ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

EDF – Generation and Engineering Division
73 373
Le Bourget du Lac Cedex
France
Tel: +33-4-79 60 60 28
Fax: +33-4-79 60 62 35
eMail: pierre.brun@edf.fr
http://www.edf.fr

AfDB

COORDINATED INVESTMENT PLANNING

Scott Wilson
Kanthack House, Station Road,
Ashford, Kent TN 23 1 PP
England
Tel: +44 (0) 1233 658200
Fax: +44 (0) 1233 658209
eMail: alan.bates@scottwilson.com
http://www.scottwilson.com

with participation of:

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

VOL 2 - GENERATION

FINAL REPORT

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PHYSICAL UNITS AND CONVERSION FACTORS

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

General Conversion Factors for Energy

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

ABBREVIATIONS AND ACRONYMS

ADB	African Development Bank
ADF	African Development Fund
CCGT	Combined Cycle Gas Turbine
CIDA	Canadian International Development Agency
DANIDA	Danish Development Assistance
DFID	Department for International Development (UK)
DIDC	Department for International Development Cooperation (GoF)
DSA	Daily Subsistence Allowance
EEHC	Egyptian Electric Holding Company
EEPCO	Ethiopian Electric Power Corporation
EHVAC	Extra High Voltage Alternating Current
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EN	Eastern Nile
ENCOM	Eastern Nile Council of Ministers
ENSAP	Eastern Nile Subsidiary Action Program
ENSAPT	Eastern Nile Subsidiary Action Program Team
ENTRO	Eastern Nile Technical Regional Office
ENTRO PCU	Eastern Nile Technical Regional Office Power Coordination
UnitEU	European Union
FIRR	Financial Internal Rate of Return
GEP	Generation Expansion Plan
GTZ	German Technical Co-operation
HPP	Hydro Power Plant
HFO	Heavy fuel oil
HVDC	High Voltage Direct Current
ICCON	International Consortium for Cooperation on the Nile
ICS	Interconnected System
IDEN	Integrated Development of the Eastern Nile
JICA	Japanese International Co-operation Agency
JMP	Joint Multipurpose Project
LNG	Liquefied Natural Gas

LOLP	Loss of Load Probability
LPG	Liquefied Petroleum Gas
MIWR	Ministry of Irrigation & Water Resources (Sudan)
MWR	Ministry of Water Resources (Ethiopian)
MWRI	Ministry of Water Resources and Irrigation (Egypt)
MSD	Medium speed diesel (TPP)
NBI	Nile Basin Initiative
NEC	National Electric Company (Sudan)
NELCOM	Nile Equatorial Lake Council of Ministers
NELSAP	Nile Equatorial Lake Subsidiary Action Program
NG	Natural Gas
NGO	Non Governmental Organization
NORAD	Norwegian Aid Development
NPV	Net Present Value
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
OPEC	Organisation of the Petroleum Exporting Countries
PBP	Pay Back Period
PHRD	Policy & Human Resource Development Fund
PIU	Project Implementation Unit
PRSP	Poverty Reduction Strategy Paper
RE	Rural Electrification
SAPP	Southern Africa Power Pool
SIDA	Swedish International Development Agency
SSD	Slow speed diesel (TPP)
STPP	Steam Turbine Power Plant
STS	Senior Technical Specialist
TAF	Technical Assistant Fund
TPP	Thermal Power Plant
UA	Unit of Account
UNDP	United Nations Development Program
WB	World Bank

1 OVERVIEW OF MODULE 6 VOLUME 2

1.1 OBJECTIVE OF MODULE 6

The overall objective of Module 6 is to evaluate the potential benefits for the region (Egypt, Ethiopia and Sudan) provided by an interconnection of the three power systems according to various level of integration (or coordination) of these systems.

Accordingly Module 6 will cover:

- the determination of least-cost generation expansion plan for the three isolated systems,
- the determination of least-cost generation expansion plan for the coordinated system,
- the determination of the least-cost interconnection option in term of technology,
- the transmission system analysis,
- the recommendation of a Regional Investment Program.

The present Volume 2 is focussed on the determination of the Generation Expansion Plans for the three isolated power systems and the coordinated system, the evaluation of the power exchanges and Economic Study.

1.2 METHODOLOGY

1.2.1 MINIMIZING REGIONAL COSTS

The potential benefits for the region resulting from the interconnection will be evaluated by the comparison of two situations:

S1: independent development of the three power systems assuming the presence of no interconnection, this situation would lead to the determination by the Consultant of one investment program for each power system: P_{Egypt}, $P_{Ethiopia}$, P_{Sudan}.

S2: combined development of the three power systems assuming the presence of an interconnection and various level of coordination between the power systems. This would lead to the determination by the Consultant of a coordinated investment program $P_{Intercon}$.

The potential benefits provided by the interconnection will be given by the difference of costs between these two situations:

$$\text{Benefits from the interconnection} = \text{Cost}\,[P_{Egypt}, P_{Ethiopia}, P_{Sudan}] - \text{Cost}\,[P_{Intercon}]$$

1.2.2 POWER POOL MODELS

Economic power exchanges take advantage of generation cost differences between the interconnected power systems in order to minimize the global regional generation cost : at any time, the demand is supplied from the lowest cost generation units available in the region (global merit order), within the limits of the interconnection capacity and possible operation constraints. The resulting power exchanges may vary in amount and direction according to the evolution of each power system (demand variation, hydrology variation, generation investments, etc).

In the present economic Study the amount of power trades between Egypt, Ethiopia and Sudan, and the resulting benefits for the region, will be assessed along two approaches (as per TOR) in order to cover a large range of possible situations: loose pool and tight pool models. These two models, described hereafter, can be understood as two different stages of power market development, or in other words, as two different levels of coordination between the power systems.

1.2.2.1 Loose Pool model: coordination of operation

The loose pool model refers to a scheme where the operation of the generation is coordinated regionally (either by direct coordination or through a power pool) while each country keeps its independence for the decision of generation investment. In other words, each country keeps its own generation expansion plan unchanged, and its ability to be self-sufficient and cover its own peak demand.

The loose pool model represents the first stage of development of a regional power market providing the relevant price signals for operation (spot market and market for forwards within the current year).

The generation investment cost of the region remains unchanged, while the operation cost (fuel savings) is reduced through regional coordination and the use of Ethiopian hydro surplus.

This approach is similar to the one carried out for the Ethiopia-Sudan interconnection Study (2005).

1.2.2.2 Tight pool model: coordination of operation and generation investments

The tight pool model could be understood as a fully integrated regional power system.

In this theoretical model, further to the operation which is regionally coordinated (as in the loose pool model), the generation investment decisions are also coordinated and optimised at a regional level allowing to take advantage of the countries complementary resources (low cost hydro generation in a country, low cost thermal generation in an other, etc).

Of course, even in this theoretical case, some part of the generation would be still dispatched on a non economic basis (e.g. irrigation), and the transmission and distribution network would set limits to amount of power exchanges possible between the different areas.

The tight model represents a highly developed power market providing the relevant price signal for:

- operation decisions: through a spot market and a forward market the actors could decide whether to buy/sell energy on the market or operate their own existing generation units,
- investment decisions: through a forward market with a medium term horizon (> 4 - 5 years), the actors could decide whether to contract now for energy to be delivered in n years, or to invest in new generation units of their own.

This regional operation and investment coordination would result in:

- operation cost savings : expensive fuel in one country would be substituted by lower cost generation fuel available in another country,

- investment savings : the commissioning of "expensive" plants in one country might be postponed if a corresponding less expensive capacity is available in another country.

1.2.2.3 Summary table

Model	Level of coordination	Generation Expansion Plans	Type of savings
Isolated systems	No coordination	GEP Egypt, GEP Ethiopia, GEP Sudan	Reference situation
Loose pool model	Operation	Same as above	Fuel costs
Tight pool model	Operation and investment	Updated GEP	Fuel costs and investment costs

Table 1.2-1 - Tight and loose pool models - Main characteristics

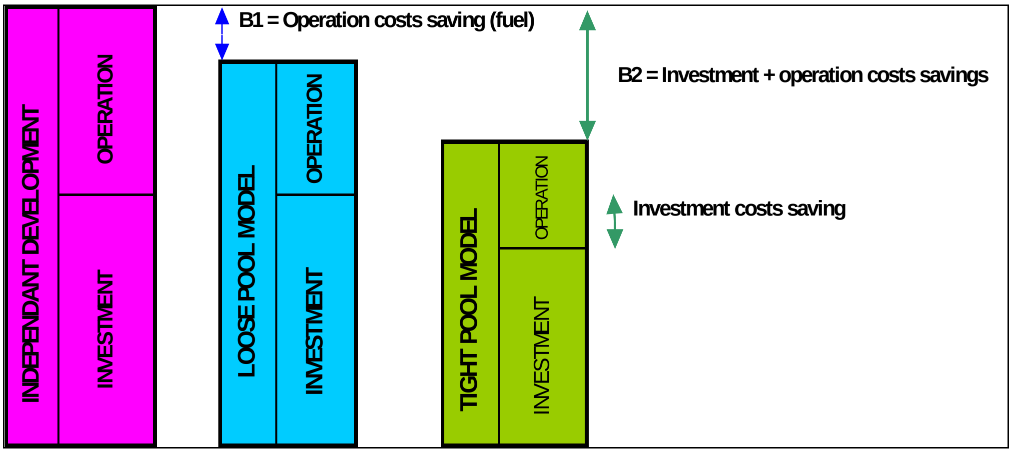

Figure 1.2-1 - Savings from tight and loose pool models

1.2.3 POINT OF VIEW OF THE ECONOMIC ANALYSIS

1.2.3.1 A cost approach

In the course of the Eastern Nile Power Trade Program Study, the point of view of the analysis starts from a regional view (Phase I) to progressively focus on the Interconnection project (Phase II). In the present Module 6, the point of view of the economic analysis is regional, meaning the objective is to measure the potential global benefit (in fact cost savings) for the region, and not the specific benefit for each country.

As per TOR, and according to good methodology, a cost approach[1] is carried out in the present economic Study, with the objective to determinate the least cost regional plan. The costs involved

[1] costs include externalities : non energetic benefits and mitigation costs

here are generation and interconnection investment costs, and the operation costs depending on the presence or not of the interconnection[2].

This means, for example, that the share of cost of projects (interconnection or HPP) between the different countries is not considered or relevant at this stage, because it does not change the global cost for the region. Subsidies to fuel, duties or taxes are not considered either because they don't change the cost paid by the countries to develop their generation mixes.

In the same way, the allocation of the benefits to the different stakeholders is not relevant at this stage. In other words, the possible selling price of power and wheeling tariff are not relevant in the present economic analysis[3].

In this way, the global benefits (i.e. the global cost reduction) for the region could be evaluated.

By contrast, the economic and financial analysis from the point of view of the interconnection project (Business Plan of the project) will be evaluated in Phase II of Eastern Nile Power Trade Program Study, while the economic and financial analysis from the point of view of the HPP projects are evaluated in the relevant pre-feasibility or feasibility studies.

1.2.3.2 Selling price of energy and sharing savings

In order to give more understanding on the cost approach, the relation between the selling price of energy, the generation cost of energy and the sharing of global savings can be illustrated by the following simple example:

Hypothesis:

Country A exports to country B one MWh generated at 40 $/MWh, which comes in substitution of 100 $/MWh generation in country B.

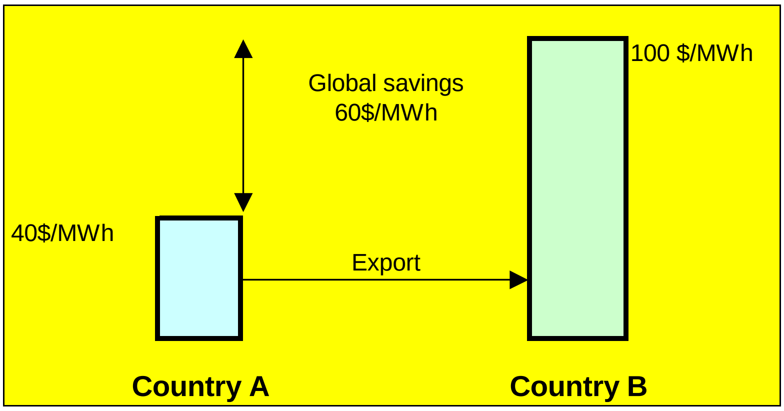

Figure 1.2-2 - Relation between savings and selling price (1)

Economic approach of the global savings:

In country A: the generation cost increases by 1 x 40 $.

In country B: the generation cost decreases by 1 x 100 $.

Global cost savings for A + B: 1 x 60 $.

[2] the costs independent of the presence or not of the interconnection are not relevant for the Study

[3] The selling price of energy would be relevant for the economic Study if the point of view of the analysis was from the Utilities.

<u>What are the savings for each country</u> ?

The savings for each country depend on how the global saving is shared between A and B, which is a result from the negotiation of selling price.

If the negotiated selling price is 70 $/MWh (savings shared 50% for each country):

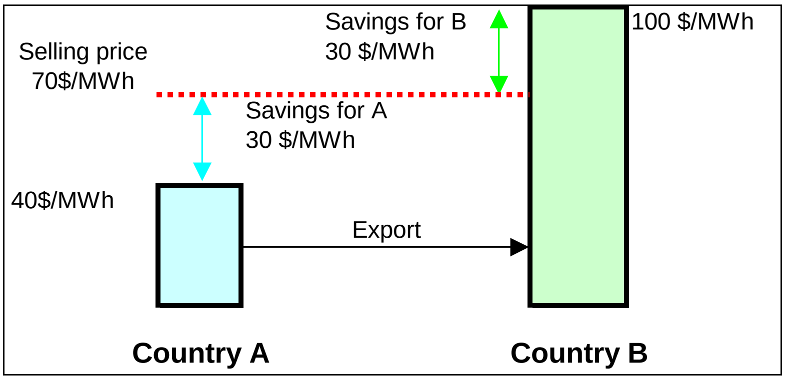

Figure 1.2-3 - Relation between savings and selling price (2)

- For country A: 100 $ generation is saved, 70 $ import is paid for import -> net savings = 30 $.

- For country B: 40 $ additional generation is paid, 70 $ is received from export ->net savings= 30$

The global saving is still 60 $, the value found by the cost approach.

<u>Conclusion</u>:

➔ the selling price of energy is a way of sharing the global cost savings between the actors.

➔ the net saving for each country depends on the negotiated selling prices:

Net savings for the importing country = Fuel savings – Selling price per MWh x Imported energy

Net savings for the exporting country = Selling price per MWh x Exported energy – Generation cost of the exported energy

1.3 COMPARISON OF GENERATION COSTS IN THE THREE POWER SYSTEMS

A first picture of the possible economic power exchanges in the region can be given though the comparison of the generation cost in the different power systems:

The comparison of economic costs of generation (also called levelized cost[4]) is pertinent when power trade are the result of new generation investments purposely decided in the exporting country to come in substitution of otherwise necessary (and more expensive) generation investments in the importing country.

[4] includes fixed (=investment + fixed O&M cost) and variable cost of generation

The comparison variable cost of generation[5] is pertinent when the investment decisions are not related to the power trade, but only to the demand development of each country, and available power is exported from one country to the other in substitution to more expensive generation.

The generation costs are evaluated on the basis of the market fuel price projection[6] (because the purpose of the Study is the evaluation of power exchanges – see Module 3 Vol 4,) which might be very different than the present fuel costs paid by the Utilities.

1.3.1 COMPARISON OF ECONOMIC COSTS OF GENERATION

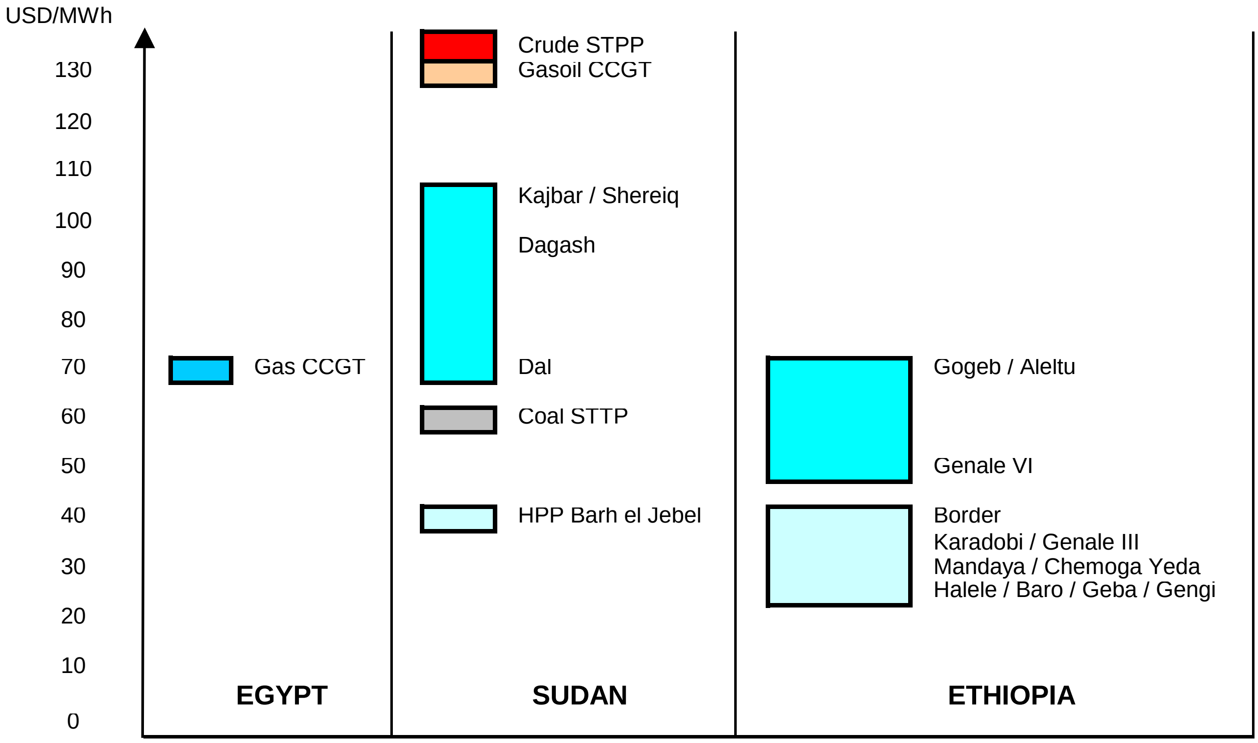

Figure 1.3-1 - Comparison of economic generation costs in the different generation mixes (6 000 hours/ year) - Year 2030 - Medium fuel price scenario (60 USD/bbl) - 10% discount rate

From the most cost effective projects to the more expensive we found:

- the lower cost generation projects is composed by a group of Ethiopian HPP projects (Mandaya, Karadobi, Border, Halele, Geba, etc) with economic cost from 25 to 40 USD/MWh;
- close to 40 USD/MWh, we found the Bahr el Jebel HPP projects in South Sudan;
- close to 60-70 USD/MWh, we found gas-fired CCGT in Egypt, coal-fired STPP in Sudan (but the number of coal-fired STTP is Sudan is limited by transmission capacity), and a group of hydro projects in Ethiopia;
- from 70 to 110 USD/MWh, we find the HPP projects in the Main Nile river in Sudan;

[5] includes solely the part of cost dependant on the amount of generation = fuel cost + variable O&M cost
[6] Annual Energy Outlook 2006 from US Department of Energy

- finally, the most expensive units are gas oil-fired CCGT and crude oil-fired STPP in Sudan.

Accordingly, considering the cost and availability of power surplus, the bulk of power export in the region will come from cost effective HPP projects in Ethiopia (all Sudanese cost effective hydro power being absorbed by Sudan own internal demand).

Power export to Sudan would lead to the greater economic savings, because of greater cost differential between saved and imported energy, as well as lower transmission cost (shorter transmission line).

1.3.2 COMPARISON OF VARIABLE COSTS OF GENERATION

While the economic cost of generation (related to what is often called Long Term Marginal Cost of generation) includes investment and operation costs, the variable cost (related to what is called Short Term Marginal cost) only includes fuel and variable O&M cost.

The following table compares, for year 2030, and for the medium fuel price projection the economic cost and the variable cost of generation for the main TPP candidates (crude oil = 60 USD/bbl, to be compared to market prices over 90 USD/bbl in November 2007) :

	Economic cost (6000 hours/year)	Variable cost	Ratio var. cost / economic cost
(Egypt) gas-fired 750 MW CCGT	71 USD/MWh	55 USD/MWh	77%
(Sudan) 500 MW gasoil-fired CCGT	130 USD/MWh	112 USD/MWh	86%
(Sudan) 500 MW crude oil-fired STPP	133 USD/MWh	105 USD/MWh	79%
(Sudan) coal-fired STPP	57 USD/MWh	29 USD/MWh	51%

Table 1.3-1 - Comparison of economic and variable costs of generation – Year 2030 – Medium fuel price projection – 10% discount rate

The variable cost represents most of the generation cost of CCGT and STPP (between 77 to 85%). This proportion increases in time along the general increase of fuel prices. This means that most of the future savings resulting from power trade will come from fuel savings (and not investment savings).

1.4 INDEPENDENT DEVELOPMENT OF THE THREE POWER SYSTEMS

This paragraph presents the main characteristics of the least cost generation expansion plans determined by the Consultant for the three isolated systems in absence interconnection between them. The reference hypothesis considered are described in detail in Modules 2 and 3 of the present Study.

1.4.1 EGYPT

Main hypothesis:

- Medium demand projection (5.6% average annual growth rate).

- Medium fuel price projection (crude oil: 60 USD/bbl, NG = 8.6 USD/MBTU in 2030).
- Power export to Jordan (200 MW) and Libya (200 MW).
- No exchange with Sudan or Ethiopia.

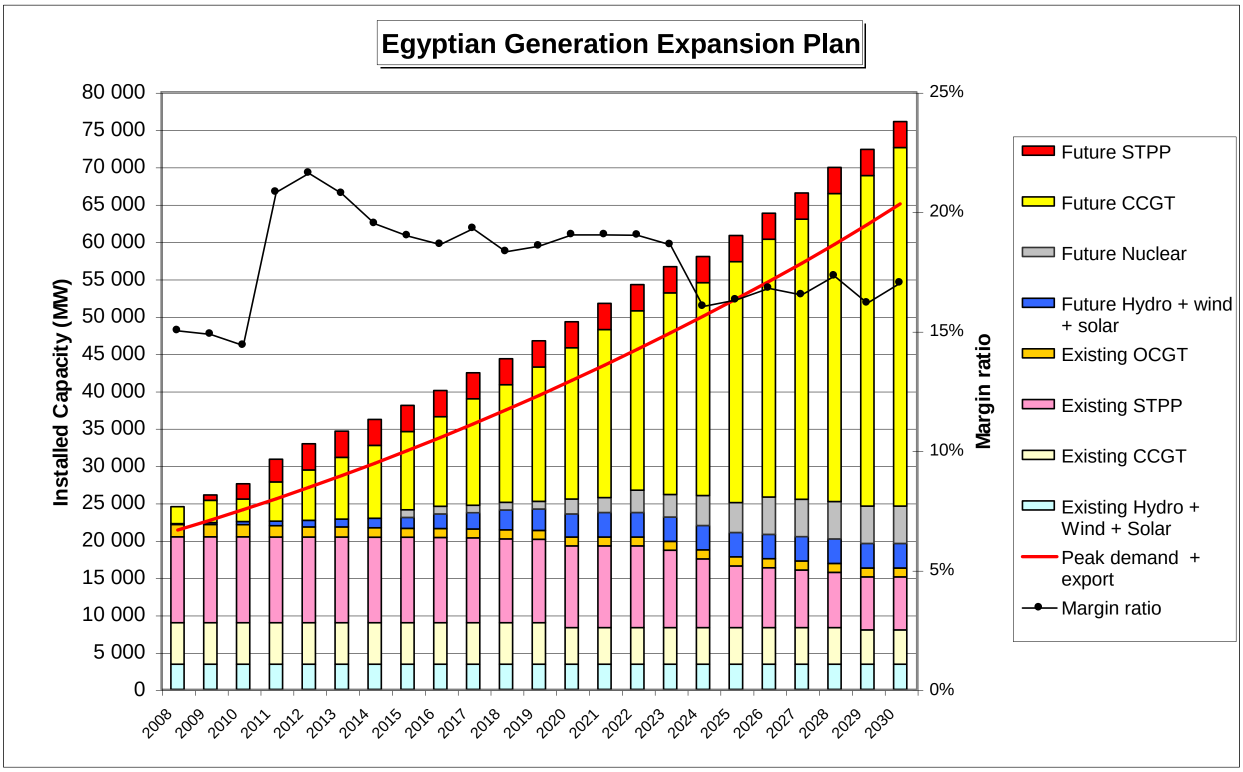

Figure 1.4-1 –Generation Expansion Plan – Egypt – Medium demand projection - No interconnection with Sudan / Ethiopia

Because of the large availability of natural gas in Egypt, the main part of the future development of generation capacity will be made on gas-fired CCGT. From 2020 on, the Egyptian power system needs, on average, three new 750 MW CCGT every year.

1.4.2 ETHIOPIA

<u>Generation expansion plan for the Medium demand projection - Main hypothesis</u>:

- Medium demand projection (average annual growth rate: 10.9%).
- Medium fuel price projection (crude oil: 60 USD/bbl in 2030).
- No exchange with Egypt or Sudan.
- Power export to Kenya (200 MW in 2011, 600 MW in 2020 and 1200 MW in 2030).
- Power export to Djibouti (<53 MW).

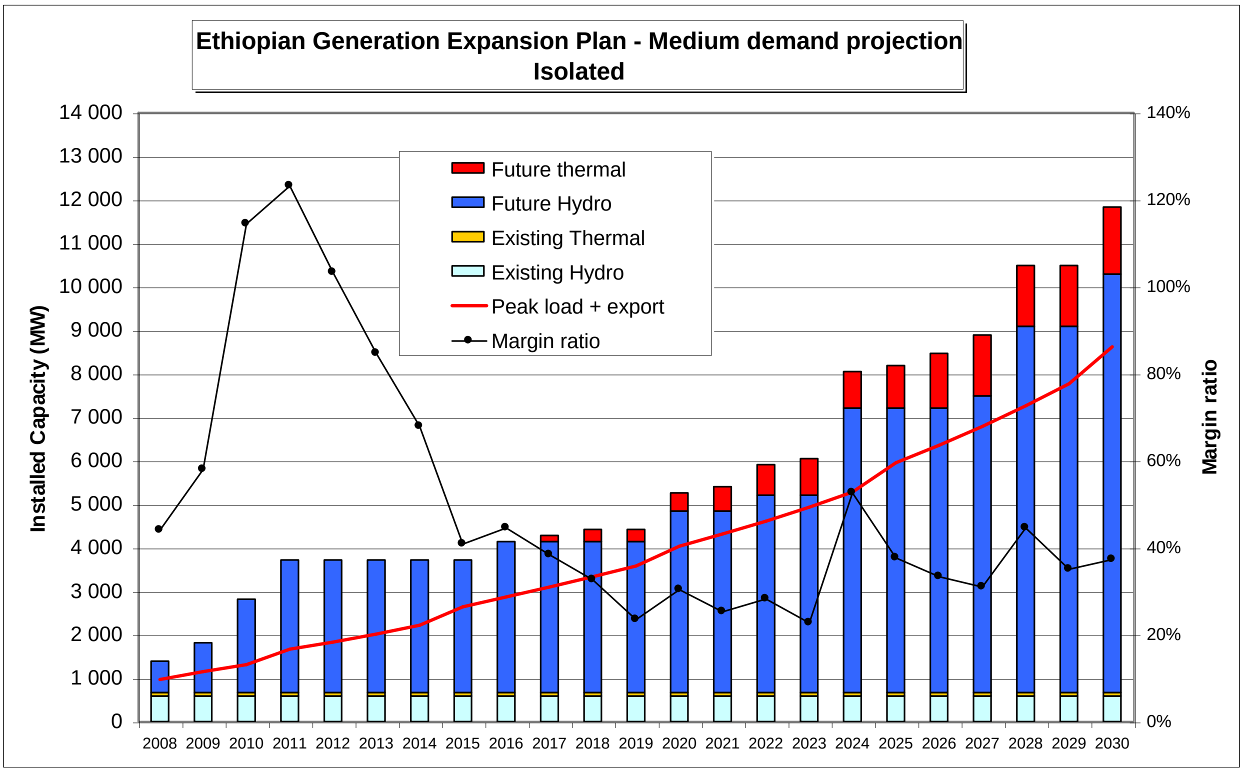

Figure 1.4-2 - Generation Expansion Plan - Ethiopia – Medium demand projection - No interconnection with Sudan / Egypt

The associated schedule of HPP commissioning is the following:

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	TPP	Capacity MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014					
2015					
2016	Halele Worabesa	420	2 245		
2017				OCGT	140
2018				OCGT	140
2019					
2020	Baro I + I + Gengi	700	4 409	OCGT	140
2021				OCGT	140
2022	Geba I + II	368	1 788	OCGT	140
2023				OCGT	140
2024	Mandaya	2 000	12 100		
2025				OCGT	140
2026				OCGT	280
2027	Chemoga Yeda	280	1 415	OCGT	140
2028	Karadobi	1 600	6 000		
2029					
2030	Border	1 200		OCGT	140
Total		9 675			1 540

Table 1.4-1 - Generation expansion plan - Ethiopia - HPP schedule – Medium demand projection

From 2010 to 2014, and with the commissioning of Gibe III (1870 MW), Ethiopia can take advantage of a significant surplus of hydro generation which can be exported to Sudan through the future 200 MW Ethiopia – Sudan interconnection.

To provide a satisfactory balance between supply and demand, the commissioning of the three large HPP on Blue Nile River (Mandaya, Karadobi, Border) is required from 2024 to 2030.

<u>Generation expansion plan for the Target demand projection - Main hypothesis</u>:

- High demand projection (also called "target scenario"): average annual growth rate =14.3%
- Medium fuel price projection.
- No exchange with Egypt or Sudan.
- Power export to Kenya (from 200 MW in 2011 to 1200 MW in 2030) and Djibouti (<53 MW).

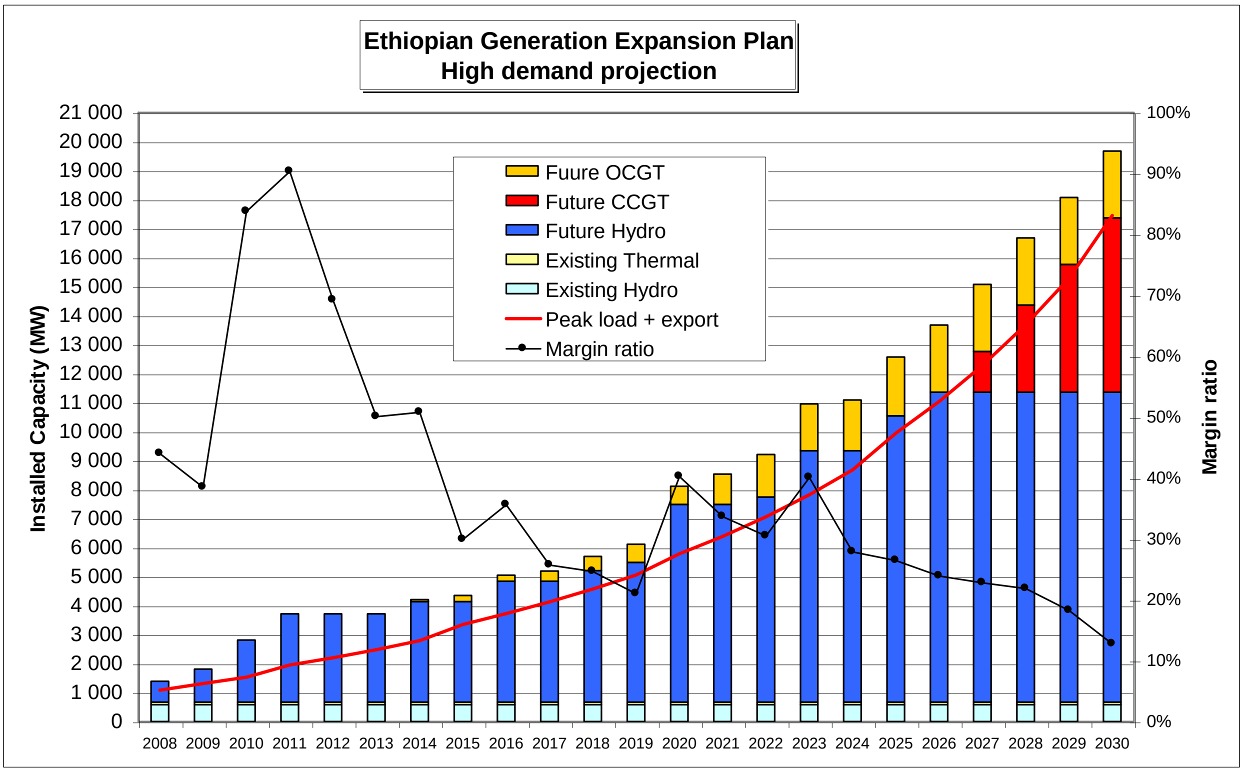

Figure 1.4-3 - Generation expansion plan - Ethiopia - High demand projection

In the target demand projection, the peak demand in 2030 is more than twice the peak demand in the medium projection: 14 330 MW instead of 6 814 MW. The largest HPP projects, Mandaya, Karadobi and Border are required in 2020, 2023 and 2025 (instead of 2024, 2028 and 2030 in the medium demand projection). All the hydropower projects identified in Module 3 Vol 3 (including Gojeb) are required in the Ethiopian power system by 2027.

The following table gives the schedule of commissioning:

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	CCGT MW	OCGT MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014	Halele Worabesa	420	2 245		70
2015					140
2016	Baro I + I + Gengi	700	4 409		
2018	Geba I + II	368	1 788		140
2019	Chemoga Yeda	280	1 415		140
2020	Mandaya	2 000	12 100		140
2021					-
2022	Genale III	254			420
2023	Karadobi	1 600	8 600		420
2024					140
2025	Border	1 200	6 000		140
2026	GenaleVI - Aleltu E&W	569	2 850		280
2027	Gogeb	153	520	1400	280
2028				1600	
2029				1400	
2030				1600	
Total		10 651		6000	2310

Table 1.4-2 - Generation expansion plan - Ethiopia - High demand projection

1.4.3 SUDAN

<u>Main hypothesis</u>:

- Medium demand projection (average annual growth rate: 9.8%).
- Medium fuel price projection (crude oil: 60 USD/bbl in 2030).
- No exchange with Egypt or Sudan.

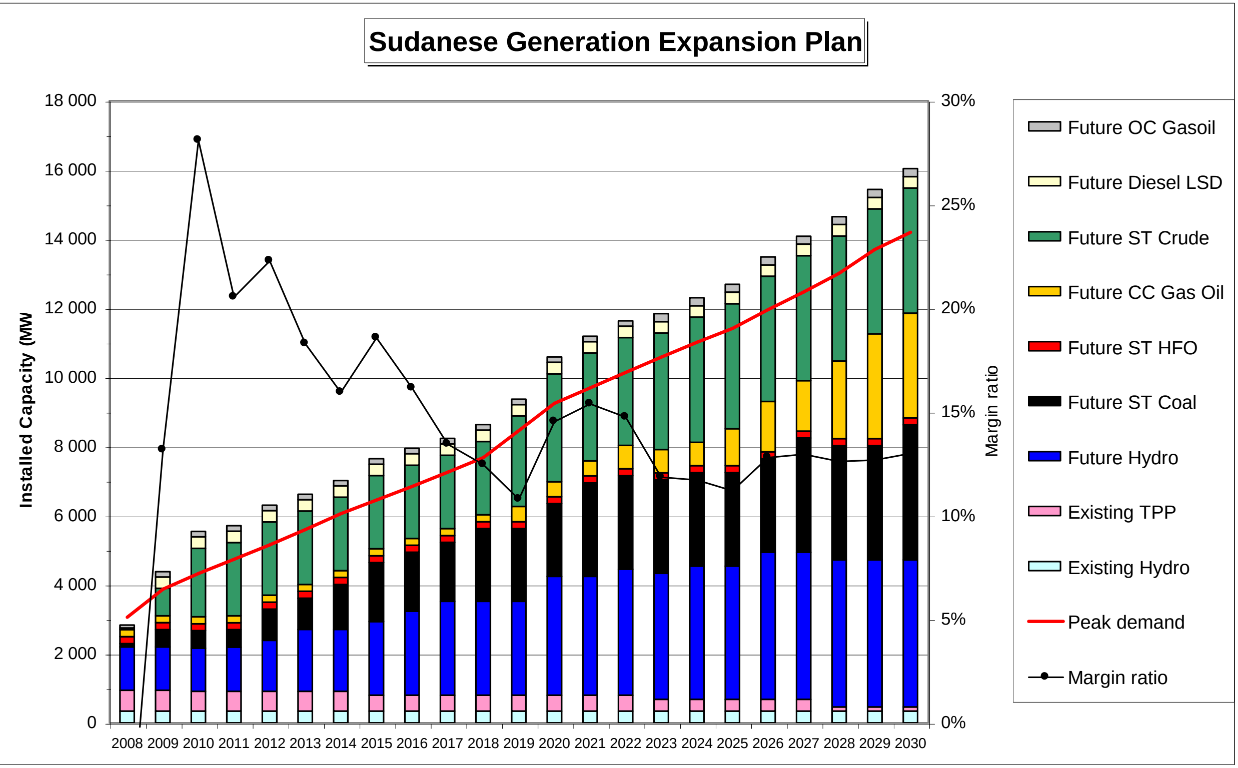

Figure 1.4-4 - Generation Expansion Plan – Sudan – Medium demand scenario

In the next 25 years, the Sudanese power system will evolve from a 50/50 thermal/hydro generation mix to a thermal dominated (75/25) generation mix. The new thermal generation capacity will be a combination of imported coal fired STPP, gas-oil fired CCGT and crude oil-fired STPP.

The resulting increase in fuel consumption, the proximity with Ethiopia, and the complementarity with the Ethiopian hydro based system, makes Sudan a natural market for the Ethiopian hydro export.

1.5 COMBINED DEVELOPMENT OF THE THREE POWER SYSTEMS

This paragraph examines the combined development of the three power systems upon the two levels of coordination described previously (loose and tight pool models). The amount of economic power exchanges is determined for various levels of interconnection capacity through simulation of the power systems. The economic profitability of the interconnection is evaluated under the key economic parameters.

1.5.1 COMMISSIONING DATE AND PHASING OF THE INTERCONNECTION

Based on the duration of technical studies, tender process and construction, the earliest commissioning date of the interconnection is close to 2015.

Regarding hydro generation, the earliest commissioning date of the large Ethiopian HPP projects on the Blue Nile (Mandaya, Karadobi, Border) is around 2020.

Accordingly, the present Study will consider 2020 as the commissioning date of the new interconnection project. However, the design of the interconnection (AC link between Ethiopia and Sudan, AC or DC link up to Egypt) offers some flexibility and a commissioning in two phases of the (2015 to Sudan and 2020 to Egypt) is also examined in the Study.

1.5.2 LOOSE POOL MODEL

The operation optimization software SDDP was used to simulate the optimal operation (i.e. least cost dispatch) of the integrated system according to the capacity of the interconnection.

1.5.2.1 Characteristics of the hydro surplus in the loose pool model

Origin of the hydro surplus :

Basically, the Ethiopian hydro surplus in the loose pool approach are inherent to the development of a purely hydro system based on large size HPP:

a. Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following commissioning until the Ethiopian demand growth completely absorbs them. The surpluses are maximal on the commissioning of large HPP, and minimal just before new commissioning.

   NB : Smaller HPP projects would be included at a faster rate into the Ethiopian Generation Expansion Plan (i.e absorbed more rapidly by the demand growth) and would result in much less hydro surplus, but the resulting Ethiopian generation plan would be more expensive due to the reduced competitiveness of smaller HPP projects.

b. In a hydro dominated power system, a large amount of installed overcapacity is required in order to keep a proper supply / demand balance all year long, and even on the driest years.

The resulting hydro surplus, can be provided for export, on favourable hydrological conditions, at no additional cost for the Ethiopian power system.

Characteristics and costs of the hydro surplus

In the loose pool model, the generation expansion plan of Ethiopia is left unchanged compared to the "independent" development, with the exception of Mandaya which is anticipated from 2024 to 2020 in line with the commissioning of the connection to Egypt.

This model is typical of the actual power exchanges between European countries (spot market, month to month exchanges) which take benefits of temporary (short to medium term) power surplus appearing in one country or another. The additional HPP investments for Ethiopia are minimized, resulting in possible lower selling costs, but with the drawback of having more variability of the amount of power export from one year to another.

In actual operation, the main part of the power exchanges could probably be arranged on an annual basis, at the end of each wet season, when the amount of available energy in the reservoirs for the remaining part of the hydrological cycle is known.

1.5.2.2 Power exchanges

The power exchanges and the resulting generation savings have been evaluated for a variety of interconnection capacities (up to 1200 MW to Sudan and up to 2000 MW to Egypt). The following figure presents the evolution of the economic power exchanges for a scheme with 1200 MW capacity between Ethiopia and Sudan and 700 W capacity between Ethiopia and Egypt:

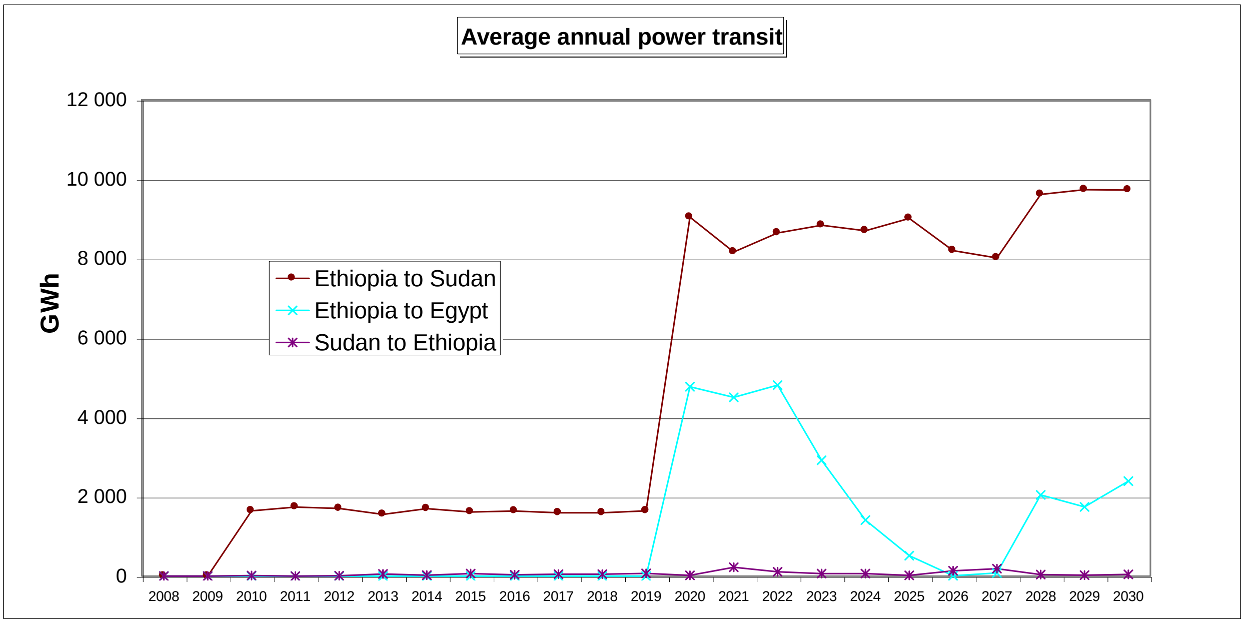

Figure 1.5-1 - Average annual power transit – ET-SU=1200 MW – ET-EG= 700 MW – Loose pool

In order to minimize the regional operation costs, the economic exchanges develop preferably toward Sudan where the fuel savings are higher (because of higher local generation cost). The average annual power export from Ethiopia to Sudan, arises to 8900 GWh/year over the 2020-2030 period, and nearly saturates the 1200 MW capacity continuously.

The average annual power export from Ethiopia to Egypt, arises to 2300 GWh/year over the 2020-2030 period, peaking during the first years following the commissioning of Mandaya (2020), Karadobi (2028) and Border (2030).

1.5.2.3 Sensitivity analysis

The basic principle in the sensitivity analysis is to change one single key economic parameter of the Study at a time in order to check its impact on the results.

In addition to the sensitivity to the capacity of the interconnection, the sensitivity was check along :

- high / medium / low fuel price projections (impact on fuel cost savings),
- high / medium / low Ethiopia demand projections (impact on the amount of hydro surplus),
- high / medium / low discount rate,
- phasing of the commissioning (one or two stages).

An overview of the economic results is presented in §0.

1.5.2.4 CO2 savings

The following table provides the annual quantity of CO_2 savings in tons and the corresponding present worth value of the CO_2 savings in 2008, based on a 5 or 10 USD/t CO_2 value:

Case		Additional export TWh/year	CO2 reduction M ton	8% discount rate 5 USD/tCO_2 MUSD	8% discount rate 10 USD/tCO_2 MUSD	10% discount rate 5 USD/tCO_2 MUSD	10% discount rate 10 USD/tCO_2 MUSD	12% discount rate 5 USD/tCO_2 MUSD	12% discount rate 10 USD/tCO_2 MUSD
Ethiopia-Sudan :	700 MW	4.1	3.09	83	166	54	108	37	74
Egypt-Ethiopia :	700 MW	3.9	1.68	45	90	29	59	20	40
Total		8.0	**4.77**	128	256	84	167	57	114
Ethiopia-Sudan :	1200 MW	7.1	5.34	143	286	94	187	64	128
Egypt-Ethiopia :	700 MW	2.3	0.99	27	53	17	35	12	24
Total		9.4	**6.33**	170	339	111	222	76	152
Ethiopia-Sudan :	1200 MW	7.1	5.34	143	286	94	187	64	128
Egypt-Ethiopia :	2000 MW	2.9	1.25	33	67	22	44	15	30
Total		10.0	**6.59**	177	353	115	231	79	158

Table 1.5-1 - Present worth value of CO_2 emission savings – Loose pool

These savings will have to be included in the economic analysis if the interconnection project is eligible to Clean development Mechanism (CDM).

1.5.2.5 Economic analysis

The economic analysis consists in comparing the net balance between:

- the cost of the interconnection (given in § 15.2),
- the "benefits" provided by the interconnection consisting in generation cost savings (given in § 11.5) and CO_2 emission savings (given in § 14) (if the interconnection project is CDM eligible).

The classic economic criteria "Net Present value" and "Benefit to Cost ratio" are used hereafter to quantify the profitability. It is reminded that the point of view of the analysis is regional.

1.5.2.5.1 Cost of the interconnection

The following table summarizes the investment cost (including IDC) of interconnection project for the three main options (more details are provided in Module 6 Vol 3):

Option			Investment cost ($MUSD_{2006}$)		
Capacity to Egypt	**Capacity to Sudan**	**Interconnection points**	**a = 10%**	**a = 12%**	**a = 8%**
700 MW	700 MW	Mandaya - Rabak / Merowe -Nag Hammadi 500 kV AC			
		Total :	**1 033**	**1 071**	**995**
700 MW	1200 MW	Mandaya - Rabak 500 kV AC	554	575	534
		Merowe -Nag Hammadi 500 kV AC	666	691	642
		Total :	**1 220**	**1 265**	**1 176**
2000 MW	1200 MW	Mandaya - Rabak 500 kV AC	363	376	350
		800 kV DC link + 500 KV AC Assiut-Samalut	2 520	2 645	2 414
		Total :	**2 883**	**3 021**	**2 764**

Table 1.5-2 - Investment cost of the interconnection options

The following table gives the present worth of the interconnection cost in 2008, for a commissioning of the interconnection in 2020, calculated on the base of the expenditure schedule of the interconnection during construction, the annual O&M cost and the discount rate:

Option			**PW cost ($MUSD_{2006}$)**		
Capacity to Egypt	**Capacity to Sudan**	**Interconnection points**	**a = 10%**	**a = 12%**	**a = 8%**
700 MW	700 MW	Mandaya - Rabak / Merowe -Nag Hammadi 500 kV AC	374	305	464
700 MW	1200 MW	Mandaya - Rabak 500 kV AC Merowe -Nag Hammadi 500 kV AC	433	355	534
2000 MW	1200 MW	Mandaya - Rabak 500 kV AC 800 kV DC link + 500 KV AC Assiut-Samalut	1 014	841	1 244

Table 1.5-3 - Present Worth Cost in 2008 of the interconnection options

1.5.2.5.2 Present worth of generation savings

In order to determine the additional generation savings provided solely by the new interconnection project, without inclusion of those provided by the future 200 MW Ethiopian-Sudanese interconnection, the savings are measured by comparison to the following reference situation:

- commissioning of the 200 MW Ethiopia-Sudan interconnection in 2010,
- generation expansion plans of Egypt, Ethiopia and Sudan resulting from the independent development of the three power systems.

The following table summarizes the present worth of generation savings for the main capacity options and key economic parameters of the study (10% discount rate):

Present worth of generation savings (MUSD2006) :

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 0 MW	SU : 700 MW, EG : 700 MW	SU : 700 MW, EG : 2000 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High		2 610		3 360	3 610
Median	Median	1 150	1 710	1 870	2 090	2 210
Median	Low	840	1 120	1 340	1 520	1 520
Low	Median	1 170	1 920	2 260	2 540	2 590
High	Median	820	1 170		1 590	1 640

Table 1.5-4 - Present worth value of generation savings – Loose Pool

These generation savings result are fuel cost reduction from substitution of hydro power to thermal power. The values given are net of the interconnection transmission losses and from additional HPP investment cost in some scenarios (eg Mandaya anticipated in 2020 instead of 2024 in the medium demand projection).

NB : Other "non power" downstream benefits resulting from Ethiopian large new hydro projects (such as sediment capture, flood alleviation, etc) remain the same whether the interconnection is committed or not, because there is no change in the schedule on HPP commissioning in the loose pool approach.

1.5.2.5.3 Net savings

The following table presents the net savings (= generation savings minus interconnection cost) according to the various capacity options and key economic parameters of the study:

Net Present Value (MUSD2006):

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High	2 240	2 930	2 600
Median	Median	1 340	1 660	1 200
Median	Low	750	1 090	500
Low	Median	1 540	2 110	1 580
High	Median	800	1 160	630

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	Median	8%	2 570	1 950
Median	Median	12%	940	490

Table 1.5-5 - Net Present Value of the interconnection – Loose pool model

The interconnection project is profitable under a wide range of hypothesis : its Net Present Value is positive for every capacity options considered and a wide range of key economic parameters. The following comments can be added :

FAVORABLE EVOLUTION OF ECONOMIC PARAMETERS :	
High fuel price	100 USD/bbl crude oil price projected in 2030 (instead of 60 USD/bbl in medium projection). For comparison the current market price, probably deeply distorted by speculations, is in the range of 90 to 100 USD/bbl (November 2007)
Low discount rate	8%, instead of 10% in base case : favors long term investment (i.e HPP against TPP)
UNFAVORABLE EVOLUTIONS OF ECONOMIC PARAMETERS:	
Low fuel price	35 USD/bbl crude oil price projected in 2030. Though this level cannot be completely rejected, it might not be the most probable one considering the past two years evolutions.
Ethiopian High demand	A 14.3% annual growth rate of the Ethiopian demand (instead of 10.9%) would leave reduced hydro surplus available for export (except if additional cost efficient HPP projects are studied).
High discount rate	12%, instead of 10% in base case : favors short term investment (i.e TPP against HPP)
INDIFFERENT ECONOMIC PARAMETERS :	
Egyptian and Sudanese Demand	The level of Egyptian and Sudanese demands has no impact on the profitability of the interconnection because the same type and amount of generation will be "saved" : gas-fired CCGT in Egypt, combination of gasoil-CCGT and crude oil STPP in Sudan.

1.5.2.5.4 Comparing options

The different option capacities can be compared through the NPV, and also through the Benefit to Cost Ratio (also called BCR) given in the table below:

Benefit / Cost ratio (present worth of benefits / present worth of cost) :

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High	7.1	7.8	3.6
Median	Median	4.6	4.8	2.2
Median	Low	3.0	3.5	1.5
Low	Median	5.2	5.9	2.6
High	Median	3.2	3.7	1.6

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	Median	8%	5.8	2.6
Median	Median	12%	3.6	1.6

Table 1.5-6 - Benefit to Cost Ratio – Loose pool model

The benefit to Cost ratio is another way to express the profitability. It is equal to the Net Present value of the benefits (called here "generation savings") divided by the Net Present value of the cost. A value greater than one means the benefits outbalance the cost of the project.

The NPV is maximized for a 1200 MW (Sudan) 700 MW (Egypt) scheme. While still positive, the NPV decreases going up to a 2000 MW (for Egypt) and 1200 MW (for Sudan) scheme. This is due to the significantly higher cost of the 2000 MW link to Egypt (because of longer distance) while the additional fuel savings are low, the main part of the Ethiopia hydro surplus having already been provided for export.

The analysis of the BCR shows an equivalence – for this criteria - between the 700 MW (Sudan) 700 MW (Egypt) scheme and the 1200 MW (Sudan) 700 MW (Egypt) scheme. This is explained by the lower investment cost of 700 MW / 700 MW option.

The BCR then decreases going up to a 2000 MW (for Egypt) for the same reason as the NPV, but remains largely greater than 1.

1.5.2.5.5 Savings per country and Pay back period

The pay-back period is the period of time necessary for the savings (i.e. mainly fuel savings) to balance the expenses (interconnection cost and anticipation cost of Mandaya HPP[7]). At the end of the payback period the present value of the savings is equal to the present value of the expenses.

For a scheme with 1200 MW capacity to Sudan and 700 MW capacity to Egypt, the interconnection investment is paid after 4 full years of operation (medium demand projection for all countries, medium fuel price projection, 10% discount rate). This very short pay back period is consistent with the high benefit to cost ratio of the interconnection project.

The average export to Egypt amounts to 2.3 TWh/year, with 120 $MUSD_{2006}$/year average fuel savings (natural gas), while the average export to Sudan amounts to 8.9 TWh/year, with an average fuel savings of 760 $MUSD_{2006}$/year (450 $MUSD_{2006}$/year from crude oil and 210 $MUSD_{2006}$/year from gas oil).

1.5.2.5.6 Phasing of the interconnection

[7] For the Ethiopian medium demand projection, the commissioning of Mandaya in the loose pool model is anticipated from 2024 (independent development approach) to 2020. For the low demand projection, Mandaya is anticipated from 2025 to 2020. For the target projection, there is no anticipation because the "natural" commissioning date of Mandaya is 2020.

An underlying finding from the previous results is the large benefit that would result from a significant increase of the committed Ethiopia-Sudan interconnection beyond its original 200 MW.

In the previous analysis, the selected commissioning date of the new interconnection project is 2020, because from that date large amount of hydro surplus could be provided from large Ethiopian HPP projects on Blue Nile (Mandaya, Karadobi, Border).

The previous economic analysis shows that the most promising interconnection options are 1200 MW export capacity to Sudan and 700 or 2000 MW export capacity to Egypt. It is interesting to note that these options gives some flexibility in the phasing of the interconnection, which in turn provides some additional economic return.

For example, in the 2000 MW (Egypt) - 1200 MW (Sudan) scheme, the interconnection between Ethiopia and Sudan is through a double circuit 500 kV AC line between Mandaya to Rabak. If commissioned before 2020 (i.e. before the connection of Mandaya on the grid) the maximum transmission capacity of this line would be around 500 MW[8]. On the Sudanese side, the 500 kV Rabak-Merigan and Rabak-Jebel Aulia would have to be anticipated accordingly from its initial commissioning date (2020 in Sudanese Transmission Master Plan) in order to receive this additional power.

Considering the time necessary for detailed study, tender, construction, the earliest date of commissioning for this part of the interconnection between Ethiopia and Sudan is around 2015. This means an additional equivalent 500 MW transit capacity could be connected from 2015.

The simulations show that the resulting additional power exchanges during the 2015 to 2020 period would bring an additional fuel saving of 440 MUSD (Present Worth Value in 2008), while the additional investment cost for the interconnection is in the range of 120 to 160 MUSD (Present Worth Value in 2008) depending on the actual interconnection option.[9]

Accordingly, the Consultant would suggest to consider in the Phase II of the present Study a commissioning in two phases of the interconnection, the first phase in 2015, increasing the capacity between Ethiopia and Sudan, the second phase in 2020 with the completion of the interconnection to Egypt.

1.5.3 TIGHT POOL MODEL

1.5.3.1 Introduction

The tight pool approach is probably more relevant to the final objective of the interconnection and the emergence of a large power market. In this approach, the countries coordinate their decisions of generation investments in order to minimize the global regional generation cost (investment and operation). More precisely, this means that hydro generation investments in Ethiopia are purposely anticipated (compared to the pool approach) in order to provide additional and more regular export power to Egypt and Sudan.

Theoretically, some generation investments could be delayed in Egypt and Sudan due to the increased power import. However, due to the continuous increase of the fuel prices all over the period of the Study, the investment cost represents only 15 to 25% of the total generation cost of

[8] Before the commission of Mandaya, the maximum transmission capacity is be limited by the fact that there would be no injection of MVAR at Mandaya substation to maintain the voltage.
[9] This cost is split in : 80 to 120 MW (depending on the option) for the anticipation of Mandaya-Rabak, and 35 MUSD for the anticipation of 500 kV Rabak-Meringan and 500 kV Rabak-Jebel Aulia

new thermal plants by 2020-2030 (see §9.2. Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would keep their ability to balance their power demand with their own supply whenever power import are not available.

