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Support to AUC for the implementation, coordination and monitoring of the Electricity Harmonisation Regulatory Strategy and Action Plan

Lot 9.5: Strategic Planning, Action Plan and Guidelines for the African Single Electricity Market (AfSEM)

Deliverable 5: Technical and Operational Readiness (Action Plan and Guidelines)

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Abbreviations

AfCFTA	African Continental Free Trade Area
AfDB	African Development Bank
AFSEC	African Electrotechnical Standardisation Commission
AfSEM	African Single Electricity Market
AGC	Automatic Generation Control
AMR	Automated Meter Reading
AMU	Arab Maghreb Union
APUA	Association of Power Utilities in Africa
ATC	Available Transmission Capacity
AU	African Union
AUC	African Union Commission
AUDA	African Union Development Agency
CAPEX	Capital Expenditures
CAPP	Central African Power Pool
COMELEC	Comité Maghrébin de l'Electricité
COMESA	Common Market for Eastern and Southern Africa
CREEE	Centre for Renewable Energy and Energy Efficiency
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DES	Distributed Energy Storage
DG	Distributed Generation
DIE	Department of Infrastructure and Energy
DMS	Distribution Management System
DSM	Demand Side Management
DSO	Distribution System Operator
EAC	East African Community
EAPP	Eastern Africa Power Pool
ECCAS	Economic Community of Central African States
ECOWAS	Economic Community of West African States
ED	Energy Division

ELTAM	Egypt-Libya-Tunisia-Algeria-Morocco
EMS	Energy Management System
ERERA	ECOWAS Regional Electricity Regulatory Authority
EU	European Union
EURELECTRIC	Association of the Electricity Industry in Europe
FPM	Forward Physical Market
HPP	Hydro Power Plant
HVAC	High-Voltage Alternate Current
HVDC	High-Voltage Direct Current
IC	Information and Communication
ICC	Information and Coordination Centre
ICT	Information and Communication Technology
IDA	International Development Association
IDM	Intraday Market
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent Power Producer
IRB	Independent Regulatory Board
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
ITO	Independent Transmission Operator
LTN	Long-Term Nominations
MEDELEC	Liaison Committee between associations of electricity companies
MEDREG	Mediterranean Regulators Organisation
Med-TSO	Mediterranean TSO Organisation
MMS	Market Management System
NEPAD	New Partnership for Africa's Development
NERC	Nigerian Electricity Regulatory Commission
NKE	Non-Key Expert
NORAD	Norwegian Agency for Development Cooperation
NTC	Net Transfer Capacity
OPEX	Operating Expense

OTC	Over-The-Counter
PMU	Phasor Measurement Unit
PPA	Power Purchase Agreement
PV	Photovoltaics
RAB	Regulatory Asset Base
RE	Renewable Energy
REA	Rural Electrification Agency
REC	Regional Economic Community
RES	Renewable Energy Sources
RR	Regional Regulator
RSMO	Regional System Market Operator
RURA	Rwanda Utilities Regulatory Authority
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SCADA	Supervisory Control and Data Acquisition
SIDA	Swedish International Development Agency
SPD	Small Power Distributor
SPP	Small Power Producer
TAF	Technical Assistance Facility
TANESCO	Tanzania Electric Supply Company
TRM	Transmission Reliability Margin
TSO	Transmission System Operators
TTC	Total Transfer Capacity
TYTNDP	Ten-Year Transmission Network Development Plan
UAE	Arab Electricity Union
USAID	United States Agency for International Development
WACC	Weighted Average Cost of Capital
WAMS	Wide Area Measurement System
WAPP	West African Power Pool

EXECUTIVE SUMMARY

E.1 INTRODUCTION

The need to achieve a harmonised and continental African electricity market was driven by the collaboration between the AUC and EU, which commenced in 2015 and was implemented under the EU TAF. This was done through the provision of support and expertise to ED of AUC-DIE. This collaboration was implemented in four phases, with the fourth one spanning the period 2019 to 2021. The fourth phase comprised 7 lots which included the Lot 9.5 on "Strategic Planning, Action Plan and Guidelines for the African Single Electricity Market (AfSEM)", of which the current deliverable, the Technical and Operational Readiness (Guidelines and Action Plan), is one of the key components for the implementation of AfSEM.

The implementation of Lot 9.5 is a continuation of the AUC's Strategy and Action Plan for the development of a Harmonised Regulatory Framework for the Electricity Market in Africa, which was adopted by the Heads of State and Government of the AU in 2017. AfSEM, as an overall electricity initiative of the AU, will cover strategic policy and planning aspects of the whole electricity value chain that relate to generation, transmission, distribution and end-use, at the national, regional and continental levels.

To achieve the single and integrated electricity market in Africa, it is imperative that the African interconnected power system is technically and operationally ready such that all the necessary preconditions for the interconnection of any two or more national and regional power systems are fulfilled, for electricity trading to take place in a safe, secured and reliable manner. In addition, it is important that African Power Pools and their member utilities/TSOs possess the necessary capabilities and tools as well as human resources for the operation and management of the interconnected power systems.

E.2 PRIMARY OBJECTIVE

The primary objective of the Technical and Operational Readiness Deliverable, is to first assess the current state of technical and operational readiness of Power Pools and on that basis, develop the Guidelines and Action Plan for achieving the Technical and Operational Readiness for implementing AfSEM. This also includes proposing solutions to potential technical challenges that could emerge due to interconnections of both intra- and inter-regional transmission networks.

E.3 TECHNICAL AND OPERATIONAL READINESS GUIDELINES – KEY ELEMENTS

The Guidelines have been developed to assist African Power Pools and the regional regulatory authorities/associations regarding the technical and operational decisions for proposed cross-border transactions. This report therefore provides a detailed explanation of the purpose of each Guideline, and highlights the major issues that Power Pools and the regional regulatory authorities/associations need to take into account in the implementation of the Guidelines (see Table E-1).

Table E-1: The Guidelines and areas covered under the Technical and Operational Readiness

No.	Guidelines and areas covered
1	Roles of System Operators (National TSOs, Control Area Operators, and RSMOs)
2	Dispatch, System Operations, and ICT
3	Power (Generation and Transmission) System Adequacy, Capability and Robustness (Capacity Readiness)
4	Market Compatibility for Trading

5	System Operators and Coordinated Planning. Which covers the following sub-Guidelines: 5.1: Synchronising Procedures; 5.2: Operational Data; 5.3: Transmission Capacity Allocation; and 5.4: Ancillary Services Provision
6	Interconnection of Off-grid Mini-grids. Which covers the following sub-Guidelines: 6.1: Technical Modalities for Main Grid Connection of Off-Grid Mini-Grids; and 6.2: Regulatory Frameworks for Main Grid Connection of Off-Grid Mini-Grids and Micro-DSOs.

E.4 Recommendations for the AfSEM Policy and Strategy

For policy and strategy purposes, the Technical and Operational Readiness (Guidelines and Action Plan) will provide African Power Pools and their members/TSOs, the regional regulatory authorities/associations and stakeholders, with a set of Guidelines that will ensure that the integrated power system is technically and operationally ready for electricity trading to take place, in a safe, secured and reliable manner. The report has recommended an Action Plan to be implemented in three phases over the following three time horizons: the short-term (2021-2025), medium-term (2026-2030) and long-term (2031-2040). The key activities which define each of the three phases (see Table E-2) are elaborated in the report in detail at the national, regional and continental levels.

Table E-2: The key activities covered under the Technical and Operational Readiness

Time horizon	Key activities
Short-term	• Establishment of national and regional institutions/entities in charge of system operation • Establishment of dispatch and system control centres with ICT capabilities in the national TSOs, the Control Area Operators, and the RSMOs • Generation and transmission system adequacy • Transmission capacity readiness • Generation capacity readiness • Development of harmonised Grid Codes for cross-border transactions • Market compatibility for trading • Synchronising procedures • Operational data • Transmission capacity allocation • Ancillary services adequacy • Interconnection of off-grid and mini grid: Rural electrification standards and options when the main grid encompasses the mini-grid
Medium-term	• Generation and transmission system adequacy • Transmission system capacity readiness • Generation system capacity readiness • Market compatibility for trading • Synchronising procedures

	• Operational data • Transmission capacity allocation • Ancillary services adequacy • Dispatch, System Operations, and ICT
Long-term	• Generation and transmission system adequacy • Transmission system capacity readiness • Generation system capacity readiness • Market compatibility for trading • Synchronising procedures • Operational data • Transmission capacity allocation • Ancillary services adequacy

E.5 Assessing and Quantifying the Technical and Operational Readiness

In order to achieve the Technical and Operational Readiness for the implementation of AfSEM, it is imperative that the Readiness is assessed and quantified. For policy and strategic purposes, the following indicators (both qualitative and quantitative) are proposed for monitoring and assessing the technical and operational capabilities of African Power Pools, to undertake intra- and inter-Power Pool exchanges:

- Existence of a fully functional Power Pool's Information and Coordination Centre (ICC);
- Establishment and operationalisation of a fully functional Regional System Market Operator with the Coordination Centre and a market trading platform;
- Existence of adequate and fully functional Area Control Centres of the Control Area Operators within each Power Pool;
- Existence of adequate and fully functional National Dispatch Centres of the national TSOs within each Control Area;
- Implementation of a harmonised regional Grid Code;
- Improvement of capacity readiness and adequacy (percentage of priority generation and transmission projects implemented, disaggregated according to the short-, medium- and long-terms);
- Implementation and use of the market trading platforms under each Power Pool/RSMO;
- Preparation of procedures for the synchronisation at the intra- and inter-Power Pool levels;
- Preparation of the mechanism for exchange of operational data in the synchronised power system;
- Allocation of cross-border transmission capacity at varying levels;
- Establishment and operationalisation of the Ancillary Services Market;
- Provisions in the regulatory framework to allow the intentional islanding of interconnected mini-grids.

1 INTRODUCTION

1.1 BACKGROUND

To achieve a harmonised continental electricity market, i.e. AfSEM, a collaboration between the AUC and the EU commenced in 2015. This has been implemented under the EU TAF, through the provision of support and expertise to ED of AUC-DIE. The collaboration has been implemented under the four successive phases (see Table 1-1).

Table 1-1: Implementation phases of the AUC-EU collaboration

Phase	Period	Characteristics
1	2015-2016	Involved the development, validation, and approval (by the AU Summit) of "the Strategy and the Action Plan for a Harmonised Regulatory Framework for the Electricity Market in Africa".
2	2017	Covered support to AUC-DIE for the implementation of the Strategy and Action Plan regarding: - Coordination Role of the AUC, - Development of Continental Transmission Tariff Methodology, and - Institutional and Policy Model for Micro and Mini-Grids.
3	2018-2019	Involved the development of a Continental Transmission Tariff Calculation Tool for international bilateral transactions.
4	2019-2021	Covered provision of support to AUC-DIE for the implementation, coordination, and monitoring of the Strategy and Action Plan. Comprised a number of activities including the current Lot 09.5 assignment - Strategic Planning, Action Plan and Guidelines for the African Single Electricity Market (AfSEM).

It is important to highlight that AfSEM is a key activity of the AUC and hence a continuation of the AUC's Strategy and the Action Plan for a Harmonised Regulatory Framework for the Electricity Market in Africa, which was adopted by the AU Heads of State and Government in 2017. As an overall electricity initiative of the AU, AfSEM will cover strategy, policy, and planning aspects of the entire electricity value chain at the national, regional, and continental levels.

AfSEM is particularly relevant to the AU's vision for an integrated and prosperous continent, as outlined in its Agenda 2063 development blueprint. It is one of the tools which would equip AfCFTA to catalyse the socio-economic development of the continent. AfSEM is expected to enhance the delivery of quality and reliable electricity service to the citizens on the continent. It is also expected to create a market that will provide reliable electricity at least cost to consumers and catalyse cost-efficient response for strong growth of electricity demand. It will thus serve as an essential tool for exploiting the full potential of the continent's RES, and play a pivotal role in the transition to a greener energy sector as well as help to achieve 100% access to electricity.

The integrated electricity market will ensure system stability and provision of reliable and secure electricity supply, as well as contribute to cost-efficient decarbonisation of the energy sector. It is in this light that AU decided to develop AfSEM under Lot 09.5, with the view to ensuring its progressive implementation and full operationalisation by 2040. The *Guidelines and Action Plan on the Technical and Operational Readiness covered in this report*, will ensure that all the necessary preconditions required for interconnection to take place between two or more integrated power systems, have been satisfied to pave the way for exchanges and trading to commence.

The Technical and Operational Readiness deliverable will ensure that all the technical and operational capabilities of Power Pools and their member utilities, which are crucial for the establishment of the regional

electricity markets are in place. In addition, this deliverable will allow for the development and implementation of key technical documents and regulations for the operation of the mutually interconnected systems in a transparent and non-discriminatory manner.

1.2 SIGNIFICANCE OF TECHNICAL AND OPERATIONAL READINESS

The Technical and Operational Readiness of an integrated power system defines the state where all the preconditions for interconnection of any two or more power systems have been met, so that electricity trading can take place in a safe, secured and reliable manner. The Technical and Operational Readiness of Power Pools and their member utilities/TSOs, is therefore pivotal for the establishment of the interconnected regional and continental electricity markets for implementation of AfSEM. In addition, it is imperative that Power Pools and their member utilities/TSOs possess the necessary technical capabilities and human resources for the operation and management of the interconnected power systems.

The secure and reliable operation of the interconnected power systems is also subject to preconditions such as:

- sufficient capacities of generation plants and transmission networks (capacity adequacy and readiness), and
- installation of modern software and ICT equipment at the dispatch and control centres.

This requires that the RSMOs as well as the Control Area Operators and the national TSOs, have reliable software and ICT equipment installed at their dispatch and control centres that can monitor the conditions of their interconnected transmission systems. This will ensure that information on the status of the interconnected transmission systems can be indicated in the dispatch and control centres for information and coordination, as well as for system reliability purposes.

1.2.1 Specific Objectives

The overall objective of Phase 3 Task 2 as it pertains to this deliverable (i.e. Deliverable 5), is to identify the current situation and on that basis develop the Guidelines and Action Plan for Technical and Operational Readiness for implementing AfSEM, including system planning and technical operation of the integrated electricity market.

The specific objectives of the Technical and Operational Readiness deliverable are as follows:

- review and assess the dispatch and control capabilities of Power Pools for both intra- and inter-Power Pool exchanges for the realisation of AfSEM, and make recommendations for improvement to facilitate the electricity market integration,
- identify and propose solutions to potential technical challenges to be addressed due to interconnections of both intra- and inter-regional transmission networks,
- synchronise with the continental TYTNDP from the Continental Master Plan, and establish a continental interconnection targets for the short-, medium- and long-terms,
- carry out scenario analysis and quantify opportunities regarding the Technical and Operational Readiness,
- identify and propose solutions for interconnection of off-grid systems to the main grid, and
- develop an interactive map of Africa depicting the results of the continent’s Technical and Operational Readiness.

1.3 RATIONALE FOR DEVELOPING GUIDELINES AND ACTION PLAN FOR TECHNICAL AND OPERATIONAL READINESS

The development of the Technical and Operational Readiness (Guidelines and Action Plan) will assist the RSMOs and the electricity utilities/TSOs as members of Power Pools, as well as the regional and national regulatory authorities to identify and address the technical and operational challenges that could affect cross-border trading. The Guidelines and Action Plan will enable the RSMOs and regulators to establish consistent ways for interpreting and implementing the technical regulations and standards for cross-border transactions.

The Guidelines will assist the interconnected power systems to identify all the relevant technical and operational issues and address them, to pave the way for cross-border electricity trading, as well as to incentivise investment in cross-border projects to facilitate international transactions. It will ensure that all the technical issues which affect cross-border trading have been properly analysed and the impacts of the interconnection have been thoroughly evaluated on both national and regional security of electricity supply. Additionally, it will ensure that unacceptable technical risks associated with cross-border projects are identified and addressed for the interconnected power system. Regarding policy-making and strategy, it will highlight the policy aspects for the realisation of AfSEM. It will strengthen the awareness of policymakers on key technical issues which need to be in place for cross-border trading to take place for the realisation of AfSEM.

The Action Plan will identify the main policy actions and activities which need to be implemented within *the short- (2021-2025), medium- (2026-2030) and long- (2031-2040) terms* that will allow for all the necessary preconditions for the Technical and Operational Readiness to be met, for effective implementation of AfSEM.

1.4 SCOPE OF GUIDELINES AND ACTION PLAN FOR TECHNICAL AND OPERATIONAL READINESS

The Guidelines have been developed to assist Power Pools and regional regulatory authorities in respect of the technical and operational decisions for proposed cross-border transactions, and are therefore expected to apply to varying situations (see Table 1-2).

Table 1-2: Situations for applying the Guidelines

No.	Situation	Characteristics
1	Applicable to the long-term cross-border transactions by Power Pools	The Guidelines will apply to long-term cross-border transactions (of at least 1 year) through the transmission network, where the cross-border network operating voltage meets the threshold defined by Power Pools and the regional regulatory authorities. The long-term nature of the transactions will give comfort to investors who will be assured that they can recoup their investment plus a reasonable return, over the term of the transaction.
2	Applicable to the State-owned, private and joint venture utilities	The Guidelines will apply to the State-owned, privately owned or joint ventures, if these entities have been licensed by the national regulatory authorities in their respective countries, and have also gone through the necessary registration processes with the RSMO at the regional level. The Guidelines have been designed to allow IPPs and large customers to trade electricity directly across borders by making provision for such situations.
3	Adapted for the long-term trading in the national electricity markets	Though the focus of the Guidelines is on the long-term cross-border transactions, it is expected that some aspects of the Guidelines could be relevant for the long-term national transactions. In that regard, the national regulatory authorities and TSOs are encouraged to adapt relevant sections of the Guidelines to their national long-term transactions involving the State-owned or incumbent electricity utility and IPPs.

2 METHODOLOGY

2.1 EXPECTED OUTCOMES

The Technical and Operational Readiness (Guidelines and Action Plan) task involves carrying out a review and assessment of the framework for system planning and technical operation of an integrated electricity market. It also includes carrying out analysis regarding the technical and operational readiness for AfSEM.

The Guidelines cover a number of key elements (see Table 2-1).

Table 2-1: Key elements of the Guidelines

No.	Guidelines	Characteristics and key elements
1	Roles of System Operators	Discussed the need for the national regulatory authorities to act within the powers and duties specified in their national legislations. Established the decision-making boundaries of the national TSOs, the Control Area Operators and the RSMOs in respect of technical and operational decisions for cross-border trading.
2	Dispatch, System Operations, and ICT	Discussed how the RSMOs of Power Pools and the Control Area Operators and the national TSOs rely on software and ICT equipment to monitor the conditions of their interconnected transmission systems. Described the need for the RSMOs and the Control Area Operators and the national TSOs to be equipped with modern communication and signalling equipment that will enable them to monitor the conditions of the interconnected power system at all times.
3	Power (Generation and Transmission) System Adequacy, Capability and Robustness (Capacity Readiness)	Discussed the need to ensure capacity readiness of the power system infrastructure. Ensured that priority generation and transmission projects need to be implemented on time to relieve the network of all constraints to facilitate cross-border trade. Required that the Power Pool Masterplans are synchronised at the continental level with the Continental Master Plan and subsequently updated on uniform basis.
4	Market Compatibility for Trading	Established the need for market compatibility and highlighted the significance of developing a joint trading platform for the integrated electricity market. Highlighted the significance of developing common rules to govern trading between integrated markets.
5	System Operators and Coordinated Planning	Described the role of system operators to achieve coordinated planning regarding the following: 5.1: Synchronising Procedures; 5.2: Operational Data; 5.3: Transmission Capacity Allocation; and 5.4: Ancillary Services Provision.
6	Interconnection of Off-grid Mini-grids	Addressed the key issues that must be considered and also identified the conditions for connecting isolated mini-grid systems to the main grid by covering the following:

		6.1: Technical modalities for main grid connection of off-grid mini-grids; and 6.2: Regulatory frameworks for main grid connection of off-grid mini-grids and micro-DSOs.

In addition to the Guidelines, the current report includes the Action Plans which need to be implemented to achieve the Technical and Operational Readiness for interconnected power systems. The report also includes the Action Plan for the Interconnection of Off-grid Mini-grids to the main grid. The Action Plan covers the actions required at the national, regional and continental levels as pertaining to:

- Short-Term Actions (2021-2025);
- Medium-Term Actions (2026-2030); and
- Long-Term Actions (2031-2040).

2.2 APPROACH

The establishment and operationalisation of AfSEM will involve stakeholders both within and outside the African continent and in that regard, the Technical and Operational Readiness deliverable has been developed based on a *consultative, cooperative and participatory* approach. This approach implied that ED of AUC-DIE worked collaboratively with the EU TAF Team to set up meetings with Power Pools, the regional regulatory authorities/associations and other key institutions.

These meetings enabled the EU TAF Team, ED of AUC-DIE and stakeholders to discuss the key Technical and Operational Readiness issues for operationalising AfSEM, based on lessons learnt from the Regions/Power Pools of the African continent, as well as from Europe and other jurisdictions. These meetings also enabled the EU TAF Team to take into account, all the relevant technical and operational issues including suggestions and inputs from stakeholders, for the development of the Guidelines and Action Plan.

3 REVIEW AND ASSESSMENT OF CURRENT TECHNICAL AND OPERATIONAL READINESS OF AFRICAN POWER POOLS

3.1 SAPP

SAPP was created as a Power Pool in 1995 on the basis of:

- the Inter-Governmental Memorandum of Understanding between the SADC Member States (to enable the establishment of a Power Pool in the SADC Region), and
- the Inter-Utility Memorandum of Understanding between the electricity utilities of the SADC Member States (to establish basic management and operating principles of a Power Pool).

The two Memoranda were revised in 2006 and 2007, respectively.

Additionally, SAPP adopted:

- the Agreement Between Operating Members (to establish the specific rules of operation and pricing) in 1995 (revised in 2008), and
- the Operating Guidelines (to provide standards and operating guidelines) in 2014.

Also, SAPP adopted the Coordination Centre Constitution.

The above five agreements govern SAPP as a Specialised Institution of SADC.

Based on the Host Country Agreement between SAPP and the Government of Zimbabwe from 2006, headquarters of SAPP (i.e. the SAPP Coordination Centre) are in Harare, Zimbabwe. Although SAPP recognises the importance of a regulatory role for its work, no specialised institution of SADC has been established yet as the regional regulatory authority. However, it should be mentioned that SADC has established the Regional Electricity Regulatory Association, which has helped in harmonising the SADC Region’s regulatory policies on energy and its subsectors (i.e. it only has the authority to issue guidelines, without any mandatory obligation on SAPP member states to implement same).

SAPP was established as an instrument of an official cooperation among the SADC Member States with the objective to provide regional solutions to electricity problems in the SADC Region. It coordinates the planning and operation of the electric power system among member utilities in response to concerns about the costs and benefits of electricity generation, as well as the lack of strong cross-border transmission lines. It aims to reduce investment and operating costs of electricity generation while maximising reliability, as well as to remove transmission-related barriers. SAPP also addresses soft barriers to entry in both generation and trading in electricity, which includes cost-reflective tariffs to sustain current generation levels and routine maintenance. Moreover, it co-ordinates financial support for transmission projects.

Currently, SAPP covers 12 of the 16 SADC Member States (9 of which are interconnected at transmission level and actively operate in SAPP; another 3 are at various stages of joining in the interconnection) and is made up of 17 member utilities (12 national electricity utilities, 2 independent transmission companies, and 3 independent power producers). SAPP member utilities can be either the operating members (i.e. connected through SAPP and members of the regional electricity market), and non-operating members (i.e. not yet connected, but part of SAPP, and not active in the regional electricity market). All participating member utilities must be situated in a country, which was a member of SADC in September 1994. Full membership is for the national electricity utilities only, and is restricted to one per country as designated by the country's government. Other electricity utilities situated in SADC may become member utilities subject to the approval of the SAPP Executive Committee. SAPP member utilities have undertaken to share information and knowledge, be politically neutral, and develop common planning and operating criteria and procedures and to accept wheeling on behalf of other members when this is technically and economically feasible. The SAPP membership application fees amounts to USD 2,500.00 non-refundable and are paid into the SAPP account.

SAPP's governing structure has five main levels (see Table 3-1).

Table 3-1: SAPP's governing structures

No.	Organ	Description
1	SADC Directorate of Infrastructure and Service	Facilitates, through strategic expertise, the provision of adequate, integrated and cost-efficient infrastructure and related services to support regional integration and poverty eradication.
2	Executive Committee	Acts as the Board of SAPP and is the authority governing the coordination and formulating the objectives of SAPP. Specifies and amends from time to time the duties of the Management Committee, the Sub-Committees and any Working Group or Task Force, which may be established. Composed of the Chief Executives of only member utilities which generate wholesale and retail electricity to final customers. A country with more than one utility meeting these requirements is required to designate one utility to represent it on the Executive Committee. Has a chairperson who holds office for a period of at least one year, but not more than three years. The chairmanship rotates among the member utilities which are signatories of the Agreement Between Operating Members.
3	Management Committee	Reports to the Executive Committee. Oversees the work and decides on the recommendations of the Sub-Committees and the Coordination Centre Board. Makes all decisions on the matters not specifically delegated to the Sub-Committees. Also comprises the Crime and Prevention Working Group, which implements strategies to combat theft/vandalization of electricity infrastructure in its member utilities.
4	Sub-Committees	Function under the Management Committee. Alert and advise the Management Committee on best practices and related issues in their domains. Currently, there are four Sub-Committees: a) Markets Sub-Committee, b) Operating Sub-Committee, c) Planning Sub-Committee, and d) Environmental Sub-Committee. The activities and functions of the Sub-Committees are contained in the SAPP Inter-Utility Memorandum of Understanding.
5	Coordination Centre Board	Functions under the Management Committee. Supervises the work of the Coordination Centre and the Project Advisory Unit.

Duties of the Coordination Centre and its Sub-Committees of importance for technical and operational readiness (i.e. Operating, Planning and Market) are well defined for the purpose of electricity trading (see Annex 8.1). It should be noted that a unique feature of electricity trading in the SADC Region is that SAPP is based on the previously mentioned agreements and the above governing structure, rather than law/Directive (as the case is in WAPP of the ECOWAS Region). However, the Inter-Governmental Memorandum of Understanding establishes that the SAPP agreements must be interpreted in a manner consistent with the SADC Treaty and that the final and binding dispute resolution forum is the SADC Tribunal.

Back in 1995, the lack of strong cross-border transmission lines was more than obvious. Transmission-wise, at that time, the SADC Region was divided for practical purposes into a northern sector where base load was supplied primarily from hydro power plants, and a southern sector where base load was supplied primarily by coal-fired thermal power plants. Since its inception, SAPP has made efforts to link the northern and southern sectors into a coherent regional transmission system (see Figure 3-1), and has been a major force in rationalising the SADC Region's electricity generation and transmission operations, including co-ordinating financial support for transmission projects.

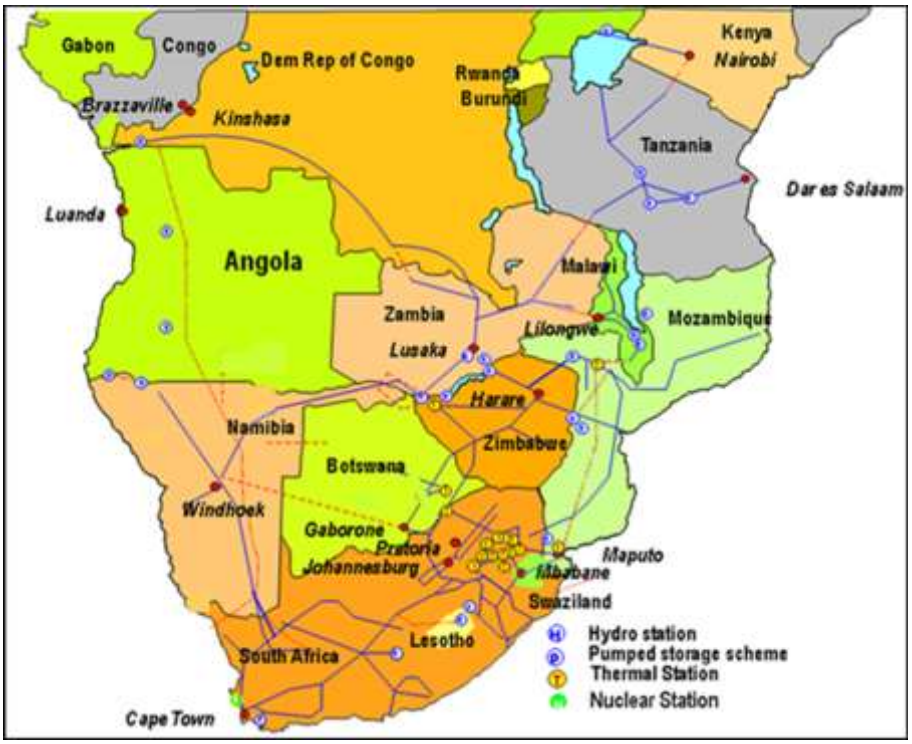

Figure 3-1: SAPP grid map (source: SAPP)

SAPP has a Project Advisory Unit funded by the World Bank that focuses on both generation and transmission projects preparation and coordination. It has also been instrumental in assisting its member utilities to improve integration of renewable producers by determining the impact of variable renewable energy generation technologies on the operation of the interconnected system and coming up with mitigation measures. In that view, it encourages the involvement of IPPs and the development of DSM measures. It has come up to the point where it undertakes to harmonise Grid Codes in the SADC Region, in cooperation with the Regional Electricity Regulatory Association.

The SAPP Pool Plan from 2017 envisages a development of the main transmission corridors with the aim to integrate new generation projects that are committed. SAPP defined the high priority generation and transmission projects, and identified required interconnectors and their transfer limits (see Figure 3-2). The priority generation and transmission (integration) projects for SAPP have also been identified and listed in the Continental Master Plan 1 Baseline Study (Deliverables 2&3) for the short-, medium- and long terms.

The SAPP priority transmission projects are divided into three categories:

1) the projects to interconnect the non-operating members, which are not yet interconnected to the SAPP grid (Angola, Malawi, and Tanzania),

2) the projects to relieve transmission congestions, both in internal/domestic transmission networks and on cross-border interconnectors, and

3) the projects to evacuate power from new generation power plants to load centres.

Moreover, SAPP is currently running trials on the new proposed nodal transmission pricing methodology in order to ensure recovery of investments in new and existing transmission infrastructure used in electricity trading.

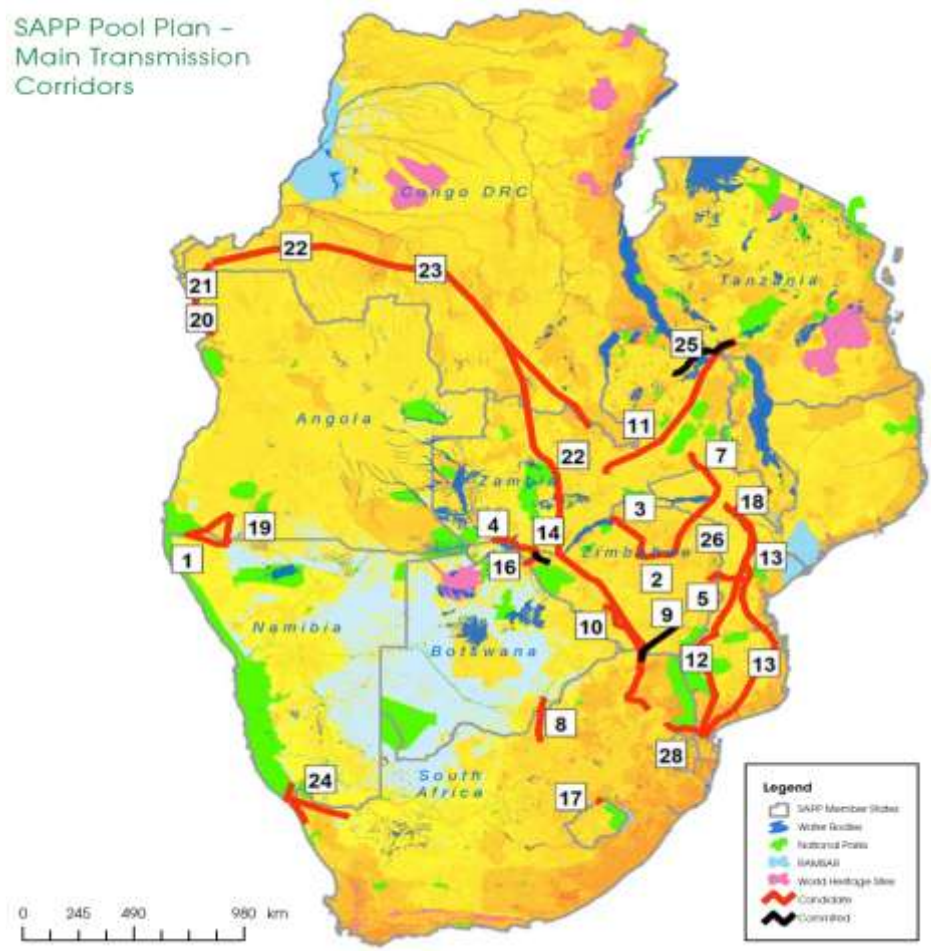

Figure 3-2: SAPP main transmission corridors (source: SAPP Pool Plan 2017)

SAPP coordinates not only the planning of the regional power system, but also the operation in order to alleviate main transmission bottlenecks that could affect market integration (see Figure 3-3). In that view, it performs the following activities:

1) calculates and publishes the operating reserve which each of the 10 operating members shall keep (this operating reserve is composed of the spinning reserve and the quick reserve, which are based on the size of the largest generator and the maximum demand in each of the national systems),

2) defines transfer limits between the electricity utilities per each of the cross-border interconnections (these limits are thermal limit, voltage limit, stability transfer limit, and applicable transfer limit),

3) applies an imbalance management mechanism to minimise imbalance energy at the cross-border interconnections (this will be complemented by the introduction of the Balancing Market that SAPP will soon implement instead of the intraday market),

4) publishes the SAPP transmission maintenance schedule for planned outages (annually and quarterly),

5) publishes main parameters of the demand and supply per the member country and the member utility (installed capacity, operating capacity, current peak demand, peak demand plus reserves, and capacity excess/shortfall including reserves).

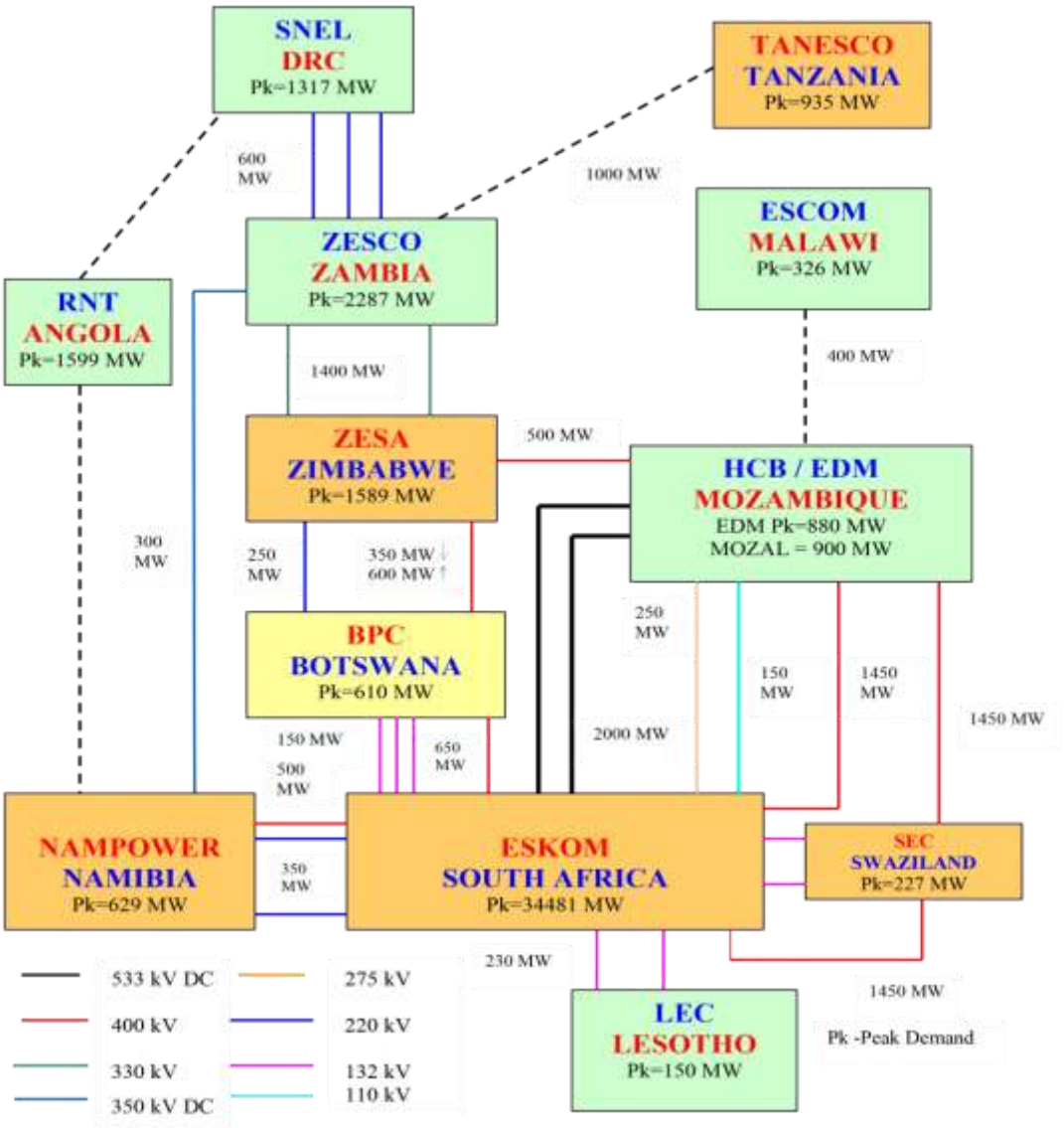

Figure 3-3: SAPP regional power system with interconnectors (source: SAPP)

The Coordination Centre undertakes various activities that include the SAPP regional transmission network and transaction monitoring, planning and operational system analysis, routine reporting, data provision, and advice to member utilities, as well as project preparations services. It has a SCADA/EMS system in place used for visualisation of interconnectors that is operational, and a project to upgrade it is in progress. However, since it is only a secretariat and not a real transmission system controller, its SCADA/EMS is a read-only – this means that the Coordination Centre observes all transmission systems in the SADC Region through its SCADA/EMS, but does not have a control mode. All operational measures relating to the real-time control and dispatch in SAPP are performed by the SAPP member utilities at their control centres, while the Coordination Centre only advises them how to operate.

