EASTERN AFRICA POWER POOL (EAPP) AND EAST AFRICAN COMMUNITY (EAC)

FINAL MASTER PLAN REPORT

EXECUTIVE SUMMARY

REGIONAL POWER SYSTEM MASTER PLAN

AND GRID CODE STUDY

May 2011

SNC·LAVALIN

PB PARSONS BRINCKERHOFF 100 YEARS

SNC LAVALIN INTERNATIONAL INC.

in association with

PARSONS BRINCKERHOFF

PREFACE

The objective of the present study is to identify regional power generation and interconnection projects in the power systems of EAPP and EAC member countries in the short-to-long term. The study also aims at developing a common Grid Code (Interconnection Code) in order to facilitate the integrated development and operations of the power systems of the member countries.

The study further aims at contributing to the institutional capacity building for the EAPP and EAC through training of counterpart staff. The development of institutional capacity will enable EAPP/EAC to implement the subsequent activities, including the updating of both the Master Plan and the Interconnection Code.

This study covers the following countries in alphabetical order: Burundi, Djibouti, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda.

The Master Plan Report has been organized according to the following structure:

Volume	Section
Executive Summary	
Volume I	**01 – Introduction**
	02 - Demand Forecast (wbs 1100)
	03 - Generation Supply Study & Planning Criteria (wbs 1200)
	04 - Supply-Demand Analysis & Project Identification (wbs 1300)
Volume II	**05 - Transmission Network Study (wbs 1400)**
	06 - Interconnection Studies (wbs 1500)
	07 - Regional Market Operator Location (wbs 2900)
Volume III	**08 - System Studies For Expansion Plan (wbs 2100)**
Volume IV	**09 - Environment Impact Assessment (wbs 2200)**
	10 - Cost Estimates And Implementation Schedules (wbs 2300)
	11 – Financial & Economic Evaluation – Risk and Benefits (wbs 2400/2500)
	12 - Development and Investment Plan (wbs 2600)
	13 - Institutional and tariff aspects (wbs 2700)
	14 – Project Funding (wbs 2800)
	15 – Conclusions
Appendix A	**TOR, Cost Estimates and Implementation Schedules for Feasibility Studies for Projects identified in the first five years**
Appendix B	**Part I – WBS 1100 Demand Forecast**
	Part II – WBS 1200-1300 Gen. Supply Study – Supply Demand Analysis
	Part III – WBS 1400-1500 Transm. Network – Interconnection Studies
	Part IV – WBS 2600-2700 Investment Plan – Institutional & Tariff Aspects

Acronyms and Abbreviations

A

AC	Alternate Current
AEO	Annual Energy Outlook
AfDB	African Development Bank
AICD	Africa Infrastructure Country Diagnostic
ARIMA	Autoregressive Integrated Moving Average
ARR	Annual Required Revenue
Avg	Average

B

BADEA	Arab Economic Development Bank in Africa
bbl	Oil barrel
BCR	Benefit/Cost Ratio
BR	Burundi

C

CAPEX	Capital Expenditure
CBEMA	Computer and Business Equipment Manufacturers' Association
CCGT	Combined Cycle Gas Turbine - Thermal Power Plant
CDM	Clean Development Mechanism
CEO	Chief Executive Officer
CF	Capacity Factor
CIRR	Commercial Interest Reference Rate
CKT	Circuit
CO_2	Carbon Dioxide
COR	Composite Outage Rate
CPI	Consumer Price Index

D

DB	Djibouti
DC	Direct Current
DC	Democratic Republic of Congo
DGHER	General Directorate for Hydropower and Rural Electrification
DOE	Department of Energy (USA)
DRC	Democratic Republic of Congo
DSCR	Debt Service Coverage Ratio

E

EAC	East African Community
EAPMP	East African Power Master Plan Study
EAPP	Eastern Africa Power Pool
EdD	Électricité de Djibouti
EDF	Électricité de France
EEHC	Egyptian Electric Holding Company
EEPCo	Ethiopia Electric Power Corporation

EETC	Egyptian Electricity Transmission Company
EG	Egypt
EIA	Energy Information Administration
EIC	Existing Interconnections
EIJLLST	Egypt, Iraq, Jordan, Libya, Lebanon, Syria and Turkey
EIRR	Economic Internal Rate of Return
EMF	Electro-Magnetic Field
EMP	Environmental Management Plan
ENPTPS	Eastern Nile Power Trade Program Study
ENPV	Economic Net Present Value
ENTRO	Eastern Nile Technical Regional Office
EPC	Engineering Procurement and Construction
EPCM	Engineering Procurement and Construction Management
Esc.	Escalation
ESIA	Environmental and Social Impact Assessment
ET	Ethiopia
EU	European Union

F

FC	Fictitious Company
FDI	Foreign Direct Investment
FIRR	Financial Internal Rate of Return
FNPV	Financial Net Present Value
FOR	Forced Outage Rate
FS	Feasibility Study
FttH	Fibre-to-the-Home

G

GCI	Global Competitiveness Index
GDP	Gross Domestic Product
GHG	Green House Gases
GNI	Gross National Income
GoE	Government of Ethiopia
GT	Gas Turbine
GTP	Growth and Transformation Plan

H

HFO	Heavy Fuel Oil
HPP	Hydro Power Plant
HVAC	High Voltage Alternate Current
HVDC	High Voltage Direct Current

I

ICNIRP	International Commission of Non-Ionizing Radiation Protection
ICS	Interconnected System (Ethiopia)
ICT	Information and Communication Techonology
IDC	Interest during Construction
IDO	Industrial Diesel Oil

IFC	International Financial Corporation
IMF	International Monetary Fund
Inst. Cap.	Installed Capacity
IP	Internet Protocol
IPO	Initial Public Offering
IPP	Independent Power Producer
IRR	Internal Rate of Return
IT	Information Technology

J

JMP	Joint Multipurpose Project

K

KenGen	Kenya Electricity Generation Company
KETRACO	Kenya Electricity Transmission Company Limited
KPLC	Kenya Power and Lighting Company Ltd
KTCIP	Kenya Telecommunications Infrastructure Project
KY	Kenya

L

LAP	Libyan African Portfolio
LCEMP	Least Cost Electricity Master Plan
LCPDP	Least Cost Power Development Plan
LD	Liquidated Damage
LDC	Load Duration Curve
LDCs	Least Developed Countries
Level of Prep.	Level of Preparedness
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LRO	Light Residual Oil
LSD	Low-Speed Diesel Engine
LTPSPS	Long-Term Power System Planning Study
LVL	Level

M

MAED	Model for Analysis of Energy Demand
Max	Maximum
MD	Maximum Power Demand
Min	Minimum
MINIFRA	Rwanda Ministry of Infrastructure
MOU	Memorandum of Understanding
MoWR	Ministry of Water and Energy
MP	Master Plan
MPIP	Medium-term Public Investment Plan
MSD	Medium-Speed Diesel Engine

N

NBI	Nile Basin Initiative
NEC	Sudan National Electricity Corporation
NELSAP	Nile Equatorial Lakes Subsidiary Action Program
NG	Natural Gas
NGP	National Generation Plan
Nom. Cap.	Nominal Capacity
NPV	Net Present Value

O

OCGT	Open Cycle Gas Turbine - Thermal Power Plant
ODA	Official Development Assistance
OECD	Organization of Economic Cooperation and Development
OLADE	Organización Latinoamericana de Energía (Latin American Energy Organization)
OLTC	On-Load Tap Changers
O&M	Operation and Maintenance
ONRD	Office of Natural Resources Damage
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating Expenditure
OPTGEN	Optimal Generation (Planning Model)

P

PF	Plant Factor
PPA	Power Purchase Agreement
PPE	Personal Protective Equipment
PSIP	Power Sector Investment Plan
PSMP	Power System Master Plan Study
pu	Per Unit

R

RALF	Regression Analysis Load Forecast
RCC	Regional Coordination Center
RECO	Rwanda Energy Corporation
Ref	Reference
REGIDESO	Régie de production Distribution d'Eau et d'Electricité
RFP	Request for Proposal
RGP	Regional Generation Plan
RMO	Regional Market Operator
RMOC	Regional Market Operation Center
RoC	Return on Capital
RoCE	Return on Capital Employed
RoE	Return on Equity
ROR	Run-Of-River
RTL	Rwandatel S.A.
RW	Rwanda
RWASCO	Rwanda Water Supply Corporation

S

SAPP	Southern African Power Pool
SCS	Self-Contained System (Ethiopia)
SD	Sudan
SDDP	Stochastic Dual Dynamic Programming
SEACOM	
SEEE	Society of Electrical and Electronics Engineers
SIL	Surge Impedance Loading
SINELAC	Société Internationale d'Électricité des Pays des Grands Lacs
SNEL	Société Nationale d'Électricité – République Démocratique du Congo
SPV	Special Project Vehicle
SRMC	Short Run Marginal Cost
SSEA	Strategic/Sectoral, Social and Environmental Assessment of Power Development Options in the Nile Equatorial Lakes Region
STPP	Steam Thermal Power Plant
SVC	Static Var Compensator

T

TANESCO	Tanzania Electric Supply Company Ltd
TOR	Terms of Reference
TPP	Thermal Power Plant
TSO	Transmission System Operator
TZ	Tanzania

U

UETCL	Uganda Electricity Transmission Company
UEGCL	Uganda Electricity Generation Company Limited
UG	Uganda
UIC	Unlimited Interconnections
UN	United Nations
UNCTAD	United Nations Conference on Trade And Development
USBR	United States Bureau of Reclamation
UTL	Uganda Telecom Ltd

W

WACC	Weighted Average Cost of Capital
WB	World Bank
WBS	Work Breakdown Structure
WEF	World Economic Forum

Y

yr	Year

EXECUTIVE SUMMARY

TABLE OF CONTENTS

1 INTRODUCTION 1

1.1 Study Objectives 1
1.2 Project Background 1
1.3 Content and objectives of the master plan report 4
1.4 Organization of the Executive Summary Report 4

2 DEMAND FORECAST (WBS 1100) 5

3 GENERATION SUPPLY STUDY AND PLANNING CRITERIA (WBS 1200) 6

3.1 Objectives 6
3.2 Generation Planning Criteria 6
3.3 Hydrology Database and Hydro Capability by Country 7
3.4 Total Identified Options by country 7
3.5 Assessing and ranking of all future hydro options 8
3.6 Assessing and ranking of all future thermal options 9
3.7 Database for the study 10

4 SUPPLY-DEMAND ANALYSIS AND PROJECT IDENTIFICATION (WBS 1300) 11

4.1 Objectives and Methodology 11
4.2 SDDP and OPTGEN Models 11
4.3 National Plans 12
4.4 Regional Plans 14

5 TRANSMISSION NETWORK STUDY (WBS 1400) 18

5.1 Objectives 18
5.2 2009 Network Model 18
5.3 2013 Network Model 19

6 INTERCONNECTION STUDIES (WBS 1500) 21

6.1 Objectives 21
6.2 Common Transmission Planning Criteria 21
6.3 Identification of Interconnection Projects and Generic Designs 23
6.4 Vision 2038 24

7 REGIONAL MARKET OPERATOR (RMOC) LOCATION (WBS 2900) 27

7.1 RMOC Functions and Structure 27
7.2 Selection Criteria 29
7.3 Results of the Analysis 30
7.4 Analysis for the highest ranked group 31
7.5 Conclusions and Recommendation 33

8 SYSTEM STUDIES FOR EXPANSION PLAN (WBS 2100) 34

8.1 Objectives 34
8.2 Input data 34
8.3 Methodology 34
8.4 System Studies for the years 2013 and 2018 35
8.5 The Horizon Year – Vision 2038 39

9 ENVIRONMENTAL IMPACT ASSESSMENT (WBS 2200) 41

10 COST ESTIMATES AND IMPLEMENTATION SCHEDULES (WBS 2300) 42
10.1 Generation Projects 42
10.2 Transmission Lines 42
11 ECONOMIC AND FINANCIAL ANALYSIS – RISKS AND BENEFITS (WBS 2500) 45
11.1 Objectives 45
11.2 Economic Evaluation of Interconnection Projects 45
11.3 Financial Analysis 48
11.4 Other Benefits and Returns 49
11.5 Risk Analysis and Mitigation Measures 50
12 INVESTMENT PLAN (WBS 2600) 51
13 INSTITUTIONAL AND TARIFF ASPECTS (WBS 2700) 54
13.1 Institutional Aspects 54
13.2 Financial Viability and Tariffs 55
14 PROJECT FUNDING (WBS 2800) 59

LIST OF TABLES

Table 1-1 Ongoing Interconnection projects 2
Table 3-1 Typical Characteristics for Different Types of Power Plants 7
Table 3-2 Yearly Hydro Capability by Country 7
Table 3-3 Future Supply and Surplus by Country 8
Table 3-4 Typical Duration of Different Pre-Commissioning Activities 8
Table 3-5 Identified Hydro Potential by country for the first 10 years 9
Table 3-6 Fuel Price Projections over Study Horizon 9
Table 3-7 Thermal Generation costs by Country for Different Plant Types 9
Table 4-1 Methodology of Supply-Demand Study 11
Table 4-2 Coordination of OPTGEN and SDDP towards Optimal Solution 12
Table 4-3 National Generation Expansion Plans 13
Table 4-4 Average Surplus over Study Period (2013-2038) 14
Table 4-5 Schedule of interconnection projects selected 15
Table 4-6 Benefit Cost Analysis Present Values in MUSD 15
Table 4-7 Interconnection Projects 2013 – 2017 (NGP_RIP) 16
Table 4-8 List of Identified Regional Generation Projects – NGP_RIP 16
Table 6-1 Power System Reliability Criteria 21
Table 6-2 Equipment Maximum Loading 21
Table 6-3 Steady State Voltage Limits 21
Table 6-4 Dynamic Voltage Limits 22
Table 6-5 Frequency Limits 22
Table 6-6 Stability Types and Recommendations 22
Table 6-7 AC Line Characteristics for a distance of 100 km (100 MVA base) 23
Table 6-8 Existing, under-construction and fund secured interconnections 23
Table 6-9 Possible AC interconnections of EAPP/EAC countries 24
Table 6-10 Possible bipolar HVDC interconnections of EAPP/EAC countries 24
Table 6-11 Unit Cost of transmission lines 24
Table 6-12 Disbursement Schedule for construction costs 24
Table 6-13 Maximum Exchange between Countries Over Study Horizon 25
Table 7-1 RMOC main function and responsibilities 28

Table 7-2 Evaluation of criteria for the RMOC location (based on WEF GCI) 31
Table 7-3 Doing Business index for EAPP countries 32
Table 10-1 EPC 43
Table 10-2 Total Project Costs 43
Table 11-1 Identified Interconnection Projects 45
Table 11-2 Capital Cost of Interconnection Projects 46
Table 11-3 NPV of Operating Cost Savings 46
Table 11-4 Economic Analysis Results 47
Table 11-5 Escalated Project Capital Costs with IDC 48
Table 11-6 Financial Analysis Results 49
Table 12-1 5-year Total Generation Investment Plan 51
Table 12-2 Capital Cost Required for Interconnector projects 51
Table 12-3 Investment required for interconnection projects 52
Table 12-4 Capital expenditure in 5 year blocks in US$ million 53
Table 13-1 Key Financial ratios 56

LIST OF FIGURES

Figure 4-1 Map of Selected Regional Interconnections Projects – NGP_RIP 17
Figure 5-1 2013 EAPP/EAC Interconnected System 20
Figure 6-1 EAPP/EAC Interconnections and Transfers by the Year 2038 26
Figure 7-1 Structure of proposed RMOC 28
Figure 8-1 HVDC modeling 35
Figure 10-1 Typical Sequence of Milestones 44

1 INTRODUCTION

1.1 Study Objectives

The objective of the study is to identify power generation and interconnection projects, at Master Plan level, to interconnect the power systems of EAPP and EAC countries in short-to-long term. The study also aims at developing common Transmission Interconnection Code in order to facilitate the integrated development and operations of the power systems of EAPP and EAC countries.

The study further aims at contributing to the institutional capacity building for the EAPP and EAC staff through training of counterpart staff. The development of institutional capacity will enable EAPP / EAC to implement the subsequent activities, including the updating of both the Master Plan and the Grid Code reports.

This study covers the following countries in alphabetical order: Burundi, Djibouti, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda.

1.2 Project Background

Countries in the region, by and large, have been planning and implementing the development of their power system in an isolated manner with a view to satisfying the national demand growth. Bilateral power exchange agreements exist between some countries in the Region. However, the volume of power exchange is not significant and exporting parties have frequently been unsuccessful in their commitments to deliver the power in accordance with their contractual obligations because of deficits in their systems.

The existing power interconnection projects include:

- DRC, Burundi, and Rwanda interconnected from a jointly developed hydro power station Ruzizi II, (capacity 45 MW) operated by a joint utility [SOCIETE D'ELECTRICITE DES PAYS DES GRAND LACS (SINELAC)];
- Cross-border electrification between Uganda and Rwanda, Tanzania and Uganda, and Kenya and Tanzania;
- Kenya – Uganda interconnection; and
- Egyptian power system interconnection through Libya to other Maghreb countries and Southern Europe; and through Jordan to Eastern Mediterranean.

