ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

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AfDB

POWER TRADE

STRATEGY REPORT

VOL 1

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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 x 10^{-5}	947.8	0.2778
Gcal	4.1868 x 10^{-3}	1	10^{-7}	3.968	1.163 x 10^{-3}
Mtoe	4.1868 x 10^{4}	10^{7}	1	3.968 x 10^{7}	11630
MBtu	1.0551 x 10^{-3}	0.252	2.52 x 10^{-8}	1	2.931 x 10^{-4}
GWh	3.6	860	8.6 x 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. TRENDS AND OBSTACLES

1.1 INTRODUCTION

Regional electricity trade can provide a range of benefits to participants. The "loosest" trading arrangements provide for voluntary economy energy transactions among parties, and impose no obligations to transact or provide services. The "tightest" arrangements provide for joint planning and operations to such an extent that the entire region in many respects resembles a single pool. Regional trade in general provides benefits because there are economies of scale in planning, constructing, and operating generation and transmission systems. Thus a number of smaller systems can combine in some fashion to become effectively a single larger system.

Electricity markets including regional trade can deliver benefits to all countries and final customers in the form of lower prices and improved products and services. It can also result in the increased development of generation sources and a cleaner environment. Real electricity market, however, requires a market of well-informed customers who have many suppliers from which to choose. The two major elements supporting a vibrant market are market commercial rules supporting the entry and success of a wide variety of generators, marketers, and basic consumer information and protection measures to assure customers get sufficient information about their choices.

In addition to these direct benefits, regional trade can provide the benefits of competition and private investment. This provides competitive pressures on existing systems, even state-owned monopolies, and encourages the inflow of private capital.

Obtaining the potential economic benefits of regional trade depends on factors, such as the physical capability of interconnections or the regulatory and institutional environment. It also depends on the commercial factors which are the subject of evaluation in this Chapter 1. Analysis in this Chapter is organized to:

- Analyse electricity trade and the potential benefits of the regional electricity market
- Identify and analyse the main commercial barriers to regional trade

1.2 TRENDS OF ELECTRICITY TRADE IN THE EAST NILE REGION

Generally, the first step consists in reviewing existing data on historical levels of electricity trade in the region, including any forecasts of future trade. Key factors affecting the level of trade include:

- National energy policy (self-sufficiency in electricity generation);
- The balance of supply and demand over different time periods;
- The operating costs of existing generating plants;

- The capital and operating costs of potential future new generating plants, and their performance;
- Limitations on economic dispatch, for example due to must-run generation;
- The physical capability of interconnections;
- The physical losses and transmission service charges associated with regional transactions;
- Reliability criteria.

Using the work carried out in Modules 1 to 6 of the Project, we identified potential sources of economic benefits, and accordingly the basis for future trade. Potential benefits are due to:

- Access to the economies of scale of larger generating plants and/or lower cost fuel sources, which could be developed jointly. This provides lower capital and operating costs.
- Larger systems with a wider range of loading patterns, plant types, sizes, costs, and locations have more opportunities to capture operating savings. In general, regional trade permits the lowest operating cost generators to run at maximum output a larger fraction of the time. For example, regional trade may reduce the amount of hydro spill. This provides lower operating costs.
- Differences in timing of when new plants are needed in different countries of the region. This permits the temporary sharing of resources and thus lower capital costs.
- If some new plants are low enough in cost, they could be built before a reliability-based need for them develops, to permit high cost existing plants to be shut down. This provides lower operating costs.
- Reduction in spinning and/or operating reserves through reducing the impact of the outage of the largest generator. This provides increased reliability and/or reduced operating costs.
- Reduction in planning reserves through pooling of loads and resources. Larger load reduces the impact of an outage of the largest generator, and increasing the number of generators improves the probabilities regarding concurrent outages. This provides lower capital costs.

With the exception of Egypt, which is presently interconnected with Jordan, Libya and Syria since 1999 (EIJLST), there is no interconnection allowing power trade between Egypt, Sudan and Ethiopia.

The existing EIJLST cross-border trade is characterized by capacity transactions and interchange of surplus power and energy through yearly bilateral contracts in application of General Interconnection Agreements for the Electrical Interconnection among the concerned countries (Egypt, Jordan, Libya and Syria).

Each party having excess (firm power) shall, at its own option, make available to the other parties:

- a defined firm power and associated energy which it desires to sell for a defined period;
- at times other than emergencies such surplus power and energy, it may desire to sell.

1.3 COUNTRY INFORMATION

This section provides summary of country information dealing with the commercial aspects of the electricity market. This summary is based on the information countries provided by answering to the specific questionnaire submitted by the Consultant (see Appendix 1) and on data collection on the existing legal background.

1.3.1 EGYPT

Present Status of Electricity Market

Several laws and decrees govern the Egyptian electricity sector. The list of legal documents collected in presented on Appendix 2.

Since the enactment of law n°164 issued 30/06/2000 concerning the transformation of the Egyptian Electricity Authority into the Egyptian Electricity Holding Company, it was necessary to restructure the Holding company.

Starting on 1st of July 2001, successive restructuring steps of the company have been taken by unbundling the production, transmission and distribution activities, leading to the formation of 16 affiliated electricity companies as private companies under Private Sector Law n°159, including six (6) generating companies, one (1) transmission company and nine (9) distribution companies.

The National Control Centre, established in April 1983, is assigned the responsibility for the operation of all generating units.

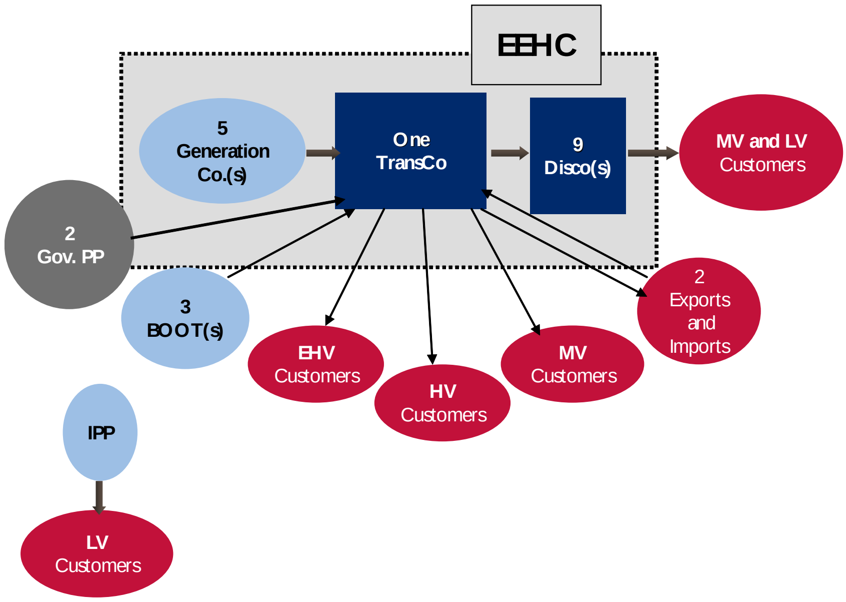
These 16 companies are 100% owned by EEHC. However the Law n°89 permits sales of 49% of the shares of these companies, no shares have been sold yet.

At present, EEHC owns 90% of the installed generation capacity. Three private BOOT projects contribute with 9% of the installed generation capacity (Suez Gulf, Sidi Krir and Port Said East). The last 1% is made of the present wind farms and small isolated units.

The electrical energy is sold to the present 22 million consumers on both the Medium Voltage and Low Voltage by EEHC and privately owned companies. At present, there exist seven private distribution companies. However, their share does not exceed 1% of the present market.

The present electricity market is organized in the Single Buyer form. The Egyptian Electricity Transmission Company “EETC”, which is the only company licensed for EHV and HV electricity transmission, purchases electrical energy from all generation companies. EETC in its turn sells the electrical energy to the present nine distribution companies and the present 81 EHV and HV consumers. Furthermore, EETC is exchanging energy with neighbouring countries over the present interconnections.

Figure 1: Present Structure of the Electricity Market



By the Law, EEHC is responsible for proposing the electricity tariffs for various categories on all voltage levels. The Ministerial Cabinet approves the tariffs. In 2006, EEHC was allowed to yearly increase the cost of electricity by 7.5% to take into consideration an average inflation rate of 5% and a 2.5% increase in fuel cost (oil) in order to reach petroleum cost in 8-10 years.

The costs of social provision are carried out by the electricity companies. The residential sector is still subsidized.

The Electricity Utility and Consumer Protection Regulatory Agency is responsible for regulating, monitoring and control over all matters relating to electric generation, transmission, distribution and consuming. The Regulatory Agency is responsible of issuing licenses for the construction, management, operation and maintenance of power generation, transmission, distribution and sale.

Major points describing the current commercial aspects of cross-border trade are:

- EEHC is the only company which exports/imports electricity;
- It is not possible for large consumers (companies) to trade directly with a foreign power suppliers;

- EEHC is a single electricity importer/exporter and no licenses or permissions are needed for import/export of electricity. EEHC negotiates its own prices for import/export of electricity;

- There are presently no regulations concerning the cross-border trade;

- The Ministry of Electricity and Energy controls and supervise the cross-border trade and electricity markets;

- The Ministerial Cabinet is the lawful entity that has the right for approving tariffs for internal and cross-border trade;

- The licenses conditions do not require a permission for import/export of electricity;

- The relationship among various sector participants is governed by a set of contracts and power purchase agreements. In general, the electricity sector companies do fulfil their contractual obligations to the fullest. The BOOT PPA's are a good example. However, the present contractual framework needs to be further developed to provide for new concepts to the Egyptian Electricity Market such as Third Party Access, etc. Since, present legislations do not provide support for those concepts, the enhancement of the present contractual framework hinges upon the issuance of the new electricity law, which is supposed to establish a competitive electricity market in Egypt.

- The present legal framework provides a firm basis for present commercial contracts, however, it does not provide a similar support for more competitive contracts.

- For EEHC owned entities, wholesale prices are determined by a charges model used by EEHC to distribute cost among EEHC market participants. Privately owned entities, established under law no. 8, 1997, are free to negotiate their tariffs, when applicable.

- There is no special taxation on Imports/Export of electricity.

Proposed Future Electricity Market Structure

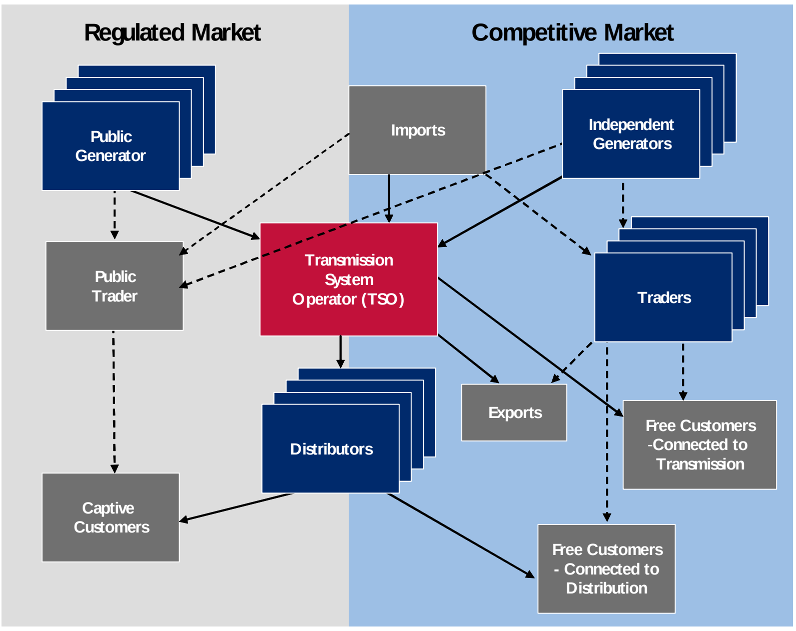
The new Electricity Law, expected to be issued in 2008, is currently under review and will allow market competition.

It is proposed that the electricity market in its final form shall be harmonized with the present practices in the EU. To that end, the transitional market is composed of two submarkets working in parallel:

(i) a competitive market where eligible consumers enjoy the liberty of choosing their electricity supplier;

(ii) a regulated market for non-eligible consumers. This regulated market should gradually contract to the account of the competitive market up to the point where the whole market is fully competitive.

