INTEGRATION OF VARIABLE RENEWABLE ENERGY SOURCES

in the National Electric System of Zambia

RES4AFRICA FOUNDATION — RENEWABLE ENERGY SOLUTIONS FOR AFRICA

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LIST OF ACRONYMS

Abbreviation	Explanation
AGL	Above Ground Level
CAGR	Compound Annual Growth Rate
CDF	Cumulative Distribution Function
CEC	Copperbelt Energy Corporation
CF	Capacity Factor
COD	Commercial Operation Date
DHI	Diffuse Horizontal Irradiation
DNI	Direct Normal Irradiation
DR	Discount Rate
DSM	Demand Side Management
EAPP	Eastern Africa Power Pool
EENS	Expected Energy Not Supplied
ENH-LWA	Enhanced VRES deployment – Low Water Availability scenario
ENH-NWA	Enhanced VRES deployment – Normal Water Availability scenario
ENTSO-E	European Network of Transmission System Operators for Electricity
ESMAP	Energy Sector Management Assistance Program
EVR-LWA	Existing Variable RES – Low Water Availability scenario
EVR-NWA	Existing Variable RES – Normal Water Availability scenario
FOR	Forced Outage Rate
GHI	Global Horizontal Irradiation
GRZ	Government of the Republic of Zambia
GRARE	Grid Reliability and Adequacy Risk Evaluator
GT	Gas Turbine
HCO	Heavy Crude Oil
HHV	Higher Heating Value
HFO	Heavy Fuel Oil
HSD	High Speed Diesel engine
HV	High Voltage
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IRR	Internal Rate of Return
ISN	Isolated Node
ITT	Itezhi Tezhi
LCOE	Levelized Cost Of Electricity
LNG	Liquefied Natural Gas
LOI	Lack Of Interconnection
LOLE	Loss Of Load Expectation
LOLP	Loss Of Load Probability
LOP	Lack Of Power
LPG	Liquefied Petroleum Gas
LTO	Line and/or transformer overload

MCL	Maamba Collieries Limited
MOE	Ministry Of Energy
MSD	Medium Speed Diesel engine
n.a.	not available
NECL	Ndola Energy Company Limited
NG	Natural Gas
NPB	Net Present Benefit
NPC	Net Present Cost
NREL	National Renewable Energy Laboratory (U.S. Department of Energy)
NSP	Network Splitting
NTC	Net Transfer Capacity
O&M	Operation & Maintenance
PCC	Point of Common Coupling with the grid
PDF	Probability Density Function
PPA	Power Purchase Agreement
PSS/E	Power System Simulator for Engineering (Siemens software tool)
PV	Photovoltaic
RES	Renewable Energy Sources
RoR	Run-of-River
SAM	System Advisor Model
SC-CFB	Supercritical - Circulating Fluid Bed
SNEL	Société Nationale d'Électricité of the Democratic Republic of Congo
SO	System Operator
T&C	Technical & Commercial
TANESCO	Tanzania Electric Supply Company
TSO	Transmission System Operator
US	United States
VRES	Variable Renewable Energy Sources
VOLL	Value Of Lost Load
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	Zambia Electricity Supply Corporation
ZWG	Zambian Working Group

GLOSSARY OF TERMS

Capacity Factor	The capacity factor of a power plant, or group of power plants, is the ratio between the actual output over a period of time (typically one year) and the potential output if the operation at full nameplate capacity could be possible continuously over the same period of time
Expected Energy Not Supplied	Expected value of the yearly average energy of the not supplied load due to unavailability in the generation and/or transmission system considering the restrictions set by the power transfer capacity of the lines and transformers and the power plant limits
Gross Demand	Energy/power sent-out by the generators, excluding the consumptions of power plant auxiliaries and the share of export towards the neighbouring countries. This demand includes the High Voltage, Medium Voltage and Low Voltage network losses.
Levelized Cost Of Electricity	The levelized cost of electricity represents the installed capital costs and ongoing operating costs of a power plant, converted to a level stream of payments over the plant's assumed financial lifetime. Installed capital costs include construction costs, financing costs, tax credits, and other plant-related subsidies or taxes. Ongoing costs include the cost of the generating fuel (for power plants that consume fuel), expected maintenance costs, and other related taxes or subsidies based on the operation of the plant
Loss Of Load Expectation	Stand-by duration, in hours/year, of the period in which it is not possible to fulfil the demand
Loss Of Load Probability	Probability of not being able to fulfil the expected weekly peak load
Net Demand	Energy/power sent-out by the generators, excluding the consumptions of power plant auxiliaries, the high voltage transmission network losses and also the share of export towards the neighbouring countries
Net Transfer Capacity	Maximum total exchange program (MW) between two interconnected power systems/ areas available for commercial purposes, for a certain period and direction of active power flow. NTC is obtained from subtracting the corresponding transmission reliability margin from total transfer capacity

Operating Reserve	The un-used capacity above system demand which is required to cater for regulation, short-term load forecasting errors, and unplanned outages. It consists of Spinning and Quick Reserve. It can also be classified as the sum of Instantaneous, Regulating and 10 Minute reserves. Operating reserve should be fully activated within 10 minutes.
Programmable Generation	Generation in which the dispatching program can be planned according to the demand due to the low variability of primary source (hydropower, geothermal, biomass, fossil fuels)
Quick Reserve	The capacity readily available from non-spinning reserve which can be started and loaded within ten (10) minutes or load that can be interrupted within ten (10) minutes.
Spinning Reserve	The unused capacity which is synchronized to the system and is readily available to assume load without manual intervention
Value Of Lost Load	The value of lost load is the estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service
Variable Generation	Generation with a non-programmable dispatching program due to the variability and intermittency of the primary source (wind and solar)

EXECUTIVE SUMMARY

Zambia is endowed with outstanding and diversified renewable energy sources, namely hydro, wind and solar. For many decades, the development of the electricity sector was based on the exploitation of hydro resources that made the electric power system dependent on water and particularly exposed to the climate change. The variable renewable energy sources (VRES), namely wind and solar, can be efficiently exploited in the power sector to improve energy diversification and strengthen both short- and long-term power system resilience, to cope with current and future water challenges related to climate change. However, the deployment of VRES generation shall be accurately designed to ensure sufficient security and reliability margins. The current study was focused on the integration of variable renewables into the Zambian electrical grid considering development scenarios until 2030. It provided the optimal VRES capacity, as a proper combination of wind and PV capacity, that can be installed in Zambia considering both technical and economic constraints (i.e. balancing resources, reserve requirements, generation fleet flexibility, security of supply, grid loadability and economic competitiveness of VRES technologies in the regional power pool). Both the electrical self-sufficiency of Zambia and the power trading opportunity on the competitive regional market have been analysed. In this framework, the generation fleet flexibility and the role of interconnections have been studied because they play a role of utmost importance to maximize VRES integration in Zambia, following the load pattern and dealing with the intermittency of VRES generation when a high penetration level is achieved.

The analyses clearly highlight that additional capacity from VRES can be integrated, on top of the projects already in the Country's pipeline. The operational flexibility ensured by the hydroelectric power plants allows 27% VRES penetration both in 2025 and 2030, even without power trading on the competitive market. An installed capacity up to 1,176 MW from PV and 1,200 MW from wind can be integrated by 2025; these capacities can be increased up to 1,376 MW from PV and 1,400 MW from wind by 2030. These optimal VRES capacities, in addition to the existing and committed programmable generation fleet (2,413 MW hydro and 370 MW fossil fuels power), are not enough to ensure the electrical self-sufficiency of Zambia, therefore, additional non-VRES flexible capacity (e.g. hydropower) shall be integrated to achieve this target (about 600 MW with 30% capacity factor by 2030). The exploitation of the network interconnections ensures high standards of security of supply also increasing VRES penetration up to 36%, both in 2025 and 2030. Economic benefits from power export are envisaged increasing the installed capacity up to 1,826 MW from PV and 1,900 MW from wind by 2030 (1,576 MW from PV and 1,600 MW from wind are the limits by 2025). The exploitation of network interconnections and the cooperation of the national electricity companies will play a key role in VRES exploitation and the optimal use of energy sources in southern Africa, improving system resilience in case of extreme climate conditions.

Introduction

Historically, the Government of the Republic of Zambia (GRZ) has focused on water exploitation in the electricity sector. Hydropower is the most important energy source for the Country and accounts for about 85% of total National installed capacity in the year 2019. However, the energy crisis of 2015/2016 pushed the GRZ to undertake a diversification process of the energy mix in the electricity sector. With the Vision 2030 and the Seventh National Development Plan 2017-2021, the GRZ aims to create a diversified and resilient electricity sector to sustain the National growth. In this regard, in 2017, the GRZ through the Ministry of Energy (MOE) launched the initiative "REFiT Strategy" to accelerate private investments in small and medium sized renewable energy projects to open the power sector ever more. So, the renewal process of the energy mix in the electricity sector is ongoing with the aim to achieve a utility-scale development of non-hydro renewable sources able to supplement the large hydro energy sources, which have been negatively affected by the climate change, and to increase the security of supply.

Zambia owns a high intensity of sunshine and a very good wind potential, besides being one of the most water-rich countries in Africa.

Concerning hydro resources, hydropower potential exceeds 6,000 MW, of which only 2,400 MW is exploited. The hydro potential exploitation is expected to achieve 3,150 MW by the end of 2020 when the Kafue Gorge Lower power plant will be completed. The hydro potential in Zambia results from six river basins with huge catchment areas that, however, are dealing with the effect of the climate change. The two major rivers in the Country, such as the Zambezi River (the fourth largest river system in Africa) and the Kafue River own most of the potential. 96% (2,300 MW) of the existing hydropower plants are along these rivers. Current small hydropower (≤20 MW installed capacity) stand at about 44 MW (0.7% of National hydro potential).

Thanks to its latitude near the equator, very high solar resources are present in Zambia. The average value of GHI (Global Horizontal Irradiation) exceeds 2,000 kWh/m²/year; GHI reaches 2,150 kWh/m²/year in favourable regions. The sites with the highest solar irradiation are in the south-western areas of the Country while the irradiation decreases towards the northern and eastern areas (Fig. 1).

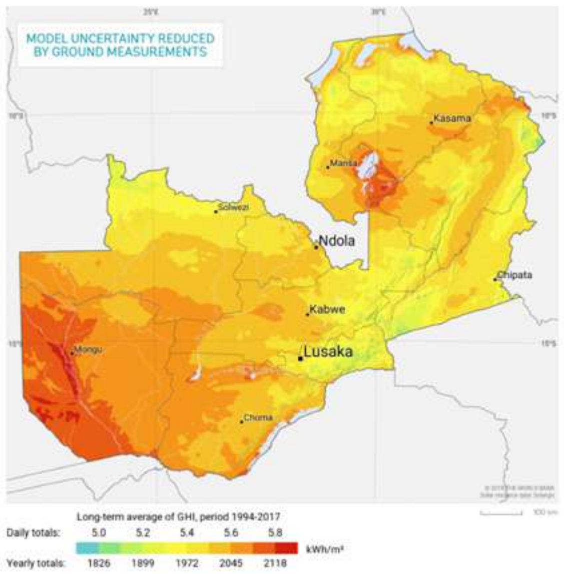


Fig. 1. Global Horizontal Irradiation in Zambia (© 2019 The World Bank, Solar resource data: Solargis)

About the wind resources, Zambia was historically considered a low potential Country; only few wind measurements at 10 m AGL (Above Ground Level) were available until 2015. However, in 2015, The MOE and the World Bank launched a renewable energy wind mapping for Zambia in the framework of the Energy Sector Management Assistance Program (ESMAP). Meteorological data is collected at 80 m AGL at eight sites over a 2-year period and long-term estimations were processed to provide a high-resolution mesoscale wind atlas. Long-term wind estimations show an average wind speed at 130 m AGL between 7 and 8 m/s that joined with the fast improvements in turbine design and manufacturing (higher hub heights and larger swept areas than older technologies) highlight a very good wind potential in the Country. The locations with the highest wind speed are the eastern areas of the Country, but these are remote from the grid and correspond to areas with a low population density. Nevertheless, there are also locations with very good potential close to the grid, with higher population density in the area around Lusaka (Fig. 2).

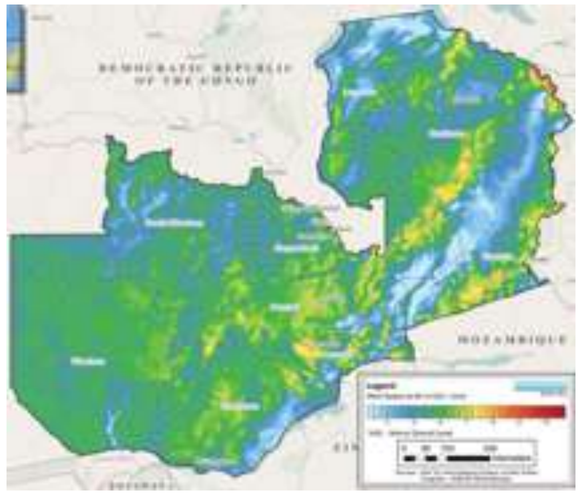


Fig. 2. Mean wind speed at 80 m height above ground level m/s (source: The World Bank – ESMAP)

This outstanding renewable energy potential can be efficiently exploited in the power sector to boost generation so to cope with the demand growth (CAGR 2019-2030 equal to 3.8%) and the lack of hydropower due to low rainfall, improving the security of supply both in short and long term.
Whilst hydro power is largely exploited in Zambia, photovoltaic (PV) power plants were only recently introduced, while wind power plants are still not developed. A wide deployment of variable renewable energy sources (VRES) requires proper integration strategies; it shall be accurately designed to ensure sufficient security margins and reliability levels. The exploitation of the generation fleet flexibility and the interconnections with the neighbouring countries becomes of utmost importance to follow the load pattern and for dealing with the variability of wind and PV generation.
The aim of this study is to estimate the optimal amount of VRES that can be integrated into the Zambian electric power system in the mid- and long-term (years 2025 and 2030), identifying possible criticalities and suggesting remedial measures concerning both the operation of the generation system and the network.

The Zambian Power System

Zambia's total electricity generation in 2018 was equal to 15.9 TWh/year, out of which 92% for domestic demand and network losses, 8% for export. The peak power demand, excluding export, was about 2.2 GW.

Annex 1 depicts the generation capacity mix in 2019. The generation heavily relies on hydropower with 2,413 MW equal to 84.4% of total generation capacity. Additional 833 MW are expected within 2023, 750 MW of which are expected by the end of 2020 when Kafue Gorge Lower hydro project will be completed. Coal is the second electricity source with 265 MW maximum power equal to 9.3% of total generation capacity; 3.7% is from Heavy Fuel Oil power plants (105 MW) while only 2.6% of total generation capacity is from PV power plants (76 MW).

Concerning the interconnections with the neighbouring countries, the Zambian electric power system is currently interconnected with DRC, Malawi, Namibia and Zimbabwe for a total of about 1,250 MW and 1,000 MW net transfer capacity under import and export conditions respectively. Zambia is an active member of the Southern African Power Pool; i.e. the cooperation of the national electricity companies in southern Africa with the scope to optimize the use of available energy sources in the region and enhance energy exchange between countries facilitating the development of a competitive electricity market in the Southern African Development Community (SADC).

Scenario

The study covers the period until 2030, with special focus on two target years: a mid-term year, 2025, and a long-term year, 2030.

A reference scenario named "Enhanced VRES deployment with normal water availability (ENH-NWA)" has been defined considering the following main assumptions:

- reference demand growth pattern and increasing firm export agreements with the neighbouring countries;
- average hydropower availability according to the historical data;
- programmable generation fleet (such as hydropower and fossil fuels plants) including only the existing and committed power plants. No candidates from non-VRES technologies were considered;
- high integration of wind and PV generation including the feasible additional capacity that does not affect the reliability, integrity and efficiency of the electric power system.

Two operating conditions were analysed for the reference scenario:

1. Isolated Country (ISO), analysing the possibility to guarantee the electrical self-sufficiency of Zambia increasing only VRES capacity and neglecting candidates from other energy sources (e.g. hydropower candidates). The optimal VRES capacity mix to meet the domestic demand and the firm export has been assessed neglecting power trading with the interconnected countries on the competitive market;
2. Interconnected Country (INT), analysing the opportunity to increase VRES integration exploiting the export capacity to the neighbouring countries and the power trading on the competitive market.

The Zambian generation system is closely dependent from hydropower and a very high exploitation of water for electricity sector will continue in the future. In this context, both long-lasting climatic changes and singular extreme natural events, which are becoming more frequent in the last decades, are expected to affect the security of supply. Starting from the reference scenario, additional analyses/sensitivities have been performed to investigate the impact of the climate change on the operation of the electric power system and the VRES integration level. Two extreme weather conditions were simulated: firstly, low rainfall periods with a prolonged drought have been assumed simulating -33% hydropower availability compared to normal conditions, then also a wet year has been analysed assuming +44% hydropower availability compared to normal conditions.

Additional analyses at the target year 2022 have been performed by the Consultant at the end of the study with the aim to highlight a development plan for VRES in worst-case scenario for system development in the short term. Delays in transmission projects have been simulated to assess the VRES penetration comply with the current transmission network and generation facilities.

Demand Forecast

The demand forecast is based on ZESCO and CEC predictions. The total demand (domestic demand, firm export and transmission and commercial losses) expected by 2025 is about 24.4 TWh/year (CAGR +5.0% in 2019-2025) with a peak power demand of 3.5 GW. In 2030, the demand achieves 27.6 TWh/year (CAGR +2.5% in 2025-2030) with a peak load equal to 3.9 GW (Fig. 3).

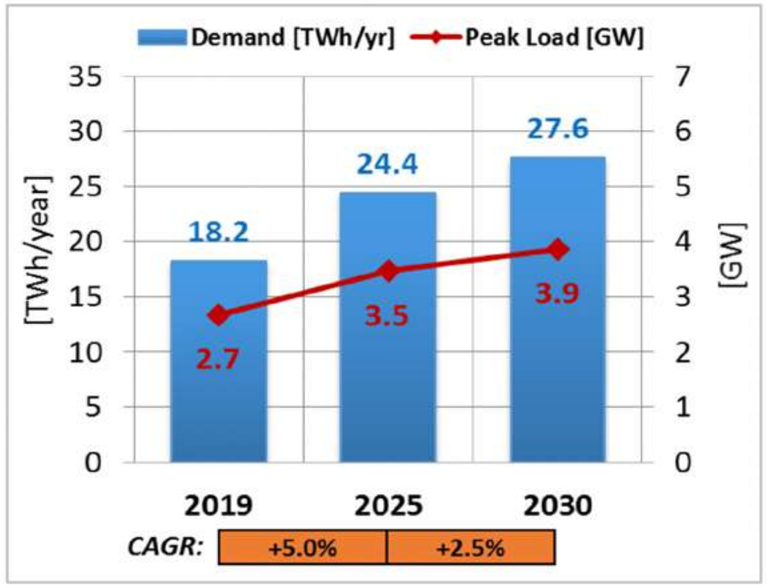


Fig. 3. Demand Forecast of Zambia for 2025 and 2030, including losses and firm export

Firm export was considered as part of the electricity demand because it is the result of firm contracts to supply electricity to some neighbouring countries or obligations such as the supply of electricity to towns on the border with Zambia. 200 MW firm export was considered with DRC, 100 MW with Namibia and 70 MW with Malawi (90% annual load factor), both in 2025 and 2030.

Generation Mix

The important demand growth and the shortage of hydropower due to the climate change shall be sustained by a diversified and robust power generation growth roadmap. For these reasons, an expansion plan of VRES generation was studied to meet the security of supply by providing, if any, information on the need for additional non-VRES generation to ensure the electrical self-sufficiency of Zambia.

The baseline generation mix includes only the existing and committed programmable generation fleet (such as hydropower and fossil fuels plants) and the existing VRES capacity (the PV power plants recently put in service). Starting from this generation fleet, additional VRES power plants (projects in pipeline or VRES candidates) were included in the system finding the optimal VRES integration from technical and economic point of view. The study is not a least cost generation expansion plan by comparing the costs of VRES and non-VRES technologies (e.g. hydropower candidates). Therefore, no candidates from non-VRES technologies (e.g. hydropower candidates) were considered.

Annex 1 shows the programmable capacity considered in reference scenario 2025 and 2030, and the VRES estimated capacities.

3,146 MW hydropower capacity was assumed both in 2025 and 2030: 2,190 MW from hydro power plants with reservoir and 956 MW from run-of-river power plants (including the largest under-construction project in the Country, i.e. Kafue Gorge Lower for 750 MW, and the extension of smaller hydro power plants such as Lusiwasi and Chishimba Falls). While only 370 MW were assumed from conventional fossil fuel generation, i.e. the existing coal and heavy fuel oil power plants.

Referring to the above-mentioned generation scenario, the annual production expected from programmable power plants in the average year is about 18.3 TWh/year both in 2025 and 2030; 15.6 TWh/year are estimated from hydro power plants and 2.7 TWh/year are available from fossil fuel power plants. VRES generation has been integrated to achieve the supply-demand balance until the techno-economic viability requirements are met.

Levelized Cost of Electricity from VRES Technologies

An assessment of the levelized cost of electricity (LCOE) from wind and photovoltaic technologies has been performed proving an indication of their competitiveness. Capacity factors of wind and PV power plants have been considered together with the investment costs, operating costs and lifetime[1] of these technologies to provide a qualitative assessment of LCOE that was considered in the cost-benefit analysis (Fig. 4). A big reduction of LCOE from PV power plants has been assumed in the short term as effect of the Round 1 of GET FiT program in which 120 MW PV capacity was committed with a weighted average LCOE equal to 4.41 US$c/kWh (the lowest bid was 3.99 US$c/kWh).

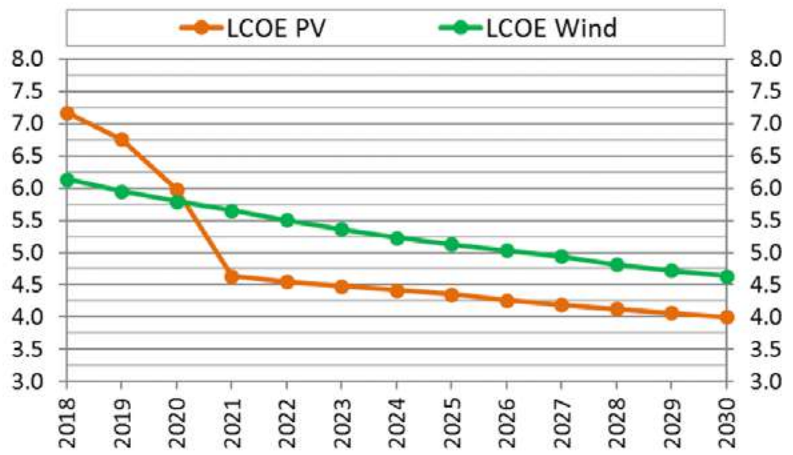


Fig. 4. Forecast of the weighted average levelized cost of electricity from VRES technologies (US$c/kWh)

[1] Lifetime has been assumed equal to the duration of PPAs that will be signed with the IPPs (Independent Power Producers); hence, 20 years instead of 25 years which is the typical lifetime of wind and PV power plants.

Interconnections

Zambia is involved in important interconnection projects in the framework of SAPP to improve the security of supply and the use of sources in Southern Africa regions (ZIZABONA project, Zambia-Mozambique project, Kolwezi-Solwezi project and Zambia-Malawi projects) and the power pools integration (Zambia-Tanzania-Kenya project to integrate the Southern African Power Pool and the Eastern Africa Power Pool). Additional 5,800 MW exchange capacity is expected in the long term. Fig. 5 shows the interconnection projects and the maximum net transfer capacities considered in the study. Interconnection projects follow the important development plan of the Zambian transmission network in which several internal reinforcements were planned by ZESCO to improve the adequacy and the system security.

The analyses have been carried out adopting a complete generation and transmission network model of the Zambian electric power system (330-220-132-88-66 kV); while an equivalent model of the neighbouring countries based on Zambian net transfer capacity and SAPP marginal clearing prices has been defined to simulate the power trading on the competitive market in the interconnected scenario.

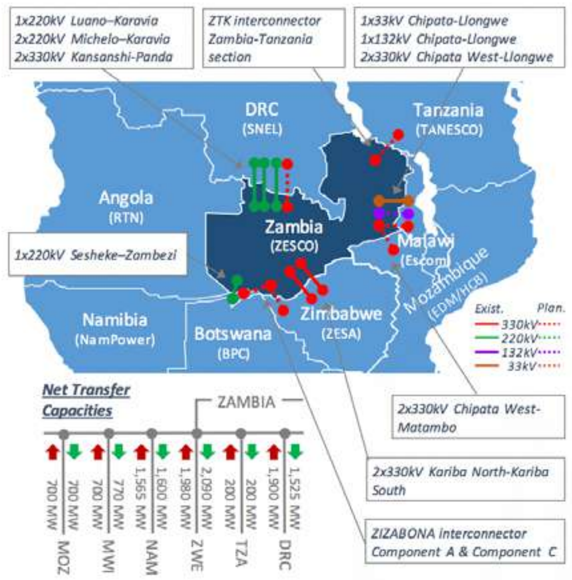


Fig. 5. Net Transfer Capacity expected between Zambia and the neighbouring countries in 2025 and 2030

Several questions arise on whether the generation-transmission system of Zambia is suitable for integrating large amounts of VRES. The key questions to be addressed are:

- Is the VRES generation alone able to meet the demand for electricity maintaining high standards of security of supply?
- Are the Zambian hydro power plants sufficiently flexible to cope with the variability of wind and PV productions?
- Is the transmission network suitable to integrate additional VRES capacity?
- What is the role of the interconnections?
- Is there a cost opportunity in VRES investments to increase export towards the neighbouring countries where the electricity generation cost is higher?

Hence, an integrated approach has been developed for the in-depth analysis of technical and economic constraints that could have an impact on the enhanced deployment of wind and PV sources in the Zambian interconnected system.

Methodology

The approach adopted to evaluate the optimal wind and PV capacities that can be installed in Zambia in 2025 and 2030 includes different phases in which, progressively, technical and economic constraints are integrated and analysed. Fig. 6 summarizes the integrated multi-phase approach applied. Starting from the data collection exercise and the setup of the reference scenarios (Task 1), a screening of the operating reserve constraints has been performed (Task 2), then the energy balance and economic constraints have been investigated (Task 3), closing with the analysis of grid constraints (Task 4).

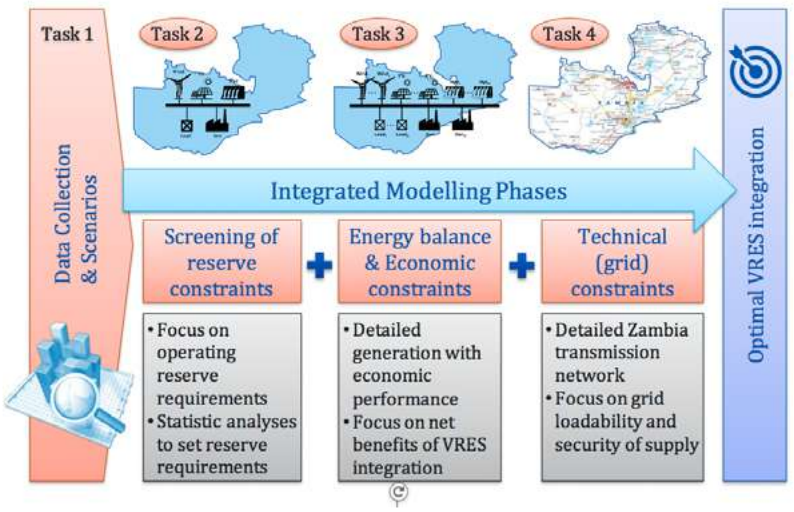


Fig. 6. Scheme of the integrated multi-phase approach

Task 2 allowed the assessment of the operating reserve requirements in presence of VRES generation. A hybrid approach combining probabilistic and deterministic methods has been developed for the dynamic sizing of the operating reserve. The main achievement of Task 2 was used to set-up the best market and reliability models to be used in the following tasks.

In Task 3, the simulation of the system operation on an hourly basis, with the optimal coordinated hydro-thermal dispatching performed to minimize the system costs, allowed to select the cost-effective VRES capacity mix that could be integrated in Zambia. A detailed model of the generation fleet allowed in-depth analyses of system operation considering both supply-demand and economic constraints. Finally, in Task 4, a grid impact study of the VRES capacity selected in Task 3 has been performed, examining the system adequacy and the grid loadability, to define the optimal amount from both a technical and economic point of view of wind and PV capacity that can be integrated in 2025 and 2030 in the Zambian electric power system, maintaining high standards of security of supply and improving the system resilience.

The analyses were performed through the application of state-of-the-art computational tools, developed by CESI, simulating the market mechanisms with a deterministic algorithm[2] and the system reliability with a probabilistic algorithm[3].

[2] PromedGrid software for market modelling. See www.cesi.it

[3] GRARE software (Grid Reliability and Adequacy Risk Evaluator). See www.cesi.it/grare

Wind and PV Integration Outlook

The study clearly shown that additional capacity from VRES can be integrated in the Zambian electric power system, on top of the projects already in the Country's pipeline (Annex 2). The following wind and PV capacities can be installed in Zambia in the mid- and long-term without the exploitation of the interconnections (scenario with isolated Country):

- up to 1,176 MW from PV and 1,200 MW from wind in 2025;
- up to 1,376 MW from PV and 1,400 MW from wind in 2030.

+34% VRES installed capacity can be integrated both in the mid- and long-term scenarios exploiting the interconnections and the power trading in the competitive market (scenario with interconnected Country):

- up to 1,576 MW from PV and 1,600 MW from wind in 2025;
- up to 1,826 MW from PV and 1,900 MW from wind in 2030.

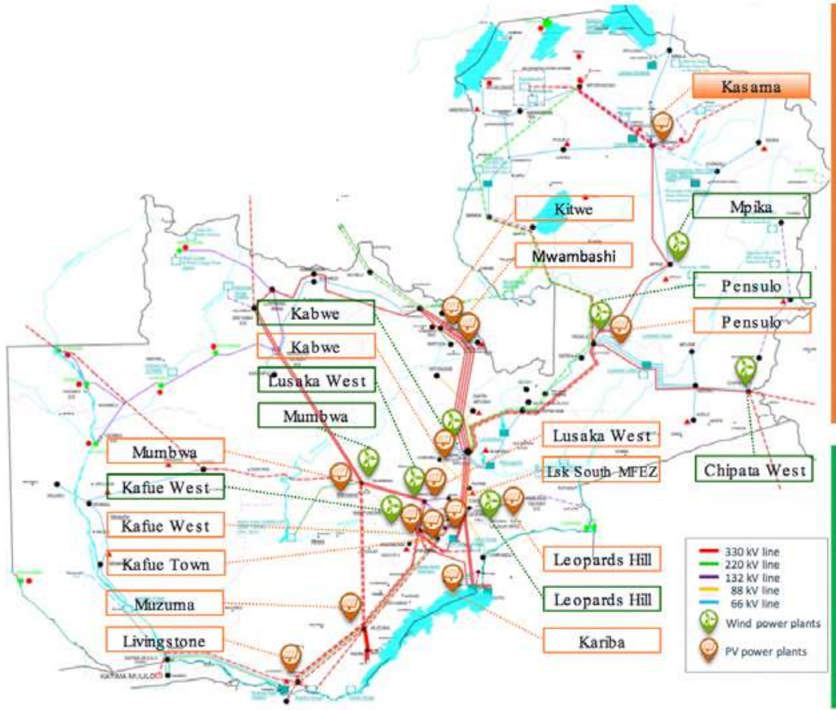
The above-mentioned capacity mixes allow to maximise the VRES penetration, resulting in an increase of the security of supply, and the economic benefits for the system. Due to the intrinsic features of the primary source, unlike wind, PV power production is concentrated in a limited number of hours and therefore it can benefit more of the hydropower flexibility. Consequently, PV technology is more affected by the lack of hydropower if low rainfall periods occurs. Therefore, despite PV technology is cheaper than wind technology, a balanced integration of both technologies is recommended since this diversification improves the system resilience.

Annex 1 shows the generation capacity mix that could be achieved in Zambia in 2025 and 2030: VRES installed capacity attains 47% of the total generation fleet in 2025 and it grows up to 51% in 2030 interconnected scenario. The hydropower renewable capacity is estimated to decrease from 84% recorded in 2019 up to 48% in 2025 and 44% in 2030. Only 5% is the remaining non-renewable capacity assumed in the mid and long term.

A high share of VRES penetration (i.e. the share of energy demand that can be supplied by VRES power plants) and a well-balanced energy mix can be achieved both in the mid- and in the long-term scenarios reducing the dependency from hydropower and increasing the security of supply.

Without power trading on the competitive market, about 27% VRES penetration can be achieved both in 2025 and 2030; 10% from PV and 17% from wind power plants. Hydropower production (15.6 TWh/year both in 2025 and in 2030) supplies 64% of the demand in 2025 and 56% in 2030. Up to 2.8 TWh/year PV and 4.8 TWh/year wind productions are expected within the year 2030. The exploitation of the power trading on the competitive market can increases the VRES penetration up to 36% both in 2025 and 2030 (13% from PV and 23% from wind power plants). In 2030, PV and wind productions achieve 3.7 TWh/year and 6.5 TWh/year respectively. VRES production curtailments are negligible and not very frequent (0.25% of potential production is the maximum value recorded in a mid-term scenario).

The wind and PV power plants already in pipeline were assumed to be connected to the grid in the substations listed in Annex 2. The additional capacity was distributed in the system considering the locations with higher wind/solar potential and strength of the National grid. Fig. 7 shows the location of VRES projects and the wind and PV capacities that can be integrated at each substation in isolated (ISO) and interconnected (INT) scenarios. Such capacities comply with the Zambian reliability standards (network loadability) and they allow the maximum VRES energy integration at the target years, minimizing production curtailments due to network overloads or over-generation phenomena. The figures recommended for specific substations should be subjected to further detailed studies with the aim of with the aim of identifying any static, dynamic and power quality issue and providing countermeasures needed for the full integration of the recommended VRES capacities, completing in this way the integration analyses.



Max PV capacity [MW]

S/S	25-ISO	25-INT	30-ISO	30-INT
Kabwe	140	140	190	140
Kafue Town	40	40	40	40
Kafue West	100	150	100	150
Kariba	90	90	90	90
Kasama	-	-	-	50
Kitwe	-	100	100	100
LeopardsHill	150	200	150	250
Livingstone	50	100	50	150
Lusaka West	-	100	50	150
Lsk South MFEZ	76	76	76	76
Mumbwa	170	220	170	220
Muzuma	220	220	220	270
Mwambashi	40	40	40	40
Pensulo	100	100	100	100
TOTAL	1,176	1,576	1,376	1,826

Max wind capacity [MW]

S/S	25-ISO	25-INT	30-ISO	30-INT
Kabwe	150	200	200	200
Kafue West	100	200	100	250
LeopardsHill	250	300	250	300
Lusaka West	150	200	150	250
Mpika	100	100	250	250
Mumbwa	170	220	170	220
Pensulo	280	280	280	330
Chipata West	-	100	-	100
TOTAL	1,200	1,600	1,400	1,900

Fig. 7. Wind and PV capacities that can be installed at each substation in the mid- and long-term

Security of Supply

The quantitative evaluation of static reliability of the electric power system (adequacy) proved that a progressive deployment of VRES generation will not worsen the security of supply both in 2025 and 2030. Wind and PV installed capacities calculated in the isolated scenario improve the security of supply, but they are not enough to meet the Zambian reliability standards without power import from the neighbouring countries. Hence, since additional VRES capacity is not cost effective, additional non-VRES flexible capacity shall be integrated to achieve the electrical self-sufficiency of Zambia: 100 MW power plants with 48% capacity factor by 2025 and 570 MW power plants with 30% capacity factor by 2030.

No risk of energy not supplied resulted from the interconnected scenarios, since the suitable exchange capacity between Zambia and the neighbouring countries help to balance the variability of wind and PV productions meeting the demand.

The Role of Hydropower

The great amount of hydroelectric generation, largely coupled with high capacity reservoir, owns a suitable operational flexibility that plays a key role in the development of wind and PV power production in Zambia. Climate change forces hydropower sector to cope with shorter rainy seasons and longer dry seasons. With the current generation mix, hydroelectric reservoirs must store huge volumes of water in short periods (the months earlier in the year) to make it available in the second half of the year (dry season) to meet the annual demand. A great seasonal stress of the reservoirs and the risk of lack of power at the end of the year arise, especially if consecutive dry years occur, as experienced in recent years. The integration of VRES, which peaking during the dry season when water availability is minimal, would reduce the reservoir's stress thanks to the good complementarity of hydro sources. On the contrary, VRES integration leads more stress in the daily operation of the hydro power plants with reservoir to cope with steeper ramps and deeper turn downs to meet the net load (load net of VRES production). Hydropower management must change from a demand-dependent approach to a VRES-dependent approach.

As highlighted in the average day 2030 (Fig. 8), without power trading on the competitive market (left side), a hydropower displacement from the daytime hours to the night hours is expected to make room to the wind and PV production. The integration of the Countries in the competitive market (right side in Fig. 8) allows a better integration of VRES and makes convenient the power import during the night, when the price of electricity in SAPP is low, and the power export during the daytime hours when the price in SAPP is higher than the price in Zambia. Import helps to meet the demand avoiding unserved energy, while export can allow the full exploitation of VRES avoiding production curtailments, mainly during the daytime hours. In this context, hydro power plants can operate to maximise VRES integration and the economic benefits of energy trade, exploiting the market price.

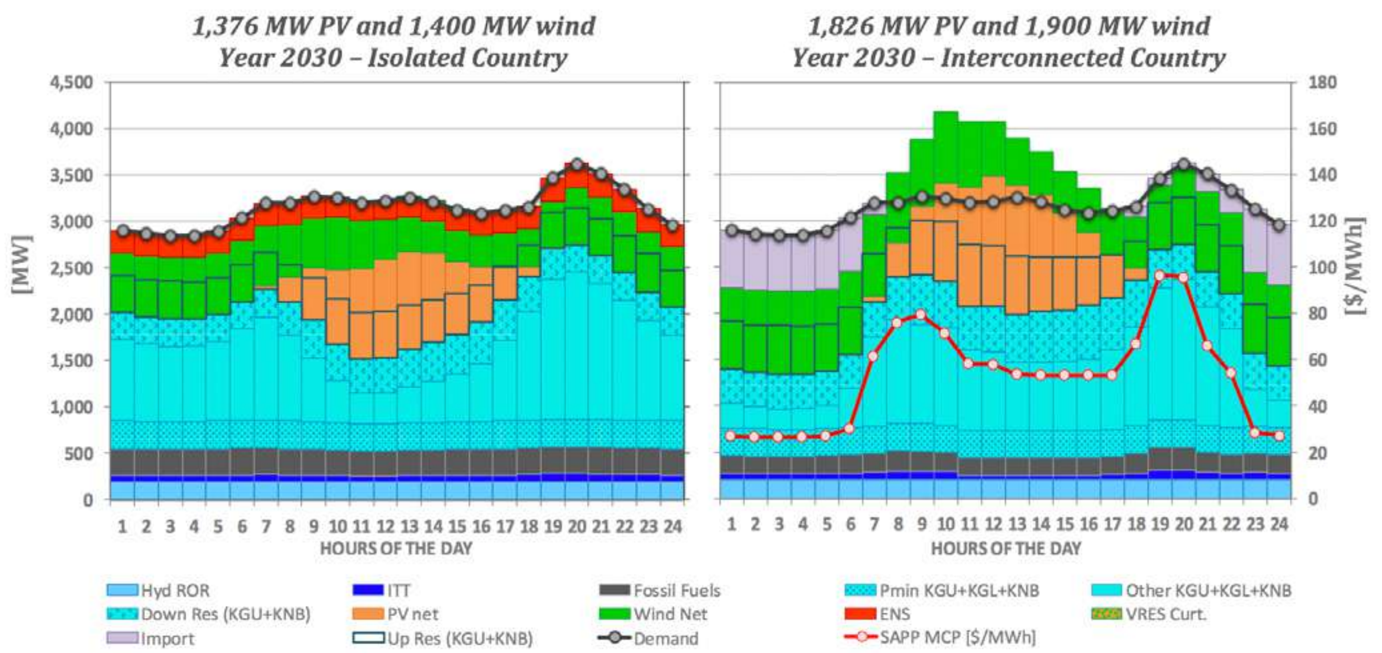


Fig. 8. 24-h power balance in the average day 2030. Isolated scenario, including firm export, is compared with the interconnected scenario including power trading

The Zambian generation system is closely dependent from hydropower and a very high exploitation of water for electricity sector will continue in the future. An energy diversification strategy in the electricity sector including technologies with low water use needs, such as wind and photovoltaic, could offer an important technical solution for Zambia that could strengthen both short- and long-term resilience of the power system and may face current and future water challenges related to climate change. VRES power plants are less impacted by climate change and they can face the lack of hydropower during drought periods. Additional VRES generation can be integrated under low rainfall scenario reaching about 40% VRES penetration in 2030. The lack of hydropower (-4.7 TWh/year in the dry year) can only be partially replaced by VRES generation; in fact, power import or additional programmable capacity is needed to meet the security of supply. On the contrary, under the wettest conditions (+6.8 TWh/year from hydropower), dispatch challenges with the neighbouring countries arise to avoid VRES production curtailments (up to 69% in 2025 and 37% in 2030) due to over-generation phenomena. The coordination with the neighbouring countries and the exploitation of the exchange capacity will be crucial to maximise the cost-effective use of resources both in Zambia and in SAPP.

The Role of the Interconnections and the Transmission Grid

The interconnections among countries will play an important role in large-scale integration of VRES throughout southern Africa. The integration of the markets and an effective cooperation among the countries will lead to the maximization of VRES penetration and the best use of energy sources at regional level, not only on a national basis. Interconnections improve the flexibility of the systems to cope with the variability and uncertainty of VRES production, maintaining the security of supply and avoiding over-generation phenomena.

The exploitation of the interconnections and the energy trade on the competitive market would increase VRES penetration in Zambia (+9%). The additional VRES capacity joined with the flexibility of its hydro power plants would allow Zambia to take market opportunities in SAPP. As shown in Fig. 8 (right side) on a daily basis, Zambia could import more power at low price overnight to increase exports during the daytime when the price in SAPP is higher. Benefits result also on a yearly basis, as highlighted in Fig. 9. Zambia is a net exporter between March and September due to SAPP marginal prices greater than those in Zambia; while it is a net importer at the beginning and at the end of the year, mainly due to the lack of hydropower. Up to 2.9 TWh/year import and 2.8 TWh/year export are expected in 2030 on the competitive market (2.0 TWh/year import and 3.5 TWh/year export in 2025), i.e. energy trade net of firm export. Firm export leads to additional 2.9 TWh/year.

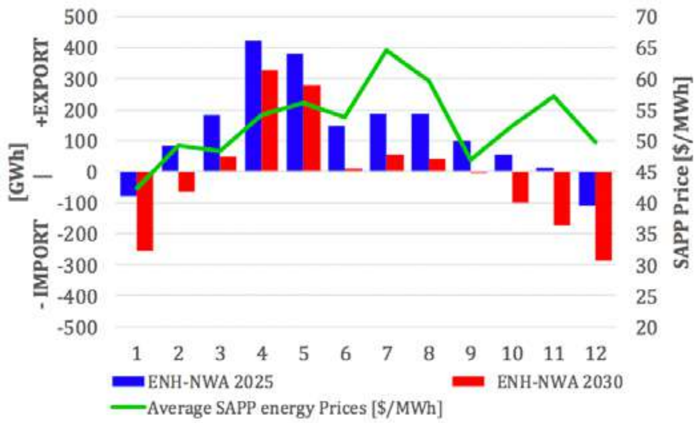


Fig. 9. Monthly import-export energy trading on the competitive market

Interconnections allow the exploitation of the renewable energy during both the wet years and the dry years to cope with the over-generation phenomena or lack of power. In the long-term scenario, +44% hydropower (+6.8 TWh/year) due to wet conditions leads to -80% import and +138% export; while -33% hydropower (-4.7 TWh/year) due to low rainfalls leads to +76% import and -64% export.

The system reliability impact study shown that the transmission network expansion plan outlined by ZESCO will allow the development of big amount of VRES generation both in the mid- and in the long-term. A few network reinforcements have been advised to avoid load shedding actions due to the demand growth, while no critical network overloads resulted from VRES power plants integration.

Worst-case scenario in the short term

The role of transmission grid is crucial for the development of great amount of utility-scale PV and wind projects. The high number of request for connections of VRES projects at the beginning of a renewable energy development programme and the relatively short time to market of these projects often clash with the times for realization and the uncertainties of transmission projects. In this context, the integration of great amount of VRES could be very challenging in the short-term. For these reasons the maximum wind and PV installed capacity that could be installed by 2022 with the current transmission grid (i.e. the worst-case scenario for the system development) have been assessed, providing a set of feasible solutions[4].

The current electric power system in Zambia will be able to integrate all PV projects in pipeline by 2022 (660 MW) reaching 736 MW installed capacity from PV power plants, even without energy exchanges with the interconnected countries on the competitive market (Isolated Country). Furthermore, 130 MW wind installed capacity could be integrated without relevant over-generation problems or network overloads (scenario “Current Roadmap”). Alternatively, without wind projects in 2022, up to 956 MW from PV can be integrated in the isolated scenario, while up to 1,006 MW in the interconnected scenario (scenario “100% PV”). The maximum PV installed capacity shall be reduced if additional wind projects want to be integrated into the system by 2022. Up to 496 MW from PV and 260 MW from wind could be integrated in the isolated scenario, while up to 596 MW from PV and 260 MW from wind could be integrated in the interconnected scenario (scenario “Balanced VRES mix”).

The VRES development plan 2020-2030 resulting from the study is shown in Annex 3.

Conclusions and Recommendations

Thanks to the excellent solar and wind potential in the country, the reduction of VRES investment costs, the flexibility of the hydro generation fleet and the on-going interconnection projects, wind and PV technologies can play a key role to reduce the dependence on water of the Zambian electricity sector. An energy diversification strategy based on the exploitation of wind and solar potential supported by additional programable generation and/or the exchange capacity from the interconnection projects can strengthen both short- and long-term resilience of the power system and may face current and future water challenges related to climate change.
The analyses clearly highlight that additional capacity from VRES generation can be integrated on top of the projects already in the Country’s pipeline. 27% VRES penetration can be achieved without power trading on the competitive market, both in 2025 and 2030.

[4] The Lusaka Transmission and Distribution System Rehabilitation Project also had to be included in the model to meet the demand expected in 2022 (19.6 TWh/year, including domestic demand, T&C losses and firm export to DRC and Malawi). This is the minimum system reinforcement required by the target year to allow the security of supply in the Lusaka area and the better network performance.

This optimal VRES integration results from 1,176 MW PV and 1,200 MW wind capacities in 2025 and from 1,376 MW PV and 1,400 MW wind capacities in 2030. However, additional non-VRES flexible capacity (e.g. hydropower) shall be integrated to achieve the electrical self-sufficiency of Zambia (about 600 MW maximum power with 30% capacity factor by 2030, in addition to the existing and committed non-VRES projects).

The existing and committed network interconnections with the neighbouring countries improve the flexibility of the system to cope with the variability and uncertainty of VRES production. Therefore, they can help Zambia to increase VRES exploitation maintaining high standards of security of supply and improving the system resilience in case of extreme climate conditions. VRES penetration levels up to 36% can be reached exploiting the power trading on the competitive market, both in 2025 and 2030. Up to 1,576MW from PV and 1,600 MW from wind capacity can be installed in 2025, while up to 1,826 MW PV and 1,900 MW wind capacities in 2030.

In the short term (2022) all PV projects included in the current roadmap could be integrated even if delays will occur in the transmission development plan. Up to 1,006 MW PV capacity could be achieved without any wind project, while it shall be reduced up to 596 MW if 260 MW wind capacity will be developed by 2022.

The achievements of the current study provided a preliminary estimation of the optimal wind and PV capacity that could be technically and economically integrated in the Zambian electric power system. Further static, dynamic and power quality analyses outside the scope of the current study are required and a specific feasibility study for each wind and PV project that will be integrated in the system is recommended.

Moreover, innovative strategies for the control and operation of VRES power plants are recommended to maximise VRES exploitation and maintain a secure operation of the electric power system. These strategies can counterbalance critical situations due to VRES intermittency, reducing the risk of production curtailments due to over-generation phenomena (i.e. when the generation available in the system is higher than the demand). Two actions should be considered during the VRES integration process to reduce the risks concerning the power system operation in presence of a big amount of VRES power plants:

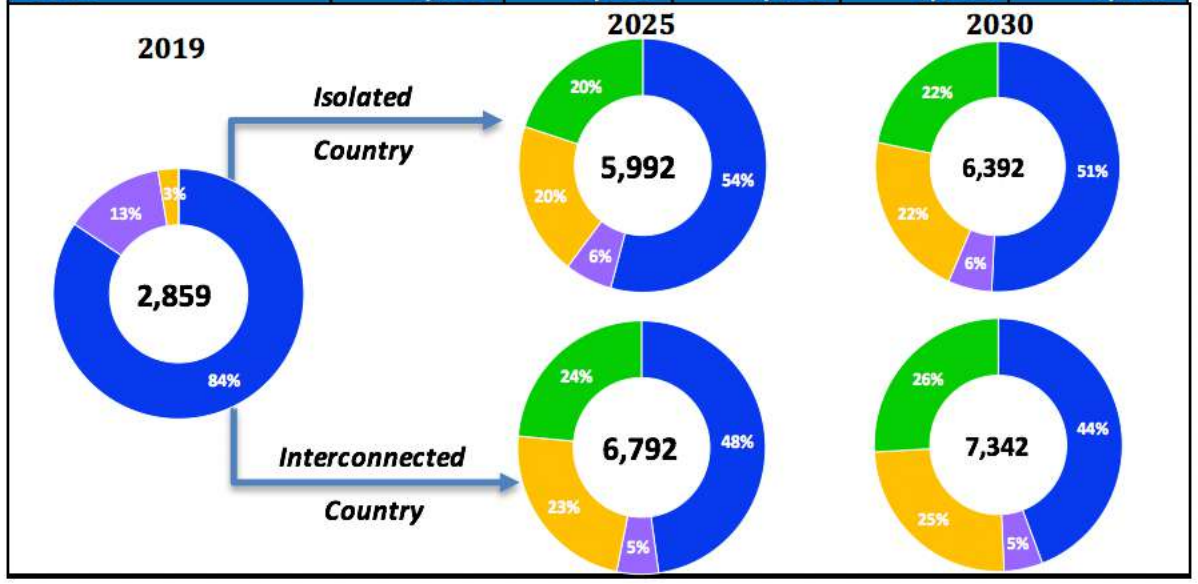
- A central control room for VRES power plants, with clusters of different plants, would allow a better forecast of generation lowering forecast errors and minimizing reserve need. A greater penetration of VRES generation is possible if the uncertainty of its prediction is reduced.
- Participation of VRES to ancillary services markets, for instance availability to decrease their production (downward reserve) to ensure the stability of the power system. In this way, VRES downward reserve can replace the hydro one.

These actions are usually addressed during the short-term and real-time operation of the power systems. Experiences in advanced markets with high VRES penetration show significant rooms for reducing VRES energy curtailments when appropriate real time control systems are put in place.

Annex 1

Capacity mix in 2019 and estimated at years 2025 and 2030 in isolated (ISO) and interconnected (INT) scenarios with enhanced VRES deployment (MW)

Source	2019	2025 ISO	2030 ISO	2025 INT	2030 INT
Hydropower	2,413	3,246	3,246	3,246	3,246
Fossil	370	370	370	370	370
PV	76	1,176	1,376	1,576	1,826
Wind	-	1,200	1,400	1,600	1,900
Total	2,859	5,992	6,392	6,792	7,342



Annex 2

PV and wind projects in the pipeline

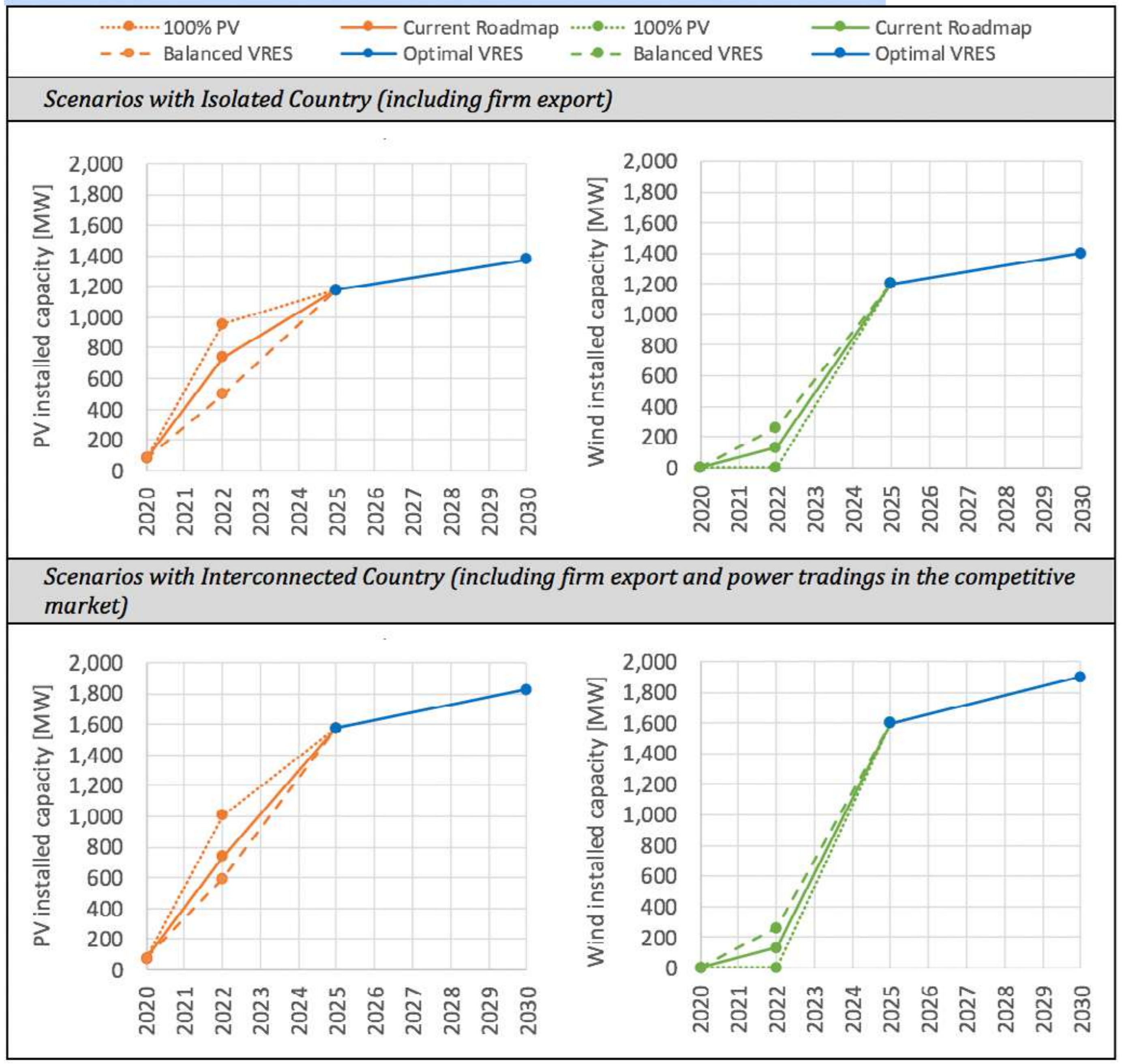
PV Project	Status	Pmax [MW]	Substation
Bangweulu	existing	47.5	LS-MFEZ
Ngonye	existing	28.2	LS-MFEZ
Bulemu West	committed	20	Kabwe
Bulemu East	committed	20	Kabwe
Solar one	committed	20	Kafue Town
Solar Two	committed	20	Kafue Town
Garneton North	committed	20	Mwambashi
Garneton South	committed	20	Mwambashi
Kanona	committed	100	Safal
Muzuma	committed	100	Muzuma
Green Field	committed	50	Leopards Hills
Globeleq project	candidate	100	Leopards Hills
MGC project	candidate	100	Mumbwa-Nambal
Hive project	candidate	90	Kariba North Bank
TOTAL		735.7	

Wind Project	Status	Pmax [MW]	Substation
Serenje	candidate	130	Pensulo
TOTAL		130	

Annex 3

VRES development plan 2020-2030

Different short-term paths to achieve the optimal VRES capacity mixes in 2025 and 2030 have been highlighted to provide a set of feasible solutions; within the range of solutions found in the short term, greater PV integration implies a lower wind integration and vice versa.



1 BACKGROUND

The electricity sector in Zambia is overseen by the Ministry of Energy (MOE), which provides policy guidance, and it is dominated by the vertically integrated utility company ZESCO Limited (ZESCO). The utility is fully owned by the Government of the Republic of Zambia (GRZ) through the Industrial Development Corporation (IDC), the holding company for most of state-owned enterprises in Zambia. ZESCO owns and operates over 80% of the generation, transmission, and distribution assets in the country and supplies electricity to all grid-connected consumers, except for some mining consumers in the Copperbelt Province, which are served by the Copperbelt Energy Corporation (CEC). The latter is an independent transmission company that purchases bulk power from ZESCO and supplies the mines, smelters and refineries in the Copperbelt Province by means of its own transmission and distribution network. Other Independent Power Producers (IPPs) operates in the electric power sector under long-term Power Purchase Agreements (PPAs) with ZESCO: Maamba Collieries Limited (MCL), Itezhi-Tezhi Power Corporation (ITPC), Ndola Energy Company Limited (NECL) and Lunsemfwa Hydro Power Company Ltd (LHPC).

The electricity sector includes also the independent Energy Regulation Board (ERB) created under the Energy Regulation Act of 1995 to balance the needs of the consumers with the need of the undertakings. It is responsible for licensing, tariff setting and quality of supply for all segments of the electricity sector. Furthermore, about the rural areas of the Country, the Rural Electrification Authority (REA) is the institution responsible for providing electricity infrastructure to all rural areas using appropriate technologies to increase access to energy, productivity and quality of life.

Zambia is an active member of the Southern African Power Pool (SAPP), the cooperation of the national electricity companies in southern Africa with the scope to optimize the use of available energy sources in the region and enhance energy exchange between countries facilitating the development of a competitive electricity market in the Southern African Development Community (SADC).

Historically, the GRZ focused on the electricity production from hydropower that is the most important energy source for the Country. However, the energy crisis of 2015/2016 pushed the GRZ to diversify the generation mix. With Vision 2030 and National Development Plans, the GRZ is focused on diversifying its energy mix with renewable sources other than the hydroelectric source to complement the large base of hydro resources development. A diversified mix of energy resources allows ensuring the security of supply and contributes to mitigate climate change. In this regard, the GRZ through the MOE launched the initiative "REFiT Strategy" to accelerate private investments in small- and medium sized renewable energy projects in order to open the power sector ever more developing a renewable energy subsector to supplement the large hydro energy sources which have been negatively affected by climate changes. Zambia is rich in renewable energy resources: the identified potential includes hydropower in excess of 6,000 MW, 5.5 kWh/m2/day of annual average daily radiation, average wind speed at 130 m between 7 and 8 m/s and 80 hot springs to be exploited for geothermal production. This potential can be exploited to meet the growing internal demand (expected CAGR 3.8% in the period 2019-2030) and increase energy trading opportunity with the neighbouring countries.

The existing power generation capacity is about 2.9 GW. Hydropower plays an important role in the existing Zambian generation fleet with about 84% of total installed capacity and it will continue in the future; about 13% of total capacity is from coal and fuel oil power plants while 2.6% from PV power plants. Additional 80 MW gas turbine installed capacity is operated by CEC for emergency power supply to its mine customers.

In this context, an exploitation plan towards a diversification strategy of the energy mix including low water consumptions technologies, such as wind and photovoltaic, will address the consequences of climate change (more frequent low rainfall periods and droughts) improving the resilience of the power system. Moreover, a better water exploitation during the year is possible thanks to the complementarity of wind and solar sources with hydro sources; wind and solar radiation are greater during the dry season and lower during the wet season when more water is available for hydropower. Wind and photovoltaic integration could allow additional technical-economic benefits as a faster commissioning of new capacity with more opportunities for Independent Power Producers (IPPs) investments, new opportunities for the Zambian manufacturing and service sectors, decentralization of the power supply structure thanks to their availability in different regions of the country (wind and solar sources are more diffused than hydropower source needed to big hydropower plants located on large rivers and lakes).

The Zambian renewable energy potential, together with the decreasing levelized cost of electricity (LCOE) from wind and photovoltaic technologies (competitive in the mid- and long-term with the cheapest technologies) will allow attractive perspectives for private investors. Technical investigations are needed to identify possible criticalities both about the operation of the power system and the network reinforcements needed to the connection of new VRES power plants in accordance with the security criteria adopted by the system operator.

2 SCOPE OF WORK

The objective of this activity addresses the integration of variable renewable energy sources (VRES) such as wind and solar into the Zambian electric power system. Increasing penetration of wind and photovoltaic technologies was analysed in the mid- and long-term (horizon years 2025 and 2030) keeping the reliability, integrity and efficiency of the electric power system.

CESI (hereinafter called the "Consultant"), as an independent center of expertise and global provider of technical services to customers throughout the energy value chain, carried out a technical study to meet the following specific objectives, which collectively form the basis of the scope of work:

- Assessment of the optimal technical-economic amount of VRES generation (wind and PV) that is possible to integrate in the Zambia without affecting the reliability, integrity and efficiency of the whole electric power system;
- Evaluation of the operating reserve requirements in presence of VRES generation and analysis of generation flexibility identifying possible constraints that can limit the VRES integration;
- Execute market-based analyses with an optimal coordinated hydro-thermal scheduling of the generation fleet, to assess the benefits for Zambian electric power system due to the integration of wind and solar energy (e.g. interaction between hydropower and VRES generation during the year, impact of droughts on generation fleet operation, security of supply during low rainfall periods, increasing energy export);
- Preliminary network impact study based on the system adequacy (security of supply) and the grid loadability to evaluate the adequacy of the transmission system integrating new wind and PV capacities and propose network reinforcements needed to maximise their exploitation.

Qualitative considerations on system resilience improvement in presence of extreme events were included in the study. Furthermore, additional observations were provided about the benefits of innovative VRES power plants control to better exploit resources.

3 METHODOLOGY AND EXPECTED OUTCOMES

The study performed to evaluate the optimal VRES energy integration that could be achieved in the mid- and long-term in the Zambian electric power system has been structured in five tasks, as detailed in Figure 3.1:

- Task 1: Data collection and set up of reference scenarios
- Task 2: Analysis of reserve requirements and generation flexibility identifying possible constraints for the VRES integration
- Task 3: Optimal coordinated hydro-thermal dispatching in presence of VRES
- Task 4: System reliability impact study
- Task 5: Conclusions, Recommendations and Executive Summary

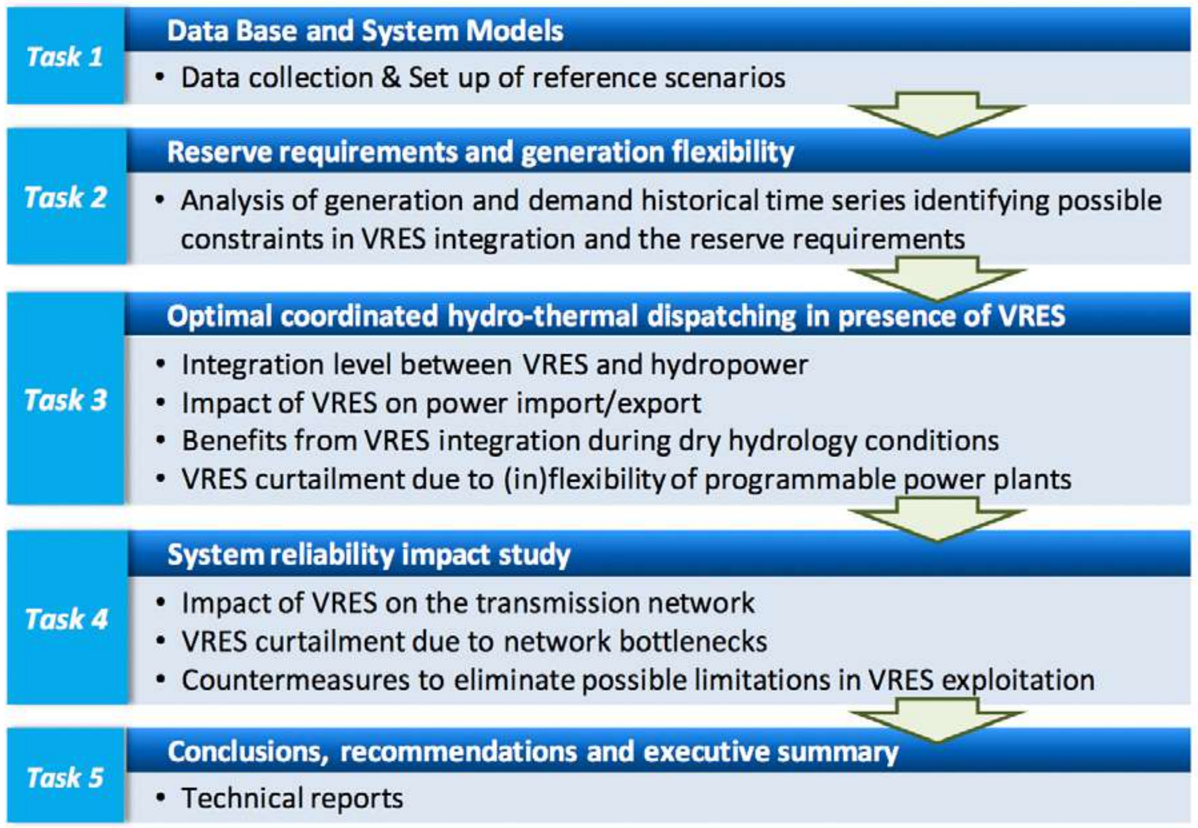


Figure 3.1 – Overall work process

Task 1 allowed the definition of reference scenarios and the collection of all data needed to build proper models of the Zambian electric power system.

Task 2, Task 3 and Task 4 represents the phases of the integrated methodology adopted to assess VRES installed capacity complying with technical-economic constraints (Figure 3.2).

Task 2 allowed the assessment of the operating reserve requirements in presence of VRES generation. The main achievement of Task 2 was used to set-up the best market and reliability models to be used in the following tasks. The methodology developed in Task 2 to assess the operating reserve requirements in presence of large amount of VRES was applied in the hourly dispatch simulated in Task 3 and Task 4, in which more in-depth technical-economic analyses incorporating the costs of generation technologies (Task 3) and the reliability of transmission system (Task 4) were performed. The economic constraints applied to a detailed generation fleet model in Task 3 allowed to select the cost-effective VRES capacity mix that could be integrated in Zambia. Later, in Task 4, a grid impact study of the optimal VRES capacity selected in Task 3 was performed to define the wind and PV capacity that can be included in the Zambian electric power system (for the years 2025 and 2030), giving economic benefits for the whole system, but without affecting the system security.

Conclusions and recommendations for the integration of variable renewable energy in the National electric system of Zambia have been provided in Task 5 with the final report and executive summary.

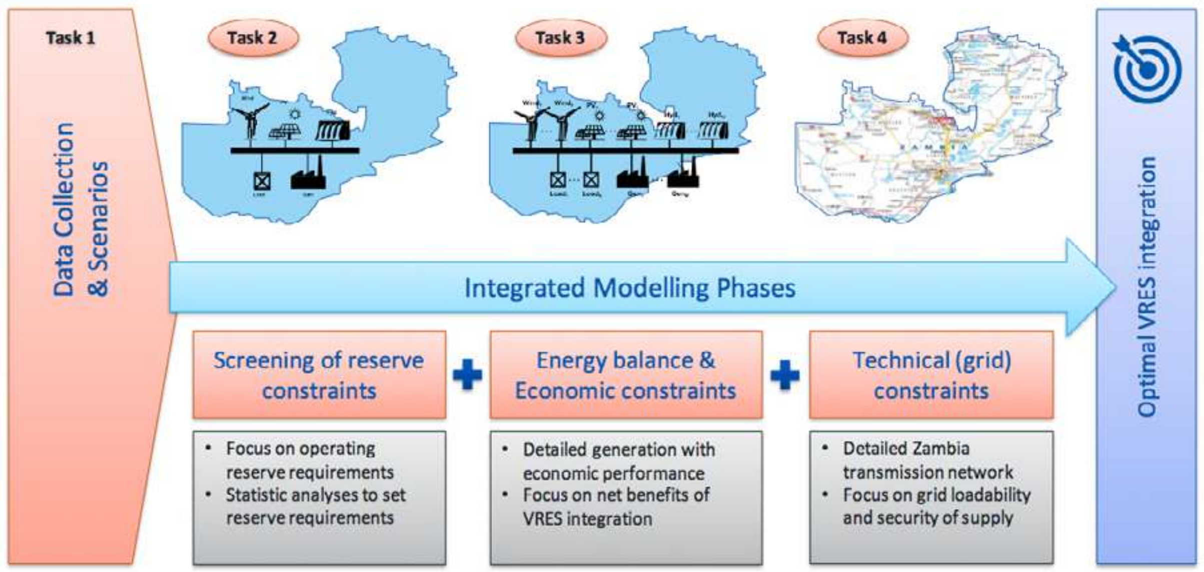


Figure 3.1 – Overall work process

The description of the expected results of each task, with the explanation of the methodology that was adopted to obtain these outcomes, is highlighted in the following sections.

3.1 Task 1 – Data collection and set up of reference scenarios

The objectives of Task 1 are the data collection on the electric power system in Zambia, the definition of methodology and assumptions for technical studies, and finally the set-up of database suitable for technical analyses. The database includes information about the following topics:

- Electricity demand forecast, both in term of annual energy demand and power consumptions during peak load condition;
- Technical characteristics of each generation unit in operation, under construction or committed;
- Transmission network models;
- System reliability criteria and methodology to evaluate reserve requirements in presence of VRES;
- Data for economic evaluations as fuel prices, costs for VRES technologies and standard investment costs for network components.

An assessment of the levelized cost of electricity from wind and photovoltaic technologies has been carried out proving an indication of their competitiveness. LCOE forecast is crucial to define the optimal VRES capacity – from an economical point of view – that can be integrated in the electric power system. Wind and PV power plants expected productions have been considered together with the investment costs, operating costs and lifetime of these technologies in order to provide a qualitative assessment of LCOE.

The definition of the basic assumptions and the reference scenarios is a very important stage of the activity because affect the outcome of the study. Together with the ZWG, the relevant scenarios were identified in terms of:

- Target years: two horizon years 2025 and 2030;
- Demand forecast: a demand growth pattern based on a business as usual approach was the reference for the analysis and it was applied at each scenario;
- Hydrology conditions: average hydrology and low hydrology to assess the impact of drought on the generation fleet operation;
- Network structure expected in the target years and needed for the analyses object of Task 4;
- Generation capacity according to the last most recent generation expansion plan of the Country. Existing, under construction and committed power plants make the reference generation fleet of the study;
- Availability of interconnections with neighbouring countries and expected power exchanges.

Expected results of Task 1

- The database that includes the network model, the load and generation fleet for all scenarios to be considered in the study;
- The scenarios to perform the simulations;
- The Inception report with a summary of the assumptions adopted in the analyses.

3.2 Task 2 – Analysis of reserve requirements and generation flexibility

Starting from the system model prepared in the Task 1, an assessment of the operating reserve requirements and generation flexibility identifying the constraints that could limit the integration of the VRES generation were performed. More in detail, the aim of this task is to quantify the operating reserve with a high wind and PV penetration and different capacity mixes, analysing also the ability of the programmable generation fleet to provide that reserve to integrate the VRES power plants in the electric power system.

This task is based on the analysis of the yearly profiles of load and generation at the two target years defined in Task 1. In particular, the curves of historical data were adapted to the horizon years taking into account the expected evolution of the demand, the possible power exchange with neighbouring countries (import and/or export) and the development of the new generating units.

More in detail, the analyses included in this task can be summed up as follow:

- Investigation of the demand profile (hourly time-series) and load forecast error (difference between actual demand and day ahead forecast).
- Investigation of the energy exchange with the neighbouring countries due to PPA expected for the target years. The exchanges were treated as an additional demand (in case of export), or as an additional production (in case of import)
- Analysis of the historical wind speed measures to assess the wind power production time-series and the expected distribution of the wind production forecast error through a statistical approach;
- Analysis of the historical irradiation data to assess the PV power production time-series and the expected distribution of the PV production forecast error through a statistical approach;

Based on the above-mentioned information, the following outcomes were investigated:

- an estimation of the operational reserve (due to the load quantity and the expected renewable production) to be covered by the programmable (hydro and thermal) power plants. In the analysis, the Consultant assumed that the reserve was entirely supplied by the programmable units within Zambia. The hypothesis is in fact that it is not possible to share the reserve across the borders;
- considerations about the flexibility of the power plants, identifying possible critical situations that can occur during the year and the way to resolve them, for example with a modulation of the production of the hydro power plants with reservoir.

At this stage an estimation of the reserve to be assured in the power system for several wind and PV capacity mixes was investigated in detail, as well as an analysis of the impact of the flexibility of the programmable power plants. At this stage the analyses were carried out neglecting the network constraints, focusing on the ability of the generation fleet to keep balanced the system and to provide the necessary flexibility and reserve to allow the development of VRES generation.

The main achievement of Task 2 was used to set-up the best market and reliability models to be used in the following tasks and they were verified through more in-depth technical-economic analyses incorporating the costs of generation technologies (Task 3) and the reliability of transmission system (Task 4).

Expected results of Task 2

- An estimation of the operational reserve needed to assure the security of the system, for several combinations of wind and PV capacities;
- Analysis of the flexibility of the programmable (hydro and thermal) power plants, with the identification of possible constraints that can limit the development of VRES generation.

3.3 Task 3 – Optimal coordinated hydro-thermal dispatching in presence of variable renewable energy sources

The aim of this task is to evaluate the impact of VRES integration on the Zambian system operation over one year simulating an optimal coordinated hydro-thermal scheduling. Task 3 allows deterministic simulations of the generation system operation, hour by hour, with an optimal hydropower scheduling for the best use of sources available in the electric power system.

The simulation of the Zambian power system operation was performed by means of a day-ahead market simulator developed by CESI, named PromedGrid. PromedGrid simulates the dispatching optimization of hydro-thermal generation in meshed electric power systems with a high level of detail. The quadratic fuel consumption curves and the flexibility constraints for thermal generation units are simulated, like zonal reserve margin constraints and transfer capacity among areas/countries. Furthermore, a detailed hydro generation model is included to simulate the optimal hydropower dispatching. The model includes data for reservoir, pumped-storage and run-of-river hydro power plants. The main technical data concerns the minimum/maximum power, the efficiency of the hydraulic/electric energy conversion, the reservoir volume and the expected hourly natural inflows along with the initial and final amount of water in each reservoir for the simulated annual period. It is also possible to specify the natural inflows for each week as well as the minimum and maximum amount of water in each reservoir.

The program was used to simulate the hourly operation for the selected target years in the defined scenarios; 8,760 hours were simulated for each year. The power system constraints handled in the procedure were the integral limitations of the hydro plants water reservoirs, the transfer capacity of the interconnection corridors between countries and the technical and economic characteristics of generation units.

In order to assess the VRES generation impact on the Zambian system operation for each target year, PromedGrid simulations were performed for two basic cases:

- Scenarios with new VRES production: several wind and PV capacity mixes were simulated to assess the most suitable one for different operation conditions (e.g. average water condition, dry year, max export, etc.);
- Scenario with the existing VRES production: scenario with only wind and PV power plants already in service; it is needed to evaluate only the impact of the new wind and PV capacity in the system evaluated in the previous scenarios;

Each scenario has been analysed both with an isolated Country model and with an interconnected Country model in which a proper equivalent model of the neighbouring countries has been performed.

The generation fleet of Zambia has been modelled in detail together with the net transfer capacities between the countries (only in the interconnected scenario). Benefits of increasing wind and photovoltaic integration have been assessed to meet the optimal technical-economic amount of VRES sustainable for the system in the two analysed years in different hydropower and import/export conditions.

The following simulations were proposed:

- New wind and PV capacity included in the system to meet the National demand without import from the interconnected Countries (Isolated model of Zambia)
- Additional wind and PV capacity included in the system to increase the VRES penetration exploiting the export capacity towards the interconnected countries where the electricity price is higher.
- Low hydrology scenario useful to evaluate the impact of droughts on the system operation and the benefits of wind and PV generation in this condition (droughts are more and more frequent).

Wind and solar radiation are higher during the dry season and lower during the wet season when more water is available for hydropower. Therefore, the complementarity of wind and solar sources with hydro sources has been investigated highlighting the impact on the over-generation phenomenon and associated production curtailment, on water exploitation and on power exchanges between countries.

Comparing the energy production in scenarios with and without new wind and PV capacity, it is possible to evaluate in quantitative terms the displaced energy for different used technologies, the differences in electricity production costs and the marginal costs.

Expected results of Task 3

- Optimal VRES capacity that can be integrated in Zambia - from a techno-economic point of view - to meet the National demand and also to increase/decrease the export/import energy;
- VRES penetration and integration with hydropower during one-year simulation, also with effect during dry hydrology conditions;
- Possible hydropower constraints during the year, over-generation or lack of power phenomena.

3.4 Task 4 – System reliability impact study

The objective of this task was to assess the impact of variable renewable generation on the reliability, efficiency and security of the Zambian electric power system. If adverse impacts were identified, mitigating measures have been proposed and evaluated in terms of their costs.

Unlike Task 3, the current task allows annual base analyses of system operation with probabilistic approach (Monte Carlo method), with focus on the transmission network (330, 220, 132, 88, 66 kV network models have been analysed) and the security of supply. The VRES capacity assessed in the reference scenario from the simulations performed in Task 3 was integrated in the National grid analysing the network loadability and the system reliability with probabilistic analyses.

More in detail, the objectives of the system reliability impact study are to:

- check if the system follows the applicable Zambian electric reliability standards also in presence of variable RES. An evaluation of generation and transmission network adequacy has been carried out by means of the reliability indexes (EENS, LOLE and LOLP) to assess the security of supply level, without and with new VRES power plants;
- estimate the risk of VRES production curtailment due to network congestions, highlighting the amount of curtailed energy from VRES power plants and the distribution of these curtailments over the year. The unavailability of system elements (generation units and transmission equipment) and the random availability of VRES (wind especially) have been considered in a probabilistic way;
- propose network reinforcements, in addition to those already decided by the ZWG for the horizon years, needed to maximise the VRES integration if adverse impacts of VRES generation on electric power system were highlighted. An assessment of the network reinforcements costs was carried out considering both capital and operating costs over a proper period of operation (e.g. 40 years).

The technical criteria for evaluating the security of supply and the impact of RES power plants on the reliability of the system shall be based upon the current planning and operating practices adopted in Zambia and specifically in the Grid Code requirements.

1. First, the probabilistic approach allows estimating the annual value of Expected Energy Not Supplied (EENS) due to the unavailability in the generation system (both programmable and variable power plants).
2. Second, the reliability analysis allows to identify the network bottlenecks limiting the production from VRES or, as alternative, the risks of VRES production to be curtailed due to network congestions. The analysis allows identifying the network reinforcements needed to ensure the secure evacuation of electricity produced by VRES.

For the reliability analysis the GRARE software (Grid Reliability and Adequacy Risk Evaluator) has been used. The GRARE simulation tool has been developed by CESI on behalf of the Italian TSO (Terna) and is widely used for reliability analyses in presence of substantial penetration of VRES generation in Europe, the Arab Countries, Latin American countries and some African countries (Algeria, Egypt, Ethiopia, Kenya, Libya, Morocco, South Africa, Sudan and Tunisia). In the framework of this study, the GRARE software tool has been used to perform a quantitative assessment of the static reliability and adequacy of the Zambian interconnected power system. The reliability analysis is carried out in a probabilistic way by using the Monte Carlo approach to simulate the inherent probabilistic nature of the composite generation and transmission system behaviour.

The method simulates the performance of the system in an assigned year by the generation of a large quantity of scenarios, determined in a random way, on the basis of which the operating policies are applied. Normally, hundreds of years are considered, each one with a different system configuration.
GRARE software has dedicated models for wind and PV productions which consider the random availability of these resources. The models of wind and PV power plants are based on the following assumptions:

- the generation of the various power plants is statistically independent;
- the production of a single power plant and its statistical variability is modelled by typical probability distribution of weekly production that are appropriately discretized; the combination of different types of weekly diagrams allow for modelling of monthly and seasonal variability of wind production.

- the statistical variability of the production of a single wind or solar power plant is modelled by means of an appropriate probability density distribution of deviations from average values and assuming that sites are statistically independent one another.

Zambian electric power system includes a substantial share of hydro production. Hydro power plants play an important role to cover annual demand; therefore, a suitable model of these units was created to simulate the electric power system operation.

For this task a full model of Zambian electric power system has been used with a detailed representation of generation fleet, load distribution and transmission networks. An equivalent model of the neighbouring countries has been defined to simulate both PPAs and power trading on the competitive market.

The simulation model linked to the Monte Carlo method allows estimating the values of the main operating results and risk indexed such as:

- generators production (for each generator: produced energy, yearly hours of activity, any average incremental cost, non-produced amount due to transmission restrictions);
- data regarding network congestion (for each critical line: hours/year in which re-dispatching and marginal gain is required);
- the energy exchanges between the areas constituting the system;
- the Expected Energy Not Supplied (EENS) and other reliability indexes such as Loss of Load Expectation (LOLE) and the Loss of Load Probability (LOLP)
- risk of RES generation curtailment due to lines/transformers overloads in the network or over-generation phenomena.

The power system operation has been simulated for both reference years without and with the new VRES generation to catch the impact of the additional VRES capacity in the system.

Expected results of Task 4

- assessment of the generation and transmission network adequacy of the Zambian power system, without and with new VRES power plants, by means of the reliability indexes (EENS, LOLE and LOLP);
- the evaluation of the impact of the new VRES power plants on the reliability, efficiency and security of the power system for each target year object of the analysis;
- the main network reinforcements needed to maximise the VRES integration keeping the compliance with Zambian reliability standards.

3.5 Task 5 – Conclusions, recommendations and executive summary

On the basis of the activities carried out, a set of clear recommendations for the integration of the new VRES generation expected for the target years were provided. The recommendations cover but they are not limited to the following:

1. Assessment of the optimal amount of variable renewable generation that it is possible to integrate in the Zambian electric power system;
2. Impact of the expected renewable generation on the reliability of the power system and security of supply;
3. Impact of droughts on the electric power system operation and interaction between programmable generation (i.e. hydropower, fossil fuels, etc.) and VRES generation during the year;
4. Expected impact of energy export on the optimal amount of wind and PV generation that can be integrated in Zambia;
5. Recommendations for system reinforcements and upgrades, listing the reasons for the upgrade and their associated costs.

If violations of operation limit such as network bottlenecks occur, the Consultant provided the mitigation solutions to ensure a secure evacuation of electricity produced by VRES generation. The technical solution can be in form of corrective actions by which the system condition is restored to comply with operation limits or as transmission network reinforcements.

Expected results of Task 5

- Final Report with conclusions and recommendations for the integration of variable renewable energy in the National electric system of Zambia;
- Executive summary.

4 VRES INTEGRATION STUDY REPORTS DESCRIPTION

The results of VRES Integration Study have be provided by means several Reports as listed hereunder:

- **Inception Report** which includes the Task 1 of the project:
  - Data collection, including demand trends, generation expansion plan and transmission assets expected in the target years. The data collection enabled the development the models of the Zambian power system expected in 2025 and in 2030;
  - Description of the assumptions to be assumed for the analyses and the potential issues identified for the study;
  - Description of the expected results of each task and the methodology that were adopted to obtain these outcomes.

- **Technical Report N1** including the results of Task 2 of the project:
  - Operation reserve requirements in presence of VRES generation;
  - Analysis of generation flexibility to meet wind and solar production variability and uncertainty.

- **Technical Report N2** including the results of Task 3 and Task 4:
  - Optimal economic amount of VRES capacity that can be integrated in Zambia considering an optimal coordinated hydro-thermal dispatching in presence of variable renewable energy sources (Task 3);
  - System reliability impact study focused on the system adequacy and grid loadability (Task 4).

- **Final Report** which includes the overall results of the VRES Integration Study.

- **Executive Summary** which includes a brief of the outcomes of the VRES Integration Study, the conclusions and the recommendations to exploit the VRES potential in Zambia.

TASK 1 – DATA COLLECTION AND SET UP OF REFERENCE SCENARIOS

The data collection, together with the identification of the most important assumptions of the study and the most interesting scenarios, has been carried out with the close collaboration of the ZWG. The present section refers to the Task 1 of the study and includes the following information:

- Description of the analysed scenarios;
- Data collection, including demand trends, generation expansion plan and transmission assets expected in the target years. The data collection allowed the development of the models of the Zambian electric power system foreseen in the horizon years 2025 and 2030;
- Description of the main assumptions assumed for the analyses and the potential issues identified for the study.
- Description of the methodology to be adopted to assess the optimal VRES integration in the mid- and long-term scenarios.

5 SCENARIOS

The long-term analysis of VRES generation integration into the power system of Zambia is carried out for the target years 2025 and 2030, two import-export conditions and three water availability conditions (Figure 5.1). Scenarios with the isolated Country were the benchmark cases because they are useful to evaluate the electrical self-sufficiency of Zambia including VRES power plants in the electrical power system. These scenarios were analysed considering the average hydrological condition (normal water availability), the dry hydrological condition (low water availability) and the wet hydrological condition (high water availability). Additional scenarios were analysed considering the interconnected Country to analyse the opportunity to export power toward the neighbouring countries, under three hydrological conditions.

Figure 5.1 – Scenarios configuration

The following scenarios have been analysed for each target year:

√ **Enhanced VRES deployment with normal water availability:** it is the reference scenario with an enhanced deployment of wind and PV capacity under normal (average) water conditions. The following basic assumptions have been adopted:

- demand growth pattern based on a business as usual approach;
- hydropower availability according to the average values from historical data (normal availability). Current water resource management policies continue, if there will be no major changes in the Country priorities and policies, so that normal circumstances can be expected to continue unchanged;
- optimal technical-economic amount of wind and PV generation that can be integrated in the Zambian electric power system able to keep the reliability, integrity and efficiency of the system;
- Existing, under construction and committed programmable power plants (hydro and fossil fuels generation fleet).

A gap analysis between the ENH-NWA scenario and one scenario including only the existing VRES power plants (EVR-NWA scenario: Existing Variable RES with Normal Water Availability) has been carried out to assess the impact of additional VRES capacity in the Zambian electric power system.

- √ **Enhanced VRES deployment with low water availability**: it is the second scenario with an enhanced deployment of wind and PV capacity. The scope of this scenario is to analyse the impact of droughts on the system operation highlighting the benefits of wind and solar generation and the improved resilience of the system in this condition. The following basic assumptions have been adopted:

- demand growth pattern based on a business as usual approach;
- low availability of water for hydropower due to climate changes that cause low rainfall (the amount of energy expected during the dry year has been calculated from the hydrological historical data provided by the ZWG);
- optimal technical-economic amount of wind and PV generation that can be integrated in the Zambian electric power system;
- Existing, under construction and committed programmable power plants (hydro and fossil fuels generation fleet).

A gap analysis between the ENH-LWA scenario and one scenario including only the existing VRES power plants[1] (EVR-LWA scenario: Existing Variable RES with Low Water Availability) has been carried out to assess the impact of additional VRES capacity in the Zambian electric power system under dry conditions.

- √ **Sensitivity scenario with high water availability:** starting from the results under normal water availability, the Consultant increased the hydro power production to simulate the wet year calculated from the hydrological historical data provided by the ZWG and he analysed the impact on the optimal wind and PV capacity assessed under the normal hydrological condition. This sensitivity scenario is useful to highlight possible dispatch challenges under the wettest conditions, comparing the results of simulation without and with power exchanges with the neighbouring countries. The following basic assumptions have been adopted:

- demand growth pattern based on a business as usual approach;
- high availability of water for hydropower to simulate the wet year according to the data provided by the ZWG;
- optimal wind and PV generation calculated from the scenario with normal water availability;
- Existing, under construction and committed programmable power plants (hydro and fossil fuels generation fleet).

Interconnected scenarios have been analysed considering an equivalent model of the power exchanges with the neighbouring countries based on the historical time-series of power exchanges and the price figures provided by SAPP.

[1] only PV power plants are currently in operation

6 DATA COLLECTION

This part of the activity is devoted to collect data of the Zambian electric power system, the expected peak and minimum loads, the forecast of annual demand, technical characteristics of generation units, the figures of wind speed and solar radiation to assess the future VRES productions and the economic parameters.

The data collection, together with the identification of the most important assumptions of the study, has been carried out with the close collaboration of the ZWG. The latter provided many data to the Consultant in order to allow the best representation of Zambian electric power system expected in 2025 and 2030. Missing information has been supplemented by the Consultant according to their knowledge on the international practises and agreed with the ZWG before starting the technical analyses.

6.1 Demand forecast

This section highlights the assumptions regarding the long-term demand forecast for the Zambian electric power system. The Consultant collected and analysed the historical data, the most recent demand forecast and the information about the firm contracts with the neighbouring countries to adjust a demand forecast according to the specific assumptions of the current study.

ZESCO provided a demand forecast from WSP case file based on ECA Updated Load Forecast Report (October 2017), ZESCO Statistical Report 2016, ZESCO hourly demand data for 2017 and ZESCO PSS/E model for 2018. Technical and commercial (T&C) losses resulting from this demand forecast were about 9.6% of sent-out energy, instead of 12% reported in the assumptions table; furthermore, a different firm export was assumed (110 MW instead of 370 MW assumed in the current study).

T&C losses represent the losses due to heat dissipation on the transmission and distribution systems plus additional losses, called commercial losses, due to other aspects such as metering issues, direct theft etc. The downward trend of T&C losses recorded in the last years suggests that it is reasonable for ZESCO to achieve T&C losses of around 12% of sent-out energy. The network losses on ZESCO's grid due to the wheeling of power through ZESCO's grid were assumed to be balanced by the supplier of the wheeled power; thus, they were not included in the demand forecast of Zambia.

Firm export is an export towards neighbouring countries that must be considered as part of the electricity demand because there are firm contracts to supply electricity to some neighbouring countries or obligations such as the supply of electricity to towns on the border with Zambia.

The Consultant reviewed the demand forecast provided by ZESCO adjusting both T&C losses and the firm export providing an assessment of the energy/power sent-out expected in the long-term.

The main assumptions of the demand forecast are resumed in Table 6.1, while the results up to the year 2035 are reported in Table 6.2, Table 6.3 and Figure 6.1. The domestic load (including CEC load), firm export, T&C losses and generators sent-out were highlighted both in terms of energy and peak power demand . The total domestic energy demand expected in 2025 is about 18.59 TWh/year with a peak power demand of 2,679 MW. In 2030 the annual domestic demand reaches 21.39 TWh with a peak load of 3,035 MW.

[2] The energy/power sent-out is the energy/power injected into the grid at the generator terminals, excluding the consumptions of power plant auxiliaries and the share of non-firm export towards the neighbouring countries.
[3] The peak power is the maximum power demand expected in one hour over a period of one year.

Table 6.1 - Summary of demand forecast assumptions

Assumption	Values
Population and population growth, household size	Population of 15.9 million in 2016, growing at 2.9% per annum to 2040 using CSO projections.
Household electrification access	Grid connections at just under 22% of households in 2016 to 39% in 2030 and to 49% by 2040; consistent with GRZ target of 51% by 2030.
GDP growth	IMF projections to 2021; thereafter GDP per capita assumed to grow at 3.4% per annum in line with historical growth rates over the past 10 years, implying total GDP growth rates of 6.3% per annum.
Mining loads	Forecast provided by Chamber of Mines. 750 MW in 2016 rising to 1,385 MW by 2031, shrinking to 1,291 MW by 2040.
DSM	Various demand-side measures proposed by ZESCO and assumed. Major impacts from ripple control for electric geysers (50 MW in 2018), LPG for cooking (200 MW by 2037) and energy efficiency labelling of electrical appliances (50 MW by 2026).
Rooftop solar PV	No rooftop solar PV programmes proposed in Zambia, but many countries have introduced them. A token 100 kW per year assu-med.
Technical and Commercial (T&C) losses	12% of sent-out energy throughout the planning period.
Firm export load	Cross-border load treated as firm: 100 MW with 90% load factor to Namibia, 200 MW with 90% load factor to DRC and 70 MW with 90% load factor to Malawi.

Table 6.2 – Long-term forecast of energy demand

Year	Domestic Load	Firm Export	T&C Losses		Sent-out	Sent-out Growth Rate	Load Factor
	[GWh/yr]	[GWh/yr]	[GWh/yr]	[%]	[GWh/yr]	[%]	[%]
2019	13,129	2,917	2,188	12%	18,235	-	77.8%
2020	13,867	2,917	2,289	12%	19,073	4.6%	78.3%
2021	14,634	2,917	2,393	12%	19,945	4.6%	78.7%
2022	15,492	2,917	2,510	12%	20,920	4.9%	79.2%
2023	16,425	2,917	2,638	12%	21,980	5.1%	79.6%
2024	17,450	2,917	2,777	12%	23,145	5.3%	80.1%
2025	18,586	2,917	2,932	12%	24,436	5.6%	80.5%
2026	19,422	2,917	3,046	12%	25,386	3.9%	80.7%
2027	19,870	2,917	3,107	12%	25,895	2.0%	80.9%
2028	20,350	2,917	3,173	12%	26,440	2.1%	81.1%
2029	20,867	2,917	3,243	12%	27,028	2.2%	81.3%
2030	21,391	2,917	3,315	12%	27,623	2.2%	81.5%
2031	21,938	2,917	3,389	12%	28,245	2.3%	81.7%
2032	22,506	2,917	3,467	12%	28,890	2.3%	81.9%
2033	23,113	2,917	3,550	12%	29,580	2.4%	82.0%
2034	23,757	2,917	3,637	12%	30,312	2.5%	82.2%
2035	24,438	2,917	3,730	12%	31,086	2.6%	82.3%

Table 6.3 – Long-term forecast of peak power demand

Year	Domestic Load	Firm Export	T&C Losses	Peak Sent-out	Peak Sent-out Growth Rate
	[MW]	[MW]	[MW]	[MW]	[%]
2019	1,984	370	321	2,676	-
2020	2,079	370	334	2,783	4.0%
2021	2,176	370	347	2,893	4.0%
2022	2,285	370	362	3,017	4.3%
2023	2,404	370	378	3,152	4.5%
2024	2,535	370	396	3,301	4.7%
2025	2,679	370	416	3,465	5.0%
2026	2,790	370	431	3,591	3.6%
2027	2,845	370	438	3,654	1.8%
2028	2,905	370	447	3,722	1.9%
2029	2,970	370	455	3,795	2.0%
2030	3,035	370	464	3,869	2.0%
2031	3,103	370	474	3,947	2.0%
2032	3,176	370	484	4,029	2.1%
2033	3,254	370	494	4,118	2.2%
2034	3,337	370	505	4,212	2.3%
2035	3,424	370	517	4,312	2.4%

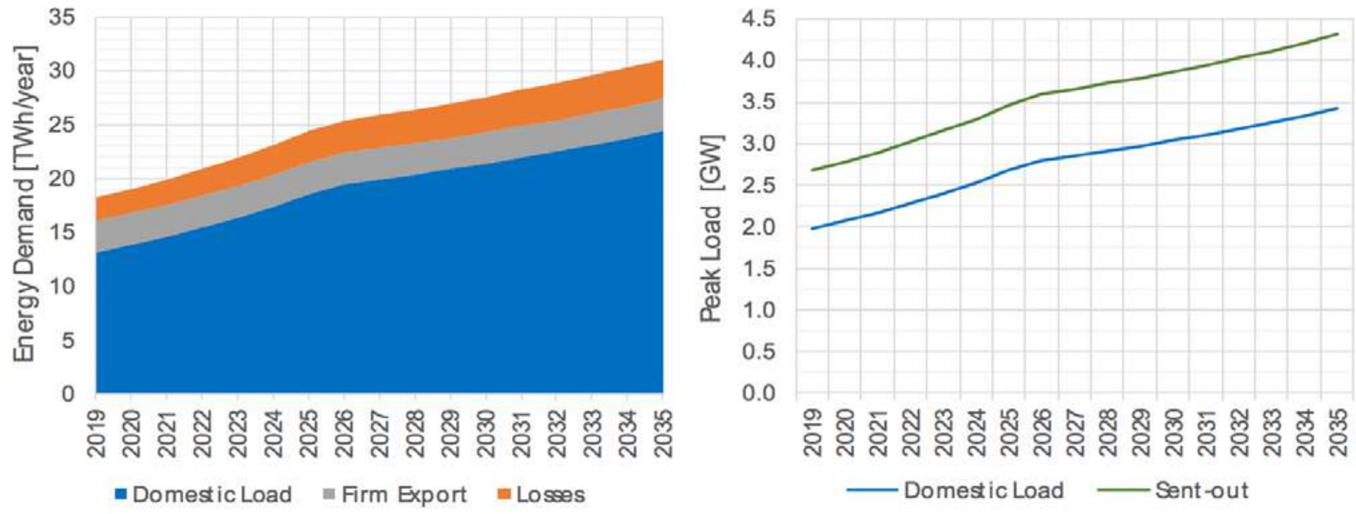


Figure 6.1 – Long-term demand forecast of Zambia

Copperbelt Energy Corporation (CEC) performed the projections of the demand growth by 2030 for the Copper Belt region. The energy demand with the maximum and minimum power expected in the period 2019-2030 by CEC are shown in Table 6.4. The projections do not include the system losses for the CEC network that are expected equal to 3% of energy/power sent-out. The Consultant considered the CEC demand forecast for the model of the Copper Belt region.

Table 6.4 – CEC projections to year 2030[4]

Year	Energy Demand (GWh)	Peak Demand (MW)	Minimum Demand (MW)
2019	4,772	647	582
2020	4,867	660	594
2021	4,965	673	606
2022	5,958	687	618
2023	6,077	700	630
2024	6,198	714	643
2025	6,322	729	656
2026	6,449	743	669
2027	6,578	758	682
2028	6,709	773	696
2029	6,843	789	710
2030	6,980	804	724

[4] The figures for CEC are already part of the figures for Zambia captured in Table 6.2 and Table 6.3

The historical hourly time-series provided by ZESCO were used to calculate the hourly time-series of demand expected in 2025 and 2030, needed for yearly based analyses. For the total country an annual profile (8,760 h) was created considering the expected peak power demand and the total forecasted energy demand, rescaling the historical time-series provided by ZESCO for the year 2018 to meet the targets of peak load and energy demand at 2025 and 2030.

As regards historical consumption data, Figure 6.2 shows hourly Zambian end users consumption for the years 2017 and 2018, while Figure 6.3 details load profile in four weeks of the year. It can be noted the limited variation both over the 24 hours of the day and over different months, which implies a high yearly load factor. Figure 6.4 shows the calculated load forecast error calculated over the year 2018 as the difference between actual and forecasted load divided by forecasted error.

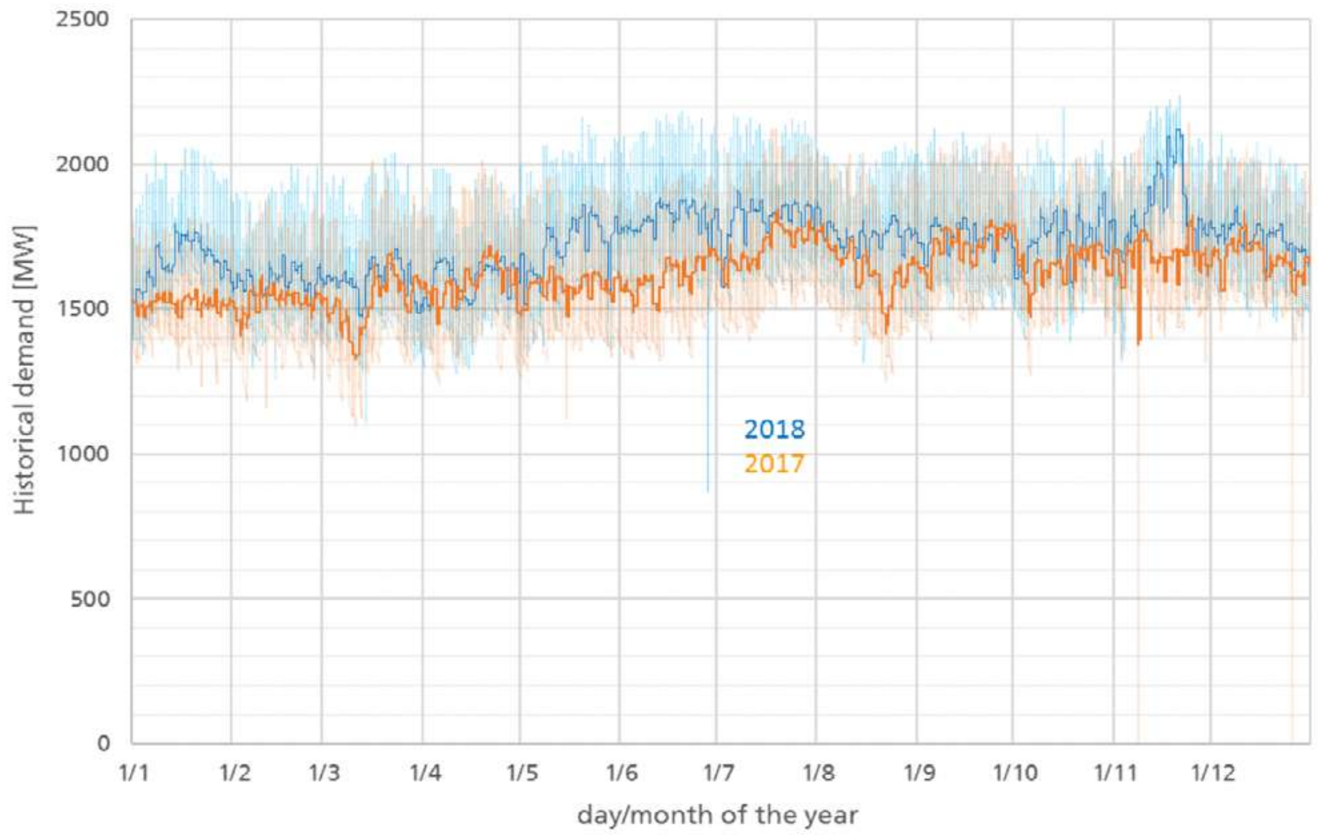


Figure 6.2 – 2017 and 2018 Zambia load. In bold line 24-hours average

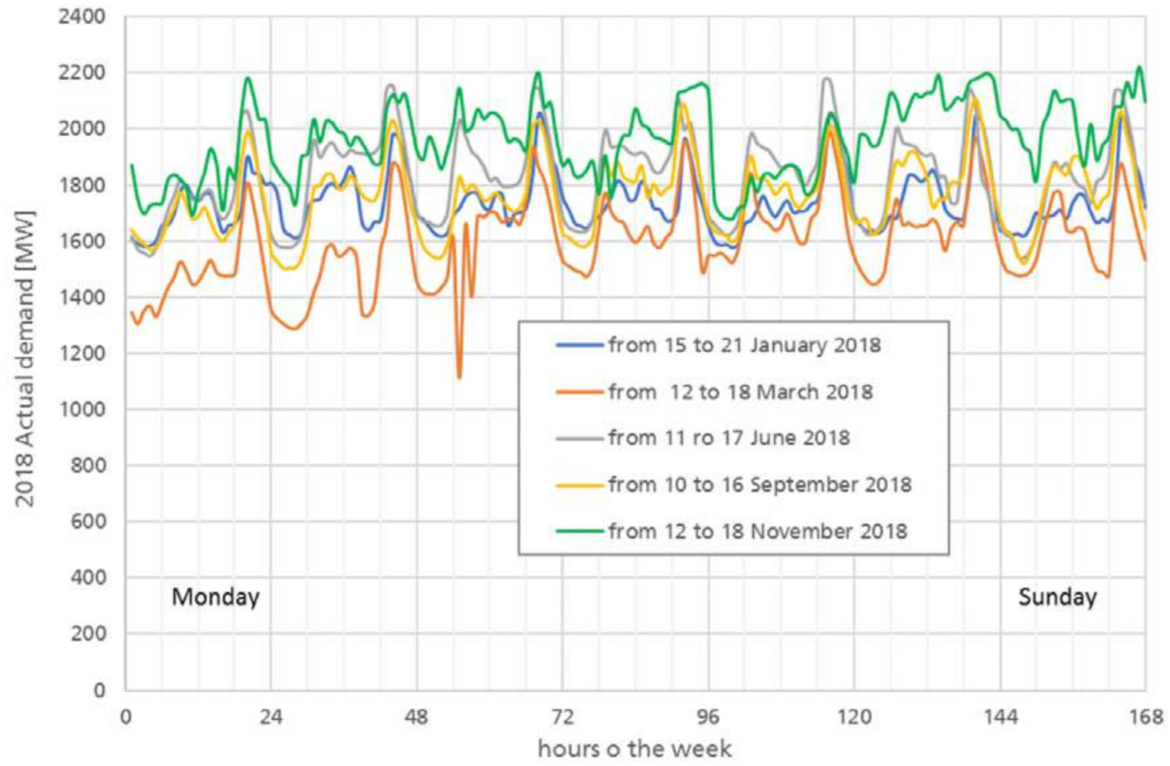


Figure 6.3 – 2018 Zambia actual demand

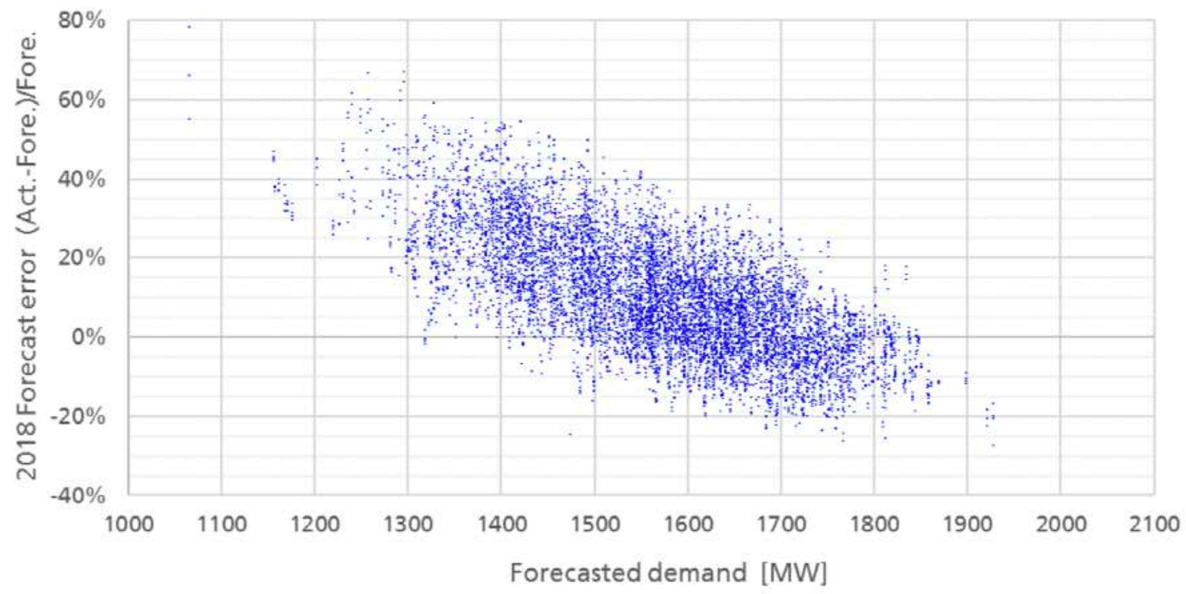


Figure 6.4 – Load forecast error for the year 2018

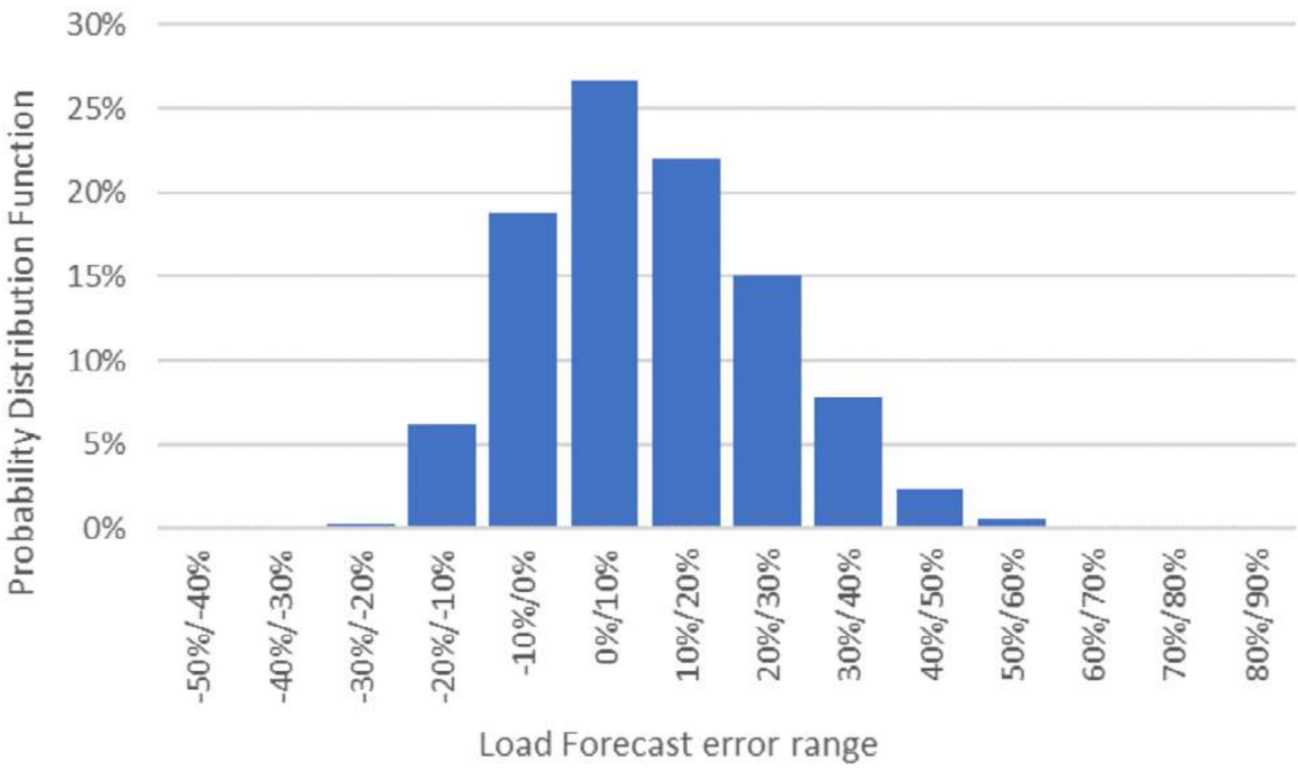


Figure 6.5 – Probability Distribution Function for load forecast error for the year 2018

The hourly time-series of load (including domestic demand, firm export and T&C losses) calculated for 2025 and 2030, together with load factors[5] (daily, monthly and yearly) are highlighted in Figure 6.6 and Figure 6.7. Both in 2025 and in 2030, the yearly load factor is equal to 82%; the monthly load factors are in the range 78-87% while the daily load factors in the range 80-98%.