Other ongoing power interconnection systems are shown in:Table 1-1

Table 1-1 Ongoing Interconnection projects

From	To	Type / Length	Capacity (MW)	Earliest Year in Operation	Status	Comments
Tanzania	Kenya	400 kV 2 circuits 260 Km	1520	2015	Ongoing FS, detailed design and tender documents preparation	Bidding for line construction may start at the end of 2011.
Rusumo	Rwanda	220 kV 1 circuit 115 Km	320	2015	FS completed	Lines associated to the Rusumo Falls HPP connecting the project with the grids of Tanzania, Rwanda and Burundi.
Rusumo	Burundi	220 kV 1 circuit 158 Km	280	2015		
Rusumo	Tanzania	220 kV 1 circuit 98 Km	350	2015		
Ethiopia	Kenya	500 kV-DC bipole 1120 Km	2000	2016	Design and tender document preparation study to start early 2011	New design study aims at highly optimistic completion of phase I (1000 MW) of the project by 2013 and phase II upgrade to 2000 MW by 2019.
Ethiopia	Sudan	500 kV 4 circuits 570 Km	3200	2016	FS completed	

From	To	Type / Length	Capacity (MW)	Earliest Year in Operation	Status	Comments
Egypt	Sudan	600 kV-DC bipole 1665 Km	2000	2016	FS completed	
Uganda	Kenya	220 kV 2 circuits 254 Km	300	2014	Under construction	Runs from Lessos substation in Kenya to Bujagali substation passing through Tororo substation in Uganda, duplicating the existing 132kV line.
Uganda	Rwanda	220 kV 2 circuits 172 Km	250	2014	Detailed and Tender Documents preparation study starts in 2011	Line from Mbarara to Mirama (border Uganda) to Birembo/Kigali (Rwanda)
Rwanda	DRC	220 kV 1 circuit 68 Km	370	2014	Under construction	Line between new substation at Kibuye Methane Gas plant in Rwanda and Goma (DRC), thus completing the loop around lake Kivu.
DRC	Burundi	220 kV 1 circuit 105 Km	330	Expected in 2014	FS, detailed engineering and tender documents preparation study to start early 2011	Line from future substation Kamanyola/Ruzizi III (DRC) to Bujumbura (Burundi). Study Includes 220kV line between a new substation in Bujumbura to Kiliba (DRC).
Burundi	Rwanda	220 kV	330	2016	FS update to start early 2011	Line Rwegura (Burundi) – Kigoma (Rwanda), previous FS recommended 110kV. Feasibility Study update to re-examine 220kV option and re-route line to feed intermediate locations.

1.3 Content and objectives of the master plan report

This Master Plan Report provides the findings from the Regional Power System Master Plan. The Interconnection Code (Grid Code) is part of a separate report.

The Master Plan first discusses all the input data necessary for the planning exercise: Demand Forecast (WBS 1100), Generation Supply analysis, including existing and future thermal, hydro and renewable energy projects, and planning criteria (WBS 1200). The existing transmission network data and models are compiled in WBS 1400 and common planning criteria and basic unit costs are developed for the candidate interconnection projects in WBS 1500.

A preliminary identification of the regional projects (generation and interconnections) is performed including a supply-demand analysis for each country and a regional interconnection plan is developed under WBS 1300. An estimation of the regional benefits of different scenarios is also performed.

Detailed system studies for each country and reinforcement needs are identified in WBS 2100 while other aspects of the projects such as the environmental impacts (WBS 2200), Cost Estimates (2300), Financial-Economic Analysis and risk assessment (WBS 2500) are presented in the report.

Finally an investment plan for the identified interconnection projects is developed in WBS 2600 and the analysis of institutional and tariff aspects as well as project funding requirements are included in WBS 2700 and WBS 2800 respectively.

An analysis of the requirements and recommendation for the location of the Regional Market Operator (RMOC) – RCC is carried out under WBS 2900.

Appendix A contains for the initial phase of development (2013-2017) the TOR, cost estimates and implementation schedules for the indentified projects.

Appendix B contains specific information and tables for particular sections of the report.

1.4 Organization of the Executive Summary Report

1) introduction
2) demand forecast (1100)
3) generation supply study and planning criteria (1200)
4) supply-demand analysis and project identification (1300)
5) transmission network study (1400)
6) interconnection studies (1500)
7) regional market operations centre location (2900)

2 DEMAND FORECAST (WBS 1100)

The purpose of the report is to identify or provide an array of demand forecast scenarios (namely base, high and low scenarios) for each EAPP/EAC member country, suitable for deriving Master Plans for the EAPP/EAC member countries.

We identified the most recent existing national demand forecast available and reviewed the adopted methodology, key assumptions and overall results. This review allowed us to form an opinion on the suitability of the forecast for use in the EAPP/EAC study.

The EAPP/EAC study horizon year is 2038 and most existing national demand forecasts do not extend this far into the future. As such, we have extended the existing national demand forecasts to cover the study horizon.

In addition to reviewing the most recent existing demand forecast for each country, we have developed independent base, high and low demand forecasts.

Our independent demand forecasts are based on our own assumptions and methodologies, utilising the data collected and analysed as part of the data collection process. Where data availability and quality permit, the independent demand forecasts are based on our econometric based Regression Analysis Load Forecast (RALF) model. The data available for some of the EAPP/EAC countries however is of poor quality, un-reliable and contains many gaps. Where the data did not permit an independent econometric demand forecast to be developed, we used a combination of growth rate analysis, electrification assumptions, population data and specific consumption assumptions to derive suitable independent demand forecasts.

3 GENERATION SUPPLY STUDY AND PLANNING CRITERIA (WBS 1200)

3.1 Objectives

Having prepared the load forecast, the next step in this master plan was to evaluate the generation supply and set up the planning criteria in order to move on to the next task which is the supply-demand balance and development of national and regional generation plans. The objectives of this WBS were then to:

- Update the available data on generation supply for each country
- Define the generation planning criteria
- Provide a hydrology database and Update the hydro capability of each country.
- Asses and rank all Hydro and Thermal Future options

Update of Generation Data

Updating the generation data was achieved with the help of the different utilities participating in this project. In addition several studies and reports provided important amounts of information for the study. These reports included country and regional master plans as well as individual project feasibility studies. Data that was collected for each country comprised of specific characteristics of the generation system's components such as technical and performance characteristics (max. generation; fuel type; heat rate, etc.) costs (capital cost, fixed and variable O&M) as well as the level of preparation of the project (existing, under construction, under study, etc.)

3.2 Generation Planning Criteria

The planning's main objective is to determine the schedule of commissioning of new generation entry such as to minimize an objective cost function for the entire power system:

min NPV[Cost(Investment + O&M + Fuel + Un-served Energy + Externalities)]

Economic Criteria for the project were first set forth:

- Costs were expressed in terms of mid 2009 (ref. price year)
- Discount Rate = 10%
- Cost of Un-served Energy = 1.10 USD/kWh

In addition to the above mentioned economic criteria, reliability criteria were also defined to ensure the resulting generation plans provided an acceptable level of reliability and stability to the power system. Since the systems in the EAPP/EAC are dominated by hydro energy, and with its availability being the major hurdle to system reliability, the following criteria were observed by the planners:

- The probability of deficit must be less than 100% for any given month
- The probability that in any given month the deficit exceeds 2% of the energy demand should be less than 5%.
- The planning horizon was defined as starting at the beginning of year 2013 and ending at the end of 2038

Outage rates for different types of plants also affect reliability and were all included in the modeling of the power system. In addition, in order to determine the retirement dates of existing or future plants, the service lives of the various types of power plants were collected. Finally, general cost items such as Fixed and Variable O&M were tabulated as they affect the minimization of the objective cost function. All this data is summarized in Table 3-1

Table 3-1 Typical Characteristics for Different Types of Power Plants

Generation type	Yearly Scheduled maintenance (weeks)	FOR (%)	Availability factor (%)	Normal Service Life (years)	Yearly Fixed O&M (USD/kW)	Variable O&M (c/kWh)
Coal STPP	6	8	80	25	50 to 70	0.65
Oil STPP	4	7	80	25	30 to 35	0.45
OCGT	4	5	80	20	10	0.50
CCGT	3	5	80	20	20	0.40
MSD	5	8	75	20	20	1.20
LSD	4	8	75	25	9	1.00
Geothermal	2	6	80	20	35	0.45
Cogeneration	8	6	75	25	70	0.65
Nuclear	4	3	90	40	75	Inc. in Fixed
Hydroelectric	4	0	90	50	10	0

3.3 Hydrology Database and Hydro Capability by Country

The planning study was performed with the aid of software that deals with historical hydrology records (SDDP/OPTGEN) to optimize and simulate the operation for all hydro sites. Hence the hydrology database for these hydro sites was updated and harmonized to have the same historical years for all sites. A period of 35 years was used (1972 – 2006) with monthly data for inflow in m^3/s.

Using the historical data, an annual hydro production by plant and then by country was generated to assess the hydro capability of the region. Results are in Table 3-2.

Table 3-2 Yearly Hydro Capability by Country

Country	MW	Hydro Generation	
		Avg. (GWh)	Firm (%)
Egypt	2902	13897	95%
Ethiopia	16204	76986	70%
Kenya	1300	6135	58%
Burundi, Eastern DRC, Rwanda *	961	4620	79%
Sudan	4678	26393	84%
Tanzania	3544	19722	69%
Uganda	2730	20025	100%
EAPP/EAC	*32319*	*167778*	*78%*
** Rwanda, Burundi and East DRC are merged because of the shared Ruzizi projects.*			

3.4 Total Identified Options by country

A listing has been prepared on a country by country basis of all the existing and identified future power options, with the following main remarks:

- Projects less than 10 MW have been omitted
- Plants that would come online prior to January 2013 were considered as existing/committed
- Capital costs including connection to the network costs have been updated and harmonized
- Mitigation costs have been included

- Earliest on-power date were assessed for all projects

Table 3-3 shows total available generation in 2030, along with the potential surplus:

Table 3-3 Future Supply and Surplus by Country

Country	*Existing 2012 MW*	*Future 2013-2030 MW*	*Total 2030 MW*	*Demand 2030 MW*	*Surplus 2030 MW*
Burundi	49	422	470	385	86
Djibouti	123	187	310	198	112
East DRC	74	1,117	1,191	179	1,012
Egypt	25,879	46,570	72,449	69,909	2,540
Ethiopia	2,179	13,617	15,796	8,464	7,332
Kenya	1,916	7,188	8,805	7,795	1,010
Rwanda	103	411	514	484	30
Sudan	3,951	11,310	15,261	11,054	4,207
Tanzania	1,205	4,881	6,086	3,770	2,316
Uganda	822	2,531	3,353	1,898	1,455
TOTAL	*36,436*	*87,334*	*123,769*	*104,136*	*20,099*

This table shows Ethiopia as the main net exporter of the region, mainly due to its high hydro capability.

3.5 Assessing and ranking of all future hydro options

Ranking of future hydro options depends mostly on the capital cost and the earliest on power date. On-power dates depend on the actual level of preparedness of the project, whether it's already under construction or still in reconnaissance level. Typical durations for the different activities before the completion of a project are in Table 3-4 hereafter:

Table 3-4 Typical Duration of Different Pre-Commissioning Activities

Activity	Time in months
Prefeasibility study, following a reconnaissance level project identification	6-12
Feasibility study (including consultant selection)	12-24
Feasibility study update (where required)	6-12
Environmental study and approval	12
Preparation of IPP process and tendering (where applicable)	12
Project financing (IPP or public ownership)	12
Final design (including consultant selection) – depending on size/complexity	12-18
Tendering	6-12
Construction (depending on size/complexity)	36-60

With the list of identified hydro options from a previous section and having updated all the investment costs, escalating them to the reference price year of 2009 and including Interest during construction, a primary screening process evaluated whether a project is:

- In: available anytime after the earliest on-power date;
- After 2017: potential future candidate that has a low level of preparedness ; or
- Out: Project has several conflicts

Table 3-5 summarizes these results by country for the first two 5-year periods of the study:

Table 3-5 Identified Hydro Potential by country for the first 10 years

Country	New hydro on-power 2013-2017 (MW)	New hydro on-power 2018-2022 (MW)
Burundi	62	90
Eastern DRC	145	1,446
Egypt	40	0
Ethiopia	4,582	9,735
Kenya	256	300
Rwanda	28	0
Sudan	0	2,870
Tanzania	477	2,648
Uganda	100	2,000
TOTAL	**5,691**	**19,089**

3.6 Assessing and ranking of all future thermal options

For thermal plants a similar process was followed to assess the available options and rank them. First the capital cost of different types of thermal plants was calculated based on current prices and recent studies. In addition, the minimum Lead-time to on power needed to be determined. Other characteristics and costs were also calculated or researched such as Heat-Rates of different plants, calorific contents and price projections of different fuels. The fuel price projections for the study horizon in 5 year intervals are presented in Table 3-6.

Table 3-6 Fuel Price Projections over Study Horizon

Year	*Crude Oil $/bbl*	*IDO $/lt*	*HFO US$/lt*	*Coal US$/Mt*	*NG US$/m3*
2013	78.9	0.6	0.6	80.0	0.2
2018	95.3	0.7	0.7	74.3	0.3
2023	101.6	0.8	0.7	73.7	0.3
2028	108.0	0.8	0.7	74.1	0.3
2033	117.0	0.9	0.8	75.8	0.3
2038	127.3	1.0	0.9	78.6	0.4

With all the cost and specification data collected, the unit generation cost of thermal plants was calculated in c/kWh. A summary of typical generation costs by country is presented Table 3-7 below, based on 75% capacity factor:

Table 3-7 Thermal Generation costs by Country for Different Plant Types

Country	Type	Capacity (MW)	Unit Cost ($/kW)	Total cost c/kWh	Fixed cost %	Variable cost %
Egypt	STPP - NG	1300	1196	3.47	59%	41%
	CCGT - NG	1000	1020	3.47	59%	41%
	Nuclear	1000	4420	9.40	90%	10%
Ethiopia	Geothermal	75/100	3501	8.48	79%	21%
Kenya	Geothermal	140	4434	10.13	83%	17%
	STPP - coal (Richards Bay)	300	3110	10.97	54%	46%
Rwanda	Diesel/Methane	100	1444	8.74		
Sudan	STPP - Crude	250	2033	13.43	77%	23%
Tanzania	STPP - Coal	400	3483	9.42	30%	70%
	OCGT - NG	240	1000	7.13	72%	28%
Uganda	CCGT - Gasoil	185	1361	24.41	28%	72%
	STPP - HFO	60	2033	18.90	11%	89%

Using these costs, future thermal plants were ranked, and together with the previously described ranking of hydro options provided the generation planner with a preliminary idea of what to expect from the actual results of the supply-demand balance in the next WBS.

3.7 Database for the study

The database for the study including the common period hydrologies, characteristics of existing generation plants as well as future projects has been made available to the client both in excel format and in SDDP/OPTGEN format. A catalogue for all Hydro projects in the region has been included in the Appendix A of the WBS 1200 Appendices.

4 SUPPLY-DEMAND ANALYSIS AND PROJECT IDENTIFICATION (WBS 1300)

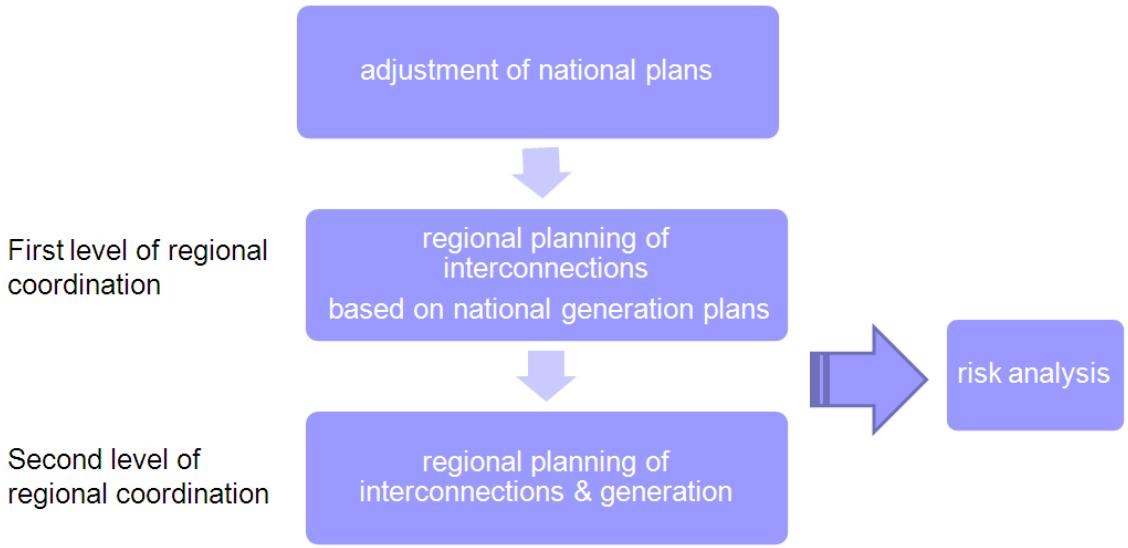
4.1 Objectives and Methodology

A supply-demand study for each country and for the EAPP/EAC region was conducted with the following objectives:

- Set up regional database of existing and future generation and interconnection projects
- Set up advanced optimization/simulation models OPTGEN/SDDP for the regional master plan exercise
- Develop/update supply-demand balances by country, identifying significant surpluses (National Plans)
- Develop regional master plan with different degrees of regional planning coordination
- Identify projects for the first 5-years in the planning horizon (2013-2018)

The methodology followed to achieve these objectives is described in Table 4-1:

Table 4-1 Methodology of Supply-Demand Study

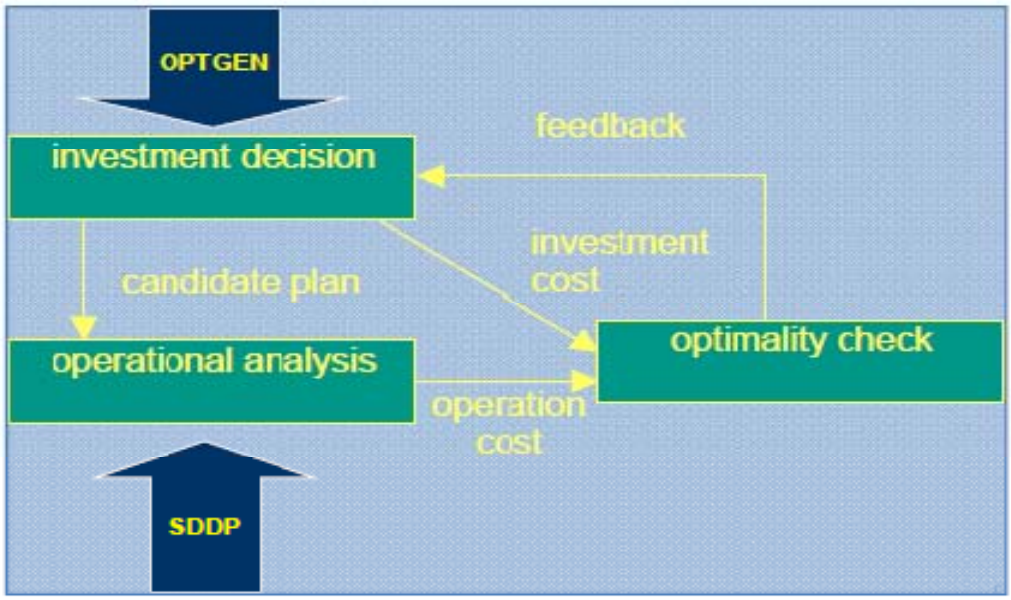


4.2 SDDP and OPTGEN Models

Establishing the supply-demand balance for each power system and then for the region altogether required the assistance of models to simulate each power system with all of its components, represent the load forecast and deal with the hydrology records. SDDP and OPTGEN (www.psr-inc.com.br) were deemed as the adequate tools for this study.