Figure 2: Proposed Structure of the Electricity Market



In the competitive market:

- Eligible consumers have the right to conclude direct bilateral contracts with present/future generation companies to satisfy their needs of electricity on a basis of free competition;
- The Transmission System Operator (TSO) is responsible for fulfilling those contracts for a unified transmission access charge proposed by the TSO and approved by the Regulatory Agency;
- The TSO purchases the required balancing energy to the account of consumers or generators in the case of any deviation from the quantities specified in the concluded contracts.

In the regulated market:

- Non-eligible consumers purchase their electricity needs against a regulated tariff approved by the Regulatory Agency.
- Government owned companies are the ones responsible for satisfying the needs of this customer class. This electricity is sold for the regulated price determined by the Regulatory Agency on economic basis;
- It is allowed to satisfy a part of the market needs from private generation entities.

The sudden transition into the competitive market form is a risk. However, there are a number of constraints that should be removed prior to the move to a fully competitive market structure. Those constraints are:

- The present tariff is less than the economic cost of service. The present tariff structure is unbalanced;
- Collections;
- The need to establish an attractive environment for investors.

In alleviating the aforementioned constraints, the following steps are suggested by the Regulatory Agency:

(i) The present tariff for EHV and HV consumers shall reach an economic level;

(ii) Performance enhancement for electricity companies;

(iii) Revisit the subsidies question;

(iv) Issuance of necessary rules, codes, etc.

It is targeted to have the electricity market open for HV and EHV customers in 2010.

1.3.2 ETHIOPIA

The list of collected laws and legal documents governing the Ethiopian electricity and water sectors is presented on Appendix 3.

In 1992, Ethiopia launched an economic reform programme aimed at achieving economic growth through private-sector participation. The Government is now also committed to promoting Ethiopia as a destination for foreign direct investment (FDI).

The liberal economic policy of the 1990s resulted in an average GDP growth rate of about 5% per annum from 1993–1994 to 2000–2001. Inflation has been consistently low, averaging 1.5% from 1997–1998 to 2000–2001. Owing to the collapse of the world price of coffee, the major export commodity, the trade-balance-to-GDP ratio has increased from 11.5% in 1997–1998 to 18% in 2000–2001 (Ministry of Finance and Economic Development, 2003). In general, however, macroeconomic conditions have been stable.

The Investment Proclamation of 2002, as amended in 2003 (Proclamation No. 375/2003, Negarit Gazeta No.8, 28 October 2003), and the 2003 Regulation on Investment Incentives constitute the main legal framework for both foreign and domestic investment in Ethiopia. Included in the framework are: forms of investment and capital requirement, investment permits, concessions, incentives and facilities, including one-stop service to investors.

In its 3-year Strategic Plan (2003–2006), the Ethiopian Investment Commission (EIC) envisages attracting FDI from selected home countries by introducing prospective foreign investors to Ethiopia's investment opportunities and conditions. The EIC also encourages existing foreign investors to invest in new or expansion projects. Above all, the EIC plans to improve its service delivery by drastically reducing the time it takes to provide services to investors.

Comprehensive energy policy measures in power sub-sector are to build national capacity in engineering, construction, operation, and maintenance and gradually enhance local manufacturing capability of electrical equipment and appliances.

The government has taken several measures to address the power sector issues and continues to make more changes. The specific changes that have been made recently are embodied in two parallel efforts: to delineate operation and regulatory functions, and liberalize the sector to promote private investment.

The Electricity Proclamation (No. 86/1997) and the Ethiopian Water Resources Management Proclamation (197/2000) are the two laws governing electric energy.

Proclamation No. 86/1997 has been enacted to regulate the activities of electricity suppliers and thereby operation and regulatory functions were delineated. The proclamation also provides for the establishment of a regulatory authority, The Ethiopian Electricity Agency (EEA), the regulatory body established by the Electricity Proclamation (2000) is responsible, among other things, for recommending tariffs and establishes the principle of third party access to the grid for facilitating private investment in the future.

An investor must have a permit for the use of water resources for the generation and transmission of electricity. The generation, transmission and distribution of electricity also require a license from the EEA. In addition, the licensee needs an investment permit from the EEA, as it is delegated to issue these by the EIC, pursuant to Article 41 of Proclamation No. 375/2003.

The enactment of the Investment Proclamation No. 37/1997 particularly allows the participation of domestic private investors in the production and supply of electrical energy with an installed capacity of up to 25 mega-watts. On the other hand, production and supply of electrical energy with an installed capacity of above 25 mega-watts is open to foreign investors.

The provision embraces the development of small and medium scale capacity plants from diesel, coal, gas, hydro and other sources. Council of Ministers Regulations No. 7/1996 and as amended in No. 36/1998 extends attractive package of encouragement in the form of duty and profit tax exemptions. The investment law coupled with the new regulatory framework is believed to provide a conducive ground for private investment in the sector.

An investor is allowed to invest in all aspects of electrical energy, except in the transmission and distribution of electricity through the Integrated National Grid System, an area reserved for the Government.

With a view to expanding the energy supply, the government has recently revised the legal and regulatory framework for power generation, transmission and distribution, and foreign investors are now particularly sought to set up hydroelectric power plants. Arrangements can be made with the Ethiopian Electric Power Corporation (EEPCO) for bulk sales of electric power for transmission and distribution.

As per Regulation N°49/1999 on electricity Operation, the price for supplying energy and power to retail or bulk customers shall, subject to adjustments to meet financial requirements to be defined as necessary, be determined on the basis of the system marginal cost and optimum system planning. Where such an approach becomes inapplicable to pricing outside the national grid system due to technical reasons, such pricing shall be based on average cost of supply, and an acceptable rate of return on investment.

With regard to generation pricing within the national grid system (the ICS):

- The most efficient generation facility identified to meet the system's peak demand shall constitute the base for marginal generation capacity cost;
- The most efficient generation facility identified to meet the system's base load shall provide the base for computation of energy price;
- Marginal energy cost shall, in the case of hydro power plants, be computed on the basis of the cost which is not attributed to capacity;
- Generation cost of thermal plants and wholesale purchase price of power and energy shall be computed on the basis of planned generation and shall be distributed on the system generation price.

With regard to generation pricing outside the national grid system (the SCS):

- The most efficient generation facility used to meet the system demand shall constitute the base for determining the marginal generation capacity cost;
- Marginal energy cost shall be computed for each generation facility;
- For cases of small hydro power plants similar approach may be used as in the case of large hydro power plants in the national grid system;
- Generator's specific prices shall be spread over the system generation price on the basis of planned generation within the system; and, where appropriate, frequent review of such price by the EEA shall be maintained.
- Appropriate incentive and penalty mechanisms shall be incorporated in the pricing process for securing a higher level for availability of thermal generating facilities.

The price of bulk energy and power from private producers shall be determined in accordance with power purchase agreements as approved by the EEA, and shall be directly transferred to customers.

The system marginal transmission capacity cost shall form the base for transmission pricing within the national grid system (the ICS). The system's transmission capacity cost outside the national grid system (the SCS) shall be determined on the basis of estimated or actual accounting costs and an acceptable rate of return on investment.

With regard to power distribution pricing within the national grid system (the ICS), system marginal distribution capacity cost shall form the base for distribution pricing. Accordingly, therein, the system's distribution capacity cost shall be determined on the basis of estimated or actual accounting costs and an acceptable rate of return on investment.

Energy and power metering costs and billing costs shall form the base for determining marginal customer related costs.

Payment of connection charges shall be related to additional costs resulting from supplying new demand.

Charges on reactive power consumption shall be related to the capacity cost that each reactive power consumption entails at the voltage level at which the consumption is effected.

Other appropriate charges may be effected in accordance with contractual agreements between licensees and customers.

The EEA shall, in consultation with licensees, determine generation, transmission and distribution efficiency indexes indicating potentials for improving electricity services that would have ultimate bearing on prices.

Interconnection with Sudan is planned for the next few years and with Kenya in a more distant future. Those interconnections should “monetize” Ethiopia’s abundant hydro resources, as well as provide cheaper and reliable power to neighbouring countries, most of them burdened by expensive thermal generation or facing significant power shortages.

EEPCO signed a MOU on Power System Interconnection with KPLC of Kenya on May 17, 2006.

Ethiopia already signed a MOU on Power System Interconnection with the neighbouring Republic of Djibouti and Sudan to export electricity.

The Ministry of Mines and Energy is currently studying the reform of the Ethiopian electricity sector, including unbundling of the generation, transmission and distribution activities.

Major points describing the current commercial aspects of cross-border trade are:

- EEPCO is the only company that presently can export/import electricity;
- It is not possible for large consumers (companies) to trade directly with a foreign power suppliers;
- Any licensee desiring to import or export electricity generated within Ethiopia shall have to obtain prior permission from EEA; conditions for the import and export of electricity shall be determined by the Ministry, subject to recommendations made by EEA;
- EEA is the lawful entity that has the right for setting and approving tariffs for internal trade;
- The present contractual framework needs to be further developed to provide for new concepts to the Ethiopian Electricity Market such as Third Party Access. Since, present legislations do not provide support for this concept, the enhancement of the present contractual framework depends on restructuring the electricity sector to establish a competitive electricity market in Ethiopia.

1.3.3 SUDAN

The list of collected laws and legal documents governing the Sudanese electricity and water sectors is presented on Appendix 4.

Development policies are calling for rational use of natural resources and environmental protection through range rehabilitation and forestry development. In the 1990's Sudan has undertaken strategies and policies aiming at sustainable development, as it ratified and signed the UN conventions on environment.

A Higher Council for Environment and Natural Resources (HCENR) was established in 1992 with the mandate of co-ordinating activities pertaining to the environment and developing policies and strategies in this regard. The HCENR is implementing three strategic projects: Support for Strategic Planning for Sustainable Environment Development; National Biodiversity Strategy and Action Plan and Climate Change. These strategies together with the National Action Plan for combating desertification and mitigating the effects of drought have been harmonised through the Formulation of a National Strategy for Sustainable Development.

This action was supported by the promulgation of the Environment Conservation Act 2000, which provides a policy and institutional framework for the conservation of the environment and natural resources. A 25-years National Strategy (2002 –2027) has been formulated.

The Government of Sudan started a firm move towards:

- Liberalizing the economy;
- Restructuring the economy (privatisation of public corporations ending the State's monopoly of certain production and service fields);
- Modernization of laws and regulations of investment encouragement;
- Implementing a flexible investment law which provides all sorts of exemptions and concessions which include the following:
    - complete exemption from customs fees for capital projects;
    - freedom of capital transfer;
    - simplify procedures through a single outlet “One Stop Shop”;
    - grant exemptions from profit taxes of 5 to 10 years for investment projects;
    - grant customs exemptions for strategic projects and non-strategic capital goods;
    - strategic projects are given the necessary land free-of-charge;
    - non-strategic projects are given land at an encouragement price;
    - the investor has the right to operate without a Sudanese partner;
- The investment law has provided the following fundamental guarantees:
    - no confiscation of property will occur except through the legal system and after payment of a reasonable compensation;

- the investor has the right to re-transfer the capital in case the project isn't executed or is liquidated;
- transfer of profits and costs of finance will be executed in the currency of import and on the date due (after payment of the legal duties);
- the project is automatically included in the registry of importers and exporters.

To promote the investment climate, the Sudanese government has established number of regional agreements aimed at encouraging investment and creating trade opportunities with other nations:

- Sudan joined the COMESA trade bloc;
- Sudan is looking forward to joining the World Trade Organization;
- Sudan is attempting to join the Arab Free Trade Organization in 2007;
- Sudan has strengthened relations with regional and international organizations and corps related to investment.

The institutional framework of the energy sector in Sudan is diverse. The Ministry of Energy and Mining is the main policy and planning body. Together with its General Energy Administration, they form an umbrella organization for a system of independent establishments. Corporations like the General Petroleum Directorate and the National Electricity Corporation (NEC), although working under the guidance of the Minister, they are practically autonomous, and managed by Boards of Directors, headed by the Minister of Energy or his designate.

