Nile Basin Initiative

Eastern Nile Technical Regional Office (ENTRO)

Power Market Integration Activity Contribution to Climate Mitigation

Consultancy Service

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Final Report

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Acronyms and Abbreviations

AM	Approved Methodology
BM	Build Margin
CCGT	combined cycle gas turbine
COP	Conference of the Parties
DNA	Designated National Authority
DOE	Designated Operational entity
EB	Executive Board
ENCOM	Eastern Nile Council of Ministries
ENSAP	Eastern Nile Subsidiary Action Program
ENTRO	Eastern Nile Technical Regional Office
EPA	Environmental Protection Agency
ERU	Emission Reduction Unit
ET	Emission trading
EU ETS	European Union Emission Trading Scheme
GDP	Gross Domestic Product
GHG	Greenhouse Gases
JI	Joint Implementation
KWh	Kilo watt hours
LULUCF	Land Use/ Land Use change and forestry
MBTU	Million British Thermal Units
MOP	Meeting of Parties
MW	Megawatts
NPV	Net Present Value
OM	Operating Margin

Executive Summary

The Eastern Nile Power Trade Project and the Ethiopia-Sudan Interconnection Project point towards a future where the energy markets in the Eastern Nile (EN) countries is transformed from three national independent markets into one regional integrated market. As a result, planners in the EN region will have the opportunity to compare under a single framework the two options for expanding electric generation capacity: hydropower; or burning of fossil fuels (oil, coal, or natural gas). These two options can be compared in their profitability, but also in their impact on the environment and in particular their impact on anthropogenic emissions of carbon dioxide, and hence on climate change mitigation. Without introducing connectivity between the three countries, the two options for electricity generation may not both be feasible for each country considered independently. The objectives of this study are: (i) Document how the Eastern Nile Power Trade Project and the Ethiopia-Sudan Transmission Line have integrated the energy markets in the three EN countries from three different national markets into one regional market; (ii) Analyze how the integration of the markets offers an opportunity for a different screening criterion to be used in selection of new energy sources for the region; and (iii) Illustrate with examples how integration of three markets can be used within the Clean Development Mechanism (CDM) process to secure certified emission reductions(CERs).

Based on analysis of the power development plans for the three countries, the Power Trade Study identified the potential for export of electricity from Ethiopia to Sudan and Egypt as a promising trade opportunity. Hydropower projects in Ethiopia are identified as power supply projects that rely on clean technology and have the potential to satisfy regional demand, beyond the national boundaries. The ENCOM has decided as a strategic choice to proceed with the option of 1200MW/2000MW transmission line for export of electricity from Ethiopia to Sudan/Egypt. Under this scenario, and assuming that Sudan uses coal as an alternative energy source we estimate a steady state emission reduction of 6.2 million tonnes of CO_2 per year. In recent years, the value of the CERs declined significantly, in response to trends in supply and demand, and due to uncertainty about future regulation environment. A current CER price of $1.3 translates into a yearly credit of about $8 million USD. Assuming that Egypt use natural gas as an alternative source of energy we estimate a steady state emission reduction of 4.6 million tonnes of CO_2 per year, and a yearly credit of about $6 million USD.

As an alternative scenario, we analyze a project recommended by the Power Trade Study involving connecting Egypt to the regional electricity grid, for the purpose of importing (700MW) of electricity from Ethiopia to Egypt instead of local generation from natural gas. This scenario may represent an economically attractive and relatively optimal candidate for engaging the CDM. The annual average price of natural gas declined significantly in recent years, by about 40% between 2007 and 2011. Under such conditions, it is not clear that export of electricity from Ethiopia to Egypt instead of local generation of electricity from natural gas would be an economically profitable activity. This conclusion can change, however, if credit due to potential CERs is added to the equation. Conditions such as these make it feasible to satisfy the "additionality" requirement, and hence successfully engage the CDM process. Additionality requires that the planned emission reductions would not occur without the additional incentive provided by the CERs. With an estimated steady state emission reduction of about 1.6 tonnes of CO_2 per year and a current CER price of about US $1.3, a project for exporting (700MW) of electricity from Ethiopia to Egypt could receive CERs with a current market value of about $2 million USD, per year.

1.0 BACKGROUND

The Eastern Nile Power Trade Project and the Ethiopia-Sudan Interconnection Project are two complementary ENSAP projects. The objective of the Eastern Nile Power Trade Project is to "promote Eastern Nile regional power trade through coordinated planning and development of power generation and transmission interconnection and creation of an enabling environment." The objective of Ethiopia-Sudan Interconnection project is to "facilitate, through high voltage transmission line, cross-border power trade between Ethiopia and Sudan, and thus optimize utilization of existing and planned generation capacity." While the former emphasizes institution building and policy formulation, the latter is concerned with infrastructure development and optimizing the use of electricity generation capacity. These two projects will have important impact on the region. Taken together, the two projects transform the energy market in the Eastern Nile (EN) countries from three national independent markets into one regional integrated market. The three EN countries have different types of natural resources that can be used for enhancing electric generation capacity: Ethiopia is relatively rich in hydropower potential; Sudan is relatively rich in oil resources; and Egypt is relatively rich in natural gas resources. Following integration of the three national markets into one regional market, planners in the EN region will have the opportunity to compare under a single framework the two options for expanding electric generation capacity: generating electricity from hydropower; or generating electricity from burning fossil fuels (oil, or natural gas). These two options can be compared in their profitability. However, another important way to compare these two options is relative to their impact on the environment and in particular their impact on anthropogenic emissions of carbon dioxide, and hence on the process of climate change. Without the connectivity introduced between the three countries, the two options for electricity generation may not both be feasible for each individual country taken separately.

The Power Trade project in the Nile Basin is an effort to promote regional power trade through coordinated planning and development of power generation and transmission. By facilitating cross border power trade, it will be possible to take advantage of complementary renewable resources and replace gas production in Egypt and oil production in Sudan with surplus renewable hydropower energy from Ethiopia. The concept is that the power trade would reduce the greenhouse gas (GHG) emissions as it would replace a carbon intensive fuel source with a renewable source. These greenhouse gases are the main drivers in global and regional climate change. A reduction in GHG may receive credit if the project can qualify for a Clean Development Mechanism under renewable energy registration.

The African continent has not attracted as many clean development mechanism investments (less than 2% of project activity) as other regions such as China, India, and Latin America. (Figure 1: Registered Clean Development Mechanism Projects around the World (Source: UNFCC) Figure 1). The reasons for this underperformance in Africa include lack of capacity, and limited awareness about the CDM in Africa. However, the post-2012 market (2nd commitment period of the Kyoto protocol) offers a very different picture, with Africa is emerging as a significant player.

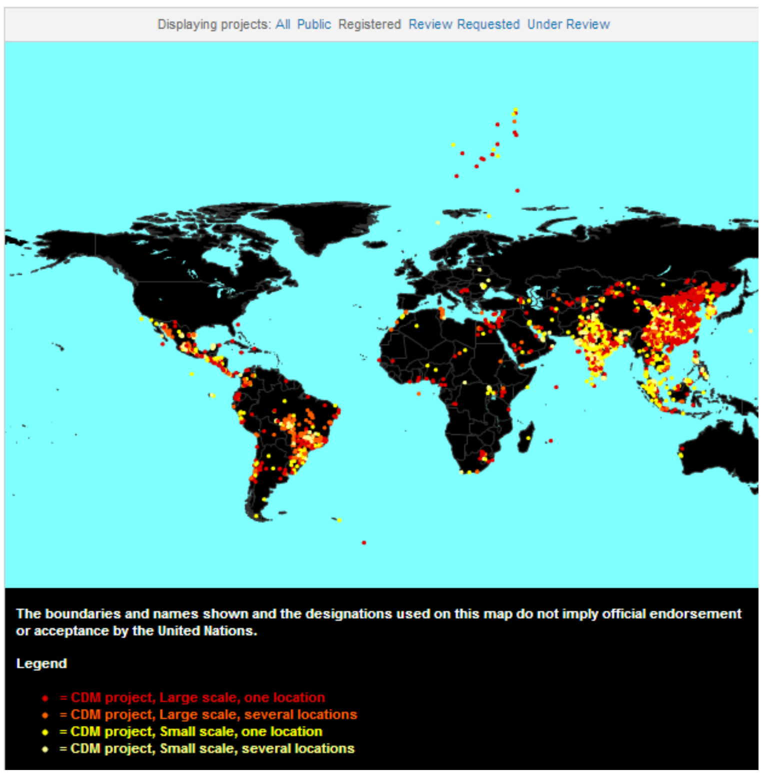

Figure 1: Registered Clean Development Mechanism Projects around the World (Source: UNFCC)

The Power Trade Project could be a first step in attracting investments and extend the benefits of CDM to Africa. The purpose of this study is to analyze, document and quantify the

Power Trade Project and provide a guideline for how it may apply for CDM registration. Ultimately the goal is to show how these efforts can be used to guide future activities.

2.1 Carbon Trading and the Kyoto Protocol

In 1997, the Kyoto Protocol was developed to place a limit on GHG emissions. The Protocol set targets for industrialized countries to reduce their domestic emissions by an average of 5% below 1990 levels in the period 2008-2012 (the first commitment period). The Kyoto Protocol, created a new commodity in the form of emission reductions or removals. Carbon, the principal green-house gas, is now tracked and traded like any other commodity on the "carbon market."

The Kyoto Protocol allows for three main flexible mechanisms of reducing one tonne of a greenhouse gas (GHG) emissions: Emissions Trading (ET), Joint Implementation (JI) and the Clean Development Mechanism (CDM). While different in operation, these three mechanisms are based on the same principle: help industrialized countries decrease the volume of GHG regardless of where the reduction is implemented at the lowest cost possible. JI and the CDM are called "project-based" mechanisms because they fund actual projects whereas ET is a transfer of from one country to another.

The Kyoto Protocol entered into force in February 2005 and the carbon units are tracked and recorded through a registry system. The carbon units are categorized as follows based on the flexible mechanism implemented:

- A Removal Unit (RMU) is based on land-use/land-use change and forestry (LULUCF)
- An Emission Reduction Unit (ERU) is generated by a joint implementation project in which a developed country buys a credit from projects in transitional economies
- A Certified Emission Reduction (CER) is generated from a clean development mechanism project in which a developed country buys a carbon credit from a sustainable project in a developing nation.

In the past decade Africa did not engage the CDM to any significant degree. However, the post-2012 market (2nd commitment period of the Kyoto protocol) offers a very different picture. China accounted for 43% of post-2012 CERs in 2011. Other Asian countries accounted for 25% of the volume. Africa is emerging as a significant player, accounting for 21% of post-2012 CERs.

The following are a few examples of projects which are eligible to receive certified carbon credits:

1. Renewable Energy Projects. Use sources of energy that are readily available and quickly replenished by nature such as hydro, wind and solar. To qualify, the projects must need the revenue from carbon credits to become economically viable and emissions cannot be released elsewhere as a result of the renewable power installation. (Feed-in tariffs subsidized by the national government are usually not eligible)

2. Forestry projects. Use the carbon sequestration capacity of trees and, thus, earn carbon credits. There is a collaborative initiative for Reducing Emissions from Deforestation and Forest Degradation (REDD) in the developing countries.

3. Sustainable agriculture. Uses adapted grazing land management techniques to reduce emissions related to livestock production and other sustainable farming techniques which facilitate increased carbon storage in soil.

4. Low-emission consumer goods. Allow project developers to earn carbon credits offset from the emissions prevented and sell these credits to generate a return on their investment. The funds they earn are used to pay back investors and to keep the project financially feasible.

2.2 Clean Development Mechanism (CDM)

The three main sectors of the carbon trading market are rooted in (1) European Union Emission Trade Scheme (EU ET S) and the associated European Union Allowances (EUA) issued and distributed by the European Union to the different countries, as the main tool for establishing the European Cap and Trade mechanism; (2) The CDM and the associated CERs; and (3) The voluntary offset markets where companies, individuals, and events buy emission reductions certificates to reduce their carbon footprint, and the associated Voluntary Emissions Reductions (VERs). The size of these three market sectors are quite different. In 2011, the last year for which data is available, trade in secondary EUAs, CERs and VERs accounted for (77%, 19%, <1%). CERs can be sold both for countries attempting to satisfy Kyoto Protocol obligations, and corporations attempting to remain within their EU emissions caps. As a result CERs offer the most attractive instrument to be engaged by power projects on the Nile basin.

The (CDM) would be most suitable for Egypt, Sudan, and Ethiopia, especially for the hydro power generation, power trade projects currently under consideration and thus warrant main focus in this report. CDM is an important part of the Kyoto Protocol as it has an explicit mandate to promote sustainable development (unlike JI or ET) and that it directly involves developing countries in reducing greenhouse gas emissions.

The CDM was established under Article 12 of the Kyoto Protocol, and allows a country with an emission-reduction commitment to "effectively" implement an emission-reduction project in different (usually developing) countries. Such projects can earn saleable certified emission reduction (CER) credits, (each CER is equivalent to one tonne of CO_2 reduction). These CERs can in turn be sold to industrialized countries or corporations for use in accounting of their emission reduction and can be counted towards meeting Kyoto targets. This is the first global, environmental investment and credit scheme of its kind, providing standardized emissions offset instrument, CERs.

The CDM is often regarded as the most efficient and effective long term method to reduce and offset GHG emissions. It is a system by which low-cost carbon emission reductions in developing countries can be implemented and made viable with the help of funds from developed countries in exchange for offset credits. CDM helps support projects undertaken in developing countries and are intended to meet two overall objectives: first, to address the sustainable development needs of the host country; and second, to reduce/limit carbon emissions to generate CERs that are deemed valid for developed countries' emission reduction targets for 2008-2012 and thus increase their compliance options.

CDM Engagement Steps

The specific steps for engagement of the CDM are:

(i) A project participating in the CDM has to first be approved by a designated national authority as contributing to the country's sustainable development objectives;

(ii) Formal registration by the Executive Board of the CDM has to be secured;

(iii) The project has to establish a baseline scenario to determine emissions levels assuming that the project is not developed. This is often called "Quantification";

(iv) The project has to meet the "additionality" requirement which establishes that the planned reductions would not occur without the additional incentive provided by the CERs credits. The CDM should only generate carbon credits from activities beyond business-as-usual, i.e. from projects that were built only because of the extra income from selling carbon credits; and

(v) A crediting period must be determined and the project must demonstrate "permanence" The project has to be monitored over a pre-specified accounting period to determine the difference between actual emissions and the corresponding emissions under the baseline assumptions. This difference is then credited to the project as a CER. The emissions reductions are verified during the crediting period and must show that there is indeed a reduction in emission and not "leakage" or displacement of carbon emissions to a different location.

<u>CDM story in numbers</u>

According to the CDM watch organization, "The first CDM project was registered on 18th November 2004, and the next ones followed rapidly. In 2010, the 2,000th project was registered. Now, with another 2,500 projects at the validation stage, the mechanism is expected to generate more than 2.9 billion CERs in the first commitment period of the Kyoto Protocol. The UNFCC celebrated the issuance of the billionth certified emission reduction credit of CO_2 equivalent offset. They present the CDM story in numbers as follows:

- 4,600 CDM projects registered since 2004
- 1,900 small scale projects
- 3,200 renewable energy projects (120 GW installed capacity)
- 161 countries-76 have registered CDM projects, CER's issued to projects in 50 countries

- $215 billion invested in CDM projects

Carbon Funds

Many specialized businesses serve as Carbon Funds; they are agents that buy credits on behalf of clients (government, business etc.) seeking CERs. Renewable energy sources such as biomass and hydropower are generally more interesting to carbon funds.

Table 1 is a list of important carbon funds that apply to hydropower that ENTRO may consider applying or partnering. The Nairobi Framework (NF) was initiated in order to help countries in sub-Sahara Africa improve their level of participation in CDM. The UNFCCC secretariat is the facilitator of the NF and works to enhance the regional distribution of CDM projects. Some initiatives already undertaken include: The African Carbon Forum, the Workshop on Accelerating Low Carbon Energy in Africa through Carbon Finance, and a Regional Distribution session.