OPTGEN is a computational tool for determining the least-cost expansion plan of a multi-regional hydro-thermal system while SDDP is a probabilistic multi-area hydro-thermal production costing model. Both models work in coordination as shown Table 4-2 below:

Table 4-2 Coordination of OPTGEN and SDDP towards Optimal Solution



Inputs for the models included generation characteristics gathered in WBS 1200, interconnection characteristics such as power rating and capital cost, project status (Existing/Future) with on-power dates for future projects, hydrology historical records and load forecasts.

Demand forecasts prepared in WBS 1100 provided several options for each country. The most appropriate option was selected given the criteria upon which the forecast was developed. In most cases, a revised national plan forecast was selected as the existing national plans formed the basis for the plans that were developed in this study.

4.3 National Plans

Most of the countries in EAPP/EAC had a recent existing national generation expansion plan. However for consistency with the criteria set forth in this study, all power systems national plans had to be repeated or even developed from scratch for some countries which did not have a recent study.

The existing system was first simulated with the load projections and then OPTGEN selected the optimal entrance schedule for each future project. The results were then manually checked for the criteria defined in WBS 1200 concerning the deficit probability. When needed, changes to the OPTGEN results were made and set as fixed modifications to the plan. Then additional runs of the model were performed to re-optimize the plan. Once the final national generation plan was obtained, the new system was simulated in SDDP to get energy generation results for the entire study period.

Detailed results of each country's national plan such as the yearly additions by plant name and capacity, the yearly capacity profile of the system by category of fuel (clean; conventional; renewable) and the yearly energy generation by category of fuel, are presented in the report and its appendices.

Table 4-3 presents a summary of the capacity profile results for each country for the entire study period in 5-year intervals. The capacity profile was split into three categories: Clean (such as NG and Geothermal) conventional (Such as Diesel; HFO; Coal) a*nd* renewable (Hydro; Wind and Solar).

Table 4-3 National Generation Expansion Plans

Year	Installed Capacity (MW) by Category			Total Installed Capacity (MW)	Load (MW)	Reserve	
	Renewable	Clean	Conventional			(MW)	(%)
BURUNDI							
2013	43	0	6	49	56	-8	-13.7%
2018	63	0	106	169	116	53	45.8%
2023	63	0	206	269	204	64	31.5%
2028	207	0	306	512	327	186	56.9%
2033	233	67	506	805	481	324	67.4%
2038	233	67	606	905	667	238	35.6%
DJIBOUTI							
2013	0	147	147	116	30	86	286.7%
2018	20	176	196	158	38	120	315.8%
2023	60	176	236	173	62	111	179.0%
2028	60	176	236	191	45	146	324.4%
2033	60	199	259	210	49	161	328.6%
2038	60	199	259	232	40	192	480.0%
EASTERN DRC							
2013	89	0	18	106	72	35	48.4%
2018	249	0	18	266	93	174	187.6%
2023	289	0	18	306	121	185	152.4%
2028	433	0	18	450	160	290	181.1%
2033	433	67	18	517	211	306	145.0%
2038	433	67	18	517	276	241	87.6%
EGYPT							
2013	4,794	13,353	14,190	32,337	28,383	3,954	13.9%
2018	8,519	18,480	21,250	48,249	37,630	10,619	28.2%
2023	10,519	24,980	26,905	62,404	49,034	13,370	27.3%
2028	10,919	33,480	36,965	81,364	63,311	18,053	28.5%
2033	10,919	49,940	44,244	105,103	80,874	24,228	30.0%
2038	10,919	64,592	52,914	128,425	102,282	26,142	25.6%
ETHIOPIA							
2013	4,593	7	290	4,890	1,964	2,926	148.9%
2018	6,966	82	290	7,338	3,279	4,059	123.8%
2023	8,528	182	430	9,140	4,912	4,228	86.1%
2028	8,566	182	430	9,178	7,247	1,932	26.7%
2033	10,566	1,557	710	12,833	10,692	2,141	20.0%
2038	13,014	3,057	2,110	18,181	15,783	2,398	15.2%
KENYA							
2013	1,127	434	1,072	2,633	1,958	675	34.5%
2018	1,182	1,345	1,372	3,899	3,085	815	26.4%
2023	1,493	2,929	1,182	5,604	4,537	1,067	23.5%
2028	1,723	3,827	2,382	7,932	6,697	1,235	18.4%
2033	1,779	6,801	2,382	10,962	9,723	1,239	12.7%
2038	1,779	9,949	3,882	15,610	13,852	1,758	12.7%
RWANDA							
2013	64	100	42	205	94	111	117.9%
2018	64	100	42	205	165	40	24.1%
2023	64	100	142	305	276	29	10.5%
2028	208	100	342	649	417	232	55.7%
2033	236	167	442	844	594	249	42.0%
2038	286	167	642	1,094	806	288	35.7%
SUDAN							
2013	1,778	0	2,100	3,878	2,019	1,859	92.1%
2018	1,976	0	2,683	4,659	3,626	1,033	28.5%
2023	3,479	0	3,988	7,466	5,956	1,510	25.4%
2028	4,637	0	7,098	11,734	9,374	2,360	25.2%
2033	4,637	0	11,557	16,193	13,942	2,251	16.1%
2038	4,637	0	16,371	21,007	19,827	1,180	6.0%

Year	Installed Capacity (MW) by Category			Total Installed Capacity (MW)	Load (MW)	Reserve	
	Renewable	Clean	Conventional			(MW)	(%)
TANZANIA							
2013	561	702	160	1,423	1,213	210	17.3%
2018	1,249	1,002	360	2,612	1,839	773	42.0%
2023	2,149	964	460	3,573	2,479	1,094	44.1%
2028	2,777	1,017	660	4,454	3,353	1,101	32.8%
2033	3,262	714	1,400	5,376	4,532	843	18.6%
2038	3,601	1,510	2,300	7,411	6,344	1,067	16.8%
UGANDA							
2013	647	0	235	882	715	167	23.4%
2018	997	0	292	1,289	990	299	30.2%
2023	1,247	90	292	1,629	1,310	319	24.3%
2028	1,547	90	492	2,129	1,722	407	23.6%
2033	2,296	90	542	2,928	2,162	766	35.4%
2038	2,296	90	761	3,147	2,650	497	18.8%

In terms of energy and surplus by country, Ethiopia's generation plan provides it with an average surplus over the study period of around 12,557 GWh. Table 4-4 shows a summary of the energy surplus results for the national generation expansion plans by country for the main exporters in the EAPP/EAC region:

Table 4-4 Average Surplus over Study Period (2013-2038)

Country	Load (GWh)	Surplus (GWh)	Surplus/Load (%)
Ethiopia	28,386	12,577	44%
Uganda	7,768	2,636	34%
Tanzania	18,455	5,059	27%
Burundi, Rwanda, Eastern DRC	3,369	840	25%
Sudan	46.707	7,824	17%
Kenya	39,975	6,003	15%

4.4 Regional Plans

The national plans developed earlier provided the starting point for a regional study that included an interconnections plan in addition to the generation plan. Several cases were run combining between regional and national plans to determine which case would be the most appropriate for the region under-study. The most notable of the cases were:

- NGP_RIP: The national generation plans derived earlier were not changed. However a regional planning was conducted for the interconnection projects.
- RGP_RIP: In this case, the generation plan of each power system was optimized on a regional level in coordination with other systems' plans and with a regional interconnections plan.

The differences in the generation plans between both cases are presented in the report and its appendices. The interconnections selected in both plans are listed in Table 4-5 below:

Table 4-5 Schedule of interconnection projects selected

Name	From	To	Voltage	Capacity	Invest	Year in-operation	
				MW	M$	RGP_RIP	NGP_RIP
TZ-KY_4S	Tanzania	Kenya	400 kV-AC	1520	117.0	2015	2015
TZ-UG_2S	Tanzania	Uganda	220 kV-AC	700	30.4	2015	2023
TZ-RW_2S	Tanzania	Rwanda	220 kV-AC	320	37.6	2015	2015
TZ-BR_2S	Tanzania	Burundi	220 kV-AC	280	47.9	2015	2015
ET-KY_5dS	Ethiopia	Kenya	500 kV-DC	2000	845.3	2016	2016
ET-SD_5S1	Ethiopia	Sudan	500 kV-AC	1600	255.4	2016	2016
ET-SD_5S2	Ethiopia	Sudan	500 kV-AC	1600	255.4	2016	2016
EG-SD_6dS	Egypt	Sudan	600 kV-DC	2000	1,033.9	2016	2016
UG-RW_2G1	Uganda	Rwanda	220 kV-AC	520	51.3	2016	OUT
ET-KY_5dG1	Ethiopia	Kenya	500 kV-DC	2000	845.3	OUT	2020
ET-SD_5G1	Ethiopia	Sudan	500 kV-AC	1600	255.4	2020	2020
EG-SD_6dG1	Egypt	Sudan	600 kV-DC	2000	1,033.9	2020	2020
UG-KY_2G1	Uganda	Kenya	220 kV-AC	440	71.0	OUT	2023
ET-SD_5G2	Ethiopia	Sudan	500 kV-AC	1600	255.4	2025	2025
EG-SD_6dG2	Egypt	Sudan	600 kV-DC	2000	1,033.9	2025	2025

There were no major differences in between the two interconnection plans. The bigger differences were observed in the generation plans where expensive generation was displaced to make way for cheaper exports from neighboring countries through the various selected interconnection projects. Two sensitivity analyses were run on each of the two cases: The first one had the capital costs of interconnections doubled and the other one had a limit imposed on the number of interconnections between Egypt and Sudan at 1 DC double circuit line of 2000 MW. Results of these analyses are in the report as well.

A Benefit-Cost analysis was performed on all the cases studied to determine which scenario was the optimal one. The main results of this analysis are summarized below in Table 4-6:

Table 4-6 Benefit Cost Analysis Present Values in MUSD

Cases	Generation Cost (MUSD)			Interc. Cost (MUSD)	Total Cost (MUSD)	Benefit (MUSD)		
	Invest	O&M	Total			Gross	Net	Yearly
NGP_RIP	107,318	218,006	325,325	4,465	329,790	29,659	25,194	969
RGP_RIP	100,980	217,758	318,738	3,795	322,533	36,246	32,451	1,248

The first level of regional coordination (NGP_RIP) generates a net benefit over the study period of 25,194 MUSD. Spread annually, the revenues per year amount to 969 MUSD compared to an annualized investment of 172 MUSD. With a second level of regional coordination (RGP_RIP) the numbers increase to 32,451 MUSD net and 1,248 MUSD per year for a 146 MUSD annualized investment.

As expected, a larger benefit is expected from the case with regional generation planning as it reduces addition of expensive generation and relies more on cheap exports. However,

generation planning on a regional scale was deemed too complicated to implement hence the more adequate scenario selected was the NGP_RIP. It involves planning on a regional level for the interconnections however each country is responsible for its own generation plan and can meet its own load using local generation.

As presented next in Table 4-7 almost all the interconnections under study currently are selected to come online in the first 5 years (2013 – 2017). These are even needed when the cost of interconnections is doubled in the sensitivity analysis.

Table 4-7 Interconnection Projects 2013 – 2017 (NGP_RIP)

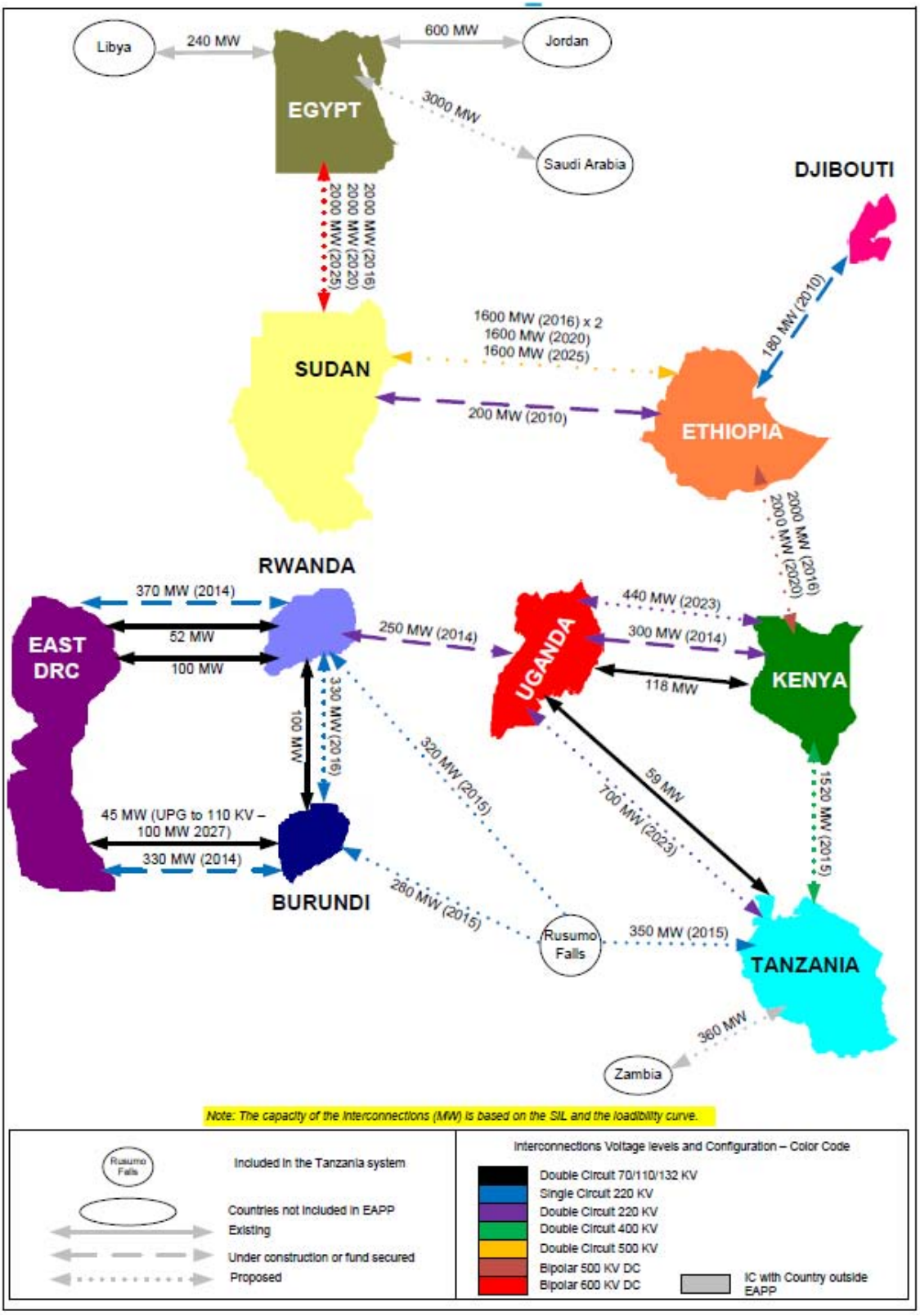
Connecting	Voltage (kV)	Capacity (MW)	Date
Tanzania-Kenya	400	1520	2015
Ethiopia-Kenya	DC 500	2000	2016
Ethiopia-Sudan	500	2 x 1600	2016
Egypt-Sudan	DC 600	2000	2016
Rusumo HPP Transmission system			2015

Table 4-8 lists the main identified regional generation projects determined by NGP_RIP while Figure 4-1 shows the corresponding map of selected interconnection projects, where it can be observed that interconnections are required from 2018 onwards, complementing the ones highlighted previously in Table 4-7.

Table 4-8 List of Identified Regional Generation Projects – NGP_RIP

Country	Plant Name	Type	Installed Cap (MW)	Date
Eastern DRC	Ruzizi III	Hydro	145	2024
	Ruzizi IV	Hydro	287	2027
Ethiopia	Mandaya	Hydro	2000	2031
	Gibe III	Hydro	1870	2013
	Gibe IV	Hydro	1468	2016
	Karadobi	Hydro	1600	2036
Rwanda	Kivu I	Methane	100	2013
	Kivu II	Methane	200	2033
Tanzania	Stieglers Gorge (I, II, III)	Hydro	1200	2020;2023;2026
Uganda	Karuma	Hydro	700	2016
	Ayago	Hydro	550	2023
	Murchison Falls	Hydro	750	2032

Figure 4-1 Map of Selected Regional Interconnections Projects – NGP_RIP



5 TRANSMISSION NETWORK STUDY (WBS 1400)

5.1 Objectives

Transmission system studies were performed to determine the needed reinforcements in order to accommodate the new generation and interconnections among EAPP/EAC countries. The basis for the system study was prepared first by developing a PSS/E database for each existing system (as of 2009) and extending the network model up to 2013, the initial year of the study.

