Low-carbon Energy Projects for Development in Sub-Saharan Africa

Unveiling the Potential, Addressing the Barriers

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2008
The World Bank
Washington, DC

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The Norwegian Trust Fund for Private Sector and Infrastructure (NTF-PSI), established by the Royal Norwegian Ministry of Foreign Affairs and the World Bank Group (WBG) in 2002, is an "umbrella" trust fund for supporting private-sector development and infrastructure within WBG operations. The NTF-PSI funds activities across the World Bank and International Finance Corporation (IFC) that aim to develop WBG and client-country capacity, promote inclusion of cross-cutting issues into World Bank and IFC operations, and foster cooperation among WBG units.

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Abbreviations and Acronyms

AfDB	African Development Bank
AG	Associated Gas
BRT	Bus Rapid Transit
CAPEX	Capital Expenditure
CCGT	Combined-cycle Gas Turbine
CDCF	Community Development Carbon Fund
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CF	Carbon Finance
CFL	Compact Fluorescent Lamp
CIF	Climate Investment Funds
CMM	Coal Mine Methane
CPF	Carbon Partnership Facility
DNA	Designated National Authority
ECOWAS	Economic Community of West African States
ERC	Emission Reduction Credit
ERPA	Emission Reduction Purchase Agreement
ESOU	Energy Sector Operational Unit
FIRR	Financial Internal Rate of Return
GGFR	Global Gas Flaring Reduction
GHG	Greenhouse Gas
HFO	Heavy Fuel Oil
IPP	Independent Power Producer
MFP	Multi-Functional Platform
OCGT	Open-cycle Gas Turbine
ODA	Official Development Assistance
OPC	Ordinary Portland Cement
PDD	Project Design Document
PHRD	Policy and Human Resources Development Fund
PIN	Project Idea Note
POA	Program of Activities
PPA	Power Purchase Agreement
PPO	Pure Plant Oil
PV	Photovoltaics
UEMOA	Economic and Monetary Union for West Africa
UNFCCC	United Nations Framework Convention on Climate Change

Acknowledgments

This study was led by Christophe de Gouvello, senior energy specialist in the World Bank Energy Cluster—first for Africa (AFTEG) and now for Latin America (LCSEG)—who, along with team members Massamba Thioye, senior energy consultant, and Felix B. Dayo, director and principal consultant at Triple "E" Systems, Inc., prepared this report. All three authors have served for three or more years on the Methodology Panel (MethPanel), a regulatory body of the Clean Development Mechanism (CDM) of the Kyoto Protocol. Major financing for this study was provided by the Norwegian Trust Fund for Private Sector and Infrastructure (NTF-PSI). The editing and printing of this report were supported by Carbon Finance Assist (CF-Assist) of the World Bank.

The authors gratefully acknowledge the valuable contributions of Govinda Timilsina, senior research economist in the Development Economics Research Group (DECRG) of the World Bank, and Francisco Sucre, senior energy specialist at COPCO. Sebastien Pascual, junior professional associate in the World Bank's Latin America and Caribbean Region Energy Unit (LCSEG) processed the data and, with the assistance of Jewel Caguiat of the CGMAD, International Finance Corporation, generated the country-based results. The team is grateful to Gauthier Le Maux of the World Bank Carbon Finance Business (CFB), Africa Region, whose valuable research on the cement industry was used in this study. The authors also recognize Natsuko Toba in the World Bank's Finance, Economics, and Urban Department (FEU), who provided valuable contributions in the final phase of writing.

The study team wishes to thank the numerous local experts and government and private-company representatives (many of whom are listed in Annex B of this report) who graciously agreed to be interviewed for this study during the team's 12-country field visit. We appreciate their valuable data and insights.

The team is especially grateful to Ashok Sarkar, senior energy specialist in the Energy, Transport and Water Department (ETWES) of the World Bank and former member of the MethPanel, and Johannes Heister, senior environmental economist and head of the methodology group in the Carbon Finance Unit (ENVCF), for their valuable advice and support throughout the study.

We extend our appreciation to peer reviewers Xiaodong Wang and Dana Rysankova, senior energy specialists in the Energy Cluster for Africa (AFTEG), and Venkata Ramana Putti, senior environmental specialist and team leader for Carbon Finance Assist (CF-Assist) in the Sustainable Development Group of the World Bank Institute (WBISD) for their valuable comments. Special thanks go to AFTEG staff members, particularly Michel Layec, lead energy economist, Philippe Benoit, lead specialist (now LCSEG sector manager), and Subramaniam Vijay Iyer, sector manager, who offered valuable advice from an operational perspective during the early stages of the study.

Finally, special thanks go to Norma Adams, editor, who took on the complex task of transforming the original manuscript into a readable document; Beni Chibberrao, who designed the report covers; and Nadine Dulac and Samira Elkhamlichi from Carbon Finance Assist (CF-Assist) (WBISD), who coordinated the production and dissemination of the report.

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Executive Summary

Amid rising oil prices and the adverse effects of global climate change, Sub-Saharan Africa has an unprecedented opportunity: choosing a cleaner development pathway via low-carbon energy alternatives that can reduce greenhouse gas (GHG) emissions and, at the same time, meet current suppressed energy demand and future needs more efficiently and affordably. Indeed, countries across the region stand to benefit from an increasing array of financial instruments—from the Clean Development Mechanism (CDM) and Carbon Finance (CF) products to the newly created Climate Investment Funds (CIF)—with which to develop clean and efficient energy. These and other innovative instruments can help to channel the additional funds needed for investing in new and existing generation assets to increase energy services via efficiency improvements or by turning net energy consumers into net producers in return for avoidance of future GHG emissions. Using such instruments, global efforts to combat climate change can provide the region's countries energy solutions for sustainable socioeconomic development.

While opportunities for such sustainable solutions are considerable in theory, to date, Sub-Saharan Africa has missed out. In the context of the CDM, for example, the region's current share in the project pipeline is only 1.4 percent—only 53 out of 3,902 projects—or nine times smaller than its global share in GHG emissions.[1] Thus, despite its comparatively small economies, the region's number of CDM projects should be larger.

Financial Instruments: An Overview

The CDM, defined in Article 12 of the Kyoto Protocol, is a process of certifying emission reductions achieved by projects executed in developing countries. Under the CDM, projects that demonstrate that they avoid GHG emissions that otherwise would have occurred can obtain international certificates, termed certified emission reductions (CERs). CERs are calculated using CDM approved methodologies. CF—a way to ascertain the future revenues from the sale of the CERs—serves as a bridge between CDM projects and the financial carbon markets, allowing CDM project developers to reflect the value of the CERs in their business plans. As a result, since November 2001, implementation of the CDM has generated strong financial incentive, unleashing a dynamic, bottom-up response from project developers worldwide. Indeed, the number of validated CDM projects has grown rapidly, more than doubling every year (figure 1).

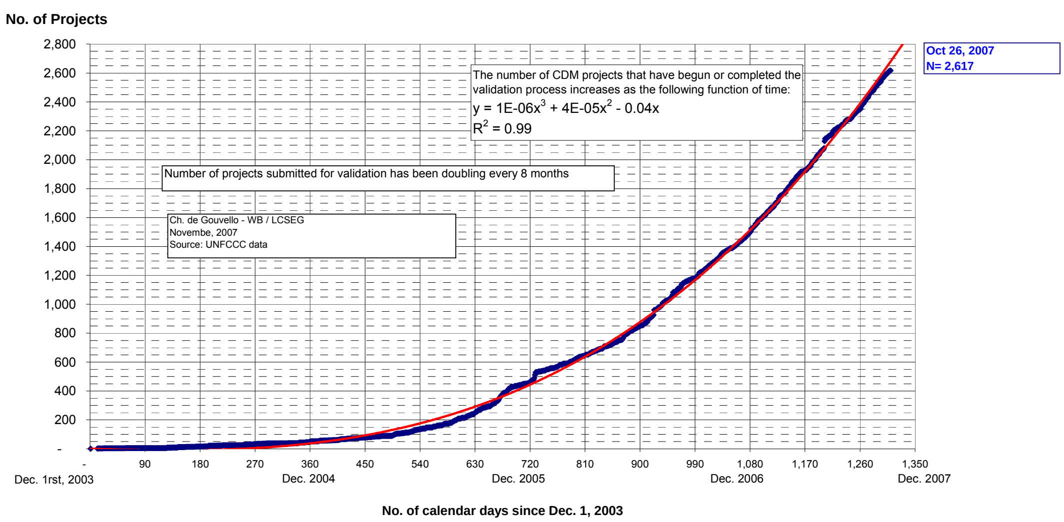
Over the past decade, the Carbon Finance Unit of the World Bank (ENVCF) has played a pioneering role in CF development, beginning with the creation of the world's first carbon fund, known as the Prototype Carbon Fund (PCF) in 1999. Subsequently, the World Bank has been asked to host and manage other carbon funds on behalf of industrialized countries wishing to benefit from World Bank experience to ensure their efficient purchase of CERs needed to comply with emission targets of the Kyoto Protocol. As a result, other funds have been created, including those targeting specific

[1] Including emissions from land use and land-use change.

project segments. By March 2008, the number of carbon funds hosted in the World Bank had increased to 11, and the total funds pledged had reached more than US$2.1 billion. Outside the World Bank, more than 60 carbon funds have been created. Worldwide, CF transactions related to CDM projects are expected to channel more than US$5 billion to developing countries before the end the first commitment period of the Kyoto Protocol in 2012. On September 25, 2007, the World Bank Board of Executive Directors approved the creation of the Carbon Partnership Facility (CPF) to purchase post-2012 emission reductions. The target size of the Facility over the first five years of operation is expected to reach €5 billion.

Besides CF tools, in July 2008, the Board of Directors officially approved the creation of the CIF, international investment instruments designed to provide interim, scaled-up funding for financing investment in projects and programs in developing countries that contribute to the transfer of low-carbon technologies and the testing of innovative approaches to climate change, respectively.

Figure 1: Number of CDM Projects That Have Already Applied for Validation



Implications for the Energy Sector

More than two-thirds of the more than 108 methodologies approved under the CDM to date are related to the energy sector. This emphasis is reflected in the pipeline of projects already submitted for validation, most of which are clean energy projects. As a result, a wide array of technical opportunities is available for reducing emissions associated with the energy sector—both projects focused solely on reducing emissions of the existing infrastructure, referred to as "pure decarbonization," as well as those that also increase or free up supply capacity that can contribute to sustainable economic and social development.

Together with CF tools, the CIF, and other financial instruments aimed at promoting low-emission technologies, the CDM can affect the development of the energy sector in developing countries. For example, it can optimize primary energy demand, make a cleaner technology preferable when additional power-generation capacity is needed, or realize a local renewable-energy potential. In such large countries as Brazil, China, and India, where hundreds of CDM projects are already in the pipeline, the CDM is expected to influence energy planning exercises.

Like other developing regions where CDM projects have been successfully implemented using commercially available technologies, Sub-Saharan Africa is similarly endowed with resources and facilities. For example, the region has many open-cycle power plants to which a second cycle could be added, thereby increasing generation capacity and plant efficiency at zero additional emissions. Efficient cogeneration plants could be added to sugar mills. In addition, refineries, flared gas, landfills, and other concentrated sources of GHG emissions could be used to generate power and heat. Incandescent lamps could be replaced by compact fluorescent lamps, thus saving significant amounts of fossil-fuel energy and, at the same time, reducing household energy bills.

Many such options comply with the conventional energy sector's strategy to provide consumers sufficient, cost-effective, and reliable energy supplies. But without supporting quantitative data, which is currently lacking, a common assumption among those in the climate-change community unfamiliar with the region is that its weak CDM portfolio simply reflects its poverty—that is, its countries have few industries, little emissions, and thus limited emission-reduction opportunities. Without verifiable data that demonstrates the region's technical potential, it is difficult for energy practitioners familiar with the region to convince a broader audience of Sub-Saharan Africa's significant potential for low-carbon energy development, particularly CDM projects, and the uptake of associated financial assistance.

Exploring Potential via the CDM Lens

Past efforts to produce detailed inventories of Sub-Saharan Africa's energy conservation potential proved extremely difficult. Earlier assessments were heavily constrained by an inability to form technical teams large enough to develop the detailed methodological framework required to cover the wide range of technical processes, equipment types, and operational conditions and assess an even greater diversity of emission-reduction potential. To date, few, if any, reports have been published on inventories of GHG emission-reduction opportunities in the region. However, with the recent development of the CDM methodological framework, that situation has changed.

The dynamic, bottom-up CDM process provides an unprecedented opportunity for exploring low-carbon energy opportunities. Each methodology developed under the CDM captures relevant details of the technology and operational parameters that determine emission reductions for one or more processes and describes the types of facilities in which these processes operate. In addition, the CDM validation pipeline database, publicly available on the website of the United Nations Framework Convention on Climate Change (UNFCCC), provides concrete examples of the facilities, processes, and achievable emission reductions. Thus, for any given country, it becomes far easier to count the number of facilities where emission-reduction projects corresponding to approved CDM methodologies can be developed.

Study Approach

Using the CDM lens, this study aimed to explore the potential for low-carbon energy projects for development in Sub-Saharan Africa. To this end, the study team identified technologies that could use the available approved CDM methodologies—many of which have already been applied successfully to projects in other developing regions—to both reduce GHG emissions and support energy development in the region via additional energy supply or more cost-effective use (box 1).

Box 1: Reshaping the CDM Scope from an Energy-sector Perspective

To ease comprehension for energy specialists unfamiliar with CDM terminology, the study team aggregated the methodologies approved by the CDM Executive Board and the corresponding clean energy technologies along the production chains of the most relevant energy subsectors. Generically, these production chains consist of three main stages: generation or production, transmission or transport and distribution, and consumption and use. The aim was not to propose a purely academic typology, but to choose one, among others, to help energy practitioners and decision makers relate the large amount of complex CDM information to the operational categories with which they are familiar.

The proposed structure, adjusted to reflect the feedback of energy practitioners and decision makers in Africa, is as follows:

- **Power.** The main stages of this subsector are generation, transmission and distribution, and consumption.
- **Fuels for industry**. This subsector includes several production chains, among which the two most important are oil and gas and coal. For oil and gas, the main stages are production (upstream industry), refining (downstream industry), transport (generally by pipeline, boat, or surface motorized means), and consumption in the industry, mainly for thermal uses in furnaces and boilers.
- **Fuels for vehicles**. While the conventional upstream part of this production chain is the same as that for the fuels-for-industry subsector, it differs with respect to clean-energy alternatives via the introduction of biofuel production (bio-ethanol and bio-diesel). Consumption occurs in motorized vehicles.
- **Woodfuel for households**. Sometimes referred to as traditional energy, this subsector encompasses the production, transport, and consumption of ligneous woodfuels.

The 22 technologies identified, organized along the production chains of the subsectors most relevant to Sub-Saharan Africa, are as follows:

- **Power**

  Generation from Fossil Fuels
  - Second-cycle additions to open-cycle, gas turbine plants
  - Combined heat and power for industry

  Generation from Renewable Energy
  - Combined heat and power in sugar mills
  - Agricultural residue
  - Forest and wood-processing residues
  - Typha australis
  - Jatropha biofuel
  - Hydroelectricity
  - Photovoltaics in isolated rural areas
  - Landfill gas

  Transmission and Distribution
  - Grid-loss reduction

  Consumption and Use
  - Non-lighting electricity for industry
  - Switch to compact fluorescent lamps
  - Energy-saving household appliances

- **Fuels for industry**

  Production
  - Flared gas recovery
  - Coal mine methane
  - Waste gases in crude oil refinery

  Thermal Use and Consumption
  - Improved steam system
  - Reduced clinker use in cement manufacturing

- **Fuels for vehicles**

  Production
  - Biodiesel from Jatropha

  Consumption and Use
  - Shift to Bus Rapid Transit (BRT)

- **Woodfuel for households**

  Production
  - Improved charcoal production

The study team investigated existing databases and visited 12 countries to collect primary data with which to build a bottom up–driven, clean energy projects inventory for the region.[2] Where no detailed data were available at the facility level, the team used a mix of bottom-up and top-down approaches. Based on the current, publicly available information in the UNFCCC CDM pipeline, the team determined the average size and characteristics of the clean energy projects and host facilities. Then, aggregated country-sector data were used to estimate how many facilities, on average, should be present in the respective countries and thus how many projects could be developed. In addition, the team used specific methods to determine the contribution of these projects to the energy sector (in terms of added energy or demand management), expected volume of emission reduction and corresponding carbon revenue (assuming US$10 per tCO_2), and the required investment.

Synthesis of Study Results

This study revealed a large, diversified range of CDM opportunities across Sub-Saharan Africa's energy sector. For the 44 countries and 22 technologies considered, the study team estimated a technical potential of more than 3,200 clean energy projects, including 361 large programs (known as Programs of Activities), each consisting of hundreds or even thousands of single activities. If fully implemented, this estimated technical potential could provide more than 170 GW of additional power-generation capacity, more than twice the region's current installed capacity. The additional energy provided, both electrical and thermal, would equal roughly four times the region's current modern-energy production. The achievable avoidance of future GHG emissions would total about 740 million tCO_2 per year, more than the region's current annual GHG emissions (680 million tCO_2).[3]

About 64 percent of the *emission-reduction* potential would be related to biomass (e.g., bagasse, agricultural and agro-industrial residues, and forest and wood-industry residues), while 53 percent of the potential for *added power-generation capacity* would be derived from the improved use of fossil fuels. One should also note that clean energy projects that incur only incremental investment on already existing facilities (e.g., fossil fuel or sugarcane–based cogeneration in industry) could deliver one-third potential additional capacity and one-fifth emission reductions. Table 1 presents the aggregate results for the region, according to each of the technologies studied.

[2] The databases that have been used are presented as an excel file in a separate volume.

[3] Because the technical potential of clean energy generation is larger than the current energy demand, it could meet future demand growth and thus avoid additional GHG emissions under a business-as-usual development scenario.

Table 1: Consolidated Results of Potential Clean-energy Project Opportunities for Sub-Saharan Africa (All)

Technology	No. of projects	Projects' emissions reductions: millions tCO_2/yr	Projects' emissions reductions: % of country total	Reductions over projects' life span (millions tCO_2)[1]	Value of projects' emissions reductions (millions US$): US$5/ tCO_2	Value of projects' emissions reductions (millions US$): US$10/ tCO_2	Electricity generation: Projects (GWh/ yr	Electricity generation: Projects (% country total)	Added power of projects (MW): 90% load factor	Added power of projects (MW): % of total installed	Total investment cost of projects (billions US$)
Second-cycle addition to open-cycle gas turbine	204	36.1	5.3	360.8	1,804.0	3,608.1	51,912	0	5,931	8.6	7.1
Combined heat and power for industry	373	72.9	10.7	729.4	3,647.0	7,294.0	156,314	0	17,844	25.9	17.8
Combined heat and power in sugar mills	67	2.4	0.4	24.4	122.1	244.2	3,489	0	661	1.0	1.0
Agricultural residue	553	140.8	20.7	1,408.4	7,042.2	14,084.3	216,842	1	27,504	40.0	38.5
Forest residue[2]	321	62.6	9.2	625.8	3,128.9	6,257.9	98,415	0	12,483	18.1	17.5
Wood-processing residue[2]	406	20.3	3.0	203.4	1,029.9	2,053.9	31,987	0	4,057	5.9	5.7
Typha australis	40	3.1	0.5	31.0	155.1	310.3	4,675	0	593	0.9	0.8
Jatropha biofuel	555	176.8	26.0	3,712.0	18,560.0	37,120.0	218,767	1	27,748	40.3	53.6
Hydroelectricity	26	25.2	3.7	528.6	2,643.1	5,286.3	35,961	0	6,443	9.4	9.4
Landfill gas	3	0.9	0.1	9.0	44.8	89.6	49	0	10	0.0	0.0
Grid-loss reduction	20	1.1	2.2	11.3	56.6	113.2	31,974	0	4,056	5.9	--
Non-lighting electricity for industry	20	1.5	0.2	1.4	6.9	13.9	5,837	0	740	1.1	--
Switch to compact fluorescent lamps	49	13.3	2.0	132.7	663.4	1,326.8	17,269	0	15,246	22.1	4.8
Energy-saving household appliances	30	7.4	1.1	74.4	372.0	744.0	11,131	0	1,412	2.1	--
Flared gas recovery	55	91.8	13.5	917.6	4,588.0	9,176.1	353,409	1	44,826	65.1	--
Coal mine methane	18	2.5	0.4	24.7	123.6	247.2	809	0	109	0.2	0.1
Waste gases in crude oil refinery	26	4.3	0.6	43.4	216.9	433.8	5,777	0	659	1.0	0.9
Improved steam system	211	36.6	5.4	366.4	1,831.8	3,663.6	--	--	--	0.0	--
Reduced clinker use in cement manufacturing	46	2.8	0.4	28.4	142.1	284.1	--	--	--	0.0	0.1
Shift to Bus Rapid Transit (BRT)	63	12.4	1.8	260.2	1,301.0	2,602.0	--	--	--	0.0	--
Biodiesel from Jatropha	60	3.2	0.5	66.2	330.9	661.8	--	--	--	0.0	--
Improved charcoal production	68	22.5	3.3	224.8	1,123.8	2,247.5	--	--	--	0.0	0.2
Reduced methane leakage in pipelines[3]	13	0.1	0.0	0.7	3.6	7.2	--	--	--	0.0	--
Total	**3,227**[4]	**740.7**	**109.0**	**9,785.0**	**48,937.8**	**97,869.7**	**1,244,618**	**4**	**155,078**	**225.3**	**157.6**

Note: In 2003, the region's total electricity generation was 327,079 GWh per year and total installed power was 68,841 MW.

[1] With regard to projects' life span, a carbon-crediting period of 21 years was used for Jatropha biofuel, hydroelectricity, shift to BRT, and biodiesel from Jatropha; for all other technologies, a 10-year crediting period was assumed.
[2] Results for forest and wood-processing residues are disaggregated in this table.
[3] This technology does not have a corresponding chapter section.
[4] The 3,227 projects include 361 Programs of Activities.

At this stage, it was not possible to include an economic analysis of the cost effectiveness of the project opportunities inventoried in this study. Such an analysis would have required numerous economic comparisons of these low-emission energy alternatives with more conventional ones at the local level, which, in turn, would have required additional data collection. But the ever-increasing number of similar clean energy projects registered in the UNFCCC pipeline being implemented in other countries, mainly by the private sector, strongly indicates that such projects can be attractive when taking carbon revenue into account.

While already unexpectedly large, this potential is not inconsistent with the rapid scaling up of the CDM worldwide, which is roughly doubling each year. Indeed, the potential can be considered underestimated for two major reasons. First, the number of methodologies approved by the CDM's Executive Board is increasing every two months, suggesting that many more clean-energy activities might be applicable to the region. Second, for various types of projects, the study team could neither collect exhaustive data nor the potential (e.g., geothermal, concentrated solar power, wind farms, small hydropower plants, waste-to-energy projects¸ building energy efficiency, solar water heaters and improved household stoves, among others).

In addition, two investment curves—one for GHG abatement and the other for additional generation capacity—were created (figure 2).[4] The study also attempted to assess the financing needed to implement these potential projects. Data were unavailable for projects representing 36 percent of added power-generation capacity and 21 percent of emission reductions.[5] A conservative estimate of the total capital cost of the remaining 2,755 clean energy projects is about US$157 billion. If the capital cost of large flared, associated-gas recovery projects could be calculated, this figure would likely exceed US$200 billion.

[4] These results, along with corresponding tables synthesizing CDM opportunities, are presented by country in a separate volume. The excel file, which contains all of the databases and calculations used to generate the tables and curves presented here, is provided in an annexed CD. Readers can easily revise the key assumptions and parameters when more accurate data become available.

[5] Data were unavailable for the following project categories: efficiency improvements in electricity distribution, steam systems, and BRT; energy-efficiency improvements in household appliances and industrial equipment (motors); methane leakage reduction in pipelines and emission reduction in oil-producing facilities (flaring); and industrial fuel switching.

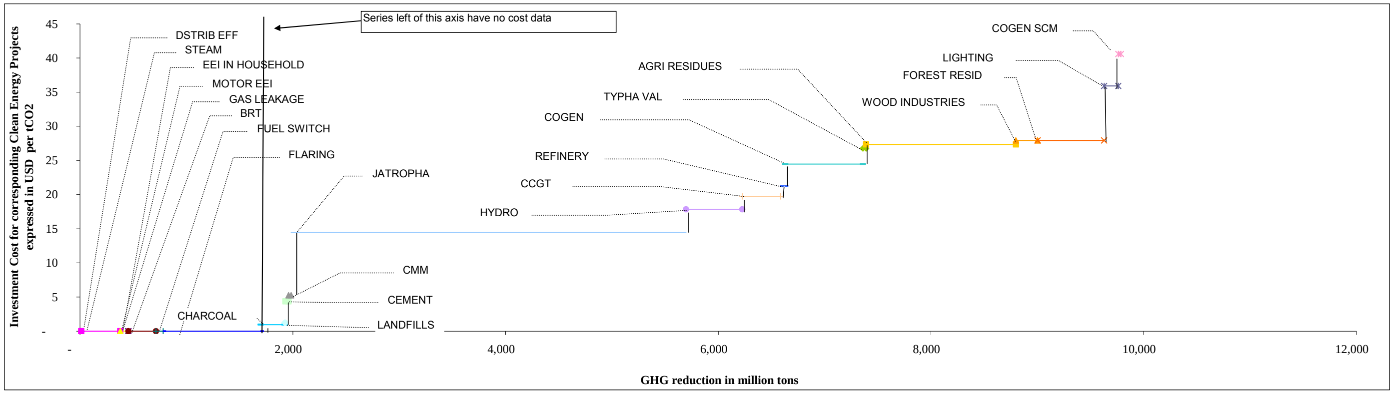
Figure 2: Consolidated Investment Curves for Sub-Saharan Africa (All)

Potential for Emission Reductions

(Ranked by Investment Cost for Corresponding Clean Energy Projects expressed in USD per tCO2)

No cost data was available for the listed categories

Sector	Investment Cost ($/tCO2)	Reduction over project life (10 or 21 years) *
DISTRIB EFF IM	-	11
STEAM	-	366
EEI IN HOUSEH	-	74
MOTOR EEI	-	1
GAS LEAKAGE	-	1
BRT	-	260
FUEL SWITCH	-	66
FLARING	-	918
CHARCOAL	1	225
LANDFILLS	1	9
CEMENT	4	28
CMM	5	25
JATROPHA	14	3,712
HYDRO	18	529
CCGT	20	361
REFINERY	21	43
COGEN	24	729
TYPHA VAL	27	31
AGRI RESIDUES	27	1,408
WOOD INDUST	28	203
FOREST RESID	28	626
LIGHTING	36	133
COGEN SCM	41	24

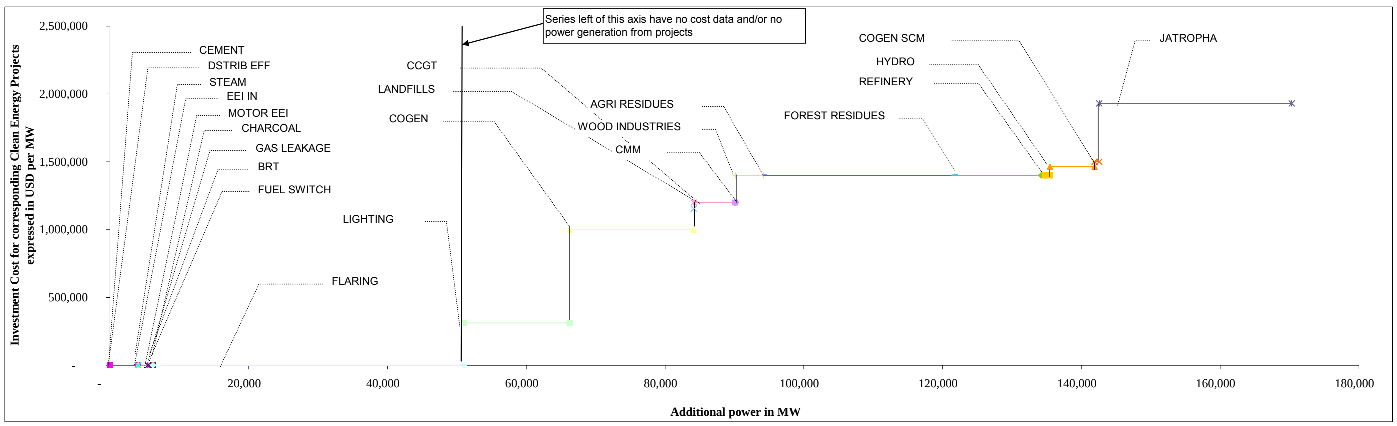


Potential for Additional Generation Capacity

(Ranked by Investment Cost for Corresponding Clean Energy Projects expressed in USD per MW)

No cost data and/or no power generation from projects

Sector	Investment Cost ($/MW)	Additional power due to the project implementation (load factor = 90%) MW
CEMENT	-	-
DISTRIB EFF IM	-	4,056
STEAM	-	-
EEI IN HOUSEH	-	1,412
MOTOR EEI	-	740
CHARCOAL	-	-
GAS LEAKAGE	-	-
BRT	-	-
FUEL SWITCH	-	-
FLARING	-	44,826
LIGHTING	312,500	15,246
COGEN	1,000,000	17,844
LANDFILLS	1,154,813	10
CCGT	1,200,000	5,931
CMM	1,200,000	109
WOOD INDUST	1,400,000	4,057
AGRI RESIDUES	1,400,000	27,504
FOREST RESID	1,400,000	12,483
TYPHA VAL	1,400,000	593
REFINERY	1,400,000	659
HYDRO	1,463,517	6,443
COGEN SCM	1,500,000	661
JATROPHA	1,930,533	27,748



* A carbon crediting period of 10 years was used for all sectors with the exception of Jatropha, BRT, Hydro and Fuel Switch. For these the study assumed a crediting period of 21 years (3 x 7 years). This was done so as to reflect the difference in capital investment useful life accross sectors (up to 30 years for Hydro, etc.)

Note: Clean Energy projects simultaneously deliver power and generate emission reductions. Therefore, investment costs related to emission reductions cannot be isolated from investment costs related to power generation. As a consequence, unitary cost expressed in US$/tCO2 presented here are not marginal emissions abatement costs but investment costs corresponding to the associated clean energy projects divided by the volume of emission reductions generated by these projects during their lifetime as CDM projects activities generating certified emissions reductions (CERs). Lifetime considered for corresponding CDM project activities is the most probable crediting period as defined by the CDM, e.g. one single 10 years crediting period or 7 years renewed three times, depending of the type of project considered.

Unlocking Sub-Saharan Africa's Potential

Based on field visits to 12 countries and many exchanges with potential project developers, energy-sector authorities, and other stakeholders, the study team investigated the barriers that have limited the implementation of clean energy projects in Sub-Saharan Africa relative to other developing regions. The study found that the region faces key institutional, market, and project-level barriers.

Beyond pointing out the obstacles, the study team developed preliminary recommendations for energy-sector authorities and the international donor community—particularly the Energy Sector Operational Units (ESOUs) of development agencies—on how to address these barriers and thus begin to unlock Sub-Saharan Africa's large potential for clean energy projects.

Recommendations for Mitigating Barriers

1) It is essential to fill the regulatory and logistics gaps that bar clean energy projects from access to energy markets.

Without appropriate market access, clean energy projects can realize neither their contribution to energy development nor global environment benefits. To date, regulatory gaps in the region's energy sectors hinder or prevent clean energy projects from selling their energy production. One example is the lack of purchase tariffs in monopolistic, vertically integrated public-power sectors. Filling such gaps is a priority that may require technical support that can apply lessons from international best practices.

2) Market access requires appropriate infrastructure planning and policies to overcome logistics bottlenecks.

In many cases, especially for biomass-based cogeneration and power generation, the primary energy resource is dispersed, creating a dual logistics challenge: collection and transport to the transformation facility and construction of transmission lines to convey the power generated to market. Meeting this challenge requires appropriate planning of clean-energy and infrastructure development and policy and financing mechanisms. In many countries across the region, outside technical assistance is needed to develop planning capacity.

3) Technical information on mature, clean energy technologies must be appropriately disseminated.

In Sub-Saharan Africa, the sustainability of clean energy development is hindered by a lack of technical knowledge, information sharing, and capacity building, including the necessary background data and inventory of potential energy sources. For example, most of the region's small- and medium-sized industries ignore the opportunity provided by energy-efficient options for improved profitability and competitiveness. As a result, the use of older inefficient and polluting equipment persists. With regard to agro-industry and forest and wood-processing industries, residual biomass (e.g., sugarcane bagasse, groundnut shell, rice husk, and palm fiber) is commonly viewed as a waste-disposal issue or, in certain cases, is burned inefficiently to generate a limited amount of process heat to eliminate an undesirable byproduct.

To engage potential clean-energy project developers who currently run inefficient facilities or waste bio-energy, the first step is to disseminate information to them on existing technologies that would become attractive via carbon revenues (or sometimes without them). One approach might be to jointly organize technology-focused national or multinational information campaigns with equipment and technical-services providers, targeting the technologies that match the available clean-energy potentials of the region and decision makers of corresponding companies.

4) The local skills required to run mature, clean technologies must be developed.

A significant share of the region's GHG emissions results from inappropriate maintenance schemes, themselves caused by lack of a skilled labor force. For example, the region's principal barrier to efficient industrial steam systems is poor maintenance. When steam traps malfunction, the traps are not immediately repaired or replaced; such routine neglect causes the release of condensate into drainage lines and thus the loss of considerable amounts of energy that should have been put into productive use in industrial processes. In the area of bio-energy, lack of mastery of certain techniques (e.g., achieving high enough yields to make production competitive), also generates bottlenecks that limit the development of corresponding clean-energy potential. Countries in the region must be assisted in building national technical capacity rather than relying on traditional turnkey solutions with imported technology, in which case scaling up and efficiency will be limited.

5) Technical assistance and research and development (R&D) are required to enable clean energy technologies to achieve full efficiency and sustainability.

In Sub-Saharan Africa, the capacity to adapt technologies to local resources is low compared to other developing regions. For example, biomass products typically require drying and size reduction before becoming usable fuels. In certain applications, they require carbonization (e.g., for charcoal production). Most countries in the region lack the equipment required to obtain the full energy potential from local biomass. Thus, specific technical assistance and R&D activities are required to adapt efficient, pre-use transformation solutions and combustion equipment to the unique characteristics of diverse biomass residues found in Sub-Saharan Africa. In addition, research and knowledge should be gathered on reducing the time and costs involved in biomass-residue collection, transport, and other infrastructure- and logistics-related activities.

Local research is required not only to realize maximum potential from local clean-energy potential at least cost, but also to ensure sustainable resource use. Because of its numerous potential benefits for the local energy sector (e.g., reduced dependency on high-priced petroleum products) and the economy (e.g., new income-generation activities), biomass residues represent an especially attractive, clean-energy potential. At the same time, environmental and social impacts assessments are critical. In the context of Sub-Saharan Africa subsistence-farming practices, agricultural productivity is especially sensitive to the amount of post-harvest residue on farms. Therefore, it is vital that agricultural research be conducted to strike an optimal balance between fuel and alternative uses.

6) Support is still required to develop local expertise and institutional procedures to facilitate project developers' access to the benefits provided by an increasing range of financial resources earmarked for climate change.

In Sub-Saharan Africa, relevant actors' lack of knowledge and information regarding the CDM and CF opportunities and procedures presents a key obstacle to CDM project identification. In previous capacity-building programs, the focus of seminars and workshops was often too theoretical, and the targeted group too limited, involving mainly professionals from the environment community. Most countries in the region have enough well-trained professionals who could, if properly trained in the CDM and CF, provide key services to help potential project developers prepare clean energy projects (or at a minimum, develop such projects to a point where they could be integrated into carbon fund portfolios and receive assistance to undergo the entire CDM procedure). The same recommendation would likely hold true for accessing the new CIF.

A critical lesson learned from previous capacity-building efforts is that they should target the right groups: decision makers from industry and local engineering consulting firms. Technical capacity-building activities should involve learning-by-doing strategies involving both local consultants and project developers. In addition to these core groups, each country's relevant institutions should be informed of their potential roles in facilitating CDM development. For example, energy-sector authorities should take appropriate actions to remove specific sectoral barriers that discourage project developers from making investment decisions.

7) Post-Kyoto carbon funds are required to internalize the global benefit of investment decisions and level the playing field for clean energy technologies.

Certain clean energy options, particularly those based on renewable energy, have been unable to compete when the energy market gives zero value to the global environmental benefits provided by these alternatives. The number and wide range of clean energy projects submitted from around the world to the CDM have demonstrated that CF is effective in achieving such internalization. However, most carbon-finance transactions are limited to "the first commitment period" of the Kyoto Protocol, which ends in 2012. Because of uncertainty regarding the post-Kyoto regime, it has become difficult for CDM projects to monetize their post-2012 GHG emission reductions. In the case of Sub-Saharan Africa, where the start of CDM implementation has been delayed, most CDM-eligible clean energy projects are expected to deliver, at best, a small fraction of their emission reductions before 2012.

As a result, instruments that provide financial value to future emission reductions from the region's clean energy projects must be created. New carbon funds that buy post-2012 CERs are an absolute condition for countries in Sub-Saharan Africa to develop their large potential of clean energy projects and thus move along a cleaner development pathway. Featuring such carbon funds to facilitate project access is desirable. Most of the region's CDM projects are smaller than the minimum size required by many existing carbon funds. This issue can be addressed, in part, by bundling many similar smaller projects under the CDM's new Program of Activities. At the same time, bundling projects triggers additional coordination challenges that may be difficult to address when similar projects are scattered across countries, certain ones of which may be in conflict or post-conflict situations. Therefore, for smaller clean energy projects located in least-developed countries of Sub-Saharan Africa, special windows streamlining access remains a desirable feature for post-2012 carbon funds.

8) However, Carbon Finance alone will not solve the investment financing gap. Earmarked Climate Investment Funds are essential.

For any capital-intensive infrastructure in Sub-Saharan Africa, lack of investment and financing capacity is a chronic barrier, whether involving conventional or clean energy projects. It is important to note that CF alone cannot resolve this issue for clean energy projects. Carbon funds provide neither equity nor investment financing. While signing Emission Reduction Purchase Agreements in hard currency with an entity with a high credit rating may help leverage commercial financing, the carbon-revenue channel does not usually suffice to ensure financial closure. In the context of resource constraints and political pressure on public utilities to contain a looming energy crisis, most industrial companies seek quick fixes and less capital-intensive options, which are usually more carbon intensive. For many of the region's smaller poor countries (e.g., Burkina Faso, Burundi, Cape Verde, Chad, and

Senegal), this frequently means the multiplication of small diesel or heavy fuel-oil generators (less than 10 MW each) and simple, short-lived repairs of inefficient, outdated gensets. In larger countries (e.g., Kenya and Nigeria), it is more likely that power-utility decision makers will implement single-cycle, Greenfield facilities, which are faster to build and cheaper to operate compared to combined-cycle systems or large hydropower plants.

Breaking this vicious circle, which harms not only these countries' economies but also the global environment, requires new investment financing instruments earmarked to promote medium-term clean and efficient solutions, in addition to existing instruments to finance shorter-term solutions and carbon funds to internalize global benefits. Thus, compatibility between the new CIF and the CDM is critical since many of the region's clean energy projects must overcome both a lack of investment financing and low returns compared to other investment opportunities, and thus may need to remain eligible for CDM and CF.

Since financing and implementing capacity may not be enough to explore the region's large range of clean-energy opportunities, the policy dialogue, generally structured around a country's most relevant strategic objectives, would permit prioritizing the various options identified and strengthening ownership of those projects that best serve the sector policy.

What Donors Can Do

A range of objective reasons thus explains why Sub-Saharan Africa has performed poorly under the CDM and, as a result, has been deprived of its benefits. Overcoming the barriers discussed above presents a challenge, but the required solutions are clear. Interestingly, the Energy Sector Operational Units (ESOUs) of Multilateral Financial Institutions are well prepared to tackle most of the issues. Indeed, ESOUs are endowed with a unique set of organizational features, which, if linked with those of their local counterparts, position them as key contributors to unlocking the region's large potential for CDM-eligible, clean energy projects.

1) Decades of trust building and direct access to key decision makers well position ESOUs to assist sector authorities to fill the awareness gap and remove policy barriers.

An analysis of the major barriers preventing CDM-eligible, clean energy projects from development in Sub-Saharan Africa have revealed the importance of filling regulatory gaps in the region's energy sectors.

Over decades of policy dialogue and financial support, ESOUs have built extensive networking and trust with the region's energy-sector ministries, public utilities, and private-sector decision makers, well placing them to convey key strategic messages and help develop and implement the measures required to unlock these benefits. In countries across the region, ESOUs often present decision makers the only viable option for gaining access to international experience and expertise. Thus, it is important that strategic opportunities related to carbon-based benefits be integrated into the policy dialogue that ESOUs regularly maintain with the region's energy-sector authorities.

2) Clean energy projects in Sub-Saharan Africa require the external technical expertise that ESOUs have a history of providing.

In Sub-Saharan Africa, most potential clean-energy projects require external technical assistance. Unlike carbon funds, which lack the required sector-specific expertise and financial resources for activities other than CF transactions, ESOUs have a history of providing such expertise using in-house staff or outside consultants knowledgeable about international best practices. Examples include support in preparing technical and non-technical loss-reduction projects in public utilities, policy and regulatory frameworks for gas flare–reduction projects, community-based projects to develop sustainable agroforestry for woodfuel and charcoal production, and decentralized rural electrification projects using photovoltaics. Energy investment projects financed by international development agencies typically devote millions of dollars to technical-assistance components. Thus, if the recipient countries are willing, future ESOU projects could easily incorporate technical assistance to address capacity needs for efficient and sustainable implementation of clean energy technologies, especially if additional funds are made available for that purpose. Such technical-assistance activities would serve to enhance the development objectives of these projects.

3) Logistics bottlenecks and sustainability issues require multi-sectoral coordination and support.

International development agencies have a history of coordinating support across sectors (e.g., rural road construction and agricultural development). External support can often create an incentive for administrative divisions to overcome communication barriers.

4) ESOUs are organized to offer the multi-country coordination required by many of the region's larger, clean energy projects.

Because of their small size, many countries in Sub-Saharan Africa require international coordination to facilitate the development of larger, clean energy projects. This is the case for the regional transmission grid system, gas pipelines for regional markets, large hydropower plants, and flared-gas recovery projects. The transaction costs of many smaller-scale, dispersed projects—from improved energy efficiency for industry (e.g., improved motors and steam traps) to smaller hydropower plants and diverse biomass-based energy—could be streamlined via large national or multinational Programs of Activities. ESOUs are already playing such a facilitation role across the region. The Global Gas Flaring Reduction Partnership illustrates how multilateral development agencies can catalyze the working together of larger private and public actors to reduce gas flaring in developing countries. Such capacity positions ESOUs as natural partners for countries preparing to implement such complex projects and programs.

5) Although the private sector in Sub-Saharan Africa is weak, ESOUs are used to promoting private-sector participation.

In other developing regions, CDM-eligible, clean energy projects have been developed mainly by private sponsors, and most Emission Reduction Purchase Agreements have been signed with private companies undertaking the principal investment on their own. The limited flow of private investment across Sub-Saharan Africa explains, in large part, the region's lack of CDM-eligible, clean energy projects. But ESOUs are used to designing projects aimed at attracting and supporting private investments. Typical examples are donor-supported projects that facilitate the participation of Independent Power Producers. In short, ESOUs already have the expertise and experience to catalyze the development of private-based, clean energy projects in the region's energy sector.

6) Clean energy projects in Sub-Saharan Africa require external donor financing, which ESOUs can channel to the project level.

Because of myriad investment barriers, both private- and public-based energy projects are difficult to finance in Sub-Saharan Africa. In most cases, financial closure can only be reached via the financial support provided by international development agencies. The CF market alone cannot provide investment financing. Indeed, ESOUs are the main providers of financing for energy investment projects in the region. Given their accumulated experience and know-how with regard to financing conventional energy projects, ESOUs can be instrumental to channeling resources of the newly created CIF to finance clean energy projects.

Concluding Remarks

This study has demonstrated that the potential for clean energy projects in Sub-Saharan Africa is large. In this context, innovative, climate change–related financial instruments offer an unprecedented opportunity to explore this overlooked potential for the socioeconomic benefit of countries across the region. This goal can be achieved via appropriate coordination of the new climate-change aid with conventional energy sector–based support provided by development aid agencies. An illustration of such required coordination is the need to fill regulatory gaps in the region's energy sectors, which prevent implementation of clean energy projects. Without appropriate coordination between climate-change and conventional-development aid, economies in Sub-Saharan Africa will be further hindered, or even prevented, from receiving their share of the carbon revenues that already flow to the world's other developing regions.

As discussed above, the financing required to implement some 2,755 potential clean energy projects for which preliminary costing could be done is estimated at about $US158 billion. If the capital cost of projects related to large flared, associated-gas recovery could be calculated, this figure would likely exceed US$200 billion. While this figure may be perceived as large, in the context of global climate change, it represents only a small fraction of recently estimated amounts required for industrialized countries to shift from conventional to cleaner energy over the next several decades.

Part I

Clean Energy Projects for Sub-Saharan Africa: An Overlooked Potential

Chapter 1

Introduction

This study aims to inform energy practitioners and decision makers in Africa and the international donor community of Sub-Saharan Africa's large potential of clean energy projects that can benefit from carbon finance (CF) and new climate investment funds (CIF) and thus contribute to reducing the gap in energy supply-demand and future greenhouse gas (GHG) emissions in the region. The study analyzes project activities already implemented in other regions of the developing world under the Clean Development Mechanism (CDM) of the Kyoto Protocol that could be implemented in Sub-Saharan Africa. In all, the study team identified 22 clean-energy project opportunities for countries across the region. For each of the technologies considered, the team detailed the number of potential projects, project size, associated generation capacity, corresponding project investment cost, associated emission reductions expected, and estimated carbon revenue generated; consolidated results were also provided for the 44 countries assessed (Annex A). In addition, the study sought to identify the major barriers to implementing such projects in Sub-Saharan Africa, even as other developing regions are experiencing exponential growth in the number of similar projects implemented under the CDM. Finally, the study offers both national governments across the region and the international donor community preliminary recommendations for overcoming these barriers to begin to unlock the region's considerable potential of clean energy projects.

Study Rationale

Africa, the world's least developed region, also has its lowest electrification rate. Nearly 92 percent of rural residents and 75 percent of people living on the subcontinent—about 550 million people—lack access to electricity. Some 130 million households still depend on traditional biomass for cooking.[6] Many countries across Sub-Saharan Africa experience uneven provision of petroleum derivatives, resulting in recurring suppressed demand in the industry and transport sectors. Most electricity consumers currently connected to the grid regularly experience power shortages caused by insufficient installed capacity or lack of fuel to run expensive, inefficient power plants. But the region's sustainable development depends on adequate, reliable, and secure energy supplies used safely efficiently with minimal undesirable externalities that can be internalized by such corrective measures as market or non-market instruments. The gap to fulfill these requirements remains large. Indeed, the World Bank estimates that US$11 billion will be needed over a 25-year period (2005–30) for all residents to gain full electricity access.

[6] See "Clean Energy for Development Investment Framework: Progress Report of The World Bank Group Action Plan," September 27, 2007or visit http://go.worldbank.org/3RMQOAKN80.

Atop this challenge, Sub-Saharan Africa is currently jeopardized by rising oil prices and the adverse effects of global climate change. At the same time, countries in the region stand to benefit from a growing variety of financial instruments to develop clean and efficient energy. These innovative instruments include the Clean Development Mechanism (CDM), Carbon Finance (CF) products, and the recently created Climate Investment Funds (CIF).[7] Interestingly, the region's large capacity shortage translates into ample opportunities for clean and efficient energy development without the problem of stranded assets. Such financial instruments can help to channel the additional funds needed for investing in new generation assets (e.g., combined-cycle turbines), as well as existing ones (e.g., efficient lamps and motors), to increase energy services via efficiency improvement or by turning net energy consumers into net producers (e.g., power generation from industrial biomass) in return for avoidance of future greenhouse gas (GHG) emissions. In short, the global efforts to combat climate change through the CDM, CF, CIF, and other instruments can provide Sub-Saharan Africa solutions for sustainable and efficient clean-energy development and socioeconomic growth.

An Overlooked Potential

To date, countries in Sub-Saharan Africa remain largely marginalized from the benefits offered by a growing array of CDM opportunities. Currently, only 53 out of 3,902 CDM projects are located in Sub-Saharan Africa.[8] The region's meager 1.4-percent share in the CDM pipeline is nine times smaller than its share in terms of GHG emissions (including LULUCF in 2000) and three-to-four times smaller for other indicators (table 1.1). Thus, even though its countries' economies are small compared to other developing economies, the region's number of CDM projects should be greater.

Like other developing regions where CDM projects have been successfully implemented using commercially available technologies, Sub-Saharan Africa is similarly endowed with resources and facilities. For example, the region has many open-cycle power plants to which a second cycle could be added, thereby increasing generation capacity and plant efficiency at zero additional emissions. Efficient cogeneration plants could be added to sugar mills. In addition, refineries, flared gas, landfills, and other concentrated sources of GHG emissions could be used to generate power and heat. Incandescent lamps could be replaced by compact fluorescent lamps, thereby saving significant amounts of fossil-fuel energy and, at the same time, reducing household energy bills.

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[7] On July 1, 2008, the World Bank Board of Executive Directors officially approved the creation of the CIF, under which two trust funds will be created (boxes 8.1 and 8.2).

[8] As of May 23, 2008; more details are available at http://cdmpipeline.org.

Table 1.1: Sub-Saharan Africa's Weight Relative to Non-Annex 1 Countries for a Series of Indicators

Indicator	*Share in non-Annex 1 group (%)*
Foreign direct investment, net inflows, 2004 (US$)	5.7[c]
Gross domestic product, 2004 (US$)	5.1[d]
Electricity consumption, 2004	5.1[d]
CO_2 emissions, 2004 (without LULUCF[a])[b]	5.4[e]
GHG emissions, 2000 (with LULUCF[a]) (tCO_2e)	13.0[e]
Registered CDM projects	
Number	1.5[f]
Volume of CERs	1.9[f]
Number of projects in validation pipeline	1.4[f]

[a] LULUCF = Land Use, Land Use Change, and Forestry
[b] In 2004, non-Annex 1 countries represented 41.2% (12.2 $BtCO_2$) of the world's total CO_2 emissions, while countries in Sub-Saharan Africa accounted for 2.21% (657.8 $MtCO_2$).
[c] Average value over the 2001–05 period (World Development Indicators Online).
[d] Data source: World Development Indicators Online.
[e] Data source: Climate Analysis Indicators Tool, World Resources Institute.
[f] As of May 23, 2008 (http://unfccc.int).

Many such options comply with the conventional energy sector's strategy to provide consumers sufficient, cost-effective, and reliable energy supplies. But without supporting quantitative data, which is currently lacking, a common assumption among development practitioners in the climate-change community unfamiliar with the region is that its weak CDM portfolio simply reflects its poverty—that is, its countries have few industries, little emissions, and thus limited emission-reduction opportunities. Without verifiable data that demonstrates the region's technical potential, it is difficult for energy practitioners familiar with the region to convince a broader audience of Sub-Saharan Africa's significant potential for clean-energy development, particularly CDM projects, and the uptake of associated financial assistance.

The next section discusses the underlying core concepts of current climate change–linked financial instruments and the recent explosive growth in CDM projects.

Financial Instruments: Core Concepts

The Clean Development Mechanism (CDM), defined in Article 12 of the Kyoto Protocol, is a process of certifying emission reductions achieved by projects executed in developing countries.[9] Under the CDM, projects that demonstrate that they avoid GHG emissions that otherwise would have occurred can obtain international certificates, termed certified emission reductions (CERs). CERs are calculated using CDM approved methodologies. This certification process ensures that these emission reductions are "additional;" that is, because of less attractive economics or specific barriers (e.g., technology risk, limited access to capital, or logistic constraints), in the absence of the CDM, the less carbon-intensive option would not have been preferred. An international authority issues the CERs after the emission reductions have been effectively achieved.[10] For example, if a wind-power project substitutes fossil fuel–fired electricity with wind-based electricity, project participants can obtain CERs each year corresponding to the emissions that would have been generated from the fossil-fuel plant to produce the same amount of electricity. These CERs can then be sold at carbon markets or to contracted purchasers. CERs are essentially output-based revenue that will add to commercial revenue from energy sales. In this way, the CDM internalizes a project's global benefits, whose valuation is ensured by the markets. As a result, since November 2001, implementation of the CDM has generated a strong financial incentive, unleashing a dynamic, bottom-up response from project developers worldwide.

For a CDM project developer, it is as important to sell these CERs as to sell energy in the future. This is where Carbon Finance (CF) intervenes. CF is a way to ascertain the future revenues from the sale of the CERs, typically by setting Emission Reduction Purchase Agreements (ERPAs), which commit both the CDM project developer and a CER buyer (e.g., a carbon fund) to such transactions. As a result, CF tools are a bridge between CDM projects and the financial carbon markets, allowing CDM project developers to reflect the value of the CERs in their business plans. Such ERPAs mitigate risks for both the project developer and CER buyer regarding the volume and value of a future transaction.