Table 1: List of Carbon Funds that may finance Hydropower-related CERs in Africa

Carbon Fund Name	Project Types/Notes
Austrian JI/CDM	Hydropower, clean biomass
Netherlands CDM	Hydropower, clean biomass
Danish CDM	Hydropower, clean biomass
African Carbon Asset Development (ACAD)	Various projects in Africa, managed by UNEP
African Carbon Support Program (ACSP)	Various projects, provide technical support, managed by AfDB
Carbon Fund for Africa (FCA)	Various Projects
African Biofuels and Renewable Energy Fund (ABREF)	Hydropower
UNDP MDG Carbon Facility	Must contribute to MDG; for

countries with no CDM project;

2.0 STUDY OBJECTIVES AND TASKS (From TOR)

The three main objectives of this study are:

(i) Document how the Eastern Nile Power Trade Project and the Ethiopia-Sudan Transmission Line have integrated the energy markets in the three EN countries from three different national markets into one regional market;

(ii) Analyze how the integration of the markets offers an opportunity for a different screening criterion to be used in selection of new energy sources for the region; and

(iii) Illustrate with examples how integration of three markets (Ethiopia, Sudan and Egypt) can be used within the CDM process to secure certified emission credits.

The tasks of this study are:

1. Review the power development plans of the EN countries and develop power demand trajectories

2. Identify how the regional power trade project can assist in filling the power demand in the EN countries according to the power trade studies. The consultant shall identify opportunities as well as peak demand complementarities and other opportunities as well.

3. Develop necessary tools to estimate carbon emissions due to power development trajectories with and without the regional power trade options developed in the power trade studies.

4. Estimate carbon emission savings that integration of the EN power market will provide

5. Make recommendations for further carbon financing engagement

6. Conduct a preliminary Economic appraisal on the carbon emissions reduction financing opportunities

7. Prepare road map for carbon trade engagement.

3.0 METHODOLOGY OF THIS STUDY

The proposed methodology for this study consists of the following four steps:

3.1 Step:1 Review of power development plans and Power Trade Studies of the EN countries

The first step in this study will consist of

(i) A thorough review of national power development plans to define demand trajectories, and proposed supply projects for each of the EN countries;

(ii) A review of the Power Trade Studies in order to identify mechanisms that have already been discussed on how to match demand projections and supply projects at the regional scale; and

(iii) An identification of power supply projects that rely on clean technology and have the potential to satisfy regional demand, beyond the national boundaries.

3.2 Step 2: Select an "ideal" scenario as specific example for illustrating how integration of the national energy markets into a regional market can facilitate engagement of the Clean Development Mechanism (CDM).

In the second step of the proposed methodology, we will seek to select an "ideal" example for illustrating how integration of the national energy markets into a regional market can facilitate engagement of the CDM. For this purpose, we will

(i) Identify different possible scenarios of regional power development integration as candidates for engagement of the CDM, based on the review in Step 1;

(ii) Develop an objective screening criterion for comparing and ranking of the different scenarios; and

(iii) Apply the screening criterion to select a relatively "ideal" scenario for illustrating how integration of energy markets can facilitate engagement of the CDM

3.3 **Step 3:** Estimate the potential reduction in carbon emission due to the adoption of a clean development option at the regional scale.

In Step 3 we will estimate the carbon emissions assuming the clean power development choice made possible through regional integration, and the default choice for power development option. The difference between the two estimates will define the potential carbon emission reduction.

3.4 **Step 4:** Provide a road map for engagement of the CDM process , economic analysis, and recommendations

The estimates of the reduction in carbon emissions from adopting clean development option will be used to recommend a specific road map for engaging the CDM. Economic analysis will be carried out to estimate the financial costs and potential returns for the specific scenario of regional power development. Although we will put some efforts into estimation of the financial and non-financial benefits of the proposed scenario, our main efforts will focus on estimation of the financial returns from the CERs given current market conditions. We will conduct a preliminary evaluation on financing opportunities to fund any project with the aim of reducing carbon emissions. We will identify promising opportunities (in both mitigation and adaptation funding mechanisms) and outline a roadmap for the CDM engagement process.

4.0 APPLICATION OF METHODOLOGY: Estimation of Power Market Integration Activity Contribution to Climate Mitigation

4.1 **Step 1**: Review the national power development plans and Power Trade Studies of the EN countries.

Egypt and Ethiopia are similar in size, with about 1 and 1.1 million square kilometers, respectively and a population of 84 and 91 million respectively. Sudan is somewhat larger with about 1.9 million square kilometers (of these, 616 thousand km2 form the independent nation of South Sudan) and holds less than half the population of the other two nations. Table 2 provides a summary of basic information about population, economies and the electric sector in Egypt, Ethiopia, and Sudan. Several important observations can be made. Ethiopia already has the largest population in the region, and the fastest population growth; in addition, it has the fastest growing economy, and the lowest level of current electricity consumption per person. These facts combined together support the likelihood that the demand for electricity is likely to grow the fastest in Ethiopia, especially if the current indicators persist into the future. This prediction is an important factor that will be addressed later.

Table 2: Basic Information about Population, Economy, and Electric Sector in Egypt, Sudan, and Ethiopia (CIA World facts book)

	Egypt	Ethiopia	Sudan
Population in millions (2012)	84	91	34
Population growth (2012)	1.9%	3.2%	1.9%
GDP per capita (2012)	$6600	$1100	$2800
GDP growth (2011)	1.8%	7.5%	-3.9%
Consumption of electricity (KWh, 2009)	115.8 billion	3.6 billion	4.6 billion
Consumption of electricity per capita (KWh per person, 2008)	1400	45	120
Production of electricity (KWh, 2009)	136.6 billion	4.0 billion	6.5 billion
Anticipated annual increase in demand for electricity in the future	5.4%	10.9%	5%

Table 3: Power development Plans in Egypt, Ethiopia, and Sudan 2006-2030 (Source: Power Trade Study reports, updates by countries, and minor modifications to account for separation in Sudan)

Year		2006	2007	2008			2009			2010			2011				2012		
Egypt	Peak load (MW)	18400	19600	20900			22260			23600			25060				26550		
	Total capacity (MW)	20600	22200	24500			26400			27900			29860				31850		
	Added Capacity (MW)			2000	150	60	1000	700	130	1350	10	160	750	1000	5	200	1750	40	200
	Type			CCGT	Solar	Hydro	CCGT	Steam	Wind	Steam	Hydro	Wind	CCGT	Steam	Hydro	Wind	Steam	Hydro	Wind
Ethiopia	Peak load (MW)			820			970			1120			1270				1420		
	Total capacity (MW)		730	800			1900			2000			2940				4150		
	Added Capacity (MW)						1100			100			900		40		1210		
	Type						Hydro			Hydro			Hydro		Wind		Hydro		
Sudan	Peak load (MW)	1220	1920	2580			3400			4180			4480				4970		
	Total capacity (MW)	870	1200	1600			4100			5270			5760				6300		
	Added Capacity (MW)		330	400			2500			1170			290	30	270		380	160	
	Type		comm	comm			comm			comm			Therm	Hydro	comm		Therm	comm	

Year		2013			2014			2015			2016				2017		
Egypt	Peak load (MW)	28120			29800			31560			33250				35000		
	Total capacity (MW)	34400			36700			38850			41150				43600		
	Added Capacity (MW)	1000	1350	200	1000	1100	200	500	450	1000	500	1300	300	200	500	1750	200
	Type	CCGT	Steam	Wind	CCGT	Steam	Wind	CCGT	Steam	Nuclear	CCGT	Steam	Solar	Wind	CCGT	Steam	Wind
Ethiopia	Peak load (MW)	1580			1770			1970			2130				2300		
	Total capacity (MW)	4790			5200			6680			6680				6680		
	Added Capacity (MW)	640			410			1480									
	Type	Hydro			Hydro			Hydro									
Sudan	Peak load (MW)	5100			5350			5600			5900				6200		
	Total capacity (MW)	6600			6850			7490			7790				8230		
	Added Capacity (MW)	300			210	40		380	340	-80	300				440		
	Type	hydro			Therm	comm		Therm	Hydro	retire	Hydro				Therm		

Year		2018				2019			2020				2021			2022			2023	
Egypt	Peak load (MW)	36900				38880			40960				42960			45050			47250	
	Total capacity (MW)	46350				48850			51200				53850			56450			59150	
	Added Capacity (MW)	500	1750	300	200	1000	1300	200	500	650	1000	200	500	1950	200	500	1000	1000	500	2200
	Type	CCGT	Steam	Solar	Wind	CCGT	Steam	wind	CCGT	Steam	Nuclear	wind	CCGT	Steam	wind	CCGT	Steam	Nuclea r	CCGT	Steam
Ethiopia	Peak load (MW)	2490				2690			2910				3150			3410			3690	
	Total capacity (MW)	6680				6680			6680				6680			7380			7680	
	Added Capacity (MW)															700			300	
	Type															hydro			hydro	
Sudan	Peak load (MW)	6600				6700			7200				7600			7900			8250	
	Total capacity (MW)	8610				9340			10500				11100			11100			11350	
	Added Capacity (MW)	380				450	280		950		200		600						250	
	Type	Therm				Therm	Hydro		Therm		comm		Therm						Therm	

Year		2024			2025	2026		2027		2028		2029		2030	
Egypt	Peak load (MW)	49550			51823	54200		56700		59300		62000		64900	
	Total capacity (MW)	61550			64200	66950		69700		72450		75200		77950	
	Added Capacity (MW)	500	900	1000	2650	1750	1000	1750	1000	1750	1000	1750	1000	1750	1000
	Type	CCGT	Steam	Nuclear	Steam	Steam	Nuclear	Steam	Nuclear	Steam	Nuclear	Steam	Nuclear	Steam	Nuclear
Ethiopia	Peak load (MW)	3990			4320	4670		5050		5460		5910		6400	
	Total capacity (MW)	8170			8570	9470		10220		11580		11800		12240	
	Added Capacity (MW)	490			400	900		750		1350		220		440	
	Type	Hydro			Hydro	Hydro		Hydro		Hydro		Hydro		Hydro	
Sudan	Peak load (MW)	8650			8950	9350		9750		10250		10650		11100	
	Total capacity (MW)	11450			11900	12250		12600		13000		13900		13900	
	Added Capacity (MW)	100			450	350		350		400		900			
	Type	Therm			Therm	Therm		Therm		Therm		Therm			

Power Development Plans

Table 3 summarizes the basic features of the power development plans for Egypt, Ethiopia, and Sudan. These plans are summarized based on the information in the Power Trade Study and minor modifications by the consultant to account for the independence of South Sudan. The observations and recommendations in this report are not sensitive to these modifications.

Several observations can be made from Table 3:

(i) There are great differences in the current rates of electricity consumption in the region form 45 KWh per person in Ethiopia to 120 KWh per person in Sudan and 1,400 KWh per person in Egypt;

(ii) The aggregate demand for electricity in the region is likely to increase by a factor of about 2.5 (from a power load of about 33,000 MW to 82,000MW). This additional demand will have to be satisfied by adding new capacity from combination of thermal power generation options, hydropower, in addition to other renewable sources;

(iii) Egypt which already exploited most of its hydropower potential will follow in the future a diversified expansion strategy that features (a) new renewable sources such as nuclear, solar, and wind; (b) traditional sources such as steam turbines and thermal units; in addition to (c) increasing reliance on abundant natural gas as a source of energy using Combined Cycle Gas Turbines (CCGT) units. These CCGT units emit greenhouse gases and produce electricity at a relatively high cost which is a function of natural gas price;

(iv) Ethiopia, which enjoys the largest untapped potential of hydropower in the region (total potential estimated at 30,000 MW), will follow in the future an ambitious strategy of accelerated growth in developing this hydropower potential, for domestic consumption as well as export to the region. Hydropower is by far the largest source of electricity in Ethiopia, now and into the future;

(v) Sudan's situation lies in the middle, both geographically as well as in the level of exploitation of its hydropower potential. By roughly 2020, Sudan is anticipated to develop most of its hydropower potential. Additional capacity after that date will rely on thermal generation units, which produce electricity at relatively the highest cost in the region of about (0.13$ per KWh in 2006); and

(vi) Ethiopia is the country with the largest excess capacity relative to domestic demand (defined here as (capacity –peak load)/peak load. Without exports, the relative excess capacity in 2030 is anticipated to be about 90%. This fact makes Ethiopia the most likely candidate to export electricity in the region.

Based on a thorough the analysis of the power development plans for the 3 countries, the Power Trade Study identified the potential for export of electricity from Ethiopia to Sudan and Egypt as a potential trade opportunity that deserved further investigation. Hydropower projects in Ethiopia are identified as power supply projects that rely on clean technology and have the potential to satisfy regional demand, beyond the national boundaries.

In the Eastern Nile Power Trade Program Study, four interconnection plans (including both AC and DC options) were presented to connect the electrical networks in Ethiopia, Sudan, and Egypt. Such physical interconnections should make it feasible to export electricity from Ethiopia to Egypt. It was concluded that "to transmit a huge power over a long distance, such as between Ethiopia and Egypt, DC solutions are the less expensive ones." The Power Trade Study estimates that transmission costs under the DC option would range from about 21 USD/MWh to about 28 USD/MWh. The associated investment costs were estimated to be about USD 760 Million.

Financial Costs and Benefits from Interconnection

The basic idea behind the perceived opportunity for export of electricity from Ethiopia to Sudan and Egypt can be explained by reviewing Figure 1.3.1 from Module 6: Volume 2 of the Power Trade Study report.

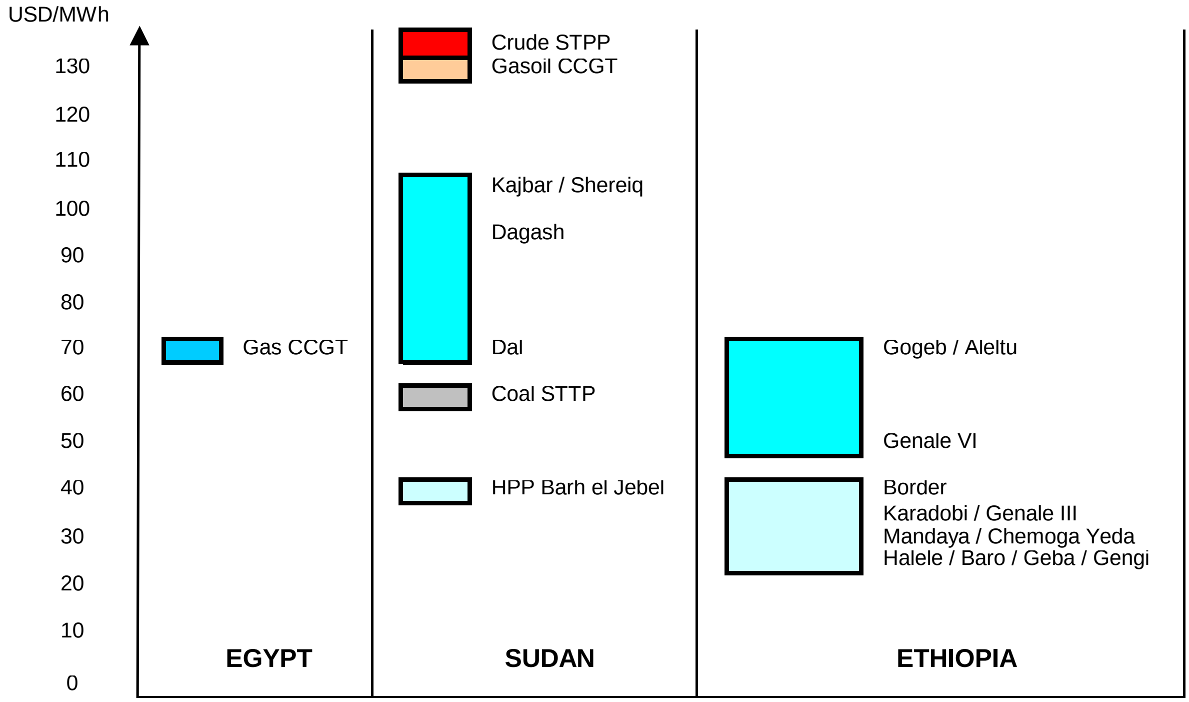

Figure 2: Comparison of economic generation costs in the different generation mixes (6 000 hours/ year) - Year 2030 - Medium fuel price scenario (60 USD/bbl) - 10% discount rate

(Figure 1.3. 1 , from Module6-Vol 2 of the Power Trade Study Report)

Ethiopia is anticipated to produce electricity from hydropower in the decade from 2020 to 2030 at a cost of about $25-40 per MWh. During that same decade, Egypt plans to produce electricity from CCGT at a cost of about $70 per MWh (double the corresponding cost of hydropower in Ethiopia), and Sudan plans to produce electricity from thermal sources at a cost of $130 per MWh (double the corresponding cost for CCGT in Ethiopia). Hence, if electricity can be transmitted between the three countries for a reasonable cost, significant regional savings can be achieved by replacing generation from thermal units in Sudan and CCGT units in Egypt with hydropower produced in Ethiopia. An efficient mechanism can be designed to share these savings between the countries. These regional savings come primarily from savings in fuel costs. hence, any analysis of the opportunity for electricity export from Ethiopia to Sudan would be somewhat sensitive to fluctuations in prices of oil and natural gas.