5.2 2009 Network Model

Large systems were represented by the high level transmission system (bulk network) close to the areas of interest with explicit modeling of the large power plants. Remote sub-transmission networks were modeled in the load flow case but not analyzed. The transmission system in locations nominated for the interconnections were modeled in more detail. Medium and small systems were modelled using a full representation. Interconnection projects among the pool members and other countries were taken into consideration (e.g. Egypt-Jordan and Tanzania-Zambia). Detailed studies and conclusions for the 2009 studies are found in the WBS 1400 report.

5.2.1 Burundi

The Burundi System is interconnected through its Northern system to Rwanda and the Democratic Republic of Congo (DRC). System studies were performed using the full system model, however, only the 110 kV network was monitored.

5.2.2 Djibouti

The Djibouti system consists of few transmission lines and generation. In the near future, an interconnection with Ethiopia will provide the Djibouti system with an alternative source of generation. System studies were performed using the full Djibouti interconnected system model but excluding the isolated systems and the interconnection with Ethiopia.

5.2.3 Democratic Republic of Congo (East)

The Eastern DRC System is interconnected with Rwanda and Burundi. System studies were performed using the full system case, however, only the 70/110 kV network was monitored.

5.2.4 Egypt

As the interconnection of the Egyptian system within the EAPP project would be most likely via the Southern part of Egypt, only a portion of the full system was considered. System studies were performed using the full system case, however, only the Southern part up to Cairo (mostly 220 kV) and the full 500 kV network was monitored.

5.2.5 Ethiopia

The Ethiopian system will be interconnected with Djibouti through its Eastern zone, with Sudan through its North-Western zone and with Kenya through its Southern zone. System studies were performed using the full system case, however, only the 230/400 kV network was monitored.

5.2.6 Kenya

As the interconnection of the Kenyan system within the EAPP project would be through the bulk system (220 kV and above), only that portion of the full system was considered along with the interconnection to Uganda. System studies were performed using the full system case, however, only the high voltage network (220 kV and above) was monitored.

5.2.7 Rwanda

The Rwanda System is interconnected through its Southern system to Burundi and the Democratic Republic of Congo (DRC). System studies were performed using the full system case, however, only the 110 kV network was monitored.

5.2.8 Sudan

As the interconnection of the Sudan system within the EAPP project would be through the bulk system (220 kV and above), only that portion of the full system was considered. System studies were performed using the full system case, however, only the high voltage network (220 kV and above) was monitored.

5.2.9 Tanzania

The interconnection of the Tanzanian system within the EAPP project would be most likely with Kenya through its Northern part and with Rwanda and Burundi through its Western part. An isolated system, Bukoba, located in the Northern area of Tanzania is interconnected with the Ugandan system. This area is considered in the Ugandan system instead in the next section. System studies were performed using the full system case, however, only the 220 kV network was monitored.

5.2.10 Uganda

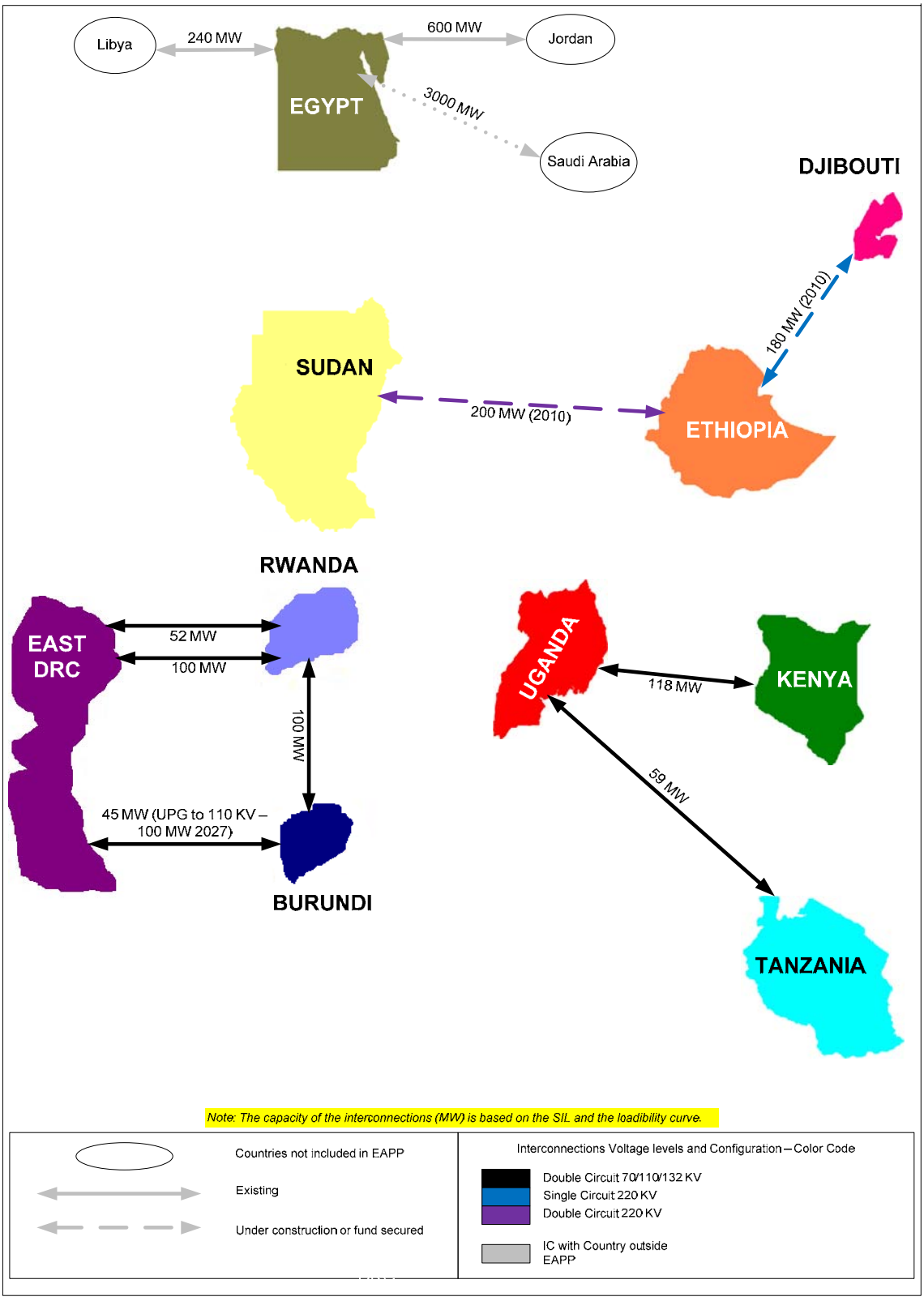
The Ugandan system is interconnected within the EAPP project with Kenya through its Eastern part and would be most likely interconnected with Rwanda through its South-Western part. The Ugandan system also provides power to the Bukoba area in Northern Tanzania. This area is isolated and therefore an interconnection between the Ugandan system and the Tanzanian system is not considered. System studies were performed using the full system case, however, only the 132 kV network was monitored.

A single line diagram was drawn for each of the 10 power systems representing the network as of year 2009. These network models are available in the report.

5.3 2013 Network Model

Interconnections that would exist in year 2013 were also presented and are shown in Figure 5-1.

Figure 5-1 2013 EAPP/EAC Interconnected System



6 INTERCONNECTION STUDIES (WBS 1500)

6.1 Objectives

The objectives of this WBS were to:

- Develop common transmission planning criteria
- Identify major interconnection projects
- Propose generic designs for interconnections
- Provide a preliminary idea of the state of the interconnected system in 2038

Once done, the project could move into the next phase by taking these interconnection projects to the economical and financial sides of the study (cost estimates, economic and financial analysis, project funding, etc...)

6.2 Common Transmission Planning Criteria

The developed transmission planning criteria was mainly used in the interconnection studies among the EAPP/EAC countries. It was also used in the local network reinforcing studies along with the regional planning criteria. Four categories of criteria were identified:

- Power system reliability (steady state and dynamic):

Table 6-1 Power System Reliability Criteria

Reliability	Integrated system
Steady-state adequacy	N-1
Dynamic security	N Transmission N-1 Transmission N-1 Generation

- Equipment duty and rating (normal and contingency):

Table 6-2 Equipment Maximum Loading

Operating Conditions	Maximum Loading
Normal (N-0)	100%
Contingency (N-1)	120%

- System Performance:
  - Voltage limits (normal, contingency, dynamic):

Table 6-3 Steady State Voltage Limits

Operating Conditions	Voltage Limits
Normal (N-0)	[0.95-1.05]
Contingency (N-1)	[0.90-1.10]

Table 6-4 Dynamic Voltage Limits

Dynamic voltage excursions	*Voltage limits (p.u.)*
Surges and dips outside nominal voltage	Within CBEMA curve
Maximum temporary overvoltage	1.2 p.u. for a maximum of 1 second
Maximum temporary under-voltage	0.8 p.u. for a maximum of 1 second

- o Frequency limits (normal, system disturbance, system fault, extreme):

Table 6-5 Frequency Limits

Operating conditions	Frequency limits (Hz)
Normal	[49.5 – 50.5]
System disturbance	[49.0 – 51.0]
Maximum band under system fault	[48.75 – 51.25]
Extreme system operation or fault conditions	f < 47.5 or f > 51.5

- o Reactive power supply: Generators should operate between unity PF and their rated PF; SVC's should operate close to zero output or if needed not more than 70% of its rated output
- o Short-circuit levels: within equipment ratings
- o Load power factor: not less than 0.9 lag on transmission level
- o Spinning reserve: Sharing of spinning reserve

- Stability (transient, oscillatory, voltage, frequency)
  - o Fault clearing times: at 220 kV and above, faults should not exceed 5 cycles. For lower levels it should not exceed 6 cycles.
  - o Stability types:

Table 6-6 Stability Types and Recommendations

Stability type	Recommendations
Transient (Angle)	All generators should remain in synchronism following any single contingency
Oscillatory (Angle)	Relative generator rotor angles within each system and between the systems are well damped. For example, the oscillation is reduced to 50% of its initial value within 5 seconds.
Voltage	No voltage collapse
Frequency	Frequency should recover to stable state without load curtailment following the loss of a unit

6.3 Identification of Interconnection Projects and Generic Designs

Most of the interconnection projects identified in WBS 1300 were AC lines. The following are the proposed generic characteristics of these AC lines at different voltage levels.

Table 6-7 AC Line Characteristics for a distance of 100 km (100 MVA base)

Voltage level (kV)	220	400	500
Conductor	2-Drake ACSR (468.6 mm^2)	4-Flint AAAC (375.4 mm2)	4-Flint AAAC (375.4 mm2)
R (pu)	0.00734	0.00147	0.00094
X (pu)	0.06068	0.01681	0.01076
B (pu)	0.18779	0.67596	1.05619
SIL (MW)	176	633	989
Rating (A)	1780	3100	3100
Rating (MVA)	678	2147	2685

For the HVDC Lines (Egypt – Sudan and Kenya – Ethiopia), the conductor chosen was 4-Pheasant (4 x 726 mm^2). Two voltage levels were proposed to be used in this study; 500 kV and 600 kV. The dc resistance of this conductor is 45 mΩ/km at 25°C which is equivalent to 50 mΩ/km at 50°C and the total resistance per pole (4 conductors) would be 12.5 mΩ per km.

These characteristics were considered when modelling all lines, whether existing, under-construction or proposed. The lines for the identified projects are summarized in the following tables.

Table 6-8 Existing, under-construction and fund secured interconnections

Interconnection	Voltage (kV)	Distance (km)	Capacity (MW)	Configuration	Status
Uganda-Kenya	132	117	118	Double-circuit	Existing
Tanzania-Uganda	132	85	59	Single-circuit	Existing
Ethiopia-Sudan	220	321	200	Double-circuit	Under Construction
Ethiopia-Djibouti	220	283	180	Single-circuit	Under Construction
Uganda-Kenya	220	254	300	Double-circuit	Fund Secured
Uganda-Rwanda	220	172	250	Double-circuit	Fund Secured

Table 6-9 Possible AC interconnections of EAPP/EAC countries

Interconnection	Voltage (kV)	Distance (km)	Capacity (MW)	Losses (%)	Configuration
Ethiopia-Djibouti	220	283	420	4.82	Double-circuit
Ethiopia-Sudan	500	544	1600	4.60	Double-circuit
Uganda-Kenya	220	254	440	4.50	Double-circuit
Uganda-Kenya	400	254	1620	3.25	Double-circuit
Tanzania-Kenya	400	260	1520	3.11	Double-circuit
Tanzania-Uganda	220	85	700	2.29	Double-circuit
Tanzania-Rwanda	220	115	320	2.86	Single-circuit
Tanzania-Burundi	220	158	280	3.48	Single-circuit
Uganda-Rwanda	220	172	520	3.52	Double-circuit

Table 6-10 Possible bipolar HVDC interconnections of EAPP/EAC countries

Interconnection	Voltage (kV)	R (mΩ/km)	Distance (km)	Capacity (MW)	Losses (MW)	Losses (%)
Ethiopia-Kenya	500	50	1120	2180	66.53	1.53
Egypt-Sudan	600	50	1665	2140	66.19	1.55

The above configurations for all the proposed interconnections were used in the system studies in WBS 2100 and in preparing the cost estimates for each project in WBS 2300 as well as the individual project portfolios.

A preliminary estimate of the costs of these lines was prepared in this WBS and is presented in Table 6-11.

Table 6-11 Unit Cost of transmission lines

Technology	Voltage Level (kV)	Configuration	line Cost (k$/km)	Converter Cost ($/kW/Terminal)	Fixed Cost for additional AC requirements (M$)
HVDC	500	Bipolar	276	120	13
HVDC	600	Bipolar	290	125	16
AC	220	Double-circuit	240	-	10
AC	400	Double-circuit	400	-	13
AC	500	Double-circuit	440	-	16

The duration of a study from the proposal to awarding the contract of each project takes approximately two years. The construction period depends on the length of the interconnection where it can vary from two to four years. Table 6-12 gives an approximate disbursement schedule as a function of different line lengths.

Table 6-12 Disbursement Schedule for construction costs

Year of Construction	Line Length		
	<100 km	<300 km	>300 km
Cost of year # 1	60%	50%	40%
Cost of year # 2	40%	25%	20%
Cost of year # 3	-	25%	20%
Cost of year # 4	-	-	20%

6.4 Vision 2038

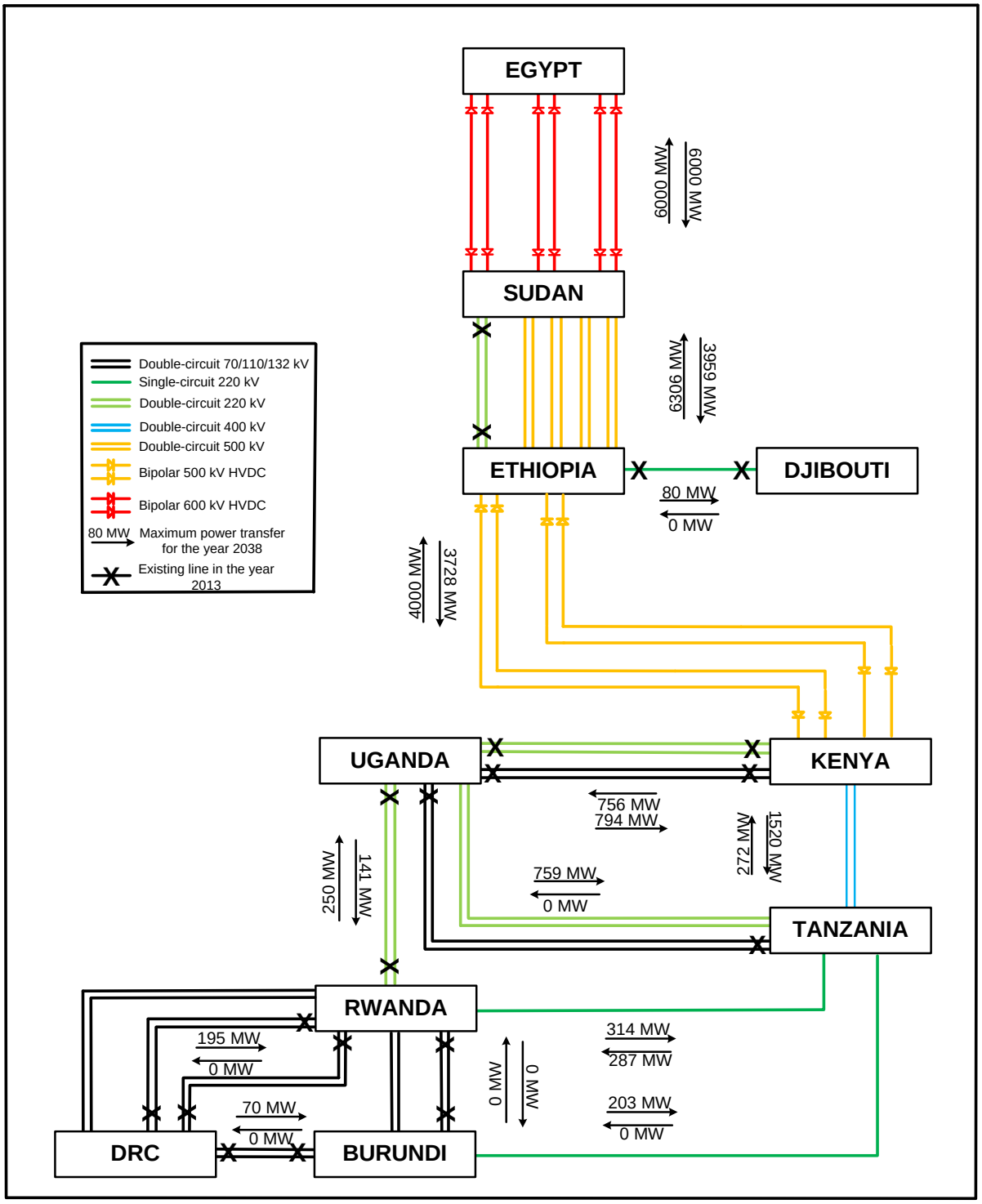
Looking ahead to year 2038, the maximum power transfers between any two countries were found to be as given in Table 6-13.