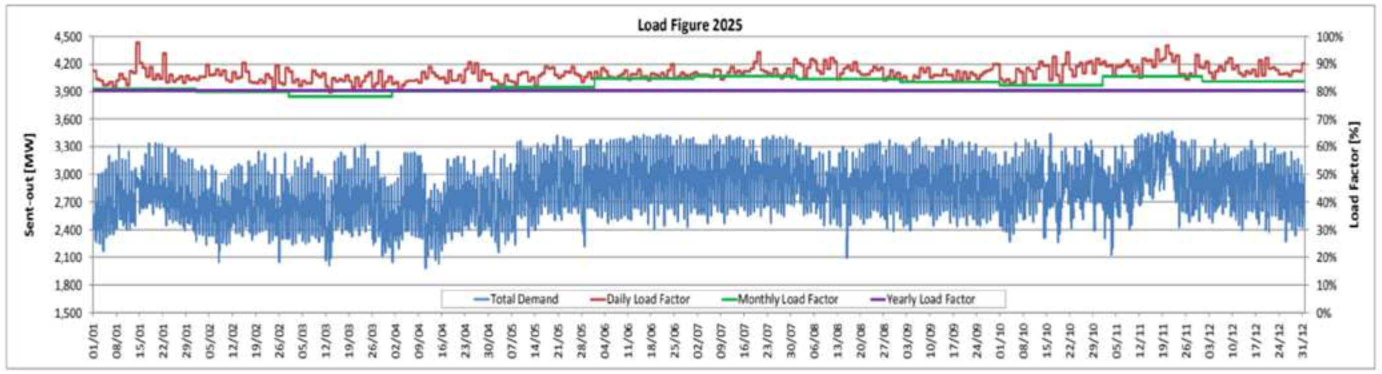


Figure 6.6 – Hourly time series of Zambian gross demand expected in 2025

[5] The load factor is the ratio between the average load and the peak load in a specified time period (day, month or year).

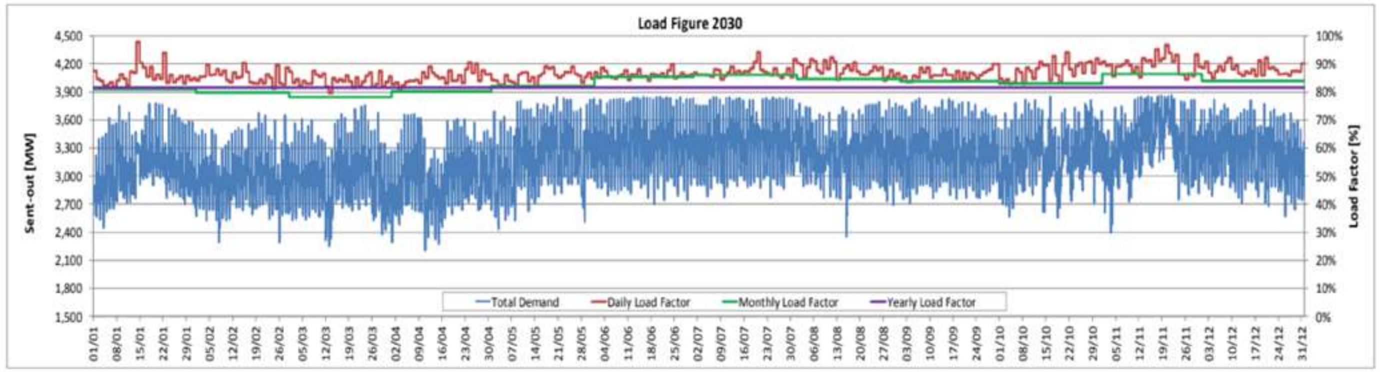


Figure 6.7 – Hourly time series of Zambian gross demand expected in 2030

Figure 6.8 shows the duration curve of the sent-out power expected at the target years, while Figure 6.9 and Figure 6.10 highlights the Probability Density Function (PDF) and the Cumulative Distribution Function (CDF) of load for the years 2025 and 2030 respectively.

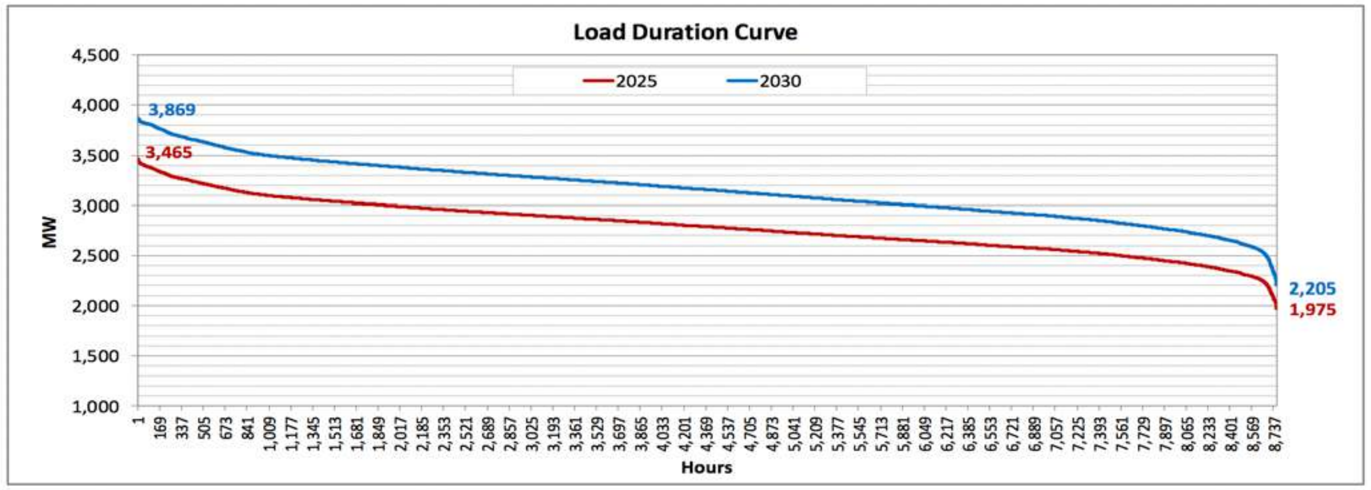


Figure 6.8 – Load duration curve assumed in 2025 and 2030

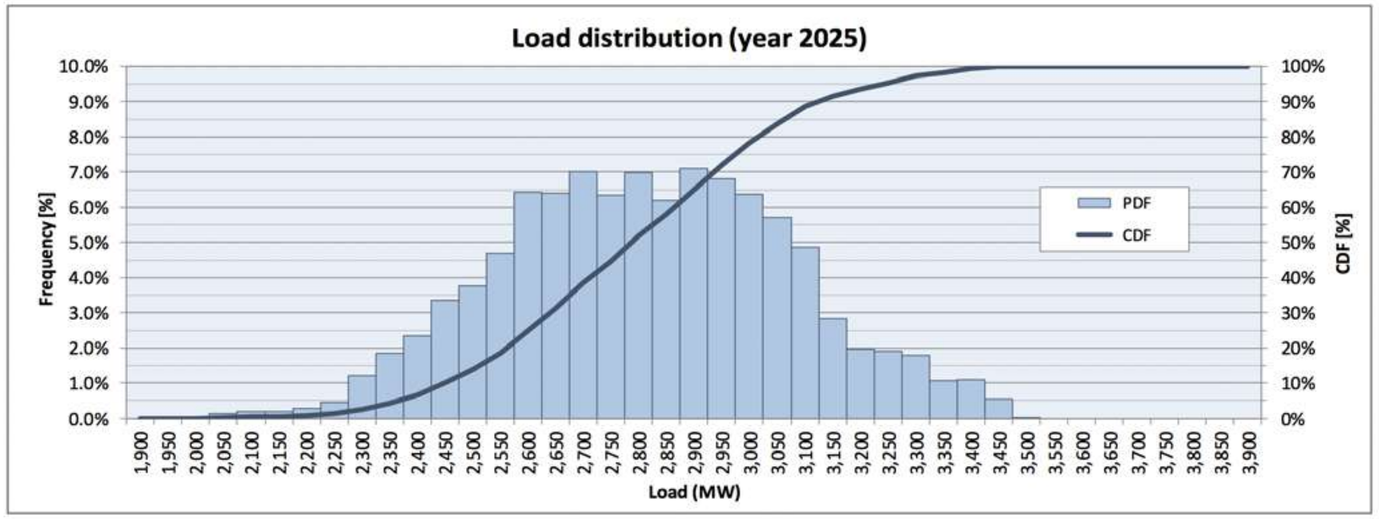


Figure 6.9 – Probabilistic distribution of load to year 2025

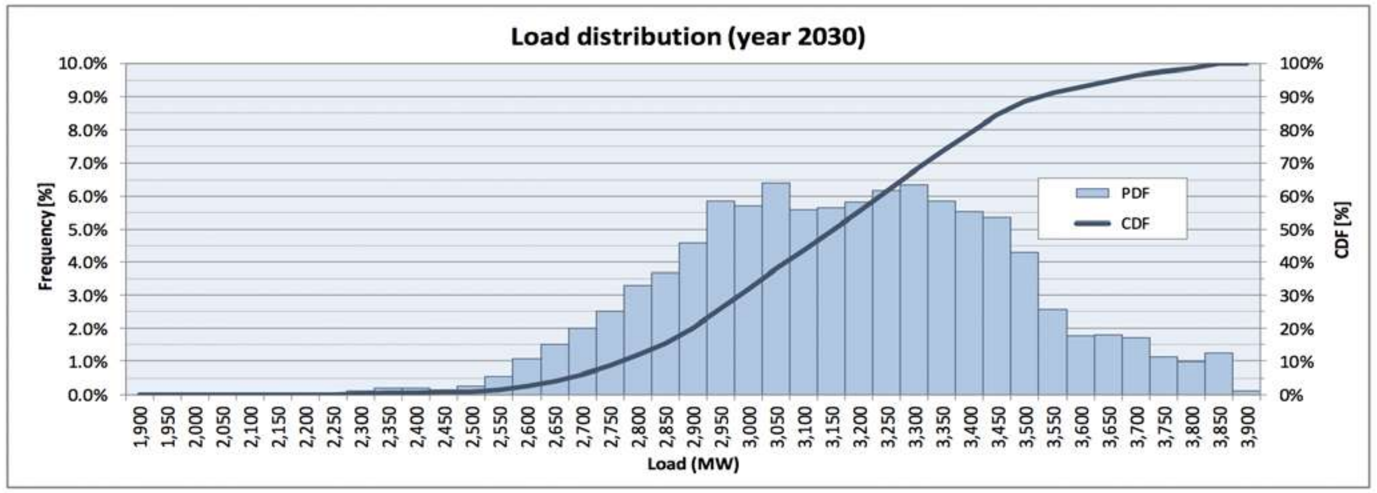


Figure 6.10 – Probabilistic distribution of load to year 2030

6.2 Power generation system

This section gives a description of the forecasted generation fleet to cover the demand at the target year 2025 and 2030, highlighting the existing power plants that will still be in service and the additional capacity already foreseen by the national authorities (power plants under construction, committed or with high probability to be built). The information about the existing and future generation fleet has been provided by the ZWG during the data collection phase. The main data was collected by means of a specific data questionnaire and merged with information included in the last Power System Development Master Plan (2010) and public sources. The missing information was proposed by the Consultant according to his knowledge and international standards.

Table 6.5 shows the maximum power of the generation fleet available in 2019, and the generation fleet expected to be committed in 2025 and 2030. The maximum capacity available in 2019 is 2,859 MW, about 13% from conventional thermal power plants and 87% from renewable sources (84.4% from hydropower plants and 2.6% from PV power plants). In the mid-term an increase of hydro available capacity is foreseen, the most important source in the country, together with new wind and PV power plants.

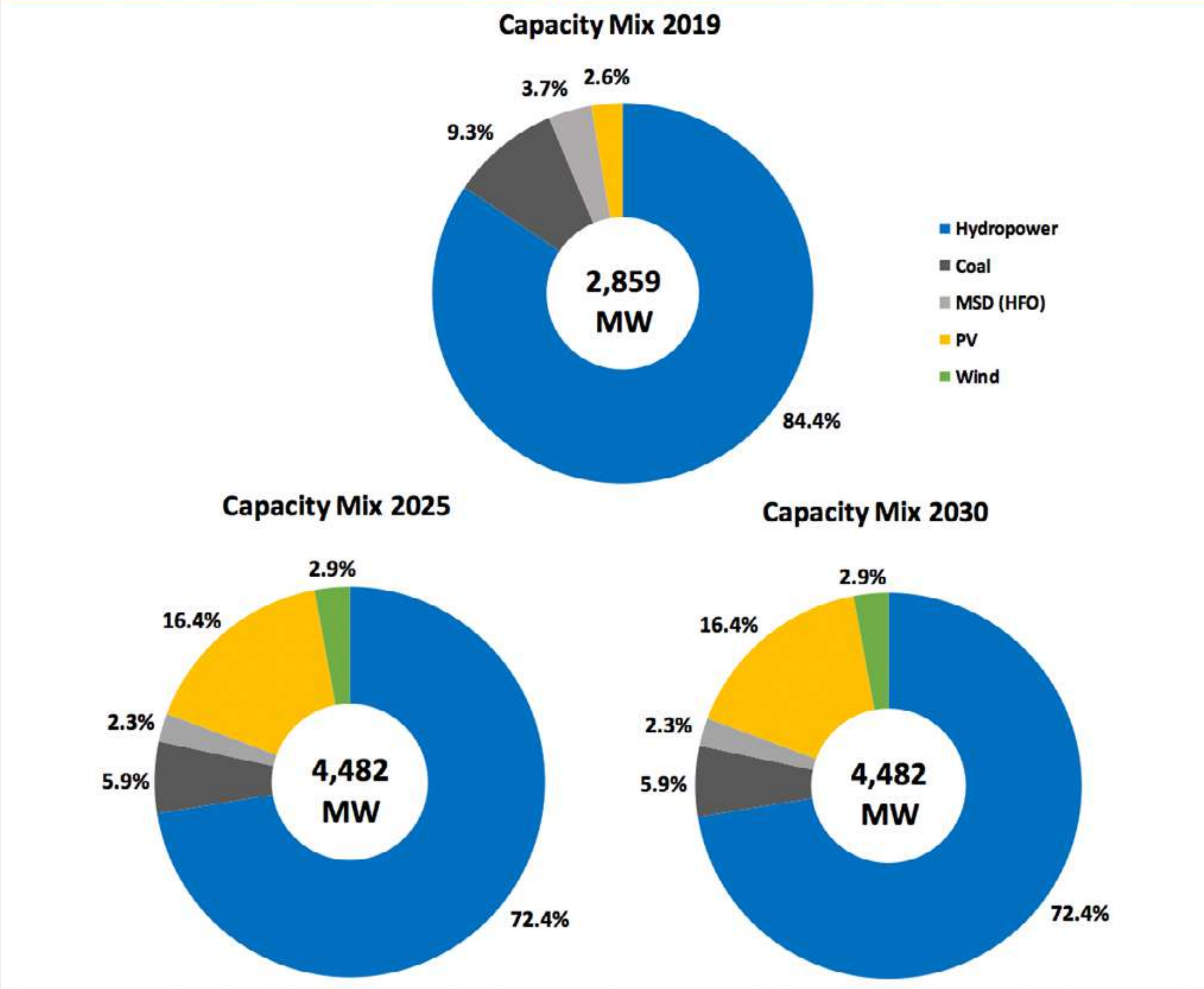
The analysis of recent studies, such as the SAPP Pool Plan 2017 and the generation plan for WSP case file, and other public sources highlighted some big generation projects from hydropower and coal that could be candidates to be developed in the mid- and long-term (e.g. 101 MW Kalungwishi I, 1,200 MW Batoka Gorge North, 340 MW EMCO Coal, 124 MW Mambilima Falls, 600 MW Devil's Gorge). According to the ZWG, the Consultant analysed the opportunity to cover the growing demand with VRES generation, on top the under construction and committed hydropower projects. No additional hydropower and fossil fuel candidates were included in the power system because the scope of the study is not the evaluation of the least cost generation expansion plan but the assessment of the optimal technical-economic penetration of VRES (wind and PV) starting from the existing and committed generation fleet, regardless of the cost of other new technologies. For this reason, the generation fleet assumed to be in service in the base case 2025 and 2030 included the new Kafue Gorge Lower hydropower plant and the extension of Lusiwasi and Chishimba Falls run-of-river power plants, together with all committed VRES power plants and the candidate VRES projects indicated by the ZWG because they are a high probability to be built.

The Commercial Operation Date (COD) for the new generation capacity indicated by the ZWG is expected by 2023, therefore the same maximum generation capacity was considered in the base cases 2025 and 2030. 4,482 MW will be available for both years: 8.2% from fossil fuel generators and 91.8% from renewable energy sources. The increase of VRES role in the capacity mix expected in the mid- and long-term (16.4% from PV power plants and 2.9% from wind farms) will reduce the dependencies from hydropower (72.4% of the total capacity).

Figure 6.11 shows the generation expansion plan 2019-2030 according to the committed generation as agreed with the ZWG. The plan highlights the growth of the maximum power available in the power system, for each generation source. The comparison between the maximum power available at peak load (total power net of PV and wind generation according to the current SAPP guidelines) and the peak load in the period 2019-2030 is shown in Figure 6.12 with the reserve margin (available capacity above the capacity needed to meet peak load). The detail of each power plant included in the generation expansion plan is available in Table 6.6. The COD of wind and PV projects was useful for their priority in the integration process; however, it was not a limit for the analyses, in particular in 2025. In other words, if wind and/or PV feasible capacity in 2025 was lower than the expected capacity, some projects were postponed avoiding possible over-generation phenomena.

Table 6.5 – Maximum power of the generation fleet

Source	2019	2025	2030
Hydropower	2,413	3,246	3,246
Conventional	370	370	370
Coal	*265*	*265*	*265*
Medium Speed Diesel engine *(HFO)*	*105*	*105*	*105*
PV	76	736	736
Wind	-	130	130
Total	**2,859**	**4,482**	**4,482**



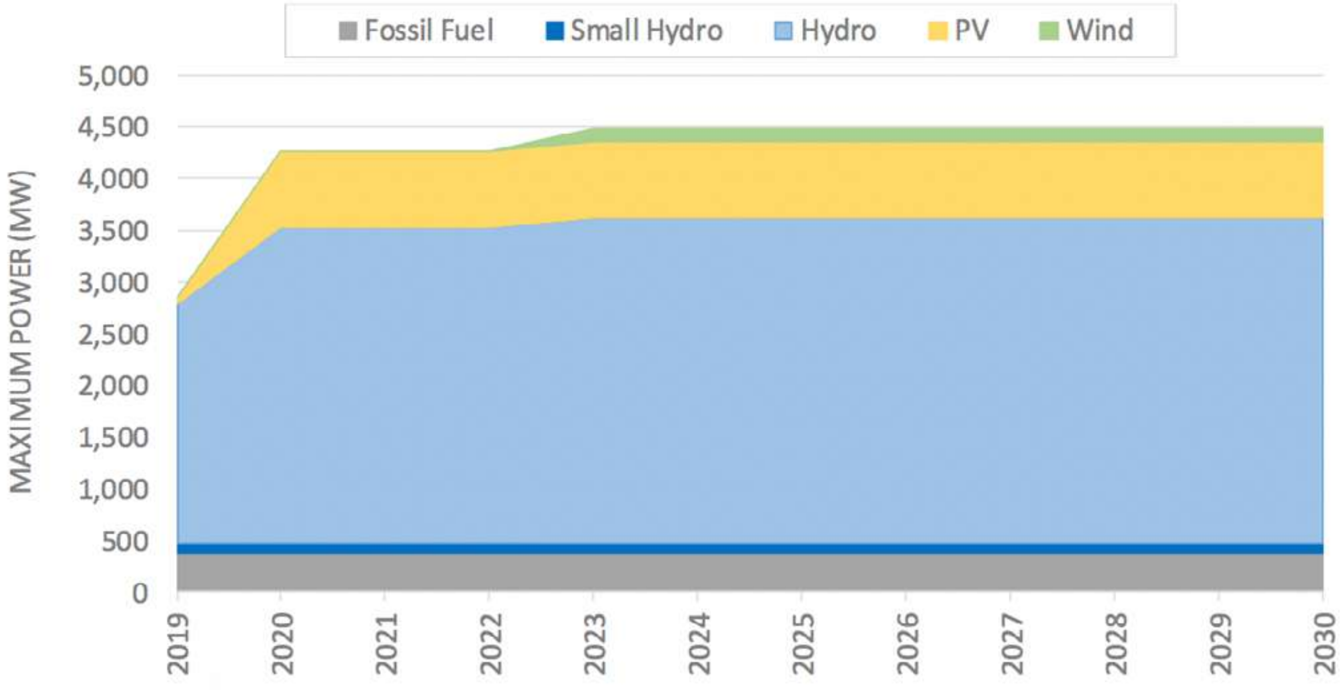


Figure 6.11 - Generation expansion plan 2019-2030

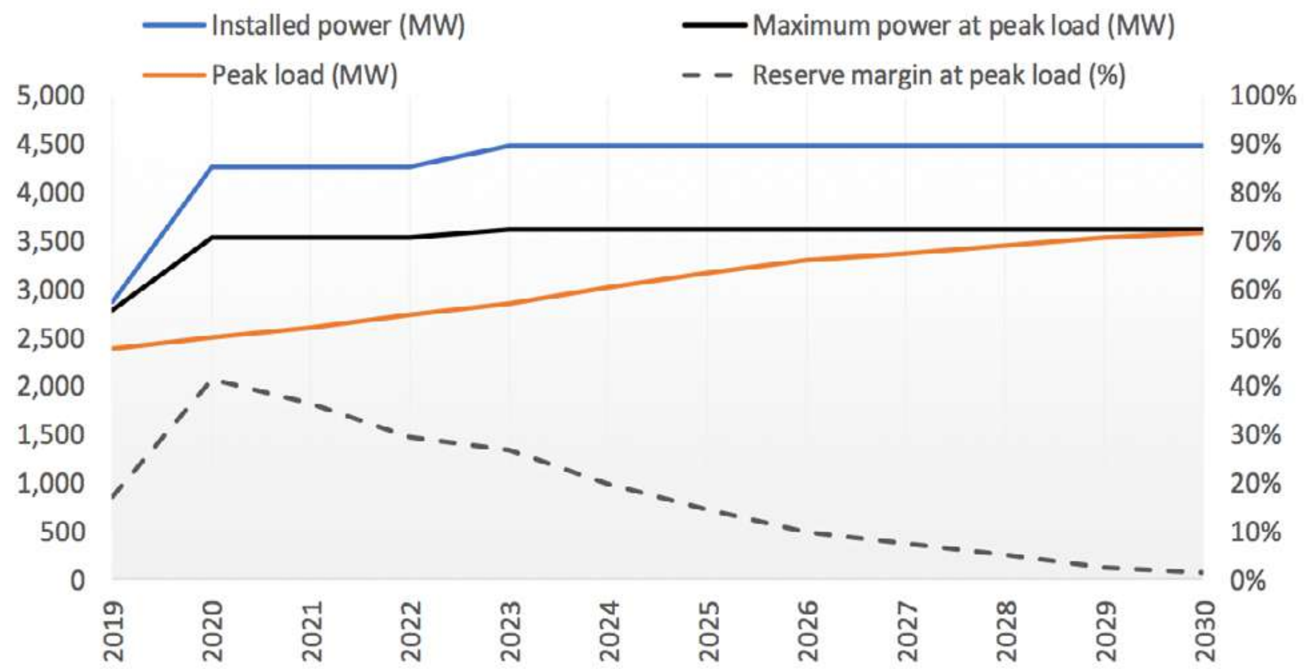


Figure 6.12 – Reserve margin of generation at peak load in the period 2019-2030[6]

[6] According to the current SAPP guidelines, the reserve margin available at peak load is the difference between the maximum power available at peak load and the peak load value, as a percentage of the peak load. The maximum power available during the peak load includes only hydro and fossil fuel generation (total power net of PV and wind generation)

Table 6.6 – Detailed generation expansion plan 2019-2030

Plant name	Owner	Category	Type	Status	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Itezhi Tezhi	ITTPC	Hydro	Reservoir	Existing	MW	120	120	120	120	120	120	120	120	120	120	120	120
Kafue Gorge	ZESCO	Hydro	Reservoir	Existing	MW	990	990	990	990	990	990	990	990	990	990	990	990
Kariba North Bank	ZESCO	Hydro	Reservoir	Existing	MW	720	720	720	720	720	720	720	720	720	720	720	720
Kariba North Bank Ext	KNBEPC	Hydro	Reservoir	Existing	MW	360	360	360	360	360	360	360	360	360	360	360	360
Victoria Falls A1&2	ZESCO	Hydro	RoR	Existing	MW	2	2	2	2	2	2	2	2	2	2	2	2
Victoria Falls A3&4	ZESCO	Hydro	RoR	Existing	MW	6	6	6	6	6	6	6	6	6	6	6	6
Victoria Falls B	ZESCO	Hydro	RoR	Existing	MW	60	60	60	60	60	60	60	60	60	60	60	60
Victoria Falls C	ZESCO	Hydro	RoR	Existing	MW	40	40	40	40	40	40	40	40	40	40	40	40
Lunzua	ZESCO	Small Hyd.	RoR	Existing	MW	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Lusiwasi	ZESCO	Small Hyd.	RoR	Existing	MW	12	12	12	12	-	-	-	-	-	-	-	-
Musonda Falls	ZESCO	Small Hyd.	RoR	Existing	MW	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Musonda Falls	ZESCO	Small Hyd.	RoR	Existing	MW	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Chishimba Falls	ZESCO	Small Hyd.	RoR	Existing	MW	1.2	1.2	1.2	1.2	-	-	-	-	-	-	-	-
Chishimba Falls	ZESCO	Small Hyd.	RoR	Existing	MW	4.8	4.8	4.8	4.8	-	-	-	-	-	-	-	-
Shiwangándu	ZESCO	Small Hyd.	RoR	Existing	MW	1	1	1	1	1	1	1	1	1	1	1	1
Lunsemfwa	LHPC	Small Hyd.	RoR	Existing	MW	24	24	24	24	24	24	24	24	24	24	24	24
Mulungushi	LHPC	Small Hyd.	RoR	Existing	MW	20	20	20	20	20	20	20	20	20	20	20	20
Mulungushi	LHPC	Small Hyd.	RoR	Existing	MW	12	12	12	12	12	12	12	12	12	12	12	12
Kafue Gorge Lower	ZESCO	Hydro	RoR	Under Cons.	MW	0	750	750	750	750	750	750	750	750	750	750	750
Lusiwasi Upper	ZESCO	Hydro	RoR	Under Cons.	MW	15	15	15	15	15	15	15	15	15	15	15	15
Lusiwasi Lower	ZESCO	Hydro	RoR	Committed	MW	-	-	-	-	86	86	86	86	86	86	86	86
Chishimba Falls	ZESCO	Small Hyd.	RoR	Committed	MW	-	-	-	-	15	15	15	15	15	15	15	15
Maamba	MCL	Fossil Fuel	Coal	Existing	MW	265	265	265	265	265	265	265	265	265	265	265	265
Ndola I	NECL	Fossil Fuel	HFO	Existing	MW	48	48	48	48	48	48	48	48	48	48	48	48
Ndola II	NECL	Fossil Fuel	HFO	Existing	MW	57	57	57	57	57	57	57	57	57	57	57	57
Bangweulu	Neoen/First Solar	PV	PV	Existing	MW	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
Ngonye	EGP	PV	PV	Existing	MW	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
Bulemu West	Building Energy	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Bulemu East	Building Energy	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Solar one	Globeleq, Aurora	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Solar Two	Globeleq, Aurora	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Garneton North Solar	CEC, Innovent	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Garneton South Solar	CEC, Innovent	PV	PV	Committed	MW	-	20	20	20	20	20	20	20	20	20	20	20
Kanona	Mansen, ZESCO	PV	PV	Committed	MW	-	200	200	200	200	200	200	200	200	200	200	200
Green Field	Greenfield Energy	PV	PV	Committed	MW	-	50	50	50	50	50	50	50	50	50	50	50
Globeleq Project	Globeleq	PV	PV	Candidate	MW	-	100	100	100	100	100	100	100	100	100	100	100
MGC Project	MGC	PV	PV	Candidate	MW	-	100	100	100	100	100	100	100	100	100	100	100
Hive	Hive	PV	PV	Candidate	MW	-	90	90	90	90	90	90	90	90	90	90	90
Serenje Acess Power	Total EREN	Wind	Wind	Candidate	MW	-	-	-	-	130	130	130	130	130	130	130	130
				Maximum power	MW	2,859	4,269	4,269	4,269	4,482	4,482	4,482	4,482	4,482	4,482	4,482	4,482
				Maximum power at peak load[7]	MW	2,783	3,533	3,533	3,533	3,746	3,746	3,746	3,746	3,746	3,746	3,746	3,746
				Peak load	MW	2,293	2,397	2,502	2,621	2,753	2,896	3,057	3,172	3,238	3,308	3,384	3,461
				Reserve margin at peak load[8]	%	17.1%	41.3%	36.2%	29.2%	26.7%	19.8%	14.3%	9.6%	7.3%	4.9%	2.4%	1.3%

[7] According to the SAPP guidelines the maximum power at peak load needed to calculate the reserve margin includes only hydro and thermal power (total power net of PV and wind generation).
[8] The reserve margin at peak load is the difference between the maximum power at peak load and the peak load value, as a percentage of the peak load (SAPP guidelines)

6.2.1 Hydropower generation

Currently hydropower plants play an important role to cover the annual demand in Zambia, with an overall installed power of 2,413 MW, of which 91% are from reservoir plants and the remaining 9% from Run-of-River (RoR) power plants (Table 6.7). Hydroelectric installed capacity accounts for 85% of the overall Zambian installed capacity. Within the year 2023 about 850 MW of run-of-river plants should come into service, while about 20 MW should de retired.

The majority of the installed capacity and generated energy is concentrated along Zambezi river and its affluent Kafue river. After feeding the 108 MW RoR plants installed at Victoria Falls, the Zambezi flows into the Kariba reservoir, that feeds the Kariba North Bank (720 MW) and the Kariba North Bank Extension (360 MW), owned by Zambia, and the Kariba South Bank (1,050 MW), owned by Zimbabwe. After feeding the Itezhi Tezhi reservoir power plant (120 MW), Kafue river flows to the Kafue Gorge Upper reservoir (990 MW) and into the future Kafue Gorge Lower RoR plant (750 MW). The overall production of the power plants on the Kafue river accounts for 58% of the expected overall Zambian hydroelectric production, considering average hydrological conditions, with the Kafue Gorge Upper alone accounting for 38%. Victoria Falls RoR plant and the Kariba plant account for 35% of the total Zambian hydroelectric production. The relevance of mentioned plants in terms of generated energy and installed power clearly emerges also from Figure 6.13, while Figure 6.14 shows modest capacity factor for the under construction Kafue Gorge Lower plant and very low (15%) for the existing Kariba North Extension plant, likely used more as peaking power plants than baseload power plants.

Currently, only Kafue Gorge power plant is equipped with the Automatic Generation Control (AGC) able to provide the instantaneous balancing service needed to maintain the frequency in the standard frequency range. When Kafue Gorge is activated to limit the frequency error, Kariba North Bank is operated to restore the operating reserve in Kafue Gorge. Therefore, now Kariba North Bank provides the slow operating reserve while Kafue Gorge the fast operating reserve. If the latter reserve is not enough, the additional reserve is provided by other SAPP countries. In future is planned that also Kariba North Bank will be equipped with an AGC. For this reasons, Kafue Gorge and Kariba North Bank were considered must-run power plants, together with the upstream power plants (Itezhi Tezhi and Victoria Falls) which affect their operation.

Figure 6.15 shows the location of existing and scheduled hydro plants on the Zambia map.

A suitable model of each hydropower plant was created considering the characteristics of the power plants, the monthly generation of large hydropower plants, the reservoir characteristics (minimum and maximum water volume) and the average annual expected production for run-of-river power plants (medium and small hydro power plants). The available data on existing and future hydropower plants are provided in the following paragraphs.

Table 6.7 – Main parameters of the existing and committed hydropower plants

Hydro plant name	Owner	Type	N° of units	Installed capacity	Minimum Power	Maximum Power	Average generation	Avg CF	COD	Retirement date	Forced Outage Rate	Maint.	Nominal production factor	Live storage	Turbined water**
-	-	-	-	MW	MW	MW	GWh/y	%	year	year	%	weeks/yr	MW/(m³/s)	Mm3	Mm3
Itezhi Tezhi	ITTPC	Reservoir	2	120.0	36.0	120.0	610	58%	2016	n.a.	2%	2.6	0.380	5,305	5,780
Kafue Gorge	ZESCO	Reservoir	6	990.0	99.0	990.0	5,984	69%	1977	n.a.	2%	2.6	3.560	800*	6,051
Kafue Gorge Lower	ZESCO	ROR	5	750.0	90.0	750.0	2,491	38%	2020	n.a.	2%	2.6	1.728*	-	5,190
Victoria Falls A1&2	ZESCO	ROR	2	2.0	0.6	2.0	14	80%	1938	n.a.	2%	2.6	0.667*	-	
Victoria Falls A3&4	ZESCO	ROR	2	6.0	1.8	6.0	42	80%	1954/1968	n.a.	2%	2.6		-	
Victoria Falls B	ZESCO	ROR	6	60.0	6.0	60.0	420	80%	1968	n.a.	2%	2.6	0.937*	-	
Victoria Falls C	ZESCO	ROR	4	40.0	6.0	40.0	280	80%	1972	n.a.	2%	2.6		-	
Kariba North Bank	ZESCO	Reservoir	4	720.0	108.0	720.0	4,289	68%	1976	n.a.	2%	2.6	0.791*	64,740*	19,520
Kariba North Bank	KNBEPC	Reservoir	2	360.0	108.0	360.0	467	15%	2015	n.a.	2%	2.6	0.791*		2,124
Lusiwasi	ZESCO	ROR	4	12.0	1.8	12.0	84	80%	1967	2023	3%	2.6	4.138*	-	
Lusiwasi Upper	ZESCO	ROR	3	15.0	2.5	15.0	57	43%	2019	n.a.	3%	2.6	0.752*	-	
Lusiwasi Lower	ZESCO	ROR	2	86.0	25.8	86.0	328	43%	2023	n.a.	3%	2.6	4.138**	-	
Lunzua	ZESCO	ROR	2	14.8	4.4	14.8	65	50%	2015	n.a.	3%	2.6	n.a.	-	
Musonda Falls	ZESCO	ROR	5	5.5	0.3	5.5	30	63%	2018	n.a.	3%	2.6	n.a.	-	
Musonda Falls	ZESCO	ROR	2	4.5	0.6	4.5	25	63%	2018	n.a.	3%	2.6	n.a.	-	
Chishimba Falls	ZESCO	ROR	4	1.2	0.2	1.2	7	70%	1959	2023	3%	2.6	n.a.	-	
Chishimba Falls	ZESCO	ROR	4	4.8	0.7	4.8	29	70%	1959	2023	3%	2.6	n.a.	-	
Chishimba Falls	ZESCO	ROR	3	15.0	3.0	15.0	75	57%	2023	n.a.	3%	2.6	n.a.	-	
Shiwa Ngándu	ZESCO	ROR	2	1.0	0.1	1.0	7	80%	2012	n.a.	3%	2.6	n.a.	-	
Lunsemfwa	LHPC	ROR	4	24.0	3.6	24.0	149	71%	1945/2012	n.a.	3%	2.6	1.104**	-	
Mulungushi	LHPC	ROR	2	20.0	6.0	20.0	159	91%	2009	n.a.	3%	2.6	2.869**	-	
Mulungushi	LHPC	ROR	2	12.0	3.6	12.0	96	91%	1927	n.a.	3%	2.6		-	
Total Zambia[9]			**60**	**3,245.8**	**505.3**	**3,245.8**	**15,588**								

(* ref. [10], ** Consultant assumption from public domain sources)

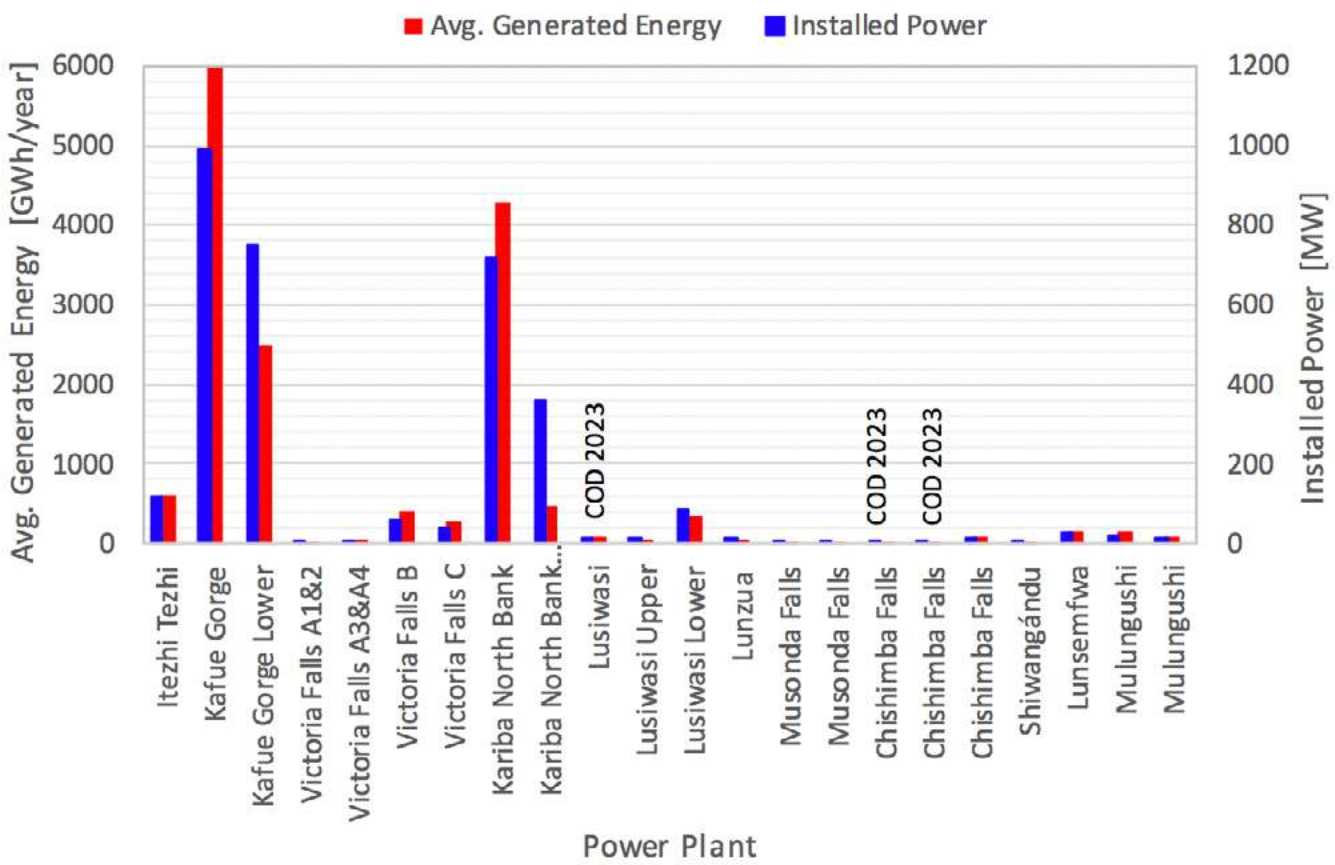


Figure 6.13 – Installed capacity and expected yearly average generated energy for hydropower plant, under average hydrological conditions (COD: Commercial Operating Date)

[9] Total amount expected in 2025 and 2030, excluding the power plants that will be decommissioned in 2023

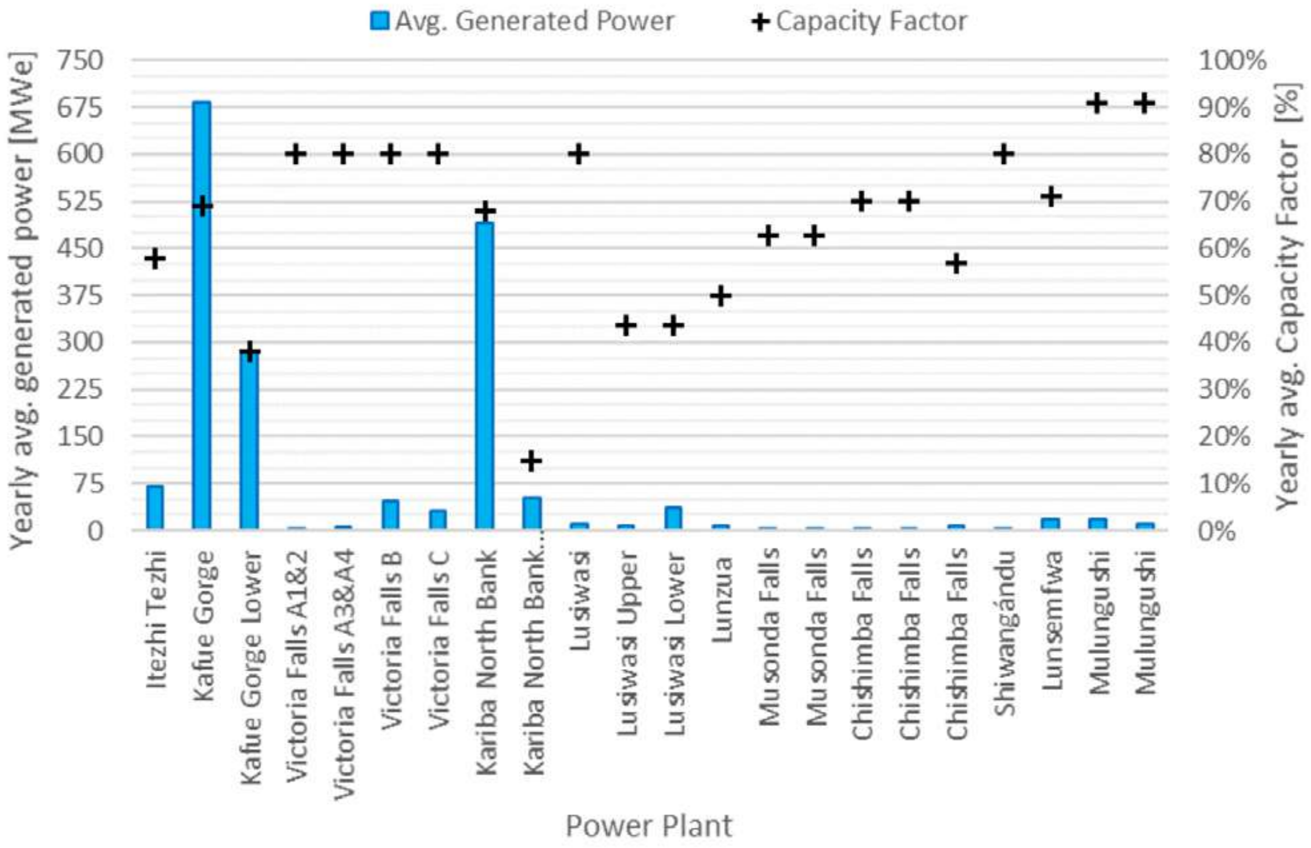


Figure 6.14 – Average generated power and Capacity Factor for hydropower plant under average hydrological conditions

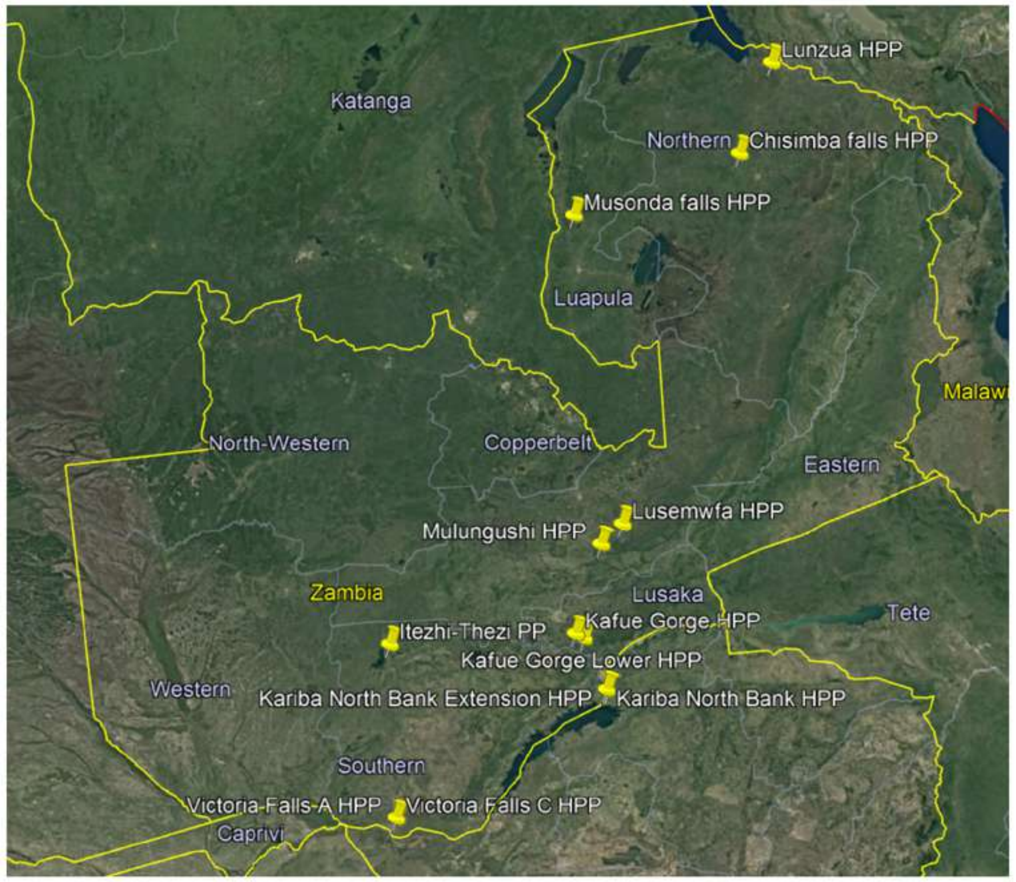


Figure 6.15 – Map showing the location of the hydro power plants listed in Table 6.7.

6.2.1.1 Kafue river

Power plants cascade along Kafue river it composed by the existing Itezhi Tezhi (ITT) plant upstream, Kafue Gorge (Upper) plant in the middle and the under-construction Kafue Gorge Lower downstream. ITT reservoir live storage is far higher than that of Kafue Gorge, that is higher than that of Kafue Gorge Lower, which was considered a Run-of-river plant.

For ITT dam daily data on reservoir level, stored volume and inflow are available over the period 1978-2019. From them the Consultant extrapolated daily average dam outflow. The results are shown in Figure 6.16, while Figure 6.17 shows ITT Dam monthly inflow under dry, average and wet years. It can be noted that ITT inflow is higher during the rainy season, from January to May, peaking in March, when maximum turbining capacity is usually exceeded.

ITT reservoir acts to level the flow disparity between the wet and dry seasons and supplies water to the Kafue Gorge reservoir. Between ITT reservoir and Kafue Gorge reservoir the Kafue river path isn't clearly defined while crossing the so called "Kafue Flats", which is the second biggest flood plain in Zambia. Kafue flats are flooded in rainy season, subtracting part of the water headed to Kafue Gorge reservoir. Furthermore, Kafue Flats are characterized by an extremely flat topography, with a vertical disparity of 5-6 meters over 230 km. Thus, it takes ITT outflow up to 90 days to reach Kafue Gorge reservoir. Nevertheless, the flow-adjusting function of the ITT reservoir makes a positive contribution to operation of the Kafue Gorge power plant.

The operation rules for ITT and Kafue Gorge reservoirs have evolved over time. Each set of rules has been developed based on earlier ones. In March a minimum flow of 300 m3/s must be released by ITT reservoir to preserve the ecological balance of the Kafue Flats (Figure 6.18). Furthermore, after the severe drought of 1991, new rules were implemented. They consisted of lower rule curves, indicating minimum water levels for the two reservoirs (Figure 6.19 and Figure 6.20). The lower rule curve for ITT reservoir indicates the minimum level at any moment in time that should be exceeded to generate energy higher than firm energy at Kafue Gorge power plant. The curve requires that generation is restricted to firm generation whenever the water level at ITT dam is on or below this curve. The lower rule curve for Kafue Gorge reservoir allows for limited depletion of the water level in the downstream part bearing in mind the requirements of safe power generation [9].

Any measure of Kafue Gorge inflow is available. Even if it can be reasonably assumed that flat flooding limits the flow to Kafue Gorge reservoir when high release from ITT reservoir occurs, the estimation of the monthly average flow to Kafue is far too complex to be here performed, also considering the lack of basic information. Therefore, the yearly generated electricity target for Kafue Gorge has been converted into turbined water, by considering the average production factor (MW/m3/s), and it has been assumed that yearly cumulated inflow is equal to yearly turbined water. The obtained yearly inflow has been then monthly profiled on the base of the ITT outflow monthly profile, shifted forward of three months.
Figure 6.21 shows Kafue Gorge reservoir historical data, Figure 6.22 and Figure 6.24 show monthly and yearly pattern of generated electricity.

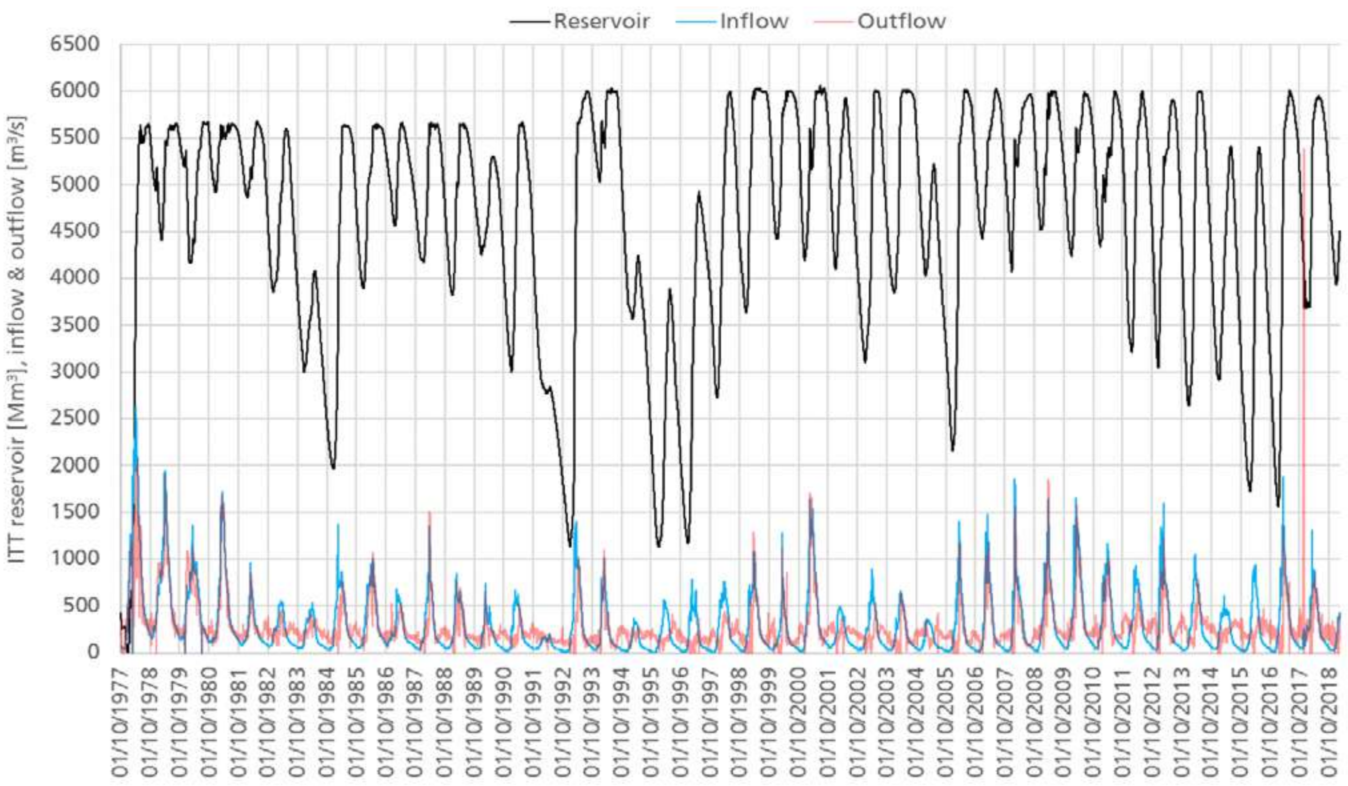


Figure 6.16 – ITT plant stored volume, inflow and estimated outflow

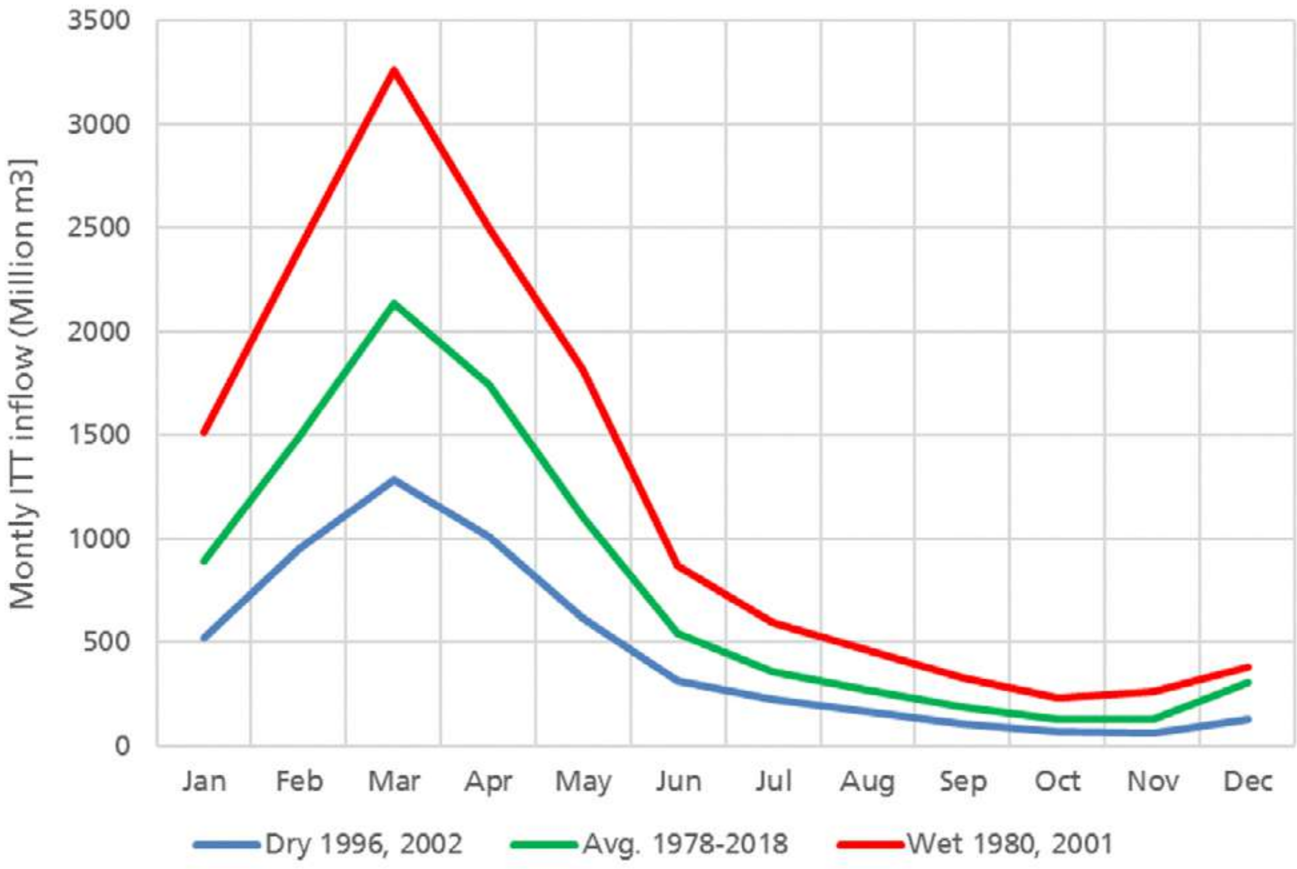


Figure 6.17 – ITT Dam monthly inflow under dry, average and wet years.

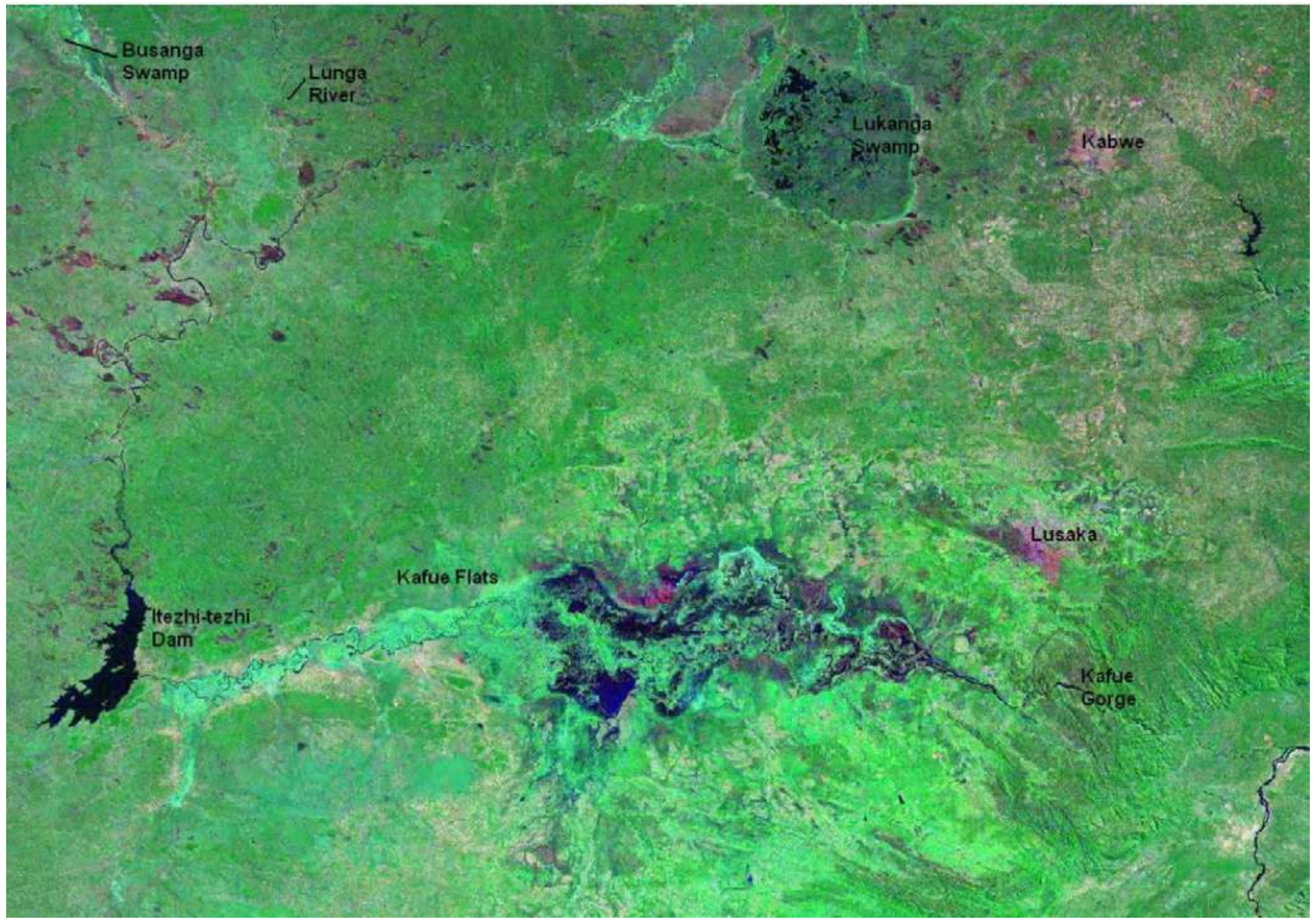


Figure 6.18 – Satellite picture of the Kafue Flats (Source APFM, [9]).

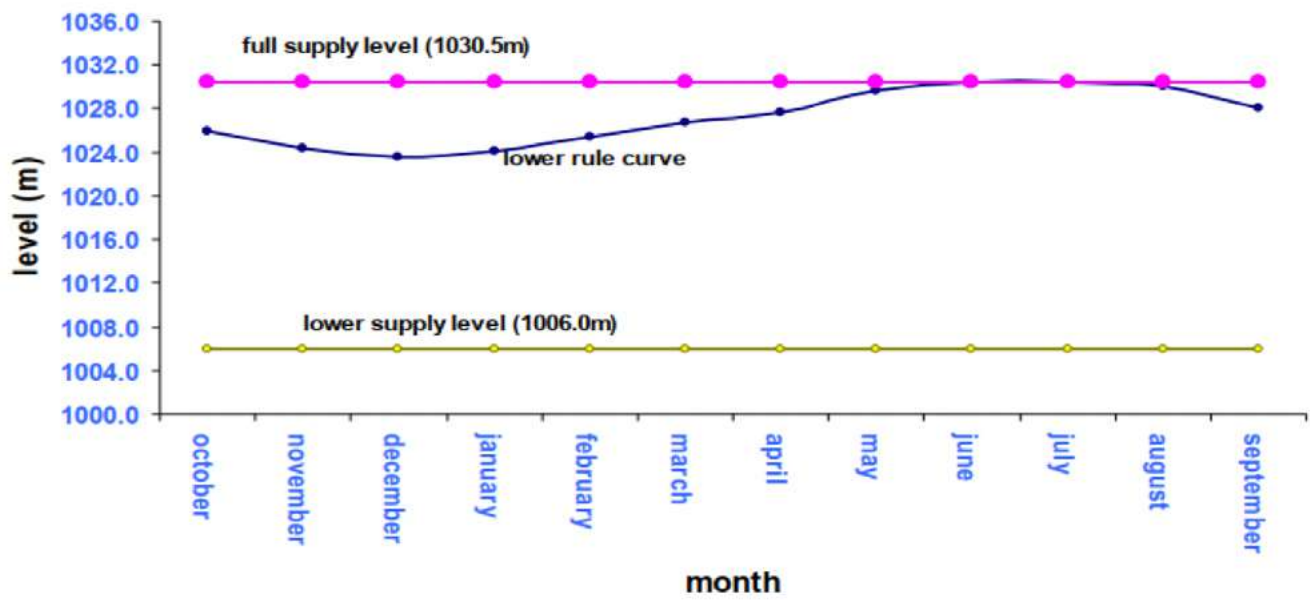


Figure 6.19 – Operation rule curve for ITT reservoir (Source APFM, [9])

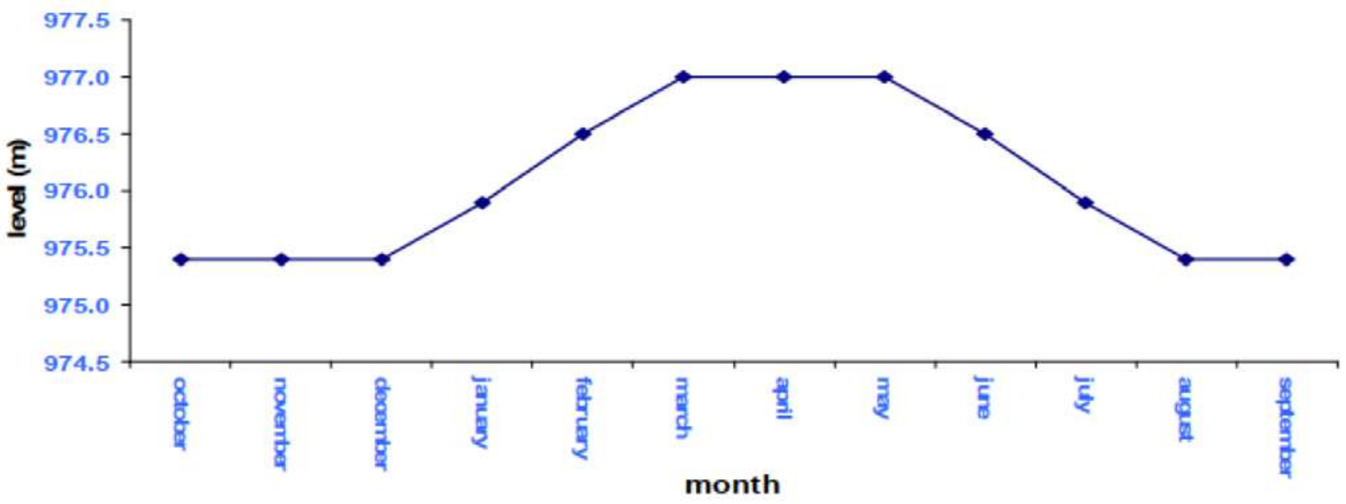


Figure 6.20 – Operation rule curve for Kafue Gorge reservoir (Source APFM, [9])

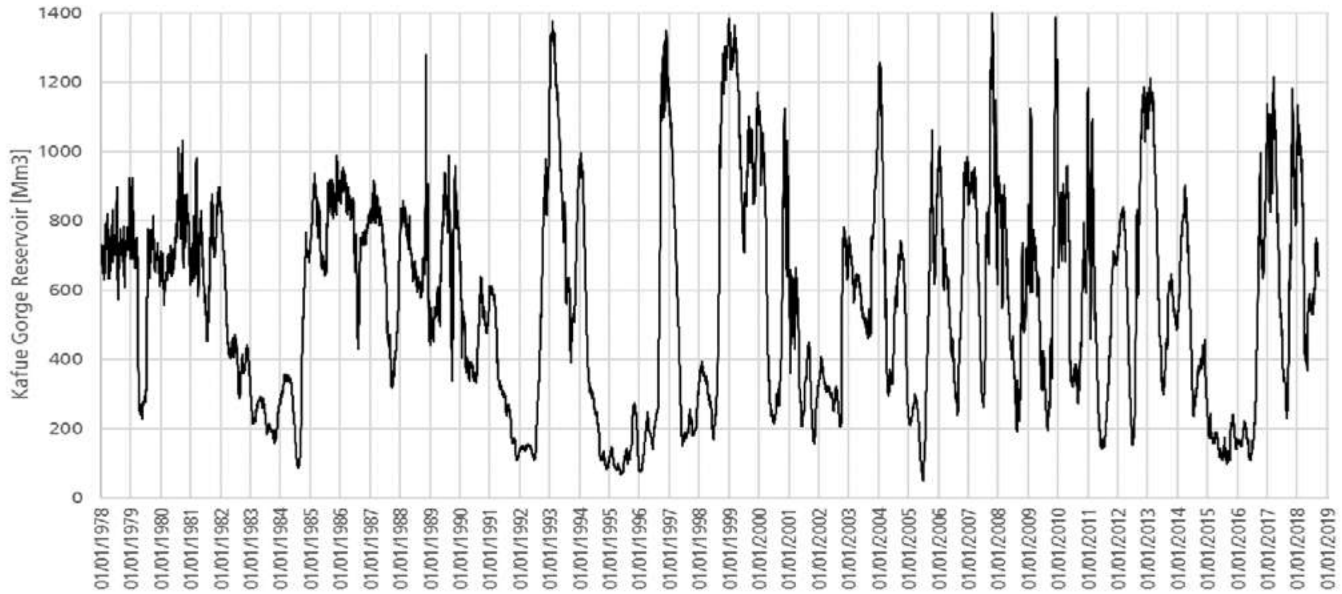


Figure 6.21 – Kafue Gorge reservoir historical data

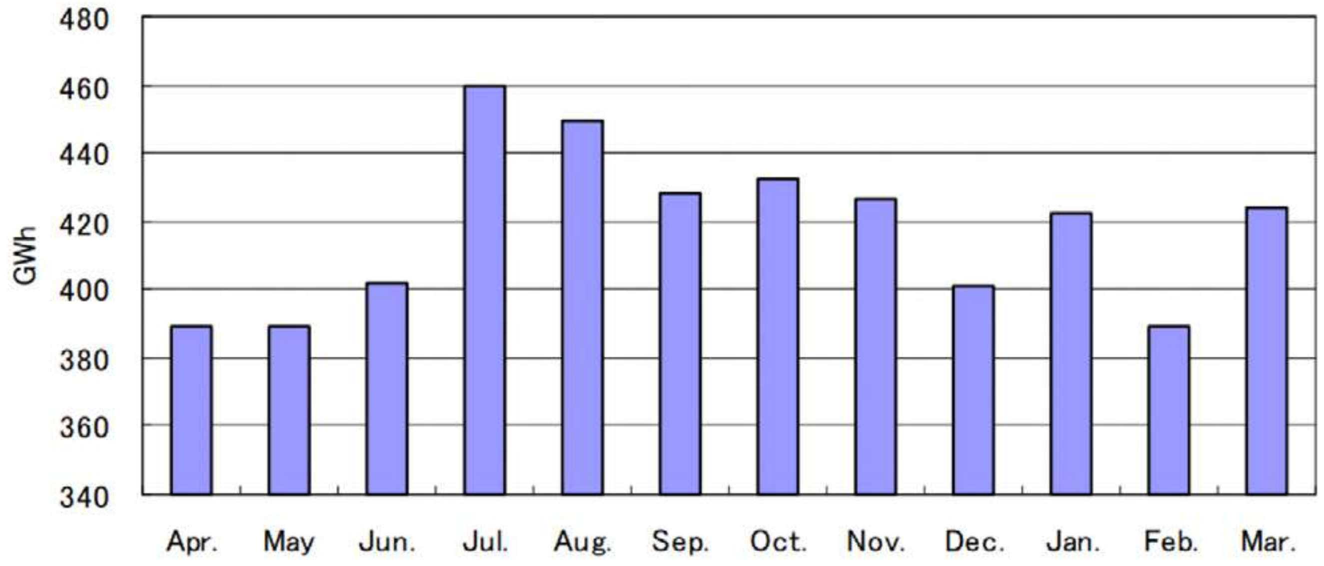


Figure 6.22 – Kafue Gorge monthly generate electricity over the period 1998-2002 (Source MEWD, [10])

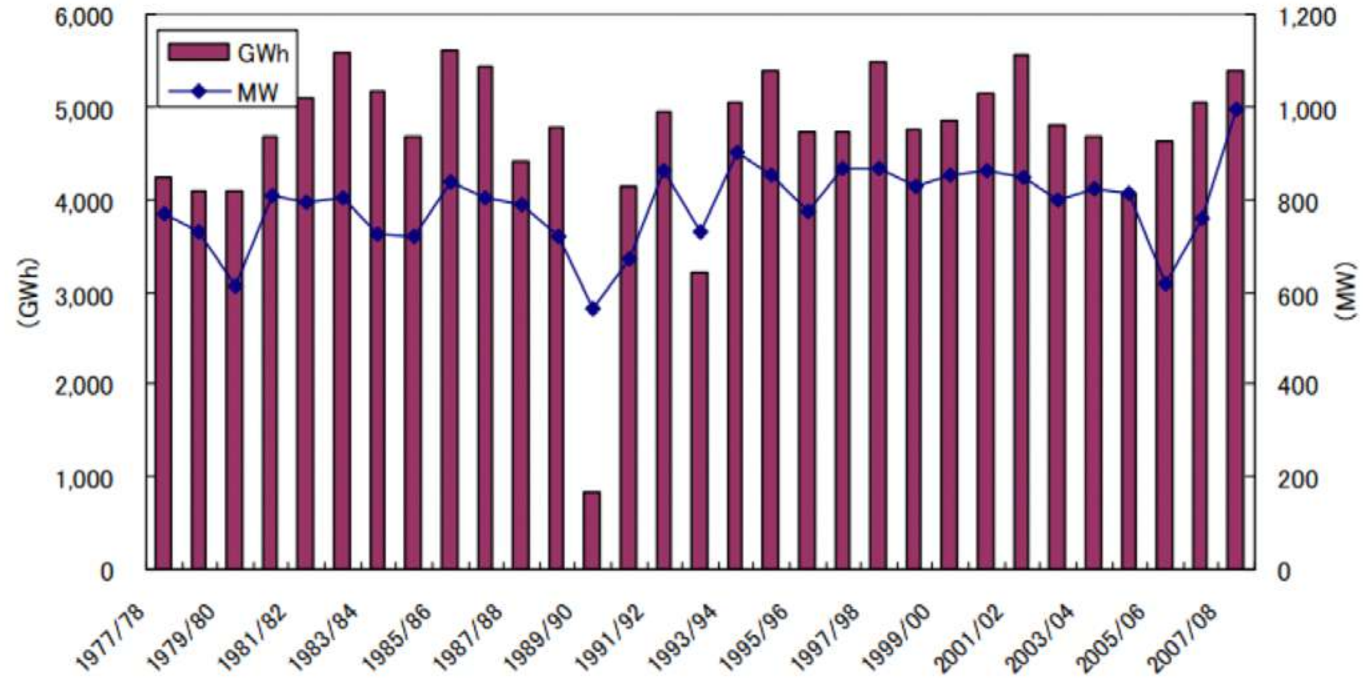


Figure 6.23 – Kafue Gorge yearly generated electricity over the period 1977-2008 (Source MEWD, [10])

6.2.1.2 Zambezi River (Victoria Falls & Kariba North Power Plants)

Victoria Falls is a run-of-river power plant operating in parallel to the famous cascades, upstream of the Kariba artificial lake. Figure 6.24 and Figure 6.25 shows available Zambezi flow data at Victoria Falls, that has been considered also as Kariba Lake inflow.

Figure 6.26 and Figure 6.27 show available historical data on Victoria Falls power plant production, while Figure 6.28 shows historical monthly trend for the Kariba lake level and, finally, Figure 6.29 and Figure 6.30 show available historical data on Kariba North power plant production. It can be noted that Kariba North production is almost flat over the months of a years, while yearly generated energy has substantial variation due to rainfall pattern.

Figure 6.31 shows existing Power Plants at Kariba lake dam: Kariba North Bank and Kariba North Bank Extension on the Zambia side, Kariba South Bank[10] on the Zimbabwe side. Each year the Zambezi River Authority (ZRA) allocates half of the available amount of water to each utility (ZESCO for Zambia and ZPC for Zimbabwe). Considering historical data, the following allocation to each utility can be considered:

- average year: 20.00 billion m3
- above average year: 22.25 billion m3
- below average year: 15.80 billion m3

[10] Installed power of 750 MW, that should be extended up to 1,050 MW

	Oct.	Nov.	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	max	min	ave
1978/79	550.55	601.71	835.10	1,071.70	1,523.85	2,469.46	4,132.12	3,885.23	2,252.68	1,246.49	763.81	568.30	4,132.12	550.55	1,658.42
1979/80	428.20	488.02	795.29	1,224.13	2,426.83	2,615.39	3,077.00	2,754.82	1,959.41	1,037.46	668.43	502.17	3,077.00	428.20	1,498.09
1980/81	384.68	423.44	591.86	843.60	1,176.43	1,902.23	3,100.19	3,210.79	2,093.58	1,055.32	651.66	479.81	3,210.79	384.68	1,326.13
1981/82	348.11	319.59	423.80	558.29	765.51	957.71	1,423.79	1,579.44	1,157.10	659.54	482.13	373.16	1,579.44	319.59	754.01
1982/83	317.29	364.57	598.32	842.39	1,033.94	1,227.45	1,381.16	1,331.15	902.59	549.26	420.28	331.49	1,381.16	317.29	774.99
1983/84	260.64	297.19	422.29	633.04	867.75	1,273.47	2,049.55	1,766.23	1,033.37	514.53	377.52	293.56	2,049.55	260.64	815.76
1984/85	241.84	279.17	405.63	619.52	962.58	1,170.32	1,762.20	2,153.66	1,660.37	757.19	467.10	339.63	2,153.66	241.84	901.60
1985/86	256.29	247.49	314.31	489.27	698.90	1,018.57	1,760.80	2,683.44	1,691.02	768.08	471.81	353.27	2,683.44	247.49	896.11
1986/87	317.15	446.56	684.45	876.82	1,054.90	1,472.11	2,235.42	1,965.80	1,278.23	643.88	467.22	354.36	2,235.42	317.15	983.08
1987/88	290.29	270.33	404.14	531.66	835.09	1,311.90	1,940.60	2,388.34	1,675.52	795.70	479.74	360.48	2,388.34	270.33	940.32
1988/89	283.98	300.50	454.62	672.60	1,108.78	2,795.89	3,272.67	3,590.39	2,571.99	1,379.35	650.46	432.24	3,590.39	283.98	1,459.46
1989/90	332.24	298.66	302.04	538.97	864.49	1,003.67	1,164.17	1,194.06	1,167.40	615.55	415.72	300.94	1,194.06	298.66	683.16
1990/91	253.35	236.56	324.11	553.36	930.41	2,065.06	2,295.37	2,003.50	1,231.50	539.36	379.09	288.35	2,295.37	236.56	925.00
1991/92	224.56	276.81	466.02	652.77	814.71	1,014.49	1,101.69	1,048.19	712.93	444.47	332.67	251.84	1,101.69	224.56	611.76
1992/93	184.93	213.17	292.84	461.99	741.87	1,236.97	2,411.44	3,122.88	1,886.87	801.13	420.11	287.78	3,122.88	184.93	1,005.16
1993/94	219.92	211.79	350.82	538.85	926.21	1,540.15	2,040.09	1,299.46	542.09	361.64	291.19	220.17	2,040.09	211.79	711.86
1994/95	163.96	164.36	230.16	361.88	507.94	773.39	1,408.22	1,253.30	508.10	317.45	245.27	178.11	1,408.22	163.96	509.35
1995/96	126.09	133.47	239.80	387.79	536.49	695.12	913.75	1,013.22	547.12	335.81	256.26	186.08	1,013.22	126.09	447.58
1996/97	130.39	132.84	223.35	420.59	767.71	1,012.81	1,456.18	1,723.84	1,266.26	528.11	326.79	233.47	1,723.84	130.39	685.20
1997/98	168.03	159.74	239.33	516.49	857.17	2,110.46	3,170.68	2,826.72	1,690.58	727.00	438.12	304.08	3,170.68	159.74	1,100.70
1998/99	212.35	181.03	295.68	540.88	854.75	1,867.01	2,644.55	3,024.32	1,815.93	736.02	421.25	282.70	3,024.32	181.03	1,073.04
1999/00	203.14	196.34	276.44	456.28	638.48	974.19	2,665.20	2,431.60	1,513.26	638.63	368.68	261.12	2,665.20	196.34	885.28
2000/01	171.67	145.21	278.23	569.54	919.29	2,325.08	3,074.11	3,287.84	2,112.01	974.83	507.49	351.52	3,287.84	145.21	1,226.40
2001/02	239.08	246.13	424.22	561.34	717.83	1,053.96	1,706.71	1,940.91	1,634.16	812.40	431.95	296.61	1,940.91	239.08	838.77
2002/03	226.86	202.70	282.83	501.87	831.01	1,300.96	2,226.46	3,422.10	2,211.60	1,092.60	521.07	337.67	3,422.10	202.70	1,096.48
2003/04	230.41	208.74	298.55	558.43	908.48	2,107.00	4,051.29	3,535.83	2,227.32	1,080.18	522.95	343.84	4,051.29	208.74	1,339.42
2004/05	241.84	216.41	334.51	502.47	775.33	1,142.96	1,378.68	1,384.15	1,122.58	558.89	371.63	275.59	1,384.15	216.41	692.09
2005/06	177.66	165.59	308.93	560.82	921.02	1,327.20	2,375.63	2,482.70	1,898.12	903.61	449.66	295.84	2,482.70	165.59	988.90
2006/07	228.05	248.17	395.75	702.00	2,016.28	4,279.80	3,360.58	2,761.50	1,829.41	946.07	549.76	385.14	4,279.80	228.05	1,475.21
ave.	255.64	264.70	396.32	612.05	964.97	1,587.75	2,261.39	2,312.60	1,523.90	752.43	453.44	326.53	2,312.60	255.64	975.98

Figure 6.24 – Zambezi flow at the Victoria Falls Power Plant site (Big Tree observation station) over the period 1978-2007 (Source MEWD, [10])

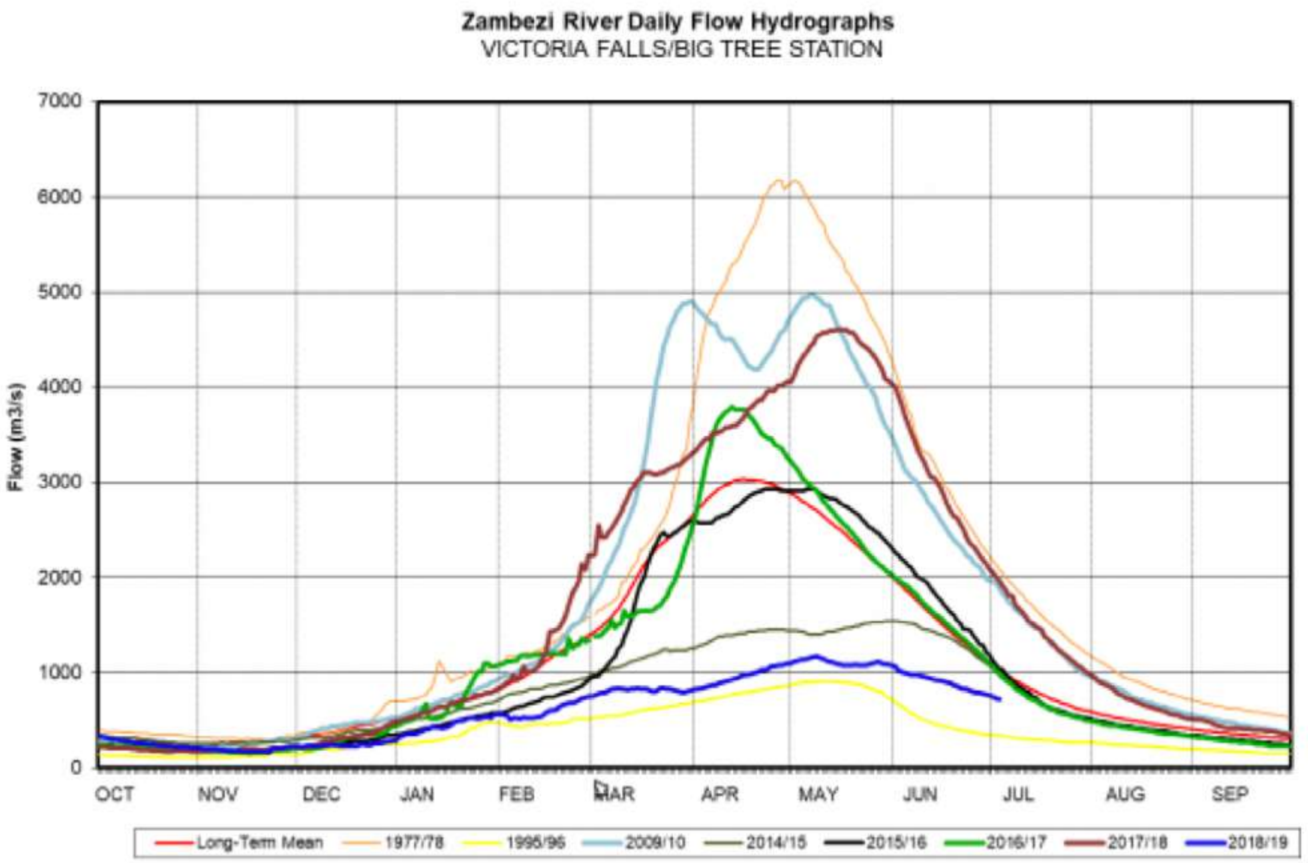


Figure 6.25 – Zambezi flow at the Victoria Falls Power Plant site (Big Tree observation station) [http://www.zambezira.org/hydrology/river-flows]

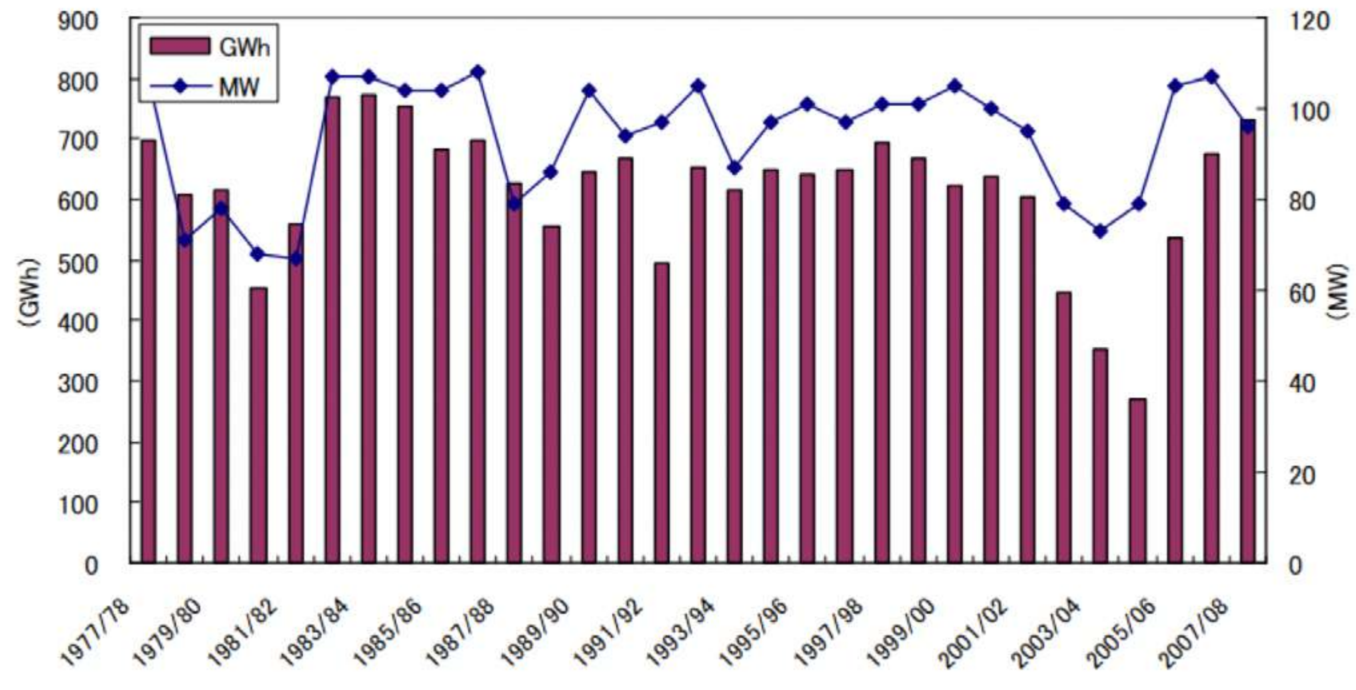


Figure 6.26 – Yearly energy generated by Victoria Falls power plant (Source MEWD, [10])

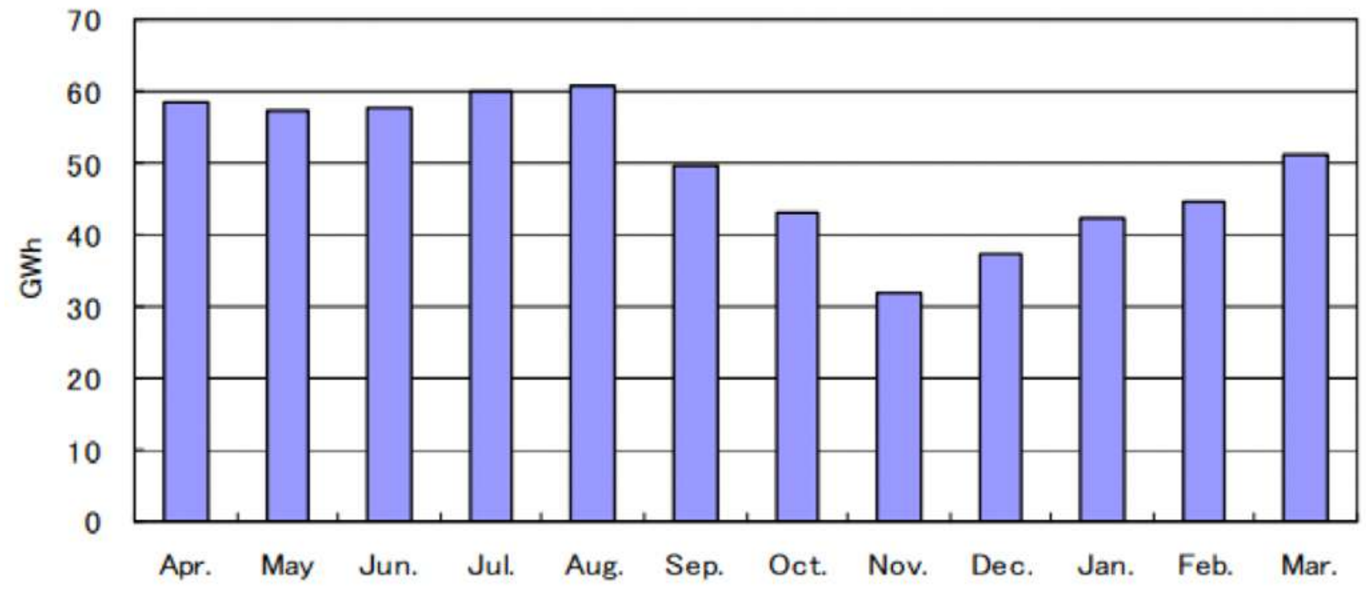


Figure 6.27 – Monthly average generated energy by Victoria Falls power plant over the period 1998 – 2002 (Source MEWD, [10])

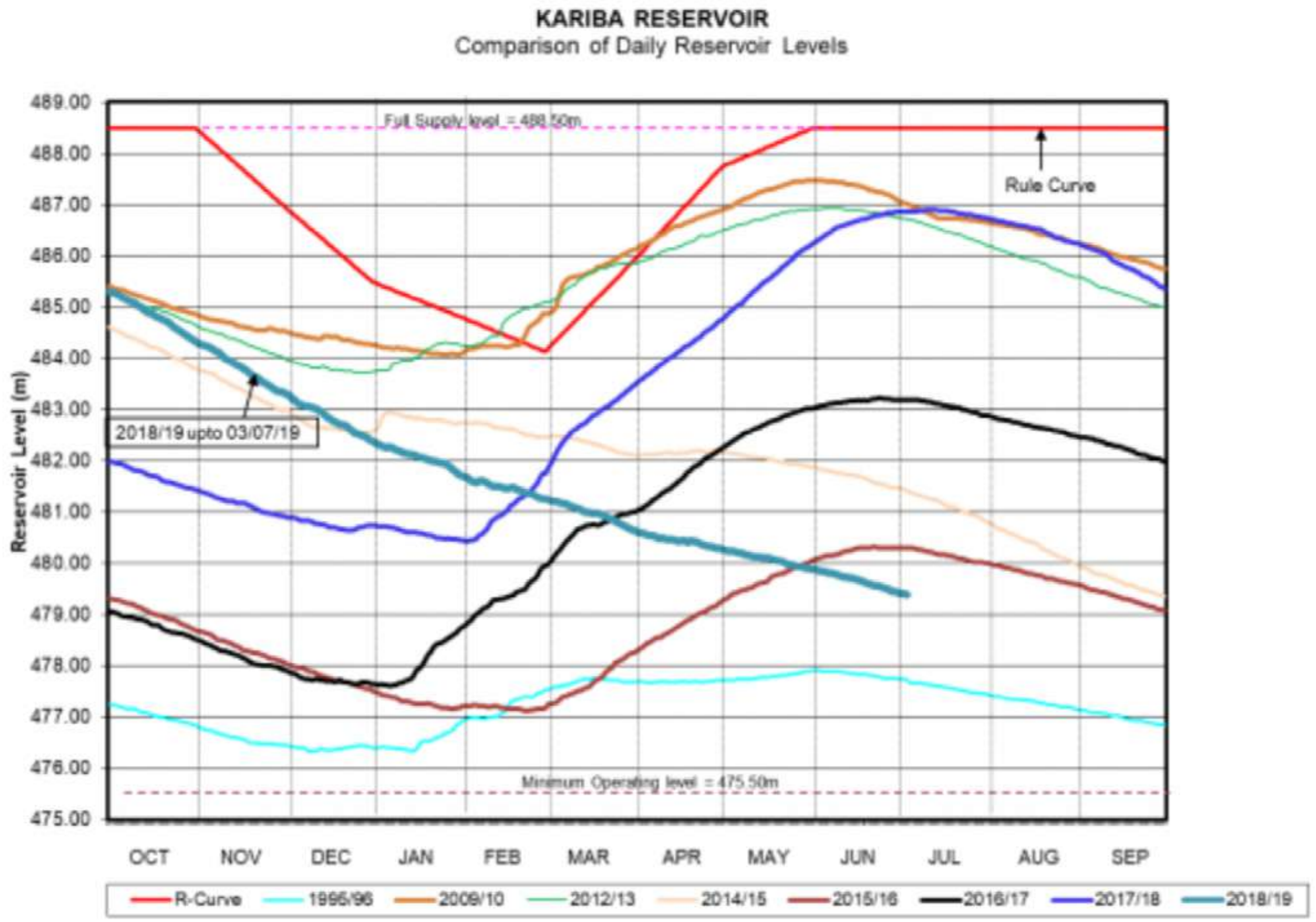


Figure 6.28 – Kariba reservoir historical level [http://www.zambezira.org/hydrology/lake-levels

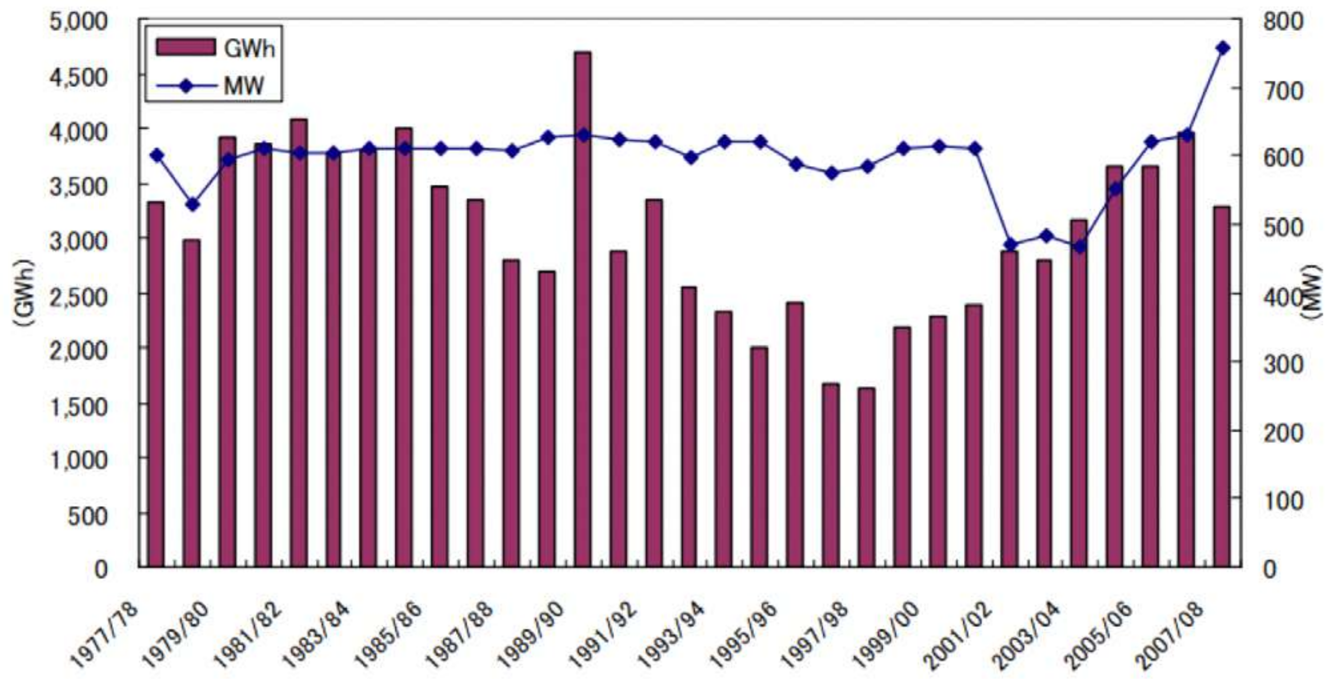


Figure 6.29 – Yearly energy generated by Kariba North Power Plant (Source MEWD, [10])

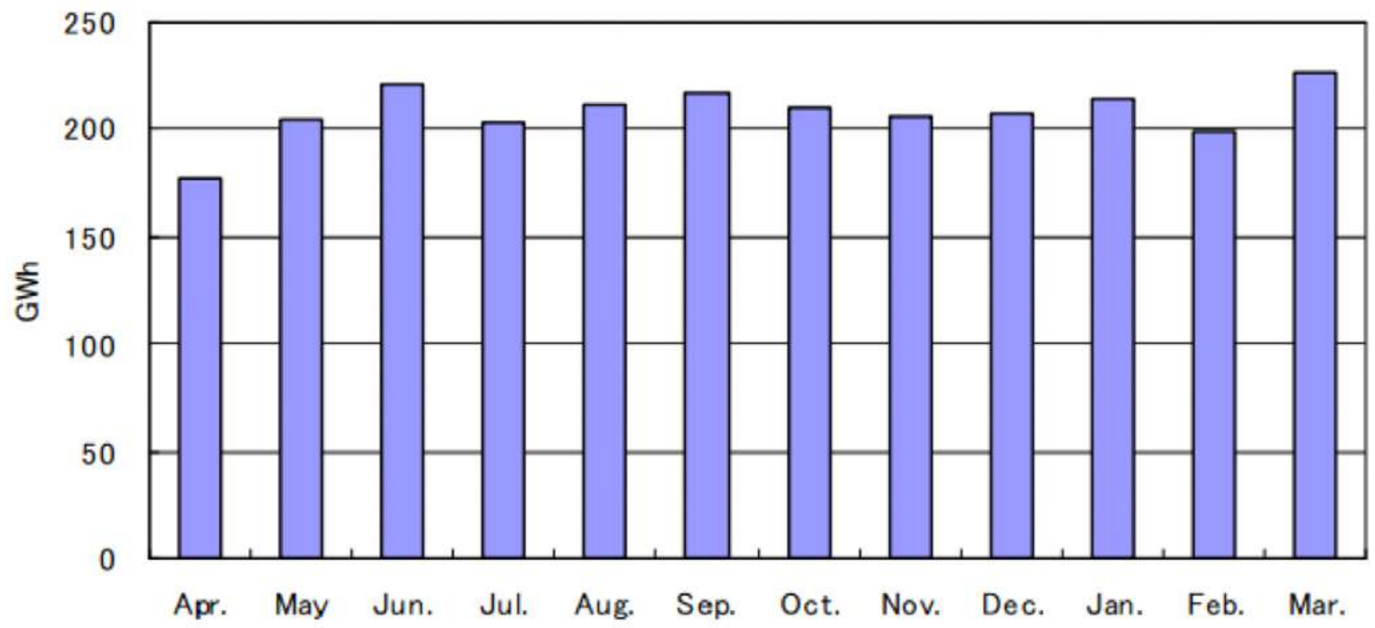


Figure 6.30 – Monthly average generated energy by Kariba North power plant over the period 1998 – 2002 (Source MEWD, [10])

Figure 6.31 – Existing power plants at Kariba lake dam

6.2.1.3 Other hydro power plants

For other minor hydro power plants this paragraph shows available information regarding inflow and production that was used as reference to define an average hourly production profile.

