Final Report

Consultancy Services & Owner's Engineer for the Synchronisation of WAPP Interconnected Network

Benin

West African Power Pool

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December - 2016

Interim Report

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1 Executive summary

The Member States of the Economic Community of West Africa States (ECOWAS) have resolved to establish a well-functioning, cooperative, power pooling mechanism for West Africa known as the West African Power Pool (WAPP). WAPP is envisaged as a mean to providing the citizen of the Member States access to stable and reliable electricity at affordable costs through the interconnected Power Systems of member states.
To this end, the Joint Venture Lahmeyer International GmbH and CESI S.p.A. is in charge of the WAPP synchronization project, aimed at identifying the necessary actions to be undertaken in order to allow a synchronized operation of all existing WAPP interconnected countries (Senegal, Mali, Ivory Coast, Ghana, Togo, Benin, Nigeria, Burkina Faso and Niger) and Mauritania.
The project is divided in two phases: phase one deals with the identifications of necessary networks reinforcements and adaptation of operational rules stated in the WAPP Operation Manual, while phase two is related to the owner's engineering for commissioning the identified reinforcements and to support WAPP in the synchronization attempt.

The current Final Report document summarizes the main findings of phase one, and is organized as follows:

- Chapter 1, Executive summary: it provides an overview of main criticalities and actions necessary for a successful synchronization of the WAPP network;
- Chapter 2, Implementation Road Map: it proposes a stage-wise road map, stating targets, procedures, timelines for implementing the recommendations output of phase one of the study;
- Chapter 3, Back-to-back HVDC alternatives at Sakété and North Core interconnections: it presents a further analysis on the back-to-back HVDC alternative discussed during the Interim Report Workshop;
- Chapter 4, General recommendations on Renewables integration: it summarizes some observations and recommendations on the impact of RES penetration within the WAPP network.

During phase one, a network model has been built in order to perform static and dynamic analysis, aimed at identifying necessary network reinforcements; a measurement campaign has been carried out in nine generating units across the WAPP countries, intended to gather necessary information for assessing the dynamic behaviour of the network and update the network model database. Those activities, together with the analysis of the WAPP Operation Manual and a comparison with data collected and actual implementation of the operating rules, have resulted in the following main findings:

- Necessity to strengthen the collaboration between WAPP and member states, especially for data exchange and for creating permanent working groups, with the scope to review and update operating procedures and studies and ensuring a safe synchronized operation of the WAPP network;
- The level of operation rules implementation varies among the member states; this is the main obstacle to a successful synchronization of the network. It is of utmost importance and first priority to address this issue before any synchronization attempt; provided that a full compliance with the rules stated in the WAPP operation manual is not achieved within

the next couple of years, it will be at least necessary to share and agree to a Road Map for meeting a minimum set of targets, as presented in the following chapters. The successful synchronization will require a strong commitment by WAPP and all member states;

- It must be underlined that even the compliance with the mentioned minimum set of targets could prove difficult for involved utilities given the as-is situation (e.g. impossibility to enforce regulations to local stakeholders, as IPPs, which already have a contract not including compliance with those rules); for this reason, as the Road Map is adopted, it is strongly recommended to involve and on-board regulatory bodies of each member state to ensure the necessary commitment at all decision-making levels;

The Road Map also includes the list of proposed short-term reinforcements based on the results of simulation analysis. Different priorities (high, medium and low) have been associated to each reinforcement.

The back-to-back HVDC link alternative at Sakété substation has been investigated as a solution to be considered in case the observed criticalities (in particular generation deficit and lack of primary reserve) in the Nigerian power system cannot be successfully solved. Some investigations on costs and benefits of this solution have been provided.

In the last chapter some general recommendations are provided for an effective and smooth variable renewables integration according to international best practices and experience from countries with high amount of installed renewable generation.

2 Implementation Road Map

2.1 Introduction

According to the project scheduling, that has been updated in accordance with WAPP to accommodate the additional work required to carry out phase one activities, contracts awarding to begin phase two are foreseen during first months of 2017.

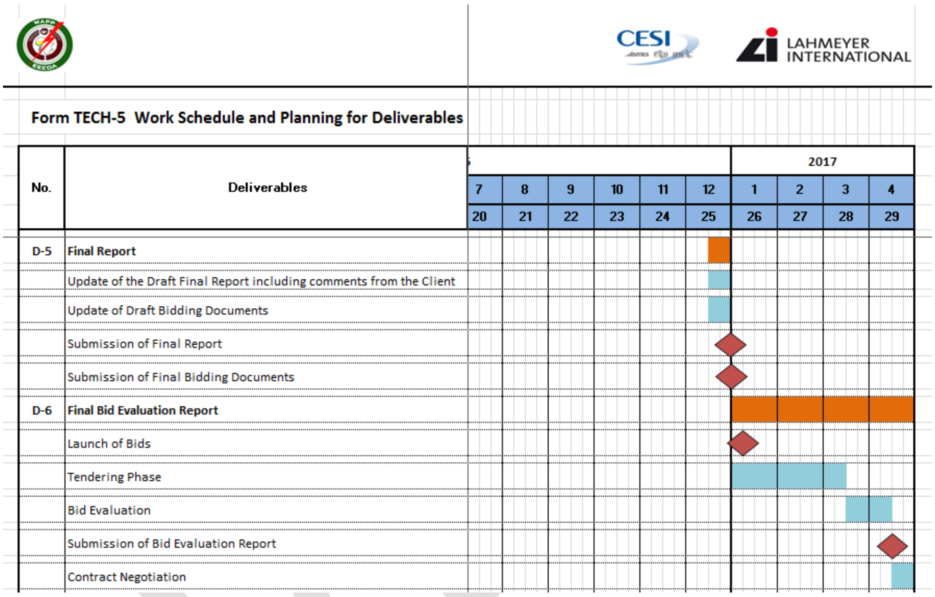


Figure 1: summary of phase one remaining activities

Phase two is related to the Owner's Engineering and supervision of the reinforcements construction identified during phase one studies; however, since the output of the analysis has underlined the necessity to fill several gaps (as reported in the next paragraphs and in the Interim Report [1]) before any synchronization attempt, it is necessary to detail a Road Map containing actionable steps to guide WAPP and the member states to meet the proposed targets.

The aim of this chapter is to illustrate targets and procedures to be implemented during the coming months and years until the completion of phase two.

2.2 Operational procedures adaptation

2.2.1 Introduction

As reported in the Interim Report [1], a minimum set of targets and actions have been identified, according to three priority levels, as reported in the following table. Those targets will be mapped into a specific timeline, according to phase two activities.

The actual implementation of the recommendations below (or at least those which require an implementation within the different member states) shall be managed and monitored by WAPP organization as dedicated projects (some of them may be anyway grouped in a unique project). The Consultant recommends to structure each specific project with a dedicated team composed of the following members:

- 1 project manager from WAPP for the roll-out of the project, the coordination of the team and the actions and the monitoring of the correct implementation in the different member states;
- 1 technical advisor for the development of a detailed technical framework of the project, for a critical analysis/review of the decisions taken by the team and for providing support to any technical issue which may arise during the implementation;
- 1 representative of each of the member state (or at least each of those involved in the specific project); the representative shall be officially nominated by the member state and shall be actually empowered for the implementation of the project within the member state.

The project shall start with an implementation deadline already defined and shall comprise periodic meetings to verify the state of the work-in-progress in the different member states and the respect of the deadlines. Restrictive measures or “sanctions” may be developed to get an effective full commitment of all the member states.

