ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

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AfDB

POWER TRADE

STRATEGY REPORT

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with participation of:

- EPS (Egypt)
- Tropics (Ethiopia)
- YAM (Sudan)

FINAL REPORT

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PHYSICAL UNITS AND CONVERSION FACTORS

bbl	barrel	(1t = 7.3 bbl)
cal	calorie	(1 cal = 4.1868 J)
Gcal	Giga calorie	
GWh	Gigawatt-hour	
h	hour	
km	kilometer	
km²	square kilometer	
kW	kilo Watt	
kWh	kilo Watt hour	(1 kWh = 3.6 MJ)
MBtu	Million British Thermal Units	(= 1 055 MJ = 252 kCal)
	one cubic foot of natural gas produces approximately 1,000 BTU	
MJ	Million Joule	(= $0,948.10^{-3}$ MBtu = 238.8 kcal)
MW	Mega Watt	
m	meter	
m^3/d	cubic meter per day	
mm	millimeter	
mm^3	million cubic meter	
Nm^3	Normal cubic meter, i.e. measured under normal conditions, i.e. 0°C and 1013 mbar	
	(1 Nm^3 = 1.057 m^3 measured under standard conditions, i.e. 15°C and 1013 mbar)	
t	ton	
toe	tons of oil equivalent	
tcf	ton cubic feet	
°C	Degrees Celsius	

General Conversion Factors for Energy

To:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3412	1

ABBREVIATIONS AND ACRONYMS

ADB	African Development Bank
ADF	African Development Fund
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CIDA	Canadian International Development Agency
CT	Combustion Turbine
DANIDA	Danish Development Assistance
DFID	Department for International Development (UK)
DIDC	Department for International Development Cooperation (GoF)
DSA	Daily Subsistence Allowance
EEHC	Egyptian Electricity Holding Company
EEPCO	Ethiopian Electric Power Corporation
EHV	Extra High Voltage
EHVAC	Extra High Voltage Alternating Current
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EN	Eastern Nile
ENCOM	Eastern Nile Council of Ministers
ENSAP	Eastern Nile Subsidiary Action Program
ENSAPT	Eastern Nile Subsidiary Action Program Team
ENTRO	Eastern Nile Technical Regional Office
ENTRO PCU	Eastern Nile Technical Regional Office Power Coordination Unit
FIRR	Financial Internal Rate of Return
GEP	Generation Expansion Plan
GTZ	German Technical Co-operation
HPP	Hydro Power Plant
HFO	Heavy fuel oil
HV	High Voltage
HVDC	High Voltage Direct Current
ICCON	International Consortium for Cooperation on the Nile
ICS	Interconnected System
IDEN	Integrated Development of the Eastern Nile
IDO	Industrial Diesel Oil
IMF	International Monetary Fund
JICA	Japanese International Co-operation Agency
JMP	Joint Multipurpose Project
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas
LRFO	Light Residuel Fuel Oil
MENA	Middle East, North Africa Countries
MIWR	Ministry of Irrigation & Water Resources (Sudan)
MWR	Ministry of Water Resources (Ethiopia)
MWRI	Ministry of Water Resources and Irrigation (Egypt)
MSD	Medium Speed Diesel (TPP)
NBI	Nile Basin Initiative
NEC	National Electricity Corporation (Sudan)
NECC	National Electricity Control Centre (Egypt)
NELCOM	Nile Equatorial Lake Council of Ministers
NELSAP	Nile Equatorial Lake Subsidiary Action Program
NG	Natural Gas

NGO	Non Governmental Organization
NORAD	Norwegian Aid Development
NPV	Net Present Value
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OPEC	Organization of the Petroleum Exporting Countries
PPA	Power Purchase Agreement
PBP	Pay Back Period
PHRD	Policy & Human Resource Development Fund
PIU	Project Implementation Unit
PRSP	Poverty Reduction Strategy Paper
RCC	Regional Electricity Control Centre (Egypt)
RMC	Regional Market Co-ordinator
RE	Rural Electrification
REB	Regional Energy Broker
REM	Regional Electricity Market
SAPP	Southern Africa Power Pool
SIDA	Swedish International Development Agency
SO	System Operator
SSD	Slow speed diesel (TPP)
STPP	Steam Turbine Power Plant
STS	Senior Technical Specialist
TAF	Technical Assistant Fund
TPP	Thermal Power Plant
UA	Unit of Account
UNDP	United Nations Development Program
WB	World Bank

1. INTRODUCTION

There are wide variations between the countries in terms of their existing and future internal electricity market structures, the pace at which reform may take place, the changing demand patterns and the fuel supply situation. As a starting point, it can not be assumed that all countries will have the same need or desire to trade in a similar manner at the time when a regional market is initiated. It is therefore desirable to establish a market structure which has the flexibility to cope with the differing possibilities to trade.

There are a number of possible market designs which may serve as models for consideration by the countries. However the design of the regional market will be limited by the evolving structures of the individual markets. As an example, a centrally dispatched regional market ("tight pool") would not be possible unless each of the countries within the region agrees to permit a single dispatch entity to have unit-by-unit dispatch control over every generating unit within the region. Or, a power exchange with open access to all generators and consumers could only function if each country had already moved to a fully competitive internal market. Both these examples are extreme cases and while they may become a long term objective, it is reasonable to presume that the medium term solution will be based on a much more restricted approach to regional trade.

An essential feature of the regional market design should be to acknowledge that flexibility may be required to accommodate the approaches taken in each country in restructuring their electric systems and in the design of their own markets. The regional market should ideally allow each country maximum flexibility in determining what capacity and energy it may wish to buy or sell and the type of transaction that it may wish to use. An efficient market design should allow market participants a maximum choice in trading opportunities. In developing options for a regional market design it is helpful to understand the type of transactions that would be possible between national systems.

In general, there are three durations of capacity and/or energy transactions possible, corresponding to different requirements to balance national energy markets through trading:

- long-term generating capacity and/or energy for one or more years to meet a capacity or generation shortage;
- medium-term seasonal generating capacity and/or energy for a month, week or day to smooth out the load curve;
- short term balancing as in an hourly spot energy market.

Each of these may be required by different countries at different stages in their system development. Within these trading timeframes, a variety of different services may be included in addition to bulk energy and capacity: these include emergency services, spinning and other forms of reserve. Transactions may also differ as to whether they are for firm or interruptible services.

The proposals for the market need to be placed within a relevant time frame. In the long term, the markets in each country may possibly have moved towards fully competitive structures, enabling correspondingly competitive regional trading. However, the time frame for such a development is unpredictable and would not provide useful guidance for the short term steps which could be proposed.

It is more practical to adopt a medium term horizon consistent with the foreseeable developments within each country. The context for the regional market implementation would then be the status of the internal country markets as foreseen for around that time.

2. BARRIERS TO DEVELOPING A HIGHLY INTEGRATED MARKET

There are a number of factors that need to be considered due to the limitations they impose on possible market designs and the extent of competition.

A regional market with multiple buyers and sellers?

A highly competitive regional market would require that multiple buyers and multiple sellers in each country have access to the market.

This may very well not be possible in the first stage:

- It is unlikely and/or unknown whether there will have been sufficient vertical unbundling in the three countries to enable independent generators or independent distributors to participate directly in a regional market.
- There is no common or clear commitment to open access to the national transmission systems. This would also prevent individual companies participating in the market.

A regional system operator?

Co-ordination of dispatch and control will of course be required and to a large degree this can be provided by operating under common Operating Guidelines. A tighter pool would require that two functions currently carried out at a national level would need to be passed to the regional level:

- System reliability and centralised dispatch;
- Long term planning of the expansion of both generation and transmission to ensure security of supply at the regional level.

A further degree of integration would exist if countries were prepared to plan and adopt capacity and reserve requirements on a regional, rather than national basis. Experience shows that the countries are not yet ready to rely to a significant extent on reserve provided by other countries, or to substantially relinquish their orientation towards self-sufficiency in power supply.

We therefore conclude that reliability and dispatch will remain wholly the responsibility of individual national system operators.

3. EXPERIENCE FROM OTHER MARKETS

Other regions and countries have developed power markets of different types, especially African regions have started to develop regional power pools and the lessons from their experience are helpful in considering the options for the East Nile regional electricity market.

An overview of the existing African regional electricity organizations is provided in Appendix 1.

3.1 OPTIONS FOR THE EAST NILE ELECTRICITY MARKET

At its most basic level, the regional market may be considered to comprise a number of market participants (traders), a regional market co-ordinator (RMC) and a set of market rules. We now consider the separate components and their options leading to a recommendation for market design and a more detailed description of the proposed regional market structure.

3.1.1 WHO ARE THE MARKET PARTICIPANTS?

A distinction should be made between membership by countries of the Regional Electricity Market, and participants in the market. Each member country would agree to accept the overall Regional Electricity Market rules and would designate one or more market participants or traders.

The question of who is permitted to trade is closely tied up with the stage of restructuring of the national markets.

- In the case of a vertically integrated market, it is obvious that there can be only one trader per national or integrated system.
- Unbundled generation (e.g. as in the single buyer model). After generation has been unbundled, each generator has the possibility to trade in the region if permitted. There are two cases:
  - The single buyer does not sell but may buy.
  - The single buyer sells into the regional market in competition with his generators. However, this would require that national transmission had been unbundled and priced transparently so that there is no discrimination between the single buyer and generators in a country.
- Unbundled distribution and/or large consumers. As for generation, there are two cases: when only distributors/eligible consumers are allowed to buy in the regional market; or when the single buyer is also allowed to buy from the regional market. To avoid discrimination by the single buyer, it would be necessary that transmission had been unbundled and transparent transmission pricing introduced.
- Third party countries. There need be no restrictions on exports to third party countries but imports would need to conform to the requirements of the market rules.

Each country will determine whether it has one or more participants in the market. If sole traders persist for a period, the Regional Electricity Market will not differ significantly from the current situation in which national system operators organise trade between themselves. As multiple sellers and/or buyers appear, the complexity of trade will grow and the information required by the system operators (SOs) will increasingly lie with other bodies. This will create the need for market information concerning contractual obligations of buyers and sellers to be rapidly made available to all SOs. The prime requirement for the regional market co-ordinator is to ensure that this information exchange takes place according to market rules designed to ensure efficiency and fairness.

For competition to develop, there should be multiple buyers and sellers as rapidly as possible. During a transitional period when some member countries may be complying and others not, it will be necessary to consider mechanisms that ensure that reciprocal trading relations are on non-discriminatory terms.

We propose the concept of a market Trader. A trader will be a legal and credit-worthy body in one member country of the Regional Electricity Market. As a registered participant in the regional market it must agree to abide by the market rules.

Initially, there must be at least three market traders (one for each of the countries). The number may be expanded without limit as the trading possibilities grow.

3.1.2 TYPES OF TRADE

The long term vision should be the development of an integrated and competitive wholesale market at the regional level comprising a range of bilateral contracts and a spot market to determine a common clearing price. Within the time horizon for the initial steps of the REM this is not likely to be feasible, therefore each type of market should be considered separately:

- **Bilateral contracts.** Bilateral contracts are contracts freely negotiated between two parties, and which do not involve any third party in the contractual relationship. In the Regional Electricity Market, bilateral trades should continue to be contracted between any two parties but the regional market co-ordinator may have a role in facilitating the matching of the requirements as well as in ensuring that the contracts and their execution conform to the market rules.

  Bilateral trades already occur between the EIJLST utilities although there is no common set of rules. In a coordinated market contracts may be required to be limited to predefined types following standard formats, or unconstrained. Since each country will have different requirements and wish to freely negotiate their contracts, flexibility in the range and form of contracts will be an important requirement for the Regional Electricity Market.

  Contracts can be for capacity or energy or both, covering any time period (but usually medium to long term), and either flat or sculpted to match the load shape. A wide range of contracts can be consistent with a coordinated market providing the quantity obligations are notified to the market co-ordinator (and all the SOs) and the contracts conform to a minimum set of market rules necessary to ensure system reliability.

- **Short term trades.** Short term trades are required for emergency conditions and to settle short term deviations from contract quantities. This can either be handled through flexible terms in the bilateral contracts or through the establishment of a short term balancing market (spot market). The advantage of a spot market is that it creates open access to the market and a transparent regional electricity spot price through which market participants can seek the cheapest way of meeting their short term requirements. However, there are a number of conditions to fulfil:

    - Locational factors will have a strong influence on the costs of trades. An effective method for transmission pricing will be necessary and the market would require transparent and reliable methods for calculating the feasible short term trades, since a simple matching of bid and offer prices would not produce the feasible optimal flows. All the national SOs would need to be simultaneously involved in the process of determining a feasible and least cost dispatch schedule.
    - Access rights to the transmission systems of all countries.
    - A regional settlement system for short term trades.
    - Close co-ordination between national dispatch centres and accurate measuring of short term flows.

  Short term balancing of feasible flows to ensure system reliability based on predetermined prices would be possible but would not produce the most efficient result.

The first step of the market should be to create a consistent framework for bilateral trades comprising a common, minimum set of contract rules and notification of contract physical obligations (but not financial terms). The feasibility of a balancing market for short term exchanges should be examined to determine the time frame for introducing a price-based system with locational transmission pricing. An intermediate step could be a physical balancing market settled at predetermined generation and transmission prices (which would typically be defined to be avoidable costs, hence it would be a cost-based system).

3.1.3 BILATERAL CONTRACT TYPES

There are many possible bilateral contract types. The main distinguishing characteristics are physical (firm and non-firm), financial, dispatchable and non-dispatchable contracts (by non-dispatchable we mean that the scheduling of the plant is under the control of. the buyer or seller, but not the system operator. Therefore the plant can not contribute to the control and balancing of the system).

- Physical contracts may be for energy, capacity or both. A physical contract is for a transaction which results in actual delivery of the electricity service. They may be written against the system or an individual plant (e.g. thermal, hydro). Transmission rights will be required if third party countries are involved. Transmission rights could be the responsibility of either party but more usually of the seller.

  A firm, physical contract may be to supply agreed amounts of energy or capacity at specified times in the future (e.g. one month, one season, one year, peak times, base load). The firmness of the contract will depend on the reliability of the system against which the contract is written.

A non-firm physical contract may be interruptible at the seller's instigation (under specified conditions), or may be written against a single plant, in which case the firmness of the contract depends on the reliability and availability of the individual plant.

The price set in a physical contract may reflect the technical characteristics of the plant(s), such as a two part tariff for capacity and energy.

- Financial contracts are for transactions which do not result in any delivery of electricity, but are designed to produce predictable and stable prices for one party while placing the price risk on the counter-party. The most common form of financial contract is a contract for differences (CfD). In a CfD, the settlement price for electricity (strike price) at a future date is fixed. If the actual price (e.g. a spot market price) varies from the settlement price, the parties settle the difference between them. Financial contracts, therefore, normally require a spot market with a common clearing price against which to hedge the contract. Although two parties may devise financial contracts, it is likely that these could not be used until a liquid regional spot market had been developed.

  Financial contracts are very flexible as they can be designed to share the price risk between the two parties in any pattern agreed between them. They are also flexible in that a financial contract can be signed with any party, not only someone who is involved in the physical transaction.

- Dispatchable contracts. A dispatchable contract could be for capacity or energy where the scheduling is under the control of a system operator (or market operator). It will be important for the reliability of the regional market that there are sufficient dispatchable contracts to provide the flexibility for regional market operation. Some flexibility in contracts can also be provided by allowing the buyer to resell (e.g. into a secondary market or a pool).

- Non-dispatchable contracts. These could be for firm energy or for capacity where the scheduling is under the control of the buyer (or in some cases of the producer, e.g. for run-of-river hydro plant). The existence of take or pay conditions on fuel supply would commonly require that the related generation contracts are non-dispatchable or have only very limited flexibility matching the flexibility in the take or pay conditions.

All types of bilateral contracts may be permitted provided they conform to the minimum rules of the market. Some examples of typical contracts are:

- **Physical non-dispatchable contract**. This can be seasonal, monthly, weekly etc. The generation is defined by the needs of the buyer, so that the buyer effectively "owns" the generation. The system operator is informed of the contract and must schedule the generation (i.e. it is "must run" generation as determined by the buyer's requirement). The contract can be mainly for energy or just for secondary services such as reserve.

- **Physical dispatchable contract**. The buyer "owns" a share of the scheduled generation but each plant is under the control of the system operator, who dispatches the whole system for maximum economic benefit (i.e. least cost). If the buyer has insufficient energy, the rest is bought from the pool, if he has too much, he sells to the pool.

- **Supply contract**. There is a commitment to supply a defined amount of energy and available capacity, but this is not linked to any particular plant(s). There is no commitment to generate and so the contract does not affect dispatch. The generator must meet the supply obligation with his own generation, or by buying from other generators or from the pool. The buyer must take the supply but can resell if excess to requirements.

3.1.4 CO-ORDINATION OF BILATERAL TRADES?

The next question to consider is the options for the role the market co-ordinator plays in bilateral contract trading.

- **Mediated trades**. Should the regional market co-ordinator (RMC) have a role in setting up or negotiating the bilateral trades? The extreme case would be when the market co-ordinator is an intermediary in all trades. Potential buyers and sellers would notify the RMC, the RMC would then match the offers and agree the outline terms of the contract.

  This type of role is almost certainly unnecessary and a potential barrier to trade. The range and scope of contracts will be highly flexible and matching would be unlikely to be more rapid through a mediator. It would be important to avoid confusion if there was a requirement for each country to directly contact each other as well as the regional RMC. Furthermore, the commercial terms of the contract should be confidential and the RMC would therefore be unable to resolve differences between the parties. Finally, the RMC is unlikely to be sufficiently credit-worthy to be joined in any way as a party to the contract, nor should the RMC be allowed to carry any market risk.

  A more limited information exchange role could be of some benefit. To fulfil this role, the RMC should maintain up-to-date information on the electricity balances and forecasts for each country. A further useful function could be for the regional RMC to maintain a bulletin board which would allow countries to inform each other of potential surpluses and deficits.

- **Central settlement**. It is possible to consider that the RMC would run a centralised settlement system. However, the RMC cannot be a party to the contract settlement for two main reasons:
  - The participants will want to maintain complete commercial confidentiality of the financial terms of their contracts.
  - The RMC would not be creditworthy enough to carry any of the financial risk.

The co-ordination role of the RMC for bilateral trades should therefore be limited to maintaining an information base on the electricity balances (present and future, including expansion plans) of the region.

The RMC’s most important function in this area will be to ensure that market information concerning the physical obligations in the contracts are transmitted rapidly and reliably to all SOs to enable them to take these obligations into account in their dispatch schedules.

3.1.5 SYSTEM RELIABILITY AND SECURITY

A major consideration is how to ensure system reliability and security, and what role, if any, the RMC has in this. Generally, technical issues will follow the requirements of common Operating Guidelines (See Appendix 2: SAPP Operating Guidelines). There are several possibilities to consider:

- **Centralised dispatch**. This is sensible, since the generation plant may be considered to be embedded in the national transmission systems. There is no distinct regional transmission system. All (or most) of the lines that will be used for inter-country trade are also part of the national transmission systems and will need to be fully under the control of national system operators. It is possible to develop a multi-level form of central dispatch market. However, the complexities of such alternatives would need to be thoroughly understood and considered before developing a market design based on this concept. Therefore the prime level of control should stay at the national level.

- **Relevant information for transmission access**. A minimum level of shared information will be necessary to ensure that access to transmission lines, which could be designated as part of the regional exchange capacity, is transparent. The RMC should have a role in ensuring that the system control implications of all regional trades is known to all national system controllers. To meet this need, there should be a requirement that the trade obligations under each contract are notified to the RMC for sharing with all SOs. There should further be a requirement that available capacities on all transmission lines is notified.

- **Planning and system expansion**. Planning of national transmission system expansion is the responsibility of national system operators. The RMC should have a role in co-ordination of these plans to encourage the development of regional transmission capacity. National systems will be free to develop their own generation expansion plans. They will presumably wish to do this on a least cost basis and should be encouraged to include regional resources and expansion plans in their scope. It may be desirable to consider ways in which positive incentives could be created for encouraging the development of least cost generation expansion plans on a regional basis.

- **Capacity requirements**. Each member country will need to meet an installed capacity obligation for reliability. There are two options for how this could be fulfilled:
    - Integrated utilities will need to have an agreed level of reserve. Where generation has been unbundled, the firmness of this capacity will depend on the terms in the PPAs. To assist with this and to ensure that the PPAs are acceptable, there could be model PPAs or model clauses covering the requirements of the regional market. This will be particularly important where some degree of flexibility in capacity availability and its dispatchability exists in the contracts.
    - Bilateral contracts can be part of the capacity for reserve. Contracts will need to have been notified to the RMC and be of an acceptable form. Obviously, capacity can not be double counted in two countries.

3.1.6 TRANSMISSION: PRICING, CAPACITY AND ACCESS

Inefficient and inequitable transmission pricing could be one of the major barriers to developing economic trade. This will undoubtedly be a main topic of negotiation and discussion between the members in the detailed planning for creating the market. Prices must be neither too high nor too low. If transmission prices are too high, or not on a comparable basis along different paths, trade will either be discouraged entirely or the pattern of trade will be distorted from the least cost solution. On the other hand, unless transmission prices fully reflect the long term cost of new transmission investment, there would not be sufficient incentives to create new transmission capacity for the long term expansion of regional trade. This is a complex topic and a full discussion is outside the scope of this section (see also Volume 3). The main issues will be:

- The unbundling (or at least accounting separation) of the transmission function from generation and distribution, as a basis for determining transparent and cost reflective tariffs.

- The assurance of access on equitable terms.

- The avoidance of cross-subsidy between generation and transmission, which could otherwise give a trade advantage to the high transmission price (low generation price) country.

- The transmission pricing methodology adopted by each country. There is a need for compatibility between countries as experience elsewhere shows that different methods can be an important barrier to trade. As discussed in Volume 3, there are numerous cost allocation possibilities such as contract path, boundary flows, MW-km etc. When the transaction crosses one or more countries, i.e. when wheeling occurs, it becomes necessary to account for the additional congestion and losses within the countries.

  In Volume 3, we propose to follow the transmission pricing methodology that has been adopted by the European TSOs, which is based around a cost component method. Since the number of market participants may initially be small, and the transactions will probably involve long electrical distances, the transport cost component will likely be a large component and a distance-dependent method such as MW-km type of approach may be preferred. Distance-dependent transmission pricing is commonly used for wheeling transactions. This is transparent, easy to implement and fairly representative of the usage of the networks. One drawback is that it creates a large different in costs between short distance and long distance transactions. Another drawback is that it does not cover the actual additional costs of congestion or losses which result from the transaction. There are various methods of overcoming these problems but they may be implemented at a later stage when the volume of transactions grows.

  There will clearly be a difficulty in implementing a common approach for inter-country transactions if different methods are used within each country.

- The RMC will need to play an active role in promoting the establishment of a satisfactory pricing approach, and will also need to act as the tariff regulator.

3.1.7 WHEELING

Wheeling occurs whenever the transaction passes through a third country. It does not raise different problems in principle from transmission pricing as a whole, but it is a further complication since the geographical character of the region may lead to a high proportion of wheeling transactions.

Because wheeling introduces a third party to the transaction who is not a beneficiary of the electricity exchange, efficient tariffs are highly important. There is a further question of the allocation of the third party charges. The simplest approach is to allocate them 50% to each of the producer and buyer, so that there is some economic signal on the producer to influence their choice of location.

Finally, for wheeling transactions it is especially important to have established clear rules for the unloading of contracts when third party transmission systems are congested. The rules will need to take into account the firmness of different contracts and will also have obligations for disclosure of relevant information to the RMC.

3.1.8 SHORT TERM TRADING

Bilateral contracts can be used for medium to long term trades. This can be defined to be anything from 1 hour forward up to several years. Short term trading refers to trading for 1 hour or less. This is required for emergency conditions and for the balancing of deviations from contracts and residual trading after all the bilateral contracting has been agreed.

It was already suggested in section 3.1.2 that short term trading should be handled through some sort of spot market when the conditions are appropriate to establish one. The disadvantage of trying to settle imbalances through bilateral contracts is that it imposes a large transaction burden on the parties. A centralised system reduces the information flows. The advantages of such a system outweigh the disadvantages once the volume of short term transactions has grown beyond a certain minimum level. The question of when to establish a short term market is therefore partly a pragmatic issue of the number of transactions occurring.

In competitive markets within integrated systems (i.e. a single country) the short term pool is almost always operated integrally with the SO, because they largely share the same information; only the SO knows how to balance the short term market taking account of transmission constraints, and the SO also requires the short term market information to finalise the dispatch instructions.

Since the form of the regional spot market cannot follow that of a traditional pool with centralised dispatch, a more flexible approach of a ***regional energy broker*** may be considered. The role of the Regional Energy Broker (REB) will be to manage residual trading, i.e. transactions within the hour with buy/sell opportunities that remain after the bilateral transactions. Options for the mode of operation of the energy broker are:

- **Bulletin board.** This approach requires the REB to maintain a real time information exchange to allow buyers and sellers to rapidly find each other. Thereafter, the trade is concluded by bilateral agreement (or, if possible, screen based trades). The drawbacks are that it imposes an administrative burden on the parties and may not result in simultaneous clearing of the imbalances due to the delay in posting agreed deals.

- **Cost based market**. The broker matches buyer and seller quantities which are settled at predetermined declared costs. This will not necessarily result in a least cost solution for a number of reasons:
  - Costs are virtually impossible to monitor and the declared costs may deviate significantly from real marginal costs.
  - Incremental and decremental costs differ (it is possible to include incremental and decremental costs in the system).
  - Costs are not necessarily constant over the range of energy traded.

- **Price-based market**. In the price based approach each trader quotes prices for hourly blocks of energy for increasing production (incremental price) and decreasing production (decremental price). The regional broker establishes a schedule of trades by matching buy and sell quotes, usually according to the rule that the highest buy is matched with the lowest sell until no more trades are possible. This results in the maximum value of avoided cost. Settlements may be either bilateral or settled centrally at the average pool marginal price

The bulletin board approach is information intensive and relies heavily on sophisticated and reliable information and communication technologies. This is a realistic option by 2006 but can not be recommended with confidence today.

The price based market is simpler than the cost based market in that it avoids the need for any external scrutiny and monitoring of declared costs. However, there could be lack of confidence that the market would establish efficient prices for two reasons:

- The initial market may be very thin and heavily influenced by a small number of trades
- The market may be manipulated by the bids of dominant traders.

The cost based market overcomes these difficulties and may be more suitable for the initial introduction stage, but only if all participants agree to reveal their costs (which they have not so far agreed to do).

Both types of market will face difficulties due to the transmission costs over long distance trades, since buy and sell prices are not at the same location. An algorithm to adjust the matching of prices will be needed to take account of real time transmission constraints and transmission costs. This could be quite complex if different countries have different methods of transmission pricing, and is another argument in favour of a simple but consistent approach. In any case, the resulting adjusted schedule will not be the optimum solution but there will need to be a practical compromise between complexity and accuracy.

3.1.9 DETAILED MARKET DESIGN

After the general form of the REM has been agreed in principle, the next phase of development will require a number of further issues to be considered in more detail. The following notes briefly identify the issues which will probably need to be considered by the RMC during the next phase of the work:

- Co-ordination of dispatch instructions. The method of communication and rules by which the system operators in each country will coordinate their actions and take account of the regional transactions. It is assumed that SOs will be operating according to common Operating Guidelines and in addition they will need to share and take account of information concerning the bilateral contracts between multiple buyers and/or sellers. At the third stage of the market they will also receive information from the RMC notifying of trades concluded through the spot market.

- Transmission congestion. When any transmission line becomes congested there will need to be rules for prioritising the transactions. All market members must agree to reduce transactions under the instruction of the SOs, the rules to be coordinated and monitored by the RMC.

- Development of acceptable basis for transmission charges. Transmission pricing is likely to be one of the most sensitive issues, both because of its critical nature for creating incentives or barriers to trade, and because of the difficulty of achieving a measure of consistency between the member countries. It is important to avoid cross-subsidies within a country between generation and transmission and to find an approach which provides the desired incentives for short distance trades, long distance trades and new investment.

- Co-ordination of planning and system expansion. The RMC will clearly have a role in co-ordination of information related to long term planning. Generation expansion is likely to be the responsibility of individual countries (subject to their system reliability commitments) but transmission expansion may require a higher level of RMC involvement. Since expansion of regional transmission capacity will always involve more than one country, there should be clearly defined procedures for considering such expansion once it has been initiated by one member country.

- Independence of market operator role from supervisory role. Market operation should be carried out under a defined set of rules designed to achieve efficient system operation for the benefit of all participants. The rules themselves are likely to be created/modified by a higher level body (the Management Committee). The relation between the two needs to be carefully considered.

- Trading liquidity. The efficiency of the markets to establish competitive prices (especially the spot market) will depend on the volume of trading and number of active participants. It is likely that the detailed market design will change as the trading liquidity grows.

- Fair allocation of benefits and savings. The market rules should be designed to allocate a fair share of the savings on trading transactions between the buyer and seller. Typically, the aim will be to share the savings equally between the two parties. The main issue will concern the allocation of transmission costs, especially in wheeling transactions when third parties are involved.

- International trade issues; taxes, exchange rates, credit-worthiness of buyers. Cross-border trades require resolution of a number of issues which do not arise in national transactions, including the incidence and impact of taxes on trade prices and profits, the allocation of the foreign exchange risk, and the credit-worthiness of the buyer and enforceability of the contract (legal jurisdiction and international dispute resolution procedures).

- Non-payment guarantees. A common basis for providing security over contractual liabilities will be required. If sovereign guarantees are not available, bonds may be required. A satisfactory basis will also need to be found for involving different types of market participants, if the market develops from trading between single utilities to trading between multiple buyers and sells.

3.2 OUTLINE PROPOSAL FOR MARKET DESIGN

3.2.1 REGIONAL COOPERATIVE FRAMEWORK UNDER DEVELOPMENT

3.2.1.1 The NBI Regional Power Trade Project

Following the Shared Vision of the Nile Basin Initiative adopted by the Nile Council of Ministers in Dar es Salaam on 22 February 1999, the Ministers responsible for electricity affairs in the countries of Burundi, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Kenya, Rwanda, Sudan, Tanzania, and Uganda, adopted, on May 20-21, 2003, the long-term vision for the Nile Basin Power Forum and approved the Regional Power Trade Project Implementation Plan, including the establishment of a Nile Basin Power Forum.

Objectives:

The Nile Basin Power Forum will:

- increase cooperation in the development of regional plans and investment for expanding generation and transmission;
- facilitate common understanding of power sector reform strategies and harmonized regulatory regimes;
- promote power trade; ensures equitable trading regimes;
- facilitate learning, and supports new information and communication technologies.

The Nile Basin Power Forum:

The Nile Basin Power Forum will be a regional, self-sustaining, legally established institution that:

- Manages and updates a database of regional power systems
- Develops regional plans for expanding generation and transmission
- Stimulates subsidiary- level project investment for regional interconnection
- Facilitates a common understanding on a power sector reform strategy and a harmonized regulatory regime
- Designs the power market and establishes standards for operation of the interconnected system
- Promotes cooperation in regional power trade, the development of a power market
- Ensures an equitable trading regime for all participants in the regional power market
- Achieves the confidence of all participants in the regional power market through a strong transparent decision making process
- Facilitates a learning environment for understanding the nuances of legal, regulatory, and pricing regimes required for regional power trade
- Liases with similar forums in other regions.

It is expected that, over time, the Power Forum will facilitate the formation of three new entities: a regulatory forum, a regional dispatch centre, and a power exchange. The Power Forum will continue to function as a regional planning agency.

The Regional Power Trade Implementation Project:

An effective Power Trade Market

Five Years Program:

1. Agreed institutional and investment framework;
2. Strengthen existing and initiate new transmission lines;
3. Power trade agreements concluded;
4. Agreed technical operational standards;
5. Strengthen professional networking, common database;
6. Power Forum established, operating; ideas on transmission tariffs, operating standards, study on demand & supply in region completed;
7. Regional power project identified and study started;
8. Preparation of documents for financing completed and design started;
9. Infrastructure: feasibility studies, new transmission lines;
10. Trade: bilateral linked to new transmission lines;
11. Intergovernmental agreements;
12. Inter-utility agreements;
13. Nile Basin regulatory forum (pricing, standardization, reforms);

14. 4+ bilateral links established (Ethiopia-Sudan, Kenya-Uganda, Rwanda-Burundi-DRC, Kenya-Tanzania, Tanzania-Uganda);
15. Human capacity strengthened;
16. Agreement on power sector reform strategy.

10–20 years Program:

1. Improved power infrastructure in place;
2. Improved quality of supply;
3. Increased access of supply;
4. Harmonize regulatory regimes;
5. Increased cross-border trade;
6. Agreed investment plan;
7. Bilateral and regional PT agreements finalized;
8. Some priority projects operational;
9. Permanent regional (subregional) power pool established;
10. Loose pool (SAPP style);
11. Taxation tariff agreement and access terms;
12. Standard contracts;
13. More interconnections (E\N-NEL);
14. 3–5000 MW new hydro;
15. New CCC-Ts (Egypt, Tanzania, Eritrea);
16. SAPP type trade;
17. 20–40 TWh;
18. Subregional, regional, interregional grids;
19. Regional grid control center established;
20. Regional electricity market established.