State-owned NEC is responsible for electricity generation, transmission and distribution in Sudan. NEC transmits electricity through two interconnected electrical grids, the Blue Nile Grid and the Western grid, which cover only a small portion of the country. Regions not covered by the grid often rely on small diesel-fired generators for power. Only 30 percent of the population currently has access to electricity, but the government hopes to increase that figure to 90 percent in coming years.

Major points describing the current commercial aspects of cross-border trade are:

- NEC is the only company that can presently export/import electricity;
- It is not possible for large consumers (companies) to trade directly with a foreign power suppliers;
- NEC is a single importer/exporter of electricity and no licenses or permissions are needed for import/export of electricity;
- There are no regulations concerning the cross-border trade;
- The Ministry of Energy and Mining controls and supervise the cross-border trade and electricity markets;

- The Ministry of Energy is the lawful entity that has the right for setting and approving tariffs for internal trade;

- The present legal framework provides a firm basis for present commercial contracts, however, it does not provide a similar support for more competitive contracts.

- The present contractual framework needs to be further developed to provide for new concepts to the Sudanese Electricity Market such as Third Party Access. Since, present legislations do not provide support for this concept, the enhancement of the present contractual framework depends on restructuring the electricity sector to establish a competitive electricity market in Sudan.

A High Committee has been formed to study the issue of reforming and restructuring the national electricity sector towards the opening of the sector including privatisation.

1.4 COMMERCIAL BARRIERS FOR THE DEVELOPMENT OF THE ELECTRICITY MARKET

Essential conditions for development of the effective regional electricity market are: electricity trade and prices in the region should be set by supply and demand, clear commercial separation of generation, transmission, and distribution functions, and a division of the network operations from the power trade functions.

Ideally the full potential for trade identified in Section 1.2 could be realized. The factors which prevent that full realization are linked to the pricing, legislative, regulation, and institutional issues. We have observed the key commercial barriers which currently reduce or eliminate trade including:

- Policy favouring domestic generating plants or fuels;
- Artificially low prices to key customer groups;
- Limited ability of key customers to buy from competitive suppliers;
- Limited private ownership in the power sector;
- Financially weak utilities that are not creditworthy trading partners.

State ownership and vertically integrated utilities still prevail in the countries. In addition, most of the listed commercial barriers are clearly visible in the existing organizational structures. While this structure is a clear obstacle in developing the electricity market, it could be improved to increase electricity exchanges and contracting among the existing utilities. To overcome some of these obstacles during the interim period, the existing utilities should already start developing more formal commercial and contracting arrangements. Utilities are also in the best position and have staff that could be trained to develop these arrangements.

The countries are moving at different speed into reorganizing the electricity sector and creating national competitive internal electricity market. Once the power grid is open to more players, initial inter-utility arrangements should be transferred to the independent entity and expanded to accommodate new market structure and participants.

A properly functioning electricity market has the following characteristics. Lack of any one of them also represents a barrier to commercial trade.

- ***Knowledge***:
  - Parties understand what kinds of transactions can be beneficial to them;
  - Parties have the timely information they need regarding which transactions are currently available;
  - Parties have the timely information they need to evaluate potential transactions;
  - Parties understand and accept the risks involved;

- ***Contracts:***
  - Contracts exist to cover all potentially beneficial transactions;
  - There are mechanisms for agreeing on prices and other terms;
  - Procedures exist for resolving disputes fairly and efficiently;
  - Parties are willing to accept the obligations that, when accepted by all, allow all parties to benefit;

- ***Credibility:***
  - Parties trust their counterparts to fulfill the physical commitments they make;
  - Parties assume financial responsibility for the transactions they undertake;
  - Parties understand the physical requirements of the interconnected system, and plan and operate accordingly;

- ***Finance:***
  - Organizations have the financial resources to pay for the transactions they undertake;

- ***Physical:***
  - Equipment exists to measure and record usage (metering);
  - Communication links exist to support real-time transactions;

- ***Administrative:***
  - There is a sound legal and regulatory basis for commercial transactions;
  - Financial and banking services exist to support transactions, including currency exchange issues;

- ***Transmission Access:***
  - System access is available to parties wishing to transact, on a transparent and non-discriminatory basis;
  - Electrical system services needed to support transactions are available and provided on reasonable terms;
  - The treatment of losses is specified and understood.

All of these issues will also have to be addressed as a condition for developing electricity market in the East Nile Region.

1.5 CONCLUSIONS AND RECOMMENDATIONS

Based on our analysis, we developed a list of conclusions and recommendations designed to address critical problems in developing commercial aspects of the regional market.

Conclusions from the analysis are:

- There is a clear understanding of the benefits that synchronous operation and electricity trade could bring to utilities and countries in the region;
- There is also a clear understanding that the benefits, the present generation and transmission projects under study will bring to the Region, are only a portion of the benefits that could be obtained by broadening cooperation and ultimately develop electricity market;
- There is a willingness on all parties to broaden cooperation;
- Parties need information on what kinds of transactions will be available and the risks involved;
- Standard contracts or mechanisms do not exist to cover all potentially beneficial transactions, to agree on prices and other terms;
- Procedures for resolving disputes fairly and efficiently are not developed;
- The legal and regulatory basis for commercial transactions is not developed;
- Financial and banking services do not exist to support transactions, including currency exchange issues;
- In the concerned countries, transmission system access is not available to parties wishing to transact;

Based on the present status of electricity trade, the Consultant developed a list of recommendations that should gradually broaden electricity trade and strengthen commercial aspects of the electricity market. First steps could be developed during the time electricity sector is dominated by vertically integrated utilities:

Exchange and trade electricity based on regularly announced prices of electricity available for trade:

- The first step in developing regional trade should be an agreement for member countries to announce prices of electricity available for trade. Using this information, countries could increase trade by importing generation when the offered price is lower than their internal cost of generation including transmission losses. The trade will proceed as long as the price difference would economically justify the trade. In theory, this will tend to levelize generation prices throughout the region. Technical constraints or other technical and non-technical limitations would still be a limiting factor. However, readily available information about the possibility of trade and cost savings will serve as the catalyst in facilitating the amount of trade among countries. To accompany this type of trade, commercial aspects should be developed based on predetermined type of contracts.

Announce medium-term and long-term needs/surpluses of electricity:

- Countries (national utilities) should prepare and announce medium-term and long-term needs/surpluses of electricity (primarily on a monthly or yearly basis). This step will further increase potential for more inter-utility and utility-customer contracts. Country legislation and contracting arrangements should be adjusted to allow gradual increase of the percentage of electricity generation allowed to be contracted from other countries in the region. This practice is in line with a gradual opening of electricity markets.

Calculate and exchange short-term needs/surpluses of electricity and short-run marginal costs of electricity:

- Then the practice described above should be expanded to shorter time period. Consequently, countries (national utilities) should prepare and exchange short-term needs/surpluses of electricity and prices of electricity (primarily on a weekly or monthly basis). This information will allow utilities or large customers to have updated and readily available information about the electricity trade and act accordingly. The practice will also create the seed of the regional electricity market, where sellers and buyers will have to adjust price to reach the regional equilibrium.

Define commercial aspects of electricity exchanges (commercial rules, pre defined contracts for several types of transactions):

- To simplify and expedite the commercial aspects of trade, standard types of contracts should be developed. Standard contracts should be developed and should cover several time horizons and types of transactions.

Including purchase/sales bids from other countries:

- Commercial rules for single buyer or power exchange in each country should be developed to allow purchase/sales bids from other countries. This step should gradually increase the percentage of purchase/sales bids allowed to compete with the domestic resources.

Taxation issues:

- Two systems of taxation apply to electricity. The first is VAT, and the second is a series of national taxes. As a general rule, taxation of electricity imports/exports should be standardized for all countries. We propose to adopt the EU taxation practice (EU proposal is that electricity shall be taxed at the level of output).

- When electricity is traded between countries, this principle means taxation in the country where the electricity is finally consumed and accordingly, electricity could be traded without tax. A country taxing inputs should not discriminate against imported electricity.

- Agreement will have to be reached at what extent the regional electricity market will allow countries the possibility for using tax policy to pursue national objectives of employment, environment, transport and energy policy.

- In the field of direct corporation taxes, there should be an agreement to harmonise tax bases on which corporation tax is levied. In this context, a potential problem exists from a state aid point of view if a specific exemption of direct tax is applied only for public or national companies.

- The taxation harmonization is to be applied at the time when electricity sectors in most member countries achieve commercial separation of generation, transmission and distribution functions, established a single buyer or power exchange entities, and impose the cost-based pricing of electricity.

Transmission access and pricing:

- International transmission access and pricing requires a set of rules in order to work effectively. Working groups will need to be established to develop technical and commercial rules for using the international transmission systems, and for the co-operation among the electricity utilities in each country in a first step, and among the Transmission System Operators (TSOs) after complete restructuring of the national electricity sectors. Non-discriminatory transmission pricing policy is the key in developing regional markets. Commercial aspects of the transmission pricing policy should be applied that are both transparent and standardized for all countries. Pricing policy could also be in line with the EU transmission pricing practice if agreed.

- Commercial rules for transmission access will include: transmission pricing regulations, associations' agreements, rules for international exchanges of electricity, how the individual countries' transmission pricing systems fit together to ensure cost-reflectivity and non-discriminatory access, transmission pricing policy and policy for congestion principles that directly affect how regional transmission transactions are handled commercially, and clear understanding which costs may be recovered in the access fees.

- In future (depending on the will of the Governments to liberalize their electricity sector), TSOs will have to become independent from other activities of a vertically integrated utilities, such as generation and distribution. The TSO should not discriminate between system users or classes of system users in favour of its subsidiaries or shareholders with the minimal requirement to have separate accounts according to generation, transmission, distribution and other activities.

Stranded Costs:

- Creation of the regional electricity market will have to clarify the issue of stranded costs. Current EU proposal is to recover and charge stranded costs only to the loads in the territory where they are connected, but not to the cross-border trade. In this case, the cost base for cross-border elements of transmission fees should exclude stranded costs or costs of ancillary services or public service obligations that are not directly related to the transmission service.

Regulatory aspects:

- Commercial aspects of electricity trade also include several areas, which will require harmonisation and attention of the national regulatory bodies to guarantee the proper and efficient functioning of the internal electricity market. As an example, regulatory attention has to be dedicated to the correct unbundling of accounts, i.e. the correct distribution of investment costs to revenue from electricity trading and to revenue from transmission fees.

Regional development to follow progress of the internal market:

- Commercial rules for internal markets in each country should be developed taking into account integration into regional market. Development of internal market will, in some countries, precede the development of the regional market. However, internal market rules should be synchronized with the development of regional commercial rules.

Development of a regional market using the African experience:

- In developing the East Nile Regional Electricity Market, countries in the region should learn and benefit from the African experience [SAPP, WAPP], and also avoid some of the pitfalls in developing regional markets.

- Since, East Nile Regional Market will ultimately become part of the broader Nile Basin Energy Market, commercial rules among East Nile member countries should be very similar or the same as applied in other NBI countries. The commercial contracts, rules and regulation developed by other African Experiences [SAPP, WAPP] should be critically reviewed and used as a template in developing the East Nile Regional Market rules. This experience and exercise will allow for much easier development and future transformation of the East Nile Regional Electricity Market.

2. PRICING & TARIFFS

2.1 TRANSPARENT, COST BASED PRICING AND TARIFF POLICY

2.1.1 BASIC PRINCIPLES

The establishment of a transparent electricity tariff policy for each of the beneficiary countries will require the consolidation of the electric utilities involved with respect to the general methodology and main objectives to be incorporated and considered. The desired transparent tariff structures and levels for all consumer classes should be cost-based and according to market economy conditions.

Cost-based electricity pricing provides the means for the electric utility to operate the overall power system (generation-transmission-distribution) free of deficits. At the same time, it secures part of the equity capital and the financial charges required for system rehabilitation and future expansion. It should be made clear that in case foreign investments are to be attracted in the power sector of the East Nile Region, it will be necessary by the enterprises involved to guarantee the required revenues that will in turn support the return on investment and debt coverage.