The tight pool approach has been carried out for the medium and the low Ethiopian demand projections. Indeed, the tight schedule of Ethiopian HPP for the high demand projection (independent development case, see §10.1.2) offers virtually no room for anticipation of any HPP projects.

1.5.3.2 Economic power exchanges

1.5.3.2.1 Medium demand projection for Ethiopia

The following figure presents the evolution of the economic power exchanges for a scheme with 1200 MW capacity between Ethiopia and Sudan and 2000 MW capacity between Ethiopia and Egypt, and the medium demand projection for Ethiopia:

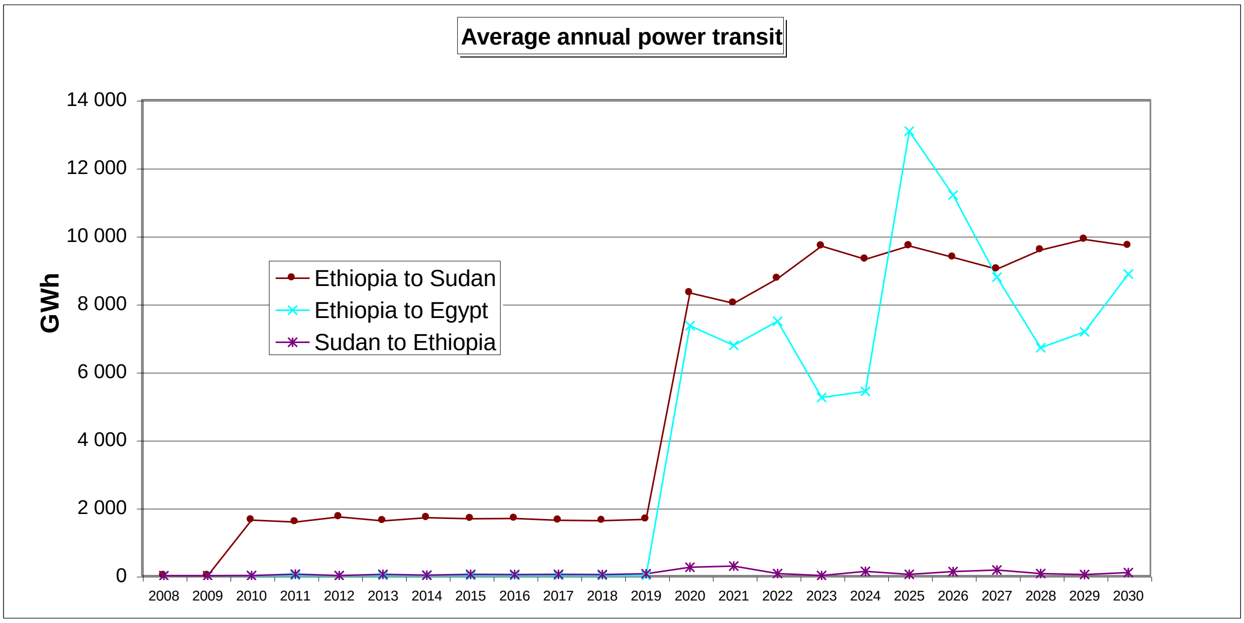

Figure 1.5-2 - Average annual power transit - ET-SU=1200 MW, ET-EG=2000 MW- Tight pool – Medium demand projection for Ethiopia

The increase of power exchange is readily appearing with comparison to the loose pool situation:

- The average annual power export from Ethiopia to Sudan arises to 9200 GWh/year over the 2020-2030 period, and saturates the 1200 MW capacity continuously (equivalent to 7700 h / year at 1200 MW).
- The average annual power export from Ethiopia to Egypt arises to 7700 GWh/year over the 2020-2030 period (equivalent to 4380 h / year at 2000 MW).

The underlying generation expansion plan for Ethiopia includes the following modifications compared to the "independent development" situation:

- anticipation of Mandaya from 2024 to 2020,
- anticipation of Geba I+II: from 2022 to 2021,
- anticipation of Chemoga Yeda from 2027 to 2022,
- anticipation of Karadobi from 2028 to 2025,
- Genale III enters the GEP in 2022,
- Genale IV enters the GEP in 2023,
- Aleltu East and West enters the GEP in 2029.

Border commissioning date is left unchanged at 2030 in order to keep a 5-year interval between the commissioning dates of Mandaya, Karadobi and Border, compatible with the reduction of the negative downstream effects during the successive filling of these large reservoirs.

1.5.3.2.2 Low demand projection for Ethiopia

Apart from the Ethiopian hydro projects identified for the present Study in Module 3, other medium scale hydro projects might exist which could cover part of the internal Ethiopian power demand evolution. Accordingly, the low demand projection might give some additional appreciation of the potential amount of power that could be exported from Ethiopia.

For a scheme with 1200 MW capacity to Sudan and 2000 MW capacity to Egypt, the amount of power exchanges to Egypt increases to 12700 GWh/year over the 2020-2030 period (equivalent to 6300 h / year at 2000 MW):

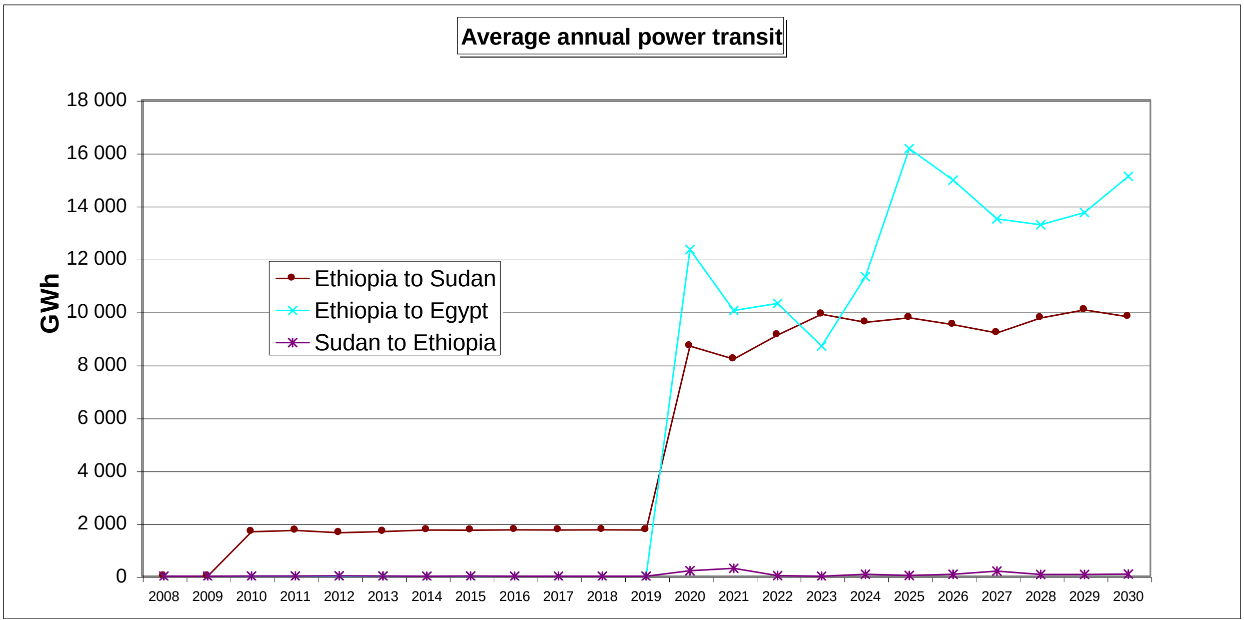

Figure 1.5-3 - Average annual power transit - ET-SU=1200 MW, ET-EG=2000 MW- Tight pool – Low demand projection for Ethiopia

1.5.3.3 CO2 savings

The following table presents the annual quantity of CO_2 savings in tons and the corresponding present worth value of the CO_2 savings in 2008, based on a 5 or 10 USD/t CO_2 value:

Case		Additional export	CO2 reduction	Present worth value					
				8% discount rate		10% discount rate		12% discount rate	
				5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2
		TWh/year	M ton	MUSD	MUSD	MUSD	MUSD	MUSD	MUSD
Ethiopia-Sudan :	1200 MW	8.1	6.1	163	327	107	214	73	146
Egypt-Ethiopia :	700 MW	5.2	2.2	60	120	39	78	27	54
Total		13.3	**8.3**	223	446	146	292	100	199
Ethiopia-Sudan :	1200 MW	7.5	5.6	151	302	99	198	68	135
Egypt-Ethiopia :	2000 MW	7.7	3.3	89	178	58	116	40	79
Total		15.2	**9.0**	240	480	157	314	107	214

Table 1.5-7 - Present worth value of CO_2 emission savings – Tight pool model

These savings will have to be included in the economic analysis if the interconnection project is eligible to Clean development Mechanism (CDM).

1.5.3.4 Economic analysis

1.5.3.4.1 Present worth of generation savings

The following table gives the present worth of generation savings for the most relevant options (10% discount rate):

Present worth of generation savings (MUSD$_{2006}$)

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	3 800	4 150
Medium	Medium	2 360	2 600
Medium	Low	1 360	1 490
Low	High	3 140	4 020
Low	Medium	2 420	3 020

Table 1.5-8 - Present worth value of generation savings – Tight Pool model

NB: These generation savings are net of interconnection transmission looses, and of the additional investment costs resulting from the anticipation of several HPP in Ethiopia (compared to the independent development of Ethiopia).

1.5.3.4.2 Net savings

The following table presents the net savings (generation savings minus interconnection cost) according of the various capacity options and key parameters of the study:

NPV (MUSD$_{2006}$):

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	3 310	3 110
Medium	Medium	1 870	1 560
Medium	Low	870	450
Low	High	2 650	2 980
Low	Medium	1 930	1 980

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	Medium	8%	3 320	2 760
Medium	Medium	12%	1 180	910

Table 1.5-9 - Net Present Value of the interconnection – Tight pool model

The anticipation of large Ethiopian HPP, along with an increase of power exports, provides an increase of the profitability of the interconnection project for the region.

1.5.3.4.3 Comparing options

The next table presents the Benefit to Cost Ratio:

Benefit / Cost ratio :

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	7.8	4.0
Medium	Medium	4.8	2.5
Medium	Low	2.8	1.4
Low	High	6.4	3.9
Low	Medium	4.9	2.9

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	Medium	8%	7.2	3.2
Medium	Medium	12%	4.3	2.1

Table 1.5-10 - Benefit to Cost Ratio – Tight pool model

While the benefit to cost ratio would favors the ET-SU: 1200 MW – ET-EG: 700 MW scheme, the Net Present Value is close to the ET-SU: 1200 MW – ET-EG: 2000 MW scheme. Accordingly, this larger design is probably preferable for the region, giving more flexibility for the future expansion of the power market in the region .

1.5.3.4.4 Savings per country and Pay back period

For a scheme with 1200 MW capacity to Sudan and 2000 MW capacity to Egypt, the interconnection investment is paid after 7 full years of operation (medium demand projection for all countries, medium fuel price projection, 10% discount rate). The average export to Egypt would be 7.7 TWh/year, with 420 $MUSD_{2006}$/year average fuel savings, while the average export to Sudan would be 9.2 TWh/year, with an average fuel savings of 810 $MUSD_{2006}$/year.

Whenever the Ethiopia demand follows the low demand projection, the pay back period would be 8 years. The average export to Egypt would increase to 12.7 TWh/year, with 680 $MUSD_{2006}$/year average fuel savings, while the average export to Sudan would be 9.4 TWh/year, with an average fuel savings of 820 $MUSD_{2006}$/year.

1.6 SUMMARY OF ADVANTAGES / DISADVANTAGES RESULTING FROM THE INTERCONNECTION PROJECT

A large part of the benefits from the interconnection (power trades, downstream power effects) can be evaluated in terms of monetary values, however these benefits do not represents all the possible positive outcome from the project.

In order to widen the view, the following simplified tables summarizes for the region and for each country, the main advantages and disadvantages from the interconnection project (these tables are adapted from the detailed information provided Module 5 EIA). In order to be more specific, the tables indicate the origin of the advantages or disadvantages:

- Power market: when the advantage/disadvantage exists if and only if the interconnection exists.
- HPP projects in Blue Nile River: when the advantage/disadvantage exists even in the absence of the interconnection.

Regarding the HPP positive or negative impacts and associated mitigation measures, only a brief overview is provided here, the reader is invited to find more information in the relevant pre-feasibility HPP Studies (Mandaya, Border, etc).

Note on relation between the interconnection project and HPP downstream benefits:

In the following table, for the sake of simplification, the downstream benefits are attributed to the HPP and not to the interconnection project.

Indeed, one of the results of the Study is to show that, even without interconnection, Ethiopia needs to develop the large hydro projects (identified in Module 3 Vol 4) in order to cover its own power demand over the next 25 years. The main part of the downstream benefits (regulation of flow, flood mitigation, uplift effect, etc) will be provided by the first large HPP project commissioned on the Blue Nile river (Mandaya or Karadobi). Subsequent projects would bring much lower additional downstream benefits.

For the target demand projection in Ethiopia, and without interconnection, the Study shows that Mandaya is required in 2020 and Karadobi in 2023. Accordingly, in this situation the downstream benefits are not attributable to the presence of the interconnection (commissioned in 2020)

In the Ethiopian medium demand projection, Mandaya is required in 2024 in the independent development situation, or in 2020 in the interconnected situation. Accordingly, the interconnection will induce a 4 years anticipation of Mandaya, and of the associated downstream benefits compared to the independent development scheme.

However, the possibility of selling part of the power from the large Blue Nile HPP projects for export would make these projects more bankable, favouring the possibility of rising funds for actually building them. Accordingly, there is an indirect link between the interconnection project, favouring the financial feasibility of the large Blue Nile HPP projects, and the resulting HPP downstream benefits.

1.6.1 REGION

Origin	Advantages
Power market	Creation of a power pool: - global generation cost savings,

	- reduction of the cost of electricity for final user would favor overall development, - economies of scale in new generation capacity: development of larger low-cost hydropower plants made possible through the creation of larger power market, - hydro-thermal complementarity between Egypt, Ethiopia and Sudan, - mutual assistance in case of disturbances, - first step to the connection of the North Africa power systems to the South East African power pool. Regional cooperation and trust building
Hydro projects	Coordination of the operation of HPP on the Nile river for overall regional benefit. Regulation of inflows and continuous availability of water. Reduction in CO_2 emissions

Origin	**Disadvantages**
Power market	None

Table 1.6-1 - Advantages / disadvantages for the region

1.6.2 EGYPT

Origin	**Advantages**
Power market	Fuel savings (mainly Natural gas). Reduction in CO_2 emission. Securisation of the long term cost of generation (hydro power base imports have a generation cost independent of the variation of fossil fuels). Possibility for Egyptian generator companies to invest in low-cost hydro generation in Ethiopia.
Hydro projects	Regulation of inflows: - improved guarantee for irrigation, - opportunity to operate Aswan at lower level for a reduction of evaporation and a conversion to usable supply yield which may more than offset the reduction in power generation, - opportunity to avoid / reduce spilled energy (eg 1998/199). Reduced sediment: extension in life of High Aswan dam

Origin	**Disadvantages**
Power market	None
Hydro projects	Head loss on Aswan during filling large reservoirs on Blue Nile river: Impact along time to be studied under a variety of conditions (hydrology,

	sequence of HPP, reservoir sizes, etc) in term of irrigation, capacity (MW), energy (GWh).

Table 1.6-2 - Advantages / disadvantages for Egypt

1.6.3 ETHIOPIA

Origin	Advantages
Power market	Valorisation of the hydro power surplus inherent to the Ethiopian power system. Valorisation of the hydro potential of Ethiopia for the benefit of Ethiopia and the interconnected countries. Boost for the development of the Ethiopian power mix, and consequently to the electrification rate in Ethiopia. Securisation of power supply in Ethiopia in case of drought conditions (possibility of thermal power import from Egypt and Sudan). Important role for the connection to Kenya and at a latter stage to the SAPP. Increase foreign exchange earnings. Construction employment, new skills for the future.
Hydro projects	Major energy benefits Low-cost renewable energy. Regional development (new roads, bridge, development of rural electrification, etc). Poverty reduction. Construction employment, new skills for the future. Development of irrigation.

Origin	Disadvantages
Hydro projects	Capital intensive projects may take time to be finance. Negative ES impacts (but can be mitigated through identified measures)

Table 1.6-3 - Advantages / disadvantages for Ethiopia

1.6.4 SUDAN

Origin	Advantages
Power market	Fuel savings (crude oil and derivatives). Saved fossil fuel could be exported at a higher price rather than burned in thermal plants. Access to the Mediterranean power market, and in the long term to the SAPP. Re-enforcement of the complementarily between the Ethiopian hydro system and the Sudanese hydro/thermal system.
Hydro projects	Regulation of inflows (additional irrigation, navigation, uplift effect at Roseires, Sennar and Merowe: 2 200 GWh/year, equivalent to DAL generation). Reduced sediment: reduction in dredging costs at Roseires, reduction in drainage canal desilting maintenance cost, reduction in pump replacement cost. Increased irrigation supply reliability / Development of Irrigation agriculture: two crops per year.

	Flood reduction.

Origin	**Disadvantages**
Hydro projects	Reduction in flooding and sediment will lead to the conversion of recession agriculture to irrigation agriculture (but can be mitigated through identified measures).

Table 1.6-4 - Advantages / disadvantages for Sudan

1.7 CONCLUSION

The present Power Trade Study is the first quantitative Study bringing lights to the future evolution of the Egyptian, Ethiopian and Sudanese power systems up to 2030, and evaluating the benefits that would result from the establishment a regional power market between Egypt, Ethiopia and Sudan.

Previously, the generation expansion plan of Sudan (LTPPS 2006) was studied up to 2030, the Egyptian generation expansion plan covered the period up to 2028, the Ethiopian expansion plan (EPSEMPU June 2006) the period up to 2015, while power exchanges potential was assessed at scooping level.

The present Study demonstrates there are significant benefits for the Egypt, Ethiopia, and Sudan to develop an interconnection project in order provide Egypt and Sudan with the hydro surplus available from the large Ethiopian HPP projects, and consequently save fossil fuels and reduce CO_2 emissions in Egypt and Sudan.

1.7.1 ETHIOPIAN HYDRO SURPLUS

Ethiopia is well endowed with hydro resources. The hydro potential is estimated at about 30 000 MW, with only a fraction of which has been exploited so far. Accordingly, the Ethiopian power system will be the main source of power export in the Egyptian, Ethiopian, Sudanese regional market.

Part of the Ethiopian hydro surplus available for export are inherent to the internal development of the Ethiopian hydro mix:

a - Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following the commissioning of these large HPP projects, until the Ethiopian demand growth gradually absorbs them.

b - In order to maintain a proper supply / demand balance all year long, and even on the driest years, the Ethiopian hydro power system requires a large amount of installed overcapacity. The resulting hydro surplus can be provided for export on favorable hydrological conditions.

Further to these surplus "inherent" to any hydro power system, additional hydro power could be made available if the commissioning of large Ethiopian hydro plants is purposely anticipated (with respect to their "natural" schedule when Ethiopia develops "independently") or if hydro power projects are specifically developed for export.

The final amount economic hydro power available for export will also depend on the growth rate of the Ethiopian demand, the amount of power exported to other countries (e.g. Kenya) and the cost effectiveness of possible other Ethiopian hydro projects.

1.7.2 PHASING OF THE INTERCONNECTION

The design of the interconnection (AC link between Ethiopia and Sudan, AC or DC link up to Egypt) gives some flexibility in the phasing of the interconnection. A commissioning in two phases would add to the profitability of the project: connection to Sudan in 2015 (earliest possible date considering duration of technical studies, tender process, construction) followed by a connection to Egypt in 2020 (earliest possible date when large amount of hydro power would be available from Ethiopian Blue Nile HPP projects).

1.7.3 ECONOMY OF THE INTERCONNECTION

The present Study shows that the interconnection project is characterized economically by a very good profitability, a short payback period and a high benefit to cost ratio.

The economy and optimal capacity of the interconnection were analyzed for two levels of coordination (or two types of power markets) between the three power systems: the loose pool and the tight pool models which are reminded briefly hereafter.

1.7.3.1 Loose pool model

The loose pool model consists basically in exporting the hydro surplus inherent to "independent" development the Ethiopian power system. The main characteristic of this model are:

- generation expansion plan of Ethiopia left unchanged compared to the "independent" development, with the exception of Mandaya which is anticipated from 2024[10] to 2020 in line with the commissioning of the connection to Egypt.
- the generation expansion plans of Egypt and Sudan left unchanged,
- lower amount of power export (compared to the tight pool approach).

This model is typical of the actual power exchanges between European countries (spot market, month to month exchanges) which take benefits of temporary (short to medium term) power surplus appearing in one country or another. The additional HPP investments in Ethiopia are minimized, resulting in possible lower selling costs, but with the drawback of having more variability of the amount of power export from one year to another.

In actual operation, the main part of the power exchanges could probably be arranged on an annual basis, at the end of each wet season, when the amount of available energy in the reservoirs for the remaining part of the hydrological cycle is known.

Accordingly very good BCR and short payback periods are achieved, the variability of the hydro surplus being balanced by the low global additional generation investment cost. The best scheme, from a strictly economic point of view, would be ET-SUD: 1200 MW and ET-EG: 700 MW, with a

[10] For the Ethiopian low demand projection, Mandaya is anticipated from 2025 to 2020, while for the high demand projection no anticipation is required because the "natural" date of commissioning of Mandaya is 2020.

benefit to cost ratio of 4.8 and a very short 5 year-payback period for the reference hypothesis (medium demand projection, medium price projection).

However, going up to 2000 MW capacity to Egypt would still be very profitable for the region (benefit to cost ratio =2.2), and would give more freedom and flexibility for a future evolution to a tight pool model and an expansion of the power market to the South (Kenya and SAPP) and to the North.

1.7.3.2 Tight pool model

In the tight pool model, the commissioning of several large hydro Ethiopian plants (Mandaya, Karadobi, Border, etc) is purposely anticipated, compared to the "independent" development of Ethiopia, in order to provide an additional and more regular amount of power export. Thus, the power exports arise for one part, from the "natural" hydro surplus inherent to the Ethiopian hydro generation mix, and for the other part from the anticipation of major Ethiopian HPP.

It is suggested to keep unchanged the generation expansion plans of Egypt and Sudan because, due to the projected fuel price increase along the period of the Study, the investment represents only 15 to 25% of the total generation of new thermal plants (or even 10 to 20% if crude oil reaches 100 USD/bbl). These countries would still keep their ability to balance their power demand with their own supply whenever power import are available or not.

The tight pool model is characterized by:

- increased amount of exports (compared to loose pool),
- lower variability of the power export to Egypt along the period of study (compared to loose pool),
- higher generation investment cost in Ethiopia (because of HPP anticipation).

The profitability of the project is still very good. The Net Present Value and the Benefit to Cost Ratio (BCR) are relatively similar than those in the loose pool model, the larger HPP investment costs being compensated by the larger fuel savings associated with larger export. The payback period is longer but still shorter than 10 years for the medium demand projections.

The BCR criteria would give some economic advantage to the scheme with ET-EG: 700 MW, but as in the loose pool approach, going to 2000 MW for the connection to Egypt is certainly preferable, with still a short pay back period of 7 to 8 years, and a Benefit to Cost ratio of 2.7 to 4, according to hypothesis considered.

In actual operation, because of the increased HPP investment in Ethiopia, the power exchanges would probably be arranged largely on PPA basis, while additional exchanges on a spot to year basis are still possible according to the actual condition of the power systems.

The selling price of energy would be higher than in the loose pool model in order to recover the anticipated HPP investment.

1.7.3.3 Preservation of the benefits on adverse evolution of key hypothesis

The key parameters affecting the profitability of the interconnection project are the evolution of the fuel cost (a lower fuel cost evolution would reduce fuel savings), and to a lower extend the evolution of the Ethiopian demand (a higher Ethiopian demand would reduce the amount of hydro surplus).

However the interconnection project retains a good profitability (overall benefits for the region greater than costs) in all scenarios considered in the Study.

While it would difficult to derive any definite conclusion, it can be observed that the average crude oil market price during the last 12 months amounted to about 70 USD/bbl (with a maximum of 95 USD/bbl reached in November 2007). This is nearly half way between the high and medium fuel price projections considered in the present Study (55 USD/bbl and 91 USD/bbl respectively on average over 2015 to 2030).

1.7.4 POTENTIAL AND ACTUAL SAVINGS

The generation savings evaluated in this Module 6 are potential (i.e. theoretical) savings resulting either from the optimal coordination of the three generation mixes, or from a "perfect" power market (either loose or tight pool). The actual savings will depend on the nature and importance of the future power pool, the type of possible power exchanges (spot, forwards, PPA, etc,), the actual level of coordination between the different Utilities, the policy to share costs and benefits of the interconnection and the HPP, the agreed selling price of energy, the wheeling tariff, etc.

1.7.5 LOOKING INTO THE FUTURE

The interconnection project presents a short pay back period (<10 years) for the most relevant projections (high or medium fuel price projections, medium or low demand projections for Ethiopia).

At the end of the payback period (i.e before 2030), the investment cost of the interconnection will be recovered. The remaining cost associated with the transmission of power will be the transmission losses, and to a lesser extend the O&M costs. This reduction of transmission cost will boost the relative economic advantage of hydro power export from Ethiopia, giving opportunity to even more hydro investments, for the benefit of the interconnected power systems (lower cost of electricity and reduction of emissions). In the same way, the hydro economic advantage over thermal generation will probably keep on increasing with the probable continuing increase of crude oil price after 2030.

Finally, when the perspective is widen to the development of the African power markets, the commissioning of the interconnection between Egypt, Ethiopia and Sudan will be a determining step forward to the completion of the connection between the North Africa power markets and the South African power markets (SAPP).

2 OBJECTIVE OF MODULE 6

The overall objective of Module 6 is to evaluate the benefits for the region (Egypt, Ethiopia and Sudan) provided by an interconnection of the three power systems according to various level of integration (or coordination) of these systems.

The questions related to this issue are:

- What are the options for the interconnection: line route, technology, capacity, commissioning date, etc ?
- Is there any need / benefit to reinforce the planned interconnection between Ethiopia and Sudan (planned capacity: 200 MW commissioning date: 2010) ?
- Is there any need, because of the interconnection, to reinforce the planned development of the transmission system in each power system ?
- What is the amount of economic power exchanges between the countries ?
- What are the resulting benefits for the region according to what options ?

Accordingly Module 6 will cover:

- the determination of least-cost generation expansion plan for each of the three power systems and for the coordinated system,
- the determination of the economic power exchanges minimizing the global cost of generation,
- the determination of the least cost interconnection option in term of technology,
- the transmission system analysis,
- the recommendation of a Regional Investment Program.

The present Volume 2 is focussed on the Generation Expansion Planning and Economic Study.

3 ORGANISATION OF MODULE 6 REPORT

This Module is organized in four Volumes:

- Volume 1: Executive summary of Module 6
- Volume 2: Generation Investment Planning and Economic Study
    - Least cost Generation Expansion Plan for the three isolated power systems.
    - Least cost Generation Expansion Plan for the interconnected system according to tight pool or loose pool power market.
    - Evaluation of the potential benefits for the region provided by the interconnection according to various level of integration (or coordination).
- Volume 3: Transmission Study
    - Volume 3-1: Analysis of the Network Expansion Plan - Egypt

  - Volume 3-2: Analysis of the Network Expansion Plan - Ethiopia
  - Volume 3-3: Analysis of the Network Expansion Plan - Sudan
  - Volume 3-4: Analysis of the Interconnection:
    - Interconnection options (Line routes / technologies / costs);
    - Transmission study (necessary reinforcements resulting from the interconnection, load low, short circuit analysis, etc).
- Volume 4: Recommendation for a coordinated regional investment plan.

The present Volume 2 is focussed on the Generation Expansion Planning and Economic Study.

4 METHODOLOGY

4.1 EVALUATION OF THE BENEFITS FOR THE REGION

The benefits for the region resulting from the interconnection will be evaluated by the comparison of two situations:

S1: independent development of the three power systems assuming the presence of no interconnection, this situation would lead to the determination by the Consultant of one investment program for each system: P_{Egypt}, $P_{Ethiopia}$, P_{Sudan}.

S2: development of the three power systems assuming the presence of an interconnection and various level of coordination between the power systems. This would lead to the determination by the Consultant of a coordinated investment program $P_{Intercon}$.

The benefits would be given by the difference of costs between these two situations:

Benefits from the interconnection = Cost [P_{Egypt}, $P_{Ethiopia}$, P_{Sudan}] – Cost [$P_{Intercon}$]

What are the costs involved in situation S1 (isolated development) ?

The cost of the investment program of each power system is composed of the cost of the associated Generation Expansion Plan (GEP) and Transmission Master Plan (TMP).

The cost of the GEP is composed of:

- investment cost in the required new generation units,
- operation cost (O&M + fuel costs) for both existing and future generation.

The cost of the TMP is composed of:

- the investment cost in the required new transmission lines, substation and related equipments,
- O&M costs for both existing and future transmission equipment.

Accordingly, the cost of the investment program for the three separated power systems can be written as:

Cost 1 = Cost [(GEP_{Egypt} + TMP_{Egypt}) + ($GEP_{Ethiopia}$ + $TMP_{Ethiopia}$) + (GEP_{Sudan} + TMP_{Sudan})]

What are the costs involved in situation S2 (coordinated development) ?

The commissioning of the interconnection will allow a reduction of investment cost (less capacity is required) and operation cost of the three GEP (fuel savings), at the expense of the cost of the interconnection (investment cost and O&M cost). Furthermore, compared to the development of the transmission in the isolated scheme, each transmission system might possibility requires some additional re-enforcement (called TR hereafter) because of the increased load flows inside some zone of each power system power system resulting from the interconnection.

Accordingly, the cost of the investment program for the three interconnected power systems can be written as:

$$\text{Cost 2} = \text{Cost}\ [(GEP'_{Egypt} + TMP_{Egypt} + TR_{Egypt}) + (GEP'_{Ethiopia} + TMP_{Ethiopia} + TR_{Ethiopia}) + (GEP'_{Sudan} + TMP_{Sudan} + TR_{Sudan})] + \text{Interconnection cost}$$

<u>Benefits for the region</u>:

The benefits for the region is given by the difference between Cost 1 and Cost 2:

$$\text{Benefits} = \text{Cost}\ [(GEP_{Egypt} - GEP'_{Egypt} + TR_{Egypt}) + (GEP_{Ethiopia} - GEP'_{Ethiopia} + TR_{Ethiopia}) + (GEP_{Sudan} - GEP_{Sudan} + TR_{Sudan})] + \text{Interconnection cost}$$

or

$$\text{Benefits} = \text{Cost}\ [(GEP_{Egypt} + GEP_{Ethiopia} + GEP_{Sudan})] - \text{Cost}\ [(GEP'_{Egypt} + GEP'_{Ethiopia} + GEP_{Sudan}] + \text{Interconnection cost} + \text{Cost}\ [TR_{Egypt} + TR_{Ethiopia} + TR_{Sudan})]$$

or

Benefits = [cost of the GEP for the 3 isolated power systems] – [cost of the GEP for the three interconnected power system] + Interconnection cost + Cost of the additional transmission re-enforcement in each country.

It is noticeable that the cost of the development of the three Master Plan in the isolated scheme is not necessary for this evaluation.

4.2 LEAST-COST GENERATION EXPANSION PLAN FOR THE THREE SEPARATED SYSTEMS

The first step in the evaluation of the benefits is the determination by the consultant of the least cost GEP for the three isolated power systems (i.e in absence of interconnection).

The general formulation of the cost function to minimize is:

NPV [investment cost + fuel cost + O&M + unnerved energy cost + externalities]

where :

NPV: Net Present Value over the planning period (2007-2030).

Investment cost: generation investment costs over the planning period.

O & M cost: O&M cost of generation over the planning period.

Fuel cost: fuel cost over the planning period.

Unserved energy cost: cost of unserved (i.e. unsupplied) energy over the planning period.

Externalities: refers to non energetic benefits of costs, for example:

- irrigation benefits,
- mitigation measurements (which might be included otherwise in the investment cost).

At this stage of the Study, and because of the time horizon of the Study (2030), some costs or benefits can be evaluated only in a qualitative way. These externalities could not be considered directly in the cost function. This problem is overcome by properly screening and ranking the HPP project in Module 4 considering both quantitative and qualitative criteria. As a result of this multicriteria ranking, the HPP projects have been sequenced starting from the commissioning of the "best" one. This sequencing is considered as an input to the determination of the GEP in the present Volume 2, while the timing of commissioning is optimised by the Planning Software.

These three GEP are determined on the base of:

- The target level of reliability defined in Module 4 (LOLP = 8 hours / year).
- The characteristics of the existing generation mixes described in Module 2.
- The characteristics of the HPP and TPP generation candidates, the demand and fuel price projections described in Module 3.
- The ranking and sequence of commissioning of HPP project determined in Module 4.

4.3 LEAST-COST GENERATION EXPANSION PLANS FOR THE INTERCONNECTED SYSTEM

The second step in the evaluation of the benefits is the determination by the Consultant of the least cost GEP for the three power systems interconnected through the interconnection project.

The general formulation of the cost function to minimize is:

NPV [investment cost $_{\text{generation + interconnection}}$ + fuel cost + O&M +unnerved energy cost + externalities]

With:

- The same target level of reliability as without interconnection (LOLP = 8 hours / year).
- A commissioning of the interconnection in 2015 (= earliest commissioning date considering construction duration).
- Interconnection capacity and costs (investment and O&M) determined in Vol 3 of the present Module.
- Cost of possible transmission reinforcement in the three power systems made necessary because of increased load flows resulting from the interconnection (determined in Vol 3 of the present Module).

The economic exchanges will be a result of the simulations for two different levels of coordination between the power systems, or in other terms two different models of regional power pool:

- tight pool model,
- loose pool model.

These two pool models are described in the next paragraph.

4.4 COORDINATION OF POWER SYSTEMS AND MODELS OF POWER POOL

This paragraph proposes a simplified presentation of power markets and a describes the two power pool models considered in the Economic Study (loose and tight pool models).

4.4.1 SPOT (OR DAY-AHEAD) MARKET

The creation of a spot market is typically the first sep in the implementation of a power market.

On this market, the actors (generation companies, distribution companies, traders, larger industrial consumers, etc) can buy or sell energy for day + 1, per hour, per block (ie. several hours), for base load, for peak load, etc.

The price of energy depends on the hours of delivery, and type of delivery (hours, block base, etc) as can be seen on the following graph which presents the price on EEX spot market for March 15, 2007:

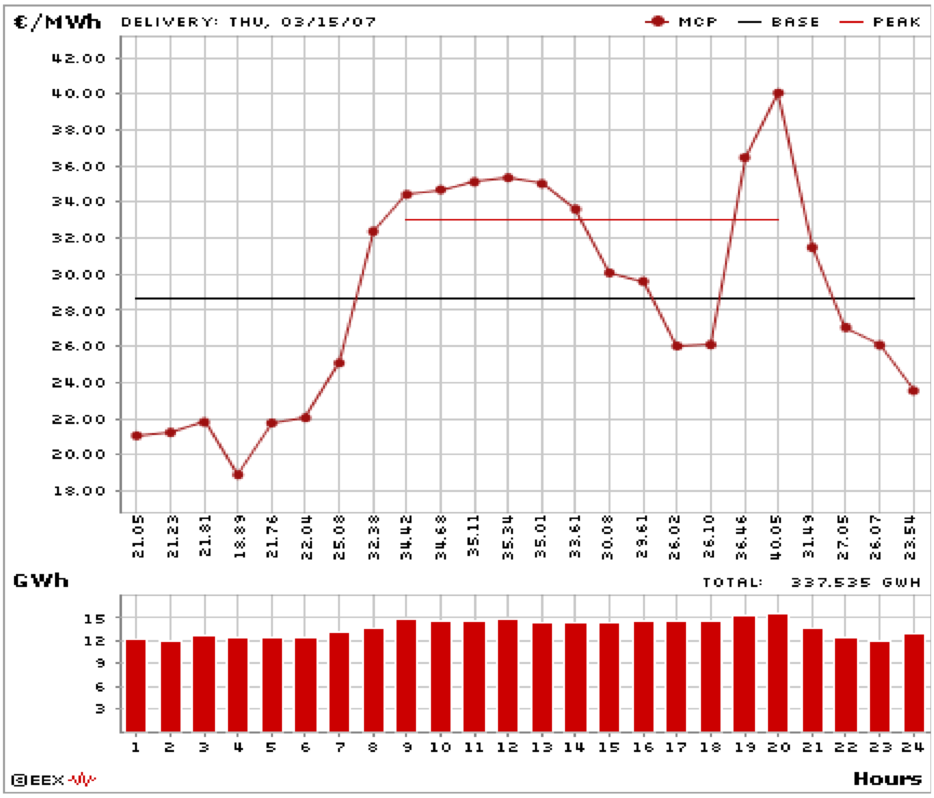

Figure 4.4-1 - EEX spot market price for March 15, 2007

The price evolution obviously follows the evolution of the demand, increasing with the increase of demand and the increasing cost of generation.

The possibility to buy or sell on the spot market allows generation companies to reduce their operation costs (fuel costs). The daily choice is then to buy energy on the spot market or to operate their own generation units. This decision is made daily on the basis of the global merit order among its company generation units and the market price.

A generation company has also the possibility to sell its energy on the market if its own marginal cost of generation is lower than the market price. In this way the market becomes an additional customer for the generation customer.

Type of transaction	Delivery horizon	Sub type	Decision
Buy or sale MWh	Day + 1	Hour, block, base, peak, etc	Operation decision: buy on the market or operate

Table 4.4-1 - Main characteristics of a Spot Market

4.4.2 FORWARD (OR FUTURE) MARKET

When a power market enlarges and develops, it can be observed:

- a global increase in the energy exchanged on the market,
- a global increase in the number of actors,
- a global increase in the fluidity of the market, meaning that each buyer finds energy to buy on the market whatever the amount of energy.

The type of possible transactions also increases with the growing and maturation of a power market. The usual next step after a spot market is the creation of a forward (or future) market.

On this market, the actors can buy or sell energy (usually base or peak) for:

- month + N months (with N typically covering the current year and year +1),
- quarter + N quarters (with N typically covering the current year and year +1),
- year + N quarters (with N typically from 1 to 6 years).

The price of energy depends on the time of delivery (month, quarter or year), and type of delivery (base or peak load, etc) as can be seen on the following table which presents the price on EEX German Power Futures for March 15, 2007:

German-Power-Futures

Prices and tradingvolumes - 03/15/2007
Values in Euro/MWh, GWh and Number of Contracts

NAVIGATION
DAY
WEEK
PRINTABLE VERSION

YEAR

GERMAN-BASELOAD-YEAR-FUTURES

NAME	BEST BID	BEST ASK	NO. OF CONTR.	LAST PRICE	ABS. CHANGE	LAST TIME	LAST VOL.	SETTL. PRICE	VOL.	OTC CLEARING	OPEN INTEREST
Cal-08	-	-	-	-	0	-	-	52,66	-	-	107
Cal-09	-	-	-	-	0	-	-	53,40	-	-	11
Cal-10	-	-	-	-	0	-	-	54,13	-	-	-
Cal-11	-	-	-	-	0	-	-	55,25	-	-	-
Cal-12	-	-	-	-	0	-	-	55,75	-	-	-
Cal-13	-	-	-	-	0	-	-	56,25	-	-	-

Figure 4.4-2 - Prices of EEX German power futures

The price evolution obviously follows the evolution of the demand along the year (for delivery in N months or N quarters) or over the next years (for delivery on N years).

As with the spot market, the possibility to buy or sell in N months or quarters allows generation companies to reduce their operation costs (fuel costs) through the choice between buying energy on the market or to operate their own generation units.

In addition to this, provided the future market has a time horizon long enough (> 3 or 4 years), the generation company has the choice between buying on the forward market or investing in new generation capacity.

Type of transaction	Delivery horizon	Sub type	Decision
Buy or sale MWh	Month + n	base load, peak load	Operation decision: buy on the market or operate
Buy or sale MWh	Quarter + n	base load, peak load	Operation decision: buy on the market or operate
Buy or sale MWh	Year + n (<3)	base load, peak load	Operation decision: buy on the market or operate
Buy or sale MWh	Year + n (>3)	base load, peak load	Investment decision: buy on the market or invest in new generation capacity

Table 4.4-2 - Main characteristics of a Forward Market

4.4.3 LEVEL OF COORDINATION BETWEEN POWER SYSTEMS - LOOSE AND TIGHT POOL MODELS

This paragraph present the two models of power pools / coordination considered for the simulation of the interconnected system and the determination of the regional investment plan.

4.4.3.1 Economic power trades

Economic power trades are grounded on the cost differences of power generation units in neighbouring countries. Economic exchanges are those minimizing the global cost of generation. The presence of an interconnection allows to supply one country at some particular moment with lower cost generation units available in other country. This supply may not be continuous, and may vary in direction and level according to the nature of the power mixes (demand variation, hydrology, etc).

In the present economic Study the amount of power trades between Egypt, Ethiopia and Sudan, and the resulting savings for the region, will be assessed along two approaches (as per TOR): loose pool model and tight pool model. These two models described hereafter, can be understood as two different stages of development of a power market, or different level of coordination / cooperation between the three power systems.

4.4.3.2 Loose Pool model: coordination of operation

In the loose pool model, the investment decisions for new generation units is the same as when the power systems are left isolated. In other words, each country keeps the ability to be self-sufficient and to cover its own peak demand. The GEP of each country remains identical to the ones without interconnection.

The operation of generation is coordinated on a regional basis (or regional dispatch centre) on the global merit order, within the limits set by the interconnection capacities.

The loose pool model represents the first stage of development of a regional power market providing the relevant price signals for operation (spot market and market for forwards within the current year).

The resulting saving is a global reduction of operation costs (mainly fuel costs).

4.4.3.3 Tight pool model: coordination of operation and generation investments

A fully integrated regional power system would lead to the lowest global generation cost for the region.

In this theoretical situation, all the interconnected power mixes would be operated as a single one, on the basis of a global (i.e. regional) merit order (i.e. from least cost to the most expensive generations units) from a single dispatch centre. At any partial moment (hour, day, year) the total demand would be supplied by the lowest cost generation unit available in the region.

Furthermore, in this model, the investment generation expansion plan would be also optimised at a regional level allowing to take advantage of the countries complementary resources (low cost hydro generation in a country, low cost thermal generation in an other, etc).

In a nutshell, operation and investment are coordinated in the tight pool model.

Of course, even in this theoretical case some part of the generation would be still dispatched on a non economic basis (e.g. irrigation), and the transmission and distribution network would set limits to amount of power exchanges possible between the different areas.

This tight model can be understood as a representation of a regional mature power system providing the relevant price signal for:

- operation decision: through the existence of a spot market and a forward market, the actors decide whether to buy energy on the market or operate their own generation units,
- investment decision: through the existence of a forward market with a relevant time horizon (>3 to 4 years), the choice whether to buy now energy delivered in next years, or investment in their own new generation units.

This regional operation and investment regional optimisation (or coordination) would result in:

- operation cost savings (expensive fuel in one country would be substituted by lower cost generation fuel available in another country),
- investment savings (the commissioning of some "expensive" plants might be postponed if firm capacity is available from another country through the interconnection, leading to a larger development of lower cost generation in another country).

4.4.3.4 Summary table

Model	Level of coordination	GEP	Savings
Isolated system	No coordination	GEP Egypt, GEP Ethiopia, GEP Sudan	Reference situation
Loose pool model	Operation	Idem as above	Fuel costs
Tight pool model	Operation and investment	Updated GEP	Fuel costs and invest. costs

Table 4.4-3 - Summary characteristics of tight and loose pool models

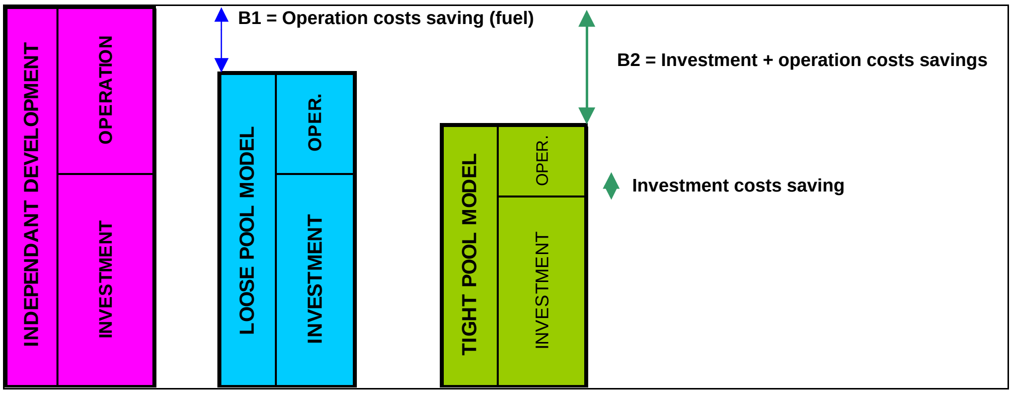

Figure 4.4-3 - Benefits provided by tight and loose pool models

<u>Important notes</u>:

In the loose pool model the operation savings come from:

- thermal to thermal substitution: the generation from a high cost thermal unit in one power system is replaced by the generation from a lower cost thermal unit). Here the term costs refers to the variable cost of operation (fuel cost and variable O&M cost),
- thermal to hydro substitution: the generation from high cost thermal unit in one power system is replaced by the generation of hydro plant in another system. The cost of the extra hydro generation is essentially free, because the planning of planting of HPP is left unchanged in the loose pool model (the surplus energy come from water that would have been spilled without interconnection, particularly in the first years following the commissioning of large HPP, when the internal demand is not still high enough to absorb the new hydro generation).

The tight pool model leads to global generation savings (operation + investment) greater than the loose pool model. Generally speaking, both operation and investment cost would be lower in the tight pool model (as presented in the previous figure). However, when HPP projects are involved, the global investment cost might be greater, because of the greater investment cost of HPP, but the global cost would still be lower, because of the fuel savings resulting from substitution of thermal generation by hydro generation.

4.5 POINT OF VIEW OF THE ECONOMIC ANALYSIS

In the course of the Eastern Nile Power Trade Program Study, the point of view of the analysis starts from a global view of the situation (Phase I) and progressively narrows on the Interconnection project (Phase II). Accordingly, depending on the phase and module of the present Study, the point of view of the economic analysis evolves in order to consider sequentially all the different issues.

Module 6:

In Module 6, the point of view of the economic analysis is regional, meaning the objective is to measure the global benefit (i.e savings) for the three countries, and not the benefits specifics for each country.

A cost approach is considered (including externalities e.g. non energetic benefits and mitigation costs) as per TOR. The global (and real) cost for the region is evaluated and considered. What is evaluated and analysed is the modification of the global cost (generation investment, interconnection investment, operation cost) with and without interconnection.

This means, for example, that the share of cost of projects (interconnection or HPP) between the different countries is not considered or relevant at this stage, because it does not change the global cost of investment for the region.

Subsidies to fuel are not considered either, nor duty or taxes, or the selling price of energy for the same reason.

In the same way, the allocation of the benefits to the different stakeholders is not relevant. In other words, the possible selling price of power and wheeling tariff are not relevant in the economic analysis.

In this way, the global benefits (i.e. the global cost reduction) for the region could be evaluated.

As a result, the economic Study in Module 6 will evaluate the potential benefits for the region according to various options (interconnection, power pool models, etc).

Link with Module 7 of the present Study:

The actual global benefits for the region will depend on the actual organisation set up to develop power exchanges through the interconnection (power pool, institutional reforms, etc). This part will be analysed in Module 7 (Development of a Strategy for Power Trade):

- what is the relevant power pool model for the region,
- what are the stages of implementation of this model,
- what type of transactions,
- pricing mechanism,
- how to share the cost of the interconnection,
- how to operate the interconnection. What rules ?
- what institution reform,
- etc.

Link with Phase II – Financial analysis:

In the financial analysis carried out in Phase II of the present Study the point of view of the analysis will be significantly different: it will be from the interconnection project itself, and the question will be what is the profitability of the interconnection project considering:

- the cost of the project: interconnection cost (investment, O&M), corporate income tax, equity / debt ratio, cost of equity and debt, etc,

- the income of the project: transmission tariff, subsidies, etc.

This analysis will be carried out through a simplified business plan.

4.6 SELLING PRICE OF ENERGY AND SAVING SHARING

In line with the previous paragraph, the purpose of this part is to clarify some concepts peripheral to the Economic Study. These concept are discussed more deeply in Module 7.

4.6.1 COST OF GENERATION, SELLING PRICE OF ENERGY, SHARING SAVINGS

In compliance with the TOR, and as best practises, the economic Study is a cost approach evaluating the global cost savings for the region:

- reduction of operation costs (mainly fuel costs),
- reduction / increase of investment costs.

Accordingly, the selling price of energy, which is a way of sharing the savings, is not relevant at this stage.

The relation between the selling price of energy, the generation cost of energy and the sharing of savings can be illustrated by the following example:

<u>Hypothesis</u>:

Country A exports to country B one MWh generated at 40 $/MWh, which comes in substitution of 100 $/MWh generation in country B.

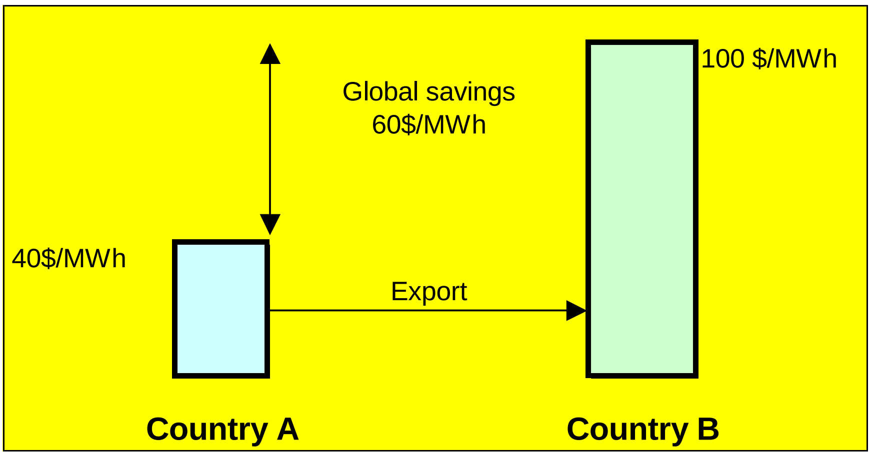

Figure 4.6-1 - Relation between savings and selling price (1)

<u>Economic approach of the global savings</u>:

In country A: the generation cost increases by 1 x 40 $.

In country B: the generation cost decreases by 1 x 100 $.

Global cost savings for A + B: 1 x 60 $.

What are the savings for each country ?

The savings for each country depend on how the global saving is shared between A and B, which is a result from the negotiation of selling price.

If the negotiated selling price is 70 $/MWh (savings shared 50% for each country):

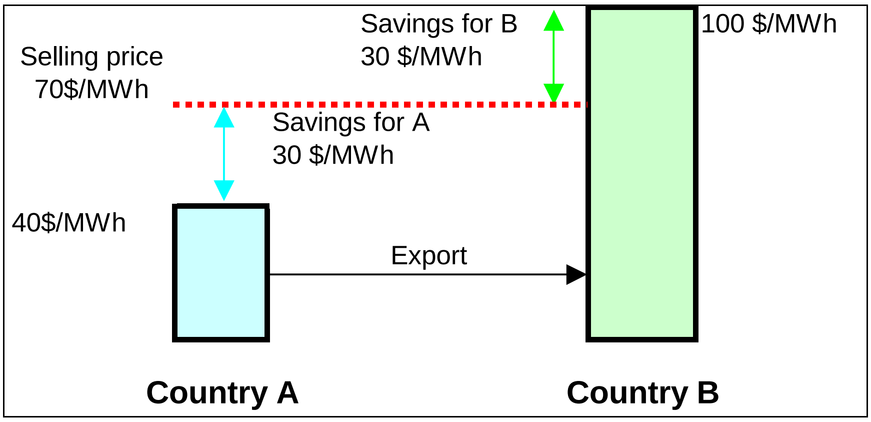

Figure 4.6-2 - Relation between savings and selling price (2)

- For country A: 100 $ generation is saved, 70 $ import is paid for import -> net savings = 30 $.
- For country B: 40 $ additional generation is paid, 70 $ is received from export ->net savings= 30$

The global saving is 60 $, which is of course the same value found by the cost approach.

Conclusion:

➔ the selling price is a way of sharing the global cost savings between the actors.

➔ the net savings for each country depends on the negotiated selling prices:

Net savings for the importing country = Fuel savings – Selling price per MWh x Imported energy

Net savings for the exporting country = Selling price per MWh x Exported energy – Generation cost of the exported energy

4.6.2 SHARING DOWNSTREAM BENEFITS

Apart from power generation, large HPP projects might provide benefits at other downstream locations (flood alleviation, sediment reduction, regulation of inflow favourable to irrigation, etc).

These benefits are not within the control of a private generator that would invest in the hydro power plant, and accordingly could not be sold by the private generator. The benefits at other locations would have to be taken into account in negotiations between the Eastern Nile countries in relation with the allocation of costs and benefits between countries.

4.6.3 BASE OF TARIFF FOR A POWER PURCHASE AGREEMENT

Power purchase agreements are discussed more thoroughly in Module 7 (Development of a Strategy for a Power Pool). The link between the tariff for a PPA and the notion of generation cost and of marginal value of energy is presented hereafter.

The tariff of electricity in a PPA is a result of negotiation between:

- an investor developing a project with a profitability objective (e.g. IRR level),
- a buyer, who wants to buy energy at a lower cost than he could generates otherwise.

Accordingly, the investor will calculate what is its minimum selling price acceptable covering:

- the cost of generation (investment + O&M along the duration of the PPA),
- the profitability margin.

The buyer will calculate the cost of the avoided energy (investment + fuel cost + O&M along the duration of the PPA). This is the maximum price the buyer would accept to pay.

The tariff of the PPA will be negotiated between these two values.

5 PLANNING SOFTWARE

The planning software used in the present Study by the Consultant to determined the generation expansion plans (isolated or coordinated) and the power exchanges between the three power systems is the powerful stochastic integrated OPTGEN / SDDP software package provided by PSR (Brazil). These Models are described briefly in the folders given in Appendix M6 Vol 2.

5.1 OBJECTIVE FUNCTION

The general purpose of generation investment planning is to determine the least cost schedule of commissioning of new generation units over a given period of time within acceptable level of reliability of power supply.

More precisely, the objective cost function is:

Min [NPV (Investment costs + O & M cost + Fuel costs + Unserved energy cost + Externalities)]

where:

NPV: Net Present Value over the planning period (2007-2030).

Investment costs: generation and interconnection investment costs over the planning period.

O & M cost: O&M cost of generation and interconnection over the planning period.

Fuel cost: fuel cost of generation (TPP) over the planning period.

Unserved energy cost: cost of unserved (i.e. unsupplied) energy over the planning period.

Externalities: other costs or benefits such as mitigation costs, irrigation benefits, etc.

5.2 MAIN PRINCIPLE OF THE OPTIMISATION PROCESS

The expansion problem can be viewed as an iterative two stage decision process:

- investment step: evaluation of the new capacities required (TPP, HP),
- operational step: calculation of the optimal operation policy given the new capacities obtained in the investment step.

The investment step is solved by OPTGEN which found an approximated solution (Expansion Plan x*).

The operation step is solved by SDDP which precisely calculate the cost of operation on a stochastic basis given the planning of new capacity found by OPTGEN. Besides SDDP calculates the derivatives of the operation cost for each new capacity (generation and / or interconnection).

These derivative functions are feedback to OPTGEN and allow to direct OPTGEN to an improved expansion plan.

SDDP is called back again, giving to OPTGEN new values of derivative functions, allowing OPTGEN to improve on the previously found expansion plan.

After a number of iterations, which depends on the complexity of the power system, the least cost generation plan is found.

This iterative process is illustrated in the hereafter figure:

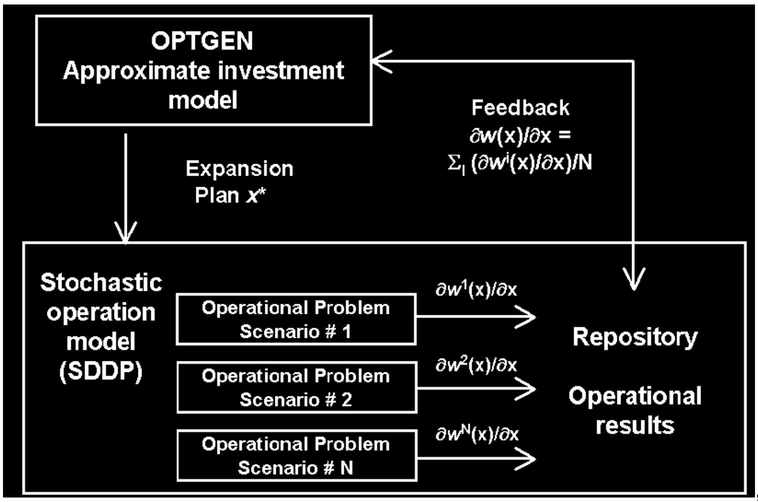

Figure 5.2-1 - Optimisation iterative process

<u>Algorithm highlights</u>:

The investment model (OPTGEN) uses mixed integer programming techniques.