There have been important trends in the cost of fuel since 2007, the date of the Power Trade Study. The price of natural gas declined significantly by about 40% from 7.1 USD per MBTU, which is the average for 2007, to 4.0 USD per MBTU, which is the average for 2011. However, during the same period, the price of oil moved in the opposite direction increasing by about 30% from 72 USD per barrel, which is the average for 2007, to 95 USD per barrel, which is the average price for 2011. These trends will have important implications to the analysis presented in the following sections.

Different models were used to optimize the financial gains from the transfer of electricity from Ethiopia to Sudan and Egypt given a set of assumed constraints describing hydrology, electricity interconnections, energy prices, levels of demand, and discount rates. Three options were considered in details, as described in Table 4 below (700MW/700MW; 700MW/1200/MW; and 2000MW/1200MW).

Table 4: Investment cost of the Interconnection Options

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 , from Module 6-Vol 2 of the Power Trade Study Report)

Two observations are important to make here. First, the difference between the unit cost of generating of electricity from hydropower in Ethiopia and the unit cost of generating electricity by thermal units in Sudan is significantly larger than the corresponding difference between hydropower in Ethiopia and electricity from natural gas in Egypt, (See Figure 2). Second, the investment cost for extending transmission lines to cover Egypt is rather high compared to the cost for Ethiopia-Sudan interconnection, as seen in Table 4. As a result the optimization model used in the Power Trade Study selects the option that maximizes Ethiopia's export to Sudan and minimizes Ethiopia's export to Egypt (1200MW/700MW). However, the option of (700MW/700MW) ranks a close second, aided by the fact that it has the lowest investment cost. (See Table 5and Table 6).

Table 5: Net Present Value of the interconnection – 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	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

(Table 1.5 5, from Module 6-Vol 2 of the Power Trade Study Report)

Table 6: Benefit to Cost Ratio – Loose pool model

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

(Table 1.5 6, from Module 6-Vol 2 of the Power Trade Study Report)

In the Power Trade Study, the option of importing electricity from Ethiopia to Egypt was studied considering only technical and economic factors without detailed consideration of how to engage a carbon trade process such as that facilitated by the CDM. In this study, we will focus on the impact of adding considerations for such opportunity on the overall feasibility of this option, including feasibility of the physical infrastructure investment in a new interconnection project linking Ethiopia, Sudan, and Egypt.

4.2 Step 2: Selection of an "ideal" scenario as specific example for illustrating how integration of the national energy markets into a regional market can facilitate engagement of the Clean Development Mechanism (CDM)

To illustrate how integration of the markets in the EN countries can be used within the context of the CDM process to secure certified emission credits, we first describe an abstract example involving two countries A and B. In this example: Country A has several options to satisfy energy demand including (1) a local fossil-fuel based or "grey" option, and (2) a regional renewable or "green" option that involves importing electricity from its neighbor B. Country B produces excess green energy. Country A engages a transmission project in the CDM process to receive credit (CER) for choosing the green renewable regional option of importing electricity from Country B instead of adopting the local grey option and releasing carbon to the atmosphere. Under this scenario everyone benefits: Country A gets financial credit proportional to the CERs and Country B successfully markets its excess electricity energy. In addition, the region enjoys collaboration and greater stability through stronger ties between countries with conflict and the global environment receives less carbon pollution. In order for this scenario to work, however, Country A has to engage the CDM early on in the process and satisfy all the requirements to receive CERs.

Considerations for CDM Engagement

Two considerations are important regarding the process of engaging the CDM:

First, the process is designed to engage countries and not a group of countries. Recall that in Section 2 we outlined the first step in engaging the process as: "A project participating in the CDM has to first be approved by a designated national authority as contributing to the country's sustainable development objectives." Hence, for projects in the Nile basin that are interested in the CDM process, a specific country has to take the responsibility for engaging the CDM. Most of the analysis in the Power Trade Study was carried from a regional perspective that outlines benefits costs of investments in regional power trade. In order to engage in the CDM process, however, regional projects need to be partitioned into subprojects that are sponsored by one of the countries.

Second, the “additionality” requirement provides a strong constraint in how the CDM works. “The project has to meet the “additionality” requirement which establishes that the planned reductions would not occur without the additional incentive provided by the CERs credits.” In essence, the CER is intended to make up for the opportunity cost of pursuing a “cleaner” project. This is an extremely important requirement. Any project that is deemed technically feasible and financially profitable without the credit from potential CERs, would automatically be disqualified from engaging the CDM process. It cannot receive credit for CERs.

Potential Power Trade Scenarios

We begin by exploring two power trade scenarios: either export of electricity from Ethiopia to Sudan, or export of electricity from Ethiopia to Egypt. In the first scenario, Sudan would be the country to engage the CDM. In the second scenario Egypt would be the country to engage the CDM. Our criterion for the selection of the “ideal” scenario, to serve as specific example for illustrating how integration of the national energy markets into a regional market can facilitate engagement of the CDM, is designed around the two considerations outlined above.

Scenario I: Electricity Export from Ethiopia to Sudan to Replace Electricity Generated from Oil

A potential power development scenario for further consideration in this study is the import of electricity from Ethiopia to Sudan. In this specific example, Country A is Sudan, and Country B is Ethiopia. The energy imported by Sudan is electricity generated from hydropower in Ethiopia to satisfy growing demand in Sudan, especially at peak demand months in summer. This specific scenario is proposed for two reasons: (i) it represents the only regional integration scenario for which some physical infrastructure has already been built to enable such integration, and; (ii) the simple nature of the regional integration process in this scenario is another appealing feature since it enhances clarity in our attempt to illustrate how regional integration may facilitate an engagement with the CDM process in ways that would not have been feasible without such integration.

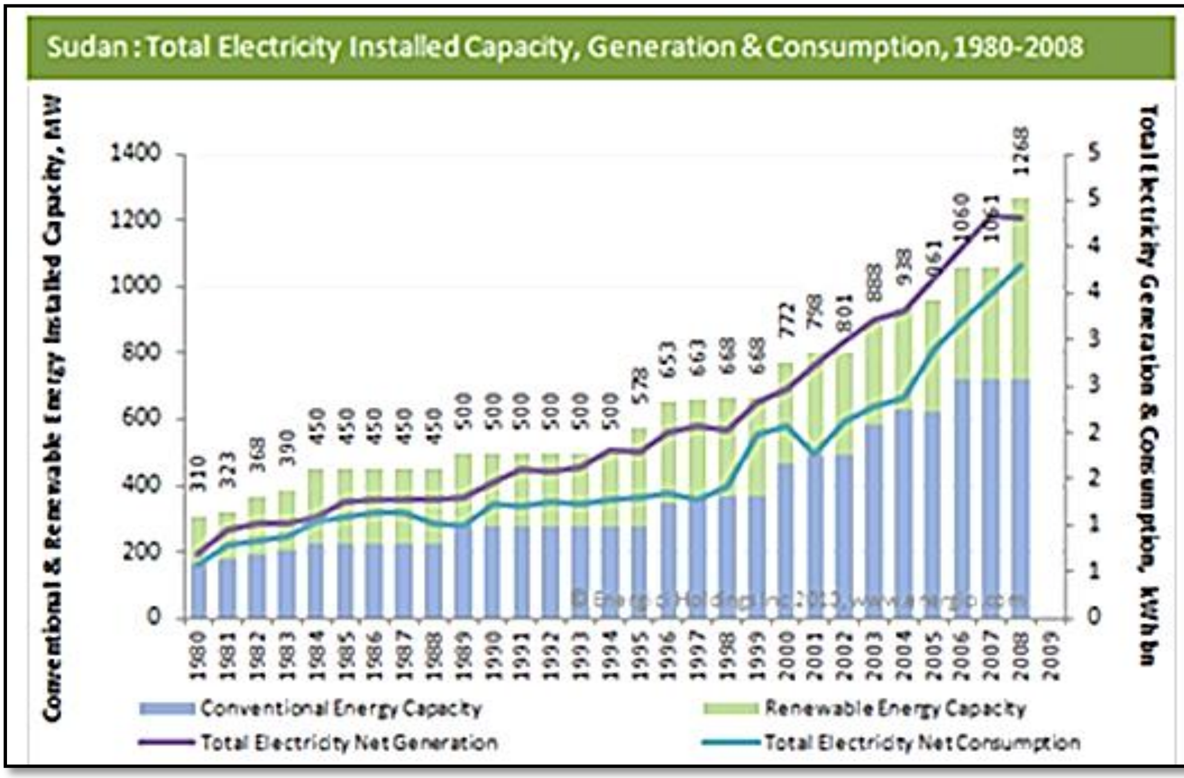

Figure 3: Generation and Consumption of Electricity in Sudan (1980-2008) (US EIA)

As seen in Figure 3, the electricity generated in Sudan at an annual time scale exceeds the annual consumption. However, the generation capacity of hydropower stations is highly seasonal, with minima in the April-June low flow season. This low-flow period corresponds to the warm season, which has peak demand for electricity, resulting in a gap between demand and supply. This gap is currently filled by increasing generation from Sudanese thermal stations using oil as a fuel such as those in Buri and Gari, resulting in significantly higher cost and increasing emissions of CO_2 to the atmosphere. There are plans for increasing this thermal generation capacity through the construction of new stations in Kosti and Foula, close to Sudanese oil fields. The other options for satisfying this demand would include expansion of hydropower capacity through building of new stations, or import of electricity generated by hydropower stations in Ethiopia. The latter option would be optimal for enhancing regional cooperation since Ethiopia has a strategic objective of increasing its hydropower generation capacity by building a series of dams on its rivers, and export of generated electricity to its neighbors.

The main challenge with the scenario of importing electricity from Ethiopia to Sudan to replace electricity generated from oil is the highly profitable nature of such activity! As shown in Figure 2 there is a large difference between the cost of generation of electricity from hydropower in Ethiopia ($35 per MWh) and the cost of generation of electricity by thermal stations fueled by oil in Sudan ($140 per MWh), a factor of four. Due to this large difference, the optimization model used in the Power Trade Study picks investments that emphasize import of electricity from Ethiopia to Sudan as the most feasible economically (700MW/700MW & 700MW/1200 MW). The high level of profitability justifies the investment in that activity, even without any credit that can be gained due to any potential CERs. This fact makes it almost impossible to satisfy the "additionality" requirement of the CDM, unless the price of oil declines dramatically in the future.

The recent trends in the fuel costs resulted in increasing the cost of oil from $72 in 2007 when the Power Trade Study report was published, to more than $95 in 2011, the last year for which we have complete yearly records. The implication of this trend is that investment in the import of electricity from Ethiopia to Sudan to replace electricity generated from oil is even more profitable now compared to 5 years ago.

Scenario II: Electricity Export from Ethiopia to Egypt instead of Local Generation of Electricity from Natural Gas (700MW)

From the perspective of regional cooperation, export of electricity from Ethiopia to satisfy the demand for electricity in Egypt can be a significant booster of regional economic integration. It may provide added incentives for Ethiopia to engage in sustainable long term collaboration on a set of broad strategic issues regarding management of the Eastern Nile water resources.

From the technical and economic points of view, an attractive option for satisfying future demand for electricity in Egypt is generation of electricity by burning of abundant natural gas using (CCGT): a conventional "grey" option (see Table 3) Ethiopia is rich in hydropower potential for generation of electricity which offers an alternative "green" renewable option.

However, in order for the import of electricity from Ethiopia to Egypt to make economic sense the combined cost of electricity generation from hydropower plants (HPP) (typically about 35 USD/MWh) and the cost of transmission has to be smaller than the cost of electricity generated using natural gas in Egypt. The latter depends on the future price of natural gas.

In order for import of electricity from Ethiopia to Egypt to make economic sense the Power Trade Study estimates that the price of natural gas in the coming decade should be about 5 - 6 USD/MBTU. However, the recent trend in the price of natural gas has been negative. The price of natural gas declined significantly by about 40% from 7.1 USD per MBTU, which is the average for 2007, to 4.0 USD per MBTU, which is the average for 2011. The current price of natural gas is about half of that target price (currently @ about 3 USD/MBTU). Under such conditions, it is not clear that import of electricity from Ethiopia to Egypt instead of local generation of electricity from natural gas would be an economically feasible activity. This conclusion can change, however, if credit due to potential CERs is added to the equation. It is indeed conditions such as these is what may make it feasible to satisfy the “additionality” requirement, and hence successfully engage the CDM process.

Based on the above analysis we recommend that a separate project involving connecting Egypt to an already connected network between Sudan and Ethiopia, for the purpose of importing electricity from Ethiopia to Egypt, may represent the ideal candidate for engaging the CDM process. The engagement with the CDM is on the basis of Egypt decision to import electricity, instead of the local generation of electricity. Ethiopia cannot receive credit for the generation of electricity from hydropower due to the profitable nature of hydropower generation in Ethiopia, and the lack of a cheaper fossil fuel-based alternative.

In the Power Trade Study, three options for power trade from Ethiopia to (Sudan/Egypt) were considered: (700MW/700MW), (1200MW, 700MW), (1200MW, 2000MW) as detailed in Table 4. Based on pure economic analysis, these options were ranked as (1) (1200MW, 700MW), (2) (700MW, 700 MW) as close second, and (3) (1200MW, 2000MW), as a distant third. We recommend that the (700MW/700MW) option for transmission be considered. In making this recommendation, we offer four reasons:

(i) The (700MW/700MW) and the (1200MW,700MW) are close in terms of their Net Present Value and Benefit /Cost ratios (see Table 5 and Table 6), with minor differences.

(ii) The (700MW/700MW) option needs the least amount of financial investment, which should make it easier to secure financing.

(iii) As shown in Table VI, the (700MW/700MW) option involves exporting 70% more electricity from Ethiopia to Egypt, 3.9 TWh compared to 2.3TWh. As a result we would expect significantly more credit for potential CERs with option (700MW/700MW). Hence, we recommend this option as the ideal scenario for illustrating how integration of the national energy markets into a regional market can facilitate engagement of the (CDM)

Table 7: Total additional export and CO2 reductions - Loose pool

Case		Additional export TWh/year	CO2 reduction M ton
Ethiopia-Sudan :	700 MW	4.1	3.09
Egypt-Ethiopia :	700 MW	3.9	1.68
Total		8.0	**4.77**
Ethiopia-Sudan :	1200 MW	7.1	5.34
Egypt-Ethiopia :	700 MW	2.3	0.99
Total		9.4	**6.33**
Ethiopia-Sudan :	1200 MW	7.1	5.34
Egypt-Ethiopia :	2000 MW	2.9	1.25
Total		10.0	**6.59**

(Table 1.5 1 , from Module 6-Vol 2 of the Power Trade Study Report)

(iv) Ethiopia already has the largest population in the region, and the fastest population growth. The same country has the fastest growing economy, and the lowest level of current electricity consumption per person. These facts combined together support the likelihood that the demand on electricity will grow the fastest in Ethiopia, especially if the current indicators persist into the future. High demand for electricity in Ethiopia would limit the feasibility of the two other options which both involve massive exports of electricity.

4.3 Step 3 Estimate the potential reduction in carbon emission due to the adoption of a clean development option at the regional scale.

In this section we calculate the emission reduction that could receive CER credit using the “ideal” scenario developed in section 5.2. The ideal scenario consists of building a 1,665 km transmission line from Sudan to Egypt that enables the export from Ethiopia to Egypt of 700 MW of electricity per year. This scenario has the best possibility of qualifying as a CDM project and receiving CER credits. Table 8 is a summary of how the scenario would be carried out including added capacity to Egypt in 2023 of 500 MW and then 200MW added the following year capping at 700MW that is maintained.