Three control areas (ESKOM (South), ZESA (Central), and ZESCO (North)) are designated to ensure the management of tie-line flows and the frequency of the SAPP interconnected system by utilising appropriate operational and ICT capabilities. These control areas deal with operating members not meeting requirements of the control areas that are responsible for controlling interconnectors. These control areas will be equipped with computers / software for dealing with dispatch requirements.

The member utilities provide the Coordination Centre with metering data based on a data form prescribed by the Coordination Centre. Metering data come as a file and the entries are automated. All files are opened to the member utilities to see the details and calculation data. Since metering data are sent by the member utilities to the Coordination Centre, it does not guarantee their quality. The member utilities only ask the Coordination

Centre for clarification of invoices (not for metering data). Standardised databases are needed, and data sharing needs to be improved.

The Coordination Centre also offers the operational regional electricity market platform for trade that is available 24 hours.

SAPP has developed and adopted a number of system and market governance documents to sustain the regional system and market operation (see Annex 8.2).

Apart from promoting the development of cross-border transmission capacity and coordinating the planning and operation of the electric power system in the SADC Region, SAPP has been developing a competitive electricity market therein since 2001 and is now able to offer its member utilities a platform for electricity trading.

In the beginning, the electricity market in the SADC Region was based on a series of bilateral OTC/forward contracts between the electricity utilities. Then, SAPP implemented firstly the short-term energy market in 2001, secondly the day-ahead market in 2009, and thirdly the periodic energy imbalance settlements in 2010. In 2016/2017, SAPP completed the Market Trading Platform which enabled it to move from a cooperative to a competitive Power Pool. In 2017/18, a total of USD 106.55 million was exchanged on the competitive market. A total of USD 95.02 million or 88% of the revenues from the competitive market was exchanged between buyers and sellers, while a total of USD 12.53 million or 12% was collected as congestion income, wheeling, transmission losses, and administration fees. The Market Trading Platform maintains bank accounts at Stanbic Bank Botswana Ltd primarily for clearing purposes, accounting for market transactions, security custodial services, administration fees, wheeling fees, and transmission losses.

Currently, the regional electricity market in the SADC Region under SAPP comprises the bilateral market, the forward physical market, the day-ahead market, and the intraday market (see Table 3-2). These markets are not meant to compete against each other, rather these should complement each other. In the near future, SAPP plans to transform the intraday market into the balancing market making it the real-time market by mid-2021. Also, it has plans to establish anew the ancillary services market and the financial instruments markets.

Table 3-2: The regional electricity market in the SADC Region under SAPP

Market	**Main focus**	**Main characteristics**
Bilateral market	Bilateral trading focuses mainly on meeting long-term demand and supply balance and on underpinning generation and transmission investments.	Trading arrangements are mutually agreed bilaterally between two parties, i.e. bilateral contracts are not negotiated through the central platform. Volumes and prices are the key parameters. Trading paths are to be secured in advance. All bilateral contracts are registered with their agreed trading paths, maximum volume and the two counterparts. All nominations and actual utilisation of bilateral contracts are maintained by SAPP daily. Firm contracts have penalties for non-delivery, and are generally not interruptible. Non-firm contracts are interruptible with notice (if notice is submitted on time, there are no penalties applied), and are generally less than 75% reliable. SAPP facilitates realisation of contracts, provides reconciliation of balance, calculates imbalance energy and coordinates its management, calculates transmission losses and transmission pricing/wheeling charges and performs settlement of both losses and wheeling through a common methodology and acts as a central counterpart for the settlement of these, optimises the use of transmission capacity between the countries, etc.
Forward physical market	Competitive trading focuses mainly on meeting short-term demand and supply balance,	Trading is realised in monthly or weekly auctions (or any other defined periods longer than one day ahead) for future delivery according to the contract specifications. A single calculation is

	i.e. allowing market participants to balance their monthly/weekly positions.	executed based on the collection of all orders and available transmission capacity. Auctions are executed every trading day for a physical delivery of the traded volume the next delivery period. The delivery period is the next month, or the next week, where the market result is calculated with one price and scheduled volume for all hours defined for the given products. The following energy contracts may be traded in auctions: - monthly trade's hourly energy baseload contracts for each of the 24 hours of all days in the following month, - hourly energy baseload contracts for the time-of-use contracts with different hourly patterns valid for all days in the following month (for off-peak hours and non off-peak hours), and - weekly trade's hourly energy contracts for the time-of-use contracts with different hourly patterns valid for all days in the following week (for off-peak hours, peak hours, and standard hours).
Day-ahead market	Electricity trading focuses mainly on assisting in managing load and generation fluctuations, and optimising supply and demand portfolios in a bid to minimise cost of supply and maximise participants profits.	Trading takes place in auctions a day in advance of the delivery of such trades. A single calculation is executed based on the collection of all orders and available transmission capacity. A balance price between generation and consumption is valid for all trades. A price and a volume is calculated for each hour in the next delivery period. Hourly energy contracts are enabled for each of the 24 hours of the following day, or a future day.
Intraday market (to be replaced by the balancing market in mid-2021)	Electricity trading focuses mainly on settling all the outstanding requirements after actual trading in the day-ahead market has been done, i.e. balancing market participants' portfolios during the day of trade.	Trading takes place continuously every day around the clock until one hour before delivery. Prices are set based on a first-come, first-served principle. For information purposes only, a closing price for each hour is reported after the intraday market is closed. This price can be a volume-weighted price (average cost) for all trades in the given hour. Hourly energy contracts are enabled for one or more hours for periods as specified by the SAPP Market Operator. The general rule is that whatever transmission capacity not utilised in the forward physical market and the day-ahead market is given to the intraday market. The balancing market is in its final stages of development and will be implemented soon (with gate closure time 15 minutes in the beginning, and 5 minutes later on).

The forward physical market and the day-ahead market are based on the principle of the auction model, which means that all market participants trade on equal terms and that they have a physical grid point for delivery of generation or withdrawal of consumption, in a given market area. This requires an agreement with the national TSO and a Balance Responsible Party, responsible for the market participants' portfolio balance in the physical grid point (area). The auction trading model uses the available transmission capacity of the area interconnections given by the national TSOs, to run an implicit auction. This calculation determines both a system price and an area price, if any congestion in the area model is detected. The system price is calculated assuming no grid congestion, and is the unconstrained price. If the contractual flow of power between the pre-defined areas exceeds the transmission capacity available for market trade, grid congestion occurs and

separate price areas are created (“market splitting”). The auction model is a fully transparent trading methodology where market participants submit orders that are seen only by the Power Exchange and the submitting market participant.

On the other hand, the intraday market is based on the continuous trading model which means a continuing matching of the orders submitted to the intraday market that can be of type sell (sales order), or buy (purchase order). The continuous trading model means that the orders are either matched automatically by the system on price, or a buyer / seller can accept and “hit” an order in the intraday market. The intraday market contracts are settled at the matched price. The continuous trading model is fully transparent where all market participants’ orders are only seen by the Power Exchange, as well as the market participant that owns the order. Normally trading is open 24/7 every day, but can be configured to operate for only a part of the day.

Management of transmission capacity is integrated in all market timeframes. Available transmission capacities of the interconnections between the market areas are given to the markets by the responsible TSOs and submitted to SAPP. Based on the market participants’ portfolio orders and the available transmission capacities, the market clearing engine calculates if there is congestion in the grid, or if demand for trade of electricity between the market areas is fulfilled with the available transmission capacity. TSOs are responsible for transmission capacity per hour between the market areas in both directions. The values are entered using the market trading platform and data is automatically stored in the platform’s database.

Available transmission capacities of all interconnections, which are open market information and required information the market participant needs before concluding the bidding process, have to be entered for the forward physical market products and the day-ahead market product. The intraday market will use the transmission capacity available after the forward physical market and the day-ahead market has closed the market. The intraday market system module will calculate for all interconnections, hour by hour for the next delivery day, the available transmission capacity for the intraday market. TSOs responsible for the interconnections can also use a system function to release more, or revoke, available transmission capacity for each interconnection at any time. If a TSO decides to stop trading in the intraday market between two areas, the available transmission capacity will be set to zero (0). The intraday market system module will, in real-time, re-calculate available transmission capacity based on the matched orders. New values will be made available to all users logged on the intraday market system.

The whole process starts with the TSOs entering transmission capacities for the forward physical market and trading in the monthly and weekly products. Then, after bilateral contracts are nominated, the system module in the market trading platform calculates the transmission capacity available for the day-ahead market. Next, the intraday market system module calculates for all interconnections, hour by hour for the next trading period, the rest of transmission capacity that will be available for trading in the intraday market. TSOs responsible for the interconnections can, for every hourly shift, use a market trading platform system function to release more or revoke available transmission capacity for each interconnection at any time. Available transmission capacity set to zero (0) on an interconnection stops trading between the market areas.

The financial settlement of all the market trades is also integrated in the market trading platform.

In addition to the organised wholesale electricity markets as outlined above, SAPP also calculates and settles the following services:

1) Settlement of losses – collecting payments and distributing revenues for market and bilateral trades;
2) Settlement of wheeling – collecting payments and distributing revenues for market and bilateral trades;
3) Calculation and settlement of imbalance energy.

The regional electricity market in the SADC Region under SAPP is governed by a set of documents and implemented by a dedicated structure (see Table 3-3). The market surveillance responsibilities in SAPP are given to the SAPP Markets Monitoring and Surveillance Team in 2019, in line with the current market growth and expected participation of new market participants such as IPPs and others. The market surveillance function is, in principle, the official established market regulatory body that has access to the database of the

SAPP Market Operator. Market surveillance activities result in reports covering at least the evaluation of the market pricing, the evaluation of the individual participants' behaviour, and the report on the status/trend in the development of fundamental figures with a potential influence on pricing.

Table 3-3: Governing documents and the structure for implementation of the regional electricity market under SAPP

Governing documents	Implementation structure
Market Book of Rules, as a set of rules governing the SAPP Market Operations, making the agreement between all participants and the SAPP Market Operator	Markets Sub-Committee Market Surveillance and Monitoring Team Market Operator
Market Participation Agreement, between each participant and the SAPP Market Operator	Control Area Operators and national TSOs for dispatch, scheduling and imbalance management

SAPP is aware of the changes expected in the near future, especially in view of the SAPP-EAPP Interconnection. The rules, standards, and guidelines (particularly the operational rules) are needed for such inter-Power Pool operation. The work on the SAPP-EAPP Interconnection has been underway for some time and the two Power Pools have made the governance structure to manage the whole process. The structure also contains a block separately reserved to the regulators.

3.2 WAPP

WAPP was created as a Power Pool in 1999 by Decision A/DEC.5/12/99 of the 22nd Summit of the ECOWAS Authority of Heads of State and Government. In 2006, the Articles of Agreement for WAPP organisation and functions were adopted by Decision A/DEC.18/01/06 of the 29th Summit of the ECOWAS Authority of Heads of State and Government. Also in 2006 in the same Summit, WAPP was granted the status of Specialised Institution of ECOWAS by Decision A/DEC.20/01/06 (the WAPP Secretariat headquartered in Cotonou, Benin has been granted such status). Since the regulatory role is indispensable for WAPP, the ECOWAS Regional Electricity Regulatory Authority was established in 2008 also as Specialised Institution of ECOWAS with headquarters in Accra, Ghana.

WAPP was established to leverage on the electricity generation potentials of the Western Africa Region, electrically interconnect the ECOWAS Member States, and establish the regional electricity market with a view of solving the power supply crisis. Hence, it promotes and develops electricity generation and transmission infrastructures, and coordinates exchanges in electricity among the ECOWAS Member States.

Currently, WAPP covers 14 of the 15 ECOWAS Member States and is made up of 36 member utilities, i.e. public and private companies that are either "transmission using members" and/or "transmission owning/operating members". Hence, WAPP member utilities are generation, transmission, distribution and retail supply companies operating in the electricity systems in the Western Africa Region to which WAPP ensures regional integration of the electricity system and market.

WAPP's governing structure has four main levels (see Table 3-4).

Table 3-4: WAPP's governing structures

No.	Organ	Description
1	General Assembly	The highest decision-making body of WAPP, which is composed of all 36 member utilities that are the electricity companies from the ECOWAS Member States.
2	Executive Board	Responsible for implementing the decisions of the General Assembly, and composed of 15 members whereof the Secretary General, an Honorary Member, and 13 Directors General and Managing Directors and Chiefs Executive Officers of the ECOWAS national electricity utilities. To this effect, it has the largest power to ensure the realisation of the WAPP mission and objectives.

3	Organisational Committees	Provide support and expertise to the Executive Board on all matters in respect of collective policy formulation functions for developing, maintaining and updating common “rules of practices” on technical, planning, operational, and environmental aspects of WAPP. There are five such Committees: a) Engineering and Operations Committee, b) Strategic Planning and Environment Committee, c) Finance Committee, d) Human Resource and Governance Committee, and e) Distribution and Commercialisation Committee.
4	General Secretariat	The administrative and technical organ in charge of the day-to-day management of the activities of WAPP, composed of three Departments: a) Information and Coordination Centre, b) Administration and Finance, and c) Planning, Investment, Programming and Environmental Safeguards.

As the development of adequate regional generation capacity and the regional transmission interconnectivity an essential condition precedent to establishing a regional electricity market, WAPP concentrated majorly on developing and progressing towards the implementation of the Regional Generation and Transmission Infrastructure Masterplan, reviewed every five to six years, which has already resulted with completing some milestone projects, some are in the execution stage, and others are in the planning stage. The priority generation and transmission (integration) projects for WAPP have also been identified and listed in the Continental Master Plan 1 Baseline Study (Deliverables 2&3) for the short-, medium- and long terms.

Currently, although there are some interconnections among different ECOWAS Member States, WAPP does not operate as a single synchronous zone due to power system stability issues. More precisely, 9 ECOWAS Member States are electrically interconnected, but operate as three synchronous networks (see Table 3-5) with predictable directions of electricity flows (see Figure 3-4).

Table 3-5: WAPP’s three main synchronous zones

No.	Zone	Countries	Composition	Companies
1	Synchronised Eastern Network	Part of Togo/Benin, Nigeria, Niger	Three power subsystems managed by three companies	CEB of Togo/Benin, TCN of Nigeria, and NIGELEC of Niger
2	Synchronised Central Network	Burkina Faso, Cote d’Ivoire, Ghana, part of Togo/Benin, and part of Mali	Four power subsystems managed by five companies	SONABEL of Burkina Faso, CIE of Cote d’Ivoire, GRIDCo of Ghana, CEB of Benin/Togo, and EDM-SA of Mali
3	Synchronised Western Network	The second part of Mali, Senegal, and Mauritania	The Senegal River Development Organization (OMVS), which operates a common power system made of two WAPP member states and distributes the output from HPPs Manantali and Felou	SENELEC of Senegal and EDM of EDM

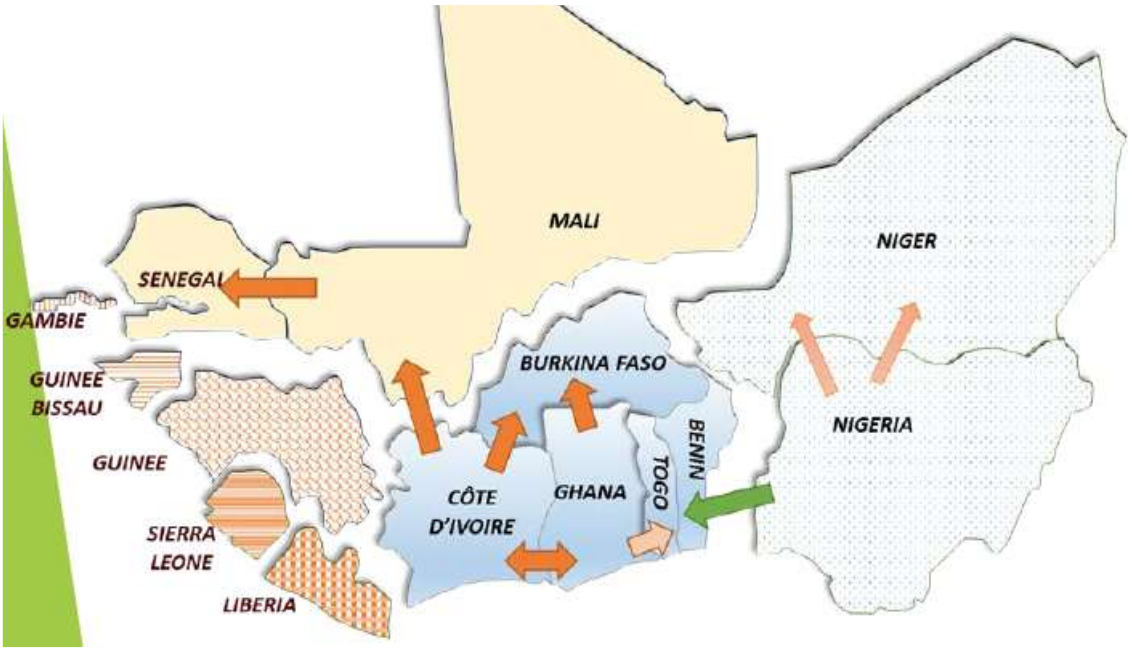

Figure 3-4: Directions of electricity flows in the WAPP three main synchronous zones (source: WAPP)

Transmission systems of the remaining WAPP member states are not yet interconnected (Liberia, Sierra Leone, Guinea, Gambia, and Guinea Bissau). However, there are both plans and activities to interconnect (see Figure 3-5):

1) EAGB of Guinea Bissau and NAWEC of The Gambia to SENELEC of Senegal (OMVG),
2) NPA of Sierra Leone and LEC of Liberia to EDG of Guinea and then to SENELEC of Senegal on the one side and to CIE of Cote d'Ivoire on the other one (CLSG), and
3) CIE of Cote d'Ivoire to TCN of Nigeria (Coastal Backbone).

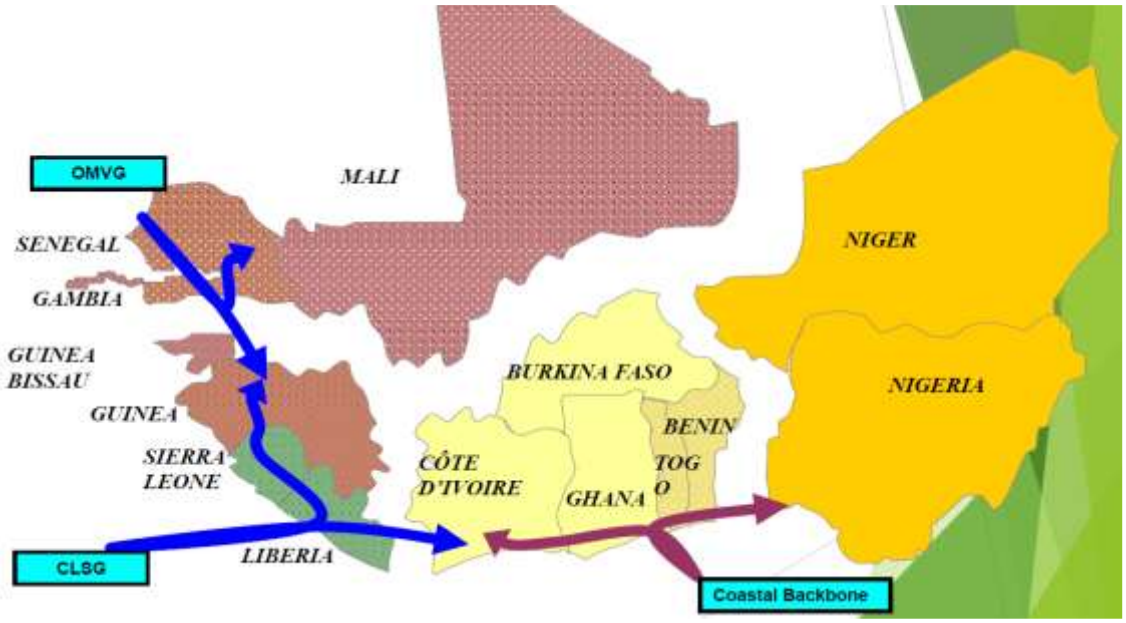

Figure 3-5: WAPP plans and activities for interconnection (source: WAPP)

Most notable in that direction is the latest Masterplan 2019 – 2033, adopted by the ECOWAS Heads of State and Government in December 2018 through Supplementary Act A/SA.4/12/18, which aims at ensuring the synchronisation and stability of the power system in the short-term, improving the integration of variable RE generation in the medium-term, and complying with the (N-1) security criterion in the long-term. The Masterplan contains the priority list of transmission line projects (see Figure 3-6) that shall enable WAPP to interconnect

not only within 14 mainland ECOWAS Member States (internally), but also beyond its current area of coverage (externally):

1) Internally, WAPP implements the major 330 kV transmission backbone projects in the Western Africa Region to help alleviate operational challenges within the electricity networks of WAPP members. These challenges are linked with the inefficient operations which are a weakness at both technical and commercial level (due to large frequency deviations, significant technical and non-technical losses, low collection rates, etc.); and

2) Externally, WAPP plans to extend its links to the Northern Africa through Morocco and the Central Africa (CAPP) to Inga Dam, which would result in further economic diversification of its current energy mix (31.1% of thermal projects operating mainly with natural gas, and 68.9% of renewable energy projects of which 29.5% involve variable renewable energy).

Figure 3-6: WAPP high voltage transmission networks and prospective interconnection projects (source: WAPP)

The synchronisation project, i.e. integration of the above noted three main separated unsynchronised areas and the remaining five not-interconnected (isolated) systems into a single synchronous zone covering the 14 mainland ECOWAS Member States, is ongoing. Being funded by the World Bank's grant of US$ 21.5 million, the synchronisation project has two subcomponents:

1) Technical assistance and logistical support at the WAPP General Secretariat (ongoing); and

2) Integration and Synchronisation of the System in two phases

    a. Phase 1 – Study of the Synchronisation (executed), and

    b. Phase 2 – Acquisition and installation of equipment required for synchronisation (ongoing)

        - Voltage control - Installation of Static Var Compensator in Matam,

        - Network safety and security - Installation of PMUs at each end of the interconnection lines to integrate to WAMS and installation of decoupling relays,

        - Frequency control - Upgrading work on groups to participate in frequency tuning.

Three working groups have been established in that direction, namely for: 1) frequency adjustment, 2) protection coordination, and 3) network reliability assessment. These advise on the implementation of the system services market, i.e. the establishment of primary, secondary and tertiary reserves, the maintenance of the system voltage plan, and the provision of mutual support in emergencies (black-start capability). A tentative objective for the synchronisation is set at 2021-2022.

The Information and Coordination Centre, which is currently a Department under the General Secretariat of WAPP and soon-to-be the RSMO, works intensively on both subcomponents of the synchronisation project as one the WAPP's priority projects. Such work is based on the Centre's tasks to:

1) collect, analyse and disseminate information portraying overview of WAPP's state and evolution,
2) monitor the evolution of the electricity situation in ECOWAS Member States with special focus on the national power systems faced with emergency situations (in order to forewarn the risks of performance deficiencies and to provide them with corrective measures),
3) analyse periodically the economic and technical potentials and feasibility of electricity trading arrangements among its members,
4) facilitate the development of technical norms and standards for the efficient operation of the national and interconnected electricity networks,
5) provide support for monitoring of technical performances of the electricity utilities, and
6) organise periodic meetings of the Engineering and Operations Committee and the Distribution and Commercialisation Committee.

Being responsible for promoting operational coordination between transmission owning/operating members through actual day-to-day information sharing/exchange between the operational coordination centres of the WAPP members, the Information and Coordination Centre is also dedicated to implementing another project, funded by the EU's subsidy of EUR 30 million, for establishing itself as the RSMO in two subcomponents:

1) the construction of its own building (technical and administrative) at Calavi, Benin (execution of 77%), and
2) the installation of SCADA/EMS/MMS/WAMS and equipment for communication and market monitoring at the Centre, 5 control area centres and national control centres (execution 64%) (see Figure 3-7).

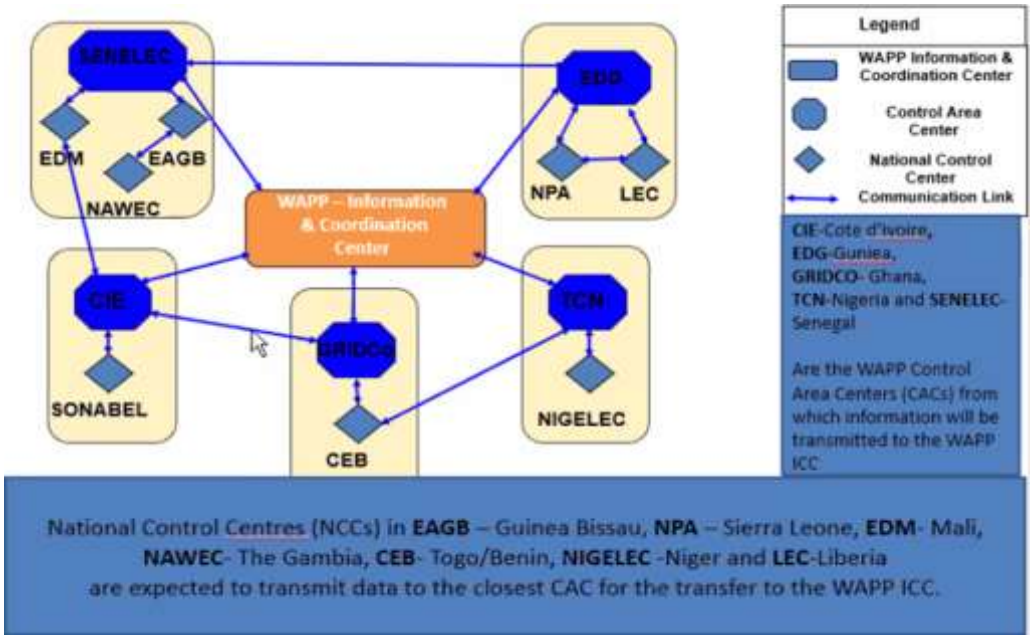

Figure 3-7: Communication concept of the Information and Coordination Centre of WAPP (source: WAPP)

The project's current status is as follows:

- the statement of works and designs for SCADA/EMS/MMS/WAMS Systems were finalised and approved,
- SCADA/EMS/MMS/WAMS Systems have been developed at the contractor office with the involvement of the Information and Coordination Centre staff,
- factory acceptance testing for SCADA/EMS/MMS/WAMS Systems were completed,
- phasor measurement units were installed in selected locations with site acceptance tests completed,
- installation of telecommunication equipment in the WAPP countries is ongoing,
- construction of the Information and Coordination Centre building in Calavi, Benin is ongoing.

The percentage completion of the building is estimated at 77% (to be finalised by December 2021). The percentage completion of equipment installation stands at 64%; equipment is already fully installed at the utilities' locations and SCADA/EMS/MMS/WAMS installations at the Centre are expected to be finalised by January 2022, site acceptance tests performed by April 2022, and go-live made by May 2022.

By then, the Information and Coordination Centre will be able to connect and operate/coordinate with five control area centres and national control centres in the full capacity of the RSMO (i.e. market operator of the regional system). SCADA/EMS/MMS/WAMS Systems are expected to enable the Centre to monitor the regional system in real-time and operate the day-ahead market, i.e. to: (1) facilitate regional coordination of cross-border electricity exchanges, and (2) monitor the WAPP System Operation, by (i) alerting and advising the control area centres in the event of security risks in the regional system, and (ii) maintaining frequency and voltage levels within operating limits to ensure the quality of service parameters.

Electricity trading is based on Directives adopted by the ECOWAS Council of Ministers and on a number of market governance documents developed by WAPP and the Information and Coordination Centre and approved by ERERA as the regional regulatory authority (Regional Regulator) (see Annex 8.3).

Already at the initial stage of the regional electricity market development, WAPP articulated the Market Design and Roadmap, charting the course it is following in order to bring about the actualisation of the integrated regional electricity market (see Table 3-6). The course has been charted in such way to allow the regional electricity market to develop gradually, in three phases enabling the national power systems to adapt flexibly and rationally in tune with their current organisational diversity.

Table 3-6: The ECOWAS Regional Electricity Market Roadmap

Phase	Time domain	Situation	Main characteristics
1	Today 2018-2022	In Phase 1, some regional transmission infrastructure necessary for the integrated regional electricity market are expected to be commissioned. Most transactions actually happen between adjacent countries.	Regional Regulator (ERERA) and the RSMO (the Information and Coordination Centre) are appointed. The Regional Market Rules, the Dispute Resolution Rules and other market governance documents are adopted. The regional electricity market is a bilateral market where bilateral trading is realised on the basis of bilateral contracts on purchase and sale of electricity. Traditional PPAs still exist. Bilateral trading is formalised as the one that is carried out on a "case by case" basis. Pricing formula is based on two terms (capacity and energy). Bilateral contracts (between countries, between national companies) are standardised through approved model contracts for trade in the short-, medium- and long-term. Commercial instruments (type of bilateral contracts, short-term exchanges) are standardised.

			Pricing for transmission services is bilaterally agreed between trading parties, i.e. between parties involved in a bilateral contract for existing contracts. Although the short-term bilateral contracts are limited to adjacent countries, this does not preclude transactions involving transit countries. In such case, contractual parties have to incorporate and negotiate with the third country providing the wheeling services the admitted losses and the fee for wheeling. The regional operational and commercial coordination is initiated. Preparation for Phase 2 are performed.
2	Short-term 2022+	Phase 2 will be launched upon successful realisation of Phase 1 and based on preparations performed therein. Real competition will be introduced in the regional electricity market through operationalisation of the day-ahead market.	Bilateral contracts will be allowed between neighbouring countries and between non-bordering ones (with transit through third countries), based on standard commercial instruments. Traditional PPAs will still exist. Back up of contracts in the market (possibility) will be enabled. Short-term exchanges will be enabled through the competitive trading in the day-ahead market (or the spot market). Regional transmission pricing for cross-border electricity trading will be deployed and implemented. For new bilateral contracts, pricing for transmission services will be governed by the Regional Transmission Pricing Methodology, already approved by ERERA. WAPP has developed internally the MW mile method for transmission pricing model in line with the Methodology. Regional Regulator (ERERA) and the RSMO will be fully functioning.
3	Long-term	In Phase 3, the day-ahead market will be liquid, trade in the bilateral market will be dynamic, and other markets such as the ancillary services and financial products markets will be introduced.	The Western Africa Region will have enough generation and transmission capacity. The market will be fully open and competitive. Trading in the bilateral market and the day-ahead market will be dynamic. New market services (some ancillary services, financial products) will be introduced. Regional master planning regarding transmission assets will be enforceable; in other words, countries will be “obliged” to implement certain transmission projects identified by the approved Masterplan. The Western Africa Region will have enough participants in the market making it very competitive with less risk of a monopolistic market.

Phase 1 of the regional electricity market was formally launched in June 2018, after all conditions precedent are met for Phase 1. In the current situation (May 2021, toward the end of Phase 1), not all conditions precedent for Phase 2 are fulfilled yet (see Table 3-7).

Table 3-7: Current situation (May 2021, toward the end of Phase 1) and conditions precedent for Phase 2

Current situation	**Conditions precedent**
Exchanges of electricity are bilateral. Trading in electricity is majorly cross-border with the prices of transmission	The Information and Coordination Centre is spun off from the general structure of WAPP and consolidated as the

and energy mutually agreed by contractual parties in bilateral contract. The Information and Coordination Centre deals only with those TSOs which represent market participants in their respective countries and exchange data with the Centre (i.e. the Centre does not have a contact with contractual parties from bilateral contract, but with TSOs) on a transaction concluded between contractual parties on the basis of a bilateral contract. There are 12 bilateral contracts among 6 WAPP member utilities across 9 ECOWAS Member States and Mauritania, with trading up to 6.1 TWh. A standard bilateral contract on sale and purchase of electricity is developed and contractual parties in a transaction are recommended to use it as a template. TSOs have already installed meters in all substations at interconnections/interconnectors, and the Centre does the automatic meter reading at every interconnection point, which is important for future billing and settlement of transactions. Transmission line projects are prioritised given that WAPP shall integrate the power systems of the 14 mainland ECOWAS Member States in the short-term. The anticipation of increased trade in electricity through the regional market platform has led to increased enquiries from potential market participants who are eager to have an outlet to sell their electricity. ERERA and WAPP are in the process of mobilisation and registration of new market participants according to the Regional Market Rules. The Electronic Data Processing System, requisite to effectively monitor, coordinate and manage the regional system and market, is currently under development. Even before the MMS future readiness, WAPP is already conducting daily scheduling trials of cross-border exchanges in electricity in respect to the existing bilateral contracts on a manual basis. 12 bilateral contracts are scheduled and confirmed by the market division daily. This trial scheduling is designed to get the national utility operators to grow accustomed to the protocols involved in operating in the regional market.	RSMO, an independent regional institution. System-wise it only monitors, studies and reviews how the system operates, but market-wise it does the scheduling, clearing and settlement, billing and invoicing for the needs of the day-ahead market. The RSMO designate is equipped with the hardware and software necessary for efficient operationalisation of the processes incumbent upon it in its role as the RSMO in Phase 2, which involves at least: - procurement of the hardware and software systems, - training in the use of the different systems, and - a period of testing for both systems and human capability. Countries have performed the necessary actions to implement open access in their transmission systems. The Regional Market Rules for Phase 2 are drafted, reviewed, adopted and approved by ERERA. The agreed plan for implementation of regional standards continues is being implemented. Regional transmission tariff model and wheeling services are agreed and put in place, and tariffs are actually calculated and enforced by ERERA. Agreement on enforceability of regional transmission projects and reinforcement of domestic transmission systems is reached and implemented. The Electronic Data Processing System is put in place and operationalised to enable transactions in the day-ahead market on the basis of MMS and AMR (part of the Electronic Data Processing System). Training is performed at two levels: - at the level of market operator, tackling specific needs to operate the day-ahead market and trading with transit through third countries, and - at the level of market participants (utilities) and domestic TSOs, making them capable of trading efficiently and operating the domestic systems safely and meeting the regional standards.

Once fully established, the regional electricity market will enable customers to enter the market, participate in the market, and exit the market (see Figure 3-8).

The market will allow the exchange of electricity between market participants on the basis of:

1) remuneration for the use of the assets of each TSO,
2) reimbursement to TSOs of losses caused by exchanges, and
3) payment of the operating costs of the specialised institutions in charge of the regional electricity market (the RSMO and ERERA).

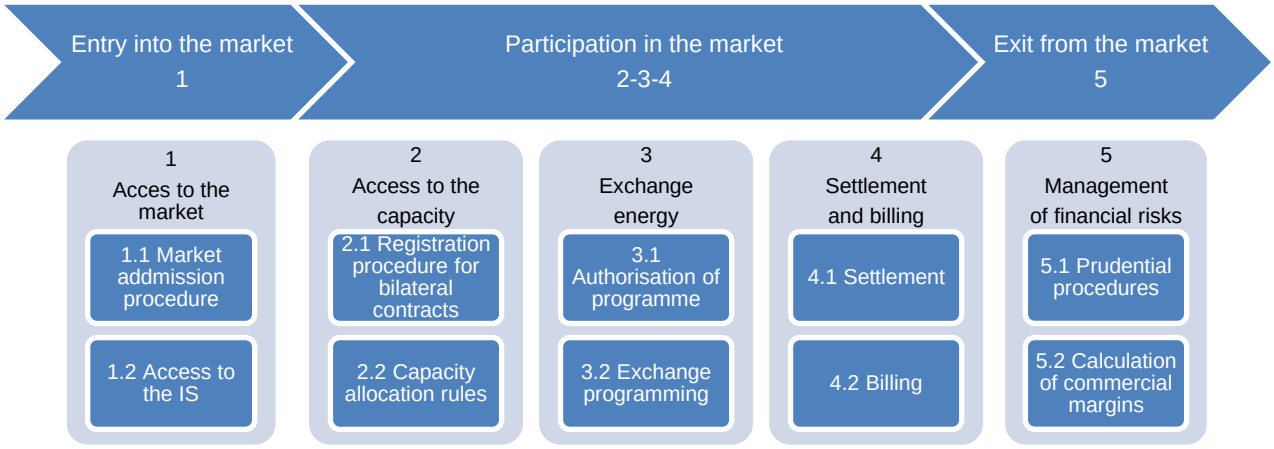

Figure 3-8: Customer journey in the market (source: WAPP)

By pooling the energy resources and creating the regional electricity market, WAPP will bring immense opportunities and benefits to market participants, such as: optimisation of investments, optimisation of operating costs, improving security of electricity supply thanks to mutual assistance, improving reliability of the electrical system with reserve sharing possibilities, increasing cross-border electricity exchanges at competitive costs, etc. Through the supply or purchase of electricity at competitive prices in the framework of the regional electricity market, all market participants, i.e. electricity utilities, should profit once the infrastructures and the market are in place.

