Project Name	**Development of a low-cost investment plan and regulatory frameworks for BESS deployment in West Africa (WAPP grid)**
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Report on the Least-Cost Investment Plan for Work Package 1 (Develop a Least-Cost Investment Plan for the Deployment of BESS to Support the Implementation of the ECOWAS Master Plan for Regional Transmission and Power Generation Infrastructure)

LIST OF ABBREVIATIONS

Abbreviation	Definition

A: Amper

AC: Alternating Current

ADB: African Development Bank

Av Cap: Available Capacity in MW (Available Power)

AVR: Automatic Voltage Regulator

BAU: Business As Usual

BESS: Battery Energy Storage System

BMS: Battery Management System

CAES: Compressed Air Energy Storage

COMMI: Commissioning

DECOM: Decommissioning

DFI: Development Finance Institutions

ECREEE**:** ECOWAS Center for Renewable Energy and Energy Efficiency

ECOWAS**:** Economic Community of West African States

EFR: Enhanced Frequency Response

EMS: Energy Management System

ERERA**:** ECOWAS Regional Electricity Regulatory Authority

ESIA: Environmental and Social Impact Study

ESS: Energy Storage System

EV: Electric Vehicle

FCR: Frequency Control

FES: Flywheel Energy Storage

GESI: Gender Equality and Social Inclusion

GIZ: Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

HFO**:** Heavy Fuel Oil

IPP: Independent Power Producer

Kton: kilotonne

kV: kiloVolt

kVA: kiloVoltAmpère

kW: kiloWatt

kWh: kiloWatt–hour

LA: Lead–Acid

LCIP: Least Cost Investment Plan

LCOS: Levelized Cost of Energy Storage

LCOE**:** Levelized Cost of Energy

LFP: Lithium-iron-phosphate

LFO**:** Light Fuel Oil

LSE: Load-Serving Entity

ms: millisecond

MVA: MegaVoltAmpère

MW: MegaWatt

NMC: Lithium-Nickel-Manganese-Cobalt

PCC: Point of Common Coupling

PCS: Power Conversion System

PMS: power management system

PPP: Public Private Partnership

ProCEM: Promotion of a Climate-friendly Electricity Market in the ECOWAS Region

PV: PhotoVoltaic

RE**:** Renewable Energy

RESPITE: Regional Emergency Solar Power Intervention Project

RMS : Root Mean Square (Simulations)

SCS: Supervisory Control System

SDG: Sustainable Development Goals

SOC: State of Charge

SOH: State of Heath

SLD : Single Line Diagram

SVC: Static VAR Compensator

T&D: Transmission and Distribution

ToR**:** Terms of reference

TSO: Transmission System Operator

V: Volt

Country Codes (ISO):

BJ	Benin
BF	Burkina Faso
CI	Côte d'Ivoire
GH	Ghana
GM	Gambia
GN	Guinée
GW	Guinée-Bissau
LR	Liberia
ML	Mali
NE	Niger
NG	Nigeria
SN	Senegal
SL	Sierra Leone
TG	Togo

ICE	Internal Combustion Engine
OCGT	Open Cycle Gas Turbine

EXECUTIVE SUMMARY

As a reminder, the objective of the mission is to lead the development of a Low-Cost Investment Plan and Regulatory Frameworks for the deployment of BESS in West Africa (WAPP grid) and the main objectives of the study are summarized in the table below:

Table 1: Summary of the objectives of the BESS project

Work Package	Objective
WP 1: Investment plan for BESS	• Final Report on Data Collection and Grid Models • Presentation of BESS's final investment plan
WP 2: Regulatory and institutional frameworks	• Submission of the final report on the regulatory and institutional framework for due diligence • Submission of final documents on the regulatory and institutional framework
WP 3: Environmental Frameworks	• Submission of the due diligence report on the environmental framework • Submission of final documents on the environmental framework
Training	• Developed training material • Two training sessions were held

In order to develop the BESS investment plan, simulation studies for the enterprise-wide BESS on the WAPP network must be carried out. Before conducting the study, it is essential to update the data from the regional interconnected grid model. As mentioned in the Terms of Reference, the ECOWAS Master Plan 2019-2033 and the available PSS/E files will serve as a starting point and will be updated. To this end, data collection is mandatory and requested to have a reliable and up-to-date regional network model.

Several challenges associated with this phase were addressed as follows:

1. First, the data collection required good collaboration from WAPP and its utilities to provide data on the interconnected grid model as well as ongoing and upcoming projects in ECOWAS countries. In addition, in addition to WAPP, ECREEE and ERERA were involved from the very beginning of the project to its completion including the early appointment of contact members, who assisted and supported the project team in data collection.

2. Secondly, some data was not available at the WAPP, ERERA and ECREEE levels and was requested and provided by some utilities, ministries in charge of energy, environment, national electricity regulators in ECOWAS Member States. Given the short duration of the project, the limited time available for data collection and the number of countries to be considered, it was not possible to conduct interviews with all relevant public services and ministries in all Member States.
3. Thirdly, although it has been difficult to collect data on future projects. It was also found that some technical data on the current network was not available. In this case, assumptions were made based on the state of the country's electricity systems and the state of the interconnected WAPP grid, in agreement with relevant stakeholders.

As data collection is one of the main prerequisites for the success of the BESS study, this required good collaboration between the following stakeholders:

- The West African Power Pool (WAPP) integrates the national power systems of Member States into a unified regional electricity market and coordinates electricity exchanges among Member States, which are expected to have a relatively good overview of current and future projects in ECOWAS Member States;
- The ECOWAS Regional Electricity Regulatory Authority (ERERA) regulates cross-border interconnections and electricity trade;
- The ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) responsible for the promotion and development of renewable energy and energy efficiency projects and their integration into energy activities and policies in the region;
- TSOs of ECOWAS Member States;
- Ministries of Energy of ECOWAS Member States;
- the Ministries of Environment and Gender of ECOWAS Member States; and
- GIZ supports the renewable energy and energy efficiency programmes of member countries.

At the kick-off meeting of "Battery Energy Storage Systems (BESS)" on December 12, 2022, it was mentioned that the team of consultants in addition to office collection data will proceed with the data collection visit plan in ECOWAS countries.

On 27 February 2023, a letter of introduction from the consultant was sent to the Ministry of Energy, Utilities and TSOs by the WAPP requesting the data and documents on the power supply system and the framework governing the energy sector. The letter also informed the countries of the consultant's mission to visit the country.

As a result of the conduct of the consultant's data collection mission and engagement at different levels, data and information were collected from, among others, utilities/TSOs and power producers, the regulatory authority, and the Ministry of Environment and Gender. Based on the data and information collected, the consultant prepared a data collection report.

From 19 to 21 June 2023, a validation workshop was held in Saly, Senegal with all the referents of the stakeholders of the Ministry in charge of Energy, Utilities/TSO, ECREEE, ERERA, WAPP, OMVG, OMVS-SOGEM, TRANSCO, GIZ and the Consultant to validate the data collection report. The data collection report was validated on a country-by-country basis and the final grid template for each country was approved by the country representatives.

At the end of the workshop, a final version of the data collection report incorporating feedback from stakeholders as well as updated grid templates were finalized into a detailed report final version of the report.

In addition, on October 14, 2023, the 2025 and 2030 grid templates and accompanying files were sent to stakeholders for review and comment.

On November 30, 2023, at the request of WAPP, the consultant presented the 2025 and 2030 grid models to the System Reliability Assessment Working Group (SRAWG) for preliminary comments on LTCs, and further comments were received on each country's electricity systems. Detailed system data was also provided as a data file in EXCEL format and validated.

In order to reduce the assumptions for the Nigerian grid as much as possible, a special meeting was held on 30 January 2024 with representatives of TCN, WAPP and the consultant to receive realistic information and consent on the proposed assumption regarding the PV plants and their locations in the years 2025 to 2030. This was successfully achieved, allowing the study to move forward.

With all the data collected, which made it possible to propose the 2025 and 2030 grid models, the studies were carried out in accordance with the terms of reference and the proposed methodologies which led to the following results:

1. Application 1: Frequency Control

This study demonstrated the economic viability of investing in BESS to provide frequency control services, compared to investments in gas turbines, assumed to be often used for frequency control. Focusing on the investment cost of a one-hour battery, the results showed substantial potential savings of 64% and 75% compared to gas turbine investments by 2025 and 2030, respectively. In addition, the exploration of extending battery life for possible additional applications revealed that BESS retains its economic advantage, even with investments of 4 hours by 2030 and 3 hours by 2025.

2. Application 2: Voltage Control

The comparison of BESS and reactances clearly shows that a BESS cannot and cannot become cost-effective to act solely for voltage control, as its cost is not competitive with the costs of reactances, even considering the future reduction in BESS investment costs. However, the voltage control capability of the BESS will be of significant interest in the combined applications of the BESS such as power transfer and voltage control, or frequency control and voltage control: the placement of the BESS in locations where a large capacitor or reactance would otherwise have to be installed will result in the corresponding capacitor or CAPEX savings of reactance.

3. Application 3: Energy Shift (Arbitrage)

The feasibility of implementing the Energy Shift application only (without renewable energy projects such as photovoltaics) seems limited by 2025 but more appropriate by 2030. These findings align with similar international system-wide studies, often suggesting the viability of market BESS after 2030, depending on the penetration of renewables, especially PV installed capacity. It is essential to recognize the inherent limitations of these results, related to data and simplifications of the simulation process. A more granular representation can result in relatively higher investments in BESS. The study also assumed relative stability in fossil fuel prices and considered investment in thermal capacity to be certain. One direction for future work could be to consider replacing part of this thermal capacity with photovoltaics in combination with storage.

Based on the country-by-country results, it appears that The Gambia has significant potential for investment in BESS in both 2025 and 2030, while Mali and Burkina Faso also have favourable marginal cost structures, conducive to promoting BESS after 2030. In addition, the complementary role of interconnections with BESS is noteworthy, as greater penetration of solar PV by 2030 is offset by an increase in net transfer capacity (NTC).

4. Application 4: Transmission Congestion Relief

The use of batteries as a tool to decongest the electricity grid offers significant advantages, in particular by avoiding costly investments in line reinforcements. An analysis of the cost of the reinforcements needed over the next few years makes it possible to determine the priority investments, including the installation of lines and the installation of batteries. Based on the cost of reinforcements and the overload to be mitigated, batteries are strategically positioned to optimize the use of existing lines and defer investment in expensive new power lines.

The efficiency of this method is closely related to the specific topology of the grid, the capacity of the batteries required and the level of overloads identified in the model (which in turn is related to the assumed distribution of the generation dispatch). The most promising cases are those where the required grid reinforcement would be costly, the overload is limited (hence a low-dimensioning, low-cost BESS), and preferably the load growth is low (thus postponing the need for reinforcement for many years).

From this analysis, very encouraging results emerge, such as:

- Installation of a 10 MW/20 MWh BESS at JERICHO 1 substation to avoid congestion (overload) of JERICHO 1 line NG_AYEDE 1 in Nigeria
- Installation of a 12 MW/24 MWh BESS at the PAPALANTO 1 substation in 2030 to avoid congestion (overload) of the NG_PAPALANTO 1 OTTA 1 line in Nigeria.

In both cases, the installation of a BESS seems cost-effective even if there is no price difference between the charging time (usually at noon when the PV generates electricity, or during the night when the cost is low), and the discharge time (usually the peak charging time, in the evening). For the other cases analysed, profitability only comes into play once at least a given difference in the price per MWh is observed.

In conclusion, these are places where very expensive reinforcements can be avoided by installing batteries with a power of about 10MW and a capacity of 2 hours. However, such cases must be discussed with the network operator, in particular to confirm the occurrence of congestion and to check that there are no less costly options for the operator, such as possible redispatching.

5. Application 5: Black Start

Black Start as a standalone application doesn't make economic sense due to BESS's high capital expenditures. However, the BESS installed for other applications could certainly come in handy when restoring the grid after a large power outage.

1. INTRODUCTION

1.1 Scope of the study

The West African energy sector has been evolving at a significant rate, creating many challenges for the planning and operation of the power system.

To address those energy challenges and pool efforts at exploiting the region's abundant natural resources, the Economic Community of West African States (ECOWAS), through its Directorate in charge of Energy, established an institutional governance mechanism that resulted in the creation of specialised institutions and agencies with different mandates:

- the West African Power Pool (WAPP) integrates the national power systems of Member States into a unified regional electricity market and coordinate trading of electricity among member States,
- the ECOWAS Regional Electricity Regulatory Authority (ERERA) regulates cross-border interconnections and electricity trading, and
- the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE) promote and develop renewable energy and energy efficiency projects and mainstream it into energy activities and policies for the region.

Currently through judicious development and realization of key priority infrastructure projects for power generation and transmission, the fourteen (14#) ECOWAS mainland countries are interconnected, the bilateral electricity market was launched in 2018 enabling power trade among ECOWAS member states.

The ongoing investment program of the energy sector for the ECOWAS region is dictated by the 2019 – 2033 ECOWAS Master Plan for the development of Regional Power Generation and Transmission Infrastructure that was prepared with the support of the European Union and approved in December 2018 by the Authority of the ECOWAS Heads of State and Government through Supplementary Act A/SA.4/12/18.

The ECOWAS Master Plan contains seventy-five (75#) priority projects of which twenty-eight (28#) are transmission line projects (investment requirement of USD 10.48 billion) and forty-seven (47#) are generation projects of approximate total capacity of 15.49 GW (investment requirement of USD 25.91 billion). Utility-scale renewable energy projects comprise 68.9% (10.67 GW) of the generation capacity in the interest of diversifying the regional generation mix, specifically with photovoltaic (PV) technologies that is exhibiting decreasing costs.

As a result, through a multi-stakeholders efforts, the grid of all the 14 ECOWAS mainland countries are interconnected and the region is achieving its energy transition through the promotion of renewables (such as solar PV and wind) and assess the cost benefits of development of Battery Energy Storage Systems (BESS) to support the interconnected grid in order to achieve higher integration of vRE into the grid that shall guarantee flexibility of system response to cope with the intermittency of these sources. The assessment of the BESS deployment was recommended in the Master Plan to support especially variable renewable energy sources (vRE), such as solar PV and wind. This formed the basis for this study and the development of a Least Cost Investment Plan (LCIP) and regulatory frameworks for BESS deployment in West Africa since the exploration of the use of BESS can provide relevant grid services among others frequency regulation, flexible ramping, black start, congestion relief.

BESS can be used to overcome several challenges related to large-scale grid integration of renewables. First, batteries are technically better suited to frequency regulation than the traditional spinning reserve from power plants. Second, batteries provide a cost-effective alternative to network expansion for reducing curtailment of wind and solar power generation.

Similarly, batteries enable consumer peak charge avoidance by supplying off-grid energy during on-grid peak consumption hours. Third, as renewable power generation often does not coincide with electricity demand, surplus power should be either curtailed or exported. Surplus power can instead be stored in batteries for consumption later when renewable power generation is low and electricity demand increases.

The financial viability of a BESS project for renewable integration will depend on the cost–benefit analysis of the intended application.

To achieve this objective, there is the need for the elaboration of a least-cost investment plan for BESS to support the implementation vRE projects as well as the development of a regional regulatory framework including intaking into account environmental and gender aspects.

BESS will fulfil objectives that generate multiple benefits such as facilitate the integration of variable renewables, improvement in energy efficiency, reliability of electricity supply, and access to and security of energy. As such, BESS have a critical role in transforming energy systems that will be clean, efficient, and sustainable.

A major advantage provided by BESS is flexibility in addressing the full range of active and reactive power needs.

In summary, this study has the objective to conduct the Development of a Least Cost Investment Plan and Regulatory Frameworks for BESS deployment in West Africa and is summarised in the table here:

Table 1-1: Summary of Components of the BESS Study

Work Package	Objective
WP 1: Investment plan for BESS	• Final report on data collection and grid models delivered • Final BESS investment plan submitted
WP 2: Regulatory and institutional frameworks	• Submission of the final due diligence regulatory and institutional framework report • Final regulatory and institutional framework documents delivered
WP 3: Environmental Frameworks	• Submission of the due diligence report on environmental framework • Final documents on environmental framework delivered
Trainings	• Training material developed • Two sessions of training conducted

1.1. The Regional Interconnected Power System and ECOWAS Electricity Market Description

Through a multi-stakeholder' efforts, the grid of all the 14 ECOWAS mainland countries are interconnected as at today and given that Cape Verde is an island, future investigations will explore the possibility of interconnecting it to the mainland countries.

However, the interconnected network covers currently three geographical areas that are under a synchronisation process: Area 1 (Nigeria – Niger and part of Togo/Benin), Area 2 (Part of Togo/Benin-Ghana – Burkina – Cote D'Ivoire – Liberia – Sierra Leone – Guinea - Part of Mali) and Area 3 (part of Mali – Senegal - Gambia - Mauritania), as detailed here after.

Within the framework of the WAPP synchronisation project,

- A first synchronisation trial was performed on 22nd October 2022 and lasted close to 10 hours and 2nd trial was performed on 11th – 13th of March 2023 and lasted a little over 48 hours.
- A permanent synchronization of Area 2 and Area 3 was then carried out on 8th July 2023 at 05:50 am (GMT + 1).

- The synchronization project is underway, and barring any unforeseen events, the sub-region will have a synchronized regional grid before 2025.

Concerning power generation within the region, currently, the electricity sector of the ECOWAS countries supplies only 30% of the population. The region's peak load exceeded 6,500 MW for a total consumption of almost 40,000 GWh. In the promotion and development of power generation, WAPP is focused on the promotion of larger power generation projects and ECREEE both smaller on-grid renewable energy projects and off-grid.

Currently, there are many constraints such as insufficiency of generation and the need to increase the share of renewable energies in the energy mix for cleaner energy generation. The levels of electricity tariffs in member countries are among the highest in the world, partly due to the inability to achieve economies of scale for generation due to the lack of interconnection between member countries, which constitutes a bottleneck for regional trade. The region is endowed with abundant natural resources such as solar energy in the north, hydroelectricity in the west and gas in the east.

To achieve energy diversification within the regional grid, it is necessary for member countries to be perfectly synchronized to fully exploit these resources.

The ECOWAS region has set a clear target to increase the share of renewable energy in the region’s overall electricity mix to 10% in 2020 and 19% in 2030. Including large hydro, the share would reach 35% in 2020 and 48% in 2030.

The region will not only have to strengthen its network with full synchronization, but also to increase its flexibility and develop a framework for a more sustainable and reliable way of delivering electricity.

One of the main obstacles facing the interconnected regional electricity system is the weak interconnections between countries, which constitutes a bottleneck for regional trade.

Currently, due to weak interconnections between member countries through long-distance lines, many interconnection lines are facing stability limits before they can reach the thermal limits of the lines. This is a major obstacle that limits regional trade among member countries, which requires further reinforcements. These reinforcements would be in the form of interconnection lines or compensation devices including energy storage, compensators in series or in shunt to reinforce the stability of the system and to allow more regional exchanges. In the case of some countries such as Nigeria, Ghana and Cote d’Ivoire, there is excess generation capacity that can be exported to neighbouring countries. However, this possibility is limited due to network grid constraints.

The scope of the project covers the regional interconnected grid that is expected to be synchronous by 2025. In particular, any other grids that will not be synchronous with the ECOWAS mainland continental WAPP are out-of-scope of the study: Example are Cabo Verde, five (5) independent grids in Niger, off-grid mini-grids across the different countries, and other off-grid applications.

Key interventions through energy storage system investments by batteries (BESS) should be required to offer the most cost benefits in terms of increased regional trade, allowing more Renewable Energy (RE) to be integrated into the system and to increase system stability.

The study only considers front-of-meter BESS application at transmission grid level. Behind-the-meter and distribution grid applications are out of scope. A potential interconnection of the WAPP grid with other countries (Morocco, CAPP, etc.) is not considered in the study and the grid of Mauritania, which is interconnected with WAPP, is represented as an equivalent model. The ECOWAS Master Plan for Regional Power Transmission and Generation Infrastructure includes interconnection to CAPP and COMELEC by 2033.

Regarding the status of the ECOWAS Regional Electricity Market, it was launched in 2018 and this resulted in bilateral trades among ECOWAS countries. The WAPP hopes to launch other market products including the Day-Ahead market in the near future that shall allow buyers to buy power from sellers within a day schedule. The Day-Ahead market is a pilot test from 2023 to 2024 with the market participants.

1.2. BESS Investment Plan Documents

For the proper understanding of this BESS Investment Plan report, it is essential to consult and consider the following related documents:

- BESS Assumptions and Methodology for Work Package 1 – ref 6279-BESS-ME- 001
- BESS Data Collection Report and Grid Model - Volume 1: Main Document – ref 6279-BESS-DC-005
- BESS Data Collection Report and Grid Model - Volume 2: Annexes – ref 6279- BESS-DC-005
- WAPP BESS Grid Models 2025 & 2030 – ref 6279- BESS-RP-003

- Assessment of the Status of Implementation of the ECOWAS Master Plan for the Development of Regional Power Generation and Transmission Infrastructure 2019 - 2033 - meeting report on 14 April 2023 in Lomé.

2. BATTERY ENERGY STORAGE SYSTEMS

2.1. Battery Technologies

The lithium-ion technology is currently the most mature technology for stationary battery storage applications. BESS are already used by power system operators and market participants in many countries and the market is currently experiencing a fast growth. For example, the United Kingdom has already installed more than 4000 MW of BESS.

This study is basing its technical and economic analysis on the characteristics of lithium-ion batteries with lithium-iron-phosphate (LFP) and lithium-nickel-manganese-cobalt (NMC) chemistries because these chemistries (LFP in particular) constitute the vast majority of ongoing battery storage projects in the world and is the most mature technology. Depending on the evolution of technology and prices, it is possible that future actual BESS projects in the WAPP region will be based on other technologies, as presented below (other lithium-ion chemistries, sodium-sulfur batteries, redox-flow batteries, sodium-ion batteries, etc.), but technology evolution should not invalidate the conclusion of the study as long as costs will remain similar. Should a new technology bring drastic cost reduction, then the study would have to be re-evaluated.

The study is considering utility-scale multi-MW BESS, connected at the level of the transport network. These systems are called front-of-meter as they are not associated with power consumption behind the same connection point. They can be collocated with production units, e.g. solar photovoltaic plants, but it is not mandatory or required by the applications that are being considered.

2.1.1. Lithium-ion batteries

Lithium-ion batteries were invented in the 1970s and the market has grown significantly since then with the use of these batteries in portable electronic equipment and, more recently, in electric vehicles. Thanks to the growing size of the market, the price of these batteries has fallen sharply, see Figure 1.

Figure 1: Volume-weighted average lithium-ion battery pack and cell price split, 2013-2023

Source: BloombergNEF. Historical prices have been updated to reflect real 2023 dollars. Weighted average survey value includes 303 data points from passenger cars, buses, commercial vehicles, and stationary storage.

Figure 1: Lithium-ion batteries cost reduction (source BloombergNEF)

The main lithium-ion battery chemistries are:

- NMC – lithium nickel manganese cobalt
- LFP – lithium fer phosphate
- NCA – lithium nickel cobalt aluminium
- LCO – lithium cobalt
- LMO – lithium manganese
- LTO – lithium titanate

The most widely used batteries in stationary applications are NMC and LFP batteries, the latter of which are capturing most of the current market thanks to their lower cost than NMC batteries and their safety advantages. LFP batteries have a lower energy density than NMC batteries, but this point is less important in stationary applications than in mobile applications.

Figure 2 shows a comparison of the main characteristics of different lithium-ion battery chemistries.

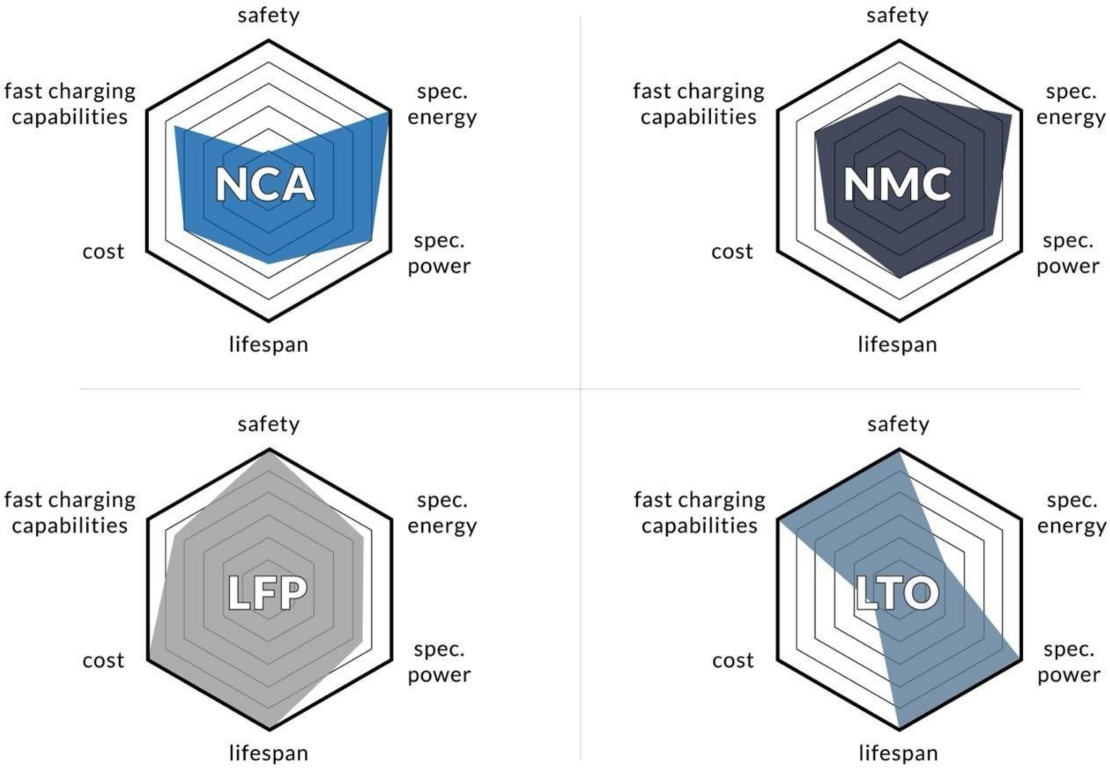

Figure 2 : Comparison of different characteristics of lithium-ion batteries chemistries (source: https://www.hoferpowertrain.com/articles/the-future-of-battery-solutions-in-the-e-mobility)

A storage system based on lithium-ion batteries is made up of the following elements:

- The battery cell itself. It is within the cell that the chemical reaction occurs. The cells have a cylindrical or prismatic format.
- The cells are then grouped into modules where they will be connected in series and parallel in order to reach the desired voltage
- The modules are stored in racks which will be integrated into cabinets or containers equipped with everything necessary in terms of temperature management, fire protection, etc.
- The system is equipped with a BMS (Battery Management System), that is to say electronic equipment which will monitor and manage the charge of the cells
- The battery racks are connected to a converter or PCS (Power Conversion System) which ensures bidirectional conversion between direct current and alternating current.

- Then, this PCS will, depending on the needs, be connected to an electrical system composed of cables, protection equipment and transformers in order to ensure connection to the electrical network at the desired voltage
- Finally, an EMS (Energy Management System) manages the BESS by controlling the PCS to charge or discharge the batteries according to the needs of the chosen application.

The different components are shown in Figure 3.

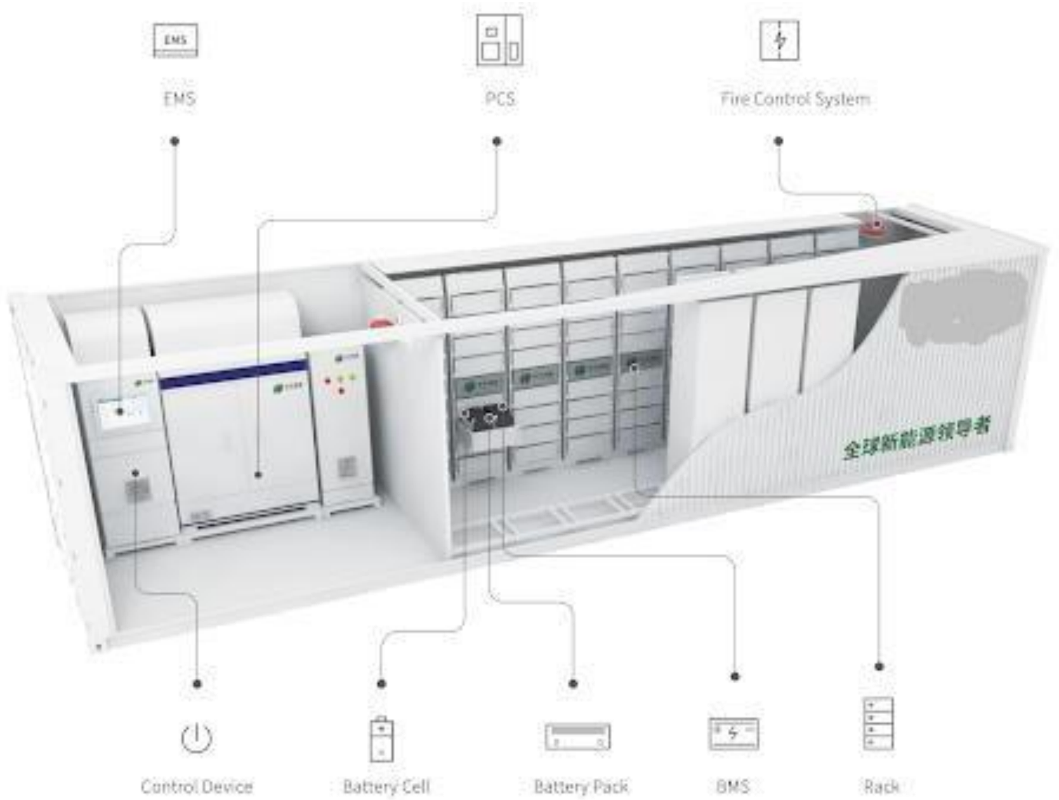

Figure 3 : 3D view of a BESS based on lithium-ion batteries (source : https://yes-eu.com/energy- storage-systems/)

2.1.2. Redox flow batteries

The operation of redox flow batteries is similar to that of lithium-ion batteries except that the electrolytes are stored in external reservoirs and are delivered by pumps to the location where the chemical reaction occurs, which is called the “stack”. The main advantage of these batteries lies in the decoupling between power and available energy. Indeed, for the same power (that is to say the same stack), can easily, and at a relatively low cost, increase the size of the reservoirs which contain the liquid electrolyte to increase the quantity of energy available. Redox flow batteries are more bulky and therefore intended mainly for stationary applications.

If the cost of redox flow batteries remains high for short-term applications (1 to 4 hours), particularly because they do not benefit from the economies of scale linked to the production of lithium-ion batteries for electric vehicles, they could prove to be competitive in applications requiring long storage times, for example 8 hours or more.

Most current redox flow batteries use vanadium as chemical element, but there are also redox flow batteries based on zinc or iron.

2.1.3. Sodium-sulfur batteries

The sodium-sulfur (NaS) battery is a “molten salt” type battery whose particularity is a high operating temperature, around 300°C. In this way, it is potentially interesting for warm countries where yield losses linked to high temperatures are lower than in temperate countries. The lifespan, expressed in number of cycles, is lower than that of lithium-ion batteries. Without an application for electric vehicles and with only one company supplying this type of battery (Niterra), it is also unlikely that it will be able to obtain the economies of scale necessary for a reduction in costs comparable to that experienced by lithium-ion batteries.

2.1.4. Main characteristics of batteries

The table below gives the main characteristics of batteries.

Key active material	lithium nickel manganese cobalt oxide	lithium manganese oxide	lithium nickel cobalt aluminium	lithium iron phosphate	lithium titanate
Technology short name	NMC	LMO	NCA	LFP	LTO
Cathode	$LiNi_xMn_yCo_{1-x-y}O_2$	$LiMn_2O_4$ (spinel)	$LiNiCoAlO_2$	$LiFePO_4$	variable
Anode	C (graphite)	C (graphite)	C (graphite)	C (graphite)	$Li_4Ti_5O_{12}$
Safety					
Power density					
Energy denisty					
Cell costs advantage					
Lifetime					
BES system performance					
Advantages	-good properties combination -can be tailored for high power or high energy -stable thermal profile -can operate at high voltages	-low cost due to manganese abundance -very good thermal stability -very good power capability	-very good energy and good power capability -good cycle life in newer systems -long storage calendar life	-very good thermal stability -very good cycle life -very good power capability -low costs	-very good thermal stability -long cycle lifetime -high rate discharge capability -no solid electrolyte interphase issues
Disadvantages	-patent issues in some countries	-moderate cycle life insufficient for some applications -low energy performance	-moderate charged state thermal stability which can reduce safety -capacity can fade at temperature 40-70°C	-lower energy density due to lower cell voltage	-high cost of titanium -reduced cell voltage -low energy density

Source: International Renewable Energy Agency, based on Nitta *et al.*, 2015; Müller *et al.*, 2017; Blomgren, 2017; and data from Navigant Research (Tokash and Dehamna, 2016).

Storage technology	***Cycle life at 80% DOD***	***Efficiency***	***Advantage***	***Disadvantage***
Lead Acid	300-3000	70-90%	- Inexpensive - Mature technology	- Limited cycling capability for most standard types - Low energy density - Environmental hazard
NiCd	3000	80 %	- Good cycle life - Good performance at low temperatures - More tolerant to hostile environments or conditions	- Memory effect - High self-discharge rate - Environmental hazard
NiMH	2000	50-80 %	- High energy density - Good abuse tolerance - Good performance at low temperatures	- Damage may occur with complete discharge - High costs
Li-ion	3000	75-90 %	- High energy density - Low self-discharge rate - No memory effect	- Expensive although costs are decreasing - Not safe depending on type
Flow batteries	2,000-20,000	65-85 %	- Scalability - Lifespan not dependent on DOD	- Need for electrolyte tanks - High maintenance - Complex monitoring and control mechanisms
NaS	4500	89 %	- High efficiency and cycle life - Low cost battery materials - High energy density	- High operating temperatures -Temperature is to be maintained close to 300oC which might affect battery performance - Corrosive materials
NaNiCl2	1,500-3,000	85-95 %	- Long cycle life - High energy density	- High operating temperatures - Thermal management requirement
EDLC	1,000,000	95%	- High power Density, fast response - Lifetime - Safety - Wide operating temperature range (-40 to 65 ºC)	- Low energy density

2.1.5. Impact of local temperature and atmospheric conditions

Standard lithium-ion BESS are typically designed to operate at temperature ranging between -30°C and +50°C, which should suitable for operation in most of the ECOWAS countries. Site-specific conditions (temperature, humidity, altitude, etc) will however have to be taken into account during the detailed design phase of battery projects.

2.1.6. Conclusion regarding battery technologies

The most mature and economically competitive technology at the date of this study is lithium-ion LFP technology. The hypotheses, particularly economic, of this study are therefore based on this technology. However, other BESS technologies should not be excluded for countries that decide to carry out a concrete project. In particular, projects carried out in 2030 or beyond will have to take into account the technological developments that have taken place in the meantime.

2.2. Applications of BESS

Five BESS applications have been selected for this study. They include the applications for which (front-of-meter) BESS are currently in use in other parts of the world and the applications for which it is likely that BESS will play a role in the coming years. Behind-the-meter applications such as critical backup, renewables self-consumption or grid tariff peak shaving (demand charge reduction) are out of scope of the study.

2.2.1. Frequency Control

BESS are used in many countries for grid balancing, i.e. to compensate for short term variation in the production/consumption balance and to support the stability of the frequency. BESS are well suited for this application as they can react very quickly to frequency deviation, they are bidirectional and can absorb or provide power and have a limited energy reservoir that can meet short power needs.

Frequency control can be divided into several products, typically:

- The primary reserve that can react within seconds of frequency deviation and maintain the balance for a short period of 15 to 30 minutes. This is also called Frequency Containment Reserve (FCR): it is automatic and distributed in a selection of power plants and BESS across all the synchronously interconnected grids. Also, it reacts on a local measurement of the frequency deviation. As a result, the interconnection flows are modified, altered with respect to the initial, programmed interconnection flows.

- The secondary reserve is triggered after a few minutes and will relieve and restore the FCR. The secondary frequency control is automatic and centralized. It is based on frequency deviation and the deviation of cross-border flows (with respect to their scheduled values) as measured by the SCADA/EMS at the National Control Center.

- The tertiary reserve: it is triggered manually by an operator and restores an optimal generation dispatch or is used in case of exceptional events. The action of the tertiary control restores the secondary reserve.

BESS are today the most competitive option for the provision of primary reserve in many countries and are more and more being used for secondary reserve. Implementation for secondary reserve is a bit more complex than for primary reserve because secondary reserve has to be provided even in the case where the imbalance lasts for a long time, e.g. longer than what the battery can provide with its limited energy reservoir. In the case the BESS operator has to combine the BESS with other assets (e.g. thermal power plant) in order to take over in the (rare) case of long duration imbalances. BESS are not yet competitive for tertiary reserve applications because activation is less frequent and does not generate sufficient revenues.

Sizing the need for frequency control reserves in the WAPP region is out-of-scope of this study. Primary reserve requirement per country have been obtained during the data collection phase and will be used to size the required BESS.

2.2.2. Voltage Control

BESS power conversion systems (PCS) can provide or absorb reactive power. As such, they can thus provide voltage support for the power grid. In areas where capacitors or SVC's are planned or if the need is observed during the grid computations during the present study, the BESS option can potentially compete with the capacitors or SVC's option.

BESS are typically more expensive that capacitors or SVC, the business case is thus usually not favourable for the voltage control as stand-alone application. However, because BESS can also provide active energy, it is possible to combine voltage control (requiring reactive energy) with other applications (requiring active energy) resulting in an improved business case.

2.2.3. Energy Time Shift

BESS can also be used to shift energy from period of cheap and abundant energy to period of expensive or scarce energy. In countries with high shares of variable renewable energy production, such as wind and solar, BESS can store surplus electricity during times of high sun or wind and provide electricity during other periods.

In theory, BESS could also be used in countries with a shortage of electricity production capacity. They would store electricity produced by thermal plants during periods of low demand to produce electricity during times of high demand, thus avoiding load shedding. However, due to the high capex of BESS, it is usually making more economic sense in that case to invest in more thermal capacity (if possible) or to invest in combined solar plus storage.

2.2.4. Transmission congestion relief

Transmission system operators can benefit from BESS in the management of grid congestions. This can be for the management of occasional congestions, where BESS is used in the redispatch strategy, or potentially to avoid structural congestions. In that case, the BESS allows system operators to optimize the use of the existing grid and can help reducing or deferring the need for grid reinforcements.

The aim of the study is to show in which case BESS can be substituted to grid reinforcement and in which case the grid reinforcement is the best economical option.

2.2.5. Black start

Black start units are used for grid restoration after a black out. These units have the ability to produce electricity without relying on the grid itself, either to provide the right voltage and frequency parameter or to provide power to auxiliaries. BESS can provide black start services if their PCS are equipment with the grid-forming capability. BESS can also be used in the reconstruction process to help balance the grid thanks to their fast power response to frequency deviations.

2.2.6. Combined applications

Since BESS are versatile and can be used in different applications, it is also possible to combine the applications to improve the BESS business case ("revenue stacking"). It is possible to use the same BESS for different application at the same time, for example if one application uses active energy and the other application uses reactive energy, or at different moments of the day. As the power system evolves, it is also possible to change the BESS applications over the years.

3. DATA COLLECTION (KEY FINDINGS & ISSUES)

The data and documents were collected in two phases of visits to the majority of the 14 countries concerned, which in-country visits took place between 5 March and 28 April 2023. Given that the Ministries in charge of environment were not the institutional focal point for either WAPP, ECREEE and ERERA, most of the letters issued through emails and addressed identified did not receive any feedback. A second attempt became imperative to request the Ministers in charge of energy to request their counterpart minister in charge of environment to designate a focal person for the study and provide the required data. This challenge delayed and made it difficult to collect all environmental and gender data.

All the information and details relating to this data collection and documents can be found in the two-volume report "BESS Data Collection Report and Grid Model - 6279-BESS-DC-005".

An adopted EXCEL template was sent out for the data collection. However, the non-use of the EXCEL file to provide the required accompanying data and the Work Package 1 questionnaire made it difficult for the consultant to analyse and process this data.

Despite the challenges in acquiring all the data, a workshop was held at Saly in Senegal from June 19 to 21, 2023 with all the Stakeholders from the ECOWAS Ministries in charge of energy, TSO, ERERA, ECREEE, WAPP, OMVG, OMVS-SOGEM, TRANSCO, GIZ to validate the data collection that was prepared by the Consultant. This in-person meeting provided opportunity to validate the data collection report, organise a country-by-country section with participants from each country to fill the data gap and to endorse the grid models.

Also, on November 30, 2023, at WAPP request the consultant presented the 2025 and 2030 Grid Models to the System Reliability Assessment Working Group (SRAWG) for preliminary comments on the SLDs, and further comments were received on each country's power systems. A detailed system data was also provided in EXCEL format file data and validated.

Another challenge was difficulty in getting the Nigeria grid completed as a result of the SRAWG comments but through a special meeting were organised on January 30, 2024 with representatives from TCN, WAPP and the consultant successfully completed this activity enabling the study to advance.

4. 2025 AND 2030 GRID MODELS

Following the data collection and modelling, the results of the 2025 and 2030 single line diagrams (SLD's) of each country are obtained and are presented in Annex 1 and Annex 2 respectively. In this comprehensive overview, the SLD present simplified representations of the power transmission systems, highlighting key components and connections. To enhance readability, certain elements such as some capacitors and some reactances are not shown, although well present in the database.

The detailed information on the Grid Model is presented in a separate document "**Grid Model Report 2025 and 2030".**

The planned PV plants lead to the following installed capacities in MW:

Table 2: Planned PV plant capacities in MW

Planned PV plants	**YEAR**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
		MW	MW	MW	MW	MW	MW
Total ECOWAS (MW)		3101	4133	4836	5449	5839	9019
Planned PV plants		2025	2026	2027	2028	2029	2030
Benin	BJ	125	300	300	300	300	300
Burkina Faso	BF	391	471	491	491	536	536
Côte d'Ivoire	CI	320	360	465	465	465	465
Ghana	GH	156	366	366	466	466	466
Gambia	GM	131	231	231	234	234	234
Guinea	GN	0	0	0	0	0	0
Guinea-Bissau	GW	0	0	66	66	66	66
Liberia	LR	31	31	31	31	31	31
Mali	ML	626	626	626	626	671	821
Niger	NE	174	174	174	244	244	244
Nigeria	NG	418	773	1285	1575	1875	4905
Sierra-Leone	SL	104	116	116	116	116	116
Senegal	SN	250	250	250	250	250	250
Togo	TG	375	435	435	585	585	585

Given the variability of the vRE injections (mainly from PV, while some Wind Power Plants are also planned), most countries have already planned the installation of BESS, as per the following table.

Table 3: BESS installations planned prior to this study.

Planned BESS	YEAR	2025	2026	2027	2028	2029	2030
	BESS	MW	MW	MW	MW	MW	MW
	TOTAL	320	380	386	436	436	457
Benin	BJ	0	0	0	0	0	0
Burkina Faso	BF	20	80	80	80	80	80
Côte d'Ivoire	CI	105	105	105	105	105	105
Ghana	GH	30	30	30	30	30	30
Gambia	GM	6	6	6	6	6	6
Guinea	GN	0	0	0	0	0	0
Guinea-Bissau	GW	0	0	6	6	6	6
Liberia	LR	5	5	5	5	5	5
Mali	ML	25	25	25	50	50	51
Niger	NE	25	25	25	50	50	70
Nigeria	NG	0	0	0	0	0	0
Sierra-Leone	SL	0	0	0	0	0	0
Senegal	SN	91	91	91	91	91	91
Togo	TG	13	13	13	13	13	13

5. 2025 AND 2030 : TTC and NTC

5.1. Introduction

This present "TTC and NTC computations" chapter takes place in the frame of the assessment of the Energy Shift application of the BESS. Indeed, before storing surplus renewable energy, it is first interesting to check whether this surplus can be exported to neighbouring countries. It is only if export is limited, either by the capacity of neighbouring countries to consume, or by the interconnection capacity (Net Transfer Capacity or NTC) that it makes sense to store energy surpluses locally.

The generation dispatch as present in the ECOWAS grid model for 2025 and 2030 (14 interconnected systems of the ECOWAS) is probably not the result of an optimization at the WAPP level. In order to run such an optimization, the Cross-Border flows should not exceed the Net Transfer Capacity at each border: the NTC is then part of the data needed for generation simulations at yearly level and related optimizations. The NTC is derived from the TTC by subtracting the Transmission Reliability Margin (TRM), which enables the flows related to the primary frequency control of all power systems that are synchronously interconnected.

NTC = TTC – TRM

Usually, the transfer capacity at midday moment is less critical than at evening time because, for most countries, the load is lower at midday than at evening time. Currently, several interconnection lines have been designed for the supply of the evening load of land-locked countries: as shown in the following chapters, the related planned and unavoidable transfers play a role in the remaining transfer capacity if any.

5.2. Total Transfer Capacity (TTC) Estimates

The 2025 and 2030 conditions will be described in this report deal with both evening and midday conditions (see the Grid Model Status report for the details). Both evening and midday conditions of 2025 are representative of the constraints: transfers that cannot take place because of NTC constraints may show countries (power systems) candidates for a BESS solution, likely charging at midday (because of no export opportunities) and discharging in the evening (possibly because no import opportunities).

The export possibilities for any country will then depend on the **generation available** after the loads of that country are supplied.

For several countries of the WAPP, the remaining available generation at that moment is low, typically in the evening and in some case zero (it is mainly the case for countries that are importing at that time, due to the fact that import is a profitable option and is part of their Energy Strategy).

For each interface, the TTC is computed by an iterative process consisting in increasing the generation where possible in the country on one side of the interface and decreasing the generation in the country on the other side of the interface.

In the present case, only the conventional generation is modified: thermal and hydro power plants.

Three specific situations are worth to be noted:

- Flows existing in the base case (as identified in the Grid Model Status report) are by definition within the capacity. If such a flow, for example an export cannot be increased, then it is at its maximum value and represents the (total) transfer capacity.
- In some cases, the iterative process stops because the generation on the other side cannot be decreased anymore: it has reached zero.