An effective Regional Power Forum

5–20 years Program:

1. Forum established, operational;
2. Has a finite life in initial stages: well-established, functioning regional institution providing a learning environment, setting institutional and regulatory framework;
3. Will evolve into a regulatory forum, regional dispatch center, and regional planning;
4. Setting investment plans;
5. Managing institutional issues;

6. Identify generation projects;
7. Make the collaborative market work smoothly;
8. Successful in mobilizing funds;
9. Managed good database;
10. Database, plans, and priorities for power plant, for example, time schedule for financing, implementation, etc.;
11. Managing power tariffs, cost database;
12. Common regulations for the integrated system during this period;
13. Legally binding agreements in place;
14. Strengthening human capacity;
15. Confidence of all players in industry: strong, transparent, effective decision making.

20–50 years Program:

1. No power forum, but a power exchange;
2. Strong regulatory institution;
3. Handling all regional matters.

Organization for its Implementation:

The development objective of the RPT Project is to establish the institutional means to coordinate the development of regional power markets among the Nile Basin countries.

The following project governance, management & coordination, has been adopted including:

- Project Steering Committee, composed of the Ministers responsible of electricity affairs;
- Project Technical Committee, composed of two representatives Ministry & Utility;
- Project Management Unit (PMU),
- Coordination with other SVP Projects & Subsidiary Action Programs,

The Project Steering Committee. A Project Steering Committee will be established to provide strategic guidance, direction, and oversight to ensure that the project objectives are achieved, within the overall framework of the NBI and its shared vision, and that the project remains within budget and on schedule.

The Steering Committee will be composed of two senior officials from each country, one from the ministry responsible for power and deregulation and one from the power utility; a Nile–TAC member from the PMU host country, in this case Tanzania; and a Nile-SEC representative.

To provide a link to the SAPs, representatives of Eastern Nile Technical Regional Office (ENTRO) and the Nile Equatorial Lakes Coordinating Unit (NEL-CU) will be invited to participate as observers.

The development partners, likely represented by Norway, the focal point partner; a World Bank representative; one representative from the Project Services Agency (PSA); and other technical experts will also be invited as observers.

The Steering Committee will meet at least once a year in Dar es Salaam.

The Project Technical Committee. A Technical Committee will be established to provide technical guidance to the activities of the Power Forum.

The Technical Committee will consist of two senior technical experts from each country, one from the ministry responsible for power, with broad knowledge of sector reform and deregulation, and one from the power utility with expertise in transmission system operations and power system planning; the project manager; and the PMU lead specialists.

To provide a link to the SAPs, representatives of ENTRO and the NEL-CU will be invited to participate in the committee. The Technical Committee will meet at least twice a year, in the PMU premises in Dar es Salaam.

The Project Management Unit. The PMU for this project will be located in Dar es Salaam, Tanzania. The PMU will operate at the basin-wide level. In support of the NBI, the PMU's primary responsibility will be managing and implementing the RPT Project. In addition, in support of the overall SVP, the PMU will provide necessary support to the national activities of the other regional SVP projects in the country of its location.

The PMU office will be staffed by a project manager, preferably with technical expertise in power system planning; a financial manager/procurement specialist; two lead specialists, one with expertise in power systems operations and economics and one with expertise in hydropower planning and water resources; an environmental/water specialist; and other administrative and support staff.

At the national level, Technical Committee members will also function as national focal points in each country to provide national input in the work of the RP T Project and regional studies, and to serve as liaison with relevant national ministries and institutions. These Technical Committee members/focal points will work on an as-needed basis from their respective offices.

Establishment of the Regional Power Forum:

With a World Bank Funding and in order to set up the appropriate regional organization, the RPTP launched the Project "Consultancy to develop an Institutional, Regulatory and Cooperative Model for the Nile Basin Power Forum and Power Trade" with the following main objectives:

- To assist the RPTP and the Power Technical Committee (PTC) of the NBI to review institutional arrangements adopted worldwide by regional power trade organizations and submit discussion papers;
- To draft and submit a report detailing broad contours of an institutional and legal arrangement suitable for the Nile Basin Forum, and a strategic roadmap towards the establishment of such forum;
- To assist the RPTP and the PTC to review and develop a model for the regulatory and institutional frameworks needed to establish and support Regional Power Trade at the Nile

sub-basin and basin levels, and a strategic roadmap towards the establishment of such a power market.

This project started recently and is ongoing. In consideration of the institutional developments led by the PMU – RPTP, it is obvious that the proposed approach for the East Nile Basin riparian States should be in conformity with what was adopted by the Ministers responsible of electricity affairs in Dar es Salaam, May 20-21, 2003.

3.2.1.2 The East African Power Pool – EAPP

In February 2005, the Ministers in charge of Electricity Affairs signed the Inter-Governmental Memorandum of Understanding which enables the establishment of the East African Power Pool.

At the same time, the General Managers of the Electricity Utilities of the same countries signed the Inter-Utility Memorandum of Understanding, which establishes EAPP's basic management and operating principles.

These two MOUs (presented in Appendix 1 and 2 of Volume 5) represent a major political recognition and endorsement of the necessity to establish a Regional Electricity Market in Eastern Africa, with the view to improve the competitiveness and the economic efficiency of the electric systems in the region.

It is also obvious that any further development towards the integration of the national electricity power systems should be integrated in the Regional Strategy for the implementation of the East African Power Pool.

The Inter-Governmental MOU includes articles defining:

- The EAPP's Objectives and Headquarters;
- Obligations of Parties;
- Resources;
- EAPP Organization Structure;
- Assignments of EAPP's Organs;
- Cooperation and relationship with Regional Economic Communities and Regional Development Initiatives;
- Resolution of differences;
- Consistency with regional acts, treaty, etc.

Through the Inter-Utility MOU, the electricity utilities of the riparian States clearly indicates their will:

- to participate in the East Nile Power Trade,
- to develop interconnections between their respective networks,
- to expand generation capacity and energy trade among themselves to reduce electricity production cost in the region,

- to coordinate the installation and operation of generation and transmission facilities in their respective networks,
- to facilitate in the long run the development of an electricity market in the region.

The objective of the Inter-Utility MOU is to facilitate the establishment of the East Nile Power Trade which in turn has the objective to provide reliable and economical electric supply to the consumers of each of the East Nile riparian States consistent with reasonable utilisation of natural resources and effect on the environment.

Its purpose is to establish the basic principles under which the East Nile Power Trade will operate:

- the co-ordination of and the co-operation in the planning and operation of the various systems to minimise costs while maintaining reliability, and
- the full recovery of costs and the equitable sharing of the resulting benefits.

The Inter-Utility MOU includes the following articles:

- Management Structure of the EAPP;
- Financing of EAPP's Activities;
- Commencement and Termination of the MOU;
- Conditions for Membership;
- Agreements with non-members;
- Ownership and Operation of Interconnected Transmission Facilities;
- Composition of the Structural Organs, Operational Rules, Duties, etc.

3.2.2 PROPOSED SOLUTION

The formal market bodies will comprise a Management Committee (EAPP Organizational Structure), a regional market co-ordinator (RMC) to be set up by the EAPP Permanent Secretariat and a regional energy broker (REB). Following the evaluation of options in section 3.1, the proposed regional market design can be summarised:

- Participants in the market are designated traders. There may be initially only one per country but the number should grow as power systems become unbundled. It is desirable to reach a multiple trade (multiple buyers and sellers) market as soon as possible, for competition to develop.

- Technical operation and responsibility for system reliability and security remains with each country's system operator (SO). Operation will be consistent with common Operating Guidelines.

- There is a regional market co-ordinator (RMC) who proposes the market rules to the EAPP Steering Committee and monitors compliance of traders and SOs with the rules.

- Traders sign a market operations agreement to adhere to the market rules.
- An obligation for installed capacity for reliability can be fulfilled with own generation or bilateral contracts with traders in other systems.
- Medium and long term trades are handled through flexible bilateral contracts freely negotiated between traders, but subject to a minimum set of market rules (the most important issues will concern disclosure and notification of the physical obligations in the contracts).
- The RMC assists with information exchange through a bulletin board and notifies national SOs of contracted trades to enable them to fulfil their system reliability obligations.
- Transmission charges should be set to by a fair method to avoid barriers to trade and encourage investment in new regional transmission capacity.
- Most transfers will be done through bilateral contracts but a Regional Energy Broker (REB) schedules short term energy through:
    - A bulletin board, or
    - Matching of buyers and sellers.
- The REB may match buyers and sellers on a cost based or price based method. The cost based method could be the initial step but the aim would be to move to a price based method.
- The REB provides settlement information for short term trades. The settlement mechanism will need further examination but may be built upon existing institutions and practice.

The advantages of the proposed solution lie in its **flexibility**:

- It allows the number of traders to grow as the market structures in each country evolve
- It does not initially require a common internal market structure in each market
- It allows countries to chose the form and type of bilateral trades to suit their requirements, subject to compliance with a common minimum set of agreed rules
- It is well adapted to a staged development; the bilateral contract market can be expanded until the volume and complexity of transactions requires and justifies the implementation of the short term energy broker
- It allows the short term market to be developed in a number of steps, e.g. from a bulletin board to a price-based broker.
- At all stages trading in the market is voluntary although certain steps would need to be taken in a coordinated way by members (e.g. once a member has signed the market agreement, the market rules will govern all future trans-national trading).

Figure 3.1 : Bilateral Contract Market

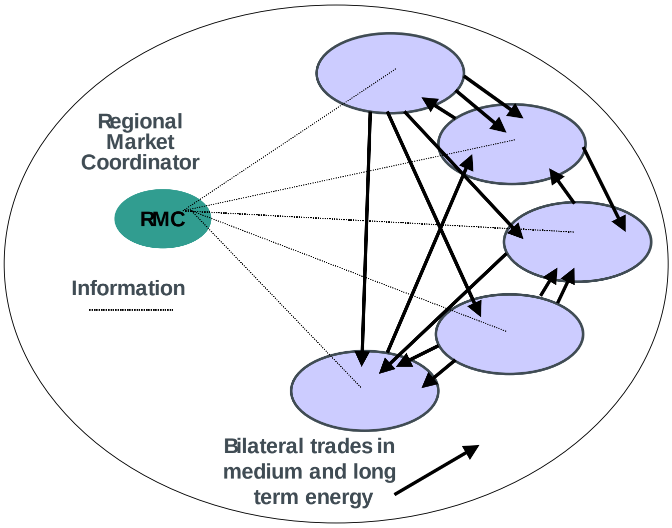
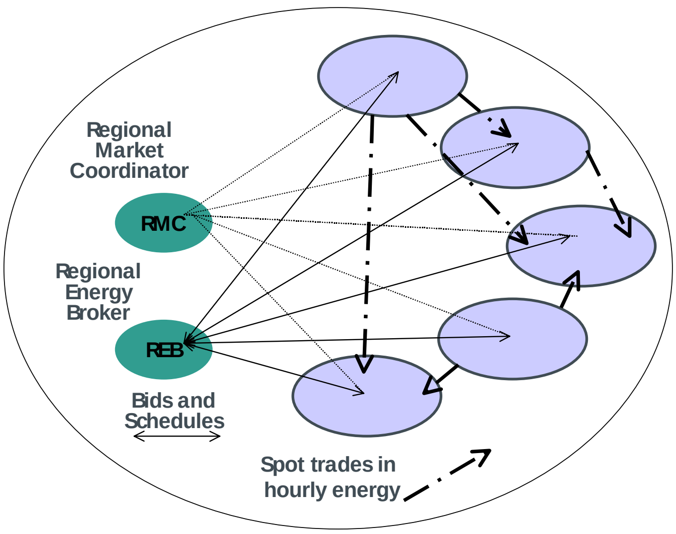


Figure 3.2: Regional Market Broker



3.2.3 REGIONAL MARKET IMPLEMENTATION

The implementation phase of development of the Regional Electricity Market should follow after the proposed conceptual design of the Regional Electricity Market has been agreed in principle. Three main areas will need to be considered in developing the implementation plan. Firstly, the timetable and stages for development of the market will need to be agreed. Secondly, The market rules and codes will need to be drafted. Thirdly, proposals should be made for the market institutions and their roles.

3.2.3.1 Stages

The proposed solution allows the market to be developed in stages. These could be, for example:

Stage 1: Bilateral trade between utilities

- Flexible trading conforming to a set of minimum market rules;
- Bilateral contracts freely negotiated between utilities;
- Regional market co-ordinator facilitates trades with information exchange.

Stage 2: Bilateral trade between unbundled generators, distributors and large consumers

- Allows more traders to increase the level of competition;
- RMC ensures all market information supplied to Sos.

Stage 3: Short term exchanges through regional market broker

- Gradual introduction of a competitive short term market;
- Market priced balancing market facilitates the further development of bilateral trades;
- Other staging is possible. In particular, the market broker step could be implemented much earlier subject to the willingness and agreement of the members. The advantage of introducing this earlier is that it creates a common clearing system and price against which much more flexible financial hedging contracts can be written, facilitating the further development of the market.

3.2.3.2 Market Rules

The implementation of the market at its various stages will require a set of market rules and codes. These are likely to cover the following topics:

- Market members agreement between the countries covering broad principles of market operation. These rules and principles should build on those already established and agreed in other relevant international agreements especially the Energy Protocol and GATT/WTO rules.

- Eligibility criteria for a market trader.
- Technical rules for market operation. These could, as a minimum, be simply common Operating Rules (e.g. conform to UCTE rules) and will be expected to cover requirements for system reliability and security (e.g. capacity reserve requirements, operating standards).
- Rules governing contracts (rules may be required to specify eligible contract types and minimum standard conditions in bilateral contracts and PPAs, in order to satisfy the technical requirements. However, it is also possible that no such restrictions may need to be imposed).
- Access conditions to member countries' transmission systems.
- Regulation of transmission costs and transmission charges.
- Requirement to exchange market information between the traders, national system operators and regional market co-ordinator.
- Exchange of information and procedures for planning and coordinated system expansion.
- Rules for operating the market broker system, including bidding rules, bid matching rules.
- Criteria for resolving transmission constraints, allocating contracts to transmission capacity and stopping transactions due to emergency conditions.
- Settlement rules for market transactions, including disclosure of relevant contract information, resolution of measured technical data, credit requirements, guarantees and securities, currencies, taxes.
- Dispute resolution procedures.

A number of separate documents must be developed to set out all specifications of rules and codes. The overall functioning of the regional market should be summarised in a ***market operations manual*** which explains the total operation of the market, its structure, types of contract trading permitted, rules for membership, and the relationship of the various contracts and agreements. It will also set out the procedures for modifying and adapting the market rules over time. Such a manual will assist all parties in understanding how the market works and will also assist the participants in training their staff. Membership of the market will be conditional on signing a market operation agreement to accept the principles of the market as set out in the market operations manual.

3.2.3.3 System Operational Rules – Grid Codes

The more detailed rules and codes will be set out in a second level of documents which will be subject to periodic (possibly frequent) revisions. There are likely to be at least two documents.

The system operational rules could be in the form of a **regional level grid code** which should, in turn, be incorporated into the national system grid codes. This will cover dispatch rules, access conditions, as well as information disclosure requirements. The pricing and settlement rules will be in the form of bilateral contract terms (for long term trades) and a multilateral (pool) agreement (for short term trades). Another part of the pricing rules will be the transmission pricing agreement.

The National System Grid Codes gather all the rules used to operate in real time the transmission system and the guidelines used to prepare the operation for the coming days.

The commissioning of an international interconnection affects the operation of the power system. It is necessary to adapt and modify the National System Grid Code of the interconnected systems to prepare the operation of the interconnection itself and to clarify the information to be exchange between the different control centres.

No formal national system grid codes have been developed by the three countries. So, some years before the commissioning date, it is necessary to set a working group, including a technical team and a commercial team, in charge of developing a regional system grid code for the three countries. The task of the working group will be fed by the experience of Egypt in the operation of the interconnections with Jordan and Libya. This task will also be based on the previous adaptation of the existing practices of Ethiopia and Sudan performed for the commissioning of the 220 kV interconnection link between Gonder and Gedaref.

The commissioning and the operation of an international interconnection concern two parts of a grid code, a technical part and a commercial part.

➢ Technical part

The following points must be assessed and reviewed by the technical team.

- Operation of the interconnection link:
    - Selection of compatible Electronic Technology (ET) for measurement and data exchange.
    - Agreement concerning the language for communication between the Control Centres.
    - Agreement concerning the time reference
    - Agreement concerning the voltage control on the border substations and the reactive flows on the interconnection link.
- Preparation of the operation of the interconnection link:
    - Mutual training of the control centre staff in particular of the shift operators.
    - Coordination of the maintenance planning of the interconnection link and of the vicinity network equipment close to the border substations
    - Coordination of Network expansion in the vicinity of the border substations.
    - Coordination about network studies and exchange of data.
    - Agreement concerning the post mortem analysis, period, type and volume of data...
- Operation of the interconnected system:
    - Agreement concerning the primary reserve, amount and sharing between the three countries.

- Elaboration of a common defence plan, including a common load shedding scheme.
- Agreement concerning the time adjustment.
- Implementation of Automatic Generation Control (AGC) in the three countries with common rules for the calculation of the secondary reserve.

➢ Commercial part

The following points must be assessed and reviewed by the commercial team taking into account the different contracts between the three parties (long term contract, short term contract, economy energy contract).

- Agreement concerning the metering equipment.
- Agreement concerning the billing and settlement.
- Agreement concerning the transit fees and the inadvertent energy compensation.
- Agreement about the procedure to announce the type of the contract.

A sample of common Operating Guidelines is provided on Appendix 2 (SAPP Operating Guidelines).

The documented market design details should serve as the basis for testing through simulation of the market. A simulation should be conducted in real time and continued in parallel with actual operation of the existing regional system. This will help to identify and resolve problems before they arise. It can also be part of the training activities for market participants.

3.2.3.4 Market Institutions and their Role

The proposed solution requires the creation of a Regional Market Co-ordinator (RMC) and a Regional Energy Broker (REB). We assume in the following part of the Module that these entities will be set up under the East African Power Pool Organization. These will be administrative bodies and since these will be responsible for running two parts of the same market, they need not be totally separate organisations. For example, the REB could be a department of the RMC whose functions are carried out by the EAPP Permanent Secretary.

EAPP Management Structure

According to the EAPP Inter-Governmental and Inter-Utility MOUs (Refer to Appendix 1 and 2 of Volume 5), the EAPP Management Structure is composed of the Ministers Conference, the Steering Committee, the Independent Regulatory Board and the Permanent Secretary with Technical Sub-committees and a Coordination (& Information) Centre.

The EAPP ***Management Structure*** will have the following functions and features:

- Sets overall policy for the aims, development and operation of the market;
- Approves the rules and codes proposed by the RMC (EAPP Permanent Secretary) and their subsequent modification;
- Approves the membership of traders;
- Investigates complaints and negotiates disputes between traders, and between the market and member countries;
- Approves changes in market membership;
- Approves any exceptions from the rules;
- Creates the statutes for the organisation and operation of the RMC (EAPP Permanent Secretary) and REB;
- Investigates causes of anti-competitive behaviour of the market or unexpected operation.

The EAPP Management Structure is an important body for ensuring successful implementation and development of the market. Careful consideration should be given to its membership and decision making procedures to ensure that it is able to balance the conflicting interest and pressures of the market members and the ultimate consumers. Experience in other markets has shown that simple representative bodies with majority voting and/or veto rights can hamper the evolution of the market as there will undoubtedly be the need for continual (and sometimes radical) revision of the rules and procedures.

The EAPP Management Structure will oversee the design of the market during the transitional stages leading up to its first establishment. Because the regional market will involve participation by the countries, they should be well represented during the development of detailed design and implementation. Unless these potential market participants believe that the trading arrangements are appropriate for their interests, the market is not likely to be successful. However, independent members will bring a broader perspective and help to overcome conflicts of interest in market design, once the overall objectives and principles have been agreed by the member countries.

The EAPP Management Structure will, at an early stage, need to settle logistical issues concerning the market institutions.

The EAPP Permanent Secretary and the Coordination & Information Centre and the future REB will share a common location, at least initially, since this will minimise the cost of setting up communication and co-ordination functions. This location will be decided by the EAPP Management Structure. We would also propose that the institutions adopt English as the common language and all settlements are carried out in a common currency (eg the Euro or $).

The EAPP Permanent Secretary [RMC]

The EAPP Permanent Secretariat will provide overall information co-ordination, supervision and management of the regional market. Working under the policy and direction of the EAPP Steering Committee, the EAPP Permanent Secretariat:

- Proposes the market rules and rule changes to the Management Committee;
- Administers the rules;
- Deals with standardisation issues such as training of technical staff, communication standards;
- Prepares all documentation and manuals on the market rules and codes;
- Facilitates bilateral contract trading by:
  - Determining the minimum set of common rules (if any) for contracts;
  - Coordinating exchange of information and maintaining central database on electricity balances and expansion plans;
  - Maintains a bulletin board of energy requirements;
  - Co-ordinates information exchange between traders and system operators on physical obligations in contracts;
  - Maintains information on available capacities in transmission lines.
- Monitors compliance of members with overall market rules;
- Promotes the use of transmission for regional trading by:
  - Particular attention to rules of transmission access;
  - Developing proposals for transmission pricing;
  - Coordinating transmission expansion plans.
- Develops procedures and mechanisms for dispute resolution;
- Provides a secretariat for the Management Committee.

To carry out these functions, the EAPP Permanent Secretariat will establish a number of specialist departments. These include:

- **Technical Sub-Committees**. The technical sub-committees will work closely with national SOs in a monitoring (but not operational) role. National SOs will retain their full responsibility for ensuring reliability and security of their own systems, but the technical sub-committees will monitor conditions for the security and reliability of the whole regional system including co-ordination of emergency procedures and maintenance programmes. It will also be responsible for information exchanges covering long term planning and short term provision of market information to SOs, monitor compliance with operational rules.

We suggest that they also include:

- **Commercial and market development sub-committees** responsible for pricing rules (especially transmission), trade and market development, and settlement procedures.
- **Legal and regulation sub-committees** responsible for issuing market rules and codes, contract terms, and dispute resolution.

In the early stages of the market, the functions of the EAPP Permanent Secretariat are an extension of the close collaboration between Sos, which currently takes place in connection with inter-country electricity exchanges and co-ordination of measures for ensuring system reliability and control. It is possible that the functions could be fulfilled without the need to establish a new centralised and permanent body, so long as trading is mainly or exclusively occurring between single traders (i.e. SOs) in each country, and relations can be built on existing institutions.

As the market moves to more advanced trading between multiple traders, there is likely to be a stronger requirement to create a permanent body. Whether such a body will need to be based at a single centralised location should be examined at the time. A major concern will be the need to implement secure and robust communication systems for exchanging market information. This will be implemented within the EAPP Coordination and Information Centre. Its location, technical and financial requirements for its implementation and operation with the national control centres of the member countries will be elaborated and decided by the EAPP Management Structure.

Regional Energy Broker (REB)

The REB will not necessarily be required to be set up at the first stage, since the bilateral contract market may operate for some time before the energy broker system is implemented. When it is set up, it may be separate or function as a department of the RMC (provided the RMC is itself an independent body). Its functions will be:

- Detailed design of the short term market and proposal of spot market rules;
- Ensure the availability of software, communication and other information and computer systems necessary to support the market operations;
- Operating the energy broker market (which may change over stages from a bulleting board, to a cost-based broker system, to a price-based bidding system), including determining transactions, transaction prices and distributing transaction information to the national SOs and the settlement body;
- Calculating information required for market settlement.

In order to ensure efficient and non-discriminatory operation of the market, the REB should be an independent body charged with ensuring efficient operation of the market as a whole, and should have very close ties with the national SOs in order to exchange market information rapidly.

3.2.3.5 Implementation Plan

A feasibility study concerning the above three aspects of the Regional Electricity Market development (conceptual design and stages of development, market rules, and market institutions) will need to be elaborated and formed into a timetabled set of actions. Early meetings of the EAPP Management Structure are therefore likely to be concerned with decisions to approve the conceptual market design, carry out the feasibility study, and approve the implementation plan prior to setting up the permanent market institutions.

Once the detailed market design stage commences, a standing sub-committee of the EAPP Permanent Secretariat (RMC) will prepare the market rules and codes.

The EAPP Permanent Secretariat is or will be established as a permanent body in Addis Abeba – Ethiopia. The REB will be established when it is decided to create the regional short term market. The market supervision role of the EAPP Permanent Secretariat will include the need to develop and coordinate the market rules and ensure satisfactory standards and infrastructure for communication systems within the region.

The three proposed stages are indicative and may be changed. A flexible approach should be taken towards the formation of regional institutions, in order to respond to changing circumstances in national markets without creating unnecessary centralised bureaucratic structures.

4. HYDROPOWER DEVELOPMENT: THE FINANCING CHALLENGE

4.1 THE CHALLENGE

Lack of finance is often put forward as one of the main factors hindering the development of sustainable hydropower projects.

This is particularly the case in many African countries where public funds are scarce and private investors and lenders tend to consider that the relative country risk is high. Indeed, securing the finance for a large hydro project has proven be a daunting task in many instances. On a worldwide scale, it is estimated that to harness most of the remaining realistic hydro potential during the 21st century will require sustainable funding of 10 to 20 $billion per year.

For Africa alone, where more than 90 % of the realistic potential remains to be exploited, this would mean more than 2 $billion per year to be mobilized.

In order to tackle such a challenge, all sources of funds are needed, whether public or private, and all avenues that could possibly ease the financial burden must be explored.

4.2 COMBINING PUBLIC AND PRIVATE FUNDS

Hydropower projects are fundamentally of a public nature, in the sense that they exploit the natural potential offered by the land and water resources of the country. They bring about political benefits such as reduced import dependency. Even more important is the fact that they are long-term infrastructure projects, which can provide a unique role in the global development of the country. For instance, what would be today the economic situation of Norway, New Zealand, or the Canadian province of Quebec if their hydro potential would have been left untapped?

This explains why the vast majority of existing hydro schemes have been developed under the traditional model of a utility (either public or, if not, closely regulated) or a governmental agency managing the various phases of the project life cycle: planning, design, construction, operation, as well as rehabilitation and upgrading when the time comes. Therefore, existing hydro projects have been largely funded by public resources, drawing on multilateral or bilateral aid when needed.

Even though cost overrun and schedule delays have been observed, the World Commission on Dams report acknowledges that 'cost recovery has not been a substantial problem for hydropower projects'. Indeed, the well-known long-term benefits of hydro (practically indefinite service life, extremely low operating costs, highly sustainable and reliable performance, substantial GHG emissions avoided, etc.) often made hydro the preferred option when the public sector was entrusted with the task of developing generation facilities.

Undoubtedly, those involved in this undertaking were conscientiously working with the aim to provide wealth to future generations, above and beyond the short-term return on their investment.

However, the scarcity of public funds and the shift to a deregulated power industry has created a different scene for hydro development. In the 90's, it was expected that the private sector would step in and that the public sector would simply set the rules and sit back, relying on market mechanisms for projects to be developed, funded, constructed and operated. In the case of hydro (but, more surprisingly, to a large extent also in the case of thermal) this has proven to be an unrealistic expectation. Even though a few success stories of purely private hydro development have been recorded, most recent hydro projects, especially large ones, have continued to rely on public funds, while many others have been dramatically delayed, with serious negative implications in terms of sustainable development and climate change.

Those funding difficulties are not the result of reduced benefits. On the contrary:

- In new deregulated markets, existing hydro is demonstrating more than ever its unique value in terms of flexibility and reliability, and storage (or pumped-storage) is offering the owner the possibility of optimising generation in line with real time market conditions.
- Hydro is the most industrially mature and commercially viable contributor to achieve the goals of the 2002 implementation plan of the World Summit on Sustainable Development regarding the urgent need to increase the share of renewable energy in the world energy mix (item 19e). Here again, its storage ability represents the necessary back up that other renewable sources need.

There are 3 main reasons why hydro has not been much favoured by the private sector when it comes to developing new generation projects:

i. Hydro projects don't usually get full credit for all their benefits. In addition to the mere generation of kWh, they contribute significant ancillary services to the power systems (black start, spinning reserve, synchronous condenser, steady state operation of thermal units etc.), which rarely get a fair recognition, if any. Moreover, most hydro projects offer important non-power benefits such as flood control, recreation, fishing opportunities, irrigation, and water supply. Most of those are not easily marketable products and don't bring revenues to private developers.

   Last but not least, despite its key role in reducing global warming, up to now hydro has hardly benefited from any environmental premium in the market.

ii. A hydro project selected as a 'best option' on economic, social and environmental grounds (for instance in the framework of a least-cost development plan) cannot be readily transformed into a viable financial product.

This gap between economic and financial viability reflects the divorce between long-term and short-term interests: over the project's lifetime, and provided that reasonable discount rates are being used, hydro has excellent payback levels thanks to the high amounts of energy generated and services rendered to the system, compared to the discounted construction and operation costs.

Nevertheless, the rather high initial investment costs require high revenues in the first 10 to 15 years to satisfy the lenders' debt coverage ratio, and the corresponding tariff structure may not be easily accommodated by market conditions (where, in some cases, prices are driven to the low range by existing hydropower plants which have been in operation for decades, and are therefore fully depreciated!).

iii. The risk profile of hydro, which is perceived as very high by private investors, is acting as a deterrent or at least leading to unrealistically high expectations in terms of Internal Rate of Return (IRR). Here again, there is obviously a short-term/long-term issue. Most of the risks associated with hydro projects can materialize either during the development phase or the construction phase. But, once those crucial phases have been passed, most hydro projects enjoy a very long and virtually risk-free life, while their thermal competitors will still have to face a much more rapid aging process and fuel price variations largely driven by political uncertainties, which can exceed the hydrological risk of most hydro projects.

For those reasons, it is likely that hydro projects developed exclusively by the private sector will remain the exception and will concern projects with a low risk profile and readily marketable benefits.

On the other hand, there is room and need for private involvement in partnership with the public sector in hydro projects where an acceptable balance between risks and rewards can be achieved between the various stakeholders. A possible arrangement for such a Public-Private Partnership (PPP) can be designed along the following principles:

- The public sector takes responsibility for those works that utilize natural elements to create storage and potential for generation (for instance the dam) while the private sector is in charge of developing this potential by investing in the power plant.
- The public sector takes natural risks such as the hydrological risk, and the private investor is held responsible for plant performance.
- The public sector puts in place the necessary tools and mechanisms to flatten the tariff profile in the early years (for instance through a specific energy fund), while the private investor pays higher royalties after debt repayment (which can be used to replenish the energy fund for other projects).

Through this combination of public and private funds and sharing of risks a win-win situation can be created:

- The Public Sector does achieve debt reduction, is in a better position to control issues of national interest such as safety, water rights, resettlement and gets full ownership of relatively new hydro at the end of the concession period. It is also a chance for the public sector to promote competition and market discipline, and to stimulate a dynamic and innovative local industry.
- The Private Sector gets access to the project with an acceptable level of risk, can provide efficient funding and add industrial value whilst getting rewarded for its performance.

If a climate of mutual confidence can be created, it will generate a higher attractiveness for the private sector, which in turn will result in increased competition and ultimately lower electricity prices.

At a time where large private power operators have learnt the lessons of the ‘Enron days’, are keen to ensure asset-based revenues and recognize the need to manage profit and risks across a diversified project portfolio, particularly the need to hedge fuel price risks, there might be a new chance for involving the private sector in the funding of hydro projects in a more realistic way.

But, in all cases, it must be kept in mind that any private investor always has the choice to put his money on another project. A hydro project will attract a serious and competent private investor, within the framework of a Public-Private-Partnership, only if the risk issue can be properly solved.

4.3 SOLVING THE RISK ISSUE

In order for investors and lenders to be willing to engage in the funding of a hydro project, it is essential that:

- All risks be properly identified and as much as possible quantified,
- All efforts be made to reduce or mitigate them,
- All residual risks be properly allocated and managed.

The main risks associated with hydro projects that may arise:

- During the development period if financial closure is not reached and development costs are lost,
- During the construction period if the project is not completed according to schedule, within the budget and with the required performance,
- During the operation period, if for any reason the project is unable to generate revenues in accordance with the assumptions made in the financial model or must bear higher operating costs.
- At any point in time under the effect of events beyond the control of any party to the various project agreements, including Force Majeure events.

  The development costs for a hydro project are definitely on the high side (typically between 10 and 100 M$ for a major project involving the creation of a large reservoir). This is due in particular to the fact that each project is site specific and therefore will require extensive technical and environmental studies, and also to the number and complexity of the agreements to be put in place.

Very few investors, if any, will be ready for that kind of expense, even if they have entered the project on a negotiated basis, while they remain exposed to a significant risk of the project never being signed.

For those reasons:

(i) A hydro project should be undertaken only after a full assessment of the options, which should be the prime responsibility of the host government, in order to firm up its status as the best choice to meet the demand.

(ii) NGOs, affected people and representatives of the main beneficiaries should be engaged in a transparent consultation process as early as possible, so that potential social or environmental difficulties be addressed in due time, thus reducing the risk of stopping the project when large development costs have already been spent.

(iii) The host government should be strongly involved in the funding of studies (technical and environmental) and site investigations during the project preparation phase, either directly or with the help of Multilateral Financial Institutions (MFIs). These costs can eventually be recovered from the private investor group selected to implement the project at a later stage. At any rate, it should also be emphasized that defining the main characteristics of the project (general layout, installed capacity, size of reservoir, etc.) is a responsibility that should not be left to any private party, as it involves the long-term utilization of a country's natural resources which must be examined on the basis of social, environmental and economic (not financial) optimization, and the host country will inherit the project at the end of the concession period.

Regarding construction, over the past decade there has been a definite trend to move towards turnkey or EPC-type contracts (Engineering – Procurement – Construction), where most, if not all, of the risks associated with design and construction are under a single point of responsibility, namely the EPC contractor.