Most of the electric utilities are allowed to recover part of each embedded cost of service. However, this practice does not allow the enterprise to develop and improve the quality of service to the consumers. An appropriate electricity tariff design should incorporate the future system requirements, i.e. it should be designed on a forward-looking basis. Therefore, besides the cost of service expenditures, the electricity tariffs should include, in some way, the utility’s future embedded costs associated with capital expenditures, operating costs and financial requirements and charges.

A useful tool that is incorporated by most of the market economy operating electric utilities is the concept of marginal cost pricing. Marginal costs, modified to conform to revenue levels based on embedded costs, may be used to indicate the directions in which tariffs might be modified in the interest of economic efficiency as well as rational use of vital resources.

Therefore, it is safe to draft common general objectives with respect to the determination of a transparent, cost-based electricity pricing and tariff policy, as follows:

- The tariff should be based on marginal cost pricing, providing clear signals to the consumers on the short as well as the long run, and therefore promote efficient consumer behaviour.
- The tariffs must secure adequate funds to reliably operate the power system while providing reasonable return on invested capital.
- The tariffs should reflect consumer burden on the overall power system and therefore should be differentiated to the degree practical (customer class distinction, voltage service level, time-of-day and seasonal use).

- The tariffs need to address social welfare and economic development issues. This may require the sustainability of several cross-subsidies that should be faced out over a predefined timeframe considering that financial objectives are met over a medium term period and not on an annual basis.

2.1.2 Consideration of Revenue Requirements

An essential requirement of an integrated electricity tariff structure is that it should produce adequate revenues to meet the financial requirements to operate, replace, and expand the power system. These requirements include operating expenses, an adequate allowance for depreciation to provide funds for replacing the system as the economic life of equipment comes to an end, and a reasonable return on investment.

The starting point for determining revenue requirements is the utility's set of financial statements. Developing the forecasted financial requirements includes the following steps:

Step 1: Financial Modelling

Financial modeling is carried out in order to simulate the future demand, supply, finance, and tariffs for the electric utility. This allows a forward-looking approach to cost-of-service. Although the forward-looking approach is not universally used in the utility industry, it is becoming the standard as the industry adopts financial practices used in other commercial enterprises. The model is used to forecast the balance sheet, income statement, and sources and uses of funds.

Step 2: Revenue Reconciliation.

Alternative financial scenarios are evaluated to ensure that the utility will have adequate revenues to meet operating costs and finance replacement and expansion programmes.

Step3: Financial Analysis

Financial analysis attempts to optimize the financial plan, ensuring adequate cash flow and balancing debt financing with internal funding. Financial ratios are calculated to evaluate key targets, including cash to debt service, the cash generation ratio, and the ratio of internal funds to construction expenditures.

Step 4: Cost Allocation

Once the utility's revenue requirements are identified, each cost component is allocated to customer classes based on causality. Energy-related costs are allocated largely in proportion to the amount of energy consumed by each class. Capacity-related costs are allocated based on class contribution to peak period system demand. Customer-related costs are assigned on the basis of number of customers and maximum demand.

Considering the above, the revenue requirements method for determining tariff structures has to take into account the balance sheets and income statements of the enterprise.

Therefore, certain assumptions will have to be outlined. Under a conventional utility model, operating expenses are passed through to the customer, and the capital program is financed from a combination of internal and external funds. The major assumptions that have to be considered in determining the cost of service are in brief the following:

- The major parameter driving the cost-of-service is the relative amounts of external financing, in the form of debt, versus internal financing, in the form of increased allowance for depreciation and return on assets. It should be noted that increasing the use of debt financing for capital requirements would lower customer revenue requirements during the period of debt build-up. In market economies, a common utility capitalisation structure is 50 percent debt, 50 percent equity.
- The second major assumption deals with depreciation of assets. Depreciation is an accounting mechanism intended to reflect the loss in value of tangible assets. In the context of utility finance, depreciation expense is the mechanism by which the utility recovers from customers the funds previously provided for the construction or acquisition of the utility power plant or any other installation. These recovered funds are available to replace the utility plant as it reaches its useful life cycle.
- In an hyper-inflationary economy, the depreciation reserve quickly loses its purchasing power and in time the depreciation fund is inadequate for the capital requirements of the utility. To ensure adequate depreciation expense, asset revaluation is advisable in a hyper inflationary economy.
- Costs of decommissioning are important components of the financial requirements. An essential financial issue is the timing of the funding period for decommissioning retired power plants. The funding period could extend from the date of commercial operation ending on the estimated date that commercial operations cease. Under this mechanism, the future costs for today's electricity customers incur decommissioning activities.

2.1.3 TARIFF DESIGN OPTIONS

Tariff design options based on Long Run Marginal Cost (LRMC) may produce more or less revenue than needed to meet financial requirements. Some economists have suggested that this need not cause a problem for a government-owned utility since surpluses and taxation and subsidization can adjust deficits, respectively. From a strict economic point of view, this solution is considered to be the most efficient. However, it has serious shortcomings as follows:

- The scarcity of public funds makes strict LRMC-based revenues unacceptable if they produce less than financial requirements.
- If LRMC-based revenues produce surpluses over financial requirements, consumer resistance generally prevents their use even if the surpluses are recycled back to consumers by way of public offers.
- The goals of increased efficiency and competition in the power sector go hand-in-hand with financial autonomy, which requires that financial requirements be met.

The use of marginal costs in allocating cost responsibilities to customer classes, and in formulating tariff schedules to recover these costs, is in accord with fundamental microeconomic theory. Simply stated: when the price the buyer is paying equals the marginal cost of supply, productive efficiency is maximized and a commensurate increase in total welfare is realized. Under a strict LRMC-based tariff design process, the individual cost-of-service for each customer class is not used. However, even if the LRMC-based tariff design process is to be used, cost-of-service for each customer class is an important point of comparison for evaluating LRMC-based tariffs. For example, cost-of-service can be used to set an upper bound on the LRMC-based tariff for a particular customer class, if the goal is to minimize the tariff but still recover utility costs to serve the customer.

From a practical standpoint, in the future it is envisaged that electricity tariff design will be based on a hybrid system of cost-of-service and LRMC. Based on the forecasted relationships between LRMC, financial requirements, and current tariffs, the potential exists to raise tariffs to cost-of-service without exceeding LRMC. This suggests that there is the potential to implement any of several alternative tariff design options that recover the overall revenue requirement and, to a greater or lesser degree, meet the objectives of LRMC pricing.

2.1.4 TARIFF TRANSITION

A comparison of current tariffs with cost-based tariff alternatives will show that in all three ENTRO countries considered here, there is a need for transition to higher tariffs. Ideally, tariffs would be increased immediately to cover the cost-of-service. One way to manage the transition would be for the government to provide direct subsidies to poor consumers. The combination of direct subsidy and cost-based electricity tariff would remove the current incentive for uneconomic uses of electricity.

Continuing to delay cost-based tariff-setting eventually will force deferral of facility replacement projects. The average cost-of-service may eventually exceed LRMC when, by necessity, the utility accelerates deferred replacement programmes. In a market economy, pricing above marginal cost is inefficient and unstable. Eventually, customers attempt to bypass the utility system by relocating or by installing auto production and conservation. Customers also attempt to access the market for competitive power supplies. The utility has weak incentives for socially desirable demand-side management and conservation, because any reduction in demand further exacerbates the gap between LRMC and average cost-of-service. Eventually corporate earnings suffer. These considerations suggest that it is important for the three countries to adopt cost-based tariffs as soon as possible.

Tariffs developed on the basis of forecasted system expansion, operations, and fuel prices are subject to significant forecast risk (for example, the risk that future fuel prices will vary from the forecast). One means of avoiding forecast risk for tariff setting is to use indexing or alternatively, cost adjustment procedures. In this way, tariffs can be made responsive to changes in underlying costs. Indexing is easier to administer and eliminates often contentious and inefficient cost adjustment procedures. Cost adjustment procedures are a more direct approach that is not subject to the accuracy trade-offs inherent in modeling complex and dynamic cost structures in a simple indexing formula.

2.2 TRANSPARENT, BULK ELECTRICITY PRICING FOR THE EAST NILE REGION

The development of the regional electricity market in the Region requires the development of a common base of understanding among the involved enterprises with respect to the bulk power tariff settings especially those components that address the transmission fees and the access to the network. One of the three countries, Ethiopia, has scheduled ambitious generation expansion plans that aim mostly in exporting power than covering future national load demand increases. Up to now no one of the involved countries has committed itself in long term bulk power transactions in the long run.

Foreseen transactions are based on market opportunities of energy and capacity charges mainly derived through avoided fuel costs and power shortages. At the beginning, the agreements will be bilateral contracts between vertically integrated public companies.

Therefore, the selection of actual pricing prescriptions for the East Nile Power Trade should not be a precondition prior to the political decision for the establishment of the East Nile Power Trade, as then it would comprise an extra obstacle for the creation of the market.

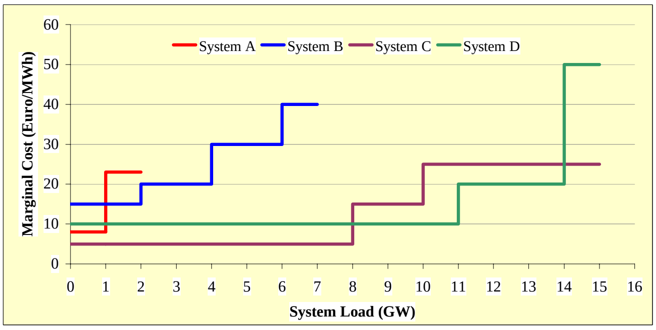
2.2.1 BULK POWER GENERATION PRICING

Transparency on generation and transmission pricing is considered important for the operation of the regional market. However, utilities will not reveal their costs and this may create some misunderstandings at the beginning of the East Nile Power Trade operation. The objective however is to establish a competitive market where export prices should be offered on the same basis, otherwise the seller would be exploiting monopoly power. The prices that will be offered will be based on the ability of a particular power system or generator to produce at lower cost, thus the market mechanisms will eventually stabilize the market conditions with respect to generation costs and prices. Therefore, more attention should be focused on transmission pricing. In fact, the greatest obstacle to the regional market may be non-transparent transmission pricing. It is therefore necessary for the market participants to have an agreed upon set of rules on transmission access.

Considering a mature situation that could emerge after a trial period of East Nile Power Trade operations, competitive bulk power generation pricing could be based on well-accepted methodologies applied in tight or loose power pools already in operation. These methods are based on the comparison of the annual marginal cost of production of the power systems involved. The methodology includes the determination of the short run marginal cost of each system on an annual basis. These calculations are based on the methodologies already outlined in section 2.1.

Considering the characteristics of the power systems that could participate in the regional market their marginal production cost could be calculated in terms of system load as shown in Figure 2.1. Based on the system marginal production cost, power exchanges could be determined on a pure economic base depending however on the particular system capability to supply the requested power at any given time. As shown in the illustrated example, system A is a small system comprising small thermal and hydro units; while systems C and D are predominately based on nuclear and coal plants. Based on these characteristics system D could supply system C for system loads higher than 8 GW while system C could supply power for system loads higher than 14 GW.

Figure 2.1.: Power system marginal production cost



Taking into account the marginal operating cost, the power flows allowed by the transmission links, and the transfer capabilities of the interconnected systems, such a loose power pool configuration could be considered for the East Nile region. However, this could take place at a later stage when enough experience and trust will be gained and established from the initiation and the operation of the East Nile Power Trade.

Concerning generation pricing in the short and medium, transparency can not be foreseen especially when independent power producers will participate in the market. Therefore, the transactions amongst the interested parties will have to be based on ad hoc competitive market conditions.

Considering the lack and difficulty of generation transparency, long-term power purchasing agreements probably should be avoided, as they may fail according to the volatility of the economies. It should be mentioned that today, there is a trend to move towards more flexible power purchase agreements and not toward long term ones.

