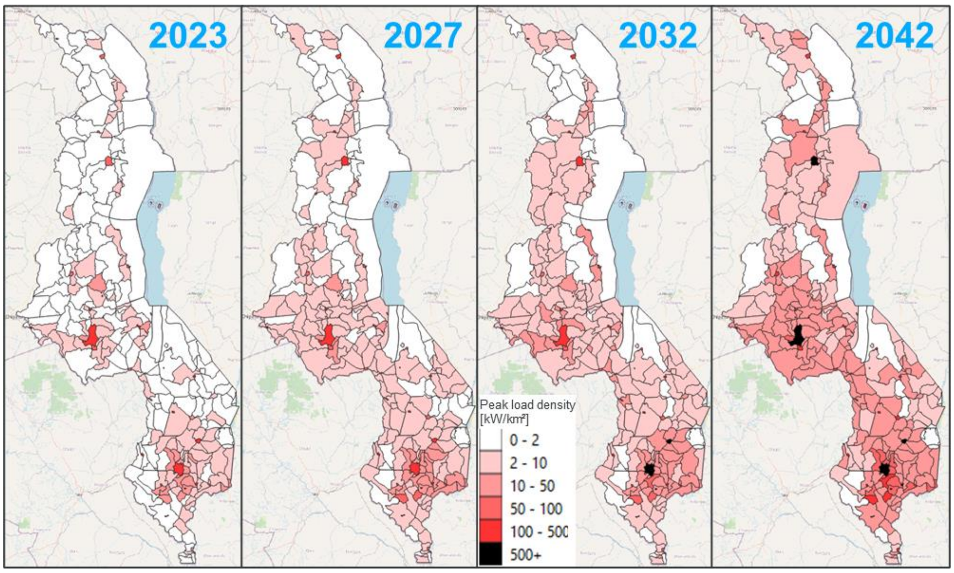


Figure 4.4.3: Evolution of the electricity demand between 2023 and 2042.

Table lists the demand in the major cities for each target year. The demand is expected to increase 4 times in Lilongwe and Blantyre and 6 times in Mzuzu. While still representing a small share of the national demand, the Northern Region should experience the highest demand growth in the next 20 years.

Table 4.4.1: Synchronous peak load in the major cities between 2023 and 2042.

City	Load 2023 (MW)	Load 2027 (MW)	Load 2032 (MW)	Load 2042 (MW)
Lilongwe	91	118	142	354
Blantyre	66	89	121	265
Mzuzu	12	23	32	71

4.3 Needs for new primary and secondary substations

The increase in demand requires profound upgrades of the existing network. New primary and secondary substations are proposed based on the following approach:

New primary substations are mainly installed in rural areas that will experience a significant demand growth and that are located far from the HV transmission system. Primary substations avoid having multiple long MV feeders in parallel and reduce the overall grid losses.

New secondary substations allow to supply concentrated load in a given area while avoiding numerous long 11kV feeders. Instead, one or two 33kV feeders are installed up to the secondary stations in which one or several 33/11kV transformers will supply 11kV feeders to power the surrounding area. This reduces the total investment costs and accounts for possible space constraints to install additional new distribution lines or cables within the city. Secondary substations are typically installed in order to supply new industrial zones developed at the city border.

As a result of the load increase across the country, a significant amount of secondary stations will require to be upgraded as primary stations. This will allow to supply the load in the city outskirts. In addition, this reduces the load at the primary substation where the secondary substation was initially connected.

The demand at each substation is calculated for the years 2023, 2027, 2032, and 2042. Each year, the peak demand is calculated for all substations. Then, new substations are proposed based on the identified weak spots in the network. Finally, the peak demand at each substation is calculated again, now considering the network upgrades (new substations). This calculated peak demand is used in the further analysis of the transmission system.

The sections below discuss the proposed primary substations. This includes new primary substations and secondary substations that will be upgraded to primary substations.

Results for 2027

In the short term, no reinforcements of substations are needed. The Zomba substation will experience a high demand growth and reach an estimated peak load of 22 MW in 2027. As a result, it should be among the first substations that ESCOM connects to the HV network. The analysis foresees this upgrade between 2027 and 2032.

Results for 2032

The following secondary substations are in need for an upgrade to primary before 2032: Chileka, Mangochi, and Zomba. The Chileka and Zomba substations will have a peak demand in 2032 that exceeds the 20 MW threshold. Notably, Zomba should be prioritized as the demand is expected to reach 32 MW by 2032. A substation upgrade in Zomba should be planned for as soon as possible.

The Mangochi substation has an estimated peak demand of 18 MW by 2032. However, this substation also supplies the eastern side of Lake Malawi up to Makanjira. The connection of Mangochi to the HV network will reduce voltage drops and grid losses and allow for a more robust supply of that region. Mangochi can be connected to the HV network in Monkey Bay. The possible extension of the transmission network from Mangochi to Makanjira should be decided based on the measured evolution of the demand and the confirmation of the industrial projects. This route passes through Maldeco, making this another candidate for an upgrade to primary substation. However, this upgrade is not critical as the demand of the Maldeco substation should remain low.

One new primary substation is proposed before 2032. The region north of Lilongwe is generally far from the HV network and experiences a high load growth, mostly due to electrification. The new substation is proposed in Mponela, north of Lilongwe. This substation would take over part of the load of the Nanjoka and Kanengo substations and supply a peak load of 24 MW in 2032.

Results for 2042

The following secondary substations are proposed to be upgraded to primary substations between 2032 and 2042:

- Area 47
- Chirimba
- Chitipi
- City Center
- Kasungu
- Limbe A
- Limbe B
- Michiru
- Sonda
- Thyolo A
- Thyolo B
- Thyolo C

In addition, two new primary substations are proposed: one in Namitete (west of Lilongwe) and one in Phalombe (south of Lake Chilwa). They will have an estimated peak demand of 28 and 30 MW by 2042.

The peak demand of these substations will exceed the 20 MW threshold between 2032 and 2042, requiring a connection to the HV network to limit grid losses and secure sufficient transformer capacity.

Some substations have a slightly lower peak demand but their upgrade to primary substation is recommended because of their location close to existing or planned HV lines. Chitipi (19 MW peak load in 2042) substation will be connected to the HV line that extends west from Lilongwe to the new primary substation in Namitete. Kasungu will become an essential HV substation that connects to the planned 400 kV backbone and the planned 132 kV line to Dwangwa. Although the peak load at MV level will only reach 12 MW in 2042, the substation will still be an important reinforcement of the HV network.

In the DIgSILENT PowerFactory model, the new HV substations are modeled and connected to the existing transmission system via adequate HV lines.

5 Transmission development plan

The transmission development plan (TDP) builds on the results of the generation and distribution development plans presented in the two previous chapters and on the integrated resource plan

(IRP) for Malawi of 2017 [4]. It serves as a strategic blueprint for the future development and expansion of the transmission system. The TDP identifies the necessary infrastructure upgrades to ensure reliable and efficient transmission operations while considering the demand growth and the integration of new power plants. Some key performance indicators (KPIs) used to evaluate a TDP may include the transmission efficiency, the network reliability, the capacity utilization, the investments costs, or the environmental impact. These indicators can help to guide the decision-making process and prioritize some investments. At the end of the exercise, the TDP outlines the transmission projects already committed in the past and the newly recommended projects to be developed over the next 20 years.

The formulation of the TDP is mainly based on the results of simulations performed in DIgSILENT PowerFactory (PF) and information retrieved from the data collection process. At first, the initial PF model of the Malawian transmission system is expanded to include the new power plants recommended on the basis of the generation development plan and to reflect the demand growth estimated in the scope of the distribution development plan. New transmission projects that have been decided or proposed in the past are also integrated as they already went through some pre-feasibility studies. These transmission projects are more likely to be implemented in the future. From this state of the model on, new reinforcements are suggested to make sure the loads can be supplied in a reliable and efficient way.

In the preliminary stage of the analysis, two high level reinforcement strategies were studied and discussed with the Stakeholders (presentation of the draft final report on June 3, 2024 in Blantyre). In Option 1, new transmission lines and transformers are added in parallel to solve any overloads that appear following the increase in generation and load. In Option 2, the existing 66kV system is upgraded to a 132kV system in order to accommodate more power flows. Both options are validated through quasi-dynamic simulations to ensure the system remains grid code compliant over the entire year of 2042. The power system calculations are complemented with a costs estimation section that serves as one of the main KPIs to compare the two options.

The comparison of the results highlighted the interest of upgrading the transmission network to 132 kV. This conclusion was completed by the Stakeholders by providing a list of decided short-term network development projects during the presentation of the draft final report on June 3, 2024 in Blantyre (source: ESCOM). The consideration of these reinforcement for the update of the network constitutes the base of the reference network structure for the grid development.

The work does not include any field studies to collect additional data about the environment. Defining the location of new substations and the distance of new transmission lines is only done approximately by looking at online maps. More precise information could only be obtained through dedicated pre-feasibility studies, which are outside the scope of this framework.

On basis of this approach, this chapter is structured as follows:

- Section 5.1 details the projects defined for the reinforcement of the transmission system. Sections 5.1.1 and 5.1.2 list the decided and potential reinforcement projects respectively as shared and discussed with the Stakeholders during the data collection phase of the project. Section 5.1.3 lists the reinforcement projects decided for the next development phase as defined by ESCOM. The integration of these projects with the chosen development strategy will define the reference network structure studied in detail in the frame of this development plan.

- Sections 5.2 and 5.3 present analyses of the development options at the study horizon, comparring the technical results and related costs.
- Based on this comparison, the long-term development strategy is defined in Section 5.4.
- In Section 5.5, the application of the selected development strategy to the latest short-term development projects determines the reference network structure at the study horizon. The evolution from the current situation to this target structure will be assess in Chapter 6.

5.1 Decided/proposed transmission projects

ESCOM already has some plans to upgrade the transmission infrastructure in the near future. The projects have been defined in previous versions of TDP and are for most illustrated in Figure 4.5.. New transmission lines appear in dashed lines on this map of Malawi from 2018, along with existing transmission lines that are represented in solid lines. The colors on the map reflects the rated voltage levels at which the transmission lines are operated.

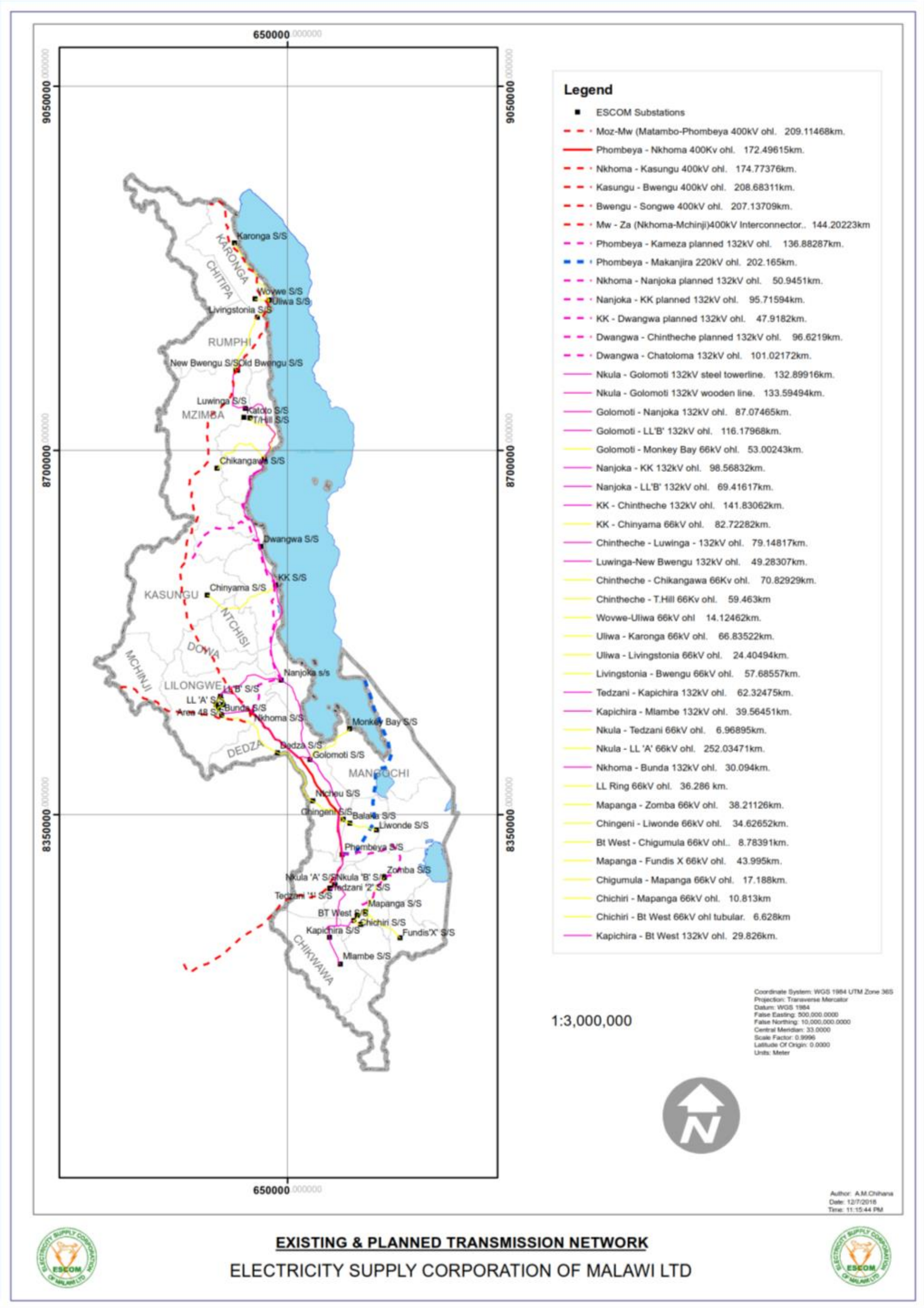


Figure 4.5.1: Map with the existing and planned transmission lines in Malawi as of 2018 [5].

Among the new transmission lines, some are already decided and waiting to be implemented [6]. The remaining ones are still in the proposal stage [7]. A screening of the projects is performed in the next sections based on their “decided” or “proposed” status. Table and Table contain additional and more recent information than on the map of Figure 4.5. and should be treated as the references.

5.1.1 List of decided transmission projects

Table presents the list of decided transmission projects in Malawi as of 2024.

Table 4.5.1: List of decided transmission projects in Malawi as of 2024 [6].

Name	Voltage (kV)	Circuits (-)	Substation		Length (km)
			From	To	
Mozambique – Malawi 400kV interconnector	400	1	Matambo (MZ)	Phombeya	212
Zambia – Malawi 400kV interconnector	400/330	1	Chipata 330kV (ZM)	Mchinji 330kV	40
			Mchinji 330kV	Mchinji 400kV	0
			Mchinji 400kV	Nkhoma 400kV	144
Eastern Backbone project	132	2	Nkhoma	Nanjoka	51
			Nanjoka	Nkhotakota	98.33
			Nkhotakota	Dwangwa	50
			Dwangwa	Chintheche	90
Western Backbone project	400	1	Nkhoma	Chatoloma	174.77
			Chatoloma	New Bwengu	208.68
			New Bwengu	Songwe	207.14
Nkhoma – Bunda TC – Malingunde – Kasiya 132kV line	132	1	Nkhoma	Bunda TC	30.06
			Bunda TC	Malingunde	17
			Malingunde	Kasiya	54

The first two projects correspond to interconnectors with Mozambique and Zambia, respectively. The one with Mozambique is the first that will be implemented. From that moment on, the Malawian power system will gain access to SAPP and its common electricity market. Malawi can also count on the neighboring countries to provide ancillary services instead of relying only on its own reserves. This new interconnector will therefore significantly change the way the Malawian power system is operated. The one with Zambia will offer a second access point to SAPP.

The Eastern Backbone project is a new double-circuit 132kV line linking the Central Region to the Northern Region along the Eastern Corridor of Malawi. It aims at replacing the existing single-circuit 132kV line built on wooden poles. Thanks to this upgrade, the transmission system will be strengthen in Malawi and the electricity transfer will be facilitated across the different regions.

The Western Backbone project is another major electricity highway between the Central Region and the Northern Region that passes through Kasungu and Mzimba. It will be operated at 400 kV to facilitate the interconnection with the transmission systems of Mozambique, Zambia, and Tanzania.

The 132kV line between Nkhoma and Kasiya will be built to supply the mining sites of Malingunde and Kasiya.

All completion dates have been omitted in the table because the original ones were overly optimistic. According to [6], the five decided transmission projects were supposed to be operational by March 2024, which is not the case.

5.1.2 List of proposed transmission projects

Table presents the list of proposed transmission projects in Malawi as of 2024.

Table 4.5.2: List of proposed transmission projects in Malawi as of 2024 [7].

Name	Voltage (kV)	Circuits (-)	Substation		Length (km)
			From	To	
Mozambique – Malawi 400kV interconnector	400	1 → 2	Matambo (MZ)	Phombeya	212
Tanzania – Malawi 400kV interconnector	400	1	Mbeya (TZ)	Songwe	113
Dwangwa – Chatoloma 132kV line	132/400	1	Dwangwa 132kV	Chatoloma 132kV	101.02
			Chatoloma 132kV	Chatoloma 400kV	0
Phombeya – Zomba – New Blantyre 132kV line	132	2	Phombeya	Zomba	75
			~~Zomba~~	~~New Blantyre~~	~~70~~
Golomoti – Monkey Bay 132kV line	132	2	Golomoti	Monkey Bay	53
Phombeya – Mangochi – Makanjira 132kV line	132	1	Phombeya	Mangochi	101
			~~Mangochi~~	~~Makanjira~~	~~101~~[26]

The first project consists in stringing a second interconnector with Mozambique on the same towers as the first one to increase the reliability of the Malawian transmission system. By doubling the interconnector, Malawi can remain connected to SAPP if one of the two transmission lines is lost. The primary reserve requirements would then drop from 120 MW after the commissioning of the first line to approximately 6 MW after the commissioning of the second line, as explained in the report of WS Generation. Section 6.1.4.3 is dedicated to the analysis of the loss of the interconnection and the potential solutions to limit its impact on the stability of the national system.

The second project is the interconnector with Tanzania and, by extension, EAPP. While the access to another electricity market is beneficial from an economical point of view, the implementation will require a sound technical coordination. Interconnecting two synchronous areas through a relatively weak 400kV system, like the one of Malawi, may result in large inter-area oscillations and transient stability issues. In addition, the new interconnector could enable a loop flow between SAPP and EAPP alongside the new link planned between Tanzania and Zambia. Extra measures are therefore needed to ensure the project correctly contributes towards sustainable energy cooperation between both countries.

The 132kV line between Dwangwa and Chatoloma serves as a bridge between the Eastern and Western Backbone projects. The project will enhance the security of supply in the grid as power can be rerouted through this 132kV line in case of contingency on any of the two backbones. Having a reliable transmission is also beneficial for promoting the development of new mining and manufacturing sites in Kasungu.

[26] The connection from Mangochi to Makanjira was initially overlooked due to uncertainties about the demand growth and new industrial projects justifying the construction of this line. However, in the updated list of decided/proposed transmission projects, this connection is now considered as crucial (see Section 5.1.3). The Stakeholders have confirmed the significant development potential in Makanjira.

The fourth project is designed to transfer power from Phombeya to the load centers of Zomba and Blantyre by means of a double-circuit 132kV line. New HV substations will be built in Zomba and in the north of Blantyre for this purpose. In the scope of this study, it is suggested to only consider the first part of the project that connects Phombeya to Zomba. The transit to Blantyre will instead be achieved through a new link from Zomba to Changalume and the reinforcement of the existing 66kV line between Changalume and Mapanga.

The fifth project plans to enhance the network between Golomoti and Monkey Bay by replacing the existing single 66kV line with a double-circuit 132kV line. This upgrade aims to provide a reliable power supply to Monkey Bay, fostering economic development in the area. This lakeshore district has great growth potential, with proposals for five-star hotels and the presence of mineral deposits attracting mining companies.

The sixth project suggests the installation of two new HV substations in Mangochi and Makanjira, which would be supplied from Phombeya through a 132kV line. However, the project does not belong to the list of priority investments of ESCOM and the results of WS Distribution only recommend to upgrade the substation in Mangochi. The possible extension of the transmission network from Mangochi to Makanjira should be decided based on the measured evolution of the demand and the confirmation of the industrial projects.

5.1.3 Updated list of decided/proposed transmission projects

During the validation of the draft transmission master plan on June 3, 2024 in Blantyre, the Consultant was informed by the Stakeholders about the projects decided by ESCOM for reinforcing and extending the transmission network. It was agreed to consider these projects, along with those presented in the previous sections, as the basis for defining the reference network structure for the long-term development of the network.

Taking into account these elements, Table and Table present the updated lists of decided/proposed transmission projects in Malawi for the years 2027 and 2032, respectively.

Year 2027

Table 4.5.3: Updated list of decided/proposed transmission projects in Malawi for the year 2027.

Name	Voltage (kV)	Circuits (-)	Substation		Length (km)
			From	To	
Mozambique – Malawi 400kV interconnector	400	2[27]	Matambo (MZ)	Phombeya	212
Eastern Backbone project	132	2	Nkhoma	Nanjoka	51
			Nanjoka	Nkhotakota	98.33
			Nkhotakota	Dwangwa	50
			Dwangwa	Chintheche	90
Golomoti – Monkey Bay 132kV line	132	2	Golomoti	Monkey Bay	53
Monkey Bay – Mangochi – Makanjira 132kV line	132	1	Monkey Bay	Mangochi	55
			Mangochi	Makanjira	101
Blantyre West – New Blantyre – Nkula B 132kV line	132	1	Blantyre West	New Blantyre	46
			New Blantyre	Nkula B	31
New Blantyre – Phalombe 132kV line	132	1	New Blantyre	Phalombe	85
Nkhotakota – Serengeti – Chinyama – Kanyika 132kV line	132	1	Nkhotakota	Serengeti	9
			Serengeti	Chinyama	70
			Chinyama	Kanyika	43
Lilongwe 132kV loop	132	1	Nkhoma	Malingunde	56
			Malingunde	Kasiya	54
			Kasiya	KIA	50
			Kanengo	KIA	16.5
			KIA	Nanjoka	64.5

[27] As highlighted in the Generation development plan final report, the addition of a second circuit to the first interconnector is recommended. Section 6.1.4.3 is dedicated to the analysis of the loss of the interconnection and the potential solutions to limit its impact on the stability of the national system.

Year 2032

Table 4.5.4: Updated list of decided/proposed transmission projects in Malawi for the year 2032.

Name	Voltage (kV)	Circuits (-)	Substation		Length (km)
			From	To	
Zambia – Malawi 400kV interconnector	400/330	1	Chipata 330kV (ZM)	Mchinji 330kV	40
			Mchinji 330kV	Mchinji 400kV	0
			Mchinji 400kV	Nkhoma 400kV	144
Tanzania – Malawi 400kV interconnector	400	1	Mbeya (TZ)	Songwe	113
Western Backbone project	400	1	Nkhoma	Chatoloma	174.77
			Chatoloma	Mzimba	119
			Mzimba	New Bwengu	87
			New Bwengu	Songwe	207.14
Phalombe – Zomba 132kV line	132	1	Phalombe	Zomba	63
Changalume – Zomba – Liwonde 132kV line	132	1	Changalume	Zomba	13
			Zomba	Liwonde	50
Phombeya – Liwonde – Mangochi 132kV line	132	1	Phombeya	Liwonde	45
			Liwonde	Mangochi	75
Kanyika – Chatoloma 132kV line	132/400	1	Kanyika 132kV	Chatoloma 132kV	24
			Chatoloma 132kV	Chatoloma 400kV	0
Mzimba – Dwangwa 132kV line	132/400	1	Mzimba 132kV	Dwangwa 132kV	115
			Mzimba 132kV	Mzimba 400kV	0

The 132kV line between Kanyika and Chatoloma completes the crucial link of the first bridge connecting the Eastern Backbone to the Western Backbone. This bridge starts from Nkhotakota, passes through Serengeti, Chinyama, and Kanyika, and terminates in Chatoloma. With this bridge in place, power exchange between the eastern and western regions of the country will be facilitated. Electricity generated on one side of the bridge could be used to supply loads located on the other side.

The 132kV line between Mzimba and Dwangwa forms a second bridge between the two backbones and completes a 132/400kV ring in the north of the country that includes the substations of Mzimba, Dwangwa, Chintheche, Luwinga, and Bwengu. This new bridge will enhance the security of supply around Mzuzu and better support future load growth. Preliminary simulations performed in the scope of Section 5.2 have also highlighted the benefits of having two bridges to distribute power and prevent overloads in case of a contingency on the Western Backbone.

5.2 Reinforcement strategies

Implementing the decided and proposed transmission projects alone will not be enough to cope with the increase in power flows expected by 2042. Preliminary load flow results reveal that mainly the 66kV system in Malawi will become unfit for transferring power from generation to load. Some 66kV lines could be loaded at more than 200% or induce a large voltage drop between the sending and receiving sides. These observations call for more reinforcements targeted foremost at the 66 kV system.

An illustration of the concepts behind the two main reinforcement strategies considered in this study is provided in Figure .

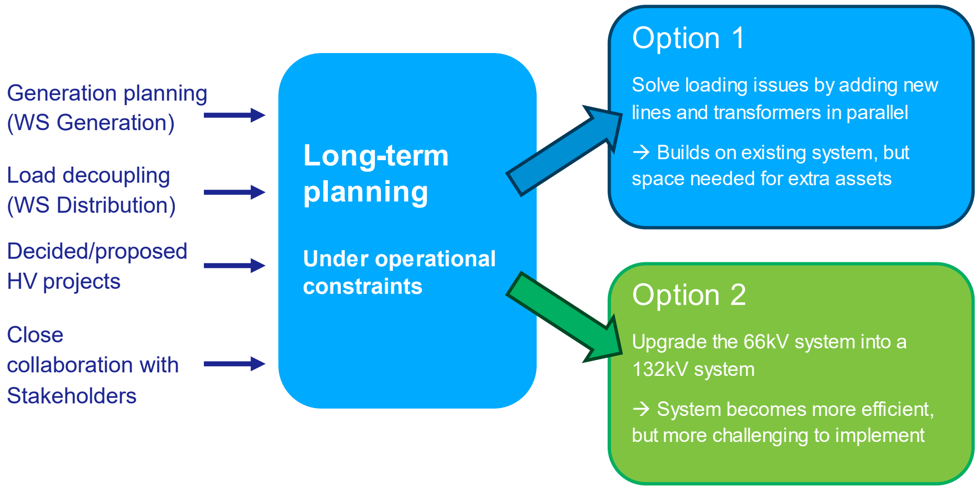


Figure 4.5.2: Concepts behind the two main reinforcement strategies.

In Option 1, the idea is to solve any sustained overloads observed from load flows simulations by adding new transmission lines and transformers in parallel. These reinforcements do not only apply to the 66kV system but also the other voltage levels when relevant. The main advantage is that Option 1 builds on the existing transmission system which can mostly be reused. The disadvantage is that the number of parallel elements can end up being high and space is needed for these extra assets. In light of this concern, Option 1 also considers the replacement of existing lines and transformers with higher rating equipment. New lines or transformers can transmit, in some cases, more than twice the maximum power tolerated by the old equipment.

In Option 2, the transmission system is reinforced by converting all existing 66kV assets into stronger ones operated in 132 kV. Additional lines and transformers can also be added in parallel if proven to be necessary despite the upgrades. The main advantage in operating at a higher voltage level is the reduction of the network losses at transmission level, which makes the system more efficient. The disadvantage is that the replacement of the entire 66kV system can be costly and technically challenging. A close coordination between the transmission and distribution levels will be necessary to ensure that power can still be properly delivered during the upgrade process.

A fair comparison between both options is performed in this section by looking for the minimum number of changes needed to make the transmission system compliant under the actual operational and planning criteria. The applied method requires to run quasi-dynamic simulations and contingency analyses on an updated PF model of the Malawian transmission system, which is representative of the expected situation in 2042.

The analysis will identify the most suitable long-term development strategy for Malawi. This strategy will be integrated with the short- and medium-term projects outlined in Section 5.1.3 to establish the reference network structure for the study horizon.

5.2.1 Operational and planning criteria

The Malawi Energy Regulatory Authority (MERA) has issued a grid code in 2016 that governs the operation and planning of the national transmission system in Malawi [2]. It outlines the criteria that must be fulfilled to maintain a reliable and efficient transmission system. The grid code fixes different rules depending on whether the system is operating in normal state (N) or after a single outage (N-1). It also foresees different ancillary services requirements depending on whether the Malawian power system is connected to SAPP or not. A summary of the most relevant criteria that need to be checked against when performing power system studies is provided hereafter.

5.2.1.1 Operating states

The acceptable operating ranges in the normal state (N) and after a single outage (N-1) are presented in Table 51. The notion of single outage encompasses the loss of a generating unit, a transmission line, or a transformer.

Table 51.5.5: Acceptable operating ranges in N and N-1 situations [2].

	N situation	N-1 situation
Voltage	±5%	±10%
Loading	100%	110%
Frequency	±0.3 Hz	±0.5 Hz

In the **normal state**,

- The voltages at all connection points are within 0.95 and 1.05 of the nominal value
- The loading levels of all transmission lines and substation equipment are below 100% of the maximum continuous ratings
- The system frequency is within 49.7 and 50.3 Hz

After a **single outage**,

- The voltages at all connection points are within 0.9 and 1.1 of the nominal value
- Transitory overloads are permitted provided that they do not exceed 110% of the maximum continuous ratings and that they can be corrected through network reconfiguration or generation redispatch
- The system frequency remains within 49.5 and 50.5 Hz

5.2.1.2 Ancillary services requirements

When not connected to SAPP, the size of the reserves is established based on a reference incident that needs to be defined every year.

For primary reserve,

- The amount of primary reserve will be, at least, the power generation needed to maintain the frequency between 49.5 and 50.5 Hz after the occurrence of the reference incident

For secondary reserve,

- The minimum amount of secondary reserve shall be the maximum between:
  - The amount of power generation needed to continuously balance generation and load under the control of AGC

- The amount of power generation needed to compensate the short-term fluctuations of VRE generation plus the errors in the VRE generation forecasts
- The amount of power generation needed to restore the primary reserve within 10 min after the occurrence of the reference incident

For tertiary reserve,

- The amount of secondary plus tertiary reserves will be the power generation needed to recover the frequency to 50 Hz in 30 min or less after the occurrence of the reference incident

When connected to SAPP, the size of the reserves shall be governed by the Agreement between Operating Members (ABOM) and the SAPP operating guidelines.

5.2.1.3 Fault clearance times

The fault clearance times, which include the breaker operating times, depend on the voltage level as follows

- 80 ms where the voltage at the connection point is 275kV or above
- 100 ms where the voltage at the connection point is above 132kV but not exceeding 275kV
- 120 ms where the voltage at the connection point is 132kV or below

5.2.2 Methodology

The flowchart of Figure 4.5. shows all the steps followed to reach the final transmission system configurations according the reinforcement strategy behind Option 1 or Option 2.

QDS stands for quasi-dynamic simulation. It refers to the dedicated time-varying load flow calculation tool from PF that can be used for medium to long-term simulations studies. The tool completes a series of load flow simulations spaced in time, with the flexibility to select the simulation period and the simulation step size. DC QDS and AC QDS means that the load flow calculations are run with DC and AC equations, respectively.

N-1 designates the contingency analysis tool from PF where the network states are evaluated following unplanned outages of single elements, such as lines or transformers. By selecting N-1 cases, only one faulty element is considered per load flow calculation. At the end of the simulations, the tool generates reports with the loading violations (DC N-1 or AC N-1) and voltage violations (only AC N-1).

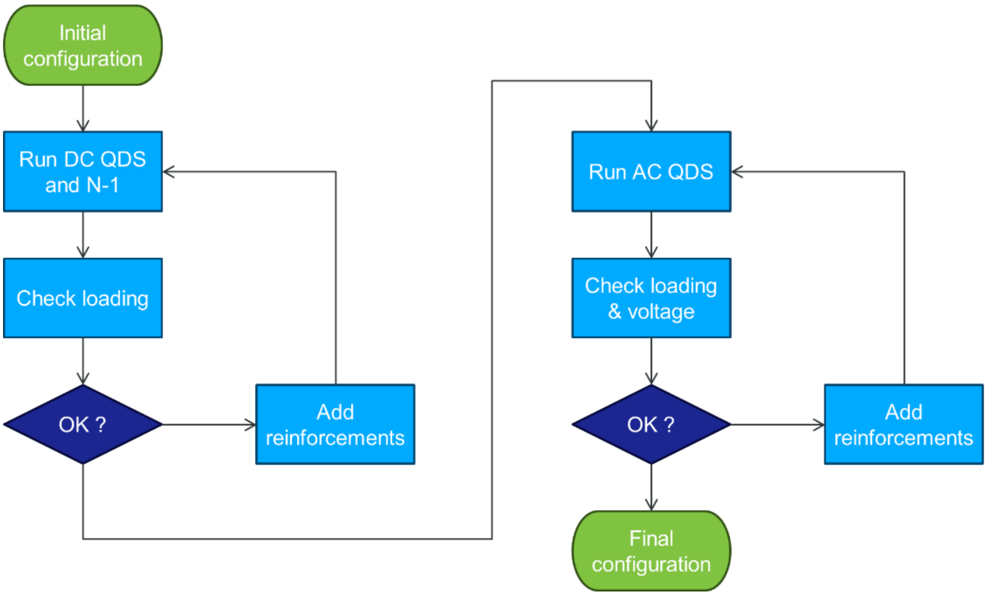


Figure 4.5.3: Flowchart presenting the steps between the initial and the final transmission system configurations.

The methodology starts by considering that the PF model has been properly updated according to the expected situation in 2042. The new generation projects, HV substations, and decided/proposed transmission projects have all been integrated beforehand inside the model. Under Option 1, the 66kV system remains unchanged and the new HV substations can be connected through 66kV or 132kV lines. Under Option 2, the 66kV system has already been replaced with a 132kV one and the new HV substations are only linked through 132kV lines.

DC QDS and contingency analyses are successively run in the next step with the aim of solving any congestion issues at transmission level. DC QDS are performed over the entire year of 2042 with a step size of 1 simulation per hour, which represents a total of 8760 DC load flow simulations per run. DC contingency analyses consider all N-1 cases based on lines and transformers at the hours of the year where the elements of the system transmit the most power. At the end of the simulations, if some elements are seen to be loaded at more than 100% in N or 110% in N-1, reinforcements would be suggested under the form of new parallel lines or an upgrade to higher rating equipment. This first loop involving DC calculations and new reinforcements continues until the system is grid compliant in N and N-1.

The methodology continues with AC QDS where the main objective is to solve any voltage issues at transmission level. To this end, large temporary static VAR compensators (SVCs) are added at every HV substation and set to maintain the terminal voltages between 0.98 and 1.02 pu. These SVCs are used to check how much reactive power must be provided or absorbed on average to maintain the terminal voltages close to 1 pu over the entire year of 2042. They are subsequently replaced with equivalent shunt reactors or capacitors. Hence, at least two runs of QDS are performed with 8760 AC load flow simulations per run. A first one with arbitrarily large SVCs and a second one with correctly sized shunt reactors and capacitors. Such a workaround allows to optimize the voltage profile across the entire system while limiting the number of operations. This second loop can include additional AC calculations to make sure the previous reinforcements remain sufficient to maintain the system grid compliant at least in N.

Once all checks have been completed, an exhaustive list of reinforcements is compiled by comparing the initial and final system configurations, for both Option 1 and Option 2.

5.2.3 Option 1

Under Option 1, any sustained overloads observed during load flows simulations are solved by adding new transmission lines and transformers in parallel. This section presents the exhaustive list of line and transformer reinforcements according to Option 1, which has been obtained by following the flowchart presented in Figure 4.5.. Load flow analyses are subsequently performed on the latest system configuration by running an AC QDS over the entire year of 2042.

5.2.3.1 List of reinforcements

Color legend for the tables

	Same number of circuits as before or one circuit along new path
	Extra circuit(s) needed to be N compliant
	Extra circuit(s) needed to be N-1 compliant
	Extra circuit(s) needed to be N-1 compliant due to radial connection

Table lists the line reinforcements needed to the existing transmission system by 2042 when following the strategy behind Option 1. Among the 45 line reinforcements, 16 of them only consist in upgrading the capacity of the existing circuit. The other reinforcements involve the commissioning of additional circuits in parallel to the existing ones and sometimes the upgrade of the existing circuit. One 33kV line is decommissioned.

In total, Option 1 foresees in the existing transmission system by 2042:

- 1131 km of new 132 kV lines
- 1260 km of new 66 kV lines
- 24 km of new 33 kV lines

A distinction is made in the comments between the reinforcements already needed to be N compliant, the extra reinforcements needed to be N-1 compliant, and the reinforcements needed for the substations connected through a radial connection.

Table 4.5.6: List of line reinforcements in the existing transmission system by 2042 under Option 1.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
66	3	Blantyre West	Chichiri	7	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second/third circuit to be N/N-1 compliant
66	2	Blantyre West	Chigumula	7	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N compliant
66	1	Chichiri	Mapanga	10.81	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant
66	1	Mapanga	Changalume	38.21	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	3	Mapanga	Fundis Cross	44.01	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second/third circuit to be N/N-1 compliant
66	1	Mapanga	Nkula B	41.81	• Nkula B - Mapanga #1 • Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	1	Nkula B	Mapanga	42.34	• Nkula B - Mapanga #2 • Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	1	Tedzani	Nkula B	8	• Type: 66kV Parakeet • Replace old circuit due to low line rating

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Upgrade circuit to be N-1 compliant
66	3	Nkula A	Nkula B	0.40	• Type: 66kV Yew • Keep old circuit • Second/third circuit to be N/N-1 compliant
66	1	Nkula A	Tedzani	8	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
132	3	Kapichira	Blantyre West	29.43	• Type: 132kV Lynx • Keep two old circuits • Third circuit to be N-1 compliant
132	2	Nkula B	Blantyre West	44	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N-1 compliant
132	2	Nkula B	Tedzani	8	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
66	2	Nkula A	Chingeni	70	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N compliant
66	2	Chingeni	Liwonde	27	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant • Second circuit to be N-1 compliant (radial)
66	1	Chingeni	Ntcheu	30	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant
66	1	Ntcheu	Mlangeni	18	• Type: 66kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant
66	1	Dedza	Tsabango	77.75	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	1	Kangoma	Tsabango	8	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	1	Tsabango	Lilongwe OT	10.25	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
66	3	Kanengo	Area 48	6.99	• Type: 66kV Parakeet • Keep old circuit • Second/third circuit to be N/N-1 compliant
132	3	Nkhoma	Tsabango	30.06	• Type: 132kV Parakeet • Keep old circuit • Second/third circuit to be N/N-1 compliant
132	3	Nkhoma	Kanengo	41.10	• Type: 132kV Parakeet • Keep two old circuits • Third circuit to be N-1 compliant
132	1	Kanengo	Nanjoka	69.12	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
132	1	Golomoti	Nanjoka	87.22	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant"
132	3	Golomoti	Nkhoma	76	• Type: 132kV Parakeet • Keep two old circuits

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Third circuit to be N-1 compliant
132	3	Phombeya	Golomoti	101	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N-1 compliant
132	3	Nkula B	Phombeya	32	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N-1 compliant
132	3	Nanjoka	Nkhotakota	98.33	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant
132	3	Nkhotakota	Dwangwa	50	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant
132	3	Chintheche	Dwangwa	90	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant
132	2	Dwangwa	Chatoloma	101.02	• Dwangwa - Chatoloma project • Type: 132kV Parakeet • Second circuit to be N-1 compliant
132	2	Tsabango	Malingunde	17	• Nkhoma - Kasiya project • Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
132	2	Malingunde	Kasiya	54	• Nkhoma - Kasiya project • Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Second circuit to be N-1 compliant (radial)
66	2	Nkhotakota	Serengeti	9	• Type: 66kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant (radial)
66	2	Chinyama	Serengeti	70	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N-1 compliant (radial)
33	2	Chinyama	Shayona	24	• Type: 66kV Oak • Keep old circuit • Second circuit to be N-1 compliant (radial)
132	2	Luwinga	Chintheche	79.09	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
132	2	New Bwengu	Luwinga	49.29	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
66	2	Chintheche	Chikangawa	70.89	• Type: 66kV Willow • Keep old circuit • Second circuit to be N-1 compliant (radial)
66	1	Chintheche	Telegraph Hill	59.46	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
33	0	Telegraph Hill	Luwinga	15.40	• Type: 33kV Hazel • Disable old circuit
66	2	Bwengu	New Bwengu	1.66	• Type: 66kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant (radial)
66	2	Livingstonia	Bwengu	57	• Type: 66kV Parakeet • Replace old circuit due to low line rating

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Second circuit to be N-1 compliant (radial)
66	2	Uliwa	Livingstonia	28	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N-1 compliant (radial)
66	2	Uliwa	Karonga	70	• Type: 66kV Parakeet • Replace old circuit due to low line rating • Second circuit to be N-1 compliant (radial)

Table lists the new lines needed to supply the HV substations by 2042 when following the strategy behind Option 1. Among the 23 new connections, 11 of them consist of one single circuit. The other reinforcements include additional circuits in parallel to make the system N and/or N-1 compliant.