Such an arrangement is almost standard for privately developed projects, since it is often required by the lenders in an attempt to reach maximum clarity in the allocation of responsibilities. But EPC contracts have also been considered by some public owners, especially after experiencing delays and cost overruns on previous projects.

Indeed, it can be quite tempting for any owner to push all the construction risks on to the contractor and give him full responsibility for overall construction management. But that same owner should not delude himself about the fact that:

(i) Any serious and reputable contractor will only accept to bear those risks that he can actually manage or be insured for. This may not be the case for all construction risks, for instance unforeseen ground conditions.

(ii) The contractor will include in his price a provision for risk, which the owner will have to pay for even if the project is constructed smoothly without significant risk materializing.

(iii) Even then, only financially strong contractors will be able to take such risks. That may not be the case for local contractors, who would be in the best position to construct the project, especially the civil works, with payments in local currency. Large international equipment suppliers are often reluctant to take a joint and several liabilities with such local civil contractors.

As a result of the above, it appears that the full turnkey approach, largely derived from thermal project practice, should be carefully qualified when applied to hydro projects. While the overall pattern may work, the owner, and possibly the host government in case of a private project, will generally find it to their own interest to retain some construction risks, including for instance all or part of the geological risks, or specific adverse events such as leakage of the reservoir outside the work area, unexploded war objects, unavailability of transmission line at the time of commissioning, political or social turmoil during construction, floods beyond a certain discharge, etc

When the owner has its own proven capacity in construction management and the necessary financial strength, substantial savings can be obtained by accepting to bear the risk of overall completion by coordinating a number of construction packages, possibly at the cost of giving up the sacrosanct project financing approach.

During the operation period, the main risk to be addressed is the water supply risk.

Whether for public or private projects, it is essential that hydrological conditions be extensively studied at the feasibility stage, and as much as possible based on long term rainfall and discharge records, so as to get a robust estimate of the average annual flow, its distribution over the year and a statistical knowledge of inter-annual variations. The only realistic way to handle the risk of such hydrological variations is to pool it within a larger portfolio of projects in order to dilute its impact. A single project company, which is a frequent case for an Independent Power Producer (IPP), is not able to do that.

Therefore, in the case of a private project, engaging in a Power Purchase Agreement (PPA) with a utility, the payment mechanism put in place in the agreement between the owner and the purchaser of the electricity must attenuate the inter-annual variations of project revenues and mitigate the impact of dry years.

It may be of mutual interest to both the owner and the off-taker to depart from the traditional format of a thermal PPA and elaborate a remuneration mechanism mostly based on capacity charge, or even a “lease” payment, where revenues would be guaranteed to the owner provided that he keeps the plant available, while the off-taker would gain the freedom to use the plant and dispatch generation to best meet his real-time needs. Obviously, this model would be particularly appropriate in the case of a pumped-storage plant.

The host government can also play a role by putting in place special “energy funds”, to which hydro plant owners can be required to contribute when they receive wet year extra revenues, while being compensated for dry years through that same fund. MFIs can assist in the development and implementation of such funds.

In all cases, revenue stability is a key component of a hydro project’s bank ability. This revenue stability is also ensured by:

(i) Obtaining from the host government the necessary guarantees regarding the consequences of an eventual construction of any other dam or irrigation project that could artificially impact the flow regime.

(ii) Entrusting Operation and Maintenance (O&M) responsibility to an experienced operator. If this operator is also a member of the ownership company, he will naturally be motivated to secure the performance level of the plant over the whole concession period. If not, some incentive mechanism has to be included in the O&M contract.

(iii) Strictly complying with all social and environmental commitments made at the time of project development and construction throughout the life of the project. This is an absolute prerequisite for building up a long-term partnership with the local population and NGOs, which is the basis for a sustainable positive climate around the project.

The other risks to be dealt with are probably less specific to hydro projects and would have to be addressed for most large infrastructure projects. They include:

- Commercial risks.
- Regulatory risks, such as change in laws.
- Macro-economic risks, such as local currency, devaluation, inflation or interest rates increase.
- Political risks, such as political violence, expropriation or convertibility.
- Natural Force Majeure events.

The above risks can hardly be assumed by a private investor or a commercial lender. Therefore, those risks must be taken on by other key stakeholders, including:

- The host government, which is chiefly responsible for creating the proper legal and institutional environment in which developers will feel reasonably protected,
- The Multilateral Financing Institutions (MFIs) and especially the World Bank Group, which can help in different ways: by lending to the project while taking political risk, by providing Partial Risk Guarantee (PRG) products or political risk insurance cover (from MIGA for instance).
- Export Credit Agencies (ECAs), which can cover part of the commercial risk.

The MFIs (such as the World Bank or the African Development Bank) have an essential role to play in providing risk mitigation and therefore in stimulating the involvement of the private capital in countries or sector with perceived high risks.

4.4 THE CRUCIAL ROLE OF MFIS

Many developing countries, especially the poorest ones, do not have the necessary resources, whether human or financial, that are required from the public sector either to develop a project on their own or to make a successful public-private partnership happen. The MFIs have an essential role in filling this gap by providing technical and financial assistance to their developing member countries. This assistance is needed on 3 different grounds:

(i) MFIs should help to ‘set the scene’:

- Assist governments in creating an attractive environment for the private sector
- Mobilize grant assistance for capacity building
- Support base-line studies
- Encourage development of local capital market
- Set the tone for other lenders

- Promote trans-boundary and regional opportunities
- Collaborate with professional organizations in progressing hydropower sustainability

(ii) MFIs should help to prepare and develop projects:

- Assist in setting up a realistic option assessment process
- Fund feasibility studies
- Contribute to simplify and standardize documentation to make projects easier to close

(iii) MFIs should contribute directly to solve the financial challenge:

- Provide loans which attune with the creation of long-term infrastructure assets
- Lend more at decentralized level
- Provide insurance and guarantees for risks that neither the private sector nor the government can handle
- Provide refinancing facilities to allow commercial banks to extend loan tenors
- Assist government authorities in raising their share of equity
- Mobilize international co-financing

There are some good news regarding this necessary involvement of the MFIs:

- After a decade of declined support to water infrastructures in general and hydro projects in particular, the World Bank adopted in February 2003 a Water Resources Strategy that commits the World Bank to re-engage with such projects, considering that all hydropower projects are providers of renewable energy, regardless of scale.
- During the Bonn conference on Renewables in 2004, the World Bank Group committed to increase its funding for renewable energy – including hydropower – by an average of 20 % a year over the next 5 years.
- In 2005, the World Bank has officially decided to support the construction of the 1070 MW Nam Theun 2 project in Laos, which is the largest private sector hydro project financing to date, and one of the largest internationally financed IPPs in Asia since the 1997 financial crisis. The World Bank group is now involved in about 20 hydropower–related operations.

4.5 EASING THE FINANCIAL BURDEN

Reducing the need for capital and/or increasing the project revenues is another key step towards solving the financing challenge.

Avenues for easing the financial burden include:

(i) Cost reduction

Development costs can be reduced if standard documentation is developed and a rational step-by-step approach is adopted.

Excellent project preparation, including proper site investigations, imaginative design and value engineering are important factors in reducing construction costs and uncertainties. It should be stressed again than EPC or turnkey contracts may not always be the cheapest contractual approach for constructing a hydro project. In most cases, however ensuring fair and transparent competition among contractors and equipment suppliers, as well as top of the line project management can help minimize the final construction cost.

Operation and Maintenance costs, even through a relatively modest component of the overall cost of a hydro project, can be efficiently optimized by implementation of modern techniques.

(ii) Local involvement in construction

The funds needed for construction should ideally be borrowed in the same currency as the future revenue stream in order to minimize devaluation concern. In turn, it means that there is a clear advantage in utilizing local or regional resources for the construction of the project. Hydro projects often offer such possibility, since the amount of imported equipment is often comparatively lower than for thermal projects. In particular local or regional contractors can be mobilized at an attractive price for the construction of the civil works, possibly as partners or subcontractors of larger international firms. The Concession Agreement may stipulate an obligation for ‘local preference’, but it must be kept in mind that such a clause must remain realistic and consistent with the actual availability of proper local resources. Development of local capital market also needs to be favoured.

(iii) Identification and valuation of all benefits

Efforts should be made to provide financial reward for the many benefits that hydro projects bring about in addition to the mere generation of electricity. This includes other services rendered to the power system (dynamic benefits), but also social and environmental benefits such as improvement of roads and bridges, recreational activities, local or regional job opportunities, flood protection, water supply, irrigation, fishery, navigation, etc.

Not all of those benefits are easily marketable but all efforts should be made to internalize them in the economic analysis when setting up investment priorities. Political benefits such as reduced import dependency should also be taken into account.

(iv) Carbon credits

A specific example of environmental benefits generated by hydro projects is the reduction of GHG emissions. The current payments made under the nascent carbon emission market are about 20 euros/ton CO2 equivalent. Up to now, only small, run-of-river hydro projects have had access to Carbon Finance under the Kyoto Mechanisms (CDM and JI). The deals have been concluded on a basis of approximately 5 USD/ton CO2 equivalent resulting in increase revenues in the range of 5 to 10 %, in other words ‘a sweetener not a honey pot’ (J. Plummer). The somewhat theoretical restriction imposed by the UNFCC that projects have to be ‘additional’ to what would have happened anyway, is currently hindering the implementation of CDM and JI for hydro projects, along with the issue of methane emissions by large reservoirs in tropical areas. The IHA (International Hydropower Association) is currently working with other key partners in order to progress on solving those various issues. Should those efforts be successful, the environmental value of the investment (carbon credits) could become a more systematic complement of the traditional electricity scale.

(v) Staged development

Hydro project may often be constructed in several phases, and planned as such from the start. This brings the obvious advantage of better matching the evolution of the electricity demand over time. It can also greatly reduce the need for external, funds, as the revenues from the early phases of the project may be a significant source of finance for the construction of the subsequent stages. This approach has been applied with success for large projects such as Three Gorges in China, for cascade schemes and for rehabilitation projects.

(vi) Rehabilitation and Uprating (R&U)

The lifetime of hydro projects can be extended almost indefinitely if they are properly maintained and provided that rehabilitation is undertaken at the adequate time. Rehabilitation projects are often an opportunity to increase the performance of the original scheme and modify its characteristics in order to better respond to changing needs.

Improved performance is often obtained at a reduced cost compared to a totally new project. The associated risk profile is usually very favorable, including a nominal environmental footprint. In 2004, the World Bank entrusted Electricité de France with the task of elaborating a Framework for Policy and Decision-Making on Dam and Hydro Plant Rehabilitation and Uprating, which is now available for decision-makers when engaging in such projects.

(vii) Longer repayment terms

Hydro projects require relatively high upfront investment costs but deliver a sustainable attractive cash flow in the long term. Therefore long repayment periods can be decisive for the financial viability of a hydro project. OECD has recently decided to expand the allowed loan tenors from 12 to 15 years for renewable energy projects. It was confirmed in November 2005 that this applies to all hydro projects developed according to proper sustainability principles.

4.6 CONCLUSION:

Hydropower development has a long story to tell. As one of the oldest industrial sources of electricity it has gone through a number of challenges. For many years, technical challenges were tremendous, but almost exclusively technical. They were successfully tackled by calling upon engineers' talent.

Then came the increased awareness regarding environmental and social issues. Lessons had to be learnt from success and mistakes, sometimes in a harsh way, and there is now definite hope that improved decision-making processes will take place, based in particular on the International Hydropower Association (IHA) Sustainability Guidelines.

Today, hydropower projects are facing another major challenge: how to fill the gap between economic and financial viability in a short-term oriented, deregulated power market?

It is becoming more and more obvious that the private sector alone cannot provide the answer. The very essence of hydropower benefits leaves no choice but to bring the pendulum between public and private involvement into a more balanced position compared to the situation experienced during the last decade.

That requires governments to play a very active role in this challenge and Multilateral Financing Institutions to act as a catalyst for public-private partnership.

As the world is becoming every day more aware of the need to develop low-emission energy sources, hydropower is certainly entering into a new era. With its vast untapped hydro potential, Africa is in a position to be at the forefront of this process.

APPENDIX 1:

OVERVIEW OF THE AFRICAN REGIONAL ELECTRICITY ORGANIZATIONS

BACKGROUND

As already mentioned, there are many reasons for not applying the interconnection experience of the industrialized countries directly to developing countries. It is not difficult to comprehend that, both in concept and design as well as within the framework of a profitability analysis, the standards that must be applied to developing countries are completely different from those of deregulating, industrialized countries.

In terms of network integration, the industrialized countries have so far promoted the interconnection of power transmission networks with different objectives linked to geography, resources, economy and scale characteristics. Nevertheless, the various interconnection patterns can serve as a reference for the regions intending to promote system interconnection as they proceed to make institutional and technical choices.

The economic and system reliability benefits of effective regional arrangements for trading electricity, especially power pools, have long been recognized, and proven, in interconnected intersystem markets in North America and Europe.

These benefits have been identified as providing special additional advantaged in developing regions such as Southern /Central and Western Africa, the Mekong Region of Southeast Asia, the former Soviet subsystem in the five Central Asia republics, Northeast Asia, Central America and South America.

There is already, in other African regions, significant experience in the development and implementation of regional trading arrangements in the context of multi-party international arrangements. Indeed, arrangements such as SAPP in Southern/Central Africa, WAPP in Western Africa, have already ventured into developing functioning power pools in genuine multi-country contexts. This is an advance beyond the power pool developments in North America. There, power pools are either internal to a US state (e.g. Texas), or to a country (e.g. Canada), or (as in most cases) multi-state but essentially within the US and subject to the jurisdiction of the US Federal Energy Regulatory Commission (FERC). No effort has been made to create an inter-country supervisory entity in North America, e.g. under the energy provisions of the North America Free Trade Agreement (NAFTA).

In Europe, too, the development towards inter-country power pools has been seriously constrained by the reluctance of governments and power systems to yield sovereignty and by the “principle of subsidiarity” that limits the ability to develop EU-wide supervisory or regulatory institutions.

Hence, while there is a wealth of information on the evolution of pooling arrangements in both Europe and North America, the priority focus of research consists in establishing multi-national pooling/regional market arrangements in the developing regions cited above. While most of these arrangements are still in very embryonic stages of development, there has already been some significant analysis and resulting dialogues in some of them. In at least one (SAPP – Southern African Power Pool), moreover, there has already been significant experience in the initial development of the power pool itself and of the related institutions and some experience in their operations. WAPP (Western Africa Power Pool) follows similar tracks.

The ensuing analysis will focus on the challenges of establishing a functioning power pool in a multi-national context and of a pool between systems with huge disparities in size and capabilities and, in many cases, limited interconnection between them. ENTRO RPT is dominated by country systems in various stages of development. Moreover, in most cases, these systems face serious current challenges to ensure adequacy of power supply for economic growth and adequate investment – both domestic and foreign – to achieve it.

We will therefore focus on analysing these efforts in other African developing regions (SAPP and WAPP) and attempting to derive from them an assessment of the implementation challenges that will face ENTRO RPT, and to the extent we will so indicate, possible options or directions for the ENTRO RPT. We will identify feasible options for moving forward on each of the issues that will probably face ENTRO and its member countries in establishing the Regional Power Trade structure.

1. SAPP – SOUTHERN AFRICAN POWER POOL

1.1 Background

Historically electricity trading in Southern Africa started in the early 1960 as bilateral trade after the commissioning of the Kariba Hydro Power Station situated on the border between Zambia and Zimbabwe. The great hydro potential of the Zambezi River gave rise to the commissioning of more plants. This saw the extension and more bilateral electricity trading arrangements being put in place.

The Southern African Power Pool (SAPP) was created in April 1995 through the SADC treaty and an Inter Governmental Memorandum of Understanding (IGMOU) to optimise the use of available energy resources in the region and support one another during emergencies. At the time of creation, the SADC governments agreed to allow their national power utilities to enter into the necessary agreements that regulate the establishment and operation of the SAPP.

Thereafter, the SADC Utilities signed an Inter Utility Memorandum of Understanding (IUMOU) in order to facilitate and develop power pooling and trade in the region. The SAPP comprises of 12 SADC Member States Utilities in exclusion of the utilities of the two SADC island states of Madagascar and Mauritius. It is funded by subscriptions paid by the member utilities. The SAPP Co-ordination Centre is based in Harare, Zimbabwe and SAPP operations are run through subcommittees.

The SAPP facilitates optimal utilization of regional hydro and thermal energy resources and reduces capital and operating costs through coordination.

1.2 SAPP Vision & Objectives

SAPP Vision:

- Facilitate the development of a competitive electricity market in the Southern African region.
- Give the end user a choice of electricity supply.
- Ensure that the Southern African region is the region of choice for investments by energy intensive users.
- Ensure sustainable energy developments through sound economic, environmental and social practices.

SAPP Objectives:

- Provide a forum for the development of a world class, robust, safe, efficient, reliable and stable interconnected electrical system in the southern African region.
- Co-ordinate and enforce common regional standards of Quality of Supply; measurement and monitoring of systems performance.
- Harmonise relationships between member utilities.
- Facilitate the development of regional expertise through training programmes and research.
- Increase power accessibility in rural communities.
- Implement strategies in support of sustainable development priorities.

SAPP Values:

- Respect for others and develop mutual trust
- Honesty, complete fairness and integrity in dealing with issues
- Selfless discharge of duties
- Full accountability to the organisation and its stakeholders
- Encourage openness and objectivity

1.3 SAPP Organisation

Four agreements govern the operation of SAPP, including bilateral trading. These agreements are:

1. The Inter-Governmental Memorandum of Understanding which enables the establishment of SAPP;
2. The Inter-Utility Memorandum of Understanding, which establishes SAPP's basic management and operating principles;
3. The Agreement Between Operating Members which establishes the specific rules of operation and pricing; and
4. The Operating Guidelines, which provide standards and operating guidelines.

The Pool is comprised of twelve SADC members' states of which nine are operating members. Angola, Malawi and Tanzania are non-operating members since they are not connected to the other SAPP countries.

All participating electricity enterprises must be situated in a country which was a member of SADC in September 1994. Originally, full membership was for national utilities only and was restricted to one per country as designated by the country's government.

SAPP members have signed the Inter-Utility Memorandum of Understanding and are entitled to participate in the Planning and Environmental Sub-Committee only. A key objective of the Planning Sub-Committee is to conduct all relevant studies to allow for the construction of interconnections with members who are still isolated from the main network. There are two categories of membership:

- Operating Members: Are members who are signatories of all principal documents governing SAPP and have their system interconnected internationally with at least one member. They are responsible for meeting all policy procedures guidelines established by SAPP
- Non-Operating Members: There are members who are signatories to only one SAPP Principle document Inter-Utility Memorandum of Understanding. They participate in all activities except those related to operation of the power pool.

Membership of non-SADC country utilities is subject to the approval by a two thirds majority of the SAPP Executive Committee before being forwarded tothe SADC Energy Ministers' Committee for ratification.

In April 2001, SAPP introduced the Short Term Energy Market (STEM) to complement the bilateral trade. The STEM facilitates contracts of periods up to a month long for the supply of electrical energy to individual customers and utilities.

To date nine countries are participating with the exception of Angola, Malawi and Tanzania. This market is now 5 % (approximately 144 - GWh per annum) of the total trade in SAPP in term of the volumes traded. The SAPP successfully opened the Coordination Centre in Harare in 2000. This is where central coordinating issues are carried out including the administering and management of the STEM.

SAPP is now developing a Spot Market with the assistance of NordPool Consulting through the funding from NORAD. Competitive trading arrangements are to be put in place. The mode of operation of the SAPP spot market has not yet been finalized, but it could take one of two recommended forms – power exchange or central dispatch with unit commitment. Each would have different impacts on billing and metering.

Major transmission constraints have been noted between Zimbabwe – Botswana and South Africa. This is due to the geographical locations of the countries where major trading is from South to North and vice versa depending on time of day. Utilities have entered into different peak and off peak contracts.

The Grand Inga site in the Democratic Republic of Congo (DRC) has got a hydro potential of close to 40 000 MW. It is the desire of the DRC to develop this site to its full potential for the benefit of Northern and Southern Africa. The realization of the interconnection of DRC to the Northern countries would mark the beginning of an interconnected African Grid. The Zambia – Tanzania – Kenya Interconnection would also facilitate the interconnection to Eastern Africa. Africa can utilize the diversity in resources and time differentials for the economic dispatch of the generating units.

The governance and membership of the SAPP was initially derived from the desire for economic co-operation, equitable sharing of resources and support of one another in times of crisis under the SADC protocol. The environment under which the power pool now operates has significantly changed warranting a review of the SAPP governance and membership criteria.

A Special Documentation Review Working Group (DRWG) was set up to review the SAPP documents [Inter-Governmental MOU (IGMOU) and the Inter-Utility MOU (IUMOU)] so as to considered admitting Independent Power Producers (IPP) and Independent Transmission Companies (ITC) into SAPP. The IGMOU establishing SAPP has been reviewed and was signed by the SADC Energy Ministers on 23rd March 2006.

The representation is now as follows:

- One representative from each operating member, one from each non-operating member, one from each ITC and one from each IPP.
- Each member will carry one vote.
- Chairmanship will be restricted to the CEOs from Government owned Power Utilities that are Operating Members.

The overall restructuring of SAPP is shown hereunder. The restructuring of SADC has necessitated this. Also as SAPP is moving towards competitive markets the Markets Sub-Committee has been introduced.

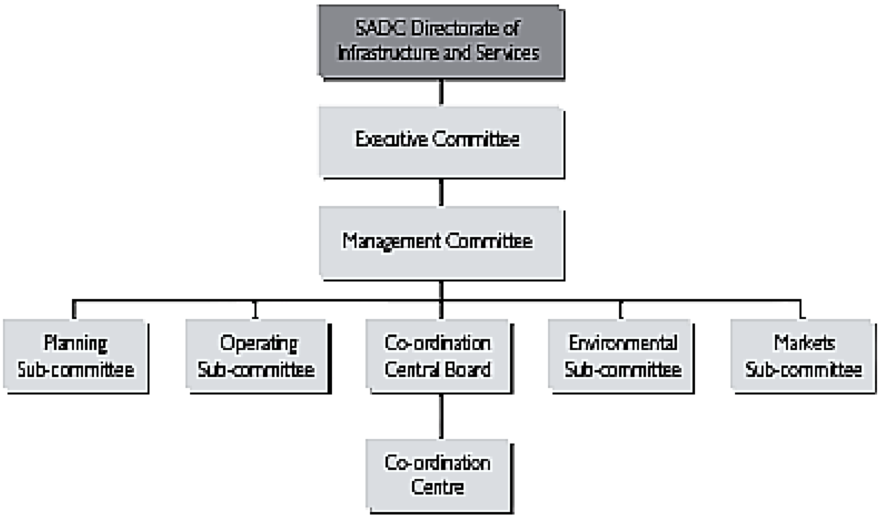


Figure 1. – Management Structure of SAPP

In addition to trade, the SAPP coordinates planning and operation of the interconnected regional power system and ensures system security and reliability.

The ongoing restructuring of utilities within the SAPP is meant to replace traditional monopolies with advanced market structures that favour competition, enhance efficiency and facilitate access at competitive tariffs (cost – reflective tariffs).

2. WAPP – WEST AFRICAN POWER POOL

2.1 Background

The ECOWAS (Economic Community of West African States) pursues objectives of promoting economic cooperation and integration in West Africa. Among others, Article 26 of the revised ECOWAS Treaty stresses importance of the need for regional industrial, scientific and technological cooperation in general and cooperation in the energy sector in particular.

In 1982, the Heads of States and Governments adopted decision A/DEC.3/5/82 relative to ECOWAS energy policy. In December 1999, after an energy crisis has lead to severe electric power shortages in the region, the Heads of States and Governments adopted decision A/DEC.5/12/99 aiming to establish a regional electricity market, the West African Power Pool (WAPP). This decision was consequent to the adoption of the Regulatory Prescription

(C/Reg.7/12/99) for the regional market design and preparation of a Master Plan of electricity generation and transmission development. In the same decision the Heads of States and Governments created a Steering Committee (SC) consisting of Energy Ministers to coordinate WAPP implementation process.

In addition, since 1992, the ECOWAS Executive Secretariat supported by the World Bank and the Italian Government initiated the Project of West Africa Gas Pipeline (WAGP). In December 1992, independent consultant Bain Cnueo & Associati completed a pre-feasibility study that recommended further project implementation. To this end, a Protocol of Understanding (PU) on natural gas was prepared and signed by beneficiary countries: Ghana, Togo, Benin and Nigeria. Participating countries signed the Protocol in September 1995. One of its provisions concerns the private sector involvement in the Project implementation. In 1997 a group consisting of Chevron Nigeria Ltd, NNPC, GNPC, SOTOGAZ, SOBEGAZ expressed an interest in realising the Project feasibility study.

In March 1999, a study financed by the group (Commercial Group) was performed by Pipeline Engineering GmbH, Germany. It produced recommendations with respect to the project's technical feasibility and financial viability. In August 1999, assisted by the ECOWAS, the four participating States approved the Commercial Group with Chevron Nigeria Ltd in the lead in the role of a Project promoter.

2.2 WAPP Objectives

The following are the objectives of the WAPP project:

- To institutionalise more formal and extensive regional co-operation in the development of cost-effective electricity infrastructure and energy trading networks in order to increase energy supply and enhance energy security within the region;
- To improve system reliability and power quality throughout the region;
- To lower system costs by:
  - increasing economic trading of both power and energy within the region;
  - optimising the utilisation of energy resources in the region, and
  - managing more effectively and efficiently the region's seasonal and weather-related imbalances;
- To reduce the overall amount of capital needed for system expansion in the region by promoting implementation of "bankable" projects on a least-cost basis;
- To create an investment environment for the region's power sector that will facilitate the financing of priority generation and transmission projects;
- To create an ongoing forum in which regional power issues can be discussed and worked out within an agreed-upon policy framework and set of operating principles;
- To create a transparent and reliable mechanism for the prompt settlement of commercial electricity transactions;

- To increase the overall level of electricity service within the region through the implementation of priority generation and transmission projects as the basis for economic development and the extension of paid-for electrical service to more consumers.

2.3 Organization Adopted for the WAPP implementation

To implement the WAPP Master Plan, as well as to examine and study thoroughly how to implement the regional electricity market, the Member States and the ECOWAS Executive Secretariat adopted the following organization:

- The WAPP Steering Committee composed of the Ministers in charge of Energy. The Steering Committee examines the recommendations of the Project Implementation Committee (PIC) and adopts the implementation programmes in each country.
- The WAPP Project Implementation Committee (PIC) composed of the Managing Directors of the Electricity Utilities. The PIC supervises and examines the conclusions of the WAPP Groups of Experts and formulates recommendations proposed to the Steering Committee for adoption.
- The WAPP Groups of Experts, Technical and Institutional, composed of Experts from the Member States and from Electricity Utilities. They are in charge of technical and institutional studies in order to develop the WAPP and submit their recommendations to the WAPP PIC.
- The Project Teams composed of Experts from the States and Electricity Utilities in charge of coordinating the studies and supervising the projects implementation.

Then, the following decisions have been made based on the studies supervised by the Executive Secretariat with the support of USAID and the French Ministry of Foreign Affairs:

- Signing of the Energy Protocol Memorandum by the Member States in September 2000 in Lomé to confirm their will to jointly develop regional energy resources;
- Signing of the Protocol of Cooperation between electric utilities and adoption of an action plan for WAPP implementation in Dakar in March 2001;
- Adoption of the investment programme for the interconnection of the electric grids of zones A et B1 in Cotonou in September 2001;
- Decision A/DEC.8/121/01 with respect to financing mechanisms of the WAPP project;
- Adoption of the resolutions to put in place a legal and institutional framework, organisational structure and a regional regulatory agency for WAPP in Accra, in April 2002;
- Adoption of the resolutions relative to the ECOWAS Energy Protocol and Energy Observatory and the Capacity Building Programmes and Training in Conakry, in October 2002.
- Decision A/DEC.17/01/03 relative to adoption of the ECOWAS Energy Protocol aiming to facilitate unrestricted exchange of energy, hardware and energy products between the Member States, to attract and protect private capital and to ensure protection of environment and enhancement of energy efficiency.

[1] Zone A: Bénin, Burkina Faso, Côte d'Ivoire, Ghana, Niger, Nigeria et Togo.
Zone B: Gambie, Guinée - Bissau, Guinée Conakry, Liberia, Mali, Sénégal et Sierra Leone.

- Decision A/DEC.2/01/03 relative to creation of the ECOWAS Energy Observatory, the first component of the ECOWAS Information and Coordination Centre, supervisory organism responsible for alerting the Member States about potential shortages and identifying preventive measure to be undertaken allowing to avoid them and facilitating development of common operational norms and standards for data acquisition and processing and performance control.

The main purpose of the Energy Protocol is to:

- Ensure free flow of energy and energy materials and products between ECOWAS member states, and protection for international investors;
- Attract national and international private investments for the financing of power projects in the region.

The provisions of the Protocol will facilitate these purposes by creating a favourable environment meeting international standards through:

- The creation of an effective open, competitive and non-discriminatory market with provisions related to freedom of transit, open access to transmission facilities, protection of environment and energy efficiency as well as dispute non-discriminatory trade rules and dispute settlement for transit;
- The promotion and protection of energy investments in ECOWAS region with provisions to secure energy investments such as:
    - Equitable, stable and transparent conditions for investments;
    - Respect of contractual obligation and effective dispute settlement;
    - Non-discriminatory treatment and compensation in the case of loss or expropriation;
    - Guarantee for transfer of profits and repatriation of capital;
    - Right to employ key personnel of the investor choice;
    - Non-discriminatory trade rules consistent with WTO agreement.

The ECOWAS Ministers Council also adopted the following programme in Dakar on January 28, 2003:

- Capacity building and training programme concerning Ministries, utilities, working groups, the Steering Committee and ECOWAS Executive Secretariat. The programme will facilitate development of competences for accelerated regional electricity market implementation. Reinforcement of logistical means for utility companies, Member States and the Executive Secretariat required to improve the sector efficiency (commercial, technical and financial) and to foster competition make subject of a separate section of this document.

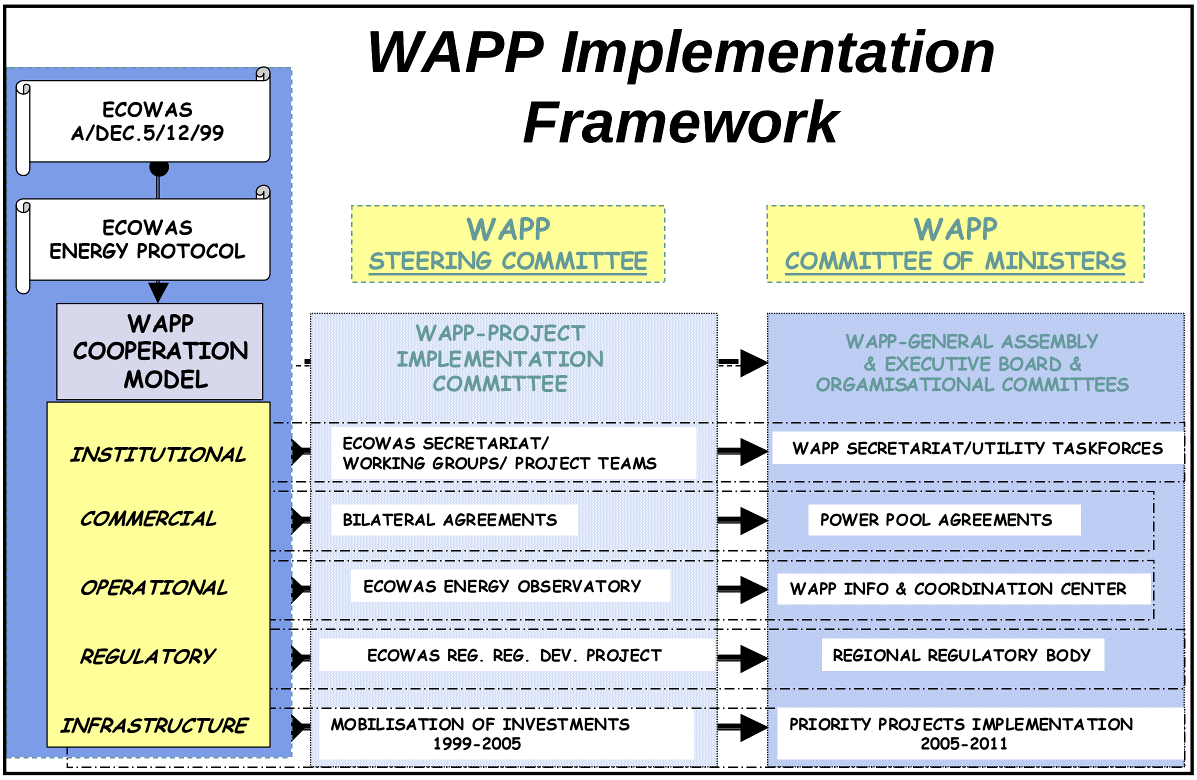


Figure 1. – WAPP Implementation Framework

2.4 Strategy Adopted for WAPP Implementation

The Meeting of the Energy Ministers of the ECOWAS Member States is the organ responsible for implementation of the West African Energy Protocol signed by the Heads of State and Chiefs of Government on January 31, 2003, and ratified by the Member States. They must encourage co-operative efforts aimed at facilitating and promoting market-oriented reforms and modernization of energy sectors in the countries of West Africa.