Table 8: 700MW Scenario for CDM Engagement

<table>
<tr><th rowspan="2">Years</th><th colspan="4">Ethiopia</th><th colspan="4">Egypt</th></tr>
<tr><th>Peak Load</th><th>Total Capacity</th><th>Added Capacity</th><th>Type</th><th>Peak Load</th><th>Total Capacity</th><th>Added Capacity</th><th>Type</th></tr>
<tr><td>2020</td><td>3750</td><td>6700</td><td></td><td>Hydro</td><td>41000</td><td>51000</td><td></td><td>Mixed</td></tr>
<tr><td rowspan="2">2021</td><td rowspan="2">4350</td><td rowspan="2">6700</td><td rowspan="2"></td><td rowspan="2">Hydro</td><td rowspan="2">43000</td><td rowspan="2">53700</td><td>500</td><td>CCGT</td></tr>
<tr><td>2200</td><td>Mixed</td></tr>
<tr><td rowspan="2">2022</td><td rowspan="2">4600</td><td rowspan="2">7400</td><td rowspan="2">700</td><td rowspan="2">Hydro</td><td rowspan="2">45000</td><td rowspan="2">56200</td><td>500</td><td>CCGT</td></tr>
<tr><td>2000</td><td>Mixed</td></tr>
<tr><td rowspan="2">2023</td><td rowspan="2">5750</td><td rowspan="2">7800</td><td rowspan="2">400</td><td rowspan="2">Hydro</td><td rowspan="2">47250</td><td rowspan="2">58900</td><td>500</td><td>Import</td></tr>
<tr><td>2200</td><td>Mixed</td></tr>
<tr><td rowspan="2">2024</td><td rowspan="2">6250</td><td rowspan="2">8300</td><td rowspan="2">500</td><td rowspan="2">Hydro</td><td rowspan="2">49500</td><td rowspan="2">61400</td><td>200</td><td>Import</td></tr>
<tr><td>300</td><td>CCGT</td></tr>
</table>

							2000	Mixed
2025	6600	8700	400	Hydro	51800	64050	2650	Mixed
2026	6900	9600	900	Hydro	54200	66800	2750	Mixed
2027	7300	10350	750	Hydro	56700	69550	2750	Mixed
2028	7600	11700	1350	Hydro	59300	72300	2750	Mixed

To calculate the emission reductions we apply the following formula:

$$Emission\ Reduction\ = Baseline\ Emission - Project\ Emission - Leakage$$

The baseline emissions are the GHG release associated with the scenario that would most likely occur in the absence of the CDM project (i.e. what will happen under business-as-usual). The project emissions encompass the carbon emissions associated with conducting the project.

The leakage is the displacement of emissions from one country to another due to the project. A positive value for leakage in this context would mean that Egypt's carbon emissions increase despite its importation of hydropower-generated electricity. This could occur if the transmission system between Ethiopia and Egypt is not reliable and Egypt is forced to build its CCGT plants anyway, resulting in plant emissions *and* transmission line emissions that are higher than the project had accounted. A negative value for leakage implies that the project reduces emissions in Ethiopia directly, and also reduces emissions in Egypt. In the context of this project, because electricity transmission is only in one direction, from Ethiopia to Egypt, negative leakage does not have a realistic meaning. The lowest value that we can assign to leakage is zero.

The emissions reductions are the difference between the baseline emissions and the project emissions, accounting for any displacement. To receive CER credit, the emissions reductions must be positive and additional to what would have occurred without the CDM. Consequently, developing the baseline is critical for deciding whether a CDM project will actually reduce emissions.

CDM Baseline Methodologies

CDM regulators place great effort in ensuring that baselines are reasonable and realistic to certify that no unfair advantage is gained from assuming that a carbon intensive alternative is the most likely. Several methodologies have been approved by the UNFCC for baseline and emission reduction calculations (See Table 9). If there is no approved methodology to establish a baseline applicable to the project, a new methodology can be submitted for approval before the project as a whole can be validated. These methodologies in essence dictate what can be included in the baseline, the project emissions and the leakage depending on the type of project (renewable energy, afforestation, etc.)

Table 9: List of UNFCC Approved Methodologies for Calculating Baseline and Emissions Reductions Relevant to Electricity Transmission and Generation Projects

Number	Name
AM0019	Renewable energy projects replacing part of the electricity production of one single fossil fuel fired power plant that stands alone or supplies to a grid, excluding biomass projects --- Version 2.0
AM0026	Methodology for zero-emissions grid-connected electricity generation from renewable sources in Chile or in countries with merit order based dispatch grid --- Version 3.0
AM0027	Substitution of CO2 from fossil or mineral origin by CO2 from renewable sources in the production of inorganic compounds --- Version 2.1
AM0029	Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas --- Version 3.0
AM0045	Grid connection of isolated electricity systems --- Version 2.0
AM0052	Increased electricity generation from existing hydropower stations through Decision Support System optimization --- Version 2.0

AM0103	Renewable energy power generation in isolated grids --- Version 2.0.0
AM0104	Interconnection of electricity grids in countries with economic merit order dispatch --- Version 1.0.0
AM0108	Interconnection between electricity systems for energy exchange --- Version 1.0.0
ACM0002	Consolidated baseline methodology for grid-connected electricity generation from renewable sources --- Version 13.0.0
ACM0018	Consolidated methodology for electricity generation from biomass residues in power-only plants --- Version 2.0.0

For the Power Trade Project, we recommend following the UNFCC approved new methodology: the AM0108 "Interconnection between electricity systems for energy exchange." An alternative methodology would be the ACM002: "Consolidated baseline methodology for grid-connected electricity generation from renewable sources." The main difference between these two is that AM0108 focuses on the ability to trade power and the transmission line construction, while AM002 focuses on the source of energy. The AM0108 most closely fits the Power Trade Project thus in this report, the emissions reductions were calculated using the AM0108 methodology. Descriptions of both methodologies AM0108 and AM002 are included in their entirety in the appendix.

AM0108 Interconnection between electricity systems for energy exchange

AM0108 was approved on September 13, 2012. This methodology may make power trade projects viable as the projects benefit from revenue from CERs. It is useful for countries whose renewable energy resources exceed local demand and could be easily exported; as is the case for hydropower in Ethiopia. The methodology was prepared specifically for the interconnection project which is being developed jointly by the Ethiopian Electric Power Corporation (EEPCo) and the Kenya Electricity Transmission Company Limited (KETRACO). It may be possible to use lessons from that project and PDD documentation to speed up the process for the transmission line between Ethiopia and Egypt. The news site All Africa reports that the Ethiopia-Kenya project “will lead to an annual reduction of over 7 million tonnes of CO_2 per year. This reduction is equivalent to the CO_2 emissions from a coal-fired power station generating about 4,700 GWh of electricity per year, and is also practically equal to Ethiopia's or Côte d'Ivoire's current total annual CO_2 emissions. Over the project's 10-year crediting period, emission reductions (ER) will total approximately 70 million tonnes of CO_2 and revenues from the sale of these ERs will strengthen the project's viability.”

The AM108 methodology applies to project activities that involve the establishment of new electrical interconnections between grids to achieve or increase electricity exchange between two grids.

The methodology is applicable under the following conditions:

- The interconnection is through the construction of new transmission lines;
- The relation between annual electricity flow from the exporting (Ethiopian) to the importing (Egyptian) electricity system and vice versa shall not fall below 80/20.
- The exporting electricity system must have more than 15 per cent of reserve capacity. Having reserve capacity ensures that the importing country can receive a reliable supply of electricity and is not forced to build more conventional plants to meet the demand due to an unreliable importing network.
- Any other interconnections that the importing and the exporting electricity system have with neighbouring grids prior to the implementation of the project activity (i.e. Sudan, Kenya, Djibouti) should be identified and described in the CDM-PDD.
- The geographic and system boundaries for the relevant country electricity systems can be clearly identified and information on the characteristics and composition of the grids is available;
- The amount of electricity generated in the exporting electricity system by hydropower plants with a power density of the reservoirs below or equal to 4 W/m^2 and that start commercial operation during the crediting period shall be excluded from the calculations of the emission reductions. (According to original power development plans in Ethiopia,

in 2023 and 2024 Ethiopia should commission Advance Beko Abo, and Mandaya hydropower projects. While Mandaya reservoir power density is less than 4 W/m2, the power density of the Beko Abo which will generate about 700MW, is greater than 4 W/m2. Hence in engaging the CDM the Beko Abo project should be emphasized)

- The most plausible baseline scenario is that the new grid-connected generation capacity using the similar fuel/technology mix as existing power units in the importing electricity system that will provide the same amount of electricity to end users.

Some alternative baselines to consider would be whether the proposed project would occur without being registered as a CDM, whether Egypt could generate electricity capacity from a renewable energy source to meet its demand or whether isolated mini-grids could provide the electricity. Egypt has abundance in gas and currently gas is cheap; there is not much renewable ability to try to provide its own renewable source of energy; the same project without registering is too expensive and mini projects would not enjoy the economies of scale. If there is only one alternative scenario that is not prevented by any barrier, then this scenario alternative is the most plausible baseline scenario. Thus, the most likely baseline, is that Egypt meets its energy demand with conventional existing technology mix such as CCGT using the relatively inexpensive natural gas as a fuel.

Emission Reduction

The approved methodologies make adjustments to fine-tune the emission reduction calculation, however, a quick “back-of-the-envelope” calculation with simplifying assumptions can provide a relative magnitude for the scenario in which Egypt imports 700 MW of selected.

- Assuming hydropower has negligible carbon emissions
- Assuming leakage is negligible
- Applying the United States’ average emissions rate from natural gas-fired generation of 1135 lbs/MWh (EPA) = 0.51 T CO_2/MWh
- Using the 700 MW of electricity being imported from Ethiopia to Egypt with a load factor of 63% applied during one year (8760 hours)

We can calculate an average yearly emission reduction close to 2 million tonnes of CO_2: The project emissions would be zero and the baseline emissions would be.

$$0.51\, T \frac{CO2}{MWh} * 700MW * 8760h * 0.63 \; = \; 1.97\, million \sim 2\, million\, T\; CO2$$

The AM0108 methodology tweaks these values to be more exact each year and it specifies what must be included in the project, the baseline and the leakage factor. A more detailed calculation following the AM0108 methodology is included in the Appendix.

Emissions factors for importing and exporting electricity systems in the baseline and project activity are included. Methane and nitrous oxide are excluded from the baseline for simplification. This leads to a conservative baseline. Emissions associated with deforestation for the construction of the transmission line as well as sulfur hexafluoride release are excluded but methane from hydropower reservoirs is included. The operating margin (OM) and the build margin (BM) of the electricity system are included and assumed to be zero because electricity emissions factors from Ethiopia are negligible since a renewable energy source is used. The operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed CDM project activity. The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected. The OM refers to the effect of the project on operations. The BM refers to the effect of the project on capacity expansion (deferring or avoiding capacity additions that would have taken place "but for" the project).

Carrying out the calculations from the AM0108 methodology (see appendix), we get an average emissions reduction of 1.03 million tonnes of CO_2 per year from 2020 to 2028.

Description	Unit	Symbol	2020	2021	2022	2023	2024	2025	2026	2027	2028
Emission reductions in year *y*	M t CO2	ER_y	0.00	0.00	0.00	1.16	1.62	1.62	1.62	1.62	1.62

Monetary Value of CER

The value of the CER's has fluctuated dramatically like any other commodity in the market, based on the supply and demand. The news media Reuters reported that "Analysts cut their price forecasts for United Nations' carbon permits to 2020 further as over-supply continued to put pressure on prices.” They report that last month prices fell to about 1.0 euros per tonne of CO2. Some expect that the price will stay below 3 euros indefinitely. With an emission reduction of about 1.6 tonnes of CO_2 per year and a price of 1 euro per tonne, (1 euro is about US $1.3). This would mean that the Project could receive financial credit of about 2 million USD per year.

4.4 **Step 4** Provide a road map for engagement of the CDM process, economic analysis, and recommendations

Institutional Roles

In applying for the CDM, several parties are involved. This section provides a brief description on the institutions’ roles. The designated operational entity (DOE’s) validates the project design document (PDD) and checks if the Marrakesh Accords’ requirements are met. The DOE then recommends to the CDM Executive Board whether to certify or not the credits generated by the project. If the Board does not disagree with this recommendation within 8 weeks, the project is automatically registered and constitutes final approval. The project can begin monitoring and claiming credits for the reduction of emissions. This means that the CDM Executive Board trusts the recommendations of the validators in principle, but there is a “checks-and-balances” option enabling the Executive Board to have the last word in case of disagreement. After the initial phase, another DOE validates the reductions during the entire period in which the project claims reductions.

CDM Registration Steps

The CDM registration process consists of the following steps (Figure 4) :

1. Preparing the Project Design Document (PDD)

    a. Local stakeholder consultation

    b. Environmental impact assessment (EIA)

    c. Methodologies to estimate the baseline

    d. Demonstrating additionality

2. Getting approval from each country involved

3. Validation and 30 day public comment period

4. Registration by the CDM Executive Board

5. Monitoring emission reductions

6. Verification, certification and issuance of emission reduction credits

7. Renewal of the crediting period

Figure 4: CDM Project Cycle (Source: CDM Watch)

The first step to engage in the CDM is to prepare a PDD. This report has attempted to provide some of the necessary information for the DOE to prepare a PDD. Particularly the selection of a feasible and justifiable baseline, the explanation of a valid approved methodology for the project and an example of the calculation and magnitude for emission reductions.

<u>What is needed in the PDD?</u>

The PDD is one of 3 documents required to register along with a validation report from DOE and letter of approval from DNA (designated national authority). It has the following components:

- A general description of the project.
- A baseline derived from an approved baseline methodology. (If there is no approved methodology to establish a baseline applicable to the project, a new methodology can be submitted for approval before the project as a whole can be validated. The baseline the scenario that would most likely occur in the absence of the CDM project (i.e. what will happen under business-as-usual) Developing a baseline is critical for deciding whether a CDM project is additional. When assessing the PDD it is worthwhile checking whether all alternative scenarios have been considered.. The PDD should have considered all realistic credible alternative scenarios, investment and barrier analysis to show the option is only financially attractive with carbon credit and that the carbon credit eliminates barriers/risk and have a common practice check.

• The estimated lifetime of the project and the crediting period

> The project operator can chose between two different approaches to decide upon the length of the crediting period: A maximum of 7 years which may be renewed at most 2 times. This would require an updated PDD. OR A maximum of 10 years with no option of renewal.

• A demonstration of how the project generates emission reductions that are additional to what would have occurred without the CDM.

• An analysis of the environmental impacts

• A discussion of the stakeholder consultation process and how stakeholder comments were taken into account

• A monitoring and verification plan

The PDD should have considered all realistic credible baseline alternative scenarios, investment and barrier analysis to show the option is only financially attractive with carbon credit and that the carbon credit eliminates barriers/risk. After submitting a PDD, the DOE will officially engage in the CDM process shown in Figure 4.

5.0 SCENARIO III: EXPORT OF ELECTRICITY FROM ETHIOPIA TO SUDAN AND EGYPT (1200MW/2000MW)

In the analysis presented in section 4, we made two assumptions:

(i) We compared different export options, based on the economic feasibility analysis in the Power Trade Study only, without considerations for other comparison criterion.

(ii) The analysis of the different options assumed a base case of electricity generation in Sudan from oil based fuels, which is a relatively expensive option. While this option may be profitable in economic terms, it does not favor engagement with the CDM.

Any strategic analysis of different options for development in the EN region would favor scenarios that enhance large-scale cooperation in the region such as the (1200MW/2000MW) scenario of export of electricity from Ethiopia to (Sudan/Egypt). In fact the Eastern Nile Council of Ministers (ENCOM) has decided to proceed with the option of 1200MW/2000MW transmission line for export of electricity from Ethiopia to Sudan/Egypt. Although before the recent separation into two states, Sudan was relatively rich in oil resources, separation left Sudan with significantly less oil resources. Under these conditions, generation of electricity from coal which is a relatively less expensive option (see Figure 2) deserves further consideration. In this section, we analyze the carbon trade implications of the 1200MW/2000MW option of export of electricity from Ethiopia to Sudan/Egypt, assuming base case scenario of local generation of electricity from coal in Sudan, and from natural gas in Egypt.