Negative values of TTC are to be considered as “zero capacity”: the negative result shows that the interface is importing in the base case, like for example, Burkina Faso (BF) is importing some MW from Côte d’Ivoire in the evening case.

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5.3. Load Balancing in 2025 Baseline Scenarios

The 2025 evening load flow computation leads to the following generation, load and loss situation.

Table 4: Generation, Load and Losses of WAPP Models (2025 Evening and Midday Cases)

Evening 2025	Generat ion, P	Genera tion, Q	Load, P	Load, Q	Losses , P	Losses , Q	Exp ort
Case	MW	Mvar	MW	Mvar	MW	Mvar	MW
10 NG Nigeria	10173,7	283,9	9451,1	4370,1	356,3	-2317,3	366,3
11 NE Niger	284	-33,2	386,1	171,1	11,5	-813,7	- 113,6
12 GN Guinea	557,4	323,1	731,6	303,2	43,1	-538	- 217,3
13 CI Côte d'Ivoire	2705,3	141	1996,1	820,1	71,8	-830,6	637,4
14 LR Liberia	119,7	34,1	199,3	102,5	10,4	-15,4	-90
15 SL Sierra Leone	422,3	92,6	261,7	237,2	4	-95,5	156,6
16 ML Mali	366,7	19	508,4	302,1	9,8	-482,9	- 151,5
17 SN Senegal	1797,7	19,5	1543,2	404,1	32,8	-252	221,7
18 GM Gambia	100,5	40	180,2	63,2	1,3	-15,7	-81
19 GH Ghana	3928,2	293,6	3858,1	1428,6	115,8	525,4	-45,7
20 Togo-Benin	698,6	336,9	946,7	402,6	27,6	-407,5	- 275,7
21 BF Burkina Faso	157,3	82,3	457,3	255,6	25,7	-401,4	- 325,7
22 GW Guinea- Bissau	41,3	7,3	109	56,8	1,3	-29,1	-69
23 MR Mauritania	172,8	28,3	183,4	60,4	1,4	-44,4	-12
Total	**21525,5**	**1668,4**	**20812,2**	**8977,6**	**712,8**	**-5718,1**	

2025 Midday	Generation, P	Generation, Q	Load, P	Load, Q	Losses, P	Losses, Q	Export
Case	MW	Mvar	MW	Mvar	MW	Mvar	MW
10 NG Nigeria	7081,3	632,7	6881,7	2622,8	199,2	-4287,3	0,4
11 NE Niger	404,1	-11	378,4	174,6	7,4	-790,9	18,3
12 GN Guinea	483,3	177,6	505,3	217,5	25,3	-699,3	-47,3
13 CI Côte d'Ivoire	1495,9	-247	1271,3	428,1	34,8	-1312,6	189,8
14 LR Liberia	87,5	15,2	113,2	54	5,4	-53,9	-31,1
15 SL Sierra Leone	135,4	-52,7	200,8	96,8	1,5	-164,4	-66,9
16 ML Mali	585,7	-120,8	246,4	109,3	21,5	-499,1	317,8
17 SN Senegal	851	-188	1062,7	402,7	19,4	-557,5	- 231,1
18 GM Gambia	125	-17,7	122,9	43,9	2,1	-9,8	0
19 GH Ghana	2604,3	-511,8	2665,3	1058,6	39,3	-298,7	- 100,3
20 Togo-Benin	787,9	269,5	720,5	351,4	34,7	-426,3	32,7
21 BF Burkina Faso	349	7	340,8	142,1	11	-518,5	-2,8
22 GW Guinea- Bissau	28,6	-14,8	94,6	45,8	1	-32,9	-67
23 MR Mauritania	172,8	12,2	183,4	60,4	1,5	-46,7	-12,1
Total	**15191,8**	**-49,6**	**14787,3**	**5808**	**404,1**	**-9697,9**	

Note that the sum of exports is not zero because the WAPP system is connected to the power system of Mauritania, which is here importing 12,3 MW (in both cases).

5.4. Transfers observed in the 2025 Reference Case

The 2025 conditions, as described in the Grid Model Status report, are considered as the “base case”. The base cases themselves are intrinsically assumptions not only related to the load forecasts, but also to the generation levels in each power system, at the “evening” time and at the “midday” time. The generation levels in each power system derive mainly from the PSSE file 2025 provided by the WAPP.

This “base case” will be further used for modifications of generation levels applied to identify TTC values (modifications are increase and decrease of generation levels until a constraint appears).

The cross-border transfers of the base case are the following.

Table 5: Cross-border transfers observed in the Reference Cases (2025)

From – to	2025 Midday MW	2025 Evening MW
BF-CI	-4,2	-176,1
BF-GH	54,6	-26,2
BF-ML	0	0
BF-NE	-52,8	-122
BJ-NE	-4,4	-24,3
BJ-NG	38,8	-108
BJ-TG	-18,8	202,8
CI-GH	47,6	217,2
CI-GN	0	0
CI-LR	117,1	196,3
CI-ML	18,5	38,7
GH-TG	50	136,2
GM-SN	0,6	-46,6
GN-GW	49,8	-24,9
GN-LR	-58,5	-151,7
GN-ML	-107	101,4
GN-SL	37,6	-114,4
GN-SN	32,2	-22,6
GW-SN	-17,3	93,5
LR-SL	29,7	-39,2
ML-SN	232,2	-11,9
NE-NG	-39,2	-259,5

Note that the base case transfers result from the various generation dispatch set in each power system: these do not affect the maximum transfer values (the TTC).

5.5. Total Transfer Capacity (TTC)

The TTC being determined from an iterative process, several factors can cause the iterative process to stop.

These factors are as follows:

1. Maximum generation level in the exporting country has been reached
2. Minimum generation level in the importing country has been reached (note that wheeling transfers are to be analysed using grid capacity rather than by country to country transfers like for the TTC)
3. Minimum voltage reached
4. Line or transformer loading limit reached
5. Non convergence of the load flow computation

The TTC results from 2025 evening case are presented below.

In most cases there is one first constraint limiting the TTC, then a second constraint just behind it, then a third constraint behind: this means that solving one constraint for increasing the TTC is not always a solution that can increase significantly the TTC.

The Grid Model set-up in the present project can be used for identifying, case by case, the ways to increase the TTC on any given interface: this can involve changing the transformers tap settings, the generators voltage settings, and/or capacitors and reactors taps settings. In some cases also, introducing an additional capacitor or transformer may alleviate a constraint, increasing thereby the TTC. This kind of investigation would then be a case by case process.

The obtained TTC results can be shown in the form of a matrix:

TTC evening	TO	Benin	Burkina Faso	Côte d'Ivoire	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NE	NG	SN	SL	TG
Benin	BJ										-24,3	-108			202,8
Burkina Faso	BF			-107	37,5						-5,6				
Côte d'Ivoire	CI		195,4		258,5		0		216,5	38,7					
Ghana	GH		70,6	-139,3											210,3
Gambia	GM												-9,9		
Guinea	GN			0				0,6	-83,5	183			112,6	-31,1	
Guinea-Bissau	GW						26,5						90,2		
Liberia	LR			-180,3			147,1							-27,2	
Mali	ML			-38,7			-70,8						68,7		
Niger	NE	26,4	130,6									-241			
Nigeria	NG	496,6									470,7				
Senegal	SN					46,6	22,6	-93,5		11,9					
Sierra Leone	SL						116,2		40,8						
Togo	TG	-202,8													

5.6. Transmission Reliability Margin (TRM) Estimates

The TRM values are approximated by the calculation of sums of the inrush power that would come from all countries “behind” each interface. As far as the expectable sudden vRE input power decreases are not larger than the largest synchronous generator input power, the midday and evening worst events are the same (the tripping of the largest power plant), and the TRM values are therefore the same for midday and evening.

Table 6: TRM proposed at each interface, in MW, based on the influx of energy from the primary frequency control of the countries "behind" the interface.

TRM	TO	Benin	Burkina Faso	Côte d'Ivoire	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NE	NG	SN	SL	TG
Benin	BJ	1,0									0,4	24,3			18,6
Burkina Faso	BF		0,3	7,1	3,1						12,2				
Côte d'Ivoire	CI		3,8	37,3	41,0				16,1	34,7					
Ghana	GH		2,9	294,1	24,5										12,9
Gambia	GM					0,1							0,9		
Guinea	GN						2,2	13,8	1,7	1,9			20,8	2,7	
Guinea-Bissau	GW						0,5	0,1					0,7		
Liberia	LR			40,4			97,6		0,2					21,9	
Mali	ML			11,2			3,2			1,1			120,8		
Niger	NE	1,0	9,7								0,4	70,3			
Nigeria	NG	40,9									17,0	124,9			
Senegal	SN					18	6,8	1,2		2,2			7,5		
Sierra Leone	SL						2,6		0,9					0,4	
Togo	TG	29,2			101,4										0,5
Min. Contrib. (MW) to Frequency Containment		72	16,66	390	170	18	113,0	15	19	40	30	220	151	25	32

5.7. Results from the formula NTC = TTC - TRM

From the estimated TTC in §5.2 and the estimated MRT in §5.3, the NTC can be calculated. Because some TTC values showed no capacity (values shown as negative in the table), the associated NTC value will also show no capacity (and will be displayed as negative).

Table 7: Net transfer capacity for 2025 Evening scenario in MW (capacities are only positive values)

TRM	TO	Benin	Burkina Faso	Côte d'Ivoire	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NE	NG	SN	SL	TG
Benin	BJ										-24,7	-132,3			184,2
Burkina Faso	BF			-114,1	34,4						-17,8				
Côte d'Ivoire	CI		191,6		217,5				200,4	4,0					
Ghana	GH		67,7	-433,4											197,4
Gambia	GM												-10,8		
Guinea	GN							-13,2	-85,2	181,1			91,8	-33,8	
Guinea-Bissau	GW						26,0						89,5		
Liberia	LR			-220,7			49,5							-49,1	
Mali	ML			-49,9			-74,0						-52,1		
Niger	NE	25,4	120,9									-311,3			
Nigeria	NG	455,7									453,7				
Senegal	SN					28,6	15,8	-94,7		9,7					
Sierra Leone	SL						113,6		39,9						
Togo	TG	-232,0			-237,6										

Negative values indicate zero capacity due to flows that are in the opposite direction and are inherently in the 2025 evening baseline scenario.

Table 8: Net transfer capacity for 2025 Midday scenario in MW (capacities are only positive values)

NTC Midday	**TO**	Benin	Burkina Faso	Côte d'Iv.	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NOT	NG	SN	SL	TG
Benin	BJ										4,3	-40,2			-21,3
Burkina Faso	BF			-5,0	82,4						-65,0				
Côte d'Ivoire	CI		3,7		225,2				159,6	-26,1					
Ghana	GH		-54,0	-360,1											84,9
Gambia	GM												-0,3		
Guinea	GN							54,1	-29,4	-139,7			217,7	49,9	
Guinea-Bissau	GW						-42,4						-17,0		
Liberia	LR			-126,5			-20,7							29,4	
Mali	ML			-29,7			227,0						391,5		
Niger	NE	5,9	49,9									-82,0			
Nigeria	NG	-25,0									199,8				
Senegal	SN					-18,6	23,4	18,0		-104,9					
Sierra Leone	SL						103,0		10,7						
Togo	TG	-3,5			-117,5										

Negative values indicate zero capacity due to flows that are in the opposite direction and are intrinsically the midday 2025 baseline scenario.

Table 9: Net transfer capacity for 2030 Evening scenario in MW (capacities are only positive values)

Evening 2030	***TO***	Benin	Burkina Faso	Côte d'Iv.	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NE	NG	SN	SL	TG
Benin	BJ										0,7	-135,0			-64,6
Burkina Faso	BF			-173,0	-187,5						-26,0				
Côte d'Ivoire	CI		162,1		717,6				97,5	63,2					
Ghana	GH		199,9	-961,0											489,4
Gambia	GM												-25,4		
Guinea	GN							251,0	32,1	227,1			109,0	3,1	
Guinea-Bissau	GW						-265,3						220,7		
Liberia	LR			-88,8			-131,4							-113,7	
Mali	ML			-79,8			-228,0						-5,4		
Niger	NE	7,8	41,3									-199,1			
Nigeria	NG	93,8									310,3				
Senegal	SN					52,2	-114,9	-125,5		-25,1					
Sierra Leone	SL						-8,4		90,9						
Togo	TG	58,9			-366,2										

Negative values indicate zero capacity due to flows that are in the opposite direction and are inherently the 2030 evening reference scenario.

Table 10: Net Transfer Capacity for 2030 MW at midday (capacities are only positive values)

NTC 2030	***TO***	Benin	Burkina Faso	Côte d'Iv.	Ghana	Gambia	Guinea	Guinea-Bissau	Liberia	Mali	Niger	Nigeria	Senegal	Sierra Leone	Togo
FROM		BJ	BF	CI	GH	GM	GN	GW	LR	ML	NE	NG	SN	SL	TG
Benin	BJ										86,8	-107,4			-475,8
Burkina Faso	BF			-6,6	28,7						75,8				
Côte d'Ivoire	THERE		23,8		263,5				-21,9	-168,7					
Ghana	GH		16,1	-392,8											454,9
Gambia	GM												77,1		
Guinea	GN							-51,0	108,7	-42,7			217,8	213,5	
Guinea-Bissau	GW						61,8						-96,5		
Liberia	LR			30,4			-160,9							-44,9	
Mali	ML			129,1			40,6						-150,3		
Niger	NOT	-79,7	12,9									419,1			
Nigeria	NG	61,1									-208,9				
Senegal	SN					-42,8	63,1	130,2		45,0					
Sierra Leone	SL						102,0		111,7						
Togo	TG	428,0			-569,2										

Negative values indicate zero capacity due to flows that are in the opposite direction and are inherently the 2030 mid-day reference case.

5.8. Conclusion on NTC

The conclusion of the technical section is as follows:

- A grid model for the interconnected and synchronised regional grid conditions of 2025 and 2030 has been set-up based on the PSSE WAPP data file of 2022 and on the basis of the Data Collection that has been organised in the frame of the present project, from December 2022 to August 2023.
- As a whole, the power systems of the ECOWAS countries proved to show some spare generation and this spare generation capacity made possible the computation of the Total Transfer Capacity at the interfaces of the power systems constituting the WAPP power system.
- The evening and midday conditions of 2025 and 2030 have been selected as representative of the transfer constraints: in the application 3 (Energy Shift) of BESS in the present project, transfers that cannot take place because of NTC constraints may show that some countries (power systems) are candidates for a BESS solution.
- The NTC computations presented in the above table can then be used by appropriate models for evaluating potential Energy Shift applications of Battery Energy Storage Systems.

6. METHODOLOGY & ASSUMPTIONS

A full description of the methodology and assumptions used in this study is available in a specific document “BESS Assumptions and Methodology for Work Package – ref 6279-BESS-ME-001”.

The key assumptions that should be kept in mind while reading this report are the following:

- The study considers the ECOWAS regional interconnected power system as one synchronous grid from 2025 on (while it can be before that date)
- Energy exchanges between countries or BESS size and location are optimized from a technical and economical point of view for the whole ECOWAS and do not take any political or regulatory constraints into account
- The study considers the technical and economical optimal BESS deployment but does not define the regulatory framework for this deployment: system operator ownership, IPP’s, liberalized market, etc.. These subjects are developed in work package 2
- The generation capacity other than BESS are considered as an input to the study and are fixed at the data collection stage, but take into account the construction of new assets as planned in each country. The model used in the simulation is not allowed to add or remove any thermal or renewable power generation unit compared to what exists or is already planned in each country.
- Interconnections and energy exchanges with countries outside of ECOWAS are not considered.
- Fuels prices (gas, HFO, LFO) are considered
- Discount rate is considered

7. SIMULATIONS AND TECHNO-ECONOMIC ANALYSES

7.1. Frequency Control App

7.1.1. Objectives

The purpose of this section is to conduct an economic evaluation of the provision of frequency monitoring services (in particular, the primary reserve) under the BESS project, comparing it to the business-as-usual (BAU) scenario for thermal generators (ICE or OCGT). To do this, the required reserves for each country in the WAPP area have been calculated, using the European ENSTO-E methodology. Subsequently, the total costs have been compared as described in the following sections.

7.1.2. Key Assumptions

According to the methodology, the Consultant has estimated and proposed the following table- using requirements from the ENTSO-E approach, for each ECOWAS system.

Table 11: Minimum primary reserves per country.

Version A: based on the generation forecasts for 2025 from the Data Collection, with security factor of 1.07

Control Area		Area	Gen. 2016 (GWh)	Contribution Coefficient 2018 (%)	Minimum Primary Reserve 2018 (MW)	Generation 2025 (GWh)	Contribution Coefficient 2025 (%) in each area	Contribution Coefficient 2025 (%) of total	Minimum Primary Reserve 2025 (MW)	Minimum Primary Reserve 2030 (MW)
2 largest Units: names					Egbin 1,2				Egbin, CIPREL 5	Egbin, CIPREL 5
2 largest Units: MW					460				620	620
Requirement (MW)					493				664	664
CA1	CI	CIE	10.072	92%	89	15.564	84%	9,6%	63,5	63,5
	BF	SONABEL	923	8%	8	2953	16%	1,8%	12,0	12,0
			10.995	**100%**	**97**	**18.517**	**100%**	**11,4%**	**75,5**	**75,5**
CA2	TG-BJ	CEB	1.055	4%	9			0,0%		0,0
	TG					2.500	9%	1,5%	10,2	10,2
	BJ					2.165	8%	1,3%	8,8	8,8
	GH	GRIDCo	12.939	52%	114	23.481	83%	14,4%	95,8	95,8
					123	28.146	100%	**17,3%**	**114,8**	114,8
CA3	NG	TCN	28.412	99%	217	92.500	98%	56,8%	377	377,2
	NE	NIGELEC	349	1%	3	2179	2%	1,3%	9	8,9
				100%	**220**	**94.679**	**100%**	**58,1%**	**386**	**386,1**
CA4	GN	EDG				3242	46%	2,0%	13,2	13,2
	SL	EGTC				2660	38%	1,6%	10,8	10,8
	LI	LEC				1115	16%	0,7%	4,5	4,5
						7017	100%	**4,3%**	**29**	28,6
CA5	ML-SN-MR	SOGEM	1.282	25%	12	2.166	15%	1,3%	8,8	8,8
	ML	EDM-SA	851	16%	8	4679	32%	2,9%	19,1	19,1
	SN	SENELEC	3.052	59%	28	8.192	56%	5,0%	33,4	33,4
	GM	NAWEC				936	13%	0,6%	3,8	3,8
	GW	EAGB				730	10%	0,4%	3,0	3,0
				100%	48	14.537	100%	**8,9%**	**59**	59,3
		TOTAL	58.936		488	162.896		100%	664	664

Version B: based on the generation metering's of 2023 from the WAPP, with security factor of 1.00

Control Area		Area	Gen. 2016 (GWh)	Contribution Coefficient 2018 (%)	Minimum Primary Reserve 2018 (MW)	Generation 2023 (meterings) (GWh)	Contribution Coefficient 2025 (%) in each area	Contribution Coefficient 2025 (%) of total	Minimum Primary Reserve 2025 (MW)	Minimum Primary Reserve 2030 (MW)
2 largest Units: names					Egbin 1,2				Egbin, CIPREL 5	Egbin, CIPREL 5
2 largest Units: MW					460				620	620
Requirement (MW)					488				620	620
CA1	CI	CIE	10.072	92%	89	*13.343*	92%	14,5%	90,0	*90,0*
	BF	SONABEL	923	8%	8	*1126*	8%	1,2%	7,6	*7,6*
			10.995	**100%**	**97**	***14.469***	**100%**	**15,7%**	**97,6**	***97,6***
CA2	TG-BJ	CEB	1.055	4%	9			0,0%		*0,0*
	TG					*692*	3%	0,8%	4,7	*4,7*
	BJ					*692*	3%	0,8%	4,7	*4,7*
	GH	GRIDCo	12.939	52%	114	*23.485*	94%	25,5%	158,4	*158,4*
					123	*24.868*	100%	**27,0%**	**167,7**	*167,7*
CA3	NG	TCN	28.412	99%	217	*36.623*	98%	39,8%	246,9	*246,9*
	NE	NIGELEC	349	1%	3	*781*	2%	0,8%	5,3	*5,3*
				100%	**220**	***37.404***	**100%**	**40,7%**	**252,2**	***252,2***
CA4	GN	EDG				*3628*	82%	3,9%	24,5	*24,5*
	SL	EGTC				*473*	11%	0,5%	3,2	*3,2*
	LI	LEC				*334*	8%	0,4%	2,3	*2,3*
						4435	100%	**4,8%**	**30**	*29,9*
CA5	ML-SN-MR	SOGEM	1.282	25%	12	*1.857*	17%	2,0%	12,5	*12,5*
	ML	EDM-SA	851	16%	8	*1597*	15%	1,7%	10,8	*10,8*
	SN	SENELEC	3.052	59%	28	*6.645*	62%	7,2%	44,8	*44,8*
	GM	NAWEC				*380*	9%	0,4%	2,6	*2,6*
	GW	EAGB				*296*	7%	0,3%	2,0	*2,0*
				100%	48	*10.775*	100%	**11,7%**	**73**	*72,7*
		TOTAL	58.936		488	*91.951*		100%	620	620

While it is the responsibility of the WAPP to decide on the sizing of the reserves for the frequency control, the assumed/suggested steps of computations for this study are the following:

- Step 1: Identification of the nominal capacity of a unit from the two power plants having the largest units. In 2025 these power plants appear to be CIPREL 5 (Atinkou) in Côte d'Ivoire, of 390 MW and Egbin in Nigeria (230 MW). This amounts to 620 MW from 2025 on.
- Step 2: Application of a security sizing factor. In case the factor is taken as similar to the one used at ENTSO-E, a parameter of 1,07 is assumed. As a result, the total primary reserve requirement is found to be 1.07 x 620 = 664 MW : This assumption is used for Version A of the table 11 here above. In contrast, Version B is based on a factor of 1.00.
- Step 3: break-down of the total requirement into contributions from each member system. Using the planned energy forecasts for the near future, contribution factors in % of the total generated energy are presented in a column and serve to compute the contributions for 2025 in MW and the contributions for 2030.

In the present case, the same total requirement and the same contribution factors are found for

2025 and 2030. In the future, both the total requirement and the contribution factors can be modified according to ad-hoc decisions at WAPP level, for example deciding for version A, version B or another version of table 11. In the rest of the report, version A is used for calculations, as the study is aligned with the 2025 and 2030 network models.

For this application, it has been decided to compare the investment in BESS with most likely primary frequency control technology in the region. To evaluate the financial model for providing frequency control, the focus will be solely on the costs of providing such service, namely, the investment and fixed O&M costs, while disregarding the fuel costs. It is assumed that the unit providing the frequency control service will compensate the fuel cost of providing the regulation up and down irrespective of being a battery or a thermal generator (In other words, fuel costs can be disregarded because the frequency control is symmetrical: sometimes the plant uses more fuel to balance the need for higher power, sometimes uses less fuel to balance the need for less power, on average there is no fuel usage impact) .

The comparison of primary frequency control costs (FCR) from BESS and hydro power plants is not meaningful since hydro is the most expensive option due to its high CAPEX. Moreover, determining standard costs for hydro is challenging as they vary depending on the specific site where the project is planned.

The conclusion of comparing investments in BESS with investments in thermal generators ICE HFO/LFO generators and OCGTs, which are commonly used in the region, is the following: available data from the countries' master plans indicates a cost range of $ 950,000 to $ 1,400,000 per MW for ICE and OCGTs installations. From this range, an average cost of $ 1,100,000 per MW is assumed. Additionally, an OPEX of 2%/year of CAPEX is assumed.

The comparison examines the cost of investing 1MW of BESS capacity versus the cost of investing in an additional 1MW of a thermal generator (assuming the rest of the capacity is used as based load).

In this scenario, a one-hour battery is sufficient to provide frequency control service. Considering that thermal generators typically have a lifespan of around 25 years, while batteries are assumed to have a 10-year lifespan, anticipating a refurbishment that extends the battery's life by an additional 15 years. Assuming that advances in battery technology over the next decade will benefit from economies of scale and learning curves, thus increasing their lifespan. The refurbishment cost is estimated to be 40% of the current CAPEX, accounting for the decrease in CAPEX over time.

7.1.3. Effect of BESS on Frequency

The above minimum requirements for the primary reserve indicate values that are safe for a large, interconnected grid and where the primary reserve is located in the power plants that have been designated for providing this ancillary service (the frequency control) in addition to the generation of power. The release of power must be total (100% of the reserve within the 30th second after the event).

Whether in the form of reserve inside power plants or reserve inside BESS, the frequency is stabilized in less than one minute, possibly showing minor residual oscillations before it reaches its final value after a damping period. As a matter of fact, because BESS do not suffer from mechanical inertia of the many parts of the injectors (whether for gas turbines, steam turbines, ICE or hydro turbines), BESS are much faster than power plants to release the power reserve. As a result, the frequency control from BESS is much more efficient (the frequency stabilizes faster) than with frequency control performed by power plants.

7.1.4. BESS investments in 2025

Choosing BESS for frequency control proves to be a cost-effective option compared to investing in thermal generators. Illustrated in the table below is the financial analysis. The NPV cost of each option has been computed, including CAPEX and OPEX costs, the comparison is between a thermal generator (Reference strategy) with a 1-hour battery system (Project strategy). As seen in for Nigeria (NG), a saving of 258 kUSD is obtained by the BESS option, representing around 64% of the cost of the thermal generator. Should there be a need for an extended battery duration as a consequence of the need for additional applications, it remains economically advantageous to invest in batteries up to a 3-hour storage duration, when compared to a thermal generator. Beyond this threshold, higher-duration batteries could potentially surpass the cost of thermal generators.

7.1.5. BESS investments in 2030

The results for 2030 are very similar to those for 2025. As shown in Table 3 on the next page, in this case, the discounted BESS NPV savings could range from $0.8 million to $195 million, which represents approximately 75% of the cost of the thermal generator. If other battery applications are considered, such as those that require longer durations, BESS will remain economically feasible for batteries of up to 4 hours. The considerably lower CAPEX cost in 2030 will make it possible to invest in batteries that are larger in terms of energy, up to 4 hours of batteries in 2030 compared to 3 hours of batteries when investing in 2025.

7.1.6. Conclusion on Frequency Control

In this section, the cost-effectiveness of investing in BESS for providing frequency control services has been assessed in comparison to investing in gas turbines. The evaluation focused on the investment cost of a 1-hour battery, revealing potential savings of 64% and 75% compared to gas turbine investments in 2025 and 2030, respectively. Additionally, the cost implications of extending the battery's duration for potential additional applications is evaluated. The analysis indicates that BESS remains economically advantageous, even with 4-hour storage BESS investments in 2030 and 3-hour storage BESS investments in 2025. The BESS releases the reserve power of the Frequency Containment Reserve much faster than a conventional power plant: BESS are nowadays a common asset (although recent) for frequency control. It proves to be an effective way mastering the active power balance so that frequency deviations are minimized

Table 12: Cost Comparison BESS vs Gas Turbine invested in 2025 – Frequency Control

	Values in kUSD of 2023	BF	BJ	CI	GM	GH	GN	GW	ML	NE	NG	SL	SN	TG
BESS	Capacity (MW)	9	12	64	4	115	13	3	19	377	9	11	33	10
	CAPITAL EXPENDITURES ($k)	3,027	4,127	21,840	1,307	39,484	4,471	1,032	6,569	129,664	3,061	3,715	11,487	3,508
	Operating Expenses ($k)	396	540	2,857	171	5,164	585	135	859	16,959	400	486	1,502	459
	NPFF ($k)	3,423	4,667	24,697	1,478	44,648	5,056	1,167	7,428	146,623	3,461	4,200	12,990	3,967
Gas Turbine	Capacity (MW)	18	24	127	8	230	26	6	38	754	18	22	67	20
	CAPITAL EXPENDITURES ($K)	16,000	21,818	115,455	6,909	208,727	23,636	5,455	34,727	685,455	16,182	19,636	60,727	18,545
	Operating Expenses ($k)	2,905	3,961	20,960	1,254	37,893	4,291	990	6,304	124,438	2,938	3,565	11,024	3,367
	NPFF ($k)	18,905	25,779	136,414	8,163	246,620	27,927	6,445	41,032	809,893	19,119	23,201	71,752	21,912
Savings	BESS Cost Reduction ($k)	15,482	21,112	111,718	6,685	201,972	22,871	5,278	33,603	663,269	15,658	19,001	58,762	17,945
	BESS Cost Reduction (%)	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%

Table 13: Cost Comparison BESS vs Gas Turbine invested in 2030 – Frequency Control

	Values OF 2023	BF	BJ	CI	GM	GH	GN	GW	ML	NE	NG	SL	SN	TG
BESS	Capacity (MW)	9	12	64	4	115	13	3	19	377	9	11	33	10
	CAPITAL EXPENDITURES ($k)	1,314	1,791	9,480	567	17,138	1,941	448	2,851	56,281	1,329	1,612	4,986	1,523
	Operating Expenses ($k)	169	230	1,218	73	2,202	249	58	366	7,231	171	207	641	196
	NPFF ($k)	1,483	2,022	10,698	640	19,340	2,190	505	3,218	63,512	1,499	1,819	5,627	1,718
Gas Turbine	Capacity (MW)	18	24	127	8	230	26	6	38	754	18	22	67	20
	CAPITAL EXPENDITURES ($k)	9,935	13,547	71,688	4,290	129,603	14,676	3,387	21,563	425,613	10,048	12,193	37,707	11,515
	Operating Expenses ($k)	1,804	2,459	13,014	779	23,528	2,664	615	3,915	77,266	1,824	2,213	6,845	2,090
	NPFF ($k)	11,738	16,007	84,703	5,069	153,131	17,341	4,002	25,477	502,880	11,872	14,406	44,552	13,606
Savings	BESS Cost Reduction ($k)	10,256	13,985	74,005	4,429	133,791	15,151	3,496	22,260	439,367	10,372	12,587	38,925	11,887
	BESS Cost Reduction (%)	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%

7.2. Voltage Control App

7.2.1. Objectives

BESS are controlled by power electronics forming an inverter. As for PV power plants and Full Converter Wind Generator, the inverter can be controlled to provide or absorb reactive power, thereby controlling the voltage at the connection node, in the same way as capacitors and reactances, respectively provide or absorb reactive power.

The objective is here to analyse whether BESS can compete with the traditional means to control the voltage in the grid once generators are already connected: the shunt capacitors and the shunt reactances are the main means for the grid planner to ensure the grid operation in the acceptable voltage range. Reactive power is rather a local issue in the sense it cannot be transferred on very long distances with reasonable losses: therefore, capacitors tend to increase the voltage where needed and reactances tend to reduce the voltage where needed.

7.2.2. Effect of BESS on Voltage

Injecting Mvars whether from capacitors, from generators or from BESS will have exactly the same impact on the voltage at steady state. During transients, BESS can have a faster action.

Absorbing Mvars whether from reactances or from BESS will have exactly the same impact on voltage at steady state. Here as well, during transients, BESS can have a faster action. For absorbing Mvars, generators based on alternators (synchronous machines) is possible but only to a limit that shows a small absorption capacity before instabilities appear.

Therefore, BESS is effective for voltage control, provided that the transformer at AC side of the BESS ("step-up transformer") as well as the inverter are sized as per the resulting complex power in MVA instead of being sized for the active power only (in MW). This often requires a 15% to 20% oversizing of the converter and transformer, with the resulting overcosts.

7.2.3. Economic comparison of BESS with conventional means of voltage control

The data collection led to identify some reference costs in the Electricity Sector Master plans of some countries. Typical reference costs for capacitors and for reactances are presented in the right most columns of the following table for sizes like 30 Mvar, 40 Mvar and 100 Mvar.

Table 14: Typical costs for 2-hour BESS, capacitors and reactances

BESS 2h	BESS	BESS	BESS Estimate	BESS Estimate	Generation Q (static)	Q absorption (static)	Q (+/-) (dyn)	Q (+/-) (dyn)
	2025	2030	2025	2030	Capacitors	Reactors	SVC*	STATCOM**
Mvar	kUSD/ MVA	kUSD/ MVA	kUSD	kUSD	kUSD	kUSD	kUSD/Mvar	kUSD/MVar
30	733	503	21988	15099	657	2332		
40	733	503	29317	20132	984	4078	120	450
100	733	503	73292	50330	1771	7156	120	370

(*) source: ESB, Intec (**) source: KETRACO Master Plan 2023

The comparison of BESS and capacitors clearly shows that:

- a BESS cannot be nor become profitable for acting as “static” voltage control only nor even when compared to an SVC, since it cost is not competitive with the capacitors costs or reactor costs or SVC (source: Bloomberg, January 2023).
- A BESS can be competitive when compared to a STATCOM[1] (IGBT based) depending on the size and supposing that the need for dynamic (or fast) voltage control is confirmed.

7.2.4. Conclusion on the cost-effectiveness of BESS for voltage control

BESS can absorb and can produce reactive power (expressed in Mvar’s) and therefore can act as capacitors and reactances act, of like generators generator or absorb reactive energy.

With this characteristic in mind, BESS can control the voltage as good as these conventional means at steady state, and even better during the very short term after events (transients).

However, the investment cost for BESS is significant when compared to these conventional assets.

The comparison of BESS and reactances clearly shows that a BESS cannot be and cannot become profitable for acting for voltage control only, since it cost is not competitive with the

[1] it is capable of yielding high re-active power input to the grid more or less unimpeded by suppressed grid voltages, and with high dynamic response. This is useful, for instance, to support more or less weak grids loaded by a large percentage of air conditioners in hot and humid cli-mates, and to improve the availability of large wind farms under varying grid conditions. (ref: ABB SVC and STATCOM shut compensation, 2019)

reactances costs, even when considering the future CAPEX cost reduction of BESS.

However, the voltage control capability of BESS will be of significant interest in the frame of combined applications of BESS like Energy Shift and Voltage Control, or frequency control and Voltage Control: locating the BESS at places where a large capacitor or large reactance should otherwise be installed will provide the corresponding savings of capacitor or reactance CAPEX.

7.3. Energy Time Shift Application

7.3.1. Objectives

This application aims at evaluating the financial and economic feasibility of shifting energy from the low demand/ low prices hours to the high demand/high prices hours. The feasibility of such arbitrage depends on a number of conditions, particular to each country.

For instance, the shape of the demand profile: a flat hourly demand curve will not be suitable for BESS arbitrage, while an hourly load curve where the peak demand is much higher than the off-peak demand will give incentives to install BESS. In order to simulate the WAPP power system a simplified modelling of the whole system has been considered. A summary of the main inputs is presented here below.

7.3.2. Main Inputs

Nowadays, WAPP system's main installed capacity corresponds to gas-fired generators, followed by Hydro and HFO. By 2030 Solar PV is expected to become the third largest technology in WAPP area

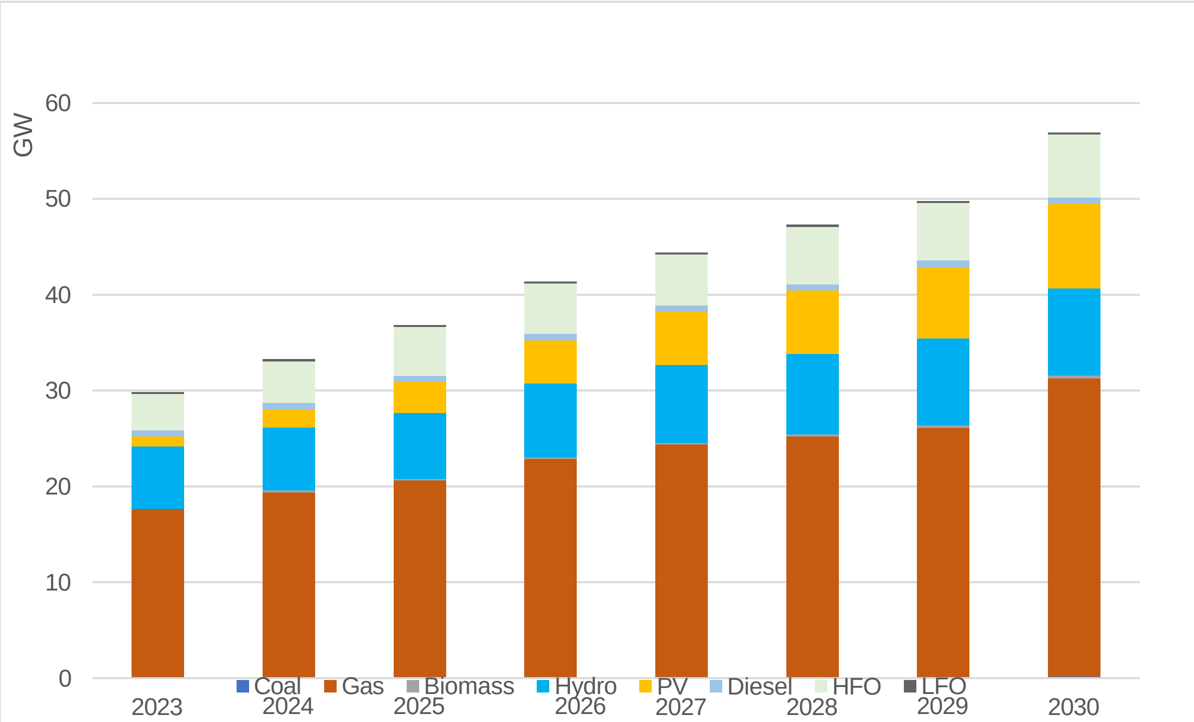

Figure 4: Installed capacity in the ECOWAS continental area by technology

The fuel prices considered in the database reflect the local cost of supplying each fuel for each country, and therefore can include subsidies as obtained during the data collection process from each country. In the following table the fuel costs in ($/MWh) are shown. Please bear in mind that a cost of 1500 $/MWh[1] for the Value of lost load (VOLL) is assumed, meaning the cost of having Energy Not Served (ENS) in the system.

Table 15: Fuel Costs by Country

($/MWh)	2023	2024	2025	2026	2027	2028	2029	2030
BF_Biomass	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
BF_Diesel	68.00	68.00	68.00	68.00	68.00	68.00	68.00	68.00
BF_HFO	53.89	53.89	53.89	53.89	53.89	53.89	53.89	53.89
BF_Local Gas	40.64	41.86	43.11	44.41	45.74	47.11	48.52	49.98
BJ_Biomass	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
BJ_Diesel	70.80	72.20	73.63	74.59	75.54	76.50	77.49	78.48
BJ_LFO	57.46	58.59	59.75	60.50	61.28	62.07	62.89	63.67
BJ_Local Gas	40.64	41.86	43.11	44.41	45.74	47.11	48.52	49.98
CI_Biomass	27.60	27.60	27.60	27.60	27.60	27.60	27.60	27.60
CI_HFO	20.75	20.75	20.75	20.75	20.75	20.75	20.75	20.75
CI_Local Gas	35.29	36.35	37.44	38.57	39.72	40.92	42.14	43.41
GH_Diesel	35.29	35.29	35.29	35.29	35.29	35.29	35.29	35.29
GH_HFO	27.60	27.60	27.60	27.60	27.60	27.60	27.60	27.60
GH_LocaGas	41.49	42.74	44.02	45.34	46.70	48.10	49.54	51.03
GM_Diesel	131.23	131.23	131.23	131.23	131.23	131.23	131.23	131.23
GM_HFO	135.75	135.75	135.75	135.75	135.75	135.75	135.75	135.75
GN_HFO	71.80	71.80	71.80	71.80	71.80	71.80	71.80	71.80
GN_LFO	40.84	40.84	40.84	40.84	40.84	40.84	40.84	40.84
GN_Local Gas	11.18	11.52	11.86	12.22	12.58	12.96	13.35	13.75
GW_Diesel	110.46	110.46	110.46	110.46	110.46	110.46	110.46	110.46
GW_HFO	110.46	110.46	110.46	110.46	110.46	110.46	110.46	110.46
LR_HFO	56.15	56.15	56.15	56.15	56.15	56.15	56.15	56.15
ML_Diesel	81.43	81.43	81.43	81.43	81.43	81.43	81.43	81.43

[1] The WAPP transmission master plan proposes a range for the cost of NSE between 1,000 and 1,500 USD/MWh. Taking the upper bound considering inflation and similar values used in other projects.

($/MWh)	2023	2024	2025	2026	2027	2028	2029	2030
ML_HFO	63.22	63.22	63.22	63.22	63.22	63.22	63.22	63.22
NE_Coal	57.88	57.88	57.88	57.88	57.88	57.88	57.88	57.88
NE_HFO	57.88	57.88	57.88	57.88	57.88	57.88	57.88	57.88
NE_LFO	145.89	145.89	145.89	145.89	145.89	145.89	145.89	145.89
NG_HFO	114.84	114.84	114.84	114.84	114.84	114.84	114.84	114.84
NG_Local Gas	22.02	22.68	23.36	24.06	24.79	25.53	26.30	27.09
SL_Biomass	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
SL_Diesel	174.02	174.02	174.02	174.02	174.02	174.02	174.02	174.02
SL_HFO	174.02	174.02	174.02	174.02	174.02	174.02	174.02	174.02
SN_Coal	55.49	63.18	65.41	64.86	64.86	64.86	64.86	64.86
SN_Diesel	57.88	57.88	57.88	57.88	57.88	57.88	57.88	57.88
SN_HFO	45.42	41.41	38.15	35.30	34.21	34.21	34.21	34.21
SN_Int. Gas	60.88	66.36	63.94	61.53	59.35	59.35	59.35	59.35
SN_LFO	79.32	69.46	71.90	71.30	71.30	71.30	71.30	71.30
SN_Local Gas	61.65	67.20	64.75	62.31	60.11	60.11	60.11	60.11
TG_Diesel	20.75	21.16	21.58	21.86	22.14	22.42	22.71	23.00
TG_HFO	16.84	17.17	17.51	17.73	17.96	18.19	18.43	18.66
TG_Local Gas	11.91	11.88	11.84	11.73	11.69	11.66	11.62	11.58

In terms of the final electricity consumption, most of the countries are aligned with a growth rate of around 18% in 2025 and 60% in 2030 compared to 2023.

In particular, Nigeria (NG), Niger (NE) and Senegal (SN) and Sierra Leone (SL) assume a high rate at the beginning of the period reflecting COVID recovery and then a higher growth rate this leads to CAGR of more than 10% in these countries.

Table 16: Demand growth by country

	BJ	BF	CI	GM	GH	GN	GW	LR	ML	NE	NG	SL	SN	TG
2025	18%	18%	17%	18%	31%	17%	13%	17%	15%	47%	32%	33%	66%	20%
2030	67%	70%	62%	45%	36%	30%	57%	77%	87%	195%	99%	142%	108%	73%
CAGR	8%	8%	7%	5%	4%	4%	7%	9%	9%	17%	10%	13%	11%	8%

In the Figure below the yearly evolution of the energy demand per each country is depicted.

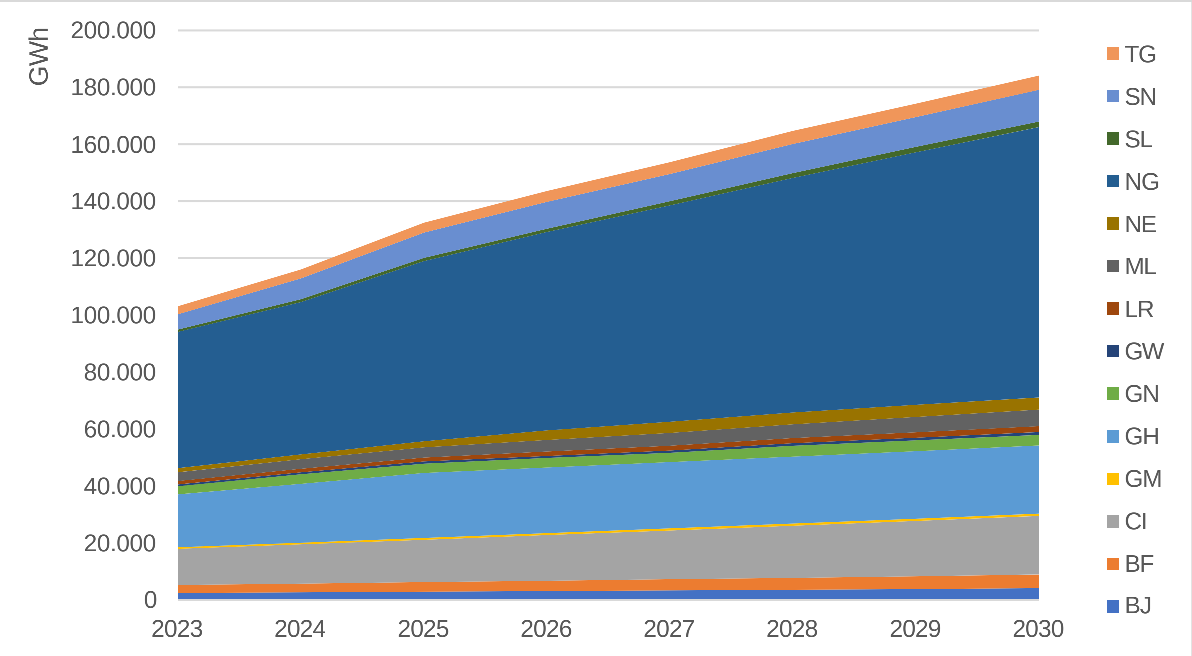

Figure 5: Demand evolution of energy per country.

Finally, to model the solar production, two representative days are considered, one for the rainy season, and other for the dry season as shown in the graph below. As expected in the dry season a higher solar production is observed with respect to the rainy season.