In order to allow the ECOWAS Executive Secretariat and the Meeting of the Energy Ministers to fully play their role in elaborating and implementing the policies of the regional energy programmes, an institutional assistance was necessary. This assistance has been provided by the donors acting in the energy sector at national and regional levels. This assistance allowed developing energy policies based on the diversification of the energy sources and the implementation, follow up and coordination of regulatory mechanisms at the regional level based on dispute resolution, tariff definition, and elaboration of standards for the operation of the interconnected electrical power systems.

Following the decisions mentioned above, the ECOWAS Executive Secretariat developed a three-year development programme with the aim to ensure the WAPP project's transition from conceptual to operational phase.

The ECOWAS Executive Secretariat programme included the following activities:

- Review of the WAPP Generation and Transmission Master Plan;
- Implementation of the WAPP Legal and Regulatory Framework :
  - ratification of the ECOWAS energy Protocol,
  - development of the Regional Regulatory Body;
- WAPP Targeted organizational Structure:
  - Elaboration of governance rules and procedures,
  - Establishment of WAPP constituting bodies: General Membership, Executive Board, Technical Committee, Planning Committee, Dispute Resolution Commission, General Management Group.
- WAPP Information and Coordination Centre:
  - Data collection : standardization and harmonization,
  - National grid codes and regional harmonisation,
  - Technical framework for the regional interconnected electricity system;
- Capacity Building and Training Programme;
  - National and regional regulatory mechanisms,
  - Electric power contracting process,
  - Competitiveness and efficiency improvement of the electricity companies.

2.5 Articles of Agreement for the Establishment and Functioning of the WAPP

The 29th Summit of the Heads of State and Government of the ECOWAS Member States held in Niamey, January 2006, adopted the Articles of Agreement establishing the *new WAPP Organisation* by Decision A/DEC.18/01/06 on 12 January 2006.

By Decision A/DEC. 20/01/06, the ECOWAS Heads of State and Government granted the status of “Specialised Institution of ECOWAS” to the West African Power Pool.

The objective of the Articles of Agreement is to institute a management structure for the West African Power Pool (WAPP), its organisation and functions, in order to establish a good framework of cooperation between its Members to ensure improved efficiency of power supply in ECOWAS Member States and increased access to energy for its citizens

The WAPP is an international organisation that has public interest and Members recognize that the WAPP Organisation exists and operates for the benefit of the bulk electric transmission system and to ensure the reliability of the entire region’s power supply. As such, Members are required to act to further these goals by participating in projects and complying with regulatory requirements. Failure to comply with these provisions will be considered a violation of the Articles of Agreement and the Member may be removed in accordance with the provisions for Removal of Members in the Membership Agreement.

The governance of the WAPP structure is composed of:

- The General Assembly,
- The Executive Board,
- The Organisational Committees,
- The WAPP General Secretariat,
- WAPP Information Coordination Centre.

The composition, functioning and duties of the components of the WAPP governance structure are defined by the Articles of Agreement.

The Organisational Committees are:

- The Engineering and Operating Committee,
- The Strategic Planning Committee,
- The Finance and Human Resources Committee.

The WAPP General Secretariat is the administrative organ to support the Executive Board in the accomplishment of the duties of the Executive Board and also responsible for the day-to-day management of WAPP. The WAPP General Secretariat would take responsibility for coordination of a team of independent professionals – permanent core staff of the WAPP Secretariat – that would implement day-to-day tasks required to accomplish the mission of WAPP. The staff of the WAPP Secretariat would perform the secretariat function for all meetings of the permanent WAPP Committees and any ad hoc tasks forces.

The WAPP Information and Coordination Centre is an organ of the WAPP Secretariat and shall promote operational coordination between Transmission Owning/Operating Members through actual day-to-day information sharing/exchange between WAPP Operational Coordination Centers in both Zones A & B.

The Articles of Agreement define also the Membership, Removal and Re-Instatement conditions as well as Finance aspects (Operating Budget, Monthly Assessments, Audits, Financial Obligations), Dispute Resolution, Supplementary Dispositions (liability, insurance and indemnification, regulatory affairs) and Final Dispositions (Statute, Effective Date and Transitional Provisions).

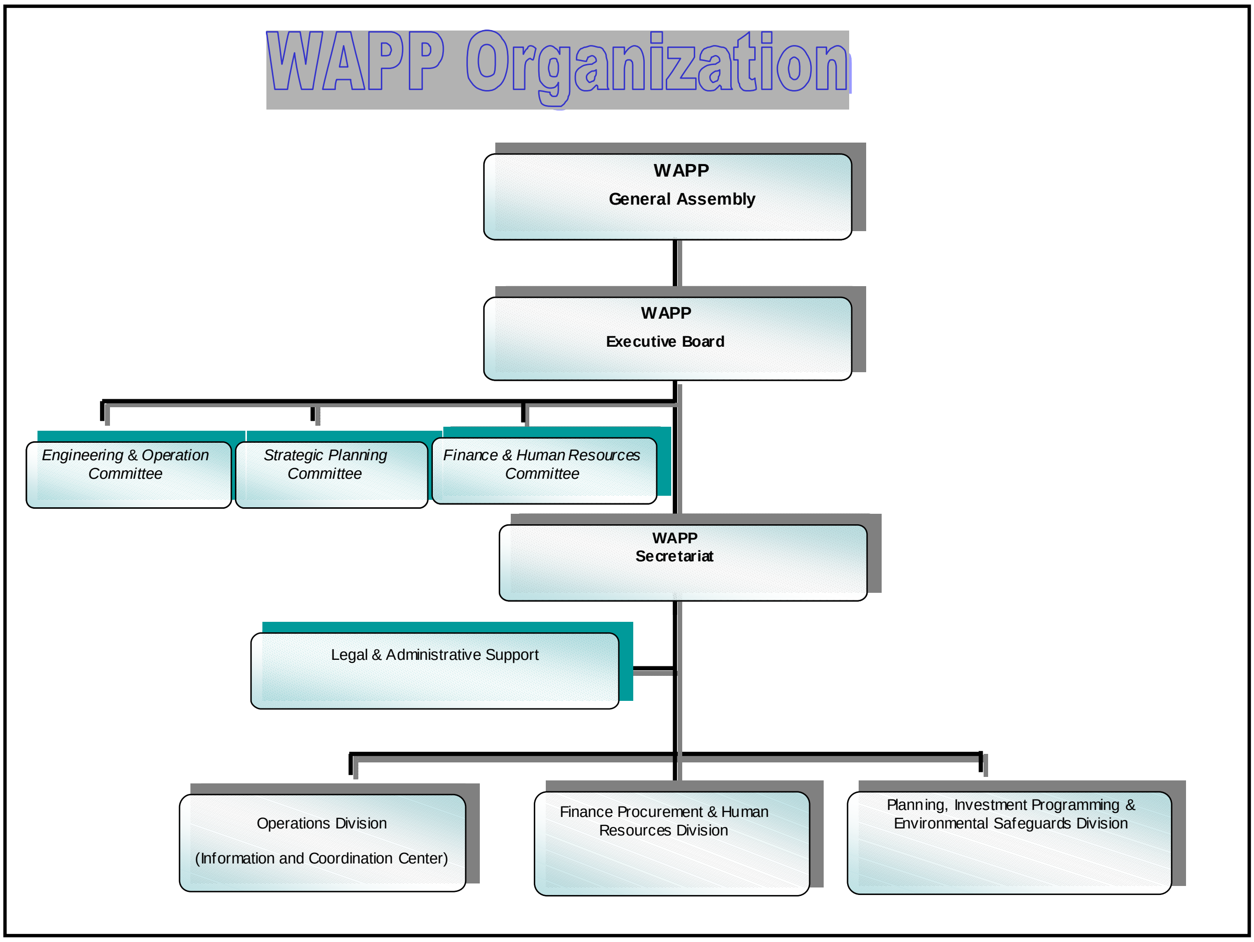


Figure 2. – WAPP Organization

2.6 WAPP General Secretariat

The mandate given to the WAPP General Secretariat by the WAPP General Assembly is as follows:

- Facilitating the expansion of transmission and generation infrastructure,
- Co-ordinating the planning and operation of the electric power system,
- Ensuring sustainable energy development through sound environmental practices,
- Facilitating institutional building and capacity development of member utilities,
- Promoting effective communications among WAPP Organization members, donors and the public.

The WAPP General Secretariat has to:

- Administrate the WAPP:
  - Operationalise WAPP work programs,
  - Develop Monitoring and Evaluation systems for the WAPP and Priority Projects,

- Develop self-assessment mechanisms,
- Convene statutory meetings.

➢ Build Capacities:

- Build Capacity in WAPP Secretariat to enable it facilitate the development of the WAPP, and manage its day-to-day operation,
- Strengthen capacities in utilities to ensure their effective participation in the WAPP.

➢ Create awareness:

- Develop WAPP Internal Communication Program (Website, “intranet”, reports, newsletters,...),
- Maintain interface with funding agencies,
- Maintain interface with Regional, national and other regulatory bodies,
- Maintain interface with similar power pools.

➢ Increase infrastructures:

- Timely mobilize funding to implement Priority Projects as defined by revised Master Plan,
- Continuously review and update Master Plan and prepare Contingency Scenarios,
- Harmonize Planning Practices,
- Harmonize Environmental and Social Impact Assessment Policies and review continuously,
- Harmonize Procurement Policies and Practices,
- Ensure timely availability of funding,
- Develop and Implement Results Framework for Priority Projects,
- Develop and Implement Monitoring and Evaluation Plan.

➢ Create market:

- Harmonize Rules of Operation and develop WAPP Operations Protocol / Grid Code (Operational Security and Mitigation Plan).
- Harmonize “Rules of Practice”: Planning / Commercial, Environmental,
- Create Operational and Accounting Control Centres in line with recommendations of Master Plan.
- Formulate Market Development Plan and implement.

3. CAPP – THE CENTRAL AFRICAN POWER POOL

3.1 Definition, Mission and Vision

The Central African Power Pool (CAPP) is a very new sub regional institution, created in Brazzaville on 12 April 2003 under the auspices of the Economic Community of Central African States (ECCAS).

The documents governing the CAPP are:

- the Inter-Governmental MOU,
- the Inter-Utility MOU.

These two basic agreements created the current institutional framework for the CAPP organizational structure. This structure was organized to develop the components of the power pool: its interconnected infrastructure and its governance system.

CAPP presently is the focal point for discussions on regional power markets; member states of ECCAS rely upon CAPP for technical analysis of proposals for power sharing between member states.

CAPP is assigned to:

- Promote power policies
- Promote studies and construction of common infrastructures and the organization of energy exchanges and the related services in ECCAS.
- Develop regional power management and trading arrangements in Central Africa. It aspires to become a major player in regional cooperation in the power sector.

CAPP vision is to exploit the enormous hydroelectric potentialities of the Central Africa estimated at more than 650 Thousands GWh (53 %) of the whole African potential, to satisfy all demands in electricity with the households, the states and the central African industry.

3.2 Members

Any public, private, and/or semi-public electricity supply enterprise of ECCAS member states may become member of CAPP.

Present members of CAPP are AES-SONEL (Cameroon), ENERCA (Central African Republic), SNE (Republic of Congo), SEEG (Gabon), SEGESA (Equatorial Guinea), SNEL (Democratic Republic of Congo), EMAE (Sao Tome & Principe), and STEE (Chad).

Expected members: ENE-EP/EDEL (Angola), ELECTROGAZ (Rwanda) and REGIDESO (Burundi).

3.3 Structural Organs and Organization Chart

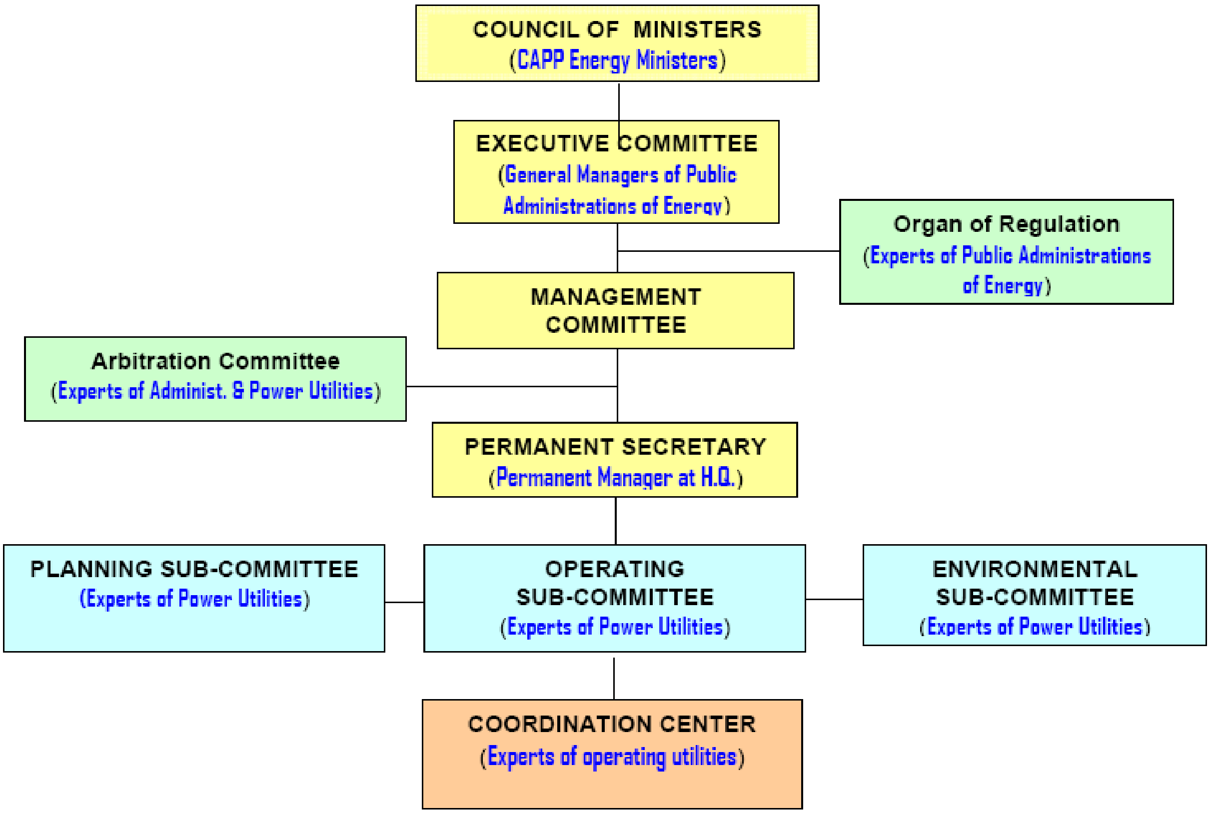


Figure 3. – CAPP Structural Organs & Organization Chart

4. REGIONAL MULTI-PURPOSE WATER RESOURCES DEVELOPMENT ORGANIZATION – AN EXAMPLE “OMVS”

OMVS is the Senegal River Basin Organization.

4.1 Background

The OMVS river basin organization was established about three decades ago by three out of the four riparian states. Mali’s principal interests are the maintenance of river levels so as to obtain navigable access to the sea and energy produced by the Manantali dam. Mauritanian and Senegalese interests converge in power production and irrigation, while Senegal seeks improved livelihoods for local populations. These varied interests are typical of a transboundary water management situation. The Manantali dam, although located in Mali, belongs to all the members of the OMVS authority.

The first institutions to develop the Senegal River valley were created during the colonial period. On 25 July 1963, very soon after independence, Guinea, Mali, Mauritania and Senegal signed the Bamako Convention for the Development of the Senegal River Basin.

This convention declared the Senegal River to be an 'International River' and created an 'Interstate Committee' to oversee its development. The Bamako Convention was supplemented by the Dakar Convention, signed on 7 February 1964, concerning the status of the Senegal River. The Interstate Committee laid the foundation for sub regional cooperation in development of the Senegal River basin.

On 26 May 1968, the Labé Convention created the Organization of Boundary States of the Senegal River (OERS, Organisation des Etats Riverains du Sénégal) to replace the Interstate Committee, broadening the field of sub regional cooperation. Indeed, OERS objectives were not limited to the valorisation of the basin but aimed at the economic and political integration of its four member states. After Guinea withdrew from the OERS, Mali, Mauritania and Senegal decided, in 1972, to set up the OMVS, which pursues the same objectives.

4.2 OMVS ' vision for regional cooperation:

OMVS' vision is to implement a joint Basin development program that reinforces regional integration, yields benefits, and sustains growth among the four associated riparian countries. This includes:

(i) development of multi-purpose water resources infrastructure to increase water availability and hydropower generation;

(ii) in creasing income-generating activities at the local level to alleviate rural poverty in the Basin;

(iii) implementing a regional health plan with correlated activities;

(iv) modernizing Basin institutions within the context of the Inclusive Framework;

(v) implementing the Water Charter principles with improvement of the Basin management and planning tools; and

(vi) implementing the regional infrastructure program.

These perspectives align with the New Partnership for Africa's Development (NEPAD) program, in particular the infrastructure window

4.3 Legal and Regulatory framework – Governance

The OMVS has since created a flexible and functional legal framework enabling collaboration and a co-management of the basin. The principal legal texts governing OMVS are:

- the Convention concerning the status of the Senegal River (Convention relative au statut du fleuve Sénégal), 11 March 1972. By this convention, the Senegal River and its tributaries were declared an 'International Watercourse', guaranteeing freedom of navigation and the equal treatment of users;

- the Convention creating the OMVS (Convention portant création de l'Organisation pour la Mise en Valeur du Fleuve Sénégal), 11 March 1972;
- the Convention concerning the Legal Status of Jointly-owned Structures (Convention relative au statut juridique des ouvrages communs), 12 December 1978, supplemented by the Convention concerning the Financing of Jointly Owned Structures (Convention relative aux financements des ouvrages communs), 12 March 1982. These declare that:
  - all structures are the joint and indivisible property of the member states;
  - each co-owner state has an individual right to an indivisible share and a collective right to the use and administration of the joint property;
  - the investment costs and operating expenses are distributed between the co-owner states on the basis of benefits each co-owner state draws from the exploitation of structures. This distribution can be revised on a regular basis, depending on profits;
  - each co-owner state guarantees the repayment of loans extended to the OMVS for the construction of structures;
  - two entities manage the jointly-owned structures for the OMVS: one dedicated to the management and development of the Diama dam (SOGED, Société de gestion et d'exploitation du barrage de Diama), the other to the Manantali dam (SOGEM, Société de gestion de l'énergie de Manantali), both created in 1997.
- in 1992, signature of a framework cooperation agreement between Guinea and the OMVS (Protocole d'Accord–Cadre de Coopération entre la République de Guinée et l'OMVS), creating a framework for cooperation in actions of mutual interest concerning the Senegal River and its basin, including a provision allowing Guinea to attend OMVS meetings as an observer;
- the Senegal River Water Charter, May 2002 (Charte des Eaux du Fleuve Sénégal) whose purpose is to:
  - set the principles and procedures for allocating water between the various use sectors;
  - define procedures for the examination and acceptance of new water use projects;
  - determine regulations for environmental preservation and protection; and
  - define the framework and procedures for water user participation in resource management decision-making processes.

The OMVS functions with the following management bodies:

- Permanent bodies;
- Conference of Heads of State and Government (CCEG, Conférence des Chefs d'Etat et du Gouvernement);
- Council of Ministers (CM, Conseil des Ministres);
- High Commission (HC, Haut Commissariat), executive body;
- Permanent Water Commission (CPE, Commission Permanente des Eaux) made up of representatives of the organization's member states, and which defines the principles of and

procedures for the allotment of Senegal River water between member states and use sectors. The CPE advises the Council of Ministers;

- Non-permanent bodies;
- An OMVS national coordination committee in each member state;
- Local coordination committees;
- Regional Planning Committees (CRP, Comités Régionaux de Planification);
- Consultative Committee (CC, Comité Consultatif).

This organizational framework, statutorily strong but flexible on the operational level, enables all of the actors and stakeholders to participate effectively in the efficient management of both the basin's natural resources and its other economic potentials. For more than thirty years now, they have been able to find suitable solutions to all of the technical, social, political and other problems linked to the development of the Senegal River basin's water resources.

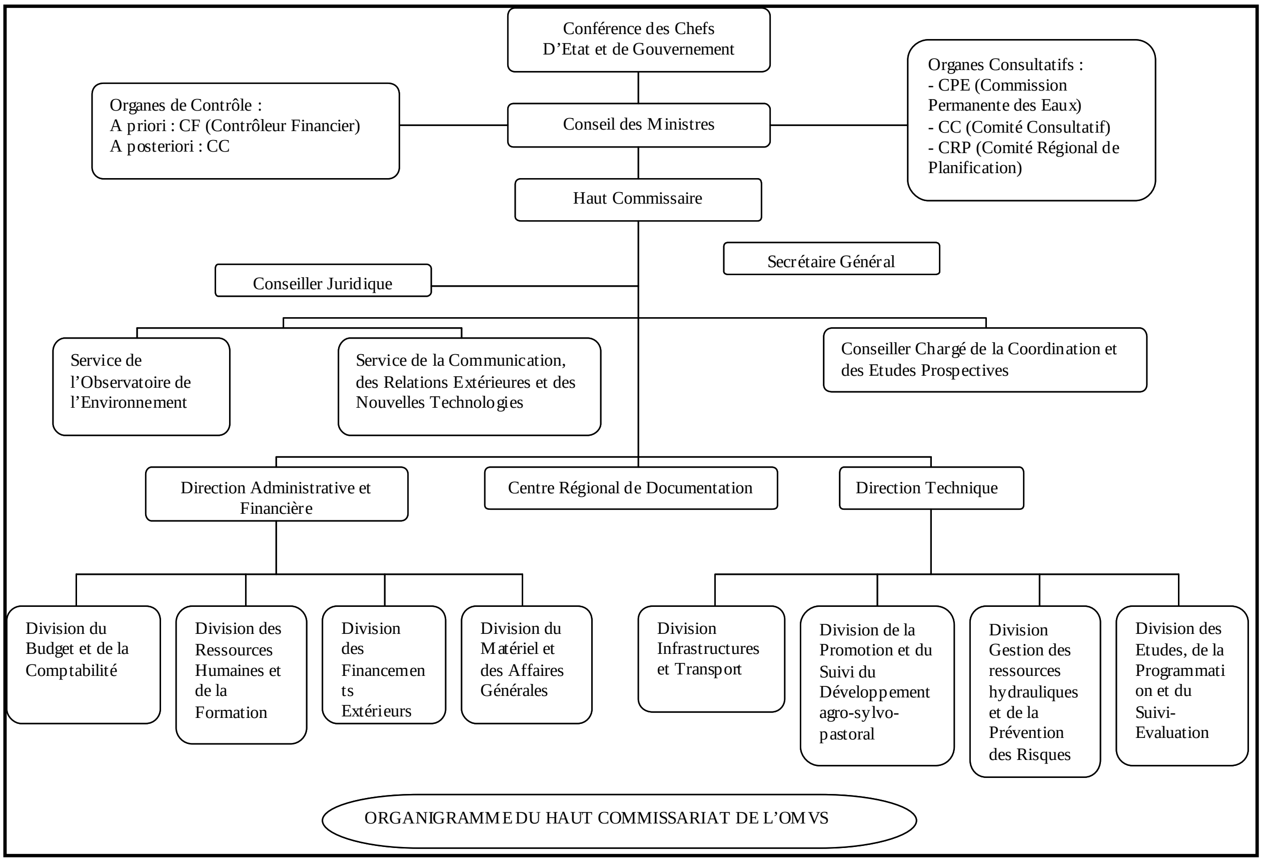


Figure 4. – OMVS Haut Commissariat Organization Chart

1963	Guinea, Mali, Mauritania, and Senegal establish the Interstate Committee and declare the Senegal River an international river.
1968	The four basin countries form the Organization for the Coastal States of the Senegal River (OERS) and define a basinwide development program.
1972	Mali, Mauritania, and Senegal create the Senegal River Development Organization (OMVS) to implement the development program outlined by the OERS.
1978	Mali, Mauritania, and Senegal sign a convention establishing the legal status of common works.
1982	Mali, Mauritania, and Senegal sign a convention on financing the common works.
1984	Twelve donors support building the Manantali and Diama Dams.
1986	The Diama Dam becomes operational.
1990	The Manantali Dam becomes operational.
1992	The OMVS-Guinea protocol is signed.
1997	The Regional Hydropower Project begins.
2000	The Diama Dam Management Company (SOGED) and the Manantali Dam Management Company (SOGEM), the dams' management agencies, are established.
2002	Electricity generated at Manantali is transmitted to Bamako, Dakar, and Nouakchott. Mali, Mauritania, and Senegal sign and ratify the Water Charter.
2003	Guinea participates in the OMVS Heads of State Summit in Nouakchott.
2004	The first interministerial meeting between Guinea and the OMVS member states is held, in Nouakchott.
2004	The first technical meeting on establishing an inclusive framework for the basin's joint management is held, in Conakry.

Figure 5. – Chronology of Cooperation in the Senegal River Basin

4.4 Financing Infrastructure

The most valuable outcome of cooperation is the strong intra-basin relationships that have been formed, which have facilitated economic growth through joint development of infrastructure. For example, in addition to the common interest in establishing and maintaining a reliable energy supply, Mali wanted navigation to the sea and Mauritania and Senegal wanted to expand irrigation in the valley. Rather than pursue these goals unilaterally, the OMVS countries chose to share the burden of large loans to fund their development plans, so that each economy would not need to carry the full weight of the investments.

The countries could have followed the common international practice of preserving sovereignty and minimizing commitments to other countries by opting to share the benefits based on a minimum common denominator or by .splitting the difference.. Instead, the Senegal Basin countries opted to act as a single community and to maximize their common interest. Their decisions were based on consensus and the principles of solidarity and equity. Solidarity means joint fiscal responsibility for shared infrastructure, even if the immediate outcomes do not benefit a particular country. Equity means that each country.s share of the benefits is congruent with its needs.

To obtain financing for the Diama and Manantali Dams, the countries needed to define common ownership and the related principle of financial solidarity. The countries agreed to guarantee and repay construction loans according to a formula that apportioned repayment based on benefits received. Doing so allowed donors to conclude agreements directly with each country for its share of the total loan repayment.

The loans to construct the Diama and Manantali Dams were guaranteed equally by Mali, Mauritania, and Senegal, but loan repayment is proportional to the benefits each country derives from the dams. Under the current benefit-sharing formula, 42.1 percent of the benefits accrue to

Senegal, 35.3 percent to Mali, and 22.6 percent to Mauritania. To revise the formula, a country applies in writing to the OMVS Council of Ministers.

This approach ensured an equitable allocation of water to different sectors, including irrigation and joint exploitation of the basin.s hydroelectric potential. Mali receives 52 percent (104 MW) of the electricity generated at Manantali, Mauritania 15 percent (30 MW), and Senegal 33 percent (66 MW). Expansion of irrigation was also divided equitably, with the irrigated area increasing from 20,000 hectares in 1980 to 120,000 hectares after the dams began operating, with most of the increase in the valley between Mauritania and Senegal. Agricultural intensification also helped smooth the unequal balance of payments among the OMVS members.

Two types of funding are used to finance the development of the Senegal River basin. The first one covers the operating costs of the various OMVS bodies, and comes from the three member states; each of them pays one third of the total in January of every year. To finance the jointly owned structures and other development activities, funds are sought in the form of loans extended either to the states or directly to the OMVS. In this case, the member states must guarantee the loans. Each member state ensures the reimbursement of its share of the loans.

The apportionment of costs and debts is done according to the accepted formula, subject to revision, as stipulated in the conventions. The underlying principle of cost recovery is that the users pay, but economic conditions are also taken into consideration.

Taxes paid to the organization are used to cover operating expenses.

4.5 Managing Multiple Uses

Due to potential conflicts between power generation and the other uses of the Senegal River, the three governments have embarked through OMVS on the implementation of an environmental impact alleviation and follow-up programme (PASIE, Plan d'Atténuation et de Suivi des Impacts sur l'Environnement). It is an environmental programme specifically designed to address, monitor and mitigate the environmental issues raised by (or related to) the development and distribution of power from the Manantali power plant.

The OMVS's fundamental conventions of 1972 and the Senegal River Water Charter signed in May 2002, which establish its legal and regulatory framework, clearly state that river water must be allocated to the various use sectors. The resource is not allocated to riparian states in terms of volumes of water to be withdrawn, but rather to uses as a function of possibilities. The various uses can be for agriculture, inland fishing, livestock raising, fish farming, tree farming, fauna and flora, hydroelectric energy production, urban and rural drinking water supply, health, industry, navigation and the environment.

The principles and procedures for the allocation of water were drawn up and a Permanent Water Commission (PWC) was set up to serve as an advisory body to the OMVS's Council of Ministers that makes decisions and asks the High Commission to oversee their application. The OMVS's process for managing needs has four steps.

- First, an inventory of needs is taken by the OMVS National Committees under the Ministries in charge of water in each country. The 'state of needs' is then sent to the OMVS High Commission.
- The High Commission centralizes all of the needs, writes a synthesis report and convenes a meeting of the Permanent Water Commission to vote on recommendations. It then draws up a record of the proceedings with precise recommendations for the Council of Ministers.

- The Council of Ministers makes decisions based on the information provided by the Permanent Water Commission, either in a formal meeting or by informal telephone consultation. The High Commission receives instructions from the Council of Ministers and transmits to member states and other actors the procedures for carrying out the measures adopted by consensus by the member states in the Council of Ministers.
- The work of the Permanent Water Commission and the criteria used by the ministers for decision-making are based on the following general principles:
  - reasonable and fair use of the river water;
  - obligation to preserve the basin's environment;
  - obligation to negotiate in cases of water use disagreement/conflict; and
  - obligation of each riparian state to inform the others before undertaking any action or project that could affect water availability.

The objective of the OMVS method of water allocation is to ensure that local populations benefit fully from the resource, while ensuring the safety of people and structures, respecting the fundamental human right to clean water and working towards the sustainable development of the Senegal River basin.

4.6 Power System Management

Owned jointly by the OMVS countries, the Manantali Dam and its network of 1,300 kilometres of transmission lines came on line in 2002. Mali's national grid was connected in January, Senegal's in July, and Mauritania's in November 2002. Since May 2003, the station has been working at full capacity, generating 200 MW.

Manantali Dam was built on the Bafing River, entirely within Mali. It has a storage capacity of 11.3 cubic kilometres and an annual generating capacity of 800 GWh. It regulates the flow at 300 cubic meters per second. Electricity generation in the region is still not sufficient, but since 2002 it has become more reliable and is slowly transforming the lives of people in Mali, Mauritania, and Senegal.

The Diama Dam, located 23 kilometres from the Senegal River's mouth, was built to block intrusion into the river by the Atlantic Ocean, to facilitate perennial irrigation, and to improve the water supply of Dakar and Nouakchott by filling Lac de Guiers in Senegal and Lac Rkiz in Mauritania. Used jointly with the Manantali Dam, the Diama Dam has ensured a water supply for Dakar and reduced irrigation costs.

In 1997 the OMVS countries initiated the Regional Hydropower Project at Manantali. The project installed electricity-generating turbines with capacity of 200 MW and laid transmission lines to Bamako, Dakar, and Nouakchott. It also established the institutions to operate the generating system. Two operating agencies, the Manantali Dam Management Company (SOGEM) and the Diama Dam Management Company (SOGED), were commissioned in 2000. In addition, an independent entity from the private sector was appointed to operate the Manantali Dam under SOGEM's supervision. Mirroring OMVS's Permanent Water Commission, which advises on water allocation, the Permanent Technical Committee on Interconnection was created, along with a Management Committee for Interconnection, to define the program of production, supply, and regulation of electricity production.

4.7 Lessons from the Senegal Basin

Cooperative development of the Senegal River has benefited the economies of Mali, Mauritania, and Senegal by increasing the reliability of key inputs such as electricity and water.

- Grasping opportunities through cooperation. The group.s success in collectively raising external investment shows what can be done if all parties cooperate rather than acting unilaterally.
- Engaging top political leaders. Political will was fundamental to engendering trust among basin countries and with key international partners.
- Sharing a vision for development. From the outset, the Senegal basin.s development was based on an agreed plan that reflected the countries. priorities through a regional approach.
- Engaging all stakeholders. To tap regional opportunities, stakeholders at all levels need to participate in identifying and developing opportunities, and then in sharing the benefits.
- Looking at different scales of development. Outcomes at the local, national, and regional levels from development must also be assessed.
- Binding cooperation with legal instruments. Legal instruments are needed capture the agreements and bind future cooperation.
- Promoting private sector involvement. Maintaining a consistent policy for private sector involvement was critical.

This project was not easy to manage because all the decisions have to be made unanimously. It has lasted for 25 years.

Joint ownership of infrastructure has meant that the basin countries have a common interest in safeguarding the works and the benefits that flow from them. OMVS is really an integrating factor for the three countries.

The Manantali and Diama Dams and the relationships established through the OMVS helped pull Mauritania and Senegal back from armed conflict. Ethnic violence triggered by a simmering dispute over animal grazing rights erupted in the valley in mid-April 1989. At least 50,000 people fled their homes as tensions escalated. The Organization of African Unity attempted to mediate the conflict in 1990 but was unsuccessful.

Remarkably, in July 1991 Mauritania and Senegal worked out an agreement themselves, based on recognition of their shared interests in the jointly owned dams. Even though diplomatic ties had been ruptured, the two countries managed to continue to collaborate through OMVS. The lessons the two countries had learned from their OERS experience and the fact that OMVS continued to operate during the conflict gradually eased tensions between them, initiating a process of normalization, with refugees returning to the valley and diplomatic ties resuming in May 1992.