5.1 Export of Electricity from Ethiopia to Egypt (2000MW)

In this section we calculate the emission reduction that could receive CER credit using the scenario that enables the export from Ethiopia to Egypt of 2000 MW of electricity per year. Table 10 is a summary of how the scenario would be carried out including added capacity of 500 MW of power imported from Ethiopia to Egypt every year starting in 2021 and concluding in 2024 capping out at 2000 MW. The assumption here is that imported electricity would replace local electricity generation from natural gas.

Table 10: 2000MW Scenario for Egypt CDM Engagement

Years	Ethiopia				Egypt			
	Peak Load	Total Capacity	Added Capacity	Type	Peak Load	Total Capacity	Added Capacity	Type
2020	3750	6700		Hydro	41000	51000		Mixed
2021	4500	6700		Hydro	43000	53700	500	**Import**
							2200	Mixed
2022	5250	7400	700	Hydro	45000	56200	500	**Import**
							2000	Mixed
2023	6050	7800	400	Hydro	47250	58900	500	**Import**
							2200	Mixed
2024	6850	8300	500	Hydro	49500	61400	500	**Import**
							2000	Mixed
2025	7300	8700	400	Hydro	51800	64050	2650	Mixed
2026	7950	9600	900	Hydro	54200	66800	2750	Mixed
2027	8700	10350	750	Hydro	56700	69550	2750	Mixed
2028	9400	11700	1350	Hydro	59300	72300	2750	Mixed

To calculate the emission reductions we apply the following formula:

$$Emission\ Reduction\ = Baseline\ Emission - Project\ Emission - Leakage$$

The baseline emissions are the GHG release associated with the scenario that would most likely occur in the absence of the CDM project (i.e. what will happen under business-as-usual). The project emissions encompass the carbon emissions associated with conducting the project. The leakage is the displacement of emissions from one country to another due to the project. A positive value for leakage in this context would mean that Egypt's carbon emissions increase despite its importation of hydropower-generated electricity. This could occur if the transmission system between Ethiopia and Egypt is not reliable and Egypt is forced to build its CCGT plants anyway, resulting in plant emissions *and* transmission line emissions that are greater than the project had accounted. A negative value for leakage implies that the project reduces emissions in Ethiopia directly, and also reduces emissions in Egypt. In the context of this project, because electricity transmission is only in one direction, from Ethiopia to Egypt, negative leakage does not have a realistic meaning. The lowest value that we can assign to leakage is zero.

The AM108 methodology applies to project activities that involve the establishment of new electrical interconnections between grids to achieve or increase electricity exchange between two grids.

The methodology is applicable under the following conditions:

- The interconnection is through the construction of new transmission lines;
- The relation between annual electricity flow from the exporting (Ethiopia) to the importing (Egypt) electricity system and vice versa shall not fall below 80/20.
- The exporting electricity system must have more than 15 per cent of reserve capacity. Having reserve capacity ensures that the importing country can receive a reliable supply of electricity and is not forced to build more conventional plants to meet the demand due to an unreliable importing network.
- Any other interconnections that the importing and the exporting electricity system have with neighbouring grids prior to the implementation of the project activity (i.e. Sudan, Kenya, Djibouti) should be identified and described in the CDM-PDD.
- The geographic and system boundaries for the relevant country electricity systems can be clearly identified and information on the characteristics and composition of the grids is available;
- The amount of electricity generated in the exporting electricity system by hydropower plants with a power density of the reservoirs below or equal to 4 W/m^2 and that start

commercial operation during the crediting period shall be excluded from the calculations of the emission reductions.

- The most plausible baseline scenario is that the new grid-connected generation capacity using the similar fuel/technology mix as existing power units in the importing electricity system that will provide the same amount of electricity to end users.

Some alternative baselines to consider would be whether the proposed project would occur without being registered as a CDM, whether Egypt could generate electricity capacity from a renewable energy source to meet its demand or whether isolated mini-grids could provide the electricity. Egypt has abundance in natural gas and currently natural gas is relatively cheap; the same project without registering is too expensive and mini projects would not enjoy the economies of scale. If there is only one alternative scenario that is not prevented by any barrier, then this scenario alternative is the most plausible baseline scenario. Thus, the most likely baseline, is that Egypt meets its energy demand with conventional existing technology mix such as CCGT using the relatively inexpensive natural gas as a fuel.

Emission Reduction

The approved methodologies make adjustments to fine-tune the emission reduction calculation, however, a quick "back-of-the-envelope" calculation with simplifying assumptions can provide a relative magnitude for the scenario in which Egypt imports 2000 MW of selected.

- Assuming hydropower has negligible carbon emissions
- Assuming leakage is negligible
- Applying the United States' average emissions rate from natural gas-fired generation of 1135 lbs/MWh (EPA) = 0.51 T CO_2/MWh
- Using the 2000 MW of electricity being imported from Ethiopia to Egypt with a load factor of 63% applied during one year (8760 hours)

We can calculate an average yearly emission reduction of 5.63 million tonnes of CO2 for the 2000 MW in one year. This reflects the baseline emissions since it assumes project and leakage emissions would be zero. However it gives a rough estimate of the magnitude for the maximum possible emissions reduction.

$$0.51\,T\,\frac{CO2}{MWh} * 2000MW * 8760\,\frac{h}{yr} * 0.63 \;=\; 5.63\,million\;\;T\;CO2$$

The AM0108 methodology tweaks the emission reduction values to be more exact each year and it specifies what must be included in the project, the baseline and the leakage factor. A more detailed calculation following the AM0108 methodology is included in Appendix C. The calculation makes the following assumptions:

- Emissions factors for importing and exporting electricity systems in the baseline and project activity are included.
- Methane and nitrous oxide are excluded from the baseline for simplification. This leads to a conservative baseline.
- Emissions associated with deforestation for the construction of the transmission line as well as sulfur hexafluoride release are excluded but methane from hydropower reservoirs is included.
- The operating margin (OM) and the build margin (BM) of the electricity system are included and assumed to be zero because electricity emissions factors from Ethiopia are negligible since a renewable energy source is used. The operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed CDM project activity. The OM refers to the effect of the project on operations. The build margin is the emission factor that refers to the group of prospective power plants whose construction and future operation would be affected. The BM refers to the effect of the project on capacity expansion (deferring or avoiding capacity additions that would have taken place “but for” the project).

Carrying out the calculations from the AM0108 methodology (see Appendix C), we get the following emissions reductions in CO2 per year from 2020 to 2028. Once the 2000 MW transmission line is established, the project reaches a steady state where the emissions reductions are 4.64 million tonnes of CO2e per year.

Table 11: Estimated Emissions Reductions from 2020-2028 for 2000 MW Power Transmission from Ethiopia to Egypt

Description	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Power Exported	MW	0	500	1000	1500	2000	2000	2000	2000	2000
Baseline emissions	M t CO2	0.00	1.41	2.81	4.22	5.63	5.63	5.63	5.63	5.63
Project emissions	M t CO2	0.00	0.25	0.50	0.75	0.99	0.99	0.99	0.99	0.99
Leakage emissions	M t CO2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emission reductions	M t CO2	0.00	1.16	2.32	3.48	4.64	4.64	4.64	4.64	4.64

Monetary Value of CER

To calculate the monetary value of the CER we employ a Net Present Value approach. This allows future net cash flows to be translated to the equivalent current ones so the project value can be compared on a present value basis. The NPV requires determination of four main aspects: 1) the appropriate time horizon, 2) the yearly cash flow, 3) a reasonable discount factor and 4) the aggregate discounted net cash flow.

The CDM project investor must consider several contractual factors that are negotiated aspects of the project.

- **Time horizon** --can include the project lifetime (often 30-70 years for large infrastructure projects) or the CER "crediting period" (either one 10 year term or three 7 year terms according to the rule of the CDM).
- **Carbon Inflator** -- an annual percentage increase in the value of a tCO2e because the damage caused by 1CO2te emission gets worse each year due to positive feedbacks. Thus, the carbon value for 1 tCO2e should increase year by year.
- **Discount rate** -- reflects the opportunity cost of the project and will affect the NPV (higher DR, lower NPV)

- **Risk level** -- who takes the risk, the buyer or the seller; how are liquidated damages considered if the CER is not delivered or if the carbon credits are not issued. These aspects are reflected in the price and discount rate
- **Political and institutional uncertainty beyond 2012** -- The Kyoto protocol has been established up to 2012, however since CER's could be generated up to 21 years (3 periods of 7 years each) one can infer that the policy makers intended CER's to keep the value after 2012. The European Union Emission Trading Scheme (EU ETS) is the single largest market for greenhouse gases emission allowances. Still, the future of the market is uncertain following the UNFCCC protocol. According to the World Bank, currently "Carbon Funds are primarily interested in buying Certified Emission Reductions (CERs) from projects that will generate sizeable CERs before the end of 2012"
- **Transaction cost in applying for the project**--- these cost varies depending upon the project type and size, often falling in the $50,000-$250,000 range for pre-implementation (UNEP, 2005).

The following are the assumptions used in this analysis:

- **Time Horizon**: we select crediting period to be when the capital expenditure cost is generated, 2020 (0th year) until the end of the third term crediting period, 2041. Some projects do not generate candidate CERs until after the fifth year but the crediting period remains the same. The numbers of interest are the steady state values.
- **Currency:** is shown in US dollars since most of the projects use USD for the PDD.
- **Carbon Inflator:** is excluded for simplicity. It can be reflected in the discount rate.
- **Transaction costs**: excluded for the CDM project. This assessment aims to investigate the project's potential benefit in carbon emission reduction, not costs. The CDM costs of applying should be considered separately.
- **Price:** A benchmark price often used for investment appraisal is the World Bank Prototype Carbon Fund price. The WB PCF was the first carbon fund formed by a partnership of 17 companies and 6 governments to pioneer the market for project based GHG reduction. However, like with many commodities in the market, the price value of the CER's has fluctuated dramatically, based on the risk, supply and demand. The news media Reuters reported that "analysts cut their price forecasts for United Nations' carbon

permits to 2020 further as over-supply continued to put pressure on prices." They report that last month prices fell below 1.50 euros but are now back up to 2 euros per tonne CO2. Some experts expect that the price will stay below 3 euros indefinitely. For this analysis we use Friday November 9 2012 spot price of €1.01 (Reuters) with $1.28 USD to 1 Euro rate on the same date. (fx.rate.net)The price is maintained constant as it is considered a fixed negotiated price as of the 0th year of the project.

- **Discount Rate:** Many studies use a high discount rate of 10-12%. This is meant to reflect the high risk associated with investing in developing countries. An alternative discount rate is 6.24% which reflects a US 10-year corporate bond with triple B rating (some risk). The outcome using both discount rates is shown in Tables below.

Table 12 and 13 show the Net Present Value calculated for this scenario for three 7 year terms that constitute a crediting period. The scenario described here is simply one case, and in fact, the most relevant aspect of the study is the steady state net value of the carbon emission. Once Egypt begins to import 2000 MW of power, it could save 4.64 million tonnes of CO2. With a carbon price of $1.28 USD, the country could receive $5.93 million USD per year as a certified emission reduction.

Table 12: Net Present Value of the Emission Reduction using a Discount Rate of 6.24%

Discount Rate	6.24	%	DR based on 10 year triple B bond (www.bondsonline.com)
Carbon Price	1.28	USD	Carbon Price based on Nov 9, 2012 Reuters Spot Price converted to Dollars

	Year		Emission reduction	Net Value	Discount factor	Present Value
			Million t CO2	Million USD	---	Million USD
Crediting Period	**2020**	0	0.00	0.00	1.00	0.00
	2021	1	1.16	1.48	0.94	1.40
	2022	2	2.32	2.97	0.89	2.63
	2023	3	3.48	4.45	0.83	3.71
	2024	4	4.64	5.93	0.78	4.66
	2025	5	4.64	5.93	0.74	4.38
	2026	6	4.64	5.93	0.70	4.13
	2027	7	4.64	5.93	0.65	3.88
tin g	**2028**	8	4.64	5.93	0.62	3.66

	2029	9	4.64	5.93	0.58	3.44
	2030	10	4.64	5.93	0.55	3.24
	2031	11	4.64	5.93	0.51	3.05
	2032	12	4.64	5.93	0.48	2.87
	2033	13	4.64	5.93	0.46	2.70
	2034	14	4.64	5.93	0.43	2.54
Crediting Period	**2035**	15	4.64	5.93	0.40	2.39
	2036	16	4.64	5.93	0.38	2.25
	2037	17	4.64	5.93	0.36	2.12
	2038	18	4.64	5.93	0.34	2.00
	2039	19	4.64	5.93	0.32	1.88
	2040	20	4.64	5.93	0.30	1.77
	2041	21	4.64	5.93	0.28	1.66
					NPV Million USD	**60.36**

Table 13: Net Present Value of the Emission Reduction using a Discount Rate of 10%

Discount Rate	10	%
Carbon Price	1.28	USD

Carbon Price based on Nov 9, 2012 Reuters Spot Price converted to Dollars

	Year		Emission reduction	Net Value	Discount factor	Present Value
			Million t CO2	Million USD	---	Million USD
Crediting Period	**2020**	0	0.00	0.00	1.00	0.00
	2021	1	1.16	1.48	0.91	1.35
	2022	2	2.32	2.97	0.83	2.45
	2023	3	3.48	4.45	0.75	3.34
	2024	4	4.64	5.93	0.68	4.05
	2025	5	4.64	5.93	0.62	3.68
	2026	6	4.64	5.93	0.56	3.35
	2027	7	4.64	5.93	0.51	3.04
Crediting Period	**2028**	8	4.64	5.93	0.47	2.77
	2029	9	4.64	5.93	0.42	2.52
	2030	10	4.64	5.93	0.39	2.29
	2031	11	4.64	5.93	0.35	2.08
	2032	12	4.64	5.93	0.32	1.89
	2033	13	4.64	5.93	0.29	1.72
	2034	14	4.64	5.93	0.26	1.56
Crediting Period	**2035**	15	4.64	5.93	0.24	1.42
	2036	16	4.64	5.93	0.22	1.29
	2037	17	4.64	5.93	0.20	1.17
	2038	18	4.64	5.93	0.18	1.07
	2039	19	4.64	5.93	0.16	0.97
	2040	20	4.64	5.93	0.15	0.88
	2041	21	4.64	5.93	0.14	0.80
					NPV Million USD	**43.71**

5.2 Export of Electricity from Ethiopia to Sudan (1200 MW)

In this section we calculate the emission reduction that could receive CER credit using the scenario that enables the export from Ethiopia to Sudan of 1200 MW of electricity per year. Table 14 is a summary of how the scenario would be carried out including added capacity of up to 1200 MW imported from Ethiopia to Sudan starting in 2025 and being phased-in and concluded in 2028. The assumption here is that imported electricity would replace local electricity generation from coal.

Table 14: 1200MW Scenario for Sudan CDM Engagement

Years	Ethiopia				Sudan			
	Peak Load	Total Capacity	Added Capacity	Type	Peak Load	Total Capacity	Added Capacity	Type
2020	3750	6700		Hydro	7200	10500		Mixed
2021	4500	6700		Hydro	7600	11100	600	**Thermal**
2022	5250	7400	700	Hydro	7900	11100		
2023	6050	7800	400	Hydro	8250	11350	250	**Thermal**
2024	6850	8300	500	Hydro	8650	11450	100	**Thermal**
2025	7300	8700	400	Hydro	8950	11900	100	**Import**
							350	Thermal
2026	7950	9600	900	Hydro	9350	12250	350	**Import**
2027	8700	10350	750	Hydro	9750	12600	350	**Import**
2028	9400	11700	1350	Hydro	10250	13000	400	**Import**

To calculate the emission reductions we apply the following formula:

$$Emission\ Reduction\ = Baseline\ Emission - Project\ Emission - Leakage$$

The baseline emissions are the GHG release associated with the scenario that would most likely occur in the absence of the CDM project (i.e. what will happen under business-as-usual). The project emissions encompass the carbon emissions associated with conducting the project. The leakage is the displacement of emissions from one country to another due to the project. A positive value for leakage in this context would mean that emissions increase despite importation of hydropower-generated electricity. This could occur if the transmission system between Ethiopia and Sudan is not reliable and Sudan is forced to build its coal-fired electricity plant to maintain reliability. This would result in plant emissions *and* transmission line emissions that are greater than the project had accounted. A negative value for leakage implies that the project reduces emissions in Ethiopia directly, and also reduces emissions in Sudan. In the context of this project, because electricity transmission is only in one direction, from Ethiopia to Sudan, negative leakage does not have a realistic meaning. The lowest value that we can assign to leakage is zero.