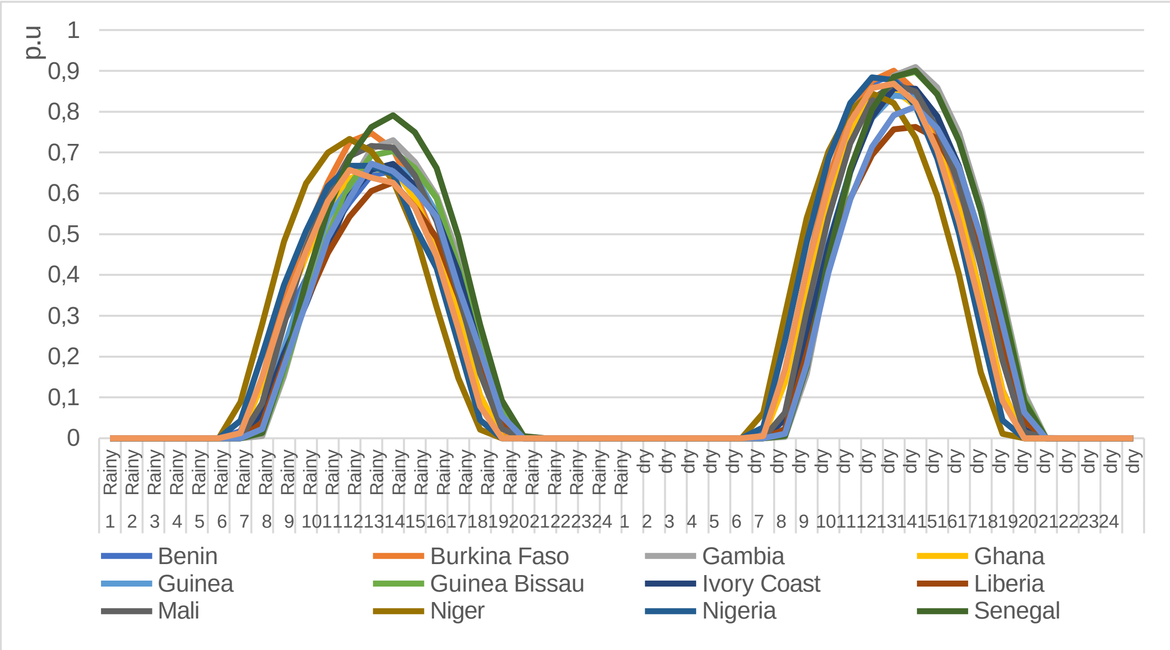

Figure 6: ***PV profiles per country***

As mentioned in the methodology, results are presented for investment decisions made in 2025 or 2030.

As mentioned in the methodology the results are presented for the investment decisions made either in 2025 or 2030.

In particular, the main parameter for BESS investment will be CAPEX, which is expected to decrease rapidly in the following years; in addition, the intraday price differences will drive investment decisions, depending on PV penetration, transmission capacity, and hydro expansion. Batteries of 2h and 4h are evaluated, for the preliminary simulations it is assumed that 4h BESS to be the standard size for energy shift applications.

7.3.3. BESS investments in 2025

When deciding the investments in 2025, the simulation shows the only country to show profitable investments in Batteries is Gambia (GM), with a capacity of 120 MW. In the Figure below the average marginal costs in the region for 2025 are shown. It can be observed that marginal costs remain high for Gambia (GM) and Sierra-Leone (SL), which reflects both ENS[2] in Sierra Leone (SL) for 2025 (1.3% of total demand) and high fuel costs in Mali (ML), Niger (NE), and Gambia (GM) in 2030.

Table 17: BESS Investments 2025 - Energy Shift Application

	BF	BJ	CI	GH	GM	GN	GW	LR	ML	NE	NG	SL	SN	TG
Capacity (MW)	0	0	0	0	120	0	0	0	0	0	0	0	0	0

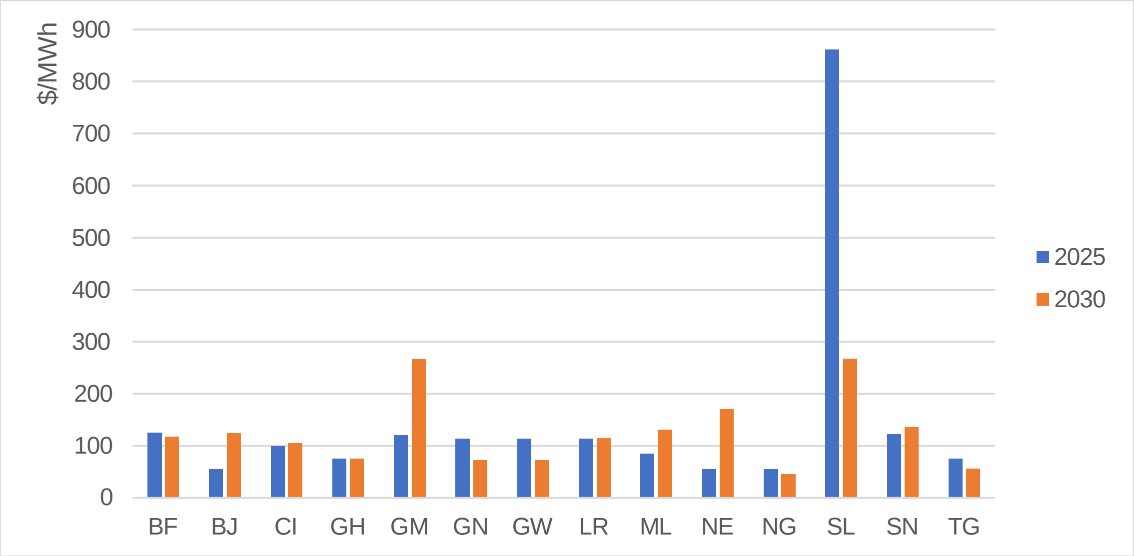

Figure 7: Annual average electricity prices per country with BESS investments in 2025

The graphs below show the intraday variability of prices both for the year 2025 and 2030. In 2025 Sierra Leone (SL), Mali (ML), Burkina Faso (BF) and Mali (ML) present the higher price difference of 1042 $/MWh, 100 $/MWh, 100 $/MWh and 99 $/MWh respectively for the dry season. While in 2030, Gambia (GM), Mali (ML) and Burkina Faso (BF) present the higher price difference of 404 $/MWh, 164 $/MWh and 160 $/MWh respectively for the wet season.

[2] 1500 USD/MWh for the Energy Not Served (ENS) or Non Served Energy (NSE)

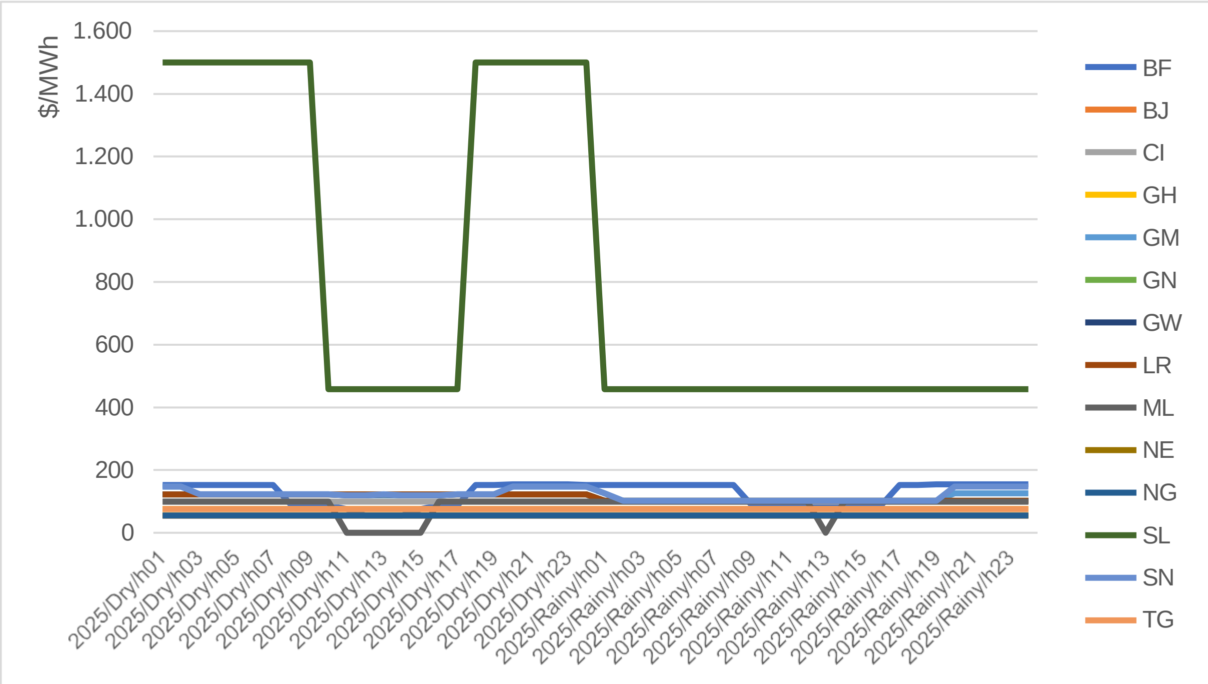

Figure 8 : Average hourly electricity prices per country per season by 2025 - BESS 2025

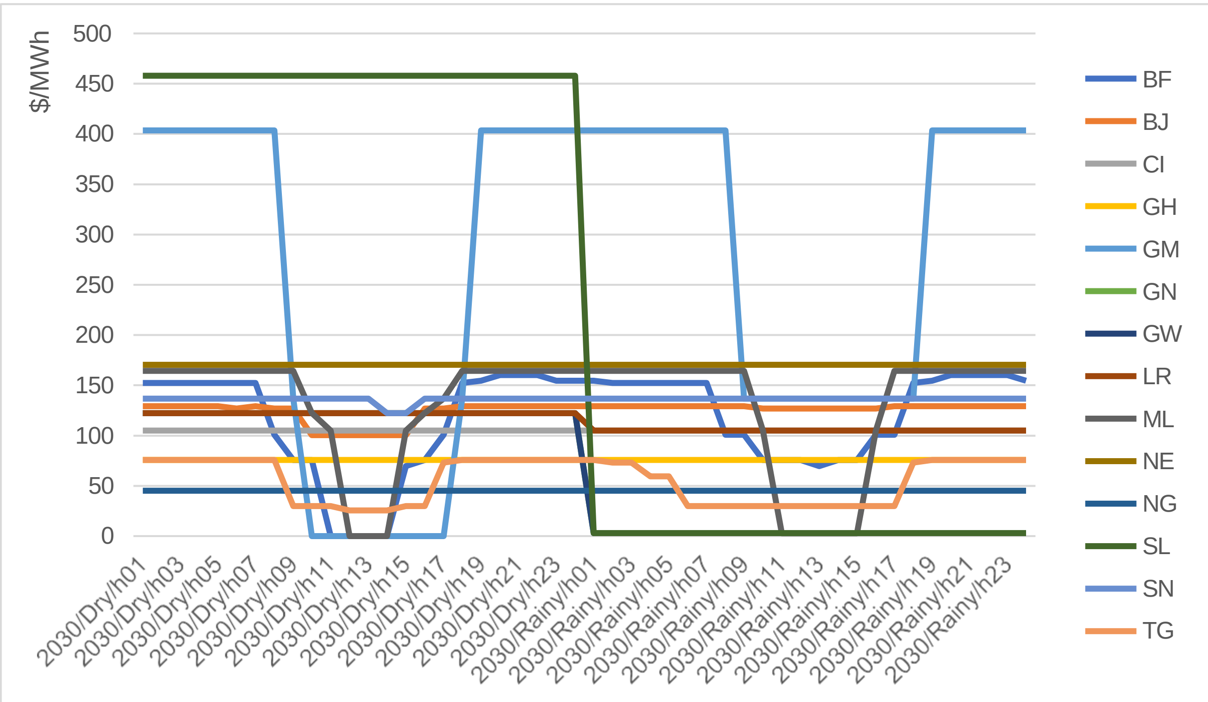

Figure 9: Average hourly electricity prices per country per season by 2030 - BESS 2025

Despite the high price difference in Sierra Leone (SL) in 2025, in 2030 there are no intraday price differences, the price remains high in the dry season while it remains very low in the dry season. This is a consequence of the commissioning of the hydro projects by 2027 which makes that BESS investments are not attractive from 2027 onwards in Sierra Leone (SL).

Finally, as shown in the financial model below, investing in a battery of 120 MW in Gambia will ensure sales of 52 MUSD per year and costs of around 14 MUSD per year. However, there is a risk of lower cash inflows in 2027, 2028, and 2029 when revenues drop to 27% of the average of the rest of the years.

BESS Financial Model for The Gambia

Table 18: BESS Financial Model GM 2025 - Energy Shift

Year		Valuation in 2023	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Prices and volumes														
	Selling price	USD/MWh			135.91	141.77	270.52	288.55	290.74	403.54	403.54	403.54	403.54	403.54
	Purchase price	USD/MWh			110.04	99.44	45.79	55.99	65.93	68.15	68.15	68.15	68.15	68.22
	Sales Volumes	GWh			135.38	114.38	171.85	158.19	165.44	171.85	171.845	171.845	171.845	171.965
	Buy Volumes	GWh			167.44	141.14	212.31	195.48	204.66	212.12	212.12	212.12	212.12	211.91
Revenue			-	-	18,3989	16,2163	46,4879	45,6461	48,1003	69,3462	69,3462	69,3462	69,3462	69,3943
	Energy Sales		-	-	18,399	16,216	46,488	45,646	48,100	69,346	69,346	69,346	69,346	69,394
Costs			-	(151,680)	(20,700)	(16,310)	(11,998)	(13,220)	(15,769)	(16,732)	(16,732)	(16,732)	(16,732)	(16,732)
	Capital Expenditures		-	(151,680)				-	-					
	Operating Costs		-		(2,275)	(2,275)	(2,275)	(2,275)	(2,275)	(2,275)	(2,275)	(2,275)	(2,275)	(2,275)
	Energy Purchases			-	(18,425)	(14,035)	(9,723)	(10,944)	(13,494)	(14,456)	(14,456)	(14,456)	(14,456)	(14,456)
Net	**Cash Flow**			**(151,680)**	**(2,301)**	**(93)**	**34,490**	**32,426**	**32,331**	**52,615**	**52,615**	**52,615**	**52,615**	**52,663**

In summary, according to the financial model, the investment and operation of the BESS can result in an NPV of approximately $31,528K in 2023, implying an IRR of 13.92%.

NPPF		**31 528 $**
	Energy Sales	239 126 $
	Energy Arbitrage	168 437 $
	Capital Expenditures	(125 355 $)
	Operating Costs	(11 554 $)
FIRR		13.92%

By including the emission reductions of around 0.1 kton of CO_2 at 20 USD/ton per year, the EIRR maintains the same value as the FIRR of 13.92%

7.3.4. BESS investments in 2030

The Figure below shows the average marginal costs in the region for 2025 (No investments) and 2030

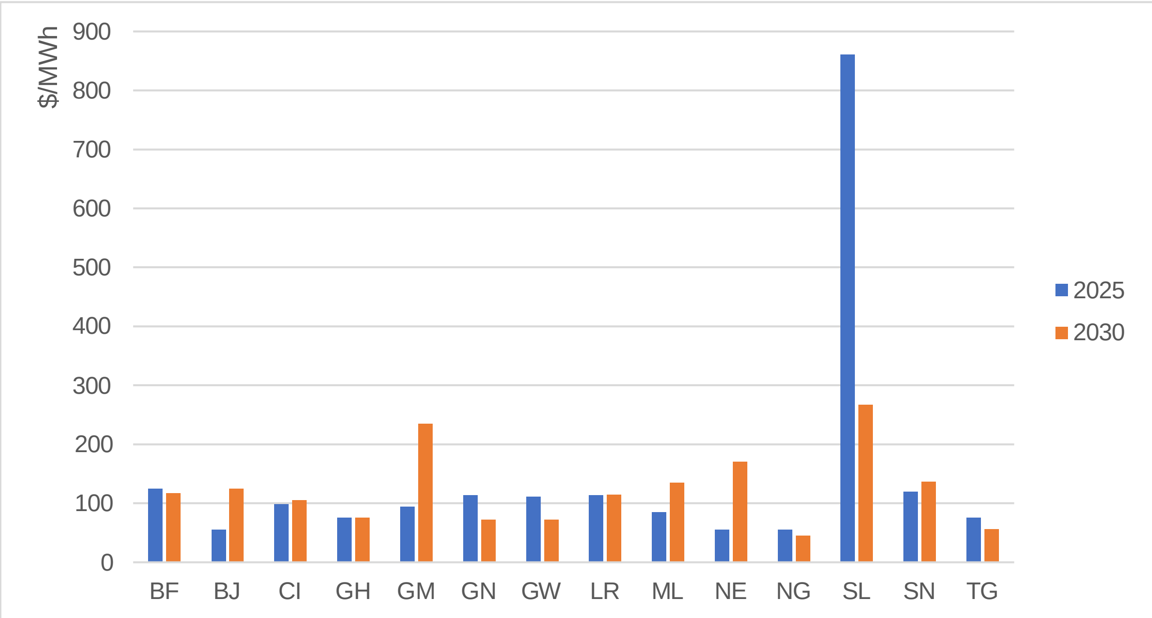

Figure 10: Annual average electricity by country with BESS in 2030

The graph above shows the marginal costs remain high for Gambia (GM) and Sierra Leone (SL), which reflects both ENS in Sierra Leone (SL) for 2025 (1.3% with respect to total demand) and high fuel costs in Mali (ML), Niger (NE), and Gambia (GM) in 2030.

The graphs below show the intraday variability of prices both for the year 20250 and 2030. In 2025 Sierra Leone (SL), Gambia (GM), Burkina Faso (BF) and Mali (ML) present the highest price difference of 1 042$/MWh, 147$/MWh, 100$/MWh and 99$/MWh respectively for the dry season. While in 2030, Gambia (GM), Mali (ML) and Burkina Faso (BF) present the higher price difference of 267$/MWh, 164$/MWh and 160$/MWh respectively for the dry season.

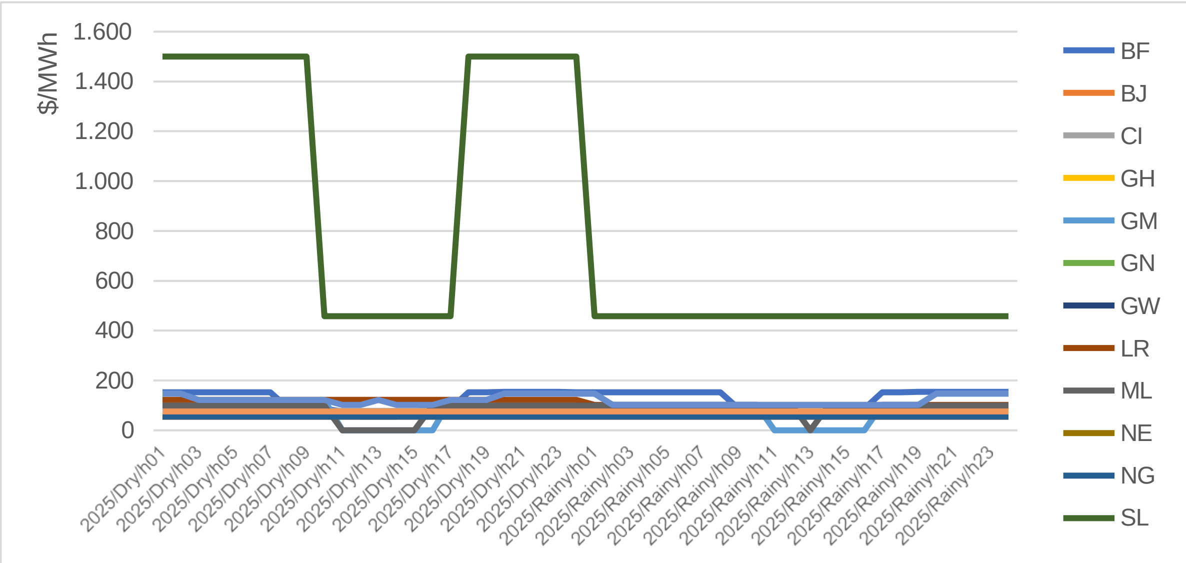

Figure 11: Average electricity prices by country and season - BESS 2025

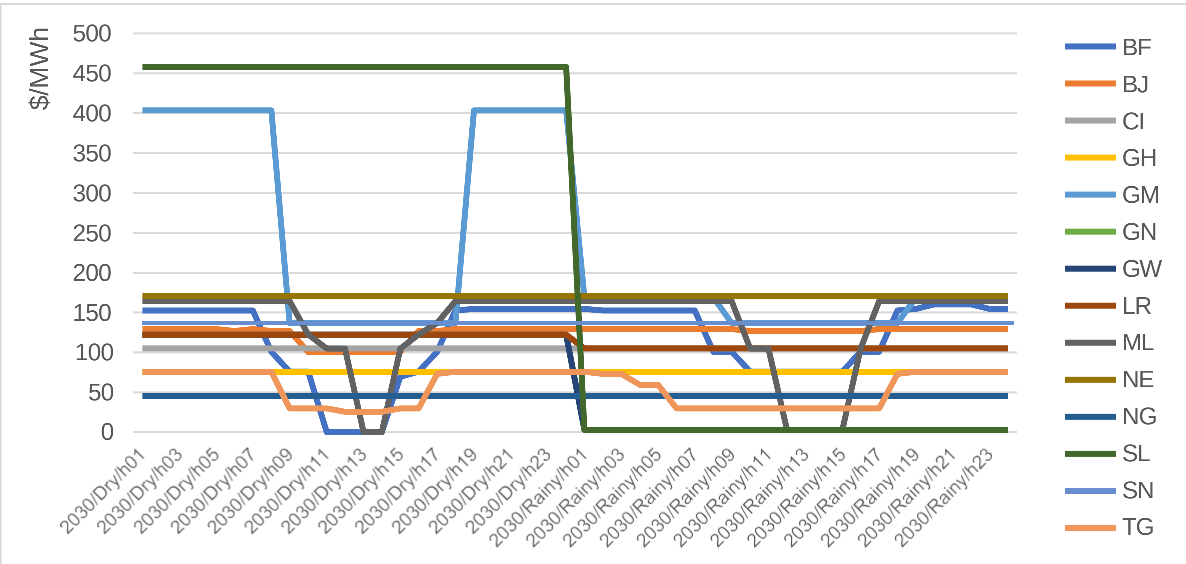

Figure 12: Average electricity prices by country and season - BESS 2030

Despite the high price difference in Sierra leone (SL) in 2025, in 2030 there are no intraday price differences, the price remains high in the dry season while it remains very low in the dry season. This is a consequence of the commissioning of the hydro projects by 2027 which makes that BESS investments are not attractive from 2027 onwards in Sierra Leone (SL). Finally, given that the price differential is the main driver for BESS investments in the energy shift application, the following BESS capacity expansion results are obtained.

Table 19: BESS Investments 2030 - Energy Transition Application

	BF	BJ	CI	GH	GM	GN	GW	LR	ML	NE	NG	SL	SN	TG
Capacity (MW)	25	0	0	0	147	0	0	0	55	0	0	0	0	0

BESS Financial Model for Burkina Faso

Table 20: BESS Financial Model Burkina Faso (BF) 2030 - Energy Shift

Year		Valuation in 2023	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Prices and volumes													
	Selling price	USD/MWh		156.31	156.31	156.31	156.31	156.31	156.31	156.31	156.31	156.31	156.31
	Purchase price	USD/MWh		39.20	39.20	39.20	39.20	39.20	39.20	39.20	39.20	39.20	39.20
	Sales Volumes	GWh		35.80	35.801	35.801	35.801	35.801	35.801	35.801	35.801	35.801	35.776
	Buy Volumes	GWh		44.08	39.78	39.78	39.78	39.78	39.78	39.78	39.78	39.78	39.75
Revenue				5,596.0	5,596.0	5,596.0	5,596.0	5,596.0	5,596.0	5,596.0	5,596.0	5,596.0	5,592.2
	Energy Sales			5,596	5,596	5,596	5,596	5,596	5,596	5,596	5,596	5,596	5,592
Costs			(21,700)	(2,053)	(1,885)	(1,885)	(1,885)	(1,885)	(1,885)	(1,885)	(1,885)	(1,885)	(1,884)
	Capital Expenditures		(21,700)										
	Operating Costs			(326)	(326)	(326)	(326)	(326)	(326)	(326)	(326)	(326)	(326)
	Energy Purchases			(1,728)	(1,559)	(1,559)	(1,559)	(1,559)	(1,559)	(1,559)	(1,559)	(1,559)	(1,558)
Net Cash			(21,700)	3,543	3,711	3,711	3,711	3,711	3,711	3,711	3,711	3,711	3,708

NPPF		**487 $**
	Energy Sales	17 644 $
	Energy Arbitrage	17 644 $
	Capital Expenditures	(11 136 $)
	Operating Costs	(11 136 $)
FIRR		**11.00%**

BESS Financial Model for The Gambia

Table 21: BESS Financial Model GM 2030 - Energy Shift

Year			**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Prices and volumes													
	Selling price	USD/MWh		297.49	297.49	297.49	297.49	297.49	297.49	297.49	297.49	297.49	297.41
	Purchase price	USD/MWh		136.76	136.76	136.76	136.76	136.76	136.76	136.76	136.76	136.76	136.76
	Sales Volumes	GWh		192.56	192.555	192.555	192.555	192.555	192.555	192.555	192.555	192.555	192.409
	Buy Volumes	GWh		237.68	237.52	237.52	237.74	237.52	237.52	237.74	237.52	237.68	237.74
Revenue				57,2841	57,2841	57,2841	57,2841	57,2841	57,2841	57,2841	57,2841	57,2841	57,2251
	Energy Sales			57,284	57,284	57,284	57,284	57,284	57,284	57,284	57,284	57,284	57,225
Costs			(127,596)	(34,420)	(34,399)	(34,399)	(34,428)	(34,399)	(34,399)	(34,428)	(34,399)	(34,420)	(34,428)
	Capital Expenditure s		(127,596)										
	Operating Costs			(1,914)	(1,914)	(1,914)	(1,914)	(1,914)	(1,914)	(1,914)	(1,914)	(1,914)	(1,914)
	Energy Purchases			(32,506)	(32,485)	(32,485)	(32,514)	(32,485)	(32,485)	(32,514)	(32,485)	(32,506)	(32,514)
Net Cash Flow			(127,596)	22,864	22,885	22,885	22,856	22,885	22,885	22,856	22,885	22,864	22,797

NPPF		**6 634 $**
	Energy Sales	180 613 $
	Energy Arbitrage	180 613 $
	Capital Expenditures	(65 477 $)
	Operating Costs	(65 477 $)
FIRR		**12.31%**

BESS Financial Model for Mali

Table 22: BESS ML 2030 Financial Model - Energy Transition

Year		Valuation in 2023	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Prices and volumes													
	Selling price	USD/MWh		164.37	164.37	164.37	164.37	164.37	164.37	164.37	164.37	164.37	164.37
	Purchase price	USD/MWh		44.39	38.01	38.01	38.04	38.04	38.04	38.01	38.01	38.04	38.04
	Sales Volumes	GWh		78.76	78.762	78.762	78.762	78.762	78.762	78.762	78.762	78.762	78.708
	Buy Volumes	GWh		97.04	96.98	96.98	97.04	97.04	97.04	96.98	96.98	97.04	97.04
Revenue				12,9459	12,9459	12,9459	12,9459	12,9459	12,9459	12,9459	12,9459	12,9459	12,9369
	Energ Sales			12,946	12,946	12,946	12,946	12,946	12,946	12,946	12,946	12,946	12,937
Costs			(47,740)	(5,023)	(4,402)	(4,402)	(4,407)	(4,407)	(4,407)	(4,402)	(4,402)	(4,407)	(4,407)
	Capital Expenditure s		(47,740)										
	Operating Costs			(716)	(716)	(716)	(716)	(716)	(716)	(716)	(716)	(716)	(716)
	Energy Purchases			(4,307)	(3,686)	(3,686)	(3,691)	(3,691)	(3,691)	(3,686)	(3,686)	(3,691)	(3,691)

NPPF		**2 142 $**
	Energy Sales	40 818 $
	Energy Arbitrage	40 818 $
	Capital Expenditure s	(24 498 $)
	Operating Costs	(24 498 $)
FIRR		**11.98%**

In summary, according to the financial model, the investment and operation of BESS will lead to the following figures:

- In Burkina Faso: NPV of around \$487k in 2023, implying an IRR of 11.00%.

NPPF	25 MW de BESS	487 $
	Energy Sales	17 644 $
	Energy Arbitrage	12 649 $
	Capital Expenditures	(11 136 $)
	Operating Costs	(1 026 $)
FIRR		11.00%

By including the emission reductions of around 3 kton of CO2 at 20USD/ton per year, an EIRR of 11.38% is obtained.

- In The Gambia: An NPV of around \$6,634 in 2023, implying an IRR of 12.31%.

NPPF	147 MW de BESS	6 634 $
	Energy Sales	180 613 $
	Energy Arbitrage	78 146 $
	Capital Expenditures	(65 477 $)
	Operating Costs	(6 035 $)
FIRR		12.31%

Including emission reductions of approximately 0.13 kton CO2 at USD 20/tonne per year, an **EIRR of 12.31**% is obtained.

- In Mali: An NPV of around \$2,142 in 2023, which implies an IRR of 11.98%.

NPPF	55 MW the BESS	2 142 $
	Energy Sales	40 818 $
	Energy Arbitrage	28 899 $
	Capital Expenditures	(24 498 $)
	Operating Costs	(2 258 $)
FIRR		11.98%

Including emission reductions of approximately 0.23 kton CO2 at USD 20/ton per year, an EIRR of 11.99% is obtained.

7.3.5. Sensitivity Study

This section illustrates the extent to which the *BESS* financial outcomes are influenced by fluctuations in three key parameters: the discount rate, the CAPEX, and the fuel prices. The analysis examines how the FNPV (*F*inancial *N*et *P*resent *V*alue) fluctuates with changes in these parameters. Results are provided for investments in both 2025 and 2030, *and final values are presented* per standard MW of BESS investment, considering that no investments are proposed for Mali (ML) and Burkina Faso (BF) in 2025.

1) Discount Rate

The discount rate plays a key role in financial and economic assessments, serving as a direct indicator of investment risks in the region and the minimum profitable rate for undertaking a particular investment. Recent practices in the region have seen the use of discount rates ranging from 8% to 12%. Consequently, the following figures depict how the FNPV fluctuates with an increase in the discount rate, presenting results for investments in both 2025 and 2030.

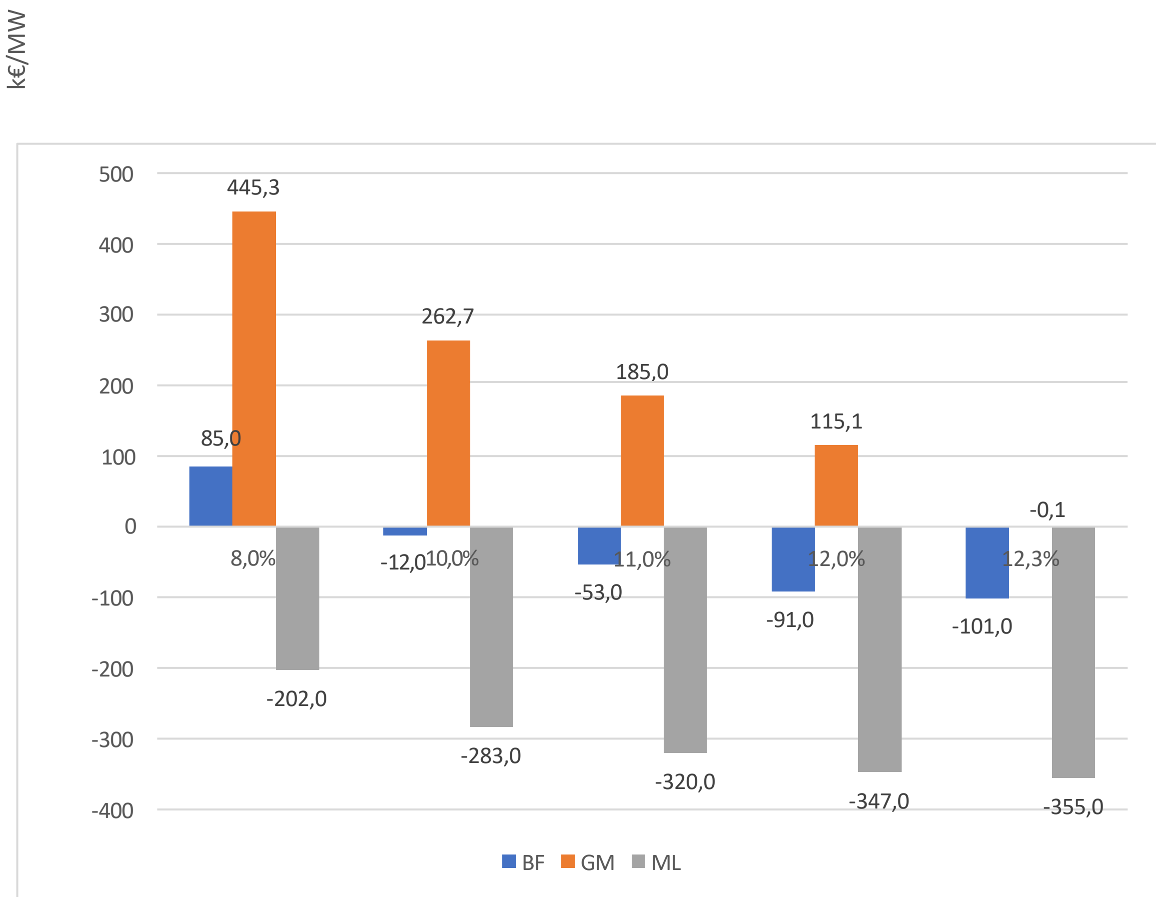

Figure 13 : NPV Sensitivity - NPF vs. Discount Rate – 2025

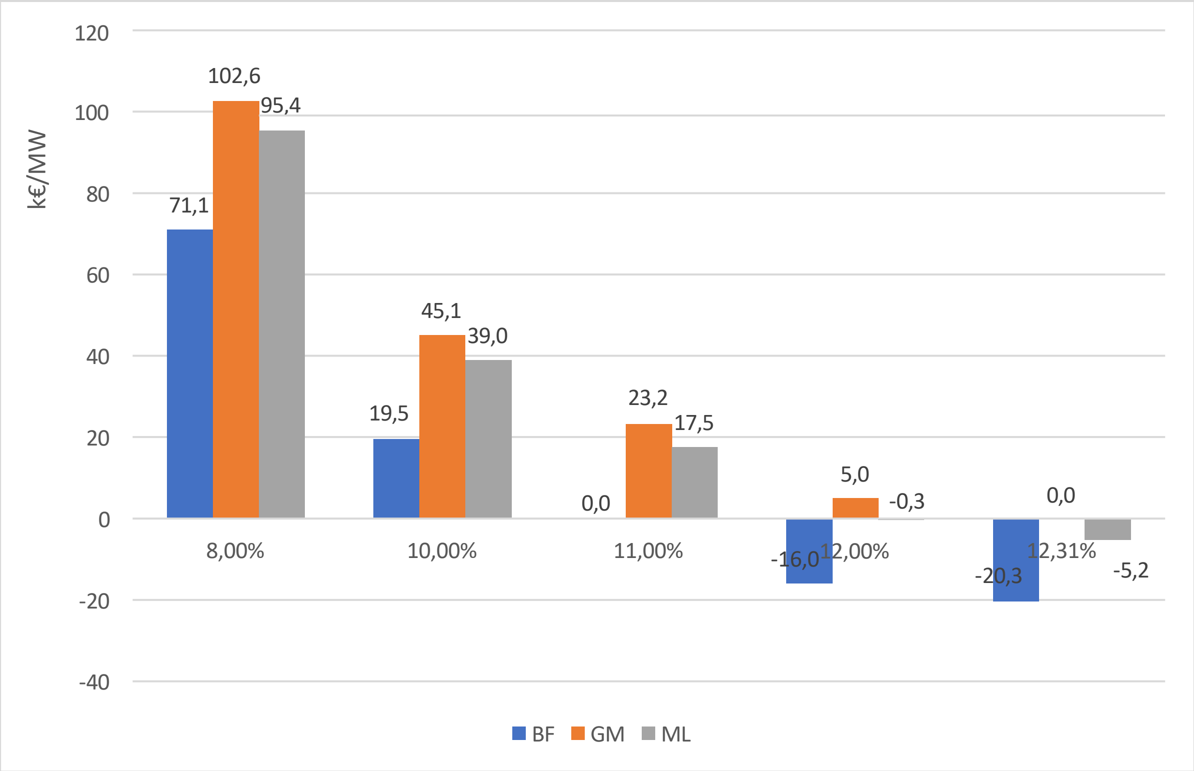

Figure 14 : NPV Sensitivity - NPV vs Discount Rate - 2030

In 2025, the analysis reveals that Mali (ML) investments in BESS do not yield profitability across any scenarios, aligning with its FIRR of 4.46%. Conversely, BESS investments in Burkina Faso (BF) demonstrate profitability when applying an 8% discount rate. These findings suggest potential profitability for BESS investments in Mali (ML), highlighting the need for further examination, and potentially incorporating additional applications into a more comprehensive financial model. Additionally, for Gambia (GM), a mere 2% fluctuation in the discount rate results in FNPV variations ranging from -60% to 70%, underscoring the project's sensitivity to changes in the discount rate.

Looking ahead to 2030, a 2% variation in the discount rate can lead to FNPV fluctuations between -180% and 260%, varying from country to country.[3] This underscores the critical importance of selecting the appropriate discount rate or ensuring consistency across different feasibility studies in the regions.

2) Capital Expenditures

The capital expenditure required for BESS installation stands as another critical parameter. Especially within the battery market, where a significant decrease in investment costs has been anticipated. However, due to the energy crisis, this downward trend has been hindered, prompting revaluations by various sources such as Bloomberg and NREL. In this report, the base case for cost reduction follows the trajectory outlined in the 2022 Bloomberg NEF report. Additionally, exploring low- and high-case scenarios based on the Annual Technology Baseline report by NREL, which assumes varying levels of capex reduction as detailed in the table below.

Table 23: BESS Investment Scenarios – % decrease from 2023 value.

	Low	Base	High
2025	-21%	-16%	-12%
2030	-59%	-43%	-28%

[3] The figures also identify the discount rates corresponding to a null FNPV, also known as FIRRS, 11% for Burkina

Faso (BF), 12% for Gambia (GM), and 12.31% for Mali (ML).

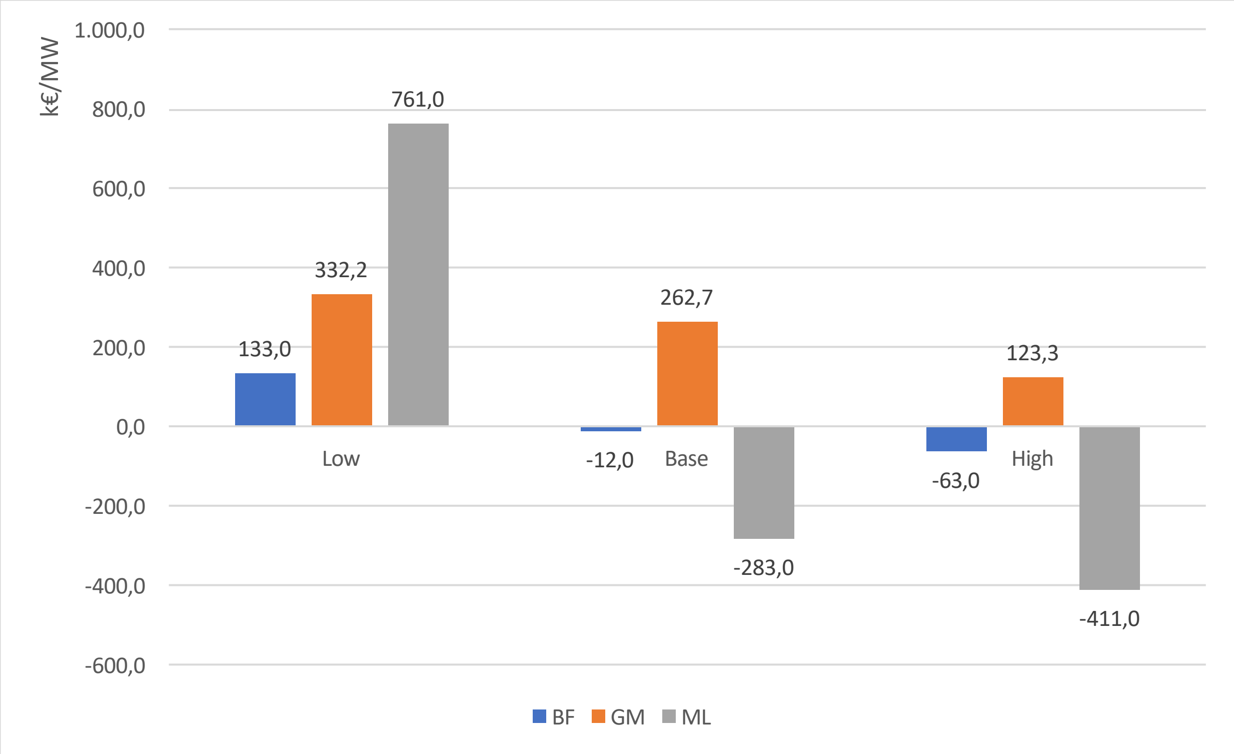

Figure 15 : NPV Susceptibility - NPF vs CAPEX - 2025

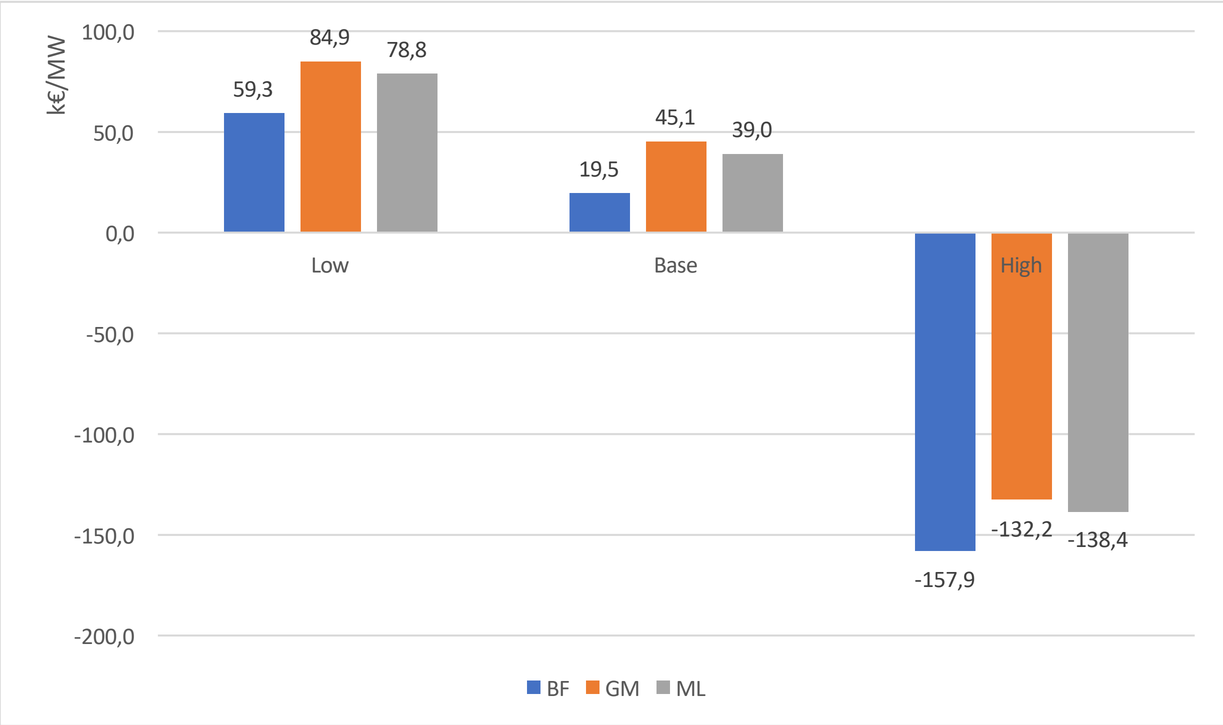

Figure 16 : NPV Susceptibility - NPPF vs CAPEX - 2030

The above figures demonstrate the sensitivity of BESS investments to changes in capital expenditures. In 2025, the results reveal that the outcomes of the High-CAPEX scenario are qualitatively similar to those of the Base-CAPEX scenario: BESS investments in Burkina Faso (BF) and Mali (ML) are not profitable in both cases, while investments in Gambia (GM) generate a positive NPV. Conversely, the numbers show that the Low-CAPEX scenario transforms BESS's investments in Mali (ML), Burkina Faso (BF), and Gambia (GM) into profitable businesses.

By 2030, investments in all countries become unprofitable in the high capital expenditure scenario, resulting in negative NPCF values. However, in the Low-CAPEX scenario, NPV increases in varying percentages ranging from 90% to 20%, depending on the country.

3) Fuel Prices

The decision to invest in BESS is highly dependent on the hourly price differences in each country, and therefore it is important to evaluate variations in fuel prices. While incorporating this sensitivity into the financial model, it's crucial to recognize that shifts in fuel prices would alter dispatch strategies within each country and affect energy flows between them. Consequently, conducting a comprehensive new simulation would be required to recalculate energy arbitrage in each country. To streamline this sensitivity analysis, considering a +-20% variation solely in the fuel price of the peak generator (Gas for Benin, HFO for Mali, HFO for Gambia) in each country, while keeping all other factors constant.