In total, Option 1 foresees for supplying the new HV substations by 2042:

- 141 km of new 132kV lines
- 456 km of new 66kV lines

Table 4.5.7: List of new lines to supply the new HV substations by 2042 under Option 1.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
66	1	Chichiri	Chirimba	6.5	• Type: 66kV Parakeet • Replace existing 66kV line Chichiri-Nkula A due to low line rating
	1	Chirimba	Chileka	10	
	1	Chileka	Nkula A	30	
66	1	Chichiri	Limbe A	6.5	• Type: 66kV Parakeet • Same paths as existing MV feeders
	1	Limbe A	Limbe B	1	
	1	Mapanga	Limbe B	9	
66	1	Blantyre West	Michiru	9.5	• Type: 66kV Parakeet • Same paths as existing MV feeders
	1	Michiru	Chirimba	9.5	
66	2	Changalume	Zomba	13	• Type: 66kV Parakeet • Same paths as existing MV feeders • Second circuit to be N compliant

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Monkey Bay	Maldeco	28.5	• Type: 132kV Parakeet • Same paths as existing MV feeders
	1	Maldeco	Mangochi	21	
66	2	Chigumula	Thyolo B	12	• Type: 66kV Parakeet • Second circuit to be N-1 compliant (radial)
	2	Thyolo B	Thyolo A	14	
	2	Thyolo A	Thyolo C	21	
66	2	Fundis Cross	Phalombe	35	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
66	3	Area 48	Area 47	4.5	• Type: 66kV Parakeet • Loop-in loop out of existing 66kV line Area 48-Lilongwe • Second/third circuit Area 48-Area 47 to be N/N-1 compliant
	1	Area 47	Lilongwe OT	8.5	
66	2	Area 47	Chitipi	9	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
66	2	Barracks	City Centre	2.5	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
66	2	Chitipi	Namitete	36	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Kanengo	Mponela	36	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Luwinga	Sonda	9.5	• Type: 66kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
66	2	Chinyama	Kanyika	40	• New mining site • Type: 66kV Parakeet • Second circuit to be N-1 compliant (radial)

Table lists the 3-winding transformer reinforcements in the existing transmission system by 2042 when following the strategy behind Option 1. The first reinforcement draws a connection between Changalume 66kV and Phombeya 132kV through Zomba. The other reinforcements consists either in upgrading and/or commissioning additional transformers in parallel.

In total, Option 1 foresees in the existing transmission system by 2042:

- 41 new 3-winding transformers

Table 4.5.8: List of 3-winding transformer reinforcements in the existing transmission system by 2042 under Option 1.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Comments
132	66	11	4	Zomba	• Rating: 50 MVA • New paths between Changalume 66kV and Phombeya 132kV
132	66	11	6	Blantyre West	• Rating: 50 MVA • Replace old transformers BT West IBT1 and BT West IBT2 due to low rating • Keep old transformer BT West IBT3 • Six transformers to be N compliant
132	66	11	6	Kanengo	• Rating: 50 MVA • Replace old transformers Kanengo IBT1, Kanengo IBT2, and Kanengo IBT3 due to low rating • Keep old transformer Kanengo IBT4 • Six transformers to be N compliant
132	66	11	2	Tedzani	• Rating: 50 MVA • Replace old transformers Tedzani IBT3 due to low rating • Two transformers to be N compliant
132	66	33	3	Nkhotakota	• Rating: 50 MVA

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Comments
					• Replace old transformers Nkhotakota IBT1 and Nkhotakota IBT2 due to low rating • Two/three transformers to be N/N-1 compliant
132	66	33	3	Chintheche	• Rating: 50 MVA • Replace old transformers Chintheche IBT2 and Chintheche IBT3 due to low rating • Upgrade transformers to be N compliant
132	66	11	6	Nkula B	• Rating: 50 MVA • Replace old transformers Nkula IBT5 and Nkula IBT6 due to low rating • Four/six transformers to be N/N-1 compliant
132	66	11	5	Tsabango	• Rating: 50 MVA • Keep old transformer Tsabango T1 • Four/five transformers to be N/N-1 compliant
132	66	11	3	New Bwengu	• Rating: 50 MVA • Replace old transformer New Bwengu IBT1 • Two/three transformers to be N/N-1 compliant
400	132	33	3	Phombeya	• Rating: 200 MVA • Keep old transformer Phombeya T2 • Two/three transformers to be N/N-1 compliant
400	132	33	3	Nkhoma	• Rating: 200 MVA • Keep old transformer Nkhoma T2 • Two/three transformers to be N/N-1 compliant
400	132	33	3	New Bwengu	• Western backbone project • Rating: 200 MVA • Two/three transformers to be N/N-1 compliant

5.2.3.2 Load flow analyses

The results presented below summarize the outcomes of 8760 load flow calculations performed by running an AC QDS over the entire year of 2042. All line loadings and voltage magnitudes have been collected and compiled in the form of boxplots and histograms. These representations provide a concise way to understand the expected performances of the Malawian power system in 2042, when upgraded according to Option 1.

Line loadings

Figure 4.5. displays the boxplots of line loadings over the entire year of 2042 under Option 1. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the loading values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in

Table .

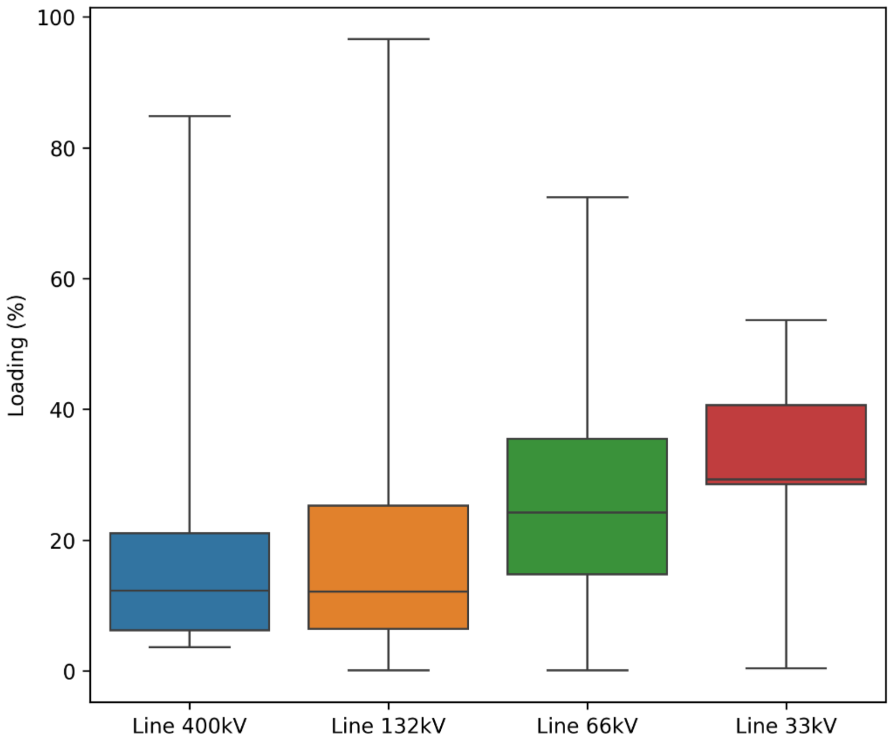


Figure 4.5.4: Boxplots of line loadings over the entire year of 2042 under Option 1.

Table 4.5.9: Five-number summary of line loadings over the entire year of 2042 under Option 1.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Line 400kV	3.60	6.19	12.26	21.06	84.79
Line 132kV	0.08	6.41	12.12	25.26	96.63
Line 66kV	0.07	14.73	24.18	35.46	72.40
Line 33kV	0.38	28.48	29.29	40.64	53.67

The third quartile Q3 is the value below which 75% of the loading values falls. Hence, under Option 1, the loading stays 75% of the time below 21% for the 400kV lines, 25% for the 132kV lines, 35% for the 66kV lines, and 41% for the 33kV lines. The sizes and the positions of the boxes show that the loading remains on average low for the 400kV and 132kV lines and slightly higher for the 66kV and 33kV lines.

For a few hours of the year, the maximum loading Q4 can reach up to 85% for the 400kV lines, 97% for the 132kV lines, 75% for the 66kV lines, and 54% for the 33kV lines. High loadings remain nevertheless a rare occurrence as illustrated by the histograms shown in

Figure .

Each histogram presents the number of times a category of lines is loaded at a given percentage of their capacity during the year 2042. It can be observed that most loading values remain below 20% for the 400kV lines. The loading of the 132kV lines is overall higher but still remains most of the time below 50%. For the 66kV and 33kV lines, almost all loading values remain below 60% of the line ratings.

Keeping the loading of the assets below 50-60% is usually necessary to ensure that the remaining assets do not become overloaded after a N-1 contingency. This is especially valid for the assets with a high rating, such as the 400kV and 132kV lines, whose loss could represent a huge burden on the transmission system in case they were initially highly loaded.

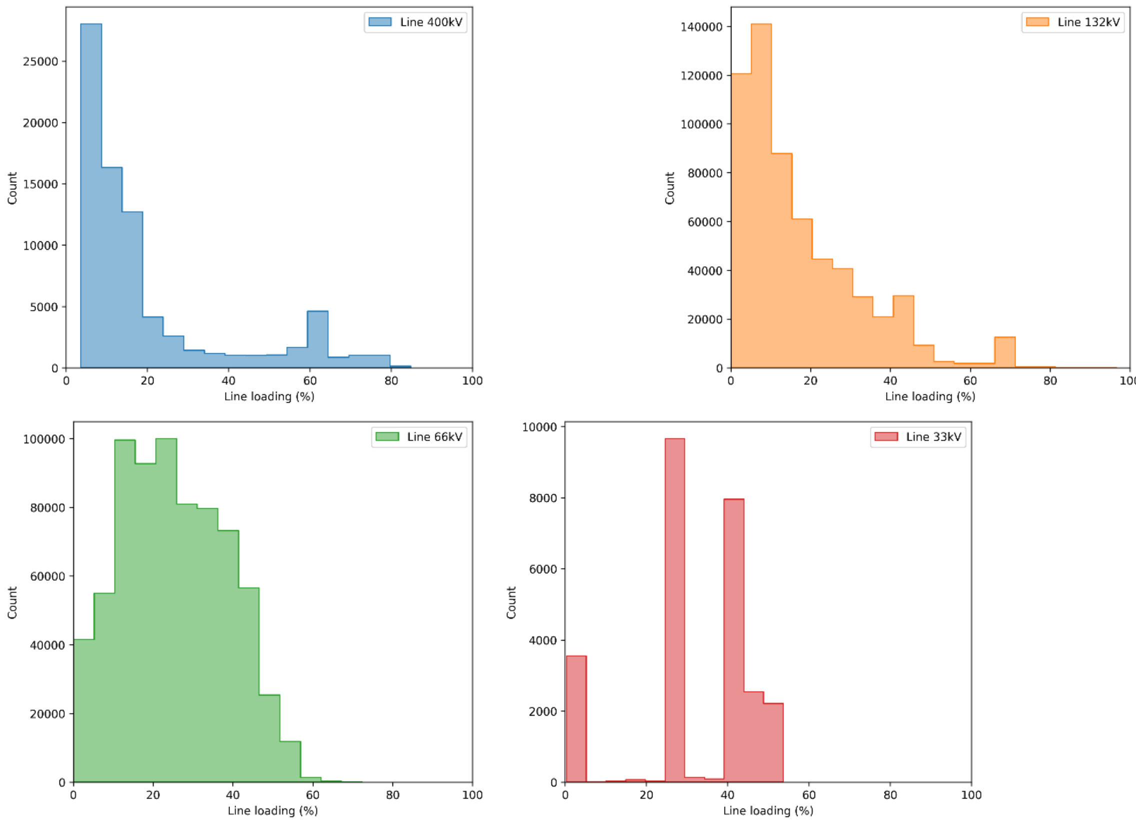


Figure 4.5.5: Histograms of line loadings over the entire year of 2042 under Option 1.

Voltage magnitudes

Figure 4. displays the boxplots of voltage magnitudes over the entire year of 2042 under Option 1. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the voltage values. The whiskers of the boxplots correspond to

the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in Table.

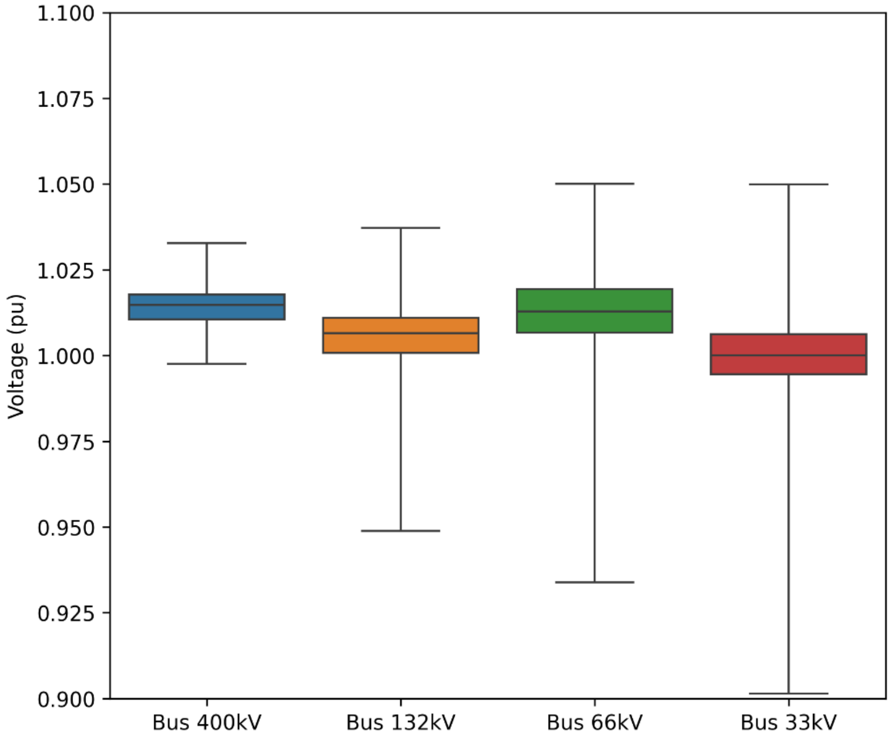


Figure 4.5.6: Boxplots of voltage magnitudes over the entire year of 2042 under Option 1.

Table 4.5.10: Five-number summary of voltage magnitudes over the entire year of 2042 under Option 1.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Bus 400kV	0.998	1.011	1.015	1.018	1.033
Bus 132kV	0.949	1.001	1.007	1.011	1.037
Bus 66kV	0.934	1.007	1.013	1.019	1.050
Bus 33kV	0.901	0.995	1.000	1.006	1.050

For all voltage levels, the first quartile Q1 lies between 0.995 and 1.011 pu and the third quartile Q3 lies between 1.006 and 1.019 pu. In other words, the voltage magnitudes in the Malawian system remain 50% of the time within a small range that spans between 0.995 and 1.019 pu.

While the voltage magnitudes of the 400kV and 132kV buses always remain within the acceptable range set between 0.95 and 1.05 pu in normal operating conditions, the same cannot be said for the 66kV and 33kV buses. For a few hours of the year, the voltage magnitudes can drop down to 0.934 pu for the 66kV buses and 0.901 pu for the 33kV buses. These conditions occur on the few occasions when the generation dispatch did not foresee sufficiently active generating units in the neighborhood of the 66kV and 33kV buses. Such an issue could easily be solved by either keeping a generating unit in standby, adjusting the voltage setpoints of the other generating units, or changing the tap positions of the transformers and the shunt reactors/capacitors. Low voltages remain nevertheless a rare occurrence as illustrated by the histograms in

Figure.

Each histogram presents the number of times a bus of a certain voltage level reaches a given value during the year 2042. It can be observed that most voltage values are closely distributed around 1 pu.

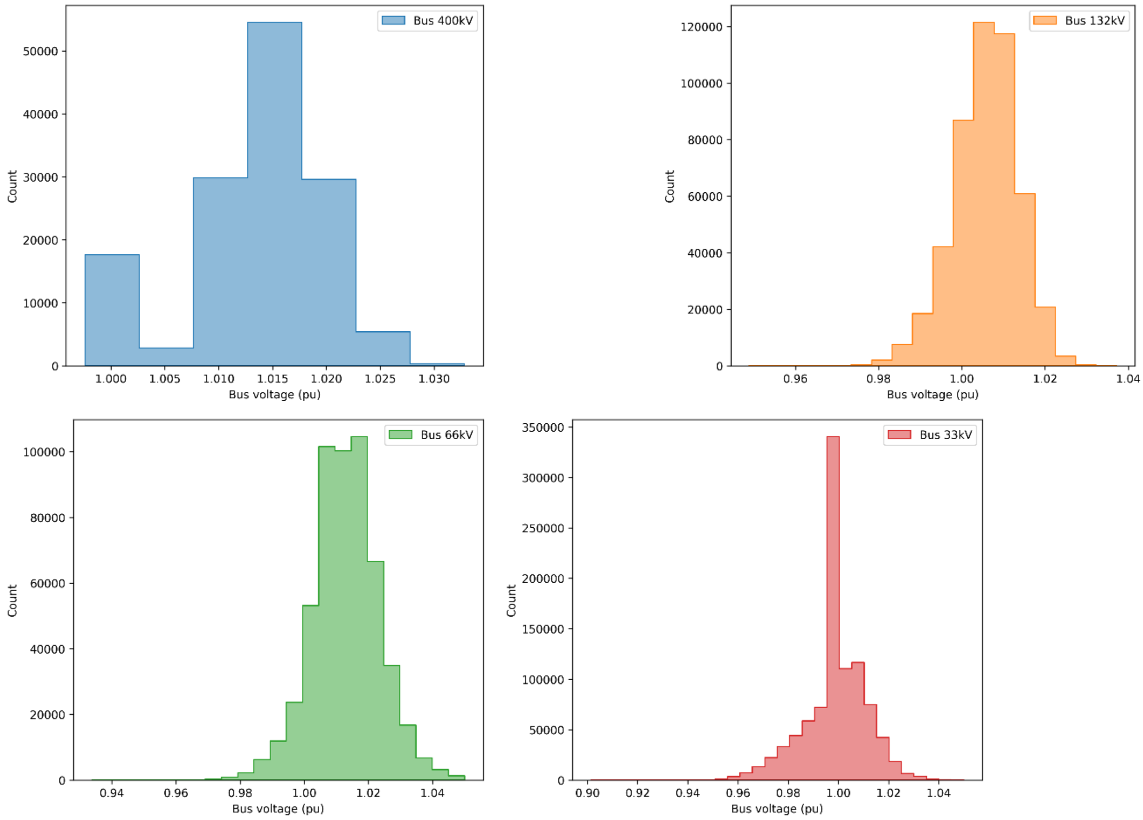


Figure 4.5.7: Histograms of voltage magnitudes over the entire year of 2042 under Option 1.

Network losses

Figure 4.5. compares the percentage of losses in the transmission system versus the electrical loads over the entire year of 2042 under Option 1. The share of losses is an important KPI for selecting the best reinforcement strategy as higher losses would lead to higher operational costs.

The losses would account for 633 GWh in 2042 under Option 1, which represents about 5.26% of the total generated energy.

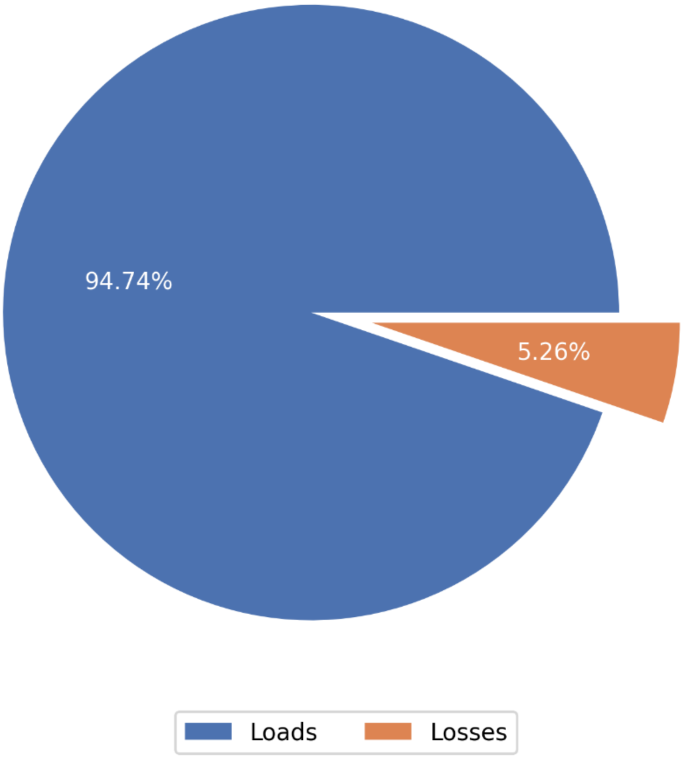


Figure 4.5.8: Pie chart comparing percentage of losses versus loads over the entire year of 2042 under Option 1.

5.2.4 Option 2

Under Option 2, the transmission system is first reinforced by converting all existing 66kV assets into stronger ones operated in 132 kV. Additional lines and transformers can also be added in parallel if proven to be necessary despite the upgrades. This section presents the exhaustive list of line and transformer reinforcements according to Option 2, which has been obtained by following the flowchart presented in Figure 4.5.. Load flow analyses are subsequently performed on the latest system configuration by running an AC QDS over the entire year of 2042.

5.2.4.1 List of reinforcements

Color legend for the tables

(white)	Same number of circuits as before or one circuit along new path
(yellow)	Extra circuit(s) needed to be N compliant
(blue)	Extra circuit(s) needed to be N-1 compliant
(green)	Extra circuit(s) needed to be N-1 compliant due to radial connection

Table lists the line reinforcements needed in the existing transmission system by 2042 when following the strategy behind Option 2. Among the 49 line reinforcements, 33 of them only consist in upgrading the capacity of the existing circuit and operating it in 132 kV. The other reinforcements also involve the commissioning of additional circuits in parallel to the existing ones.

In total, Option 2 foresees in the existing transmission system by 2042:

- 2365 km of new 132kV lines

A distinction is made in the comments between the reinforcements already needed to be N compliant, the extra reinforcements needed to be N-1 compliant, and the reinforcements needed for the substations connected through a radial connection.

Table 4.5.11: List of line reinforcements in the existing transmission system by 2042 under Option 2.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Blantyre West	Chichiri	7	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Blantyre West	Chigumula	7	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Chichiri	Mapanga	10.81	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Chigumula	Mapanga	17.19	• Type: 132kV Parakeet • Upgrade circuit to 132kV"
132	1	Mapanga	Changalume	38.21	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Mapanga	Fundis Cross	44.01	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	1	Mapanga	Nkula B	41.81	• Nkula B - Mapanga #1 • Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Nkula B	Mapanga	42.34	• Nkula B - Mapanga #2 • Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tedzani	Nkula B	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Nkula A	Nkula B	0.40	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Upgrade circuit to 132kV • Second circuit to be N compliant"
132	1	Nkula A	Tedzani	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tedzani	Chichiri	59	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tedzani	Tedzani IV	1	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Nkula A	Chingeni	70	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Chingeni	Liwonde	27	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	1	Chingeni	Ntcheu	30	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Ntcheu	Mlangeni	18	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Mlangeni	Dedza	49.81	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Dedza	Tsabango	77.75	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kangoma	Tsabango	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tsabango	Lilongwe OT	10.25	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kanengo	Area 48	6.99	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Upgrade circuit to 132kV
132	1	Kanengo	Kauma	7.38	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Barracks	Kauma	4.04	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Barracks	Kangoma	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	3	Nkhoma	Tsabango	30.06	• Type: 132kV Parakeet • Keep old circuit • Second/third circuit to be N/N-1 compliant
132	1	Kanengo	Nanjoka	69.12	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N compliant
132	1	Golomoti	Nanjoka	87.22	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant
132	3	Phombeya	Golomoti	101	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N-1 compliant
132	3	Nkula B	Phombeya	32	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N compliant
132	3	Nanjoka	Nkhotakota	98.33	• Eastern backbone project • Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Third circuit to be N-1 compliant"
132	3	Nkhotakota	Dwangwa	50	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant"
132	3	Chintheche	Dwangwa	90	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant"
132	2	Dwangwa	Chatoloma	101.02	• Dwangwa - Chatoloma project • Type: 132kV Parakeet • Second circuit to be N-1 compliant"
132	2	Tsabango	Malingunde	17	• Nkhoma - Kasiya project • Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
132	2	Malingunde	Kasiya	54	• Nkhoma - Kasiya project • Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
132	2	Nkhotakota	Serengeti	9	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Chinyama	Serengeti	70	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Chinyama	Shayona	24	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Luwinga	Chintheche	79.09	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Keep old circuit • Second circuit to be N-1 compliant
132	2	New Bwengu	Luwinga	49.29	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
132	2	Chintheche	Chikangawa	70.89	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Chintheche	Telegraph Hill	59.46	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant
132	1	Telegraph Hill	Luwinga	15.40	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Bwengu	New Bwengu	1.66	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Livingstonia	Bwengu	57	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Uliwa	Livingstonia	28	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Uliwa	Karonga	70	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	1	Wovwe	Uliwa	8	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Upgrade circuit to 132kV

Table lists the new lines needed to supply the HV substations by 2042 when following the strategy behind Option 2. Among the 23 new connections, 13 of them consist of one single circuit. The other reinforcements include additional circuits in parallel to make the system N-1 compliant due to radial connection.

In total, Option 2 foresees for supplying the new HV substations by 2042:

- 585 km of new 132kV lines

Table 4.5.12: List of new lines to supply the new HV substations by 2042 under Option 2.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Chichiri	Chirimba	6.5	• Type: 132kV Parakeet • Replace existing 66kV line Chichiri-Nkula A due to low line rating
	1	Chirimba	Chileka	10	
	1	Chileka	Nkula A	30	
132	1	Chichiri	Limbe A	6.5	• Type: 132V Parakeet • Same paths as existing MV feeders
	1	Limbe A	Limbe B	1	
	1	Mapanga	Limbe B	9	
132	1	Blantyre West	Michiru	9.5	• Type: 132kV Parakeet • Same paths as existing MV feeders
	1	Michiru	Chirimba	9.5	
132	1	Changalume	Zomba	13	• Type: 132kV Parakeet • Same paths as existing MV feeders
132	1	Monkey Bay	Maldeco	28.5	• Type: 132kV Parakeet • Same paths as existing MV feeders
	1	Maldeco	Mangochi	21	
132	2	Chigumula	Thyolo B	12	• Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
	2	Thyolo B	Thyolo A	14	
	2	Thyolo A	Thyolo C	21	
132	2	Fundis Cross	Phalombe	35	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	1	Area 48	Area 47	4.5	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
	1	Area 47	Lilongwe OT	8.5	• Replace existing 66kV line Area 48-Lilongwe
132	2	Area 47	Chitipi	9	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Barracks	City Centre	2.5	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Chitipi	Namitete	36	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Kanengo	Mponela	36	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Luwinga	Sonda	9.5	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Chinyama	Kanyika	40	• New mining site • Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)"

Table lists the 3-winding transformer reinforcements in the existing transmission system by 2042 when following the strategy behind Option 2. The three reinforcements consists in commissioning additional transformers in parallel.

In total, Option 2 foresees in the existing transmission system by 2042:

- 6 new 3-winding transformers

Table 4.5.13: List of 3-winding transformer reinforcements in the existing transmission system by 2042 under Option 2.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Comments
400	132	33	3	Phombeya	• Rating: 200 MVA • Keep old transformer Phombeya T2 • Two/three transformers to be N/N-1 compliant
400	132	33	3	Nkhoma	• Rating: 200 MVA • Keep old transformers Nkhoma T2 • Two/three transformers to be N/N-1 compliant
400	132	33	3	New Bwengu	• Western backbone project • Rating: 200 MVA • Two/three transformers to be N/N-1 compliant

5.2.4.2 Load flow analyses

The results presented below summarize the outcomes of 8760 load flow calculations performed by running an AC QDS over the entire year of 2042. All line loadings and voltage magnitudes have been collected and compiled in the form of boxplots and histograms. These representations provide a concise way to understand the expected performances of the Malawian power system in 2042, when upgraded according to Option 2.

Line loadings

Figure displays the boxplots of line loadings over the entire year of 2042 under Option 2. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the loading values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in Table.

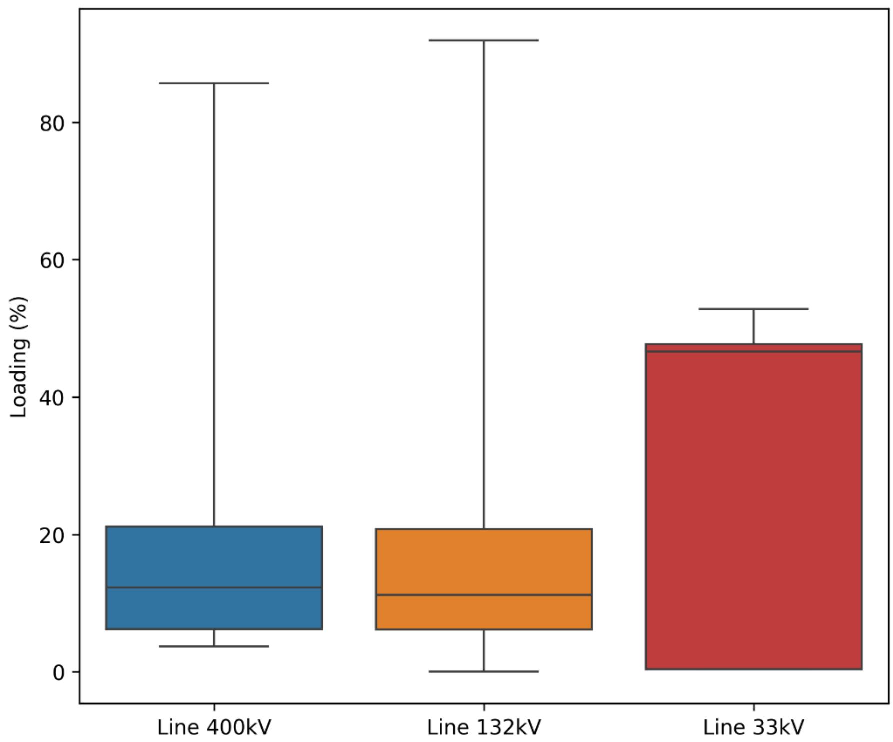


Figure 4.5.9: Boxplots of line loadings over the entire year of 2042 under Option 2.

Table 4.5.14: Five-number summary of line loadings over the entire year of 2042 under Option 2.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Line 400kV	3.70	6.21	12.30	21.15	85.67
Line 132kV	0.02	6.13	11.19	20.76	91.96
Line 33kV	0.38	0.40	46.61	47.74	52.81

The third quartile Q3 is the value below which 75% of the loading values falls. Hence, under Option 2, the loading stays 75% of the time below 21% for the 400kV and 132kV lines, and 48% for the 33kV lines. The sizes and the positions of the boxes show that the loading remains on average low for the 400kV and 132kV lines and is higher for the 33kV lines.

For a few hours of the year, the maximum loading Q4 can reach up to 86% for the 400kV lines, 92% for the 132kV lines, and 53% for the 33kV lines. High loadings remain nevertheless a rare occurrence as illustrated by the histograms shown in

Figure.

Each histogram presents the number of times a category of lines is loaded at a given percentage of their capacity during the year 2042. It can be observed that most loading values remain below 20% for 400kV lines. The loading of the 132kV lines is overall higher but still remains most of the time below 40%. For the 33kV lines, all loading values remain below 53% of the line ratings.

Keeping the loading of the assets below 50-60% is usually necessary to ensure that the remaining assets do not become overloaded after a N-1 contingency. This is especially valid for the assets with a high rating, such as the 400kV and 132kV lines, whose loss could represent a huge burden on the transmission system in case they were initially highly loaded.

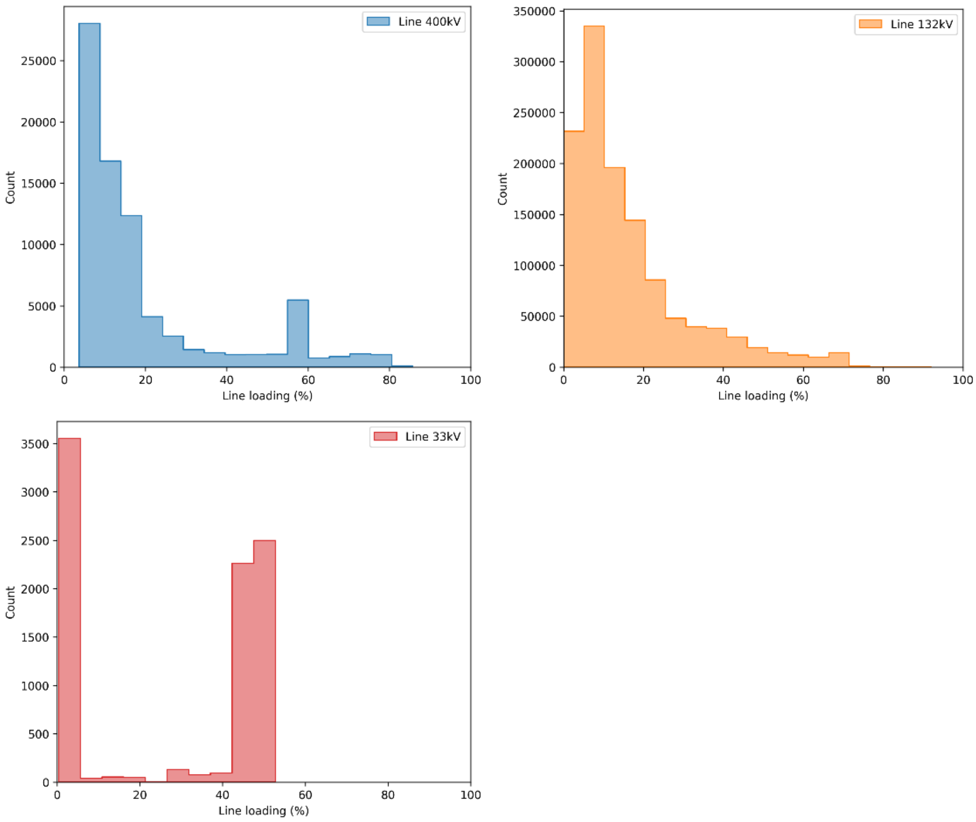


Figure 4.5.10: Histograms of line loadings over the entire year of 2042 under Option 2.

Voltage magnitudes

Figure 4.5.1 displays the boxplots of voltage magnitudes over the entire year of 2042 under Option 2. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the voltage values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in

Table.

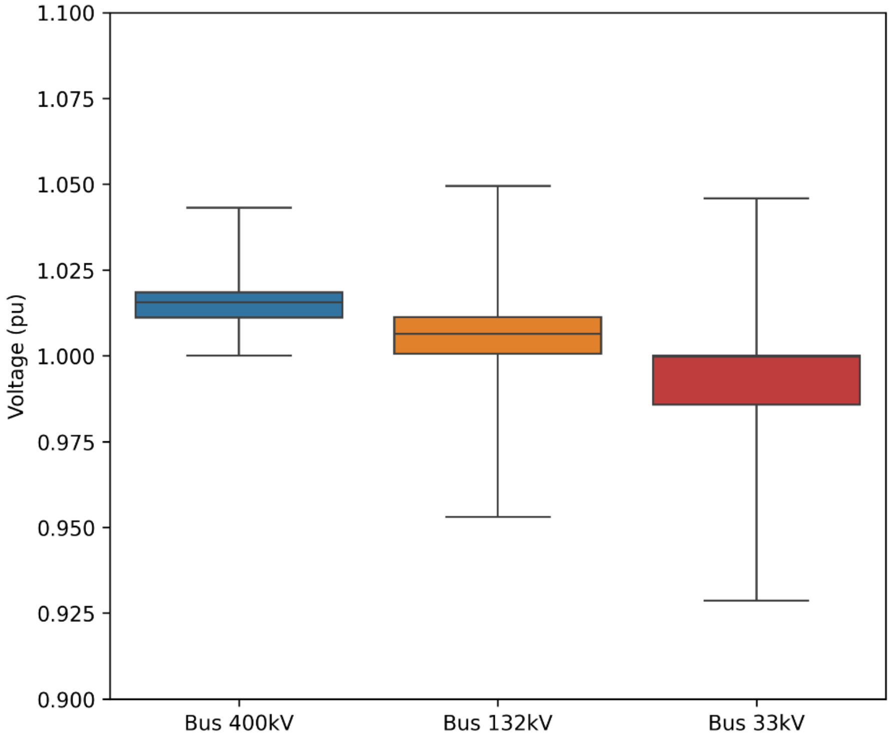


Figure 4.5.11: Boxplots of voltage magnitudes over the entire year of 2042 under Option 2.

Table 4.5.15: Five-number summary of voltage magnitudes over the entire year of 2042 under Option 2.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Bus 400kV	1.000	1.011	1.016	1.019	1.043
Bus 132kV	0.953	1.001	1.006	1.011	1.050
Bus 33kV	0.929	0.986	1.000	1.000	1.046

For all voltage levels, the first quartile Q1 lies between 0.986 and 1.011 pu and the third quartile Q3 lies between 1.000 and 1.016 pu. In other words, the voltage magnitudes in the Malawian system remain 50% of the time within a small range that spans between 0.986 and 1.016 pu.

While the voltage magnitudes of the 400kV and 132kV buses always remain within the acceptable range set between 0.95 and 1.05 pu in normal operating conditions, the same cannot be said for the 33kV buses. For a few hours of the year, the voltage magnitudes can drop down to 0.929 pu for the 33kV buses. As explained in the scope of Option 1, such an issue could easily be solved by either keeping a generating unit in standby, adjusting the voltage setpoints of the other generating units, or changing the tap positions of the transformers and the shunt reactors/capacitors. Low voltages remain nevertheless a rare occurrence as illustrated by the histograms in Figure 1.