Table 6-13 Maximum Exchange between Countries Over Study Horizon

From	To	Maximum Transfer (MW)	Interconnections
Sudan	Egypt	6000	3 bipolar 600 kV HVDC
Egypt	Sudan	6000	
Djibouti	Ethiopia	0	1 single-circuit 220 kV
Ethiopia	Djibouti	80	
Kenya	Ethiopia	4000	2 bipolar 500 kV HVDC
Ethiopia	Kenya	3780	
Sudan	Ethiopia	3959	4 double-circuit 500 kV 1 double-circuit 220 kV
Ethiopia	Sudan	6600	
Burundi	Tanzania	203	1 single-circuit 220 kV
Tanzania	Burundi	166	
Kenya	Tanzania	1520	1 double-circuit 400 kV
Tanzania	Kenya	1520	
Rwanda	Tanzania	320	1 single-circuit 220 kV
Tanzania	Rwanda	320	
Uganda	Tanzania	759	1 double-circuit 220 kV 1 double-circuit 132 kV
Tanzania	Uganda	437	
Rwanda	Uganda	167	1 double-circuit 220 kV
Uganda	Rwanda	250	
DRC	Rwanda	195	1 single-circuit 220 kV 1 double circuit 110 KV 1 double circuit 70 KV
Rwanda	DRC	0	
DRC	Burundi	70	1 single-circuit 220 kV 1 double circuit 110 KV
Burundi	DRC	0	
Kenya	Uganda	756	2 double-circuit 220 kV 1 double-circuit 132 kV
Uganda	Kenya	794	

Finally, the state of the interconnected system in year 2038 including all identified interconnections is shown in Figure 6-1.

Figure 6-1 EAPP/EAC Interconnections and Transfers by the Year 2038



7 Regional Market Operator (RMOC) Location (WBS 2900)

This part summarizes the findings and recommendations for the location of the EAPP Regional Coordination Center (RCC) or Regional Market Operation Center (RMOC) as it is now called.

Through the course of this study it has been clarified that the duties and roles of the Coordination Centre should be more aligned with a Regional Market Operator and not a Regional Power System Dispatcher. The required staffing and IT systems that are required by a RMOC are obviously different to that needed by a Regional Power System Dispatcher.

A great deal of information has been made available by the countries and also publicly available data and indices from international organizations have been collected.

Analyzing the functional requirements of the RMOC, it is clear that an indispensable "minimum" technical requirement for the facilities is very reliable internet services with very robust back-up systems of dedicated phone lines and fax. However; real time dedicated data lines are not required. Most countries of the EAPP meet this minimum requirement, or are in the process of modernizing their telecommunications infrastructure, therefore the deciding criteria needs to be focused on other characteristics of the environment in which the RMOC will be functioning and evolving.

It was found that some of the most relevant aspects of the "country environment" that will positively contribute to the daily tasks of the RMOC include the development of institutions, the development of infrastructure; the financial and commodity market development and the technological development/accessibility and business practices.

Another important factor is the degree of evolution of the electricity market in each specific country, including the unbundling of the sector, the legal framework and the participation of the private sector.

The analysis focuses on parameters that as much as possible can be measured or compared between countries. It needs to be highlighted that the present analysis is based on the most recent information available; however, it is obvious that the performance of each country in each one of the criteria may change in the future. Clearly the final decision on the location of the RMOC is going to be taken at the ministerial level and will need to consider political aspects.

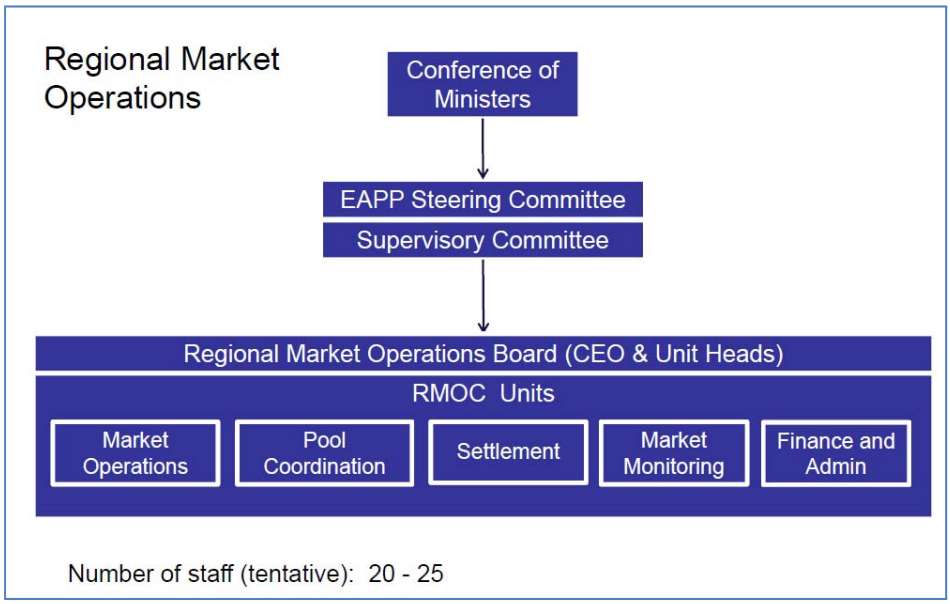
Four countries have offered to host the RMOC (Ethiopia, Sudan, Kenya and Rwanda). However, the analysis includes all the EAPP member countries.

The analysis concludes that based on the criteria and data used Kenya has the best mix of characteristics that would enable the establishment and development of the RMOC. However, as mentioned earlier most countries in the region meet, or will soon meet, the minimum technical requirement of reliable, high speed communications, so this result is obtained based on factors related to the present "country-environment"

7.1 RMOC Functions and Structure

The basic structure of the proposed RMOC and its different organizational units is illustrated in Figure 7-1 below.

Figure 7-1 Structure of proposed RMOC



The Operational Duties of the RMOC are summarized in Table 7-1 below.

Table 7-1 RMOC main function and responsibilities

Functions	Specific Responsibilities
System Operation Coordination	Scheduling pool interconnectors Monitoring load flows and taking action on variances Balancing market counterparty for imbalance settlement
Market Administration	Market Monitoring and surveillance Administration of contracts Dispute Management Membership Administration
Market Operation	Managing the Balancing Market Managing the Day Ahead Market (Stage 2)
Settlement	Meter Reading administration Balancing Market billing Day Ahead Market Settlement Payment

The RMOC will handle the bids and offers of participants in the balancing market, and when developed the day ahead markets. In this context, the type of communication facilities required will be very reliable internet services with very robust back-up systems of dedicated phone lines and fax in the context of the short and medium term. However; real time dedicated data lines are not required.

The main requirement is for the RMOC to have direct access to the interconnection meters (meter reading) downloading data which can be transmitted via the internet and is not time critical and can be done 3 or 4 times a day and IT infrastructure to run the settlements procedures.

7.2 Selection Criteria

Due to the nature of its functions and responsibilities as the operator of the regional market, there is no particular need for the RMOC to be located close to a large supply centre or a large load centre or a large electricity transit hub. In this regard, selection criteria based on amounts of trade, import or export may not be as important as factors that involve the capabilities to operate an electricity market.

It is difficult to arrive at a set of engineering or technical criteria that would point to one location over another. However, it is clear that an indispensable "minimum" technical requirement for the facilities is very reliable internet services with very robust back-up systems of dedicated phone lines and fax, although real time dedicated data lines are not required. Most countries of the EAPP meet, or will soon meet, this minimum requirement, therefore the deciding criteria needs to be focused on other characteristics of the environment in which the RMOC will be functioning and evolving.

The following are aspects of the host country that are likely to have a positive impact on the day-to-day operations of the future RMOC as well as in its future development.

Development of Institutions

The institutional environment in a given country is determined by the legal and administrative framework within which individuals, firms, and governments interact. The importance of a sound and fair institutional environment for the development and operation of the RMOC cannot be understated.

Development of Infrastructure

Extensive and efficient infrastructure is critical for ensuring the effective functioning of the economy of the country as a whole and is a relevant requisite for the operation of the RMOC. A well developed infrastructure network should allow for easy and rapid access to the movement of people and flow of data. The RMOC will also require a reliable electricity supply that is free of interruptions and shortages.

Financial Market and Commodity Development

The RMOC will be responsible for operating the balancing and day-ahead markets and settling the contracts. It will therefore benefit from an environment in which there exist sophisticated financial markets and a sound banking sector, properly regulated securities exchanges, venture capital, and other financial products. The banking sector needs to be trustworthy and transparent, and financial markets need appropriate regulation. Local well-developed commodity/financial markets will facilitate access of the RMOC to local qualified skills and consultancy, lowering the overall operating costs.

Technological Development or Accessibility

Due to its sophisticated nature, the RMOC will benefit from the agility with which the hosting country adopts existing technologies to enhance the productivity of its industries, with specific emphasis on its capacity to fully leverage information and communication technologies (ICT) in daily activities and production processes for increased efficiency and competitiveness. ICT access and usage are key enablers of countries' overall technological readiness. Whether the technology used has or has not been developed within national borders is irrelevant for its ability to enhance productivity.

Business Practices

Business sophistication in a country concerns the quality of a country's overall business networks as well as the quality of individual firms' operations and strategies. The quality of a country's business networks and supporting industries, as measured by the quantity and

quality of local suppliers and the extent of their interaction, is important for a variety of reasons. Due to the nature of its mission the RMOC will clearly benefit from operating in an environment with a high level of sophistication.

Evolution of the National Electricity Market

Countries in the region are now in different stages of the path to reform of their electricity sectors, which in general aim at opening up certain areas for competition (generation, distribution) and creating the institutions and legal framework to support the competitive market.

The RMOC with its mandate to administer and operate the regional complex markets such as the day-ahead and balancing as well as the settlement of trade, would certainly benefit from a country environment in which an already established and well-functioning electricity market operates.

Other aspects

Other important issues that may be considered are those that concern the support systems and culture such as:

- Open and accessible banking system with secure and reliable electronic interfaces and efficient foreign currency management
- Ease of physical access: Hub airport and reasonable entry and exit administration
- Access to skilled support organizations: IT, Legal, Accounting etc.
- Equitable distribution of institutions should be the policy. Hosting of institutions should be based on the requirements for that institution and hosting should be evaluated against such criteria taking into account countries that already host some institutions so that countries that do not are given the first opportunity if they meet the criteria and are willing to host.

7.3 Results of the Analysis

7.3.1 Analysis of the offers to host the RMOC

Letters were received from Ethiopia, Sudan, Kenya and Rwanda. All these countries have expressed interest in hosting the RMOC and have demonstrated to fulfill the minimum requirements in terms of communication infrastructure.

Sudan reports that it would make available for the RMOC its current and future capabilities in terms of communication infrastructure, land, and the possibility to (depending on the final requirements for the RMOC) to provide the facilities at minimal cost or even free of charge.

Ethiopia remarks its commitment to the interconnections to fulfill the regional power market and the aggressive program being carried out to improve and further develop the telecommunication system.

Kenya has highlighted the advantages of its location, developed communication infrastructure, advanced banking system and absence of foreign exchange restrictions.

Rwanda mentions as advantages, in addition to its position in the indices published by WEF/IMF for the region, the following: implementation and running costs including level of local salaries, rents, telecoms, banking, etc; access to existing infrastructure which may reduce start-up capital requirements; and ease of travel to/from the RMOC to member countries.

7.4 Analysis for the highest ranked group

Some criteria that are considered relevant for the operation and development of the RMOC are:

- Institutions
- Infrastructure
- Financial Market Development
- Technological Readiness and
- Business Sophistication

Table 7-2 below shows the evaluation of the criteria for some of the EAPP member countries based on the WEF GCI for the period 2010-11. The average is also shown by giving each of the 5 criteria the same weight. The data tables for each country are included in section above.

Table 7-2 Evaluation of criteria for the RMOC location (based on WEF GCI)

LOCATION OF RMOC - EVALUATION							
	Burundi	**Egypt**	**Ethiopia**	**Kenya**	**Rwanda**	**Tanzania**	**Uganda**
Institutions	2.8	4.0	4.0	3.2	5.3	3.7	3.4
Infrastructure	2.2	4.0	2.7	3.0	3.0	2.4	2.4
Financial Market Development	2.3	4.0	3.3	4.7	4.1	4.0	4.1
Technological Readiness	2.3	3.3	2.5	3.1	3.1	2.6	2.9
Business sophistication	2.8	4.0	3.2	4.0	3.5	3.5	3.2
AVERAGE	**2.5**	**3.9**	**3.1**	**3.6**	**3.8**	**3.2**	**3.2**

notes:

Source: The Global Competitiveness Report 2010-2011 - World Economic Forum

Data for Djbouti, DRC and Sudan not available

Scores range from 1 to 7

The evaluation shows that the countries can be grouped in three categories: Egypt, Rwanda and Kenya with high scores (3.9 - 3.6) then Tanzania, Uganda and Ethiopia (3.2 - 3.1) with medium scores and Burundi with a low score (2.5). Data for Djibouti and DRC was not reported, but the assessment of the countries based on the information collected indicates that according to these criteria these countries are most likely in the low score region. As for Sudan, the GCI index is not available either. The score for Sudan, based on the assessment of the data examined, is likely to be in the medium score region.

Other relevant indices such as the “Doing Business” index published by the WB/FMI for the EAPP countries the index is shown in Table 7-3 below.

Table 7-3 Doing Business index for EAPP countries

Country	Doing Business ranking
Djibouti	158
DR Congo	175
Egypt	94
Ethiopia	104
Kenya	98
Rwanda	58
Sudan	154
Tanzania	128
Uganda	122
Burundi	135

From the above table it is observed that the ranking of the different groups of countries is similar to the ranking obtained by the use of selected criteria in Table 7-2. The 3 countries coming on top in the evaluation of the "Doing Business" index are Rwanda (58), Egypt (94) and Kenya (98). Then the medium scores are for Ethiopia (104), Uganda (122) and Tanzania (129), followed by Sudan (154), Djibouti (158) and DR Congo (175).

From this analysis we conclude that the countries in the highest ranked group are Rwanda, Egypt and Kenya.

7.4.1 Analysis of other factors

Market Development

Countries in the region are now in different stages of the path to reform of their electricity sectors, which in general aim at opening up certain areas for competition (generation, distribution) and creating the institutions and legal framework to support the competitive market.

The RMOC with its mandate to administer and operate the regional complex markets such as the day-ahead and balancing as well as the settlement of trade, would certainly benefit from a country environment in which an already established and well-functioning electricity market operates.

Kenya and Uganda can be considered the most advanced in the region in terms of the implementation of unbundling of the sector, establishment of regulation, private sector participation and competition. Although they have not yet reached the level of a well-functioning competitive market and they still face serious challenges such as limited supply, poor reliability and high level of losses, the advances achieved up to date are important enough to be factored in this evaluation.

Ease of travel

Kenya and Ethiopia can be considered the best locations when it comes to aerial transportation to/from any other country in the EAPP. From Addis Ababa and Nairobi, daily flights serve all the other capitals often with direct flights.

7.5 Conclusions and Recommendation

7.5.1 Main Findings

- Given the functions and responsibilities of the RMOC as a market operator, the selection should be based on criteria that correlate to its specific needs. Selection criteria based on amounts of trade, import or export may not be as important as factors that involve the capabilities to operate an electricity market.
- Most countries in the region meet, or will soon meet, the minimum technical requirement for speed and reliability of their communication infrastructure.
- Four countries have expressed interest in hosting the RMOC: Ethiopia, Sudan, Kenya and Rwanda
- Factors that are likely to have a positive impact on the day-to-day operations of the future RMOC as well as in its future development include: Institutions; Infrastructure; Financial Market Development; Technological Readiness and Business Sophistication.
- Evaluation of the countries based on above factors put Rwanda, Egypt and Kenya in the highest ranked group
- Other important factors to consider are the degree of development of the implementation of sector reforms and the electricity market as well as access to the selected location via air transportation.
- Kenya and Uganda are considered the highest ranked in terms of development of the sector restructuring and markets while Ethiopia and Kenya are best ranked in terms of access.

7.5.2 Recommendations

Based on the detailed analysis of all the relevant factors considered as well as the expressed interest of the countries offering to host the RMOC, Kenya emerges as the country with the best balance of characteristics for hosting the RMOC as evaluated in this report.

As mentioned earlier all countries already meet or will soon meet the minimum requirements for fast and reliable communications needed for the RMOC to operate. So basically any country willing to host the RMOC would be equipped to do it. The factors analyzed in this report try to discern any possible “comparative advantages” that may exist and by its nature may change in the future. Finally the decision of the location would have to come from the relevant political authorities in the framework of the EAPP Ministerial Council.

8 SYSTEM STUDIES FOR EXPANSION PLAN (WBS 2100)

8.1 Objectives

- To evaluate the technical feasibility of the selected interconnection projects.
- To identify the national system reinforcements required for satisfactory technical performance of the interconnection projects.