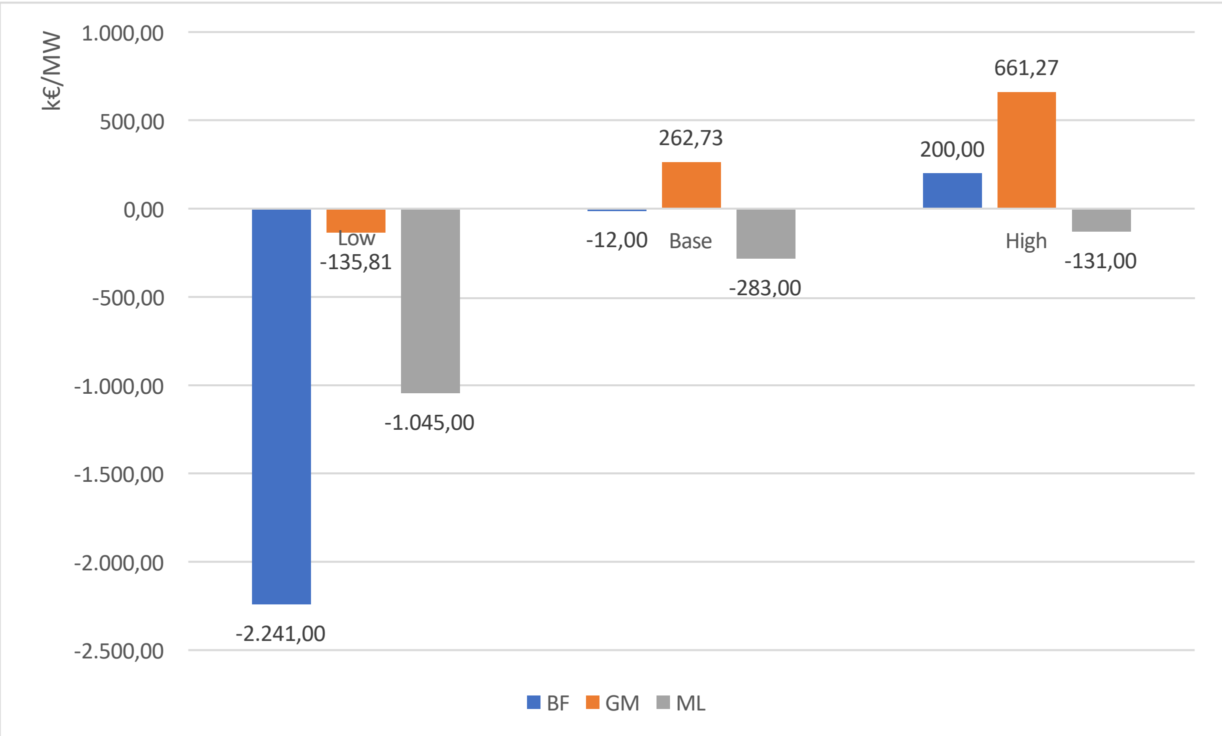

Figure 17 : NPV Sensitivity - NPF vs Fuel Price – 2025

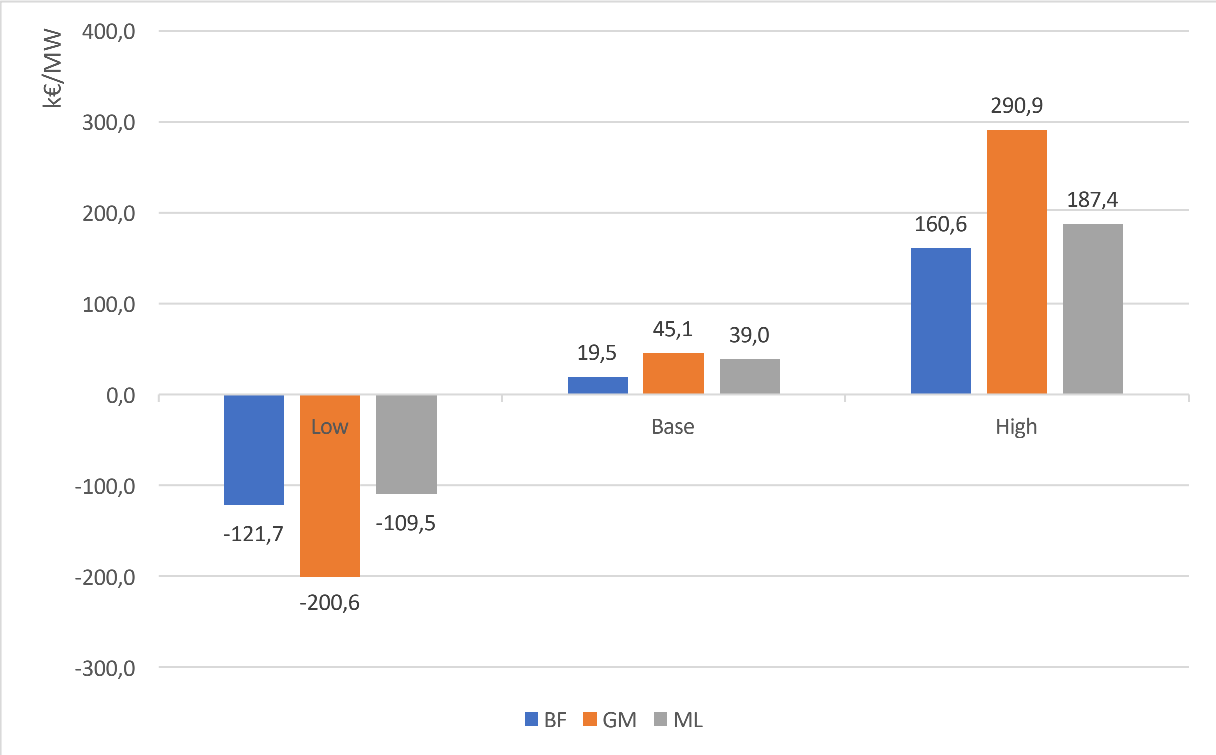

Figure 18 : NPV Sensitivity - NPF vs Fuel Price - 2030

The depicted Figure underscores the high sensitivity of BESS investment profitability to fuel prices. It's important to bear in mind, as highlighted in the section's introduction, that a more robust sensitivity analysis would entail a complete re-run of the model to recalibrate energy arbitrage resulting from price fluctuations. Nonetheless, this Figure illustrates that in 2025, these price variations consistently result in negative FNPV for Mali (ML), while Burkina Faso (BF) becomes profitable with higher prices, and Gambia (GM) experiences increased profitability. Looking ahead to 2030, a price increase renders BESS investments profitable across all examined countries, whereas a price decrease leads to non-profitability in all countries.

7.3.6. Conclusion on the Energy Shift Application

Based on the previous findings, the feasibility of implementing the energy shift application appears quite restricted in 2025 but slightly broader by 2030. These outcomes are in line with analogous international system-wide studies, typically indicating the viability of Battery BESS post-2030, conditional upon the penetration of PV capacity. It is crucial to acknowledge the limitations of these results, starting from the data collection constraints by assuming demand profiles for certain countries and simplifications within the simulation process. A more detailed representation might lead to relatively higher investments in BESS.

Nevertheless, it is notable that Gambia exhibits significant potential for BESS investment, while Mali (ML) and Burkina Faso (BF) also demonstrate favourable marginal cost structures contributing to promoting BESS post-2030. Additionally, it's worth emphasizing the complementary role of interconnections with BESS, whereby higher solar PV penetration by 2030 is offset by increased NTCs..

7.4. Transmission Congestion Relief Application

7.4.1. Objectives

The "Congestion relief" application aims to study the profitability of batteries as a tool for relieving network congestion. Batteries can be used to unload lines and thus avoid costly reinforcements. This application has several advantages:

- Avoiding investment in reinforcement when the overload is low and can be reduced using a small battery.
- Fast resolution of overloads, because installing a battery is much quicker than reinforcing a line.

The main criterion is therefore the line loading, which should be kept below 100%.

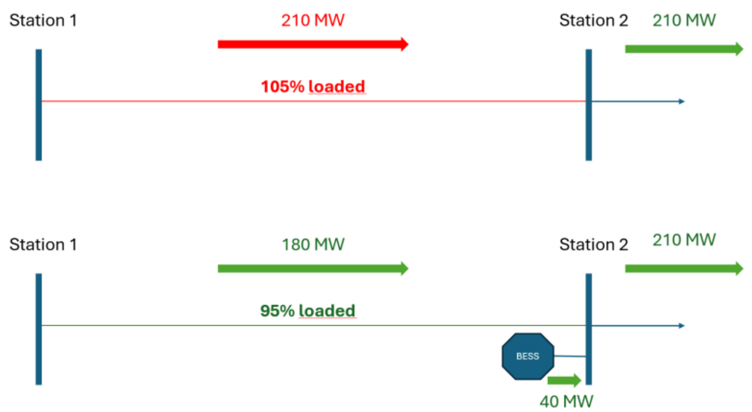

Figure 19 : Principle of battery decongestion

This principle will be applied to the few reinforcements that appeared to be necessary to avoid overloads appearing on the 2025 power flow computations or the 2030 power flow computations. Some remarks have to be mentioned:

- The Grid model is based on the values that were in the initial file (PSSE file of the WAPP grid, prepared between 2019 and 2022 during the ECOWAS Master Plan for Regional Power Transmission and Generation Infrastructure), and updated in terms of new line projects and new power plants projects, as well as load values.
- As such, the various active power set points at generators, as provided in that file, have not been modified: to some extent, these could be modified by the grid operators to avoid, if possible, some overloads using the redispatching possibilities.
- These reinforcements are described in the WAPP BESS Grid Model 2025-2030 Report

7.4.2. Reinforcement costs in 2025

As a first step, the cost of reinforcements for 2025 was calculated on the basis of the reinforcements required for midday and evening operation points.

To determine the cost of line reinforcements, the length of each line has been multiplied by the cost of conductors per km. These costs depend on the conductor parameters (voltage, diameter, material, etc.) and the country. The costs have been simplified by taking the average cost for each type of conductor.

Table 24: Costs of conductors

Conductors			
CABLES	(k€/km)	**LINES**	(k€/km)
C 063kV 185 mm²	200	L 020kV 55mm²	22
C 063kV 240 mm²	250	L 020kV 95mm²	24,2
C 063kV 400 mm²	280	L 020kV 117mm²	25,3
C 063kV 630 mm²	300	L 033kV 55mm²	26
C 090kV 630 mm² ALU	534	L 033kV 95mm²	28,6
C 161kV 1200 mm²	600	L 033kV 117mm²	29,9
C 225kV 1600 mm²	763	L 063kV 228 mm² DT	100
		L 063kV 228 mm² ST	75
		L 090kV 228 mm² ST	122
		L 110 kV DT	176
		L 132kV DT	175
		L150 kV ST	150
		L 161kV 177 mm² ST	100
		L 161kV 253 mm² DT	200
		L 161kV 253 mm² ST	150
		L 225 kV 570mm² ST	196
		L 225 kV 570mm² DT	298
		L 330kV 860 mm² DT	400
		L 330kV 400 mm² ST	300
		L 330kV 860 mm² ST	300

The cost of each reinforcement has therefore been calculated in order to rank these from the most expensive to the cheapest.

Table 25: Estimated cost of reinforcements for 2025

Name	Coun-try	Length	Line Type	Cost/km	Cost	Cost
		km		kEUR /km	Meur	MUSD
LR_CI_Yekepa_Man 225kV_1	Liberia	152	L 225 kV 570mm² ST	196	29,8	32,6
NG_AZARE 1-DUTSE 1 132kV-2	Nigeria	108	L 132kV	175	18,9	20,7
NG_YENAGOA1 GBARAIN1 132kV-3	Nigeria	25	L 132kV	175	4,4	4,8
NG_Kumb T-Agundi 1 132kV-2	Nigeria	11	L 132kV	175	1,9	2,1
NG_AKANGBA 1 IJORA 1 132kV-3	Nigeria	7	L 132kV	175	1,2	1,3
SN_KOUNOU 0-SOCOCI 0 90kV-2	Senegal	3	L 090kV 228 mm² ST	122	0,4	0,4
GN_Kalum 0 Hamdalaye 0 60kv-2	Guinea	1,4	L 063kV 228 mm² ST	75	0,1	0,1

Note that the first reinforcement of the list is already planned for the year 2027 and was part of the CLSG project since its very beginning. For this reason and because it is part of a larger structure that will contribute to strategic interconnections of the west part of the WAPP, it will not be replaceable by a BESS. It is presented in the above table to provide an example.

Also, all the power transfers in the grid model for 2025 and the grid model for 2030 are due to both the distribution of the loads (as these were in the PSSE file provided by the WAPP in early 2023) and the distribution of the injections (generation set-points), which also originate from the PSSE file provided by the WAPP in early 2023. Among the overloads that are observed here, some might be alleviated by redispatching actions to be carried out by the dispatchers. Details can be found in the Grid Model Report (6279 BESS WP 1 Grid Model Status_Rev9.pdf).

7.4.3. Overloaded lines in 2025

The value of the overloads before reinforcement needs to be determined in order to be able to size the necessary batteries. To do this, the overload level of each line in % is identified, as well as the flow passing through the line (in MW). The overload in MW is then calculated as follows:

$$P_{overload} = P_{line} * \frac{\%_{load} - 100}{100}$$

For each case, the highest overload value between the two operating points (midday or evening) has been chosen to correspond to the most extreme cases.

Table 26: Overloads before reinforcements

Name	Time of overload	Overload before reinforcement	Line Load	Overload
		%	MW	MW
LR_CI_Yekepa_Man 225kV_1	Midday	106,7	295,7	19,8
NG_AZARE 1-DUTSE 1 132kV-2	Midday	119,1	139,7	26,7
NG_YENAGOA 1 GBARAIN UBIE 1 132kV-3	Evening	108	136,8	10,9
NG_Kumb T-Agundi 1 132kV-2	Midday	135,7	86,3	30,8
NG_AKANGBA 1 IJORA 1 132kV-3	Evening	100,2	70,8	0,1
SN_KOUNOU 0-SOCOCI 0 90kV-2	Evening	147,3	109,9	52,0
GN_Kalum 0 Hamdalaye 0 60kV-2	Evening	104,8	31,1	1,5

Based on those sets of data, one can draw up a graph ranking the lines according to the cost of reinforcement and the overload to be alleviated. Potentially profitable batteries will be those that avoid very costly reinforcement where the overload is among the lowest.

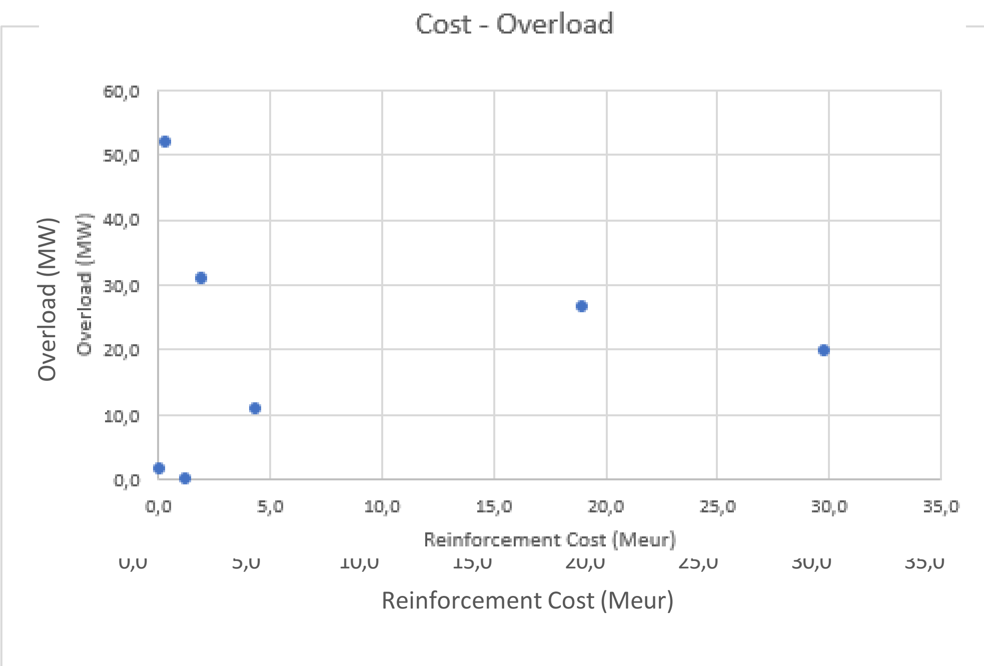

Figure 20 : Representation of lines as a function of cost and overload for 2025

7.4.4. Sizing of BESS 2025

In order to check how BESS can alleviate overloads, a cost comparison is to be carried out. The following lines have been selected and a BESS has been sized to eliminate the overload.

Table 27: Selection of the two reinforcements that are most likely to be postponable or replaceable by BESS.

Name	Cost (Dead)	Cost (MUSD)	Overload (MW)	Moment of occurrence	BESS Sizing (MW)
LR_CI_Yekepa_Man 225kV_1	33,3	36,5	19,8	Midday	20
NG_AZARE 1-DUTSE 1 132kV-2	18,9	20,7	26,7	Midday	130

These are the two lines with the combination of highest reinforcement costs and moderate overload to eliminate. The battery will therefore be placed on the downstream substation, in our case YEKEPA 2 and DUTSE 1. These two substations have different configurations which will influence the sizing of the batteries. The YEKEPA BESS has to consume (charge) during the low cost hours (likely in the night) in order to alleviate the YEKEPA-MAN overload which occurs during midday hours.

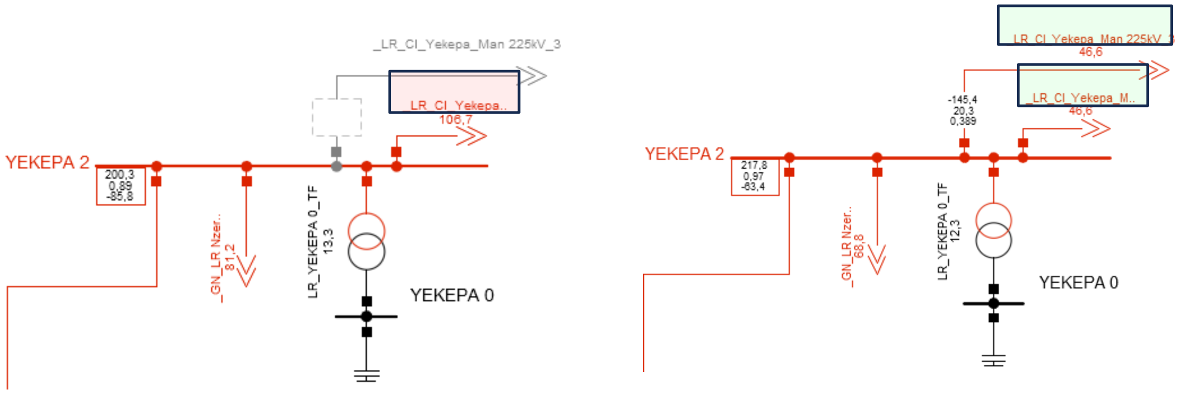

Figure 21 : YEKEPA 2 before and after reinforcement

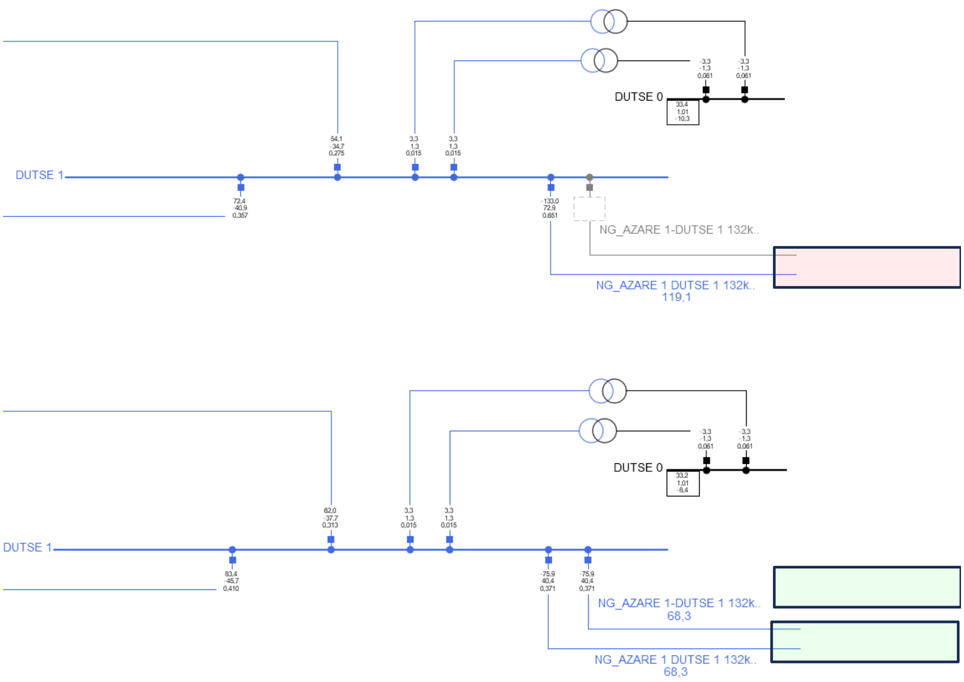

Figure 22 : DUTSE 1 before and after reinforcement

The power of the batteries is initially set at the overload level and then gradually increased if insufficient to obtain a line loading below 100%.

In the case of YEKEPA 2, the overload was 19.8MW and the installation of a battery producing 20MW was enough to bring the line's loading below 100% (reaching in fact 94.6%).

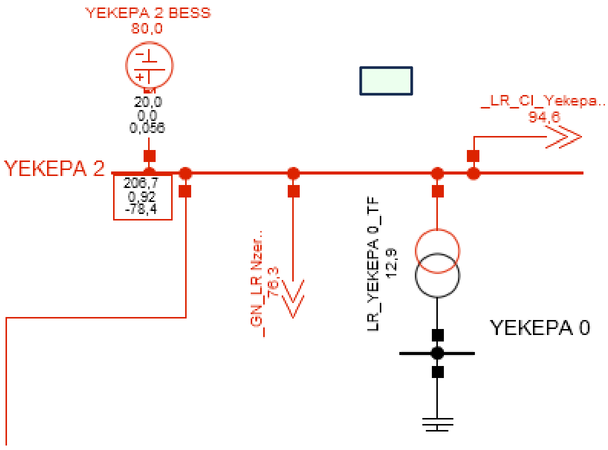

Figure 23 : YEKEPA 2 after battery setting

For the DUTSE 1 substation, the overload was 26.7 MW, but the battery power had to be increased to 130 MW to achieve a line load of less than 100%, in fact here a line load of 99.1%.

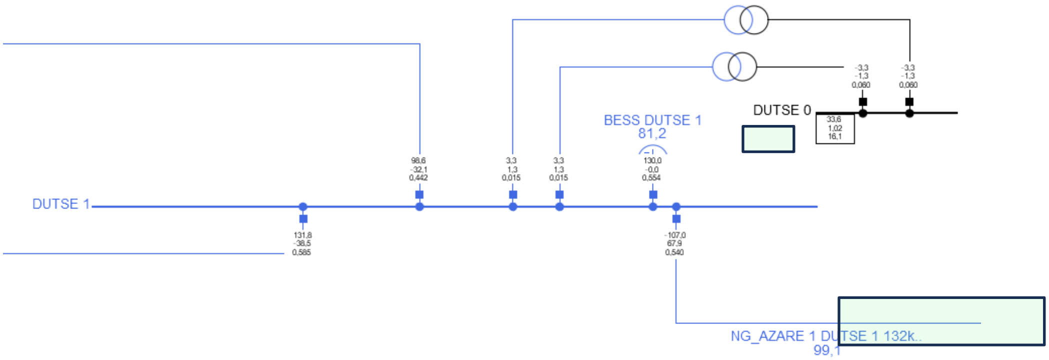

Figure 24 : DUTSE 1 after battery setting

7.4.5. Reducing Congestion by 2030 – Identifying Potential Sites for BESS

The same process has been used for the 2030 reinforcements. The overloads appear during the peak load (evening), and lead to the following reinforcements.

1. Reinforcement costs

Table 28: Reinforcement costs for 2030

Name	Country	Length	Type	Cost/km	Cost	Cost
		km		MUSD/ km	Meur	MUSD
CI_GH Bingerville_Elubo 225kV-2	Ghana	187	L 225 kV 570mm² ST	196	36,7	40,1
GH_CAPE COAST 1a ABOADZE 1 161kV-2	Ghana	66	L 161kV 253 mm² ST	150	9,9	10,8
GH_PRESTEA 2 ELUBO 2 161kV-2	Ghana	75	L 161kV 253 mm² ST	150	11,3	12,3
GN_Kalum 0 Hamdalaye 0 60kv-2	Guinea	278	L 063kV 228 mm² ST	75	20,9	22,8
GN_MATOTO 1 MANEAH 1 110kV-3	Guinea	39	L 110 kV	176	6,9	7,5
NE_MARADI 1a MALBAZA 1 132kV-2	Niger	199	L 132kV	175	34,9	38,2
Ne_Rule 2_1 Rule RD1 132KV-3	Niger	10	L 132kV	175	1,8	1,9
NG_AKANGBA 1 IJORA 1 132kV-2	Nigeria	7	L 132kV	175	1,2	1,3
NG_AKANGBA 1PAPA RD 1 132kV-3	Nigeria	6	L 132kV	175	1,1	1,2
NG_AKOKA 1 IJORA 1 132kV-2	Nigeria	12	L 132kV	175	2,1	2,3
NG_AKOKA 1 OWOROSOKI 1 132kV-3	Nigeria	4	L 132kV	175	0,7	0,8
NG_ALAUSA 1 OKE_ARO 1 132kV-3	Nigeria	17	L 132kV	175	3,0	3,3
NG_AMUWO ODOFIN 1 APAPA RD 1 132kV-2	Nigeria	15	L 132kV	175	2,6	2,9
NG_AYEDE 1 IBADAN NORD 132kV-2	Nigeria	159	L 132kV	175	27,9	30,5
NG_AYEDE 1 JERICHO 1 132kV-2	Nigeria	155	L 132kV	175	27,2	29,7
NG_BENIN 1 IRRUA 1 132kV-2	Nigeria	93	L 132kV	175	16,3	17,8

Name	Country	Length	Type	Cost/km	Cost	Cost
		km		MUSD/ km	Meur	MUSD
NG_EGBIN 1 IKORODU 1 132kV-3	Nigeria	15	L 132kV	175	2,6	2,9
NG_GANMO 1 ILORIN 1 132kV-3	Nigeria	15	L 132kV	175	2,6	2,9
NG_IKEJA IN 1 ILLUPE 1 132kV-3	Nigeria	10	L 132kV	175	1,8	1,9
NG_KADUNA 1 VILLE DE KADUNA 1 132kV-2	Nigeria	8	L 132kV	175	1,4	1,5
NG_KANO 1 ET AGUNDI 1 132kV-2	Nigeria	11	L 132kV	175	1,9	2,1
NG_JOS 1 MAKERI 1 132kV-3	Nigeria	54	L 132kV	175	9,5	10,4
NG_OFFA 1 OMUARAN 1 132kV-2	Nigeria	55	L 132kV	175	9,6	10,6
NG_ONITSHA 1 AWKA 1 132kV-2	Nigeria	42	L 132kV	175	7,4	8,1
N_Papalanto 1 Otta 1 132KV-3	Nigeria	154	L 132kV	175	27,0	29,5
NG_YENAGOA 1 GBARAIN UBIE 1 132kV-3	Nigeria	12	L 132kV	175	2,1	2,3
SN_KOUNOU 0 SOCOCI 0 90kV-	Senegal	3	L 090kV 228 mm² ST	122	0,4	0,4
SN_SOMETA 0 OLAM_0 0 90kV-	Senegal	3	L 090kV 228 mm² ST	122	0,4	0,4
SN_SOCOCI 0 OLAM_0 0 90kV-	Senegal	10	L 090kV 228 mm² ST	122	1,2	1,3

2. Line overloads

Table 29: Line overloads for 2030

Name	Overload before reinforcement %	Line Load MW	Overload MW
CI_GH Bingerville_Elubo 225kV-2	148,8	457,7	223,4
GH_CAPE COAST 1a ABOADZE 1 161kV-2	128,2	180,3	50,8
GH_PRESTEA 2 ELUBO 2 161kV-2	111,3	358,7	40,5
GN_Kalum 0 Hamdalaye 0 60kv-2	117,8	37,6	6,7
GN_MATOTO 1 MANEAH 1 110kV-3	118,6	171,5	31,9
NE_MARADI 1a MALBAZA 1 132kV-2	122,2	78,4	17,4
NE_Rule 2_1 Rule RD1 132KV-3	115,8	69,2	10,9
NG_AKANGBA 1 IJORA 1 132kV-2	178,2	143,7	112,4
NG_AKANGBA 1PAPA RD 1 132kV-3	123,3	106,1	24,7
NG_AKOKA 1 IJORA 1 132kV-2	146,7	172,9	80,7
NG_AKOKA 1 OWOROSOKI 1 132kV-3	101,4	121,3	1,7
NG_ALAUSA 1 OKE_ARO 1 132kV-3	113	143,6	18,7
NG_AMUWO ODOFIN 1 APAPA RD 1 132kV-2	115,2	138,7	21,1
NG_AYEDE 1 IBADAN NORD 132kV-2	115,1	151	22,8
NG_AYEDE 1 JERICHO 1 132kV-2	108,8	95,3	8,4
NG_BENIN 1 IRRUA 1 132kV-2	106,1	141,8	8,6
NG_EGBIN 1 IKORODU 1 132kV-3	110,6	134,8	14,3
NG_GANMO 1 ILORIN 1 132kV-3	102,1	68,9	1,4
NG_IKEJA IN 1 ILLUPE 1 132kV-3	104,9	122,6	6,0
NG_KADUNA 1 VILLE DE KADUNA 1 132kV-2	112,2	102,8	12,5
NG_KANO 1 ET AGUNDI 1 132kV-2	123,8	142,4	33,9
NG_JOS 1 MAKERI 1 132kV-3	114,6	89	13,0
NG_OFFA 1 OMUARAN 1 132kV-2	120,5	58,8	12,1
NG_ONITSHA 1 AWKA 1 132kV-2	113,1	99	13,0
NG_Papalanto 1 Otta 1 132kV-3	103,6	126,8	4,6
NG_YENAGOA 1 GBARAIN UBIE 1 132kV-3	134,8	168,1	58,5
SN_KOUNOU 0 SOCOCI 0 90kV-	186,2	139,7	120,4
SN_SOMETA 0 OLAM_0 0 90kV-	100,6	75,3	0,5
SN_SOCOCI 0 OLAM_0 0 90kV-	116,7	88,1	14,7

In the same way as for 2025, a graph ranking the lines according to the cost of reinforcement and the overload to be discharged is drawn. Potentially, profitable batteries will be those that avoid very costly reinforcement where the overload to be alleviated is low. .

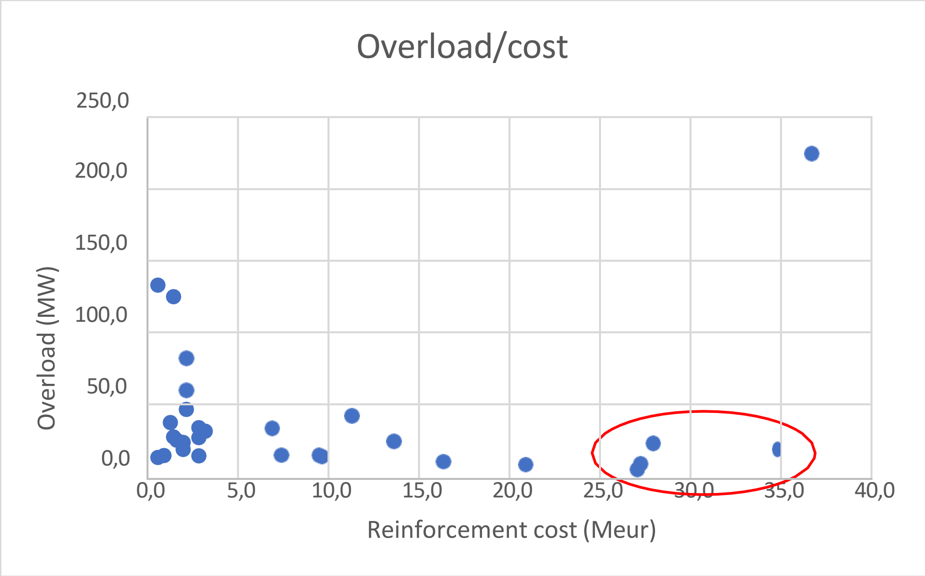

Figure 25 : Representation of lines as a function of cost and overload by 2030

The four most promising overloads were selected to test the congestion relief application with BESS for 2030 (circle in red). After setting the BESS at each station, the power of each BESS was increased until reaching a line load below 100%. The results are presented below..

Table 30: Congestion Relief Results for 2030

Name	Reinf-orcem ent Cost	Reinf-orcem ent Cost	Over-load	Location of BESS	Alimenta tion BESS	BESS cost	Loading the line with BESS, No reinforcem.
	Meur	MUSD	MW	(Substatio n)	MW	MUSD	%
NE_MARADI 1a MALBAZA 1 132kV-2	34,9	38,2	17,4	MARADI 1a	47		99,5
NG_AYEDE 1 IBADANNORTH 132kV-2	27,9	30,5	22,8	IBADAN NORTH	30	26,04	99,7
NG_AYEDE 1 JERICHO 1 132kV-2	27,2	29,7	8,4	JEROCHO 1	10	8,68	99,1
N_Papalanto 1 Otta 1 132KV-3	27,0	29,5	4,6	PAPALANTO1	12		99,8

All these overloads appear in the evening: the BESS must then charge during the hours with low energy cost (potentially at night or during a high PV injection) and discharge during peak charging (in the evening).

7.4.6. Transmission Congestion Relief – Economic Analysis

7.4.6.1. Approach to the Economic Analysis of Transmission Congestion Relief

As indicated in the tables presented in above paragraphs §8.4.3 and §8.4.5,

- the two overloads selected for 2025 are occurring during midday
- all overloads identified for 2030 are occurring during the peak load time, i.e. in the evening.

Two factors have to be taken into account:

1. Even if both a line reinforcement and a BESS can be solutions to alleviate an overload, these two solutions do not provide the same service, because a line usually can transfer about hundreds of MW while a BESS can only alleviate overloads of some dozens of MW. Therefore, the BESS is not supposed to replace a line reinforcement forever, but rather to replace it for a duration of several years. This duration is assumed4 here to be 10 years.

2. Contrarily to a line, a BESS will charge during some hours and discharge during some other hours, likely every day if the overload appears every day. Since the electricity cost is not flat during the day, the cost of charging and the revenue of discharging inevitably play a role.

Since the electricity cost (or price in case of a market) is not known with accuracy, the proposed approach aims at identifying what is the minimum price difference that would make the BESS profitable compared to the "Business as Usual" (BaU) solution (which is the line reinforcement). In this approach, the BESS is supposed to have a 85% efficiency and the charge and discharge duration are expected to be 4 hours each.

The results presented below show that:

- For some cases the BESS is profitable whatever the energy price profile.
- For some other cases, the BESS is profitable (compared to the BaU solution of immediately reinforcing) if at least some difference of energy price brings an additional revenue. The difference of energy price is then indicated, and is called "minimum energy cost difference".

Once the daily energy cost (or price) profile is known for a given location, the reader will be in a position to conclude on the profitability of installing a BESS *for transmission congestion relief*:

- if the energy cost profile shows daily differences larger than the "minimum energy price difference", then installing a BESS will be profitable for Application 4

[4] A more detailed estimate of this deferral duration would require load forecasts beyond 2030 for each substation of the country.

- On the opposite, if the energy price profile does not show daily differences larger than the "minimum energy price difference" during a number of hours long enough to charge the BESS (say 4 hours), then installing a BESS will NOT be profitable for Application 4

Considering that the typical economic lifetime for a transmission line is about 40 years, the approach consists then in the comparison of the discounted global costs of the two solutions:

The NPV of the costs of "BAU" (i.e. the line reinforcement in year X) on 40 years

- The NPV of the costs of "BESS and line deferred to year X+10" on 40 years

A discount rate of 10 % is used for the economic analysis.

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7.4.6.2. Reducing electricity transmission congestion by 2025: economic analysis

The analysis of the two selected transport congestions in 2025 is presented below.

A) LR YEKEPA 2– CI_MAN 2 225 kV

Country: Liberia

Minimum cost difference result: USD 178 **/MWh**

(e.g., in USD/MWh 100 at noon, 278 in the middle of the peak evening)

Such values of costs will not be found in the WAPP context: therefore, a BESS cannot be profitable for relieving the congestion of the existing YEKEPA- MAN 225 kV circuit.

Under these conditions, the economic analysis on 45 years leads to the following results.

Cost NPV (BESS with Line Forwarding)		**(36 740 $)**
	Energy Sales	21 902 $
	Energy Purchases	(13 680 $)
	CAPEX BESS	(27,033 $)
	BESS Operating Expenses	(3 760 $)
	NPV Deferred Line	(14 169 $)
Cost NPV (Line Reinforcement)		**(36 801 $)**
NPV gains (BESS w deferal versus BAU)		61 $

To conclude, this case does not show any profitability range for a BESS for that application.

B) NG_AZARE 1-DUTSE 1 132kV

Country : Nigeria

Minimum cost difference result: 278 **USD/MWh**

(e.g. USD/MWh 100 at noon, 378 at peak in the evening)

Such cost values will not be found in the context of WAPP: a BESS cannot therefore be cost-effective to relieve congestion in the existing circuit NG_AZARE 1-DUTSE 1 132kV.

Some details are set out below, however, using the energy costs above. The 45-year economic analysis leads to the following.

Cost NPV (BESS with line deferral)		**$21.287**
	Energy Sales	302,316 $
	Energy Purchases	(88 918 $)
	CAPEX BESS	(175,716 $)
	BESS Operating Expenses	(24 438 $)
	NPV Deferred Line	8,043 $
Cost NPV (Line Reinforcement)		**$20.889**
NPV gains (BESS w deferal versus BAU)		399 $

To conclude, this case does not show any profitability range for a BESS for that application.

7.4.6.3. Reducing electricity transmission congestion by 2030: economic analysis

For 2030, the selected cases are analysed as follows.

A) NE_MARADI 1- MALBAZA 1_

Country: Niger

Minimum cost difference result: **USD 36.90/MWh**

(e.g., USD/MWh 100 at noon, 136.9 at evening peak)

Under these conditions, the economic analysis on 45 years leads to the following results.

Cost NPV (BESS with line deferral) kUSD		**(23 700 $)**
	Energy Sales (kUSD)	$78.754
	Energy purchases (kUSD)	(61 653 $)
	CAPEX BESS (kUSD)	(27 864 $)
	OPEX BESS (kUSD)	(3,748 $)
	Deferred Line NPV (kUSD)	(9,189 $)
Cost NPV (Line Reinforcement) kUSD		**(23 886 $)**
Gains on NPV (BESS w deferral versus BAU), kUSD		186 $

B) NG_AYEDE 1 IBADAN NORD 1

<u>Country: Nigeria</u>

Minimum cost difference result: **31 USD/MWh**

(e.g. USD/MWh 100 at noon, 131 at peak in the evening)

Under these conditions, the 45-year economic analysis leads to the following results.

Cost NPV (BESS with Line Posting) kUSD		**(18 771 $)**
	Energy Sales (kUSD)	48 102 $
	Energy purchases (kUSD)	(39 353 $)
	CAPEX BESS (kUSD)	(17 786 $)
	OPEX BESS (kUSD)	(2,392 $)
	Deferred Line NPV (kUSD)	(7,342 $)
Cost NPV (Line Reinforcement) kUSD		**(19 085 $)**
Gains on NPV (BESS w deferral versus BAU), kUSD		314 $

C) NG_AYEDE 1 JERICHO 1

<u>Country: Nigeria</u>

Minimum cost difference result: **0 USD/MWh**
Under these conditions (flat-rate cost profile), the 45-year economic analysis leads to the following results.

Cost NPV (BESS with Line Posting) kUSD		**(14 761 $)**
	Energy Sales (kUSD)	$12.240
	Energy purchases (kUSD)	(13 118 $)
	CAPEX BESS (kUSD)	(5,929 $)
	OPEX BESS (kUSD)	(797 $)
	Deferred Line NPV (kUSD)	(7,157 $)
Cost NPV (Line Reinforcement) kUSD		**(18 605 $)**
Gains of NPV (BESS w deferral versus BAU), kUSD		$3.844

This case shows the cost-effectiveness of a BESS operating to reduce congestion, even for a fixed cost profile.

D) NG_PAPALANTO 1 OTTA 1

<u>Country: Nigeria</u>

Minimum cost difference result: **0 USD/MWh**

Under these conditions (flat-rate cost profile), the 45-year economic analysis leads to the following results.

Cost NPV (BESS with Line Posting) kUSD		**(16 236 $)**
	Energy Sales (kUSD)	$14.688
	Energy purchases (kUSD)	(15 741 $)
	CAPEX BESS (kUSD)	(7,114 $)
	OPEX BESS (kUSD)	(957 $)
	Deferred Line NPV (kUSD)	(7,111 $)
Cost NPV (Line Reinforcement) kUSD		**(18 485 $)**
Gains of NPV (BESS w deferral versus BAU), kUSD		$2.249

This case shows profitability for a BESS operating for congestion relief, even for a flat cost profile...

As a whole, knowing that usually the cost difference between low-cost hours and high-cost hours is much higher than USD 35 per MWH, all the above cases are potentially very profitable. These are worth to be analysed more in detail with the grid operators of the related grids, considering the local load forecasts, and the merit order and generation unit scheduling. Note that any plan for Demand Response involving or not Load Aggregators may also affect the above results.

7.4.7. Conclusion on the prospects for Transmission Congestion Relief by BESS

As a conclusion, the application of batteries as a tool for decongesting the electricity network offers significant advantages, in particular by avoiding costly investment in line reinforcements. An analysis of the cost of the reinforcements required over the next few years will enable to determine the priority investments among which installation of lines and the installation of batteries. Based on the cost of reinforcements and the overload to be alleviated, the batteries are strategically positioned to optimise the use of existing lines and postpone the investment in new costly power lines.

The effectiveness of this method is closely linked to the specific topology of the grid, the power of the batteries required, and the level of the overloads identified in the model (itself being linked to the assumed generation dispatch). Nonetheless, there are some very encouraging results such as JERICHO 1 and PAPALANTO 1 in 2030 where very costly reinforcements can be avoided by installing batteries with a power around 10MW and a capacity of 4 hours.

7.5. Black start application

BESS, if they are equipped with grid forming inverters, can be used to provide black start services, i.e. to allow transmission system operators to reconstruct the grid in the event of a blackout. Due to their very fast reactivity, BESS can also help further in the process by providing frequency control during reconstruction.

This study has been conducted with the assumption that the WAPP grid is completely synchronized as of 2025 and very stable, i.e. with very few blackouts. In that case, the business case for installing BESS for the black start application only is not interesting. Indeed, compared to other black start units such as diesel generators, BESS are very capex intensive, and they are thus not competitive.

However, if BESS are installed for other applications, such as frequency control or energy-time shift, they should ideally be designed with the possibility to be used for black start applications as well.

7.6. Combined Applications

A BESS can, with the same technical specifications, prove interesting for many applications. This brings a lot of flexibility to the network operators if the latter owns the battery or has exclusive use of it. Indeed, even if the BESS has for example been installed to carry out frequency regulation it can also be used by the operator for one of the other applications (voltage regulation, energy time-shift, congestion relief transmission or black start) depending on network needs. This can happen occasionally, in a very specific or exceptional situation, or on a more lasting basis if the needs of the network evolve. For example, if frequency regulation requirements decrease structurally, the BESS can be “reprogrammed” for another application. This flexibility is a considerable advantage for managing evolving networks.

If the application combination is thought out from the start, it can also improve the business case of the BESS project and reduce costs for the network operator.

There are three ways to combine BESS, which are discussed in this section.

1) Combination of two applications at the same time

In this case, a BESS of the same size (or slightly bigger size) can be used for two applications at the same time. This means that the revenues of both applications can be obtained with a similar capex investment as in the single use case. For example, it is possible to combine active power applications (e.g. frequency control or energy time-shift) with reactive power applications (e.g. voltage control) using the same BESS.

If an application requiring active power is considered and for which a positive business case has been confirmed, for example frequency regulation or energy time-shift, an assessment can be carried out to see if the same BESS could be used for voltage control at a limited additional cost.

Assuming that the same quantity of MW and Mvar have to be provided at all times, the power conversion system and grid connection of the BESS will have to be oversized (higher MVA). At a $\cos \varphi = \cos 45° = 0.707$, which gives equal MW and Mvars, the PCS and grid connection will have to be oversized by 41% compared to the original BESS.

With a cost estimate of 200 k$/MVA for the PCS and grid connection scope, the voltage control functionality can be added at an additional cost of 82 k$/MVA compared the initial BESS used for active energy application only.

For a 30 MVA BESS, for example, this means oversizing the PCS and grid connection to 42.3 MVA (while keeping the same battery bank, therefore the same MWh's) for an extra cost of 2460 k$.

If this figure is compared with the first row of the table in section, seeing that the use of capacitors still remains much cheaper than BESS (657 k$ for a 30 Mvar capacitor) but that BESS could possibly compete with reactances (2332 k$ for a 30 Mvar reactance).

2) Combination of two applications at different times

In this case, a same BESS is used at some moments for one application and at other moments for another application. It could in theory be possible to combine some of the applications in such a way, for example voltage support and grid congestion relief if their needs never occur at the same time. However, the confirmation of this possibility requires a detailed analysis of each case, which is out-of-scope of the current study.

For the case of black start, as mentioned earlier, it is clearly conceivable to use BESS that are normally dedicated to other applications, during grid restoration after a blackout.

3) Combination of two applications by dividing a larger BESS

It is also possible to combine several applications on one BESS site by adding the different power and energy requirements of each application. In that case power/energy is not shared among applications but the project can still benefit from some economies of scale. To give an example, if two applications each require a 50MW/200MWh BESS, then one could install a single 100MW/400MWh system which will be virtually divided into two systems. This will create some savings in terms of project development, sourcing costs, etc. Since the savings are relatively small, it is usually required that each stand-alone application already has a positive business case to begin with.

7.7. Other results

7.7.1. Dynamic stability study

7.7.1.1. Objective

The objective is here to run dynamic simulations for assessing the risk of frequency collapse in case the largest single mode event occurs. By analysing the list of power plants and the active power sudden decrease in case of a generation tripping, the largest event proves to be the generator tripping of the CIPREL5 (Atinkou) Gas unit in Côte d'Ivoire, because its tripping also provokes the sudden reduction of the power generated by the steam turbine that is part of the same combined cycle. The total power lost is then 390 MW.