The Carbon Finance Unit of the World Bank (ENVCF) has played a pioneering role in CF development. In 1999, ENVCF created the world's first carbon fund, called the Prototype Carbon Fund (PCF). PCF fund allocation, amounting to US$180 million, was fully committed in 2003. Subsequently, the World Bank was asked to host and manage other carbon funds on behalf of Annex 1 governments that wished to benefit from World Bank experience to ensure their efficient purchase of CERs needed to comply with emission targets of the Kyoto Protocol. As a result, other funds were created, including those targeting specific project segments. The Community Development Carbon Fund (CDCF), for example, focuses exclusively on small projects (less than 15 MW) that nevertheless have a high development impact. As of March 2008, the number of carbon funds hosted in the World Bank had increased to 11, and total funds pledged had reached more than US$2.1 billion (16 governments and 66 firms). Outside the World Bank, more than 60 carbon funds have been created. In 2007, it was estimated that the global size of carbon investment vehicles had

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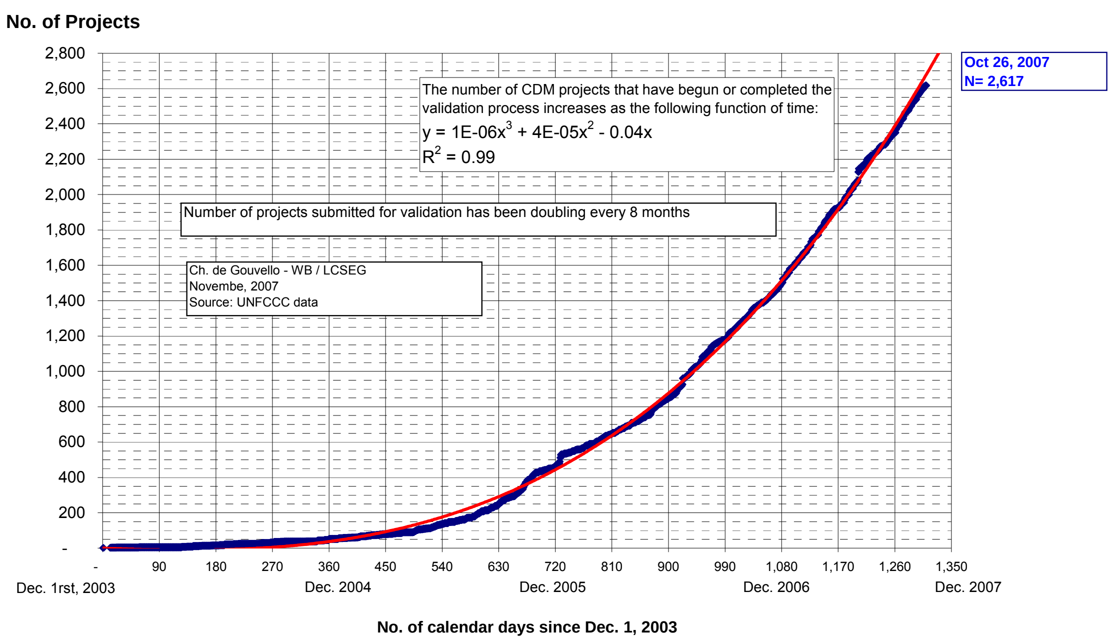
[9] In the context of the Kyoto Protocol, developing countries are also referred to as non-Annex 1 countries, while industrialized countries that committed to reducing their GHG emissions before 2012 are known as Annex 1 countries.

[10] CERs are issued by the CDM Registry Administrator (Clean Development Mechanism Registry Requirements of Decision 17/CP17 of the Marrakech Accords, Appendix D, article 6).

reached 7 billion Eurodollars, of which the World Bank's CF share represented 10 percent.[11] As figures 1.1 and 1.2 show, growth of the CDM-based carbon market has accelerated as the CDM has become fully operational.

Several years after the CDM's official creation at the Conference of the Parties 7 (COP-7) in Marrakesh, an intensive learning process has allowed the CDM regulatory bodies, the Executive Board and MethPanel,[12] to examine some 260 methodologies and approve more than 108. The growing number of approved methodologies, more than two-thirds of which are energy-related, is reflected in the ever-widening scope of activities covered, which are available to project developers who wish to apply for the CDM. As each new methodology is approved, it can be used by any similar project worldwide, thereby unleashing a new segment of GHG mitigation projects. As a result, the number of CDM projects either validated or under validation has increased exponentially, from 60 projects in late 2004 to 3,902 by mid-May 2008 (figure 1.3).[13]

Figure 1.1: Number of CDM Projects That Have Already Applied for Validation



[11] Mission Climate Research Report no. 12, Non. 2007 (www.caissedesdepots).
[12] The Executive Board is a political body appointed by the COP to enact official decisions regarding practical modalities of the CDM. The MethPanel is group of experts appointed by the Executive Board to provide technical recommendations on baseline and monitoring methodologies and CDM project-cycle procedures, as well as address cross-cutting policy issues, such as the definition of additionality, taking national policies into account in project host countries, and reducing transaction costs of small-scale projects. The three principal authors of this study, all of whom are senior energy specialists, have served on MethPanel for several years or more.
[13] More detailed information is available at http://cdmpipeline.org.

Figure 1.2: Volume of CDM-related Carbon Finance Transactions

(millions US$)

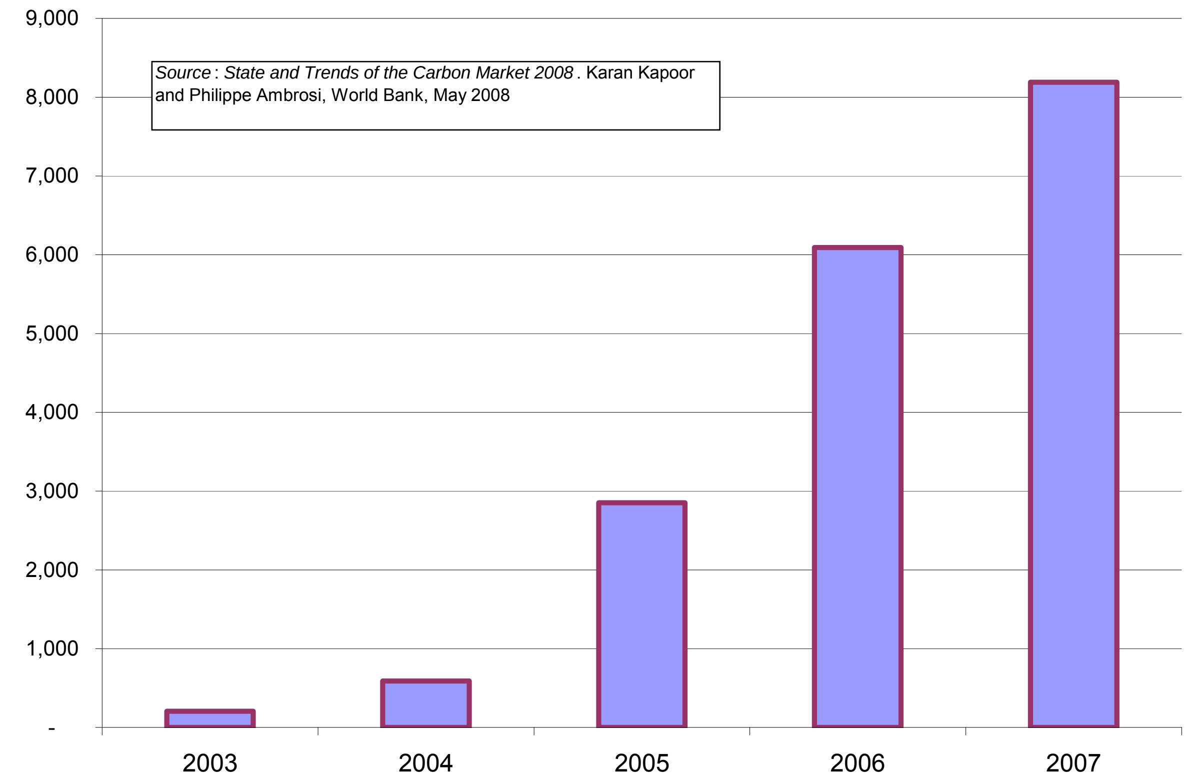
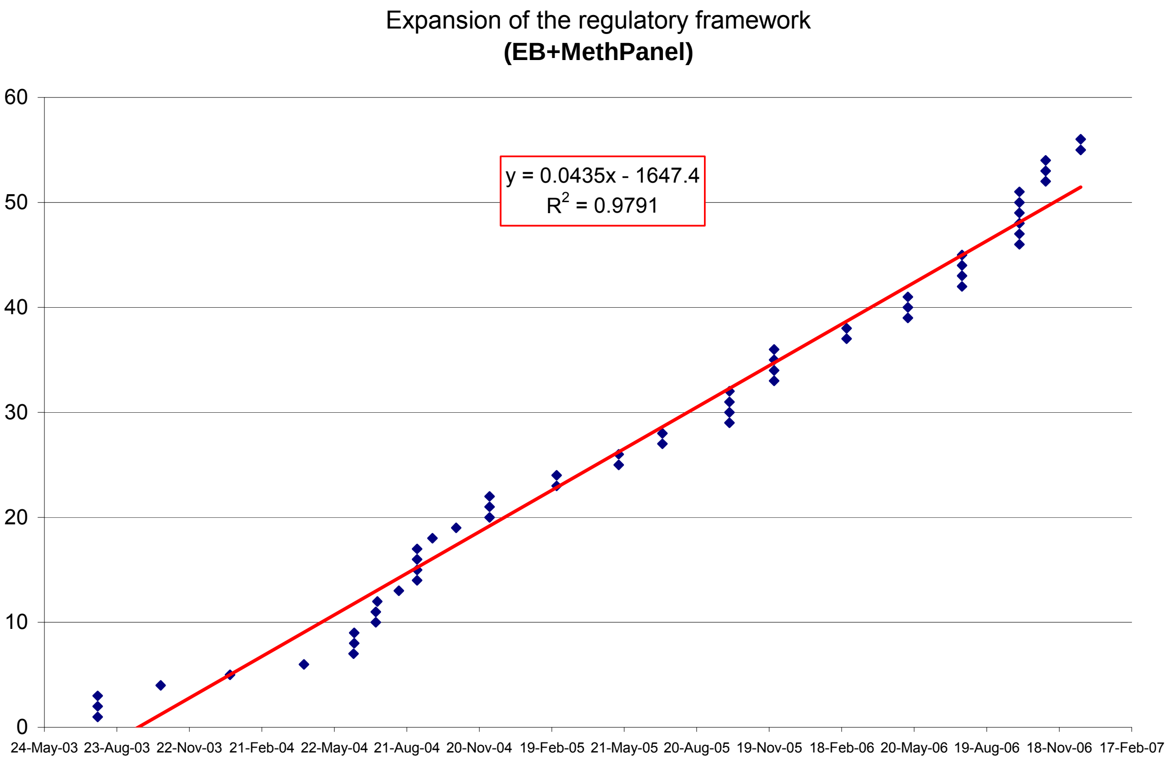


Figure 1.3: Pace of Releasing Approved Methodologies by Regulatory Bodies



Implications for the Energy Sector

Most of the many approved methodologies under the CDM are related to the energy sector. This emphasis is reflected in the pipeline of projects that have already been submitted for validation, most of which are clean energy projects. As a result, there is a wide array of technical opportunities for reducing emissions associated with the energy sector. Briefly, one can distinguish between projects that increase or free supply capacity and those that only reduce emissions of existing infrastructure. The latter could be qualified as "pure de-carbonization" of the existing energy system; that is, nothing is achieved beyond emission reduction, with the supply level left unchanged. A good example is the flaring of methane extracted from coal mines for safety reasons. By installing flares, the coal-mine methane, which is usually vented, can be destroyed and transformed into CO_2, thereby significantly reducing emissions associated with coal-energy production. While worthy of consideration, de-carbonization does not necessarily fit easily into a conventional energy-sector strategy centered on ensuring the sufficient low-cost and reliable energy supply required for economic and social development. Therefore, this report focuses more on clean-energy opportunities that could somehow contribute to the energy development of Sub-Saharan Africa, either by increasing energy supply or gaining more utility from existing capacity.

Indeed, the CDM can contribute to the core energy business by widening the scope of attractive options to meet increasing demand, and, in some cases, lowering the cost of supply compared to conventional, non-CDM alternatives. A good example of such a win-win scenario is the generation of electricity from wasted heat in industry and open-cycle power plants. With carbon revenues, such valorization of waste heat can become a profitable option that can compete with more conventional greenfield power-generation investment.

Together with Carbon Finance (CF), as well as other instruments aimed at promoting low-emissions technologies, the CDM can affect the development of the energy sector. Indeed, in such large countries as Brazil, China, and India, where hundreds of CDM projects are already in the pipeline, the mechanism is expected to affect energy planning exercises. Specific ways in which the CDM can affect energy-sector development in developing countries are summarized as follows:

- *Optimize primary energy demand.* The CDM can reduce energy demand via process efficiency improvements (e.g., increased steam efficiency in industrial facilities, greater boiler pressure, or mono-phased electrical motors); improved power-grid efficiency (e.g., supervisory control and data acquisition, better transmission, and optimization of dispatch to reduce non-distributed energy); retrofitting of power plants; and regional interconnection (e.g., optimized load curves of generation plants).

- *Make a cleaner technology preferable when added power-generation capacity is needed*. Examples include adding a second cycle to a single-cycle power plant and gas flaring-to-energy projects.

- *Realize a local renewable-energy potential.* Typical examples include power generation or combined heat and power from agricultural and forestry residues, establishment of medium-sized hydropower plants (10–300 MW) or wind farms (where supporting policies are in place), and retrofitting older hydropower plants.

- *Enable clean industrial auto-production to become cost effective and attractive*. Examples include power generation or combined heat and power from waste heat or gas, combustion of industrial biomass residue, and anaerobic fermentation of solid or liquid waste. In certain cases, large consumers can become net producers.

- *Make access to traditional and modern forms of energy, including fuelwood and electricity, more sustainable in rural and peri-urban areas.*

As indicated above, CDM can also have a pure decarbonization effect; that is, it can lower emissions of current energy supply systems via reducing gas-pipeline leakage, avoiding SF_6 (sulfur hexafluoride) leaks in electrical systems, implementing projects that convert coal-mine methane into energy, and switching of power and non-power industries to cleaner-burning fuels.

Reshaping the CDM Scope from an Energy-sector Perspective

Currently, the methodologies approved by CDM Executive Board are numbered chronologically, according to their approval dates; thus, the first approved methodology is numbered AM001, the second AM002, and so on. To date, these methodologies have not been formally organized by sector or activity type (the accompanying text for each methodology may suggest relevant sectors or activities). Looking at the long numbered list of methodologies posted on the official CDM United Nations Framework Convention on Climate Change (UNFCCC) website is not especially helpful to the non-specialist seeking to grasp the scope of sectors and subsectors already covered. But approved methodologies and corresponding potential clean-energy projects can be redistributed in a way that eases comprehension for energy specialists unfamiliar with the CDM jargon.

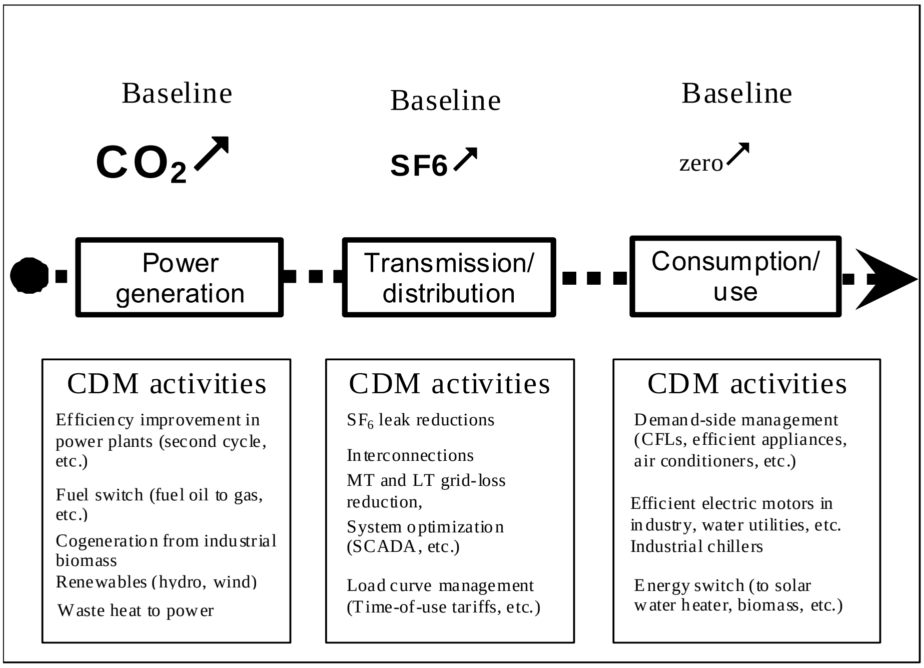
To this end, the study team chose to aggregate the approved methodologies and corresponding clean energy projects along the production chains—also referred to as energy chains or subsectors—that best correspond to the current representation of the energy sector. Generically, these chains consist of three main stages: production or generation, transport, and consumption. Of course, there is no unique way to aggregate all methodologies and clean-energy alternatives. The study team's objective was not to propose a purely academic typology, but rather to choose one, among others, that helps energy practitioners and decision makers relate the large amount of complex CDM information available to the operational categories to which they are accustomed. The proposed structure has been tested in a number of presentations to energy practitioners and decision makers in Africa and the international donor community and has been adjusted to reflect their feedback.

The four subsectors retained for the purpose of this report are as follows (figure 1.4):

- **Power**. The main stages of this subsector are generation, transmission and distribution, and consumption.
- **Fuels for industry**. This subsector includes several production chains, among which the two most important are oil and gas and coal. For oil and gas, the main stages are production (upstream industry), refining (downstream industry), transport (generally by pipeline, boat, or surface motorized means), and consumption for thermal industrial uses, mainly in fixed furnaces and boilers.
- **Fuels for vehicles**. While the conventional upstream part of this production chain is the same as that for the fuels-for-industry subsector, it differs with respect to clean-energy alternatives via the introduction of biofuel production (bio-ethanol and bio-diesel). Consumption occurs in motorized vehicles.
- **Woodfuel for households**. Sometimes referred to as traditional energy, this subsector encompasses the production, transport, and consumption of ligneous biomass.

Figure 1.4: Clean Energy Opportunities Across Key Subsectors

1.4a: Power



1.4b: Fuels for Industry

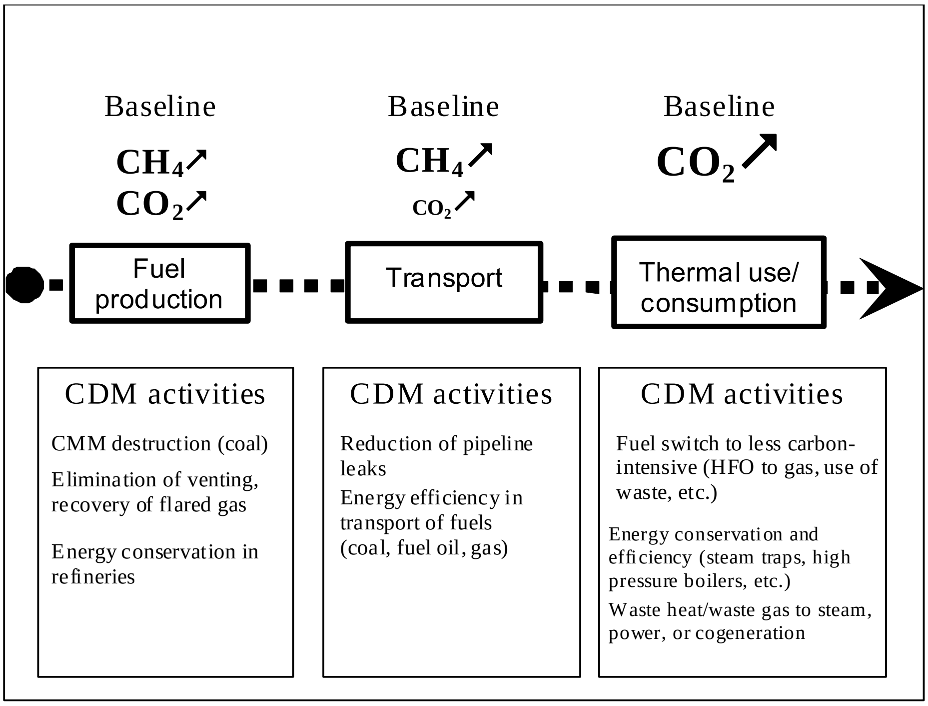
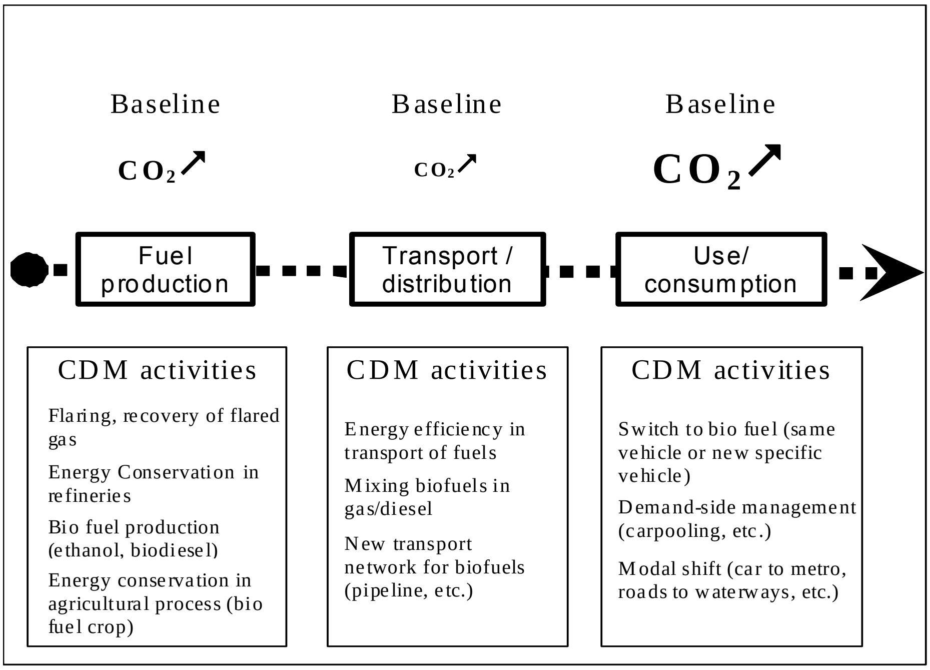
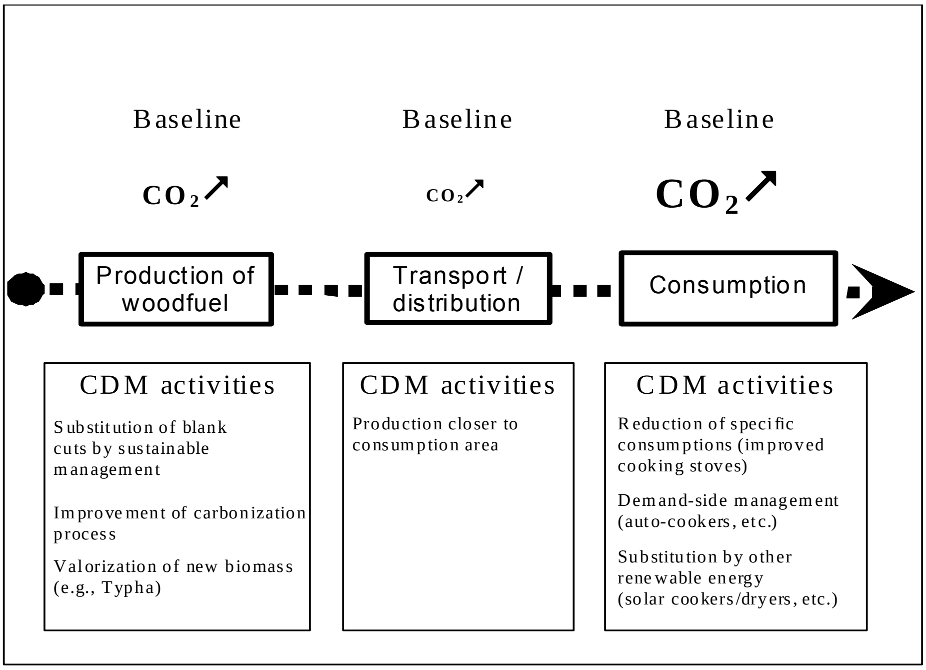


Figure 1.4: Clean Energy Opportunities Across Key Subsectors

1.4c: Fuels for Vehicles



1.4d: Woodfuel for Households



In figure 1.4, the upper portion of figures 1.4a-d indicates the principal GHG emitted in the baseline and the stage in the respective production chains where such emissions occur. The lower portion of each figure shows the types of CDM activities—either already in place under the CDM framework or that may be covered in the future—that could reduce these emissions. For a current chronological listing of the relevant approved methodologies, organized by each of these four subsectors, see Appendix 2.1.

Synergy between CDM/CF and Energy Development

Together, the CDM and CF can serve as powerful synergic instruments to boost clean and efficient energy development in Sub-Saharan Africa. The following subsections demonstrate how these paired instruments are compatible with and enhance conventional energy-sector development strategies.

Complementarity of Carbon Finance and Conventional ODA

In contrast to official development assistance (ODA), generally limited to supporting project investment costs, carbon finance (CF) revenues are operational, generated along the project lifetime (up to 21 years).[14] Together, CF revenues and ODA can demonstrate powerful complementarities. CF allows an energy project to add revenue on top of other commercial revenue (e.g., energy sales), which can improve project cash flow significantly. Such added revenue may be important for poor countries and low-income market segments in particular, whose payment capacity may be too low to enable the energy project to reach a break-even point.

Desirable Features of Carbon Finance Revenues

CF revenues are also high-quality cash flows. Since CER purchasers are usually from developed countries, purchase agreements are generally issued in foreign currencies, either US dollars or euros. This feature is attractive to poor countries that face commercial deficits. While energy projects are generally import intensive, negatively affecting the balance of payment, CERs produced by cleaner energy projects are a high-value, exportable by-product. Since ERPAs are international contracts expressed in hard currencies, they are also free of inflation risk and, to a certain extent, exchange risk, at least against local currency devaluation. For many CDM projects presented for validation, project developers insist that CDM revenues permit hedging their debt cash flow against currency devaluation. When a CER purchaser is a highly rated entity, such as a World Bank–hosted carbon fund, ERPAs can help bring financial closure to a project; this is often an issue in Sub-Saharan Africa, especially when private-sector participation is desired. Adding such high-quality cash flow can be a key argument to convince commercial banks or private investors to increase their financial participation in the investment, as a commercial loan or equity.[15]

Leverage of Private-sector Participation and Advanced Technologies

Less carbon-intensive technologies are often more advanced and capital intensive. They usually cannot be implemented by current players in a poor country's energy sector. More

[14] CDM rules allow a project to claim CERs for up to three consecutive, seven-year crediting periods.

[15] In the case of the Abanico Hydroelectric Project (29.76 MW) in Ecuador, the Interamerican Investment Corporation agreed to introduce a clause in the loan agreement providing a 1-percent interest reduction if the ERPA was signed. The loan contract explicitly established that emission revenues be given full credit toward satisfying minimum project-revenue requirement for debt service (http://cdm.unfccc.int).

advanced technologies may be dominated by an exclusive group of foreign companies averse to poor business environments. Such companies may prefer to focus on developed-country markets or require a higher investment return for projects undertaken in poor countries. But under the CDM with CF, those companies may reconsider their position in order to comply with their own country's emission reduction obligations or because they regard the CER as a premium to cover the risk associated with the project activity location or simply to reach their standard in terms of minimum investment return. In short, CF can serve as a powerful tool to leverage private-sector participation that brings advanced technologies to clean and efficient energy projects.

Viability of CDM-eligible Projects Compared to Conventional Energy Projects

For any specific energy goal (e.g., increased generation capacity), various alternatives must be analyzed to determine the preferred, and eventually qualified, baseline. The alternative that generates the least amount of emissions may be more expensive than the preferred baseline. In such cases, carbon revenue can turn low-emission alternatives into more attractive ones.[16] In some cases, the cleaner option is more profitable in theory, but its implementation is constrained, thus making it CDM-eligible. This is typically the case for theoretically cost-effective, energy-efficiency measures for which market failures prevent implementation. By attracting new players, CDM with CF can help overcome such barriers. Depending on the volume of CERs generated and the market valuation, a cleaner CDM-eligible alternative can become viable and even more profitable than the baseline option. A typical example is waste management in modern landfills; that is, the capture and use of methane, closure of an open-dumped landfill, creation of a modern one, and construction of a power unit fueled by the newly collected gas suddenly become cost effective thanks to carbon revenue.

Output-based Aid Incentive for Efficiency

As a process of ex-post certification of the emission reductions performed by a project, CDM projects must comply with a mandatory monitoring plan. The financial value of corresponding CERs is realized only after certification is completed. Thus, the quantity of certifiable emission reductions is determined by applying methodologies that rely on baseline emissions calculation and measurement of actual project emissions, with the balance resulting in CERs. If the project is more efficient—that is, if more final energy is delivered for the same quantity of primary energy—the baseline emissions calculated will be higher (as a result of the higher level of service delivered for which the baseline must be adjusted) and the monitored project emissions lower. As a result, CDM-based CF can be used to create an incentive for precise measurement of results and global efficiency during project operation time (e.g., transmission and distribution). Carbon revenue can fuel financial awards for efficiency gains. Therefore, CF can enhance positive incentives for ensuring effectiveness throughout the project lifetime. It may also be used for compensation schemes to withdraw inefficient cross subsidies for fossil fuels used by households. The host country's energy sector may benefit significantly from such a strategy since it will help develop or conserve generation capacity at a competitive cost, ensuring a higher leverage effect.

[16] Unlike the Global Environment Facility, which finances the incremental cost between a clean alternative and the baseline option, the value of CDM-based carbon revenue is independent from the cost difference between the two alternatives. The CDM process accounts for physical emission reductions performed by a project to which the market assigns a value. Therefore, expected carbon revenue may or may not equal the cost difference.

Study Purpose and Objectives

This study aims to reveal Sub-Saharan Africa's technical potential for clean energy projects that can benefit from the CDM and other climate-related financial instruments to narrow the region's growing gap between energy supply and demand and, at the same time, reduce future GHG emissions. To this end, the study analyzes 22 types of clean energy projects already implemented in other developing regions under the CDM that have potential application in countries of Sub-Saharan Africa. Detailed technical assessments are provided at both country and regional levels, including the number of potential projects, project size, generation capacity, project investment cost, expected emission reductions, and potential carbon revenue generated. The study also identifies barriers that have prevented the region from reaping its share of the benefits from clean-energy opportunities and offers strategic mitigation measures.

Structure of This Report

The next chapter focuses on the CDM as a methodological framework for revealing Sub-Saharan Africa's large potential for clean energy development. Chapters 3–6 assess technical opportunities, including inventories of resources and facilities, for clean energy projects in the region, organized by the most relevant energy subsectors (power, fuels for industry, fuels for vehicles, and woodfuel for households). Chapter 7 then synthesizes results of these assessments for Sub-Saharan Africa and the 22 technologies covered. Chapter 8 reviews the major barriers to CDM project implementation and offers energy-sector authorities and the donor community strategic recommendations for unlocking the region's potential for clean energy projects. Chapter 9 concludes.

Chapter 2

CDM Methodological Framework

Opportunities for reducing greenhouse gas (GHG) emissions usually exist in several segments of energy systems. Their exhaustive identification requires an in-depth mastering of a broad spectrum of technical knowledge, mainly in systems operation rather than theory. A unique industrial process can accommodate a significant number of energy transformations involving various ways in which to achieve energy savings along the production chain. Each transformation can be achieved using one of a number of technologies. Each potential clean-energy solution can reduce emissions by a certain quantity, in accordance with the primary source used.

In contrast to industrialized countries, where old technologies quickly disappear as new ones become commercially available, developing countries often retain older technologies for longer periods, sometimes decades, while newer technologies substitute for only a limited share of older ones. Across Sub-Saharan Africa, Asia, and Latin America and the Caribbean, one might possibly encounter 100-year-old boilers. In addition to the age of equipment, the history of facility operations and maintenance bear on energy efficiencies and thus the intensity of the GHG emissions produced.

In the past, producing detailed inventories of energy conservation potentials in Sub-Saharan Africa, where access to data has been extremely difficult, has proven a daunting task. Earlier assessments were heavily constrained by an inability to form technical teams large enough to cover the range of required expertise. All of the issues associated with activities to improve energy efficiency also apply to the reduction of GHG emissions, whose scope is even broader because it encompasses processes linked not only to fossil-fuel combustion, but also to CH_4 (methane) captured from biomass decomposition, SF_6 (sulphur hexafluoride) leaks in circuit breakers, and various other emission sources. For such reasons, few reports, if any, have been published on inventories of GHG emission-reduction opportunities in Sub-Saharan Africa.

Tracking Opportunities via the CDM Lens

Against the backdrop of this challenge, the robust instrument of the Clean Development Mechanism (CDM) provides an unprecedented methodological framework for assessing clean energy opportunities.[17] Each methodology developed under the CDM captures clear details of the technology and operation parameters that command emission reductions for one or more processes. It also describes the types of facilities in which these processes operate. In addition, the CDM validation pipeline database, publicly available on the website of the United Nations Framework Convention on Climate Change (UNFCCC), provides concrete examples of the facilities, processes, and achievable emission reductions. Thus, for any given

[17] The CDM Executive Board published the first approved GHG emission reduction baseline and monitoring methodologies July 30, 2003.

country, it becomes far easier to count the number of facilities where emission-reduction projects corresponding to approved methodologies can be developed.

By virtue of its bottom-up design, the CDM process gives all actors across all sectors an opportunity to propose GHG emission-reduction activities in facilities located in any non-Annex 1 country. Proponents can recommend methodologies to calculate and monitor emission reductions that can be developed in any type of facility operating in non-Annex 1 countries. Once the CDM Executive Board approves a methodology, all other projects of the same nature worldwide can use it to have the required emission reductions certified. The resulting CERs can be sold at the carbon credit market, thus creating a powerful incentive for the development of proposals for activities that will result in emission reductions and the development of methodologies linked to them. This process has encouraged the creativity of many actors across an array of economic sectors worldwide. As of mid-May 2008, some 260 methodologies had been proposed in many diversified sectors by project developers located in more than 50 countries. By that same date, about 106 methodologies had been approved, of which some were “consolidated,” covering a wide range of activities; of these, about 26 simplified methodologies had been reserved for small-scale projects. Each of the approved methodologies has unleashed a new segment of mitigation activities, resulting in increased demand for validation of projects. To date, about 3,900 projects have had their descriptions posted freely on the website of the UNFCCC secretariat.[18]

Because of their many years of participation in meetings of the CDM Methodology Panel, this study team has had the opportunity to master the powerful instruments of the CDM methodologies, including this study’s core methodology on a potential CDM projects inventory in Sub-Saharan Africa. The basic principle has been to develop an inventory of opportunities for clean energy projects that can provide energy and emission reductions across the subcontinent using the approved CDM methodologies, many of which have already been applied to on-the-ground projects.[19] The existence of CDM emission-reduction projects in non-Annex 1 countries is a good indication that such projects can be implemented in Sub-Saharan Africa.

Building a Projects Inventory

The study team adopted a bottom-up, quantification approach to building a clean energy projects inventory. As data became available on facilities that could replicate a similar activity already implemented as a CDM project by a facility in another non-Annex 1 country, the team gathered the data and made a precise counting of the corresponding number of individual projects. To this end, the team investigated existing databases and visited 12 countries in Sub-Saharan Africa to collect primary data.[20] For certain categories of clean energy projects for which no detailed data were available at the facility level, the team used a mix of bottom-up and top-down approaches. Using available data from project design documents of actual projects,[21] the team first determined the average size and characteristics of the corresponding CDM project and the host facility. It then gathered data aggregated at the sector or subsector level to estimate the average number of facilities—and thus potential

[18] More detailed information is available at http://cdmpipeline.org.
[19] Concrete project descriptions are available on the UNFCCC website.
[20] The countries visited were Benin, Burkina Faso, Ethiopia, Ghana, Kenya, Liberia, Mali, Niger, Nigeria, Senegal, South Africa, and Togo; see Annex 2 for a list of key contacts in these countries.
[21] Posted in the CDM validation pipeline by the UNFCCC Secretariat.

number of clean energy projects under the CDM—that should be present in a particular country.

Limitations of This Study

It should be noted that the potential estimated in this study is technical. For various project types, it was not possible to collect exhaustive data or estimate the potential; this was the case for small hydropower plants, wind farms, waste-to-energy projects, geothermal plants (for which the Rift Valley has a large potential), solar water heaters, concentrated solar power (South Africa is planning a 100-MW pilot plant), building and vehicle energy efficiency, ethanol from sugarcane, and improved household stoves, among others. An economic assessment of the various segments of this technical potential was beyond the scope of this study.[22] Thus, at this stage, it is not possible to determine what share of this technical potential could be achieved by overcoming the barriers identified by the study or a timeline for its realization. Where possible, illustrative cases, using data collected from various projects, are presented in boxes in the technical chapters of Part II (chapters 3–6).[23,24]

Although exhaustive cost-effectiveness assessments could not be performed, it should be noted that the increasing number of similar clean energy projects registered in the UNFCCC pipeline are being implemented in other countries thanks to CDM/Carbon Finance, providing a strong indication that these clean energy projects are usually not economically meaningless and thus are worth considering as plausible options. At the same time, case-by-case economic and financial assessments are required to ensure that internalization of the global environmental benefits they provide make them attractive options.

For similar reasons, the additionality of these potential projects, as defined under the CDM regulatory framework, could not be tested. Additionality—meaning that the emission reduction that these projects aim to achieve would not have occurred in the absence of the benefits provided by the CDM—can derive from various reasons that make more carbon-intensive alternative more likely to occur. Examples include additional investment or operation-and-maintenance costs; added risks that reduce the confidence of potential project developers and financing partners; lack of local awareness, knowledge, or expertise; market distortions that favor more carbon-intensive options (i.e., social subsidizing of fossil fuels); tariff barriers; country-specific transaction costs; and lack of access to capital for capital-intensive clean options. Testing additionality of CDM projects can generally be done only at the project level on the basis of country- and sector-specific information, which was not feasible for the 44 countries and 22 technologies covered in this study.[25]

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[22] Such an analysis would have required numerous economic comparisons of these alternatives with more conventional ones, which, in turn, would have required the collection of many additional data. This type of analysis may be feasible, especially at the country level, where conventional and clean-energy alternatives can be more clearly identified, project by project, to perform such a comparison.

[23] For reasons of confidentiality, the precise names and locations of the projects for which data were collected are not indicated. Since the data are from actual projects implemented in various countries over different time periods, the carbon and electricity prices presented in the illustrative cases differ.

[24] For various reasons beyond the scope of this study, it has not been possible to assess the region's potential for such clean-energy technologies as improved stoves and large and small wind farms (chapter 7).

[25] See Annex A for a list of the countries considered in this study.

Relevant Methodologies

For several reasons, this study does not attempt to encompass every CDM approved methodology. First, the study's coverage centers on emission-reduction activities that can contribute to Sub-Saharan Africa's energy development via supply- or demand-side side activities. Second, some industrial activities for which approved methodologies are available do not exist in Sub-Saharan Africa. Third, since the CDM Executive Board approves new methodologies about every two months, some of the latest ones may be missing. Appendix 2.1 contains a current chronological listing of the relevant approved methodologies, organized by energy subsector.

Appendix 2.1: Approved Methodologies for Potential Clean Energy Projects in Sub-Saharan Africa

Power sector

Large-scale	*Title*
AM0005	Small-emission biomass
AM0007	Analysis of the least-cost fuel option for seasonally-operating biomass cogeneration plants (v. 1)
AM0014	Natural gas–based package cogeneration (v. 4)
AM0015	Renewable energy (bagasse)
AM0019	Renewable energy project activities replacing part of the electricity production of one single fossil fuel–fired power plant that stands alone or supplies electricity to a grid, excluding biomass projects (v. 2)
AM0020	Baseline for improvements in water-pumping efficiency (v. 2)
AM0022	On-site wastewater gas to energy in industry
AM0024	GHG reductions via waste-heat recovery and use for power generation at cement plants (v. 2)
AM0026	Zero-emissions, grid-connected electricity generation from renewable sources in Chile or countries with merit order–based dispatch grid (v. 3)
AM0029	Grid-connected, electricity-generation plants using natural gas (v. 3)
AM0032	Waste gas/heat to power cogeneration
AM0035	SF6 emission reductions in electrical grids (v. 1)
AM0038	Improved electrical energy efficiency of an existing submerged electric arc furnace used or the production of SiMn (v. 2)
AM0042	Grid-connected electricity generation using biomass from newly developed, dedicated plantations (v. 2)
AM0045	Grid connection of isolated electricity systems (v. 2)
AM0046	Distribution of efficient light bulbs to households (v. 2)
AM0048	New cogeneration facilities supplying electricity and/or steam to multiple customers and displacing grid/off-grid steam and electricity generation with more carbon-intensive fuels (v. 2)
AM0049	Methodology for gas-based energy generation in an industrial facility (v. 2)
AM0052	Increased electricity generation from existing hydropower stations through Decision Support System optimization (v. 2)
AM0058	Introduction of a new primary district heating system (v. 1)
AM0060	Power saving through replacement by energy-efficient chillers (v. 1)
AM0061	Rehabilitation and/or energy efficiency improvement in existing power plants (v. 2)
AM0062	Energy efficiency improvements of a power plant through retrofitting turbines (v. 1)
AM0067	Methodology for installation of energy-efficient transformers in a power-distribution grid (v. 2)
Consolidated	***Title***
ACM0002	Grid-connected electricity generation from renewable sources (v. 7)
ACM0004	Waste gas/heat to power generation
ACM0006	Electricity generation from biomass residues (v. 6.1)
ACM0007	Conversion from single- to combined-cycle power generation (v. 3)
ACM0011	Baseline for fuel switching from coal and/or petroleum fuels to natural gas in existing power plants for electricity generation (v. 2.1)
ACM0013	Baseline and monitoring for new grid-connected fossil fuel–fired power plants using a less GHG-intensive technology (v. 2)
ACM0014	Mitigation of greenhouse gas emissions from treatment of industrial wastewater (v. 2.1)
Small-scale	***Title***
AMS-I.A	Electricity generation by the user
AMS-I.B	Mechanical energy for the user with or without electricity
AMS-I.C	Thermal energy for the user with or without electricity
AMS-I.D	Grid-connected, renewable electricity generation
AMS-II.A	Supply-side, energy-efficiency improvements: transmission and distribution
AMS-II.B	Supply-side, energy-efficiency improvements: generation
AMS-II.C	Demand-side, energy-efficiency activities for specific technologies

Appendix 2.1: Continued.

AMS-II.E	Energy efficiency and fuel switching measures for buildings
AMS-II.J	Demand-side activities for efficient lighting technologies
AMS-III.M	Reduction in consumption of electricity by recovering soda from paper manufacturing process
AMS-III.P	Recovery and utilization of waste gas in refinery facilities
AMS-III.Q	Waste gas–based energy systems

Fuels for industry (subsector)

Large-scale	***Title***
AM0007	Analysis of least-cost fuel option for seasonally-operating biomass cogeneration plants (v. 1)
AM0009	Recovery and use of otherwise flared gas from oil wells (v. 3.1)
AM0017	Steam-system efficiency improvements by replacing steam traps and returning condensate (v. 2)
AM0018	Steam optimization systems (v. 2.1)
AM0023	Leak reduction from natural-gas pipeline compressor or gate stations (v. 2)
AM0024	GHG reductions via waste-heat recovery and use for power generation at cement plants (v. 2)
AM0032	Waste gas/heat to power cogeneration
AM0033	Substitution of raw materials in cement
AM0036	Fuel switch from fossil fuels to biomass residues in boilers for heat generation (v. 2)
AM0037	Flare (or vent) reduction and use of gas from oil wells as a feedstock (v. 2.1)
AM0040	Alternate carbonate materials for clinker
AM0043	Leak reduction from a natural-gas distribution grid by replacing old cast-iron pipes or steel pipes without cathodic protection with polyethylene pipes (v. 2)
AM0044	Energy-efficiency improvement projects: boiler rehabilitation or replacement in industries and district heating sectors (v. 1)
AM0053	Biogenic methane injection into a natural-gas distribution grid (v. 1.1)
AM0054	Energy-efficiency improvement of boiler by introducing oil/water emulsion technology (v. 2)
AM0055	Baseline and monitoring for recovery and use of waste gas in refinery facilities (v. 1.2)
AM0056	Efficiency improvement by boiler replacement or rehabilitation and optional fuel switch in fossil fuel–fired steam boiler systems (v. 1)
AM0068	Methodology for improved energy efficiency by modifying ferroalloy production facility (v. 1)

Consolidated	***Title***
ACM0003	Emission reduction through partial substitution of fossil fuels with alternative fuels or less carbon-intensive fuels in cement manufacture (v. 7.1)
ACM0004	Waste gas/heat to power generation
ACM0005	Increasing the blend in cement production (v. 4)
ACM0008	Coal-bed, coal-mine, and ventilation-air methane capture and use for power (electrical or motive) and heat and/or destruction by flaring or catalytic oxidation (v. 4)
ACM0009	Industrial fuel switching from coal or petroleum fuels to natural gas (v. 3)
ACM0012	Baseline for GHG emission reductions for waste gas, waste heat, or waste pressure–based energy system (v. 2)
ACM0014	Mitigation of greenhouse gas emissions from treatment of industrial wastewater (v. 1)
ACM0015	Baseline and monitoring for project activities using alternative raw materials that do not contain carbonates for clinker manufacturing in cement kilns (v. 1)

Small-scale	***Title***
AMS-II.D	Energy efficiency and fuel-switching measures for industrial facilities
AMS-II.G	Energy-efficiency measures in thermal applications of non-renewable biomass
AMS-II.H	Energy-efficiency measures through centralization of utility provisions of an industrial facility
AMS-II.I	Efficient utilization of waste energy in industrial facilities
AMS-III.B	Switching fossil fuels
AMS-III.K	Avoidance of methane release from charcoal production by shifting from pit method to mechanized charcoaling process
AMS-III.M	Reduced electricity consumption via recovery of soda from paper-manufacturing process
AMS-III.P	Recovery and use of waste gas in refinery facilities

Fuels for vehicles (subsector)

Large-scale	*Title*
AM0031	Bus Rapid Transit projects (v. 1)
AM0047	Production of biodiesel based on waste oils and fats from biogenic origin (v. 2)
Small-scale	***Title***
AMS-III.C	Emission reductions by low-GHG-emitting vehicles
AMS-III.O	Hydrogen production using methane extracted from biogas
AMS-III.S	Introduction of low-emission vehicles to commercial-vehicle fleets
AMS-III.T	Plant-oil production and use for transport applications

Woodfuel for households (subsector)

Large-scale	*Title*
AM0041	Mitigation of methane emission in wood-carbonization activity for charcoal production (v. 1)
Small-scale	***Title***
AMS-I.C	Thermal energy for the use with or without electricity
AMS-I.E	Switch from non-renewable biomass for thermal applications by the user
AMS-II.G	Energy-efficiency measures in thermal applications of non-renewable biomass
AMS-III.K	Avoidance of methane release from charcoal production by shifting from pit method to mechanized charcoaling process
AMS-III.R	Methane recovery in agricultural activities at household/small-farm level

Note: The list of approved methodologies for CDM project activities continues to expand; the most up-to-date listing is available on the UNFCCC website (http://cdm.unfccc.int).

Part II

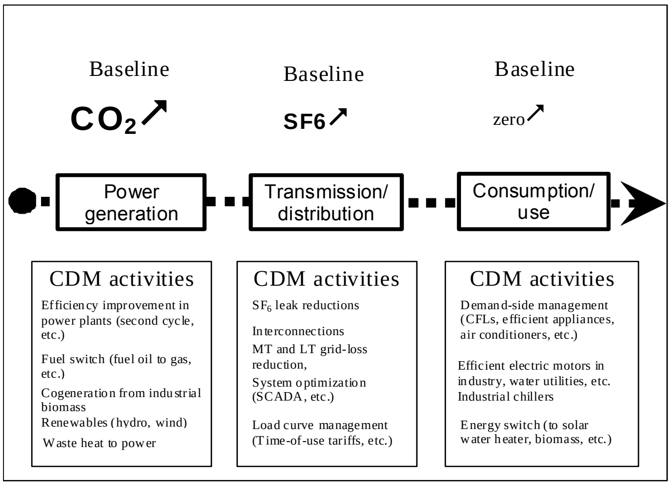
Technical Opportunities: Assessment and Inventory

Chapter 3

Power Sector Development

The clean-energy technologies considered in this chapter as potential CDM opportunities encompass generation based on fossil fuels and a range of renewable energies, grid-loss reduction for transport and distribution, and several technologies covering consumption and use by industries and households. In all, 14 technologies are featured. Figure 3.1 shows the physical distribution of potential CDM activities for Sub-Saharan Africa along the power-sector production chain; the accompanying list of approved UNFCCC approved methodologies is by no means exhaustive of potential opportunities for the sector.

Figure 3.1: CDM Opportunities along the Power-sector Production Chain



Power Generation	**Transmission/ distribution**	**Consumption/ use**
Efficiency improvement	***SF6 leaks reduction***	***Demand-side management***
ACM007, ACM0013	AM0035	AM0020, AM0046
AM0052, AM0061	*Energy efficiency*	AMS-II.C, AM0044
AM0062, AMS-II.B	AMS-II.A, AM0045	AM0058
Fuel switch		*Energy switch*
ACM0011, AM0014		AMS-I.B,C
AM0029, AM007		
Renewable energy		
ACM0002, AM0019		
AM0026, AM0042		
AM0048, AM0015		
AMS-I.A,D, AM0005		
AM0032, ACM0004		
ACM0012, AM0024		
AMS-III.Q, AM0022		

Baseline for Emission Calculation

A key parameter for calculating the reduction of GHG emissions for grid-based power projects is the grid GHG emission factor. The quantitative-analysis approach adopted for this study can only yield approximate estimates of grid-emission factors for the countries studied. The main assumption of the study in estimating the grid-emission factor was that the CDM project would not displace hydroelectricity, but would only displace fossil fuel–based power plants at the margin. For each country, an average carbon-emission factor (tC/TJ) was calculated, based on the respective country's fuel consumption, net calorific values of the fuels, and their carbon-emission factors. For projects aimed at improving energy efficiency, the carbon-emission factor of the baseline fuel was calculated as the weighted average of the carbon-emission factor of the fuels mix consumed in the country. For heat and electricity displaced by the project, baseline emissions were calculated as the primary energy needed to produce the displaced energy (GJ) times the average carbon-emission factor (tC/TJ). To account for electricity generated from renewable energy, such as hydroelectricity, a correction factor, calculated as the power capacity of the fossil fuel–based power plant divided by the total installed power capacity, was used to adjust the emission factor. This figure is conservative, given that the load factor of hydroelectric power plants is generally far less than that of fossil fuel–based power plants in many of these countries, especially where the dominant power systems are thermal.[26]

Generation from Fossil Fuels

3.1 Second-cycle Additions to Open-cycle, Gas Turbine Plants

Converting an open-cycle gas turbine (OCGT) to a combined cycle gas turbine (CCGT) via a second-cycle addition, known as single-cycle closure, recovers part of the energy wasted in hot exhaust gases (at temperatures generally above 500°C). Closure of the open Brayton cycle with an additional Hirn cycle is achieved using a waste-heat recovery boiler. The recovered heat is used to generate steam with or without auxiliary fuels. The steam, in turn, is used to drive a steam turbine to generate additional power.

The conversion process increases efficiency considerably, making this type of investment theoretically profitable most of the time. Thus, it will be dispatched more frequently, significantly increasing the plant's load factor, often 20–70 percent or more. The result is that the same plant will displace more of the other low-efficiency, fossil fuel–fired plants that currently run at the operating margin, leading to significant GHG emission reductions and thus significant carbon revenue potential, along with more revenue from energy sales.

Despite its potential, this attractive project opportunity is often lost across countries in Sub-Saharan Africa because of the poor credit rating of project hosts, who cannot achieve financial closure for such projects. This is often the case with the public utilities still in place in many such countries. When additional capacity is needed to meet growing demand, capacity expansion strategies usually involve building more OCGTs or implementing smaller, less efficient diesel/fuel-oil generators operated by the utility or an independent power producer (IPP). Without the ability to implement modest capacity addition, shortages are

[26] Pertinent assumptions for baseline-emission considerations are included for each of the technologies featured in Part II (chapters 3–6) of this report.

allowed to develop. The results are power rationing among connected consumers and lead consumers having to install small, inefficient diesel generators on-site. In either case, more emissions are generated than would have occurred if a second cycle had been added.

3.1.1 Technical Evaluation

Conversion from an OCGT to a CCGT presents a good CDM opportunity for countries in Sub-Saharan Africa.[27] Carbon finance can provide additional hard-currency revenue and thus help to cover currency and credit risks, improve financial returns, and bring about financial closure to projects. A recent analysis of a project in Ghana illustrates the possibilities (box 3.1.1).

Box 3.1.1: Carbon Finance Achieves Financial Closure for Ghana Project

The proposed Takoradi Project in Ghana involved the installation of heat-recovery steam generators to utilize waste heat from two 110-MW generators at an existing power plant. The generators used light fuel oil imported from Nigeria. Because of growing power demand (6–7 percent annually), Ghana would have required additional fossil fuel–based sources of electricity without the project. Although profitable in theory—a 36-percent internal rate of return without certified emission reductions (CERs)—the project would not likely have been approved without the CDM.