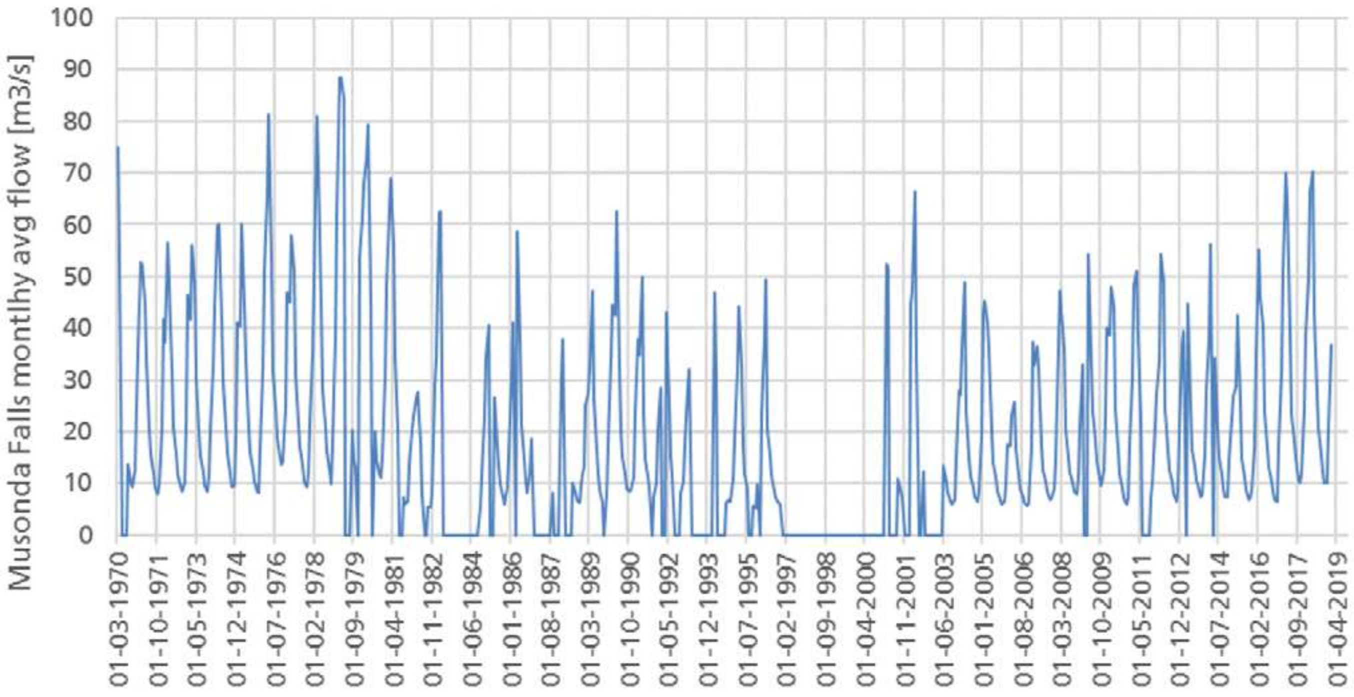


Figure 6.32 – Musonda falls historical monthly average flow

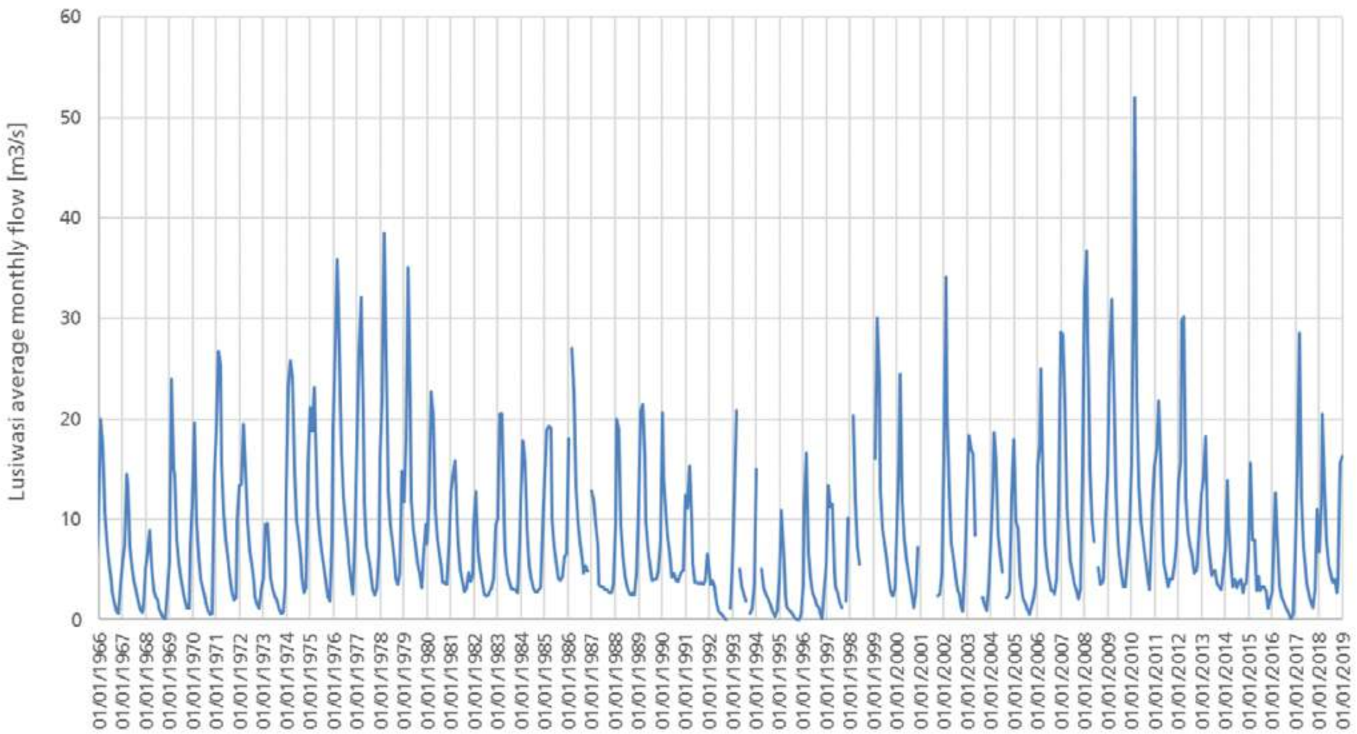


Figure 6.33 – Lusiwasi historical monthly average flow

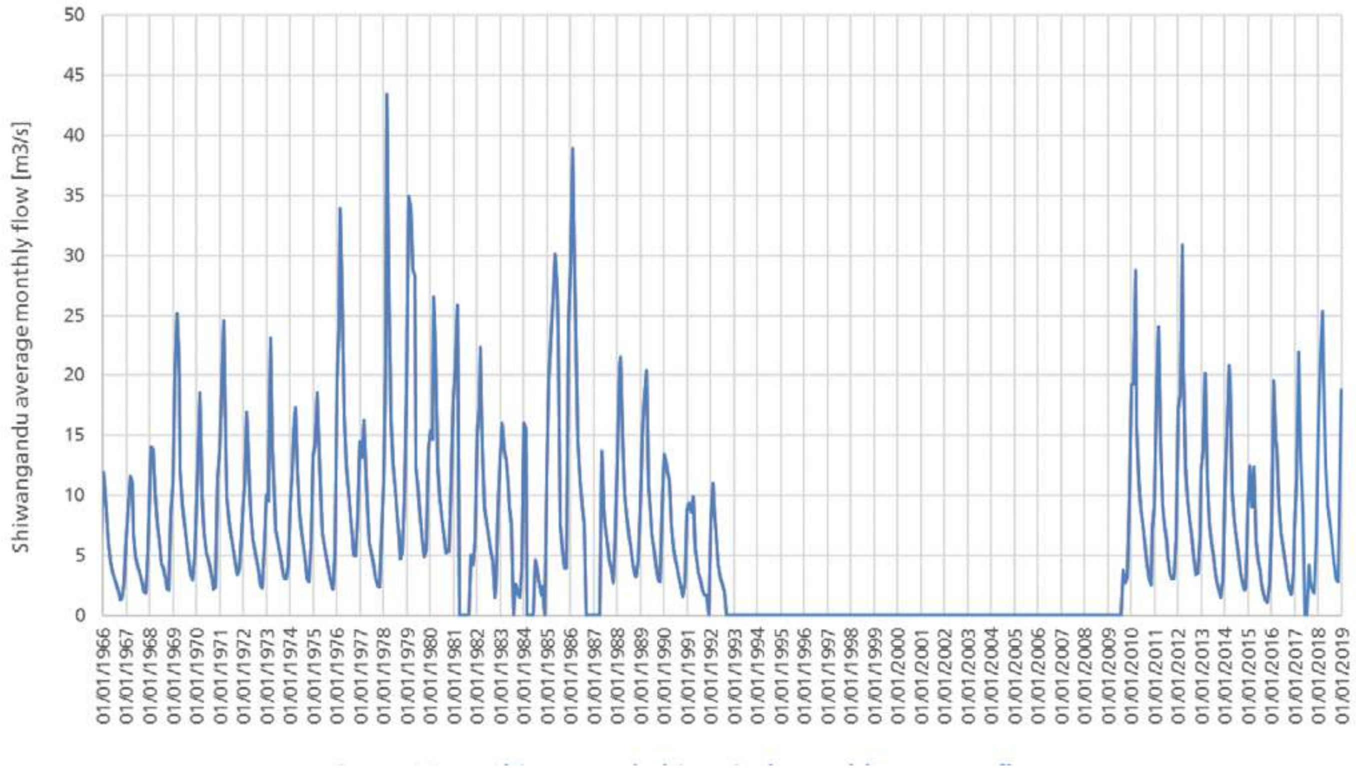


Figure 6.34 – Shiwangandu historical monthly average flow

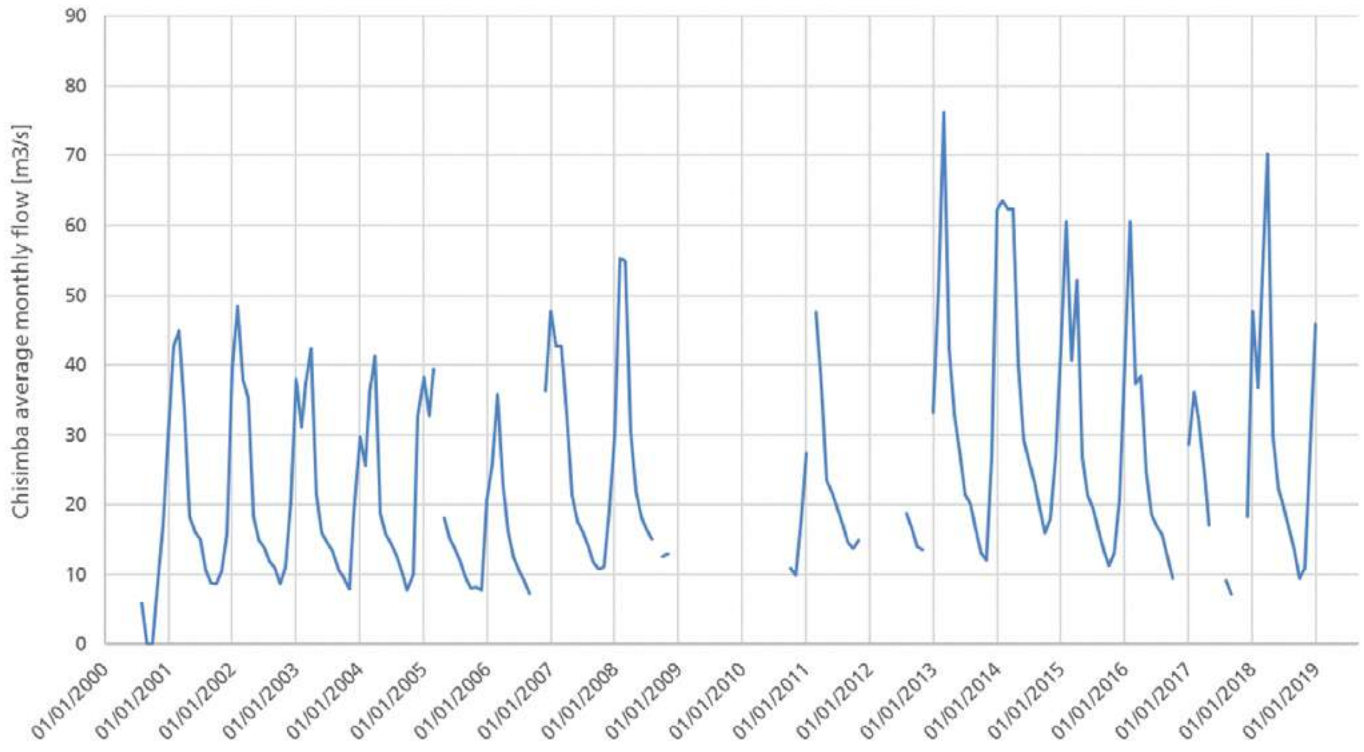


Figure 6.35 – Chisimba historical monthly average flow

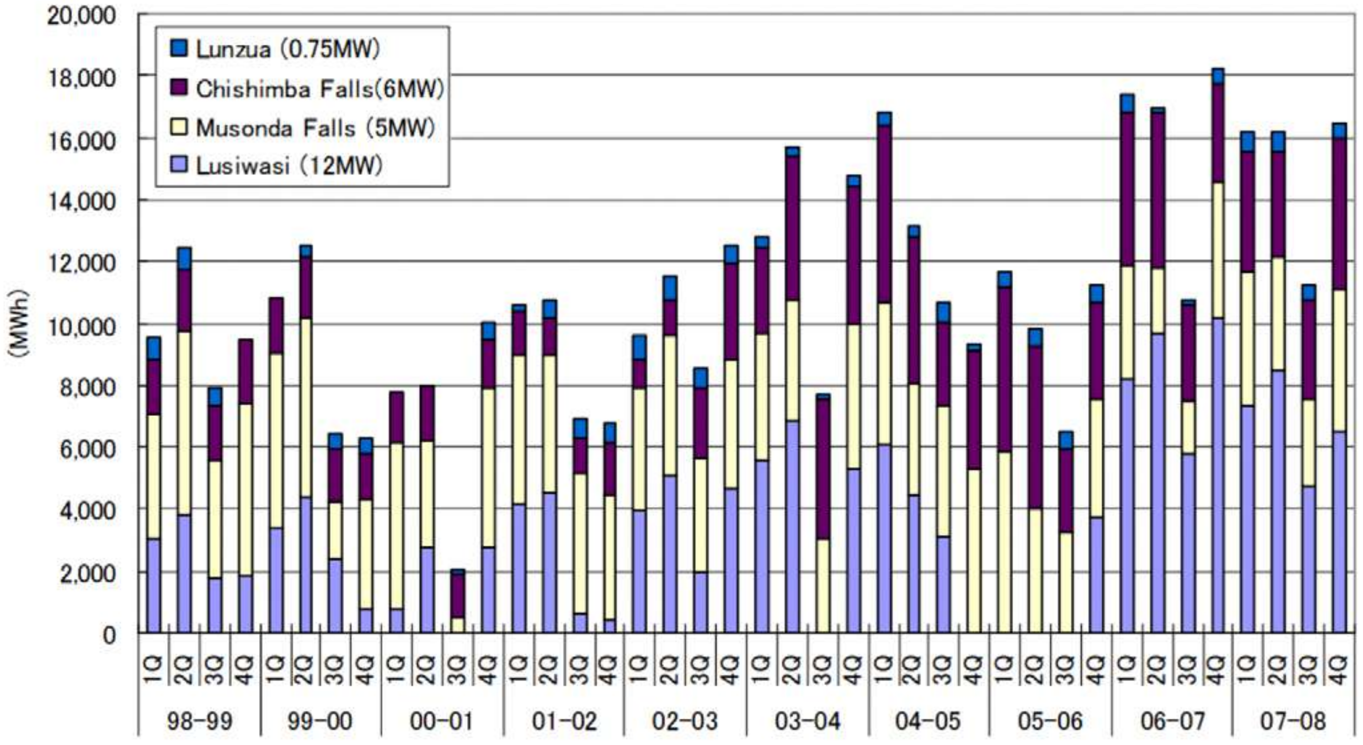


Figure 6.36 – Historical quarterly production for Lunzua, Chisimba, Musonda and Lusiwasi power plants over the period 1998-2008

6.2.2 Conventional generation fleet

Current Zambian generating fleet run on fossil fuels is composed by a coal and a medium speed reciprocating engine power plant. Two Circulating Fluid Bed Rankine cycles were built at Maamba, close to the Kariba lake, at a coal mine operated by Maamba Collieries Limited (MCL). The objective of the baseload power plant is to generate electricity while preventing pollution due to self-burning of low grade coal stockpiled for decades and in the project area. It entails the re-use of what has and would otherwise be left as waste in the project areas [11]. The Heavy Fuel Oil (HFO) reciprocating engine power plant was built at Ndola.

Table 6.8 shows the main technical features of existing plants (no additional fossil fuel power plants are planned), in particular:

- Power plant name;
- Number of units;
- Type of power plant;
- Total installed capacity of each power plant (Pinst);
- Maximum power output of each power plant (Pmax) that can be used to meet power demand;
- Technical minimum power (Pmin) as percentage of the maximum power output. This power represents the minimum power output of each group able to assure a stable operation of the power plant;
- Commercial Operation Date (COD);
- Availability parameters: Forced Outage Rate (FOR) and maintenance duration;
- HHV heat rate and efficiency at max load.

Table 6.8 – Technical parameters of existing thermal generation fleet

Power Station Name	N° units	Type	Fuel	Pinst. [MW]	Pmax [MW]	Pmin [%Pmax]	COD	FOR [%]	Maint. [days/yr /unit]	HHV Heat Rate [kcal/kWh]	HHV Efficiency [%]
Maamba (MCL)	2	SC-CFB	Coal	300	265	56.6%	2016	10%	30	2,360	36.4%
Ndola I (NECL)	8	MSD	HFO	48	48	30%	2013	3%	25	1,955	44.0%
Ndola II (NECL)	8	MSD	HFO	57	57	30%	2017	3%	25	1,955	44.0%
TOTAL				405	370						

Additional operating information about Maamba coal power plant was provided by MCL:

- CO_2 emission in the range 1.0-1.2 kg/kWh, but a carbon emission price is not applicable;
- Start-up fuel for each start-up: approximately 40-80 KL High Speed Diesel (HSD) required for each unit depending on the condition of start-up (Hot or Cold);
- Start-up power for each start-up: approximately 90-170 MWh is required for each unit depending on the condition of start-up (Hot or Cold);
- Minimum notice to synchronize is between 6.5-16.0 hours, depending on starting condition and upon stabilization/restoration of grid supply;
- The minimum number of consecutive hours in which the units have to run for technical constraints after each start-up was not indicated by MCL because Maamba is a baseload power plant. However, the Consultant proposes a minimum time on equal to 8 hours if a degree of flexibility were to be included in the analyses to increase the VRES penetration;
- Lifetime of generation assets is 40 years.

The details of the PPAs between ZESCO and the Independent Power Producers are confidential, and they cannot be disclosed. Therefore, as agreed with the working group, the conventional fossil fuel power plants were modelled assuming a market dispatch based on SAPP fuel price forecast and an operating flexibility based on technical features (maximum power, technical minimum power, minimum time on and minimum time off).

6.2.3 Variable RES generation plan

Wind farms and solar power plants are generation units with power production dependent on non-controllable sources (wind and solar radiation). Their power production is affected by the variability of primary sources and by the uncertainty of their forecasting. Therefore, this type of generation can be classified as variable RES power plants.
The simulation tool adopted for the probabilistic analyses has dedicated models to simulate wind farms and photovoltaics parks production. These models consider the random availability of wind and solar radiation by means of Monte Carlo approach, considering also the effects due to capacity factors, seasonal variation and diurnal variation of RES.

6.2.3.1 *Solar generation*

The World Bank under a project covering biomass, solar and wind mapping funded by the Energy Sector Management Assistance Program (ESMAP) developed a solar resource model for Zambia that was refined by integrating fields measurements performed on six selected sites shown in Figure 6.38 and Figure 6.37, over a period of two years. The model results are represented in Figure 6.38, and they show a generally high solar resource, especially for the south-western part of Zambia, where average value of global horizontal irradiation (GHI) exceeds 2,000 kWh/m²/year.

No.	Site name	Nearest town	Latitude [°]	Longitude [°]	Altitude [m a.s.l.]	Measurement station host*
1	Lusaka UNZA	Lusaka	-15.39463°	28.33722°	1263	UNZA
2	Mount Makulu	Chilanga	-15.54830°	28.24817°	1227	ZARI/ZMD
3	Mochipapa	Choma	-16.83828°	27.07046°	1282	ZARI/ZMD
4	Longe	Kaoma	-14.83900°	24.93100°	1169	ZARI
5	Misamfu	Kasama	-10.17165°	31.22558°	1380	ZARI/ZMD
6	Mutanda	Mutanda	-12.42300°	26.21500°	1316	ZARI/ZMD

**Zambia Meteorological Department (ZMD), Zambia Agriculture Research Institute (ZARI) and School of Agricultural Sciences at University of Zambia (UNZA)*

Figure 6.37 – Selected sites geographical data (Source World Bank, [8])

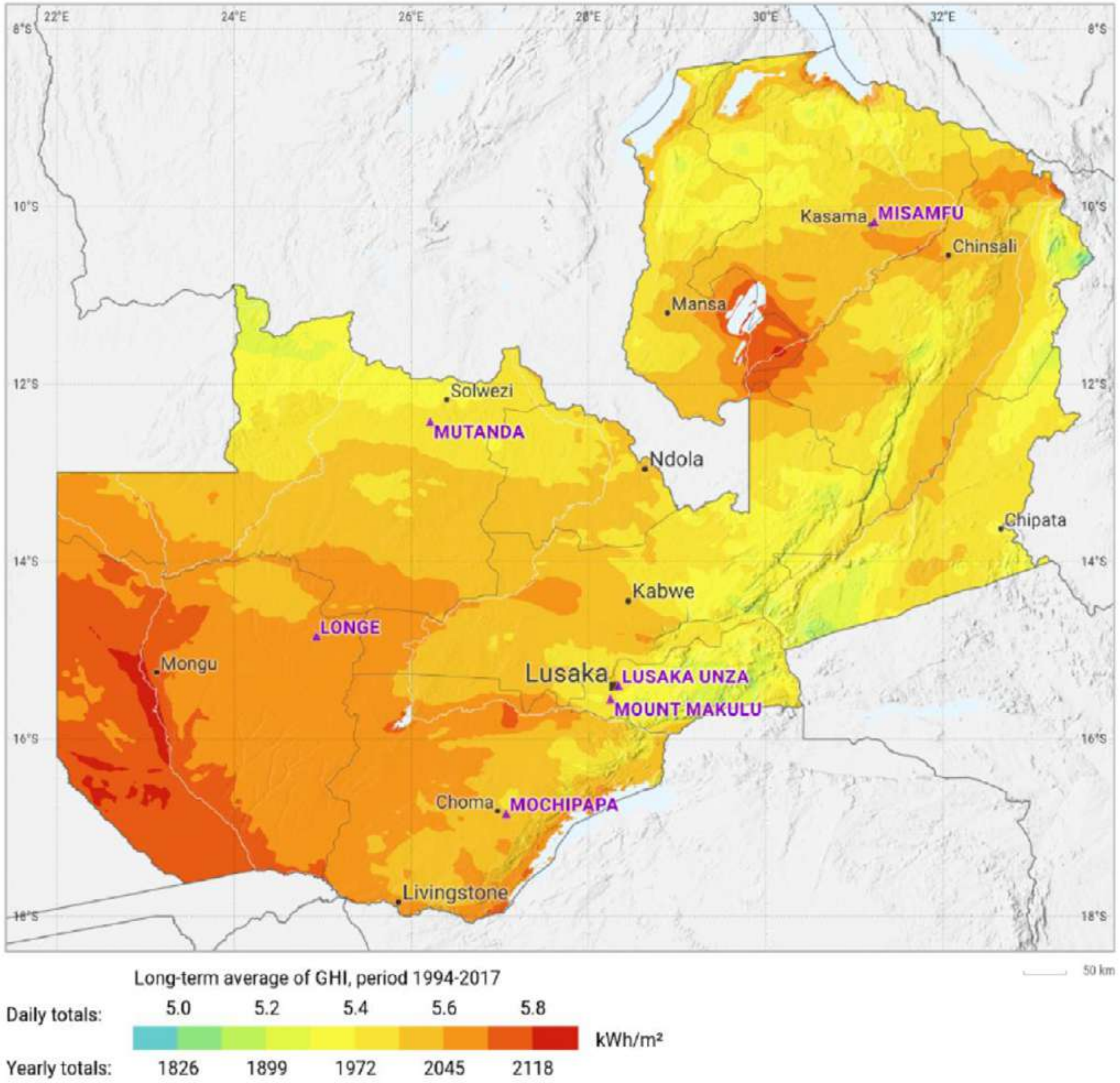


Figure 6.38 – Selected sites for solar data measurements (Source World Bank, [8])

Month	Global Horizontal Irradiation [kWh/m^2]						Variability between sites [%]
	Lusaka	Mount Makulu	Mochipapa	Longe	Misamfu	Mutanda	
January	5.16	5.15	5.28	5.32	4.84	4.87	4.0
February	5.18	5.13	5.37	5.45	4.99	4.89	4.2
March	5.22	5.16	5.30	5.44	5.16	5.18	2.1
April	5.24	5.24	5.32	5.77	5.20	5.47	4.1
May	5.11	5.08	5.08	5.48	5.37	5.49	3.8
June	4.71	4.69	4.71	5.13	5.42	5.34	6.8
July	4.90	4.88	4.93	5.33	5.56	5.45	5.9
August	5.71	5.69	5.81	5.98	6.08	5.90	2.6
September	6.47	6.42	6.54	6.46	6.43	6.23	1.6
October	6.66	6.52	6.68	6.44	6.32	6.11	3.4
November	6.05	5.86	5.86	5.77	5.84	5.41	3.7
December	5.45	5.35	5.46	5.41	5.27	5.08	2.7
YEAR	5.49	5.43	5.53	5.67	5.54	5.45	1.5

Figure 6.39 – Daily averages of Global Horizontal Irradiation at six sites (Source World Bank, [8])

Month	Temperature [°C]					
	Lusaka	Mount Makulu	Mochipapa	Longe	Misamfu	Mutanda
January	20.9	21.2	21.4	22.2	20.0	20.6
February	20.9	21.1	21.0	22.5	19.9	20.4
March	20.5	20.7	20.5	22.7	19.9	20.4
April	19.2	19.4	19.0	21.9	19.4	19.7
May	17.1	17.2	16.7	20.2	18.1	18.5
June	15.0	15.1	15.0	17.6	16.2	16.8
July	14.4	14.5	14.4	17.0	16.0	16.9
August	17.1	17.2	17.4	20.1	18.7	20.3
September	20.5	20.9	21.1	23.7	21.6	23.2
October	23.0	23.4	23.5	25.5	23.2	24.5
November	22.9	23.2	22.9	23.6	22.3	21.7
December	21.5	21.8	21.7	22.4	20.5	20.4
YEAR	20.2	20.5	20.4	22.5	20.5	21.1

Figure 6.40 – Monthly averages of air-temperature at the six sites (Source World Bank, [8])

Figure 6.41 shows the performances that could be reached by fixed tilted PV systems with standard modules (mono-facial) in the six monitoring sites. The electricity production is very similar in all sites with capacity factors between 19% and 20%. The monthly variation in the expected solar production is highlighted in Figure 6.42. The highest levels of solar production are expected during the months from July to September, while the lowest solar production levels should occur in January and December. This is the combined effect of GHI and air temperature on PV power production; in fact, the latter becomes greater as the GHI is higher and the air temperature is lower.

The peak season for solar generation occurs during the dry season when reservoir levels and hydro generation are at their lowest values. In these terms, there is a complementarity between solar generation and hydro generation that can help the system during the dry season.

	Lusaka	Mount Makulu	Mochipapa	Longe	Misamfu	Mutanda
PVOUT Average daily total [kWh/kWp]	4.56	4.51	4.62	4.66	4.52	4.48
PVOUT Yearly total [kWh/kWp]	1665	1649	1689	1702	1651	1638

Figure 6.41 - PV electricity yield for standard fixed modules (Source World Bank, [8])

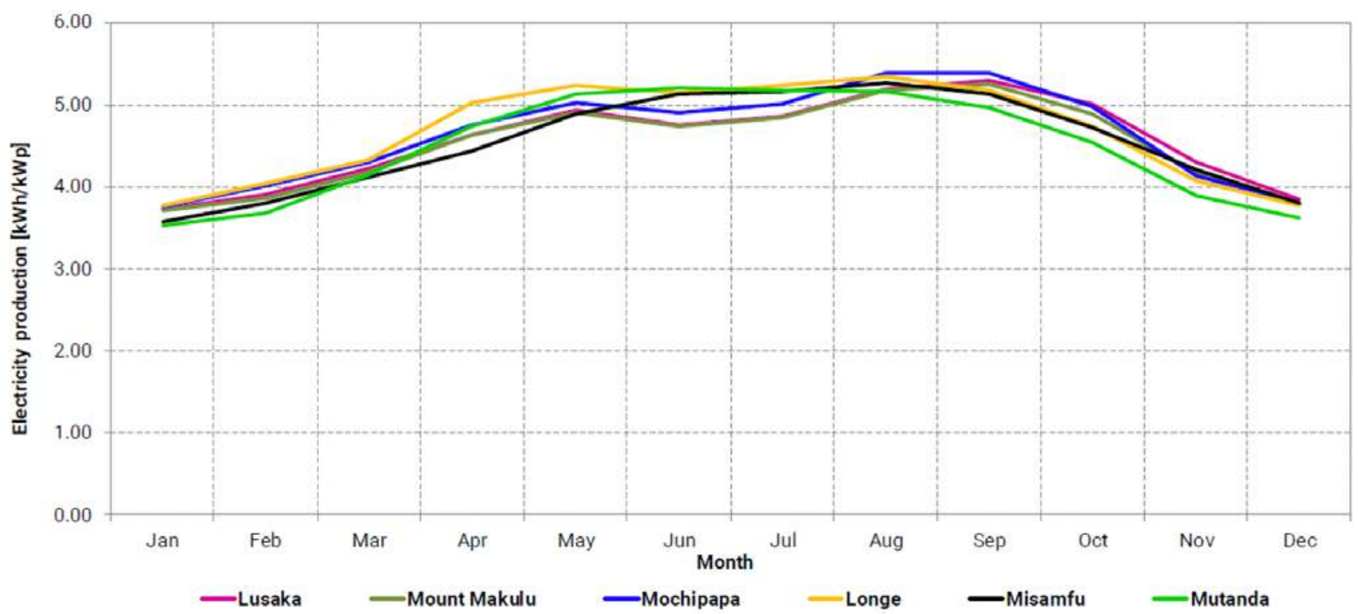


Figure 6.42 – Monthly variation in solar production from 1 kWp fixed tilted PV systems (Source World Bank, [8])

The electricity production expected by a PV power plant is strictly dependent by the technology adopted to exploit the solar source; a wide range of capacity factors can be achieved using fixed-tilt solar power systems (with mono-facial or bi-facial modules) or axis tracking systems (single-axis or dual-axis tracker). Excluding the axis tracking systems due to the important increase of investment costs, the Consultant developed both a standard model based on mono-facial fixed-tilt power system and a more advanced fixed-tilt model based on bi-facial modules. The latter was considered in addition to the standard model to assume the use of new technologies in the long-term with 4-5% increase in capacity factors.

Starting from the hourly time series of GHI, DNI, DHI and temperature available for the six monitoring sites, the Consultant estimated the hourly time-series of electricity production from PV power plants located at that sites, by using a specific tool develop by NREL named System Advisor Model (SAM). The System Advisor Model is a performance and financial tool designed to facilitate decision making for people involved in the renewable energy industry. SAM makes performance predictions and cost of energy estimates for grid-connected power projects based on installation and operating costs and system design parameters that are specified as inputs to the model.

Currently Zambia has only two PV power plants in service with a total installed capacity equal to 75.7 MW; both power plants located near Lusaka. For the target years 2025 and 2030 the installation of new PV power plants is foreseen. Table 6.9 shows the list of PV projects in pipeline (370 MW) and the expected candidates provided by MOE (290 MW), that will all be built not too far from Lusaka. For each PV project the following relevant information is reported: size of the power plant, project status, location and Point of Common Coupling (PCC) with the National grid, possible commercial operation date, PPA tariff and solar irradiation profile that was associated in the model. The PCC with the National grid is approved for the committed projects while it is only proposed for the candidate projects. Therefore, the PCC of the candidate projects could be changed if network constraints were highlighted in System Reliability Impact Study (Task 4).

The reference weather data applied for each PV projects is the result of the comparison between the sites of PV projects and the locations of the weather stations, considering their distance and the potential of PV power plant sites. The result of these assumptions is an expected production of 1.3 TWh/year from 736 MW PV power plants with standard fixed modules; an additional production (4-5%) could be assumed if bi-facial PV modules will be used to improve the exploitation of the solar sources in the Country. Figure 6.43 and Figure 6.44 highlight the monthly profile and the average daily figures expected from 736 MW PV power plants with standard fixed modules.

Table 6.9 – Existing, committed and candidate PV power plants

Power Plant Name	Owner	Pmax [MW]	Project Status	Location	PCC	COD	Tariff [US$c/kWh]	Ref. weather data
Bangweulu	Neoen/First Solar	47.5	existing	Lusaka	LS-MFEZ S/S	2019	6.02	Lusaka
Ngonye	Enel Green Power	28.2	existing	Lusaka	LS-MFEZ S/S	2019	7.84	Lusaka
Bulemu West	Building Energy	20.0	committed	Bulemu	Kabwe S/S	2020	3.999	Lusaka
Bulemu East	Building Energy	20.0	committed	Bulemu	Kabwe S/S	2020	3.999	Lusaka
Solar one	Globeleq, Aurora	20.0	committed	Kafue	Kafue Town S/S	2020	4.52	Mt Makulu
Solar Two	Globeleq, Aurora	20.0	committed	Kafue	Kafue Town S/S	2020	4.52	Mt Makulu
Garneton North	CEC, Innovent	20.0	committed	Kitwe	Mwambashi S/S	2020	4.80	Lusaka
Garneton South	CEC, Innovent	20.0	committed	Kitwe	Mwambashi S/S	2020	4.80	Lusaka
Kanona	Masen, ZESCO	100.0	committed	Serenje	Safal S/S	n.a.	n.a.	Lusaka
Muzuma	Masen, ZESCO	100.0	committed	Serenje	Muzuma S/S	n.a.	n.a.	Lusaka
Green Field	Greenfield Energy	50.0	committed	Lusaka	n.a.	n.a.	n.a.	Lusaka
Globeleq project	Globeleq	100.0	candidate	Lusaka	Leopards Hills S/S	2020	7.35	Lusaka
MGC project	MGC	100.0	candidate	Mumbwa	Mumbwa-Nambal S/S	2020	7.00	Lusaka
Hive project	Hive Energy	90.0	candidate	Siavonga	KNB S/S	2020	5.25	Mt Makulu
TOTAL		**735.7**	**-**				**-**	**-**

Figure 6.43 – Expected monthly production pattern from PVPPs in the pipeline.

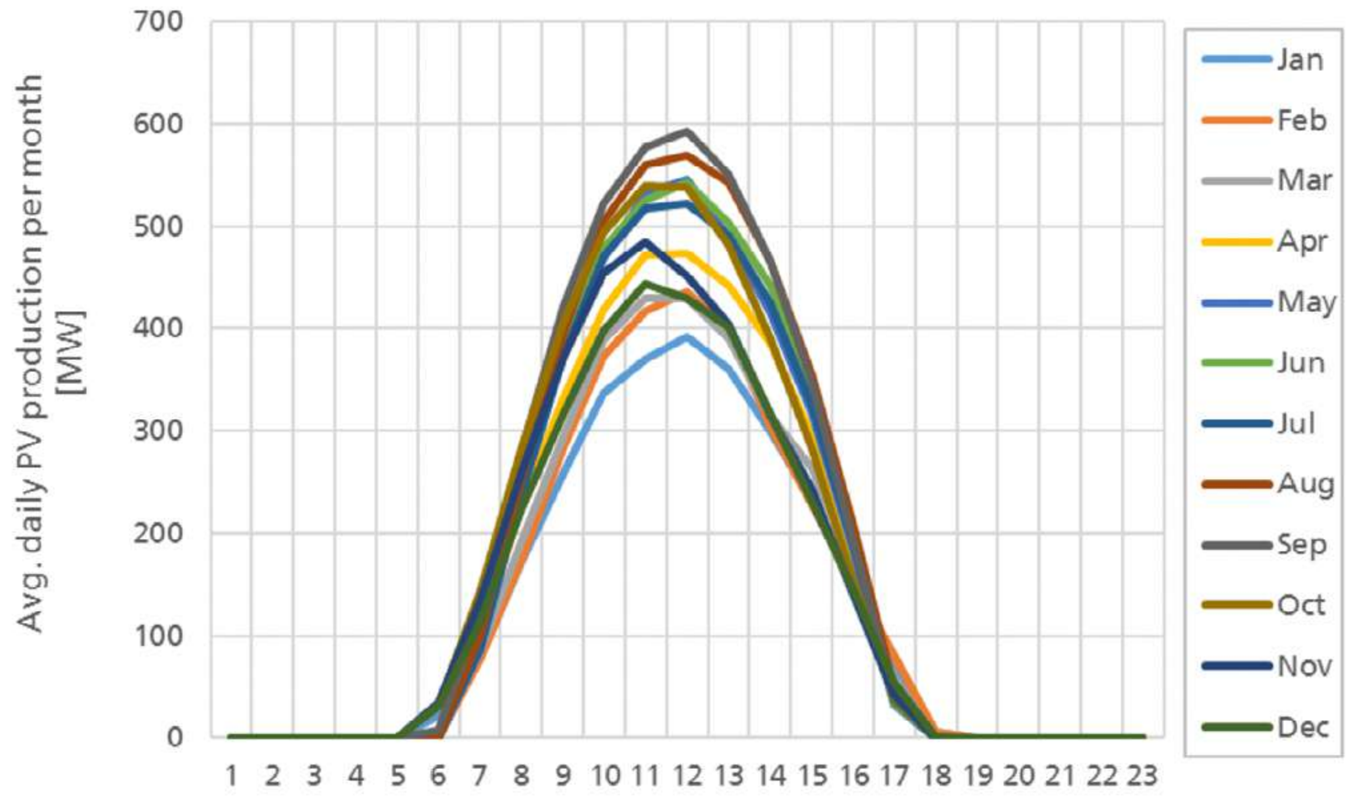


Figure 6.44 – Average daily PV production patterns per month

6.2.3.2 Wind generation

Zambia is still in the early stages of exploring the resource potential for wind power: to date there are no utility scale wind turbines operating in the country and there is only one candidate project, the Acess Power Wind Project in Pensulo, Serenje District, with a nominal capacity of 130 MW that should come online on 2023. The World Bank commissioned to DNV GL a mesoscale wind atlas for Zambia, to be validated with wind speed measurements taken at eight met masts over a period of two years. Figure 6.45 shows the mesoscale wind speed map at 80 m AGL, as simulated by the DNV GL Wind Mapping System. Figure 6.46 shows the location of the installed met masts.

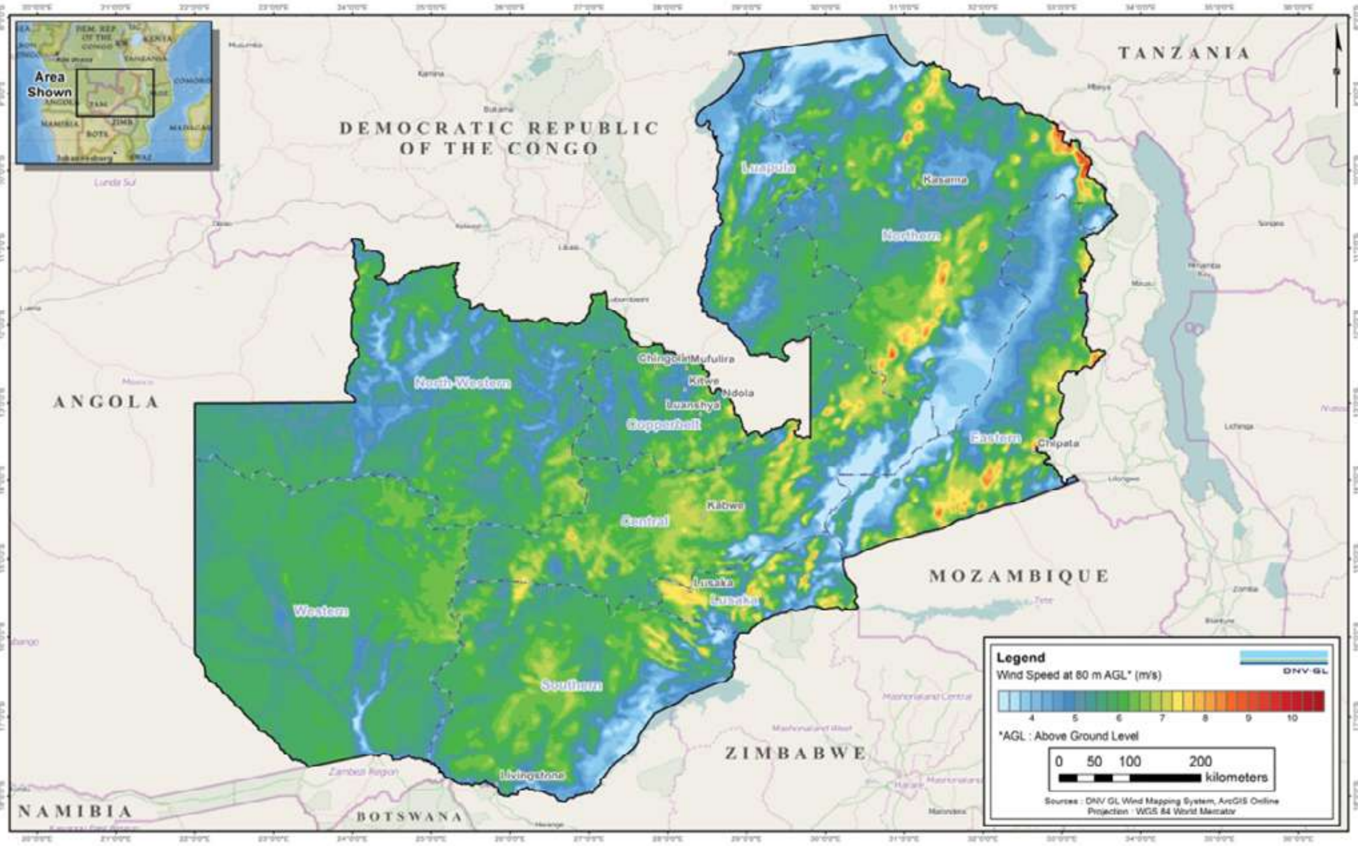


Figure 6.45 – Mesoscale wind speed map at 80 m AGL (Source World Bank, [6])

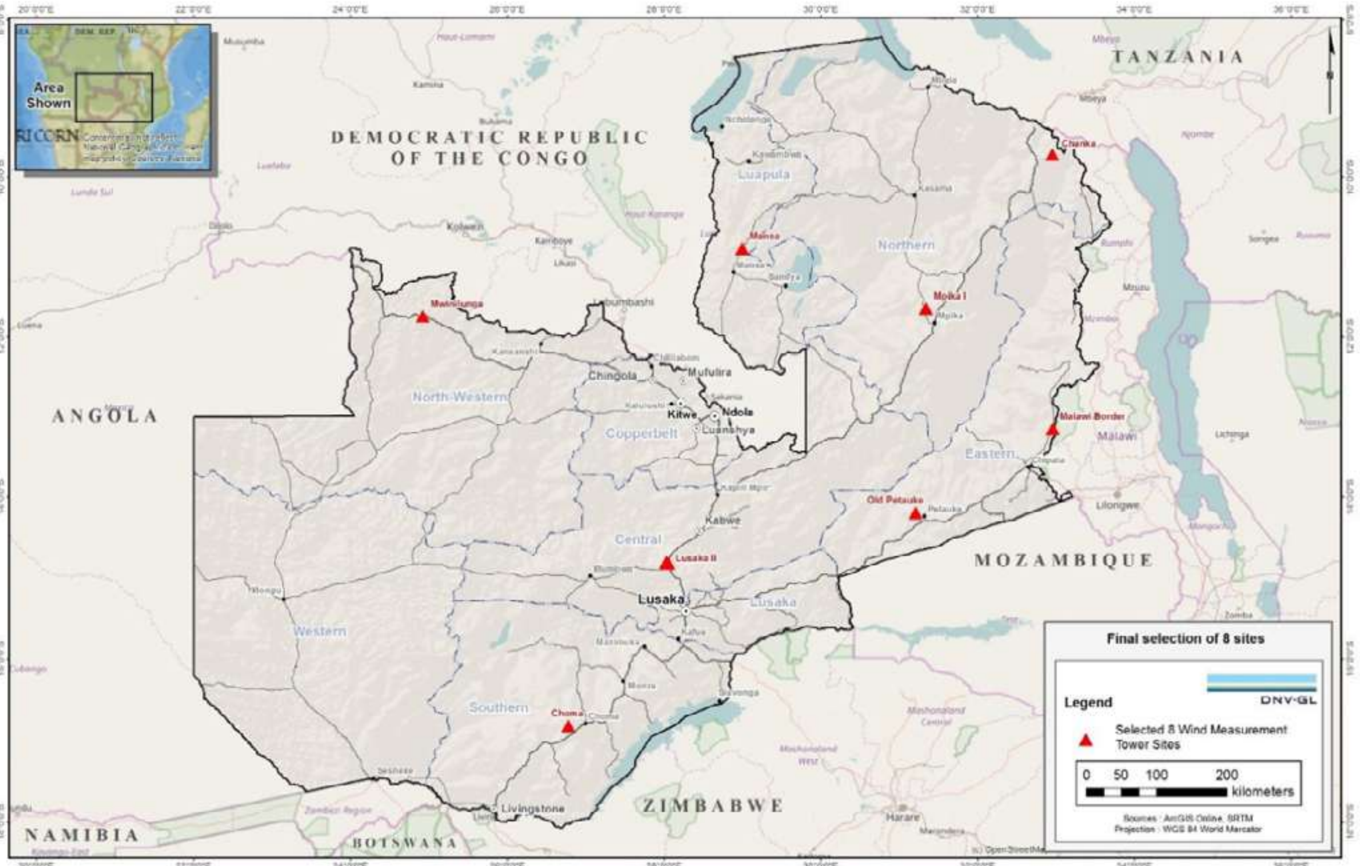


Figure 6.46 – Location of the eight met masts used for the monitoring campaign (Source World Bank, [5])

Figure 6.47 shows the mean wind speed measured at 80 m AGL during the monitoring period, which resulted on average around 6 m/s. Starting from measures collected over two years at 80 m AGL, DNV GL executed long-term adjustment of wind speed and estimates the wind speed from the measurement height to the 130 m hub height. Figure 6.48 summarizes the average turbine wind speed that could be expected at each site at 130 m: 7.5 m/s mean wind speed is the average on the monitored sites, with 8.2 m/s mean wind speed expected in the best site near Lusaka.

Mast	Height [m]	Data Period	Data coverage [%]	Measured mean wind speed [m/s]
Choma	80.0	01/11/2016 – 10/01/2018	95	6.5
Mwinilunga	80.0	03/12/2016– 09/01/2018	100	6.0
Lusaka	80.0	21/11/2016– 09/01/2018	99	6.2
Mpika	80.0	20/11/2016– 09/01/2018	100	6.2
Chanka	80.0	23/11/2016– 10/01/2018	100	6.5
Petauke	80.0	09/12/2016– 09/01/2018	100	5.7
Mansa	80.0	26/11/2016– 10/01/2018	100	5.8
Malawi	80.0	21/12/2016– 10/01/2018	100	5.8

Figure 6.47 – Mean wind speed at 80 AGL measured over the indicated period (Source World Bank, [5])

Site	Average turbine wind speed at 130 m [m/s]
Choma	7.4
Mwinilunga	7.5
Lusaka	8.2
Mpika	7.3
Chanka	7.5
Petauke	7.0
Mansa	7.3
Malawi	7.1

Figure 6.47 – Mean wind speed at 80 AGL measured over the indicated period (Source World Bank, [5])

The Consultant assumed that candidate wind farms will be equipped with two different wind turbine types; in the short- and mid-term with wind turbines rated 4.0 MW, hub height 130 m and rotor diameter 140 m, representing the current state of the art; while in the long-term with wind turbines rated 4.2 MW, hub height 140 m and rotor diameter 150 m, considering the ongoing technological development in the wind power sector. Figure 6.49 shows the considered wind turbine power curves while the resulting wind farms capacity factors for the eight met masts are shown in Table 6.10. The Acess Power Wind Project in Pensulo is the only candidate wind project indicated by the ZWG (details in Table 6.12); additional candidate wind farms were assumed to be placed near the eight met masts with a site priority according to the best potential location and access to the grid.

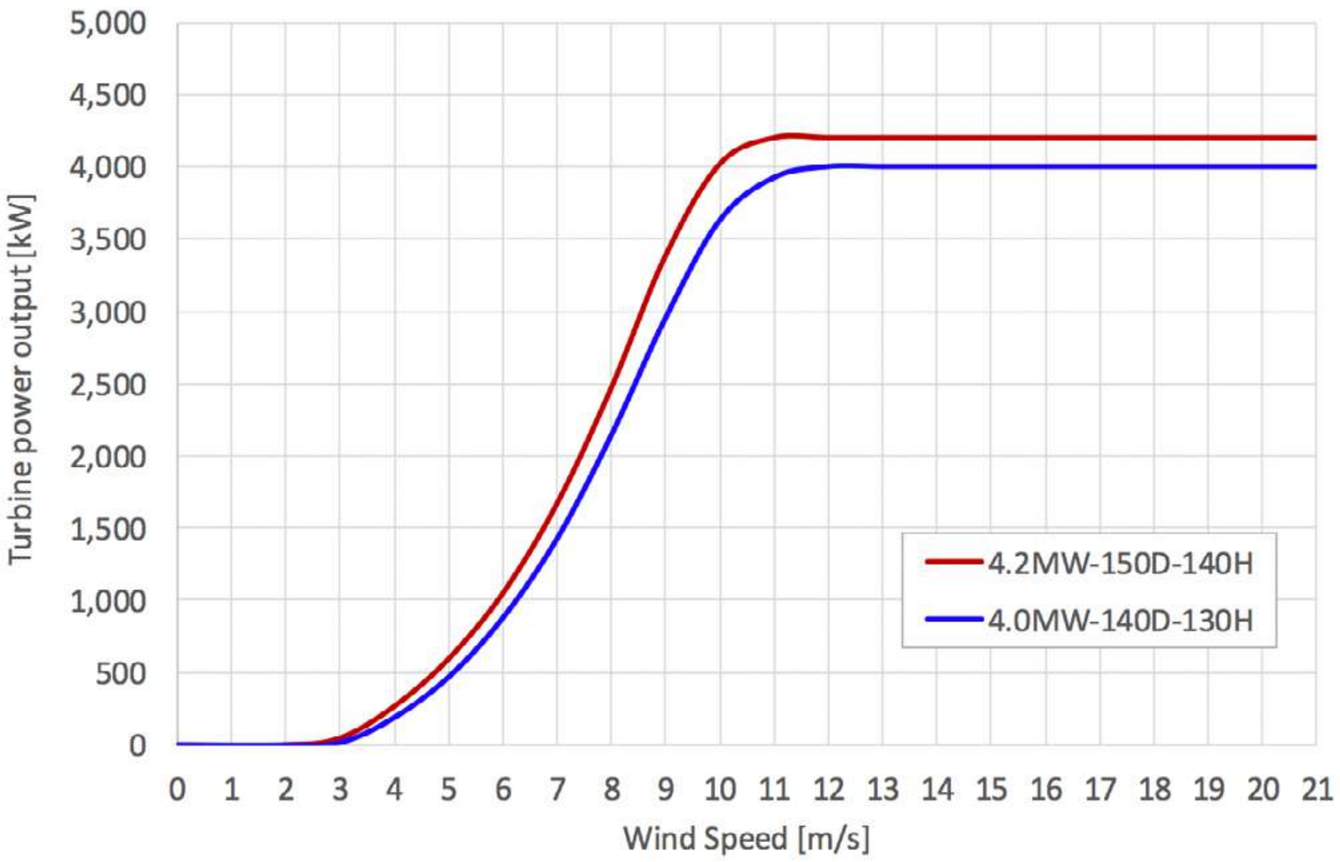


Figure 6.49 – Wind power curves

Table 6.10 – Considered capacity factors with reference wind turbines

Site	4.0MW-140D-130H	4.2MW-150D-140H
Choma	31.5%	36.7%
Mwinilunga	33.9%	38.8%
Lusaka	40.4%	46.2%
Mpika	33.3%	38.0%
Chanka	35.5%	40.1%
Petauke	29.8%	34.6%
Mansa	32.7%	37.9%
Malawi	31.3%	36.9%

Table 6.11 – Candidate wind power projects

Power Plant Name	Owner	Pmax [MW]	Project Status	Location	PCC	COD	Tariff [US$c/kWh]
Serenje Acess Power Wind Project	Access Infra Africa Limited, Total EREN S.A.	130	candidate	Serenje	Pensulo S/S	2023	8.80

6.3 Power transmission network

The main actors of the power transmission system are:

- ZESCO: a vertically integrated power utility that generates, transmits, distributes and supplies electricity in Zambia, fully owned by the Government of the Republic of Zambia. ZESCO operates the electricity grid and is responsible for much of the country's power generation.
- Copperbelt Energy Corporation Plc (CEC) is an independent transmission company that purchases power from ZESCO and supplies the mines, smelters and refineries in the Copperbelt Province through its own transmission and distribution network. CEC grid is interconnected also with the Democratic Republic of Congo (DRC).

Figure 6.50 reports the planned and existing transmission system in Zambia. The transmission grid comprises transmission lines and substations at 330 kV, 220 kV, 132 kV, 88 kV and 66 kV voltage levels. The 330 kV system is the backbone of the grid; it connects the greater hydro power stations located in the southern part of the country with the biggest load centres in Lusaka and Central provinces up to the Copperbelt region. Furthermore, it allows the strong connection of the eastern regions of the country.

6.3.1 Power system models

ZESCO provided the PSS/E models of the Zambian electric power system for the years 2018, 2022, 2025 and 2030. In detail, the SAPP PSS/E model during the peak load condition has been provided for each year: "2018 Base Case.sav", "ZAM-DRC_v12_2022.sav", "ZAM-DRC_v12_2025.sav", "ZAM-DRC_v12_2030.sav".

The power system models 2025 and 2030 were the reference for the system reliability impact study (Task 4) focused on generation and transmission adequacy. ZESCO updated and validated the PSS/E models 2025 and 2030 according to the last transmission expansion plan. The list of grid projects that were considered in the VRES integration study for the period 2018-2025 are highlighted in Table 6.12.

The Consultant converted PSS/E models (static models) in SPIRA format to perform the probabilistic simulations with GRARE tool. Furthermore, before starting with the simulations, the Consultant proceeded to update the power system database for all target years object of the simulations:

- The power system model of Zambia was extracted by the SAPP model, with all interconnection lines with the neighbouring countries. An equivalent model of the neighbouring countries was defined.
- An update of the Zambian loads was carried out according to the last demand forecast (see section 6.1); furthermore, an hourly time-series of national demand was included in GRARE model to simulate a whole year.

- The power generation system was updated according to the generation expansion plan defined in the section 6.2. Committed and candidate VRES projects indicated by the working group were included according to the provided grid connection points; additional VRES power plants resulting by the Task 3 of the study were included in the system taking into account the locations with the best wind/solar potential and the closeness to the national grid.
- Additional grid reinforcements due to VRES integration were object of the Task 4 of the study.

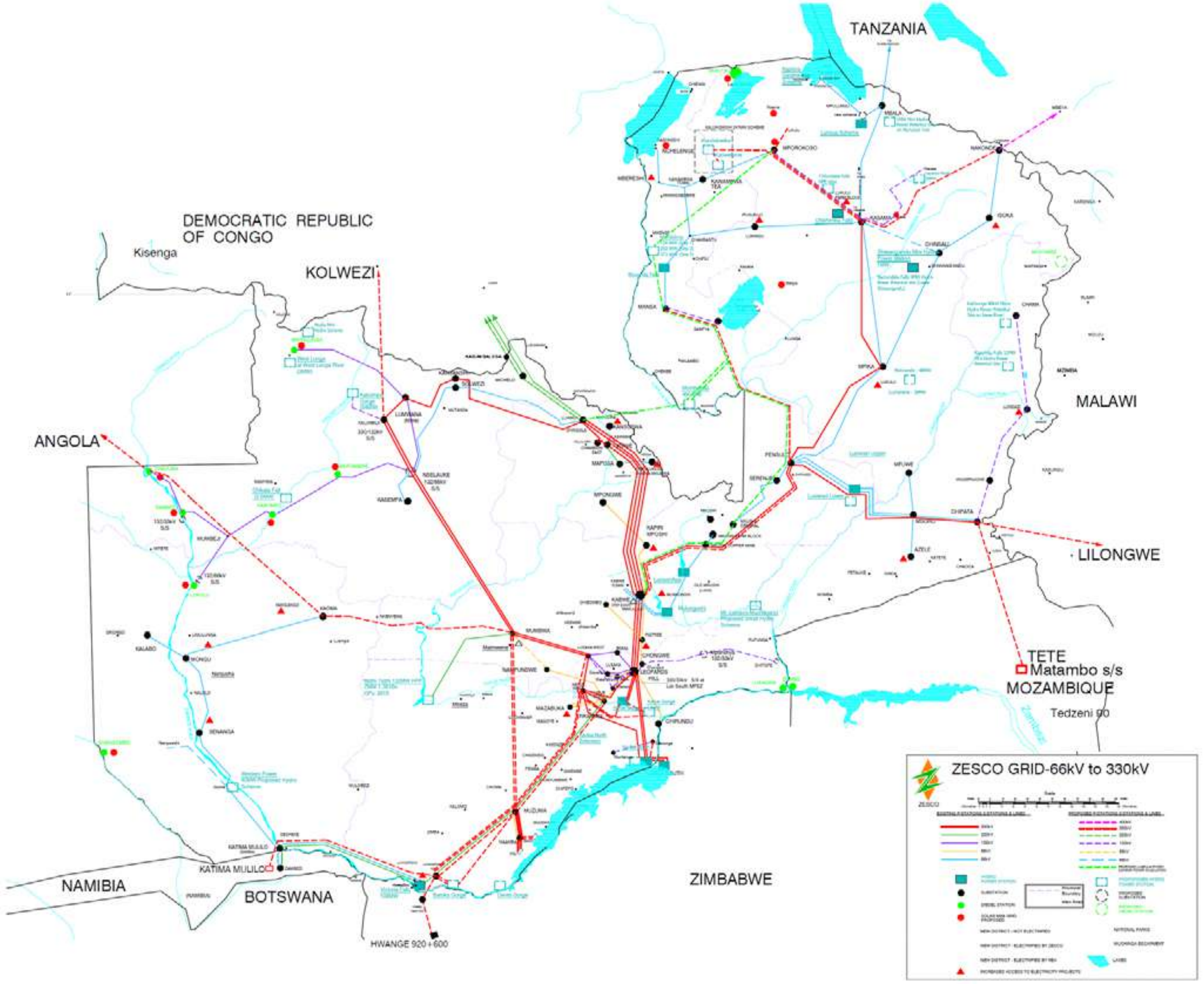


Figure 6.50 – Planned and existing transmission system in Zambia. Source ZESCO

Table 6.12 – List of grid projects 2018-2025

S/No.	NAME OF PROJECT	PROJECT SCOPE	STATUS	COD
1	Lusiwasi Upper- Lusiwasi Evacuation Line	• 1x66kV Overhead line, 7km to Lusiwasi and 83km to Pensulo	Under construction	2018
2	330kV Mpika substation	• Mpika 330/66kV, 2x90MVA • 1x30MVAr Pensulo Line Reactor, Mpika • 1x30MVAr 330kV Shunt Reactor, Mpika	Under construction	2019
3	Chipata - Lundazi - Chama	• Chipata West-Mwasemphangwe 132kV line at 83km • Mwasemphangwe 132/33kV substation, 2x15 MVA transformers • Mwasemphangwe-Lundazi 132kV line at 84km • Lundazi 132/33kV substation, 2 x 25MVA transformers • Lundazi-Egichikeni 132kV line at 47km • Egichikeni 132/33kV substation, 2x15 MVA transformers • Egichikeni-Chama 132kV line at 85km • Chama 132/33kV substation, 2x25 MVA transformers	Under construction	2019
4	Kafue Gorge Lower Power Evacuation	• 1x330kV Overhead line, KGL- LSMFEZ, 50km • 1x330kV Overhead line, KGL- Lusaka West, 106km • 1x330kV Overhead line, KGL- Kafue Gorge, 11km • Kafue West-Lusaka West 1x330kV Overhead line, 48km	Committed	2020
5	SVC for Luano and Kalumbila	• 180MVar Capacitive and 360MVar Inductive SVC at Luano 330kV • 170MVar Capacitive and 180MVar Inductive SVC at Kalumbila 330kV and a 50MVAr capacitor bank on the 330kV busbar	Planned	2020-2021
6	Kasama – Nakonde Transmission Project	• 1x330kV Overhead line, Kasama - Nakonde, 211km, with line reactors of 30MVAr at each end • 1x132kV Overhead line, Kasama - Kayambi, 170km • 330kV Overhead line, Kasama - Mporokoso, 159km, with line reactors of 30MVAr at each end • Nakonde 330/66kV, 1x90MVA, 30MVAr bus reactor • 330kV double ckt to Tunduma substation at 40km • Tunduma 400/330kV, 3x315MVA • 1x30MVAr 330kV Bus Reactor, Nakonde • Mporokoso 330/66kV substation with 1x65MVA Transformer and 30MVAr bus reactor • Reconfigure the 66kV Kawambwa- Mporokoso existing line to LILO at 10km from existing Mporokoso 66kV S/S	Committed	2021
7	Pensulo - Mansa Transmission Project	• 1x330kV Overhead line Pensulo- Mansa, 294km, with line reactors of 45MVAr at each end • 1x132kV Overhead line Mansa- Samfya, 62km • Samfya 66/33kV, 2x30MVA • 66kV Mansa 330/66kV to LILO Musonda Falls-Mansa Town 66/33kV substation at 7km to Mansa Town substation • Musonda T-Off 66/33kV substation, 2x16MVA transformers, 33kV side connecting to Musonda 10MW Power Station at 5km • Mansa Town 66/11kV substation, 2x25MVA transformers • Mansa 330/66kV, 2x90MVA,30MVAr bus reactor	Committed	2021
8	Kabwe - Pensulo 2nd Line	• 1x330kV Overhead line, 298km, with line reactors of 40MVAr at each end	Committed	2021
9	Upgrade of transformers at Kitwe and Luano	• Luano 330/220kV, 4x315MVA • Kitwe 330/220kV, 4x315MVA	Construction	2021

S/No.	NAME OF PROJECT	PROJECT SCOPE	STATUS	COD
10	LTDRP 132kV	• Reinforcement of Lusaka 132kV Sub-Transmission Network • Leopards Hill 1 x 250MVA transformer, 330/132kV • Leopards Hill-Roma-Lusaka West-Coventry -Leopards Hill 132kV ring uprated to 400MVA • Halfway between Coventry and Lusaka West there shall be a 132/33/11kV Industrial substation with 2x90MVA @ 132/33kV and 3x30MVA @ 132/11kV • Water Works substation shall be uprated as follows: 2x90MVA @ 132/33kV and 3x30MVA @ 132/11kV • At Roma substation, 2x30MVA, 132/11kV additional capacity	Committed	2021
11	Livingstone - Victoria - Hwange Interconnector (ZIZABONA Phase 1)	• 1x330kV Overhead line, 10km	Planned	2022
12	Livingstone - Caprivi (ZIZABONA Phase 2)	• 1x330kV Overhead line, 230km	Planned	2022
13	Mozambique 330kV Interconnector	• 2x400kV Overhead line, 366km from Chipata West in Zambia to Matambo in Mozambique with 60MVAr line reactors at either end of each line • Create 400/330kV Chipata West substation extension with 3x315MVA transformers	Planned	2022
14	Livingstone - Muzuma - Kafue West 2nd Line	• 2x330kV Overhead line, 348km	Planned	2025[11]
15	Kafue Town - Mazabuka	• 1x88kV Overhead line, 55km • Mazabuka 88/33kV, 1x45MVA	Planned	2025[12]
16	Kalungwishi - Kasama Power Evacuation	• 330kV Overhead line, Kalungwishi-Mporokoso, 90km • 330kV Overhead line, Kabwelume-Kalungwishi, 0.6km • 330kV Overhead line, Kundabwika to Kalungwishi, 42km • 20MVar reactors to be install on opposite ends of the Kalungwishi to Mporokoso line	Planned	2025[11]
17	Lufubu Power Evacuation	• 1x330kV Overhead line to Mporokoso, 60km	Planned	2025[12]
18	Lusaka West - Kabwe-Luanshya- Kitwe/Luano	• 2x330kV Overhead line, Lusaka West-Kabwe, 100km • 2x330kV Overhead line, Kabwe- Luanshya, 160km • 1x330kV Overhead line, Luanshya- Luano, 86km • 1x330kV Overhead line, Luanshya- Kitwe, 50km	Planned	2025[11]
19	Malawi 330kV Interconnector	• 2x330kV Overhead line, 35km from Chipata West S/S to the border and 125km from border to Llongwe with 30MVAr line reactors at either end of each line • Create 400/330kV S/S at Lilongwe 2x250MVA capacity	Planned	2025[12]
20	Kolwezi-Solwezi Interconnector	• 2x330kV Overhead line, 148km from Kansanshi in Zambia to Panda in DRC	Planned	2025[12]
21	Muzuma - Choma	• 2x132kV Overhead line, 26km • Choma 132/33kV, 2x20MVA	Planned	2025
22	Sesheke - Mongu - Shangombo	• 1x220kV Overhead line, Sesheke - Nangweshi, 165km • 1x220kV Overhead line, Nangweshi - Mongu, 125km • 1x220kV Overhead line, Nangweshi -Shangombo, 130km • Nangweshi 220/66/33kV, 2x63MVA • Shangombo 220/66/33kV, 2x63MVA • Mongu 220/66/33kV, 2x63MVA	Planned	2025

[11] The network reinforcement is out of service in the PSSE model 2025 provided by ZESCO. The Consultant considered it not available over the whole year simulated in scenarios 2025. It was included in scenarios 2030.
[12] The network reinforcement was considered fully available at the beginning of the year 2025.

6.3.2 Interconnections with neighbouring countries

Concerning the interconnections with the neighbouring countries, the current grid is interconnected with Democratic Republic of Congo, Namibia, Malawi and Zimbabwe by means of:

- 1x220 kV AC overhead line Luano (Zambia) – Karavia (DRC);
- 2x220 kV AC overhead line Michelo (Zambia) – Karavia (DRC);
- 1x220 kV AC overhead line Sesheke (Zambia) – Zambezi (Namibia). This interconnection allows the power exchange up to the central Namibia by means of the 350 kV HVDC link between Zambezi and Gerus stations in Namibia (Caprivi Link Interconnector, 350 MW);
- 2x330 kV AC overhead line Kariba North (Zambia) - Kariba South (Zimbabwe);
- 1x33 kV AC overhead line Chipata (Zambia) - Llongwe (Malawi). A 5-years PPA, take or pay, for 20 MW export from Zambia to Malawi has been signed by ZESCO and ESCOM at the end of the year 2018. This PPA is just a pilot start and additional export is expected in the coming years.

Important interconnection projects are expected in the next years in SAPP to improve the markets integration, the security of supply and the use of sources. Zambia is in a strategic geographic position; in the centre of SAPP, it borders with eight countries that are member of SAPP and it is involved in important interconnection projects. The list of interconnection projects indicated by ZESCO and that was considered in the analyses are the following:

- ZTK project;
- ZIZABONA project;
- Zambia-Malawi projects;
- Kolwezi-Solwezi project;
- Zambia-Mozambique project.

ZTK project includes the construction of a transmission line to connect the power networks of Zambia, Tanzania and Kenya (about 2,800 km). The project will allow the connection of the Southern African Power Pool with the East African Power Pool and it is crucial to create the largest power pool on the continent. The connection of SAPP and EAPP grids will improve the diversification of power supply and the power generation mix; therefore, also the competition in the markets reducing the power tariff and increasing the access to energy and the industrial development. The ZTK Interconnector was divided in two projects: the Zambia-Tanzania Interconnection and the Kenya-Tanzania Interconnection. The first one, to the Zambian side, includes the construction of a double circuit 330 kV transmission line from Kabwe-Pensulo-Mpika-Kasama-Nakonde in Zambia to Tunduma S/S in Tanzania. The project continues with other three connection points in Tanzania (Mbeya S/S, Singida S/S and Arusha S/S) to Nairobi in Kenya. The interconnection between Zambia and Tanzania will have a maximum capacity of 500 MW; however, a transfer limit equal to 200 MW will be set due to steady state voltage constraints in the northern parts of the system in Zambia (Source SAPP [1]).

The ZIZABONA project is a new interconnection project between Zimbabwe, Zambia, Botswana and Namibia with the scope to facilitate the establishment of a western transmission corridor in Southern Africa. The electricity utilities ZESA (Zimbabwe), ZESCO (Zambia), BPC (Botswana) and NamPower (Namibia) signed an Inter-Utility Memorandum for the development of ZIZABONA project in 2007, and an Inter-Governmental Memorandum of Understanding was signed by the governments of the four countries in 2012. The project will be developed as three components, namely:

- Component A: 330 kV overhead line from Livingstone S/S (Zambia) to Hwange S/S (Zimbabwe), with a switching station Victoria Falls S/S (Zimbabwe)
- Component B: 330 kV overhead line from Victoria Falls S/S (Zimbabwe) to Pandamatenga S/S (Botswana)
- Component C: 330 kV overhead line from Livingstone S/S (Zambia) to Zambezi S/S (Namibia) network.

A new 132 kV AC overhead line, single circuit, between Chipata S/S in Zambia and Llongwe S/S in Malawi is expected to increase of additional 50 MW the export capacity to Malawi, helping the latter to improve the security of supply by meeting the growing electricity demand. Furthermore, a new 330 kV AC overhead line, 160 km double circuit, between Chipata West S/S in Zambia and Llongwe S/S in Malawi is expected in 2025.

The Kolwezi-Solwezi power interconnector is a project to connect SNEL and ZESCO transmission networks from the town of Kolwezi in DRC to the district of Solwezi in Zambia. A new 330 kV AC overhead line, 148 km double circuit (each circuit rated at 850 MVA), between Kansanshi S/S in Zambia to Panda S/S in DRC is expected in the mid-term: 700 MW phase 1 in 2025 and 1,300 MW phase 2 in 2030.

Finally, a new 400 kV AC overhead line, 366 km double circuit, from Chipata West S/S in Zambia to Matambo S/S in Mozambique is expected in 2022.

Table 6.13 shows the existing Net Transfer Capacities (NTCs) between the Zambian power system and the systems of the interconnected countries. NTC is the maximum power exchange between two interconnected power systems compatible with the fulfilment of the security standards established by the respective power systems and available for commercial purposes, for a certain period and direction of active power flow. The values were provided by ZESCO and rounded by the Consultant.

The list of the new interconnection projects to be considered in the study is reported in Table 6.14. For each project, the maximum exchange capacity, the expected Commercial Operation Date (COD) and the current project status are highlighted.

Table 6.13 – Existing net transfer capacities between Zambia and the neighbouring countries

From	To	NTC From -> To [MW]	NTC To -> From [MW]	Comment
ZESCO (Zambia)	ZESA (Zimbabwe)	640	530	• 642 MW is a steady state limit. Contingency is the loss of ZESA 330 kV Alaska Sherwood line • 530 MW is a steady state limit. Contingency is ZESA 330 kV Insukamini - Marvel
ZESCO (Zambia)	NAMPOWER (Namibia)	150	115	• Both NTCs are due to contingency of NamPower Omburu - VanEck or Omburu-Osona. Assumes no generation at Rucaana Nampower
ZESCO (Zambia)	SNEL (DRC)	225	600	• 225 MW is the steady state limit. Loss of one ZESCO 330 kV Leopards Hill - Kabwe • 600 MW is the thermal limit on tie-lines under one tie line contingency

Table 6.14 – New interconnection projects

Project Name	Country From	Country To	Voltage	Capacity	Length	COD	Status (*)
			kV	MW	km		
ZTK	Zambia	Tanzania	330 AC	500	-	2021	3
ZIZABONA A	Zambia	Zimbabwe	330 AC	1,450	101	2022	3
ZIZABONA C	Zambia	Namibia	330 AC	1,450	231	2023	4
Zambia-Malawi	Zambia	Malawi	132 AC	50	146	2020	3
Zambia-Malawi Interconnector	Zambia	Malawi	330 AC	700	160	2025	4
Kolwezi-Solwezi Interconnector	Zambia	DRC	330 AC	700-1,300	148	2025-2030	4
Zambia-Mozambique interconnector	Zambia	Mozambique	330-400 AC	700	366	2022	4

(*) State 1: Projects that are already under construction
State 2: Regulatory approval received and are under preparation of tender document
State 3: Projects that have a recent feasibility Study and starting application process
State 4: Projects that are currently undergoing Feasibility Studies

Some Power Purchase Agreements as take-or-pay contracts were signed, or will be signed, by ZESCO in order to export RES generation to the interconnected countries. The following PPAs have been considered in the analyses:

- Existing PPA between ZESCO (Zambia) and ESCOM (Malawi) for a firm capacity of 20 MW and energy calculated with 90% annual load factor;
- Existing PPA between CEC (Zambia) and SNEL (DRC) for a firm capacity of 200 MW and energy calculated with 90% annual load factor;
- Future PPA between ZESCO (Zambia) and ESCOM (Malawi) for a firm capacity of 50 MW and energy calculated with 90% annual load factor;
- Future PPA between ZESCO (Zambia) and NamPower (Namibia) for a firm capacity of 100 MW and energy calculated with 90% annual load factor.

Table 6.15 and Table 6.16 show the maximum exchange capacities between Zambia and the interconnected countries according to the existing and future network infrastructures. The Consultant considered these values as the Net Transfer Capacities (NTCs) among the countries. The capacity of the interconnection Zambia-Tanzania is 500 MW but as before mentioned the NTC was conservatively set to 200 MW due to steady state voltage constraints in the northern parts of the system in Zambia.

ZESCO didn't indicate electrical sections inside the National Grid with limited exchange capacity; therefore, the Zambian electric power system was simulated as a unique market area. The map of the existing and planned interconnections, together with the NTCs expected by 2023, is in Figure 6.51.

Table 6.15 – Maximum export capacity from Zambia

Year	Maximum NTC from Zambia to						Total available export capacity
	DRC	Namibia	Malawi	Mozambique	Tanzania	Zimbabwe	
2018	225	150	20	-	-	640	1,035
2025	925	1,600	770	700	200	2,090	6,285
2030	1,525	1,600	770	700	200	2,090	6,885

Table 6.16 – Maximum import capacity to Zambia

Year	Maximum NTC to Zambia from						Total available import capacity
	DRC	Namibia	Malawi	Mozambique	Tanzania	Zimbabwe	
2018	600	115	0	-	-	530	1,245
2025	1,300	1,565	700	700	200	1,980	6,445
2030	1,900	1,565	700	700	200	1,980	7,045

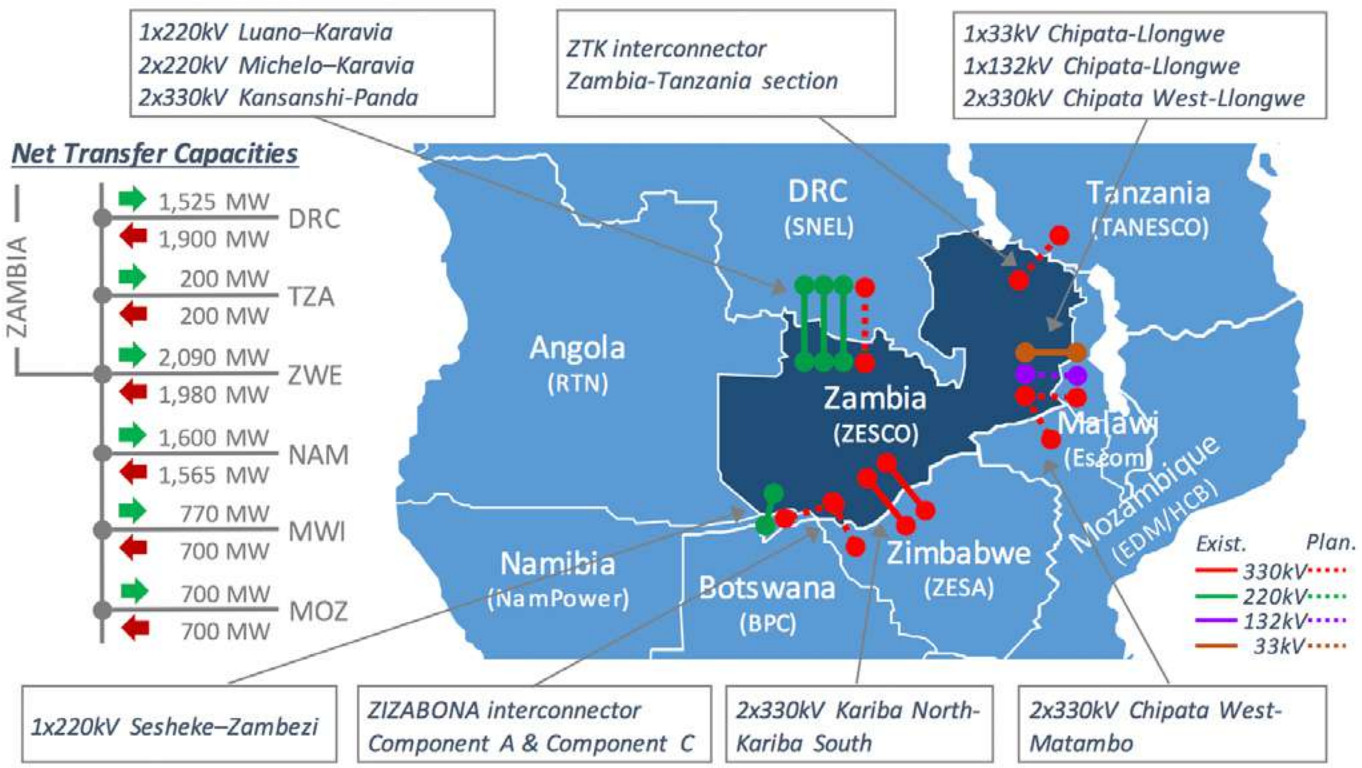


Figure 6.51 – Net transfer capacities and interconnections expected in the long-term between Zambia and the interconnected countries

Zambia, with ZESCO Limited, Copperbelt Energy Cooperation and Lunsemfwa Hydro Power Company, is an active member of the Southern African Power Pool (SAPP); the cooperation of the national electricity companies in Southern Africa with the scope to facilitate the development of a competitive electricity market in the Southern African Development Community (SADC). All the interconnections between the SAPP countries are highlighted in Figure 6.52.

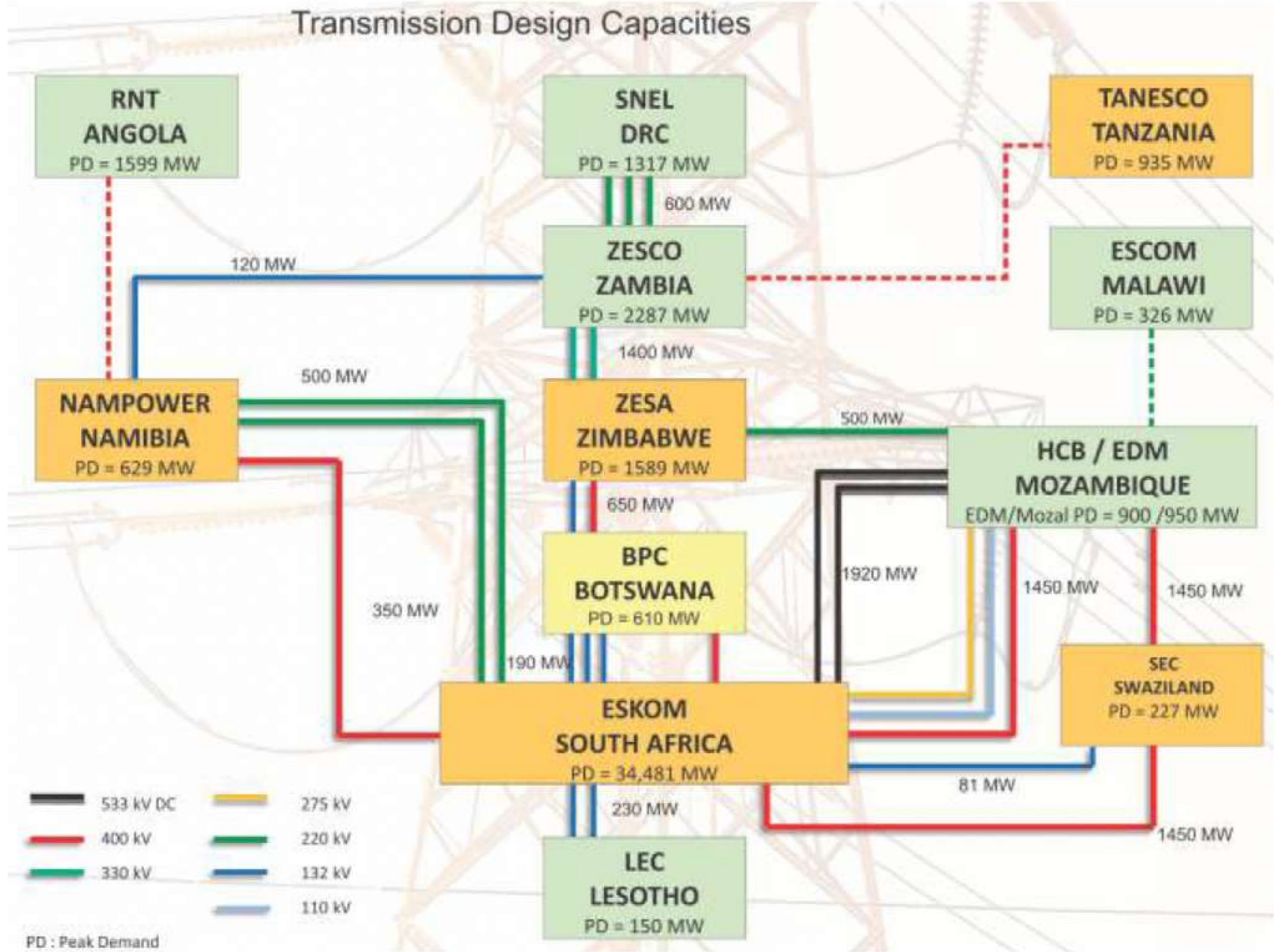


Figure 6.52: Planned and existing interconnections within the SAPP system (Source SAPP [2])

6.3.3 Unavailability of network equipment

No specific information was provided about the forced unavailability rates of lines and transformers in Zambia; the Consultant propose the following values based on his experience.

Transmission lines

The following unavailability rates, calculated for 100 km of line, are proposed for high voltage transmission lines.

Table 6.17 – Lines unavailability rates (p.u./100 km)

Voltage level	Unavailability
330 kV	0.0020
220 kV	0.0035
≤132 kV	0.0045

For the equivalent lines and busbar couplers the unavailability is considered practically zero (0.0000001).

Autotransformers and transformers

The following unavailability rates are proposed for Zambian transformers and autotransformers:

Table 6.18 - Transformers unavailability rates

Transformer	Unavailability
ATR	0.0003
Step-up transformer	0.000001

The step-up transformers (for the production units) have zero downtime (0.000001) because it is normally included in the forced outage rate of generators.

6.4 Security of supply

The way in which the power system can meet the electricity demand growth is named "system adequacy". System adequacy measures the ability of a power system to cope with its electricity demand under all standard conditions it may operate, avoiding loss-of-load events, for a given security of supply. The system adequacy includes the ability of the generation fleet to cover the load and the ability of the transmission system to perform the system balance, considering uncertainties in the generation availability, load level and grid accessibility.

The transition from a conventional power system, with widely programmable and predictable generations, to a power system with large amount of variable renewable energy sources creates new challenges to the security of supply for the system operators. Proper methods must be used in the system planning to assess the system adequacy in the mid- and long-term and to define the proper investments to achieve a given security of supply. The assessment methods of system adequacy can be deterministic or probabilistic, or a combination of both. The deterministic approaches were largely adopted in the past; however, the probabilistic methods are quickly being introduced by system operators in electric power system with high penetration of variable RES. The latter catch the probabilistic behaviour of the new variable energy sources improving the accuracy of the adequacy analyses.

In the current study, the quantitative evaluation of the system adequacy has been carried out by means of probabilistic analyses. The latter allow the calculation of reliability indexes that expresses, as a probability, the comparison between the values of the load to be supplied and the value of the production and transmission system capacities. The following reliability indexes have been evaluated and used for the analysis of system reliability:

- **Expected Energy Not Supplied (EENS)**: this index represents the yearly expected average energy value of not supplied load (MWh/year or p.u. of annual demand) due to unavailability in the generation and/or transmission system considering the restrictions set by the power transfer capacity of the lines and transformers and the power limits of the power plants.
- **Loss of Load Expectation (LOLE)**: the number of hours in which the entire demand cannot be served (hours per year).
- **Loss of Load Probability (LOLP)**: probability (%) of not being able to cover the weekly peak load (52 hours per year).

According to Zambia Bureau of Standard and the international practises, the Consultant proposes the following limits to evaluate the adequacy of generation and transmission system in presence of big amount of variable RES:

- LOLE ≤ 48 h/year[13]
- LOLP ≤ 1%
- EENS ≤ 1.10-4 p.u. of the yearly demand[14]

[13] According to the Zambia Bureau of Standard ZS-387-1 2011, Annex D, Commercial and small to medium industrial

[14] International standard

The cost of the energy not supplied (or unserved energy) is high, but assessing a specific value is difficult because it would require a separate study to calculate an actual and reliable Value Of Lost Load (VOLL), considering the costs and weighting from different consumer groups. However international comparison shows that figures of VOLL up to 5 or 10 US$/kWh can be justified; furthermore, values between 1 and 3 US$/kWh were used in the last SAPP development plan [1]. For these reasons we can assume a VOLL equal to 2 US$/kWh to assess the cost of the energy not supplied and possible benefits from EENS reduction.

6.5 Power system resilience

Climate change is impacting different phases of the electricity sector, and it is expected to continue in the future. Both long-lasting climatic changes and singular extreme natural events, which are becoming more and more frequent in the last decades, affects the demand, supply, production, transmission and distribution of electricity. To lessen the climate change impact on the electricity sector, proper measures must be considered by planners and operators of the system not only assuring high levels of reliability but also improving the power system resilience. For a long time, only the concept of reliability was considered in the planning process and in the operation of the electric power systems; however, the increasing frequency of extreme natural events led the stakeholders to evaluate the system resilience as well. Even if these two concepts are similar, there are some crucial differences should be remarked to fully capture the importance of this new perspective:

- Reliability: it concerns the ability of the electric power system to deliver electricity in the quantity and with the quality demanded by end-users, considering scheduled and reasonably expected forced outages of system elements (Adequacy). Furthermore, reliability concerns the ability of the power system to resist sudden disturbances (e.g. as short circuits or the loss of system elements) from credible contingencies, while avoiding critical operating situations (Operating Reliability).
- Resilience: it is the ability of the electric power system to withstand and recover from shorter-term extreme, damaging conditions or immediate physical shocks and as longer-term climate changes occur. A resilient system is the one that acknowledges that long-duration outages can occur, prepares to manage them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future meeting the reliability of the system. Resilience has reliability as a final goal, and it directly impacts the reliability.

The resilience concept is based on the idea that disruptive events occur regularly and that systems should be designed to adapt quickly because the impact was less. An energy diversification strategy in the electricity sector is one solution that can support both short- and long-term resilience of a power system affected by climate change.

The Zambian generation system is closely dependent from hydropower; about 85% of current energy production is from hydro power plants and a high exploitation of water for electricity sector will continue in the future. In this context, more frequent drought periods and changes in rainfall patterns due to climate change is expected to create or worsen the energy supply to meet both domestic demand and bilateral agreements with the neighbouring countries. Diversifying the energy mix to include technologies with low water use needs, such as wind and photovoltaic, could offer an important technical solution for Zambia and may face current and future water challenges related to climate change. Thanks to the very good potential of VRES and the generation fleet flexibility in the country, wind and PV technologies could play unique and important roles with respect to more traditional technologies. VRES power plants are few impacted by climate change and they can compensate the lack of hydropower if more frequent low rainfall periods will occur in the future.

Qualitative considerations on system resilience improvement in presence of extreme events were included in the study. Furthermore, additional observations were provided about the benefits of innovative VRES power plants control to better exploit resources.

A specific scenario was analysed considering a low water availability for hydropower due to low rainfalls caused by the climate change. The scope of this scenario is to analyse the impact of droughts on the system operation and the benefits of wind and solar generation to improve the system resilience in case of extreme climate conditions. The optimal VRES capacity that could be installed in this condition was highlighted.

6.6 Fuel prices

Zambia's generation mix is largely driven by hydro power, which accounts for 85.6 percent (2,398 MW) of total national installed capacity. Conventional fossil fuel generation accounts for 14.5% of total capacity: 10.7% (300 MW) from Coal and 3.8% from Heavy Fuel Oil (105 MW). No additional fossil fuel power plants are expected by 2025 and 2030; therefore, coal and HFO will be the only fossil fuels that will compete with new VRES.

The Figure 4.32 shows the fossil fuel price forecast defined in the SAPP Pool Plan 2017 [2] for the period 2017-2040; it is based on International Energy Agency (IEA) World Energy Outlook 2016 and Bloomberg data provided by World Bank. As mentioned in [2], "*The prices are based on international prices, adapted to Southern Africa. The South African gas price is estimated as an LNG netback price, with data sourced from the Integrated Resources Plan (IRP) model and updated for the exchange rate. The coal transport costs in Malawi are extracted from the recently completed IRP. HFO and Diesel are linked to the price of crude oil. Following IEA-based analysis of the relationship between crude oil and refined products, prices were set according to their ratio to the world price of crude oil. For Diesel it is set to 1.32 of the price of oil, and for HFO the factor is 0.9*". The price forecast for Coal (domestic) and HFO was the reference to evaluate the production costs of Zambian fossil fuels power plants expected at years 2025 and 2030 (Table 6.19).

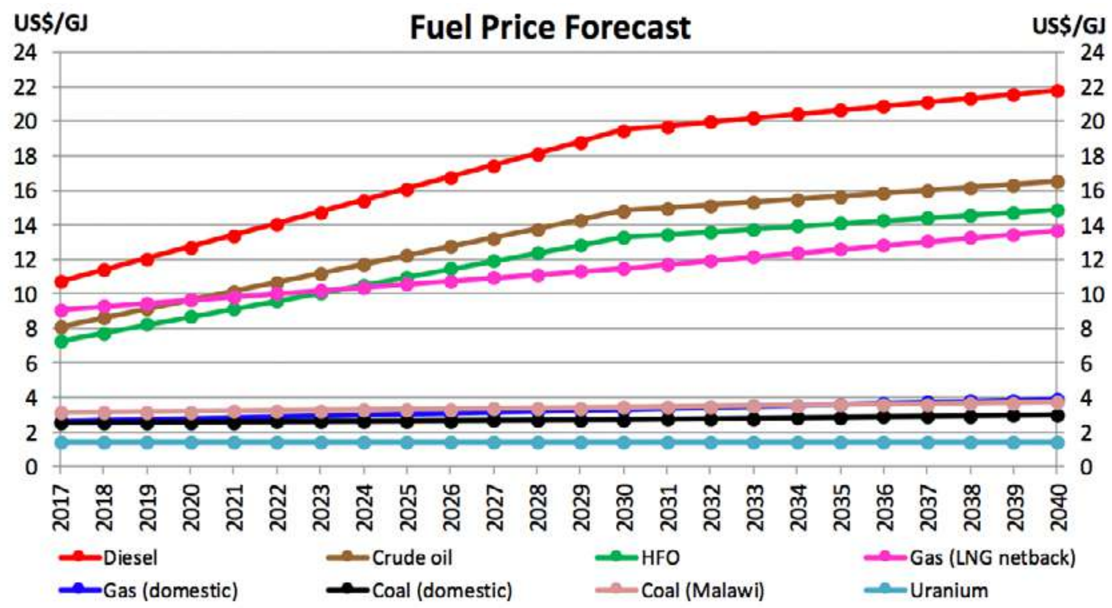


Figure 6.53 – Forecast of fuel prices 2017–2040 (Source: SAPP [1])

Table 6.19 – Fuel prices for electricity production expected at target years in SAPP

Fuel code	Fuel name	Price 2017 US$/GJ	Price 2025 US$/GJ	Price 2030 US$/GJ
C	Coal (domestic)	2.50	2.62	2.70
D	Diesel	10.70	16.12	19.50
HCO	Heavy Crude Oil	8.10	12.22	14.80
HFO	Heavy Fuel Oil	7.30	10.99	13.30
LNG	Liquefied Natural Gas	9.10	10.58	11.50
NG	Natural Gas (domestic)	2.60	3.03	3.30
U	Uranium	1.40	1.40	1.40

6.7 Costs for variable RES technologies

Costs for solar and wind technologies continue falling in the last years, increasing the completeness of VRES with fossil fuel technologies and other renewable energy sources. The cost reductions of utility-scale PV projects continue to be driven by falling PV module prices and balance of system (BOS) costs. The electricity cost from onshore wind projects likewise continue to decrease thanks to the reductions in total installed costs, as well as the improvements in turbine design and manufacturing (higher hub heights and larger swept areas collect more electricity from a given resource than older technologies) able to improve the turbine performance increasing the capacity factor. Furthermore, the introduction of auction mechanisms to develop VRES projects fostered the fast decrease of the electricity costs from wind and PV sources.

The reduction of the electricity cost from utility-scale PV and onshore wind projects in the last years is well highlighted in Figure 6.54 and Figure 6.55. The figures show the results of IRENA calculations carried out on a world-wide database of onshore wind and PV projects in the period 2010-2018; the global weighted average installed costs, the capacity factors and the levelized costs of electricity (LCOE) for solar PV and onshore wind projects are showed.

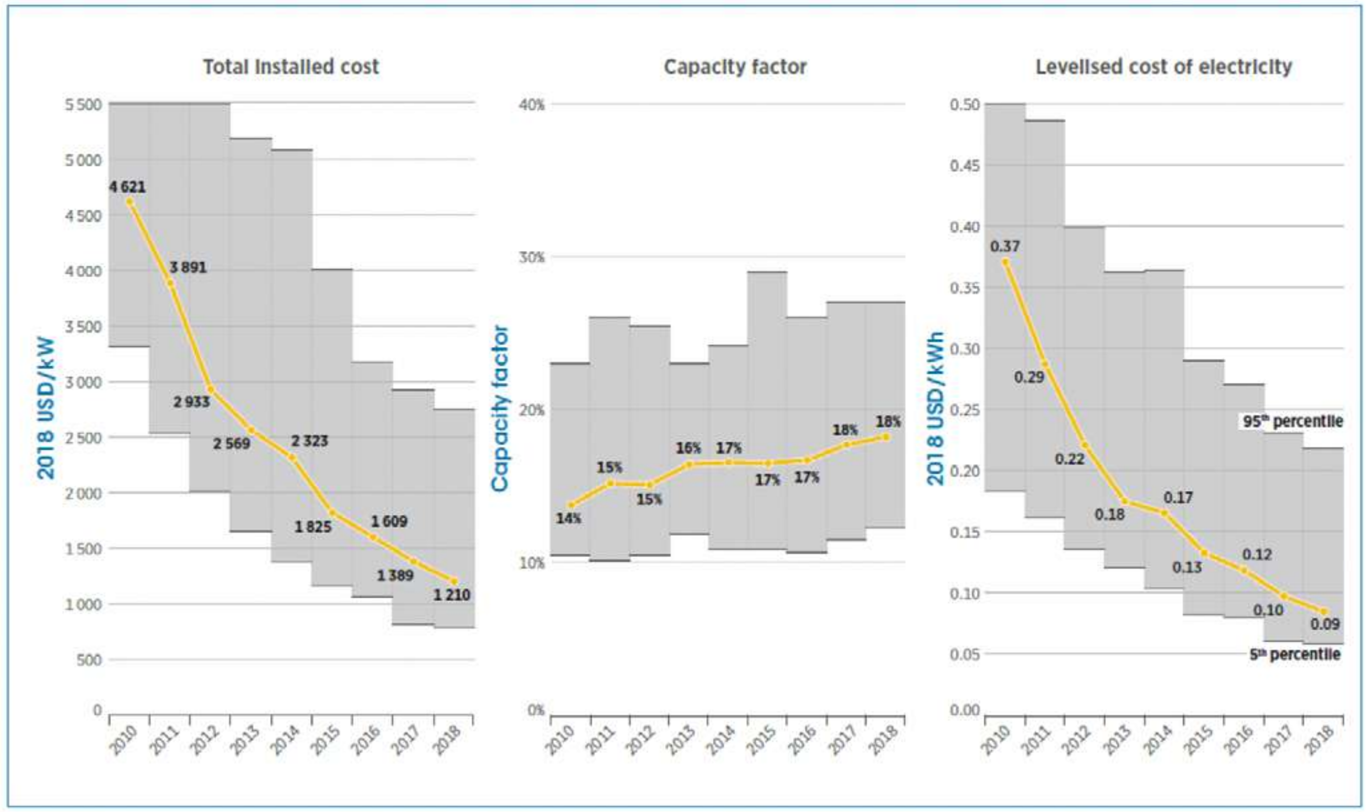


Figure 6.54 – Global weighted average total installed costs, capacity factors and LCOE for solar PV; world data 2010–2018. Source IRENA [3]

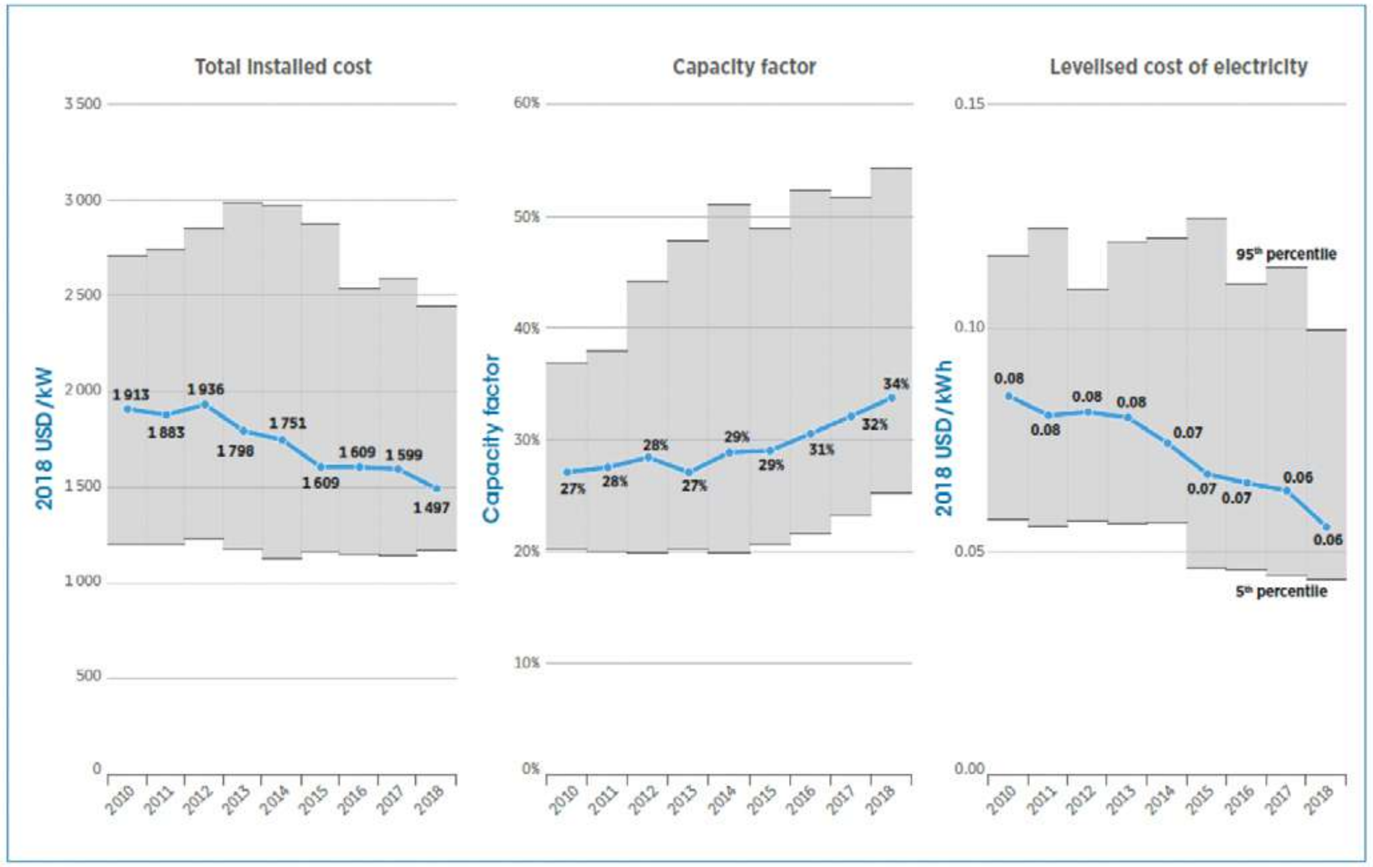


Figure 6.55 - Global weighted average total installed costs, capacity factors and LCOE for onshore wind; world data 2010–2018. Source IRENA [3]

The electricity costs from VRES projects are specific for the analysed country because they depend by several aspects regarding the potential of solar and wind in the country, the economic conditions and the environmental issues. Therefore, an assessment of the levelized costs of electricity from wind and photovoltaic technologies in Zambia has been carried out proving an indication of their competitiveness. Capacity factors of wind and PV power plants have been considered together with the investment costs, operating costs and lifetime of these technologies to provide a qualitative assessment of LCOE to be adopted as reference in the cost-benefit analysis of VRES integration. International standards and the experiences of RES4Africa's partners on southern Africa regions have been used as reference.

LCOE is usually defined as the total cost for the construction and operation of a power plant over an assumed lifetime divided by the expected energy production over the same period; both of which are discounted back to a common year using a discount rate that reflects the average cost of capital. Hence, the formula used for calculating the LCOE of renewable energy technologies is:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + O\&M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where:

- I_t is the investment expenditure in year t;
- $O\&M_t$ is the operation and maintenance expenditure in year t;
- E_t is the energy produced in year t;
- r is the discount rate;
- n is the plant lifetime;

The forecast of LCOE from wind and PV power plants has been performed by the Consultant considering the following assumptions:

- **Investment costs and operating costs**

The values for investment costs (CAPEX) and O&M costs (OPEX) of each technology, specific to one installed kW, have been assumed considering the results of the GET FiT[15] Round 1, international standards and the experience of RES4Africa's partners in southern Africa regions. Figure 6.56 shows the forecast of CAPEX and OPEX for wind and PV technologies in the period 2019-2030. About CAPEX, the reduction of wind projects costs was assumed quite linear over the planning period, while an important reduction was assumed in the short-term (2020-2021) for PV technology. The latter is the effect of GET FiT Round 1 in which 120 MW PV capacity was committed with a weighted average LCOE equal to 4.41 US$c/kWh (the lowest bid was 3.99 US$c/kWh).

[15] GET FiT is an initiative designed to assist the Government of the Republic of Zambia in the implementation of its REFiT Strategy. GET FiT aims to support small- and medium-scale Independent Power Producer projects up to 20 MW and procure the 200 MW of PV and small hydro energy projects in the Country.

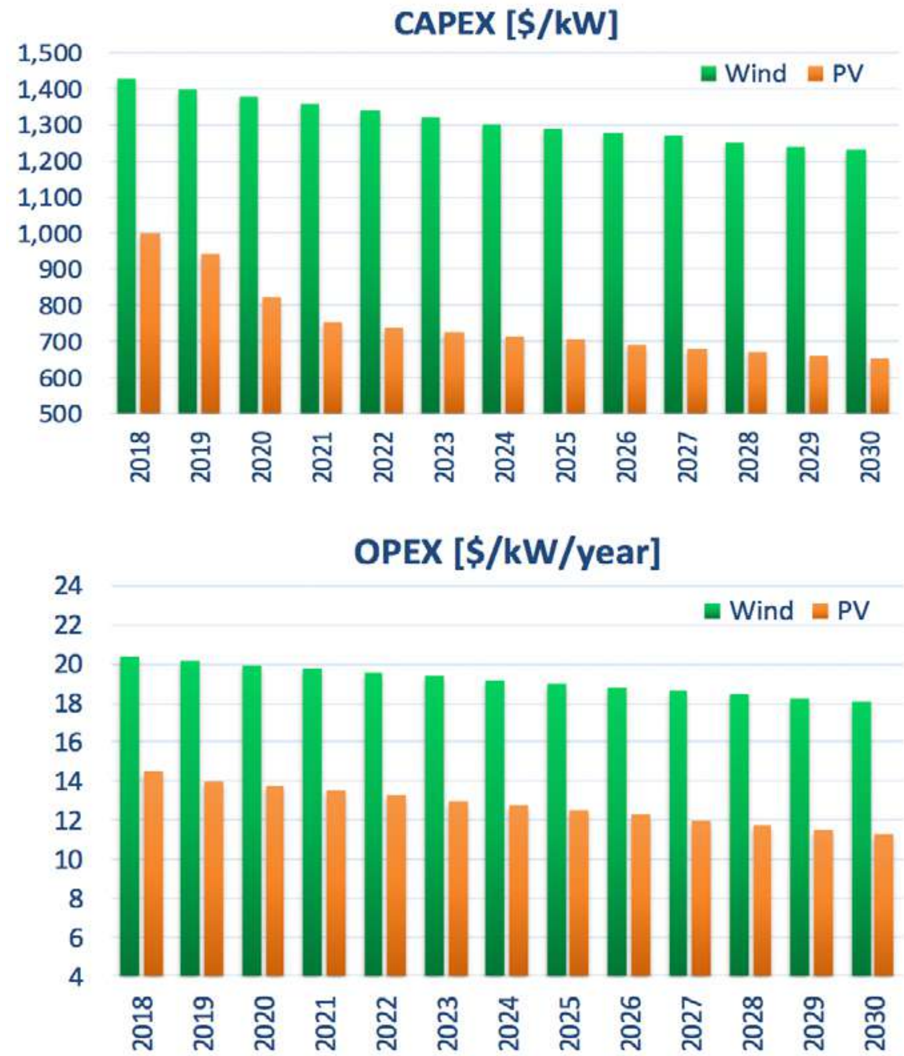


Figure 6.56 – Forecast of capital and O&M costs until the target year 2030

- **Operating hours**

Starting from the average capacity factors of wind and PV generation calculated from wind speed and solar radiation measures with state-of-art technologies, technological developments able to improve the power plants performance increasing the capacity factor have been assumed in the long-term. From the wind side, the Consultant considered improvements in turbine design and manufacturing, such as higher hub heights and larger swept areas, while bi-facial photovoltaic panels have been introduced for new PV power plants.