2.2.2 BULK TRANSMISSION PRICING

In opposition to the generation system that will operate under liberalized conditions, the natural monopoly elements of the power system such as the high voltage transmission network involved should be made transparent, and therefore transparency should be introduced in transmission pricing.

The transmission and distribution networks will be required to provide access to all potential users, enabling buyers and sellers to compete in the market for electricity. Nevertheless, network access needs to be offered on a fair and non-discriminatory basis and to be organized as simply as possible to ensure that competition in the market is both fair and efficient. On the other hand, each member country may select among the single buyer and the negotiated third party access models for organizing their electricity market. Regardless of which model is chosen, separate pricing of transmission services has to be realized. Similarly, in order for every organized electricity market, competitive or not, to have access to different electricity systems, it is very important to take the necessary steps for regulation of the transmission function, in terms of access conditions, pricing and investments.

2.2.2.1 Transmission Pricing Basic Principles

The methodologies used to allocate transmission costs applied to regional electricity markets can be different based on the following principles:

Secure and reliable power system operations

Information exchange amongst the utilities is essential in order to secure reliable system operation considering that the existing networks in the region will support significant but not unlimited cross-border power flows. Therefore, existing or future network limitations should be considered in the transmission pricing methods.

Cost reflective pricing

Considering that the regional electricity market will be operated and monitored by the participating country's utilities, then . Furthermore, the transmission fee levied by each participating country for a regional market transaction should reflect its cost. In case where this condition is agreed and met by each member of the East Nile Power Trade, the total fee for regional transmission should also be cost-reflective. However, several transmission pricing methods applied today may not satisfy this condition and should be avoided as it will be described later on in this section.

Transparency

Network users (generators, suppliers and eligible consumers) should be able to estimate the overall transmission fee based on the fee structure of each affected country in order to secure electricity trade without fictitious barriers.

Physical power flow considerations

To avoid discrimination, a East Nile Power Trade participating country's fees should be applied to the transmissions that utilize its network. Since the power flows are distributed over the interconnected East Nile network following Kirchhoff's law, physical flow modeling should be applied in replacement of contract path approaches that do not reflect actual burden on the transmission network and in most cases discriminate over particular areas in the East Nile Power Trade.

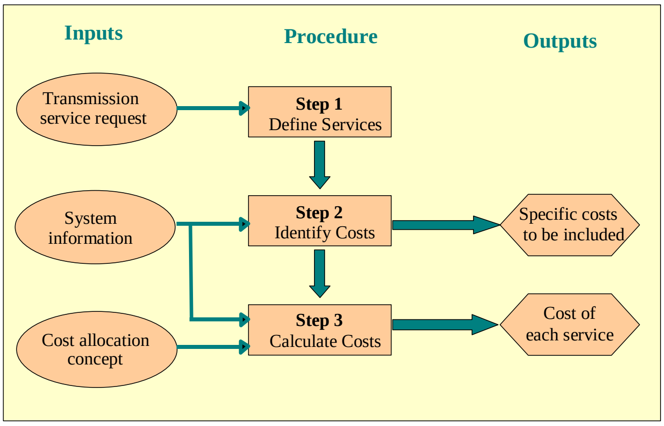
2.2.2.2 Transmission cost allocation

The subject of transmission pricing is very complicated. The methods briefly mentioned here are basic and fundamental, however they approach the subject in line of the work of the

European TSOs mentioned as well as the experiences from already operating markets. As the market will continue to develop, the existing methodologies will be enriched and revised, while new ones will appear, depending on the degree of each country's development and the maturity of the market itself.

Considering that almost all transmission pricing methods rely on the cost burden of each transaction, an attempt is made herein to describe a systematic cost allocation procedure that could be applied regardless of the transmission pricing method that will be applied. Figure 2.2. presents the overall methodology that could be followed.

Figure 2.2.: Transmission service pricing general methodology



Transmission service pricing could be carried out in three distinct steps:

Step 1: definition of transmission services

Step 2: identification of transmission service costs

Step 3: calculation of transmission costs

Step 1: *Definition of transmission services*

The various types of transmission services that will need to be provided by the participating parties into the regional electricity market, may be best described in terms of their specific attributes and characteristics. These attributes are typically defined within the terms and conditions of a formal transmission service agreement. Key attributes include:

- Quantity of service to be delivered:
  - Capacity (MW)
  - Energy (MWh)
- Firmness of service:
  - Interrupt only during system emergencies

  - Interrupt to avoid interrupting transmission customers
  - Interrupt to avoid curtailing economic transactions

- Duration of service:
  - Starting date of service
  - Ending date of service

- Receipt and delivery points:
  - Receipt point identities (one, several, all)
  - Delivery point identities (one, several, all)
  - Inter / intra control area implications, the directionality (single or bilateral) and the physical distance of transfer
  - Stipulations on use
  - Notice required for changes

- Time of use profiles of service:
  - Aggregate measures (load factor, seasonal or time-of-day use
  - Specific or typical hourly schedules by week, month or season
  - Notice requirements

- Power loss responsibility:
  - Amount provided by transmission system provider
  - Providing entity

- Other system operating characteristics:
  - How service will be used
  - Substitution flexibility
  - Provisions for backup service or service from alternative sources as well as provisions for maintenance co-ordination
  - Other provisions

Step 2: ***Identification of transmission service costs***

The power transmission cost can be classified into fixed and variable cost. The fixed cost includes capital costs, operating and maintenance costs. Variable costs include mainly losses and depend on the utilisation of the network. The major part of transmission cost is that of the fixed costs. Fixed costs have to be recovered independently of how much energy is demanded. The transmission service components that need to be incorporated in transmission pricing deal with the ancillary services and the indirect components relative to these services.

The ancillary services includes the following:

- The ability to keep a reactive balance;
- The ability to provide a change in real power supplied to, or taken from, the system at short notice;
- The capability of generating plant to start while disconnected from off-site supplies ("black-start");
- Load reduction.

The indirect components include the following cost components:

- Levies;
- Cost arising from regulatory review;
- Public service obligation;
- Stranded investments.

To facilitate the analysis of costs associated with a specific transmission service, components include the following:

- Analyse and arrange service to be provided;
- Bill for services and collect revenues;
- Provide additional facilities when necessary ;
- Control power flow and frequency;
- Provide adequate reactive supply and voltage control;
- Keep system secure and available;
- Monitor / meter service delivery.

These service components include all the activities that are required to provide a complete transmission service. In a traditional vertically-integrated utility, these services would probably all be provided by the same organisation. In the future, however, various other industry structures are possible, and it is quite likely that at least some portion of one or more of these service components will be provided by other organisations or parties. For example, an independent transmission company having no affiliation with any entity involved in generation or distribution. Step 2 concludes with the identification and listing of all the capital and operating costs associated with each of the actions identified previously. The listed cost items will then be quantified based on the methods described in step 3.

Step 3: ***Calculation of transmission costs***

The first step for transmission pricing is the choice of the cost allocation method, which directs to the appropriate pricing method, taking into account several basic principles which are applied for every tariff system. While, there is no one correct pricing method, always the criterion should be, to adopt the simplest method, in order to achieve a reasonable level of cost reflectiveness.

2.2.2.3 Transmission Pricing Methods

The transmission pricing methods applied today may be classified into two main categories as follows:

- distance related (not usual nowadays);
- non-distance related.

These pricing methods use the cost allocation methods similar to the one mentioned above. The tariffs used in practice are often a mixture of the different pricing methods described below. Also, transmission tariffs are always influenced by the rules of the regulator.

The transmission pricing methods applied today are the following:

Postage Stamp

This method, like the postal service, is based on average costs and is not related to distance, neither does it distinguish between the entry and exit points. This method is based on the fact that a country is considered as a copperplate, there should not be thus any restriction on commercial transactions. The eventual network congestion should be addressed through redispatching and the related cost are mutualized and integrated in the network access tariff.

Contract Path

It is based on a possible path between entry and exit point, agreed in a contract. It takes into account the used assets for the possible path as well as the energy and capacity flow. This method allows identifying the real transfer and the part of the transmission capacity that is used however it may sometimes lead to unfair charges since it does not consider the physical power flow of the network. This method is applied in case of cross border trading.

Zonal

In this procedure, the transmission system is divided into zones and the system power costs are associated to the zones. The transmission tariffs are designed in different levels for each zone and a tariff, which will characterise geographic dependence, is created.

Investment Cost Related Pricing

It examines the variation of transmission cost, in terms of MW-km, as a result of variation of transfer capacity. Considering the capital and operating cost for necessary transmission capacity equal to 1 MW-km, costs may be allocated to each node depending on its location and utilisation. This method:

- identifies two cost components, namely, transport cost (price per MW-km) and security cost (price per MW);
- calculates costs at peak load and provides an economic signal to new users of the transmission network;
- it is preferred against methods like LRMC or SRMC due to the difficulties of predicting potential generation developments and utilisation.

Considering the work that has been carried out today in Europe by the TSO organisations as well as EURELECTRIC, it is necessary to note that they are in support of what they call the ***Cost Component Method***. This method combines some of the characteristics of the methods mentioned above but it gives great emphasis on the transparency of transmission pricing. A brief description of this method is presented herein, but further evaluation and discussion should be carried out since the EU Member Sates have not yet come to a conclusion. It should be mentioned that it is not the intention of the Consultant to propose a method that will not be widely acceptable, however upon review it considers that this method satisfies all the basic principles specified in section 2.2.2.1.

Cost Component Method

The method assumes that each participating country in the East Nile Power Trade separates its transmission system costs into discrete components. Several of these components may be related to congestion management, reflect incentives to avoid congestion or include any other economic signals related for example to transmission losses. The possible list of cost components could include the following:

- System costs for allowing generators to reliably access the grid;
- System costs for allowing eligible consumers to reliably access the grid;
- Costs of transport to/from the borders and through transit countries;
- Cost of outside the region interconnections;
- Cost of congestion;
- Cost of losses.

For different types of regional electricity trade transactions (export, import, transit), only some of these cost components apply. Each participating country's fee structure for a particular component may be flexible. For example, from current practice many countries appear to prefer a postage stamp structure for their entire fee, other countries may prefer nodal or zonal prices to represent one, two or all of the components.

In general, the aforementioned cost components can be grouped to their relevance to the different types of regional transactions as follows:

Imports: the cost component reflects the load access (L) and it is the most important for imports and will apply once for each regional transaction;

Exports: the cost component reflects the generation access (G) and it is the most important for exports and will apply once for each regional transaction;

Transit: the cost component reflecting transport to/from the boarder and through the transit countries (T) that represents the charges that could apply in each of the countries affected by a transaction. It may have a distance-dependent component; can be direction dependent; may include losses and costs of short-term congestion management.

It should be noted that these costs should be calculated by the Utilities based on a harmonised as realistic as possible analysis to be agreed upon.

It should be noted that in a particular regional transaction would apply not the full transmission fee of each involved country, but only those components L, G and T that actually apply. For instance, the exporting country would not apply the component L, any transit country would only apply the component T, while the importing country would not apply the component G. Therefore, the cost components

- G: is a charge applied to generation and exports;
- T: is a charge applied to transfers within and between countries;
- L: is a charge applied to load sites and imports.

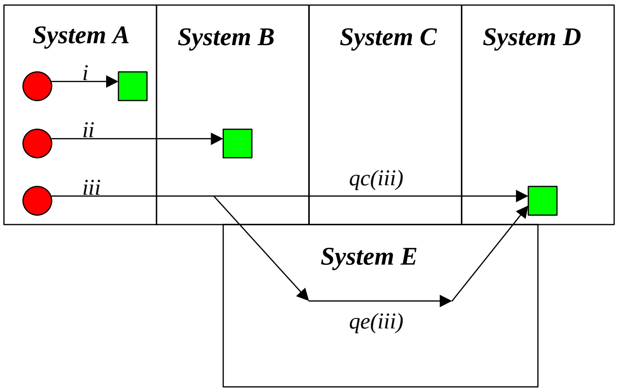
Therefore, for a transaction within a single power system, the charge per unit kW or kWh for using the transmission system is simply G+T+L. This basic principle can then be extended into regional transaction involving two or more countries as shown in figure 3. Three transactions are considered:

i) transaction within power system A,

ii) transaction exporting from power system A to system B, and

iii) transaction exporting from power system A to system D.