8.2 Input data

a) The network data developed in WBS 1400 and WBS 1500 including the collected data during the inception visits in October 2009.

b) The definition and phasing of individual interconnection projects as developed in WBS 1500 and WBS 1300.

8.3 Methodology

The system studies will be performed for the study years; 2013, 2018 and a qualitative assessment for the horizon year 2038.

Load Flow Analysis

Based on the planning criteria developed in WBS 1500, load flow analysis was performed for the peak load conditions. For each load flow study year case, the following steps were followed:

a) The base case will be checked for voltage range and line/transformer overloading under normal (N-0) condition and single line diagrams were prepared.

b) Contingency analysis was then performed for each base case and the voltage range and line/transformer overloading are checked under (N-1) conditions.

c) System reinforcements were recommended as necessary.

Short Circuit Analysis

For each short circuit study year case, three-phase symmetrical fault current was calculated at each bus of the bulk system. Short circuit calculations can be extended to include other selected buses as per EAPP/EAC recommendations.

Stability Analysis

The objective of the stability analysis is to assess the system security following a major disturbance (e.g. three -phase fault). In general, the machine rotor angles and bus voltages are monitored. For each load flow study year case, a stability contingency list was prepared and the stability analysis was carried out based on the following proposed steps:

a) run for 1.0 second disturbance free, then apply three-phase fault

b) clear the fault and trip one branch

c) continue simulation for sufficient time to demonstrate system integrity and satisfactory damping and voltage stability

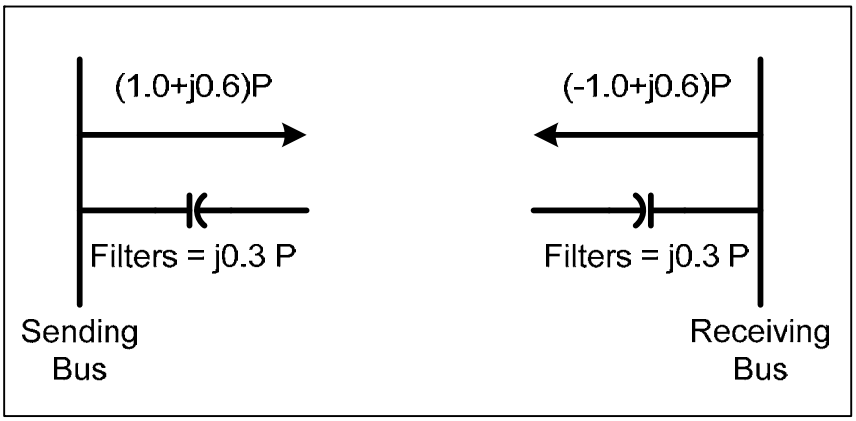
In modeling the system for stability studies, fast responding equipment such as the Static Var Compensators (SVC) will be taken into consideration. Such equipment will help in improving both transient stability and steady state (voltage) stability. Slower responding equipment such as transformer taps and fixed shunt will have only steady state models and will be frozen at their pre-disturbance values in stability studies.

In the following sections, load flow, short circuit and stability analyses shall be performed on the electrical network of years 2013 and 2018 of each country as described above.

Modelling of HVDC Line

Each HVDC line was modeled by two buses; a sending bus and a receiving bus. The DC power transfer is modeled as a positive load at the sending bus and as a negative load at the receiving bus. Station reactive power requirements are always positive at both the sending and receiving buses. The value of the reactive power is typically 60% of the active power. Filters are modeled as capacitor banks at the two buses and are typically 50% of the station reactive power (or 30% of the active power), as shown in Figure 8-1. For example, a 2000 MW HVDC line would be modeled by 2000+j1200 MVA load with 600 MVAr capacitor banks at the sending bus; and by -2000+j1200 MVA load with 600 MVAr capacitor banks at the receiving bus.

Figure 8-1 HVDC modeling



8.4 System Studies for the years 2013 and 2018

8.4.1 Burundi, Eastern DRC, Rwanda

The power systems of the three countries Burundi, Democratic Republic of Congo (DRC-Eastern Part) and Rwanda are very much interconnected. For example, the Ruzizi I & II in DRC supply Burundi through Rwanda.

This is why in the analysis, the three power systems were studied as ONE Interconnected System.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the interconnected Systems (Burundi, Eastern DRC and Rwanda):

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (0.0 MW power exchange) and 2018 (16 MW import from Rusumo Falls and 64 MW export to Uganda).

b. In Y-2013, four new 70/110 kV substations, one 110 kV line, one transformer and two shunt compensations were added for satisfactory operation under (N-0) and (N-1) conditions.

c. In Y-2018, 15 new substations (mostly 220 kV), 8 110 kV line, one transformer and one shunt compensation were added for satisfactory operation under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 70/110/220 kV network. The maximum value was found to be <10 kA which is

considered way below the typical 40/63 kA switchgear for this voltage level. Therefore, the 70/110/220 kV system would not experience any switchgear short circuit rating problems.

For stability analysis, three cases were found to be unstable in Y-2013. With the system reinforcements up to Y-2018, only one case was found to be unstable. With future system development and possible load shedding schemes, the instability problems could be overcome.

Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.2 Djibouti

The interconnection of the Djibouti system within the EAPP/EAC project would be via PK12-230 kV to Ethiopia at D.Dawa-230 kV substation.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Djibouti System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (80 MW import from Ethiopia) and 2018 (80 MW import from Ethiopia).

b. In Y-2013, no system additions were considered.

c. In Y-2018, one 63 kV substation was added and the system performance was satisfactory under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 63/230 kV network. The maximum value was found to be <10 kA which is considered way below the typical 40/63 kA switchgear for this voltage level. Therefore, the 63/230 kV system would not experience any switchgear short circuit rating problems.

No stability problems were found in Y-2013 or Y-2018 cases. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.3 Egypt

The interconnection of the Egyptian system within the EAPP/EAC project would be most likely via the Southern part of the 500 kV Network. System studies will be performed using the full system case, however, only the 500 kV network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Egyptian System:

a. The performance of the existing system with zero import from Sudan under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 and 2018.

b. In year 2013, no import was scheduled from Sudan. In year 2018, Egypt would import 2000 MW from Sudan over one bipolar HVDC line.

c. In year 2018 with 2000 MW import, three 500 kV circuits and three shunt compensations were needed for satisfactory system operation.

Three-phase short circuit calculations based on the classical assumptions were performed for the 500 kV network. The maximum value was found to be 41 kA which is considered well below the typical 50/63 kA switchgear for this voltage level. Therefore, the 500 kV system would not experience any switchgear short circuit rating problems.

The stability results show that all studied cases are transiently stable. However, there were some cases with poor damped oscillations which would disappear with the system

development by year 2018. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.4 Ethiopia

The interconnection of the Ethiopian system within the EAPP/EAC project would be via Wolita-500 kV to Kenya, Gondar-230 kV and Mandaya-500 kV to Sudan and D.Dawa-230 kV to Djibouti. System studies will be performed using the full system case, however, only the 230/400 kV network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Ethiopian System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (280 MW export to Djibouti and Sudan) and 2018 (2964 MW export to Djibouti, Sudan and Kenya).

b. In Y-2013, more than ten 230 kV circuits/transformers in addition to shunt compensation were added for satisfactory operation under (N-0) and (N-1) conditions.

c. In Y-2018, more 230/400/500 kV circuit/transformers and shunt compensations were added for satisfactory operation under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 230/400/500 kV network. The maximum value was found to be <15 kA which is considered way below the typical 50/63 kA switchgear for this voltage level. Therefore, the 230/400/500 kV system would not experience any switchgear short circuit rating problems.

A few angle oscillations were found in Y-2018 cases which could be overcome by possible load shedding or installing power system stabilizers. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.5 Kenya

The interconnection of the Kenyan system within the EAPP/EAC project would be via Lessos-220 kV to Uganda, Isinya-400 kV to Tanzania and Longonot-500 kV (HVDC) to Ethiopia. System studies will be performed using the full system case, however, only the 220 kV and above network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Kenyan System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (80 MW export to Uganda) and 2018 (344 MW import from Ethiopia and 26 MW import from Tanzania).

b. In both Y-2013 and Y-2018, many new lines/transformers and shunt compensations were added for satisfactory operation of the 220 and 400 kV network under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 220/400 kV network. The maximum value was found to be <15 kA which is considered way below the typical 50/63 kA switchgear for this voltage level. Therefore, the 220/400 kV system would not experience any switchgear short circuit rating problems.

A few angle oscillations were found in both Y-2013 and Y-2018 cases which could be overcome by possible load shedding or installing power system stabilizers. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.6 Sudan

The interconnection of the Sudanese system within the EAPP/EAC project would be via Gedaref-220 kV and Kosti-500 kV to Ethiopia and Kosti-500 kV to Egypt. System studies will be performed using the full system case, however, only the 220/500 kV network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Sudanese System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (200 MW import from Ethiopia) and 2018 (2730 MW import from Ethiopia and 2000 MW export to Egypt).

b. In Y-2013, four 220/500 kV circuits/transformers in addition to one shunt compensation were added for satisfactory operation under (N-0) and (N-1) conditions.

c. In Y-2018, five 220 kV circuit/transformers and many shunt compensations were added for satisfactory operation under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 220/500 kV network. The maximum value was found to be <15 kA which is considered way below the typical 50/63 kA switchgear for this voltage level. Therefore, the 220/500 kV system would not experience any switchgear short circuit rating problems.

No stability problems were found in Y-2013 or Y-2018 cases. In some cases, small angle oscillations were found which could be overcome by possible load shedding or installing power system stabilizers.Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.7 Tanzania

The interconnection of the Tanzanian system within the EAPP/EAC project would be most likely via Arusha to Kenya, Shinyanga to Uganda and Mbeya to Zambia. System studies will be performed using the full system case, however, only the 220/400 kV network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Tanzanian System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (0.0 MW exchange) and 2018 (95 MW export to Kenya).

b. Starting from Y-2013, the new 400 kV network was considered on the top of the existing 220 kV network through the path Iringa – Dodoma – Singida. By Y-2018, the 400 kV network would expand to include more 400 kV lines.

c. In Y-2018, the performance of the system under both (N-0) and (N-1) conditions is satisfactory.

Three-phase short circuit calculations based on the classical assumptions were performed for the 220/400 kV network. The maximum value was found to be <10 kA which is considered way below the typical 50/63 kA switchgear for this voltage level. Therefore, the 220/400 kV system would not experience any switchgear short circuit rating problems.

No stability problems were found in Y-2013 or Y-2018 cases. In some cases, small angle oscillations were found which could be overcome by possible load shedding or installing power system stabilizers. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.4.8 Uganda

The interconnection of the Ugandan system within the EAPP/EAC project would be via Toro-132/220 kV to Kenya, MSKW-132 kV to Tanzania and Mirama-132 to Rwanda. System studies will be performed using the full system case, however, only the 132 kV and above network will be monitored.

The following conclusions can be drawn based on the load flow analysis of the 2013 and 2018 peak load cases of the Ugandan System:

a. The performance of the existing system under steady state (N-0) and contingency (N-1) conditions is satisfactory for both years 2013 (80 MW import from Kenya and 38 MW export to Tanzania) and 2018 (80 MW import from Kenya, import 59 MW from Tanzania and export 133 MW to Rwanda).

b. In both Y-2013 and Y-2018, many new/upgraded lines and shunt compensations were added for satisfactory operation of the 132/220 kV network under (N-0) and (N-1) conditions.

Three-phase short circuit calculations based on the classical assumptions were performed for the 132/220 kV network. The maximum value was found to be <15 kA which is considered way below the typical 50/63 kA switchgear for this voltage level. Therefore, the 132/220 kV system would not experience any switchgear short circuit rating problems.

No stability problems were found in Y-2013 or Y-2018 cases. Detailed results regarding load flow, short-circuit and stability studies can be found in the main report WBS 2100.

8.5 The Horizon Year – Vision 2038

8.5.1 Burundi, Eastern DRC, Rwanda

The adopted 220 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 70/110/220 kV substations with a defined firm capacity (e.g. 200-300 MVA).

8.5.2 Djibouti

The adopted 63/230 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 63/230 kV substations with a defined firm capacity (e.g. 100-150 MVA).

8.5.3 Egypt

With the system expansion, it is possible that the 500 kV network would become very dense which may result in technical problems, such as short circuit level. As the 500 kV network would become the backbone of the Egyptian System, it would be possible to divide it into zones connected by a higher level grid composed of both AC network at a higher voltage level (e.g. 765 kV) and HVDC lines.

8.5.4 Ethiopia

The adopted 400/500 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 230/400/500 kV substations with a defined firm capacity (e.g. 500-750 MVA).

8.5.5 Kenya

The adopted 400 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 220/400 kV substations with a defined firm capacity (e.g. 500-750 MVA).

8.5.6 Sudan

The adopted 500 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 220/500 kV substations with a defined firm capacity (e.g. 500-750 MVA).

8.5.7 Tanzania

The adopted 400 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers similar to Dar es Salaam would be divided in multiple 400/220 kV substations with a defined firm capacity (e.g. 500 MVA).

8.5.8 Uganda

The adopted 220 kV voltage level was found to be adequate and can still handle more load levels beyond the horizon year of 2038. Large load centers would be divided in multiple 132/220 kV substations with a defined firm capacity (e.g. 200-300 MVA).

9 ENVIRONMENTAL IMPACT ASSESSMENT (WBS 2200)

The development of the interconnections that will facilitate the implementation of the EAPP/EAC will incorporate construction through open spaces and, potentially, populated areas. The high voltage transmission lines will require construction of: foundations, suspension towers, conductors and insulators, together with associated fittings, accessories and diagnostics.

Transmission lines have the potential to affect the environment in many ways and the impacts can differ greatly between projects and sites. The length of a transmission line will depend upon the requirements for the supply and delivery of electricity and therefore the zone of influence will be very project specific with regard to the Environmental and Social Impact Assessment (ESIA).

For each interconnection project, an ESIA will be required to accurately and objectively examine the potential environmental and social risks and impacts of any such project within the context of the particular zone of influence. Good industry practice would see the ESIA undertaken early in the planning stages of the project such that the mitigation of any potentially significant impacts can be, as far as is practical, incorporated into the project design.

Scoping is a process by which agreement upon the Terms of Reference (ToR) of the ESIA is sought from all relevant authorities and stakeholders, including potentially affected communities. We have presented in this report a 'scoping level' discussion on the potentially significant environmental and social risks and impacts associated with the development of large-scale transmission projects. These are:

- Soils and Geology
- Water Environment
- Air Quality
- Ecology
- Noise
- Land Use
- Socio-Economics
- Health and Safety
- Cultural Heritage
- Electromagnetic Fields

Early consultation is essential for a good scoping process in order to satisfy all such parties that the full ESIA will present a comprehensive analysis of a project; adding the benefit of local knowledge to the industry standard assessments. Allowing affected communities the opportunity to have their comments, questions or concerns addressed increases public confidence in, and acceptance of, the ESIA process.

10 COST ESTIMATES AND IMPLEMENTATION SCHEDULES (WBS 2300)

Cost estimates are provided for the recommended projects (see WBS 1300) as follows:

- Engineering, Procurement and Construction (EPC) Costs
- Full project costs including Contingency and Interest During Construction (IDC)
- Division of the project cost to identify amount to be spent in foreign and local currency

Recent projects involving 500 kV and 765 kV HVAC interconnections as well as the Gulf Corporation Council Interconnection involving 220 kV and 400 kV transmission facilities were used as an indicator to determine costs for the HVAC transmission. For the HVDC transmission costs from the Ethiopia-Kenya Interconnection Project by Fichtner in May 2009 and the Nile Basin Initiative by EDF & Wilson Scott in December 2008 were used. The costs provided in this report are based on 2010 numbers and no escalation has been included. All costs presented are best estimates based on current market conditions and are subject to changing economic trends.

10.1 Generation Projects

The costs for all hydro, thermal and wind generation projects selected by the NGP_RIP are presented in section 3 of the Main report. These costs are calculated including IDC, escalation to 2009 MUSD to harmonize all project costs at the same year and environmental mitigation.

10.2 Transmission Lines

The transmission line costs are based on the quantity of line materials, unit costs of these materials and the cost of construction, as well as conditions of the right-of way.
For HVDC technology, the conductor chosen is 4-Pheasant (4 x 726 mm^2). Two voltage levels are proposed in this study; 500 kV and 600 kV.

For the HVAC technology the following characteristics of the transmission line are assumed:

Voltage level (kV)	220	400	500
Conductor	2-Drake ACSR (468.6 mm^2)	4-Flint AAAC (375.4 mm2)	4-Flint AAAC (375.4 mm2)

10.2.1 Substations

The substation costs are based on connections to existing substations that would involve modification to existing structures. This includes additional circuit breakers and other required substation equipment at each line end.

10.2.2 Convertors

These costs are based on a complete turnkey contract for the convertor stations including supply, delivery, installation and site leveling and preparation. The main components included are the convertor and the HVDC transformer.

10.2.3 EC Project Costs

The following table provides a breakdown of the costs for transmission lines, substations and convertors for the recommended projects.

Table 10-1 EPC

		km	Year	Transmission	Substations	Convertors	Total
				US $ Million	US $ Million	US $ Million	US $ Million
1	Tanzania-Kenya 400 kV - 2 Circuits	260	2015	104	13		**117**
2	Tanzania-Uganda - 220 kV-2 Circuits	85	2023	20	10		**30**
3	Uganda-Kenya 220 kV 2 Circuits	254	2023	61	10		**71**
4	Ethiopia-Kenya 500 kV-DC-bipole	1120	2016	309	13	524	**846**
5	Ethiopia-Sudan 500 kV - 2 Circuit	570	2016	239	16		**255**
	Ethiopia-Sudan 500 kV - 2 Circuit	570	2016	239	16		**255**
6	Egypt-Sudan 600 kV-DC bipole	1665	2016	483	16	535	**1034**
7	Ethiopia-Kenya 500 kV-DC-bipole	1120	2020	309	13	524	**846**
8	Ethiopia-Sudan 500 kV - 2 Circuit	544	2020	239	16		**255**
9	Egypt-Sudan 600kV-DC bipole	1665	2020	483	16	535	**1034**
10	Ethiopia-Sudan 500 kV - 2 Circuit	544	2025	239	16		**255**
11	Egypt-Sudan 600kV-DC bipole	1665	2025	483	16	535	**1034**
	TOTAL						**6032**

10.2.4 Total Project Costs

The table below provides a breakdown of the total project costs including contingency and IDC for each of the projects.