APPENDIX 2:

SAMPLE OF OPERATING GUIDELINES

"THE SOUTHERN AFRICAN POWER POOL OPERATING GUIDELINES"

August 14, 1996

SOUTHERN AFRICAN POWER POOL

OPERATING GUIDELINES

14 AUGUST 1996

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PREAMBLE

The objective of this document is to ensure that all the Operating Members of the Southern African Power Pool (SAPP) operate the interconnected Southern African network efficiently and effectively and that all Members participate equitably in the obligations and in the benefits resulting from the Pool. These guidelines will be amended from time to time by the Operating Sub-Committee of the SAPP, as the need arises.

All interconnected utilities to SAPP must comply with the contents of this document. It can also be used as a basis to prepare more detailed documents governing the operation of each individual network.

This document is based on the North American Electric Reliability Council (NERC), Operating Guidelines (27 February 1991). It will enable all the Operating Members to monitor the operations of the Southern African Grid and to compare them against a benchmark.

INTRODUCTION

The English language, both written and spoken, will be the medium of official communication between the Operating Members of the SAPP.

The Operating Guidelines are designed to ensure co-ordinated operation between interconnected systems and to achieve high levels of system reliability and control at the Points of interconnection. The Guidelines specify how the basic operating policy of the SAPP shall be implemented. The Guidelines are based on established technical and on operating experience accumulated over years. The input of the System Controller is vital to the establishment and maintenance of good operating policy.

In practice, certain Clauses are more important than others. Therefore, the Clauses are classified either as Operating Requirements or as Operating Recommendations.

An Operating Requirement is a statement that describes the obligations of a Control Area or a System functioning as part of a control area. The Operating Requirement may also specify whether compliance to Guidelines must be monitored or not.

An operating Recommendation is a statement describing good operating practice that should be followed by a Control Area or by a System belonging to a Control Area. The degree of enforcement of an Operating Recommendation may vary from Control Area to Control Area and should take into account system conditions and characteristics.

SUMMARY OF OPERATING GUIDELINES

GUIDELINE I : SYSTEM CONTROL

A. GENERATION CONTROL

Each Control Area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules with its load. It shall also provide a contribution to System frequency regulation as defined hereafter.

B. VOLTAGE CONTROL

Each System and Control Area shall operate capacitive and inductive reactive resources so as to maintain within specified limits, the voltage levels inside the Systems and at the Points of interconnection. Reactive power generation, transmission equipment switching and load shedding if necessary, shall be implemented to maintain these voltage levels. Each System and Control Area shall have adequate MVAr reserves so as to maintain the voltage to acceptable levels under credible contingency conditions.

C. TIME AND FREQUENCY CONTROL

Frequency in the interconnection shall be scheduled at 50 Hz and maintained to that value, except for those periods in which frequency deviations are scheduled to correct time error.

Return of Inadvertent Energy and correction of time errors shall be scheduled and carried out within the range of frequencies specified in this document and bearing in mind that Interconnection reliability has first priority.

Each Control Area shall participate in the correction of time error.

Control Areas which are interconnected shall select one Control Area each year to monitor time error and to issue time error correction orders.

D INTERCHANGE SCHEDULING

The scheduling of power transfers between Control Areas shall be done through transmission paths either belonging to those Control Areas or pre-arranged via wheeling contract(s) when other Control Areas are involved.

D. INTERCHANGE SCHEDULING (CONT.)

The net amount of interchange scheduled between Control Areas shall not exceed the mutually agreed transfer limits of the interconnectors and alternate paths which are involved in the scheduled power transfer. When establishing normal and emergency transfer limits, the sending party and the receiving party shall consider the effects of the power through their own and all other parallel Systems based on acceptable criteria. In no case shall the scheduled power transfer between two Control Areas exceed the total rated capacity of transmission facilities owned or arranged for between the two Control Areas.

Alterations to power transfer schedules, shall be made at a time and at a rate of change agreeable to both the supplier and the receiver and within the capability of each party to control the change.

E. CONTROL PERFORMANCE CRITERIA

The Control Performance Criteria defines a minimum standard of control performance. Each Control Area should operate its System(s) above this minimum requirement and the actual level of performance should be the highest that can be achieved, taking into account economic and technical considerations.

F. INADVERTENT ENERGY MANAGEMENT

Through reliable metering equipment and daily schedule verification, each Control Area shall accurately account for Inadvertent Energy interchanges. Being aware of generation and load patterns, each Control Area shall be proactive in preventing the accumulation of Inadvertent Energy and to do this in accordance with procedures set by the Operating Sub-Committee.

Each Point of Interconnection between Control Areas shall be equipped with a common MWh meter and the readings shall be provided hourly to all relevant Control Centres.

G. CONTROL SURVEYS

At least every six (6) months, the Co-ordination Centre or its representative shall conduct a survey to assess the control performance of the Control Areas. The purpose of these surveys will be to highlight control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic generation control, general control performance deficiencies and any other factors contributing to inadequate control performance.

H. CONTROL EQUIPMENT REQUIREMENTS

The control equipment of each Control Area shall be designed and operated so as to ensure that the Control Area can continuously and accurately meet its control obligations (towards its own System(s) and towards the other Control Areas) and that it can measure its performance. The control equipment shall be designed and operated in accordance with acceptable industry norms.

All interconnections between Control Areas shall be equipped to telemeter MW power flow at the Points of Interconnection to area Control Centres simultaneously.

The System Controller's displays and consoles shall offer him a clear and understandable picture of his Control Area parameters. This includes all the necessary information from other Control Areas in addition to his own.

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GUIDELINE II : SYSTEM SECURITY

A. ACTIVE POWER (MW) SUPPLY

Each Control Area shall operate its active power resources to ensure a level of operating reserve sufficient to account for such considerations as errors in load forecasting and exchange schedules, generation or transmission equipment unavailability, number and size of generating units, forced outage rates, maintenance schedules, regulating requirements, and load diversity between Control Areas. Following the loss of load or active power resource(s), the Control Area shall take appropriate steps to reduce its Area Control Error to zero within ten (10) minutes.

Each Operating Member shall declare its own operating reserve philosophy with regard to the following:

(i) the permissible mix of spinning and quick reserve;

(ii) procedure for applying operating reserve policy in practice; and

(iii) the limitations, if any, upon the amount of interruptible load which may be considered as quick reserve.

This philosophy shall not be less onerous than the minimum reserve policy specified in this Guidelines.

B. REACTIVE POWER (MVAR) SUPPLY

Each Control Area shall supply its own reactive power requirements, including appropriate reserves to maintain voltage levels during a contingency. The reserve shall be located, electrically, where it can be applied effectively and timeously when a contingency occurs.

Control Areas shall co-ordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at levels consistent with interconnection security.

C. TRANSMISSION OPERATION

Transmission equipment is to be operated within its normal rated except for short periods after a contingency has occurred.

C. TRANSMISSION OPERATING (CONTD.)

When the loading or voltage level on transmission facilities deviate from normal operating limits or are likely to exceed emergency limits following a contingency, and when such events can threaten the reliability of the Interconnection, Control Area(s) experiencing or causing the condition, shall take immediate steps to remedy the situation. These steps include notifying other Control Areas, initiating load relief measures and taking all other actions that the situation warrants.

System operation shall be co-ordinated between Systems, Control Areas and the Pool. This includes the monitoring of MW and MVAr flows and the co-ordination of equipment outages, voltage levels and switching operations that affects two or more Systems.

D. RELAY CO-ORDINATION

Systems and Control Areas shall co-ordinate the application, operation and maintenance of protective relays on the Interconnection, including the co-ordination of under-frequency load shedding relays. Criteria which will enhance system reliability with the minimum adverse affect on the performance of the Interconnection should be developed.

System Controllers shall be familiar with the operating settings of protective relays and shall have access to all relevant relay information to enable them to operate the interconnected system.

E. MONITORING INTERCONNECTION PARAMETERS

Each System and Control Area shall continuously monitor those parameters (such as MW flows, MVAr flows, frequency, voltage, phase angle, etc), internal and external to its System or Control Area, that indicate the level of security of the Interconnection.

F. INFORMATION EXCHANGE – NORMAL SYSTEM CONDITIONS

Information concerning system conditions shall be transmitted to adjacent Control Areas and non-adjacent Control Areas, as needed, to ensure efficient and effective operation of the Interconnection.

G. INFORMATION EXCHANGE – DISTURBANCE REPORTING

Disturbances or unusual occurrences which jeopardize the operation of the interconnected system, that result or could result in equipment damage or customer supply interruptions, shall be studied in sufficient depth to increase the understanding of the phenomena occurring in the system and to enable the Members to prevent the occurrence of such incidents or at least reduce their impact. The recordings associated with a disturbance shall be made available to the other Operating Members.

H. MAINTANANCE CO-ORDINATION

Each System shall prepare inspection and maintenance schedules for its generation and transmission facilities, its protection, control and communication equipment and of any other relevant facility. These inspection and maintenance schedules shall be co-ordinated with those of other affected Systems and Control Areas to ensure that the equipment outages will not violate the reliability criteria.

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GUIDELINE III : EMERGENCY OPERATIONS

A. INSUFFICIENT GENERATION CAPACITY

A control Area which experience a shortage of generation shall promptly balance its generation and interchange schedules to its load, without regard to financial implications, to avoid prolonged use of the assistance provided by interconnection frequency bias. The emergency reserve provided in a frequency deviation is intended to be used only as a temporary source of emergency energy and is to be promptly restored so that the interconnection system can again withstand the next contingency. A Control Area unable to balance its generation and interchange schedules to its load shall have the responsibility to shed sufficient load to permit the correction of its Area Control Error.

A Control Area anticipating a shortage of generation shall bring to service all available generation, postpone equipment maintenance, re-schedule interchange and prepare to shed load.

B. TRANSMISSION – OVERLOAD, VOLTAGE CONTROL

If a transmission facility becomes overloaded or if voltage/reactive levels are outside established limits and the situation cannot be remedied by normal means such as adjusting generation or interconnection schedules, and if a credible contingency under these conditions would adversely impact on the interconnection, appropriate measures, including load shedding, shall be implemented promptly to reduce the loading of the transmission facility to a level below the established limits. This action shall be taken by the System or Control Area causing the problem if that system or Control Area can be identified, otherwise by all Systems or Control Areas, as appropriate, if responsibility cannot be readily determined.

C. LOAD SHEDDING

After taking all other remedial steps, a System or Control Area whose integrity is still in jeopardy due to insufficient generation or transmission capacity, shall shed load rather than risk an uncontrolled failure of components making up the interconnection between Control Areas.

D. SYSTEM RESTORATION

After a system collapse, restoration shall begin when it can proceed in an orderly and secure manner. Systems and Control Areas shall co-ordinate their restoration actions. Generally, restoration starts with the auxiliary supply of power stations and transmission substations, although this can change depending upon the incident. Even though the restoration shall be done as speedily as possible, System Controllers shall avoid premature action to prevent another collapse of the system.

D. SYSTEM RESTORATION (CONTINUED)

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must continuously remain in balance at normal frequency as the system is restored.

EMEGENCY INFORMATION EXCHANGE

A System or Control Area which is experiencing or anticipating an emergency shall communicate its current and expected status to neighboring Systems and Control Areas first and then to the other Operating Members. Systems capable of providing assistance shall declare their capabilities.

SPECIAL SYSTEM OR CONTROL AREA ACTION

Because the facilities of each System may be vital to the secure operation of the interconnection, Systems and Control Areas shall make every effort to remain connected to the interconnection. However, if a System or Control Area determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system.

If the interconnection splits into several parts, abnormal frequency and voltage deviations may occur. To permit re-synchronisation, relief measures shall be brought by those Systems responsible for the frequency and voltage deviations.

G. CONTROL CONTRE BACK-UP

Each Control Area shall have a survival plan to continue operation of its System in the event its control centre becomes inoperable.

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GUIDELINE IV : OPERATING PERSONNEL

RESPONSIBILITY AND AUTHORITY

Each System Controller shall be delegated sufficient status and authority to take any action necessary to ensure that the System or Control Area for which the Controller is responsible, is operated in a stable and reliable manner.

B. SELECTION

Each System and Control Area shall select its System Controllers based on criteria that are designed to promote reliable operation.

C. TRAINING

Each System and/or Control Area shall provide its personnel with training that is designed to promote reliable operation.

D. RESPONSIBILITY TO OTHER OPERATING GROUPS .

Each System and Control Area's personnel shall supply the information required by other Systems, Control Areas or by the Operating Sub-Committee.

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GUIDELINE V: OPERATIONS PLANNING

A. NORMAL OPERATIONS

Each Control Area shall plan its future operations in co-ordination with other affected Control Areas to ensure that normal interconnection operation will proceed in an orderly and consistent manner.

B. PLANNING FOR SHORT-TERM EMERGENCY CONDITIONS

A set of plans consistent with these Operating Guidelines (particularly Guideline III) shall be developed, maintained, and implemented as required by each System and Control Area to cope with operating emergencies. These plans shall be co-ordinated with other Systems and Control Areas as appropriate.

C. PLANNING FOR LONG-TERM EMERGENCY CONDITIONS

Each System and Control Area shall maintain comprehensive and co-ordinated procedures to deal with long-term capacity or energy shortages.

D. LOAD SHEDDING

Each System and Control Area shall prepare a program of manual and automatic load shedding sufficient to arrest frequency or voltage decay, or extreme power flows that could cause an uncontrolled failure of failure of components of the Interconnection. The program shall be co-ordinated throughout the Interconnection so as to avoid high transmission loading and extreme voltage deviations.

E. SYSTEM RESTORATION

Each System and Control Area shall develop and periodically update a plan of action to restore its system in an orderly manner in the event of a partial or total shutdown. This plan shall be co-ordinated with other Control Areas to ensure a consistent Interconnection restoration.

Reliable and adequate sources for starting up generating units shall be provided in each System. When these sources are remote from the generating units, a proper procedure shall be established in order to minimize start- up time. Generation restoration procedure shall be verified and tested at regular intervals to be defined by the Operating Sub-Committee.

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GUIDELINE VI : TELECOMMUNICATIONS

A. FACILITIES

Each System and Control Area shall install adequate and reliable telecommunication facilities for their own needs and those of other Systems and Control Areas so as to ensure that the exchange of information necessary to maintain the reliability of the Interconnection can take place. Wherever possible, there will be back-up facilities and route diversity.

B. SYSTEM CONTROLLER TELECOMMUNICATION PROCEDURES

Procedures for System Controller to System Controller communications shall be established by Systems and Control Areas to ensure that communications between operating personnel are consistent, efficient, and effective during normal and emergency conditions.

C. LOSS OF TELECOMMUNICATIONS

Operating instructions and procedures shall be established by each System and Control Area to enable operation to continue during the loss of telecommunicatIon facilities.

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TERMS USED IN THE GUIDELINES

Adjacent System or Adjacent Control Area: Any System or Control Area directly Interconnected with (so as to be significantly affected by the existence of) another System or Control Area.

Area Control Error (ACE): The instantaneous difference between actual and scheduled tie line interchanges between Control Areas, taking into account the difference between the scheduled and actual frequency.

Automatic Generation Control (AGC): Equipment which automatically adjusts a Control Area's Operating capacity, plus firm purchase from other Systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.

Cold Reserve: Cold Reserve is all generating capacity available for operation but not synchronized to the system; it is the Slow Reserve plus Quick Reserve.

Control Area: Control Area shall mean an electrical System with borders defined by points of Interconnection and capable of maintaining continuous balance between the generation under its control, the consumption of electricity in the Control Area and the scheduled interchanges with other Control Areas.

Control-Performance Criteria (CPC)**:** The CPC survey provides two measures of the performance of ACE. The measures are referred to as A1 – Zero Crossing, and A2 –Ld Compliance.

Demand: The rate at which energy is being used by the customer, expressed in MW or GW.

Disturbance:

1. Any perturbation to the electric system.
2. The unexpected change in ACE that exceeds five (5) times Ld which is caused by the sudden loss of generation or interruption of load.

Dynamic Schedule: A schedule that is continuously adjusted in real time to match an actual interchange. Commonly used for "scheduling" generation from another Control Area.

Emergency Energy: Emergency Energy shall mean energy supplied from other Operating Members to an Operating Member who experiences a loss of generating or transmission facilities as the result of an unscheduled outage (or outages) or any cause not reasonably foreseeable. Such energy shall be available for a period of six (6) hours starting from the occurrence of the emergency, after which the Operating Member must obtain other types of services or shed load, should the shortage continue.

Emergency Generation. Emergency Generation is the short- term generation of the plant above its rated capacity.

TERMS USED IN THE GUIDELINES (CONTD.)

Emergency Situation: An Emergency Situation shall mean a situation where a Member is faced with an unplanned loss of generation of transmission facilities or another situation beyond its control, which impairs or jeopardizes its ability to supply its System Demand, adjusted for imports and exports of Firm Power. Such emergency shall not exceed six (6) hours.

Force Majeure: Force Majeure shall have the same meaning as in Clause 2.18 of the SAPP Agreement Between Operating Members shall apply, except for Clause 2.18.4 which shall read as follows:

"any other cause beyond the control of a Party, provided the Party experiencing such cause and the other Party agree that such cause should be regarded as Force Majeure".

Frequency Bias Setting: A value, in MW/0.1 Hz, set into a Control Area's AGC Equipment to represent a Control Area's response to deviation from scheduled frequency.

Hourly Value: Data measured on a clock-hour basis. When related to energy or similar data, it is the value accumulated during the sixty (60) minute interval ending at the hour which is specified.

Inadvertent Energy Flow: Inadvertent Energy Flow shall mean the difference between the net scheduled energy delivered and the actual net energy delivered in any specific hour.

Interconnection: When starting with a capital letter, it shall mean high voltage transmission lines and substations making up international backbone of the Southern Africa Grid. When not starting with a capital letter, it shall mean the facilities that connect two adjacent Systems or Control Areas.

Interruptible or Curtailable Load: Interruptible or Curtailable Load shall mean a consumer load or a combination of consumer loads which can be contractually interrupted or reduced by remote control or on instruction from the utility when such contracts are in place and such instructions have been given from the Member's Control Centre.

Leap Second: A second of time added occasionally by the Bureau of Standards to correct for the offset between the clock-hour day and the solar day.

Ld: See Guideline 1 on System Control.

Load: The amount of electric power delivered or required at any specified point on a system.

Metered Value: A measured (electrical) quantity that may be collected by telemetering, SCADA, or other means.

TERMS USED IN THE GUIDELINES (CONTD.)

Mothballing: Mothballing plant stored for longer than one (1) year; the plant is dry stored and may be partially dismantled and specifically protected.

Non-Spinning Reserve: Shall have the same meaning as Cold Reserve.

Neighboring System: See Adjacent System.

Net Energy for load: Net system generation plus interchange received minus interchange delivered in a time interval.

Operating Reserve: The un-used capacity above System Demand which is required to cater for regulation, short-term load forecasting errors, and unplanned outages. It consists of Spinning and Quick Reserve.

Operating Security: The ability of a power system to withstand or limit the adverse effects of any credible contingency to the System including overloads beyond emergency ratings, excessive or inadequate voltage, loss of stability or abnormal frequency deviations.

Planned Outage: Unless otherwise agreed and confirmed in writing between all relevant Control Centres, planned Outages shall mean outages which are scheduled with at least two weeks notice and agreed in writing between the Control Centres.

Points of Interconnection: The Points of Interconnection between Operating Members shall be those locations where their respective transmission facilities are physically connected. Unless otherwise agreed, the transactions under the Service Schedules shall be deemed to take place at the Points of Interconnection. The Management Committee shall update from time to time, the list giving the Points of Interconnection between the networks of the Operating Members.

Quick Reserve: Quick Reserve is interruptible load or capacity readily available from Cold Reserve which can be started and loaded within ten (10) minutes to meet the system demand. This includes hydro plant, gas turbines, pumped storage and interruptible load.

Reserve Storage: Reserve Storage is plant that is stored for more than three (3) months in a wet or dry stored condition. Some auxiliary plant may be run periodically.

Regulating Margin: The on-line capacity that can be increased or decreased to allow the system to respond to all reasonable demand changes in order to comply with the Control Performance Criteria.

SAPP : Southern African Power Pool.

Service Schedules: Service Schedules shall mean schedules governing various types of transactions that may be entered between Operating Members to reduce costs or improve reliability of supply.

TERMS USED IN GUIDELINES (CONTD.)

Slow Reserve: Slow Reserve is capacity available from Cold Reserve and considered to be ready for synchronization to the system within twenty-four (24) hours. The purpose of slow reserve is to replace any generating units on unplanned outages or to meet forecasted demand.

Special Protection System (SPS) :Shall mean a protection scheme designed to perform functions other than the isolation of electrical faults; it is also called “remedial action scheme”. See Guideline II “Relay Co-ordination”.

Spinning Reserve: Spinning Reserve shall mean the unused capacity which is synchronized to the System and which can be delivered immediately without manual intervention.

Station Service: Shall mean electric supply to ancillary equipment used to operate a generating station or substation.

Station Service Generator: Shall mean a generator used to supply electrical energy to station service equipment.

Supervisory Control and Data Acquisition (SCADA): Shall mean a system of remote control and telemetry used to monitor and control the transmission system.

System: A combination of generation, transmission, and other components making up the network of an electric utility, or group of utilities.

System Controller: A person who controls the electric system.

Time Error Monitor(Monitor): Control Area designated to monitor time errors.

Unplanned Outage: Unless otherwise agreed and confirmed in writing between all relevant Control Centres, Unplanned Outages shall mean outages which are not scheduled with the advance notice of two weeks and agreed in writing.

Wheeling: Wheeling shall mean transmitting a contractual amount of power over specified time periods through the System of an Operating Member who is neither the Seller nor the Buyer of this power.

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GUIDELINE I : SYSTEM CONTROL

A. GENERATION CONTROL…

Criteria:

Each Control Area shall operate sufficient generating capacity under Automatic Generation Control (AGC):

(1) to continuously balance its generation and interchange schedules to its load,

(2) provide its contribution to interconnection frequency regulation, as specified hereafter.

Requirements:

1. Automatic Generation Control (AGC) shall continuously compare:

   (i) total net actual interchange adjusted for actual frequency and;

   (ii) total net scheduled interchange adjusted for scheduled frequency;

   to determine the Control Area's Area Control Error (ACE) and respond by returning the ACE to zero.

2. Each Control Area shall provide an amount of Spinning Reserve responsive to AGC, which is synchronized to the interconnection. This amount shall be raised or lowered by AGC to provide adequate system regulation and satisfy Control Performance Criteria.

3. Each Control Area shall operate its AGC on tie-line bias mode, unless such operation is adverse to System or Interconnection reliability. The requirements for tie-line bias control are as follows:

   3.1 The Control Area shall set its frequency bias (expressed in MW/0,1 Hz) as close as practical to the Control Area's frequency response characteristic. Frequency bias may be calculated in several ways:

      3.1.1 A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by recording and averaging the frequency response characteristic after several disturbances during peak hours.

A. GENERATION CONTROL (CONTD.)

3.1.2 A variable (linear or non-linear) frequency bias value may be used which is based on a variable function of tie-line deviation versus frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response as it varies with parameters such as load, generation, governor characteristics and frequency.

3.2 The Operating Sub-Committee shall approve performance standards applicable to frequency bias.

3.2.1 In no case shall the monthly average frequency bias be less than 1% of the Control Area's estimated yearly peak demand per 0.1 Hz.

3.3 Each Control Area shall review its frequency bias settings by 1 January of each year and shall recalculate its settings to reflect any change of frequency response characteristic in the Control Area.

3.3.1 The bias setting or the method used to determine the setting may be changed whenever any of the parameters listed in Clause 3.1.2 above changes.

3.4 Each Control Area must be able to prove to the Operating Sub-Committee that its frequency bias settings closely match its frequency response characteristic.

3.5 Each Control Area shall communicate its frequency bias setting and the method for determining that setting to the Operating Sub-Committee.

Recommendations:

1. AGC should be in service all the time and when not possible, arrangements must be made to include the System in an established Control Area or to switch over to temporary manual control.

2. Turbine governors and other control systems, including AGC and HVDC control systems should be tested periodically to verify their correct operation. The maximum intervals between such tests shall be specified by the Operating Sub- Committee.

3. Turbine governors and HVDC controls, where applicable, should respond to system frequency deviation, unless there is a temporary operating problem.

A. GENERATION CONTROL (CONTD.)

4. Each Member should establish normal and emergency rates of response for each generator and each HVDC terminal.

5. Load –limiting devices should be applied only when the rate of load change has an adverse effect on the generators or when it can jeopardize transmission security.

6. The Regulating Margin should be distributed between as many generating units as possible.

7. Each Control Area should schedule its generation so as to comply with the Control Performance Criteria for any expected change in load characteristics and daily load patterns.

8. All generating units of consequential size should be equipped with AGC's to ensure that the Control Area continuously adjust its generation to its load plus its net scheduled interchange.

9. Frequency dead band be set to less than 0.05 Hz.

10. ACE dead band be set to less than 0.05 Hz.

Background:

Accurate and adequate generator control helps reduce time error, frequency deviations, and Inadvertent Energy interchanges.

Each Control Area will respond to frequency deviations in accordance with the response characteristics of its own System. Most of this response will be reflected in the Control Area's net interchanges. By monitoring the interchange deviations from schedule, the frequency deviation from schedule, and by using the Control Area's frequency response characteristic, it is possible to determine through the AGCs, whether the imbalance between load and generation is internal or external to the Control Area. If internal, the AGC will adjust the generation to correct the imbalance. If external, no AGC action should occur. However, the frequency response to the interchange deviations through the governors, should be allowed to continue until the external system with the generation surplus or defiency corrects its imbalance and returns the frequency to schedule.

Until system response can be continuously measured, it must be estimated. This estimate is the tie-line frequency bias setting. The closer the tie-line frequency bias matches the actual system frequency response, the better AGC will be able to distinguish between internal and external imbalances and reduce the number of unnecessary control actions. Therefore, the basic requirement of tie-line frequency bias is that it matches the actual system response as closely as practicable.

B. VOLTAGE CONTROL

Criteria :

Each System and Control Areas shall maintain system and Interconnection voltages within agreed upon high and low limits by operating suitable capacitive and reactive resources. Reactive generation scheduling, transmission equipment switching and load shedding if necessary, shall be implemented to maintain voltage levels under credible contingency conditions.

Requirements:

1. Devices used to regulate transmission system voltages and reactive flows should be under the control of the Control Centre.

2. Control Centres shall monitor transmission system voltages to immediately identify any deviation from prearranged voltage levels and take corrective action. (see Appendix 1B "Transfer Capability").

   2.1 Pre-arranged voltage levels, reactive control equipment settings and changes in transmission configuration shall be co-ordinated with adjacent Systems.

   2.2 Transfer limits shall take into account voltage or reactive power restrictions. These restrictions should be clearly displayed in each Control Centre.

   2.3 Control Centres shall monitor and keep reactive power flows within agreed upon limits on the interconnectors between neighbouring countries.

Recommendations:

1. Important transmission lines should remain in service during light-load periods whenever possible. They should be removed from service for voltage control only after all reactive power sources have been utilised and only if studies indicate that system reliability will not be degraded below acceptable levels. Whenever possible, switching lines out for voltage control, shall be restricted to lines other than the interconnections between neighbouring systems.

2. Automatic voltage regulators on generators, synchronous condensers and Static Var Compensators (SVC's) shall be kept in service whenever possible.

3 Devices used to regulate transmission system voltage and reactive power flows maybe switchable without having to de-energise other equipment facilities.

B. VOLTAGE CONTROL (CONTD.)

4. When a generator's automatic voltage regulator is out of service, field excitation shall be maintained at a level adequate for stable operation.

5. Systems with HVDC transmission facilities shall utilize the power resources associated with the DC converters.

C. TIME AND FREQUENCY CONTROL

Criteria:

Interconnection frequency shall be scheduled at 50 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error.

Operating limits for frequency deviation and time error shall be established with Interconnection reliability as first priority.

Each Control Area shall participate in all time error corrections.

One Control Area shall be selected every year to monitor the time error of the Interconnection and to issue time error correction orders.

Requirements:

1. Every year the Operating Members shall designate a Control Area (the Monitor) which shall monitor time and initiate or terminate corrective actions when time error reaches +/- 10 seconds.

2. Time error corrections shall start and end on the hour, a notice shall be given at least thirty (30) minutes before the time error correction is to start or stop.

3. Each order of time error correction shall be identified (by a number).

4. The offset to carry out the time error correction shall be implemented as follows:

   4.1 The frequency scheduled may be offset by 0.02 Hz, leaving the frequency bias unchanged , or

   4.2 If the normal frequency (50 Hz) cannot be offset, the net interchange schedule (MW) may be offset by an amount corresponding to a 0.02 Hz frequency deviation (i.e 20 % of the frequency bias setting).

C. TIME AND FREQUENCY CONTROL (CONTD.)

4.3 Inadvertent interchange accumulations may be paid back unilaterally by offsetting a tie-line schedule when such action will contribute to the correction of a time error.

4.3.1 If time is slow and there is a negative accumulation (under-generation), the AGC may be offset to over-generate and pay –back inadvertent interchange accumulation and at the same time reduce time error.

4.3.2 If time is fast and there is a positive accumulation (over-generation), the AGC may be offset to under-generate and pay-back inadvertent interchange accumulation and reduce time error.

4.3.3 AGC offset may be made by either offsetting the frequency schedule up to 0.02 Hz, leaving the bias setting normal or offsetting the net tie-line schedule by up to 20 % of the Control Area's bias or 5 MW, whichever is greater.

4.3.4 Inadvertent pay-back shall end when either the time error is zero or has changed signs, the accumulation of inadvertent interchanges has been corrected to zero, or a scheduled time error correction begins, which takes precedence over offsetting frequency schedule to pay-back inadvertent.

5. Time error correction notifications will be broadcast by the Monitor to the Operating Members.

6. The Monitor shall periodically issue a notification of time error, accurate to within 0.1 second, to Members to ensure uniform calibration of time standards.

7. Each Control Area shall, at least annually, check and calibrate its time error and frequency devices against a common reference.

8. When one or more Control Areas have been separated from the interconnection, upon reconnection, they shall adjust their time error devices to coincide with the Interconnection by one of the following methods:

8.1 Before connection, the separated area may institute a Time Error Correction Procedure to correct its accumulated time error to coincide with the indicated time error of the Monitor, or

C. TIME AND FREQUENCY CONTROL (CONTD.)

8.2 After interconnection, the time error devices of the previously separated area may be corrected to coincide with the indicated time error of the Monitor. A notification of adjustment time error shall be passed through the Monitor as soon as possible after interconnection.

9. Time error correction procedures are found in Appendix 1.A

Recommendations:

1. The Control Areas may implement automatic time error control as part of their AGC scheme.

   1.1 If automatic time error correction is used, all Control Areas should participate.

   1.2 Automatic time error control in progress should be suspended whenever an announced time correction is to start.

2. Systems using time error devices that are not capable of automatically adjusting for leap-seconds should arrange to receive advance notice of the leap-second and make the necessary manual adjustment in a manner that will not introduce a disturbance into their control system.

Background:

The difference between load and generation results in frequency deviations from 50 Hz, and the integrated deviation appears as a departure from standard time.

The satisfactory operation of the Interconnected systems is dependent, in part, upon accurate frequency transducers and recorders and time error devices associated with AGC equipment.

D. INTERCHANGE SCHEDULING BETWEEN CONTROL AREAS

Criteria:

Power transfers between Control Areas shall be scheduled through transmission paths either belonging to those Control Areas or pre-arranged via wheeling contract(s) when other Control Areas are involved.

D. INTERCHANGE SCHEDULING BETWEEN CONTROL AREAS (CONTD).

The net amount of interchange scheduled between Control Areas shall not exceed the mutually agreed transfer limits of the common interconnections and alternate paths which have been arranged for between the parties. When establishing normal and emergency transfer limits, the sending, wheeling, and receiving Control Areas shall consider the effect of power flows through their own and other parallel Systems or Control Areas based on mutually acceptable reliability criteria. In no case shall the scheduled power transfers between two Control Areas exceed the total installed capacity of own or pre-arranged transmission facilities between the two Control Areas.

Schedule changes shall be made at a time and rate agreeable to both the supplier and receiver and within the capacity of each Party to control the change.

Requirements:

1. Interchanges shall be scheduled only between Control Areas directly interconnected unless there is a wheeling contract or mutual agreement with another Control Area(s) to provide wheeling services.

2. Interchange schedules or schedule changes shall not violate established reliability criteria in another system.

   2.1 When Control Areas are interconnected in such a way that parallel flows present reliability problems, the affected Control Areas shall develop multi-Control Area interchange monitoring techniques and pre-determined corrective actions to mitigate or alleviate potential or actual transmission system overloads.

   2.2 Transfer limits shall be re-evaluated and interchange schedules adjusted as soon as practicable if transmission facilities become overloaded or are taken out of service, or when changes are made to the bulk system which can affect transfer limits. These should be determined both in terms of transient stability and thermal rating and should be provided to the Control Centres on an on-going basis.

3. The maximum net scheduled interchange between two Control Areas shall not exceed the lesser of two values:

   3.1 The total capacity of the transmission facilities in service between the two Contorl Areas owned by the them or available to the under wheeling arrangements, contracts, or mutual agreements, or

D. INTERCHANGE SCHEDULING BETWEEN COTROL AREAS (CONTD)

3.2 The mutually established transfer capacity between two Control Areas considering other transmission facilities available to them under wheeling arrangements. (Transfer Capacity is defined in Appendix I.B "Transfer Capacity").