The Volta River Authority, the project developer and public utility, was owed a large sum of money by the Electricity Corporation of Ghana, a public distribution company whose customers had not paid their bills. Unable to recover its costs, the Authority became a huge credit risk and could not raise project capital from banks or private investors. Because of these difficulties, the project was declared eligible for CDM and thus for carbon finance. As the table below illustrates, by registering as a CDM project, the Takoradi Project had potential carbon revenue of US$2.4 million per year (US$25 million over 14 years, assuming a conservative price of US$4 per tCO2).

Parameter	Value	Unit
Additional capacity from second cycle	110	MW
Additonal investment cost	150	millions US$
Emission reductions	595,601	tCO_2/yr
Price of tCO_2	4.0	US$/$tCO_2$
Carbon revenue (at best)	2.38	millions US$/yr
Total carbon revenue (2 * 7 yrs)	24.90	millions US$
IRR without CERs revenue	36	%
IRR with CERs revenue	43	%

Sources: PINs and Project Design Document

Analyses showed that earnable carbon funds more than covered currency risk and significantly alleviated credit risk. On this basis, along with gas availability from Nigeria, the project was expected to reach financial closure and be implemented as a CDM project.

Both bottom-up and top-down approaches were used to evaluate the potential for developing CCGT power as CDM projects in the countries studied. Using the Platts UDI World Electric Power Plants (WEPP) Database, it was revealed that many open-cycle units are operational, under construction, or firmly planned for construction across Sub-Saharan Africa. Currently, the region has 165 OCGT operational or under-construction installations,

[27] The relevant approved methodology is ACM0007.

commissioned since 1991, that could potentially lead to CDM projects (table A3.1-1).[28] Their power generation range is 5–295 MW, with total installed power exceeding 7,600 MW and annual production capacity of 56,000 GWh. Using a top-down approach to evaluate the CCGT potential of firmly planned, but not yet operational, OCGT projects, it was found that some 39 such projects could be implemented (table A3.1-2).[29]

But several factors suggest that the number of CDM projects eventually implemented in the region will be lower. First, CDM projects may be implemented with multiple OCGT units in single projects.[30] For example, Delta Units 1–6 may be implemented as a multiple-unit CDM project (close the cycle of 4 units), while 2 units are kept as OCGTs to provide some peaking plant capacity. Second, a power system's technical operations may decide to leave units as OCGTs. For example, in South Africa, some OCGTs serve as back-up plants at nuclear power stations; thus, from a systems perspective, it may be impractical to convert these units to higher dispatchable power facilities. Third, in Nigeria, the many OCGTs that currently serve the power needs of onshore and offshore oil and gas facilities are unlikely to be converted. For these reasons, the potential number of CDM projects identified in this study, along with their parameter estimates, should be viewed only as an indication of potential opportunity. The eventual outcome will be dictated by the unique circumstances in the respective host countries, which cannot be captured within the scope of this study.

3.1.2 Quantitative Analysis

The method used to evaluate GHG emissions reduction was based on the quantity of recovered energy, the amount of natural gas (the baseline fuel) that would be consumed to produce the equivalent amount of recovered energy, and the GHG emissions that would result from the combustion of this quantity of natural gas. The method applies not only to cases for which exhaust gas is used to generate steam without burning additional fossil fuel in the Hirn cycle; it also applies to cases where additional quantities of fuel are burned in heat-recovery boilers to produce this steam (box 3.1.2).

Results of the quantitative analysis showed that Nigeria has the greatest opportunity for potential GHG emission reduction. Recovery of otherwise wasted useful energy would result in an annual reduction of about 1.5 million tCO_2. Because the air-to-fuel ratio is fixed, the waste heat estimation is conservative. For all power plants, a value of 57.69 kg of air per 1 kg of fuel was assumed. For other open-cycle power plants, extrapolations were based on data from the operating conditions of OCGTs in Côte d'Ivoire.

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[28] The studied considered only OCGTs commissioned after 1991. Assuming that a power plant has a 30-year lifetime, all plants commissioned after 1991 could operate until 2021; thus, CDM projects with a 10-year crediting period implemented today could operate over their remaining lifetime.

[29] The estimated unitary investment cost is US$1.2 million; this figure has been adjusted to account for the warmer temperatures of potential project locations in Sub-Saharan Africa (Sathaye and Phadke 2006).

[30] This finding was confirmed during the study team's interactions with utility companies operating in the various countries.

Box 3.1.2: Calculating the Open- to Combined-cycle Conversion Potential

Data from the Azito and Ciprel OCGT power plants in Côte d'Ivoire were used to calculate the energy saved in all the OCGT facilities studied. Use of this data is considered conservative as the recently installed gas turbines of these facilities are among the region's most efficient. The total installed capacity of the country's OCGT facilities was about 500 MW, and the electricity production based on this capacity about 4,000 GWh.

For each of the other units available in Sub-Saharan Africa, the annual electricity generation in the existing OCGT facility was calculated based on the available capacity of the open cycle, as follows:

$EG_{i,y} = EG_{ic,y} * P_{i,y} / P_{ic,y}$

where,

$EG_{i,y}$ = electricity generated by the single-cycle facility in country i in year y (GWh),
$EG_{ic,y}$ = electricity generated by the Azito single-cycle facility in year y (GWh),
$P_{i,y}$ = power generated by the single-cycle facility in country i in year y (MW), and
$P_{ic,y}$ = power generated by the Azito single-cycle facility in year y (MW).

The gas exhaust temperature was assumed to be 544°C for all OCGTs, corresponding to an enthalpy of the gas exhaust H_{ocgt} (about 595 kJ/kg). The exhaust-gas flow rate in an OCGT Q_{gas} was calculated based on the power capacity of the facility and the exhaust-gas flow rate of OCGTs in Côte d'Ivoire $Q_{gas\ ic}$.

$Q_{gas,i} = Q_{gas,\ ic} * P_{i,y} / P_{ic,y}$

where,

$Q_{gas,i}$ = exhaust-gas flow rate for the OCGT in country i (kg/sec) and
$Q_{gas,\ ic}$ = exhaust-gas flow rate of the Azito single-cycle facility (kg/sec).

The air-to-fuel ratio, a parameter that determines the optimality of combustion, was assumed to be 57.69.

Determining the power capacity added from conversion of an existing OCGT to a CCGT was based on the additional power capacity expected from the converted Azito facility installations weighted with the power ratio, assuming no auxiliary fuel was combusted in the waste recovery boiler; that is:

$DPi,y = DPic,y * P_{i,y} / P_{ic,y}$

where,

DPi,y = additional power from converting the OCGT to CCGT in country i (MW) and
DPic,y = additional power from converting the Azito OCGT to a CCGT (MW).

The otherwise wasted energy recovered via the conversion of OCGT to CCGT was calculated as follows:

$RE_{i,y} = Q_{gas,i} * (H_{ocgt} – H_{ccgt})$

where,

$RE_{i,y}$ = energy recovered as a result of the conversion from OCGT to CCGT (TJ/year),
H_{ocgt} = enthalpy of the exhaust gases from the OCGT (kj/kg), and
H_{ccgt} = enthalpy of the exhaust gases from the CCGT (kj/kg).

The emissions reduction was calculated as follows:

$ER_{i,y} = RE_{i,y} * CEF$

where,

$ER_{i,y}$ = emission reduction in country i in year y (tCO_2e/year) and
CEF = emission factor of natural-gas combustion (tCO_2e/TJ).

The study found that some 204 CDM projects could be developed across Sub-Saharan Africa.[31] Closure of the open cycles would yield about 36 million tCO_2e per year. Additional power capacity of nearly 6,000 MW could be added to the region's installed power capacity. The total needed investment of US$7.1 billion would yield carbon revenues of US$3.6 and $1.8 billion, respectively, over 10- and 5-year crediting periods at CO_2 prices of US$10 and $5 per ton (table 3.1).

Of the countries analyzed, Nigeria was found to have the greatest potential for converting OCGTs to CCGTs under the CDM. The GHG emissions reduction from the country's 132 potential projects was estimated at 24 million tCO_2 per year or about 6 percent of the country's GHG emissions. If implemented, these projects would increase the country's installed power capacity by 67 percent. Annual electricity generation from the projects would exceed the country's total electricity generation for 2003. The cost of these projects is estimated at US$4.73 billion. Sale of emission reduction credits (ERCs) from the projects would generate added financial revenue, improving the projects' profitability by about US$2.4 billion over a 10-year crediting period (based on a price of US$10 per tCO_2e) (table 3.1.1).

Conversion to CCGTs under the CDM would offer the energy sectors of many countries a significant development opportunity. In Côte d'Ivoire, for example, the growing energy supply deficit is expected to increase further with construction of the Bobo Dioulasso-Ouagadougou interconnection line, which will allow Burkina Faso to buy more electricity from the Côte d'Ivoire grid. Via the CDM projects, Côte d'Ivoire could obtain an additional 245 MW of power capacity (144 MW from Azito and 101 MW from Ciprel). Additional power generation would constitute an increase of more than 20 percent of the country's installed power capacity of 1,204 MW. This added power would generate 1,800 GWh of electricity each year or about 32 percent of total generation. The cost of open-cycle closure at Azito and Ciprel is estimated at about US$300 million. The carbon revenue generated from the sale of ERCs would improve the Azito and Ciprel projects' annual profitability, estimated at US$7.7 and $7.6 million, respectively, based on US$10 per ton of CO_2 and US$3.85 and $3.8 million, based on US$5 per ton of CO_2.

[31] The 204 total assumes that every OCGT unit is converted to a CCGT; however, if each power plant, usually consisting of multiple OCGT units, were packaged as a CDM project, the total number of projects would be significantly lower.

Table 3.1.1: Results Summary of CDM Opportunities: Second-cycle Addition to Open-cycle Gas Turbine

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions (millions US$)		Electricity generation			Total installed power of country (MW)	Added power of projects (MW)		Total investment cost of projects (millions US$)
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed	
Angola	8	20.39	0.3	1.53	3.1	15.6	31.2	1,920	4,943,861	257.5	670	51.2	7.6	61.5
Benin	3	2.27	0.2	7.84	1.8	8.9	17.8	240	234	97.5	71	29.3	41.4	35.2
Cameroon	1	6.81	0.4	5.23	3.6	17.8	35.6	3,920	468	11.9	900	58.6	6.5	70.3
Chad	1	0.19	0.3	155.07	3.0	14.8	29.7	92	390	423.8	40	48.8	120.6	58.6
Congo, Rep.	1	5.31	0.7	1.40	0.7	3.7	7.4	353	97	27.6	327	12.2	3.7	14.6
Côte d'Ivoire	6	6.42	1.5	23.16	14.9	74.4	148.8	4,620	1,953	42.0	1,260	244.6	19.4	293.5
Equatorial Guinea	2	4.87	0.3	0.64	0.3	1.6	3.1	28	41	146.2	13	5.1	39.4	6.2
Ethiopia	3	4.37	0.2	4.08	1.8	8.9	17.8	2,294	234	10.2	690	29.3	4.2	35.2
Gabon	5	4.95	0.8	1.53	0.8	3.8	7.6	1,500	99	6.6	400	12.4	3.1	14.9
Ghana	5	6.66	0.8	11.58	7.7	38.6	77.2	5,360	1,014	18.9	1,310	126.9	9.7	152.3
Kenya	3	9.88	0.3	3.12	3.1	15.4	30.9	4,976	406	8.2	934	50.8	5.4	60.9
Mali	1	0.67	0.8	11.53	0.8	3.8	7.7	460	101	21.9	437	12.6	2.9	15.1
Mauritius	2	4.01	0.2	4.78	1.9	9.6	19.2	1,285	252	19.6	954	31.6	3.3	37.9
Mozambique	1	2.30	0.8	3.23	0.7	3.7	7.4	11,580	97	0.8	2,340	12.2	0.5	14.6
Niger	2	1.23	0.8	6.61	0.8	4.1	8.2	205	107	52.3	122	13.4	11.0	16.1
Nigeria	132	105.19	24.0	22.80	239.8	1,199.3	2,398.5	20,700	31,495	152.2	5,890	3,942.8	66.9	4,731.4
Senegal	2	5.49	0.2	1.43	1.8	9.3	18.5	1,387	243	17.5	476	30.5	6.4	36.6
South Africa	10	423.81	6.1	3.37	60.6	303.2	606.4	227,000	7,962	3.5	40,480	996.8	2.5	1,196.1
Sudan	7	10.79	0.6	5.37	5.8	29.0	57.9	91	760	835.4	39	95.2	241.1	114.2
Tanzania	6	3.97	0.6	14.22	5.6	28.2	56.4	3,150	741	23.5	860	92.8	10.8	111.3
Togo	3	2.38	0.2	8.73	2.1	10.4	20.8	97	273	281.4	215	34.2	15.9	41.0
Total	**204**	**679.58**	**36.1**	**5.31**	**360.8**	**1,804.0**	**3,608.1**	**291,258**	**51,912**	**17.8**	**58,428**	**5,931.0**	**10.2**	**7,117.0**

3.1.3 Barriers to Implementation

Across Sub-Saharan Africa, two major factors hinder the conversion of OCGTs to CCGTs as CDM projects.[32] First, faced with growing numbers of unserved electricity consumers, many governments in the region are under political pressure to accelerate electricity access. These governments often pressure utility managements to generate at any cost. In turn, electric power companies—mostly public companies—seek quick fixes to power-generation inadequacies, and are thus more likely to maintain open-cycle facilities, which are easier to construct than steam turbines and combined-cycle systems and cheaper to operate. Thus, when limited government funding for capacity expansion becomes available, power-utility decision makers are more likely to implement single-cycle, Greenfield facilities, which have limited construction delays. Without effective interventions, this pattern will likely continue.[33]

3.1.4 Mitigation Recommendations

Introduction of competition through the unbundling of vertically integrated, monopoly power-supply systems can go a long way toward introducing a best-practices decision-making process in Sub-Saharan Africa's power sector. In addition to this medium- to long-term strategy, carbon finance, including that offered by the CDM, is a short-term strategy well suited to overcoming the above-mentioned barriers. Carbon finance can help to attract IPPs by ensuring that the selection process permits less emitting options to compete for and benefit from carbon revenue.

When a project organizes a bidding process to select a private IPP to install and run an additional capacity required by demand development or decommission older facilities, preparatory studies can plan for two options: 1) the least-cost option that would have been considered in the absence of the CDM and carbon finance, such as a diesel plant or gas-fired open cycle and 2) a less emission-intensive option, such as a combined cycle, which may be less profitable or face constraints or risks that may require an offer with more attractive conditions.

The CO_2 emissions of both options would be calculated, and the potential GHG emissions avoided by the second option would be determined. According to price conditions offered by carbon funds, potential carbon revenues would be calculated and the financial analysis re-calculated. If results showed that the second option could compete with the first, an Emission Reduction Purchase Agreement (ERPA) could be prepared with a carbon fund. The ERPA would be integrated into the bidding documents to select the IPP. Adequate bid-evaluation modalities would be prepared, and bidders would then be authorized to make offers on either or both options, with only the second option offered the carbon revenue detailed in the ERPA.

[32] Energas Varadero (Project 0918) is the only example of a registered OCGT-to-CCGT conversion project in the UNFCCC pipeline.
[33] Implementing single-cycle closure projects under the CDM framework can help to mitigate this barrier.

3.2 Combined Heat and Power for Industry

In countries of Sub-Saharan Africa, most industrial energy systems are not integrated. Heat and power are generated in separate, stand-alone facilities; fossil fuels are commonly used to generate steam in boilers at an average pressure (10–20 bars). This steam provides heat for industrial production processes. Electricity, an equally needed energy input in industrial production, is supplied from an existing grid or on-site power-generation facilities (usually diesel generators). This configuration—stand-alone steam and power generation—common to the region's industrial operations, results in a low total energy efficiency, leading to energy waste and increased carbon-intensive production processes.

3.2.1 Technical Evaluation

No reliable industrial-facility database exists for Sub-Saharan Africa; therefore, this study could not use a bottom-up approach to identify facilities where the relevant CDM approved methodologies could be applied.[34] Instead, a five-step, top-down approach was used to assess the CDM potential for combined heat and power projects in the industrial sector of countries in the region.[35]

The first step was to determine each country's fossil-fuel consumption.[36] For the 41 countries for which data were available, crude oil consumption in 2003 totalled 1.36 million barrels per day or 68 million tons per year. Added to this consumption was that of coal; annual consumption totalled about 182.2 million tons,[37] of which 99.3 million tons was consumed in the industrial sector. Natural gas consumption for the same year totalled 14.3 billion m^3,[38] of which 10.4 billion m^3 was consumed in industries.

The second step was to determine the proportion of oil consumed in the transport sector. Using the energy balances of some of the countries studied, it was found that an average of 55 percent of the oil consumed in the region in 2003 was in the transport sector (UEMOA 2005).[39] This average was used as a characteristic default parameter for all countries where country-specific data was unavailable (table 3.2.1).

[34] The relevant approved methodologies are AM0014, AM0048, and ACM0006.
[35] The estimated unitary investment cost was US$1 million (Joshi 2005).
[36] Crude oil consumption (barrels per day) for the year 2003 was used for this analysis; the main data source was USDOE (2003).
[37] Coal consumption occurred mainly in South Africa (177 millions tons per year), Zimbabwe (3.2 millions tons per year), and Botswana (900,000 tons per year).
[38] Natural gas consumption occurred mainly in Nigeria (9.20 billion m^3 per year), South Africa (2.2 billion m^3 per year), and in Côte d'Ivoire (1.4 billion m^3 per year).
[39] Also see Mauritius energy and water statistics (2005).

Table 3.2.1: Transport Sector Oil Consumption in Selected Countries of Sub-Saharan Africa

Country	*Transport sector (% country consumption)*
Benin	65
Burkina Faso	46
Cape Verde	39
Chad	40
Côte d'Ivoire	59
Guinea	40
Guinea Bissau	41
Mali	73
Mauritania	59
Mauritius	52
Niger	94
Nigeria	73
Senegal	52
Togo	40
Average	**55**

The third step was to determine the average thermal efficiency of fossil-fuel generated power in the region. The fuel consumption for electricity generation was based on available statistics from three countries for consecutive years each (table 3.2.2).

Table 3.2.2: Average Fuel Consumption for Electricity Generation in Three Countries of Sub-Saharan Africa

Country	*Diesel oil consumption (tons per GWh)*	*Energy balance (year)*
Burkina Faso	231	2005
Burkina Faso	260	2006
Niger	268	2004
Niger	270	2005
Senegal	276	2004
Senegal	214	2005

Based on the data in table 3.2.2, an average specific fuel consumption for electricity generation, 253 tons of diesel oil per GWh, was used in the calculations for all countries in the region. This figure corresponds to an average thermal efficiency of 33 percent for electricity generation.

The fourth step was to determine the total fossil fuel consumed for heating needs across the region. For each country, the oil consumed for industrial heating in a particular year was estimated by subtracting the amount used for transport and electricity generation from the total amount used. Added to this figure was the coal and gas consumed in the industrial sector to meet heating needs during the same year. The result was the estimate of fossil fuels consumed for heating needs for the year in question. It was assumed that 20 percent of this fossil fuel estimate was used to meet high-temperature heating needs (e.g., clinker production in cement plants). It was also assumed that high-temperature heating needs could not be met using heat recovered from flue gases or that remaining after electricity extraction from high enthalpy steam. It was thus assumed that this 20-percent quantity was not used in cogeneration projects, which can only supply low- or medium-temperature heat sources (commonly found in food industries).

The final step was to decide on the steam-generation baseline and project scenarios. A baseline boiler efficiency of about 90 percent was assumed for steam-generation processes. Using the 2003 database for all countries in Sub-Saharan Africa, the baseline scenario assumed that the countries generated about 2.9 million TJ per year of steam-based heat energy to meet low- and medium-temperature heating needs. In the CDM project scenario, boilers operating at 45 bars and 450°C were assumed to generate superheated steam for the combined production of electrical and heat energy. (The superheated steam feeds back pressure turbines with an exhaust of low-pressure steam that is then used as the heat source for industrial processes.) The ratio of the quantity of energy used to produce electricity and that used to produce heat was estimated as the ratio of the enthalpy decrease of the steam via the back pressure turbines and the heating processes.

3.2.2 Quantitative Analysis

In the evaluation, the CDM project scenario assumed that 1) steam at 5 bars undergoes enthalpy decrease of about 0.43 GJ per ton via the back pressure turbines and 2) extracted steam undergoes enthalpy decrease of about 2.21 GJ per ton via the heating processes.

The project scenario also estimated an annual production of 0.555 TJ of electrical energy or 154 TWh plus 2.9 million TJ of heat energy (steam) needed for process heating, according to the baseline scenario requirement. The electricity generated in this CDM cogeneration case represents about 48 percent of the region's 2003 electricity production. At a 90-percent load factor, this figure is equivalent to about 17.8 GW of installed capacity. At a conservative efficiency of 85 percent for the cogeneration cycle (CDM project scenario) and an efficiency of 35 percent for electricity production (baseline scenario), the region's annual fuel savings using the CDM project scenario to generate the baseline energy consumption was estimated at about 0.84 million TJ. This figure would result in a GHG emission reduction of about 72.9 million tCO_2e per year, generated via some 373 CDM projects.

To determine the potential number of CDM projects, the size of GHG emission reduction was limited to 40,000 tCO_2e for any project in countries where the total emission reduction was less than 200,000 tCO_2 per year and 80,000 tCO_2e for any project in countries where the total emission reduction was higher than 200,000 tCO_2 per year. If CERs were sold at US$5 per tCO_2e, these projects would yield CDM incomes of about US$3.65 billion in 10 years. At a price of US$10 per tCO_2e, these incomes would amount to US$7.3 billion per year. The estimated emission reduction of these cogeneration projects represents 3 percent of the region's estimated GHG emissions for 2005 (table 3.2.3).

Table 3.2.3: Results Summary of CDM Opportunities in Sub-Saharan Africa: Combined Heat and Power for Industry

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions: millions tCO_2/yr	Projects' emissions reductions: % of country total	Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions (millions US$): US$5/tCO_2	Value of projects' emissions (millions US$): US$10/tCO_2	Electricity generation: Country, 2003 (GWh/yr)	Electricity generation: Projects (GWh/yr)	Electricity generation: Projects (% country total)	Total installed power, country (MW)	Added power of projects (MW): 90% load factor	Added power of projects (MW): % of total installed	Total investment cost of projects (millions US$)
Angola	6	20.39	0.4	2.23	4.5	22.7	45.4	1,920	1,121.8	58.4	670	128.1	19.1	128.1
Benin	3	2.27	0.1	5.48	1.2	6.2	12.4	240	307.4	128.1	71	35.1	49.6	35.1
Botswana	5	3.92	0.4	10.83	4.2	21.2	42.4	940	927.1	98.6	130	105.8	81.4	105.8
Burkina Faso	12	1.17	0.1	8.20	1.0	4.8	9.6	306	237.0	77.4	149	27.1	18.2	27.1
Burundi	1	0.41	0.0	9.73	0.4	2.0	4.0	148	98.6	66.6	40	11.2	27.9	11.2
Cameroon	5	6.81	0.2	2.85	1.9	9.7	19.4	3,920	479.3	12.2	900	54.7	6.1	54.7
Cape Verde	1	0.28	0.0	8.17	0.2	1.2	2.3	41	57.2	139.5	82	6.5	8.0	6.5
Central African Republic	1	0.34	0.0	8.82	0.3	1.5	3.0	104	73.6	70.8	38	8.4	22.1	8.4
Chad	1	0.19	0.0	4.15	0.1	0.4	0.8	92	19.6	21.4	40	2.2	5.6	2.2
Comoros	1	0.10	0.0	6.55	0.1	0.3	0.7	19	16.8	88.3	8	1.9	23.5	1.9
Congo, Dem Rep.	4	2.37	0.3	13.48	3.2	16.0	32.0	5,400	752.4	13.9	2,591	85.9	3.3	85.9
Congo, Rep.	2	5.31	0.1	1.25	0.7	3.3	6.7	353	164.6	46.6	327	18.8	5.7	18.8
Côte d'Ivoire	9	6.42	0.8	11.70	7.5	37.6	75.1	4,620	2,084.0	45.1	1,260	237.9	18.9	237.9
Equatorial Guinea	7	4.87	0.6	12.26	6.0	29.8	59.7	28	1,922.8	6,867.3	13	219.5	1,688.5	219.5
Ethiopia	3	4.37	0.2	5.21	2.3	11.4	22.8	2,294	563.2	24.6	690	64.3	9.3	64.3
Gabon	4	4.95	0.1	2.84	1.4	7.0	14.0	1,500	358.4	23.9	400	40.9	10.2	40.9
Ghana	4	6.66	0.3	4.95	3.3	16.5	33.0	5,360	815.0	15.2	1,310	93.0	7.1	93.0
Guinea	3	1.34	0.1	7.53	1.0	5.0	10.1	775	248.8	32.1	254	28.4	11.2	28.4
Guinea Bissau	1	0.38	0.0	9.24	0.4	1.8	3.5	55	87.2	158.7	24	10.0	41.9	10.0
Kenya	4	9.88	0.4	3.60	3.6	17.8	35.5	4,978	874.4	17.6	934	99.8	10.7	99.8
Madagascar	3	2.54	0.1	5.36	1.4	6.8	13.6	820	336.2	41.0	186	38.4	20.7	38.4
Malawi	1	0.86	0.1	6.74	0.6	2.9	5.8	1,293	140.9	10.9	300	16.1	5.4	16.1
Mali	1	0.67	0.0	0.05	0.0	0.0	0.0	460	0.8	0.2	437	0.1	0.0	0.1
Mauritania	4	2.63	0.3	11.58	3.0	15.2	30.5	150	751.8	501.2	197	85.8	43.6	85.8
Mauritius	4	4.01	0.1	1.85	0.8	3.7	7.4	1,285	181.7	14.1	954	20.7	2.2	20.7
Mozambique	4	2.30	0.2	7.62	1.8	8.8	17.6	11,580	444.2	3.8	2,340	50.7	2.2	50.7
Namibia	5	9.80	0.2	2.03	2.0	10.0	19.9	1,460	492.7	33.8	300	56.2	18.8	56.2
Niger	1	1.23	0.0	3.58	0.4	2.2	4.4	205	101.4	49.5	122	11.6	9.5	11.6
Nigeria	40	105.19	6.0	5.70	59.9	299.6	599.2	20,700	16,360.7	79.0	5,890	1,867.7	31.7	1,867.7
Rwanda	2	0.78	0.1	10.05	0.8	3.9	7.9	113	193.4	171.1	29	22.1	77.2	22.1
Senegal	4	5.49	0.2	2.68	1.5	7.4	14.7	1,387	365.2	26.3	476	41.7	8.8	41.7
Seychelles	1	0.92	0.1	6.26	0.6	2.9	5.8	240	142.7	59.4	30	16.3	54.3	16.3
Sierra Leone	1	1.18	0.0	2.09	0.2	1.2	2.5	260	60.8	23.4	120	6.9	5.8	6.9
Somalia	1	0.75	0.0	1.73	0.1	0.6	1.3	270	32.1	11.9	80	3.7	4.6	3.7
South Africa	195	423.81	58.6	13.81	585.5	2,927.3	5,854.7	227,000	119,199.2	52.5	40,480	13,607.2	33.6	13,607.2
Sudan	10	10.79	0.8	7.14	7.7	38.5	77.1	3,900	1,904.1	48.8	760	217.4	28.6	217.4
Swaziland	4	1.14	0.2	15.21	1.7	8.7	17.4	460	368.3	80.1	130	42.0	32.3	42.0
Tanzania	3	3.97	0.3	6.55	2.6	13.0	26.0	3,150	634.9	20.2	860	72.5	8.4	72.5
Togo	3	2.38	0.1	5.14	1.2	6.1	12.2	97	302.0	311.4	215	34.5	16.1	34.5
Uganda	2	1.62	0.1	5.33	0.9	4.3	8.6	1,928	212.8	11.0	300	24.3	8.1	24.3
Zambia	3	2.44	0.2	8.31	2.0	10.2	20.3	8,350	479.8	5.8	1,790	54.8	3.1	54.8
Zimbabwe	14	11.78	1.1	9.74	11.5	57.4	114.8	8,880	2,399.0	27.0	1,960	273.9	14.0	273.9
Total	**373**	**679.58**	**72.9**	**10.73**	**729.4**	**3,647.0**	**7,294.0**	**327,079**	**156,314**	**47.8**	**67,886**	**17,844**	**26.3**	**17,844**

As table 3.2.3 shows, South Africa has the greatest CDM potential, with some 195 industrial cogeneration projects and a potential GHG emissions reduction of about 58.6 million tCO_2e per year. These results provide the upper limits of potential energy-efficiency improvement that can be implemented as such projects in these countries.

In sum, using combined heat and power systems to replace stand-alone generation facilities in industries has an annual production potential of about 2.84 PJ of steam, 153.4 TWh of electricity, and 17.8 GW of additional installed power capacity. To put these facilities in place, an estimated US$17.8 billion investment would be required. Operating the facilities as CDM projects would yield a total emission reduction of 72.9 million tCO_2 per year; the potential revenue generated from the sale of emission reductions would total about US$718 million per year at a carbon market price of US$10 per tCO_2e.

3.2.3 Barriers to Implementation

Developing combined heat and power systems for industry as CDM projects faces several major challenges in countries of Sub-Saharan Africa. First, industries in these countries often lack knowledge about cogeneration opportunities. As mentioned above, industrial operators commonly generate steam from stand-alone boilers and electricity from a combination of stand-alone and grid-based power. They often rely on on-site power-generation facilities as a backup to unreliable grid supply. But decision makers in many of these industries often overlook key facts: The best thermal efficiency that can be obtained from stand-alone systems is only about 55 percent; moreover, recent advances in combined heat and power technology make it possible to increase station thermal efficiency to at least 85 percent.

Second, the heat supply of industrial operations is a common constraint. In most stations, heat demand must be met because heat is unavailable to import from other facilities. But lacking options to recover excess power usually means that a station’s heat demand results in excess power production. Where commercial technologies with a best-fit, heat-to-power ratio cannot be identified, it is not possible to implement cogeneration projects. In many countries across the region, regulations do not allow the wheeling of excess power production through existing national grids.

Third, many of these countries have poorly defined or non-existent power purchase agreements (PPAs). Even in cases where clear regulations are in place to promote the wheeling of excess power through existing grids, the contract binding the purchase of the excess power from the industrial sources becomes a critical element in the viability of cogeneration systems. Because of these countries’ inadequate experience with the technology, the PPAs are usually poorly defined. In many cases, institutional arrangements for the development of guidelines for new projects are not in place. The result is that negative signals are often sent to project promoters, whose industrial facilities may have the potential to plan and implement such projects.

3.2.4 Recommendations for Mitigation

These major barriers can be overcome by governments introducing sound policy frameworks that facilitate the creation of an enabling environment within which industrial cogeneration systems can be promoted and developed. Such an environment can ensure reliable returns on investment from such facilities while engendering the support of financial institutions that will make favorable-term loans available from local and overseas banks. This type of approach has succeeded in such cases as Tunisia, where the government requested industries to consider implementing cogeneration units in return for access to attractive financing.

In addition, key actions involving information sharing, evaluation of facility capacity, and development of improved regulatory and legal frameworks can promote industrial cogeneration systems as CDM projects. Effective knowledge sharing and information dissemination are critical to any program promoting cogeneration systems, whether in developing or developed countries. On a global scale, the World Alliance for Decentralized Energy (WADE) has accelerated the worldwide development of cogeneration and other decentralized energy systems. At a regionwide level, the European Trade Association for the Promotion of Cogeneration, known as Cogen Europe, has worked toward the wider use of cogeneration in Europe. And Cogen Asia has contributed to the growing penetration of combined heat and power systems across the Asia region. Similarly, Sub-Saharan Africa must galvanize cogeneration information sharing among industry personnel in each country to eliminate the barrier of inadequate technical knowledge and communications.

In addition, countries in Sub-Saharan Africa should undertake early studies on the industrial sector's capacity for combined heat and power systems. Such studies should consider the heat-to-power ratio of each facility to ensure that related issues do not prevent the respective countries from making the best use of the technology. Furthermore, sound frameworks for PPAs between industries and power utilities must be put in place and endorsed at the highest level of government. If PPAs are transparent, industries will be encouraged to invest in the cogeneration plants, which will provide them a reliable source of added income from the sale of excess power to the grid. According to information obtained from the study team's interactions with decision makers in Nigeria, that country's industrial sector is expected to contribute about 10 percent of the country's total grid-based power generation by 2010 via the implementation of combined-heat-and-power systems in lead industries and export of excess power to the grid. For this to happen, the Nigerian government recognizes the need for a sound and transparent PPA framework.[40] Finally, the region's development partners can contribute to improving the regulatory framework where needed through sector-based dialogue with decision makers at an institutional level.

Generation from Renewable Energy

3.3 Combined Heat and Power in Sugar Mills

Across Sub-Saharan Africa, sugar factories' needs for heat and electricity are usually met from stand-alone power and steam plants. In many sugar plants, heavy fuel oil is used to generate steam from boilers of average pressure ratings of 10–20 bars. After depressurization, this steam is used as a heat source in sugar-plant distillation and crystallization processes. Electricity requirements are usually met from a combination of grid-based power and on-site diesel generation sets. Such a configuration results in enormous energy inefficiency and wastage. In the few sugar plants where cogeneration systems are in place, the Hirn thermodynamic cycle is used inefficiently, with a low-to-medium pressure boiler and a back-pressure turbine, thereby preventing increased power generation when the sugar facility's steam consumption decreases. Sugarcane offers many potential advantages for increased power generation in sugar mills and reduced GHG emissions. In addition to providing raw materials for ethanol production, it grows faster than most other energy crops. The two major types of potential biomass fuels produced by sugar-processing factories are cane trash (leaves

[40] In January 2007, the study team met with A. O. Adegbulugbe, Special Energy Adviser to the President of Nigeria, regarding ongoing work on the development of a transparent power purchase agreement for independent power producers operating in Nigeria.

and plant tops burned before harvesting) and bagasse (residue from the syrup extraction process). Table 3.3.1 lists biomass cogeneration projects that have been registered or are in the process of being approved under the CDM (ACM0006).

Table 3.3.1: Biomass Cogeneration Projects Approved or Requesting Registration, by Host Country

ACM0006 version	Project title	Month/year registered
Brazil		
4	Santa Terezinha Tapeijara Cogeneration	June 2007
Chile		
1	Nueva Aldea Biomass Power Plant, phase 1	March 2006
2	Nueva Aldea Biomass Power Plant, phase 2	June 2006
1	Trupan Biomass Power Plant	June 2006
China		
3	Hebei Jinzhou Straw-fired Power	March 2007
3	Shandong Yucheng Xinyuan Biomass Heat and Power	March 2007
3	Henan Luyi Biomass Cogeneration	March 2007
3	Zhongjieneng Suqian Biomass Direct Burning Power Plant	March 2007
3	Zhongjieneng Jurong Biomass Direct Burning Power Plant	March 2007
4	Shandong Shanxian Biomass Power Plant	June 2007
India		
3	Deoband Bagasse Cogeneration	November 2006
3	R.K. Powergen Grid-connected Renewable Energy Biomass Power	December 2006
3	Bagasse-based Cogeneration, Titawi Sugar Complex	March 2007
3	Bagasse-based Cogeneration, Nanglamal Sugar Complex	March 2007
3	Bagasse-bsed Congeneration, Mawana Sugar Works	March 2007
3	Installation of Cogeneration at Sugar Manufacturing Unit of Mawana Sugars, Ltd.	March 2007
3	Bagasse-based Cogeneration Power, Khatauli	March 2007
3	Bagasse-based Cogeneration Power, Seohara, Uttar Pradesh	March 2007
3	Bagasse-based Cogeneration Power, Uttar Pradesh	April 2007
3	Bagasse-based Cogeneration Power, Sameerwai	May 2007
4	Energy-efficiency Improvement Project, ISL	March 2007
4	Biomass Cogeneration-based Power Generation	April 2007
4	KM Renewable Energy	April 2007
4	DSCL Sugar Ajbapur Cogeneration	May 2007
4	WCPM Energy Efficiency	June 2007
4	SSML Simbhaoli Biomass Power	September 2007
4	DSM-Dhampur Bagasse Cogeneration	Review requested
4	Sugars, Ltd. (MSL) at Mawana, Uttar Pradesh	Review requested
4	DSM-Asmoli Bagasse Cogeneration Plant for Electricity Generation for Grid Supply, Mawana	Review requested
5	Bagasse-based Cogeneration Project, Pudukkottai, Tamil Nadu	September 2007
5	Power-capacity Expansion Project, Dwarikesh Puram	Review requested
5	Greenfield Power Project, Dwarikesh Dham	Registration requested
Thailand		
4	A.T. Biopower Rice Husk Power, Pichit	June 2007
4	Khon Kaen Sugar Power Plant	July 2007

3.3.1 Technical Evaluation

The study team obtained statistics on sugar-mill power-generation facilities and their operating parameters from the Platts UDI World Electric Power Plants (WEPP) Database (2006) (table A3.1-3). Review of this data showed that unit boilers in the region operate at low-to-medium pressure (15–47 bars) at temperatures below 450°C, with the exception of captive power plants in Reunion (Le Gol) and Mauritius (Belle Vue), which use high-pressure boilers. The data also showed that captive power plants are subcritical at all sugar mills.

A recent study by the Energy, Environment, and Development Network for Africa (AFREPEN), which analyzed the potential of large-scale, biomass-based generation plants, identified the sugar-industry sector as a major cogeneration user. The Mauritius cogeneration example was considered a successful example of optimizing biomass use in sugar mills. Indeed, in 2002, 40 percent of that country's total electricity generation came from sugar mills, half of which was from bagasse.

3.3.2 Quantitative Analysis

As box 3.3.1 illustrates, the mean value for sugar-mill efficiency is conservative if one considers that many captive power plants with a total capacity as high as 145 MW are operating under low pressure (4–24 bars). In the present study, this average efficiency was used for countries where data was unavailable. For countries in which data was available, the average efficiency was calculated based on the operating parameters of the captive power plants. The CDM project in Sub-Saharan Africa would implement an efficient, high-pressure (more than 80 bars) captive power plant with an efficiency of about 110 kWh per ton of cane to replace the baseline low-pressure systems.[41]

Box 3.3.1: Calculating the Generation Efficiency of Sugar Mills

To estimate the efficiency of electricity generated from captive power plants at sugarcane mills, the AFREPEN study made several operating assumptions: 1) 25–31 bars of pressure yield an efficiency of 50 kWh per ton of cane, 2) 44 bars yield 80 kWh per ton of cane, and 3) 80 or more bars 110 kWh per ton of cane. Based on this study's data, 500 MW are generated under BP process, 87 MW under a medium-pressure process, and 148 MW under a high-pressure process. Thus the average efficiency (AE) is as follows:

AE = (500 * 50 + 87 * 80 + 148 * 110)/(500 + 87 + 148) = 66 kWh/ton of cane

Using the above assumptions, the study team's analysis of existing sugar mills in Sub-Saharan Africa showed that 67 CDM projects can be implemented. Increased electricity production resulting from this efficiency improvement is estimated at about 3,500 GWh, representing 1.23 percent of the energy generated in the countries where sugar mills operate. With a 90-percent load factor, this improvement will lead to additional power capacity of 660 MW or about 0.7 percent of installed capacity in those countries. The total emissions reduction achievable is estimated at about 2.4 million tCO_2 per year, representing about 0.13 percent of the countries' total emissions. Revenue from sale of CERs is estimated at US$244 million for 10 years, and the investment costs of corresponding projects is estimated at about US$990 million (table 3.3.2).

[41] For the baseline, a default emission factor of 0.7 tCO_2 per MWh was used for all countries in Sub-Saharan Africa. It was assumed that the electricity generated by the CDM projects would not displace hydroelectricity.

Table 3.3.2: Results Summary of CDM Opportunities in Sub-Saharan Africa: Combined Heat and Power in Sugar Mills

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' (10-yr life span (millions tCO_2)	Value of projects emissions reductions (millions US$)		Electricity generation			Total installed power, country (MW)	Added power of projects (MW)		Total investment cost of projects (millions US$)
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed	
Angola	1	20.39	.01	0.05	0.1	0.6	1.1	1,920	15.8	0.82	670	3.0	0.4	4.5
Cameroon	2	6.81	.04	0.66	0.4	2.2	4.5	3,920	63.8	1.63	900	12.1	1.3	18.1
Chad	1	0.19	.01	5.89	0.1	0.6	1.1	92	16.1	17.5	40	13.0	7.5	4.6
Congo, Dem. Rep.	1	2.37	.06	2.34	0.6	2.8	5.5	5,400	79.2	1.5	326	15.0	4.6	22.5
Congo, Rep.	1	5.31	.01	0.27	0.1	0.7	1.4	353	20.2	5.7	327	3.8	1.2	5.8
Côte d'Ivoire	1	6.42	.03	0.53	0.3	1.7	3.4	4,620	48.4	1.0	1,260	9.2	0.7	13.8
Ethiopia	2	4.37	.04	1.04	0.4	2.3	4.5	2,294	64.7	2.82	399	12.2	3.1	18.4
Gabon	1	4.95	.01	0.15	0.1	0.4	0.7	1,500	10.3	0.69	400	2.0	0.5	2.9
Kenya	6	9.88	.23	2.31	2.3	11.4	22.8	4,976	326.3	6.56	934	61.8	6.6	92.7
Liberia	1	0.53	.01	1.48	0.1	0.4	0.8	1,196	11.2	--	955	2.1	0.2	3.2
Madagascar	3	2.54	.08	2.98	0.8	3.8	7.6	1,197	108.2	13.2	956	20.5	2.1	30.8
Malawi	2	0.86	.10	11.51	1.0	4.9	9.8	1,293	140.7	10.88	935	26.6	2.8	40.0
Mauritius	13	4.01	.12	3.08	1.2	6.2	12.4	1,195	176.8	13.8	954	33.5	3.5	50.2
Senegal	1	5.49	.02	0.32	0.2	0.9	1.8	1,290	25.5	1.8	476	4.8	1.0	7.2
South Africa	16	423.81	.90	0.21	9.0	44.9	89.7	227,000	1,281.8	0.56	40,480	242.8	0.6	364.1
Sudan	1	10.79	.17	1.57	1.7	8.5	16.9	84	242.0	6.2	39	45.8	116.1	68.8
Swaziland	3	1.14	.20	17.35	2.0	9.9	19.8	460	283.5	61.63	40,481	53.7	0.1	80.5
Tanzania	5	3.97	.10	2.54	1.0	5.0	10.1	3,150	144.0	4.57	860	27.3	3.2	40.9
Uganda	3	1.62	.06	3.58	0.6	2.9	5.8	1,928	82.7	4.29	859	15.7	1.8	23.5
Zambia	1	2.44	.10	4.02	1.0	4.9	9.8	8,350	140.4	1.68	860	26.6	3.1	39.9
Zimbabwe	2	11.78	.14	1.23	1.4	7.2	14.5	8,880	207.3	2.33	860	39.3	4.6	58.9
Total	**67**	**679.58**	**2.4**	**0.36**	**24.4**	**122**	**244**	**283,528**	**3,489**	**1.23**	**93,972**	**661**	**0.7**	**991**

3.3.3 Barriers to Implementation

Cogeneration faces an array of communication, financial, regulatory, and technological barriers. Most small- and medium-sized sugar industries ignore the cogeneration option and the opportunity it provides for improved profitability and competitiveness. Among the countries covered by this study, many industries are experiencing structural financial crisis. Rather than invest in improved performance, companies prefer to reserve most of their liquidity for the purchase of raw materials, usually paid for in cash (because of suppliers' distrust of transactions other than cash-and-carry). In Senegal, for example, local financial institutions have virtually abandoned the financing of industrial development projects, especially those that focus on efficiency improvements. Many such projects lack adequate indices that can lead to positive decisions for access to venture capital.

Another major barrier involves the cogeneration technology. Because the system is sized to ensure that the host facility's heat demand is satisfied, electricity production often exceeds the demand for power. Thus, it is imperative that industrial companies aiming to implement cogeneration systems be able to sell their excess generation to the electricity company (in the case of distribution and business monopoly) or consumers at an acceptable price. If the regulatory framework does not have suitable PPA arrangements in place, industrial companies will lack the financial incentive to exploit the cogeneration opportunity, and industrial managers will perceive energy generation as a distraction from their core business.

3.3.4 Mitigation Recommendations

Overcoming these various barriers requires that governments in the region facilitate the guarantee of local bank loans by financial institutions. This has been the case in such countries as Tunisia, where the government requested that all industrial operators with cogeneration potential exploit it. As an incentive, Tunisian government facilitated access to financing with attractive terms. African development partners can contribute to improving the regulatory framework through sector-based dialogue with decision makers at the institutional level.

3.4 Agricultural Residue

Agricultural residue is biodegradable, non-fossilized organic matter (and the gas captured from its decay) originating from plants, animals, and microorganisms. This study considered residues typically produced during the harvesting of agricultural crops in countries of Sub-Saharan Africa: 1) perennial plantation crops (cocoa, coffee, coconut, and oil palm) and 2) annual agricultural crops (cotton, groundnut, corn, millet, rice, sorghum, cassava, and wheat).

Because they are costly to gather, agricultural residues have not been widely used for energy generation in Sub-Saharan Africa.[42] Nonetheless, their value as a fuel source for large-scale heat and power generation has been demonstrated and commercialized in other world regions. In the United States, for example, biomass that includes agricultural residue currently plays a recognizable part in the country's energy systems. In the year 2000, biomass (defined as wood, wood wastes, agricultural residues, and dedicated energy crops) represented about 3 percent of total U.S. energy consumption (EIA 2000). In many countries of Sub-Saharan Africa, biomass energy (consisting mainly of fuelwood, charcoal, agricultural

[42] Two exceptions include sugarcane residue (e.g., bagasse) in power generation and steam production in sugar industries.

residue, dung), constitutes a significant proportion of household energy consumption, and to a lesser degree, industrial consumption. In many such applications, biomass is used in traditional facilities characterized by low-energy efficiencies. Its main household applications are cooking and heating, while industrial applications range from mineral processing (e.g., brick, lime, tile, and ceramics), metal processing, and refrigeration using absorption systems (Thioye 1997a, b).

3.4.1 Technical Evaluation

When biomass (ligno-cellulosic materials) is combusted, the basic reaction resulting in energy generation can be represented by the following stochiometric equation:

$$CH\gamma O\chi + (1 + 4\gamma/4 - \chi/2)\ O_2 \rightarrow CO_2 + \gamma/2\ HO_2 + NCV$$

where,

NCV (net calorific value) = heat produced in the reaction that is captured in the boiler to generate steam and electricity.

NCV can be calculated as follows:

$$NCV = 393.500 + 102.225 * \gamma - \chi(1+0.5\gamma) * (110.100 + 102.225 * \gamma) \text{ in KJ/kmole}$$

Applied to wood, the above formula yields an NCV of 18.6 MJ per kg. The NCVs of agricultural residues considered in this study are less than that of wood.

This study's technical evaluation centered on quantifying the potential use of agricultural residues generated in Sub-Saharan Africa as fuel for power generation, using energy-efficient conversion facilities as defined by international best practices. In other developing regions, many such activities have been implemented as CDM projects under ACM0006 (table 3.4.1).

Compared to CDM opportunities for which potential projects could be clearly identified with existing facilities (e.g., sugar mills), assessing the potential of agricultural residue projects required a more top-down approach. Because of the diversity of organizations and producers that generate agricultural residues, available data is not organized in a way that permits the counting of potential projects. Thus, the top-down approach used is indicative of the region's CDM project potential and cannot be used for making country- or project-specific decisions, which would require more detailed levels of data gathering beyond the scope of this study.[43]

[43] The estimated unitary investment cost of US$1.4 million assumes the use of biomass co-combustion technology and a power-generation unit higher than 5 MW (Squilbin 2002).

Table 3.4.1: CDM Projects in the UNFCCC Registration/Validation Pipeline Using Agricultural Residue as Fuel for Power Generation

Project title	*Location*	*Power capacity (MW)*	*Residue type*	*Emission reduction (tCO_2e/year)*
Biomass generation	Jiangsu, China	25.0	Cotton straw	109,105
Biomass power generation	Gaotang, Shandong, China	30.0	Cotton stalk	140,695
Biomass cogeneration	Heilogjiang, Tangyuan, China	24.0	Maize straw	183,692
Biomass generation	Wudi, Shandong, China	24.0	Cotton waste	113,433
A.T. biopower	Pichit, Thailand	22.0	Rice husk	70,772
Biomass power	Shanxian, Shandong, China	25.0	Cotton, corn straw	127,102
Biomass cogeneration	Koppo, Karnataka, India	26.0	Cane trash, coconut fronds, sawdust, wood chips, bamboo chips, bagasse	40,246
Biomass cogeneration	Uttar Pradesh, India	8.5	Rice husk, bagasse pith, black liquor	33,422
Biomass power plant	Jurong, Zhongjieneng, China	24.0	Agriculture (various)	123,558
Biomass power plant	Suquian, Zhongjieneng, China	24.0	Agriculture (various)	123,055
Biomass cogeneration	Luyi, Henan, China	25.0	Wheat, maize, cotton	185,664
Biomass combined heat and power	Yucheng Xinyuan, China	15.0	Xylose, furfural	189,662
Straw-fired power	Jinzhou, Hebei, China	24.0	Corn, wheat straw	178,626
Grid-connected biomass power	Chitradurga District, India	20.0	Agriculture (various)	113,150
Biomass power plant	Trupan, Chile	30.0	Agriculture (various)	101,846
Biomass power plant (phase 1)	Nueva Aldea, Chile	30.0	Wood waste	106,122

Source: https://cdm.int/Projects/projectsearch.html

The analyses consisted of several key steps. First, the quantities of the types of agricultural residues available in each country were estimated. Second, the energy content of the residue available under the project scenario was estimated based on the quantity of each type of residue produced, the percentage of recoverable residue for energy generation on a dry-mass basis and their NCVs. Third, the energy consumed during preparation and transport of biomass residue to the project site under the project scenario was estimated.

With regard to baseline emission considerations, it was assumed that, in the absence of the CDM project, a fossil fuel would have been used to produce the energy. Since it was not known whether the biomass residue would be used for power or heat generation, it was assumed that a fossil fuel with the lowest carbon-emission factor (i.e., natural gas) would be used in the baseline case for the same quantity of energy generated.[44] The implication is that the emission reduction may be overestimated in countries where energy consumption is mainly from renewable energy. Conversely, in countries where non-renewable fuels, such as diesel or coal, predominate, the emission reduction may be underestimated. The study team considered the approximation used in this analysis adequate for making useful conclusions about the robustness of this type of CDM opportunity in the region.

For both perennial plantation and annual agricultural crops, the residue potential was estimated using the residue-to-product ratio (RPR) method.[45] For perennial plantation crops, the amount of residue was calculated using an average RPR value for each crop, thus neglecting real-life variations in RPR values resulting from changes in weather, crop types grown, water availability, soil fertility, farming practices, and other factors. For annual agricultural crops too, the RPR estimates are indicative of potential and should not be viewed as numbers for project planning and execution.[46]

In practice, a proportion of these resources will prove difficult to collect or will not be recoverable since they have other non-energy and energy uses.[47] Thus, caution must exercised in using the results of this generalized estimate. As Koopmans and Koppejan (1997) concluded, estimates that show considerable quantities of unused residues require that more data be collected on their current availability and use before recommending strategies for their increased use in energy generation. Any potential conclusions drawn from study results for a particular country or area may have little relevance elsewhere, given the enormous diversity between and within countries. Because many variables influence database results in this type of study, a subnational, or even smaller, geographical system may be required for program or project use. Practical applications of study results should not lose sight of social implications. For example, promoting the use of agricultural residues for power generation will not only valuate the residues but may also deprive a proportion of the population—often the poorest—of its cooking and heating fuel. For this reason, studies should be conducted to determine the possible effects of increased farm-level use of residues on soil conservation and degradation, the local environment, income generation, and local communities. The authors of this report agree with this conclusion. At the same time, the study results can indicate the potential for developing residue-based energy generation facilities as CDM projects in countries of Sub-Saharan Africa.

This study used data on the annual production of the various agricultural products covered, the RPR for each of the products, and the estimated calorific values for each of the residue types to develop a quantitative indication of the potential power generated in each of the countries studied. Table 3.4.2 summarizes the various RPR and calorific values used in the calculations.

[44] The baseline emission was calculated as the energy made available by the project (net energy content of the biomass) times the emission factor of the natural gas.
[45] For the crops considered, average RPR values were taken from various sources, including the Food and Agriculture Organization of the United Nations (2005), Central Bank of West African States (2005), and the United States Department of Agriculture (2007).
[46] Annual agricultural crops are a key source of residue for energy generation in countries where an agrarian culture predominates; large quantities of residue are generated at and between harvest times as part of regular farm management.
[47] This assessment did not consider the effect of price on resource availability.

Table 3.4.2: RPR and Calorific Values of Agricultural Residues

Residue product	RPR	Energy content (MJ/kg)
Groundnut straw	0.126	17.8
Groundnut shell	0.582	17.8
Corn stem	0.444	17.4
Corn cob	0.444	17.8
Millet straw	0.500	10.2
Rice straw	0.571	10.2
Rice husk	0.200	14.5
Sorghum stem	0.500	17.0
Cassava stem	0.370	17.0
Cocoa pod	0.500	17.0
Coffee husk	0.357	18.3
Wheat stem	0.444	17.4
Cotton stem	0.235	17.2
Cotton shell	0.189	16.3
Coconut husk	0.333	14.8
Coconut shell	0.526	15.0
Palm fiber	0.180	9.6
Palm cob	0.240	4.4

Sources: Squilbin (2002) and Koopmans et al. (1997).