Table 1: Recommendations for the operational procedures adaptation

Short Term Actions (Priority 1)	Medium Term Actions (Priority 2)	Long Term Actions (Priority 3)
ST1: Annual revision and publication of the minimum expected values of primary control reserve and network frequency characteristic	MT1: Implementation of a compliance monitoring process of generating units	LT1: Implementation of a secondary frequency control on all the control areas
ST2: Establish criteria and list of generating units participating to primary frequency control	MT2: Implementation of a compliance monitoring process of utilities	LT2: General revision of WAPP Operation Manual
ST3: Establish technical requirements of primary frequency control	MT3: Statistical analysis of ACE	LT3: Tests of System Defense Plan and Restoration Plan
ST4: Accounting for primary control reserves in dispatching activities	MT4: Execution of operational security analyses in operational planning	
ST5: Automatic calculation of ACE	MT5: Assessment of NTC of tie-lines	
ST6: Definition of quality targets and statistical analysis of frequency	MT6: Harmonization of the UFLS schemes	

It is important to underline that the Consultant discourages any synchronization attempt until all the minimum targets are met.

Each recommendation and action is presented here below with a specific implementation timeframe. It must be noted that the long term recommendations are not included in the roadmap timeline, since they are measures to be implemented in the following 5/7 years, and thus they don’t represent mandatory actions before the synchronization attempt. Nevertheless some recommendations have been provided regarding the first steps which shall start in the short/mid-term.

2.2.2 ST1: Annual revision and publication of the minimum expected values of primary control reserve and network frequency characteristic

Each year WAPP shall calculate and publish on its website the minimum expected primary control reserve and the minimum expected network power frequency characteristic values. These values shall be defined for the overall network and for each Control Area, based on considerations on the Primary Control target. The calculated values shall then be officially communicated to each Control Area Operator. WAPP shall remind to TSOs that they shall guarantee these minimum value 100% of the time in order to ensure the Power System Reliability with respect to the standards defined in the Operation Manual.

The minimum primary reserve value for the overall WAPP network is based on the **reference incident**, which is currently equal to **390 MW** according to the WAPP Operation Manual (simultaneous loss of the largest unit in Nigeria and Ghana, more precisely at Egbin and Akosombo power plants).

The Primary Control Reserve contribution of each Control Area shall be calculated according to a defined and agreed allocation criteria. It is recommended to adopt the ENTSO-E methodology [3]: such approach defines a contribution coefficient for each control area which represents the share of the sum of the energy produced and consumed in one year in the control area in proportion to the entire power system. The sum of all contributions coefficients of all control areas therefore shall amount to 1:

Each Control Area "i" shall contribute with an internal primary reserve (Ri) which represents a part of the total primary control reserve (Rtot) of the interconnected power system and is calculated as follows:

$$Ri = Ci * Rtot$$

$$Ci = Ei/Etot$$

- Ei = electrical energy produced and consumed in one year in the control area "i";
- Etot = total electrical energy produced and consumed in one year in all control areas of the interconnected network;
- Ci = contribution coefficients of the control area "i".

In Table 2 is shown the calculation of reserve and network frequency characteristic based on the data of the year 2015 provided by WAPP.

Implementation timeframe (from the final meeting for phase one of the current project):

- **Within two months WAPP and the utilities shall agree on the common criteria to calculate the primary frequency control;**
- **Each year within the end of February WAPP shall calculate and communicate the updated values.**

Table 2: Primary Reserve and Network Frequency Characteristic Calculation

Area	Generation + Consumption 2015 (GWh)	Contribution coefficient ci (%)	Minimun Primary Reserve (MW)	Minimun Network Power Frequency Characteristic (MW/Hz)
TCN	60831	53%	205	1025
CEB	3201	3%	11	54
NIGELEC	1057	1%	4	18
SOGEM	1118	1%	4	19
GRIDCo	22286	19%	75	375
CIE	16353	14%	55	275
SONABEL	2243	2%	8	38
EDM-SA	2245	2%	8	38
SENELEC	6436	6%	22	108
TOTAL	**115769**	**100%**	**390**	**1950**

2.2.3 ST2: List of generating units participating to primary frequency control

The current lack, in most of the member states, of an actual policy concerning primary frequency control represents a strong barrier for TSOs to procure the necessary primary frequency reserve. The first step to close the gap is therefore that TSOs and/or authorities specify within their Grid Codes the units which shall take part to primary frequency control. Usually, all the units connected to the transmission network shall be included but also the most relevant units connected to the distribution networks, especially in a scenario of increasing distributed generation. The definition of thresholds in terms of rated power and/or voltage level of the connection point shall be based on an analysis of the power system operating conditions and especially on the units which are, on average, grid-connected and on their characteristics. Special attention shall be paid to the off-peak operating conditions as they usually represent the most critical ones. The units participating to primary control shall be identified in order to cover in all the normal operating conditions the primary reserve assigned to a specific power system (or control area).

Reliability criteria shall also be taken into consideration in the definition of the thresholds with the scope of limiting the share of the primary reserve concentrated in a single unit. The definition of the criterion shall be theoretically based on long term statistical analyses but a limit of **5%** of the overall primary reserve provided by a single unit is a value commonly accepted and used [3].

For WAPP power system, with an overall minimum primary reserve of 390MW, it means that no more than 19.5MW of primary reserve shall be provided by a single unit. It also represents about 9% of the largest units of WAPP power system (i.e. the steam turbines of Egbin power station). The respect of such constraint shall be verified once the thresholds for the participation to primary control have been decided.

Three different scenarios are taken in consideration for the selection of generating units which shall participate to primary frequency control (see

Table 3).

- **<u>Scenario 1</u>** represents the current situation, i.e. considering only the units which have been declared by utilities as participating to primary frequency control (details are shown in Table 4);
- **<u>Scenario 2</u>** represents a situation in which the thresholds for the participation to frequency control are set in different way among the countries in order to get an average share of primary reserve aligned with the reliability criterion (details are shown in Table 5).
- **<u>Scenario 3</u>** considers that not only the units connected to the transmission network but also the main units connected to the distribution networks (only for the power systems of NIGELEC, SONABEL and EDM-SA) participate to primary frequency control (details are shown in Table 6).

Table 3: Amount of installed power of units participating to primary frequency control

Area	Minimum primary reserve to be procured [MW]	Total Installed Capacity of units participating to frequency control [MW]			
		Scenario 1 [MW]	Scenario 2 [MW]	Scenario 2 criterion	Scenario 3 [MW]
TCN	205	4584	10706	>100 MW	13169
CEB	11	91	321	>10 MW	401
NIGELEC	4	0	104	>10 MW	194
SOGEM	4	200	260	>10 MW	260
GRIDCo	75	1595	2803	>100 MW	4463
CIE	55	210	1090	>100 MW	1874
SONABEL	8	173.5	274	All	274
EDM-SA	8	0	241	>10 MW	297
SENELEC	22	0	600	>10 MW	684
TOTAL	**390**	**6854**	**16399**		**21616**

Since the primary reserve shall be ensured in all the operating conditions, an analysis shall be performed on the worst operating conditions which means, for primary frequency reserve, the off-peak conditions. The following tables present the results of the analysis for three different scenarios:

Table 4: Scenario 1 – Share of primary reserve among the regulating units

Area	Minimum primary reserve to be procured [MW]	Scenario 1	
		Installed capacity of units participating to frequency control [MW]	Share of primary reserve for each participating unit [%]
TCN	205	2198	9%
CEB	11	58	19%
NIGELEC	4	0	-
SOGEM	4	200	2%
GRIDCo	75	1092	7%
CIE	55	140	39%
SONABEL	8	37	20%
EDM-SA	8	0	-
SENELEC	22	0	-
TOTAL	390	3725	10%

Table 5: Scenario 2 – Share of primary reserve among the regulating units

Area	Minimum primary reserve to be procured	Scenario 2		
		Installed capacity of units participating to frequency control		Share of primary reserve for each participating unit
	[MW]	[MW]	criterion	[%]
TCN	205	4589	>100 MW	4%
CEB	11	108	>10 MW	10%
NIGELEC	4	38	>10 MW	9%
SOGEM	4	240	>10 MW	2%
GRIDCo	75	1770	>100 MW	4%
CIE	55	798	>100 MW	7%
SONABEL	8	64	All	12%
EDM-SA	8	35	>10 MW	22%
SENELEC	22	178	>10 MW	12%
TOTAL	**390**	**7820**		**5%**

Table 6: Scenario 3 – Share of primary reserve among the regulating units

Area	Minimum primary reserve to be procured	Scenario 3	
		Installed capacity of units participating to frequency control	Share of primary reserve for each participating unit
	[MW]	[MW]	[%]
TCN	205	5510	4%
CEB	11	118	9%
NIGELEC	4	64	6%
SOGEM	4	240	2%
GRIDCo	75	2405	3%
CIE	55	1233	4%
SONABEL	8	64	12%
EDM-SA	8	41	18%
SENELEC	22	193	11%
TOTAL	**390**	**9868**	**4%**

From the above tables, the scenario 2 seems to be the most suitable for WAPP power system for the following reasons:

- It ensures the requirement of the minimum primary reserve which shall always be available (390MW), even in the off-peak operating conditions,

- Setting to 5% of the rated power of each unit participating to frequency control, the share of power which shall be dedicated to primary frequency control (primary reserve), the scenario 2 can also ensure the respect of the requirement for the reliability of the primary reserve, even in the worst operating conditions like off-peak. The Table 5 shows that in this case, the share of primary reserve does not exactly match the expected distribution among the member states but can be easily compensated with the introduction of secondary control and shall not therefore represent a constraint.

The above analyses shall be periodically performed and reviewed by WAPP. They shall then be further discussed with the member states and sent to the competent national authorities as they represent technical information to be used for the revisions and updates of the national Grid Codes for what concerns the participation to primary frequency control.

Implementation timeframe (from the final meeting for phase one of the current project):

- **Within two months WAPP and the utilities shall agree on the criteria and the list of units participating to primary frequency control;**
- **Within fourteen months the identified units shall be under primary frequency control.**

2.2.4 ST3: technical requirements of primary frequency control

Among many technical requirements for primary frequency control, according to the proposed approach aimed at identifying suitable actions for minimizing the time required to synchronize the WAPP network, the Consultant suggests to concentrate on droop/dead band and primary reserve settings.

The criteria, list and size of the primary reserve have been discussed in the previous paragraphs. Especially, it has been analyzed into details the reasons why the Consultant recommends that each single generating unit participating to frequency control shall keep at least a **5% reserve margin** with respect to the maximum and minimum load of the unit, to be dedicated to primary frequency control and to be delivered if and when required.

Two other key elements of the primary frequency control provided by each participating unit are the specifications of the settings of droop and dead-bands. Concerning dead-bands settings, the measurement campaign [6]. and following analysis have demonstrated that the current settings are not compatible with a safe and effective synchronous operation of the overall power system. The primary frequency target, as defined in [2], is to control the frequency within the standard frequency range (i.e. 50Hz ±200mHz) even in the occurrence of the Reference Incident (loss of 390MW). It means that the dead-bands set on the primary frequency control provided by the participating units shall be small enough with respect to the ±200mHz of the standard frequency range, otherwise the primary frequency control would be ineffective to face disturbances or equipment faults. Typical value are about 10% of the standard frequency range, i.e. ± 20mHz.

The Consultant recognises that such values are far from the current values adopted by power producers but also wants to put in evidence that the reduction of the dead band is one of the fundamental step before any new synchronisation attempt could be scheduled. The Consultant may propose to have a reduction in two steps:

- **Set dead band settings to ± 50mHz on all the units participating to primary frequency control within the first six months from the final meeting for phase one of the current project;**
- **Set dead band settings to ± 20mHz on all the units participating to primary frequency control within 1.5 years from the final meeting for phase one of the current project.**

It is of utmost importance to align the dead-band settings in all the generating units in order to assure a coordinated and balanced primary frequency control.

As far as frequency droop is concerned, the standard values usually set into the speed governors of generating units correspond to a typical value of 4-5%. These settings are in line with the values measured on the generating units during the measurement campaign [6]. The Consultant recommends therefore to adopt such settings on all the generating units participating to frequency control (i.e. the generating units of the scenario 2 above described) with the following refinement:

- The frequency droop to be adopted for gas and hydro turbines shall be at maximum 4%;
- The frequency droop to be adopted for all the other generating units shall be at maximum 5%.

Moreover, with reference to the above mentioned scenario 2 concerning the generating units participating to frequency control, these settings also ensure a correct network frequency characteristic [MW/Hz] in all the operating conditions, even in off-peak. As a matter of fact, the primary frequency control target in off-peak conditions requires that the 390MW of primary reserve shall be provided for a frequency deviation of 200mHz; taking into account a frequency dead-band of 50mHz, it means that the minimum network frequency characteristic shall be about 2600MW/Hz, which represents an average frequency droop of 6% for the units participating to frequency control in such conditions.

2.2.5 ST4: Accounting for primary control reserves in dispatching activities

The major gap the Consultant has identified is related to primary frequency control management across the WAPP network; nevertheless, short term recommendations 1, 2 and 3 wouldn't be effective without proper planning and accounting of primary frequency control requirements during operational planning, and in particular D-1 activities.

For this reason, it is suggested that each utility shall prepare, if not already present, a day-ahead unit commitment plan according to the following steps:

- Utilities:
    - A load forecast (hourly) shall be prepared for the day ahead;
    - For each hour, the list of unit in service shall be prepared, indicating set points to cover the load as per load forecasting. IPPs and renewables shall be taken into account as well;

- For each unit participating in primary frequency control, the minimum requirements, as stated in the previous recommendations, shall be respected; especially, a 5% primary control margin shall be ensured and therefore the participating unit shall not be committed with a load greater than 95% of the declared maximum load or lower than 105% of the declared minimum load.
- Unit commitment plan shall be sent to WAPP within 1 p.m. of D-1;

- WAPP:
  - Shall collect the unit commitment sheet from all the utilities, and cross check that all the requirements are met, otherwise perform a check with the concerned parties.

Implementation timeframe (from the final meeting for phase one of the current project):

- **Within two months WAPP and the utilities shall agree on a common format/sheet and mean of data exchange;**
- **Within 6 months all the Utilities shall perform the above suggested actions;**
- **Within 1 year the overall process shall be in place as described.**

It must be noted that the short term recommendation 4 will overlap with medium term recommendation 4. In particular:

- **Within 2 years the described activities shall include an operational security check, as described in medium term recommendation 4.**

2.2.6 ST5: Automatic calculation of ACE

As defined in [2], each control area shall be operated by an individual load dispatch center that has the responsibility for the transmission system operation of this area, including the responsibility for availability, operation and provision of primary and secondary frequency controls within the control area to maintain the power interchange of its control area at the scheduled value and, consequently, to support the restoration of frequency deviations in the interconnected network. Control areas are usually coincident with the territory of a TSO or a country. Moreover, another prerequisite for an area of a power system to be defined as a control areas is the availability of sufficient controllable generation to compensate the foreseen net load variation.