Table 10-2 Total Project Costs

		km	Year	EPC	Contingency	IDC	Total
1	Tanzania-Kenya 400kV - 2 Circuits	260	2015	117	12	6	135
2	Tanzania-Uganda - 220 kV-2 Circuits	85	2023	30	3	1	34
3	Uganda-Kenya 220kV 2 Circuits	254	2023	71	7	4	82
4	Ethiopia-Kenya 500kV-DC-bipole	1120	2016	846	85	79	1010
5	Ethiopia-Sudan 500 kV - 2 Circuit	570	2016	255	25	24	304
	Ethiopia-Sudan 500 kV - 2 Circuit	570	2016	255	25	24	304
6	Egypt-Sudan 600kV-DC bipole	1665	2016	1034	103	97	1234
7	Ethiopia-Kenya 500kV-DC-bipole	1120	2020	846	85	79	1010
8	Ethiopia-Sudan 500 kV - 2 Circuit	544	2020	255	25	24	304
9	Egypt-Sudan 600kV-DC bipole	1665	2020	1034	103	97	1234
10	Ethiopia-Sudan 500 kV - 2 Circuit	544	2025	255	25	24	304
11	Egypt-Sudan 600kV-DC bipole	1665	2025	1034	103	97	1234
	TOTAL			**6032**	**601**	**556**	**7189**

Note: The environmental impact costs have not been included because mitigation costs would be specific to the areas impacted by the line route and at this stage the lines have been identified at a high level with no routing details. A full environmental impact assessment (EIA) would need to be done once the routing of the lines have been defined. An EIA is typically 0.1% of the total project cost.

Contingency and IDC was calculated as follows:

- Contingency – 10% of EPC Costs.

- IDC – estimate using a nominal interest rate of 5% and a construction schedule as follows:
  - Project 1 – 3 years
  - Project 2 – 2 years
  - Project 3 – 3 years
  - Projects 4-11 – 4 years

10.2.5 Project Implementation Schedules

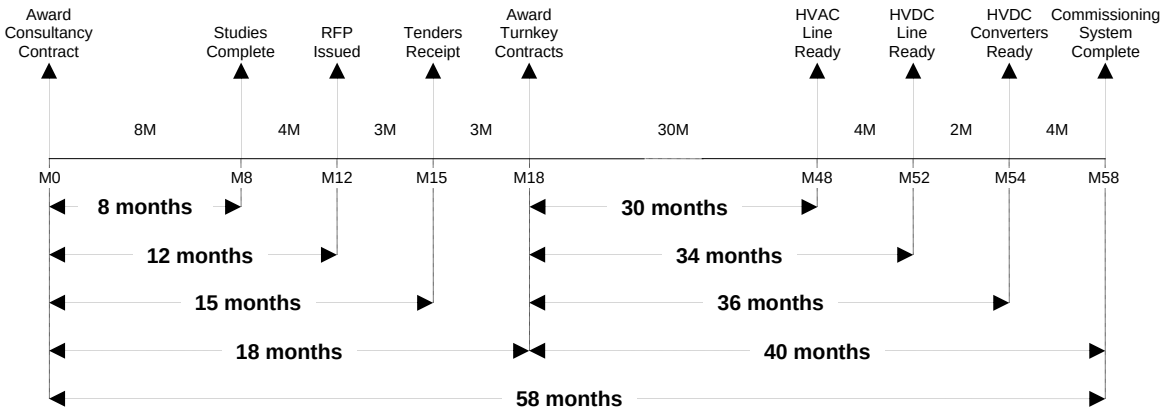
This section presents the typical project implementation schedules for the different types of interconnection projects.

Detailed and specific schedules for each project should be developed further before start-up of the projects.

10.2.6 Typical Sequence of Milestones

The figure below illustrates the typical sequence of key milestones up to completion of commissioning works and without including warranty period or performance guarantee period which may vary from one to three years for such project.

Figure 10-1 Typical Sequence of Milestones



10.2.7 Typical Implementation Schedules

Typical implementation schedules for different components and types of projects are included in the main report. These include

- 500 kV/600 kV HVDC Converter Stations and HVDC Transmission Line
- 500 HVAC Transmission Line

11 ECONOMIC AND FINANCIAL ANALYSIS – RISKS AND BENEFITS (WBS 2500)

11.1 Objectives

In WBS 1300, 11 different interconnection projects were identified for the next phase of the study. The economic and financial viability of the projects was studied by evaluating different economic and financial indicators such as Benefit/Cost Ratio (BCR), Net Present Value (NPV) and Internal Rate of Return (IRR).

These projects are listed in Table 11-1.

Table 11-1 Identified Interconnection Projects

#	Connecting	Voltage (kV)	Capacity (MW)	Date
1	Tanzania-Kenya	400	1520	2015
2	Tanzania-Uganda	220	700	2023
3	Uganda-Kenya	220	440	2023
4	Ethiopia-Kenya	DC 500	2000	2016
5	Ethiopia-Sudan	500	2 x 1600	2016
6	Egypt-Sudan	DC 600	2000	2016
7	Ethiopia-Kenya	DC 500	2000	2020
8	Ethiopia-Sudan	500	1600	2020
9	Egypt-Sudan	DC 600	2000	2020
10	Ethiopia-Sudan	500	1600	2025
11	Egypt-Sudan	DC 600	2000	2025

A 12th project was identified as the combination of projects 2 and 3 into one single project as they had a similar purpose and the same entry date (2023).

An additional objective of this WBS was to analyze risks involved with the project and propose the mitigation measures.

11.2 Economic Evaluation of Interconnection Projects

Economic evaluation of projects was achieved by inspecting the following indicators:

- Benefit-Cost Ratio (BCR)
- Economic Internal Rate of Return (EIRR) in %
- Economic Net Present Value (ENPV) in MUSD

Inputs and assumptions for the economic study included:

- Discount Rate = 10%
- Project Lifetime = 30 years
- Price Reference Year: 2010
- Currency: USD
- Project investment costs with disbursement schedule
- O&M Costs of the Lines (2% for all projects)

- Total Operating Cost Savings of the 10 Power Systems

Data for project costs were provided in WBS 2300 and Table 11-2 summarizes these costs in addition to the disbursement schedule in %:

Table 11-2 Capital Cost of Interconnection Projects

#	Connecting	Capital Cost (MUSD)	Date	Start of Construction	Disbursement (%)			
1	Tanzania-Kenya	117	2015	2012	50	25	25	
2	Tanzania-Uganda	30	2023	2021	60	40		
3	Uganda-Kenya	71	2023	2020	50	25	25	
4	Ethiopia-Kenya	845	2016	2012	40	20	20	20
5	Ethiopia-Sudan	511	2016	2012	40	20	20	20
6	Egypt-Sudan	1,034	2016	2012	40	20	20	20
7	Ethiopia-Kenya	845	2020	2016	40	20	20	20
8	Ethiopia-Sudan	255	2020	2016	40	20	20	20
9	Egypt-Sudan	1,034	2020	2016	40	20	20	20
10	Ethiopia-Sudan	255	2025	2021	40	20	20	20
11	Egypt-Sudan	1,034	2025	2021	40	20	20	20
12	Uganda-Tanzania/Kenya	101	2023	2020	39	33	28	

Operating cost savings were calculated by simulating the entire system with and without a certain interconnection project and comparing the operating costs such as fuel cost and O&M of plants as well as deficit costs. The NPVs of operating cost savings for each project discounted to 2013 (first year of the study) are listed in Table 11-3.

Table 11-3 NPV of Operating Cost Savings

#	Connecting	Capital Cost (MUSD)	Operating Cost Savings (MUSD)
1	Tanzania-Kenya	117	1,081
2	Tanzania-Uganda	30	18
3	Uganda-Kenya	71	24
4	Ethiopia-Kenya	845	1,205
5	Ethiopia-Sudan	511	6,087
6	Egypt-Sudan	1,034	10,156
7	Ethiopia-Kenya	845	426
8	Ethiopia-Sudan	255	620
9	Egypt-Sudan	1,034	4,714
10	Ethiopia-Sudan	255	308

#	Connecting	Capital Cost (MUSD)	Operating Cost Savings (MUSD)
11	Egypt-Sudan	1,034	2,191
12	Uganda-Tanzania/Kenya	101	134

With all the inputs and economic parameters at hand the results of the economic analysis were as follows in Table 11-4.

Table 11-4 Economic Analysis Results

#	Connecting	B/C Ratio	ENPV (MUSD)	EIRR (%)
1	Tanzania-Kenya	8.48	788	43.5%
2	Tanzania-Uganda	1.20	2	12.1%
3	Uganda-Kenya	0.68	-10	6.7%
4	Ethiopia-Kenya	1.37	270	15.3%
5	Ethiopia-Sudan	11.47	4,592	87.4%
6	Egypt-Sudan	9.45	7,506	71.4%
7	Ethiopia-Kenya	0.71	-144	7.1%
8	Ethiopia-Sudan	3.42	363	32.6%
9	Egypt-Sudan	6.42	3,289	47.8%
10	Ethiopia-Sudan	2.74	162	20.8%
11	Egypt-Sudan	4.81	1,434	45.5%
12	Uganda-Tanzania/Kenya	2.65	69	18.5%

Results showed that most of the projects were economically viable with BCR greater than 1 (ENPV greater than 0) and EIRR greater than the discount rate of 10%. However two projects (3 and 7) had a BCR less than 1 and an EIRR smaller than the discount rate. Project 3 was also examined as part of project 12, joint with project 2 since they had a similar purpose (transmit power from the south of EAPP/EAC to Kenya) and the same entry date (2023). That joint project had positive results with a BCR of 2.65 and an EIRR of 18.5%.

Concerning project 7, it's a project to be examined in detail in relation with P4 in terms of the capacity size and timing. A request has been received to carry out additional analyses on the interconnection between Kenya and Ethiopia. The analysis and results will be included in a separate report.

Sensitivity analyses were conducted on all 12 projects testing the following:

- Discount Rate: +/- 2%
- Capital Cost: +/- 10%
- Benefits: +/- 10%
- Project Completion Date: Delayed by 3 years.

Results for all these sensitivities are in the report. The main conclusions were:

- Most of the project are robust enough to still be economically viable in spite of unfavorable changes in some of the inputs and parameters (increased capital cost, reduced benefits, increased discount rate.
- Projects 3 and 7 remain unviable even when benefits increase or capital costs decrease.

11.3 Financial Analysis

Financial evaluation of projects was performed by inspecting the following:

- Annual Required Revenue (ARR) in MUSD
- Financial Net Present Value (FNPV) in MUSD
- Financial Internal Rate of Return (FIRR) in %
- Payback Time in years
- Levelized Tariff in c/kWh

To calculate the above mentioned financial indicators, the financial model used in this study relied on the following inputs and assumptions:

- Transmitted Energy in GWh through each line for the entire study horizon;
- Capital costs and disbursement schedules, along with O&M costs presented earlier;
- Debt/Equity Ratio of 70:30;
- Loan information: Interest rate 7%, 3 years of grace period, 12 years repayment period;
- Rate of Return on Equity (RORE) of 20%
- Corporate Tax Rate of 35%;
- Inflation Rate of 3% used to escalate costs and tariffs;
- Project Lifetime of 30 years; and
- Weighted Average Cost of Capital (WACC) = 9.19% (Calculation details in the report).

Using the inflation rate of 3%, investment costs were escalated to the disbursement years. Interest during construction (IDC) was added as well. Table 11-5 shows the total escalated capital costs of projects escalated including the IDC:

Table 11-5 Escalated Project Capital Costs with IDC

	Project #												
(MUSD)	**Total (excl. #12)**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Capital Costs excl. Inflation and IDC	6,032	117	30	71	845	511	1,034	845	255	1,034	255	1,034	101
Escalation	1,356	10	12	27	84	51	103	201	61	246	111	450	39
IDC	969	13	3	10	123	74	151	139	42	170	49	196	13
Total Capital Costs	8,357	140	45	108	1,053	636	1,288	1,185	358	1,449	415	1,680	153

Feeding all the inputs and assumptions into the financial model, the results of the financial evaluation turned out as such, in Table 11-6.

Table 11-6 Financial Analysis Results

#	Connecting	ARR (MUSD)	FNPV (MUSD)	FIRR (%)	Payback Time (Year)	Levelized tariff ($/kWh)
1	Tanzania-Kenya	154	6.50	9.86%	7	0.005
2	Tanzania-Uganda	24	2.15	10.72%	7	0.009
3	Uganda-Kenya	55	2.47	9.86%	7	0.015
4	Ethiopia-Kenya	1,042	3.50	9.23%	7	0.029
5	Ethiopia-Sudan	629	2.11	9.23%	7	0.007
6	Egypt-Sudan	1,274	4.28	9.23%	7	0.016
7	Ethiopia-Kenya	801	2.77	9.23%	7	0.024
8	Ethiopia-Sudan	979	0.84	9.23%	7	0.011
9	Egypt-Sudan	979	3.39	9.23%	7	0.021
10	Ethiopia-Sudan	174	0.63	9.23%	7	0.014
11	Egypt-Sudan	705	2.53	9.23%	7	0.029
12	Uganda-Tanzania/Kenya	79	4.62	10.09%	7	0.013

It should be noted that the levelized tariff in this analysis only provides a benchmark for the transmission tariff or transmission wheeling charge formulation for negotiation purposes. The actual transmission tariff should also consider the cost of supply and market situation in the participating countries.

All projects have a payback time of 7 years which is much less than the project lifetime of 30 years and the loan repayment period of 12 years. In addition, the FNPV is positive and the FIRR is greater than the WACC of 9.19%. Hence they are all financially viable.

Sensitivity analyses were conducted on all 12 projects testing the following:

- Capital Cost: +/- 10%
- Energy Transmitted: +/-20%
- Project Completion date: Delayed by 3 years
- Rate of Return on Equity: +/- 10%
- Interest Rate +/- 2%
- Inflation Rate: +/- 2%

Results for all these sensitivities are in the report. The main conclusion of these sensitivities was that all projects remained financially viable with a payback time significantly less than the project lifetime, an FIRR greater than the WACC and an FNPV which was positive.

11.4 Other Benefits and Returns

There were some benefits that were not considered in the analysis. If taken into consideration the benefits would improve the results and render the projects more viable economically. Those include but are not limited to:

- Reduction in GHG emissions through the displacement of fossil-fuel generation by renewable energy
- Benefits arising from regional coordination in generation planning such as displacing fossil-fuel additions which leads to further reduction in GHG emissions.
- Expenditures, jobs and income created by interconnection projects

11.5 Risk Analysis and Mitigation Measures

The major risks associated with these projects were identified as:

i. Design misspecification;

ii. Construction risks including cost overruns, completion delay and/or failure to meet the performance criteria at completion;

iii. Operating costs including cost overruns, variation demand from the demand forecast, equipment performance and/or power supply deficiencies;

iv. Environmental risks to obtain permits the permitting and acquire land as well as resettlement issues

v. Commercial and counterpart risks

vi. Financial risks such as failure to raise required finance; and

vii. Political risks.

These risks and the associated mitigation measures are distributed among:

a) The Project Company

b) The Utility

c) The Construction Company

d) The Supplier/Contractor

e) The Public Sector

f) The Insurer/Government guarantees.

A table in the report explains each of these risks, allocating them to the responsible party and presents the required mitigation measures.

12 INVESTMENT PLAN (WBS 2600)

The least cost development plan for the study period has been derived from the results of the generation planning and transmission/interconnection study activities, economic and financial evaluation, and the strategic environmental impact assessment as well as the risk evaluation and mitigation.

Table 12-1 presents the generation investment plan by country in 5 year-blocks taking into account all hydro, thermal and wind generation projects selected by the NGP_RIP. The numbers are all in constant 2009 MUSD prices, including IDC:

Table 12-1 5-year Total Generation Investment Plan

Country	*Total Investment Cost (MUSD)*	*2009-2013*	*2014-2018*	*2019-2023*	*2024-2028*	*2029-2033*	*2034-2038*
Burundi	1,106.76	32.85	221.15	289.00	122.58	296.68	144.50
Djibouti	451.31	95.51	172.11	78.54	13.87	85.74	5.54
Eastern DRC	1,611.46	59.12	361.32	656.27	534.75	0.00	0.00
Egypt	163,119.46	14,031.85	27,408.25	30,826.09	34,541.49	37,438.41	18,756.77
Ethiopia	28,122.00	1,933.21	3,435.50	2,272.88	5,802.56	8,337.79	6,340.07
Kenya	37,642.83	4,022.16	3,674.23	5,260.85	7,344.28	8,816.80	8,431.33
Rwanda	2,241.20	361.30	0.00	202.30	289.00	1,015.60	373.00
Sudan	23,518.74	242.22	3,914.08	8,143.40	4,247.52	4,756.41	2,215.11
Tanzania	16,674.33	1,524.66	2,205.77	2,011.54	3,018.69	5,952.87	1,960.80
Uganda	6,265.78	574.04	929.12	373.26	2,723.01	1,205.17	461.18
Total EAPP/EAC Region	***280,753.87***	***22,876.91***	***42,321.53***	***50,114.13***	***58,637.75***	***67,905.48***	***38,688.29***

Table 12-2 sets out the capital cost required for each interconnection project in US$ (millions) together with the commissioning year.