The AM108 methodology applies to project activities that involve the establishment of new electrical interconnections between grids to achieve or increase electricity exchange between two grids.

The methodology is applicable under the following conditions:

- The interconnection is through the construction of new transmission lines;
- The relation between annual electricity flow from the exporting (Ethiopian) to the importing (Sudan) electricity system and vice versa shall not fall below 80/20.
- The exporting electricity system must have more than 15 per cent of reserve capacity. Having reserve capacity ensures that the importing country can receive a reliable supply of electricity and is not forced to build more conventional plants to meet the demand due to an unreliable importing network.
- Any other interconnections that the importing and the exporting electricity system have with neighbouring grids prior to the implementation of the project activity (i.e. Kenya, Djibouti) should be identified and described in the CDM-PDD.
- The geographic and system boundaries for the relevant country electricity systems can be clearly identified and information on the characteristics and composition of the grids is available;
- The amount of electricity generated in the exporting electricity system by hydropower plants with a power density of the reservoirs below or equal to 4 W/m^2 and that start commercial operation during the crediting period shall be excluded from the calculations of the emission reductions.

- The most plausible baseline scenario is that the new grid-connected generation capacity using the similar fuel/technology mix as existing power units in the importing electricity system that will provide the same amount of electricity to end users.

Some alternative baselines to consider would be whether the proposed project would occur without being registered as a CDM, whether Sudan could generate electricity capacity from a renewable energy source to meet its demand or whether isolated mini-grids could provide the electricity. Currently coal is relatively cheap source. Thus, the most likely baseline, is that Sudan meets its energy demand with conventional existing technology mix such as coal-fired generation. Using oil would be impractical since oil could receive a much higher price sold in the open market than burned for electricity.

Emission Reduction

The approved methodologies make adjustments to fine-tune the emission reduction calculation; however, a quick "back-of-the-envelope" calculation with simplifying assumptions can provide a relative magnitude for the scenario in which Sudan imports 1200 MW of power.

- Assuming hydropower has negligible carbon emissions
- Assuming leakage is negligible
- Applying the United States' average carbon dioxide emissions rate from coal-fired generation of 2249 lbs/MWh (EPA). This is equivalent to 1.02 T CO2/MWh. Coal generation releases average emission of 13 lbs/MWh of sulfer dioxide and 6 lbs/MWh of nitrogen oxides.

Using the 1200 MW of electricity being exported from Ethiopia to Sudan with a load factor of 63% applied during one year (8760 hours), we can calculate an average yearly emission reduction of 6.69 million tonnes of CO2 for the 1200 MW in one year. This reflects only the baseline emissions since it assumes project and leakage emissions would be zero. However it gives a rough estimate of the magnitude for the maximum possible emissions reduction.

$$1.02\,T\,\frac{CO2}{MWh} * 1200MW * 8760\,\frac{h}{yr} * 0.63 \;=\; 6.69\,million\;\;T\;CO2$$

The AM0108 methodology tweaks the emission reduction values to be more exact each year and it specifies what must be included in the project, the baseline and the leakage factor. A more detailed calculation following the AM0108 methodology is included in the Appendix. The calculation makes the following assumptions:

- Emissions factors for importing and exporting electricity systems in the baseline and project activity are included.
- Methane and nitrous oxide are excluded from the baseline for simplification. This leads to a conservative baseline.
- Emissions associated with deforestation for the construction of the transmission line as well as sulfur hexafluoride release are excluded but methane from hydropower reservoirs is included.
- The operating margin (OM) and the build margin (BM) of the electricity system are included and assumed to be zero because electricity emissions factors from Ethiopia are negligible since a renewable energy source is used. The operating margin is the emission factor that refers to the group of existing power plants whose current electricity generation would be affected by the proposed CDM project activity. Current operations are not meant to be affected. The build margin refers to the effect of the project on capacity expansion (deferring or avoiding capacity additions that would have taken place "but for" the project). Since the project replaces the fuel type but does not defer or avoid capacity expansion, the BM is zero.

Carrying out the calculations from the AM0108 methodology (see appendix) we get the following emissions reductions in CO2 per year from 2020 to 2028. Once the 1200 MW transmission line is established, the project reaches a steady state where the emissions reductions are 6.16 million tonnes of CO2e per year.

Table 15: Estimated Emissions Reductions from 2020-2028 for 1200 MW Power Transmission from Ethiopia to Sudan

Description	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Power Exported	MW	0	0	0	0	0	100	450	800	1200
Baseline emissions	M t CO2	0.00	0.00	0.00	0.00	0.00	0.56	2.53	4.50	6.76

Project emissions	M t CO2	0.00	0.00	0.00	0.00	0.00	0.05	0.22	0.40	0.60
Leakage emissions	M t CO2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emission reductions	M t CO2	0.00	0.00	0.00	0.00	0.00	0.51	2.31	4.11	6.16

Monetary Value of CER

To calculate the monetary value of the CER we employ a Net Present Value approach. This allows future net cash flows to be translated to the equivalent current ones so the project value can be compared on a present value basis. The NPV requires determination of four main aspects: 1) the appropriate time horizon, 2) the yearly cash flow, 3) a reasonable discount factor and 4) the aggregate discounted net cash flow.

The CDM project investor must consider several contractual factors that are negotiated aspects of the project. These are described in section 5.1 above. The following are the associated assumptions used in this analysis:

- **Time Horizon**: we select crediting period to be when the capital expenditure cost is generated, 2020 (0th year) until the end of the first term crediting period, 2028. Some projects do not generate candidate CERs until after the 0^{th} year but the crediting period remains the same.
- **Currency:** is shown in US dollars since most of the projects use USD for the PDD.
- **Carbon Inflator:** is excluded for simplicity. It can be reflected in the discount rate.
- **Transaction costs**: excluded for the CDM project. This assessment aims to investigate the project's potential benefit in carbon emission reduction, not costs. The CDM costs of applying should be considered separately.
- **Price:** A benchmark price often used for investment appraisal is the World Bank Prototype Carbon Fund price. The WB PCF was the first carbon fund formed by a partnership of 17 companies and 6 governments to pioneer the market for project based GHG reduction. However, like with many commodities in the market, the price value of the CER's has fluctuated dramatically, based on the risk, supply and demand. The news

media Reuters reported that "analysts cut their price forecasts for United Nations' carbon permits to 2020 further as over-supply continued to put pressure on prices." They report that last month prices fell below 1.50 euros but are now back up to 2 euros per tonne CO2. Some experts expect that the price will stay below 3 euros indefinitely. For this analysis we use Friday November 9 2012 spot price of €1.01 (Reuters) with $1.28 USD to 1 Euro rate on the same date. (fx.rate.net)The price is maintained constant as it is considered a fixed negotiated price as of the 0th year of the project.

- **Discount Rate:** Many studies use a high discount rate of 10-12%. This is meant to reflect the high risk associated with investing in developing countries. An alternative discount rate is 6.24% which reflects a US 10-year corporate bond with triple B rating (some risk).

Table 16 and 17 show the Net Present Value calculated for this scenario for three 7 year terms that constitute a crediting period. The scenario described here is simply one case, and in fact, the most relevant aspect of the study is the steady state net value of the carbon emission. Once Sudan begins to import 1200 MW of power, it could save 6.16 million tonnes of CO2. With a carbon price of $1.28 USD, the country could receive $7.88 million USD per year as a certified emission reduction.

Table 16: Net Present Value of the Emission Reduction using a Discount Rate of 6.24%

Discount Rate	6.24	%	DR based on 10 year triple B bond (www.bondsonline.com)
Carbon Price	1.28	USD	Carbon Price based on Nov 9, 2012 Reuters Spot Price converted to Dollars

	Year		Emission reduction	Net Value	Discount factor	Present Value
			Million t CO2	Million USD	---	Million USD
Crediting Period	**2020**	0	0.00	0.00	1.00	0.00
	2021	1	0.00	0.00	0.94	0.00
	2022	2	0.00	0.00	0.89	0.00
	2023	3	0.00	0.00	0.83	0.00
	2024	4	0.00	0.00	0.78	0.00
	2025	5	0.51	0.66	0.74	0.49
	2026	6	2.31	2.96	0.70	2.06
	2027	7	4.11	5.26	0.65	3.44
Crediting P	**2028**	8	6.16	7.88	0.62	4.86
	2029	9	6.16	7.88	0.58	4.57

	2030	10	6.16	7.88	0.55	4.30
	2031	11	6.16	7.88	0.51	4.05
	2032	12	6.16	7.88	0.48	3.81
	2033	13	6.16	7.88	0.46	3.59
	2034	14	6.16	7.88	0.43	3.38
Crediting Period	**2035**	15	6.16	7.88	0.40	3.18
	2036	16	6.16	7.88	0.38	2.99
	2037	17	6.16	7.88	0.36	2.82
	2038	18	6.16	7.88	0.34	2.65
	2039	19	6.16	7.88	0.32	2.50
	2040	20	6.16	7.88	0.30	2.35
	2041	21	6.16	7.88	0.28	2.21
					NPV Million USD	**53.24**

Table 17: Net Present Value of the Emission Reduction using a Discount Rate of 10%

Discount Rate	10	%
Carbon Price	1.28	USD

Carbon Price based on Nov 9, 2012 Reuters Spot Price converted to Dollars

	Year		**Emission reduction**	**Net Value**	**Discount factor**	**Present Value**
			Million t CO2	**Million USD**	**---**	**Million USD**
Crediting Period	**2020**	0	0.00	0.00	1.00	0.00
	2021	1	0.00	0.00	0.91	0.00
	2022	2	0.00	0.00	0.83	0.00
	2023	3	0.00	0.00	0.75	0.00
	2024	4	0.00	0.00	0.68	0.00
	2025	5	0.51	0.66	0.62	0.41
	2026	6	2.31	2.96	0.56	1.67
	2027	7	4.11	5.26	0.51	2.70
Crediting Period	**2028**	8	6.16	7.88	0.47	3.68
	2029	9	6.16	7.88	0.42	3.34
	2030	10	6.16	7.88	0.39	3.04
	2031	11	6.16	7.88	0.35	2.76
	2032	12	6.16	7.88	0.32	2.51
	2033	13	6.16	7.88	0.29	2.28
	2034	14	6.16	7.88	0.26	2.08

Crediting Period	**2035**	15	6.16	7.88	0.24	1.89
	2036	16	6.16	7.88	0.22	1.72
	2037	17	6.16	7.88	0.20	1.56
	2038	18	6.16	7.88	0.18	1.42
	2039	19	6.16	7.88	0.16	1.29
	2040	20	6.16	7.88	0.15	1.17
	2041	21	6.16	7.88	0.14	1.07
					NPV Million USD	**34.58**

6.0 CONCLUSIONS AND RECOMMENDATIONS

In seeking to define a viable project that could illustrate how to successfully engage the CDM and receive credit for CERs, we conclude the following:

- For any project to engage the CDM , it has to meet the "additionality" requirement which establishes that the planned emission reductions would not occur without the additional incentive provided by the CERs.
- There is a tradeoff between economic feasibility of a power transmission project and its potential for successful engagement of the CDM. A project that is clearly profitable financially, and without added incentives from the CERs, would have difficulty satisfying the additionality requirement of the CDM. On the other hand, a project that is clearly not profitable economically, may manage to satisfy the additionality requirement, but the additional incentives from the CERs may not be sufficient to attract financial investment in the project.
- The ideal successful project for engaging the CDM is one that is potentially feasible, marginally profitable. In that case, any additional incentives from CERs would make it, no doubt, profitable and hence attractive for financial investments.
- The main challenge with the scenario of export of electricity from Ethiopia to Sudan, instead of local generation of electricity from oil based fuel, is the highly profitable nature of such activity which should justify investment in that activity, even without any

credit that can be gained due to approval of CERs. This fact makes it almost impossible to satisfy the “additionality” requirement.

- Applying the above principles, export of electricity from Ethiopia to Sudan instead of local generation of electricity from oil is too profitable to succeed in engaging the CDM. While export of electricity from Ethiopia to Sudan instead of local generation from coal, or export of electricity from Ethiopia to Egypt instead of local generation from natural gas are promising projects for successfully engaging the CDM.
- For engaging the CDM, we recommend a project that has been considered as a feasible option by the Power Trade Study and consists of the development of a transmission line connecting Egypt to the already connected regional network between Sudan and Ethiopia. Under this scenario, Egypt receives 700MW of imported electricity from Ethiopia generated from renewable hydropower, and thus, averting the generation of electricity from CCGT fueled by natural gas. This supply of electricity will be in two phases: In 2023 Egypt will receive 500 MW imported electricity and in 2024 Egypt will receive an additional 200 MW from Ethiopia.
- According to original power development plans in Ethiopia, in 2023 and 2024 Ethiopia should commission Advance Beko Abo (~700 MW), and Mandaya hydropower projects. While Mandaya reservoir power density is less than 4 W/m2, the power density of the Beko Abo which will generate about 700MW, is greater than 4 W/m2. Hence in engaging the CDM the Beko Abo project should be emphasized.
- We recommend applying the AM0108 approved methodology when developing the PDD. We recommend conducting a clear barrier analysis to ensure that the scenario does not have other constraints. In order to demonstrate that the additionality condition is met due to the low price of natural gas, Egypt or Sudan would need to show that the CER credits are needed to engage in this clean project.

REFERENCES

United Nations. Clean Development Mechanism Executive Board. 2004. Approved Consolidated Baseline Methodology ACM0002: Consolidated baseline methodology for grid-connected electricity generation from renewable sources. Version 2. http://cdm.unfccc.int/UserManagement/FileStorage/ACM0002_Consolidated_elct_version_2.pdf.

United Nations. United Nations Framework Convention on Climate Change. 1992. Kyoto Protocol to the United Nations Framework Convention on Climate Change. http://unfccc.int/resource/docs/convkp/kpeng.html.