The combination of these two elements in the case of WAPP power system as well as the indications reported in [2] lead to the definition of the following control areas (Table 7). The table also reports the minimum expected primary reserve and the minimum network frequency characteristic assigned to each control area and which shall always be ensured by the responsible control area operator and also suggests a possible control area operator (see also [2]). In any case, the nomination of control area operator shall be agreed between the different operators and the decision may also include considerations on the infrastructure actually available as well as already existing technical and commercial agreement for the tie-line power exchange.

Table 7: Definition of the proposed control areas

Control Area	Minimum primary reserve to be procured [MW]	Minimum expected network frequency characteristic [MW/Hz]	Suggested control area operator
TCN+NIGELEC	208	1042	TCN
CEB + GRIDCo	86	429	GRIDCo
SOGEM+SENELEC+EDM-SA	33	165	SENELEC
CIE + SONABEL	63	313	CIE
TOTAL	**390**	**1950**	

Starting from the above definition of the control areas and their technical parameters, each control area operator shall define an internal process to automatically calculate and update its ACE. WAPP shall monitor the correct implementation of the calculus and the use of correct parameters.

Implementation timeframe (from the final meeting for phase one of the current project):

- **Within 6 months all the control area operators shall be nominated and shall perform the above suggested actions.**

2.2.7 ST6: Definition of quality targets and statistical analysis of frequency

The synchronization of WAPP power system requires to get similar qualities parameters of frequency control in the different areas.

According to the studies and analyses performed, the Consultant suggests to set a short-term reference target according to the current values of GRIDCO/CIE/SONABEL power system in order to get an homogeneous quality of frequency control over the different power systems. Once this first goal has been achieved, the targets shall then be further improved in the following years in order to improve the overall quality of frequency control within WAPP power system.

Table 8: Frequency statistics from the measurement campaign

Control Area	Measurement Time	Time with Δf < 200mHz	Time with Δf > 200mHz
Nigeria – Niger	21445	26.7%	73.3%
Mali – Sénégal	4320	50.5%	49.5%
Ghana – Cote d'Ivoire	12960	75.4%	24.6%

The KPIs that shall be taken into account are:

1. % of Time with Δf < 200mHz;
2. % of Time with Δf > 200mHz.

The implementation timeline shall be as follows (from the final meeting for phase one of the current project):

- **Within 6 months, all the control areas shall be operated for more than 50% of time with frequency deviations lower than 200mHz;**
- **Within 1 year, all the control areas shall be operated for more than 75% of time with frequency deviations lower than 200mHz;**
- **Within 2 years, all the control areas shall be operated for more than 85% of time with frequency deviations lower than 200mHz;.**

The possibility to reach the above targets quasi exclusively depend on the implementation of the previous recommendations; in that sense, the above KPI also represents an index of the level of implementation of the previous recommendations.

The calculus of the KPI shall be performed by each control area operator on an annual base of time and shall be updated every month. The data collection process shall be defined as follows:

1. All TSOs of a Synchronous Area shall calculate and send to WAPP, monthly (e.g. by , the measurement of System Frequency and data of each KPI presented in the above list);
2. WAPP shall keep track, update and publish on its website the KPIs for all the WAPP member utilities;
3. WAPP shall define a proper file exchange form (e.g. in excel format) and means of exchange (e.g. upload on a shared area/email).

WAPP shall monitor the correct implementation of the process and critically review the data sent by the control area operators. In case the above indicated targets are not reached, the control area operator shall give evidence of the causes and remedial actions shall be discussed and agreed between WAPP and the responsible control area operator.

2.2.8 MT1: Implementation of a compliance monitoring process of generating units

As pointed out during the analyses performed, there are currently large differences between expected and actual characteristics of frequency control due to a lack of, among other:

- detailed requirements for frequency control;
- specific knowledge of power plant operators.

It is then suggested to WAPP to promote actions to build and develop specific technical capacity for the implementation of a monitoring process of the compliance of generating units; in particular:

- Each year WAPP or a delegated external certification body shall perform a measurement campaign among about 20% of the units participating in the primary frequency control, in order to have all the participating units be assessed within 5 years;
- Scope of the campaign shall be:
    - Check compliance with declared parameters;

- Update the database provided by the Consultant to perform the studies;
- Check the implementation of the mandatory recommendations prior the synchronization attempt.

The Consultant suggests to allocate in phase two of the current project a specific budget to perform such measurement, according to the following timeline (from the final meeting for phase one of the current project):

- **A first measurement campaign shall take place within 1 year;**
- **A second measurement campaign shall take place within 2 years.**

The scope will be, among others, to check the data submitted by the Utilities; in particular the KPIs specified in short term recommendation 6 shall be compliant with the targets sets, otherwise the Consultant discourages any synchronization attempt.

2.2.9 MT2: Implementation of a compliance monitoring process of utilities

Implementing the provisions stated in the WAPP operating manual will take time; for this reason, it is important to monitor the progress through a compliance monitoring process.

Such process shall be built upon the compliance survey developed by the Consultant, and combine it with on-site visits at utilities premises with the scope to:

- analyze the congruity of the responses with respect to actual practices of the utilities,
- analyze with the utilities the actions which shall be taken to improve their compliance level;
- share the results of the survey.

The suggested implementation timeline is as follows (from the final meeting for phase one of the current project):

- **Every year, WAPP shall send the survey to the Utilities;**
- **The Utilities shall submit the survey to WAPP in one month from the receipt;**
- **WAPP shall send to the Utilities the results of the implementation progress;**
- **Once a year, WAPP and the Utilities shall meet to discuss:**
  - **Implementation progress;**
  - **Proper actions, if any;**
  - **Review and update the survey.**

2.2.10 MT3: Statistical analysis of ACE

It is suggested to calculate and keep track of the following statistics regarding secondary frequency control:

- Mean value (calculated over the time needed to restore the frequency defined in the operation Manual, namely 20 minutes);

- Standard deviation (same approach applied for the mean value);

Each utility shall send updated figure to WAPP monthly (within first week of each month); WAPP shall calculate each KPI, keep track of them, update figure for the WAPP network.

The results of such analyses will provide valuable information for the definition of a suitable secondary reserve within each control area.

Implementation timeframe (from the final meeting for phase one of the current project):

- **Within 1 year, all the control area operators shall perform the above suggested actions.**

2.2.11 MT4: Execution of operational security analyses in operational planning

It is strongly suggested that the following provisions are adopted during operational planning phases, in order to anticipate potential problems mainly with frequency control and coordinate proper action across the Utilities within the WAPP network. In particular each Utility shall:

- coordinate with WAPP to data format to exchange individual grid models to be merged into a single WAPP network model (e.g. excel or other standard formats);
- prepare individual grid models for simulating:
  - year-ahead conditions;
  - week-ahead conditions.
- coordinate, develop with WAPP and update each 6 months a common list of year-ahead scenarios to assess the operation of the interconnected transmission system on operational security. The starting point for those scenarios have been provided by the Consultant in the term of the already developed models for the current project. It's WAPP and Utilities responsibility to review and update those models and scenarios for specific purposes and applications. The scenarios (at least two, peak and off-peak, as developed by the Consultant for the current study), shall include the following variables:
  - demand;
  - import/export conditions;
  - contribution from renewable energy sources, as foreseen in the WAPP network in the coming years;
  - unit commitment;
  - planned outages.
- coordinate, develop with WAPP and update week-ahead grid models;
- perform coordinated operational security analyses simulating that the operational security limits are not violated in N and N-1 conditions;
- evaluate coordinated/local proper actions until the system doesn't violate operational security limits in N and N-1 conditions.