Table 12-2 Capital Cost Required for Interconnector projects

	From	To	Commissioning Year	Capital Cost (US$m.)
Project 1	Tanzania	Kenya	2015	117
Project 2	Tanzania	Uganda	2023	30
Project 3	Uganda	Kenya	2023	71
Project 4	Kenya	Ethiopia	2016	845
Project 5	Ethiopia	Sudan	2016	511
Project 6	Sudan	Egypt	2016	1034
Project 7	Kenya	Ethiopia	2020	845
Project 8	Ethiopia	Sudan	2020	255
Project 9	Sudan	Egypt	2020	1034
Project 10	Ethiopia	Sudan	2025	255
Project 11	Sudan	Egypt	2025	1034
Project 12	Uganda	Kenya & Tanzania	2023	101
Total				**6031**

Table 12-3 details the investment required for the interconnector projects together with the expected disbursement. With Projects 2 & 3 combined to create Project 12, the total capital cost required adds up to US$ 8,357 million. This amount is made up of US$ 6,032 million for capital expenditure, US$ 969 million for IDC and US$ 1,356 million allowance for price escalation.

Table 12-3 Investment required for interconnection projects

Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Project 1	**140**			**64**	**36**	**39**											
Capex	*117*			*59*	*29*	*29*											
IDC	*13*			*2*	*4*	*6*											
Escalation	*10*			*4*	*3*	*4*											
Project 4	**1,053**			**372**	**210**	**227**	**244**										
Capex	*845*			*338*	*169*	*169*	*169*										
IDC	*123*			*13*	*25*	*36*	*48*										
Escalation	*84*			*21*	*16*	*21*	*27*										
Project 5	**636**			**225**	**127**	**137**	**148**										
Capex	*511*			*204*	*102*	*102*	*102*										
IDC	*74*			*8*	*15*	*22*	*29*										
Escalation	*51*			*12*	*9*	*13*	*16*										
Project 6	**1,288**			**455**	**257**	**277**	**299**										
Capex	*1,034*			*414*	*207*	*207*	*207*										
IDC	*151*			*16*	*31*	*44*	*59*										
Escalation	*103*			*25*	*19*	*26*	*33*										
Project 7	**1,185**							**418**	**236**	**255**	**275**						
Capex	*845*							*338*	*169*	*169*	*169*						
IDC	*139*							*15*	*28*	*41*	*54*						
Escalation	*201*							*66*	*39*	*45*	*52*						
Project 8	**358**							**126**	**71**	**77**	**83**						
Capex	*255*							*102*	*51*	*51*	*51*						
IDC	*42*							*4*	*9*	*12*	*16*						
Escalation	*61*							*20*	*12*	*14*	*16*						
Project 9	**1,449**							**512**	**289**	**312**	**336**						
Capex	*1,034*							*414*	*207*	*207*	*207*						
IDC	*170*							*18*	*35*	*50*	*67*						
Escalation	*246*							*80*	*48*	*55*	*63*						
Project 10	**415**												**147**	**83**	**89**	**96**	
Capex	*255*												*102*	*51*	*51*	*51*	
IDC	*49*												*5*	*10*	*14*	*19*	
Escalation	*111*												*39*	*22*	*24*	*26*	
Project 11	**1,680**												**593**	**335**	**362**	**390**	
Capex	*1,034*												*414*	*207*	*207*	*207*	
IDC	*196*												*21*	*40*	*58*	*77*	
Escalation	*450*												*159*	*88*	*97*	*106*	
Project 12	**153**											**49**	**54**	**49**			
Capex	*101*											*36*	*36*	*30*			
IDC	*13*											*2*	*4*	*7*			
Escalation	*39*											*12*	*14*	*13*			
Total	**8,357**			**1,116**	**630**	**680**	**691**	**1,057**	**597**	**644**	**695**	**49**	**794**	**467**	**451**	**486**	
Capex	*6,032*			*1,015*	*507*	*507*	*478*	*854*	*427*	*427*	*427*	*36*	*552*	*288*	*258*	*258*	
IDC	*969*			*39*	*76*	*109*	*137*	*37*	*72*	*103*	*138*	*2*	*30*	*57*	*72*	*96*	
Escalation	*1,356*			*62*	*47*	*64*	*76*	*166*	*98*	*114*	*130*	*12*	*212*	*123*	*121*	*132*	

Table 12-4 shows the total investment required for the interconnection projects in 5 year blocks in US$ million inclusive of capital cost, IDC and price escalation. The total values amount to US$ 1,746 million for the period 2009 to 2013, US$ 3,669 million between 2014 and 2018, US$ 2,546 million for the third 5 years period (2019 to 2023) and finally US$ 486 million for the period 2024 to 2028. All feasible interconnection projects investigated in this study will have been developed by then and hence the table does not show any capital expenditure for the 2 5 years periods 2029-2033 and 2034-2038.

Table 12-4 Capital expenditure in 5 year blocks in US$ million

	2009 - 2013	2014 - 2018	2019 - 2023	2024 - 2028	2029 - 2033	2034 - 2038
Capex	1,522	2,693	1,560	258		
IDC	115	458	299	96		
Escalation	109	518	598	132		
Total	**1,746**	**3,669**	**2,456**	**486**		

13 INSTITUTIONAL AND TARIFF ASPECTS (WBS 2700)

13.1 Institutional Aspects

Only Egypt, Uganda and Kenya have previous experience of operating international interconnectors (ignoring the lower voltage cross border supplies between Tanzania - Kenya and Uganda - Rwanda). There is thus a considerable need for institutional strengthening covering interconnector operation and tariff negotiations in all member countries, with the probable exception of Egypt, Kenya and Uganda.

Many of the EAPP/EAC member countries are undertaking significant electrification programmes which may lead to considerable expansions in demand and rapid growth rates. The drawback of such electrification programmes is that these projects are likely to rely very heavily on official development assistance. Given the potential for high returns on investment in interconnector projects, these lower cost sources of funding may consider the interconnection projects as commercial ventures and thus be reluctant to release funding.

An additional competitor for funds in the region may be loss reduction measures. Given the high level of losses in some of the member countries, it is possible that donors will see loss reduction measures as a better investment than providing investment for connections to generation, much of which will be lost.

In general the countries considered have a high level of indigenous resources that should allow significant substitution for imported liquid fuels for at least the planning horizon.

With the exception of Egypt, tariffs in the rest of the Candidate countries are in general cost reflective and should thus present a level playing field for imports to compete against. Egypt has a plan to remove subsidies but, based upon history, the removal may take longer than expected.

The current structure in the participating countries is a mix of public and private ownership. The dominant consideration, however, is that all markets are of a single buyer status, such that there is no contestability and/or two way bidding systems. This implies that, unless the situation changes, contracts and import decisions will be on either a Government to Government basis or a utility to utility basis. This will most likely result in long term contracts being on a Government to Government basis with short term purchases and system operation devolving on the single buyer TSOs. There is thus the possibility of developing both a long term contracts market and a day ahead market since the TSOs will be in a good position to determine where non-contract purchases will fit in the next day's dispatch. The short term mechanism will be a very efficient tool for managing the gluts and overcoming shortages as hydro conditions vary throughout the region.

It should also be noted that all the Ministries have a positive attitude towards trade in the electricity sector, although the majority of them see it as a chance to earn foreign exchange by exporting rather than a chance to save fuel costs by importing and benefit from the mutual capacity support advantages. Thus, in the medium term, some of the countries maintain capacity margins above the required levels to maintain an isolated level of reliability. It is expected that, as the feasibility studies progress some of these advantages may become more apparent.

In general the market environment in the target countries is favourable to the establishment of interconnectors. Indeed many of the countries are pro-active with regard to development of electricity trade. Perhaps the only drawback is that, at present, there seems to be too many sellers and too few buyers although negotiations and the setting of suitable tariffs will ensure that economic trade takes place whenever possible. It should be noted that the conclusions for this analysis may have been very different if carried out 10 - 15 years ago, before considerable restructuring and the removal of subsidies on tariffs took place.

13.2 Financial Viability and Tariffs

The financing analysis includes the development of detailed financial accounts for each of the interconnector projects. These accounts are then used to derive a set of key financial indicators. These financial indicators provide a clear assessment of the ease with which the proposed projects could be financed.

In order to determine the financing viability of the each of the proposed interconnector projects we have returned to economic 'first principles'. To assist in the review of the financing viability of the proposed interconnector projects we have developed a series of fictitious companies (FC), one for each proposed interconnector project. It is assumed that each FC will buy energy from the seller at its 'production cost' and sell energy to the buyer at a price equal to their avoided costs of generation (both CAPEX and OPEX). Its financial base will consist of the loans to finance the transmission line and injections of equity by both buyer and seller to generate its liability base and match the assets of the transmission line (which it is assumed to own).

The creation of financial accounts for each FC provides a useful tool for analysing the viability of each proposed interconnector. If the present value of the cash flow of a particular FC is positive then it can be assumed that there are benefits to share between the parties from that particular interconnector. On this basis, the interconnector project may be judged against standard project benchmarks such as:

- Net Present Value (NPV),
- Internal Rate of Return (IRR),
- Return on Equity (RoE),
- Return on Capital (RoC), and,
- Debt Service Coverage Ratio (DSCR).

These benchmarks will allow for comparable project assessment and thus additionally allow for the determination of the viability of the interconnectors.

Having derived the financial accounts for the FC's, it is possible to determine the key financing indicators which can be used to determine the financing viability of the projects. These key ratios and statistics are presented in Table 13-1 below. Financing performance indicators that fall below their respective hurdles rates are highlighted in red.

Table 13-1 Key Financial ratios

Project	From	To	RoE		Project IRR		DSCR			RoC		
			IRR	NPV	IRR	NPV	Minimum	Average	Maximum	Minimum	Average	Maximum
Project 1	Tanzania	Kenya	60.5%	$743.01	41.0%	$715.53	0.37	12.12	19.31	-0.04	1.26	2.15
Project 2	Tanzania	Uganda	8.2%	-$4.11	6.0%	-$10.83	-0.44	1.02	5.16	-0.09	0.11	0.34
Project 3	Uganda	Kenya	3.2%	-$30.10	-0.4%	-$57.58	-0.48	0.18	2.25	-0.11	0.04	0.36
Project 4	Kenya	Ethiopia	26.3%	$305.64	7.4%	-$104.72	-0.35	1.66	4.40	-0.11	0.09	0.40
Project 5	Ethiopia	Sudan	141.3%	$4,756.83	86.2%	$4,608.49	3.68	19.01	38.69	0.24	1.23	4.39
Project 6	Sudan	Egypt	119.3%	$7,867.34	69.9%	$7,470.80	4.89	16.80	24.21	0.25	1.06	2.71
Project 7	Kenya	Ethiopia	4.6%	-$221.46	-0.7%	-$630.69	-0.06	0.78	1.61	-0.09	0.04	0.12
Project 8	Ethiopia	Sudan	56.9%	$513.89	28.9%	$413.20	0.75	3.58	6.65	0.01	0.43	0.72
Project 9	Sudan	Egypt	76.5%	$4,933.22	45.8%	$4,499.05	4.17	11.65	18.67	0.25	0.73	1.80
Project 10	Ethiopia	Sudan	26.6%	$349.94	17.5%	$246.21	0.64	3.92	8.19	-0.01	0.39	0.72
Project 11	Sudan	Egypt	81.7%	$3,375.23	42.8%	$2,917.69	3.09	6.35	10.94	0.23	0.55	1.12
Project 12	Uganda	Tanzania & Kenya	20.0%	$125.70	15.2%	$87.59	0.07	1.81	15.85	-0.06	0.43	1.18

Please note: "Minimum" stands for the minimum recorded value over the life of the project.
"Maximum" stands for the maximum recorded value over the life of the project.

Based on the financing analysis presented in Table 13-1, Projects 2 and 3 are not viable for financing. Not only do these two options show a negative RoE and Project NPV, but the key financing ratios (equity IRR, project IRR, DSRC and RoC) are all below their respective hurdle rates. The non-viability of Projects 2 and 3 is in-line with the economic and financial analysis which replaced these projects with a combined project 12 (which is shown to be viable for financing in our analysis). As such, on the basis of the input data assumed, dropping projects 2 and 3 in favour of project 12 seems reasonable.

It should also be noted that, under the assumptions used in this study, Project 7 (the second Kenya-Ethiopia interconnector) would not be viable for financing. All key financing ratios for Project 7 fall below their respective hurdle rates. Of the remaining projects, Project 4 would cause notable concern for would be financers due to low Project IRR indicators. Other financing performance indicators may, however, allay any fears that prospective financiers might have in financing this project. Projects 1, 5, 6 and 8-12 are shown to be in good financial health (although the debt service coverage ratio's of projects 1, 8, 10 and 12 may give rise to a need for some financial engineering in the form of multi year average DSCR targets).

Levelised cost based tariffs are likely to lead to an economically inefficient solution regarding the use of the lowest cost generation. For this reason, it is strongly recommended that levelised tariffs are not used for the proposed interconnector projects. It is strongly recommended that a tariff setting process is used rather than negotiating a set tariff level.

The underlying components of any proposed tariff setting process (and related tariff structure) are:

- Whenever it is economic for an energy flow to take place on the interconnector, the tariff should ensure that such a flow takes place.
- Both parties should be able to cover their operating costs as well as repayment of loan and interest, whilst obtaining a return on equity invested.

In addition to achieving these two criteria and obtaining an optimal use of resources, we must also consider the following issues:

- Each utility will pay its in country share of investment costs.
- There are benefits from the interconnector project for both buyer and seller
- Only consider those investments associated with the interconnector between point A and Point B (i.e. exclude sales over the interconnector within the exporting country).

The process and structure should also include the possibility of a variation in imported fuel prices making imports more, or less, attractive.

Such a process would:

- Determine tariffs annually depending on expected trade and a sharing of the difference between the supply costs and the avoided costs (after an allowance for loan repayments and the cost of operations and maintenance). If the difference was not sufficient to cover loan repayments and O&M costs, which may be regarded as sunk costs, then the tariff process would make sure the deficit was shared between the two parties. If the difference was sufficient to cover loan repayments and O&M costs then the tariff process would make sure that surplus was shared between the two parties. The method for splitting the surplus/deficit can be defined using a ratio split. As long as avoided costs are greater than the costs of supply, however, trading would take place, which is the economically sensible solution.

- Allow for adjustment of the tariffs and payment with the benefit of hindsight. Assumptions made at the beginning of the tariff period with regard to the benefits of sales of the tariff are likely to be inaccurate in terms of both volume of trade and specific benefits. This is a reflection of the uncertainties with regard to load forecasts, fuel prices and generator outages. As such any changes will affect both the benefits to be shared and the level of sales that the fixed costs (loan repayments and O&M costs) can be spread over. Thus in the first year of operation we would envisage a single meeting to set the tariffs for the first year of operation based upon the best available assumptions. Subsequent years would see the meeting covering both the setting of future tariffs and the determination of rebates for the previous year's operation. It is important that such rebates are presented as a fixed sum, rather than as an adjustment to the proposed tariff, to avoid distorting the despatch cost which has been developed to ensure transfer whenever it is economic.

Note that these recommendations only refer to utility to utility long term contracts, not to any day trading. Such a form of long term contract will, however, be essential if finance is to be secured. The process of tariff adjustment should be an integral part of the PPA between the countries.

14 PROJECT FUNDING (WBS 2800)

Capital and Investment Funds are, like all other goods, subject to conditions of supply and demand. It is on this basis that we analyse the financing of the development programme for the EAPP/EAC as defined above.

The report starts with a review of demand for funds in the electrical sector during the period up to 2015. This included the interconnections as well as the internal generation, transmission and distribution requirements for each country. This is because these projects will be competing for the funds that could be available for financing the interconnector project(s).

We then look at the possible 'demand side management' reduction in the funds available in terms of loss reduction, improved collections and improvements in operating practices.

This is followed by an analysis of the supply of funds available, which show quite clearly that Government and official development assistance (ODA) will not be sufficient to cover all capital requirements. It may also be the case that the timeline for raising ODA funds as well as the possible conditions attached to these funds may make private sector involvement desirable. This will require the injection of funds from the private sector to fund the program in full or a significant portion of it. The various methods of private sector involvement are defined with their strengths and weaknesses compared.

We finish by comparing possible timelines for the various sources of funding as well as presenting roadmaps for both public and private sector financing and actions that may mitigate delays.

Finally, the international market for private funds is extremely competitive and EAPP/EAC will have to be proactive to succeed in this market. We discuss the processes that will be required to facilitate the receipt of private funds for the EAPP/EAC.

It is almost certain that at least some of the proposed interconnectors will require private funding. This is due to either the lack of concessional funding or the relatively short time frame for completion of the initial projects. When considering private funding it is important to ensure that the tariff is based upon a reasonable return on capital and not on the profits of the interconnector. This will ensure that any economic rents are shared between the two countries interconnected and not taken by the developer.

Difficulties in obtaining private funding may arise from the relatively difficult and investor-unfriendly business environments in the member countries. This may be further compounded by variations in investment incentives. It may be worthwhile for the EAPP/EAC, as an organisation, to seek addressing these issues for electrical interconnections only. These issues include licensing, dispute resolution, guarantees against nationalisation, repatriation of profits etc. An investor's code, in effect, paralleling the grid code. We also recommend that the EAPP/EAC be charged with providing a one-stop shop for promoting investment in the EAPP/EAC interconnections rather than the individual member countries. As we have seen the member countries may well require significant private internal investment in their own electricity sector and will be concentrating on this aspect.

SNC-LAVALIN Inc.
T&D Division
1801 McGill College Ave.
Montreal, Quebec
Canada H3A 2N4
Tel.: (514) 393-1000
Fax: (514) 334-1446

www.snclavalin.com