4. The sending, wheeling and receiving Control Areas that are parties to an interchange transaction shall agree on the following:

   4.1 The schedule's magnitude, starting and ending times.

   4.2 A change of schedule must be entered five (5) minutes before the hour and must reach the full magnitude on the hour.

   4.3 The scheduled generation in one Control Area that is to be delivered to another Control Area must also be scheduled with all wheeling Control Areas unless there is a contract or mutual agreement among the sending, wheeling and receiving Control Areas to do otherwise.

5. Control Areas shall develop procedures to disseminate information on interchange schedules and facilities out of service which may have adverse effect on other Control Areas not involved in the scheduled interchange. The involved parties shall predetermine schedule priorities which will be used if a schedule reduction becomes necessary.

Background:

Scheduled interchanges must be co-ordinated between Control Areas to prevent frequency deviations, accumulation of inadvertent interchanges and violations of mutually agreed transfer limits.

E. CONTROL PERFORMANCE CRITERIA

Criteria:

The Control Performance Criteria defines a standard of minimum control performance. Each Control Area shall exceed this minimum as much as it can reasonably be done.

Requirements:

1. Two criteria shall be used to continually monitor control performance during normal conditions (see Section 2.1 in the "Control Performance Criteria Training Document").

E. CONTROL PERFORMANCE CRITERIA (CONTD.)

1.1 ***A1 Criteria***- The Area Control Error (ACE) must return to zero at least every ten (10) minutes. Violations of this criteria are counted for each subsequent ten (10) minute period that the ACE fails to return to zero.

1.2 ***A2 Criteria***- The average ACE for each of the 6 ten (10) minute periods during the hour (i.e for the ten (10) minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must not exceed specific limits, referred to as Ld. These limits are determined from the Control Area's rate of change of demand characteristics. (See Section 2.1.2.1 in the "Control Performance Criteria Training Document" appended to these Guidelines for the methods for calculating Ld).

2. Two criteria shall be used to continually monitor control performance during disturbances (see the "Control Performance Criteria Training Document" Section 2.2):

   2.1 ***B1 Criteria***- The ACE must return to zero within ten (10) minutes following the start of the disturbance.

   2.2 ***B2 Criteria***- The ACE must start to return to zero within one (1) minute following the start of the disturbance.

3. The ACE used to determine compliance to the Control Performance Criteria shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

4. All Control Areas shall respond to control performance surveys that are requested by the Operating Sub-Committee.

Recommendations

1. Each Control Areas should comply with the A1 and A2 Criteria . A1 Criteria should be met at least 90% of the time and A2 Criteria on average 80% for each month.

Background:

Control performance is the degree to which a Control Area succeeds in matching its generation to its demand plus scheduled power interchanges taking into account the effects of frequency bias. The Control Performance Criteria (CPC) establishes minimum standards for control performance and provide a means for measuring the relative control performance of each Control Area. While these standards define the minimum acceptable performance, each Control Area shall meet and strive to exceed these standards.

F. INADVERTENT ENERGY MANAGEMENT

Criteria:

Each Control Area shall, through daily schedule verification and the use of reliable metering equipment, accurately account for Inadvertent Energy interchanges. Recognising generation and load patterns, each Control Area shall do its best to prevent inadvertent interchange accumulation. Each Control Area shall reduce accumulated Inadvertent Energy.

At least a common MWh- meter, with readings provided hourly to the relevant Control Centres shall measure the power transfers at each Point of Interconnection between two Control Areas.

Accumulation of Inadvertent Energy:

Inadvertent Energy is defined to be the difference between the net scheduled energy on the tie-lines in a Control Area and net actual energy delivered on the tie-lines in that Control Area.

The Inadvertent Energy needs to be monitored and managed carefully.

Requirements:

1. Inadvertent Energy interchange shall be calculated and recorded hourly and may be accumulated as a credit or debit to a Control Area (see the "Inadvertent Interchange Accounting Training Document" appended to these Guidelines).

2. All interchanges, between Control Areas, shall be included in the Inadvertent Energy interchange account.

3. Inadvertent Energy interchange accumulations shall be paid back by any one or both of the following methods:

   3.1 ***Method 1***- Inadvertent Energy interchange accumulations may be paid back by scheduling interchange with another Control Area

      3.1.1 The other Control Area must have an inadvertent accumulation in the opposite direction.

      3.1.2 The scheduled amount of inadvertent pay-back shall be agreed upon by all Control Areas involved.

F. INADVERTENT ENERGY MANAGEMENT (CONTD.)

3.2 ***Method 2***- Inadvertent Energy interchange accumulation may be paid back unilaterally by offsetting tie-line schedules when such action will contribute to the correction of the existing time error.

3.2.1 If time is slow and there is a negative accumulation (under generation), the AGC may be offset to over-generate and pay-back inadvertent interchange accumulation and reduce time error.

3.2.2 If time is fast and there is a positive accumulation (over-generation), the AGC may be offset to under-generate and pay-back inadvertent interchange accumulation and reduce time error.

3.2.3 AGC offset may be made either offsetting the frequency schedule by up to 0,02 Hz, leaving the bias setting normal or offsetting the net tie-line schedule by up to 20% of the Control Area's bias or 5 MW, whichever is greater.

3.2.4 Inadvertent pay-back shall end when the time error becomes zero or has changed signs, the accumulation of inadvertent interchange has been corrected to zero, or a scheduled time error correction begins, because this action takes precedence over offsetting frequency schedule to pay-back inadvertent.

3.2.5 Control Areas using automatic time error control techniques shall not use Method 2 to reduce their accumulations of inadvertent. Method 1 is the only acceptable way for these Control Areas to reduce their accumulations of inadvertent.

4. Inadvertent Energy interchange accumulated during on-peak hours shall be paid back during on-peak hours. Inadvertent Energy accumulated during off-peak hours shall be paid back during off-peak hours.

5. Each Control Area shall submit a monthly summary of inadvertent Energy interchange as detailed in Appendix I.C "Inadvertent Interchange Energy Accounting Practices".

5.1 Inadvertent Energy summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both on-peak and off-peak periods.

5.2 Each Control Area shall submit its monthly summary report to the Operating Sub-Committee representative who will prepare a composite tabulation for distribution to all other Operating Sub-Committee representatives.

F. INADVERTENT ENERGY MANAGEMENT (CONTD.)

5.3 Each Operating Sub-Committee representative shall distribute a monthly summary to their respective Control Areas as agreed upon.

Background:

Inadvertent Energy is the difference between the Control Area's net actual interchange and net scheduled interchange. Interchange is partially due to the frequency deviations occurring on the Interconnection. Unintentional Inadvertent Energy interchanges are due to instrument and control errors, improper control settings, poor generator response time, fluctuations in demand, etc.

G. CONTROL SURVEYS .

Criteria:

The Co-ordination Centre shall request control performance surveys bi-annually or whenever required. These surveys shall serve the purpose of identifying control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, insufficient generation under automatic generation control, general control performance deficiencies, or other factors contributing to inadequate control performance deficiencies, or other factors contributing to inadequate control performances.

Requirements:

1. The following surveys, as described in the Control Performance Criteria Training Document, shall be conducted when called for by the Co-ordination Centre:

   1.1 An Area Control Error survey to determine the Control Areas' interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

   1.2 An Area Frequency Response Characteristics survey to determine the Control Areas' response to changes on system frequency.

   1.3 A Control Performance Criteria survey to monitor the Controls Area's control performance during normal conditions and during disturbances.

H. CONTROL EQUIPMENT REQUIREMENTS

Criteria:

The control equipment of each Control Area shall be designed and operated to enable the Control Area to continuously meet its System and Interconnection control obligations and measure its performance. The control equipment shall be designed and operated in accordance with accepted industry norms.

All Control Area interconnections shall be equipped to telemeter MW power flows at the Points of Interconnection to both area Control Centres simultaneously. The telemetering shall be from an agreed-upon terminal ultilising common metering equipment.

The Control Centre displays and consoles shall present a clear and understandable picture of Control Area parameters. This shall include the necessary information from the Control Area itself as well as all the necessary information from other Control Areas.

Requirements:

1. Each Control Area shall perform control error checks at the end of every hour using tie-line MWh meters to determine the accuracy of its control equipment.

2. The Control Centre shall adjust control settings to compensate for equipment error until repairs can be made.

3. All tie-line flows between Control Areas shall be included in each Control Area’s ACE calculation.

4. Control Centres shall be provided with a recording of all variables necessary to monitor control performance, generation response, and after-the-fact analysis of area performance. As a minimum, Area Control Error (ACE), system frequency, and net actual tie-line interchanges shall be continuously recorded.

5. Adequate and reliable back-up power supplies shall be provided and periodically tested at the Control Centres and other critical locations to ensure continuous operation of AGC and vital data recording equipment during the loss of normal power supply.

6. All tie-line MW and MWh/hr measurements shall be telemetered to both Control Centres and shall originate from a common, agreed upon terminal using common primary metering equipment.

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APPENDIX 1.A : TIME ERROR CORRECTION PROCEDURES

1. A time correction may be terminated after five (5) hours or after any hour in which a time correction of 0.5 seconds has NOT been achieved. A time correction may be extended beyond five (5) hours if the average correction has exceeded 0.5 seconds per hour.

2. After the termination of a time correction because of the “5-hour rule” above, or failure to make a correction of 0.5 seconds per hour, slow time correction may be reinstated after the frequency has returned to 50 Hz or above for a period of sixty (60) minutes. At least one (1) hour should elapse between the termination and re-initiation notices.

3. The Monitor may postpone or cancel a time correction if requested to do so by any Member, or if warranted by the overall capacity situation.

4. The time reference for the Southern African Power is UTC (Universal Time Co-ordinated) plus two (2) hours.

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APPENDIX I.B : TRANSFER CAPABILITY

TRANSFER LIMIT CRITERIA

1. STUDY METHOD

The transfer limits must be determined for normal operation and emergency condition using steady state, stability and voltage collapse models. This must be done using, as far as possible, the N-1 criteria. These limits must be identified and the limit which have the most severe consequences if exceeded, should be recommended as the transfer limit to the appropriate Control Centres. If an operating condition in a system creates a problem, it shall be reflected in the calculation of the transfer limit of the tie-line.

2. CONTINGENCIES

The following single contingencies are recommended:

1.1 Steady State:

- Loss of any transmission line having an impact on the loading of the tie-lines
- Loss of the largest reactive power source
- Evaluation of the danger of voltage collapse

2.2. Transient Condition:

- ❖ System intact:
    - Step-up transformer in the ZESA/ZESCO system.
    - Loss of one or several generators due to a common cause
    - Tripping of one large generator in the Eskom / BPC system
    - Loss of any transmission line or tie-line that could have an impact on the interconnected system
- ❖ Evaluate the ARC policy on tie-lines.
- ❖ Evaluate auto-reclose following single line-to-ground fault on any transmission line that will have an impact on the Interconnection.

APPENDIX I.B : TRANSFER CAPABILITY (CONTD)

3. RESULT ANALYSIS

The results of the above studies must show the following criteria are met:

3.1 Steady State:

- No transmission line or transformer should be loaded more than 100% of its nameplate rating.
- The busbar voltages should remain within the following bands

Normal operation:

VOLTAGE	MIN kV (PU)	MAX kV (PU)
400 kV	380 (0,95)	420 (1,05)
330 kV	313,5 (0,95)	345,5 (1,05)
275 kV	261 (0,95)	289 (1,05)
220 kV	209 (0,95)	231 (1,05)
132 kV	125 (0,95)	138 (1,05)

The voltage at the following power stations must remain within the following bands:

Kariba South:	Hwange;
324 kV (0,98 pu)	338 kV (1,024 pu)
335 kV (1,015 pu)	345 kV (1,045 pu)

For a N-1 criteria the voltage at Kariba South must remain within the following band:

322 kV (0,9 75 pu)
340 kV (1,03 pu)

3.2 Transient Condition:

- The interconnected systems must remain in synchronism following the disturbances mentioned in 2.2.

APPENDIX I.B : TRANSFER CAPABILITY (CONTD)

- Following the first swing, the busbar voltages on the Interconnection should not be lower than the values specified in the table below for more than 100 msec:

VOLTAGE	VOLTAGE DIP
400 KV	-10 %
330 KV	-10%
275 KV	-10%
220 KV	-10%
132 KV	-10%

4. GENERAL

- The system to be studied should be clearly defined as well as the year to study;
- The transfer limits should be studied for peak and minimum load conditions;
- The output of each station should be clearly specified;

During emergencies, the Control Centres can operate the lines at a higher loading than the transfer limits. During such conditions, the Control Centres must realize that they could experience severe voltage dips, should a fault occur. These risks must be accepted if transfer limits are exceeded.

A report has to be issued by the study group and evaluated by the OSC. The transfer limits shall be updated once the OSC accepts new results and recommendations.

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APPENDIX I.C : INADVERTENT INTERCHANGE ENERGY ACCOUNTING PRACTICES

A. INTRODUCTION .

Uniform accounting practices will help to identify and eliminate errors. They will also highlight poor control performances that contribute to the accumulation of inadvertent interchanges.

These practices outline the methods and procedures required to reconcile energy accounting and inadvertent interchange balances.

The Control Areas must adhere to the Operating Guidelines to properly monitor and account for inadvertent interchanges.

B. SCHEDULES .

All hourly schedules and schedule changes shall be agreed to between the relevant Control Areas prior to implementation. The Agreement shall cover magnitude, rate of change and common starting time.

Dynamic schedule integrated on an hourly basis shall be agreed to between the relevant Control Areas after the end of the hour, but in such a manner as not to impact on inadvertent account.

C. ACCOUNTING PROCEDURES

1. ***Daily accounting***- Each Control Area shall agree with adjacent Control Areas upon the following quantities for each hour and on a daily basis:

   1.1 Scheduled interchanges (MWh).
   1.2 Actual interchanges (MWh) as derived from the SCADA system.
   1.3 Total amounts during each day for on-peak and off-peak periods (for operational purposes).

2. ***Monthly accounting***- After having agreed on scheduled and actual interchanges during the on-peak and off-peak hours of each day, adjacent Control Areas shall verify that the accumulated values for the month end balance.

3. The on-peak and off-peak hours are defined as follows:

Weekdays:	on-peak	:	06H00 - 20H00
	off-peak	:	20H00 - 06H00

APPENDIX I.C : INADVERTENT INTERCHANGE ENERGY ACCOUNTING PRACTICES (CONTD)

Saturdays :	on-peak	:	07H00 - 13H00
	off-peak	:	00H00 - 07H00
	off-peak	:	13H00 - 24H00
Sundays :	off-peak	:	00H00 - 24H00

D. ADJUSTMENTS FOR ERRORS

1. Periodic adjustments shall be made to correct for differences between hourly telemetered MWh totals and the totals derived from the tariff meters on the tie-lines.

2. Adjacent Control Areas shall agree upon the differences described above and shall assign the relevant corrections to the on-peak and off-peak hours.

3. Any adjustment necessary due to known meter errors, transmission losses or other circumstances shall be split between on-peak and off-peak hours as appropriate.

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A. REAL POWER (MW) SUPPLY

Criteria:

Each Control Area shall operate its active power resources so as to ensure a level of operating reserve sufficient to account for such considerations as errors in forecasting, generation or transmission equipment unavailability, loss of generating units, forced outage rates, maintenance schedules, regulating requirements and load diversity between Control Areas. Following the loss of load or of active power resources, the Control Area shall take appropriate steps to reduce its Area Control Error to zero within ten (10) minutes and to protect itself against the next contingency.

The Operating Sub-Committee shall specify the operating reserve policy in terms of:

(i) the permissible ratio between Spinning and Quick Reserve,
(ii) the procedure for applying Operating Reserve policy in practice, and
(iii) the limitations, if any, upon the amount of interruptible load which may be considered as Quick Reserve.

1. Requirements:

1.1 The System Controller shall be kept informed of all generation and transmission resources available for use.

1.2 The System Controller shall have all the necessary information, including weather forecasts and past load patterns, to predict the system's near-term load pattern.

1.3 Each Operating Member shall provide, as a minimum, Operating Reserve as follows:

1.3.1 An amount of Spinning Reserve responsive to Automatic Generation Control (AGC), which is sufficient to provide normal regulating margin, plus

1.3.2 An additional amount of Operating Reserve sufficient to reduce the Area Control Error to zero within ten (10) minutes following the loss of generating capacity which would result from the most severe single contingency. Interruptible load may be included in Quick Reserve provided that it can be interrupted in less than ten, (10) minutes and remain disconnected until replacement generation can be brought to service.

A. REAL POWER (MW) SUPPLY (CONTD.)

1.3.3 Additional resources shall be made available as soon as practicable to restore the necessary Operating Reserve after the initial reserve has been used as the result of an incident.

1.4 In order to ensure compliance with Clause 1.3 above, the Operating Reserve shall be sufficiently dispersed throughout the system, shall take into account the effective contribution of unused generating capacity in an emergency, the time required for these contributions to be effective, the transmission limitations at the time and all the local requirements that may exist.

1.5 All Operating Members shall from time to time, review the adequacy of their Operating Reserve policy by evaluating the impact of all relevant contingencies.

2. Operating Reserve Obligation:

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

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

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

Each Member shall declare its annual peak demand and its largest unit that is in service, everytime these values change.

The following formula shall be used to calculate the minimum System Operating Reserve Requirements (SORR) of an Operating Member;

A. REAL POWER (MW) SUPPLY (CONTD.)

$$SORR = PORR \times \frac{(2Ds/Dt + Us/Ut)}{3}$$

where:

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

An example where the sharing of Spinning Reserve between Operating Members has been calculated can be found on the following Table:

	Largest Generator	Maximum Demand	Operating Reserve	Spinning Reserve	Quick Reserve
ESKOM	920	27972	1091,6	545,8	545,8
ZESA	220	1767	119,0	59,8	59,5
ZESCO	150	1030	76,1	38,0	38,0
BPC	33	215	16,4	8,2	8,2
EdM	24	169	12,3	6,1	6,1
NAMPOWER	80	321	34,0	17,0	17,0
SNEL	62	400	30,7	15,3	15,3
LEC		0			
SEB		0			
TANESCO		0			
ENE		0			
TOTAL	1489	31874	1380	690	690

Recommendations:

The effect of station service generators on area security should be considered before their shut down for economic reasons.

B. REACTIVE POWER (MVAR) SUPPLY

Criteria:

Each Control Area shall supply its own reactive power requirements and shall keep appropriate reserves to maintain voltage levels during a contingency. This includes the Control Area's share of the reactive power required by the interconnections between Members' Systems. The reserves shall be located electrically where they can be applied effectively and timeously when a contingency occurs.

Control Areas shall co-ordinate the use of voltage control equipment to maintain transmission voltages and reactive power flows at levels consistent with the Interconnection security.

Requirements:

1. The System Controller shall receive all the necessary information on available generation and flows of reactive power.

2. Reactive sources shall be operated so that scheduled voltages can be maintained under all normal and first contingency conditions.

3. Reactive energy sources shall be dispersed and located in such a way that they can be applied effectively and quickly when contingencies occur.

4. Prompt action shall be taken to restore reactive energy resources if these drop below acceptable levels.

5. The System Controller shall take all necessary actions, including load reductions, to prevent voltage collapse when reactive energy sources are insufficient.

Recommendations:

1. Surveys to determine compliance with voltage limits and reactive power requirements should be conducted on a regular basis.

2. Reactive power reserves should be automatically applied in the event of an emergency.

C TRANSMISSION OPERATION

Criteria:

Transmission equipment is to be operated within its nameplate rating except for temporary conditions after a contingency has occurred.

C. TRANSMISSION OPERATION (CONTD.)

When line loadings, equipment loadings or voltage levels deviate from the ratings or are excepted to exceed emergency ratings following a contingency, with the result that the reliability of the Interconnection is at risk, Control Areas experiencing or causing the condition shall take immediate steps to remedy the situation. These steps include informing other Systems, adjusting generation, changing schedules between Control Areas, initiating load relief measures and taking every action that may be required.

Transmission system operation shall be co-ordinated between Control Areas. This includes co-ordination of equipment outages, voltage levels, MW and MVAr flows, and switching operations that affect two or more Systems.

Requirements:

1. System Controllers shall monitor all critical transmission system loadings and shall check that voltage limits and emergency ratings are not exceeded.

2. Transmission Planned Outages shall be co-ordinated with other Systems that are likely to be affected.

3. Transmission Forced outages shall be communicated to any System that may be affected.

4. Forced Outages of key transmission facilities shall be communicated to all adjacent Systems as quickly as possible.

5. Each Control Area shall use appropriate, up-to-date studies as reference for establishing transmission operation procedures.

Recommendations:

1. Important transmission lines should be kept in service during light-load periods whenever possible. They should be removed from service for voltage control only after all other reactive control measures have been implemented in full and provided that studies can show that system reliability is not degraded below acceptable levels.

D. RELAY CO-ORDINATION

Criteria:

Systems and Control Areas shall co-ordinate the application, and maintenance of protective relays. They shall develop criteria which will enhance system reliability with minimum adverse effects on the Interconnection.

D. RELAY CO-ORDINATION (CONTD)

System Controllers shall be familiar with the intended operation of protective relays and shall have access to the information relating to the operation of these relays.

Requirements:

1. Appropriate technical information concerning protective relays shall be available in each Control Centre.

2. System Controllers shall be familiar with the purpose, operation and limitations of protection schemes.

3. If equipment or protection relay fails and reduces system reliability, the appropriate personnel shall be notified and corrective action shall be carried out as soon as possible.

4. All new protective schemes and all modifications to existing protective schemes shall be co-ordinated between neighbouring Systems if these neighbouring Systems are affected by the change.

5. Protection on major transmission lines and interconnections shall be co-ordinated with other interconnected Systems.

6. Neighbouring Systems shall be notified in advance of changes in generating sources, transmission, load or operating conditions which could require changes in their protection schemes.

7. The Control Centres shall monitor the status of every Special Protection System (SPS) and notify all affected Systems of each status change.

Recommendations:

1. Protection design and operation should consider the following:

   1.1 Protection schemes should be of minimum complexity consistent with achieving their purpose.

   1.2 Back-up protection schemes should be in service to enable Members to carry out normal maintenance and calibration on the main protective scheme without having any impact on protection availability.

   1.3 Protection schemes should not normally operate for brief overloads, transient surges or power swings.

D. RELAY CO-ORDINATION (CONTD)

1.4 High speed relays, high speed circuit breakers and automatic reclosing should be used where studies indicate their application will enhance stability margins. Single pole tripping and reclosing may be appropriate on some lines.

1.5 Automatic reclosing under out-of-step conditions should be prevented by blocking relays.

1.6 Under-frequency load shedding relays should be co-ordinated so as to ensure system stability and integrity.

1.7 Protection applications, setting and co-ordination should be reviewed periodically and whenever major changes in generation, transmission, load or operating conditions are anticipated.

1.8 The adequacy of the communication channels used for line and other protections, should be assessed periodically. Automated channel monitoring and failure alarms should be provided for protection communication channels if such failure can cause loss of generation, loss of load or cascading outages.

2. Each Member shall implement protection philosophy and preventive maintenance procedures which will improve their system reliability with the least adverse effects on the Interconnection. These procedures shall be provided to all relevant staff and should specify when instruction and training are necessary. Each Member should co-ordinate these procedures with any other Members that could be affected. These procedures should include:

2.1 Planning and application of protection schemes.

2.2 Review of protection schemes and settings.

2.3 Intended operation of protection schemes under normal, abnormal and emergency conditions.

2.4 Testing and preventive maintenance of relays shall be scheduled at regular intervals, as well as other key protection equipment and associated components.

2.4.1 Testing operation of the complete protection scheme should be tested under conditions as close as possible to actual conditions, including actual circuit breaker operation where feasible.

D. RELAY CO-ORDINATION (CONTD)

2.4.2 The testing of communication channels between protection relays belonging to different Systems, should be carried out and the test results recorded.

2.5 Analysis of actual protection operation.

3. A prompt investigation should be made to determine the cause of abnormal protection performance and correct any deficiencies in the protection scheme.

4. Special Protection Systems (SPS):

4.1 The Control Centres shall monitor the status of each Special Protection System (SPS) and notify all affected Members of any change in status.

4.2 SPS should be designed for periodic testing without affecting the integrity of the protected System. They should normally achieve at least the same level of reliability as that provided by other protection schemes.

4.3 SPS should be designed with inherent security to minimize the probability of mal-operation, even with the failure of a primary component.

4.4 Each SPS should be reviewed periodically to determine if it is still required and if it will still perform the intended functions. Seasonal changes in the SPS or its relay settings and the concerned Member shall then inform the other Members about the new settings.

4.5 Every time an SPS operates, the incident should be reviewed and analysed for correctness.

5. Prompt action shall be taken to correct the causes of mal-operation.

Background

Protection greatly influences the operation of interconnected Systems, especially under abnormal conditions. Protection schemes used on the interconnection for generator tripping and other remedial measures, are of primary concern to the respective Members. However, the protection for internal use in a System often directly, or indirectly, affects adjacent Systems.

D. RELAY CO-ORDINATION (CONTD)

Special Protection Systems also known as Remedial Action Schemes, are relay configurations designed to perform functions other than isolation of electrical faults. These schemes are usually installed to maximize transfer capability. However, they may be used to maintain system or generator stability or to control active and reactive power flows on critical components immediately following a disturbance, or to split a system or open an interconnection at preplanned locations to prevent cascading. The general design objective for any SPS shall be to perform its intended function(s) in a dependable manner while refraining from unnecessary operation. An SPS can expose a System to a greater reliability risk. The integrity of a whole System may depend on its correct operation.

E MONITORING SYSTEM PARAMETERS .

Criteria:

Each System and Control Area shall continuously monitor those parameters (such as MW, Flow, MVAr flow, frequency, voltage, phase angle, etc.), internal and external to its System or Control Area, that indicate the condition of the Interconnection.

The Control Centres shall be provided with adequate equipment to accomplish this objective. Measuring instruments of suitable range and reliability for both normal and emergency conditions shall be installed and maintained at strategic points.

Requirements:

1. Monitoring equipment shall be used to bring to the System Controller's attention, any deviation from normal operating condition and to indicate, if appropriate, the need for corrective action.

2. Each Control Area shall use sufficient instruments of suitable range, accuracy and sampling rate to ensure accurate and timely monitoring of the Interconnection under normal and emergency situations.

3. Control Centres shall monitor transmission line status, MW and MVAr flows, voltages, Load Transfer Capability (LTC), settings and status of rotating and static reactive resources.

4. Control Centres shall monitor system frequency.

5. Reliable instrumentation, including voltage and frequency meters with sufficient range to cover probable contingencies, shall be available in the Control Room of every power station.

E MONITORING SYSTEM PARAMETERS (CONTD

6. Automatic oscillographs and other recording devices shall be installed at key locations and set to standard time to assist post- disturbance analysis.

7. Because of possible system separation, frequency information from several locations shall be monitored at the Control Centres.

8. Monitoring shall be sufficient, so that in the event of system separation, both the existence of the separation and the boundaries of the separated areas can be determined.

9. Transmission line monitoring shall be capable of evaluating the impact of losing any significant transmission or generation facility on the Interconnection both inside and outside the Control Area.

10. Critical unmanned facilities shall be monitored for physical security

11. Planned Outages of generation or transmission facilities shall be taken into account in the monitoring scheme.

12. Voltage schedules shall be co-ordinated from a central location within each Control Area and co-ordinated with adjacent Control Areas.

13. All tie-line SCADA metering between Control Areas, shall be available to all the Operation Members' Control Centres.

Background:

The System Controllers must have information available to them at all times so that they can accurately assess the status of the system under normal operating conditions, make the correct decisions following the occurrence of a contingency and rapidly restore system integrity after a disturbance.

F. INFORMATION EXCHANGE- NORMAL SYSTEM CONDITIONS

Criteria

System conditions – information concerning system conditions shall be transmitted to all Control Centres as needed.

Requirements:

1. Each Control Area shall disseminate information on actual and scheduled interchanges, voltages and Planned Outages which may have adverse effect on other Control Areas.

F. INFORMATION EXCHANGE – NORMAL SYSTEM CONDITIONS (CONTD.)

2. Control Centers shall notify other Systems of current or foreseen operating conditions which may affect the Interconnection reliability. Examples of operating conditions that may affect reliability are: critically loaded facilities, Planned and Forced Outages, the commissioning of new facilities, abnormal voltage conditions, new or degraded protective systems, Force Majeure and new or degraded communication channels.

Recommendations:

To ensure that communication networks are functioning properly and timely exchange of information takes place, specific monitoring and testing procedures of communication facilities, should be developed, documented and implemented in every System.

G. INFORMATION EXCHANGE – DISTURBANCE REPORTING

Criteria:

Disturbance reporting – Disturbances or unusual occurrences which may jeopardize the operation of the Interconnection, that will result, in equipment damage or customer supply interruptions, shall be studied pro-actively and in sufficient depth to enable the Operating Members to take the appropriate measure to prevent such incidents. The facts surrounding a disturbance shall be made available to all Control Centres.

Requirements:

1. Major operating problems that could affect other Systems shall be reported as soon as possible to neighbouring Systems. These could include loss of generation, of load or of facilities

2. Large disturbances affecting two or more Systems shall be promptly analysed by the affected Members.

3. Based on the magnitude and duration of the disturbance or abnormal occurrence, those Systems or Control Areas responsible for investigating the incident shall provide oral and if necessary, written reports.

Recommendations:

1. If an operating problem cannot be resolved quickly, the probable duration and possible effects should be reported to the other Control Centres.

G. INFORMATION EXCHANGE – DISTURBANCE REPORTING (CONTD.)

2. The Control Centre experiencing a disturbance, should provide a written preliminary report to the other Control Centres within fourteen (14) days.

3. When there has been a disturbance affecting the Interconnection, Member's delegates to the Operating Sub-Committee, should make themselves available to the System or Systems immediately affected, in order to assist in the investigation.

Background :

Other affected Systems must be kept informed of potential or actual operating problems. Disturbances which result in substantial customer interruptions attract news media. The event and its causes will also be of considerable interest to the Operating Members, and should be viewed by the Control Centres as a learning experience.

H. MAINTENANCE CO-ORDINATION

Criteria

Each system shall establish schedules for inspection and preventive maintenance of its generation, transmission and protection facilities: as well as of its control, communication and other auxiliary systems. These maintenance and inspection schedules shall be co-ordinated with other Control Centres and Control Areas to ensure that the outage pattern does not violate agreed upon reliability criteria.

Requirements:

1. Planned generator and transmission Outages that may affect the reliability of Interconnected operations, shall be planned and co-ordinated (notification of cancellation at least twenty-four (24) hours in advance) between the affected Systems and Control Areas. Special attention shall be given to the results of pertinent studies. A Planned Outage shall be advised at least two (2) weeks in advance and confirmed in writing. Each Control Area must be advised of any return of equipment to service.

2. If mutually agreed between Members an unplanned outage may be converted to a planned outage, provided that the requesting member submits a documented case specifying the reason for the extended unplanned outage and the time period before the equipment is returned to service.

3. Scheduled generator and transmission outages that may affect the reliability of interconnected operations shall be planned and co-ordinated among affected Members and control areas. Special attention shall be given to results of pertinent studies.

H. MAINTENANCE CO-ORDINATION (CONTD.)

4. Scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., shall be co-ordinated as required.

5. Scheduled outages of telemetering and control equipment and associated communication channels shall be co-ordinated between the affected systems and control areas.

6. Annual maintenance plans shall be co-ordinated between the effected members and submitted to the Operating Sub-Committee in October of the previous year.

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GUIDELINE III : EMERGENCY OPERATIONS

A. INSUFFICIENT GENERATING CAPACITY

Criteria:

A Control Area which experiences a shortage of generation, shall promptly balance its generation and interchange schedules to its load without regard to cost , to avoid excessive use of the assistance provided by interconnection frequency bias. The reserve inherent to frequency deviation is intended to be used only as a temporary source of emergency energy and is to be promptly restored to enable the interconnected Systems to withstand the next contingency. A Control Area unable to balance its generation and interchange schedules to its load shall shed sufficient load to ensure that its Area Control Error (ACE) is corrected.

A Control Area anticipating a shortage of generation, shall bring to service all available generation, postpone equipment maintenance, schedule energy purchases and prepare itself to reduce load.

Requirements:

1. Agreements between neighbouring Systems or within the SAPP, shall contain provisions for compulsory emergency assistance to Operating Members for periods not exceeding six (6) hours.

2. When a shortage of generation occurs, generation and transmission facilities shall be used to the fullest extent practicable to promptly restore normal system frequency and voltage, and return ACE to the performance criteria specified in Guideline I.E

   2.1 If Automatic Generation Control (AGC) has become in-operative, manual control shall be used to balance generation and scheduled interchanges to load.

   2.2 The deficient System shall schedule all available assistance that is required with as much advance notice as possible.

   2.3 The deficient System shall use the assistance provided by the frequency bias only for the time needed to accomplish the following:

      2.3.1 Load its operating reserve as fast as possible.
      2.3.2 Analyse its ability to recover using only its own resources.
      2.3.3 If necessary, determine the availability of assistance from other Members and schedule that assistance.

A. INSUFFICIENT GENERATING CAPACITY (CONTD.)

3. If all other steps prove inadequate to remedy the situation, the deficient system shall take immediate action which includes, but is not limited, to the following:

    3.1 Schedule all available emergency assistance from other Systems.

    3.2 Implement manual load shedding.

4. Unilateral adjustment of generation to return frequency to the scheduled value by other Control Centres, beyond that supplied through frequency bias and new interchange schedules, shall not be attempted. Such adjustment may result in the transfer limits of the transmission facilities being exceeded.

Recommendations:

1. Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.