This process shall be in place within 1.5 years from the final meeting of phase one of the current project; each 3 months WAPP shall evaluate the implementation status and take proper actions with the Utility to meet the target.

It is recommended to start with the above mentioned timeframes and then include D-1 condition scenarios, to be simulated daily, according to short term recommendation 4.

2.2.12 MT5: Assessment of NTC of tie-lines

WAPP and Utilities shall coordinate in order to assess maximum and net transfer capacity across tie-lines; the methodology, unless decided otherwise by WAPP and the Utilities, shall be the same used to asses transfer limits in the Interim Report of phase one of the current project.

The calculations shall be performed monthly, and the results shall be used as technical constraints limits in the scheduling of the exchanges and as a input for the scenarios used in the operational planning timeframes.

This process shall be in place within 1.5 years from the final meeting of phase one of the current project; each 3 months WAPP shall evaluate the implementation status and take proper actions with the Utility to meet the target.

2.2.13 MT6: Harmonization of the UFLS schemes

The Under Frequency Load Shedding (UFLS) plan is one of the typical remedial actions implemented in the power systems and is considered part of the Defense Plan. The UFLS is designed to quickly and automatically balance the system in case of large generation deficits occurring after the loss of generation or network separations.

It is recommended to perform the harmonization of the UFLS schemes with the following actions:

- agree the characteristics of a harmonized defence plan for the first frequency thresholds in the so-called “solidarity range”, which could be considered according to the ENTSO-E approach [7] and as also recommended in the WAPP Master Plan.
- each individual Utility shall perform the adjustment of its System Defence Plan under the WAPP supervision
- WAPP shall monitor the proper implementation of the updated thresholds (in charge of utilities) on the protection relays of the equipment used for the activation of load shedding actions

This process shall be in place within 2 years from the final meeting of phase one of the current project;

- **The definition and agreement on the revised harmonized UFLS shall take place within 6 months;**
- **The adjustment of the system defence plans shall take place within 2 years.**

Each 6 months WAPP shall evaluate the implementation status and take proper actions with the Utility to meet the target.

As a long-term action it is suggested to evaluate the possibility to include also derivative thresholds in the UFLS schemes. To this purpose in the Interim Report [1] the Consultant has performed simulations to determine harmonized settings which may be adopted in the WAPP system The proposed settings have to be considered as preliminary settings based on a limited amount of significant simulations.

2.2.14 LT1: Implementation of a secondary frequency control on all the control areas

The secondary control process shall be designed in each control area to control the ACE towards zero by activation of secondary reserves within 20 minutes, i.e. the designed time to restore frequency. The implementation of the secondary control process was detailed in [1] and includes several aspects in terms both of infrastructure and procedures.

Furthermore, in order to assure the secondary frequency control to operate in a proper way, it is strictly necessary, as pre-condition, to fulfil the settings and performance requirements of the primary frequency control. For this reason the implementation of the secondary frequency control shall start only after the implementation of the short-term recommendation on primary control.

In the next months (short-term horizon) a survey on the current available infrastructure (e.g. AGC on units, communication system, etc.) for each control area could be performed in order to assess the necessary investments and time. For those control areas with infrastructure already installed the implementation of the secondary frequency control could be anticipated in the mid-term, while for the remaining control area it is necessary to install the required infrastructure before to implement the secondary control.

2.2.15 LT2: General revision of WAPP operation manual

WAPP Operation Manual needs a general revision in different topics as detailed in [1]. The revision of the document could be a long process since it involves many stakeholders (WAPP, Utilities, Authority and regulatory bodies, etc.) and should foresee different phases until the approval of a revised Operation Manual. For this reason this activity was classified as a long-term recommendation (over 2 years). Nevertheless it is recommended to start in the short term with the definition and implementation of the revision process and to establish a working group in charge to perform this task.

2.2.16 LT3: Tests of System Defense Plan and Restoration Plan

To ensure the efficiency of their System Defence Plan and Restoration Plan, each TSO should periodically assess the proper functioning of all equipment and capabilities contributing to these plans.

To this purpose, TSOs should periodically verify the compliance of the capabilities used in those plans, and especially:

- Each TSO shall periodically test (in accordance with the DSOs) the protection relays of the equipment used for the activation of load shedding actions ,
- Each TSO shall periodically test (in accordance with the DSOs) the proper functioning of the communication systems used in the Defence and Restoration Plans,
- Each generating unit participating to the System Restoration Plan and delivering Black Start service shall periodically perform Black Start Capability test,
- Each generating unit participating to the System Restoration Plan and delivering quick re-synchronisation service shall periodically perform full load rejection tests.

TSOs shall also periodically assess and review the effectiveness of their Defence and Restoration Plans. Such analysis shall be carried out on the basis of computer simulation and/or real tests.

WAPP shall supervise and monitor the definition and implementation of the test procedures of each TSO to be included in their grid codes, verifying the compliance with the current and future (revised) Operating Manual.

2.3 Priority list for the proposed reinforcements.

Here below a priority list for the suggested reinforcement is presented, the proposed reinforcements are based on the results of simulation analysis performed on 2016 scenarios and were presented in the Interim Report [1] and the proposed priorities following listed were agreed with WAPP.

2.3.1 High priority reinforcements

- Tuning of PSS in the most relevant units equipped with PSS (installed but not tuned).

  The detailed list of units has been identified according to the information collected through a specific survey submitted to all the utilities.
- Field tests on governors of the most relevant units before the synchronization attempt to check the compliance with the setting targets according to the roadmap (Recommendation MT1, §2.2.8).
- Installation of out-of-step relays at Segou and Sikasso 225 kV substations in Mali (EDM-SA) able to separate EDM-SA and CIE control areas.
- Installation of a special protection scheme at Ferké (CIE) substation, consisting in the installation of an intertrip relay able to trip the 225/90 kV transformer in case of trip of the Ferké – Bouake 2 225 kV line.
- Installation of a special protection scheme at B.Kebbi (TCN) substation, consisting in the installation of an intertrip relay able to trip the two 330/132/33 kV transformers (connecting B.Kebbi 1 132 kV busbars) in case of trip of Kainji – B.Kebbi 330 kV line.
- Installation of a special protection scheme at Kano (TCN) substation, consisting in the installation of an intertrip relay able to trip the two 330/132/33 kV transformers (connecting Kumb T2A 132 kV) in case of trip of Kaduna – Kano 330 kV line.

2.3.2 Medium priority reinforcements

- Installation of an SVC of +/- 30 MVAR at Matam (SOGEM) 225 kV substation
- Upgrade and tuning of PSS in the most relevant units without PSS but with possible upgrade in the exciter to provide the PSS.

2.3.3 Low priority reinforcements

- Installation of PMUs at the interconnections ends.

The first list of PMUs could include only substations with adequate communication systems already installed. In a second phase, together with necessary investments on the communication systems, the installation of PMUs could be extended also to all the identified substations.