The operation model (SDDP) is based on Stochastic Dual Dynamic Programming which allows to consider explicitly the hydrological uncertainties (as opposed to a deterministic approach based on firm energy and firm capacity). Aside from calculating the optimal operating policy the model calculates several economic indices such as network congestion revenues, water values, etc.

The convergence and optimality of the solution is based on a mathematical criterion.

5.3 MODELLING HIGHLIGHTS FOR THE PRESENT STUDY

The modelling capabilities of OPTGEN/SDDP are presented in detail in Appendix M6 Vol 3.

Apart from the "standard" modelling capabilities, OPTGEN / SDDP package offers capabilities particularly pertinent to the present Study:

Power interconnections:

- modelling of the three generation mixes (Egypt, Ethiopia and Sudan) linked by interconnections, each generation mix having to balance its demand from 2008 to 2030 (including power import / export);
- modelling of interconnection: max capacities in each direction, losses rate, wheeling costs, interconnections could be considered as candidate investments.

Hydro continuity across several countries:

- modelling hydro scheme with hydrological continuity between Ethiopia and Sudan (Blue Nile river and Tekese / Sobat river. Accordingly the downstream impact are considered and evaluated by the model.

Hydropower plant and water uses:

- modelling of hydro scheme:
    - live and dead storage (e.g. Mandaya, Border, Karadobi),
    - storage = f (height) (e.g. Roseires, Merowe, Mandaya, Gibe III),
    - storage = f (area),
    - evaporation = f (month),
    - energy coefficient = f (height) (e.g. Roseires, Merowe, Mandaya),
    - irrigation demand, operation with priority to irrigation or priority to power (e.g. Sudan),
    - water balance in cascade, spillage, monthly inflow series, etc.
- topology of hydro schemes: representation of hydro scheme topology, downstream impact of upstream projects (dead storage, regulation effect) are automatically considered;
- stochastic approach considering the hydrological uncertainties and generation unit outages.

6 BASIC ECONOMIC PARAMETERS

The basic economic parameters considered in this Module 6 are:

Discount rate:

Base case: 10% , sensitivity analysis 12% and 8%. This value refers to real value[11] (see Module 4).

Net Present Values (NPV) are discounted in 2008.

[11] The discount rate can be given in real value (ie. without inflation) or in nominal value (including inflation)

Cost of unserved energy:

2000 USD/MWh (ref Module 4)

Reference Currency:

USD2006

Exchange rate:

1 € = 1.25 USD2006 (average exchange rate in 2006)

Cost escalation:

Classically, economic approaches use constant money[12]. This is equivalent to assuming zero escalation over the project period. The same results would be obtained in current money if escalation was affecting all costs and revenues equally.

Besides, the use of constant money allows to compared future costs more readily than the use of current money (where the comparison is affected by inflation).

Duties and Taxes:

In the economic study, the point of view is the one of the three countries. Accordingly, duties and taxes, being essentially transfer of funds, are excluding from the economic analysis.

Period of study:

2008 – 2030.

Time steps:

12 months per year. Each month is divided in 5 blocks.

Reference hydrology:

1955 – 2004.

Simulations:

The model optimise and simulate the generation mix for 50 hydrological "scenarios".

Each hydro scenario has the duration of the study period (ie. 23 years, from 2008 to 2030).

The first scenario is composed of the hydrological years 1954, 1955, 1956, etc

The second scenario is the result of the circular shift of one year applied to the first scenario: 1955, 1956, 1957. The following table presents the resulting first 13 years of the 50 hydro scenarios:

[12] Also called real cost

	Period of Study												
Scenario	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966
2	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967
3	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968
4	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969
5	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
6	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971
7	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972
8	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
9	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
10	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975
11	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
12	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
13	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
14	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
15	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
16	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
17	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
18	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
19	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
20	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
21	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
22	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
23	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
24	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
25	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
26	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
27	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
28	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
29	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
30	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
31	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
32	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
33	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
34	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
35	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
36	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
37	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
38	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
39	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	1954
40	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	1954	1955
41	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	1954	1955	1956
42	1995	1996	1997	1998	1999	2000	2001	2002	2003	1954	1955	1956	1957
43	1996	1997	1998	1999	2000	2001	2002	2003	1954	1955	1956	1957	1958
44	1997	1998	1999	2000	2001	2002	2003	1954	1955	1956	1957	1958	1959
45	1998	1999	2000	2001	2002	2003	1954	1955	1956	1957	1958	1959	1960
46	1999	2000	2001	2002	2003	1954	1955	1956	1957	1958	1959	1960	1961
47	2000	2001	2002	2003	1954	1955	1956	1957	1958	1959	1960	1961	1962
48	2001	2002	2003	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
49	2002	2003	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964
50	2003	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965

Table 5.3-1 - hydro scenarios

In this way, each year of the study period "sees" all 50 possible hydrological years (which are given the same probability). Each simulation along each hydro scenario simulates the behaviour of the generation mixes along a real sequence of past hydrology. While the average over all hydro scenario provides the average behaviour (e.g average power, average export, average storage, etc) of the generation mixes over all hydro uncertainties.

7 ECONOMIC COMPARISON OF THERMAL CANDIDATES

The characteristics of thermal candidates are described in Module M3.

The purpose of the present paragraph is:

1. For each power system, to compare economically the different possible thermal candidates (capacity, fuel, technology) in order to focus the economic analysis (i.e. determination of the generation expansion plan) to the least-cost option.

   This analysis is based on the classic screening curve approach (explained in details in Appendix M6 Vol 2) which compares, on an annual basis, the total economic cost[13] of the different thermal candidates, according to its load factor[14].

2. Compare the generation cost of the different power systems in order to identified the power system with the lower generation cost, which will possibly be the origin of power export through the interconnection, and the power system with the highest cost (which will possibility be the destination of the power exported).

7.1 RANKING OF THERMAL CANDIDATES IN EGYPT

7.1.1 BASE CASE (10% DISCOUNT RATE)

The following figure presents the screening curves for the Egyptian generic[15] thermal candidates (770 MW gas-fired CCGT, 650 MW gas-fired STPP, and 250 MW gas-fired OCGT) for the reference discount rate (10% discount) and year 2015.

[13] Including investment cost, fuel cost, O&M cost and considering construction schedule, life duration and discount rate.
[14] Load factor: annual generation / maximum possible annual generation.
[15] Generic: refers to the fact that the candidates is constructed in a generic site (i.e. not already equipped).

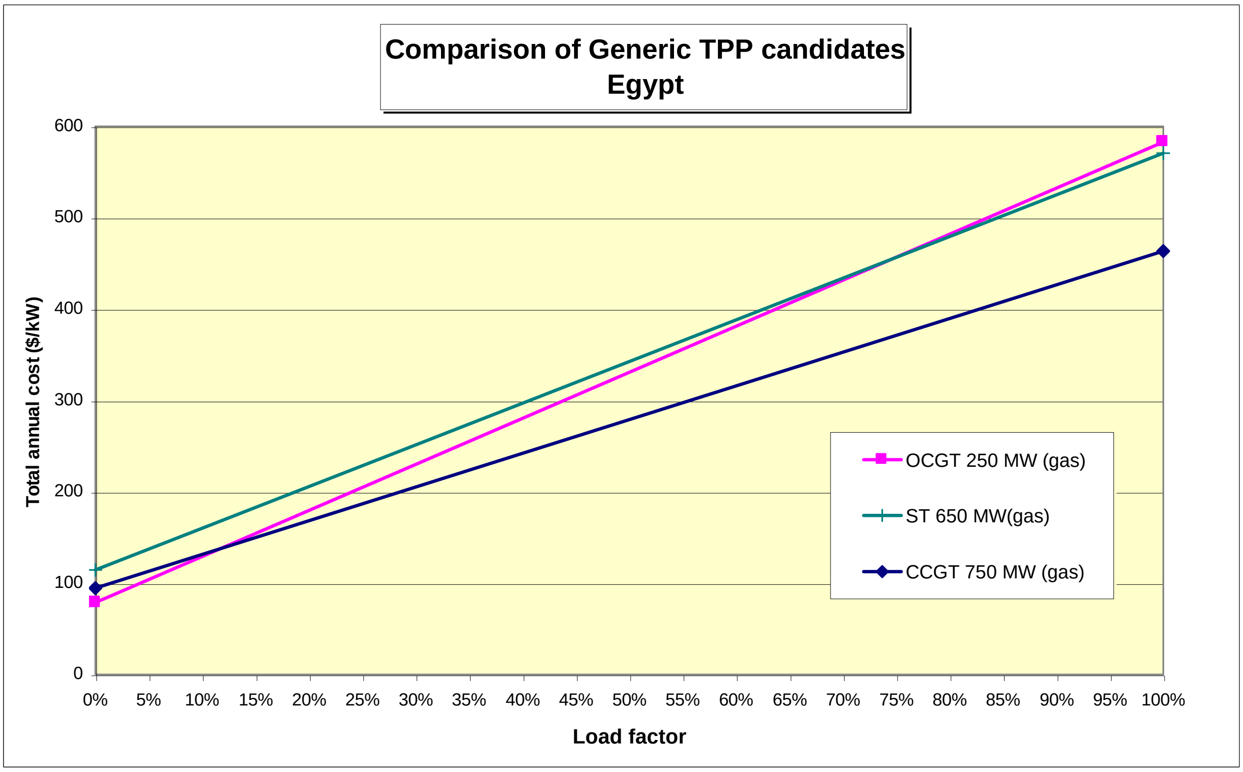

Figure 7.1-1 - Comparison of generic thermal candidates – Year 2015 - Egypt

Comparison of generic TPP candidates:

From the previous figure, it can be observed that:

- For load factor greater than 10% (about 900 hours per year), the least cost option for new generation investment is the development of new-gas-fired 770 MWCCGT. 250 MW gas-fired OCGT are significantly more expensive, while 650 MW gas-fired STPP are even more expensive.
- For load factor lower than 10%, the least cost option is the development of new 250 MW gas-fired OCGT.
- For any load factor, 650 MW STTP are more expensive than OCGT or CCGT.

Comparison of generic CCGT and CCGT candidates on existing sites:

The development of new CCGT plant on already existing and equipped sites allows to reduce the investment cost compared to generic candidates installed on new sites. This is the case for the new CCGT listed in EEHC expansion plan (table 6.1-1 of Module 3 Vol 2): Sidi Krir, Kurimat, Nobaria, Atfe, Sharm El Sheik, Alexandria East.

For this reason, all these new CCGT will enter the Egyptian generation expansion plan before the generic CCGT candidates.

Comparison of generic CCGT and STPP candidates on existing sites:

While **Figure 7.1-1** shows that generic gas-fired STTP are significantly more expensive than gas-fired CCGT, the development of new steam plants on already existing and equipped sites allows to reduce the investment cost. The following figures compares the cost of these sites compared to the generic gas-fired OCGT and CCGT:

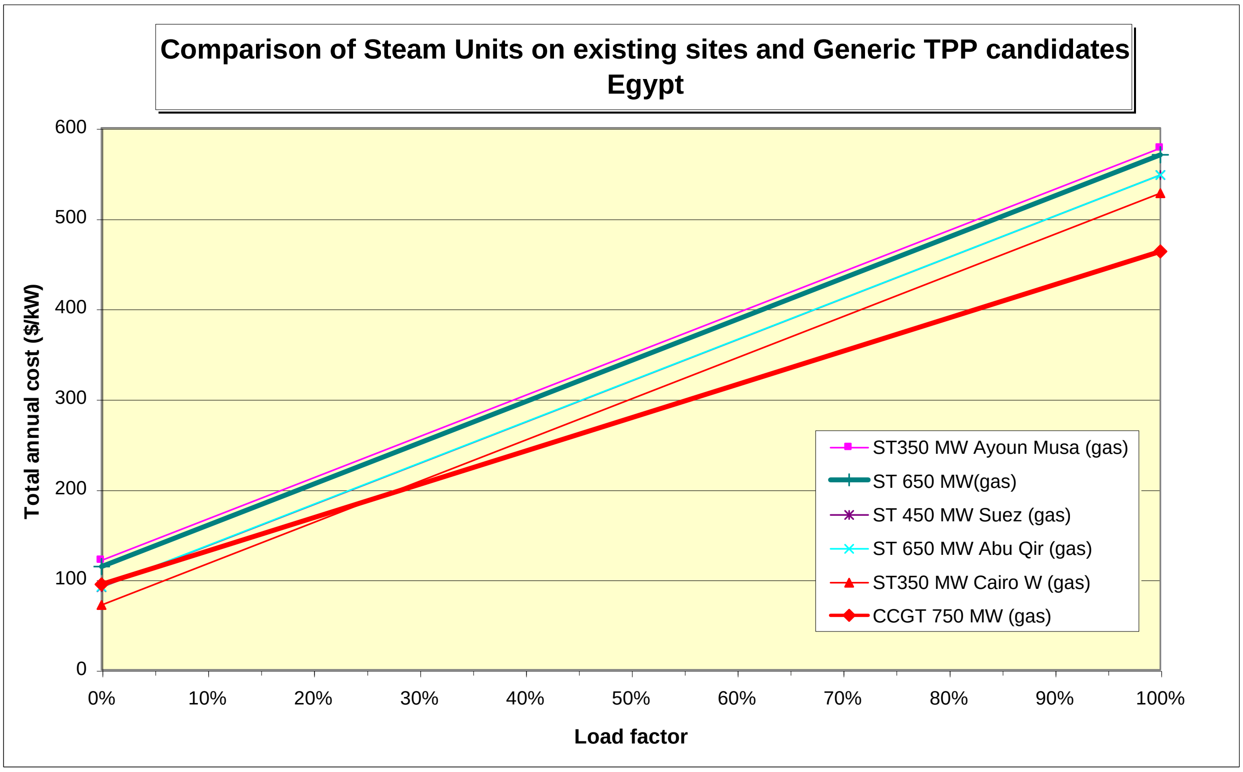

Figure 7.1-2 - Comparison of generic CCGT & OCGT and new STTP on existing sites – Year – 2015 - Egypt

The previous figure shows that the cost of new STPP developed on existing sites (Ayoun Musa, Abu Qir, Cairo W, Suez) is indeed lower than the cost of generic new 650 MW STPP, nevertheless it is still greater than the cost of generic CCGT.

The only exception is 350 MW gas-fired STPP at Cairo W, which is less expensive that 750 MW gas-fired CCGT for load factor lower than 20% (about 1 800 hours per years).

While all these new gas-fired STPP (except for Cairo W) are more expensive than the generic 750 MW gas-fired generic CCGT, they will be considered as committed according to EEHC generation expansion plan (Module 3 Vol 2 Table 7.1-1), in order to preserve some diversity in the generation technologies. They represent a total of 3 500 MW new capacity.

7.1.2 Sensitivity to fuel cost

The fuel cost increases along the period of study according the three fuel price projections described in Module 3 Vol 5.

The following figure presents the screening curves for the medium fuel price projection for year 2030 (and 10% discount rate):

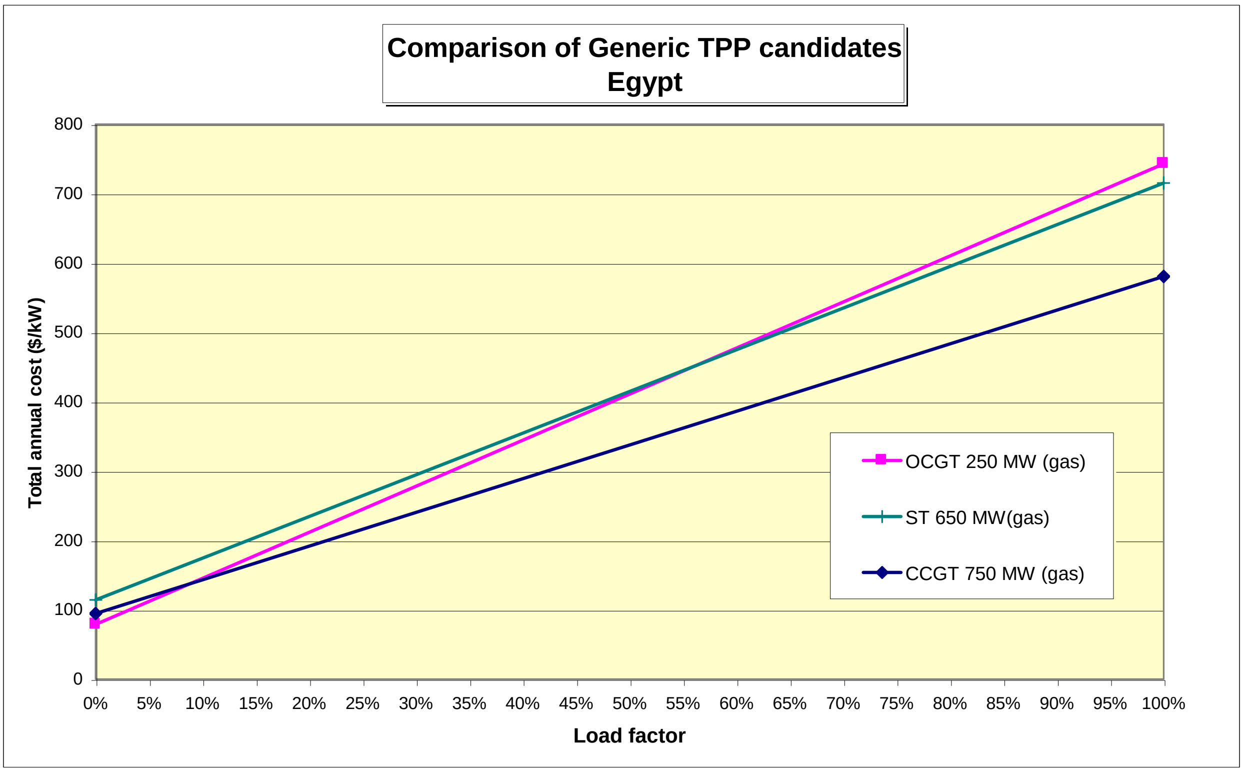

Figure 7.1-3 - Comparison of generic TPP - Year 2030 - Medium fuel price projection - Egypt

There is a general increase of the economic cost of the generic thermal plants candidates, but without any impact on the ranking of the project. The break even point between OCGT and CCGT is still around 10% load factor.

The following figure presents the screening curves for the high fuel price projection for year 2030 (and 10% discount rate):

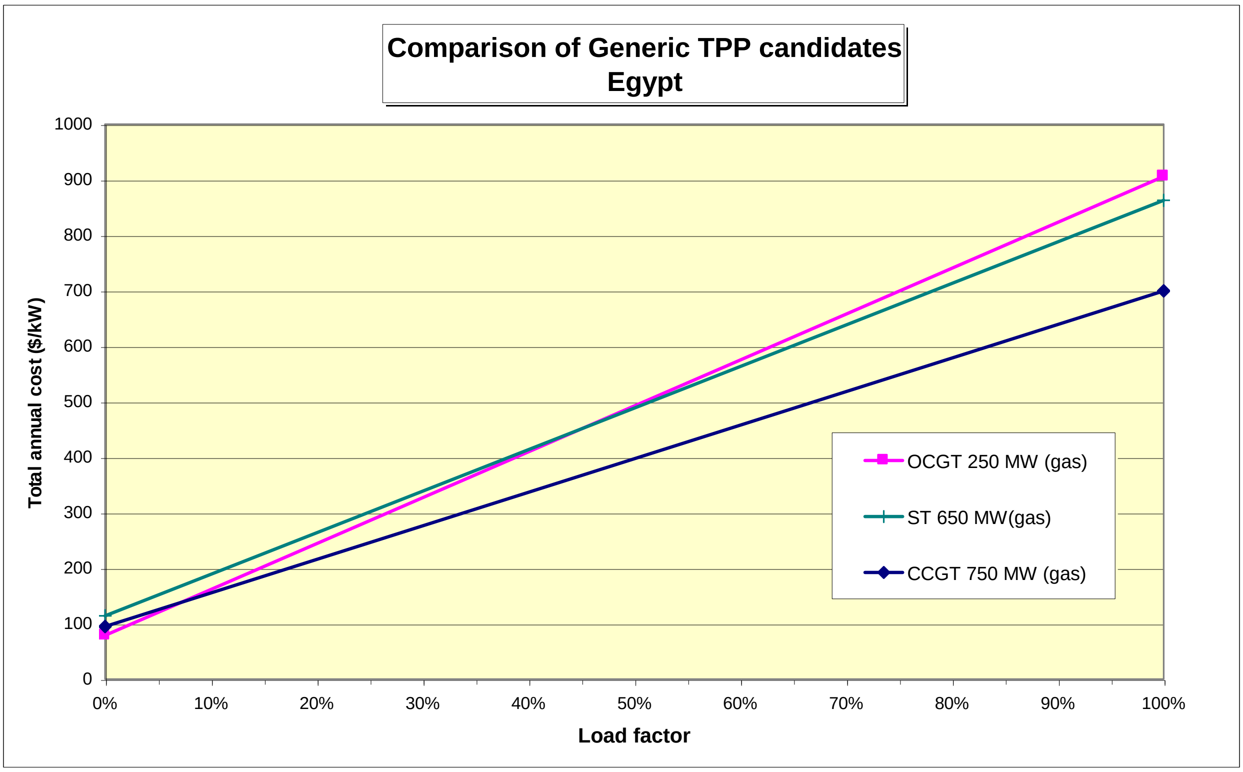

Figure 7.1-4 - Comparison of generic TPP candidates – Year 2030 – High fuel price projection – Egypt

The previous two figures show that an increase of fuel price shift the breakeven point between the economic cost of gas-fired OCGT and gas-fired CCGT to slightly lower values (i.e. about 8% instead of 10%).

The general ranking between the different candidates is not affected.

7.1.3 SENSITIVITY TO DISCOUNT RATE

The two following figures shows that the previous conclusions remained unchanged for 12% and 8% discount rates (year 2015 – Medium fuel price projection).

<u>For 12% discount rate</u>:

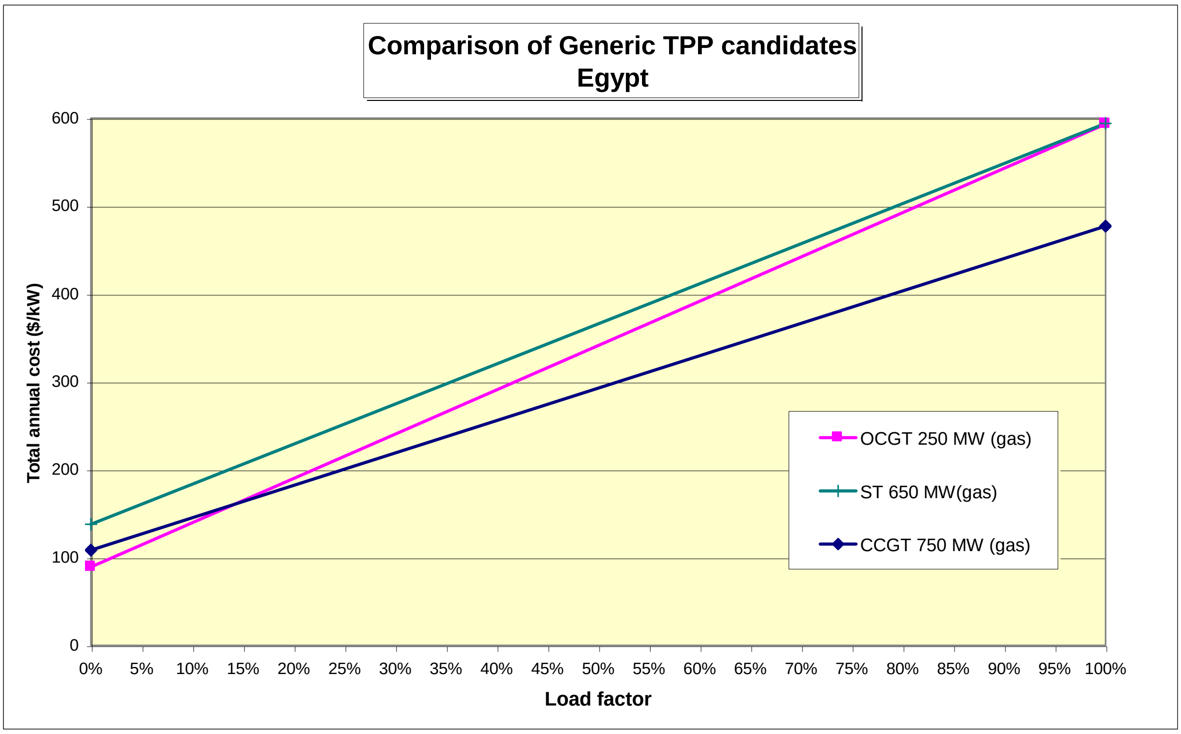

Figure 7.1-5 - Comparison of generic TPP candidates - 12% discount rate – Year 2015 - Egypt

<u>For 8% discount rate</u>:

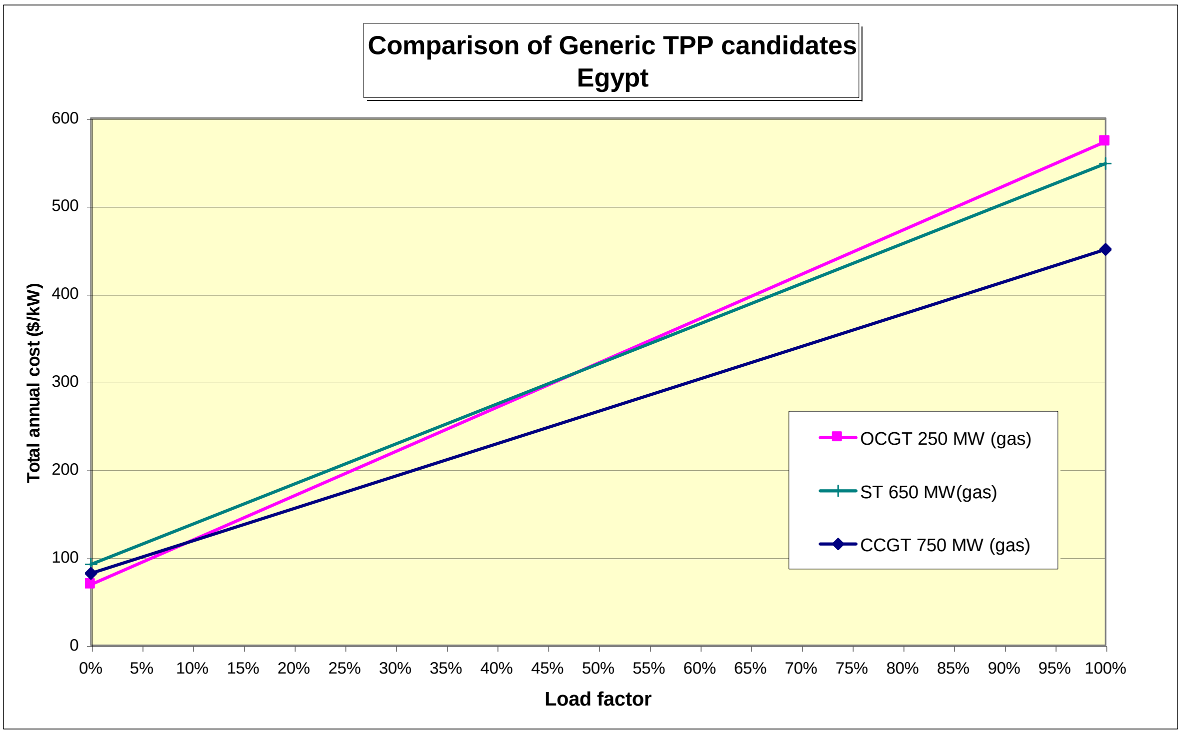

Figure 7.1-6 - Comparison of generic TPP candidates - 8% discount rate – Year 2015 - Egypt

Discussion:

A lower discount rate increases the relative profitability of candidates with greater investment cost. Accordingly, the break even point between OCGT and CCGT shift to 8% load factor (for 8% discount rate) instead of 12% load factor (for 12% discount rate).

7.1.4 CONCLUSION FOR THE DETERMINATION OF THE GENERATION EXPANSION PLAN

On the base of previous analysis, the bulk of the development of the least-cost thermal generation expansion plan will be based on new 750 MW gas-fired CCGT which constitute the least-cost option. The new CCGT projects identified on existing sites (Sidi Krir, Kurimat, Nobaria, Atfe, Sharm El Sheik, Alexandria East) will be committed first due to their lower investment costs.

Some 3 500 MW of gas-fired STPP projects already identified on existing sites will be committed in order to preserve some technology diversity. However, the development of generic STPP is more costly than generic gas-fired CCGT and will not be considered in the expansion plan.

The development of new peak generation (for duration lower than 900 hours per year) will be based on new 250 MW gas fired OCGT.

7.1.5 ECONOMIC COST PER MWH

From the previous curves, it is possible to calculate the average economic cost per MWh of the generic candidates as a function of the annual load factor. The following figure gives these costs for year 2020 and a 10% discount rate:

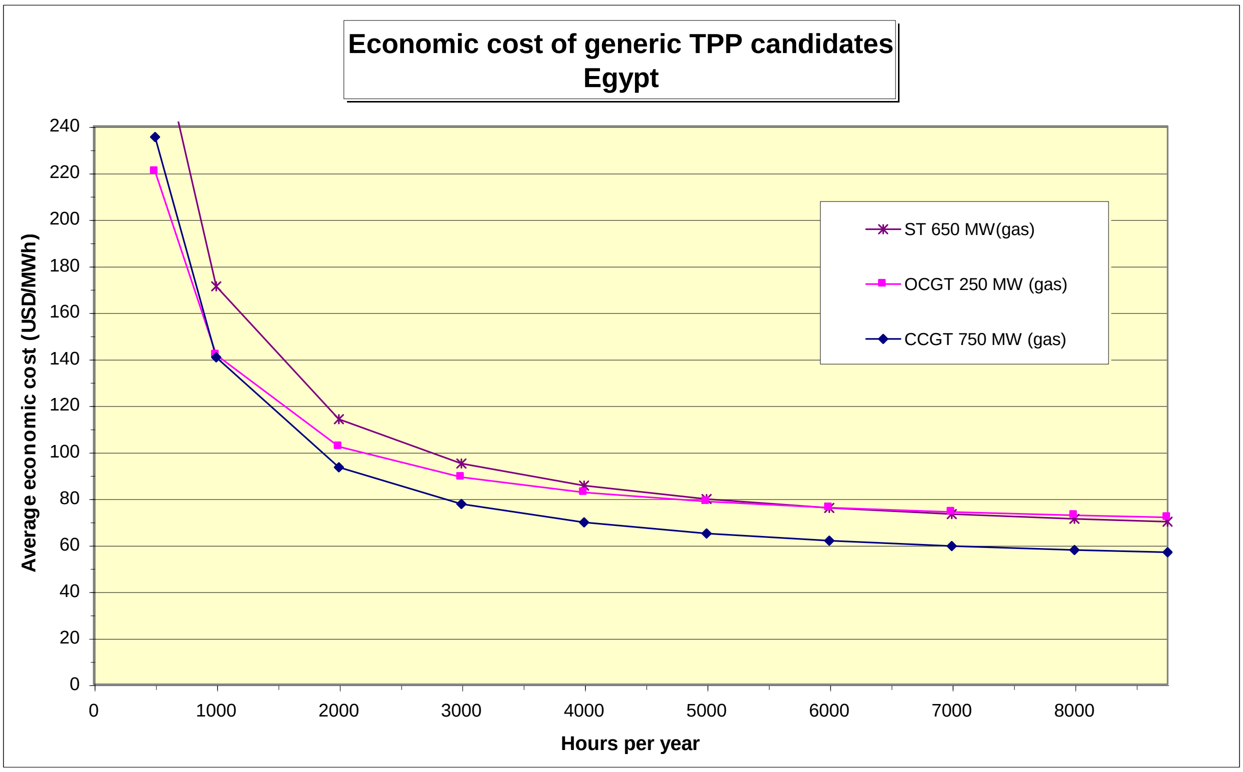

Figure 7.1-7 - Comparison of the economic cost per MWh of generic TPP candidates – Year 2020 - Egypt

For a an annual generation duration of 5 000 hours/year, the average economic cost of generation in Egypt is in the range of 60 to 65 USD/MWh.

7.2 RANKING OF THERMAL CANDIDATES IN SUDAN

According to the findings of Module M3 Vol 4, the TPP candidates for the development of new generation in Sudan are:

- coal-fired STPP (150 MW, 400 MW, 600 MW),
- gas oil-fired CCGT (200 MW, 350 MW, 450 MW),
- crude oil-fired STPP (150 MW, 250 MW, 500 MW),
- LSD (40 MW),
- gas oil-fired OCGT (41 MW to 268 MW).

In this paragraph the economic comparison is made along two directions:

- first, the impact of scale effect is analyzed for each type of generation,
- then the different types of generation are compared.

7.2.1 BASE CASE (10% DISCOUNT RATE)

7.2.1.1 Scale effect for gas oil-fired OCGT candidates

The following figure compares the economic cost of OCGT for different installed capacities (year 2015 – Medium fuel cost projection):

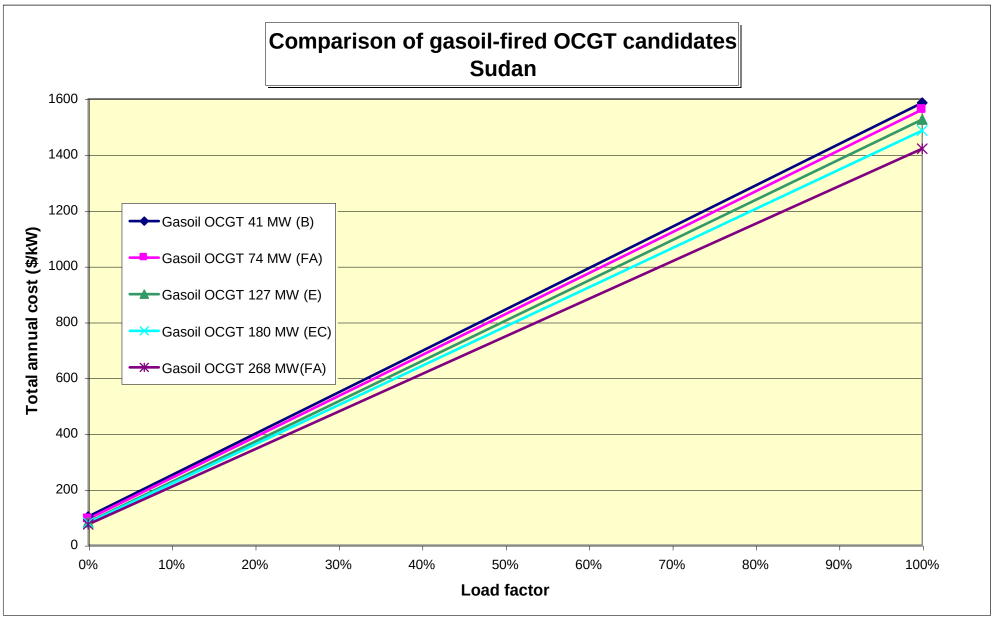

Figure 7.2-1 - Comparison of gas oil-fired OCGT candidates – Year 2015 - Sudan

For load factor < 5%, which is the usual load factor for OCGT, the increase of installed capacity from 41 MW to 268 MW reduces the economic cost of generation by 28%.

The GEP will consider 74 MW OCGT up to 2015, and 127 MW OCGT afterward.

7.2.1.2 Scale effect for oil-fired STTP candidates

The following figure compares the economic cost of oil-fired STPP for different installed capacities (year 2015 – Medium fuel cost projection):

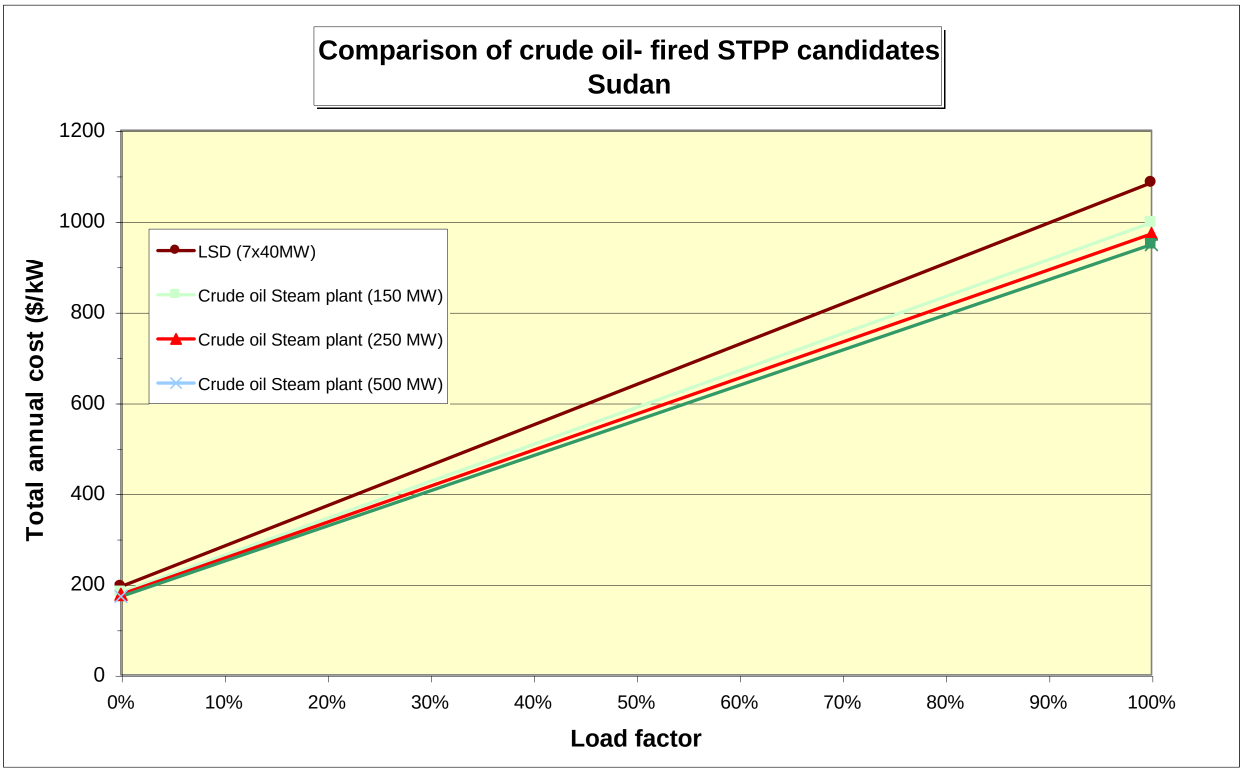

Figure 7.2-2 - Comparison of crude oil-fired STPP candidates – Year 2015 - Sudan

As an example, for load factor of 80%, the increase of installed capacity from 150 MW to 500 MW reduces the economic cost of generation from crude oil-fired STPP by 5%.

The GEP will consider 250 MW crude-oil STPP up to 2010, and up to 500 MW afterward.

7.2.1.3 Scale effect for gas oil-fired CCGT candidates

The following figure compares the economic cost of gas oil-fired CCGT for different installed capacities (year 2015 – Medium fuel cost projection):

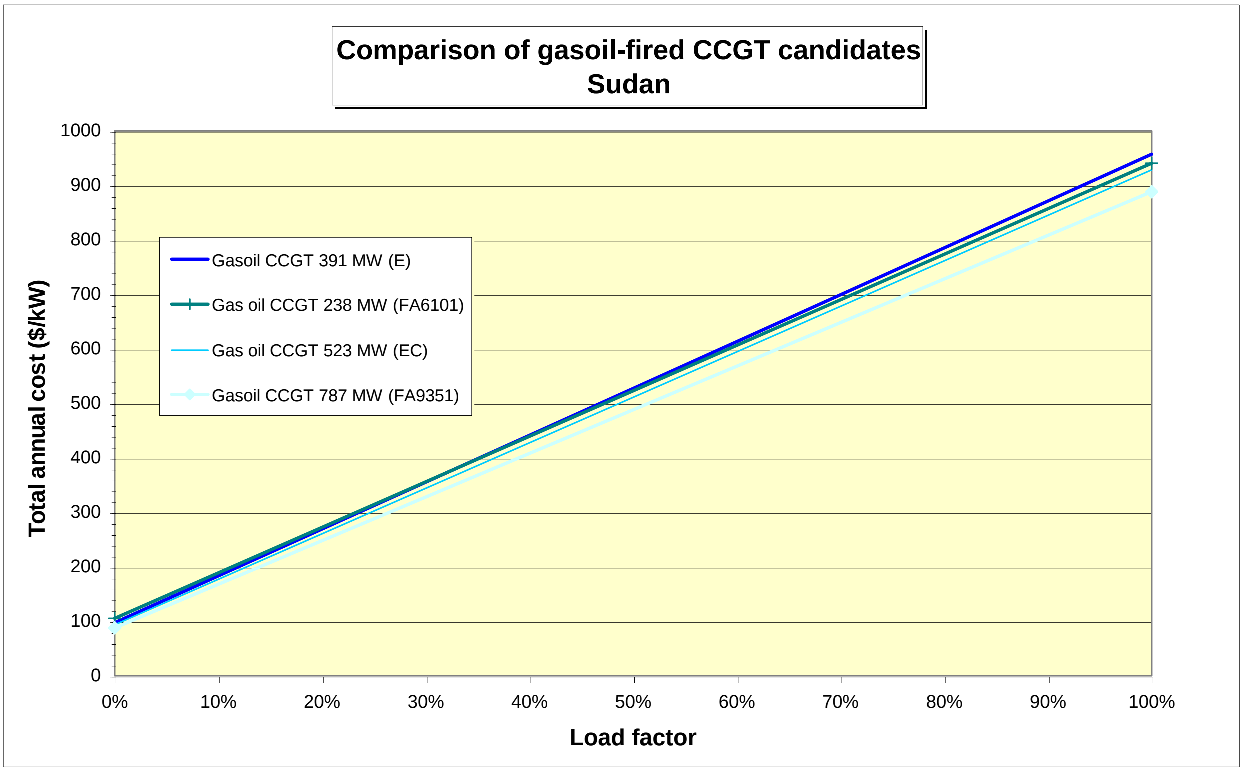

Figure 7.2-3 - Comparison of gas oil-fired CCGT candidates – Year 2015 - Sudan

As an example, for load factor of 80%, the increase of installed capacity from 391 MW to 787 MW reduces the economic cost of generation from gas oil-fired STPP by 6%.

The GEP will consider 250 MW gas oil-fired CCGT up to 2019, and up to 500 MW up to 2027 and up to 787 MW afterward.

7.2.1.4 Scale effect for coal-fired STPP candidates

The following figure compares the economic cost of coal-fired CCGT for different installed capacities (year 2015 – Medium fuel cost projection):

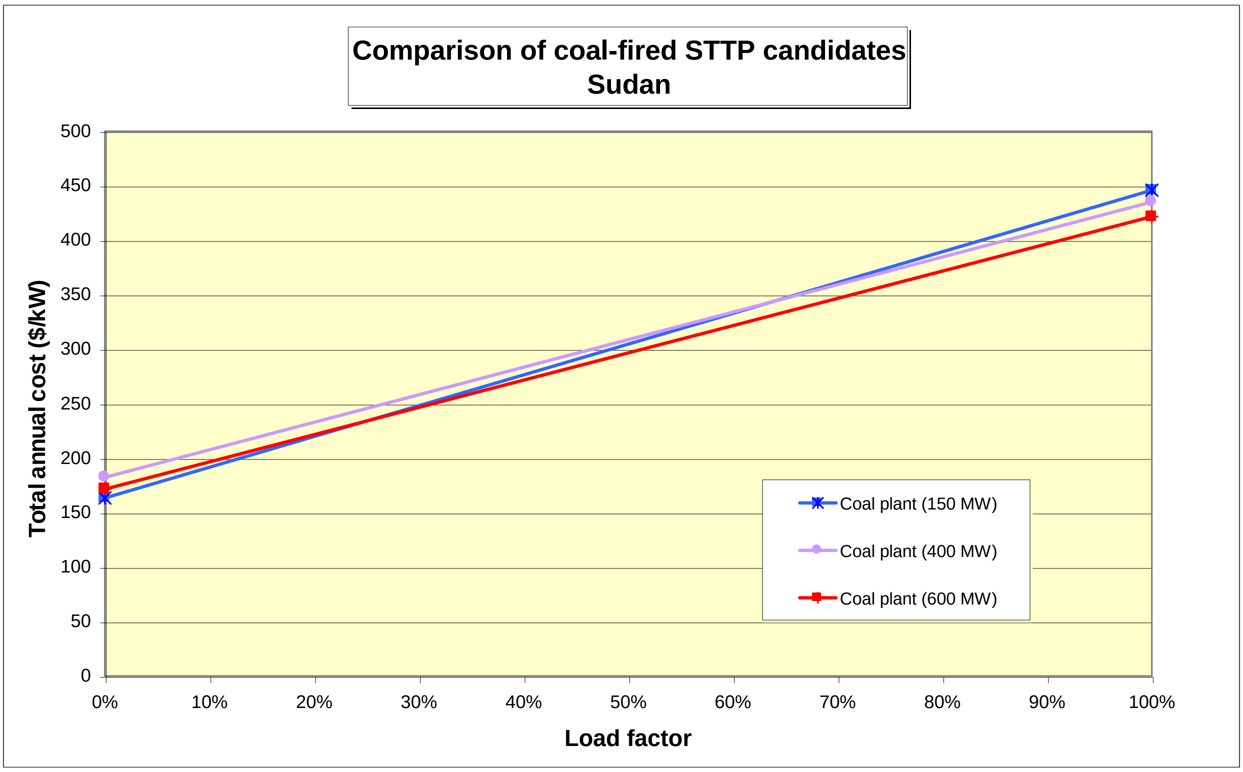

Figure 7.2-4 - Comparison of coal-fired STPP candidates – Year 2015 - Sudan

Due to a different technology, the 150 MW circulating fluidized bed has an investment cost per kW lower than the more evolved (and more environmental friendly) pulverized fuel 400 and 600 MW.

However for base load generation (>80% load factor), the increase of installed capacity from 150 MW to 600 MW reduces the economic cost of generation from coal-fired STPP by 5%.

The GEP will consider 150 MW coal-fired up to 2011, 400 MW up to 2020, and up to 600 MW afterward.

7.2.1.5 Comparison of the main generic TPP candidates

After the previous comparisons relative to different capacity inside each technology family, the following figure compares the different technologies, considering – for the purpose of simplification – only one capacity for each technology (year 2015 – Medium fuel cost projection):

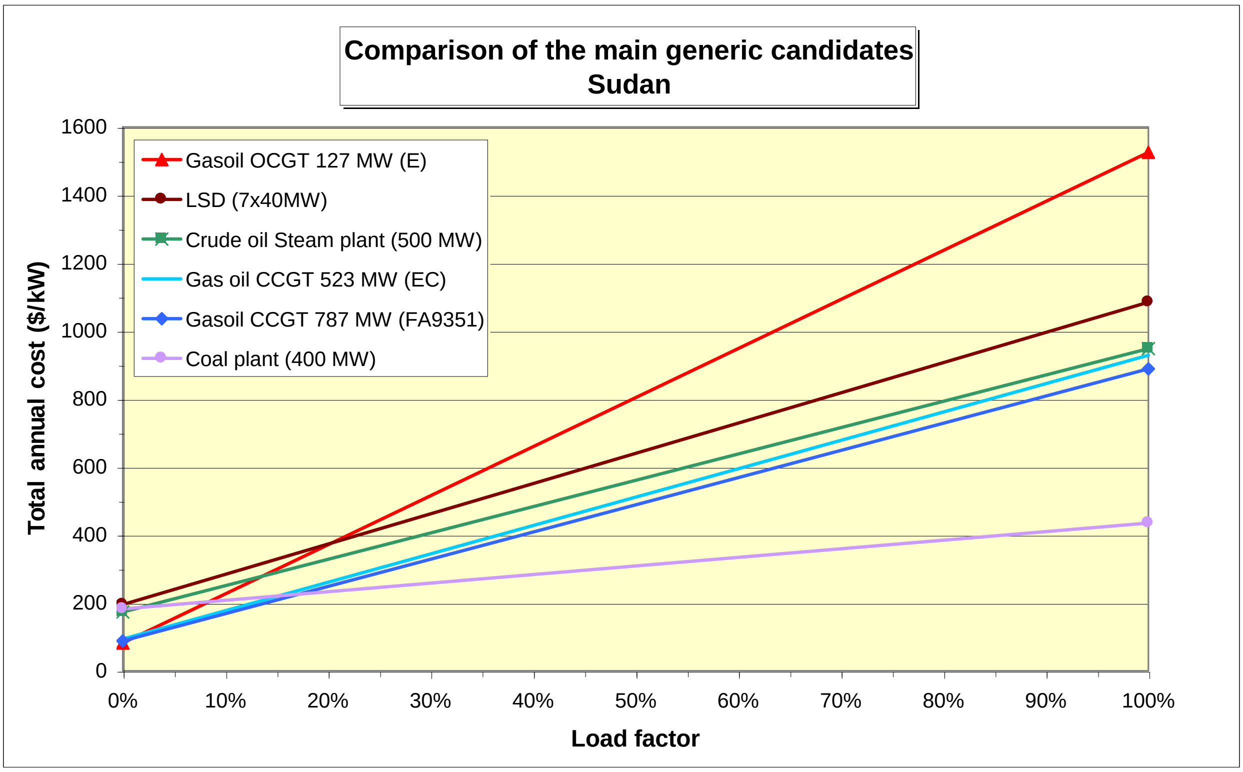

Figure 7.2-5 - Comparison of the main TPP candidates – Year 2015- Sudan

The previous figure allow to determine the following least-cost option for new generation investments according to the duration of average annual generation:

- For load factor greater than 17% (about 1 500 hours per year), the coal-fired STPP is the least cost option for base and semi-base generation.
- For load factor lower than 17% and greater than 2% (between 170 hours and 1 500 hours per year), the gas-oil fired CCGT is the least cost option.
- For load factor lower than 2% (about 170 hours per year), the OCGT is the least cost option.

Crude-oil STPP is more expensive than gas-oil CCGT for all load factors, even if the difference between both types of generation is reduced for high load factor (i.e. base generation).

LSD is even more expensive but presents the advantage of short construction duration.

7.2.2 SENSITIVITY TO FUEL COST

The following figure presents the screening curves for the medium fuel price projection for year 2030 (and 10% discount rate):

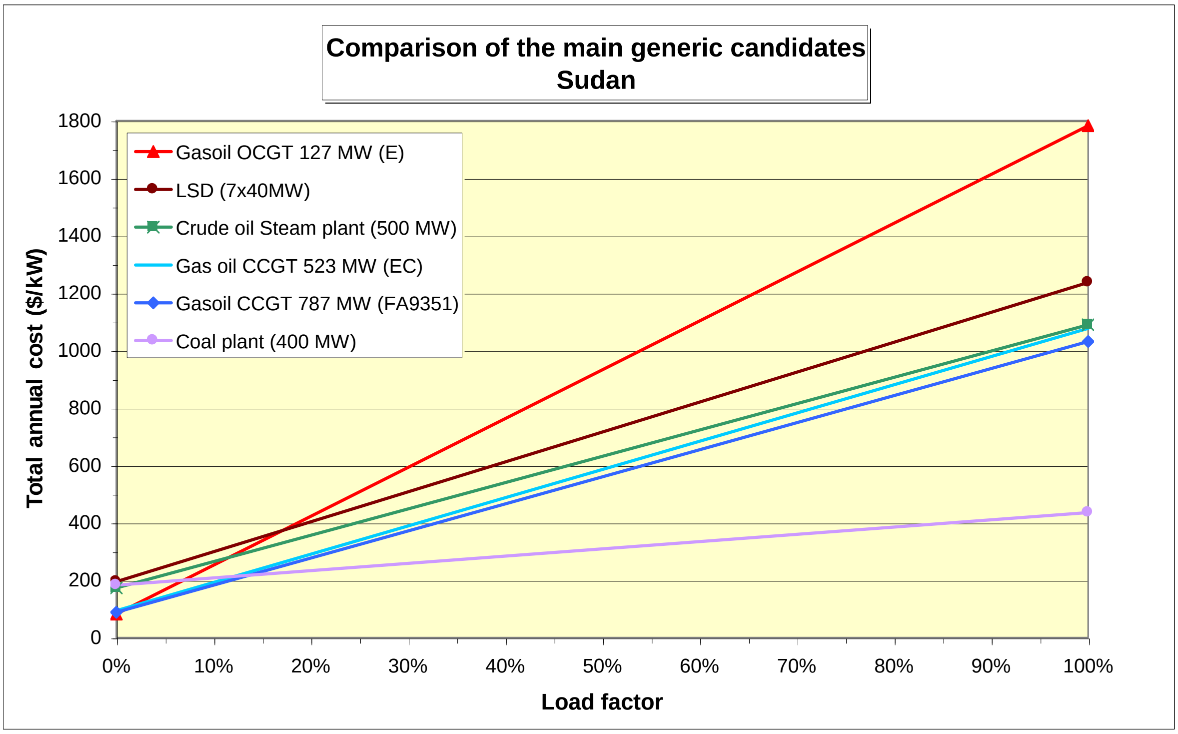

Figure 7.2-6 - Comparison of the main TPP candidates - Year 2030 - Medium fuel price projection – Sudan

The following figure presents the screening curves for the high fuel price projection for year 2030 (and 10% discount rate):

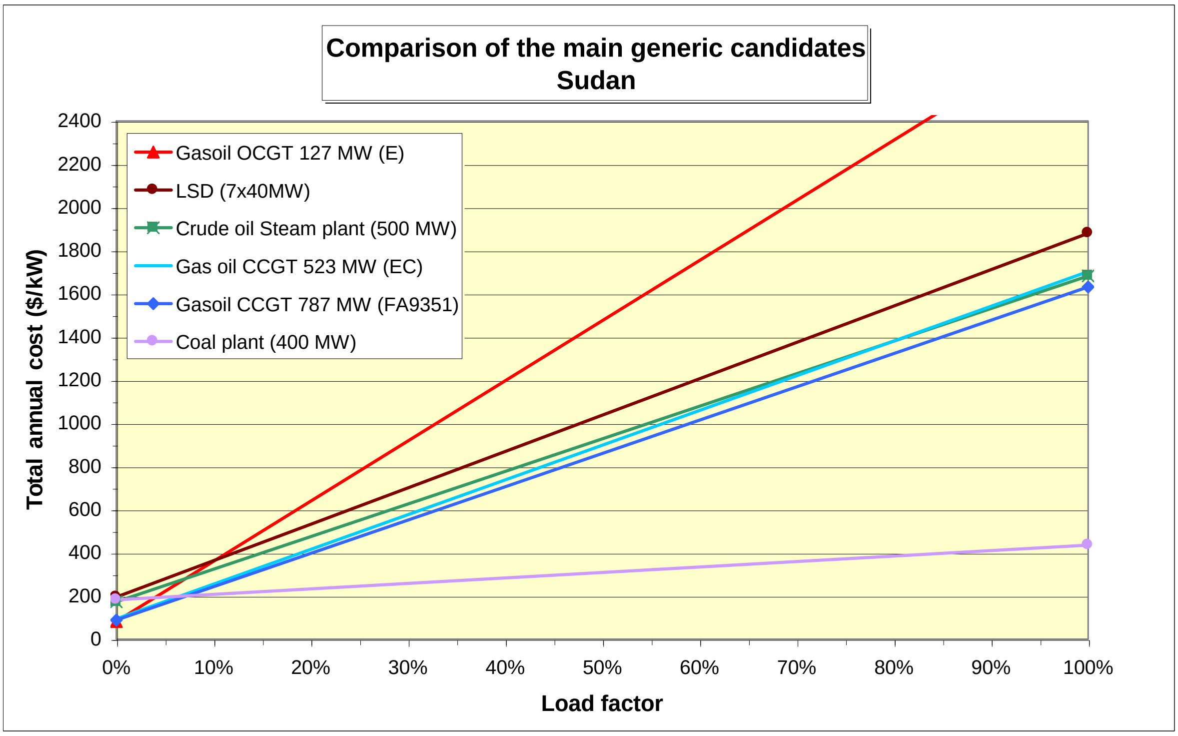

Figure 7.2-7 - Comparison of TPP candidates - Year 2030 - High fuel price projection - Sudan

The previous figure shows that the ranking between the different TPP candidates is not affected by the increase of fuel cost:

- for base load and semi base load generation the least cost option is the development of new coal-fired STTP,
- for lower load factor, the gas-oil fired CCGT is the least cost option,
- for peak generation, the OCGT is the least cost option.

When fuel price increases, the break even point between these different technologies shifts towards lower load factor. This phenomenon is amplified by the fact coal keeps the same cost for all fuel price projection.

7.2.3 SENSITIVITY TO DISCOUNT RATE

The two following figures shows that the previous conclusions remained unchanged for 12% and 8% discount rates (year 2015 – Medium fuel price projection).