7.7.1.2. Dynamic Stability Approach

For both the 2025 evening and the 2025 midday case, the following paragraphs will compare two cases for the tripping of the largest single mode power tripping: 390 MW at CIPREL 5. The objective here is to check that the frequency behaviour is acceptable even in pessimistic conditions. Since BESS are known to control the frequency much faster than power plants, the pessimistic conditions are represented by a frequency control based on power plants, i.e. not based on BESS. In many large interconnected systems, about one power plant out of 4 is controlling the frequency. It is not clear what is prensently the situation in the WAPP system. Therefore the following two cases are pure (pessimistic) assumptions and do not pretend to represent the present dynamic behaviour of the WAPP system. These differ as follows:

- The case where a "long list of power plants" are controlling the frequency
- The case where a "short list of power plants" are controlling the frequency

A subset has been selected for each country, almost randomly since no data has been available on the subject. For the long list, a list of 29 "controlling" plants is proposed as follows:

Plant_CI KOSSOUG1		**Plant_NG_EGBIN2 G1-G4**
Plant_GM BRIKAM1G1-G3		Plant_NG_GEREGU3 G1-G6
Plant_GN AMARIA_G1		Plant_NG_JEBBA GS3 G1-G6
Plant_GN FOMI_G1-G3		Plant_NG_KAINJI G1-G3
Plant_GN GRKINKON_G		Plant_NG_OMOTOSHO G1-G2
Plant_GN KALETA_G1-G3		Plant_NG_SHIRORO3 G1-G3
Plant_GN KOUKOUTAMBA_G1-G2		Plant_NG_ZUNGERU G1-G4
Plant_GN MORISANAKO_G		Plant_SN 0GT1CAPB_G1-G2
Plant_GN SOUAPITI_G1-G4		Plant_SN 0GT1KOUN_G1-G2
Plant_GW BISSAU1G3 sym_41_3		Plant_SN 0ST1CAPBG1
Plant_ML GOUINA G1-G2		Plant_SN 0ST1KOUNG1

Plant_ML MANANTALI_G1-G2		Plant_SN KAHONE3G1-G2
Plant_NE GOUDELG12		Plant_SN KAYAR_11G1
Plant_NE saw K1-G4		Plant_SN SAMBAN G3-G4
Plant_NE Sulkad G1-G3		

The short list of frequency controlling plants is the following, limited to 4 power plants:

Plant_NG_EGBIN2G1-G4
Plant_NG_GEREGU3 G1-G6
Plant_NG_KAINJI G1-G3
Plant_CI KOSSOUG1

The Grid Model is very flexible: any list of dispatchable power plants can be considered for frequency control.

As a reminder of the Application 1, BESS investments for frequency control are not mandatory but are profitable provided these replace the primary reserve of the power plants that presently control the frequency. The chapter on Application 1 (BESS for Frequency Control) clearly shows that BESS are more advantageous than thermal power plants for controlling the frequency.

2025 Evening case- tripping GT unit of Ciprel 5 (Atinkou) plant, Côte d'Ivoire (390 MW)

With the **"long list of controlling plants ",** the behavior appears as follows:

The frequency tends to stabilize at 49.8 Hz, with some undamped oscillations (before or without introducing Power Systems stabilizers, which are present in some production units, into the model).

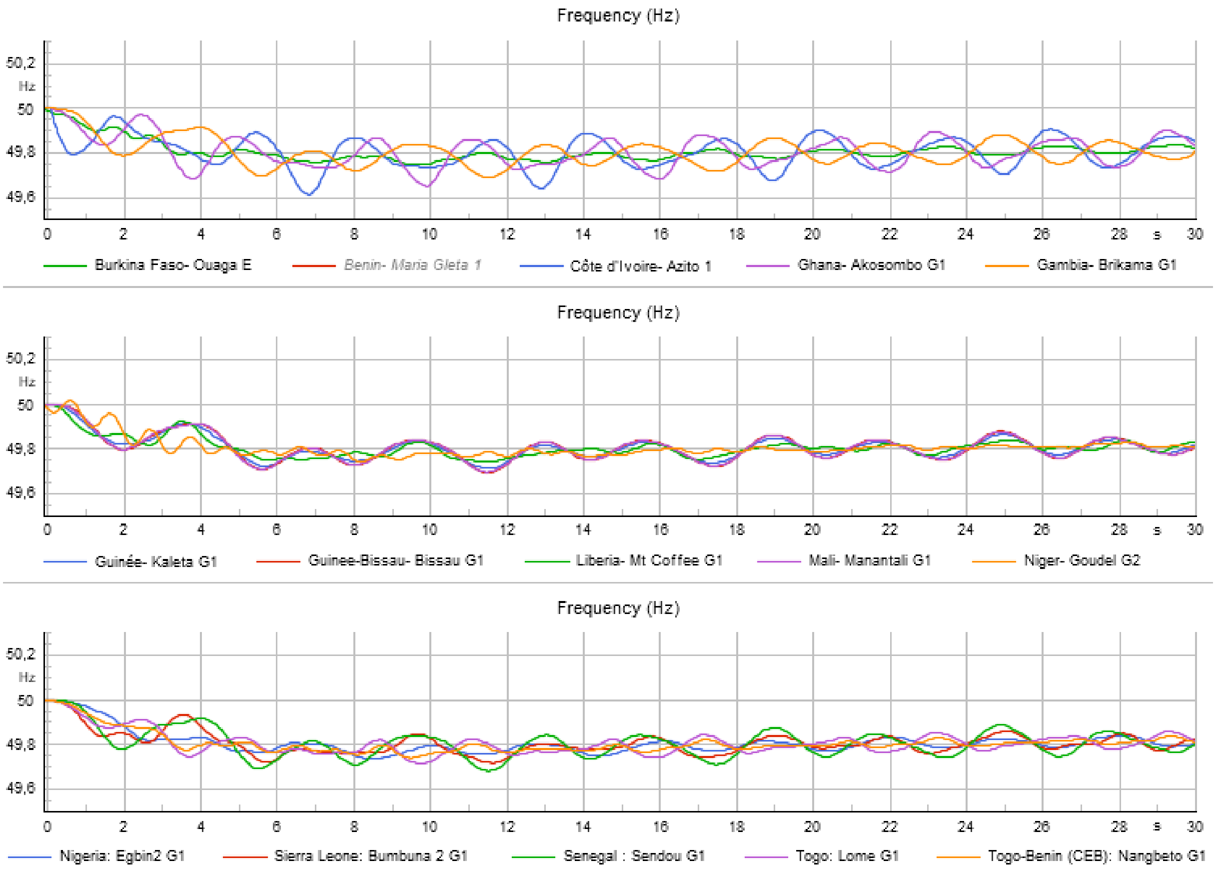


Figure 26 : Evening Frequency, GT trips at CIPREL5 390 MW (Côte d'Ivoire), long list of controlling PP

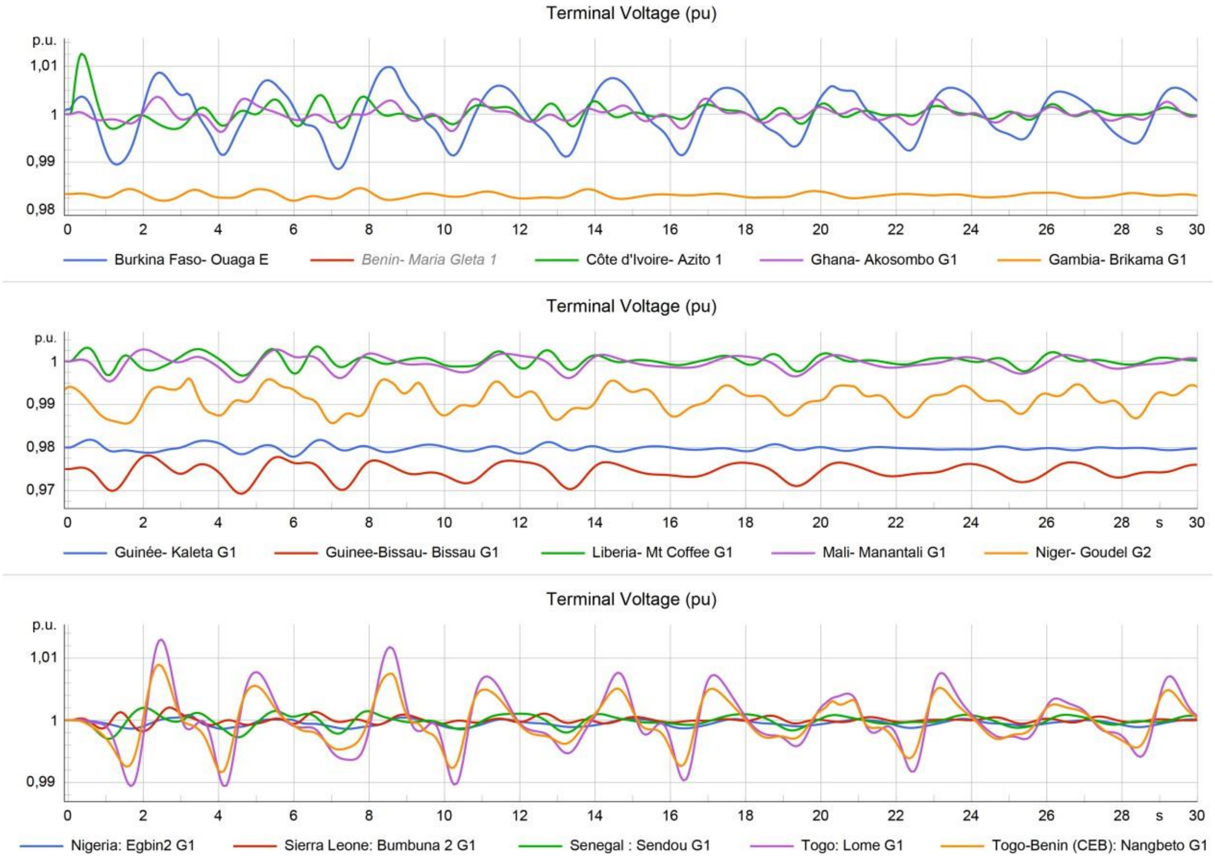


Figure 27 : Evening Voltages, GT trips at CIPREL5 390 MW (Côte d'Ivoire), long list of controlling PP

When the frequency controlling plants are those on the **short list of frequency controlling plants** (see above), the behavior is as follows:

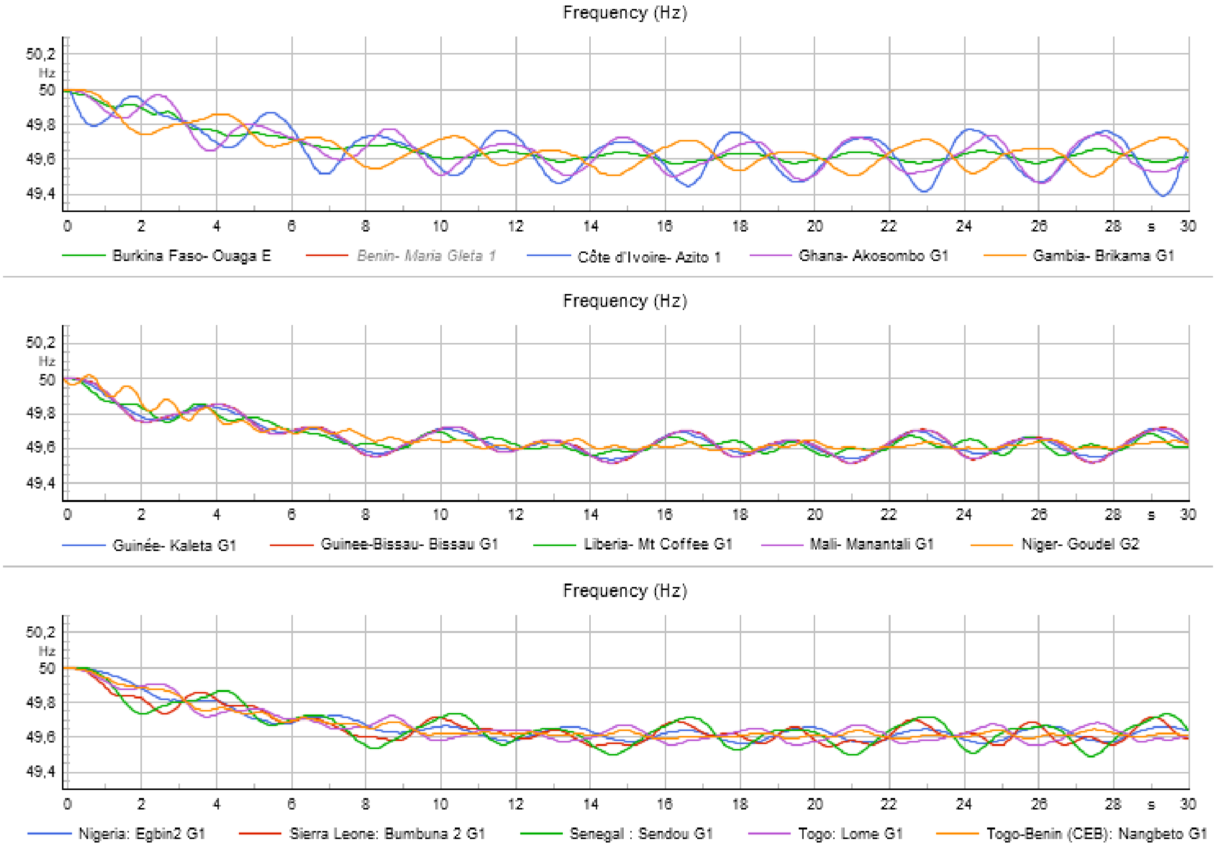


Figure 28 : Evening Frequency, GT trips at CIPREL5 390 MW (Côte d'Ivoire), short list of controlling PP

The frequency tends to stabilize at 49.6 Hz, with some undamped oscillations.

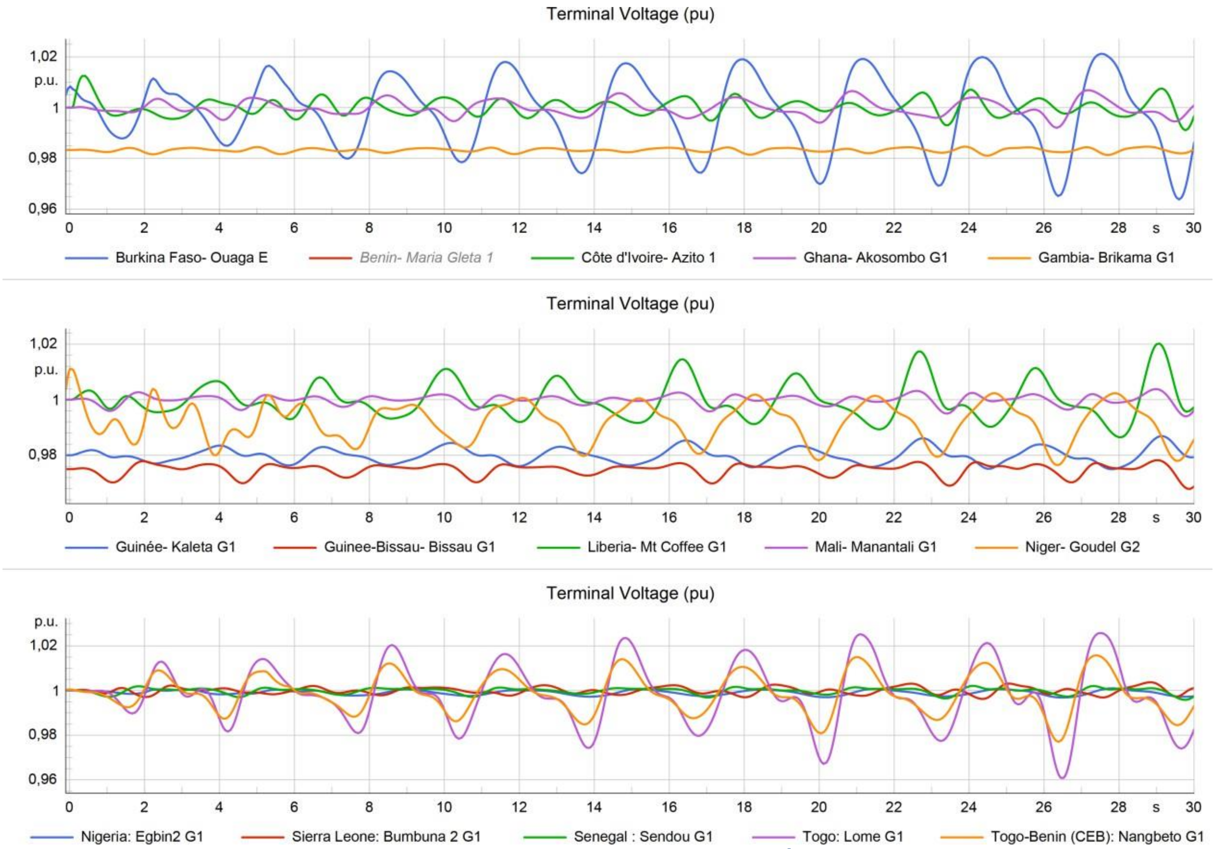


Figure 29 : Evening Voltages, GT trips at CIPREL5 390 MW (Côte d'Ivoire), short list of controlling PP

2025 Midday - Tripping of GT unit Ciprel 5 power plant (Atinkou), Côte d'Ivoire (390 MW)

With the **"long list of frequency controllling plants",** the behavior appears as follows.

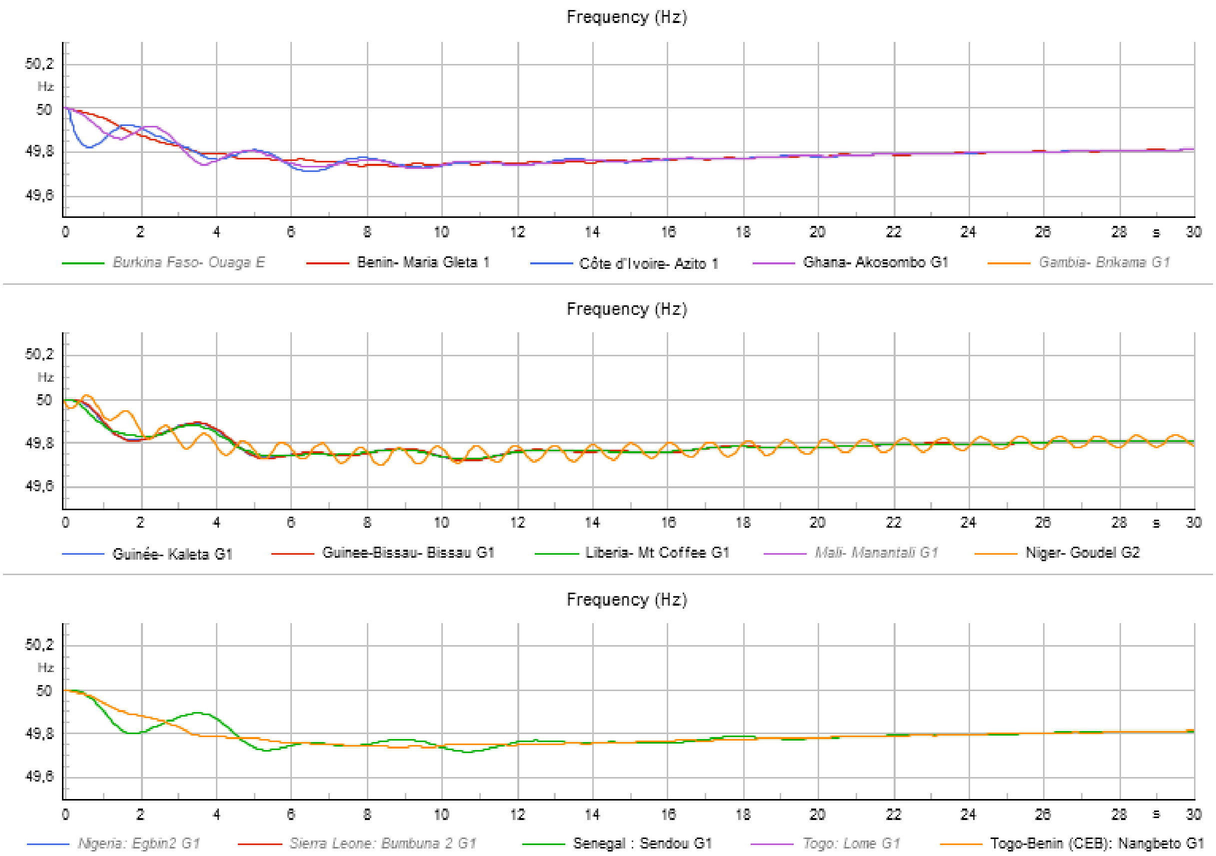


Figure 30 : Midday Frequency, GT trips at CIPREL5 390 MW (Côte d'Ivoire), long list of controlling PP

The frequency tends to stabilize at 49.8 Hz. In this context, voltages also show some oscillations. These remain within acceptable ranges, according to the following curves.

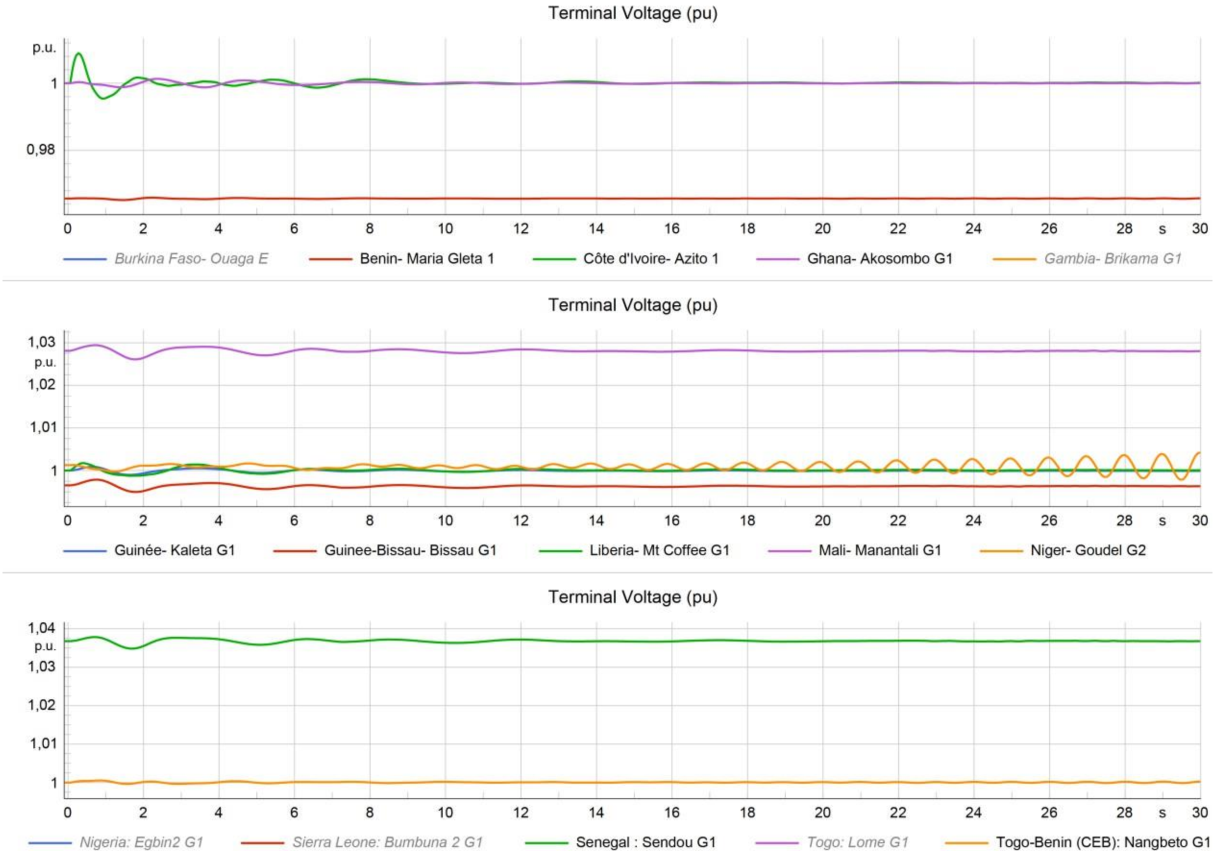


Figure 31 : Midday Voltages, GT trips at CIPREL5 390 MW (Côte d'Ivoire), long list of controlling PP

When only the "**short list of plants**" controls the frequency, the control is less efficient and the behavior shows a greater frequency drop, as follows.

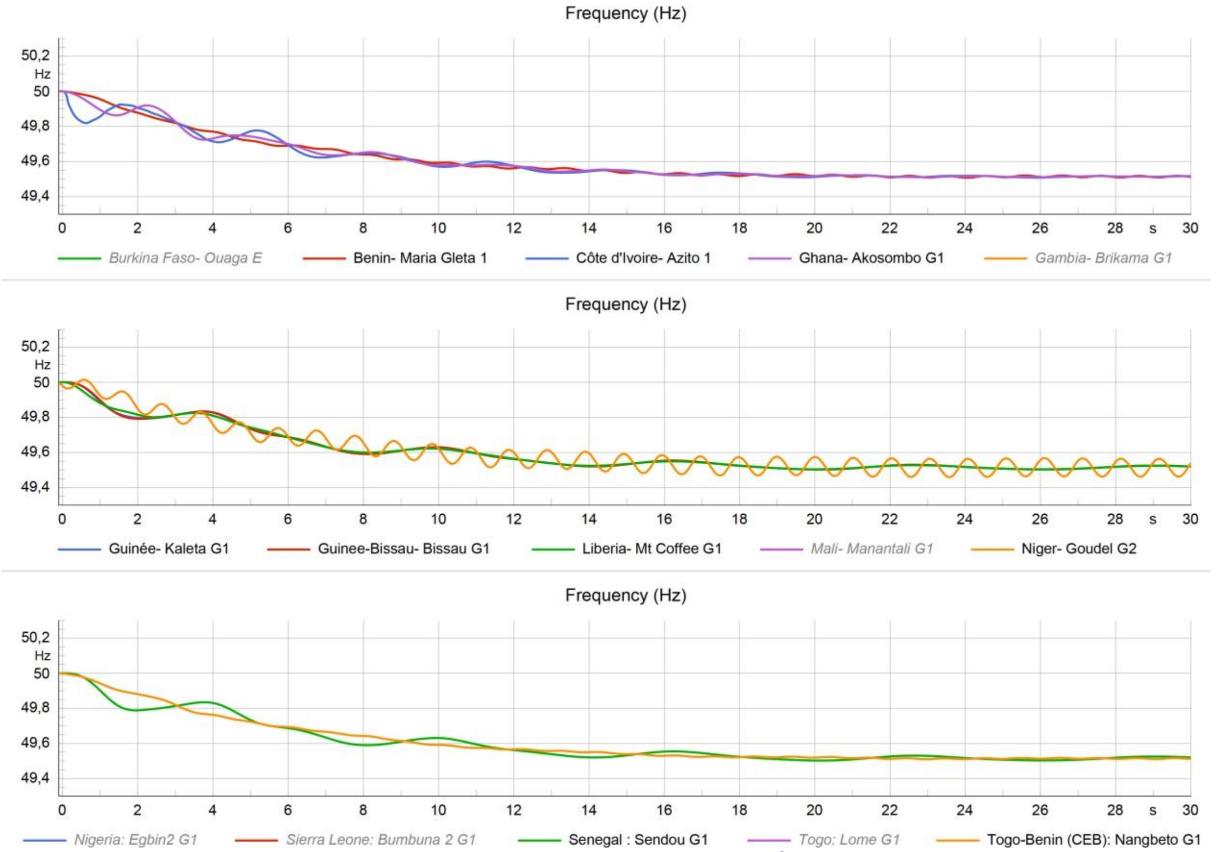


Figure 32 : Midday Frequency, GT trips at CIPREL5 390 MW (Côte d'Ivoire), short list of controlling PP

The frequency tends to stabilize at 49.6 Hz, with some undamped oscillations.

In this context of less efficient frequency control, the voltages also have oscillations and some are not damped, which is a sign of instability.

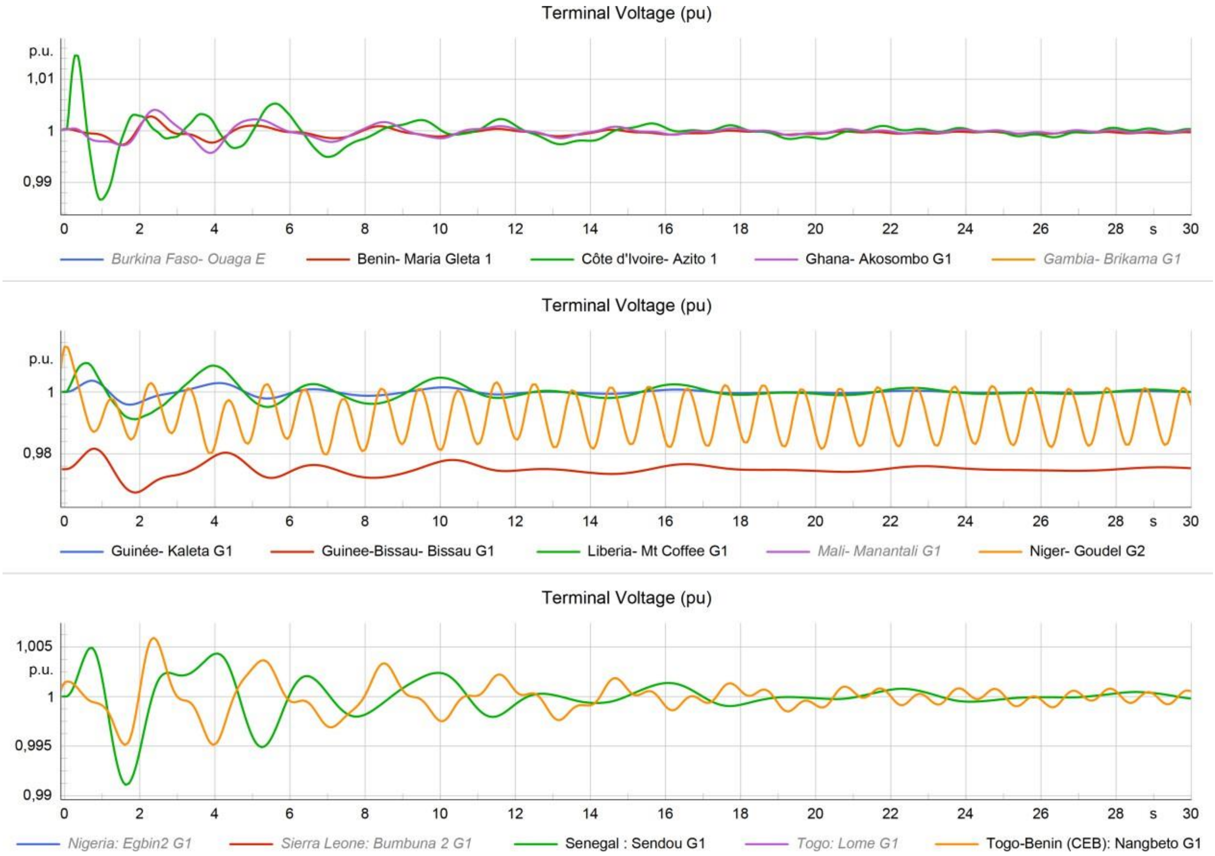


Figure 33 : Midday Voltages, GT trips at CIPREL5 390 MW (Côte d'Ivoire), short list of controlling PP

This leads to conclude that concentrating the frequency control on only some power plants (like here 4 power plants, like 3 power plants of Nigeria and one in Côte d'Ivoire) is not an acceptable option: the frequency control has to be distributed on the whole WAPP zone.

7.7.1.3. Conclusion

The simulations have shown that for the two sets of power plants defined as controlling the frequency, the frequency can be kept above the 49,5 Hz level.

This level is well above the 49,0 Hz threshold under which the Automatic Frequency Load Shedding (AFLS) starts to operate and causes some Energy Not Served.

When the list of power plants controlling the frequency is limited to a few power plants the voltage behaviour show undamped oscillations or increasing oscillations, which is an unacceptable behaviour. Hence, provided that the frequency control is well distributed on the whole ECOWAS grid, the grid of 2025 can therefore be considered as safe with regards to the dynamic stability.

7.7.2. Transient stability study

7.7.2.1. Objective

The objective is to simulate how the system reacts to strong events like short circuits. Considering the typical delay of action of protections and the breaker activation time, the short circuit simulated is of 100 ms duration. The location of the proposed short-circuits is at 50% of a selection of interconnections line. These will be assessed first on the Midday case where less power plants are controlling the voltage plan, and therefore there are, at that moment, less nodes with controlled voltage (conversely longer distances, higher impedance between these, and potentially higher phase difference resulting in more risk of loss of synchronism, i.e. out-of-step).
After the Midday case, the Evening case is to be analysed as well.

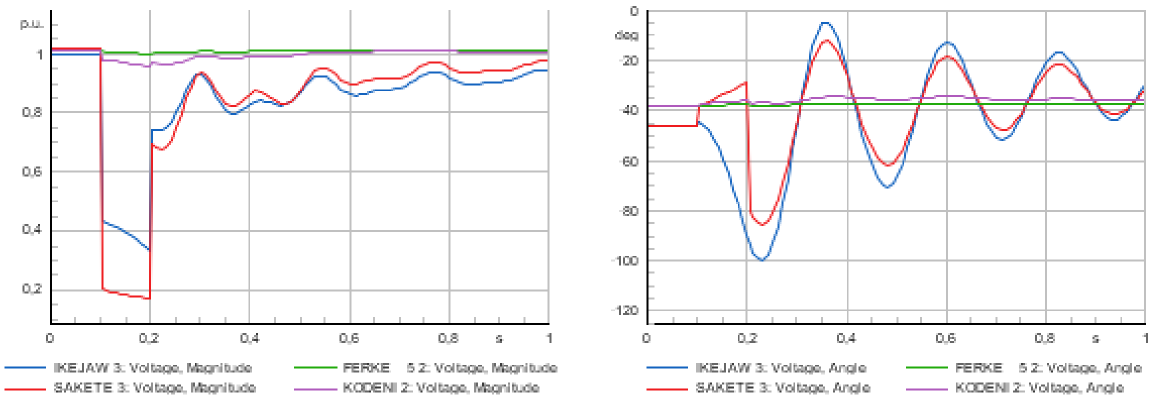
7.7.2.2. Approach

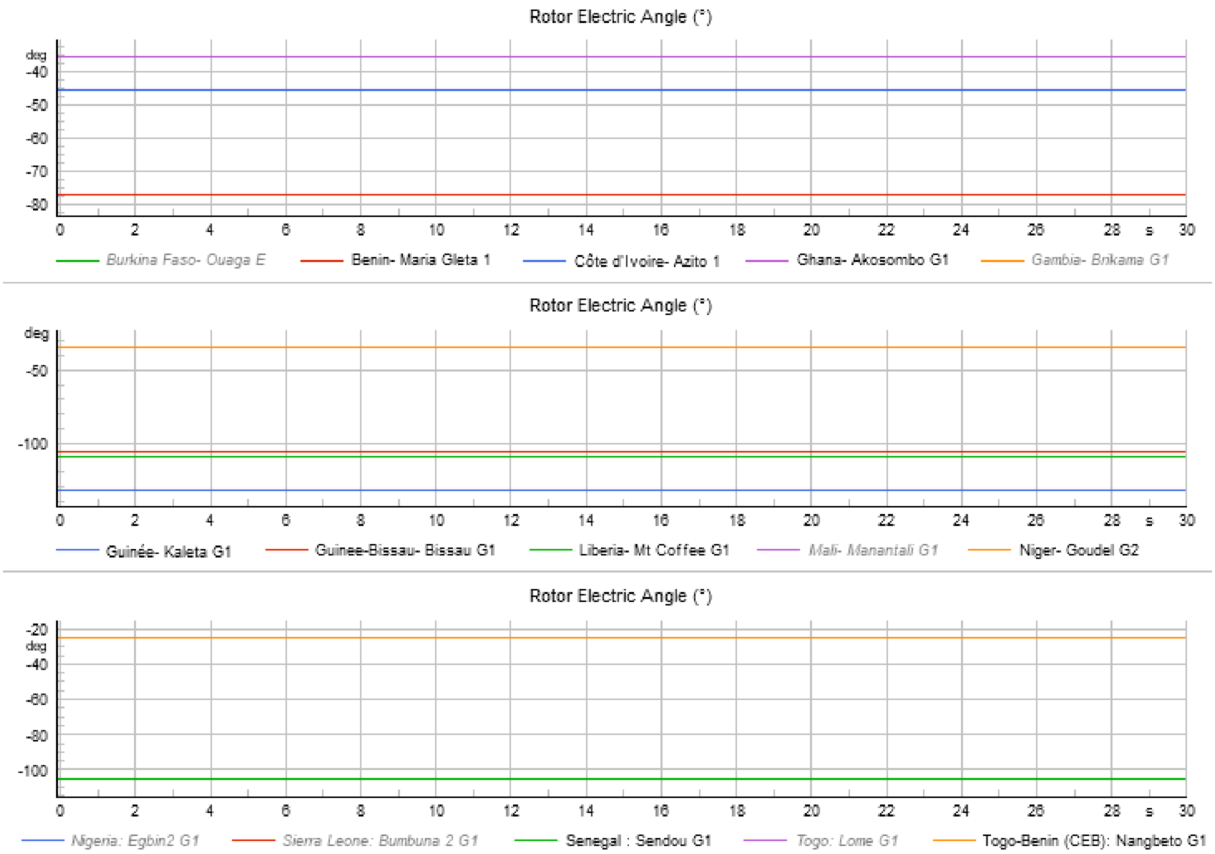
The proposed substations close to where short-circuits will be simulated are the following:

1. Nigeria: Ikeja West (line to Sakete, Benin)
2. Côte d'Ivoire: Ferke (line to Kodeni, Burkina Faso)
3. Mali: Kayes (line to Bakel, Senegal)
4. Guinea: Linsan (line to Kamakwie, Sierra Leone)

7.7.2.3. Results for 2025 Midi (PV Injection Peak)

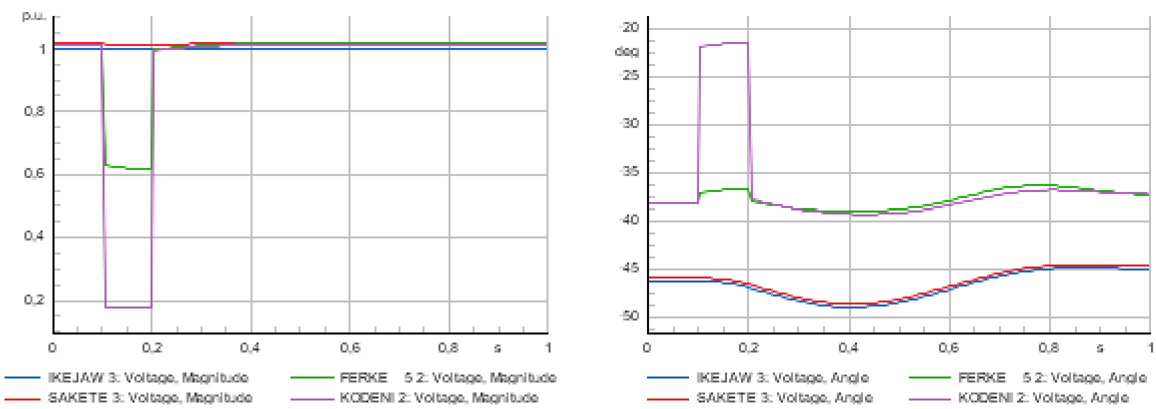
1. **Nigeria: Ikeja West (line to Sakete, Bénin)**

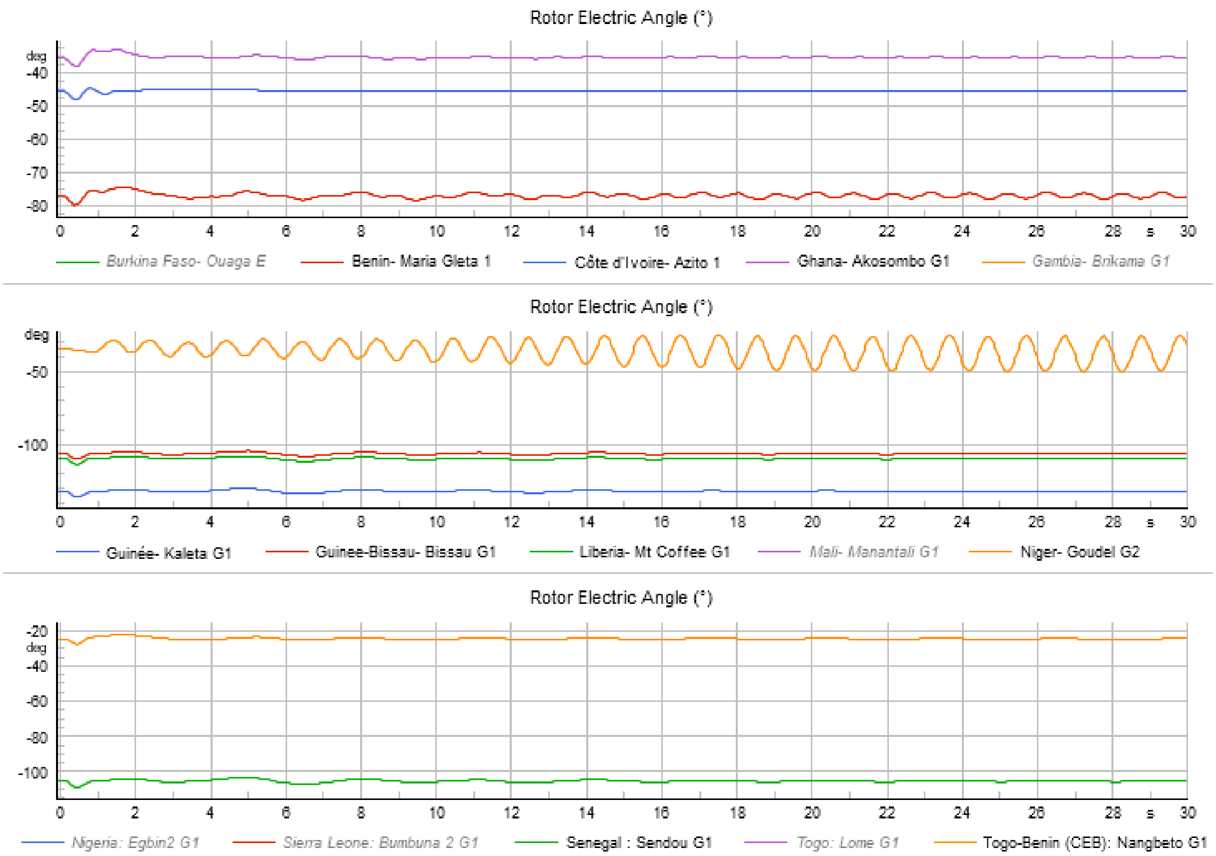




Transient stability is confirmed: there is no loss of synchronism.

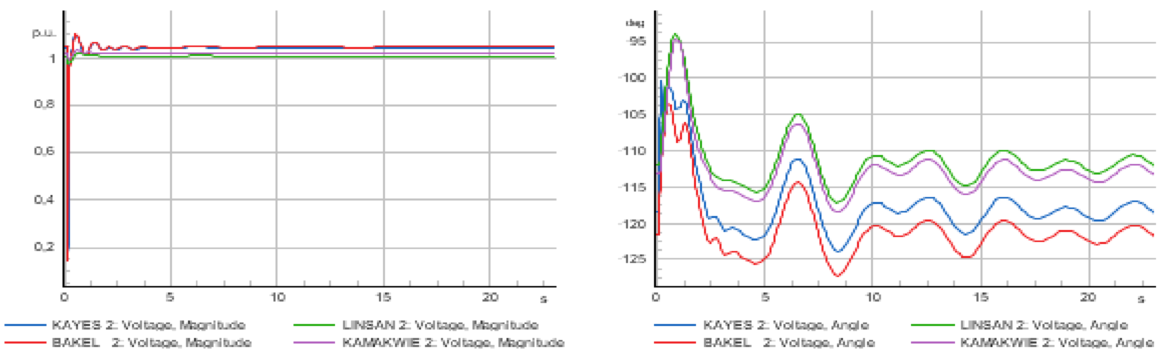
2. **Ivory Coast: Ferke (line to Kodeni, Burkina Faso)**

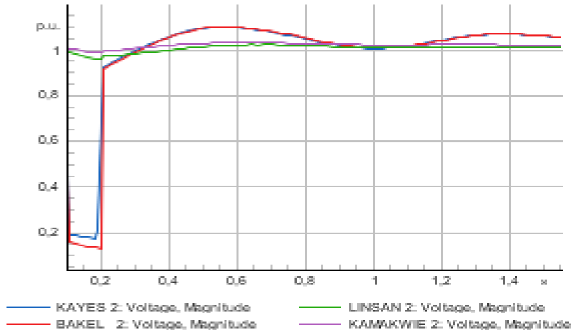


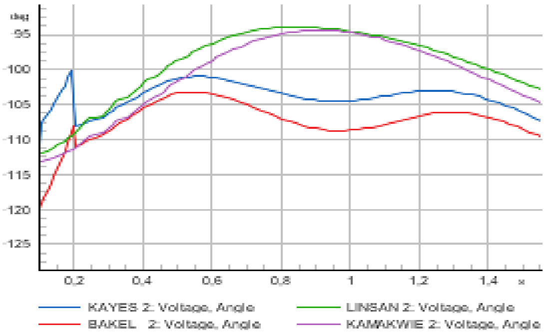


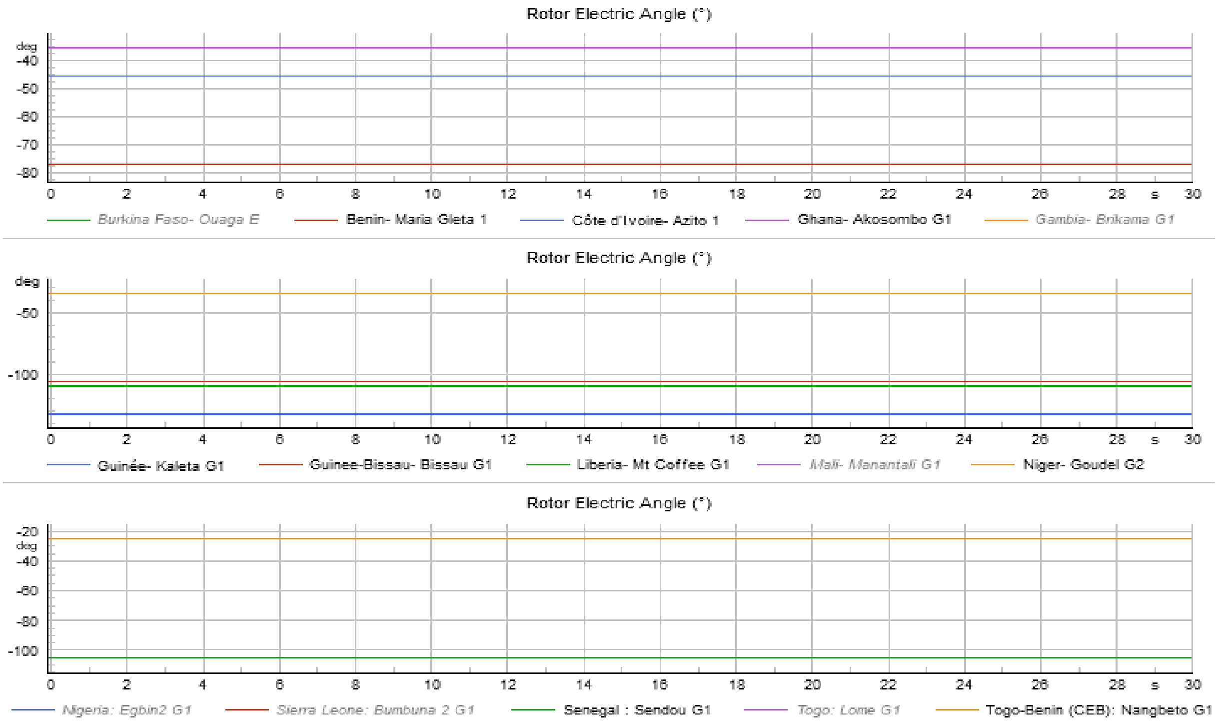
Transient stability is confirmed: there is no loss of synchronism.