3.4.2 Quantitative Analysis

Using 2003 crop-production data, the quantities of residues generated were estimated for each country studied (table A3.1-4). These figures, in turn, were used to estimate annual electricity generation, potential power capacity, and achievable emissions reduction from the CDM project (box 3.4). As stated previously, the study assumed that the energy generated by the project facility would have been generated in the baseline using the fossil fuel with the lowest carbon emission factor (natural gas). It was also assumed that, because agricultural residue is carbon neutral, GHG emissions would result only from residue processing and handling (using a fuel oil with a carbon emission factor of 21.2 tC per TJ) and transport from the collection site to the project site (using diesel). Project and leakage emissions were estimated as a simple function of the dry mass quantity of the agricultural residue processed. Table 3.4.3 summarizes the results of the quantitative analysis.

Box 3.4.1: Calculating the Energy-generation Potential of Agriculture Residues

The following equation was used to estimate the tonnage of residues generated for each agricultural product:

$Resid_i = RPR_i * Crop_i$

where,

$Resid_i$ = tons of residue from crop i,
RPR_i = residue production ratio for crop i, and
$Crop_i$ = quantity of crop i produced in the focal year.

Annual electricity generation and potential power capacity were calculated as follows:

$TE_j = {}_i\Sigma$ Residi, j * $PCI_i * f_i$
EGj = TEj * EFF * B_F
MWj = EGj/(8760 * CF)

where,

TE_j = total energy of the extracted agricultural residues in country j (TJ),
Residi, j = amount of residue type i available in country j (tons),
PCIj = energy content of the agricultural residue (TJ/ton),
f_i = fraction of residue type i available for energy generation,
EGj = electrical energy generated (MWh),
EFF = energy efficiency of the project generation facility (fraction),
B_F = conversion factor (MWh/TJ),
MW_j = estimated installed power capacity (MW), and

In the above equations, f_i equals zero for residues used for non-energy purposes (e.g., straw for animal feed); in cases where some of the residue is not recovered (e.g., because of mulching or other agricultural practices), f_i may equal less than 1.

The emissions reduction resulting from the CDM project was estimated as follows:
$BE_j = TE_j * CEF_q$
$PE_j + LE_j = 0.6 * {}_i\Sigma\ RPR_{i,\ j} * f_i$
$ER_j = BE_j – (PE_j + LE_j)$

where,

BE_j = baseline emission in country j (tCO_2e),
CEF_q = emission factor of baseline fuel (tCO_2e/TJ),
PE_j = project emission in country j (tCO_2e),
LE_j = leakage emission in country j (tCO_2e), and
ER_j = emission reduction (tCO_2e).

Table 3.4.3: Results Summary of CDM Opportunities in Sub-Saharan Africa: Agricultural Residue

Country	No. of projects	Electricity generation of projects (GWh/yr)	Added power of projects (MW)	Added power of projects as % of total installed power, country (MW)	Projects' emissions reductions (thousands tCO_2e)	Total investment cost of projects (millions US$)
Angola	13	5,258	667	99.6	3,384.4	934
Benin	11	4,345	551	779.5	2,830.1	772
Botswana	1	46	6	4.5	29.7	8
Burkina Faso	6	2,462	312	209.6	1,573.6	437
Burundi	2	704	89	221.1	454.5	125
Cameroon	11	4,339	550	61.2	2,837.3	771
Central African Republic	2	616	78	205.7	399.4	109
Chad	4	1,623	206	509	982.7	288
Congo, Dem. Rep.	23	8,898	1,129	43.9	5,720.4	1,580
Congo, Rep.	1	264	33	27.6	165.0	47
Côte d'Ivoire	17	6,646	843	66.9	4,341.0	1,180
Equatorial Guinea	1	18	2	17.3	11.3	3
Ethiopia	44	17,440	2,212	320.6	11,457.1	3,097
Gabon	1	188	24	6.0	122.0	33
Ghana	20	8,008	1,016	77.5	5,171.4	1,422
Guinea	5	1,907	242	95.2	1,219.2	339
Guinea Bissau	1	218	28	116.5	140.1	39
Kenya	25	9,911	1,257	134.6	6,527.5	1,760
Madagascar	7	2,615	332	178.6	1,623.6	464
Malawi	19	7,500	951	317.1	4,915.2	1,332
Mali	6	2,319	294	67.3	1,473.6	412
Mozambique	19	7,462	946	40.5	4,849.8	1,325
Namibia	1	159	20	6.7	103.1	28
Niger	1	140	18	14.6	34.2	25
Nigeria	82	32,427	4,113	69.8	20,645.3	5,758
Rwanda	2	746	95	331.1	483.8	133
Senegal	5	1,896	240	50.5	1,219.6	337
Sierra Leone	1	179	23	18.9	106.8	32
South Africa	137	53,895	6,836	16.9	35,496.3	9,570
Sudan	3	1,132	144	30.0	660.6	201
Swaziland	1	269	34	26.3	177.4	48
Tanzania	37	14,762	1,872	217.7	9,629.3	2,621
Togo	5	2,125	269	125.5	1,387.0	377
Uganda	18	7,001	888	296.0	4,539.7	1,243
Zambia	13	5,258	667	37.3	3,453.6	934
Zimbabwe	10	4,068	516	26.3	2,677.5	722
Total	**554**	**216,842**	**27,504**	**41.5**	**140,843.1**	**38,506**

In estimating the number of potential CDM projects, a maximum plant-generation capacity of 50 MW was assumed, based on the observation that most biomass residue projects in the UNFCCC project pipeline have capacities of about 25 MW. Given this assumption, a total of 554 such projects were identified. It was estimated that about US$38.5 billion will be needed to implement these projects, which would generate some 41.5 GW of additional power, representing nearly 42 percent of the region's installed capacity. If implemented within the CDM protocol, these projects would reduce emissions by about 140 million tCO_2e per year. However, this estimate is conservative, given that the baseline CH_4 emissions likely to occur as a result of the anaerobic degradation of the residues dumped at points of production. These emissions will be avoided when the residues are used for energy generation in the project scenario.

3.4.3 Barriers to Implementation

CDM opportunities involving energy generation from agricultural residues may be hindered by a variety of factors. A major constraint is the region's poor transport infrastructure, which can prevent access to residues located in remote areas where much of the harvesting of agricultural products occurs. In addition, the region lacks many of the technological skills needed for pre-use transformation. For example, before being used as a fuel, agricultural residues may require pre-drying, size reduction, or briquetting to increase energy density. Furthermore, compared to fossil fuel–fired generation, biomass-fueled systems tend to have higher initial capital and investment requirements and a higher unit cost of electricity generation (CIWMB 1999; Dayo 2005b; Squilbin 2002). Another problem involves weak or non-existent power purchase agreements (PPAs). Because many countries in Sub-Saharan Africa lack well-established PPAs, selling the grid the excess electricity typically generated by such projects becomes problematic, which can deter investment in facilities. Finally, as discussed above, using agricultural residues as a fuel for energy generation may adversely affect agriculture if the amounts collected exceed what is needed to maintain soil productivity.

3.4.4 Mitigation Recommendations

Surmounting the above-mentioned barriers requires a set of strategic actions. Prior to developing such projects, each country in Sub-Saharan Africa should develop a comprehensive national program on biomass-fueled energy generation. A pioneering program activity would center on the effects of transport infrastructure on access to and recoverability of agricultural residues. Such national reviews would use geographic information system (GIS) techniques to map residue occurrence and availability with infrastructure and potential sites for energy-generation facilities. Such national programs would also feature capacity building in required pre-use transformation and energy-generation technologies. Furthermore, each country should put a comprehensive regulatory and institutional framework in place to ensure a transparent operational environment for the adoption of clean-energy technologies. Such frameworks would address power purchase tariffs; PPAs; power-sector reform; roles of independent power producers and rules of engagement; and technology adaptation, specification, and quality control protocols. Moreover, to uphold the sustainable-development value of CDM projects, an optimal balance must be struck with regard to use of agricultural residue. As previously stated, not all residues should be recovered as they are needed to maintain soil productivity and control erosion. In this context, agricultural research should be conducted to develop optimum extension-service procedures that help farmers cope with increased residue use. Finally, cooling systems for crops conservation, based on absorption systems using low-pressure boilers, can be used on-site to transform agricultural residues into useful energy, thus eliminating the need for collection and transport (Thioye 1997a, b).

3.5 Forest and Wood-processing Residues

With appropriate pre-processing, residues generated from forest logging operations and roundwood industries can be used as fuel for power generation. The waste residues from logging operations include tree branches, tops of trunks, stumps, branches, and leaves. Residues from wood-processing industries—sawmills, pulp mills, and veneer and plywood plants—commonly consist of log cores, wood slabs, end pieces, bark, and sawdust (CIWMB 1999); most of these residues are dumped at industry sites or used in alternative ways (e.g., sawdust for landfills). Common pre-processing techniques for use as fuel include drying to reduce moisture content, size reduction to increase ease of handling, and briquetting to increase energy density. The sections below analyze the biomass-to-energy potential of forest and wood-processing residues for countries in Sub-Saharan Africa.

3.5.1 Technical Evaluation: Forest Residue

The study team used a three-step evaluation approach. First, it assessed the amount of residue each country generated in logging operations. Next, it estimated the quantity of forest residue available for energy generation, using a factor representing collectible residue. This quantity was then converted into energy units using characteristic calorific values of the residues. Finally, the team estimated the potential for electrical energy generation and added power capacity.[48]

For each country, the team used a generation rate of 0.2 tons for each cubic meter of roundwood produced (Koopmans and Koppejan 1997). This figure is equivalent to 0.31 m^3 of residue generated per cubic meter of roundwood.[49] While information on recovery rates for Sub-Saharan Africa is sparse, a recent study on logging operations in Central Africa indicated that about 67 percent of residues are recoverable (Dramé 2007). Using this figure in the current analysis, the effective average residue-recovery rate for logging operations is 0.134 tons of residue per ton of roundwood produced.

It was assumed that the residue (on a dry basis) would be used as a fuel in steam-turbine facilities with an energy efficiency of about 33 percent. It should be noted that the estimated power-generating capacity would be higher if the residue were used as fuel in a cogeneration facility, combined cycle, or biomass gasifier.

3.5.2 Quantitative Analysis: Forest Residue

Box 3.5.1 shows the equations used to estimate the potential for energy generation from forest residue and the resulting reduction in GHG emissions. The study team assumed that, without the CDM project, fossil-fired fuel would have been used to produce the resulting energy. Since it was not known whether the forest residue would be used to generate power or heat, the study team assumed that all of the biomass fuel produced via the project would be used to generate power. With regard to baseline emission assumptions, the team chose natural gas (i.e., the fossil fuel with the lowest carbon emission factor) as the fuel that would have been used to generate the same amount of electrical energy. Diesel was the assumed fuel for transport and transformation activities. The team assumed that project emissions were limited to the energy used to process the residue and transport it to the project site. Zero leakage was assumed. Production statistics from the Food and Agriculture Organization of the United Nations (FAO) (for year 2003) were used to simulate the potential reduction in GHG emissions. Table 3.5.1 summarizes the results of the quantitative analysis.

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[48] The estimated unitary investment cost was US$1.4 million, based on biomass co-combustion technology and a power-generation unit higher than 5 MW (Squilbin 2002).

[49] A report on residue generation from U.S. lumber operations cited a recovery rate of 0.2051 m^3 per cubic meter of roundwood used (USDA and USDOE 2005).

Box 3.5.1: Calculating Energy Generation from Forest Residue

To estimate the achievable energy generation from forest residue and the corresponding addition to installed power capacity and reduction in GHG emissions, the following equations were used:

$FResid_{j,y} = RWP_{j,y} * RGR_j$
$RE_{j,y} = FResid_{j,y} * ERFR_j * CF_{fr}$
$GWH_{j,y} = RE_{j,y} * EFF * FEP$
$PMW_{j,\ y} = GWH_{j,y}/(8760 * CAPF)$

where,

$FResid_{j,y}$ = forest residue produced in logging operations in country j during year y (tons/year),
$RWP_{j,y}$ = volume of roundwood produced in country j in year y (m^3/year),
RGR_j = amount of residue produced per volume of roundwood produced in country j (tons/m^3),
$RE_{j,y}$ = energy content of recovered forest residue in country j in year y (TJ/year),
$ERFR_j$ = percent of economically recoverable forest residue in country j,
CF_{fr} = calorific value of forest residues (MJ/kg),
$GWH_{j,y}$ = electrical energy producible from the biomass-to-energy system (GWh),
EFF = energy efficiency of the power system,
FEP = conversion factor (277.78 MWh/TJ),
$PMW_{j,\ y}$ = estimated installed power capacity of the project (MW), and
CAPF = capacity factor of the power-generation equipment.

Emission reductions resulting from the CDM project were calculated as follows:

$BE_j = TE_j * CEF_g$
$PE_j = FResid_{j,y} * ERFR_j * CF_{fr} * CEF_d$
$LE_j = 0$
$ER_j = BE_j – (PE_j + LE_j)$

where,

BE_j = baseline emission in country j (tCO_2e),
CEF_g = emission factor of baseline fuel (tCO_2e/TJ),
PE_j = project emission in country j (tCO_2e),
CEF_g = emission factor of diesel (tCO_2e/TJ),
LE_j = leakage emission in country j (tCO_2e), and
ER_j = emission reduction (tCO_2e).

Table 3.5.1: Results Summary of CDM Opportunities in Sub-Saharan Africa: Residue from Roundwood Production

Country	No. of projects	Projects' emissions reductions (millions tCO_2e/yr)	Roundwood production (millions m^3/yr)	Residue generation (millions tons/yr)	Projects' energy generation, GWh/yr (% country total)	Added power of projects, GW (% of total installed)	Total investment cost of projects (billions US$)
Angola	12	0.60	4.6	0.92	938 (49)	0.12 (18)	0.17
Botswana	2	0.10	0.8	0.15	155 (17)	0.02 (15)	0.03
Cameroon	29	1.46	11.2	2.24	2,293 (58)	0.29 (32)	0.41
Central African Republic	3	0.13	1.0	0.20	205 (197)	0.03 (68)	0.04
Chad	18	0.93	7.1	1.42	1,457 (1,584)	0.18 (616)	0.26
Congo, Dem. Rep.	191	9.55	73.4	14.69	15,024 (278)	1.91 (74)	2.67
Congo, Rep.	61	0.30	2.3	0.47	480 (136)	0.06 (50)	0.08
Côte d'Ivoire	27	1.34	10.3	2.07	2,114 (46)	0.27(29)	0.38
Equatorial Guinea	2	0.11	0.9	0.17	177 (633)	0.02 (173)	0.03
Ethiopia	249	12.48	96.0	19.19	19,633 (856)	2.50 (361)	3.49
Gabon	12	0.60	4.6	0.91	935 (62)	0.12 (30)	0.17
Ghana	57	2.87	22.0	4.40	4,507 (84)	0.57 (44)	0.80
Kenya	58	2.88	22.2	4.43	4,534 (91)	0.58 (62)	0.80
Lesotho	5	0.27	2.0	0.41	419 (--)	0.05 (66)	0.07
Malawi	15	0.73	5.6	1.12	1,150 (89)	0.15 (49)	0.20
Mozambique	47	2.35	18.0	3.61	3,691 (32)	0.47 (20)	0.66
Nigeria	182	9.14	70.3	14.05	14,377 (69)	1.82 (31)	2.55
Rwanda	14	0.71	5.5	1.10	1,124 (995)	0.14 (375)	0.20
Sierra Leone	14	0.72	5.5	1.10	1,131 (435)	0.14 (120)	0.20
Somalia	27	1.38	10.6	2.12	2,164 (801)	0.27 (343)	0.38
South Africa	86	4.34	33.3	6.67	6,820 (3)	0.86 (2)	1.21
Sudan	51	2.56	19.6	3.93	4,021 (106)	0.51 (67)	0.71
Swaziland	2	0.12	0.9	0.18	182 (40)	0.02 (18)	0.03
Tanzania	62	3.10	23.8	4.76	4,873 (155)	0.62 (72)	0.86
Uganda	102	5.13	39.4	7.88	8,063 (418)	1.02 (341)	1.43
Zambia	21	1.05	8.0	1.61	1,648 (20)	0.21 (12)	0.29
Zimbabwe	24	1.18	9.1	1.82	1,864 (21)	0.24 (12)	0.33
Total	**1,319**	**66.12**	**508.2**	**101.64**	**103,979 (33)**	**13.12 (21)**	**18.46**

The analysis showed that about 13 GW of additional installed power capacity or 21 percent of installed capacity could be put in place using about 102 million tons of residues generated from logging operations. About US$18.6 billion would be needed to put the facilities in place, resulting in emission reductions totaling more than 66 million tCO_2e. The study team assumed that the maximum capacity of each CDM project could not exceed 10 MW, given the diffuse nature of forest residues compared to agricultural residues. Given this assumption, an estimated 1,319 such CDM projects could be implemented in Sub-Saharan Africa. Using a carbon price of US$5 per tCO_2e, the resulting minimum inflow of carbon funds into these countries would total about US$330 million per year.

3.5.3 Technical Evaluation: Wood-processing Residue

The study team assumed that the wood-processing residue (on a dry basis) would be used to fuel steam turbines with an energy efficiency of about 33 percent. It should be noted that the estimated power-generation capacity would be higher if the residue were used in cogeneration, combined cycles, or biomass gasifiers.

3.5.4 Quantitative Analysis: Wood-processing Residue

Box 3.5.2 shows the equations used to estimate the potential for energy generation from wood-processing residue and the resulting reduction in GHG emissions. FAO statistics on roundwood production in logging operations, roundwood supplied as fuelwood, and the amount of pulp produced in each country were used in the simulation, the results of which are summarized in table 3.5.2. Additional parameters used in the simulation were f_{RW} (tons of roundwood used to produce 1 ton of pulp [1.77 tons based on the Kraft process]), D_L (density of lumber from tropical forest [0.65 tons/m^3 based on the biomass-to-energy project in Cameroon]), and f_{RWP} (amount of residue recovered per quantity of roundwood processed [0.347 tons of residue/m^3 of lumber processed based on the biomass-to-energy project in Cameroon]); the f_{RWP} parameter assumed that only 85 percent of the residues generated from wood processing could be recovered for energy generation after accounting for all other uses.

Box 3.5.2: Calculating Energy Generation from Wood-processing Residue

The following equations were used to estimate the residue generated, electricity generated, corresponding installed power capacity, and achievable reduction in GHG emissions:

$RWPI_{i,y} = TRWP_{i,y} – FW_{i,y} – RWP_{i,y}$
$RWP_{i,y} = (TPP_{i,y} * f_{RW})/D_L$

where,

$RWPI_{i,y}$ = quantity of roundwood supplied to wood-processing industries in country i during year y (m^3/yr),
$TRWP_{i,y}$ = total roundwood produced in logging operations in country i in year y (m^3/yr),
$FW_{i,y}$ = fuelwood consumption in country i in year y (m^3/yr),
$RWP_{i,y}$ = roundwood used in the production of pulp in country i in year y (m^3/yr),
$TPP_{i,y}$ = production of pulp in country i in year y (tons/yr),
f_{RW} = tons of roundwood used to produce 1 ton of pulp, and
D_L = density of lumber from tropical forest (tons/m^3).

Lumber residues generated during the processing of roundwood supplied to the wood-processing industries in each country were estimated as follows:

$WPR_{i,y} = f_{RWP} * RWPI_{i,y} * f_{av}$

where,

$WPR_{i,y}$ = residue from wood-processing industry in country i in year y (tons/yr),
f_{RWP} = residue recovered per quantity of roundwood processed (tons of residue/m^3 of roundwood processed), and
f_{av} = fraction of residue produced available for energy generation.

Table 3.5.2: Results Summary of CDM Opportunities in Sub-Saharan Africa: Residue from Wood-processing Facilities

Country	No. of projects	Projects' emissions reductions (millions tCO_2e/yr)	Roundwood processed (millions m^3/yr)	Residue generated (millions tons/yr)	Projects' energy generation, GWh/yr (% country total)	Added power of projects, GW (% of total installed)	Total investment cost of projects (billions US$)
Angola	12	0.40	1.0	0.37	625 (33)	0.08 (12)	0.11
Botswana	1	0.04	0.1	0.04	62 (7)	0.01 (6)	0.01
Cameroon	19	0.68	1.8	0.62	1,066 (27)	0.14 (15)	0.19
Central African Republic	7	0.26	0.7	0.24	410 (394)	0.05 (137)	0.07
Chad	8	0.29	0.8	0.26	451 (490)	0.06 (191)	0.08
Congo, Dem. Rep.	38	1.38	3.7	1.27	2,163 (40)	0.27 (11)	0.38
Congo, Rep.	9	0.34	0.9	0.31	531 (150)	0.07 (56)	0.09
Côte d'Ivoire	18	0.63	1.7	0.58	994 (22)	0.10 (8)	0.18
Equatorial Guinea	4	0.16	0.4	0.14	248 (886)	0.03 (242)	0.04
Ethiopia	31	1.10	2.9	1.02	1,734 (76)	0.22 (32)	0.31
Gabon	37	1.32	3.5	1.22	2,072 (138)	0.26 (66)	0.37
Ghana	14	0.51	1.4	0.47	799 (15)	0.10 (8)	0.14
Kenya	16	0.57	1.5	0.53	903 (18)	0.12 (12)	0.16
Malawi	5	0.20	0.5	0.18	308 (24)	0.04 (13)	0.06
Mozambique	14	0.49	1.3	0.46	778 (7)	0.10 (4)	0.14
Nigeria	98	3.52	9.4	3.25	5,540 (27)	0.70 (12)	0.98
Rwanda	5	0.19	0.5	0.17	293 (259)	0.04 (98)	0.05
Sierra Leone	1	0.05	0.1	0.04	73 (28)	0.01 (8)	0.01
Somalia	1	0.04	0.1	0.04	65 (24)	0.01 (10)	0.01
South Africa	165	5.90	15.7	5.44	9,283 (4)	1.18 (3)	1.65
Sudan	23	0.82	2.2	0.80	1,287 (34)	0.16 (21)	0.23
Tanzania	23	0.81	2.2	0.76	1,280 (41)	0.16 (19)	0.23
Uganda	33	1.20	3.2	1.10	1,880 (98)	0.24 (79)	0.33
Zambia	9	0.31	0.8	0.29	494 (6)	0.06 (3)	0.01
Zimbabwe	10	0.34	0.9	0.32	543 (6)	0.07 (4)	0.10
Total	**602**	**21.54**	**57.2**	**19.87**	**33,881 (11)**	**4.30 (7)**	**6.02**

As table 3.5.2 shows, about 4.3 GW of additional installed power capacity or about 7 percent of installed capacity could be put in place in the countries indicated, using about 19.9 million tons of residues generated in the region's wood-processing operations. A total of about US$6 billion would be needed to put these facilities in place, which would reduce emissions by more than 21 million tCO_2e. It is important to stress that this emission-reduction estimate is conservative—that is, the study did not consider the baseline emissions of CH_4 likely to occur as a result of the anaerobic degradation of the residues dumped at points of production; such emissions would be avoided when the residues are used for energy generation in the project scenario. The study team assumed that the maximum capacity of each CDM project would not exceed 10 MW. Given this assumption, the team estimated that about 602 such projects could be implemented in Sub-Saharan Africa. Using a carbon price of US$5 per tCO_2e, the resulting minimum inflow of carbon funds into these countries would total about US$105 million per year.

3.5.5 Barriers to Implementation

Several major barriers are likely to hinder the implementation of energy projects fueled by forest and wood-processing residues as CDM projects in Sub-Saharan Africa. First, residue access and recoverability may be constrained by the region's poor transport infrastructure. But the situation is less of a bottleneck than for agricultural residues because access roads have usually been created for lumber trucks to facilitate the timely extraction of logged roundwood. Second, before being used as fuels, forest and wood-processing residues usually require pre-use transformations (e.g., drying, sizing, and densification), for which relevant technologies may be missing. Third, like other biomass-fueled systems (e.g., agricultural residue), systems fueled by forest and wood-processing residues tend to have higher initial capital and investment requirements and a higher unit cost of electricity generation compared to fossil fuel–fired generation.[50]

3.5.6 Mitigation Recommendations

Overcoming the above-mentioned barriers suggests a set of actions within an overall strategy to promote forest and wood-processing residues as fuels for generating energy. As a first step, each country should conduct a comprehensive national review of the effects of existing transport infrastructure on residue access and recoverability. Such reviews should use geographic information system (GIS) techniques to map residue occurrence with infrastructure and sites of potential energy-generation facilities. Project proponents can use mapping on a case-by-case basis to propose actions that eliminate access and recoverability barriers to the maximum desired extent.[51,52] At program outset, efforts should be made to develop the required pre-firing transformation and energy-generation technology skills.[53] In addition, each country should put a comprehensive regulatory and institutional framework in place to ensure a transparent operational environment for adopting clean-energy technologies. Such a framework should address power purchase tariffs; PPA format; power-sector reform; the role of independent power producers and rules of engagement; and technology adaptation, specification, and quality-control protocols. Finally, the wood-processing industry must be encouraged to invest in energy generation using waste generated from its operations. This sector should be targeted for government-led international collaborations that build capacity in the design and development of CDM projects. Such ventures should also target energy planners, industrial subsector, banking sector, municipalities, and civil society.

3.6 Typha Australis

Typha australis (family *Typhaceas*), a perennial, rhizomatous plant found in tropical, subtropical, and Mediterranean regions, is an invasive species that can reach 3.5 meters in height. In Sub-Saharan Africa, Typha is found in abundance along the Senegal and Niger rivers, where it has spread rapidly in recent years. Currently, the plant impedes navigability and blocks water distribution pipes on the Senegal River. The resulting inefficiency of irrigation systems has reduced rice productivity in the river basin by four-fifths (from 5 tons per hectare to 1). At the same time, Typha is a promising biomass source for energy generation. A recent study by Pro-Natura, an international nongovernmental organization, which focused on the use of Typha as a wood substitute in charcoal production, found that the plant's carbonization output was about 33 percent in weight of dry matter. This and other studies have shown that the calorific value of Typha could reach 17 MJ per kg of dry matter—an energy content greater than that of many biomass residues used for power generation. Available harvestable quantities in the Senegal River valley are estimated at 200,000 tons per year, with an energy content of 3,400 TJ per year (PICDCS 2005). In light

[50] Under the CDM, extra revenues from CERs can improve the financial standing of such projects, while enabling the technology and financial contributions of foreign partners.

[51] It should be noted that not all residues produced during logging operations in the forest should or can be recovered. Woody debris left on the ground has been known to deter erosion, and its decomposition helps to maintain soil fertility. At the same time, excessive accumulation of forest biomass can present a health threat to live trees, making the forest susceptible to disease, insect infestation, and high-intensity forest fires.

[52] Even where transport infrastructure is weak, the CDM can generate incentives to establish the required collection systems in ways that enhance success in project implementation.

[53] It should be noted that implementing such projects within the CDM framework can facilitate the acquisition of the appropriate technologies and capacity building.

of these findings, the study team evaluated the potential use of Typha biomass for power generation in Senegal.

3.6.1 Technical Evaluation

Since the availability of data on Typha as a biomass resource in Sub-Saharan Africa is limited to Senegal, the study team's quantitative analysis focused on potential opportunities in that country. However, the team is of the opinion that results from Senegal will provide an indicator of energy generation potential when biomass availability is established for other countries in the region.

This evaluation considered the harvesting, drying, and use of Typha as a biomass fuel in a steam-based power generator with an average energy efficiency of about 33 percent.[54] (The estimated power-generation capacity would be higher if the residue were used as a fuel in a cogeneration facility or a combined cycle with a biomass gasifier.) This analysis assumed a heating value of 17 MJ per kg for dry Typha. It assumed that the installed power capacities for each of the biomass-fired, steam-turbine generators would not exceed 10 MW. The capital expenditure (CAPEX) for the biomass-fueled, steam-turbine facility was assumed to be about US$1.4 million per MW capacity. The energy consumed in the collection of Typha was assumed to be about 0.6 TJ per 1,000 tons collected. This assumption was used to calculate leakage emissions associated with use of the biomass for energy generation.

3.6.2 Quantitative Analysis

Results of the study team's analysis are summarized in table 3.6.1.

Table 3.6.1: Results Summary of CDM Opportunities in Senegal: Power Generation from *Typha australis*

No. of projects	Projects' emissions reductions (millions tCO_2e/yr)	Available resource quantity (millions tons/yr)	Projects' energy generation, GWh/yr	Projects' energy generation as % country total, 2003	Added power of projects (MW)	Added power of projects as % of total installed, 2003	Total investment cost of projects (millions US$)
4	0.21	0.2	312	15	40	4	55

It was estimated that 4 CDM projects using Typha could be implemented in the Senegal and Niger river valleys to replace more carbon-intensive, power-generation fuels. Using natural gas as the baseline fuel, the analysis showed that the switch from fossil fuel–fired to biomass-fueled power generation would result in a gross emission reduction of 214,000 tCO_2e per year. Given leakage emissions during transport from the river and drying outside the project boundary, estimated at 7,000 tCO_2e per year, the net GHG emission reduction would be 207,000 tCO_2e per year. Power generated from these projects would yield CDM revenues amounting to US$10.5 million in 10 years at a carbon price of US$5 per tCO_2e or US$21 million at a carbon price of US$10 per tCO_2e. The projects could supplement production by 4,700 GWh per year. At a 90-percent load factor, this figure would correspond to an additional 40 MW of power capacity or 4 percent of total installed power. If Typha were used in cogeneration, the emission reduction induced by these projects could reach 400,000 tCO_2e per year. In short, there is a strong potential for Typha to fuel steam turbines in Senegal, Mali, and Niger. A capital cost of US$55 million is required to put these projects in place.[55]

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[54] The estimated unitary investment cost was US$1.4 million, based on biomass co-combustion and a power-generation unit greater than 5 MW (Squilbin 2002).

[55] AM0007 or a revised version of ACM0006 can be used to implement these CDM projects.

3.6.3 Barriers to Implementation

Several key factors hinder the use of Typha as a power-generation fuel in Sub-Saharan Africa: 1) difficult access and recoverability, 2) pre-use transformation technology requirements, and 3) higher investment cost compared to fossil fuels. Inadequate manual harvesting methods—typically a sickle is used, yielding only 40 kg per hour—combined with poor water and road transport networks, make access to this biomass resource difficult and expensive. After harvesting, Typha requires pre-use transformations for which the required technology skills are often lacking across the region. These processes include drying, size reduction, carbonization (in charcoal applications), and gasification. Finally, like other biomass energy systems, Typha-fueled systems tend to have higher capital costs requiring greater investment when a firm investment decision (FID) is taken.

3.6.4 Mitigation Recommendations

The CDM can help to overcome many of these barriers. Technology transfer from developed countries through bilateral and multilateral arrangements can significantly increase the potential for project success. For example, amphibian vehicles manufactured in Denmark can be adopted for mechanical harvesting. The vehicles have a working platform on which various harvesting units (e.g., cutter, chopper, conveyor, and binder) can be mounted. The vehicles can harvest 30–40 tons of dry biomass per day. Cutter boats—with a working platform fitted out with one or two screw engines with variable power providing for a speed of up to 8 km per hour—might be able to harvest about 10 tons per hour. Drying Typha where it is harvested can eliminate the transport barrier. (Given Senegal's delta climate, with a temperature range of 35–45°C, sun-drying cannot exceed 10 days.) Although a higher initial investment is required, Typha is far cheaper than fossil fuels, making such biomass projects more profitable. The availability of carbon finance and specific types of support, such as Climate Investment Funds (CIF), are key to overcoming investment barriers.

To date, *T. australis* has been perceived as a threat to agriculture, health, and environment. Eradication is difficult, expensive, and environmentally dangerous. Thus, the best threat-management strategy should include its use. This approach adds an important dimension to the CDM projects that contributes to the sustainable development of the Senegal River delta region.

3.7 Jatropha Biofuel

Across Sub-Saharan Africa, fossil fuel–fired, diesel-generation sets bridge the supply gap of existing grids to satisfy power demand. In Nigeria, for example, where only half of the country's 6,000-MW installed power capacity is available, standby diesel-generation sets have proliferated in most economic sectors. In 2004, it was estimated that non-grid power generation, mainly diesel-generation sets, comprised more than half of the country's installed grid capacity (Triple "E" 2005). For the region's net oil-importing countries, especially those without abundant hydropower resources, foreign exchange requirements for the import of needed petroleum products to fuel power generation and other economic activities have seriously constrained economic development and sustainability. Coupled with this problem are the negative environmental consequences associated with fossil-fuel use. The substitution of petroleum fuels with biofuels produced in-country can both enhance the balance of payment in these countries and contribute to environmental sustainability.

The region's growing interest in using *Jatropha curcas* as a biofuel is well-documented (NNPC 2007; Eco-World 2007). One particularly encouraging report states that countries in Sub-Saharan Africa are increasingly using pure Jatropha oil as a biofuel to operate Multi-Functional Platforms (MFPs), which use energy more effectively (UNDESA 2007). According to the report, a typical MFP is a 10-horsepower diesel engine capable of driving ancillary modules, including an oil press, an electricity generator (for water pumping, lighting, power tools, de-huskers, and battery chargers), a grinding mill, and a compressor (for inflating tires). Originally designed to run on diesel, some countries have re-designed the MFP to operate on Jatropha oil. Such examples abound in Ghana, Mali, Mozambique, Tanzania, and Zambia, and the list is growing.

3.7.1 Technical Evaluation

For various reasons, the UNFCCC listing of approved methodologies for biofuels has been slow to emerge. Recent evaluations of the biomass life-cycle emission profile—from biomass cultivation to biofuel production and use—show that, while the combustion process may be GHG-emission neutral, earlier points along the production chain may involve net emissions of GHGs, which must be accounted for in emission reduction calculations. Another key issue involves potential leakage emissions during pre-project activities, which, if unaccounted for, can result in an overestimation of GHG emission reductions. Equally important is the concern that large-scale cultivation of biofuel feedstock may lead to accelerated deforestation of the world's currently robust forest resources. For example, in Malaysia, dense forest resources, along with their rich carbon-sink characteristics, have been destroyed for plantation palms. Thus, it is critical that projects designed to reduce GHG emissions do not inadvertently reduce the carbon-sink capacity of the ecosystem. Finally, there is a global concern that biofuels produced from agricultural feedstock used for food products—such as the recent U.S. experience in the production of ethanol from corn—may put food security at risk, leading to an expansion of global poverty (Smith 2007).

In its aim to minimize the pitfalls that are likely to prevent CDM projects from achieving net GHG emission reductions, the study team found that biodiesel from *J. curcas* is perhaps one of the few choices that can be carefully organized and developed. There is global interest in the burgeoning biodiesel industry, catalyzed by recent increases in the price of crude oil. Unlike Europe, where transport is the focus of biodiesel fuel use, countries in Sub-Saharan Africa, especially net importers of petroleum, may find additional fuel uses, such as power generation or household cooking. In this context, the study team analyzed the potential of Jatropha as a fuel for power generation in existing diesel generation sets. The strength of the analysis is that thermal power generation from petroleum diesel, with electricity distributed to on- and off-grid consumers, is common across Sub-Saharan Africa. Substitution with Jatropha oil, either pure plant oil or processed, offers these countries a viable alternative that can reduce their financial burden from high crude oil prices and global carbon emissions. Such countries as Nigeria, which are endowed with abundant oil and gas resources, can benefit from using refined Jatropha oil for power generation as it will contribute to reducing their own carbon footprint.[56]

Biodiesel production from Jatropha begins by extracting oil from oilseeds that are crushed and pressed. The resulting residue cake can be used as fertilizer or animal feed. Raw plant oils are filtered and mixed with ethanol or methanol to initiate the esterification process, which separates fatty acid methyl esters, the basis of biodiesel, from glycerin and other byproducts. After purification, the glycerin can be used in soap production. With slight

[56] The carbon emission reduction pathway considered in this report when biodiesel from Jatropha is used as a transport or power-generation fuel is the displacement of the more carbon-intensive fossil fuel used in the baseline. The emission reduction achievable from afforestation or other upstream activities is not considered. In this way, double counting resulting from land use for Jatropha cultivation is avoided.

modifications to cookstoves or lamps, the extracted oil—even before esterification—can be used for cooking or lighting (box 3.7.1). These uses illustrate the robust opportunities for developing biodiesel-fueled cookstoves from Jatropha as CDM projects in many countries of Sub-Saharan Africa.

Box 3.7.1: Jatropha-fueled Stove Launched in Leyte

An environmentally friendly cookstove that uses coconut oil and other plant oils like those from the "tuba-tuba" or Jatropha is now being sold in Leyte, Philippines. Called Protos, this stove resembles a kerosene pressure stove and can also use kerosene. But its manufacturer, Bosch and Siemens Home Appliances Group (BSH), is pushing for the use of the plant oils, which are cheap and environmentally friendly. "The plant stove is easy to operate and offers a safe cooking environment because plant oil can neither burn nor explode," said Dr. Elmar Stumpf, BSH plant-oil stove project manager. Sisinio Balaga, 56, a resident of Baybay town and a user of the plant-oil stove for more than s year, says the new stove is not only user-friendly but efficient and affordable. The stove cooks food faster than traditional stoves. "It takes only about 20 minutes to cook rice with the oil-plant stove, while a kerosene stove usually takes about 30 minutes," Balaga said.

Source: *Philippine Daily Inquirer* (April 21, 2006).

This study analyzed two potential CDM project scenarios using biodiesel from Jatropha oil: 1) processing and blending with petro-diesel to produce transport fuel and 2) replacement of petro-diesel to power diesel generation sets.[57] This section of the report focuses on the second scenario, which has three major features:

- cultivation and harvesting of *J. curcas* on 2 percent of each country's land,
- extraction and trans-esterification to produce refined Jatropha oil (B100), and
- replacement of petro-diesel with B100 in all diesel-powered generation facilities.

Most countries in Sub-Saharan Africa use diesel fuel for on-site power generation to supplement national- or local-grid supplies. To reduce the possibility of leakage and other emissions not accounted for in this analysis, the study team assumed that the land earmarked for Jatropha plantations would be degraded land. The team also assumed that planting on degraded land, versus non-degraded land, would not incur added costs since Jatropha is known to thrive on all types of lands. Furthermore, cultivation on degraded land would ensure against deforestation and the resulting loss of carbon sequestration. It would also ensure that the shift in pre-project activities (e.g., grazing), which have been significant sources of leakage emissions, is negligible. The emission-reduction calculations analyzed below do not cover the carbon sequestration that would occur as a result of afforestation of degraded land by Jatropha plantations.[58]

3.7.2 Quantitative Analysis

Box 3.7.2 shows the quantitative relationships that were used to evaluate the potential for CDM projects in Sub-Saharan Africa that replace petro-diesel with biodiesel from Jatropha for power generation.

[57] The estimated unitary cost was US$1.4 million per 1,000 ha, based on the actual cost of Jatropha cultivation project in Senegal (the corresponding CDM project activity is currently in the validation process).
[58] The baseline emission has been calculated as the energy content of the produced Jatropha oil times the carbon emission factor of the diesel oil.

Box 3.7.2: Calculating the Power Generation Potential of Biodiesel from Jatropha

The amount of B100 biodiesel required to replace the quantity of petro-diesel used for power generation in each country of Sub-Saharan Africa was estimated in terms of both quantity and energy, as follows:

$QJ_{i,y} = VDC_{i,y} * fDP_{i,y} * JDE_{i,y}$
$EJ_{i,y} = QJ_{i,y} * CVJ_{i,y} * CF_{i,y}$

$QJ_{i,y}$ = quantity of Jatropha-based biodiesel required to replace petro-diesel to produce the same amount of electricity in country i during year y (tons/day),
$VDC_{i,y}$ = total volume of petro-diesel consumed in country i during year y (barrels/day),
$fDP_{i,y}$ = fraction of petro-diesel consumed for power generation in country i in year y,
$JDE_{i,y}$ = density of biodiesel produced from Jatropha (tons/barrel),
$EJ_{i,y}$ = energy content of Jatropha-based biodiesel required to replace petro-diesel (TJ/year),
$CVJ_{i,y}$ = calorific value of Jatropha-based biodiesel (TJ/ton), and
$CF_{i,y}$ = average capacity utilization of diesel-generation plants (days/year).

The achievable emission reduction was calculated as follows:
$ER_{i,y} = EJ_{i,y} * EF_D * MW_{CO2}/MW_C$

where,

$ER_{i,y}$ = annual emission reduction (tCO_2e),
EF_D = emission factor for petro-diesel (tC/TJ),
MW_{CO2} = molecular weight of CO_2 (44), and
MW_C = molecular weight of C (12).

This scenario included several key assumptions.[59] First, it was assumed that using B100 for power generation in existing diesel engines would require certain engine modifications. It was assumed that the capital cost of retrofitting would not exceed 15 percent of the cost of purchasing a new medium-capacity diesel-generation set. The diesel-generation set CAPEX for 10–500 kVA capacity in Nigeria, whose average cost was estimated at US$195 per kW (Triple "E" 2005), was used for all Greenfield medium-sized diesel-generation sets in countries of Sub-Saharan Africa. Based on these assumptions, the CAPEX for retrofitting existing generators to use B100 biodiesel would not exceed US$29,250 per MW for all countries in the region. Second, it was assumed that all existing petrol-diesel generators, both grid and non-grid, would be retrofitted to consume B100 biodiesel. Third, it was assumed that the shift to B100 biodiesel would be implemented as a program of activities (POA) in each of the countries, with each POA not exceeding a total capacity of about 10 MW. A recent survey of off-grid generation sets in Nigeria, most of which are diesel, established 5–500 kVA as the available capacity range in that country (Triple "E" 2005). With a mean capacity of 50 kW, a single POA would cover a minimum of about 200 generation sets. Table 3.7.1 shows the emission reductions likely to result from substituting Jatropha-based biodiesel for petro-diesel for power generation in selected countries of Sub-Saharan Africa.

[59] For both scenarios considered in this report, reduction in GHG emissions was assumed to result from the replacement of petro-diesel with Jatropha-based bio-diesel. Jatropha plantations were assumed to be in units of 10,000 hectares. The capital cost for plantation implementation, including the cost of Jatropha-oil extraction, was estimated at US$750,000 per 1,000 hectares (CJP 2007a, b). The capital cost of the biodiesel production plant was estimated at US$150 per ton of Jatropha oil produced (CJP 2007c). The assumed maximum capacity of each Jatropha crude-oil processing plant was 100,000 tons per year. A CDM project was assumed to equal a single biodiesel production facility with a processing capacity of 100,000 tons or less per year, together with its ancillary Jatropha cultivation.

Table 3.7.1: Results Summary of CDM Opportunities in Sub-Saharan Africa: Jatropha Biofuel for Power Generation

Country	Quantity of Jatropha oil (B100) required to replace petro-diesel for power generation (thousands tons/yr)	Projects' energy generation (GWh/yr)	Added power of projects, MW (% of total installed)	Projects' emissions reductions (thousands tCO_2/yr)	No. of projects	Total investment cost of projects (millions US$)
Angola	154.8	562.38	71(11)	404.91	8	2.09
Benin	22.2	80.59	10(14)	58.02	1	0.30
Burkina Faso	14.6	53.02	7(5)	38.17	1	0.20
Botswana	42.9	155.94	20(15)	112.28	2	0.58
Cameroon	64.7	235.08	30(3)	169.25	3	0.87
Central African Republic	4.3	15.59	2(5)	11.23	1	0.06
Chad	4.2	15.42	2(7)	11.10	1	0.06
Congo, Dem. Rep.	41.3	150.12	19(1)	108.09	2	0.56
Congo, Rep.	23.5	85.53	11(9)	61.59	2	0.32
Côte d'Ivoire	64.2	233.18	30(2)	167.89	3	0.87
Equatorial Guinea	4.9	17.75	2(17)	12.78	1	0.07
Ethiopia	117.7	427.67	54(8)	307.92	6	1.59
Gabon	40.5	147.21	19(5)	105.99	2	0.55
Ghana	146.5	532.12	67(5)	383.12	7	1.98
Guinea	16.0	58.12	7(3)	41.85	1	0.22
Guinea Bissau	4.5	16.30	2(9)	11.74	1	0.06
Kenya	157.8	573.14	73(8)	412.66	8	2.13
Madagascar	23.7	85.97	11(6)	61.90	2	0.32
Malawi	22.8	82.92	11(4)	59.70	2	0.31
Mali	7.5	27.22	3(1)	19.60	1	0.10
Mauritania	43.6	158.48	20(10)	114.10	2	0.59
Mozambique	67.4	244.97	31(1)	176.38	4	0.91
Namibia	70.2	254.86	32(11)	183.50	4	0.95
Niger	9.7	35.30	4(4)	25.41	1	0.13
Nigeria	353.2	1,283.21	163(3)	923.98	17	4.77
Rwanda	15.5	56.44	7(23)	40.64	1	0.21
Senegal	40.1	145.65	18(4)	104.87	2	0.54
Seychelles	31.0	112.59	14(48)	81.07	2	0.42
Sierra Leone	20.4	74.19	9(8)	53.42	1	0.28
Somalia	--	--	--	--	--	--
South Africa	1,090.2	3,960.49	502(1)	2,851.53	51	14.72
Sudan	266.4	967.65	123(16)	696.70	13	3.60
Swaziland	11.2	40.73	5(4)	29.33	1	0.15
Tanzania	101.7	369.49	47(5)	266.03	5	1.37
Togo	13.7	49.61	6(3)	35.72	1	0.18
Uganda	35.1	127.43	16(5)	91.75	2	0.47
Zambia	44.4	161.47	20(1)	116.26	2	0.60
Zimbabwe	52.1	189.11	24(1)	136.16	3	0.70
Total	**3,246.8**	**11,795.54**	**1,496(2)**	**8,492.72**	**168**	**43.84**

Results of this analysis showed that a program substituting petro-diesel with biodiesel from Jatropha for power generation in countries of Sub-Saharan Africa would require about 3.2 million tons of B100. This quantity would generate 1.5 GW of power or about 2 percent of installed power capacity and an emission reduction estimated at 8.5 million tCO_2e per year. The estimated US$44 million required for retrofitting existing diesel-generation sets excludes costs for Jatropha plantation, extraction, and processing. It is assumed that these costs would be borne by another national project targeted at producing biodiesel from Jatropha to partially meet the needs of the transport sector and for export. For most off-grid and a few grid-based diesel-generation sets, biodiesel replacement fuel would be purchased from each country's major biodiesel facilities. An estimated 168 CDM projects, most of which would be developed as POAs (each not exceeding 10 MW), can be implemented in these countries.[60]

[60] Barriers to implementing these CDM projects are similar to those that constrain CDM projects that introduce B20 as a petro-diesel substitute fuel for the transport sector. These barriers, along with mitigation recommendations, are discussed in chapter 5.

3.8 Hydroelectricity

Sub-Saharan Africa is endowed with significant hydroelectric-power potential. The hydropower potential of five key countries—Burkina Faso, Côte d'Ivoire, Democratic Republic of Congo, Guinea, and Mali—may alone yield about 119.63 million tCO_2e emission reductions, especially if projects are implemented to replace electricity otherwise generated from fossil fuel–dependent self-producers. Other countries across the region have many similar potential opportunities.[61] In using the CDM methodology framework, the study team considered the chronic supply deficits that typify many countries in Sub-Saharan Africa.[62] If implemented, the CDM projects would not displace power generated from stations operating at the margin, but may delay the construction of future thermal power stations.

3.8.1 Technical Evaluation and Quantitative Analysis

At this stage, it has not been possible to include an exhaustive economic analysis of the cost effectiveness of implementing hydropower activities as CDM projects in Sub-Saharan Africa. The required level of data for this analysis was unavailable for many countries in Sub-Saharan Africa. The six countries for which adequate data were available are covered below.

Guinea. Considered West Africa's water reservoir, Guinea has a significant hydraulic potential—26,000 GWh of probable reserves and 6,400 MWh of firm reserves, of which only 1 percent is used owing to low public investment in the power sector. Urban electrification plans are at initial stages of execution, while such plans are virtually lacking in rural areas. Many industrial and some commercial consumers located near the city of Conakry have on-site power-production facilities to bridge the country's prevalent supply-demand gap. Non-grid power production accounts for up to 400 or more GWh per year, most or all of which is thermal-based. Such self-production would be replaced by the implementation of large-scale hydropower projects.

The main aim of large-scale hydropower projects is to improve the country's hydroelectric potential in the framework of implementing the energy integration policy of the Economic Community of West African States (ECOWAS). Several opportunities under consideration are the FOMI project on the Niger River, Kouroussa region (9-MW power plant); TIOPO project on the Kogon River, Boke region (120-MW power plant); and Kaleta-Souapiti hydroelectric complex on the Konkoure River (515-MW power plant). With an average annual production of 2,353 GWh, the Kaleta-Souapiti hydroelectric complex would be implemented on the subregional interconnected network. At a total cost of about US$605 million, this project would help to strengthen zone B of the West African Electric Energy Exchange, thereby increasing the economic attractiveness of many other hydroelectric production sites located within the community. Using a baseline emission factor of 0.8t CO_2 per MWh for thermal-based self-production (mostly off-grid in supply-deficit countries) and a 21-year, carbon-crediting period, replacement with hydropower would reduce annual GHG emissions by about 320,000 tons of CO_2 over the 21-year period, achieving an emission reduction of at least 6.72 million tons. At a carbon price of US$10 per tCO_2e, this figure corresponds to an injection of about US$67.2 million into the country's power sector from carbon sales over the period.

[61] Thus, additional studies are required to estimate the corresponding potential in other countries.
[62] Hydropower projects can be implemented under the CDM using ACM0002.

Côte d'Ivoire. The development potential of Côte d'Ivoire's hydropower projects is estimated at about 1,650 MW. Rehabilitation of the Buyo hydroelectric plant will help to increase the country's annual power production from 711 to 1,067 GWh. The plant will help to replace fossil fuel–generated electricity used in the baseline scenario in the countries interconnected to Côte d'Ivoire: Benin, Burkina Faso, Mali, and Togo. Using a baseline emission factor of 0.8 tCO_2 per MWh and a 21-year, carbon-crediting period, the corresponding emission reduction would equal 284,800 tCO_2e per year or 5.98 million tCO_2e over the 21-year period. Using a price of US$10 per tCO_2e, emission reductions would generate carbon-revenue sales equivalent to about US$59.8 million.

Another attractive potential development is the Soubre hydroelectric dam, considered under a Build, Own, Operate, and Transfer (BOOT) arrangement. This project would add about 320 MW to the country's current installed capacity and generate about 1,700 GWh per year. Dam construction and implementation would require an investment estimated at US$320 million. Carefully planned development would be required in order to protect Taï National Park and anticipate the possibility of registering this activity as a CDM project.

Mali. Mali's hydropower project portfolio is robust. As table 3.8.1 suggests, various projects could be registered under the CDM. The highlighted projects have an installed power capacity of 228.7 MW and an annual energy generation of about 1.118 TWh. Mali must implement these projects to cover the rising power demand resulting from increased economic growth. Indeed, over the past few years, power demand has increased 15 percent. To resolve the problem, installed power capacity must be increased at least 10 MW each year. If any of these projects cannot be implemented for lack of financial resources, the country will be compelled to revert to less expensive, thermal plant construction.

The per-unit (MW) investment requirement for these hydropower plants is higher than for comparable thermal stations. Likewise, the capital cost of hydropower projects is high compared to alternative thermal plants, whose capital cost usually runs below US$1,000 per kW. In the context of serious energy deficit, the higher cost of hydropower projects reduces the probability of their implementation. In fact, the Malian government's preference is to direct available financial resources to thermal plants, which can produce more power for the same amount invested. Thus, it is not surprising that the country's energy policy document emphasizes the implementation of more thermal plants until the year 2010 to avoid a situation in which power generation cannot cover demand because of scarce investment funds.

Table 3.8.1: Planned Hydropower Projects, Mali

Hydroelectric dam	Power (MW)	Production (TWh/year)	Start date	Cost (millions US$)	Capital cost (US$/kW)
Felou	59.0	0.350	2009	104	1,763
Kenie	34.5	0.175	2009	140	4,058
Sotuba	6.0	0.040	--	30	5,000
Taoussou	20.0	0.090	--	--	--
Markala	13.5	0.040	--	50	3,704
Talo	0.7	0.003	--	--	--
Gouina	95.0	0.420	--	238	2,505

Source: Malian energy policy document.

Using the diesel-station baseline scenario, with an emission factor of 0.8 tCO_2 per MWh and a 21-year, carbon-crediting period, the hydropower projects would help to reduce GHG emissions by about 898,686 tCO_2e per year. Over 21 years, emission reductions would total 18.87 million tCO_2e. At a carbon price of US$10 per tCO_2e, these reductions would yield additional project revenues totaling US$188.7 million.

Democratic Republic of Congo. The Democratic Republic of Congo boasts Sub-Saharan Africa's most robust hydropower potential. The Inga hydroelectric energy complex, located on the Congo River in the upper reaches of Kinshasa, is one of the most important in the region. Each of its power stations, Inga I and Inga II, has an installed power of 1,800 MW. Both sites currently operate at less than 20-percent capacity. Poor maintenance has made it increasingly difficult to derive power from nearly two-thirds of the turbines currently in place.