Each histogram presents the number of times a bus of a certain voltage level reaches a given value during the year 2042. It can be observed that most voltage values are closely distributed around 1 pu.

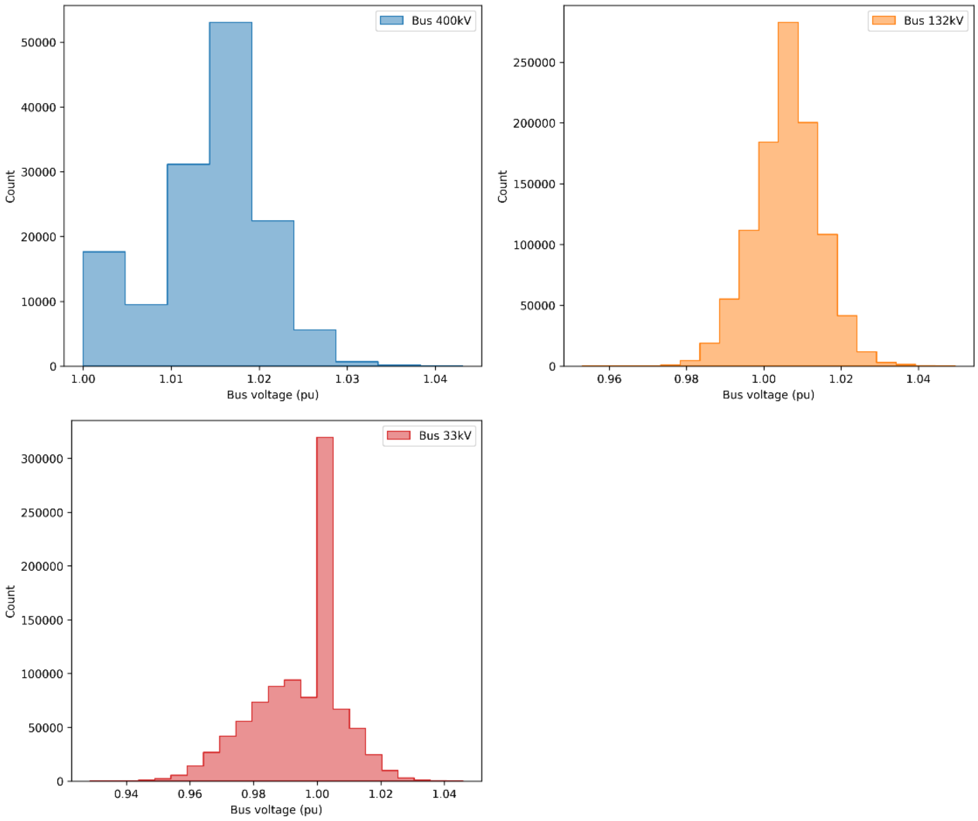


Figure 1.5.12: Histograms of voltage magnitudes over the entire year of 2042 under Option 2.

Network losses

Figure compares the percentage of losses in the transmission system versus the electrical loads over the entire year of 2042 under Option 2. The share of losses is an important KPI for selecting the best reinforcement strategy as higher losses would lead to higher operational costs.

The losses would account for 473 GWh in 2042 under Option 2, which represents about 3.94% of the total generated energy.

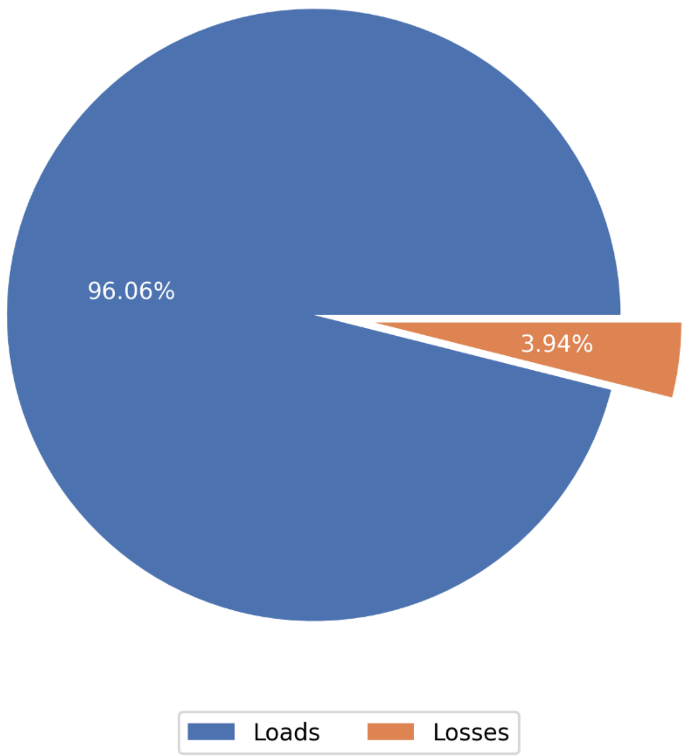


Figure 4.5.13: Pie chart comparing percentage of losses versus loads over the entire year of 2042 under Option 2.

5.3 Costs estimation

From a network security perspective, the reinforced systems under Option 1 and Option 2 display similar properties by design. They both satisfy the loading and voltage criteria in N and N-1 based on static load flow calculations performed for the year 2042. One practical way to decide between the two options consists in comparing the total costs associated with their respective implementation. The strategy leading to the least-cost system development will be the prefer one to be implemented by 2042. The considered costs for this analysis include the investment costs and the costs corresponding to the transmission losses.

In this section, a provisional costs estimation is established for both options based on the lists of reinforcements presented in Section 5.2 and some average unitary costs assumed per equipment type. For new lines and transformers, the unitary costs are for most derived from pricing schedules shared by ESCOM for existing projects [8]. For the remaining equipment, the unitary costs are estimated based on the experience of the Consultant and some interpolations/extrapolations.

5.3.1 Unitary costs

5.3.1.1 Lines

Table shows the average costs estimates for installing new transmission lines in Malawi. The costs values for single-circuit lines operated at 400, 132 and 66kV levels have directly been provided by ESCOM. The remaining ones have been obtained by interpolations/extrapolations

The costs of double-circuit lines are estimated by applying a factor of 1.6 to the costs of single-circuit lines.

Table 4.5.16: Costs estimates of new transmission lines.

Voltage levels (kV)	Costs single-circuit lines (kUSD/km)	Costs double-circuit lines (kUSD/km)
400	280	448
330	259	414.4
220	226	361.6
132	200	320
66	180	288
33	170	272

5.3.1.2 Transformers

Table presents the average costs estimates for installing new transformers in Malawi. These values have been derived from the pricing schedules shared by ESCOM for several recent transformers in Malawi [8].

The transitions between the costs of 2-winding and 3-winding transformers are estimated by considering a factor of 1.16.

Table 4.5.17: Costs estimates of new transformers.

Rating (MVA)	Voltage levels (kV)	Costs 2-winding transformers (kUSD)	Costs 3-winding transformers (kUSD)
200	400/132	3100	3596
40/50	132/33	2100	2436
25/30	132/33	1150	1334
20/25	66/33	800	928

5.3.1.3 Substations

Table highlights the average costs estimates related to the installation of new substations. These values have been derived based on the experience of the Consultant in various development studies, and in particular in Africa.

The costs for installing a new substation include the base costs for the construction site opening and the costs of one bay per connected line or transformer. In the case of substation upgrade to higher voltage levels, only the costs of new bays are considered.

Table 4.5.18: Costs estimates of new substations.

Voltage levels (kV)	Construction site opening (kUSD)	Air-insulated substation bay (kUSD)
400	5285	3120
330	4991	2496
220	4404	1321
132	3083	1028
66	1922	825
33	1233	801

5.3.1.4 Reactive compensation devices

Table provides the average costs estimates for installing new reactive compensation devices. Like for the substations, these values have been derived based on the experience of the Consultant.

Table 4.5.19: Costs estimates of new reactive compensation devices.

Type	Costs devices (kUSD/Mvar)
Static VAR compensator	147
Capacitor	18
Reactance	18

5.3.2 Investment costs for Option 1

Table provides the costs estimates of the new circuits and substation bays to be considered under Option 1 for reinforcing the existing transmission system by 2042. The total costs amount to 423 MUSD for the circuits and 62 MUSD for the substation bays.

Table 4.5.20: Costs estimates of line reinforcements under Option 1.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
66	3	Blantyre West	Chichiri	7	3276	3300
66	2	Blantyre West	Chigumula	7	2016	1650
66	1	Chichiri	Mapanga	10.81	1946	0
66	1	Mapanga	Changalume	38.21	6878	0
66	3	Mapanga	Fundis Cross	44.01	20598	3300
66	1	Mapanga	Nkula B	41.81	7526	0
66	1	Nkula B	Mapanga	42.34	7621	0
66	1	Tedzani	Nkula B	8	1440	0
66	3	Nkula A	Nkula B	0.40	115	3300
66	1	Nkula A	Tedzani	8	1440	0
132	3	Kapichira	Blantyre West	29.43	5886	2056
132	2	Nkula B	Blantyre West	44	14080	2056
132	2	Nkula B	Tedzani	8	1600	2056
66	2	Nkula A	Chingeni	70	20160	1650
66	2	Chingeni	Liwonde	27	7776	1650
66	1	Chingeni	Ntcheu	30	5400	0
66	1	Ntcheu	Mlangeni	18	3240	0
66	1	Dedza	Tsabango	77.75	13995	0
66	1	Kangoma	Tsabango	8	1440	0
66	1	Tsabango	Lilongwe OT	10.25	1845	0
66	3	Kanengo	Area 48	6.99	2013	3300
132	3	Nkhoma	Tsabango	30.06	9619	4112
132	3	Nkhoma	Kanengo	41.10	8220	2056
132	1	Kanengo	Nanjoka	69.12	13824	0
132	1	Golomoti	Nanjoka	87.22	17444	0
132	3	Golomoti	Nkhoma	76	15200	2056
132	3	Phombeya	Golomoti	101	20200	0
132	3	Nkula B	Phombeya	32	6400	0
132	3	Nanjoka	Nkhotakota	98.33	19666	2056
132	3	Nkhotakota	Dwangwa	50	10000	2056
132	3	Chintheche	Dwangwa	90	18000	2056
132	2	Dwangwa	Chatoloma	101.02	20204	2056
132	2	Tsabango	Malingunde	17	3400	2056
132	2	Malingunde	Kasiya	54	10800	2056
66	2	Nkhotakota	Serengeti	9	1620	1650
66	2	Chinyama	Serengeti	70	20160	1650
33	2	Chinyama	Shayona	24	4080	1602
132	2	Luwinga	Chintheche	79.09	15817	2056
132	2	New Bwengu	Luwinga	49.29	9859	2056
66	2	Chintheche	Chikangawa	70.89	12760	1650
66	1	Chintheche	Telegraph Hill	59.46	10703	0
33	0	Telegraph Hill	Luwinga	15.40	0	0
66	2	Bwengu	New Bwengu	1.66	299	1650

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
66	2	Livingstonia	Bwengu	57	16416	1650
66	2	Uliwa	Livingstonia	28	8064	1650
66	2	Uliwa	Karonga	70	20160	1650
				Total	**423206**	**62142**

Table provides the costs estimates of the new lines and substation bays to be considered under Option 1 for supplying the new HV substations. The total costs amount to 93 MUSD for the circuits and 59 MUSD for the substation bays.

Table 4.5.21: Costs estimates of new lines to supply the new HV substations under Option 1.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
66	1	Chichiri	Chirimba	6.5	1170	825
	1	Chirimba	Chileka	10	1800	1650
	1	Chileka	Nkula A	30	5400	825
66	1	Chichiri	Limbe A	6.5	1170	1650
	1	Limbe A	Limbe B	1	180	1650
	1	Mapanga	Limbe B	9	1620	1650
66	1	Blantyre West	Michiru	9.5	1710	1650
	1	Michiru	Chirimba	9.5	1710	1650
66	2	Changalume	Zomba	13	3744	3300
132	1	Monkey Bay	Maldeco	28.5	5700	2056
	1	Maldeco	Mangochi	21	4200	2056
66	2	Chigumula	Thyolo B	12	3456	3300
	2	Thyolo B	Thyolo A	14	4032	3300
	2	Thyolo A	Thyolo C	21	6048	3300
66	2	Fundis Cross	Phalombe	35	10080	3300
66	3	Area 48	Area 47	4.5	1296	4125
	1	Area 47	Lilongwe OT	0	0	825
66	2	Area 47	Chitipi	9	2592	3300
66	2	Barracks	City Centre	2.5	720	3300
66	2	Chitipi	Namitete	36	10368	3300
132	2	Kanengo	Mponela	36	11520	4112
132	2	Luwinga	Sonda	9.5	3040	4112
66	2	Chinyama	Kanyika	40	11520	3300
				Total	**93076**	**58536**

Table provides the costs estimates of the new 3-winding transformers to be considered under Option 1 for reinforcing the existing transmission system by 2042. The total costs amount to 107 MUSD for the circuits and 66 MUSD for the substation bays.

Table 4.5.22: Costs estimates of 3-winding transformer reinforcements under Option 1.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Costs circuits (kUSD)	Costs bays (kUSD)
132	66	11	4	Zomba	9744	7412
132	66	11	6	Blantyre West	12180	5559
132	66	11	6	Kanengo	12180	3706
132	66	11	2	Tedzani	4872	1853
132	66	33	3	Nkhotakota	7308	3706
132	66	33	3	Chintheche	7308	0
132	66	11	6	Nkula B	14616	7412
132	66	11	5	Tsabango	9744	7412
132	66	11	3	New Bwengu	7308	3706
400	132	33	3	Phombeya	7192	8296
400	132	33	3	Nkhoma	7192	8296
400	132	33	3	New Bwengu	7192	8296
				Total	**106836**	**65654**

Table lists the costs of the construction site openings under Option 1, which are needed for installing the new HV substations. The total costs amount to 38 MUSD.

Table 4.5.23: Costs estimates of site opening for new substations under Option 1.

Voltage (kV)	Substation	Costs site opening (kUSD)
66	Chileka	1922
66	Chirimba	1922
66	Limbe A	1922
66	Limbe B	1922
66	Michiru	1922
66	Zomba	1922
132	Maldeco	3083
66	Thyolo A	1922
66	Thyolo B	1922
66	Thyolo C	1922
66	Phalombe	1922
66	Area 47	1922
66	Chitipi	1922
66	City Centre	1922
66	Namitete	1922
132	Mponela	3083
132	Sonda	3083
66	Kanyika	1922
	Total	**38079**

Table lists the costs of the new shunt inductors that have been inserted in the scope of Option 1. A total of 210 Mvar is needed to adjust the voltage profiles in the system, which amounts to 4 MUSD.

Table 4.5.24: Costs estimates of new shunt inductors under Option 1.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
400	Chatoloma	L	110	1980
400	Mchinji	L	15	270
400	New Bwengu	L	85	1530
			Total	**3780**

Table lists the costs of the new shunt capacitors that have been inserted in the scope of Option 1. A total of -820 Mvar is needed to adjust the voltage profiles in the system, which amounts to 15 MUSD.

Table 4.5.25: Costs estimates of new shunt capacitors under Option 1.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
132	Blantyre West	C	-30	540
132	Mlambe	C	-50	900
66	Chichiri	C	-45	810
66	Chigumula	C	-15	270
66	Mapanga	C	-50	900
66	Changalume	C	-25	450
66	Fundis Cross	C	-50	900
66	Chingeni	C	-25	450
66	Liwonde	C	-20	360
66	Ntcheu	C	-5	90
66	Mlangeni	C	-5	90
66	Chirimba	C	-15	270
66	Chileka	C	-25	450
66	Limbe A	C	-20	360
66	Limbe B	C	-15	270
66	Michiru	C	-5	90
66	Zomba	C	-5	90
66	Thyolo A	C	-15	270
66	Thyolo B	C	-10	180
66	Thyolo C	C	-5	90
66	Phalombe	C	-15	270
66	Dedza	C	-35	630
66	Kangoma	C	-5	90
66	Lilongwe OT 1	C	-15	270
66	Lilongwe OT 2	C	-25	450
132	Kanengo	C	-15	270
66	Kanengo	C	-15	270
66	Kauma	C	-5	90

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
66	Area 48	C	-20	360
66	Barracks	C	-10	180
66	Chinyama	C	-35	630
66	Kanyika	C	-5	90
33	Shayona	C	-15	270
66	Area 47	C	-20	360
66	Chitipi	C	-10	180
66	City Centre	C	-15	270
66	Namitete	C	-15	270
132	Mponela	C	-30	540
66	Chikangawa	C	-30	540
66	Telegraph Hill	C	-15	270
66	Uliwa	C	-10	180
66	Karonga	C	-25	450
			Total	**14760**

5.3.3 Investment costs for Option 2

Table provides the costs estimates of the new circuits and substation bays to be considered under Option 2 for reinforcing the existing transmission system by 2042. The total costs amount to 434 MUSD for the circuits and 119 MUSD for the substation bays.

Table 4.5.26: Costs estimates of line reinforcements under Option 2.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Blantyre West	Chichiri	7	1400	2056
132	1	Blantyre West	Chigumula	7	1400	2056
132	1	Chichiri	Mapanga	10.81	2162	2056
132	1	Chigumula	Mapanga	17.19	3437	2056
132	1	Mapanga	Changalume	38.21	7642	2056
132	2	Mapanga	Fundis Cross	44.01	14084	4112
132	1	Mapanga	Nkula B	41.81	8362	2056
132	1	Nkula B	Mapanga	42.34	8468	2056
132	1	Tedzani	Nkula B	8	1600	2056
132	2	Nkula A	Nkula B	0.40	128	4112
132	1	Nkula A	Tedzani	8	1600	2056
132	1	Tedzani	Chichiri	59	11800	2056
132	1	Tedzani	Tedzani IV	1	200	2056
132	1	Nkula A	Chingeni	70	14000	2056
132	2	Chingeni	Liwonde	27	8640	4112
132	1	Chingeni	Ntcheu	30	6000	2056
132	1	Ntcheu	Mlangeni	18	3600	2056
132	1	Mlangeni	Dedza	49.81	9962	2056
132	1	Dedza	Tsabango	77.75	15550	2056
132	1	Kangoma	Tsabango	8	1600	2056

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Tsabango	Lilongwe OT	10.25	2050	2056
132	1	Kanengo	Area 48	6.99	1398	2056
132	1	Kanengo	Kauma	7.38	1476	2056
132	1	Barracks	Kauma	4.04	808	2056
132	1	Barracks	Kangoma	8	1600	2056
132	3	Nkhoma	Tsabango	30.06	9619	4112
132	1	Kanengo	Nanjoka	69.12	13824	0
132	1	Golomoti	Nanjoka	87.22	17444	0
132	3	Phombeya	Golomoti	101	20200	0
132	3	Nkula B	Phombeya	32	6400	0
132	3	Nanjoka	Nkhotakota	98.33	19666	2056
132	3	Nkhotakota	Dwangwa	50	10000	2056
132	3	Chintheche	Dwangwa	90	18000	2056
132	2	Dwangwa	Chatoloma	101.02	20204	2056
132	2	Tsabango	Malingunde	17	3400	2056
132	2	Malingunde	Kasiya	54	10800	2056
132	2	Nkhotakota	Serengeti	9	2880	4112
132	2	Chinyama	Serengeti	70	22400	4112
132	2	Chinyama	Shayona	24	7680	4112
132	2	Luwinga	Chintheche	79.09	15817	2056
132	2	New Bwengu	Luwinga	49.29	9859	2056
132	2	Chintheche	Chikangawa	70.89	22685	4112
132	2	Chintheche	Telegraph Hill	59.46	19028	4112
132	1	Telegraph Hill	Luwinga	15.40	3080	2056
132	2	Bwengu	New Bwengu	1.66	531	4112
132	2	Livingstonia	Bwengu	57	18240	4112
132	2	Uliwa	Livingstonia	28	8960	4112
132	2	Uliwa	Karonga	70	22400	4112
132	1	Wovwe	Uliwa	8	1600	2056
				Total	**433684**	**119248**

Table provides the costs estimates of the new lines and substation bays to be considered under Option 2 for supplying the new HV substations. The total costs amount to 100 MUSD for the circuits and 68 MUSD for the substation bays.

Table 4.5.27: Costs estimates of new lines to supply the new HV substations under Option 2.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Chichiri	Chirimba	6.5	1300	2056
	1	Chirimba	Chileka	10	2000	2056
	1	Chileka	Nkula A	30	6000	2056
132	1	Chichiri	Limbe A	6.5	1300	2056
	1	Limbe A	Limbe B	1	200	2056
	1	Mapanga	Limbe B	9	1800	2056
132	1	Blantyre West	Michiru	9.5	1900	2056
	1	Michiru	Chirimba	9.5	1900	2056
132	1	Changalume	Zomba	13	2600	2056
132	1	Monkey Bay	Maldeco	28.5	5700	2056
	1	Maldeco	Mangochi	21	4200	2056
132	2	Chigumula	Thyolo B	12	3840	4112
	2	Thyolo B	Thyolo A	14	4480	4112
	2	Thyolo A	Thyolo C	21	6720	4112
132	2	Fundis Cross	Phalombe	35	11200	4112
132	1	Area 48	Area 47	4.5	900	2056
	1	Area 47	Lilongwe OT	8.5	1700	2056
132	2	Area 47	Chitipi	9	2880	4112
132	2	Barracks	City Centre	2.5	800	4112
132	2	Chitipi	Namitete	36	11520	4112
132	2	Kanengo	Mponela	36	11520	4112
132	2	Luwinga	Sonda	9.5	3040	4112
132	2	Chinyama	Kanyika	40	12800	4112
				Total	**100300**	**67848**

Table provides the costs estimates of the new 3-winding transformers to be considered under Option 2 for reinforcing the existing transmission system by 2042. The total costs amount to 22 MUSD for the circuits and 25 MUSD for the substation bays.

Table4.5.28: Costs estimates of 3-winding transformer reinforcements under Option 2.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Costs circuits (kUSD)	Costs bays (kUSD)
400	132	33	3	Phombeya	7192	8296
400	132	33	3	Nkhoma	7192	8296
400	132	33	3	New Bwengu	7192	8296
				Total	**21576**	**24888**

Table lists the costs of the construction site openings under Option 2, which are needed for installing the new HV substations. The total costs amount to 52 MUSD.

Table 4.5.29: Costs estimates of site opening for new substations under Option 2.

Voltage (kV)	Substation	Costs site opening (kUSD)
132	Chileka	3083
132	Chirimba	3083
132	Limbe A	3083
132	Limbe B	3083
132	Michiru	3083
132	Maldeco	3083
132	Thyolo A	3083
132	Thyolo B	3083
132	Thyolo C	3083
132	Phalombe	3083
132	Area 47	3083
132	Chitipi	3083
132	City Centre	3083
132	Namitete	3083
132	Mponela	3083
132	Sonda	3083
132	Kanyika	3083
	Total	**52411**

Table lists the costs of the new shunt inductors that have been inserted in the scope of Option 2. A total of 200 Mvar is needed to adjust the voltage profiles in the system, which amounts to 4 MUSD.

Table 4.5.30: Costs estimates of new shunt inductors under Option 2.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
400	Chatoloma	L	105	1890
400	Mchinji	L	15	270
400	New Bwengu	L	80	1440
			Total	**3600**

Table lists the costs of the new shunt capacitors that have been inserted in the scope of Option 2. A total of -590 Mvar is needed to adjust the voltage profiles in the system, which amounts to 11 MUSD.

Table 4.5.31: Costs estimates of new shunt capacitors under Option 2.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
132	Mlambe	C	-45	810
132	Chichiri	C	-40	720

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
132	Chigumula	C	-25	450
132	Mapanga	C	-15	270
132	Changalume	C	-10	180
132	Fundis Cross	C	-45	810
132	Chingeni	C	-15	270
132	Liwonde	C	-20	360
132	Ntcheu	C	-5	90
132	Mlangeni	C	-5	90
132	Chirimba	C	-15	270
132	Chileka	C	-10	180
132	Limbe A	C	-20	360
132	Limbe B	C	-15	270
132	Michiru	C	-10	180
132	Thyolo A	C	-15	270
132	Thyolo B	C	-10	180
132	Thyolo C	C	-5	90
132	Phalombe	C	-15	270
132	Dedza	C	-25	450
132	Lilongwe OT 1	C	-15	270
132	Lilongwe OT 2	C	-10	180
132	Kanengo	C	-40	720
132	Kauma	C	-5	90
132	Area 48	C	-20	360
132	Chinyama	C	-15	270
132	Kanyika	C	-5	90
132	Shayona	C	-5	90
132	Area 47	C	-20	360
132	Chitipi	C	-10	180
132	City Centre	C	-15	270
132	Namitete	C	-15	270
132	Mponela	C	-30	540
132	Kasiya	C	-5	90
132	Chikangawa	C	-5	90
132	Karonga	C	-10	180
			Total	**10620**

5.3.4 Costs comparison

The objective of this section is to sum up the costs for implementing Option 1 and Option 2 and to highlight the differences between the two reinforcement strategies. The cost estimates of the decided/proposed transmission projects are excluded from the comparison since they are common to both options.

Figure illustrates the total costs estimates split by type of assets for both reinforcement strategies. Overall, the total costs estimates amount to 866 MUSD for Option 1 and 834 MUSD for Option 2. Implementing the second option is thus 32 MUSD cheaper than implementing the first one.

Looking more closely at the figure, it can be observed that Option 2 actually requires a higher investment costs than Option 1 for the new substations and lines (798 MUSD for Option 2 vs. 740 MUSD for Option 1). The savings are mainly achieved by suppressing the needs for transformers as the total costs of this category amount to 22 MUSD for Option 2 and up to 107 MUSD for Option 1. Some savings are also achieved at the level of the shunt reactors/capacitors as the total costs amount to 14 MUSD for Option 2 and 19 MUSD for Option 1.

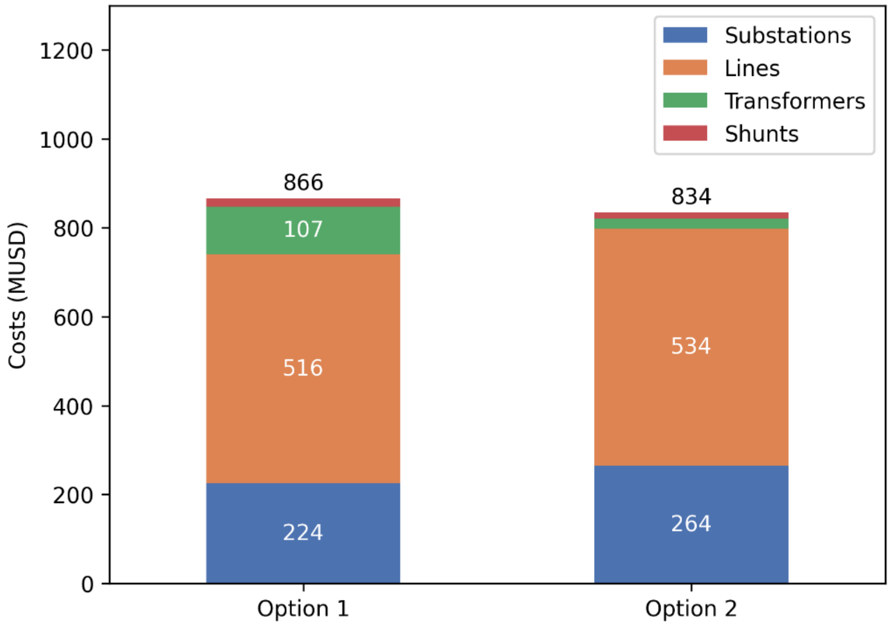


Figure 4.5.14: Total costs estimates split by reinforcement categories.

On top of having lower investment costs, Option 2 is also associated with lower network losses than Option 1 as shown in Section 5.2. The yearly losses amount to 473 GWh for Option 2 and 633 GWh for Option 1 in 2042. Considering an average electricity cost[28] of 61.5 USD/MWh in 2042, the estimated yearly costs due to network losses would represent 29 MUSD/year for Option 2 and 39 MUSD/year for Option 1 (see Table). A yearly saving of 10 MUSD is thus achieved by operating the transmission system at a higher voltage level.

Table 4.5.32: Estimated yearly costs due to losses in 2042.

Category	Option 1 (MUSD/year)	Option 2 (MUSD/year)
Losses	38.94	29.12

5.4 Selection of the reinforcement strategy

Based on the analyses presented in the previous sections and in close collaboration with the Stakeholders of the Transmission Working Group, the Consultant recommended the selection of Option 2 (upgrade of 66 kV transmission level to 132 kV) as the reinforcement strategy for the

[28] This cost includes the yearly marginal cost of generation, the generation fixed cost, and the annualized build cost.

development of the transmission network. This was confirmed during a dedicated meeting held with the WG on May 8, 2024.

Table provides a summary table with the investment and operational costs for both reinforcement strategies. The two options show similar investment costs for network upgrades needed to handle the required flows in 2024, while respecting the operational criteria in N and N-1 conditions. Option 2 remains nevertheless slightly more advantageous as it is overall 32 MUSD cheaper than Option 1.

Additionally, Option 2 presents lower costs associated with network losses. A net annual saving of 10 MUSD is expected to be achieved when operating the Malawian power system at a higher voltage level. The costs difference between both options increases therefore by 10 MUSD after each year of operation.

Furthermore, due to the upgrade to the 132kV level, Option 2 offers better prospects for future development beyond 2042. A higher voltage level not only facilitates the integration of long-distance transmission lines but also supports the installation of new power plants in remote locations.

All these factors make Option 2 the preferred reinforcement strategy for the Malawian power system over Option 1.

Table 4.5.33: Costs comparison between the two target structures for 2042.

Criteria	Option 1	Option 2
Investment costs	**-** (866 MUSD)	**+** (834 MUSD)
Network losses	**-** (39 MUSD/year)	**+** (29 MUSD/year)
Future development	**-**	**+**

As explained before, the most suitable long-term development strategy will be integrated with the short- and medium-term projects outlined in Section 5.1.3 to establish the reference network structure for the study horizon. The results of this process are presented in the next section.

5.5 Reference network structure

This section analyses the reference network structure at the study horizon 2042, obtained by applying the development strategy defined in the previous sections to the current transmission network. It takes into account the decided and proposed network reinforcement projects presented in Section 5.1.3.

5.5.1 List of reinforcements

Color legend for the tables

	Same number of circuits as before or one circuit along new path
(yellow)	Extra circuit(s) needed to be N compliant
(blue)	Extra circuit(s) needed to be N-1 compliant
(green)	Extra circuit(s) needed to be N-1 compliant due to radial connection

Table lists the line reinforcements needed in the existing transmission system by 2042 for the reference network structure when considering the updated list of decided/proposed transmission projects (cf. Section 5.1.3). Among the 44 line reinforcements, 31 of them only consist in upgrading the capacity of the existing circuit and operating it at 132 kV. The other reinforcements also involve the commissioning of additional circuits in parallel to the existing ones.

In total, the reference network structure foresees for the transmission system at the study horizon 2042:

- 1692 km of new 132kV lines
- 24 km of new 33kV lines

A distinction is made in the comments between the reinforcements already needed to be N compliant, the extra reinforcements needed to be N-1 compliant, and the reinforcements needed for the substations connected through a radial connection.

Table 4.5.34: List of line reinforcements in the existing transmission system by 2042 for the reference network structure.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Blantyre West	Chichiri	7	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Blantyre West	Chigumula	7	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kapichira	Blantyre West	29.43	• Type: 132kV Parakeet • Upgrade circuit to be N-1 compliant

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Kapichira	Blantyre West	30.16	• Type: 132kV Parakeet • Upgrade circuit to be N-1 compliant
132	1	Chichiri	Mapanga	10.81	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Chigumula	Mapanga	17.19	• Type: 132kV Parakeet • Upgrade circuit to 132kV"
132	1	Mapanga	Changalume	38.21	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Mapanga	Fundis Cross	44.01	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Mangochi	Makanjira	101	• Monkey Bay – Mangochi – Makanjira 132kV line project • Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
132	1	Mapanga	Nkula B	41.81	• Nkula B - Mapanga #1 • Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Nkula B	Mapanga	42.34	• Nkula B - Mapanga #2 • Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tedzani	Nkula B	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Nkula A	Nkula B	0.40	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant
132	1	Nkula A	Tedzani	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Tedzani	Chichiri	59	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tedzani	Tedzani IV	1	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Nkula A	Chingeni	70	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Chingeni	Liwonde	27	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Chingeni	Ntcheu	30	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Ntcheu	Mlangeni	18	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Mlangeni	Dedza	49.81	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Dedza	Tsabango	77.75	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kangoma	Tsabango	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Tsabango	Lilongwe OT	10.25	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kanengo	Area 48	6.99	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Kanengo	Kauma	7.38	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Barracks	Kauma	4.04	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Barracks	Kangoma	8	• Type: 132kV Parakeet

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
					• Upgrade circuit to 132kV
132	2	Nkhoma	Tsabango	30.06	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
132	3	Nkhoma	Kanengo	41.10	• Type: 132kV Parakeet • Keep two old circuits • Third circuit to be N-1 compliant
132	1	Golomoti	Nanjoka	87.22	• Type: 132kV Parakeet • Replace old circuit due to low line rating • Upgrade circuit to be N-1 compliant
132	3	Phombeya	Golomoti	101	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N-1 compliant
132	3	Nkula B	Phombeya	32	• Type: 132kV Parakeet • Replace old circuit A due to low line rating • Keep two old circuits B and C • Upgrade circuit A to be N compliant
132	3	Nanjoka	Nkhotakota	98.33	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant"
132	3	Nkhotakota	Dwangwa	50	• Eastern backbone project • Type: 132kV Parakeet • Third circuit to be N-1 compliant"
33	2	Chinyama	Shayona	24	• Type: 33kV Oak • Keep old circuit • Second circuit to be N-1 compliant (radial)

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	2	New Bwengu	Luwinga	49.29	• Type: 132kV Parakeet • Keep old circuit • Second circuit to be N-1 compliant
132	1	Chintheche	Telegraph Hill	59.46	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	1	Telegraph Hill	Luwinga	15.40	• Type: 132kV Parakeet • Upgrade circuit to 132kV
132	2	Bwengu	New Bwengu	1.66	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Livingstonia	Bwengu	57	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Uliwa	Livingstonia	28	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	2	Uliwa	Karonga	70	• Type: 132kV Parakeet • Upgrade circuit to 132kV • Second circuit to be N-1 compliant (radial)
132	1	Wovwe	Uliwa	8	• Type: 132kV Parakeet • Upgrade circuit to 132kV

Table lists the new lines needed to supply the HV substations by 2042 for the reference network structure. Among the 18 new connections, 10 of them consist of one single circuit. The other reinforcements include additional circuits in parallel to make the system N-1 compliant due to radial connection.

In total, the reference network structure foresees for supplying the new HV substations by 2042:

- 375 km of new 132kV lines

Table 4.5.35: List of new lines to supply the new HV substations by 2042 for the reference network structure.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Comments
		From	To		
132	1	Chichiri	Chirimba	6.5	• Type: 132kV Parakeet • Replace existing 66kV line Chichiri-Nkula A due to low line rating
	1	Chirimba	Chileka	10	
	1	Chileka	Nkula A	30	
132	1	Chichiri	Limbe A	6.5	• Type: 132V Parakeet • Same paths as existing MV feeders
	1	Limbe A	Limbe B	1	
	1	Mapanga	Limbe B	9	
132	1	Blantyre West	Michiru	9.5	• Type: 132kV Parakeet • Same paths as existing MV feeders
	1	Michiru	Chirimba	9.5	
132	2	Chigumula	Thyolo B	12	• Type: 132kV Parakeet • Second circuit to be N-1 compliant (radial)
	2	Thyolo B	Thyolo A	14	
	2	Thyolo A	Thyolo C	21	
132	1	Area 48	Area 47	4.5	• Type: 132kV Parakeet • Replace existing 66kV line Area 48-Lilongwe
	1	Area 47	Lilongwe OT	8.5	
132	2	Area 47	Chitipi	9	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Barracks	City Centre	2.5	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Chitipi	Namitete	36	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Kanengo	Mponela	36	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)
132	2	Luwinga	Sonda	9.5	• Type: 132kV Parakeet • Same path as existing MV feeder • Second circuit to be N-1 compliant (radial)

Table lists the 3-winding transformer reinforcements in the existing transmission system by 2042 for the reference network structure. The three reinforcements consists in commissioning additional transformers in parallel.

In total, the reference network structure foresees in the existing transmission system by 2042:

- 6 new 3-winding transformers

Table 4.5.36: List of 3-winding transformer reinforcements in the existing transmission system by 2042 for the reference network structure.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Comments
400	132	33	3	Phombeya	• Rating: 200 MVA • Keep old transformer Phombeya T2 • Two/three transformers to be N/N-1 compliant
400	132	33	3	Nkhoma	• Rating: 200 MVA • Keep old transformers Nkhoma T2 • Two/three transformers to be N/N-1 compliant
400	132	33	2	New Bwengu	• Western backbone project • Rating: 200 MVA • Second transformer to be N-1 compliant

5.5.2 Load flow analyses

The results presented below summarize the outcomes of 8760 load flow calculations performed by running an AC QDS over the entire year of 2042. All line loadings and voltage magnitudes have been collected and compiled in the form of boxplots and histograms. These representations provide a concise way to understand the expected performances of the Malawian power system in 2042 for the reference network structure.

Line loadings

Figure displays the boxplots of line loadings over the entire year of 2042 for the reference network structure. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the loading values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in Table.

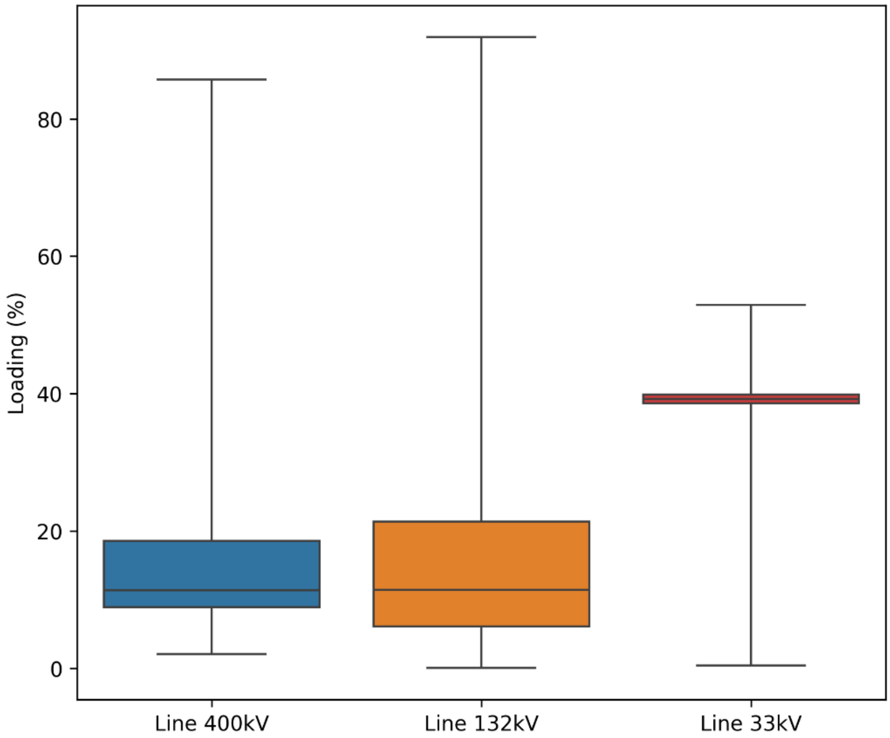


Figure 4.5.15: Boxplots of line loadings over the entire year of 2042 for the reference network structure.