- Installation and tuning of PSS in the most relevant units without PSS and without a possible upgrade in the exciter to provide the PSS.
- Installation of an SVC of +/- 20 MVAR at Dosso (NIGELEC, or alternatively Niamey) 132 kV substation (NIGELEC)
- Installation of an SVC of +/- 20 MVAR at Gazaoua (NIGELEC) 132 kV substation (NIGELEC)

2.4 Timeline

Consultancy Services & Owner's Engineer
for the Synchronisation of WAPP Interconnected Network
Phase 2 - Owner's Engineering

Implementation Road Map

No.	Deliverables	2017												2018												2019			
		1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Short term																													
ST 1	Annual revision and publication of the minimum expected values of primary control reserve and network frequency characteristic		Criteria adopted												Values updated														
ST 2	List of generating units participating to primary frequency control		List adopted												Units with p.f.c.														
ST 3	Technical requirements of primary frequency control						D.B.50 mHz						Droop						D.B.20 mHz										
ST 4	Accounting for primary control reserves in dispatching activities		Format adopted				D-1 activities						Complete process												Security check				
ST 5	Automatic calculation of ACE						ACE calculated																						
ST 6	Definition of quality targets and statistical analysis of frequency						50% of target						75% of target												85% of target				
Medium Term																													
MT 1	Implementation of a compliance monitoring process of generating units												1st campaign												2nd campaign				
MT 2	Implementation of a compliance monitoring process of utilities												Survey												Survey				
MT 3	Statistical analysis of ACE												Statistics calculated																
MT 4	Execution of operational security analyses in operational planning																		Analysis performed										
MT 5	Assessment of NTC of tie-lines																		Analysis performed										
MT 6	Harmonization of the UFLS schemes						Settings agreem.																		Settings update				

3 Back-to-back HVDC alternatives at Sakété and North Core interconnections

Task 4 of Project Phase 1 was related to the evaluation of a Back to back DC link alternative at Sakété substation; the objective of the activity was to calculate the costs and effects on the stability of the system of a back-to-back 600 MW DC link alternative in Sakété.
Among exploring two different technologies, it was considered also the possibility to install an alternative configuration, consisting of a 300 MW Back-to-Back DC link expandable to a 2 x 300MW capacity, compared to the 600MW single Back-to-Back HVDC link originally proposed.

As discussed in the Interim Report [1], the back-to-back HVDC link alternative at Sakété substation is a solution to be considered in case the observed criticalities (in particular generation deficit and lack of primary reserve) in the Nigerian power system cannot be successfully solved.
From a technical perspective, the conclusion outlined in the Interim report is:

- The results of the performed analysis shows that both the current available technologies – namely VSC and LCC – are feasible;
- If the deficiencies in the Nigerian power system was effectively solved and the recommended measures to fill the gap with the WAPP Operation Manual was implemented, it would be possible to interconnect the power system without the HVDC link;
- Furthermore, it is important to underline that in the future scenarios (2020) the Nigerian power system should be interconnected not only through the Ikeja – Sakete 330 kV line, since new interconnections are planned (North Core project interconnecting Nigeria, Niger, Benin and Burkina Faso).

It is clear then that the installation of the back-to-back link could be a solution in case the stakeholders will declare that the roadmap proposed in this report, representing the minimum conditions to safely interconnect the system cannot be met in the short-medium term (3-5 years).
In this case, the only viable solution for a secure interconnection is represented by the installation of a back-to-back link, as specified in the Interim Report [1]: it must be noted that this wouldn't be a long term solution, since the provisions stated in the WAPP Operation Manual shall be fulfilled by the Utilities and the discussed challenges properly addressed.

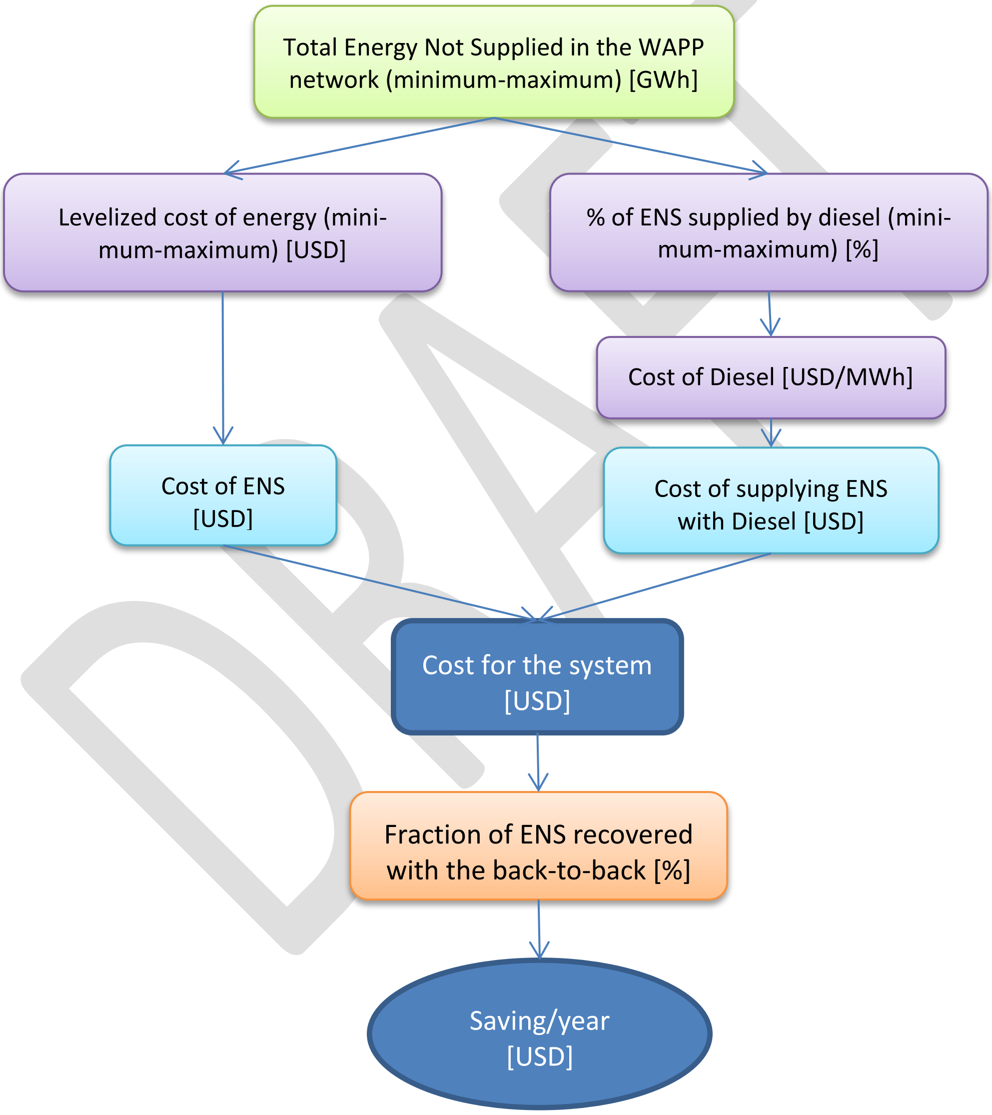
The decision to be taken by WAPP, Utilities and remaining stakeholders involves between 71% and 85% of the total reinforcements costs that have been estimated, and thus it has to be addressed properly.
For this reason, apart from the analysis already developed in the Interim Report, a more qualitative scenario is presented here, considering also the associated costs to install a back-to-back in the area interested by the North Core project.