3. **Mali: Kayes (line to Bakel, Senegal)**



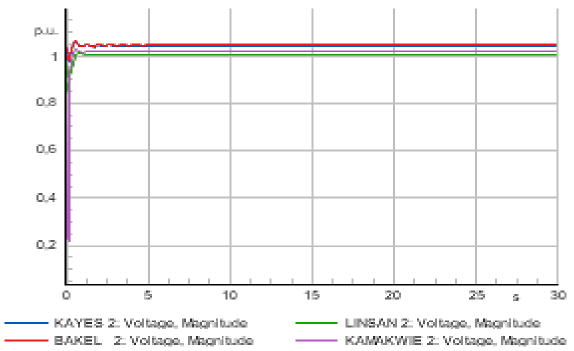


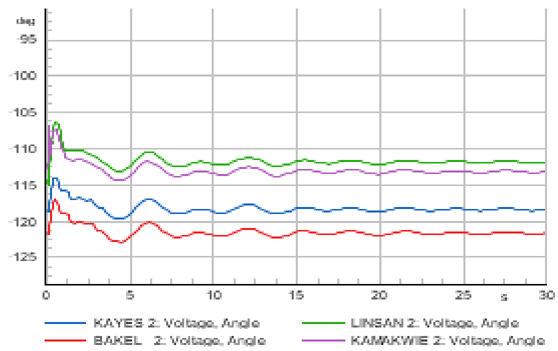


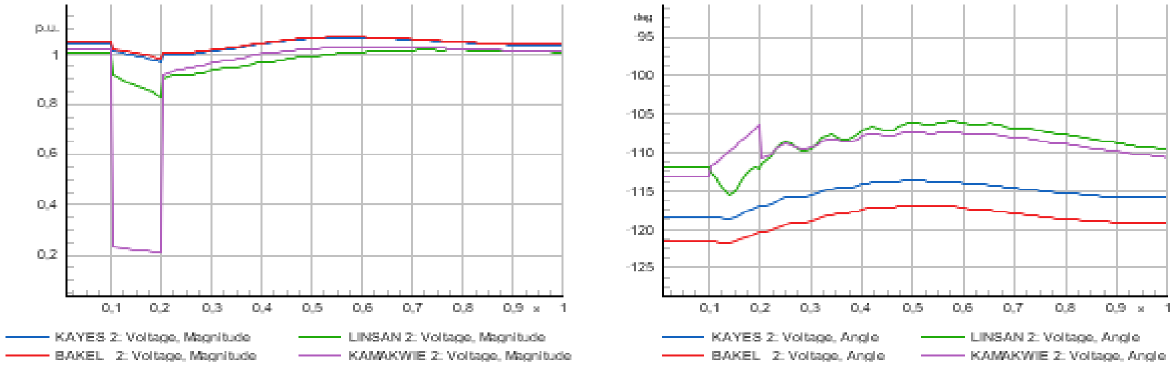


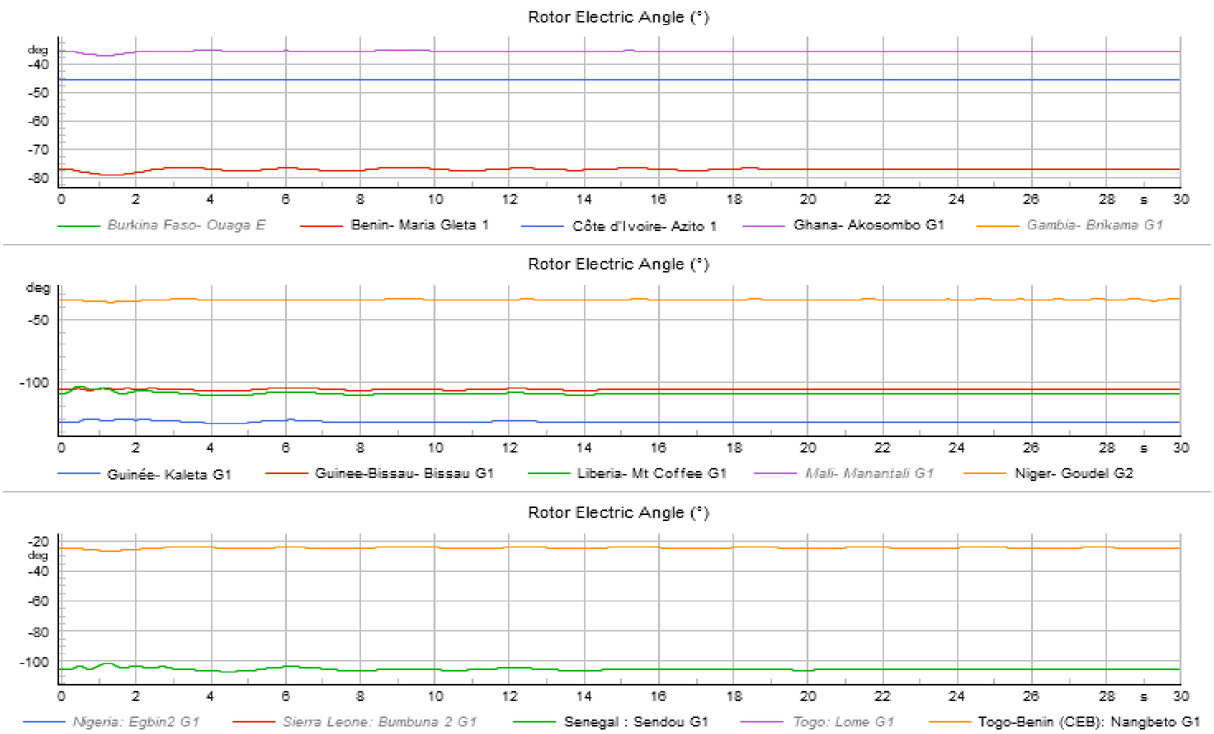
Transient stability is confirmed: there is no loss of synchronism.

4. Guinea: Linsan (line to Kamakwie, Sierra Leone)





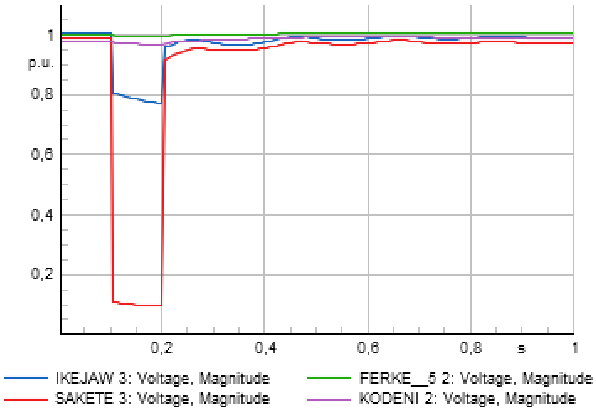


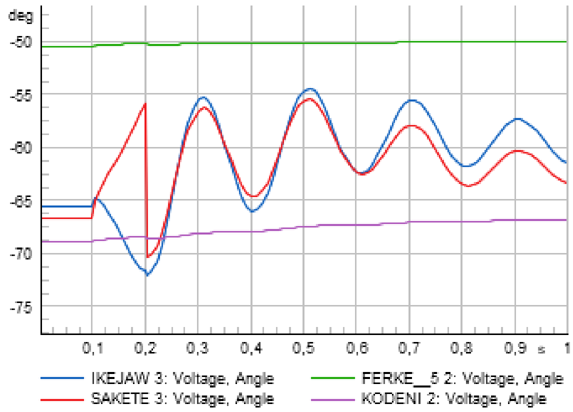


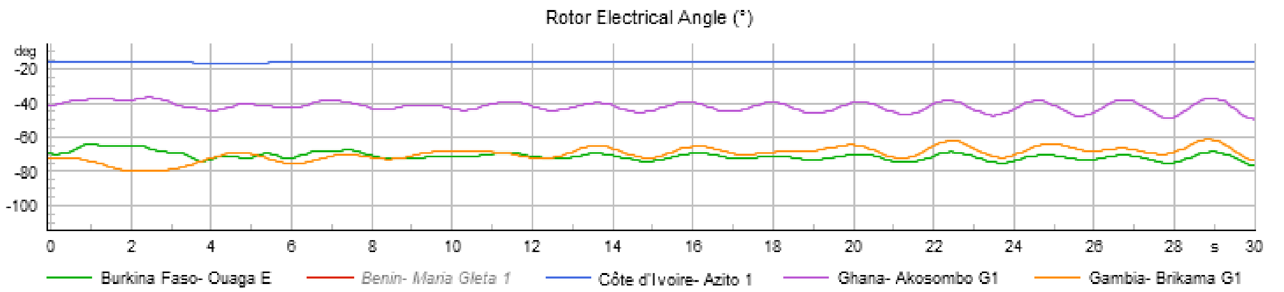
Transient stability is confirmed: there is no loss of synchronism

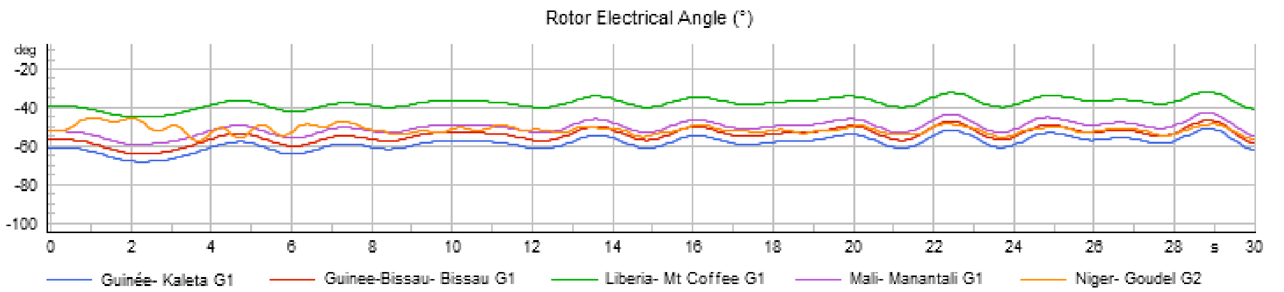
7.7.2.4. Results for 2025 Evening (Peak Load)

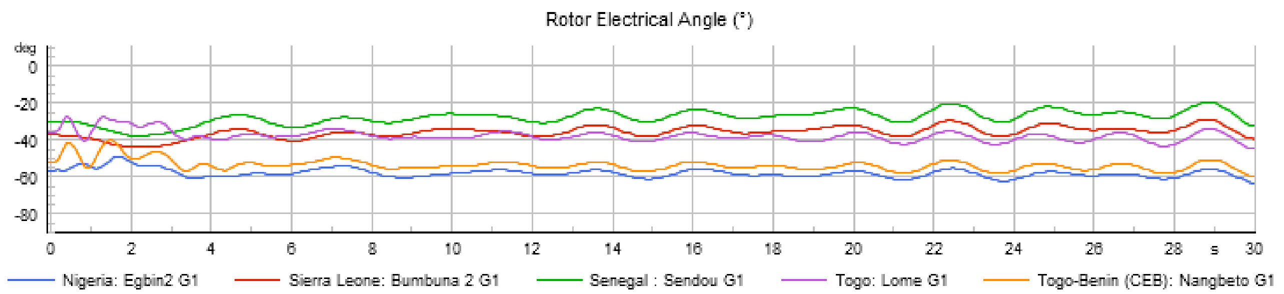
1. **Nigeria: Ikeja West (line to Sakete, Bénin)**





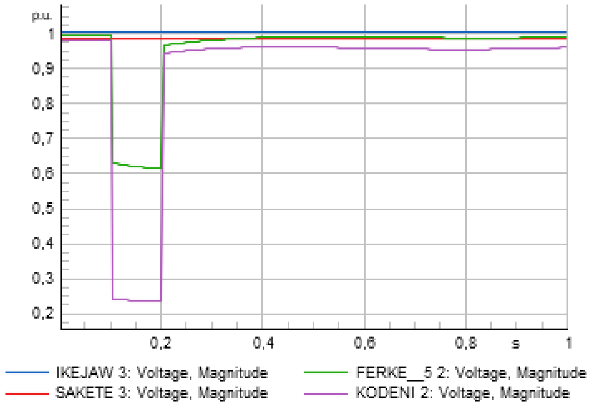


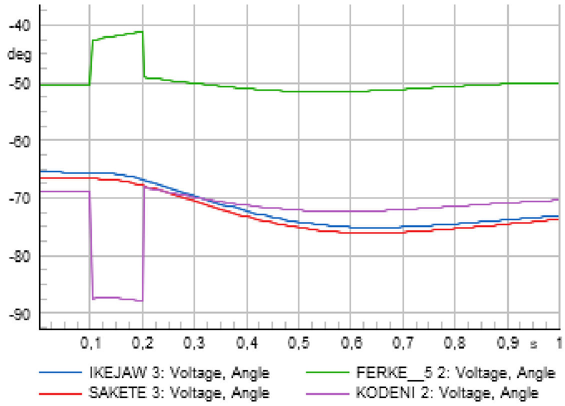


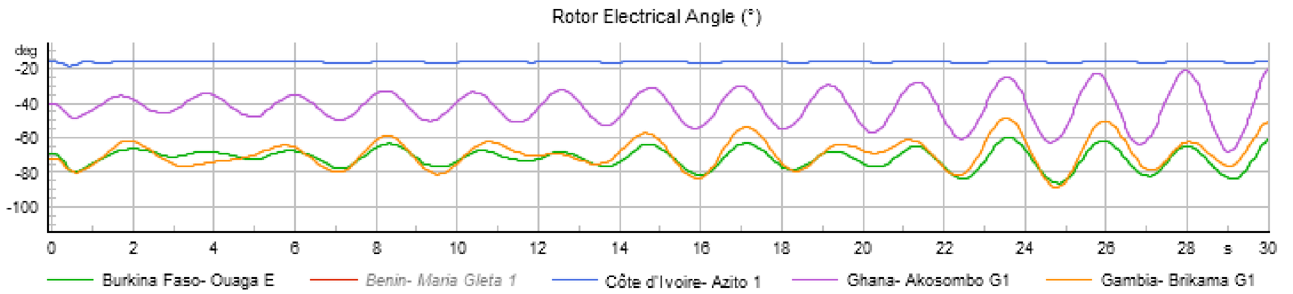


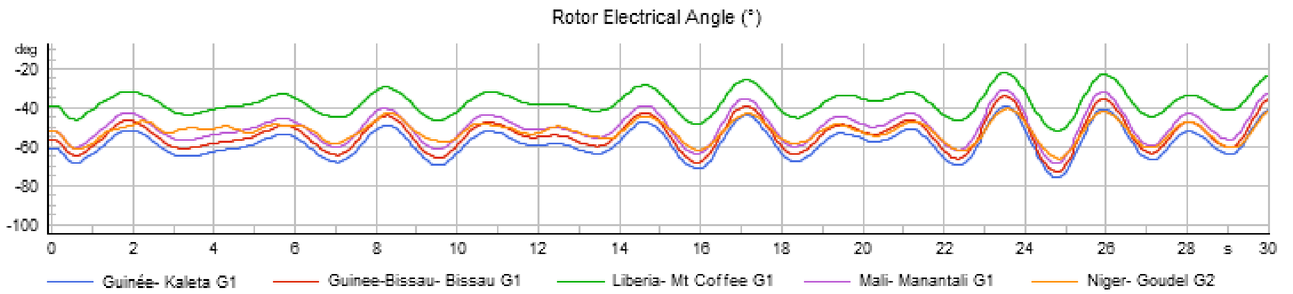
Transient stability for that event is confirmed, only very slight oscillations are appearing. showing the interest for more detailed dynamic data analysis and possibly for Power System Stabilizer (PSS) modelling and tuning. Note that in the case where a unit (BJ_BIOM_KA) is absorbing some reactive power (here 5 Mvar), it proves to lose synchronism at t= 14.3 s. The above simulation is made with the generator in PQ mode, so that it does not absorb reactive power. As a result it does not lose the synchronism.

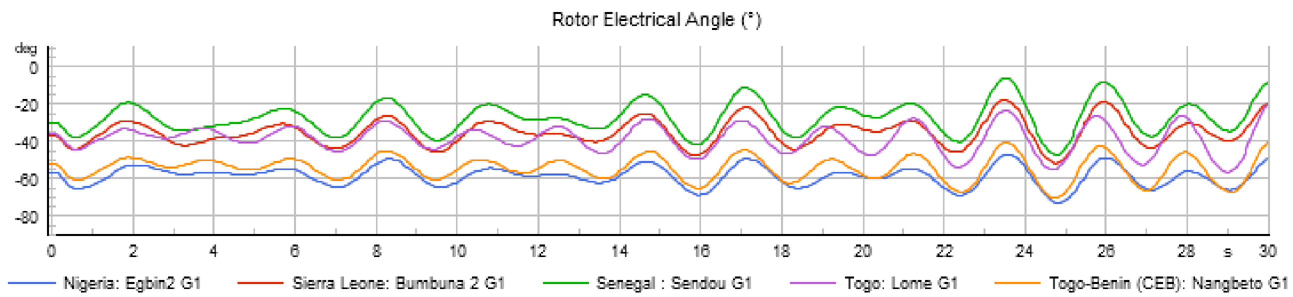
2. **Côte d'Ivoire: Ferke (line to Kodeni, Burkina Faso)**







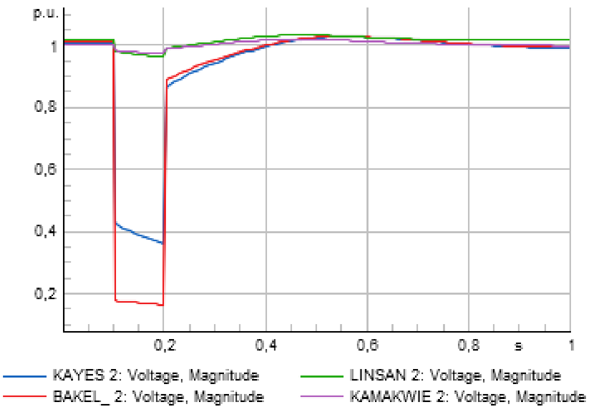


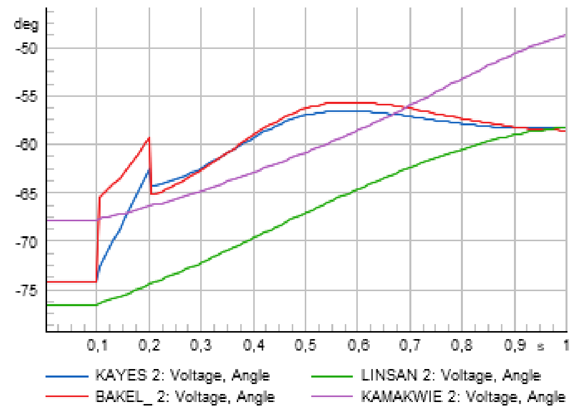


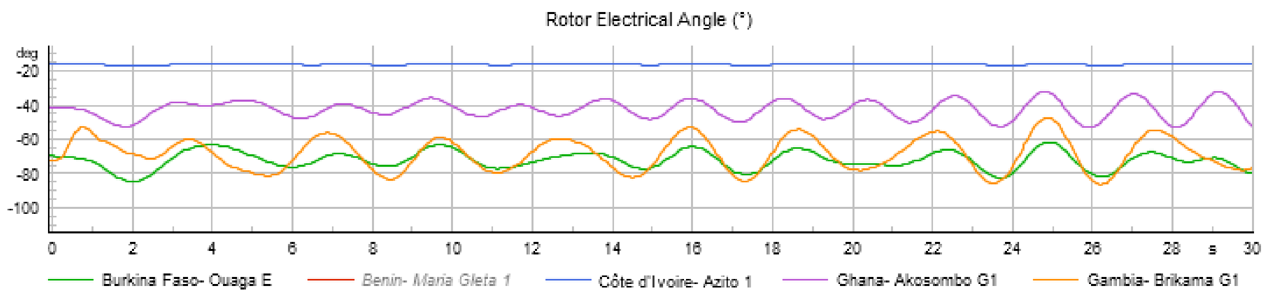
Transient stability for that event is confirmed, but oscillations are appearing showing the interest or the need for both more detailed dynamic data analysis and Power System Stabilizer (PSS) modelling and tuning.

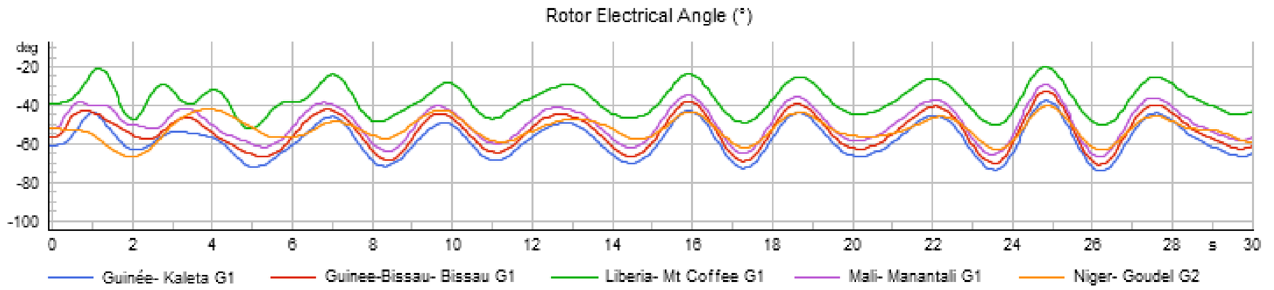
3. Mali: Kayes (line to Bakel, Senegal)

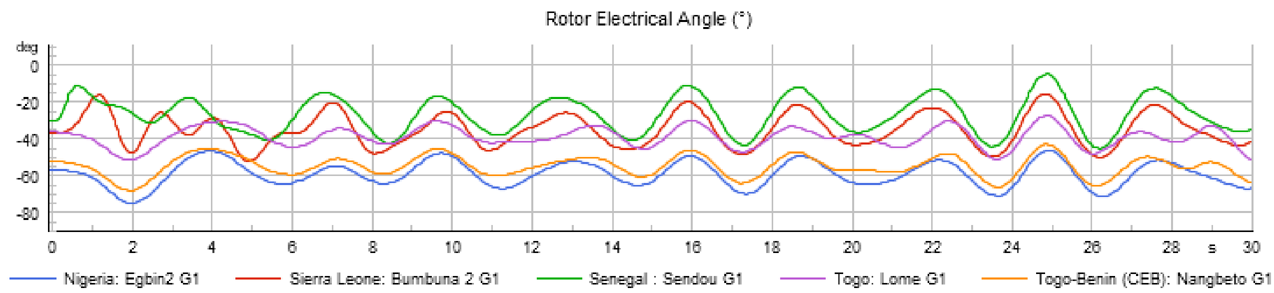
For the case of a short-circuit on the first OMVS line between Mali and Senegal, the voltages and angles evolve as follows.







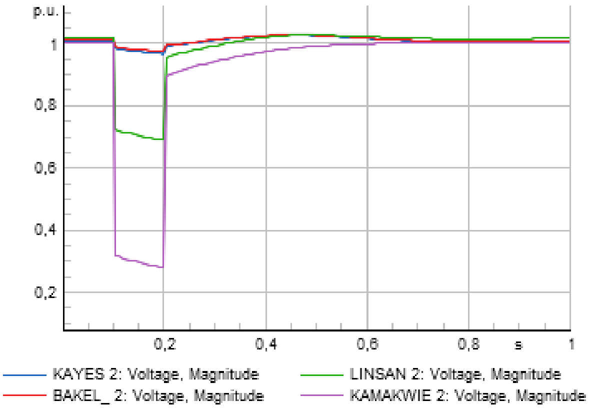


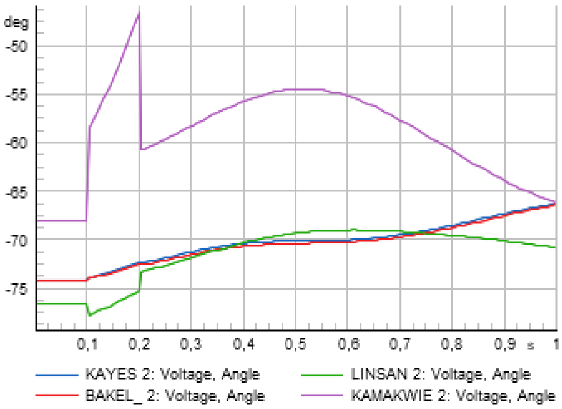


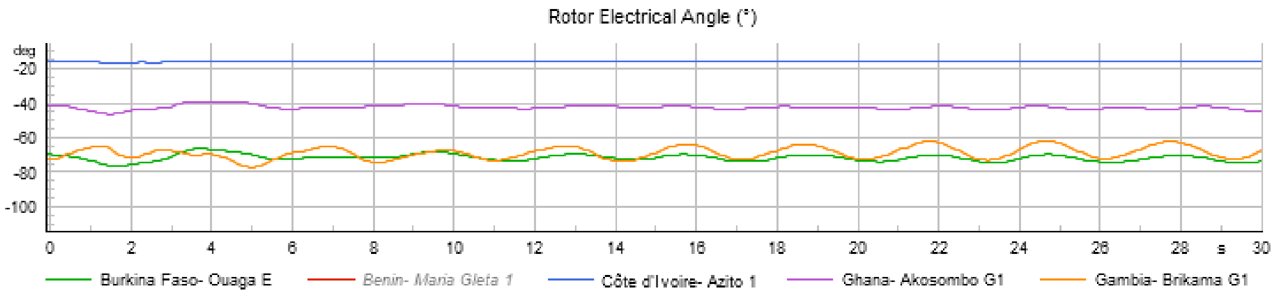
The transient stability of this event is confirmed, but oscillations appear, which shows the interest or need for a more detailed analysis of the dynamic data and Power System Stabilizer (PSS) modeling and tuning.

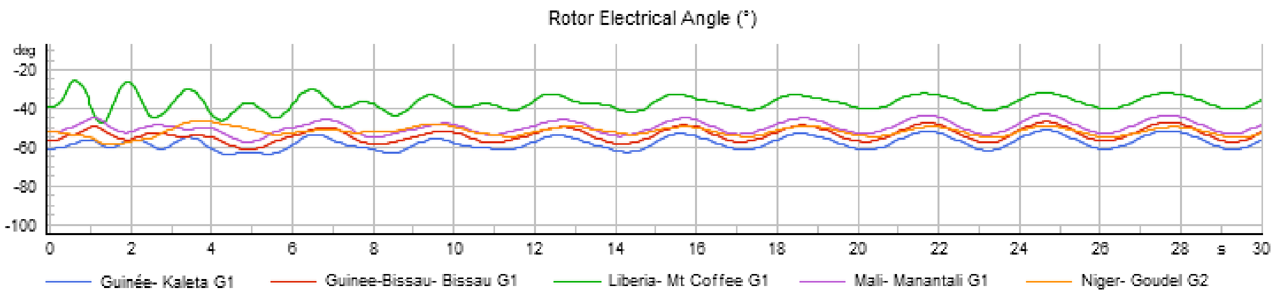
4. **Guinea: Linsan (line to Kamakwie, Sierra Leone)**

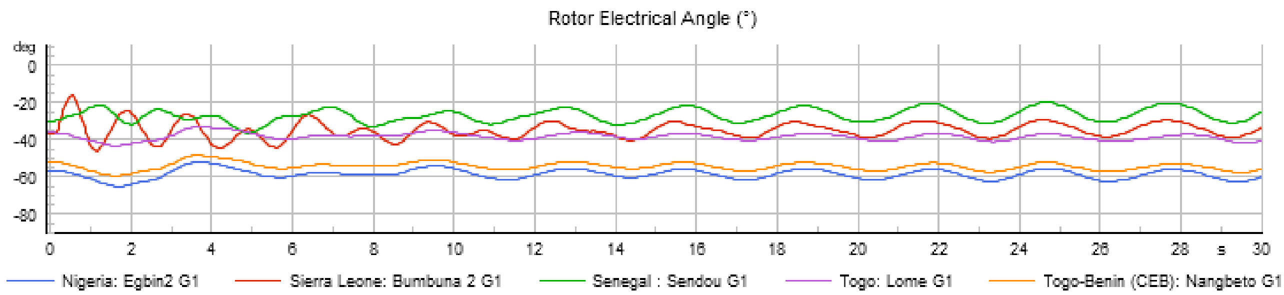
For the case of a short-circuit on the line between Guinea and Sierra Leone, the voltages and angles evolve as follows.











The transient stability of this event is confirmed, but oscillations appear, which shows the interest or the need for a more detailed analysis of the dynamic data and Power System Stabilizer (PSS) modeling and tuning.

7.7.2.5. Conclusion

For 2025 Midday case, all the short-circuit cases simulated prove that the transient stability is preserved: the simulations have shown that no loss of synchronism (out of step) appears in the grid modelled.

For 2025 Evening case, all the short-circuit cases simulated prove that the transient stability is preserved (the simulations have shown that no loss of synchronism (out of step) appears in the grid modelled) but oscillations appear and should be investigated:

1. Firstly by improving the data collection regarding dynamic parameters of the generation units : including generator parameters, operating points and their limits, and the PSS presence or not (and if present its parameters and tuning).

2. Secondly, if the presence of oscillations is confirmed, then improved tuning of PSS and analysis of the cross-border flows on the oscillations are to be investigated: the conclusions may become that beyond a given threshold of cross-border power flow, oscillations appear. In such case, the recently installed WAMS system can be used by the dispatchers as a warning tool indicating the need to reduce specific cross-border flows. Such analysis are beyond they scope of this study.

Knowing that the distance protections and the differential protections installed on the transmission lines eliminate short-circuits in about 100 ms, the above simulations lead to conclude that:

- The ECOWAS grid of 2025 can be considered as safe with regards (specifically) to the transient stability.
- In case generators absorb a significant amount of reactive power (MVAr's), out of step may occur: specific means should then be envisaged and compared, including the addition of shunt reactances.

Low frequency oscillations appear with a period of about 3 s and should be further investigated (see above), but these are not of the type of "inter-area oscillations" since there is no sign that one zone is oscillating "against" another (i.e. in opposition of phase).

7.7.3. Grid Code Analysis

BESSs are required to follow the requirements imposed on "inverter-based generation units" as defined in the connection code (section CC 1.2.1). These requirements are relatively similar to the European requirements (European network code RfG - Requirements for Generators) and therefore do not pose a particular problem for converters used for BESS. However, the following observations come:

1) LFSM-O and LFSM-U

Production and storage units are required to vary their production, upwards or downwards, in the event of a significant and abnormal deviation in frequency. The WAPP grid code provides that each network operator defines the frequency at which these modes must activate, between 50.2Hz and 50.5Hz for LFSM-O and between 49.5Hz and 49.8Hz for LFSM-U. To avoid an impact on the operation of the BESS, it will be necessary to ensure that the frequency remains sufficiently close to 50Hz so that the activation of the LFSM-O or LFMS-U remains exceptional.

2) Synthetic inertia

The WAPP grid code provides for the possibility for network operators to impose requirements in terms of synthetic inertia for production units based on inverters, including BESSs. If BESS capable of providing synthetic inertia are increasingly common, it will be appropriate for network operators to assess the need for this imposition taking into account the impact it could have on the attractiveness of the market for equipment suppliers.

3) Choice of parameters by network operators

Most of the parameters provided in the grid code can be chosen or modified by each network operator. A detailed analysis must be carried out by country, depending on the local network situation, in order to find a good balance between network security (stronger requirements) and the possibility for a maximum of equipment manufacturers to meet these conditions (less strong requirements). The risk is to see significantly higher BESS costs in certain countries, if equipment manufacturers have to adapt their equipment to meet non-standard requirements.

4) Conclusion regarding grid code

The WAPP grid code does not present any specificity or particular technical requirement to be taken into account in this study at the WAPP scale, and the hypotheses, particularly economic ones, can be based on BESS equipment, which meets international standards. Obviously, the concrete realization of BESS projects will require a more in-depth analysis of the grid code requirements, and in particular the specific requirements defined by the network operators concerned by these concrete projects.

7.7.4. Potential for photovoltaics with state-of-the-art electronics

For the voltage control application, the addition of BESS could potentially be avoided by adapting photovoltaic or wind farms, particularly in terms of their power electronics. Indeed, by oversizing the inverters and by choosing flexible electronic equipment in terms of their power factor, it is possible to supply or absorb reactive energy, even when there is no wind or no sun.

For the frequency control application, the contribution of solar and wind farms can also be considered but generally only for downward regulation, that is to say by restricting production to restore frequency. Upward regulation requires permanently restricting the production unit in order to be able to increase production when needed. This is generally not economically interesting and, in any case, this power is not available if there is no wind or sun.

8. BESS IMPLEMENTATION PLAN for 2025 and 2030

8.1. Summary of recommended BESS sizes for 2025 and 2030

The tables below summarize the recommended battery sizes by application and country for 2025 and 2030

Table 31: Summary of Recommended Battery Sizes 2025

2025	Frequency control (MW - 1hr)	Voltage control	Energy time-shift (MW - 4hr)	Transmission congestion relief	Black Start
Côte d'Ivoire	**63.5**				
Burkina Faso	**12**				
Togo	**10.2**				
Benin	**8.8**				
Ghana	**95.8**				
Nigeria	**377.2**				
Niger	**8.9**				
Guinea	**13.2**				
Sierra Leone	**10.8**				
Liberia	**4.5**				
Mali-Senegal-Mauritania	**8.8**				
Mali	**19.1**				
Senegal	**33.4**				
Gambia	**3.8**		**120**		
Guinea-Bissau	**3**				

Table 32: Table 9 2 Summary of Recommended Battery Sizes 2025

2030	Frequency control (MW - 1hr)	Voltage control	Energy time-shift (MW - 4hr)	Transmission congestion relief (MW – 4hr)	Black Start
Côte d'Ivoire	**63.5**				
Burkina Faso	**12**		**25**		
Togo	**10.2**				
Benin	**8.8**				
Ghana	**95.8**				
Nigeria	**377.2**			**22**	
Niger	**8.9**				
Guinea	**13.2**				
Sierra Leone	**10.8**				
Liberia	**4.5**				
Mali-Senegal-Mauritania	**8.8**				
Mali	**19.1**		**55**		
Senegal	**33.4**				
Gambia	**3.8**		**147**		
Guinea-Bissau	**3**				

8.2. Estimated Project Cost

To specify and carry out well-defined and agreed cases.

9. CONCLUSIONS

9.1. Application 1: Frequency Control

The assessment has demonstrated the economic viability of investing in BESS to deliver frequency control services, comparing it with investments in gas turbines. Focusing on the investment cost of a 1-hour battery, the results showed substantial potential savings of 82% and 87% in comparison to gas turbine investments by 2025 and 2030, respectively. Furthermore, the exploration of extending the battery's duration for possible additional applications revealed that BESS retains its economic advantage, even with 4-hour investments.

9.2. Application 2: Voltage Control

The comparison of BESS with reactances clearly shows that a BESS cannot be and cannot become profitable for acting for voltage control only, since its cost is not competitive with the reactances costs, even when considering the future CAPEX cost reduction of BESS.

However, the voltage control capability of BESS will be of significant interest in the frame of combined applications of BESS like Energy Shift and Voltage Control, or frequency control and Voltage Control: locating the BESS at places where a large capacitor or large reactance should otherwise be installed will provide the corresponding savings of capacitor or reactance CAPEX.

9.3. Application 3: Energy Shift (arbitrage)

The feasibility of implementing the energy shift application seems to be limited by 2025 but more appropriate by 2030. These results align with similar international system-wide studies, often suggesting the viability of merchant BESS after 2030, depending on the penetration of renewables, in particular, PV capacity. It's essential to recognize the limitations inherent in these findings, related to data and the simplifications in the simulation process. A more granular representation may result in relatively higher investments in BESS. The study also took the hypothesis of relatively stable fossil fuel prices and considered investment in thermal capacity as certain. A direction for future work could be to consider the replacement of some of that thermal capacity by PV in combination with storage.

From the results by country, Gambia demonstrates significant potential for BESS investment both in 2025 and 2030, while Mali and Burkina Faso also exhibit favourable marginal cost structures, conducive to promoting BESS post-2030. Furthermore, the complementary role of interconnections with BESS is noteworthy, whereby higher solar PV penetration by 2030 is counterbalanced by increased Net Transfer Capacities (NTCs).

Finally, taking into account the results of the sensitivity study, the following can be observed:

1) The selection of the discount rate is of critical importance and consistency among different studies is needed to compare different solutions on the same basis. In particular, the discount rate sensitivity in 2025 highlights potential profitability for Mali BESS investments, which suggest a further examination of additional applications into a comprehensive financial modelling.
2) CAPEX variations underscore the need for careful investment planning, with Low-CAPEX scenarios turning BESS investments into profitable ventures across multiple countries in both 2025 and 2030.
3) Fuel price sensitivity demonstrates the impact on BESS investment profitability, emphasizing the necessity for robust sensitivity analysis (considering the effect of price variation on the energy arbitraged) to ensure profitability for each country.

9.4. Application 4: Transmission Congestion Relief

The application of batteries as a tool for decongesting the electricity network offers significant advantages, in particular by avoiding costly investment in line reinforcements. An analysis of the cost of the reinforcements required over the next few years enables to determine the priority investments among which installation of lines and the installation of batteries. Based on the cost of reinforcements and the overload to be alleviated, the batteries are strategically positioned to optimise the use of existing lines and postpone the investment in new costly power lines.

The effectiveness of this method is closely linked to the specific topology of the grid, the power of the batteries required, and the level of the overloads identified in the model (itself being linked to the assumed generation dispatch). The most promising cases are those where both the required grid reinforcement would be costly, the overload is limited (hence a BESS of low sizing, low cost), and preferably the load growth is low (thereby deferring for many years the need for a reinforcement). This is described by the following graphic

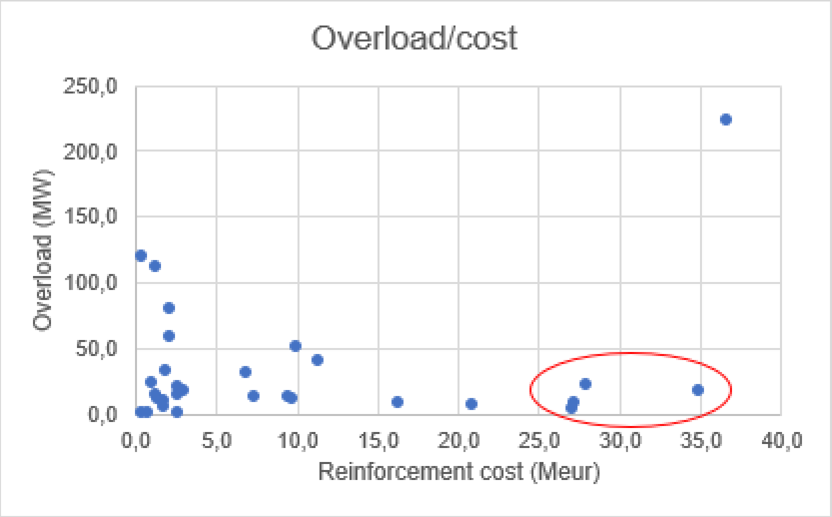


Figure 31: the reinforcement of the grid required would be costly, the overload is limited (hence a low dimensioning, low cost BESS),

From this analysis, there are some very encouraging results for 2030 such as :

- Installing a BESS of 10 MW/20 MWh at substation JERICHO 1 for avoiding the congestion (overload) of the line NG_AYEDE 1 JERICHO 1 in Nigeria.
- Installing a BESS of 12 MW/24 MWh at substation PAPALANTO 1 in 2030 for avoiding the congestion (overload) of the line NG_PAPALANTO 1 OTTA 1 in Nigeria.

For these two cases, installing a BESS appears profitable even if there is no price difference between the charging time (usually midday when PV generate power, or during the night when the cost is low), and the discharging time (usually the peak load time, in the evening). For the other cases analysed, the profitability comes only once at least a given difference of MWh price is observed.

As a conclusion, these are places where very costly reinforcements can be avoided by installing batteries with a power around 10MW and a capacity of 2 hours. Such cases should however be discussed with the grid operator, notably to confirm the appearance of the congestion and check that for the operator there are no less costly option like possibly redispatching. .

9.5. Application 5: Black Start

Black start as a stand-alone application does not make economic sense due to the high capex of BESS. However, BESS installed for other applications could prove useful during reconstruction in the event of a black-out.

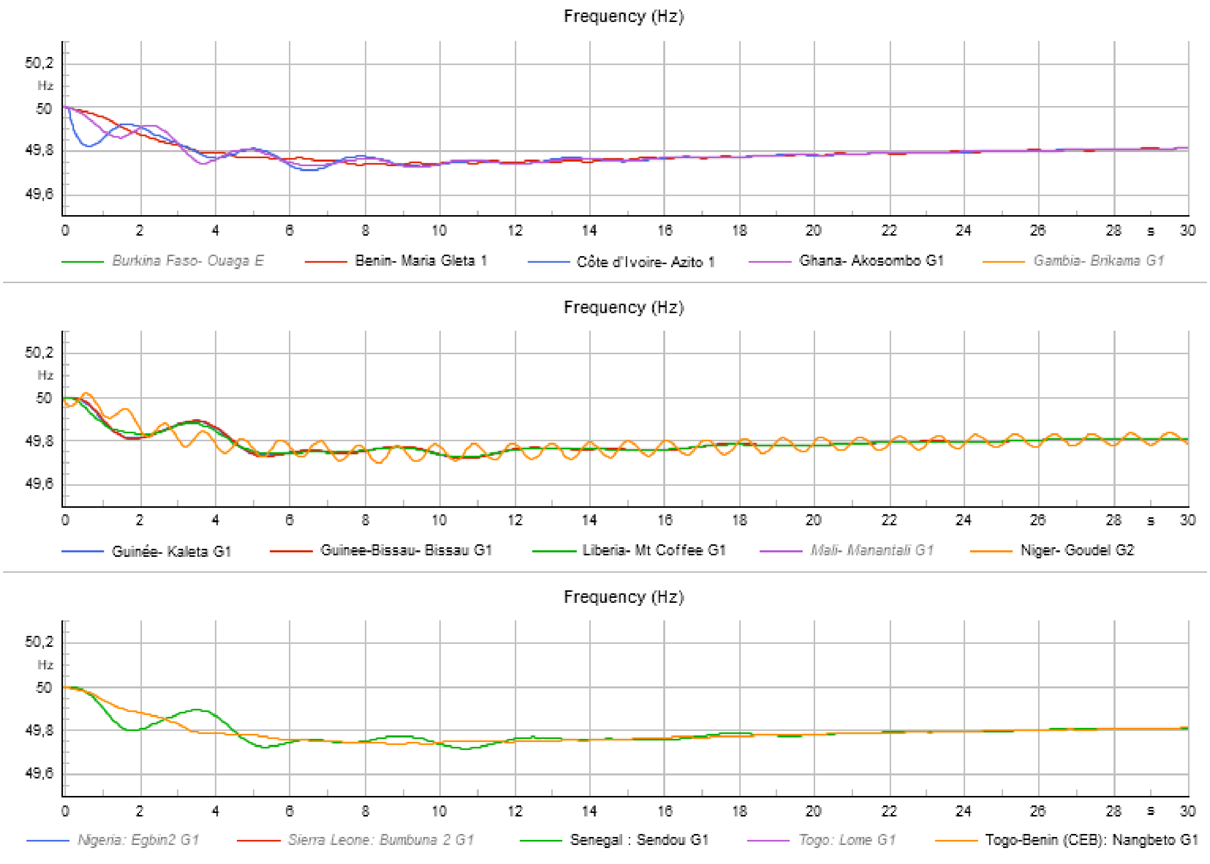
9.6. Other results:

9.6.1. Dynamic Stability

The dynamic stability is analysed here for the most constraining active power imbalance event: the tripping of the 390 MW CIPREL 5 (Atinkou) power plant in Côte d'Ivoire.

The simulations have shown that for the two sets of power plants defined as controlling the frequency, the frequency can be kept above the 49,5 Hz level.

This level is well above the 49,0 Hz threshold under which the Automatic Frequency Load Shedding (AFLS) starts to operate and cause some Energy Not Served.



Providing that the Frequency Control is distributed on the whole ECOWAS grid, the grid of 2025 can therefore be considered as safe with regards to the dynamic stability

9.6.2. Transient Stability

For 2025 Midday case, all the short-circuit cases simulated prove that the transient stability is preserved: the simulations have shown that no loss of synchronism (out of step) appears in the grid modelled.