3.3 EAPP

EAPP was established as a Power Pool in 2005 by the two Memoranda of Understanding:

- the Inter-Governmental Memorandum by the Eastern Africa countries (to enable the establishment of EAPP), and
- the Inter-Utility Memorandum by the electricity utilities of these countries (to define the fundamental principles for the management and operation of EAPP).

In 2006, by Decision of the Heads of State and Government at the 11th Summit of COMESA, EAPP evolved into a regional organisation and was adopted as a Specialised Institution of COMESA for the electricity sector.

Headquarters of EAPP (i.e. the EAPP's Permanent Secretariat) are located in Addis Ababa, Ethiopia. In 2012, the Conference of Energy Ministers of the EAPP Member States approved the transformation of EAPP's Regulatory Forum into EAPP Independent Regulatory Board as a Regional Regulator, located at the EAPP's Permanent Secretariat in Addis Ababa, Ethiopia.

EAPP was established with the purpose to foster power system interconnectivity in the Eastern Africa Region, by encouraging cross-border electricity exchanges through the regional investment in electricity generation, transmission, and interconnection, and through the establishment of an operative framework for regional electricity exchanges. It facilitates bilateral and multilateral issues between its member utilities (active or affiliated) to enable development of the Power Pool (EAPP member utilities may include vertically integrated utilities or integrated utilities, owners of generation facilities and/or distribution companies and/or large consumers which are authorised within their national boundaries to trade within EAPP by their national system operator, TSOs, ITOs, and ISOs).

Currently, EAPP comprises 13 electricity utilities from 12 Member States. These are either active members (public or concessionary utilities in charge of electricity generation, transmission or distribution in the region) or affiliate members (IPPs operating in the region who have fulfilled the membership conditions).

EAPP's governing structure has six main levels (see Table 3-8).

Table 3-8: EAPP's governing structures

No.	Organ	Description
1	Conference of Ministers	The highest decision-making body of EAPP. Responsible for resolving major policy issues and for admitting new members to EAPP. Represented by the Energy Ministers in each member state.
2	Steering Committee	Reports directly to the Conference of Ministers and acts as the Board of Directors of EAPP. Consists of the chief executive officers or managing directors of EAPP member utilities.
3	Independent Regulatory Board	EAPP's organ which acts as the regional regulatory authority (Regional Regulator) with mandate of providing fair and effective regulatory services to facilitate the development and efficient operation of the regional electricity market in the Eastern Africa Region and to ensure a conducive environment for regional infrastructure investments. Responsible for enforcing standards, procedures and specifications as set out by the Steering Committee; organising the electricity markets in EAPP; and settling any disputes which may arise between EAPP member utilities or related to the exchange and transactions within EAPP. Consists of nominees of the national regulatory authorities in EAPP member states. With the support of the World Bank, the following six documents were recently completed as part of its full operationalisation: a) Ten-Year Strategic Plan (2021-2030); b) Three-Year Action Plan (2021- 2024); c) Self-Sustaining Funding Mechanism Report; d) IRB office Operations Manual; e) Capacity Building Recommendations (Training Needs Assessment); and f) Road Map and Implementation Plan.
4	Permanent Secretariat	Oversees the administration of EAPP. Headed by an Executive Secretary recommended by the Steering Committee.
5	Technical Sub-Committees	Operational arms responsible for the implementation of technical activities: a) Planning Sub-Committee, which is responsible for coordination of master plans and development programmes of EAPP member utilities; b) Operations Sub-Committee, which is responsible for definition of the operation and maintenance rules of power plants and networks involved in EAPP (its other specific tasks are defined in the Operation Agreement); and c) Environment Sub-Committee, which is responsible for the environmental impact assessment and mitigation measures on the electrical installations within EAPP.
6	Coordination Centre	Yet to be established under the guidance of the Sub-Committee on Operation. To become responsible for the collection of technical and commercial information necessary for the operation of the regional interconnected power system and exchanges of electricity between EAPP member utilities/countries.

In 2021, the regional electricity system and market operation in the Eastern Africa Region is at a critical juncture since many national transmission systems will soon be interconnected and many of the electricity utilities will be enabled for the first time to trade in electricity across borders. The priority generation and transmission (integration) projects for EAPP have been identified and listed in the Continental Master Plan 1 Baseline Study (Deliverables 2&3) for the short-, medium- and long terms.

Several critical interconnection projects which will serve as the main backbone transmission lines are progressing and are close to completion:

1) Ethiopia-Kenya interconnector (HVDC 500 kV, 1100 MW), expected to be commissioned before the end of 2021 and committed 400 MW for export as per the first phase of PPA;

2) Ethiopia-Sudan interconnector (the second phase), under study;

3) Zambia-Tanzania-Kenya interconnector, under implementation; and

4) Uganda-Tanzania interconnector, under study.

Hence, EAPP with the support of development partners (World Bank, SIDA, NORAD, AfDB, USAID) initiated several activities and programmes to ensure the Power Pool's interconnected grid is operated safely for the purpose of facilitating regional electricity trade. This has been guided by the EAPP Ten-Year Strategic Plan (2021-2030) and the Three-Year Action Plan (2021-2024). The ongoing activities include:

1) Operational Readiness Study (IC compliance, development of operation guidelines, Power Balance Statement, and development of the EAPP load flow and dynamic simulation model);

2) Preparation for the Commercial Readiness Study and implementation of the EAPP trading platform;

3) Preparation for the development of Regional Power System Master Plan and feasibility studies of regional interconnection projects; and

4) Capacity building of the EAPP's and electricity utilities' staff (the EAPP Permanent Secretariat and the EAPP Technical Sub-Committees members).

The Operational Readiness Study is being performed with the support of the World Bank through the consultancy services conducted by TRACTEBEL. One of the four tasks of the Study is the "Power System Analysis of the EAPP Region'', wherein the steady-state and dynamic analyses are conducted for the EAPP Region for 2020 and 2025 to show transmission bottlenecks that could affect the regional electricity market (the full final report was made available and shared on 28 May 2021).

The following recommendations are given to address them:

- The load flow analysis detected many violations under (N) and (N-1) conditions in several EAPP member states, and called for the development of a mitigation plan under the Operational Readiness and its implementation by specific countries;

- The transient stability analysis detected cases in which a loss of synchronism was observed, and called for the installation of the Out-Of-Step protection at all tie-lines indicated in the analysis;

- The transient stability analysis also called for the installation and adjustment of the Out-Of-Step protection for isolated units losing synchronism, as identified in some simulations;

- The analyses advised the deployment of the Special Protection Schemes in case of radial interconnections (single or double circuit) to prevent system collapse in case of system separation due to the loss of the interconnection (e.g. tower failures);

- The dynamic simulations identified some interarea modes with low damping ratios, and recommended the installation of Power System Stabilisers where they are not and their proper tuning. It also recommended to enforce, via grid code requirements, that every generating unit with nominal capacity equal or higher than 30 MVA be equipped with a Power System Stabiliser in service tuned to provide positive damping for electromechanical oscillations within the range of 0.15 to 2.0 Hz;

- The dynamic simulations also suggested the installation of Phasor Measurement Units at the tie-lines to improve the observability of interarea modes and provide useful data for other applications (real-time monitoring, post-mortem analysis of widespread blackouts, model validation, etc.);

- The analyses called for the definition of the Net Transfer Capacities between neighbouring systems/countries or different scenario to guarantee safe and stable operation as the complexity of the grid increases;
- The analyses detected that long overhead lines on 220 kV, 400 kV and 500 kV must have adequate reactive power compensation;
- The studies asked for paying attention to the operation of parallel lines at different voltage levels. As the grid evolves rapidly, it is common to build new lines at higher voltage levels along the corridor of existing lines. If these lines at different voltage levels are operated in parallel, it is often observed that the line on the lower voltage is the limiting factor on the transfer capacity;
- The studies called for the implementation of AGC at the national and regional levels in presence of increased system complexity due to RES integration and deployment of interconnections. AGC should be implemented to provide both secondary frequency and tie-line power flow control; and
- The studies proposed the deployment of a harmonised Under Frequency Load Shedding scheme, in forward looking manner in the sense of a need for harmonisation of at least the first stage of the scheme for a future interconnection with SAPP.

In addition to the implementation of the regional projects, the EAPP Ten Year Strategic Plan (2021-2030) also identified yet another part of the hard infrastructure to be installed at the EAPP Headquarters Building that will give the Grid Coordination Unit the ability to monitor the regional electricity system operation (i.e. power flows and system stability) while facilitating the regional electricity market operations. This includes ICTs, communications infrastructure, SCADA/EMS for monitoring, and AGC for flow control at the interconnectors. It should be noted that although the EAPP Grid Coordination Unit will be equipped with such hard infrastructure, the regional dispatch and control is not envisaged at EAPP. The use of such hard infrastructure will be limited to monitoring and coordination (i.e. without having the capability to intervene on the interconnectors), whereas the real-time operation will be kept in the hands of transmission system operators in the EAPP member states.

The EAPP Three-Year Action Plan (2021-2024) followed the above strategic lines and identified the regional dispatch and control/ICT capabilities to be a priority, with a tentative budget which is yet to be funded. In the short-term period (for 2022), it is planned to conduct preparatory activities for the design of SCADA/EMS/AGC, engage consultancy services, and finalise the design with the aim to get the necessary approval upon which SCADA/EMS/AGC will be procured. In the same short-term period (2022), it is also planned to develop a Roadmap for EAPP Energy Information System, and then to implement it. Such short-term activities make a part of the preparatory works for coordination of the electricity system operation with the electricity market trade for which a short-term trading platform is needed.

EAPP is conducting different studies of the trading platform development under the World Bank financing (IDA Grant). The current status of activities is the following:

- EAPP Market Design – ongoing, expected to be completed in July 2021;
- Drafting of the Rules for the EAPP – expected to start in August 2021 and to be completed in December 2021;
- Preparation of the EAPP Market Trading Platform – expected to start in April 2022 and completed in December 2022; and
- Electricity trade – expected to start on the EAPP Market Platform in January 2023.

Under the AfDB financing, EAPP is also conducting the “capacity building for the operationalisation of the EAPP regional power market trade project” (for the shadow market operations).

The above ongoing activities will feed into the revision of existing system and market governance documents which were previously developed and adopted as a basis for electricity trade in the Eastern Africa Region (see Annex 8.4).

The current situation as regards electricity trade in the Eastern Africa Region is characterised by the absence of a centrally organised short-term electricity market and thereto related day-ahead/intraday/balancing market trading platforms. The cross-border electricity trades between market participants from the interconnected countries are based on bilateral agreements in the bilateral OTC/forward market wherein EAPP has no role. Such trades are managed based on long-term schedules (e.g. weekly) and on beforehand agreed exchange prices of electricity.

Schedules of electricity exchanges and power flows are monitored by the national dispatching and control centres of system operators of the electricity systems between which trades are realised and which are responsible for metering. Since EAPP is not involved in exchange of and/or trade in electricity, it only receives information on trades from the related system operators. Five control areas are yet to be established: 1) Egypt-Libya; 2) Sudan-South Sudan; 3) Ethiopia; 4) Kenya, Uganda, Rwanda, Burundi; and 5) Tanzania.

Trades are based on traditional long-term bilateral contracts on purchase and sale of electricity (which run for approximately 3 years; every time a MWh is exchanged from one country to another the price of exchange is the same and will only change when the contract is up for a new negotiation, i.e. every third year), and that on a rather small scale (e.g. Ethiopia-Sudan up to 140 MW per hour; Ethiopia-Djibouti up to 60 MW per hour; and Kenya-Uganda for +/- 4 MW for managing imbalances in each of the power system).

Such trades are handled bilaterally, as they are realised between the electricity utilities from each side of a border for a contracted quantity at a contracted price, which comprises losses as well. The electricity network losses which are caused by a cross-border transaction are included in the price noted in the contract on purchase and sale of electricity. A buying party pays 100% of losses incurred by a transaction and each contractual party covers losses in its system.

There are no wheeling transactions yet (across a third country). However, several studies have analysed costs of such wheeling (i.e. a loss study is made for the Ethiopia-Kenya-Tanzania transaction, for which incremental losses with/without transaction are identified based on computer modelling and load flow calculations).

Sales volume in the long-term wholesale market are low, and additional quantities of electricity should be brought for trade in the bilateral market. It would also be necessary to increase a currently limited number of market participants, increase a currently limited transmission capacity for wheeling, and increase a currently limited number of transmission interconnectors available.

However, a currently low sales volume does not prevent EAPP to work on a further development of the regional electricity market. In parallel with the development of SCADA/EMS/AGC system, it also works on the short-term trading platform expecting some short-term trade as well (i.e. it has developed a pilot system to test a potential short-term market setup).

Future short-term trade will differ from current long-term one in so far as short-term exchanges on interconnectors will be determined daily for each hour of the coming day, as part of the daily, day-ahead planning of operation, where covering of the load also in a systematic way will take generation from adjacent countries into account. The main difference between short- and long-term trade will be in the determination of electricity price used for settlement of electricity exchanged between the countries.

A new actor will be introduced for the short-term cross-border electricity trade – the market operator. In EAPP, the market operation is supposed to be facilitated by the Coordination Centre which will replace the current day-ahead procedures taking place today within TSOs' and producers when it comes to plan for the interconnector short-term exchange and generation plans for the coming day. The Coordination Centre, given the role of performing market operation, will on a daily basis receive information from TSOs and producers and after calculation of prices and schedules, schedules will be sent to TSOs and producers.

The Market Road Map was elaborated for development in the period 2010-2025 (see Figure 3-9).

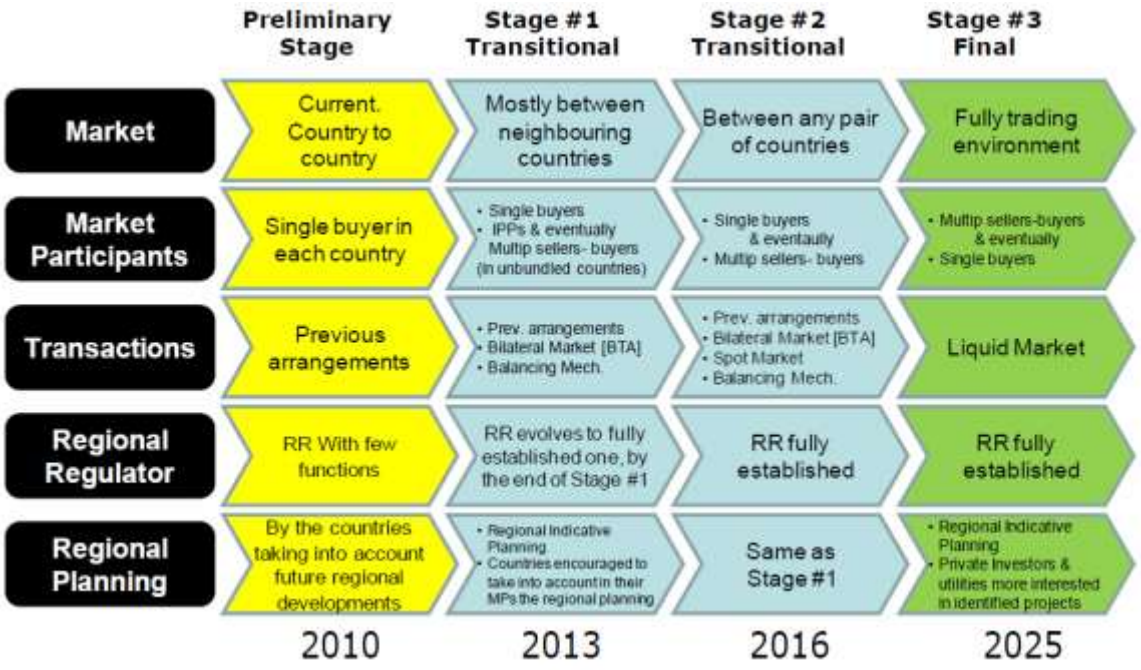

Figure 3-9: EAPP Market Road Map (source: EAPP)

It covered five dimensions (the black boxes) illustrating what was needed in order to have a fully-fledged EAPP regional electricity market in 2025. It is still appropriate and correct, also comparing with the European market development as a reference. However, as very little has happened since 2010 where it was published, the very first steps were identified in 2014 taking the current EAPP market design as a point of departure. In 2021, all these steps have entered into another revision.

3.4 CAPP

CAPP was created as a Power Pool in 2003 on the basis of:

- the Inter-Governmental Framework Agreement Establishing the Central African Power Pool as a Specialised Agency of ECCAS, and
- the Inter-Utility Agreement.

Complementary legal texts on CAPP were adopted in 2004. The Conference of Heads of State and Government adopted the Central African Electricity Market Code in 2009, and approved a CAPP levy and the creation of a Development Fund for the electricity sector of the Central Africa in 2015.

Headquarters of CAPP are located in Brazzaville, the Republic of the Congo. The founding documents (i.e. the Inter-Governmental Framework Agreement) and later legal texts (i.e. the Central African Electricity Market Code) envisage the establishment of a CAPP regulatory body.

CAPP was established with the aim to develop a regional electricity market in the Central Africa Region through physical connections (e.g. transmission lines) and harmonised regulations. Hence, it is responsible for the implementation of energy policy, the construction of the ECCAS infrastructure, and the organisation of exchanges in electricity and related services in the Region. It facilitates the development of priority integration projects and the pilot cross-border electrification programme, which aim to build electricity networks and a future regional energy exchange.

Currently, CAPP covers 11 ECCAS Member States and is made up of 12 member utilities, i.e. public, private and/or mixed generation, transmission and distribution undertakings. Hence, CAPP member utilities are generation, transmission, distribution and retail supply companies operating in the electricity systems in the Central Africa Region to which CAPP ensures regional integration of the electricity system and market.

CAPP's governing structure (see Table 3-9) follows the main objectives by undertaking related actions (see Table 3-10).

Table 3-9: CAPP's governing structures

No.	Organ	Description
1	Council of Ministers	The highest decision-making body of CAPP. Composed of the ministers in charge of energy. Signs or amends the constitutive act of CAPP. Approves the Inter-Utility Agreement. Defines the common energy policy. Approves community energy development plans. Sets up the Executive Committee and the Management Committee. Approves the admission of new members. Takes sanctions against defaulting members.
2	Executive Committee	Responsible for implementing the decisions of the Council of Ministers. Composed of the general directors or general secretaries of the ministries in charge of energy. Currently supported by the Management Committee and in future by the regulatory body (not yet effectuated). Defines common energy policy implementation plans and programs, particularly in terms of pricing policies, planning and standardisation. Defines the orientations of the CAPP's activities and monitor their application. Approves the CAPP's action programs. Proposes the admission of new members. Proposes sanctions against defaulting members. Harmonises and approves the tariffs for access to international networks proposed by the Management Committee. Enacts the rules of the game between members participating in exchanges and at competitive auctions in CAPP.
3	Regulatory Body (not established yet; some activities are underway to establish it by the yearend 2021 with AfDB's financing)	Responsible for dealing with the regulatory affairs in CAPP. Ensures the application of the rules of the game between members participating in the exchanges and at competitive auctions in CAPP. Harmonises the accounting and billing procedures for electricity exchanges (power and energy). Requires the accounting separation and management of the accounts of integrated utilities participating in CAPP. Harmonises network access tariffs for member utilities of the Operation Sub-Committee. Organises the electricity markets in CAPP. Harmonises the accounting and invoicing procedures for electricity exchanges.
4	Management Committee	Reports to the Executive Committee and the Council of Ministers. Composed of the general managers or chief executive officers of the CAPP member utilities whose meetings are prepared by the Committee of Experts. Currently supported by the Permanent Secretariat and in future by the Committee of Experts and the conciliatory body (not yet effectuated). Ensures the execution of plans and programmes relating to common energy policy. Ensures the coordination of the work of the Technical Sub-Committees. Approves the documents and programs of the various Technical Sub-Committees. Proposes options for the development of the power system to the Executive Committee. Appoints the Permanent Secretary. Sets up, if necessary, the Technical Sub-Committees or ad hoc commissions. Approves the CAPP's budgets. Organises training for technical staff involved in the operation of CAPP. Performs other more specific tasks related to operating members as defined in the Operating Agreement.
5	Conciliatory Body (not established yet)	Resolves any dispute that may arise between members related to the exchange or the transactions in CAPP.
6	Permanent Secretariat	The CAPP's administrative organ. Headed by a Permanent Secretary who performs activities under the authority of the Management Committee. Liaises between the bodies of CAPP and ECCAS on the one hand and the other organisations involved in the development of the African electricity sector. Prepares

		the meetings of the Council of Ministers, the Executive Committee, the Management Committee, and the Technical Sub-Committees for which it provides the secretariat with the assistance of the host body. Provides up-to-date transparent information and as comprehensive as possible to CAPP members, development partners and public, particularly on regional interconnections and available generation capabilities. Submits action plans and budgets to the Management Committee. Develops cooperative relations between CAPP and African institutions for international financing of the electricity sector. Keeps and archives the minutes of meetings of the CAPP's bodies. Manages the CAPP's permanent administration. Ensures that the decisions of the CAPP's decision-making bodies are implemented. Assists the Management Committee in the accomplishment of its mission. Looks for ways and means to mobilise funds according to the recommendations of the Executive Committee. Composed of three Technical Sub-Committees: a) Planning Sub-Committee (currently, the only one which is active), b) Operation Sub-Committee (to establish the Coordination Centre), and c) Environment Sub-Committee.
7	Coordination Centre (not established yet)	Envisaged under the Operation Sub-Committee, however not effectuated yet. Responsible for managing the movements of energy. Centralises in real time all technical information coming from different interconnected systems of member utilities, with a view to realise technical harmonisation of commercial trade.

Table 3-10: CAPP's main objectives and actions undertaken

No.	Objective	Actions undertaken
1	Securing the supply of electricity to CAPP member utilities/member states	Harmonisation of national policies and master plans for the development of electricity systems, taking into account their impact on the environment
2	Facilitating and coordinating the implementation of regional electricity infrastructure projects	Joint operation, by appropriate multilateral structures, of works and interconnection lines involving several members/countries
3	Improving the integration of the national electricity markets of CAPP member states with a view to create the regional electricity market	Definition and implementation of common legal and technical instruments for the market, such as laws, and technical and commercial rules for the exchange in electricity
4	Increasing the regional electrification rate and satisfying all forms of electricity demand	Development rural electrification policies and financing instruments

In the above set-up, the technical expertise required to accomplish the CAPP's mission sits outside the Permanent Secretariat, within the national electricity utilities. The Permanent Secretariat is still lacking the technical expertise that the Technical Sub-Committees are supposed to provide (only the Planning Sub-Committee is currently operational). Hence, there is a shortage of technical expertise within the CAPP's operational structures which constitutes a major disadvantage when it comes to contributing to and/or supervising the development of interconnection projects. Considerable delays in the construction of generation and transmission infrastructure are reflected in the delayed establishment of a regional electricity market.

Existing high-voltage transmission networks as well as national projects of CAPP member states by 2035 (see Figure 3-10), show that there is a significant need to strengthen internal transmission networks and construct cross-border interconnections. Of all Power Pools, CAPP is the one with the fewest interconnections to date. The only cross-border high voltage link exists between Congo and D.R. Congo. Part of the D.R. Congo's high-voltage transmission network is connected to SAPP interconnected network.

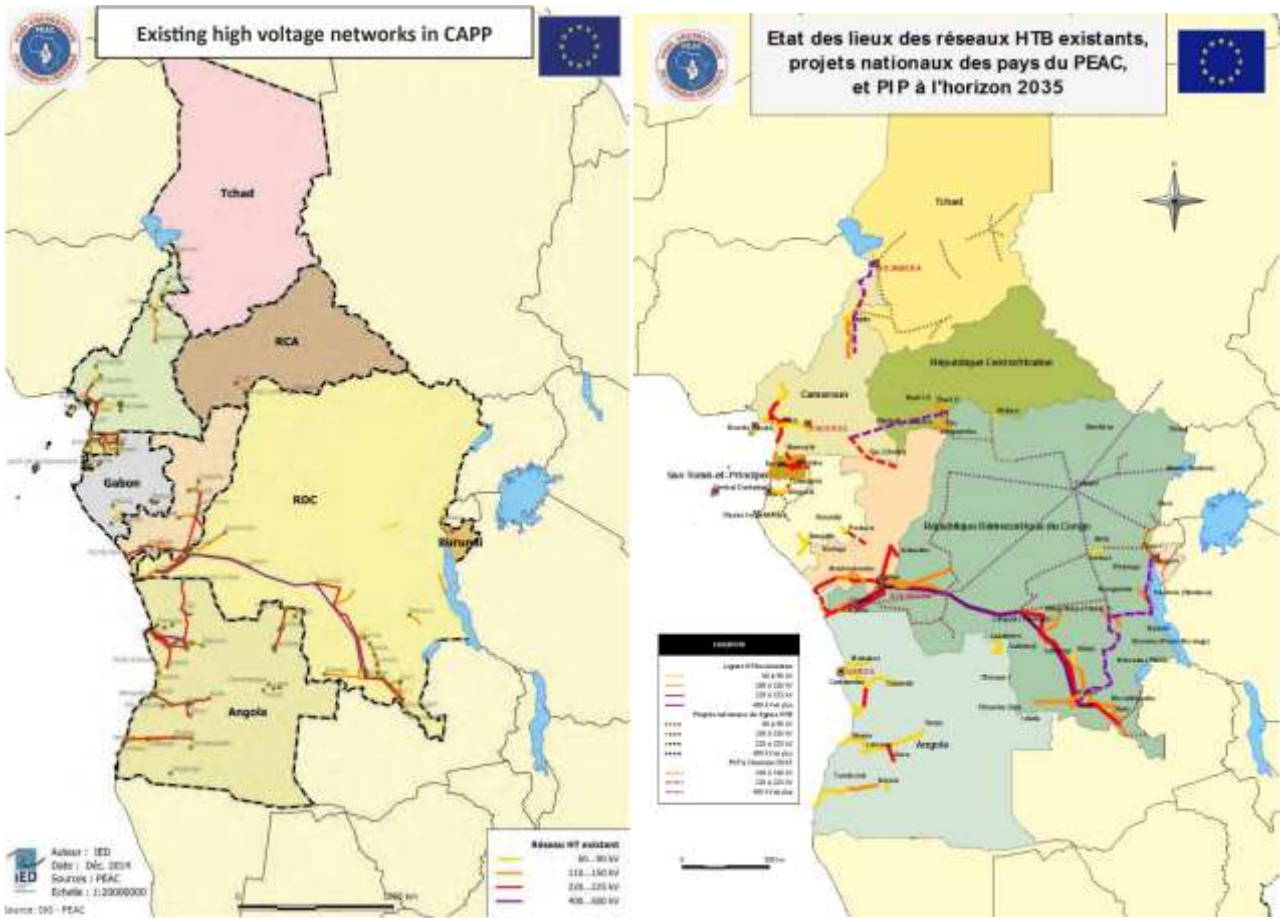

Figure 3-10: Existing high-voltage transmission networks in CAPP (left) as well as national projects of CAPP member states by 2035 (right) (source: CAPP)

However, many cross-border projects within CAPP will entry into service by 2035. Two types of such projects are distinguished:

1) the priority integration projects (26 in total as of 2019), which are the projects with an integrative character related to the development of generation power plants and electricity interconnection networks, and

2) the cross-border electrification projects (16 in total as of 2019), which are the projects with a rural character and often involve at least two (2) CAPP member states.

The priority generation and transmission (integration) projects for CAPP have been identified and listed in the Continental Master Plan 1 Baseline Study (Deliverables 2&3) for the short-, medium- and long terms.

The following investments are key for the establishment of the regional electricity market:

1) rehabilitation/construction of generation power plants evenly distributed across all members countries along the North-South backbone,

2) construction of ultra-high-voltage interconnection and distribution substations with sufficient reactive power compensators,

3) construction of the North-South backbone infrastructure in sections to connect and operate the foregoing elements to the benefit of regional distribution grids, and

4) interest for macro-equipment for hydroelectric power plants.

The specific benefits for the regional electricity market from the above 4 elements will facilitate the development of intra-regional projects that make a real contribution to equitable power distribution, for example:

1) finalisation of development of Grand Poubara (Gabon), and even equipping Empress Falls (Gabon), to benefit Gabon and Congo by adapting the path of the backbone with a hybrid coastal/continental branch,
2) focus on equipping Warak and Lom Pangar to benefit Cameroon and Chad,
3) focus on equipping Chollet to benefit Congo and Cameroon,
4) focus on rehabilitating Ruzizi so that the regional needs of eastern D.R. Congo and Burundi can be met, and
5) focus on rehabilitating Inga generation power plant means to benefit Kinshasa, Brazzaville and Pointe Noire.

According to the Inter-Utility Agreement, the Coordination Centre is envisaged to function under the Operation Sub-Committee (this Sub-Committee has not been established yet) and manage transfer of electricity. It is tasked to centralise in real-time all technical information coming from different interconnected systems of CAPP member utilities with a view to harmonise exchanges from the technical and commercial viewpoints. However, the Coordination Centre has not been effectuated yet.

Also, CAPP has not set up a RSMO to act as an independent market operator to run the regional electricity market and coordinate electricity trade. Such market operator should involve joint supervision of trade agreed and authorised by the national transmission network management authorities (none of CAPP member states has set up an independent network transmission management authority for the moment, despite appropriate legislation in Cameroon, D.R. Congo and Gabon; this role is currently fulfilled by the electricity utilities' electricity transfer directorates).

CAPP does not have SCADA/EMS/MMS/WAMS Systems to support system and market operation of the regional electricity market.

There are several Decisions of the CAPP's Council of Ministers and market governance documents developed by CAPP providing a basis for electricity trade in the Central Africa Region (see Annex 8.5).

A review of the current situation on the ground as regards electricity trade in the Central Africa Region shows that the "market" is truly embryonic since the regional electricity network is not synchronised at the level of CAPP. The lack of electricity trade is the norm today – it is currently conducted only sporadically between a few neighbouring CAPP member utilities/states on the basis of bilateral contracts and without any specific rules for the regional trade. This must be covered through the Regional Market Rules for electricity trade in the Central Africa Region which are still missing. These rules must be supplemented by regional wheeling charges.

Currently, there are only three bilateral contracts regarding cross-border electricity trade over the two interconnections:

1) the Inga (D.R. Congo) – Brazzaville (Congo) interconnection, and
2) the interconnection from the Ruzizi II regional generation power plant between the east of the D.R. Congo, Burundi and Rwanda.

Cross-border electricity trade over the above two interconnections is performed on a rather small-scale and driven by existing diversity and bilateral trade agreements where CAPP has no role. Such trade is realised between the electricity utilities from each side of a border for a contracted quantity at a contracted price, which comprises losses as well. The electricity network losses which are caused by a cross-border transaction are included in the price noted in the bilateral contract on purchase and sale of electricity. CAPP is not involved in exchange and/or trade – it only receives ex post information from system operators of the electricity systems between which a cross-border electricity trade is realised.

With gradual development of other interconnections, the situation will initially be a scattered market made up of additional bilateral trade agreements that will gradually come into force:

1) Maroua (Cameroon) – Ndjamena (Chad) or

2) Inga (D.R. Congo) – Cabinda (Angola) – Pointe Noire (Congo).

Subsequently, in the long-term, electricity trade will be possible as the various generation power plants are commissioned, and reserves are built up.

In order to sustain the regional electricity market, CAPP needs firstly to develop and pool generation and transmission infrastructure, and secondly to establish an operational regional electricity market platform for trade which is preconditioned by:

1) harmonisation of the electricity sector legislation and its implementation,

2) improvement of the legal/contractual agreements between CAPP member states (e.g. balance between supply and demand),

3) elimination of the differences in regulatory approaches between CAPP member states,

4) preparation of the interconnection agreements, and

5) third party access to grids in all CAPP member states.

The setting up of the regional electricity market is planned in two phases (see Table 3-11). Phase 1 corresponds in fact to the current situation wherein electricity trade cannot really be envisaged as the current market does not yet exist. As a result, completion of the listed tasks constitutes a prerequisite for Phase 2.

Table 3-11: Setting up of the regional electricity market in the Central Africa Region under CAPP

Phase	Period	Component	Focus	Tasks
1	2016-2020 (short- to medium-term)	Infrastructure construction	Infrastructure construction must provide the Region with sufficient transmission capacity and adequate generation capacity to have a sufficient surplus to be able to exceed its bilateral contracts.	Develop a training programme with the following objectives: - build project management and electricity infrastructure project management capacities, and - build capacities of existing regional institutions, particularly CAPP, to be able to perform activities required for implementing, operating and monitoring the regional electricity market. Formalise trade transactions which are currently executed on a “case-by-case” basis and standardise procedures such as: - bilateral agreements between CAPP member states and between CAPP member utilities, and - trade instruments (types of contract, short-term trade). Agree wheeling charges by the parties. Coordinate regional electricity trade based on: - agreement on a harmonisation path towards regional operating standards and procedures as specified in the regional operating code, and - agreements to be signed with the various transmission network management

				authorities in CAPP member states to draw up a plan enabling them to comply with regional standards.
		Setting up of the missing institutions required to prepare Phase 2 of the regional electricity market	Two institutions remain to be created: - the Central Africa Regional Electricity Regulation Commission, and - the RSMO.	Finalise the preparation and setting up of the Central Africa Regional Electricity Regulation Commission for supervision of drafting and recommendation of rules, application of rules, adoption of decisions on pricing, consideration of the components of the regional master plan, and conflict resolution. Prepare to create the institution that will play the role of the RSMO for establishing and integrating the technical rules for operation, management and determination of prices of cross-border power flows through monitoring developments in the national electricity sectors, periodically analysing the economic and technical viability of arrangements for cross-border electricity trade among users of the transmission network, maintaining and monitoring the technical performance of the electricity utilities, and facilitating the drafting of technical standards and requirements to collect and process useful data.
2	2020-2030 (long-term)	Bringing into operation of all regional infrastructure associated with all the priority infrastructure projects and establishing the rules for pooling this infrastructure	The pooling within the regional electricity market of the now operating infrastructure presupposes that: - the rules will have been agreed, - a planning process will have been set up, - transit and wheeling charges will have been developed and adopted, and - a longer-term vision will have been elaborated.	Agree upon the rules to share the costs and benefits of the regional priority infrastructure projects that will now all be in operation. Settle the terms and conditions for completing projects that are delayed. Set up a planning process that involves regional optimisation concepts and enables CAPP member states to take decisions regarding their respective national expansion plans in line with the regional plan. Develop bilateral agreements on transit across third-party countries using standardised trade instruments. Adopt regional wheeling charges. Perform the first short-term trade transactions over the regional electricity market and not solely via bilateral agreements. Elaborate a longer-term vision with a liquid regional electricity market with more sophisticated trade transactions (day-ahead, dynamic trade, etc.).
		Coming of age of the institutions that are now all in place	From the institutional point of view, the following institutions will all have now been created and will be operational, fulfilling their	Set up the CAPP governance structure (especially the Permanent Secretariat and its bodies) which carries out its tasks in terms of supervising and coordinating market developments as well as making decisions on the main policy aspects.

			role on a day-to-day basis: - the CAPP Permanent Secretariat and its bodies, - the Central Africa Regional Electricity Regulation Commission, and - the RSMO.	Develop functions of the Central Africa Regional Electricity Regulation Commission which draws up the Regional Market Rules and standards, applies these, and resolves conflicts among operators/market participants. Develop functions of the RSMO which ensures the regional standards have been harmonised throughout the Region and that all the countries comply with the minimum standards for operating, planning and constructing infrastructure/assets. Develop a training programme to build capacities of CAPP member utilities to effectively operate in the regional electricity market and trade electricity in a regional context.
		Harmonising national regulations at the regional level	National regulations will have been harmonised at the regional.	Harmonise national regulations to facilitate regional electricity trade by means of free access to transmission capacity for grid users (third party access to networks).

Actions, main activities and sub-activities are further developed for each of the Phases and put into the Action Plan for the regional energy policy strategy for the Central Africa regional energy policy strategy under CAPP (see Annex 8.6). Actions are divided into five categories of the results-oriented strategic objective prioritisation matrix, and then structured in main activities and sub-activities for the two Phases.

CAPP will bring immense opportunities and benefits to market participants by pooling the energy resources and creating the regional electricity market in the Central Africa Region. It is also determined to play a role of information and standardisation in terms of pricing, in the sense of a path towards remunerative tariffs, essential for a greater involvement of the private sector. Currently, almost all rates in the Central Africa Region do not reflect the economic costs. With the exception of Chad, which has some of the highest tariffs on the continent, other CAPP member states have for most tariff levels generally lower than the other countries of the continent. This observation is emphasised by a significant level of technical and non-technical losses. Because these rates are not remunerative, and also taking into account the very high level of technical and non-technical losses, CAPP member utilities have very low or even non-existent cash flow margins. So many factors compromise long-term financial viability and capacity to ensure a financial balance of their operation and explain the reluctance of the private sector to get involved alone, or even in public-private partnerships.

All dimensions of energy efficiency are a challenge for countries in the Central Africa Region. This includes the area of technical and non-technical generation, transmission and distribution losses, as well as efficiency standards for lighting, appliances, buildings and key industries. Only a few CAPP member states have adopted effective policies, regulations and standards incentivising the use of renewable energy and energy efficiency solutions. Only three countries (Angola, Cameroon, Rwanda) have set concrete targets of achieving 100% electricity access by 2030.