A proposed rehabilitation project of Inga II's four turbines would provide 412 MW, adding 506 TWh in annual production. If implemented, the project would help to power four energy-intensive, blended magnesium production projects at Pointe Noire in the interconnected neighboring country of Republic of Congo. If not implemented, magnesium production facilities in the Republic of Congo would have to rely on on-site, fossil fuel–fired thermal plants to meet immediate power needs. It can be correctly assumed that only one thermal station would supply adequate electric power over the proposed project period. Using a baseline emission factor of 0.65 tCO_2 per MWh for the thermal station and a 21-year accounting period, the proposed project's emission reduction would equal about 3.65 million tCO_2e per year or 76.62 million tCO_2e over the period. At a carbon price of US$10 per tCO_2e, additional revenues would total about US$766.2 million. In addition, the Inga III project, scheduled to come on stream by 2012, should provide an additional 3,500 MW. Still another planned Inga project with about 13,500 MW capacity is scheduled for a later date. To benefit from the CDM, these projects will be required to have interconnection with other non-Annex 1 countries dependent on energy production from fossil fuels.

Republic of Congo. Energy planning reports in the Republic of Congo have identified six hydropower projects, one of which is the US$9.2 million, 74-MW Moukoukoulou rehabilitation project currently under implementation. Another is the US$52 million, 16-MW Djoue dam extension project. The other four are new hydropower construction projects: Imboulou (US$ 280 million, 12 MW), Liouesso (US$748 million, 374 MW), Sounda, and Chollet. Like the Democratic Republic of Congo, the Republic of Congo can claim CDM credits only for those projects that will replace in-country thermal power plants or the grids connected to them. This is a key issue because the Republic of Congo relies heavily on the Democratic Republic of Congo for its portfolio of power production projects and imports; thus, a substantial portion of its electric power supplies are hydroelectric projects.

Burkina Faso. In 1999, Burkina Faso's hydroelectric production potential was estimated at more than 686 TWh per year. Using diesel installation stations with a baseline emission factor 0.8 tCO_2 per MWh and a 21-year accounting period as an alternative scenario, the country's proposed hydropower projects would reduce GHG emissions by about 548,800 tCO_2e per year. About 11.5 million tCO_2e per year would be reduced over the 21-year period. At a carbon price of US$10 per tCO_2e, these reductions would yield additional revenues totaling US$115.2 million over that time.

3.8.2 Barriers to Implementation

Most countries in Sub-Saharan Africa face financial challenges that often prevent the development of hydroelectric power facilities. The required financial resources for such projects, usually unavailable locally, are mainly sourced from private and international financial institutions. In recent years, the flow of foreign direct investment (FDI) funds for infrastructure development in the region's energy sector has declined; in turn, the lack of financial capital has barred implementation of many such projects.

Faced with dwindling funding, governments across the region are often pressured to accelerate the development of generation infrastructure to meet the rising demand of growing populations and an increasing need to expand access to modern energy supplies. In such a situation, governments have been known to resort to implementing less sustainable power-production options requiring smaller investments characterized by shorter implementation time frames. The result is the development of many small- and medium-scale diesel-generation sets in off-grid locations. Even when implemented as part of grid extension, such efforts often install single-cycle gas turbines, which are quicker to implement and far less costly than most equivalent-capacity hydropower projects. In short, given the higher unit investment costs of most hydropower projects and the longer duration required for their development, many of the region's potential projects remain undeveloped.

3.8.3 Mitigation Recommendations

Carbon finance can assist in alleviating the above-mentioned financial barriers in various ways. The availability of carbon funds can mitigate the poor credit rating of the public utilities that will implement the hydropower projects, as well as the country risks faced by potential foreign investors via a new strain of revenue. Carbon funds can also compensate for market distortions, which often favor baseline technologies. Furthermore, they may be used to finance the social costs associated with the shift from conventional to cleaner technologies. The illustrative case highlighted in box 3.8.2 suggests the potential for the region.

Table 3.8.2: Impact of Carbon Finance on Hydropower Plant Project

Parameter	*Value*	*Unit*
Installed power capacity	25	MW
Electricity generated	160	GWh/yr
Investment cost	37	millions US$
Net electricity revenue	4.05	millions US$/yr
Emissions reduction	137,600	tCO_2/yr
Price of tCO2	10.0	US$/$tCO_2$
Carbon revenue	1.38	millions US$/yr
Carbon revenue (paid upfront)	3.70	millions US$
Total carbon revenue (3 * 7 years)	28.9	millions US$
FIRR without CERs	9.2	%
FIRR with CERs	14.3	%

Via carbon funds, the CDM can play a role alongside traditional international financial assistance. For these reasons, it is recommended that the CDM be considered as an option in the early stages of project design and that the CER purchase agreement be offered, together with the tender document, to level the playing field during least-cost competitive bidding.

3.9 Photovoltaics in Isolated Rural Areas

The implementation of photovoltaics (PV) technology in Sub-Saharan Africa started in the early 1980s, propelled by key regional and national solar programs within the framework of bilateral cooperation (Germany, France, India, Italy, Japan, and Spain). Development covered mainly solar home systems, pumping systems, and PV stations (mini network) for applications ranging from lighting and telecommunications to sump pump, irrigation, and refrigeration. According to a recent report (ENDA-TM 2005), the distribution of PV power was distributed as follows: telecommunications (19 percent), PV stations (15 percent), pumping systems (24 percent), solar home systems (37 percent), and community systems (5 percent).

With regard to solar home systems, an average 10-person household using a 75-W system at a cost of US$1,420.00 was considered. Electrification projects based on the installation and development of such PV systems were found profitable only if a minimum amount of equipment was installed. An initial financial evaluation of a JICA-initiated project in Senegal, which set up a special purpose vehicle (SPV) development and management mechanism, concluded that profitability was assured for a minimum of 200 SPVs and a monthly rental fee of about US$9.00.[63]

3.9.1 Technical Evaluation

The study team considered the development of solar PV opportunities within the framework of rural electrification. Thus, CDM project activities would be initiated and coordinated by rural electrification or other agencies in charge of rural electrification in the countries involved.[64] Such projects, using wind or solar PV, would be implemented in rural locales where CDM revenues would catalyze electrification. In the baseline scenario, it was assumed that participating stakeholders used kerosene to meet their lighting needs. The projects would be implemented by concessionaires whose revenue would be derived from the sale of emission reduction credits, along with government-based subsidies that encourage the implementation of PV systems in rural and peri-urban communities, especially those where rural electrification needs would otherwise be met by fossil fuel–fired generators.

In the case of Senegal, the number of subscribers in 13 rural electrification concessions is nearly 240,000 households, of which more than 118,000 might be electrified from the network and more than 121,000 from decentralized power production. The study team assumed that, with CDM, these households—which otherwise would have been supplied by centralized fossil-fuel production—would be supplied power from solar PV facilities (table 3.9.1).

Table 3.9.1: Subscribers in Rural Electrification Concessions, Senegal

Concession	*Year*	*No. of subscribers*	*Customer network*	*Household PV system*
Saint Louis-Dagana-Podor	2007	21,863	16,397	5,466
Kebemer-Louga-Linguere	2008	18,620	13,965	4,655
Mbour	2008	15,803	11,852	3,951
Kolda-Velingara	2008	18,552	13,914	4,638
Sedhiou	2010	8,885	6,611	2,204
Fatick-Gossas	2008	27,000	20,250	6,750
Kaolack-Nioro	2008	22,000	16,500	5,500
Foundiougne	2009	2,000	1,500	500
Kaffrine Tamba-Kedougou	2011	20,000	0	20,000
Matam-Bakel	2010	22,690	17,018	5,673
Diourbel-Bambey-Mbacke	2011	28,989	0	28,989
Rufisque-Thies-Tivaouane	2011	21,185	0	21,185
Ziguinchor-Oussouye-Bignona	2012	11,800	0	11,800
Total		**239,317**	**118,007**	**121,310**

[63] Established for a population of 4,608 and allocated to 422 households, the SPV was developed as a pilot project for the sale of energy service to consumers in Mar Island, Senegal. Users paid an initial sum of US$106, along with the monthly rental fee. A total of 95 SPVs were installed and operated hitch free, with users paying the rent at the specified recovery rate of more than 90 percent by January 2003.

[64] Projects implemented under the CDM can use AMS-I.A, which applies to small-scale activities that generate renewable energy for individual households and other low-quantity electricity users without grid access.

In the case of Mali, nearly one-fifth of the population—2.2 million out of 11.7 million people—lacks access to an adequate electricity supply. A basic conclusion that one can draw from the country's rural electrification plans is the need for a two-zone approach to program implementation. The first zone—comprising the regions of Gao, Kidal, Mopti, and Timbuktu—would use mainly diesel or hybrid sources linked to MT networks. The second zone—comprising the regions of Selingue loop (Koulikoro, Segou, and Sikasso) and Kayes—would use the MT interconnected network from existing or planned stations. For sites in either zone that are isolated from existing or planned networks, stand-alone diesel or hybrid sources or hydropower plants would be used.

Another key issue that planners of solar-system implementation must consider is available specific solar insolation. The entire African continent enjoys sufficient year-round solar radiation. Typical examples of available specific solar radiation (measured in kWh per m^2 per day) in Sub-Saharan Africa are as follows: Burkina Faso (5.5), Cote d'Ivoire (4–5), Mali (6), Niger (6), Nigeria (4–7), Senegal (5.4), and Togo (4.5).

3.9.2 Quantitative Analysis

Table 3.9.2, which compares population, population density, and electrification rates for selected countries analyzed in this study, shows that Senegal has the third highest rate of electrification (after Côte d'Ivoire and Cape Verde). If one excludes the six smallest countries in term of land area (Burundi, Cape Verde, Gambia, Guinea Bissau, Mauritius, and Reunion), the other 16 countries have an average population slightly higher than that of Senegal and an average population density slightly less than that of Senegal. Thus, the study team assumed that, for these 16 countries, the number of subscribers covered by PV-powered rural electrification would be, on average, comparable to that of Senegal.

Table 3.9.2: Population, Population Density, and Electrification Rate in Selected Countries of Sub-Saharan Africa

Country	Population (millions)	Area (thousands of km^2)	Population density (per km^2)	Electrification rate (%)
Benin	7.86	112.62	70	15
Burkina Faso	13.90	274.20	51	8
Burundi	8.09	27.83	291	2
Cape Verde	0.42	4.03	104	60
Central African Republic	4.30	622.98	7	30
Chad	9.94	1,284.00	8	1
Congo, Dem. Rep.	62.66	2,345.41	27	5
Congo, Rep.	3.70	342.00	11	5
Côte d'Ivoire	17.65	322.46	55	75
Eritrea	4.79	121.32	39	--
Gambia	1.64	11.30	145	--
Guinea	9.69	245.86	39	7
Guinea Bissau	1.44	36.12	40	26
Liberia	3.04	111.37	27	--
Madagascar	18.60	587.04	32	10
Mali	11.72	1,240.00	9	30
Mauritania	3.18	1,030.70	3	15
Mauritius	1.24	2.04	608	--
Niger	12.52	1,267.00	10	5
Reunion	0.79	2.52	313	--
Rwanda	8.65	26.34	328	--
Senegal	11.99	196.19	61	31
Togo	5.55	56.78	98	10

Therefore, for each of the 16 countries, the study team calculated an average of 120,000 households and a 75-W PV kit per household. The corresponding electric power produced was calculated as 144 MW. This amount was based on hypothetical power distribution among user types (equivalent to 1,500 MWh per day for the 16 selected countries or 5,049 GWh for an entire year). Using a baseline scenario whereby electricity would have been generated from diesel fuel with a carbon emission factor of 0.8 tCO_2 per MWh, the emission-reduction potential for these 16 countries would equal 439,000 tCO_2 per year. Over 10 years, the corresponding emission reduction would be 4.39 million tCO_2e. Total project cost would be US$2.3 billion at an assumed price of US$10 per tCO_2e, yielding US$43.9 million per year from the sale of certified emission reduction (CER) credits.

3.9.3 Barriers to Implementation

Projects using PV technologies in isolated rural areas, while likely to be implemented, could encounter financial and technology-access barriers that undermine sustainability. For example, such projects may not be guaranteed investment flows to meet operation and maintenance costs. Collecting regular payments from household users in low-income areas may also be difficult. In the case of public facilities, such as health centers or rural schools, it may be difficult to secure payment from local authorities or the families that benefit from such social services. In addition, such projects may lack access to solar technologies.

3.9.4 Mitigation Recommendations

It is recommended that such projects be implemented by rural electrification agencies using the CDM program of activities (POA) framework. Used appropriately, carbon funds can play a vital role in mitigating the above-mentioned barriers. Revenue from the sale of emission reductions can be used to subsidize equipment and other operation and maintenance costs. By levelizing payment irregularities, carbon finance can further contribute to ensuring project sustainability. With regard to access to solar technologies, the CDM process can play a positive role by facilitating partnerships with technical experts.

3.10 Landfill Gas

The capture of landfill gas to generate power involves extraction and collection using wells connected to vacuum pumps and power units. The landfill gas is used as a fuel to operate the engines that move the generators and produce electricity. To estimate the potential of landfill-gas capture as clean-energy CDM projects in countries of Sub-Saharan Africa, the study team focused on projects related to the recovery and use of landfill methane to produce electricity or heat. Because the team could not collect enough data to estimate the regional potential, data related to only three countries—Côte d'Ivoire, Guinea, and Senegal—are presented here.[65]

3.10.1 Technical Evaluation

Although the value of the power that can be produced from landfill gas is generally insufficient to make capture and heat or power generation cost effective, the high global warming potential of methane—21 times that of CO_2—makes such projects implemented under the CDM economically attractive (box 3.10.1).

[65] Under the CDM, such projects can use ACM0001.

Box 3.10.1: Impact of Carbon Finance on Waste-To-Energy Projects

The significant volume of carbon revenue that waste-to-energy projects can obtain is revolutionizing the economics of the waste-management sector. Carbon finance can increase project IRRs by more than 30 percentage points (at a conservative emission-reduction price of $4.50 per tCO2e). As a result, the carbon revenues from landfill methane projects are sufficient to render such projects viable (Bishop 2005). Additional emission reductions can be achieved by using the captured methane for generating energy (heat or electricity), which is more profitable than capture and flaring only. The table below illustrates the impressive potential.

Parameter	US$/1,000m^3 CH4	US$/ MWh
Landfill methane destruction	up to 60	up to 16
Fossil-fuel displaced (gas, coal)	5.3, 12.0	1.6, 3.6
Total carbon revenue	up to 65.3, 72.0	up to 17.6, 19.6

Source: Bishop (2005).

The combined profit expected from carbon finance and energy sales makes the full package (capture plus energy production) a generally attractive investment. While the installed power-generation capacity is limited (1–20 MW), transaction costs can be reduced by bundling similar activities in a single CDM project, as illustrated below.

Parameter	Value	Unit
Equipped landfills*	6	Number
Installed power capacity (6 landfills)	20	MW
Investment cost (6 landfills)	20.75	millions US$
Emission reductions	483,000	tCO_2/yr
Price of tCO_2 (conservative)	3.5	Euros/tCO_2
Carbon revenue	1.69	millions US$
Total carbon revenue (3 * 7 yrs)	9.56	millions of Euros

Landfill investment cost (MW)	millions US$	IRR without CERs (%)	IRR with CERs (%)
1	1.1	1.1	6.7
2	2.1	5.3	11.8
3	3.2	5.8	13
4	4.0	3.7	12.1
5	4.8	5.1	14.3

* bundled as a single CDM project.

As previously proposed, the study team limited its focus to cities with more than 1 million residents, an average annual precipitation above 500 mm, and organized waste disposal systems (SSA-Landfill Studies 2003).[66] Data on landfill discharge were available from only three cities that were in compliance with these criteria: Abidjan, Conakry, and Dakar. Thus, municipal landfill data from these cities were used to estimate the potential of landfill-gas capture for energy generation as CDM projects for countries in Sub-Saharan Africa. It should be emphasized that greater opportunities exist in many larger cities, including Accra, Lagos, and Johannesburg. The study analysis used 2003 population data for

[66] Experience has shown that, in cities where waste is dumped in unorganized landfills, less than half finds its way to municipal landfills.

Abidjan, Conakry, and Dakar as the base case for estimating landfill opportunities for the cities. Realistic population growth rates and other relevant parameters were then used to upgrade available statistics to the year 2008, considered as the starting date for methane-recovery project activity. The quantity of waste sent to the landfill was calculated from the waste-production rate, expressed in kilograms of waste, by inhabitant and year, number of inhabitants, and percentage of waste brought to the landfill.[67]

Distribution of the quantity of gas produced by the landfill discharge over various years of project activity has been calculated using the first-order decay model (Mexico Landfill Biogas Model 2003). According to this model, the methane production index k determines the kinetics of gas production. The value of k depends on waste humidity, availability of methane-generating elements for bacteria, pH, and temperature (table 3.10.1).

Table 3.10.1: Methane Production Index k, by Pluviometry

Average annual pluviometry (mm)	*Index k*
0–249	0.040
250–499	0.050
500–999	0.065
> 1,000	0.080

Source: Mexico Landfill Biogas Model (2003).

The total quantity of gas produced from waste degradation in the landfill depends heavily on waste composition, mainly organic-matter content. But absence of humidity inhibits activity of the bacteria that produces the gas. Table 3.10.2 gives typical values for L_0, which in the model represent potential gas production as a function of pluviometry.

Table 3.10.2: Potential Gas Production in a Landfill (L_0) as a Function of Pluviometry

Average annual pluviometry (mm)	*L_0 in m^3 per ton of waste*
0–249	60
250–499	80
> 500	84

3.10.2 Quantitative Analysis

Using the methodology framework described above, the study team calculated the energy-generation potential of methane-captured landfill gas (box 3.10.2).

The study team estimated that the reduction in GHG emissions resulting from projects implemented in Côte d'Ivoire, Guinea, and Senegal would represent about 1.84 percent of the three countries' GHG emissions for 2005.

[67] The estimated annual cost for landfill-gas recovery and destruction for power generation was US$3 million for an installation of 112 million m^3. The corresponding CDM project activity, Methane Recovery and Effective Use of Power Generation Project Norte III-B Landfill (No. 0928), was registered in April 2007.

Box 3.10.2: Calculating the Energy-generation Potential of Landfill Gas

The quantity of biogas produced in year n was calculated as follows:

$Qn = \sum_i 2 * k * L_0 * Mi * e^{-kti}$

where,

n = year for which the quantity of gas produced by the landfill was estimated,
i = year of opening the discharge

Mi = mass of waste sent to the landfill during year i, and
t_i = age in year n of waste sent to the disposal in year i (ti = year n – year i).

The recovery efficiency of biogas was assumed to be 70 percent and the fraction of methane in the biogas 0.5.

For Côte d'Ivoire, it was estimated that methane capture at Akouédou landfill site in Abidjan would result in GHG emission reduction of 442,000 tCO_2e per year.[68] At a carbon price of US$5 per tCO_2e, this emission reduction would generate an income of US$22.1 million over a 10-year period. Using the captured gas for electricity would generate about 24.87 GWh per year over 10 years, representing about 0.54 percent of the country's annual electricity production. This figure is equivalent to installing an additional 5.11 MW or 0.42 percent of the country's current installed power capacity. At an assumed capture cost of 0.0275US$ per m^3 per year and an installed cost of power generation capacity of US$1 million per MW, total project cost was estimated at US$5.9 million.

Similar figures were summarized for the Conakry and Mbeubeuss landfill sites in Guinea and Senegal, respectively.[69] For Guinea, the reduction in GHG emissions would be about 158,000 tCO_2e per year. At a carbon price of US$5 per tCO_2e, CER income would be about US$7.9 million over a 10-year crediting period. Using captured landfill gas as a fuel, annual electricity production would total 8.4 GWh or 1.1 percent of the country's total annual production. About 1.73 MW of installed capacity or 0.67 of the country's current installed power capacity would be added. The project cost would total about US$1.99 million.

For Senegal, the reduction in GHG emissions would be about 296,000 tCO_2e per year. At a carbon price of US$5 per tCO_2e, certified emission reduction (CER) income would be about US$14.8 million over a 10-year crediting period. Using captured landfill gas as a fuel, annual electricity production would total 15.7 GWh or 1.13 percent of the country's total annual production. About 3 MW of installed capacity or 0.64 of the country's current installed power capacity would be added. The project cost would total about US$3.5 million.

3.10.3 Barriers to Implementation

Two major barriers may limit the success of captured landfill gas for energy generation implemented as CDM projects in Sub-Saharan Africa. First, most landfill sites in these countries are unmanaged. In most large cities across the continent, unmanaged district waste sites have low-height, wildly scattered stockpiles generated from various sectors, rendering the anaerobic decomposition of organic matter ineffective. Without waste management, landfill gas collection is barred from outright destruction and fuel use. Second, project proponents face the challenge of acquiring needed licenses for exploiting methane-recovery

[68] The landfill project in Côte d'Ivoire used the country's emission factor of 0.69 tCO_2 per MWh.
[69] The landfill projects in Guinea and Senegal used a default emission factor of 0.8 tCO_2 per MWh.

opportunities. They often discover conflicts of competence between environmental ministries and district or city municipalities, which impede the licensing process. Third, there are generally no tipping fees in Africa.

3.10.4 Mitigation Recommendations

Overcoming these two major hurdles requires a clear national policy on landfill management and an appropriate regulatory framework. A sound national policy should cover responsibility for waste collection, classification, and management. An appropriate regulatory framework should cover such issues as liberalization of production, electricity distribution, and clear guidance on excess-production supply and pricing for the grid. Developing such a framework is a decisive incentive for attracting potential investors.

Transmission and Distribution

3.11 Grid-loss Reduction

This analysis centered on grid-loss reduction of electricity distribution networks in countries of Sub-Saharan Africa. Information on system losses from power networks was not readily available from the countries studied. The data used to quantify the CDM potential were obtained from ECOWAS (table 3.11.1).[70]

Table 3.11.1: Power-distribution Losses in ECOWAS Countries

Country	*Rate of loss (%)*
Benin	26
Burkina Faso	37
Ghana	23
Nigeria	35
Senegal	24
Average loss	**26**

Source: ECOWAS (2005).

3.11.1 Technical Evaluation

This study assumed that power-system losses for countries in Sub-Saharan Africa—with the exception of those in the Southern African Development Community (SADC)—could be reduced from an average of 27 percent to 8 percent, thereby reducing fossil-fuel combustion.[71] For countries in the integrated SADC grid region, where power-supply losses average about 15 percent, The study assumed that power transmission and distribution losses would be reduced from the 15-percent average to the 8-percent level via grid refurbishment projects. The achievable reduction in potential emissions when power losses are reduced from the prevailing 27-percent level to 8 percent was estimated as follows: an average 33-

[70] Grid-loss reduction projects can use AMS-II.A.
[71] According to international best practices, an efficient power-distribution network requires that not more than 8 percent of the power generated and supplied to end users be recorded as system losses.

percent power-system efficiency was assumed for the fossil fuels used to generate the energy; the savings in fossil fuels resulting from reducing energy losses from 27 to 8 percent was calculated for each country; and the implied emission reduction was estimated by multiplying this savings by the average emission factors for fossil fuels used in each country.

Box 3.11.1 describes a distribution loss-reduction project in India, the cost of which totalled US$28 million. Over a 7-year period, the reduction in GHG emissions amounted to some 2.45 million tons of CO_2.

Box 3.11.1: Innovations from New Delhi in Technical-loss Reduction

New Delhi Power Limited (NDPL), a power-distribution company serving about one-third of residents in North Delhi, India, was established jointly by Tata Power and the Delhi government. In keeping with the Tata Group's social, business, and environmental commitment, NDPL strives for sustainable development and growth through improved efficiency and service delivery. The company's innovative approach to power distribution centers on interventions that minimize technical losses.

Several NDPL interventions currently being considered under the CDM framework are high-voltage distribution systems (HVDS), shunt capacitors, and amorphous core transformers. HVDS involves a network conversion that would replace 1,000-, 630-, and 400-kVA transformers and associated low-tension cables with single-phase (10-25 kVA) and three-phase (above 25 kVA) transformers and high-tension cables. Installation of shunt capacitors for reactive power management would also reduce technical losses. At peak load, NDPL draws 1,000 MVA from the power supplier. By commissioning capacitor banks (319 MVAR) in a phased way, the peak reactive load would likely fall to 208 MVAR and the MVA to 875, a net savings of 125 MVA. Using a system power factor of 0.97 and assuming 8-hour service, annual savings in reactive units from the supplier would be about 349 million units. In addition, replacement of coil-rolled, grain-oriented (CRGO) steel with amorphous core transformers would result in savings estimated at 25, 31, and 245 W for 16, 25, and 250 kVA, respectively.

3.11.2 Quantitative Analysis

To adjust for the GHG emission reduction estimated from the annual energy saved via refurbishing existing distribution and transmission facilities, a correction factor—calculated as the fraction of power generated from fossil fuels—was applied. This calculation is conservative because the load factor of fossil fuel–based power plants is usually higher than those of hydropower plants. An average loss rate was assumed on the lines in the countries analyzed. With regard to imported power, the study did not consider the energy production source to avoid double counting emission reductions. It was assumed that the electricity generated in each country would be fully consumed; the resulting overestimation of emission-reduction potential in power-exporting countries could be easily corrected once data on power import and export for each country became available. This type of correction was not included in the results of this analysis.

Table 3.11.2 summarizes results of the analyses for countries in Sub-Saharan Africa whose annual emission reductions exceed 10,000 tCO_2e. Projects aimed at refurbishing and upgrading transmission and distribution grids in these countries are likely to achieve these potential emission reductions; thus, such opportunities should be actively pursued.

Table 3.11.2: Results Summary of CDM Opportunities in Sub-Saharan Africa: Grid-loss Reduction

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$)		Energy generation			Total installed power, country (MW)	Added power of projects (MW)	
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed
Angola	1	20.39	0.11	0.53	1.08	5.42	10.85	1,920	369	19.20	670	46.76	6.98
Benin	1	2.27	0.04	1.64	0.37	1.86	3.72	240	46	19.20	71	5.84	8.27
Botswana	1	3.92	0.16	4.21	1.65	8.24	16.43	940	180	19.20	130	22.89	17.61
Burkina Faso	1	1.17	0.04	3.16	0.37	1.85	3.70	306	59	19.20	149	7.46	5.00
Burundi	1	0.41	0.00	1.00	0.04	0.20	0.41	148	28	19.20	40	3.60	8.92
Cameroon	1	6.81	0.03	0.45	0.30	1.52	3.04	3,920	753	19.20	900	95.46	10.61
Cape Verde	1	0.28	0.01	2.24	0.06	0.32	0.64	41	8	19.20	82	1.00	1.22
Central African Republic	1	0.34	0.01	2.34	0.08	0.39	0.79	104	20	19.20	38	2.53	6.67
Chad	1	0.19	0.01	7.45	0.14	0.71	1.43	92	18	19.20	40	2.24	5.53
Congo, Dem. Rep.	1	2.37	0.02	0.64	0.15	0.76	1.53	5,400	1,037	19.20	2,591	131.51	5.08
Congo, Rep.	1	5.31	0.00	0.10	0.05	0.26	0.51	353	68	19.20	327	8.60	2.63
Côte d'Ivoire	1	6.42	0.34	5.23	3.36	16.81	33.62	4,620	887	19.20	1,260	112.51	8.93
Equatorial Guinea	1	4.87	2.50	0.05	0.02	0.12	0.25	28	5	19.20	13	0.68	5.25
Ethiopia	1	4.37	0.05	1.22	0.53	2.66	5.31	2,294	440	19.20	690	55.87	8.10
Gabon	1	4.95	0.13	2.68	1.33	6.64	13.29	1,500	299	19.20	400	36.53	9.13
Ghana	1	6.66	0.08	1.22	0.81	4.06	8.12	5,360	1,029	19.20	1,310	130.53	9.96
Guinea	1	1.34	0.05	3.73	0.50	2.49	4.99	775	149	19.20	254	18.87	7.73
Guinea Bissau	1	0.38	0.01	2.23	0.85	0.43	0.85	55	11	19.20	24	1.34	5.64
Iles Maurice	1	4.01	0.24	6.09	2.44	12.22	24.43	1,285	955	33.95	954	55.33	5.80
Kenya	1	9.88	0.20	2.00	1.97	9.87	19.75	4,976	436	19.20	934	121.18	12.97
Madagascar	1	2.54	0.06	2.44	0.62	3.10	6.20	820	248	19.20	186	19.97	10.76
Malawi	1	0.86	0.00	0.55	0.05	0.24	0.47	1,293	157	19.20	300	31.49	10.50
Mali	1	0.66	0.02	2.63	0.17	0.87	1.75	460	88	19.20	437	11.20	2.56
Mauritania	1	2.63	0.02	0.89	0.23	1.16	0.45	150	29	19.20	197	3.65	1.85
Mozambique	1	2.30	0.00	0.20	0.04	0.22	2.33	11,580	2,223	19.20	2,340	282.01	12.05
Niger	1	1.23	0.03	2.77	0.34	1.71	3.42	205	39	19.20	122	4.49	3.12
Nigeria	1	105.19	0.71	0.68	7.11	35.54	71.09	20,700	1,449	7.00	5,890	183.79	4.10
Rwanda	1	0.78	0.00	0.09	0.01	0.03	0.07	113	22	19.20	29	2.75	9.62
Senegal	1	5.49	0.24	3.90	2.14	10.72	21.44	1,387	266	19.20	476	33.78	7.09
Sierra Leone	1	1.18	0.04	3.42	0.40	2.02	4.03	260	50	19.20	120	6.33	5.28
Somalia	1	0.75	0.04	5.57	0.42	2.09	4.19	270	52	19.20	80	6.58	8.22
South Africa	1	423.81	12.94	3.05	129.41	647.06	1,294.12	227,000	5,890	7.00	40,480	2,015.47	4.98
Swaziland	1	1.14	0.05	4.12	0.47	2.35	4.71	460	88	19.20	130	11.20	8.62
Tanzania	1	3.97	0.02	0.61	0.24	1.21	2.41	3,150	605	19.20	860	2.36	8.92
Togo	1	2.38	0.01	0.43	0.10	0.52	1.03	97	19	19.20	215	76.71	1.10
Uganda	1	1.62	0.00	0.19	0.03	0.15	0.30	928	370	19.20	300	46.95	15.65
Zambia	1	2.44	0.01	0.34	0.08	0.42	0.83	8,350	1,603	19.20	1,790	203.35	11.36
Zimbabwe	1	11.78	0.68	5.79	6.82	34.11	68.22	8,880	1,705	19.20	1,960	216.26	11.03
Total	**38**	**51.95**	**1.13**	**2.18**	**11.32**	**56.58**	**113.12**	**327,079**	**31,974**	**9.78**	**68,841**	**4,056.00**	**5.89**

3.11.3 Barriers to Implementation

In Sub-Saharan Africa, the main barrier to realizing the potential opportunity of grid-loss reduction projects is financial. Many countries in the region experience difficulty raising funds for such projects faced with competing activities that can meet the welfare needs of citizens in more direct, easily measurable ways. The result is that many countries consider grid-loss reduction projects a lower investment priority.

3.11.4 Mitigation Recommendations

Alongside complementary traditional sources of financial assistance, the CDM can play a vital role in overcoming the financial hurdles associate with implementing grid-loss reduction projects in Sub-Saharan Africa.

Consumption and Use

3.12 Non-lighting Electricity for Industry

Industries commonly use electricity for lighting, cooling processes, powering motors, and space air conditioning. In each of these areas, there is ample room for improving energy-use efficiency and thus reducing industry energy demand.[72]

3.12.1 Technical Evaluation

In this analysis, the study team calculated an average carbon emission factor for the saved electricity, including renewable energy for countries where more than 50 percent of the electricity produced is from renewable sources (e.g., Burundi, Democratic Republic of Congo, or Republic of Congo). For countries in which less than 50 percent of the electricity produced is from renewable sources, the team assumed that only fossil-fuel sources would be displaced at the margin. It was assumed that the energy saved would result in less generation from power plants that burn fossil fuels. The team derived a general energy-consumption pattern for countries in Sub-Saharan Africa based on energy audits conducted for many countries in the region. Energy audits offer country-level data on such parameters as average share of industrial energy consumption, share of industrial energy by use type, and percentage of energy savings achieved by the sector. As a first approximation, the team used these general parameters to estimate the potential energy-efficiency improvement for these countries. It was recognized that energy-consumption patterns differ by country; at the same time, the results obtained using these general parameters can serve to indicate the magnitude of achievable energy efficiency and associated reduction in GHG emissions in these countries (table 3.12.1).

Table 3.12.1: Share of Electricity Consumed by Industry in Selected Countries of Sub-Saharan Africa

Country	*Industry sector share (%)*	*Source*
Niger	38.6	Energy balance 2005
Nigeria	34.2	Energy balance 2004
Senegal	33.2	Energy balance 2005
Togo	30.0	Energy balance 2005

Sources: CMA Chalifour Marcotte and Associates, Ltd. (1997); Triple “E” (2005).

[72] Under the CDM, such projects can use AMS-II.C.

The study team constructed a generalized table of information that categorizes electricity consumption by industrial end uses, along with their potential energy savings, common in Sub-Saharan Africa. This information draws heavily on the few energy audits that have been conducted in countries of the region (table 3.12.2).

Table 3.12.2: Share of Electricity by Industrial End Use and Potential for Energy Savings

End-use type	*Electricity share (%)*	*Energy savings potential (%)*
Lighting	20	11
Industrial process cooling	18	7
Motors	16	4
Air conditioning	13	13

Source: CMA Chalifour Marcotte and Associates, Ltd. (1997).

3.12.2 Quantitative Analysis

Based on the assumption that only the fossil-fuel component of the electricity supplied to industrial facilities is involved in the emission reduction and using the above-mentioned generalized data and energy data from each country in the region, the study team developed a spreadsheet-based estimation procedure that was used to evaluate the potential energy savings and thus GHG emission reductions from these project types. Table 3.12.3 summarizes the results of this evaluation.

Each country's potential for improved industrial energy efficiency is qualified by the extent of its industrial production, as indicated by the industry sector's level of electricity consumption, and its percentage of fossil fuel–based electricity generated by the national power grid. For most countries across the region, the potential savings from industrial efficiency improvements in electricity use is not robust. It was found that 10 countries—Botswana, Ethiopia, Kenya, Mozambique, Nigeria, South Africa, Sudan, Tanzania, Zambia, and Zimbabwe—contribute about 90 percent of the total energy savings and about 97 percent of the emission reduction expected from such types of projects. If one assumes that each country, with the exception of South Africa,[73] develops a single CDM program of activities (POA), then some 20 CDM projects could be implemented, with a total GHG emission reduction of 1.5 million tCO_2 per year. These projects would lead to a reduction in power demand equal to 1.1 percent of the total installed capacity of the countries studied.

[73] For South Africa, an average POA is assumed to have an emission reduction of about 100,000 tCO_2 per year.

Table 3.12.3: Results Summary of CDM Opportunities in Sub-Saharan Africa: Improved Use of Non-lighting Electricity for Industry

Country	No. of projects	Country GHG emissions, 2005 (millions Tco_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$)		Electricity generation			Total installed power, country (MW)	Added power of projects (MW)	
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed
Angola	0	20.4	0.00	0.02	0.03	0.17	0.34	1,920	35.04	1.83	670	4.44	0.66
Benin	0	2.3	0.01	0.42	0.09	0.47	0.94	240	11.67	4.86	71	1.48	2.09
Botswana	1	3.9	0.01	0.34	0.13	0.67	1.34	940	44.49	4.73	130	5.64	4.34
Burkina Faso	0	1.2	0.01	0.50	0.06	0.29	0.59	306	7.26	2.37	149	0.92	0.62
Burundi	0	0.4	0.00	0.11	0.01	0.02	0.05	148	3.21	2.17	40	0.41	1.01
Cameroon	0	6.8	0.00	0.01	0.00	0.05	0.10	3,920	71.85	1.83	900	9.11	1.01
Cape Verde	0	0.3	0.00	0.22	0.01	0.03	0.06	41	0.77	1.87	82	0.10	0.12
Central African Republic	0	0.3	0.00	0.22	0.01	0.04	0.08	104	1.91	1.84	38	0.24	0.64
Chad	0	0.2	0.00	0.71	0.01	0.07	0.14	92	1.67	1.82	40	0.21	0.52
Comoros	0	0.1	0.00	0.28	0.00	0.01	0.03	19	0.35	1.86	8	0.04	0.55
Congo, Dem. Rep.	0	2.4	0.00	0.04	0.01	0.04	0.09	5,400	61.05	1.13	2,591	7.74	0.30
Congo, Rep.	0	5.3	0.00	0.02	0.01	0.04	0.09	353	11.58	3.28	327	1.47	0.45
Côte d'Ivoire	1	6.4	0.04	0.61	0.39	1.94	3.89	4,620	54.08	1.17	1,260	6.86	0.54
Equatorial Guinea	0	4.9	0.00	0.00	0.00	0.01	0.01	28	0.59	2.11	13	0.07	0.58
Ethiopia	1	4.4	0.01	0.26	0.11	0.56	1.12	2,294	41.99	1.83	690	5.33	0.77
Gabon	0	5.0	0.00	0.08	0.04	0.21	0.42	1,500	27.56	1.84	400	3.50	0.87
Ghana	0	6.7	0.00	0.04	0.26	0.13	0.26	5,360	100.01	1.87	1,310	12.68	0.97
Guinea	0	1.4	0.00	0.36	0.05	0.24	0.48	775	14.19	1.83	254	1.80	0.71
Guinea Bissau	0	0.4	0.00	0.21	0.01	0.04	0.08	55	1.00	1.83	24	0.13	0.54
Kenya	1	9.9	0.02	0.22	0.22	1.10	2.20	4,976	82.09	1.65	934	10.41	1.11
Madagascar	0	2.5	0.01	0.23	0.06	0.30	0.59	820	15.02	1.83	186	1.91	1.03
Malawi	0	0.8	0.00	0.02	0.00	0.01	0.01	1,293	23.66	1.83	300	3.00	1.00
Mali	0	0.7	0.00	0.25	0.02	0.08	0.17	460	8.46	1.84	437	1.07	0.25
Mauritania	0	2.6	0.00	0.09	0.02	0.11	0.23	150	2.82	1.88	197	0.36	0.18
Mauritius	1	4.0	0.03	0.71	0.28	1.43	2.86	1,285	34.98	2.72	954	4.44	0.47
Mozambique	1	2.3	0.04	1.78	0.41	2.05	4.10	11,580	157.49	1.36	2,340	19.98	0.85
Namibia	0	9.8	0.00	0.00	0.00	0.00	0.00	1,460	46.66	3.20	300	5.92	1.97
Niger	0	1.2	0.01	0.52	0.06	0.32	0.64	205	7.42	3.62	122	0.94	0.77
Nigeria	1	105.2	0.06	0.06	0.62	3.15	6.25	20,700	386.04	1.86	5,890	48.97	0.83
Rwanda	0	0.8	0.00	0.01	0.00	0.00	0.01	113	3.15	2.79	29	0.40	1.40
Senegal	1	5.5	0.02	0.37	0.20	1.02	2.04	1,387	25.40	1.83	476	3.22	0.68
Seychelles	0	0.9	0.00	0.13	0.01	0.06	0.12	240	4.33	1.80	30	0.55	1.83
Sierra Leone	0	1.2	0.00	0.11	0.01	0.06	0.12	260	4.72	1.82	120	0.60	0.50
Somalia	0	0.8	0.00	0.17	0.01	0.06	0.13	270	4.92	1.82	80	0.62	0.78
South Africa	9	423.8	1.10	0.26	10.95	54.76	109.52	227,000	4,075.00	1.80	40,480	516.87	1.28
Swaziland	0	1.1	0.01	0.62	0.07	0.36	0.71	460	22.84	4.96	130	2.90	2.23
Tanzania	1	4.0	0.02	0.40	0.16	0.78	1.58	3,150	58.27	1.85	860	7.39	0.86
Togo	0	2.4	0.01	0.35	0.08	0.42	0.84	97	10.43	10.76	215	1.32	0.62
Uganda	0	1.6	0.01	0.53	0.08	0.42	0.85	1,928	31.89	1.65	300	4.05	1.35
Zambia	1	2.4	0.03	1.29	0.32	1.58	3.16	8,350	113.39	1.36	1,790	14.38	0.80
Zimbabwe	1	11.8	0.07	0.61	0.72	3.59	7.17	8,880	227.57	2.56	1,960	28.86	1.47
Total	**20**	**679.6**	**1.53**	**0.23**	**1.39**	**6.94**	**13.89**	**327,079**	**5,837**	**1.78**	**68,841**	**740**	**1.08**

3.12.3 Barriers to Implementation

The implementation of “win-win” energy-efficiency projects for industry in Sub-Saharan Africa faces key challenges. While industrial energy audits routinely suggest improvement measures, experience across the region shows that most are not implemented. The measures taken are usually limited to those that can be enacted quickly without significant levels of investment. In addition, unless bundled, energy-efficiency measures are usually characterized by low levels of emission reduction and are thus not attractive. Other common barriers include the need to attract the interest of multiple actors and project participants, lack of investment funds for project financing, lack of required technology skills.

3.12.4 Mitigation Recommendations

The CDM provides an effective means for mitigating the above-mentioned barriers. For example, using the POA, mitigation measures can be bundled by project component. In addition, the carbon credits earned from such projects can provide financial opportunities for implementing other projects and efficiency measures, while the linkage with Annex 1 participants can provide a bridge to strengthening managerial and technical capacity. Thus, conscious efforts at national industrial grouping levels should be taken to ensure the implementation of these projects as CDM POAs. Finally, to ensure that the CDM POAs succeed, the governments of the respective countries must lend their support to the industrial groupings.

3.13 Switch to Compact Fluorescent Lamps

Although most consumers in Sub-Saharan Africa with access to electricity still use incandescent lamps for lighting, compact fluorescent lamps (CFLs) are fast becoming a more affordable, energy-efficient option for bulb replacement. Many CFLs fit in incandescent light fixtures. But compared to incandescent lamps of the same luminosity, CFLs require less energy and last longer. Because CFLs generate less heat than incandescent lamps, they can relieve user discomfort, especially in hotter climates. In many countries across the region, lighting contributes significantly to peak demand. In countries where it is difficult to meet consumer energy demand, shaving of the peak via the introduction of more efficient, end-use devices such as CFLs can assist in better management of limited supplies.

In the U.S., it has been estimated that switching to a CFL can save more than US$30 in electricity costs over its lifetime and save 2,000 times its weight in GHGs (Energy Star 2007). Although the CFL purchase price is higher than that of an incandescent lamp of equivalent luminosity, this cost is recovered in energy savings and replacement costs over time. Projects that introduce CFLs into residential lighting systems and focus on switching from incandescent lamps offer a feasible path to clean energy investment in Sub-Saharan Africa. Under the CDM, two types of user-level projects are envisioned (using AM0046): 1) electric-utility initiated switching from incandescent bulbs to CFLs and 2) non-utility, concessionaire-initiated switching in rural areas.

3.13.1 Technical Evaluation

To assess the potential for improved lighting efficiency in Sub-Saharan Africa, the study team conducted a preliminary evaluation of electricity consumption data for selected ECOWAS countries for which data was available.[74] This exercise helped the team to determine an average regional value for the quantity of electricity consumed for lighting. The team considered the difference between peak and average electricity demand for the month of January. This month was chosen to ensure the elimination of unrelated effects at the household level. To obtain characteristic figures for the lighting effect at the household level, ECOWAS data was analyzed to quantify variations between peak and average electricity demand for the countries studied.

Results showed that peak and average demand varied between 32 and 52 percent (table 3.13.1). The study team assumed in that lighting represents 32 percent of peak demand for electricity in Sub-Saharan Africa. The team assumed the energy consumed for lighting in each country as the minimum between 32-percent peak demand and the energy derived from fossil-fueled thermal power plants installed on the grid. For most countries in the region, spinning reserves on the grid were observed as low or zero; as a result, peak demand is usually about equal to installed energy. In addition, the team assumed that peak lighting usually occurs for about 3 hours per day (7:00–10:00 p.m.).[75]

Table 3.13.1: Lighting Power and Peak Demand in Selected ECOWAS Countries

Country	Peak demand (MW)	Base-load demand (MW)	Lighting demand (MW)	Lighting/peak demand (%)
Benin	117	68	49	0.419
Burkina Faso	84	40	44	0.524
Mali	88	60	28	0.318
Senegal	305	195	110	0.361

Source: ECOWAS (2005).

3.13.2 Quantitative Analysis

To further evaluate the potential of CFL energy-efficiency projects in Sub-Saharan Africa, the study team assumed that the switch from incandescent to CFL lamps would lead to 80-percent reduction in energy consumption. In the baseline, it was assumed that 5 percent of all households were already using CFLs and that 90 percent were using them as a result of project activity. To calculate the mean GHG emission factor, the analysis took into account all fuels used to generate electricity in each of the countries studied. It was assumed that each project would be implemented as a CDM program of activities (POA). To estimate the probable number of CDM POAs in each country, the team assumed that the emission reduction from each program would not exceed 100,000 tCO_2 per year. Table 3.13.2 summarizes results of the analysis.

[74] The study assumed US$10 per lighting point. The actual cost of a CFL with a 10,000-hour life span that can operate under fluctuating voltage is about US$5; 2 CFLs would be used in a lighting point over a 10-year project crediting period.

[75] The study team assumed that fossil-fuel–based electricity production was at the margin and that, during peak demand, full available capacity was in operation. The lowest value between the power consumed due to lighting and the fossil fuel–based power capacity was used to calculate the energy consumed for lighting that could lead to a reduction in GHG emissions. The 80-percent displacement in power capacity (represented by the replacement of 40-W incandescent bulbs with 8-W CFLs) during CFL operating time results in CO_2 emission reduction.

Table 3.13.2: Results Summary of CDM Opportunities in Sub-Saharan Africa: Switch to Compact Fluorescent Lamps

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$)		Electricity generation			Total installed power, country (MW)	Added power of projects (MW)		Total investment cost of projects (millions US$)
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed	
Angola	1	20.39	0.14	0.67	1.36	6.83	13.66	1,920	169.03	8.80	670	154.37	23.04	48
Benin	1	2.27	0.02	0.85	0.19	0.96	1.93	240	23.88	9.95	71	16.36	23.13	5
Botswana	1	3.92	0.03	0.76	0.30	1.50	3.00	940	32.80	3.49	130	29.95	23.04	9
Burkina Faso	1	1.17	0.04	3.46	0.40	2.02	4.05	306	50.12	16.37	149	34.33	23.04	11
Burundi	1	0.41	0.01	1.50	0.06	0.31	0.61	148	13.59	9.18	40	9.31	23.04	3
Cameroon	1	6.81	0.01	0.13	0.09	0.46	0.92	3,920	227.06	5.79	900	207.36	23.04	65
Cape Verde	1	0.28	0.00	0.67	0.02	0.10	0.19	41	2.36	5.74	82	1.61	1.97	1
Central African Republic	1	0.34	0.01	3.06	0.10	0.52	1.03	104	12.78	12.29	38	8.76	23.04	3
Chad	1	0.19	0.01	5.75	0.11	0.55	1.10	92	13.62	14.80	40	9.33	23.04	3
Comoros	1	0.10	0.00	2.14	0.02	0.11	0.22	19	2.74	14.45	8	1.88	23.04	1
Congo, Dem. Rep.	1	2.37	0.04	1.69	0.40	2.00	4.01	5,400	871.57	16.14	2,591	596.97	23.04	187
Congo, Rep.	1	5.31	0.03	0.49	0.26	1.30	2.60	353	110.00	31.16	327	75.34	23.04	24
Côte d'Ivoire	1	6.42	0.30	4.75	3.05	15.24	30.49	4,620	423.68	9.17	1,260	290.19	23.04	91
Equatorial Guinea	1	4.87	0.00	0.01	0.01	0.03	0.06	28	3.28	11.71	13	3.00	23.04	1
Ethiopia	1	4.38	0.02	0.48	0.21	1.05	2.10	2,294	174.08	7.59	690	158.98	23.04	50
Gabon	1	4.95	0.08	1.59	0.79	3.95	7.89	1,500	100.92	6.73	400	92.16	23.04	29
Ghana	1	6.67	0.08	1.22	0.82	4.08	8.15	5,360	330.50	6.17	1,310	301.82	23.04	94
Guinea	1	1.34	0.07	5.16	0.69	3.45	6.91	775	85.50	11.03	254	58.56	23.04	18
Guinea Bissau	1	0.38	0.01	1.69	0.06	0.32	0.64	55	8.00	14.53	24	5.48	23.04	2
Kenya	1	9.88	0.15	1.54	1.52	7.61	15.22	4,976	235.64	4.74	934	215.19	23.04	67
Madagascar	1	2.54	0.05	1.99	0.50	2.53	5.06	820	62.45	7.62	186	42.77	23.04	13
Malawi	1	0.86	0.00	0.53	0.04	0.22	0.45	1,293	75.69	5.85	300	69.12	23.04	22
Mali	1	0.66	0.07	10.45	0.69	3.47	6.94	460	112.19	24.39	437	76.85	17.58	24
Mauritania	1	2.63	0.02	0.78	0.21	1.03	2.06	150	25.47	16.98	197	17.45	8.86	5
Mauritius	1	4.01	0.16	4.09	1.64	8.20	16.40	1,285	200.94	15.64	954	137.63	14.43	43
Mozambique	1	2.30	0.00	0.16	0.04	0.19	0.37	11,580	590.35	5.10	2,340	539.14	23.04	168
Niger	1	1.23	0.04	2.89	0.36	1.78	3.56	205	40.94	19.97	122	28.04	23.04	9
Nigeria	1	105.19	1.09	1.03	10.86	54.33	108.65	20,700	1,485.98	7.18	5,890	1,357.06	23.04	424
Rwanda	1	0.78	0.00	0.12	0.01	0.05	0.09	113	9.62	8.51	29	6.59	23.04	2
Senegal	1	5.49	0.13	2.35	1.29	6.45	12.90	1,387	160.25	11.55	476	109.76	23.04	34
Seychelles	1	0.92	0.00	0.21	0.02	0.10	0.20	240	7.57	3.15	30	6.91	23.04	2
Sierra Leone	1	1.18	0.02	2.08	0.24	1.22	2.45	260	30.28	11.64	120	27.65	23.04	9
Somalia	1	0.75	0.02	2.17	0.16	0.82	1.63	270	20.18	7.48	80	18.43	23.04	6
South Africa	10	423.81	10.01	2.36	100.14	500.70	1,001.39	227,000	10,212.62	4.50	40,480	9,326.59	23.04	2,915
Swaziland	1	1.14	0.03	2.70	0.31	1.54	3.09	460	32.80	7.13	130	29.95	23.04	9
Tanzania	1	3.97	0.03	0.68	0.27	1.35	2.70	3,150	216.97	6.89	860	198.14	23.04	62
Togo	1	2.38	0.06	2.45	0.58	2.92	5.84	97	72.22	74.46	215	49.47	23.04	15
Uganda	1	1.62	0.00	0.12	0.02	0.10	0.19	1,928	75.69	3.93	300	69.12	23.04	22
Zambia	1	2.45	0.01	0.30	0.07	0.37	0.73	8,350	451.60	5.41	1,790	412.42	23.04	129
Zimbabwe	1	11.78	0.47	4.01	4.72	23.62	47.23	8,880	494.48	5.57	1,960	451.58	23.04	141
Total	**49**	**679.58**	**13.27**	**1.95**	**132.68**	**663.38**	**1,326.76**	**327,079**	**17,269**	**5.28**	**68,841**	**15,246**	**22.15**	**4,764**

Results of this analysis showed that the use of 476 million efficient lighting devices as CFLs in countries of Sub-Saharan Africa will reduce power demand about 15,200 MW (32-MW reduction per 1 million CFLs), representing 22.7 percent of these countries' total installed capacity. Project cost was calculated as the cost of CFLs. It was assumed that 2 CFLs at US$5 each would be used during the crediting period. As expected, the study team found that the opportunity for energy savings—and thus reduction in GHG emissions—is more robust in countries with higher thermal-generation capacity. The cost-effectiveness of each country's project was found to be a function of the existence of thermal power plants in the country supply system. For example, CFL projects in Gabon and Ghana would yield the same level of emission reduction, but would cost about US$52 million in Ghana (with 10-percent fossil-fuel thermal plants) compared to US$16 million in Gabon (with 60-percent fossil-fuel thermal plants). In summary, the potential reduction in GHG emissions from introducing more efficient CFLs into residential lighting would total about 13 million tCO_2 per year, achievable via some 49 CDM POAs. About US$4.76 billion would be needed to cover CFL supplies and ancillary programs.

3.13.3 Barriers to Implementation

n Sub-Saharan Africa, projects that feature the switch to CFLs face challenges involving the management of subsidies, coordination of diverse stakeholders, customer access to supplies, and quality control. Generating initial household interest in the CFLs usually requires subsidizing some project inputs, such as the price of the CFLs. If the subsidy program is not properly organized and managed (e.g., if its cost is hidden), project success is less likely. In addition, CFL projects usually involve multiple actors—households, project proponents, and government. Ineffective coordination of such groups with diverse perspectives can also inhibit success. Another potential barrier centers on unreliable customer access to the CFL bulbs. Because CFLs are commodities that are replaced infrequently, it is difficult to maintain stock levels at traditional stores. As a result, points of sale are usually centralized at large stores in city centers, which may be located far from users' homes, particularly those in rural areas. Finally, owing to weak quality-control regimes in many countries of the region, lower-quality bulbs are likely to find their way into the market. The lower performance of such bulbs may discredit project performance in the minds of consumers and thus constrain success.