- **Power plant lifetime and PPA duration**

The power plant lifetime for wind and PV power plants is commonly considered equal to 25 years. However, the duration of Power Purchase Agreements (PPAs) to be put in place with independent power producers was conservatively used for the evaluation of the discounted cash flow and the total energy produced; this is because the PPA duration is the period in which the remuneration is granted. Therefore 20 years have been assumed for the discounted cash flow both for PV and wind projects.

- **Discount Rate**

The discount rate, which considers both cost of debt and cost of equity, has been assumed equal to 10%.

Starting from this information, the expected LCOE has been calculated for each year in the period 2018-2030. Figure 6.57 shows the LCOE from wind and PV projects with COD between 2018 and 2030, together with the moving average LCOE calculated in the period between the COD of the first project (2019 for PV and 2023 for wind) and the specific year. The moving average LCOE represents the average cost of electricity expected from wind/PV power plants built within a specific year, assuming a gradual VRES power plants integration every year. Detailed data and results about the forecast of LCOE for new wind and PV projects are highlighted in Table 6.20 and Table 6.21.

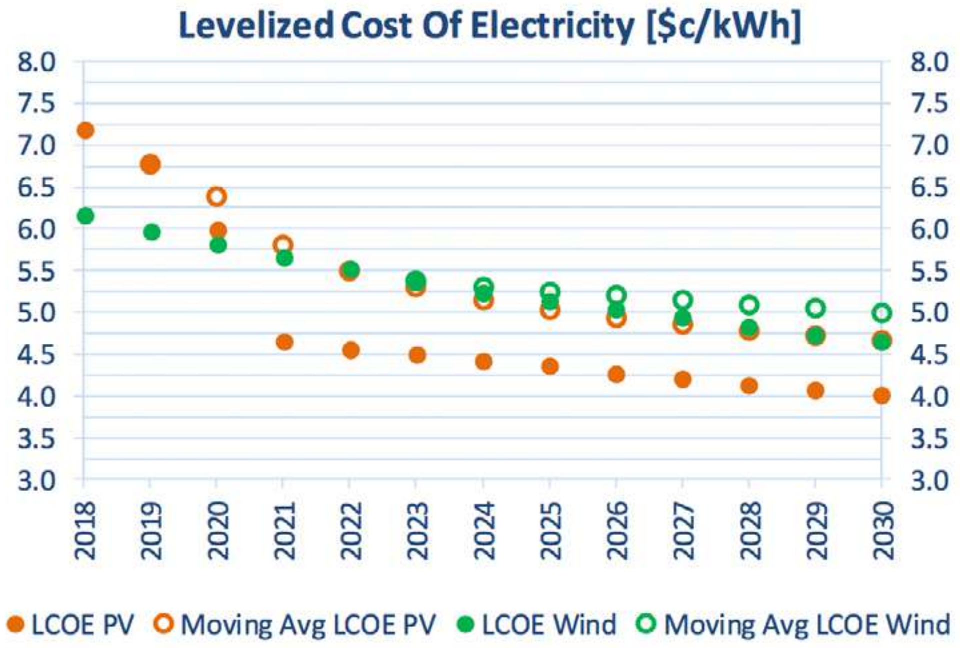


Figure 6.57 – Comparison between annual LCOE and moving average LCOE for wind and PV technologies

Table 6.20 – LCOE for PV power plants

Year	CF [%]	EOH [h/yr]	CAPEX [US$/kW]	OPEX [US$/kW/yr]	LCOE [US$c/kWh]	Moving Average LCOE [US$c/kWh]
2018	21.0	1,840	1,000	14.5	7.17	-
2019	21.0	1,840	940	14.0	6.76	6.76
2020	21.0	1,840	820	13.8	5.98	6.37
2021	25.0	2,190	750	13.5	4.64	5.80
2022	25.0	2,190	735	13.3	4.55	5.48
2023	25.0	2,190	725	13.0	4.48	5.28
2024	25.0	2,190	715	12.8	4.42	5.14
2025	25.0	2,190	705	12.5	4.35	5.03
2026	25.0	2,190	690	12.3	4.26	4.93
2027	25.0	2,190	680	12.0	4.19	4.85
2028	25.0	2,190	670	11.8	4.13	4.78
2029	25.0	2,190	660	11.5	4.06	4.71
2030	25.0	2,190	650	11.3	4.00	4.65

Table 6.21 – LCOE for wind power plants

Year	CF [%]	EOH [h/yr]	CAPEX [US$/kW]	OPEX [US$/kW/yr]	LCOE [US$c/kWh]	Moving Average LCOE [US$c/kWh]
2018	35.0	3,066	1,430	20.4	6.14	-
2019	35.4	3,103	1,400	20.2	5.95	-
2020	35.8	3,140	1,380	20.0	5.80	-
2021	36.3	3,176	1,360	19.8	5.65	-
2022	36.7	3,213	1,340	19.6	5.51	-
2023	37.1	3,250	1,320	19.4	5.37	5.37
2024	37.5	3,287	1,300	19.2	5.23	5.30
2025	37.9	3,324	1,290	19.0	5.13	5.24
2026	38.4	3,360	1,280	18.8	5.03	5.19
2027	38.8	3,397	1,270	18.6	4.94	5.14
2028	39.2	3,434	1,250	18.4	4.81	5.09
2029	39.6	3,471	1,240	18.2	4.72	5.03
2030	40.0	3,508	1,230	18.1	4.63	4.98

6.8 Costs for grid reinforcements

The cost-benefit analysis for the VRES integration in an electric power system must considers the cost of additional grid reinforcements that could be needed for the optimal economic exploitation of VRES technologies. Grid reinforcements in addition to the projects already defined in the transmission expansion plan for the target years 2025 and 2030.

The cost of a grid reinforcement includes both the investment cost (CAPEX) and the operational cost (OPEX). No information was provided by ZESCO for the unitary investment costs and O&M costs for new transmission assets (lines and transformers). Based on CESI experience and international sources, the Consultant proposes to adopt standard investment costs for lines and transformers as in Table 6.22 and O&M costs equal to 1.5% of the overall CAPEX of the grid reinforcement. Furthermore, a discount rate of 10% and a lifetime of the new transmission assets equal to 40 years were applied in the economic analyses.

Table 6.22 – Specific investment costs (CAPEX) of the transmission facilities

Transmission Facility	Unit	Specific investment costs
AC 400 kV overhead line, double circuit	[kUS$/km]	425
AC 400 kV overhead line, single circuit	[kUS$/km]	360
AC 330 kV overhead line, double circuit	[kUS$/km]	350
AC 330 kV overhead line, single circuit	[kUS$/km]	300
AC 220 kV overhead line, double circuit	[kUS$/km]	250
AC 132 kV overhead line, double circuit	[kUS$/km]	180
600 MVA 400/330 kV transformer	[kUS$]	6,000
400 MVA 400/330 kV transformer	[kUS$]	4,000
400 MVA 400/220 kV transformer	[kUS$]	4,000
400 MVA 330/220 kV transformer	[kUS$]	4,000
350 MVA 330/132 kV transformer	[kUS$]	3,800
200 MVA 330/132 kV transformer	[kUS$]	2,800
90 MVA 220/132 kV transformer	[kUS$]	1,800

TASK 2 – ANALYSIS OF RESERVE REQUIREMENTS AND GENERATION FLEXIBILITY

7 OBJECTIVES AND SCOPE OF WORK

The study addresses the integration of variable renewable energy sources (VRES) such as wind and solar into the Zambian electric power system. The inherent variability and uncertainty in variable generation technologies add to the variability and uncertainty in the electric power system and can have significant effects on the system operation. Variability is the expected change in generation-demand balance (e.g. load changing throughout the day and wind and solar power resource changes) while uncertainty is the unexpected change in generation and demand balance from what was forecasted (e.g. a contingency or a load or variable generation forecast error). The increasing penetration of wind and photovoltaic technologies make it necessary to supplement the operating reserve requirements to preserve the reliability, integrity and efficiency of the electric power system.

The Consultant presented a reserve sizing method based on a probabilistic approach to evaluate the operating reserve requirements due to VRES integration. Different VRES capacity mixes were analysed and possible constraints in the flexibility of programmable generation were highlighted, if any. Data collected in section 6 are the reference to develop a suitable model of Zambian electric power system in the mid- and long-term scenarios.

Task 2 is based on the analysis of the yearly profiles of load and VRES generation at the target years 2025 and 2030. More in detail, the following analyses have been performed:

- Investigation of the demand profile (hourly time-series including firm export) and load forecast error (difference between actual demand and day ahead forecast).
- Analysis of the historical wind speed measures to assess the wind power production time-series and the expected distribution of the wind production forecast error through a statistical approach;
- Analysis of the historical irradiation data to assess the PV power production time-series and the expected distribution of the PV production forecast error through a statistical approach;

Based on the above-mentioned information, an estimation of the operational reserve (due to the load quantity and the expected renewable production) to be covered by the programmable (hydro and thermal) power plants in Zambia has been performed.

At this stage an estimation of the reserve to be assured in the power system for different wind and PV capacity mixes has been investigated in detail. At this stage the analyses have been carried out neglecting the network constraints, focusing on the ability of the generation fleet to keep system balance and to provide the necessary flexibility and reserve to allow the development of VRES generation.

The main achievement of Task 2 have been used to set-up the best market and reliability models to be used in the following tasks and they have been verified through more in-depth technical-economic analyses incorporating the costs of generation technologies (Task 3) and the reliability of transmission system (Task 4).

8 RESERVE SIZING METHODOLOGY

8.1 Current operating reserve requirements

Zambia, with ZESCO Limited, Copperbelt Energy Cooperation, Lunsemfwa Hydro Power Company and Ndola Energy, is an active member of the Southern African Power Pool (SAPP); the cooperation of the national electricity companies in Southern Africa with the scope to facilitate the development of a competitive electricity market in the Southern African Development Community (SADC) region. In the framework of SAPP, all the operating members are involved to operate the interconnected Southern African electric power network safely, efficiently, effectively and in an environmentally sustainable manner, with an equal participation in the obligations and in the benefits resulting from the cooperation. The operating reserve requirement is currently defined for the whole interconnected Southern African electric power system and it is divided among the operating members that are obliged to maintain their portion of operating reserve to meet 150% capacity of the largest generation unit in the pool, according to the SAPP Operating Guidelines [12]. The reserves are updated annually.

The SAPP is divided into three Control Areas, each with its own control area system operator:

- Eskom Control Area: Eskom serves as control area system operator for Botswana, Lesotho, southern Mozambique, Namibia, South Africa and Swaziland (now called Eswatini);
- ZESA Control Area: Zimbabwe Electricity Supply Authority (ZESA) is the control area system operator for Zimbabwe and northern Mozambique;
- ZESCO Control Area: Zambia Electricity Supply Corporation (ZESCO) is the control area system operator for Zambia and the DRC.

Each Control Area Operator shall operate its active power resources to ensure a level of operating reserve sufficient to account for such considerations as errors in forecasting, generation or transmission equipment unavailability, loss of generating units, forced outage rates, maintenance schedules, regulating requirements and load diversity between Control Areas.

There are many different terms, definitions, and rules concerning what operating reserves entail for power system operators. According to the SAPP Operating Guidelines, SAPP and ZESCO defines the **Operating Reserve** as the unused capacity above system demand which is required to cater for regulation, short-term load forecasting errors and unplanned outages. It consists of Spinning and Quick Reserve and should be fully activated within 10 minutes:

- **Spinning Reserve** shall mean the unused capacity which is synchronized to the system and is readily available to assume load without manual intervention.
- **Quick Reserve** is capacity readily available from non-spinning reserve[16] which can be started and loaded within 10 minutes or load that can be interrupted within 10 minutes.
- The operating reserve can also be classified as the sum of Instantaneous, Regulating and Ten-minute reserves:
- **Instantaneous Reserve** is defined as generation capacity or contractual interruptible load that is available to respond fully within 10 seconds due to a sudden deviation in frequency outside the allowed dead band. This response must be sustained for at least 10 minutes.

[16] Non-spinning reserve is all generating capacity available for operation but not synchronized to the system, according to the SAPP Operating Guidelines.

- **Regulating Reserve** is the provision of generation and load response capability, including capacity, energy and manoeuvrability that respond to automatic generation control signals issued by the System Operator. This includes generation that is under Automatic Generation Control (AGC) and can respond within 10 seconds and be fully active within 10 minutes of activation. This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore instantaneous reserve within 10 minutes of the disturbance.
- **Ten-minute reserve** is the reserve required to balance supply and demand for changes between the day-ahead market and real time such as load forecast errors and unit unreliability. Ten-minute reserve is used to restore regulating reserve when required (via telephone or with direct control). Ten-minute reserve must be activated, on request, within 10 minutes and must be sustainable for 2 hours.

According to the SAPP Operating Guidelines, the following operating reserve obligation must be applied: "Every Operating Member in SAPP shall be obliged to maintain their calculated portion of Operating Reserve sufficient to cover 150% of the loss of the sent-out capacity of the largest generating unit in service in the Interconnection at that time. Furthermore, this operating reserve shall be sufficient to reduce the Area Control Error (ACE) to zero within ten (10) minutes after a loss of generation.

The Operating Reserve shall be made up of Spinning Reserve and Quick Reserve. At least 50% of the Operating Reserve shall be Spinning Reserve which will automatically respond to frequency deviations. Interruptible load may be included in the Quick Reserve provided that it can be interrupted remotely in less than ten (10) minutes from the Control Centre.

The above shall establish the minimum amount of Operating Reserve that each Operating Member will be obliged to carry and indicates the level below which a Member is at fault.

Each Member shall declare its annual peak demand and its largest unit that is in service, every time these values change. The annual peak demand should reflect the power which was consumed within the boundary of the power system of each Operating Member, whether the power came from imports (or purchases). The annual peak demand should however exclude exports and any load that was reduced."

The minimum System Operating Reserve Requirements (SORR) of a SAPP operating member is calculated with the following formula:

$$SORR = PORR * \frac{\left(2\frac{D_s}{D_t} + \frac{U_s}{U_t}\right)}{3} \qquad (1)$$

where:

SORR = Minimum System Operating Reserve Requirement
PORR = Total Pool Operating Reserve Requirement
Ds = Individual System's Annual Peak Demand
Dt = Total Sum of Individual System's Annual Peak Demand
Us = Individual System's Largest Unit
Ut = Sum of Individual System's Largest Units (sum of Us)

This Operating Reserve is sufficient to reduce the Area Control Error (ACE) to zero within 10 minutes following the loss of generating capacity which would result from the most severe single contingency. Interruptible load may be included in Quick Reserve if it can be interrupted in less than 10 minutes and remain disconnected until replacement generation can be brought to service.
The sharing of the operating reserve between operating members for the year 2019 is shown Table 8.1.

SAPP OPERATING RESERVES FOR 2019					
Utility Name	Largest Generator [MW]	Maximum Demand [MW]	Spinning Reserve [MW] e	Quick Reserve [MW] f	Operating Reserve [MW] g = e + f
ESKOM	930	37769	501.3	501.3	1002.6
ZESA	220	1615	45.8	45.8	91.6
ZESCO	180	1811	42.4	42.4	84.7
BPC	150	610	26.4	26.4	52.7
EdM	38	955	14.6	14.6	29.3
CEC	10	699	8.3	8.3	16.6
NamPower	92	647	18.9	18.9	37.8
SNEL	65	2276	31.4	31.4	62.8
LEC	24	150	4.7	4.7	9.5
EEC	10	236	3.7	3.7	7.4
TOTAL	1719	46768	698	698	1395

Table 8.1 - Sharing of the Operating Reserve between Operating Members (Source: ZESCO)

In Zambia, only Kafue Gorge Upper and Kariba North Bank power plants response or hold the operating reserve during normal and abnormal operation (availability of the AGC at the two stations). CEC has no installed generation that is online to respond to system conditions at any given time; so, CEC is supported by the ZESCO reserve at any given time. The overall reserve for the year 2019 for ZESCO network is combined reserve for ZESCO and CEC, which is 101.3 MW.

8.2 Operating reserve requirements with VRES generation

Integration of VRES generation, such as wind and photovoltaic generation, into the power grid introduces major challenges for power system planning and operation because VRES are non-programmable, or programmable in a limited share. Therefore, when a high penetration of VRES must be integrated into the grid, their variability will significantly impact many technical issues, e.g., reserve requirements.

Wind power can be considered one of the most variable resources; it is a non-linear function of wind speed and fluctuates on various time-scales from seconds to seasons, and also depending on time of the day or night, according to the availability of the primary source. Wind power production has a seasonal pattern due to meteorology but also a diurnal pattern due to daily weather, influenced especially by temperature. Wind speeds are subject to a broad range of uncertainty of both atmospheric and geographic nature; then the predictability of wind speed is rather low and has limited accuracy; consequently, it affects the predictability of the wind farms production.

On the other hand, photovoltaic power plants convert sun light into electrical energy, depending on the intensity of solar radiation. While dependence on the position of the power plant is not a big issue, the time-characteristics of solar energy can result in additional requirements for the power system, with different features with respect to wind. Electricity production from PV has both seasonal variation – with the peak in summer and diurnal variation – and it is typically peaking during mid-day. It also fluctuates in inter-hourly scale for example due to clouds and rainfall. However, the output power from PV generation is more predictable than wind power production.

The knowledge of the variable output characteristics of wind and photovoltaic power plants is very important to deal with their impacts on reserve requirements. Wind power is much more fluctuating and unpredictable than power production from PV, and also than load. Besides, while PV generation occurs only in a limited set of hours (daytime hours), not so happens for wind generation available also during night hours. Therefore, wind and PV generation have very different features, in terms of requirements for the reserve.

The operating reserve is used to restore the balance in the control area; therefore, it must be sized according to the expected system imbalances and a predefined reliability level. The system imbalance represents the difference between demand and generation due to the variability of renewable energy, i.e. wind and photovoltaics, the variability of the demand and unexpected outages of power plants, or relevant transmission assets. The system operator need to determine the operating reserve ex ante to assure a proper reliability and security of the electric power system.

The operating guidelines in place in Zambia do not include specific reserve requirements due to the operation of Variable Renewable Energy Sources (VRES) power plants in the system. However, the VRES integration into a power system may need an additional amount of reserve due to the variability and uncertainty of wind and solar radiation; especially when a high penetration of these sources is envisaged, as the scope of the current study.

A statistical method to size the operating reserve requirements with a high penetration of wind and photovoltaic generation in the system is proposed by the Consultant and presented in the following sections. The method is well described in literature and is used by several transmission system operators. It is generally accepted as a good method, allowing considering variable generation, while trading off complexity and accuracy.

Not a single approach is worldwide accepted sizing the operating reserve requirements in electric power system with high VRES penetration. Several methodologies are adopted by the system operators; the most suitable approach depends on the types of balancing power, the structure of the ancillary service market, the system imbalance sources, the reliability level required by the system operator and the operating rules of the system operator.

The methodologies can be mainly distinguished as deterministic or probabilistic and static or dynamic. The deterministic approaches size the reserve according to a specific event, such as the largest contingency. However, these approaches do not consider the probability or the correlation between sources of imbalances. On the contrary, the probabilistic (stochastic, statistic) methods allow to size the reserve such that a certain system reliability level is assured, estimating the probability distribution of system imbalances. The reserve requirements can be determined for long time periods such as one year (static sizing) or more frequent periods depending on the current or expected status of the system (dynamic sizing). Deterministic approaches are usually static while probabilistic approaches can be static or dynamic (Holttinen et al. (2012)).

A hybrid approach (Figure 8.1) has been applied by the Consultant combining probabilistic and deterministic approaches. The dynamic sizing of the system imbalances due to forecast errors is performed applying the probabilistic "Graf-Haubrich method" (Consentec 2008, 2010, Maurer et al. 2009) for different wind and PV production clusters to estimate the system imbalance expected for each hour of the year, with a desired system security level. The stochastic convolution of uncorrelated sources of imbalance (load, PV production and wind production forecast errors) results in the joint distribution function, for each wind-PV production cluster (combination of wind and PV productions considering five production steps for each source: 0%-20%, 20%-40%, 40%-60%, 60%-80%, 80%-100% of the installed capacity). From the resulting Probability Distribution Function (PDF) the negative and positive imbalances[17] are derived as specific percentiles corresponding to pre-defined deficit probabilities. In statistical terms, the balancing area imbalance follows the joint distribution of the individual factors' distribution functions and the reserve is set according to a pre-defined percentile (security level) of that function. The negative capacity requirements to balance the negative forecast errors represent the maximum downward operating reserve, while the upward operating reserve results by the largest contingency that could occur during the system operation (the out of service of the largest power unit or the maximum positive forecast error).

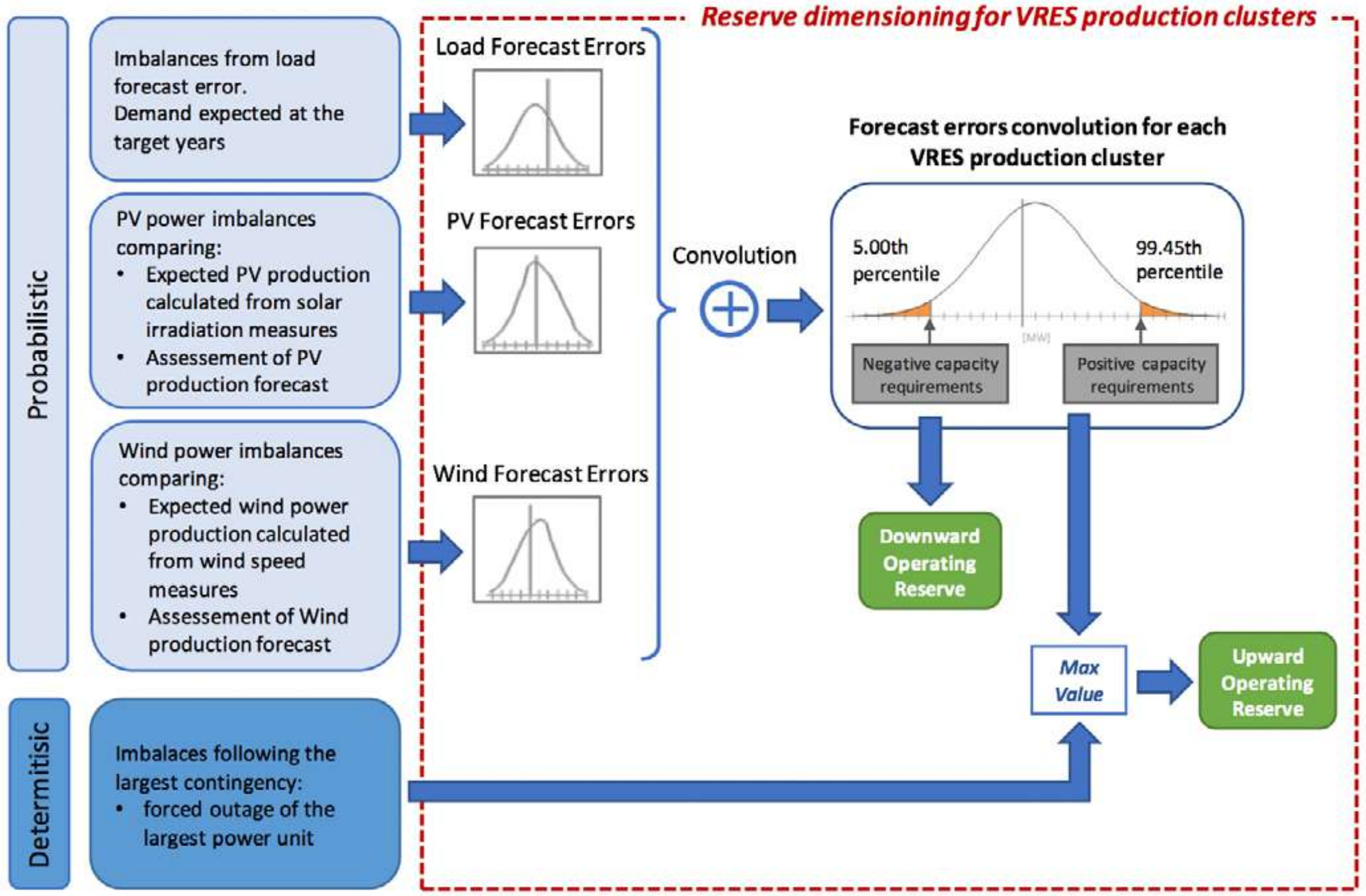


Figure 8.1 – Schematic process for the sizing of the operating reserve in presence of VRES

When positive forecast error (actual production lower than forecasted one) occurs, missing VRES production must be balanced activating the upward reserve provided by the programmable generating units, to avoid load curtailment. The 99.45th percentile of the probability distribution curve of the expected forecast errors determines the upward operating reserve needs, with the loss of the largest power unit in Zambia set as the lower limit (the current reserve sharing in SAPP has been neglected with the aim of apply a more conservative approach in reserve supply. Self-sufficiency in the operational reserve has been simulated). The 99.45th percentile comply with the acceptable number of hours with unserved load for one year (48 hours equal to 0.55% of the time of a year[18]). On the contrary, when negative forecast error (actual production higher than forecasted one) occurs, exceeding VRES production must be accommodated by using downward reserve provided by the programmable generating units, to avoid VRES production curtailments. The 5th percentile determines the downward operating reserve needs, with an accepted generation curtailment less than 1% of the annual expected production and an overall security level equal to 94.45%. Figure 8.2 shows VRES yearly gross production to be curtailed due to insufficient downward reserve against the forecast error distribution percentile on which downward reserve is calculated. We considered acceptable to size downward reserve share due to VRES forecast error on 5th percentile of VRES forecast error corresponding to a curtailment of about 0.60% of gross VRES yearly generation.

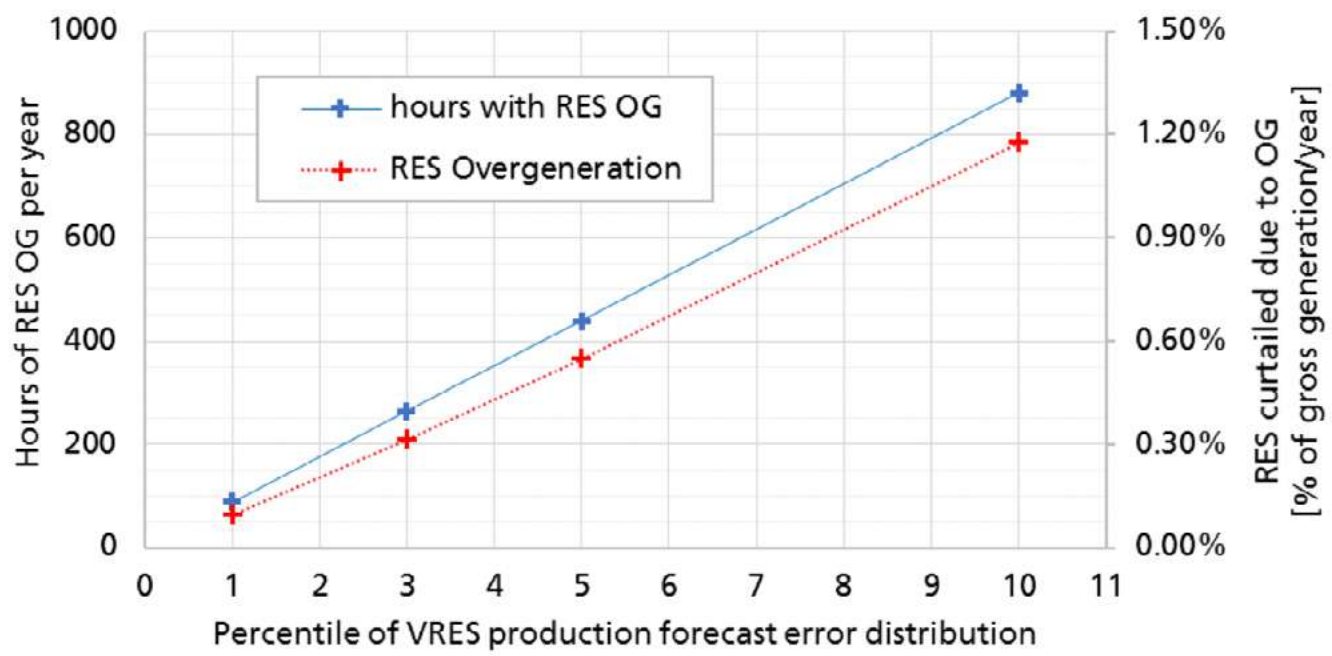


Figure 8.2 – Hours a year with RES production over-generation (OG) and corresponding energy curtailment as a function of percentile of VRES production forecast error distribution.

[17] In this report, unless otherwise specified, the unbalances (forecast errors) are calculated as forecasted values minus actual values.

[18] According to the Zambia Bureau of Standard ZS-387-1 2011, Annex D, Commercial and small to medium industrial

The system imbalances due to the variability and uncertainty of VRES productions assumes a wide range of values according to the production forecast from wind and PV power plants. Therefore, a statistical analysis of the forecast errors was performed for five bins of wind/PV production forecast (0%÷20%, 20%÷40%, 40%÷60%, 60%÷80%, 80%÷100%) and all combinations of wind and PV production forecasts.

In detail, for each combination of wind and PV production forecasts, the upward reserve (UPR) is calculated as the maximum value between the power of the largest generation contingency

(Pgroup_max is assumed to be always a turbine of the Kariba North Bank hydroelectric plant with a maximum power equal to 180 MW) and the maximum accepted Positive Forecast Error (PFE):

$$UPR^{99.45th}_{PV+wind+load} = max\begin{cases} PFE_{[PV+wind]_{bins}+load} \\ P_{group\_max} \end{cases} \tag{2}$$

where the maximum PFE is the minimum value between the 99.45th percentile of VRES production plus load overall forecast error distribution and the VRES production forecast plus the 99.45th percentile of load forecast error distribution.

$$PFE_{[PV+wind]_{bins}+load} = min\begin{cases} PFE^{99.45th}_{[PV+wind]_{bins}+load} \\ P_{PV\_fore} + P_{wind\_fore} + PFE^{99.45th}_{load} \end{cases} \tag{3}$$

The downward reserve (DWR) is calculated as the minimum value between the 5th percentile of the of VRES production plus load overall forecast error distribution (NFE) and the maximum hourly unbalance (the complement of forecasted VRES production to VRES installed power) plus the 5th percentile of load forecast error).

$$DWR^{5th}_{PV+wind+load} = min\begin{cases} NFE^{5th}_{[PV+wind]_{bins}+load} \\ \left[P_{PV\_inst} - P_{PV\_fore}\right] + \left[P_{wind\_inst} - P_{wind\_fore}\right] + NFE^{5th}_{load} \end{cases} \tag{4}$$

9 ANALYSIS OF WIND AND PV TIME-SERIES

9.1 Wind and PV productions

For each wind site considered in [5] maximum, average and minimum wind speed over 10 minutes are available for the last part of year 2016, the whole year 2017 and almost all the year 2018. Considering the generation curve of the wind turbine showed in the section 6.2.3.2 to calculate site capacity factors, 10 minutes average wind speeds were converted into average generated power.

A wind farm is composed by several to a large number of wind turbines, depending on its size. Due to spatial variability of wind, at the same time wind turbines are subject to different wind speeds, with the generally beneficial effect of partially counterbalancing their power production fluctuation over time, smoothening wind farm overall production trend over time. As said, in our case wind speed data are available only for a single met mast per site, that is for a single wind turbine per wind farm placed in the site. Therefore, in present study the abovementioned beneficial effect had to be neglected. On the other hand, maximum and minimum wind speeds over 10 minutes were neglected too, considering only 10 minutes average speeds.

Figure 9.1 exemplifies 10 minutes average production of wind turbines placed in different wind sites and their aggregate production profile, calculated by weighting sites profiles with the expected capacity factors. Figure 9.2 shows 10 minutes average production change over the next 10 minutes for each wind site and their aggregate, for the same day of October 2017 considered in Figure 9.1, taken as an example. The production change over 10 minutes is the production deviation between the current time step and the next 10 minutes. Therefore, considering the point 1 (P1) as the mean production between time t0 and t0+10min (e.g. t0=11:00 a.m. of October, 18th) and the point 2 (P2) the mean production between time t0+10min and t0+20min, the production change over 10 minutes is calculated as the difference between P2 and P1. Thus, if P2-P1 is less than 0 it means that average production reduced over the next 10 minutes, while if P2-P1 is greater than 0 it means that average production increased over the next 10 minutes. The profiles of 10 minutes average production change were calculated for all sites and for the whole aggregate (as weighted sum of the sites). It can be noted the beneficial effect of aggregation of wind turbines subjected to different wind speeds, since their aggregated production change over ten minutes is often comparable with single sites one.

Figure 9.3 shows the effect of aggregation of wind turbines subjected to wind speed spatial variability on 10 minutes average generated power over a year. It can be noted that production of single wind turbines is very close to zero or equal to rated power for a significant fraction of time, while their aggregated production almost never assumes those values.

[19] Rated power 4.2 MW, hub height 140 m, rotor diameter 150 m.

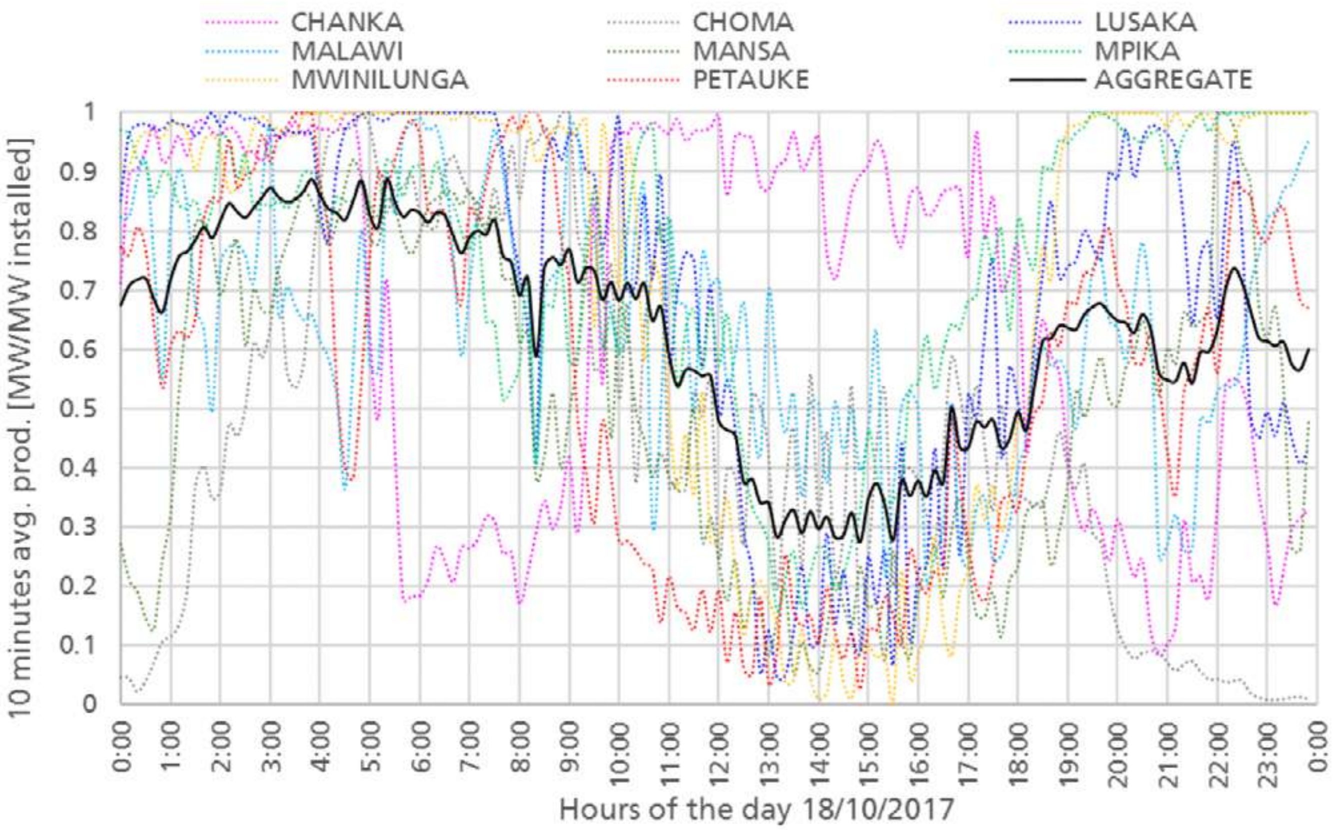


Figure 9.1 – Example of 10 minutes average specific production of wind turbines placed in different wind sites and of their aggregate production profile.

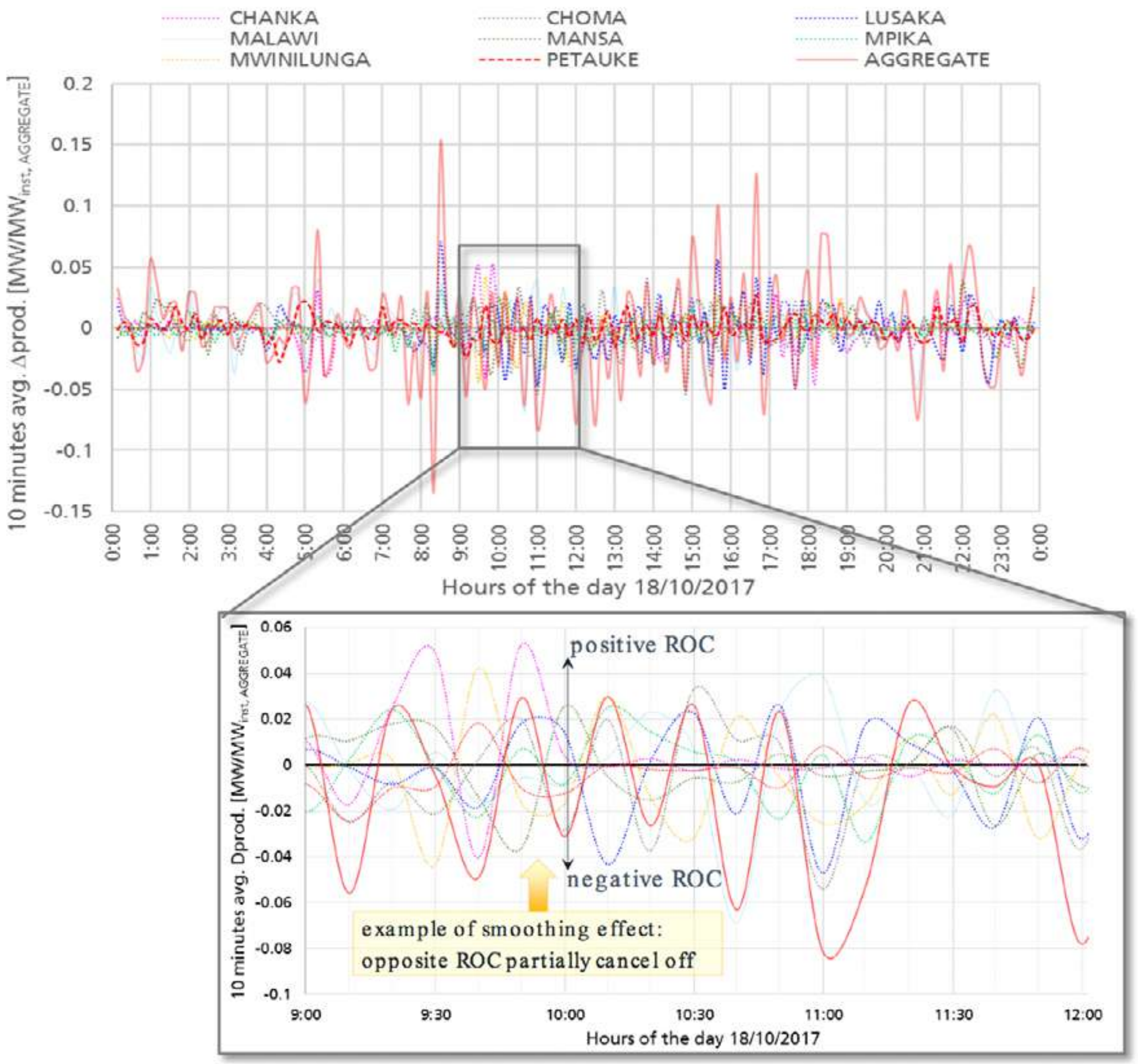


Figure 9.2 – Averaged production change over the following 10 minutes for each wind site and their aggregate.

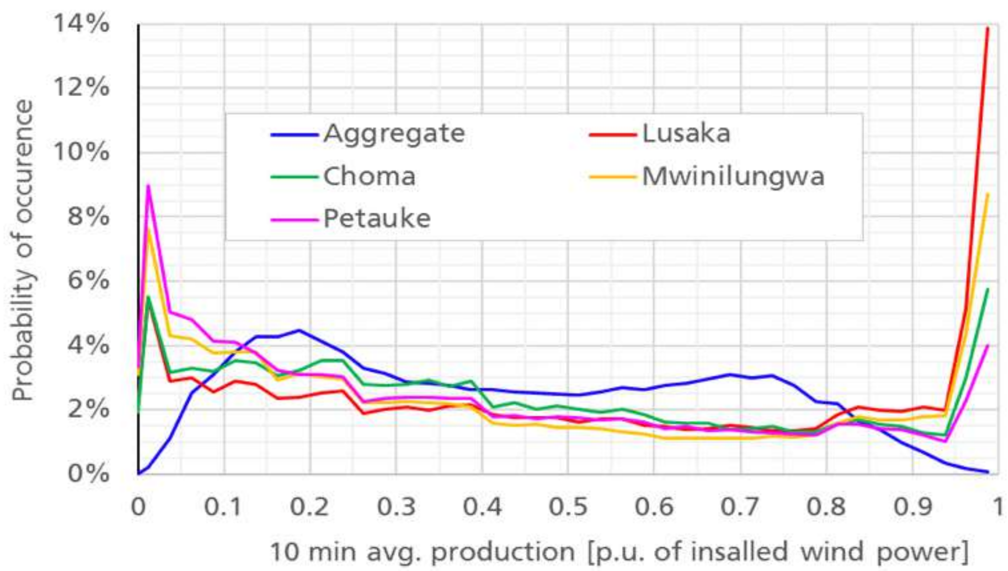


Figure 9.3 – Frequency over a year of clusters of 10 minutes average power produced by single turbines placed in considered wind sites and by their aggregate.

For each PV site considered in [7], solar irradiation and ambient temperature are available for each minute of the last part of year 2015, the whole year 2016 and almost all the year 2017. Since data for Longe and Misamfu sites show inconsistencies over the year 2016, only the following sites were considered: Lusaka, Mochipapa-Choma, Mont Makulu-Chilanga and Mutanda. Available data were averaged over time intervals of 10 minutes, then they were converted into PV generation by using SAM software developed by NREL, considering bifacial PV panels. Figure 9.4 exemplifies 10 minutes average production of different PV plants placed in considered sites and their aggregated production profile, calculated by weighting single sites production with the following percentage of aggregate installed power: Lusaka 40%, 20% for each one of the remaining sites. Figure 9.5 shows 10 minutes averaged production change over the next 10 minutes for each PV site and their aggregate, for the same day of December 2017 considered in Figure 9.4, taken as an example. It can be noted the beneficial effect of aggregation of PV plants subjected to different irradiation, since their aggregated production change results comparable to the Lusaka site one, where Lusaka is the largest installed capacity considered into the aggregate.

Sharp production change over 10 minutes exemplified in Figure 9.4 are likely because of temporary sky cloud covering, that in case of large multi MW PV plant could shade and reduce power generation of only a part of the plant. Analyses performed on the effect of clouds cutting direct irradiation only on part of a PV plant for short time like a minute[20], showed that calculating whole plant average production over 10 minutes considering irradiance for a single point of the plant doesn't induce significant underestimation of actual overall plant generation over considered 10 minutes.

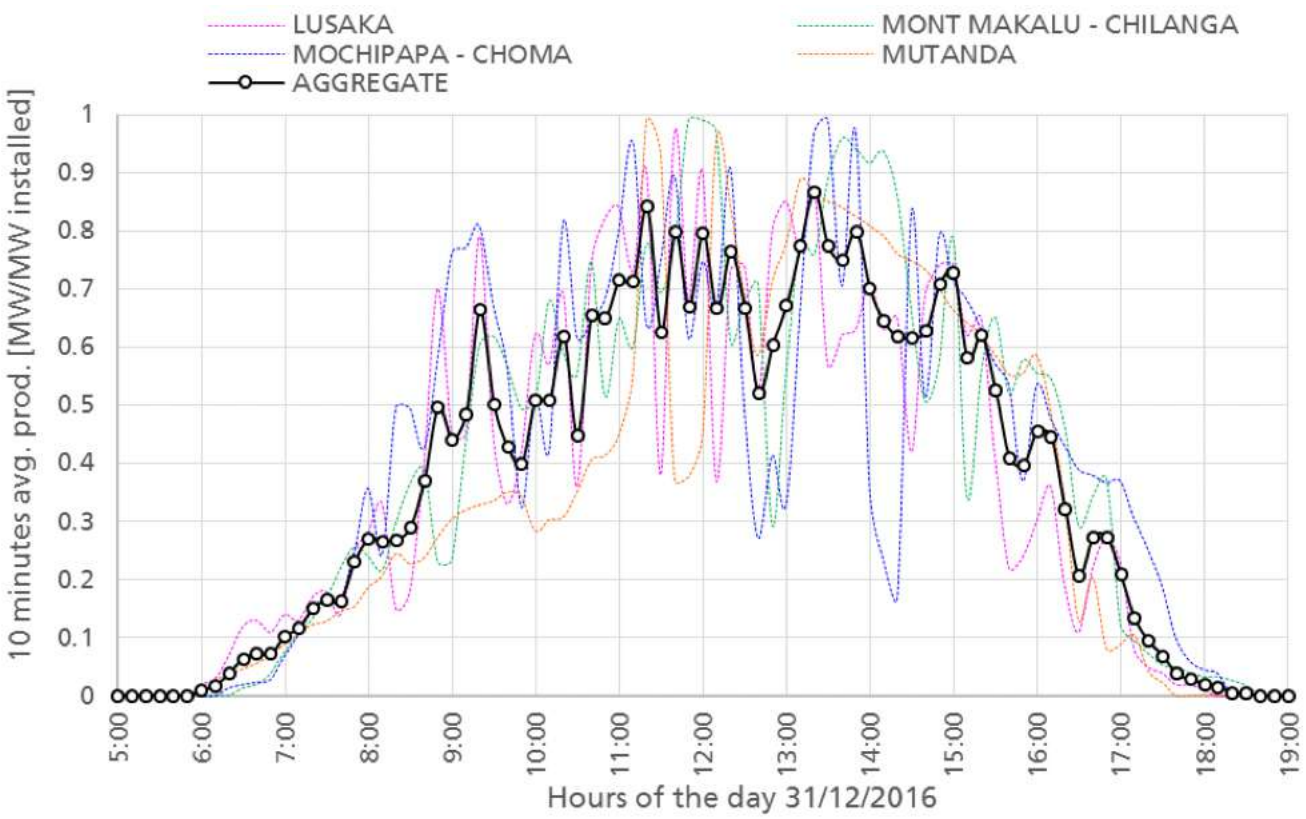


Figure 9.4– Example of 10 minutes average specific production of PV plants placed in different PV sites and of their aggregate in a day selected since characterized by highly variable sky covering.

[20] A hypothetical PV plant was split into three identical subsections, all having the same power generation on a minute basis. Then two subsections generations were shifted one minute before and one minute after the production of the third subsection, to model clouds shading one third of the plant at a time for just a minute.

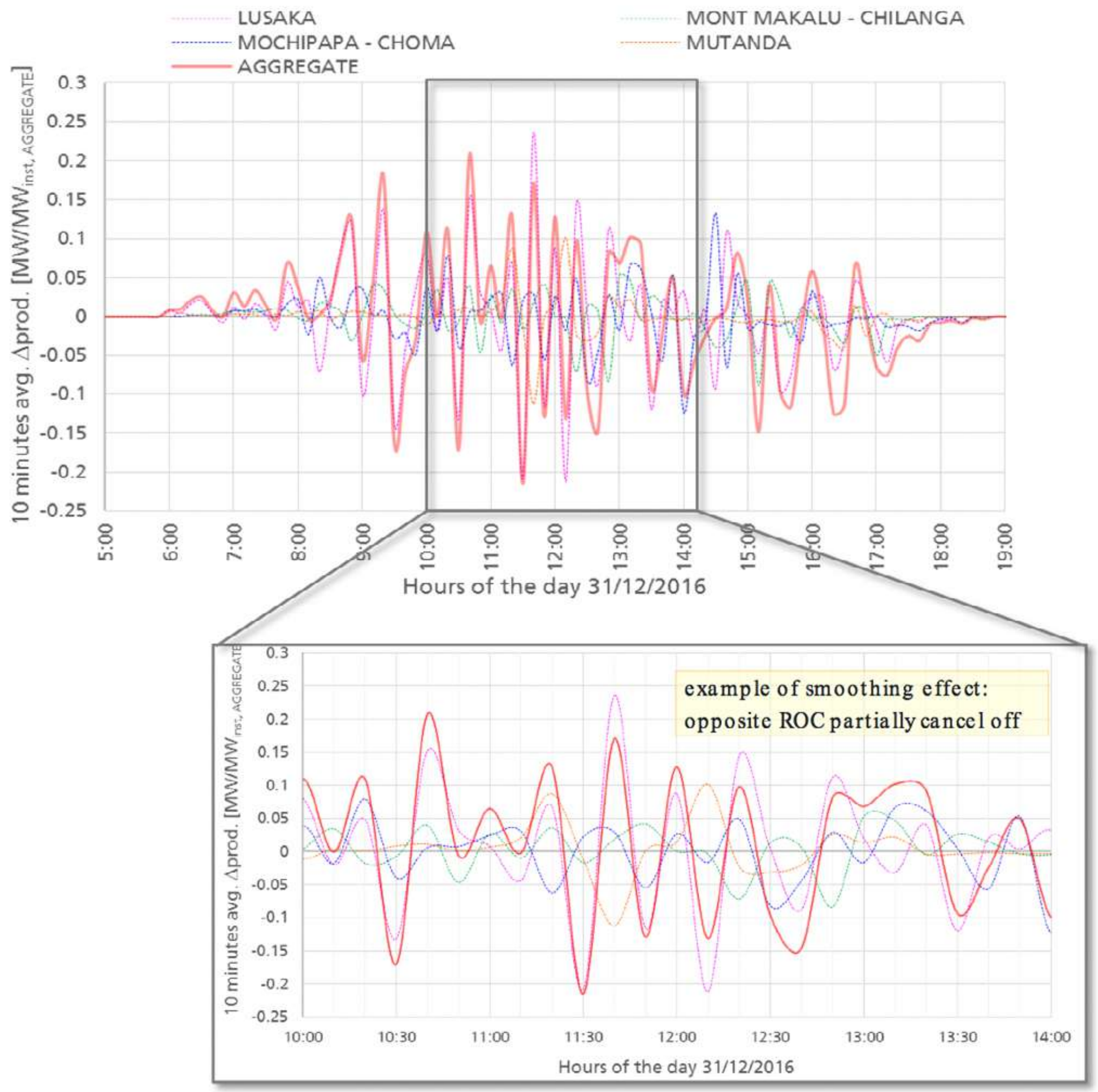


Figure 9.5– averaged production change over the next 10 minutes for PV plants placed in considered sites and for their aggregate.

Aggregate wind/PV production average change over 10 minutes for the reference year were grouped by positive and negative values and by bins of wind/PV production (Figure 9.6) or, as an alternative, by the hours of the day (Figure 9.7). For the resulting population median value and value that in module has a probability of not being exceeded of 90% (P90), 95% (P95) and 99% (P99) were calculated.

As regard PV, P90, P95 and P99 negative changes increase with generated power, while positive ones peak for intermediate generated power. Those trends are due to the effect of temporary clouds: when covering the sky, they cut PV production, sensibly around midday; when clearing the sky, they make production ramping up, again more sensibly around midday, as it can be noted from Figure 9.4. At low load positive production variation are low, due to low irradiation. Over the next 10 minutes a production change lower than 30% of installed power both positive and negative can be expected with a probability of 99%.

As regard wind, slightly higher positive and negative changes over the next 10 minutes can be observed for intermediate production, where the steepest turbine power curve results in higher power variation with wind speed change. Anyway, the dependence on generated power appears to be quite low. Over the next 10 minutes a change lower than 15% of installed power both positive and negative can be expected with a probability of 99%.

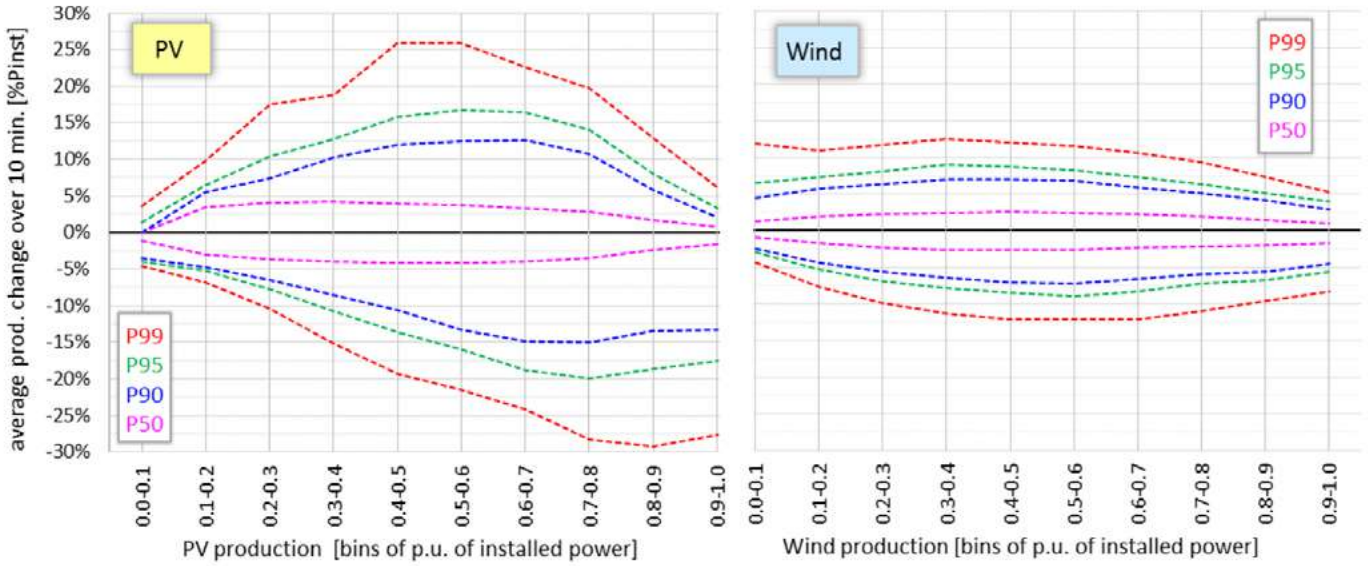


Figure 9.6 – PV and wind aggregate average P90, P95 and P99 production change over the next 10 minutes as a function of bins of installed power.

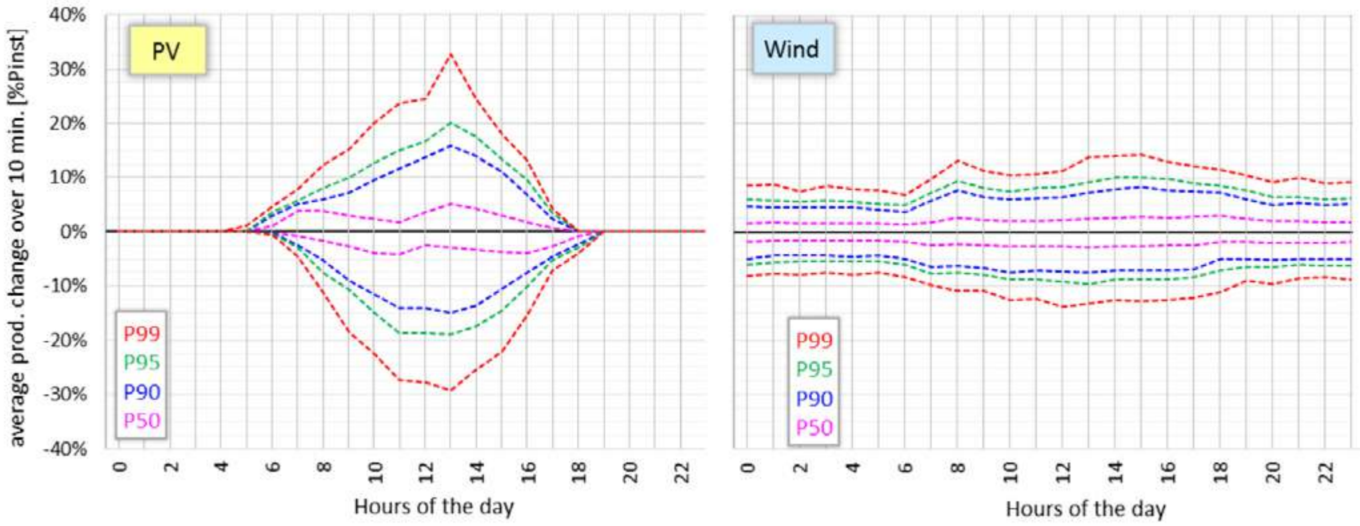


Figure 9.7 – PV and wind aggregate average P90, P95 and P99 production change over the next 10 minutes as a function of the hours of the day.

Figure 9.8 compares monthly average inflow for Itezhi Tezhi reservoir, taken as and an index of water availability for hydroelectric production (especially ROR plants), with aggregate wind and PV monthly electricity production per installed MW. It can be noted a good complementarity between water availability and PV and wind production, peaking when water availability is minimum. Monthly production changes sensibly for wind, slightly for PV. Monthly wind and PV production are well phased also with Zambia load forecasted for year 2030, which is generally lower when high amount of water is available.

Figure 9.9 shows the hourly average wind aggregate production for the average day of each month of the reference year. From November to March the production is low and almost flat over the 24 hours. In other months, production is higher in night-time and minimum from 1 p.m. to 5 p.m.. Figure 9.10 shows the hourly average PV aggregate production for the average day of each month of the reference year. Production profile follows irradiation pattern and maximum production are expected from May to October. It's interesting to note that from May to October PV production profile generally tends to complement, on average, wind profile in daylight hours, even if with a time shift of about two hours.
Figure 9.11 shows wind and PV production matching over the considered reference year. Almost half of the hours a year PV production is null, since sun is not available.

Finally, Figure 9.12 shows hourly average load for the average day of each month of the year 2030. Load is quite flat over the day, peaking between 8 p.m. and 9 p.m. and its seasonal variations are small.

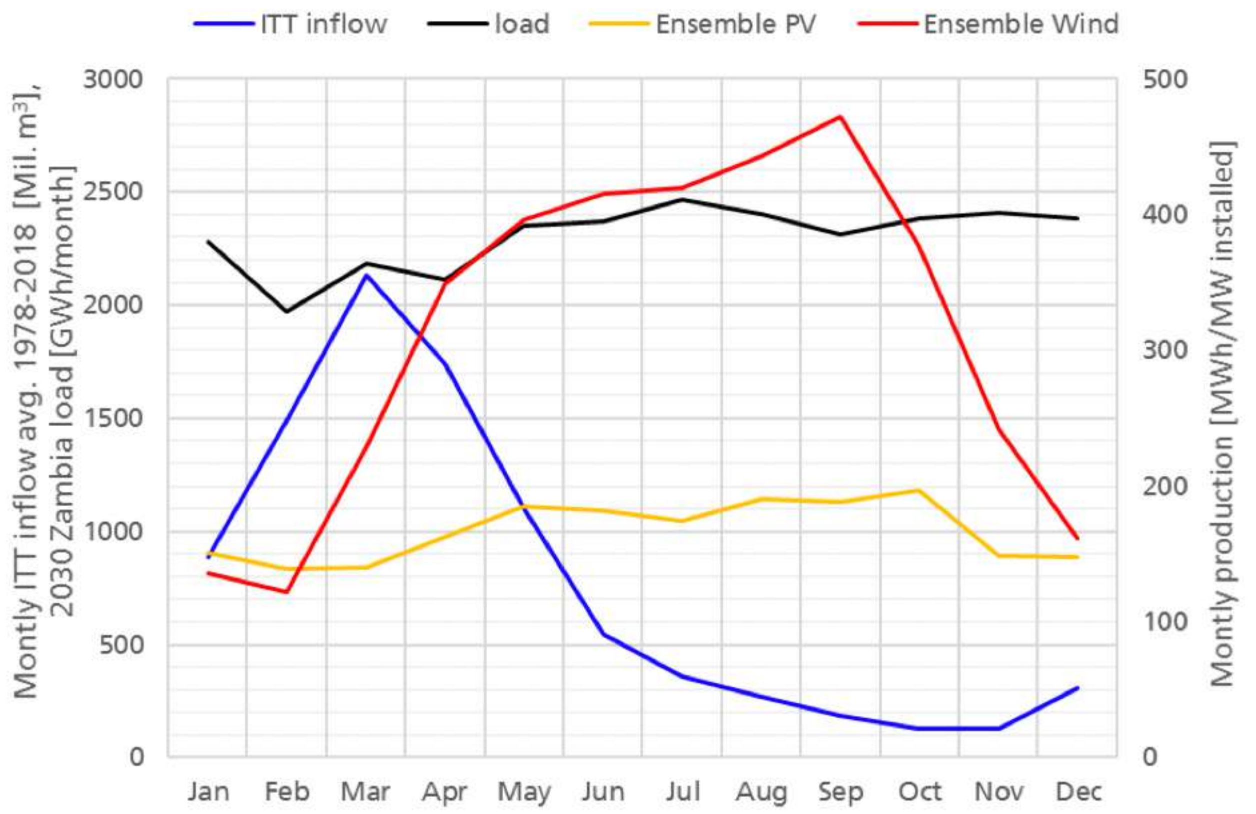


Figure 9.8 – Wind and PV expected production compared with ITT reservoir average inflow and Zambia monthly load forecasted for year 2030.

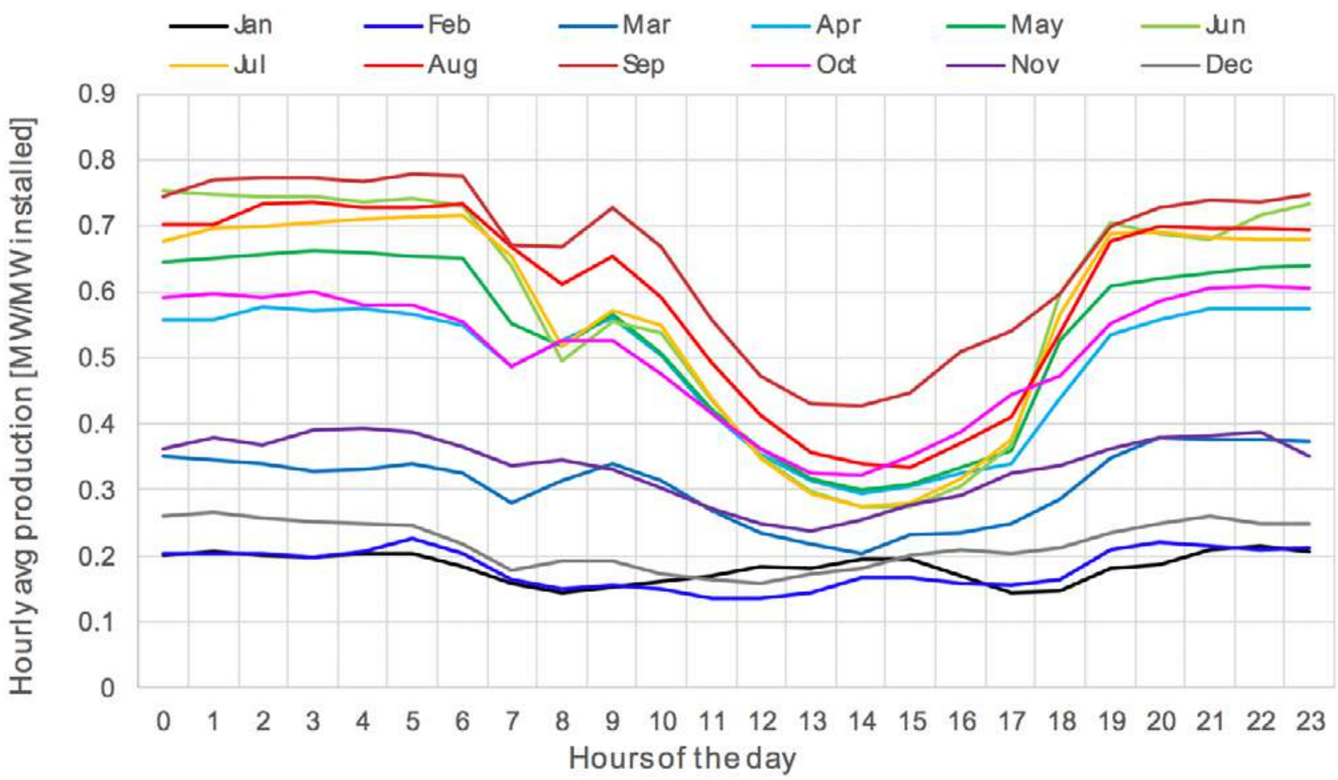


Figure 9.9 – Hourly average wind aggregate production for the average day of each month of the reference year.

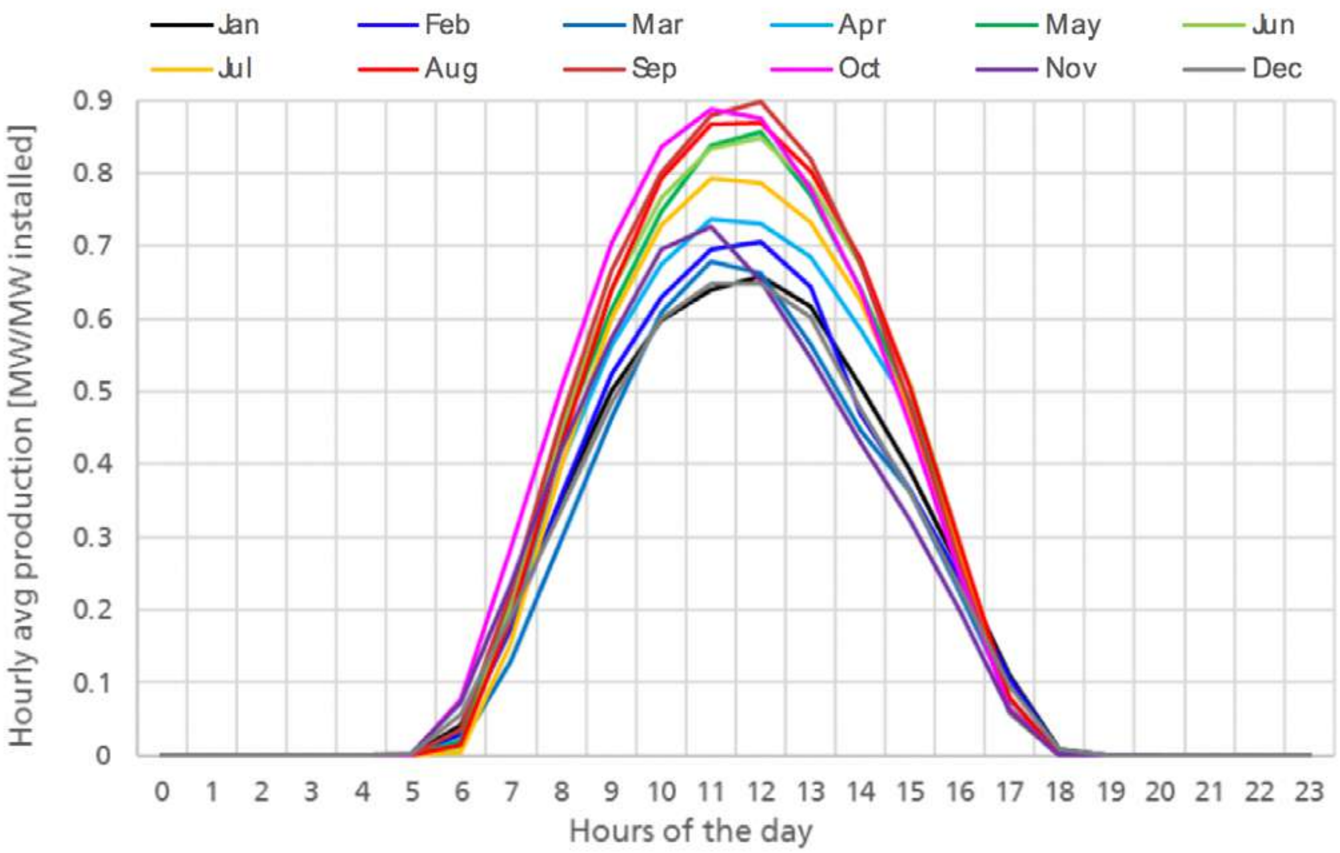


Figure 9.10 – Hourly average PV aggregate production for the average day of each month of the reference year.

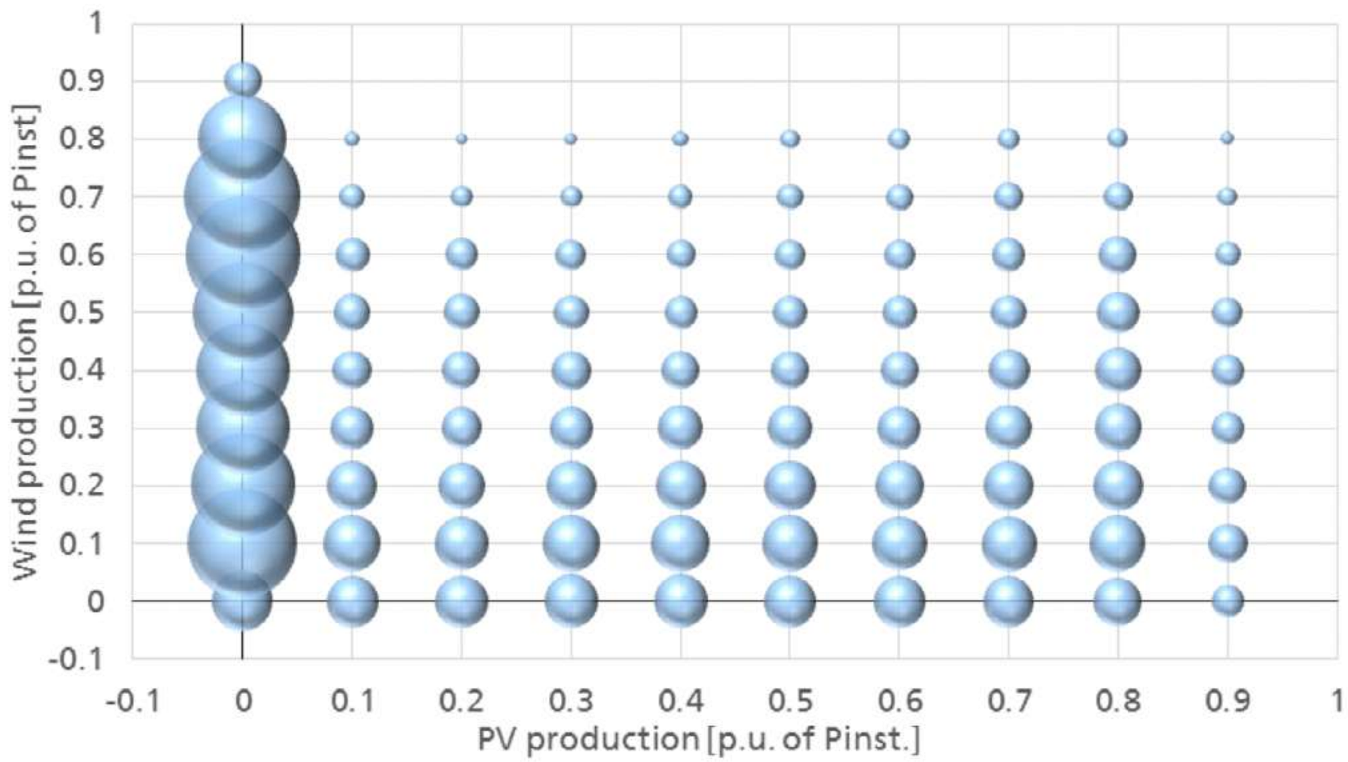


Figure 9.11 – Wind and PV production matching over the considered reference year. Bubbles area is proportional to the frequency of occurrence of wind and PV production bins.

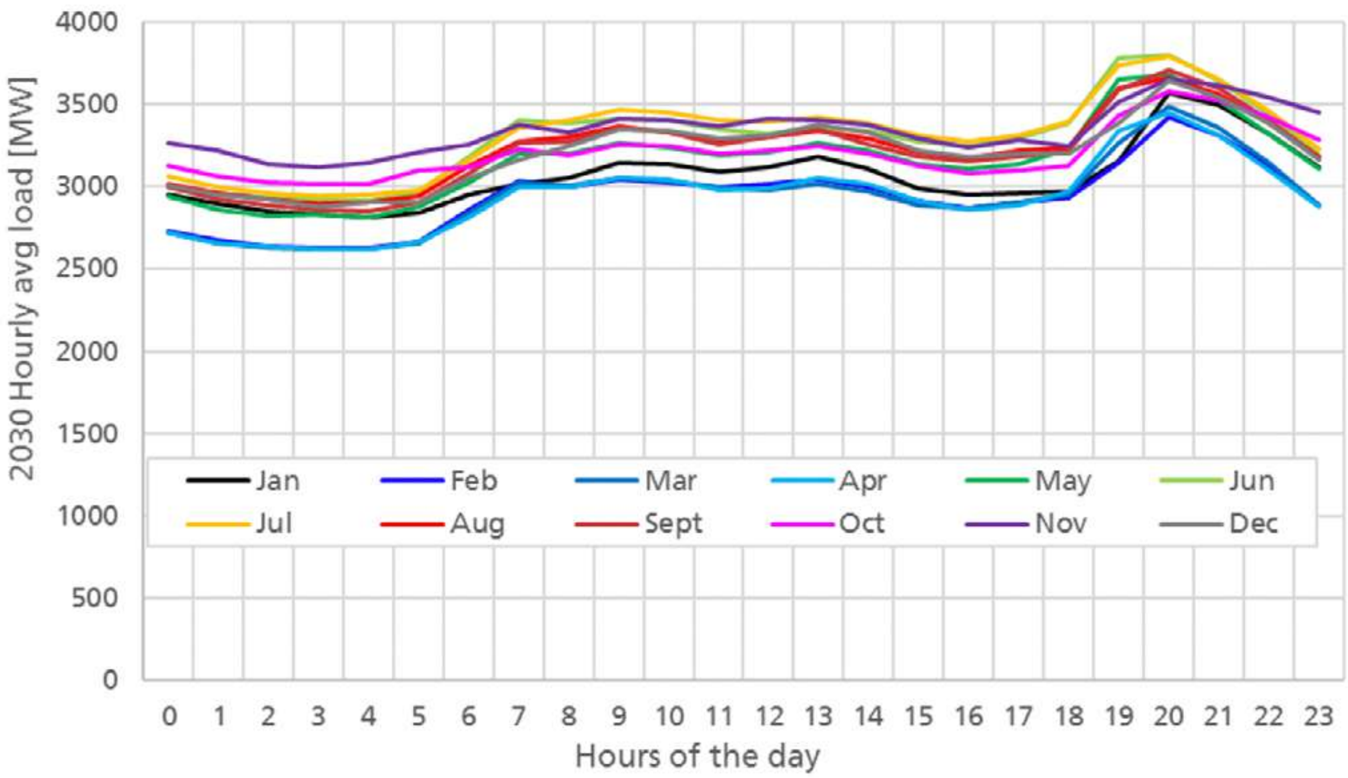


Figure 9.12 – Hourly average load for the average day of each month of the year 2030.

9.2 Wind production forecast error

9.2.1 Modelling

The modelling and prediction of time series of hourly average wind speed, and thereby the power output of wind farm, has been a subject of attention to many researchers due to its impact on the operation of conventional electric power plants that are connected to the same power grid. Several methods were developed, based on several techniques, such as measured weather and wind system data, numerical weather prediction, Monte Carlo method, pure autoregressive model (AR) to a series of observed data or autoregressive-moving-average model (ARMA), etc.

Considering that now there is not wind generation in operation in the Zambian electric power system, and thereby no historical data on wind power production and wind forecast are available, the Consultant used the ARMA model for the forecast of the behaviour of average wind speed up to 4 h in advance [15]. The method allows a good wind speed forecast in short-term, with a good trade-off between complexity and accuracy accepted in a planning study. In the ARMA model the forecast of the wind speed depends not only on the values that wind speed had in the recent past according to the autoregressive component, but it can also be a function of the residuals of past forecasts, that correspond to previous hours to that for what we are doing the forecast. The autoregressive (AR) part involves regressing the variable on its own lagged (i.e., past) values. The moving-average (MA) part involves modelling the error term as a linear combination of error terms occurring contemporaneously and at various times in the past. The application of ARMA model requires time series to be normal distributed and stationary, i.e. the method assumes that the process remains in equilibrium about a constant mean level. Therefore, in order to adjust the time series to the ARMA model, it is necessary to carry out a transformation and standardization of the wind speed time-series, given the non-Gaussian nature of the hourly wind speed distribution and the non-stationary nature of its daily evolution (in fact, the hourly wind speed generally shows a cyclic behaviour during the day, due to atmospheric stability and instability phenomena).

The mathematical expression of the general ARMA model (p,q) that is applied in this case to the series of transformed and standardized values is the following equation:

$$V^*_{t+k} = \phi_1 \cdot V^*_{t+k-1} + \phi_2 \cdot V^*_{t+k-2} + \cdots + \phi_p \cdot V^*_{t+k-p} + a_{t+k} - \theta_1 \cdot a_{t+k-1} - \cdots - \theta_q \cdot a_{t+k-q} \qquad (5)$$

Where V* is the transformed and standardized wind speed, p the order of the autoregressive process, q the order of the moving average process, φi the autoregressive parameters, θj the parameters of moving average, a is the white noise variables and k is the number of advance intervals of the forecast done at a time t.

The ARMA model was applied for each wind site to calculate the hourly forecast of wind speed and wind power production, applying the reference wind turbine power curves defined in section 6.2.3.2. The aggregation of the eight wind sites analysed with the ARMA model allowed the forecast of the wind power production for the overall country and the calculation of the forecast errors as the difference between the hourly forecast and the 10 minutes actual power. The probabilistic analysis of the wind power production forecast errors was carried out assessing the probabilistic distribution functions of wind production forecast errors, for different wind production clusters.

9.2.2 Results

In the following of the Report, unless otherwise specified, VRES production forecast errors are calculated as forecasted production minus actual production. Therefore, a positive forecast error means that VRES forecasted production is higher than actual one and missing generation must be filled with upward reserve provided by programmable generating units. On the contrary, a negative forecast error means that forecasted production is lower than actual one, and the exceeding VRES generation must be balanced activating the downward reserve from the programmable generating units able to provide this service.
Wind production forecast error was calculated for 10 minutes time intervals over the reference year for each wind site and for their aggregate. Then errors were grouped by positive and negative populations, for which values whose module has a probability of not being exceeded of 90% (P90), 95% (P95) and 99% (P99) were calculated, as well as standard deviation for the whole errors population. Results are shown in Table 9.1, from which it can be noted that aggregate production forecast is affected by an error lower than the corresponding one for each wind site, due to the beneficial effect of aggregating productions of plants affected by different wind profile over time.

Figure 9.13 shows the Probability Density Function of production forecast error for several wind plants among those considered in the study and for the aggregate of all considered plants. As anticipated in Table 9.1, aggregate PDF is more concentrated around a null error and has a more symmetric shape than PDF of single plants; furthermore, it's quite similar to a Normal distribution having the same mean and standard deviation (Figure 9.14).

Table 9.4 and Figure 9.16 show P90, P95 and P99 production forecast error for considered wind sites aggregate, grouped by positive and negative values, as a function of forecasted production and expressed as percent of installed power. At high forecasted production negative errors (actual production higher than forecasted one) tends to be very small, since generation is close to its maximum. At low forecasted production, positive errors (actual production lower than forecasted one) tend to be very small too, since generation is close to zero. P90, P95 and to some extent P99 positive errors remain quite constant for forecasted generation above 30% of the installed power, respectively around 20% and 30% of installed power, while negative P90, P95 and especially P99 peak for a forecasted generation around 20%-30% of the installed power, respectively around 30%, 40% and 60% of installed power. If errors were expressed as percent of forecasted production, instead of installed capacity, they would result lowering with production increasing.

Wind site		Chanka	Choma	Lusaka	Malawi	Masa	Mpika	Mwinilunga	Petakue	Aggregate
Positive error [% Pinst]	P50	8.9%	11.4%	10.2%	9.4%	9.4%	8.6%	9.6%	7.7%	5.6%
	P90	35.1%	32.2%	34.0%	30.9%	33.8%	29.8%	32.3%	26.7%	16.4%
	P95	44.9%	41.6%	44.4%	41.7%	44.5%	38.5%	45.2%	35.0%	20.3%
	P99	64.0%	62.2%	64.0%	62.3%	66.5%	60.8%	72.8%	50.4%	28.3%
Negative error [% Pinst]	P50	-13.3%	-14.7%	-11.5%	-16.0%	-12.5%	-13.5%	-9.0%	-13.4%	-7.1%
	P90	-43.6%	-42.1%	-40.9%	-50.9%	-40.7%	-42.8%	-33.9%	-43.5%	-20.4%
	P95	-55.2%	-51.4%	-52.1%	-63.3%	-51.8%	-53.5%	-44.6%	-55.7%	-26.2%
	P99	-79.8%	-68.7%	-71.8%	-81.8%	-78.4%	-75.7%	-67.7%	-80.3%	-40.4%
All errors	RMSE	23.1%	22.4%	21.9%	24.4%	22.2%	21.8%	20.3%	21.3%	11.4%

Table 9.1 – P90, P95 and P99 positive and negative wind production forecast errors and standard deviation for the whole errors population, for wind plants placed in considered sites and for their aggregate.

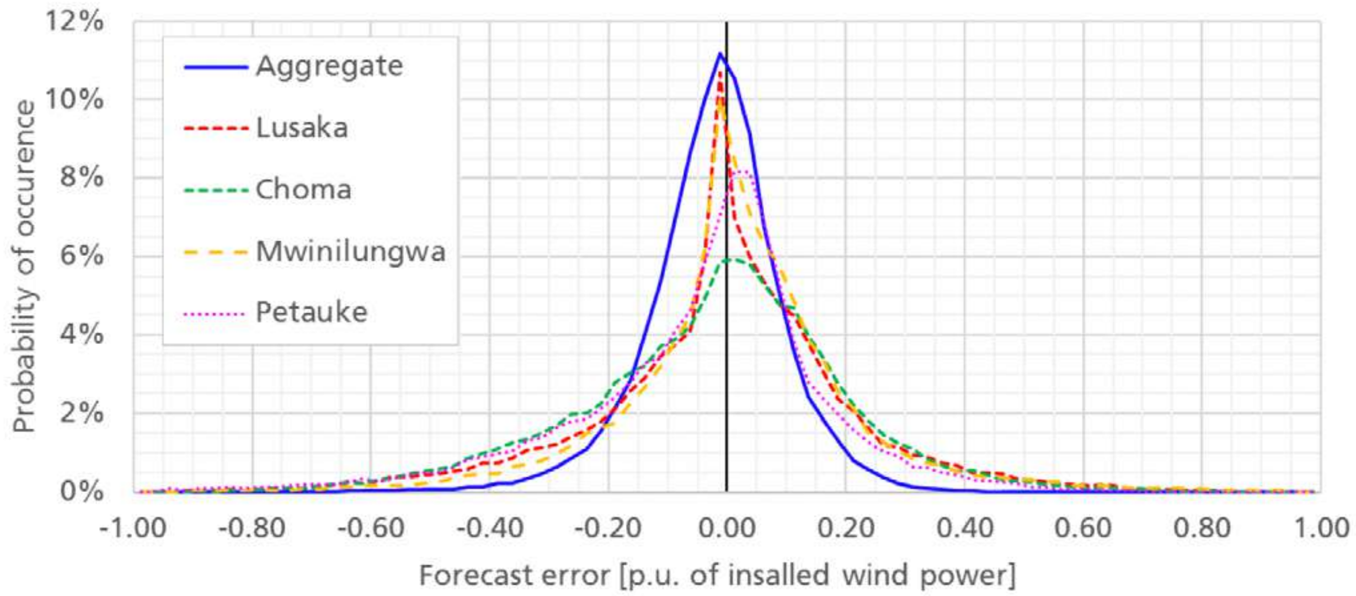


Figure 9.13 – Wind production forecast error Probability Density Function for some of selected wind sites and for all sites aggregate.

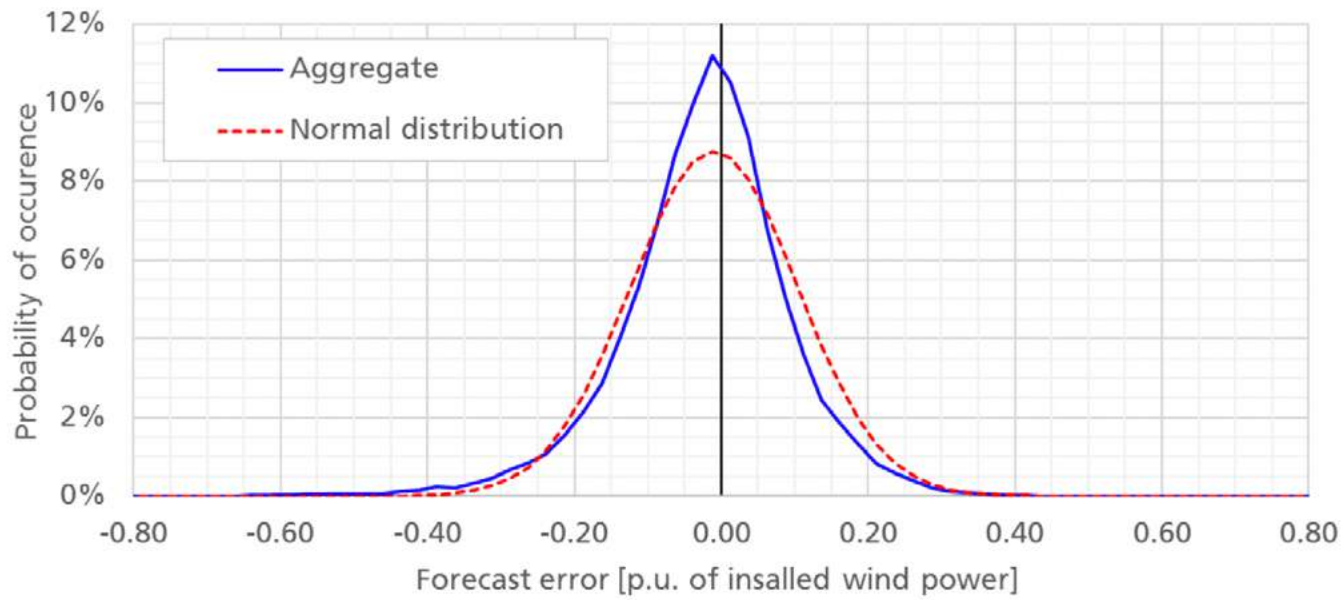


Figure 9.14 – Wind production forecast error PDF for all sites aggregate and for a Normal Distribution having the same mean and standard deviation.

Wind Aggregate		Production forecast bins [p.u. of Pinst]									
		0.0-0.1	0.1-0.2	0.2-0.3	0.3-0.4	0.4-0.5	0.5-0.6	0.6-0.7	0.7-0.8	0.8-0.9	0.9-1.0
Positive error [% of Pinst]	P50	2.1%	3.5%	5.6%	6.7%	6.4%	7.2%	7.3%	7.2%	7.6%	4.9%
	P90	4.9%	8.5%	14.3%	16.8%	16.4%	19.4%	19.5%	19.1%	19.2%	16.1%
	P95	5.8%	9.9%	17.0%	19.4%	20.1%	24.1%	23.5%	23.0%	23.3%	21.0%
	P99	7.4%	12.9%	20.8%	24.8%	27.8%	35.9%	30.7%	29.6%	32.6%	29.1%
Negative error [% of Pinst]	P50	-5.9%	-7.1%	-8.8%	-9.4%	-8.8%	-8.1%	-7.1%	-4.8%	-3.6%	-2.1%
	P90	-16.3%	-19.5%	-28.2%	-25.6%	-22.6%	-22.7%	-19.0%	-11.5%	-9.1%	-4.5%
	P95	-19.6%	-24.3%	-38.8%	-32.0%	-27.4%	-27.0%	-23.0%	-13.5%	-10.9%	-5.0%
	P99	-26.8%	-36.9%	-57.1%	-44.3%	-35.6%	-36.8%	-31.5%	-17.8%	-13.0%	-6.4%
All errors	RMSE	7.0%	9.1%	13.6%	12.8%	11.9%	12.6%	11.5%	9.3%	8.9%	7.1%

Table 9.2 - P90, P95 and P99 for positive and negative wind production forecast error as a function of clustered bins of forecasted production.

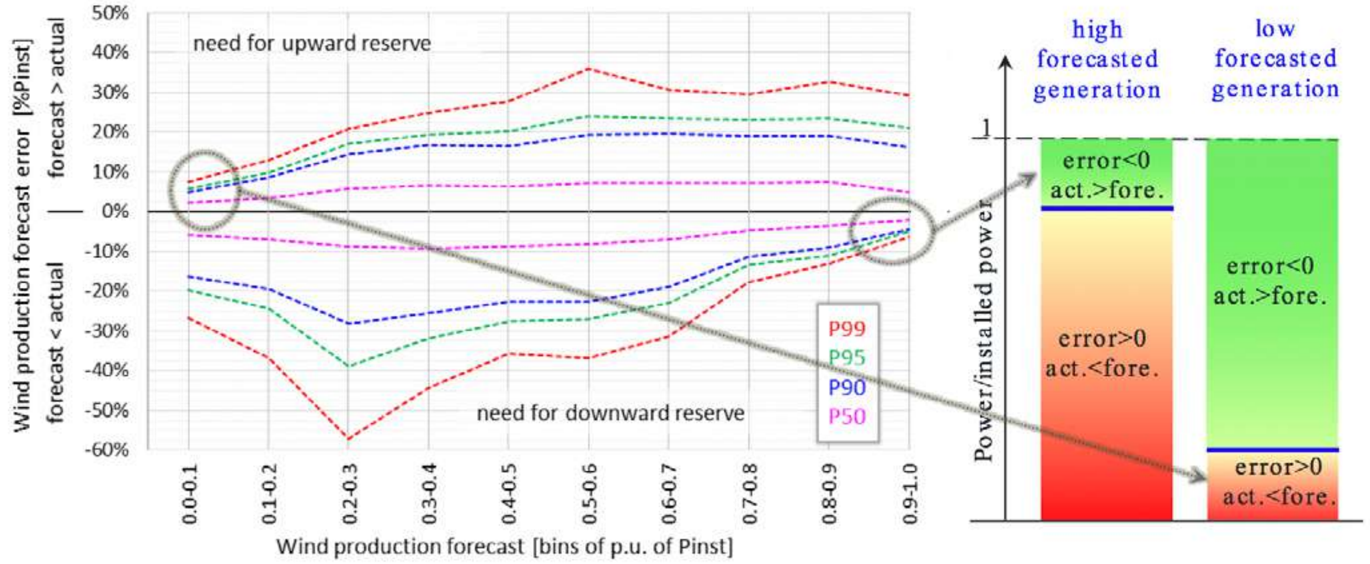


Figure 9.15 - P90, P95 and P99 for positive and negative wind production forecast error as a function of bins of forecasted production.

9.3 PV production forecast error

9.3.1 Modelling

PV production prediction methods are rapidly evolving and improving, pushed by the need for integrating increasing amount of PV generation into grid, while keeping its reliability by properly managing the intrinsic natural variability of solar irradiation. Better PV generation prediction means lower forecasting errors to be accommodated by using upward and downward power reserves provided by non VRES sources. On the market different predicting methods are available, based on several techniques, such as measured weather and PV system data, satellite and sky imagery observations of clouds, numerical weather prediction. Better performing methods should be selected according to forecasting time horizon; short term (below six hours) forecasts result more accurate when they make use of measured data, while for longer time horizon methods based on numerical weather prediction models assure better results. Anyway, often best forecast can be obtained by combining different methods, for instance using numerical weather prediction model results in stochastic learning models or using measured data for post-processing numerical weather prediction model results to correct their systematic deviations from measured data. Generally, higher forecasting errors occur in days with frequent irradiation fluctuations, as exemplified in Figure 9.4. Fortunately, forecast errors at distant PV plants tend to partially cancel out, due to spatial variability of solar irradiation trend over time.

With the available information, the Consultant developed a proper model to predict PV generation on an hourly basis; such model is a good trade-off between complexity and the accuracy accepted in a planning study framework. 24 hours ahead persistence model was here assumed. Since it's quite a rough predicting method, especially in days characterized by highly variable weather and solar irradiation, the model was refined by:

- considering a 10 minutes forecast, instead of an hourly average one; in this way the effect of natural irradiation increase/decrease trend over time in case of clear sky can be accounted in;
- tuning the model on the average actual generated power over periods of 3 hours.

On a yearly basis, adopted forecasting model results in a standard deviation of PV aggregate production error around 5% of installed power.

9.3.2 Results

As anticipated in previous section, PV production forecast error was calculated for 10 minutes time intervals over the reference year for each PV site and for their aggregate. Then errors were grouped into positive and negative populations, for which values whose module has a probability of not being exceeded of 90% (P90), 95% (P95) and 99%, (P99) were calculated, as well as standard deviation for the whole errors population. Results are shown in Table 9.3, from which it can be noted that aggregate production forecast is affected by an error lower than the corresponding one for single PV plants, due to the beneficial effect of aggregating productions of plants affected by different solar irradiation profile over time, as already commented when speaking of PV production change over next 10 minutes (section 9.1).

Table 9.4 and Figure 9.16 show P90, P95 and P99 production forecast error for considered PV plants aggregate, grouped by positive and negative values, as a function of forecasted production and expressed as percent of installed power. At high forecasted production negative errors (actual production higher than forecasted one) tend to be very small, since generation is close to its maximum. At low forecasted production, positive errors (actual production lower than forecasted one) tend to be very small too, since generation is close to zero. P90, P95 and P99 positive errors for high forecasted production and negative errors for intermediate forecasted production are higher, mainly due to the effect of temporary sky covering already mentioned in section 9.1 coupled to the difficulty to effectively take it into account with a 24 hour ahead persistence predicting model, especially when an highly variable weather day is followed by a stable weather (clear sky) day or vice versa. P99 positive and negative error are respectively lower than 30% and 40% of installed power.

PV site		Lusaka	Chilanga	Mochipapa	Mutanda	Aggregate
Positive error [% Pinst]	P50	0.0%	0.0%	0.0%	0.0%	0.0%
	P90	7.4%	7.3%	7.1%	6.9%	4.3%
	P95	15.3%	15.7%	15.4%	15.5%	8.5%
	P99	34.7%	34.2%	35.3%	35.8%	18.8%
Negative error [% Pinst]	P50	-3.3%	-3.1%	-2.7%	-2.8%	-2.3%
	P90	-22.8%	-22.6%	-21.8%	-21.1%	-12.5%
	P95	-31.2%	-30.6%	-31.7%	-30.4%	-17.5%
	P99	-52.1%	-49.9%	-54.1%	-49.4%	-28.3%
All errors	RMSE	9.2%	9.1%	9.3%	9.1%	5.2%

Table 9.3 – P90, P95 and P99 positive and negative PV production forecast errors and standard deviation for the whole errors population, for PV sites and their aggregate.

PV Aggregate		Production forecast bins [p.u. of Pinst]									
		0.0-0.1	0.1-0.2	0.2-0.3	0.3-0.4	0.4-0.5	0.5-0.6	0.6-0.7	0.7-0.8	0.8-0.9	0.9-1.0
Positive error [% of Pinst]	P50	0.5%	1.4%	2.1%	2.6%	3.2%	4.3%	4.2%	3.8%	2.6%	2.3%
	P90	1.9%	5.2%	8.2%	9.9%	12.6%	16.0%	16.1%	16.9%	14.8%	13.2%
	P95	2.5%	6.7%	11.2%	12.8%	15.4%	20.5%	19.7%	21.5%	19.7%	19.6%
	P99	4.2%	9.2%	15.7%	17.7%	21.5%	28.2%	27.6%	30.7%	29.4%	31.0%
Negative error [% of Pinst]	P50	-0.9%	-1.6%	-2.5%	-3.0%	-3.8%	-4.2%	-4.3%	-2.7%	-1.4%	-0.7%
	P90	-4.3%	-7.2%	-12.4%	-14.8%	-16.9%	-17.8%	-14.5%	-12.7%	-7.2%	-3.1%
	P95	-6.3%	-12.3%	-18.8%	-20.7%	-21.7%	-22.5%	-18.4%	-15.9%	-9.1%	-4.1%
	P99	-19.8%	-28.0%	-36.8%	-34.5%	-30.7%	-31.1%	-25.1%	-20.3%	-11.8%	-5.3%
All errors	RMSE	-40.7%	-41.1%	-66.8%	-52.8%	-43.2%	-41.2%	-33.8%	-28.9%	-17.0%	-6.6%

Table 9.4 - P90, P95 and P99 for positive and negative PV aggregate production forecast error as a function of bins of forecasted production.

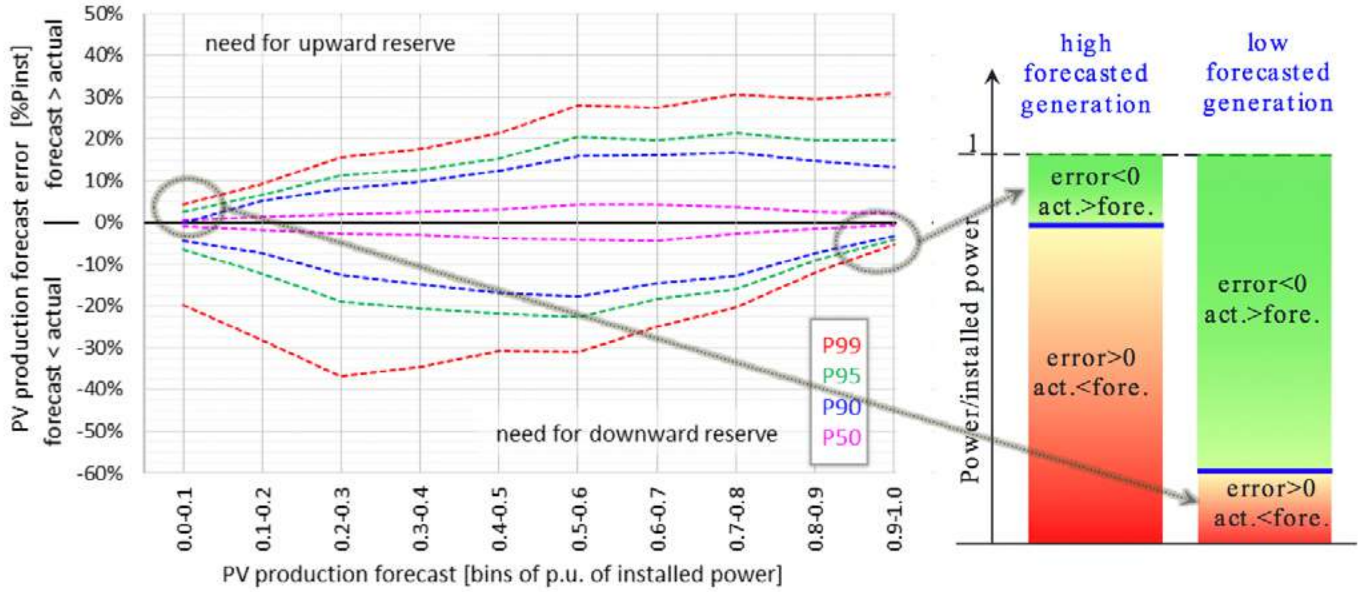


Figure 9.16 - P90, P95 and P99 for positive and negative PV aggregate production forecast error as a function of bins of forecasted production.

9.4 Wind and PV aggregate production forecast error

Wind and PV forecast error distributions were convolved to find the forecast error distribution of aggregate wind and PV production. Convolutions were calculated for each possible matching between PV and wind considered production bins (25 combinations). As mentioned in section 8.2, the Consultant accepted partial load curtailment due to VRES forecasted production higher than the actual one up to 0.55% of the time of a year (LOLE equal to 48 hours) ; therefore the 99.45th percentile of error distribution was assumed as the maximum forecast error to be covered by the operating reserve. While the 5th percentile of VRES production forecast error was assumed to size the downward reserve.

Table 9.5 shows 99.45th and 5th percentiles of forecast error distribution for different wind and PV installed power mixes, expressed as a percentage of total installed power and as a function of wind and PV production bins. It can be noted that when both wind and PV are installed in tested mixes, 99.45th and 5th percentiles of forecast error distribution are always lower respectively than 30% and 25% of total installed power. It can be also proven that overall wind and PV production 99.45th and 5th percentiles of forecast errors are lower in absolute value than the ones that would be obtained by adding 99.45th and 5th percentiles of errors calculated for PV and wind productions separately.

By weighting 99.45th and 5th percentiles of forecast error distributions corresponding to different combinations of production bins with the occurrence of those bins over the reference year, reported in Table 9.6, weighted 99.45th and 5th percentiles were calculated for each considered wind and PV mix and reported in Table 9.7, along with corresponding yearly maximum values. As shown in Figure 9.17, yearly maximum of 99.45th percentiles is minimum for a balanced wind and PV mix (50%, 50%), while the yearly maximum of 5th percentiles is minimum for a mix in which PV prevails (75%, 25%)

Finally, Figure 9.18 shows 99.45th and 5th percentiles of VRES production forecast errors for the case PV:wind installed power 2:1, taken as an example, for each hours of the reference years. The aim of the picture is to give a general idea of period of the year and of the day in which higher positive and negative forecast errors are more likely. Plotted values were calculated applying results reported in Table 9.5 for the case PV:wind 2:1 to the forecasted PV and wind production, according to the following formulas:

$$PFE^{99.45th}_{PV+wind} = min\begin{cases} PFE^{99.45th}_{[PV+wind]\_bins} \\ P_{PV\_fore} + P_{wind\_fore} \end{cases} \qquad (6)$$

$$NFE^{5th}_{PV+wind} = min\begin{cases} NFE^{5th}_{[PV+wind]\_bins} \\ P_{PV\_inst} - P_{PV\_fore} + P_{wind\_inst} - P_{wind\_fore} \end{cases} \qquad (7)$$

To facilitate results interpretation, average wind and PV production over the reference year can be consulted in Figure 9.9 and Figure 9.10. It can be noted that higher positive forecast errors are likely from April to October:

- both in central hours of the day, when PV is on average high (and higher than in winter season) and wind production is decreasing down to afternoon minimum, which however is higher than its winter daylight production level,
- and in the remaining part of the day, due to medium to high wind production, much higher than its corresponding winter season level.

Negative forecast errors are higher for intermediate wind and PV productions, conditions that on average happens between 9 a.m. and 10 a.m. and 15 p.m. and 17 p.m.