For 2025 Evening case, all the short-circuit cases simulated prove that the transient stability is preserved (the simulations have shown that no loss of synchronism (out of step) appears in the grid modelled) but oscillations appear and should be investigated:

- Firstly by improving the data collection regarding dynamic parameters of the generation units: including generator parameters, operating points and their limits, and the PSS presence or not (and if present its parameters and tuning).
- Secondly, if the presence of oscillations is confirmed, then improved tuning of PSS and analysis of the cross-border flows on the oscillations are to be investigated: the conclusions may become that beyond a given threshold of cross-border power flow, oscillations appear. In such case, the recently installed WAMS system can be used by the dispatchers as a warning tool indicating the need to reduce specific cross-border flows. Such analysis is beyond the scope of this study.

Knowing that the distance protections and the differential protections installed on the transmission lines eliminate short-circuits in about 100 ms, the above simulations lead to conclude that:

- the ECOWAS grid of 2025 can be considered as safe with regards (specifically) to the transient stability.
- In case generators absorb a significant amount of reactive power (MVARs), out of step may occur: specific means should then be envisaged and compared, including the addition of shunt reactances.
- Low frequency oscillations appear with a period of about 3 s and should be further investigated (see above), but these are not of the type of “inter-area oscillations” since there is no sign that one zone is oscillating “against” another (i.e. in opposition of phase).

10. RECOMMENDATIONS

10.1. Proposed BESS pre-investment studies for 2025 and 2030

It is necessary to carry out further pre-investment studies to confirm the feasibility studies the proposed BESS projects. As part of the roles and responsibilities of key stakeholders are concerned, the countries where the BESS projects are identified should be supported to further investigate the proposed BESS projects with the support of donors. Any of the regional energy sector entities such as WAPP, ERERA and ECREEE could also be involved as well.

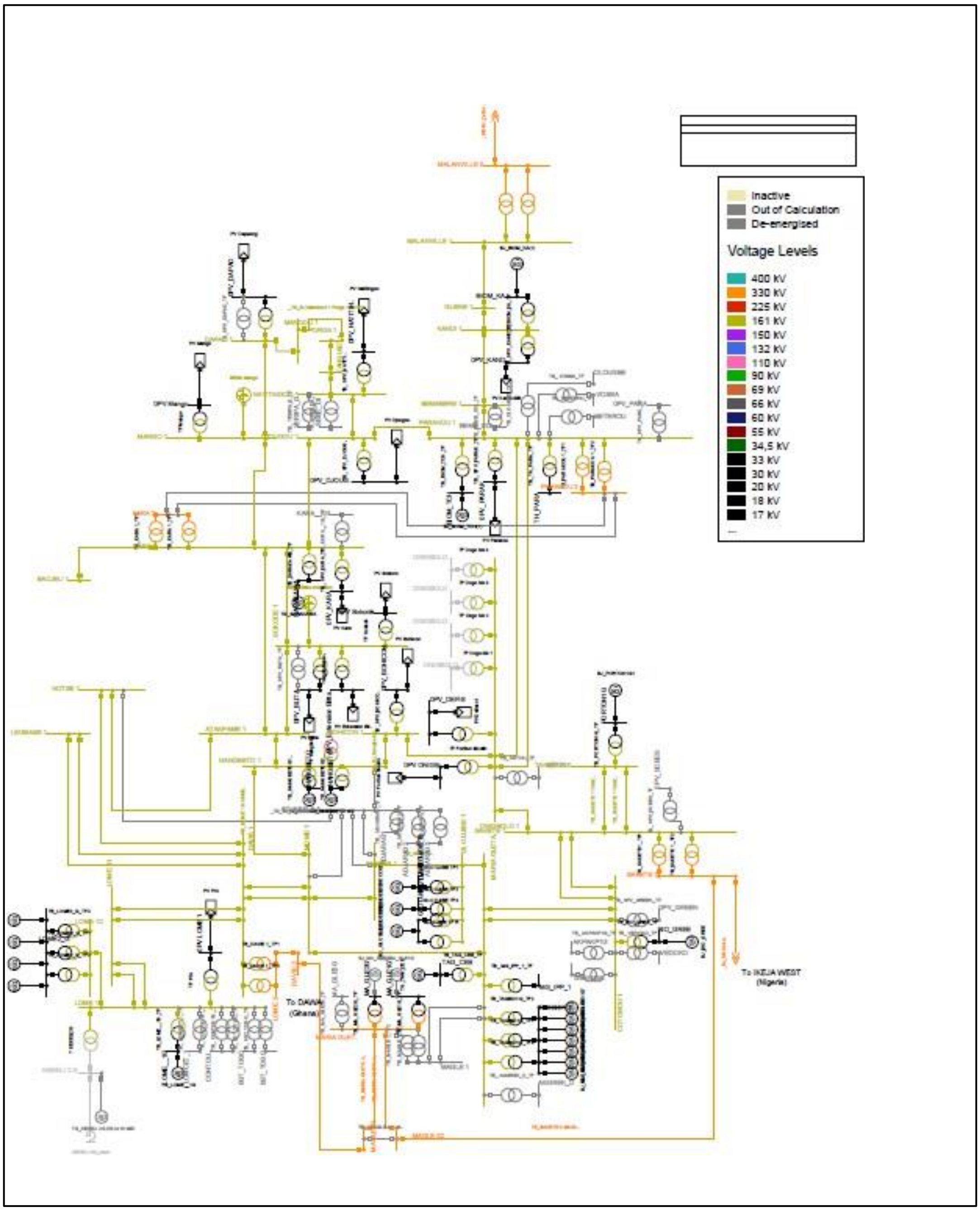
10.2. Investment in power generation to support BESS deployment

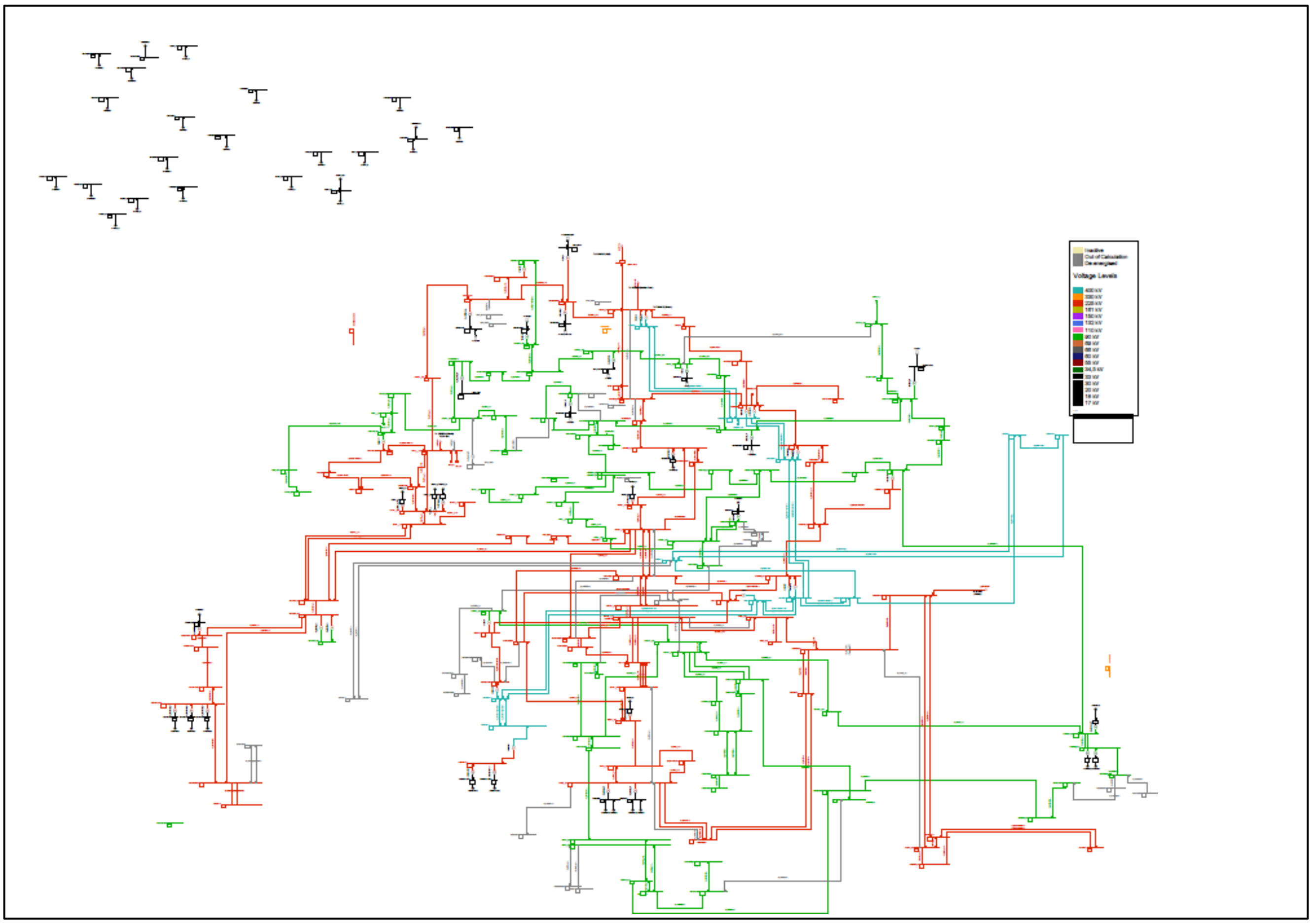
Solar PV projects with integrated BESS offer scalability and flexibility to accommodate the growing electricity demand of the ECOWAS region. As the load increases over time due to population growth, industrial expansion, BESS can be expanded or added to existing solar installations both as on grid or off-grid system to meet the rising demand efficiently. Also, by deploying solar PV with BESS, utilities and grid operators can avoid or delay investments in new conventional generation capacity and transmission infrastructure to meet the growing load. Also, BESS can act as distributed resources that defer the need for costly infrastructure upgrades, resulting in cost savings for utilities and ratepayers. As a result, there is the need for multi- stakeholders (ECOWAS countries Ministries, Utilities, Private Sector, WAPP, ECREEE, ERERA etc) to collaborate and promote the realisation of the needed generation investment that can be supported by BESS.

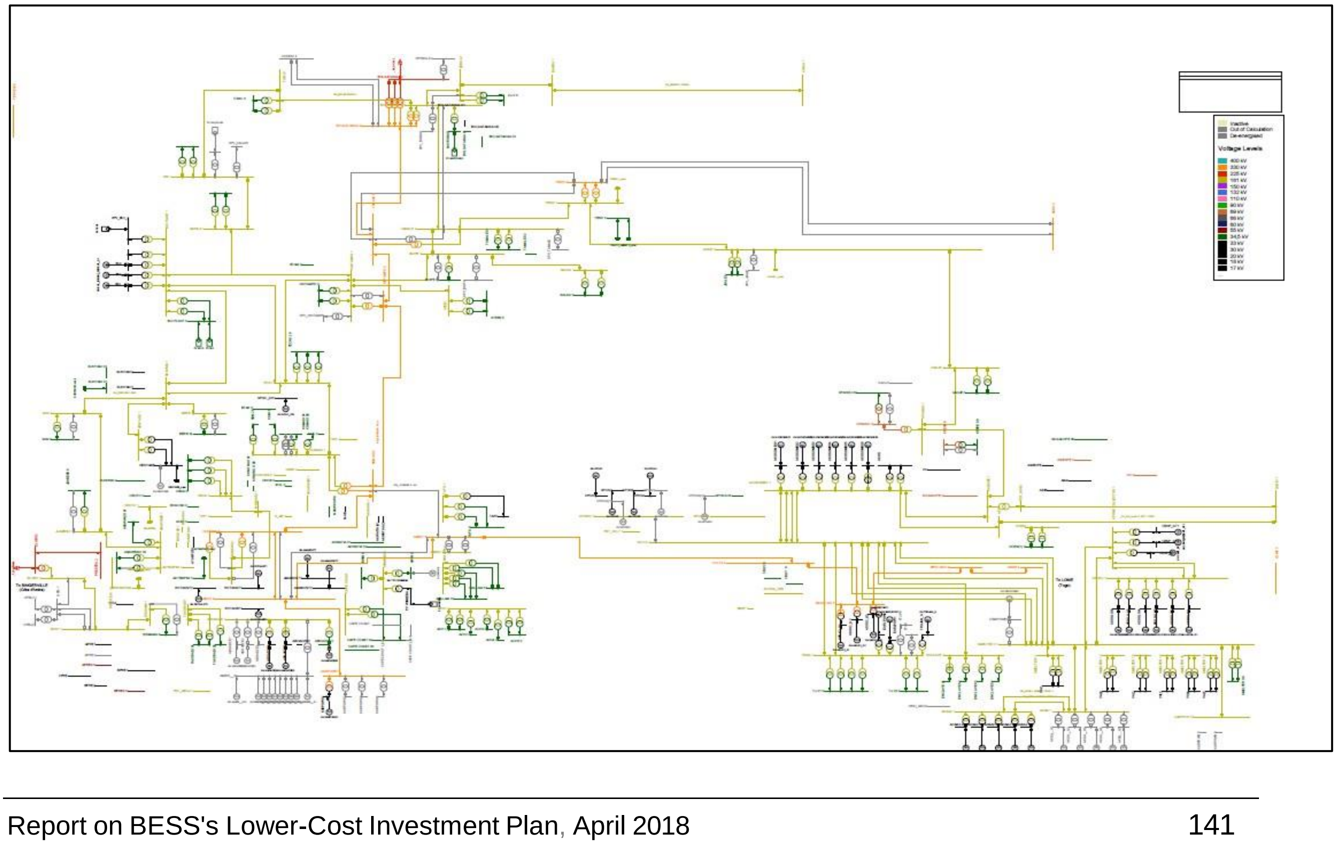
In the context of investing, implementing the energy shift with BESS application solely (without Renewable Energy Projects such as PV) seems to be limited by 2025 but more appropriate if paired with PV and other renewables. If the future cost of PV and BESS continue to go down against a rising fossil cost, then the replacement of some thermal capacity by PV in combination with storage will be inevitable.

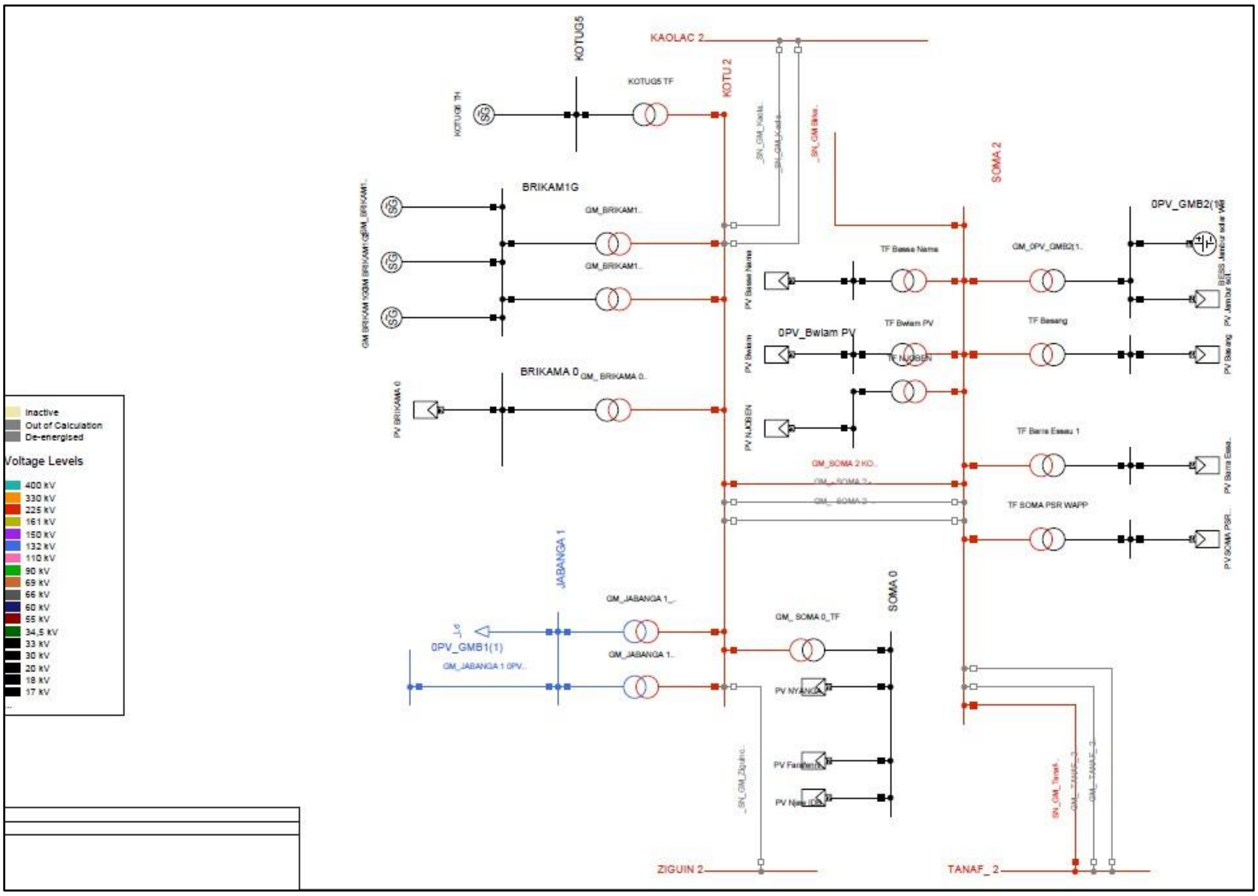
11. ANNEXES

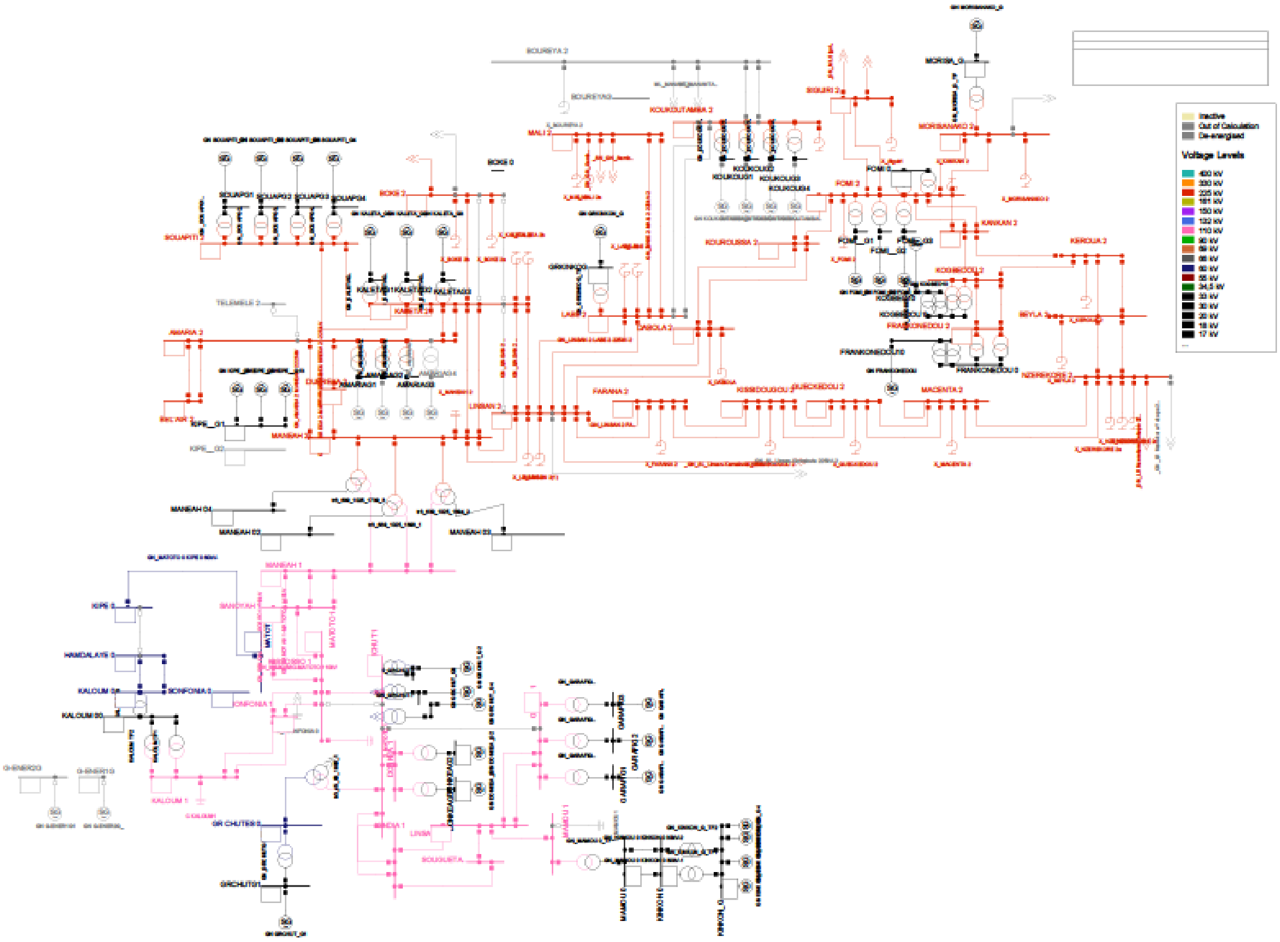
11.1. Appendix 1 – 2025 Single-line diagrams

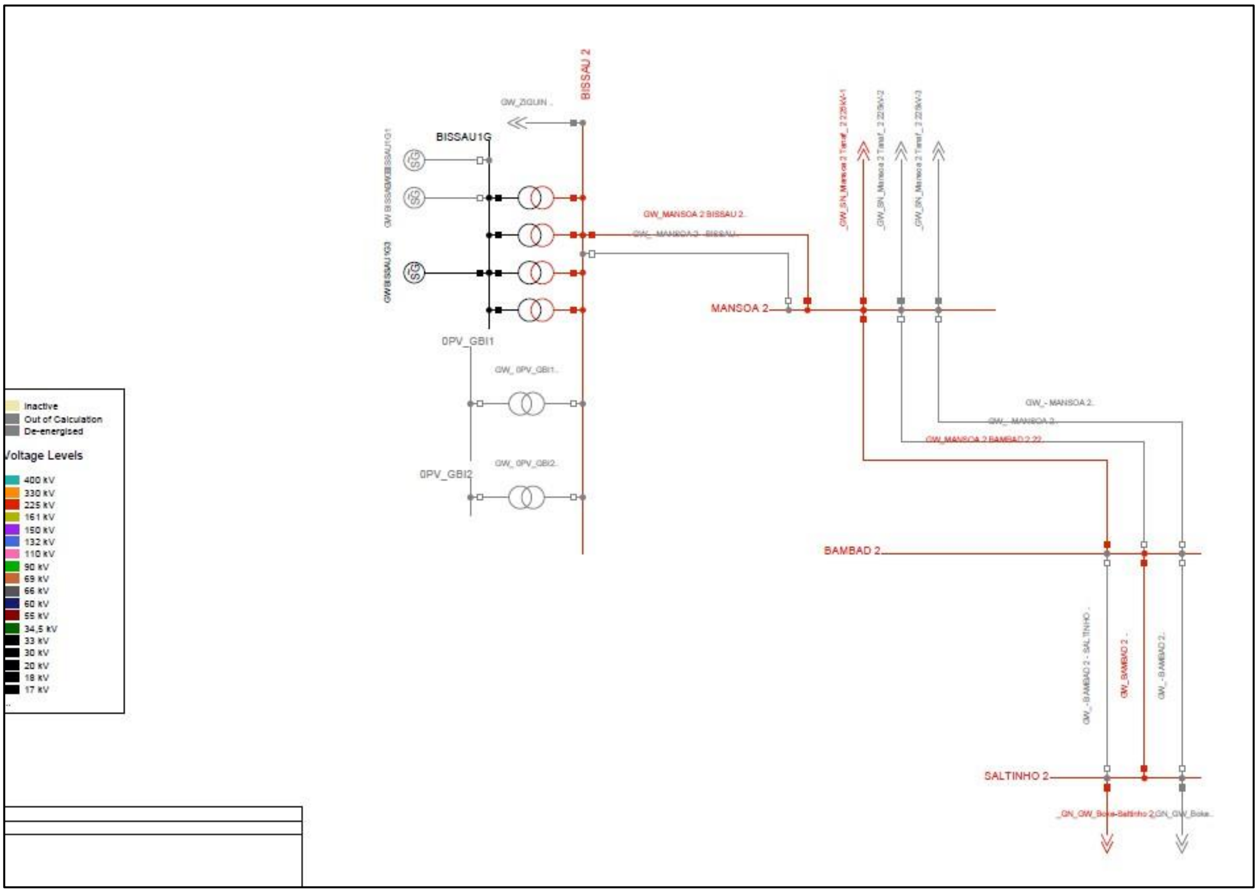







KAOLAC 2
KOTUG5
KOTU 2
KOTUG5 TF
SOMA 2
BRIKAM1G
GM_BRIKAM1..
BRIKAMA 0
OPV_Bwiam PV
TF Bwiam PV
TF Besang
TF Berra Essau 1
TF SOMA PSR WAPP
OPV_GMB2(1)
JABANGA 1
GM_JABANGA 1_
OPV_GMB1(1)
SOMA 0
GM_SOMA 0_TF
PV NYANGA
ZIGUIN 2
TANAF_2
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34.5 kV
33 kV
30 kV
20 kV
18 kV
17 kV





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BISSAU1G
MANSOA 2
BAMBAD 2
SALTINHO 2
0PV_GBI1
0PV_GBI2
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
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66 kV
60 kV
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20 kV
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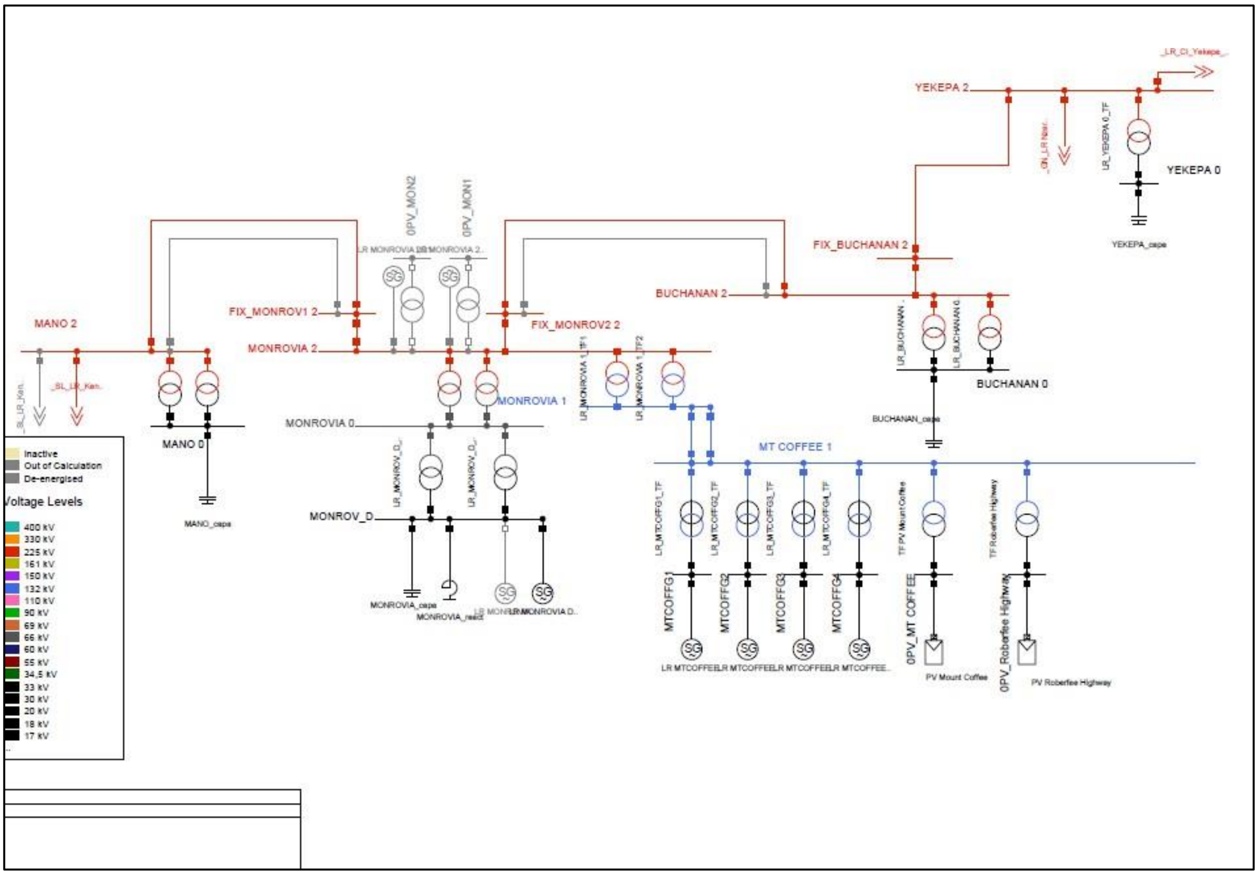
17 kV



YEKEPA 2
YEKEPA 0
FIX_BUCHANAN 2
BUCHANAN 2
BUCHANAN 0
MANO 2
MANO 0
FIX_MONROV1 2
MONROVIA 2
FIX_MONROV2 2
MONROVIA 1
MONROVIA 0
MONROV_D
MT COFFEE 1
0PV_MON2
0PV_MON1
MTCOFFG1
MTCOFFG2
MTCOFFG3
MTCOFFG4
0PV_MT COFFEE
0PV_Roberfee Highway
PV Mount Coffee
PV Roberfee Highway
Inactive
Out of Calculation
De-energised
Voltage Levels
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161 kV
150 kV
132 kV
110 kV
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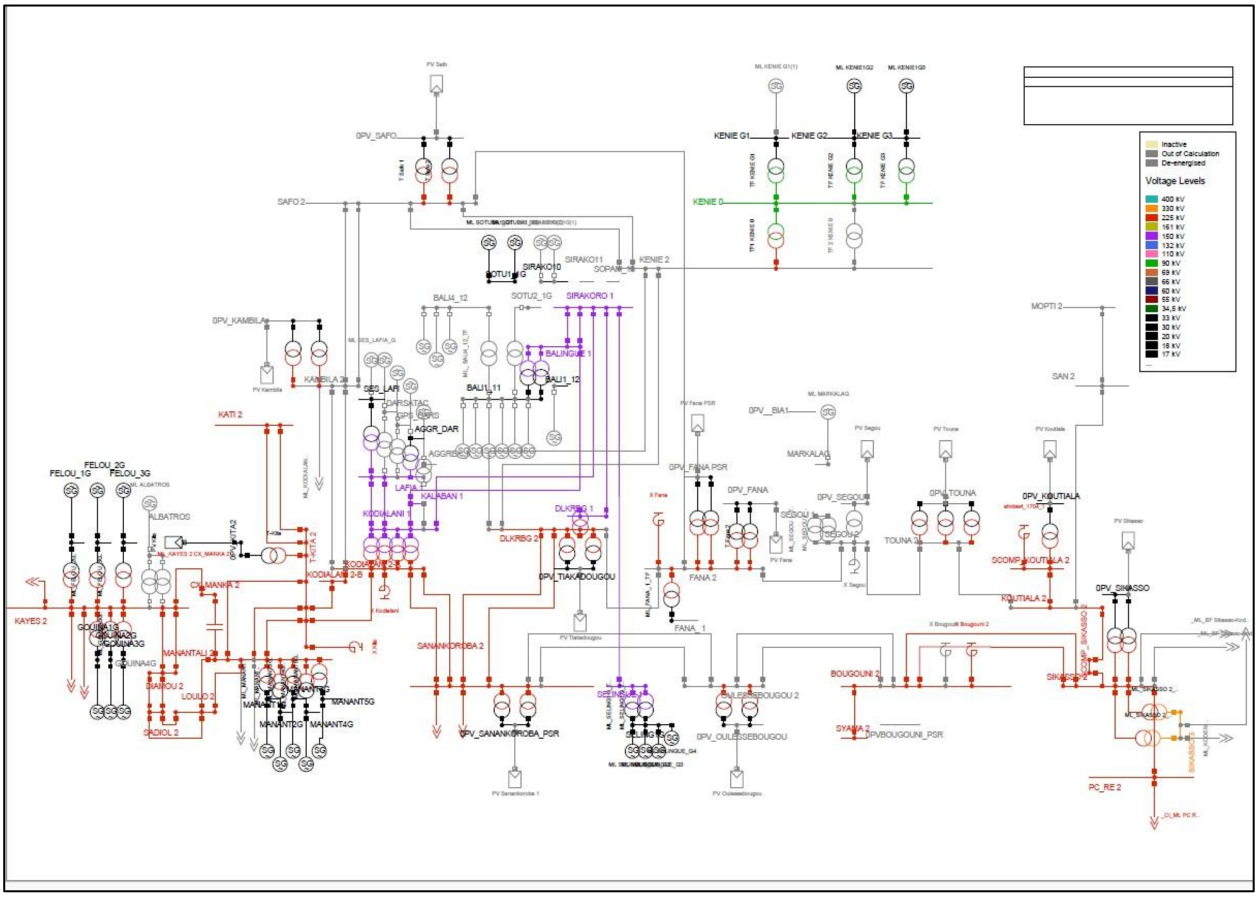
17 kV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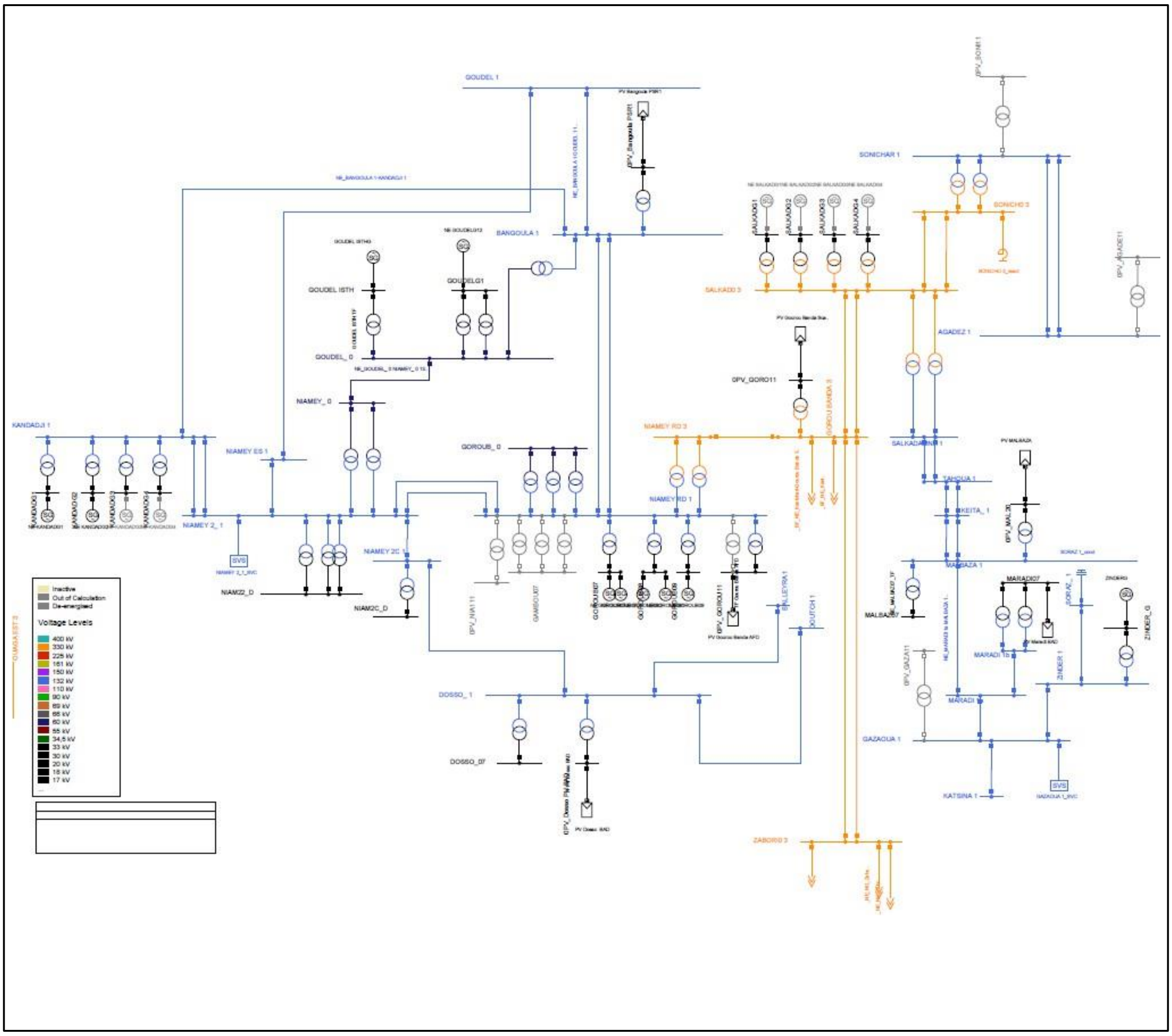
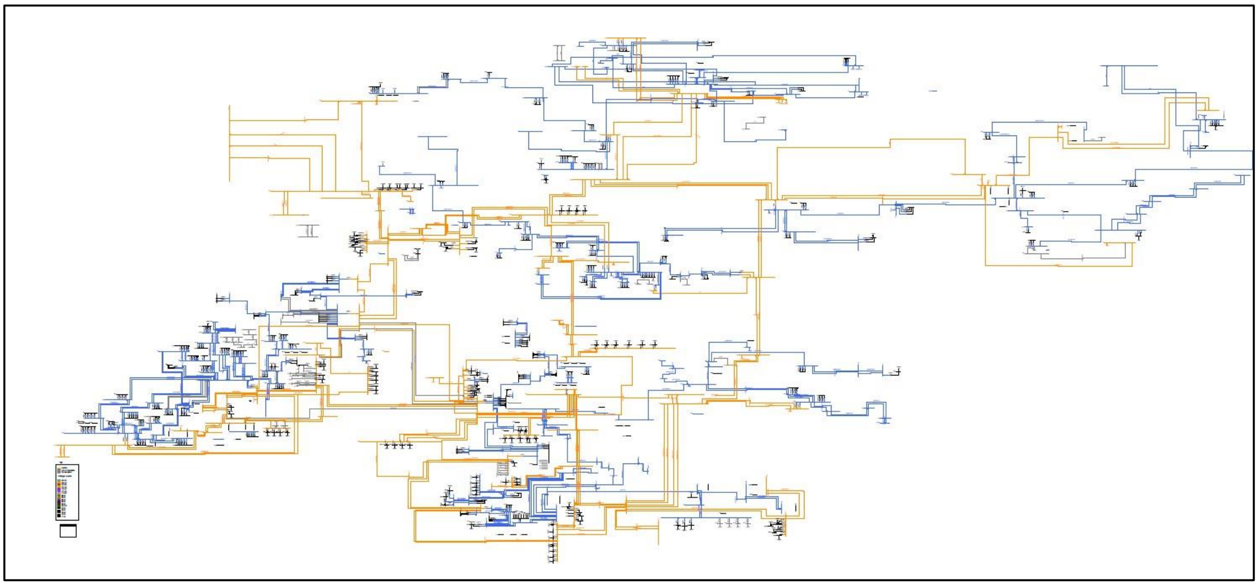
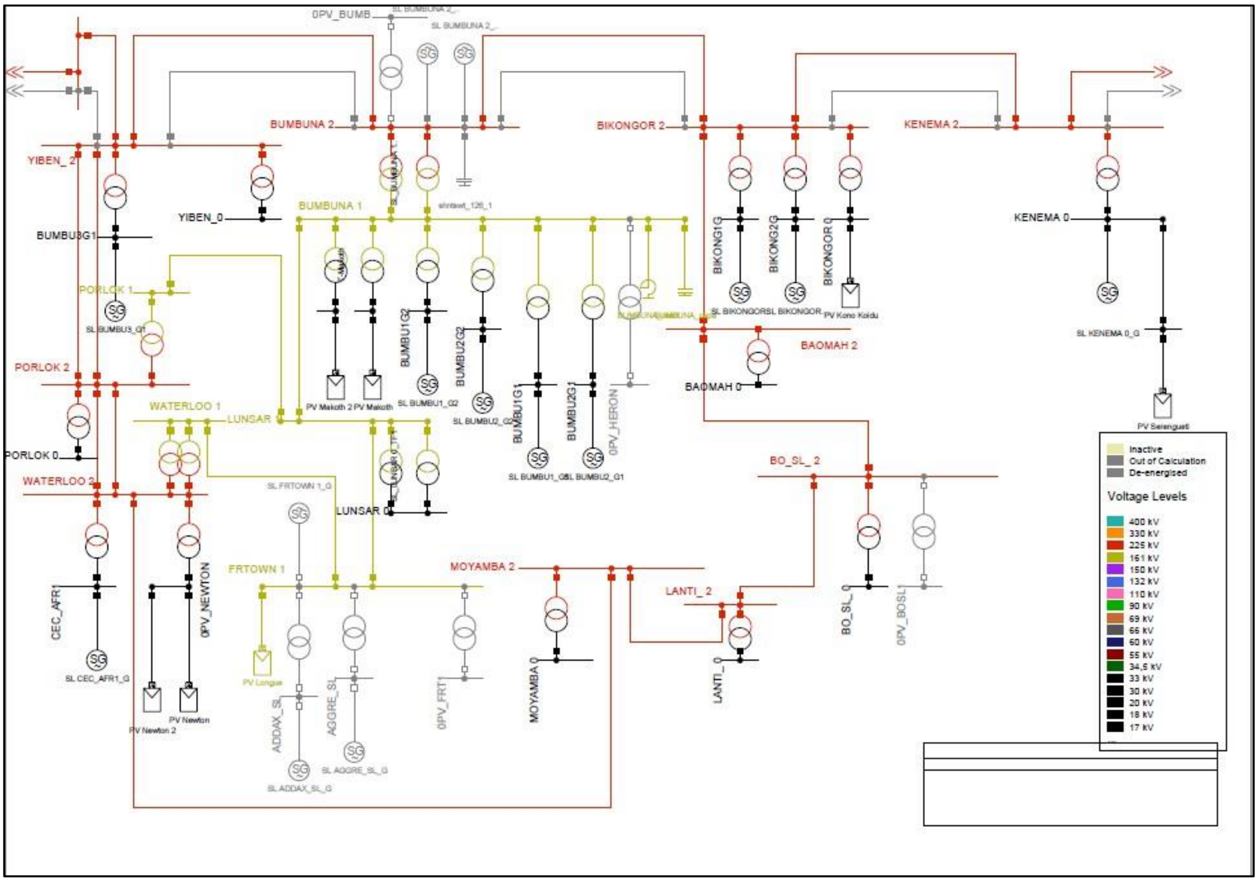
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV
KENIE G1
KENIE G2
KENIE G3
KENIE 0
KENIE 2
SAFO 2
0PV_SAFO
SIRAKORO 1
BALINGUE 1
KATI 2
KAYES 2
FELOU_1G
FELOU_2G
FELOU_3G
ALBATROS
MANANTALI 2
KODIALANI 1
KALABAN 1
LAFIA
DLKRBG 1
DLKRBG 2
0PV_TIAKADOUGOU
SANANKOROBA 2
0PV_SANANKOROBA_PSR
SELINGUE 2
OULESSEBOUGOU 2
0PV_OULESSEBOUGOU
FANA 2
0PV_FANA
SEGOU 2
0PV_SEGOU
TOUNA 2
0PV_TOUNA
0PV_KOUTIALA
KOUTIALA 2
SCOMP_KOUTIALA 2
0PV_SIKASSO
SIKASSO 2
BOUGOUNI 2
SYAMA 2
MOPTI 2
SAN 2
PC_RE 2