3.13.4 Mitigation Recommendations

With regard to subsidies, lowering the price of the CFL bulb to under US$3—equivalent to the price of an incandescent bulb—can eliminate the affordability issue for consumers. Under the CDM, additional revenues from the CERs can be used to cover the cost difference between the CFLs and incandescent bulbs. In Senegal, the Rural Electrification Agency intends to apply such an approach in its rural electrification program.

3.14 Energy-saving Household Appliances

Households require electricity to power an array of electronic appliances—from radios and television sets to air-conditioners, refrigerators, and stoves. Energy savings can be achieved by taking proven measures that increase the energy efficiency of these appliances: retrofitting existing equipment, replacing devices with more energy-efficient ones, and implementing energy management in consumer households.[76]

3.14.1 Technical Evaluation

Assessing the emission-reduction potential of such projects required that the study team determine the following:

1. percent of household electricity consumption,
2. electricity consumption of household appliances,
3. reduction in appliance energy consumption via energy-saving measures,
4. resulting reduction in household energy consumption and thus emissions,
5. carbon-emission coefficient of the fuel used, and
6. emissions reduction.

From the 2005 energy balance, the percentage of household electricity consumption was determined for several countries: Senegal (39.9 percent), Niger (46.1 percent), and Togo (52.0 percent). For all of the countries studied for which data was not available, the average of these three values (46 percent) was assumed.[77] The electricity consumption of household appliances was determined by subtracting electricity consumption for lighting from the total household electricity consumed. A 10-percent savings in appliance energy consumption via energy-saving measures was used. This figure was based on results of a recent demand-side energy audit in Senegal, which concluded that achievable savings in demand management programs can vary between 10 and 20 percent (Thioye and Ngom 2004). To determine the reduction of energy consumption leading to emissions reduction, assumptions were made for grid generation dominated by fossil fuels and renewable energy. Fossil-fuel units were assumed to be at the margin and "low-cost, must-run" units were considered baseload power plants. In this case, the CDM project activity would displace only fossil fuel–fired power plants. Fore renewable-energy units, it was assumed that a portion of the electricity displaced would be produced from renewable sources. An average carbon-emission coefficient of the fuels consumed in the country was used. Potential CO_2 emission reduction was then calculated as the potentially saved energy from the energy-savings program times the average carbon-emission coefficient of the fuels consumed for electricity generation.

3.14.2 Quantitative Analysis

The above-mentioned assumptions were used to develop a spreadsheet calculation to evaluate the extent of energy savings and the resulting reduction in GHG emissions achievable. It was found that 30 improved household energy-efficiency projects, with emission reductions exceeding 10,000 tons of CO_2 per year, could be achieved. For South Africa, a POA emission reduction of 500,000 tons of CO_2 per year was considered; for Nigeria and Zimbabwe, POAs with respective emission reductions of 100,000 tons of CO_2 were used. The annual energy

[76] A new methodology (NM0235) for the energy-efficiency improvement of household appliances has been submitted to the CDM Executive Board for approval.
[77] Electricity consumption in the countries studied was based on 2003 data from the U.S. Department of Energy.

savings was estimated at 40,000 TJ of electricity, equivalent to 86,000 TJ of fossil fuel per year (all of the electricity saved would not be generated by fossil fuel–fired power plants). For the 30 projects, the annual emission reduction would total 7.4 million tons of CO_2; at US$10 per ton of CO_2, added CDM revenues would equal about US$740 million over the 10-year crediting period.

On average, the countries studied comprise 0.31 percent of GHG emissions. The achievable energy savings of Benin and Togo (24 and 14 GWh, respectively), though weak compared to the other countries studied, constitutes a significant proportion of these countries' national electricity production (10 and 17 percent, respectively). For the countries studied, the overall reduction in energy consumption would represent only 3.6 percent of electricity production, while the reduction in power would constitute 2 percent of total installed capacity (table 3.14.1)

Table 3.14.1: Results Summary of CDM Opportunities in Sub-Saharan Africa: Improved Energy Efficiency of Household Appliances

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions: millions tCO_2/yr	Projects' emissions reductions: % of country total	Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$): US$5/tCO_2	Value of projects' emissions reductions (millions US$): US$10/tCO_2	Electricity generation: Country, 2003 (GWh/yr)	Electricity generation: Projects (GWh/yr)	Electricity generation: Projects (% country total)	Total installed power, country (MW)	Added power of projects (MW): 90% load factor	Added power of projects (MW): % of total installed
Angola	1	20.39	0.02	0.08	0.07	0.86	1.72	1,920	58.40	3.04	670	7.41	1.11
Benin	1	2.27	0.01	0.28	0.06	0.32	0.64	240	23.96	9.98	71	3.04	4.30
Botswana	1	3.92	0.09	2.32	0.91	4.54	9.08	940	99.40	10.57	130	12.61	9.70
Burkina Faso	0	1.17	0.00	0.23	0.03	0.13	0.27	306	10.00	3.27	149	1.27	0.85
Burundi	0	0.41	0.00	0.07	0.00	0.01	0.03	148	5.61	3.79	40	0.71	1.76
Cameroon	0	6.81	0.00	0.08	0.06	0.28	0.55	3,920	136.36	3.48	900	17.30	1.92
Cape Verde	0	0.28	0.00	0.14	0.00	0.02	0.04	41	1.47	3.58	82	0.19	0.23
Central African Republic	0	0.34	0.00	0.10	0.00	0.02	0.04	104	2.69	2.58	38	0.34	0.90
Chad	0	0.19	0.00	0.28	0.00	0.03	0.05	92	2.02	2.19	40	0.26	0.63
Comoros	0	0.10	0.00	0.11	0.00	0.00	0.01	19	0.45	2.35	8	0.06	0.69
Congo, Dem. Rep.	0	2.37	0.00	0.00	0.00	0.00	0.01	5,400	21.59	0.40	2,591	2.74	0.11
Congo, Rep.	0	5.31	0.00	0.01	0.00	0.00	0.01	353	11.77	3.33	327	1.49	0.46
Côte d'Ivoire	1	6.42	0.02	0.25	0.16	0.80	1.60	4,620	67.52	1.46	1,260	8.56	0.68
Equatorial Guinea	0	4.87	0.00	0.01	0.00	0.02	0.04	28	0.92	3.30	13	0.12	0.90
Gabon	1	4.95	0.02	0.47	0.23	1.16	2.32	1,500	50.38	3.36	400	6.39	1.60
Ghana	1	6.67	0.01	0.22	0.15	0.74	1.48	5,360	187.78	3.50	1,310	23.82	1.82
Kenya	1	9.88	0.03	0.33	0.33	1.64	3.29	4,976	159.09	3.20	934	20.18	2.16
Madagascar	1	2.54	0.00	0.13	0.03	0.17	0.34	820	26.42	3.22	186	3.35	1.81
Malawi	0	0.86	0.03	0.10	0.01	0.04	0.08	1,293	44.78	3.46	300	5.68	1.89
Mali	0	0.66	0.00	0.17	0.01	0.06	0.11	460	4.20	0.91	437	0.53	0.12
Mauritania	0	2.63	0.00	0.03	0.01	0.04	0.08	150	3.04	2.03	954	0.39	0.20
Mauritius	1	4.01	0.01	0.36	0.14	0.72	1.45	1,285	53.83	4.19	197	6.83	0.72
Mozambique	0	2.30	0.00	0.03	0.00	0.03	0.06	11,580	286.01	2.47	2,340	36.28	1.55
Niger	1	1.23	0.00	0.27	0.03	0.17	0.33	205	11.66	5.69	122	1.48	1.21
Nigeria	4	105.19	0.34	0.32	3.41	17.06	34.13	20,700	695.67	3.36	5,890	88.24	1.50
Rwanda	0	0.78	0.00	0.01	0.00	0.00	0.01	113	6.02	5.33	29	0.76	2.67
Senegal	1	5.49	0.01	0.18	0.10	0.49	0.98	1,387	37.08	2.67	476	4.70	0.99
Seychelles	0	0.92	0.01	0.79	0.07	0.37	0.73	240	9.07	3.75	30	1.15	3.83
Sierra Leone	0	1.18	0.00	0.47	0.06	0.28	0.55	260	6.84	2.63	120	0.87	0.72
Somalia	0	0.75	0.00	0.93	0.07	0.35	0.70	270	8.70	3.22	80	1.10	1.38
South Africa	11	423.81	6.60	1.56	66.00	329.99	659.97	227,000	8,103.58	3.57	40,480	1,027.85	2.54
Swaziland	1	1.14	0.03	2.27	0.26	1.30	2.60	460	48.80	10.61	130	6.19	4.76
Tanzania	0	3.97	0.00	0.11	0.42	0.21	0.42	3,150	106.03	3.37	860	13.45	1.56
Togo	1	2.38	0.00	0.16	0.04	0.19	0.38	97	14.35	14.79	215	1.82	0.85
Uganda	0	1.62	0.00	0.03	0.00	0.02	0.05	1,928	64.01	3.32	300	8.12	2.71
Zambia	0	2.44	0.00	0.04	0.00	0.05	0.10	8,350	202.24	2.42	1,790	25.65	1.43
Zimbabwe	2	11.78	0.18	1.57	1.85	9.26	18.53	8,880	463.08	5.21	1,960	58.74	3.00
Total	**30**	**679.58**	**7.44**	**1.09**	**74.40**	**372.00**	**744.00**	**327,079**	**11,131**	**3.40**	**68,841**	**1,412**	**2.05**

3.14.3 Barriers to Implementation

Implementation barriers to these types of projects commonly consist of a lack of information and interest in needed follow-up activities. Such projects require planning and execution of verification and maintenances tasks. In addition, they often require initial household incentives and consumer information outreach and awareness-raising programs.

3.14.4 Mitigation Recommendations

Faced with an inability to satisfy growing household electricity demand, power companies could use such projects within the framework a CDM POA. Income from the sale of CERs could be used to pay an energy service company to verify project implementation and maintenance of household appliances.

Appendix 3.1: Inventory Results

Table A3.1-1: Gas-turbine Operating Units in Sub-Saharan Africa Where Combined-cycle Clean Energy Projects Can Be Implemented

Company	Plant	GT units	MW	Year	Fuel
Angola					
National Electric Company (ENE)	Lobito	1, 2, 3, 4	5, 5, 5, 5	1991, 1991, 1991, 1991	oil
	Cazenga	3, 4, and 5	40, 20, 20	1992, 2001, 2001	kerosene
Cabinda Gulf Oil	Malongo Terminal	1	5	--	gas
Benin					
Benin Electricity and Water Company	Cotonou	1	20	1998	oil
Congo, Rep.					
ENI Congo	Djeno ENI	1	25	2002	gas
Cote d'Ivoire					
Co. Ivorienne Prd. Elec. (CIPREL)	Vridi CIPREL-1	1, 2, 3	33, 33, 33	1995, 1995, 1995	gas
	Vridi CIPREAL-2	1	110	1997	gas
Azito Energie SA	Azito	1, 2	144, 144	1999, 2000	gas
Equatorial Guinea					
Marathon Eg. Production, Ltd.	Bioco LPG Plant	1, 2	5.25, 5.25	2000, 2000	gas
Gabon					
Shell Group	Rabi	1, 2, 3	5.17, 5.17, 5.17	1995, 1995, 1995	gas
Gabon Refinery Company	Port-Gentil Refinery	3, 4	5, 5	1998, 1998	oil
Ghana					
Ghana National Petroleum Corporation	Efaso Barge-1	1, 2, 3	45, 45, 45	2002, 2002, 2002	gas
	Efaso Barge-2	1, 2	62.5, 62.5	2002, 2002	oil
Kenya					
Labuan Shipyard & Engineering	Kipevu Barge	1	44	1997	oil
Kenya Electricity Generation Company, Ltd.	Kipevu	2, 3	30, 30	1991, 1999	kerosene
Mali					
Mali Energy	Dar Salaam	1	25.8	1999	oil
Mauritius					
Central Electricity Board	Nicolay	2, 3	26.3, 38.34	1991, 1995	liquefied petroleum gas (LPG)
Mozambique					
Mozambique Electricity	Maputo	8	25	1991	oil
Niger					
Niger Electric Company	Niamey	1, 2	13.5, 14	1980, 1982	oil
Nigeria					
Power Holding Company of Nigeria	Delta (Ughelli)	15, 16, 17, 18, 19, 20	100, 100, 100, 100, 100, 100	1991, 1991, 1991, 1991, 1991, 1991	oil
Desaim Engineering Corporation	Desaim	1	22.8	1994	oil
Nigerian National Petroleum Corporation	Eleme Refinery	1, 2, 3, 4	33, 33, 33, 33	1994, 1994, 1994, 1994	gas
Exxon Mobil Corporation	Qua Iboe Terminal	1	25	1994	gas
Nigeria Energy Company (ENCON)	Ewekoro Works	1	3.7	1995	oil
Nigerian Agip Oil Company (NAOC)	Obiafu-Obrikom Gas Plant	4, 5, 6	26.3, 26.3, 26.3	1999, 1999, 1999	gas

Company	Plant	GT units	MW	Year	Fuel
Nigeria *(continued)*					
Total SA	Obite Gas Plant	1, 2, 3	5, 5, 5	1999, 1999, 1999	gas
Shell Petroleum Development Company	Bonny Island Shell	1, 2, 3, 4, 5, 6, 7, 8	39.1, 39.1, 39.1, 39.1, 85.4, 85.4, 39.1, 39.1	2000, 2000, 2000, 2000, 2000, 2000, 2000, 2000	liquefied natural gas (LNG)
Power Holding Company of Nigeria	Afam V	01, 02	138, 138	2001, 2001	gas
AES Corporation	Ebute Barge	1, 2, 3, 4, 5, 6	30, 30, 30, 30, 30, 30	2001, 2001, 2001, 2001, 2001, 2001	gas
Power Holding Company of Nigeria	Delta (Ughelli) Ext	1, 2, 3, 4, 5, 6	25, 25, 25, 25, 25, 25	2002, 2002, 2002, 2002, 2002, 2002	gas
AES Corporation	Ebute Barge	7, 8, 9	30, 30, 30	2002, 2002, 2002	gas
Rivers State Government	Alode-Eleme	1	20	2004	gas
Shell Petroleum Development Company	Bonny Island Terminal	4, 5, 6	25, 25, 25	2005, 2005, 2005	gas
Nigerian Agip Oil Company (NAOC)	IDU Field	1, 2	10, 10	2005, 2005	gas
Nigeria Energy Company (ENCON)	Ikorodu	1, 2, 3	10, 10, 10	2005, 2005, 2005	oil
Dangote Industries, Ltd.	Obajana Cement Plant	1, 2, 3	44.3, 44.3, 44.3	2005, 2005, 2005	gas
Rivers State Government	Omoku	1, 2, 3, 4	25, 25, 25, 25	2005, 2005, 2005, 2005	gas
	Trans-Amadi	1, 2, 3	10, 10, 10	2005, 2005, 2005	gas
Rockson Engineering, Ltd.	Alaoji	1, 2, 3, 4	120, 120, 120, 120	2006, 2006, 2006, 2006	gas
Power Holding Company of Nigeria	Calabar	1, 2, 3, 4, 5	110, 110, 110, 110, 110	2006, 2006, 2006, 2006, 2006	gas
	Egbema	1, 2, 3	110, 110, 110	2006, 2006, 2006	gas
	Eyaen	1, 2, 3, 4	110, 110, 110, 110	2006, 2006, 2006, 2006	gas
	Gbarain/Ubie	1, 2	110, 110	2006, 2006	gas
	Geregu	1, 2, 3	138, 138, 138	2006, 2006, 2006	gas
Lyk Engineering Corporation	Ibom-1	1, 2	35.5, 35.5	2006, 2006	gas
	Ibom-2	1	108.6	2006	gas
Nigeria Energy Company (ENCON)	Ikorodu	4	70	2006	oil
Power Holding Company of Nigeria	Sapele	5, 6, 7, 8	110, 110, 110, 110	2006, 2006, 2006, 2006	gas
	Papalanto	1, 2, 3, 4, 5, 6, 7, 8	41.89, 41.89, 41.89, 41.89, 41.89, 41.89, 41.89, 41.89	2007, 2007, 2007, 2007, 2007, 2007, 2007, 2007	oil
Shell Petroleum Development Company	Bonny Island Terminal	1, 2, 3	10, 10, 10	--, --, --	gas
	Forcados Oil Terminal	1, 2, 3, 4, 5	7.5, 7.5, 7.5, 7.5, 7.5	--, --, --, --, --	gas
	Port Harcourt Central	1, 2	7.5, 7.5	--, --	gas
Senegal					
National Electricity Company (SENELEC)	Cap des Biches	3, 4	25, 37.4	1995, 2000	oil
Sudan					
National Electricity Corporation (NEC)	Khartoum North	1, 2, 3, 4	25.24, 25.24, 25, 25	1992, 1992, 2001, 2001	oil
	El Gaili-3	1, 2, 3	31.5, 31.5, 31.5	2003, 2003, 2003	LPG
Tanzania					
Globeleq	Ubungo Songas	1, 2, 3, 4, 5, 6	20, 20, 37.5, 37.5, 37.5, 37.5	1994, 1994, 1995, 1995, 2005, 2005	gas
Togo					
Togo Electricity	Lome	1, 2, 3	25, 25, 20	1978, 1978, 1998	oil
Total power capacity of operating open-cycle units: 7,635 (MW)					

Source: Platts UDI World Electric Power Plants (WEPP) Database (2006).

Table A3.1-2: Open-cycle, Gas-turbine Units Planned for Future Commissioning in Sub-Saharan Africa

Company	Plant	GT units	MW	Year	Fuel
Benin					
Benin Electricity and Water Company	Cotonou	2, 3	20, 20	--, --	oil
Cameroon					
Ocelot International, Ltd.	Sanaga South	1	120	--	gas
Chad					
Esso Chad	Doba Esso	1	100	--	oil
Ethiopia					
Ethiopian Electric Power Corporation	EEPC	1, 2, 3	20, 20, 20	--, --, --	oil
Nigeria					
Shell Petroleum Development Company	Afam Spdc	1, 2, 3	167, 167, 167	2008, 2008, 2008	gas
Power Holding Company of Nigeria	Lagos	B1, B2, B3	183, 183, 183	2012, 2012, 2012	oil
Geometric Power, Inc.	Aba Power	1	105	--	oil
Power Holding Company of Nigeria	Abuja	1	100	--	oil
	Akodo	1	100	--	oil
Shell Petroleum Development Company	CPP Western	1, 2, 3, 4	50, 50, 50, 50	--, --, --, --,	gas
	Gbaran Gas Plant	1, 2, 3	10, 10, 10	--, --, --	gas
Lyk Engineering Corporation	Ibom-2	2, 3, 4, 5	108.6, 108.6, 108.6, 108.6	--, --, --, --	gas
Power Holding Company of Nigeria	Kaduna	1	100	--	oil
Shell Petroleum Development Company	Southern Swamp AGGP	1	30	--	gas
South Africa					
Eskom	Atlantis	1	146	2006	oil
	Mossel Eskom	1	146	2006	oil
	Atlantis	2, 3, 4	146, 146, 146	2007, 2007, 2007	oil
	Mossel Eskom	2, 3	146, 146	2007, 2007	oil
DME Peaking Project	Eastern Cape Peaker	1	500	--	oil
Southern Africa Independent Power	Kwazulu IPSA	1	20	--	gas
DME Peaking Project	Kwazulu Peaker	1	500	--	gas
Total power capacity: 4,511.4 (MW)					

Source: Platts UDI World Electric Power Plants (WEPP) Database (2006).

Table A3.1-3: Sugar Mills and Their Characteristics in Sub-Saharan Africa

Company	Plant	Unit	MW	Status	Year	U Type	Fuel	S Press	S Type	S Temp
Congo										
Sucrerie de Kiliba (SUCRAF)	Kiliba Mill	1	2.85	Ret.	1988	ST	Bag	23	SUBCR	300
Congo, Rep.										
Soc. Agri. Raff. Ind Sucre (SARIS)	N'Kayi Mill	1	6	Opr.		ST/S	Bag		SUBCR	
Ethiopia										
Finchaa Sugar Factory	Finchaa									
Wonji/Shoa/ Metahara	Wonji/Shoa/ Metahara									
Kenya										
Chemelil Sugar Factory	Chemelil Sugar	1, 2	2.5, 3	Opr.		ST	Bag			
Miwani Sugar Factory	Miwani Sugar	2, 3	1.5, 2	Opr.		ST	Bag			
Muhoroni Sugar Factory	Muhoroni Sugar	1, 2, 3	0.75, 0.75, 1.5	Opr.		ST	Bag			
Mumias Sugar Corporation	Mumias Sugar	1, 2, 3, 4, 5, 6, 7	1.25, 1.25, 1.25, 1.75, 2.5, 7, 2.5	Opr.	1972, 1972, 1975, 1975, 1978, 1995, 1996	ST	Bag	23, 23, 23, 23, 24, 23, 23	SUBCR	266, 266, 266, 266, 329, 360, 360
Nzoia Sugar Company, Ltd.	Nzoia Sugar Mill	1	1.5	Opr.	1986	ST	Bag			
South Nyanza Sugar Company	South Nyanza Sugar	1	4	Opr	1991	ST	Bag	22	SUBCR	310
Liberia										
Liberia Sugar Corporation	Libsuco Plant	1	1.9	Unk.	1976	ST	Bag	15	SUBCR	280
Malawi										
Sugar Corporation of Malawi (SUCOMA)	Dwangwa Mill	1, 2	3.5, 3.5	Opr.		ST/S	Bag	28	SUBCR	400
	Nchalo Mill	1, 2, 3	3.5, 2.5, 4	Opr.		ST/S	Bag	17, 17, 30	SUBCR	300, 315, 377

Table A3.1-3 *(Continued)*

Company	Plant	Unit	MW	Status	Year	U Type	Fuel	S Press	S Type	S Temp
Mauritius										
Harel Freres, Ltd.	Beau Plan Sugar	1	2.5	Ret.	1976	ST	Bag	12	SUBCR	299
Comp Therm Belle Vue (CTBV)	Belle Vue	1, 2	35, 35	Opr.	2000	ST	Bag	82, 82	SUBCR	252, 252
Deep River Beauchamp Est.	Deep River	1, 2	24.65, 4	Opr.	1998, 1998	ST/S, ST	Bag	45, 4	SUBCR	475, 300
Fuel Sugar Estate	Fuel	1, 2	21.7, 18	Opr.	1982, 1998	ST/S, ST/S	Bag	47, 44	SUBCR	450, 430
Illovo Sugar, Ltd.	Highlands Estate	1	2.2	Opr.		ST/S	Bag		SUBCR	
Mon Desert Alma, Ltd.	MDA Mill	1	11.2	Opr.	1997	ST/S	Bag	31	SUBCR	430
Medine Sugar Estate	Medine Mill	1, 2, 3	10, 1.5, 1.5	Opr.	1980, 1980, 1980	ST, ST/S, ST/S	Bag	32, 17, 17	SUBCR	420, 250, 250
Mon Loisir Sugar Estate	Mon Loisir	1	12	Opr.	1998	ST/S	Bag	19	SUBCR	325
Mon Tresor Mon Desert Sugar	Mon Tresor	1	12.5	Opr.	1998	ST/S	Bag	26	SUBCR	400
Mount Sugar Estate Company	Mount Sugar	1	2.25	Opr.	1975	ST	Bag	22	SUBCR	332
Cie Sucriere de Riche-en-eau	Riche-en-eau	1, 2, 3	6, 3.2, 1.6	Opr. Opr. Stn.	1998	ST, ST/S, ST/S	Bag	18, 26, 26	SUBCR	310, 400, 400
Savannah Sugar Estate Company, Ltd.	Savannah Estate	1	15.3	Opr.	1998	ST	Bag	31	SUBCR	410
Mauritius Sugar Authority	Union St. Aubin	1, 2	2.5, 12.2	Opr.	1990, 1997	ST, ST/S	Bag	23, 30	SUBCR	280, 435

Table A3.1-3 *(Continued)*

Company	Plant	Unit	MW	Status	Year	U Type	Fuel	S Press	S Type	S Temp
Reunion										
Compagnie Thermique du Gol	Le Gol-1	1, 2	28, 28	Opr.	1995, 1995	ST	Bag	88	SUBCR	540
	Le Gol-2	1	55	Con.	2006	ST/S	Bag		SUBCR	
SNE Reunion	Reunion Sugar	1	24.6	Opr.	1983	ST	Bag	45	SUBCR	435
Rwanda										
Regie Sucriere de Kabuye	Kabuye Sugar	1	1.1	Opr.	1992	ST	Bag	18	SUBCR	320
Senegal										
Compagnie Sucriere du Senegal	Compagnie Sucriere du Senegal									
Somalia										
Juba Sugar Mill	Juba Sugar	1	2.2	Stn.	1978	ST	Bag	24	SUBCR	369
South Africa										
Tongaat-Hulett Sugar, Ltd.	Amatikulu Mill	1, 2, 3	4, 4, 4	Opr.		ST/S	Bag	31	SUBCR	370
Union Cooperative	Dalton Mill	1, 2	1.5, 3	Opr.		ST/S	Bag	19	SUBCR	280
Tongaat-Hulett Sugar, Ltd.	Darnall	1, 2	6.5, 6.5	Opr.		ST/S	Bag	31	SUBCR	380
	Entumeni	1, 2, 3	1, 1.5, 1.5	Opr.		ST/S	Bag	25, 17, 10	SUBCR	330, 300, 245
Illovo Sugar, Ltd.	Eston Mill	1, 2	5, 3.5	Opr.	1980, 1965	ST/S	Bag	31	SUBCR	395
Tongaat-Hulett Sugar, Ltd.	Felixton Mill	1, 2, 3	10.5, 10.5, 10.5	Opr.		ST/S	Bag	31	SUBCR	400
Illovo Sugar, Ltd.	Gledhow Mill	1, 2, 3	6.45, 2.75, 5	Opr.	1978, 1971, 1979	ST/S	Bag	30	SUBCR	354
Transval Suiker Beperk	Komati Mill	1, 2	10, 10	Opr.	1993, 1993	ST/S	Bag	44	SUBCR	410
Tongaat-Hulett Sugar, Ltd.	Maidstone Mill	1, 2, 3, 4, 5, 6	2, 3, 3, 6, 7.2	Opr.		ST/S	Bag	31, 14, 14, 31, 31, 31	SUBCR	400, 260, 260, 400, 400, 400
Transval Suiker Beperk	Malelane Mill	1, 2, 3, 4	12, 8, 6.4, 8	Opr.		ST/S	Bag	31, 31, 31, 31,	SUBCR	400, 400, 400, 400
Illovo Sugar, Ltd.	Merebank Mill	1	0.75	Opr.	1996	ST/S	Bag	19	SUBCR	290
	Noodsberg Mill	1, 2, 3	8, 5.5, 5.5	Opr.	1982, 1965, 1965	ST/S	Bag	33, 30, 30	SUBCR	400, 290, 290
	Pongola Mill	1, 2, 3, 4	1.7, 1, 0.5, 5	Opr., Dac., Opr. Opr.	1961, 1964, 1998, 1977	ST/S	Bag	17, 17, 30, 30	SUBCR	240, 240, 380, 380
	Sezela Sugar Plant	2, 3, 4	8, 5, 6	Opr.	1982, 1971, 1986	ST/S	Bag	32, 21, 21	SUBCR	400, 340, 340
	Umfolozi Mill	1, 2	10, 6	Opr.	1986, 1966	ST/S	Bag	30, 30	SUBCR	400, 400

Table A3.1-3 *(Continued)*

Company	Plant	Unit	MW	Status	Year	U Type	Fuel	S Press	S Type	S Temp
South Africa *(continued)*										
Illovo Sugar, Ltd.	Umzimkulu Mill	1, 2, 3	3.75, 1.5, 4	Opr.	1965, 1965, 1977	ST/S	Bag	30, 30, 31	SUBCR	390, 390, 400
Sudan										
Kenana Sugar Company	Kenana Sugar Company									
Swaziland										
Royal Swazi Sugar Corporation	Mhlume Mill	1, 2, 3, 4	1.5, 2, 3, 7.5	Opr.		ST/S	Bag	23, 23, 23, 23	SUBCR	340, 340, 340, 340
	Simunye Mill	1, 2 3	3.5, 3.5, 10	Opr.		ST/S	Bag	31, 31, 31	SUBCR	390, 390, 390
Ubombo Sugar, Ltd.	Ubombo Mill	1, 2, 3, 4, 5	2, 2, 4, 3.5, 3.5	Ret., Opr. Opr., Opr., Opr.	1976, 1976, 1966, 1977, 1986	ST/S	Bag	30, 30, 30, 30, 30	SUBCR	385, 385, 385, 385, 385
Tanzania										
Kagera Sugar Estate, Ltd.	Kagera Mill	1, 2	2.5, 2.5	Opr.		ST/S	Bag		SUBCR	
Kilombero Sugar Company, Ltd.	Kilombero Mill	1, 2, 3, 4, 5	3.4, 3.7, 1.2, 0.8, 0.8	Opr.		ST	Bag	22, 22, -, -, -	SUBCR	325, 325, -, -, -
Tanzania Sugar Industries, Ltd.	Mtibwa Sugar Mill	1, 2, 3	2.5, 1.5, 9	Opr.	1977, 1990, 2003	ST/S	Bag	20, 20, -	SUBCR	271, 271, -
Tanganyika Planting Company (TPC)	TPC Sugar Mill	1, 2, SE1, SE2	2.5, 3, 0.4, 0.4	Opr.	1974, 1999, -, -	ST, ST, RSE, RSE	Bag	13, -, -, -,	SUBCR	249, -, -, -,
Uganda										
Madhvani Group	Kakira Sugar Works	1	12	Opr.	1982	ST/S	Bag			
Sugar Corporation of Uganda	Luggasi Mill	1	1.5	Opr.	1984	ST	Bag		SUBCR	
	Kinyara									
Zambia										
Zambia Sugar, PLC	Nakambala Sugar	1, 2, 3, 4, 5	2.237, 2, 2, 2, 4	Opr.	1967, 1967, 1976, 1977, 1985	ST	Bag	17, 17, 18, 17, 17	SUBCR	257, 257, 263, 277, 260
Zimbabwe										
Hippo Valley Estates, Ltd.	Chiredzi Sugar Mill	1, 2, 3, 4, 5, 6	3.5, 5, 7.5, 2, 8, 20	Opr.	-, 1964, -, -, -, 2000	ST/S, ST/S, ST, ST, ST/S, ST/S	Bag	31, 31, 17, 17, 31, -	SUBCR	385, 385, 300, 300, 385, -
Tongaat-Hulett Sugar, Ltd.	Triangle Mill	1, 2, 3, 4, 5, 6	7.5, 3, 1.5, 7.5, 8, 8	Opr.	1963, -, -, 1963, -, -	ST/S	Bag	31, 31, 31, 31, 31, 31	SUBCR	340, 340, 340, 340, 340, 340

Source: Platts UDI World Electric Power Plants (WEPP) Database (2006).

Table A3.1-4: Estimate of Agriculture Residues Generated in Sub-Saharan Africa, 2003
(thousands of tons)

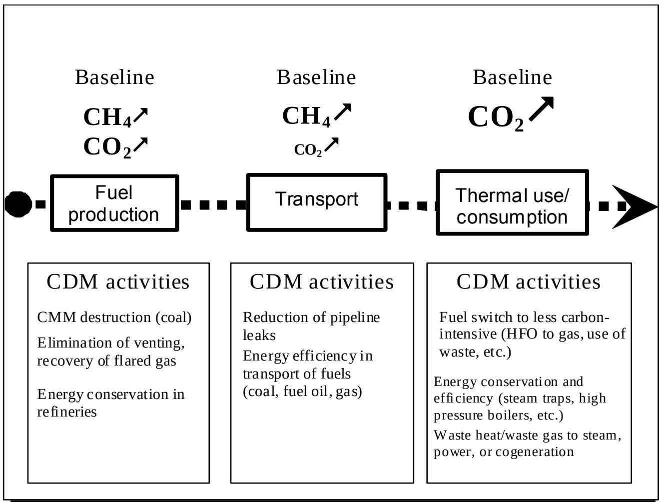
Country	Ground-nut straw	Ground-nut shell	Corn stem	Corn cob	Millet straw	Rice straws	Rice husk	Sorghum stem	Cassava stem	Cocoa pod	Coffee husks	Wheat stem	Cotton stem	Cotton shell	Coconut husk	Coconut shell	Palm fiber	Palm cob
Angola	8.32	4.84	320.0	142.3	69.0	0.0	0.0	0.0	3,187.0	0.0	0.0	0.0	-	-	-	-	-	-
Benin	16.38	9.53	374.2	1,663.2	0.0	36.97	7.39	81.90	1,148.2	0.0	0.0	0.0	82.07	15.51	0.0	0.0	0.0	0.0
Botswana	0.08	0.04	4.44	19.8	0.55	0.0	0.0	16.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Burkina Faso	30.91	17.99	13.78	950.12	481.50	42.57	8.51	700.0	0.0	0.0	0.0	0.0	32.47	25.04	0.0	0.0	0.0	0.0
Burundi	0.0	0.0	54.67	242.96	0.0	36.57	7.31	37.0	262.6	0.0	0.0	0.0	-	-	-	-	-	-
Cameroon	28.34	16.50	422.2	1,877.0	0.0	0.0	0.0	300.0	444.0	90.0	21.4	0.0	-	-	-	-	-	-
Central African Republic	17.64	10.27	48.89	217.28	0.0	16.97	3.39	21.25	208.5	0.0	0.0	0.0	-	-	-	-	-	-
Chad	56.70	33.0	47.74	212.2	148.8	52.0	10.4	225.0	119.0	0.0	0.0	0.0	-	-	-	-	-	-
Congo, Dem. Rep.	46.37	26.99	513.4	2,282.0	0.0	180.3	131.4	0.0	5,546.0	0.0	11.4	0.0	0.0	0.0	0.0	0.0	28.80	6.91
Congo, Rep.	2.99	1.74	0.0	0.0	0.0	0.0	0.0	0.0	3.3	0.0	0.6	0.0	-	-	-	-	-	-
Côte d'Ivoire	18.90	11.0	511.11	2,271.6	0.0	657.14	131.43	0.0	555.6	665.0	57.14	0.0	80.94	15.3	123.33	64.91	64.80	15.55
Equatorial Guinea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7	1.5	1.4	0.0	-	-	-	-	-	-
Ethiopia	0.0	0.0	12.18	5,412.0	0.0	0.0	0.0	900.0	0.0	0.0	92.9	0.0	-	-	-	-	-	-
Gabon	2.52	1.47	13.78	61.2	0.0	0.0	0.0	0.0	85.2	0.3	0.0	0.0	-	-	-	-	-	-
Ghana	49.10	28.57	514.50	2,287.0	71.90	138.20	27.60	199.70	3,607.0	368.0	0.0	0.0	-	-	-	-	-	-
Guinea	37.80	22.0	155.56	691.4	0.0	514.29	102.86	0.0	500.0	0.0	0.0	0.0	-	-	-	-	-	-
Guinea Bissau	2.52	1.47	17.69	78.6	23.6	56.17	11.23	11.70	14.1	0.0	0.0	0.0	0.0	0.0	15.17	7.98	0.0	0.0
Kenya	0.0	0.0	977.80	434.60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Madagas-car	0.0	0.0	155.56	691.36	0.0	1,731.4	346.29	0.0	811.5	0.0	23.21	0.0	0.0	0.0	66.66	35.09	0.0	0.0
Malawi	20.31	11.82	777.80	3,457.0	0.0	28.60	5.70	0.0	963.0	0.0	0.0	0.0	-	-	-	-	-	-
Mali	20.65	12.02	204.0	906.67	487.50	410.29	82.06	332.0	0.0	0.0	0.0	0.0	146.05	27.60	0.0	0.0	0.0	0.0
Mozam-bique	13.86	8.07	644.40	2,864.0	0.0	114.9	23.0	157.0	2,278.0	0.0	0.0	0.0	-	-	-	-	-	-
Namibia	0.0	0.0	14.67	65.20	31.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Niger	13.36	8.07	0.0	0.0	1,050.0	22.46	4.49	250.0	0.0	0.0	0.0	0.0	2.35	0.45	0.0	0.0	0.0	0.0
Nigeria	370.06	215.38	2,124.0	9,440.0	3,141.0	2,024.0	405.0	4,014.0	14,140.0	183.0	0.0	0.0	-	-	-	-	-	-
Rwanda	0.0	0.0	43.22	192.10	0.0	0.0	0.0	114.0	290.0	0.0	8.0	0.0	-	-	-	-	-	-
Senegal	103.38	60.17	183.56	815.86	344.5	143.43	28.69	75.5	148.52	0.0	0.0	0.0	11.77	2.22	0.0	0.0	0.0	0.0
Sierra Leone	2.02	1.17	0.0	0.0	0.0	151.40	30.30	10.50	144.0	5.50	6.40	0.0	-	-	-	-	-	-
South Africa	0.0	0.0	5,331.6	2,369.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Sudan	151.20	88.0	0.0	0.0	332.0	0.0	0.0	2,114.0	0.0	0.0	0.0	177.80	-	-	-	-	-	-
Swaziland	0.52	0.30	31.11	138.30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Tanzania	10.46	6.09	14.36	6,380.0	0.0	389.0	77.70	400.0	2,593.0	0.0	20.40	0.0	-	-	-	-	-	-
Togo	0.0	0.0	215.56	958.03	25.0	38.86	7.77	90.0	268.52	0.0	0.0	0.0	-	-	-	-	-	-
Uganda	19.53	11.37	600.0	2,667.0	350.0	0.0	0.0	210.0	2,037.0	0.0	66.40	0.0	-	-	-	-	-	-
Zambia	5.29	3.08	516.0	2,293.0	17.50	0.0	0.0	0.0	352.0	0.0	0.0	60.0	-	-	-	-	-	-
Zimbabwe	18.90	11.0	400.0	1,778.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	62.0	-	-	-	-	-	-

Chapter 4

Fuels for Industry

This chapter features potential clean-energy CDM opportunities related to gas recovery in fuel production (flared-gas recovery, coal mine methane, and waste gases in crude oil refinery) and thermal use and consumption (improved steam system and reduced clinker use in cement manufacturing). Figure 4.1 shows the physical distribution of potential activities for Sub-Saharan Africa along the fuels-for-energy (e.g., coal, fuel oil and gas) subsector production chain; the accompanying list of UNFCCC approved methodologies is illustrative.

Figure 4.1: CDM Opportunities along the Fuels-for-Industry Production Chain



Fuel production	Transport/ distribution	Consumption/ use
Flaring, recovery of flared gas	***Energy efficiency in fuel transport***	***Fuel switch***
AM0009, AM0037	AM0053	AM0049, AMS-III.B
AMS-III.K	***Reduction of pipeline leaks***	AM0007, AMS-II.D ACM0009, AM0036
Energy-efficient refineries	AM0023, AM0043	
AM0055, AMS-III.P		*Energy-efficiency (steam traps, etc.)*
CMM destruction (coal)		ACM0012, AMS-III.M AM0032, ACM0004
ACM0008		AM0017, AM0018 AM0038, AM0054 AM0056, AM0060 AM0024, ACM0003 AM0033, ACM0015 AM0040

Production

4.1 Flared Gas Recovery

In oil-producing countries, a combination of flaring, venting, and fugitive release of associated gas (AG), a byproduct of crude-oil production, is a leading source of GHG emissions. In the absence of AG markets, oil fields commonly flare the excess gas that remains after all field requirements have been satisfied. Associated natural gas is also vented for reasons of safety control. One proven way to reduce these emissions is to capture the otherwise flared gas and use it as a fuel for energy generation. This study considered 12 countries in Sub-Saharan Africa with significant activities related to oil-and-gas production. These countries are (in descending order, according to annual quantity of crude oil produced): Nigeria, Angola, Sudan, Equatorial Guinea, Gabon, Republic of Congo, Chad, Cameroon, Côte d'Ivoire, Ghana, South Africa, and Democratic Republic of Congo.[78]

4.1.1 Technical Evaluation

One common parameter used to characterize the quantity of natural gas produced from a certain quantity of crude oil is the gas-to-oil ratio. Specifically, this ratio is the quantity of gas produced with oil from an oil well, usually expressed as the volume of gas co-produced with the oil per barrel of oil (standard cubic feet per barrel) (box 4.1.1).

The baseline emissions for potential flared gas–recovery projects is calculated as the tCO_2e resulting from the flaring and venting of AG produced in each country studied that is not used for any end use. The baseline emissions equal those resulting from AG combustion (90 percent) and venting (10 percent). Table 4.1.1 summarizes the results of the analysis carried out to estimate the extent of gas flaring and venting and the resulting baseline GHG emissions for each of the 12 countries.

Box 4.1.1: Calculating the Quantity of Associated Gas from Crude-oil Production

Using available data on the average gas-to-oil ratio in oil-production activities and annual crude-oil production, the study team estimated AG production in 12 oil-producing countries of Sub-Saharan Africa, as follows:

$AG_{i,y} = (CO_{i,y} * GOR_i * 365) * CF$

where,

$AG_{i,y}$ = associated gas produced in country i during year y (m^3),

$CO_{i,y}$ = crude oil produced in country i during year y (bbls/day),

GOR_i = average annual gas-to-oil ratio characteristic of crude-oil production in country i (ft^3/bbl), and

CF = conversion factor (ft^3 to m^3).

$AGF_{i,y} = AG_{i,y} – AGU_{i,y}$

where,

$AGF_{i,y}$ = associated gas flared in country 1 during the base year (m^3) and

$AGU_{i,y}$ = associated gas used in country i during the base year (m^3).

[78] Flared gas–recovery projects developed under the CDM can use AM0009 and AM00037.

Table 4.1.1: Associated Natural Gas Production and Flaring in Major Oil-producing Countries of Sub-Saharan Africa (2003)

Country	Crude-oil reserves (billion barrels)	Natural-gas reserves (trillion m^3)	Crude-oil production (million barrels/day)	Associated gas produced (billion m^3)	Associated gas flared or vented (billion m^3)	Estimated GHG emissions from gas flaring and venting (million tCO_2e)
Angola	5.40	0.057	1.250	12.921	12.171	49.291
Cameroon	0.40	0.113	0.090	0.930	0.884	3.579
Chad	1.50	0.096	0.170	1.757	1.669	6.761
Congo, Dem. Rep.	1.54	0.003	0.022	0.227	0.216	0.875
Congo, Rep.	1.60	0.091	0.240	2.481	2.357	9.545
Cote d'Ivoire	0.10	0.028	0.089	0.920	0.269	1.088
Equatorial Guinea	1.10	0.051	0.350	3.618	3.437	13.920
Gabon	2.50	0.028	0.240	2.429	2.308	9.346
Ghana	0.02	0.024	0.062	0.062	0.059	0.239
Nigeria	35.90	5.148	2.280	42.422	19.016	77.016
South Africa	0.02	0.010	0.030	0.310	0.078	0.314
Sudan	5.00	0.088	0.414	4.279	4.065	16.465
Total	**55.08**	**5.737**	**5.181**	**72.409**	**46.528**	**188.439**

The 2003 database used in this study indicated that about 64.3 percent of the 72.4 billion m^3 of natural gas produced in these 12 countries was flared (EIA, 2000–07). That is, flaring amounts to about 46.6 billion m^3 of natural gas, representing slightly more than 35 percent of global flaring. AM0009 requires the evaluation of various options to determine the most likely course of action with respect to use of the natural gas produced in association with crude oil, taking into consideration economic attractiveness and project barriers.

As such, gas produced in association with oil can be treated in five ways:

- vented (released into the atmosphere) at the oil-production site;
- flared at the oil-production site;
- consumed on-site;
- injected into the oil reservoir; or
- recovered, transported, processed, and distributed to end users (assumes the inclusion of use at an IPP-built power plant).

Thus, in table 4.1.1., the figures in column 6 refer to the natural-gas volumes that remain after subtracting on-site consumption, injection into oil reservoirs, and recovery for other end uses from the total produced in oil-production operations. Thus, the figures represent the volume of gas either flared or vented.

4.1.2 Quantitative Analysis

The study team sought to answer three major questions:

- What capacity of power could be generated if all the associated natural gas flared in Sub-Saharan Africa were used to generate power?
- What quantities of GHG emission reductions could be achieved?
- What level of investment would be required to put these capacities in place?

The study team used the flaring and venting estimates shown in table 4.1.1 to answer these questions. Box 4.1.2 shows the sets of equations used to quantitatively assess the opportunity for flared-gas reduction as CDM projects in the 12 oil-producing countries considered. For each country, the study team used the 2003 EIA data, combined with in-country information where available.

In its analysis, the study team assumed the following:

- For all the countries considered, natural gas is used to enhance oil-field operations and generate in-field electricity.
- For Angola, Côte d'Ivoire, Equatorial Guinea, Gabon, Nigeria, and South Africa, a certain level of market infrastructure is in place for natural gas. For the other seven countries, 5 percent of the produced AG is consumed for field operations and 95 percent flared.
- In Cameroon, 50 percent of the natural gas consumed (reported in 2004) is from non-associated gas field.
- In South Africa, 25 percent of the AG produced in oilfields is flared, while 75 percent is harnessed for local use.
- With the exception of Nigeria, the median African gas-to-oil ratio (1,000 SCF per barrel of oil) is used to estimate the AG produced.
- The AG used for power generation is consumed in combined-cycle, gas-turbine systems with a 59-percent energy efficiency.
- Ten percent of flared gas is vented; thus, both are reflected in baseline emissions.
- The size of each combined-cycle, gas turbine is 500 MW, except in cases where total capacity is much less and is taken as a single project.
- Leakage emissions from gas flare-out projects are negligible.
- Grid emissions in the baseline and leakage emissions are not considered.

Box 4.1.2: Estimating Potential Power Generation from Flared Gas Recovery

The study team estimated the amount of electrical energy that could be generated and the GHG emissions avoided if all of the natural gas currently flared in the 12 countries studied were used as a fuel in combined-cycle, gas-turbine systems to generate power.

The estimated potential was calculated as follows:

$EEG_{i,y} = ((AGF_{i,y} * NHV_{ng} * EFF_{ccgt})/(CF_v * CF_h)) * 10^6$

where,

$EEG_{i,y}$ = potential electrical energy generated (GWh),

NHV_{ng} = net heating value of natural gas (MMBTU/1,000 ft^3),

EFF_{ccgt} = energy efficiency of combined-cycle gas turbine system (%),

CF_v = conversion factor (ft^3 to m^3), and

CF_h = conversion factor (MMBTU per GWh).

The potential power capacity was estimated as follows:

$PPCi,y = EEG_{i,y}/(8{,}760 * CAPF)$

where,

PPCi,y = potential power capacity in country i in year y (MW) and

CAPF = average capacity factor of the CCGT plant.

The likely reduction in GHG emissions was calculated as follows:

$BE_{i,y} = (AGF_{i,y} * Den_{ng} * GWP * f_v + (1-f_v) * AGF_{i,y} * Den_{ng} * 44/12) * 10^6$

$PE_{i,y} = AGF_{i,y} * Den_{ng} * 44/12) * 10^6$

where,

$BE_{i,y}$ = baseline emissions in the absence of the CDM project (tCO_2e),

$PE_{i,y}$ = project emissions (tCO_2e),

Den_{ng} = density of natural gas (kg/m^3),

GWP = global-warming potential of methane gas (21), and

f_v = fraction of gas recorded as flared that is vented.

The annual emission reduction was calculated as follows:

$ER_{i,y} = BE_{i,y} – PE_{i,y}$

Table 4.1.2 summarizes the results of the analysis for each of the 12 oil-and-gas producing countries considered.

Table 4.1.2: Results Summary of CDM Opportunities: Flared-gas Recovery

Country	No. of projects	Total installed power, country, 2003 (MW)	Added power of projects (MW)	Added power of projects as % of total installed	Projects' emissions reductions (millions tCO_2e/yr)
Angola	8	670	7,729	1,154.0	15.822
Cameroon	1	900	561	62.0	1.149
Chad	2	30	1,060	3,534.0	2.170
Côte d'Ivoire	1	919	171	19.0	0.349
Congo, Dem. Rep.	1	2,570	137	5.0	0.281
Congo, Rep.	3	121	1,497	1,237.0	3.064
Equatorial Guinea	4	13	2,183	16,790.0	4.468
Gabon	3	400	1,466	366.0	3.000
Ghana	1	1,310	37	3.0	0.077
Nigeria	12	5,890	12,077	205.0	24.721
South Africa	1	40,480	49	0.1	0.101
Sudan	3	760	2,582	340.0	5.285
Total	**40**	**54,063**	**29,548**	**54.6**	**60.486**

The analysis showed that, if flared gas is used in combined-cycle, gas turbines to generate electricity in the 12 countries considered, about 29.5 GW of installed capacity can be put in place, representing nearly 55 percent of the installed power capacity in those countries and about 43.2 percent of the installed capacity in Sub-Saharan Africa. The analysis also showed that this power capacity, which leads to the complete elimination of flaring in the region, results in an annual GHG emission reduction of about 60.5 million tCO_2e. Additional environmental benefits would be derived by converting flared gas to power, as a lower energy-emission factor is added to a grid with a capacity deficit where the shortfall in generation is met by higher-emission-factor, off-grid plants (e.g., diesel generators in Nigeria); thus, high GHG-emission, power production from plants in the build margin, in addition to some of the off-grid diesel plants, is displaced in many countries, especially those dominated by thermal plants. Given that many countries in the region have grids with capacity deficits—South Africa has just joined the league—such new gas-based capacities are unlikely to displace operating-margin power plants for some time.

Experience in Nigeria could lead one to conclude that most of the otherwise-flared, captured gas is used mainly for power generation, it can be assumed that a portion of the AG will be used for various purposes, as follows: fuel in industries shifting from more carbon-intensive options, such as coal and petroleum, to natural gas; feedstock in the production of liquefied natural gas (LNG), especially in Angola, Nigeria, and other countries similarly endowed with natural gas; feedstock in the extraction of C_3 and C_4 hydrocarbons, which are then blended into liquefied petroleum gas (LPG) for domestic energy use and export; feedstock in petrochemical production; and medium for field pressurization when re-injected to improve recovery of crude oil in producing fields. Whichever end-use pattern is evolved in the respective countries, the enormous waste of cleaner energy that results from AG flaring and venting can be mitigated through appropriate planning and implementation of gas-flare reduction projects.

The CDM can be one of the financial mechanisms used to implement such projects, since the return on flare-reduction investments is usually marginal or negative without earnings from certified emission reductions (CERs). That CERs can be earned from flare-reduction programs has been established through the 2006 registration of a flared-gas recovery project hosted in Nigeria.[79] This project is a US$480 investment that recovers otherwise flared AG to produce electricity. Produced fluids from nearby fields—operated by ENI Nigerian AGIP Oil Company (NAOC) in the Oil Mining Lease area 60 (OML60) of Delta State—are collected and sent to the Kwale Oil-Gas Processing Plant (OGPP). The fluid consists mainly of crude oil, water, and natural gas. At the Kwale OGPP, which lacks economically viable, commercial, or other AG outlet, the AG is flared on separation from the oil. In addition to the Kwale OGPP, some flaring and venting occur at the oil fields for emergency purposes. In the project scenario, the otherwise flared AG is captured and marketed for use by end-use gas consumers. Lacking local-market outlets, NAOC, the project proponent, and its joint-venture partners have created a demand for the gas through the construction of an independent, gas-fired power plant (480 MW) at Okpai, consisting of a high-efficiency, combined-cycle, gas turbine. The power plant's main goal is to absorb part of the AG produced at Kwale OGPP. With the development of the Okpai independent power plant, most of the AG from Kwale OGPP is captured and used in a purpose-built Greenfield development plant at Okpai. The final investment decision was supported by the project's CDM prospects. Potential carbon revenues helped developers face such factors as high cost of capital due to national political risks, electricity payment guarantee by the national public utility and operational load factor.

The above example from Nigeria, along with a Chad case study (box 4.1.3), provides the logical strength for the study team's assumption that flared-gas reduction as a CDM project should be feasible in many countries of Sub-Saharan Africa with existing oil-and-gas operations. Estimates of the potential magnitude of GHG emission reduction from projects aimed at reducing or completely capturing flared gas, as estimated in table 4.1.2, should be viewed as the potential order of magnitude. It should be noted that the achievable emission reduction may be higher, since it will be derived not only from flare avoidance, but also from the displacement of otherwise-supplied power, especially in cases where gas-fired power projects replace power generation using more carbon-intensive fuels (e.g., coal and petroleum products). That many such projects are not emerging in the UNFCCC project pipeline is a good indication that barriers to their development exist.

Determining the costs for AG handling and recovery is difficult since it depends on many project variables, as well as implied costs for processing facilities and treatment and end-use applications. Typically, the key variables that determine project cost are 1) onshore versus offshore, 2) AG production rate and composition, and 3) gas-disposition alternative. Generally, offshore capital investments are more expensive than onshore ones since all facilities are located on a production platform where space and weight are paid at a premium. Gas compression and disposition infrastructure is likely to cost more offshore. Also, more remote offshore facilities require more investment to access the chosen gas-disposition alternative. With regard to the rate of production and composition, AG investments benefit from economies of scale (unit costs would be expected to improve substantially as production rates increase). Regarding the gas-disposition alternative, the options routinely used by industry to avoid gas flaring are reinjection into a shallow aquifer, re-injection for storage in a depleted reservoir, re-injection for pressure maintenance into producing formation, and transport via pipeline to inlet flange of various end-use consumers.

[79] Registered November 9, 2006, the project (reference number 0553 in the UNFCCC project register), is entitled Recovery of Associated Gas That Would Otherwise Be Flared at Kwale Oil-Gas Processing Plant, Nigeria. AM0002 (version 2) was used to develop this project under the CDM, resulting in an annual emission reduction totaling about 1.5 million tCO_2e.