In particular, it has been supposed that the total amount for the installation of the back-to-back is:

- Least cost configuration and technology, as reported in the Interim Report: 300MW LCC, estimated equal to 67MUSD;
- Back-to-back in the North core region (estimated capacity: 450MW): 87MUSD;
- Total minimum investment: 154MUSD.

As further remark it is important to underline that if a back-to-back will be adopted within the North Core project it is suggested to evaluate also the option to consider DC lines instead of AC, in particular regarding the 330 kV and 450 km line from Goroubanda (Niger) to Ouagadougou Est (Burkina Faso), which should lead to a cost reduction (cost of the overhead DC line about 2/3 of the equivalent AC line, saving on the series/shunt reactive power compensation, while the cost of the converter stations is higher in the range of about 1.5-2).

In order to have a qualitative information regarding the possible benefit associated to the installation of the two back-to-back links, the following approach has been taken into account.



The following assumptions have been made to perform the calculations:

	Total Energy Not Supplied in the WAPP network [GWh]	Levelized cost of energy [USD/MWh]	% of ENS supplied by Diesel [%]	Fraction of ENS recovered with the back-to-back [%]
minimum	3.800,41	120	20%	5%
maximum	5.700,61	200	40%	10%

	Cost of ENS [USD]	Cost of supplying ENS with Diesel [USD]	Cost for the system [USD]	Saving/year [USD]
minimum	456.049.120	266.028.653	722.077.773	36.103.889
maximum	1.140.122.799	798.085.959	1.938.208.758	193.820.876

From the above figures, the range of annual savings would be between 36 MUSD and 193 MUSD.

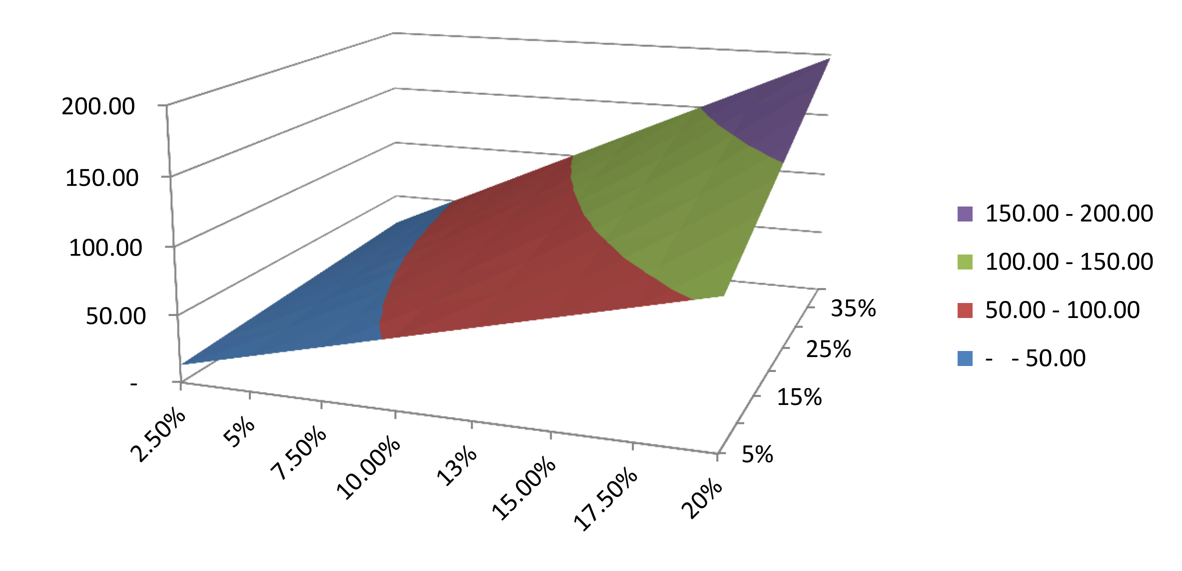
The sources considered for the analysis are:

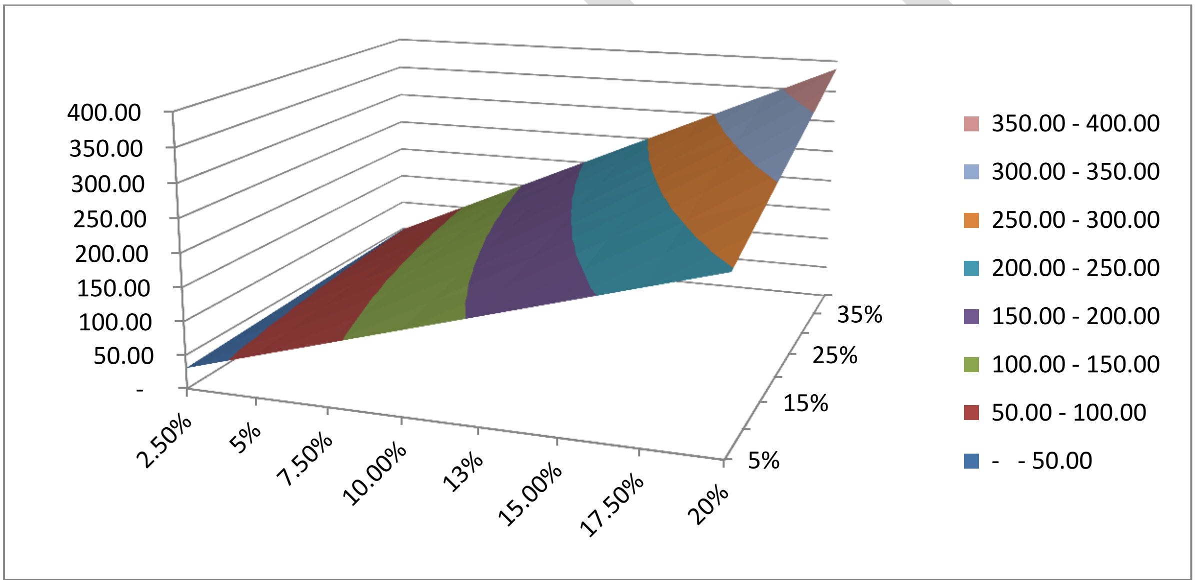
- “ENS”: reports presented by Utilities during the kick-off meeting of the current project (December 2014);
- “Levelized cost of energy”: WAPP Irena report, "Planning and prospect for renewable energy", Table 20. Levelised Cost of Electricity: Comparisons in 2020, pag.65;
- “% of E NS supplied by Diesel” and “Fraction of ENS recovered with the back-to-back [%]”: consultant assumptions.

It must be noted that this represents a qualitative approach, since for an extended cost/benefit analysis it should be considered at least:

- Different costs of generation for each unit;
- Impact on GDP growth for each country;
- Cost of energy allocated by each source;
- The cost of maintenance of the two back-to-back;
- Economic energy interchanges and trade.

Furthermore, the ENS has different causes, and it is clear that the installation of the back-to-back would only help to reduce a fraction of that unsupplied energy; for this reason, a sensitivity is presented here, according to different levels of “% of ENS supplied by Diesel” and “Fraction of ENS recovered with the back-to-back [%]” (respectively, between 5% and 40% and between 2,5% and 15%) .
The two following surfaces have been computed using, respectively, the minimum and maximum values of the other variables reported in the previous table. The savings are in MUSD.





As it is shown, the savings vary between 13MUSD and 197MUSD, and between 31MUSD and 387MUSD per year.