2. Plant operators should be supplied with instructions specifying the frequency and voltage below which it is undesirable to continue to operate generators connected to the system.

    2.1 Protection systems should be installed to automatically trip the generators at pre-determined high and low frequencies.

    2.2 If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliary load.

    2.3 Identify and address the problems that could delay the restoration of the System.

3. Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generation units or their auxilaries, maintain communication channels and facilitate re-start.

B. TRANSMISSION - OVERLOAD, VOLTAGE CONTROL

Criteria:

If a transmission facility becomes overloaded or if voltage / reactive power levels are outside established limits and the condition cannot be relieved by normal means such as adjusting generation or service schedules, and if a credible contingency under these conditions would adversely impact the Interconnection, appropriate relief measures, including load shedding, shall be implemented promptly to return the transmission facility to within established limits. This action shall be taken by the System or Control Area experiencing the problem if that System or Control Area can be identified, or by other Systems or Control Areas, as appropriate, if that identification cannot readily be made.

Requirements:

1. If an overload on a transmission facility or an abnormal voltage/reactive power condition persists and is caused by another System, the affected System shall notify the neighbouring or remote System of the severity of the overload or abnormal voltage/reactive conditions and request appropriate remedy.

2. If an overload on a transmission facility or abnormal voltage/reactive condition persists and equipment is endangered, the affected System may disconnect the facility at risk. Neighbouring Systems impacted by the disconnection shall be notified prior to switching, if practicable, otherwise, promptly thereafter.

3. Action to correct a transmission overload shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighbouring Systems. If all other means fail, corrective action may require load shedding.

4. Systems shall take all appropriate action up to and including shedding of firm loads in oeder to keep the transmission facilities within acceptable operating limits.

C. LOAD SHEDDING

Criteria:

After taking all other remedial steps, a System or Control Area whose integrity is In jeopardy due to insufficient generation or transmission capacity shall shed customers rather than risk an uncontrolled failure of components making up the Interconnection.

C. LOAD SHEDDING (CONTD.)

Requirements:

1. When a severe under-frequency occurs, automatic load shedding shall be co-ordinated throughout the Interconnection together with other operations, such as generator tripping or isolation, shunt capacitor tripping, and other automatic actions which occur during abnomal frequency or voltage conditions.

2. Automatic load shedding shall be in steps and initiated by one or more of the following parameters: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow. See table in Appendix III.A "Automatic Under frequency Load Shedding in the SAPP".

3. If a System or Control Area is separated from the Interconnection and there is insufficient generating capacity to restore system frequency following automatic under-frequency load shedding, additional load shall be shed manually before re-synchronising.

Recommendations:

1. Voltage reduction for load relief should be restored to in the distribution networks. Voltage reductions on the sub-transmission or transmission system may be effective in reducing load; however, voltage reductions should not be restored to on the high voltage transmission system unless the system has been isolated from the Interconnection.

2. In those situations where it will be beneficial, manual load shedding should be implemented to prevent voltage collapse or imminent separation from the Interconnection due to transmission overload.

D. SYSTEM RESTORATION

Criteria:

After a system collapse, restoration shall begin as soon as possible, provided it can proceed in an orderly and secure manner. Systems and Control Areas shall co-ordinate their restoration actions. Priority shall be given to the auxiliary supply of power stations and of transmission sub-stations. Even though the restoration is to be expeditious, Control Centres shall avoid premature action to prevent another collapse of the System.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency during this process.

D. SYSTEM RESTORATION (CONTD.)

Requirements:

1. Each Member shall have a restoration plan:

   1.1 Operating personnel shall be trained in the implementation of the plan. Such training should include simulation exercises, if practicable.

   1.2 The restoration plan shall be updated, as necessary, to reflect changes in the power network and correct deficiencies found from experience and during the restoration exercises.

   1.3 Each Control Area shall identify interconnections with adjacent Control Areas that may be used to restore power and obtain agreement for their use.

   1.4 Telecommunication facilities needed to implement the plan shall be periodically tested.

2. Following a disturbance in which one or more areas are isolated, steps shall immediately be taken to return the system to normal:

   2.1 The Control Centre shall determine the extent and condition of the isolated area(s).

   2.2 The System Controller shall then take the necessary action to restore system frequency to normal, including adjusting generation, placing additional generators on line, or shedding load.

   2.3 When voltage, frequency and phrase angle permit, the Control Centre may re-synchronise the isolated area(s) with the surrounding area(s), properly notifying adjacent Systems of the size of the area being reconnected and the capacity of transmission lines effecting the reconnection.

E EMERGENCY INFORMATION EXCHANGE

Criteria:

A System or Control Area which is experiencing or anticipating an emergency shall communicate its current and future status to neighbouring Systems and Control Areas within the SAPP. Systems able to provide emergency assistance shall make known their capabilities.

E. EMERGENCY INFORMATION EXCHANGE (CONTD.)

Requirements:

1. A System shall inform neighbouring Systems and Control Areas within the SAPP, through pre-determined communication channels, whenever the following situations are anticipated or arise:

    1.1. The System's condition is burdening other Systems or reducing the reliability of the Interconnection.

    1.2. The System is unable to purchase capacity to meet its load and reserve requirements on a day-ahead basis or at the start of an hour.

    1.3. The System's line loadings and voltage/reactive power levels are such that a single contingency could threaten the reliability of the Interconnection.

    1.4. The System anticipates 8% or greater voltage reduction or appeals to the public for load reduction because of an inability to purchase emergency capacity.

    1.5. The System has instituted 8% or greater voltage reduction or appeals to the public to reduce load or load shedding for system wide problems.

F. SPECIAL SYSTEM OR CONTROL AREA ACTION

Criteria:

Because the facilities of each System may be vital to the secure operation of the Pool, Systems and Control Areas shall make every effort to secure the Interconnection. However, if a System or Control Area establishes that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its network.

If the Interconnection is split, abnormal frequency and voltage deviations may occur. To permit re-synchronising, relief measures shall be applied by the System(s) causing the frequency and voltage deviations.

Requirements:

1. When an emergency occurs, a prime consideration shall be to safeguard the Interconnection. This will permit maximum assistance to the System(s) in trouble.

F. SPECIAL SYSTEM OR CONTROL AREA ACTION (CONTD.)

2. If an area is separated during a disturbance, interchange schedules between Control Areas or fragments of Control Areas within the separated area shall be immediately reviewed and appropriate adjustments made in order to facilitate restoration. Attempts shall be made to maintain the adjusted schedules whether generation control is manual or automatic.

Recommendations:

1. If abnormal levels of frequency or voltage resulting from a disturbance make it unsafe to operate the generators or their support equipment connected to the System, their separation or shutdown should be accomplished in a manner which minimizes the time required to re-synchronise and restore the System.

2. AGC should remain operative whenever possible.

G. CONTROL CENTRE BACK-UP

Criteria:

Each Control Area shall have a plan to continue its operations in the event that its Control Centre becomes inoperable.

Recommendations:

1. When a Member develops a plan to ensure continued operations in the situation where a Control Centre becomes in-operable, Guideline I should be taken into account to ensure that the Control Area does not become a burden to the other Systems.

   1.1 If the Control Area has a back-up Control Centre, it should be remote from the site of the main Control Centre.

   1.2 Each Control Area should have communication equipment installed at its back-up Control Centre, capable of communicating with the key points of its own Control Area and with the other Control Areas.

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APPENDIX III. A: UNDER- FREQUENCY LOAD SHEDDING SETTING OF ALL UTILITIES

AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING IN THE SAPP

UTILITY	UNDER-FREQUENCY	% LOAD OF MAX DEMAND TO BE SHED	TIME DELAY
ESKOM	Voluntary		
	1. 49,2 Hz	10%	0,3 seconds
	2. 49,1 Hz		0,3 seconds
	3. 49,0 Hz		0,3 seconds
	Mandatory		
	1. 48.8 Hz	10%	2 seconds
	2. 48,5 Hz	10%	2 seconds
	3. 48,2 Hz	10%	2 seconds
	4. 47,9 Hz	10%	2 seconds
ZESA	Mandatory		
	1. 48,8 Hz	5%	No time delay
	2. 48,5 Hz	5%	No time delay
	3. 48,2 Hz	5%	No time delay
	4. 49,0 Hz	5%	20 seconds
	5. Rate 0,8Hz/secs	15%	No time delay

APPENDIX III. A: UNDER- FREQUENCY LOAD SHEDDING SETTING OF ALL UTILITIES

AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING IN THE SAPP (CONTD.)

UTILITY	UNDER-FREQUENCY	% LOAD OF MAX DEMAND TO BE SHED	TIME DELAY
ZESCO	Mandatory 1. 48,8 Hz 2. 48,5 Hz 3. 48,2 Hz 4. 49,0 Hz 5. Rate 0,8 Hz/ seconds	 5% 5% 5% 5% 15%	 No time delay No time delay No time delay 20 seconds No time delay
BPC	Mandatory 1. 49,0Hz 2. 48,7Hz 3. 48,3Hz 4. 48,1Hz	 4.7% 5.2% 9.4% 24.1%	 2 seconds 2 seconds 2 seconds 2 seconds
NAMPOWER	Under review		
SNEL			
EDM	No scheme		
LEC	No scheme		
SEB	No scheme		

GUIDELINE IV: OPERATING PERSONNEL

A RESPONSIBILITY AND AUTHORITY

Criteria:

Each System Controller shall be delegated sufficient status and authority to take any action necessary to ensure that the System or Control Area for which he is responsible, is operated in a stable and reliable manner.

Requirements:

1. Each Control Area and Control Centre shall provide its System Controllers with a clear definition of their authority and responsibilities.

2. Each Control Area and Control Centre shall advise the other Control Centres of the authority and responsibilities of its own System Controllers.

B. SELECTION

Criteria:

Each Control Centre Area shall selects its System Controllers using criteria likely to promote reliable and safe operation.

Recommendations:

1. Personnel selected as System Controllers should be capable of directing other operating personnel in their own System, and, at the same time, working efficiently with their counterparts in other Control Centres.

   1.1 A System Controller should have:

   - a high level of intellectual ability and above-average reasoning capability especially when under stress:

   - reasonable mechanical, electrical and mathematical aptitudes, communication, supervision and decision-making skills.

   1.2 System Controllers should also be proficient in lower-level assignments.

2. To maintain an adequate level of capability and expertise in system operations, each System should have and implement screening techniques and selection procedures for its System Controllers. These should include:

B. SELECTION (CONTD

2.1 Evaluation of the candidates against a fairly detailed job description.

2.2 Analysis of the candidate's past records and experience.

2.3 In-depth interview with each candidate.

2.4 Evaluation of intelligence, logical frame of mind, technical aptitudes, mathematical and communications skills together with psychological fitness.

2.5 Educational and academic background.

2.6 Physical examination.

3. Establish a Grading Committee in each Control Area to evalute/interview candidates and assess them against a detailed job description.

C. TRAINING

Criteria:

Each System and/or Control Area shall provide its personnel with training that is designed to promote reliable and safe operation.

Requirements:

1. Each Control Area shall provide its System Controllers with guidelines to resolve those problems that can be caused by realistic contingencies and known restrictions on equipment.

2. Each System Controller shall be thoroughly educated and trained in the Control Area operating policies and in the basic principles of interconnected system operation as outlined in these Operating Guidelines.

Recommendations:

1. Each System should implement a training program for its Control Centre personnel.

   1.1 Training should include both classroom and on-the-job training.

   1.2 Each System should periodically simulate emergency situations in order to maintain a high level of readiness among Control Centre personnel.

   1.3 Inter-Utility exchanges of System Controllers should be encouraged.

C. TRAINING (CONTD)

2. Each System should consider training on power system simulator.

3. Each System should consider the list of items in Appendix IV. A for inclusion in their training program.

4. Each System should consider the simulation of unusual occurrences as part of their training program.

Background:

The increasing sophistication of Control Centres which covers control equipment, instrumentation and data presentation techniques, plus the interconnection of adjacent Systems, requires careful selection and training of Control Centre personnel. Proper and quick action during an emergency, as well as minute-to-minute operation of a complex system, depends upon human performance. Each System Controller should be well qualified, adequately educated, mentally suited, and thoroughly conversant with the principles and procedures of interconnected system operations.

To operate a power system effectively, a System Controller must have a thorough understanding of the basic principles of electricity and since a power system consists of a variety of components, equipment and apparatus, through understanding of their characteristics and how these devices integrate to form a system, is absolutely essential. The System Controllers should also be capable of supervising others, of good communication and of proper decision-making.

In anticipation of abnormal situations on the Interconnection, System Controllers should receive special training to increase their awareness and make them capable of quickly conveying key information to other Control Centres.

D. RESPONSIBILITY TO OTHER OPERATING GROUPS

Criteria:

The operating personnel of each System and Control Area shall be responsive to requests for information emanating from other Systems or Control Areas and from the Operating Sub-Committee.

Requirements:

1. The operating personnel of Systems and Control Areas shall be aware of the operating information required by other Systems or Control Areas and by the Operating Sub-Committee.

D. RESPONSIBILITY TO OTHER OPERATING GROUPS (CONTD.)

Background:

A key element of good system operation is the efficient transfer of information to other operating personnel in the SAPP during normal and emergency conditions.

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APPENDIX IV. A. : SUGGESTED ITEMS FOR INCLUSION IN THE TRAINING COURSE OF SYSTEM CONTROLLERS

This Appendix lists the items that should be included in a training course for System Controllers.

A. NORMAL OPERATIONS

1. Basics of Power Flows:

1.1 Alternating Current (AC):

- 1.1.1 Generation
- 1.1.2 Transmission
- 1.1.3 Transformation
- 1.1.4 Loads and effect on system
- 1.1.5 Phase angle
- 1.1.6 Phase shifting transformers
- 1.1.7 Reactors
- 1.1.8 Capacitors
- 1.1.9 Parallel flows

1.2 Direct Current (DC):

- 1.2.1 Transmission
- 1.2.2 Interconnections

2. Voltage Control:

- 2.1 Load characteristics
- 2.2 Standards
- 2.3 Schedules
- 2.4 Cause for voltage deviations
- 2.5 Generation excitation
- 2.6 Transformer taps
- 2.7 Reactive sources e.g
  - 2.7.1 Generators
  - 2.7.2 Synchronous condensers
  - 2.7.3 Capacitors
  - 2.7.4 Reactors
  - 2.7.5 Static VAr compensators
- 2.8 Line and cable switching

A. NORMAL OPERATIONS (CONTD.)

3. ***Concepts of Active Power Control***:

    3.1 Operating Reserve
    3.2 Dispatching techniques
    3.3 Generators AGC's and Governors
    3.4 Area Control Error (ACE)
    3.5 Interchange control
    3.6 Inadvertent interchange
    3.7 Special operating programme(s)

4. ***Economic Operation:***

    4.1 Dispatching techniques
    4.2 Heat rates
    4.3 Fuel costs
    4.4 Start-up and shutdown costs
    4.5 Pumped storage costs
    4.6 Unit commitment
    4.7 Economic loading
    4.8 Effects of Transmission losses
    4.9 Reactive flows
    4.10 Utilisation of limited energy capacity
    4.11 Pumped storage capacity
    4.12 Incremental and decremental costs
    4.13 Accounting procedures

5. ***Operating Guidelines and Constraints:***

    5.1 Operating Manual
    5.2 Operating Guidelines
    5.3 Control Performance Criteria
    5.4 Reliability Criteria for Interconnected Systems Operation
    5.5 Contingency assessment.

        5.5.1 Generator outages
        5.5.2 Transmission lines outages
        5.5.3 Transformer outages
        5.5.4 Busbar Outages
        5.5.5 Combination of above
        5.5.6 Outages of reactive energy sources

A. NORMAL OPERATIONS (CONTD.)

5.6 Equipment capabilities and limits:

5.6.1. Thermal
5.6.2. Voltage / Reactive
5.6.3. Relay
5.6.4. Stability

5.7 Reserve requirements (special)
5.8 Time error and frequency
5.9 Voltage
5.10 Switching-voltage and redistribution of power flows

6 Operating considerations:

6.1 Safety of personnel and equipment
6.2 Synchronising
6.3 Line switching and clearance
6.4 Ferro resonance
6.5 Metering failures
6.6 Maintenance scheduling criteria:

6.6.1 Generation
6.6.2 Transmission
6.6.3 Substation
6.6.4 Protection

B. ABNORMAL OPERATIONS

1. Dynamic Performance of System:

1.1 Transient stability
1.2 Oscillations
1.3 Relay action
1.4 Control-initiated swings
1.5 Causes of disturbances
1.6 Special Protection System (SPS)

B. ABNORMAL OPERATIONS (CONTD.) .

2. Dynamic Performance of Equipment:

2.1 Governor response
2.2 Exciter response
2.3 Relays and breakers
2.4 Under-frequency relays:
2.5 Metering
2.6 Automatic controls:

  2.6.1 Plant
  2.6.2 AGC
  2.6.3 Voltage
  2.6.4 Generator and load tripping
  2.6.5 System separation

2.7 Special Protection System (SPS)

3. Recognition of Abnormal Conditions:

3.1 Loss of load
3.2 Breaker operation
3.3 Line fault
3.4 Generator trip
3.5 Frequency deviation
3.6 Interchange deviation
3.7 Voltage level
3.8 System separation
3.9 Communication with power stations, substations and other utilities
3.10 Parallel flows

4. Remedial Action:

4.1 Islanding
4.2 Load shedding
4.3 Generator dropping / trips
4.4 Shifting generation
4.5 Switching generation
4.6 Isolated system operation
4.7 High-and-low –frequency operation
4.8 High-and-low-voltage operation

B. ABNORMAL OPERATIONS (CONTD.)

5. Recovery:

5.1 Generation start-up capabilities and pick-up rates
5.2 Sectionalising
5.3 Load pickup priorities and problems
5.4 Synchronising within a System and at the Points of Interconnection

C. COMMUNICATIONS

1. Facilities Available:

1.1 Common power line carrier schemes
1.2 Private microwave systems
1.3 Radio
1.4 Emergency power supplies
1.5 Satellite communication systems

2. Information Exchange:

2.1 Standard terminology
2.2 Neighbouring Systems
2.3 Power Plants
2.4 Substations
2.5 Management
2.6 News Media
2.7 Governmental agencies

D. INTERCONNECTED SYSTEM OPERATION

1. SAPP Operating Criteria and Guidelines:

2. ***Philosophy of Operation***:

2.1 Benefits
2.2 Obligations
2.3 Responsibilities
2.4 Authority

D. INTERCONNECTED SYSTEM OPERATION (CONTD.)

3. ***Effects on System Performance***:

   3.1 Frequency
   3.2 Interchanges
   3.3 Reserves
   3.4 Mutual assistance
   3.5 Pooling arrangements
   3.6 Communications

4. ***Abnormal Operations:***

   4.1 Responsibilities
   4.2 Actions required

D. MODERN POWER SYSTEM CONTROL AIDS

1. ***Equipment:***

   1.1 Man-machine interface
   1.2 Supervisory control
   1.3 Data acquisition
   1.4 Fail over and restart

2. ***Theory and use of Software Applications for Normal and Emergency Conditions:***

   2.1 Interaction of software results on Systems and other programs
   2.2 Effects

3. ***Alternative Control Methods during Equipment and Software Unavailability:***

4. ***Typical Software Applications:***

   4.1 Economic dispatch
   4.2 AGC
   4.3 Unit commitment
   4.4 Operator load flow
   4.5 Contingency analysis

E. MODERN POWER SYSTEM CONTROL AIDS (CONTD.)

4.6 Corrective strategies
4.7 State estimation
4.8 Interchange accounting
4.9 Transmission evaluation
4.10 Automated billing

F. SUPERVISORY SKILLS

1. Personnel supervision
2. On-the-job training, preparation of
3. Verbal communication
4. Decision - making
5. Influence of stress

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GUIDELINE V: OPERATIONS PLANNING

A. NORMAL OPERATIONS

Criteria:

Each Control Area shall plan its future operations in-co-ordination with other affected Control Areas to ensure that normal operation on the Interconnection proceed in an orderly and efficient manner.

Requirements:

1. Each Control Area shall schedule its plant and interchanges so as to meet the daily load pattern and the changes in load characteristics.
2. The results of studies dealing with the operation of the System shall be available to System Controllers.

Recommendations:

1. Periodic reviews should be conducted with planning engineers to ensure that the long- term plans comply with the SAPP Operating Guidelines.
2. A Control Centre should participate in the studies conducted by other Control Centres when:

   2.1 The facilities in a System may affect the operation of the Interconnection.

   2.2 The operating conditions impose restrictions on generating facilities.

   2.3 It is necessary to know the operating limitations on the system when all transmission facilities are in service.

   2.4 It is necessary to know the operating limitations on the system when transmission facilities are scheduled or forced out of service.

   2.5 Voltage and reactive power schedules are likely to be restricted.

3. Studies should be made at least annually (or at such times as system changes warrant) to determine the transfer capacity between Control Areas.
4. The determination of generating capability should take into account, among other variables, weather, ambient air and water conditions, and fuel quality and quantity.

A. NORMAL OPERATIONS (CONTD.)

5. Each Control Area should determine the power transfer capabilities of its transmission system and identify potential problems by conducting simulation studies.

    5.1 Thermal and stability limits, previous short-and long term loading, voltage limits and seasonal (temperature) characteristics should be considered when determining the capability of transmission facilities.

    5.2 Transfer capability studies should consider voltage, reactive, thermal, and stability limits of internal and external system equipment. (Ref: “Transfer Capability”); Generating unit and transmission facility outage patterns should be considered. Studies should determine the additional reactive power that is required under reasonable generating and transmission contingencies.

6. Computer models and data utilized for analysis and planning system operations should be updated and replaced as necessary to ensure that they can accurately and adequately represent the System. The same software and computer platforms should be used throughout the SAPP. (It is recommended to move away from main frame computers to personal computers).

7. Neighbouring systems should use uniform line identifiers and ratings when referring to transmission facilities being part of an interconnected network.

B. PLANNING FOR SHORT-TERM EMERGENCY CONDITIONS

Criteria:

A set of contingency plans consistent with SAPP Operation Guidelines (particularly Guideline III) shall be developed, maintained and implemented to enable the Systems and Control Areas to cope with operating emergencies. These plans shall be co-ordinated with other Systems and Control Areas as appropriate.

Requirements:

1. Plans developed and maintained to cope with operating emergencies shall include procedures that can be executed by System Controllers.

Recommendations:

1. Appropriate government agencies should be informed about these plans.

C PLANNING FOR LONG-TERM EMERGENCY CONDITIONS

Criteria:

Each System and Control Area shall maintain comprehensive and co-ordinated procedures to deal with long-term capacity or energy deficiencies.

Recommendations:

1. The SAPP should develop capacity and energy emergency plans that will enable it to reduce to the fullest extent possible, the impact of a capacity of energy shortage on its customers.

2. Appropriate governmental agencies should be appraised of the plans.

3. If existing interchange agreements cannot be implemented, new agreements providing for emergency capacity or energy transfers, should be prepared.

4. The energy emergency plan should include or consider the following items:

   4.1 Co-ordination with neighbouring Systems.

   4.2 An adequate plan of fuel inventory which recognizes reasonable delays or problems in the delivery or production of fuel.

   4.3 Fuel switch-over and removal of environmental constraints for generating units and other facilities.

   4.4 The reduction of the System ‘s own energy use to a minimum.

   4.5 Appeals to the public through the media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

   4.6 Load management and voltage reductions.

   4.7 The operation of all generating sources so as to save the fuel which is in short supply.

   4.8 Appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that relies on fuels other than the one in short supply.

   4.9 Use of interruptible and curtailable loads to conserve the fuel in short supply.

C. PLANNING FOR LONG-TERM EMERGENCY CONDITIONS (CONTD)

4.10 Request appropriate Government Agencies to direct programs which will save energy.

4.11 A mandatory load curtailment plan will be used as a last resort. This plan should preserve the loads essential to the health, safety, and welfare of the community.

4.12 Notify appropriate Government Agencies as the various steps of the emergency plan are implemented.

4.13 Notify co-generators and independent power producers to maximize availability and output.

5. The capacity emergency plan should address the following items:

5.1 Co-ordination with neighbouring Systems.

5.2 Plans to seek removal of environmental constraints which reduce the capacity of generating units.

5.3 The reduction of the System's own energy consumption to a minimum.

5.4 Implementation of load management as appropriate.

5.5 The operation of all generating sources to maximize output and availability.

5.6 Appeals to large industry and commercial customers to reduce no essential energy use during peak and standard hours and maximize any customer owned generation.

5.7 Use interruptible load and curtailable customer loads to reduce capacity requirements.

5.8 Request appropriate Government Agencies to direct programs which will reduce capacity requirements.

5.9 A mandatory load curtailment plan will be used as a last resort. This plan should preserve the loads essential to the health, safety, and welfare of the community.

5.10 Notify appropriate Government Agencies as the various steps of the emergency plan are implemented.

C. PLANNING FOR LONG-TERM EMERGENCY CONDITIONS (CONTD.)

5.11 Notify co-generators and independent power producers to maximize availability and output.

6. Every System and Control Area should participate in the co-ordination of capacity and energy emergency plans and offer all possible assistance during such emergencies. The following steps should be taken:

   6.1 Establish and maintain reliable communications between Systems.

   6.2 If a capacity or energy emergency is foreseen, contact neighbouring Systems as far in advance as possible to assess regional conditions and arrange for all the relief that is available or necessary.

   6.3 Co-ordinate transmission and generation maintenance schedules to maximize capacity available or to conserve the fuel in short supply; this includes cooling water for hydro stations.

   6.4 Arrange deliveries of electrical energy from remote Systems through normal channels.

   6.5 Continue to assess the level of generating capacity available and of energy supply and forecast future needs.

Criteria:

Each System and Control Area shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays, or extreme power flows that could result in an uncontrolled failure of components of the Interconnection. The program shall be co-ordinated throughout the Interconnection to prevent excessive transmission loadings and voltage deviations.

Requirements:

1. Each System shall establish plans for automatic load shedding and System Controllers shall have authority to implement manual load shedding when necessary.

   1.1 Load shedding plans shall be co-ordinated with those of other Members.

   1.2 Automatic load shedding shall be initiated as soon as system frequency voltage has declined to a level agreed upon beforehand.

D. LOAD SHEDDING

1.2.1 Automatic load shedding shall be carried out in steps and in function of one or more of the following parameters: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.

1.2.2 The amount of load shed in each step shall be calculated to minimize the risk of uncontrolled separation, loss of generation, or system shutdown.

1.3 Automatic load shedding shall be co-ordinated throughout the SAPP with under-frequency isolation of generating units, tripping of shunt capacitors or any other automatic action which will occur under abnormal frequency, voltage, or power flow conditions.

Recommendations:

1. Automatic load shedding plans should be based on system dynamic performance where the greatest probable imbalance between load and generation is simulated.

   1.1 Plans to shed load automatically should be analysed to ensure that no unacceptable over-frequency, over- voltage or transmission overload will occur.

   1.1.1 If over-frequency is likely, the amount of load shed should be reduced or automatic over-frequency load restoration should be provided.

   1.1.2 If over-voltages are likely, the load shedding program should be modified to minimize that probability.

2. When scheduling an automatic load shedding operation, the System Controllers should consider the needs of their own Control Area or Utility as well as the capabilities of the interconnectors.

3. A generation-deficient Control Area may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the Interconnection. This isolation plan may be implemented only with the consent of neighbouring Systems and if it leaves the Interconnection intact.

4. Each System and Control Area should consider isolating its generators to protect them from extended abnormal voltage and frequency conditions. If feasible, generators should be separated carrying their own auxiliary load.

E. SYSTEM RESTORATION

Criteria:

Each System and Control Area shall develop and periodically update a plan to restore its electric network in a stable and orderly manner in the event of a partial or total shutdown. This plan shall be co-ordinated with other Control Areas to ensure a consistent restoration of the Interconnection.

A reliable and adequate source of black start power shall be provided. Where these sources are remote from the generating units, instructions shall be issued to expedite availability. Steps to restore generation, shall be verified by real life testing whenever possible.

Requirements:

1. Each System and Control Area shall establish a restoration plan with adequate operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunication channels.

   1.1 Restoration plans must be developed with the intent of restoring the integrity of the Interconnection.

   1.2 Restoration plans shall be co-ordinated with neighbouring Systems.

2. System restoration procedures shall be verified by real life testing and simulation.

Recommendations:

1. Where an outside source of power is necessary for starting up generating units, switching procedures should be pre-arranged and periodically reviewed with System Controllers and other operating personnel.

2. Periodic tests should, where possible, be carried out to verify black-start capability.

3. In order to systematically restore loads without overloading the rest of the system, opening circuit breakers should be considered to isolate loads in blacked-out areas i.e. sectionalise the “dead” system.

4. Load shed during a disturbance should be restored only when doing so will have an adverse effect on the System or the Interconnection.

   4.1 Load may be restored manually or by supervisory control only by direct action or by an order issued by the Control Centre as generating and transmission capacity become available.

E. SYSTEM RESTORATION (CONTD.)

4.2 Automatic load restoration may be used to reduce restoration time.

4.2.1 Automatic restoration should be co-ordinated with neighbouring Systems and Control Areas.

4.2.2 Automatic restoration should not aggravate frequency excursions, overloading tie-lines, or burden any portion of the Interconnection.

5. All synchronoscopes should be calibrated in degrees. Voltage angle differences at the points of re-synchronisation should be communicated in degrees.

6. Re-energising oil-filled pipe-type cables should be given special consideration, especially if loss of oil pumps could cause gas pockets to form in pipes or potheads.

7. The following should be considered when trying to maintain normal transmission voltage during restoration:

   7.1 Remove shunt capacitors, switch-in shunt reactors or add small blocks of load to prevent excessive Ferranti effect when energizing long transmission lines or high-voltage cables at the end of a long, lightly-loaded system.

   7.2 The capability of the generators to provide or absorb reactive power.

8. The Control Centres should know the re-synchronising points and procedures. Procedures should provide for alternative courses of action when there is a lack of information or loss of communication that would affect re-synchronising.

9. Each power station should have written procedures for orderly start-up and shutdown of the generating units.

   9.1 These procedures should be updated when required.

   9.2 Exercises should be held periodically to ensure that plant operators are familiar with the procedures.

10. Each power station should have a source of emergency power to reduce the time required for restarting. Hydro-electric power stations should have built-in restarting facilities.

11. Back-up voice telecommunication facilities, including emergency power supplies and alternative telecommunications channels should be provided to ensure co-ordinated control of operations during the restoration process.

E. SYSTEM RESTORATION (CONTD.)

12 Control Centres using SCADA systems should consider providing master trip reset points to each sub-station and power station high voltage yard to expedite the restoration process.

13 Protection schemes should be in working order during the restoration. Relay polarization sources should be maintained during the process.

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GUIDELINE VI: TELECOMMUNICATIONS

A FACILITIES

Criteria

Each System and Control Area shall be equipped with adequate and reliable telecommunication facilities internally and with other Systems and Control Areas to ensure the exchange of information necessary to maintain the reliability of the Interconnection. When possible, redundant facilities using alternative routes and medium, shall be provided.

Requirements:

1. Reliable and secure telecommunication networks shall be provided within and between Systems and Control Areas.

2. Dedicated telecommunication channels shall be provided between a Control Centre and the Control Centre of each adjacent Syatem.

3. All dedicated telecommunication channels should not require intermediate switching to establish communication.

4. Alternate and physically independent telecommunication channels should be provided for emergency use to back up the circuits used for critical data and voice communications.

5. Restoration services on critical telecommunications channels should be available twenty-four (24) hours per day, every day of the year.

6. Each Control Centre should be able to take control of any telecommunication channel for System Controller use when necessary.

Background:

In addition to internal System and Control Area telecommunication channels, telecommunication channels shall be installed on every interconnection linking the Member's Systems. These channels should provide adequate telecommunication capabilities during emergency situations, or when adverse operating conditions are imminent.

B. SYSTEM OPERATION TELECOMMUNICATION PROCEDURES

Criteria:

Procedures for Control Centre to Control Centre communications, shall be established by System and Control Areas to ensure that communication between operating personnel are consistent, efficient, and effective during normal and emergency conditions.

Requirements:

Each Control Area shall provide the means to co-ordinate telecommunications between the Systems in the Control Area. This shall include the ability to investigate and recommend solutions to telecommunication problems within the Control Area and the Control Areas.

C. LOSS OF TELECOMMUNICATION

Criteria:

Operating instructions and procedures shall be established by each Control Area to enable operations to continue during the loss of telecommunication facilities.

Requirements:

Each Control Area shall have operating instructions and procedures to enable continued operations during the loss of telecommunication facilities.

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PROCEDURE FOR REVISING THESE OPERATING GUIDELINES

INTRODUCTION

These Operating Guidelines shall be based on good logic, scientific reasoning and operating experience. The Guidelines shall be correct, practical and highly considered by all System Controllers. System Controllers shall contribute to the updates and development of the Guidelines to ensure a practical operator's perspective.

The operating policies embodied in the Guidelines shall leave an adequate margin for contingencies. The Directives of the Operating Sub-Committee shall be focused towards interconnected system operations and shall set the pattern for future SAPP and system policies.

The Operating Sub-Committee will continue to investigate the technical background supporting these Guidelines with the assistance of individual Members and through its own efforts. Any Member utility can recommend revisions to the Guidelines through its representation at the Operating Sub-Committee.

REVISION PROCEDURES

1. Any SAPP Member can recommend revisions to the Guidelines through its representative at the Operating Sub-Committee.

    1.1 A revision may cover a portion of, or the whole of the Guidelines.

    1.2 The proposal for revision must be in writing, and must consider the content of the other Guidelines to ensure compatibility and consistency.