3.5 COMELEC

COMELEC, which was initially created in 1974 and later enlarged in 1975 and 1989, currently acts as a supranational committee of the electricity utilities of the Northern African countries belonging to the AMU. Its permanent nature was confirmed in 1990 by decision of the Ministers responsible for energy of the AMU Member States and its Secretary General. Headquarters of COMELEC are located in Algiers, Algeria (i.e. the General Secretariat of COMELEC is domiciled under the aegis of the Minister responsible for energy of the

host country, i.e. the Algerian Minister responsible for energy). No regulatory organ has been envisaged so far under the COMELEC's founding documents and the Statute and Internal Rules of Procedure.

COMELEC was established with the aim to create and coordinate energy policy and liberalisation efforts, particularly with regard to the transmission systems of the AMU Member States. Acting as a platform for cooperation, rather than a Power Pool, it aims to maintain the regular exchange of information between its member utilities, coordinate the equipment and professional training, monitor the network interconnection, promote the industrial integration in the Maghreb countries, etc. Internationally, COMELEC maintains relations with counterparts organisations such as the Association of the Electricity Industry in Europe (EURELECTRIC), the Association of Power Utilities in Africa (APUA), and the Arab Electricity Union (UAE). COMELEC is also an active member of MEDELEC, the "Liaison Committee" between the various associations of electricians from countries bordering the Mediterranean (created in 1992).

Currently, COMELEC covers 5 AMU Member States and is made up of 5 member utilities. These utilities are State-owned vertically integrated electricity utilities (whereof two of them also perform gas activities) operating in the electricity systems in the Northern Africa Region to which COMELEC serves as a platform for exchange and cooperation, allowing them to get to know each other, to elaborate problems, to seek solutions together, and above all to work towards coordination of strategic choices. Regional integration of the electricity system and market is pursued in the Mediterranean Region, i.e. the integration is sought with Southern Europe rather than the rest of Africa.

COMELEC's governing structure (see Table 3-12) follows the main objectives by undertaking related actions (see Table 3-13).

Table 3-12: COMELEC's governing structures

No.	Organ	Description
1	Management Committee	Decision-making body. Defines the strategic axes of development of COMELEC, and oversees their implementation (its resolutions are taken at unanimously). Composed of two representatives per national body member of COMELEC (the Chief Executive Officer and one of his/her collaborators as specified by the Internal Rules of Procedure).
2	General Secretariat	Supporting and implementing body, provided by the COMELEC headquarters country (Sonelgaz/Algeria). Prepares the work of the Management Committee, disseminates its decisions and recommendations, represents COMELEC to international organisations, and ensures the implementation of work programmes.
3	Commissions	Facilitating implementation of the work programme: a) Planning and Studies Commission, b) Technical Commission, c) Human Resources and Management Commission, d) Commission des Interconnections Maghrébines, e) Commission for New and Renewable Energies, and f) Commercial Commission. The Planning and Studies Commission deals with interconnection studies and development plans for Maghreb networks, establishment of a tariff system for electrical energy at Maghreb scale, as well as the control of electrical consumption. The Technical Commission steers working groups on generation, transmission and distribution, focusing on aspects such as the possibilities of reducing the costs of structures, the cross-border electrification of villages, the studies of Maghrebian normalisation and integration, etc.

		The Commission des Interconnections Maghrébines supervises the operation of the Maghreb interconnections, coordinates the operation of interconnected Maghreb networks, ensures the compliance of future Maghreb interconnections with the rules in force, and participates in the promotion of inter-Maghreb exchanges with a view to form a Maghreb market for electricity. More specifically, it studies and defines the operating conditions, and coordinates the development of cross-border electricity exchanges between Tunisia, Algeria and Morocco, taking into account of the Maghreb-Europe interconnection via Spain.

Table 3-13: COMELEC's main objectives

No.	Objective
1	Reinforce interconnection lines and develop exchanges in electricity, with the aim of ensuring network solidarity while avoiding the risk of the spread of serious incidents.
2	Elaborate equipment programmes and joint project studies, disseminate a long-term master plan for the Maghreb network, plan development of pumping station projects, etc.
3	Elaborate and permanently update a map of the Maghrebian electricity network, including distribution network involving the supply of border villages from the nearest network and under the most favourable technical and economic conditions.
4	Organise feeding of cross-border villages (for example, feeding the Tunisian village of Sakiet Sidi Youcef from the Algerian network or the Moroccan village of Figuig from the Algerian network in Beni Ounif).
5	Plan common use of electricity-related training structures.
6	Promote the Maghreb industrial integration, the intervention of design offices and works and manufacturing companies of electrical equipment in the Maghreb, through the strengthening of engineering function.

In the above set-up, the COMELEC Commissions retain the technical expertise required for development of joint studies of a regional significance and scale, the results of which are integrated into the development of member utilities' activities and concern several areas. For example, they participated in the ELTAM study (Egypt-Libya-Tunisia-Algeria-Morocco interconnection) which enabled the signing of a project implementation agreement between the 5 countries. Moreover, they contributed to the MEDRING study for the joint exploitation of the interconnected loop network between the countries of the Mediterranean Region. Furthermore, they contributed to the realisation of the SYSTMED study relating to the development of electricity networks of countries bordering the Mediterranean.

Through the above studies as well as the other ones, COMELEC has so far worked on:

1) the harmonisation of planning and forecasting methodologies,
2) the knowledge of customers and their management (tools, methodologies and results),
3) the systematic monitoring of technological, institutional and economic aspects,
4) the coordination of operations in the exploitation of the interconnected Maghreb system, etc.

COMELEC also prepares and disseminate annual statistics of electricity activity in the Maghreb, giving the main management parameters for each of the electricity utilities (the latest publicly available for 2015). The electricity network losses are not part of a statistics bulletin. In the period from 2000 till 2014, total installed generation capacity was increased from 17,875 MW to 38,451 MW due to the introduction of combined cycle gas turbines and the introduction of renewable energies, mainly wind power. In the same period, total generation was increased from 61,095 GWh to 145,533 GWh. A progressive evolution towards the energy mix wherein renewable energies will constitute a base in the long-term, is noticeable in electricity generation.

The existing interconnections (intra-Maghreb and Euro-Maghreb, see Figure 3-11 and Figure 3-12) make it possible to facilitate electricity exchanges by securing both the electricity systems and the energy supply. Traditional links have existed in the Maghreb for a long time due to previously established cooperation in the electricity sector (between Algeria and Tunisia since 1953; between Algeria and Morocco since 1988; and between Tunisia and Libya which is still not activated for technical reasons linked with network stability). Today, the intra-Maghreb interconnection which functions between Morocco, Algeria and Tunisia, allows electricity exchanges (commercial and non-commercial) between the electricity systems of the three countries. Despite the potential of existing intra-Maghreb interconnection, exchange of electricity between the Maghreb countries is still at a rather limited level (see Figure 3-13). The Euro-Maghreb interconnection consists of two 400 kV HVAC submarine links of 1400 MW capacity between Morocco and Spain, commissioned in 1997 and 2006.

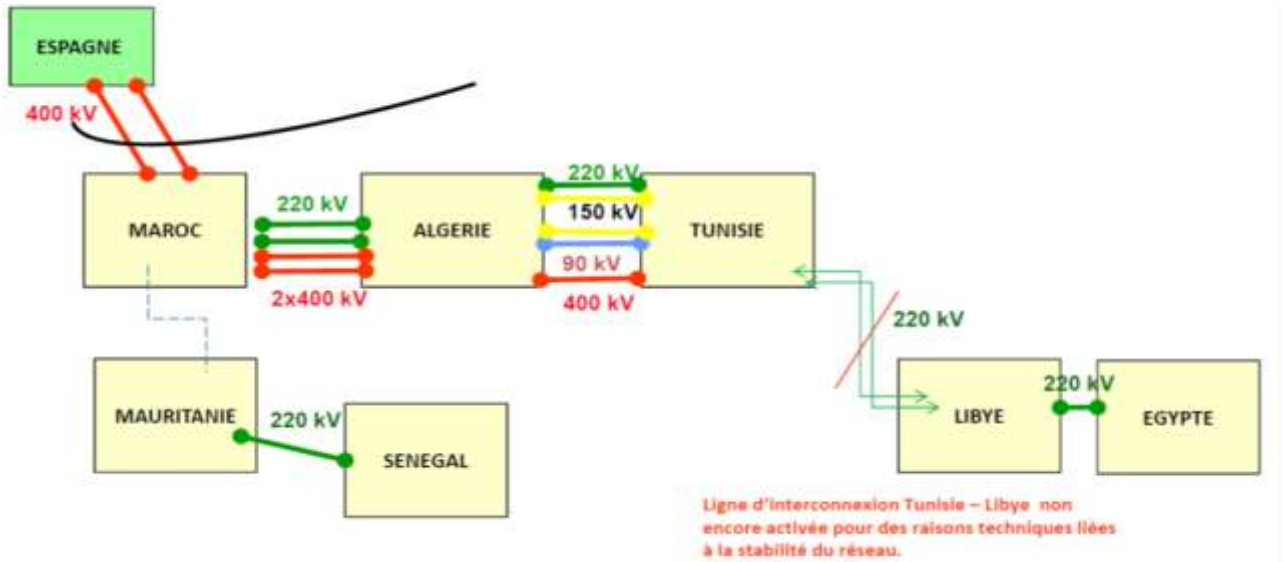

Figure 3-11: Existing intra-Maghreb and Euro-Maghreb interconnections (source: COMELEC)

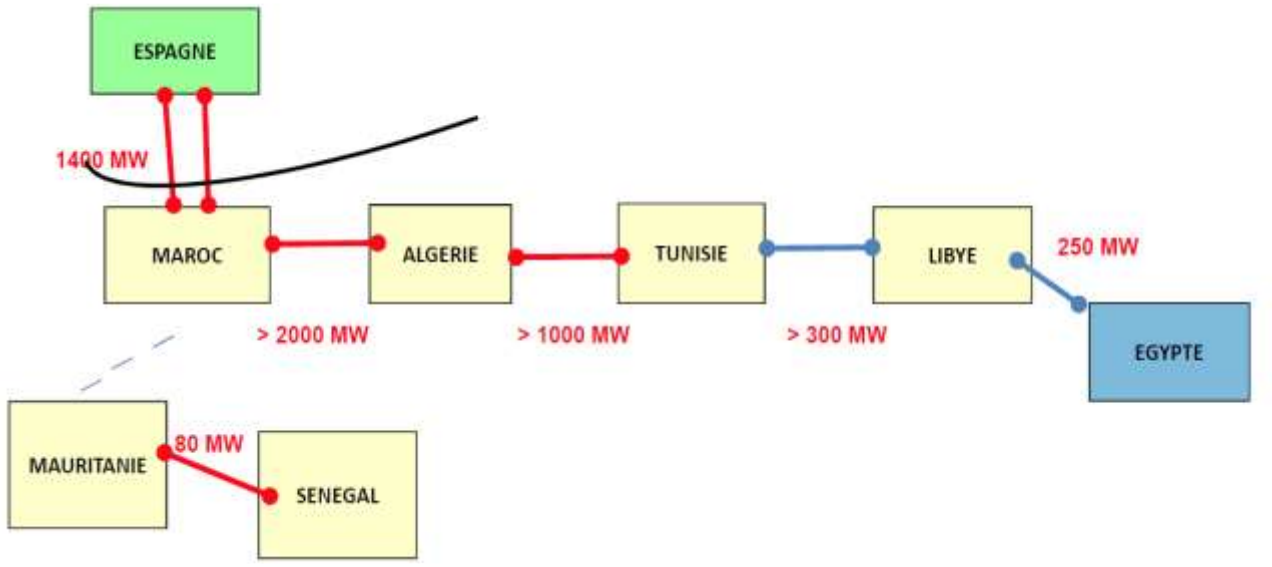

Figure 3-12: Transit capacity of the existing intra-Maghreb and Euro-Maghreb interconnections (source: COMELEC)

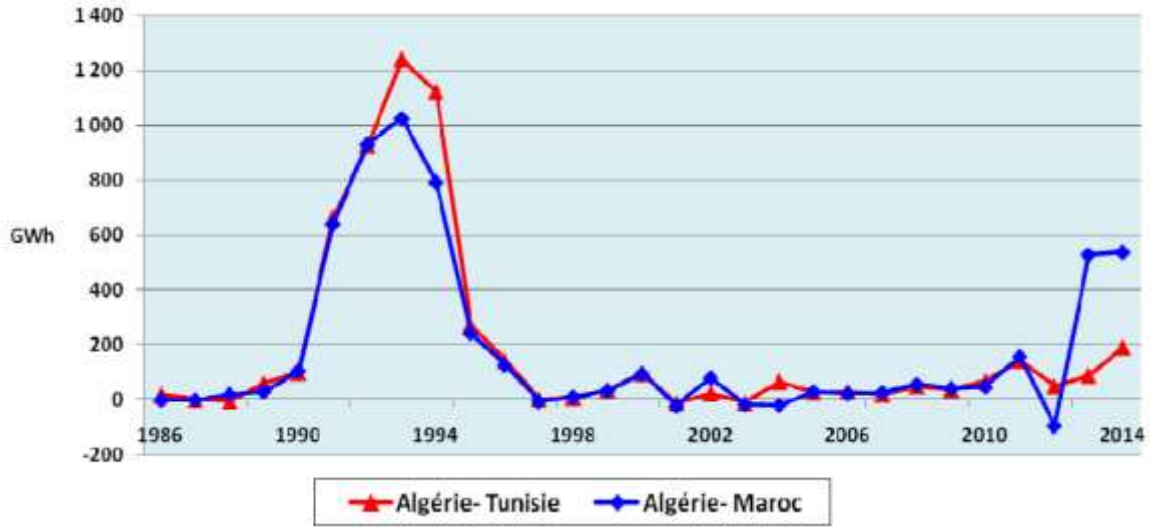

Figure 3-13: Development of cross-border trade over the intra-Maghreb interconnection (source: COMELEC)

Depending on the success in mobilisation of funding sources, COMELEC will going forward, work on the regional integration (see Figure 3-14), through:

1) the preparation for the reliable synchronous operation of the interconnected electricity system of the ELTAM countries (as a part of the extension of the intra-Maghreb interconnection),
2) the development of regional interconnections (COMELEC-WAPP and COMELEC-Europe), and
3) the development of the Maghreb electricity market (implementation, following the work carried out as part of the IMME study).

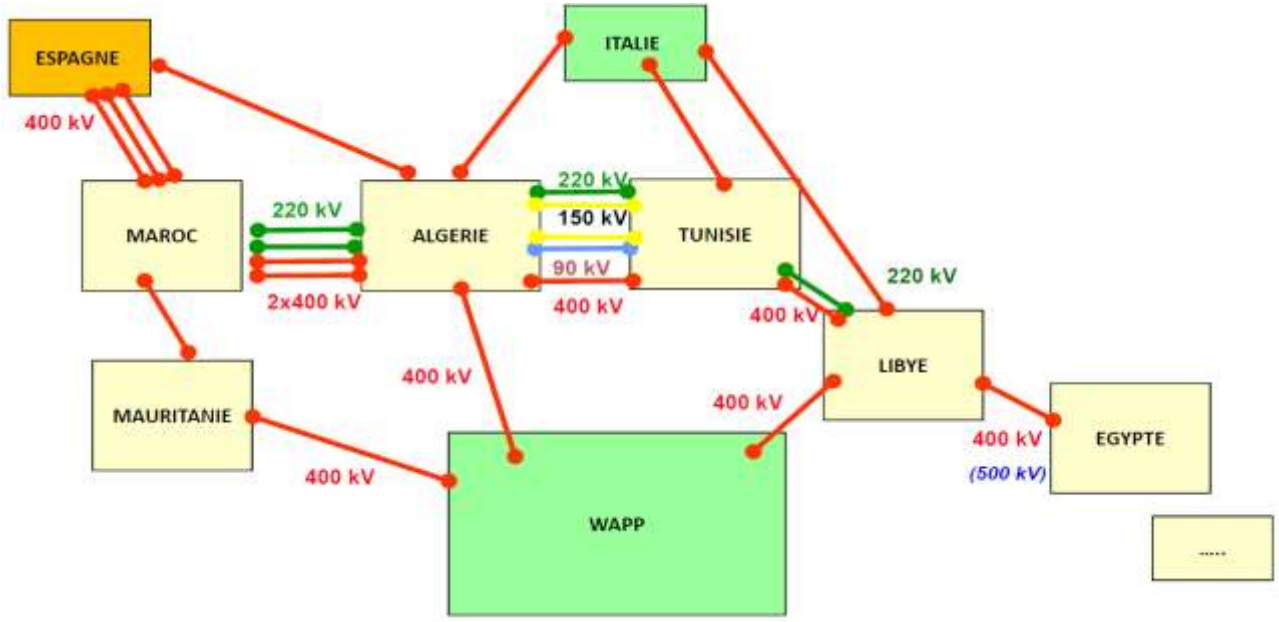

Figure 3-14: Future development of the intra-Maghreb and Euro-Maghreb interconnections (source: COMELEC)

Since COMELEC only coordinates and facilitates cooperation between its member utilities on aspects of cross-border exchange and trade in electricity, it does not function as a Power Pool in the sense of SAPP, WAPP, EAPP, and CAPP. Also, it does not have an information and control centre as pertains in the other Power Pools; hence, no regional SCADA/EMS/MMS/WAMS Systems of COMELEC to support system and market operation of the regional electricity market. If COMELEC is to be transformed into a Power Pool, it should become responsible for both the implementation of energy policy, monitoring studies and construction of regional economic community infrastructure and the organisation of exchanges of electricity and related services in the Northern Africa Region.

COMELEC has developed a Technical Grid Code, which is used by system operators to manage operation in the interconnection and share common power/capacity reserves. Procedures in case of system restoration are also made common. In late 2020, Med-TSO held the webinar “Mediterranean Grid Code and its application to the Maghreb Pilot Project”, which showcased the work carried out by Med-TSO in the last Mediterranean Project 1 and 2 for developing a shared set of technical rules and procedures that constitute the building blocks for the elaboration of the Mediterranean Grid Codes Guidelines. From 2021, Med-TSO implements the TEASIMED Project where one of the objectives is to consolidate the Common Target Regulatory Framework to let it become a real Mediterranean Grid Code (for that purpose it already developed the Guidelines for the Mediterranean Grid Code).

Currently, there are only two types of electricity exchange in COMELEC, and that for:

1) provision of support to secure operation of the electricity systems in the interconnection, and
2) trade in electricity across borders of the countries in the AMU Region.

Cross-border electricity trade in the AMU Region is enabled by the complementarities of the national electricity systems (i.e. by complementary generation portfolios on the supply side, and by complementary consumption profiles on the demand side because of different working and non-working days and hours and time zones), and the constructed 400 kV transmission network backbone (from Morocco over Algeria to Tunisia, with the existing connection to Spain).

Since COMELEC does not have an operational regional electricity market platform for trade, cross-border electricity trade is realised between the member utilities from each side of a border (i.e. their holding companies which are in charge for international electricity trade) based on 5-year framework contracts under which the actual delivery of electricity is agreed in shorter periods between minimum and maximum quantities. A contracted quantity at a contracted price also comprises losses which are caused by a cross-border transaction, and transit fees are applied in case of wheeling or transmission of electricity (probably including OPEX, CAPEX and losses for infrastructure used in a transaction). Only in Algeria, final customers have a possibility to become eligible customers, hence the trade is practically only between the electricity utilities. COMELEC is not involved in exchange and/or trade – it only receives information from system operators of the electricity systems between which a cross-border electricity trade is realised.

The 400 kV transmission network backbone is subject to some trading limitations (mostly due to loop flows in internal transmission networks) on the borders between Morocco and Algeria on the one side (TTC=2500 MW and NTC=1000 MW; however, current limit is 400 MW from Morocco to Algeria and 600 MW from Algeria to Morocco), and Algeria and Tunisia on the other. Since Tunisia does not have a very strong 400 kV network, cross-border transmission capacities are rather low.

COMELEC is well positioned to serve as a link between European and African transmission systems across the Mediterranean. Its members (i.e. the member utilities’ system operators) participate in the work of Med-TSO, whereas individual national regulatory authorities in these regulatory jurisdictions cooperate within MEDREG (currently only Algeria and Morocco have the national regulatory authorities). Both Med-TSO and MEDREG offer COMELEC platforms for discussion, analysis, and information sharing for matters concerning the development of the electricity sector in the Mediterranean Region. Since this Region is of importance for both Europe and Africa, COMELEC is in a position to encourage and facilitate dialogue between the two sides and strengthen the interconnection between Europe and Africa (through WAPP in the west and even EAPP over Egypt in the east) in order to establish wider electricity markets, including at the continental level.

4 REVIEW AND ASSESSMENT OF CURRENT FRAMEWORKS FOR THE INTERCONNECTION OF OFF-GRID MINI-GRIDS

4.1 IMPORTANCE OF INTERCONNECTING OFF-GRID SYSTEMS TO THE MAIN GRID AND ROLE UNDER AFSEM

4.1.1 Overview

Off-grid systems for rural electrification play a crucial role in new access creation; 579 million people still do not have access to electricity in sub-Saharan Africa. Depending on the local characteristics of each area and the distance from the main grid, grid extension can be a costly option and off-grid solutions are the most cost-effective approaches. Population density is one of the key factors in the investigation of cost-effectiveness of mini-grids versus Solar Home Systems. Where the population density is such that the investment in a distribution grid makes economic sense, mini-grids are the preferred solution. Mini-grids can provide all tiers of electricity access, and from the technical perspective there is the option to be deployed according to microgrid standards, allowing technically the effective operation also in connection with the main grid.

Rural mini-grids are autonomous when first deployed. Many times after 10-15-20 years of operation, these mini-grids are encompassed by the main grid. This is perceived as a risk by the investors and at the same time if no proper provisions are made, valuable equipment like power lines and solar PV arrays are discarded. This is simply an unacceptable situation and sustainability of any investment needs to be actively pursued.

In this direction, the AUC has developed the following guidelines documents:

1. Guidelines for institutional and policy model for micro- / mini-grids;
2. Unlocking Africa's Mini-Grid Market; and
3. Exploring Africa's Mini-Grid Tariff Methodologies.

The second document above details the issues relating to mini-grid connection and the third one further details tariff setting issues.

4.1.2 Regulatory Framework Overview for Rural Mini-Grids Encompassed by the Main Grid

Four primary issues ought to be addressed by the national regulatory authorities at the stage when the mini-grid is deployed autonomously in a rural area:

1) It is not economically viable for mini-grid developers to comply with the same standards as large-scale, interconnected generators;
2) Mini-grid developers are extremely cost sensitive and requiring compliance with the Grid Code at mini-grid commissioning can add significant CAPEX and slow the pace of mini-grid deployment;
3) Mini-grid developers cannot absorb the same costs or delays that are tolerated by large-scale generation developers; and
4) The cost of applying for connection can be difficult for mini-grid developers to control or predict, adding uncertainty to their cost-benefit analysis.

There are three regulatory options in relation to technical standards for network connection (see Table 4-1).

Table 4-1: Regulatory options and option challenges for network connection

No.	Regulatory option	Option challenges
1	Do not set standards (except minimum safety standards)	Without technology or equipment standards, low quality equipment can cause system failures, lower service quality, and present health and safety risks. They can also give mini-grid service a bad name. The lack of power quality standards may damage upstream (utility company) or downstream (end-user) equipment and/or result in low quality services that alienate customers.
2	Require all mini-grids to adhere to utility grid standards	Gaps in national grid standards may not adequately address every mini-grid technology, leading to regulatory grey areas for some mini-grid developers. Complying with national grid standards may be too expensive for some smaller mini-grid projects and may hinder innovation or adaptation to local conditions.
3	Develop mini-grid specific standards	Significant time and effort from the national regulatory authorities are required to develop new mini-grid specific standards.

In any case, safety related standards need always to be enforced.

Moreover, there are four regulatory options regarding when to require grid-compliance of the mini-grids (see Table 4-2).

Table 4-2: Regulatory options and option challenges for grid-compliance readiness

No.	Regulatory option	Option challenges
1	Do not require the mini-grid to be Grid Code-compliant	If mini-grids are not required to be Grid Code-compliant, connections between the mini-grid and main grid may be more difficult, more expensive, or less likely to happen. Mini-grid final customers may not get the same electricity availability and power quality as those on the national grid.
2	Require the mini-grid to be Grid Code-compliant at project commissioning	Requiring all mini-grids to be Grid Code-compliant at commissioning requires larger up-front investments from developers that will be a barrier to small-scale projects. Stringent standards may slow down innovation in a country's mini-grid sector, resulting in lower/slower penetration of the mini-grid in off-grid areas.
3	Require the mini-grid to be Grid Code-compliant at connection	Requiring all mini-grids to be Grid Code-compliant at the time of connection implies a period of time when mini-grids will not comply with the Grid Code, and can result in different levels of service for mini-grid ratepayers between utility-served ratepayers. Mini-grid owners may never bring their mini-grid into Grid Code-compliance.
4	Develop different Grid Code-compliance timing requirements based on project classes or categories	Basing Grid Code-compliance timing requirements on project classes creates a more complicated regulatory environment that can confuse potential developers and slow both project development and connection application processing time.

Many countries are currently considering grid-compliance from the start for new mini-grids, especially for the ones with larger installed capacity.

Based on past experiences from around the world there are six main options available for when the main grid reaches the location of a mini-grid (see Table 4-3)[1].

Table 4-3: Main options available for when the main grid reaches the location of a mini-grid

No.	Option	Option characteristics
1	Small power producer (SPP)	The mini-grid converts to a main grid-connected SPP, and no longer sells at retail to villagers.
2	Small power distributor (SPD)	The mini-grid converts to an SPD that buys its full supply at wholesale from the main grid, and sells its purchased electricity to villagers at retail (with or without backup generation).
3	SPP + SPD	The mini-grid continues to sell electricity to its retail customers with its own generated electricity or wholesale purchases from the main grid operator, and also sells electricity to the main grid operator when a surplus is available.
4	Side-by-side but not interconnected	The mini-grid continues to serve customers even when the main grid arrives, with no electrical interconnection between it and the main grid, even though both operate in the same village.
5	Compensation and exit	The mini-grid goes out of business, and the developer receives some compensation for assets taken over by the main grid operator (typically a State-owned national electricity utility).
6	Abandonment	This is the worst case scenario that needs to be avoided by all means.

As will be detailed in Section **Error! Reference source not found.**, A number of African counties have already explored innovative approaches on what happens when the main grid encompasses an autonomous mini-grid (see 4.2 Experiences from African Countries). A number of these has also taken the step forward to implement specific measures in their respective regulatory frameworks. It has to be highlighted that the adoption of any approach needs to be coupled with clear and specific methodologies on determining costs and prices. For example, compensation and exit is a valid option, but it needs to be coupled with a specific methodology on who determines the compensation amount based on which rules.

Furthermore, not yet extensively explored is the tariff setting approach followed after the mini-grid is connected to the main grid and can subsequently operate in interconnected mode or islanded mode at will. In general, the tariff-setting approaches can take one of the general forms (see Table 4-4)[2].

Table 4-4: General forms of the tariff setting approaches

No.	Forms	Form characteristics
1	Uniform national tariff	The national regulatory authority sets standard national tariff for all mini-grids that is equivalent to the main grid tariff.
2	Efficient new entrant	The national regulatory authority sets single benchmark tariff for all mini-grids, estimated as the cost of service for an efficient new market entrant.

[1] Tenenbaum, Bernard; Greacen, Chris; Vaghela, Dipti. 2018. Mini-Grids and Arrival of the Main Grid: Lessons from Cambodia, Sri Lanka, and Indonesia. Energy Sector Management Assistance Program Technical Report; No. 013/18. World Bank, Washington, DC. © World Bank.

[2] Meister Consultants Group, Exploring Africa's Mini-grid Tariff Methodologies, USAID, AUC, 2020

3	Bid tariff	Tariff is set at the lowest price bid by mini-grid developers in a competitive process.
4	Individualised cost-based tariff	The national regulatory authority develops tariff limits for each mini-grid individually based on the estimated cost recovery tariff for that mini-grid (standard tariff for all customers/households served by that mini-grid).
5	Willing buyer/willing seller	Tariff is set through an agreement with the mini-grid developer and customer (either individual customers or a community of customers).
6	Service-based regulatory structures	The mini-grid operator prepares service packages which most often include the provision of appliances usually set on a willing buyer/willing seller approach.

In the cases that the interconnection approach ends up resembling a micro-DSO, the main approach recommendations regarding mini-grid tariffs remain valid after interconnection as well. However, the actual pricing needs to be adjusted to reflect:

1) the interconnected reality which allows the purchase of electricity at wholesale grid cost,
2) the sale of electricity using feed-in tariffs or net-metering/net-billing schemes, and
3) the possibility to allow mini-grid operators to offer at a price ancillary services to the grid.

The actual pricing also needs to ensure uninterrupted power supply to its users in the event of a main grid failure.

The general forms No. 4, 5 and 6 as presented above can be adapted for setting the tariff framework after a rural mini-grid interconnects with the main grid. Several main components should be determined in order to implement such an approach (see Table 4-5).

Table 4-5: Main components to be determined when adapting the tariff framework after a rural mini-grid interconnects with the main grid

No.	Component	Description	Implementation
1	Regulatory Asset Base (RAB)	Allows the assessment of the value of regulated assets on which the mini-grid developer is allowed to earn a return.	*On the basis of providing detailed tools that have pre-set categories for asset base inputs*. Nigeria, Tanzania, and Kenya all have detailed Excel-based tools that offer categories that are allowed within the RAB. For example, in Nigeria's tool there are entries available for both: - generation assets (solar panel, solar cables, battery bank, solar inverter, battery inverter, sub-distribution infrastructures, generation house, PH costs) and - distribution assets (poles, grid low voltage, grid connections, customer connections, smart meters). It is unclear whether mini-grid developers can enter in categories within the RAB that are outside the pre-set inputs. In these tools, there are no parameters guiding the costs of specific components of the RAB.
			On the basis of defining broadly as with catch-all terminology.

			Several countries define the RAB with terminology such as "the sum of all assets used and useful in providing regulated services" (Zambia). This approach gives the national regulatory authority the discretion to determine the reasonableness of entries on a case-by-case basis.
			On the basis of leaving types of costs included within the RAB unspecified in regulation. Several countries do not specify what is included within the RAB in their regulations. It is presumed in these countries, that it is left to regulatory discretion to assess the types of assets that can be claimed by developers for return.
2	Allowed Rate of Return	Allows the rate of return allowed for mini-grid developers on their capital investment.	*On the basis of calculating "allowable rate of return" based on the weighted average cost of capital (WACC).* Both Ethiopia and Zambia track the allowed rate of return to the developer's WACC, which is determined by the cost of debt and cost of equity. This can be calculated on this individual developer-level or by using industry benchmark figures. Regulations can also require a target debt to equity ratio.
			On the basis of identifying or capping at a specified rate of return. Several countries set a maximum rate of return that the developers can earn on their RAB. For example, Kenya caps the developer's internal rate of return at 18% for mini-grid projects. In a related approach, Nigeria capped the rate of return at a specific number but pegged it to the non-recourse commercial debt interest rate plus six percent. In calculating the rate of return, it is normally the developer that bears the risk of foreign exchange, which increases developer risk.
3	Depreciation	Allows the calculation of depreciation of assets.	*On the basis of straight-line depreciation.* The national regulatory authorities that referenced depreciation cited a straight-line depreciation approach applied either over the "asset's useful lifetime" or for a pre-set number of years (e.g. 20 years). Some countries, for example Zambia, set the straight-line approach as the default methodology but allowed for an exemption based on individual project needs.
			On the basis of depreciation referenced but precise methodology unspecified. Other countries referenced depreciation as part of the calculation of the RAB and ongoing costs of the mini-grid.

4	Treatment of capital subsidies	Determines how capital subsidies provided by the country or other grant sources should be incorporated within the asset base and depreciation of assets.	*The current norm is to exclude these subsidies from the RAB calculation, while many regulations make no reference to an approach for treating capital subsidies.*

4.2 EXPERIENCES FROM AFRICAN COUNTRIES

4.2.1 Nigeria

The Regulation[3] provides the isolated mini-grid operator with two options when the main grid encompasses the mini-grid, i.e. he may:

1) convert the isolated mini-grid into an interconnected mini-grid, or
2) transfer all assets he does not want to remove from the mini-grid system to the distribution licensee in return for compensation.

4.2.2 Rwanda

The Regulation[4] provides the isolated mini-grid operator with several options when the main grid arrives to the isolated mini-grid site, i.e. he may:

1) relocate assets,
2) sell parts of the assets to the utility,
3) become a small power producer selling electricity for a fixed renewable feed-in tariff, and/or
4) become a distributor of electricity purchased from the main grid.

The terms are still not explicit enough to remove all private developers' uncertainty regarding grid arrival. RURA provides mediation or conflict resolution in case the utility and mini-grid operators cannot reach agreement on a purchase price or compensation. RURA is mandated to consider the mini-grid operator's effort in familiarizing customers with electricity services over years. Any asset's sales price is to be based on the net book value of the fixed asset indexed with the consumer price index and based on generally accepted accounting principles: the value of current assets minus the current liabilities, plus the present value of expected net profits over the remainder of the isolated grid licence and based on a discount rate provided by the authority.

4.2.3 Tanzania

The Regulation[5] provides the isolated mini-grid operator with several options when upon the arrival of the main grid, i.e. he may:

1) interconnect and operate as a small power producer (selling wholesale electricity to TANESCO),
2) interconnect and operate as a small power distributor (purchasing wholesale electricity from TANESCO),
3) interconnect and operate as both a small power producer and a small power distributor, and

[3] NERC, NERC Regulation for Mini-Grid, 2019

[4] IRENA, Policies and Regulations for Renewable Energy Mini-grids, 2018

[5] Ibid

4) be compensated for the distribution assets if they chose not to interconnect and complied with necessary standards. Compensation is limited to those cases in which the main grid arrives within two to fifteen years of the mini grid's commercial date of operation. The compensation amount is limited to the replacement cost of based on the REA's average capital cost for installing distribution in rural areas measured on a cost per kilometre basis, minus depreciation measured from the date when the mini-grid's assets were installed.

4.2.4 Zambia

The Regulation[6] allows the following options for grid encroachment:

1) The main grid acquires only the client base and builds a completely new distribution network. The mini-grid operator abandons all assets of the mini-grid and removes from the area;

2) The main grid acquires the client base and the distribution network of the mini-grid. The mini-grid operator disconnects and abandons all generation and storage assets of the mini-grid and removes from the area;

3) The main grid acquires the client base and the complete distribution network, generation and storage assets of the mini-grid;

4) The mini-grid operator becomes a small power distributor for the main grid. The mini-grid operator discontinues operation of his generation and storage assets and resells only electricity from the main grid as a retailer. The customer base remains with the mini-grid operator;

5) The mini-grid operator becomes a small power producer or integrated/embedded power producer. The mini-grid operator sells all is generated electricity to the main grid. The main grid acquires the client base and the distribution network of the mini-grid from the mini-grid operator; and

6) The mini-grid operator and the main grid conclude contract for net-metering. In case of excess electricity from the mini-grid, the mini-grid operator has the right to sell the excess electricity to the main grid. In case of electricity deficit, the main grid delivers the requested electricity to the mini-grid operator. The prices of selling and buying are subject to a net-metering agreement.

4.2.5 The Gambia

The Regulation[7] permits the mini-grid operator to choose between the following three options:

1) Outright sale – sell all network and renewable generation assets to the utility operating the grid;

2) Independent power producer – sell network assets to the utility and continue to generate electricity as an IPP for sale to the utility or other customers (as permitted by other regulations, e.g., third party / open access, feed-in tariffs, net-metering, or a power purchase agreement); and

3) Small power distributor – continue to operate the distribution network, with the generation component being retained with the possibility of bi-directional flow of power between the mini-grid and the utility. In essence this option allows the operation as a grid-connected mini-grid.

4.2.6 Sierra Leone

Based on the type of licence granted, the arrival of the main grid could have two different types of impacts[8]:

[6] Energy Regulation Board, Technical Requirements for Mini-grids in Zambia, 2018

[7] Ministry of Petroleum and Energy of the Republic of The Gambia, Validated Green Mini-Grids Policy, 2020

[8] IRENA, Policies and Regulations for Renewable Energy Mini-grids, 2018

1) For the basic licence holder (i.e. where the tariff is set by mutual agreement by the licensee and the consumers), the arrival of the main grid or full mini-grid licenced project would require it to decommission and remove its assets within two months without being entitled to any refund or compensation; and

2) For the full licence holder (i.e. where the tariff is set by the national regulatory authority), on arrival of the main grid, the licence can be converted into an interconnected mini-grid contract or the developer can remove all its assets. If it chooses to remove its assets, the developer will get financial compensation equivalent to the remaining depreciated value of the privately financed assets. In addition, it will also be able to receive development and construction costs, as defined during the tariff determination by the commission plus one audited annual revenue generated from the mini-grid.

4.3 WAY FORWARD

The national regulatory authority should be entrusted to ensure that the public has access to safe and reliable electricity. When creating the regulations governing the connection of mini-grids to the main grid, they must balance the potential that mini-grids provide to expand the reach of the grid with the need to provide safe and affordable electricity to the public. A good connection regulation should address five points[9]:

1) Define the process for applying for connection;

2) Identify who is responsible for the required analyses and systems upgrades;

3) Outline safety and protection requirements;

4) Outline the required connection testing and the commissioning process; and

5) List any required communication and data exchange requirements with the utility and the national regulatory authority.

In most cases, the connection of mini-grids can be effectively addressed by the Grid Codes if these are updated to accommodate new generation technologies and effective regulation for smaller generators.

Finally, specific provisions should be made not only concerning the options for grid interconnection, but also a specific framework for setting tariffs after this interconnection has taken place.