Box 4.1.3: Flared-gas-to-energy Projects: The Case of Sedigi Field in Chad

The case of Chad has been studied extensively by the World Bank in the context of the Global Initiative on Natural Gas Flaring Reduction. One study focused on global benefits shows an attractive potential for reducing CO_2 emissions from flaring and displacing more carbon-intensive energy sources than are currently required for Chad's economic development.[1] The concept for the development of the Sedigi oil field and the refinery at Farcha, as initially conceived by the Chadian government, does not leave room for gas use, other than small quantities for power generation at the Sedigi field and fuel at the Farcha refinery.

The World Bank study compares a range of scenarios for gas disposal, mix of refinery products, and options for electricity supply. With respect to GHG emissions, two extreme scenarios are considered. Scenario 1 is the baseline scenario as presently conceived by the government. Beyond the limited consumption of gas for power generation at the field, the rest is flared. Refined products are sold locally, heavy fuel oil is sold to the rehabilitated STEE power plant, and surplus gasoline is exported. Scenario 2 maximizes use of flared gas. It entails converting the STEE power plant from oil to gas when upgrading its production facilities, supplying gas to industrial sites (e.g., substituting pressure on natural wood resources). Industrial plants could use the Sedigi gas through a direct pipeline connecting the gas transmission line from Sedigi to the new Farcha power plant or via an LPG supply. LPG produced at the new refinery in Farcha would cover local demand, and surplus LPG would be sold in regional markets. Study results are presented in the table below.

Investment cost	Millions of US$
Scenario 1: Baseline	
Wellhead—oil	Sunk cost
Oil pipeline	Sunk cost
Refinery	78.1
Power plant STEE diesel engines Sc.0	35.0
Total cost	113.1
Scenario 2: Added investment to minimize flaring	
Wellhead—additional gas facilities	9.0
Gas pipeline to N'Djamena	25.0
Additional gas facilities at refinery	2.0
Additional gas facilities at industrial customers	0.3
Facilities for LPG to local market and export	5.3
Total cost	154.7
Total emission reduction in 14 years (tCO_2)	3,333,065
NPV baseline scenario	99.3
NPV scenario minimizing flaring	114.1
Total CO_2 revenue over 14 years	16.7
NPV of CO_2 revenue	5.6
IRR baseline scenario (%)	42
IRR scenario minimizing flaring (%)	36

A first conservative estimate of avoided emissions indicates they will steadily increase from 140,000 tCO_2 per year in year 1 to 330,000 tCO_2 in year 14, totaling 3.3 million tons over the period—which is significant compared to national emissions—and the carbon revenue generated will range from US$700,000 in year 1 to US$1.7 million in year 14. The scenario minimizing flaring is more costly in terms of investment. While the corresponding IRR is slightly lower than in the baseline scenario (Scenario 1), it is still high, and the NPV is increased by 15 percent (in Scenario 2).

[1] Flared Gas Utilization Strategy: Opportunities for Small-scale Uses of Gas, Global Gas Flaring Reduction—Public-Private Partnership (GGFR), Report No. 5, May 2004.
[2] Assuming that the energy displaced by the new use of the flared gas is not more carbon intensive than the flared gas, which is a conservative assumption since natural gas has a relatively low carbon content per energy unit.

In addition, costs are subject to significant fluctuations. With the recent growth in oil-and-gas activities, equipment and services manufacturers and suppliers have raised their prices. The cumulative effect has been tight capacity, coupled with high raw-materials costs. As a result, the capital required for the same set of facilities has nearly doubled.

4.1.3 Barriers to Implementation

Despite Sub-Saharan Africa's appreciable endowment of natural gas resources, only one gas flare-out CDM project has been registered in the UNFCCC project pipeline to date. The development and eventual registration of this project was supported by the Global Gas Flaring Reduction (GGFR) program of the World Bank. In keeping with the GGFR groupings, the barriers that have constrained the development of natural gas flare-out projects under the CDM can be considered as either "hard" or "soft." The main hard barriers include inertia with regard to development of access to adequate gas markets, weak local gas markets and lack of infrastructure, and unreliability of AG supply. The major soft barriers are an undeveloped regulatory framework and poor fiscal and gas-pricing regimes.

Hard Barriers

In relation to the large AG endowment and production capacities in such countries as Angola, Democratic Republic of Congo, Gabon, Nigeria, Republic of Congo, and Sudan, local gas markets are inadequate to sustain gas flare-outs. Access to international gas markets—via the development of capital-intensive LNG facilities or long-distance pipelines—is usually required before significant end uses can be established. Whichever transport mode is selected, even after the market is identified, final investment decisions are usually not made until firm contract for supply to the end-use market is in place. These are usually long-term contracts (e.g., 20–25 years), requiring the appropriate finalization of many critical issues, and thus a long negotiating time, before parties can sign. The implication is that, in many of these countries, the plan to reduce gas flaring depends largely on how fast such projects can identify and reach agreement with potential buyers in international energy markets; thus, this becomes the most important factor in a project's development and a critical issue dictating the pace of access and development of the gas-supply infrastructure. More often than not, sound bilateral and multilateral cooperation will be essential to mobilizing adequate markets and needed financial resources for such projects. Such access has begun to develop in some of the larger gas-producing countries, including Nigeria, which currently has some 6 LNG trains in place, and Angola, which reached a final investment decision to build an LNG project designed to take in significant amounts of offshore flared gas. This development would not have occurred without bilateral and multilateral cooperation.

Even in cases where international markets have been identified and a firm plan has been put in place to assimilate them into the consumption equation, viable local markets are often needed to catalyze gas flare-out projects. Unfortunately, in many countries across the region, local markets for AG are either not available or are located far from gas-producing fields, requiring heavy investments in in-country transport and distribution infrastructure. The inability to identify and mobilize local markets, combined with a lack of investment in developing the required infrastructure, can prevent flare-out projects from achieving their goal. In many countries across the region, the inertia associated with development of access to local markets has created a barrier toward the use of natural gas in such economies; in such cases, gas continues to be flared until a vintage market, usually the power sector, catalyzes the development of its use in other sectors of the economy. This was demonstrated in Nigeria, where the power sector has been the "anchor" demand and catalyst for boosting gas use within the country's economy. Other than power generation, gas utilization in that country did not become appreciable until construction of the Escravos-Lagos Pipeline (ELP) was completed to transport natural gas to the Egbin Power Station in Lagos, about 1,000 km from the Niger Delta gas-producing fields (Triple "E" 2005). With implementation of the ELP, gas use in industries along the pipeline, including cement and foods, became feasible. The ELP transports natural gas to industrial areas in and around Lagos, where a large percentage of the country's major industries are located, providing ongoing opportunities to shift from fuel oil to natural gas. Natural-gas availability in the Lagos industrial areas is expected to catalyze the implementation of such Greenfield projects as fertilizer, methanol, cement, aluminum, and steel.

Gas infrastructure projects usually require large capital investments and yield a lower return on investments compared to alternative opportunities. Once these investments are made, they are usually guaranteed via long-term supply contracts characterized by take-or-pay clauses. The capital-intensive nature of such projects, combined with the difficult task of putting together a critical mass of start-up consumers for local markets, is usually an inhibiting factor in the development of gas flare-out projects.

Since AG is produced with crude oil, its supply is only as reliable as the oil production. Any disruption to oil supplies will affect the volume of AG available to consumers. To avoid this risk—which may deter the development of gas-supply contracts, especially if amelioration schemes are not included in the contract—most gas-supply programs have linked supplies from non-associated gas (NAG) fields.

Soft Barriers

In many countries across the region, the weak regulatory framework for oil-and-gas production bars resource use. Traditionally, oil revenue has played an important role in these countries' economic development. In this context, oil-production regulations have considered AG a waste output of the crude-oil production process. Lack of an AG market has been conveniently dealt with by institutionalizing flaring as a disposal option. Ownership rights to the AG are either unclear or non-existent. As a result, gas development prospects have been held up by the low value placed on natural gas, compared to other energy sources, particularly oil and coal. In addition, while provisions in production contracts recognize that AG can be used by operators within their oil fields (e.g., for enhanced oil recovery or energy), they provide no right to sell or commercialize it downstream. In Nigeria, for example, AG has had zero economic value in the calculation protocols used to estimate benefit sharing between production partners until recently. Many existing production-sharing agreements do not allow for the recovery of costs incurred in harnessing AG recovery for productive uses.

In the 1980s, when international discussion on the need to use otherwise wasted AG was at its peak, buffered by environmental concerns over flaring, the Nigerian government introduced a marginal penalty for gas flaring. The penalty was so negligible that virtually all oil-and-gas operators paid it for a time instead of implementing aggressive gas flare-out schemes or even using the AG for beneficial gas-lifting operations in their fields. But more recently, collaborative approaches are being developed between stakeholders—from operators and governments to communities and third parties—to accelerate and effectively achieve flare down via enabling frameworks (as articulated in the Voluntary Standard for Global Gas Flaring and Venting). This is the case in Nigeria, where an emerging regulatory framework guiding the country's oil-and-gas industry and contractual obligations between oil-and-gas production partners are being developed to place an adequate premium on the value of otherwise flared natural gas (box 4.1.4).

More work along these lines is needed in many of the region's other oil-producing countries. The World Bank–supported GGFR program has been helpful in this regard and will continue to play a relevant role in reducing the adverse effects of an undeveloped gas-use regulatory framework on the region's flare-out projects.

Box 4.1.4: Committee Develops Flare-reduction Road Map for Nigeria

Major stakeholders came together at a 2007 forum to develop a realistic time frame for reducing Nigeria's gas flaring, taking into account the country's complex challenges. The Flare Reduction Committee, which emerged at a workshop held by the World Bank-supported Global Gas Flaring Reduction (GGFR) program in Abuja earlier in the year, includes high-level representatives from ministries and sector companies. This ad-hoc committee focuses on assessing the environmental, health, and financial effects of eliminating or continuing routine flaring after December 2008, given the major barriers to a faster reduction time frame. The range of impediments includes inadequate infrastructure for gas transport, inadequate gas pricing, lack of available capital for gas-utilization projects, and security issues in the Niger Delta. The committee expects to provide input to the Nigerian government and draft an integrated flare reduction plan.

In many countries of Sub-Saharan Africa, energy prices are administratively determined and do not reflect market realities. Subsidized energy production sends the wrong signal to market participants. In many countries with oil-and-gas activities, gas price subsidies are driven initially by the need to promote gas use in the power sector to displace the use of expensive petroleum products. In the past, this strategy has worked in certain countries that have witnessed an impressive development of gas-fired power facilities. But it has been difficult to remove the subsidy to allow for the competitive pricing of natural gas, which can promote use efficiency and optimal capacity expansion of the infrastructure required for production and distribution of the energy resource. Beyond the incentives developed for the power sector, low gas prices become a negative incentive for gas infrastructure expansion because, under such pricing and fiscal regimes, it is often difficult to attract the required local and international investment to develop gas infrastructure to a level that will reduce flaring significantly. In many of the region's countries, this factor has been recognized as an impediment to gas industry development. Ongoing efforts are in place in such countries as Nigeria to restructure the natural gas sector to promote its aggressive development under a competitive market regime.

The CDM can play an important role in mitigating both hard and soft barriers. Developing gas flare-out as CDM projects, for example, can be used as a forum for cooperation between Annex 1 and non-Annex 1 countries, which demand clean energy and achievable emission reductions from CDM projects in the region's host countries. The participation of Annex 1 countries can provide bilateral and multilateral support for gas-sector development in those countries. Finally, the GGFR continues to play an ongoing key role in developing gas flare-out projects.

4.1.4 Mitigation Recommendations

The above-discussed barriers suggest a set of actions that, if taken, can promote the use of AG in the economic development of countries endowed with this valuable resource. For the domestic energy market to play a significant role in the gas flare-out strategy, the required gas transport and distribution infrastructure must be put in place. For this to happen, the local market must be firmly identified and established because the economic and financial feasibility of gas supply projects depends on reliable information about such markets. In addition, the necessary investment required for development of gas transport and distribution infrastructure must be secured.

Power-sector planning in the affected countries must address these market and infrastructure barriers. A forward-looking national gas policy, characterized by a transparent legal, fiscal, and approval framework for the gas industry, should be put in place immediately in these respective countries as part of a program to promote domestic gas use and encourage export-based projects. In each country, the natural-gas requirement for power generation should be the driving force for gas-network extension. Each country should implement dedicated trunk lines to catalyze in-country use of gas, and the level of domestic energy demand should be reflected in national development plans.

In planning gas-flare out projects, it is important to couple the supplies of natural gas from AG fields with a reliable amount of supplies from NAG fields in the gas supply schemes to guarantee that shortages that may occur during reduced oil production or interruptions can be adequately handled.

National governments should put fiscal and monetary incentives in place to promote the increased domestic use of natural gas for particular end uses. To attract foreign and local investors, the respective governments should encourage domestic banks working alone or in collaboration with overseas banks to set up low-interest, energy investment funds that entrepreneurs can tap for energy projects.

Finally, given the capital-intensive nature of gas infrastructure projects, combined with the difficult task of putting together a critical mass of start-up consumers for local markets, the governments of countries endowed with oil-and-gas resources should encourage AG users to assess carbon funds via the CDM process, which can serve as another veritable source of funds for gas-sector activities.

4.2 Coal Mine Methane

Many coal mines are gassy, requiring constant lowering of methane concentration in mining areas below the explosive range. This is usually achieved by ventilating the mine with air to dilute the concentration of coal mine methane (CMM) below the explosion limits. The resulting low-concentration methane air (< 1.5 percent) is too poor to be used and is usually vented into the atmosphere. Instead of diluting the CMM concentration, an alternative strategy is to extract the methane through surface wells and horizontal boreholes during and before mining. The extracted methane can then be variously used. For example, it can be injected into natural-gas pipelines, where it becomes a fuel for end uses; it can be used to generate power, fired on its own or co-fired in boilers, or used as a fuel to meet household energy needs.

Nine countries in Sub-Saharan Africa—Botswana, Democratic Republic of Congo, Niger, Nigeria, South Africa, Swaziland, Tanzania, Zambia, and Zimbabwe—are endowed with good-quality coal reserves that have been exploited and will continue to be used to supply primary energy demand in the foreseeable future. Coal resources in these countries total some 49.96 billion tons (2003 figure), about 97 percent of which is represented by South Africa. Projects that capture CMM for energy use are already being implemented in developing countries as CDM projects (table 4.2.1).

Table 4.2.1: CMM Capture-to-energy Projects Registered in the UNFCCC Pipeline

Date registered	*CDM Project Title*	*Location*	*Capacity (MW)*	*Average emission reduction (tCO_2e)*
Feb, 18, 2007	Huabei Haizi and Luling Coal Mine Methane Utilization Project	Haizi and Luling, China	16.5	296,278
March 31, 2007	Pansan Coal Mine Methane Destruction Project	Pansan, China	8.4 + 4,000 households	126,233
May 22, 2007	Yangquan Coal Mine Methane Utilization for Power Generation	Shanxi Province, China	90	2,136,174
Sept. 24, 2007	Jingxi Fengcheng Mining Administration CMM Utilization Project	Fengcheng, China	7.5	190,378
Oct. 08, 2007	Shanxi Liulin Coal Mine Methane Utilization Project	Jinjiashuang Xingui and Liulin, China	12	318,166
Dec.11, 2007	Shanxi Yangcheng Coal Mine Methane Utilization Project	Yangcheng, China	16.5 + 1,380 households	423,195

Note: CMM capture-to-energy projects can use ACM0008.

In addition to the six projects listed in table 4.2.1, developed to generate power or provide a source of household heat, a single project was registered to provide CMM as a fuel for an industrial aluminum-hydroxide furnace. These and other projects currently in the UNFCCC validation pipeline are concrete evidence that CMM capture-to-energy projects can be developed successfully as CDM projects in the coal-producing countries of Sub-Saharan Africa.

4.2.1 Technical Evaluation

The study team evaluated the possibility of using captured CMM to generate electricity, which would reduce GHG emissions from venting and replace other fossil fuel–based capacity. The top-down analysis used aggregate country data on coal production, not mine-by-mine data, to estimate CMM potential. The extent of methane released depends on a mine's gassy nature and whether coal is produced from surface or underground mines. The methane-release model of the Intergovernmental Panel on Climate Change (IPCC) involves three main emission sources: depressurization of strata caused by mining; broken coal; and coal remaining on roofs, floors, and pillars after mining. A recent study on South Africa coal mines shows that the IPCC model may have overestimated methane emissions. The study concluded that use of the 1996 IPCC default factors for CMM emissions in that country grossly overstated methane emissions for that year. It also concluded that the IPCC model overestimated annual CMM emissions reported in the 2003 South African National Communications by about four-and-a-half times. The conclusion of that study, adopted here, is that South Africa's coal-mining operations may not be as gassy as has been previously thought.[80]

The present study used two methane emission factors (low and high) to evaluate CMM-to-energy projects for South Africa. The low value of 0.000368 tCH_4 per ton of coal produced was derived from the South Africa study (Lloyd 2003; Lloyd et al. 2000), while the

[80] The estimated unitary investment cost was US$1.2 million (only the CCGT electricity-production system was considered) (Sathaye and Phadke 2006).

high value of 0.0104 tCH_4 per ton of coal produced was derived from a lifecycle emission study (Delucchi 2003). The high value, representing gassy mines, was used for all other countries in Sub-Saharan Africa.

4.2.2 Quantitative Analysis

Box 4.2.1 shows the quantitative relationships used to evaluate the potential of CMM-to-energy projects as CDM projects in countries of Sub-Saharan Africa. In the baseline scenario, it was assumed that a portion of the methane produced during coal production is for energy at the mine, another portion is flared to ensure safety and/or meet regulatory requirements, and the remainder vented. The project scenario involved the capture of otherwise flared CMM and its use as a fuel to generate electricity in a gas turbine.

Box 4.2.1: Calculating CMM-to-energy Project Potential

For each country in Sub-Saharan Africa, the study team estimated the total methane-emission potential from coal mining using the following equation:

$CMME_{i,y} = MEF * CP_{i,y}$

where,

$CMME_{i,y}$ = methane emission in coal-mining operations (tCH_4) in country i during year y,
MEF = average methane emission factor for coal-mining operation (tCH_4/ton of coal), and
$CP_{i,y}$ = quantity of coal mined in country i during year y.

Methane produced during the process of coal mining (i.e., vented) was calculated as follows:

$CCMV_{i,y} = CMME_{i,y} – CMMU_{i,y}$

where,

$CMMV_{i,y}$ = coal mine methane vented (tCH_4) and
$CMMU_{i,y}$ = coal mine methane used for energy and flared for regulatory or safety purposes at mines (tCH4).

Given the baseline scenario, baseline emissions were calculated as follows:

$BE_{i,y} = CCMV_{i,y} * GWP_m + CMMU_{i,y} * MW_{CO2}/MW_{CH4}$

where,

$BE_{i,y}$ = baseline emissions (tCO_2e) in country i during year y,
GWP_m = global warming potential of CH_4 (21),
MW_{CO2} = molecular weight of carbon dioxide (44), and
MW_{CH4} = molecular weight of methane (16).

Project and leakage emissions and emission reductions were calculated as follows:

$PE_{i,y} = CMME_{i,y} * MW_{CO2}/MW_{CH4}$
$ER_{i,y} = BE_{i,y} – PE_{i,y} – LE_{i,y}$

where,

$PE_{i,y}$ = project emissions (tCO_2e) in country i during year y,
$ER_{i,y}$ = emission reduction (tCO_2e) in country i during year y, and
$LE_{i,y}$ = leakage emissions (tCO_2e) in country i during year y and is assumed negligible.

Along with use of the equations in box 4.2.1, the study team assumed a project installation cost of US$1.2 million per installed megawatt capacity. For all mines, it was assumed that 5 percent of CMM would be used as mine fuel or flared for regulatory purposes, while the remaining recovered CMM would be used in a gas turbine with 35-percent thermal efficiency to generate electricity in a system with 85-percent capacity utilization. The emission reduction from displaced power (when the power generated is supplied to a grid) was not included in this calculation.

Results of the analysis showed that, if all the CMM produced in the nine coal-producing countries were captured and used to generate power, the additional installed capacity put in place would range from a low generating capacity of about 0.2 MW (Nigeria) to a high of slightly above 67.0 MW (South Africa, non-gassy mine scenario) or 1,966.1 MW (South Africa, gassy mine scenario) (tables 4.2.2a and 4.2.2b).

Table 4.2.2a: CMM Capture and Use for Power Generation in SSA Countries: Non-gassy Mine Assumption for South Africa

Country	No. of projects	Coal produced, 2003 (tons/yr)	CMM produced, 2003 (tons/yr)	Added power of projects (MW)	Added power of projects as % of total installed	Projects emissions reductions (tons/yr)	Total investment cost of projects (millions US$)
Botswana	2	900,000	9,720	7.4	5.690	168,202.3	8.87
Congo, Dem. Rep.	1	100,000	1,080	0.8	0.030	18,689.1	0.99
Níger	1	150,000	1,628	1.2	0.021	28,033.7	1.48
Nigeria	1	20,000	216	0.2	0.003	3,737.8	0.20
South Africa	5	239,400,000	88,099	67.0	0.170	1,524,535.7	80.39
Swaziland	1	370,000	3,996	3.0	2.340	69,149.8	3.65
Tanzania	1	80,000	864	0.7	0.080	14,951.3	0.79
Zambia	1	200,000	2,160	1.6	0.090	37,378.3	1.97
Zimbabwe	3	3,400,000	36,720	27.9	1.420	635,430.9	33.51
Total	**16**	**244,470,000**	**142,855**	**109.8**	**0.200**	**2,500,108.9**	**131.83**

Table 4.2.2b: CMM Capture and Use for Power Generation in SSA Countries: Gassy Mine Assumption for South Africa

Country	No. of projects	Coal produced, 2003 (tons/yr)	CMM produced, 2003 (tons/yr)	Added power of projects (MW)	Added power of projects as % of total installed	Projects' emissions reductions (tons/yr)	Total investment cost of projects (millions US$)
Botswana	2	900,000	9,720	7.4	5.690	168,202.3	8.87
Congo, Dem. Rep.	1	100,000	1,080	0.8	0.030	18,689.1	0.99
Níger	1	150,000	1,628	1.2	0.021	28,033.7	1.48
Nigeria	1	20,000	216	0.2	0.003	3,737.8	0.20
South Africa	5	239,400,000	2,585,520	1,966.1	4.857	44,826,453.0	2,359.30
Swaziland	1	370,000	3,996	3.0	2.340	69,149.8	3.65
Tanzania	1	80,000	864	0.7	0.080	14,951.3	0.79
Zambia	1	200,000	2,160	1.6	0.090	37,378.3	1.97
Zimbabwe	3	3,400,000	36,720	27.9	1.420	635,430.9	33.51
Total	**16**	**244,470,000**	**2,640,276**	**2,008.9**	**3.400**	**45,802,026.2**	**2,410.74**

The study team is of the opinion that up to five CDM projects could be implemented in South Africa, yielding more than 1.5 million tCO2e (non-gassy mine scenario) to over 44.8 million tCO2e (gassy mine scenario). Similar CDM projects could be developed in Botswana and Zimbabwe, while smaller ones could be packaged in Democratic Republic of Congo, Niger, Swaziland, Tanzania, and Zambia. With regard to Nigeria, the study team believes that prospects for such CDM projects are not especially bright, given the country's current low coal production. However, given that a plan is under way to revitalize the country's coal production for power-plant fuel use, one cannot rule out the possibility that such projects may emerge as an option in the near future. China's experience shows that, although these projects are capital intensive, carbon finance can almost double the FIRR, making CMM-based power generation an attractive option (table 4.2.3).

Table 4.2.3: Financial Impact of Carbon Finance on CMM-to-energy Projects in China

Parameter	*Value (million US$)*
Underground CMM recovery and drainage	14
Drilling of CBM production wells	16
CMM-fired power plant (120 MW)	98
Transmission lines	1
Other (contingencies, resettlement, consulting, and training)	28
Total investment cost	**157**
Emission reduction (MtCO_2/yr)	2.65
CO_2 revenue (million US$/yr)	11
Total carbon revenue (2 * 7 years) (million US$)	158
CO_2 revenue (% energy sales)	57
CO_2 revenue (% O&M)	251
FIRR without carbon revenue (CMM recovery + power plant) (%)	6.81
FIRR with Carbon Revenue (CMM recovery + Power Plant) (%)	11.40

Sources: PINs and Project Design Documents of large CMM projects in China.

4.2.3 Barriers to Implementation

Development of CMM-to-energy CDM projects in Sub-Saharan Africa's coal-producing countries faces several major challenges: the relatively small size of project opportunities in most countries, the notion that coal mines in South Africa are not as gassy as previously thought, and the negative view of coal industry officials toward CMM-capture projects.

With the exception of Botswana, South Africa, and Zimbabwe, the volume of CMM available for capture across the subcontinent's coal-mining operations is small. The likely inability of smaller projects to achieve economies of scale puts their economic feasibility in doubt. Using the usual criteria for making investment decisions, it is doubtful whether most of them could attract investment funds. Implementing such projects under the CDM framework can help lift the economic feasibility barrier: As extra revenue from CERs improve the financial standing of such projects, it becomes easier to make the final investment decision.

As previously mentioned, recent research suggests that South Africa's coal mines may not be as gassy as once thought. As the continent's premier coal producer and one of the world's leading global producers and consumers of coal, South Africa represents the region's best opportunity for CMM-to-energy activities that reduce global GHG emissions. The notion that South Africa's coal mines are as gassy as once thought may explain why no CMM-to-energy projects from that country are in the UNFCCC pipeline, as well as deflated initial interest in such activities as a source of emission reduction. It may also explain the lack of enthusiasm in pursuing similar projects in Botswana and Zimbabwe, not to mention the region's marginal coal-producing countries. Implementing such projects under the CDM framework may help to mitigate certain risks associated with this uncertainty and the learning cost involved in the development work needed to shed more light on this issue.

Experience in China—where CMM-to-energy activities have been successfully developed and implemented as CDM projects—indicates that coal industry officials and mine operators commonly perceive CMM as a safety hazard, rather than a valuable energy resource. Given that mine decision makers' may be initially unwilling to invest in improved degasification projects, equity contributions to even non-marginal CMM-capture projects may not be forthcoming; this, in turn, could impede the ability to attract debt financing since many international and local financing institutions require a certain level of gearing ratio before approving project funding. More recently, the successful commissioning of such projects in China is a good indicator of the CDM's effectiveness in mitigating such barriers (table 4.2.3).

4.2.4 Mitigation Recommendations

To remove the above-identified barriers to CMM-to-energy CDM projects in Sub-Saharan Africa, the study team recommends that each of the region's coal-producing countries take a variety of actions to better estimate and manage the region's CMM recovery potential. First, CMM inventories in the respective countries are needed. This effort will require that the recent study to establish a more realistic estimate of CMM emission rates in South Africa be expanded to a larger sample size to include mines in the other coal-producing countries. Second, because of the unstable nature of methane supplies from coal-mining operations, all CMM-to-energy projects should have backup fuel supplies and services. Third, to develop interest in CMM-to-energy CDM projects and their associated benefits, the coal sectors of the respective countries require strategic capacity building in coal-mine management. Finally, where access to capital is difficult or country risk is high, special financing schemes and guarantees are needed to facilitate financial closure of CMM-to-energy CDM projects. Because these projects usually have high incremental costs compared to other energy-generation alternatives, the coupling of such financial schemes with earnings from the sale of carbon credits will alleviate the financial and investment barriers typical of such projects.

4.3 Waste Gases in Crude Oil Refinery

In all crude-oil refinery operations, waste gases—incondensable gases rich in hydrogen, methane, and other light hydrocarbons—are produced in the rectification tower. This section evaluates Sub-Saharan Africa's potential for clean-energy projects under the CDM that involve cleaning waste gases of unwanted impurities and compressing them to pressure levels that make them useful for energy generation.[81]

4.3.1 Technical Evaluation

In 2004, the installed crude-oil refining capacity in Sub-Saharan Africa amounted to about 1.5 million barrels of crude oil (table 4.3.1). Despite their rich energy value, waste gases often exist at low pressures and thus are not useful without upgrading to meet energy-production specifications. The clean-energy CDM potential analyzed below involves the upgrading of these otherwise flared waste gases for use as a fuel for on-site power generation, replacing heavy fuel oil and other fossil fuels traditionally used in refineries for on-site power generation.[82]

[81] Projects developed under the CDM can use ACM0012. One similar project has already been implemented in Argentina.
[82] The estimated unitary cost was US$1.4 million, covering the CCGT cost of $1.2 million and $.2 million for the recovery system and compressor (Sathaye and Phadke 2006).

Table 4.3.1: Installed Crude-oil Refining Capacity in Sub-Saharan Africa

Country	*No. of Plants*	*Distillation capacity (million BBls/day)*	*% Africa capacity*
Angola	1	0.04	1.20
Cameroon	1	0.04	1.30
Congo, Dem. Rep.	1	0.02	0.46
Congo, Rep.	1	0.02	0.65
Cote d'Ivoire	1	0.06	2.02
Eritrea	1	0.02	0.46
Gabon	1	0.02	0.53
Ghana	1	0.04	1.40
Kenya	1	0.09	2.80
Liberia	1	0.02	0.46
Madagascar	1	0.02	0.46
Nigeria	4	0.44	13.71
Senegal	1	0.03	0.84
Sierra Leone	1	0.01	0.31
Somalia	1	0.01	0.31
South Africa	4	0.47	14.64
Sudan	3	0.12	3.81
Tanzania	1	0.02	0.46
Zambia	1	0.02	0.74
Total	**27**	**1.50**	**100.00**

4.3.2 Quantitative Analysis

To evaluate the potential of such clean-energy CDM projects in Sub-Saharan Africa, the study team assumed that incondensable gases represent 2 percent of crude-oil feedstock in refineries and that 90 percent are recoverable using the technology implemented under the CDM project (consistent with AM055). The team also assumed that, without the CDM project, these incondensable gases would not be recovered, but would be flared (consistent with AM0055). For all of the refinery cases analyzed, heavy fuel oil was considered the baseline fuel for on-site power generation. Finally, it was estimated that the capital cost of the power plant and necessary ancillaries to use the otherwise flared gas would total about US$1.4 million per MW. Results of the study team's analysis are presented in table 4.3.2.

Table 4.3.2: Results Summary of CDM Opportunities: Waste-gas Recovery for On-site Power Generation in Sub-Saharan Africa

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$)		Electricity generation			Total installed power, country (MW)	Added power of projects (MW)		Total investment cost of projects (millions US$)
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	Projects (GWh/yr)	Projects (% country total)		90% load factor	% of total installed	
Angola	1	20.4	0.13	0.63	1.3	6.4	12.8	1,920	152.2	7.93	670	17.38	2.59	24.3
Cameroon	1	6.8	0.14	2.03	1.4	6.9	13.8	3,920	163.9	4.18	900	18.71	2.08	26.2
Congo, Dem. Rep.	1	2.4	0.05	2.08	0.5	2.5	4.9	5,400	58.5	1.08	2,591	6.68	0.26	9.4
Congo, Rep.	1	5.3	0.07	1.30	0.7	3.5	6.9	353	82.0	23.22	327	9.36	2.86	13.1
Côte d'Ivoire	1	6.4	0.16	2.42	1.6	7.8	15.5	4,620	253.7	5.49	1,260	28.96	2.30	40.6
Gabon	1	5.0	0.06	1.13	0.6	2.8	5.6	1,500	66.4	4.42	400	7.57	1.89	10.6
Ghana	1	6.7	0.15	2.22	1.5	7.4	14.8	5,360	175.6	3.28	1,310	20.05	1.53	28.1
Kenya	1	9.9	0.30	3.00	3.0	14.8	29.6	4,976	351.3	7.06	934	40.10	4.29	56.1
Liberia	1	0.5	0.05	9.31	0.5	2.5	4.9	--	58.5	0.00	955	6.68	0.70	9.4
Madagascar	1	2.5	0.05	1.94	0.5	2.5	4.9	820	58.5	7.14	186	6.68	3.60	9.4
Nigeria	4	105.2	1.45	1.37	14.5	72.3	144.6	20,700	1,713.5	8.28	5,890	195.60	3.32	273.8
Senegal	1	5.5	0.09	1.62	0.9	4.5	8.9	1,387	105.4	7.60	476	12.03	2.53	16.8
Sierra Leone	1	1.2	0.02	2.03	0.2	1.2	2.4	260	39.0	15.01	120	4.46	3.71	6.2
Somalia	1	0.8	0.02	3.18	0.2	1.2	2.4	270	39.0	14.46	80	4.46	5.57	6.2
South Africa	4	423.8	1.12	0.26	11.2	56.0	112.0	227,000	1,830.6	0.81	40,480	208.97	0.52	292.6
Sudan	3	10.8	0.40	3.72	4.1	20.1	40.2	3,900	476.2	12.21	760	54.36	7.15	76.1
Tanzania	1	4.0	0.04	0.90	0.4	1.8	3.6	3,150	58.5	1.86	860	6.68	0.78	9.4
Zambia	1	2.4	0.06	2.34	0.6	2.9	5.7	8,350	93.7	1.12	1,790	10.69	0.60	15.0
Total	**26**	**679.6**	**4.4**	**0.64**	**43.4**	**216.9**	**433.8**	**327,079**	**5,777**	**1.77**	**68,841**	**659**	**0.96**	**923**

Study results revealed 26 achievable projects at refineries in 18 countries across the region. These projects would allow for the recovery of 63,600 TJ of energy and avoid emissions totaling 4.3 million tCO_2 per year and 43 million tCO_2 in 10 years. The reduction in GHG emissions would represent an average of 0.19 percent of these countries' GHG emissions. Sold at US$5 per ton, the CERs would generate additional income estimated at US$217 million in 10 years. Sold at US$10, this income would increase to US$434 million. The projects would permit the generation of 5,777 GWh per year in the 18 countries where implemented through installations with a total capacity of 612 MW. This additional power capacity would represent 1.2 percent of current installed capacity and would cost US$930 million. In Republic of Congo, Senegal, and Madagascar the electricity generated by these projects would represent 23, 7.6, and 7 percent of respective national electricity production.

At this stage, it has not been possible to include an economic analysis of the cost effectiveness of the project opportunities inventoried in this study. This would require many economic comparisons of alternative technologies with conventional ones, requiring the collection of many additional data. But the two cases illustrated below, using data collected from projects that have been implemented in countries other regions, suggest that implementing waste-recovery projects in various types of industries can be economically meaningful when taking into account carbon revenues and thus worth considering (tables 4.3.3 and 4.3.4).

Table 4.3.3: Waste-heat Recovery for Power Generation in a Cement Factory

Parameter	*Value*	*Unit*
Industrial capacity (clinker)	2,500	1 clinker/day
New waste heat–based generation capacity	13.2	MW
Investment cost	16.3	million US$
New power production O&M cost	1.1	million US$
Electricity revenue	3.4	million US$
Price of CO_2	107,000	tCO2/yr
Carbon revenue	0.64	million US$
Total carbon revenue (3 * 7 years)	12.84	million US$
IRR without CERs revenue	17.8	%
IRR with CERs revenue	13.3	%

Table 4.3.4: Waste-gas Recovery for Power Generation in the Steel Industry

Parameter	*Value*	*Unit*
Production capacity (steel)	1.5	million tons/yr
Installed power capacity	50	MW
Investment cost	5.29	million US$
New power production O&M cost	1.7	million US$/yr
Electricity revenue	2.2	million US$/yr
Emission reductions	79,122	tCO_2/yr
Price of CO_2	3.0	US$/$tCO_2$
Carbon revenue	0.237	million US$/yr
Total carbon revenue (10 years)	2.37	million US$
IRR without CERs revenue	5.17	%
IRR with CERs revenue	9.84	%

4.3.3 Barriers to Implementation

Several key barriers are likely to inhibit the success of these clean-energy CDM projects in Sub-Saharan Africa: the small-scale capacity of many of the region's crude-oil refineries, low-capacity utilization at existing facilities, and lack of access to and knowledge about waste energy–recovery technologies. World-scale refineries have capacities of not less than 100,000 barrels of crude oil per day, and have in place deep refining technologies beyond primary crude-distillation technology. Such refineries are equipped with technologies and facilities for higher recovery of more light products from a barrel throughput of crude oil. Only 7 of the region's operating refineries can be classified as world scale: Nigeria (3), South Africa (3), and Sudan (1). All other refining capacities across the region considered what it termed "kettles." In an age of globalized supply of refined products, economies of scale do not favor production from kettles. Although many of these countries may continue to hold on to such facilities from a perspective of national supply security, the future supplies of refined products into these countries will be more economical as imports rather than domestic production. With regard to this issue, a study conducted by the African Development Bank (AfDB) (Dayo 1995) called for either the modernization of these refineries to world standard or their conversion to sub-regional storage depots for petroleum products. The inability to continue producing competitive supplies of petroleum products for the region may prevent the near-term implementation of waste heat–recovery projects in such existing facilities.

Another key barrier to project implementation is that many existing refineries in these countries run at low-capacity utilization. Improperly implemented maintenance has resulted in frequent breakdowns of facilities, resulting in high levels of product imports to meet domestic demand. The refining facilities in Nigeria exemplify this situation. Moreover, mechanical recompression—a widely used technology for handling waste gases before their use as a fuel in power generation—is not commonly found in Sub-Saharan Africa. While the indigenous capacity to handle such technology may not be trivial in many countries, without building such capacity, dependence on engineering and technical skills from external, developed nations may discourage the development of these types of CDM projects.

4.3.4 Mitigation Recommendations

The CDM can help to provide the needed technology for waste-gas recovery and use in the region's refineries. Because many refineries are owned by Annex 1 companies with emission-reduction commitments, the need for CERs can serve as an incentive for them to implement these clean-energy CDM projects. Thus, informing the region's refinery managers on opportunities provided under the CDM, coupled with discussion with decision makers at the parent company, can facilitate the implementation of these potential projects.

Thermal Use and Consumption

4.4 Improved Steam System

Steam is a common medium for heat exchange in process industries. Generally, when heat energy in steam is transferred in a process, the temperature of the process is controlled. Controlling the steam pressure enables the transfer of heat at the constant temperature of steam condensation. In this way, steam plays an important role in industrial operations. In many countries of Sub-Saharan Africa, steam is generated in fossil-fuel boilers and distributed to in-factory, end-use facilities.

4.4.1 Technical Evaluation

In most industries across Sub-Saharan Africa, steam generation-and-distribution systems are operated at low-level efficiencies. Typically, such systems are characterized by older, inefficient boilers; distribution subsystems either without steam traps or non-operative ones; venting of live steam; condensate lines that send live steam or hot water to the drain; and improperly lagged steam lines. These features suggest opportunities for improving the steam-system efficiency of the region's industries.

Several measures commonly considered to improve the energy efficiency of steam systems are 1) optimizing or redesigning the condensate return system, 2) improving steam distribution system and use, and 3) retrofitting or replacing older boilers. The first measure involves installation of condensate-treatment equipment to comply with boiler-feedwater requirements and reuse of the treated feedwater, thereby reducing the steam required to preheat the feedwater. Without the clean-energy CDM project, some condensate is collected but is too contaminated to be used as feedwater. The measure also involves recovery of the flash steam and heat from the condensate that cannot be reused, replacement of heat exchangers to improve heat exchange and avoid leakage and contamination, and the building of new condensate return lines. The second measure includes performing steam-trap surveys and implementing repairs and replacement recommendations, installing new steam traps where necessary and returning condensate to the boiler house, and conducting employee-education programs on steam energy efficiency. Taking these measures, along with the third measure and other related actions, usually results in the optimization of steam production and distribution, thereby reducing the amount of steam production needed to meet end-use requirements.

Implementing projects that cover these energy-efficiency measures results in reduced GHG emissions because, by saving steam, less fossil fuel is required to generate the steam needed to maintain the particular industry's baseline level of production. One example of a steam-system, energy-efficiency project, implemented in China by an American energy service company, involves the installation of 2,280 steam traps. The first phase of the project has resulted in 15,640 tons of coal equivalent saved per year, 40,000 tCO_2 avoided, and nearly US$200,000 in annual carbon revenue. Without the CERs, the project would have had an IRR of 41 percent; with the CERs, the IRR is 11 percent higher (52 percent) (box 4.4.1).

Box 4.4.1: Carbon Finance Benefits for Steam-efficiency Project in China

In Fushun, China, a bundled CDM project, prepared by an American energy service company specialized in steam-air and water systems, is being implemented for a set of petrochemical refineries and chemical industries (ethylene, acrylic-fiber, and detergent plants). The first phase of the project has covered 2,280 steam traps. The resulting benefits—steam and coal savings, CO_2 emission reductions, and corresponding carbon revenue—are presented in the table below.

Parameter	Value	Unit
Project cost	1.77	millions US$
Condensate recovered	585,000	tons/yr
Direct steam saved	45,000	tons/yr
Indirect steam saved	65,000	tons/yr
Total steam saved	110,000	tons/yr
Equivalent coal saved	15,643	tons of coal/yr
Project savings	0.8	millions US$/yr
Emission reductions	40,046	tons CO_2/yr
Carbon price	4.50	US$/$tCO_2$
Carbon revenue	180,209	US$/yr
Total carbon revenue (10 years)	1.80	millions US$
IRR without CERs revenue	41	%
IRR with CERs revenue	52	%

Sources: PINs and Project Design Documents

A second project phase, envisioned to improve the functioning of an additional 4,369 steam traps, will more than double the quantity of steam and coal saved (38,950 tons of coal per year) and double CO_2 emission reductions and resulting carbon revenue (99,700 tCO_2 per year and US$500,000 per year, respectively).

4.4.2 Quantitative Analysis

Using the 2003 energy database for the countries considered, the study team estimated the industrial steam energy for each country and calculated the fossil-energy savings that would be achieved when savings of about 15 percent in status-quo steam energy is reached via the steam-system, energy-efficiency project. Using each country's energy balance, an energy-balance equation was set up to estimate fuel-energy consumption for steam generation (box 4.4.2).

To estimate the number of steam-system, energy-efficiency CDM projects that could be developed in each country considered, the study team made the following assumptions:

- The steam-system, energy-efficiency CDM project will be implemented as a Program of Activities and
- Each of the component project activities does not have more than 60,000 tCO_2e emission reduction.

Box 4.4.2: Calculating Steam-system Energy Efficiency

The heat hended for steam generation in each country was calculated as follows:

$HSG_{i,y} = Є_i * β_i * FCIH_{i,y}$

where,

$HSG_{i,y}$ = energy in steam generated (GJ/yr) in country i during year y,

$Є_i$ = assumed average boiler efficiency for steam generation in country i,

$β_i$ = average fraction of industrial heating energy used to generate steam in country i, and

$FCIH_{i,y}$ = fossil fuel consumed (GJ/yr) for industrial heating in country i and year y.

Fossil-fuel consumption ($FCIH_{i,y}$) was estimated for each country as follows:

$FCIH_{i,y} = OI_{i,y} + CI_{i,y} + NGI_{i,y}$

where,

$OI_{i,y}$ = oil consumed (GJ/yr) in country I industry in year y,

$CI_{i,y}$ = coal consumed (GJ/yr) in country i industry in year y, and

$NGI_{i,y}$ = natural gas consumed (GJ/yr) in country i in year y.

Fossil-fuel consumption in the industries of each country was estimated as follows:

$OI_{i,y} = TO_{i,y} – OT_{i,y} – OEG_{i,y}$

$CI_{i,y} = TC_{i,y} – (f_{iC,y} * EG_{i,y} * 3{,}600)/(η_c * P_c)$

$NGIi, y = TNG_{i,y} – (f_{iG,y} * EG_{i,y} * 3{,}600)/(η_G * P_G)$

where,

$TOI_{i,y}$ = total oil consumed (GJ/yr) in country i in year y,

$TCI_{i,y}$ = total coal consumed (GJ/yr) in country i in year y,

$TNGI_{i,y}$ = total natural gas consumed (GJ/yr) in country i in year y,

$OT_{i,y}$ = oil consumed (GJ/yr) in country i transport sector in year y,

$OEG_{i,y}$ = oil used for electricity generation (GJ/yr) in country i in year y,

EGi,y = electricity generated (GWh) in country i in year y,

$f_{iC,y}$ = fraction of country i power generated using coal as fuel,

$f_{iG,y}$ = fraction of country i power generated using natural gas as fuel,

$η_c$ = average thermal efficiency of country i coal-fired power plants,

$η_G$ = average thermal efficiency of country I natural gas–fired power plants,

P_c = average gross calorific value of coal used for power generation (GJ/ton) in country I, and

P_G = average gross calorific value of natural gas used for power generation (GJ/million m^3) in country i.

Results of the simulation for a 15-percent savings in baseline steam energy are presented in table 4.4.1. The analysis indicated that about 17,860 TJ of energy would be saved in the countries studied if measures to improve steam energy efficiency were implemented. This savings in energy would lead to a reduction in GHG emissions estimated at 37 million tCO_2e per year. The study team estimated that some 211 CDM projects could be implemented in these countries.

Table 4.4.1: Results Summary of CDM Opportunities: Improved Steam-system Efficiency in Industries of Sub-Saharan Africa

Country	No. of projects	Country GHG emissions, 2005 (millions tCO_2/yr)	Projects' emissions reductions		Reductions over projects' 10-yr life span (millions tCO_2)	Value of projects' emissions reductions (millions US$)		Electricity generation	Total installed power, country (MW)
			millions tCO_2/ yr	% of country total		US$5/ tCO_2	US$10/ tCO_2	Country, 2003 (GWh/yr)	
Angola	7	20.4	0.2	1.13	2.3	11.5	23.1	1,920	670
Benin	2	2.3	0.1	2.78	0.6	3.2	6.3	240	71
Botswana	6	3.9	0.2	5.50	2.2	10.8	21.5	940	130
Burkina Faso	1	1.2	0.5	4.16	0.5	2.4	4.9	306	149
Burundi	1	0.4	0.0	4.94	0.2	1.0	2.0	148	40
Cameroon	3	6.8	0.1	1.45	1.0	4.9	9.8	3,920	900
Cape Verde	0	0.3	0.0	4.15	0.1	0.6	1.2	41	82
Central African Republic	0	0.3	0.0	4.48	0.2	0.8	1.5	104	38
Chad	0	0.2	0.0	2.11	0.0	0.2	0.4	92	40
Comoros	0	0.1	0.0	3.33	0.0	0.2	0.3	19	8
Congo, Dem. Rep.	5	2.4	0.2	6.85	1.6	8.1	16.2	5,400	2,591
Congo, Rep.	1	5.3	0.0	0.64	0.3	1.7	3.4	353	327
Côte d'Ivoire	1	6.4	0.4	5.94	3.8	19.1	38.2	4,620	1,260
Equatorial Guinea	12	4.9	0.3	6.22	3.0	15.2	30.3	28	13
Ethiopia	3	4.4	0.1	2.65	1.2	5.8	11.6	2,294	690
Gabon	2	5.0	0.1	1.44	0.7	3.6	7.1	1,500	400
Ghana	5	6.7	0.2	2.51	1.7	8.4	16.8	5,360	1,310
Guinea	2	1.4	0.0	3.82	0.5	2.6	5.1	775	254
Guinea Bissau	1	0.4	0.0	4.69	0.2	0.9	1.8	55	24
Kenya	5	9.9	0.2	1.83	1.8	9.0	18.0	4,976	934
Madagascar	2	2.5	0.1	2.72	0.7	3.5	6.9	820	186
Malawi	1	0.9	0.0	3.42	0.3	1.5	2.9	1,293	300
Mali	0	0.7	0.0	0.03	0.0	0.0	0.0	460	437
Mauritania	5	2.6	0.2	5.88	1.6	7.7	15.5	150	197
Mauritius	2	4.0	0.1	1.80	0.7	3.6	7.2	1,285	954
Mozambique	3	2.3	0.1	3.87	0.9	4.5	8.9	11,580	2,340
Namibia	3	9.8	0.1	1.03	1.0	5.1	10.1	1,460	300
Niger	1	1.2	0.0	1.82	0.2	1.1	2.2	205	122
Nigeria	20	105.2	3.0	2.89	30.4	152.2	304.3	20,700	5,890
Rwanda	1	0.8	0.0	5.10	0.4	2.0	4.0	113	29
Senegal	2	5.5	0.0	0.95	0.5	2.6	5.2	1,387	476
Sierra Leone	0	1.2	0.0	1.06	0.1	0.6	1.2	260	120
Somalia	0	0.8	0.0	0.88	0.1	0.3	0.7	270	80
South Africa	74	423.8	29.7	7.02	297.4	1,486.8	2,973.5	227,000	40,480
Swaziland	2	1.1	0.1	7.72	0.9	4.4	8.8	460	130
Tanzania	4	4.0	0.1	3.33	1.3	6.6	13.2	3,150	860
Togo	2	2.4	0.1	2.61	0.6	3.1	6.2	97	215
Uganda	1	1.6	0.0	2.71	0.4	2.2	4.4	1,928	300
Zambia	3	2.4	0.1	4.22	1.0	5.2	10.3	8,350	1,790
Zimbabwe	15	11.8	0.6	4.95	5.8	29.2	58.3	8,880	1,960
Total	**211**	**679.6**	**36.6**	**5.39**	**366.4**	**1,831.8**	**3,663.6**	**327,079**	**68,841**

4.4.3 Barriers to Implementation

The most important barrier to the implementation of improved steam-system, energy-efficiency projects under the CDM in Sub-Saharan Africa is the absence of a maintenance culture in most of the countries considered. The industrial settings of many countries lack adequate preventive maintenance. The regular maintenance specified by equipment manufacturers to ensure sound performance is rarely included in the production cycle. Production boundaries are stretched thin, and required production often must continue until equipment failure occurs. For example, it is not uncommon to find dilapidated steam-line laggings that should have been replaced years earlier still in use, resulting in high radiative losses. When steam traps malfunction, they are often not repaired or replaced; as a result, condensate are routinely released into drainage lines, causing the loss of considerable amounts of enthalpy that should have been put into productive use.

4.4.4 Mitigation Recommendations

The above-described barriers can be overcome through better dissemination of technical information and training of the staff responsible for the operation and maintenance of energy-related equipment. The carbon funds earned by implementing such projects under the CDM framework can help to fund these activities. Under the CDM, inadequate access to spare parts—a major barrier to ensuring timely, regular maintenance at industrial facilities—can be overcome by including a provision in the Emission Reduction Purchase Agreement that links guaranteed spare-parts availability with an Annex 1 purchaser of the resulting carbon credits, who has an interest in the sustainability and guaranteed measurability of the emission reduction. One can easily envision steam-trap CDM projects implemented with Annex 1 participants as partners that provide direct access to needed spare parts for preventive maintenance, receiving, in return, CERs from the proposed project activities.

4.5 Reduced Clinker Use in Cement Manufacturing

The use of blended cement has become common practice in parts of Asia, but has not been adopted widely in Sub-Saharan Africa. Given that the cement sector is an important global source of GHG emissions, implementing blended-cement projects in Sub-Saharan Africa can add value to global efforts to reduce emissions. Table 4.5.1 lists selected blended-cement projects registered in the UNFCCC pipeline.

Over the past two years, many such projects in non-Annex 1 countries (e.g., India) have been registered in the UNFCCC validation pipeline and are currently earning carbon credits. But recently, there has been a lull in registering submitted projects because of a lack of clarity on how to interpret certain sections of the relevant approved methodology (ACM0005). Specifically, the use of barriers to prove additionality of many projects that have undergone the registration process has raised the need to complement these barriers with investment analysis to screen out common-practice projects that would have been implemented without the CDM framework.

Table 4.5.1: Projects Registered in UNFCCC Validation Pipeline Using ACM0005

Registration date	*CDM project title*	*Location*	*Capacity (MW)*	*Average emission reduction (tCO_2e)*
Dec. 11, 2007	Shanxi Yangcheng Coal Mine Methane Utilization Project	Yangcheng, China	16.5 + 1,380 households	423,195
Oct. 08, 2007	Shanxi Liulin Coal Mine Methane Utilization Project	Jinjiashuang Xingui and Liulin, China	12	318,166
Sept. 24, 2007	Jingxi Fengcheng Mining Administration CMM Utilization Project	Fengcheng, China	7.5	190,378
May 22, 2007	Yangquan Coal Mine Methane Utilization for Power Generation	Shanxi Province, China	90	2,136,174
March 31, 2007	Pansan Coal Mine Methane Destruction Project	Pansan, China	8.4 + 4,000 households	126,233
Feb. 18, 2007	Huabei Haizi and Luling Coal Mine Methane Utilization Project	Haizi and Luling, China	16.5	296,278

4.5.1 Technical Evaluation

Cement, a major industrial commodity, is produced in many countries across Sub-Saharan Africa. The cement industry is an important source of GHG emissions and thus a good candidate for strategies to reduce CO_2 emissions. According to available statistics, in 2004, about 21.8 million tons of cement were produced in 21 countries across the region. Most of the cement produced was Ordinary Portland Cement (OPC), which results from the calcination of limestone and silica in the following reactions:

- limestone + silica (1,450ºC) = clinker + carbon dioxide
- clinker ground with gypsum (95:5 % ratio by weight) = OPC + carbon dioxide

In both reactions—electricity used in the kiln or in grinding raw materials and clinker with gypsum—CO_2 is released. In cement production, CO_2 is released during high-temperature calcination of carbonates in the raw materials in the kiln, from fuel combusted in the kiln to produce energy for the calcinations reaction, and from electrical energy used in the kiln for raw materials and cement grinding. A significant proportion of the GHG released during the production of OPC cement results from the calcinations reaction.