Pinst PV:wind [% $Pinst_{PV+wind}$]	wind prod. forecast [p.u.]	Positive Forecas Error (actual<forecast) (99.45th) [% $Pinst_{wind+PV}$]					Negative Forecast Error (actual>forecast) (5th) [% $Pinst_{wind+PV}$]				
		PV production forecast (p.u. Pinst)					PV production forecast (p.u. Pinst)				
		0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0
1:0 [100%:0%]	0.0-0.2	5%	17%	25%	29%	31%	1%	15%	18%	14%	7%
	0.2-0.4	5%	17%	25%	29%	31%	1%	15%	18%	14%	7%
	0.4-0.6	5%	17%	25%	29%	31%	1%	15%	18%	14%	7%
	0.6-0.8	5%	17%	25%	29%	31%	1%	15%	18%	14%	7%
	0.8-1.0	5%	17%	25%	29%	31%	1%	15%	18%	14%	7%
1:1 [50%:50%]	0.0-0.2	6%	9%	13%	14%	15%	11%	14%	14%	13%	11%
	0.2-0.4	11%	13%	16%	17%	17%	15%	17%	17%	16%	15%
	0.4-0.6	16%	17%	18%	20%	20%	12%	14%	15%	13%	12%
	0.6-0.8	15%	17%	19%	20%	20%	7%	10%	11%	10%	8%
	0.8-1.0	17%	18%	20%	21%	21%	4%	7%	9%	7%	5%
2:1 [67%:33%]	0.0-0.2	4%	11%	16%	19%	19%	7%	13%	14%	12%	8%
	0.2-0.4	8%	13%	17%	20%	20%	10%	14%	16%	14%	10%
	0.4-0.6	11%	14%	18%	21%	21%	8%	12%	14%	12%	9%
	0.6-0.8	10%	15%	19%	22%	22%	5%	10%	12%	10%	6%
	0.8-1.0	11%	15%	20%	22%	23%	3%	9%	11%	9%	4%
1:2 [33%, 67%]	0.0-0.2	8%	9%	10%	11%	11%	14%	15%	15%	15%	14%
	0.2-0.4	14%	15%	16%	17%	17%	20%	20%	20%	20%	19%
	0.4-0.6	21%	21%	22%	22%	23%	16%	16%	17%	16%	15%
	0.6-0.8	20%	21%	21%	22%	22%	10%	11%	11%	11%	10%
	0.8-1.0	22%	22%	23%	23%	24%	5%	7%	7%	6%	5%
3:1 [75%, 25%]	0.0-0.2	4%	12%	18%	21%	22%	5%	13%	15%	12%	7%
	0.2-0.4	6%	13%	19%	22%	23%	7%	14%	16%	13%	9%
	0.4-0.6	9%	14%	20%	22%	23%	6%	12%	15%	12%	7%
	0.6-0.8	8%	14%	20%	23%	24%	4%	11%	13%	11%	6%
	0.8-1.0	9%	15%	21%	23%	25%	2%	10%	13%	10%	4%
1:3 [25%, 75%]	0.0-0.2	9%	9%	10%	10%	10%	16%	16%	16%	16%	16%
	0.2-0.4	16%	17%	17%	18%	17%	22%	22%	22%	22%	22%
	0.4-0.6	24%	24%	24%	24%	25%	18%	18%	18%	18%	17%
	0.6-0.8	23%	23%	23%	23%	23%	11%	12%	12%	11%	11%
	0.8-1.0	25%	25%	25%	26%	26%	6%	7%	7%	6%	6%
0:1 [0%, 100%]	0.0-0.2	11%	11%	11%	11%	11%	21%	21%	21%	21%	21%
	0.2-0.4	21%	21%	21%	21%	21%	29%	29%	29%	29%	29%
	0.4-0.6	31%	31%	31%	31%	31%	23%	23%	23%	23%	23%
	0.6-0.8	30%	30%	30%	30%	30%	15%	15%	15%	15%	15%
	0.8-1.0	34%	34%	34%	34%	34%	8%	8%	8%	8%	8%

Table 9.5 – 99.45th and 5th percentiles of VRES production forecast error distribution for different PV and wind power installed mix.

wind prod. forecast [p.u. Pinst]	Forecast PV & wind bins frequency over reference year					
	PV production forecast (p.u. Pinst)					Total per bin wind
	0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	
0.0-0.2	14.7%	4.1%	3.8%	3.3%	1.3%	27.2%
0.2-0.4	11.7%	2.9%	3.1%	3.0%	2.8%	23.5%
0.4-0.6	8.5%	1.2%	2.0%	2.0%	2.2%	15.9%
0.6-0.8	15.9%	1.2%	1.2%	1.7%	1.0%	21.0%
0.8-1.0	11.6%	0.2%	0.0%	0.2%	0.3%	12.4%
Total per bin PV	62.4%	9.7%	10.1%	10.3%	7.5%	100.0%

Table 9.6 – Frequency of PV and wind bins of forecasted generated power over the reference year.

PV:wind Pinst	PV:wind $\%Pinst_{PV+wind}$	Forecast Error [% on $Pinst_{PV+wind}$]			
		Yearly Average		Yearly Maximum	
		99.45th	5th	99.45th	5th
1:0	100%, 0%	12%	6%	31%	18%
1:1	50%, 50%	13%	11%	21%	17%
2:1	67%, 33%	12%	9%	23%	16%
1:2	33%, 67%	16%	14%	24%	20%
3:1	75%, 25%	11%	8%	25%	16%
1:3	25%, 75%	18%	16%	26%	22%
0:1	0%, 100%	23%	21%	34%	29%

Table 9.7 – Maximum and weighted 99.45th and 5th percentiles of VRES production forecast error distribution for different PV and wind power installed mixes.

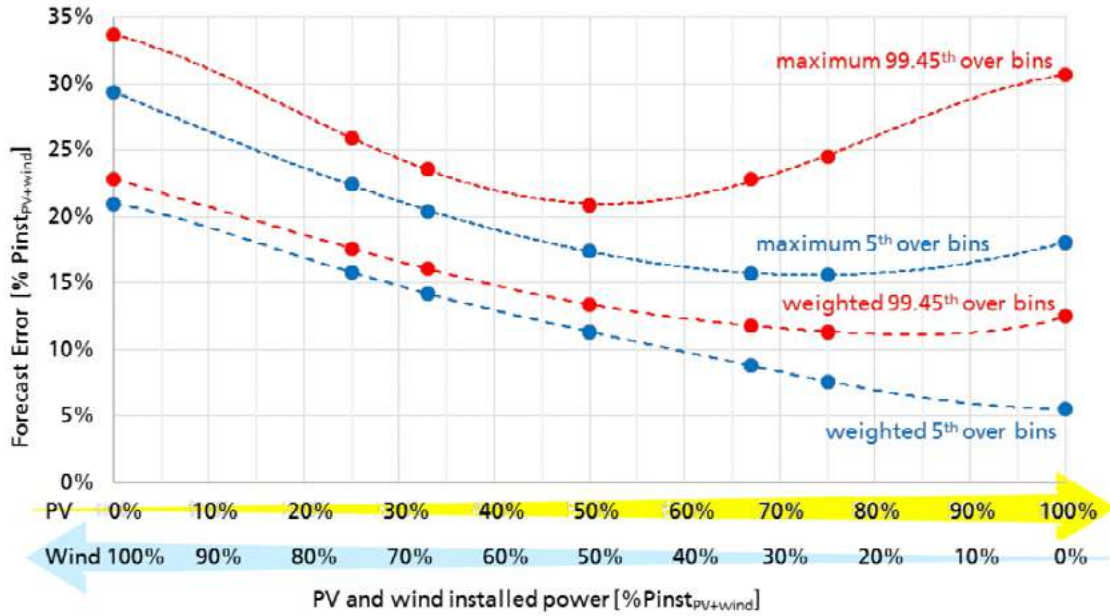


Figure 9.17 – maximum and weighted 99.45th and 5th percentiles of VRES production forecast error distribution for different PV and wind power installed mixes.

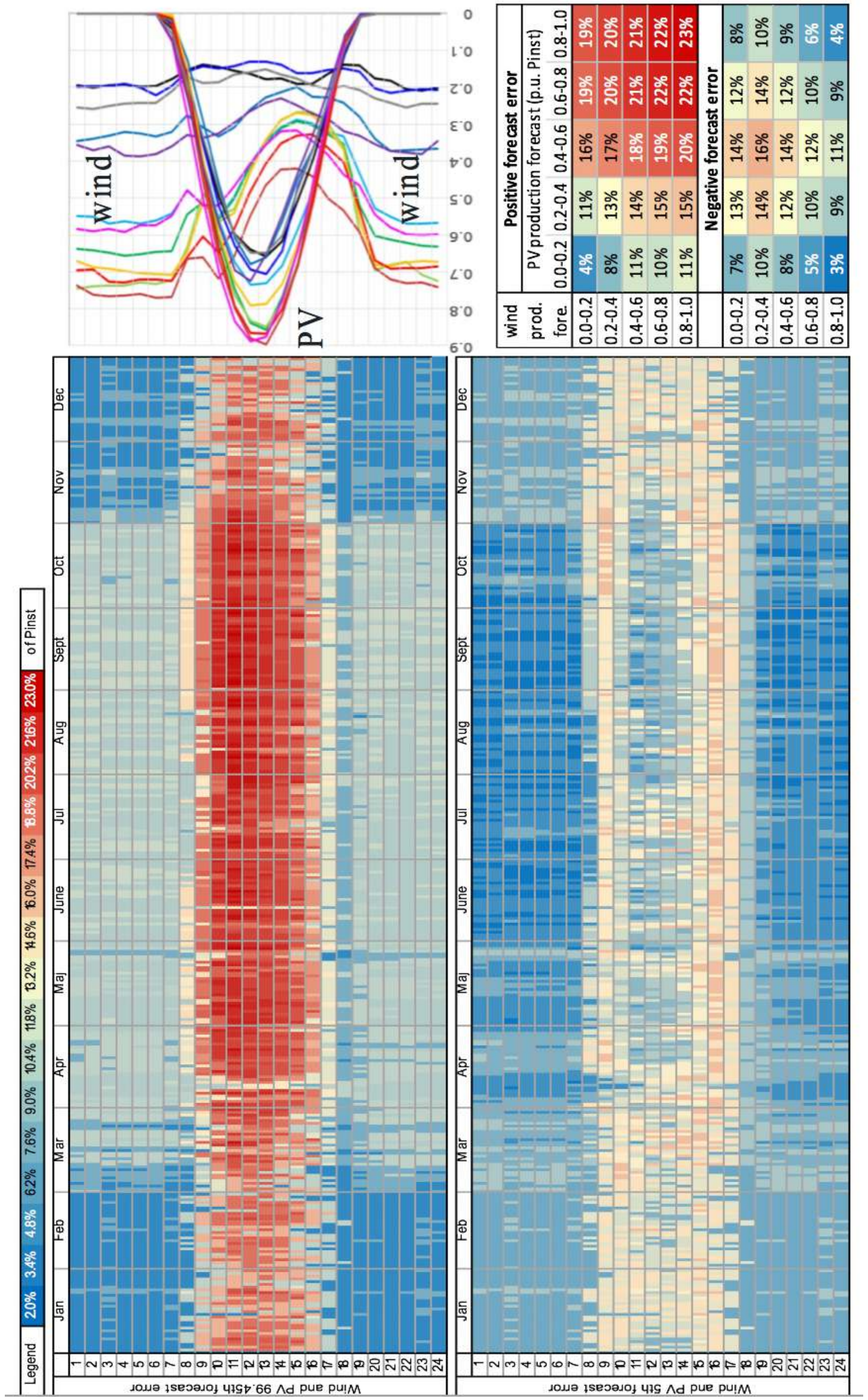


Figure 9.18 – Positive (99.45th percentile) and negative (5th percentile) VRES production forecast error distribution for the case PV:wind installed power 2:1 taken as an example, as a function of wind and PV hourly production forecast.

10 UPWARD AND DOWNWARD RESERVES

This section illustrates the methodology applied to assess wind plus PV aggregate production and load overall forecast error, on which upward and downward reserves must be sized for reference years 2025 and 2030. To show some numerical results, the following VRES installed power were considered, purely as an example: 1,000 MW PV and 500 MW wind coupled to 2025 Zambia load (3,465 MW peak power demand and 24,4 TWh/year), 1,500 MW PV and 750 MW wind coupled to 2030 Zambia load (3,869 MW peak power demand and 27,6 TWh/year). The optimal capacity mix of PV and wind power was defined in following Task 3 of the Study, testing also the impact of different wind and PV mixes, but for each considered mix, upward and downward reserves were calculated according to the methodology defined in Task 2.

As regard load forecast error estimate, a 24-hour ahead persistence forecasting model was considered and tuned to obtain a standard deviation of forecast errors (both positive and negative) equal to 2%. Considering different impact of load and generation on reserve need, load forecast error was calculated as actual load minus forecasted one, which is the opposite in sign of wind and PV production forecast error.

Overall forecast error distribution was calculated by convolving wind plus PV aggregate production forecast error distribution with load forecast error distribution. Convolutions were calculated for each possible matching between considered PV and wind production bins (25 combinations). Then, adopting the same criteria explained in section 9.4, 99.45th and 5th percentiles of the overall forecast error distribution were considered for each PV and wind production bins set, applying formulas (2) and (4). In particular, upward reserve (UPR) was calculated as the maximum value between minimum value between 99.45th percentile of VRES plus load forecast error (PFE) and VRES forecasted generation plus the 99.45th percentile of load forecast error distribution, and the power that would be lost in case of a contingency of the biggest programmable non VRES unit, assumed to be always a turbine of the Kariba North Bank hydroelectric plant (Pgroup_max=180 MW). Downward reserve (DWR) was calculated as the minimum value between 5th percentile of VRES production plus load forecast error distribution (NFE) and the complement of forecasted VRES production to VRES installed power plus the 5th percentile of load forecast error distribution.

Table 10.1 shows 99.45th and 5th percentiles of VRES production forecast error distribution for wind and PV assumed installed mixes, while Table 10.2 shows 99.45th and 5th percentiles of VRES production plus load overall forecast error distribution for the same VRES mixes. By comparing the two tables, it can be noted that difference between overall VRES plus load forecast error and VRES only forecast error results generally higher the lower is VRES only forecast error. The lower bounding of UPR with the power of one Kariba North Bank turbine increase UPR only for the production bins 0-0.2 p.u. PV and 0-0.2 p.u. wind installed power, as shown in Table 10.3, which illustrates upward and downward reserves.

P installed	wind prod. forecast [p.u.]	Positive Forecas Error (actual<forecast) (99.45th) [MW]					Negative Forecast Error (actual>forecast) (5th) [MW]				
		PV production forecast [p.u.]					PV production forecast [p.u.]				
		0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0
PV=1000 MW, wind=500 MW	0.0-0.2	66	164	243	280	292	108	188	216	180	122
	0.2-0.4	114	189	261	297	306	149	217	236	203	155
	0.4-0.6	163	212	277	312	320	119	186	211	178	128
	0.6-0.8	155	219	288	324	333	76	156	185	149	92
	0.8-1.0	171	226	296	332	342	41	133	166	128	62
PV=1500 MW, wind=750 MW	0.0-0.2	99	246	364	420	437	162	283	324	270	183
	0.2-0.4	171	283	392	445	459	224	325	354	304	232
	0.4-0.6	244	317	416	468	479	178	278	316	267	192
	0.6-0.8	232	328	432	486	500	113	234	277	224	138
	0.8-1.0	257	339	444	498	514	62	199	248	192	94

Table 10.1 – 99.45th and 5th percentiles of VRES production forecast error distribution.

Zambia load & VRES P installed	wind prod. forecast [p.u.]	Positive Forecas Error (actual<forecast) (99.45th) [MW]					Negative Forecast Error (actual>forecast) (5th) [MW]				
		PV production forecast [p.u.]					PV production forecast [p.u.]				
		0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0
Load year 2025, PV=1000 MW, wind=500 MW	0.0-0.2	170	219	281	315	318	167	228	249	219	175
	0.2-0.4	200	242	299	331	332	193	249	266	238	198
	0.4-0.6	224	262	315	346	347	169	225	244	216	176
	0.6-0.8	231	271	326	359	360	138	197	218	188	146
	0.8-1.0	237	278	335	367	369	114	176	198	168	124
Load year 2030, PV=1500 MW, wind=750 MW	0.0-0.2	207	301	404	457	467	211	309	344	296	224
	0.2-0.4	259	337	431	482	488	256	346	372	327	262
	0.4-0.6	301	368	455	504	509	218	305	337	292	227
	0.6-0.8	308	380	472	523	529	167	262	297	250	180
	0.8-1.0	319	392	484	535	543	128	228	268	219	144

Table 10.2 – 99.45th and 5th percentiles of VRES production plus load overall forecast error distribution.

Zambia load & VRES P installed	wind prod. forecast [p.u.]	Upward reserve (99.45th) [MW]					Downward reserve (5th) [MW]				
		PV production forecast [p.u.]					PV production forecast [p.u.]				
		0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0
Year 2025, PV=1000 MW, wind=500 MW	0.0-0.2	180	219	281	315	318	167	228	249	219	175
	0.2-0.4	200	242	299	331	332	193	249	266	238	198
	0.4-0.6	224	262	315	346	347	169	225	244	216	176
	0.6-0.8	231	271	326	359	360	138	197	218	188	146
	0.8-1.0	237	278	335	367	369	114	176	198	168	124
Year 2030, PV=1500 MW, wind=750 MW	0.0-0.2	207	301	404	457	467	211	309	344	296	224
	0.2-0.4	259	337	431	482	488	256	346	372	327	262
	0.4-0.6	301	368	455	504	509	218	305	337	292	227
	0.6-0.8	308	380	472	523	529	167	262	297	250	180
	0.8-1.0	319	392	484	535	543	128	228	268	219	144

Table 10.3 – 99.45th and 5th percentiles of VRES production plus load overall forecast error distribution when considering also the impact on upward reserve of a contingency of the largest unit dispatched.

Figure 10.1 shows cumulative descending curves for upward and downward reserves resulting for the assumed wind and PV installed power coupled to 2025 and 2030 Zambia load, calculated combining upward and downward reserves for bins of wind and PV forecasted productions with the occurrence of those bins over the reference year.

Figure 10.2 shows upward and downward hourly average reserves for 2025 load, 1,000 MW PV and 500 MW wind installed power, with the aim to give a general idea of period of the year and of the day in which higher upward and downward reserves need is more likely. Reserves pattern can be explained with the same consideration made in section 9.4 regarding positive and negative VRES production forecast errors (Figure 9.18), complemented with the abovementioned impact of load forecast error. In Figure 10.2 in green colour are shown hours in which the contingency of one unit of Kariba North Bank set an upward reserve higher than the one resulting from the convolution of VRES and load forecast errors.

Finally, Figure 10.3 shows, as an example, upward and downward reserve profiles for the 1st October 2025; reserves are plotted around hydroelectric production bars assuming that reserve will be provided by that source. The generation fleet assumed in Zambia at the target year includes the existing and committed hydro power plants, the existing fossil fuel units and the existing, the committed and candidate VRES power plants. Candidates of technologies other than wind and PV were not considered in this study. For this reason, a share of import is needed at 2025 if only 1,000 MW PV and 500 MW wind installed capacities are integrated in the system.

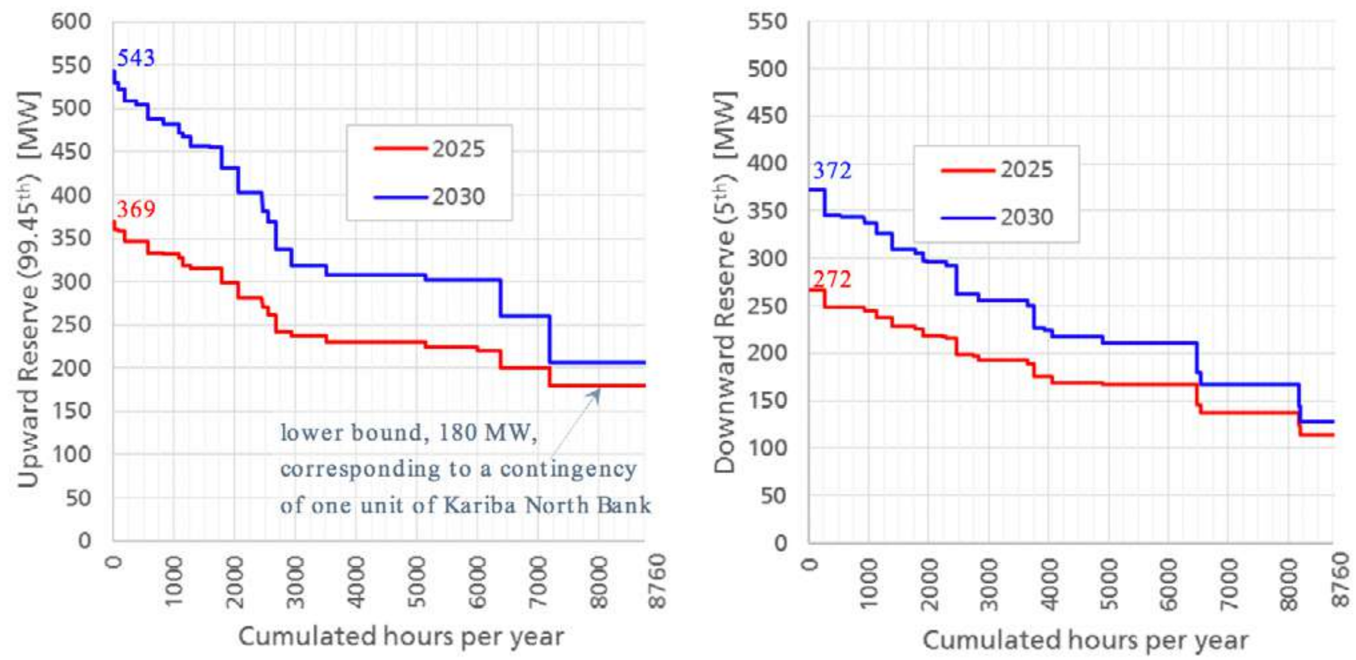
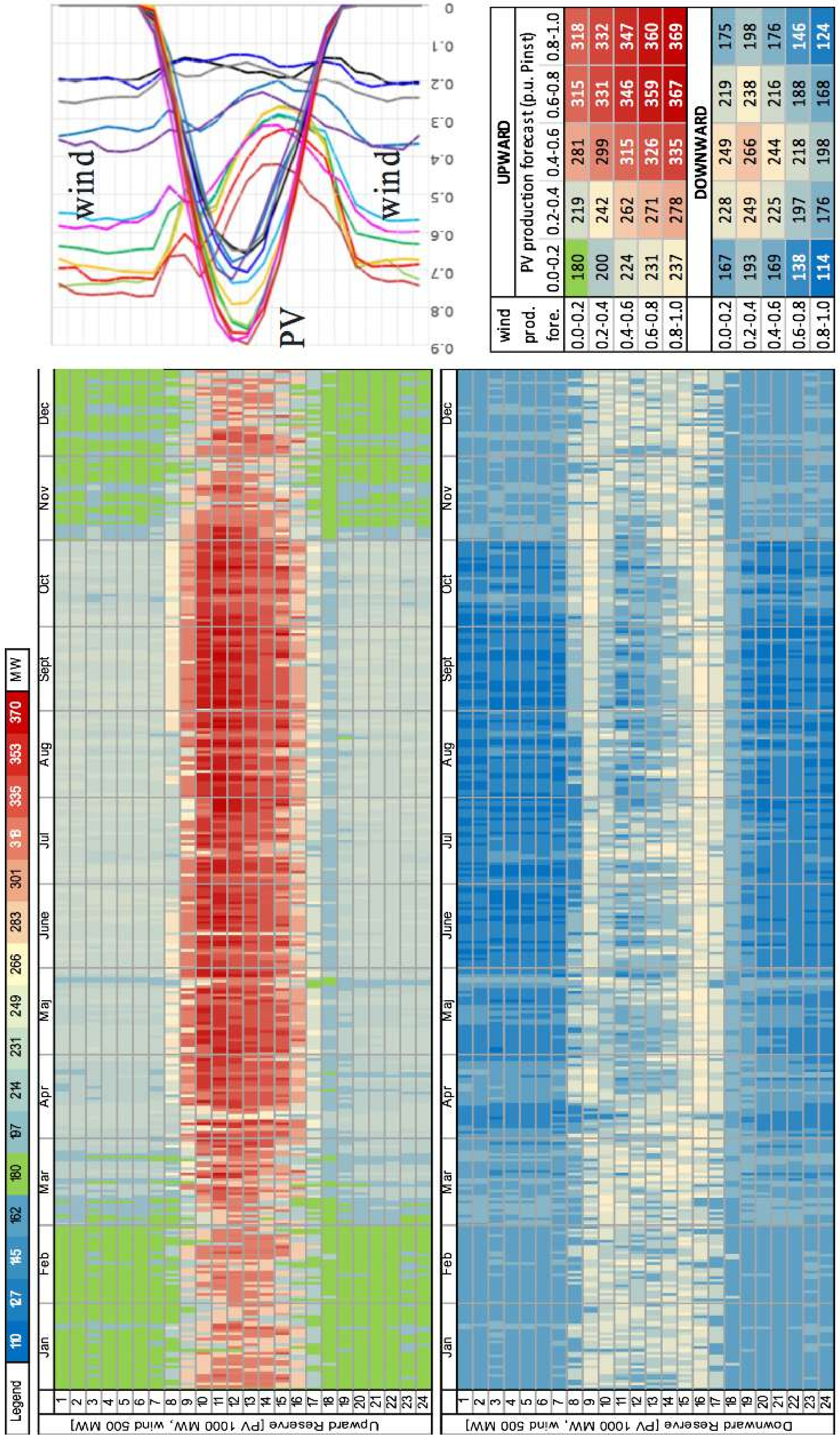


Figure 10.1 – cumulative descending curves for upward and downward reserve resulting for the assumed wind and PV installed power coupled to 2025 and 2030 Zambia load.



wind prod. fore.	PV production forecast (p.u. Pinst) 0.0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0
UPWARD					
0.0-0.2	180	219	281	315	318
0.2-0.4	200	242	299	331	332
0.4-0.6	224	262	315	346	347
0.6-0.8	231	271	326	359	360
0.8-1.0	237	278	335	367	369
DOWNWARD					
0.0-0.2	167	228	249	219	175
0.2-0.4	193	249	266	238	198
0.4-0.6	169	225	244	216	176
0.6-0.8	138	197	218	188	146
0.8-1.0	114	176	198	168	124

Figure 10.2– Upward and downward hourly average reserve for 2025 load, 1,000 MW PV and 500 MW wind installed power.

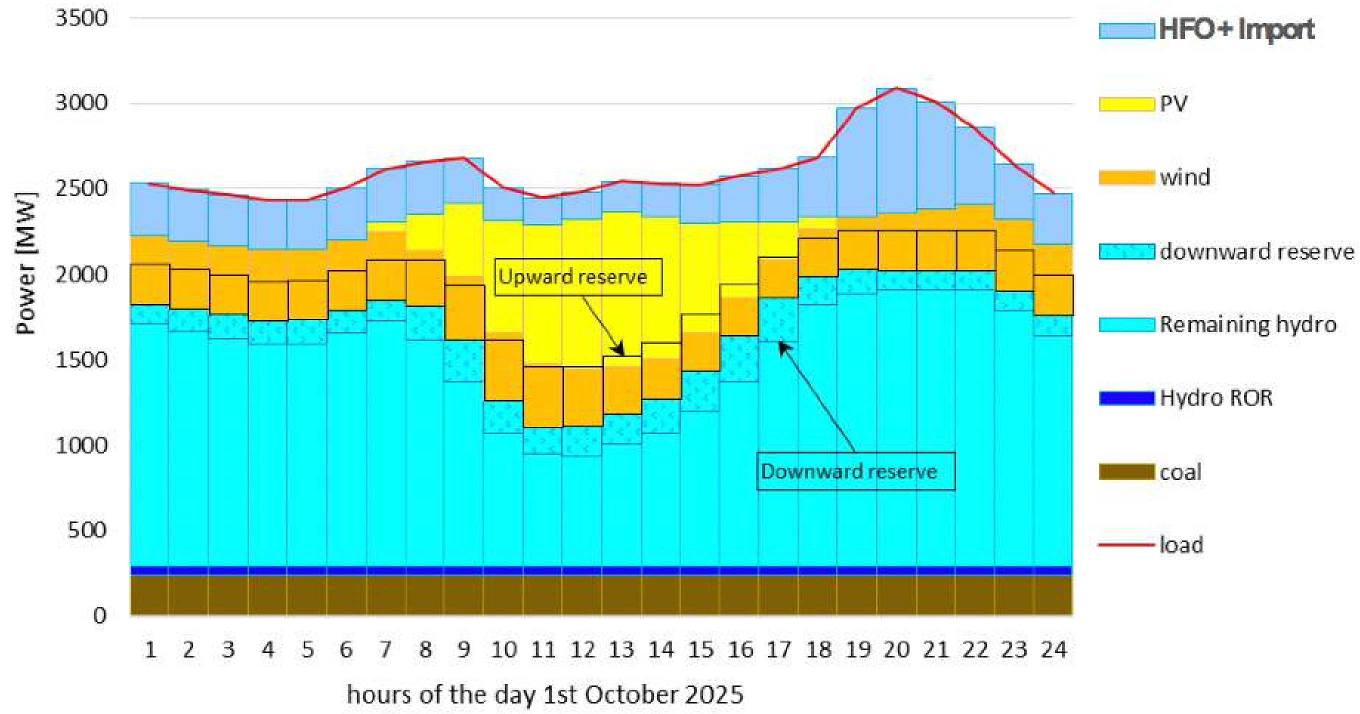


Figure 10.3 – Example of upward and downward reserve profiles for the 1st October 2025.

The main achievement of Task 2 was used to set-up the best market and reliability models to be used in the following Task 3 and Task 4. At the end of Task 4 the Consultant provided the detail of the operating reserve requirements needed to manage the variability and unpredictability of the optimal VRES capacity that could be integrated in the reference scenario with normal (average) water availability, both in the mid- and long-term.

TASK 3 – OPTIMAL COORDINATED HYDRO-THERMAL DISPATCHING IN PRESENCE OF VARIABLE RENEWABLE ENERGY SOURCES

11 OBJECTIVES AND SCOPE OF WORK

The aim of this task is to determine the optimal amount of variable RES that can be integrated in the Zambian electric system from a technical and economic point of view and to evaluate its impact on the system operation, over one year, and simulating an optimal coordinated hydro-thermal dispatch. Starting from the existing and committed generation fleet, the Consultant first analysed the capability of VRES generation (wind and PV) to meet the national demand expected in mid- and long-term scenarios (including firm export obligations), assessing the optimal VRES penetration with an isolated pattern. In addition, the Consultant studied the opportunity to increase the VRES installed capacity in Zambia exploiting the interconnection capacity with the neighbouring countries and the price differentials with the rest of SAPP.

Task 3 allows deterministic simulations of the generation system operation, hour by hour, with an optimal hydropower dispatch for the best use sources available in the simulated electric power system. The operation of the Zambian electric power system – both isolated or interconnected – has been simulated by means of a day-ahead market tool developed by CESI, named PromedGrid. It simulates the optimal dispatching of hydro-thermal generation in meshed electric power systems with a high level of detail, for which a detailed hydro generation model is needed. The model includes data for reservoir and run-of-river hydro power plants. The main technical data concerns the minimum/maximum power, the efficiency of the hydraulic/electric energy conversion, the reservoir volume and the expected hourly natural inflows along with the initial and final amount of water in each reservoir for the simulated annual period. The integral limitations of the hydro plants water reservoirs, the net transfer capacity between the simulated interconnections and the techno-economic characteristics of generation units have been modelled in the simulator.

To assess the VRES generation impact on the Zambian system operation for each target year, the benefits of increasing wind and photovoltaic integration have been assessed to meet the maximum amount of VRES could be integrated in the system minimizing load shedding and maximizing the net benefits (benefits-costs) for the system.

Considering the case of isolated country model, the maximum amount of VRES to be installed in Zambia has been assessed following a technical approach, focused on the maximization of energy demand coverage by the additional installed capacity and, at the same time, the minimization of the excess energy production that cannot be integrated in the Zambian power system. In case of interconnected model, the maximum capacity of VRES that could be installed in Zambia has been assessed following an economic approach focused on the maximization of the export of energy towards the neighbouring countries.

At the end of Task 3 the Consultant provided an assessment of the maximum VRES (wind and solar) exploitation in Zambia based both on technical and economic constraints. Reserve requirements, must-run constraints, minimum outflow from hydro power plants, VRES production intermittency, the available exchange capacity and Power Purchase Agreements (PPAs) between countries were considered. Annual based analyses were carried out with different hydrology conditions (normal, low and high-water availability) to analyse the impact of climate change on VRES integration. In this way, a wide range of results is provided based on different operating conditions.

12 ANALYZED SCENARIOS AND MODELLING

12.1 Analysed scenarios

All the scenarios defined in the section5 have been analysed in Task 3 to evaluate a large range of conditions in VRES integration (Figure 5.1): two target years (2025 and 2030), two import-export conditions (isolated and interconnected Country) and three hydrological conditions (normal, low and high water availability). Scenarios with the isolated Country (ISO) are the benchmark cases because they were useful to evaluate the electrical self-sufficiency of Zambia including VRES power plants in the electrical power system. In the isolated scenarios, the Consultant evaluated the ability of Zambian to meet the domestic demand and the firm export obligations (from power purchase agreements with the neighbouring countries) with only its own generation fleet, without any support from neighbouring countries (no import/export on the competitive market was simulated in isolated scenarios). In addition, scenarios with the interconnected Country (INT) were simulated to analyse the cost-effectiveness of additional VRES capacity to export power toward the neighbouring countries. In these additional scenarios, all the interconnection projects in pipeline were considered available for energy trading in the competitive market.

Different hydrological conditions were defined to analyse the impact of the climate change on the VRES integration. The condition with normal water availability depicts the reference scenario based on the average 30-year record of water inflows; the low water availability condition is below the average 30-year water inflows (-33%), while the condition with high water availability is above the 30-year average value (+44%).

Figure 12.1 – Scenarios configuration

The following scenarios have been analysed for both Zambian isolated or interconnected power system each target year:

√ Enhanced VRES deployment with normal water availability (ENH-NWA): reference scenario to assess the maximum wind and PV installed capacities that can be integrated in the Zambian system under the following assumptions:
- demand growth pattern based on a business as usual approach;
- hydropower availability according to the average values from historical data (normal availability). Current water resource management policies continue, if there will be no major changes in the Country priorities and policies, so that normal circumstances can be expected to continue unchanged;
- the programmable generation (from hydropower and fossil fuels) includes only existing, under construction and committed power plants. No candidates from hydropower or fossil fuel technologies were considered in the study.

√ Enhanced VRES deployment with low water availability (ENH-LWA): scenario including the maximum wind and PV installed capacities can be integrated in the Zambian system if low rainfall occurs. The following basic assumptions were adopted:
- demand growth pattern based on a business as usual approach;
- low availability of water for hydropower due to climate changes that cause low rainfall. -33% of hydropower has been considered, compared to normal water availability scenario;
- the programmable generation (from hydropower and fossil fuels) includes only existing, under construction and committed power plants. No candidates from hydropower or fossil fuel technologies were considered in the study.

√ Sensitivity scenario with high water availability (ENH-HWA): starting from the results under normal water availability, the Consultant increased the hydro power production to simulate the wet year (+44% of hydropower has been considered, compared to normal water availability scenario) and analysed the impact on the optimal wind and PV capacity assessed under the normal hydrological condition. This sensitivity scenario aims to highlight possible dispatch challenges under the wettest conditions, comparing the results of simulation without and with power exchanges with the neighbouring countries.

The main results have been compared with the simulations including only the existing VRES power plants (75.6 MW PV power plants) and the existing, under construction and committed programmable power plants (hydro and fossil fuels generation fleet). No candidates from hydropower or fossil fuel technologies were analysed.

12.2 Model description

The two models that have been used in PromedGrid tool, respectively isolated and interconnected Zambian power system, include a detailed design of the generation fleet of Zambia Figure 12.2. Each power plant is defined with all operational features needed to allow a careful simulation of system operation reaching the most suitable coordinated hydro-thermal dispatching in presence of VRES generation. The isolated model includes also the model of the firm export to be covered by the Zambian generation fleet to cope with the Power Purchase Agreements expected with the neighbouring countries. While for the interconnected scenarios, an equivalent model of the competitive market has been set up, based on the historical on the marginal clearing price of SAPP (2018) and the net transfer capacity expected between Zambia and the interconnected countries in the target years. No changes in SAPP prices were considered, assuming a generation development with a business as usual approach. The interconnected scenarios aim to evaluate the opportunity to increase VRES integration exploiting the export capacity; for this reason, the Consultant assumes a limited import capacity enough to avoid the load shedding (500 MW in 2025 and 750 MW in 2030) and an export capacity equal to 45% of the expected net transfer capacity. The latter is the maximum load factor in the export condition (ratio between the maximum export and the net transfer capacity from Zambia to the interconnected countries) recorded in 2018 and transposed in mid- and long-term scenarios. The Consultant assumed a load factor in export condition lower the 100% NTC because the new interconnection projects will be developed to support the integration of SAPP countries (also with the Eastern Africa Power Pool in the case of the ZTK project) and not only to exploit the Zambian generation sources.

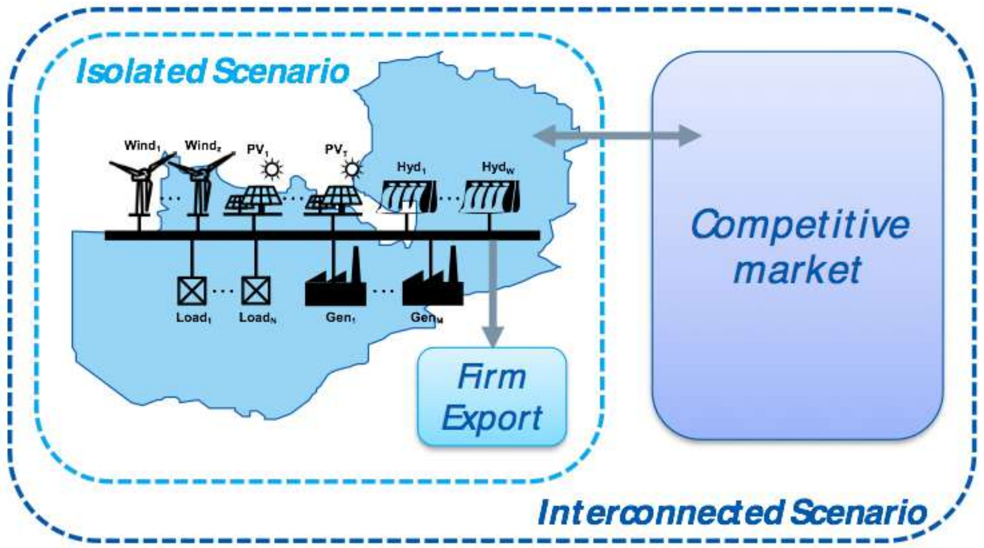


Figure 12.2 – Scheme of simulated models

PromedGrid is a day-ahead market simulator developed and owned by CESI. This software tool simulates the day-ahead hourly energy market, characterized by a system marginal price and by a congestion management based on a zonal market-splitting. It carries out an optimal coordinated hydro-thermal dispatch of the generation fleet, over a period of one year, with an hourly detail.
PromedGrid's electricity market simulator is based on a detailed model of the electric power system which considers the following aspects:

- Equivalent network model (i.e. interconnections between market/network zones);
- Hourly load and reserve margin for each market/network zone;
- Import/export from/to other neighbouring electric systems;
- Hydro generation set;
- Thermal generation set;
- Other RES generation (wind, solar, geothermal, biomass, etc.);
- Fuel prices.

PromedGrid can be used to evaluate economic scenarios of generation and power exchanges for the energy market and can help evaluating different aspects of a simulated target year:

- The electricity prices of each market/network zone by simulating the day-ahead energy market operation while also managing possible inter-area congestions based on market splitting criteria;
- The production of each generating unit;
- The active power flow in the equivalent interconnections linking the different market zones;
- The generation costs, the revenues, the profits and the market shares of each generation unit;
- The generator's surplus, the consumer's surplus and the congestion surplus (market surplus) for each hour and for each market/network zone.

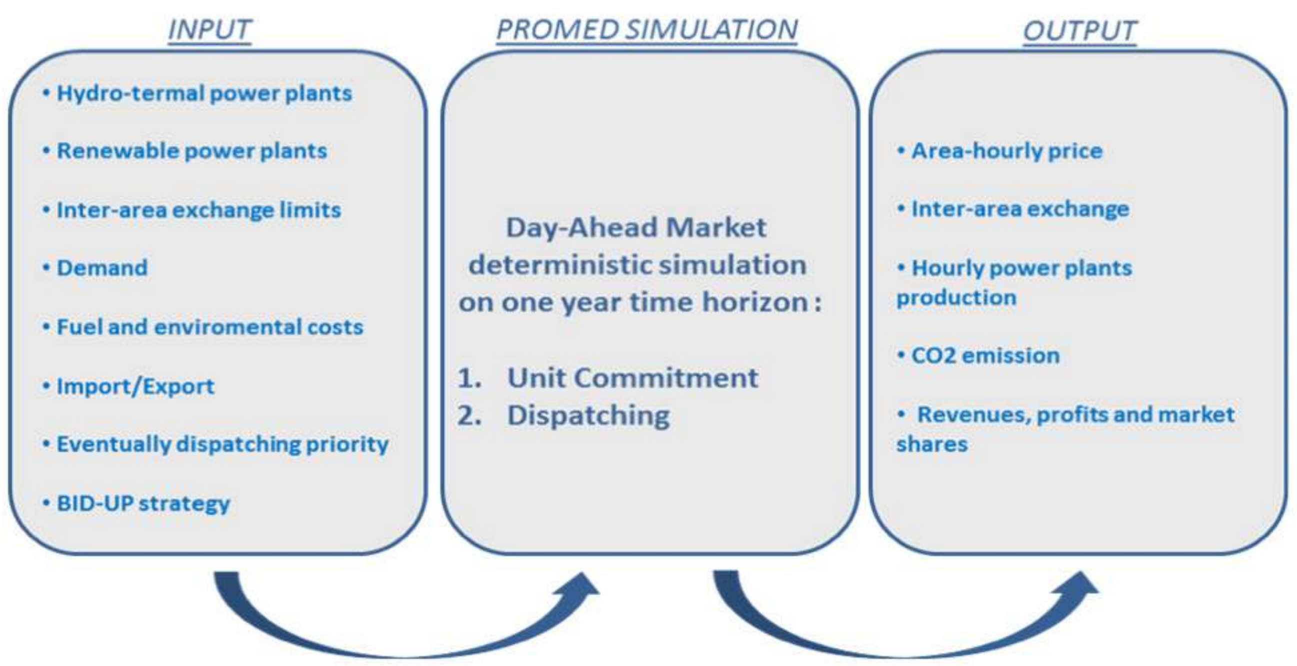


Figure 12.3 – Schematic representation that resumes PromedGrid working

More details about PromedGrid features were provided in Annex 1 – PROMEDGRID simulation tool.

12.3 Methodology

The methodology that is going to be presented in this chapter has been used to define the most suitable combination of wind and PV capacities that could be installed in Zambia to maximize the net benefits, in 2025 and 2030. It involves the assessment of the maximum VRES capacity curve and then the selection of the most suitable wind and PV capacity mix to achieve technical benefits in case of isolated model or technical and economic benefits for the interconnected one, deriving from VRES energy integration.

12.3.1 Isolated system

The maximum VRES capacity that could be integrated in the electric power system can be composed of different combinations of wind and PV capacities.

As far as the isolated country case is concerned, the main goal of the analysis consists in the identification of the optimal VRES installed capacity mix that can satisfy the country energy demand and to limit the amount of excess energy that cannot be integrated in the system. Therefore, the curve of optimal wind and PV capacity mix has been identified following an iterative process over a discrete number of VRES capacity and evaluating step-by-step the net marginal over-generation related to the additional installed capacity of PV and wind.

The first step to draw the curve was the identification of the research area bounded by two extreme points: the maximum additional PV installed capacity with the existing wind installed capacity (0 MW) and the maximum wind capacity with the PV installed capacity (75.7 MW). The iterative procedure highlighted in Figure 12.4 has been adopted to identify these two points. Starting from the existing wind or PV capacity (Step 0: 0 MW for wind or 75.6 MW for PV), the procedure implies:

- increasing the PV/wind installed capacity (Step i);
- running the market simulation by means of PromedGrid to simulate the system operation in presence of the additional PV/wind installed capacity;
- calculating the net marginal over-generation from the additional PV/wind installed capacity to evaluate if there is more room for additional PV/wind capacity or not. The marginal over-generation are calculated as the difference between the simulation results of Step i and Step i-1;
- until the condition for the net marginal over-generation is respected (less or equal to 1%) the PV/wind installed capacity can be increased; the installed capacity with a net marginal over-generation equal to 1% is the maximum capacity can be integrated in the system.

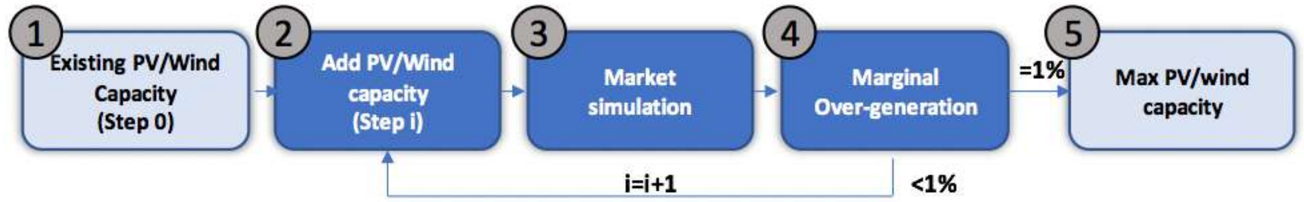


Figure 12.4 – Iterative process to evaluate the maximum PV/wind capacity that can be integrated in the isolated system

Iterative approach highlighted in Figure 12.5 has been applied to define all the other points of the maximum VRES capacity curve. Several steps of PV installed capacity have been defined; then, for each k-th PV step, the maximum wind installed capacity has been assessed with the iterative approach analysing the marginal over-generation deriving from the additional wind installed capacity. Until the value of the marginal over-generation is lower than 1%, a further step (i+1) of wind capacity can be still considered valid; on the contrary, when the its value is equal to 1% all the process can restart considering a new k-th PV step until the curve is complete.

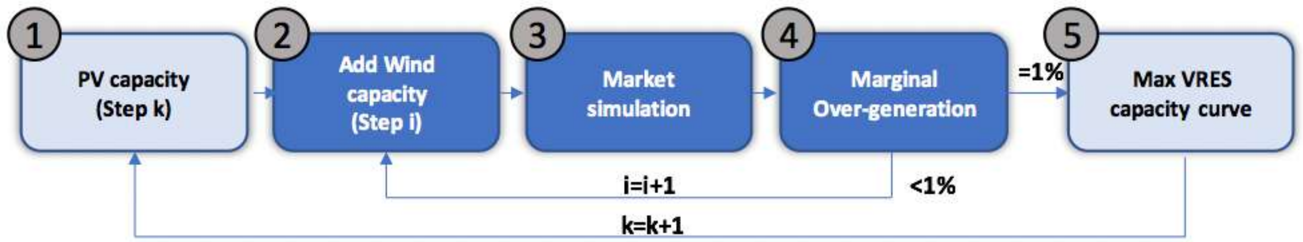


Figure 12.5 – Iterative procedure for the creation of the maximum VRES curve for the isolated scenarios

Marginal over-generation is assessed and used as limit criteria being an indication of the amount of exceeding energy produced by the additional VRES capacity installation that cannot be integrated in the system and used to meet the Zambian electricity demand, representing therefore a not profitable investment. It has been calculated as:

$$OG_{marginal} = \frac{(OG)_{step\ i} - (OG)_{step\ i-1}}{(Wind\ Cap.)_{step\ i} - (Wind\ Cap.)_{step\ i-1}}$$

where:

- OG: amount of over-generation
- $Wind\ Cap.$: additional wind capacity

In conclusion, this approach allows to draw a curve of discrete points representing optimal mix of PV and wind capacity that delimitates an area of other possible combinations of VRES capacity whose associated energy curtailment is below 1 %.

12.3.2 Interconnected system

For each of scenario, the case of Zambia interconnected to the neighboring countries has also been considered.

The main goal of the analysis has consisted, through an iterative approach like the one described in the previous chapter, in the assessment of the optimal VRES installed capacity mix that can grant the country security of supply and maximize the amount of energy that can be exported. To calculate the amount of energy exchanges among Zambia and SAPP countries, the equivalent zone representing the SAPP has been modelled in PromedGrid, using historical electricity prices and net transfer capacity limits (2018).

In analogy to the isolated country system, the first phase for the interconnected case has consisted in the identification of the two extreme points (the maximum additional PV installed capacity with the existing wind and the maximum wind capacity without no PV installed capacity). Starting from the curves evaluate with the isolated model, the iterative procedure reported in Figure 12.6 is applied to evaluate the cost-effective increase of VRES capacity in Zambian system exploiting the interconnection capacities with the rest of SAPP. In order to evaluate if there is more room for additional PV/wind capacity or not, the net marginal benefits, calculated as the difference between the marginal benefits and marginal costs between the simulation results of Step i and Step i-1, have been used as limiting criteria. A net marginal benefit greater than 0 indicates that the PV/wind installed capacity can be increased; the installed capacity results with a net marginal benefit equal to 0 is the maximum capacity can be integrated in the system.

Figure 12.6 - Iterative process to evaluate the maximum PV/wind capacity that can be integrated in the interconnected system

The same iterative approach highlighted in Figure 12.5 and discussed in the previous chapter has been applied to define all the other points of the maximum VRES capacity curve, as reported in Figure 12.7. For each discrete k-th step of PV installed capacity the maximum wind installed capacity has been assessed analysing the difference between the marginal benefits and the marginal costs (net marginal benefits). Until the value of the marginal benefits is greater than 0, a further step (i+1) of wind capacity can be still considered valid; on the contrary, when the its value is equal to zero all the process can restart considering a new k-th PV step until the curve is complete.

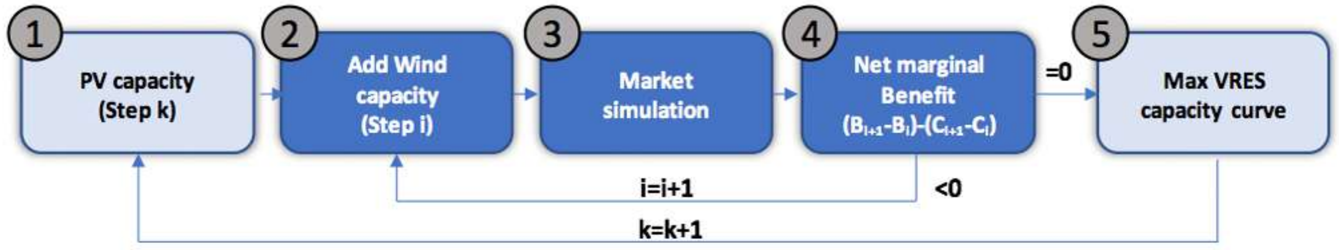


Figure 12.7 – Iterative procedure for the creation of the maximum VRES curve for the interconnected scenarios

Marginal benefits (Bmarginal) measure the economic impact that additional PV and wind capacities would have over the whole interconnected system in terms of thermoelectric energy production reduction. In fact, an increase of PV/wind installed capacity is expected to be able to replace fossil energy generation and grant higher economic and environmental benefits. They have been calculated as:

$$B_{marginal} = (C_{TH})_{step\ i} - (C_{TH})_{step\ i-1}$$

where:

- C_{TH}: cost of thermoelectric generation. It includes all the costs related to fuel, O&M and start-up of all thermoelectric generation units in Zambia and SAPP equivalent market zone that are in service in the considered step.

Marginal Costs (Cmarginal) have been calculated referring to the equivalent operating hours of wind and PV generation fleets and their average LCOE expected for the two horizon years under analysis (see section 6.7).

It is important to underline that LCOE depends on the VRES energy integrated in the system; if part of VRES production must be curtailed due to over-generation phenomena or network constraints, the energy that can be integrated into the system is lower and – consequently – the expected LCOE is higher.

This is the reason why it is important to define a net levelized cost of electricity $LCOE_{net}$ that considers the expected VRES power plants production not interested by curtailment (i.e. the net VRES power plants production):

Defining $E_{additional\,VRES}$ the amount of additional gross production from additional wind and PV capacity ($P_{additional\,VRES}$) and $E_{curtailed\,VRES}$ the curtailed production, it is possible to evaluate the marginal cost of a specific amount of VRES capacity as follow:

$$C_{marginal} = LCOE_{net} * E_{additional\,VRES}$$

Consequently, the replacement of energy from fossil fuels/import to VRES leads a cost; it is related to the technology itself and to the operating costs along its lifetime, resumed in the LCOE. In case the high VRES installed capacity entails over-generation in the system, VRES energy must be curtailed increasing LCOE of VRES technologies and reducing the cost-effectiveness of VRES use; less VRES capacity can be integrated in the system in an economic way.

Summarizing the above-mentioned methodology, it allows to define a curve of optimal VRES capacity mix points and an area of other possible combinations of wind and PV capacities with net marginal benefit greater than 0, as schematized in Figure 12.8.

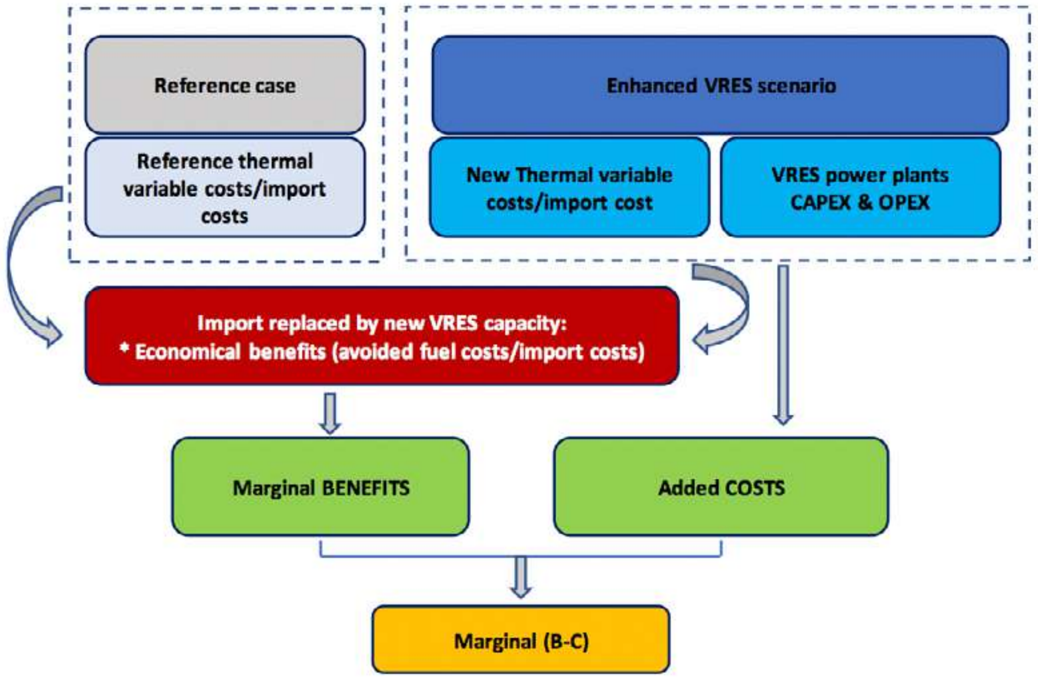


Figure 12.8 – Schematic diagram of cost-benefit analysis methodology for interconnected scenarios

13 RESULTS OF OPTIMAL COORDINATED HYDRO-THERMAL DISPATCHING IN PRESENCE OF VRES

The aim of this chapter is to present the results of the simulations performed with PromedGrid tool for the Zambian isolated and interconnected system. The chapter is organized as follow:

- The scenario with Enhanced VRES deployment and Normal Water Availability (ENH-NWA) has been analysed for the target years 2025 and 2030. Both the isolated and the interconnected Country conditions have been studied and compared (section 13.1).
- The impact of the climate change on the VRES integration had been analysed simulating a lower water availability for hydropower. Scenarios with Enhanced VRES deployment and Low Water Availability (ENH-LWA) has been analysed and compared with the results of ENH-NWA scenarios. The results are reported in (section 13.2);
- Finally, a sensitivity analysis with High Water Availability (HWA) has been performed to analyse the impact of a wet year on the VRES installed capacities calculated in the ENH-NWA scenarios. The results are highlighted and discussed in section 13.3.

13.1 Enhanced VRES deployment with Normal Water Availability (ENH-NWA)

This section shows the results of the analysis carried out assuming a normal demand growth and average hydropower availability (normal water availability). Starting from the existing and committed programmable generation (from hydropower and fossil fuels), the maximum wind and PV capacity mix that could be integrated in 2025 and 2030, from a techno-economic point of view, and its impact on security of supply and on the energy exchanges with neighbouring countries have been highlighted.

The Consultant performed analyses on Zambian electric power system operating as an isolated system (ISO) with the aim to maximise VRES penetration, minimize the load curtailment and assure the security of the system operation in the mid- and long-term scenarios. Then, the affordability of additional VRES installed capacity in Zambia exploiting the interconnections has been analysed with an equivalent interconnected model (INT) based on Zambian net transfer capacity and SAPP prices.

Figure 13.1 shows all possible combinations of wind and PV capacities, and the associated VRES penetration, that result from the isolated scenarios with normal water availability. The two red curves represent the upper limit of VRES capacity mixes that could be installed in Zambia in 2025 and 2030 limiting the VRES generation curtailments. In fact, the marginal VRES curtailments are negligible for any couple of wind and PV capacity under these lines. In the same figure, the green curves represent, the VRES penetration (% of Zambian demand, including Transmission & Commercial (T&C) losses and firm export) of each couple of wind and PV capacity of the red curves. The point EVR represent the existing VRES mix, with 75.6 MW PV installed capacity and 0 MW wind capacity. The red area shows the pattern with the highest VRES penetration (greater than 25% in 2030), starting from the existing VRES capacity mix.

Figure 13.2 shows all possible combinations of wind and PV capacities that result from the interconnected scenarios with normal water availability. The blue curves represent the upper limit of the cost-effective wind and PV capacity combinations calculated in 2025 and 2030; any couple of wind and PV capacity over these lines lead to higher costs than benefits in the reference year. Furthermore, the green curve shows the ratio between the benefits (avoided imports) and the costs of additional VRES capacity, i.e. the capacity greater than those calculated in the isolated scenario, in long-term scenario. Each couple of PV and wind capacity on the solid blue line lead to a point on the green line. The blue area shows the pattern with the highest benefits (the ratio benefit/cost is near to 120%), starting from the existing VRES capacity mix.

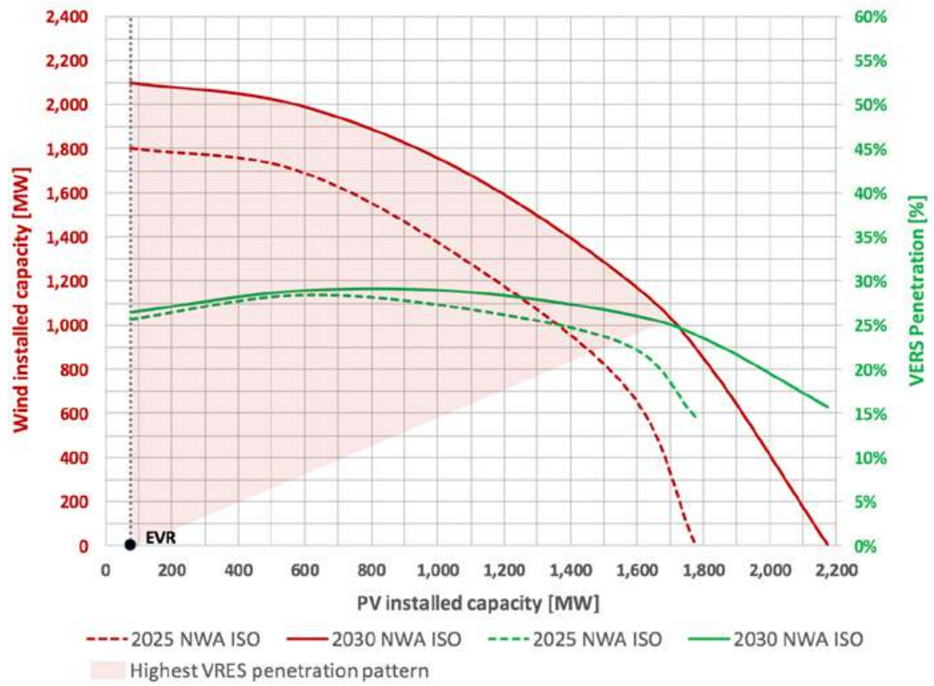


Figure 13.1 – VRES capacity curves (red lines) and VRES penetration (green lines) from PromedGrid simulations carried out for ENH-NWA isolated scenarios 2025 and 2030

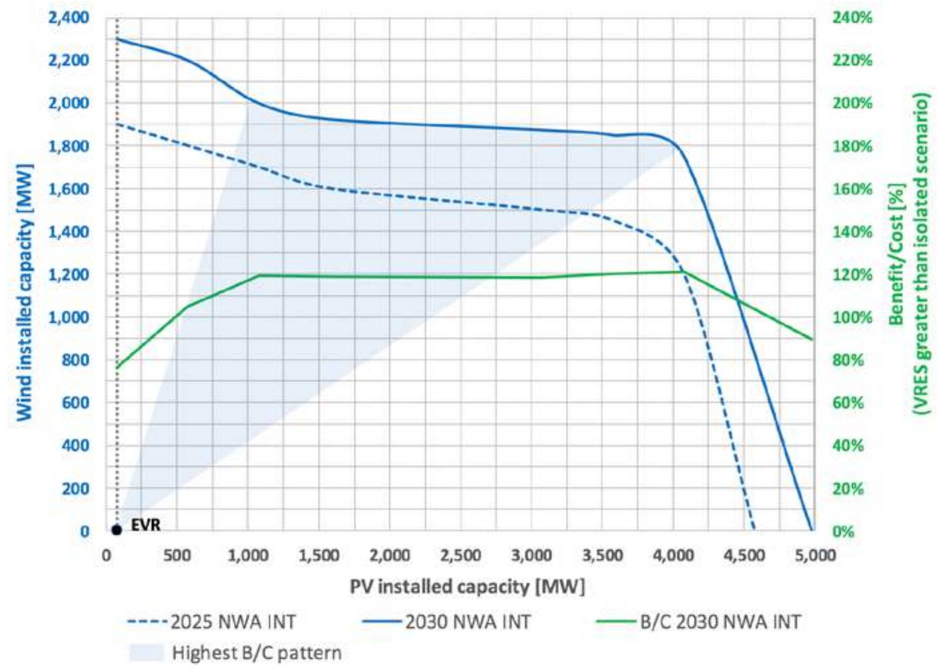


Figure 13.2 – VRES capacity curves (blue lines) and Benefit/Cost (green lines) from PromedGrid simulations carried out for ENH-NWA interconnected scenarios 2025 and 2030

Referring to both 2025 and 2030, the VRES mix curves obtained in case of isolated or interconnected country allow to identify a restricted range of optimal PV and wind capacity mix able to guarantee techno-economic benefits and to select the reference case for further analysis and sensitivities. The range of the optimal points have been identified considering the following conditions, respectively represented by the red and blue areas highlighted in Figure 13.1, Figure 13.2 and Figure 13.3:

- *Technical constraint*: the red area highlighted in Figure 13.1 and Figure 13.3 allows the selection of a range of optimal VRES mixes that can guarantee the greater security of supply (VRES penetration above 25%) without the risk of high VRES energy production curtailment in the isolated country condition (electrical self-sufficiency of Zambia).
- *Economic benefits:* the blue area, Figure 13.2 and Figure 13.3, refers to the range of optimal points from a techno-economic point of view, that can guarantee a percentage benefits-costs ratio greater than 120% and a high VRES penetration in the Zambian power system, due to associated PV and wind capacities greater than the values found in the isolated case.

Hence, considering the common area of the two conditions (isolated and interconnected) for both 2025 and 2030 target years, the optimal VRES mixes (purple circles) have been identified supposing a linear VRES growth from the EVR point to the middle points of the common area on the red curves (limits of isolated scenarios), and moving on until the limits of the interconnected scenarios (Figure 13.3).

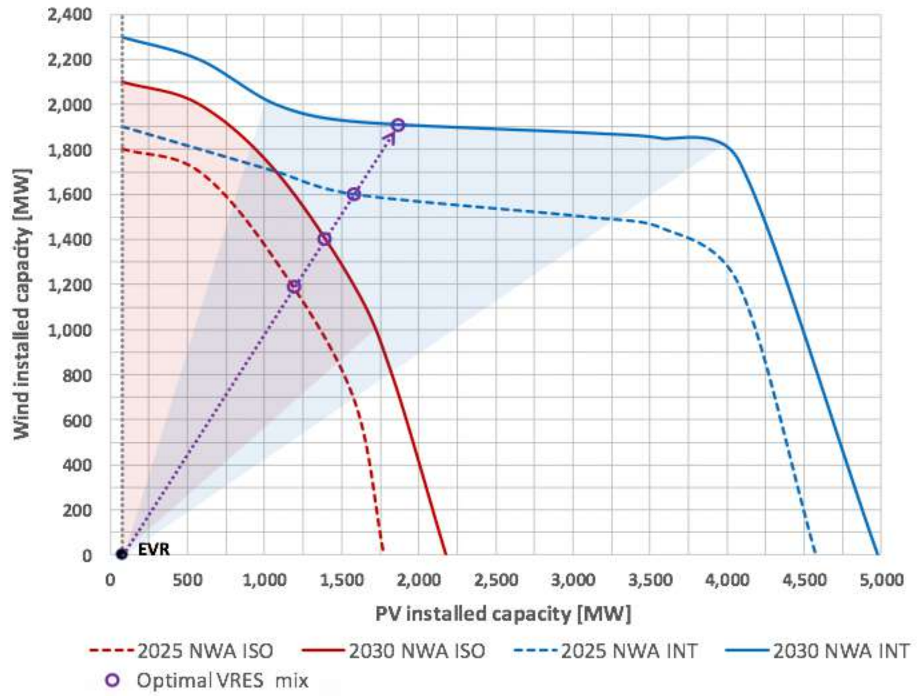


Figure 13.3 – Optimal VRES mix for isolated and interconnected ENH-NWA scenarios

The summary of the optimal PV and wind installed capacities that could be reached in ENH-NWA scenarios are highlighted in Table 13.1; the total capacity of each source, with the existing and additional shares, are shown together with the amount due to the interconnections. As far as the isolated scenarios, the most suitable mix that can be integrated in the power system from the security of supply point of view, foresees additional capacity up to 2,300 MW in 2025 and 2,700 MW in 2030, where high energy demand in Zambia is expected. The additional capacity is equally distributed among PV and Wind technologies, leading to a positive impact in term of energy sources diversification for electricity production.

The values of PV and wind mix in 2025 and 2030 further increase in case the possibility for energy exchanges with neighbouring countries is considered, as in the interconnected case scenario. +800 MW in 2025 and +950 MW in 2030 could be integrated in the Zambian electric power system reaching 3,100 MW VRES installed capacity in 2025 and 3,650 MW in 2030.

Scenario	Type	Unit	Existing	Additional	Total	Delta INT-ISO
2025 ISO-NWA	WIND	[MW]	0.0	1,200	1,200.0	-
	PV	[MW]	75.6	1,100	1,175.6	-
	TOT VRES	**[MW]**	**75.6**	**2,300**	**2,375.6**	**-**
2025 INT-NWA	WIND	[MW]	0.0	1,600	1,600.0	+400
	PV	[MW]	75.6	1,500	1,575.6	+400
	TOT VRES	**[MW]**	**75.6**	**3,100**	**3,175.6**	**+800**
2030 ISO-NWA	WIND	[MW]	0.0	1,400	1,400.0	-
	PV	[MW]	75.6	1,300	1,375.6	-
	TOT VRES	**[MW]**	**75.6**	**2,700**	**2,775.6**	**-**
2030 INT-NWA	WIND	[MW]	0.0	1,900	1,900.0	+500
	PV	[MW]	75.6	1,750	1,825.6	+450
	TOT VRES	**[MW]**	**75.6**	**3,650**	**3,725.6**	**+950**

Table 13.1 – Optimal PV and wind capacity mixes for isolated and interconnected ENH-NWA scenarios

The histograms of Figure 13.4 show the country energy balance for the two target years 2025 and 2030 under three conditions of VRES installed capacity: the existing VRES (EVR), the VRES capacity from isolated scenarios (ISO) and from interconnected scenarios (INT).

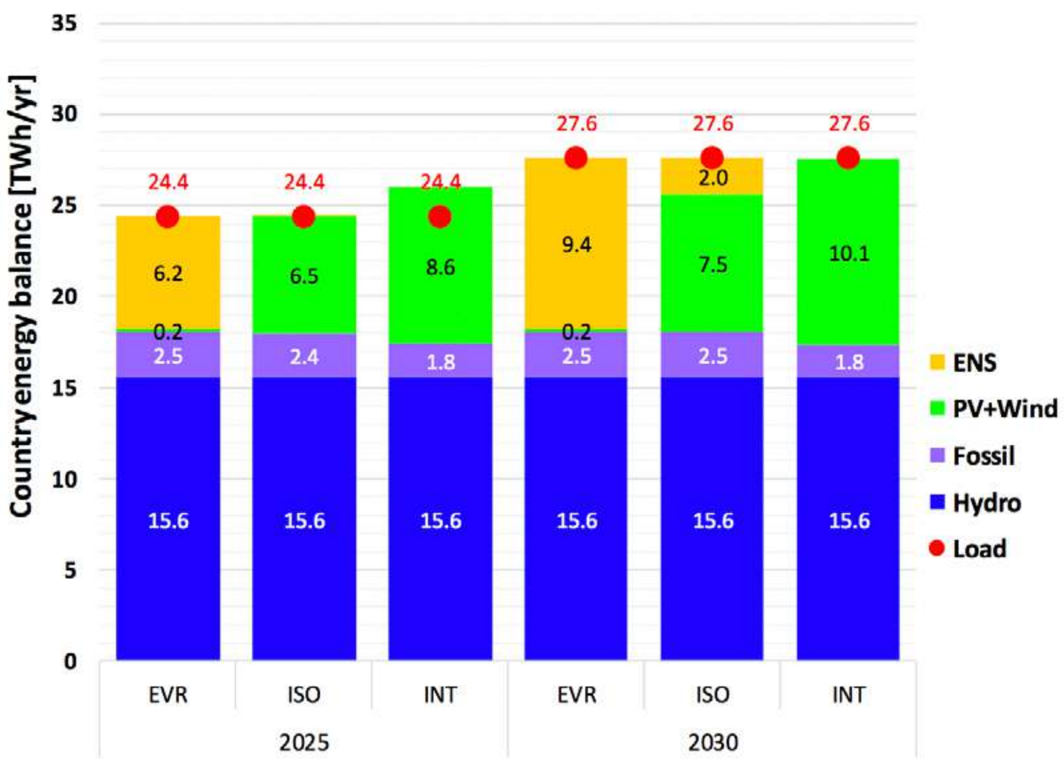


Figure 13.4 – Country energy balance for isolated and interconnected Zambia - ENH-NWA 2025 and 2030

Comparing the two target years, the Zambian energy demand increases by 13% while no variation in terms of fossil and hydroelectric annual production were simulated (only existing and committed programmable power plants were considered to evaluate the possible electrical energy self-sufficiency of Zambia increasing only VRES capacity. The commercial operating date of all hydro committed capacity is expected within 2023). The energy demand is not achieved in EVR scenario and in ISO scenario, both in mid- and long-term: the Energy Not Supplied (ENS) is equal to 6.2 TWh/year in 2025 and 9.4 TWh/year in 2030 with only the existing VRES capacity; it decreases up to 0.4 TWh/year in 2025 (1.6·10-2 p.u. of demand) and 2.0 TWh/year in 2030 (7.3·10-2 p.u. of demand) with the optimal VRES capacity mixes found in isolated scenarios but it results over the standard (<1·10-4 p.u. of demand). Figure 13.5 shows the ENS duration curves for isolated scenarios 2025 and 2030.

A VRES capacity greater than the optimal combinations calculated in the isolated scenarios would lead to non-negligible VRES production curtailments, increasing the levelized cost of electricity from VRES technology. Therefore, cheaper programmable generation is advised in isolated scenario to limit ENS and assure the security of supply: the Consultant advises about 100 MW installed capacity with 45% capacity factor within 2025 and 500 MW installed capacity with 45% capacity factor within 2030, based on the ENS duration curves in Figure 13.5. The interconnections with the neighbouring countries help to meet the energy demand assuring the security of supply without any additional programmable generation, both in 2025 and in 2030.

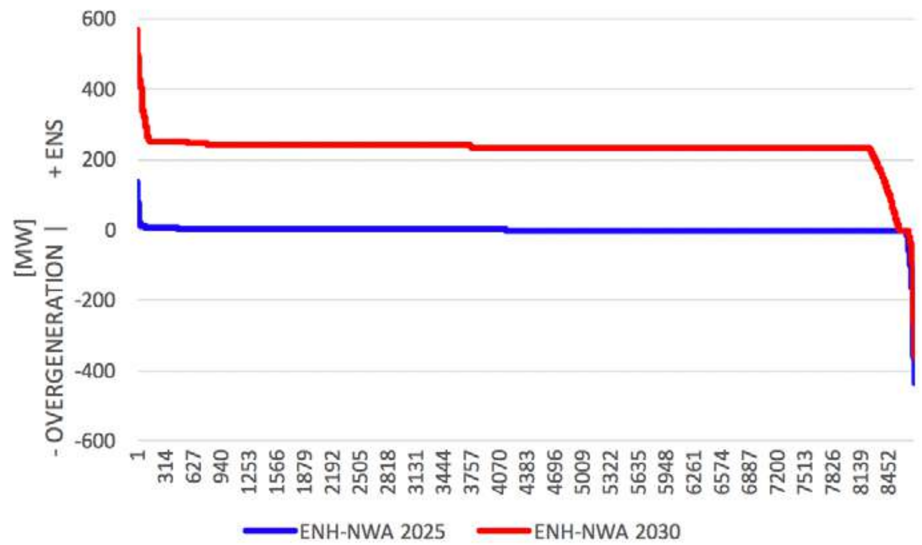


Figure 13.5 – Duration curve of ENS–OG for Isolated Zambia (ENH-NWA 2025 and 2030)

About the interconnected case, Zambia benefits from import, reducing ENS, but also from export capacity increasing the VRES energy production, +32% in 2025 and +35% in 2030 compared to isolated condition. The positive impact over the power exchanges with the other SAPP countries can be clearly noted in Figure 13.6 and Figure 13.7, which compares the duration curves and the yearly amount of power exchanges for both target years. They show the power exchanges on the competitive market, excluding the firm export based on bilateral agreements.

Figure 13.6 shows the duration curve of power exchanges expected in the competitive market; the number of hours of import and export are comparable, with 2.0 TWh/year import and 3.5 TWh/year export expected in 2025 and 2.9 TWh/year import and 2.8 TWh/year export expected in 2030. The monthly distribution of power exchanges in Figure 13.7 allows observing that:

- Central months of the year are characterized by higher amount of energy transits from Zambia towards the neighbouring countries, due to economic convenience (high energy prices);
- The higher internal energy demand and limited additional PV and wind capacity installation with respect to 2025 (+15%) lead to a reduction of the amount of energy exported towards the neighbouring countries (still concentrated in the same months of the year) and consequently to higher amount of energy imported to cover the Zambian load and reduce the ENS to 0.

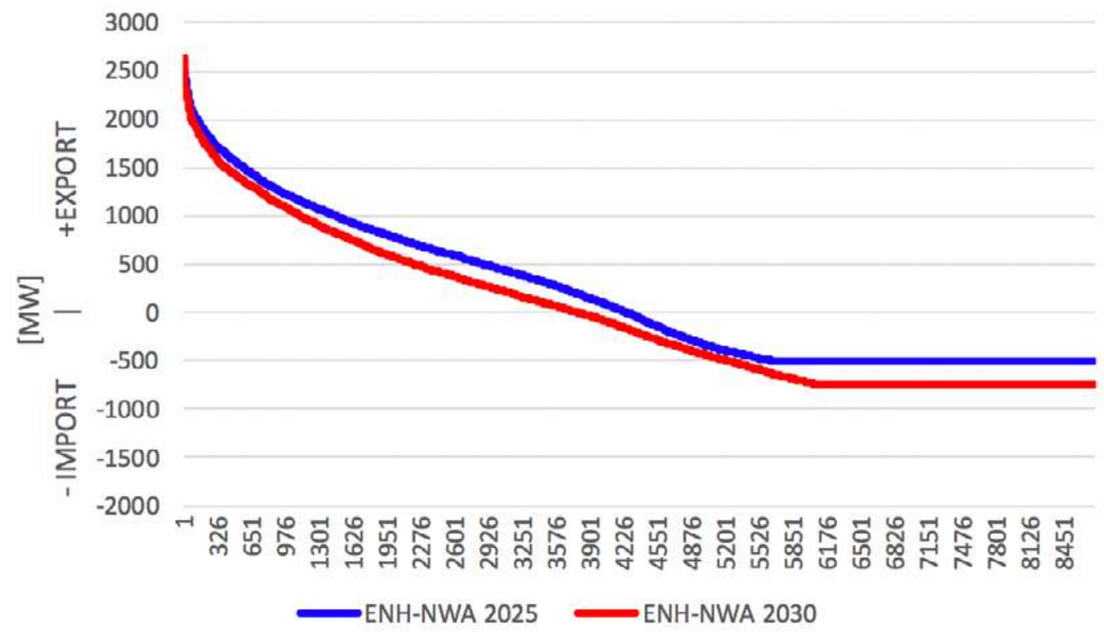


Figure 13.6 – Import-export duration curves on the competitive market (ENH-NWA 2025 and 2030)

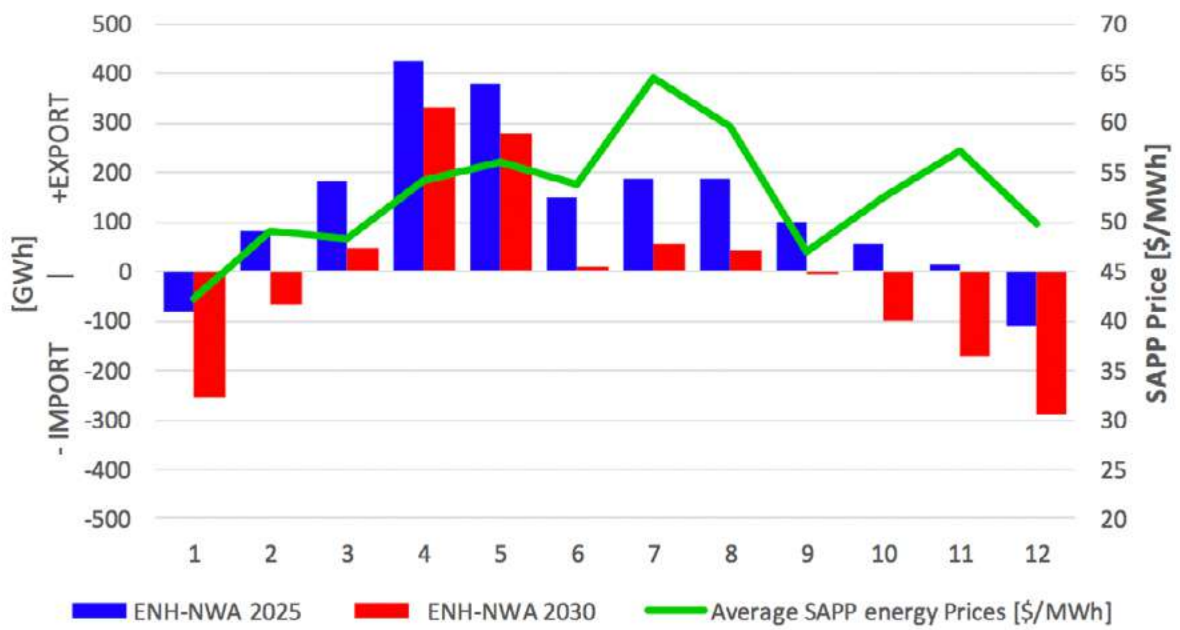


Figure 13.7 - Monthly import-export energy profile on the competitive market (ENH-NWA 2025 and 2030)

Hereafter, the results of the hourly simulations of the optimal coordinated hydro-thermal dispatch are reported to evaluate the impact of a significant VRES integration on the Zambian system operation. The results are exemplified in Figure 13.8 and Figure 13.9 as hourly profile for the average day in the isolated and interconnected scenarios 2030. In detail, the two figures show the 24-hour profile of the supply-demand balance in the average day of the year, highlighting:

- The demand, including the domestic demand of Zambia, the firm export and the transmission and commercial losses;
- The production from the run of river hydropower plants ("Hyd ROR") Chishimba Falls, Lunsemfwa, Lunzua, Lusiwasi, Mulungushi, Musonda Falls, Shiwa Ngándu and Victoria Falls;
- The production of Itezhi Tezhi reservoir hydropower plant ("ITT");
- The production from conventional fossil fuel power plants, including Maamba coal power plant and Ndola heavy fuel oil power plant ("Fossil fuels");
- The production from Kafue Gorge Upper ("KGU"), Kafue Gorge Lower ("KGL") and Kariba North Bank ("KNB") – including the extension – hydropower plants, divided as follow:
  - Technical minimum power of the power plants to assure the minimum water release in the river without loss of water/energy ("Pmin KGU+KGL+KNB");
  - Downward operating reserve provided by Kafue Gorge Upper and Kariba North Bank ("Down Res (KGU+KNB)") to cope with VRES integration;
  - Unconstrained generation ("Other KGU+KGL+KNB");
- PV power production net of energy curtailments ("PV net");
- Wind power production net of energy curtailments ("Wind net");
- Possible energy not supply due to lack of power ("ENS");
- Possible curtailments of VRES production due to over-generation phenomena ("VRES Curt.");
- The upward operating reserve provided by Kafue Gorge Upper and Kariba North Bank power plants ("Up Res (KGU+KNB)") to cope with VRES integration. This is not power needed to meet the demand, but it is power available to cope with the downward variations of VRES production during the hour and even hour by hour;
- The import from the neighbouring countries ("Import");
- The marginal clearing prices on the day-ahead market in SAPP ("SAPP MCP [US$/MWh]").

The current management of Zambian hydro reservoir power plants is performed to follow, as much as possible, the profile of the national demand. In the ENH-NWA isolated scenario (Figure 13.8) the daily production of hydropower plants with reservoir is meanly shifted during night to integrate PV generation. The flexibility of the hydro power plants and the big availability of hydro power generation, coupled with the capacity of existing reservoir, are the key to the optimal deployment of high VRES capacities in the isolated system. The interconnections and the SAPP price profile allow a better integration of VRES and make convenient the power import during the night, when the SAPP price is low, and the power export during the daytime hours when the SAPP price is higher than the price in Zambia, with an optimal hydro power plants operation more in line with the national load profile.

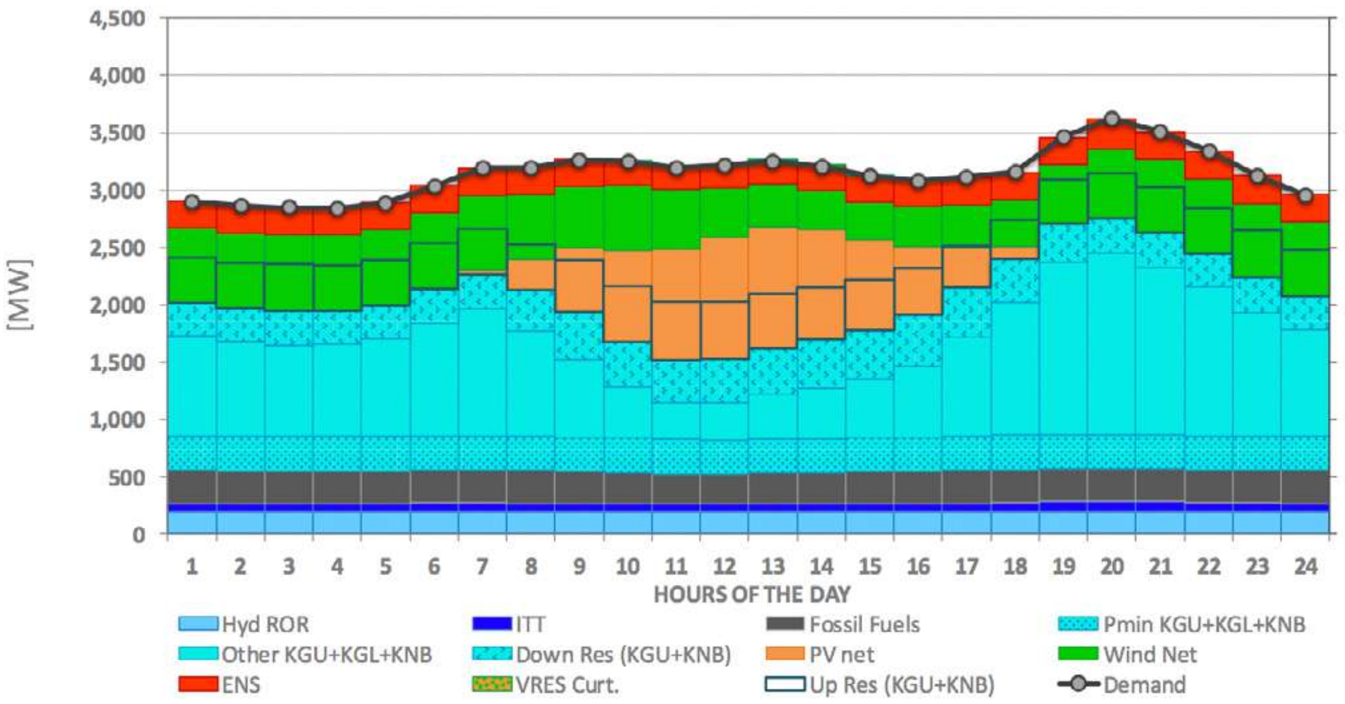


Figure 13.8 – Hourly generation and demand balance in the average day 2030 (ENH-NWA-ISO 2030)

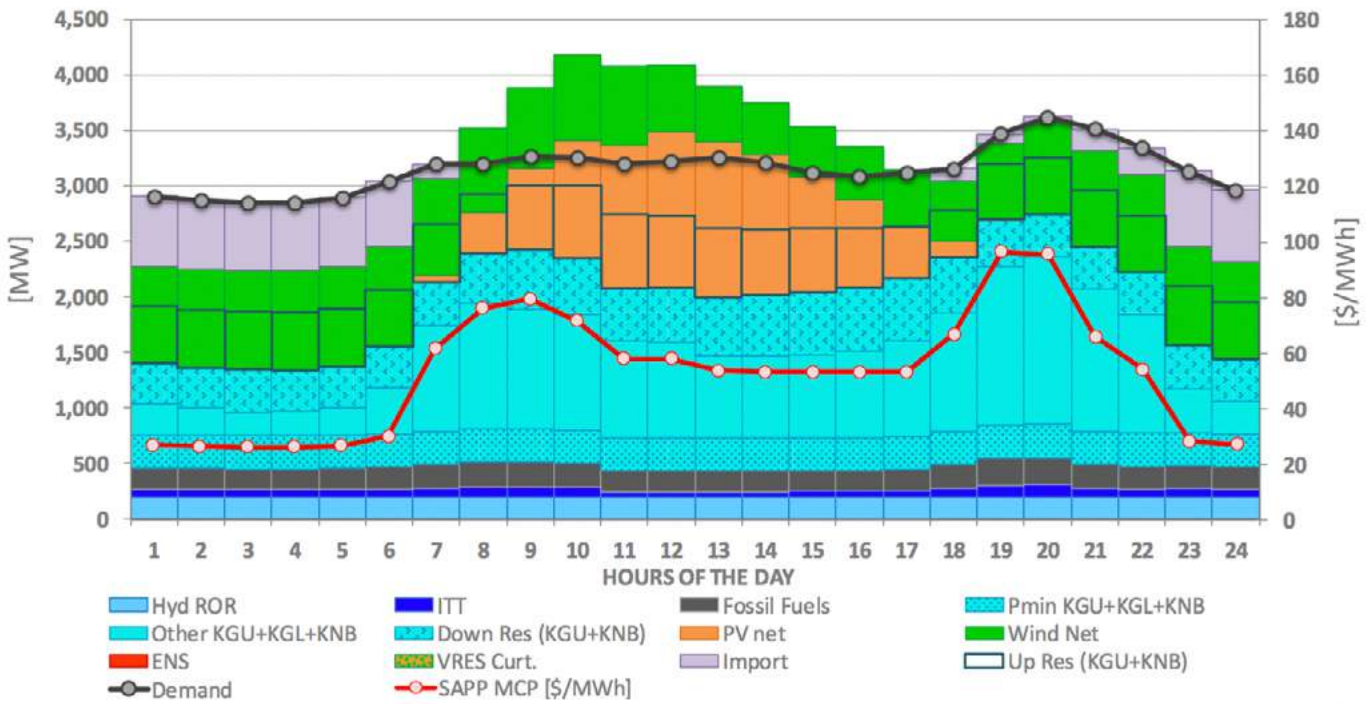


Figure 13.9 – Hourly generation and demand balance in the average day 2030 (ENH-NWA-INT 2030)

Figure 13.10 shows the hourly power profile of Zambian hydro generation during the average day expected in ENH-NWA-ISO scenario 2030; the national load and the residual load (defined as the difference between the load and the VRES generation) are also shown. This is an example to highlight the effects of high VRES capacity on hydro power plant operation. Once again, high VRES penetration strongly influences the dispatch of hydro generation fleet in isolated Country configuration, causing an increased production during the night hours to make room to the PV production during the daytime hours. Changes are expected in hydropower management, from a demand-dependent approach to a VRES-dependent approach.

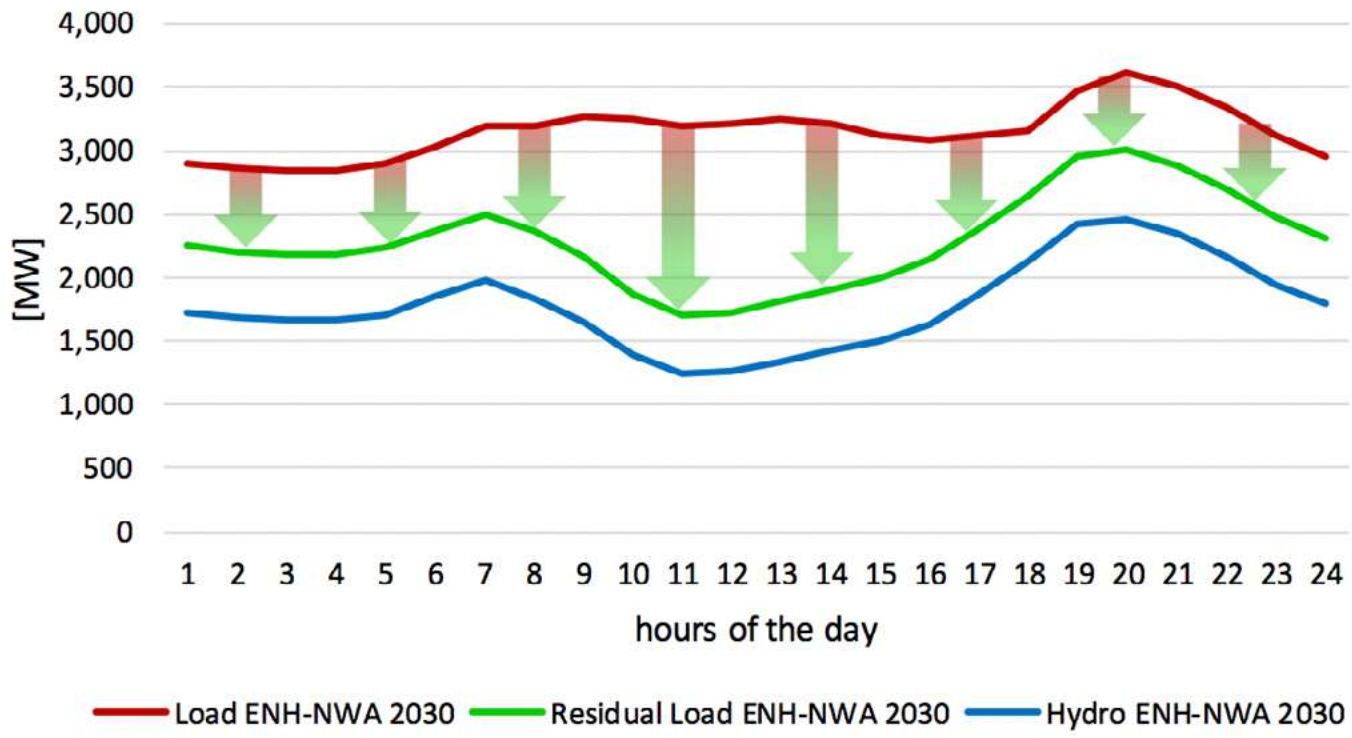


Figure 13.10 – Residual load profile for Isolated Zambia (ENH-NWA-ISO 2030)

The limited additional VRES integration in 2030 isolated ENH-NWA scenario, with expected ENS, is related to the management of the downward operating reserve in charge of the Zambian hydroelectric power plants. Figure 13.11 shows the daily dispatch of Zambian generation fleet during the day with the biggest production from VRES power plants (21 of September 2030). In the period between 10 and 14 the high PV and wind power productions force the displacement of hydropower from daytime to night-time hours. The hourly power profile of the hydroelectric power plants with reservoir (Kafue Gorge and Kariba North Bank) conflict with the minimum power that should be kept coping with the downward operating reserve requirements and the technical minimum power constraints. It can be observed that the available capacity and flexibility of these hydroelectric plants are fully exploited; additional VRES production would be curtailed between 10 and 14.

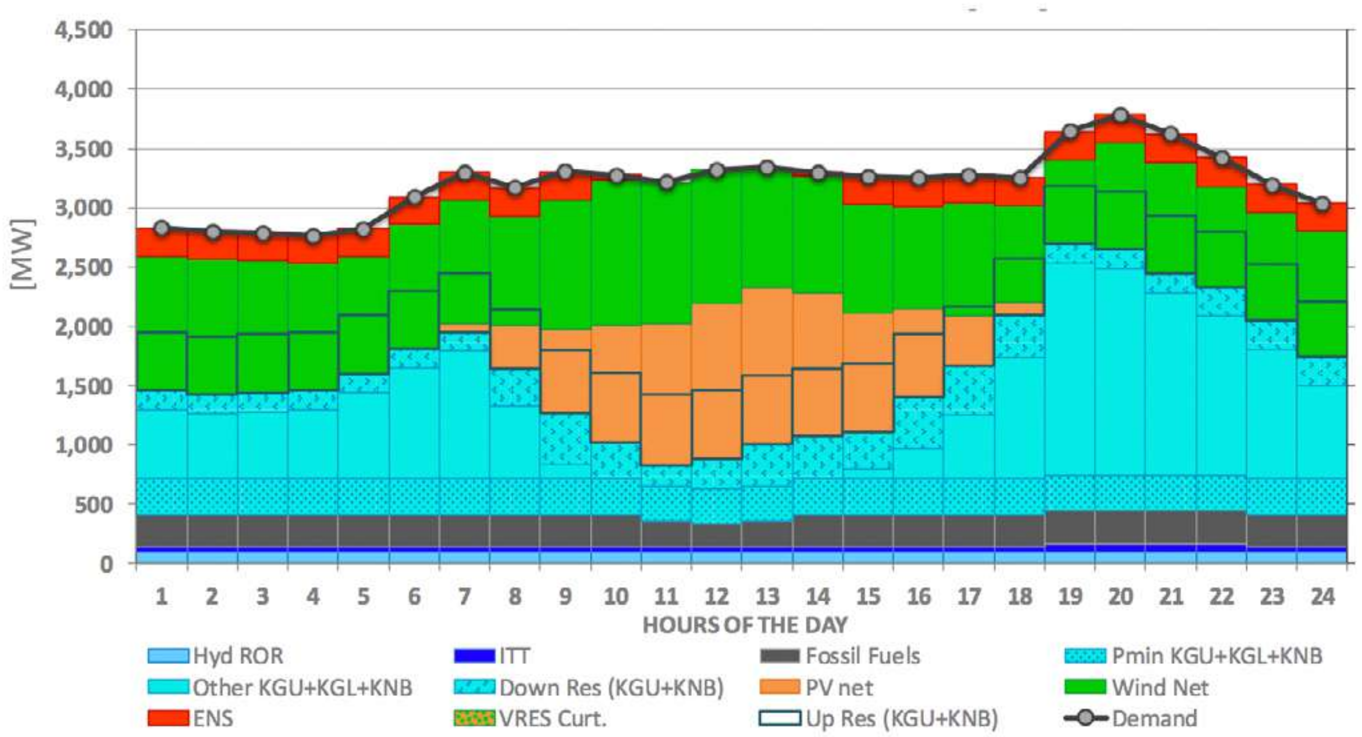


Figure 13.11 – Hourly generation and demand balance in the day with the biggest VRES production, 21 of September 2030 (ENH-NWA-ISO 2030)

In conclusion, the results obtained from the simulations performed with PromedGrid for the ENH-NWA scenario considering the isolated and interconnected system in the two target years 2025 and 2030 show that:

- The flexibility of hydro power plants in Zambia allows the integration of big amount of VRES and the safe operation of the system with the proper reserve requirements needed to balance the variability and unpredictability of wind and PV generation;
- Up to 25% VRES penetration could be reached in long-term isolated scenario, with 1,400 MW wind installed capacity and 1,376 MW PV installed capacity. +950 MW could be integrated exploiting the export capacity towards the neighbouring countries and the SAPP electricity price, reaching 1,900 MW total wind installed capacity and 1,826 MW total PV installed capacity;
- Without considering the import/export capacities, the above mentioned VRES installed capacities can limit the energy not supplied but without meeting the minimum-security standard, both in 2025 and in 2030. The integration of Zambia in SAPP would allow the whole fulfilment of the internal demand assuring the security of supply. Otherwise, cheaper programmable generation is advised to assure the electrical self-sufficiency of Zambia: about 100 MW installed capacity with 45% capacity factor within 2025 and 500 MW installed capacity with 45% capacity factor within 2030.
- The optimal VRES installed capacities calculated with the isolated model are comply with the reserve requirements (fully supplied by ZESCO) and the minimum VRES curtailment approach. Any additional VRES installed capacity would create non-negligible VRES production curtailments and additional costs for the system.
- The VRES integration in the isolated system stresses the operation of hydro power plants with reservoir, mainly on the daily dispatching. They are forced to displace their production from the central hours of the day to the night hours making room for PV and wind productions. This stress for the operation of hydropower plants with reservoir is mitigated from the availability of interconnections with the neighbouring countries.
- The operating reserve requirements, according to the methodology described in Task 2, needed to manage the variability and unpredictability of the optimal VRES capacities that could be integrated in the reference scenario with normal water availability (ENH-NWA-ISO and ENH-NWA-INT) are highlighted in Annex 2 – Operating reserve requirements with the optimal VRES installed capacities.

13.2 Enhanced VRES deployment with Low Water Availability (ENH-LWA)

This paragraph shows the results of the optimal coordinated hydro-thermal dispatching with an enhanced development of VRES generation capacity and a reduced availability of water energy. The results of low water availability scenarios under isolated and interconnected country conditions are compared with those calculated under normal water condition to highlight the impact of low rainfall due to the climate change on VRES integration and hydropower dispatching. The ENH-LWA scenario considers a reduction of -33% of water availability for electricity purpose (the hydropower generation reaches 10.9 TWh/year in the dry year analysed) and no other different assumptions with respect to the ENH-NWA scenarios discussed above.

Figure 13.12 shows the optimal VRES capacity curves for ENH-LWA isolated scenarios and associated VRES penetration curves compared with ENH-NWA scenarios for target years 2025 and 2030. The most suitable combinations of wind and PV capacities for low water availability scenario have been selected by the Consultant assuming linear growth of wind and PV capacities from EVR capacity mix to 2030 ENH-NWA capacity mix with the isolated country model.

In both target years, the low water availability allows an increase of the maximum amount of renewable energy sources that could be integrated into the Zambian power system to meet the internal energy demand. Such increase is limited (with respect to the ENH-NWA) to less than 4% in both target years due to the fact that existing reservoir hydropower plants, that should be able to displace water during the day in order to meet the demand and the VRES production profile, are used to provide reserve to the system, hence have a limited range of power production modulation.

Similarly, as reported in Figure 13.13, the low water availability condition allows a higher amount of VRES capacity integration into the Zambian power system in case of interconnected scenario: +6% of additional MW can grant in 2025 and +8% in 2030 compared to ENH-NWA-INT scenarios.

The lack of hydropower due to climate reasons (low rainfall, drought) could be only partially compensated by means of additional VRES capacity because of the limited flexibility of hydro power plants during dry conditions. The lack of water and the downward operating reserve constraints reduce the operating bandwidth of the hydro reservoir power plants, limiting additional VRES integration.

The PV and wind capacities that have been identified by the Consultant as the optimal VRES mixes in case of ENH-LWA scenarios are resumed in Table 13.2.

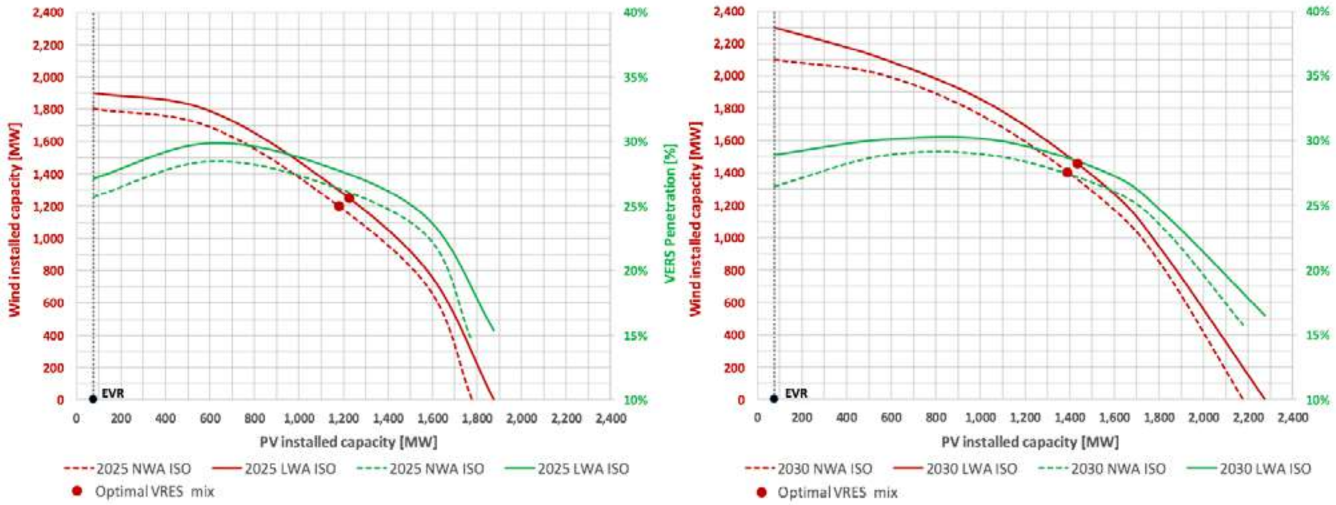


Figure 13.12 – VRES mix curves for isolated scenarios 2025 and 2030 (LWA vs NWA)

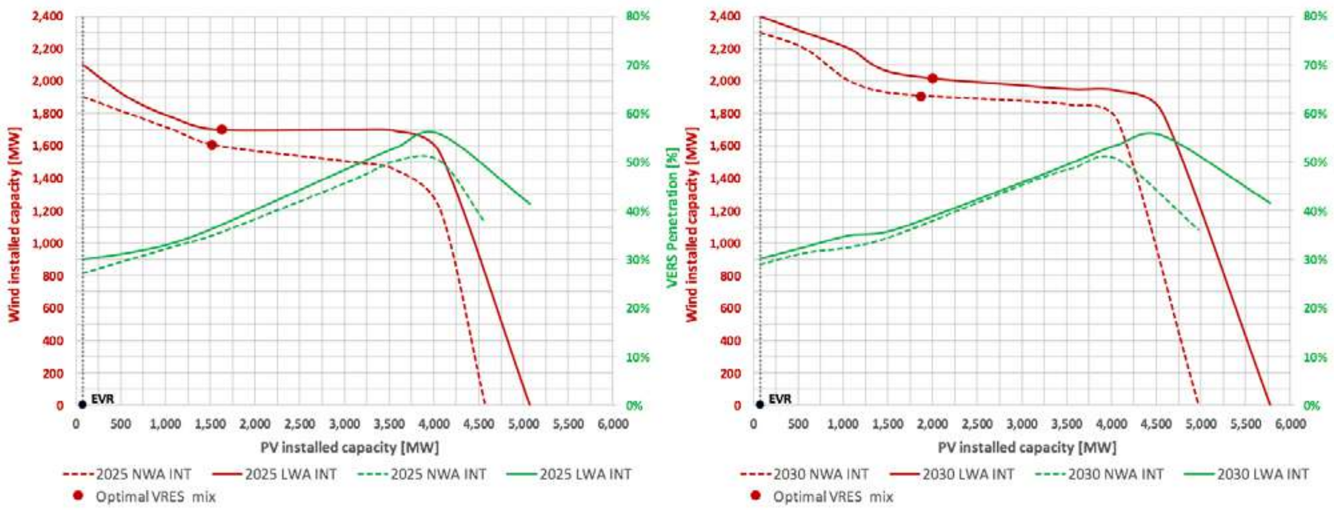


Figure 13.13 – VRES mix curves for interconnected scenarios 2025 and 2030 (LWA vs NWA)

Table 13.2 – Optimal PV and wind capacity mixes for isolated and interconnected ENH-LWA scenarios

Scenario	Type	Unit	Existing	Additional	Total	LWA vs NWA
2025 ISO-LWA	WIND	[MW]	0.0	1,235	1,235.0	+35
	PV	[MW]	75.6	1,145	1,220.6	+45
	TOT VRES	**[MW]**	**75.6**	**2,380**	**2,455.6**	**+80**
2025 INT-LWA	WIND	[MW]	0.0	1,700	1,700.0	+100
	PV	[MW]	75.6	1,600	1,675.6	+100
	TOT VRES	**[MW]**	**75.6**	**3,300**	**3,375.6**	**+200**
2030 ISO-LWA	WIND	[MW]	0.0	1,435	1,435.0	+35
	PV	[MW]	75.6	1,350	1,425.6	+50
	TOT VRES	**[MW]**	**75.6**	**2,785**	**2,860.6**	**+85**
2030 INT-LWA	WIND	[MW]	0.0	2,025	2,025.0	+125
	PV	[MW]	75.6	1,925	2,000.6	+175
	TOT VRES	**[MW]**	**75.6**	**3,950**	**4,025.6**	**+300**

The results obtained for the four optimal VRES mix in the ENH-LWA scenarios are restated in the histograms of Figure 13.14, that report country energy balance for the two target years 2025 and 2030 in the isolated and interconnected scenarios, compared with ENH-NWA scenarios.