Figure 2.3.: Transmission charges of power transactions



The total transmission charge for the three transactions has as follows:

Transaction charge i:

$$TC_i = G_A + T_A + L_A$$

Transaction charge ii:

$$TC_{ii} = G_A + T_A + T_B + L_B$$

Transaction charge iii:

$$TC_{iii} = G_A + T_A + T_B + qc \cdot T_C + qe \cdot T_E + T_D + L_D$$

Where: qc and qe are the quantities of the power flow due to transaction iii affecting power systems C and E

The Cost Component Method is driven by physical flows thus allows to allocate the costs to the participating parties being the generators, the suppliers and the eligible consumers while at the same time it is not transaction related. This method is based on an objective approach reflecting costs of the national as well as the regional transactions, it allows for subsidiarity, it is user friendly not imposing barriers to electricity trade, while it is linked to the physics of the exchanges and not to the contract paths. Moreover, it also allows the analysis and incorporation of congestion costs. The disadvantage of the method is that it needs strong data exchanges between the Utilities and good simulation models.

3. CONTRACTS

3.1 BACKGROUND

As a result of the relative lack of development of inter-country electricity trade in the region, there has not been the imperative to more fully develop robust commercial contracts between participants and, therefore, electricity trade has been contracted on an ad-hoc basis, driven by factors such as the avoided cost of imported fuel and the reliability and security requirements of each power system. However, it is considered that the realization of the economic benefits of a regional electricity market requires the establishment of a robust contractual framework between market participants.

A number of other factors have also contributed to the lack of development of a commercial contractual framework, including:

- the absence of foreign investment in the region's electricity sectors has meant that pressure from this source for a set of transparent, "bankable" and enforceable contracts has been absent;
- this has been accentuated by the limited number of independent power producers in the region;
- the slow pace of liberalization of domestic electricity sectors has meant that contract have not been developed;
- the vertically-integrated nature of electricity companies in the region's three countries and the fact that they have not been fully unbundled has meant that there has been little incentive to identify and separate out the responsibilities and obligations of the utilities' generation, transmission and distribution functions;
- the self-sufficiency of the individual power systems has meant that there has been little need to develop long-term contracts for cross-border electricity trade.

Although there are other factors which are probably more important prerequisites to the establishment of the regional electricity market, the creation of a contractual framework within which participants can freely negotiate electricity trades is an important element in the overall development of the market. This will include the rules for the enforcement of the terms and conditions of contracts, possibly the establishment of a common governing law, as well as the establishment of a supporting organizational and institutional structure. It might also imply changes to the organizational structure of domestic electricity sectors.

3.2 CONTRACTUAL FRAMEWORK INFLUENCES

3.2.1 THE EU ELECTRICITY MARKET

Due to the recent developments with respect to Turkey's connections to UCTE system, EIJLLST Project had turned out to be part of prospective Mediterranean Ring (MEDRING) and the interconnection of Turkey with the UCTE grid via Greece and Bulgaria is prerequisite for the feasibility of prospective Mediterranean Synchronous Ring.

The Egypt participation in the MEDRING Project (closure of the Mediterranean Electrical Ring) and the future development of South-North HVDC links will involve integration of the Maghreb and Mashrek Electricity Markets with the EU Internal Electricity Market and harmonization of the electricity market rules will be also a prerequisite for the concerned countries.

Therefore, the EU Electricity Directives is probably an important external influence on the development of a contractual framework for the regional electricity market. The EU directives are aimed at the organization and structure of member countries' electricity sectors. The directives contain a set of high level principles which are aimed at encouraging:

- competition in generation;
- the unbundling of accounts; and
- competition for customers.

In promoting competition in generation, governments choose between two methods for allowing new generation:

- the **tendering** process, under which an independent body draws up an inventory of new production requirements and potential new producers bid for the required capacity under a tendering process. By implication, the adoption of this option requires the establishment of a market based on the "single buyer" principle.
- the use of **authorizations**, under which anyone is allowed to build and operate a generating plant, provided that it complies with the planning and energy supply criteria for an authorization as specified in the member state. The adoption of this process implies a different market structure, in effect one in which there is either a pool or a large number of purchasers of electricity, be they distributors or large customers.

Experience in the EU to date has been that most states have chosen the authorizations option - it is considered the most transparent and effective process for opening generation up to competition.

The requirement for unbundling is considered essential in order to prevent discrimination against potential users of the transmission network. It requires that management of the transmission network is separated out, that there is a separation of transmission accounts and that all information is treated in a confidential manner. This is also associated with the development of new rules for network access, for which governments have three choices:

- a **negotiated TPA**, under which each user of the network negotiates access with the system operator; indicative prices are published and access contracts involve the generator, customer and network(s) owner;
- a **regulated TPA**, under which tariffs are fixed by a regulator, they are published and they apply to all users; or
- the **single buyer model**, which is simple, provides less choice to sector participants and requires tariffs to be published.

Almost all EC member states have chosen the regulated TPA option on basis that it is the method which will permit greatest competition. Fixed and published prices ensure that no discrimination can emerge; companies can plan in advance in the knowledge that tariffs are transparent and the cost of possible renegotiations of contracts and agreements is minimized.

There are lessons to be gained from the EU's experience in the liberalization of member states' internal electricity markets and its efforts to create a single market. The countries of the East Nile Region should not be afraid to learn from this experience, adopting best practice to suit the region's particular characteristics.

3.2.2 DIRECTION OF THE MARKET

The development of a contractual framework best suited to the East Nile Electricity Market must take account of the current environment as well as the future direction of market development. The nature of the future market is likely to involve a number of iterations before a solution acceptable to all is achieved – the contractual framework and its detailed requirements will be conditioned by this agreement.

Despite this uncertainty, it is considered worthwhile to examine what type of contracts might be required and what concerns they would be required to address.

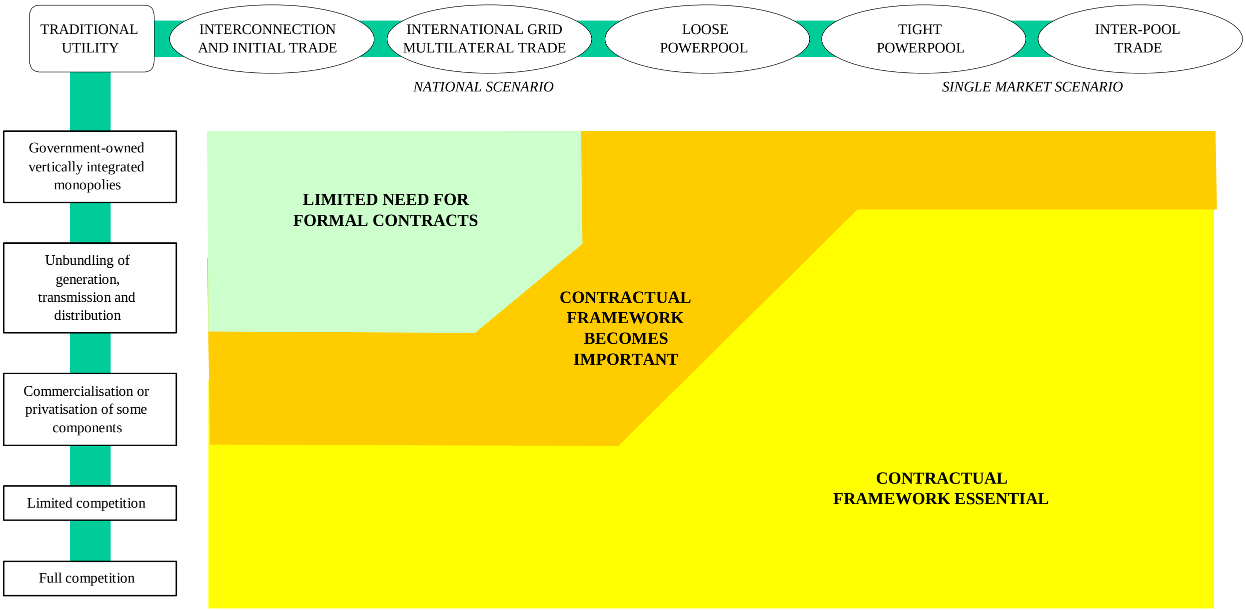
The range of future structural options for the regional electricity market have been identified before. On one side, these range from the vertically-integrated and government-owned utility to the fully competitive and unbundled sector. On the other side, cross-border trade range from the current position of ad-hoc arrangements to one in which the three (and even more) countries' electricity sectors operate as a single market in a tight power pool.

The need for a formal contractual framework varies across all these options, as follows:

- prior to the commercialisation or part-privatisation of the sector, and before a loose power pool is implemented, there is considered to be little need for a formal contractual framework. It is possible that trade can continue to be conducted on the current ad-hoc basis.
- once entities are privatised, a loose power pool is implemented or there is greater cross-border trading, a formal contractual framework becomes important. The contracts can be seen as forming the rock upon which the organisations' future cash flows (and therefore their return to investors) is based.
- as soon as competition is introduced, even in a limited form, the contractual framework is essential.

This outline is summarised in Figure 3.1.

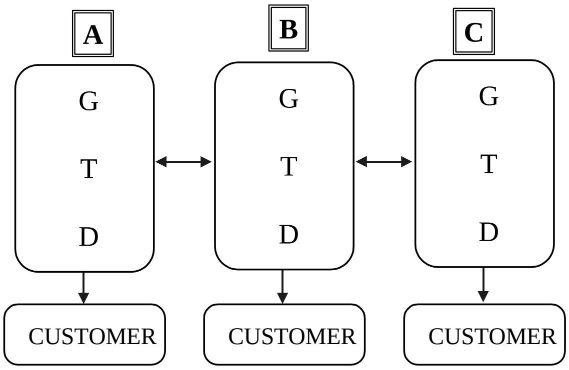
Figure 3.1.: Contractual framework requirement



The possible evolution of the market is also illustrated in Figures 3.2. to 3.5. These figures illustrate the possible evolution in the relationships between participants in the electricity sectors (G being Generation, T transmission, D distribution and customers) of three countries (called A, B and C) as a regional market develops.

The current position is shown in Figure 3.2. – the three countries are characterised by vertically-integrated state-owned utilities and customers have no choice as to their supplier. There is a limited amount of bilateral trade and wheeling among the three countries and, as a result, there is considered to be a limited need for the creation of a formal contractual framework to define these relationships.

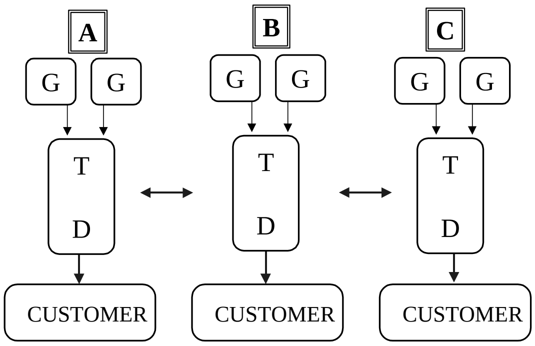
Figure 3.2.: Current Regional Market Structure (Vertically-integrated utilities, some bilateral trade)



- Vertically integrated state-owned utilities
- Bilateral trading: A-B, B-C
- Some wheeling A-C
- No customer choice

The first step in the liberalization of the countries' domestic electricity sectors is likely to involve the separation out of generation. Assuming that countries in the region follow a gradual approach to market liberalization, the single buyer model is likely to be adopted in the first instance. Electricity purchasing responsibility is likely to rest within the (monopoly) transmission/distribution entity and domestic generation is unlikely to be able to trade with the single buyer in another country. Cross-border trade is likely to continue to be conducted on an ad-hoc basis between respective single buyers, although the need to more closely define internal contractual relationships (particularly if there are foreign investors involved in new generation) is likely to create some pressure for a better definition of cross-border contracts. Customers will, however, still have no choice over their supplier. This step in the evolution of the market is illustrated in Figure 3.3.