As a conclusion, it is possible to state that for a deeper analysis of the costs and benefits of the back-to-back a dedicated study shall be performed; nevertheless, as already reported in the Interim Report and in the introduction of this paragraph, the back-to-back alternative is technically feasible and would have a benefit if the Utilities already foresee a challenge in implementing the roadmap presented.
Therefore the ultimate decision is linked with the commitment and feasibility to implementing the roadmap within the timeframe and targets presented in this report.

4 General recommendations on Renewables integration

Considering the growing importance of renewables and especially non-programmable or Variable Renewable Energy Sources (VRES) all over the world, including Africa as shown in Figure, policy-makers and the industry need to address emerging issues to ensure continued growth of variable renewables and their successful integration in electricity systems.

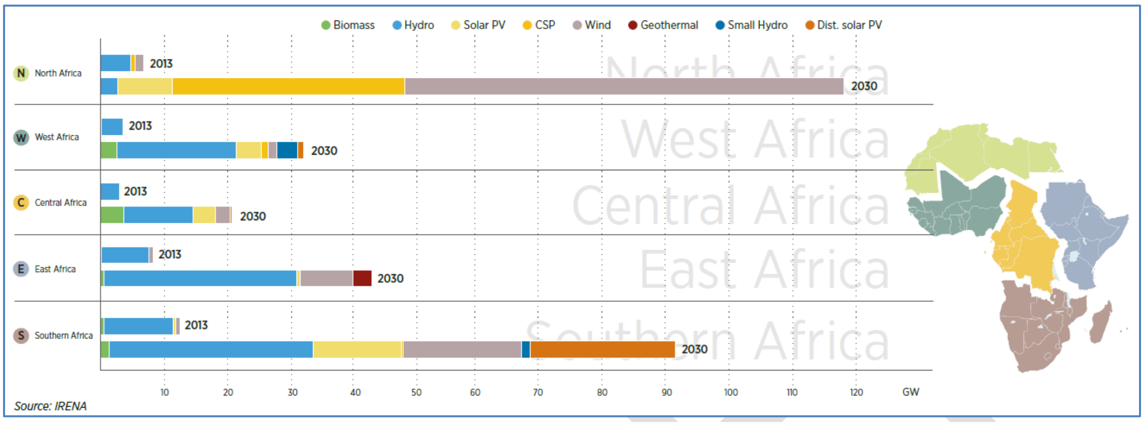


Figure 4.1: Capacity development of Renewables in Africa according to IRENA future scenario [4]

The main **operational challenges** related to the integration of non-programmable Renewables are:

- Daily load-profile changes (e.g. ramps due to PV or Wind plants);
- Risk of over-generation (e.g. in case of dispatching priority for RES and low load-high sun/wind conditions);
- System Inertia Reduction (non-synchronous and static generation);
- Reduced current contribution during faults and increased impact on voltage profile during faults (increased extension of voltage sags during faults);
- Reduced participation in voltage and frequency control (with possible negative effects on system's dynamic behavior);
- Reserve margin reduction (less conventional generation connected to the grid);
- Network Congestions (in case of highly loaded network portions with high RES penetration).

Although VRES may involve a number of challenges, **affordable solutions** will help to decrease or eliminate their impact. Solutions can be divided in two categories [5]: technologies and market redesign.

<u>Technologies solution for RES Integration</u>

A number of "technological" solutions which have been deployed to address the various challenges posed by the integration of VRES in the electric power system. These solutions include:

- **Improved Forecasting**: better forecasting accuracy can help minimize VRES integration cost and allow grid operators to schedule VRES and reduce the need for operating reserves and balancing costs. The cost of forecasting has dropped over the last couple of years making it a popular and frequently used mitigation solution. Forecasting accuracy can be further improved by other mitigation strategies, such as faster scheduling and larger balancing areas.

- **Greater Flexibility of Generation**: flexibility is needed for generation to respond rapidly to the changing load conditions that has required short start-up and shutdown times compared to steady base-load operation. The need for fast ramp up and down mode imposes additional costs, including a quicker equipment wear and increased fuel consumption, and thus higher overall emissions. This option may be costlier compared to other options. Compensation and/or regulatory measures for new generation are important for successful implementation of VRES.
- **Advanced operating procedures:** to optimise reserve capacity and flexibility of conventional generation should be introduced to manage intermittency and variability.
- **An expansion of the transmission and distribution grids,** including cross-border interconnections, may be necessary together with an optimum operational cooperation between TSO's and DSO's.
- **Increased visibility of Distributed Generation**: Distributed generation (DG) is usually "hidden" to system operators, as they do not receive dispatch commands. DG is projected to grow rapidly in the coming years and this growth can cause scheduling conflicts. Better coordination between DSOs and TSOs in liberalized markets is mandatory.
- **Demand Response**: i.e. the short-term adjustment of demand to address temporary shortage or excess power from variable renewables, must be developed further.
- **Energy Storage**: The most established, although geographically limited, energy storage technology is pumped hydro storage which requires transmission capacity and takes a long time to build. There are many types of energy storage using different technologies such as battery, flywheel or compressed air energy storage. Energy storage can help to use load shifting, shorter-term balancing and fast-acting instantaneous supply solutions. Type, characteristics and location of Battery Electrical Storage Systems depend on many factors, like the type of service they are required for, the type and location of RES and conventional plants and electricity transmission facilities.

<u>Policies and market design for RES integration</u>

The market rules established before the large expansion of VRES need to be adjusted. Effective market redesign practices until now have included the following:

- **A holistic and long-term approach** to system design is key when planning variable renewables integration. Moreover policymakers and the industry are encouraged to conduct technical and economic analyses with comprehensive assessment, which include the associated costs for the complete power system.
- **Market redesign:** Policymakers must design market rules to ensure a more sustainable energy system in line with the objectives of the Energy Trilemma (energy security, energy equity, and environmental sustainability), including clearly defined CO_2 emissions regulations.
- **Adjustments to existing market design** can be efficient, for example:
  - **Larger balancing areas:** Sharing the implications of variability and load forecast errors across a broader region provides a natural reduction in the system balancing costs.
  - **Aggregating the bids** of different plants in the market can facilitate a reduction in the overall variability of electricity supply and thus reduce the forecast errors and system balancing needs.

- Ancillary services can be provided by variable renewables, even in the absence of sun and wind, with help of new technologies. Responsibilities for system balancing have to be shared fairly among market participants, including variable renewables generators.
  - **Hourly and sub-hourly scheduling:** Taking into account the technical limitations of conventional plants for more efficient use of available transmission and generation capacity.
  - **Nodal pricing** demonstrates the benefits of an appropriate selection of location for renewables power plant and as a result, smoother integration of intermittent renewable generation technologies.
- **Introduction of capacity markets** can help ensure security of supply, as energy-only based markets are often insufficient to guarantee supply in systems with a large share of variable renewables.

5 References

[1] Interim Report, September 2016

[2] Operation Manual for WAPP Interconnected Power System and its implementation, July 2007

[3] Guideline on electricity transmission system operation, Draft EU Commission Regulation, May 2016

[4] Africa 2030: Roadmap for a renewable energy future, IRENA, 2015

[5] Variable renewables integration in electricity systems: how to get it right, WEC 2016

[6] Consultancy Services & Owner's Engineer for the Synchronisation of WAPP Interconnected Network, Measurement Campaign Report, Report CESI, April 2016

[7] Current practices in Europe on Emergency and Restoration, ENTSO-E, 2014