APPENDIX A: CDM Methodologies

Approved consolidated baseline and monitoring methodology ACM0002

“Consolidated baseline methodology for grid-connected electricity generation from renewable sources”

http://cdm.unfccc.int/methodologies/DB/UB3431UT9I5KN2MUL2FGZXZ6CV71LT/view.html

Approved baseline and monitoring methodology AM0108

“Interconnection between electricity systems for energy exchange”

http://cdm.unfccc.int/methodologies/DB/KR3GWTWMUQ7EWN1UR7Z7H92VA5JQEW

APPENDIX B: Emission Reduction Spreadsheet and calculation (Scenario II)

EMISSION REDUCTION

$$ER_y = BE_y - PE_y - LE_y$$

Description	Unit	Symbol	2020	2021	2022	2023	2024	2025	2026	2027	2028	Average
Emission reductions in year *y*	M t CO2	ER_y	0.00	0.00	0.00	1.16	1.62	1.62	1.62	1.62	1.62	1.03
Baseline emissions in year *y*	M t CO2	BE_y	0.00	0.00	0.00	1.41	1.97	1.97	1.97	1.97	1.97	1.25
Project emissions in year *y*	M t CO2	PE_y	0.00	0.00	0.00	0.25	0.35	0.35	0.35	0.35	0.35	0.22
Leakage emissions in year *y*	M t CO2	LE_y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

LEAKAGE

* If Leakage is negative (which occurs often because the Reserve capacity is often greater than 15%, then leakage is zeroed out. No negative leakages is allowed.

$$LE_y = 8760 \times (0.15 - RC_y) \times CAP_{\exp,\ y} \times EF_d$$

$$RC_y = 1 - \frac{(LOAD_{\max,\ y} + CAP_{NL,y})}{CAP_{\exp,\ y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Leakage emissions in year *y*	LE_y	t CO2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Minimal reserve capacity in the exporting electricity system in the year *y*	RC_y		0.44	0.35	0.38	0.26	0.25	0.24	0.28	0.29	0.35
Maximum system load in the exporting electricity system (excluding the project exports) in the year *y*	Load_max,y	MW	3750	4350	4600	5250	5550	5900	6200	6600	6900
Theoretical maximum capacity of the new transmission line in year *y*	CAP_NL,y	MW	0	0	0	500	700	700	700	700	700
Installed power capacity in the exporting electricity system in the year *y*	CAP_exp,y	MW	6700	6700	7400	7800	8300	8700	9600	10350	11700
Emission factor for the electricity generated by diesel power plants	EF_d*	t CO2/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

* AMS-I.F default value of 0.8 tCO2/MWh for generators >200 kW; otherwise use regional or average default values if they are reliable and documented

BASELINE EMISSIONS

$$BE_y = INE_{imp,y} \times EF_{imp,y} + INE_{exp,y} \times EF_{BSL,exp,y}$$

$$INE_{imp,y} = INE_{imp,measured,y} - PTC_{exist} \times 876$$

$$INE_{exp,y} = INE_{exp,measured,y} - \max\left[0;\left(INE_{exist,exp,hist} - INE_{exist,exp,measured,y}\right)\right]$$

$$EF_{exp,y} = \max\left\{EF_{exp,OMadapted,y}; EF_{exp,BM,y}\right\}$$

$$EF_{exp,OMadapted,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Start Year			2020								
Baseline emissions in the year *y*	BE_y	(t CO2)	0	0	0	1407294	1970211.6	1970211.6	1970211.6	1970211.6	1970211.6
Net amount of electricity received in the importing electricity system because of the project activity in year *y*	$INE_{IMP,Y}$	(MWh)	0	0	0	2759400	3863160	3863160	3863160	3863160	3863160
Net amount of electricity received in the exporting electricity system because of the project activity in year *y*	$INE_{EXP,Y}$	(MWh)	0	0	0	0	0	0	0	0	0
CO_2 emission factor for the importing electricity system in the year *y*	$EF_{IMP,y}$	(t CO2 per MWh)	0	0	0	0.51	0.51	0.51	0.51	0.51	0.51
CO_2 baseline emission factor for the exporting electricity system	$EF_{BSL,EXP,Y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
CO_2 project emission factor for the exporting electricity system	$EF_{exp,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
"Adapted" simple operating margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,OMadapted,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Build margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,BM,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the importing electricity system, measured in the new line in year *y*	$INE_{IMP,measured}$	(MWh)	0	0	0	2759400	3863160	3863160	3863160	3863160	3863160
Power transmission capacity of the existing transmission lines between exporting and importing electricity systems	PTC_{exit}	(MWh)	0	0	0	0	0	0	0	0	0

Net amount of electricity received in the exporting electricity system, measured in the new line in year *y*	$INE_{exp,measured, y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity received in the exporting electricity system from the importing electricity system in the existing lines	$INE_{exist,exp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$INE_{exist,exp,measured, y}$	(MWh)	0	0	0	0	0	0	0	0	0

PROJECT EMISSIONS

$$PE_y = PE_{elec,y} + PE_{def,1} + PE_{CH4,y} + PE_{SF6,y}$$

$$PE_{elec,y} = OUTE_{\exp,y} \times EF_{\exp,y} + OUTE_{imp,y} \times EF_{imp,y} + \max\left[0;\left(OUTE_{imp-other,y} - OUTE_{imp-other,hist}\right)\right] \times EF_{imp,y}$$

$$OUTE_{imp,y} = OUTE_{imp,measured,y} + \max\left[0;\left(OUTE_{exist,imp,measured,y} - OUTE_{exist,imp,hist}\right)\right]$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Project emissions in year *y*	PE_y	(t CO2)	0	0	0	248346	347684.4	347684.4	347684.4	347684.4	347684.4
Project emissions from incremental electricity generation in year *y*	$PE_{elec,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0								
Project emissions from new hydropower reservoirs in year *y*	$PE_{CH4,y}$	(t CO2)	0	0	0	248346	347684.4	347684.4	347684.4	347684.4	347684.4
Project emissions from fugitive SF_6 emissions in year *y*	$PE_{SF6,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year *y*	$OUTE_{exp,y}$	(MWh)	0	0	0	2759400	3863160	3863160	3863160	3863160	3863160
Amount of electricity supplied from the importing electricity system to the exporting electricity system because of the project activity in year *y*	$OUTE_{imp,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Amount of electricity sent from the importing electricity system to the third party electricity system in the year *y*	$OUTE_{imp-other,y}$	(MWh)	0	0	0	0	0	0	0	0	0

Historical amount of electricity sent from the importing electricity system to the third party electricity system	$OUTE_{imp-other,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied from the importing electricity system to the exporting electricity system, measured in the new line in year *y*	$OUTE_{imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity supplied to the exporting electricity system from the importing electricity system in the existing lines	$OUTE_{exist,imp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied to the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$OUTE_{exist,imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0

DEFORESTATION

** assume no deforestation (desert everywhere)

$$PE_{def,1} = \sum_{k}\left(L_{DEF,k} \times W_{DEF,k} \times M_{A,k} \times 0.5 \times \frac{44}{12}\right)$$

Description	Symbol	Unit	2020
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0

Segment of transmission line	k=	Unit	1	2	3
Length deforested for segment k (100m)	L_def,k	(100m)	16650		
Width deforested for segment k (100m)	W_def, k	(100m)	1		
Aboveground biomass of land to be deforested for segment k (tonnes d.m./ha)	M_A,k	tonnes d.m/ha	0		

SULFUR HEXAFLOURIDE

*can be excluded from ex ante ER estimate

$$PE_{SF6,y} = M_{SF6,y} \times GWP_{SF6}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Project emissions of SF_6 from new equipment (e.g. transformers) installed under the project activity in year *y* (t CO_2)	$PE_{SF6,y}$	*t CO2*	0	0	0	0	0	0	0	0	0
The average quantity of SF_6 emitted from equipment installed under the project activity in year *y* (tSF_6)	$M_{SF6,y}$	*t SF6*	0	0	0	0	0	0	0	0	0
Global warming potential of SF_6 (t CO_2/tSF_6)	GWP_{SF6}	*t CO2/tSF6*	23,900								

* GWP: Intergovernmental Panel on Climate Change, Working Group 1, Climate Change 2007, Chapter 2.10.2.
Project participants shall update GWPs according to any decisions by the CMP. For the first commitment period GWPSF6=23,900

METHANE

$$PE_{CH4,y} = \frac{EF_{res} \times \min\left(EG_{z,y}, OUTE_{\exp,y}\right)}{1000}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
	PE_CH4	tCO2	0	0	0	248346	347684.4	347684.4	347684.4	347684.4	347684.4
Default emission factor for emissions from reservoirs of hydro power units with power densities between 4 and 10 W/m^2	EF_res*	kgCO2 per MWh	90								

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year y	OUTEexp,y*	(MWh)	0	0	0	2.76E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06
Electricity generation from hydro power unit z with the power density between 4 and 10 W/m^2 in year	EG_z,y	MWh									
		1	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	0

*Decision by methodology reviewers (EB 23) to apply value 90

**Assume OUTE < Egz,y. This will be a conservative estimate; IF OUTE is higher than EG it means higher PE and less Emissionr reduction

Emission Factor for Generated Electricity: (Option A)

Option

Amount of fuel type i consumed by power unit m in year y (mass or volume unit)

FC_i,m,y									
m=1									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									
m=2									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									
m=3									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

*"Tool to calculate the emission factor for an electricity system")

Net calorific value (energy content) of fuel type i in year y (GJ/mass or volume unit)

NCV_i,y									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1-NG	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4
2									
3									

** use regional or natioal default values or see "Tool to calc EF of elec sys"
or use IPCC defalt values at upper limit of uncertainity at 95% CI
Table 1.2 Ch 1 Vol2 2006 IPCC Guidelines on National GHG Inventories

Average CO2emission factor of fuel type i used in power unit m in year y (tCO2/GJ)

EF_CO2,i,y									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583
2									
3									

FC_i,m,y*NCV_i,y*EF_CO2,i,y									
m=1	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0
m=2	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0
m=3	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

Option A

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

$EG_{m,y}$	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*									
(MWh)	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1									
	2									
	3									

*"Tool to calculate the emission factor for an electricity system")

$EF_{EL,m,y}$	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*									
(t CO_2/MWh)	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	0

Emission Factor for Generated Electricity: (Option B)

Option B

Average CO_2 emission factor of fuel type *i* used in power unit *m* in year *y* (tCO_2/GJ)	EF_CO2,m,i,y										
	m=1		**0.000**	**0.075**	**0.075**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1-NG	0	0.0748	0.0748	0	0	0	0	0	0
		2									
		3									
	m=2		**0**	**0**	**0**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1	0	0	0	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583
		2									
		3									
	m=3		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1									
		2									
		3									

** use natioanla or regional defulat values

or use IPCC defalt values at upper limit of uncertainity at 95% CI

Table 1.4 chap 1 vol2 of 2006 IPCC Guidelines on National GHG inventories

** See Tool to calc EF for elec syst

Average net energy conversion efficiency of power unit *m* in year *y* (%)	n_m,y									
	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0.4	0.4	0	0	0	0	0	0
		0	0	0	0.6	0.6	0	0	0	0
	3									

Use either:

- Documented manufacturer's specifications or
- Data from the utility, the dispatch center or official records if it can be deemed reliable; or

- The default values provided in the table in Annex 1 of the "Tool to calc EF for elec sys"

Option B

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

$EF_{EL,m,y}$

Net amount of electricity generated and delivered to the grid by power unit m in year y ((t CO2/MWh))	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0.6732	0.6732	0	0	0	0	0	0
	2	0	0	0	0.3498	0.3498	0	0	0	0
	3	0	0	0	0	0	0	0	0	0

use the fuel type with the highest CO_2 emission factor for $EF_{CO2,m,i,y}$.

APPENDIX C: Emission Reduction Spreadsheet and calculation (Scenario III)

(i) Export of Electricity from Ethiopia to Egypt

EMISSION REDUCTION

$$ER_y = BE_y - PE_y - LE_y$$

Description	Unit	Symbol	2020	2021	2022	2023	2024	2025	2026	2027	2028
Emission reductions in year *y*	M t CO2	ER_y	0.00	1.16	2.32	3.48	4.64	4.64	4.64	4.64	4.64
Baseline emissions in year *y*	M t CO2	BE_y	0.00	1.41	2.81	4.22	5.63	5.63	5.63	5.63	5.63
Project emissions in year *y*	M t CO2	PE_y	0.00	0.25	0.50	0.75	0.99	0.99	0.99	0.99	0.99
Leakage emissions in year *y*	M t CO2	LE_y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

LEAKAGE

* If Leakage is negative (which occurs often because the Reserve capacity is often greater than 15%, then leakage is zeroed out. No negative leakages is allowed.

$$LE_y = 8760 \times (0.15 - RC_y) \times CAP_{\exp,y} \times EF_d$$

$$RC_y = 1 - \frac{(LOAD_{\max,y} + CAP_{NL,y})}{CAP_{\exp,y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Leakage emissions in year *y*	LE_y	t CO2	0	0	0	0	0	0	0	0	0
Minimal reserve capacity in the exporting electricity system in the year *y*	RC_y		0.44	0.33	0.29	0.22	0.17	0.17	0.22	0.24	0.30
Maximum system load in the exporting electricity system (excluding the project exports) in the year *y*	Load_max,y	MW	3750	4000	4250	4550	4850	5200	5500	5900	6200
Theoretical maximum capacity of the new transmission line in year *y*	CAP_NL,y	MW	0	500	1000	1500	2000	2000	2000	2000	2000
Installed power capacity in the exporting electricity system in the year *y*	CAP_exp,y	MW	6700	6700	7400	7800	8300	8700	9600	10350	11700
Emission factor for the electricity generated by diesel power plants	EF_d*	t CO2/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

* AMS-I.F default value of 0.8 tCO2/MWh for generators >200 kW; otherwise use regional or average default values if they are reliable and documented

BASELINE EMISSIONS

$$BE_y = INE_{imp,y} \times EF_{imp,y} + INE_{exp,y} \times EF_{BSL,exp,y}$$

$$INE_{imp,y} = INE_{imp,measured,y} - PTC_{exist} \times 8760$$

$$INE_{exp,y} = INE_{exp,measured,y} - \max\left[0; \left(INE_{exist,exp,hist} - INE_{exist,exp,measured,y}\right)\right]$$

$$EF_{exp,y} = \max\left\{EF_{exp,OMadapted,y}; EF_{exp,BM,y}\right\}$$

$$EF_{exp,OMadapted,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Start Year			2020								
Baseline emissions in the year *y*	BE_y	(t CO2)	0	1E+06	3E+06	4221882	5629176	5629176	5629176	5629176	5629176
Net amount of electricity received in the importing electricity system because of the project activity in year *y*	$INE_{IMP,Y}$	(MWh)	0	3E+06	6E+06	8278200	11037600	11037600	11037600	11037600	11037600
Net amount of electricity received in the exporting electricity system because of the project activity in year *y*	$INE_{EXP,Y}$	(MWh)	0	0	0	0	0	0	0	0	0
CO_2 emission factor for the importing electricity system in the year *y*	$EF_{IMP,y}$	(t CO2 per MWh)	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
CO_2 baseline emission factor for the exporting electricity system	$EF_{BSL,EXP,Y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
CO_2 project emission factor for the exporting electricity system	$EF_{exp,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
"Adapted" simple operating margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,OMadapted,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Build margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,BM,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the importing electricity system, measured in the new line in year *y*	$INE_{IMP,measured}$	(MWh)	0	3E+06	6E+06	8278200	11037600	11037600	11037600	11037600	11037600
Power transmission capacity of the existing transmission lines between exporting and importing electricity systems	PTC_{exit}	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the exporting electricity system, measured in the new line in year *y*	$INE_{exp,measured,\ y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity received in the exporting electricity system from the importing electricity system in the existing lines	$INE_{exist,exp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$INE_{exist,exp,measured,y}$	(MWh)	0	0	0	0	0	0	0	0	0

PROJECT EMISSIONS

$$PE_y = PE_{elec,y} + PE_{def,1} + PE_{CH4,y} + PE_{SF6,y}$$

$$PE_{elec,y} = OUTE_{exp,y} \times EF_{exp,y} + OUTE_{imp,y} \times EF_{imp,y} + \max\left[0;\left(OUTE_{imp-other,y} - OUTE_{imp-other,hist}\right)\right] \times EF_{imp,y}$$

$$OUTE_{imp,y} = OUTE_{imp,measured,y} + \max\left[0;\left(OUTE_{exist,imp,measured,y} - OUTE_{exist,imp,hist}\right)\right]$$

Description	**Symbol**	**Unit**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Project emissions in year *y*	PE_y	(t CO2)	0	248346	496692	745038	993384	993384	993384	993384	993384
Project emissions from incremental electricity generation in year *y*	$PE_{elec,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0								
Project emissions from new hydropower reservoirs in year *y*	$PE_{CH4,y}$	(t CO2)	0	248346	496692	745038	993384	993384	993384	993384	993384
Project emissions from fugitive SF_6 emissions in year *y*	$PE_{SF6,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year *y*	$OUTE_{exp,y}$	(MWh)	0	2759400	5518800	8278200	11037600	11037600	11037600	11037600	11037600
Amount of electricity supplied from the importing electricity system to the exporting electricity system because of the project activity in year *y*	$OUTE_{imp,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Amount of electricity sent from the importing electricity system to the third party electricity system in the year *y*	$OUTE_{imp-other,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical amount of electricity sent from the importing electricity system to the third party electricity system	$OUTE_{imp-other,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied from the importing electricity system to the exporting electricity system, measured in the new line in year *y*	$OUTE_{imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity supplied to the exporting electricity system from the importing electricity system in the existing lines	$OUTE_{exist,imp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied to the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$OUTE_{exist,imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0

DEFORESTATION

** assume no deforestation (desert everywhere)

$$PE_{def,1} = \sum_k \left(L_{DEF,k} \times W_{DEF,k} \times M_{A,k} \times 0.5 \times \frac{44}{12} \right)$$

Description	Symbol	Unit	2020
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0