For 12% discount rate:

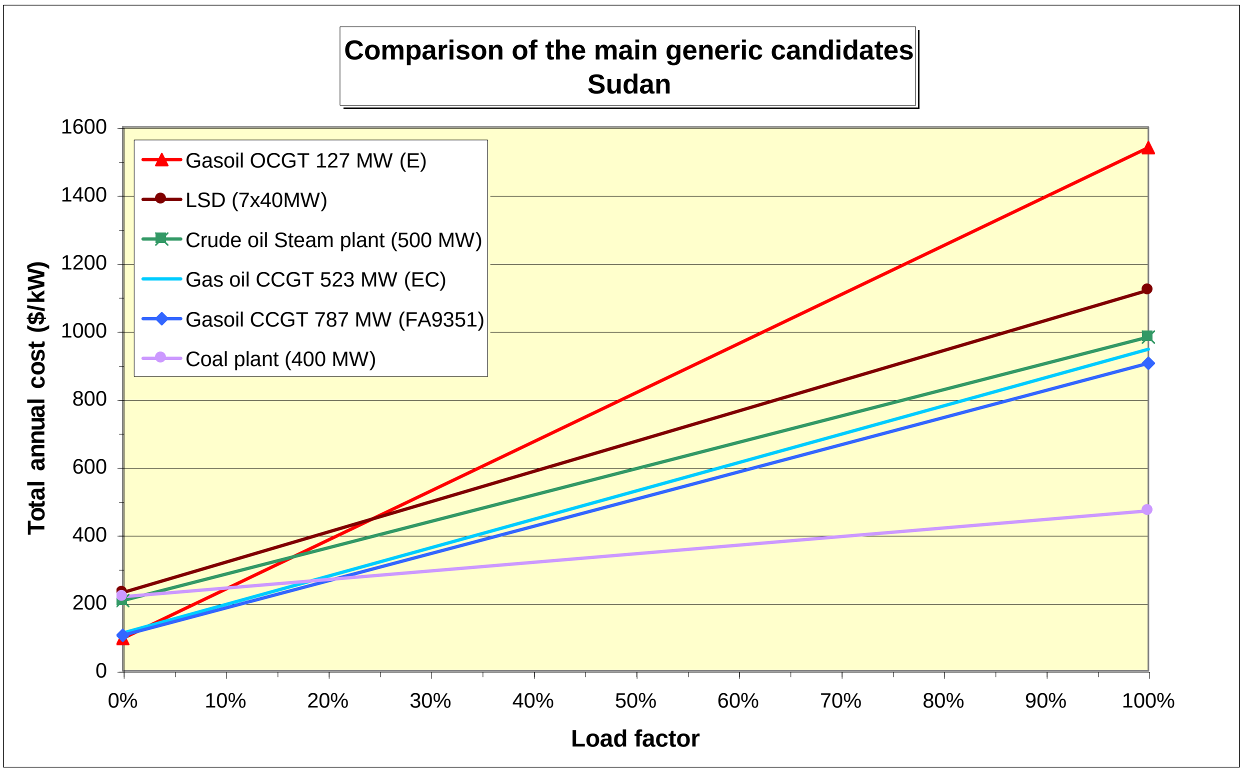

Figure 7.2-8 - Comparison of generic TPP candidate - 12% discount rate - year 2015 - Sudan

For 8% discount rate:

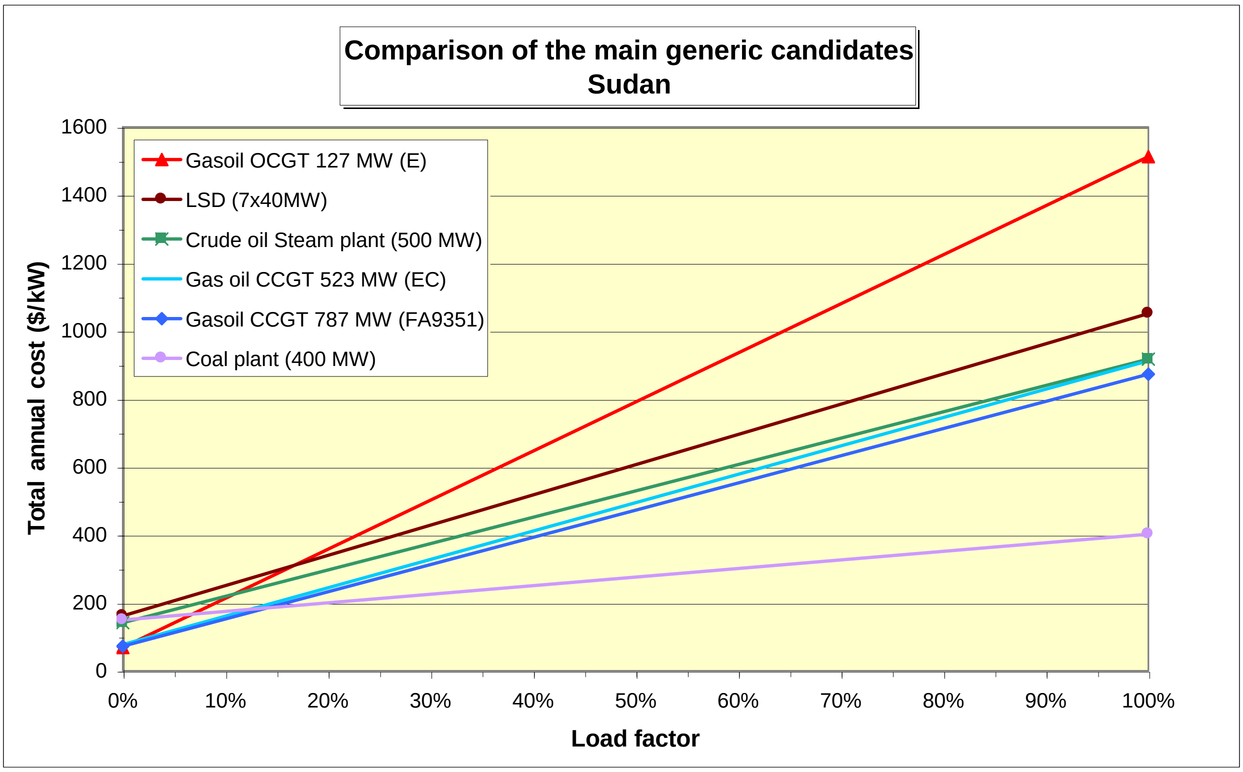

Figure 7.2-9 - Comparison of generic TPP candidates - 8% discount rate - Year 2015 - Sudan

Discussion:

A lower discount rate increases the relative profitability of candidates with greater investment cost (coal-fired STTP). Accordingly, the break even point between coal-fired STPP and gas oil-fired CCGT shifts from 20% load factor (for 12% discount rate) to 15% (for 8% discount rate).

The general ranking between the different candidates remains unchanged.

7.2.4 CONCLUSION FOR THE GENERATION EXPANSION PLAN

From the previous analysis, the following conclusions could be derived for the determination of the Sudanese Generation Expansion Plan:

- For base load and semi base load generation the least cost option is the development of new coal-fired STTP,
- for lower load factor, the gas oil-fired CCGT is the least cost option,
- for peak generation, the OCGT is the least cost option.

Coal-fired STTP:

The coal-fired STTP being located in Port Sudan, the total possible new capacity in coal-fired generation is limited by transmission capacity to the Sudanese load centers.

Accordingly, the schedule of planting for coal-fired STTP will be very close to the one defined in the Sudanese Generation Expansion Plan 2006, except for the addition of another 400 MW coal-fired

STPP in 2015, because the transmission study carried out in Module 6 demonstrated the transmission system is strong.

Gas oil-fired CCGT and crude oil-fired STPP:

The previous analysis shows that gas oil-fired CCGT and crude oil-fired STPP are more expensive than coal-fired STPP. However, due to the transmission network limiting the total coal-fired STTP capacity, CCGT and crude oil-fired STTP are the next choice for semi-base load generation.

In order to preserve some diversity in fuel origin and to be consistent with Sudanese Generation Expansion Plan 2006, the proportion of new gas oil-fired CCGT and crude oil-fired STPP will be 2 to 1.

Low Speed Diesel:

The Sudanese generation mix has been suffering significant power shedding in the recent years. This power shedding will last up to 2009 or so with the commissioning of new capacity. In this context, and due to the short construction duration of LSD, the commissioning of a group of 7 x 40 MW LSD is considered in 2009 as in NEC Generation Expansion Plan 2006.

OCGT:

For the same reason as for LSD, the commissioning of a 74 MW OCGT is considered in 2009.

7.2.5 Economic cost per MWh

From the previous curves, it is possible to calculate the average economic cost per MWh of the generic candidates as a function of the annual load factor. The following figure gives these costs for year 2020 and 10% discount rate:

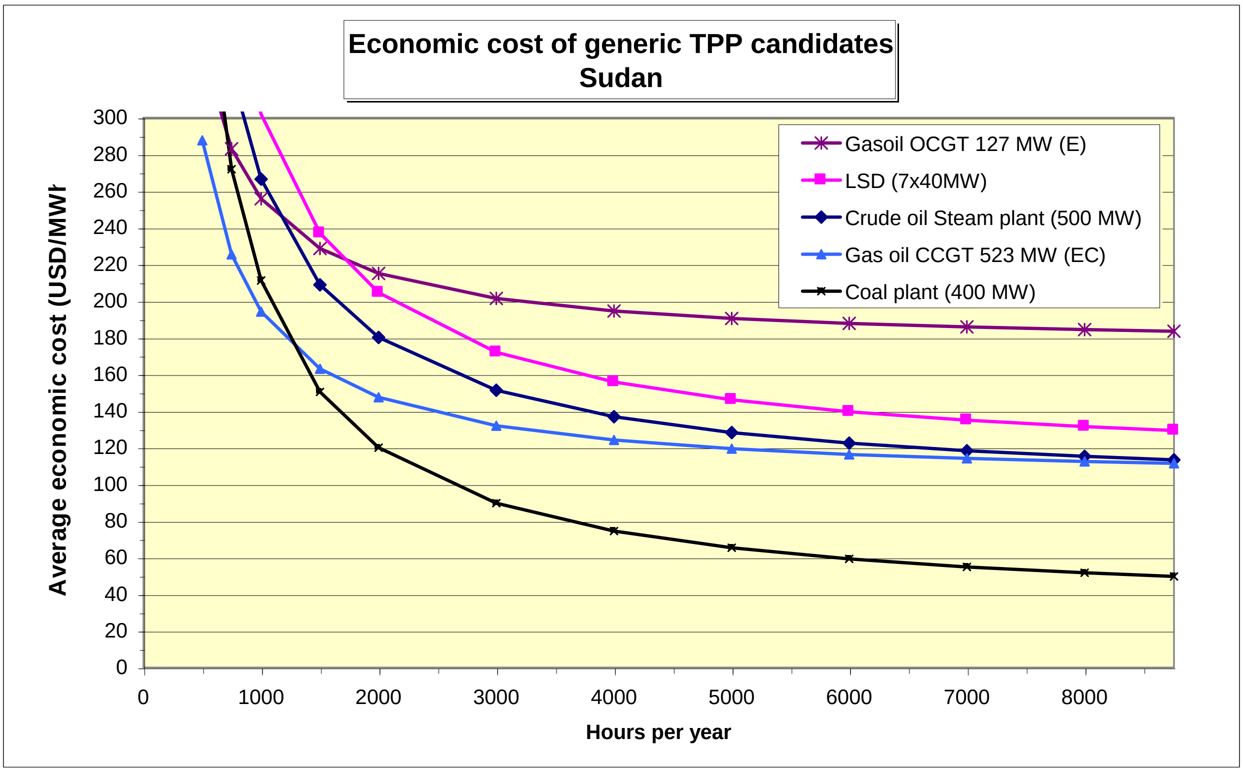

Figure 7.2-10 - Comparison of economic cost USD/MWh TPP candidates - Year 2020 - Medium fuel price scenario – Sudan

7.3 RANKING OF THERMAL PROJECTS IN ETHIOPIA

7.3.1 COMPARISON OF TPP CANDIDATES

The following figure presents the screening curves for the Ethiopian generic thermal candidates: 70 MW and 140 MW HFO-fired OCGT, 200 MW HFO-fired CCGT for year 2015 and medium fuel price projection:

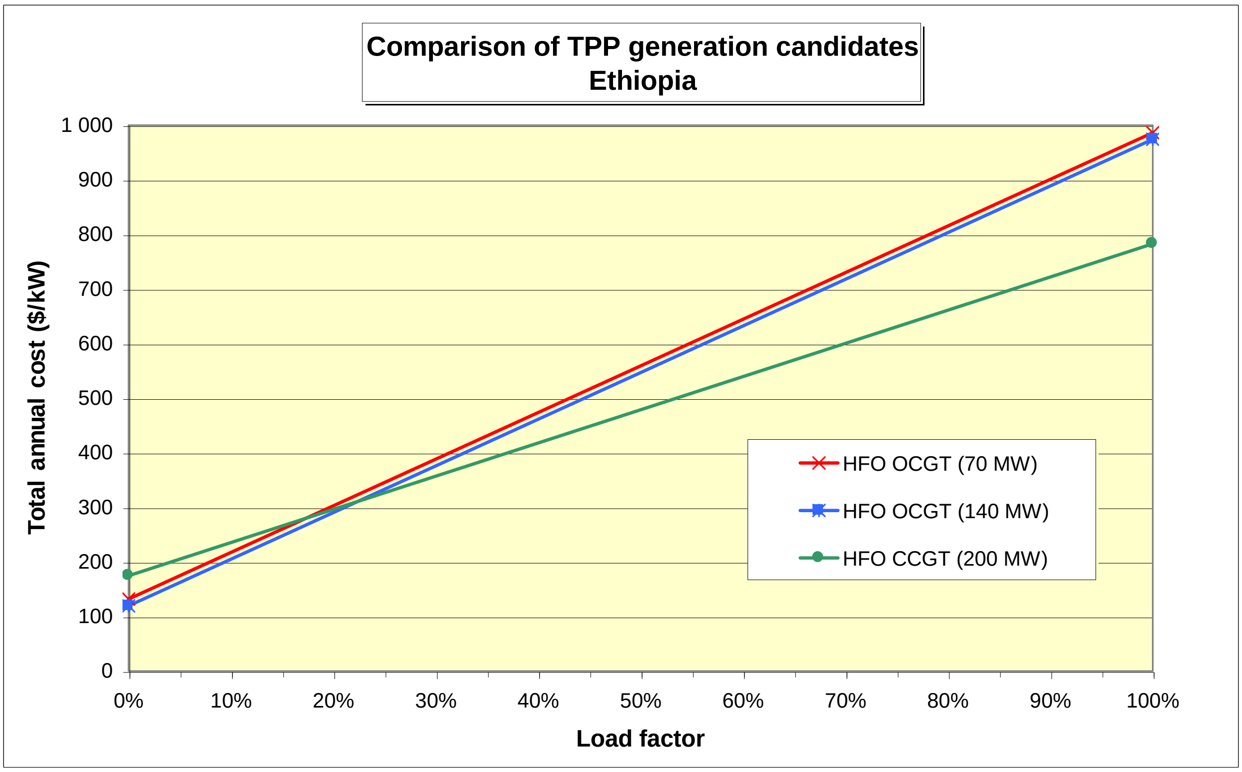

Figure 7.3-1 - Comparison of thermal candidates - Ethiopia - Year 2015

HFO-fired CCGT is the least cost option base load generation, while HFO-fired OCGT is the least cost option for peak load generation.

The breakeven point between HFO-fired OCGT and CCGT is for a load factor in the range of 20 to 25%.

7.3.2 ECONOMIC COST PER MWH

From the previous curves, it is possible to calculate the average economic cost per MWh of the generic candidates as a function of the annual load factor. The following figures gives these costs for year 2020 and 10% discount rate:

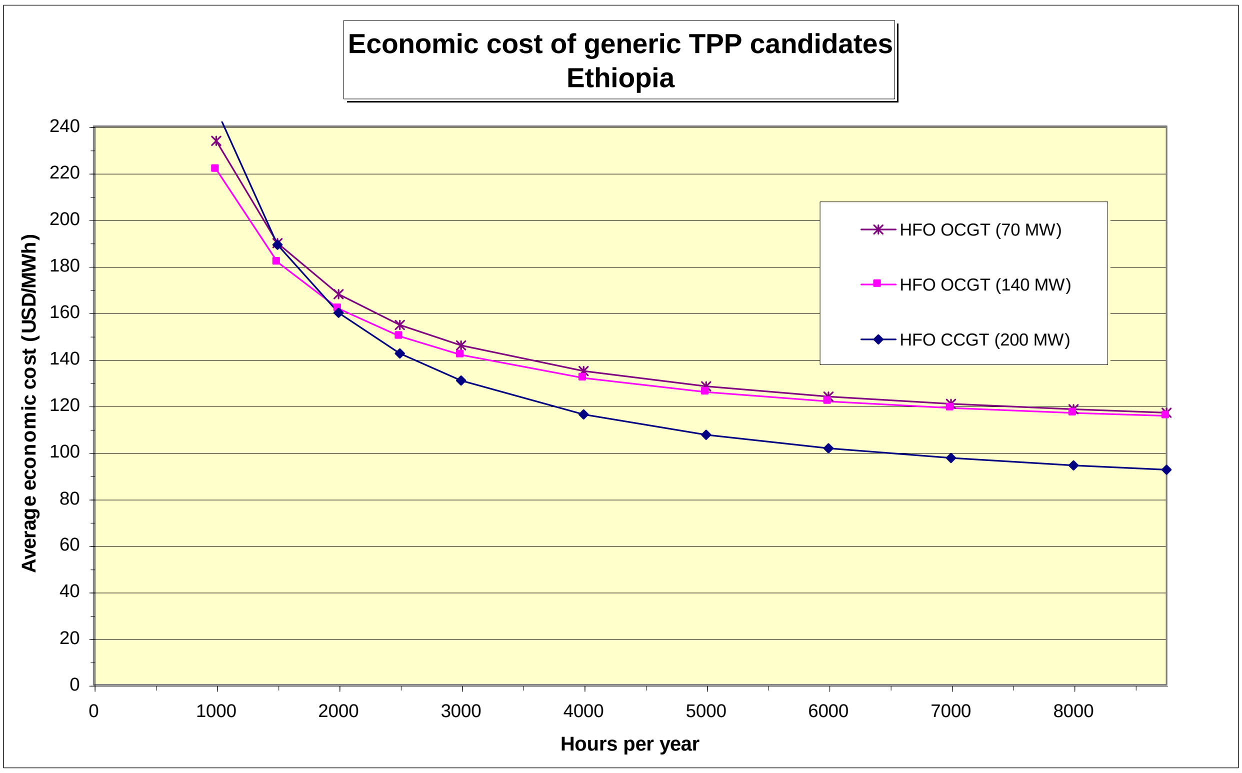

Figure 7.3-2 - Economic cost USD/MWh of TPP candidates – Year 2020 - Ethiopia

8 THERMAL AND HYDROPOWER COSTS IN THE THREE POWER SYSTEMS

The previous analysis was focused on the identification of the best thermal option, in each power system, according to the load factor.

The next step is to compare, in each power system, the economic cost (which includes investment and operation costs) of TPP and HPP candidates. This analysis is carried out on the basis of the findings of Module M3.

8.1 EGYPT

No significant HPP candidates relevant for the present Study are considered.

8.2 ETHIOPIA

8.2.1 HPP PROJECTS ECONOMIC COSTS AND SEQUENCING

The following table summarizes the main economic characteristics of HPP projects in Ethiopia as identified in Module 3 Vol 3. In this table, the HPP projects are ranked on the basis of the average economic cost per MWh:

Project name	Installed capacity MW	Average energy GWh/year	Average load factor Hours/ year	Construction period years	Project cost $MUSD_{2006}$	Economic cost 12% discount rate USD_{2006}/MWh	Economic cost 10% discount rate USD_{2006}/MWh
Total Halele+Werabesa	422	2 245	5 300	5	507	36.4	30.0
Total Baro I + II + Gengi	900	4 409	4 900	5	1 007	39.6	32.3
Total Geba I + II	372	1 788	4 800	6	418	39.5	32.3
Total Chemoga-Yeda I + II	281	1 415	5 000	4	403	40.3	32.6
Mandaya	2 000	12 100	6 100	8	2 640	41.2	33.0
Genale III	258	1 200	4 700	5	304	41.5	34.1
Karadobi	1 600	8 600	5 400	8	2 040	44.8	35.9
Border	1 200	6 000	5 000	6	1 626	47.2	38.3
Genale VI	256	1 000	3 900	4	383	59.4	49.3
Gojeb	153	520	3 400	5	287	90.5	74.4
Aleltu West	265	1 050	4 000	6	561	92.9	75.6
Aleltu East	186	800	4 300	6	438	95.2	77.4

Table 8.2-1 - Comparison of HPP economic cost (USD/ MWh) - Ethiopia

NB :

- In this table, the transmission cost and the possible mitigation measurements (environmental and social mitigation, including public heath) are included in the project cost. For example, Karadobi has a mitigation cost of 59.4 MUSD and a transmission cost of 94.4 MUSD, for Mandaya these costs amount to 20 and 174 MUSD, and for Border 114 and 175 MUSD (detailed mitigation costs are provided in the respective pre-feasibility Study[16]).
- The average energy given in this table for Karadobi consider only the energy generated at Karadobi and not the additional energy provided by downstream impact (up to 2 600 GWh more). In fact, the downstream impact will come from the coordinated impact of Karadobi, Mandaya and Border and will depend on the order of commissioning between these projects. The simulation of the power system made by SDDP will automatically consider the downstream impact through the accurate representation of the hydro schemes.

The analysis carried out in Module M4 (Planning and Evaluation Criteria) shows that on the basis of various criteria (technical, socio environmental) the first group of projects listed in the previous table – from Halele Worabesa to Border - are equivalent.

Accordingly, the screening criterion for discriminating these projects and determining the optimal sequencing in the Generation Expansion Plan is the economic cost. This criteria will provide the least cost solution. The HPP project having the lowest cost will enter first in the GEP (Halele + Worabesa), then Baro I + II + Gengi, then Geba I + II, etc.

Furthermore, it should be noted that the resulting sequencing is compatible with a proper development of the installed capacity in Ethiopia: the first (and lower cost projects): Halele + Worabesa (422 MW), Baro I + II + Gengi (900 MW), Geba I + II (372 MW) having lower installed capacity, while larger project (Mandaya 2000 MW), Karabobi (1 600 MW), Border (1200 MW), will enter the Generation Expansion plan in a latter period when the total Ethiopian peak load gets up to greater values.

Finally, the determination of the optimal date of commissioning of each HPP, along the sequencing defined above, will be made by the Generation Planning Software.

[16] There is no sedimentation management cost for Mandaya, Karadobi and Border because the sediments simply accumulate in these large reservoirs.

8.2.2 COMPARISON OF HPP AND TPP CANDIDATES

Most of the HPP candidates in Ethiopia offer a high degree of seasonal regulation due to their large reservoirs. Their average annual duration of generation is in the range of 5 000 to 6 000 hours / year (e.g. 6 000 hours/year for Mandaya, 5 000 hours/year for Border, 5 300 hours/year for Karadobi).

The **Table 8.2-1** shows that the economic cost of HPP candidates is between 25 to 40 USD/MWh while **Figure 7.2-10** shows that TPP generation is much more expensive, around 100 USD/MWh for HFO-fired CCGT for base generation.

Accordingly, the Generation Expansion Plan will be based on HPP (for base and semi-base generation) while same OCGT might be needed for peak generation.

8.3 SUDAN

8.3.1 HPP PROJECTS ECONOMIC COSTS AND SEQUENCING

The following table summarizes the main economic characteristics of HPP projects in Sudan as identified in Module 3 Vol 4. In this table, the HPP projects are ranked on the basis of the commissioning date:

Project name	Installed capacity MW	Average generation GWh/year	Average load factor h/year	Construction duration year	Total cost MUSD2006	Commissioning date	USD/MWh a = 10%
Rumela	30	82	2 700	5	193	2011	299
Shereiq	315	1 546	4 900	6	1 190	2013	106
Dal Low	400	2 160	5 400	6	1 096	2015	71
Kajbar	300	1 400	4 700	7	1 125	2016	107
Dagash	285	1 476	5 200	6	1 048	2017	95
	1 300						
Fula Alt 1	720	4 119	5 700	8	1 319	2020	42.7
Shukoli	210	1 422	6 800	8	420	2022	39.3
Lakki	210	1 415	6 700	8	429	2024	40.4
Bedden	400	2 761	6 900	8	880	2026	42.4
	1 540						

Table 8.3-1 - Sequencing and economic cost of HPP in Sudan

The sequencing and commissioning date for the HPP for the present Study is kept identical to the one determined in the Sudan LTPPS 2006 (October 2006) because of its consistency with the result of Module 4 of the present Study.

It should be kept in mind that the more cost effective projects, which are all located on Bahr el Jebel in the South of the country, could not be commissioning before a significant increase of the power demand in the South and the connection of this area to the main transmission grid (2020).

8.3.2 COMPARISON OF HPP AND TPP CANDIDATES

Most of the HPP candidates in Sudan offer a high degree of seasonal regulation due to their large reservoirs. Their average annual duration of generation is in the range of 5 000 to 6 000 hours/year.

For this range of load factor, **Figure 7.2-10** shows that alternative generation from TPP candidate would have an economic cost in the range of (for year 2020):

- 60 to 65 USD/MWh for coal-fired STPP (whose development is constrained by transmission limitation),
- 120 USD/MWh for gas oil-fired CCGT,
- 130 USD/MWh for crude oil-fired STPP.

Accordingly, in the first period of the Generation Expansion Plan (up to 2020), the economic cost of HPP is 30 to 60 USD/MWh less expensive than gas oil-fired CCGT or crude oil-fired STPP.

While after 2020, this difference increases, in favor of new HPP, when the HPP in South Sudan enter the GEP.

9 COMPARISON OF THE GENERATION COSTS IN THE THREE POWER SYSTEMS

The purpose of this paragraph is to give a synthetic view of the generation costs in the region. This comparison is made of the basis of:

- the economic cost of generation (also called levelized cost of generation, which includes fixed and variable cost of generation),
- the variable cost of generation (which includes solely the part of cost dependant on the amount of generation).

The first approach is pertinent when generation investments are specifically decided for export purposes, in substitution for new possible investments in the importing country.

The second approach is pertinent when investments are decided only for the requirement of internal demand, and if surplus are available for exports, in substitution to more expensive generation in the importing country

9.1 COMPARISON OF ECONOMIC COSTS OF GENERATION

From the previous analysis it is possible to present a schematic view of the economic cost of generation in the three generation mix showing how new TPP and HPP candidates compare (year 2020 – Medium fuel price projection – TPP with load factor from 5 000 to 6 000 hours/year).

It is reminded that the economic cost includes all cost of generation: from investment cost (considering the life duration of the power plant and the discount rate) to variable cost (fuel cost and O&M). Accordingly, this approach is relevant to compare the total cost of new power projects in the different country (and not to compare the variable costs of existing thermal plants).

Furthermore, as explained in Module 3 Vol 4, the cost evaluation is done on the basis of international market fuel price projection (because the purpose of the Study is the evaluation of power exchanges) which might be very different than the present fuel cost paid by the Utilities.

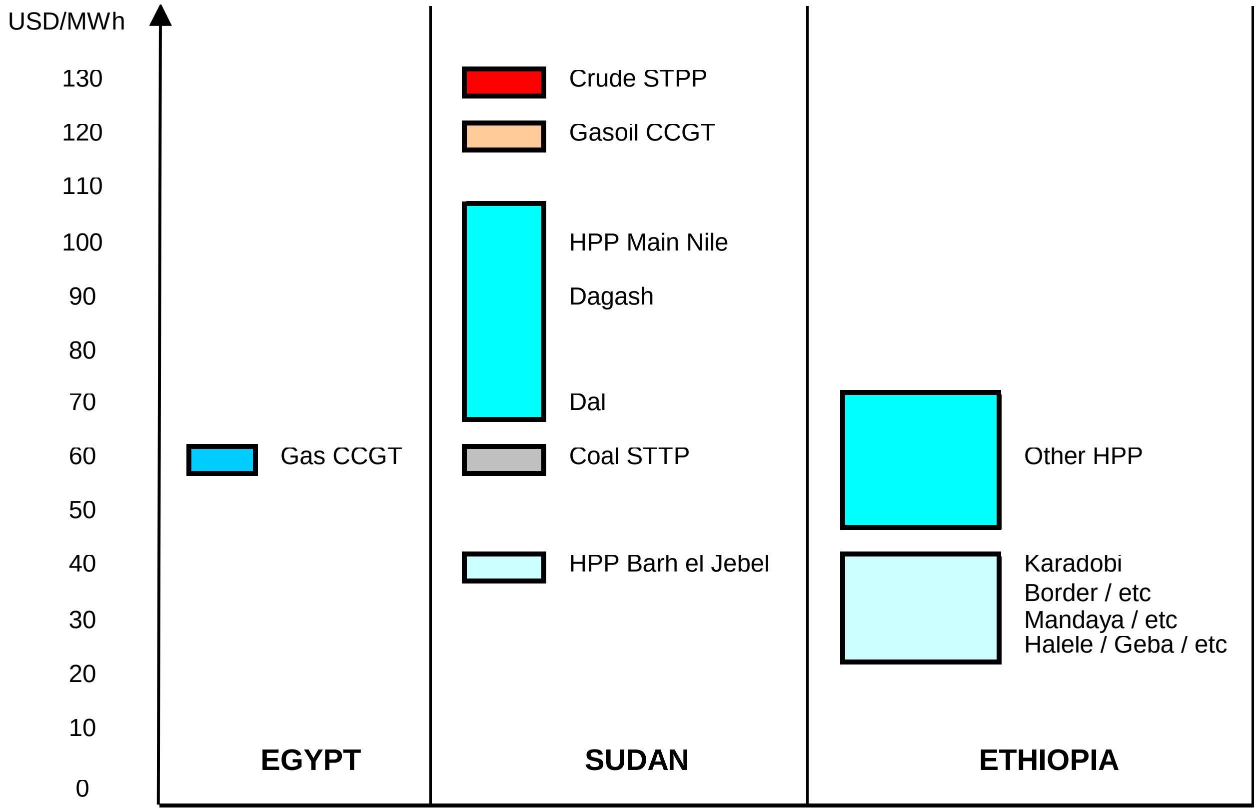

Figure 9.1-1 - Comparison of generation economic cost in the different generation mixes (6 000 hours/ year) - Year 2020 - Medium fuel price scenario - 10% discount rate

From the most cost effective projects to the more expensive we found:

- the lower cost generation projects is composed by a group of Ethiopian HPP projects (Manaday, Karadobi, Border, Halele, Geba, etc) with economic cost from 25 to 40 USD/MWh;
- then close to 40 USD/MWh we found the Bahr el Jebel HPP project in South Sudan;
- then close to 60 USD/MWh, we found CCGT in Egypt, coal-fired STPP in Sudan (but the number of coal-fired STTP is Sudan is limited by transmission capacity), and a group of hydro projects in Ethiopia;
- then from 70 to 110 USD/MWh, we find the HPP projects in the Main Nile river in Sudan;
- finally, the most expensive units are gas oil-fired CCGT and crude oil-fired STPP is Sudan.

Accordingly, considering the cost and availability of power surplus, the bulk of power export will come from cost effective HPP projects in Ethiopia (all cost effective hydro power in Sudan being absorbed by Sudan internal demand).

Power export to Sudan would lead to the greater economic savings, because of greater cost differential between saved and imported energy, as well as lower transmission cost.

This analysis made of the basis of the comparison of the generation cost in the different generation mixes will be confirmed by simulation of the three power systems in **part 1**.

At the end of the planning period, the increase of fuel price (except coal price which is constant) results in a shift upward of the TPP cost, increasing the relative economic advantage of HPP candidates:

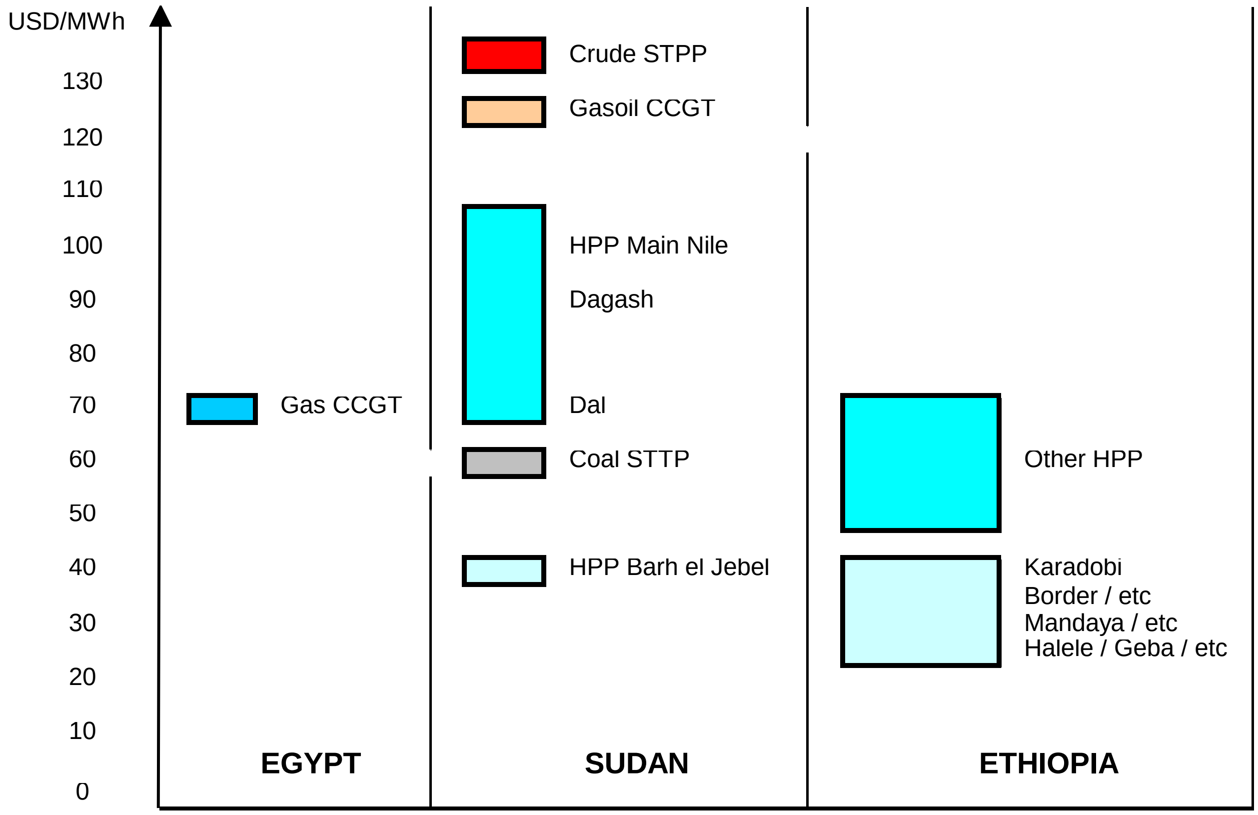

Figure 9.1-2 - Comparison of the generation economic cost in the different generation mixes (6 000 hours/year) – Year 2030 – Medium fuel price scenario – 10% discount rate

9.2 COMPARISON OF VARIABLE COSTS OF GENERATION

While the economic cost of generation (related to what is often called long term marginal cost of generation) includes investment and operation costs, the variable cost (related to what is called short term marginal cost) only includes fuel and variable O&M cost.

The following two tables compare, for year 2020 and for the medium and high fuel price projections, the economic cost and the variable cost of generation for the main TPP candidates:

	Economic cost (6 000 hours/year)	Variable cost	Ratio var. cost / economic cost
(Egypt) gas-fired 750 MW CCGT	62 USD/MWh	46 USD/MWh	74%
(Sudan) 500 MW gas oil-fired CCGT	116 USD/MWh	101 USD/MWh	87%
(Sudan) 500 MW crude oil-fired STPP	122 USD/MWh	94 USD/MWh	77%
(Sudan) coal-fired STPP	57 USD/MWh	28 USD/MWh	50%

Table 9.2-1 - Comparison of economic and variable costs of generation – Year 2020 – Medium fuel price projection – 10% discount rate

	Economic cost (6 000 hours/year)	Variable cost	Ratio var. cost / economic cost
(Egypt) gas-fired 750 MW CCGT	68 USD/MWh	52 USD/MWh	74%
(Sudan) 500 MW gas oil-fired CCGT	179 USD/MWh	164 USD/MWh	92%
(Sudan) 500 MW crude oil-fired STPP	182 USD/MWh	154 USD/MWh	85%
(Sudan) coal-fired STPP	57 USD/MWh	28 USD/MWh	50%

Table 9.2-2 - Comparison of economic and variable costs of generation – Year 2020 – High fuel price projection – 10% discount rate

The variable cost represents most of the generation cost of CCGT and STPP (between 75 to 92%). This proportion increases in time along with the general increase of fuel prices. This means that most the future savings resulting from power trade will come from fuel savings (an not investment savings).

10 INDEPENDANT DEVELOPEMENT OF THE THREE POWER SYSTEMS

The following paragraphs present the main characteristics of the least cost generation expansion plans determined with SDDP software by the Consultant for the three isolated systems (i.e. without the presence of the interconnection between them), on the basis of the reference hypothesis described in Modules 2 and 3 of the present Study.

10.1 EGYPT

10.1.1 MEDIUM DEMAND PROJECTION

<u>Main hypothesis</u>:

- Medium demand projection (5.6% average annual growth rate).
- Medium fuel price projection (crude oil: 60 USD/bbl, NG = 8.6 USD/MBTU in 2030).
- Power export to Jordan (200 MW) and Libya (200 MW).
- No exchange with Sudan or Ethiopia.
- 10% discount rate.

The following figure presents the evolution of the installed capacity per generation types:

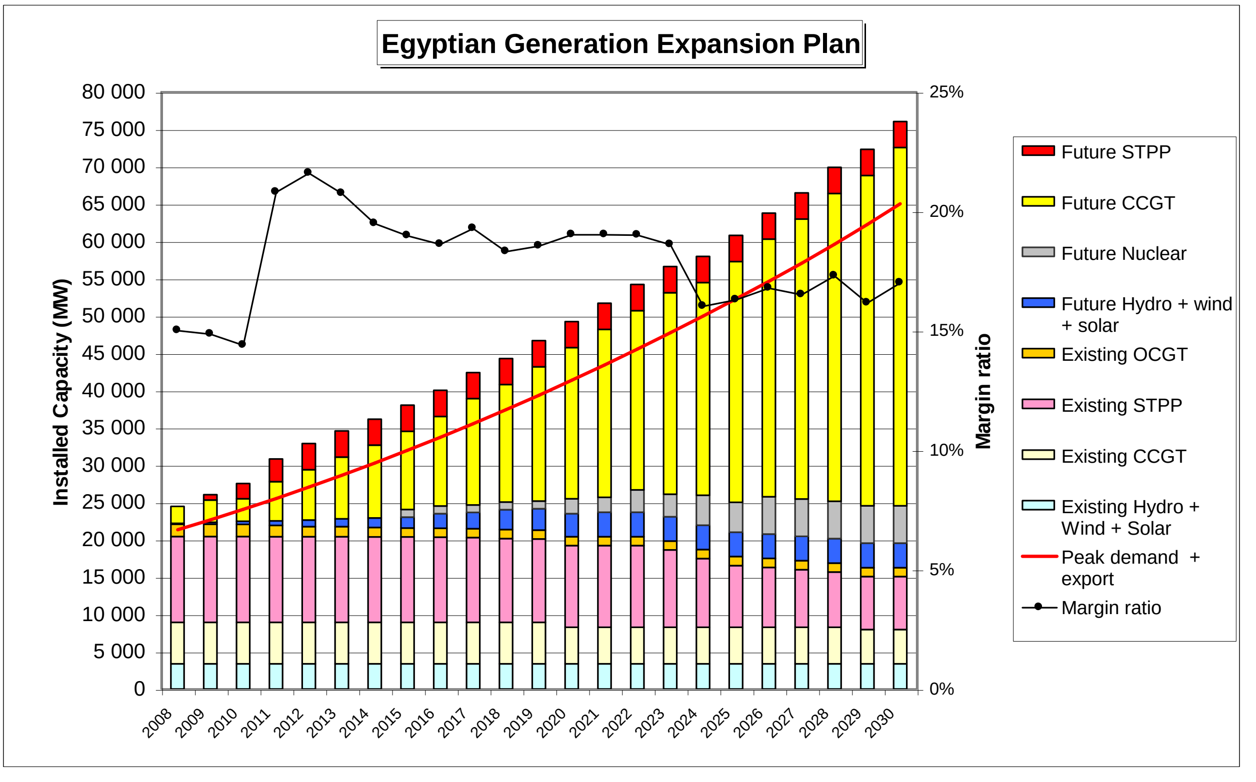

Figure 10.1-1 - Generation Expansion Plan – Egypt – Medium demand projection - No interconnection with Sudan / Egypt

<u>Note</u>:

In this figure, the term "existing" refers to power plants existing before 2008 while "future" refers to power plants committed after 2008.

<u>Comments</u>:

As explained in the paragraph 7.1**,** considering the availability of natural gas in Egypt, the least cost option for the development of new generation is gas-fired CCGT. Accordingly, the bulk of the development of new generation capacity is made on gas-fired CCGT. From 2020 on, the Egyptian system needs on average three new 750 MW CCGT every year.

The following table (on next page) presents the main numerical values of the GEP.

10.1.2 HIGH AND LOW DEMAND PROJECTIONS

See discussion in part §12.3.

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		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Future CCGT		2 250	3 000	3 000	5 250	6 750	8 250	9 750	10 500	12 000	14 250	15 750	18 000	20 250	22 500	24 000	27 000	28 500	32 250	34 500	37 500	41 250	44 250	48 000
Future STPP		0	700	2 050	3 050	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500	3 500
Future Nuclear		0	0	0	0	0	0	0	1 000	1 000	1 000	1 000	1 000	2 000	2 000	3 000	3 000	4 000	4 000	5 000	5 000	5 000	5 000	5 000
Future Hydro + wind + solar		125	255	415	615	874	1 074	1 274	1 474	1 974	2 174	2 674	2 874	3 074	3 274	3 274	3 274	3 274	3 274	3 274	3 274	3 274	3 274	3 274
Existing CCGT		5 564	5 564	5 564	5 564	5 564	5 564	5 564	5 564	5 564	5 564	5 564	5 564	4 890	4 890	4 890	4 890	4 890	4 890	4 890	4 890	4 890	4 589	4 589
Existing OCGT		1 650	1 650	1 633	1 527	1 371	1 351	1 280	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200	1 200
Existing STPP		11 484	11 484	11 484	11 447	11 447	11 447	11 419	11 419	11 392	11 337	11 216	11 155	10 942	10 942	10 942	10 350	9 214	8 273	8 024	7 720	7 398	7 095	7 095
Existing Hydro + Wind + Solar		3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372	3 372
Peak demand + export		21 321	22 659	24 058	25 519	27 040	28 621	30 263	31 964	33 724	35 545	37 425	39 364	41 363	43 422	45 530	47 710	49 950	52 250	54 600	57 042	59 583	62 225	64 984
Margin ratio		15%	15%	14%	21%	22%	21%	19%	19%	19%	19%	18%	19%	19%	19%	19%	19%	16%	16%	17%	17%	17%	16%	17%

Table 10.1-1 - Generation expansion plan – Egypt – Medium demand projection

10.2 ETHIOPIA

10.2.1 MEDIUM DEMAND PROJECTION

<u>Main hypothesis</u>:

- Medium demand projection (average annual growth rate: 10.9%).
- Medium fuel price projection (crude oil: 60 USD/bbl in 2030).
- No exchange with Egypt or Sudan.
- Power export to Kenya (200 MW in 2011, 600 MW in 2020 and 1200 MW in 2030) .
- Power export to Djibouti (<53 MW).
- 10% discount rate.

The following figure presents the evolution of the installed capacity for the different generation types:

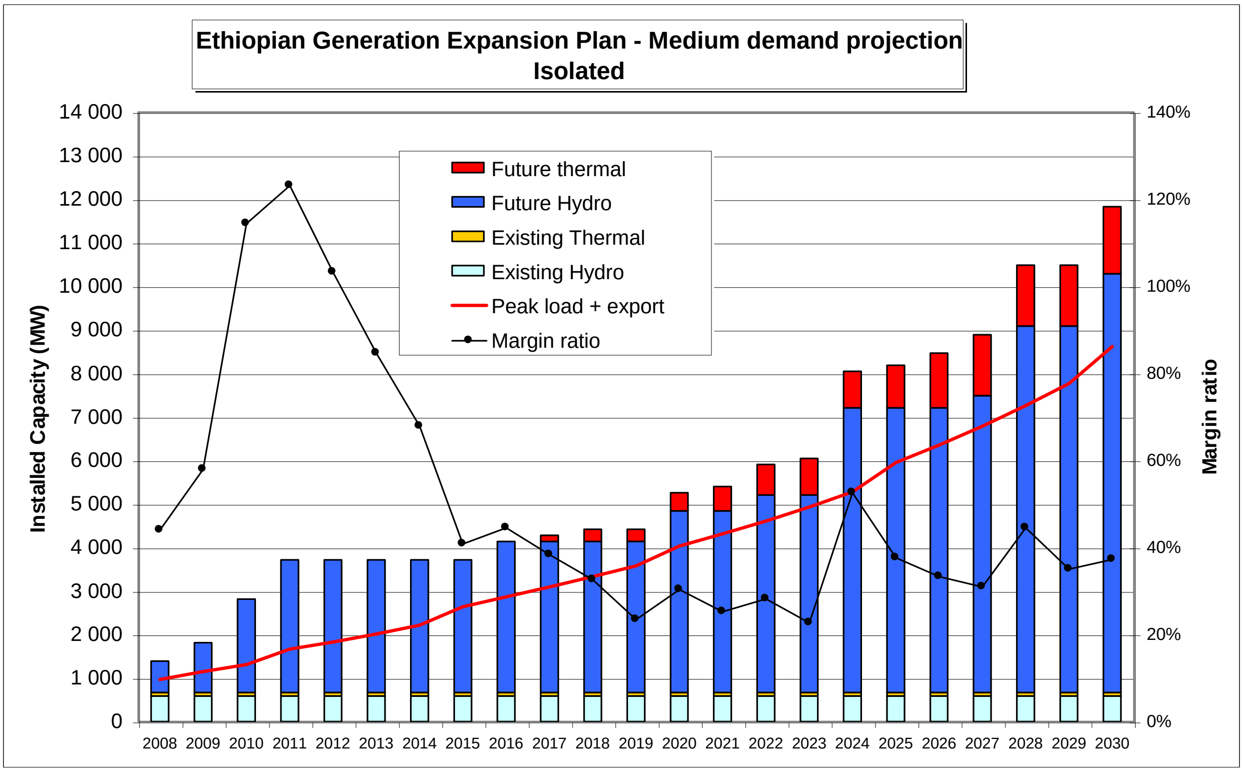

Figure 10.2-1 - Generation Expansion Plan - Ethiopia – Medium demand projection - No interconnection with Sudan / Egypt

<u>Note</u>:

In this figure, the term "existing" refers to power plants existing before 2008 while "future" refers to power plants committed after 2008.

The associated schedule of HPP commissioning is the following:

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	TPP	Capacity MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014					
2015					
2016	Halele Worabesa	420	2 245		
2017				OCGT	140
2018				OCGT	140
2019					
2020	Baro I + I + Gengi	700	4 409	OCGT	140
2021				OCGT	140
2022	Geba I + II	368	1 788	OCGT	140
2023				OCGT	140
2024	Mandaya	2 000	12 100		
2025				OCGT	140
2026				OCGT	280
2027	Chemoga Yeda	280	1 415	OCGT	140
2028	Karadobi	1 600	6 000		
2029					
2030	Border	1 200		OCGT	140
Total		9 675			1 540

Table 10.2-1 - Generation expansion plan - HPP Ethiopia – Medium demand projection

Comments on hydro surplus:

From 2010 to 2018, Ethiopia can take advantage of a significant surplus of hydro generation which can be exported to Sudan through the future 200 MW interconnection.

Subsequently, the commissioning of large HPP such as Mandaya (2000 MW), Karadobi and Border leads to significant surplus of hydro generation for periods of 2 to 4 years after commissioning, before the increase of Ethiopian demand completely absorbs these additional generation.

For example, in 2024, Mandaya represents more than 1/3 of the Ethiopian peak demand (including exports to Kenya). From the commissioning of Mandaya in 2024, it takes up to 2028 for the Ethiopian demand to increase by about 2000 MW (installed capacity of Mandaya), and up to 2029 to increase by 12 TWh (average generation of Mandaya). This means that during this period, only part of Mandaya generation will be necessary for the Ethiopian demand, the other part (ie. the surplus) could be exported at no additional cost for the Ethiopian system (i.e without any additional generation investment cost).

In 2028, Karadobi would represent more than 20% of the peak demand (including exports). It would take 2 to 3 years for the demand to absorb Karadobi capacity and generation.

Accordingly, the "natural" hydro surplus in the Ethiopian generation expansion plan results from the large size of the major HPP projects relative to the Ethiopian demand (Mandaya represents more than one third of the peak demand in 2024). The delivery of this surplus power would not induce additional generation cost to the Ethiopian system (the investment is the same).

Smaller projects would be included at a quicker step in the Ethiopian GEP, would be absorbed more rapidly by the demand growth, and would result in much less hydro surplus, but would lack the economic competitiveness of largest HPP projects.

10.2.2 HIGH (TARGET) DEMAND PROJECTION

The main hypothesis for establishing the generation expansion plan for Ethiopia for the high demand projection are:

- High demand projection (also called "target scenario"): average annual growth rate =14.3%
- Medium fuel price projection.
- No exchange with Egypt or Sudan.
- Power export to Kenya (from 200 MW in 2011 to 1200 MW in 2030) and Djibouti (<53 MW).

In the high demand projection, the peak demand in 2030 is more than twice the peak demand in the medium projection: 14 330 MW instead of 6 814 MW.

The impact on the generation expansion plan of Ethiopia is obviously significant as shown in the following figure where the largest HPP projects, Mandaya, Karadobi and Border are commissioned in 2020, 2023 and 2025 (instead of 2024, 2028 and 2030 in the medium demand projection).

Such a tight schedule of commissioning seems very difficult to carry out considering the large size of those reservoirs, the financing requirements, and the negative downstream effects during the successive fillings of these reservoirs located of the Blue Nile.

In particular, the impact on Aswan level has been evaluated to a 12 m loss of height when filling Mandaya, 8 m when filling Karadobi and 2 m when filing Border, while the average loss of energy at Aswan from the filing / operation Mandaya over a 50 year-period are reported to be in the range of 200 GWh (ref: Mandaya pre-feasibility study).

Further studies are recommended to analyze fully all the aspects of the impact of Blue Nile large HPP on Aswan.

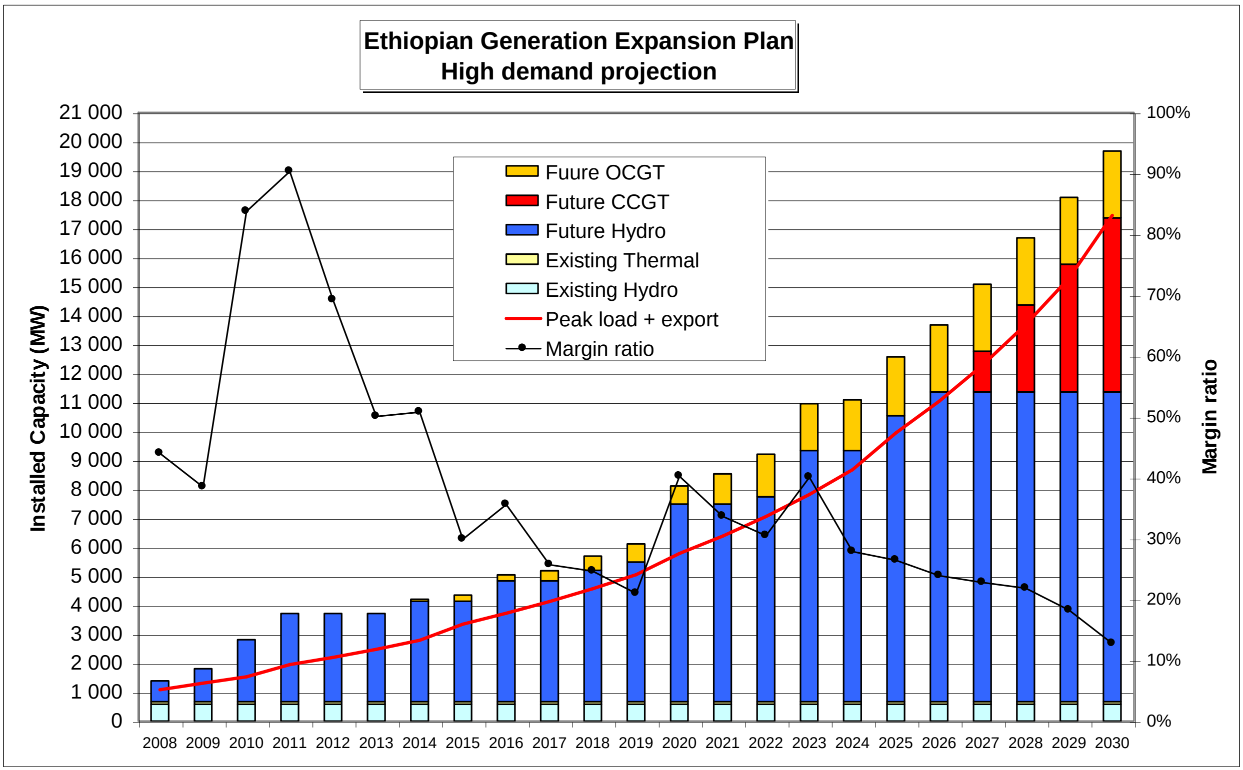

Figure 10.2-2 - Generation expansion plan - Ethiopia - High demand projection

In the medium demand projection, the commissioning of all hydropower projects identified in Module 3 Vol 3 (except Gojeb) was sufficient the balance demand and supply (with some additional OCGT for peak generation) up to 2035.

On the other hand, in the high demand projection, all the hydropower projects identified in Module 3 Vol 3 (including Gojeb) are absorbed in the Ethiopian power system by 2027. From 2027 on, and within the limit of the list hydropower projects identified in this Study, all required new generation capacities would have to be made on CCGT.

Obviously, further to the hydro projects identified in Module 3, there may probably be other potential hydro projects feasible in Ethiopia. However, it was not within the reach of the present Study to push further their identification and analysis.

Within these limits, the main outcome of this expansion plan based on the available data and hypothesis, is to point out the fact that the high demand projection would lead probably to a significant increase of generation cost from 2027, after all cost effective hydro project like Mandaya, Karadobi, Border have been commissioned. Some thermal generation capacity (more expensive than hydro generation) would probably be required at this time horizon, while other potential hydro project would probably have generation cost greater than the large projects currently under study.

It also means that the hydro surplus would disappear from 2027, except if new cost effective HHP are identified in the future.

The following table gives the schedule of commissioning:

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	CCGT MW	OCGT MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014	Halele Worabesa	420	2 245		70
2015					140
2016	Baro I + I + Gengi	700	4 409		
2018	Geba I + II	368	1 788		140
2019	Chemoga Yeda	280	1 415		140
2020	Mandaya	2 000	12 100		140
2021					-
2022	Genale III	254			420
2023	Karadobi	1 600	8 600		420
2024					140
2025	Border	1 200	6 000		140
2026	GenaleVI - Aleltu E&W	569	2 850		280
2027	Gogeb	153	520	1400	280
2028				1600	
2029				1400	
2030				1600	
Total		10 651		6000	2310

Table 10.2-2 - Generation expansion plan - Ethiopia - High demand projection

10.2.3 LOW DEMAND PROJECTION

The main hypothesis for establishing the generation expansion plan for Ethiopia for the low demand projection are:

- Low demand projection: 10.0% average annual growth rate.
- Medium fuel price projection.
- No exchange with Egypt or Sudan.
- Power export to Kenya: from 200 MW in 2011, 600 MW in 2020 and 1200 MW in 2030.
- Power export to Djibouti : < 53 MW.

In the low demand projection, the peak demand in 2030 is about 20% lower than the peak demand in the medium projection: 5 506 MW instead of 6 814 MW.