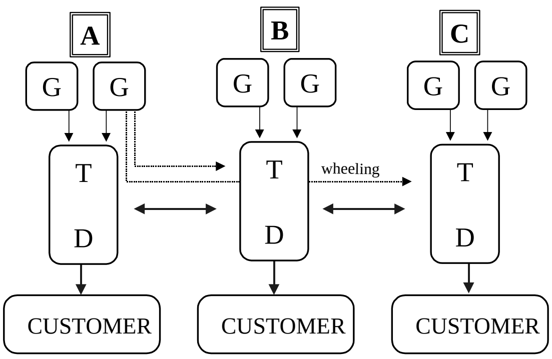
Figure 3.3.: First Stage of Market Development (Generation separated out, single buyer model adopted, some bilateral trade)



- Generation separated out
- Single buyer model (only T/D can trade)
- Bilateral trading: A-B, B-C
- Some wheeling A-C
- No customer choice

The next stage in market development is likely to involve permitting generators to become involved in cross-border trade. This is illustrated in Figure 3.4.

Figure 3.4.: Regional Market Evolves (Generation separated out and able to trade, single buyer model for electricity purchases, bilateral trade)

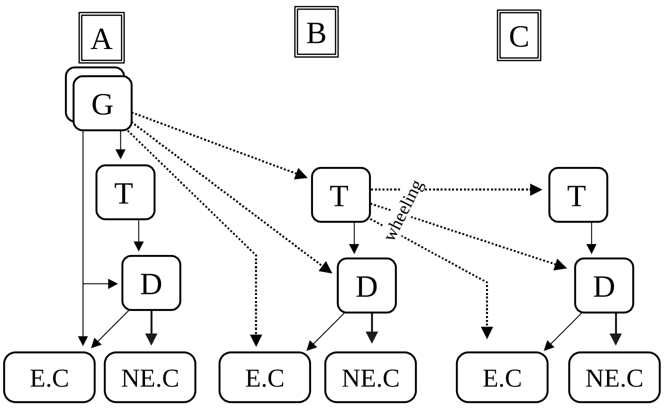


- Generation separated out and able to trade
- Single buyer (T/D) model for electricity purchases
- Bilateral trading between single buyers: A-B, B-C and some wheeling A-C
- Cross-border trade G(A) to single buyers in B and C (wheeling)
- No customer choice

The single buyer model is retained for electricity purchases (with responsibility retained in the transmission/distribution entity) and customers have no choice over supplier. This change is a very significant stage in the evolution of the regional market - generation in country A is able to sell to the single buyer in country A, to the single buyer in country B and, by wheeling through country B, to the single buyer in country C. The combination of the opening up of other countries' (possible cheaper) generating capacity to single buyers and the widening of the range of potential purchasers for generators' output will now force the development of the related contractual framework. The absence of the necessary contractual framework at this stage is likely to frustrate the development of the market.

The final stage in the possible development of the market would be the granting to eligible customers the ability to choose their supplier, with potential range of suppliers not being restricted by national boundaries. This is illustrated in Figure 3.5. Under this structure, generation in country A is able to sell to all eligible customers (be they transmission authorities, distribution companies or large consumers) in all three countries (A, B and C). In Figure 3.5., a direct relationship is shown, for example, between generation in country A and distribution in country C – it should be noted that this relationship could also be established through the framework created by a regional power pool. This level of market development cannot be achieved without the existence of a robust contractual framework.

Figure 3.5.: Regional market with customer choice



- Competitive regional market
- Generation separated out; Eligible Customer choice
- Multilateral trading between single all parties

3.3 CONTRACTUAL FRAMEWORK

As discussed in Section 3.2., the proximity of the EU Electricity Market and the direction of individual countries' electricity markets are considered the principal influences on the future contractual framework for a regional electricity market. The possible evolution of the market must also be taken into account in considering the contractual framework.

Experience from power pools elsewhere in the world suggests that their development is largely dependent on three basic factors:

- the establishment of a set of rules for participants in the market;
- the evolution of individual markets in a manner which does not contradict the desire to exploit the benefits associated with the creation of a regional electricity market; and
- the creation of a broad and consistent contractual framework which can be used to determine relationships between market participants.

The establishment of a set of **Market Rules** can be preceded with Memoranda of Understanding or similar documents at the political level. However, they need the agreement of all market participants, and participation in the market has to be made dependent upon adherence to those rules. The market rules are likely to cover issues such as:

- the operating guidelines for the market;
- The governance of the market, so that all participants feel that they have a voice in the market;
- The procedure for the resolution of disputes;
- The reserve requirements of individual countries;
- A requirement to supply emergency energy for a certain period every year;
- The methodology for determining transmission pricing as applicable to regional trade;
- The adoption of a consistent approach to transmission access;
- A requirement to allow wheeling through individual countries' transmission networks;
- A commitment to the exchange of information related to, for example, maintenance schedules and generating costs;
- The operation and responsibilities of a regional information and co-ordination centre; and
- The procedures for the admission of new members.

With the liberalisation and restructuring of the electricity sector in each of the countries proceeding at a different rate, it is important that **country-specific rules** (such as national grid codes) take into account the potential development of the regional electricity market. Conversely, despite the political commitment to the creation of the regional market, it is important that the creation of rules for the regional market takes account of national developments. National regulators will therefore need to balance the requirements of ensuring that regional market rules are taken into account in the domestic market and of ensuring that no commitment is made at the regional level which might contradict national policy. For example, it may be impossible to agree on international access and pricing issues before domestic legislation has been agreed). The potential for conflict is likely to be particularly acute in relation to transmission pricing and access. There will be a need to create a transmission agreement at the regional level and for the countries in the region to adopt a common transmission pricing methodology applicable to all regional trade in electricity.

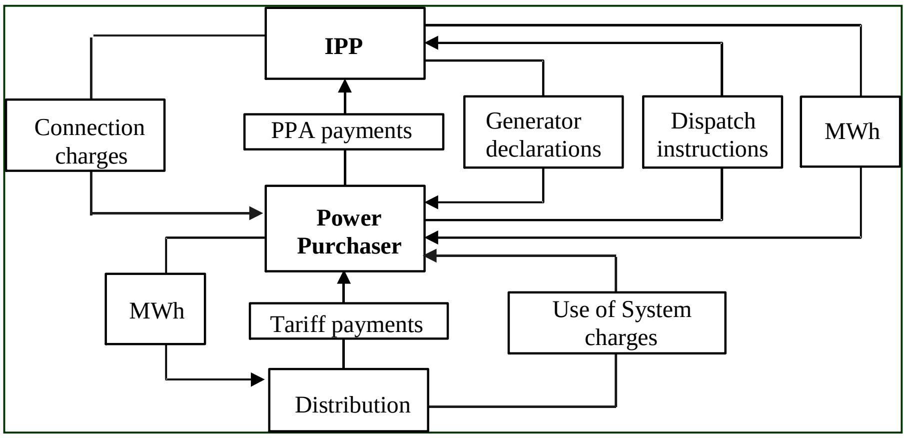
In general, the removal of barriers to trade will require consistency among the countries in a number of areas, including:

- Demonstrating their commitment to the development of regional trade;

- Removing provisions within existing laws or regulations which might hinder the move to a more competitive regional market;
- Consistency in the content and implementation of rules governing access to the transmission network;
- The development of a standardised protocol governing the operation of a regional transmission network (the absence of such a protocol might undermine system reliability);
- A commitment to transparency of costs, for generation (for which greater transparency is achieved if a two part tariff structure is employed) and, in particular, for transmission (for which tariffs have to be separated out);

At the country-specific level, the determination of the **type of contracts** required is probably best illustrated by considering what is required when an Independent Power Producer (IPP) is introduced into the sector. Adopting a single-buyer structure for simplicity, the links between an IPP and other sector participants is shown in Figure 3.6.

Figure 3.6.: Contract Content



Even under this simplified structure, it can be seen that three basic forms of agreement would be required, as follows:

- *Grid Code*:

  The Grid Code can be considered the basic element of any contractual framework for a restructured electricity sector. Its functions include:

  - the provision of a clear description of system planning and operational rules;
  - it applies to both the incumbent utility (or single purchaser) and any IPPs within the country;
  - it is required by an IPP to provide comfort that the rules of the sector will be applied fairly to all.

- *Power Purchase Agreements (PPA)*:

  Likewise, the PPA applies both to the incumbent utility and to the IPP:

  - It must protect the incumbent utility from IPP's shortcomings
  - It should give the IPP incentive to:
    - provide economic and secure electricity; and
    - comply with the technical rules of system operation.
  - It should also protect the IPP against uncontrollable risks.

- *Connection Agreement*

  The connection agreement:

  - ensures that only technically sound schemes are allowed to connect to the incumbent utility's system;
  - it is a commercial agreement between the incumbent utility and IPP to allow the latter to connect to the incumbent utility's system;
  - it allows the incumbent utility to charge for connection; and
  - it gives the IPP qualified right to export electricity from its power station.

The contract between a generator and a purchaser of electricity (the PPA in many circumstances) is likely to be the core element in the new developing market structure and it will need to address the following issues:

- How to create a payments and incentives framework that benefits both sides. This has normally been achieved through the separation of payments for energy and those for capacity, with energy payments divided into fuel, and fixed and variable operations and maintenance components and determined in $/KWh, and with capacity payments expressed in $/KW/year. In all cases, there needs to be an allowance for price escalation.

- The definition of performance responsibilities, including:

  - the date of start of the contract and its duration;
  - the operating parameters of the plant - start-up time; close-down time; minimum downtime between operations;
  - plant dispatchability - fully dispatchable projects being preferred as they give operating benefits and flexibility.

- Force Majeure clauses, which would be required to protect both sides from events outside of their control;

- It would also be possible to include various clauses related to:

  - Water release through hydropower plants for downstream utilisation or conservation measures for the protection of the environment, technical limits, etc.;

- Fuel used, for example specifying fuel content and diversity, imposing a requirement for the generator to maintain on-site stocks of at least 30 days, requiring the generator to be able to use other fuels.

- Such an agreement might also specify a preferred location for generation, particularly new generation, because of possible effects on the existing network, transmission constraints and the need to meet connection costs.

A sample structure of PPA is provided in Appendix 5.

3.4 THE WAY FORWARD

As can be seen from the analysis contained above, the responses to the questionnaires are far from complete. In addition, not one PPA has been made available for the purposes of the study. The comparison of existing contractual arrangements with those which would facilitate the exploitation of the economic benefits associated with regional electricity trade has thus been replaced by a methodology which examines contractual requirements at each stage in the possible development of the market.

In considering the development of a regional electricity market, the most difficult contractual issue is likely to be related to the transmission access and pricing. These are the essential prerequisites to market development – the market will not evolve without their resolution. However, addressing the issues in the region is made harder by incomplete policies relating to the future direction of individual countries electricity markets. In addressing these central issues, there are a few basic principles which need to be recognised:

- cost reflectivity
- consideration of physical constraints
- non-discrimination and transparency

The process by which a new contractual framework will emerge can be summarised as follows:

- Define the future structure of domestic electricity sectors - the first and probably most important step in the process, from which all other steps flow;
- Once this is resolved, and there will be many policy issues which have to be addressed in this process, new legislation will have to be passed to create the new legal framework for the sector (for example, a new Electricity Law);
- Out of this process, the roles, responsibilities, rights and obligations of sector participants will be defined and agreed;
- At this stage, it is possible to determine what type of contracts are required;
- The Grid Code, the basic building block of a restructured electricity sector, would need to be resolved next (if there is no competition in generation, this will only be an "operational" document);

- After this, and as liberalization is more likely to start in generation than elsewhere, the agreement between the generator and power purchaser will need to be resolved. Contracts with large customers can wait as competition at the supply level is likely to be some time in coming;
- Finally, cross-border contracts can be addressed.

APPENDIX 1:

QUESTIONNAIRE ON INSTITUTIONAL, LEGAL, REGULATORY AND COMMERCIAL ASPECTS

QUESTIONNAIRE: INSTITUTIONAL ASPECTS

In addition to the Organisational Structure of the Electricity Sector, please supply the following information oriented towards an initial review of the existing and future market structures in each country.