[9] Tetratech, Unlocking Africa's Mini-Grid Market, USAID, AUC, 2019

5 GUIDELINES FOR TECHNICAL AND OPERATIONAL READINESS

The Technical and Operational Guidelines are described hereafter, explaining the significance of each for implementation of AfSEM. These Guidelines are expected to enhance cross-border electricity trades by encouraging more electricity transactions, at intra- and inter-Power Pool levels.

5.1 GUIDELINES 1: ROLES OF SYSTEM OPERATORS (NATIONAL TSOS, CONTROL AREA OPERATORS, AND RSMOS)

The Guidelines 1 seek to clarify how the system operators will carry out their responsibilities in respect of cross-border electricity transactions for the realisation of AfSEM. The boundaries of responsibilities are established for all involved – the national TSOs, the Control Area Operators, and the RSMOs – for cross-border electricity transactions (see Table 5-1). Such division of responsibilities minimises investment risks for investors and customers, while also addresses potential technical and operational risks to market participants.

Table 5-1: Main responsibilities of the national TSOs, the Control Area Operators, and the RSMOs

System operator	Responsibilities	
National TSOs	1) Ensure that the level of electricity transmission on the interconnectors under its responsibility as submitted to and agreed with the RSMO is not violated	
	2) Ensure that the operating ranges for the technical parameters for the interconnectors under its responsibility are adhered to	
	3) Monitor and ensure that the national interconnected system is operated in a safe manner and to prevent cascading effects on other interconnected power systems	
	4) Support provision of ancillary services and other services when called upon by the Control Area Operator or the RSMO, in times of emergencies to other interconnected systems	
	5) Maintain constant communication with its Control Area Operator in line with established procedures	
	6) Maintain the needed communication with the RSMO when required	
Control Area Operators	1) Ensuring that inter-area flows are not violated	
	2) Ensuring the safe and secured operation within each Control Area	
	3) Maintaining constant communication with the RSMOs so that flow levels in the interconnectors are maintained and technical parameters are not breached	
	4) Communicating and working collaboratively with other Control Area Operators, as well as the national TSOs within its Control Area during times of emergency	
	5) Adhere to the RSMOs procedure for restoring the system back to normal within its Control Area, during times of emergencies	
RSMOs	1) System Operation Coordination	Coordinating and scheduling Power Pool interconnectors Monitoring load flows and taking action on variances through coordination of the national TSOs and Control Area Operators

		Acting as a balancing market counterparty for imbalance settlement
	2) Market Administration	Market monitoring and surveillance Contracts administration Dispute management Membership registration and administration
	3) Market Operation	Managing the forward physical market with monthly or weekly auctions Managing the day-ahead and intraday markets Managing the regional balancing market
	4) Settlement	Carrying out meter read administration Carrying out forward physical market settlement Carrying out day-ahead and intraday markets settlement Undertaking balancing market billing Dealing with settlement, billing and payment
	5) System Operations	Providing oversight on technical aspects of the integrated regional market Ensuring fair and non-discriminatory access to grid and cross-border interconnections Coordinating efforts of the national TSOs to dispatch electricity through the international interconnectors Operational planning of interconnectors Capacity allocation and congestion management

Based on the above discussions, the Guidelines 1 for the national TSO, the Control Area Operators, and the RSMOs are formulated as follows:

Guidelines 1.1: Role of the National Transmission System Operators (TSOs)

- For the safe, secured, and reliable operation of the interconnected power system, the national TSOs will need to act within the powers and duties prescribed in the licence issued by the national regulatory authorities and in the legislation.
- For cross-border electricity trading under AfSEM, the national TSOs will ensure that the level of flows on the interconnectors under its jurisdiction, are within the accepted level and within the operating ranges so that the technical parameters are not violated.
- The national TSOs will be required to provide support when called upon by the RSMOs and the Control Area Operators in times of emergencies.
- The national TSOs will need to maintain constant communication with its Control Area Operators and with the RSMOs at all times.

Guidelines 1.2: Role of Control Area Operators

- Each Power Pool will be grouped into a number of Control Areas for operational purposes.
- Each Control Area Operator will coordinate its operations with the national TSOs within its area of operation, in accordance with the regional technical operations manual developed by the RSMO and approved by the regional regulatory authority. This will ensure that interconnector flows with other areas are not violated but rather maintained according to the agreed schedule.
- The Control Area Operators will undertake technical and operational roles and will not be involved in the commercial aspects of cross-border electricity trading between the countries or parties.

Guidelines 1.3: Role of the Regional System Market Operators (RSMOs)

- The RSMOs will be responsible for system operation coordination, market administration, market operation, and settlement.
- The RSMOs will provide oversight on technical aspects of the integrated regional electricity market and ensure fair and non-discriminatory access to grid and international interconnections. They will coordinate the efforts of the Control Area Operators and support them in coordination of the national TSOs in the Control Areas to dispatch electricity through the cross-border interconnectors.
- The RSMOs will be responsible for managing the different types of energy markets (Bilateral, Forward Physical, Day-Ahead, Intraday, and Balancing) and the Ancillary Services Market.
- The RSMOs will coordinate its operations with the different Control Area Operators, undertake market monitoring and surveillance to assess the performance and operations of the market.
- The RSMOs will manage the settlement of market fees and other charges including allocation of payments to cover compensation for ancillary services and network losses.

5.2 GUIDELINES 2: DISPATCH, SYSTEM OPERATIONS, AND ICT

With the gradual increase in the number of interconnections and the prospects for both intra- and inter-Power Pool electricity trade and wheeling in Africa, it has become necessary for the Area Control Operators and the RSMOs to be equipped with the necessary tools to coordinate system operation and electricity trade. The RSMOs use communication and signalling equipment to monitor the conditions of the power system. This requires that key information on the status of an interconnected power system is remotely indicated in the *system information, coordination and dispatch centres.* In an interconnected power system, the availability of communication and indication equipment will assure the RSMOs and the national TSOs of being able to maintain contact with the Area Control Operators and to take the necessary actions during emergencies.

For effective systems operations, good coordination between the various Control Area Operators need to be established, since most of the Control Area Operators need to cooperate with each other to ensure that the tie-lines are controlled within the required operating limits. The information exchange protocol should clearly indicate how the various Control Area Operators will interact or communicate with each other, as well as with the RSMOs. Usually, the information exchange has a hierarchy where the sources of the information (the generators and system devices) communicate with their respective Control Area Operators.

The Control Area Operators need to communicate with neighbouring ones, and then with the RSMOs. At the same time, the RSMOs for the interconnected Power Pools, will also need to communicate with each other both *operationally and on the market platform*, for the operationalisation of AfSEM.

The current status *vis-à-vis* dispatch, system operations, and ICT per Power Pool is the following:

1) WAPP. WAPP is currently constructing its Information and Coordination Centre (ICC) with support from the EU under the following two components (to be completed by April 2022):

   - Construction of ICC Building: This phase covers the ICC Building "A" (Technical Building) and the ICC Building "B" (Administrative Building). The overall estimated work completion is 77%; and
   - Installation of Equipment in ICC: This phase includes installation of equipment (SCADA/EMS/MMS/WAMS systems) in the 5 Control Area Centres and in the national TSOs in WAPP. The overall work executed is estimated to be 64%.

   The WAPP ICC SCADA and communication system when completed will facilitate:

   - regional coordination of cross-border exchanges, and
   - monitoring of the WAPP system operation by
     a. alerting and advising the Control Area Operators in the event of security risks on the regional system, and
     b. maintaining frequency and voltage levels within operating limits to ensure secured and reliable operations of the interconnected system.

2) SAPP. The SAPP Coordination Centre in Harare, Zimbabwe, is connected with the three control centres in South Africa, Zambia and Zimbabwe which perform the functions of Control Area Operators. SAPP has a SCADA system in place for visualisation of interconnectors that is operational. Meanwhile, a project to upgrade the existing SCADA system is in progress. Real time control and dispatch in SAPP is carried out by the member utilities at their respective National Control Centres. SAPP has designated Control Areas that ensure the management of tie-line flows and frequency of the interconnected system by utilising appropriate operational and ICT capabilities. The SAPP SCADA/EMS system is connected with the Control Area Operators via fibre links10, which enables the SAPP Coordination Centre to undertake network and transaction monitoring, planning and operational system analysis, routine reporting, and data provision, among others. The two fibre optic links used for voice and data communication are the Eskom-NamPower-ZESCO-ZESA-SAPP Coordination Centre, and the SAPP Coordination Centre-ZESA-BPC-Eskom.

3) EAPP. Regarding the EAPP regional dispatch and control/ICT capabilities, the Power Pool's strategic plan has identified the need to develop the "hard" infrastructure for the EAPP Grid Coordination Unit that will have the ability to monitor power flows and system stability while facilitating regional power market operations. The equipment will include ICTs, communications infrastructure, and SCADA/EMS for monitoring, and AGC for flow control at the interconnectors. In the short-term (2022), the plan is to conduct preparatory activities for the design of the EAPP SCADA, engage consultancy service and finalise the design and get the necessary approval, to be followed by the procurement of the SCADA system. The short-term period (2022) will also see the development of a roadmap for the EAPP Energy Information System, to be followed by the eventually implementation. EAPP has recognised the need to have robust regional dispatch and control/ICT capabilities for the effective functioning of the market, and the short-term action plan has identified this as a priority that needs to be implemented within the next three years.

[10] CW235, Deliverables 2 and 3 Report (Continental Master Plan 1)

4) CAPP. A fully functional CAPP Information and Coordination Centre is yet to be established for this Power Pool.

5) COMELEC. COMELEC is yet to be established as a Power Pool, and a fully functional COMELEC Information and Coordination Centre is yet to be established to be at par with SAPP or WAPP.

Based on the issues highlighted above the Guidelines 2 is formulated to read as follows:

Guidelines 2: Dispatch, System Operations, and ICT

- Power Pools will be required to develop functional RSMOs from the Information and Coordination Centres and install modern telecommunication equipment and/or carry out upgrades and expansions of existing systems. They will ensure that the facilities are constructed and/or upgraded and tested before interconnecting or coupling any two adjacent power systems.
- The availability of the equipment to be used for control and monitoring will be assessed. This will include assessment of the existing communications links between substations and power plants to be monitored or controlled, and the national TSOs' or the Control Area Operators' or the RSMOs' coordination centres.
- Coordination between Control Area Operators will be established since the Control Areas within each Power Pool need to cooperate to ensure that the tie-lines are controlled within their limits.
- The information exchange protocol will be established indicating how the different Control Area Operators should interact and communicate with each other, as well as with the RSMOs' coordination centres.
- For inter-Power Pool integration, a joint 'assessment centre' need to be established between two interconnected Power Pools to look at real-time capacities of the systems and advise on the allowable flows that can occur on the system close to real-time.
- The interoperability of the communications devices will be checked. This is necessary given that with the proliferation of vendor specific standards, communication problems can arise between substations and national control centres because of incompatibility of equipment. This problem can occur given that there are still older equipment that can be found in substations and power plants in some African countries.
- For cyber-security readiness, the national and regional control centres will be equipped with SCADA/EMS systems with in-built safety features utilising modern ICT technology that can withstand cyber-attacks.

5.3 GUIDELINES 3: POWER SYSTEM ADEQUACY, CAPABILITY AND ROBUSTNESS (CAPACITY READINESS)

The capacity readiness refers to the power system (generation and transmission) adequacy, capability and robustness.

To achieve generation and transmission adequacy, the expansion plans for Power Pools should be updated and published. The Power Pools' Master Plans should include the statement of opportunities indicating the future least-cost generation options. To realise the single continental electricity market for AfSEM, the Continental Master Plan should identify the priority generation projects per Power Pool, which are required for cross-border electricity trade in respect of intra- and inter-Power Pool transactions.

Regarding generation capability, it is imperative that power system studies are conducted to determine generator and desired system behaviour (in line with transfer limits, system stability and frequency control

requirements), as per the regional grid codes. This approach will ensure that the minimum technical requirements for generators can be formulated. The studies will also help to identify generators that will require upgrades to meet the grid code requirements.

In line with the above, EAPP has carried out power system analysis and study to assess its technical and operational readiness. The following are some observations and preliminary recommendations from the study:

1) The load flow study detected many violations under (N) and (N-1) conditions in several EAPP member countries. Mitigation plan therefore need be developed and implemented by the affected countries;

2) Out Of Step protection must be installed for all tie-lines indicated in the transient stability analysis, particularly in the cases in which loss of synchronism was observed; and

3) Out Of Step protection must be installed and adjusted for isolated units losing synchronism, as identified in some simulations of the transient stability analysis.

For EAPP, it has been observed that it is advisable to deploy Special Protection Schemes in case of radial interconnections (single or double circuit) to prevent system collapse in case of system separation, due to the loss of the interconnection (e.g. tower failures). This project is expected to be implemented very soon.

SAPP has established a Project Preparation Unit funded by the World Bank that focuses on both transmission and generation projects preparation and coordination. To ensure power systems adequacy, the SAPP priority transmission projects have been categorised into the following three groups:

1) Interconnecting the non-operating members (Angola, Malawi and Tanzania);

2) Projects to relieve transmission congestion (both interconnectors and domestic transmission networks); and

3) Transmission projects to evacuate power from new generation power plants to load centres (these are described in the SAPP Generation and Transmission Master Plan and also highlighted in the EU TAF Baseline Study for Continental Master Plan 1 (CW235, Lot 8.1, Deliverables 2 and 3).

On the transmission system capacity readiness, the Power Pools' Master Plans need to identify all the priority projects which are key for unlocking electricity trade and this should include a statement of opportunities for enhanced transmission capacity. To achieve the single electricity market for AfSEM, the Continental Master Plan will need to be synchronised with the Regional Master Plans, particularly to identify the priority projects which need to be implemented to facilitate inter-Power Pool trading.

The actual net transfer capacities of each interconnector should also be determined and published as part of the Power Pools' Master Plans, so that those that are adversely affected by the interconnection of the systems will have to be re-assessed. Additionally, tie-line capacity report (firm and non-firm) should be published by the RSMOs to provide information to potential market participants.

Based on the above discussions, the Guidelines 3 is presented as follows:

Guidelines 3: Power System Adequacy, Capability and Robustness (Capacity Readiness)

- For generation and transmission systems capacity readiness, the Power Pools' expansion plans will be synchronised with the Continental Master Plan. This will serve as the basis for inter-Power Pool coupling for trading and technical operations. The Regional and Continental Master Plans will be updated periodically on uniform basis, as more firm arrangements are made and construction is also completed for additional generation projects.
- Investment in transmission network will ensure that the interconnector firm or net transfer capacity will be adequate. This will be done by aligning the Regional Master Plans with the Continental Master Plan. This will enable the interconnectors to transmit financially-secured bilateral transactions, and also take into account the extra capacity required to accommodate highly-probable additional and future electricity trade.
- To achieve interconnector capacity adequacy and readiness, the Power Pools (RSMOs) and the national TSOs will need to work with the national and regional regulatory authorities to ensure that interconnectors fulfil the (N-1) criteria. Non-firm capacity can affect the nature of electricity trade agreements that are deemed feasible. Non-firm capacity can also influence power system stability and tie-line separation, which can lead to a scenario where a problem in one Control Area could cascade into other areas and cause network instability in another Control Area.
- For transmission network capability, the operational voltage limits of the interconnector should be verified for stability, as prescribed by the regional grid code. In addition, the quality-of-supply criteria and the harmonic limits of the interconnector need to be specified as per the technical regulations and the grid code.
- The operational voltage limits of the interconnector during switching operations need to be verified for stability. This should be done as per the regional grid code and technical regulations.
- The regional regulatory authority will develop and publish interconnector transfer limit calculation methodology including determination of the margins and the net transfer limits. As the complexity of the grid increases, it is imperative to define the net transfer capacities between neighbouring countries under different scenario, to guarantee safe and stable operation of the interconnected system.
- The calculation of the transfer limit should be done in a uniform and transparent manner based on agreed assumptions and taking into account interconnections with adjacent countries, since available capacity for trading can be affected by other trades as well as internal country flows.
- Generating units with nominal capacity equal to or higher than the required capacity threshold (in MVA) as allowed in the grid code, will be equipped with Power System Stabilizers that are tuned to provide positive damping for electromechanical oscillations, within the frequency range prescribed by the grid code.
- Phasor Measurement Units will be installed at the tie-lines to improve the observability of inter-area modes and provide useful data for other applications such as real-time monitoring, post-mortem analysis of widespread blackouts and model validation, among others.

5.4 GUIDELINES 4: MARKET COMPATIBILITY FOR TRADING

The electricity market should be a trading market, which is put into operation on the basis of a trading platform. It should expectedly accommodate least-cost electricity flows within (intra-) and between (inter-) interconnected Power Pools, given certain technical requirements and conditions are satisfied for system operation. This also assumes meeting given and fluctuating electricity demand in the power system, under

specified requirements/conditions. The trade-based electricity flows which occur throughout transmission systems reflect the trade volumes (quantity) and the market clearing prices for the different periods of electricity trade (for example, year-, quarter-, month-, week-, day-, hour-, and/or 15 or 5 minutes-ahead).

Power Pools are expected to develop their trading environment to facilitate both the bilateral trading based on cross-border bilateral contracts (usually of longer-term) and the trading through an organised platform (usually of shorter-term). Their progress into their market concept should be developed as a stepwise and evolutionary process driven by a concrete willingness to increase the regional trading in the most efficient way and offer more and more sophisticated solutions based on the needs from its members.

The only advanced trading activities among Power Pools are today taking place in SAPP (including through an organised platform). In other Power Pools, current trading is very limited, mainly based on individual bilateral trading, and is not enabled through an organised platform. This is a natural consequence of SAPP trading operations being in place over a longer term than has been the case with other Power Pools. Also, the market conditions for cross-border electricity trade are better in SAPP since it is more interconnected as a region.

Over the past number of years, SAPP has developed a holistic market concept approach (see Figure 5-1), which consists of a number of different markets that target different needs. Several bilateral contracts are still being traded within SAPP between the member countries. Additionally, four different organised markets have been made available for SAPP member utilities: 1) the Forward Physical Market – Monthly, 2) the Forward Physical Market – Weekly, 3) the Day-Ahead Market, and 4) the Intraday Market. SAPP also has a sophisticated suite of rules that has been developed, refined, and agreed to and applied over time. The ownership of the licence for the Market Trading Platform (MTP) resides with SAPP.

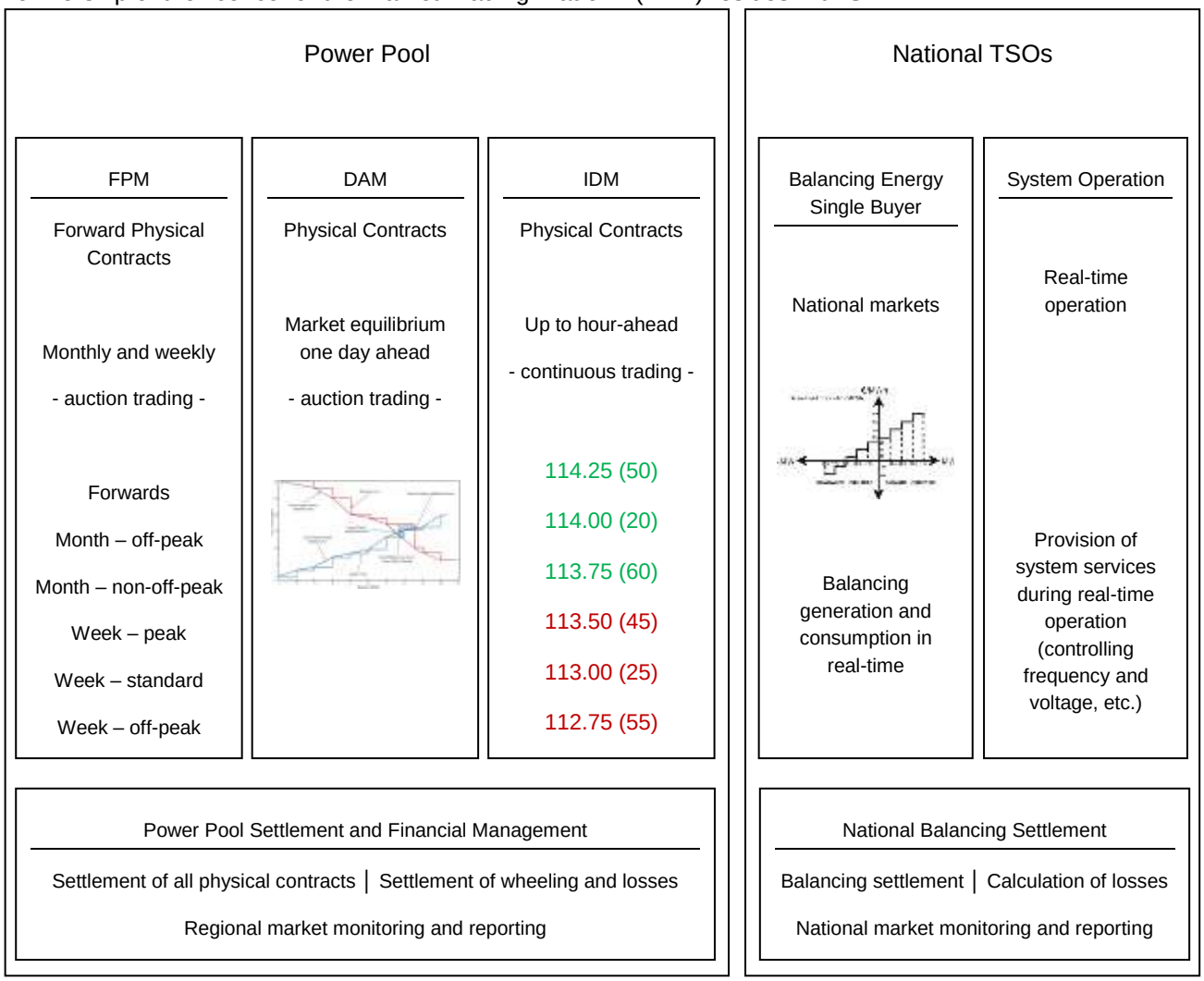

Figure 5-1: SAPP market concept (source: SAPP)

As there are no common interconnections between any two Power Pools yet, there is no inter-Power Pool trading at this stage. For that to happen, the interconnecting Power Pools will have to come up with more concrete reference to the coupling initiative between the two and more details on the governance of the cooperation as well as the concrete activities to be supported.

Based on the above discussions, the Guidelines 4 is presented as follows:

Guidelines 4.1: Market Compatibility for Trading – Bilateral Contracts

- Bilateral contracts do not have to be part of the central organised market trading platform, but can still make a vital part of the Power Pool trading environment to be used for the two main reasons:
    - long-term bilateral contracts will be a way to underpin the investment for either transmission or generation projects, and
    - long-term bilateral contracts will support non-standard longer-term agreements between two contractual parties that cannot be traded through the standardised markets.
- Even though bilateral contracts do not have to be negotiated through the central organised market trading platform, all such contracts will be registered with its agreed trading path, maximum volume and two contractual parties.
- As part of the daily operation, Power Pool will maintain all the nominations and actual utilisation of the bilateral contracts for the following reasons:
    - to be able to optimise the use of the transmission capacity between the countries in the regional transmission network,
    - to allow Power Pool to perform settlement of both wheeling and losses through a common methodology with the organised market trading and act as a central counterpart for the settlement of these, and
    - to use these values as part of the energy imbalance calculations to manage this (=inadvertent energy).

Guidelines 4.2: Market Compatibility for Trading – Forward Physical Market

- The Forward Physical Market will be designed to facilitate trading of longer-term physical contracts, i.e. to enable market participants the trade of yearly, quarterly, monthly and weekly products.
- The traded volume in the Forward Physical Market will result in a traded contract based on physical delivery on an hourly basis.
- For the yearly, quarterly, and monthly trading, two time-of-use products will be defined (such as off-peak hours and non-off-peak hours). The target is to create one common base load contract for all hours of the year, quarter, and month.
- For the weekly trading, the products will be specifically designed to cover the market participants' weekly profiles, with predefined time-of-use products (such as off-Peak, peak and standard).
- Bilateral contracts will be allowed to constitute a portion of the market participant's total electricity commitments. In order to fulfil such commitments, the Forward Physical Market can be used as an alternative to give market participants more flexibility in the planning phase. This will also secure prices for electricity deliveries to follow the price level in the market in the medium-term.

Guidelines 4.3: Market Compatibility for Trading – Day-Ahead Market

- The Day-Ahead Market will be designed to facilitate trading hour by hour to balance the market participants' internal portfolio for generation and consumption, i.e. to enable market participants the trade of hourly products for the next delivery day.
- The traded volume in the Day-Ahead Market will result in a contract based on physical delivery hour by hour.
- The Day-Ahead Market will be open for trade every hour, day by day, for the whole year and will be based on a single hour product.
- The Day-Ahead Market will be referred to as the cornerstone of the total market concept. Its market price will serve as a reference for other markets such as the Intraday Market and eventually the financial derivative market.

Guidelines 4.4: Market Compatibility for Trading – Intraday Market

- The Intraday Market will be a continuous market open for the whole market area. Trading of electricity for a new delivery day will be opened after the Day-Ahead Market is closed, and up to [one] hour ahead of real-time operation. The Intraday Market will be a supplement to the Day-Ahead Market and will help market participants to secure and adjust their balance between supply and demand on an hourly basis.
- The traded volume in the Intraday Market will result in a contract based on physical delivery hour by hour.
- The Intraday Market will allow each individual market participant to adjust the electricity balance, and will be a tool for them to manage incidents and failures in the power system between the closing of the Day-Ahead Market and delivery the next day. Market participants will be enabled to utilise their potential flexibility in generation/consumption to make use of trading opportunities in the Intraday Market, as well as trading small volumes to ensure their internal balance.
- For information purposes only, a closing price for each hour will be reported after the Intraday Market is closed. This price will be a volume-weighted price for all trades in the given hour.

Guidelines 4.5: Market Compatibility for Trading – Market Principles for the Forward Physical Market and the Day-Ahead Market

- Both the Forward Physical Market and the Day-Ahead Market will be based on an auction trading model, executing a single calculation, based on the collection of all orders and available transmission capacity, determining a balance price between generation and consumption that is valid for all trades.
- The auction model will be executed every trading day for a physical delivery of the traded volume the next delivery period.
- In the Forward Physical Market the delivery period will be the next year, the next quarter, the next month, or the next week, where the market result will be calculated with one price and scheduled volume for all hours defined for the given Forward Physical Market products.
- In the Day-Ahead Market, a price and a volume will be calculated for each hour in the next delivery period.
- The principle of the auction trading model will be that all the market participants trade on equal terms and that they have a physical grid point for delivery of generation or withdrawal of consumption, in a given market area. This requires an agreement with the national TSO and a Balance Responsible Party, responsible for the market participants portfolio balance in the physical grid point (area).
- The auction trading model will use the available transmission capacity on the area interconnections given by the national TSO, to run an implicit auction. This calculation will determine both a system price and an area price, if any congestion in the area model is detected. The system price will be calculated assuming no grid congestion, and will be the unconstrained price. If the contractual flow of power between the pre-defined areas exceeds the transmission capacity available for market trade, then grid congestion occurs and separate price areas will be created (“market splitting”).
- The auction trading model will be a fully transparent trading methodology where market participants will submit orders that are seen only by the Power Exchange and the submitting market participant.

Guidelines 4.6: Market Compatibility for Trading – Market Principles for the Intraday Market

- The Intraday Market will be based on a continuous trading model that means a continuing matching of the orders submitted to the market. The orders will be of type Sell (sales order), or Buy (purchase order). In the continuous trading model, the orders will be either matched automatically by the system on price, or a buyer / seller will accept and “hit” an order in the market. The market contracts will be settled at the matched price.
- The continuous trading model will be fully transparent where all the market participants’ orders will be seen only by the Power Exchange, as well as the market participant that owns the order. Normally, trading will be open 24/7 every day, but can be configured to operate for only a part of the day.

Guidelines 4.7: Market Compatibility for Trading – Integrated Management of Transmission Capacity

- Available transmission capacities on the interconnections between the areas will be given to the markets by the responsible national TSOs and submitted to Power Pool. Based on the market participants' portfolio orders and the available transmission capacities, the market clearing engine will calculate if there is congestion in the grid, or if demand for trade of electricity between areas is fulfilled with the available transmission capacity.
- The national TSOs will be responsible for transmission capacity per hour between the areas in both directions. The values will be entered using the market trading platform and data will be automatically stored in the market trading platform's database. Available transmission capacity on all interconnections in a meshed grid will be open market information and required information which market participant needs before concluding the bidding process.
- The national TSOs will enter available transmission capacities for the Forward Physical Market and trading in the yearly, quarterly, monthly, and weekly products. After nomination of bilateral contracts, the system module in the market trading platform will calculate the transmission capacity available for the Day-Ahead Market. The Intraday Market system module will calculate for all interconnections, hour by hour for the next trading period, the rest of transmission capacity that will be available for the Intraday Market trade.
- The national TSOs responsible for the interconnections will be allowed, for every hourly shift, to use a market trading platform system function to release more or revoke available transmission capacity for each interconnection at any time. ATC set to zero on an interconnection will stop trading between the areas.
- The Intraday Market system module will, in real-time, re-calculate available transmission capacity based on the matched orders. New values for available transmission capacity will be made available to all users logged on the Intraday Market system.

Guidelines 4.8: Market Compatibility for Trading – Integrated Financial Settlement and Other Services

- The financial settlement of the market trades will be integrated in the market trading platform.
- In addition to the organised markets as outlined above, Power Pool will also calculate and settle the following services:
    - Settlement of Losses – collecting payments and distributing revenues for both market and bilateral trades;
    - Settlement of Wheeling – collecting payments and distributing revenues for both market and bilateral trades; and
    - Energy Imbalance calculation and settlement.

Guidelines 4.9: Market Compatibility for Trading – Coupling of the Power Pools/Markets

- Power Pools wishing to couple their markets will consider the following coupling options:
    - *Order Collection Model*: Less advanced Power Pool operates a simple order collection system from its members to create one common bid for import/export towards more advanced Power Pool and either less advanced Power Pool or a dedicated unit under less advanced Power Pool is then a member of more advanced Power Pool and responsible for the scheduling of the results from this;
    - *Loose Coupling Model*: Two Power Pools operate separate market trading platforms and a coupling solution between the two is developed. There are two sub-options to this, both requiring development of a coupling system:
        - Both Power Pools will use the same market trading platform system and a new system module is created to couple the two,
        - Each Power Pool has their own (different) market trading platform and a new system module is created to couple the two;
    - *Tight Coupling Model*: Less advanced Power Pool buys access (and operation) to the more advanced Power Pool market trading platform, operates the internal less advanced Power Pool markets, but are using the same gate closure time as more advanced Power Pool and the markets are coupled through an implicit auction;
    - *Implicit Model*: Less advanced Power Pool members join the more advanced Power Pool markets and are participating under the same conditions as the current more advanced Power Pool members.

5.5 GUIDELINES 5: SYSTEM OPERATORS AND COORDINATED PLANNING

5.5.1 Guidelines 5.1: Synchronising Procedures

The synchronisation between two or more parts of the country (national level), between two or more countries (regional level), and/or between two or more Power Pools (continental level) is a problematic issue for the national TSOs, the Control Areas Operators, and the RSMOs. Namely, two or more parts of a single power system or two or more power systems or two or more Power Pools cannot be connected physically if the generators in all parts or power systems or Power Pools are not rotating approximately at the same speed (frequency). This implies that the frequency of one part or power system or Power Pool will need to be adjusted to match that of the other one before the circuit breaker can be closed to link them.

Coordination of a change in frequency requires that designated generators in the designated part or power system or Power Pool all need to change their generation output in accordance with an agreed procedure to contribute to the frequency change required. When the targeted frequency in the other part or power system or Power Pool is changing constantly and each consists of a number of control centres, the synchronisation becomes complex to achieve and requires some form of automation.

For the synchronisation to become a success, all the existing codes, standards and guidelines within each part or power system or Power Pool should be harmonised. Moreover, the operating regime in each part or power system or Power Pool and between them should be considered. Furthermore, the prior power system studies should provide possible electricity transfer scenarios over the interconnector, both in steady-state and dynamically during credible contingencies. The studies should also inform the appropriate steps to be taken to ensure control devices are correctly set and operating properly. The studies should furthermore provide information on how transfer capacity can be increased to ensure the trading.

A set of minimum requirements for the reliable and predictable synchronisation of the power systems should be developed. Minimum synchronisation requirements as well as reclosing requirements should be defined at all the possible synchronisation circuits to ensure stability for various points along the interconnector. These requirements should be preliminary assessed with the use of different synchronisation and reclosure scenarios, testing the response at various phase angle differences at the moment of synchronisation and reclosure. They should cover those aspects of the operation and technical coordination that are envisaged as essential in ensuring that the power can be transmitted in accordance with agreed electricity transactions over the interconnector.

Upon setting up the minimum requirements, such interconnection should be prepared through a synchronisation procedure. The synchronisation procedure should be developed, in consultation with the affected national TSOs, the Control Area Operators and the RSMOs, and include the responsible entity(s), the mechanism of dispatch, synchronising technical parameters (as informed by the power system studies), regulation control requirements, mandatory response, and any monetary compensation required to compensate service providers.

One interconnecting entity (part or power system or Power Pool) should be identified as the reference system and the other one as the synchroniser system. The synchroniser system requires a synchronising leader system operator (the national TSO, the Control Area Operator, or the RSMO) who has full control and priority to give instructions to designated synchronising power plants (this can be an ancillary service or mandatory).

The synchronising leaders should be determined for both interconnecting entities (including the ability for them to lead over other operators and have view of all system frequencies depending on where the separation occurred). Synchronising facilities should be installed at the interconnecting substations, as well as other points on the interconnector where system separation is possible. A synchronising check list should be developed to assist the operators.

In line with the above, the following actions will be undertaken to prepare for the synchronisation:

1) Conduct studies to determine optimal synchronising procedure with consideration of available generation sources and different pre-synchronising scenarios;

2) Develop procedure for synchronising, with consideration of the available generation and control centres;

3) Workshop and agree on procedure;

4) Reach agreement of synchronising leader(s) and roles; and

5) Implement control systems and testing of procedures.

The current status of synchronisation per Power Pool is the following:

6) SAPP. 12 of the 16 SADC Member States are covered, 9 of which are interconnected at transmission level and actively operate in SAPP. Another 3 (Angola, Malawi, and Tanzania) are at various stages of joining in the interconnection. The 2017 SAPP Pool Plan envisages a development of the main transmission corridors with the aim to integrate new generation projects that are committed. SAPP defined the high priority generation and transmission projects, and identified required interconnectors and their transfer limits. The projects to interconnect the three non-operating members, which are not yet interconnected to the SAPP grid, are made the SAPP priority transmission projects.

7) WAPP. 14 of the 15 ECOWAS Member States are covered. Although there are some interconnections among different ECOWAS Member States, WAPP does not operate as a single synchronous zone due to power system stability issues. More precisely, 9 ECOWAS Member States are electrically interconnected, but operate as three synchronous networks (Eastern, Central, and Western) with predictable directions of electricity flows. The 2018 WAPP Masterplan aims at ensuring the synchronisation and stability of the power system in the short-term, improving the integration of variable renewable energy sources in the medium-term, and complying with the (N-1) security criterion

in the long-term. The synchronisation project, i.e. integration of the noted three main separated unsynchronised areas and the remaining five not-interconnected (isolated) systems into a single synchronous zone covering the 14 mainland ECOWAS Member States, is ongoing. Three working groups have been established in that direction, namely for: 1) frequency adjustment, 2) protection coordination, and 3) network reliability assessment. These advise on the implementation of the system services market, i.e. the establishment of primary, secondary and tertiary reserves, the maintenance of the system voltage plan, and the provision of mutual support in emergencies (black-start capability). A tentative objective for the synchronisation is set at 2021-2022.

8) EAPP. 12 Member States are covered. In 2021, the regional electricity system and market operation in the Eastern Africa Region is at a critical juncture since many national transmission systems will soon be interconnected and many of the electricity utilities will be enabled for the first time to trade in electricity across borders. Several critical interconnection projects which will serve as the main backbone transmission lines are progressing and are close to completion (Ethiopia-Kenya interconnector; Ethiopia-Sudan interconnector (the second phase), under study; Zambia-Tanzania-Kenya interconnector, under implementation; and Uganda-Tanzania interconnector, under study). The EAPP Ten-Year Strategic Plan (2021-2030) and the Three-Year Action Plan (2021-2024) guide several activities and programmes to ensure the Power Pool's interconnected grid is operated safely for the purpose of facilitating regional electricity trade.

9) CAPP. 11 ECCAS Member States are covered. There is a significant need to strengthen internal transmission networks and construct cross-border interconnections. Of all Power Pools, CAPP is the one with the fewest interconnections to date. The only cross-border high voltage link exists between Congo and D.R. Congo. Part of the D.R. Congo's high-voltage transmission network is connected to SAPP interconnected network. However, many cross-border projects within CAPP will entry into service by 2035. Two types of such projects are distinguished: the priority integration projects and the cross-border electrification projects. The "market" is truly embryonic since the regional electricity network is not synchronised at the level of CAPP. The lack of electricity trade is the norm today – it is currently conducted only sporadically between a few neighbouring CAPP member utilities/states on the basis of bilateral contracts and without any specific rules for the regional trade.

10) COMELEC. 5 AMU Member States are covered. Three synchronous blocks are in operation (Morocco-Algeria-Tunisia; Libya-Egypt; and Mauritania-Senegal). The existing interconnections (intra-Maghreb and Euro-Maghreb) make it possible to facilitate electricity exchanges. The Euro-Maghreb interconnection consists of two 400 kV HVAC submarine links of 1400 MW transit capacity between Morocco and Spain. The regional integration will be pursued depending on the success in mobilisation of funding, through: 1) the preparation for the reliable synchronous operation of the interconnected electricity system of the ELTAM countries (as a part of the extension of the intra-Maghreb interconnection); 2) the development of regional interconnections (COMELEC-WAPP and COMELEC-Europe); and 3) the development of the Maghreb electricity market.