Table 4.5.37: Five-number summary of line loadings over the entire year of 2042 for the reference network structure.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Line 400kV	2.02	8.89	11.36	18.54	85.71
Line 132kV	0.04	6.11	11.40	21.34	91.95
Line 33kV	0.38	38.58	39.18	39.88	52.91

The third quartile Q3 is the value below which 75% of the loading values falls. Hence, for the reference network structure, the loading stays 75% of the time below 19% for the 400kV lines, 21% for the 132kV lines, and 40% for the 33kV lines. The sizes and the positions of the boxes show that the loading remains on average low for the 400kV and 132kV lines and is higher for the 33kV lines.

For a few hours of the year, the maximum loading Q4 can reach up to 86% for the 400kV lines, 92% for the 132kV lines, and 53% for the 33kV lines. High loadings remain nevertheless a rare occurrence as illustrated by the histograms shown in Figure.

Each histogram presents the number of times a category of lines is loaded at a given percentage of their capacity during the year 2042. It can be observed that most loading values remain below 20% for 400kV lines. The loading of the 132kV lines is overall higher but still remains most of the time below 40%. For the 33kV lines, all loading values remain below 53% of the line ratings.

Keeping the loading of the assets below 50-60% is usually necessary to ensure that the remaining assets do not become overloaded after a N-1 contingency. This is especially valid for the assets with a high rating, such as the 400kV and 132kV lines, whose loss could represent a huge burden on the transmission system in case they were initially highly loaded.

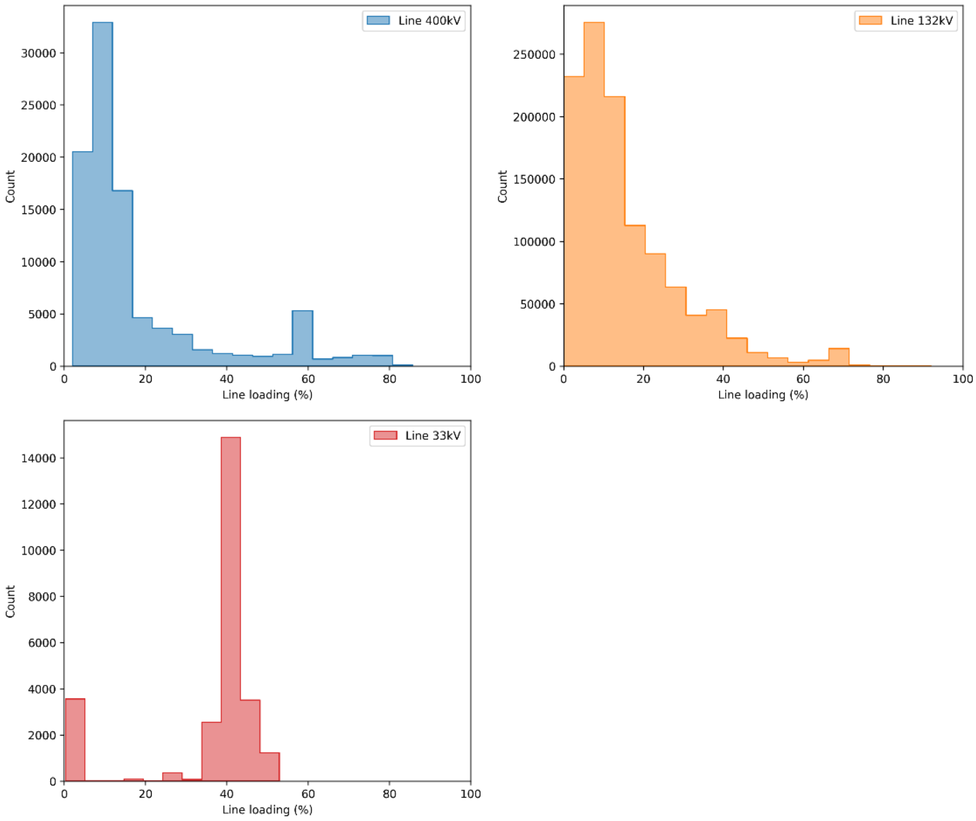


Figure 4.5.16: Histograms of line loadings over the entire year of 2042 for the reference network structure.

Voltage magnitudes

Figure displays the boxplots of voltage magnitudes over the entire year of 2042 for the reference network structure. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the voltage values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in Table.

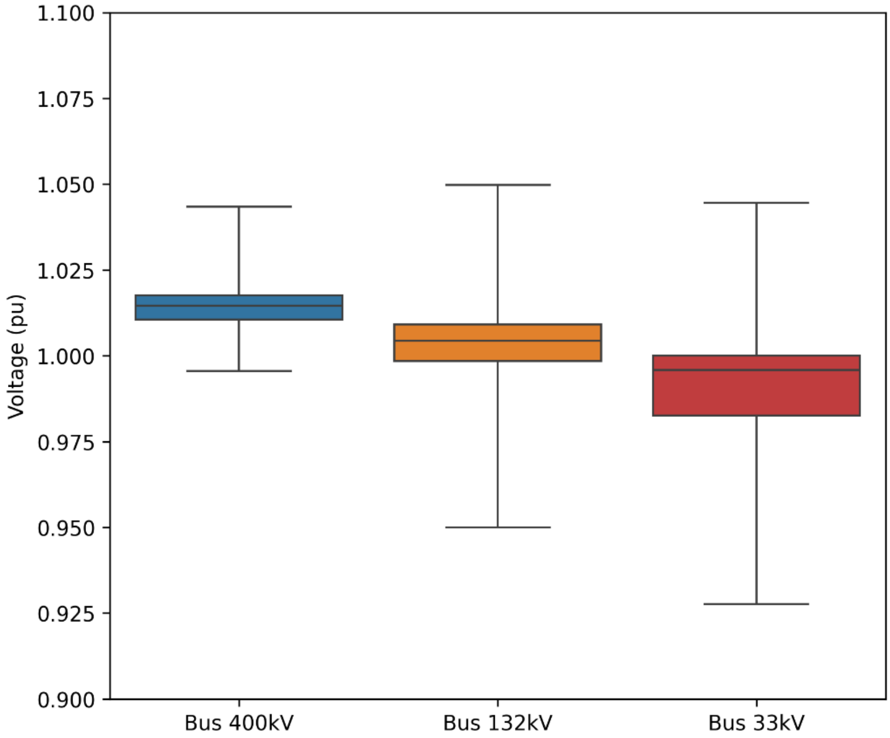


Figure 4.5.17: Boxplots of voltage magnitudes over the entire year of 2042 for the reference network structure.

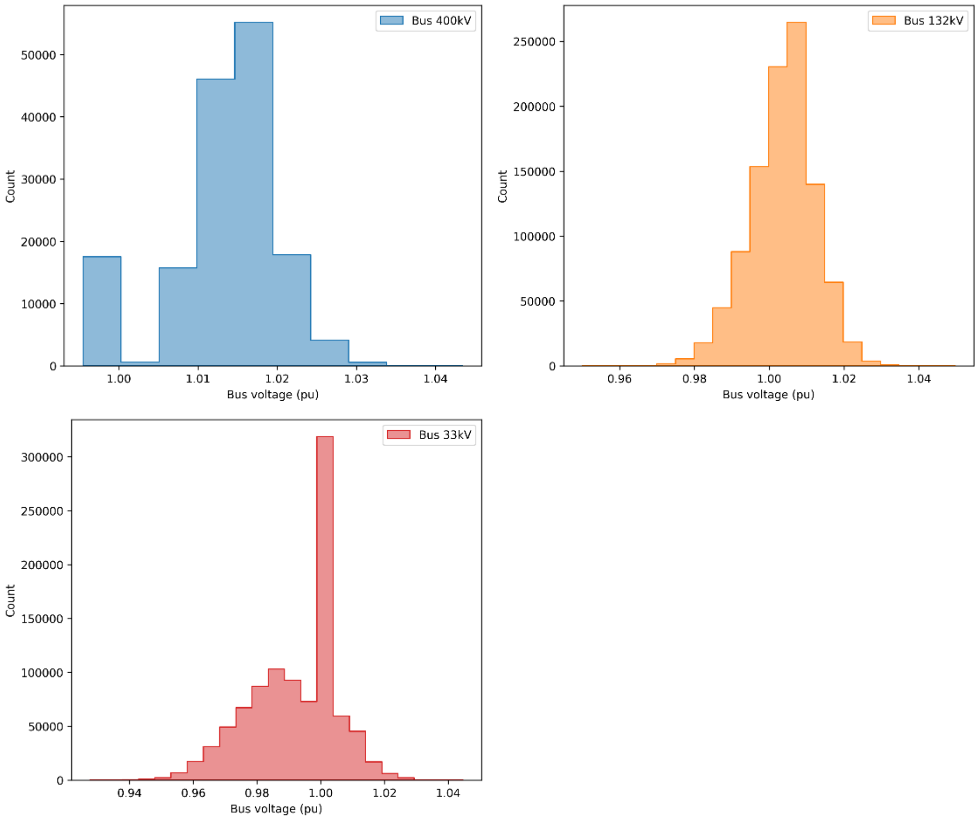
Table 4.5.38: Five-number summary of voltage magnitudes over the entire year of 2042 for the reference network structure.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Bus 400kV	0.996	1.011	1.015	1.018	1.043
Bus 132kV	0.950	0.999	1.004	1.009	1.050
Bus 33kV	0.928	0.983	0.996	1.000	1.045

For all voltage levels, the first quartile Q1 lies between 0.983 and 1.011 pu and the third quartile Q3 lies between 1.000 and 1.018 pu. In other words, the voltage magnitudes in the Malawian system remain 50% of the time within a small range that spans between 0.983 and 1.018 pu.

While the voltage magnitudes of the 400kV and 132kV buses always remain within the acceptable range set between 0.95 and 1.05 pu in normal operating conditions, the same cannot be said for the 33kV buses. For a few hours of the year, the voltage magnitudes can drop down to 0.928 pu for the 33kV buses. Low voltages remain nevertheless a rare occurrence as illustrated by the histograms in Figure.

Each histogram presents the number of times a bus of a certain voltage level reaches a given value during the year 2042. It can be observed that most voltage values are closely distributed around 1 pu.



Figuren 4.5.18: Histograms of voltage magnitudes over the entire year of 2042 for the reference network structure.

Network losses

Figure compares the percentage of losses in the transmission system versus the electrical loads over the entire year of 2042 for the reference network structure.

The losses would account for 445 GWh in 2042 for the reference network structure, which represents about 3.70% of the total generated energy.

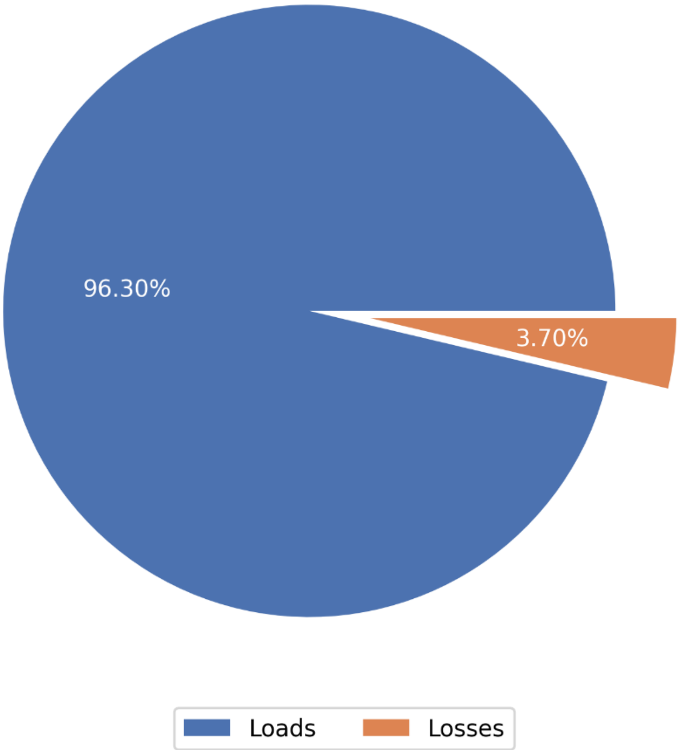


Figure 4.5.19: Pie chart comparing percentage of losses versus loads over the entire year of 2042 for the reference network structure.

5.5.3 Costs estimation

Table provides the estimation of the costs of the new circuits and substation bays to be considered for the reference network structure in order to reinforce the existing transmission system by 2042. The total costs amount to 326 MUSD for the circuits and 92 MUSD for the substation bays.

Table 4.5.39: Costs estimates of line reinforcements for the reference network structure.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Blantyre West	Chichiri	7	1400	2056
132	1	Blantyre West	Chigumula	7	1400	2056
132	1	Kapichira	Blantyre West	29.43	5886	0
132	1	Kapichira	Blantyre West	30.16	6031	0
132	1	Chichiri	Mapanga	10.81	2162	2056
132	1	Chigumula	Mapanga	17.19	3437	2056
132	1	Mapanga	Changalume	38.21	7642	2056
132	2	Mapanga	Fundis Cross	44.01	14084	4112
132	2	Mangochi	Makanjira	101	20200	2056
132	1	Mapanga	Nkula B	41.81	8362	2056
132	1	Nkula B	Mapanga	42.34	8468	2056

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Tedzani	Nkula B	8	1600	2056
132	2	Nkula A	Nkula B	0.40	128	4112
132	1	Nkula A	Tedzani	8	1600	2056
132	1	Tedzani	Chichiri	59	11800	2056
132	1	Tedzani	Tedzani IV	1	200	2056
132	1	Nkula A	Chingeni	70	14000	2056
132	1	Chingeni	Liwonde	27	5400	2056
132	1	Chingeni	Ntcheu	30	6000	2056
132	1	Ntcheu	Mlangeni	18	3600	2056
132	1	Mlangeni	Dedza	49.81	9962	2056
132	1	Dedza	Tsabango	77.75	15550	2056
132	1	Kangoma	Tsabango	8	1600	2056
132	1	Tsabango	Lilongwe OT	10.25	2050	2056
132	1	Kanengo	Area 48	6.99	1398	2056
132	1	Kanengo	Kauma	7.38	1476	2056
132	1	Barracks	Kauma	4.04	808	2056
132	1	Barracks	Kangoma	8	1600	2056
132	2	Nkhoma	Tsabango	30.06	6012	2056
132	3	Nkhoma	Kanengo	41.10	8220	2056
132	1	Golomoti	Nanjoka	87.22	17444	0
132	3	Phombeya	Golomoti	101	20200	0
132	3	Nkula B	Phombeya	32	6400	0
132	3	Nanjoka	Nkhotakota	98.33	19666	2056
132	3	Nkhotakota	Dwangwa	50	10000	2056
33	2	Chinyama	Shayona	24	4080	1602
132	2	New Bwengu	Luwinga	49.29	9859	2056
132	1	Chintheche	Telegraph Hill	59.46	11892	2056
132	1	Telegraph Hill	Luwinga	15.40	3080	2056
132	2	Bwengu	New Bwengu	1.66	531	4112
132	2	Livingstonia	Bwengu	57	18240	4112
132	2	Uliwa	Livingstonia	28	8960	4112
132	2	Uliwa	Karonga	70	22400	4112
132	1	Wovwe	Uliwa	8	1600	2056
				Total	**326428**	**92066**

Table provides the costs estimates of the new lines and substation bays to be considered for the reference network structure in order to supply the new HV substations. The total costs amount to 64 MUSD for the circuits and 53 MUSD for the substation bays.

Table 4.5.40: Costs estimates of new lines to supply the new HV substations for the reference network structure.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
132	1	Chichiri	Chirimba	6.5	1300	2056

Voltage (kV)	Circuits (-)	Substation		Length (km)	Costs circuits (kUSD)	Costs bays (kUSD)
		From	To			
	1	Chirimba	Chileka	10	2000	2056
	1	Chileka	Nkula A	30	6000	2056
132	1	Chichiri	Limbe A	6.5	1300	2056
	1	Limbe A	Limbe B	1	200	2056
	1	Mapanga	Limbe B	9	1800	2056
132	1	Blantyre West	Michiru	9.5	1900	2056
	1	Michiru	Chirimba	9.5	1900	2056
132	2	Chigumula	Thyolo B	12	3840	4112
	2	Thyolo B	Thyolo A	14	4480	4112
	2	Thyolo A	Thyolo C	21	6720	4112
132	1	Area 48	Area 47	4.5	900	2056
	1	Area 47	Lilongwe OT	8.5	1700	2056
132	2	Area 47	Chitipi	9	2880	4112
132	2	Barracks	City Centre	2.5	800	4112
132	2	Chitipi	Namitete	36	11520	4112
132	2	Kanengo	Mponela	36	11520	4112
132	2	Luwinga	Sonda	9.5	3040	4112
				Total	**63800**	**53456**

Table provides the costs estimates of the new 3-winding transformers to be considered for the reference network structure in order to reinforce the existing transmission system by 2042. The total costs amount to 18 MUSD for the circuits and 21 MUSD for the substation bays.

Table 4.5.41: Costs estimates of 3-winding transformer reinforcements for the reference network structure.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	Costs circuits (kUSD)	Costs bays (kUSD)
400	132	33	3	Phombeya	7192	8296
400	132	33	3	Nkhoma	7192	8296
400	132	33	2	New Bwengu	3596	4148
				Total	**17980**	**20740**

Table lists the costs of the construction site openings for the reference network structure, which are needed for installing the new HV substations. The total costs amount to 43 MUSD.

Table 4.5.42: Costs estimates of site opening for new substations for the reference network structure.

Voltage (kV)	Substation	Costs site opening (kUSD)
132	Chileka	3083
132	Chirimba	3083
132	Limbe A	3083
132	Limbe B	3083
132	Michiru	3083
132	Thyolo A	3083
132	Thyolo B	3083
132	Thyolo C	3083
132	Area 47	3083
132	Chitipi	3083
132	City Centre	3083
132	Namitete	3083
132	Mponela	3083
132	Sonda	3083
	Total	**43162**

Table lists the costs of the new shunt inductors that have been inserted in the scope of the reference network structure. A total of 185 Mvar is needed to adjust the voltage profiles in the system, which amounts to 3 MUSD.

Table 4.5.43: Costs estimates of new shunt inductors for the reference network structure.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
400	Chatoloma	L	70	1260
400	Mchinji	L	15	270
400	Mzimba	L	50	900
400	New Bwengu	L	50	900
			Total	**3330**

Table lists the costs of the new shunt capacitors that have been inserted in the scope of the reference network structure. A total of -540 Mvar is needed to adjust the voltage profiles in the system, which amounts to 10 MUSD.

Table 4.5.44: Costs estimates of new shunt capacitors for the reference network structure.

Voltage (kV)	Substation	Type	Value (Mvar)	Costs shunt (kUSD)
132	Mlambe	C	-45	810
132	Chichiri	C	-25	450
132	Chigumula	C	-20	360
132	Mapanga	C	-15	270
132	Changalume	C	-20	360
132	Zomba	C	-15	270
132	Fundis Cross	C	-40	720
132	Mangochi	C	-5	90
132	Makanjira	C	-5	90
132	Chingeni	C	-5	90
132	Ntcheu	C	-5	90
132	Mlangeni	C	-5	90
132	Chirimba	C	-15	270
132	Chileka	C	-10	180
132	Limbe A	C	-20	360
132	Limbe B	C	-15	270
132	Michiru	C	-5	90
132	Thyolo A	C	-15	270
132	Thyolo B	C	-10	180
132	Thyolo C	C	-5	90
132	Phalombe	C	-10	180
132	Dedza	C	-25	450
132	Lilongwe OT 1	C	-15	270
132	Lilongwe OT 2	C	-15	270
132	Kanengo	C	-5	90
132	KIA	C	-5	90
132	Kauma	C	-5	90
132	Area 48	C	-20	360
132	Chinyama	C	-15	270
33	Shayona	C	-15	270
132	Area 47	C	-20	360
132	Chitipi	C	-10	180
132	City Centre	C	-15	270
132	Barracks	C	-5	90
132	Namitete	C	-15	270
132	Mponela	C	-30	540
132	Kasiya	C	-5	90
132	Karonga	C	-10	180
			Total	**9720**

An overview of the investment costs split by studied periods of 5-10 years and by reinforcement categories is shown in Figure. When including the updated list of decided/proposed projects, the total costs estimates amount to 1306 MUSD:

- 2023-2027: **588 MUSD**
- 2028-2032: **318 MUSD**
- 2033-2042: **400 MUSD**

The splitting by studied period is obtained based on the timeline received for the decided/proposed projects and the list of reinforcements that will be detailed in Chapter 6. The costs of the decided/proposed projects are either provided or estimated based on the unitary costs of Section 5.3.1.

From 2023 to 2027, most of the investments costs (470 MUSD) are foreseen for implementing the decided/proposed projects, such as the Mozambique-Malawi interconnector, the Eastern Backbone, and other new 132kV lines across the country (see Table). The rest (118 MUSD) is needed to initiate the implementation of the reference network structure while ensuring the security of the Malawian power system.

From 2028 to 2032, the investments costs (206 MUSD) cover the remaining decided/proposed projects that include the Zambia-Malawi interconnector, the Tanzania-Malawi interconnector, the Western Backbone, and other new 132kV lines across the country (see Table). The rest (112 MUSD) is used to carry on the implementation of the reference network structure always while ensuring the security of the Malawian power system.

From 2033 to 2042, all the investments costs (400 MUSD) are intended for completing the implementation of the reference network structure as described in Section 5.5.1.

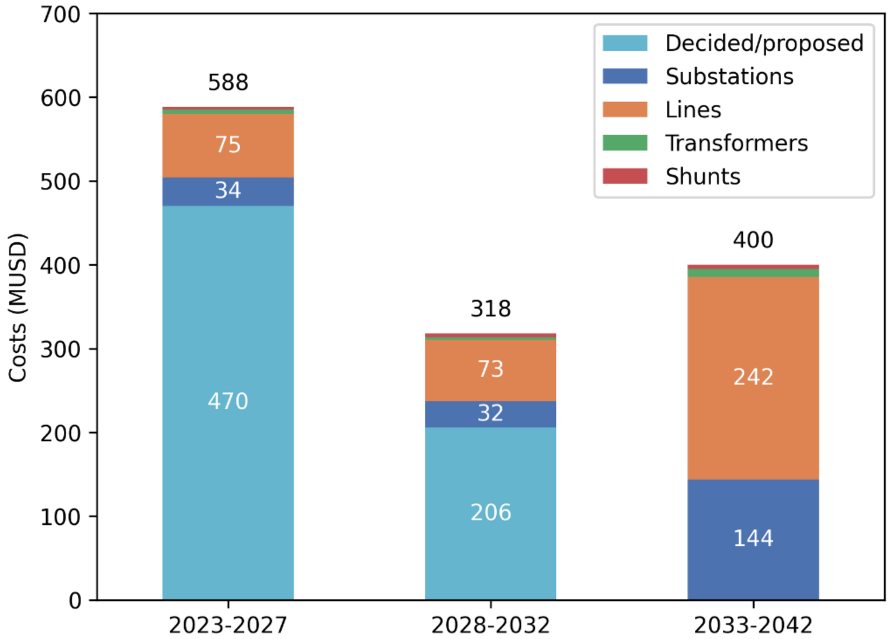


Figure 4.5.20: Total costs estimates for the reference network structure split by periods and reinforcement categories.

6 System performances

As presented in Section 5.5, the reference network structure is based on the updated list of decided/proposed projects and the conversion of the existing 66kV system into a stronger 132kV system. The next step of this study consists in establishing an approximate timeline for implementing these reinforcements and to validate the system performances for two intermediate years: 2027 and 2032.

The lists of reinforcements at the intermediate years are obtained in the same ways as for 2042. A series of DC QDS and AC QDS is performed to determine the reinforcements needed to make the transmission system N/N-1 compliant in both 2027 and 2032. One of the difficulties in implementing the reference network structure is to find a way to operate an upgraded 132kV system alongside the existing 66kV system. Due to time and costs constraints, every substation cannot be upgraded at the same time to the upper voltage level. Priority must be given to the parts of the system subject to overloads.

On the other hand, upgrading an substation implies that the adjacent ones must be upgraded since a transmission line cannot be operated at two different voltage levels. The conversion must be pursued until suitable stopping points are found, which are the system nodes where both the 132kV and 66kV levels coexist from the start. The newly upgraded lines can be connected to the 132kV terminal while the existing lines can stay on the 66kV terminal. Additional temporary 132/66kV transformers can be necessary at these junctions to ensure that the transfer capacity remains sufficient between the two voltage levels.

Once the lists of reinforcements are established, dedicated analyses are performed to validate the system structures in 2027 and 2032. The set of simulations performed using DIgSILENT PowerFactory (PF) include:

- Load flow calculations to verify the loadings of the assets and the voltages of the buses
- Short-circuit calculations to check if the fault currents remain below the breaker ratings
- Dynamic simulations to assess the transient stability, the voltage stability, and the frequency stability of the Malawian system

6.1 Year 2027

6.1.1 List of reinforcements

This section details the minimum list of reinforcements and upgrade to the transmission grid needed to accommodate the future generation and demand expected in 2027 while respecting the planning and operational constraints.

By the year 2027, eight decided/proposed transmission projects in Malawi are expected to be operational:

Table 4.6.1: List of decided/proposed transmission projects in Malawi ready by 2027.

Name	Voltage (kV)	Circuits (-)	In service by (year)
Mozambique – Malawi 400kV interconnector	400	2	2027
Eastern Backbone project	132	2	2027
Golomoti – Monkey Bay 132kV line	132	2	2027
Monkey Bay – Mangochi – Makanjira 132kV line	132	1	2027
Blantyre West – New Blantyre – Nkula B 132kV line	132	1	2027
New Blantyre – Phalombe 132kV line	132	1	2027
Nkhotakota – Serengeti – Chinyama – Kanyika 132kV line	132	1	2027
Lilongwe 132kV loop	132	1	2027

The required system upgrades in order to cope with the demand increase and respect the operational criteria are limited to:

- Upgrade from 66 kV to 132 kV in the Southern Region up to Nkula B.
- Upgrade from 33/66 kV to 132 kV in the Northern Region from Chintheche up to Telegraph Hill and Luwinga.

The detailed list of reinforcements corresponding to both development zones is provided in Table.

Table 4.6.2: List of line reinforcements in the existing transmission system by 2027.

Voltage (kV)	Circuits (-)	Substation		Length (km)	In service by (year)
		From	To		
132	1	Blantyre West	Chichiri	7	2027
132	1	Blantyre West	Chigumula	7	2027
132	1	Chichiri	Mapanga	10.81	2027
132	1	Chigumula	Mapanga	17.19	2027
132	1	Mapanga	Changalume	38.21	2027
132	2	Mapanga	Fundis Cross	44.01	2027
132	1	Mapanga	Nkula B	41.81	2027
132	1	Nkula B	Mapanga	42.34	2027
132	1	Tedzani	Nkula B	8	2027
132	1	Tedzani	Chichiri	59	2027
132	1	Chintheche	Telegraph Hill	59.46	2027
132	1	Telegraph Hill	Luwinga	15.40	2027

At the extremities of the upgraded zones, the following lines are removed because the substation in Nkula A will not be upgraded to 132 kV yet.

Table 4.6.3: List of line removals in the existing transmission system by 2027.

Voltage (kV)	Circuits (-)	Substation		Length (km)	Removed by (year)
		From	To		
66	0	Nkula A	Nkula B	0.40	2027
66	0	Nkula A	Chichiri	43	2027

Four temporary 3-winding transformers of at least 25 MVA rating must be installed in parallel to existing ones: +2 in Tedzani, +1 in Chintheche, +1 at New Bwengu. These reinforcements will make the system N compliant, but not always N-1 compliant after the loss of a transformer. They are qualified as temporary because the transformers will be decommissioned as soon as the substation upgrade will be completed. Improving the reliability of the system further would require the installation of more temporary 3-winding transformers at the three locations.

Table 4.6.4: List of temporary 3-winding transformers in the existing transmission system by 2027.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	In service by (year)
132	66	11	3	Tedzani	2027
132	66	33	3	Chintheche	2027
132	66	11	2	New Bwengu	2027

6.1.2 Load flow analyses

The results presented below summarize the outcomes of 8760 load flow calculations performed by running an AC QDS over the entire year of 2027. All line loadings and voltage magnitudes have been collected and compiled in the form of boxplots. These representations provide a concise way to understand the expected performances of the Malawian power system in 2027 with the recommended reinforcements listed in the previous section.

Line loadings

Figure displays the boxplots of line loadings over the entire year of 2027. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the loading values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in

Table.

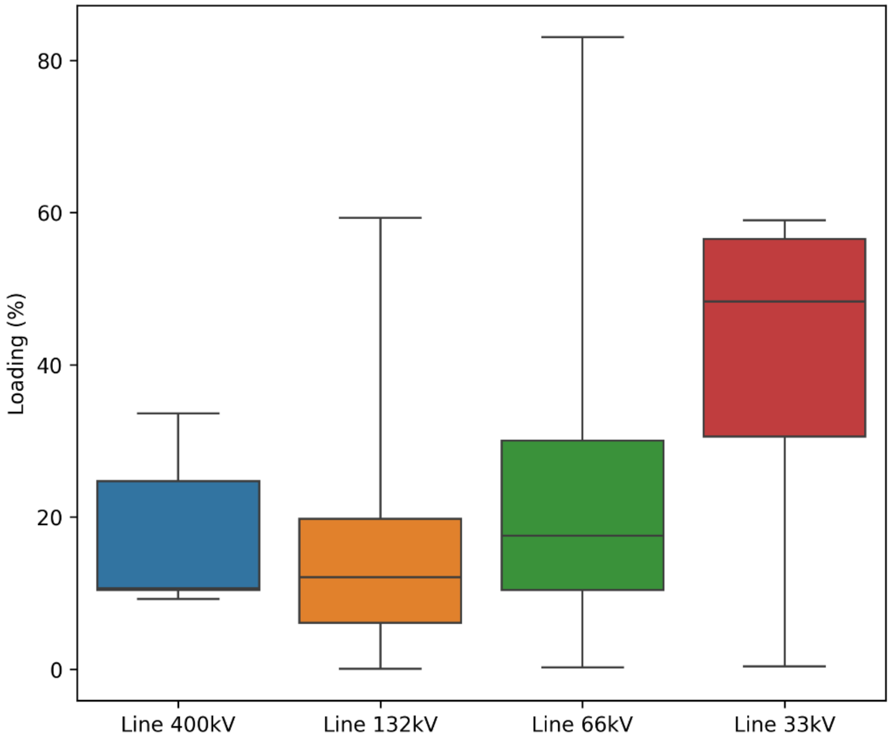


Figure 4.6.1: Boxplots of line loadings over the entire year of 2027.

Table 4.6.5: Five-number summary of line loadings over the entire year of 2027.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Line 400kV	9.19	10.36	10.67	24.67	33.63
Line 132kV	0.04	6.07	12.07	19.74	59.29
Line 66kV	0.25	10.41	17.57	30.02	83.07
Line 33kV	0.39	30.53	48.32	56.53	58.96

The third quartile Q3 is the value below which 75% of the loading values falls. Hence, the loading stays 75% of the time below 25% for the 400kV lines, 20% for the 132kV lines; 30% for the 66kV lines, and 57% for the 33kV lines. The sizes and the positions of the boxes show that the loading remains on average low for the 400kV to 66kV lines, and is higher for the 33kV lines.

For a few hours of the year, the maximum loading Q4 can reach up to 83% for the 66kV lines. High loadings remain nevertheless a rare occurrence.

Keeping the loading of the assets below 50-60% is usually necessary to ensure that the remaining assets do not become overloaded after a N-1 contingency. This is especially valid for the assets with a high rating, such as the 400kV and 132kV lines, whose loss could represent a huge burden on the transmission system in case they were initially highly loaded.

Voltage magnitudes

Figure displays the boxplots of voltage magnitudes over the entire year of 2027. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the voltage values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in

Table .

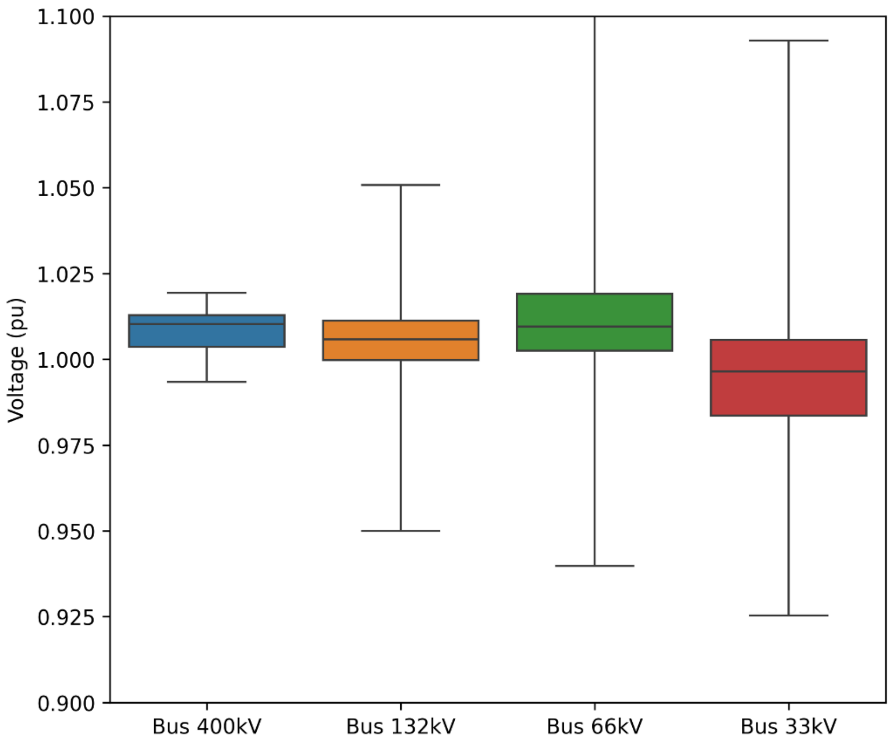


Figure 4.6.2: Boxplots of voltage magnitudes over the entire year of 2027.

Table 4.6.6: Five-number summary of voltage magnitudes over the entire year of 2027.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Bus 400kV	0.993	1.004	1.010	1.013	1.019
Bus 132kV	0.950	1.000	1.006	1.011	1.051
Bus 66kV	0.940	1.003	1.010	1.019	1.121
Bus 33kV	0.925	0.984	0.996	1.006	1.093

For all voltage levels, the first quartile Q1 lies between 0.984 and 1.004 pu and the third quartile Q3 lies between 1.006 and 1.019 pu. In other words, the voltage magnitudes in the Malawian system remain 50% of the time within a small range that spans between 0.984 and 1.019 pu.

While the voltage magnitudes of the 400kV and 132kV buses always remain within the acceptable range set between 0.95 and 1.05 pu in normal operating conditions, the same cannot be said for the other voltage levels. For a few hours of the year, the voltage magnitudes can drop down to values under 0.95 pu or rise up to values above 1.05 pu. Such an issue could easily be solved by either keeping a generating unit in standby, adjusting the voltage setpoints of the other generating units, or changing the tap positions of the transformers and the shunt reactors/capacitors. Slightly too low or too high voltages remain nevertheless a rare occurrence.

Network losses

Figure compares the percentage of losses in the transmission system versus the electrical loads over the entire year of 2027.

The losses account for 208 GWh in 2027, which represents about 5.41 % of the total generated energy.

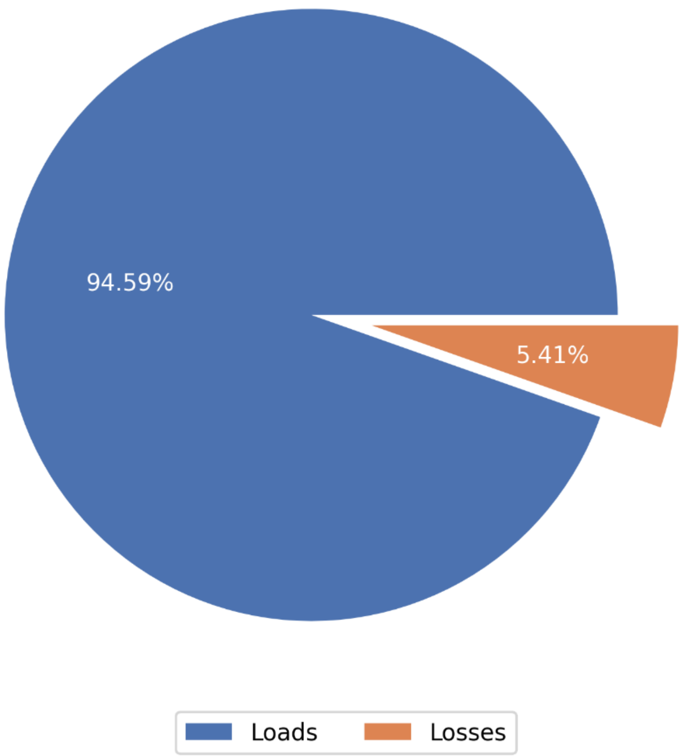


Figure 4.6.3: Pie chart comparing percentage of losses versus loads over the entire year of 2027.

6.1.3 Short-circuit analyses

Short-circuit analyses are conducted in accordance with the IEC 60909 standard, which is applicable to the calculation of short-circuit currents in low-voltage three-phase AC systems and in high-voltage three-phase AC systems, operating at a nominal frequency of 50 Hz or 60 Hz.

The analyses are conducted with a view to verify that the increase in short-circuit contribution from the generation expansion plan is compatible with the withstand capacity of the high-voltage substations. For most of the existing substations, the ratings of the circuit breakers have been shared in tabular format [9]. Different types of breakers are seen to coexist within the same substation, which leads to the definition of breaker ranges defined by a minimum and a maximum value. For the remaining substations, it will be assumed that the breaker rating is 61.2 kA at 400kV level, 40 kA at 132kV level, and 25 kA at 66kV level. These values are in line with the ratings of the existing circuit breakers in Malawi.

The maximum short-circuit currents are calculated for the hour of the year corresponding to the maximum loading in Malawi i.e. when more units are connected to the grid. The studied situation corresponds to October 5, 2027 at 6 pm, when the demand amounts to 617 MW. The dispatch of the generation units at this time is detailed in Table.

Table 4.6.7: Generation/import/DSM dispatch under peak load 2027.

Name	Type	Power (MW)	Name	Type	Power (MW)
Mozambique	Import	120	Muloza	Hydro	3
DSM	DSM	108	Nkula B	Hydro	99.7
Bagasse	Bagasse	50	Tedzani I & II	Hydro	6.61
Wind	Wind	8.91	Tedzani III	Hydro	60.5
Kapichira I	Hydro	60.17	Tedzani IV	Hydro	19.1
Kapichira II	Hydro	57.42	Wovwe	Hydro	4.29
Mapanga	Diesel	14.8	Wovwe 2	Hydro	4.5

The minimum short-circuit currents are calculated for the hour of the year corresponding to the minimum loading in Malawi i.e. when less units are connected to the grid.. The studied situation corresponds to February 25, 2027 at 11 pm, when the demand amounts to 215 MW. The dispatch of the generation units at this time is detailed in

Table.

Table 4.6.8: Generation/import/DSM dispatch under off-peak load 2027.