The main value that can be highlighted in case a lower availability of water resources is considered is that the country generation fleet is not sufficient to cover the country energy need. Furthermore, the ENS value reduces but does not reach a value of zero if additional VRES are integrated into the system. Only the interconnected scenario allows to cover the internal demand of Zambia.

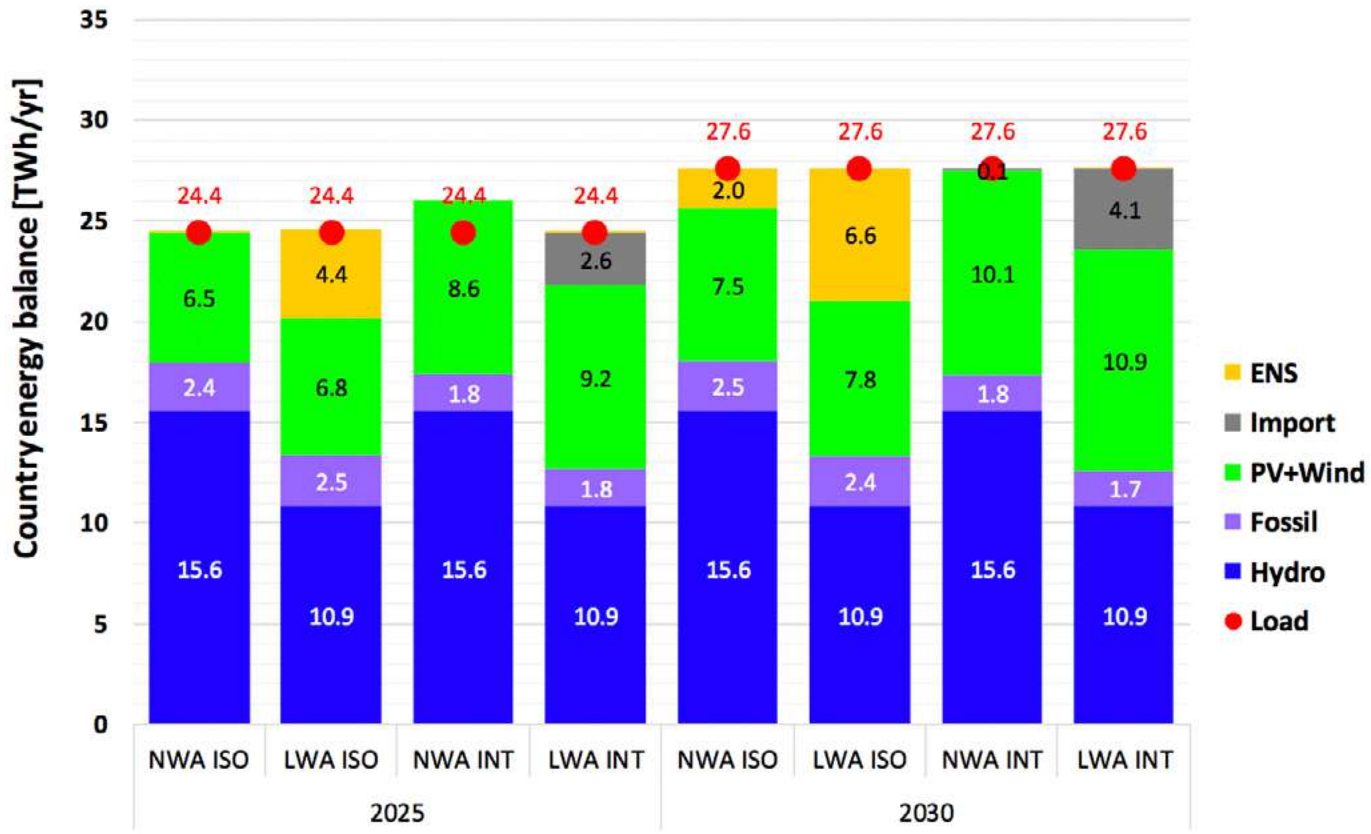


Figure 13.14 – Country energy balance for isolated and interconnected Zambia - ENH-LWA 2025 and 2030

The lowest ENS values obtained in case the interconnection among Zambia and SAPP countries are due to the possibility of importing energy from neighbouring energy markets and the different monthly energy exchanges profiles with respect to the ones discussed for the ENH-NWA scenario in section 13.1 and resumed in Figure 13.15 and Figure 13.16. During the dry year (LWA scenario) Zambia is a net importer with 4.0 TWh/year import and 1.3 TWh/year export in 2025 (+100% import and -63% export compared to NWA scenario) and with 5.1 TWh/year import and 1.0 TWh/year export in 2030 (+76% import and -64% export compared to NWA scenario).

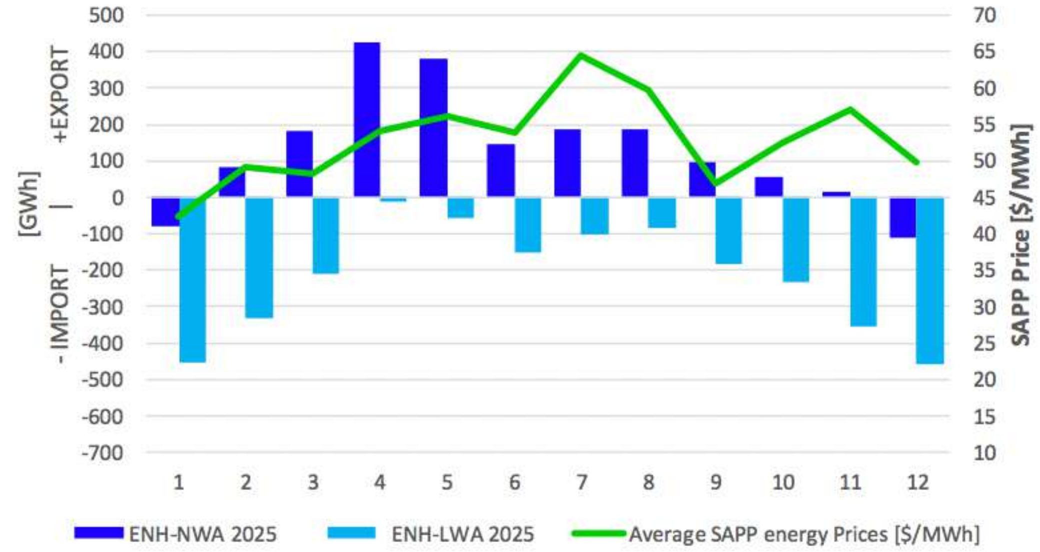


Figure 13.15 – Monthly import-export energy profile on the competitive market - ENH-LWA in 2025

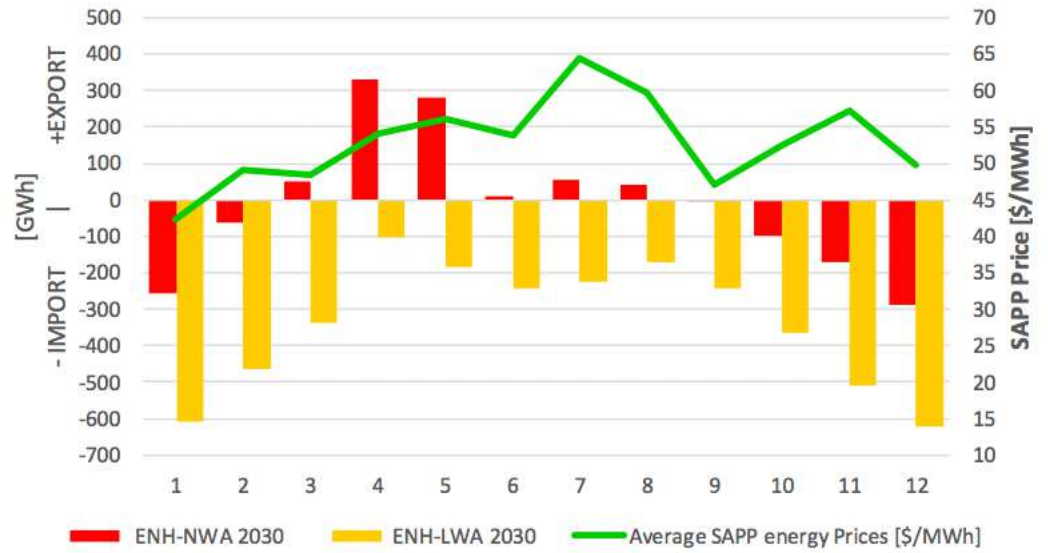


Figure 13.16 – Monthly import-export energy profile on the competitive market - ENH-LWA in 2030

The import-export duration curves of ENH-LWA interconnected scenarios are compared with those of ENH-NWA interconnected scenarios in Figure 13.17.

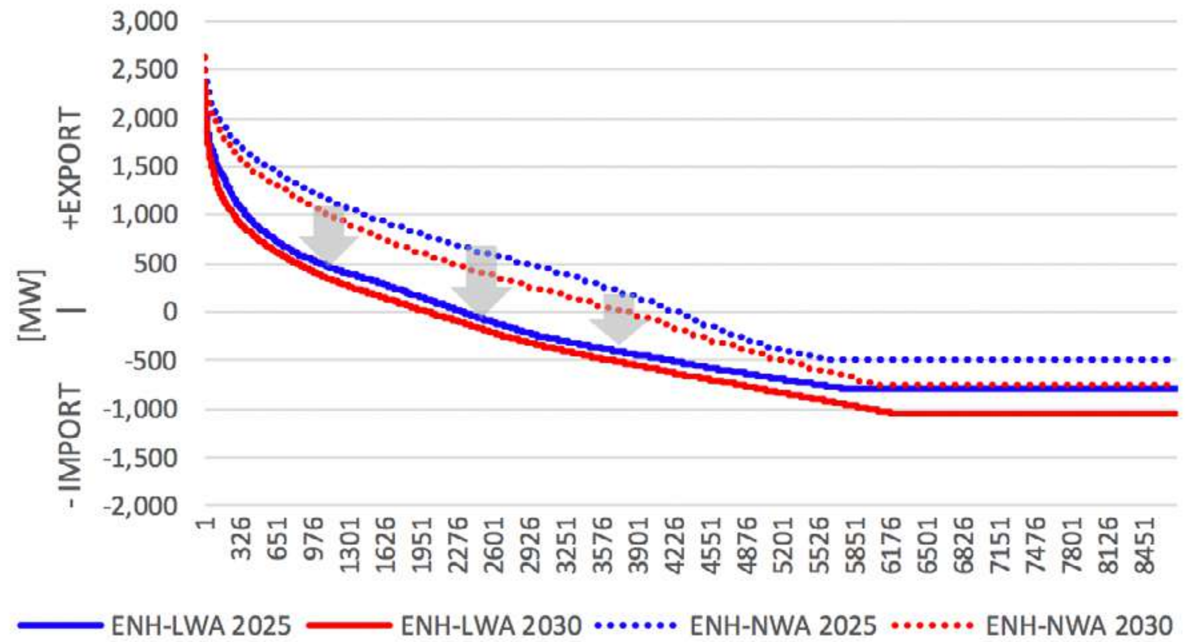


Figure 13.17 – Import-export duration curves on the competitive market (ENH-LWA 2025 and 2030)

Referring to the 2025, in the ENH-NWA the VRES integration in Zambia allows to maximize the export of energy towards SAPP market zone (characterized by average electricity prices higher than in Zambia) and to cover the internal demand. Such condition is no more valid in case of ENH-LWA scenario, where both in 2025 and 2030 Zambia imports energy for security of supply reasons during the whole year.

The ENS null value obtained in the interconnected scenario are far from the ones calculated for the isolated ENH-LWA cases, in 2025 and 2030. Figure 13.18 allows to compare the duration curves of the ENS in 2025 and 2030 for the isolated Zambia in the Normal and Low water availability scenarios

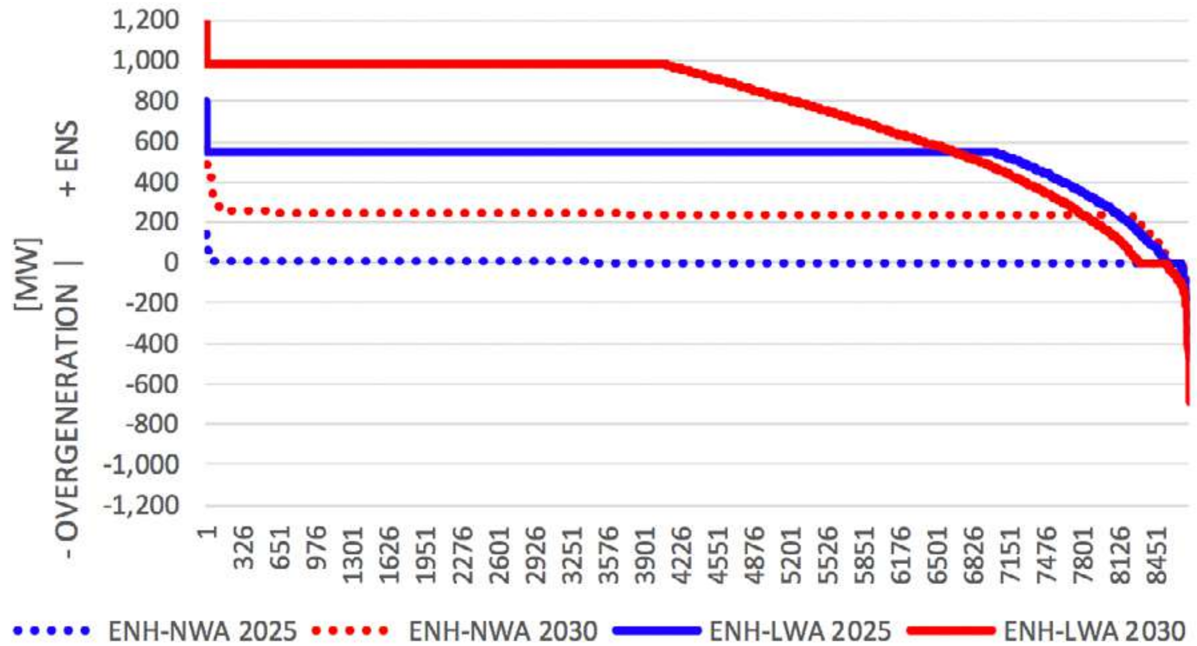


Figure 13.18 Duration curve of ENS – OG for Isolated Zambia – ENH-LWA in 2025 and 2030

The limited additional VRES capacity that can be integrated in the system in case of ENH-LWA scenario (Table 13.2) with respect to the ENH-NWA scenario leads to the weak security of supply. The flexibility of hydropower plants was fully exploited with the optimal VRES capacity mix selected in ENH-LWA scenarios; therefore, additional programmable generation (e.g. from hydro or fossil fuels) is advised instead of additional VRES capacity. To meet the demand under the isolated country condition and low water availability, the ENS duration curves in Figure 13.18 suggest 750 MW installed capacity with 67% capacity factor within 2025 and 1,000 MW installed capacity with 75% capacity factor within 2030 from new programmable generation. The interconnections with the neighbouring countries help to meet the energy demand assuring the security of supply without any additional programmable generation, both in 2025 and in 2030.

Comparing the monthly hydroelectric energy production in 2025 and 2030 of the isolated scenario in the two water availability conditions, Figure 13.19, a similar distribution of energy production profile along the year is observed, with higher production concentrated in the first and last months of the year.

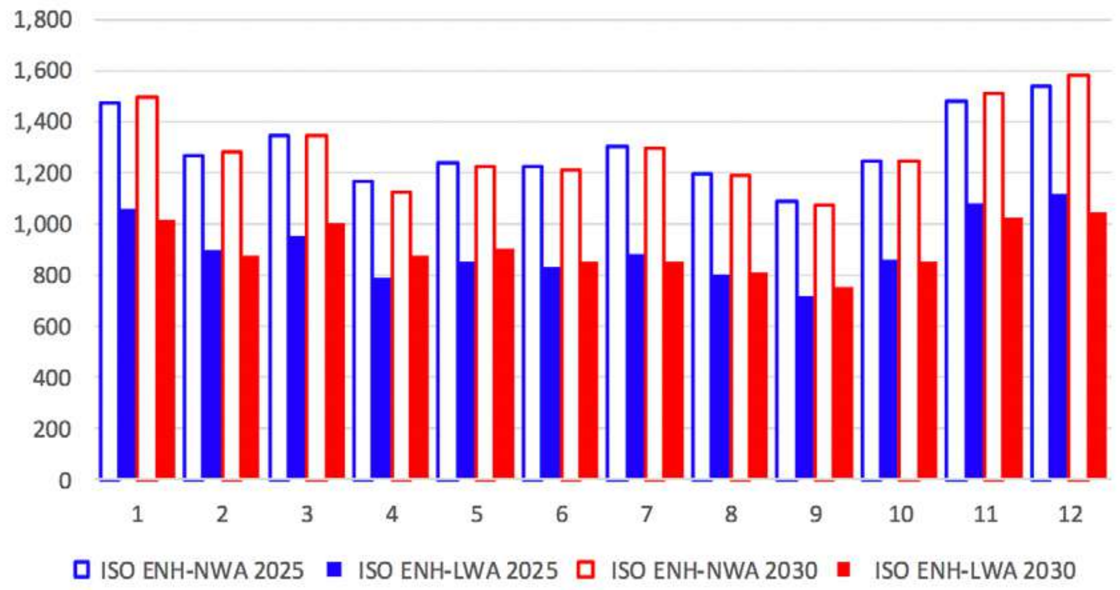


Figure 13.19 Monthly hydroelectric production Isolated Zambia – ENH -LWA and NWA in 2025 and 2030

Figure 13.20 shows the hourly generation-demand balance in the average day for isolated scenario 2025 with low water availability. The productions of each technology, with a detail of hydro power plants, VRES curtailments and the expected energy not supplied (ENS) are compared with the average daily demand. The lack of water reduces the available hydropower production, most of which should be used for operating reserve purposes; the hydropower plants with reservoir displaced their production from daytime hours to the night hours to allow the maximum VRES integration (additional VRES production would be curtailed) but significant amount of ENS occurs without the interconnection exploitation.
The isolated scenarios highlighted that Kafue Gorge and Kariba North Bank power plants operating to maximize VRES penetration reached the lower production constraints (sum of minimum technical power and downward reserve) in many hours advising against the additional VRES capacity (greater than the optimal mix). September is the most critical month for the operation of hydropower plants to cope with the VRES integration, because it is the month with the greatest production expected by VRES power plants. The dispatch of Kafue Gorge and Kariba North Bank power plants in the average day of September 2025 is shown in Figure 13.21. Both power plants meet the minimum production constraint (technical minimum power + downward operating reserve) between 10 and 14 on the day, every day of the month.

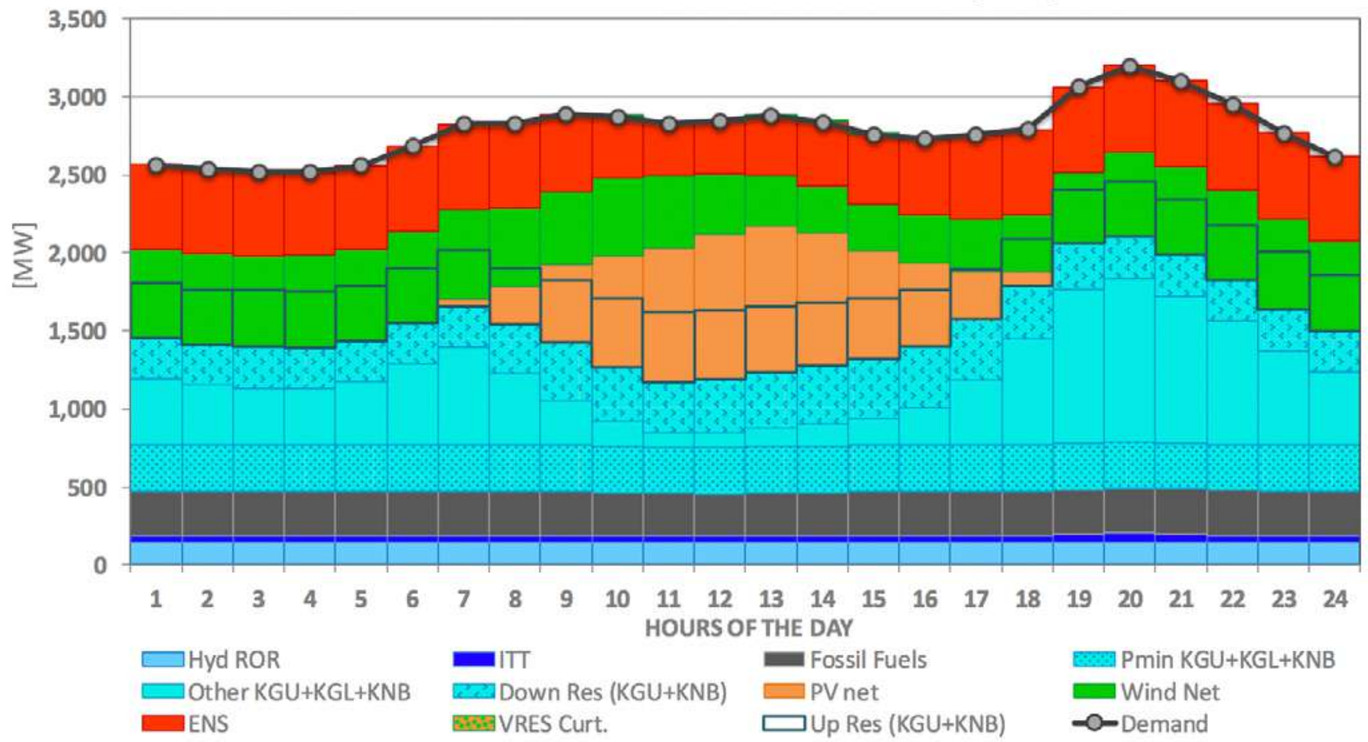


Figure 13.20 – Hourly generation and demand balance in the average day 2025 (ENH-LWA-ISO 2025)

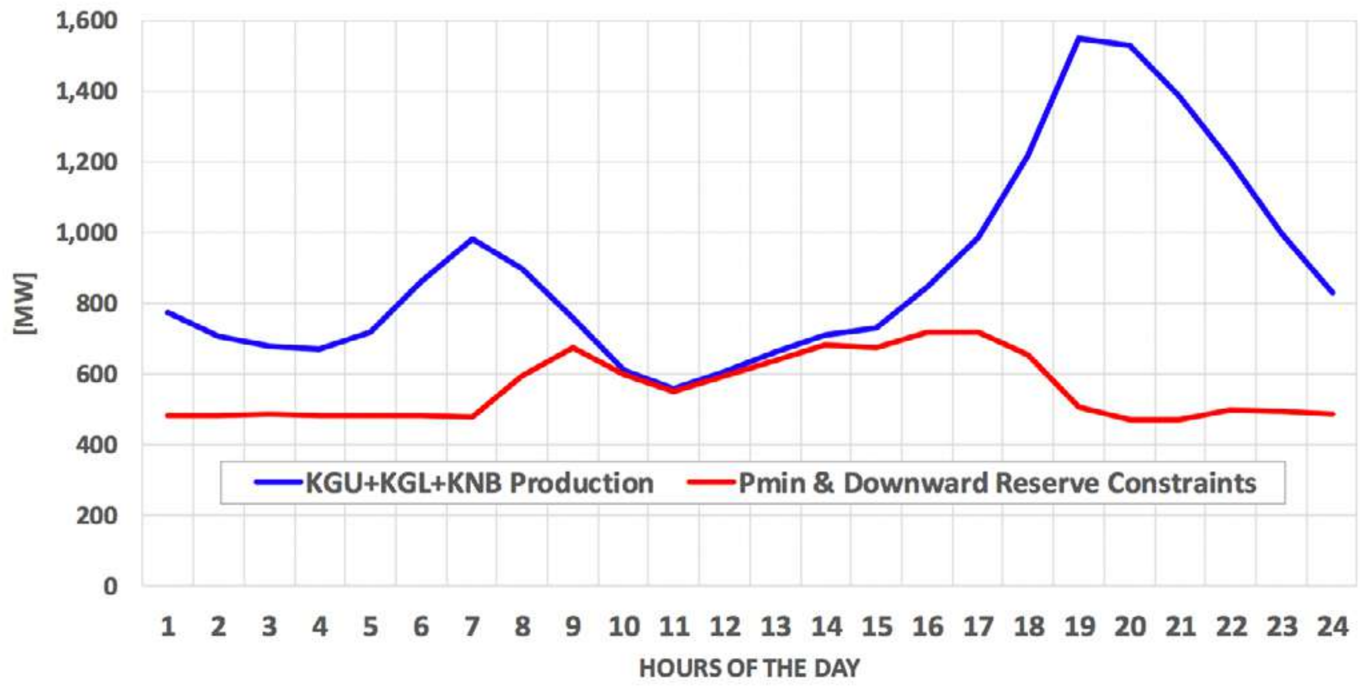


Figure 13.21 – Dispatch of Kafue Gorge (upper+lower) and Kariba North Bank power plants in the average day of September (scenario ENH-LWA-ISO 2025)

The interconnections with the neighbouring countries allow the import of energy to balance the demand (avoiding ENS) when the SAPP price is lower than the Zambian price and the export of energy when electricity from Zambia is cheaper than SAPP price, i.e. the central hours of the day. Figure 13.22 shows the energy balance of the average day 2030 in the interconnected scenario ENH-LWA 2030.

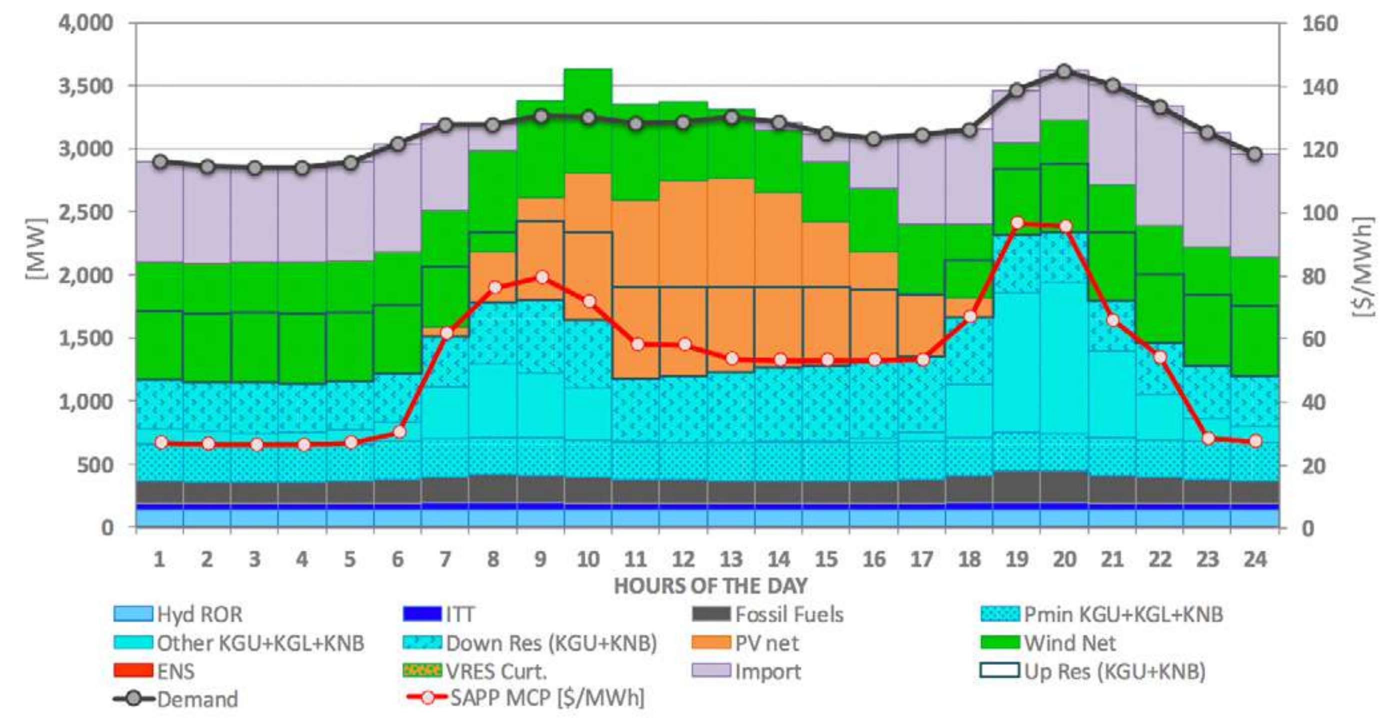


Figure 13.22– Hourly generation and demand balance in the average day 2030 (ENH-LWA-INT 2030)

In conclusion, the results obtained from the simulations performed for the ENH-LWA scenario considering the isolated and interconnected system in the two target years 2025 and 2030 show that:

- The lack of hydroelectric production, that was estimated around -33% of average production, due to low rainfall stresses even more the hydroelectric power system increasing the energy not supply;
- The reduced flexibility of the hydroelectric power system with low water availability and the reserve requirements supplied by hydro power plants needed to the VRES integration are responsible for a limited additional amount of VRES that can be integrated in the system in the isolated scenarios: less than 4% in both target years with respect to the ENH-NWA scenario;
- To meet the demand under the isolated country condition and low water availability new programmable capacity is advised: 750 MW installed capacity with 67% capacity factor within 2025 and 1,000 MW installed capacity with 75% capacity factor within 2030. Otherwise, the interconnections with the neighbouring countries would help to meet the energy demand assuring the security of supply without any additional programmable generation, both in 2025 and in 2030;
- The cost-benefit analysis of additional VRES integration exploiting the interconnections highlighted the opportunity to increase the VRES installed capacity up to +300 MW in 2030 (+125 MW from wind and +175 MW from PV technologies);
- The higher penetration of VRES in Zambia in case of interconnected system is fully exploited to cover internal demand and cannot be used for export towards neighbouring countries. Furthermore, the available transmission capacity is mostly exploited to import energy for the country security of supply.

13.2.1 Power system resilience

Climate change is impacting different phases of the electricity sector, and it is expected to continue in the future. Both long-lasting climatic changes and singular extreme natural events, which are becoming more and more frequent in the last decades, affects the demand, supply, production, transmission and distribution of electricity.

To lessen the climate change impact on the electricity sector, proper measures must be considered by planners and operators of the system not only assuring high levels of reliability but also improving the power system resilience. For a long time, only the concept of reliability was considered in the planning process and in the operation of the electric power systems; however, the increasing frequency of extreme natural events led the stakeholders to evaluate the system resilience as well. Even if these two concepts are similar, there are some crucial differences should be remarked to fully capture the importance of this new perspective:

- **Reliability:** it concerns the ability of the electric power system to deliver electricity in the quantity and with the quality demanded by end-users, considering scheduled and reasonably expected forced outages of system elements (Adequacy). Furthermore, reliability concerns the ability of the power system to resist sudden disturbances (e.g. as short circuits or the loss of system elements) from credible contingencies, while avoiding critical operating situations (Operating Reliability).
- **Resilience:** it is the ability of the electric power system to withstand and recover from shorter-term extreme, damaging conditions or immediate physical shocks and as longer-term climate changes occur. A resilient system is the one that acknowledges that long-duration outages can occur, prepares to manage them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future meeting the reliability of the system. Resilience has reliability as a final goal, and it directly impacts the reliability.

The resilience concept is based on the idea that disruptive events occur regularly and that systems should be designed to adapt quickly because the impact was less. An energy diversification strategy in the electricity sector is one solution that can support both short- and long-term resilience of a power system affected by climate change.

The Zambian generation system is closely dependent from hydropower; about 85% of current energy production is from hydro power plants and a high exploitation of water for electricity sector will continue in the future. In this context, more frequent drought periods and changes in rainfall patterns due to climate change is expected to create or worsen the energy supply to meet both domestic demand and bilateral agreements with the neighbouring countries.

Diversifying the energy mix to include technologies with low water use needs, such as wind and photovoltaic, could offer an important technical solution for Zambia that is highly dependent on hydro technology and may face current and future water challenges related to climate change. Thanks to the very good potential of VRES and the important generation fleet flexibility in the country, wind and PV technologies can play unique and important roles relative to traditional technologies. VRES power plants are few impacted by climate change and they can compensate the lack of hydropower if more frequent low rainfall periods will occur in the future, as shown by the simulations of enhanced VRES deployment scenarios with low water availability (ENH-LWA).

Therefore, considering the lower environmental impact with benefits on reducing GHG emissions (and the climate change), the growing cost reduction with costs always closer to the less expensive sources and the technological improvements achieved in the last years to reach the best source exploitation, wind and PV technologies can be considered good solutions to improve the resilience of the Zambian electric power system. They would help the Zambia's electricity sector cope with the lack of hydropower, maintaining high standards of reliability in case of low rainfall periods or droughts.

13.3 Sensitivity scenario with high water availability

Starting from the optimal mixes of wind and PV capacities selected for the scenario with normal water availability presented in the previous paragraph 13.1, a sensitivity analysis has been performed assuming a greater water availability for the electricity production to simulate the impact of a wet year. The Consultant increased the hydro power production up to 22.4 TWh/year (+44% compared to normal water availability scenario) and analysed the impact on the optimal wind and PV capacity assessed under the normal hydrological condition and recalled in Table 13.3. This sensitivity scenario aims to highlight possible dispatch challenges and VRES curtailments under the wettest conditions, comparing the results of simulation without and with power exchanges with the neighbouring countries.

Table 13.3 – Optimal PV and wind capacity mixes for isolated and interconnected ENH-NWA scenarios

Scenario	Type	Unit	Existing	Additional	Total	Delta INT-ISO
2025 ISO-NWA	WIND	[MW]	0.0	1,200	1,200.0	-
	PV	[MW]	75.6	1,100	1,175.6	-
	TOT VRES	**[MW]**	**75.6**	**2,300**	**2,375.6**	**-**
2025 INT-NWA	WIND	[MW]	0.0	1,600	1,600.0	+400
	PV	[MW]	75.6	1,500	1,575.6	+400
	TOT VRES	**[MW]**	**75.6**	**3,100**	**3,175.6**	**+800**
2030 ISO-NWA	WIND	[MW]	0.0	1,400	1,400.0	-
	PV	[MW]	75.6	1,300	1,375.6	-
	TOT VRES	**[MW]**	**75.6**	**2,700**	**2,775.6**	**-**
2030 INT-NWA	WIND	[MW]	0.0	1,900	1,900.0	+500
	PV	[MW]	75.6	1,750	1,825.6	+450
	TOT VRES	**[MW]**	**75.6**	**3,650**	**3,725.6**	**+950**

Histograms in Figure 13.23 allows to compare the different country energy balances, in the two target years and in case of isolated or interconnected system, with respect to the results from ENH-NWA case. Differently from the results presented in 13.1 and 13.2, the higher availability of water for hydroelectric production leads to significant over-generation values in ENH-HWA isolated scenarios, hence amount of exceeding energy production that cannot be integrated in the system in case of isolated system (69% in 2025 and 37% in 2030). The interconnections with the neighbouring countries allow the full exploitation of Zambian resources avoiding production curtailments and the energy not supplied (ENH-HWA-INT scenarios).

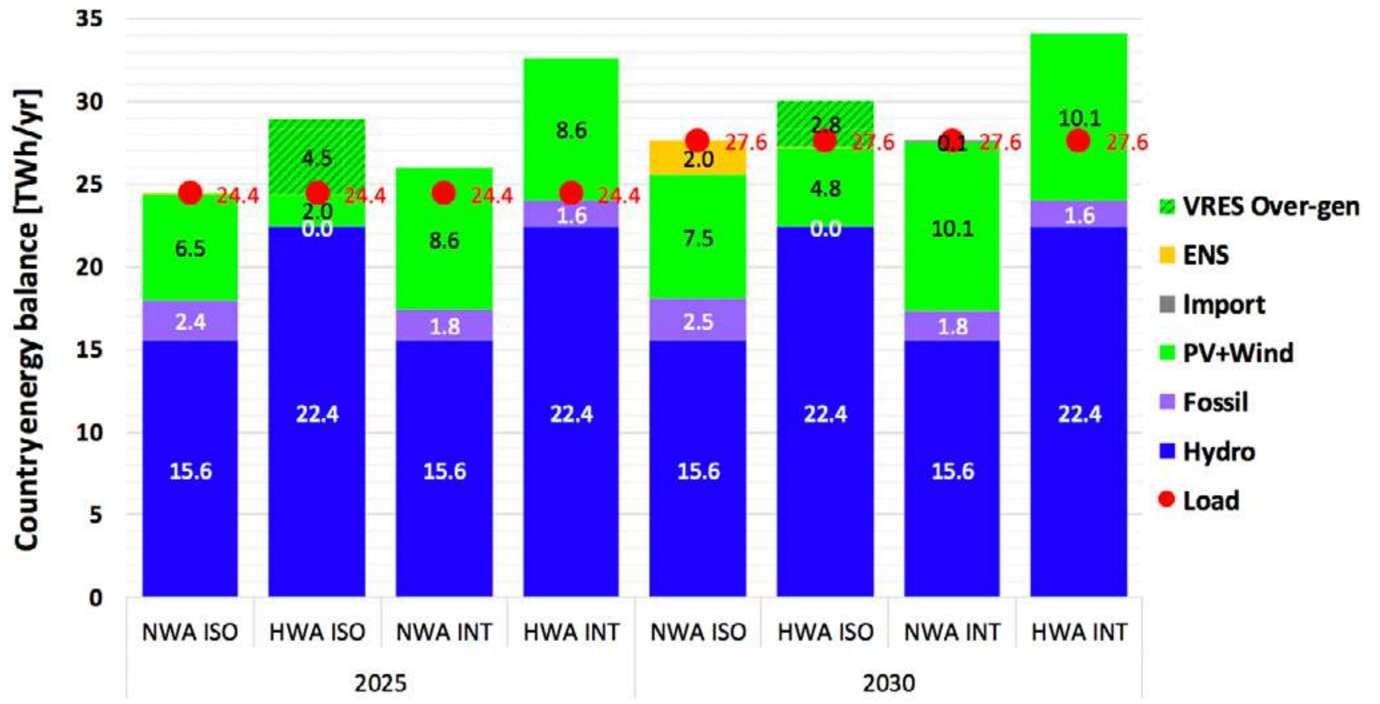


Figure 13.23 – Country energy balance for isolated and interconnected Zambia - ENH-HWA 2025 and 2030

From the duration curves of the ENS and over-generation in case of isolated country system in Figure 13.24 it is evident that a larger amount of energy production from VRES additional capacity is not integrable in the system, in fact the null amount of energy curtailment in the ENH-NWA scenario strongly increases in case of ENH-HWA cases.

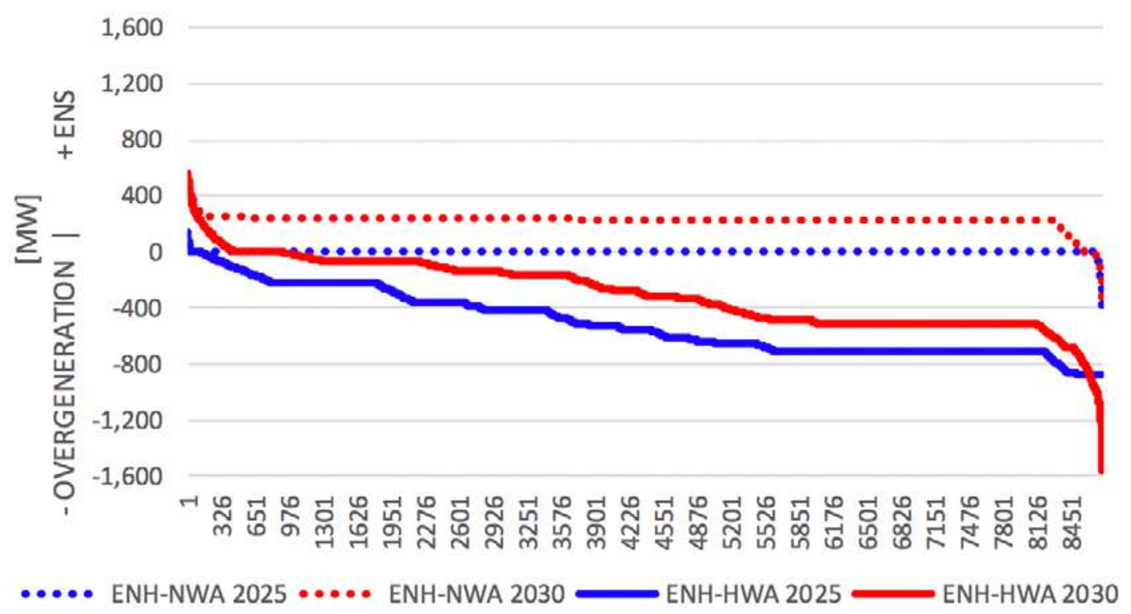


Figure 13.24 Duration curve of ENS – OG for Isolated Zambia – ENH-HWA in 2025 and 2030

The need of VRES energy curtailment is reduced (over-generation reaches null values) in case of interconnected scenarios; this result derives from the different import/export profiles (Figure 13.25 and Figure 13.26). Differently from the ENH-NWA scenario, Zambia both in 2025 and 2030 exports energy towards the rest of SAPP even during months characterized by relatively low average electricity prices. Zambia becomes a net exporter. Trading opportunity allows the demand-generation balance reducing VRES curtailments increasing the export. A greater water availability compared to NWA scenario leads to +136% export and -83% import in 2025, and +138% export and -80% import in 2030. 0.3 TWh/year import and 8.3 TWh/year export are expected in 2025, while 0.6 TWh/year import and 6.7 TWh/year export are expected in 2030.

The import-export duration curves of ENH-HWA interconnected scenarios are compared with those of ENH-NWA interconnected scenarios in Figure 13.27.

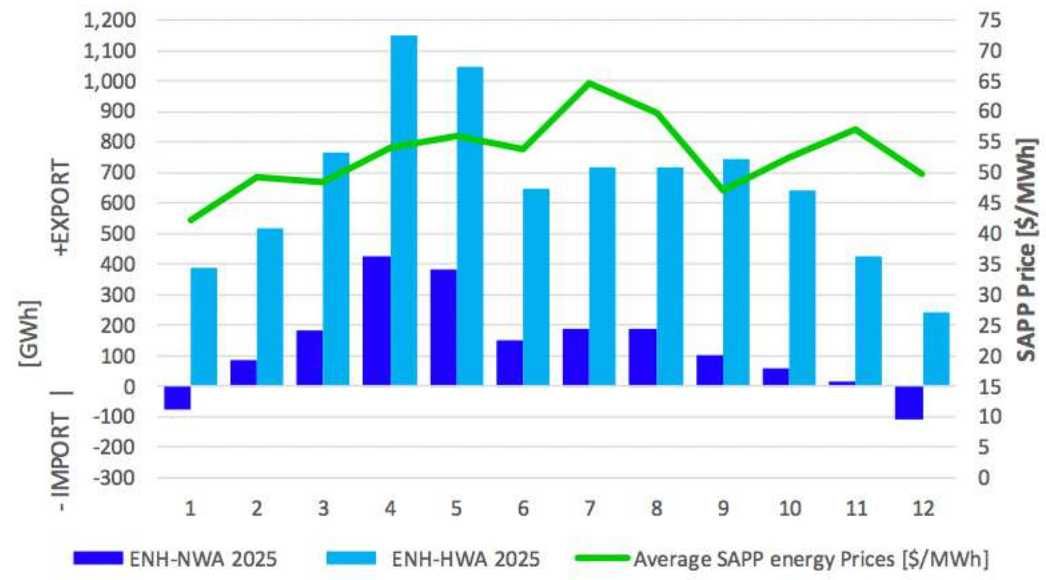


Figure 13.25 Monthly import-export energy profile on the competitive market – ENH-HWA in 2025

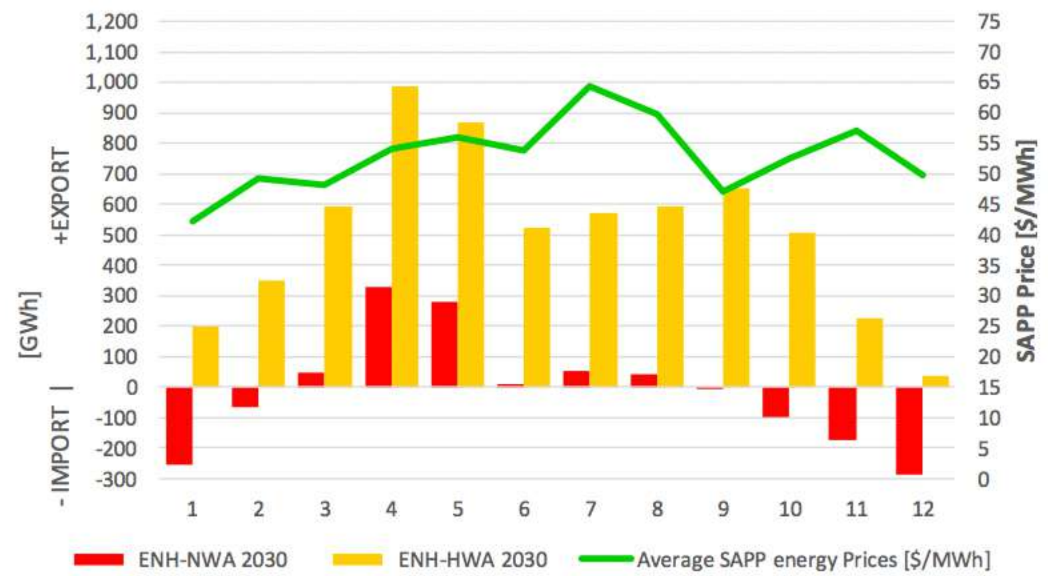


Figure 13.26 Monthly import-export energy profile on the competitive market – ENH-HWA in 2030

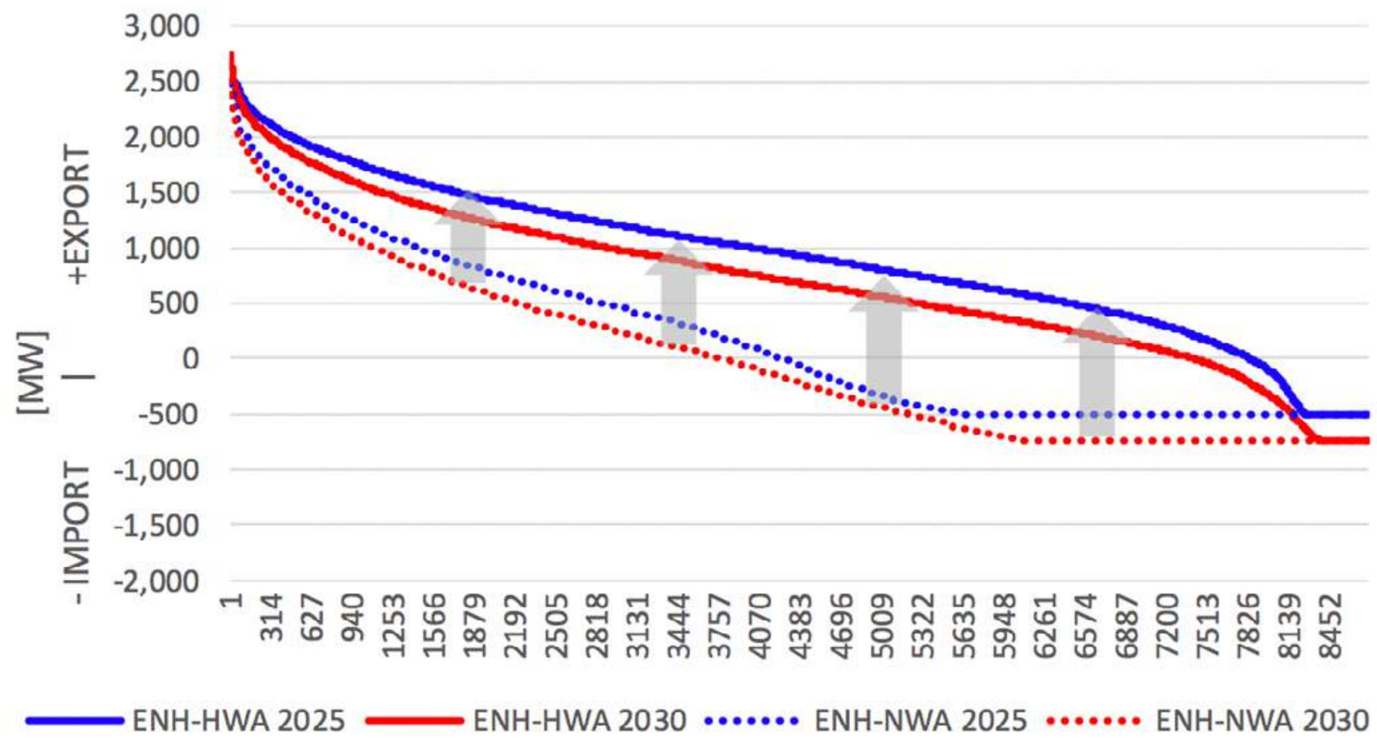


Figure 13.27 - Import-export duration curves on the competitive market (ENH-HWA 2025 and 2030)

Figure 13.28 and Figure 13.29 show the dispatching of power generating sources during the average day 2030 to balance the average hourly demand, comparing scenario with normal water availability (NWA) with high water availability scenario (HWA). The first figure is referred to the isolated scenario in which not all the optimal VRES capacity calculated in ENH-NWA scenario (1,400 MW wind and 1,376 MW PV installed capacities) can be integrated in the Zambian electric power system; high production curtailments result in the wet year. While the second figure shows the average day for the interconnected scenarios (1,900 MW wind and 1,826 MW PV installed capacities); with high water availability (wet year) the generation greater than the national demand can be exported to the neighbouring countries exploiting the wide net transfer capacity foreseen in the mid- and long-term and the competitive market, and allowing the full integration of the optimal VRES capacity calculated in ENH-NWA scenarios.

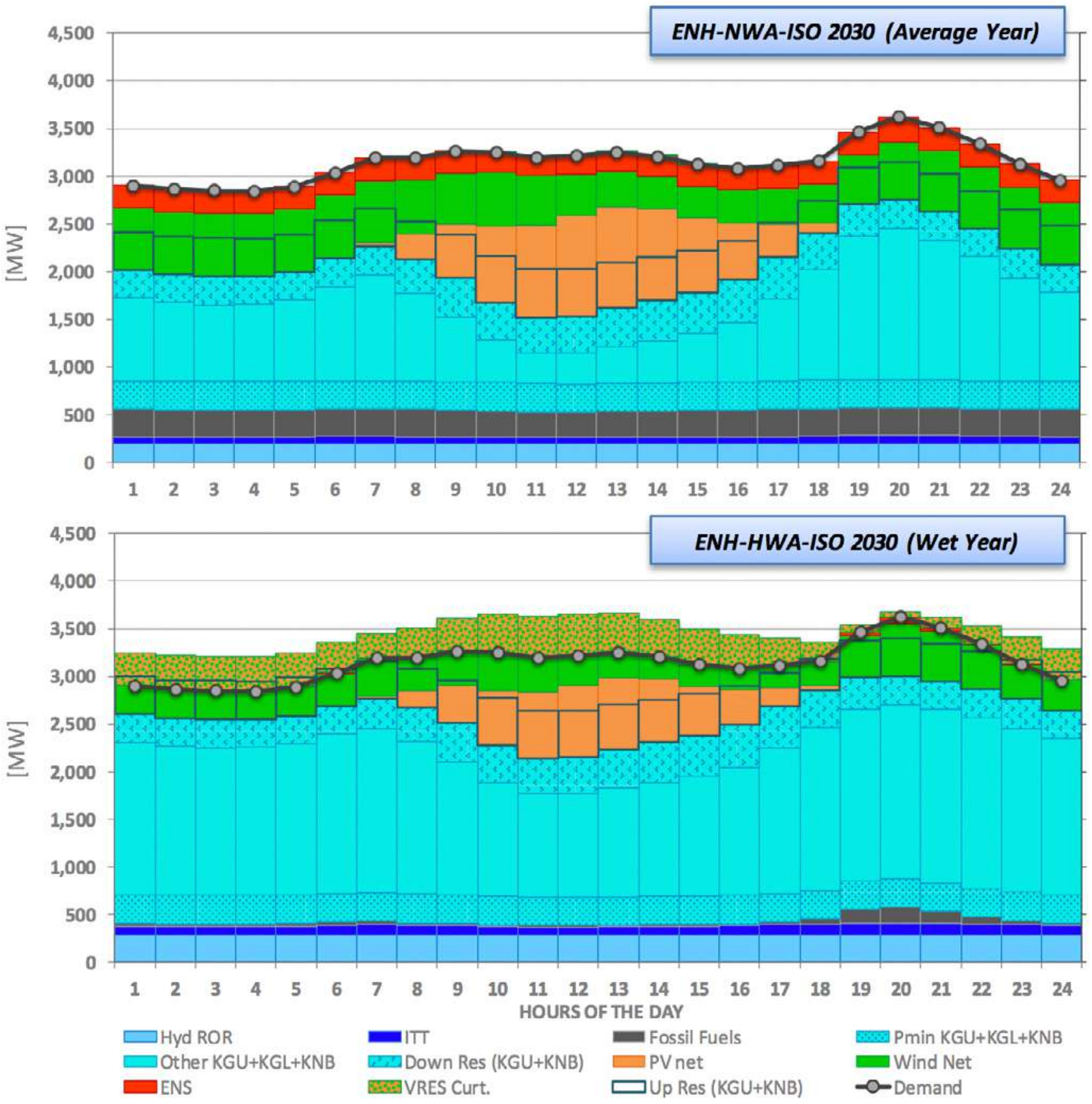


Figure 13.28 – Hourly generation and demand balance in the average day, Average Year vs Wet Year in isolated scenarios 2030

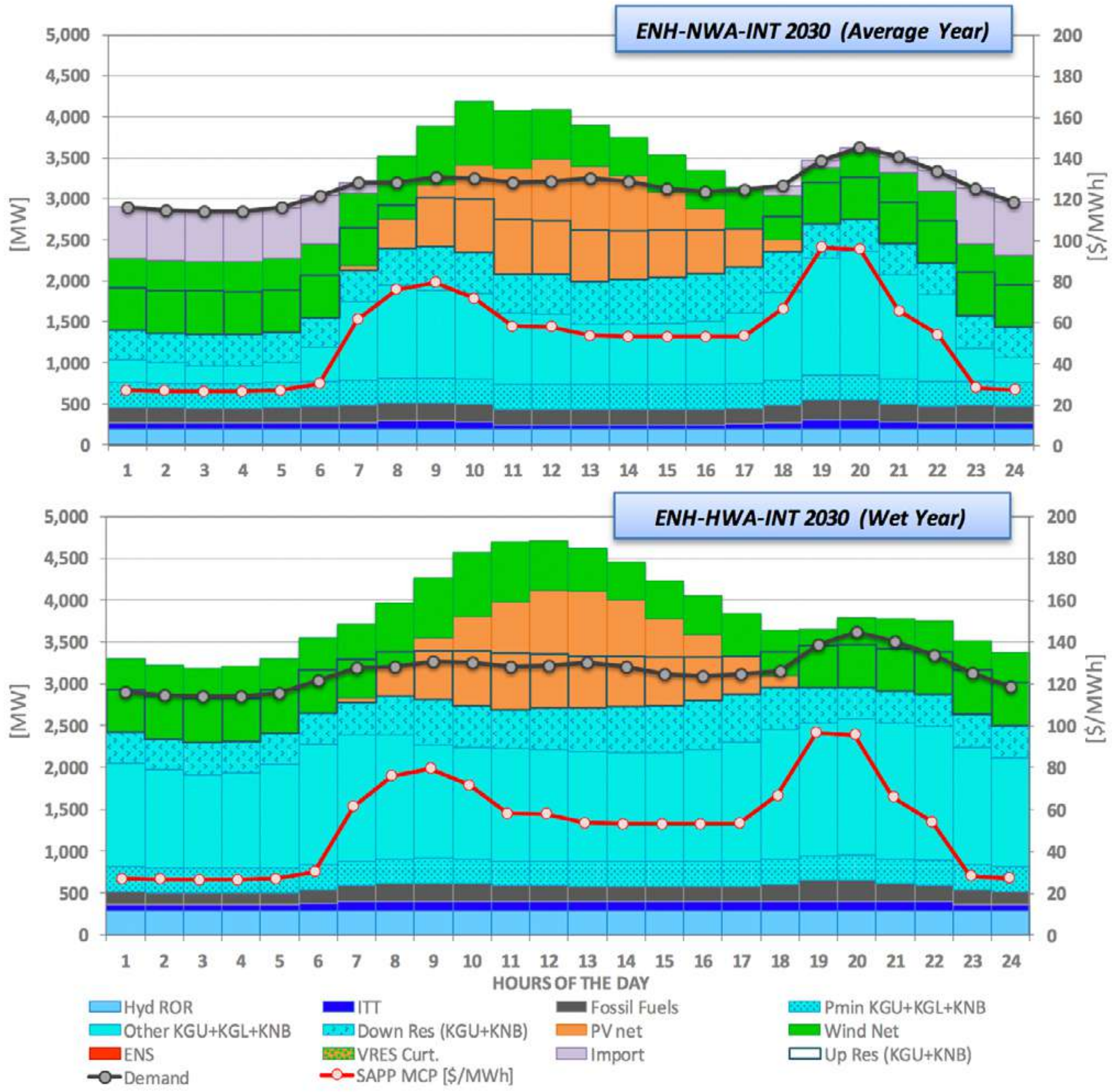


Figure 13.29 – Hourly generation and demand balance in the average day, Average Year vs Wet Year in interconnected scenarios 2030

Finally, it is possible to draw, from the results obtained for the ENH-HWA scenario, the following conclusions:

- higher water availability, with fixed VRES mix installation from ENH-NWA scenarios, lead to the necessity for VRES energy curtailment in case of isolated Zambia scenario and to the maximization of energy exchanges towards neighbouring countries in case of interconnected system.
- In both isolated and interconnected scenarios, the higher amount of water available and the hydroelectric power plants flexibility allow to fulfil the National demand (including firm export) without any dependency on import from other countries.

The maximum VRES capacity mixes assessed in Task 3 neglects transmission network constraints that could limit their integration, hence additional analyses focused on the transmission grid impact and the security of supply have been carried out in the next Task 4. The network impact of the optimal wind and PV capacity mixes resulting from the ENH-NWA interconnected scenarios 2025 and 2030 was studied.

TASK 4 – SYSTEM RELIABILITY IMPACT STUDY

14 OBJECTIVES AND SCOPE OF WORK

The objective of this task is to assess the impact of variable renewable generation on the reliability, efficiency and security of the Zambian electric power system with a specific focus on transmission network constraints that could limit the integration of cost-effective VRES capacity assessed in the previous Task 3, for both years 2025 and 2030. The optimal mixes of wind and PV capacities resulting from simulations performed in Task 3 under the reference scenario ENH-NWA (enhanced VRES deployment with normal water availability) have been incorporated in the transmission network analysing the ability of the network to operate the additional VRES installed capacity. The impact of the optimal VRES capacity is studied considering the operation of the Zambian electric power system both as an isolated system and as a system interconnected with the neighbouring countries.

The probabilistic approach (Monte Carlo method) is applied at the system operation to cover as much as possible all operating conditions expected during the year (both for the horizon year 2025 and 2030). GRARE simulation tool is used to perform a quantitative assessment of the static reliability and adequacy of the Zambian power system. Furthermore, the network loadability criteria is used to evaluate the maximum wind and PV capacities that can be integrated in the system to fulfil both technical and economic constraints.

More in detail, the objectives of the system reliability impact study are to:

- check if the electric power system follows the applicable Zambian reliability standards also in presence of variable RES. An evaluation of generation and transmission network adequacy has been carried out by means of the reliability indexes (EENS, LOLE and LOLP) to assess the security of supply level, without and with new VRES power plants;
- highlight possible transmission network congestions due to the new VRES installed capacity and the risk of VRES production curtailment that limit VRES integration in both horizon years;
- propose network reinforcements, in addition to those already decided by ZESCO for the horizon years, if they are cost-effective to maximise the VRES integration in the system.
- Unlike Task 3, the system reliability impact study allows the in-depth analysis of the Zambian transmission network during an entire year of operation. The full network model of the Zambian electric power system is considered together with the stochastic behaviour of some key parameters like wind and solar productions, forced outages of network elements (lines and transformers) and generation units.
- For each target year, 2025 and 2030, the following VRES capacity mixes have been checked in the transmission network assuming an average water availability condition:
- the existing VRES installed capacity (EVR): 75.6 MW PV installed capacity both in 2025 and 2030;
- enhanced deployment of VRES with normal water availability and isolated electric power system (EHN-NWA-ISO):
  - 2025: 1,200 MW wind and 1,176 MW PV installed capacities;
  - 2030: 1,400 MW wind and 1,376 MW PV installed capacities;
- enhanced deployment of VRES with normal water availability and interconnected electric power system (EHN-NWA-INT):
  - 2025: 1,600 MW wind and 1,576 MW PV installed capacities;
  - 2030: 1,900 MW wind and 1,826 MW PV installed capacities.

The comparison between EVR scenario and the scenarios with an enhanced development of VRES capacity is performed to assess the impact of additional wind and PV capacities on the power system.

Figure 14.1 – Reference scenarios for the system reliability impact study

15 METHODOLOGY AND ASSUMPTIONS

This section shows the methodology and the analysis process for reliability analysis of Zambian electric power system including variable RES.

GRARE (Grid Reliability and Adequacy Risk Evaluator) simulation tool has been used to analyse the system reliability impact study of variable renewable generation. GRARE is the tool of Terna (the Italian TSO), developed by CESI, that evaluates reliability and economic operational capability of an electric power system using probabilistic Monte Carlo analysis. GRARE support medium and long-term planning studies and is particularly useful for evaluating the reliability of large power systems, modelling in detail the transmission networks. GRARE is integrated in SPIRA application, that is designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) and is based on a network database of the system being analysed (www.cesi.it/grare). The technical description of GRARE simulation tool is included in Annex 3 – GRARE simulation tool.

In the framework of this study, GRARE simulation tool is used to perform a quantitative assessment of the static reliability and adequacy of the Zambian power system. The reliability analysis is carried out in a probabilistic way by using the Monte Carlo approach to simulate the inherent probabilistic nature of the composite generation and transmission system behaviour.

15.1 Model description

In-depth models of the Zambian electric power system expected in the mid- and long-term (2025 and 2030) have been developed including the full Zambian grid model (330-220-132-88-66 kV) to the model already developed in Task 3. Starting from the PSS/E models 2025 and 2030 updated and validated by ZESCO according to the most recent transmission expansion plan, the Consultant converted PSS/E models (static models) in SPIRA format to perform the probabilistic simulations with GRARE tool. Furthermore, before starting with the simulations, the Consultant proceeded to update the power system database for all target years as follow:

- The Zambian transmission network model has been extracted by the SAPP model, with all interconnection lines with the neighbouring countries.
- An equivalent model of the neighbouring countries has been set up for the interconnected scenarios, based on the historical data (2018) of the SAPP marginal clearing price and the net transfer capacity expected for the target years. No changes in SAPP prices were considered, assuming a generation development with a business as usual approach. About the Zambian exchange capacity with the neighbouring countries, the Consultant assumes an import capacity enough to avoid the load shedding (500 MW in 2025 and 750 MW in 2030) and an export capacity equal to 45% of the expected net transfer capacity, based on historical data.
- An update of the Zambian loads has been carried out according to the demand forecast (section 6.1); furthermore, an hourly time-series of national demand has been included in GRARE model to simulate a whole year.
- The power generation system has been updated according to the generation expansion plan defined in section 6.2. Committed and candidate VRES projects indicated by the working group have been included according to the provided grid connection points; additional VRES power plants resulting by the Task 3 of the study have been included in the system considering the locations with the best wind/solar potential and the strength of the national grid.

The adequacy of the Zambian electric power system in presence of VRES capacity is determined by means of a simulation model of the system operation linked to the probabilistic Monte Carlo method, using the statistical sampling based on a "Sequential" approach.

The method simulates the performance of the system in an assigned year by the generation of a large quantity of scenarios, determined in a random way, based on which the operating policies are applied. For the analyses of the Zambian electric power system, for each scenario (2025 and 2030), the Consultant simulated 500 Monte Carlo Years (MCYs), each one composed by 52 weeks with each week independently optimized. One MCY is a simulation year in which a mix of Monte Carlo variables is applied to consider the stochastic behaviour of some power system parameters: load forecast error, forced outage rate of generation fleet and network elements (lines and transformers), wind and solar productions.
For this specific activity, the Consultant considered the following:

- The sequential approach has been adopted as statistical sampling method. For each of 500 MCYs simulated, the weeks are sequentially extracted from week 1 to week 52;
- For each week, several possible system configurations are defined in a random manner based on fault probabilities of generation units, lines and transformers, the scheduled maintenance of power plants and the distribution of demand;
- The complete model of transmission and sub-transmission network of Zambian electric power system has been considered; while only an equivalent model of the neighbouring interconnected countries has been considered to simulate the operation in SAPP;
- The actions by the system operator (start-up and dispatching of units and any adjustments) are simulated to obtain either the best reliability of the supply, ensuring the system security and minimizing system costs;
- The variables of interest both for planning and design of the transmission system (load shedding and reliability indexes) are calculated using the formulation in "direct current" of the network equations. Consequently, load and production system are only considered for the active component of the respective absorbed or generated powers;
- The intermittency of wind and solar generation is considered, as well as the forecast errors of these renewable energy productions. In addition, the forecast error of power demand is considered in the probabilistic model;
- The upwards and downward operating reserve requirements in presence of VRES generation have been considered according to the results of Task 2.

15.2 Definition of risk indexes

The quantitative evaluation of static reliability of the electric power system (adequacy) is obtained through the calculation of risk indexes that expresses, as a probability, the comparison between the values of the load to be supplied and the value of the production and transmission systems capacities. The following indexes have been evaluated with GRARE simulation tool and have been used for the analysis of system reliability:

- **Expected Energy Not Supplied (EENS)**: this index represents the yearly expected average energy value of not supplied load (MWh/year or p.u. of annual demand) due to unavailability in the generation and/or transmission system considering the restrictions set by the power transfer capacity of the lines and transformers and the power limits of the power plants.
- **Loss of Load Expectation (LOLE):** the number of hours in which the entire demand cannot be served (hours per year).

- **Loss of Load Probability (LOLP):** probability (%) of not being able to cover the weekly peak load (52 hours per year).

The risk indexes calculated are defined as "static indexes" because they do not consider transient phenomena that occur during the system faults. EENS, LOLE and LOLP are calculated by GRARE for the following causes of load shedding:

- **Lack Of Power (LOP)**: the dispatched power plants of the whole system are not being able to meet the demand;
- **Lack of Interconnection (LOI):** the exchange capacities between countries are not enough to cover the import needs of each area;
- **Line/Transformer Overload (LTO):** overload of network elements (lines and transformers) inside the areas that cannot be removed through the re-dispatching of generation units;
- **Network Splitting (NSP):** formation of network islands with demand greater than generation, due to the unavailability of one or more links (line or transformer) in the network;
- **Isolated Node (ISN):** out of service of one line or transformer which causes an isolated load.

Since the EENS is a system parameter, it depends by the mutually influence between programmable productions and variable RES generations. Therefore, to assess the impact of new VRES power plants, scenarios with existing VRES power plants and with additional VRES generation were evaluated to compare the system results.

According to Zambia Bureau of Standard and the international practises, the Consultant applied the following limits to evaluate the adequacy of generation and transmission system in presence of big amount of variable RES: LOLE ≤ 48 h/year[22] , LOLP ≤ 1%[23] , EENS ≤ 1.10-4 p.u. of the yearly demand14.

These bounds are referred to all the above-mentioned causes of load shedding (lack of power, lack of interconnection, line/transformer overload, network splitting and isolated node). The Zambian electric power system can be considered adequate to cover the expected demand if EENS, LOLE and LOLP are less or equal than bounds.

15.3 Description of the procedure

For the application of the Monte Carlo method to system operation, the following assumptions are considered:

- The period of a year, for which system behaviour is examined, is divided into elementary intervals (1 hour). During each interval the system does not suffer variations, supposing they take place at the beginning of the interval;
- The state of the electric system is characterised by the following elements:
  - load of each node;
  - unavailability of generation units, lines and transformers;
  - production availability from wind and solar power sources;
  - operational policies (putting into service of groups and possibility of re-dispatching to solve network overloads).

[22] According to the Zambia Bureau of Standard ZS-387-1 2011, Annex D, Commercial and small to medium industrial

[23] International standard

- The variations in the system state are determined by:
  - casual events, therefore unexpected for the persons in charge of system operations, which cause variations both in the reliability of network components and in the production from variable RES power plants and on the load value;
  - actions on dispatching to adapt the system state to the above-mentioned configuration variations.

The calculation procedure included in the probabilistic model used for the analysis can be summarised in the following steps:

- Starting from an electric power system in which the following characteristics are known:
  - the topological features of the system (features of the network elements: nodes, lines, transformers, power stations, generators and loads);
  - the load figures;
  - the set production curves;
  - the forced unavailability rates values of the system components (generators, lines and transformers) and eventually their programmed maintenance plan;
  - the distribution of the energy capability forecast for wind and solar power parks;
  - characteristics of hydro power plants and availability of water during the year.
- An optimized maintenance plan of conventional power plants is calculated considering the residual load distribution over the year.
- The exploitation of hydro sources during the year is optimized considering the water value as an opportunity cost for water in respect to other generation sources.
- A sequence of casual generation system configurations is created extracting from each of them the generators to be considered accidentally faulted, coherently with their relative forced unavailability rates.
- The procedure associates each random configuration to the sequential weeks of the year which is compared with the programmed maintenance plan of the generators, supplying further information regarding components to consider in contingency.
- The respective diagrams of weekly load, power stations production that cannot be modulated (set production) and the productions of wind and PV power plants, randomly extracted based on their production probabilistic distributions.
- Each configuration generated in this way undergoes simplified simulation of operation iterating a procedure that sequentially scans each load situation defined in the weekly diagrams. The results obtained are referred to a single elementary interval but are representative of the average conditions in the space of an entire week[24] ;
- The procedure initially defines the weekly Unit Commitment (UC) for each hour of the week, considering the quadratic cost functions of the available power plants to determine the programmable thermal units to be considered in the analysis. In this phase the technical constraints of the network are not considered.
- The optimised hourly dispatching of units selected by Unit Commitment on the simplified network model is defined (bus-bar model of the whole system), based on quadratic cost functions while considering Joule losses. In this step the network constraints are not considered yet, therefore the expected energy produced by the power plants failing the network's limits could be evaluated.
- An optimised re-dispatching of units, with quadratic cost functions and considering the Joule losses, is performed to eliminate or to minimise any possible violation of local network constraints (lines or transformers overloads) during the analysis of the whole system (complete network model).
- Finally load-shedding policies are carried out when the re-dispatch actions were not enough to solve the overloads.

[24] This because, if the probability of forced fault and the programmed contingencies are constant during a given week, a casually extracted configuration has the same probability of occurring in each elementary interval of the week and the relative adequacy of the system can be calculated by exploring all the load conditions of the week and weighing the results with the corresponding probability.

- The simulation model also allows estimating the values of the main operating results such as:
- generators production (for each generator: produced energy, yearly hours of activity, average incremental cost, unserved energy due to transmission restrictions);
- data regarding network congestion (for each critical line: hours/year in which re-dispatching and marginal gain is required);
- risk of VRES generation curtailment due to network congestions.

The layout of the algorithm in following Figure 4.4 graphically represents the sequence used to perform a test simulation using the Monte Carlo method.

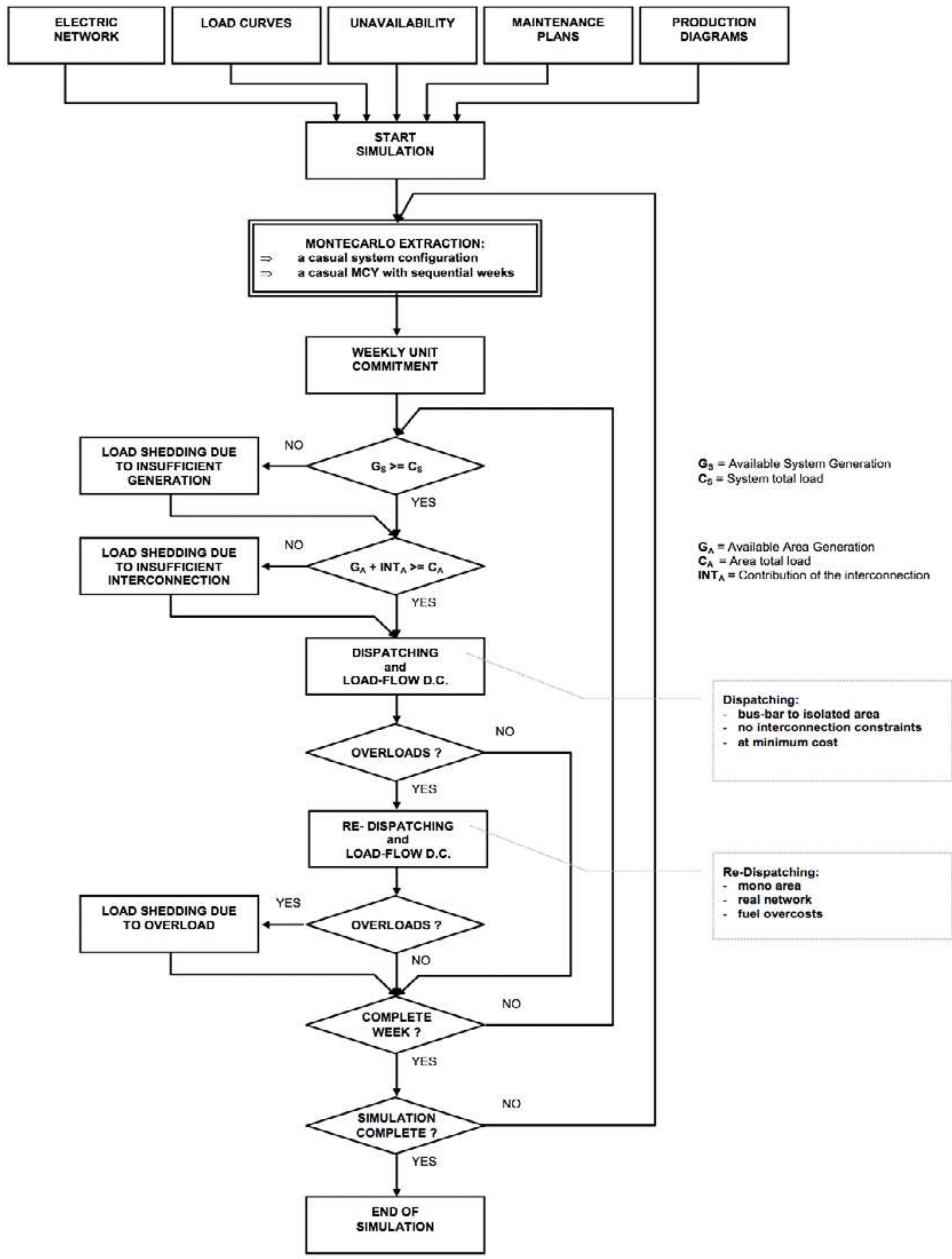


Figure 15.1 – Simplified layout of the simulation procedure

16 RESULTS OF SYSTEM RELIABILITY IMPACT STUDY

16.1 Medium and long term scenarios

Figure 16.1 shows the locations of wind and PV projects included in the Zambian transmission network to evaluate the grid impact of the optimal VRES capacity. Committed and candidate projects indicated by ZESCO in section 6.2.3 have been included in the system, in the agreed PCC; while additional VRES installed capacity has been integrated in the sites with the best potential for wind and PV projects and the network availability. The central and south-west regions are suitable for PV projects while the central and north-east regions own the best potential for wind power plants development.

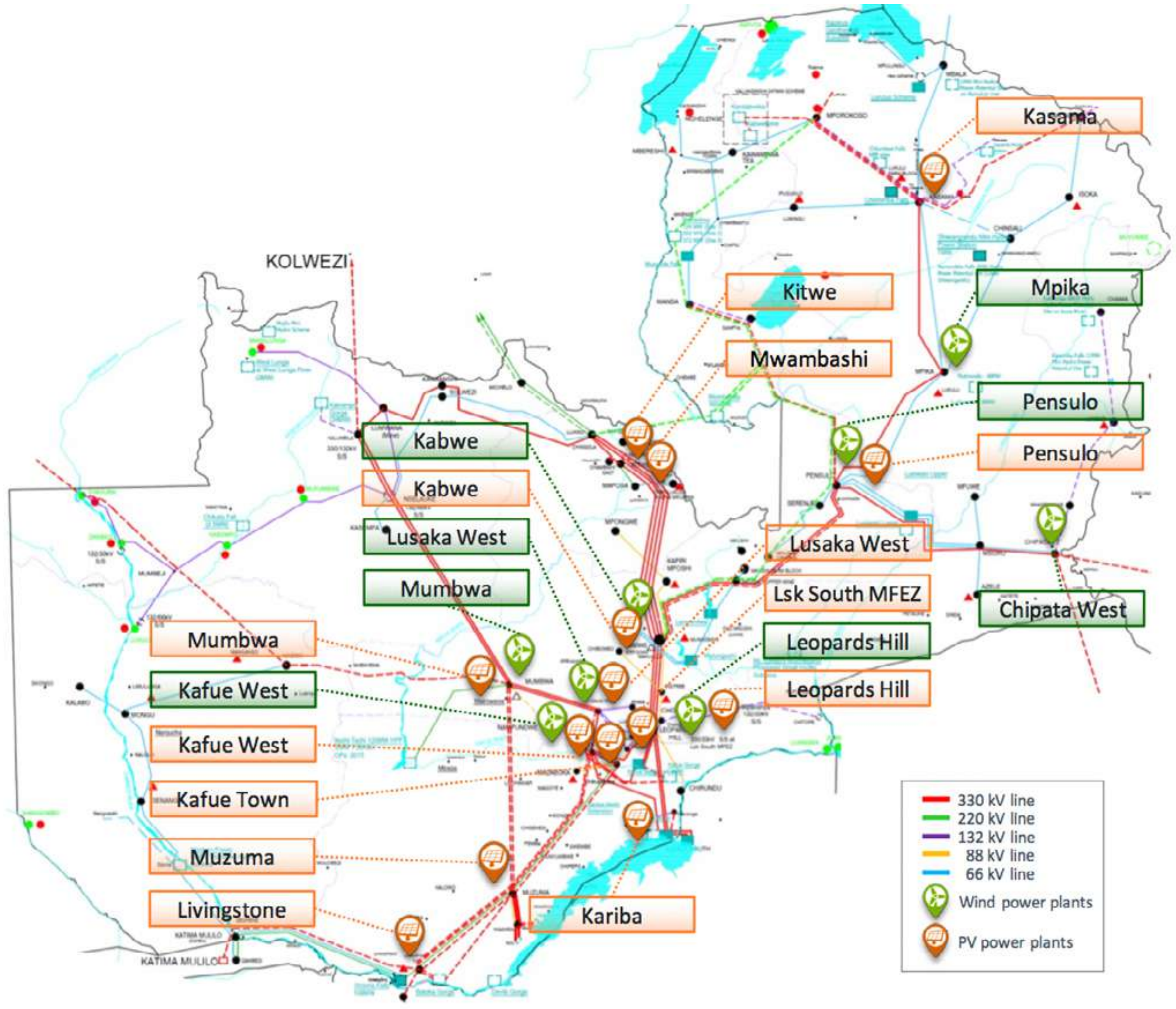


Figure 16.1 – Wind and PV projects locations in the Zambian transmission network

The simulation of the electric power system operation and the analysis of network constraints carried out on the transmission networks defined by ZESCO for the target years 2025 and 2030 highlighted the ability of the grid to integrate big amount of VRES capacity both in the mid- and long-term.

The network reinforcements already established by ZESCO in the long-term transmission grid expansion plan will allow the full integration of the optimal VRES installed capacity assessed in Task 3 for the horizon years 2025 and 2030. Therefore, no additional network reinforcements are suggested to increase VRES integration. Some additional network reinforcements have been suggested to increase the security of supply in the mid- and long-term, but they are needed to meet the growing demand and not the VRES integration. The VRES integration will not affect the security of supply.

Table 16.1 and Table 16.2 show the values of PV and wind capacities that can be integrated at each substation, in ENH-NWA-ISO and ENH-NWA-INT scenarios, resulting from system reliability and network impact study. These capacities comply with the grid code reliability standards in Zambia (line and transformer loadings lower than or equal to 100% of transfer capacity) and the maximum VRES energy integration minimizing energy curtailments due to network overloads or over-generation phenomena. They are a subset of capacities evaluated in Task 3, therefore they are convenient for the whole interconnected system.

Table 16.1 - Maximum PV installed capacities at each substation (ENH-NWA scenario)

	PV installed capacity [MW]			
S/S	ISO 2025	ISO 2030	INT 2025	INT 2030
Kabwe	140	190	140	140
Kafue Town	40	40	40	40
Kafue West	100	100	150	150
Kariba	90	90	90	90
Kasama	-	-	-	50
Kitwe	-	100	100	100
Leopards Hill	150	150	200	250
Livingstone	50	50	100	150
Lusaka West	-	50	100	150
Lsk South MFEZ	76	76	76	76
Mumbwa	170	170	220	220
Muzuma	220	220	220	270
Mwambashi	40	40	40	40
Pensulo	100	100	100	100
TOTAL	1,176	1,376	1,576	1,826

Table 16.2 - Maximum wind installed capacities at each substation (ENH-NWA scenario)

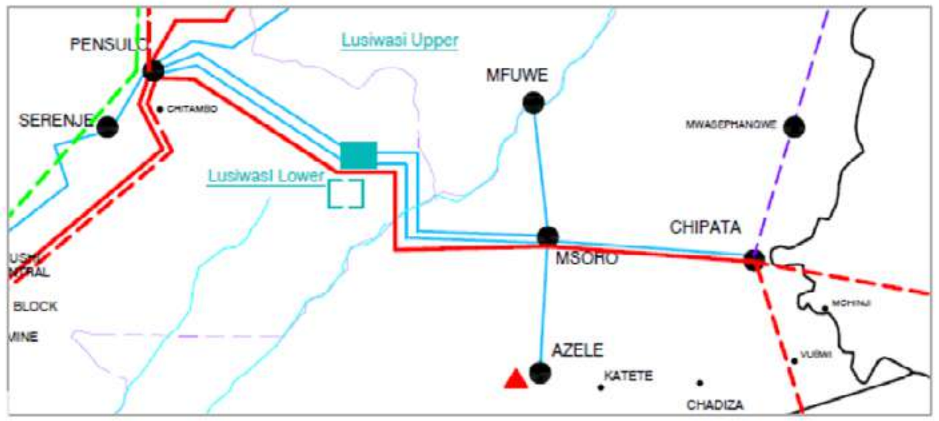
Wind installed capacity [MW]				
S/S	ISO 2025	ISO 2030	INT 2025	INT 2030
Kabwe	150	200	200	200
Kafue West	100	100	200	250
Leopards Hill	250	250	300	300
Lusaka West	150	150	200	250
Mpika	100	250	100	250
Mumbwa	170	170	220	220
Pensulo	280	280	280	330
Chipata West	-	-	100	100
TOTAL	**1,200**	**1,400**	**1,600**	**1,900**

Network loadability

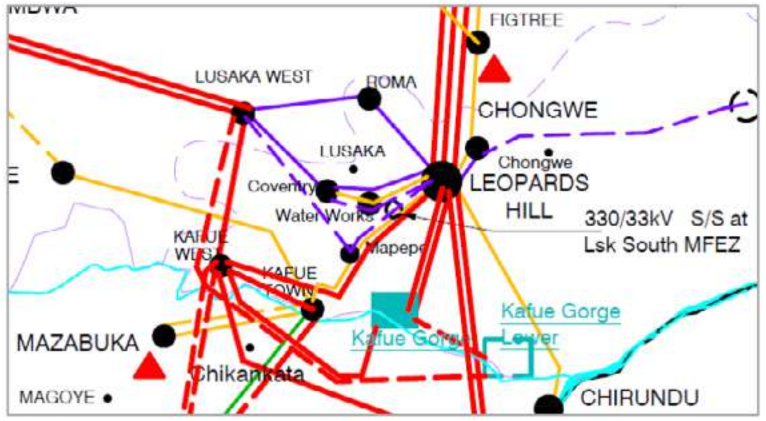
The analysis of transmission network loadability from probabilistic simulations of system operation highlighted critical network conditions resulting in load shedding actions, already in the reference scenario with only the existing VRES capacity (scenario EVR-NWA-ISO), together with the existing and committed programmable generation established by ZESCO in the long-term generation expansion plan. Some network congestions have been highlighted with the probabilistic analyses carried out over hundreds Monte Carlo years, both in 2025 and in 2030, mainly due to the growth of the domestic demand and the firm export.

The Consultant deployed the following reinforcements/operations to avoid excessive network congestions independent by VRES integration and to limit the load shedding, before to start the analyses with an enhanced development of VRES capacity. This is the minimum set of system reinforcements required by the target years for the better network performance.

- The 66 kV overhead line Lusiwasi-Mupepe has been put in service to operate a second line between Pensulo S/S and Lusiwasi S/S (blue line in the following figure). This operation has been carried out to limit the overload of the 66 kV line between Pensulo S/S and Lusiwasi S/S in N-1 condition due to the out of service of the 330 kV overhead line Pensulo-Lusiwasi-Msoro. The growth of the firm export to Malawi, from 20 MW to 70 MW, increased the network loading of the whole network between Pensulo S/S and Chipata S/S resulting in load shedding actions.



- A new 88 kV overhead line between Leopards Hill S/S and Mapepe S/S has been included in the model reaching 2x88 kV overhead lines between Leopards Hill S/S and Mapepe S/S.



- A new 88/66 kV transformer with nominal size equal to 20 MVA has been included in Kabwe S/S. The new configuration with 3x20 MVA 88/66 kV transformers allows the secure operation of the network also in N-1 condition following the outage of one 88/66 kV transformer in Kabwe S/S.

Figure 16.2 shows the loadings of the overhead lines and ENH/HV transformers resulting from scenarios 2025 and 2030, with a focus on the voltage levels greater than or equal to 66 kV. Each line and each transformer have been monitored during all the 500 Monte Carlo Years simulated with GRARE and the greatest power flows have been recorded. The frequency distributions of the overhead lines loading and transformers loading have been provided for each voltage level (330-220-132-88-66 kV), comparing the results of EVR scenario (black bars) with those from ENH-NWA scenarios, with isolated Country (red bars) and interconnected Country (green bars). Both in 2025 and in 2030, the integration of additional VRES installed capacity increases the loading of grid elements. The greatest network congestions occurred in in 88 kV and 66 kV networks with about 10% of overhead lines loaded between 90% and 100% of the maximum capacity. The loading of 330-220 kV networks is lower than that of the lower voltage levels.

Figure 16.2 - Maximum loadability of the overhead lines and transformers. Scenarios without additional VRES (EVR) compared to the scenarios with an enhanced VRES deployment, with isolated (ENH-NWA-ISO) and interconnected Country (ENH-NWA-INT). Years 2025 and 2030

Figure 16.3 shows the transmission network map with the most loaded network elements found in the target year 2025 with maximum development of VRES generation (scenario ENH-NWA-INT); lines and transformers with maximum flow greater or equal than 75% of their rated power have been highlighted with red boxes. The lists of overhead lines and transformers with maximum loading greater of equal than 50% of rated power are shown in Table 16.3 and Table 16.4, respectively. The results of each scenarios analysed at the year 2025 are compared for each network element. The comparison between the results of each scenario with enhanced deployment of VRES (ENH-NWA-ISO or ENH-NWA-INT) with those calculated with only the existing VRES power plants (EVR-NWA-ISO) allows to assess the grid impact of the optimal VRES capacities calculated in Task 3.

The integration of additional VRES capacity in 2025 increase the network loading but without network violations (the maximum loading is lower or equal than 100% of the rated power). The network elements with the maximum loading closest to the limit are in the area between Pensulo S/S and Msoro S/S. They depend mainly by the firm export to Malawi (70 MW) under N-1 condition of the 330 kV overhead lines and not by the VRES integration (the loading is unchanged without and with new VRES capacity). The Consultant advise to pay special attention on this part of the network in N-1 condition in sight of the future power exchanges with Malawi and Mozambique.

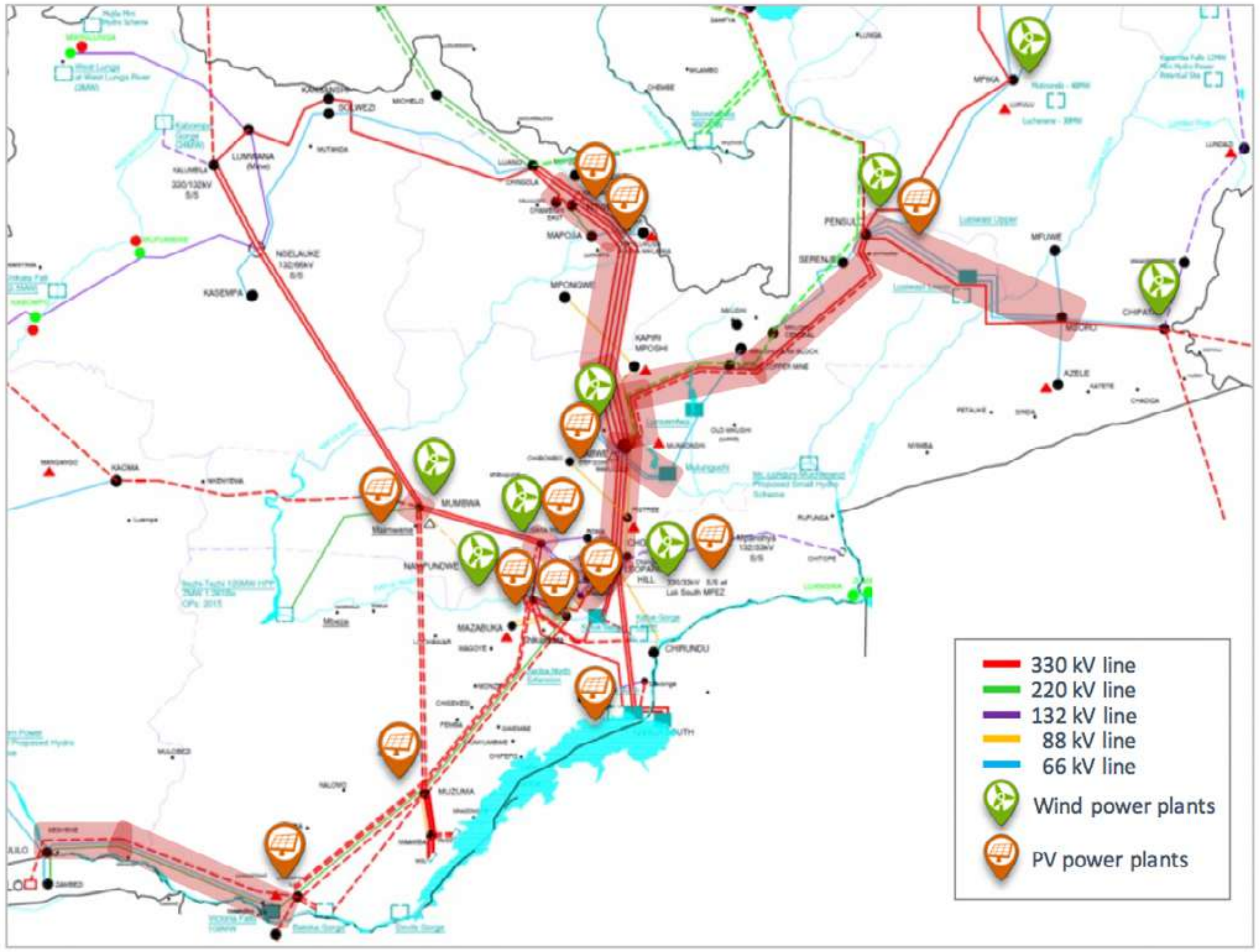


Figure 16.3 – Lines and transformer loadings greater than or equal to 75% of the maximum capacity. Scenario ENH-NWA-INT 2025

Table 16.3 – List of the most loaded overhead lines (voltage level ≥ 66 kV). Year 2025

					Max Loading %		
GRARE ID	Name_From	Name_To	kV_From	kV_To	EVR-NWA-ISO	ENH-NWA-ISO	ENH-NWA-INT
130	PENSL66	CHNSR66	66	66	100%	100%	100%
156	BRKHL66	MLNGS66	66	66	100%	100%	100%
160	MLNGS66	KABWE66	66	66	100%	100%	100%
265	LEPRD88	MAPEP88	88	88	100%	100%	100%
224	VICTR2	SESHEKE220	220	220	47%	54%	100%
225	VICTR2	LIV220	220	220	50%	57%	100%
95	NDOLA66	SKYWYS66	66	66	100%	100%	100%
133	CHNSR66	KANON66	66	66	100%	100%	100%
145	LEPRD88	MAPEP88	88	88	62%	63%	100%
32	SAFAL	KANON66	66	66	100%	100%	99%
34	SAFAL	MUPEPE66	66	66	100%	100%	99%
163	MUPEPE66	LUSW-T66	66	66	100%	100%	99%
264	LUSIW	LUSW-T66	66	66	100%	100%	99%
203	KABWE3	PENSL3	330	330	17%	40%	98%
25	LUSIW	MSORO66	66	66	96%	100%	96%
26	LUSIW	MSORO66	66	66	100%	100%	93%
229	CHAMBEAST	MWAM66	66	66	87%	87%	87%
86	MAPOS66	DLHLL66	66	66	79%	81%	81%
198	KABWE3	LEPRD3	330	330	77%	80%	80%
199	KABWE3	LEPRD3	330	330	77%	80%	80%
147	LEPRD1	WTRWK132	132	132	77%	80%	79%
157	BRKHL66	KABWE66	66	66	82%	78%	78%
197	KABWE3	KITWE3	330	330	68%	76%	77%
196	KABWE3	KITWE3	330	330	71%	77%	75%
76	KARIB_N3	LEPRD3	330	330	77%	80%	74%
142	ROMA1	LEPRD1	132	132	75%	73%	72%
82	MAPOS66	MCLRN66	66	66	71%	71%	71%
22	LUS_UP	LUSIW	66	66	67%	75%	69%
200	KABWE3	LEPRD3	330	330	59%	64%	68%
146	LEPRD88	CHONGWE	88	88	67%	67%	67%
100	DLHLL66	PAMDZ66	66	66	56%	66%	66%
202	KABWE3	LUANO3	330	330	62%	65%	66%
36	KABND66	STADM66	66	66	66%	89%	66%
140	CVNTR1	LSKWT132	132	132	66%	66%	66%
201	KABWE3	LUANO3	330	330	61%	65%	66%
84	MAPOS66	NDOLA66	66	66	66%	65%	65%
85	MAPOS66	NDOLA66	66	66	66%	65%	65%
221	KAFGR3	KAFWT3	330	330	67%	68%	64%
65	KARIB_N3	LEPRD3	330	330	74%	70%	64%
44	LUSWS	PENSL3	330	330	17%	17%	64%
54	LUSWS	MSORO330	330	330	17%	21%	64%
87	KARIB_N3	KAFWT3	330	330	71%	70%	63%
83	MAPOS66	BALUB66	66	66	63%	63%	63%
210	LEPRD3	KAFGR3	330	330	59%	65%	63%
211	LEPRD3	KAFGR3	330	330	59%	65%	63%
19	MSORO330	CHIPTAWE330	330	330	13%	17%	63%
132	LSKWT330	KABWE3	330	330	56%	62%	63%
129	PENSL66	SERNJ66	66	66	62%	62%	62%
99	SKYWYS66	DPTRD66	66	66	63%	62%	62%
151	LSKWT330	KAFWT3	330	330	65%	63%	59%
183	ITEZGITE220	MUMBWA220	220	220	58%	58%	58%
189	LSMFEZ 330	LEPRD3	330	330	47%	47%	58%
80	MAPOS66	ROAN66	66	66	58%	58%	58%
185	KAFGRLOW	KAFGR3	330	330	47%	56%	57%
4	BANCENTR	MICHL66	66	66	57%	57%	57%
141	LSKWT330	KABWE3	330	330	42%	47%	56%
158	MLNGS66	LNSMF66	66	66	56%	56%	56%
37	KABND66	LUANO66	66	66	56%	66%	56%
18	KALUMBILA330	MUMBWA330	330	330	41%	50%	56%
101	PAMDZ66	DPTRD66	66	66	54%	56%	56%
97	SKYWYS66	DLHLL66	66	66	64%	55%	55%
50	CHSNG66	CHMBS66	66	66	55%	55%	55%
159	LSKWT330	KAFWT3	330	330	60%	59%	55%
96	NDOLA66	DPTRD66	66	66	35%	55%	55%
52	CHMBS66	LUANO66	66	66	54%	55%	55%
53	CHMBS66	LUANO66	66	66	54%	55%	55%
39	STADM66	LUANO66	66	66	54%	66%	54%
40	STADM66	LUANO66	66	66	54%	54%	54%
172	ZAMB220	NAM_ZAM	220	220	21%	25%	54%
226	SESHEKE220	ZAM_NAM	220	220	21%	25%	54%
153	KZNGL66	VICTR66	66	66	39%	43%	54%
205	KABWE3	PENSL3	330	330	16%	30%	53%
181	MUZUMA	KAFTN3	330	330	41%	51%	52%
68	KITWE66	MILL66	66	66	52%	52%	52%
49	BNCNT66	LUBAMBI	66	66	52%	52%	52%
217	LUANO2	MICHL2	220	220	33%	45%	51%
17	KALUMBILA330	MUMBWA330	330	330	46%	48%	51%
139	CVNTR1	WTRWK132	132	132	50%	52%	50%
55	LUANO66	CCMTOFF	66	66	49%	57%	49%
114	MBALA66	NGOLI	66	66	51%	51%	48%
176	LUALU66	KATESHI	66	66	51%	51%	48%
177	KATESHI	NGOLI	66	66	51%	51%	48%

Table 16.4 – List of the most loaded transformers (voltage level ≥ 66 kV). Year 2025

						Max Loading %		
GRARE ID	Name_From	Name_To	kV_From	kV_To	Pn [MVA]	EVR-NWA-ISO	ENH-NWA-ISO	ENH-NWA-INT
389	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%
321	KABWE88	KABWE66	88	66	20	84%	96%	95%
322	KABWE88	KABWE66	88	66	20	84%	96%	95%
432	KABWE88	KABWE66	88	66	20	84%	96%	95%
403	LEPRD88	LEPRD3	88	330	90	89%	95%	93%
351	LSKWT330	LSKWT132	330	132	125	73%	76%	78%
373	LSKWT330	LSKWT132	330	132	125	73%	76%	78%
378	LSKWT330	LSKWT132	330	132	125	73%	76%	78%
414	PENSL3	PENSL66	330	66	60	78%	79%	73%
415	PENSL3	PENSL66	330	66	60	78%	79%	73%
404	LEPRD3	LEPRD1	330	132	150	100%	100%	70%
405	LEPRD3	LEPRD1	330	132	150	100%	100%	70%
407	LEPRD3	LEPRD1	330	132	250	70%	71%	70%
410	LUANO2	LUANO66	220	66	60	70%	70%	70%
409	LUANO2	LUANO66	220	66	60	70%	70%	70%
408	LUANO2	LUANO66	220	66	60	69%	69%	69%
413	LUANO2	LUANO66	220	66	60	69%	69%	69%
306	MSORO330	MSORO66	330	66	45	67%	73%	65%
411	LUANO2	LUANO66	220	66	65	63%	63%	63%
412	LUANO2	LUANO66	220	66	65	63%	63%	63%
399	KITWE2	KITWE66	220	66	60	62%	62%	62%
401	KITWE2	KITWE66	220	66	60	62%	62%	62%
400	KITWE2	KITWE66	220	66	60	62%	62%	62%
376	MAPOS2	MAPOS66	220	66	80	37%	48%	61%
398	KITWE2	KITWE66	220	66	60	61%	61%	61%
397	KITWE2	KITWE66	220	66	60	60%	60%	60%
420	KAFTN88	KAFTN3	88	330	125	58%	58%	59%
421	KAFTN88	KAFTN3	88	330	125	58%	58%	59%
429	MAPOS2	MAPOS66	220	66	80	36%	47%	59%
427	MAPOS2	MAPOS66	220	66	80	35%	46%	58%
395	KABWE3	KABWE88	330	88	60	57%	57%	58%
396	KABWE3	KABWE88	330	88	60	57%	57%	58%
402	LEPRD88	LEPRD3	88	330	90	56%	56%	56%
305	MSORO330	MSORO66	330	66	45	67%	100%	55%
273	SESHEKE220	SESHK66	220	66	25	40%	54%	54%
274	SESHEKE220	SESHK66	220	66	25	40%	54%	54%
343	KITWE2	FICT BUS 001	220	330	315	46%	52%	54%
346	KITWE2	FICT BUS 002	220	330	315	46%	52%	54%
349	KITWE2	FICT BUS 003	220	330	315	46%	52%	54%
353	KITWE2	FICT BUS 004	220	330	315	46%	52%	54%
310	CHIPTAWE330	CHIPT132	330	132	90	50%	51%	51%
311	CHIPTAWE330	CHIPT132	330	132	90	50%	51%	51%

Figure 16.4 shows the transmission network map with the most loaded network elements found in the target year 2030 with maximum development of VRES generation (scenario ENH-NWA-INT); lines and transformers with maximum flow greater or equal than 75% of their rated power have been highlighted with red boxes. The list of overhead lines and transformers with maximum loading greater of equal than 50% of rated power are shown in Table 16.5 and Table 16.6, respectively. The results of each scenarios analysed at the year 2030 are compared for each network element. Like the year 2025, the network elements with the maximum loading closest to the limit are in the area between Pensulo S/S and Msoro S/S. They depend mainly by the firm export to Malawi under N-1 condition of the 330 kV overhead lines and not by the VRES integration (the loading is unchanged without and with new VRES capacity).