Based on the above discussions, the Guidelines 5.1 is presented as follows:

Guidelines 5.1: Synchronising Procedures

- At the given level (national, regional or continental) level, the national TSO or the Control System Operator or the RSMO will coordinate the formation of isolated areas until such time as the synchronisation has occurred.
- For example, at the regional level:
    - The RSMO will coordinate the formation of isolated areas where such areas include more than one national system. It will also designate one national TSO to act as the Control Area Operator for such an area;
    - When frequency, voltage, and phase angle permit, the RSMO will initiate the synchronisation of the isolated area(s) with the surrounding area(s), properly notifying adjacent systems of the size of the area being connected and the capacity of transmission lines effecting the synchronisation; and
    - The synchronisation will be performed in line with the synchronising procedure.
- The synchronising procedure will be developed in consultation with the affected national TSOs, the Control System Operators, and the RSMOs. This will include the responsible entities, the mechanism of dispatch, the synchronising technical parameters, the regulation control requirements, the mandatory response, and any monetary compensation required to compensate service providers. Synchronising facilities will be installed at the interconnecting substations, and other points on the interconnector where system separation is possible.
- One system operator (the national TSO or the Control Area Operator or the RSMO depending on the level at which the synchronisation is to be realised) will be identified as the reference system operator and the other one as the synchroniser system operator. The synchroniser system operator will require a synchronising leader who has full control and priority to give instructions to designated synchronising power stations (this can be an ancillary service or mandatory).
- The synchronising leaders will be determined for both interconnecting entities (including the ability for them to lead over other operators and have view of all system frequencies depending on where the separation occurred). A synchronising check list will be developed to assist the operators.
- The synchronising leader will be the national TSO that has access to switching at the synchronising point, frequency measurements from both regions, voltage measurements from the synchronising substations, and ability to control voltages at the synchronising points. The synchronising leader will establish the target value of frequency, the maximum frequency difference, the maximum active and reactive power exchange upon closing, and the operating mode on the frequency controller.
- Plausible synchronising conditions can be as follows: system frequencies within 0.2 Hz, with closing angle of less than 20 degrees. The synchronising modes can be improved by additional compensation to compensate for power swings.
- The synchronising procedure will be defined and well-documented, including the specific multi-country synchronising procedure. This will have to be adequate to attend to the demands that will be placed in order to synchronise (and resynchronise after system separation).

5.5.2 Guidelines 5.2: Operational Data

A standard should be developed that specifies the minimum operational data to be shared between adjacent and non-adjacent system operators (the national TSOs, the Control Area Operators, and the RSMOs, depending at which level their synchronisation is realised and subsequent common operation carried out after the synchronisation). Moreover, the means of communicating these data should be developed too for which

the information exchange protocol should be devised. Data format, transmission media and protocol, security aspects and other communication means required for communication between system operators should be put in place. The protocol and channels should allow for operational data sharing between system operators.

The information exchange should have a hierarchy, where all included sources of the information (i.e. the generators and system devices) communicate directly to the respective adjacent national TSOs, the Control Area Operators, and the RSMOs, depending on the level of the synchronisation and subsequent common operation (national, regional or continental). There is also benefit in sharing certain operational data amongst non-adjacent system operators.

For example, specifically for the synchronisation between Power Pools:

1) the generators should communicate directly to the respective Control Area Operator by way of voice on AGC,
2) the Control Area Operators should communicate with the neighbouring ones by way of voice on the synchronisation, and with the respective RSMO's coordination centre by way of voice on frequency, tie-line power flows, and time,
3) the Control Area Operators should also communicate with the respective synchronising leaders by way of voice on AGC, and the two synchronising leaders should communicate with each other directly by way of voice on frequency and synchronisation,
4) the two RSMOs' coordination centres should communicate with each other both operationally (by way of voice on tie-line power flows and time) and on the market platform, including with the market operator on tie-lines power flows.

Their joint 'operations assessment centre' should be established to look at real-time data of the power systems and advise on the allowable flows that can occur on the system on a near real-time basis.

Minimum data to be exchanged should define in real-time:

1) synchronising data,
2) tie-line flow data,
3) voltage data, and
4) system status data.

Data receivers should be the control centres of the national TSOs and the Control Area Operators, as well as the RSMOs' coordination centres. The required systems for data processing and storage should be installed thereat.

In line with the above, the following actions will be undertaken to prepare for the exchange of operational data:

1) Verify existing data and formats to harmonise the data architecture and required data flows;
2) Workshop to determine the desired outcomes, and draft minimum data requirements and acquire approval;
3) Obtain funding and procure services for installation of the required SCADA and communications infrastructure to support the data transfer and storage; and
4) Implement telecommunications upgrades and expansions, including any operational data and communications that are required in terms of the devised information exchange protocol.

Based on the above discussions, the Guidelines 5.2 is presented as follows:

Guidelines 5.2: Operational Data

- Each national TSO will make available real-time data of relevant parts of its national transmission system to the neighbouring TSOs and the respective Control Area Operator, which will share these with the RSMO's coordination centre (it can also be made possible that the national TSOs share these data directly with the RSMO's coordination centre). Data exchangers will be the national TSOs' and the Control Area Operators' control centres and the RSMOs' coordination centres. The required systems for data processing and storage will be installed thereat. Details of the data to be exchanged in real-time will be agreed between the parties.
- Each national TSO/Control Area Operator will exchange with the other national TSOs/Control Area Operators and the RSMO of the same synchronous area operational data on actual and scheduled interchanges, voltages and planned outages which may have adverse effect on other national transmission systems/Control Areas. Major operating problems that could affect other national transmission systems/Control Areas will be reported as soon as possible to the neighbouring ones.
- The operational data will be exchanged by using the IT tool for real-time data exchange at the regional level as provided by the respective RSMO. The operational data to be exchanged will be determined for AGC, network operations and the synchronisation. Data required by the synchronising leaders and the communication of settings with individual power stations will be determined and implemented. Standard and means of reporting will be defined at the level of the RSMO, based on mandatory SCADA systems at the national TSOs/Control Area Operators.
- Standard will specify the minimum operational data to be shared between adjacent and non-adjacent national transmission systems/Control Areas, and the means of communicating these data. The minimum operational data will define real-time a) synchronising data, b) tie-line flow data, c) voltage data, and d) system status data.
- More detailed, the following data on the system state of the respective transmission system/Control Area will be exchanged: (a) frequency; (b) frequency restoration control error; (c) measured active power interchanges between load-frequency control areas; (d) aggregated generation infeed; (e) system state; (f) set-point of the load-frequency controller; and (g) power interexchange via virtual tie-lines. The system operators will be allowed to exchange other data as deemed appropriate.

5.5.3 Guidelines 5.3: Transmission Capacity Allocation

The cross-border transmission capacity should be allocated in a step-wise approach following the introduction of products and services on the basis of harmonised Market Rules and Grid Codes. A methodology for allocation of cross-border transmission capacity should be harmonised, preferably at the regional level (intra-Power Pool) and eventually even at the continental level (inter-Power Pool). This underlying methodology should be developed as an evolutionary process involving all system operators involved (the national TSOs, the Control Area Operators, and the RSMOs), supported by international best practice. Although this methodology can be made common for two interconnected Power Pools on their interconnections, there is the drawback as there will be an uneven playing field for electricity trade.

Multiple options are available for consideration including explicit ranking, auctions, coupling algorithms, etc. Priority rules could serve as guidance to allocate the cross-border transmission capacity in the beginning. At a later stage, as the market evolves, market-based capacity allocation should be developed to allow more flexibility. The issues of intra-country constraints (in internal national transmission networks) should also be addressed through the market-based capacity allocation. Depending on the market model, the cross-border transmission capacity for bilateral trades could be restricted in favour of market-based capacity allocation. Direction should be provided by market participants. The charging methodologies should yield full cost recovery. The capacity of the assets should be charged per adequate time period, with annual, quarterly, monthly, weekly, or daily and hourly options available. Spare capacity should be socialised.

This underlying methodology should be incorporated in the Market Rules and reflected in the Grid Code. This intent should be established with regard to full cost recovery, cost allocation, and various regulatory principles (for example, the principle of service providers getting paid before sellers are paid from market mechanism).

A governance mechanism for congestion management should be introduced to intervene in the cases of network congestion. General principles of congestion management should be the following:

1) Network congestion problems should be addressed with non-discriminatory market-based solutions which give efficient economic signals to all market participants and system operators involved. Network congestion problems should preferentially be solved with non-transaction based methods, i.e. methods that do not involve a selection between the contracts of individual market participants;

2) Transaction curtailment procedures should only be used in emergency situations where system operators involved must act in an expeditious manner and re-dispatching or countertrading is not possible. Any such procedure should be applied in a non-discriminatory manner. Except in cases of force majeure, market participants who have been allocated cross-border transmission capacity should be compensated for any curtailment;

3) The maximum capacity of the interconnections and/or the transmission networks affecting cross-border power flows should be made available to market participants, complying with safety standards of secure network operation;

4) Market participants should inform system operators involved a reasonable time in advance of the relevant operational period whether they intend to use the allocated cross-border transmission capacity. Any allocated capacity that will not be used should be reattributed to the market, in an open, transparent and non-discriminatory manner; and

5) System operators involved should, as far as technically possible, net the capacity requirements of any power flows in opposite direction over the congested interconnection in order to use it to its maximum capacity. Having full regard to network security, transactions that relieve the congestion should never be denied.

In line with the above, the following actions will be undertaken to develop the cross-border transmission capacity allocation methodology:

1) Develop rules, with assistance of the relevant studies, for the cross-border transmission capacity allocation, with consideration of the impact this will have on all market participants and the evolution of the electricity market;

2) Develop rules for cost allocation and cost recovery by capacity (network) service providers;

3) Carry out studies to determine use-of-system charges, and incorporate into the Market Rules; and

4) Review existing transfer capacities inside Power Pools.

The current status of cross-border transmission capacity allocation per Power Pool is the following:

1) SAPP. The Transmission Capacity Allocation Criteria are adopted. Content not available.

2) WAPP. The Regional Market Rules for WAPP (2015) are adopted. The Market Rules define that the access to transmission capacity in the Phase 1 will be allocated to bilateral contracts on a “first come first served basis”.

3) EAPP. The Daily Procedures for Capacity Allocation, Market Operations and Cross-Border Nominations are adopted (2014). The Daily Procedures are outlined for the market operator (the Coordination Centre), TSOs and producers. These relate to the daily coordination of events for capacity allocation, day-ahead market operation, and cross-border nominations. Chapter 1 (Introduction) defines the authority; sets out the methods by which the notices and communications

are given; and allocates responsibility for maintenance of the rules. Chapter 2 (D-1 NTC, ATC and Day-Ahead Trading Rules) focuses on the procedures at TSOs.

Based on the above discussions, the Guidelines 5.3 is presented as follows:

Guidelines 5.3.1: Transmission Capacity Allocation – Determination of Capacity Available for Allocation

- Total Transfer Capacity (TTC) will be defined as the maximum power transfer across a power corridor when the power transfer exceeds one of the four following conditions:
    - Any busbar voltage drops below 0.95 pu for system healthy conditions, unless agreed between member utilities;
    - The power flow on the corridor exceeds 95% of the maximum power transferred at the knee point of the Power-Voltage curve for that corridor (Pmax);
    - The reactive power exceeds 90% of the locally installed Static Var Compensators and/or generator reactive capacity in the affected area, i.e. a minimum 10% reactive reserve per area must be maintained on Static Var Compensators and/or generators; and
    - The drop in voltage for a 5% increase in load without transformer tap changer action exceeds 5%.
- Net Transfer Capacity (NTC) will be defined as the value that represents the capacity that may be made available for commercial trading. NTC will have to take the power system security into account, which essentially means that no part of the transmission system (feeder, transformer, generator etc.) should be operated outside of its design limits and that the transmission system as a whole should be operated to ensure that no limits and realistic fault should cause the system to become unstable or result in widespread load shedding. NTC will be calculated as the value which remains after Transmission Reliability Margin (TRM) is deducted from TTC, i.e. NTC=TTC-TRM.
- Available Transmission Capacity (ATC) will be defined as the part of NTC that remains available, after allocated transmission rights, long-term nominations (LTN) has been redrawn from NTC. ATC is simply = NTC – LTN.
- Each system operator involved will perform an adequacy analysis to identify ATC for allocation in all market timeframes based on forecasted load, scheduled and estimated generation, power reserves, already nominated capacity and capabilities of control devices.
- Each system operator involved will outline the criteria that all market participants (i.e. producers, traders, suppliers) will have to fulfil in order be given access to utilise ATC under fair and transparent conditions in line with the underlying methodology. Only temporarily, until the adoption of the underlying methodology, those market participants who are, within each national electricity market, allowed to conduct cross-border trade will be given access to utilise ATC.

Guidelines 5.3.2: Transmission Capacity Allocation – The Methodology for Allocation

- In order to maximise the economic welfare of all market participants, the cross-border transmission capacity (ATC) will be allocated by using economically efficient methodology that maximises the utilisation of the capacity.
- The underlying methodology will include explicit and implicit capacity allocation performed in auctions:
    - Explicit capacity allocation, based on type of transaction, will be performed in a multi-tier approach starting with firm bilateral transactions followed by non-firm bilateral transactions, and continuing with the transactions in the Forward Physical Market; and
    - Implicit capacity allocation will be performed for the transaction in the Day-Ahead Market and the Intraday Market.
- Preference will be given to allocation of the capacity for trade in the Day-Ahead Market via implicit auctions under the algorithm which will determine both the hourly prices and the amount of capacity allocated to each trade.
- The underlying methodology will comprise the rules for cost allocation and cost recovery by capacity (network) service providers.

Guidelines 5.3.3: Transmission Capacity Allocation – Allocation in the Market Timeframes

- The cross-border transmission capacity will be allocated separately for each market and market timeframe:
    - In the Bilateral Market timeframe by using explicit allocation methods (allocation of electricity and capacity separately) based on auctions,
    - In the Forward Physical Market timeframe by using explicit allocation methods (allocation of electricity and capacity separately) based on auctions; and
    - In the Day-Ahead and Intraday Market by using implicit allocation methods (allocation of electricity and capacity together). In the case of the Day-Ahead Market, this method will be implicit auction and in the case of the Intraday Market it will be continuous implicit allocation.
- Further details are provided in the Guidelines 4.7: Market Compatibility for Trading – Integrated Management of Transmission Capacity.

5.5.4 Guidelines 5.4: Ancillary Services Provisions

Ancillary services are necessary to support the transmission of electric power from seller to purchaser given the obligations of the national TSOs and Control Area Operators to maintain reliable operations of the interconnected transmission system[11].

Ancillary services can be grouped under one of the four main categories (see Table 5-2).

[11] Federal Energy Regulatory Commission (FERC), 1995, USA.

Table 5-2: Classification of ancillary services

No	Main groups of ancillary services	Sub-groups of ancillary services	
		Type	Usage
1	Frequency control ancillary services --- These ancillary services are used by the national TSOs and the RSMOs to maintain the frequency in the power system at any point in time, within the ranges as required by the frequency standards in the grid code and the technical regulations. Frequency will deviate necessitating frequency control, if the load varies in the power system without a corresponding variation in the generation feeding that power system.	Frequency regulation control	This is the correction of the generation/demand balance in response to minor deviations in load or generation. These ancillary services are provided by generators on Automatic Generation Control (AGC). This allows the national TSOs to continually monitor the system frequency and to send control signals out to generators providing regulation in such a manner that the frequency is maintained within the normal operating range. The control signals from the national TSOs alter the megawatt (MW) output of the generators in such a manner that this action corrects the demand/generation (supply) imbalance.
2	Operating reserves and contingency frequency control --- Operating reserves are used to balance generation to load in response to unexpected generation or transmission outages and/or a significant increase in demand. Contingency frequency control is used as the correction of the generation/demand balance following a major contingency event such as the loss of a generating unit/major industrial load, or a large transmission element. It ensures that following a contingency event, the frequency deviation remains within the contingency band and is returned to the normal operating range within the time period (minutes) indicated in the grid code.	Frequency regulation control	Contingency frequency correction services can be provided by technologies that can locally detect the frequency deviation and respond in a manner that corrects the frequency. Some examples of these technologies include: - Generator governor response, where the generator governor reacts to the frequency deviation by opening or closing the turbine steam valve (for thermal units) or turbine blades (for hydro units) and altering the MW output of the generating set accordingly; - Load shedding, where a load can be quickly disconnected from the electrical system and used to correct for low frequency only; - Rapid generation, where a frequency relay will detect a low frequency and correspondingly start a fast generator, and can be used to correct for low frequency only; - Rapid unit unloading, where a frequency relay will detect a high frequency and correspondingly reduce a generator output (can act to correct a high frequency only). Rapid generation that are used to meet generation and transmission outages are split into two as follows: - Primary or reliability reserves, which include spinning reserves and other generation units that can be started

			quickly, all of which must be fully available within the time period (minutes) as prescribed by the grid code; and - Secondary or supplemental-operating reserves, which include generation units that can begin to provide power and are fully available within the time indicated (minutes) in the harmonised grid code. These reserves are intended to replace the reliability reserves and are usually on stand-by to meet additional contingencies.
3	Network support and control ancillary services --- These ancillary services are used to control voltage and network loading, as well as to preserve transient and oscillatory stability.	Voltage control ancillary service	One method of controlling voltages on the system is through the dispatch of voltage control ancillary services where generators absorb or supply reactive power from or onto the electricity grid and control the local voltage accordingly. The voltage control ancillary services can be further categorised as follows: - Synchronous condenser, which is a generation unit that can generate or absorb reactive power while not generating energy in the market; and - Static reactive plant, which is an equipment such as capacitors or reactors that can supply or absorb reactive power.
		Network loading control ancillary service	Network loading ancillary services are used by the national TSOs to control the flow on interconnectors to within short-term limits. If for example the flow on an interconnector from region 1 to region 2 exceeds the short-term limit, the national TSOs can reduce the flow by increasing the generation levels of generators in region 2 or by shedding load in region 1. With this action, the flow on network elements can be controlled through the use of Automatic Generation Control.
		Transient and oscillatory stability ancillary service	Transient and oscillatory stability ancillary services control and fast-regulate the network voltage, increase the inertia of rotating mass connected to the power system or rapidly increase/reduce load connected to the power system. Some examples of the services are: - Power system stabilisers; - Fast regulating voltage services (synchronous condensers, Static Var Compensators, generators), - Inertia support services, etc.

4	System restart ancillary services --- These ancillary services are used to restore the state of the power system after major disturbances caused loss of supply in a part or a whole of the power system.	Black-start capability	Under conditions of system collapse, it may not be possible to draw power from the grid. Generation units that can restart without taking power from the grid are called black-start units. System restart ancillary services are required to enable the power system to be restarted following a complete or partial black-out. These ancillary services can be provided by a General Restart Source which is a generator that can start and supply energy to the transmission grid without any external source of supply. A generator that can be used to start other units should have black-start capability and must be appropriately located on the grid.

SAPP has the Agreement between Operating Members which sets the standards and obligations for all member utilities interconnecting to the SAPP grid. This is complimented by the Operating, Planning and Environmental Management Guidelines. It is currently working in collaboration with the regional regulatory association (RERA) to harmonise the Grid Codes for the SADC Region. SAPP has already established an imbalance management mechanism to minimise imbalance energy at cross-border interconnectors. This will be complemented by the introduction of the balancing market which is at its final stages of development and will be implemented soon. As part of its future development of the regional electricity market, SAPP plans to establish the Ancillary Services Market too.

For WAPP, the aim is to complete a project that will ensure the synchronisation of the interconnected network of the 14 ECOWAS countries. The synchronisation project is being carried out under the World Bank grant of US$ 21.5 million and is expected to be completed in 2022. Key aspects of the synchronisation project include:

1) Voltage control – installation of Static Var Compensators;
2) Network safety and security – installation of PMUs at each end of the interconnection lines to be integrated into the WAMS and installation of the decoupling relay; and
3) Frequency control – upgrading of works to enhance frequency setting and stability.

In order to implement the synchronisation project, WAPP has established the working groups for frequency adjustment, protection coordination, and network reliability assessment.

The study report has been elaborated on the advisability for:

1) Establishment of the Systems Services Market;
2) Establishment of the Operating Reserves (primary, secondary, and tertiary reserves);
3) Maintenance plan for good voltage for the electrical system; and
4) Provision of mutual support for restarting the system (black-start capability).

Based on the above discussions, the Guidelines 5.4 on Ancillary Services Provision is presented as follows:

Guidelines 5.4: Ancillary Services Provision

- For intra-Power Pool exchanges and trading to take place for AfSEM, each Control Area Operator should have a level of operating reserves and ancillary services in accordance with the regional harmonised Grid Code that will enable the national TSOs to restore the imbalance that could follow from a loss of unexpected generation or transmission outage.
- For inter-Power Pool trading, the interconnecting Power Pools should align their operating reserves requirements. The interconnecting Power Pools will therefore need to develop a technical document and agree on the reserve obligations on the affected national TSOs, including the reporting requirements.
- The harmonised issues related to the reserve requirements should include consideration for sharing of primary reserves for more than one Control Area Operator, as well as the alignment of inter-Control Area Operators response capability and availability periods of generators providing the reserves.
- The Control Area Operators and the national TSOs must control the voltages on the electrical network to within specified tolerances as required by the regional Grid Code. The interconnected system should have adequate reactive power compensation.
- The generator frequency control dead bands and droop settings need to be consistent for the same synchronous areas to eliminate under or over response to frequency incidents. Response time to the signals also need to be defined since large different response times (time to full response) could lead to excessive loading on certain plants in the system.
- There is the need to develop the standard for frequency regulation and mandatory frequency response actions. This should include procedure for adjusting and/or monitoring the settings of units by the national TSOs.
- Under-frequency load shedding of the interconnected Power Pools needs to be aligned to ensure that uniform settings are applied. Under-frequency load shedding is important and serves as a response requirement if most options of increasing the frequency on the system has been exhausted. It is important to implement a harmonised under-frequency load shedding scheme for the integrated electricity markets.
- The implementation of AGC at the national and regional levels should be implemented as a result of increased system complexity due to variable RES integration and deployment of more interconnections. AGC should be implemented to provide both secondary frequency and tie-line power flow control.

6 GUIDELINES FOR INTERCONNECTION OF OFF-GRID MINI-GRIDS

6.1 GUIDELINES 6.1: TECHNICAL MODALITIES FOR MAIN GRID CONNECTION OF OFF-GRID MINI-GRIDS

Rural mini-grids are expected to provide electrification to a large number of Africans living in rural areas. These investments, while on a per-project basis might not be considered high, when aggregated they amount to a huge investment that needs to be utilised as effectively as possible even in the long-term when the main grid might encompass that location. As such it is important that the technical modalities for interconnection or rural mini-grids to the main grid are made clear early on to allow proper design by mini-grid developers.

Distributed Generation (DG) units equipped with smart alternative-current inverters not only generate electricity but also play a role in managing the voltage profile along a distribution feeder and in compensating reactive power to improve the power factor and reduce technical losses. In addition, DG units coupled with Distributed Energy Storage (DES) units and advanced control systems (collectively entitled hereafter Distributed Energy Resources - DER) can enable DSOs to establish islanded mini-grids that can operate disconnected from the main distribution system, i.e. to serve final customers in the local community even when mini-grids are separated from the main distribution system. Then, mini-grid operators can use DERs to manage power and voltage fluctuations (i.e. perform dynamic control) in their mini-grids.

An area that is expected to grow in importance alongside the high penetration of DG units and DES units (i.e. DERs in general) is islanding of DG units, which could be either unintentional or intentional. Unintentional islanding of DG units is usually prevented by protection, whereas intentional islanding and island operation of mini-grids as well as their reconnection can be planned and achieved by using advanced control systems.

Islanding is an operating mode in which a portion of distribution system becomes disconnected from the main distribution system but remains energised and continues to supply electricity to final customers. DG units feeding to a disconnected portion of distribution system will not necessarily detect unintentional islanding, but may continue to feed an isolated network in one of the following two types of operation:

1) operation in isolation on internal own loads (allowed in any condition), when DG units power their own network, or part of it, when separated from the main distribution system, or

2) operation in isolation on a disconnected portion of distribution system (not allowed, except for specific cases requested by DSO), when DG units power a disconnected portion of distribution system.

Unintentional islanding of DG units which results in operation in isolation on a disconnected portion of distribution system is not allowed, mainly due to voltage stability and synchronisation issues among DG units, and interference with protection mechanisms. It is also dangerous since it creates a very high safety risk to utility workers who might not realise that a circuit is still energised. Whether or not DG units should be disconnected from a disconnected portion of distribution system in unintentional islanding depends *inter alia* on the voltage level of distribution network to which these are connected, i.e. whether DG units are smaller and connected to low-voltage or they are larger and connected to medium-voltage.

Since unintentional islanding is a more dominant problem in low-voltage distribution networks, it is therein desirable to disconnect DG units by applying DG anti-islanding (i.e. a protective measure to ensure that DG units automatically disconnect from a portion of distribution system that has become separated from the main distribution system). If such DG units are installed to be used as reserve power of final customer in parallel with supply from distribution network, a dual connection mode must be installed, with one connection to work in parallel with supply from distribution network and the other in a final customer's isolated network that is completely separated from distribution network. This requires a separate switch and additional devices. Such DG units may not concurrently feed both distribution network and the final customer's isolated network.

In medium-voltage distribution networks, wherein distribution system operation and support is more dominant problem, DSO decides on a case-by-case basis whether DG units are required to support distribution system stability or not, hence, to stay connected or be disconnected (for example, for maintenance reasons or for

accelerating the phases of restoring the electricity service). Therein, DSO can allow DG units to keep energising a disconnected portion of distribution system in unintentional islanding under a written agreement. In such case, DSO can actively control DG units to improve the efficiency, reliability, and overall performance of a disconnected portion of distribution system in unintentional islanding. The agreement shall specify that if such DG units keep on feeding a disconnected portion of distribution system in unintentional islanding and equipment connected to this portion of distribution network becomes faulty as a result of DG units' faulty operation, the producer who has fed electricity into that portion of distribution network is liable to pay compensation to DSO for any damages to be compensated for by DSO.

Unintentional islanding of DG units is subject to anti-islanding protection which is introduced to:

1) allow the de-energisation of any faults in the DSO's network,
2) avoid the formation of unwanted islands in the DSO's network, and
3) prevent any reclosing of the devices present in the DSO's network which can cause damage to people and equipment.

In case of solar PV inverters, protection from unintentional islanding is usually installed to provide protection for solar PV inverters and for the connected distribution system as well as to preserve safety of grid personnel and the general public. Solar PV inverter protection requirements are defined as per IEC 62116:2014[12] on a test procedure of islanding prevention measures for utility-connected solar PV inverters. The standard guides testing of the performance of automatic islanding prevention measures installed in or with single- or multi-phase utility interactive solar PV inverters connected to the utility grid. The test procedure and criteria described are minimum requirements. Passive anti-islanding requirements are based on the use of voltage and frequency limits.

Addressing the protection from unintentional islanding of DG units is a significant topic for DSOs which have high DG growth in their distribution systems, particularly after introducing new requirements that DG units that would previously have disconnected in the event of a system disturbance are now expected to remain connected during a significant fault ride through period. Any requirement for DG units connected to particularly low-voltage distribution network to be more resilient to distribution system disturbances can have an effect for low- and medium-voltage protection arrangements. Instances of unintentional islanding into unwanted islands and failures to disconnect can all increase. In addition, distribution network components can suffer greater stress probably resulting in higher rates of failure.

DSOs are concerned about the increased risk of unintentional islanding of DG units as a result of the introduction of requirements for making DG units more tolerant to system deviations or even self-stabilising (when DG units can be required to maintain connection for a wider frequency and voltage bandwidth). This results in increased risk for public and workers as well as increased stress to distribution networks and connected final customer equipment. Moreover, DSOs are also concerned with the requirements that TSOs should have control over the operation of larger DG units connected to medium-voltage distribution networks without regard to the effect this might have on the operation of distribution system to which these are connected. Rather than accepting the risks associated with splitting control over the same medium-voltage distribution network, DSOs prefer to retain full control over their whole distribution networks, even if this means providing some form of guarantee to TSOs at the connection point.

DG units (i.e. their operators) are also concerned about the increased risk of their unintentional islanding. They review and update relevant risk assessments to take account of the risks associated with unintentional islanding, with particular emphasis on out-of-phase reclosure, when adhering to the requirements. DSO then facilitates carrying out such a risk assessment, for example by providing an estimate of the potential trapped load. This can be provided in the form of a yearly profile, and possibly in the form of a load duration curve. DG

[12] IEC, IEC 62116:2014 Utility-interconnected photovoltaic inverters - Test procedure of islanding prevention measures, https://webstore.iec.ch/publication/6479

units (i.e. their operators) are aware that the trapped load on a network can change over time, due to the connection or disconnection of load and/or generation and network topology changes; hence, they carry out the trapped load assessment periodically.

A key influence on the stability of any unwanted island is in the short-term, i.e. second-by-second variation of the trapped load. DSO can provide a generic variability of the load with typically 1 second resolution data points, or can measure actual load variability for distribution network in question for some representative operating conditions at DG units' (i.e. their operators') expense. Armed with the above information, DG units (i.e. their operators) are able to commission appropriate modelling to simulate the stability of their plants when subject to unintentional islanding and hence assess the risks associated with an out-of-phase reclosure incident. Where DG units (i.e. their operators) consider these risks to be too high, sensitivity analysis should enable them to identify the effectiveness of various remedial actions.

Island operation is an independent operation of a whole distribution system or a portion of distribution system that is isolated after being disconnected from the main distribution system, having at least one DG unit and/or DES unit supplying power to such system/part of the system and controlling frequency and voltage.

DERs (DG units and DES units) and loads (including controllable ones) can be operated within mini-grids as single control entities. Such mini-grids can be designed to sustain intentional islanding from the main distribution system and continue supplying electricity to their final customers in an island mode caused by either unexpected power outages or a call for providing flexibility services to DSO.

Continuous supply of electricity in an island mode of mini-grids' operation which is caused by unexpected power outages is especially important for critical loads, such as hospitals, military bases, and public facilities designated for disaster evacuation. Governments that recognise value in resiliency can offer subsidies for those mini-grids capable for supplying multiple users in a neighbourhood, in the event of power outage, offering energy independence as well as local electricity generation and distribution.

Besides seeking increased robustness during unexpected power outages, DSOs also ask such mini-grids for increased availability of flexibility services essential to facilitate power balance management and management of distribution system for operation under normal and abnormal conditions (for example, under peak load conditions or various emergency ones, respectively). Implementation of flexibility services is usually required to achieve high level of renewable energy penetration.

In line with the above, there are two types of intentional islanding for the purpose of island operation of mini-grids which both offer uninterrupted power supply in mini-grids at all times, even during disconnection and reconnection (synchronisation) phases:

1) unforeseen intentional islanding, which occurs unexpectedly when there is a failure in the main distribution system and after which mini-grids can stay in an island mode and distribute back-up power (and even offer a black-start capability), and

2) scheduled intentional islanding, which is conducted when the main distribution system needs to cancel exchange of power with the mini-grid as a load shedding means (in general, this type of islanding is forecasted and can be prepared for day-ahead).

Mini-grids can offer a remedy to disrupted centralised power supply which also happens frequently in many AU Member States, even in electrified areas with power supply from the main distribution system. When there is a fault in the main distribution system or there is a load shedding, mini-grids can automatically switch to island operation, providing uninterrupted power supply to their final customers. This is particularly important for business operations that require continuous power supply; hence, mini-grids can contribute to improving these businesses' productivity. Moreover, by managing peak power demand within mini-grids, distribution network investments or upgrade costs may be deferred, offering DSOs an economic benefit. This business case is feasible particularly in remote distribution areas located at the edge of distribution system. Furthermore, mini-grids in countries with relatively high electricity tariffs can also provide the benefit of electricity bill reduction for their final customers.

Mini-grids, as a confined consortium of DERs (DG units and DES units), power electronics, concerned loads, information and ICT support within defined electrical boundaries, are considered to be a building block of future distribution mechanisms and a vital component of future smart distribution grids. Mini-grids as a distribution mechanism are capable of operating in synchronism with the main distribution system at the point of common coupling as well as in an island mode of independent operation. These modes of operation for DERs-based mini-grids in smart distribution grid paradigm include:

1) the distribution system connected mode (centralised power control),
2) the transition to an island mode of independent operation,
3) the island mode of independent operation (decentralised power control), and
4) the reconnection to the main distribution system mode.

Smart distribution grids can allow for the formation of mini-grids as wanted islands of DERs and loads that disconnect automatically when the main distribution system is down and automatically resynchronise to the main distribution system when conditions return to normal. DERs (DG units and/or DES units) within such mini-grids can then continue to generate and/or inject/withdraw electricity to serve final customers' loads within. Built-in communications infrastructure of smart distribution grids can enable DSO to manage DERs within such mini-grids to provide ancillary services under some circumstances. More precisely, DSO can make use of non-frequency ancillary services provided by DERs, i.e. services used by DSO for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black-start capability and island operation capability. Some ancillary services can be provided by DERs across different distribution systems and procured on a distribution system wide basis (e.g. black start, island operation, compensation for technical losses), while others are by definition local as they require local provision and procurement (including reactive power and voltage control).

To fulfil DSO's requests, mini-grid operators can require their DERs to have the capability to take part in island operation of mini-grids, subject to the frequency and voltage limits for island operation. For example, in the event of a power surplus, such DERs shall be capable of reducing the active power output from a previous operating point to any new operating point within the P-Q-capability diagram. A method for detecting a change from interconnected distribution system operation to island operation of mini-grid shall be agreed between DERs (i.e. their operators) and mini-grid operators, in coordination with DSO. The agreed method of detection must not rely solely on position signals of DSO's switchgear towards mini-grids. With regard to the simulation of island operation of mini-grid, DERs' performance during island operation of mini-grid shall be demonstrated and deemed successful if DERs reduce or increase the active power output from previous operating points to any new ones within the P-Q-capability diagram within the frequency and voltage limits for island operation without disconnection from the island due to over- or under-frequency.

Mini-grid operators use information, communications and control technologies to operate DERs and loads in their mini-grids in a controlled and coordinated way either while connected to the main distribution system or while islanded. By using such technologies, mini-grid operators can connect and disconnect their mini-grid from the main distribution system grid to enable them to operate in both grid-connected or island-mode. To be able to realise that, mini-grid operators rely on an intelligent control centre that can island their mini-grids from the main distribution system and can control and curtail (if required) the load within those mini-grids to match the demand with the available generation of DG units and injection/withdrawal of DES units. The intelligence behind such centre allows all of the diverse components to make up mini-grids, by working in concert to adhere to voltage and frequency parameters, and perhaps isolate and/or protect critical loads.

At the heart of mini-grid's intelligent control centre is a supervisory controller that decides which DERs (and/or loads) to use at what times in order to balance load and generation in that mini-grid. This controller may take into account predicted load profile, predicted electricity price profile, predicted wind or solar PV power profile, predicted heating or cooling needs (if the mini-grid contains cogeneration), emissions and other parameters. It may also change the operating modes of DERs, provide power setpoints to DERs, or regulate droop

characteristics. A mini-grid switch (the switch that performs islanding and connection functions) also has an intelligent controller.

The supervisory controller of a mini-grid provides the following major functions:

1) SCADA, real-time monitoring, and control of mini-grid,
2) capabilities to distribute electricity to any mini-grid users,
3) capabilities to protect and maintain the related mini-grid assets,
4) automation capabilities to ensure balance of demand and supply,
5) automation capabilities to handle islanding, connection and disconnection, etc.

It may also include commercial related activities, such as:

1) trading capabilities and
2) electricity supply and associated metered related back-office capabilities.

By using local DERs as mini-grid's primary devices, the supervisory controller of a mini-grid maintains the mini-grid's stability, voltage, frequency, and reliability.

While in the parallel operation mode, the supervisory controller of a mini-grid can interface to Distribution Management System (DMS) of DSO to perform various grid support functions such as:

1) peak load management,
2) responsive reserves,
3) ancillary services,
4) grid voltage support,
5) back-up emergency power, etc.

In the island mode, the supervisory controller of a mini-grid can be called on to perform the following functions:

1) islanding on requests,
2) islanding in emergency,
3) grid synchronising and (re-)connection,
4) balancing supply and demand,
5) black-start in islanding mode,
6) network configuration,
7) reactive power compensation/voltage control,
8) economic dispatch,
9) load control, etc.

Island operation of mini-grids should be compliant to EN 50160 criteria to ensure the quality of delivered electricity (frequency and voltage deviation, harmonic distortion, etc.). Also, IEC projects (IEC TS 62898 series: Microgrids) consider power quality in the context of island operation. In practice, power quality can be impacted in island operation of mini-grids because of higher emission of supra-harmonics from DES units and higher harmonic levels due to a generally weaker source during island operation. Power quality can be impacted in other ways too, for example, because of emission of inter-harmonics from wind and solar PV power plants, supra-harmonics from voltage source converters, over-voltages due to connection of solar PV to low-voltage

distribution networks and switching transients associated with cables in wind power plants. Wind turbine controllers in large wind power plants could become unstable due to high levels of harmonics or inter-harmonics. Similar problems can be observed with solar PV power plants. Finally, AFSEC has published the "Guide for Application of Standards for Rural Electrification in Africa".