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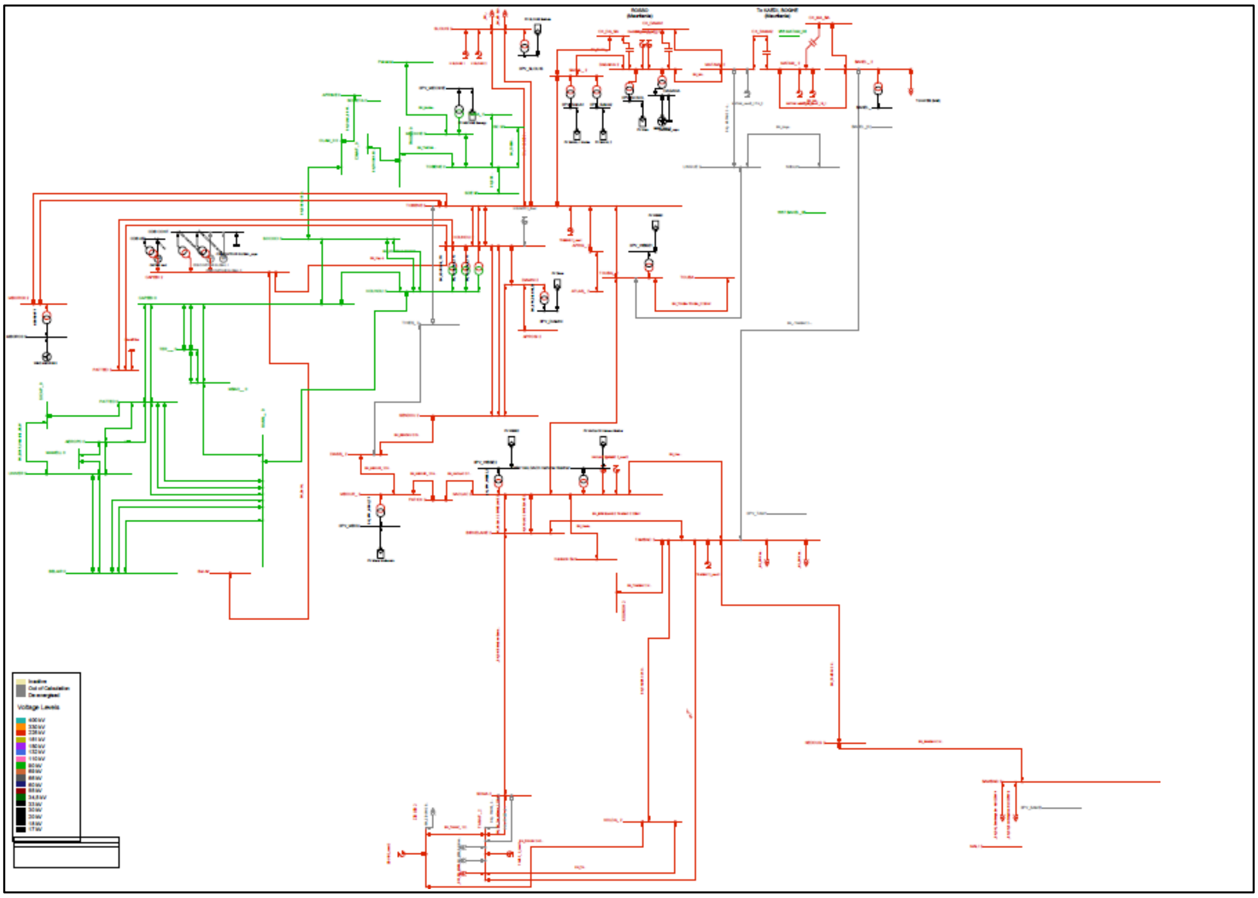
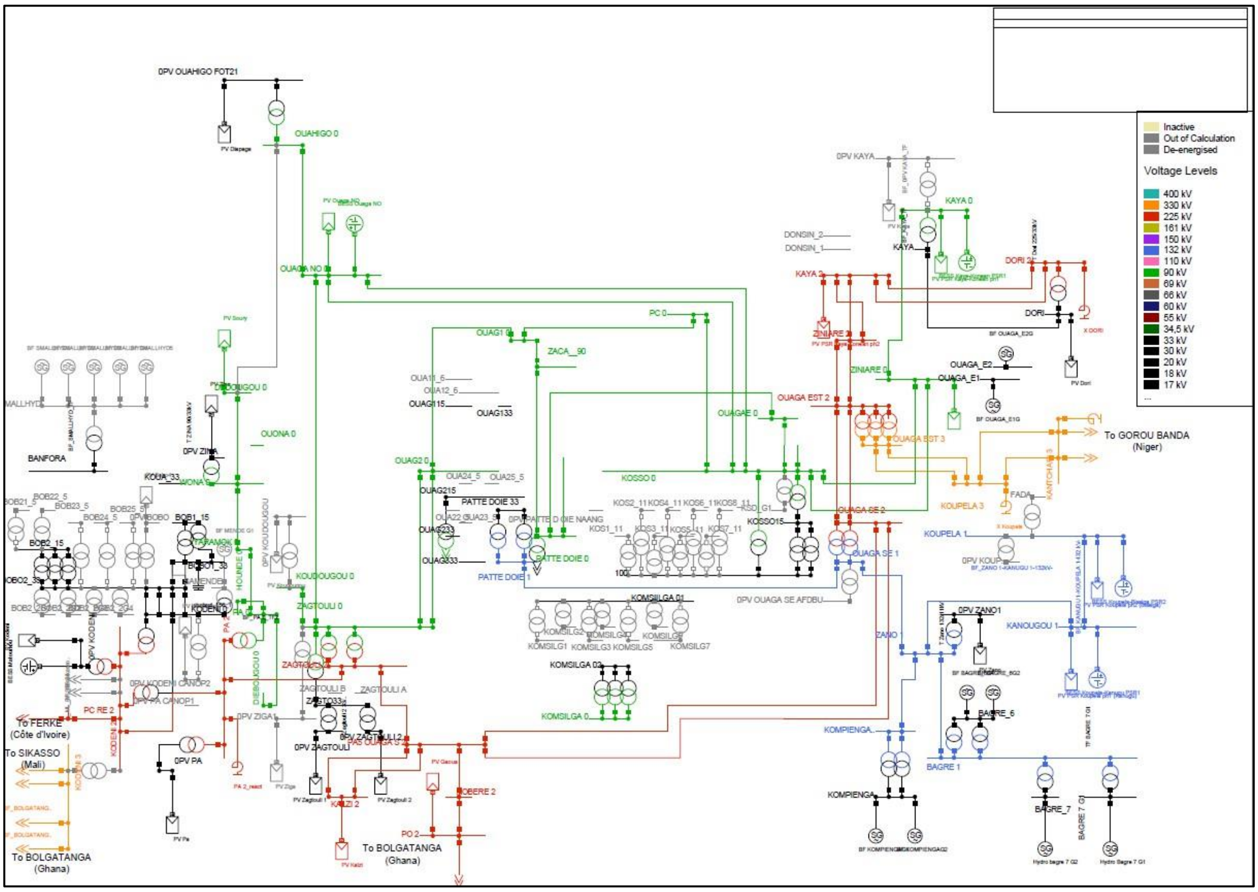
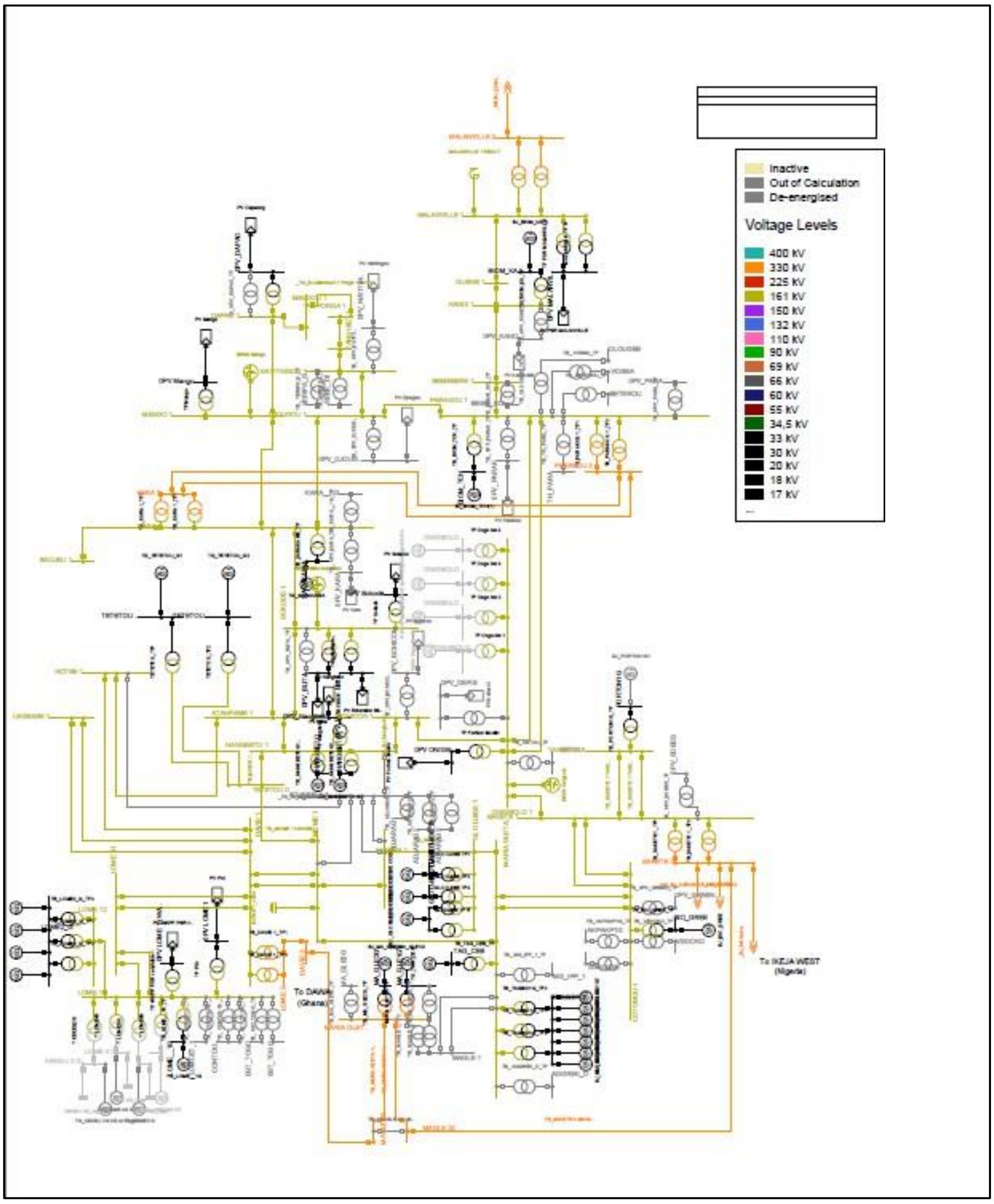
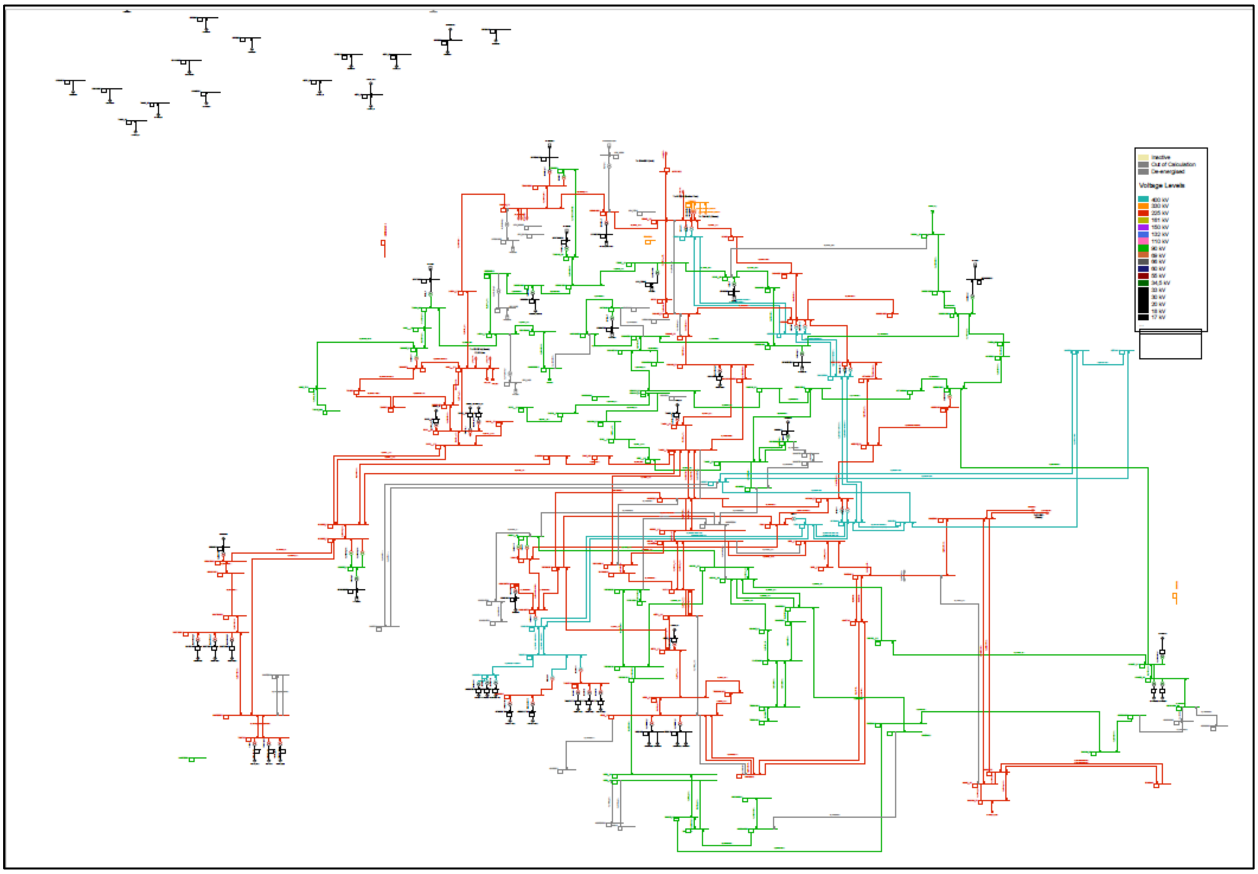
KENEMA 2
YIBEN_2
YIBEN_0
BUMBUNA 1
BUMBU3G1
PORLOK 1
PORLOK 2
PORLOK 0
WATERLOO 1
WATERLOO 2
LUNSAR 1
LUNSAR 0
FRTOWN 1
MOYAMBA 2
LANTI_2
BO_SL_2
BAOMAH 2
BAOMAH 0
KENEMA 0
BIKONG1G
BIKONG2G
BIKONGOR 0
BUMBU1G2
BUMBU2G2
BUMBU1G1
BUMBU2G1
0PV_HERON
CEC_AFR1
0PV_NEWTON
ADDAX_SL
AGGRE_SL
0PV_FRT1
MOYAMBA 0
LANTI_0
BO_SL_0
0PV_BOSL1
PV Newton
PV Newton 2
PV Longue
PV Kono Koidu
PV Serenguati
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV

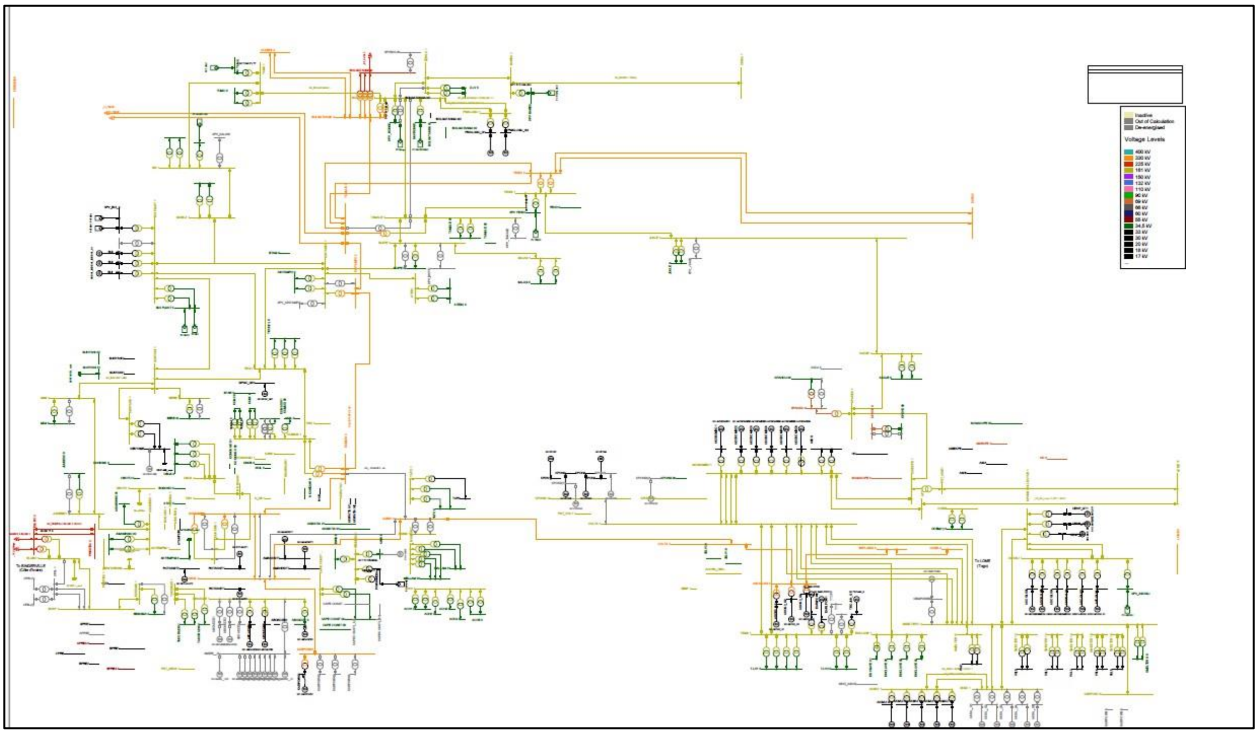


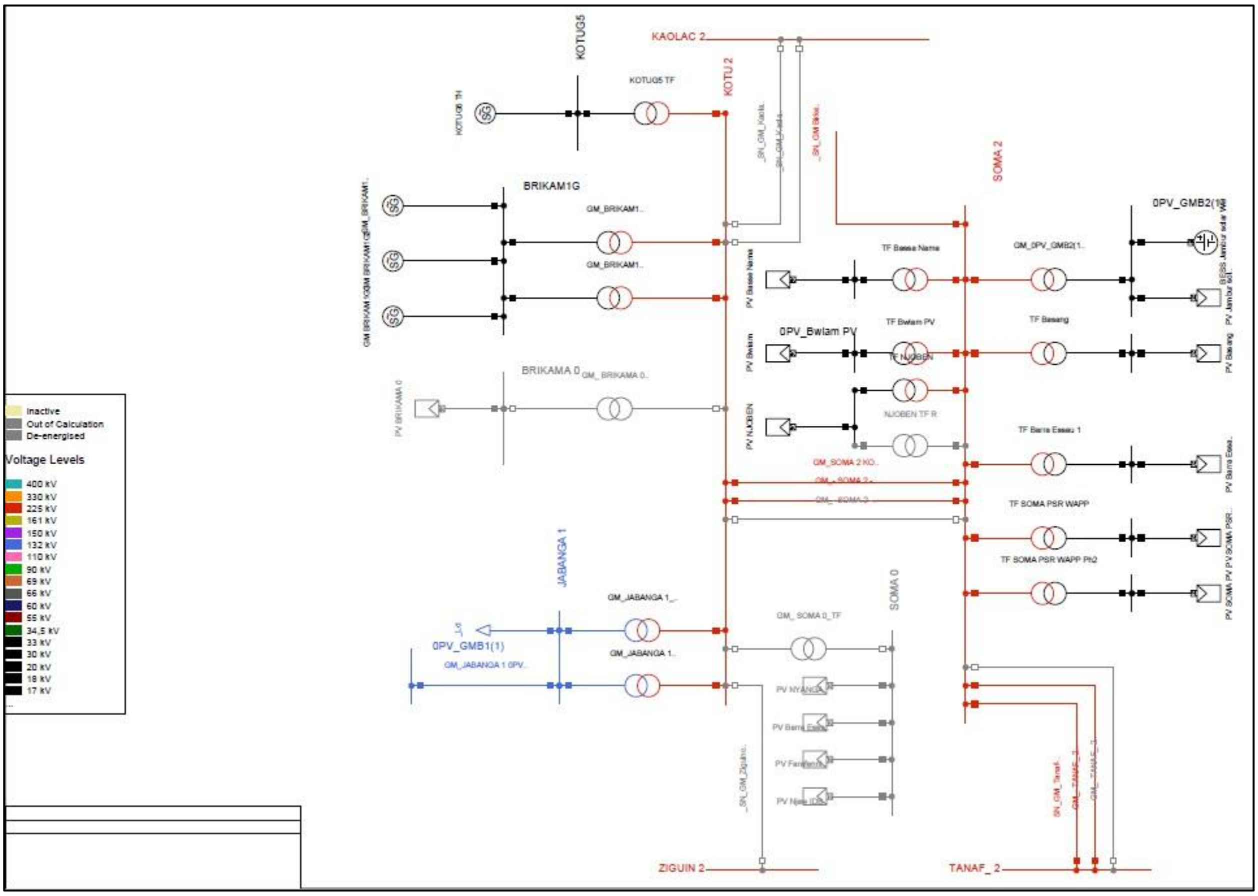
11.2. Appendix 2 – 2030 Single-line diagrams



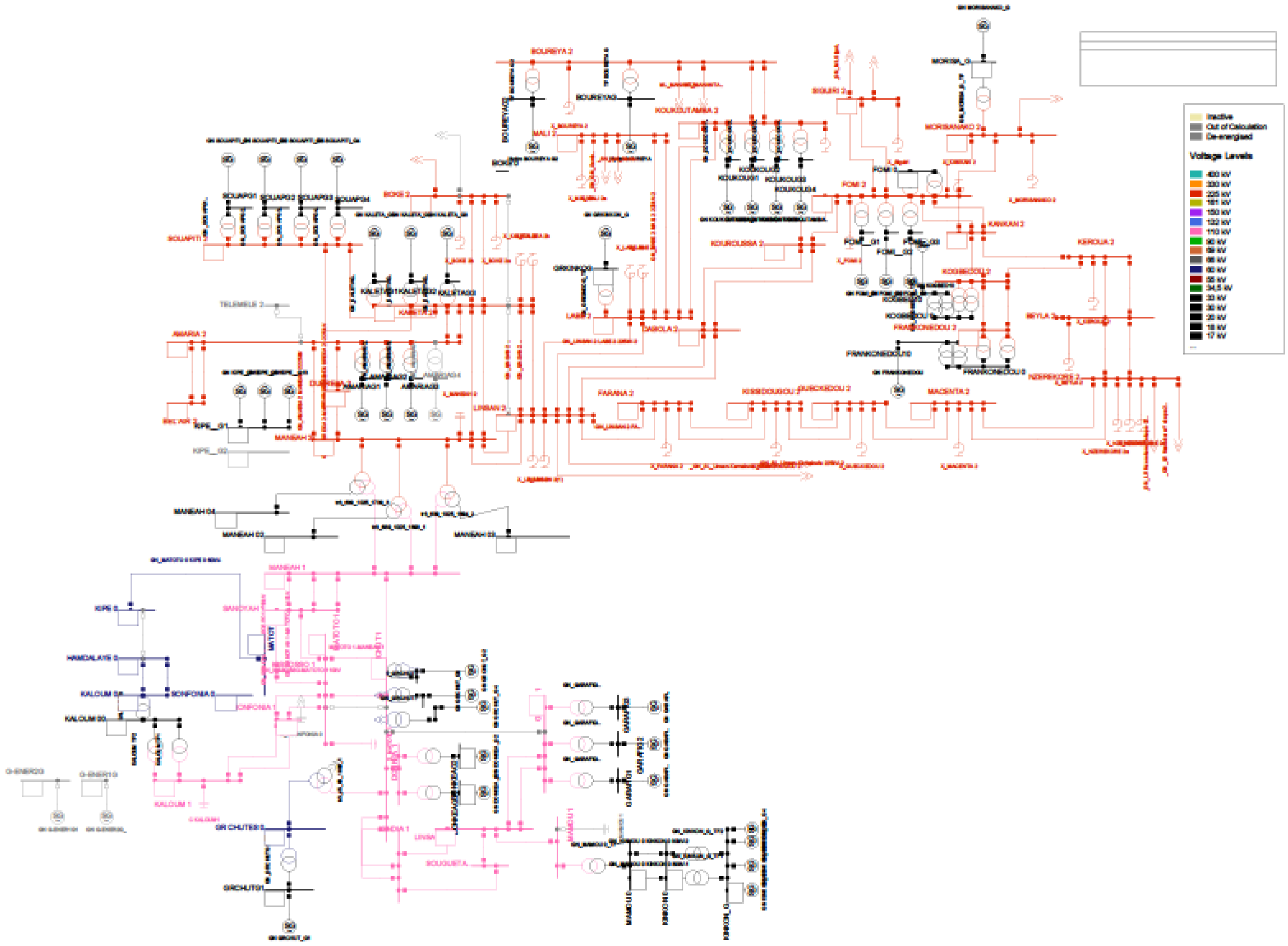

Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV
To DAWA (Ghana)
To IKEJA WEST (Nigeria)

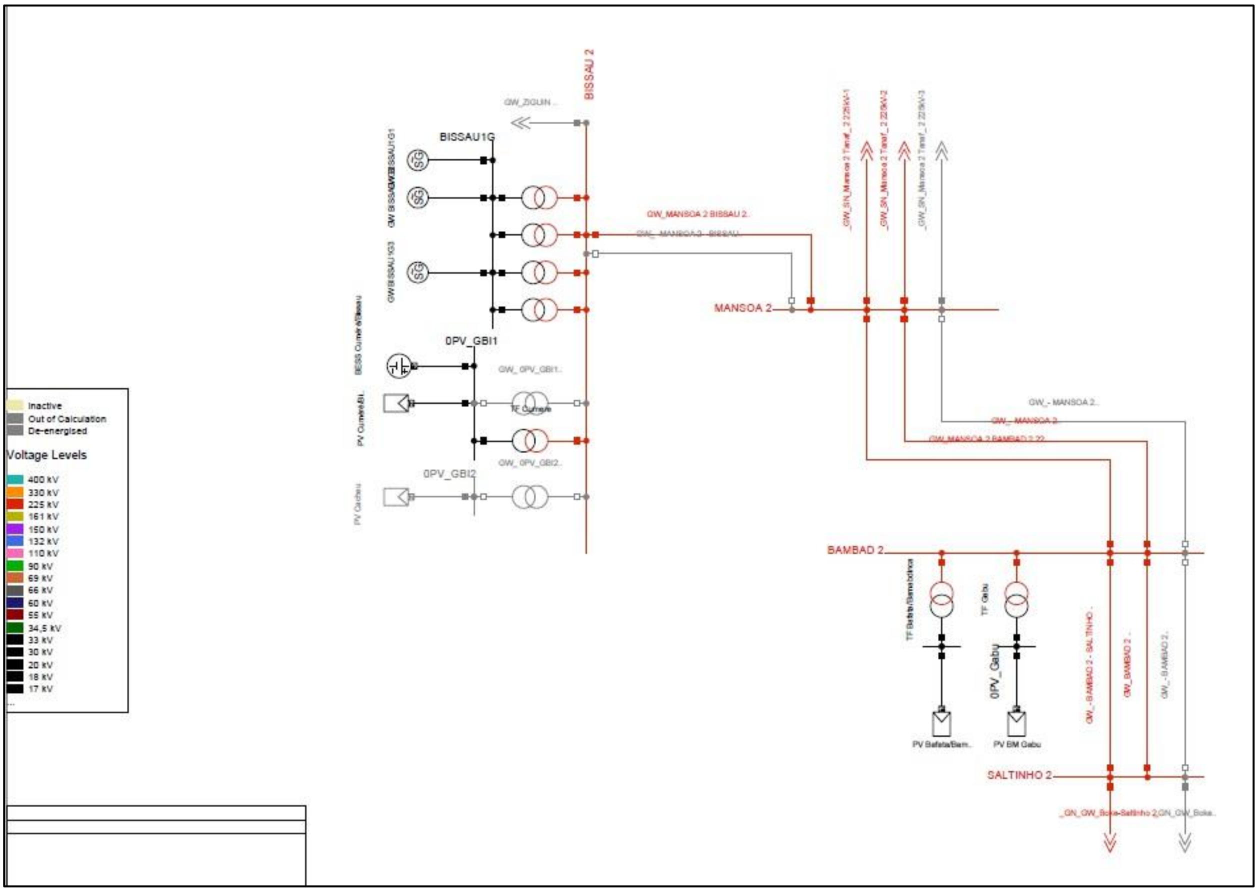


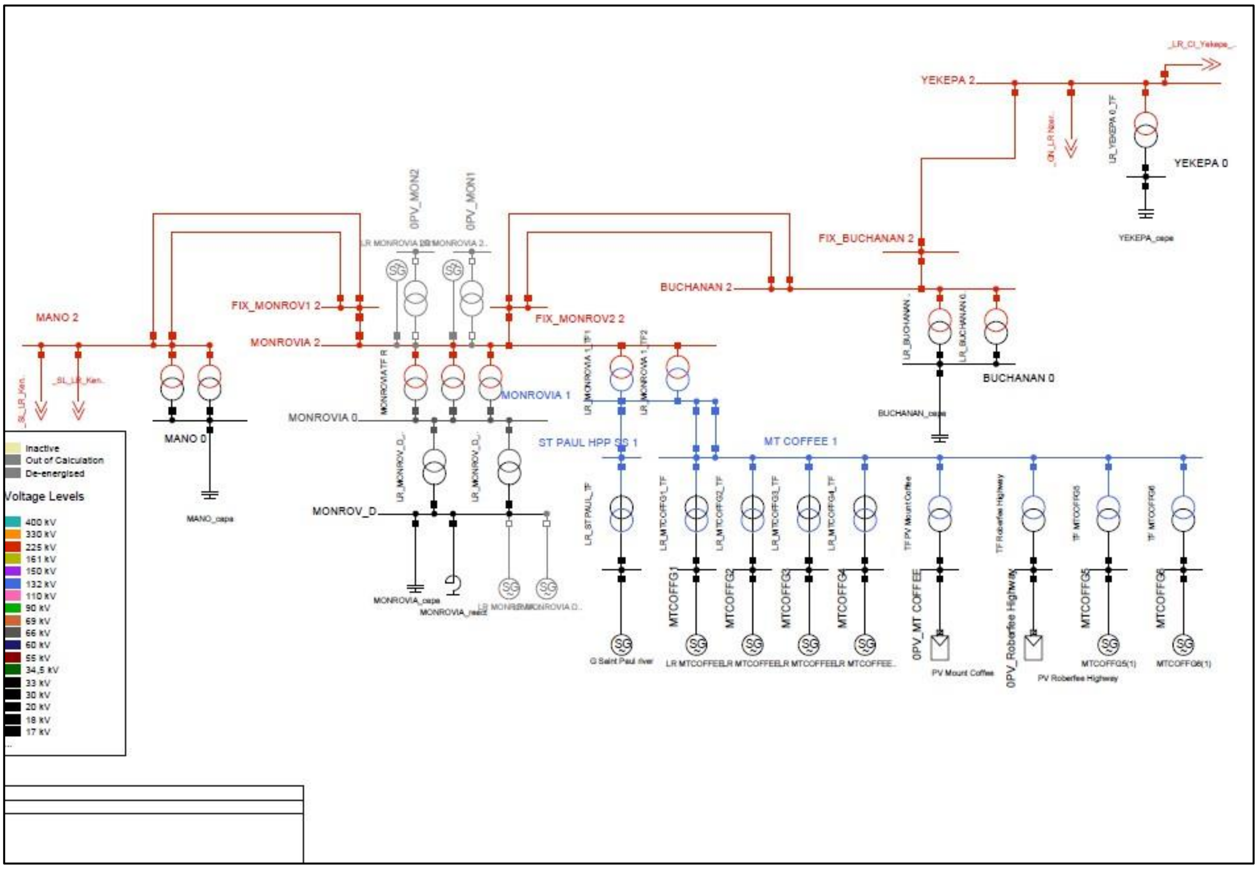


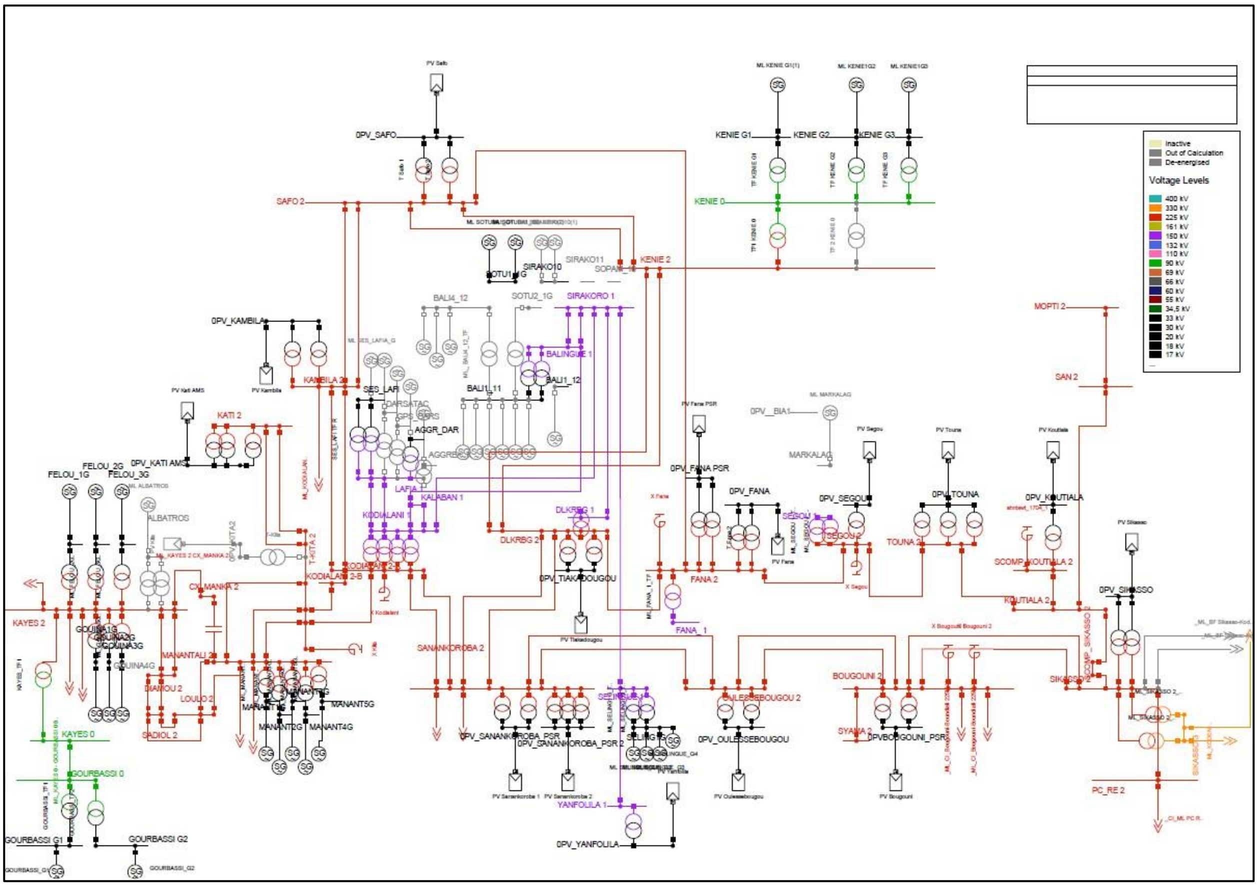


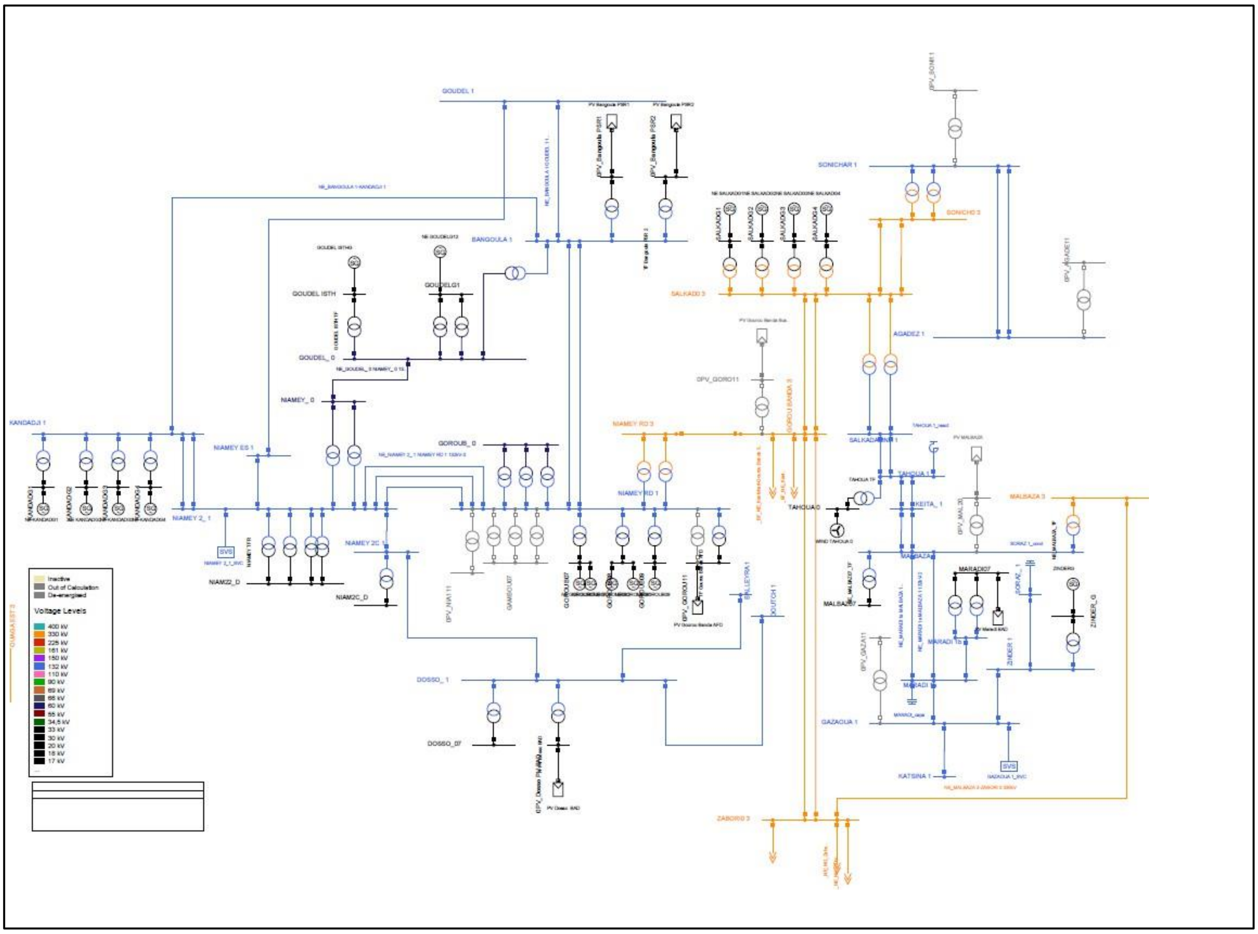
KAOLAC 2
KOTUG5
KOTUG5 TF
KOTU 2
BRIKAM1G
SOMA 2
0PV_Bwiam PV
BRIKAMA 0
0PV_GMB2(1)
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV
JABANGA 1
0PV_GMB1(1)
SOMA 0
ZIGUIN 2
TANAF_2

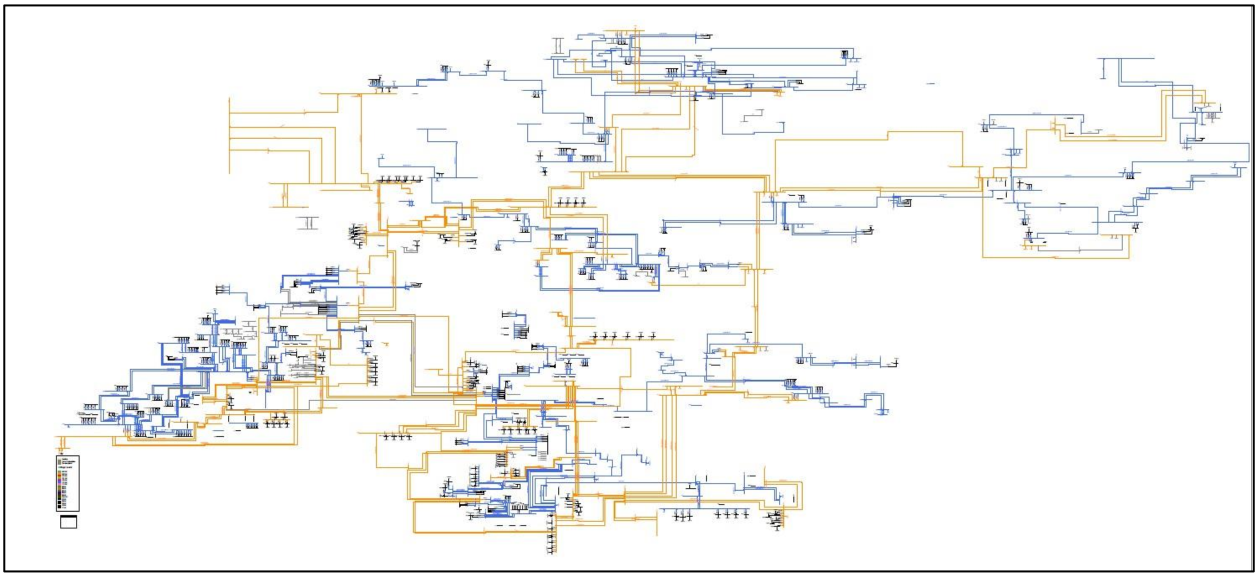


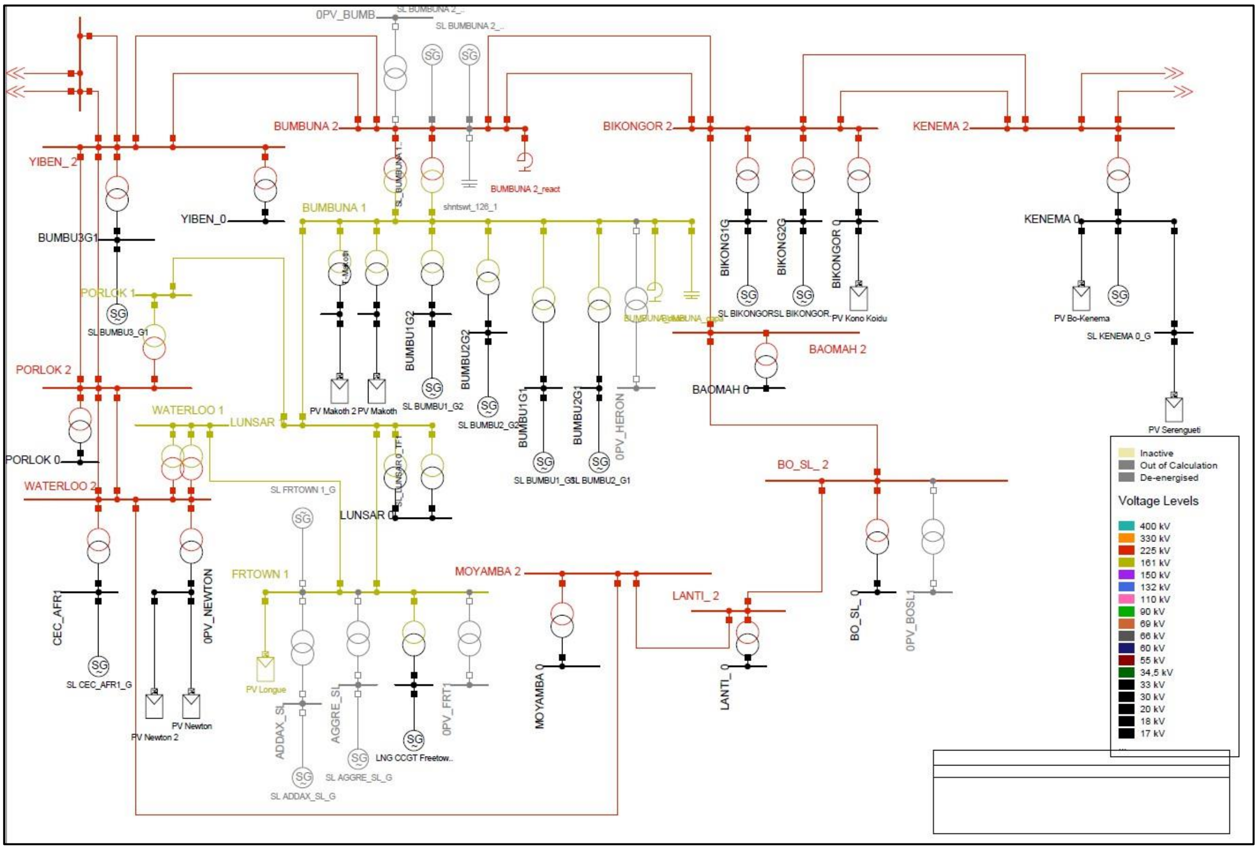

BISSAU 2
BISSAU1G
0PV_GBI1
0PV_GBI2
MANSOA 2
BAMBAD 2
SALTINHO 2
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV




KENIE 2
SAFO 2
KAYES 2
KATI 2
FANA 2
BOUGOUNI 2
SIKASSO 2
KOUTIALA 2
SANANKOROBA 2
OUELESSEBOUGOU 2
MANANTALI 2
KODIALANI 1
KALABAN 1
SIRAKORO 1
MOPTI 2
SAN 2
KENIE 0
KAYES 0
GOURBASSI 0
GOURBASSI G1
GOURBASSI G2
FELOU_1G
FELOU_2G
FELOU_3G
ALBATROS
DPV_TIAKADOUGOU
DPV_YANFOLILA
YANFOLILA 1
DPV_SEGOU
DPV_TOUNA
DPV_KOUTIALA
DPV_SIKASSO
DPV_FANA
DPV_FANA PSR
DPV_KAMBILA
DPV_SAFO
KENIE G1
KENIE G2
KENIE G3
Voltage Levels
Inactive
Out of Calculation
De-energised
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34.5 kV
33 kV
30 kV
20 kV
18 kV
17 kV


GOUDEL 1
BANGOULA 1
SONICHAR 1
SONICHI 2
SALKADO 3
AGADEZ 1
KANDADJI 1
NIAMEY ES 1
NIAMEY 2_1
NIAMEY 2C_1
NIAMEY_0
GOUDEL_0
GOUDEL ISTH
NIAMEY RD 3
NIAMEY RD 1
GOROUB_0
NIAM22_D
NIAM2C_D
DOSSO_1
DOSSO_07
TAHOUA 0
TAHOUA 1
MALBAZA 3
MARADI 1
GAZAOUA 1
KATSINA 1
ZINDER 1
ZABORI 3
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV





0PV_BUMB
SL BUMBUNA 2_
BUMBUNA 2
BUMBUNA 2_react
BIKONGOR 2
KENEMA 2
YIBEN_2
YIBEN_0
BUMBU3G1
BUMBUNA 1
shntswt_128_1
PORLOK 1
SL BUMBU3_G1
PORLOK 2
PORLOK 0
WATERLOO 1
LUNSAR
WATERLOO 2
PV Makoth 2
PV Makoth
BUMBU1G2
BUMBU2G2
SL BUMBU1_G2
SL BUMBU2_G2
BUMBU1G1
BUMBU2G1
SL BUMBU1_G1
SL BUMBU2_G1
0PV_HERON
BIKONG1G
BIKONG2G
BIKONGOR 0
SL BIKONGOR
PV Kono Koidu
BAOMAH 2
BAOMAH 0
KENEMA 0
PV Bo-Kenema
SL KENEMA 0_G
PV Serengueti
BO_SL_2
BO_SL_0
0PV_BOSL
LUNSAR 0
SL FRTOWN 1_G
FRTOWN 1
MOYAMBA 2
MOYAMBA 0
LANTI_2
LANTI_0
CEC_AFR1
SL CEC_AFR1_G
0PV_NEWTON
PV Newton 2
PV Newton
PV Longue
ADDAX_SL
AGGRE_SL
SL AGGRE_SL_G
SL ADDAX_SL_G
LNG CCGT Freetow..
0PV_FRT1
Inactive
Out of Calculation
De-energised
Voltage Levels
400 kV
330 kV
225 kV
161 kV
150 kV
132 kV
110 kV
90 kV
69 kV
66 kV
60 kV
55 kV
34,5 kV
33 kV
30 kV
20 kV
18 kV
17 kV