    1.3 The proposed revision must indicate whether it is a Requirement, a Recommendation, or a Background item, why it is needed, and how it improves the operating policies.

    1.4 The language of the revision shall agree with the purpose. That is, Criteria and Requirements are obligations, while Recommendations and Background statements simply describe good operating practices.

    1.5 The person(s) preparing a revision is consistent with the language and format of the Guidelines.

2. The proposed revision shall be presented by an Operating Sub-Committee representative to the Operating Sub-Committee.

PROCEDURE FOR REVISING OPERATING GUIDELINES (CONTD.)

3. The Sub-Committee may vote on the revision directly, or refer it to one or more Work Groups for review or improvement.

4. If the revision is referred to a Work Group and the Work Group believes a new or revised Guidelines is needed, it will prepare a draft for the Operating Sub-Committee's consideration.

5. If the Work Group rejects the proposed revision, the Operating Member can appeal directly to the Operating Sub- Committee through its representative.

6. Guidelines revisions may be approved by the Operating Sub-Committee for a "trial period." The duration of the "trial period" is one year unless stated otherwise by the Sub-Committee.

7. After a revision is presented to the Operating Sub-Committee and is accepted for further processing:

   7.1 The revision shall be distributed to the Operating Members for comments.

   7.2 The comments are forwarded to the appropriate Work Group.

   7.3 The Work Group produce a revised draft, and if necessary, after considering all the comments, and submit to the Operating Sub-Committee.

   7.4 The Operating Sub-Committee votes on accepting this draft, and if accepted, re-submit the document to the Members for final comments.

8. The adoption of amended or new Operating Guidelines require the approval of the Operating sub-Committee as indicated in the Agreement Between Operating Members. (NOTE: One vote per Operating Member).

9. This document does not need to be re-submitted for signature by the Management Committee. The Management Committee must be informed in writing of the amendment.

10. All approved revisions shall be numbered in sequence.

SIGNATORIES

IN WITNESS whereof the said Operating Members have here to set their hands:

SIGNED ON BEHALF OF BPC AT ____________________ON THIS_________DAY

OF___________________________________1996

SIGNED: ________________________ WITNESS:___________________________

NAME:__________________________ NAME: ____________________________

TITLE: ________________________ TITLE: _____________________________

SIGNED ON BEHALF OF EDM AT ____________________ON THIS_________DAY

OF___________________________________1996

SIGNED: ________________________ WITNESS:___________________________

NAME:__________________________ NAME: ____________________________

TITLE: ________________________ TITLE: _____________________________

SIGNED ON BEHALF OF ENE AT ____________________ON THIS_________DAY

OF___________________________________1996

SIGNED: ________________________ WITNESS:___________________________

NAME:__________________________ NAME: ____________________________

TITLE: ________________________ TITLE: _____________________________

SIGNED ON BEHALF OF ESCOM AT ____________________ON THIS__________DAY

OF_______________________________________1996

SIGNED: ___________________________ WITNESS:______________________________

NAME:_____________________________ NAME: _______________________________

TITLE: ___________________________ TITLE: ________________________________

SIGNED ON BEHALF OF ESKOM AT ____________________ON THIS__________DAY

OF_______________________________________1996

SIGNED: ___________________________ WITNESS:______________________________

NAME:_____________________________ NAME: _______________________________

TITLE: ___________________________ TITLE: ________________________________

SIGNED ON BEHALF OF LEC AT ______________________ON THIS__________DAY

OF_______________________________________1996

SIGNED: ___________________________ WITNESS:______________________________

NAME:_____________________________ NAME: _______________________________

TITLE: ___________________________ TITLE: ________________________________

SIGNED ON BEHALF OF SEB AT ______________________ON THIS__________DAY

OF_______________________________________1996

SIGNED: ___________________________ WITNESS:______________________________

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SIGNED ON BEHALF OF NAMPOWER AT _______________ON THIS_________DAY

OF__________________________________1996

SIGNED: ________________________ WITNESS:___________________________

NAME:__________________________ NAME: ____________________________

TITLE: ________________________ TITLE: _____________________________

SIGNED ON BEHALF OF TANESCO AT _________________ON THIS_________DAY

OF__________________________________1996

SIGNED: ________________________ WITNESS:___________________________

NAME:__________________________ NAME: ____________________________

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SIGNED ON BEHALF OF ZESA AT ____________________ON THIS_________DAY

OF__________________________________1996

SIGNED: ________________________ WITNESS:___________________________

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SIGNED ON BEHALF OF ZESCO AT ___________________ON THIS__________DAY

OF_____________________________________1996

SIGNED: __________________________ WITNESS:___________________________

NAME:____________________________ NAME: ____________________________

TITLE: __________________________ TITLE: ______________________________

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APPENDIX 1

CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT

This document provides the Survey Co-ordinator of the SAPP Control Area Performance Criteria with specific instructions to organize and report on the survey using forms contained in the document as Tables A, B and C of this document.

The Control Area may use one of two methods for reporting its control performance:

(1) 24-hour reporting, or
(2) monthly reporting.

With the first method, the Control Area measures its compliance to A1 and A2 criteria for a twenty-four (24) hour period selected at random each month by the Performance Sub-Committee Chairperson. With the second method, the Control Area continuously monitors its compliance to A1 and A2 criteria and reports its result at the end of each month. This training document explains both methods of reporting in detail.

1. AREA CONTROL ERROR

The basis for the calculation of control performance of a Control Area against the Control Performance Criteria (CPC) is the Area Control Error (ACE). The value of ACE to be used throughout the calculation should reflect an actual, unfiltered quantity as displayed to the System Operator in the control room, but obviously wrong values such as "spikes" due to telemetering error or other spurious influence should be excluded from the calculation.

2. CONTROL PERFORMANCE CRIITERIA

There are two (2) measures of the performance of ACE: they are referred to as A1 (Zero Crossing) and A2 (L^d Compliance as defined in Section 2.1.2). These measures provide the System Operator with a convenient visual indication of how well the Control Area has kept to minimum accumulation of un–intentional inadvertent interchange.

The determination of A1 and A2 depend on whether the Control Area is operating under normal or abnormal (disturbance) conditions. In addition to the criteria for normal condition, there are two (2) additional criteria which apply during disturbance conditions and which establish bounds for system recovery. The following discussion expands the definitions of the criteria found in the Guidelines:" Control Performance Criteria" and defines the criteria under both normal and disturbance conditions.

CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT (CONTD.)

2.1 ***Normal Conditions***:

The A1 and A2 criteria are the control performance standards for normal operating conditions.

2.1.1 A1 Criteria –Zero Crossing:

The A1 Criterion requires that a Control Area's ACE returns to zero within ten (10) minutes of previously reaching zero. While good control of this criteria will not totally eliminate the accumulation of un-intentional inadvertent interchange, such accumulation would be small provided the ACE crosses zero periodically.

2.1.2 A2 Criteria – L^d Compliance

The A2 Criterion requires that the average ACE for each of the twelve (12) Intervals of six (6) minutes making up the hour, be within specific limits, referred to as L^d. This criterion complements the A1 Criterion by establishing an upper bound for the average value of a Control Area' s ACE.

2.1.2.1 L^d Calculation:

L^d = (0,025)L + 5 MW

Where L may be calculated either of two ways:

METHOD A: L is the greatest hourly change (either Increasing or decreasing) in the Control Area's Net Energy sent out that occurred on the day of the Control Areas Winter or Summer peak demand.

METHOD B: L is the average of any ten (10) hourly changes (either increasing or decreasing) in Net Energy sent out that occurred during the year.

The Control Area shall determine its L^d annually upon the request of the Operating Sub-Committee. The new L^d becomes effective on 1 April of each year.

CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT (CONTD.) .

2.2 ***Disturbance Conditions***:

During disturbance, controls cannot maintain ACE within the Criteria for normal condition. This requires that a disturbance condition be defined. A disturbance is said to have occurred when a sampled value of ACE exceeds the limit called L^m due to a sudden loss of generation or load. The value of Lm has been selected as a function of L^d specifically.

$$L^m = 3L^d$$

Normal load and generation excursions (e.g. pumped storage hydro, arc furnace, rolling steel mill, etc.) that cause the ACE to exceed L^m are not included in the definition of disturbance condition.

When a disturbance condition arises, other criteria apply in addition to the A1 and A2 Criteria explained earlier.

2.2.1 B1 Criteria –System Recovery:

The B1 Criteria requires ACE to return to zero within ten (10) minutes, following the start of a disturbance. Following the step change in ACE attributed to a disturbance (as defined above), the ACE must recover and achieve a zero reading in period not to exceed ten (10) minutes. Every system should maintain sufficient reserve capability to restore control completely and return to normal operation within ten (10) minutes.

2.2.2 B2 Criteria- Recovery Initiation:

The B2 Criteria requires that the ACE stops increasing and begins to return to zero within one (1) minute following the start of the disturbance (as defined above) ACE is permitted to evolve in the same direction as the step change for a period not exceeding one (1) minute. A system should maintain sufficient reserve capability such that after the initial allowance of one (1) minute ACE will begin its recovery and tend towards zero.

3. CALCULATION OF CRITERIA

3.1 A1 Criterion:

Compliance with the A1 Criterion is measured by starting a ten (10) minute interval when the ACE reading is zero and starting the next ten (10) minute interval when the ACE is zero again (or a sign change of ACE indicating a zero crossing). To calculate the A1 Criteria, it is necessary to commit the number of ten (10) minute intervals where zero was not reached.

Where: Tm is the maximum number of ten (10) minute intervals in a reporting period during which the ACE did not reach zero.

And Tal is the maximum number of non-compliant ten (10) intervals recorded during the reporting period.

3.1.1 Determination of Tm:

For a twenty-four (24) hour period which contains no interruptions in telemetering, ACE is recorded consecutively for 1440 minutes, thus Tm = 144. Should loss of telemetering or computer unavailability result in a sustained interruption in the recording of ACE, Tm should be reduced accordingly. To reduce Tm, record the time expired during the sustained interruption in the recording of ACE, divide that time in minutes by ten (10) truncate the result to a whole number and reduce Tm by that number accordingly. Should non-consecutive interruptions of ACE recording occur in a reporting period, each should be treated separately in reducing Tm. For example, consider a twenty-four (24) hour period in which for three (3) non-consecutive periods, the recording of ACE was interrupted. These three (3) periods extended sixty-four (64) minutes, thirty-seven (37) minutes and ninety-eight (98) minutes. Dividing each by ten (10), would yield 6.4, 3.6 and 9.8 respectively. Truncating would yield 6, 3 and 9. Therefore, for this twenty-four (24) hour period:

$$Tm = 144 - 6 - 3 - 9 = 126 \quad (4)$$

If monthly average reporting is being used, Tm would be calculated in the same way with Tm = 4464 for a thirty-one (31) month with no interruptions in telemetering.

CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT (CONTD.)

3.1.2 Determination of Tal:

Once the ACE recording is initiated, if a ten (10) minute interval expires before conditions arise which would result in the termination of the timing interval, an incident of non-compliance is recorded. The incident is recorded in the hour during which the interval expired. The total number of such incidents of non-compliance recorded during a reporting period is equal to Tal.

3.1.3 Termination conditions for the ten (10) minute timing interval.

In practice, there are five (5) conditions which can arise that would cause the current ten (10) minute timing interval to terminate and a new ten (10) minute interval to initiate. As will be explained, only one of these five (5) conditions, namely the expiration of the ten (10) minute timing interval, represent an incident of non-compliance.

3.1.3.1 Beginning of twenty-four (24) hour period:

For twenty-four hour reporting, the A1 Criterion measurement begins at 00:00 and ends at 24:00. At 00:00, regardless of the current ACE reading, the last ten (10) minute timing interval of the previous twenty-four (24) hour period, is terminated and first ten (10) minute timing interval of the new twenty-four (24) hour period is initiated. If the last ten (10) minute interval of the previous twenty-four (24) hour period was initiated 23:50 and terminated at 24:00, the expiration of the ten (10) minute interval would coincide with the end-of-day termination and thus an incident of non-compliance should be recorded for the 24th hour of the previous day. If the last (10) minute interval is initiated after 23:50 and terminated at 24:00, even though ACE had not returned to zero, this interval is deemed compliant.

3.1.3.2 Zero ACE Crossing:

Any time ACE reads zero (or changes sign in successive digital samplings), the current ten (10) minute interval is terminated and new ten (10) minute interval starts. The interval represented by the terminated interval is compliant. Instantaneous telemetering errors or “spikes” that cause a zero crossing should be ignored.

3.1.3.3 Expiration of ten (10) minute timing interval:

Once initiated, if the ten (10) minute interval extends to expiration (i.e. records a full ten (10) minute period), the incident of non-compliance is recorded in the hour during which the timing interval expired. A new ten (10) minute interval is then initiated.

3.1.3.4 Occurrence of system disturbance:

For twenty-four (24) hour reporting only, the occurrence of a system disturbance as defined in Section 2.2 of this document terminates the current ten (10) minute interval and a new ten (10) minute interval is initiated.

The terminated interval is compliant should the initiated ten (10) minute timing interval expire and incident of non-compliance would be recorded as defined in 3.1.3.3 above. Disturbance conditions do not initiate a new timing interval if monthly average reporting is used.

3.1.3.5 Interruption in recording of ACE:

Should a sustained interruption in the recording of ACE occur resulting form a loss of telemetering or a computer unavailability the current ten (10) minute timing interval is terminated. The initiation of a new ten (10) minute timing interval is suspended until the recording of ACE is restored. A sustained interruption is defined as a continuous period lasting longer than one (1) minute.

3.2 ***A2 Criteria***:

Compliance with the A2 Criteria requires that the absolute value of the algebraic mean of the ACE signal (d^2) for a ten (10) minute period does not exceed the Control Area's allowance limit, L^d (see Section 2.1.2.1). As was true for the A1 Criterion, to calculate A2, it is necessary to identify the number of incidents of non-compliance.

$$A2 = \frac{(Tm - Ta2)\ 100}{(Tm)}$$

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Where: Tm is the maximum number of ten (10) minute intervals in a reporting period during which the recording of ACE was uninterrupted.

Ta2 is the number of non-compliant A2 ten (10) minute intervals recorded during a reporting period.

3.2.1 Determination of Tm and Ta2

Since the A2 Criteria requires the ACE be averaged over a discrete time period, the same factors that limit Ta2 will limit Tm. The calculation to Tm and Ta2, must be discussed jointly.

Each twenty-four (24) hour period beginning at 00:00 and ending at 24:00 contains 144 discrete ten (10) minute periods.

3.2.1(a) Determination of Tm and Ta2

Each hour (HH) contains six (6) discrete ten (10) minute periods, where period 1 spans HH:00 – HH:10 , period 2 spans HH:10 – HH:20, period 3 spans HH:20 -HH:30, period 4 spans HH:30 – HH:40, period 5 spans HH:40 – HH:50, period 6 spans HH:50 –(HH+1) :00. For a system that samples ACE every four (4) seconds, for example, the average ACE over a ten (10) minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH:00:04 and ending at HH:10:00) divided by 150. Systems calculating the A2 Criterion from the manual review of an ACE chart must sum the products of visual readings and their respective length and divide that sum by ten (10) minutes. Consider the example where ACE is visually perceived to average 10 MW for 1 minute, -5 MW for the next 1.5 minutes, -10 MW for the next two (2) minutes, -15 MW for the next three (3) minutes, and –5 MW for the last 2,5 minutes. The ten (10) minute algebraic mean would equal:

$$\frac{[(10)\ (1)] + [(-5)\ (1.5)] + [(-10)(2)] + [(-15)\ (3)] + [(-5)\ (2.5)]}{10} = -7.5 \text{ MW}$$

An incident of non-compliance is recorded for any ten (10) minute period where the absolute value of average ACE is greater than L^d.

3.2.2 Conditions that impact the calculation of Tm and Ta2

Two (2) conditions may arise which impact the normal calculation of Tm and Ta2. These conditions are the occurrence of system disturbance as defined in Section 2.2 and a sustained interruption in the recording of ACE.

3.2.2.1 Disturbance conditions:

A disturbance condition is defined in Section 2.2. For twenty-four (24) hour reporting only, the A2 Criterion is relaxed during these conditions recognizing that a Control Area has ten (10) minutes with which to respond to the disturbance.

3.2.2.1(a) Disturbance conditions:

For each such disturbance in a twenty-four (24) hour period, the discrete ten (10) minute interval in which the disturbance occurred and the succeeding ten (10) minute period interval are omitted from the calculation of A2. Functionally, both ten (10) minute periods are eliminated from the calculation, thus Tm is reduced by two (2) to normalize the percentage calculation of A2. Disturbance conditions are not omitted in the A2 calculation if monthly average reporting is used.

3.2.2.2 Sustained interruption in the recording of ACE:

In order to ensure that the average ACE calculated for any ten (10) minute interval is representative of that ten (10) minute interval, it is necessary that ACE remain uninterrupted for a period equal to or greater than five (5) minutes during that ten (10) minute interval. Should a sustained interruption in the recording for ACE due to loss of telemetering or computer unavailability result in ten (10) minute interval not containing a consecutive five (5) minute sampling of ACE, that ten (10) minute interval is omitted from the calculation of A2. Functionally, the ten (10) minute interval is assumed complaint and Tm is reduced by one to normalize the percentage calculation of A2.

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3.3 Examples:

3.3 Examples:

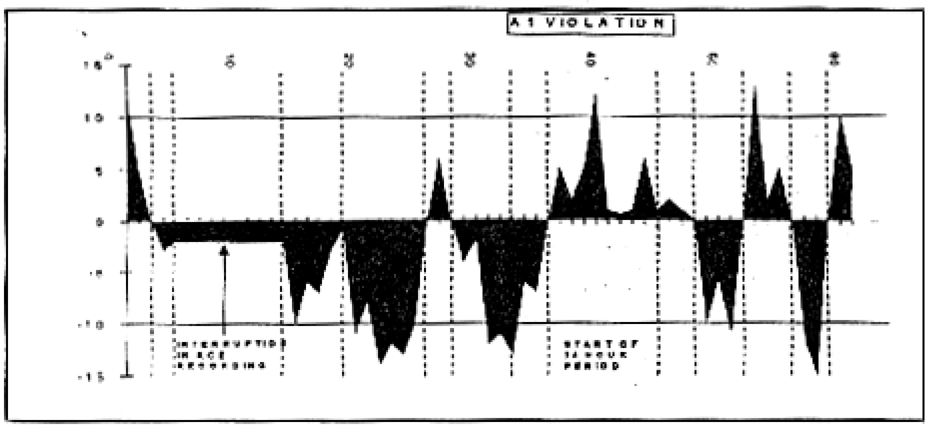

Figure I - A1 Zero Crossing Examples

Figure 1- A1 Zero Crossing Examples

Figure 1 demonstrates various examples of zero-crossing (Criteria A1) measurement particularly involving the start of a new twenty-four (24) hour period. The vertical dashed lines indicate the start of ten (10) minute timing interval. Most of these lines coincide with a zero crossing of ACE. Note that these ten (10) minute timing intervals are not cyclic to coincide with ten (10) minute increments during the hour. There are three (3) incidents during this sixty (60) minute period where the ten (10) minute timing interval is impacted by conditions other that a zero crossing.

1. Start of new day- Note that at 00:00, even though ACE equals -12 MW, a new ten (10) minute timing interval is initiated.

2. Zero crossing (Criteria A1) violation - Note that at 00:12, even though ACE equals 2 MW, a new ten (10) minute timing interval is initiated. Ten (10) minutes has expired since the last zero crossing at 00:02 indication a violation to be recorded in the hour ending 01: 00.

3. Interruption in ACE recording - Note that a ten (10) minute timing interval was initiated at 23:34 and 23:43 even though ACE equals –2.5 MW in both instances. According to the chart, there was a zero crossing at 23:32 and again at 23:47. Although fifteen (15) minutes had expired since the last zero crossing, a violation is not recorded because the time during which the interruption of ACE recording occurred is not included in the determination of the A1 Criterion.

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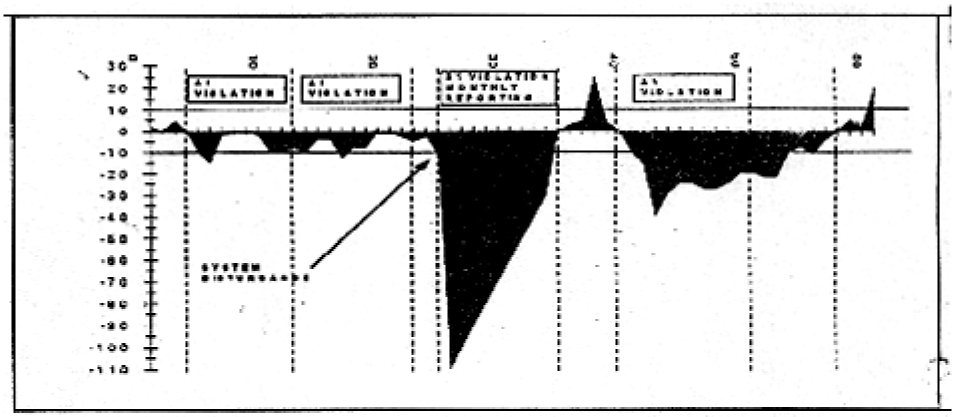

Figure II - A1-Zero Crossing & B1,2 Disturbance Examples

Figure II –A1-Zero Crossing & B1, 2 Disturbance Examples

Figure II demonstrates zero crossing (Criterion A1) examples and a disturbance condition (Criteria B1 and B2). Note that ACE crosses zero at 06:42 and does not again cross zero until 07:15, yet two (2) violations are recorded during this time interval for twenty-four (24) hour reporting. The disturbance occurring at 07:05 causes the initiation of ten (10) minute timing interval for twenty-four (24) hour reporting even though ACE equals –20 MW. For monthly average reporting, there are three (3) violations during the same period since the disturbance does not terminate the current ten (10) minute timing interval. Note that during the disturbance, ACE begins to trend towards zero almost immediately, thus being well within the one (1) minute requirements of the B2 Criteria and that ACE recovers to cross zero at 07:15 which is within the ten (10) minute requirement of the B1 Criteria. Note that if ACE did not cross zero until some time after 07:15, both the B1 and the A1 Criteria (for twenty-four [24] hour reporting) would be violated.

Other items are of interest in Figure II. Note the violation that spans the time from 06:25 to 07:02. This violation is recorded in the hour in which the ten (10) minute timing interval expired. Note also the violation that spans the time 07:20 to 07:30. ACE reaches to –40 MW during this period and the absolute value is well beyond the L^d, this period does not represent a disturbance condition to this value of ACE. Since a disturbance is not recorded during this period and since ACE has not crossed zero, the ten (10) minute timing interval expire at 07:30 and thus an A1 violation is recorded.

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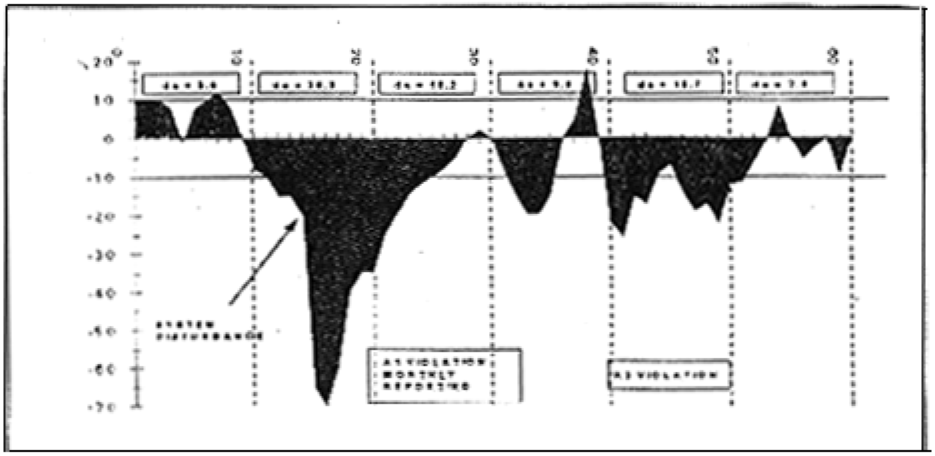

Figure III - A2- Ld Compliance B1,2 Disturbance Examples

Figure III- A2- Ld Compliance B1, 2 Disturbance Examples

Figure III demonstrates various examples of L^d compliance (Criteria A2) and a disturbance condition (Criteria B1 and B2). Note that unlike Figure I and II. Figure III is separated into six distinct, cyclic ten (10) minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d2, is compared to L^d (10MW for this system) to determine a violation.

Note that the fifth interval (01:40 – 01:50) has recorded a violation because the absolute value of the algebraic mean of 15,7 MW exceeds the L^d of 10 MW. Since disturbance conditions are included in the A2 calculation for monthly average reporting, violations are also recorded for the second and third intervals (01:10 – 01:20 and 01:20 - 01:30) if monthly average reporting is used. For Control Areas using twenty - four (24) reporting, the algebraic means would not be calculated for these two (2) intervals. This elimination of the second and third interval from further Criterion A2 analysis for twenty-four (24) hour reporting is due to the disturbance condition that occurred at 01:15. The ten (10) minute allotment for the successful recovery from a disturbance spanned both intervals. For this hour therefore, there was one (1) violation out of four (4) intervals for twenty-four (24) hour reporting and three (3) violations out of six (6) intervals for monthly average reporting.

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Note the pattern of the disturbance condition which began at 01:15. During this disturbance, both the Criteria B1 and B2 were violated. ACE did not begin to trend to zero until nearly two (2) minutes after occurrence (violating Criteria B2) and ACE was not restored to zero until 01:27 (twelve (12) minute interval which violates Criteria B1).

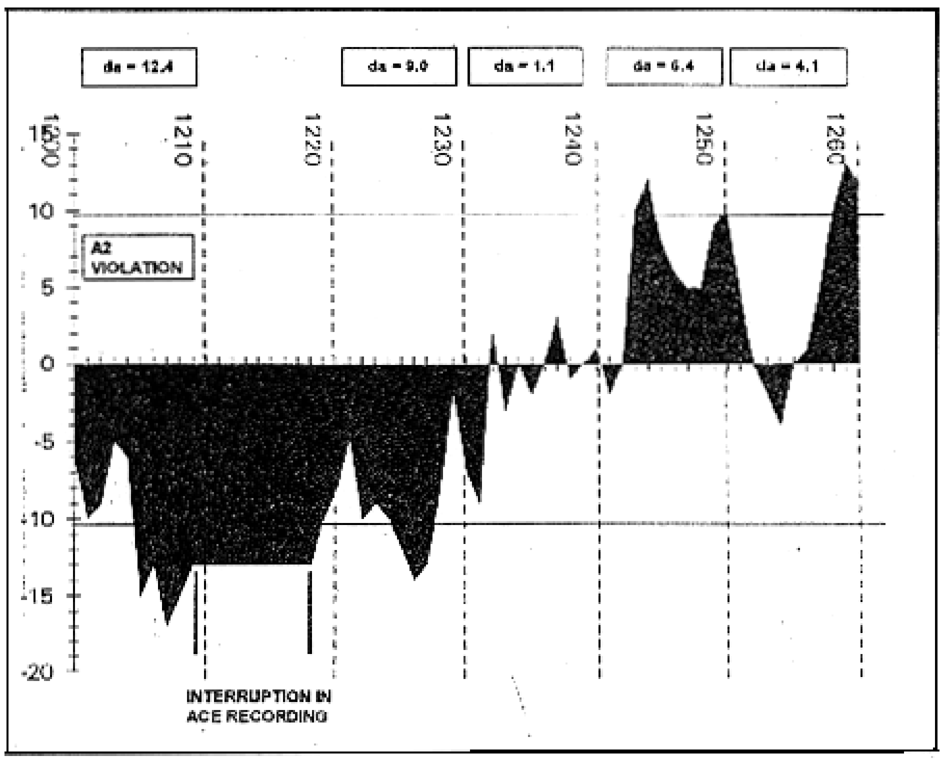

Figure IV - Ld Compliance Examples

Figure IV – Ld Compliance Examples

Figure IV demonstrates various examples of L^d compliance coupled with an interruption in the recording of ACE. At 12:09, ACE recording was interrupted and not returned until 12:18. Since the ACE recording for the interval 12:10 – 12:20 did not span a consecutive, uninterrupted period longer that five (5) minutes, this period is eliminated from further Criterion A2 analysis. In contrast, the first ten (10) minute interval of 12:00 – 12:10 is included in the analysis because ACE recording was interrupted only for the last minute of the interval. In fact, the first interval is in violation because the algebraic means of 12,4 MW exceeds the L^d of 10.0MW The algebraic means of 12,4 MW was calculated for the nine (9) minute during which ACE was not interrupted. Thus, for this hour, there was one (1) violation out of five (5) intervals.

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4. SURVEY PROCEDURES

Control Performance Survey will be conducted monthly to analyse each Control Area's level of compliance with the A1 and A2 Control Performance Criteria. The surveys provide a relative measure of each Control Area's performance. Once a Control Area starts using monthly average reporting, it may not revert to twenty-four (24) hour reporting unless agreed to by the Regional Survey co-ordinator.

4.1 Issuance of Survey - Twenty- four (24) Hour Reporting:

Twenty-four (24) hour surveys will be conducted for periods selected by the Chairman of the Performance Sub-Committee, on his own motion, or in response to specific request from members of the Sub-Committee.

4.1.1 As soon as possible after the twenty-four (24) hour survey period is chosen by the Chairman, the Chairman shall notify each Sub-Committee member by letter of the survey dates.

4.1.2 Each Sub-Committee member shall notify each Control Area using twenty-four (24) hour reporting within his Region by written request. The Sub-Committee member shall provide, for each Control Area, a copy of Table A, "SAPP Control Performance Criteria Survey- twenty-four (24) Hour" and a copy of the "Control Performance Criteria Training Document".

4.1.3 Each Control Area shall return one completed copy of Table A to the Sub-Committee member representing his Region.

4.1.4 If a Control Area is unable to report performance for the selected period because sufficient data unavailable, the regional Sub-Committee member will select another random day near to the survey period for that Control Area to use.

4.2 Issuances of Survey – Monthly reporting

Monthly averages are to be completed after the end of each month.

4.2.1 Each Control Area using monthly average reporting shall return one completed copy of Table B. "SAPP Control Performance Survey – Monthly Average" to the Sub-Committee member representing the Region by the 10th working day of the month following the month reported.

4.3 Instructions for Control Area Survey - Twenty-Four (24) Hour Reporting:

From a manual review of the ACE chart or using data derived from digital processing of the ACE signal, a representative from each Control Area will complete Table A "SAPP Control Performance Criteria Survey - twenty-four (24) Hour".

4.3.1 Hourly tables:

For each hour in the survey period, record the number of A1 Criterion violations and the inadvertent interchange.

4.3.2 A1, A2 Criteria summary:

Total Sum the number of violations recorded on the hourly tables and enter the sums on this row for each Criterion.

AVG/HR Divide the sum recorded on the TOTAL row by the number of hours recorded in the survey and enter values on this row.

MAX/HR For the hour in which the most violations have occurred for each criterion, enter the respective number of violations on this row.

MIN/HR For the hour in which the fewest violations have occurred for each Criterion, enter the respective number of violations on this row.

Percentage Compliance: Using the formulas and procedures described earlier in this document, calculate the A1 and A2 Criteria and enter on this row.

4.3.3 Analysis of Best and Poorest Hours:

Review for each hour ten (10) minute algebraic means of ACE (d2) calculated to identify A2 Criterion violations. Consider only those hours where all six (6) periods are included in the analysis, Sum the absolute values of the six algebraic means (ignore signs), / d2 / and identify those hours with the least sum and highest sum. Those hours are the BEST and POOREST hours, respectively. Record for these respective hours, the hour, the absolute value of the six (6) algebraic means / d2 / for the hour, the TOTAL of the six (6) absolute values, and by dividing the TOTAL by six (6) record the average absolute value.

4.4 Instructions for Control Area Survey Monthly Reporting:

Using data derived from digital processing of the ACE signal, a representative from each Control Area will complete Table B. “ SAPP Control Area Performance Criteria Survey – Monthly Average “.

4.4.1 Hourly tables:

For each of the twenty- four (24) hourly periods of a day, report the monthly total number, of A1 Criterion violations, A2 Criterion violations, and the number of unavailable ten (10) minute intervals. For example, if there was one violation for hour ending 01:00 every day of a thirty –one (31) day month, a thirty-one (31) would be entered for the 01:00 hourly period.

4.4.2 A1, A2 Criteria Summary:

Total sum the number of violations and unavailable ten (10) minute intervals recorded on the hourly tables and enter the sums on this row for each column.

Percentage Compliance: Using the formulas and procedures described in Section 3 of this document, calculate the A1 and A2 Criteria and enter on this row.

4.5 Instructions for Regional and SAPP Surveys:

From a review of the Control Area’s surveys, each Regional Survey Co-ordinator or Performance Sub-Committee Member will complete Table C “ SAPP Control Performance Criteria”.

4.5.1 Review Table A and Table B data received from each Control Area in the Region for uniformity, completeness, and compliance to the instructions. Iterate with Control Area survey co-ordinators where necessary.

4.5.2 Transfer the data from each Table A and Table B to the appropriate columns on Table C. Review the comments submitted and if significant, identify them with the appropriate Control Areas.

4.5.3 Mail a copy of the completed Table C to the SAPP staff.

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4.5.4. The SAPP staff will combine the regional reports into a single summary report and send one copy to each Sub-Committee member.

4.5.5. Each Sub-Committee member is responsible for sending the summary report to the utilities in the Region.

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