The impact on the generation expansion plan of Ethiopia is relatively low with only an increase of the time span between the commissioning of the larger HPP projects, with Mandaya, Karadobi and Border commissioned in 2025, 2030 and 2033 (instead of 2024, 2028, 2030):

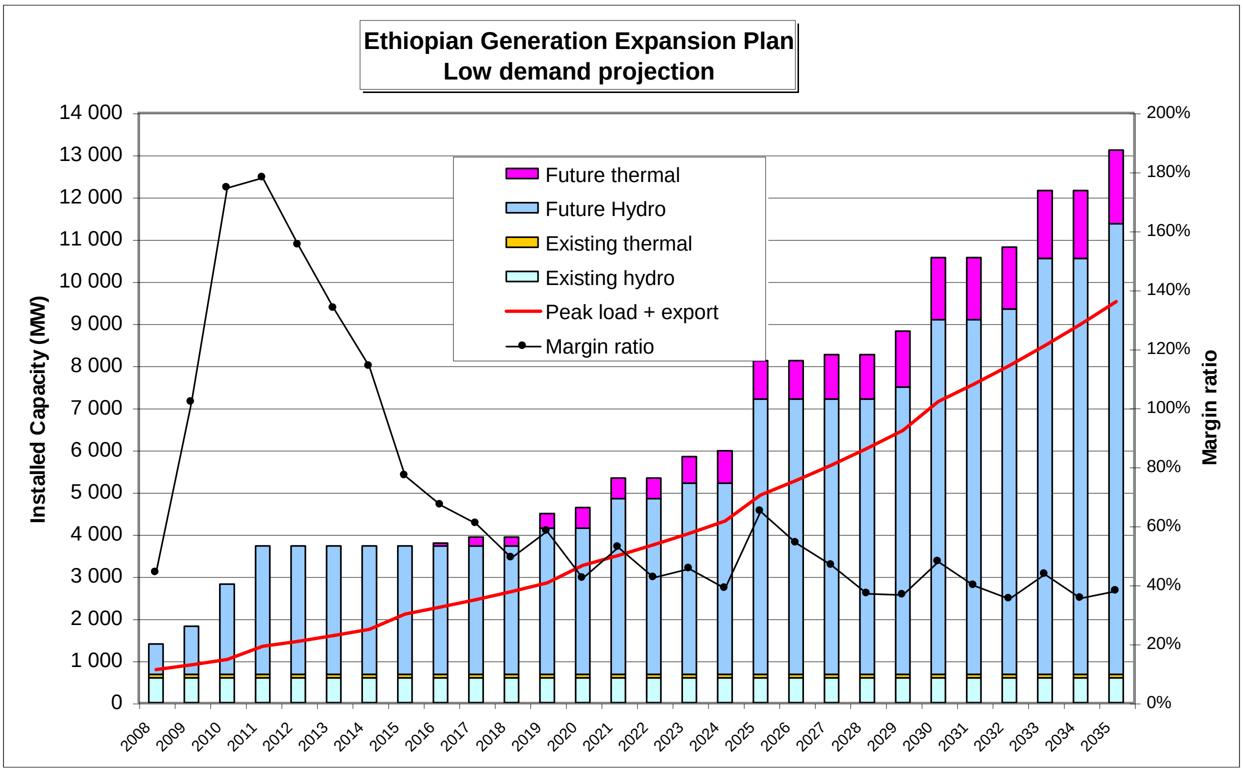

Figure 10.2-3 - Generation expansion plan - Ethiopia - Low demand projection

The following table presents the schedule of commissioning:

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh	CCGT MW	OCGT MW
2008	Gibe II	420	1 600		
	Tekeze	300	1 200		
2009	Beles	420	2 000		
2010	Neshe	97	225		
2011	Gibe III (I)				
2012	Gibe III (II)	1 870	6 240		
2014					
2015					
2016					70
2018					140
2019	Halele Worabesa	420	2 245		-
2020					140
2021	Baro I + I + Gengi	700	4 409		140
2022					-
2023	Geba I + II	368	1 788		
2024					140
2025	Mandaya	2 000	12 100		140
2026					140
2027					-
2028					140
2029	Chemoga Yeda	280	1 415		-
2030	Border	1 200	6 000		280
2031					140
2032	Genale III	254	1 000		
2033	Karadobi	1 600	8 600		
2034					140
2035	Genale VI - Aleltu E&W	569	2 850		-
Total		10 498			1 610

Table 10.2-3 - Generation expansion plan - Ethiopia - Low demand scenario

10.3 SUDAN

10.3.1 MEDIUM DEMAND PROJECTION

Main hypothesis:

- Medium demand projection (average annual growth rate: 9.8%).
- Medium fuel price projection (crude oil: 60 USD/bbl in 2030).
- No exchange with Egypt or Sudan.

The following figure presents the evolution of the installed capacity for the different generation types:

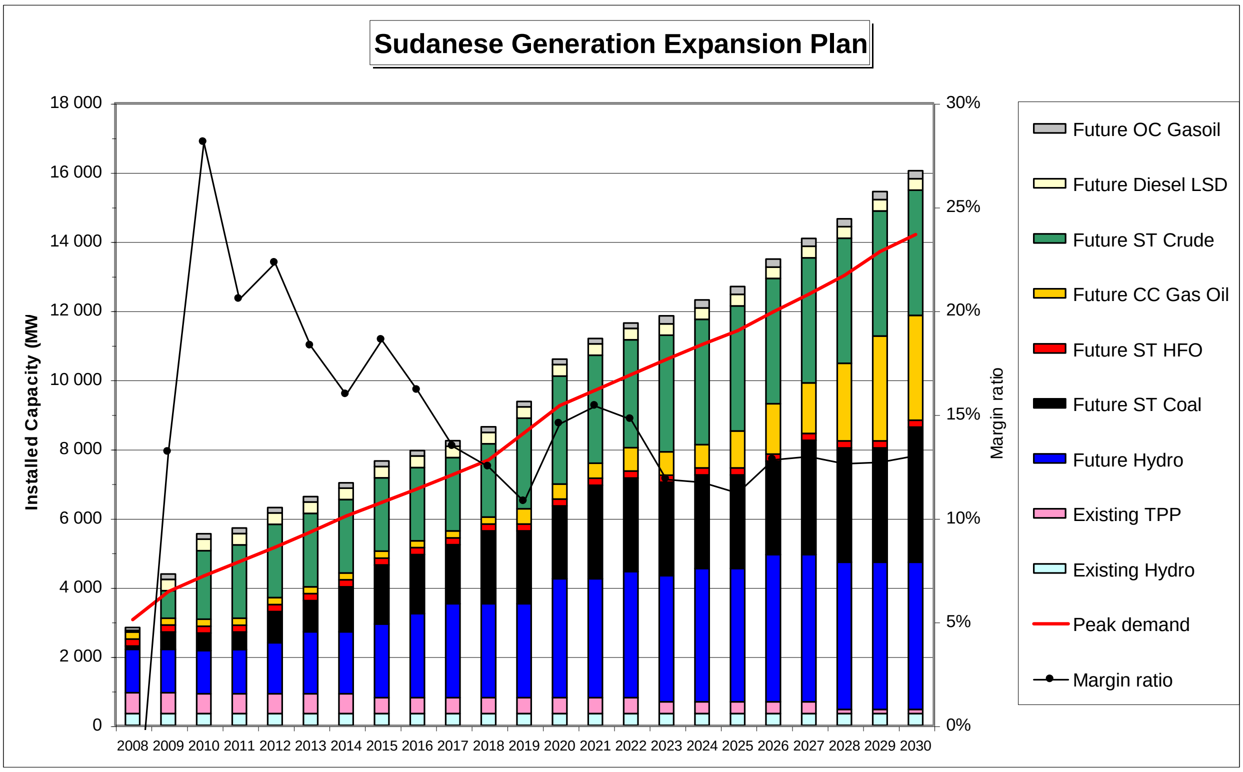

Figure 10.3-1 - Generation Expansion Plan – Sudan – Medium demand projection

<u>Comments</u>:

In the next 25 years, the Sudanese generation mix will evolve from a mix with equivalent share of hydro and thermal generation, to a generation mix where thermal generation will represent 75% of the generation. The resulting increase in fuel consumption, and its proximity with Ethiopia, makes Sudan a natural market for the Ethiopian hydro surplus generation.

Year 2008 is characterized by a lack of generation compared to demand resulting in power shedding. Afterward, the new capacities currently in construction will allow to re-balance demand and supply.

As presented in **paragraph 7.2** the development of new generation capacity in Sudan is based on:

- Coal-fired STTP located in Port Sudan:

The imported coal leads to the lowest cost of generation for base load. The total possible new capacity in coal-fired generation is limited by transmission capacity to the Sudanese load centers. Accordingly, the schedule of planting for coal-fired STTP will be very close to the one defined in the Sudanese Generation Expansion Plan 2006, except for the addition of one another 400 MW coal-fired STPP in 2015, because the transmission study carried out in Module 6 demonstrated the transmission system is strong enough.

- Gas oil-fired CCGT and crude oil-fired STPP:

Gas oil-fired CCGT and crude oil-fired STPP are more expensive than coal-fired STPP. However, due to the transmission network limiting the total coal-fired STTP capacity, CCGT and crude oil-fired STTP are the next choice for semi-base load generation.

In order to preserve some diversity in fuel origin and to be consistent with Sudanese Generation Expansion Plan 2006, the proportion of new gas oil-fired CCGT and crude oil-fired STPP will be 2 to 1 in 2030.

- Low Speed Diesel and OCGT:

The Sudanese generation mix has been suffering significant power shedding in the past recent years. This power shedding will last up to 2009 or so until the commissioning of new capacity. In this context, and due to the short construction duration of LSD, the commissioning of a group of 7 x 40 MW LSD and a 74 MW OCGT is considered in 2009 as in NEC Generation Expansion Plan 2006.

The following table (on next page) presents the main numerical values of the GEP.

10.3.2 HIGH AND LOW PROJECTIONS

See discussion in part §12.3

TPP :	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Future ST Coal	100	505	505	505	905	905	1305	1705	1705	1705	2105	2105	2105	2705	2705	2705	2705	2705	2705	3305	3305	3305	3905
Future ST HFO	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Future CC Gas Oil	200	200	200	200	200	200	200	200	200	200	200	438	438	438	676	676	676	1067	1458	1458	2245	3032	3032
Future ST Crude	0	790	1985	2120	2120	2120	2120	2120	2120	2120	2120	2620	3120	3120	3120	3370	3620	3620	3620	3620	3620	3620	3620
Future OC Gasoil	82	156	156	156	156	156	156	156	156	156	156	156	156	156	156	230	230	230	230	230	230	230	230
Future Diesel LSD	50	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330
Total future TPP	**633**	**2182**	**3377**	**3512**	**3912**	**3912**	**4312**	**4712**	**4712**	**4712**	**5112**	**5850**	**6349.8**	**6949.8**	**7187.8**	**7511.8**	**7761.8**	**8152.8**	**8543.8**	**9143.8**	**9930.8**	**10717.8**	**11317.8**
Existing TPP	**603**	**603.2**	**570**	**570**	**570**	**570**	**570**	**460**	**460**	**460**	**460**	**460**	**460**	**460**	**460**	**340**	**340**	**340**	**340**	**340**	**120**	**120**	**120**

HPP :	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Roseires	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Sennar	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Girba	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jebel Aulia	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1	28.1
Existing Hydro	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**	**341**
Sennar extension					60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Roseires New with Dind	0	0	0	0	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
Merowe	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250	1 250
Rumela				30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Shereiq						315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
Dal								340	340	340	340	340	340	340	340	340	340	340	340	340	340	340	340
Kajbar									300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Dagash										285	285	285	285	285	285	285	285	285	285	285	285	285	285
Fula													720	720	720	720	720	720	720	720	720	720	720
Shukoli															210	210	210	210	210	210	210	210	210
Lakki																0	210	210	210	210	210	210	210
Bedden																			400	400	400	400	400
Future Hydro	**1 250**	**1250**	**1250**	**1280**	**1475**	**1790**	**1790**	**2130**	**2430**	**2715**	**2715**	**2715**	**3435**	**3435**	**3645**	**3645**	**3855**	**3855**	**4255**	**4255**	**4255**	**4255**	**4255**

Table 10.3-1 - Generation expansion plan – Sudan – Medium demand projection

11 LOOSE POOL MODEL : POWER EXCHANGES & GENERATION SAVINGS

11.1 INTRODUCTION

This paragraph focuses on the evaluation of the operation savings in the loose pool model.

As explained in §4.4.3.2**,** the loose pool model refers to a scheme where the operation of the generation is coordinated regionally (either by direct coordination or through a power pool) while each country keeps its independence for the decision of generation investment.

Accordingly, the investment cost of the regional generation plan is identical as in the independent development of each power system, while the operation cost is reduced through regional coordination and the use of Ethiopian hydro surplus.

The operation optimization software SDDP allows to simulate the optimal operation (i.e. least cost dispatch) of the integrated system according to the capacity of the interconnection, as well as the evaluation of power exchanges.

Note:

This approach is similar to the one carried out for the Ethiopia-Sudanese interconnection Study in 2005.

11.1.1 ORIGIN OF THE HYDRO SURPLUS

Basically, the hydro surplus in Ethiopia are inherent to the development of a purely hydro system based on large size HPP for two reasons:

a. Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following the commissioning of these large HPP projects, during the period of time when the Ethiopian demand does not completely absorb the new generation.

   Smaller projects would be included at a quicker step in the Ethiopian GEP, and would be absorbed more rapidly by the demand growth, and would result in much less hydro surplus, but would lack the economic competitiveness of largest HPP projects.

b. In a hydro power system, in order to have a proper supply / demand balance all year long and even on the driest years, a large amount of installed overcapacity is required.

The resulting hydro surplus, can be provided for export, when available, at no additional cost for the Ethiopian power system.

11.1.2 CHARACTERISTICS AND COSTS OF THE HYDRO SURPLUS

The amount of hydro surpluses varies along the planting schedule of new hydro plants (reaching a maximum on the commissioning of large HPP, and a minimum just before new commissioning), and along each year (higher during wet season).

The hydro project investment decisions in the exporting country are decided on the basis of the internal demand requirement. The supply of power export least to no additional investment costing the hydro exporting country. Accordingly, the selling price of energy would cover presumably only a fraction of the HPP investment cost.

This type of power exchanges is typical of spot market and future market (month to month). For instance, after the wet season Ethiopia could assess the amount of stored energy in its reservoirs and evaluates the amount available for export and contract exchanges for a period of a few months.

11.2 COMMISSIONING DATE AND PHASING OF THE INTERCONNECTION

Based on the duration of technical studies, tender process and construction, the earliest date of commissioning of the interconnection is close to 2015.

However, it makes more sense to link the commissioning date of the interconnection with the commissioning of the first large HPP project close to the Sudanese (i.e. Mandaya). In the isolated development of the Ethiopian system, Mandaya is commissioned in 2024. In the scenario with interconnection, it is considered that Mandaya is commissioned at its earliest date of commissioning: 2020 and this same date of commissioning is considered for the interconnection. This 4 years shift forward is only difference with the Ethiopian generation expansion plan determined previously without interconnection. In the evaluation of the generation savings the additional investment cost (anticipation of 4 years) will be taken into account.

Additional analysis of the detailed phasing of the interconnection is provided in § 12.4.

Regarding the 200 MW Ethiopia-Sudan interconnection, the analysis of the balance between the installed capacity and peak demand in Ethiopia (see Figure 1.2-1) shows a period of time between 2010 and 2015 with a large amount of hydro surplus available further to the commissioning of the two phases of Gibe III (2011 and 2012). On this basis, and if still compatible with the schedule with the 2000 MW interconnection project, the Consultant would recommend to increase the capacity of the interconnection between Ethiopian and Sudan committed in 2010 to higher than the original design of 200 MW.

11.3 EXPORT CAPACITIES CONSIDERED

The analysis will study the export capacity of hydropower in Ethiopia to Egypt and Sudan, along with a re-enforcement of the emerging Ethiopian – Sudanese market.

Indeed, the main origin of power export in the area will come from cost competitive hydro surplus from Ethiopia, accordingly the interconnection should be sized in relation to these hydro surplus. Furthermore, with the coming Ethiopia-Sudanese interconnection (2010), the Ethiopian-Sudanese market could be considered as the first step in the development of a power market in the area. Accordingly, it is interesting to evaluated the savings related to the enlargement of this market (ie. enlargement of transmission capacity between Ethiopia and Sudan).

On these basis, this power exchanges will be considered in both ways between Ethiopia and Sudan (i.e. growing and expanding market), and only in one way between Ethiopia to Egypt (i.e. export of hydro surplus).

Five different cases will be evaluated:

- 700 MW export capacity between Ethiopia and Sudan, 0 MW capacity to Egypt.
- 700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.
- 700 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.

For example, case n°4 means that up to 1200 MW could be delivered to Sudan, while an additional 2000 MW could be delivered to Egypt.

<u>Practical limits of import / exports</u>:

Ethiopia: In 2020, an export of 1200 MW to Sudan, 2000 MW to Egypt, 600 MW to Kenya would represent more than the Ethiopian forecasted internal demand (3 800 MW compared to the 3 126 MW for the medium scenario). In other terms, it means more than doubling the Ethiopian internal demand. In 2030, this level of export would represents 2/3 of the Ethiopian internal demand. This is on the high side of values observed across the world[17].

Sudan: In 2020, a 1200 MW import would represent more than 13% of the Sudanese peak demand in 2020. A ratio of import greater than 12% to 15% coming from a single country is rarely observed across the world.

Both for the importing and exporting country, and apart from technical considerations, the actual limits to the power exchange would depend on type of power exchanges, type of contracts, type of financial funding for the associated power plants, the resulting risks and finally the national energy policy (degree of independence). Furthermore these limits are not static and evolve along with the general economic development of the countries.

<u>Economic exchanges</u>:

In the following paragraphs, the amount of power exchanges are the one minimizing the global operation cost (global merit order). There are determined by the optimization software (SDDP) which determined the optimal policy leading to the minimal operating cost based on:

- the transfer capacity of the interconnection,
- the precise description of the generation mix: hydro topology, downstream impact in particular during filling of new HPP, dead storage, evaporation, irrigation, etc (see **part 5**).

11.4 ECONOMIC POWER EXCHANGES

11.4.1 700 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN

The results are presented in Module 6 Vol 2 Appendix.

[17] One of the highest ratio export / peak demand might be Mozambique who currently exports the equivalent of its internal peak demand (500 MW).

11.4.2 700 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 700 MW BETWEEN ETHIOPIA AND EGYPT

The following figure presents the evolution of the average annual economic exchanges in the following case:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 700 MW from 2020,
- 700 MW additional export capacity to Egypt from 2020.

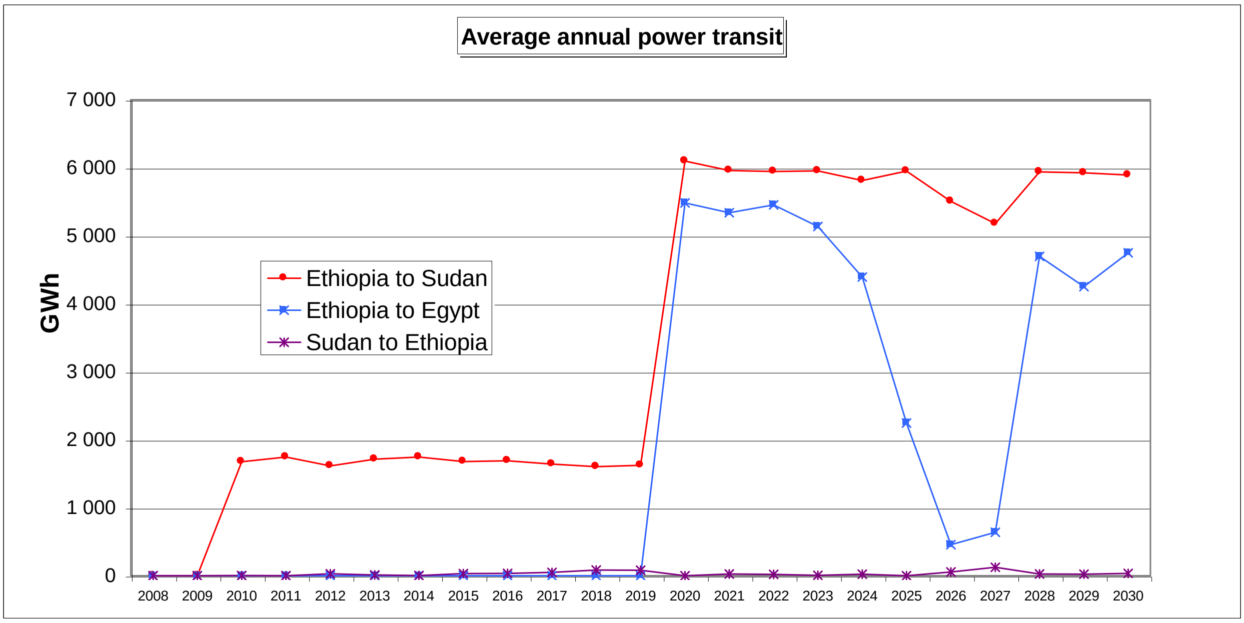

Figure 11.4-1 - Average annual power transit - ET-SU = 700 MW, ET-EG = 700 MW – Loose pool

In order to minimize the regional operation costs, the power export is preferably concentrated toward Sudan, where the fuel savings are higher: from 2020, the export capacity from Ethiopia to Sudan is still nearly saturated with an average of 5 800 GWh/year over the 2020-2030 period (equivalent to 8 300 hours / year at 700 MW). The average export from Ethiopia to Egypt is close to 3 900 GWh/year (equivalent to more than 5 500 hours / year at 700 MW).

During the first 4 years after the commissioning of Mandaya (ie. from 2020 to 2023), the Ethiopian hydro surplus available are high enough to saturate the transmission capacity to Egypt and Sudan. But afterward, Mandaya potential is gradually absorbed by Ethiopian growing demand. The remaining hydro surplus is absorbed preferentially by Sudan (which is the least cost option because of the greater thermal generation costs in Sudan), leading to reduction of power export to Egypt. With the commissioning of Karadobi in 2028 followed by Border in 2030, the hydro surplus become again large enough to provide both Sudanese and Egyptian power systems to the limit of the interconnection.

Monthly seasonality of the power exchanges is presented in the Module 6 Vol 2 Appendix.

11.4.3 700 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 2000 MW BETWEEN ETHIOPIA AND EGYPT

Case 3 examines whether there is enough hydro surplus in Ethiopia to increase the export capacity to Egypt up to 2000 MW.

The following figure presents the evolution of the average annual economic exchanges in the following case:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 700 MW from 2020,
- 2000 MW additional export capacity to Egypt from 2020.

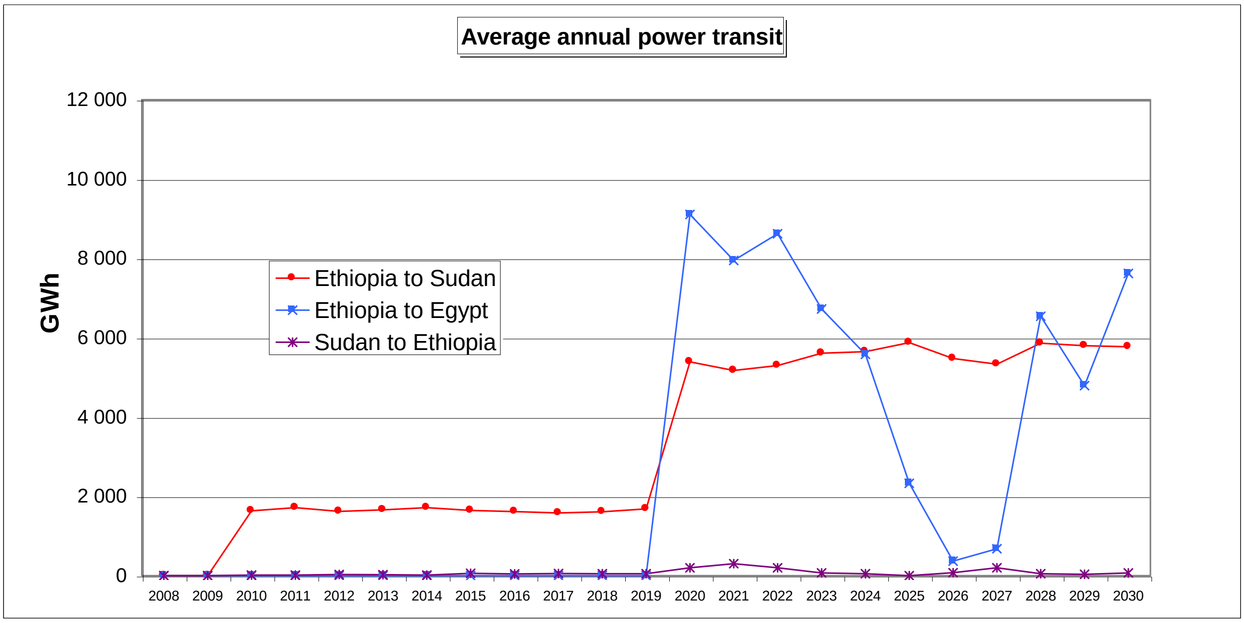

Figure 11.4-2 - Average annual power transit – ET-SU=700 MW – ET-EG=2000 MW – Loose pool

From 2020, the export capacity from Ethiopia to Sudan is still nearly saturated with an average of 5500 GWh/year over the 2020-2030 period (equivalent to 7900 hours / year at 700 MW).

The increase of export capacity to Egypt (from 700 MW to 2000 MW) results in an increase of the average export from Ethiopia to Egypt close to 5500 GWh/year, but without saturating the capacity (equivalent to 2 800 hours / year at 2000 MW).

Monthly seasonality of the power exchanges is presented in Module 6 Vol 2 Appendix.

The power exports to Egypt follows the evolution of hydro surplus in Ethiopia: they reach a maximum with the commissioning of Mandaya in 2020, Karadobi in 2028 and Border in 2030. Then they declines about 4 years after the commissioning of each major HPP project, when nearly all the available surplus have been absorbed by the Ethiopian system.

Accordingly the 700 MW (for Sudan) and 2000 MW (for Egypt) scheme seems oversized considering the hydro surplus availability in Ethiopia in the loose pool approach.

11.4.4 1200 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 2000 MW BETWEEN ETHIOPIA AND EGYPT

Case 4 examines the optimal (i.e. least-cost) share of Ethiopian hydro surplus when the transmission capacity between Sudan and Ethiopia is increased up to 1200 MW.

The following figure presents the evolution of the average annual economic exchanges in the following case:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 2000 MW additional export capacity to Egypt from 2020.

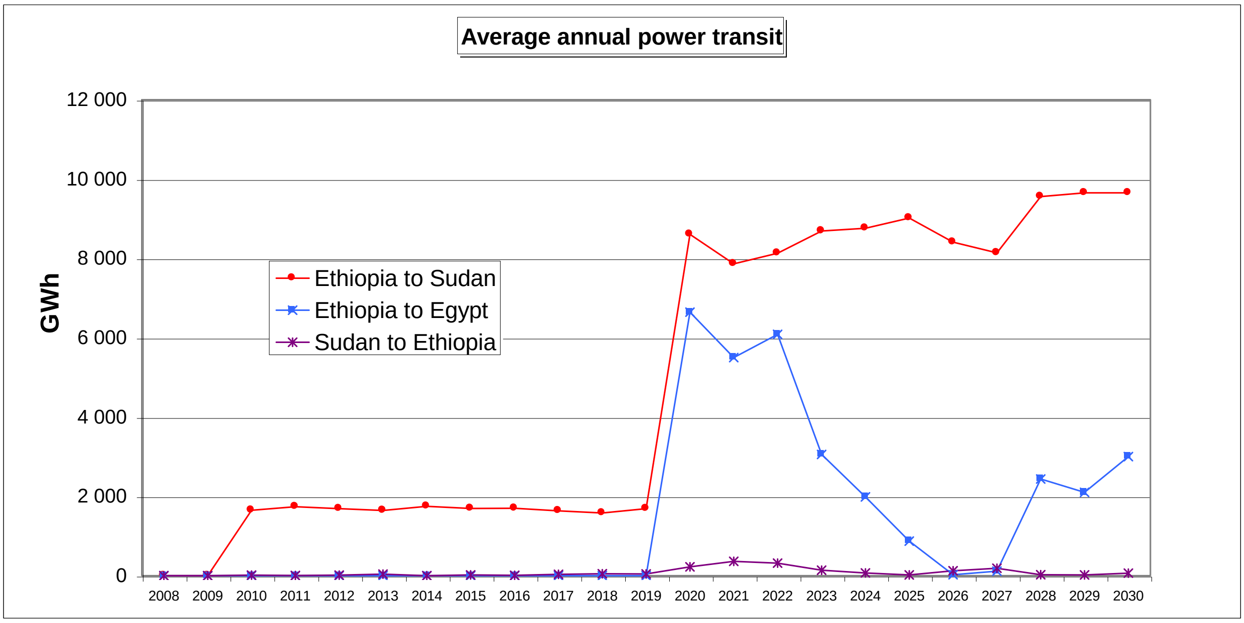

Figure 11.4-3 - Average annual power transit – ET-SU = 1200 MW - ET-EG = 2000 MW – Loose pool

The increase of the power export capacity to Sudan from 700 MW to 1200 MW, results in an increase of the average annual power export from Ethiopia to Sudan, rising to 8800 GWh/year over the 2020-2030 period. The interconnection to Sudan is still nearly saturated with an average of 7 300 hours / year at 1200 MW.

On the other hand, because of the total quantity of Ethiopian hydro surplus available for export, it is no longer possible to supply both Sudan and Egypt at full capacity of the interconnection. Accordingly, the least-cost economic choice is to maximize the power export to Sudan, where thermal generation costs are higher. The power export to Egypt reduces from an average 5 200 GWh/year (with ET-SU: 700 MW, ET-EG: 2000 MW) to 2900 GWh/year (equivalent to 1500 hours / year at 2000 MW).

The capacity of export to Egypt exceeds the hydro surplus available except during the very first years after commissioning of Mandaya (2020), Karadobi (2028) and Border (2030) meaning that transmission capacity to Egypt is oversized.

From 2025 to 2028 there is virtually no available power export to supply Egypt, the whole part of it being absorbed by Sudan (least-cost option).

Monthly seasonal variation of the power exchanges is presented in the Module 6 Vol 3 Appendix.

11.4.5 1200 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 700 MW BETWEEN ETHIOPIA AND EGYPT

Case 5 examines the optimal (i.e. least-cost) share of Ethiopian hydro surplus when the transmission capacity between Sudan and Ethiopia is increased up to 1200 MW.

The following figure presents the evolution of the average annual economic exchanges in the following case:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 700 MW additional export capacity to Egypt from 2020.

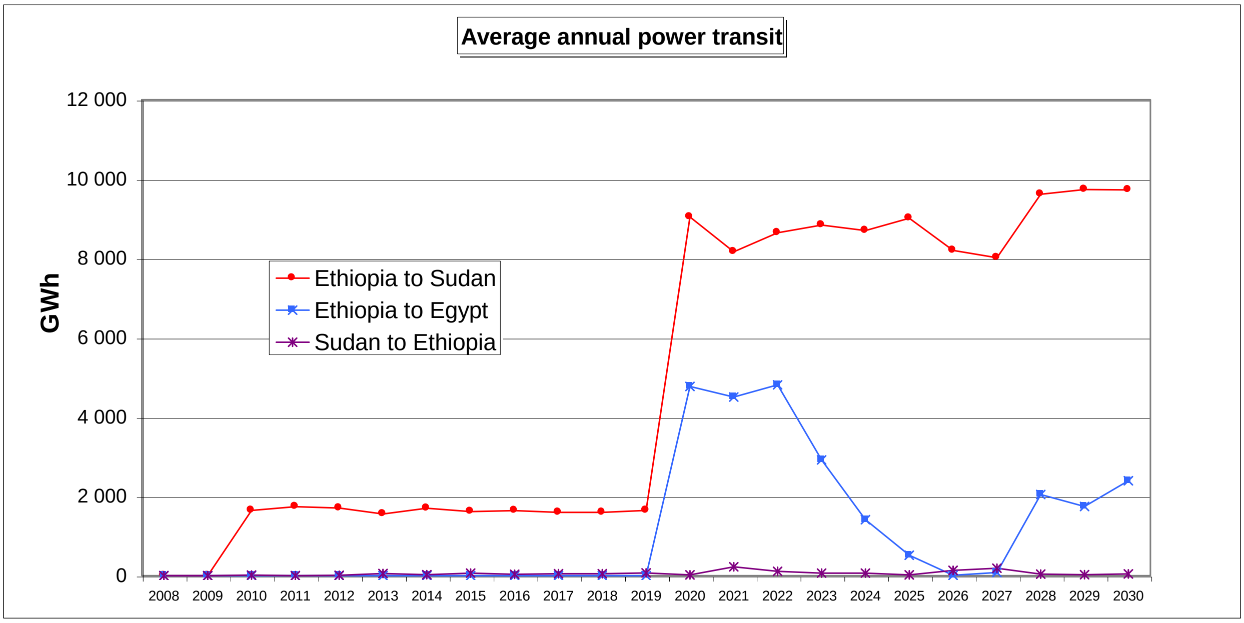

Figure 11.4-4 - Average annual power transit – ET-SU=1200 MW – ET-EG= 700 MW – Loose pool

The average annual power export from Ethiopia to Sudan, arises to 8900 GWh/year over the 2020-2030 period, and nearly saturates the 1200 MW capacity continuously.

The average annual power export from Ethiopia to Egypt, arises to 2 300 GWh/year over the 2020-2030 period, peaking during the first years after commissioning Mandaya, Karadobi and Border.

Monthly seasonal variation of the power exchanges is presented in the Module 6 Vol 3 Appendix.

This result is consistent with the ET-EG: 2000 MW, ET-SU: 1200 MW scheme, showing that a 700 MW (Egypt) 1200 MW (Sudan) seems the most appropriated scheme considering the amount of hydro surplus in Ethiopia in the loose pool context.

11.5 GENERATION SAVINGS FOR THE REGION

11.5.1 INTRODUCTION

This section deals with the first part of the savings resulting from the presence of the interconnection: the generation cost savings.

The CO_2 savings will be evaluated in part 14.

The cost of the interconnection will be dealt with in part 15.2.

The cost – benefit analysis (based on generation savings, CO_2 savings, and cost of the interconnection) will be carried out in part 15.

It is reminded that, in line with the Terms of Reference, the economic approach of Module 6 is a cost approach. The whole cost of generation (investment and operation costs) for the region, and its variation in presence of the interconnection is investigated. The share of investment between the countries is not relevant at this approach because it has no influence on the global cost of generation for the region. In the same way, the possible selling cost of power from one country to another is not considered because it does not affect the cost of generation (the selling price is a way to share the cost / benefit of a project. The price paid by the buyer is an income for the seller, accordingly the net balance of the sell / buy operation for the region is zero – See § 4.6).

Accordingly, the generation savings for the region are evaluated by comparing:

- the total generation cost (investment cost + operation cost) in the reference situation: generation expansion plan determined independently for each country (see § 15.1),
- the total generation cost (investment cost + operation cost) in presence of the interconnection for various transmission capacity.

These generation savings consist essentially in fuel cost savings, because the Generation Expansion Plan of each country is left unchanged compared to the reference situation, except for Mandaya which is anticipated to 2020 along with the commissioning of the interconnection (instead of 2024 in the reference situation).

The transmission losses are considered in the simulation software as an additional "demand" to be supplied. Accordingly, they are taken into account through their impact on the generation cost.

11.5.2 POTENTIAL GENERATION SAVINGS AND ACTUAL GENERATION SAVINGS

The generation savings evaluated in Module 6 are potential (i.e. theoretical) savings resulting from the optimal coordination of the three generation mixes. The actual savings will depend on the development of the power pool, the establishment of short-term and medium term contracts, policy to share of cost of investment and the benefit of investment, selling price, wheeling tariff, etc. Accordingly, actual savings might be significantly lower.

11.5.3 RESULTS

The following figure presents the evolution of the generation savings for the region according to the case considered. The values given are the Present worth of the savings discounted in 2008.

These savings will be compared to the cost (investment and O&M) of the interconnection to assess the overall benefit or cost for the region (see part 15).

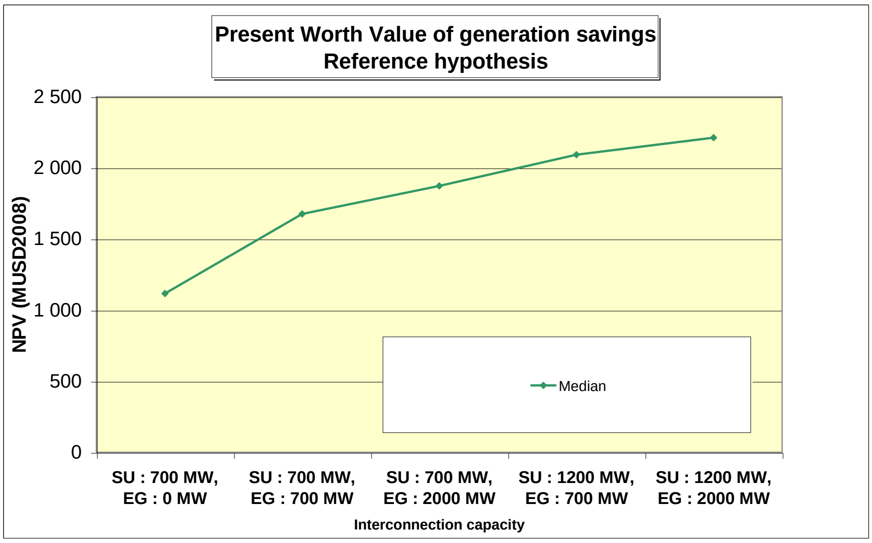

Figure 11.5-1 - Present worth of generation savings - Reference hypothesis

<u>The mechanism of generation savings in the loose pool context</u>:

Case 2 (ET-SU: 700 MW, ET-EG: 700 MW) could be used as an example to illustrate through a simplified calculation the savings mechanism in the loose pool situation.

The generation savings in case 2 are composed of:

- 2 300 MUSD operation savings,
- minus 410 MUSD investment cost due to the anticipation of the commissioning of Mandaya by 4 years.

The generation savings are as below:

- <u>Generation savings for Egypt</u>: 3.6 TWh / year are exported to Egypt and substitutes to gas-fired CCGT whose average variable cost is 50 USD/MWh (from 2020 to 2030). The resulting annual operation savings are 180 MUSD/year, which represent a present worth value in 2008 equal to 630 MUSD (10% discount rate).
- <u>Generation savings for Sudan</u>: 4.1 TWh / year are exported to Sudan and substitutes to gasoil-fired CCGT with an average variable cost of 105 USD/MWh (from 2020 to 2030). The resulting annual savings are 430 MUSD/year, which represent a present worth value of 1 500 MUSD (10% discount rate).
- <u>Additional generation cost for Ethiopia</u>: the only additional generation cost for Ethiopia, compared to the isolated scheme, is the anticipation of Mandaya by 4 years: 410 MUSD. The commissioning schedule of all other HPP is left unchanged (i.e identical to the isolated case).
- <u>Net generation savings</u>: 630 + 1500 – 430 = 1 700 MUSD which is close to the figure found by the complete simulation of the three power systems through SDDP software.

12 LOOSE POOL : SENSITIVITY ANALYSIS

12.1 INTRODUCTION

The basic principle in the sensitivity analysis is to change one single key hypothesis of the Study at a time in order to check its impact on the results.

In addition to the sensitivity to the capacity of the interconnection, the sensitivity of the results was check with the key economic parameters:

- high / medium / low fuel price projections (impact on fuel cost savings),
- high / medium / low Ethiopia demand projections (impact on the amount of hydro surplus),
- high / medium / low discount rate,
- phasing of the commissioning (one stage or two stages).

12.2 SENSITIVITY TO FUEL COST

In the loose pool model, there is no change in the generation investment schedule of each country. The bulk of the generation savings comes from the reduction of fuel cost in Sudan (gasoil fired CCGT and crude oil fired STPP) and to a lesser extend in Egypt (gas-fired CCGT).

Accordingly the fuel price projection is probably the most important and sensitive hypothesis of the Study. Three fuel price projections from have been presented in Module 3 Vol 4 (taken from the Annual Energy Outlook[18] 2006) :

- The medium fuel price projection, leads to a crude oil price of 60 USD_{2006}/bbl in 2030 and a Natural Gas price of 8.4 USD_{2006}/MBTU in 2030.
- The high price projection leads to a crude oil price of 100 USD_{2006}/bbl in 2030 and a Natural Gas price of 10.5 USD_{2006}/MBTU in 2030. This would obviously results in larger operation savings than in medium fuel price projection.
- The low price projection leads to a crude oil price of 35 USD_{2006}/ in 2030 and a Natural Gas price of 6.6 USD_{2006}/MBTU in 2030.

In order to be consistent with the reference case, the evolution of the operation is studied according the following export capacities from Ethiopia to Egypt and / or Sudan:

- 700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.
- 700 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 70 MW capacity to Egypt.

For example, case 4 means that up to 1200 MW could be delivered to Sudan, while an additional 2000 MW could be delivered to Egypt.

The main results for the "low fuel price projection" are given hereafter. The results for the " high fuel price projection" are presented in §15.3.

[18] Edited by US Department of Energy. The AEO 2007 projections are very close to the AEO 2006 used in the present Study.

12.2.1 EVOLUTION OF THE ECONOMIC EXCHANGES ACCORDING TRANSIT CAPACITY

The simulations with SDDP show that the power transit are close to those observed with the medium fuel price projection:

<u>700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt</u>:

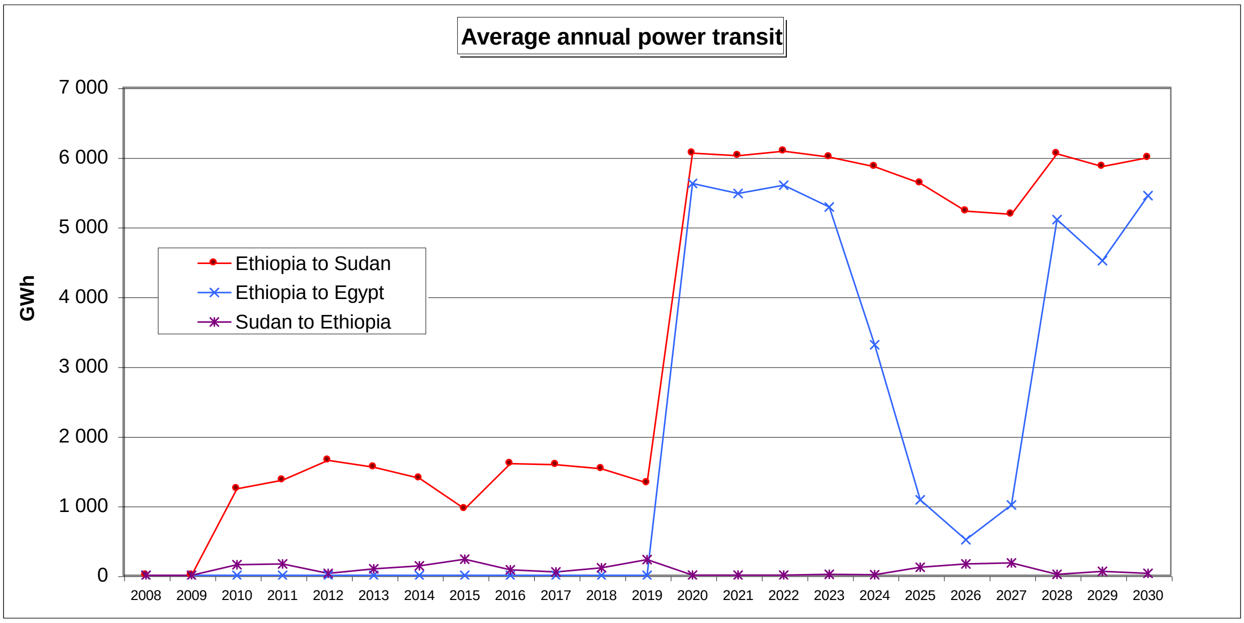

Figure 12.2-1 - Average annual power transit – ET-SU: 700 MW - ET-EG: 700 MW – Loose pool - Low fuel price projection

<u>700 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt</u>:

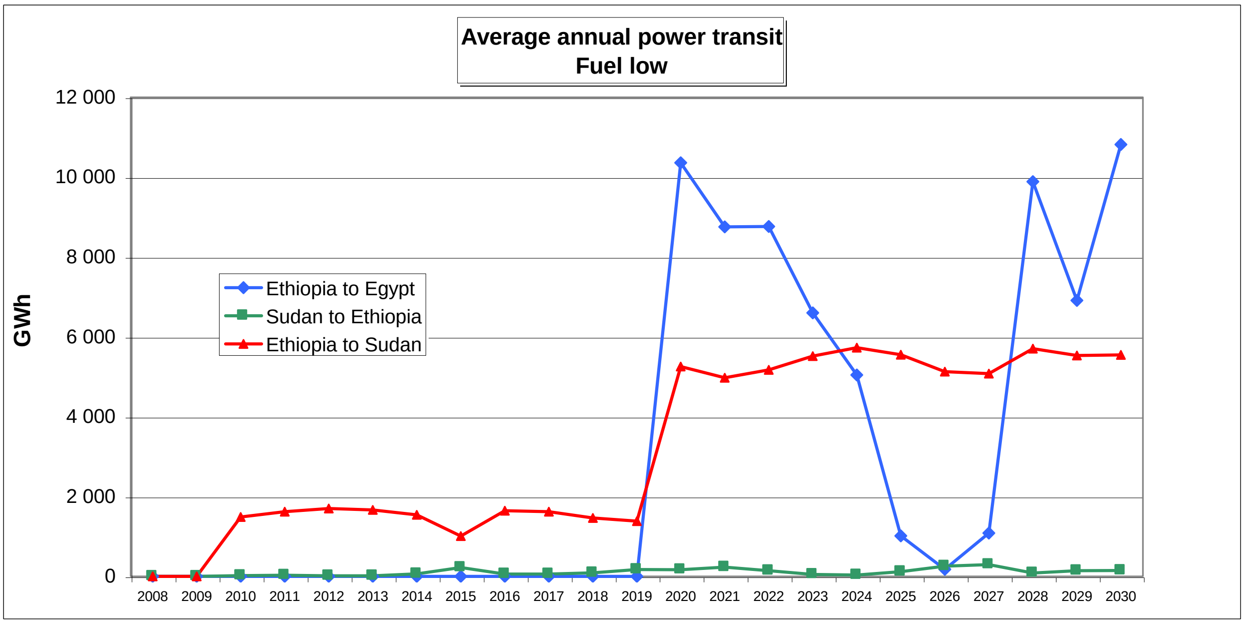

Figure 12.2-2 - Average annual power transit - ET-SU: 700 MW - ET-EG: 200 MW – Loose pool - Low fuel price projection

1200 MW export capacity between Ethiopia and Sudan, 2000 MW capacity to Egypt:

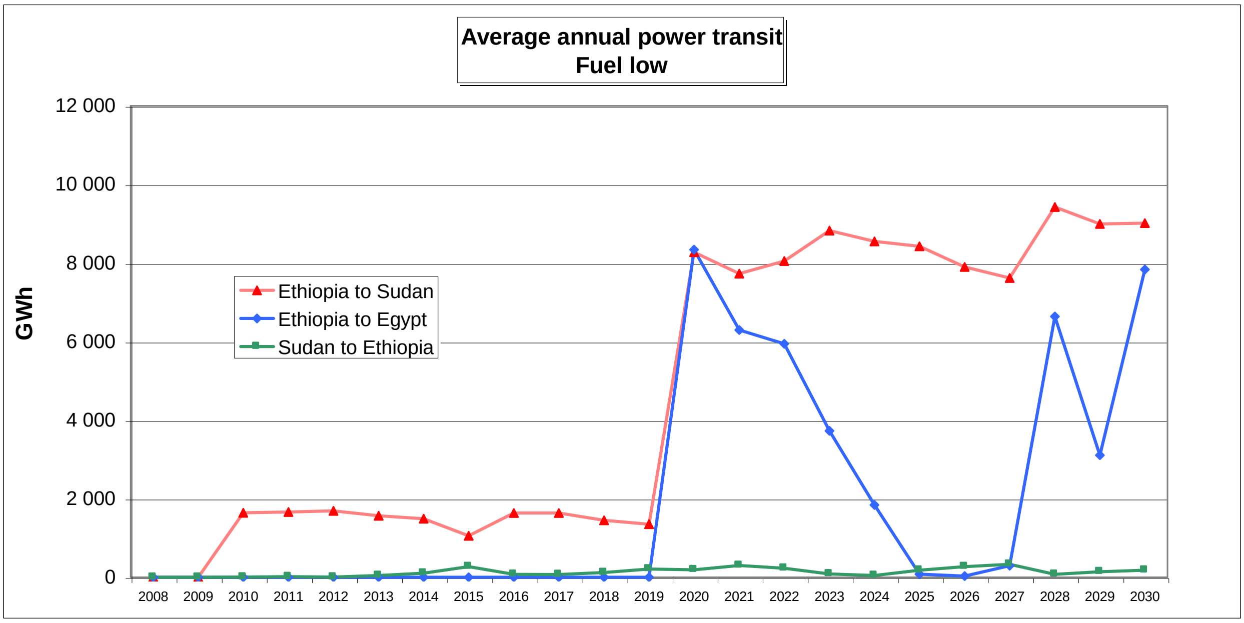

Figure 12.2-3 - Average annual power transit - ET-SU: 1200 MW - ET-EG: 2000 MW – Loose pool - Low fuel price projection

1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt:

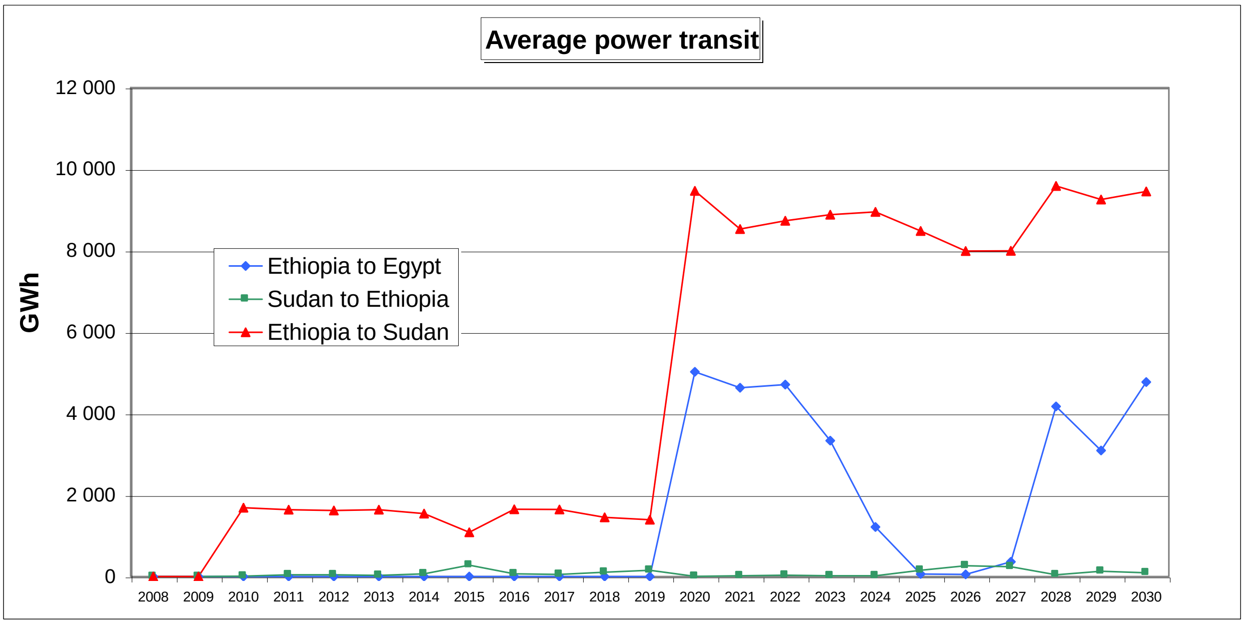

Figure 12.2-4 - Average annual power transit - ET-SU: 1200 MW - ET-EG: 700 MW – Loose pool - Low price fuel projection

12.2.2 GENERATION SAVINGS FOR THE REGION

The following figure presents the evolution of the savings for the region according to the case considered. The values given are the Net Present Value of the savings discounted in 2008.

The comparison with the medium fuel price projection shows that the savings for the region are roughly 2/3 of the savings with the medium fuel price projection.

Furthermore, the results confirm the is no significant additional savings increasing the capacity to above 700 MW for Egypt and 1200 MW for Sudan.

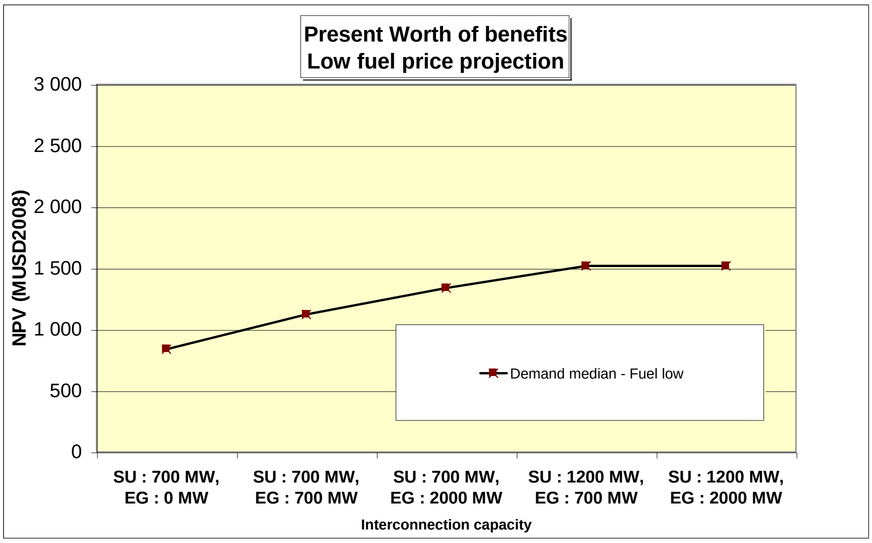

Figure 12.2-5 - Present worth of generation savings - Low fuel price projection

12.3 SENSITIVITY TO DEMAND PROJECTION

12.3.1 INTRODUCTION

Ethiopia:

As seen previously, the hydro surplus in Ethiopia provides the bulk of power export. However, according to the growth rate of the Ethiopian demand, these hydro surplus are absorbed more or less rapidly by the demand.

It is interesting to explore the two following projections:

- High demand projection (also called "target scenario"): to check if the volume of hydro surplus remains the same or if the surplus is rapidly absorbed by the Ethiopian demand.
- Low demand projection: the time interval between the commissioning of large HPP is expanded compared to the medium demand projection. This may have positive effect because of longer period of hydro surplus, but also negative effect because of longer period of low hydro surplus.

Accordingly, both demand projections will be studied in the following paragraphs.

Egypt:

The level of demand projection in Egypt has no impact on the generation savings provided by the interconnection, because:

- the volume of import from Ethiopia is limited by the hydro surplus in Ethiopia,

- the marginal cost of generation is the same whatever the demand projection (gas-fired CCGT).

This means that the same volume of hydro export substitutes to the same volume of Egyptian generation having the same generation cost.

<u>Sudan</u>:

As for Egypt, the level of demand projection in Sudan has no impact on the savings provided by the interconnection, because:

- the volume of import from Ethiopia is limited by the hydro surplus in Ethiopia and the transmission capacity, and not by the Sudanese demand,
- the marginal cost of generation remains the same whatever the demand projection(on gas-oil CCGT and crude-oil fired STPP).

The same volume of hydro export substitutes to the same volume of Sudanese generation having the same generation cost.

Accordingly, and in order to focus the analysis on the most relevant cases, the sensitivity to High and Low demand projections in Ethiopia is studied in the two following paragraphs.

12.3.2 HIGH DEMAND PROJECTION IN ETHIOPIA

12.3.2.1 Economic power exchanges and generation savings

The evaluation of economic exchanges and resulting generation savings is carried out for the following cases:

- 700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.

The commissioning date of the interconnection is kept identical to the reference hypothesis: 2020, which is also the optimal commissioning date of Mandaya in the independent development of the Ethiopian power system (see §10.2.2).

700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt:

The average annual export to Sudan amounts to 5500 GWh, while only 1900 GWh are available for export to Egypt. After 2028, there is only very limited hydro surplus for Ethiopia to be exported to Egypt.

These values represent a significant reduction compared to the "medium demand projection".

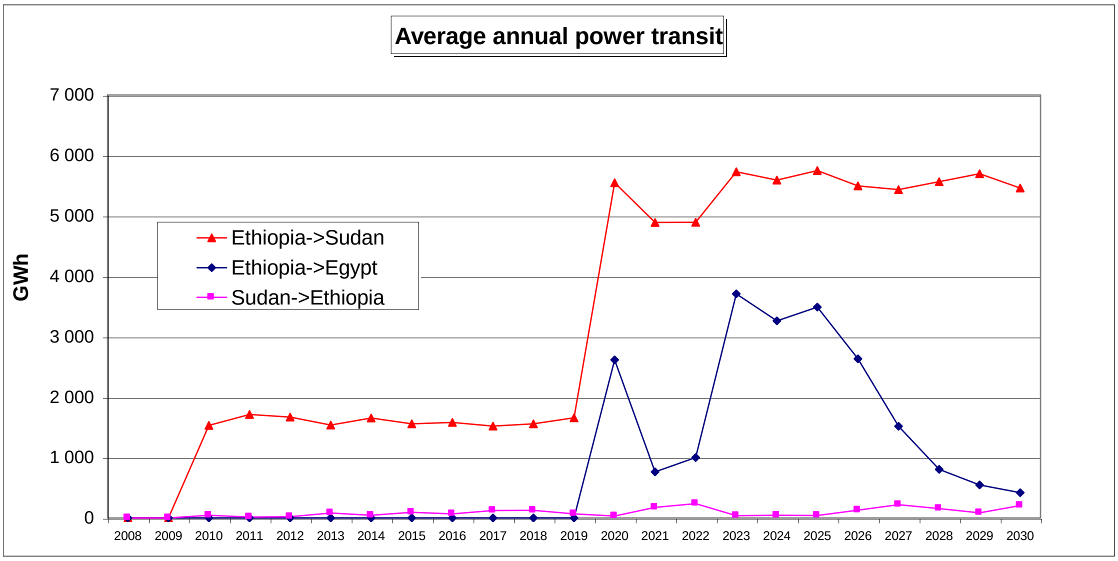

Figure 12.3-1 - Average annual power transit - High demand projection for Ethiopia – ET-SU: 700 MW ET-EG: 700 MW – Loose pool

1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt:

When a capacity of the interconnection to Sudan increases to 1200 MW, the average annual export to Sudan amounts to 8 500 GWh, while 700 GWh are available for export to Egypt. After 2028, there is only very limited hydro surplus for Ethiopia to be exported to Egypt.