Being connected to an isolated mini-grid only (i.e. staying off-grid) is still not considered a cost-efficient option compared to an existing grid-based solution; however, it can be a cost-effective solution in exceptional situations due to certain geographical specificities (such as mountains, remote areas or isolated island systems where communities are so remote that the overall cost of maintaining their connection is higher than the cost of ensuring security of electricity supply in an independent grid). Installing solar PV and DES to go off-grid while maintaining 99.99% of load served with the same quality would cost the individual customer several times more per kWh consumed than drawing power from the grid. Even for those customers ready to make significant lifestyle changes and willing to accept only 80% of their load needs being met, power from an off-grid system would still cost significantly more per kWh than drawing power from the grid. Adding a diesel generator - which would have environmental impacts - in order to significantly improve power availability to the off-grid consumer would result in significantly increased cost compared to staying connected to the grid. These costs are caused by the need to overscale the isolated mini-grid to secure the same quality and reliability level provided by the grid. In any case, by being connected to an isolated mini-grid only (i.e. staying off-grid), the customers lose the opportunity to sell their excess electricity (when remuneration schemes exists). Moreover, in case of a harmful weather event (storms or floods, for example), the recovery of electricity supply takes much longer for an off-grid system compared to an interconnected system, where DSO will always reconnect people as soon as practicable.

The following example can illustrate island operation of an interconnected mini-grid in Africa. The ABB integrated solar-diesel grid-connected mini-grid installation[13] can serve as the example. It illustrates island operation of an interconnected mini-grid in its manufacturing Longmeadow facility Johannesburg, South Africa which has fully grid-connected and off-grid functionalities. The use of renewable energy is maximised, and uninterrupted power supply is ensured to keep the lights on and the factories running during any planned or unplanned power outages on the main grid supply.

Based on the above discussions, the Guidelines 6.1 on Technical Modalities for Main Grid Connection of Off-Grid Mini-Grids is presented as follows:

Guidelines 6.1: Technical Modalities for Main Grid Connection of Off-Grid Mini-Grids

- Ensure that unintentional islanding of mini-grids does not occur.
- Ensure that a detailed framework is in place to allow the intentional islanding of interconnected mini-grids.
- Ensure that a sufficient framework is in place to allow the seamless communication between DSOs and mini-grid operators for optimal planning of intentional islanding.
- Develop a framework where mini-grids can provide extended services to the distribution grids.
- Adopt African and/or International standards.
- Facilitate the interconnection of existing rural mini-grids to the main grid when this is technically feasible and cost-effective.
- Allow the realisation of interconnected to the main grid mini-grids from the start.

[13] ABB's Grid-connected mini-grid installation in Johannesburg, South Africa, https://new.abb.com/news/detail/45805/abb-inaugurates-microgrid-in-south-africa-boosting-renewables-and-power-reliability

6.2 GUIDELINES 6.2: REGULATORY FRAMEWORKS FOR MAIN GRID CONNECTION OF OFF-GRID MINI-GRIDS AND MICRO-DSOS

Regulatory frameworks need to be in place to allow the interconnection of off-grid rural mini-grids to the main grid. Connection requires compliance with the grid code, which should outline compliance with equipment, functionality, power quality, and service standards. Compliance with the grid code adds cost to a mini-grid project and these costs do not vary with mini-grid size unless the requirements for smaller systems are less stringent. Small-scale mini-grids can be a cost-effective technological answer to off-grid electrification, but if they have to comply with the same regulations as large hydroelectric power stations, investors will hesitate to finance beneficial projects. Three countries – Zambia, Tanzania, and Rwanda – have differentiated regulatory tiers. Observed cut-offs for tiers include: 1 MW, 250 kW, 100 kW, 10 kW, and 2 kW. Even if the national regulatory authorities choose to reduce or eliminate connection requirements for smaller mini-grid tiers, all connection applicants should comply with basic safety standards.

Most countries use international standards like IEEE 1547 as the basis for their grid code. Such standards address the requirements for the performance, operation, testing, safety, and maintenance of the connection. Mini-grid developers should be allowed to use an applicable international standard, if mini-grid connection regulation or the grid code omits guidance. Developing country-specific standards is a significant investment in time and effort for a regulator and can be counterproductive. Some mini-grid developers operate internationally and have already created mini-grid designs that comply with international standards. Creating new designs that comply with country-specific standards is an additional cost that may deter investment or will be passed on to ratepayers.

Unintentional islanding from the grid is a safety issue and should be prohibited, but intentional islanding can be a key value proposition for some mini-grids. In some cases, mini-grids can provide better quality electricity and availability to their final customers than the utility can, but only if they can periodically disconnect from the grid. The grid codes should allow mini-grids to intentionally island if they comply with IEEE 1547.4-2011 or a similar standard. Even while in island operation mode, mini-grids should be held to the same power quality and availability requirements as when they are connected to the grid. Accommodating intentional islanding may require additional analysis during the application process and a change to anti-islanding tests conducted during the connection testing.

The connection approval process should streamline approval from a limited number of authorities, include harmonised application of rules between approving authorities as necessary, include clear deadlines for both the developer and approving authorities, and be appropriate for the size of the mini-grid applying for connection. This will balance the utility's need for information and the mini-grid developer's need for an approval process that is predictable in cost and duration.

Processing connection applications costs the utilities time and money. These costs can include distribution system upgrade costs, analysis, or administration costs, and/or commissioning costs. It is common, and appropriate, for the utilities to be reimbursed for some of these costs by applicants. However, high or unpredictable application costs and delays can be used by the utilities as a tool to deter developers from applying for connection. The utilities should be encouraged to create a formal, standardised table for hardware, analysis, administration, and commissioning costs so that developers can anticipate what payments must be made to the utility. Regulations should allow mini-grid developers to hire third parties to conduct required grid analyses on the effects of connection for subsequent utility review.

Mini-grid connection applications should also only be responsible for paying for equipment up to their point of supply; the utilities should be responsible for upgrades beyond it. The cost of upgrading the distribution network to accommodate proposed connection should be spread to all ratepayers at the subsequent tariff review. In order to address the possibility of delays in upgrading the utility's distribution system to accommodate the mini-grid connection, mini-grid developers should have the option to upgrade the grid beyond the point of supply, provided upgrades are done according to the utility's standards.

Interpretation of the grid code may not be the same and a third party should be available to provide a neutral interpretation to the utilities and mini-grid developers.

Variable RES generation and reverse power flow can damage utility equipment and affect power stability on a feeder or circuit. To prevent these outcomes, some national regulatory authorities and utilities impose limits on how much mini-grid generation capacity (both variable and non-variable) can be installed on a single feeder or circuit. An alternative solution is to allow the utilities to signal a reduction in variable RES generation. This type of communication and control requires specialised equipment installed in the mini-grid and adds to connection compliance cost. In general, the current mini-grid connection demand is not creating congestion on the low- and medium-voltage lines that they are connecting to, but congestion may be a problem in the future. Regulations should consider adding provisions that allow for the utility control of mini-grid generation if current generation limitations on feeder and lines prevent the future connection of additional mini-grids.

As is clear from the above, it is essential that all parameters are taken into consideration when deciding to allow a mini-grid to be installed without the ability to interconnect to the main grid. This option ought to be utilised only in very specific applications with justified reasons.

The main options available to the mini-grid operator when the main grid encompasses the mini-grid can be summarised as:

1) Small power producer (SPP). The mini-grid converts to a main grid–connected SPP and no longer sells at retail to villagers.

2) Small power distributor (SPD). The mini-grid converts to an SPD that buys its full supply at wholesale from the main grid and sells its purchased electricity to villagers at retail (with or without backup generation).

3) Micro-DSO. It is essentially a combination of options (i) and (ii). The mini-grid continues to sell electricity to its retail customers with its own generated electricity or wholesale purchases from the main grid operator and also sells electricity to the main grid operator when a surplus is available.

4) Compensation and exit. The mini-grid goes out of business, and the developer receives some compensation for assets taken over by the main grid operator (typically a State-owned national utility).

The tariff setting framework after the interconnection ought to be clear and it is recommended that differences exist from the start between:

1) mini-grids that get interconnected to the main grid after a period of autonomous operation and

2) mini-grids that are deployed interconnected to the main grid.

In the cases that the interconnection option chosen by the mini-grid operator resembles at an extent a micro-DSO, a combination of the following approaches are recommended to be utilised in terms of tariff setting:

1) Individualised Cost-Based Tariff: The national regulatory authority develops tariff limits for each mini-grid individually based on the estimated cost recovery tariff for that mini-grid (standard tariff for all customers/households served by that mini-grid). This will ensure that cost-recovery will take place and can be applicable when the mini-grid operates interconnected to the main grid.

2) Willing Buyer/Willing Seller: Tariff price is set through an agreement with the mini-grid developer and customer (either individual customers or a community of customers). This is recommended to be used for setting the islanded operation tariffs when the main grid has failed. In reality, in such a case the mini-grid operator provides a back-up power service, which needs to be priced differently. The national regulatory authority needs to make provisions to protect the customers of the mini-grid ensuring that the mini-grid operator does not charge these higher tariffs when the main grid is operational.

3) Service-Based Regulatory Structures: The mini-grid operator prepares service packages which most often include the provision of appliances usually set on a willing buyer/willing seller approach. This option needs to remain valid, for the mini-grids that were operating in such a manner before

interconnection. At the same time the actual prices of the service-based packages need to be updated in order to reflect the benefits provided by the grid connection and also the possibility for provision of higher tier electricity at lower cost.

In order to implement the above, it is recommended that the methodology followed is clearly set out in the regulatory framework for the calculation of the:

1) Regulatory Asset Base;
2) Allowed Rate of Return;
3) Depreciation; and
4) Treatment of Capital Subsidies.

Any of the approaches outlined in Section 4.1.2 can be utilised for this.

Based on the above discussions, the Guidelines 6.1 on Regulatory Frameworks for Main Grid Connection of Off-Grid Mini-Grids and Micro-DSOs is presented as follows:

Guidelines 6.2: Regulatory Frameworks for Main Grid Connection of Off-Grid Mini-Grids and Micro-DSOs

- Larger mini-grids should be compatible with the grid, but requirements could vary with mini-grid size.
- Regulations should be based on internationally recognised standards.
- The application approval process for connection should be straightforward and appropriate.
- Ensure that connection application costs and duration are predictable for the applicant.
- A process should be in place to resolve disputes between the utility and the applicant.
- Generation capacity limits on a feeder or circuit are a simple solution to congestion, but the alternative can be cost prohibitive.
- A number of options should be available to the mini-grid operator when the main grid encompasses the mini-grid.
- Tariff setting framework after interconnection with the main grid needs to be clear and detailed.

7 ACTION PLAN

7.1 TECHNICAL AND OPERATIONAL READINESS

The Action Plan identifies the key actionable programmes and activities that need to be implemented to achieve the Technical and Operational Readiness, for operationalisation of AfSEM, i.e. the key activities at the national, regional and continental levels based on the following three time horizons: the short-term (2021-2025), medium-term (2026-2030), and long-term (2031-2040).

7.1.1 Actions Required – Continental, Regional and National Levels

A set of actions is required at the national, regional and continental levels (see Table 7-1).

Table 7-1: Actions required at the national, regional and continental levels

Item	National, Regional and Continental Levels		
	National	**Regional**	**Continental**
Overall responsibility	The national level will be responsible for transposing and implementing the Technical and Operational Readiness Guidelines adopted at the continental level by AUC(-DIE) and transposed at the regional level, to the degree required at the national level	The regional level will be responsible for transposing and implementing the Technical and Operational Readiness Guidelines adopted at the continental level by AUC(-DIE), to the degree required at the regional level	The continental level will be responsible for developing and adopting effective enabling environment composed of the legal, institutional, technical, and operational frameworks for AfSEM
Responsibilities: national, regional and continental	The responsibility for transposing and implementing these Guidelines will lie with governments, the national TSOs/electricity utilities, and the national regulatory authorities	The responsibility for transposing and implementing these Guidelines will lie with RECs, Power Pools, and the regional regulatory authorities/associations	The responsibility for developing and adopting these frameworks will lie with AUC(-DIE)
Actions required	Ensure the transposition and adaptation of the Technical and Operational Guidelines adopted at the continental and regional levels, into the national regulatory and technical documents and rules, to the extent required at the national level Enforce the Technical and Operational Readiness Guidelines and underlying principles to the degree to which it falls within the competence of the national regulatory authorities and	Complete and operationalise the Technical and Operational Readiness Guidelines at the regional level by the appropriate regional institutions such as RECs, Power Pools, regional regulatory authorities /associations, etc. Transpose to the degree required at the regional level, the Technical and Operational Readiness Guidelines that have been adopted by AUC(-DIE)	Develop and adopt the legal, technical, operational, and institutional frameworks for AfSEM Develop and adopt a set of common technical rules and guidelines for AfSEM, to be adopted and implemented at the regional and national levels Monitor the compliance with adopted rules at the regional and national levels

	the national TSOs/electricity utilities Report progress in transposition of and compliance with the Technical and Operational Readiness Guidelines to RECs, Power Pools and the regional regulatory authorities/associations, for onward transmission to AUC(-DIE).	Monitor the transposition of and compliance with the Technical and Operational Readiness Guidelines at the national level within each Power Pool or REC Report progress regarding implementation and compliance with the Technical and Operational Readiness Guidelines at the regional and national levels to AUC(-DIE) Enforce the Technical and Operational Readiness Guidelines at the regional level to the extent that it falls within the competence of the regional regulatory authority/association and the RSMO	

7.1.2 Short-Term (2021-2025)

The short-term Action Plan identifies the key activities required at the national, regional and continental levels, to achieve the Technical and Operational Readiness for cross-border electricity trading (see Table 7-2).

Table 7-2: The Short-Term Action Plan

Activity	**National, Regional and Continental Levels**		
	National	**Regional**	**Continental**
Establishment of national and regional institutions/entities in charge of system operation	Establish the national TSOs which are operationally independent and/or unbundled	Establish the Control Area Operators within Power Pools Establish the RSMOs from the Information and Coordination Centres of Power Pools	
Establishment of dispatch and system control centres with ICT capabilities in the national TSOs, the Control Area Operators, and the RSMOs	Equip and upgrade the national dispatch and system control centres with modern ICT capabilities, to enable market participants to participate in the national and regional electricity markets	Implement functional Control Area Operators with adequate control centres to link the national TSOs dispatch and control centres with the RSMOs coordination centres Implement fully functional RSMOs with adequate coordination centres	
Generation and transmission system adequacy	The national TSOs/electricity utilities and the national regulatory authorities to collaborate with Power Pools and the	RECs, Power Pools, Regional Regulatory Authorities/Associations and other regional institutions, to collaborate	AUDA-NEPAD to collaborate with RECs, Power Pools and Regional Regulatory Authorities/Associations,

	regional regulatory authorities/associations, for the development of the National Master Plans in alignment with the Regional and Continental Master Plans Countries to implement their national TYTNDPs, aligned with the Regional Master Plans and the Continental Master Plan	with AUDA-NEPAD to develop the Regional and Continental Master Plans Identify all priority generation and transmission projects from the Continental Master Plan modelling, for the AfSEM operationalisation Power Pools to implement the Regional Master Plans based on the Continental Master Plan results, synchronised with the national TYTNDPs	as well as the development partners, to develop the Continental Master Plan AUDA-NEPAD to work with Power Pools to implement the short-term priority generation and transmission projects, identified from the Continental Master Plan
Transmission capacity readiness	The national TSOs to work with the national regulatory authorities, and the RSMOs the regional regulatory authorities/association, so that interconnectors fulfil the (N-1) criteria	The RSMOs and the regional regulatory authorities/associations to work with the national TSOs and the national regulatory authorities for interconnectors to meet the (N-1) criteria The RSMOs to develop for regulatory approval, a transparent interconnector transfer limit calculation methodology	AUDA-NEPAD to monitor the implementation of the short-term priority transmission projects
Generation capacity readiness	Install Power System Stabilisers (PSS) to dampen electromechanical oscillations within the frequency range prescribed by the national Grid Code	Ensure that each generation unit with nominal capacity equal or above the required capacity threshold (MVA) is equipped with a Power System Stabiliser	
Development of harmonised Grid Codes for cross-border transactions	The national regulatory authorities to ensure that cross-border transactions entered into are in accordance with the national Grid Code which is harmonised with the regional one	Power Pools to work in collaboration with the regional regulatory authorities/associations, to implement a harmonised regional Grid Code	
Market compatibility for trading	The national TSOs to cooperate with Power Pools in market development processes to enable and facilitate national market participants to trade electricity across borders in the regional electricity markets	Power Pools and the regional regulatory authorities/associations to define market concept in terms of market trading platforms, and develop the rules which govern electricity trade in separate	Power Pools and the regional regulatory authorities/associations to align market concepts and market trading platforms, and harmonise the rules which govern electricity trade in separate market

	National market participants to follow the processes	market timeframes at the regional level	timeframes at the inter-Pool level
Synchronising procedures	The national TSOs and market participants to facilitate the synchronisation processes by fulfilling all the requirements set at the regional level	Power Pools to develop a set of minimum requirements for the reliable and predictable synchronisation of the power systems at the regional level	Power Pools to harmonise the minimum requirements for the synchronisation at the inter-Power Pool level, i.e. the continental level
Operational data	The national TSOs to cooperate with each other and the relevant Control Area Operators and the RSMOs when developing the specifications for the operational data	Power Pools to specify the minimum operational data to be shared between adjacent and non-adjacent system operators, and develop means of communicating these data	Power Pools to harmonise the minimum operational datasets to be shared after the synchronisation at the inter-Power Pool level, i.e. the continental level
Transmission capacity allocation	The national TSOs and the national regulatory authorities to participate in development of the regional cross-border transmission capacity allocation rules and develop the rules for bilateral allocation	Power Pools and the regional regulatory authorities/associations to develop a methodology for allocation of cross-border transmission capacity at the regional level	Power Pools and the regional regulatory authorities/associations to harmonise the regional methodologies at the continental level (inter-Power Pool)
Ancillary services adequacy	The national TSOs to ensure availability of operating reserves and other ancillary services as per the national Grid Code, which is harmonised with the regional one, for restoring system imbalance	The RSMO to ensure each Control Area Operator has adequate operating reserves and other ancillary services, to restore system imbalance as per the regional Grid Code Align under-frequency load shedding protection in all Power Pool member utilities for uniform setting	

7.1.3 Medium-Term (2026-2030)

The medium-term Action Plan identifies the key activities required at the national, regional and continental levels, to achieve the Technical and Operational Readiness for cross-border electricity trading (see Table 7-3).

Table 7-3: The Medium-Term Action Plan

Activity	**National, Regional and Continental Levels**		
	National	**Regional**	**Continental**
Generation and transmission system adequacy	The national TSOs and national regulatory authorities to collaborate with Power Pools and the regional regulatory authorities/associations, to	RECs, Power Pools, and the regional regulatory authorities/associations to collaborate with AUDA-NEPAD to implement the medium-term priority	AUDA-NEPAD to work with Power Pools, the regional regulatory authorities/associations and RECs to implement the medium-term

	implement the medium-term projects identified in the Regional and Continental Master Plans	projects identified in the Continental Master Plan	priority generation and transmission projects, identified in the Continental Master Plan
Transmission system capacity readiness	Continue to implement projects to ensure that interconnectors meet the (N-1) criteria Implement the Quality of Service requirements for cross-border interconnectors, as per the regional Grid Code and technical regulations Continue to implement the TYTNDP, aligned with the Regional and Continental Master Plan	Verify the operational voltage limits of the interconnector for stability, as prescribed by the technical regulations and regional Grid Code Specify the Quality of Service criteria and the harmonic limits of the interconnector, as per the technical regulations and the regional Grid Code Power Pools to continue to implement the regional TYTNDPs, aligned with the Continental Master Plan	AUC(-DIE) to monitor the evolution and operation of the single and integrated continental electricity market (AfSEM)
Generation system capacity readiness	Install Phasor Measurement Units at the tie-lines to improve the observability of inter-area modes and provide useful data for other applications	The RSMOs to enforce the installation of the Phasor Measurement Units where necessary, to provide useful data for applications and events	AUC(-DIE) to monitor the evolution and operation of the single and integrated continental electricity market (AfSEM)
Market compatibility for trading	The national TSOs to enable national market participants to trade electricity in the regional electricity markets National market participants to build business capacity related to trading in the regional electricity market	Power Pools to procure market trading platforms for trading in separate market timeframes at the regional level	Power Pools to align trading with the same products in separate market timeframes at the inter-Pool level
Synchronising procedures	The national TSOs to participate in the development of interconnections and together with market participants to synchronise at the regional level	Power Pools to develop interconnections and implement the synchronisation of the power systems at the regional level	Power Pools to work towards their mutual synchronisation at the inter-Power Pool level, i.e. the continental level
Operational data	The national TSOs to share minimum operational data with each other and the relevant Control Area Operators and the RSMOs	Power Pools to enable sharing of the minimum operational data between adjacent and non-adjacent system operators, by using developed means of communicating these data	Power Pools to share mutually the minimum operational datasets after the synchronisation at the inter-Power Pool level, i.e. the continental level
Transmission capacity allocation	The national TSOs to enable participation of market participants in regional	Power Pools to allocate the cross-border transmission capacity at the regional	Power Pools to allocate cross-border transmission capacity

	allocation of cross-border transmission capacity and allocate to them the capacity for bilateral transactions	level in accordance with the developed rules	for transactions at the continental level (inter-Power Pool)
Ancillary services adequacy	The national TSOs to work with the Control Area Operators to ensure availability of adequate operating reserves and other ancillary services, as per the regional Grid Code	The RSMOs to work with the Control Area Operators to ensure that adequate ancillary services to restore any imbalance from unexpected generation loss or transmission outage, as per the regional Grid Code Develop the Ancillary Services Market for cross-border trading	AUC(-DIE) to work with Power Pools to monitor the evolution and operation of the ancillary services market under AfSEM
Dispatch, System Operations, and ICT	The national TSOs to ensure that dispatch centres upgrade and possess system control capabilities, that takes into account cyber security issues	All Power Pools to develop the RSMOs from their Information and Coordination Centres, that take into account, cyber security issues All the Control Area Operators to upgrade their systems taking into account cyber security issues	

7.1.4 Long-Term (2031-2040)

The long-term Action Plan identifies the key activities required at the national, regional and continental levels, to achieve the Technical and Operational Readiness for cross-border electricity trading (see Table 7-4).

Table 7-4: The Long-Term Action Plan

Activity	**National, Regional and Continental Levels**		
	National	**Regional**	**Continental**
Generation and transmission system adequacy	The national TSOs and national regulatory authorities to collaborate with Power Pools and the regional regulatory authorities/associations, to implement the long-term projects identified in the Regional and Continental Master Plans	RECs, Power Pools, and the regional regulatory authorities to collaborate with AUDA-NEPAD to implement the long-term priority projects identified in the Continental Master Plan	AUDA-NEPAD to work with Power Pools, the regional regulatory authorities/associations and RECs, to implement the long-term priority generation and transmission projects, identified in the Continental Master Plan
Transmission system capacity readiness	Continue to implement projects to ensure that the interconnectors meet the (N-1) criteria Continue to implement the Quality of Service requirements as per the	Enforce the Quality of Service criteria and the harmonic limits of the interconnector, as per the regional Grid Code Continue to implement the regional TYTNDP based on	AUC(-DIE) to work with Power Pools to continue with the market surveillance, and to monitor the evolution and operation of ASEM

	national Grid Code as aligned with the regional one Continue to implement the national TYTNDP, aligned with the regional one	the Continental Master Plan	
Generation system capacity readiness		Update regional generation expansion plans for all Power Pools, as more firm arrangements are made and construction is completed for more generation facilities	AUDA-NEPAD to work with Power Pools to update generation expansion plans on a uniform basis
Market compatibility for trading	The national TSOs to develop the national electricity markets in parallel to the regional ones National market participants to restructure their organisation with the aim to perform market activities in the national and regional electricity markets	Power Pools to advance market trading platforms by including relevant financial products beside physical ones for trading in separate market timeframes at the regional level	Power Pools to align all products – physical and financial – for trading in separate market timeframes at the inter-Pool level
Synchronising procedures	The national TSOs to continue with the development of interconnections and together with market participants to maintain synchronised operation	Power Pools to develop interconnections with each other, where relevant, and extend the synchronisation of the power systems at the regional level	Power Pools to mutually synchronise, where relevant, at the inter-Power Pool level, i.e. the continental level
Operational data	The national TSOs to share enlarged operational data with each other and the relevant Control Area Operators and the RSMOs	Power Pools to enable sharing of the enlarged set of operational data, and develop advanced means of communicating these data	Power Pools to share mutually the enlarged operational datasets after the synchronisation at the inter-Power Pool level, i.e. the continental level
Transmission capacity allocation	The national TSOs to enable participation of market participants in regional allocation of cross-border transmission capacity and allocate the capacity for bilateral transactions fully in line with market-based approaches	Power Pools to allocate the cross-border transmission capacity at the regional level fully in line with market-based approaches	Power Pools to allocate cross-border transmission capacity for transactions at the continental level (inter-Power Pool) fully in line with market-based approaches
Ancillary services adequacy	Implement Automatic Generation Control at the national level as a result of system complexity due to higher levels of penetration of variable RE integration	Enforce implementation of Automatic Generation Control at the regional level, as a result of higher levels of penetration of variable RE integration	AUC(-DIE) to continue to work with Power Pools to monitor the evolution of the market and operation of the

	Implement and enhance the operation of the Ancillary Services Market	Implement and enhance the operation of the Ancillary Services Market	ancillary services market under AfSEM

7.2 INTERCONNECTION OF OFF-GRID SYSTEMS AND MICROGRIDS

The ultimate pursuit is the development of a comprehensive regulatory framework in all African countries that facilitates and promotes the development of mini-grids that are able to operate grid-connected when the main grid encompasses the mini-grid. Specific activities are focused on the short-term (see Table 7-5).

Table 7-5: The Short-Term Action Plan (for the interconnection of off-grid systems and microgrids)

Activity	**National, Regional and Continental Levels**		
	National	**Regional**	**Continental**
Rural electrification standards and options for interconnection when the main grid encompasses the mini-grid	The national regulatory authorities to update and adopt a regulatory framework outlining in detail: 1 - the options a mini-grid operator has when the main grid encompasses the mini-grid, and 2 - the tariff setting methodology and tool for calculation in the cases that the mini-grid developer opts to continue operation under a scheme reflecting a micro-DSO	Regional CREEEs to develop: 1 - targeted guidelines for what happens when the main grid encompasses the mini-grid, and 2 - tariff setting guidelines in the cases when the mini-grid developer opts to continue operation under a scheme reflecting a micro-DSO	AFSEC to expand the Guide for Application of Standards for Rural Electrification in Africa to fully address the standardisation aspect of interconnecting mini-grids with the main grid

8 ANNEXES

8.1 DUTIES OF THE COORDINATION CENTRE AND SUB-COMMITTEES OF SAPP (OF IMPORTANCE FOR TECHNICAL AND OPERATIONAL READINESS)

8.2 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN SOUTHERN AFRICA UNDER SAPP

8.3 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN WESTERN AFRICA UNDER WAPP

8.4 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN EASTERN AFRICA UNDER EAPP

8.5 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN CENTRAL AFRICA UNDER CAPP

8.6 MAIN ACTIVITIES AND SUB-ACTIVITIES IN THE ACTION PLAN FOR THE CENTRAL AFRICA REGIONAL ENERGY POLICY STRATEGY UNDER CAPP

8.1 DUTIES OF THE COORDINATION CENTRE AND SUB-COMMITTEES OF SAPP (OF IMPORTANCE FOR TECHNICAL AND OPERATIONAL READINESS)

Coordination Centre	Operating Sub-Committee	Planning Sub-Committee	Markets Sub-Committee
Monitor the operation of the Power Pool Monitor transactions between operating members and between members and non-members Monitor the inadvertent power flows and the returns in kind between members Provide routine daily reports, data and information relevant to the operation of the Power Pool to the Operating Sub-Committee and to the members Monitor and advise on the use of the Operating Guidelines Monitor and report on the control performance criteria, as specified in the Operating Guidelines, to all the operating members Convene, following a disturbance affecting the parallel operation of the Power Pool, a post disturbance committee Provide information and give technical advice or support to members, in matters pertaining to parallel operation Evaluate the impact of future projects on the operation of the Power Pool and advise the Operating Sub-Committee accordingly Perform various operational planning studies to highlight possible operating problems	Establish and update the methods and standards to be used for testing generating units in order to determine their sent out capacity Conducting system operational studies Establish and update the methods and standards used to measure the technical performance (e.g. planned and forced outage rates, mean time to failure, etc.) of generating units and transmission facilities Establish and update the formula for determining the operating reserve obligations of the operating members and ensuring that these obligations are met Monitor each member’s compliance to the declared system peak and accredited capacity obligations Update approved operating procedures for the SAPP interconnected power system Monitor system performance against set criteria Ensure that generation and transmission maintenance schedules of operating members are coordinated Ensure that each operating member is equipped with or contracts the necessary control gear and ancillary facilities for reliable	Establish and update common planning and reliability standards, which have an impact on SAPP Based on individual member's plans, review, every 2 years, an overall integrated generation and transmission plan to highlight the benefits and opportunities for cost savings that can be derived by the members from the coordination of activities. The integrated generation and transmission plan shall: - Take into account the forecasted demand and energy consumption in each member's system, including DSM - Indicate the anticipated sales and purchases by each member - Contain the characteristics, location and commissioning dates of new generating units and new transmission facilities, which are planned in each member's system, when such facilities have a significant impact on the interconnected system - Contain the characteristics, location and commissioning dates of new telecommunication, tele-control and supervisory facilities, which are planned in each member's system, when such	Develop continuously an appropriate electricity market for the SADC Region Design and recommend a suitable market structure for SAPP Determine criteria to authorise members to trade in electricity Assume responsibility to admit and authorise members to trade, risk management, research and benchmarking Present all findings and recommendations to the Management Committee and carry out any other functions and activities as assigned or approved by the Management Committee Assume responsibility for all market operations in SAPP --- Market Surveillance and Monitoring Team: - conduct investigations of possible breaches on laws and regulations governing the SAPP market operations, - ensure that all participants within the market benefit from the same level of protection, regardless of type of participant, country, and size, - continuously monitor the SAPP trades and price development, and ensure that

Give advice on the short- and long-term operating problems Perform studies to determine transfer limits on timelines and inform operating members accordingly - monitor adherence of operating members to these limits Establish and update a database containing historical and other data to be used in planning and system operation studies Monitor the availability of the communication links between the Control Centres of the operating members and between these Control Centres and the Coordination Centre Advise of the feasibility of wheeling transactions Gather and act as the official custodian of data pertaining to transactions between operating members and between operating members and non-members Monitor the calculation and implementation of the various types of reserves Carry out projects and assignments as directed by the Operating Sub-Committee Monitor the protection performance on all tie-line and the coordination of their protection Monitor adherence to the Agreement by the operating members, *inter alia* regarding accredited capacity obligation and calculate the penalties for insufficient accredited capacity and their re-allocation among members Disseminate the generation and transmission maintenance schedules received from the	operation of the SAPP interconnected system Recommend procurement of appropriate software and other tools, which will enhance the value of the Power Pool operations Determine applicable penalties for non-compliance to approved procedures and enforcing such penalties and upon failure to enforce refer the matter to the Management Committee	facilities have a significant impact on the operation of the interconnected system - Identify and record new generation, transmission, telecommunication or tele-control facilities to be installed in the systems of members and endeavour to identify and record new generation, transmission, telecommunication or tele-control facilities to be installed in the systems of non-members - Be purely indicative and shall not create an obligation upon the members to comply Evaluate software and other tools which will enhance the value of planning activities such as load forecasting, determination of planning or reliability standards, cost-benefit analysis or system studies, and submit proposals to the Management Committee Submit proposals to the Management Committee regarding new service schedules, revision as necessary of existing ones Specify the reliability standards that shall be used to determine the accredited capacity obligation of each operating member Specify compliance criteria, which will enable each operating member to comply with its accredited capacity obligation Assess the benefits attributable to each operating member resulting from the installation of protection relays, control equipment or any system study Improve facility required for the satisfactory operation of the interconnected system -	the members adhere to the rules as set in the SAPP Market Book of Rules and the Participation Agreement, - keep track, check, and report anomalies on bidding behaviour by participants in the SAPP trading market based on available information, - collect information and monitor that the participants keep the markets trading rules for submission of information e.g. bilateral schedules, transmission capacities, etc., - monitor and ensure that participants do not get and misuse inside information that is not publicly available or publicly known in the market but can influence the prices in the market, - monitor that participants do not disclose information to persons not concerned before submission of such information to the market, - monitor that participants do not on purpose contribute to move prices beyond real market value, - ensure good market behaviour by monitoring and controlling of the key market components, - issue regular reports on market performance to the Management Committee, the Regional Electricity Regulatory Association, and the Markets Sub-Committee, and

operating members and advise on the adjustments that are required to maintain at all times the contractual pool reserves and the agreed upon services Coordinate the training of the members staff and if necessary, organise training seminars focusing on the operation of the interconnected system Prepare and issue annually control performance summaries report for the benefit of the Operating Sub-Committee Facilitate trading in the Day-Ahead Market		recommend to the Management Committee regarding the financial contribution of each operating member to the costs of such improvements Determine the transfer capability limits between systems on an annual basis or as and when required to enable the Operating Sub-Committee to prepare detailed operating procedures Identify specific reliability problems and recommend the generation or transmission additions or changes required to eliminate them Assess the capacities of transmission plant in the system of operating members for the purposes of calculating wheeling rates and review these on an annual basis	- any other task as assigned by SAPP from time to time.

8.2 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN SOUTHERN AFRICA UNDER SAPP

No.	Document	Description
1	Inter-Governmental Memorandum of Understanding between the SADC Member States, 1995 and revised 2006	Enables the establishment of a Power Pool in the SADC Region, i.e. establishes a framework under which the SADC Member States pronounced their intention to enhance regional power cooperation and trade through the development of SAPP. The signatories acknowledge that their national electricity utilities and other Electricity Supply Enterprises may participate as members of SAPP, subject to their own domestic laws and the terms and conditions stipulated by SAPP. If a dispute cannot be settled amicably under this Memorandum, such dispute has to be referred to the SADC Tribunal for adjudication under Article 16 of the SADC Treaty.
2	Inter-Utility Memorandum of Understanding between the electricity utilities of the SADC Member States, 1995 and revised 2007	Introduces cooperation and coordination in the development of systems while maintaining reliability, autonomy and self-sufficiency to the degree desired as well as the development of an energy market. Reiterates that non-SADC countries can become SAPP member states, subject to the outlined requirements, as well as approval of SADC. Does not restrict any SAPP member from having interconnections or agreements with non-Members, provided that: - the member(s) intending to have interconnections or agreements with non-Members shall notify SAPP of such intentions, - such interconnections or agreement(s) shall not create obligations upon a member that is not party to such agreement(s), and - such interconnections or agreement(s) shall not impair a member from fulfilling its obligations as a SAPP member. Establishes basic management and operating principles of a Power Pool. Establishes the Coordination Centre, which is regulated by the SAPP Coordination Centre Constitution. Acknowledges that the SADC government ministers and officials will still be responsible for matters normally under their jurisdiction under national legislation that regulates relationships between member states and electricity utilities. Permits SAPP, in its own discretion, to interact, consult and collaborate with other institutions and entities for the purpose of (i) information and knowledge sharing and (ii) research purposes. Sets out the dispute resolution mechanism agreed by the members, which consists of an agreed mediation and arbitration mechanism. Empowers the Coordination Centre to administer disputes.
3	Agreement Between Operating Members, 1995 and revised 2008	Establishes the basic principles and rules under which the interconnected portion of SAPP will operate. Sets the standards and obligations for all member utilities interconnecting to the SAPP grid. Establishes the specific rules of operation and pricing. Provides that an electricity utility may become an operating member of SAPP by signing the Agreement. Defines that dispute resolution under the Agreement is in accordance with that under the SAPP Inter-Utility Memorandum of Understanding. Nots that the Coordination Centre is responsible for the administration of disputes.

4	Operating, Planning and Environmental Management Guidelines, 2013	Complements the Agreement Between Operating Members. Ensures the coordinated operation between interconnected systems and to achieve high levels of system reliability and control at points of interconnection. Deals with, amongst others, system control, system security, emergency operations, operations planning, control areas, telecommunications and control personnel. Makes the SAPP pricing arrangement a key element in the operation of SAPP. Sets out the SAPP pricing arrangement in 13 detailed schedules which cover four broad types of transaction: - firm electricity contracts of varying duration, - non-firm electricity contracts of varying duration, - mutual support contracts such as operating reserve, emergency energy, and control area services, and - scheduled outage energy, energy banking, and wheeling.
5	SAPP Coordination Centre Constitution	Not available
6	Market Book of Rules	Sets the rules for governing the SAPP Market Operations. Makes the agreement between all participants and the SAPP Market Operator. A living document that has been refined and improved over time to keep pace with market developments, but binding. The most recent revision was developed in conjunction with the expansion of the Market Trading Platform in 2016, having: - DEFINITIONS, which contains the definitions for the different SAPP markets; - GENERAL, which defines the qualifying requirements to trade and rules for transmission capacity management for all market timeframes as well as the timing of all markets; - GENERAL TRADING RULES, which includes rules for bilateral contract management and the obligations on all key stakeholders; - FPM TRADING RULES, which contains the main trading rules for the Forward Physical Markets (Monthly and Weekly); - DAM TRADING RULES, which contains the main trading rules for the Day-Ahead Market; - IDM TRADING RULES, which contains the main trading rules for the Intraday Market; - SETTLEMENT CALCULATIONS, which covers the rules for settlement of all the SAPP markets including management of wheeling, transmission losses, outages and non-delivery and imbalances; - FINANCIAL RULES, which includes currency management, pricing, security (collateral) management, invoicing and credit notes, fees as well as the financial timelines and auditing requirements; - AMENDMENTS, which contain the rules for amending the rules; and - ADDENDA, which contains the detailed trading rules for all SAPP markets as well as the signatory page for each of the SAPP Market members.