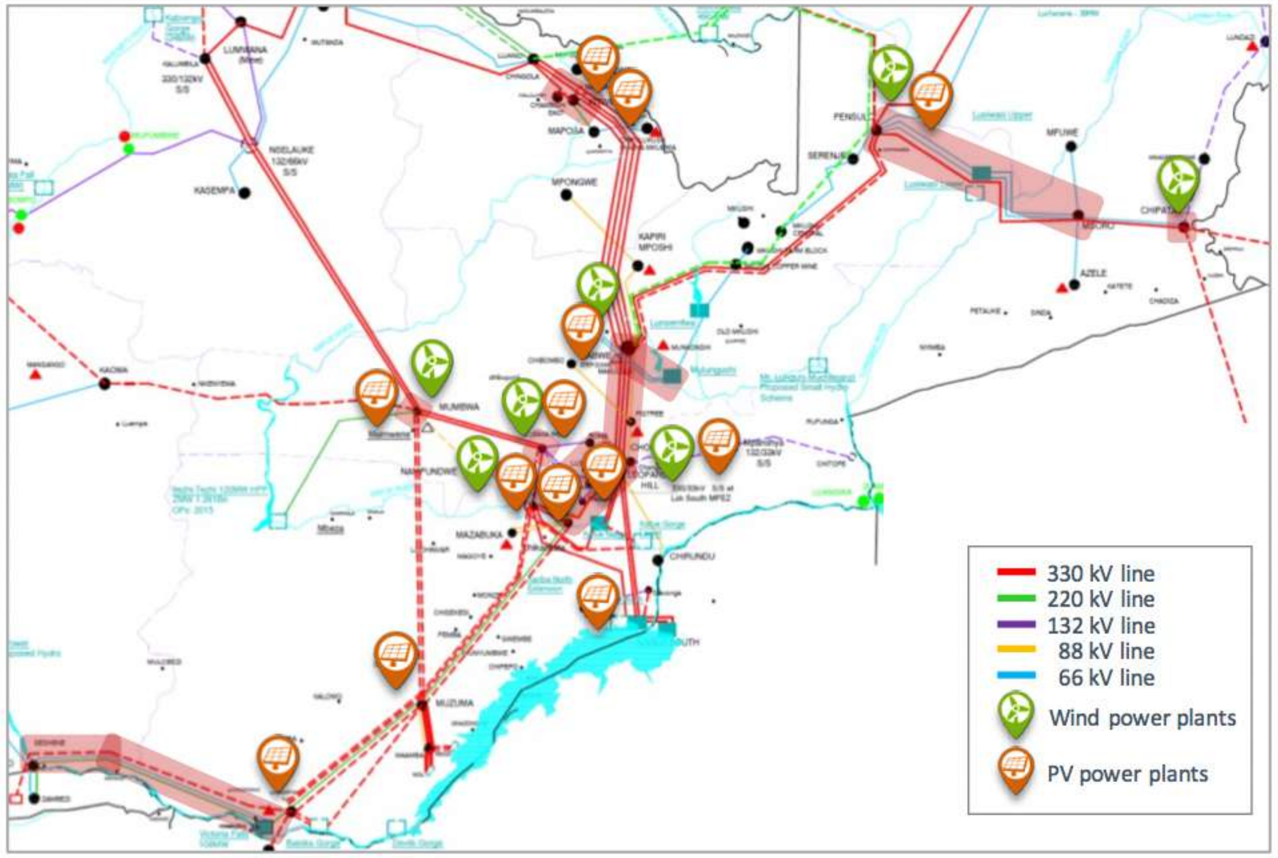


Figure 16.4 – Lines and transformer loadings greater than or equal to 75% of the maximum capacity. Scenario ENH-NWA-INT 2030

Table 16.5 – List of the most loaded overhead lines (voltage level ≥ 66 kV). Year 2030

					Max Loading %		
GRARE ID	Name_From	Name_To	kV_From	kV_To	EVR-NWA-ISO	ENH-NWA-ISO	ENH-NWA-INT
95	NDOLA66	SKYWYS66	66	66	100%	100%	100%
130	PENSL66	CHNSR66	66	66	100%	100%	100%
156	BRKHL66	MLNGS66	66	66	100%	100%	100%
160	MLNGS66	KABWE66	66	66	100%	100%	100%
265	LEPRD88	MAPEP88	88	88	98%	100%	100%
145	LEPRD88	MAPEP88	88	88	62%	93%	100%
225	VICTR2	LIV220	220	220	46%	64%	100%
133	CHNSR66	KANON66	66	66	100%	100%	100%
32	SAFAL	KANON66	66	66	100%	100%	99%
34	SAFAL	MUPEPE66	66	66	100%	100%	99%
163	MUPEPE66	LUSW-T66	66	66	100%	100%	99%
264	LUSIW	LUSW-T66	66	66	100%	100%	99%
162	MAPEP88	KAFTWNMA	88	88	38%	96%	98%
224	VICTR2	SESHEKE220	220	220	41%	57%	97%
25	LUSIW	MSORO66	66	66	100%	100%	96%
26	LUSIW	MSORO66	66	66	100%	100%	93%
229	CHAMBEAST	MWAM66	66	66	84%	88%	88%
199	KABWE3	LEPRD3	330	330	79%	78%	82%
200	KABWE3	LEPRD3	330	330	66%	62%	82%
198	KABWE3	LEPRD3	330	330	79%	78%	82%

					Max Loading %		
GRARE ID	Name_From	Name_To	kV_From	kV_To	EVR-NWA-ISO	ENH-NWA-ISO	ENH-NWA-INT
147	LEPRD1	WTRWK132	132	132	80%	83%	81%
157	BRKHL66	KABWE66	66	66	83%	78%	78%
86	MAPOS66	DLHLL66	66	66	79%	74%	75%
142	ROMA1	LEPRD1	132	132	74%	74%	73%
132	LSKWT330	KABWE3	330	330	66%	67%	72%
141	LSKWT330	KABWE3	330	330	50%	54%	69%
22	LUS_UP	LUSIW	66	66	76%	76%	69%
140	CVNTR1	LSKWT132	132	132	66%	67%	67%
146	LEPRD88	CHONGWE	88	88	64%	67%	67%
82	MAPOS66	MCLRN66	66	66	65%	67%	67%
65	KARIB_N3	LEPRD3	330	330	61%	90%	67%
76	KARIB_N3	LEPRD3	330	330	61%	90%	67%
210	LEPRD3	KAFGR3	330	330	69%	68%	66%
211	LEPRD3	KAFGR3	330	330	69%	68%	66%
129	PENSL66	SERNJ66	66	66	60%	63%	63%
54	LUSWS	MSORO330	330	330	18%	19%	63%
44	LUSWS	PENSL3	330	330	16%	19%	63%
99	SKYWYS66	DPTRD66	66	66	62%	66%	62%
221	KAFGR3	KAFWT3	330	330	64%	61%	62%
100	DLHLL66	PAMDZ66	66	66	52%	61%	62%
36	KABND66	STADM66	66	66	60%	79%	62%
19	MSORO330	CHIPTAWE330	330	330	13%	14%	61%
84	MAPOS66	NDOLA66	66	66	66%	52%	61%
85	MAPOS66	NDOLA66	66	66	66%	52%	61%
83	MAPOS66	BALUB66	66	66	59%	60%	60%
87	KARIB_N3	KAFWT3	330	330	53%	80%	59%
183	ITEZGITE220	MUMBWA220	220	220	58%	58%	58%
189	LSMFEZ 330	LEPRD3	330	330	58%	55%	57%
185	KAFGRLOW	KAFGR3	330	330	58%	58%	57%
50	CHSNG66	CHMBS66	66	66	54%	57%	57%
158	MLNGS66	LNSMF66	66	66	56%	56%	56%
151	LSKWT330	KAFWT3	330	330	59%	56%	56%
80	MAPOS66	ROAN66	66	66	54%	56%	56%
52	CHMBS66	LUANO66	66	66	51%	54%	54%
53	CHMBS66	LUANO66	66	66	51%	54%	54%
4	BANCENTR	MICHL66	66	66	52%	53%	54%
153	KZNGL66	VICTR66	66	66	39%	44%	53%
114	MBALA66	NGOLI	66	66	50%	52%	53%
176	LUALU66	KATESHI	66	66	50%	52%	53%
177	KATESHI	NGOLI	66	66	50%	52%	53%
101	PAMDZ66	DPTRD66	66	66	50%	53%	53%
159	LSKWT330	KAFWT3	330	330	55%	52%	52%
139	CVNTR1	WTRWK132	132	132	53%	54%	52%
37	KABND66	LUANO66	66	66	51%	59%	52%
97	SKYWYS66	DLHLL66	66	66	65%	65%	52%
96	NDOLA66	DPTRD66	66	66	31%	36%	52%
172	ZAMB220	NAM_ZAM	220	220	16%	25%	51%
226	SESHEKE220	ZAM_NAM	220	220	16%	25%	51%
287	KABWE3	LUANSHYA	330	330	44%	50%	51%
39	STADM66	LUANO66	66	66	49%	58%	51%
40	STADM66	LUANO66	66	66	49%	51%	51%
288	KITWE3	LUANSHYA	330	330	45%	50%	50%
283	MUMBUTUTA	LUANO3	330	330	17%	35%	50%
207	KITWE2	KNSSW2	220	220	48%	50%	50%

Table 16.6 – List of the most loaded transformers (voltage level ≥ 66 kV). Year 2030

						Max Loading %		
GRARE ID	Name_From	Name_To	kV_From	kV_To	Pn [MVA]	EVR-NWA-ISO	ENH-NWA-ISO	ENH-NWA-INT
340	CHIPTAWE330	CHIPT132	330	132	90	100%	100%	100%
351	KABWE88	KABWE66	88	66	20	70%	100%	100%
352	KABWE88	KABWE66	88	66	20	70%	100%	100%
462	KABWE88	KABWE66	88	66	20	70%	100%	100%
341	CHIPTAWE330	CHIPT132	330	132	90	52%	100%	100%
451	KAFTN88	KAFTN3	88	330	125	67%	100%	100%
434	LEPRD3	LEPRD1	330	132	150	71%	100%	100%
435	LEPRD3	LEPRD1	330	132	150	71%	100%	100%
433	LEPRD88	LEPRD3	88	330	90	92%	97%	100%
450	KAFTN88	KAFTN3	88	330	125	67%	100%	100%
419	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%
381	LSKWT330	LSKWT132	330	132	125	86%	90%	92%
403	LSKWT330	LSKWT132	330	132	125	86%	90%	92%
408	LSKWT330	LSKWT132	330	132	125	86%	90%	92%
336	MSORO330	MSORO66	330	66	45	74%	74%	84%
425	KABWE3	KABWE88	330	88	60	77%	81%	82%
426	KABWE3	KABWE88	330	88	60	77%	81%	82%
444	PENSL3	PENSL66	330	66	60	82%	85%	78%
445	PENSL3	PENSL66	330	66	60	82%	85%	78%
432	LEPRD88	LEPRD3	88	330	90	56%	73%	76%
437	LEPRD3	LEPRD1	330	132	250	71%	72%	73%
440	LUANO2	LUANO66	220	66	60	63%	66%	65%
439	LUANO2	LUANO66	220	66	60	62%	65%	65%
438	LUANO2	LUANO66	220	66	60	62%	65%	65%
443	LUANO2	LUANO66	220	66	60	62%	65%	65%
335	MSORO330	MSORO66	330	66	45	60%	72%	64%
441	LUANO2	LUANO66	220	66	65	56%	59%	59%
442	LUANO2	LUANO66	220	66	65	56%	59%	59%
429	KITWE2	KITWE66	220	66	60	55%	58%	58%
431	KITWE2	KITWE66	220	66	60	55%	58%	58%
406	MAPOS2	MAPOS66	220	66	80	35%	45%	57%
303	SESHEKE220	SESHK66	220	66	25	54%	55%	57%
304	SESHEKE220	SESHK66	220	66	25	54%	55%	57%
430	KITWE2	KITWE66	220	66	60	55%	57%	57%
428	KITWE2	KITWE66	220	66	60	54%	56%	56%
459	MAPOS2	MAPOS66	220	66	80	34%	43%	56%
427	KITWE2	KITWE66	220	66	60	53%	55%	55%
373	KITWE2	FICT BUS 001	220	330	315	46%	53%	55%
376	KITWE2	FICT BUS 002	220	330	315	46%	53%	55%
379	KITWE2	FICT BUS 003	220	330	315	46%	53%	55%
383	KITWE2	FICT BUS 004	220	330	315	46%	53%	55%
457	MAPOS2	MAPOS66	220	66	80	34%	43%	55%
398	CHAMBEAST	FICT BUS 009	66	330	120	51%	53%	53%
401	CHAMBEAST	FICT BUS 010	66	330	120	51%	53%	53%
386	LUANO2	FICT BUS 005	220	330	315	45%	51%	51%
389	LUANO2	FICT BUS 006	220	330	315	45%	51%	51%
392	LUANO2	FICT BUS 007	220	330	315	45%	51%	51%
395	LUANO2	FICT BUS 008	220	330	315	45%	51%	51%

The integration of variable RES generation in an electric power system has a system impact and a network impact. The first one concerns with the risk of over-generation due to the unpredictability and intermittency of variable RES (manly for wind), the inflexibility of programmable power plants and the lack of enough downward reserve, while the second one regards the network congestions due to the inadequacy of the transmission infrastructures. Both system impact and network impact produce a risk of VRES energy curtailment.

Table 16.7 shows the expected curtailments of wind and PV productions due to over-generation phenomena and network overloads and the net capacity factor resulting for each source after production curtailments. The risk of over-generation and the related VRES energy curtailment have been analysed in Task 3 (0.16% in 2025 and 0.07% in 2030 ENH-NWA-ISO scenarios; while no VRES production curtailments have been highlighted in the interconnected scenarios), while the network congestions have been evaluated in the system reliability impact study. Table 16.8 and Table 16.9 show PV and wind energy curtailments due to network overloads expected at each substation in 2025 and 2030.

VRES production curtailments due to over-generation phenomena or to solve network overloads are not very frequent: 0.17% of total VRES production (PV + wind) is curtailed in isolated scenario 2025, 0.25% in the interconnected scenario 2025, 0.11% in the isolated scenario 2030 and 0.05% in in the interconnected scenario 2030.

Table 16.7 – Summary of VRES curtailments due to network overloads

	ENH-NWA-ISO 2025				ENH-NWA-ISO 2030			
Source	Pinst [MW]	Prod. Curtail. due to OG [%]	Prod. Curtail. due to overloads [%]	Net CF [%]	Pinst [MW]	Prod. Curtail. due to OG [%]	Prod. Curtail. due to overloads [%]	Net CF [%]
Wind	1,200	-0.16%	-0.01%	43.1%	1,400	-0.07%	-0.06%	42.7%
PV	1,176	-0.16%	-0.005%	22.9%	1,376	-0.07%	-0.03%	22.9%
Tot. VRES	**2,376**	**-0.16%**	**-0.01%**	**33.2%**	**2,776**	**-0.07%**	**-0.05%**	**32.9%**

	ENH-NWA-INT 2025				ENH-NWA-INT 2030			
Source	Pinst [MW]	Prod. Curtail. due to OG [%]	Prod. Curtail. due to overloads [%]	Net CF [%]	Pinst [MW]	Prod. Curtail. due to OG [%]	Prod. Curtail. due to overloads [%]	Net CF [%]
Wind	1,600	-0.00%	-0.28%	43.3%	1,900	-0.00%	-0.06%	43.3%
PV	1,576	-0.00%	-0.18%	22.9%	1,826	-0.00%	-0.04%	23.0%
Tot. VRES	**3,176**	**-0.00%**	**-0.25%**	**33.2%**	**3,726**	**-0.00%**	**-0.05%**	**33.2%**

Table 16.8 – PV energy curtailments due to network overloads

	ENH-NWA-ISO 2025			ENH-NWA-ISO 2030		
S/S	**Pinst [MW]**	**Curtailed production [%]**	**Net CF [%]**	**Pinst [MW]**	**Curtailed production [%]**	**Net CF [%]**
Kabwe	140	-0.02%	23.0%	190	-0.04%	23.0%
Kafue	140	0.00%	21.9%	140	0.00%	21.9%
Kariba	90	0.00%	22.0%	90	0.00%	22.0%
Kasama	-	-	-	-	-	-
Kitwe	40	-0.01%	23.2%	140	-0.02%	23.0%
Leopards Hill	150	0.00%	23.0%	150	-0.03%	23.0%
Livingstone	50	0.00%	23.6%	50	0.00%	23.6%
Lusaka	75.7	-0.01%	23.0%	125.7	-0.02%	23.0%
Mumbwa	170	0.00%	23.0%	170	0.00%	23.0%
Muzuma	220	0.00%	23.6%	220	0.00%	23.6%
Pensulo	100	-0.01%	23.0%	100	-0.19%	22.9%
TOTAL	**1,175.7**	**-0.005%**	**22.9%**	**1,375.7**	**-0.03%**	**22.9%**

	ENH-NWA-INT 2025			ENH-NWA-INT 2030		
S/S	**Pinst [MW]**	**Curtailed production [%]**	**Net CF [%]**	**Pinst [MW]**	**Curtailed production [%]**	**Net CF [%]**
Kabwe	140	-0.63%	22.8%	140	-0.05%	23.0%
Kafue	190	0.00%	21.9%	190	0.00%	21.9%
Kariba	90	-0.02%	22.0%	90	-0.01%	22.0%
Kasama	-	-	-	50	-0.62%	23.1%
Kitwe	140	-0.05%	23.0%	140	-0.04%	23.0%
Leopards Hill	200	-0.07%	23.0%	250	-0.02%	23.0%
Livingstone	100	-0.02%	23.5%	150	0.00%	23.6%
Lusaka	175.7	-0.14%	22.9%	225.7	-0.01%	23.0%
Mumbwa	220	0.00%	23.0%	220	0.00%	23.0%
Muzuma	220	0.00%	23.6%	270	0.00%	23.6%
Pensulo	100	-1.40%	22.7%	100	-0.23%	22.9%
TOTAL	**1,575.7**	**-0.18%**	**22.9%**	**1,825.7**	**-0.04%**	**23.0%**

Table 16.9 – Wind energy curtailments due to network overloads

S/S	ENH-NWA-ISO 2025 Pinst [MW]	Curtailed production [%]	Net CF [%]	ENH-NWA-ISO 2030 Pinst [MW]	Curtailed production [%]	Net CF [%]
Kabwe	150	-0.01%	46.3%	200	-0.10%	46.2%
Kafue	100	0.00%	46.3%	100	0.00%	46.3%
Leopards Hill	250	-0.01%	46.3%	250	-0.05%	46.3%
Lusaka	150	0.00%	46.4%	150	0.00%	46.3%
Mpika	100	-0.01%	38.1%	250	-0.03%	38.1%
Mumbwa	170	0.00%	46.3%	170	0.00%	46.3%
Pensulo	280	-0.01%	35.9%	280	-0.21%	35.8%
Chipata	-	-	-	-	-	-
TOTAL	1,200	-0.01%	43.2%	1,400	-0.06%	42.7%

S/S	ENH-NWA-INT 2025 Pinst [MW]	Curtailed production [%]	Net CF [%]	ENH-NWA-INT 2030 Pinst [MW]	Curtailed production [%]	Net CF [%]
Kabwe	200	-0.45%	46.1%	200	-0.07%	46.3%
Kafue	200	0.00%	46.3%	250	0.00%	46.3%
Leopards Hill	300	-0.05%	46.3%	300	-0.03%	46.3%
Lusaka	200	-0.11%	46.3%	250	0.00%	46.3%
Mpika	100	-1.55%	37.5%	250	-0.20%	38.0%
Mumbwa	220	0.00%	46.3%	220	0.00%	46.3%
Pensulo	280	-0.89%	35.6%	330	-0.14%	36.2%
Chipata	100	-0.02%	37.0%	100	-0.02%	37.0%
TOTAL	1,600	-0.28%	43.3%	1,900	-0.06%	43.0%

Security of supply

For each target year, the quantitative evaluation of static reliability of the electric power system was performed by means of the risk indexes defined in the section 15.2. The expected energy not supplied (EENS), the loss of load expectation (LOLE) and the loss of load probability (LOLP) have been calculated for the following causes of load shedding: lack of power (LOP), lack of interconnection (LOI), line/transformer overload (LTO), network splitting and isolated node (NSP/ISN).

The summary of all reliability indexes for the electric power system expected in both target years (2025 and 2030) is shown in Table 16.10. The total values of EENS (GWh/year and p.u. of demand), LOLE (h/year) and LOLP (%) are highlighted for each reference scenarios:

- EVR-NWA-ISO: existing variable RES with normal water availability and isolated Country (only firm export is considered);
- EHN-NWA-ISO: enhanced deployment of variable RES with normal water availability isolated Country (only firm export is considered);
- EHN-NWA-INT: enhanced deployment of variable RES with normal water availability and interconnected Country.

The analyses highlighted some network splitting due to the N-1 of overhead lines or transformers. These critical conditions depend by the topology of the analysed network (330, 220, 132, 88, 66 kV) and they are independent by the VRES integration. Furthermore, no operational rules to manage these situations are included in the model. For these reasons, the values of the energy not supplied and the other indexes due to network splitting or isolated node have been highlighted in the report, to provide further information on system reliability, but they have been neglected to evaluate the impact of VRES generation on the system reliability. The causes of load shedding considered for final conclusions are only the lack of power (LOP), the lack of interconnection (LOI) and the line/transformer overload (LTO). The expected energy demand, including the firm export and the transmission and commercial losses, is 24.4 TWh/year in 2025 and 27.6 TWh/year in 2030. As highlighted in EVR-NWA-ISO scenarios, the existing and committed power plants are not enough to assure the security of supply: 24% unserved energy (5.9 TWh/year) is expected in 2025 and 33% (9.1 TWh/year) in 2030.

The integration of the optimal VRES capacity calculated in Task 3 for the isolated Country (ENH-NWA-ISO scenarios), i.e. the optimal wind and PV installed capacities from both technical and economic points of view, could supply most of the unserved energy but, as already highlighted in Task 3, they are not enough to meet the targets of security of supply (EENS ≤ 1.10-4 p.u. of the yearly demand, LOLE ≤ 48 h/year and LOLP ≤ 1%). 6.9 TWh/year from VRES generation can be integrated 2025 and 9.2 TWh/year in 2030, but 1.7% and 5.6% of Zambian demand continue to be unserved in 2025 and 2030, respectively. To assure the electrical self-sufficiency of Zambia, without power import, additional flexible capacity should be integrated.

The interconnection with the neighbouring countries (ENH-NWA-INT scenarios) allows to increase the VRES integration (up to 8.0 TWh/year in 2025 and 10.8 TWh/year in 2030) and the flexibility of the system, avoiding the lack of power and minimizing the energy not supplied to meet the reliability targets. The security of supply is reached with all reliability indexes due to lack of power (LOP) or line/transformer overloads (LTO) lower than the defined targets (EENS ≤ 1.10-4 p.u. of the yearly demand, LOLE ≤ 48 h/year and LOLP ≤ 1%), both in 2025 and in 2030. The expected energy not supplied is lower than the target also considering network splitting situations.

The summary of EENS and LOLE indexes due to the lack of power or line and transformer overloads is highlighted in Figure 16.5, in which both the X axis and the Y axis use the logarithmic scale. Interconnected scenarios are inside the security of supply area while the isolated scenarios are far from the security of supply standard due to lack of power in the system.

Table 16.10 – Security of supply indexes

			EENS [GWh/year]				
YEAR	**VRES**	**SCENARIO**	**LOP**	**LOI**	**LTO**	**NSP/ISN**	**TOTAL**
2025	EVR	NWA-ISO	5,933.28	-	0.02	1.12	**5,934.41**
	ENHAN	NWA-ISO	414.31	-	1.09	1.42	**416.82**
	ENHAN	NWA-INT	-	-	0.02	1.35	**1.36**
2030	EVR	NWA-ISO	9,093.49	-	0.05	0.97	**9,094.51**
	ENHAN	NWA-ISO	1,540.26	-	0.84	1.48	**1,542.57**
	ENHAN	NWA-INT	-	-	0.02	1.40	**1.42**

			EENS [p.u. Annual Demand]				
YEAR	**VRES**	**SCENARIO**	**LOP**	**LOI**	**LTO**	**NSP/ISN**	**TOTAL**
2025	EVR	NWA-ISO	2.43E-01	-	6.55E-07	4.58E-05	**2.43E-01**
	ENHAN	NWA-ISO	1.70E-02	-	4.44E-05	5.82E-05	**1.71E-02**
	ENHAN	NWA-INT	-	-	6.14E-07	5.50E-05	**5.57E-05**
2030	EVR	NWA-ISO	3.29E-01	-	1.63E-06	3.52E-05	**3.29E-01**
	ENHAN	NWA-ISO	5.58E-02	-	3.04E-05	5.35E-05	**5.58E-02**
	ENHAN	NWA-INT	-	-	7.60E-07	5.08E-05	**5.15E-05**

			LOLE [h/year]				
YEAR	**VRES**	**SCENARIO**	**LOP**	**LOI**	**LTO**	**NSP/ISN**	**TOTAL**
2025	EVR	NWA-ISO	8,760.0	-	1.2	91.5	**8,760.0**
	ENHAN	NWA-ISO	3,881.9	-	22.6	100.2	**3,881.9**
	ENHAN	NWA-INT	-	-	0.3	100.3	**100.6**
2030	EVR	NWA-ISO	8,760.0	-	4.8	86.0	**8,760.0**
	ENHAN	NWA-ISO	7,265.1	-	19.4	105.6	**7,265.1**
	ENHAN	NWA-INT	-	-	2.2	107.0	**109.2**

			LOLP [%]				
YEAR	**VRES**	**SCENARIO**	**LOP**	**LOI**	**LTO**	**NSP/ISN**	**TOTAL**
2025	EVR	NWA-ISO	100.0	-	0.1	1.6	**100.0**
	ENHAN	NWA-ISO	49.6	-	0.3	1.9	**49.6**
	ENHAN	NWA-INT	-	-	0.01	1.9	**1.9**
2030	EVR	NWA-ISO	110.4	-	0.1	1.6	**110.4**
	ENHAN	NWA-ISO	97.4	-	0.3	2.0	**97.4**
	ENHAN	NWA-INT	-	-	0.2	2.0	**2.2**

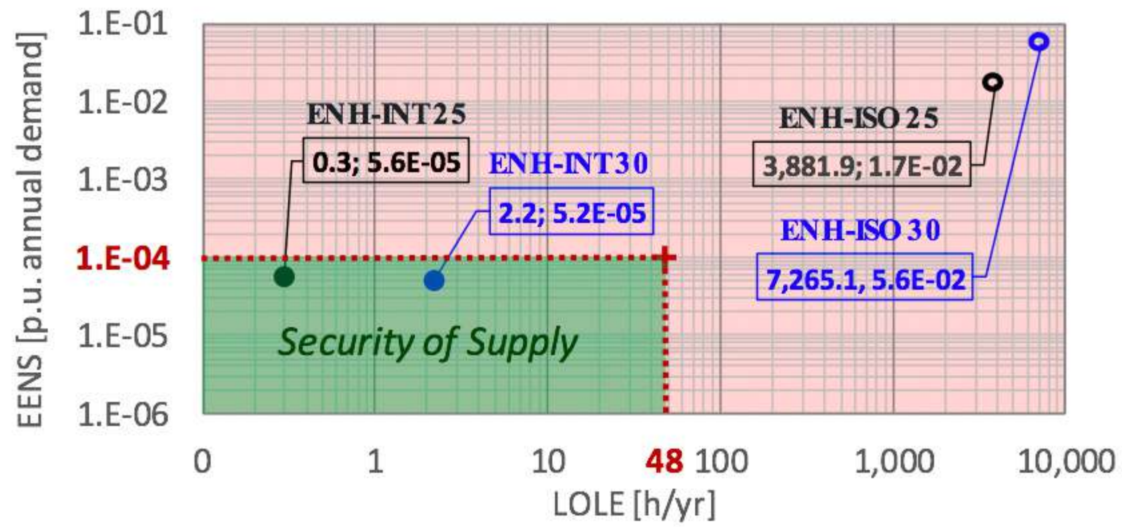


Figure 16.5 – Summary of EENS and LOLE indexes due to lack of power or line and transformer overloads

Figure 16.6 and Figure 16.7 show the distribution of the expected energy not supplied over the year, as results of Monte Carlo probabilistic analyses. The first one concerns the year 2025 and the isolated country scenario, while the second figure shows the results of the year 2030 for the isolated country condition. They are chromatic charts of the energy not supply expected for each week of the year (X axis) and each hour of the week (168 hours on the Y axis). The ENS duration curves of both scenarios are compared in Figure 16.8.

Figure 16.6 and Figure 16.8 show that 160 MW is the maximum hourly ENS expected in the year 2025, at the end of the year. However, a 100 MW programmable power plant with high flexibility and 48% capacity factor would be able to meet the 99.5th percentile of hourly ENS (100 MW) and to cover the residual ENS (416 GWh/year) assuring the security of supply with VRES capacity and isolated country.
807 MW is the maximum hourly ENS expected in the year 2030; it is mainly concentrated in the first month of the year where lower water and VRES availability occur (Figure 16.7). A 570 MW programmable power plant with high flexibility and 30% capacity factor would be able to meet the 99.5th percentile of hourly ENS and to cover the residual ENS (1,543 GWh/year) assuring the security of supply with VRES capacity and isolated country. The impact of VRES installed capacity on the electrical self-sufficiency and the security of supply in the long-term scenario (2030) is highlighted in Figure 16.9. Scenario with only the existing VRES installed capacity (76 MW from PV power plants) is compared with the scenario with the optimal VRES capacity (1,376 MW PV and 1,400 MW wind installed capacities). The results of the first one (left side of the figure) show high values of ENS during the whole year, with hourly values between 0.4 GW and 1.8 GW, while the integration of the optimal VRES capacity (right side of the figure) allows a great reduction of the unserved energy (0.8 GW is the maximum hourly value), remaining only at the beginning and end of the year, when there is less VRES availability.

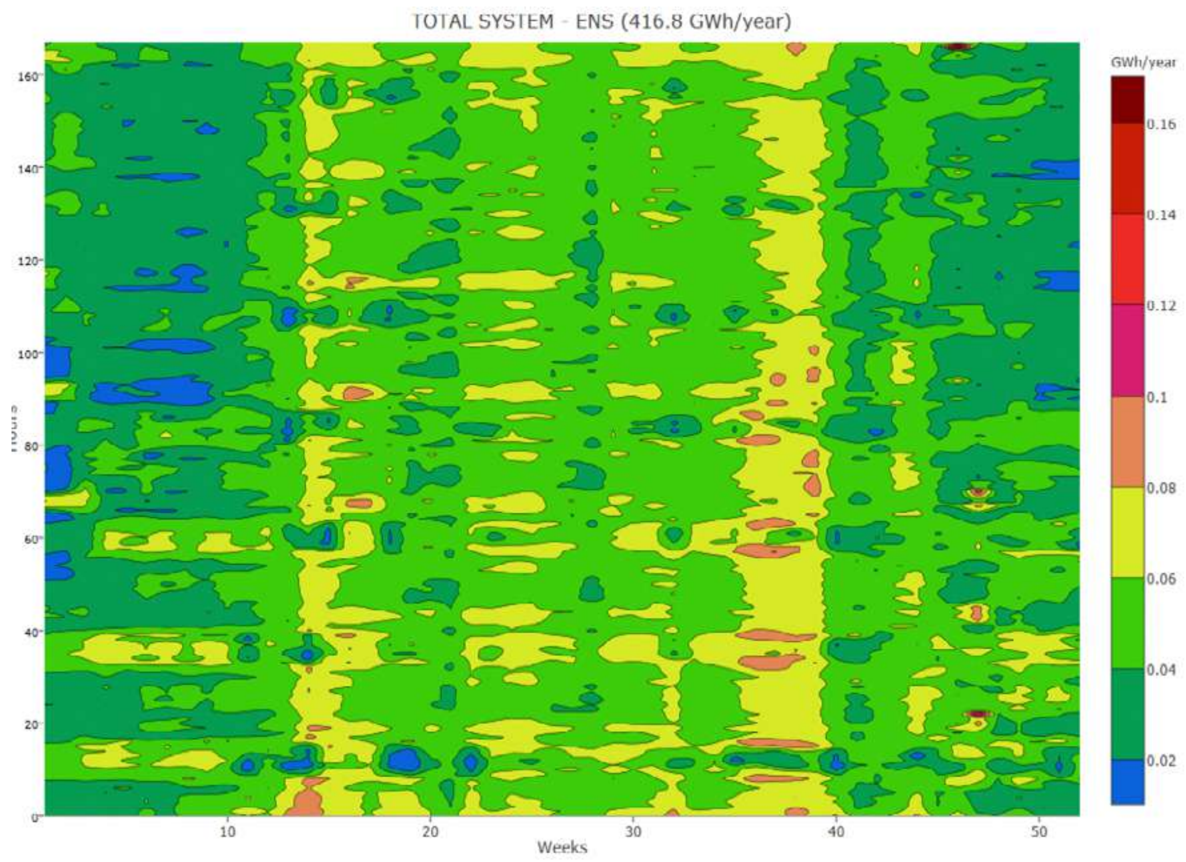


Figure 16.6 – ENS map expected in 2025 (ENH-NWA-ISO scenario)

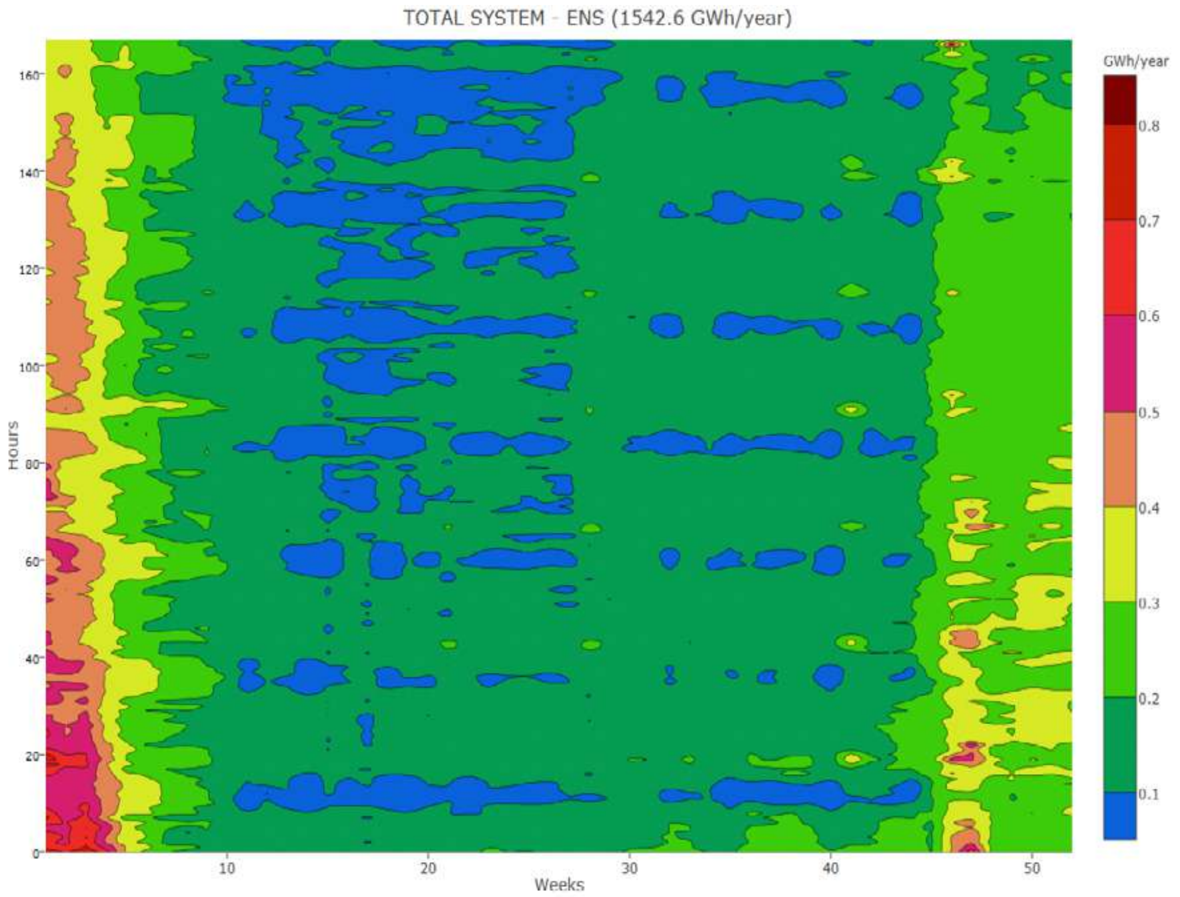


Figure 16.7 – ENS map expected in 2030 (ENH-NWA-ISO scenario)

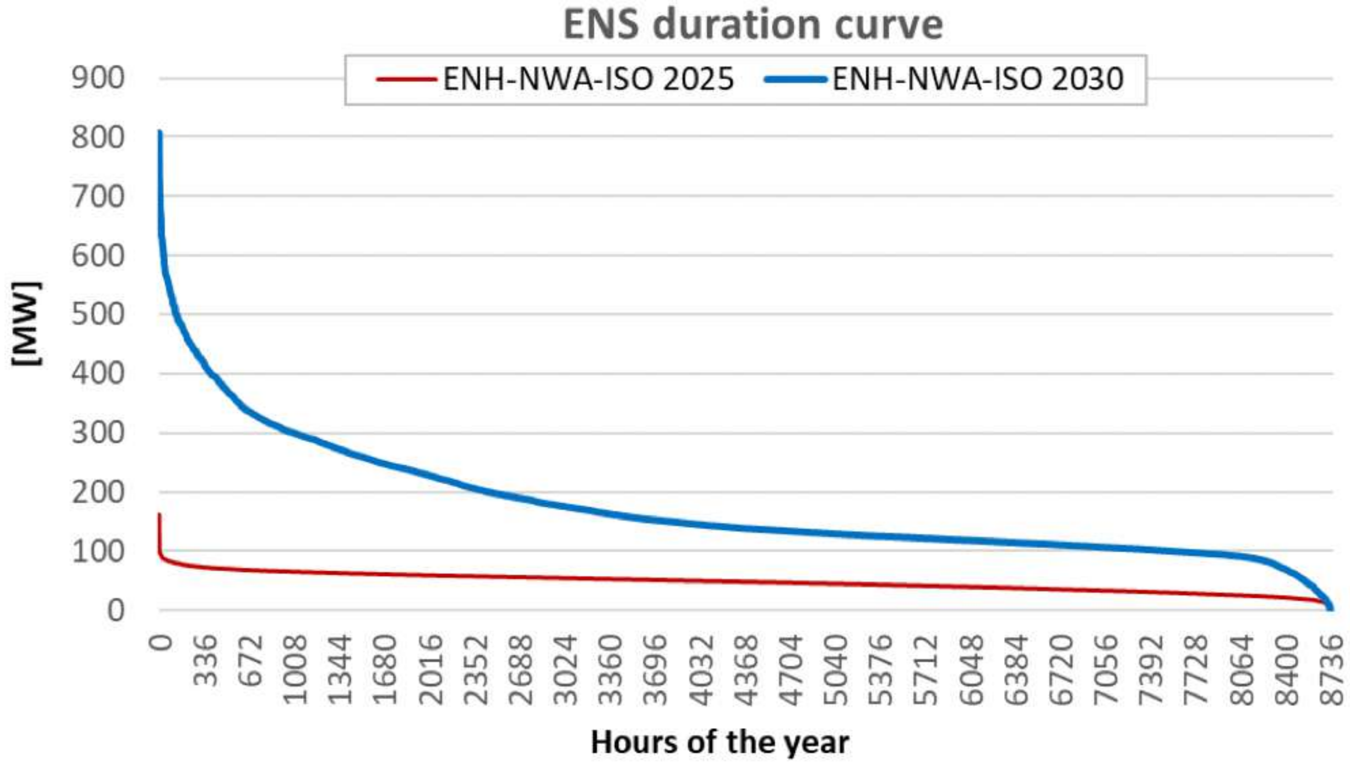


Figure 16.8 – ENS duration curves of ENN-NWA-ISO scenarios

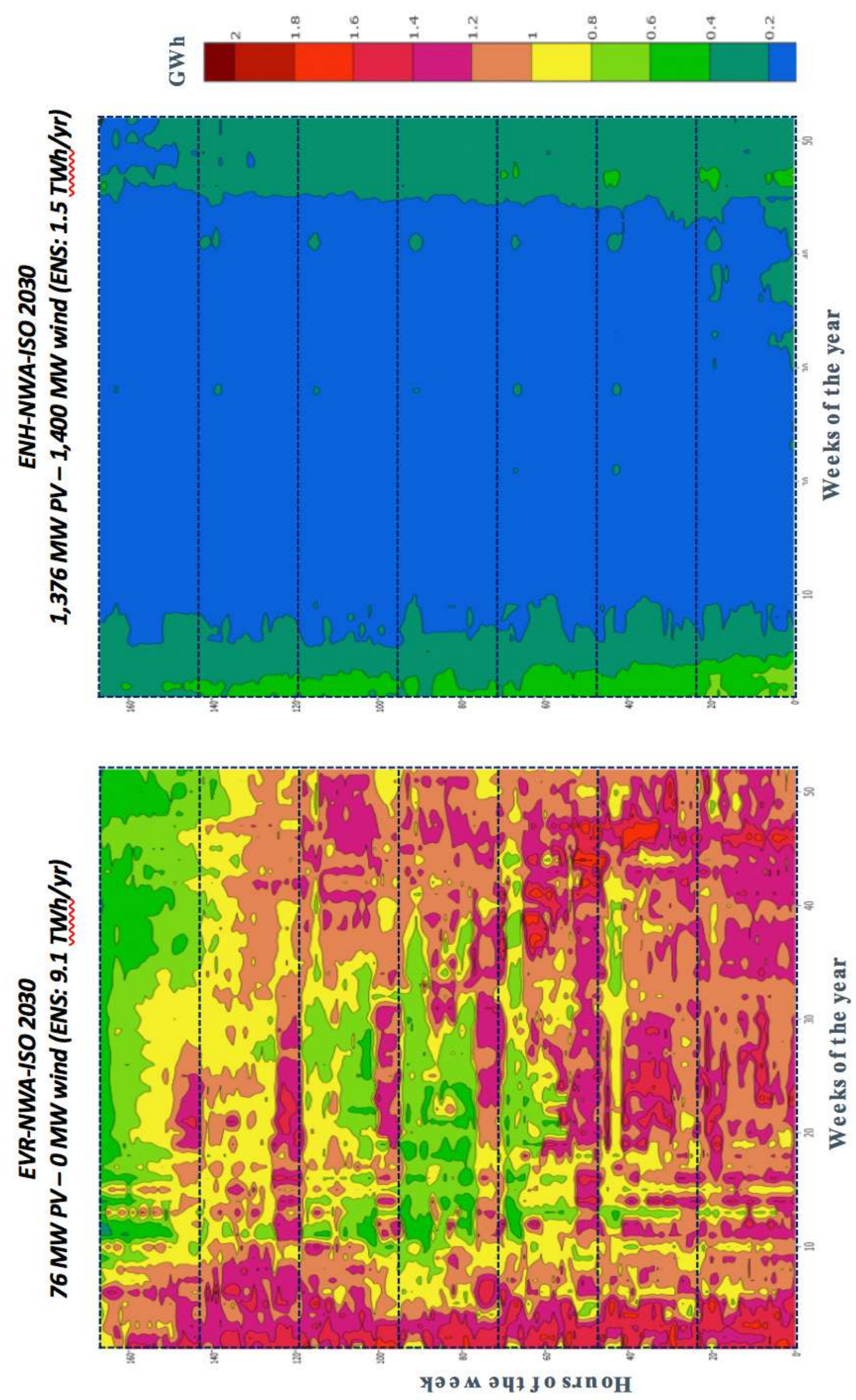


Figure 16.9 – ENS maps 2030. EVR-NWA-ISO vs ENH-NWA-ISO

16.2 Worst-case sensitivity scenario in the short term

Starting from the optimal wind and PV capacities calculated in the scenario 2025, the Consultant analysed a sensitivity scenario with the aim to assess the VRES penetration that could be achieved in the short term considering the worst-case scenario for system development. In the light of the time to market for utility-scale VRES projects, the year 2022 was selected as target year for the short-term scenario. The demand growth up to 2022 was considered, neglecting the committed and planned projects concerning the programmable generation fleet (hydro and fossil fuels) and the transmission network; i.e. the worst-case scenario for the system development in the short term.

The Consultant simulated the system operation during the whole year 2022, hour by hour (8,760 hours), assessing the VRES penetration level that can be reached with only the existing and under construction generation and transmission network facilities. The following assumptions have been applied:

- Demand expected in 2022, including the domestic demand, the transmission and commercial losses and the firm export according to the existing PPAs;
- Programmable generation fleet (hydro and fossil fuels) including only the existing and under construction power plants in 2020;
- Hydropower availability according to the average values from historical data (normal water availability)
- Transmission network like the current condition (year 2020), including also under construction projects;

The specific assumptions that have been applied are defined more in detail hereafter.

ASSUMPTIONS

Demand

Table 16.11 shows the peak power demand and the yearly energy demand that were applied in the power system model. The demand figure includes the domestic demand expected in 2022, the Transmission & Commercial losses and the firm export according to the existing PPAs with DRC and Malawi. The future PPAs considered in the scenarios 2025 and 2030 were neglected (100 MW with Namibia and additional 50 MW with Malawi).

Table 16.11 – Assumptions on the demand

Year 2022	Peak Power [MW]	Energy Demand [GWh/year]
Domestic Load	2,265	15,492
Firm Export to DRC	200	1,577 [25]
Firm Export to Malawi	20	158 [25]
Firm Export to Namibia	0	0
T&C Losses (12%)	339	2,349
Sent-out	**2,824**	**19,576**

[25] Value calculated considering the peak power with 90% load factor

Generation Fleet

About hydro and fossil fuel power plants, only the existing power plants have been considered available. The committed and planned projects (86 MW Lusiwasi Lower and 15 MW Chishimba Falls) have been considered unavailable while the under-construction hydro projects (750 MW Kafue Gorge Lower and 15 MW Lusiwasi Upper) have been assumed in service.

Under these assumptions the following generation fleet have been considered in the base case:

- **Hydro Power Plants**: 3,163 MW maximum power able to produce 15,305 GWh/year in the average year (according to Table 6.7);
- **Conventional Power Plants** (Coal and HFO): 370 MW maximum power;
- **PV Power Plants:** 75.7 MW maximum power.

Starting from the above-mentioned generation fleet the Consultant assessed the additional PV and wind installed capacity that can be integrated in the Zambian power system in the worst-case sensitivity scenario in 2022.

Operating Reserve Requirements

Currently, only Kafue Gorge power plant is equipped with the AGC able to provide the fast balancing service (response within 10 seconds and full activation within 10 minutes) needed to maintain the frequency in the standard frequency range. When Kafue Gorge is activated to limit the frequency error, Kariba North Bank is operated to restore the operating reserve in Kafue Gorge. Now Kariba North Bank provides only the slow operating reserve while Kafue Gorge the fast-operating reserve.

The installation of the AGC in Kariba North Bank is planned, however, differently from scenarios 2025 and 2030, **the AGC was considered available only in Kafue Gorge power plant to simulate the worst-case scenario in short term**. With this assumption, only Kafue Gorge provides the fast balancing service needed to manage the variability and unpredictability of VRES power plants in the sensitivity scenario.

Transmission network

Only the existing transmission network and some network reinforcements near to the completion were considered to simulate the worst-case scenario for the development of the transmission network facilities. Starting from the PSS/E model 2022 provided by the ZESCO during the data collection phase (File "ZAM-DRC_v12_2022.sav"), the Consultant applied a downgrade of the network model until reaching the current grid topology, including also the under-construction projects with expected COD by 2022. All grid projects under construction have been included ("Lusiwasi Upper- Lusiwasi Evacuation Line", "330kV Mpika substation", "Chipata - Lundazi - Chama" and "Upgrade of transformers at Kitwe and Luano". Projects number 1, 2, 3 and 9 according to Table 6.12, respectively); furthermore, the committed project "Kafue Gorge Lower Power Evacuation" with COD 2020 (project number 4 according to Table 6.12) has been included to allow the power evacuation from Kafue Gorge power plant considered in the scenario). In this context, only the existing interconnections with the net transfer capacities highlighted in Table 6.13 have been considered.

Figure 16.10 shows the configuration of the existing transmission system in Zambia.

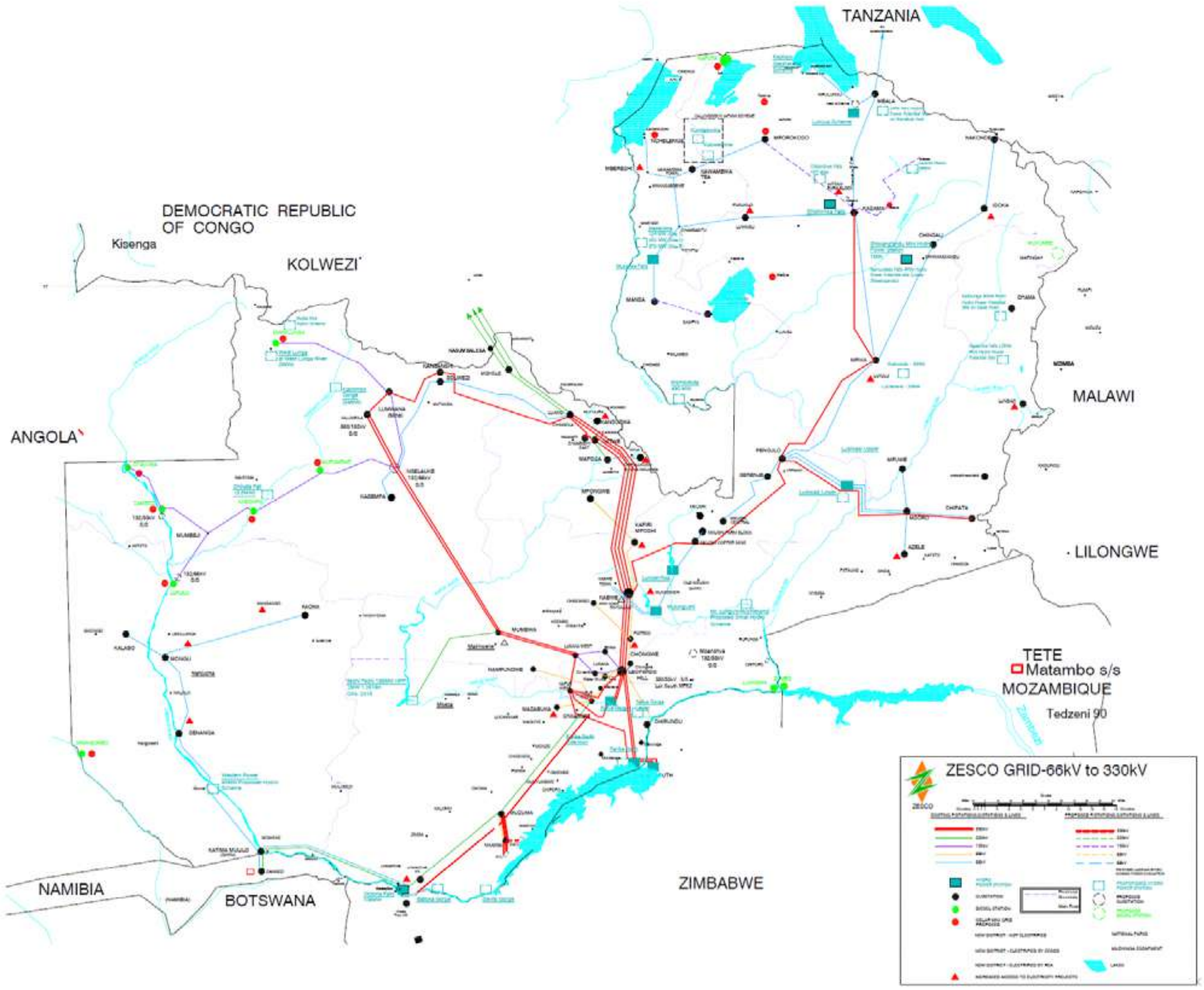


Figure 16.10 – Existing transmission system in Zambia. Source ZESCO

METHODOLOGY

The Consultant applied an iterative approach to assess the penetration level of VRES comply with the current generation and transmission network facilities (the current operating reserve availability and the grid loadability[26]). The schematic process of the methodology is highlighted in Figure 16.11 and can be summarized as follow:

- The starting point is the optimal wind and PV capacities calculated in the scenario 2025. These capacities are the input for the first run of the simulation.
- The operation of the power system is simulated hour by hour with GRARE tool analysing a whole year with a probabilistic approach (Monte Carlo method);
  - An optimization of the hydropower is carried out maximizing the security of supply and minimizing the system costs;
  - Constraints in the operating reserve requirements are analysed;
  - VRES production curtailments due to over-generation phenomena (production greater than demand) and/or network overloads are highlighted;
- If reserve constraints occur, a reduction of wind and PV installed capacities is applied;
- If VRES production curtailments (≥1% of expected production from VRES power plants) occur due to over-generation phenomena or network overloads, a reduction of wind and PV installed capacities is applied;
- The process was iterated until the secure operation of the power system, without additional network reinforcements. Several pathways for reducing the VRES installed capacity have been analysed to provide a range of feasible VRES capacity mixes;
- Considering the time to market for utility-scale PV and wind power plants, the projects already committed (370 MW PV against 0 MW wind projects) and the candidate projects provided by the working group, **the Consultant highlighted three combinations of PV and wind capacities that can be installed in 2022 with the aim to provide a range of feasible solutions.** The following scenarios have been identified:
  - **100% PV:** maximum PV integration without any wind power plants, following the trend of the requests for connection that see the predominance of PV projects in the short term;
  - **Current roadmap**: integration of the whole set of committed projects and candidates indicated by the working group (660 MW PV and 130 MW wind projects) on top of the existing PV power plants (76 MW);
  - **Balanced VRES:** scenario with only existing PV power plants, committed PV projects and additional PV and wind installed capacity (candidates) for a more balanced VRES energy mix.

[26] The grid loadability has been analysed in term of maximum load of lines and transformers of the networks with a voltage level greater than 66 kV. The voltage constraints have not been analysed because they are out of scope and out of the range of GRARE analyses.

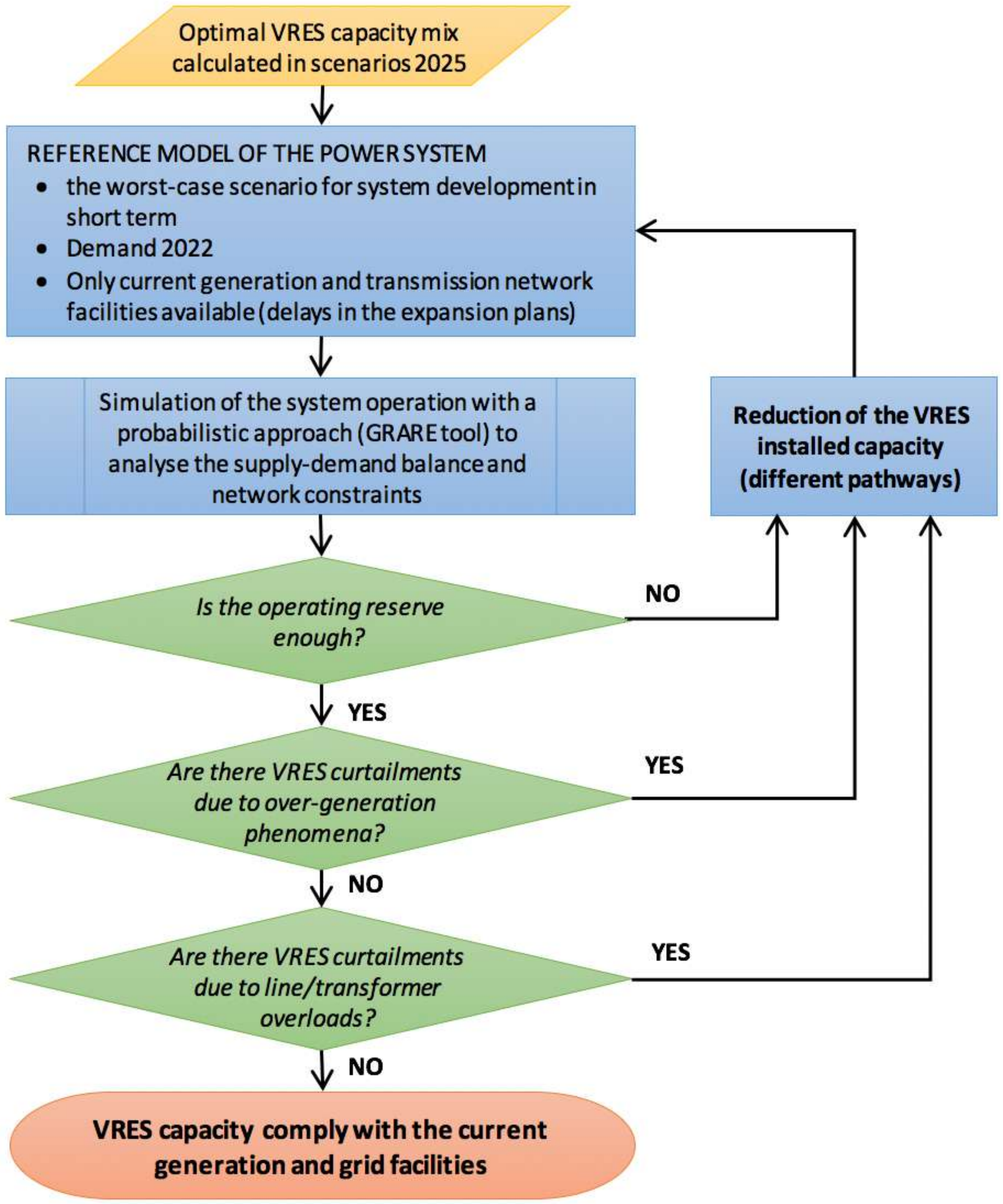


Figure 16.11 – Methodology for the worst-case sensitivity scenario in 2022

Expected outcomes

- The wind and PV capacities that can be installed in the short-term scenario, comply with the current generation and transmission network facilities;
- The most suitable distribution of wind and PV installed capacity in the network (reference substations);
- The possible unserved energy in the isolated scenario and the power exchanges with the neighbouring countries in the interconnected scenario.

RESULTS

The simulation of the system operation in the base case, i.e. with only the existing VRES power plants, highlights network constraints due to the growth of load in Lusaka area. Network overloads result on the Leopards Hill – Roma – Lusaka West - Coventry - Leopards Hill 132 KV ring due to the connection of new customers expected by 2022. The 132 kV overhead line "Leopard Hill – Water Works" is overloaded 8,500 h/year while the 132 kV overhead line "Leopard Hill – Roma" exceeds the maximum capacity more than 600 h/year, with the maximum load reaching more than double the maximum capacity.

A network reinforcement named Lusaka Transmission and Distribution System Rehabilitation Project (LTDRP) has been already defined by ZESCO to increase the capacity and to improve the security of supply in the Lusaka area. The project includes the upgrade of Leopards Hill – Roma – Lusaka West - Coventry - Leopards Hill 132 kV ring to 400 MVA and the third 250 MVA transformer 330/132 kV in Leopards Hill S/S (Figure 16.12). The project allows to avoid unserved energy equal to 3% of the demand (580 GWh/year).

Table 16.12 shows the overloads hours without LTDRP, the maximum load registered in Monte Carlo simulations on the 132 kV ring without and with the LTDRP and the avoided ENS thanks the LTDRP resulting by GRARE simulations.

In light of the huge network congestions due to the increase of load in Lusaka area, the Consultant integrated the Lusaka Transmission and Distribution System Rehabilitation Project in the base network model to limit the load shedding and to avoid excessive network congestions independent by VRES integration. This is the minimum system reinforcements required by the target year for better network performance.

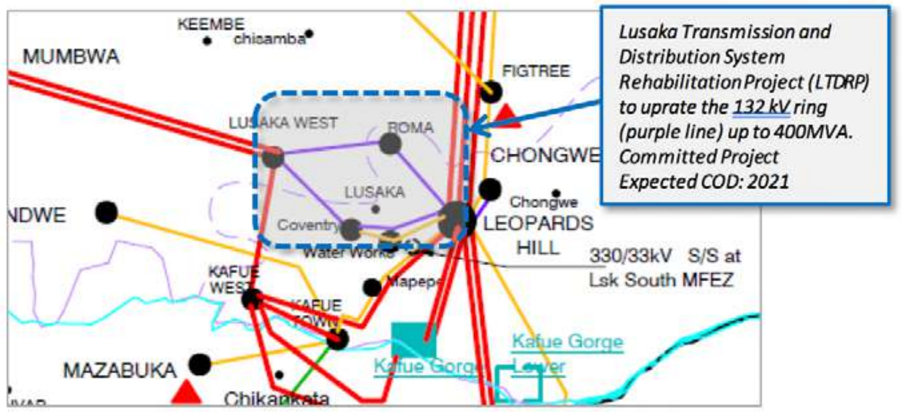


Figure 16.12 – Lusaka Transmission and Distribution System Rehabilitation Project (LTDRP) of the 132 kV ring

Table 16.12 – Load of 132 kV ring in Lusaka area without (w/o) and with (w/) the LTDRP

Type	Name From	Name To	kV From	kV To	Overload w/o LTDRP [h/year]	Max Loading w/o LTDRP	Max Loading w/ LTDRP	Avoided ENS w/ LTDRP [GWh/year]
Line	CVNTR1	LSKWT132	132	132	11	280%	57%	580 (3% of demand)
Line	LEPRD1	WTRWK132	132	132	8,521	256%	69%	
Line	ROMA1	LEPRD1	132	132	662	226%	61%	
Line	CVNTR1	WTRWK132	132	132	14	152%	44%	
Line	ROMA1	LSKWT132	132	132	7	140%	31%	
Transformer	LEPRD3	LEPRD1	330	132	1	130%	61%	
Transformer	LEPRD3	LEPRD1	330	132	1	130%	61%	

The PV and wind capacities that can be integrated in the Zambian electric power system in the analysed scenarios 2022 ("100% PV", "Current Roadmap" and "Balanced VRES") even if delays will occur in the development of transmission network reinforcements and programmable generation fleet are shown in Figure 16.13. As before mentioned, three capacity mixes were selected for each exchange condition to provide a range of feasible solutions comply with the system security and the time to market for the development of new projects by 2022.

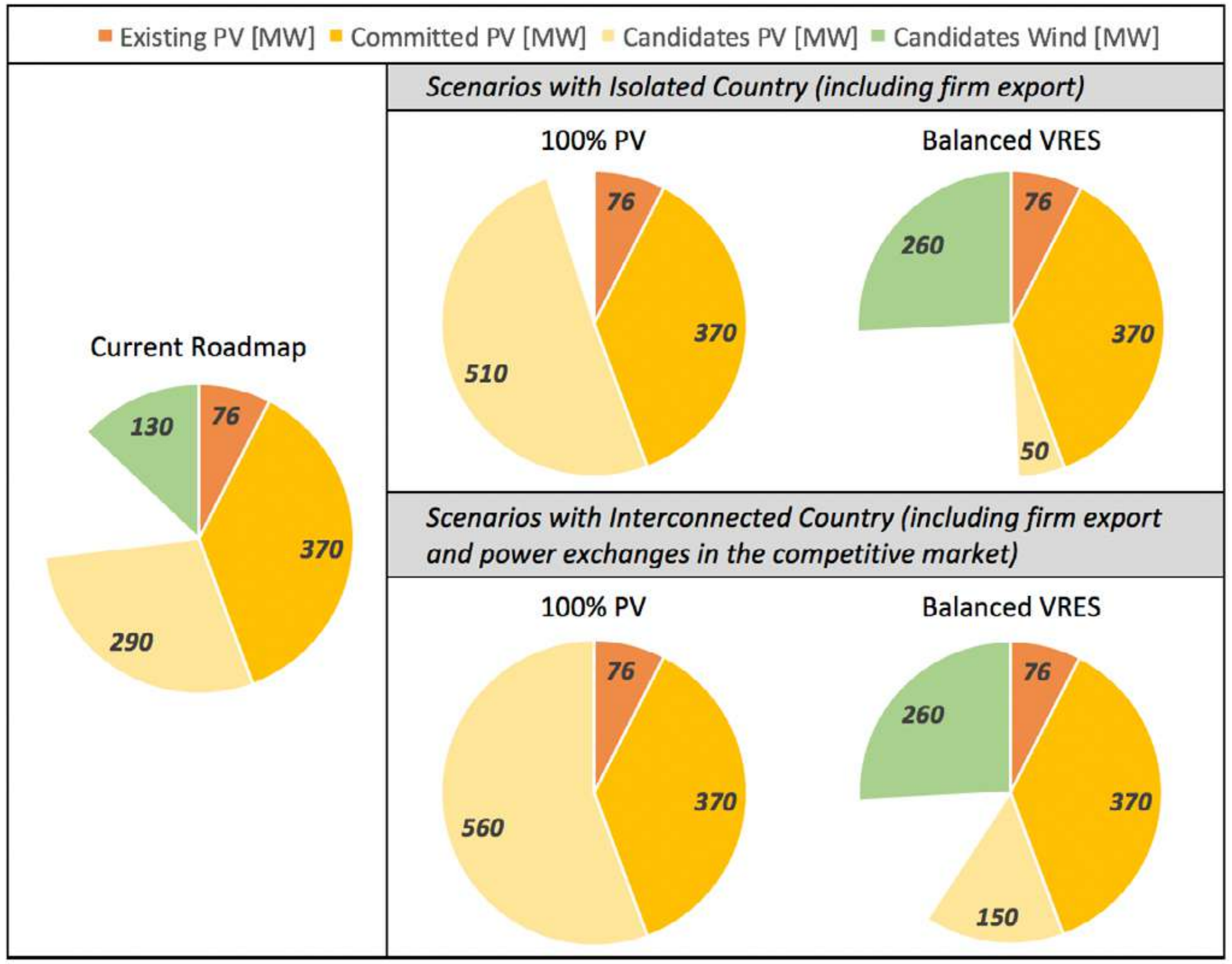


Figure 16.13 – Possible VRES capacity mixes by 2022

Without power exchanges with the neighbouring countries greater than the assumed firm export (**i.e. scenarios with Isolated Country**), the main constraint for VRES development is the over-generation phenomenon. In some hours of the year the generation in Zambia is greater than the available demand and production curtailment actions are needed to balance the system and assure the system security; the maximum VRES production curtailment resulting by the integration of the VRES capacity mixes previously presented is equal to 0.8% of the total energy production from VRES power plants in a year. This is an acceptable limitation at the beginning of a VRES integration path, even considering the lack of power exchanges over the firm export assumed in the scenario. Additional PV or wind capacity in each scenario would lead excessive production curtailments due to over-generation phenomena; under isolated conditions the reserve requirements or the capacity of the transmission network do not limit the development of the VRES capacity mixes found by the simulations. The dominate hours where there is curtailment of VRES production (PV+wind) at various analysed combination between PV and wind capacity are highlighted in Annex 4 – Worst-case sensitivity scenario in the short term.

The current roadmap of VRES development in Zambia includes 370 MW of committed projects and 290 MW of candidates from PV source by 2022 and 130 MW of wind project candidates by 2023 (Table 6.9 and Table 6.10).

Even without energy exchanges with the interconnected countries on the competitive market (scenarios with "Isolated Country"), Zambia would be able to integrate all PV projects included in the current roadmap by 2022 (660 MW) reaching 736 MW installed capacity from PV power plants in 2022. From this condition:

- +130 MW wind installed capacity could be integrated by 2022 without relevant over-generation problems or network overloads (scenario "Current Roadmap"); or
- +220 MW PV installed capacity on top of the projects in the Country pipeline could be integrated if no wind projects will be developed by 2022. Zambia would be able to integrate up to 956 MW PV installed capacity with 9.7% penetration by 2022 following a development path with only PV power plants (scenario "100% PV").

The maximum PV installed capacity shall be reduced if additional wind projects want to be integrated into the system by 2022. Assuming the integration of the existing and committed PV projects (446 MW), up to 260 MW wind power plants and additional 50 MW PV installed capacity could be integrated in the system (scenario "Balanced VRES").

The integration of Zambia in SAPP allows power exchanges among the SAPP Members on the competitive market. Additional energy exchanges on top of the firm export resulting from bilateral agreements would improve the system security increasing the security of supply and avoiding production curtailments due to over-generation phenomena in the system. So, the market integration (**scenarios with Interconnected Country**) would allow to increase the VRES integration, however only few projects can be integrated on top of those calculated in the isolated scenarios due to network constraints. While over-generation phenomena were the main constraints in the isolated scenarios, the network overloads become the main constraints in the interconnected scenarios. Only 50 MW PV installed capacity can be added in the scenario "100% PV" and 100 MW PV installed capacity in the scenario "Balanced VRES" because of VRES production curtailments due to network overloads, limited to 0.5% of the expected VRES annual production.

The results of the worst-case sensibility scenarios show different path for the VRES integration in the short term to achieve the optimal VRES capacity mixes found for the mid- and long-term scenarios under normal (average) water availability; greater PV integration implies a lower wind integration and vice versa. The development plans for PV and wind generation are shown in Figure 16.14.

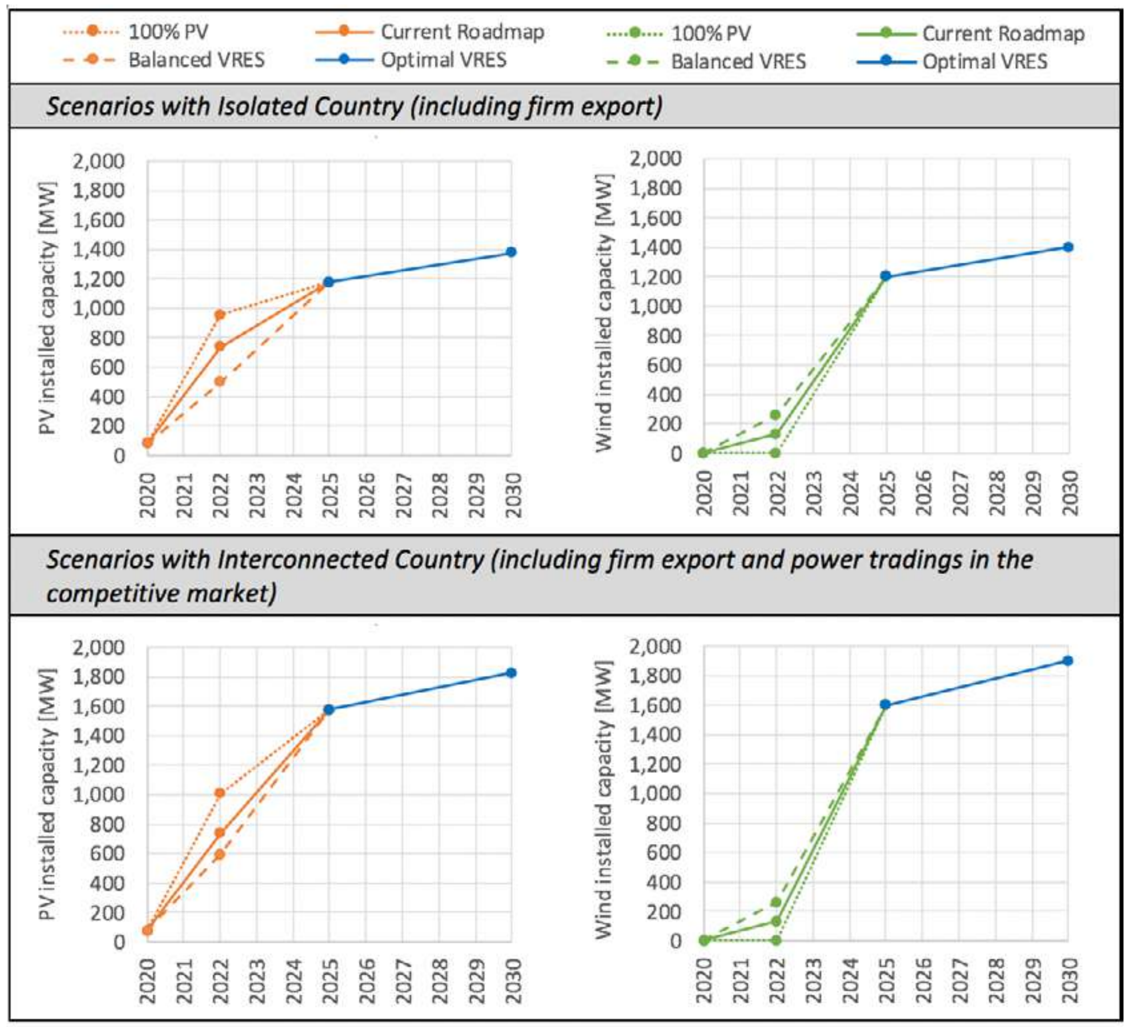


Figure 16.14 – VRES development plan 2020-2030

Table 16.13 shows the results of the system reliability impact study performed according to the before mentioned methodology, considering both the condition of isolated Country (i.e. neglecting power trading with the interconnected countries on the competitive market) and interconnected Country (i.e. considering the opportunity for power trading on the competitive market). For each scenario ("100% PV", "Current Roadmap" and "Balanced VRES") and each variable energy source (PV, wind and total VRES as sum of PV and wind) the following results are highlighted:

- Installed Power ("Pinst"): maximum power that could be integrated in the electric power system without affecting the security of the system, including the existing PV power plants;
- System Over-Generation ("System OG"): amount of power production that cannot be integrated in the system because the demand is lower than the available generation;
- Network Over-Generation ("Network OG"): amount of power production that cannot be integrated in the system due to lines and/or transformers overloads;

- Production Curtailment ("Prod. Curtail."): production curtailment due to system and local over-generation phenomena, as a percentage of expected power production (gross production);
- Net Production ("Net Prod."): annual energy that can be integrated in the system; i.e. production net of curtailments;
- Net Capacity Factor ("Net CF"): ratio between the net production over a period of one year and the potential output if the operation at full nameplate capacity could be possible continuously over the same period;
- Penetration Level: the share of energy demand that can be supplied by PV, wind or total VRES power plants;
- Weighted Average LCOE: average levelized cost of electricity weighted on the installed capacity of each project; this value provides an indication of the cost of each solution;
- ENS Reduction: the energy not supplied avoided due to VRES integration, resulting from the comparison between the scenario with only existing VRES capacity and the scenario with enhanced deployment of VRES;
- Residual ENS: energy not supplied remaining in the system after VRES integration, due to lack of power, lack of interconnection or line/transformer overload.

Table 16.13 – Results of the worst-case sensitivity scenario 2022, with isolated and interconnected Country

Scenario	Source	Pinst [MW]	System OG [GWh/yr]	Network OG [GWh/yr]	Prod. Curtail. [%]	Net Prod [GWh/yr]	Net CF [%]	Penetration Level [%]	Weighted Average LCOE [US$c/kWh]	ENS reduction [%]	Residual ENS [p.u. demand]
Isolated Country											
100% PV	PV	956	15.62	0.46	0.8%	1,893	22.6%	9.7%	5.57	-91.7%	5.8E-03
	Wind	0	0.00	0.00	0.0%	0	0.0%	0.0%	0.00		
	VRES	***956***	***15.62***	***0.46***	***0.8%***	***1,893***	***22.6%***	***9.7%***	***5.57***		
Current Roadmap	PV	736	4.06	0.51	0.3%	1,468	22.8%	7.5%	5.69	-91.0%	6.3E-03
	Wind	130	1.22	0.03	0.3%	379	33.3%	1.9%	8.83		
	VRES	***866***	***5.28***	***0.54***	***0.3%***	***1,847***	***24.4%***	***9.4%***	***6.33***		
Balanced VRES	PV	496	2.97	0.55	0.4%	990	22.8%	5.1%	5.11	-92.0%	5.6E-03
	Wind	260	5.16	0.07	0.6%	903	39.6%	4.6%	6.26		
	VRES	***756***	***8.13***	***0.62***	***0.5%***	***1,893***	***28.6%***	***9.7%***	***5.66***		
Interconnected Country											
100% PV	PV	1,006	0.00	9.93	0.5%	1,999	22.7%	10.2%	5.52	-98.9%	0.3E-05
	Wind	0	0.00	0.00	0.0%	0	0.0%	0.0%	0.00		
	VRES	***1,006***	***0.00***	***9.93***	***0.5%***	***1,999***	***22.7%***	***10.2%***	***5.52***		
Current Roadmap	PV	736	0.00	1.45	0.1%	1,471	22.8%	7.5%	5.69	-95.6%	1.2E-05
	Wind	130	0.00	0.31	0.1%	380	33.4%	1.9%	8.81		
	VRES	***866***	***0.00***	***1.76***	***0.1%***	***1,851***	***24.4%***	***9.5%***	***6.32***		
Balanced VRES	PV	596	0.00	5.46	0.5%	*1,186*	22.7%	6.1%	5.36	-99.0%	0.3E-05
	Wind	260	0.00	5.82	0.6%	902	39.6%	4.6%	6.26		
	VRES	***856***	***0.00***	***11.28***	***0.5%***	***2,088***	***27.9%***	***10.7%***	***5.75***		

The energy demand expected in 2022 is 19.6 TWh/year, including the firm export and the transmission and commercial losses. The existing power plants are not enough to assure the security of supply in the isolated scenario: 7% unserved energy (1.4 TWh/year) is expected without import from the neighbouring countries.

The integration of the VRES capacities calculated in the scenarios with isolated Country can supply most of the unserved energy (-92% ENS reduction is expected) but they are not enough to meet the targets of security of supply. Up to 2.0 TWh/year from VRES generation can be integrated (9.7% VRES penetration) but 0.6% of the demand continue to be unserved.

The exploitation of the existing interconnections does not allow a significant growth of the VRES penetration compared to isolated scenario (VRES penetration achieves 10.7% of the demand). Constraints in the current transmission network limit the exploitation of additional VRES in 2022. However, the exploitation of the existing interconnections leads benefits for the security of supply avoiding the lack of power in the system; the import of energy from the neighbouring countries allows reliability indexes lower than the defined targets (EENS ≤ 1.10-4 p.u. of the yearly demand, LOLE ≤ 48 h/year and LOLP ≤ 1%). The important interconnection projects to be developed in the mid and long term will allow a significant increase of VRES development in the Zambian electric power system as highlighted in medium and long-term scenarios.

Figure 16.15 and Figure 16.16 show the duration curves of the Zambian energy trading with the neighbouring countries expected in each scenario 2022 on the competitive market. These power exchanges are needed to meet the domestic demand, the transmission and commercial losses and the firm export agreements with DRC and Malawi. 2.28 TWh/year is the import requirement on the competitive market to meet the demand in the scenario with only the existing VRES power plants; 8,760 h of import are expected. The integration of additional VRES power plants would reduce the import requirements by more than half: 1.11 TWh/year are needed in the scenario "Current Roadmap", 0.96 TWh/year in the scenario "100% PV" and 0.88 TWh/year in the scenario "Balanced VRES".

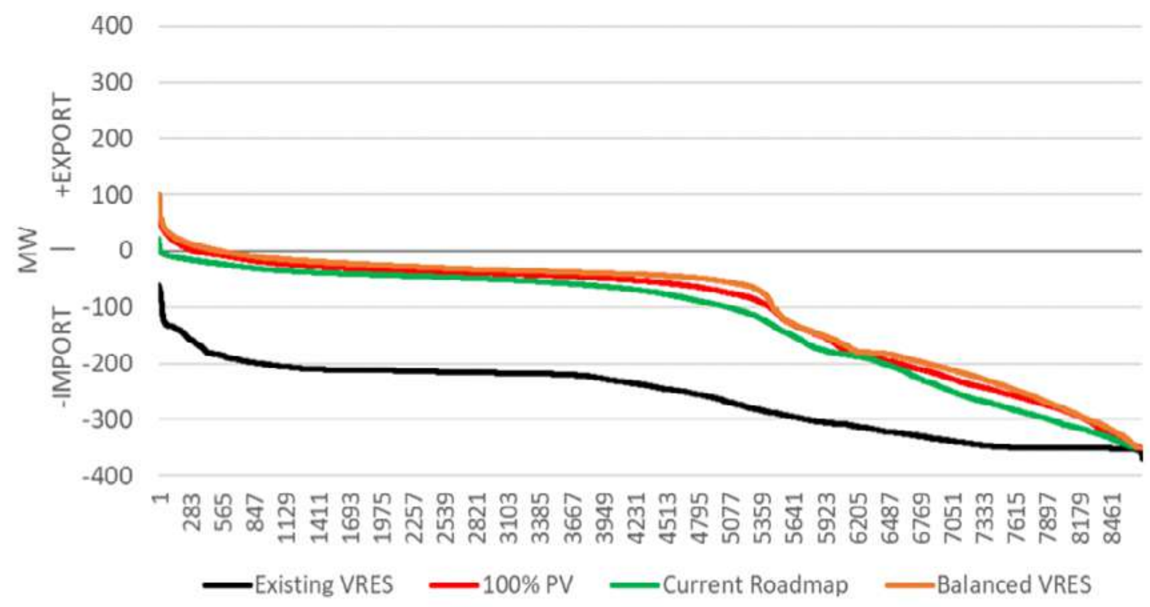


Figure 16.15 – Duration curve of power exchanges of Zambia on the competitive market in 2022 (worst-case sensitivity scenarios with Interconnected Country)

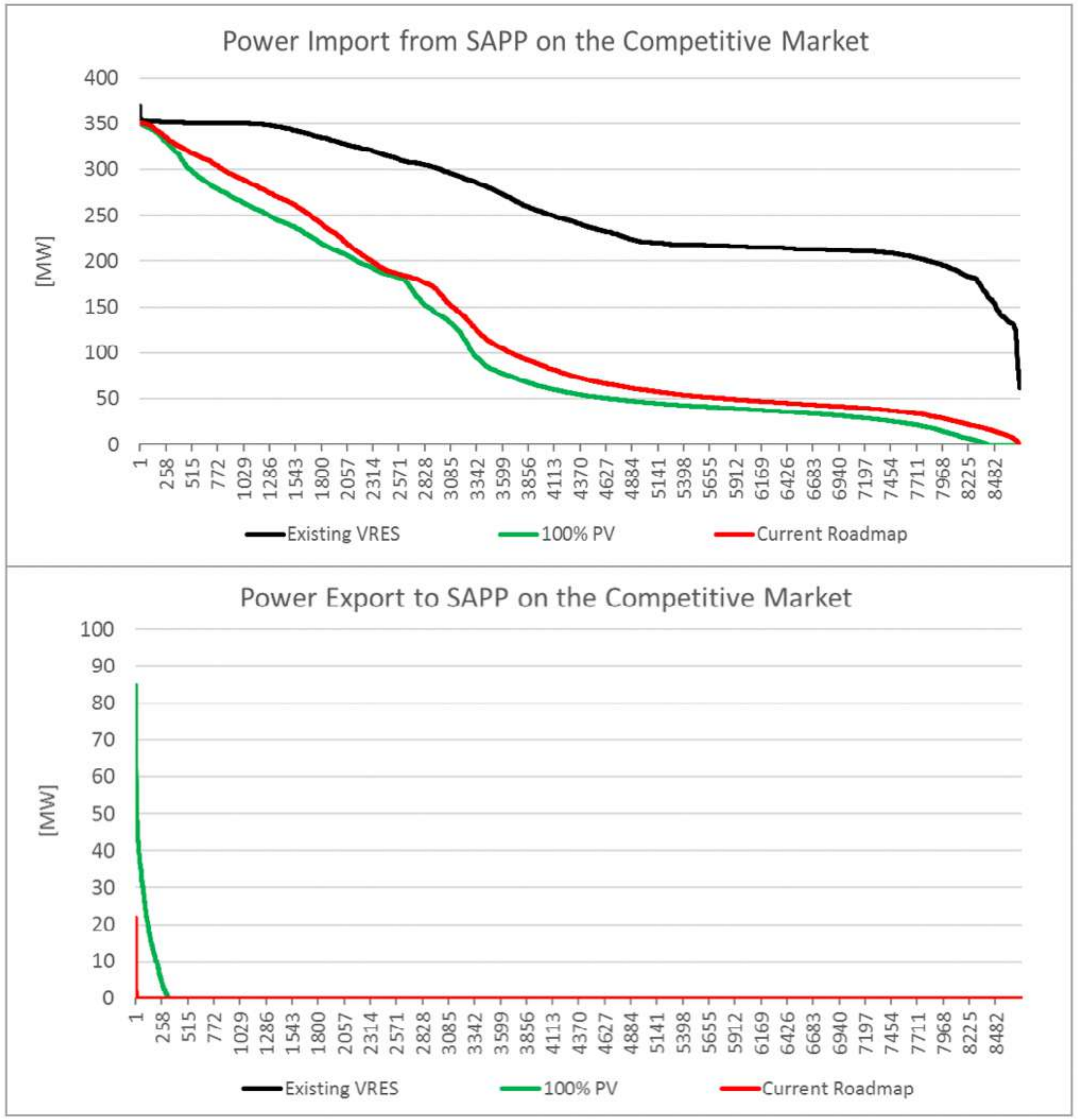


Figure 16.16 – Duration curves of Zambian import and export on the competitive market in 2022 (100% PV and Current Roadmap scenarios with Interconnected Country)

Table 16.14 and Table 16.15 show the distribution of PV and wind capacities at each substation at the target year 2022, in the worst-case scenario for the development of the transmission network and the programmable generation fleet. These capacities comply with the grid code reliability standards in Zambia (line and transformer loadings lower than or equal to 100% of transfer capacity) and minimize the energy curtailments due to network overloads or over-generation phenomena.

Table 16.14 – PV installed capacities at each substation in the worst-case sensitivity scenario 2022

	PV installed capacity [MW]					
	Isolated Country			Interconnected Country		
S/S	100% PV	Current Roadmap	Balanced VRES	100% PV	Current Roadmap	Balanced VRES
Kabwe	140	40	40	140	40	40
Kafue Town	40	40	40	40	40	40
Kafue West	70	-	-	70	-	-
Kariba	90	90	50	90	90	90
Kasama	-	-	-	-	-	-
Kitwe	-	-	-	-	-	-
Leopards Hill	150	150	50	150	150	110
Livingstone	-	-	-	-	-	-
Lusaka West	-	-	-	50	-	-
Lsk South MFEZ	76	76	76	76	76	76
Mumbwa	150	100	-	150	100	-
Muzuma	100	100	100	100	100	100
Mwambashi	40	40	40	40	40	40
Pensulo	100	100	100	100	100	100
TOTAL	956	736	496	1,006	736	596

Table 16.15 – Wind installed capacities at each substation in the worst-case sensitivity scenario 2022

	Wind installed capacity [MW]					
	ISOLATED			INTERCONNECTED		
S/S	100% PV	Current Roadmap	Balanced VRES	100% PV	Current Roadmap	Balanced VRES
Kabwe	-	-	-	-	-	-
Kafue West	-	-	-	-	-	-
Leopards Hill	-	-	80	-	-	80
Lusaka West	-	-	-	-	-	-
Mpika	-	-	-	-	-	-
Mumbwa	-	-	50	-	-	50
Pensulo	-	130	130	-	130	130
Chipata West	-	-	-	-	-	-
TOTAL	-	130	260	-	130	260

Table 16.12 shows the loadings of the overhead lines and ENH/HV transformers resulting from each scenario analysed in 2022, with a focus on the voltage levels greater than or equal to 66 kV. Each line and each transformer have been monitored during all the 500 Monte Carlo Years simulated with GRARE and the greatest power flows have been recorded. The frequency distributions of the load of overhead lines and transformers have been provided for each voltage level (330-220-132-88-66 kV), comparing the results of existing VRES scenario (black bars) with those from scenarios with an enhanced development of VRES (red, green and orange bars).

As expected, the growth of load without network reinforcements in 2022 leads a high loading of grid elements at each voltage level. Overloads of overhead lines and transformers already occur in the base case with only the existing VRES power plants (76 MW PV) and load shedding actions are needed to assure the security of the system. In this context the integration of the additional VRES power plants resulting by the simulations increases the security of supply and it does not affect the security of the system (no relevant network congestions have been detected due to VRES integration).

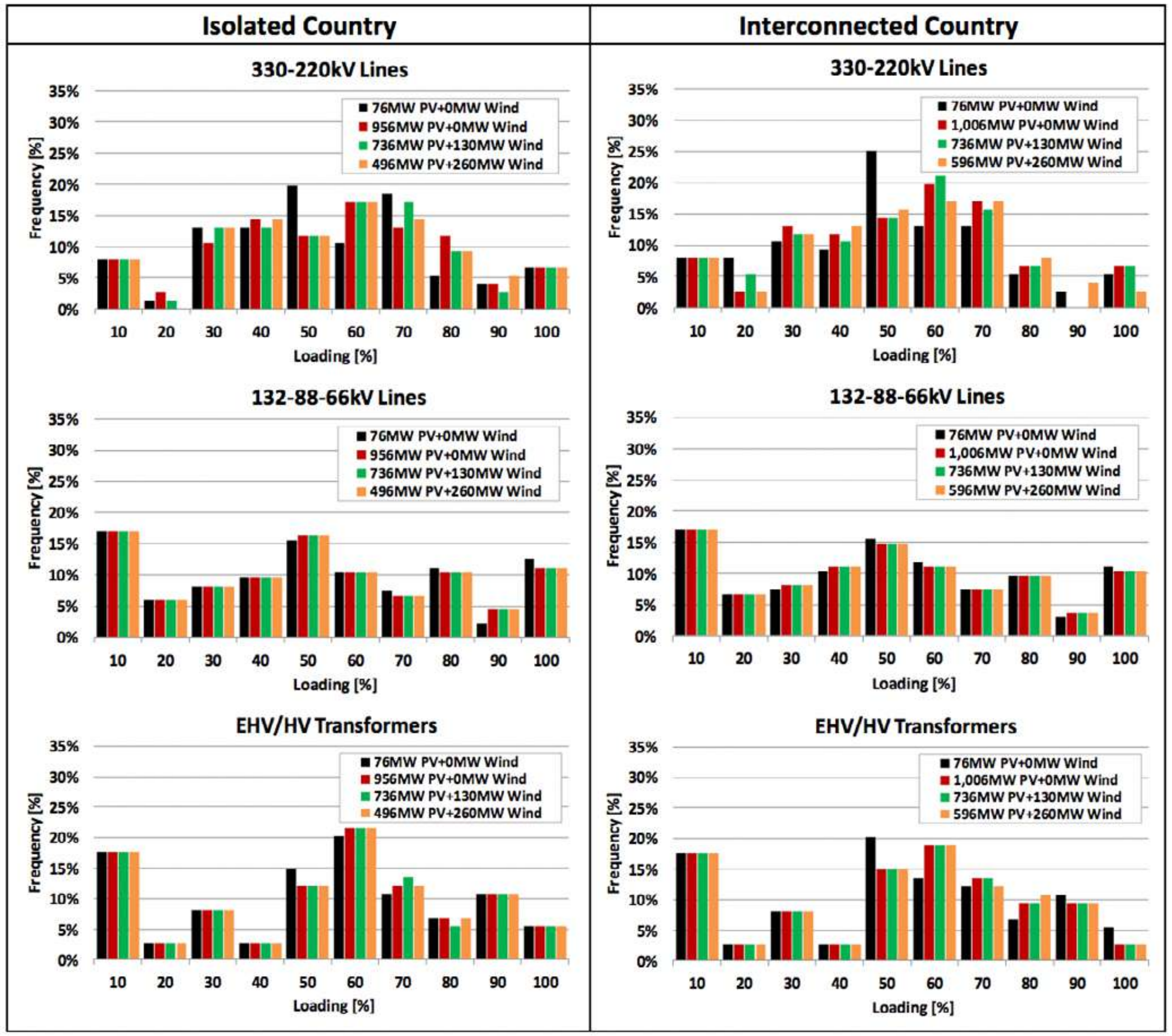


Figure 16.17 - Maximum loadability of the overhead lines and transformers in scenarios 2022

Figure 16.18 shows the transmission network map with the most loaded network elements found in both scenarios with isolated and interconnected Country; lines and transformers with maximum flow greater or equal than 80% of their rated power have been highlighted with red boxes. Similar network loading resulted by simulations with isolated and interconnected Country The lists of overhead lines and transformers with maximum loading greater or equal than 50% of rated power are shown in Annex 4.

330 kV overhead lines reach the rated power between Kafue West and Kafue Town and between Kariba and Leopard Hills, while 220 kV overhead lines reach the power limit between Muzuma, Victoria Falls and Sesheke. The greater loadings of network elements occur on the 88 kV overhead lines between Leopard Hill, Mapepe and Kafue Town and the 66 kV network between Mpika, Pensulo and Msoro. They depend mainly by the growth of load and delays in transmission reinforcements assumed in this worst-case sensitivity scenario. PV and wind installed capacities calculated in each simulated scenario are not critical for network loadability and they can be integrated in the system.

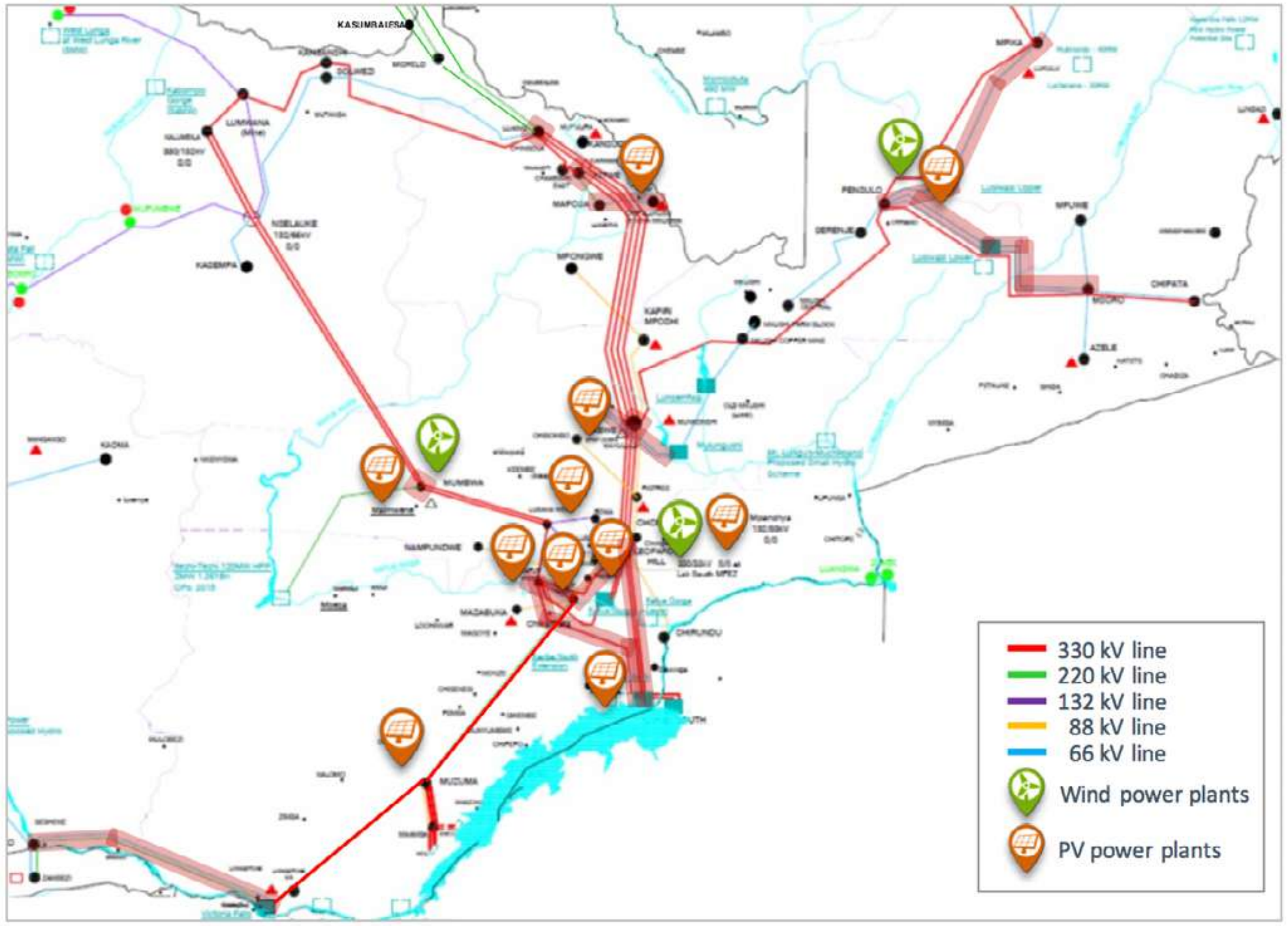


Figure 16.18 – Lines and transformer loadings greater than or equal to 80% of the maximum capacity. Scenarios 2022

17 CONCLUSIONS AND RECOMMENDATIONS OF THE STUDY

Zambia is rich in renewable energy resources, namely hydro, solar and wind energy: the identified potential includes hydropower in excess of 6,000 MW, 5.5 kWh/m2/day of annual average daily radiation and an average wind speed at 130 m between 7 and 8 m/s. This outstanding potential can be efficiently exploited in the power sector to boost generation in order to cope with the load growth (3.8% Compound Annual Growth Rate is expected in the period 2019-2030) and increase energy trade opportunities with the neighbouring countries. However, the deployment of RES generation, especially if variable as in the case of PV and wind, shall be accurately designed to ensure the compliance with reliability standards and security constraints. The exploitation of the flexibility of the generation fleet and the interconnections with the neighbouring countries becomes of utmost importance to follow the load pattern and for dealing with the variability of wind and PV generation.

The study clearly shown that additional capacity from VRES can be integrated in the Zambian electric power system, on top of the projects already in the Country's pipeline, maintaining high standards of security of supply and improving the system resilience in case of extreme climate conditions.

Starting from the existing and committed programmable generation fleet (such as hydropower and fossil fuels plants) and the existing VRES capacity (the PV power plants recently put in service), the Consultant performed two main analyses evaluating:

1. the possibility to guarantee the electrical self-sufficiency of Zambia in the mid- and long-term (target years 2025 and 2030) increasing only VRES capacity and neglecting candidates from other energy sources (e.g. hydropower candidates). The optimal VRES capacity mix to meet the domestic demand and the firm export has been assessed neglecting power trading with the interconnected countries on the competitive market (**scenario with isolated country**);
2. the opportunity to increase VRES integration exploiting the export capacity to the neighbouring countries and the power trading on the competitive market (**scenario with interconnected country**).

It is worth to underline that the aim of this VRES integration study was to calculate the optimal VRES integration in the Zambian electric power system given the existing and committed hydro and fossil fuel generation fleet. The study was not a least costs generation expansion plan, therefore, no candidates from non-VRES technologies (e.g. hydropower candidates) were analysed.

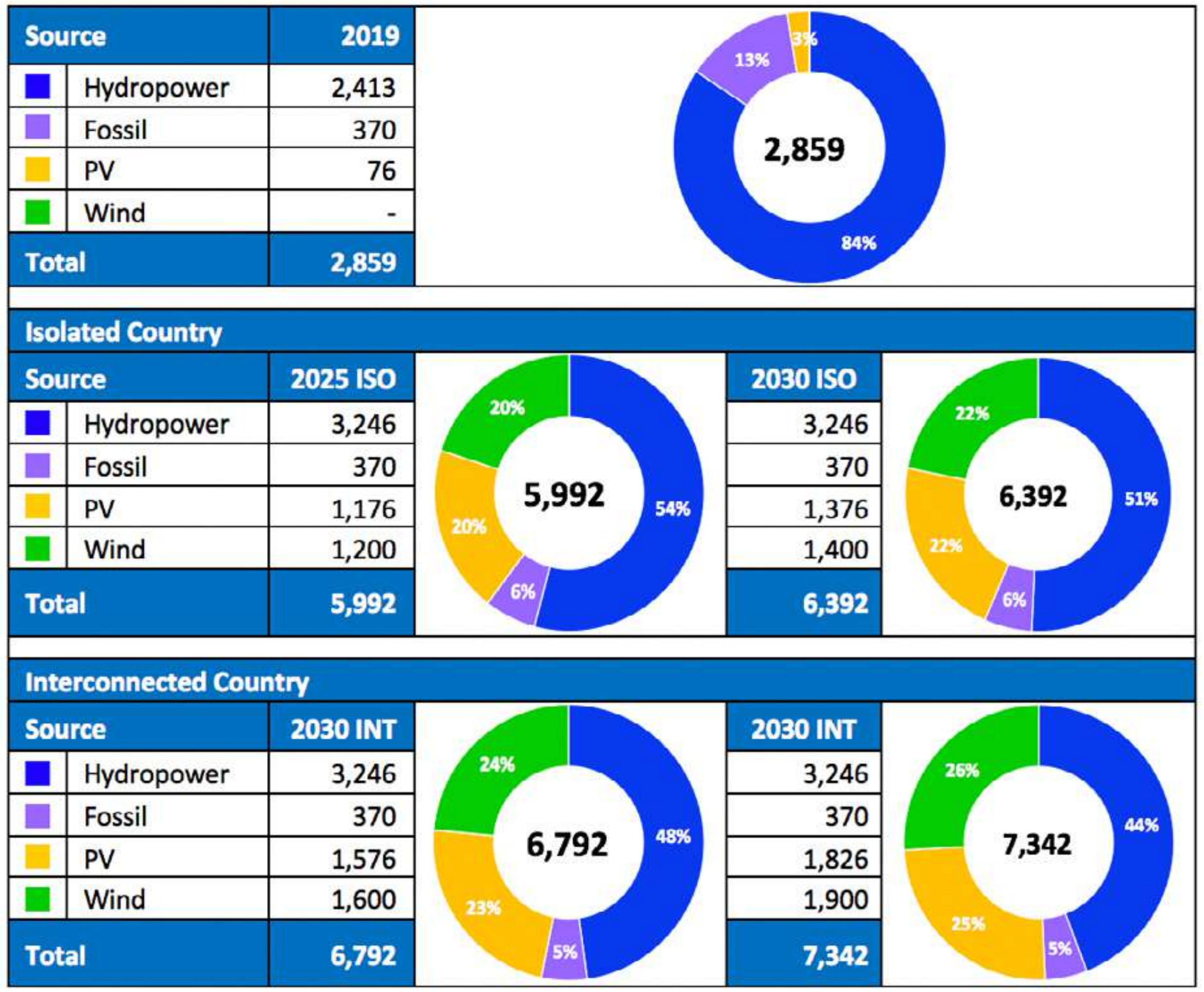
The following wind and PV capacities can be installed in Zambia without the exploitation of the interconnections (scenario with isolated country):

- up to 1,176 MW from PV and 1,200 MW from wind in 2025;
- up to 1,376 MW from PV and 1,400 MW from wind in 2030.

+34% VRES installed capacity can be integrated both in the mid- and long-term scenarios exploiting the interconnections and the export in the competitive market (scenario with interconnected country):

- up to 1,576 MW from PV and 1,600 MW from wind in 2025;
- up to 1,826 MW from PV and 1,900 MW from wind in 2030.

Figure 17.1 shows the generation capacity mix that could be achieved in Zambia in the mid- and long-term: VRES capacity could reaches 47% of the total generation fleet in 2025 and it grows up to 51% in 2030 interconnected scenario.



Source	2019
Hydropower	2,413
Fossil	370
PV	76
Wind	-
Total	2,859

Isolated Country

Source	2025 ISO	2030 ISO
Hydropower	3,246	3,246
Fossil	370	370
PV	1,176	1,376
Wind	1,200	1,400
Total	5,992	6,392

Interconnected Country

Source	2030 INT	2030 INT
Hydropower	3,246	3,246
Fossil	370	370
PV	1,576	1,826
Wind	1,600	1,900
Total	6,792	7,342

Figure 17.1 – Maximum power of Zambian generation fleet in the mid- and long-term

High share of VRES penetration[27] and a well-balanced energy mix can be achieved both in the mid- and in the long-term scenarios reducing the dependency from hydropower and increasing the security of supply:

- Without power trading on the competitive market, about 27% VRES penetration can be achieved both in 2025 and 2030; 10% from PV and 17% from wind power plants. Hydropower production (15.6 TWh/year both in 2025 and in 2030) supplies 64% of the demand[28] in 2025 and 56% in 2030. Up to 2.8 TWh/year PV and 4.8 TWh/year wind productions are expected within the year 2030.
- The exploitation of the power export on the competitive market can increases the VRES penetration up to 36% (13% from PV and 23% from wind power plants) while also improving the security of supply. In 2030, PV and wind productions achieve 3.7 TWh/year and 6.5 TWh/year respectively.

[27] The VRES penetration is the share of energy demand that can be supplied by VRES power plants

[28] The demand includes domestic consumptions, firm export and transmission and commercial losses

Without power import from the neighbouring countries, wind and PV installed capacities calculated in the isolated scenario are not enough to meet the demand assuring a security of supply in compliance with the Zambian reliability standard. Therefore, additional flexible capacity should be integrated if the electrical self-sufficiency of Zambia would be assured: 100 MW power plants with 48% capacity factor by 2025 and 570 MW power plants with 30% capacity factor[29] by 2030.

The interconnections and the integration between countries allow a more secure operation of the system in presence of VRES, alongside a greater VRES integration. The exploitation of the import/export capacity is advised to decrease the stress in the operation of hydroelectric power plants with reservoir in Zambia to cope with the variability of wind and PV production. Economic benefits can be captured both by Zambia and the neighbouring countries. Zambia could benefit from the mutual support of the neighbouring countries, avoiding load shedding or generation curtailment, while SAPP could reduce the generation costs from fossil fuel power plants exploiting more cheaper energy sources in southern African regions.

The great amount of hydroelectric generation, largely coupled with high capacity reservoir, owns a suitable operational flexibility that plays a key role in the development of wind and PV power production in Zambia. Changes are expected in hydropower management, from a demand-dependent approach to a VRES-dependent approach. As highlighted in Figure 17.2, without power trading on the competitive market (left side), a hydropower displacement from the daytime hours to the night hours is expected to make room to the PV production. The integration of the Countries in the competitive market (right side in Figure 17.2) allows a better integration of VRES and makes convenient the power import during the night, when the SAPP price is low, and the power export during the daytime hours when the SAPP price is higher than the price in Zambia. Import helps to meet the demand avoiding unserved energy, while export can allow the full exploitation of VRES avoiding production curtailments, mainly during the daytime hours. In this context, hydro power plants can operate to maximise VRES integration and the economic benefits of energy trade, exploiting the market price.

Interconnections with the neighbouring countries improve the flexibility of the system to cope with the variability and uncertainty of VRES production, maintaining the security of supply and avoiding over-generation phenomena. Up to 2.9 TWh/year import and 2.8 TWh/year export are expected in 2030 under normal water availability condition (average year). Interconnections allow also the exploitation of the renewable energy during both the wet years (increasing export) and the dry years. In the long term, Zambia becomes a net exporter during the wet years, with up to -80% import and +138% export; while Zambia becomes a net importer during the dry years with up to +76% import and -64% export.