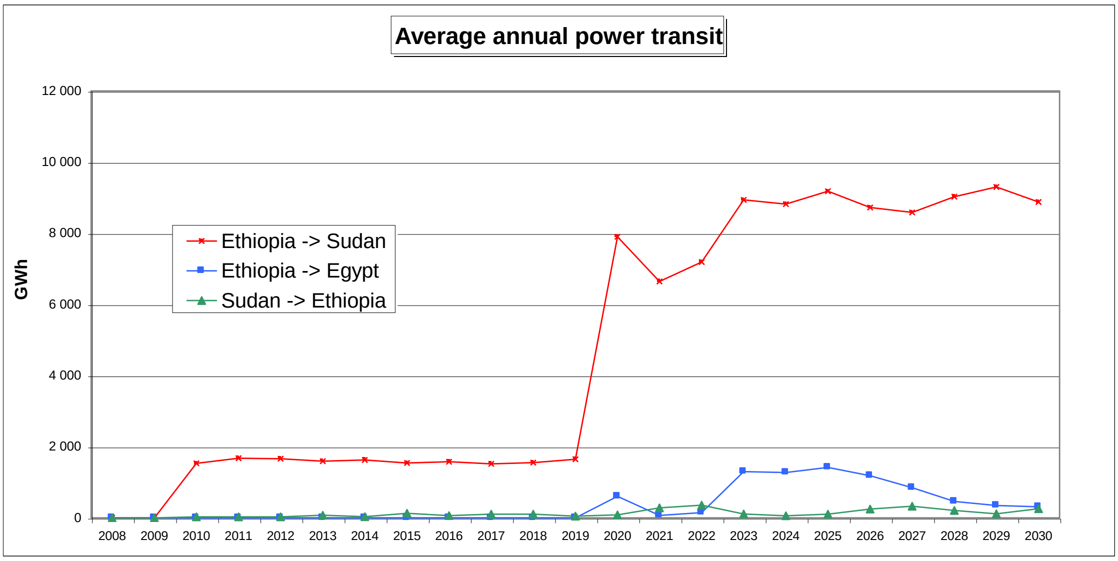

Figure 12.3-2 - Average annual power transit – ET-SU: 1200 MW – ET-EG: 700 MW - High demand projection for Ethiopia – loose pool

12.3.2.2 Generation savings and conclusion

In the high demand projection for Ethiopia, there is clearly less hydro surplus available for export than in the medium demand projection. This is due the greater growing rate of demand which absorbs more rapidly the new Ethiopian HPP. Furthermore, after 2027, all the HPP projects identified in Module 3 Vol 3 are commissioned in the GEP of Ethiopia and additional generation is CCGT based resulting in rising generation cost in Ethiopia.

The generation savings are reduced by 30 to 40% with respect to the medium demand projection for Ethiopia:

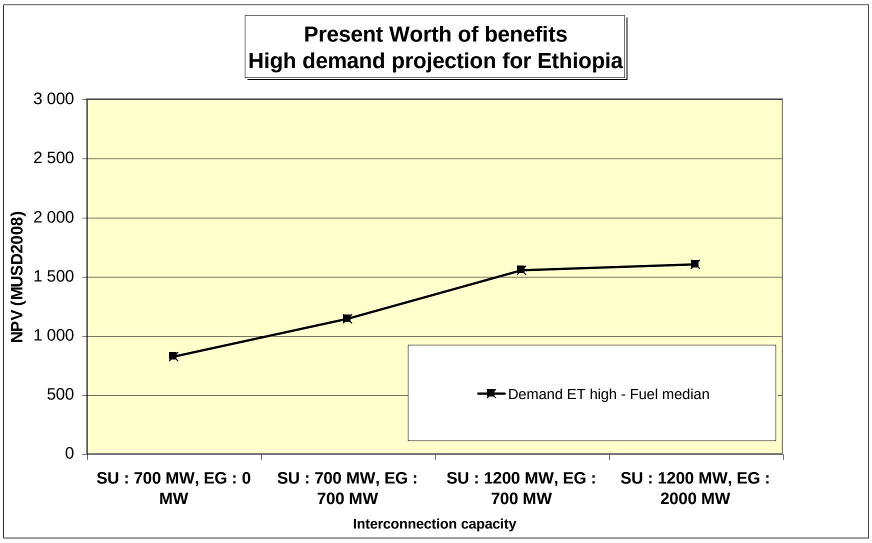

Figure 12.3-3 - Present worth of generation savings - High demand projection for Ethiopia – Loose pool

Due the limitation of the hydro surplus, there is no significant additional savings to increase the transmission capacity above 700 MW to Egypt.

12.3.3 LOW DEMAND PROJECTION IN ETHIOPIA

12.3.3.1 Economic power exchanges and generation savings

The evaluation of economic exchanges and resulting generation savings are presented hereafter for the following cases:

- 700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.
- 1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt.

The date of the commissioning of the interconnection is kept identical to the reference hypothesis: 2020. Accordingly, the date of commissioning of Mandaya is shifted from 2025 to 2020. The additional cost of investment is taken into account in the evaluation of the generation savings.

<u>700 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt</u>:

The average annual export to Sudan is equivalent to the reference case (with medium projection Ethiopian demand) (5 900 GWh/year) while there is an increase of the average export to Egypt (4 300 GWh/an instead of 3 600 GWh/year).

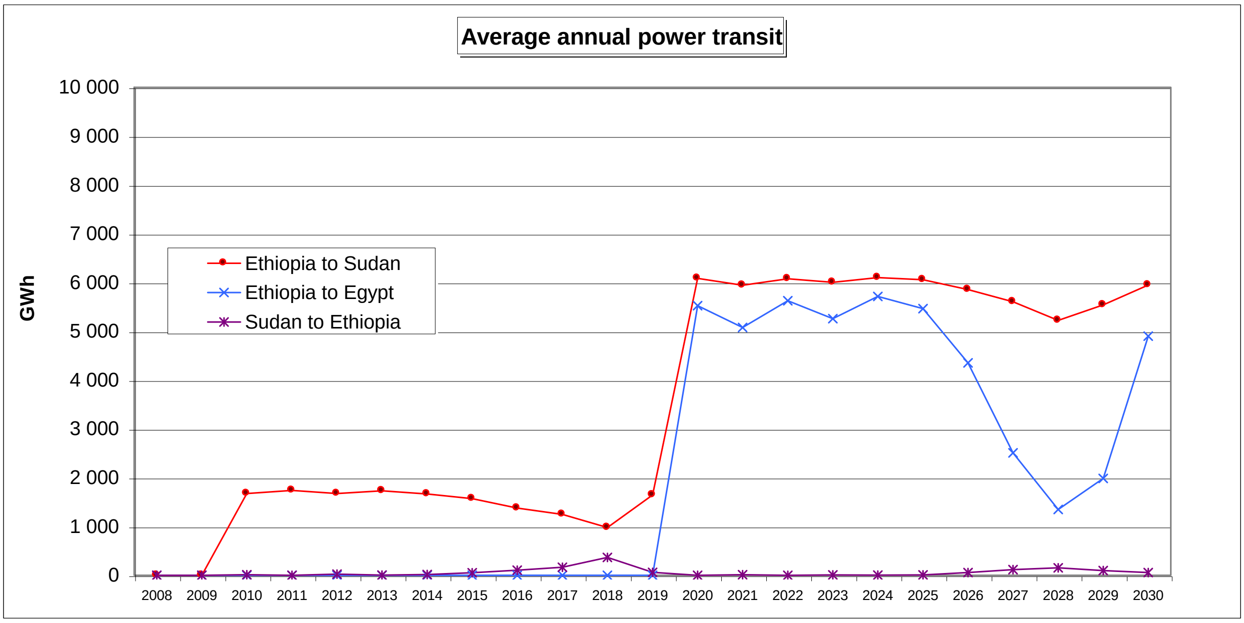

Figure 12.3-4 - Average annual transit – ET-SU: 700 MW – ET-EG: 700 MW - Low demand projection for Ethiopia – Loose pool

<u>1200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt</u>:

The average annual export to Sudan increases to 9100 GWh/year, while the average export to Egypt is reduced to 3100 GWh/year.

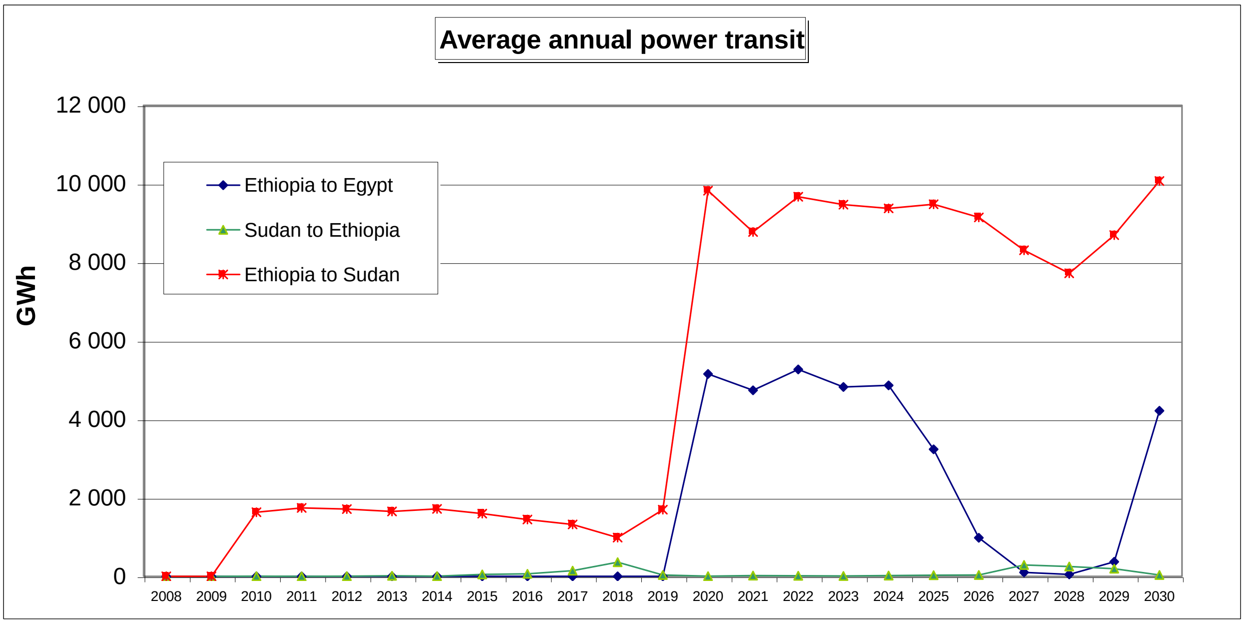

Figure 12.3-5 - Average annual power transit – ET-SU: 1200 MW- ET-EG: 700 MW - Low demand projection for Ethiopia – Loose pool

12.3.3.2 Generation savings and conclusion

In the low demand projection for Ethiopia, the amount of power exchanges is similar to the level achieved in the medium demand projection for Ethiopia. Accordingly, the generation savings are similar. These results confirm there is only minimal additional generation savings to go up to 1200 MW for Sudan and 2000 MW to Egypt:

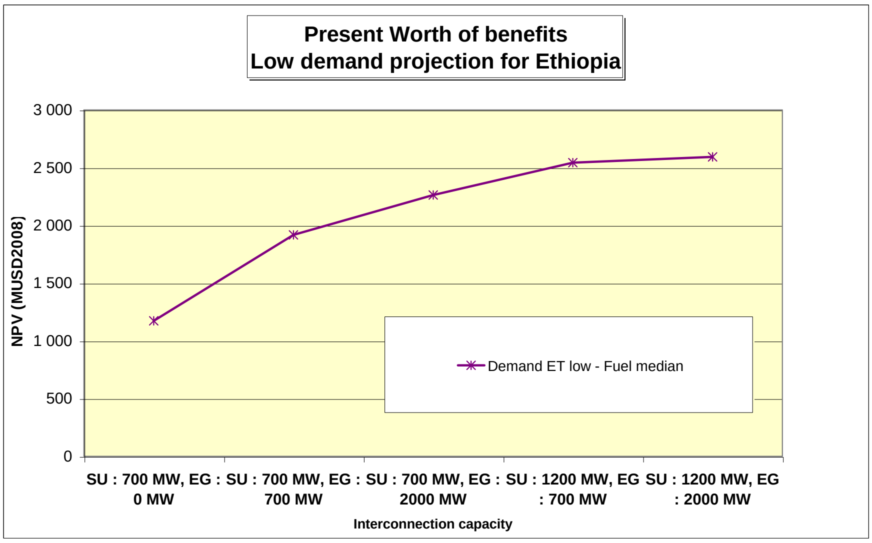

Figure 12.3-6 - Generation savings - Low demand projection in Ethiopia – Loose pool

12.4 SENSITIVITY TO DISCOUNT RATE

The reference discount rate of the Study is 10%. A higher discount rate will favour investments with short pay back periods, while a lower discount rate will favour capitalistic investments with long pay back periods.

The results with 8% and 12% discount rates are presented in Appendix Module 6 Vol 2.

12.5 PHASING OF INTERCONNECTION

An underlying finding from the previous results is there is a benefit to increase significantly the interconnection committed in 2010 between Ethiopia and Sudan to capacity greater than the original 200 MW.

In the present Study, the selected commissioning date of the new interconnection project is 2020 (see discussion in § 11.2), because from that date large amount of hydro surplus could be provided from large Ethiopian HPP projects on Blue Nile (Mandaya, Karadobi, Border).

The economic analysis (see § 15) shows that the most promising interconnection options are 1200 MW export capacity to Sudan and 700 or 2000 MW export capacity to Egypt. It can be noted that these options gives some flexibility in the phasing of commissioning, which in turn provides some additional economic return.

For example, in the 2000 MW (Egypt) – 1200 MW (Sudan) scheme, the interconnection between Sudan and Ethiopia is made through a double circuit 500 kV AC line connecting Mandaya to

Rabak. If commissioned before 2020 (i.e. before the connection of Mandaya on the Ethiopian grid) the maximum transmission capacity of this line would be around 500 MW[19]. On the Sudanese side, the 500 kV Rabak-Merigan and Rabak-Jebel Aulia would have to be anticipated accordingly to receive this additional power (the original commissioning date of these two transmission lines is 2020 in the Sudanese Transmission Master Plan) .

Considering the time necessary for detailed study, tender, construction, the earliest date of commissioning for this part of the interconnection between Ethiopia and Sudan is around 2015. This means that an additional 500 MW transit capacity could be connected from 2015.

The following figure shows the resulting evolution of economic power exchanges.

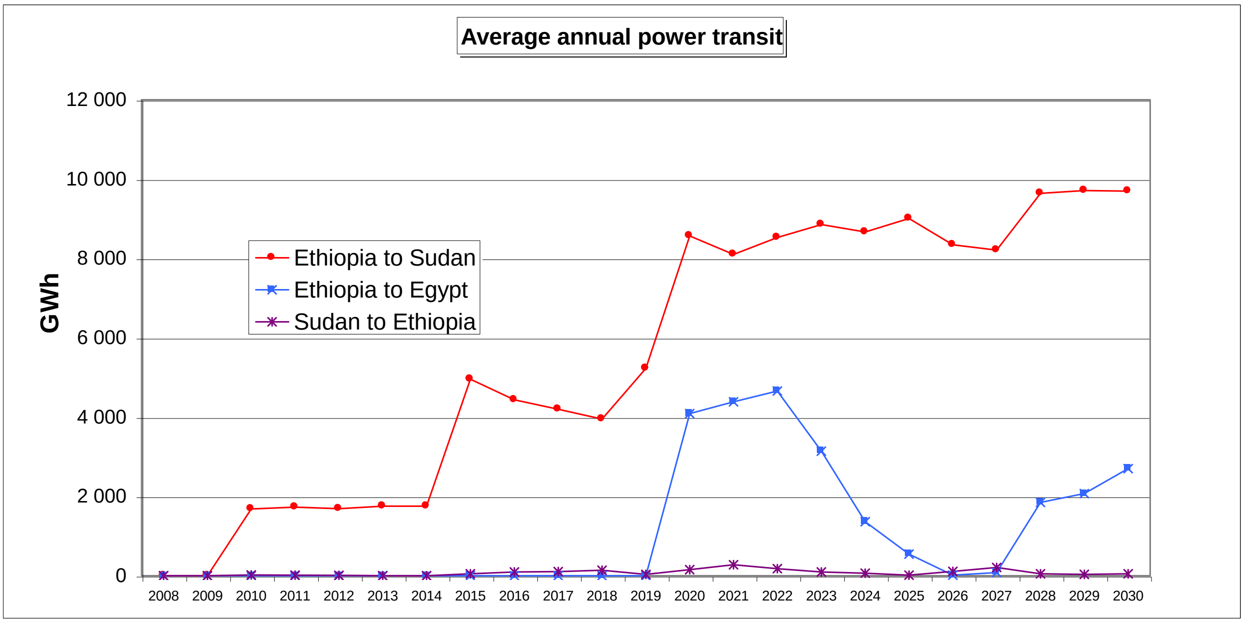

Figure 12.5-1 - Average annual power transit – ET-SU: 500 MW in 2015, 1200 MW in 2020 - ET-EG : 700MW - Medium demand projection for Ethiopia – Loose pool

The simulations show that the additional power exchanges during the 2015 to 2020 period would bring an additional fuel saving of 440 MUSD (Present Worth Value in 2008) while the additional investment cost for the interconnection is in the range of 120 to 160 MUSD (Present Worth Value in 2008) depending on the actual interconnection option.[20]

Accordingly, the Consultant would suggest to consider in the Phase II of the present Study a commissioning in two phases of the interconnection, the first phase in 2015, increasing the capacity between Ethiopia and Sudan, the second phase in 2020 with the completion of the interconnection to Egypt.

[19] Before the commission of Mandaya, the maximum transmission capacity is be limited by the fact that there would be no injection of MVAR at Mandaya substation to maintain the voltage.

[20] This transmission cost is split in two parts : 80 to 120 MW (depending on the option) for the anticipation of Mandaya-Rabak transmission line, and 35 MUSD for the anticipation of 500 kV Rabak-Meringan and 500 kV Rabak-Jebel Aulia (Present Worth Value in 2008 for a commissioning in 2015)

13 TIGHT POOL MODEL

13.1 INTRODUCTION

In the tight pool model, the countries coordinate their decision of generation investments, in order to minimize the regional generation cost (investment + operation).

The hydro generation investments in Ethiopia are anticipated (compared to the loose pool approach) in order to provide more power available for export to Egypt and Sudan.

Strictly speaking some generation investments could be delayed in Egypt and Sudan due to the increased power import. However, due to the increase of the projected fuel prices all over the period of the Study, the investment represents only 15 to 25% of the total generation cost of new thermal plants (see §9). Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would still keep their ability to balance their power demand with their own supply whenever power import are not available (and would not depend on financing / construction / hydrology risks of large HPP projects).

The tight pool approach has been carried out for the medium and the low Ethiopian demand projections. Indeed, the tight schedule of Ethiopian HPP planting for the high demand projection (isolated case, see § 12.3.2) offers no room for any anticipation of HPP projects.

13.2 MEDIUM DEMAND PROJECTION

13.2.1 UPDATED ETHIOPIAN GENERATION EXPANSION PLAN

The generation expansion plan in the tight pool presents the following modifications compared to the generation expansion plan associated with the independent development of Ethiopia :

- anticipation of Mandaya from 2024 to 2020,
- anticipation of Geba I+II: from 2022 to 2021,
- anticipation of Chemoga Yeda from 2027 to 2022,
- anticipation of Karadobi from 2028 to 2025,
- Genale III enters the GEP in 2022,
- Genale IV enters the GEP in 2023,
- Aleltu East and West enter the GEP in 2029.

The Border commissioning date is left unchanged at 2030 in order to keep a 5-year interval between the commissioning dates of Mandaya, Karadobi and Border, compatible with the reduction of the negative downstream effect during the successive filling of these reservoirs.

The following table presents the associated schedule of commissioning (called GEP-T-MD hereafter) :

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh
2008	Gibe II	420	1 600
	Tekeze	300	1 200
2009	Beles	420	2 000
2010	Neshe	97	225
2011	Gibe III (I)		
2012	Gibe III (II)	1 870	6 240
2014			
2015			
2016	Halele Worabesa	420	2 245
2017			
2018			
2019			
2020	Mandaya + Baro I + II + Gengi	2 700	16 509
2021	Geba I + II	368	1 788
2022	Chemoga Yeda + Genale III	534	1 415
2023	Genale IV	256	
2024			
2025	Karadobi	1 600	6 000
2026			
2027			
2028			
2029	Aleltu E&W	565	
2030	Border	1 200	
Total		10 750	

Table 13.2-1 - Generation expansion plan (GEP-T-MD) - Tight pool – Ethiopia – Medium demand projection

The following figure presents the evolution of the installed capacity compared to the annual peak demand:

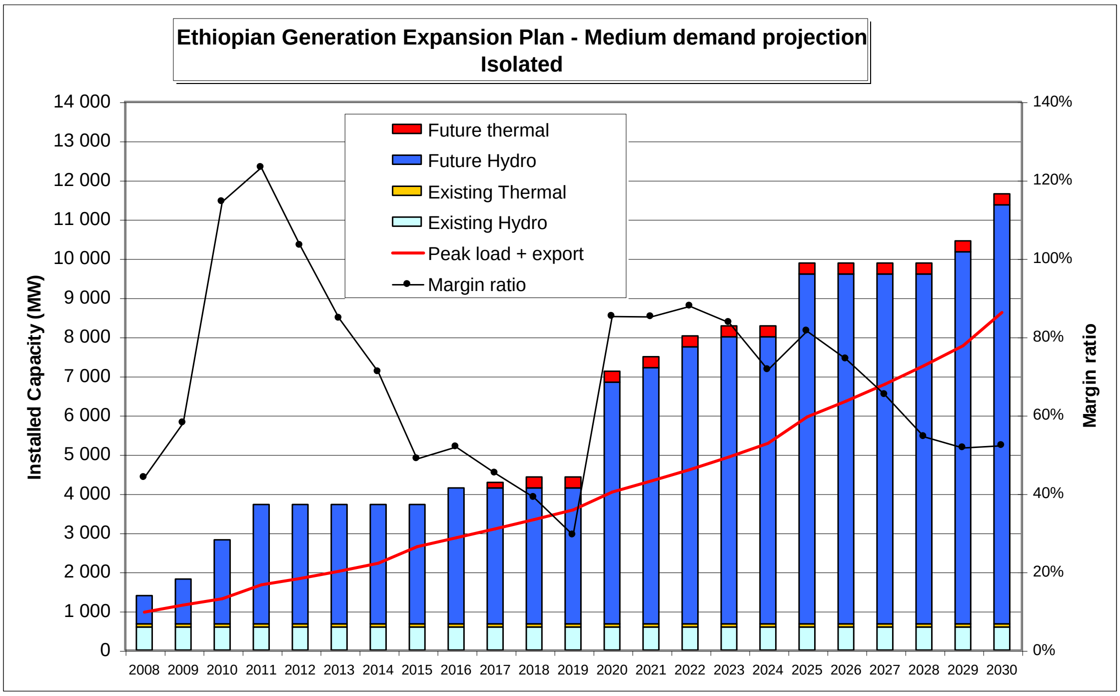

Figure 13.2-1 - Generation expansion plan - Ethiopia - Medium demand - Tight pool

13.2.2 ECONOMIC POWER EXCHANGES

13.2.2.1 1200 MW capacity to Sudan – 700 MW between Egypt and Ethiopia

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 700 MW additional export capacity to Egypt from 2020.

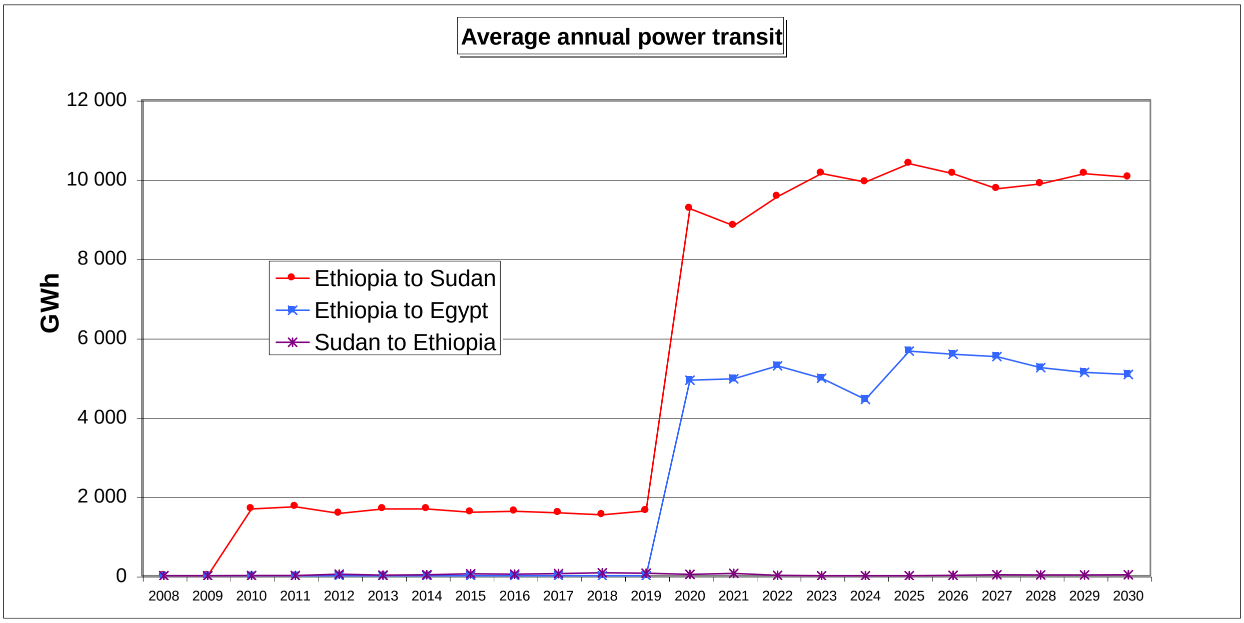

Figure 13.2-2 - Average annual power transit - ET-SU=1200 MW, ET-EG=700 MW - Tight pool – Medium demand projection for Ethiopia

The average annual power export from Ethiopia to Sudan arises to 9800 GWh/year over the 2020-2030 period, and saturates the 1200 MW capacity continuously (equivalent to 8200 h / year at 1200 MW).

The average annual power export from Ethiopia to Egypt arises to 5200 GWh/year over the 2020-2030 period, and nearly saturates the 700 MW capacity (equivalent to 7 400 h / year at 700 MW).

13.2.2.2 1200 MW capacity to Sudan – 2000 MW between Egypt and Ethiopia

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia form 2010 to 2020, 1200 MW from 2020,
- 2000 MW additional export capacity to Egypt from 2020.

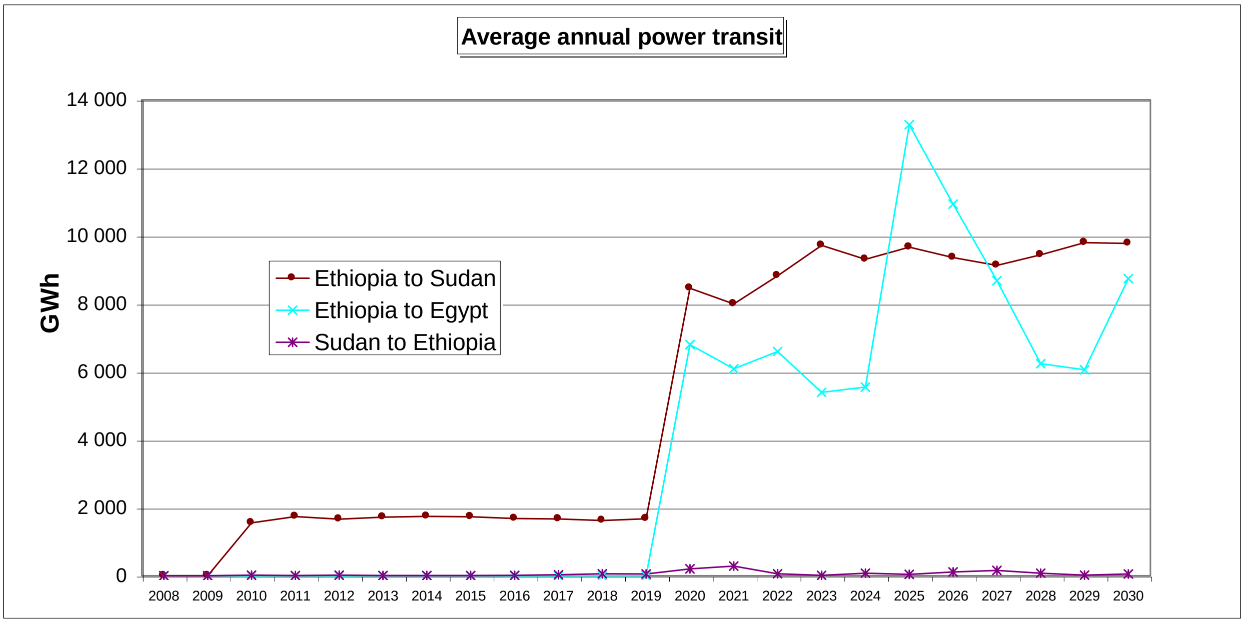

Figure 13.2-3 - Average annual power transit - ET-SU=1200 MW, ET-EG=2000 MW- Tight pool – Medium demand projection for Ethiopia

The average annual power export from Ethiopia to Sudan arises to 9200 GWh/year over the 2020-2030 period, and saturates the 1200 MW capacity continuously (equivalent to 7700 h / year at 1200 MW).

The average annual power export from Ethiopia to Egypt arises to 7700 GWh/year over the 2020-2030 period (equivalent to 3800 h / year at 2000 MW).

13.3 SENSITIVITY TO HIGH AND LOW FUEL PRICE PROJECTIONS

The sensitivity to high and low fuel price projections is presented in §15.4.

13.4 SENSITIVITY TO LOW DEMAND PROJECTION FOR ETHIOPIA

Apart from the hydro projects identified for Ethiopia in Module 3, the Consultant has been informed of the existence of medium scale hydro projects than could cover part of the internal Ethiopian power demand. Accordingly, the low demand projection might probably be more relevant to the scope of the Study with respect to the amount of power that could be exported from Ethiopia.

13.4.1 1200 MW CAPACITY TO SUDAN – 700 MW BETWEEN EGYPT AND ETHIOPIA

13.4.1.1 Updated Ethiopian Generation expansion plan

The following table presents the updated least cost expansion plan for the low demand projection and 1200 MW (to Sudan) 700 MW (to Egypt) interconnection capacity (called GEP-T-LD):

Commisioning Date	Hydro Project	Capacity MW	Average Generation GWh
2008	Gibe II	420	1 600
	Tekeze	300	1 200
2009	Beles	420	2 000
2010	Neshe	97	225
2011	Gibe III (I)		
2012	Gibe III (II)	1 870	6 240
2014			
2015			
2016			
2018			
2019	Halele Worabesa	420	2 245
2020	Baro I + II + Gengi + Mandaya	2 700	16 509
2021			
2022	Geba I + II	368	1 788
2023	Chemoga Yeda + Genale III	534	2 415
2024			
2025	Karadobi	1 600	8 600
2026			
2027			
2028			
2029			
2030	Border	1 200	6 000
Total		9 929	48 822

Table 13.4-1 - Generation expansion plan (GEP-T-LD) - Tight pool – Ethiopia – Low demand projection

The following figure presents the evolution of the installed capacity compared to the annual peak demand:

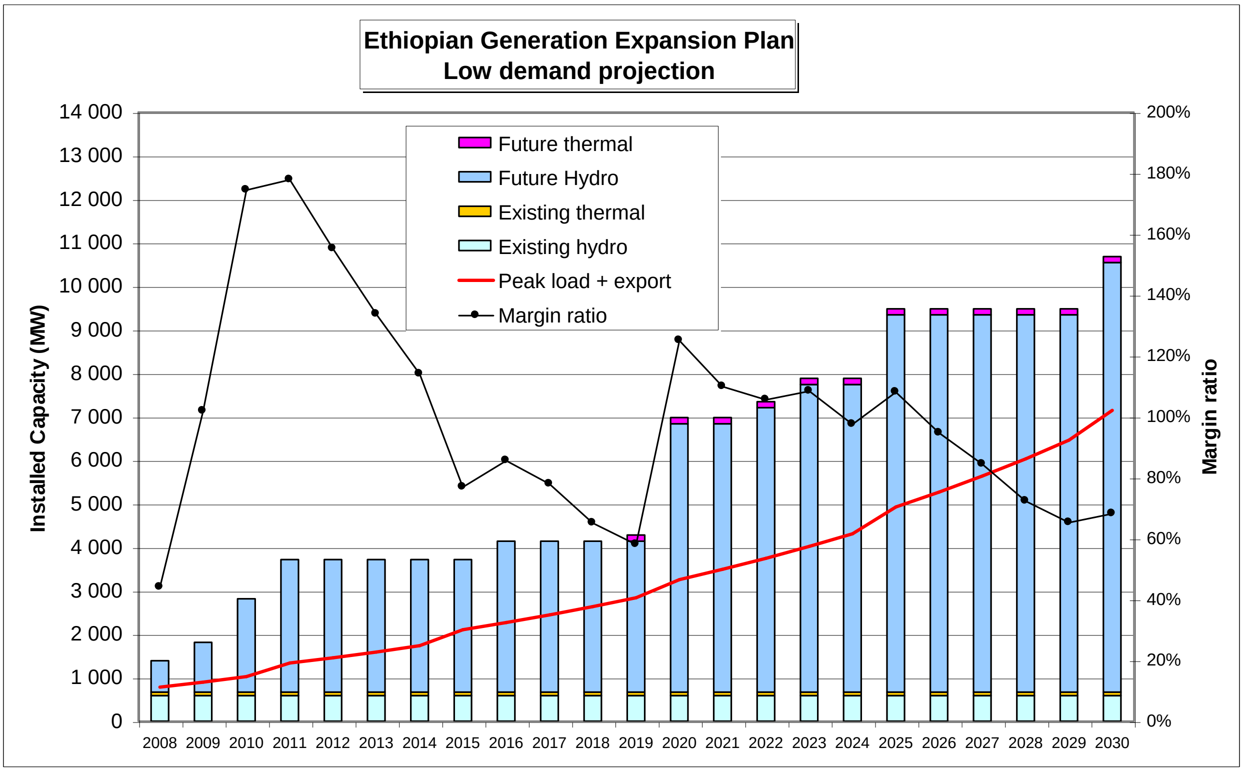

Figure 13.4-1 - Generation expansion plan - Ethiopia - Low demand - Tight pool

13.4.1.2 Economic power exchanges

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 700 MW additional export capacity to Egypt from 2020.

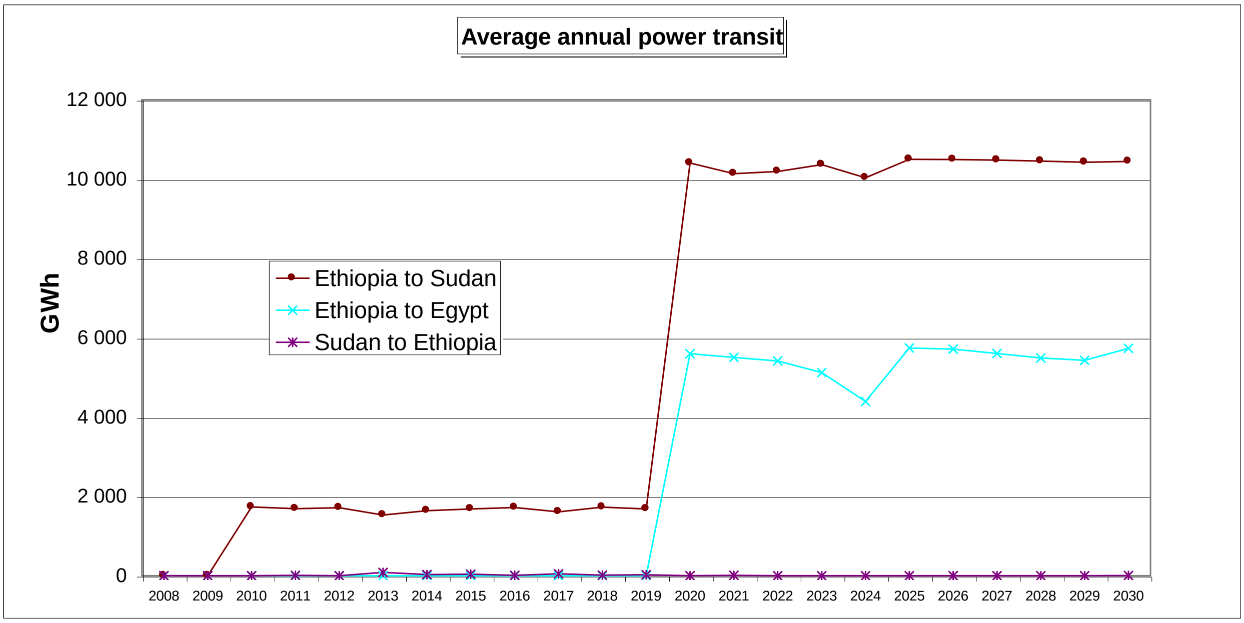

Figure 13.4-2 - Average annual power transit - ET-SU=1200 MW, ET-EG=700 MW- Tight pool – Low demand projection for Ethiopia

The average annual power export from Ethiopia to Sudan arises to 10 300 GWh/year over the 2020-2030 period, and saturates the 1200 MW capacity continuously (equivalent to 8 600 h / year at 1200 MW).

The average annual power export from Ethiopia to Egypt arises to 5 400 GWh/year over the 2020-2030 period, and nearly saturates the 700 MW capacity (equivalent to 7 800 h / year at 700 MW).

13.4.2 1200 MW CAPACITY TO SUDAN – 2000 MW BETWEEN EGYPT AND ETHIOPIA

When the capacity of the interconnection to Egypt rises to 2000 MW, the least-cost generation expansion plan for Ethiopia is identical to the one found with the medium scenario (see GEP-T-MD in §13.2.1).

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 2000 MW additional export capacity to Egypt from 2020.

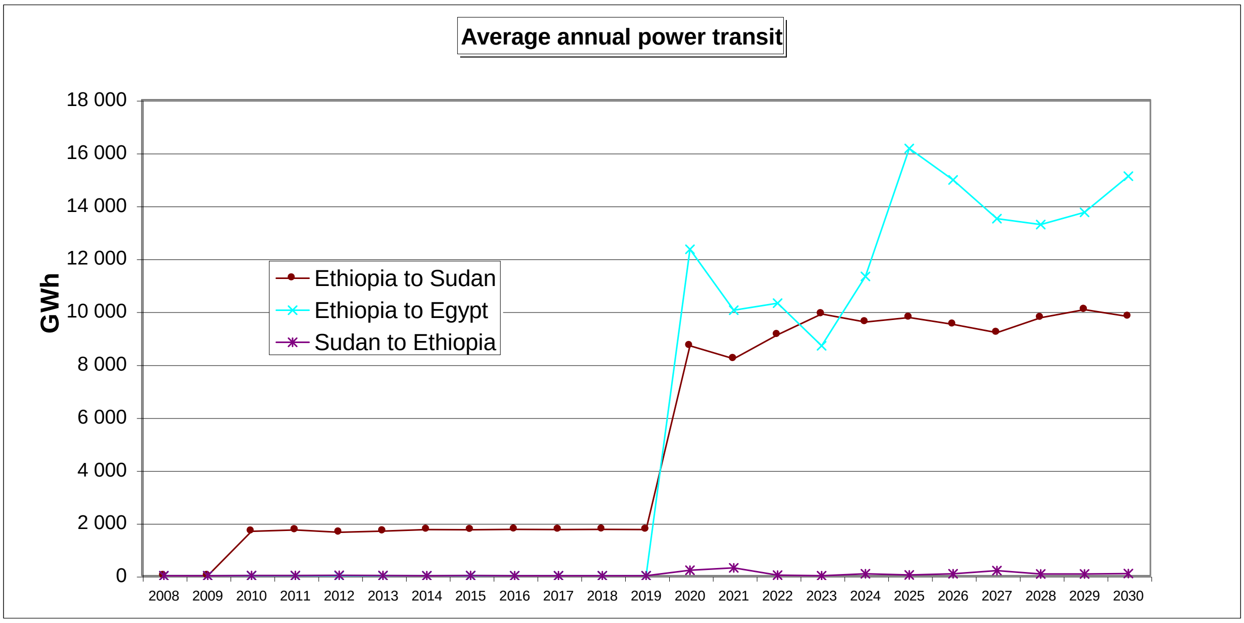

Figure 13.4-3 - Average annual power transit - ET-SU=1200 MW, ET-EG=2000 MW- Tight pool – Low demand projection for Ethiopia

The average annual power export from Ethiopia to Sudan arises to 9 400 GWh/year over the 2020-2030 period, and nearly saturates the 1200 MW capacity continuously (equivalent to 7 800 h / year at 1200 MW).

The average annual power export from Ethiopia to Egypt arises to 12 700 GWh/year over the 2020-2030 period (equivalent to 6 300 h / year at 2000 MW).

13.5 SENSITIVITY TO LOW DEMAND PROJECTION FOR ETHIOPIA AND HIGH FUEL PRICE PROJECTION

The international price of crude oil exceeded 90 USD/bbl near the completion of the present Study (October 12, 2007). By comparison, the medium fuel price projection is 60 USD_{2006}/bbl for 2030, while the high price projection is 100.4 USD_{2006}/bbl (see Module 3 Vol5). Consequently, the high fuel price projection could not be regarded as highly improbable.

Under these circumstances, the combination of a low demand projection for Ethiopia and high fuel price projection is interesting to analyze.

13.5.1 1200 MW CAPACITY TO SUDAN – 700 MW TO EGYPT

The generation expansion plan of Ethiopia remains the same as with the medium fuel price projection (see GEP-T-LD in §13.4.1.1).

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 700 MW additional export capacity to Egypt from 2020.

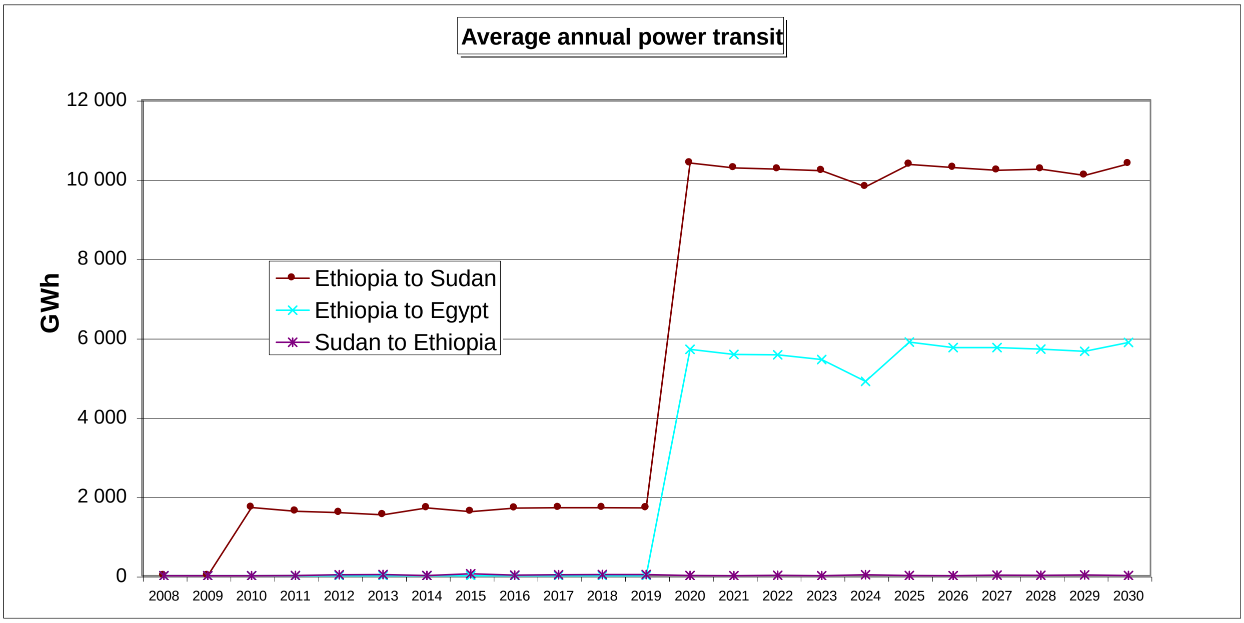

Figure 13.5-1 - Average annual power transit - ET-SU=1200 MW, ET-EG=700 MW- Tight pool – Low demand projection for Ethiopia – High fuel price projection

The average annual power export are virtually unchanged compared to the situation with the medium fuel price projection:

- 10200 GWh/year from Ethiopia to Sudan over the 2020-2030 period, which is equivalent to 8 500h/year at 1200 MW.
- 5 600 GWh/year from Ethiopia to Egypt over the 2020-2030 period, which nearly saturates the 700 MW capacity (equivalent to 8 000 h / year at 700 MW).

13.5.2 1200 MW CAPACITY TO SUDAN – 2000 MW BETWEEN EGYPT AND ETHIOPIA

When the capacity of the interconnection to Egypt rises to 2000 MW, the least-cost generation expansion plan for Ethiopia becomes identical to the one found with the medium scenario (see GEP-T-MD in §13.2.1).

The hereafter figure presents the evolution of the average annual economic exchanges in the following conditions:

- 200 MW export capacity between Sudan and Ethiopia from 2010 to 2020, 1200 MW from 2020,
- 2000 MW additional export capacity to Egypt from 2020.

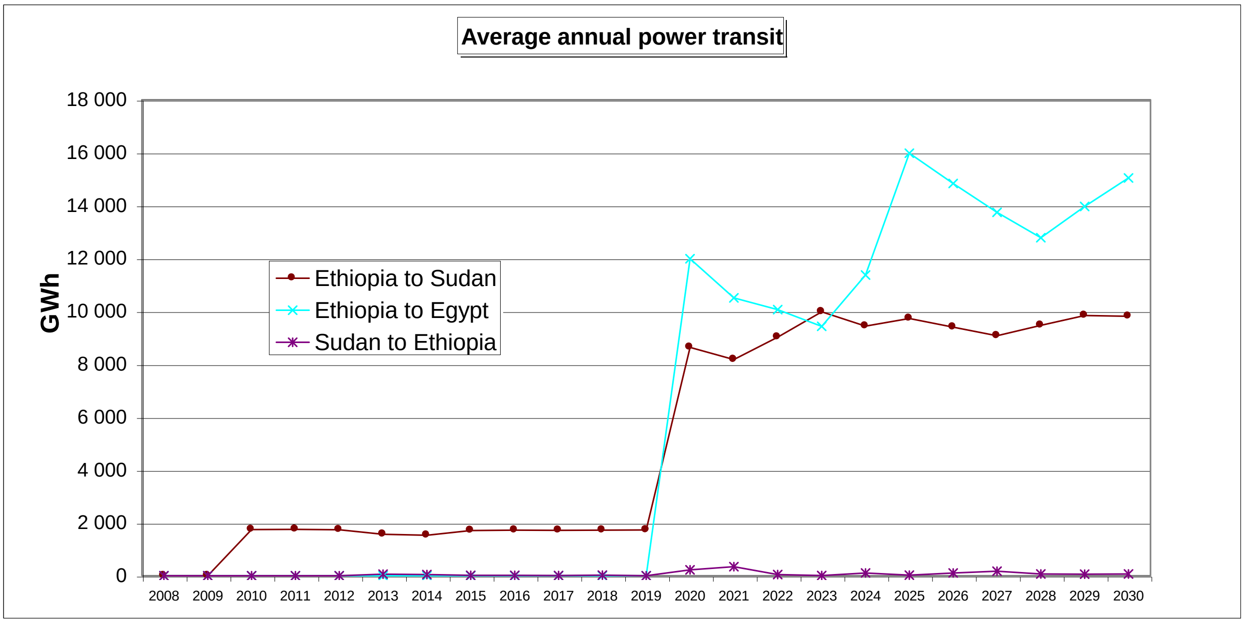

Figure 13.5-2 - Average annual power transit - ET-SU=1200 MW, ET-EG=2000 MW - Tight pool – Low demand projection for Ethiopia – High fuel price projection

The average annual power export are virtually unchanged compared to the situation with the medium fuel price projection.

13.6 SENSITIVITY TO DISCOUNT RATE

The results with 8% and 12% discount rates are presented in Appendix Module 6 Vol 2.

13.7 PHASING OF INTERCONNECTION

As explained in the loose pool analysis (cf § 12.5), the commission of the interconnection can be phased in two steps: the first step in 2015 with the interconnection between Ethiopia and Sudan, the second step in 2020 with the completion of the interconnection up to Egypt. The resulting additional fuel savings would amount 440 MUSD, while the additional transmission investment cost is between 120 to 160 MUSD (Present Worth Value in 2008).

In the tight pool context, it is possible to anticipate further the commissioning of new HPP by moving Baro I & II and Gengi from 2020 (natural commissioning date in the loose pool context) to 2015, in order to increase the hydro surplus available for power export during the 2015 to 2020 period.

The following figure presents the evolution of the economic power exchanges :

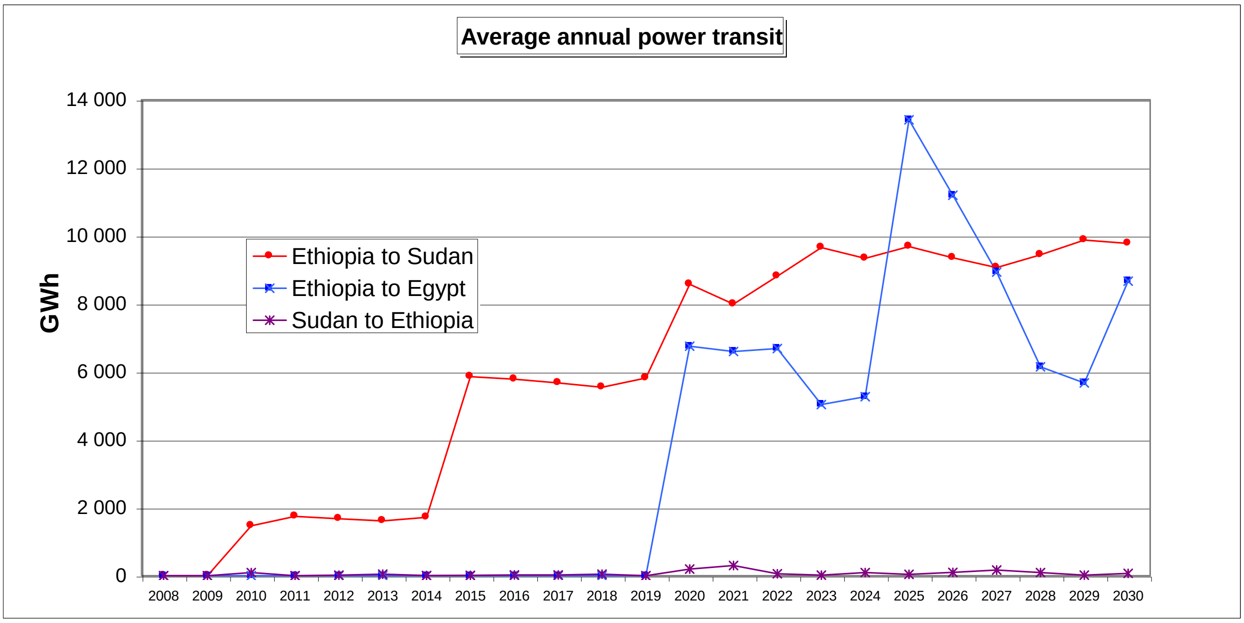

Figure 13.7-1 - Average annual power transit - ET-SU= 500 MW in 2015, 1200 MW in 2020, ET-EG=2000 MW - Tight pool – Low demand projection for Ethiopia – High fuel price projection

The simulations show that the additional power exchanges during the 2015 to 2020 period would bring an additional net generation saving of 380 MUSD (Present Worth Value in 2008) which would easily outbalance the additional investment cost for the interconnection (between 120 to 160 MUSD - Present Worth Value in 2008 - see details in 12.5).

14 CO_2 EMISSIONS SAVINGS

The interconnection project allows to substitute hydro generation (from Ethiopia) to thermal generation in Egypt (gas-fired CCGT) and Sudan (gas oil-fired CCGT and crude-oil fired STPP).

The approximated CO_2 emission per MWh for various types of thermal power plants are given in the following table (see Module 5 for details):

Plant type	Heat Value (GJ/ton fuel)	CO2 (ton / ton fuel)	Efficiency	CO_2 (ton / MWh)
Lignite-fired STPP	7	0.87	36%	1.24
Coal-fired STPP	29	2.90	37 - 39%	0.97
Oil-fired STPP	41	3.24	38 - 40%	0.75
Gas-fired STPP	44	2.53	48 - 52%	0.43

Table 13.7-1 - $C0_2$ emission for various types of thermal power plants

On this basis, the following two paragraphs provides the amount of CO_2 emission savings in Egypt and in Sudan resulting from the new interconnection, compared to the reference situation (i.e. Ethiopia-Sudan interconnection 200 MW) and the evaluation of the annual value of this saving for 5 USD/t CO_2 and 10 USD/t CO_2.

14.1 LOOSE POOL

Case		Additional export TWh/year	CO_2 reduction M ton	Annual value 5 USD/tCO_2 MUSD	10 USD/tCO_2 MUSD
Ethiopia-Sudan :	700 MW	4.1	3.09	15.5	30.9
Egypt-Ethiopia :	700 MW	3.9	1.68	8.4	16.8
Total		8.0	**4.77**	**23.8**	**47.7**
Ethiopia-Sudan :	1200 MW	7.1	5.34	26.7	53.4
Egypt-Ethiopia :	700 MW	2.3	0.99	4.9	9.9
Total		9.4	**6.33**	**31.7**	**63.3**
Ethiopia-Sudan :	1200 MW	7.1	5.34	26.7	53.4
Egypt-Ethiopia :	2000 MW	2.9	1.25	6.2	12.5
Total		10.0	**6.59**	**32.9**	**65.9**

Table 14.1-1 - Annual CO_2 emission savings – Loose pool model

The present worth value of these CO_2 savings in 2008 is given in the following table:

Case		Additional export TWh/year	CO2 reduction M ton	8% discount rate 5 USD/tCO_2 MUSD	8% discount rate 10 USD/tCO_2 MUSD	10% discount rate 5 USD/tCO_2 MUSD	10% discount rate 10 USD/tCO_2 MUSD	12% discount rate 5 USD/tCO_2 MUSD	12% discount rate 10 USD/tCO_2 MUSD
Ethiopia-Sudan :	700 MW	4.12	3.09	83	166	54	108	37	74
Egypt-Ethiopia :	700 MW	3.90	1.68	45	90	29	59	20	40
Total		8.02	**4.77**	128	256	84	167	57	114
Ethiopia-Sudan :	1200 MW	7.12	5.34	143	286	94	187	64	128
Egypt-Ethiopia :	700 MW	2.30	0.99	27	53	17	35	12	24
Total		9.42	**6.33**	170	339	111	222	76	152
Ethiopia-Sudan :	1200 MW	7.12	5.34	143	286	94	187	64	128
Egypt-Ethiopia :	2000 MW	2.90	1.25	33	67	22	44	15	30
Total		10.02	**6.59**	177	353	115	231	79	158

Table 14.1-2 - Present worth value of CO_2 emission savings

This present worth value would have to be included in the benefits of the project if eligible to Clean development Mechanism (CDM).

14.2 TIGHT POOL

In the tight pool model, the export from hydro power in Ethiopia increases compared to the loose pool model. This results in an additional reduction of the CO2 emissions in Egypt and Sudan as described in the two following tables:

Case		Additional export TWh/year	CO_2 reduction M ton	Annual value 5 USD/tCO_2 MUSD	10 USD/tCO_2 MUSD
Ethiopia-Sudan :	1200 MW	8.12	6.09	30.5	60.9
Egypt-Ethiopia :	700 MW	5.20	2.24	11.2	22.4
Total		13.32	**8.33**	**41.6**	**83.3**
Ethiopia-Sudan :	1200 MW	7.52	5.64	28.2	56.4
Egypt-Ethiopia :	2000 MW	7.70	3.31	16.6	33.1
Total		15.22	**8.95**	**44.8**	**89.5**

Table 14.2-1 - CO_2 emission savings – Tight pool model

Case		Additional export	CO2 reduction	Present worth value					
				8% discount rate		10% discount rate		12% discount rate	
				5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2	5 USD/tCO_2	10 USD/tCO_2
		TWh/year	M ton	MUSD	MUSD	MUSD	MUSD	MUSD	MUSD
Ethiopia-Sudan :	1200 MW	8.12	6.09	163	327	107	214	73	146
Egypt-Ethiopia :	700 MW	5.20	2.24	60	120	39	78	27	54
Total		13.32	**8.33**	223	446	146	292	100	199
Ethiopia-Sudan :	1200 MW	7.52	5.64	151	302	99	198	68	135
Egypt-Ethiopia :	2000 MW	7.70	3.31	89	178	58	116	40	79
Total		15.22	**8.95**	240	480	157	314	107	214

Table 14.2-2 - Present worth value of CO_2 emission savings – Tight pool model

15 ECONOMIC ANALYSIS

The economic analysis consists in comparing the net balance between:

- the cost of the interconnection (evaluated in part 15.2),
- the "benefits" provided by the interconnection: generation cost savings (evaluated in part 11.5) and CO_2 emission savings if any (evaluated in part 14),

The classic economic criteria "Net Present value" and Benefit to Cost ratio will be used to analyze the results.