Name	Type	Power (MW)	Name	Type	Power (MW)
Mozambique	Import	120	Tedzani IV	Hydro	17.19
Kapichira II	Hydro	48.66	Wovwe	Hydro	4.29
Muloza	Hydro	3	Wovwe 2	Hydro	4.5
Nkula B	Hydro	17.36			

Table presents the minimum and maximum 3-phase short-circuit currents at each substation and voltage level of the Malawian transmission system. At 66 kV level, the maximum short-circuit current reaches 10 kA in Tedzani. At 132 kV, a maximum value of 12 kA is reached in Nkula B and Phombeya. At 400 kV, the maximum value reaches 6 kA in Phombeya. The calculated short-circuit currents are always lower than the associated minimum breaker rating.

Color legend for the table

Table 4.6.9: Maximum and minimum short-circuit current values in 2027.

	Breaker rating of existing substations
	Breaker rating assumed for remaining substations

Substation	Base kV	Min breaker rating (kA)	Max breaker rating (kA)	3-phase SC max (kA)	3-phase SC min (kA)
Blantyre West	132	31.5	40	8.07	5.31
Chichiri	132	40	40	7.76	5.23
Chigumula	132	40	40	7.07	4.84
Mapanga	132	25	25	8.04	5.40
Changalume	132	40	40	3.03	2.41
Fundis Cross	132	40	40	4.16	3.19
Nkula A	66	25	25	5.51	4.21
Nkula B	132	31.5	31.5	12.21	8.02
Tedzani	132	31.5	31.5	11.07	7.09
Tedzani	66	25	31.5	9.92	6.84
Kapichira	132	40	40	7.80	4.77
Mlambe	132	31.5	31.5	3.37	2.04
New Blantyre	132	40	40	5.53	4.16
Phalombe	132	40	40	1.57	1.33

Substation	Base kV	Min breaker rating (kA)	Max breaker rating (kA)	3-phase SC max (kA)	3-phase SC min (kA)
Chingeni	66	25	25	1.43	1.20
Liwonde	66	25	25	0.88	0.73
Ntcheu	66	25	25	1.25	1.05
Mlangeni	66	25	31.5	1.22	1.02
Dedza	66	12.5	40	1.33	1.13
Tsabango	132	40	40	3.43	2.90
Tsabango	66	25	25	4.10	3.49
Kangoma	66	25	25	4.14	3.55
Lilongwe OT	66	25	40	2.83	2.46
Kanengo	132	31.5	40	4.40	3.65
Kanengo	66	25	25	6.37	5.40
Area 48	66	25	31.5	4.44	3.82
Kauma	66	25	25	4.97	4.25
Barracks	66	25	40	4.56	3.91
Nkhoma	400	40	61.2	2.98	2.52
Nkhoma	132	40	40	6.41	5.19
Malingunde	132	40	40	2.79	2.38
Kasiya	132	40	40	2.61	2.22
KIA	132	40	40	3.87	3.21
Nanjoka	132	29	40	4.70	3.70
Golomoti	132	31.5	40	5.92	4.83
Monkey Bay	132	40	40	3.16	2.67
Mangochi	132	40	40	1.63	1.41
Makanjira	132	40	40	0.87	0.76
Phombeya	400	61.2	61.2	6.08	5.10
Phombeya	132	40	40	11.65	8.69
Nkhotakota	132	25	40	2.61	1.84
Dwangwa	132	40	40	2.25	1.48
Chintheche	132	31.5	40	1.56	1.11
Chintheche	66	25	25	2.33	1.75
Serengeti	132	40	40	2.32	1.68
Chinyama	132	40	40	1.25	0.98
Kanyika	132	40	40	0.97	0.78
Chikangawa	66	25	25	0.67	0.53
Luwinga	132	40	40	1.26	0.93
Telegraph Hill	132	40	40	1.26	0.93
New Bwengu	132	40	40	1.03	0.77
New Bwengu	66	25	25	1.58	1.24
Bwengu	66	25	25	1.56	1.22
Livingstonia	66	25	25	0.98	0.81
Uliwa	66	25	25	0.90	0.75
Wovwe	66	25	25	0.89	0.74
Karonga	66	25	25	0.51	0.42

6.1.4 Dynamic analyses

The objective of the dynamic analyses is to verify whether the Malawi grid is able to withstand the consequences of a severe disturbance, such a fault or an outage event, by returning to a stable steady state while satisfying a set of acceptance criteria. The RMS simulations are associated with timescales ranging from one millisecond to several seconds. They are performed with sufficient granularity to assess potential stability issues related to rotor angle transients, voltages and frequency.

In terms of disturbance events, the following ones are considered in the present analyses:

- **3-phase short-circuit faults** on a transmission line, cleared in base time and followed by the loss of the faulted line.
  Different line opening delays depending on voltage level are considered: 80 ms for 400 kV and 100 ms for 132 kV.

In this study, three-phase faults are simulated at both extremities of all 400kV and all 132kV lines loaded above 40%, for both peak and off-peak loading conditions. Only one line is studied in case of multiple lines in parallel.

- **Loss of generation** which consists in the sudden trip of an active generating unit.

  In this study, loss of generation is considered for up to 3 thermal units, 3 PV units, and 3 WT units, for both peak and off-peak loading conditions. Only one generating unit is studied in case the power station consists of multiple units that are identical.
- **Loss of Mozambique-Malawi 400kV interconnection.**

  Three-phase faults occurring simultaneously on the two interconnectors are simulated, which are followed by the opening of both lines after 80 ms.

  In this study, this simulation is only run for off-peak loading conditions.

The acceptance criteria specify that:

- **Rotor angle stability**: all generators must remain in synchronism with the rest of the grid
- **Voltage stability**: the voltages at the different nodes have to recover within 0.9 and 1.1 of the nominal value after a disturbance
- **Frequency stability**: the frequency of the grid must remain within 49.5 and 50.5 Hz

6.1.4.1 Three-phase faults

For several transmission lines, a three-phase short-circuit fault followed by a line tripping is simulated to check the voltage and transient stability of the system.

For the peak load situation, the loss of the four following lines are studied.

- Mozambique – Malawi 400kV line = 9.8% loading
- Phombeya – Nhkoma 400kV line = 30.2% loading
- Nkula B – Phombeya 132kV line = 47.6% loading
- Kapichira – BT West 132 kV line = 52.1% loading

Globally, the results of the analyses do not highlight any problem. The only issue is identified after a fault on either side of the Phombeya-Nkhoma 400kV line. The voltage around Nkhoma is seen to return to 0.84 pu after fault clearance, which is slightly below the required value of 0.9 pu. This situation is also observed with static load flow and highlights a lack of reactive power in the Central Region under peak loading conditions. This post-incident situation out of acceptable operating range is encountered after the loss of the 400 kV link at peak demand situations and would require dedicated reactive power compensation equipment. As shown in Section 6.2, this situation is solved by 2032 with the foreseen development of the transmission network and as the slight non respect of the constraint is a consequence of events with low probability of occurrence, the investment in additional equipment is not recommended.

Figure shows the voltage profiles of some major substations after a short-circuit fault on the Phombeya-Nkhoma 400kV line.

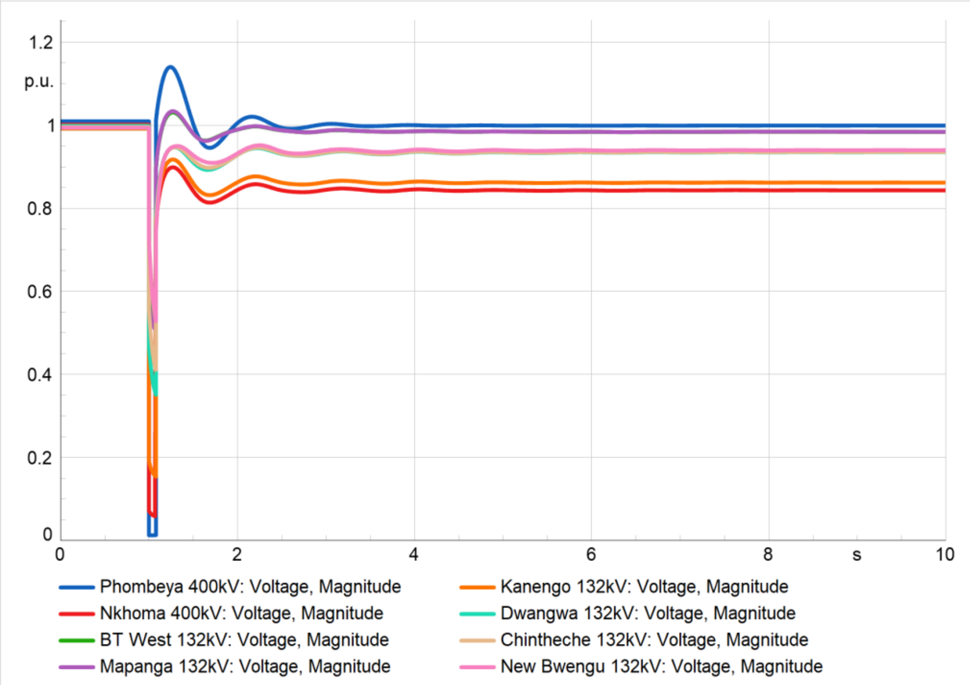


Figure 4.6.4: Voltage magnitudes in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Peak 2027.

None of the performed simulations listed above is showing any sign of transient stability issue. As an illustration, Figure shows the rotor angles of some generating units after a short-circuit fault on the Phombeya-Nkhoma 400kV line. The oscillations are quickly damped and a stable situation is reached.

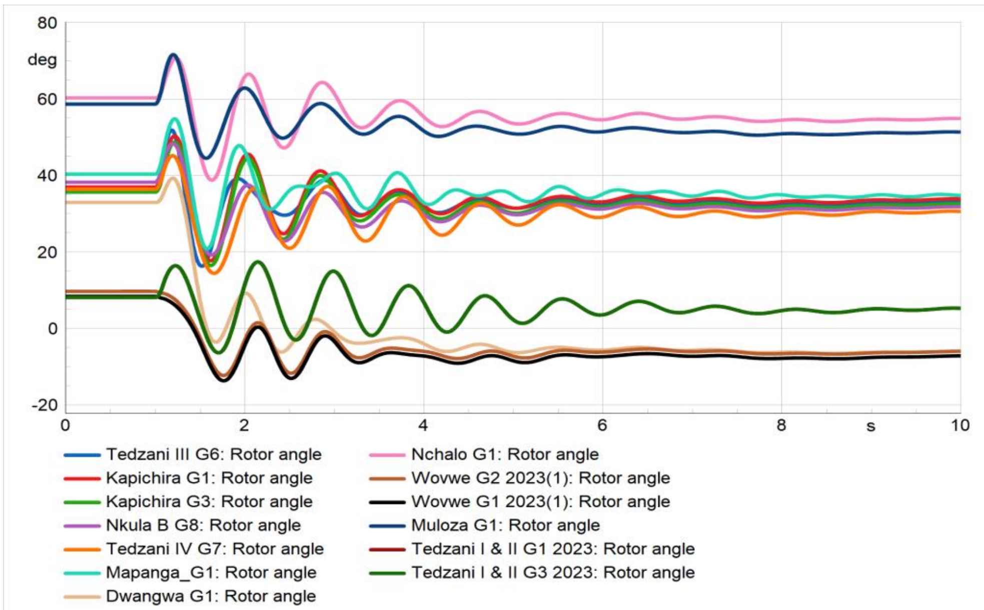


Figure 4.6.5: Rotor angles in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Peak 2027.

For the off-peak situation, the loss of the two 400 kV lines is studied. Both these lines are lightly loaded.

- Mozambique – Malawi 400kV line = 11.2% loading
- Phombeya – Nhkoma 400kV line = 19.3% loading

None of the performed simulations is showing any sign of voltage stability issue. As an illustration, Figure shows the voltage profiles of some major substations after a short-circuit fault on the Phombeya-Nkhoma 400kV line.

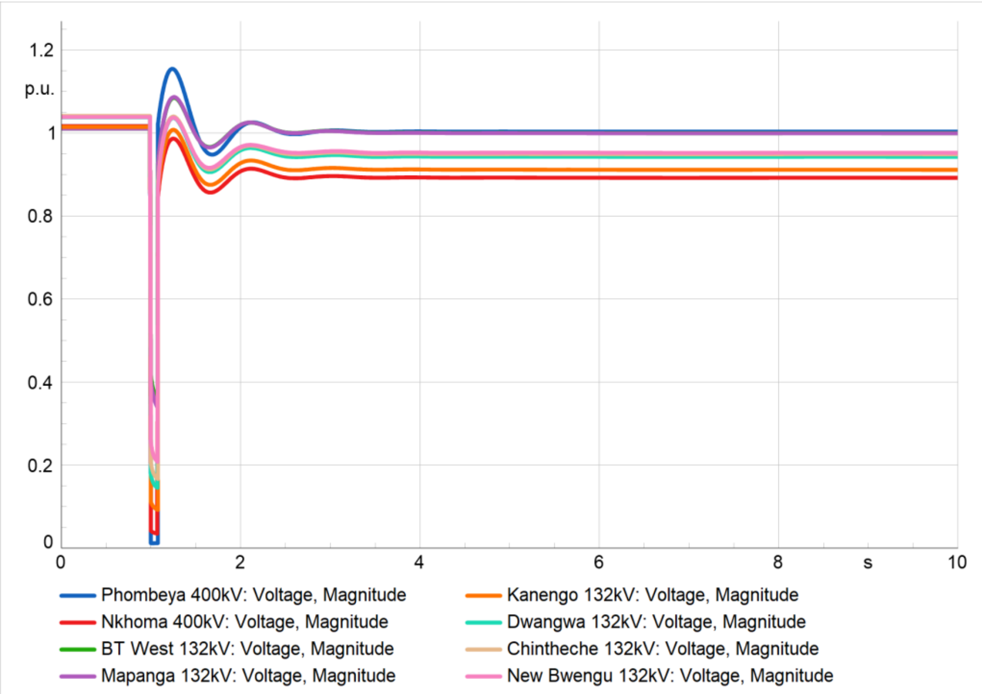


Figure 4.6.6: Voltage magnitudes in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Off-peak 2027.

As for the peak load situation studied above, none of the performed simulations is showing any sign of transient stability issue. Figure shows the rotor angles of some generating units after a short-circuit fault on the Phombeya-Nkhoma 400kV line.

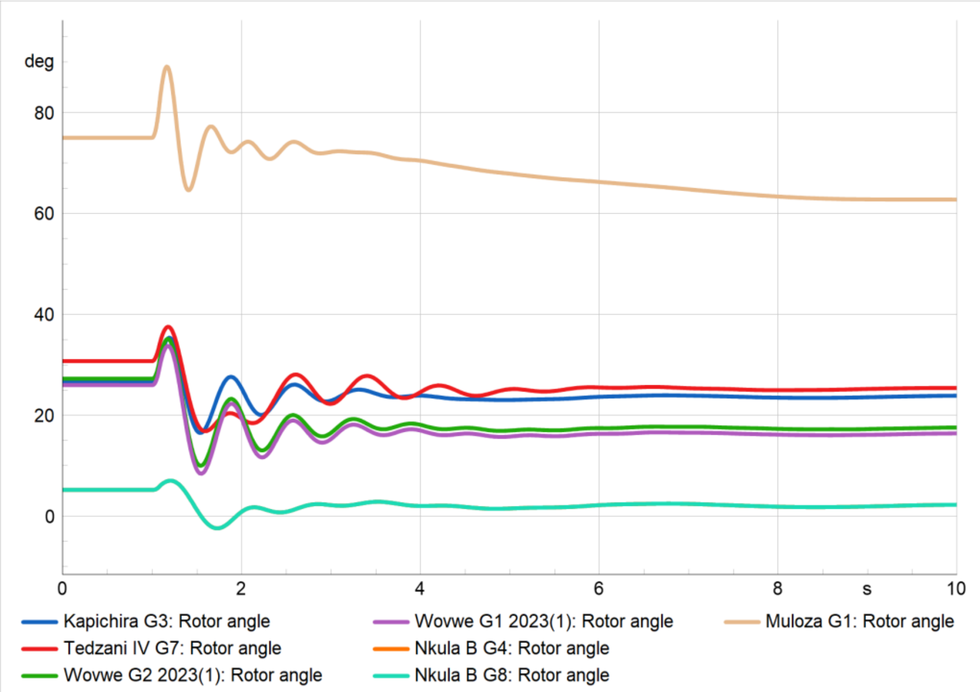


Figure 4.6.7: Rotor angles in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Off-peak 2027.

6.1.4.2 Loss of generation

For several power plants, the disconnection of a generating unit is simulated to check the frequency stability of the system.

For the peak load situation, the loss of four generating units is studied.

- Tedzani III G6 = 30.3 MW
- Kapichira G1 = 30.1 MW
- Kapichira G3 = 28.7 MW
- Mzimba WTG1 = 8.9 MW

As the power system of Malawi is interconnected with the SAPP regional system, the impact on the frequency of the loss of a generator is Malawi is very limited as illustrated in Figure for the loss of 30.3 MW. The frequency nadir remains higher than 49.93 Hz.

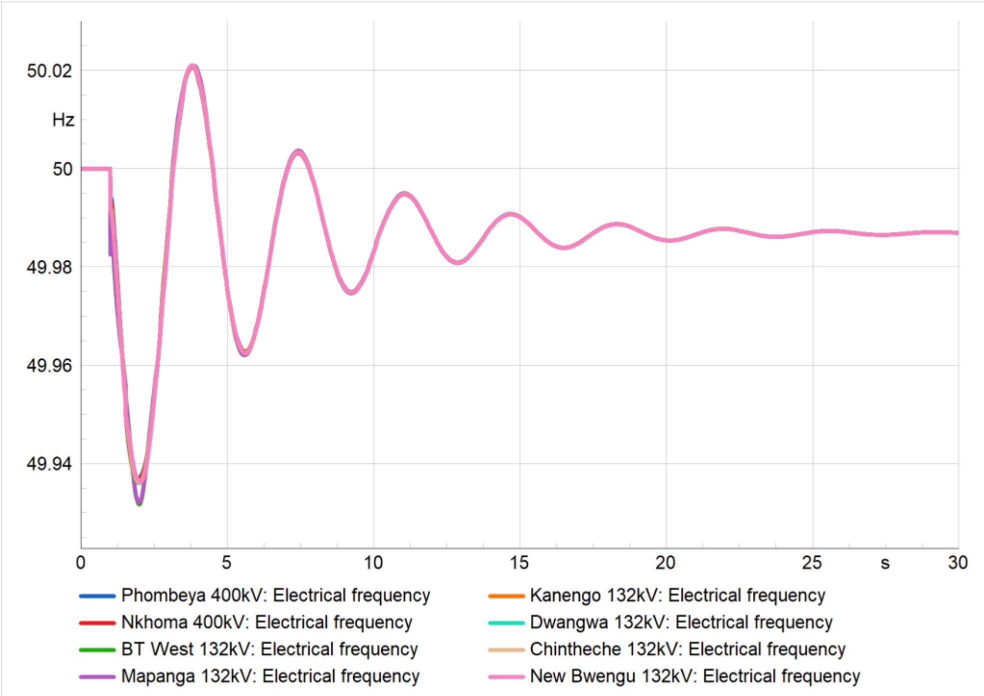


Figure 4.6.8: Electrical frequencies in Malawi after the loss of Tedzani III G6 – Peak 2027.

The loss of 30.3 MW is mainly covered by an increase in the import from Mozambique as most of the primary reserve of the interconnected regional system is maintained outside of Malawi.

Figure shows the evolution of the active power production by some generating units in Malawi. One can see that the impact on their production is limited.

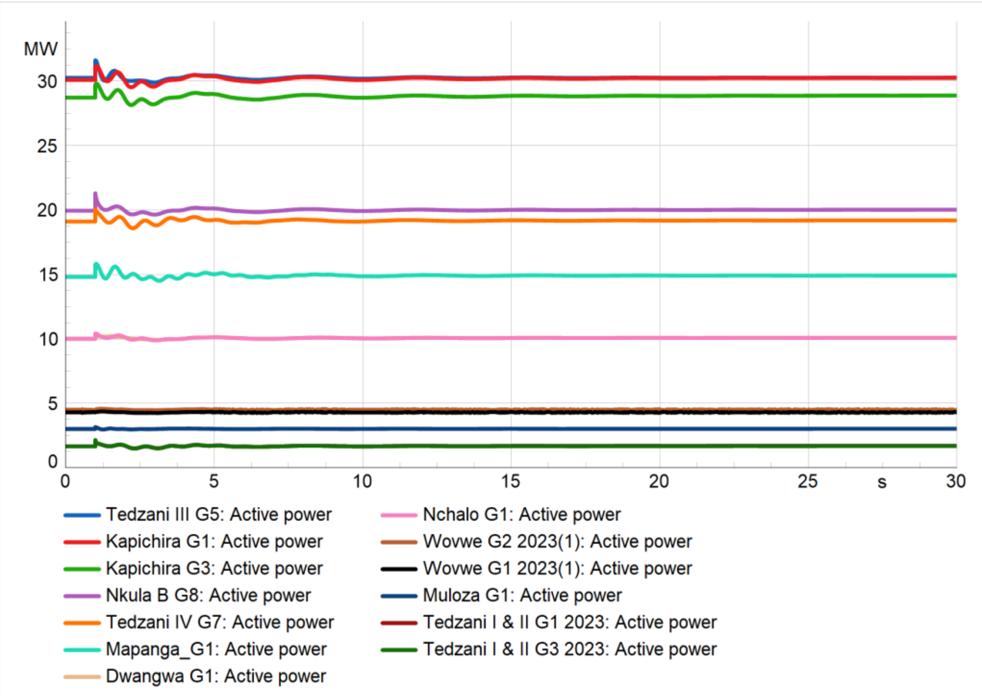


Figure 4.6.9: Active power from generating units in Malawi after the loss of Tedzani III G6 – Peak 2027.

Figure shows the low on the Mozambique-Malawi interconnection. The increase of import rapidly compensates for the loss of the unit in Malawi. The action of the secondary reserve in Malawi, which is not modeled, would bring back the import to its initial value in a second phase.

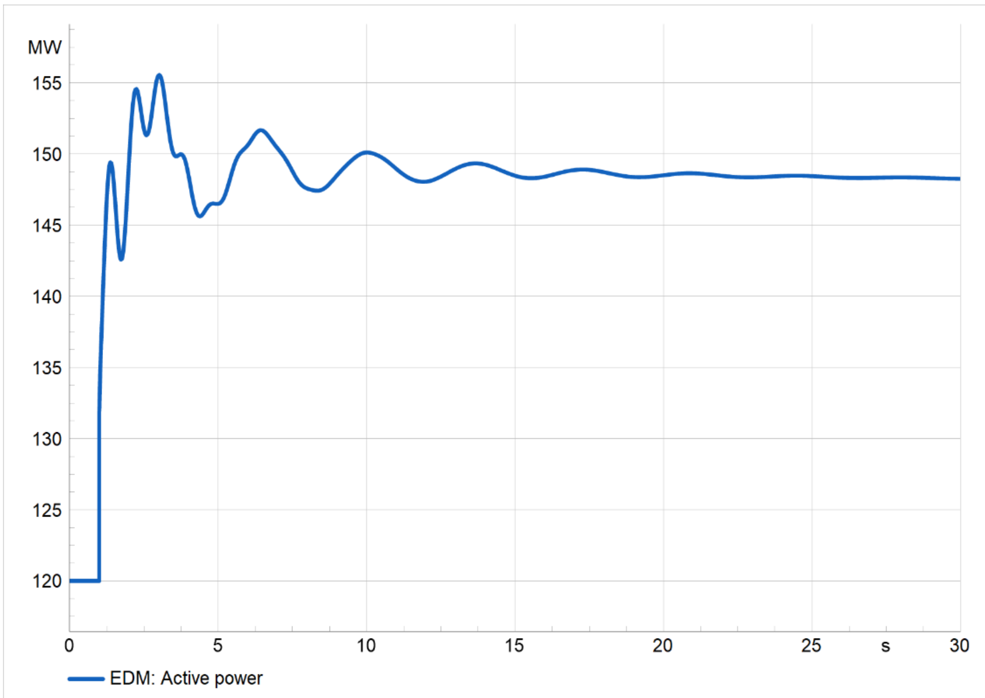


Figure 4.6.10: Active power import from Mozambique after the loss of Tedzani III G6 – Peak 2027.

For the off-peak situation, the loss of three generating units is simulated.

- Kapichira G3 = 24.3 MW
- Tedzani IV G7 = 17.2 MW
- Wovwe G2 = 4.5 MW

The results are similar to the ones of the peak demand scenario as illustrated in Figure to Figure. These figures depict the evolution of the frequency, the production of the units, and the import from Mozambique. Thanks to the Mozambique-Malawi interconnection that give access to an important inertia and reserve shared with the SAPP system, the impact of losing a generating unit is very limited.

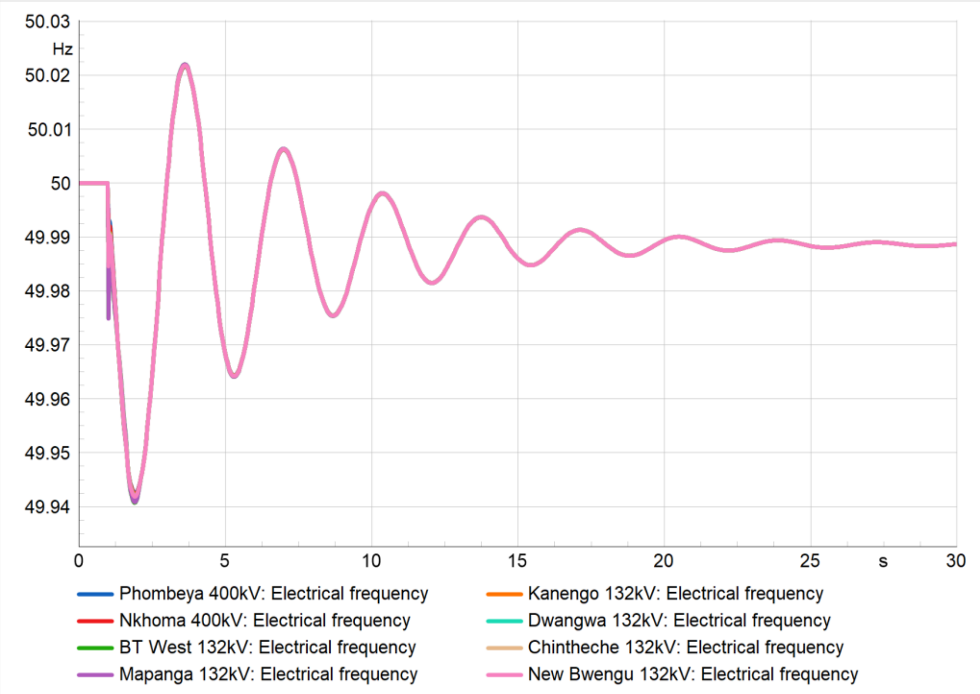


Figure 4.6.11: Electrical frequencies in Malawi after the loss of Kapichira G3 – Off-peak 2027.

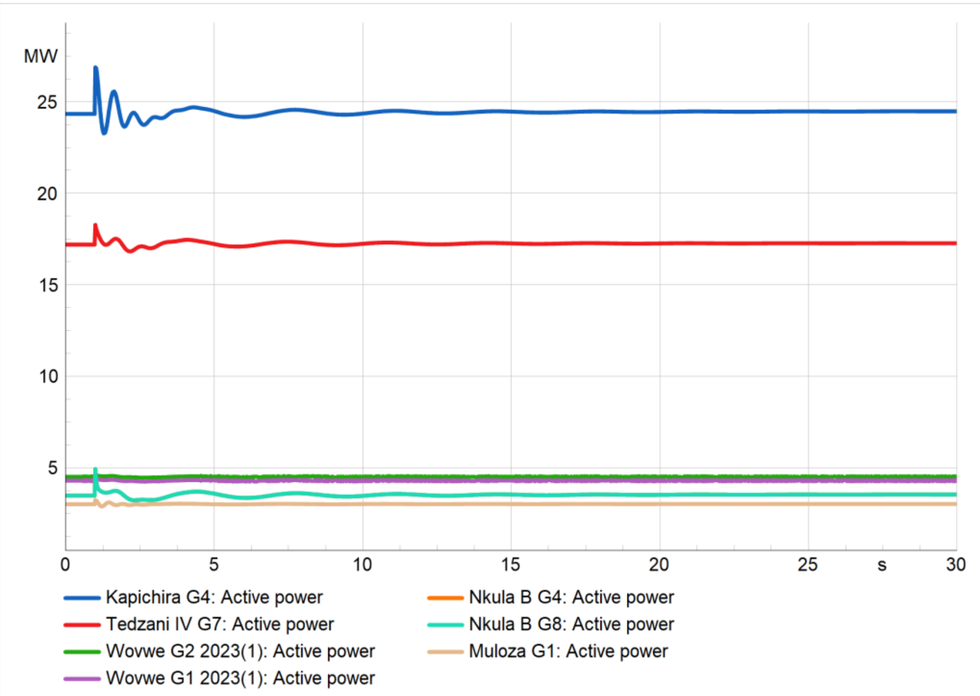


Figure 4.6.12: Active power from generating units in Malawi after the loss of Kapichira G3 – Off-peak 2027.

Figure shows that the loss of 30.3 MW is mainly covered by an increase in the import from Mozambique.

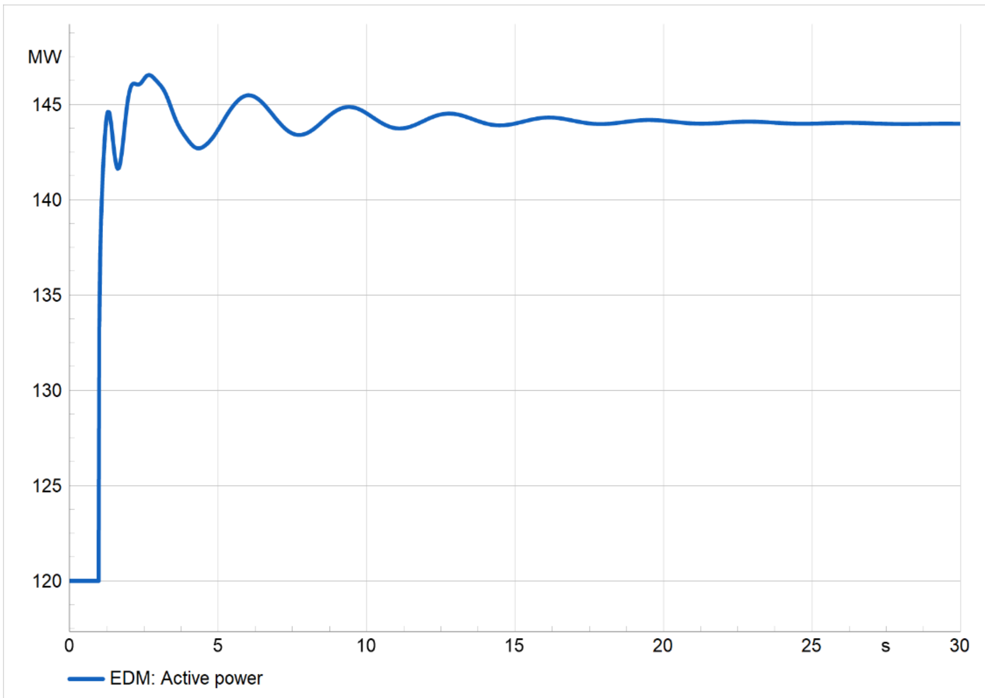


Figure 4.6.13: Active power import from Mozambique after the loss of Kapichira G3 – Off-peak 2027.

6.1.4.3 Loss of Mozambique – Malawi 400kV interconnection

As discussed and analyzed in the generation development plan report already issued in the frame of the present study, the worst incident for the frequency stability of the Malawian power system becomes the loss of the first interconnection with the SAPP regional interconnected system, i.e., the line between Malawi and Mozambique foreseen in 2024. Indeed, a constant import of 120 MW will flow in the line and the loss of this element will lead to the largest instantaneous imbalance between demand and generation in Malawi. In addition, Malawi will at the same time become isolated from the larger regional system, which would reduce its stability. The Malawian power system would return to the previous situation when it was operated as an electrical island.

The disconnection from the regional system coupled with the loss of 120 MW generation will represent an important challenge for the Malawian operators. They will have to limit the impact on the consumers connected in Malawi and to avoid a complete black-out of the country.

Techno-economic analyses were carried out in the frame of the generation development plan study to identify the most interesting solution among the possible options to maintain the stability of the isolated Malawian system. This section aims at illustrating the behavior of the system following the loss of the interconnection, depending on the different solutions implemented.

As indicated in the final report of the generation development plan, the recommended solution consists in integrating a second circuit on the interconnection with Mozambique. In this case, the N-1 criterion is respected for the regional integration and the stability is ensured by the continuous connection to SAPP. This solution would only require a limited level of primary reserve. Nevertheless, it has to be noted that, while it allows to respect the N-1 criterion for network planning, a second circuit on the interconnection line with Mozambique also presents important disadvantages:

- The two circuits will be on the same tower structure and structural default could lead to the unavailability of both circuits at the same time (structural vandalism, extreme wind speed, etc.)
- Having both regional interconnections with the same country and at the same substation might lead to additional risks, e.g., in case of unfavorable events within the substation in Matambo or its feeders, or in case of geopolitics which may affect the contract of power supply and limit the access to the regional market

Based on these considerations, it is recommended to maintain permanently the available primary reserve on the existing diesel and hydro units as well as the BESS. This reserve (amounting to 20 to 50 MW depending on the availability of the units) is not sufficient to guarantee the stability of the isolated Malawian system in case of the sudden disconnection from the regional system and the loss of the 120 MW import. The potential solutions are simulated hereafter: additional BESS dedicated to the frequency regulation or SPS (Special Protection Scheme) aiming at disconnecting rapidly a properly sized amount of load as soon as the opening of the lines is decided by the protections.

Figure illustrates the frequency collapse in Malawi after the loss of the complete link with Mozambique if only the primary reserve required in Malawi as part of the interconnected regional system is available. Based on the electrical weight of Malawi compared to the regional grid, the national participation to the total required primary reserve was estimated at 6 MW in the generation development plan study.

As shown in Figure, the local reserve is not able to compensate for the loss of the 120 MW import and the separation from the regional system. The frequency drops rapidly and cannot be brought back to 50 Hz. In reality, UFLS (underfrequency load shedding) will be triggered and part of the demand will be disconnected to rapidly recover the generation/demand balance and stabilize the frequency to avoid the complete black-out of the national system. A dedicated study should be carried out to validate and possibly adapt the settings of the automatic UFLS system to follow the system dynamics and minimize the impact on the consumers.

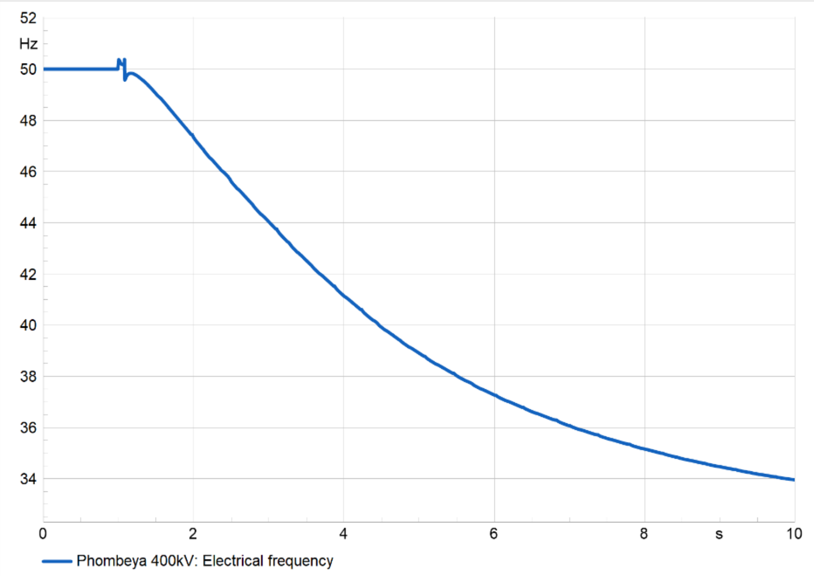


Figure 4.6.14: Electrical frequency at Phombeya after losing the interconnectors with Mozambique – Off-peak 2027.

As discussed in the generation development plan report, dedicated measures should be adopted during the period of time Malawi is connected to the SAPP with only one line or to be able to cope with the loss of both circuits of the interconnection if a double-circuit line is implemented. The objective of these measures is to guarantee the frequency stability of the national system in case of disconnection from the regional system and to avoid an impact on the consumers.

Within this framework, a primary reserve of at least 120 MW should be maintained in order to rapidly compensate for the loss of the import. The solution recommended in the generation development plan report combines the available thermal generation and a 100MW BESS dedicated to frequency management.

The behavior of the system after the loss of the interconnection is illustrated in Figure. This event is simulated under the worst situation for frequency stability, i.e., low load situation with the least amount of conventional units (hydro and thermal) connected to the system. The curves show the evolution of the frequency after the incident, with a 100 MW BESS (blue curve) and with a 100 MW BESS and the diesel units in standby (red curve), that complement the rest of the reserve provided by the hydro units in service. It can be noticed that the proper sizing of the reserve allows to stop the frequency drop and bring the system to an acceptable frequency level. In a second phase, the secondary reserve would be deployed and bring the frequency back to 50 Hz (not depicted).

Additional connected diesel units provide a rapid reserve and more inertia to the system, which allows the frequency nadir to be limited. Further tuning of the response of the BESS or adding a rapid command of the battery injection as soon as the line trips to quicken the response would allow to maintain the frequency above the first threshold of the UFLS and avoid any load shedding.

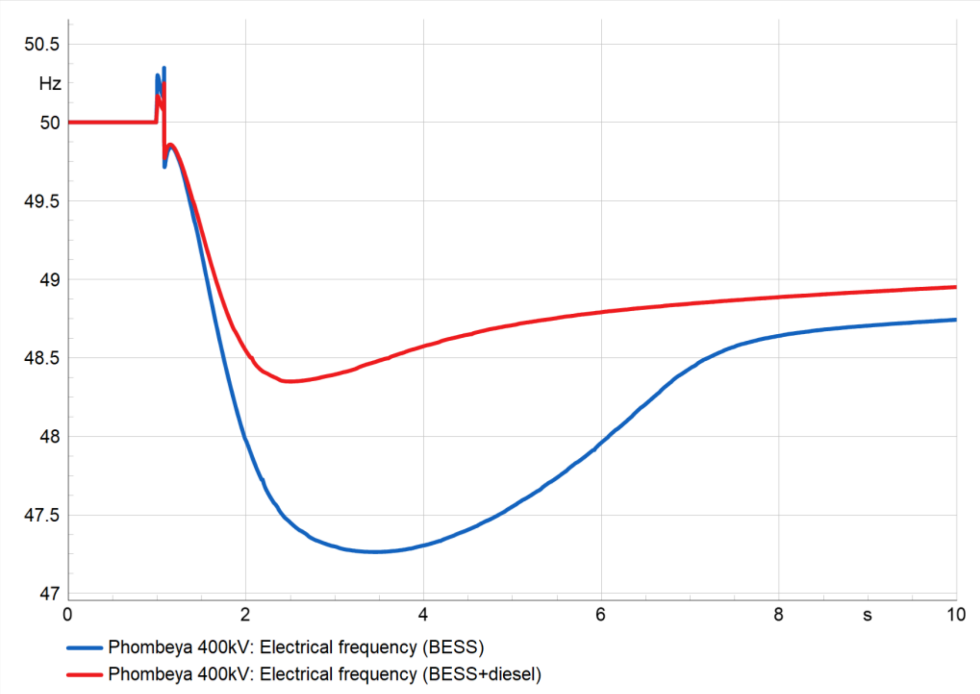


Figure 4.6.15: Electrical frequency at Phombeya after losing the interconnectors with Mozambique, with 100MW BESS (blue) and with 100MW BESS and diesel units in standby (red) – Off-peak 2027.