The Structure of the Power Sector

The aim is to identify which organizations might trade in a regional market (only monopoly utilities, independent generators, distribution companies or other large consumers?) and what institutional obstacles exist now and in the future. It is important to describe clearly the plans for reform of the sector.

- Principal organizations involved in generation, transmission, system operation, distribution (and supply); by functions and by geographical areas
- Ownership structure of those organizations (especially identify any private ownership). It would also be helpful to provide a very short history of the industry structure where this is relevant to understanding the current issues and political pressures
- Recent changes in structure or ownership
- Future plans for reform of the sector and changes to structure/ownership (key steps/stages and dates)
- Factors driving the plans for changes (e.g. need for private investment)

Key documents

Please provide a list of the key documents which describe or define the future plans for reform, restructuring and privatization of the sector, e.g.:

- Energy strategy documents
- Other key policy statements by government, including ministers' speeches
- Legislative basis (energy laws, other relevant laws, the current basis for national monopolies) for structure, ownership and definition of functions of the organisations
- Plans for changes to the legislation

Obstacles to Regional Trade

Please identify and summarize any other non-technical obstacles to trade (e.g. fuel subsidies, debts and poor revenue collection) at the various possible levels (i.e. between utilities or between separate generators and consumers).

Objectives of Government and/or Utility

Why is the Government and/or the utility interested in participating in a regional electricity market? Are there any statements of objectives or expected benefits:

- By the Government?
- By the utility?

QUESTIONNAIRE: COMMERCIAL ASPECTS – TRENDS AND OBSTACLES

1. Please specify the cross border trade of electricity in your country and list the annual volume sold and bought in GWh in the last three years.

2. Please specify the companies involved in the cross border trade. What changes can be expected by the near future?

3. Please specify the commercial basis for cross border trade in %:

Commercial basis	**% share**
Long term contracts (more than 5 years)	
Medium term contracts (1 - 5 years)	
Short term contracts (0 - 1 years)	
Spot trade	
Barter	

4. Is it possible for large consumers (companies) to trade directly with a foreign power supplier?

5. Is cross border trade organised at an electricity exchange?

6. Please describe in brief the basis for cross border trade (e.g. capacity and energy charges, time of day tariffs, short term marginal cost, market prices, barter trade etc.).

7. Please state average generation, transmission and distribution prices (per kWh) in the cross border trade in your local currency and in EU without taxes and duties.

8. Please describe briefly the major changes in regulation regimes concerning the cross-border trade during the last 3 years. (e.g. political discussions, legislation proposals etc.)

9. Please describe briefly any known deregulation and privatisation plans for the next 5 years (including if known a time schedule) which may have a substantial impact on the market structure and the cross-border trade.

10. Please specify the legislation on which the cross-border is based on in your country. (If available, provide a copy)

11. Are there any public authorities or regulatory bodies, who are allowed to control or supervise the cross-border trade and electricity markets?

12. Does a special regulatory body exist for setting or approving prices and tariffs for internal and the cross-border trade? If yes, are the prices fixed by the price regulatory body cost oriented or market oriented?

13. Are permissions/licenses needed for import/export of electricity? Which public authority is responsible for the permission/license?

14. Are reviews and approvals of import/export contracts necessary? For instance to be effective, must the Power Purchase Agreement be reviewed by certain institutions (like dispatch centres, etc) and approved by others (like Ministry of Industry)? If available, please provide copies of Power Purchase Agreements (excluding confidential information).

15. Is there special taxation on fuels or on import/export of electricity and on electricity consumption? If yes, please specify for each category.

QUESTIONNAIRE: COMMERCIAL ASPECTS – CONTRACTS

1. Please describe the commercial structure of participants in the sector, addressing issues of:

    - whether they have been commercialised or privatised or remain government entities;
    - have the entities been unbundled;
    - have the accounts of their generating, transmission and distribution functions been separated out;
    - whether the costs of social provision have been identified and whether they are being met by government.

2. Please provide copies of existing contracts between participants in domestic electricity sector (if any).
3. Please provide copies of contracts which cover cross-border electricity trade.
4. Please provide copies of existing Power Purchase Agreements or other electricity purchase agreements with independent power producers (if available).
5. Please provide details of the terms and conditions of existing wheeling arrangements.
6. What inflators have been used in tariff adjustment formulae (e.g. CPI, PPI or fuel price indices)?
7. What are the perceptions of sector participants on the main difficulties associated with existing contracts – how could they be improved.
8. What are the perceptions among independent electricity producers about the effectiveness of existing PPAs and how could they be improved.
9. What are the perceptions of power purchasers on the problems/constraints of existing contracts and how could they be improved.
10. Does the legal framework provide a firm basis for the enforcement of commercial contracts.
11. What freedom do sector participants have to set terms and conditions of their contracts, including tariffs.
12. What taxes and duties are applied to exports and imports of electricity, on producers, purchasers and IPPs.
13. In what currency is payment for imports and exports denominated. Are any government guarantees provided for payment.

QUESTIONNAIRE: LEGAL AND REGULATORY ASPECTS

Please provide:

1. A list of all laws (where 'laws' encompasses all directives, decrees, or other instruments of state legal power) relevant to the electricity system and the energy system (in the latter case if electricity is included)

2. The licensing/franchise/concession structure (if separate from the above) for the operation of generation (including autogeneration), transmission, distribution and sale of electricity (including imports and exports).

3. The legal basis for determining wholesale and retail electricity prices, and for approving and controlling electricity system investments.

4. The legal basis for the control of monopoly activities across the whole economy, and the status of pro-competition laws, including exemptions or derogations for the electricity system.

5. If there is an electricity industry regulator, the duties, responsibilities and accountability process surrounding regulatory activity.

6. The legal basis on which foreign private investment may be undertaken, including extent of permitted ownership of enterprises (minority/majority, etc.), Government guarantees, provision for repatriation of profit, etc.

7. The legal basis for environmental control of the electricity industry, especially generation, transmission and distribution, at local, national and international levels.

APPENDIX 2:

LIST OF LAWS, DECREES AND OTHER LEGAL DOCUMENTS COLLECTED IN EGYPT

1. Law 12 of Year 1976 for setting up the Egyptian Electricity Authority (EEA) with amendments;
2. Law 55 of Year 1977 concerning the Installation and Operation of Thermal Machines and Boilers;

   Law 100 of Year 1996 amending some provisions of Law 12 (1976);
3. Law 18 of Year 1998 concerning certain provisions of power distribution companies, power generation stations and transmission grids, and amending certain provisions of Law 12 (1976) – Arabic Version;
4. Law 18 of Year 1998 concerning certain provisions of power distribution companies, power generation stations and transmission grids, and amending certain provisions of Law 12 (1976) – English Version;
5. Law 164 (2000) transforming EEA into an Egyptian Electricity Holding Company (Joint stock Company);
6. Presidential Decree 326 of Year 1997 establishing the Electric Utility and Consumer Protection Regulatory Agency (in arabic);
7. Presidential Decree 339 of Year 2000 establishing the Electricity Utility and Electricity Consumer Protection Regulatory Agency;
8. Administrative Decree 32 of Year 2000 concerning the Unified Commercial Statutes for Electricity Companies;
9. Prime Minister Decree n°695 of Year 2001 concerning the formation of a Ministerial Committee and a Work Team for the reorganization of the national and local projects under the BOOT system and the BOOT system;
10. Law n°8 of the Year 1997, “Investment Guarantees and Incentives” and Law n°126 of the Year 2000 amending certain provisions of the Investment Guarantees and Incentives Law;
11. Law n°4 of the Year 1994 promulgating the environment protection and executive regulation;

12. Law n°3 of the Year 2005 concerning protection of competition;
13. Law n°67 of the Year 2006 concerning protection of consumers;
14. Draft Model Framework Contract between Generators and Transmission Company;
15. Draft Model Framework Contract between Transmission Company and Distribution Company;
16. Power Purchase Agreement between Cairo Electricity Production Company and the Egyptian Electricity Transmission Company;
17. Power Purchase Agreement between the Egyptian Electricity Transmission Company and the Canal electricity Distribution Company.
18. General interconnection agreement for the electrical interconnection among the five electrical power utilities of Egypt, Iraq, Jordan, Syria and Turkey (EISJT);
19. Bilateral interconnection agreement for the electrical interconnection between the electrical power systems of Egypt and Jordan.
20. Egypt – Libya Interconnection: Operating Procedures;
21. General Conditions for Generation License;
22. General Conditions for Transmission License;
23. General Conditions for Distribution License;
24. License for the Practice of Generating Electricity – 2002;
25. License for the Practice of Transmitting Electricity – 2002;
26. License for the Practice of Distributing Electricity – 2002;
27. Electricity Generation License Application Requirements;
28. Electricity Transmission License Application Requirements;
29. Electricity Distribution License Application Requirements;
30. Utility Consumer Contract – Arabic Version;
31. Quality of Supply Voltage Indices;
32. Electric Power Distribution Reliability Indices;
33. Customers Quality of Service Indices;
34. Electrical Distribution Network Indices;

35. Proposed Performance Indicators for Generation Companies;
36. Proposed Performance Indicators for Transmission Company;
37. Availability of Supply Indices;
38. Electricity Consumption Calculation;
39. Tariffs Group;
40. The function of ERA (Electricity Regulatory Agency);
41. Transitional Egyptian Market and the Transmission System Operator (ERA).

APPENDIX 3:

LIST OF LAWS, DECREES AND OTHER LEGAL DOCUMENTS COLLECTED IN ETHIOPIA

Proclamation N°86/1997 relating to Electricity;

1. Regulations N°49/1999 on Electricity Operation;
2. Proclamation N°197/2000 on Ethiopian Water Resources Management;
3. Proclamation N°280/2002 on Investment;
4. Detailed Structure of EEPCO;
5. Ethiopian National Mine Water and Energy Policy – 1994 and Highlights;
6. Requirements for Investment License;
7. Plan for Accelerated and Sustained Development to End Poverty (PASDEP) (2005/06-2009/10);
8. Ethiopia Country Paper on Competition;
9. PRSP Progress Report 2004;
10. Pricing Procedure for Inter-Connected System and Large Isolated Systems – 2005;
11. Uniform System of Accounts – 2005;
12. Electricity Operation Licensing Procedure;
13. Directive Electricity Services Quality Standards 2005;
14. Environment Policy of Ethiopia;
15. Guideline on Green Rating Initiative;
16. Guideline on Industrial Environmental Fund;
17. Guideline on Industrial Waste Handling;
18. Guideline on Integrated Pollution Prevention and Control;
19. Guideline on Sustainable Industrial Zone;
20. Guidelines on Pollution Release and Transfer Registry;

21. Guidelines on Strategic Environmental Assessment;

22. Guidelines on Technology Selection and Transfer;

23. Ethiopian Water Resources Management Policy;

24. Ethiopian Water Sector Strategy.

APPENDIX 4:

LIST OF LAWS, DECREES AND OTHER LEGAL DOCUMENTS COLLECTED IN SUDAN

National Electricity Corporation Act 2000;

1. Electricity Act 2000;
2. Investment Encouragement Act 1999;
3. Investment Encouragement Act 1999 – Amended 20003 & Regulation;
4. Investment Act 2004;
5. National Water Policy 02-2000;
6. Environment Protection Act 2001 (English Version);
7. Environment Protection Act 2001 (Arabic Version);
8. Sudan National Strategy 2003-2027;
9. Framework Agreement between GoS and SPLM;
10. Joint Assessment Mission (JAM) Volume I;
11. Joint Assessment Mission (JAM) Volume II;
12. Joint Assessment Mission (JAM) Volume III;
13. Strategic National Energy Plan 2007-2027;
14. Interim Poverty Reduction Strategy Paper 2004-2006;
15. International & Regional Agreements Environment (Arabic Version);
16. Dams Operation Rules;
17. NEC Sudan Projects Profile 2006;
18. NEC Organization Chart;
19. Average Tariff Implementation;
20. Electricity Tariffs 2005.

APPENDIX 5:

SAMPLE STRUCTURE OF A POWER PURCHASE AGREEMENT

POWER PURCHASE CONTRACT

BETWEEN
______________________________ COMPANY LTD.

AND

_______________________________ POWER CO., LTD.