15.1 REFERENCE SITUATION

In order to determine the generation savings related only to the new interconnection project (and not the 200 MW committed Sudan-Ethiopia interconnection), the savings are measured by comparison to the following reference situation:

- commissioning of the 200 MW Ethiopia-Sudan interconnection in 2010,
- generation expansion plans of Egypt, Ethiopia and Sudan identical to those determined without any interconnection (see **§10**).

15.2 COST OF THE INTERCONNECTION OPTIONS

The following table summarizes the investment cost (including IDC) of interconnection project for the three options of interconnection (more details are provided in Module 6 Vol 3):

Option			**Investment cost ($MUSD_{2006}$)**		
Capacity to Egypt	**Capacity to Sudan**	**Interconnection points**	**a = 10%**	**a = 12%**	**a = 8%**
700 MW	700 MW	Mandaya - Rabak / Merowe -Nag Hammadi 500 kV AC			
		Total :	**1 033**	**1 071**	**995**
700 MW	1200 MW	Mandaya - Rabak 500 kV AC	554	575	534
		Merowe -Nag Hammadi 500 kV AC	666	691	642
		Total :	**1 220**	**1 265**	**1 176**
2000 MW	1200 MW	Mandaya - Rabak 500 kV AC	363	376	350
		800 kV DC link + 500 KV AC Assiut-Samalut	2 520	2 645	2 414
		Total :	**2 883**	**3 021**	**2 764**

Table 15.2-1 - Investment cost of the interconnection options

The following table gives the present worth of the interconnection cost in 2008, for a commissioning of the interconnection in 2020, calculated on the base of the expenditure schedule of the interconnection during construction, the annual O&M cost and the discount rate:

Option			**PW cost ($MUSD_{2006}$)**		
Capacity to Egypt	**Capacity to Sudan**	**Interconnection points**	**a = 10%**	**a = 12%**	**a = 8%**
700 MW	700 MW	Mandaya - Rabak / Merowe -Nag Hammadi 500 kV AC	374	305	464
700 MW	1200 MW	Mandaya - Rabak 500 kV AC Merowe -Nag Hammadi 500 kV AC	433	355	534
2000 MW	1200 MW	Mandaya - Rabak 500 kV AC 800 kV DC link + 500 KV AC Assiut-Samalut	1 014	841	1 244

Table 15.2-2 - Present Worth Cost in 2008 of the interconnection options

15.3 LOOSE POOL MODEL

15.3.1 PRESENT WORTH OF GENERATION SAVINGS

The following table summarizes the present worth of the potential generation savings for the main capacity options and key economic parameters of the study (10% discount rate):

Present worth of generation savings (MUSD2006) :

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 0 MW	SU : 700 MW, EG : 700 MW	SU : 700 MW, EG : 2000 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High		2 610		3 360	3 610
Median	Median	1 150	1 710	1 870	2 090	2 210
Median	Low	840	1 120	1 340	1 520	1 520
Low	Median	1 170	1 920	2 260	2 540	2 590
High	Median	820	1 170		1 590	1 640

Table 15.3-1 - Present worth value of generation savings – Loose Pool

These generation savings (fuel cost reduction from substitution of thermal power by hydro[21]) are net of the interconnection transmission losses and of Mandaya anticipation cost (i.e. Mandaya commissioned in 2020 instead of 2024 (resp.2025) in the medium (reps. low) demand projection).

The present worth value is given in MUSD $_{2006}$ discounted in 2008.

15.3.2 NET SAVINGS

The following table presents the net savings (= generation savings minus interconnection cost) according to the various capacity options and key economic parameters of the study (10% discount rate):

Net Present Value (MUSD2006):

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High	2 240	2 930	2 600
Median	Median	1 340	1 660	1 200
Median	Low	750	1 090	500
Low	Median	1 540	2 110	1 580
High	Median	800	1 160	630

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	Median	8%	2 570	1 950
Median	Median	12%	940	490

Table 15.3-2 - Net Present Value of the interconnection – Loose pool model

The interconnection Net Present Value is positive for every capacity option and value of key economic parameters. This means that the interconnection project is profitable under a wide range of hypothesis.

The profitability is obviously increased if the fuel price follows the high projection.

If the Ethiopian demand follows the "low demand projection" the results are equivalent to the reference case with the "medium demand projection".

<u>Profitability under adverse evolution of key parameters</u>:

The situations which would reduce the profitability of the interconnection project are a low evolution of the fuel price (reducing the fuel savings in importing power systems) and a high evolution of the Ethiopian demand (reducing the amount of hydro surplus).

In the low fuel price projection (35 USD/bbl forecasted in 2030, while crude oil actually reached over 90 USD/bbl in November 2007), the interconnection still remains profitable, in spite of a NPV divided by a 2 to 3 factor depending on the interconnection capacity.

The same is true if the Ethiopian demand follows the "high demand projection" where the hydro surplus are reduced due to the increasing Ethiopian demand.

<u>Sensitivity to discount rate</u>:

[21] Results including CO_2 savings are presented in Appendix M6 Vol2

The sensitivity to a 8% or 12% discount rate is presented in Module 6 Vol 2 Appendix.

The interconnection project profitability increases with a 8% discount rate, and decreases with a 12%, but yet remains profitable. The ranking between the capacity options of interconnection remains unchanged.

CO2 savings :

The results including C02 savings are presented in Module 6 Vol 2 Appendix.

15.3.3 COMPARING OPTIONS

The different option capacities can be compared through the NPV, and also through the Benefit to Cost Ratio (also called BCR) given in the table below:

Benefit / Cost ratio (present worth of benefits / present worth of cost) :

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High	7.1	7.8	3.6
Median	Median	4.6	4.8	2.2
Median	Low	3.0	3.5	1.5
Low	Median	5.2	5.9	2.6
High	Median	3.2	3.7	1.6

Ethiopian demand	Fuel projection	Discount rate	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	Median	8%	5.8	2.6
Median	Median	12%	3.6	1.6

Table 15.3-3 - Benefit to Cost Ratio – Loose pool model

The benefit to Cost ratio is equal to the Net Present value of the benefits (called here "generation savings") divided by the Net Present value of the cost. A value greater than one means the benefits outbalance the cost of the project. This is another way to express the profitability of a project.

Profitability under adverse evolution of key parameters:

As for the NPV, the decrease of the profitability of the interconnection is apparent in case of low evolution of fuel costs or if the Ethiopian demand follows the high projection. However, the BCR still remains greater than 1.

Comparing capacity options through NPV:

The NPV is maximized for a 1200 MW (Sudan) 700 MW (Egypt) scheme.

While still positive, the NPV decreases going up to a 2000 MW (for Egypt) and 1200 MW (for Sudan) scheme because of the higher cost of the 2000 MW interconnection link to Egypt, while the additional fuel savings remain low because the main part of the Ethiopia hydro surplus has already been provided for export.

Comparing capacity options through BCR:

The analysis of the BCR shows a rough equivalence – for this criteria - between the 700 MW (Sudan) 700 MW (Egypt) scheme and the 1200 MW (Sudan) 700 MW (Egypt) scheme. This is explained by the lower investment cost of the option with 700 MW capacity.

The BCR decreases going up to 2000 MW (for Egypt) for the same reason as the NPV.

Comparing capacity options through incremental BCR:

Another, and better way than BCR, to compare options is the use of the incremental BCR.

When comparing two options "a" and "b", the incremental BCR is simply the ratio between the additional benefits provided by going from "a" to "b", and the additional cost of going from "a" to "b". If the incremental BCR is greater than 1, it means than the additional cost is compensated by greater additional benefits.

The net table compares the incremental benefit between EG: 700 MW–SU: 700 MW scheme and EG: 700 MW– SU: 1200 MW:

Ethiopian demand	Fuel projection	Inc BCR
Median	High	11.9
Median	Median	6.0
Median	Low	6.3
Low	Median	9.8
High	Median	6.7

Table 15.3-4 - Incremental Benefit to Cost Ratio – Loose pool model

Going from a 700 MW to a 1200 MW interconnection between Ethiopia to Sudan provides a significant additional benefit (compared to the additional cost).

On the other hand, the incremental benefit between EG: 700 MW–SU: 1200 MW and EG: 2000 MW – SU 1200 MW (given in the table below) is very low, which means there is no economic benefits to increase the capacity to Egypt up to 2000 MW:

Ethiopian demand	Fuel projection	Inc BCR
Median	High	0.43
Median	Median	0.21
Median	Low	0.00
Low	Median	0.09
High	Median	0.09

Table 15.3-5 - Incremental Benefit to Cost Ratio – Loose pool model

15.3.4 SAVINGS PER COUNTRY AND PAY BACK PERIOD

The pay-back period is the period of time necessary for the savings (= mainly fuel savings) to balance the expenses (cost of the interconnection and anticipation of HPP investment). At the end of the payback period the present value of the savings is equal to the present value of the expenses.

NB : Sharing savings and sharing costs

The present paragraph refers to fuel savings. The actual (or net) savings for Egypt and Sudan will depend on the negotiated price of the imported energy from Ethiopia. See discussion in § 4.6.

The following table presents the evolution of the annual fuel (and TPP O&M) savings for Egypt and Sudan for the ET-SU: 1200 MW, ET-EG: 700 MW scheme (medium demand projection for all countries, medium fuel price projection, 10% discount rate).

Fuel savings for Egypt:

The average export to Egypt is 2.3 TWh/year. The fuel savings consist essentially in Natural Gas savings and amounts to 120 $MUSD_{2006}$/year.

The Net Present Value of these fuel savings in 2030 is equal to 320 $MUSD_{2006}$.

Fuel savings for Sudan:

The average export to Sudan is 8.9 TWh/year.

The fuel savings consists essentially in crude oil and gas oil, with some addition of Diesel and HFO. Crude oil-fired STPP represent 45% of the Sudanese installed capacity in 2020 and 32% in 2030, while for gas oil-fired CCGT the ratio increases from 6% to 27%. Accordingly, the share of gas oil in the fuel savings increases along the period of time.

The average fuels savings amounts to 760 $MUSD_{2006}$/year, with 450 $MUSD_{2006}$/year from crude oil and 210 $MUSD_{2006}$/year from gas oil.

The Net Present Value of these fuel savings in 2030 is equal to 1 700 $MUSD_{2006}$.

Cost of HPP anticipation in Ethiopia:

The anticipation of Mandaya commissioning for 2024 to 2020 results in an additional investment cost of 410 MUSD $_{2006}$ (discounted in 2008).

Pays back period:

The present value of the interconnection investment cost is 490 $MUSD_{2006}$ for the ET-SU: 1200 MW, ET-EG: 700 MW scheme. The present value for the anticipation of Mandaya from 2024 to 2020 is 410 $MUSD_{2006.}$ Accordingly, the payback period is reached when the fuel savings are greater than 900 $MUSD_{2006}$. This level is reached as soon as the end of 2023.

This means that the interconnection is paid after only 4 full years of operation. This very short pay back period is consistent with the high benefit to cost ratio of the interconnection project.

		EGYPT						SUDAN								TOTAL		
		Import	**Fuel and O&M savings for EGYPT (MUSD)**					**Import**	**Fuel and O&M savings for SUDAN (MUSD)**							**Fuel and O&M savings**		
Year	Discount Factor	TWh	NG	HFO	Diesel	Total	NPV	TWh	HFO	DIESEL	CRUDE OIL	GASOIL	COAL	Total	NPV	Total	NPV	
2008	1																	
2019	0.3505								-4	-22	-146	-18	-1	-190	-66	-190	-66	
2020	0.3186	4.8	245	1	0	246	78	9.0	58	90	582	74	9	814	193	1 060	271	
2021	0.2897	4.5	231	3	0	234	146	8.2	70	84	545	73	6	777	418	1 011	564	
2022	0.2633	4.8	251	2	0	253	213	8.6	71	87	567	153	8	886	651	1 139	864	
2023	0.2394	2.9	158	2	0	159	251	8.8	37	99	782	170	3	1 091	913	1 250	1 163	PAY BACK
2024	0.2176	1.4	77	1	1	79	268	8.7	13	64	512	109	2	700	1 065	779	1 333	
2025	0.1978	0.5	27	0	0	27	273	9.0	2	58	443	181	1	685	1 200	712	1 474	
2026	0.1799	0.0	0	0	0	1	274	8.2	0	39	273	212	0	522	1 294	523	1 568	
2027	0.1635	0.1	4	0	0	4	274	8.0	3	35	284	193	0	515	1 378	519	1 653	
2028	0.1486	2.0	112	1	0	113	291	9.6	17	57	355	328	0	757	1 491	870	1 782	
2029	0.1351	1.7	97	0	0	97	304	9.7	11	32	327	417	0	787	1 597	884	1 901	
2030	0.1228	2.4	131	0	1	132	320	9.7	12	32	327	411	0	781	1 693	913	2 014	
Average 2020-2030 :		2.3	121	1	0	122		8.9	27	61	454	211	3	756		878		

Table 15.3-6 - Fuel savings per country - Loose pool – Medium demand projection for Ethiopia - ET-SU: 1200 MW - ET-EG: 700 MW

15.4 TIGHT POOL MODEL

15.4.1 PRESENT WORTH OF GENERATION SAVINGS

The following table presents the net savings (generation savings minus interconnection cost) according to the various capacity options and key economic parameters of the study (10% discount rate):

Present worth of generation savings ($MUSD_{2006}$)

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	3 800	4 150
Medium	Medium	2 360	2 600
Medium	Low	1 360	1 490
Low	High	3 140	4 020
Low	Medium	2 420	3 020

Table 15.4-1 - Present worth value of generation savings – Tight Pool model

NB:

These generation savings are net of interconnection transmission looses, and of the additional investment costs resulting from the anticipation of several HPP in Ethiopia compared to the independent development of each power system.

15.4.2 NET SAVINGS

The following table presents the net savings (= generation savings minus interconnection cost) according the various capacity options and key parameters of the study:

NPV ($MUSD_{2006}$):

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	3 310	3 110
Medium	Medium	1 870	1 560
Medium	Low	870	450
Low	High	2 650	2 980
Low	Medium	1 930	1 980

Table 15.4-2 - Net Present Value of the interconnection – Tight pool model

The tight pool model, along with an increase of power exports, and in spite of the additional generation investment (anticipation of the HPP schedule in Ethiopia) provides an increase of the Net Present Value of the interconnection project for the region compared to the loose pool approach.

Profitability under adverse evolution of key parameters:

In line with the loose pool results, the project remains profitable even if the fuel price follows the low projection (35 USD/bbl forecasted in 2030, while crude oil actually reached over 90 USD/bbl in November 2007).

If the Ethiopian demand evolution follows the "target" projection, there is no room to further anticipate the Ethiopian HPP investments. Accordingly, the loose pool approach is the only one relevant in this case (on the basis of the data available for the present Study).

15.4.3 COMPARING OPTIONS

The next table provides the Benefit to Cost Ratio (also called BCR):

Benefit / Cost ratio :

Ethiopian demand	Fuel projection	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Medium	High	7.8	4.0
Medium	Medium	4.8	2.5
Medium	Low	2.8	1.4
Low	High	6.4	3.9
Low	Medium	4.9	2.9

Table 15.4-3 - Benefit to Cost Ratio – Tight pool model

The benefit to cost ratio would still favor the ET-SU: 1200 MW – ET-EG: 700 MW scheme. However, the NPV of this scheme is relatively close to the ET-SU: 1200 MW – ET-EG: 2000 MW scheme for most of the key parameters. Furthermore, the analysis in the following paragraph shows that the pay back period for the 2000 MW scheme is still lower than 10 years, which is very good. Accordingly, the 2000 MW scheme to Egypt would probably more advantageous to the regional development and would give more freedom and flexibility for a future enlargement of the power market to the South (Kenya and SAPP) and to the North

15.4.4 SAVINGS PER COUNTRY AND PAY BACK PERIOD

The following two tables present the evolution of the annual fuel (and TPP O&M) savings for Egypt and Sudan for the ET-SU: 1200 MW, ET-EG :2000 MW scheme for two hypothesis:

- medium demand projection for Ethiopia,
- low demand projection for Ethiopia.

The other parameters are medium fuel price projection and 10% discount rate.

15.4.4.1 Medium demand projection for Ethiopia

Fuel savings for Egypt:

The average export to Egypt is 7.7 TWh/year. The fuel savings consist essentially in Natural Gas savings and amounts to 420 $MUSD_{2006}$/year.

The Net Present Value of these fuel savings in 2030 is equal to 920 $MUSD_{2006}$.

Fuel savings for Sudan:

The average export to Sudan is 9.2 TWh/year.

The fuel savings consists essentially in crude oil and gas oil, with some addition from Diesel and HFO. Crude oil-fired STPP represent 45% of the Sudanese installed capacity in 2020 and 32% in 2030, while for gas oil-fired CCGT the ratio increases from 6% to 27%. Accordingly, the share of gas oil in the fuel savings increases along the period of time.

The average fuels savings amounts to 810 $MUSD_{2006}$/year, with 480 $MUSD_{2006}$/year from crude oil and 230 $MUSD_{2006}$/year from gas oil.

The Net Present Value of these fuel savings in 2030 is equal to 1 800 $MUSD_{2006}$.

Cost of HPP anticipation in Ethiopia:

The anticipation of the various Ethiopian HPP (see §13.2.1) in the tight pool model results in an additional investment cost of 820 MUSD $_{2006}$ (discounted in 2008).

Payback period:

The present value of the interconnection is 1010 $MUSD_{2006}$ for the ET-SU: 1200 MW, ET-EG: 2000 MW scheme. The present value for the anticipation of the Ethiopian HPP in the tight pool approach is 820 $MUSD_{2006.}$ Accordingly, the payback period is reached when the fuel savings are greater than 1 830 $MUSD_{2006}$. This level is reached as soon as the end of 2026.

This means that the interconnection is paid after 7 full years of operation. This very short pay back period is consistent with the high benefit to cost ratio of the interconnection project.

		EGYPT						SUDAN								TOTAL		
		Import	Fuel and O&M savings for EGYPT (MUSD)					Import	Fuel and O&M savings for SUDAN (MUSD)							Fuel and O&M savings		
Year	Discount Factor	TWh	NG	HFO	Diesel	Total	NPV	TWh	HFO	DIESEL	CRUDE OIL	GASOIL	COAL	Total	NPV	Total	NPV	
2008	1																	
2019	0.3505								-5	-30	-209	-23	-1	-267	-94	-267	-94	
2020	0.3186	6.8	360	1	0	361	115	8.5	60	90	585	74	0	809	164	1 170	279	
2021	0.2897	6.1	322	5	0	328	210	8.0	62	84	542	72	0	759	384	1 087	594	
2022	0.2633	6.6	360	4	0	364	306	8.8	60	85	550	149	0	844	606	1 208	912	
2023	0.2394	5.4	300	3	0	303	378	9.7	21	90	679	149	0	939	831	1 242	1 210	
2024	0.2176	5.6	307	5	1	314	447	9.3	19	54	414	89	0	575	956	889	1 403	
2025	0.1978	13.3	689	4	1	694	584	9.7	26	62	501	198	0	786	1 112	1 480	1 696	
2026	0.1799	10.9	582	4	0	586	689	9.4	29	61	478	312	0	880	1 270	1 466	1 960	PAY BACK
2027	0.1635	8.7	471	3	1	474	767	9.1	30	56	486	300	0	872	1 413	1 346	2 180	
2028	0.1486	6.2	340	1	1	342	818	9.4	22	60	386	359	0	827	1 536	1 169	2 353	
2029	0.1351	6.1	335	2	0	337	863	9.8	13	32	336	432	0	814	1 646	1 151	2 509	
2030	0.1228	8.7	472	1	1	474	922	9.8	14	32	334	417	0	798	1 744	1 272	2 665	
Average 2020-2030 :		7.7	413	3	1	416		9.2	32	64	481	232	0	809		1225		

Table 15.4-4 - Fuel savings per country - Tight pool – Medium demand projection for Ethiopia - ET-SU: 1200 MW - ET-EG: 2000 MW

15.4.4.2 Low demand projection for Ethiopia

As discussed previously, the low demand projection for Ethiopia might be more relevant to the Study considering that some other HPP projects could cover part of the internal Ethiopian demand.

Fuel savings for Egypt:

The average export to Egypt is 12.7 TWh/year. The fuel savings consist essentially in Natural Gas savings and amounts to 680 $MUSD_{2006}$/year.

The Net Present Value of these fuel savings in 2030 is equal to 1500 $MUSD_{2006}$.

Fuel savings for Sudan:

The average export to Sudan is 9.4 TWh/year.

The fuel savings consists essentially in crude oil and gas oil, with some addition from Diesel and HFO. Crude oil-fired STPP represent 45% of the Sudanese installed capacity in 2020 and 32% in 2030, while for gas oil-fired CCGT the ratio increases from 6% to 27%. Accordingly, the share of gas oil in the fuel savings increases along the period of time.

The average fuels savings amounts to 820 $MUSD_{2006}$/year, with 480 $MUSD_{2006}$/year from crude oil and 240 $MUSD_{2006}$/year from gas oil.

The Net Present Value of these fuel savings in 2030 is equal to 1 800 $MUSD_{2006}$.

Cost of HPP anticipation in Ethiopia:

The anticipation of the various Ethiopian HPP (see §13.4.1.1) in the tight pool model results in an additional investment cost of 1 450 MUSD $_{2006}$ (discounted in 2008).

Payback period:

The present value of the interconnection is 1010 $MUSD_{2006}$ for the ET-SU: 1200 MW, ET-EG: 2000 MW scheme. The present value for the anticipation of the Ethiopian HPP in the tight pool approach and low demand projection in Ethiopia is 1460 $MUSD_{2006.}$ Accordingly, the payback period is reached when the fuel savings are greater than 2 470 $MUSD_{2006}$. This level is reached as soon as the end of 2027.

This means that the interconnection is paid after 8 full years of operation. This very short pay back period is consistent with the high benefit to cost ratio of the interconnection project

		EGYPT						SUDAN								TOTAL	
		Import	**Fuel and O&M savings for EGYPT (MUSD)**					**Import**	**Fuel and O&M savings for SUDAN (MUSD)**							**Fuel and O&M savings**	
Year	Discount Factor	TWh	DIESEL	HFO	NG	Total	NPV	TWh	COAL	DIESEL	GASOIL	HFO	Crude oil	Total	NPV	Total	NPV
2008	1																
2020	0.3186308	12.3	0	1	642	644	205	8.7	4	89	74	64	611	842	268	1 485	473
2021	0.2896644	10.0	0	6	512	517	355	8.2	0	82	74	68	553	777	493	1 294	848
2022	0.2633313	10.3	0	5	586	592	511	9.1	2	79	144	60	542	829	711	1 421	1 222
2023	0.239392	8.7	0	4	464	467	623	9.9	3	75	120	21	515	735	887	1 202	1 510
2024	0.2176291	11.3	1	7	590	597	753	9.6	0	61	103	23	496	684	1 036	1 281	1 789
2025	0.1978447	16.2	1	4	823	829	917	9.8	2	67	198	25	526	818	1 198	1 647	2 114
2026	0.1798588	15.0	1	5	825	830	1 066	9.5	4	55	268	27	425	779	1 338	1 609	2 404
2027	0.163508	13.5	1	3	695	698	1 180	9.2	0	58	309	34	502	903	1 486	1 601	2 666
2028	0.1486436	13.3	1	2	710	712	1 286	9.8	1	63	386	20	422	892	1 618	1 604	2 904
2029	0.1351306	13.7	1	3	713	717	1 383	10.1	1	33	433	13	338	818	1 729	1 535	3 111
2030	0.122846	15.1	0	2	876	878	1 491	9.8	3	34	499	19	393	948	1 845	1 826	3 336
Average 2020-2030		12.7	0	4	676	680		9.4	2	63	237	34	484	820		1500	

Table 15.4-5 - Fuel savings per country - Tight pool – Low demand projection for Ethiopia - ET-SU: 1200 MW - ET-EG: 2000 MW

15.5 DOWNSTREAM EFFECTS

Impact on Sudanese HPP:

The planning software used in the present Study (SDDP) contains a detailed modeling of the Ethiopian and Sudanese hydro schemes, including the hydro continuity between Ethiopia and Sudan hydro schemes (Blue Nile river and Tekeze / Sobat river). Accordingly, the positive downstream effects during operation of the Ethiopian HPP (flow regulation, uplift effect) and negative effects during filling (reduced inflows) are considered and properly evaluated by the planning software.

Impacts on Aswan:

The impacts of Mandaya on Aswan has been studied at pre-feasibility level in the Module M5 of the present Study. The main findings are as follow:

- The period of first filling of Mandaya reservoir will reduce levels of Lake Nasser/Nubia. The degree to which this will occur is dependent on the hydrological sequence experienced at the time of first filling and the downstream release rates adopted at Mandaya. A fall in level of some 12 m appears probable but clearly the fall may be smaller or greater according to circumstances at the time. This reduction in level would reduce the head for energy generation at Aswan by some 16% (equivalent to a 300 MW peak capacity loss).

  The following table (extracted from Mandaya pre-feasibility Study) presents the generation loss in GWh at High Aswan during the first years starting with the filling of Mandaya for five different sequences of hydrological years (starting in 1954, 1964, 1974, 1984, 1994) :

First year of sequence	Year 1	Year 2	Year 3	Year 4
1954	0	0	0	0
1964	4 524	2 970	0	1 194
1974	0	975	4	0
1984	0	0	0	138
1994	0	0	0	36
Average loss	905	789	1	274

Table 15.5-1: Effects on Mandaya filling on High Dam energy output (GWh)

  The strong dependence and variability of the loss under the hydrological condition is readily apparent. During the first two years the average loss in the range of 0.7 to 0.8 TWh. The overall average lost over a 50 year period (long term operation of Mandaya) operation has been evaluated to 0.202 TWh (cf Module 5). These values are significantly lower than the average energy that would be imported from Ethiopia (between 8.0 to 12.7 TWh/year for the most relevant scenarios of the tight pool model).

- The simulations performed in Module 5 indicate that Lake Nasser / Nubia will recover after some years. This recovery is in part associated with an important feature: when levels are reduced, and the surface area is smaller, large evaporation losses are reduced.

- If the project construction is begun, and a very severely dry hydrological sequence occurs which forces greater downstream releases to occur to satisfy water supply demands in Egypt, first filling will be slower and full generation will be delayed. This is an inescapable reality and risk. This risk will need to be accepted by the project Owner and lending agencies. The downstream releases made from Mandaya during first filling and in the operational period will require thorough study, definition and binding agreement of all parties, with variants of these releases also being agreed to cover extreme circumstances.

- With regard to sedimentation, the holding of most of Abbay's suspended sediment load and all of its bed load in Mandaya reservoir will cause significant reduction in the siltation rate of Lake Nubia/Nasser. This will extend the life of High Aswan Dam and maintain its yield for irrigation, domestic and public water supply and industry for a much longer period of years (more than a century) than might otherwise be the case. This benefit will be extended as watershed management measures are increasingly implemented in the Abbay basin – supported, it is proposed, by funds from the income stream from Mandaya's energy sales.
- Karadobi project has similar, while lower, downstream effect of Aswan (about 8 m fall in level).
- Border project has only a marginal impact with a 2 m induced fall in level at Aswan.

On a whole, more detailed studies, which do not fall within the scope of present pre-feasibility studies (Module 5), are required for:

- Defining the optimum operation of Aswan with Mandaya and other large Blue Nile HPP projects.
- Quantify both positive (extended life of Aswan when sediment inflows are reduced by deposition in Karadobi, Mandaya and Border & possible reduction of evaporation) and negative downstream impacts (loss of generation during the filling of upstream reservoirs) in terms of money.
- Identify mitigation or compensation measurements such as special tariff for importing energy to compensate for foregone energy at Aswan.

For the present economic Study, no downstream impact on Aswan has been considered considering that:

- energy losses depend heavily on the filling strategy and on High dam operation policy, and while the losses could reach some very significant value in exceptional hydrological condition, they are on average relatively minimal compared to the amount of imported energy from Ethiopia (< 1 TWh on the average during the first two years, and 0.2 TWh for long term operation, compared to 8.0 to 12.7 TWh/year average import for the most relevant scenarios of the tight pool model),
- additional studies, outside the scope of present Study, are required to analyze both negative and positive downstream impacts,
- the energy and capacity losses could be mitigated by compensation measurements such as special tariff for imported energy during the filling of large upstream reservoirs, and particular arrangements if filling should occur during an exceptional dry year.
- other potentially promising large HPP sites exist in Ethiopia which might alleviate the negative downstream impact of Nile River (i.e Gibe IV upstream of Omo river).

15.6 PHASING OF THE INTERCONNECTION

In the loose pool (see § 12.5) or tight pool (see § 15.6) approach, the commission of the interconnection can be phased is two steps: the first step being the commissioning of the interconnection between Ethiopia and Sudan in 2015 (500 kV AC transmission lines), the second step being the completion of the interconnection with the link between Ethiopia and Egypt.

This two-step phasing would increase the profitability of the interconnection (Net Present Value increased by 220 to 320 MUSD depending on the interconnection option).

16 SUMMARY OF ADVANTAGES / DISADVANTAGES RESULTING FROM THE INTERCONNECTION PROJECT

The purpose of the present economic Study was to evaluate the potential economic benefits resulting from the interconnection project.

While these benefits can be evaluated in terms of monetary values, they do not represents all the possible benefits resulting from the project.

In order to widen the view, the following simplified tables summarizes for the region and for each country, the main advantages and the disadvantages from the interconnection project (these tables are adapted from the detailed information provided Module 5 EIA). In order to be more specific, the tables indicate the origin of the advantages or disadvantages:

- Electric market: when the advantage/disadvantage exists if and only if the interconnection exists.
- HPP projects in Blue Nile River: when the advantage/disadvantage exists even in the absence of the interconnection.

Regarding the HPP positive or negative impacts and associated mitigation measures, only a brief overview is provided here, the reader is invited to find more information in the relevant pre-feasibility HPP Studies (Mandaya, Border, etc).

<u>Note on relation between the interconnection project and HPP downstream benefits</u>:

In the following table, for the sake of simplification, the downstream benefits are attributed to the HPP and not to the interconnection project.

Indeed, one of the results of the Study is to show that, even without interconnection, Ethiopia needs to develop the large hydro projects (identified in Module 3 Vol 4) in order to cover its own power demand over the next 25 years.

The main part of the down-stream benefits (regulation of flow, flood mitigation, uplift effect, etc) will be provided by the first large HPP project commissioned on the Blue Nile river (Mandaya or Karadobi). Subsequent projects would bring much lower additional downstream benefits.

For the target demand projection in Ethiopia, and without interconnection, the Study shows that Mandaya is required in 2020 and Karadobi in 2023. Accordingly, in this situation the downstream benefits are not attributable to the presence of the interconnection (commissioned in 2020)

In the Ethiopian medium demand projection, Mandaya is required in 2024 in the independent development situation, and in 2020 in the interconnected situation. Accordingly, the interconnection will induce a 4 years anticipation of Mandaya, and associated downstream benefits compared to the independent development scheme.

However, the possibility of selling part of the power from the large Blue Nile HPP projects for export would make these projects more bankable, favouring the possibility of rising funds for actually building them. Accordingly, there is an indirect link between the interconnection project, favouring the financial feasibility of the large Blue Nile HPP projects, and the resulting HPP downstream benefits.

16.1 REGION

Origin	Advantages
Power market	Creation of a power pool: - global generation cost savings, - reduction of the cost of electricity for the final user would favor overall development, - economies of scale in new generation capacity: development of larger low-cost hydropower plants made possible through the creation of larger power market, - hydro-thermal complementarity between Egypt, Ethiopia and Sudan, - mutual assistance in case of disturbances, - first step to the connection of the North Africa power systems to the South East African power pool. Regional cooperation and trust building
Hydro projects	Coordination of the operation of HPP on the Nile river for an overall benefit for the region. Regulation of inflows and continuous availability of water. Reduction in CO_2 emissions

Origin	Disadvantages
Power market	None

Table 16.1-1 - Advantages / disadvantages for the region

16.2 EGYPT

Origin	Advantages
Power market	Fuel savings (mainly Natural gas). Reduction in CO_2 emission. Securisation of the long term cost of generation (hydro power base import have a generation cost independent of the variation of crude oil price). Possibility for Egyptian generator companies to invest in low-cost hydro generation in Ethiopia.

Hydro projects	Regulation of inflows: - improved guarantee for irrigation, - opportunity to operate Aswan at lower level for a reduction of evaporation and a conversion to usable supply yield which may more than offset the reduction in power generation, - opportunity to avoid / reduce spilled energy (eg 1998/199). Reduced sediment: extension in life of High Aswan dam

Origin	**Disadvantages**
Power market	None
Hydro projects	Head loss on Aswan during filling large reservoirs on Blue Nile river: Impact along time to be studied under a variety of conditions (hydrology, sequence of HPP, reservoir sizes, etc) in term of irrigation, capacity (MW), energy (GWh).

Table 16.2-1 - Advantages / disadvantages for Egypt

16.3 ETHIOPIA

Origin	**Advantages**
Power market	Valorisation of the hydro power surplus inherent to the Ethiopian power system. Valorisation of the hydro potential of Ethiopia for the benefit of Ethiopia and the interconnected countries. Boost for the development of the Ethiopian power mix, and consequently to the electrification rate in Ethiopia. Securisation of power supply in Ethiopia in case of drought conditions (power import from Egypt and Sudan). Important role for the connection to Kenya and at a latter stage to the SAPP. Increase foreign exchange earnings. Construction employment, new skills for the future.
Hydro projects	Major energy benefits Low-cost renewable energy. Regional development (new roads, bridge, development of rural electrification, etc). Poverty reduction. Construction employment, new skills for the future. Development of irrigation.

Origin	**Disadvantages**
Hydro projects	Capital intensive projects may take time to be finance. Negative ES impacts (but can be mitigated through identified measures)

Table 16.3-1 - Advantages / disadvantages for Ethiopia

16.4 SUDAN

Origin	Advantages
Power market	Fuel savings (crude and oil derivatives). Saved fossil fuel could be exported at a higher price rather than be burned in thermal plants. Access to the Mediterranean power market, and at a latter stage to the SAPP. Re-enforcement of the complementarily between the Ethiopian hydro system and the Sudanese hydro system (power sales to Ethiopia in drought conditions).
Hydro projects	Regulation of inflows (additional irrigation, navigation, uplift effect at Roseires, Sennar and Merowe: 2 200 GWh/year, equivalent to DAL generation). Reduced sediment: reduction in dredging costs at Roseires, reduction in drainage canal desilting maintenance cost, reduction in pump replacement cost. Increased irrigation supply reliability / Development of Irrigation agriculture: two crops per year. Flood reduction.

Origin	Disadvantages
Hydro projects	Reduction in flooding and sediment will lead to the conversion of recession agriculture to irrigation agriculture (but can be mitigated through identified measures).

Table 16.4-1 - Advantages / disadvantages for Sudan

17 CONCLUSION

The present power trade Study is the first quantitative Study bringing lights to the future evolution of the Egyptian, Ethiopian and Sudanese power systems up to 2030, and evaluating the benefits that would result from the establishment a regional power market between these countries.

Previously, the generation expansion plan of Sudan (LTPPS 2006) has been studied up to 2030, the Egyptian generation expansion plan covered the period up to 2028, the Ethiopian expansion plan (EPSEMPU June 2006) the period up to 2015, while power exchanges potential was assessed at scooping level.

The Study demonstrates there are significant benefits for the Egypt, Ethiopia, and Sudan to develop an interconnection project in order provide Egypt and Sudan with the hydro surplus available from the large Ethiopian HPP projects, and consequently save fossil fuels and reduce CO_2 emissions in Egypt and Sudan.

17.1 ETHIOPIAN HYDRO SURPLUS

Ethiopia is well endowed with hydro resources. The hydro potential is estimated at about 30 000 MW, with only a fraction of which has been exploited so far. Accordingly, the Ethiopian power system will be the main source of power export in the Egyptian, Ethiopian, Sudanese regional market.

Part of the Ethiopian hydro surplus available for export are inherent to the internal development of the Ethiopian hydro mix:

- Due to the large size of Ethiopian HPP projects compared to the Ethiopian internal demand (e.g. Mandaya represents more than 1/3 of the Ethiopian demand in 2024), hydro power surpluses are available for export during the first years following the commissioning of these large HPP projects.
- In order to maintain a proper supply / demand balance all year long, and even on the driest years, the Ethiopian hydro power system requires a large amount of installed overcapacity. The resulting hydro surplus can be provided for export on favorable hydrological conditions.

Furthermore, additional hydro surplus could be made available if the commissioning dates of hydro plants are anticipated (with respect to their "natural" schedule when Ethiopia remains isolated) or if hydro power projects are specifically developed for export.

The amount economic hydro surplus will also depend on the growth rate of the Ethiopian demand, the amount of power exported to other countries (e.g. Kenya) and the cost of the Ethiopian hydro projects.

17.2 PHASING OF THE INTERCONNECTION

The design of the interconnection (AC link between Ethiopia and Sudan, AC or DC link up to Egypt) gives some flexibility in the phasing of the interconnection. A commissioning in two phases would add to the profitability of the project: connection to Sudan in 2015 (earliest possible date considering duration of technical studies, tender process, construction) followed by a connection to Egypt in 2020 (earliest possible date when large amount of hydro power would be available from Ethiopian Blue Nile HPP projects).

17.3 ECONOMY OF THE INTERCONNECTION

The present Study shows that the interconnection project is characterized economically by a very good profitability, a short payback period and a high benefit to cost ratio.

The economy and optimal capacity of the interconnection were analyzed for two levels of coordination (or two types of power markets) between the three power systems: the loose pool and the tight pool models which are described briefly hereafter.

17.3.1 LOOSE POOL MODEL

The loose pool model consists basically in exporting the hydro surplus inherent to "isolated" development the Ethiopian power system. It is characterized by:

- no modification of the generation expansion plans of Egypt and Sudan,

- the only modification of the Ethiopian generation expansion plan is the anticipation of Mandaya to 2020[22] in line with the commissioning of the interconnection,
- some variability of the amount exported power to Egypt (export to Sudan being more base-load) along the period of study depending on the Ethiopian hydro surplus available,
- lower amount of power export (compared to the tight pool approach),
- and presents the advantage of low HPP additional investment cost (the only additional investment cost is the anticipation Mandaya from 2024 to 2020 in time with the commissioning of the interconnection).

Accordingly very good BCR and short payback periods are achieved, the variability of the hydro surplus being balanced by the low global additional generation investment cost.

This model is typical of the actual power exchanges between European countries (spot market, month to month exchanges) which take benefits of temporary (short to medium term) power surplus appearing in one or other country.

The main part of the power exchanges could probably be arranged on an annual basis, at the end of each wet season, when the amount of available energy in the reservoirs for the remaining part of the hydrological cycle is known.

In this context, the best scheme, from a strictly economic point of view, would be ET-SUD: 1200 MW and ET-EG: 700 MW, with a benefit to cost ratio of 4.5 and a very short 3 year-payback period for the reference hypothesis (medium demand projections, medium price projection).

However, going to 2000 MW capacity to Egypt would still be very profitable for the region (benefit to cost ratio =2.3), and would give more freedom and flexibility for a future enlargement of the power market to the South (Kenya and SAPP) and to the North.

17.3.2 TIGHT POOL MODEL

In the tight pool model adopted in this Study, HPP investments in Ethiopia are anticipated (with respect to their schedule when Ethiopia remains isolated) in order to provide an additional amount of power export. Thus, the power exports arise for one part, from the "natural" hydro surplus inherent to the Ethiopian hydro generation mix, and for the other part from the anticipation of major Ethiopian HPP.

The generation expansion plans of Egypt and Sudan are left unchanged because, due to the projected fuel price increase along the period of the Study, the investment represents only 15 to 25% of the total generation of new thermal plants (or even 10 to 20% if crude oil reaches 100 USD/bbl). Accordingly, the Consultant would not recommend any modification of the Generation Expansion Plans of Egypt and Sudan, which means these countries would still keep their ability to balance their power demand with their own supply whenever power import are available or not.

The tight pool model is characterized by:

- increased amount of exports (compared to loose pool),
- lower variability of the power export to Egypt along the period of study (compared to loose pool),
- higher generation investment cost in Ethiopia (because of HPP anticipation).

[22] For the Ethiopian low demand projection, Mandaya is anticipated from 2025 to 2020, while for the high demand projection no anticipation is required because the "natural" date of commissioning of Mandaya is 2020.

The benefit to cost ratio is lower, and the payback period longer, than in the loose pool model but yet these economic indicators remain very good.

As the Net Present Value of the scheme with ET-EG: 2000 MW is very close to the scheme with ET-EG: 700 MW (or even greater for some hypothesis), going to 2000 MW is certainly preferable, with still a short pay back period of 6 to 7 years, and a Benefit to Cost ratio of 2.7 to 4, according to hypothesis considered.

In this model, because of the increased HPP investment in Ethiopia, the power exchanges would probably be arranged largely on PPA basis, while additional exchanges on a spot to year basis are still possible according to the actual condition of the power systems.

The selling price of energy would be higher than in the loose pool model in order to recover the anticipated HPP investment.

17.3.3 PRESERVATION OF THE BENEFITS ON ADVERSE EVOLUTION OF KEY HYPOTHESIS

The key parameters affecting the profitability of the interconnection project are the evolution of the fuel cost (a lower fuel cost evolution would reduce fuel savings), and to a lower extend the evolution of the Ethiopian demand (a higher Ethiopian demand would reduce the amount of hydro surplus).

The interconnection project results in a net profit (overall benefits for the region greater than the costs) in all scenarios considered in the Study.

While it would difficult to derive any definite conclusion, it could be noted that the average crude oil market price during the last 12 months amounts to about 70 USD/bbl, which is nearly half way between the high and medium fuel price projections considered in this Study (55 USD/bbl and 91 USD/bbl respectively on average over 2015 to 2030).

17.3.4 POTENTIAL AND ACTUAL SAVINGS

The generation savings evaluated in this Module 6 are potential (i.e. theoretical) savings resulting from the optimal coordination of the three generation mixes. The actual savings will depend on the development of the power pool, the establishment of short-term and medium term contracts, the type of power exchanges (firm, non firm energy), the policy to share costs and benefits, negotiation of selling price, wheeling tariff, share of interconnection construction cost, etc.

17.4 LOOKING INTO THE FUTURE

The interconnection between Egypt, Ethiopia and Sudan presents a short pay back period (<10 years) for the most relevant projections (high or medium fuel price projections, medium or low demand projections for Ethiopia).

At the end of the payback period (i.e 2030-2032), the investment cost of the interconnection will be recovered. The remaining cost associated with the transmission of power will be the cost of transmission losses, and to a lesser extend the O&M costs. This reduction of transmission cost will boost the relative economic advantage of hydro power export from Ethiopia, giving opportunity to more hydro investments, for the benefit of the interconnected power systems (lower cost of electricity and reduction of emissions).

Finally, when the perspective is widen to the development of the African power markets, the commissioning of the interconnection between Egypt, Ethiopia and Sudan will be a determining step forward the completion of the connection between the North Africa power markets and the South African power markets (SAPP).

EDF – Generation and Engineering Division
73 373
Le Bourget du Lac Cedex
France
Tel: +33-4-79 60 60 28
Fax: +33-4-79 60 62 35
eMail: pierre.brun@edf.fr
http://www.edf.fr

ENTRO

EASTERN NILE POWER TRADE PROGRAM STUDY

AfDB

Scott Wilson
Kanthack House, Station Road,
Ashford, Kent TN 23 1 PP
England
Tel: +44 (0) 1233 658200
Fax: +44 (0) 1233 658209
eMail: alan.bates@scottwilson.com
http://www.scottwilson.com

with participation of:

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

MODULE 6:
COORDINATED INVESTMENT PLANNING

VOL 2: GENERATION

APPENDIX

November 2007

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1 OPTGEN/SDDP MODELING CAPABILITIES

1.1 Modelling capabilities

This paragraph presents successively:

- a brief overview of the modelling capabilities of OPTGEN/SDDP,
- the modelling highlights which make OPTGEN/SDDP particularly relevant for the Present Study,
- the detailed description of the modelling capabilities of OPTGEN/SDDP.

1.1.1 OVERVIEW

OPTGEN / SDDP is a computational tool for determining least-cost expansion investment plan (generation and interconnection) of multi-regional hydrothermal systems.

Modelling of projects (HPP & TPP):

- Optional and obligatory projects (TPP, HPP).
- Sets of associated projects (TPP, HPP).
- Sets of mutually exclusive projects.
- Precedence constraints between projects.
- Minimum capacity constraints for different groups of technology and for different time intervals.

Modelling of generation mix:

- Operational details of hydro plants (water balance, limits on storage and turbined outflow, spillage, topology, etc).
- Detailed thermal plant modelling.
- Hydrological uncertainties.
- Load variation per month and time block.

1.1.2 MODELLING HIGHLIGHTS

Apart from the "standard" modelling capabilities, OPTGEN / SDDP package offers capabilities particularly pertinent to the present Study:

<u>Power interconnections</u>:

- modelling of several generation mixes linked by interconnections, each generation mix has its own demand to supply;
- modelling of interconnection: max capacities in each direction, losses rate, wheeling costs, interconnections could be considered as candidate investments.

Level of coordination between the generation mixes:

Two levels of integration of power systems are possible:

- integrated power system: coordination of the investment and operation in the different power systems (as if there was a single generation mix).
- coordinated system: investment decision are optimised as if the power mixes where isolated while operation is coordinated (i.e global merit order to the limits of the interconnection capabilities). This means that each power system retains the ability to balance its own demand with its own generation capacities, even the interconnection is not available for a long period of time.

Hydro continuity across several countries:

- modelling hydro scheme with hydrological continuity between power mixes (Nile river).

Hydropower plant and water uses:

- modelling of hydro scheme:
    - live and dead storage (e.g. Mandaya, Border, Karadobi),
    - storage = f (height) (e.g. Roseires, Merowe, Mandaya),
    - storage = f (area),
    - evaporation = f (month),
    - energy coefficient = f (height) (e.g. Roseires, Merowe, Mandaya),
    - irrigation demand, operation with priority to irrigation or priority to power (e.g. Sudan),
    - water balance in cascade, spillage, monthly inflow series, etc.
- topology of hydro schemes: representation of hydro scheme topology, downstream impact of upstream projects (dead storage, regulation effect) are automatically considered.
- stochastic approach considering the hydrological uncertainties and generation unit outages.

1.1.3 CHARACTERISTICS OF EXISTING THERMAL PLANTS

- Minimum generation (MW): for must run generation unit (ie. unit with base load regardless system operating cost).
- Maximum generation (MW).
- Force and planned outage rate.
- Variable O&M cost.
- Fuel transport cost.
- Consumption factor (or efficiency) per segment.

All these characteristics could be modified or changed along time.

1.1.4 CHARACTERISTICS OF CANDIDATE THERMAL PLANTS

Same as exiting thermal plant, with the following additions:

- investment cost (MUSD or USD/kW),
- payment schedule,
- fixed O&M cost (USD/kW),
- electric integration cost (USD),
- life time,
- minimum and maximum date of commissioning,
- optional or compulsory decision: optional = economical, compulsory = the unit is to be committed before the maximum date of commissioning even if it is not economical,
- list of:
  - set of mutually exclusive projects,
  - set of associated projects,
  - precedence constraints between projects.
- project substitute to existing project: yes / no.

1.1.5 CHARACTERISTICS OF EXISTING HYDRO PLANTS

Operation data:

- installed capacity (MW),
- maximum turbining (m^3/s),
- generation coefficient ($MWh.m^3$), might depend on head,
- O&M variable cost,
- in case of reservoir:
  - storage = f (area),
  - storage = f (head),
  - filtration = f (storage),
  - generation coefficient = f (head).
- in case of reservoir or run of river:
  - tail water (m) = f (outflow) (m): evolution of the tail water elevation according to the outflow (including or not spillage). The production factor depends on the tail water.

Plant type:

- reservoir or run of river,
- reservoir:
    - minimum / maximum storage,
    - initial condition: storage or head,
    - evaporation coefficient = f (month) in mm.
- run of river:
    - regulation factor from 0 to 1: 1 = no storage capacity, 0 = concentration of generation on peak hours.

Topological data:

- downstream plant for spilling, turbining, filtration.

Irrigation data:

- choice possible between: irrigation is priority (meet irrigation demand first, then produce power), energy is priority (meet energy demand first, then irrigate) or fixed penalty,
- time step: month.

1.1.6 INFLOWS

Historical series (month, year).

1.1.7 CHARACTERISTICS OF CANDIDATE HYDRO PLANTS

Same as existing hydro plant, with the following additions:

- dead storage,
- investment cost (MUSD or USD/kW),
- payment schedule,
- fixed O&M cost (USD/kW),
- electric integration cost (USD),
- life time,
- minimum and maximum date of commissioning,
- optional or compulsory decision: optional = economical, compulsory = the unit is to be committed before the maximum date of commissioning even if it is not economical,
- list of:
    - set of mutually exclusive projects,
    - set of associated projects,
    - precedence constraints between projects.

- project substitute to existing project: yes / no.

1.1.8 CHARACTERISTICS OF FUELS

Cost per physical unit = f (year, month).

1.1.9 INTERCONNECTION

- Capacity (MW) in each direction.
- Losses.
- Interconnection charge (USD/MWh).

Capacity (MW) may change along the planning period.

1.1.10 INTERCONNECTION PROJECTS

Same as existing interconnection, with the following additions:

- investment cost (MUSD or USD/kW),
- payment schedule,
- fixed O&M cost (USD/kW),
- life time,
- minimum and maximum date of commissioning,
- optional or compulsory decision: optional = economical, compulsory = the unit is to be committed before the maximum date of commissioning even if it is not economical,
- list of:
    - set of mutually exclusive projects,
    - set of associated projects,
    - precedence constraints between projects.
- project substitute to existing project: yes / no.

1.1.11 ECONOMIC PARAMETERS

- monetary unit (USD),
- discount rate,
- cost of unserved energy (USD/MWh),
- spilling penalty for hydro reservoirs.

1.1.12 LEVEL OF INTEGRATION OF POWER SYSTEMS

Two levels of integration of power systems are possible:

- integrated power system: coordination of the investment and operation in the different power systems (as if there was a single generation mix).
- coordinated system: investment decision are optimised as if the power mixes where isolated while operation is coordinated (i.e global merit order to the limits of the interconnection capabilities). This means that each power system retains the ability to balance its own demand with its own generation capacities, even the interconnection is not available for a long period of time.

2 SCREENING CURVES

2.1.1 INTRODUCTION

The use of screening curves is a classic and useful tool to provide a quick evaluation of the relative economic potential of various thermal candidates. These curves represent the evolution of total annual generation cost of one guaranteed kW according to the number of hours of generation per year. The different underlying concepts are presented hereafter.

2.1.2 GOING TO ANNUAL COST

Comparing different types (or technologies) of generation units often implies comparison between generation units or projects having different economic life durations. The first step to provide a fair comparison is to annualize the investment cost.

In order to do this, we have to find the constant annual value "A" such as the NPV of the annual values of "a" over the economic life time is equal to investment "I". In other words, it is equivalent to pay the value "I" in one time step (construction) or to pay the value "a" every year of the economic life. Accordingly the relation linking "I" and "a" is:

$$I = \sum_{i=1}^{d} \frac{a}{(1+r)^i}$$

where r = discount rate

I = investment

a = investment annuity

d = economic life time of the investment

The resulting value a is given by the relation: $a = \frac{I}{K(r,d)}$

where the amortization factor K is given by the relation:

$$K(r,d) = \frac{r \times (1+r)^d}{(1+r)^d - 1}$$

Once the investment cost is annualized it is possible to compare, on the same annual basis, projects having different economic lives.

2.1.3 GOING TO INVESTMENT COST PER INSTALLED KW TO INVESTMENT COST PER GARANTEED KW

Some definitions are helpful to consider these issues:

Installed capacity:

The installed capacity of a thermal plant is the nominal output, measured at the generator terminals, given by the constructor under standard conditions (usually 15°C temperature and sea level pressure conditions).

Gross available capacity:

The gross available capacity is the installed capacity less de-rating to account for age and actual temperature and pressure conditions.

Net available capacity:

The net available capacity is the gross available capacity less the power consumed by the auxiliaries. This is also referred to as "send out capacity".

Planned Outage Rate (POR):

Is the time spent on planned maintenance expressed in days per year or in percentage.

Forced Outage Rate (FOR):

Is the expected time that a generation unit is expected to be out of service for unplanned repair or maintenance, expressed as a percentage of the maximum expected days a unit should be available to generated (i.e. days of year less the number of days undergoing planned maintenance).

Annual availability:

Is the fraction of the year that a generating unit is expected to be available for service:

$$((365 - POR) \times (1 - FOR)) / 365$$

In order to make a fair comparison between investments it is necessary to consider the fact that one installed MW does not provide one available (or guaranteed) MW.

Accordingly, the comparison should be made on the basis of the investment cost of:

$$\text{Net Capacity} / k_{avail}$$

where:

k_{avail} = availability factor (considering forced and planned outage rate).

2.1.4 ANNUAL GENERATION COST

The global cost of a thermal generation unit over its economic life depends on:

- fixed costs: construction cost (more precisely cash flow schedule during construction) and annual O&M cost,
- variable cost: fuel cost and variable O&M cost,
- the economic life time of the unit.

The annual generation costs of an available kW of a thermal unit i according to the number of hour generation per a year is given by the equation:

$$\mathbf{C_i\ (h) = A_i + K_i * h}$$

where:

A_i = anticipation cost of an <u>available</u> kW	[$/kW/year]
K_i = proportional cost (fuel, lubricant, proportional O&M) of unit i	[$/kWh]
h = number of hours of generation per year	[h/year]

The anticipation cost[1] of one guaranteed kW is equal to the sum of the fixed annual costs of the facility:

$$A_= (a + Kfix) / k_{avail}$$

where:

a = investment annuity of one installed kW = (construction cost + IDC) / K (r,d).

$Kfix_i$ = annual O&M cost.

k_{avail} = availability factor (considering forced and planned outage rate).

IDC = interest during construction.

r = discount factor.

d = economic life duration.

K (r,d) = amortization factor.

In this way, it is possible to compare the total costs of thermal generation units having different economic lives and different outage rates.

[1] Called "anticipation cost" because it is also equal to the additional fixed cost paid when the commissioning of the facility i is anticipated by one year.

2.1.5 SCREENING CURVES

The diagram of screening curves presents on the same figure the evolution of the annual generation cost of a set of thermal plants (usually the thermal candidates) according to the annual generation duration (hour / year) of each unit.

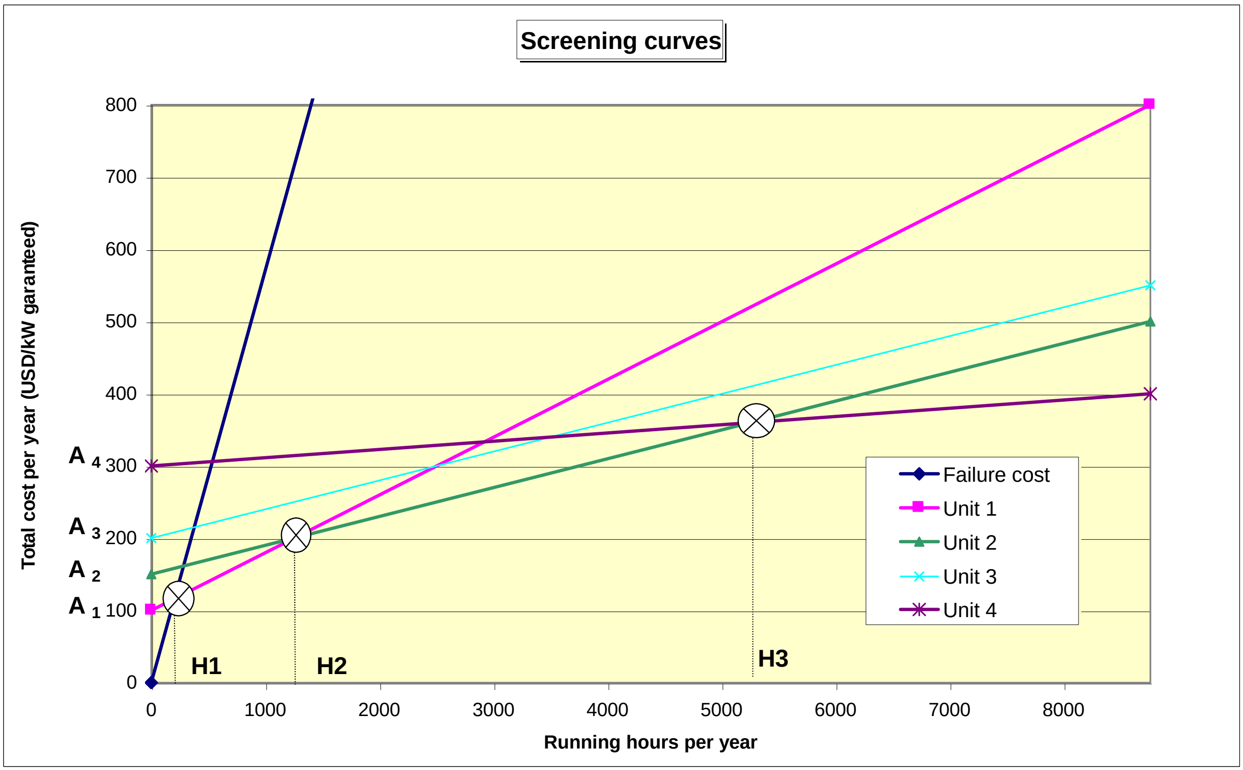

Figure 2-1 - Evolution of the annual generation cost

In the example above:

- unit 1 has a low investment cost (anticipation cost A1 = 100), but a high proportional cost, this is typical of peak generation units (e.g. OCGT),
- unit 2 has a greater investment cost (anticipation cost A2 = 150), but a slightly lower proportional cost,
- unit 3 has a greater investment cost (anticipation cost A3 = 200), but a lower proportional cost,
- unit 4 has the greatest investment cost (anticipation cost A3 = 300), but the lowest proportional cost, which is typical of base load generation.