The responses of the BESS (two batteries of 50 MW each) are depicted in Figure for both simulated cases. One can see the rapid increase of the injected active power up to the maximum capacity until it is partially replaced by the other units providing primary reserve.

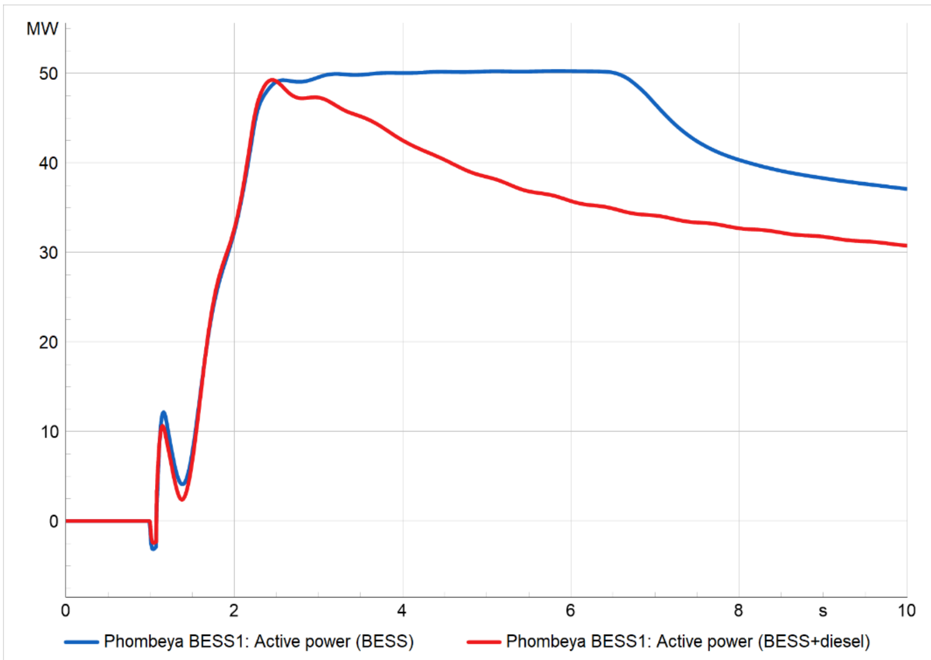


Figure 4.6.16: Active power from BESS 1 (50 MW) after losing the interconnectors with Mozambique, with 100 MW BESS (blue) and with 100 MW BESS and diesel units in standby (red) – Off-peak 2027.

Alternatively to the BESS solution, a SPS (Special Protection Scheme) associated with the tie-line could be implemented: in case of a double-circuit line tripping, an automatic protection will rapidly trigger the shedding of an amount of load corresponding to the import through the double-circuit line minus the available reserve. The next figure shows the evolution of the frequency following the loss of the link with Mozambique and the SPS rapidly triggering the shedding of 100 MW of demand in Malawi. The impact on the consumer will be important, but a complete black-out is at least avoided and the demand can gradually be resupplied with the start of the secondary reserve.

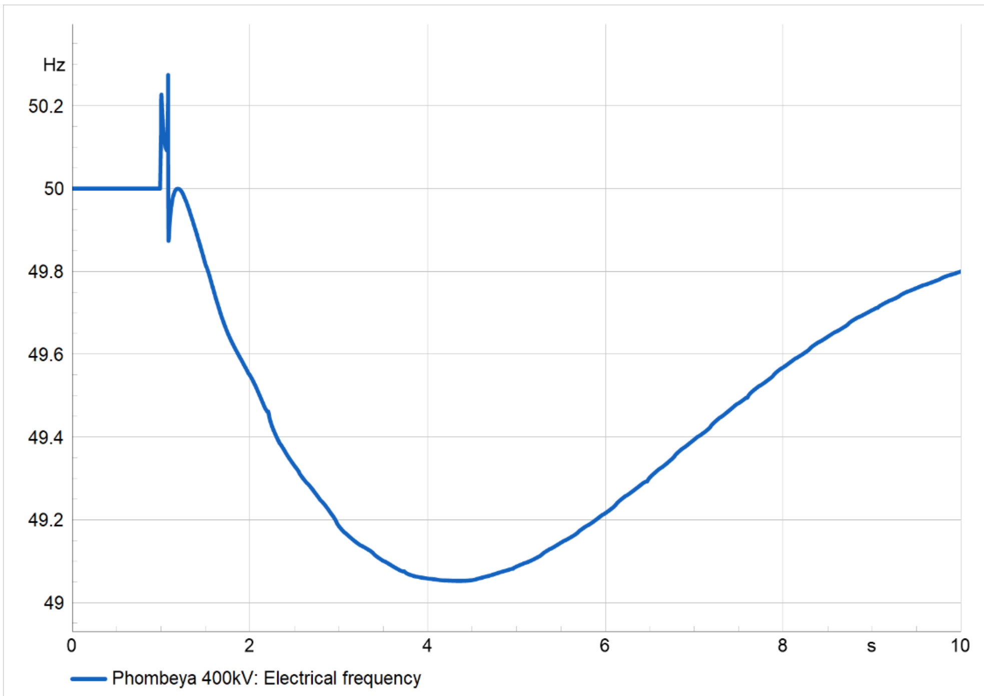


Figure 4.6.17: Electrical frequency at Phombeya after losing the interconnectors with Mozambique, with 100MW load shedding and diesel units in standby – Off-peak 2027.

6.2 Year 2032

6.2.1 List of reinforcements

This section details the minimum list of reinforcements and upgrade to the transmission grid needed to accommodate the future generation and demand expected in 2032 while respecting the planning and operational constraints.

By the year 2032, the remaining decided/proposed transmission projects in Malawi are expected to be operational:

Table 4.6.10: List of decided/proposed transmission projects in Malawi ready by 2032.

Name	Voltage (kV)	Circuits (-)	In service by (year)
Zambia – Malawi 400kV interconnector	400/330	1	2032
Tanzania – Malawi 400kV interconnector	400	1	2032
Western Backbone project	400	1	2032
Phalombe – Zomba 132kV line	132	1	2032
Changalume – Zomba – Liwonde 132kV line	132	1	2032
Phombeya – Liwonde – Mangochi 132kV line	132	1	2032
Kanyika – Chatoloma 132kV line	132	1	2032
Mzimba – Dwangwa 132kV line	132	1	2032

The system upgrades to the 132 kV level was initiated in the previous studied horizon and will continue in this next horizon. Between 2027 and 2032, the following zones will require an upgrade in order to respect the operational criteria:

- Upgrade from 66 kV to 132 kV completed in the Southern Region up to Chingeni.
- Upgrade from 66 kV to 132 kV in the Central Region from Chingeni up to Tsabango. Reinforcement of the existing 132kV line between Nkhoma and Tsabango by adding another one in parallel. The new line between Kangoma and Tsabango is operated in 66 kV until the substation in Kangoma has been upgraded to 132 kV.
- No additional reinforcement in the Northern Region between 2027 and 2032.

The detailed list of reinforcements corresponding to these development zones is provided in Table.

Table 4.6.11: List of line reinforcements in the existing transmission system by 2032.

Voltage (kV)	Circuits (-)	Substation		Length (km)	In service by (year)
		From	To		
132	1	Blantyre West	Chichiri	7	2027
132	1	Blantyre West	Chigumula	7	2027
132	1	Chichiri	Mapanga	10.81	2027
132	1	Chigumula	Mapanga	17.19	2027
132	1	Mapanga	Changalume	38.21	2027
132	2	Mapanga	Fundis Cross	44.01	2027
132	1	Mapanga	Nkula B	41.81	2027
132	1	Nkula B	Mapanga	42.34	2027
132	1	Tedzani	Nkula B	8	2027
132	1	Tedzani	Chichiri	59	2027
132	2	Nkula A	Nkula B	0.40	2032
132	1	Nkula A	Tedzani	8	2032
132	1	Tedzani	Tedzani IV	1	2032
132	1	Nkula A	Chingeni	70	2032
132	1	Chingeni	Liwonde	27	2032
132	1	Chingeni	Ntcheu	30	2032
132	1	Ntcheu	Mlangeni	18	2032
132	1	Mlangeni	Dedza	49.81	2032
132	1	Dedza	Tsabango	77.75	2032
132	1	Kangoma	Tsabango	8	2032 (66 kV)
132	2	Nkhoma	Tsabango	30.06	2032
132	1	Chintheche	Telegraph Hill	59.46	2027
132	1	Telegraph Hill	Luwinga	15.40	2027

The study on the evolution of the geographical distribution of the demand has determined the need for new HV substations by 2032 at Chileka and Mponela. The new lines to connect these new substations to the national transmission system are listed in Table. Although the Chirimba HV substation is only required by 2042, it will already be operational with the installation of these new lines. Meanwhile, the recommended HV substations in Mangochi and Zomba are already included in the list of decided/proposed transmission projects.

Table 4.6.12: List of new lines to supply the new HV substations by 2032.

Voltage (kV)	Circuits (-)	Substation		Length (km)	In service by (year)
		From	To		
132	1	Chichiri	Chirimba	6.5	2032
	1	Chirimba	Chileka	10	2032
	1	Chileka	Nkula A	30	2032
132	1	Kanengo	Mponela	36	2032

The same temporary 3-winding transformer as in 2027 is kept at New Bwengu. Like in 2027, this reinforcement will make the system N compliant, but not always N-1 compliant after the loss of a transformer.

In addition, new 3-winding transformers must be installed between the 400kV and 132kV voltage levels in Phombeya and in Nkhoma by 2032 to remain compliant after a N-1 contingency.

Table4.6.13: List of temporary 3-winding transformers in the existing transmission system by 2032.

Voltage HV (kV)	Voltage MV (kV)	Voltage LV (kV)	Circuits (-)	Substation	In service by (year)
132	66	11	2	New Bwengu	2027
400	132	33	2	Phombeya	2032
400	132	33	2	Nkhoma	2032

The previous temporary 3-winding transformers in Tedzani and in Chintheche are not needed anymore as both substations will be fully upgraded to 132 kV.

6.2.2 Load flow analyses

The results presented below summarize the outcomes of 8760 load flow calculations performed by running an AC QDS over the entire year of 2032. All line loadings and voltage magnitudes have been collected and compiled in the form of boxplots. These representations provide a concise way to understand the expected performances of the Malawian power system in 2032 with the recommended reinforcements listed in the previous section.

Line loadings

Figure displays the boxplots of line loadings over the entire year of 2032. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the loading values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in Table.

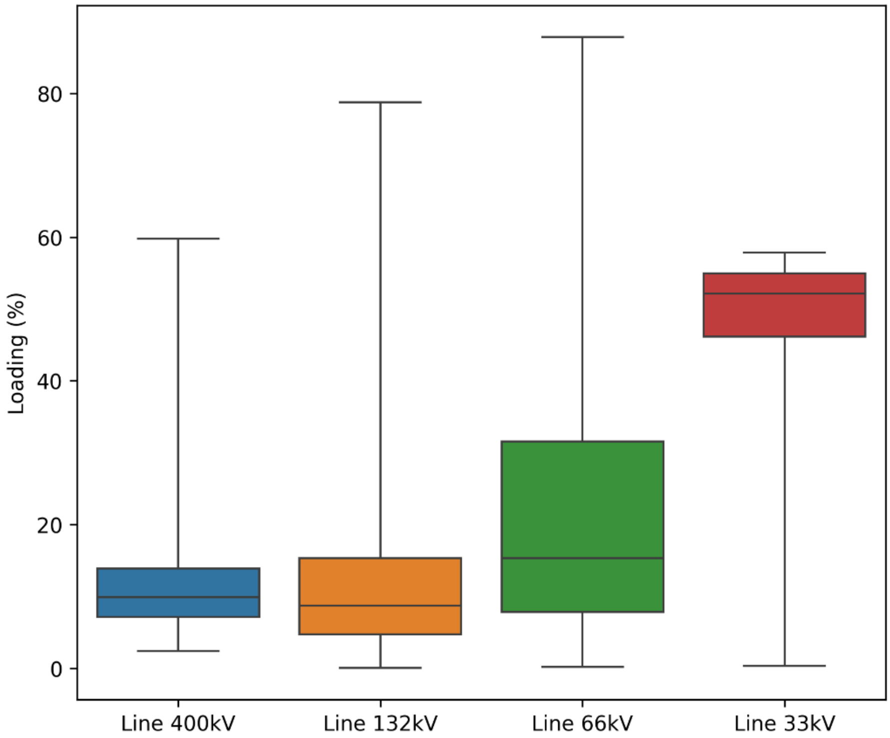


Figure 4.6.18: Boxplots of line loadings over the entire year of 2032.

Table 4.6.14: Five-number summary of line loadings over the entire year of 2032.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Line 400kV	2.44	7.14	9.91	13.93	59.79
Line 132kV	0.08	4.73	8.77	15.33	78.73
Line 66kV	0.24	7.85	15.33	31.58	87.84
Line 33kV	0.39	46.14	52.12	54.94	57.83

The third quartile Q3 is the value below which 75% of the loading values falls. Hence, the loading stays 75% of the time below 14% for the 400kV lines, 15% for the 132kV lines, 32% for the 66kV lines, and 55% for the 33kV lines. The sizes and the positions of the boxes show that the loading remains on average low for the 400kV and 132kV lines and higher for the 66kV and 33kV lines and the transformers.

For a few hours of the year, the maximum loading Q4 can reach up to 78% for the 132kV lines and 88% for the 66kV lines. High loadings remain nevertheless a rare occurrence.

Keeping the loading of the assets below 50-60% is usually necessary to ensure that the remaining assets do not become overloaded after a N-1 contingency. This is especially valid for the assets with a high rating, such as the 400kV and 132kV lines, whose loss could represent a huge burden on the transmission system in case they were initially highly loaded.

Voltage magnitudes

Figure displays the boxplots of voltage magnitudes over the entire year of 2032. Each box is drawn from the first quartile Q1 to the third quartile Q3, where the inner horizontal line represents the median Q2 of the voltage values. The whiskers of the boxplots correspond to the minimum (Q0) and maximum (Q4) values of the dataset. The values Q0 to Q4 can also be found in

Table .

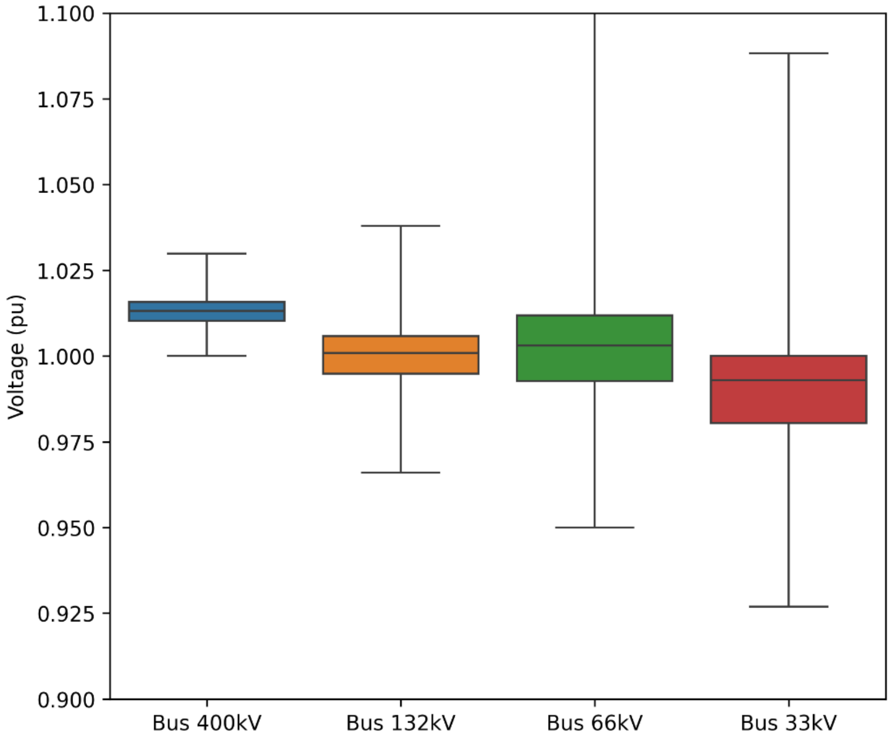


Figure 4.6.19: Boxplots of voltage magnitudes over the entire year of 2032.

Table 4.6.15: Five-number summary of voltage magnitudes over the entire year of 2032.

Type	Minimum Q0	First quartile Q1	Median Q2	Third quartile Q3	Maximum Q4
Bus 400kV	1.000	1.010	1.013	1.016	1.030
Bus 132kV	0.966	0.995	1.001	1.006	1.038
Bus 66kV	0.950	0.993	1.003	1.012	1.106
Bus 33kV	0.927	0.980	0.993	1.000	1.088

For all voltage levels, the first quartile Q1 lies between 0.980 and 1.010 pu and the third quartile Q3 lies between 1.000 and 1.016 pu. In other words, the voltage magnitudes in the Malawian system remain 50% of the time within a small range that spans between 0.980 and 1.016 pu.

While the voltage magnitudes of the 400kV and 132 kV buses always remain within the acceptable range set between 0.95 and 1.05 pu in normal operating conditions, the same cannot be said for the other voltage levels. For a few hours of the year, the voltage magnitudes can drop down to values under 0.95 pu or rise up to values above 1.05 pu. Such an issue could easily be solved by either keeping a generating unit in standby, adjusting the voltage setpoints of the other generating units, or changing the tap positions of the transformers and the shunt reactors/capacitors. Slightly too low or too high voltages remain nevertheless a rare occurrence.

Network losses

Figure compares the percentage of losses in the transmission system versus the electrical loads over the entire year of 2032.

The losses account for 222 GWh in 2032, which represents about 3.93 % of the total generated energy.

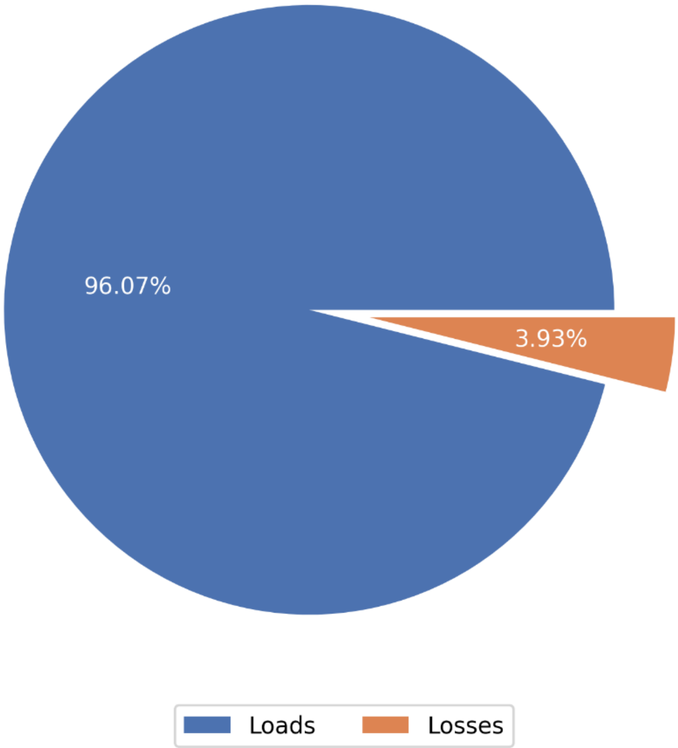


Figure 4.6.20: Pie chart comparing percentage of losses versus loads over the entire year of 2032.

6.2.3 Short-circuit analyses

Short-circuit analyses are conducted in accordance with the IEC 60909 standard, which is applicable to the calculation of short-circuit currents in low-voltage three-phase AC systems and in high-voltage three-phase AC systems, operating at a nominal frequency of 50 Hz or 60 Hz.

The analyses are conducted with a view to verify that the increase in short-circuit contribution from the generation expansion plan is compatible with the withstand capacity of the high-voltage substations. For most of the existing substations, the ratings of the circuit breakers have been shared in tabular format [9]. Different types of breakers are seen to coexist within the same substation, which leads to the definition of breaker ranges defined by a minimum and a maximum value. For the remaining substations, it will be assumed that the breaker rating is 61.2 kA at 400kV level, 40 kA at 132kV level, and 25 kA at 66kV level. These values are in line with the ratings of the existing circuit breakers in Malawi.

The maximum short-circuit currents are calculated for the hour of the year corresponding to the maximum loading in Malawi. The studied situation corresponds to October 5, 2032 at 6 pm, when the demand amounts to 900 MW. The dispatch of the generation units at this time is detailed in Table.

Table 4.6.16: Generation/import/DSM dispatch under peak load 2032.

Name	Type	Power (MW)	Name	Type	Power (MW)
DSM	DSM	129	Nkula B	Hydro	99.7
Wind	Wind	38.36	Tedzani I & II	Hydro	39.8
Kapichira I	Hydro	47.91	Tedzani III	Hydro	60.5
Kapichira II	Hydro	63.8	Tedzani IV	Hydro	19.1
Mpatamanga	Hydro	360.5	Wovwe	Hydro	3.41
Nkula A	Hydro	34.71	Wovwe 2	Hydro	3.21

The minimum short-circuit currents are calculated for the hour of the year corresponding to the minimum loading in Malawi. The studied situation corresponds to February 25, 2032 at 11 pm, when the demand amounts to 311 MW. The dispatch of the generation units at this time is detailed in Table.

Table 4.6.17: Generation/import/DSM dispatch under off-peak load 2032.

Name	Type	Power (MW)	Name	Type	Power (MW)
Wind	Wind	27.19	Muloza	Hydro	3
Kapichira I	Hydro	64.6	Nkula A	Hydro	34.71
Kapichira II	Hydro	63.8	Tedzani IV	Hydro	19.1
Mpatamanga	Hydro	81.8	Wovwe	Hydro	4.29
Mulanje	Hydro	8.01	Wovwe 2	Hydro	4.5

Table presents the minimum and maximum 3-phase short-circuit currents at each substation and voltage level of the Malawian transmission system. At 66 kV level, the maximum short-circuit current reaches 8 kA in Kanengo. At 132 kV, a maximum value of 18 kA is reached in Phombeya. At 400 kV, the maximum value reaches 9 kA in Phombeya. The calculated short-circuit currents are always lower than the associated minimum breaker rating.

Color legend for the table

Table 4.6.18: Maximum and minimum short-circuit current values in 2032.

	Breaker rating of existing substations
(grey)	Breaker rating assumed for remaining substations

Substation	Base kV	Min breaker rating (kA)	Max breaker rating (kA)	3-phase SC max (kA)	3-phase SC min (kA)
Blantyre West	132	31.5	40	9.82	7.63
Chichiri	132	40	40	9.90	7.58
Chigumula	132	40	40	8.38	6.62
Mapanga	132	25	25	9.84	7.55
Changalume	132	40	40	5.10	4.22
Zomba	132	40	40	5.08	4.22

Substation	Base kV	Min breaker rating (kA)	Max breaker rating (kA)	3-phase SC max (kA)	3-phase SC min (kA)
Fundis Cross	132	40	40	4.55	3.92
Nkula A	132	40	40	16.25	10.57
Nkula B	132	31.5	31.5	16.41	10.64
Tedzani	132	31.5	31.5	14.88	9.67
Chileka	132	40	40	7.60	5.93
Chirimba	132	40	40	8.41	6.54
Kapichira	132	40	40	9.02	7.41
Mpatamanga	400	61.2	61.2	6.33	5.61
Mpatamanga	132	40	40	14.57	13.49
Regulating Dam	132	40	40	8.14	6.55
Mlambe	132	31.5	31.5	2.84	2.40
New Blantyre	132	40	40	6.60	5.23
Phalombe	132	40	40	3.11	2.64
Chingeni	132	40	40	5.52	4.59
Liwonde	132	40	40	6.83	5.64
Ntcheu	132	40	40	3.64	3.12
Mlangeni	132	40	40	3.22	2.77
Dedza	132	40	40	2.99	2.59
Tsabango	132	40	40	6.68	5.78
Tsabango	66	25	25	4.98	4.33
Kangoma	66	25	25	5.00	4.36
Lilongwe OT	66	25	40	3.15	2.77
Kanengo	132	31.5	40	6.23	5.41
Kanengo	66	25	25	8.15	7.15
Mponela	132	40	40	2.91	2.55
Area 48	66	25	31.5	5.26	4.62
Kauma	66	25	25	6.06	5.31
Barracks	66	25	40	5.51	4.83
Nkhoma	400	40	61.2	5.63	4.89
Nkhoma	132	40	40	11.27	9.66
Malingunde	132	40	40	3.46	3.02
Kasiya	132	40	40	3.17	2.77
KIA	132	40	40	5.21	4.53
Mchinji	400	61.2	61.2	4.31	3.80
Nanjoka	132	29	40	6.87	5.94
Golomoti	132	31.5	40	8.20	6.95
Monkey Bay	132	40	40	4.50	3.85
Mangochi	132	40	40	3.32	2.86
Makanjira	132	40	40	1.19	1.04
Phombeya	400	61.2	61.2	9.25	7.90
Phombeya	132	40	40	17.62	13.53
Nkhotakota	132	25	40	4.42	3.86
Dwangwa	132	40	40	4.01	3.50
Chintheche	132	31.5	40	3.17	2.76
Serengeti	132	40	40	3.93	3.43
Chinyama	132	40	40	2.94	2.56
Kanyika	132	40	40	3.63	3.15
Chatoloma	400	61.2	61.2	3.47	3.05
Chatoloma	132	40	40	4.96	4.25
Mzimba	400	61.2	61.2	3.14	2.76
Mzimba	132	40	40	5.17	4.52
Luwinga	132	40	40	3.46	3.01
Telegraph Hill	132	40	40	3.01	2.62
New Bwengu	400	61.2	61.2	3.10	2.72
New Bwengu	132	40	40	6.66	5.78
New Bwengu	66	25	25	3.67	3.18
Bwengu	66	25	25	3.50	3.03
Livingstonia	66	25	25	1.25	1.07
Uliwa	66	25	25	1.06	0.91
Wovwe	66	25	25	1.03	0.89
Karonga	66	25	25	0.54	0.47
Songwe	400	61.2	61.2	3.47	3.09

6.2.4 Dynamic analyses

The objective of the dynamic analyses is to verify whether the Malawi grid is able to withstand the consequence of a severe disturbance, such a fault or an outage event, by returning to a stable steady state while satisfying a set of acceptance criteria. The same methodology as the one described in Section 6.1.4 is applied for the horizon of 2032.

5.1.1.1. Three-phase faults

For several transmission lines, a three-phase short-circuit fault followed by a line tripping is simulated to check the voltage and transient stability of the system.

For the peak load situation, the loss of the 12 following lines are studied.

- Mozambique – Malawi 400kV line = 7.8% loading
- Zambia – Malawi 330kV line = 2.5% loading
- Tanzania – Malawi 400kV line = 9.6% loading
- Phombeya – Mpatamanga 400kV line = 59.8% loading
- Phombeya – Nhkoma 400kV line = 51.3% loading
- Nkhoma – Chatoloma 400kV line = 23.1% loading
- Chatoloma – Mzimba 400kV line = 15.6% loading
- New Bwengu – Songwe 400kV line = 15.3% loading
- Mzimba – New Bwengu 400kV line = 11.3% loading
- Mchinji – Nkhoma 400kV line = 5.5% loading
- Kapichira – BT West 132kV line = 49% loading
- Kapichira – Mlambe 132kV line = 47% loading

None of the results of the performed simulations shows any sign of voltage stability issue. As an illustration, Figure shows the voltage profiles of some major substations after a short-circuit fault on the Phombeya-Nkhoma 400kV line. One can see that all voltages quickly return to an acceptable level after the clearing of the fault.

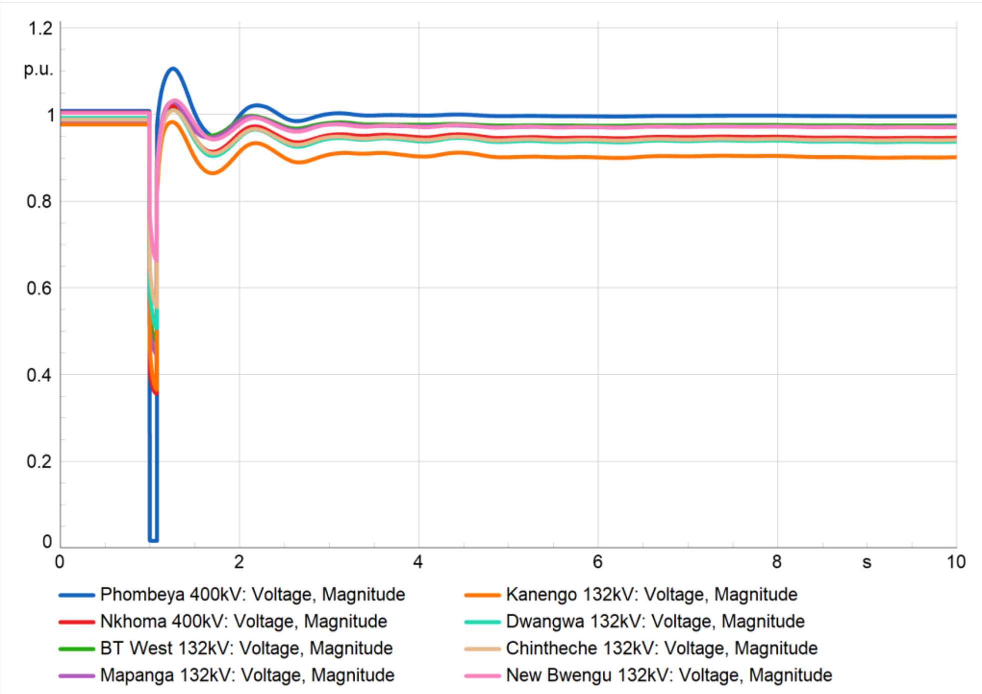


Figure 4.6.21: Voltage magnitudes in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Peak 2032.

None of the performed simulations is showing any sign of transient stability issue. As an illustration, Figure shows the evolution of the rotor angles of the main generators after a short-circuit on the Phombeya-Nkhoma 400kV line. One can see that the impact on the generators is limited and that the oscillations are well damped. This conclusion was made possible thanks to the installation of PSS (power system stabilizers) at the new Mpatamanga power plant.

In Figure , the same short-circuit is performed on the Phombeya-Nkhoma 400kV line without the PSS at Mpatamanga. While the situation remains acceptable, it can observed that the oscillations are overall less damped, especially in Mpatamanga. This example shows that installing and setting some PSS in the control loop of some well-chosen large generating units in Malawi and in the neighboring countries help to dampen the oscillations observed in the power system.

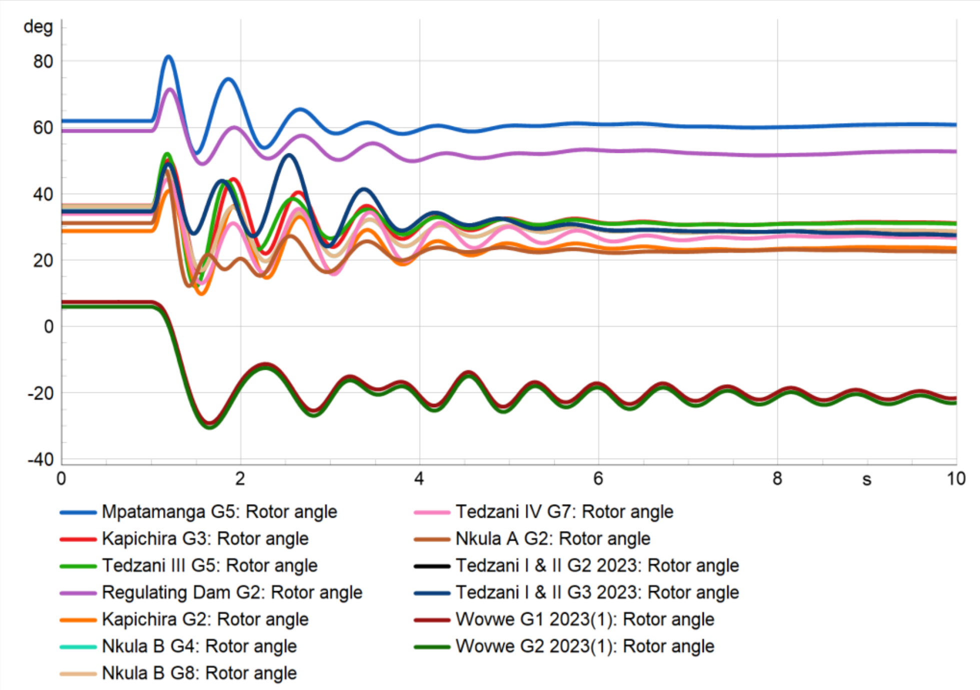


Figure 4.6.22: Rotor angles in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Peak 2032.

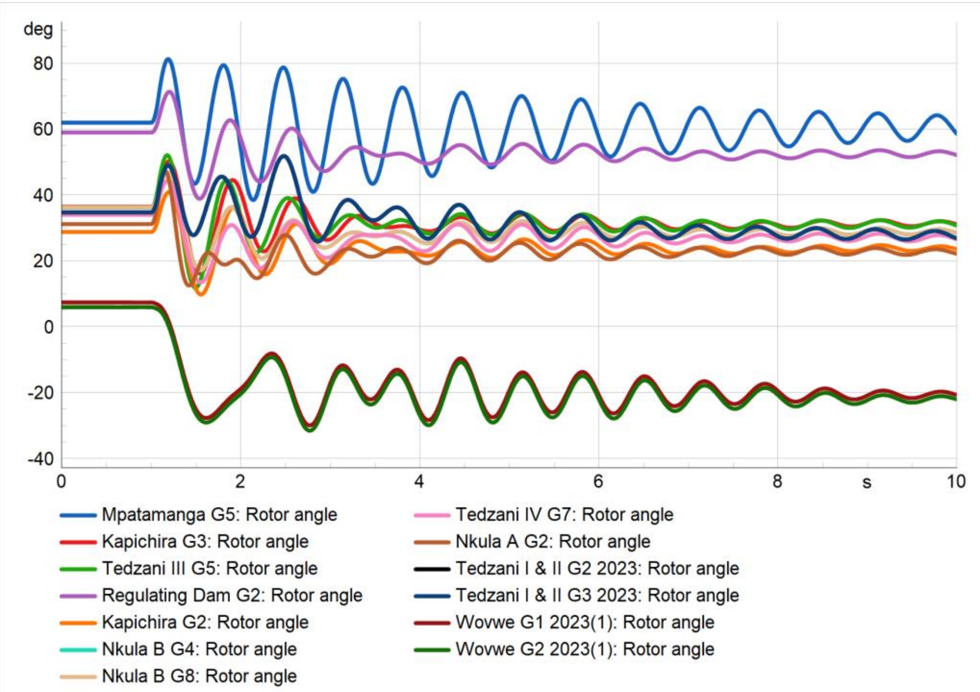


Figure 4.6.23: Rotor angles in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line (no PSS) – Peak 2032.

On a side note, tripping the Phombeya-Mpatamanga 400kV line naturally leads to the loss of the Mpatamanga power station since the power station would become isolated.

For the off-peak load situation, the loss of the 11 following lines are studied.

- Mozambique – Malawi 400kV line = 10.2% loading
- Zambia – Malawi 330kV line = 5.1% loading
- Tanzania – Malawi 400kV line = 11.2% loading
- Phombeya – Nhkoma 400kV line = 21.3% loading
- Nkhoma – Chatoloma 400kV line = 12.2% loading
- New Bwengu – Songwe 400kV line = 11.7% loading
- Chatoloma – Mzimba 400kV line = 8.4% loading
- Phombeya – Mpatamanga 400kV line = 8.2% loading
- Mzimba – New Bwengu 400kV line = 6.7% loading
- Mchinji – Nkhoma 400kV line = 4.6% loading
- Kapichira – BT West 132kV line = 52.3% loading

As for the peak demand situation studied above, none of the performed simulations is showing any sign of voltage stability issue nor transient stability issue. Figure shows the voltage profiles of some major substations after a short-circuit fault on the Phombeya-Nkhoma 400kV line.

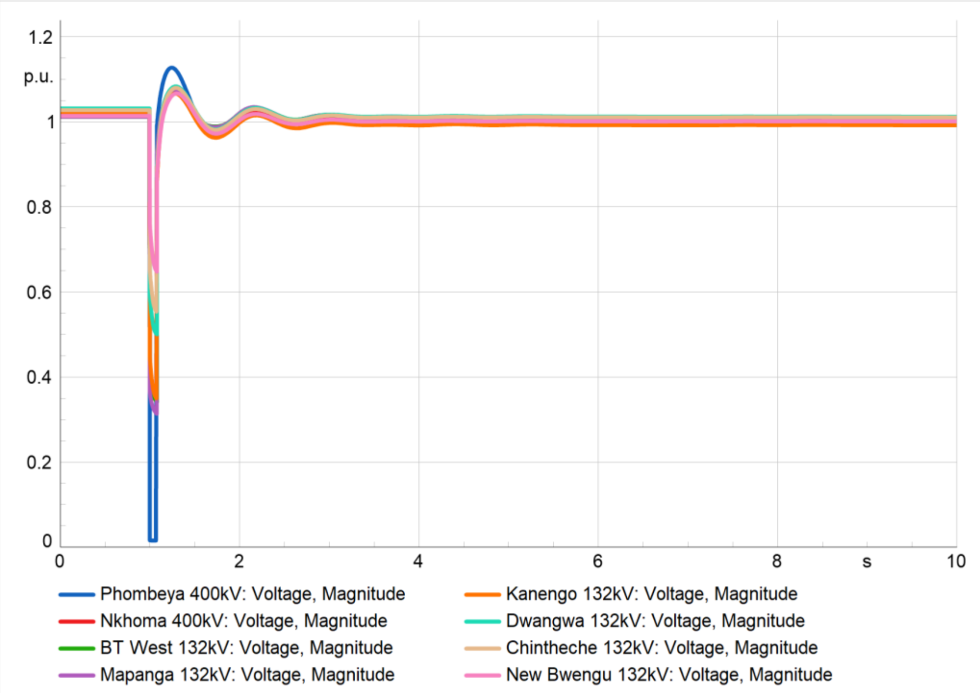


Figure 4.6.24: Voltage magnitudes in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Off-peak 2032.

Figure shows the rotor angles of some generating units after a short-circuit fault on the Phombeya-Nkhoma 400kV line.