Segment of transmission line	k=	Unit	1	2	3
Length deforested for segment k (100m)	L_def,k	(100m)	16650		
Width deforested for segment k (100m)	W_def, k	(100m)	1		
Aboveground biomass of land to be deforested for segment k (tonnes d.m./ha)	M_A,k	tonnes d.m/ha	0		

SULFUR HEXAFLOURIDE

*can be excluded from ex ante ER estimate

$$PE_{SF6,y} = M_{SF6,y} \times GWP_{SF6}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Project emissions of SF_6 from new equipment (e.g. transformers) installed under the project activity in year *y* (t CO_2)	$PE_{SF6,y}$	*t CO2*	0	0	0	0	0	0	0	0	0
The average quantity of SF_6 emitted from equipment installed under the project activity in year *y* (tSF_6)	$M_{SF6,y}$	*t SF6*	0	0	0	0	0	0	0	0	0
Global warming potential of SF_6 (t CO_2/tSF_6)	GWP_{SF6}	*t CO2/tSF6*	23,900								

* GWP: Intergovernmental Panel on Climate Change, Working Group 1, Climate Change 2007, Chapter 2.10.2.
Project participants shall update GWPs according to any decisions by the CMP. For the first commitment period GWPSF6=23,900

METHANE

$$PE_{CH4,y} = \frac{EF_{res} \times \min\left(EG_{z,y}, OUTE_{\exp,y}\right)}{1000}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
	PE_CH4	tCO2	0	0	0	248346	347684.4	347684.4	347684.4	347684.4	347684.4
Default emission factor for emissions from reservoirs of hydro power units with power densities between 4 and 10 W/m^2	EF_res*	kgCO2 per MWh	90								

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year y	OUTEexp,y*	(MWh)	0	0	0	2.76E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06
Electricity generation from hydro power unit z with the power density between 4 and 10 W/m^2 in year	EG_z,y	MWh									
		1	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	0

*Decision by methodology reviewers (EB 23) to apply value 90

**Assume OUTE < Egz,y. This will be a conservative estimate; IF OUTE is higher than EG it means higher PE and less Emissionr reduction

Emission Factor for Generated Electricity: (Option A)

Option

FC_i,m,y — Amount of fuel type i consumed by power unit m in year y (mass or volume unit)

m=1									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

m=2									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

m=3									
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

*"Tool to calculate the emission factor for an electricity system")

NCV_i,y — Net calorific value (energy content) of fuel type i in year y (GJ/mass or volume unit)

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1 - NG	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4
2									
3									

** use regional or natioal default values or see "Tool to calc EF of elec sys"
or use IPCC defalt values at upper limit of uncertainity at 95% CI
Table 1.2 Ch 1 Vol2 2006 IPCC Guidelines on National GHG Inventories

EF_CO2,i,y — Average CO2emission factor of fuel type i used in power unit m in year y (tCO2/GJ)

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583
2									
3									

FC_i,m,y*NCV_i,y*EF_CO2,i,y

m = 1	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

m = 2	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

m = 3	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

Option A

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

EG $_{m,y}$	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*									
(MWh)	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1									
	2									
	3									

*"Tool to calculate the emission factor for an electricity system")

$EF_{EL,m,y}$	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*									
(tCO_2/MWh)	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	0

Emission Factor for Generated Electricity: (Option B)

Option B

Average CO_2emission factor of fuel type *i* used in power unit *m* in year *y* (tCO_2/GJ)	EF_CO2,m,i,y										
	m=1		**0.000**	**0.075**	**0.075**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1									
		2									
		3									
	m=2		**0**	**0**	**0**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1									
		2									
		3									
	m=3		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1									
		2									
		3									

** use natioanla or regional defulat values
or use IPCC defalt values at upper limit of uncertainity at 95% CI
Table 1.4 chap 1 vol2 of 2006 IPCC Guidelines on National GHG inventories
** See Tool to calc EF for elec syst

n_m,y										
Average net energy conversion efficiency of power unit *m* in year *y* (%)	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1									
	3									

Use either:

- Documented manufacturer's specifications or
- Data from the utility, the dispatch center or official records if it can be deemed reliable; or

- The default values provided in the table in Annex 1 of the "Tool to calc EF for elec sys"

Option B

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

Net amount of electricity generated and delivered to the grid by power unit m in year y ((t CO2/MWh))	$EF_{EL,m,y}$									
	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1									
	2									
	3									

use the fuel type with the highest CO_2 emission factor for $EF_{CO2,m,i,y}$.

(ii) Export of Electricity from Ethiopia to Sudan

EMISSION REDUCTION

$$ER_y = BE_y - PE_y - LE_y$$

Description	Unit	Symbol	2020	2021	2022	2023	2024	2025	2026	2027	2028
Emission reductions in year *y*	M t CO2	ER_y	0.00	0.00	0.00	0.00	0.00	0.51	2.31	4.11	6.16
Baseline emissions in year *y*	M t CO2	BE_y	0.00	0.00	0.00	0.00	0.00	0.56	2.53	4.50	6.76
Project emissions in year *y*	M t CO2	PE_y	0.00	0.00	0.00	0.00	0.00	0.05	0.22	0.40	0.60
Leakage emissions in year *y*	M t CO2	LE_y	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

LEAKAGE

* If Leakage is negative (which occurs often because the Reserve capacity is often greater than 15%, then leakage is zeroed out. No negative leakages is allowed.

$$LE_y = 8760 \times (0.15 - RC_y) \times CAP_{\exp,y} \times EF_d$$

$$RC_y = 1 - \frac{(LOAD_{\max,y} + CAP_{NL,y})}{CAP_{\exp,y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Leakage emissions in year *y*	LE_y	t CO2	0	0	0	0	0	0	0	0	0
Minimal reserve capacity in the exporting electricity system in the year *y*	RC_y		0.44	0.40	0.43	0.42	0.42	0.39	0.38	0.35	0.37
Maximum system load in the exporting electricity system (excluding the project exports) in the year *y*	Load_max,y	MW	3750	4000	4250	4550	4850	5200	5500	5900	6200
Theoretical maximum capacity of the new transmission line in year *y*	CAP_NL,y	MW	0	0	0	0	0	100	450	800	1200
Installed power capacity in the exporting electricity system in the year *y*	CAP_exp,y	MW	6700	6700	7400	7800	8300	8700	9600	10350	11700
Emission factor for the electricity generated by diesel power plants	EF_d*	t CO2/MWh	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8

* AMS-I.F default value of 0.8 tCO2/MWh for generators >200 kW; otherwise use regional or average default values if they are reliable and documented

BASELINE EMISSIONS

$$BE_y = INE_{imp,y} \times EF_{imp,y} + INE_{exp,y} \times EF_{BSL,exp,y}$$

$$INE_{imp,y} = INE_{imp,measured,y} - PTC_{exist} \times 8760$$

$$INE_{exp,y} = INE_{exp,measured,y} - \max\left[0;\left(INE_{exist,exp,hist} - INE_{exist,exp,measured,y}\right)\right]$$

$$EF_{exp,y} = \max\left\{EF_{exp,OMadapted,y}; EF_{exp,BM,y}\right\}$$

$$EF_{exp,OMadapted,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Start Year			2020								
Baseline emissions in the year *y*	BE_y	(t CO2)	0	0	0	0	0	562917.6	2533129.2	4503340.8	6755011.2
Net amount of electricity received in the importing electricity system because of the project activity in year *y*	$INE_{IMP,Y}$	(MWh)	0	0	0	0	0	551880	2483460	4415040	6622560
Net amount of electricity received in the exporting electricity system because of the project activity in year *y*	$INE_{EXP,Y}$	(MWh)	0	0	0	0	0	0	0	0	0
CO_2 emission factor for the importing electricity system in the year *y*	$EF_{IMP,y}$	(t CO2 per MWh)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
CO_2 baseline emission factor for the exporting electricity system	$EF_{BSL,EXP,Y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
CO_2 project emission factor for the exporting electricity system	$EF_{exp,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
"Adapted" simple operating margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,OMadapted,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Build margin CO_2 emission factor for the exporting electricity system in year *y*	$EF_{exp,BM,y}$	(t CO2 per MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the importing electricity system, measured in the new line in year *y*	$INE_{IMP,measured}$	(MWh)	0	0	0	0	0	551880	2483460	4415040	6622560
Power transmission capacity of the existing transmission lines between exporting and importing electricity systems	PTC_{exit}	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the exporting electricity system, measured in the new line in year *y*	$INE_{exp,measured,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity received in the exporting electricity system from the importing electricity system in the existing lines	$INE_{exist,exp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity received in the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$INE_{exist,exp,measured,y}$	(MWh)	0	0	0	0	0	0	0	0	0

PROJECT EMISSIONS

$$PE_y = PE_{elec,y} + PE_{def,1} + PE_{CH4,y} + PE_{SF6,y}$$

$$PE_{elec,y} = OUTE_{exp,y} \times EF_{exp,y} + OUTE_{imp,y} \times EF_{imp,y} + \max\left[0;\left(OUTE_{imp-other,y} - OUTE_{imp-other,hist}\right)\right] \times EF_{imp,y}$$

$$OUTE_{imp,y} = OUTE_{imp,measured,y} + \max\left[0;\left(OUTE_{exist,imp,measured,y} - OUTE_{exist,imp,hist}\right)\right]$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Project emissions in year *y*	PE_y	(t CO2)	0	0	0	0	0	49669.2	223511.4	397353.6	596030.4
Project emissions from incremental electricity generation in year *y*	$PE_{elec,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0								
Project emissions from new hydropower reservoirs in year *y*	$PE_{CH4,y}$	(t CO2)	0	0	0	0	0	49669.2	223511.4	397353.6	596030.4
Project emissions from fugitive SF_6 emissions in year *y*	$PE_{SF6,y}$	(t CO2)	0	0	0	0	0	0	0	0	0
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year *y*	$OUTE_{exp,y}$	(MWh)	0	0	0	0	0	551880	2483460	4415040	6622560
Amount of electricity supplied from the importing electricity system to the exporting electricity system because of the project activity in year *y*	$OUTE_{imp,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Amount of electricity sent from the importing electricity system to the third party electricity system in the year *y*	$OUTE_{imp-other,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical amount of electricity sent from the importing electricity system to the third party electricity system	$OUTE_{imp-other,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied from the importing electricity system to the exporting electricity system, measured in the new line in year *y*	$OUTE_{imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0
Historical net amount of electricity supplied to the exporting electricity system from the importing electricity system in the existing lines	$OUTE_{exist,imp,hist}$	(MWh)	0	0	0	0	0	0	0	0	0
Net amount of electricity supplied to the exporting electricity system from the importing electricity system, measured in the existing lines in year *y*	$OUTE_{exist,imp,meas,y}$	(MWh)	0	0	0	0	0	0	0	0	0

DEFORESTATION

** assume no deforestation (desert everywhere)

$$PE_{def,1} = \sum_k \left(L_{DEF,k} \times W_{DEF,k} \times M_{A,k} \times 0.5 \times \frac{44}{12} \right)$$

Description	Symbol	Unit	2020
Project emissions from the deforestation during the first year of the crediting period	$PE_{def,1}$	(t CO2)	0

Segment of transmission line	k=	Unit	1	2	3
Length deforested for segment k (100m)	L_def,k	(100m)	16650		
Width deforested for segment k (100m)	W_def, k	(100m)	1		
Aboveground biomass of land to be deforested for segment k (tonnes d.m./ha)	M_A,k	tonnes d.m/ha	0		

SULFUR HEXAFLOURIDE

*can be excluded from ex ante ER estimate

$$PE_{SF6,y} = M_{SF6,y} \times GWP_{SF6}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Project emissions of SF_6 from new equipment (e.g. transformers) installed under the project activity in year *y* (t CO_2)	$PE_{SF6,y}$	*t CO2*	0	0	0	0	0	0	0	0	0
The average quantity of SF_6 emitted from equipment installed under the project activity in year *y* (tSF_6)	$M_{SF6,y}$	*t SF6*	0	0	0	0	0	0	0	0	0
Global warming potential of SF_6 (t CO_2/tSF_6)	GWP_{SF6}	*t CO2/tSF6*	23,900								

* GWP: Intergovernmental Panel on Climate Change, Working Group 1, Climate Change 2007, Chapter 2.10.2.
Project participants shall update GWPs according to any decisions by the CMP. For the first commitment period GWPSF6=23,900

METHANE

$$PE_{CH4,y} = \frac{EF_{res} \times \min(EG_{z,y}, OUTE_{\exp,y})}{1000}$$

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
	PE_CH4	tCO2	0	0	0	248346	347684.4	347684.4	347684.4	347684.4	347684.4
Default emission factor for emissions from reservoirs of hydro power units with power densities between 4 and 10 W/m^2	EF_res*	kgCO2 per MWh	90								

Description	Symbol	Unit	2020	2021	2022	2023	2024	2025	2026	2027	2028
Amount of electricity generated and sent from the exporting electricity system because of the project activity in year y	OUTEexp,y*	(MWh)	0	0	0	2.76E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06	3.86E+06
Electricity generation from hydro power unit z with the power density between 4 and 10 W/m^2 in year	EG_z,y	MWh									
		1	0	0	0	0	0	0	0	0	0
		2	0	0	0	0	0	0	0	0	0
		3	0	0	0	0	0	0	0	0	0

*Decision by methodology reviewers (EB 23) to apply value 90

**Assume OUTE < Egz,y. This will be a conservative estimate; IF OUTE is higher than EG it means higher PE and less Emissionr reduction

Emission Factor for Generated Electricity: (Option A)

Option

Amount of fuel type i consumed by power unit m in year y (mass or volume unit)

FC_i,m,y

m=1

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

m=2

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

m=3

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

*"Tool to calculate the emission factor for an electricity system")

Net calorific value (energy content) of fuel type i in year y (GJ/mass or volume unit)

NCV_i,y

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1 - NG	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4	50.4
2									
3									

** use regional or natioal default values or see "Tool to calc EF of elec sys"
or use IPCC defalt values at upper limit of uncertainity at 95% CI
Table 1.2 Ch 1 Vol2 2006 IPCC Guidelines on National GHG Inventories

Average CO2emission factor of fuel type i used in power unit m in year y (tCO2/GJ)

EF_CO2,i,y

i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583
2									
3									

FC_i,m,y*NCV_i,y*EF_CO2,i,y

m = 1	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

m = 2	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

m = 3	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

Option A

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{EG_{m,y}}$$

$EG_{m,y}$ (MWh)	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*								
m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1									
2									
3									

*"Tool to calculate the emission factor for an electricity system")

$EF_{EL,m,y}$ (tCO_2/MWh)	Net amount of electricity generated and delivered to the grid by power unit *m* in year *y*								
m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0

Emission Factor for Generated Electricity: (Option B)

Option B

Average CO_2emission factor of fuel type *i* used in power unit *m* in year *y* (tCO_2/GJ)	EF_CO2,m,i,y										
	m=1		**0.000**	**0.075**	**0.075**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1-NG	0	0.0748	0.0748	0	0	0	0	0	0
		2									
		3									
	m=2		**0**	**0**	**0**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**	**0.0583**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1	0	0	0	0.0583	0.0583	0.0583	0.0583	0.0583	0.0583
		2									
		3									
	m=3		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		i/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
		1									
		2									
		3									

** use natioanla or regional defulat values
 or use IPCC defalt values at upper limit of uncertainity at 95% CI
Table 1.4 chap 1 vol2 of 2006 IPCC Guidelines on National GHG inventories
** See Tool to calc EF for elec syst

Average net energy conversion efficiency of power unit *m* in year *y* (%)	n_m,y									
	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0.4	0.4	0	0	0	0	0	0
		0	0	0	0.6	0.6	0	0	0	0
	3									

Use either:

- Documented manufacturer’s specifications or
- Data from the utility, the dispatch center or official records if it can be deemed reliable; or
- The default values provided in the table in Annex 1 of the “Tool to calc EF for elec sys"

Option B

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

Net amount of electricity generated and delivered to the grid by power unit m in year y ((t CO2/MWh))	$EF_{EL,m,y}$									
	m/y	2020	2021	2022	2023	2024	2025	2026	2027	2028
	1	0	0.6732	0.6732	0	0	0	0	0	0
	2	0	0	0	0.3498	0.3498	0	0	0	0
	3	0	0	0	0	0	0	0	0	0

use the fuel type with the highest CO_2 emission factor for $EF_{CO2,m,i,y}$.