2.1.6 WHAT IS THE LEAST COST OPTION FOR WHAT ANNUAL GENERATION DURATION ?

From the previous figure, it is clearly apparent that:

- for a number of generation hours per year > H3, unit 4 is the one resulting in the lowest generation cost;
- from H2 hours of generation per year to H3 hours, the least cost unit is unit 2;
- for less than H2 hours of generation per year, unit 1 is the least cost option.

Unit 4 is always more expensive than one of the other units whatever the annual generation duration.

2.1.7 BALANCE TIME BETWEEN TWO TYPES OF THERMAL UNITS

The balance time hij between two types of thermal facilities i and j is defined as the annual utilization time for which the two facilities reach the same generation costs.

$$A_i + K_i \, . \, h_{ij} = A_j + K_j \, . \, h_{ij}$$

$$h_{ij} = (A_i - A_j) / (K_j - K_i)$$

It also provides the break even value between load, semi-base and peak generation among thermal facilities. In the previous example:

- Unit 4 is the base load generation unit for annual generation duration > H3. If more base load generation is required because of the expansion of the system, then more units of Unit 1 type are to be committed,
- Unit 2 is the semi-base load generation unit for annual generation duration between H2 et H3,
- Unit 1 is the peak load generation unit for annual generation duration shorter then H2.

2.1.8 OPTIMALITY OF A GENERATION MIX (PART 1)

In order to be optimal (i.e. least cost option) a generation mix should satisfy a certain number of conditions. One of these conditions is that there should be a certain balance between base, semi-base and peak units.

In the example above, the generation mix would not be optimal if the peak unit (Unit 1) was be used more than H2 hours per year. Indeed, it would be more economical in this case to commit an another semi-base unit (Unit 2) which would be less expensive.

Basically, each generation units should be called within the limits of the annual balance time described above.

2.1.9 LINK BETWEEN THE COST OF UNSERVED ENERGY AND THE LOLP

The cost of unserved energy (CUE) is the cost of power shortage to the different sectors of the national economy (heavy and light industry, service industry, etc).

The CUE has a relation with the amount and the cost of generation units to be installed in a generation mix. If, in order to reduce power shedding, the cost of generation would be greater than the CUE, then the optimal choice for the economy of the country is to have power shedding rather than build a new power unit. On the other hand, if it is possible to build a power unit having a cost lower than CUE, then the best choice is to build this unit to reduce power shedding.

Obviously this comparison of costs should also consider the duration of generation (or the duration of power shedding). This is what is presented in the following figure:

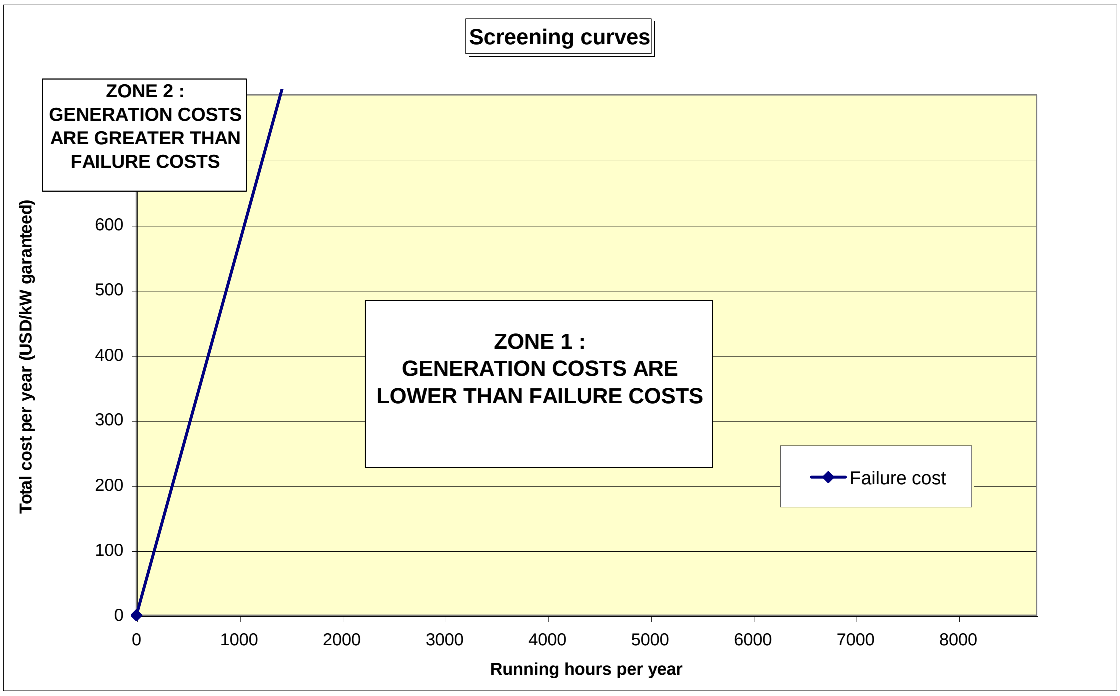

Figure 2-2 - Total generation cost

A generation unit having an annual generation cost in zone 2, have a cost greater than CUE and could not be profitable to the economy of the country.

The relation between CUE and LOLP can be found when the failure cost line is drawn on the screening curves diagram:

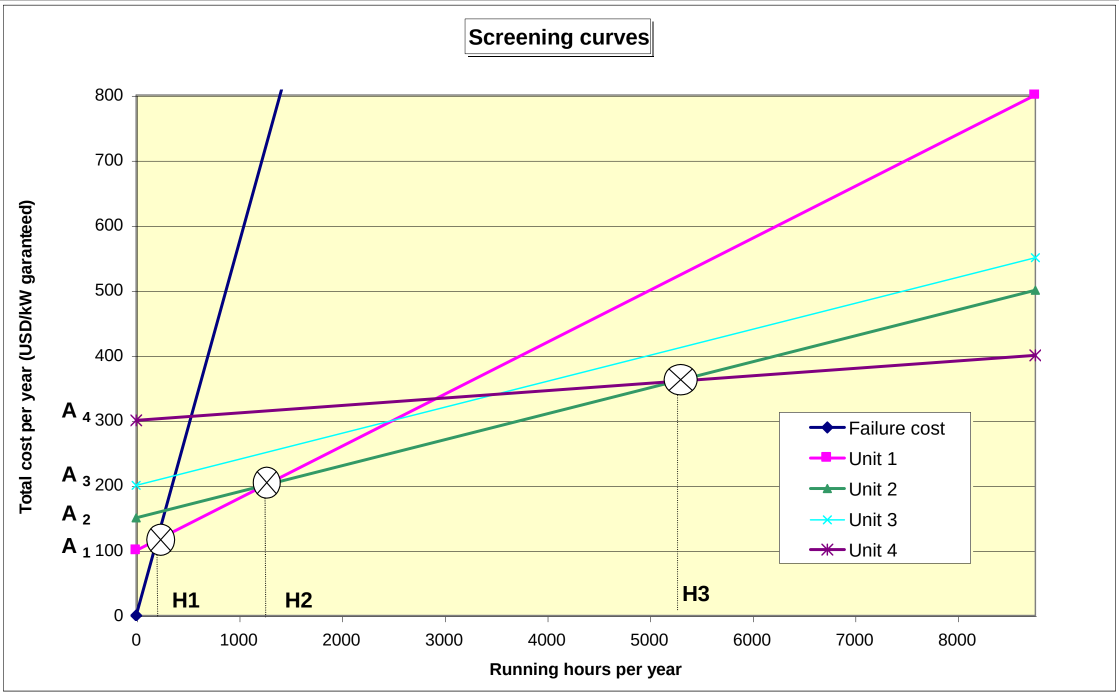

Figure 2-3 - Screening curves

For annual duration lower than H1 hours / year, the cost of generation from unit 1 (peak unit) is greater than the failure cost. This means that is not economically justified to build unit 1 if this unit is used less than H1 hours / years, it is more economical to have power shedding.

In other words, the economic duration of power shedding, given the value of the CUE, and given the characteristics of the peak unit 1, is H1. Accordingly, H1 is the value of the LOLP expressed in hours per year.

The relation linking these different quantities is:

CUE x LOLP = A1 + K1 x LOLP

where:

CUE = cost of unserved energy	[USD/MWh)
LOLP = average annual duration of power shedding	[hours /year]
A1: anticipation cost of peak generation unit	[USD/MW]
K1: proportional cost of peak generation unit	[USD/MWh]

The term K1 x LOLP being very small with respect to A, the useful relation is:

$\boxed{\text{CUE x LOLP = A1 + K1 x LOLP}}$

Example:

If the anticipation cost of the peak generation unit is 130 USD/kW and the Cost of Unserved Energy is 520 USD /MWh, then LOLP = 130 000 / 520 = 250 hours per year.

2.1.10 OPTIMALITY OF A GENERATION MIX (PART 2)

According to the previous discussion an optimal (i.e. least cost) generation mix should satisfy the two following conditions:

- The total installed capacity should be such as the shortage duration is equal to the target LOLP. This means that the target level of reliability is reached.
- The total installed capacity for each group of generation units (base, semi-base, peak) should be such than the balance times between the different groups are respected.

3 POWER EXCHANGES

This paragraph presents some complementary results regarding average monthly power transit in the loose pool and tight pool models.

3.1 Medium projection (demand & fuel prices)

3.1.1 HYPOTHESIS

- Medium demand projection for Egypt, Ethiopia and Sudan.

- Medium fuel price projection.

3.1.2 700 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN

The following figure presents the evolution of the average monthly economic exchanges between Ethiopia and Sudan in the following case:

- 200 MW capacity from 2010 to 2020,
- 700 MW capacity from 2020.

The average annual export from Ethiopia to Sudan(from 2020 to 2030) amounts to 5.9 TWh / year. In the other direction, the average annual export from Sudan to Ethiopia (from 2020 to 2030) amounts to 25 GWh / year (about 35 hours/year at 700 MW).

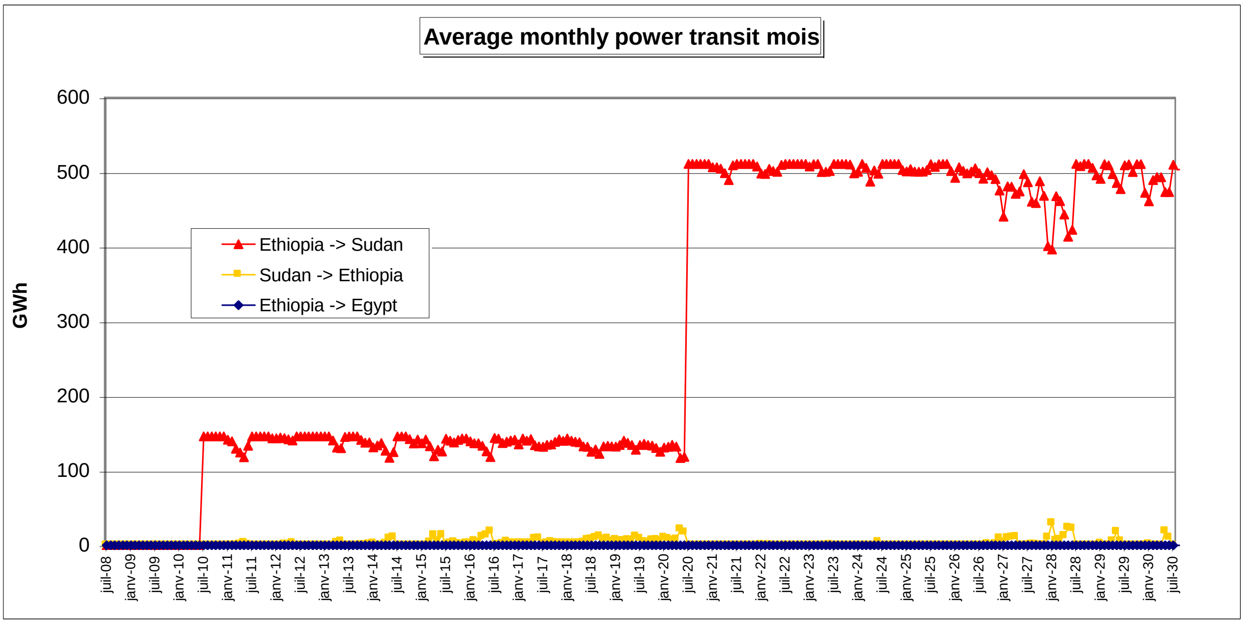

Figure 3.1-1 - Average monthly power transits – ET-SU = 700 MW – Loose pool

3.1.3 700 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 700 MW BETWEEN ETHIOPIA AND EGYPT

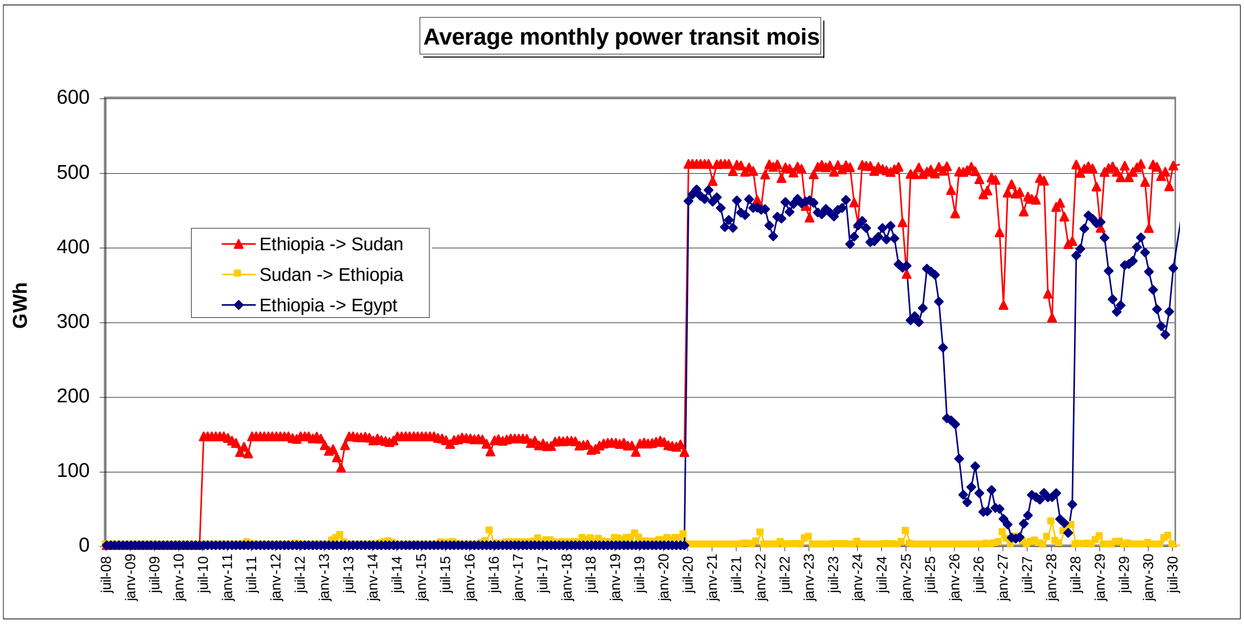

Figure 3.1-2 - Average monthly power transit - ET-SU = 700 MW, ET-EG = 700 MW – Loose pool

3.1.4 700 MW capacity between Ethiopia to Sudan, 2 000 MW between Ethiopia and Egypt

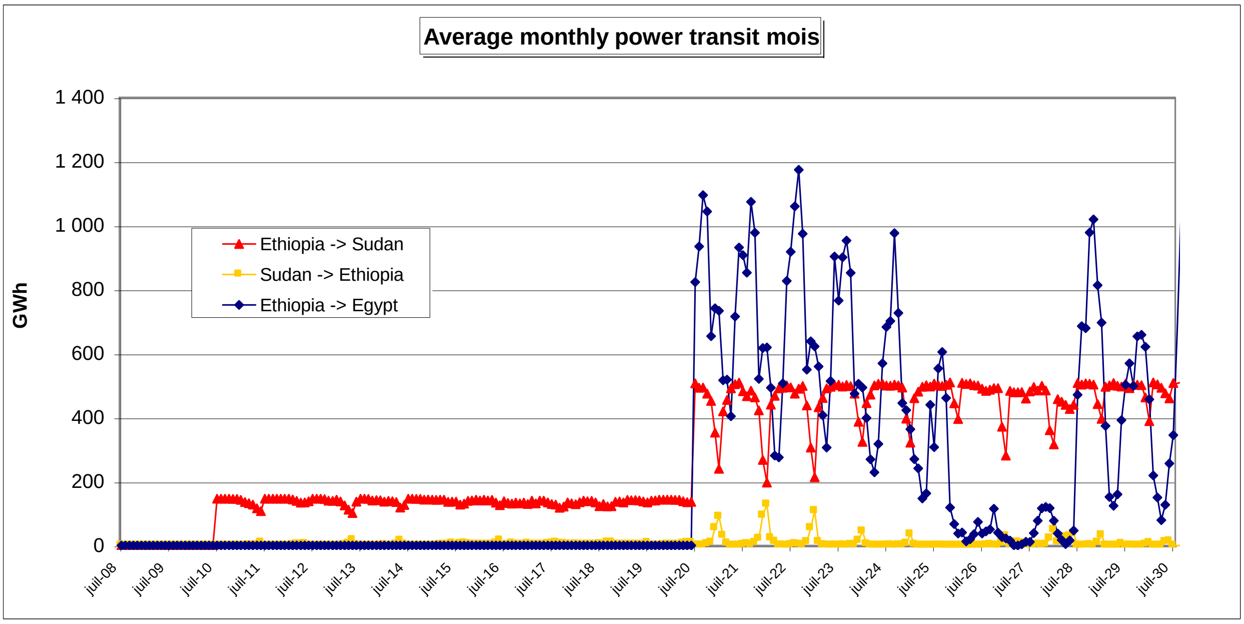

Figure 3.1-3 - Average monthly power transit – ET-SU = 700 MW – ET-EG = 2 000 MW – Loose pool

3.1.5 1 200 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 2 000 MW BETWEEN ETHIOPIA AND EGYPT

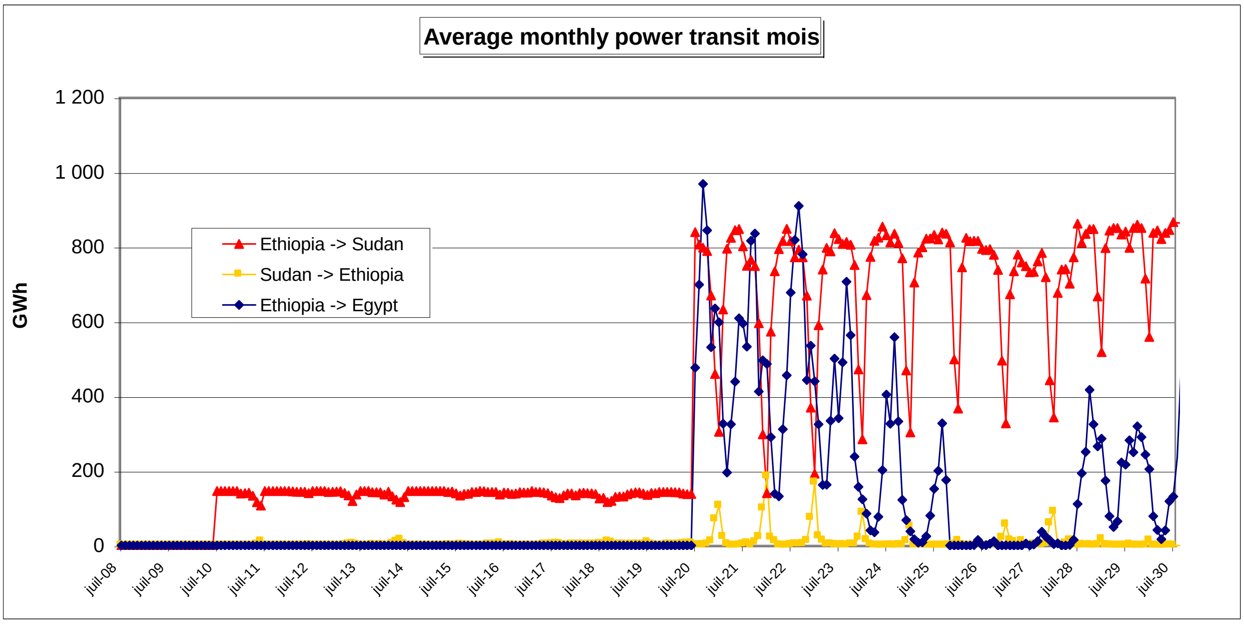

Figure 3.1-4 - Average monthly power transit – ET-SU: 1 200 MW – ET-EG: 2 000 MW – Loose pool

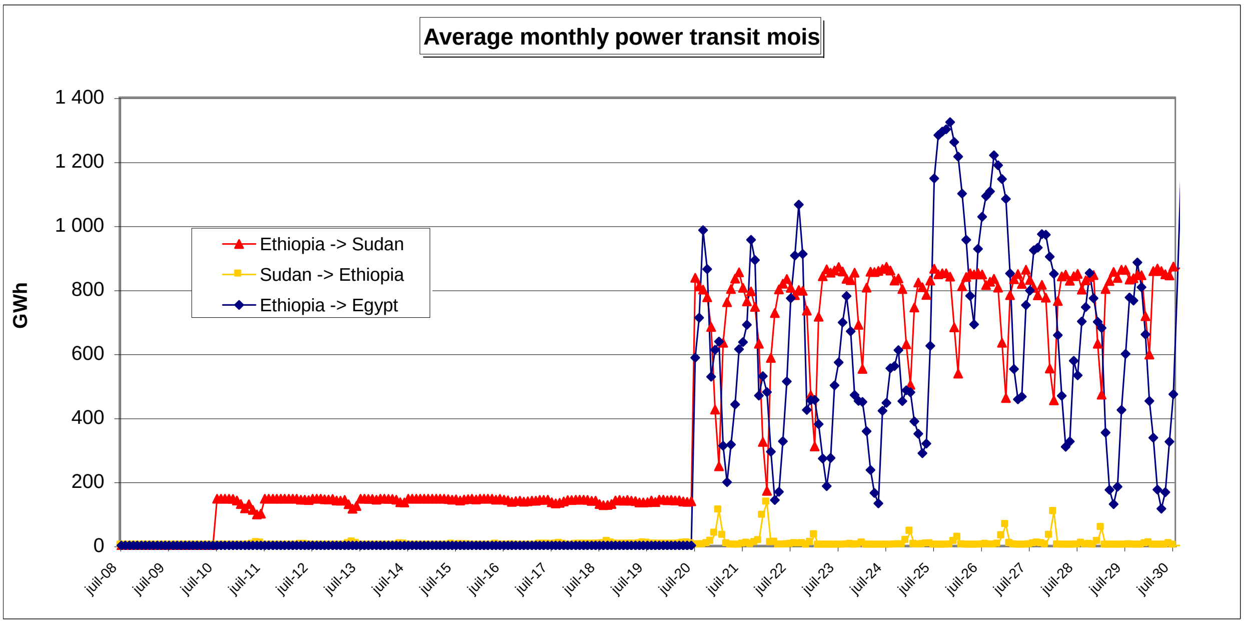

Figure 3.1-5 - Average monthly power transit – ET-SU: 1 200 MW – ET-EG: 2 000 MW – Tight pool

3.1.6 1 200 MW CAPACITY BETWEEN ETHIOPIA TO SUDAN, 700 MW BETWEEN ETHIOPIA AND EGYPT

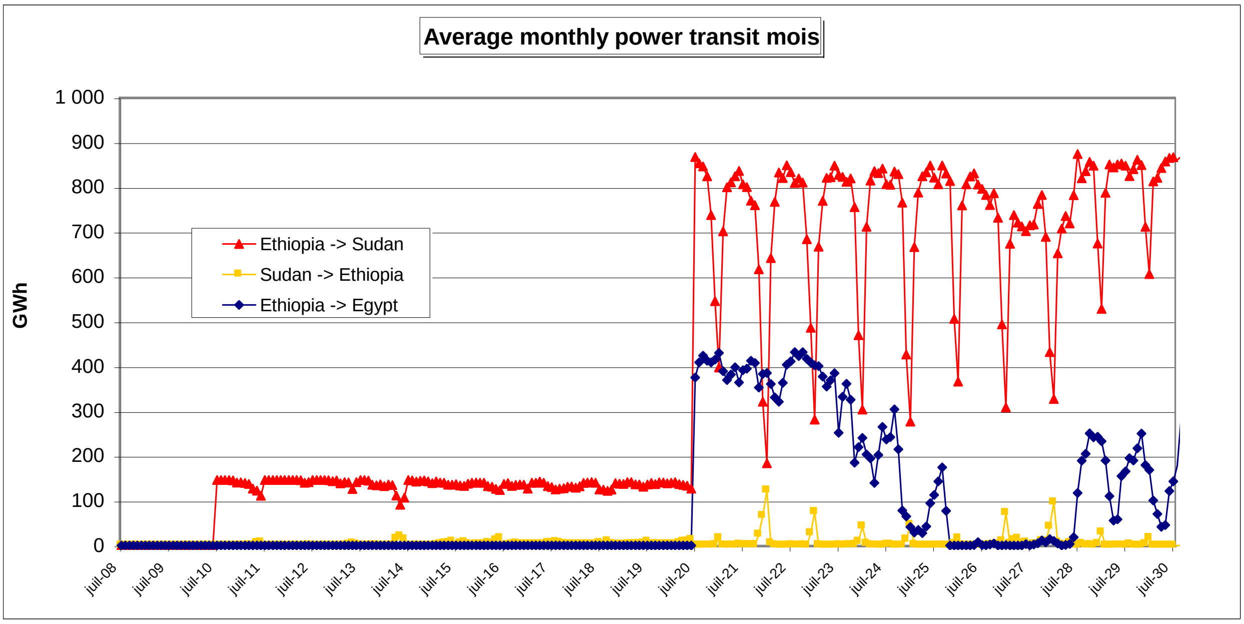

Figure 3.1-6 - Average monthly power transit - ET-SU: 1200 MW – ET-EG: 700 MW – Loose pool

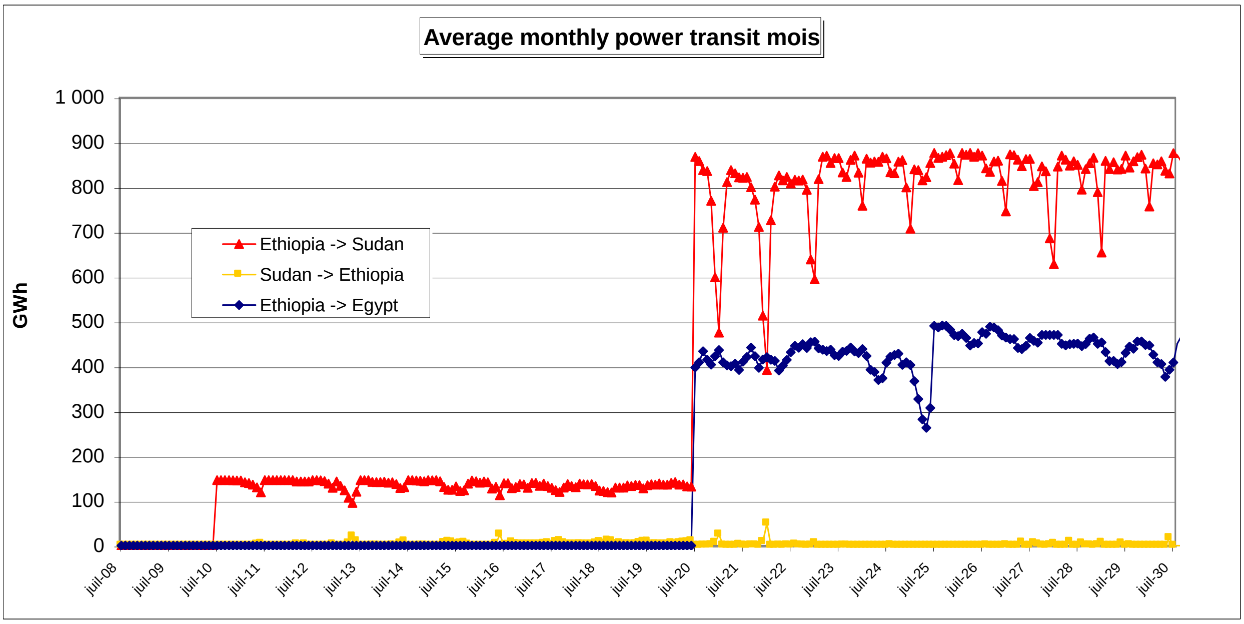

Figure 3.1-7 - Average monthly power transit - ET-SU: 1200 MW – ET-EG: 700 MW – Tight pool

3.2 Sensitivity to fuel cost: low fuel price projection

3.2.1 HYPOTHESIS

- Medium demand projection for Egypt, Ethiopia and Sudan.
- Low fuel price projection.

The simulations with SDDP show that the power transit are close to the ones observed with the medium fuel price projection:

3.2.2 700 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 700 MW CAPACITY TO EGYPT

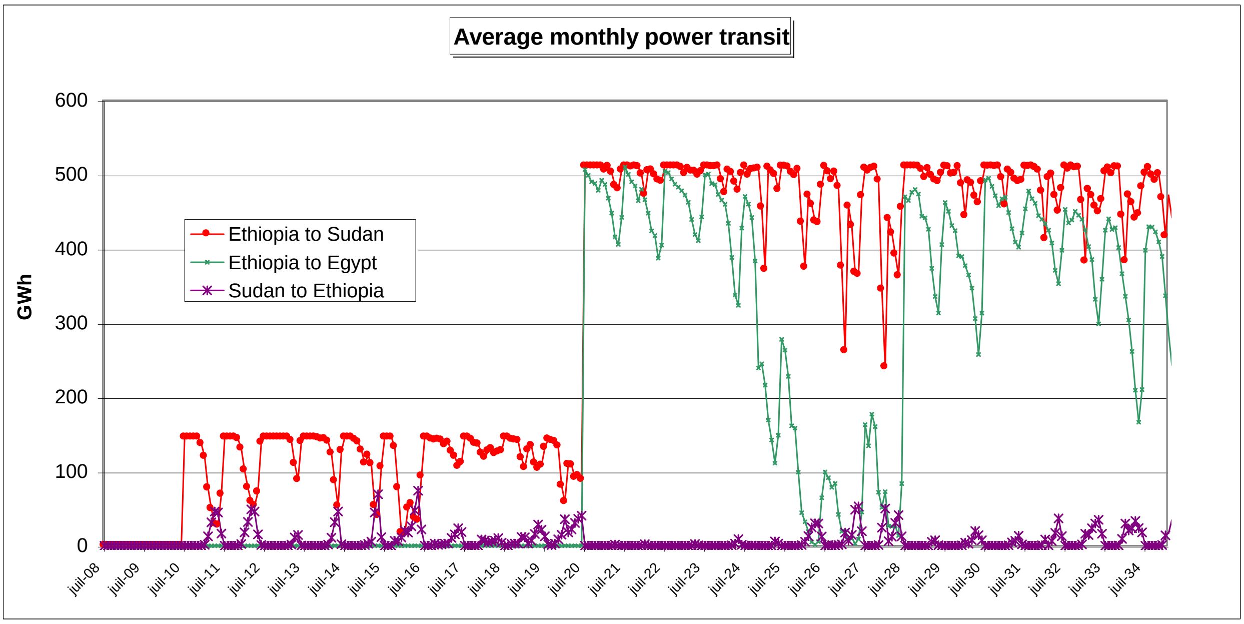

Figure 3.2-1 - Average monthly power transit – ET-SU: 700MW - ET-EG: 700 MW – Loose pool - Low fuel price projection

3.2.3 700 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 2 000 MW CAPACITY TO EGYPT

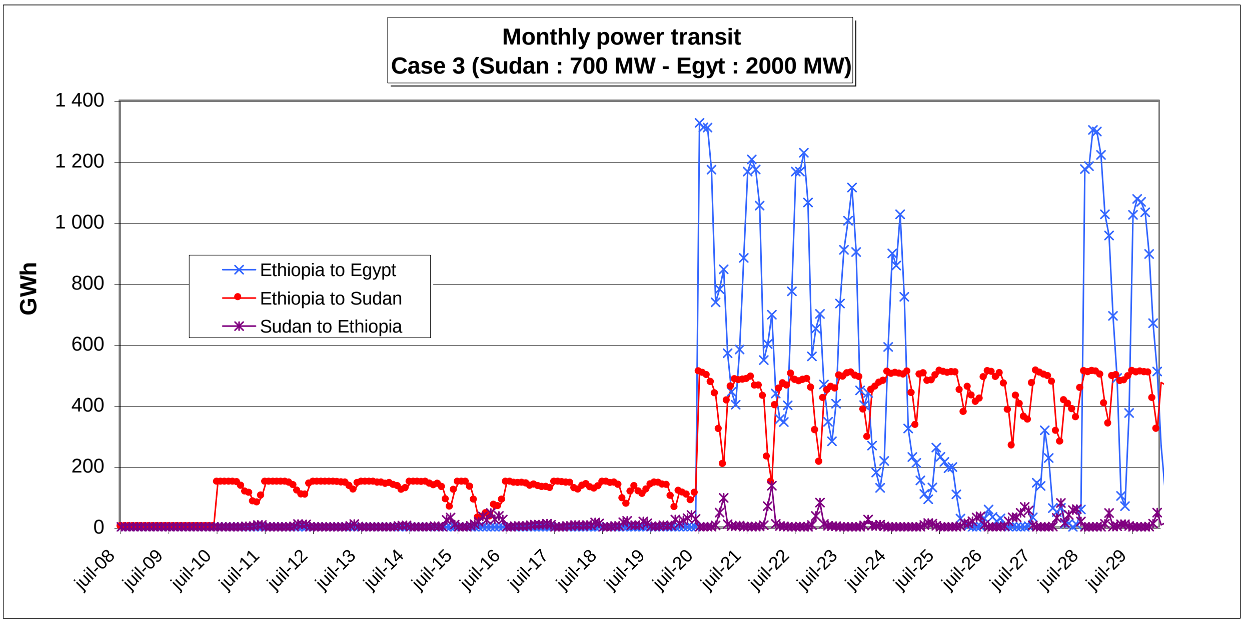

Figure 3.2-2 - Average monthly power transit - ET-SU: 700 MW - ET-EG: 2 000 MW – Loose pool - Low fuel price projection

3.2.4 1 200 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 2 000 MW CAPACITY TO EGYPT

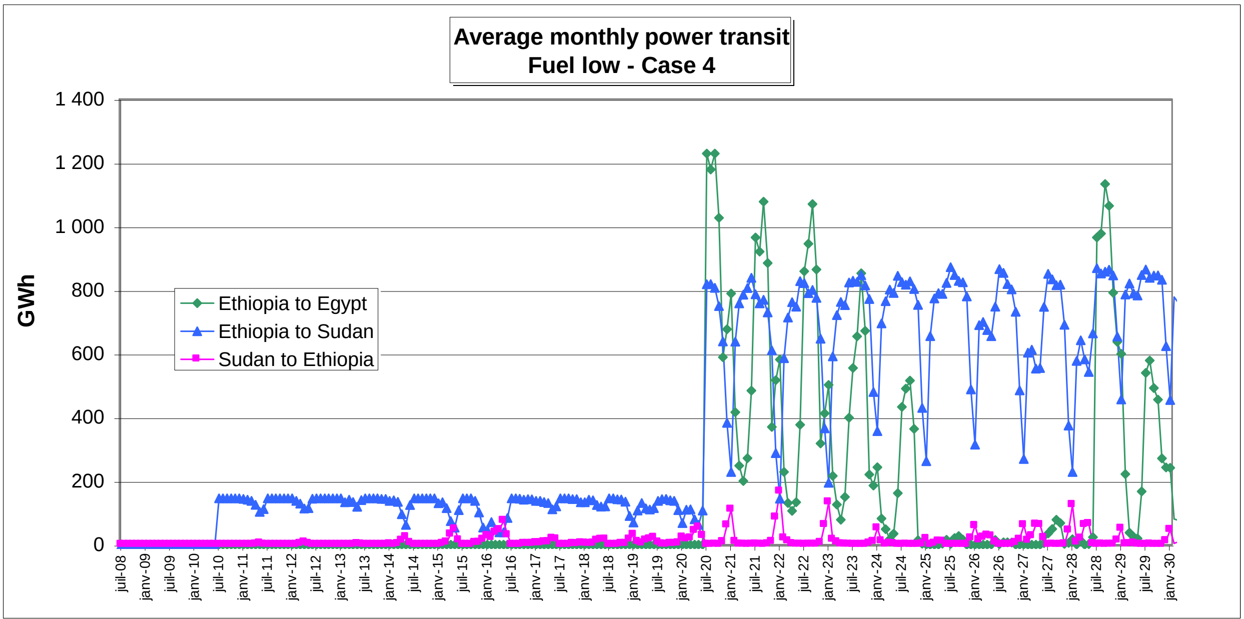

Figure 3.2-3 - Average monthly power transit - ET-SU: 1 200 MW - ET-EG: 2 000 MW – Loose pool - Low fuel price projection

3.2.5 1 200 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 700 MW CAPACITY TO EGYPT

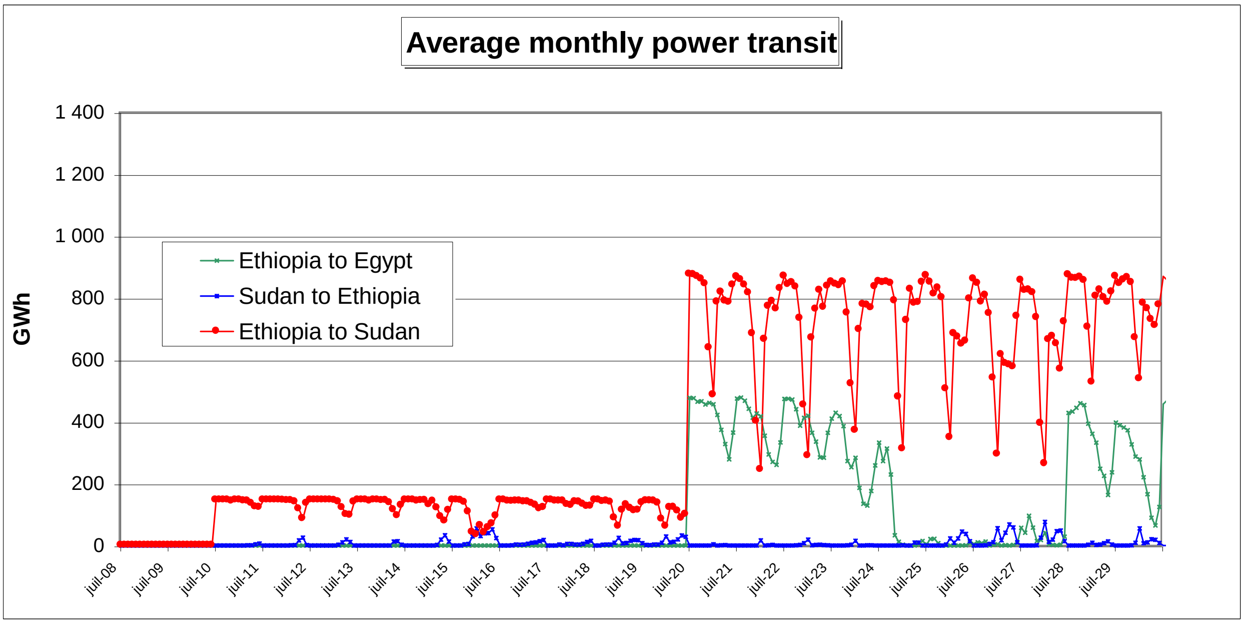

Figure 3.2-4 - Average monthly power transit - ET-SU: 1 200 MW - ET-EG: 700 MW – Loose pool - Low price fuel projection

3.3 Sensitivity to demand projection in Ethiopia: high demand projection

3.3.1 HYPOTHESIS

- Medium demand projection for Egypt and Sudan.
- High demand projection for Ethiopia.
- Medium fuel price projection.

3.3.1.1 700 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 700 MW CAPACITY TO Egypt

The average annual export to Sudan amounts to 5500 GWh, while only 1900 GWh are available for export to Egypt. After 2028, there is only very limited hydro surplus for Ethiopia to be exported to Egypt.

These values represent a significant reduction compared to the "medium demand projection".

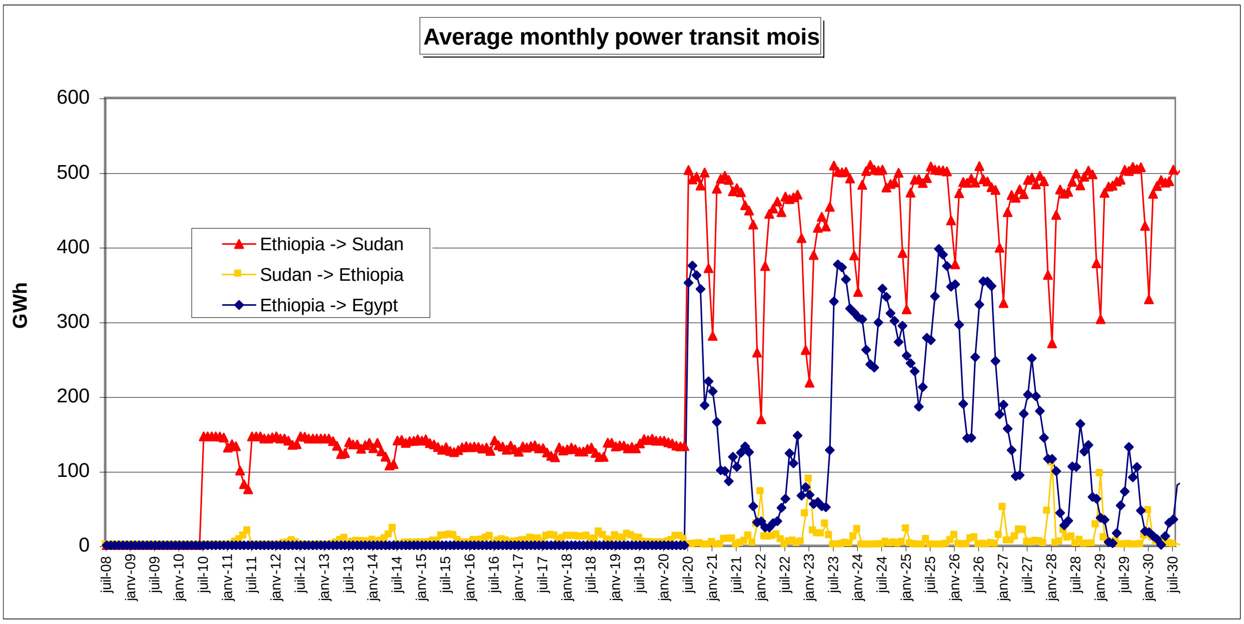

Figure 3.3-1 - Average monthly power transit - High demand projection for Ethiopia – ET-SU: 700 MW - ET-EG: 700 MW – Loose pool

3.3.2 1 200 MW export capacity between Ethiopia and Sudan, 700 MW capacity to Egypt

When the capacity of the interconnection to Sudan increases to 1200 MW, the average annual export to Sudan amounts to 8500 GWh, while only 700 GWh are available for export to Egypt.

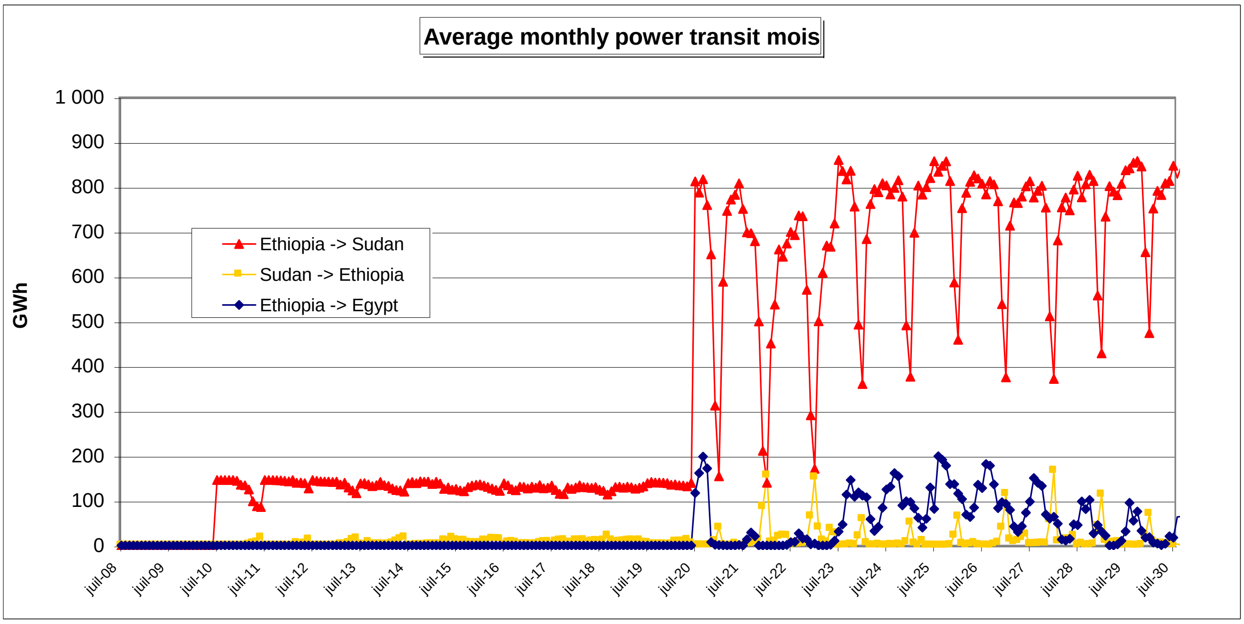

Figure 3.3-2 - Average monthly power transit - High demand projection for Ethiopia – ET-SU: 1200 MW - ET-EG: 700 MW – Loose pool

3.4 Sensitivity to demand projection in Ethiopia: low demand projection

3.4.1 HYPOTHESIS

- Medium demand projection for Egypt and Sudan.
- Low demand projection for Ethiopia.
- Medium fuel price projection.

3.4.2 700 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 700 MW CAPACITY TO EGYPT.

The average annual export to Sudan is equivalent to the reference case (with medium projection Ethiopian demand) (5800 GWh/year) while there is an increase of the average export to Egypt (4300 GWh/an instead of 3 600 GWh/year).

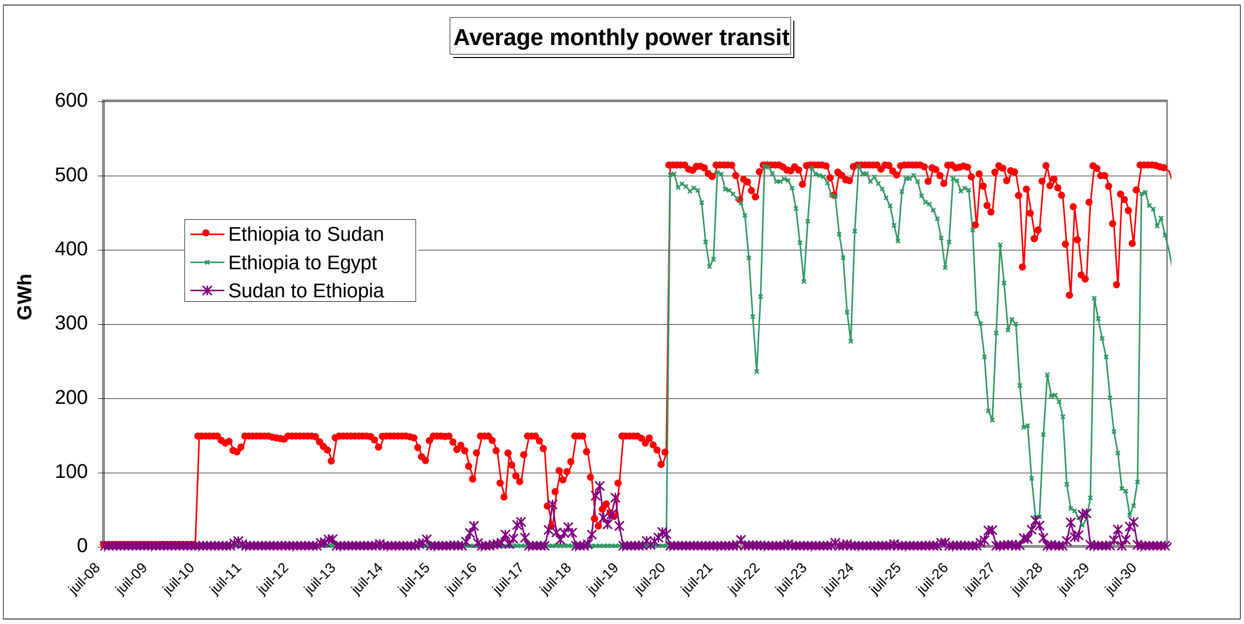

Figure 3.4-1 - Average monthly transit - ET-SU: 700 MW - ET-EG: 700 MW - Low demand projection for Ethiopia – Loose Pool

3.4.3 1 200 MW EXPORT CAPACITY BETWEEN ETHIOPIA AND SUDAN, 700 MW CAPACITY TO EGYPT.

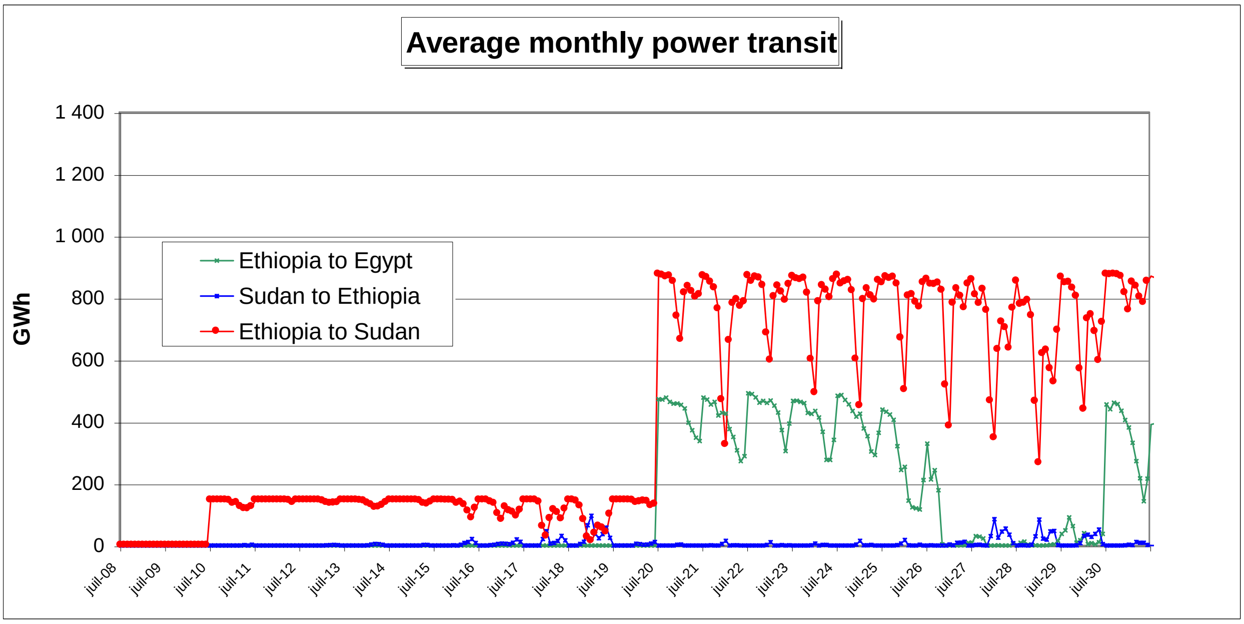

Figure 3.4-2 - Average annual power transit - ET-SU: 1200 MW - ET-EG: 700 MW - Low demand projection for Ethiopia – Loose pool

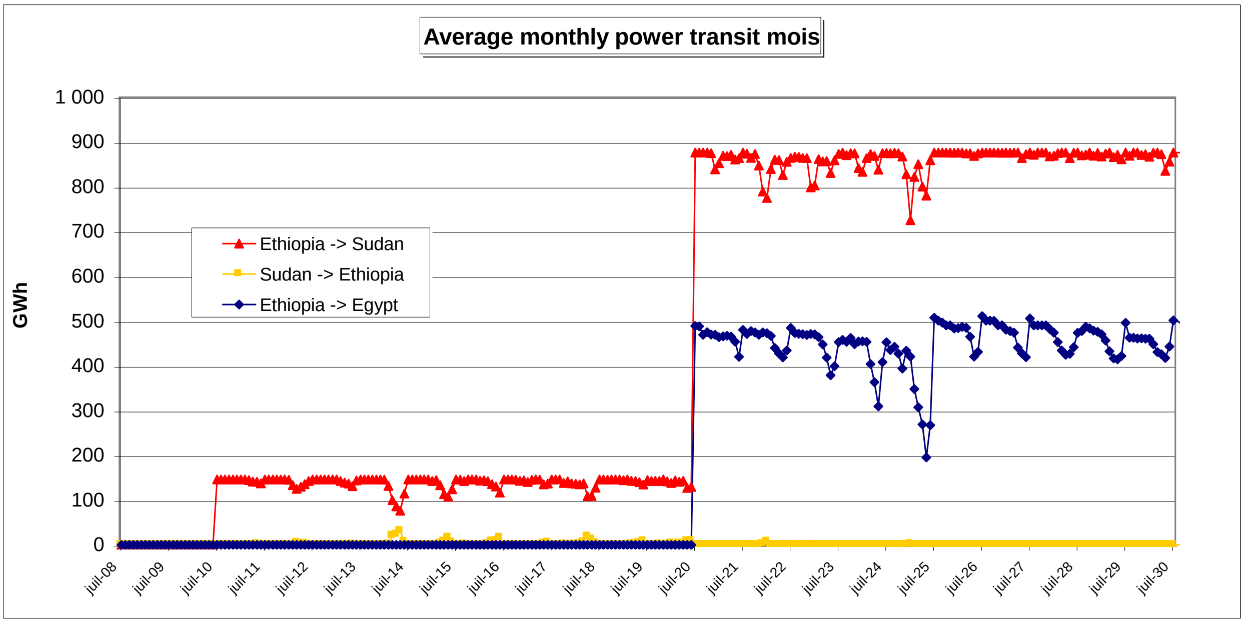

Figure 3.4-3 - Average annual power transit - ET-SU: 1200 MW - ET-EG: 700 MW - Low demand projection for Ethiopia – Tight pool

4 ECONOMIC RESULTS

4.1 Results including CO_2 savings

The following two tables present the Net Present Value and the BCR of the interconnection project including the CO2 savings (10 USD/t_{CO2} -10% discount rate – loose pool model):

Net Present Value (MUSD2006):

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High		3 160	2 830
Median	Median	1 700	2 080	1 680
Median	Low	910	1 310	730
Low	Median	1 720	2 350	1 830
High	Median	940	1 360	830

Table 4.1-1 - Net Present Value of the interconnection – CO2 = 10 USD/t

Benefit / Cost ratio (present worth of benefits / present worth of cost) :

Ethiopian demand	Fuel projection	SU : 700 MW, EG : 700 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Median	High		8.3	3.8
Median	Median	5.6	5.8	2.7
Median	Low	3.4	4.0	1.7
Low	Median	5.6	6.4	2.8
High	Median	3.4	4.0	1.8

Table 4.1-2 - Benefit to Cost of the interconnection – CO2 = 10 USD/t

4.2 Sensitivity to discount rate

The following table presents the main economic results for the loose pool model, Ethiopian demand projection, and medium fuel price projection:

	Discount rate = 8%		Discount rate = 12%	
$MUSD_{2006}$	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Present worth of generation savings	3 110	3 200	1 290	1330
Net Present Value	2 570	1 950	940	490
BCR	5.8	2.6	3.6	1.6

Table 4.2-1 - Economic results for 8% and 12% discount rate – Loose pool

The following table presents the main economic results for the tight pool model, Ethiopian demand projection, and medium fuel price projection:

	Discount rate = 8%		Discount rate = 12%	
	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW	SU : 1200 MW, EG : 700 MW	SU : 1200 MW, EG : 2000 MW
Present worth of generation savings	3 850	4 000	1 530	1 750
Net Present Value	3 320	2 760	1180	910
BCR	7.2	3.2	4.3	2.1

Table 4.2-2 - Economic results for 8% and 12% discount rate – Tight pool

5 TURBINED OUTFLOW

The average monthly turbined outflow over the 2008-2030 period is presented for Egypt, Ethiopia and Sudan in appendices :

- Appendix_M6_Vol2_outflow_EGYPT.pdf
- Appendix_M6_Vol2_outflow_ETHIOPIA.pdf
- Appendix_M6_Vol2_outflow_SUDAN.pdf