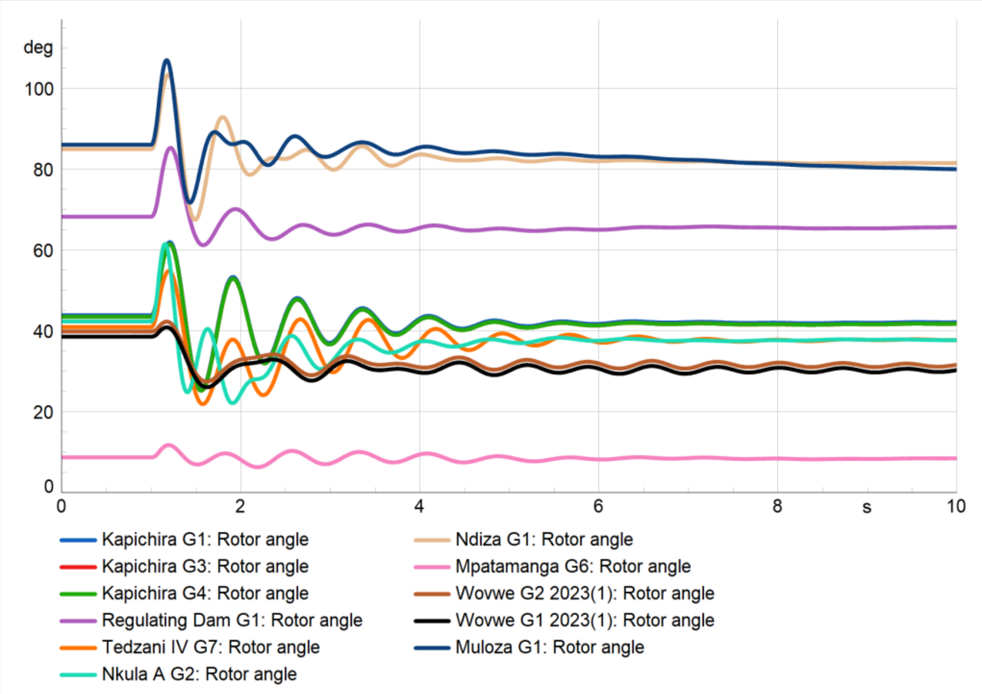


Figure 4.6.25: Rotor angles in Malawi after a 3-phase fault at 1% location of Phombeya-Nkhoma line – Off-peak 2032.

For both aspects, a stable situation respecting the operational criteria is rapidly reached after clearing the fault.

6.2.4.1 Loss of generation

For several power plants, the disconnection of a generating unit is simulated to check the frequency stability of the system.

For the peak load situation, the loss of five generating units is studied.

- Mpatamanga G1 = 51.4 MW
- Kapichira G3 = 31.9 MW
- Rumphi WTG1 = 7.9 MW
- Dedza WTG1 = 7.9 MW
- Mzimba WTG1 = 6.6 MW

As the power system of Malawi is interconnected with the SAPP regional system, the impact on the frequency of the loss of a generator is Malawi is very limited as illustrated in Figure for the loss of Mpatamanga G1 (51.4 MW). The frequency nadir remains higher than 49.93 Hz.

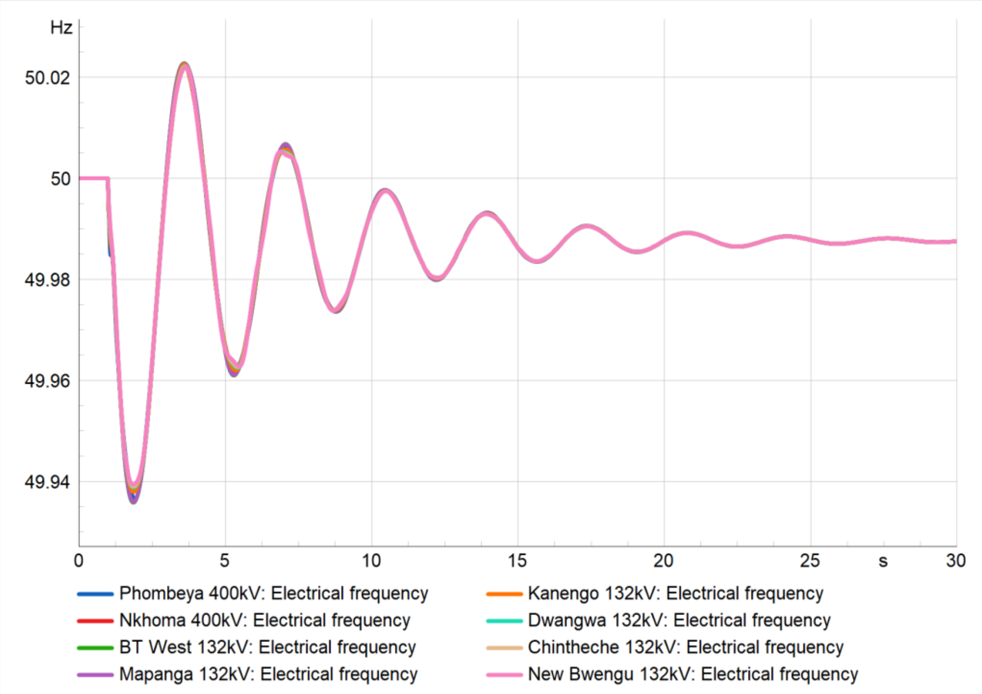


Figure 4.6.26: Electrical frequencies in Malawi after the loss of Mpatamanga G1 – Peak 2032.

The loss of 51.4 MW is mainly covered by an increase in the import from Mozambique, Zambia, and Tanzania as illustrated in the following figures.

Figure shows the evolution of the active power production by some generating units in Malawi. One can see that the impact on their production is limited.

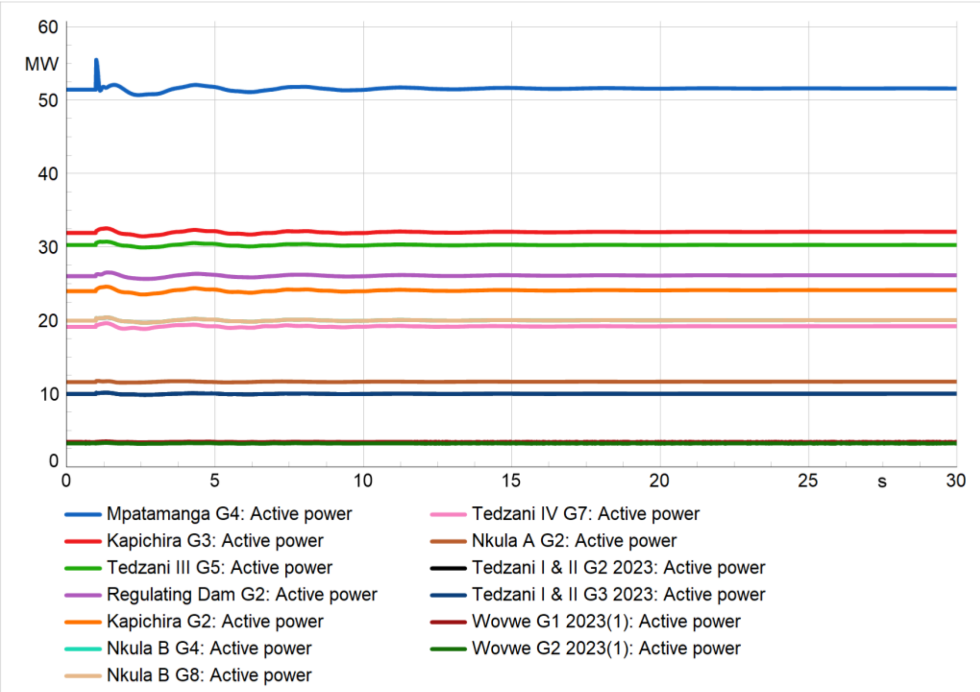


Figure 4.6.27: Active power from generating units in Malawi after the loss of Mpatamanga G1 – Peak 2032.

Figure shows the combined flow on the two Mozambique-Malawi interconnectors, the flow on the Zambia-Malawi interconnector, and the flow on the Tanzania-Malawi interconnector. The increase of import rapidly compensates for the loss of the unit in Malawi. The action of the secondary reserve in Malawi, which is not modeled, would bring back the import to its initial value in a second phase. Installing and setting some PSS in Malawi and in the neighboring countries would help to further dampen the oscillations.

Figure 4.6.28: Active power import from Mozambique, Zambia, and Tanzania after the loss of Mpatamanga G1 – Peak 2032.

For the off-peak situation, the loss of six generating units is simulated.

- Kapichira G1 = 32.3 MW
- Kapichira G3 = 31.9 MW
- Regulating Dam G1 = 26 MW
- Rumphi WTG1 = 5.6 MW
- Dedza WTG1 = 5.6 MW
- Mzimba WTG1 = 4.7 MW

The results are similar to the ones of the peak demand scenario as illustrated in Figure to Figure. These figures depict the evolution of the frequency, the production of the units, and the import from the neighboring countries. Thanks to the interconnectors that give access to an important inertia and reserve shared with the SAPP and EAPP systems, the impact of losing a generating unit is very limited.

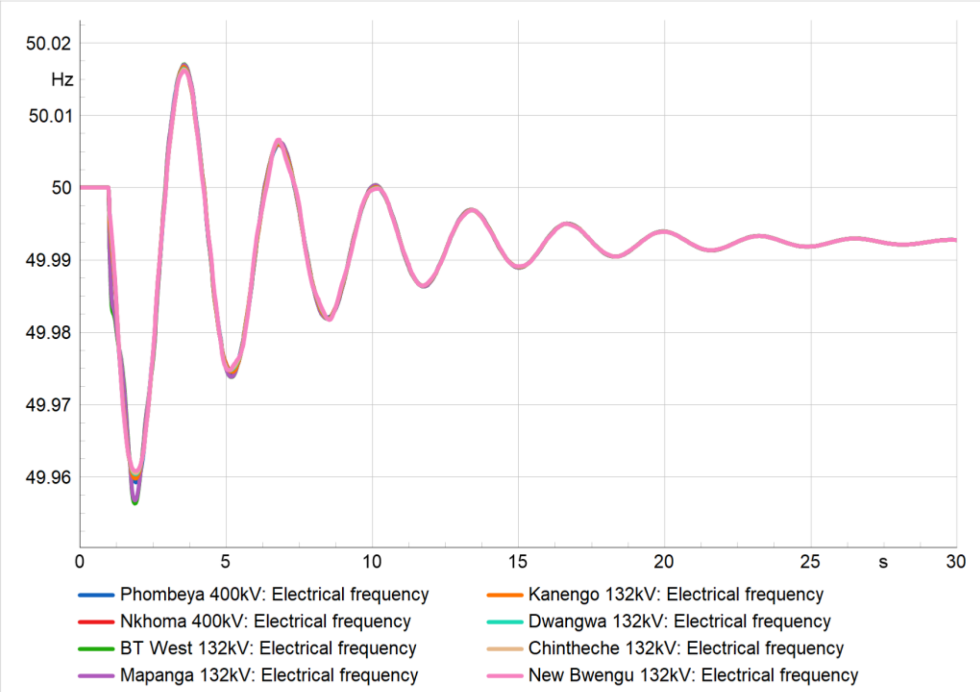


Figure 4.6.29: Electrical frequencies in Malawi after the loss of Kapichira G1 – Off-peak 2032.

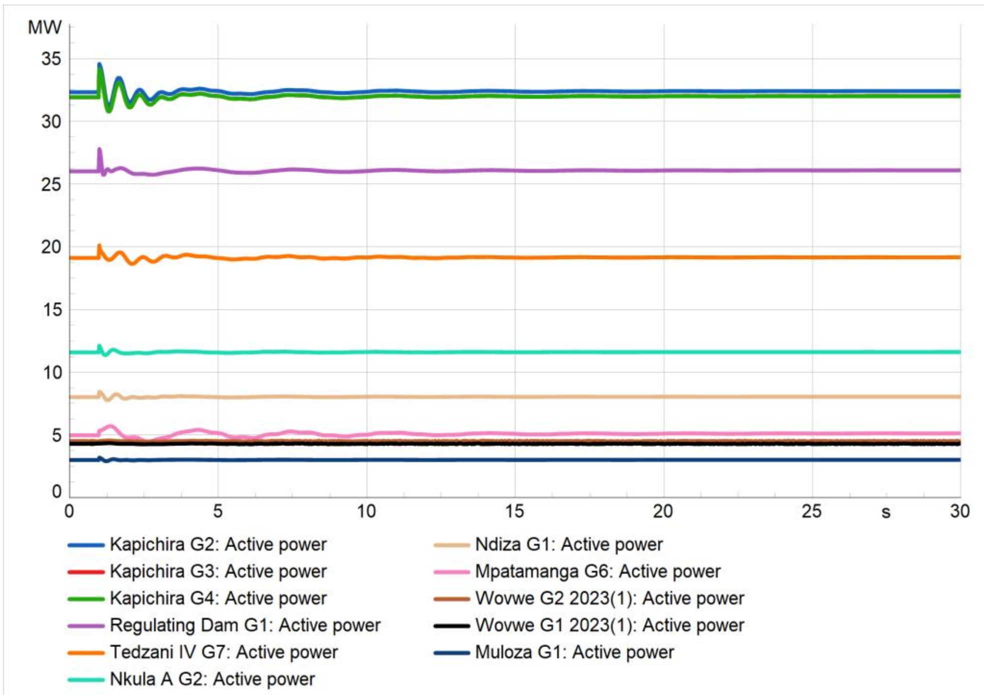


Figure 4.6.30: Active power from generating units in Malawi after the loss of Kapichira G1 – Off-peak 2032.

Figure shows that the loss of 32.3 MW is mainly covered by an increase in the import from Mozambique, Zambia, and Tanzania.

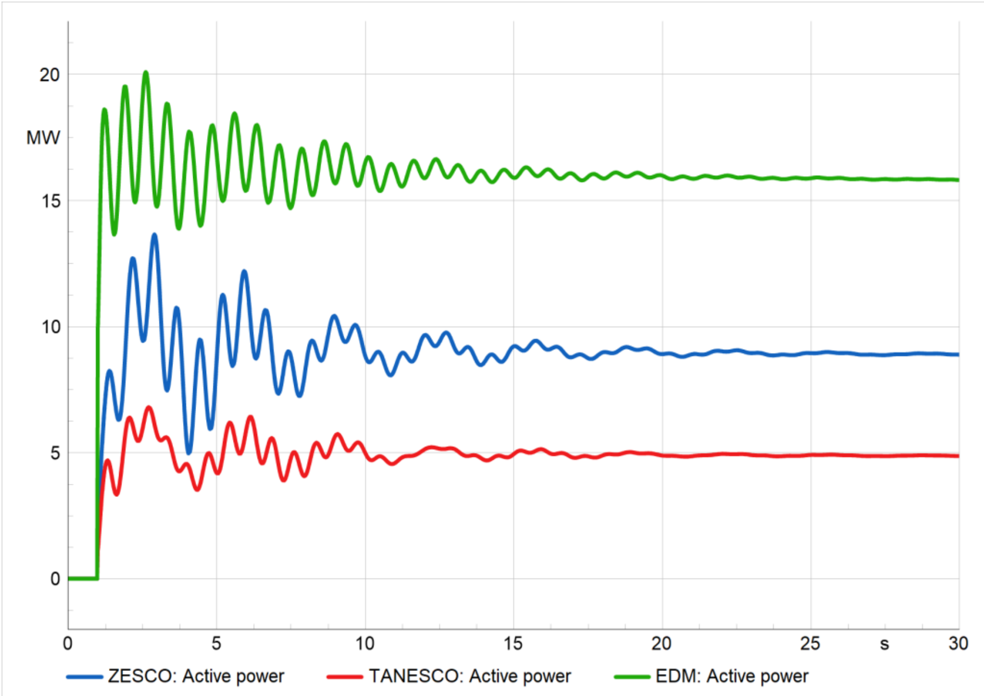


Figure 4.6.31: Active power import from Mozambique, Zambia, and Tanzania after the loss of Kapichira G1 – Off-peak 2032.

7 Legal and Regulatory Framework for Generation, Transmission, and Distribution Projects in Malawi

7.1 Introduction

This section provides an overview of the legal and regulatory framework governing generation, transmission, and distribution projects in Malawi, with a particular focus on the Environmental and Social Impact Assessment (ESIA) requirements.

7.2 Relevant Malawi Policies and Legislation.

7.2.1 Malawi Vision 2063

Malawi Vision 2063 is a comprehensive blueprint that envisions transforming Malawi into a wealthy, self-reliant, industrialized, and middle-income country by 2063. This vision is built on three key pillars: Agricultural Productivity and Commercialization, Industrialization, and Urbanization. Each pillar is supported by enablers that include Human Capital Development, Economic Infrastructure, and Environmental Sustainability. The vision emphasizes the need for sustainable and inclusive economic growth driven by innovation, technology, and a robust energy sector. Malawi Vision 2063 places significant emphasis on the development of the energy sector as a critical enabler for industrialization and urbanization. The vision outlines specific goals for energy generation, transmission, and distribution to support Malawi's economic transformation:

- Expansion of Energy Generation Capacity
  - 7.3 Increase the installed electricity generation capacity to meet the growing demand from industrial, commercial, and residential sectors.
  - 7.4 Promote the diversification of energy sources, including the development of renewable energy projects such as solar, wind, and hydropower.
  - 7.5 Encourage the adoption of clean and sustainable energy technologies to reduce the carbon footprint and mitigate the impacts of climate change.
- Enhancement of Transmission and Distribution Networks
  - 7.6 Upgrade and expand the transmission and distribution infrastructure to ensure reliable and efficient delivery of electricity across the country.
  - 7.7 Reduce transmission and distribution losses through the adoption of modern technologies and best practices.
  - 7.8 Strengthen the grid's resilience to withstand environmental challenges and improve energy security.
- Universal Access to Electricity
  - 7.9 Achieve universal access to electricity by 2063, with a focus on connecting rural and underserved areas.
  - 7.10 Implement the Malawi Rural Electrification Program (MAREP) to accelerate the electrification of remote communities.
  - 7.11 Foster public-private partnerships to mobilize resources and expertise for expanding access to electricity.

Implications for Generation, Transmission, and Distribution Projects

The goals outlined in Malawi Vision 2063 have profound implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Strategic Goals
  - 7.12 Projects must align with the strategic goals of increasing generation capacity, diversifying energy sources, and enhancing grid infrastructure.
  - 7.13 Long-term planning should incorporate the vision's targets, ensuring that projects contribute to the overarching objectives of industrialization and urbanization.
- Sustainability and Environmental Considerations
  - 7.14 Projects should prioritize sustainability by integrating renewable energy sources and adopting environmentally friendly technologies.
  - 7.15 Conduct comprehensive ESIAs to mitigate adverse impacts and ensure compliance with national and international environmental standards.
- Capacity Building and Technological Innovation
  - 7.16 Invest in capacity building and training for local stakeholders to ensure the successful implementation and maintenance of energy projects.
  - 7.17 Embrace technological innovations such as smart grids, energy storage solutions, and digital monitoring systems to improve efficiency and reliability.
- Public-Private Partnerships
  - 7.18 Leverage public-private partnerships to mobilize investment, technical expertise, and innovative solutions for energy projects.
  - 7.19 Create an enabling environment for private sector participation by ensuring transparent regulatory frameworks and attractive investment incentives.
- Focus on Rural Electrification
  - 7.20 Prioritize projects that support rural electrification to bridge the energy access gap and promote inclusive development.
  - 7.21 Implement off-grid and mini-grid solutions in remote areas to provide reliable and sustainable electricity to underserved communities.
- Monitoring and Evaluation
  - 7.22 Establish robust monitoring and evaluation mechanisms to track progress towards the vision's energy sector goals.
  - 7.23 Use data and analytics to inform decision-making, optimize project performance, and ensure accountability.

7.23.1 Environmental Policy (2004)

Environmental Policy (2004) is a critical framework that guides the integration of environmental considerations into the planning and implementation of development projects in Malawi. The policy aims to promote sustainable development by ensuring that environmental protection is a fundamental part of economic and social planning. It emphasizes the importance of preserving natural resources, reducing pollution, and fostering a healthy and productive environment for current and future generations. The Policy outlines several key elements that are essential for the sustainable development of Malawi:

- Sustainable Resource Management
  - 7.24 Promote the sustainable use and management of natural resources, including land, water, forests, and wildlife.
  - 7.25 Implement measures to prevent resource depletion and degradation, ensuring their availability for future generations.
- Pollution Control and Waste Management
  - 7.26 Establish and enforce standards for controlling pollution from industrial, agricultural, and domestic sources.
  - 7.27 Develop efficient waste management systems to minimize environmental pollution and health hazards.
- Environmental and Social Impact Assessment
  - 7.28 Mandate the conduct of ESIA for all major development projects to evaluate potential environmental impacts.
  - 7.29 Ensure that mitigation measures are implemented to address any adverse effects identified during the ESIA process.
- Conservation of Biodiversity
  - 7.30 Protect and conserve Malawi's biodiversity, including endangered species and critical habitats.
  - 7.31 Promote reforestation and afforestation programs to restore degraded ecosystems and enhance biodiversity.
- Public Awareness and Participation
  - 7.32 Enhance public awareness of environmental issues and promote community involvement in environmental conservation activities.
  - 7.33 Encourage stakeholder participation in the decision-making process for environmental management and development planning.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Policy (2004) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to Environmental Standards
  - 7.34 Projects must comply with the environmental standards and best practices outlined in the policy.
  - 7.35 Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.
- Integration of ESIA Process
  - 7.36 Conduct thorough ESIA for all projects to identify potential environmental impacts and develop mitigation strategies.
  - 7.37 Ensure that ESIA findings are incorporated into project design and implementation to minimize negative environmental effects.
- Sustainable Resource Utilization
  - 7.38 Utilize natural resources efficiently and sustainably to prevent depletion and environmental degradation.
  - 7.39 Adopt technologies and practices that enhance resource conservation, such as renewable energy sources and energy-efficient systems.

- Pollution Prevention and Waste Management
  7.40 Implement measures to control pollution from project activities, including emissions, effluents, and waste.
  7.41 Develop and maintain effective waste management systems to handle project-related waste in an environmentally responsible manner.
- Biodiversity Conservation
  7.42 Incorporate biodiversity conservation into project planning by protecting critical habitats and endangered species.
  7.43 Engage in reforestation and habitat restoration activities to offset any environmental disturbances caused by project activities.
- Stakeholder Engagement and Public Participation
  7.44 Engage local communities and stakeholders in the planning and implementation of projects to ensure their concerns and suggestions are addressed.
  7.45 Promote transparency and accountability by keeping stakeholders informed about project progress and environmental management efforts.
- Long-term Environmental Sustainability
  7.46 Focus on long-term environmental sustainability by adopting practices that reduce the ecological footprint of projects.
  7.47 Invest in technologies and processes that support environmental resilience and adaptation to climate change.

7.47.1 National Energy Policy (2018)

National Energy Policy (2018) is a strategic framework designed to enhance access to reliable, affordable, and sustainable energy services in Malawi. The policy underscores the importance of diversifying energy sources and promoting renewable energy to reduce reliance on biomass, which is a significant contributor to deforestation and environmental degradation. The policy aims to address the low electrification rate, mitigate climate change impacts, and support sustainable economic development.

Key Elements of the National Energy Policy (2018)

The National Energy Policy (2018) outlines several key elements that are crucial for the development of the energy sector in Malawi:

- Diversification of Energy Sources
  7.48 Promote the development and use of various energy sources, including hydropower, solar, wind, and biomass.
  7.49 Encourage investment in renewable energy projects to reduce dependence on traditional biomass and fossil fuels.
- Enhancement of Energy Access
  7.50 Increase the electrification rate, particularly in rural and underserved areas, to ensure equitable access to energy services.
  7.51 Implement the MAREP to extend the electricity grid and provide off-grid solutions where grid extension is not feasible.
- Energy Efficiency and Conservation

7.52 Promote energy efficiency measures and technologies to reduce energy consumption and improve the overall efficiency of the energy sector.

7.53 Encourage the use of energy-efficient appliances and industrial processes to lower energy demand and reduce environmental impacts.

- Climate Change Mitigation and Adaptation

7.54 Integrate climate change considerations into energy planning and project implementation.

7.55 Support the development of low-carbon technologies and practices to mitigate greenhouse gas emissions and enhance climate resilience.

Implications for Generation, Transmission, and Distribution Projects

The National Energy Policy (2018) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence with Policy Goals

7.56 Projects must align with the policy's goals of promoting renewable energy and ensuring energy sustainability.

7.57 Long-term planning should incorporate the policy's targets, ensuring that projects contribute to the overall objectives of increasing energy access and reducing reliance on biomass.

- Integration of Renewable Energy Sources

7.58 Developers should consider integrating renewable energy sources such as solar, wind, and hydropower into their projects.

7.59 The adoption of renewable energy technologies can help reduce greenhouse gas emissions and mitigate climate change impacts.

- Enhancement of Energy Access

7.60 Projects should focus on extending energy access to rural and underserved areas, in line with the goals of the MAREP.

7.61 Implementing off-grid and mini-grid solutions can provide reliable and sustainable electricity to remote communities.

- Energy Efficiency Measures

7.62 Incorporate energy efficiency measures into project design and implementation to reduce energy consumption and operational costs.

7.63 Promote the use of energy-efficient technologies and practices in both residential and industrial sectors.

- Climate Change Considerations

7.64 Integrate climate change mitigation and adaptation measures into project planning and execution.

7.65 Develop and implement low-carbon technologies and practices to enhance the sustainability and resilience of energy projects.

- Regulatory Compliance and Institutional Strengthening

7.66 Ensure compliance with the regulatory framework and engage with relevant institutions for project approvals and oversight.

7.67 Strengthen the capacity of local institutions to manage and regulate energy projects effectively.

The National Energy Policy (2018) provides a comprehensive framework for enhancing energy access, promoting renewable energy, and ensuring sustainable development in Malawi. Projects must align with the policy's goals and integrate renewable energy sources, energy efficiency measures, and climate change considerations into their planning and implementation.

7.67.1 Forest Policy (2016)

Forest Policy (2016) is a pivotal framework aimed at promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. The policy seeks to address the challenges of deforestation, forest degradation, and unsustainable use of forest resources, which are critical issues affecting the environment and livelihoods in the country. The Forest Policy underscores the importance of conserving forest ecosystems, enhancing carbon sequestration, and promoting the sustainable use of forest products.

The Forest Policy (2016) outlines several key elements essential for the sustainable management of forest resources in Malawi:

- Sustainable Forest Management
  - 7.68 Promote practices that ensure the sustainable management and utilization of forest resources.
  - 7.69 Implement forest management plans that balance environmental, economic, and social objectives.
- Reforestation and Afforestation
  - 7.70 Encourage reforestation and afforestation initiatives to restore degraded forest lands and increase forest cover.
  - 7.71 Support community-based reforestation projects and agroforestry practices that enhance livelihoods and biodiversity.
- Protection of Forest Resources
  - 7.72 Enforce regulations to protect forest resources from illegal activities such as logging, encroachment, and charcoal production.
  - 7.73 Establish protected areas and conservation zones to preserve critical habitats and biodiversity.
- Charcoal Production and Trade Regulation
  - 7.74 Regulate the production and trade of charcoal to reduce its impact on forest resources.
  - 7.75 Promote alternative energy sources to reduce dependency on charcoal and mitigate deforestation.
- Community Participation and Capacity Building
  - 7.76 Engage local communities in forest management and conservation efforts.
  - 7.77 Build the capacity of communities and stakeholders to effectively participate in sustainable forest management practices.

Implications for Generation, Transmission, and Distribution Projects

The Forest Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources

7.78 Projects involving land use changes must assess the impact on forest resources and implement measures to mitigate adverse effects.

7.79 Conduct ESIAs to evaluate the potential impacts on forests and develop appropriate mitigation strategies.

- Compliance with Reforestation and Sustainable Management Requirements

7.80 Projects must comply with reforestation and sustainable management requirements as outlined in the Forest Policy.

7.81 Implement reforestation initiatives to compensate for any forest loss due to project activities, ensuring no net loss of forest cover.

- Regulation of Charcoal Production and Forest Protection

7.82 Adhere to regulations regarding charcoal production and trade to avoid legal penalties and support forest conservation efforts.

7.83 Promote the use of alternative energy sources to reduce the reliance on charcoal and mitigate deforestation.

The Forest Policy (2016) provides a robust framework for promoting sustainable forest management, reforestation, and the protection of forest resources in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and sustainable management requirements, and adhere to regulations regarding charcoal production and forest protection.

7.83.1 National Climate Change Management Policy (2016)

National Climate Change Management Policy (2016) is a strategic framework designed to guide Malawi in addressing the impacts of climate change through effective adaptation and mitigation measures. The policy aims to enhance resilience to climate change, reduce greenhouse gas emissions, and promote sustainable development practices. It emphasizes the integration of climate change considerations into all sectors of the economy, including energy, to ensure a coordinated and comprehensive response to climate challenges. The Policy outlines several key elements essential for addressing climate change impacts in Malawi:

- Climate Change Adaptation

7.84 Implement measures to increase resilience to climate change impacts, particularly in vulnerable sectors such as agriculture, water resources, and infrastructure.

7.85 Promote the development and use of climate-resilient technologies and practices to minimize the adverse effects of climate change.

- Climate Change Mitigation

7.86 Develop and implement strategies to reduce greenhouse gas emissions across all sectors, including energy, transportation, and industry.

7.87 Encourage the adoption of renewable energy sources and energy-efficient technologies to lower carbon emissions.

- Capacity Building and Public Awareness

7.88 Enhance the capacity of institutions and stakeholders to effectively address climate change through training, research, and knowledge dissemination.

7.89 Raise public awareness about climate change impacts and the importance of adaptation and mitigation measures.

- Policy and Institutional Coordination
  - 7.90 Strengthen the coordination and integration of climate change policies and actions across different sectors and levels of government.
  - 7.91 Establish and support institutions responsible for overseeing the implementation of climate change policies and strategies.
- Funding and Resource Mobilization
  - 7.92 Mobilize resources from domestic and international sources to finance climate change adaptation and mitigation initiatives.
  - 7.93 Promote public-private partnerships to leverage additional funding and expertise for climate action projects.

Implications for Generation, Transmission, and Distribution Projects

The National Climate Change Management Policy (2016) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Integration of Climate Change Adaptation Measures
  - 7.94 Projects should incorporate climate change adaptation measures to enhance resilience to climate impacts such as extreme weather events, temperature variations, and changing precipitation patterns.
  - 7.95 Design infrastructure and systems that can withstand climate-related stresses and ensure continuous and reliable energy supply.
- Implementation of Climate Change Mitigation Strategies
  - 7.96 Projects must implement strategies to reduce greenhouse gas emissions, including the adoption of renewable energy sources such as solar, wind, and hydropower.
  - 7.97 Promote energy efficiency measures to reduce energy consumption and minimize the carbon footprint of energy projects.
- Compliance with National Climate Goals
  - 7.98 Ensure that projects comply with the national climate goals and targets set forth in the policy, contributing to Malawi's overall efforts to combat climate change.
  - 7.99 Monitor and report on greenhouse gas emissions and climate change impacts associated with project activities.
- Capacity Building and Stakeholder Engagement
  - 7.100 Enhance the capacity of project teams and stakeholders to understand and address climate change issues through training and knowledge sharing.
  - 7.101 Engage local communities and stakeholders in climate change adaptation and mitigation efforts, ensuring their participation and support.
- Policy and Institutional Coordination
  - 7.102 Collaborate with relevant government agencies and institutions to ensure the alignment of project activities with national climate change policies and strategies.
  - 7.103 Contribute to the development and implementation of coordinated climate action plans that integrate sectoral efforts.

The National Climate Change Management Policy (2016) provides a comprehensive framework for addressing climate change impacts and promoting sustainable development in Malawi. Generation, transmission, and distribution projects must integrate climate change adaptation and mitigation measures, comply with national climate goals, and engage stakeholders in climate action efforts.

7.103.1National Water Policy (2005)

National Water Policy (2005) aims to guide the sustainable management, development, and use of water resources in Malawi. This policy is comprehensive, addressing various aspects of water resource management, including conservation, utilization, and service delivery, to support socio-economic development and environmental sustainability. The National Water Policy (2005) outlines several key elements essential for effective water resource management and development:

- Integrated Water Resources Management (IWRM):
  - 7.104 Promotes IWRM principles to ensure the coordinated development and management of water, land, and related resources.
  - 7.105 Aims to maximize economic and social welfare without compromising the sustainability of vital ecosystems.
- Water Quality and Pollution Control:
  - 7.106 Ensures water of acceptable quality for various needs by setting standards and guidelines for water quality and pollution control.
  - 7.107 Implements measures to prevent and control water pollution, protecting both surface and groundwater resources.
- Water Utilization:
  - 7.108 Addresses the provision of water supply and sanitation services for urban, peri-urban, and rural areas.
  - 7.109 Promotes the efficient and equitable use of water resources for agriculture, irrigation, hydropower, fisheries, navigation, and eco-tourism.
- Disaster Management:
  - 7.110 Establishes preparedness and contingency plans for water-related disasters, such as floods and droughts.
  - 7.111 Aims to mitigate the impact of such disasters on communities and infrastructure.
- Institutional Roles and Linkages:
  - 7.112 Defines the roles and responsibilities of various stakeholders, including government ministries, water utilities, local governments, NGOs, and the private sector.
  - 7.113 Encourages collaboration and coordination among these stakeholders to ensure effective water management.

Implications for Generation, Transmission, and Distribution Projects

The National Water Policy (2005) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Adherence to IWRM Principles:

7.114 Projects must integrate IWRM principles into their planning and implementation processes to ensure sustainable water resource management.

7.115 Coordinated development and management of water, land, and related resources should be prioritized.

- Ensuring Water Quality and Pollution Control:

7.116 Projects must comply with the standards and guidelines for water quality and pollution control set forth in the policy.

7.117 Implementing effective pollution prevention and control measures is essential to protect water resources from contamination.

- Efficient and Equitable Water Utilization:

7.118 Projects should promote the efficient and equitable use of water resources, ensuring that water supply and sanitation services are accessible to all.

7.119 Consideration of water needs for various sectors, including agriculture, hydropower, and eco-tourism, is crucial for balanced water use.

- Disaster Management and Preparedness:

7.120 Incorporating disaster management and preparedness measures into project planning can mitigate the impact of water-related disasters.

7.121 Developing contingency plans and infrastructure to cope with floods and droughts is essential for project resilience.

The National Water Policy (2005) provides a comprehensive framework for the sustainable management, development, and use of water resources in Malawi. Generation, transmission, and distribution projects must adhere to the policy's principles and guidelines to ensure sustainable water resource management, compliance with water quality standards, efficient utilization, disaster preparedness, and stakeholder collaboration. By aligning with the National Water Policy, developers can contribute to the sustainable development of Malawi's water resources, supporting socio-economic growth and environmental conservation.

7.122 Relevant Malawi Legislative Framework

7.122.1Constitution of the Republic of Malawi (1994)

Constitution of the Republic of Malawi (1994) serves as the supreme law of the land, laying the foundation for all legal and regulatory frameworks within the country. It enshrines principles of environmental protection and sustainable development, reflecting Malawi's commitment to fostering a balanced relationship between development and environmental stewardship. The Constitution ensures that all developmental activities, including energy projects, adhere to fundamental environmental principles to safeguard the well-being of its citizens and the natural environment. The Constitution outlines several key principles and provisions that are pertinent to environmental protection and sustainable development:

- Environmental Protection

7.123 Mandates the state to adopt and implement policies and measures designed to protect and sustain the environment for present and future generations.

7.124 Requires that environmental considerations be integrated into national development plans and policies.

- Sustainable Development

7.125 Emphasizes the need for sustainable use of natural resources to ensure that development meets the needs of the present without compromising the ability of future generations to meet their own needs.

7.126 Supports economic development that is environmentally sustainable and socially inclusive.

- Public Participation and Rights

7.127 Ensures the right of citizens to participate in environmental decision-making processes.

7.128 Protects the rights of individuals and communities to access information regarding environmental matters and to seek redress for environmental harm.

- Legislative and Institutional Framework

7.129 Provides the basis for enacting environmental laws and establishing institutions to oversee environmental management and enforcement.

7.130 Encourages the development of laws and regulations that promote environmental justice and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Constitution of the Republic of Malawi (1994) has significant implications for the planning and execution of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Constitutional Provisions

7.131 Projects must comply with constitutional provisions related to environmental protection, ensuring that all activities align with the principles of environmental sustainability and stewardship.

7.132 Regular audits and environmental impact assessments should be conducted to ensure ongoing compliance with constitutional mandates.

- Integration of Environmental Considerations

7.133 Integrate environmental considerations into all stages of project planning and implementation, from initial design through to operation and maintenance.

7.134 Develop and implement ESIAs to identify potential impacts and develop mitigation strategies.

- Upholding Constitutional Rights and Principles

7.135 Uphold the constitutional rights of citizens by ensuring transparent and inclusive decision-making processes.

7.136 Provide opportunities for public participation and access to information, allowing communities to engage meaningfully in project planning and implementation.

- Sustainable Resource Management

7.137 Utilize natural resources in a manner that ensures their sustainability, preventing over-exploitation and degradation.

7.138 Adopt practices that promote the efficient use of resources, reducing waste and minimizing environmental impacts.

- Establishing Accountability and Enforcement Mechanisms
  7.139 Establish mechanisms for monitoring and enforcing compliance with environmental laws and regulations.
  7.140 Ensure that project developers are held accountable for any environmental harm caused and that appropriate remedial actions are taken.

The Constitution of the Republic of Malawi (1994) provides a foundational legal framework that mandates the integration of environmental protection and sustainable development into all aspects of national development. Generation, transmission, and distribution projects must comply with constitutional provisions, uphold the rights and principles enshrined in the Constitution, and integrate environmental considerations into their planning and implementation processes.

7.140.1Environmental Management Act (2017)

Environmental Management Act (2017) is a comprehensive legal framework designed to ensure environmental protection and sustainable management in Malawi. The Act mandates the conduct of ESIAs for all significant development projects to evaluate and mitigate potential environmental and social impacts. It establishes clear requirements and procedures for environmental protection, reflecting Malawi's commitment to sustainable development and environmental stewardship. The Environmental Management Act (2017) outlines several key elements essential for effective environmental protection and management:

- Environmental and Social Impact Assessments
  7.141 Mandates the conduct of ESIAs for all significant development projects to assess potential environmental and social impacts.
  7.142 Requires public participation in the ESIA process, ensuring that stakeholders' views and concerns are considered.
- Environmental Standards and Regulations
  7.143 Establishes standards and regulations for pollution control, waste management, and the sustainable use of natural resources.
  7.144 Provides guidelines for the management of hazardous substances and the protection of biodiversity.
- Institutional Framework
  7.145 Establishes the Malawi Environment Protection Authority (MEPA) as the primary agency responsible for overseeing environmental management and enforcement.
  7.146 Creates mechanisms for coordination and collaboration among various stakeholders, including government agencies, private sector entities, and local communities.
- Compliance and Enforcement
  7.147 Sets out penalties and sanctions for non-compliance with environmental regulations.
  7.148 Provides for regular environmental audits and inspections to ensure adherence to environmental standards.
- Public Participation and Access to Information

7.149 Ensures public access to environmental information and promotes transparency in environmental decision-making processes.

7.150 Encourages community involvement in environmental management and conservation initiatives.

Implications for Generation, Transmission, and Distribution Projects

The Environmental Management Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Conducting Comprehensive ESIAs

  7.151 Projects must conduct thorough ESIAs to identify and assess potential environmental and social impacts.

  7.152 The ESIAs should include detailed mitigation measures to address identified impacts and ensure environmental sustainability.

- Compliance with Environmental Standards and Regulations

  7.153 Projects must comply with the environmental standards and regulations established under the Act.

  7.154 Regular environmental audits and monitoring should be conducted to ensure ongoing compliance and identify areas for improvement.

- Engagement with the MEPA

  7.155 Engage with the MEPA throughout the project lifecycle to ensure compliance with regulatory requirements and obtain necessary approvals.

  7.156 Collaborate with the MEPA to address any environmental concerns and implement best practices in environmental management.

- Public Participation and Transparency

  7.157 Ensure active public participation in the ESIA process, allowing stakeholders to provide input and express concerns.

  7.158 Maintain transparency by providing access to environmental information and keeping stakeholders informed about project developments and environmental management efforts.