7	Market Participation Agreement	Sets the conditions for participation in the electricity market governed by the SAPP Market Operator. Makes the agreement between each participant and the SAPP Market Operator.
8	Ancillary Services and Transmission Pricing System	Not available
9	Market Guidelines, 2014	Not available
10	Transmission Capacity Allocation Criteria	Not available
11	Guidelines for Regulating Cross-border Electricity Trading in Southern Africa, proposed in 2006 and approved in 2010	Provides an enabling framework for cross-border electricity trade and infrastructure. Applies to any cross-border transactions, of more than 20 MW of power, and where the relevant PPA or transmission wheeling agreement is longer than one year. Does not apply to trading on the day-ahead market of SAPP. Contains principles, rules and procedures that could be adopted for reviewing major, long-term imports and exports of electricity. Does not have a formal legal status over the decisions of individual national regulatory authoritiess, and there are no mandatory obligations on SAPP member states to implement the document. To be given legal effect, the national regulatory authorities need to implement the document in their own countries.

8.3 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN WESTERN AFRICA UNDER WAPP

No.	Document	Description
1	Articles of Agreement for WAPP Organisation and Functions, 2006	Institutes a management structure for WAPP, its organisation and functions, in order to establish a good framework of cooperation between its Members. Defines provisions for membership, removal and re-instatement. Defines provisions for finance. Defines dispute resolution procedure.
2	Directive C/DIR.1/06/13 on the Organization of the Regional Electricity Market in West Africa, 2013	General principles governing the regional electricity market within the framework of the ECOWAS Energy Protocol are defined for ECOWAS to integrate national electricity systems into the integrated regional electricity market to enable the populations of the Western Africa Region have access to quality energy at a lower cost. The Directive provides the legal basis for the fundamental principles supporting the development of the regional electricity market: - Evolution of the market in 3 Phases as specified in the Market Design and Roadmap; - Functional and financial separation of generation, transmission and distribution functions; - Adoption of an ECOWAS Regional Electricity Regulatory Agency (ERERA) approved regional transmission tariffs methodology; - Legalisation of ERERA regulation on transmission open access; - Legalisation of ERERA approved templates for bilateral contracts and standard connection and use of network agreement for open access to the regional transmission network; and - Mandating ECOWAS Member States to establish independent national regulatory authorities.
3	Directive C/DIR/2/12/18 on the Securitization of the Cross-Border Power Trade under the Regional Electricity Market, 2018	Securitisation of payments related to cross-border electricity trade in West Africa are defined for the ECOWAS regional electricity market whose viability and sustainability depends on securing payment for electricity exchanges. The Directive provides the manner of tackling accumulations of substantial payment arrears to electricity suppliers, incurred by cross-border electricity trade among WAPP member utilities, which have resulted in the governments' intervention for clearance of their debt arrears. It establishes the set of rules to enhance the security of cross-border electricity trade within WAPP through secured supplies and payments. The Directive requires a number of concerted and coordinated actions from each stakeholder (the ministries in charge of economy and finance, the ministries in charge of energy, the electricity utilities providing service to the public, the national regulatory authorities, ERERA and WAPP) related to: - enhancing the creditworthiness of the electricity sector, - strengthening contractual instruments used for bilateral exchanges, - backing contracts with more solid, explicit and symmetrical guarantees, and - strengthening the role of regional institutions in bilateral trade facilitation.
4	Operation Manual for WAPP Interconnected	This document contains the standards and procedures for WAPP Interconnected Power System which ensure, by means of 8 technical policies, that all the interconnected power systems of WAPP:

	Power System, 2015	- operate the interconnected Western African network efficiently and effectively, and - participate equitably in the obligations and in the benefits resulting from the interconnection. The Operation Manual contains 8 technical policies which relate to: P1 – Load Frequency Control; P2 – Interchange Scheduling of Transmission Capacity; P3 – Operational Security; P4 – Coordinated Operational Planning; P5 – Emergency Procedures; P6 – Communication Infrastructure; P7 – Information Exchange Between Systems; and P8 – Operator Personnel and Training. These policies are designed to ensure coordinated operation between interconnected power systems and to achieve high levels of system reliability and control at the points of interconnection. They specify how the operational guidelines of WAPP shall be implemented, on the basis of established technical and operational experience accumulated over the years. It prescribes that: - WAPP is organised in five predefined control areas, whereof each is operated by a single control area operator which has its own load despatch centre for operational purposes over its control area wherein other national TSOs can exist; and - Each control area communicates and cooperates with the Information and Coordination Centre and the Engineering and Operation Committee for the purpose of implementing the technical policies by fulfilling standards through following procedures.
5	Regional Market Rules for WAPP, 2015	This set of rules governs the trading of all electricity that flows across international borders between participating countries through the Interconnected Transmission System of WAPP, in compliance with the standards and procedures defined in the Operation Manual for WAPP Interconnected Power System. The Regional Market Rules envisage three Phases of market development. In Phase 1 (today): - trading is carried out on a case-by-case basis and standardised through procedures, - the regional electricity market is a bilateral market where bilateral contracts on purchase and sale of electricity are used for trading (countries, regional companies), - trading is carried out through bilateral contracts using approved model contracts in the short-, medium- and long-term, - transmission pricing is agreed between parties involved in a bilateral contract for existing contracts and for new ones it will be governed by the appropriate methodology after approving the Regional Transmission Pricing Methodology, - ERERA is appointed as the regional regulatory authority (Regional Regulator), and is responsible for enforcement and dispute resolution, and - the Information and Coordination Centre is appointed as the RSMO, and is furnished with all provisions required to carry out the regional market operation. In Phase 2 (short-term): - bilateral trading with transit through third countries are based on standard commercial instruments (contracts), - transactions can be carried out between individual agents of the countries, - short-term exchanges are carried out through the day-ahead market which will contemplate a regional optimisation through a regional optimisation dispatching model, - transmission pricing is regulated by ERERA and it is not possible to agree it bilaterally, and

		- the RSMO (the Information and Coordination Centre will be transformed to it) is operative and with the responsibilities established by the Regional Market Rules. In Phase 3 (long-term): - the operation is done as of a liquid and competitive market in the region, - sufficient regional transmission capacity is available as well as sufficient reserve in the countries so to make it possible, - the countries or groups of companies are enabled to put their resources under a common optimisation system (unifying dispatches), and - trading is enabled for different products integrating other markets (for some ancillary services and financial products). The RSMO's functions are defined: - day-to-day management of bilateral and day-ahead markets, - coordination with the control areas for the use of interconnectors and to optimise this use, - settlement of the market fees including other charges such as fees for services, transmission payments etc., and - market monitoring and surveillance. Control areas' functions are defined: - ensure maintenance of inter-area flows, safe operation within the control area, intra-area flows, etc., - constant communication with the system and market operator to ensure flows in interconnectors, - collaboration with the RSMO on the operational planning of interconnectors, - coordination with neighbouring control areas in emergencies, - compliance with the RSMO's restoration plan in case of emergencies within the control area, - reporting, etc. Key tasks of national transmission system operators are defined: - maintain flows agreed at the regional level in the interconnectors under its responsibility, - maintain technical parameters in the interconnectors under its responsibility, - operate safely domestic system to avoid undue impacts to others, - support others in emergencies, - maintain required communication with the control area responsible of its area and comply with instructions, - maintain required communication with the RSMO, etc. As far as metering is concerned: - metering systems are the responsibility of the national transmission system operator that is managing the substation at the interconnection node, - commercial metering installations must be located at the nodes established by the regional system and market operator, and - the regional system and market operator must have right of access to all data stored in the registers of the meters, either electronically through a data collection system or by physical inspection.

6	Transmission Tariff Methodology, 2015	This is a methodology to be used by the RSMO to develop a clear, transparent and predictable model for the calculation of transmission prices. It defines steps to be followed and rules that govern transmission pricing among parties involved in cross-border electricity exchange transactions in the regional electricity market. The following cost components can be recovered through transmission prices – capital costs of transmission network and equipment, transmission system operation and maintenance costs, transmission congestion, and transmission losses. The fundamental steps in the transmission tariff methodology are: - determine regional transmission assets and asset value, - calculate annual revenue requirements for each transmission system operator asset used for regional bilateral trading, - calculate use of transmission system and associated transmission losses for each regional bilateral trade, - calculate transmission revenue requirements for each transmission system operator for regional bilateral trades, and - calculate transmission tariff and transmission losses for the purchaser of each regional bilateral trade. The regional transmission revenue and transmission losses are calculated annually. The RSMO collects the revenue from purchasers of bilateral trades for transmission tariff and transmission losses. The RSMO pays transmission system operators their allocated transmission tariff and losses revenue.
7	Short/Medium- and Long-Term Model Bilateral Contract, 2017	The buyer reimburses to the seller the costs, if any, that the seller is obliged to pay for the transmission services, provided that such costs do not exceed the transmission services costs as determined and approved in the Transmission Tariff Methodology.
8	Set of market participation documents, 2018-2019	The following documents are approved: - Regional Electricity Market Procedures, - Market Participant Agreement, - Market Participant Application Form, and - Procedure of Application for Admission in the Regional Electricity Market.
9	Set of developed, but not yet approved documents	The following documents are under development/review: - WAPP Transmission Service Access and Use Procedures, - Minimum Regional Operating Standards, - Market Monitoring Procedures, - Contract Administration Procedures (registering and approval), - Transmission Pricing Model, and - Review of the Regional Market Rules for Phase 2 (*vis-à-vis* amending registration procedures, prescribing registration fee, making electricity auctions in the day-ahead market, choosing settlement bank, and conducting dispute resolution).

8.4 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN EASTERN AFRICA UNDER EAPP

No.	Document	Description
1	Inter-Governmental Memorandum of Understanding for the establishment of EAPP, 2005	Permits the electricity utilities in the respective countries to sign the EAPP Inter-Utility Memorandum of Understanding, which defines the fundamental principles to establish and operate EAPP. Provides that the parties will cooperate with other Power Pools in other African regions. Provides that the activities of EAPP shall be consistent with the RECs. Acknowledges that it is the parties' responsibility to harmonise national electricity policies. Does not deal with admission of new members, nor does it restrict same. Does not contain a provision for a dispute resolution mechanism.
2	Inter-Utility Memorandum of Understanding, 2005	Aims at defining the fundamental principles to operate EAPP. Allows for active members (public or concessionary utilities in charge of electricity generation, transmission or distribution in the region) and affiliate members (IPPs operating in the region who have fulfilled the membership conditions). Provides that there will be an operating agreement which will define the conditions and modalities to operate EAPP interconnected system. States that this agreement will replace the multilateral agreement currently in place in the region. The status of such proposed agreement is unknown. Provides that the Memorandum can be amended by the EAPP Steering Committee by two thirds majority of EAPP members. Does not specify dispute resolution mechanism, save the statement that the Conference of Ministers responsible for energy may impose sanctions against defaulting members.
3	Master Plan, 2011 and 2014	The 2011 Master Plan identified the regional electricity generation and interconnection projects in the power systems of EAPP and the EAC Member States in the short- to long-term. It was updated in 2014, based on simulations of optimal dispatch and least-cost investment in generation and transmission for the entire system in a number of specific scenarios. The 2014 Master Plan established the power system model wherein the electricity balances are given on a regional basis and provided recommendations based on analyses of regional least-cost investments in generation and transmission (a country can be comprised of one or more regions). For each region an electricity balance must be fulfilled, but electricity may be exchanged between regions. The concept of regions was motivated by transmission and its constraints, losses and costs. The established power system model supported investing in transmission if the total regional costs are reduced more than the annualised investment costs for the line (including losses and operation and maintenance costs). Main scenario and 20 alternative scenarios were used to analyse the potential development of the electricity system. The scenarios were used to analyse the sensitivity of the results with respect to the central parameters. The focus was on decisions that can be taken in the short-term, i.e. the possible development

		of the electricity system towards 2020 and 2025, and the long-term perspectives (towards 2040).
4	Operation Agreement between EAPP members	Provided for in the Inter-Utility Memorandum of Understanding; however, the status of such agreement is unknown.
5	Grid Code (Interconnection Code), 2011 and 2014	The 2011 Grid Code (i.e. the Interconnection Code) was developed to facilitate the integrated development and operations of the power systems of EAPP and the EAC Member States by setting out the technical rules necessary for EAPP to ensure that transmission systems are operated in a safe, reliable, secure and efficient manner. It was updated in 2014 with the aim to harmonise the network operation, planning and design processes. The 2014 Grid Code (i.e. the Interconnection Code) sets out the technical rules/standards in various codes for technical planning and operation of the EAPP Interconnected Transmission System necessary for EAPP to ensure that all its transmission systems are operated in a safe, reliable, secure and efficient manner: a) General Conditions (GC), b) Planning Code (PC), c) Connections Code (CC), d) Operations Codes (OC), e) Interchange Scheduling and Balancing Codes (ISBC), f) Data Exchange Code (DEC), g) Metering Code (MC), and h) System Operator Training Code (SOTC). It aims at implementing common standards for satisfactory operational security, reliability, and quality of supply in the Interconnected Transmission System, and define responsibilities for its operation and management. Its standards and measures clearly specify what is required of EAPP member states/utilities and what evidence is needed to determine whether an entity is in compliance with the each of the requirements set out in the Code. It also ensures that system operators are trained and authorised to take necessary actions to maintain reliable grid operation. For example, it requires that transmission licensees and the Coordination Centre establish metering related policies, procedures and standards including, but not limited to registration, testing and calibration, sealing, loss adjustments, data security, inspection, testing and audit of metering equipment and measurement error correction. The loss adjustment factors including circuit losses to be applied are contained in the meter information register. Gap analysis were performed on several occasions.
6	Market Guidelines, 2014	The Market Guidelines, as a high-level document, cover the overall guidelines for market design and govern the commercial transactions pertaining to cross-border flows of electricity that utilise transmission lines and associated assets of the interconnected system of EAPP as defined within the 2014 Grid Code (i.e. the 2014 Interconnection Code). The Guidelines' scope is to form the overall guidelines upon which commercial exchange of electricity between all EAPP member states and utilities shall be conducted. Several types of physically electricity trading can be designed, including day-ahead, intraday, etc. These Guidelines stipulate the guidelines for the day-ahead market. As new types of electricity trading are introduced in the course of the development of the EAPP regional electricity market, these

		Guideline will be amended to introduce principles for the new types of trade. As far as transportation is concerned, these Guidelines call for third party access to transmission capacity, and ask for identification of total transfer capacity, long- and medium-term availability forecast, manner of capacity determination, firmness of capacity, and daily procedure for determining and notifying available capacity.
7	Day-Ahead Trading Rules, 2014	These Trading Rules detail the day-ahead market rules which govern the commercial day-ahead transactions operated by the Coordination Centre. The Rules' scope is to address the detailed rules for the short-term market of daily exchange of electricity that is coordinated by the Coordination Centre. Chapter 1 (Introduction) defines the authority of the day-ahead trading rules; scope of the day-ahead trading rules; the trading appendices; notices; maintenance of the day-ahead trading rules; assessing a change to the day-ahead trading rules; force majeure; general provisions; conditions for trading; representation and warranties; representations by the participating enterprise; representations by the Coordination Centre; listing of products; and trading facilities. Chapter 2 (The EAPP Day-Ahead Trading Rules) details the general clauses; registration of orders; quoting; price range; gate closure; order amendments; order formats; matching; procedure in case of non-matching; reports; handling of errors; and auction delay or failure. Chapter 3 (Addendums) contains Annexes on the definitions; day-ahead electricity trading algorithm; product specification; market conduit; clearing; fee schedules; and participant agreement.
8	Daily Procedures for Capacity Allocation, Market Operations and Cross-Border Nominations, 2014	The Daily Procedures is a document which outlines the daily procedures for the market operator (the Coordination Centre), transmission system operators and producers. The Procedures relate to the daily coordination of events for capacity allocation, day-ahead market operation, and cross-border nominations. Chapter 1 (Introduction) defines the authority; sets out the methods by which the notices and communications are given; and allocates responsibility for maintenance of the rules. Chapter 2 (D-1 NTC, ATC and Day-Ahead Trading Rules) focuses on the procedures at TSOs.
9	EAPP Short-Term Market and Update of Market Road Map, 2014	This document firstly outlines the framework characterising and governing the EAPP short-term cross-border market for cross-border day-ahead electricity trade. It provides the basic model for short-term electricity trade; defines how trade shall be organised and how roles and responsibilities shall be allocated; includes findings from the EAPP pilot project for short-term shadow trading; and estimates the virtual gains from short-term trade. Secondly, the document outlines the Update of the existing Market Road Map, and elaborates on the first stage of the suggested marked development; proposes next steps; and lists barriers for turning the shadow trade into real trade, i.e. for implementing physical short-term electricity trade in EAPP as seen by the EAPP Technical Sub-Committee of Operation. The Market Road Map focuses on the day-ahead market for which market operation platform has been envisaged and named EAPP DAM (EAPP Day-Ahead Market). The platform is supposed to receive bids in the form of hourly bids for demand and generation and to compute prices for multiple price areas based on available transmission capacity. It is also supposed to enable a generation of aggregated and detailed statistical information with hourly, daily,

		weekly, monthly, and yearly resolution. The platform is expected to serve for the purposes of real operation as well as for the training purposes.

8.5 LEGAL AND REGULATORY BASIS FOR ELECTRICITY TRADING IN CENTRAL AFRICA UNDER CAPP

No.	Document	Description
1	Inter-Governmental Framework Agreement Establishing the Central African Power Pool as a Specialised Agency of ECCAS, 2003	Arranges for the creation, within ECCAS, of CAPP as a framework for sub-regional integration for the exchanges of electricity. Defines the CAPP's main objectives, seat/headquarters, and obligations of the parties. Sets out the CAPP's governing structures and defines their powers. Directs the parties to cooperate in the event of a dispute, with a view to find an amicable solution. Failing this, direct them to submit the dispute to an arbitral tribunal which will rule in accordance with the rules of the United Nations Law Commission. Decisions of the arbitral tribunal are binding and binding on all the parties.
2	Inter-Utility Agreement, 2003	Sets out the CAPP's objectives. Defines the order of priority of the documents governing CAPP. Defines the conditions of membership and dealings with non-members. Defines the responsibility for interconnected electricity infrastructure. Defines the CAPP's structure and responsibilities of the CAPP bodies. Details the responsibilities of the Technical Sub-Committees. Details the functioning of the CAPP's organs. Defines the sources of financing.
3	Headquarters Agreement Between CAPP and the Republic of Congo	Arranges legal personality for CAPP with the seat in Brazzaville, the Republic of Congo.
4	Decision of the Conference of ECCAS Heads of State and Government No. 15/CEEAC/CCEG/XIV/09 on the adoption of the Central African Electricity Market Code, 2009	This instrument provides an incentive legal and regulatory framework for investments in the electricity sector. It aims at promoting cross-border exchanges in electricity in the ECCAS Region by: - establishing the principles governing the generation, transmission, distribution, import, export, transit, sale of electricity and system and related services, - specifying the principles for ensuring an adequate level of security of electricity supply and investment in infrastructure, - specifying the principles of control and regulation of the electricity sector's activities, - determining the rules for the protection of the environment and the interests of consumers, - determining the conditions for the supply of electricity and security of services and - encouraging private initiative and the establishment of a competition regime in the electricity sector. *Inter alia*, it asks for aligned: - general organisation of the electricity sector *vis-à-vis* public service obligations and consumer protection, monitoring of security of supply, technical requirements, and national regulatory bodies and regional regulation, - promotion and protection of investments through sovereignty over natural resources convertible into electricity, ownership and legal regime of

		electrical infrastructure, promotion of private investment, protection of private investment, treatment of staff of private investors, transfer of capital relating to private investment, subrogation, fiscal and customs framework, - trade in electricity and system and related services *vis-à-vis* national electricity policy, national legal and regulatory frameworks for electricity, investment planning in the electricity sector, liberalisation of electricity trade and transmission and related services between CAPP member states through interconnected networks, possible limitations, and non-discrimination with respect to origin, destination or ownership of electricity, definition and implementation of competition rules, limits on free competition, - protection of environment and development of energy efficiency by taking environmental consideration into account and developing energy efficiency, - performing electricity activities of generation, transmission, distribution and supply through appointment of operators of power plants owned by a public body, authorisation procedures for new generation capacities, tenders for new generation capacities, and appointment, obligations and independence of operators of transmission and distribution systems, - transparency of accounting and accounting unbundling from the viewpoint of right of access to accounting and accounting unbundling, - access to interconnected networks *vis-à-vis* access by third parties, market opening and reciprocity, direct lines, inter-TSO compensation mechanism, network access charges, information on interconnection capacities, congestion management, new interconnections, information and confidentiality, monitoring of import / export flows of electricity, - regional electricity network projects of common interest through qualification and prioritisation of projects of common interest, - security of supply, including operational security, maintenance of supply and demand balance, investment security, - offenses, sanctions and settlement of disputes. Its implementation will reduce the divergences between different national legal frameworks through harmonisation of the rules, procedures and practices in the electricity sector in the Central Africa Region. In addition, its implementation will also strengthen the protection of investors – public or private – in the electricity sector while reaffirming the need to preserve the environment and the ecosystems of CAPP member states.
5	Code for Operation of Interconnected Electrical Networks in Central Africa, 2012 (The CAPP Permanent Secretariat, supported by EuropeAid126679/C/SER/CG; currently under revision by the yearend 2021)	This Code lays the foundations for future operation since the interconnection of electricity grids in Central Africa is only at an embryonic stage (it should be kept in mind that although the process of deregulation is underway in most of CAPP member states, national TSOs do not yet exist in most of them). It is formulated in such a way as to facilitate transposition at the national level. It defines the actions and interactions between the network manager and users, in order to ensure optimal use of the network, adequate and secure transport of electrical energy and better security supply through: - adequate and economical ancillary services, - control of frequency and operating reserve, - voltage control, - black start capability,

		- restoration strategy adopted by the network manager in the event of a feeding shutdown (partial or total), - forward-looking management procedures, - provision of information relating to network risks and events in transmission, - development of actions to be taken by the network manager in order to achieve economical dispatch and enable users' orders for the D-Day, and - definition of the notification requirements for malfunctions and unavailability of generation units. It starts by defining tasks and obligations of the network operator, including the communication of information, the right of access to physical installations, the behaviour in emergency situations, etc. Then it continues by defining: - regulation and performance of frequency and power, where it sets goals and basic principles for primary frequency regulation, secondary regulation for adjustment of control zone balance, compensation for imbalances, tertiary adjustment, voltage and reactive power adjustment, and quality adjustment, - ancillary services, where it focuses on black start capability and congestion management, - load shedding, where it explains activation principle, procedure for protection from unforeseen events, procedure in case of shortage, management of required quantities of power to shed, and customer prioritisation, - emergency and restoration procedures, where it specifies general network restoration strategy, emergency operation and management of disturbances, network restoration, and emergency control centre, - operation planning, where it specifies the technique, design, exchange of information and procedures to be applied by the network operator to appropriate operation of the network in the short- and medium-term, defines staff functions, and determines data required for operation planning, - data exchange, where it defines components of information exchange in order to take into consideration any operational error and / or electrical network event in the operation of the network, and introduces obligation to notify, notification of a transaction and transaction notification form, recording of a transaction, timing, notification of an event and event notification form, recording of an event, operational communication and backup of data, communication infrastructure, SCADA, voice communication means, and standards for communication, - planning and provisional management of exchanges in electricity, where it provides producers with the management programme for generation on D-day, so that the generation units are available at the right time, in order to allow the network operator to distribute them by maintaining the operating reserve at the required level, and defines data and process and forward-looking management of exchanges, - coordination of stops, where it defines requirements for formal notification of judgments by producers to the network manager, and introduces scheduling of stops, procedures for changes of schedules, and additional information to notify,

		- counting and measurements, where it develops all the provisions and methods of data exchange, measurement and counting, and defines equipment and measurement data, criteria and procedures for measuring equipment, access to equipment and measurement data, control of measuring equipment, calibration of measuring equipment, and measurement data, - network access, where it develops all the interactions relating to network access, between the regional network operator and transmission and distribution network operators (local or national), and defines conditions and responsible entities for access, rights and obligations of the access manager and TSO, access procedures, power subscription, interconnection with Pools and foreign networks, access to a generation unit and injection monitoring, local generation unit, daily access programme, daily coordination programme, coordination of the call for generation units, and cogeneration and RES generation units, - security and coordination, where it provides effective security tools to the network manager when work on equipment requires safety precautions on other equipment at the connection point, and defines procedures and security measures reporting, - operation training and certification, where it requires each network operator to regularly train his staff in charge of operations management in order to prepare them for the measurements to be taken in the event of network disruption, critical network situations, stand-alone operation or restoration of supply, and defines responsibility and empowerment, certification, recommendations, and training content.
6	Decision of the Conference of ECCAS Heads of State and Government No. 73/CEEAC/CCEG/XVI/15 on approving the establishment of a CAPP levy and the creation of the Fund for development of the electricity sector of Central Africa, 2015	This instrument establishes a CAPP levy instead of annual contributions from the ECCAS Member States and operating electricity utilities to the CAPP budget. It also approves the creation of a Fund for development of the electricity sector of Central Africa. The CAPP levy is intended to finance: - (25%) equipment necessary for the operation and activities of CAPP, and - (75%) Fund for development of the electricity sector by financing total or partial infrastructure cost. The CAPP levy is applied on the consumption of electricity in the ECCAS Member States. The levy, due by electricity consumers, is a specific tax based on kWh. It is charged and is collected by the operating electricity utilities. The levy is charged at the rate per kWh fixed by each of the ECCAS Member States. The levy is charged on the number of kWh, and is billed and collected from the consumer by the operating electricity utilities. The operating electricity utilities carry out the monthly transfer of the levy receipts in the account opened at the central bank of each ECCAS Member State by the Permanent Secretariat, in the name of CAPP. The statutes of the Fund will be submitted for adoption by the Conference of the Heads of State and Government. The capital of the fund is owned by the CAPP community. The administration of the Fund is governed by decision of the Council of Ministers of CAPP in line with the criteria adopted in the statutes of the Fund. The Permanent Secretariat submits an annual report to the CAPP's policy-making bodies. The Council of Ministers of CAPP is responsible for adopting the detailed modalities of the implementation with a view to the efficient functioning of the levy.
7	CAPP Regional Energy Policy Strategy 2016-2030, 2015	This Strategy Paper encompasses technical, legal, institutional and financial provisions pertaining to the central issue of the CAPP’s governance, and

		constitutes the strategic and operational framework for setting the priorities and approaches to implement regional energy policy through these interconnected systems. Its ultimate objective is to establish the regional electricity market that guarantees a reliable, affordable and environmentally friendly electricity supply to the ECCAS Member States by way of: - providing assistance for generation and transmission infrastructure in Central Africa, - developing a legal and regulatory framework conducive to the development of the regional electricity market in Central Africa, - establishing trade rules and setting up an RSMO, - establishing and interpreting technical rules for operating, managing and pricing electricity trade, and - facilitating institutional capacity building and skills consolidation. The Strategy Paper firstly identify the actions required to establish the regional electricity market, and secondly defines the strategy for setting up the legal, IT and technical tools to plan, manage and monitor the future regional electricity market. Having in view that the establishment of the regional electricity market is conditioned by the construction of generation infrastructure to meet demand in the Central Africa Region and the construction of interconnection networks between the ECCAS Member States, the Strategy Paper defines two horizons to achieve the set objectives: - the short- to medium-term 2016-2020 period, when the priority is to mobilise financing, focuses on the realisation of electricity infrastructure both at the national and regional levels identified as priority integrating projects, and the establishment of the missing bodies to prepare the legal and regulatory frameworks for the management of regional infrastructures, and - the long-term 2020-2030 period, when all the priority integration projects will gradually enter the operating phase, focuses on the operationalisation of regional infrastructures linked to all the priority integrating projects and the establishment of rules and conditions for their pooling, the maturity of the regional institutions, and the convergence of national regulations at the regional level. In the 2016-2020 period, CAPP must fully assume the role of Programme Manager, and focus on mobilising the financing required to construct the infrastructure needed to pool generation capacity and to increase grid interconnections. It must become able to take charge of: - preparing the harmonisation of national legislation and regional regulations, - contributing to improving the regulatory and economic environment to attract private sector investment, and - ensuring the technical regulation of regional electricity trade which will increase over time. In the 2020-2030 period, CAPP (the Permanent Secretariat) must focus on ensuring the conditions are met to manage and supervise the electricity market. Considerations relating to infrastructure development will begin to take a back seat during this period as considerations regarding operational planning for the regional electricity market development, setting rates for

		wheeling and associated services, and the regulation of operators come to the fore. The Strategy Paper concludes with the Action Plan aimed at outlining a range of activities that act as a strategic plan CAPP can implement to cover the two fundamental aspects of the ECCAS energy policy: - play a key role in meeting the conditions for implementing regional infrastructure projects, and - lead the harmonious development of the regional electricity market so that it is effective and complies with the objective of developing cross-border trade and providing industrial investors and the general public with a reliable and affordable supply of electricity.

8.6 MAIN ACTIVITIES AND SUB-ACTIVITIES IN THE ACTION PLAN FOR THE CENTRAL AFRICA REGIONAL ENERGY POLICY STRATEGY UNDER CAPP

Phase	Period	Actions	Main activities and sub-activities
1	2016-2020 (short- to medium-term)	Development of generation and transmission infrastructure	Supervision by CAPP as Project Manager of the extension of regional transmission infrastructure through the completion of all priority infrastructure projects: - Lobbying ECCAS so that CAPP bodies adopt the Strategy prepared with country experts and implement its proposals, recognising in particular the CAPP Permanent Secretariat's status as Project Manager for CAPP and the creation of project companies to develop the priority infrastructure projects; - Lobbying ECCAS to support the rapid adoption of autonomous financing for CAPP such that the CAPP itself but also the project companies can function (human and financial resources); - Organisation by the Project Manager of a Donor Round Table to secure financing to construct the infrastructure sections along the South-North backbone [Maque a Do Zombo (Angola) - Memve'élé (Cameroon)] so the national generation capacity of the countries crossed by this regional interconnection can be exploited; - Development of a plan to support the implementation priority infrastructure projects so that the efficiency of the CAPP contribution as Project Manager in expanding this regional infrastructure can be monitored and assessed, with a view to proposing fair investment spread over time and around the Central Africa Region; - Creation of project companies and in the first instance project companies for the priority infrastructure projects, i.e. the Cameroon-Chad interconnection and the Inga-Cabinda-Pointe Noire interconnection, focusing available skills and financial resources on these priorities. Setting up of the procedure to formalise the relations between the Project Manager (CAPP Permanent Secretariat) and the implementers (project companies); - Evaluation of the Project Manager and the provision of assistance to project implementation as regards the CAPP's contribution to the implementation of priority infrastructure projects and the fair distribution of investments until the end of this Phase to implement the regional electricity market; and - SCADA review at the end of this Phase to understand how electricity trade systems work and what are the problems associated with the regional electricity market.
		Building institutional capacity	As supra-national Project Manager, the CAPP's direct and indirect human resources must have sufficient skills to fulfil their missions: - Reactivation of the Planning Sub-Committee and setting up of Operation and Environment Sub-Committees to that all can come into operation by the end of this Phase (programme of activities, operating budget, etc.); - Building capacities in project management and management of electricity infrastructure (learning / consolidation of skills in electricity infrastructure project management to monitor the regional electricity master plan and the national electricity master plans of CAPP member states);

			- Building capacities in line with taking ownership of the Central Africa regional electricity market operating code, i.e. to be able to conduct the activities key to implementation, operation and monitoring of the regional electricity market (teaching tool to use SCADA, digital and analogue simulators, training courses, etc.); - Formulation and implementation of the Permanent Secretariat communication policy (participate in the specification of a communication strategy, promote the actions of CAPP both internally and externally, support focal points and experts from CAPP member states in conducting their regionally-focused communication actions); - Provision of interpreting and translation services and revision of regional documents and checking of different language versions of agreements, treaties and contracts (French, English, Portuguese and Spanish) on behalf of the Permanent Secretariat; - Setting up of an audit task force to monitor technical performance; and - Setting up of an audit task force to monitor skills.
		Creation of a legal and regulatory environment	Harmonisation of national regulations and existence of legal provisions essential for the development of the regional electricity market: - Review of national regulations and setting up of a data base of legislation and regulatory documents and any other documents of relevance to the regional electricity market; - Drafting of bills to be passed by CAPP member states with the preparation of a roadmap to set up, if necessary, any required legal or regulatory modifications; - Assistance of CAPP member states in adopting bills necessary for harmonisation and the adoption of the fundamental principles for setting up the regional electricity market; and - Monitoring progress of the commissioning of the priority infrastructure projects and ensuring the legal and regulatory documents are in line with the situation and needs of the regional electricity market.
		Establishment of trade rules and regulatory framework	Development of draft inter-country and/or inter-stakeholder trade agreements, in particular according to the type of priority infrastructure projects (intra-regional / inter-regional) and the regional electricity market law: - Review of the types of agreements that exist for interconnections (identification of template contracts/agreements and overarching principles to be validated by CAPP member states, and drafting of template interconnection contracts/agreements for CAPP member states to use); - Formalisation of electricity trade currently done on a “case-by-case” basis and standardisation of procedures such as bilateral agreements between both CAPP member states and CAPP member utilities, and trade instruments (types of contract, short-term trade); - Alignment of electricity trade agreements and instruments with the Central Africa regional electricity market code; and - Setting up of mechanisms for operators and stakeholders to take ownership of the Central Africa regional electricity market code.
			Finalisation of the legal and institutional structure and preparation for setting up the Central Africa Regional Electricity Regulation Commission:

			- Review of national regulations in CAPP member states and lessons to be learned for regional regulation (specification of the structure, responsibilities, operating mode and powers of the regional regulatory authority); - Operating mode of the regional regulatory authority (supervision of drafting and recommendation of rules, application of rules, consideration of how to deal with issues such as wheeling charges and conflict resolution between operators); - Approval of the regional master plan and harmonisation of regulatory rules for the priority infrastructure projects in the pipeline; and - Review and analysis of the different types of contracts and contract negotiation strategies and techniques.
		Establishing and interpreting technical rules for operations	Preparation to coordinate operations and trade at the regional level: - Establishing and interpreting technical rules, operators take ownership of the 2011 CAPP Operating Code; - Evaluation audit of basic electricity systems (skills, procedures, administration and maintenance of SCADA, etc.); - Evaluation of gaps between local operating procedures and the CAPP Operating Code; - Skills upgrade audit; - Technical upgrade audit; and - Preparation to set up the RSMO.
2	2020-2030 (long-term)	Development of generation and transmission infrastructure	Project companies' training period completed, and move to independent operational mode under CAPP control: - Audit of project companies and proposals for improvements under the authority and supervision of CAPP; - Institutionalisation of project company reporting, setting up of a feedback loop to learn from past experience under the authority of the Planning Sub-Committee and CAPP control; - Audit of generation plant rehabilitation and construction projects carried out during Phase 1 with review of priorities by CAPP; - Evaluation of effectiveness of CAPP contribution (supranational Project Management) as regards the implementation of priority infrastructure projects and the fair distribution of investments; - Arbitration of financial and human resources among project companies in line with priority infrastructure projects development and at the behest of CAPP; - Implementation of SCADA action plans; and - Harmonisation of document management systems to prepare for the transfer of infrastructure to the operator under the authority of the Operations Sub-Committee.
		Building institutional capacity	Human resources skills consolidated and strengthened to supervise the increase in regional electricity trade via the integrated electricity systems during the integration phase: - Building of individual operator capacities in line with recommendations from the human resources audit (Phase 1 - Sub-activity 5);

			- Upgrading of protection systems, automatic systems and transmission systems in line with recommendations from the technical audit (Phase 1 - Sub-activity 4); - Building of collective and organisational capacities of the entities responsible for the integrated electricity systems; and - Evaluation of the CAPP Operating Code and update under the supervision of the Operations Sub-Committee.
		Creation of a legal and regulatory environment	Harmonisation of national regulations and existence of legal provisions essential for the development of the regional electricity market: - Review of suitability of regional and national legislation in light of the actual situation and needs of the regional electricity market following entry into operation of the priority infrastructure projects; - Verification in real-time as the priority infrastructure projects come on-line of the alignment of legal provisions with the realities and needs of the regional electricity market, and if necessary make suggestions and recommendations for any necessary adjustments in coordination with CAPP member states; and - Adoption, if necessary, of modified bills beginning with the reform of regional legislation and then moving on to national laws.
		Establishment of trade rules and regulatory framework	Focus on the development of the Central Africa Regional Electricity Regulation Commission: - Presentation of the tools prepared in Phase 1 to CAPP member states and sector stakeholders; - Monitoring and coordination of the use by CAPP member states and stakeholders of interconnection agreements/contracts; - Analysis of the optimal institutional structure to manage interconnected networks on the basis of contracts from Phase 1; - Draft community agreement and other documents required for the Commission to function, including the basic principles regarding the legal structure of the regional regulatory authority, the composition and operation of its components, guarantees of independence and of course technical and financial resources; - Organisation of seminars so CAPP member states can take ownership of the process with a view to adopting an action plan and a roadmap; and - Coordination and monitoring by CAPP of the action plan and the roadmap to create and launch the Commission.
		Establishing and interpreting technical rules for operations	Coordination of electricity trade: - Promotion of the CAPP Operating Code; - Monitoring of the SCADA action plan; - Organisation of a single centralised RSMO; - Transfer of integrated electricity systems to the 2030 Central Africa Interconnected Power System; - Audit of financial, human and organisational resources of the 2030 Central Africa Interconnected Power System and proposal of improvements; and

			- Place the RSMO under an integrated management system of the 2030 Central Africa Interconnected Power System.