[29] The capacity factor of a power plant, or group of power plants, is the ratio between the actual output over a period (typically one year) and the potential output if the operation at full nameplate capacity could be possible continuously over the same period of time

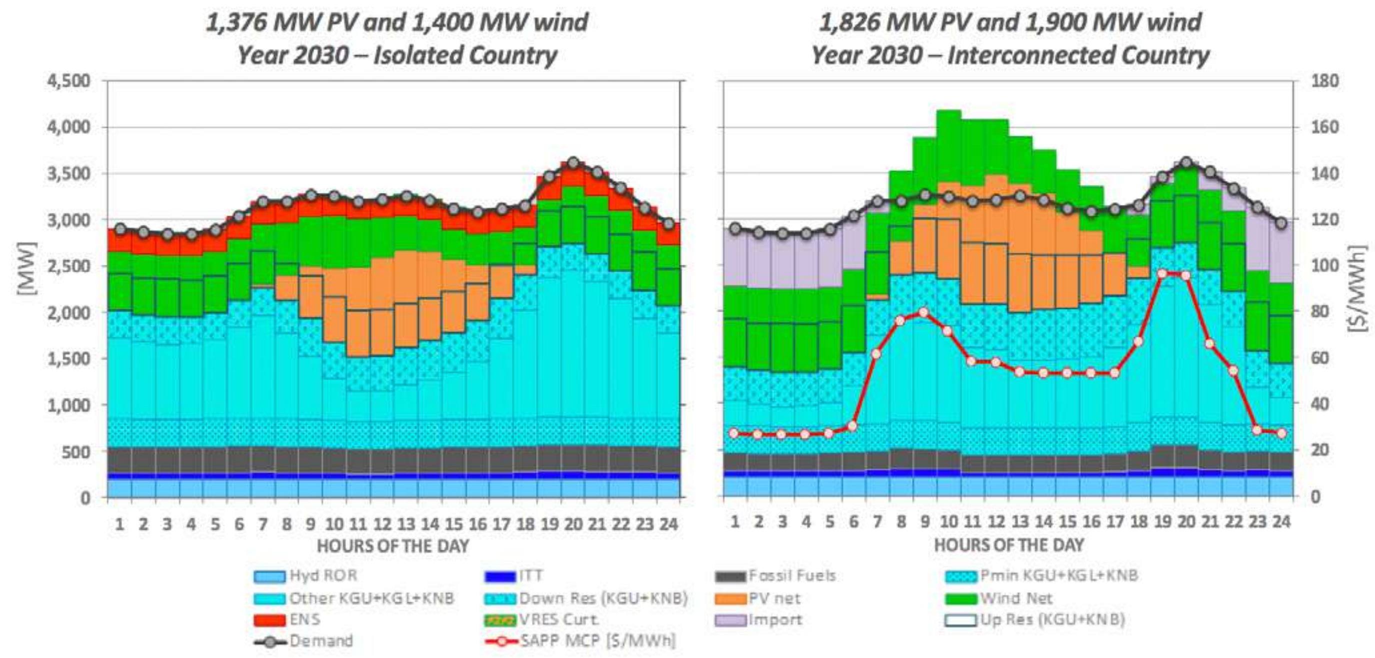


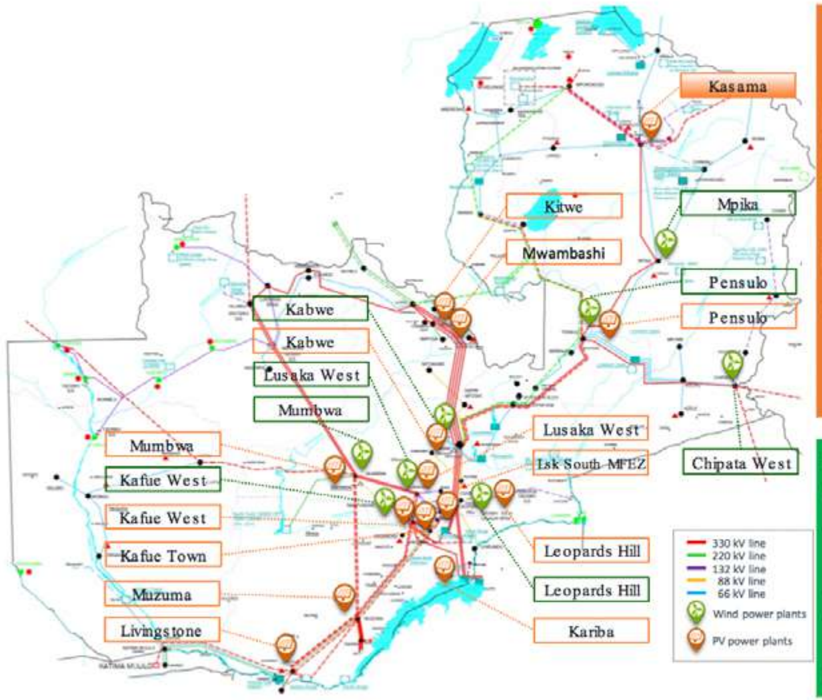
Figure 17.2 - 24-h power balance in the average day 2030. Isolated scenario with only firm export (left side) is compared with the trading opportunity scenario (right side)[30]

The Zambian generation system is closely dependent from hydropower and a very high exploitation of water for electricity sector will continue in the future. In this context, both long-lasting climatic changes and singular extreme natural events, which are becoming more frequent in the last decades, are expected to affect the demand, production and transmission of electricity; more generally the security of supply. An energy diversification strategy in the electricity sector including technologies with low water use needs, such as wind and photovoltaic, could offer an important technical solution for Zambia that could support both short- and long-term resilience of the power system and may face current and future challenges related to water shortage due to climate change.

Thanks to the very good potential of VRES (both solar radiation and wind) and the generation fleet flexibility in the country, wind and PV technologies can play a key role, replacing the traditional technologies. Additional VRES generation can be integrated under low rainfall scenario reaching about 40% VRES penetration in 2030. The lack of hydropower (-4.7 TWh/year in the dry year) can only be partially replaced by VRES generation; in fact, power import or additional programmable capacity is needed to meet the supply-demand balance.

The system reliability impact study shows that the transmission network expansion plan outlined by ZESCO will allow the development of big amount of VRES generation both in the mid- and in the long-term. Figure 17.3 shows the location of VRES projects and the optimal wind and PV capacities that can be integrated at each substation; such capacities comply with the Zambian reliability standards (network loadability) and they allow the optimization of VRES integration at the target year, minimizing production curtailments due to network overloads or over-generation phenomena. The figures recommended for specific substations should be subjected to further detailed studies with the aim of identifying any static, dynamic and power quality issue and providing countermeasures needed for the full integration of the recommended VRES capacities, completing in this way the integration analyses.

[30] "ITT": Itezhi Tezhi, "KGU": Kafue Gorge Upper, "KGL": Kafue Gorge Lower, "KNB": Kariba North Bank, "Down Res": Downward Operating reserve, "Up Res": Upward Operating reserve, "ENS": Energy Not Supplied, "SAPP MCP": Southern African Power Pool Market Clearing Price



Max PV capacity [MW]

S/S	25-ISO	25-INT	30-ISO	30-INT
Kabwe	140	140	190	140
Kafue Town	40	40	40	40
Kafue West	100	150	100	150
Kariba	90	90	90	90
Kasama	-	-	-	50
Kitwe	-	100	100	100
Leopards Hill	150	200	150	250
Livingstone	50	100	50	150
Lusaka West	-	100	50	150
Lsk South MFEZ	76	76	76	76
Mumbwa	170	220	170	220
Muzuma	220	220	220	270
Mwambashi	40	40	40	40
Pensulo	100	100	100	100
TOTAL	1,176	1,576	1,376	1,826

Max wind capacity [MW]

S/S	25-ISO	25-INT	30-ISO	30-INT
Kabwe	150	200	200	200
Kafue West	100	200	100	250
Leopards Hill	250	300	250	300
Lusaka West	150	200	150	250
Mpika	100	100	250	250
Mumbwa	170	220	170	220
Pensulo	280	280	280	330
Chipata West	-	100	-	100
TOTAL	1,200	1,600	1,400	1,900

Figure 17.3 – Maximum wind and PV installed capacities at each substation

Worst-case sensitivity scenario in the short term

Additional analyses at the target year 2022 have been performed by the Consultant with the aim to highlight a possible development plan for VRES in the short term, considering a worst-case scenario for system development, i.e. assuming a growth of demand and delays in the development of transmission network reinforcements and additional programmable generation (hydro and fossil fuel).

Different scenarios have been analysed to provide a range of feasible solutions by 2022, taking into account both the trend of connection demands and the time to market for utility-scale PV and wind projects.

- Scenario "Current Roadmap": Zambia would be able to integrate all PV projects included in the current roadmap by 2022 (660 MW) reaching 736 MW installed capacity from PV power plants in 2022, even without energy exchanges with the interconnected countries on the competitive market (scenario with isolated Country). Furthermore, 130 MW wind installed capacity could be integrated without relevant over-generation problems or network overloads;
- Scenario "100% PV": without wind projects in 2022, up to 956 MW from PV can be integrated in the isolated scenario, while up to 1,006 MW from PV in the interconnected scenario;
- Scenario "Balanced VRES mix": the maximum PV installed capacity shall be reduced if additional wind projects want to be integrated into the system by 2022. Up to 496 MW from PV and 260 MW from wind could be integrated in the isolated scenario, while up to 596 MW from PV and 260 MW from wind could be integrated in the interconnected scenario.

The development plan of VRES resulting by the study is shown in Figure 17.4. Different short-term paths to achieve the optimal VRES capacity mixes in 2025 and 2030 are highlighted; within the range of solutions found in the short term, greater PV integration implies a lower wind integration and vice versa. Only the optimal VRES capacity mix has been provided for 2025 and 2030 (both in isolated and interconnected scenarios). However, if no critical issues arise from the network analyses, other VRES capacity mixes could be integrated with minimal impact on the system benefits (as shown in Figure 13.1 and Figure 13.2 – Chapter 13.1).

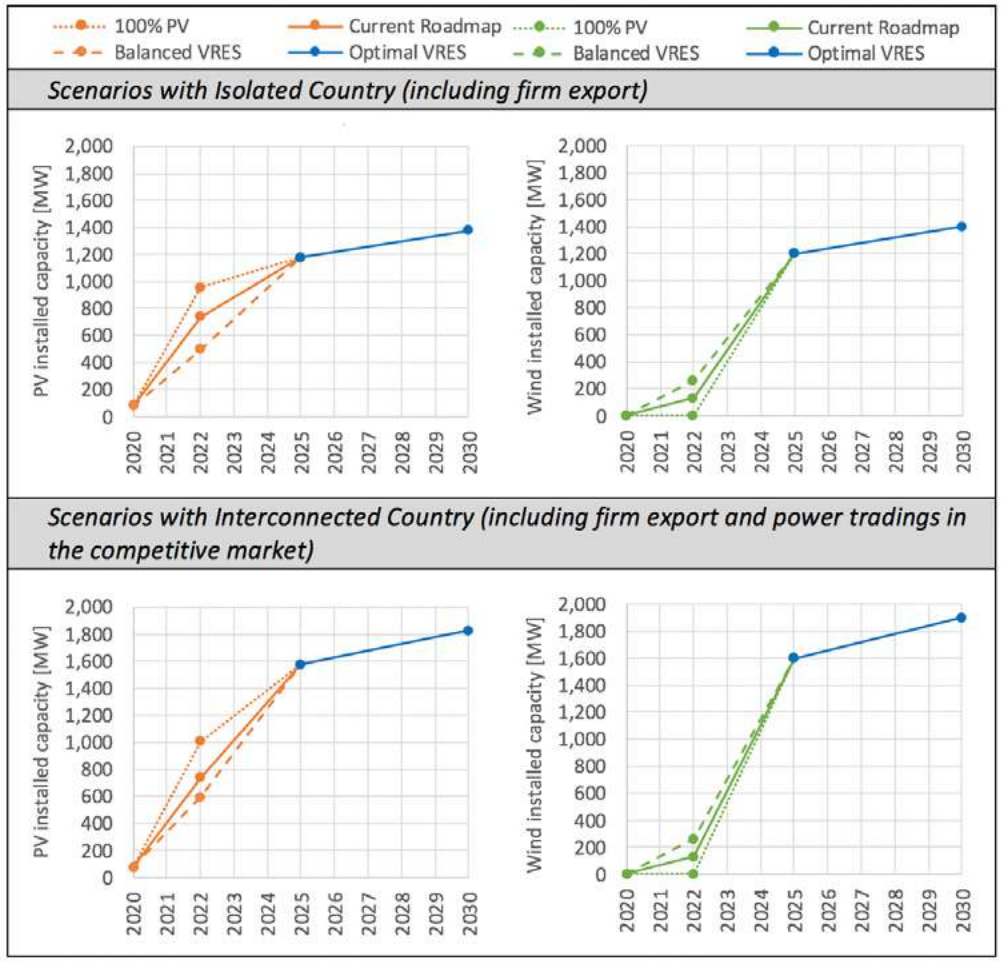


Figure 17.4 – VRES development plan 2020-2030

Recommendations

The VRES integration in a power system is an evolutionary process. System integration challenges emerge gradually; therefore, it is advisable to enhance the system's ability to incorporate VRE gradually. The first VRES power plants can usually be integrated with limited impact on the system while more effective actions must be put in place when VRES penetration becomes a significant share of the demand (greater than 5%).

The achievements of the current study provided a preliminary assessment of the VRES exploitation that can be achieved in Zambia identifying the optimal wind and PV capacity mix that could be integrated in the Zambian electric power system, from both a technical and economic point of view. However, further analyses are required and a specific feasibility study for each wind and PV project that will be integrated in the system should be performed. Both the static and dynamic behaviour of the electric power system in presence of VRES power plants must be investigated to take the most suitable measures to fully integrate VRES power plant into the system. The following analyses are recommended:

- Steady state study including:
  - power flow calculations (N condition);
  - static security assessment (N-1 condition);
  - short circuit screening;
  - voltage support and reactive compensation;
- Dynamic stability study including:
  - transient stability performance;
  - frequency performance in short- and long-term;
  - low/high voltage ride through (LVRT/HVRT) capability;
  - voltage regulation during transient state;
  - effects on spinning reserve.
- Power quality study including:
  - Harmonic distortion and resonance analysis
  - Flicker analysis

In this framework, it is advised to assign technical feasibility analyses to a technically competent and neutral body, ensuring a transparent and sound technical assessment of grid connection capacity.

Careful attention should be given also to the technical standards relating to the behaviour of VRES plants in the power system. A proper update of the grid connection rules (Grid Code) is advised to ensure that VRES power plants do not have a negative impact on the quality and reliability of electricity supply. The authority responsible for updating the Grid Code (i.e. ERB in Zambia) should refer to state-of-the-art industry standards and international experiences when identifying the technical requirements for connecting the first VRES power plants; then, the international standards should be modified to suit the local context. The authority responsible for updating the Grid Code should continuously monitor and revised the Grid Code during VRES integration process to ensure it suits the needs of the power system. An overview of the main technical requirements necessary to the grid connection of VRES power plants is highlighted in Annex 5.

Another important issue for the safe and optimal operation of the power system in presence of VRES plants is the visibility and the controllability of VRES productions. In this context, it is recommended:

- Visibility of a sufficient number of power plants to the system operator;
- Implementation of state-of-the-art centralised forecasting systems and use of these successfully for the dispatching of power plants and other operational decisions. Shorter dispatch interval should be targeted to deal with variability of wind and PV productions efficiently;
- A suitable ability of the system operator to control a sufficient number of plants close to and during real-time operations. Controllability does not necessarily be direct, but it is sufficient that plant operators respond to command signals from the system operator.

Innovative strategies for the control and operation VRES power plants are recommended to maximise VRES exploitation and maintain the secure operation of the electric power system. These strategies can counterbalance critical situations due to VRES intermittency, reducing the risk of production curtailments due to over-generation phenomena (i.e. when the generation available in the system is higher than the demand). Two actions should be considered during the integration process of VRES energy to reduce the risks concerning the electric power system operation in presence of big amount of VRES power plants:

- A central control room for VRES power plants, with clusters of different plants, will allow a better forecast of generation reducing forecast errors and minimizing reserve need. A greater penetration of VRES generation is possible if the uncertainty of its forecast is reduced.
- Participation of VRES to ancillary services markets, for instance with the availability to reduce their production (downward reserve) to ensure the stability of the power system. In this way, VRES downward reserve can replace the hydro one, potentially reducing the minimum power constraints in the system but increasing the risk to be actually required to reduce the generation.

These actions are relevant to issues which are usually faced during the short-term and real time operation of power systems. Experiences in some advanced markets with high VRES penetration show that there is a significant room for reducing the actual VRES energy curtailments when proper real time control systems are put in place.

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ANNEX 1 – PROMEDGRID SIMULATION TOOL

PromedGrid is a day-ahead market simulator developed and owned by CESI. This simulation tool implements a day-ahead hourly energy market, characterized by a system marginal price and by a congestion management based on a zonal market-splitting. It carries out an optimal coordinated hydrothermal scheduling of the generation fleet, over a period of one year, with an hourly detail.

Algorithm

PromedGrid simulates the dispatching optimization of hydro-thermal generation in meshed electric power systems with a high level of detail: quadratic fuel consumption curves and flexibility constraints for thermal generation units, zonal reserve margin constraints derived solely from internal resources or by using a mutual resource approach.

Three approaches can be used to consider network transmission constraints:

- Pure Flow-Based (FB) approach using Power Transfer Distribution Factors (PTDF);
- Available Transfer Capacity (ATC) based approach;
- Hybrid approach.

The simulation of the expected market behaviour is obtained by calculating the optimal medium-term operation schedule over the simulated yearly horizon considering both generation costs and bidding strategy. A very large quadratic programming (QP) optimization problem has to be solved to determine the likely market outcomes.

The procedure optimises coordinated hydrothermal hourly scheduling of the generation set, with the aim of minimizing the overall generation cost or maximizing the market surplus (sum of the generator's surplus, consumer's surplus and congestion surplus).

The power system constraints handled in the procedure are the integral limitations of the hydro plants water reservoirs and the transfer capacity of the equivalent lines of the interconnection corridors between market zones in addition to the technical characteristics of generation units. The optimization problem is solved by implementing the Kuhn-Tucker optimality conditions based on a particular technique, one which avoids iterations, called "Geometric Engine".

High performance and reliability of the resolution engine allows the simulation of very large scale scenarios. For example, the software has been recently used by ENTSO-E's[31] network planning department for the simulation of European scenarios involving the modelling of forty electrically interconnected countries.

System model

PromedGrid's electricity market simulation is based on a detailed model of the electric power system which takes into account the following aspects:

[31] ENTSO-E: European Network of Transmission System Operators for Electricity

- **Equivalent network model.** The network model is structured into market zones that are interconnected by equivalent interconnections. Each interconnection is characterized by a maximum active power transfer capacity in both directions which can be specified with an hourly detail in order to model different transfer capacities during day and night, summer and winter.
- **Hourly load and reserve margin for each market/network zone**. The demand is considered inelastic. It is also possible to define the minimum required operating reserve margin. The zonal reserve margin constraints can be covered solely by internal resources or by a mutual inter-area resource approach depending on the selected option. PromedGrid start-up the optimal number of units able to meet the load plus the reserve for each hour of the year. Obviously, the dispatched power only meets the load.
- **Import/export from/to other neighbouring electric systems.** Power exchanges on the borders of the emulated power system are modelled with virtual generating units for each border associated with an imposed positive production (imports) or negative production (exports) with an hourly detail. Alternatively, power exchanges on the borders can be determined dynamically by a set of sell/purchase bids assigned to the same virtual units.
- **RES generation (Renewable Energy Sources)** are modelled by imposed generation profiles for each zone/area and for each technology according to capacity assumptions and by applying characteristic generation profiles.
- **Thermal generation set**. Each unit is characterized by the generation company that owns it and by the network/market zone where it is located. For each thermal unit a technical configuration specifies the minimum and maximum power, the fuel mix (one, two or more fuel sources), the quadratic heat rate curve for each fuel in the mix, the scheduled and the forced average outage rates and the start-up/shut-down flexibility.
- **Fuel prices and EUA price**. Fuel prices are defined by taking a reference price for each type of fuel based on a monthly detail. When information is available it is possible to configure a "fuel location price" for each thermal unit. The quadratic fuel cost curve of the generation units is based on fuel prices combined with the efficiency rate curve of the generation unit. Further, a unique European Union Allowance (EUA) price for carbon emission is included to estimate the carbon cost component and its impact on the generation dispatching optimization.
- **Hydro generation set**. It is modelled by taking account of pumped-storage hydro power plants and hydro equivalents for reservoir and for run-of-river hydro power plants. One or more equivalent plants are defined for each network/market zone according to a specific equivalence methodology. The main technical data concerns the minimum/maximum power, the efficiency of the hydraulic/electric energy conversion, the reservoir volume and the expected hourly natural inflows along with the initial and final amount of water in each reservoir for the simulated annual period. It is also possible to specify by the week the natural inflows as well as the minimum and maximum amount of water in each reservoir;
- **Bidding strategy.** For each thermal unit and for each hour it is possible to specify the increments ("bid-ups") as they apply to the marginal production cost curve and that will determine the price of the bids submitted by the company to the power exchange. It is possible to emulate a real-world perfectly competitive market by adopting a specific methodology where each generation unit bases its bidding strategy on the recovery over the short-term horizon of the variable production costs.

The electricity market simulation is performed in two computational steps:

1. UNIT COMMITMENT: during this phase PromedGrid determines the hourly on/off state of each thermal unit based on a merit order of the offers and of fulfilling the constraints of the electric system.
2. DISPATCHING: in this second phase PromedGrid determines the hourly production scheduling of each thermal unit in coordination with the hydro dispatching while complying with the electric system constraints.

Main applications and results

PromedGrid is a reliable tool to evaluate economic scenarios of generation and transmission for the energy market. The main applications are the following:

- **Optimal evolution scenarios of the thermoelectric generation set in an open energy market**: if generation capacity is not much greater than demand, the market price will be high, so new power plants will be introduced. Otherwise, if generation capacity is much greater than demand, the market-clearing price will be low and new investments in generation will not be required. Based on the average price level there is variable financial cover of capital costs, which promotes variable levels of generation investment to obtain the optimum composition of generation that balances market price against the marginal production cost.
- **Congestions between market zones**: it is possible to evaluate transmission system adequacy compared to the geographical placement of generation and load by analysing congestion on interconnection lines linking different market zones.
- **Market price forecasting and volatility assessment for risk management (Aimed at to generators/traders)**: energy traders can define their risk management policies based on the analysis of price volatility, seasonal price trends, price of the market area and average yearly prices.
- **Operational planning (Addressed to generation companies - GENCO):** by means of PromedGrid a GENCO can evaluate the optimum medium-term production plan in a particular market scenario, considering technical constraints, scheduled maintenance and management of hydroelectric storages.
- **Financial justification of business-ventures and market shares of a specific generation plant:** it is possible to evaluate the ideal working period for the technology for which the investment will be made based on the price duration curves forecasted for a specific year.
- **Effectiveness of a market regulation:** the evaluation of the impact of a new regulation on the energy price and on other significant variables can be made by varying the rules of the bid curves generation model and the auction market model.

PromedGrid allows to evaluate for each hour of the simulated target year:

- The electricity prices of each market zone by simulating the operation of the day-ahead energy market while also managing possible congestions based on market splitting criteria;
- The production of each generating unit.
- The active power flow in the equivalent interconnections linking the different market zones;
- The generation costs, the revenues, the profits and the market shares of each generation unit;
- The generator's surplus, the consumer's surplus and the congestion surplus (market surplus) for each hour and for each market/network zone.

ANNEX 2 – OPERATING RESERVE REQUIREMENTS WITH THE OPTIMAL VRES INSTALLED CAPACITIES

The following figures show the upward and downward operating reserve requirements needed to manage the variability and unpredictability of the optimal VRES capacities that could be integrated in the reference scenario with normal water availability:

- Enhanced deployment of VRES with normal water availability and isolated electric power system (EHN-NWA-ISO):
  - 2025: 1,200 MW wind and 1,176 MW PV installed capacities (Figure A2.1);
  - 2030: 1,400 MW wind and 1,376 MW PV installed capacities (Figure A2.2);
- Enhanced deployment of VRES with normal water availability and interconnected electric power system (EHN-NWA-INT):
  - 2025: 1,600 MW wind and 1,576 MW PV installed capacities (Figure A2.3);
  - 2030: 1,900 MW wind and 1,826 MW PV installed capacities (Figure A2.4).

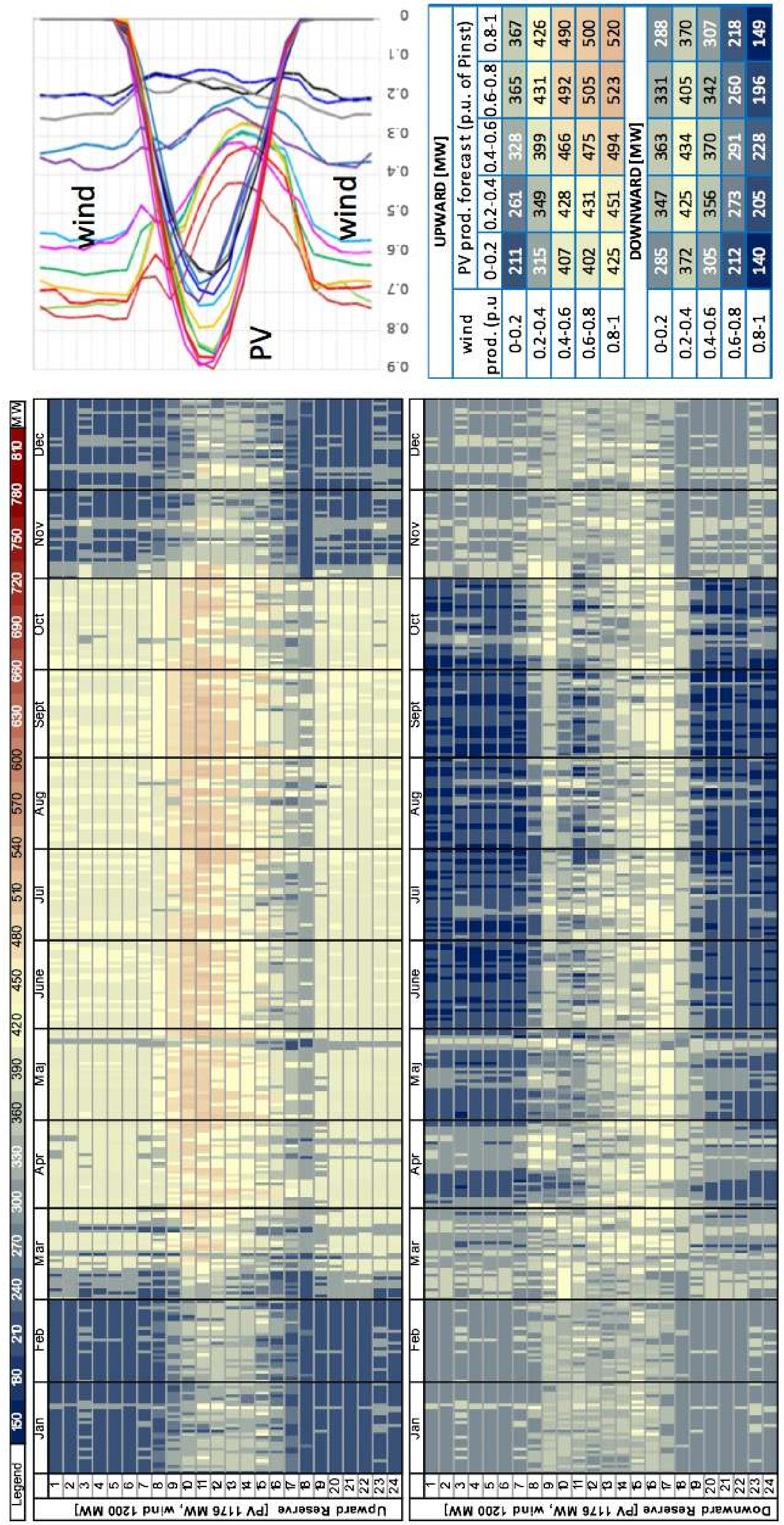
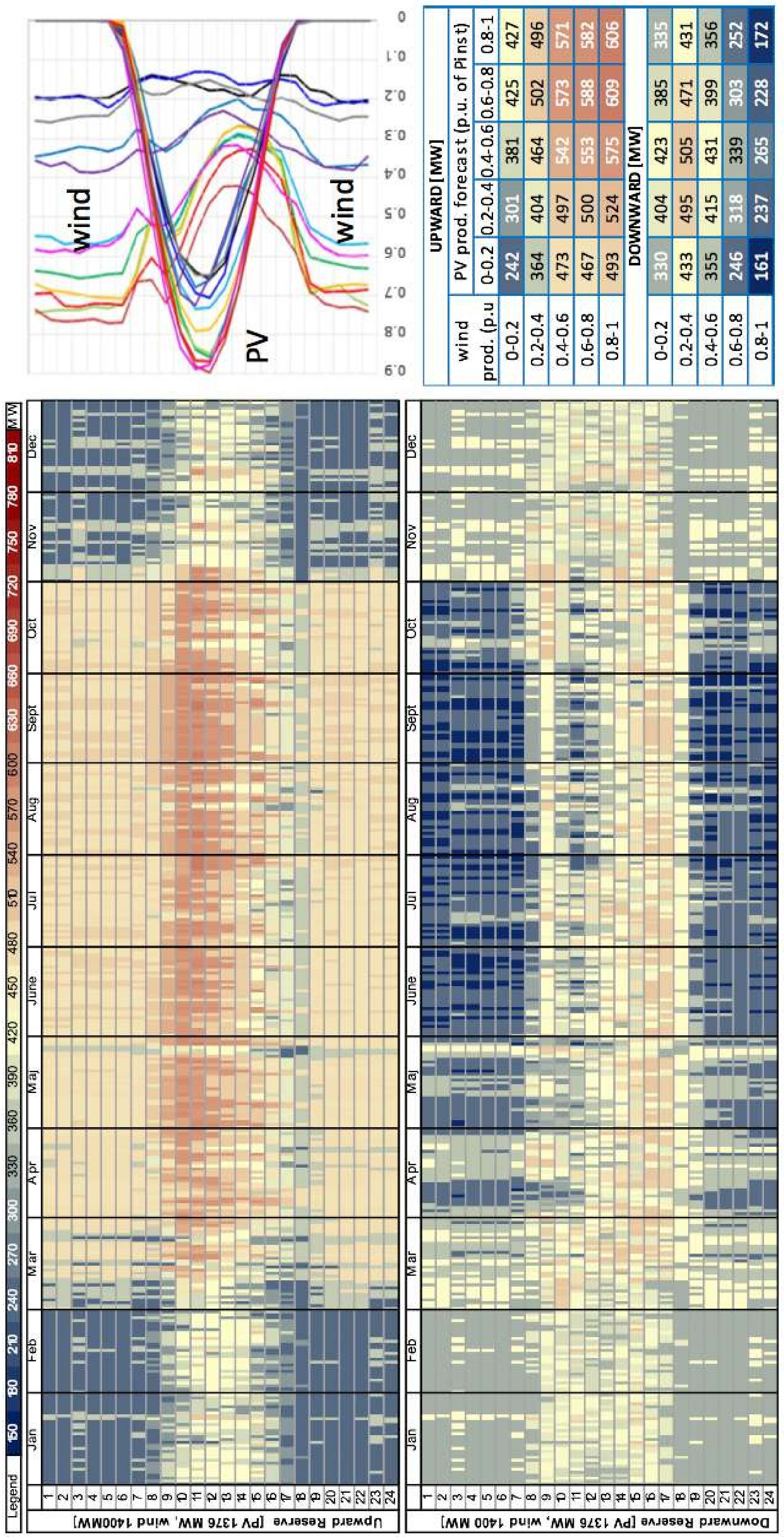
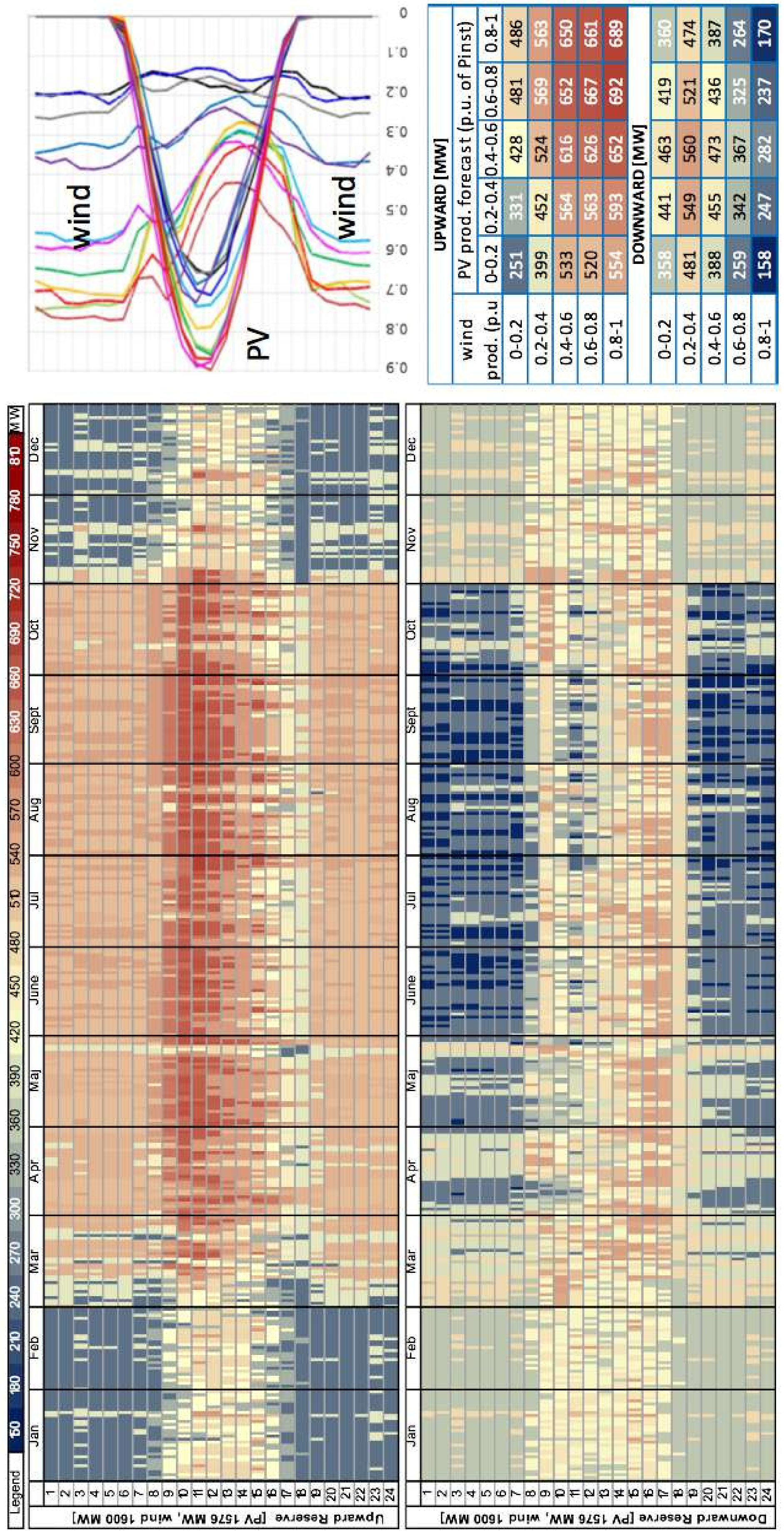


Figure A2.1– Upward and downward operating reserve with 1,176 MW PV and 1,200 MW wind installed capacity at year 2025 (reference scenario with enhanced VRES deployment, average water availability and isolated country – Scenario ENH-NWA-ISO 2025)



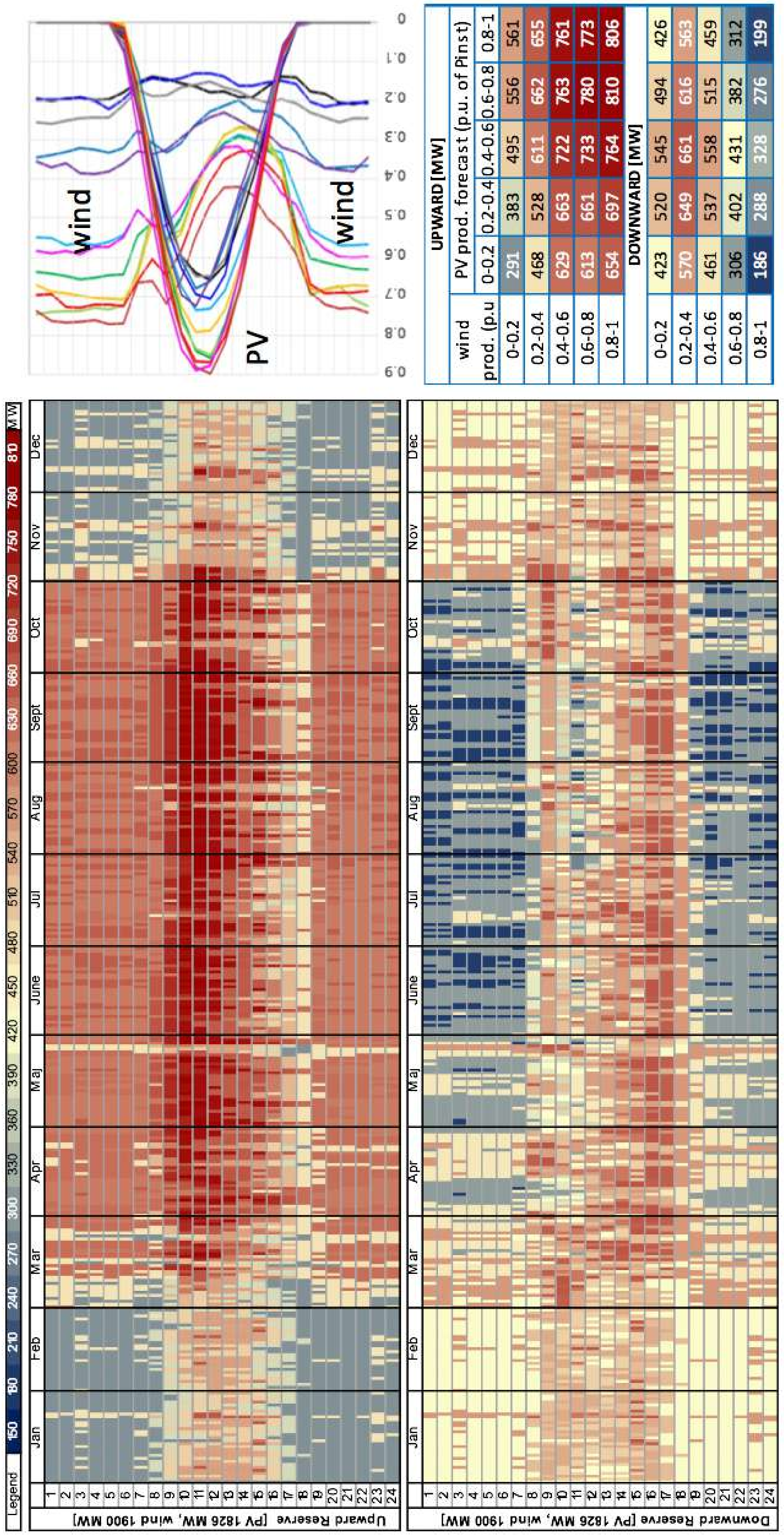
UPWARD [MW]					
wind prod. (p.u	PV prod. forecast (p.u. of Pinst) 0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1
0-0.2	242	301	381	425	427
0.2-0.4	364	404	464	502	496
0.4-0.6	473	497	542	573	571
0.6-0.8	467	500	553	588	582
0.8-1	493	524	575	609	606
DOWNWARD [MW]					
0-0.2	330	404	423	385	335
0.2-0.4	433	495	505	471	431
0.4-0.6	355	415	431	399	356
0.6-0.8	246	318	339	303	252
0.8-1	161	237	265	228	172

Figure A2.2– Upward and downward operating reserve with 1,376 MW PV and 1,400 MW wind installed capacity at year 2030 (reference scenario with enhanced VRES deployment, average water availability and isolated country – Scenario ENH-NWA-ISO 2030)



UPWARD [MW]					
wind prod. (p.u	PV prod. forecast (p.u. of Pinst) 0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1
0-0.2	251	331	428	481	486
0.2-0.4	399	452	524	569	563
0.4-0.6	533	564	616	652	650
0.6-0.8	520	563	626	667	661
0.8-1	554	593	652	692	689
DOWNWARD [MW]					
0-0.2	358	441	463	419	360
0.2-0.4	481	549	560	521	474
0.4-0.6	388	455	473	436	387
0.6-0.8	259	342	367	325	264
0.8-1	158	247	282	237	170

Figure A2.3 – Upward and downward operating reserve with 1,576 MW PV and 1,600 MW wind installed capacity at year 2025 (reference scenario with enhanced VRES deployment, average water availability and interconnected country – Scenario ENH-NWA-INT 2025)



wind prod. (p.u)	UPWARD [MW] PV prod. forecast (p.u. of Pinst) 0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1
0-0.2	291	383	495	556	561
0.2-0.4	468	528	611	662	655
0.4-0.6	629	663	722	763	761
0.6-0.8	613	661	733	780	773
0.8-1	654	697	764	810	806
DOWNWARD [MW]					
0-0.2	423	520	545	494	426
0.2-0.4	570	649	661	616	563
0.4-0.6	461	537	558	515	459
0.6-0.8	306	402	431	382	312
0.8-1	186	288	328	276	199

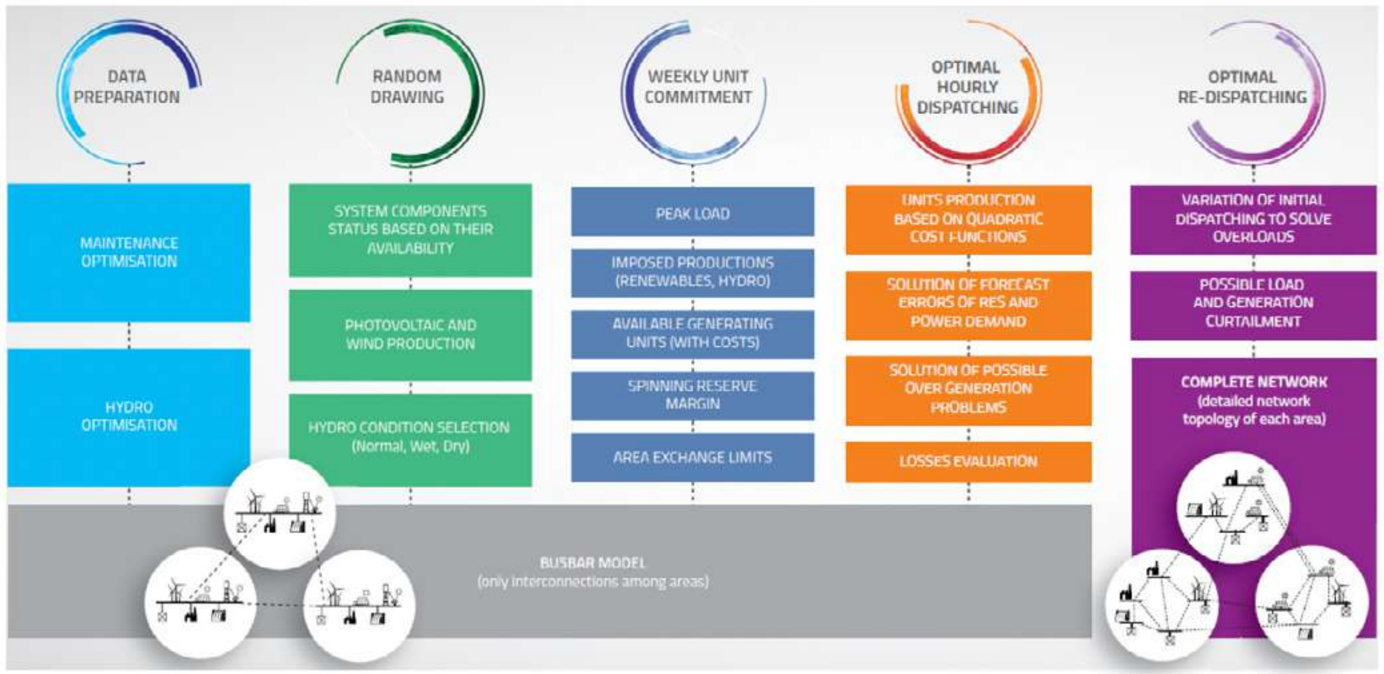
Figure A2.4– Upward and downward operating reserve with 1,826 MW PV and 1,900 MW wind installed capacity at year 2030 (reference scenario with enhanced VRES deployment, average water availability and interconnected country – Scenario ENH-NWA-INT 2030)

ANNEX 3 – GRARE SIMULATION TOOL

GRARE, Grid Reliability and Adequacy Risk Evaluator, is a powerful computer-based tool of Terna, developed by CESI[32] , which evaluates reliability and economic operational capability using probabilistic Monte Carlo analysis.

GRARE has been developed to support medium and long-term planning studies and is particularly useful for evaluating the reliability of large power systems, modelling in detail the transmission networks. The tool is developed taking advantage of a high performance multi-threaded code and it is integrated in SPIRA application, that is designed to perform steady-state analyses (e.g. load-flow, short-circuits, OPF, power quality) and is based on a network Data Base of the system being analysed.

The calculation process is performed as a series of sequential steps starting from a high-level system representation and drilling down to low-level network details. Thanks to the ability to couple the economic dispatch of the generation with the complete structure of the electrical network, GRARE can offer a unique support for the planning and evaluation of the benefits related to network investments.



The **complete network model** (lines, generators, transformers, etc.) includes different voltage level detail and the power flow derived from generation dispatching to feed the load is obtained applying a DC load flow with the possibility to obtain power losses and voltage profile estimation. Starting from a complete network model, GRARE can automatically obtain a simplified bus-bar model to complete unit commitment and market analyses where the network detail is not needed. The analysis of the full network model allows to verify the feasibility of the economic dispatching and the necessity to apply a re-dispatching or load shedding to operate the network in accordance to security criterion.

[32] www.cesi.it\grare

Algorithm and main optimization process

- The time horizon is a single year with a minimum time unit of one hour. Many Monte Carlo Years (MCYs) can be simulated, each one being split into 52 weeks with each week independently optimized.
- Probabilistic Monte Carlo method uses statistical sampling based on a "Sequential" or "Non-Sequential" approach.
- Monte Carlo convergence analysis to verify the accuracy of results obtained.
- Optimized Maintenance schedule based on residual load distribution over the year.
- Reservoir and pumping Hydro optimization mindful of water value as an opportunity cost for water in respect to other generation sources.
- Different hydro conditions managed (dry, normal, wet).

System model

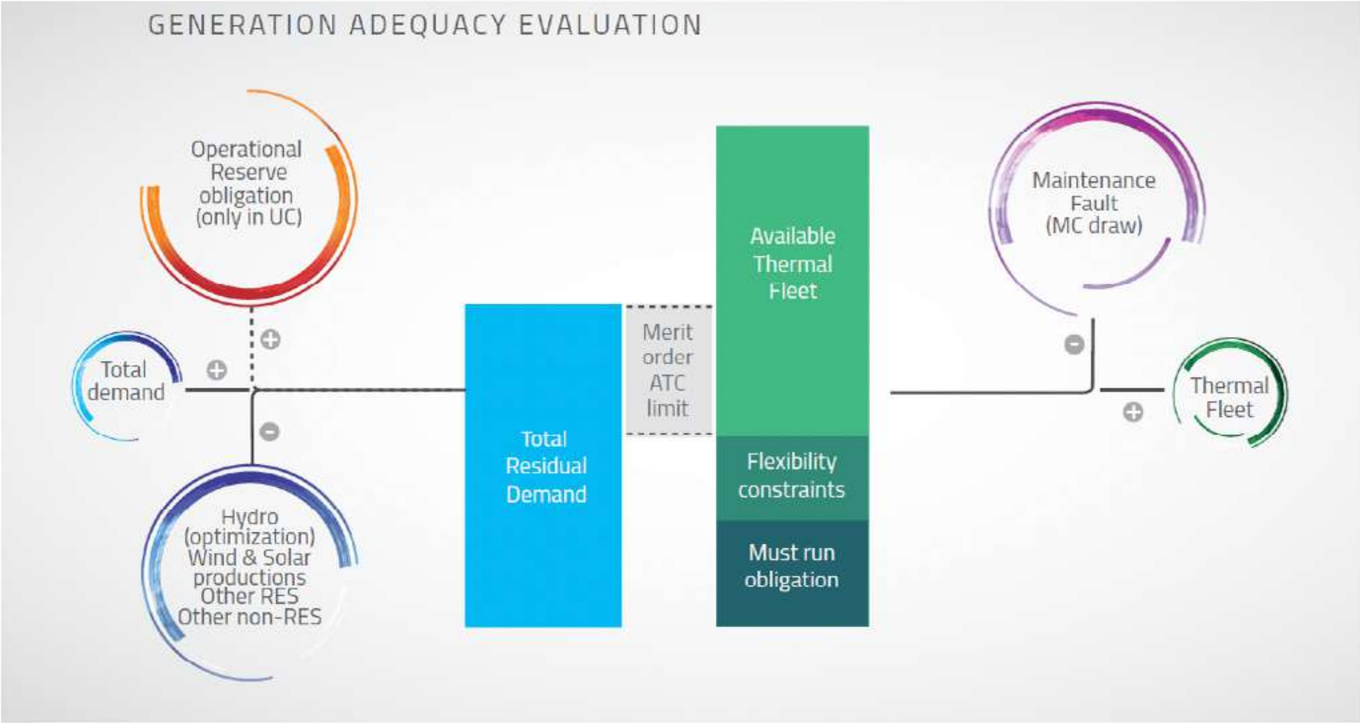
- Network detail to represent each single area (grid dimension up to 5,000 buses). A DC load flow is calculated, and an estimate of voltage level can be obtained using the Sauer algorithm.
- Area modelling to optimize Unit commitment and Dispatching consistent with transfer capacities.
- Unit Commitment and Dispatching with Flow or ATC based approach.

Market analyses

- Single year day-ahead Market analysis with area modelling detail, but with no Monte Carlo drawings.
- The general restrictions of the Unit Commitment like minimal uptime and downtime of generation units are considered for each optimization period.
- Dispatchable units characterised by power limits, costs, must-run or dispatching priority, power plants configurations, start-up and shutdown flexibility and CO2 emissions.

Adequacy analyses

- System adequacy level measured with Reliability Indexes (EENS, LOLE, and LOLP).
- Renewable production calculated by a random drawing starting from producibility figures.
- Operational reserve level evaluation taking account of largest generating unit, uncertainty of load and RES forecast, possible aggregation of Area and fixed % of load.
- Demand side management as rewarded load to be shed with priority without impact on adequacy.
- Over-generation management with possible priority on generation to be reduced.



Main applications and results

The high level of versatility and flexibility of the GRARE tool has been appreciated in Europe first and then in several countries all around the world. The program has been developed to be applied in the design phase for the Italian framework and it is now used for ENTSOE-E adequacy studies. Various TSO/ Institutions have benefited from the potentiality of the tool by using it directly or through specialist consultancy services.

- Designed for technical analyses of large electric systems.
- Evaluation of electric systems
- Generation & Transmission adequacy.
- Optimal level of RES integration.
- Cost Benefits Analysis for network reinforcements and storage which factors in Security of Supply, network overloads, RES integration, network losses, CO2 emissions and over-generation.
- Calculation of Total Transfer Capacity of interconnections.
- Generation reward evaluation for Capacity Remuneration Mechanism.
- Point Of Connection and sizing for new power plants.

ANNEX 4 – WORST-CASE SENSITIVITY SCENARIO IN THE SHORT TERM

Figure A4. 1, Figure A4. 2 and Figure A4. 3 show the dominate hours where there is curtailment of VRES production (PV+wind) due to over-generation phenomena in the "100% PV", "Current Roadmap" and "Balanced VRES" scenarios, respectively. The maximum and average production curtailments are highlighted for each hour of the day (0-23) and each month of the year; the average value is the mean of the values when the VRES production curtailment occurs. Furthermore, the frequency of occurrence of VRES production curtailment over the 24 hours of the day is highlighted. For example, in Figure A4. 1, the curtailment of VRES production has 1% of occurrence in the hour 12 of March, with a maximum production curtailment equal to 32 MW and an average production curtailment equal to 12 MW.

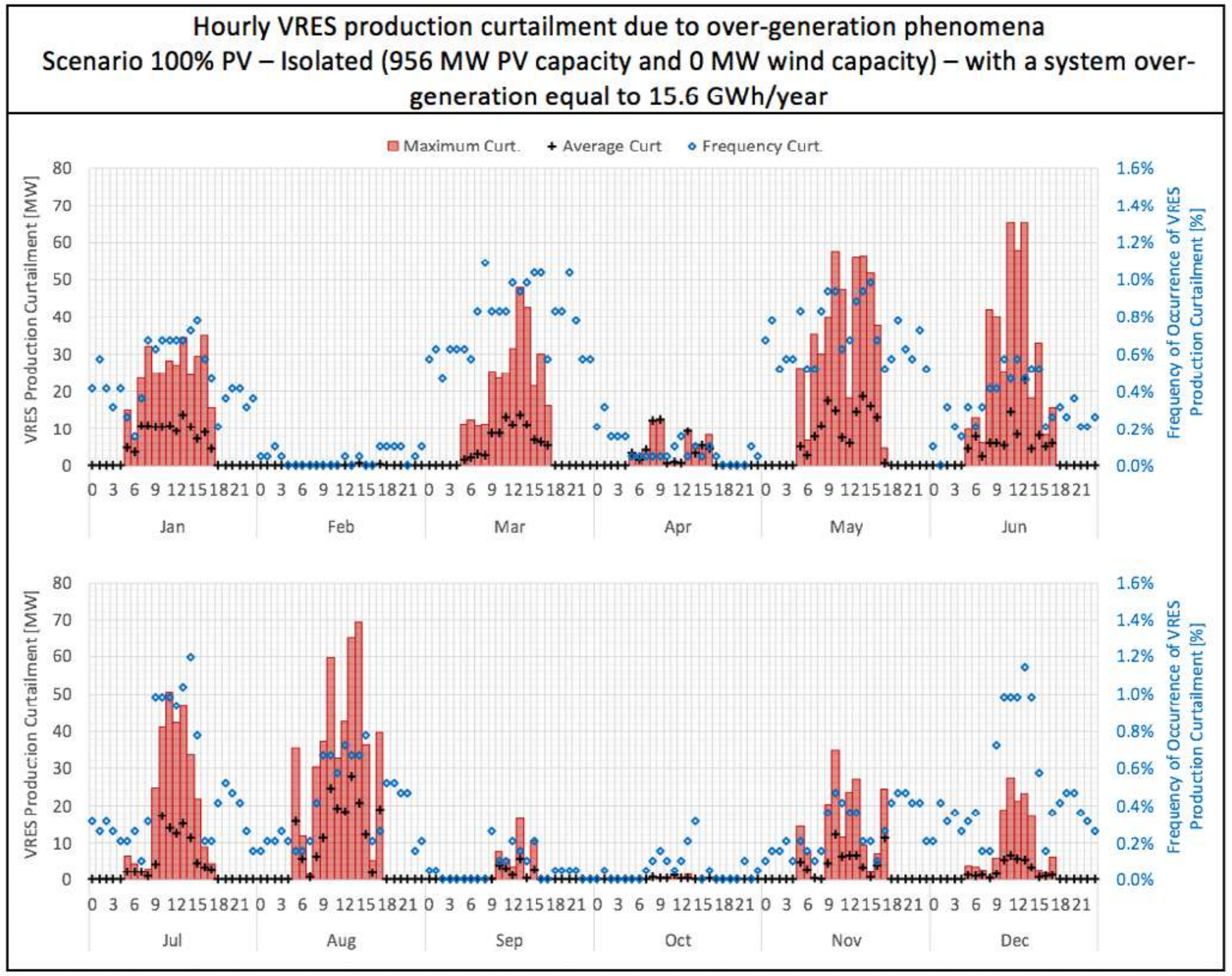


Figure A4. 1 – VRES production curtailment due to over-generation phenomena in the "100% PV" scenario. The maximum hourly value, the average hourly value and the frequency of occurrence of the VRES production curtailment are highlighted in the 24 hours of the day and on a monthly basis

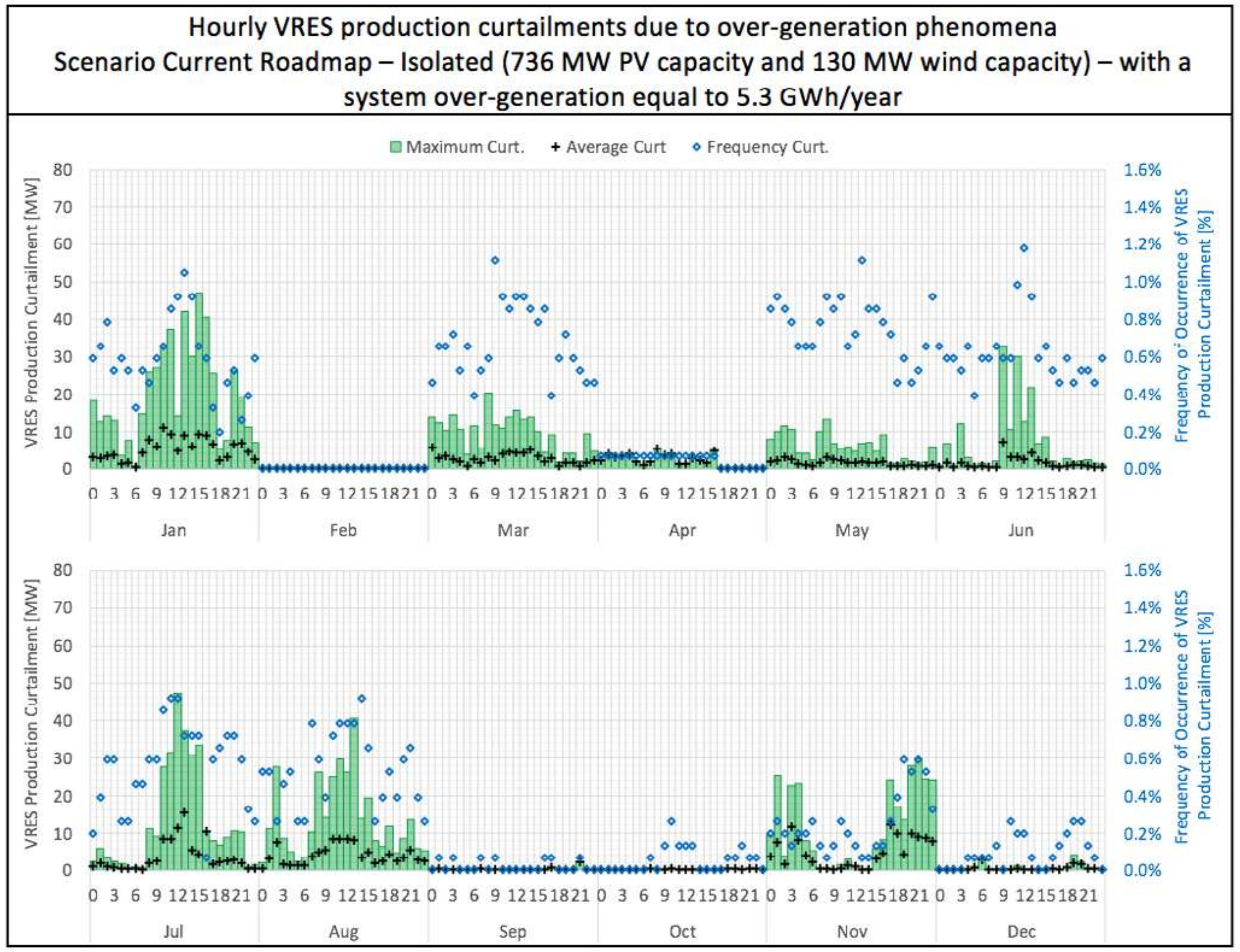


Figure A4. 2 – VRES production curtailment due to over-generation phenomena in the "Current Roadmap" scenario. The maximum hourly value, the average hourly value and the frequency of occurrence of the VRES production curtailment are highlighted in the 24 hours of the day and on a monthly basis

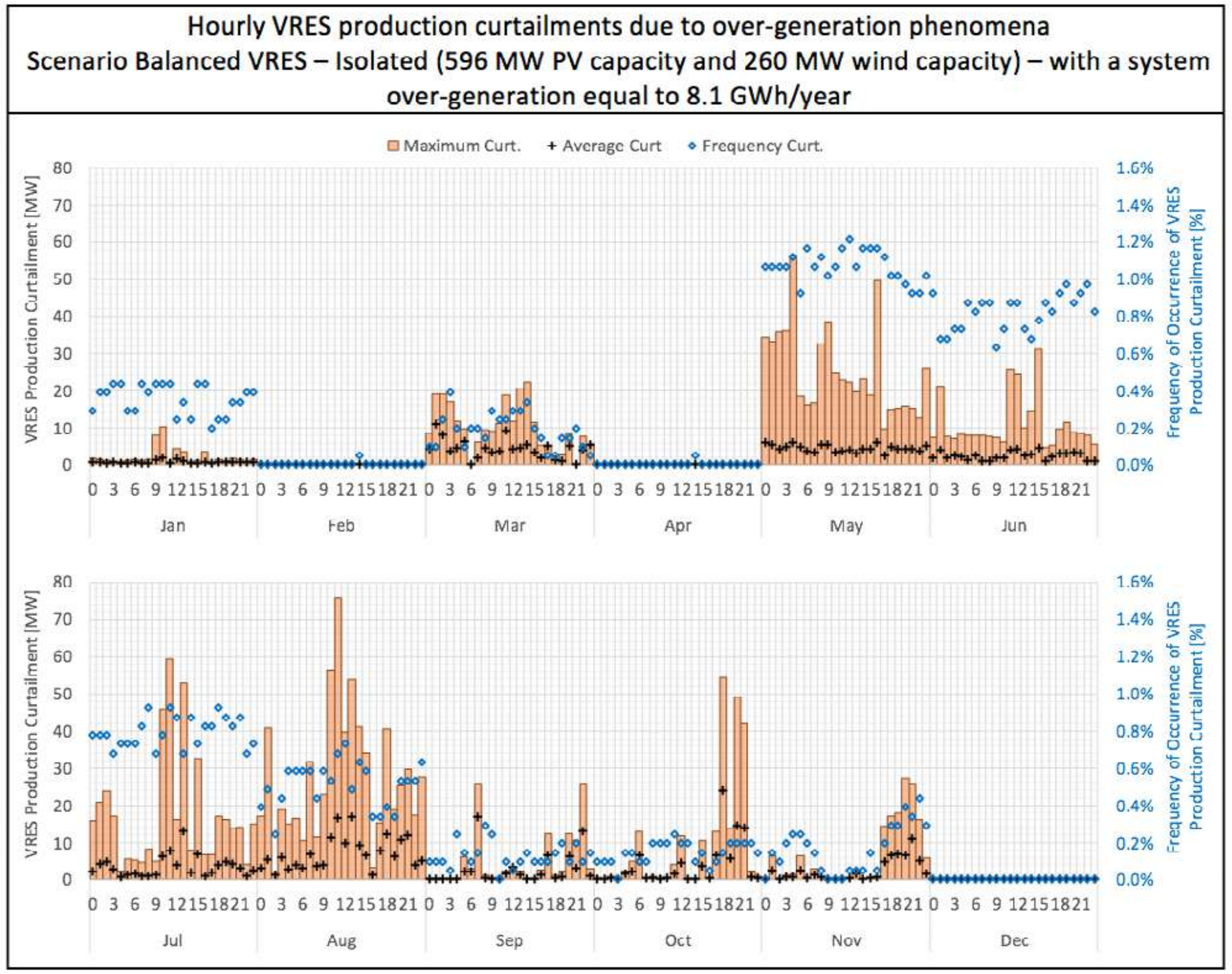


Figure A4. 3 – VRES production curtailment due to over-generation phenomena in the "Balanced VRES" scenario. The maximum hourly value, the average hourly value and the frequency of occurrence of the VRES production curtailment are highlighted in the 24 hours of the day and on a monthly basis

The following tables show the list of overhead lines and transformers with maximum loading greater of equal than 50% of rated power resulting by the system reliability impact study in the worst-case sensitivity scenario 2022. The results of the following scenarios are compared:

- Isolated Country:
  - Existing VRES: 76 MW PV and 0 MW wind installed capacity;
  - 100% PV: 956 MW PV and 0 MW wind installed capacity
  - Current Roadmap: 736 MW PV and 130 MW wind installed capacity
  - Balanced VRES: 496 MW PV and 260 MW wind installed capacity
- Interconnected Country:
  - Existing VRES: 76 MW PV and 0 MW wind installed capacity;
  - 100% PV: 1,006 MW PV and 0 MW wind installed capacity
  - Current Roadmap: 736 MW PV and 130 MW wind installed capacity
  - Balanced VRES: 596 MW PV and 260 MW wind installed capacity

Isolated Country

Table A4. 1 – List of the most loaded overhead lines (voltage level ≥ 66 kV). Isolated Country – Year 2022

GRARE ID	Name_From	Name_To	kV_From	kV_To	76MW PV 0MW Wind	956MW PV 0MW Wind	736MW PV 130MW Wind	496MW PV 260MW Wind
162	MAPEP88	KAFTWNMA	88	88	100%	100%	100%	100%
95	NDOLA66	SKYWYS66	66	66	100%	100%	100%	100%
222	KAFWT3	KAFTN3	330	330	100%	100%	100%	100%
25	LUSIW	MSORO66	66	66	100%	100%	100%	100%
22	LUS_UP	LUSIW	66	66	100%	100%	100%	100%
160	MLNGS66	KABWE66	66	66	100%	100%	100%	100%
156	BRKHL66	MLNGS66	66	66	100%	100%	100%	100%
145	LEPRD88	MAPEP88	88	88	100%	100%	100%	100%
125	MPIKA	CHLN66	66	66	100%	100%	100%	100%
128	CHLN66	MUNUGA-T66	66	66	100%	100%	100%	100%
131	PENSL66	MUNUGA-T66	66	66	100%	100%	100%	100%
36	KABND66	STADM66	66	66	100%	100%	100%	100%
86	MAPOS66	DLHLL66	66	66	100%	100%	100%	100%
157	BRKHL66	KABWE66	66	66	100%	100%	100%	100%
224	VICTR2	SESHEKE220	220	220	100%	100%	100%	100%
272	MUZUM2	VICTR2	220	220	100%	100%	100%	100%
65	KARIB_N3	LEPRD3	330	330	100%	100%	100%	100%
87	KARIB_N3	KAFWT3	330	330	96%	96%	96%	96%
26	LUSIW	MSORO66	66	66	95%	95%	95%	95%
24	LUS_UP	PENSL66	66	66	94%	94%	94%	94%
85	MAPOS66	NDOLA66	66	66	91%	82%	82%	82%
84	MAPOS66	NDOLA66	66	66	91%	89%	90%	84%
172	ZAMB220	NAM_ZAM	220	220	88%	73%	68%	83%
226	SESHEKE220	ZAM_NAM	220	220	88%	73%	68%	83%
99	SKYWYS66	DPTRD66	66	66	86%	85%	85%	82%
82	MAPOS66	MCLRN66	66	66	82%	82%	82%	82%
76	KARIB_N3	LEPRD3	330	330	82%	87%	86%	84%
38	STADM66	AVENU66	66	66	81%	81%	81%	81%
159	LSKWT330	KAFWT3	330	330	80%	76%	73%	74%
37	KABND66	LUANO66	66	66	77%	77%	77%	77%
210	LEPRD3	KAFGR3	330	330	77%	77%	77%	76%
39	STADM66	LUANO66	66	66	76%	76%	76%	76%
40	STADM66	LUANO66	66	66	76%	76%	76%	76%
229	CHAMBEAST	MWAM66	66	66	76%	76%	76%	76%
196	KABWE3	KITWE3	330	330	76%	86%	86%	86%
68	KITWE66	MILL66	66	66	76%	76%	76%	76%
100	DLHLL66	PAMDZ66	66	66	74%	87%	87%	87%
130	PENSL66	CHNSR66	66	66	73%	73%	73%	73%

					Max Loading %			
GRARE ID	Name_From	Name_To	kV_From	kV_To	76MW PV 0MW Wind	956MW PV 0MW Wind	736MW PV 130MW Wind	496MW PV 260MW Wind
83	MAPOS66	BALUB66	66	66	73%	73%	73%	73%
133	CHNSR66	KANON66	66	66	72%	72%	72%	72%
101	PAMDZ66	DPTRD66	66	66	72%	71%	71%	71%
32	SAFAL	KANON66	66	66	72%	72%	72%	72%
34	SAFAL	MUPEPE66	66	66	72%	72%	72%	72%
163	MUPEPE66	LUSW-T66	66	66	72%	72%	72%	72%
270	LUSW-T66	LUSIW	66	66	72%	72%	72%	72%
96	NDOLA66	DPTRD66	66	66	71%	73%	73%	73%
66	KITWE66	NKANA66	66	66	70%	70%	70%	70%
151	LSKWT330	KAFWT3	330	330	69%	82%	71%	69%
197	KABWE3	KITWE3	330	330	69%	72%	72%	74%
147	LEPRD1	WTRWK132	132	132	69%	69%	69%	68%
80	MAPOS66	ROAN66	66	66	68%	68%	68%	68%
97	SKYWYS66	DLHLL66	66	66	68%	49%	49%	46%
202	KABWE3	LUANO3	330	330	67%	76%	76%	76%
4	BANCENTR	MICHL66	66	66	67%	65%	65%	65%
189	LSMFEZ 330	LEPRD3	330	330	67%	63%	62%	62%
55	LUANO66	CCMTOFF	66	66	66%	66%	66%	66%
211	LEPRD3	KAFGR3	330	330	66%	66%	66%	66%
42	AVENU66	CCMTOFF	66	66	65%	65%	65%	65%
221	KAFGR3	KAFWT3	330	330	65%	67%	66%	66%
198	KABWE3	LEPRD3	330	330	64%	77%	75%	75%
199	KABWE3	LEPRD3	330	330	64%	77%	75%	75%
209	KITWE2	FRONT-TOFF	220	220	62%	66%	66%	66%
81	MAPOS66	STORK66	66	66	62%	62%	62%	62%
90	LNSHY66	STORK66	66	66	61%	61%	61%	61%
216	LUANO2	MICHL2	220	220	61%	61%	61%	61%
200	KABWE3	LEPRD3	330	330	61%	65%	63%	63%
417	PLAY SOLDIER	KASAMA	330	330	61%	62%	63%	62%
142	ROMA1	LEPRD1	132	132	61%	61%	61%	61%
201	KABWE3	LUANO3	330	330	61%	61%	61%	62%
217	LUANO2	MICHL2	220	220	61%	61%	61%	61%
49	BNCNT66	LUBAMBI	66	66	59%	59%	59%	59%
115	KASMA66	MPIKA	66	66	59%	56%	56%	56%
146	LEPRD88	CHONGWE	88	88	58%	58%	58%	58%
140	CVNTR1	LSKWT132	132	132	57%	57%	57%	57%
158	MLNGS66	LNSMF66	66	66	56%	56%	56%	56%
233	BANCENTR	BNCRF66	66	66	56%	53%	54%	54%
185	KAFGRLOW	KAFGR3	330	330	55%	54%	54%	55%
45	BNCRF66	LUANO66	66	66	55%	57%	57%	57%
46	BNCRF66	LUANO66	66	66	55%	57%	57%	57%
129	PENSL66	SERNJ66	66	66	54%	54%	54%	54%
52	CHMBS66	LUANO66	66	66	54%	54%	54%	54%
53	CHMBS66	LUANO66	66	66	54%	54%	54%	54%
223	MAPOS2	FRONT-TOFF	220	220	53%	56%	56%	56%
71	KITWE66	TURF66	66	66	51%	51%	51%	51%
184	KAFGRLOW	LSMFEZ 330	330	330	50%	51%	50%	52%
63	KITWE66	KTWNT66	66	66	50%	50%	47%	47%
48	BNCNT66	LUANO66	66	66	50%	52%	52%	52%
126	MPIKA	MPIKANEW66	66	66	50%	50%	50%	50%
127	MPIKA	MPIKANEW66	66	66	50%	50%	50%	50%
181	MUZUMA	KAFTN3	330	330	49%	60%	60%	60%
193	LSKWT330	MUMBWA330	330	330	49%	50%	50%	46%
17	KALUMBILA330	MUMBWA330	330	330	48%	46%	46%	47%
132	LSKWT330	KABWE3	330	330	47%	57%	57%	57%
50	CHSNG66	CHMBS66	66	66	47%	47%	47%	47%
67	KITWE66	NKANA66	66	66	47%	47%	47%	47%
153	KZNGL66	VICTR66	66	66	47%	54%	53%	59%

Table A4. 2 – List of the most loaded transformers. Isolated Country – Year 2022

GRARE ID	Name_From	Name_To	kV_From	kV_To	Pn [MVA]	Max Loading % 76MW PV 0MW Wind	Max Loading % 956MW PV 0MW Wind	Max Loading % 736MW PV 130MW Wind	Max Loading % 496MW PV 260MW Wind
331	KABWE88	KABWE66	88	66	20	100%	100%	100%	100%
332	KABWE88	KABWE66	88	66	20	100%	100%	100%	100%
398	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%	96%
399	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%	96%
419	LUANO2	LUANO66	220	66	60	88%	86%	87%	87%
418	LUANO2	LUANO66	220	66	60	88%	85%	86%	86%
423	LUANO2	LUANO66	220	66	60	88%	85%	86%	86%
409	KITWE2	KITWE66	220	66	60	86%	86%	86%	86%
410	KITWE2	KITWE66	220	66	60	85%	85%	85%	85%
408	KITWE2	KITWE66	220	66	60	84%	84%	84%	84%
407	KITWE2	KITWE66	220	66	60	83%	83%	83%	83%
411	KITWE2	KITWE66	220	66	60	82%	82%	82%	82%
420	LUANO2	LUANO66	220	66	60	80%	80%	80%	80%
421	LUANO2	LUANO66	220	66	65	80%	77%	78%	78%
422	LUANO2	LUANO66	220	66	65	80%	77%	78%	78%
430	KAFTN88	KAFTN3	88	330	125	69%	70%	69%	69%
431	KAFTN88	KAFTN3	88	330	125	70%	70%	70%	71%
424	PENSL3	PENSL66	330	66	60	66%	66%	66%	66%
425	PENSL3	PENSL66	330	66	60	66%	66%	66%	66%
413	LEPRD88	LEPRD3	88	330	90	69%	69%	69%	69%
444	MUZUM2	FICT BUS 011	220	330	315	79%	72%	69%	77%
415	LEPRD3	LEPRD1	330	132	150	61%	62%	63%	62%
414	LEPRD3	LEPRD1	330	132	150	61%	59%	58%	59%
405	KABWE3	KABWE88	330	88	60	64%	50%	50%	50%
406	KABWE3	KABWE88	330	88	60	64%	50%	50%	50%
279	MICHL2	MICHL66	220	66	120	57%	54%	54%	54%
361	LSKWT330	LSKWT132	330	132	125	57%	57%	58%	58%
383	LSKWT330	LSKWT132	330	132	125	57%	57%	58%	58%
388	LSKWT330	LSKWT132	330	132	125	57%	57%	58%	58%
386	MAPOS2	MAPOS66	220	66	80	53%	67%	67%	66%
433	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
435	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
436	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
438	MAPOS2	MAPOS66	220	66	80	53%	67%	67%	66%
439	MAPOS2	MAPOS66	220	66	80	52%	65%	65%	64%
437	MAPOS2	MAPOS66	220	66	80	51%	63%	60%	63%
283	SESHEKE220	SESHK66	220	66	25	50%	50%	50%	50%
284	SESHEKE220	SESHK66	220	66	25	50%	50%	50%	50%
412	LEPRD88	LEPRD3	88	330	90	46%	46%	46%	46%
366	LUANO2	FICT BUS 005	220	330	315	50%	52%	52%	53%
369	LUANO2	FICT BUS 006	220	330	315	50%	52%	52%	53%
372	LUANO2	FICT BUS 007	220	330	315	50%	52%	52%	53%
375	LUANO2	FICT BUS 008	220	330	315	50%	52%	52%	53%
353	KITWE2	FICT BUS 001	220	330	315	50%	51%	51%	51%
356	KITWE2	FICT BUS 002	220	330	315	50%	51%	51%	51%
359	KITWE2	FICT BUS 003	220	330	315	50%	51%	51%	51%
363	KITWE2	FICT BUS 004	220	330	315	50%	51%	51%	51%
387	MICHL2	MICHL66	220	66	120	50%	48%	48%	48%

Interconnected Country

Table A4. 3 – List of the most loaded overhead lines (voltage level ≥ 66 kV). Interconnected Country – Year 2022

GRARE ID	Name_From	Name_To	kV_From	kV_To	Max Loading % 76MW PV 0MW Wind	Max Loading % 1,006MW PV 0MW Wind	Max Loading % 736MW PV 130MW Wind	Max Loading % 596MW PV 260MW Wind
22	LUS_UP	LUSIW	66	66	100%	100%	100%	100%
25	LUSIW	MSORO66	66	66	100%	100%	100%	100%
36	KABND66	STADM66	66	66	100%	100%	100%	100%
86	MAPOS66	DLHLL66	66	66	100%	100%	100%	100%
95	NDOLA66	SKYWYS66	66	66	100%	100%	100%	100%
125	MPIKA	CHLN66	66	66	100%	100%	100%	100%
128	CHLN66	MUNUGA-T66	66	66	100%	100%	100%	100%
131	PENSL66	MUNUGA-T66	66	66	100%	100%	100%	100%
156	BRKHL66	MLNGS66	66	66	100%	100%	100%	100%
160	MLNGS66	KABWE66	66	66	100%	100%	100%	100%
224	VICTR2	SESHEKE220	220	220	100%	100%	100%	100%
145	LEPRD88	MAPEP88	88	88	100%	100%	100%	100%
162	MAPEP88	KAFTWNMA	88	88	100%	100%	100%	99%
157	BRKHL66	KABWE66	66	66	100%	85%	85%	85%
272	MUZUM2	VICTR2	220	220	100%	99%	98%	99%
65	KARIB_N3	LEPRD3	330	330	98%	98%	98%	87%
26	LUSIW	MSORO66	66	66	95%	95%	95%	95%
24	LUS_UP	PENSL66	66	66	94%	94%	94%	94%
87	KARIB_N3	KAFWT3	330	330	94%	100%	100%	82%
76	KARIB_N3	LEPRD3	330	330	90%	98%	98%	90%
100	DLHLL66	PAMDZ66	66	66	87%	87%	87%	87%
84	MAPOS66	NDOLA66	66	66	82%	82%	82%	82%
85	MAPOS66	NDOLA66	66	66	82%	82%	82%	82%
82	MAPOS66	MCLRN66	66	66	82%	82%	82%	82%
151	LSKWT330	KAFWT3	330	330	80%	78%	75%	73%
38	STADM66	AVENU66	66	66	78%	78%	78%	78%
37	KABND66	LUANO66	66	66	77%	77%	77%	77%
210	LEPRD3	KAFGR3	330	330	77%	73%	73%	72%
39	STADM66	LUANO66	66	66	76%	76%	76%	76%
40	STADM66	LUANO66	66	66	76%	76%	76%	76%
229	CHAMBEAST	MWAM66	66	66	76%	76%	76%	76%
68	KITWE66	MILL66	66	66	76%	76%	76%	76%
130	PENSL66	CHNSR66	66	66	73%	73%	73%	73%
83	MAPOS66	BALUB66	66	66	73%	73%	73%	73%
133	CHNSR66	KANON66	66	66	72%	72%	72%	72%
198	KABWE3	LEPRD3	330	330	72%	79%	73%	79%
199	KABWE3	LEPRD3	330	330	72%	79%	73%	79%
32	SAFAL	KANON66	66	66	72%	72%	72%	72%
34	SAFAL	MUPEPE66	66	66	72%	72%	72%	72%
163	MUPEPE66	LUSW-T66	66	66	72%	72%	72%	72%
270	LUSW-T66	LUSIW	66	66	72%	72%	72%	72%
159	LSKWT330	KAFWT3	330	330	71%	59%	56%	57%
66	KITWE66	NKANA66	66	66	70%	70%	70%	70%
197	KABWE3	KITWE3	330	330	69%	72%	73%	72%
80	MAPOS66	ROAN66	66	66	68%	68%	68%	68%
4	BANCENTR	MICHL66	66	66	67%	66%	66%	66%
196	KABWE3	KITWE3	330	330	67%	70%	70%	70%
99	SKYWYS66	DPTRD66	66	66	67%	63%	63%	63%
189	LSMFEZ 330	LEPRD3	330	330	67%	56%	56%	54%
211	LEPRD3	KAFGR3	330	330	66%	66%	67%	66%
55	LUANO66	CCMTOFF	66	66	66%	66%	66%	66%
147	LEPRD1	WTRWK132	132	132	66%	69%	69%	69%
209	KITWE2	FRONT-TOFF	220	220	66%	66%	66%	66%
172	ZAMB220	NAM_ZAM	220	220	66%	64%	64%	64%
226	SESHEKE220	ZAM_NAM	220	220	66%	64%	64%	64%
42	AVENU66	CCMTOFF	66	66	65%	65%	66%	66%
81	MAPOS66	STORK66	66	66	62%	62%	62%	62%
221	KAFGR3	KAFWT3	330	330	62%	70%	65%	65%
90	LNSHY66	STORK66	66	66	61%	61%	61%	61%
417	PLAY SOLDIER	KASAMA	330	330	61%	61%	62%	62%
101	PAMDZ66	DPTRD66	66	66	60%	47%	48%	47%
200	KABWE3	LEPRD3	330	330	60%	63%	62%	61%
142	ROMA1	LEPRD1	132	132	60%	61%	60%	60%
202	KABWE3	LUANO3	330	330	59%	61%	61%	61%
49	BNCNT66	LUBAMBI	66	66	59%	59%	59%	59%
201	KABWE3	LUANO3	330	330	58%	61%	61%	61%
208	KITWE2	MAPOS2	220	220	58%	58%	58%	58%
146	LEPRD88	CHONGWE	88	88	58%	58%	58%	58%
183	ITEZGITE220	MUMBWA220	220	220	58%	58%	58%	58%
140	CVNTR1	LSKWT132	132	132	57%	57%	57%	57%
158	MLNGS66	LNSMF66	66	66	56%	56%	56%	56%
96	NDOLA66	DPTRD66	66	66	56%	56%	56%	56%

GRARE ID	Name_From	Name_To	kV_From	kV_To	Max Loading % 76MW PV 0MW Wind	1,006MW PV 0MW Wind	736MW PV 130MW Wind	596MW PV 260MW Wind
223	MAPOS2	FRONT-TOFF	220	220	56%	56%	56%	56%
45	BNCRF66	LUANO66	66	66	56%	56%	56%	56%
46	BNCRF66	LUANO66	66	66	56%	56%	56%	56%
233	BANCENTR	BNCRF66	66	66	56%	54%	54%	54%
115	KASMA66	MPIKA	66	66	56%	56%	56%	56%
41	AVENU66	BNCRF66	66	66	55%	36%	36%	35%
181	MUZUMA	KAFTN3	330	330	54%	66%	66%	62%
129	PENSL66	SERNJ66	66	66	54%	54%	54%	54%
52	CHMBS66	LUANO66	66	66	54%	54%	54%	54%
53	CHMBS66	LUANO66	66	66	54%	54%	54%	54%
132	LSKWT330	KABWE3	330	330	54%	58%	57%	58%
153	KZNGL66	VICTR66	66	66	54%	48%	48%	48%
185	KAFGRLOW	KAFGR3	330	330	54%	54%	54%	55%
184	KAFGRLOW	LSMFEZ 330	330	330	52%	52%	50%	49%
48	BNCNT66	LUANO66	66	66	51%	52%	52%	52%
126	MPIKA	MPIKANEW66	66	66	50%	50%	50%	50%
127	MPIKA	MPIKANEW66	66	66	50%	50%	50%	50%
50	CHSNG66	CHMBS66	66	66	47%	47%	47%	47%
169	LSKWT330	MUMBWA330	330	330	47%	46%	46%	44%
67	KITWE66	NKANA66	66	66	47%	47%	47%	47%
70	KITWE66	MINDL66	66	66	46%	46%	46%	46%
216	LUANO2	MICHL2	220	220	46%	68%	55%	68%
193	LSKWT330	MUMBWA330	330	330	46%	52%	51%	52%
114	MBALA66	NGOLI	66	66	46%	46%	46%	46%
176	LUALU66	KATESHI	66	66	46%	46%	46%	46%
177	KATESHI	NGOLI	66	66	46%	46%	46%	46%
11	LUMW330	KALUMBILA330	330	330	46%	46%	46%	46%
91	IRWIN66	MCLRN66	66	66	46%	46%	46%	46%
17	KALUMBILA330	MUMBWA330	330	330	45%	46%	46%	46%
18	KALUMBILA330	MUMBWA330	330	330	45%	47%	46%	47%
222	KAFWT3	KAFTN3	330	330	45%	55%	55%	54%

Table A4. 4 – List of the most loaded transformers. Interconnected Country – Year 2022

GRARE ID	Name_From	Name_To	kV_From	kV_To	Pn [MVA]	Max Loading % 76MW PV 0MW Wind	1,006MW PV 0MW Wind	736MW PV 130MW Wind	596MW PV 260MW Wind
331	KABWE88	KABWE66	88	66	20	100%	88%	88%	88%
332	KABWE88	KABWE66	88	66	20	100%	88%	88%	88%
398	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%	96%
399	MUMBWA220	MUMBWA330	220	330	125	96%	96%	96%	96%
409	KITWE2	KITWE66	220	66	60	86%	86%	86%	86%
419	LUANO2	LUANO66	220	66	60	85%	78%	78%	78%
410	KITWE2	KITWE66	220	66	60	85%	85%	85%	85%
418	LUANO2	LUANO66	220	66	60	84%	78%	78%	78%
423	LUANO2	LUANO66	220	66	60	84%	78%	78%	78%
408	KITWE2	KITWE66	220	66	60	84%	84%	84%	84%
407	KITWE2	KITWE66	220	66	60	83%	83%	83%	83%
411	KITWE2	KITWE66	220	66	60	82%	82%	82%	82%
420	LUANO2	LUANO66	220	66	60	78%	79%	79%	79%
421	LUANO2	LUANO66	220	66	65	77%	71%	71%	71%
422	LUANO2	LUANO66	220	66	65	77%	71%	71%	71%
431	KAFTN88	KAFTN3	88	330	125	71%	71%	71%	71%
430	KAFTN88	KAFTN3	88	330	125	70%	70%	70%	70%
413	LEPRD88	LEPRD3	88	330	90	69%	69%	69%	69%
386	MAPOS2	MAPOS66	220	66	80	68%	68%	68%	68%
438	MAPOS2	MAPOS66	220	66	80	67%	67%	67%	67%
424	PENSL3	PENSL66	330	66	60	66%	66%	66%	66%
425	PENSL3	PENSL66	330	66	60	66%	66%	66%	66%
444	MUZUM2	FICT BUS 011	220	330	315	66%	65%	65%	65%
439	MAPOS2	MAPOS66	220	66	80	65%	65%	65%	65%
437	MAPOS2	MAPOS66	220	66	80	65%	65%	65%	65%
415	LEPRD3	LEPRD1	330	132	150	61%	61%	62%	62%
361	LSKWT330	LSKWT132	330	132	125	58%	57%	58%	58%
383	LSKWT330	LSKWT132	330	132	125	58%	57%	58%	58%
388	LSKWT330	LSKWT132	330	132	125	58%	57%	58%	58%
414	LEPRD3	LEPRD1	330	132	150	58%	58%	58%	58%
279	MICHL2	MICHL66	220	66	120	56%	55%	55%	55%
433	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
435	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
436	KNSSW2	KNSSW66	220	66	85	53%	53%	53%	53%
405	KABWE3	KABWE88	330	88	60	51%	51%	51%	51%
406	KABWE3	KABWE88	330	88	60	51%	51%	51%	51%
283	SESHEKE220	SESHK66	220	66	25	50%	50%	50%	50%
284	SESHEKE220	SESHK66	220	66	25	50%	50%	50%	50%
387	MICHL2	MICHL66	220	66	120	49%	49%	49%	49%
353	KITWE2	FICT BUS 001	220	330	315	49%	49%	49%	49%
356	KITWE2	FICT BUS 002	220	330	315	49%	49%	49%	49%
359	KITWE2	FICT BUS 003	220	330	315	49%	49%	49%	49%
363	KITWE2	FICT BUS 004	220	330	315	49%	49%	49%	49%
366	LUANO2	FICT BUS 005	220	330	315	48%	52%	52%	53%
369	LUANO2	FICT BUS 006	220	330	315	48%	52%	52%	53%
372	LUANO2	FICT BUS 007	220	330	315	48%	52%	52%	53%
375	LUANO2	FICT BUS 008	220	330	315	48%	52%	52%	53%

ANNEX 5 – MAIN VRES TECHNICAL CONNECTION REQUIREMENTS TO THE TRANSMISSION SYSTEM

The connection of a VRES power plant to the Zambian transmission system shall not deteriorate system security and shall meet a list of requirements at the Point of Common Coupling (PCC).
Based on the international best practices, in the following chapters the most relevant connection requirements to be included in the transmission system grid code are recommended by the Consultant. It should be noted that the threshold values of each technical requirement can be modified and must be adjusted by ZESCO in accordance with the own practices.

A4.1 Frequency range of operation

A VRES power plant must be able to remain connected to the transmission system within the frequency ranges and times specified in the following table.

Table A5.0.1 - Frequency Ranges of Operation (Must remain connected conditions)

Frequency (Hz)	Operation
47.5 ≤ F < 48.75	90 Minutes
48.75 ≤ F < 51.25	Unlimited (Continuous Range)
51.25 < F ≤ 51.5	90 Minutes
51.5 < F ≤ 52	15 Minutes

In case of frequencies outside the specified frequency and time ranges the power plant shall be allowed to disconnect. There shall no technical restriction regarding the delivery of active power or reactive power within the frequency range of 49 Hz to 51 Hz and a VRES power plant shall be permitted within of unrestricted operation within this frequency range.

A4.2 Voltage range of operation

For a VRES power plant, no disconnection of any unit within a power park is permitted as long as voltage at PCC remains within +/-10% of nominal voltage or within voltage limits for continuous operation, whichever is the narrower voltage range (Continuous Voltage Range).

A4.3 Power quality

A VRES power plant shall ensure that the power it injects into the transmission system is within the limits prescribed hereunder.

A4.3.1 Rapid voltage changes

During regular switching operations within a VRES power plant such as switching operation on a wind turbine within a wind farm or switching of a shunt reactor/capacitor, the resulting voltage change at PCC shall not deviate more than 2% of the nominal voltage.

The maximum permitted voltage change at any point in the network shall be limited to 5 % of nominal voltage in respect of changes resulting from

a. switching of several units within a VRES power plant,
b. connection of a complete VRES power plant, or
c. disconnection of a complete VRES power plant.

A4.3.2 Flicker

Each VRES power plant shall ensure a flicker emission limits based on flicker planning levels according to Zambian Grid Code. The methodology for apportioning VRES power plant specific flicker limits shall be in-line with IEC61000-3-7.
In the absence of any flicker limits apportioned, the Consultant suggests that the flicker caused by a VRES power plant shall exceed the limits depicted here below.

Table A5.2 - Flicker limits to be applied in the absence of apportioned limits

Parameter	Emission Limit (HV-EHV)
P_{st}	0.3
P_{lt}	0.3

A4.3.3 Harmonics

An individual harmonic distortion limits to each VRES power plant based on a planning level for THD according to the National Electricity Grid Code shall be required.
In the absence of any apportioned limits, the Consultant suggests that the harmonic voltage distortion limits at PCC according to table below could be apply.

Table A5.3 - Harmonic Voltage Distortion limit

Voltage at POC (kV)	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
36 < V ≤ 69	3.0	5.0
69 < V ≤ 161	1.5	2.5
161 < V	1	1.5

THD is defined as the ratio of the RMS voltage of the harmonic content to the RMS value of the fundamental voltage, expressed in percent.

$$THD = \sqrt{\frac{\sum V_i^2}{V_1^2}} * 100\ \%$$

A4.4 Reactive power control

A VRES power plant shall operate within a power factor within the proposed range of 0.90 leading to 0.90 lagging, measured at the PCC.

For voltages between 0.9 and 1.1 p.u., a VRES power plant shall provide maximum reactive support to the system.

A VRES power plant shall be capable of varying power factor continuously in the entire range of 0.90 under-excited to 0.90 over-excited during operation with maximum active power output and voltage within the Continuous Range of Operation.

A VRES power plant shall be capable of varying reactive power at the PCC within their reactive power capability range as defined by the figure below, when operating within the Continuous Voltage Range and at an active power output level between 5% and 100% of Rated Power.

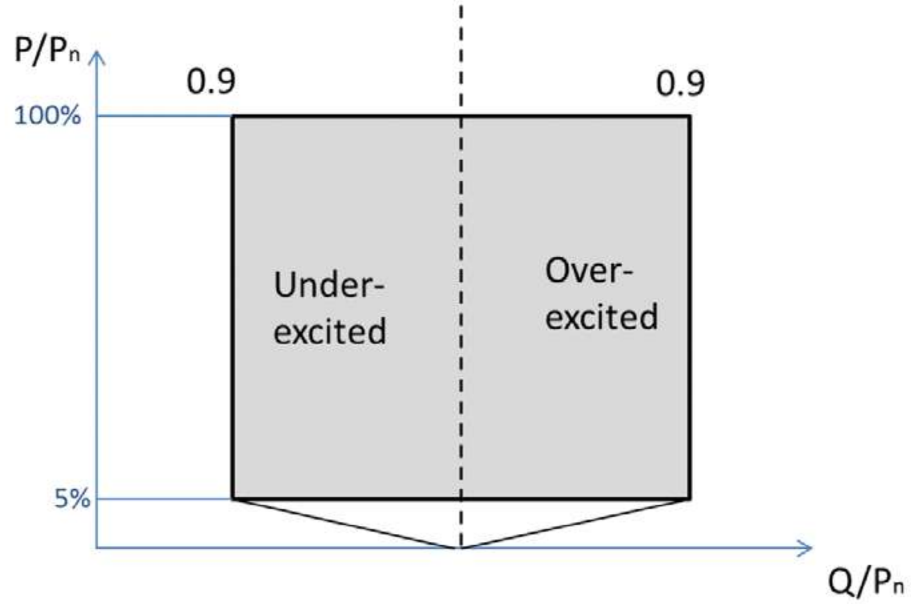


Figure A5.1 - Reactive power requirements at full/partial active power output conditions

It shall be possible to operate the VRES power plant in any operating point within the range cos φ = 0.90 under-excited (inductive) to cos φ = 0.90 over-excited (capacitive) at PCC in the voltage range indicated in the figure below and for active power range 100%-5% of Pn.

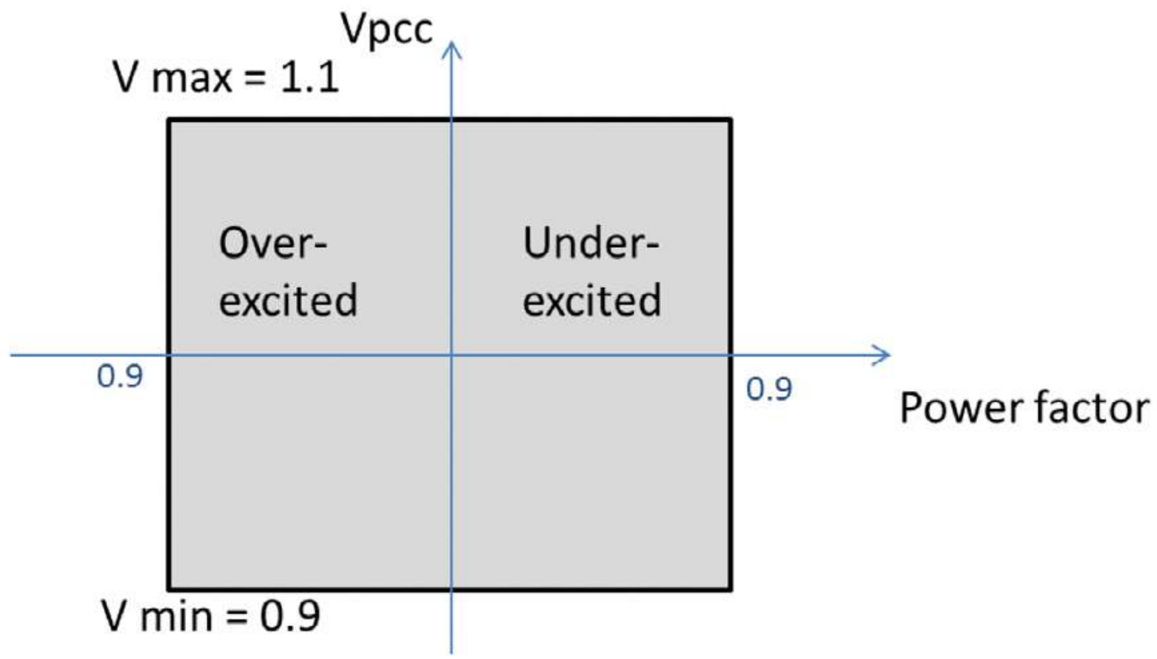


Figure A5.2 - Reactive power requirement during normal operation and nominal active power supply

A4.5 Active power control

For system security reasons it may be necessary to curtail a VRES power plant active power output.
A VRES power plant shall be capable of operating at a reduced power level if active power has been curtailed by SO, for network or system security reasons.

The accuracy of the control performed and of the set-point shall not deviate by more than ±1 % of the rated power.

The type of communication between SO (System Operator) and VRES power plant operator must be agreed between the parties and specified as part of the bilateral connection agreement.

A4.5.1 Ramp rates

The plant Control System shall be capable of controlling the ramp rate of its active power output with maximum active power per minute ramp rate set by the transmission system operator, with default at 20% per minute of unit nameplate capacity.

About the operational concerns, two ramp rate settings should be defined:

- The first is the active power ramp rate average over one (1) minute.
- The second ramp rate setting shall apply to the active power per minute ramp rate overage over ten (10) minutes.

These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down, including when responding or released from an operator deployment.

A4.6 Frequency response

A4.6.1 High frequency response for VRES power plants

During high frequency operating conditions, each VRES power plant shall be required to operate at reduced active power output in order to stabilize grid frequency.
When the frequency exceeds 50.2 Hz, each VRES power plant shall be required to reduce active power as a function of change in frequency as illustrated in figure below.

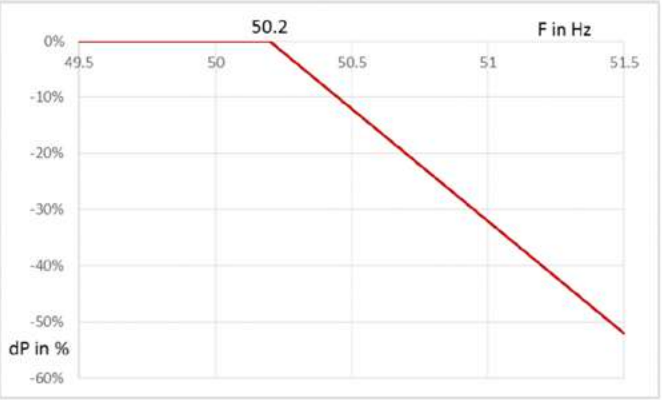


Figure A5.3 - Mandatory high frequency response for all connected VRES power plants

Note: 'dP' in the figure represents percentage of active power by which the output has to be decreased in case of increasing system frequency.

High frequency response must operate with a minimum ramp rate of 100% of rated power per minute as provided by the primary frequency control time scales.

A4.6.2 Primary and secondary frequency control

Unless otherwise required by the SO, a VRES power plant is exempted from primary or secondary frequency control capabilities except from high frequency response according to the previous section.

A4.7 Behaviour during abnormal voltage conditions

A4.7.1 Low voltage ride through (LVRT)/high voltage ride through (HVRT) capability for VRES power plants

A VRES power plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

A VRES power plant shall be designed to have LVRT and HVRT capability as illustrated in the figure below.

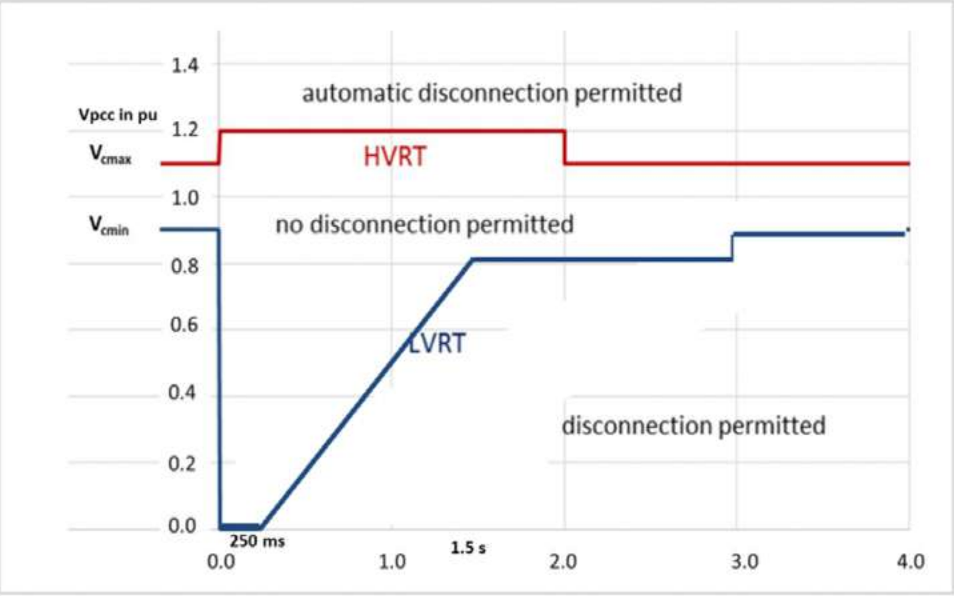


Figure A5.4 - Definition of voltage characteristic at the PCC for LVRT and HVRT

For all voltages at the PCC, which are between HVRT and LVRT, no disconnection of a VRES power plant or of individual units within a VRES power plant is permitted.

A4.7.2 Reactive current support during high impedance faults

During high impedance faults, both symmetrical and asymmetrical, all units within a VRES power plant shall support the voltage by injecting or absorbing additional reactive current ΔIq at the generator terminals proportional to the change of the unit's terminal voltage ΔVt, as depicted in the following figure.

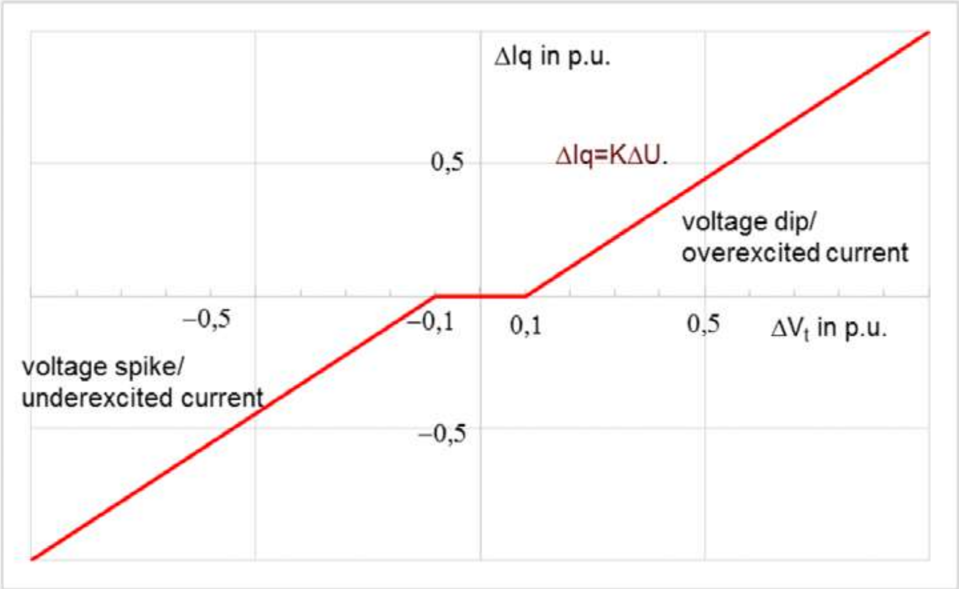


Figure A5.5 - Voltage controller characteristic

The factor of proportionality between additional reactive current and voltage deviation is named K (ΔIq=KΔVt) and the factor K must be settable in the range of 1<=K<=2.

During dynamic performance:

- Maximum in 30ms the reactive current must be injected, meaning that it shall reach at least the 90% of the nominal value
- Maximum after 60ms the reactive current must have settled, meaning that it shall remain within a tolerance band of -10%/+20% around the nominal value

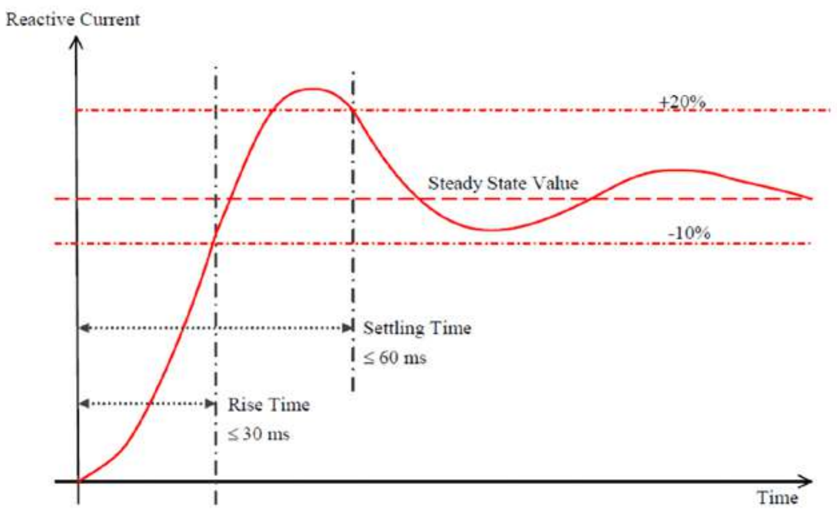


Figure A5.6 - Step response for required reactive current

A4.7.3 Active and reactive power behaviour during voltage recovery

After voltage at PCC has returned into the Continuous Voltage Range, a VRES power plant shall restore its active power output to at least 90% of its pre-fault value within 1 second.

A4.8 Protection and fault levels

A VRES power plant operator shall design, implement, coordinate and maintain its protection system to ensure the desired speed, sensitivity and selectivity in clearing faults on VRES power plant's side of the connection point (PCC).

Protection functions required for protecting the grid from getting out of normal operating ranges will be specified, including trip-settings, response times for over-/under-voltage protection, and over-/under-frequency protection.

The coordination among protections at connection point must be agreed between SO and the VRES power plant operator.

The circuit breaker used for connection switching in transmission network connected generators shall be equipped with a disconnection system to ensure safe operation during re-connection/re-synchronization to the grid.

The SO may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the network, except that, such a change shall not result in a VRES power plant being exposed to negative impacts from the network transmission system outside of the design requirements.

The SO shall inform a VRES power plant operator of the highest and lowest short-circuit current that shall be expected at the PCC as well as any other information about the network transmission system as may be necessary to define the VRES power plant's protection functions.

Where VRES power plant's protection equipment is required to communicate with the SO's protection equipment it must meet the communications interface requirements specified by the SO.

A4.9 Supervisory Control and Data Acquisition

A VRES power plant shall provide Supervisory Control and Data Acquisition (SCADA) with the capability to transmit data and receive instructions from the SO to protect system reliability.

A4.10 Environmental temperature

All components of the VRES power plants shall be designed considering the temperature of operation in the place where they will be located.
The VRES power plants shall respect all connection requirements for all temperatures at which they will be operated. The disconnection of inverters or all other equipment because of the environmental temperature is not permitted.