- Mitigation of Environmental and Social Impacts

  7.159 Develop and implement effective mitigation measures to minimize adverse environmental and social impacts.

  7.160 Monitor the effectiveness of mitigation measures and adjust them as necessary to achieve desired outcomes.

- Institutional Coordination and Collaboration

  7.161 Coordinate with relevant government agencies, private sector entities, and local communities to ensure a holistic approach to environmental management.

  7.162 Leverage the expertise and resources of various stakeholders to enhance the effectiveness of environmental protection efforts.

The Environmental Management Act (2017) provides a robust legal framework for ensuring environmental protection and sustainable management in Malawi. Generation, transmission, and distribution projects must conduct comprehensive ESIAs, comply with environmental standards and regulations, and engage with the MEPA to obtain necessary approvals.

7.162.1Energy Regulation Act (2004)

Energy Regulation Act (2004) is a pivotal framework that establishes the Malawi Energy Regulatory Authority (MERA), the key regulatory body responsible for overseeing the energy sector in Malawi. The Act provides a comprehensive structure for licensing, setting tariffs, and ensuring compliance with energy laws, promoting the efficient use and development of energy resources. It aims to create a stable and transparent regulatory environment conducive to investment and sustainable energy development. The Energy Regulation Act (2004) outlines several key elements essential for effective energy sector regulation and management:

- Establishment of MERA
  - 7.163 MERA is established as the principal regulatory body for the energy sector, with the authority to issue licenses, set tariffs, and enforce compliance with energy laws.
  - 7.164 MERA's mandate includes the regulation of electricity, gas, and petroleum sectors to ensure efficiency, reliability, and sustainability.
- Licensing and Tariff Setting
  - 7.165 MERA is responsible for issuing licenses for the generation, transmission, distribution, and supply of electricity, as well as other energy-related activities.
  - 7.166 The authority sets and reviews tariffs to ensure that they are fair, reasonable, and reflective of the cost-of-service delivery.
- Regulatory Compliance and Enforcement
  - 7.167 MERA ensures that all licensed entities comply with the relevant energy laws, regulations, and standards.
  - 7.168 The authority has the power to impose penalties and take corrective actions against entities that violate regulatory requirements.
- Promotion of Efficient Energy Use
  - 7.169 The Act promotes the efficient use and development of energy resources, encouraging the adoption of energy-efficient technologies and practices.
  - 7.170 MERA supports initiatives aimed at enhancing energy conservation and reducing wastage.
- Consumer Protection and Public Involvement
  - 7.171 The Act includes provisions to protect consumer rights and ensure that consumers have access to reliable and affordable energy services.
  - 7.172 MERA facilitates public involvement in the regulatory process, ensuring transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Energy Regulation Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Necessary Licenses

7.173 All energy projects must obtain the necessary licenses from MERA before commencing operations. This includes licenses for generation, transmission, distribution, and supply activities.

7.174 The licensing process involves submitting detailed project proposals and compliance with regulatory requirements set by MERA.

- Compliance with MERA's Regulations

7.175 Projects must adhere to all regulations, standards, and guidelines established by MERA. This includes compliance with technical, safety, and environmental standards.

7.176 Regular audits and inspections may be conducted by MERA to ensure ongoing compliance and identify areas for improvement.

- Tariff Setting and Financial Viability

7.177 Projects must work with MERA to set appropriate tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.

7.178 Financial viability and sustainability of the projects are essential, as tariffs must be fair and reflective of operational costs.

- Promotion of Efficient Energy Use

7.179 Incorporate energy-efficient technologies and practices in project design and operation to enhance overall efficiency and reduce energy consumption.

7.180 Support initiatives and programs that promote energy conservation and the efficient use of resources.

- Consumer Protection and Public Engagement

7.181 Ensure that project operations align with consumer protection regulations, providing reliable and affordable energy services.

7.182 Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.

- Enforcement and Penalties

7.183 Be aware of the enforcement mechanisms and penalties for non-compliance with MERA's regulations. This includes potential fines, suspension of licenses, and other corrective actions.

7.184 Maintain thorough documentation and records to demonstrate compliance and facilitate regulatory oversight.

The Energy Regulation Act (2004) establishes a robust regulatory framework for the energy sector in Malawi, emphasizing the importance of licensing, tariff setting, compliance, and efficient energy use. Generation, transmission, and distribution projects must obtain the necessary licenses from MERA, comply with all regulatory requirements, and promote energy efficiency and consumer protection.

7.184.1Electricity Act (2004) and Electricity Amendment Act (2016)

Electricity Act (2004) and the Electricity Amendment Act (2016) are key legislative frameworks that regulate the generation, transmission, and distribution of electricity in Malawi. These acts aim to ensure the efficient and reliable supply of electricity while promoting competition and enhancing the overall efficiency of the energy market. The amendments introduced in 2016 are particularly significant as they allow for multiple licenses beyond the previously sole holder, the

Electricity Supply Corporation of Malawi (ESCOM), thereby fostering a more competitive environment. The Electricity Act (2004) and the Electricity Amendment Act (2016) outline several key elements essential for the regulation and management of the electricity sector:

- Regulation of Electricity Generation, Transmission, and Distribution

  7.185 The Acts provide a comprehensive legal framework for regulating the generation, transmission, and distribution of electricity.

  7.186 They establish standards and procedures for the development, operation, and maintenance of electrical infrastructure.

- Licensing and Competition

  7.187 The original act centralized licensing with ESCOM as the sole license holder. The 2016 amendment, however, introduced provisions for multiple licenses, allowing other entities to enter the electricity market.

  7.188 This shift aims to encourage competition, improve service delivery, and provide more choices for consumers.

- Standards and Compliance

  7.189 The Acts set technical, safety, and environmental standards for all electricity-related activities.

  7.190 Compliance with these standards is mandatory for obtaining and maintaining licenses.

- Tariff Regulation

  7.191 The Acts empower regulatory authorities to set and review tariffs to ensure they are fair, reasonable, and reflective of the cost of electricity supply.

  7.192 Tariff regulation aims to balance the interests of consumers and service providers, ensuring affordability and financial sustainability.

- Consumer Protection and Public Involvement

  7.193 Provisions are included to protect the rights of electricity consumers and ensure they have access to reliable and affordable electricity services.

  7.194 The Acts encourage public participation in the regulatory process, enhancing transparency and accountability.

Implications for Generation, Transmission, and Distribution Projects

The Electricity Act (2004) and the Electricity Amendment Act (2016) have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Application for Multiple Licenses

  7.195 Project developers can apply for multiple licenses for generation, transmission, and distribution activities. This facilitates more integrated and efficient operations.

  7.196 The ability to hold multiple licenses encourages vertical integration, allowing developers to streamline processes and reduce operational costs.

- Enhanced Competition and Market Efficiency

  7.197 The introduction of multiple licenses fosters competition in the electricity market. This can lead to improved service delivery, better pricing, and increased innovation.

7.198 Developers must be prepared to operate in a competitive environment, focusing on efficiency, reliability, and customer satisfaction.

- Compliance with Standards and Regulations

7.199 Projects must comply with all technical, safety, and environmental standards set forth in the Acts. This includes adherence to construction, operation, and maintenance guidelines.

7.200 Regular audits and inspections by regulatory authorities ensure ongoing compliance and identify areas for improvement.

- Tariff Setting and Financial Sustainability

7.201 Developers must work with regulatory authorities to set tariffs that cover the cost-of-service delivery while ensuring affordability for consumers.

7.202 Financial planning should consider the regulatory framework for tariffs to ensure the long-term sustainability of projects.

- Consumer Protection and Public Engagement

7.203 Projects must align with consumer protection regulations, ensuring reliable and affordable electricity services.

7.204 Engage with the public and stakeholders throughout the project lifecycle to foster transparency, address concerns, and ensure accountability.

- Promoting Competition and Innovation

7.205 The Acts encourage developers to adopt innovative technologies and practices to enhance service delivery and efficiency.

7.206 Competitive dynamics in the market can drive continuous improvement and adoption of best practices.

The Electricity Act (2004) and the Electricity Amendment Act (2016) establish a regulatory framework for the electricity sector in Malawi, emphasizing the importance of licensing, competition, standards compliance, and consumer protection. Generation, transmission, and distribution projects must navigate this regulatory landscape by applying for the necessary licenses, adhering to standards, and embracing competition.

7.206.1Rural Electrification Act (2004)

Rural Electrification Act (2004) is a legislative framework designed to support the development of energy infrastructure in rural areas of Malawi. The Act aims to increase electrification rates and support socio-economic development by ensuring that rural communities have access to efficient, sustainable, and affordable energy. It establishes the necessary structures, funding mechanisms, and regulatory provisions to promote rural electrification initiatives. The Rural Electrification Act (2004) outlines several key elements essential for promoting rural electrification:

- Establishment of the Rural Electrification Management Committee

7.207 A Rural Electrification Management Committee is established to oversee the planning, implementation, and management of rural electrification projects.

7.208 The Committee is responsible for developing and updating a rural electrification master plan, setting selection criteria for projects, and ensuring the efficient and effective implementation of rural electrification programs.

- Creation of the Malawi Rural Electrification Fund

7.209 The Act establishes the Malawi Rural Electrification Fund, which finances the capital costs of rural electrification projects, operational and maintenance costs, and other related expenses.

7.210 The Fund is sourced from government appropriations, levies on energy sales, grants, donations, and other financial contributions.

- Licensing and Regulation

7.211 Rural electrification activities, including grid extension and off-grid electrification, must be licensed by the MERA.

7.212 The Act sets forth regulations for safety, tariffs, and concession agreements, ensuring that rural electrification projects meet established standards and provide reliable services.

- Promotion and Support of Rural Electrification

7.213 The Act mandates the promotion of rural electrification through public awareness campaigns, market research, and the provision of technical, commercial, and institutional advice.

7.214 It encourages the use of renewable energy resources and technologies, such as solar home systems and micro-hydropower stations, to enhance rural energy access.

- Monitoring and Reporting

7.215 The Committee is tasked with monitoring the implementation and operation of rural electrification projects to ensure compliance with the Act and related regulations.

7.216 Concessionaires are required to submit regular reports on the progress and performance of their projects, including annual plans, progress updates, and post-completion evaluations.

Implications for Generation, Transmission, and Distribution Projects

The Rural Electrification Act (2004) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Access to Incentives and Support

7.217 Projects targeting rural areas can benefit from the incentives and support provided under the Act, including funding from the Malawi Rural Electrification Fund.

7.218 Developers can leverage these resources to reduce capital costs, improve project viability, and ensure sustainable operations.

- Integration of Rural Electrification in Project Planning

7.219 Developers should consider rural electrification as an integral part of their project planning, aiming to extend energy access to underserved rural communities.

7.220 Incorporating off-grid and mini-grid solutions can enhance energy access in remote areas where grid extension is not feasible.

- Compliance with Licensing and Regulatory Requirements

  7.221 All rural electrification activities must obtain the necessary licenses from MERA and comply with the regulatory provisions set forth in the Act.

  7.222 Ensuring adherence to safety standards, tariff regulations, and concession agreements is crucial for project approval and operation.

- Promotion of Renewable Energy Technologies

  7.223 Projects should promote the use of renewable energy technologies, such as solar home systems and micro-hydropower stations, to support sustainable rural electrification.

  7.224 Emphasizing renewable energy can help reduce reliance on traditional biomass and fossil fuels, contributing to environmental sustainability.

- Engagement with Local Communities and Stakeholders

  7.225 Active engagement with local communities and stakeholders is essential for the successful implementation of rural electrification projects.

  7.226 Developers should involve communities in project planning and implementation, ensuring their needs and concerns are addressed.

The Rural Electrification Act (2004) provides a comprehensive framework for promoting rural electrification and supporting socio-economic development in Malawi. Generation, transmission, and distribution projects must leverage the incentives and support provided under the Act, integrate rural electrification into their planning, and comply with licensing and regulatory requirements.

7.226.1Forestry Act Amendment (2019)

Forestry Act Amendment (2019) is a critical legislative update that introduces stricter penalties for illegal activities, enhances regulation of charcoal production, and increases transparency and accountability in the forestry sector. This amendment aims to address the significant deforestation and forest degradation challenges in Malawi, driven by the demand for natural resources such as charcoal and firewood. The Act is designed to promote sustainable forest management and conservation efforts, ensuring the protection of forest resources for future generations. The Forestry Act Amendment (2019) outlines several key revisions and provisions essential for effective forestry management and conservation:

- Stricter Penalties for Illegal Activities

  7.227 The amendment introduces harsher penalties for deforestation, encroachment, illegal logging, and other unlawful activities within forest reserves and protected areas.

  7.228 Penalties include significant fines and long-term imprisonment, reflecting the seriousness of forest crimes.

- Enhanced Regulation of Charcoal Production

  7.229 Charcoal is now classified as a forest product, and its production, distribution, sale, possession, import, and export are regulated.

  7.230 Permits for charcoal production can only be granted by the Department of Forestry and must be accompanied by an approved reforestation or forest management plan.

- Increased Transparency and Accountability

  7.231 The Department of Forestry is mandated to improve information systems, providing the public with easy access to forestry-related data.

7.232 The amendment promotes greater stakeholder participation in forestry-related decision-making processes, ensuring inclusive and transparent governance.

- Strengthened Law Enforcement

7.233 Forestry officers are empowered to carry firearms in the line of duty to enforce forestry laws effectively.

7.234 The amendment increases penalties for a range of offences, including bribery, obstruction of justice, falsification of documents, and illegal trade in forest products.

- Promotion of Sustainable Forest Management

7.235 The amendment supports initiatives like the "Modern Cooking for Healthy Forests" program, which aims to promote sustainable cooking technologies and reduce reliance on charcoal and firewood.

7.236 It encourages public-private partnerships to enhance sustainable forest management and conservation efforts.

Implications for Generation, Transmission, and Distribution Projects

The Forestry Act Amendment (2019) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Consideration of Forest Resources

7.237 Projects involving land use changes must assess their impact on forest resources and comply with reforestation and sustainable management requirements.

7.238 ESIAs should include detailed evaluations of potential impacts on forests and outline mitigation strategies.

- Compliance with Charcoal Production Regulations

7.239 Projects must adhere to regulations regarding charcoal production, ensuring that any activities related to charcoal are properly licensed and managed.

7.240 Failure to comply with these regulations can result in severe legal penalties, including fines and imprisonment.

- Adherence to Stricter Penalties and Law Enforcement

7.241 Developers must be aware of the stricter penalties for illegal activities outlined in the amendment and ensure compliance with all forestry laws.

7.242 Regular audits and monitoring should be conducted to prevent illegal logging, encroachment, and other unlawful activities within project areas.

- Promotion of Sustainable Practices:

7.243 Projects should incorporate sustainable forest management practices to minimize environmental impacts and support conservation efforts.

7.244 Engaging in reforestation initiatives and promoting the use of alternative energy sources can help mitigate the effects of deforestation and forest degradation.

The Forestry Act Amendment (2019) provides a robust framework for addressing deforestation and promoting sustainable forest management in Malawi. Generation, transmission, and distribution projects must consider the impact on forest resources, comply with reforestation and charcoal production regulations, and adhere to the stricter penalties and enforcement measures outlined in the amendment.

7.244.1National Parks and Wildlife Act (2017)

National Parks and Wildlife Act (2017) provides the legislative framework for the protection and management of national parks and wildlife in Malawi. The Act includes provisions for the conservation of biodiversity, the regulation of activities within protected areas, and the sustainable use of wildlife resources. It emphasizes the need to balance development with environmental conservation, ensuring that natural habitats and wildlife populations are preserved for future generations. The National Parks and Wildlife Act (2017) outlines several key elements essential for the protection and management of national parks and wildlife:

- Protection of National Parks and Wildlife Reserves
  - 7.245 Establishes and manages national parks, wildlife reserves, and other protected areas to conserve biodiversity and natural habitats.
  - 7.246 Prohibits activities that may harm wildlife or degrade habitats within these protected areas, including hunting, logging, and mining.
- Conservation of Biodiversity
  - 7.247 Promotes the conservation of biodiversity through the protection of endangered and threatened species.
  - 7.248 Implements measures to restore and maintain ecological integrity and the natural processes within ecosystems.
- Regulation of Activities within Protected Areas
  - 7.249 Regulates activities such as tourism, research, and resource extraction within national parks and wildlife reserves to ensure they do not negatively impact the environment.
  - 7.250 Requires permits for activities that may affect wildlife or their habitats, ensuring that such activities are conducted sustainably.
- Community Involvement and Benefit Sharing
  - 7.251 Encourages the involvement of local communities in the management and conservation of wildlife and protected areas.
  - 7.252 Promotes benefit-sharing arrangements to ensure that communities derive economic benefits from conservation activities, such as eco-tourism and sustainable resource use.
- Enforcement and Compliance
  - 7.253 Strengthens law enforcement capabilities to combat wildlife crime, including poaching and illegal trade in wildlife products.
  - 7.254 Imposes penalties and sanctions for violations of the Act, including fines and imprisonment for illegal activities.
- Public Awareness and Education
  - 7.255 Promotes public awareness and education on the importance of wildlife conservation and the sustainable use of natural resources.
  - 7.256 Supports initiatives to educate communities and stakeholders about conservation laws and the benefits of protecting biodiversity.

Implications for Generation, Transmission, and Distribution Projects

The National Parks and Wildlife Act (2017) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Compliance with Conservation and Management Requirements
  - 7.257 Projects located near or within protected areas must comply with conservation and management requirements outlined in the Act.
  - 7.258 Conduct ESIAs to identify potential impacts on national parks, wildlife reserves, and biodiversity, and develop appropriate mitigation measures.
- Minimizing Impact on Wildlife and Biodiversity
  - 7.259 Ensure that project activities have minimal impact on wildlife and biodiversity by adopting best practices for environmental management.
  - 7.260 Implement measures to protect endangered and threatened species and their habitats, avoiding any activities that could cause harm.
- Obtaining Necessary Permits and Approvals
  - 7.261 Obtain the necessary permits and approvals from relevant authorities for any activities within or near protected areas.
  - 7.262 Engage with the Department of National Parks and Wildlife (DNPW) to ensure compliance with regulatory requirements and secure project approvals.
- Enhancing Law Enforcement and Compliance
  - 7.263 Support law enforcement efforts to combat wildlife crime by collaborating with authorities and providing resources for monitoring and enforcement.
  - 7.264 Ensure that project personnel are aware of and comply with all legal requirements related to wildlife protection and conservation.

The National Parks and Wildlife Act (2017) provides a comprehensive framework for the protection and management of national parks and wildlife in Malawi. Generation, transmission, and distribution projects must comply with conservation and management requirements, minimize their impact on wildlife and biodiversity, and obtain necessary permits and approvals.

7.264.1Water Resources Act (2013)

Water Resources Act (2013) provides a comprehensive legal framework for the management, conservation, use, and control of water resources in Malawi. The Act aims to promote the sustainable use of water resources, ensure equitable access, and protect the environment from pollution and over-exploitation. It establishes regulatory mechanisms and institutional frameworks to support the effective management of water resources, addressing the needs of various stakeholders, including domestic, agricultural, industrial, and environmental users. The Water Resources Act (2013) outlines several key elements essential for effective water resource management:

- National Water Resources Authority (NWRA):
  - 7.265 Establishes the NWRA as the primary agency responsible for regulating and managing water resources in Malawi.
  - 7.266 The NWRA is tasked with developing principles, guidelines, and procedures for the allocation and sustainable use of water resources.

- Water Abstraction and Use:
    7.267 Defines the processes for obtaining licenses for water abstraction and use, ensuring that all water use is regulated and sustainable.
    7.268 Requires the reservation of water resources to meet domestic needs and protect aquatic ecosystems.
- Groundwater Conservation:
    7.269 Provides regulations for the protection and sustainable use of groundwater resources, including the issuance of permits for borehole drilling and groundwater extraction.
    7.270 Establishes conservation areas and guidelines for preventing groundwater pollution and over-exploitation.
- Catchment Management:
    7.271 Establishes catchment management committees to oversee the sustainable management of water resources within designated catchment areas.
    7.272 Requires the development of catchment management strategies that align with the National Water Resources Master Plan.
- Control and Protection of Water Resources:
    7.273 Implements measures to prevent and control water pollution, including the regulation of effluent discharge and the prohibition of harmful substances.
    7.274 Promotes the safe storage, treatment, and disposal of waste to protect water quality and public health.
- Dams and Flood Management:
    7.275 Establishes guidelines for the construction, operation, and safety of dams, including the registration of dams with safety risks.
    7.276 Provides measures for flood mitigation and control, ensuring the protection of communities and infrastructure.
- Water Charges and Financial Provisions:
    7.277 Introduces charges for water use and services, with the revenue used to support the management and conservation of water resources.
    7.278 Establishes a Water Resources Trust Fund to finance water management projects and initiatives.
- Public Participation and Consultation:
    7.279 Ensures public participation in water resource management through consultations, stakeholder engagement, and access to information.
    7.280 Promotes transparency and accountability in decision-making processes related to water resources.

Implications for Generation, Transmission, and Distribution Projects

The Water Resources Act (2013) has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Obtaining Water Abstraction Licenses:
    7.281 Projects must obtain licenses from the NWRA for the abstraction and use of water resources. This includes providing detailed information on the intended use, location, volume, and impact on existing water users and the environment.

7.282 Compliance with licensing requirements ensures that water use is sustainable and aligned with national water management goals.

- Compliance with Groundwater Regulations:

7.283 Projects involving groundwater extraction must comply with the regulations for borehole drilling and groundwater use. This includes obtaining permits and adhering to conservation guidelines.

7.284 Proper management of groundwater resources is essential to prevent over-exploitation and ensure long-term availability.

- Integration of Catchment Management Strategies:

7.285 Projects located within designated catchment areas must align with catchment management strategies and contribute to the sustainable management of water resources.

7.286 Engaging with catchment management committees and incorporating local water management plans into project design can enhance sustainability and community support.

- Environmental Protection and Pollution Control:

7.287 Projects must implement measures to prevent water pollution and ensure the safe disposal of effluents and waste. This includes adhering to effluent discharge permits and maintaining high standards of water quality.

7.288 Protecting water resources from pollution is critical for maintaining ecosystem health and public safety.

The Water Resources Act (2013) provides a robust framework for the sustainable management and protection of water resources in Malawi. Generation, transmission, and distribution projects must comply with the Act's licensing, conservation, and pollution control requirements to ensure sustainable and responsible use of water resources. Integrating the Act's provisions into project planning and implementation, developers can contribute to the long-term sustainability of Malawi's water resources, support environmental conservation, and enhance community well-being.

7.288.1Independent Power Producer (IPP) Framework

Independent Power Producer (IPP) Framework provides a structured approach for private sector participation in Malawi's power sector. It outlines the roles, responsibilities, and processes necessary for project evaluation, approval, and procurement. The framework is designed to attract private investment, enhance competition, and ensure the efficient and reliable supply of electricity in Malawi. The IPP Framework aims to streamline the development of power projects and support the country's energy goals. The IPP Framework outlines several key elements essential for the successful involvement of independent power producers in Malawi's energy sector:

- Roles and Responsibilities

7.289 Defines the roles and responsibilities of key stakeholders, including the government, regulatory authorities, and private sector participants.

7.290 Clarifies the obligations of IPPs regarding project development, financing, construction, operation, and maintenance.

- Project Evaluation and Approval

7.291 Establishes criteria and procedures for the evaluation and approval of power projects proposed by IPPs.

7.292 Ensures that projects meet technical, financial, and environmental standards before receiving approval.

- Procurement Processes

7.293 Details the procurement processes for selecting IPPs, including competitive bidding and direct negotiations.

7.294 Aims to ensure transparency, fairness, and competitiveness in the selection of power projects.

- Regulatory and Licensing Requirements

7.295 Outlines the regulatory and licensing requirements that IPPs must comply with to operate in Malawi.

7.296 Includes provisions for obtaining generation licenses, environmental permits, and other necessary approvals.

- Financial and Contractual Arrangements

7.297 Provides guidelines for financial and contractual arrangements, including power purchase agreements (PPAs), financing structures, and risk mitigation measures.

7.298 Ensures that contracts are fair, balanced, and provide adequate protection for all parties involved.

- Monitoring and Compliance

7.299 Establishes mechanisms for monitoring and ensuring compliance with the terms and conditions of licenses and contracts.

7.300 Includes provisions for regular reporting, audits, and performance reviews.

Implications for Generation, Transmission, and Distribution Projects

The IPP Framework has significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Facilitating Private Investment

7.301 Clear guidelines and streamlined processes facilitate private investment in power projects, attracting local and international investors.

7.302 By providing a predictable and transparent regulatory environment, the framework reduces uncertainties and encourages long-term investment.

- Following the IPP Framework for Project Approvals

7.303 Developers must follow the IPP Framework's procedures for project evaluation and approval to ensure compliance with regulatory standards.

7.304 Adhering to the framework increases the likelihood of obtaining necessary approvals and licenses in a timely manner.

- Ensuring Competitive and Transparent Procurement

7.305 Developers must participate in competitive bidding processes or direct negotiations as outlined in the IPP Framework.

7.306 Ensuring transparency and fairness in procurement processes enhances the credibility and integrity of project selection.

- Complying with Regulatory and Licensing Requirements

7.307 Projects must comply with all regulatory and licensing requirements, including obtaining generation licenses, environmental permits, and other approvals.

7.308 Regular audits and monitoring are essential to maintain compliance and address any regulatory issues promptly.

- Establishing Financial and Contractual Arrangements

7.309 Developers must negotiate and finalize power purchase agreements (PPAs) and other financial contracts in accordance with the IPP Framework's guidelines.

7.310 Adequate risk mitigation measures should be incorporated to protect the interests of all parties involved.

- Monitoring and Ensuring Compliance

7.311 Implement mechanisms for ongoing monitoring and compliance with the terms and conditions of licenses and contracts.

7.312 Regular reporting and performance reviews help identify and address any issues that may arise during project implementation and operation.

The IPP Framework provides a comprehensive structure for private sector participation in Malawi's power sector, outlining clear guidelines for project evaluation, approval, and procurement. Generation, transmission, and distribution projects must follow the IPP Framework to facilitate private investment, ensure compliance with regulatory requirements, and promote transparency and competitiveness in the power market.

7.313 Guidelines and Regulations.

7.313.1EIA Guidelines

EIA Guidelines provide detailed procedures for conducting ESIAs in Malawi. These guidelines are essential tools for project developers to ensure that environmental and social impacts are thoroughly assessed and managed throughout the project lifecycle. The guidelines cover key stages such as project screening, scoping, baseline data collection, impact assessment, and the development of Environmental and Social Management Plans (ESMPs). The EIA Guidelines outline several key stages and elements essential for the effective assessment and management of environmental and social impacts:

- Project Screening

7.314 The screening process determines whether a project requires a full ESIA based on its type, size, and potential environmental impact.

7.315 Projects that are likely to have significant environmental impacts are subjected to a detailed ESIA.

- Scoping

7.316 Scoping identifies the key environmental and social issues that need to be addressed in the ESIA.

7.317 It involves consultations with stakeholders to gather input on potential impacts and concerns.

- Baseline Data Collection

7.318 Baseline data collection involves gathering information on the existing environmental and social conditions of the project area.

7.319 This data serves as a reference point for assessing the potential impacts of the project.

- Impact Assessment
  - 7.320 The impact assessment evaluates the potential environmental and social impacts of the project, both positive and negative.
  - 7.321 It considers the magnitude, extent, duration, and reversibility of the impacts.
- Mitigation Measures
  - 7.322 Mitigation measures are developed to avoid, reduce, or offset significant adverse impacts.
  - 7.323 These measures are integrated into the project design and implementation plan.
- Environmental and Social Management Plans
  - 7.324 ESMPs outline the specific actions and responsibilities for managing and monitoring environmental and social impacts throughout the project lifecycle.
  - 7.325 They include measures for impact mitigation, monitoring, and reporting.
- Public Consultation and Participation
  - 7.326 Public consultation and participation are critical components of the ESIA process, ensuring that stakeholders' views and concerns are considered.
  - 7.327 The guidelines provide methods for effective public engagement and information dissemination.
- Monitoring and Reporting:
  - 7.328 Ongoing monitoring and reporting are required to ensure that mitigation measures are effectively implemented and that environmental and social impacts are managed.
  - 7.329 Regular audits and inspections are conducted to assess compliance with ESMPs and regulatory requirements.

Implications for Generation, Transmission, and Distribution Projects

The EIA Guidelines have significant implications for the planning and implementation of generation, transmission, and distribution projects. Here are the key considerations:

- Thorough Assessment and Management of Impacts:
  - 7.330 Developers must follow these guidelines to ensure a thorough assessment and management of environmental and social impacts.
  - 7.331 Conducting comprehensive ESIAs helps identify potential issues early in the project lifecycle, allowing for effective mitigation and management.
- Regulatory Compliance:
  - 7.332 Compliance with EIA guidelines is critical for obtaining regulatory approval for projects.
  - 7.333 Proper ESIA documentation, including baseline studies, impact assessments, and ESMPs, is essential for demonstrating compliance with environmental regulations.
- Stakeholder Engagement:
  - 7.334 Effective stakeholder engagement is crucial for the successful implementation of projects.

7.335 Developers should actively involve stakeholders in the ESIA process, addressing their concerns and incorporating their input into project planning and decision-making.

- Sustainability and Long-term Success:

7.336 Ensuring environmental and social sustainability is key to the long-term success of projects.

7.337 Implementing robust ESMPs and ongoing monitoring helps mitigate adverse impacts and promotes positive outcomes for communities and the environment.

- Transparency and Accountability:

7.338 The ESIA process promotes transparency and accountability by involving stakeholders and providing access to information.

7.339 Regular reporting and public disclosure of ESIA findings and management measures enhance trust and credibility with stakeholders.

- Integration into Project Planning:

7.340 Integrating ESIA findings into project planning and design helps optimize project outcomes and minimize negative impacts.

7.341 Developers should use ESIA results to inform decision-making and improve project sustainability.

The EIA Guidelines provide a comprehensive framework for assessing and managing the environmental and social impacts of generation, transmission, and distribution projects in Malawi. Developers will ensure thorough impact assessment, regulatory compliance, effective stakeholder engagement, and long-term project sustainability. Integrating ESIA findings into project planning and implementation helps optimize project outcomes and contributes to the overall well-being of communities and the environment.

7.342 References

GoM, (1995). Constitution of the Republic Malawi, Government of Malawi (1994)

GoM, (1997). Guidelines for Environmental Impact Assessment (EIA) in Malawi, Government of Malawi (1997)

GoM, (2004). Electricity Act, Government of Malawi (2004)

GoM, (2004). Energy Regulation Act, Government of Malawi (2004)

GoM, (2004). National Environmental Policy, Government of Malawi (2004)

GoM, (2005). National Water Policy, Government of Malawi. Lilongwe, 2005.

GoM, (2008). Environment Management (Chemicals and Toxic Substances Management) Regulations, Government of Malawi. Lilongwe, 2008.

GoM, (2013). Water Resources Act, Government of Malawi (2013)

GoM, (2016). Electricity Amendment Act, Government of Malawi (2016)

GoM, (2016). National Climate Change Management Policy, Government of Malawi (2016)

GoM, (2016). National Forestry Policy, Government of Malawi. Lilongwe, 2016.

GoM, (2016). Physical Planning (Amendment) Act, Government of Malawi. Lilongwe, 2022.

GoM, (2017). Environmental Management Act, Government of Malawi (2017)

GoM, (2017). National Parks and Wildlife Act, Government of Malawi (2017)

GoM, (2018). National Energy Policy, Government of Malawi (2018)

GoM, (2019). Forestry Act Amendment, Government of Malawi (2019)

GoM, (2021). The Malawi 2063 First 10 Year Implementation Plan (2021 – 2030, Government of Malawi. Lilongwe, 2021.

8 Conclusions

The transmission development plan (TDP) presented in this study aims at providing a strategic blueprint for the future development and expansion of the Malawian transmission system over the next 20 years. The TDP has identified the necessary infrastructure upgrades and extensions to ensure reliable and efficient transmission operations while considering the demand growth and the integration of new power plants. The timeline and the costs of the investments are only indicative and will have to be revisited in due time in the scope of dedicated studies for each transmission project

A summary of the key features behind the recommended TDP is provided below. This TDP was referred to as the reference network structure in the study, which builds on the list of decided/proposed transmission projects shared by ESCOM.

8.1 Main description

As recommended by the preliminary analysis of the long-term development strategy, the proposed TDP aims to gradually phase out all existing 66kV assets and replace them with new 132kV ones by 2042. This transformation will result in a Malawian transmission system primarily composed of a main 400kV network integrating the national system to the regional network, supported by a 132kV system that connects to the distribution network. The main motivation behind this upgrade is that operating at a higher voltage level will reduce network losses and the hidden costs associated to them. Additionally, the upgrade to the 132kV level offers better prospects for future development. A higher voltage level not only facilitates the integration of long-distance transmission lines but also supports the installation of new power plants in remote locations.

8.2 List of reinforcements and costs estimates

A summary of the reinforcements foreseen in the TDP, on top of the decided/proposed transmission projects, is provided below:

Table 4.6.1: Reinforcements foreseen in the TDP

Type	Quantity	Costs MUSD
HV substations	17	209
132kV lines	2950 km	386
33kV lines	24 km	4
3-winding transformers	6	18
Shunt inductors	185 Mvar	3
Shunt capacitors	-540 Mvar	10
	Total	**630**

These costs estimates should be treated as provisional. For the row in the table corresponding to the HV substations, the costs include the site opening for the new substations and the bays required to connect new transmissions lines and transformers at both existing and new substations.

8.3 Timeline of the reinforcements

8.3.1 Short term

By the year 2027, eight decided/proposed transmission projects in Malawi are expected to be operational:

Table 4.6.2: Decided/proposed transmission projects

Name	Voltage (kV)	Circuits (-)	In service by (year)
Mozambique – Malawi 400kV interconnector	400	2	2027
Eastern Backbone project	132	2	2027
Golomoti – Monkey Bay 132kV line	132	2	2027
Monkey Bay – Mangochi – Makanjira 132kV line	132	1	2027
Blantyre West – New Blantyre – Nkula B 132kV line	132	1	2027
New Blantyre – Phalombe 132kV line	132	1	2027
Nkhotakota – Serengeti – Chinyama – Kanyika 132kV line	132	1	2027
Lilongwe 132kV loop	132	1	2027

The system should be upgraded from 66 kV to 132 kV in the Southern Region up to Nkula B and from 33/66 kV to 132 kV in the Northern Region from Chintheche up to Telegraph Hill and Luwinga. Some of the 132/66kV transformers, decommissioned as a result of the upgrade, could be relocated to substations that remain at 66kV to optimize resource utilization and enhance network resilience.

The commissioning of the first interconnection with Mozambique and the integration into the SAPP regional system will mark a significant milestone for the Malawian power infrastructure. This development will enhance the overall system stability through shared reserves and inertia. However, the large import capacity of 120 MW relative to the national system size poses a significant risk in case of disconnection. Such an incident would lead to the largest instantaneous imbalance between demand and generation in Malawi and isolate the country from the larger regional system. Without appropriate preventive measures, it will be difficult to limit the impact on the Malawian consumers and avoid a complete black-out of the country.

Possible solutions to mitigate the aforementioned risk include the installation of a second circuit between Mozambique and Malawi (as foreseen in the list of decided/proposed transmission projects), keeping spinning reserve, the deployment of BESS dedicated to reserves, the implementation of SPS, or a combination of these measures.

Furthermore, the implementation of the Eastern Backbone project will strengthen the power supply to Mzuzu and the northern part of the country. The same can be said about the other 132kV projects that will improve the transfer capacity of the system around Blantyre and Lilongwe and add paths to new substations.

8.3.2 Medium term

By the year 2032, the remaining decided/proposed transmission projects in Malawi are expected to be operational:

Table 4.6.3: Decided/proposed transmission by 2032

Name	Voltage (kV)	Circuits (-)	In service by (year)
Zambia – Malawi 400kV interconnector	400/330	1	2032
Tanzania – Malawi 400kV interconnector	400	1	2032
Western Backbone project	400	1	2032
Phalombe – Zomba 132kV line	132	1	2032
Changalume – Zomba – Liwonde 132kV line	132	1	2032
Phombeya – Liwonde – Mangochi 132kV line	132	1	2032
Kanyika – Chatoloma 132kV line	132	1	2032
Mzimba – Dwangwa 132kV line	132	1	2032

The system upgrade from 66 kV to 132 kV should be completed in the Southern Region up to Chingeni and in the Central Region from Chingeni up to Tsabango. In addition, the study on the evolution of the geographical distribution of the demand has determined the need of new HV substations by 2032 at Chileka and Mponela. The recommended HV substations in Mangochi and Zomba are already included in the list of decided/proposed transmission projects.

The Western Backbone project and the new interconnectors with Zambia and Tanzania are seen as strategic expansions as they will significantly enhance the power infrastructure in Malawi, enable further integration within SAPP, and establish a connection with EAPP. The other 132kV projects will also increase the transfer capacity and the connectivity of the system. In particular, the Kanyika-Chatoloma and Mzimba-Dwangwa 132kV lines will establish two bridges between the Eastern and Western Backbones. These bridges will facilitate power exchange across the country and help distribute power to prevent overloads in the event of a contingency.

8.3.3 Long term

By the year 2042, the system upgrade from 66 kV to 132 kV should be finished across the whole country. Moreover, HV substations are expected to be operational and integrated in the transmission network at the following locations:

- Area 47
- Chirimba
- Chitipia
- City Center
- Limbe A
- Limbe B
- Michiru
- Sonda
- Thyolo A
- Thyolo B
- Thyolo C
- Namitete

The recommended HV substations in Chatoloma and Phalombe are already included in the list of decided/proposed transmission projects and should be in service by 2032.

At the end of process, the Malawian power system will be constituted by a main 400kV network, which interconnects the primary substations of country and the SAPP/EAPP regional systems, and a supporting 132kV network, which makes the links with the distribution system. Continuous reinforcement and extension of the 132kV network are essential to meet the increasing demand and support the expansion of the distribution system.

8.4 Transmission losses

The following table presents the yearly transmission losses for the studied years, expressed as a percentage of the total generated and imported energy in Malawi. Despite significant network expansion over the study period to enhance electricity access in remote areas, the relative amount of losses decreases. This reduction is attributed to grid reinforcement and the development of the 132 kV and 400 kV networks.

Table 4.6.4: Yearly transmission losses

	2027	2032	2042
Transmission losses [%]	5.41	3.93	3.70

According to the loss reduction roadmap report prepared for ESCOM in 2021 [10], long-distance and energy-intensive transmission should be conducted at higher voltage levels, such as 132 kV and 400 kV. The report recommends, “As a general rule, transmission should be carried out at 132 kV, avoiding 33 kV.”

This philosophy underpins the development option selected as the reference for the long-term target structure, which involves upgrading the current 66 kV network to 132 kV.

9 References

[1] ESCOM, "ESCOM FUTURE PROJECTS-BASECASE 2023 IRP.pfd," 2023.

[2] MERA, "Malawi Grid Code," 2016.

[3] Economic Consulting Associates Limited, "Demand Forecast, Loss Reduction and Energy Efficiency Strategies Final Report," Ministry of Energy, Republic of Malawi, 2023.

[4] Norconsult AS, "Integrated Resource Plan (IRP) for Malawi," 2017.

[5] ESCOM, "Existing & Planned Transmission Network," 2018.

[6] ESCOM, "Transmission Projects.xlsx," 2023.

[7] ESCOM, "Transmission & Distribution Capital Investment Projects - with considerations on expected power supply sources," 2018.

[8] ESCOM, "Transformer cost estimates.xlsx," 2023.

[9] ESCOM, "Transmission Substations data.xlsx," 2023.

[10] Minsait, "Loss Reduction Roadmap - Loss Reduction Initiative," 2021.