Strategies to reduce GHG emissions from cement production mainly involve reduction of clinker-production CO_2 emissions and improved energy efficiency of the cement-production process. One proven technique for reducing CO_2 emissions is by producing cement that uses a smaller quantity of clinker than OPC while retaining strength and other OPC characteristics. Cement with such features is referred to as blended cement. Blended cement is produced by increasing the proportion of additives, such as limestone, pozzolana, and fly ash in the fine grinding process, thereby reducing the clinker content. The implication is that, for each ton of cement, less clinker is required and thus less raw material to be calcinated, resulting in lower CO_2 emissions.

4.5.2 Quantitative Analysis

Box 4.5.1 shows the quantitative relationships used to evaluate the potential for implementing blended-cement production as CDM projects in Sub-Saharan Africa. Using these equations and the identified Portland cement works in the region, the study team quantified their potential for emission reduction as CDM projects. Since micro-level data on production was unavailable in the literature for implementing a comprehensive, bottom-up approach for the region, the study team made a series of assumptions. It assumed that all of the countries analyzed produced only OPC, with a 95-percent clinker content. For the blended cement produced under the CDM projects, the study team assumed a 75-percent clinker content. For each country analyzed, the ratio for ton of raw material to ton of cement was 1.54, while the $CaCO_3$ equivalent to the raw-material ratio was 78 percent. For all countries, a CO_2-to-$CaCO_3$ stochiometric ratio of 44 percent was used in the analyses.

With regard to the CAPEX for this type of project, it was assumed that additional mobile and stationary crushers would be purchased and warehousing facilities invested in to handle the increased volume of additives. Investments would be made in mill feeders, conveyors, and loading machines. In addition, the new blended cement would require expenditures related to registering the new standard and initial marketing. Finally, a specific cost of US$4.62 per ton of cement, used in a recent blended-cement project in Nigeria (Triple "E"/ICF Consulting UK 2007), was applied to estimate the CAPEX for the potential projects.

Based on the above-mentioned assumptions, the study team developed a spreadsheet calculation schedule to estimate the GHG emission reductions achievable if blended cement were introduced in all of the countries considered, and all of the cement-production facilities shifted from OPC to blended-cement production (table 4.5.2).

Box 4.5.1: Calculating the Potential of Blended-cement Production

For a candidate cement plant producing Ordinary Portland Cement (OPC), the study team calculated the baseline emission as follows:

$BEF_{i,y} = BCCR_{i,y} * RMClink_{i,y} * CCRM_{i,y} * MW_{CO2}/MW_{CaCO3}$
$BEi,y = PCPi,y * BEF_{i,y}$

where,

$BEF_{i,y}$ = baseline emission factor (tCO_2e/ton of clinker),
$BCCR_{i,y}$ = baseline clinker to cement ratio,
$RMClink_{i,y}$ = tons of raw materials per ton of clinker,
$CCRM_{i,y}$ = fraction content of $CaCO_3$ in raw materials,
MW_{CO2} = molecular weight of CO_2 (44),
MW_{CaCO3} = molecular weight of $CaCO_3$ (100),
PCPi,y = production of project cement (OPC) (tons/yr), and
BEi,y = baseline emissions (tCO_2e/yr).

The study team calculated the project emissions resulting from converting the production facility from OPC to blended cement as follows:

$PEF_{i,y} = PCCR_{i,y} * RMClink_{i,y} * RMClink_{i,y} * MW_{CO2}/MW_{CaCO3}$
$PE_{i,y} = PCP_{i,y} * PEF_{i,y}$

where,

$PEF_{i,y}$ = project emission factor (tCO_2e/ton of clinker),
$PCCR_{i,y}$ = project clinker to cement ratio, and
$PE_{i,y}$ = project emissions (tCO_2e/yr).

For simplicity, the study team assumed that leakage emissions, defined as GHG emissions outside the project boundary resulting from project implementation were negligible.

Annual emission reductions ($ER_{i,y}$) in tCO_2e/yr were then calculated as:

$ER_{i,y} = BE_{i,y} – PE_{i,y}$

Table 4.5.2: Results Summary of CDM Opportunities: Shift from OPC to Blended-cement Production in Sub-Saharan Africa

Country	No. of projects	OPC production, 2004 (tons/yr)	Projects' emissions reductions (tCO_2/yr)	Capital cost of projects (millions US$)
Angola	1	250,000	26,426	1.16
Benin	3	250,000	26,426	1.16
Cameroon	1	900,000	95,135	4.16
Congo, Dem. Rep.	1	190,000	20,084	0.88
Côte d'Ivoire	1	650,000	68,709	3.01
Ethiopia	4	1,200,000	126,847	5.55
Gabon	1	350,000	36,997	1.62
Ghana	2	1,900,000	200,841	8.79
Guinea	1	360,000	38,054	1.67
Kenya	3	1,537,000	162,470	7.11
Malawi	1	190,000	20,084	0.88
Mozambique	1	362,000	38,265	1.64
Mauritania	1	110,000	11,628	0.51
Nigeria	5	3,173,000	335,372	14.67
Rwanda	1	115,000	12,156	0.53
Senegal	2	3,250,000	343,543	15.03
Sierra Leone	1	170,000	17,970	0.79
South Africa	4	8,883,000	938,983	41.08
Sudan	1	320,000	33,826	1.48
Tanzania	3	1,186,000	125,367	5.48
Togo	2	800,000	84,564	3.70
Uganda	2	505,000	53,381	2.34
Zambia	1	480,000	50,739	2.22
Zimbabwe	1	400,000	42,282	1.85
Total	**44**	**27,531,000**	**2,910,149**	**127.32**

Results of the analysis showed that 44 blended-cement, CDM projects could be developed in 24 countries using ACM0005. When packaged, these projects would yield a total emission reduction of 2.9 million tCO_2 per year. An estimated US$127 million would be needed to implement these projects.

4.5.3 Barriers to Implementation

The main barriers to reduced clinker use in cement manufacturing across Sub-Saharan Africa involve consumer acceptance of blended cement as a substitute for OPC, technical and human-resource capacities, and research capabilities and facilities. Consumers have long used OPC, which dominates cement markets across the region. Their aversion to switching from OPC to blended cement is based on the erroneous perception that blended-cement quality and strength are inferior those of OPC. In addition, many countries lack the technology and human resources required to provide quality assurance regarding the clinker in blended cement. The added investment and extra effort required for building technical capacity and skills are often perceived by cement companies as a burden on normal operations. In addition to having to acquire and install new equipment, launching a blended-cement project usually requires a research-and-development effort. The extensive pre-market testing that is needed—both internal and external—may discourage project implementation.

4.5.4 Mitigation Recommendations

To facilitate the introduction of blended cement into Sub-Saharan Africa's markets and implement such activities as CDM projects, the first step is to work with national (or international) organizations to put national standards in place for blended cement.

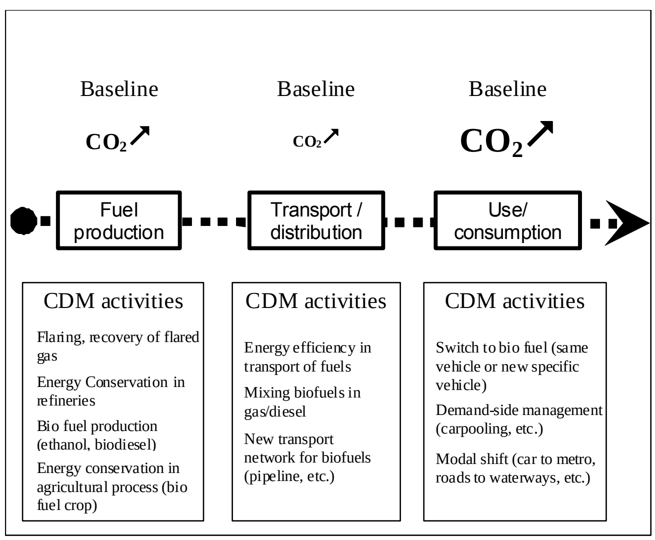
Introducing national standards should be done within each country's existing legal and regulatory framework. To enhance the success of such projects, a promotion program is needed to encourage consumer acceptance of blended cement as the perfect replacement for OPC in most applications. In addition, capacity building must be integrated into such projects to increase factory workers' technical know-how, and regional- and country-level, cement-research capabilities must be developed.

Chapter 5

Fuels for Vehicles

The two technologies highlighted in this chapter are related to fuel production from Jatropha biodiesel and more efficient vehicular consumption and use via the shift to bus rapid transit (BRT). Figure 5.1 shows the physical distribution of potential activities for Sub-Saharan Africa along the fuels-for-vehicles subsector production chain; the accompanying list of UNFCCC approved methodologies is illustrative of the clean energy CDM opportunities.

Figure 5.1: CDM Opportunities along the Fuels-for-Vehicles Production Chain



Fuel production	Transport/ distribution	Consumption/ use
Biofuel production AMS-III.O, AMS-IIIT AM0047	***Energy efficiency in transport*** AM0031	***Switch to biofuels (same or new vehicle)*** AMS-III.C, AMS-III.S
Flaring, recovery of flared gas	***Mixing biofuel in gas/diesel***	***Demand-side management***
Energy-efficient refineries	***New distribution network for biofuels***	***Modal shift (car to metro)***

Production

5.1 Biodiesel from Jatropha

Biofuel's potential to power diesel engines was first demonstrated a century ago, when Rudolf Diesel successfully ran an engine on peanut oil. While research into biofuel production from various feedstock is ongoing, the supply of biodiesel feedstock from soybean, rapeseed, and other options is limited by competition for other uses, such as food, as well as land constraints for planting. In this context, Jatropha, which is not a food crop—neither its fruit nor seed is edible—offers a more favorable option as a key feedstock for biodiesel production.[83]

Said to have originated in the Caribbean, *Jatropha curcas* was first planted in Sub-Saharan Africa by Portuguese seafarers in Cape Verde and Guinea Bissau. Today Jatropha is grown in many countries across the subcontinent. The plant is commonly used for fencing around homesteads, gardens, and fields because it is not browsed by animals.[84] Because no part of the Jatropha plant is used for food, there is inherently less price volatility. In addition, Jatropha can be grown year-round in most types of soils, even arid ones. Because abundant yields can be obtained from small plots, valuable cropland is not displaced. Beyond these advantages, pilot studies show that, compared to food-energy crops commonly used as biodiesel feedstock (e.g., corn, soybean, peanut), Jatropha has a higher oil yield per hectare.

5.1.1 Technical Evaluation

As discussed in section 3.7, it has been difficult to develop a reliable CDM methodology for biofuels. Some biofuel analyses have not supported the common notion of its carbon neutrality, especially when such analyses cover the cradle-to-grave cycle. In addition, shifting pre-project activities as a result of the biofuel project activity may nullify some of the emission-reduction claims. Furthermore, if the CDM project causes deforestation in a vegetation-rich ecosystem, emission-reduction claims may be questionable. Finally, biofuel feedstock that is also a food commodity tends to create an upward pressure on food prices and negatively affect sustainable development.

In its evaluation of Jatropha, the study team assumed that the plant would be cultivated on degraded lands to ensure that pre-project shifting of activities is minimized. By limiting cultivation to degraded lands, deforestation is not an issue (i.e., potential depletion of valuable forest resources that contribute to carbon sequestration). In its top-down analyses, the study team did not include the GHG sequestration that would occur as a result of Jatropha cultivation on degraded land in its emission-reduction estimates; the team further assumed that emissions resulting from agricultural practices (e.g., application of fertilizers and mechanical tillage) would be negligible.

[83] Section 3.7 of this report focuses on the potential use of Jatropha oil as a substitute fuel for petro-diesel to run diesel gensets in Sub-Saharan Africa. The dearth of approved CDM methodologies for this type of clean-energy project and reasons for its non-availability in the UNFCCC project pipeline were discussed.
[84] Details are available at www.jatrophaworld.org.

The scenario for this potential CDM project opportunity included the following elements: cultivation and harvesting of Jatropha on 2 percent of land in each country; extraction and trans-esterification of crude Jatropha oil to produce refined oil (B100); and blending of B100 as an equal replacement of petro-diesel to produce B20, containing up to 20-percent blend (the level at which no engine modification is required) as domestic fuel for existing stock of diesel autos.

5.1.2 Quantitative Analyses

Box 5.1.1 shows the quantitative relationships used to evaluate the potential use of Jatropha bio-diesel as a component in B20 transport fuel implemented as CDM projects in Sub-Saharan Africa. In this context, B20 was defined as a blend of 80-percent petro-diesel and 20-percent biodiesel by volume. In most of the countries considered, the amount of bio-diesel produced from dedicating 2 percent of degraded land to Jatropha cultivation for this purpose exceeds the amount needed for the blending of B20 transport fuels. The remainder can be used as a replacement fuel for petro-diesel power generation in new and existing facilities, as a fuel in residential and commercial sectors, and for export to other demand centers, such as Europe.

Based on these equations, a spreadsheet analysis was used to simulate the characteristics of a plan to produce bio-diesel from Jatropha via the appropriation of 2 percent of degraded land in each country. The simulation estimated the quantity of Jatropha bio-diesel that can be produced from this land-area appropriation, the amount of petro-diesel that can be displaced when part of the bio-diesel is blended into B20 fuel for the transport sector, the resulting emission reductions achievable in each country, the capital cost for the CDM project, and the number of potential projects in each country.

In the simulation, it was assumed that Jatropha plantations are 10,000-ha units. The capital cost for plantation implementation, including extraction of pure Jatropha oil, was estimated at US$750,000 per 1,000 ha (CJP 2007a, b), while the capital cost of the bio-diesel production plant was estimated at US$150 per ton of Jatropha oil produced (CJP 2007c). The maximum capacity assumed for each Jatropha crude-oil processing plant was 100,000 tons per year. A CDM project was assumed to equal a single bio-diesel production facility with a processing capacity of 100,000 tons or less per year, together with its ancillary Jatropha cultivation.

Box 5.1.1: Calculating the Potential of Jatropha Oil for Bio-diesel Production

For each country considered, the study team calculated the quantity of bio-diesel from Jatropha oil produced and the quantity of Jatropha bio-diesel that displaces petro-diesel in the B20 fuel as follows:

$QJOP_{i,y} = CAi,y * PDLi,y * YJOi,y/(DJO * CF * 1000)$

$QJB_{20,I,y} = QPDi,y * FRTi,y * B_{20}F$

where,

$QJOP_{i,y}$ = quantity of Jatropha oil (bio-diesel) produced (BBls/day) in country i in year y,

CA_i = country i land area (ha),

PDLi,y = percentage of degraded land in country i,

YJOi,y = Jatropha oil yield (tons/1,000 ha/yr), from cultivation through processing, DJO = density of Jatropha bio-diesel (tons/barrel of oil),

CF_{JP} = capacity factor for Jatropha production (days/yr),

$QJB_{20,I,y}$ = quantity of Jatropha bio-diesel that displaces petro-diesel in B20 (BBls/day),

QPDi,y = quantity of petro-diesel consumed in country i in year y (BBls/day),

FRTi,y = fraction of petro-diesel consumed in country I in the transport sector in year y, and

$B_{20}F$ = volume fraction of petro-diesel displaced in B20.

A scenario in which excess biofuels are produced on degraded land committed to the CDM project was estimated as follows:

$EQJO_{i,y} = QJOP_{i,y} – QJB_{20,I,y}$

where,

$EQJO_{i,y}$ = excess biofuel remaining after B20 blending needs are met (BBls/day).

The emission reduction resulting from the displacement of petro-diesel that would have been used without the project was calculated as follows:

$ER_{i,y} = QJB_{20,I,y} * CF_{TS} * EF_{DMT}$

where,

$ER_{i,y}$ = emission reduction (tCO_2e/yr),

CF_{TS} = capacity factor of diesel-transport facility features of the country (days/yr), and

EF_{DMT} = emission factor of diesel combustion in mobile sources (tons/BBl).

Results of assessing the potential of B20 transport fuel (produced from a blend of refined Jatropha oil and petro-diesel) as potential CDM projects in the 37 countries considered are presented in table 5.1.1.

Table 5.1.1: Results Summary of CDM Opportunities: Production of B20 Blended Bio-diesel from Jatropha

Country	No. of projects	Quantity of Jatropha oil produced (thousand BBls/day)	Quantity of Jatropha oil blended in B20 transport fuel (thousand BBls/day)	Emission reduction achievable (thousand tCO_2e/yr)	Cost of projects (millions US$)
Angola	40	82.51	3.29	520.6	2,142
Benin	4	7.45	0.47	74.6	193
Burkina Faso	9	18.15	0.31	49.1	471
Botswana	19	38.74	0.91	144.3	1,006
Cameroon	15	31.07	1.37	217.6	806
Central African Republic	20	41.23	0.09	14.4	1,070
Chad	40	83.37	0.09	14.3	2,164
Congo, Dem. Rep.	72	150.07	0.88	139.0	3,896
Congo, Rep.	11	22.60	0.50	79.2	587
Côte d'Ivoire	10	21.34	1.36	215.8	554
Equatorial Guinea	1	1.86	0.10	16.4	48
Ethiopia	36	74.10	2.50	395.9	1,924
Gabon	8	17.05	0.86	136.3	443
Ghana	7	15.22	3.11	492.5	395
Guinea	8	16.27	0.34	53.8	422
Guinea Bissau	1	2.39	0.10	15.1	62
Kenya	18	37.67	3.35	530.5	978
Madagascar	19	38.85	0.50	79.6	1,009
Malawi	4	7.84	0.48	76.8	204
Mali	39	82.07	0.16	25.2	2,130
Mauritania	33	68.21	0.93	146.7	1,771
Mozambique	25	51.89	1.43	226.7	1,347
Namibia	26	54.49	1.49	235.9	1,414
Niger	40	83.85	0.21	32.7	2,177
Nigeria	29	60.28	7.50	1,187.8	1,565
Rwanda	1	1.65	0.33	52.2	43
Senegal	6	12.98	0.85	134.8	337
Sierra Leone	2	4.74	0.43	68.7	123
Somalia	--	--	--	--	--
South Africa	39	80.81	23.14	3,665.9	2,098
Sudan	76	157.28	5.65	895.7	4,082
Swaziland	1	1.14	0.24	37.7	30
Tanzania	28	58.64	2.16	342.0	1,522
Togo	2	3.76	0.29	45.9	98
Uganda	6	13.22	0.74	118.0	343
Zambia	24	49.02	0.94	149.5	1,273
Zimbabwe	12	25.59	1.11	175.0	664
Total	**771**	**1,602.40**	**68.92**	**10,918.3**	**41,596**

As the results in table 5.1.1 illustrate, bio-diesel production from Jatropha offers robust opportunities for implementing CDM projects in countries across Sub-Saharan Africa. It is estimated that, if 2 percent of degraded land in each of the 37 countries considered is used to cultivate Jatropha for bio-diesel production, about 1.6 million barrels (B100) could be produced per day. If 4.3 percent of this bio-diesel is used to substitute for 20 percent of the diesel consumed in a B20 blend of transport fuel (based on 2003 figures), an annual emissions reduction of about 10.9 million tons of CO_2 could be achieved if these activities are implemented as CDM projects. The remainder of the B100 produced from the dedicated development of Jatropha plantations (2 percent of land area) could be used to generate power in existing diesel-generation facilities, as a fuel in Greenfield power-generation projects, in other energy end-use applications, and exported. About 154,000 tons of glycerin co-product could also be produced in this project scenario, yielding added benefits and revenues for project participants.

5.1.3 Barriers to Implementation

Despite its many inherent advantages, Jatropha faces various challenges that may inhibit the success of a sustainable Sub-Saharan Africa bio-diesel program, given the quantity of Jatropha oil required. First, the subsistence nature of rainfed agriculture across the region does not involve the optimal use of fertilizers, which require mechanization to achieve high yields per hectare; thus, it would be difficult for organized Jatropha farming to achieve yields in excess of 1 ton per ha. The key issue is selecting farming techniques to facilitate Jatropha bio-diesel production that can compete with petrol-diesel to make the substitution economic and hence sustainable. In most countries of Sub-Saharan Africa, Jatropha cultivation in formal farm lots is a recent phenomenon (with a few exceptions, including Malawi). In many of these countries, Jatropha has not been grown in the past for its economic or food value. Little attention has been paid to techniques that can promote sustainable Jatropha farming. But the historically weak extension-service focus on Jatropha is changing as the plant gains recognition as a feedstock for bio-diesel production.

Second, most countries in Sub-Saharan Africa lack technical know-how in Jatropha oil extraction and bio-diesel processing. The oil must first be extracted from the seeds and pre-processed to yield clear pure plant oil (PPO). Dissemination of the PPO extraction technology has gradually begun in a few countries. But the speed of technology dissemination and assimilation will need to accelerate in more countries if a sustainable, continent-wide supply axis is to be developed. The African bio-diesel supply activities—from PPO extraction to trans-esterification technology—cannot play its expected role if a traditional turnkey approach is taken that imports technology. In short, the region's low technical capacity may constitute a barrier to the global role expected from the Jatropha bio-diesel route.

Third, many countries lack adequate infrastructure and logistics to handle the expected volume of bio-diesel. Only such countries as Malawi have a tradition of making oil from seeds in rural oil mills (these can easily be adapted to Jatropha). It has been reported that small-scale processing of raw Jatropha oil into bio-diesel already exists in that country. The recent introduction of the Multi-Functional Platform (MFP), through which PPO from Jatropha will be used as a fuel, is extending such experience to more countries. For the African program to perform the global role as a major supplier of bio-diesel from Jatropha, larger-scale plants involving partnerships with more technologically advanced countries will likely be needed. Handling large volumes of oil within countries; oil transport, storage, drying, and blending; engine conversion; and processing-technology needs all require considerable efforts that may be beyond the capacity of many of these nations. A related challenge involves the cost of transporting bio-diesel from the factory to the plant where it is blended with petro-diesel. The bio-diesel factory is generally located near the plantation, while blending usually occurs at a refinery located far away. Logistics in terms of cost can constrain even a modest program.

A fourth likely barrier is the weak institutional infrastructure prevalent in many countries across the region. A reliable institutional framework for project coordination and management is essential to success.

Finally, the African bio-diesel program's expected level of Jatropha cultivation requires proper irrigation and, in many cases, fertilizers to achieve optimum yields. Although Jatropha requires less water than other biofuel feedstock (e.g., sugarcane and soybean), water for the required level of irrigation may become a constraining factor, especially in arid countries or areas facing water scarcity. In such cases, water use and yield response to droughts can be critical to success. Water for Jatropha irrigation may have to compete with irrigation of other food crops and even drinking water. A recent study on Jatropha cultivation in India observed that energy crops, particularly perennials, often have high water use due to their long growing season and deep rooting system. Therefore, water use is a decisive factor in the sustainability of Jatropha for energy use. The study concluded that an understanding of Jatropha's annual water-use structure, respiration losses, and needs in different root zones is not yet properly established. All of what is known is that Jatropha sheds all its leaves with severe water shortages. This observed phenomenon implies that, in order to thrive with appreciable yield, Jatropha requires adequate irrigation, especially when cultivated in areas prone to water shortages. It is therefore important that an accurate annual water balance be established to determine irrigation frequency in order to achieve the required yield levels.

5.1.4 Mitigation Recommendations

To achieve sustainable Jatropha farming in Sub-Saharan Africa, information on optimal inputs and other factors that enhance crop yield in both organized plantations and small-holder farms is needed regularly within an agricultural extension framework. Such data is currently unavailable in most of these countries since Jatropha has not previously been used as a food or cash crop. Given the importance of this data set, international and local agricultural research institutes, as well as universities, should be funded to generate these data through focused agricultural research. Sustainable agricultural-extension services focused on Jatropha cultivation must be established to catalyze best practices to enhance productivity in each country. In addition, infrastructure for handling the expected large volumes of bio-diesel produced—from storage facilities to fuel pumping and transfer stations and piping systems—must be put in place. Finally, adequate institutional infrastructure must be put in place in each country for appropriate organization, management, and regulatory and performance evaluation of biofuel-industry activities.

Consumption and Use

5.2 Shift to Bus Rapid Transit

In December 2006, the first Bus Rapid Transit (BRT) project was registered in the UNFCCC repository.[85] Entitled BRT Bogota, Columbia: TransMilenio Phase II to IV, the project is characterized as being capable of achieving an average of slightly more than 246,000 tCO_2e per year during its first crediting period. The core aspects of this project, summarized in the Project Design Document,[86] describe BRT as a new infrastructure

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[85] BRT projects can use AM0031.
[86] This document is publicly available at www.unfccc.int.

consisting of dedicated lanes, large-capacity buses, and elevated bus stations to allow for fast boarding and pre-board ticketing. Smaller buses offering feeder services to the main stations are integrated into the system. The integrated fare system allows for free transfers. Instead of small independent enterprises competing at a bus-to-bus level, this improved system has a consolidated structure with formal enterprises competing for concessions. Centralized, coordinated fleet control provides monitoring and communications to schedule services and respond to real-time contingencies. Finally, a scrappage program—TransMilenio retires more than 9,000 buses or more than one-third of all conventional buses from the existing fleet—reduces the risk of declining efficiency (load factor) in the remaining system.

An evaluation of these various components shows that the BRT project can rejuvenate the system infrastructure for optimal efficiency. If properly planned and implemented, many project features can be applied to revamping the public transport systems of cities across Sub-Saharan Africa. In this context, the study team took an approach suggesting that a project such as the Bogota BRT can and should be replicated in cities of Sub-Saharan Africa that have experienced or are beginning to be affected by traffic congestion and its negative effects on economic productivity.

5.2.1 Technical Evaluation

Traffic congestion usually results when many vehicles are plying a road infrastructure that lacks the capacity to permit easy traffic flow; that is, traffic demand is greater than road capacity. In extreme traffic congestion (i.e., traffic jam), vehicles are fully stopped for periods of time. Traffic congestion is common in most of the region's large urban cities. From an energy perspective, traffic jams represent the use of more transport fuels than would otherwise be required. It is well known that sound traffic management, coupled with road network planning, can reduce existing traffic jams and thus the fuel consumed from vehicle idling, acceleration, and braking in such situations. The BRT system, which provides for a bus corridor with dedicated lanes, timely schedules, and an uncongested network, is another good approach for reducing traffic congestion and the inefficient use of energy in urban road transport.

BRT is a broadly defined term applied to a variety of transport systems that, via improved infrastructure, vehicles, and scheduling, attempt to use buses to provide a service of higher quality than an ordinary bus line. Each BRT system uses its own set of improvements, many of which are shared by other BRT systems. The system's goal is to approach the service quality of rail transit while enjoying the cost savings of bus transit.

To evaluate the potential of BRT as CDM projects in countries of Sub-Saharan Africa, the study team made a series of assumptions. For any country lacking specific data, the study team assumed that the transport sector consumes 55-percent of a country's total consumption of petroleum fuel. The percentage is based on the average transport-sector consumption level for 14 countries (table 5.2.1).

Table 5.2.1: Transport-sector Consumption of Petroleum Fuel in Selected Countries

Country	*% transport fuel**
Benin	65
Burkina Faso	46
Cap-Verde	39
Côte d'Ivoire	59
Guinea	40
Guinea Bissau	41
Mauritius	52
Mali	73
Mauritania	59
Niger	94
Senegal	52
Chad	40
Togo	40
Nigeria	73
Average	**55**

* % of total country consumption.

The study team also assumed that consumption of petroleum fuels in the road transport subsector accounts for about 85 percent of the total petroleum fuels consumed in the sector for all countries in the region. It was assumed that large cities represented at least 70 percent of the fuel consumed in road transport. In addition, only cities with populations of 500,000 or more would be qualified for the BRT project. In countries without such a large populous, it was assumed that BRT would be implemented in that country's largest city. Using available population data, the study team quantified the minimum number of qualifying cities for BRT projects under the CDM (table 5.2.2).[87]

[87] For larger cities with populations of more than 1 million, multiple BRT projects could be implemented.

Table 5.2.2: Qualifying Cities in Sub-Saharan Africa for BRT CDM Projects

Country	No. of CDM projects	City	Population
Angola	1	Luanda	898,000
Botswana	1	Gaborone	186,007
Cameroon	2	Douala, Yaounde	1,494,700; 1,248,200
Chad	1	Njamena	818,600
Congo, Dem. Rep.	4	Kinshasa, Lubumbashi, Mbuji Mayi, Kananga	7,273,947; 1,283,380; 720,362; 682,599
Congo, Rep.	2	Brazzaville, Point Noire	1,174,000; 663,400
Côte d'Ivoire	2	Abidjan, Bouake	3,548,400; 569,200
Equatorial Guinea	1	Malabo	60,065
Ethiopia	1	Addis Ababa	2,973,000
Gabon	1	Libreville	419,596
Ghana	2	Accra, Kumasi	1,658,937; 1,170,270
Kenya	2	Nairobi, Mombassa	2,845,400; 828,500
Lesotho	1	Maseru	137,837
Malawi	2	Blantyre, Lilongwe	778,800; 744,400
Mozambique	1	Maputo	989,386
Namibia	1	Windhoek	233,525
Nigeria	12	Lagos, Kano, Abuja, Ibadan, Kaduna, Benin City, Port Harcourt, Maiduguri, Zaria, Ilorin, Jos, Aba	5,195,247; 2,166,554; 1,900,000; 1,835,300; 993,642; 762,719; 703,421; 618,278; 612,257; 532,089; 510,300; 500,183
Rwanda	1	Kigali	603,049
Sierra Leone	1	Freetown	772,873
South Africa	9	Johannesburg, Cape Town, Durban, East Rand, Pretoria, Port Elizabeth, Vereeniging, Bloemfontein, East London	3,192,611; 2,871,844; 2,726,257; 2,449,744; 1,780,716; 976,457; 652,299; 607,199; 512,418
Sudan	3	Umm Durman, Khartoum, Khartoum Bhari	1,271,403; 947,483; 700,887
Tanzania	1	Dares Salaam	2,339,910
Uganda	1	Kampala	1,189,142
Zambia	1	Lusaka	1,084,703
Zimbabwe	2	Harare, Bulawayo	1,444,534; 676,787

5.2.2 Quantitative Analysis

To estimate the achievable emission reduction from potential BRT projects developed under the CDM for the cities listed in table 5.2.2, the study team made simple bottom-up assumptions. For each of the countries considered, the study team assumed that the transport sector accounted for 70 percent of the crude oil consumed, that 85 percent of that sector's consumption was in urban areas, and that 60 percent of urban consumption of transport crude oil occurs in large towns and cities along the BRT routes that would be developed as CDM projects in the cities listed in table 5.2.2. In addition, it was assumed that BRT project implementation result in a 20-percent savings of transport crude-oil consumption in these towns and cities. Based on these assumptions, the emission reduction from BRT project implementation was estimated (box 5.2.1).

Box 5.2.1: Calculating Emission Reduction from BRT Projects

For each of the BRT-qualified towns and cities in Sub-Saharan Africa, baseline crude-oil consumption along the respective BRT routes was calculated as follows:

$COC_{BRT,i,y} = CCO_{i,y} * FR_{TR,i,y} * FR_{UTR,i,y} * FR_{UCTR,i,y}$

The savings in crude-oil consumption resulting from BRT project implementation was estimated as follows:

$COS_{BRT,i,y} = COC_{BRT,i,y} * FRF_{BRT,i,y}$

The resulting emission reduction from savings in crude oil was estimated as:

$ER_{BRT, i, y} = COS_{BRT, i, y} * NCV_O * EF_O$

where,

$COC_{BRT,I,y}$ = petroleum product consumed along the proposed BRT route in the baseline in country I in year y (tons/yr),

$CCO_{I,y}$ = total petroleum product consumed in country I in year y (tons/yr),

$FR_{TR,I,y}$ = fraction of petroleum products consumed in country I consumed in the transport sector,

$FR_{UTR,I,y}$ = fraction of petroleum products consumed in the transport sector of country I in year y consumed in urban areas,$FR_{UCTR,i,y}$ = fraction of urban transport sector, petroleum-product consumption in country i on the proposed BRT routes of the qualified towns and cities,

$FRF_{BRT,i,y}$ = fraction of petroleum products consumed on the proposed BRT route in the baseline saved through BRT project implementation,

$COS_{BRT, i, y}$ = quantity of petroleum products saved via BRT project implementation (tons/yr),

NCV_O = net calorific value of petroleum products saved via BRT project implementation (GJ/ton), and

EF_O = emission factor of transport-sector fuel (tCO_2/GJ).

The quantitative framework presented above was used to estimate the characteristics of BRT projects implemented as CDM projects in the 54 cities identified in table 5.2.2. Results are summarized in table 5.2.3.

Table 5.2.3: Results Summary of CDM Opportunities: Improved Energy Efficiency of Transport Sector via BRT

Country	No. of projects	Oil consumed (barrels/day)	Estimated oil savings from BRT (barrels/day)	Projects' emissions reductions (tCO_2/yr)
Angola	1	58,000	4,141	601,234
Benin	1	11,370	879	127,684
Botswana	1	13,000	928	134,759
Burkina Faso	1	7,480	409	59,446
Burundi	1	2,640	170	24,630
Cameroon	2	23,000	1,642	238,420
Cape Verde	1	1,500	70	10,107
Central African Republic	1	2,200	141	20,525
Chad	1	1,200	86	12,439
Comoros	1	640	41	5,971
Congo, Dem. Rep.	4	14,160	1,011	146,784
Congo, Rep.	2	4,400	314	45,611
Côte d'Ivoire	2	32,900	2,303	334,358
Equatorial Guinea	1	1,044	75	10,822
Ethiopia	1	32,000	2,285	331,715
Gabon	1	13,000	928	134,759
Ghana	2	45,000	3,213	466,475
Guinea	1	8,210	391	56,737
Guinea Bissau	1	2,300	112	16,292
Kenya	2	57,000	4,070	590,868
Madagascar	1	12,130	779	113,167
Malawi	2	6,000	428	62,197
Mali	1	3,840	332	48,249
Mauritania	1	23,760	1,661	241,161
Mauritius	1	19,880	1,230	178,601
Mozambique	1	13,000	928	134,759
Namibia	1	21,000	1,499	217,688
Niger	1	4,980	558	80,978
Nigeria	12	297,000	21,206	3,078,732
Rwanda	1	5,000	357	51,831
Senegal	1	20,550	1,281	185,973
Sierra Leone	1	7,000	500	72,563
South Africa	9	490,000	34,986	5,079,390
Sudan	3	94,000	6,712	974,414
Swaziland	1	3,000	214	31,098
Tanzania	1	17,000	1,214	176,224
Togo	1	7,000	333	48,375
Uganda	1	9,000	643	93,295
Zambia	1	12,000	857	124,393
Zimbabwe	2	20,000	1,428	207,322
Total	**71**	**1,441,934**	**103,525**	**14,801,987**

As table 5.2.3 illustrates, 71 BRT projects of varying capacities could be implemented under the CDM, resulting in savings of more than 103,000 barrels of oil per day and a reduction of nearly 15 million tCO_2 per year in GHG emissions.

5.2.3 Barriers to Implementation

Many countries of Sub-Saharan Africa lack both formal transport-sector planning and the data required for BRT planning and design. BRT project success is enhanced by sector-wide planning, which enables BRT planning to consider the likely effects of a range of factors—from modal shifts and user population growth to relationship with competing routes. In addition, the planning and design of BRT projects require many data that are usually unavailable in most countries of the region. The acceptable design of BRT projects under the CDM require data to assist project developers clarify such issues as energy consumption of the baseline transport system that the BRT system will fully or partially replace and the corresponding energy consumption of the BRT project, as well as the modal shifts likely to occur as a result of implementing BRT projects. Experience in implementing BRT programs worldwide shows that key components usually require data gathered through dedicated surveys. In many countries across the region, it is difficult to implement such surveys.

5.2.4 Mitigation Recommendations

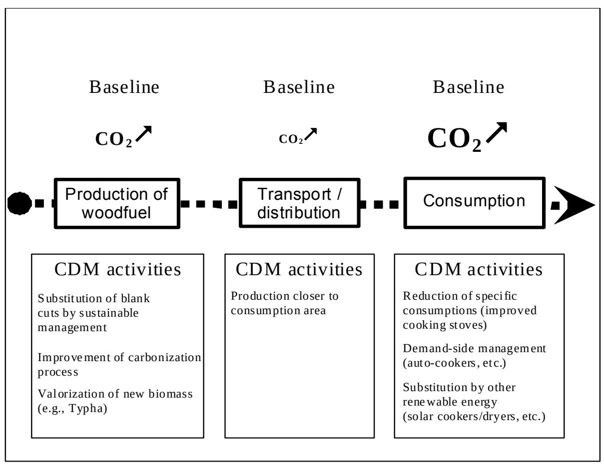
To overcome these barriers, the respective countries must incorporate BRT planning into their transport-sector strategic plans. In countries where strategic planning for the transport sector does not exist, it will be useful to prepare such plans before designing BRT systems. Integrating BRT into overall sector planning can provide valuable information to aid appropriate BRT design, without impairing the additionality of projects. It is recommended that efforts to collect the needed data described above—especially survey data—begin before planning the BRT project. Finally, public-awareness raising on the benefits of the BRT project and the inconveniences residents will likely face during system construction should be conducted well in advance of BRT construction.

Chapter 6

Woodfuel for Households

This chapter centers on the technology of improved charcoal production as a potential clean energy CDM project in Sub-Saharan Africa. Figure 6.1 shows the physical distribution of activities along the production chain of the woodfuel-for-households subsector and the UNFCCC approved methodology for this subsector.

Figure 6.1: CDM Opportunities along the Woodfuel-for-households Production Chain



Woodfuel production	Transport/ distribution	Consumption/ use
Improvement of carbonization process	***Production closer to consumption***	***Reduction of specific consumption (e.g., improved stoves)***
AM0041		
Substitution of blanks cuts by sustainable management		***Demand-side management (e.g., auto-cooker)***
Valorization of new biomass (e.g., Typha)		***Substitution by other renewable energies (e.g., solar cooker)***

Production

6.1 Improved Charcoal Production

Across Sub-Saharan Africa, biomass energy, mostly in the form of charcoal, is used by both low-income urban and most rural households. Charcoal is commonly used as fuel for cottage industries (e.g., bread baking, cottage metal smelting operations, and brick kilns). Charcoal production has been singled out as a major cause of forest degradation and deforestation in many African nations, particularly in peri-urban areas (e.g., N'Djamena in Chad). The need for greater efficiency in fuelwood gathering and charcoal production in response to the growing urban energy demand is a critical issue in Africa's energy planning and natural resources and environmental management.

6.1.1 Technical Evaluation

The transformation of wood into charcoal involves a three-phase heterogeneous process: ignition, carbonization, and cooling. It takes 6–12 hours to initially heat and ignite the kiln; once the ignition process is started, it is kept going via a small amount of air allowed into the kiln chambers until completion, signaled by the onset of carbonization. Carbonization begins when the kiln temperature reaches 180ºC. Most of the exothermic heat is released during the carbonization phase, further increasing the kiln temperature. To date, these processes have produced a host of gases, including CO_2 and CH_4. According to documentation submitted with AM0041 (UNFCCC 2007), CH_4 is released at higher kiln temperatures; kiln temperature plays a major role in carbonization and is the key to the charcoal conversion achievable. After 2–3 days of carbonization, the kiln is fully sealed to permit cooling. When the kiln temperature falls to a certain level, it is opened and the charcoal is discharged.

Charcoal production technologies can be broadly categorized as traditional earth-pit and earth kiln, improved earth kiln, and high-yield, low-emission systems. In traditional production facilities (Girard 2002; Stassen 2002), wood is put in dug-out earth pits, lit, and covered with earth. Combustion of part of the wood produces enough heat to carbonize the remainder. Alternatively, heaps of wood are covered with earth and sod and lit through openings in the earth cover (earth kilns). Those openings can be judiciously opened and closed and new ones made to control the introduction of air. This method permits more control over combustion and carbonization than the pit method. Both techniques persist because they are cheap, but they produce low yields (typically 1 kg of charcoal from 8–12 kg of wood), inconsistent quality (uniform carbonization is difficult to maintain), and environmental pollution (from the release of tars and obnoxious gases, including GHGs).

In the 1970s and 1980s, efforts were made to improve traditional charcoal making by equipping earth kilns with chimneys made from oil drums (Casamance kilns) and introducing small-scale steel or brick kilns. These methods all rely on the partial combustion of the wood charge to provide the heat needed for carbonization; therefore, yields depend heavily on the moisture content of the wood. A yield of 1 kg of charcoal from 4–5 kg of air-dried wood is possible, but 1 kg from 6–8 kg of wood is more common. The advantage of processes that use a solid cover (metal, brick, or concrete) is that the hermetic seal minimizes the effect of poor supervision and gives more consistent results. While steel and brick kilns are less labor intensive than improved earth mounds, they may be less accessible to small-scale traditional charcoal makers because of their higher costs.

The high-yield, low-emission systems aim to improve both the environmental performance of equipment and charcoal yield. Many types of commercially available systems can achieve yields up to 1 kg of charcoal from 3–4 kg of wood. Such systems are usually designed to recover the portion of the initial-combustion energy that is usually wasted in traditional systems for use in drying the initial wood charge. Typically, steel vessels or retorts are filled with pre-dried wood and placed in a ceramic, brick-lined carbonization furnace heated to 900ºC. As the wood heats, the tars and gases produced are led to a separate, high-temperature combustion chamber. The flue gas from this combustion chamber is used to heat the carbonization furnace, and the remaining heat from the furnace is used to pre-dry the wood (Stassen 2002).

The efficient heat management from this type of equipment makes it possible to produce 1 kg of charcoal from 3–4 kg of wood. Because of the combustion chamber's high temperature, all particles, tars, and gases are completely combusted. In the Netherlands, this type of equipment has been certified to meet strict emission standards for combustion installations. Emissions of CO, nitrogen oxides, and tars, as well as smell components, are well within the legal limits. The new high-yield, low-emission charcoal factories have higher investment costs than the old-fashioned brick or steel kilns or retorts. But, in many cases, the improved yield more than compensates for the higher investment; thus, lower emissions come as a no-cost bonus. In the past two years, this relatively new technology has spread not only throughout environmentally-conscious countries of the European Union, such as France, but also in Eastern Europe (e.g., Estonia) and developing countries (e.g., China, Ghana, and South Africa).

Another improved charcoal production system is known as Adam's retort. According to the developer, this innovative, low-cost technology offers 35–40 percent efficiency, compared to 18 percent for traditional systems (calculated from dry weight). During the first phase of operation, only 50 kg of waste wood or residual biomass needs to be burned in a separate firebox to dry and heat the wood and initiate the carbonization process. Recycling and clean combustion of the pyrolysis gas during the second phase of operation (retort-system) results in less emission of CO during charcoal production. The system has a low investment cost and can be simply constructed using locally available materials. An effective 30-hour production cycle (batch) and simple plant operation can result in increased income for its operators.[88]

[88] More information on Adam's retort is available at www.bioenergylists.org/en/adamretort.

6.1.2 Quantitative Analysis

Box 6.1.1 highlights the equations used to estimate the potential emission reductions from improved charcoal production as CDM projects in Sub-Saharan Africa.[89]

Box 6.1.1: Calculating Emission Reduction from Improved Charcoal Production

Using the format of AM0041, the following equations were used to estimate the potential emission reductions from improved charcoal production projects under the CDM.

$CHARp_{t,i} = CHARc_{t,i} * (1+r)$

$MB_{t,i} = A1 – B1 * YB_{t,i}$

$MP_{t,i} = A2 – B2 * YP_{t,i}$

$BE_{t,i} = (MB_{t,i} * GWP – CH4 * CHARp_{t,i})/1000$

$PE_{t,i} = (MP_{t,i} * GWP – CH4 * CHARp_{t,i})/1000$

$ERt,i = BE_{t,i} – PE_{t,i}$

where,

$CHARp_{t,i}$ = charcoal production (tons of charcoal) in country i in year t,

$CHARc_{t,i}$ = charcoal consumption (tons of charcoal) in country i in year t,

r = average fraction of charcoal lost in transport and distribution,

$MB_{t,i}$ = methane emission factor (kg of CH_4/ton of charcoal) in the baseline scenario,

$MP_{t,i}$ = methane emission factor (kg of CH_4/ton of charcoal) in the project scenario,

$YB_{t,I}$ = baseline weighted, average carbonization gravimetric yield in country I in year t (ton of charcoal/ton of wood),

$YP_{t,I}$ = project weighted, average carbonization gravimetric yield in country I in year t (ton of charcoal/ton of wood),

$BE_{t,i}$ = total baseline emissions (tCO_2e/yr) in country i in year t,

$PE_{t, i}$ = total project emissions (tCO_2e/yr) in country i in year t,

A1=A2 = first constant of the gravimetric/methane emission equation (= 147.0),

B1=B2 = second constant of the gravimetric/methane emission equation (= 340.37), and

$ER_{t, i}$ = total emission reduction (tCO_2e/yr) in country i in year t.

To evaluate the CDM potential of a project scenario that would replace inefficient traditional charcoal kilns with improved charcoal-production technologies, the study team made the following assumptions, some of which are required to implement these projects within the analytical framework:[90]

- The baseline is comprised of traditional charcoal-making facilities in all countries of Sub-Saharan Africa.

[89] These projects can use AM0041 and AMS-III.K.

[90] Since FAO data was available on charcoal consumption in each country of Sub-Saharan Africa for the period 1990–96, the study team extrapolated these statistics to estimate charcoal consumption in each of the countries studied for the year 2003 (FAO 1997).

- Thus, in the baseline scenario, a minimum charcoal yield of 250 kg can be obtained from about 1,200 kg wood.
- In all countries, traditional charcoal-making facilities are replaced by the high-yield, low-emission Adam's retort, with a yield of 250 kg of charcoal from 650 kg of wood (dry basis).
- Although CO_2 and CH_4 are released using typical charcoal-production technologies, the study team focused on emission reductions from CH_4 in the project scenario because AM0041, which provides the basis for this estimation, is valid only for CH_4 emissions; since CO_2 is emitted from a biomass resource, emission reduction cannot be claimed as this CO_2 is within the normal carbon cycle (according to the prevailing rules of the CDM process).
- The CH_4 emission factor used in the analysis is based on the characteristic equation relating CH_4 emissions to charcoal yield in the Plantar, Brazil project, which is the underlying project activity for AM0041 (UNFCCC: Project Design Document: Plantar, Brazil Charcoal Project NM0110_Rev).
- Each Adam retort is capable of producing 250 kg of charcoal in each batch process with a 30-hour batch duration. At 80-percent capacity utilization, each retort has an annual production of 58.4 tons of charcoal.
- Each CDM project contains a minimum of 150 Adam retorts, with a total capacity of 9,855 tons of charcoal per year.
- The capital cost of each CDM project is about US$126,000 (cost of retort, plus 20-percent allowance to cover other capital costs).[91]
- In each country, total losses (i.e., production facility, charcoal transport, and distribution to consumers) do not exceed 5 percent.

Table 6.1.1 summarizes results of the analysis of CDM project potential in Sub-Saharan Africa using Adam's retort technology to replace inefficient, mostly traditional charcoal facilities prevalent across the region.

[91] Basic-cost details are available at http.bioenergylists.org/en/adamretort.

Table 6.1.1: Results Summary of CDM Opportunities: Efficient Charcoal Production

Country	No. of projects and CDM Programs of Activities (CPAs)	No. of projects and Programs of Activities (POAs)	Charcoal consumption, 2003 (thousands of tons)	Projects' estimated charcoal production (thousands of tons)	Projects' emissions reductions (thousands tCO_2e)	Total investment cost of projects (millions US$)
Angola	150	3	1,411.58	1,482.16	1,867.75	18.95
Benin	2	1	12.00	12.60	15.88	0.25
Botswana	6	1	57.29	60.15	75.80	0.77
Burkina Faso	4	1	35.00	36.75	46.31	0.47
Burundi	6	1	58.00	60.90	76.74	0.78
Cameroon	14	1	135.07	141.83	178.72	1.81
Cape Verde	1	1	2.10	2.21	2.78	0.13
Central African Republic	2	1	21.52	22.60	28.47	0.29
Chad	21	1	194.69	204.42	257.61	2.61
Comoros	7	1	70.00	73.50	92.62	0.94
Congo, Dem. Rep.	42	1	398.39	418.30	527.13	5.35
Congo, Rep.	2	1	23.29	24.45	30.81	0.31
Côte d'Ivoire	163	4	1,529.26	1,605.72	2,023.45	20.53
Ethiopia	43	1	406.61	426.94	538.02	5.46
Gambia	7	1	70.00	73.50	92.62	0.94
Ghana	66	1	620.71	651.75	821.30	8.33
Guinea	16	1	147.00	154.35	194.50	1.97
Guinea Bissau	9	1	85.00	89.25	112.47	1.14
Kenya	226	5	2,125.45	2,231.72	2,812.31	28.53
Liberia	15	1	139.00	145.95	183.92	1.87
Madagascar	66	2	620.00	651.00	820.36	8.32
Malawi	54	2	506.29	531.60	669.90	6.80
Mali	10	1	93.00	97.65	123.05	1.25
Mauritania	19	1	176.00	184.80	232.88	2.10
Mauritius	1	1	1.36	1.43	1.80	0.13
Mozambique	55	2	518.55	544.48	686.13	6.96
Namibia	1	1	12.58	13.20	16.64	0.17
Niger	7	1	62.63	65.76	82.87	0.84
Nigeria	129	3	1,214.10	1,274.80	1,606.44	16.30
Rwanda	6	1	52.17	54.77	69.02	0.70
Senegal	25	1	235.70	247.49	311.87	3.16
Seychelles	2	1	20.34	21.36	26.91	0.27
Sierra Leone	13	1	120.48	126.50	159.41	1.62
Somalia	27	1	249.65	262.13	330.33	3.35
South Africa	155	4	1,456.30	1,529.11	1,926.91	19.55
Sudan	391	8	3,667.13	3,850.49	4,852.20	49.23
Swaziland	4	1	33.85	35.54	44.78	0.45
Tanzania	84	2	791.03	830.58	1,046.65	10.62
Togo	12	1	115.00	120.75	152.16	1.54
Uganda	82	2	771.00	809.55	1,020.15	10.35
Zambia	97	2	909.95	955.45	1,204.01	12.22
Zimbabwe	2	1	15.68	16.46	20.75	0.21
Total	**8 projects and 2,031 CPAs**	**8 projects and 61 POAs**	**19,184.73**	**20,143.97**	**25,384.46**	**257.84**

As table 6.1.1 shows, some 2,031 CPAs could be organized under 61 Programs of Activities. It was assumed that each CPA would consist of 150 Adam's retort facilities. In addition to these CPAs, 8 small-scale, CDM projects (1 in each of 8 countries) could be implemented in Benin, Cape Verde, Central African Republic, Congo Brazzaville, Mauritius, Namibia, Seychelles, and Zimbabwe. Implementation of these facilities would reduction carbon emissions by slightly more than 25 million tCO_2e, requiring a total investment of US$258 million and producing about 20 million tons of charcoal.

6.1.2 Barriers to Implementation

The successful introduction of efficient charcoal-production technologies in Sub-Saharan Africa may be limited by the lack of enabling policies and legal frameworks, concerns regarding the sustainability use of forest resources, and inadequate institutional capacity to develop clear, cost-effective implementation strategies. To implement improved charcoal-production technologies successfully, appropriate government policies are required to promote their assimilation within a context of sustainable resource management. Sound government policies are critical to creating an enabling environment in which such technologies can thrive, the required resources can be mobilized, and needed private-sector investment is encouraged to complement public-sector investment.[92] Without an appropriate policy and legal framework, the smooth introduction of improved charcoal technologies to replace traditional technologies may be hindered across the region.

Because charcoal production involves tree removal from forests, sustainable wood supply is an important consideration for charcoal production and management policies. Although the CDM project considered in this section replaces inefficient charcoal-production technologies with more efficient ones, requiring less wood to produce a unit of charcoal, sustainable resource issues must still be tackled. One common argument is that introducing more efficient charcoal-production technologies may result in expanded use of charcoal in Sub-Saharan economies. The concern with regard to expanded consumption is that charcoal is more likely to be produced from core forest resources, unlike fuelwood, which is usually derived from residues and non-core forest resources. If so, the increased use of core forest resources for charcoal production could pose a future threat to local forest resources, especially in the high-demand, peri-urban areas of countries that lack sound forest-management policies and practices. Even if this scenario fails to materialize, the perception of a future threat may constitute an actual barrier to introducing more efficient charcoal-production technologies in countries across the region.

It should be noted that, if charcoal were sustainably produced (i.e., without causing deforestation), it would be carbon-cycle neutral. Not only would its production using more energy-efficient technologies lead to lower GHG emissions (compared to traditional technologies), its use as a fuel in end-use facilities would be carbon-cycle neutral, as its burning would simply release time-scale CO_2 back into the atmosphere. The key point is that improved charcoal-production technologies should be introduced within the scope of each country's national forest resource management.[93]

Any sustainable charcoal-production program requires careful resource planning and technology assimilation. A sound institutional framework, seldom found in most

[92] This enabling environment is required for all types of renewable-energy technologies.

[93] An earlier study suggested that sustainable charcoal production and consumption could be promoted through a systems approach (tracking material flows from extraction through disposal) to ensure sustainable material consumption at all biomass life-cycle stages (wood harvesting, pyrolysis, charcoal use, and ash disposal).The aim of this approach would be to minimize material and energy losses at all stages in the production cycle: wood obtained from a sustainably produced, biomass resource; harvesting of wood from the biomass resource carried out using efficient methods, ensuring minimum waste generation; conversion of wood into charcoal using improved, efficient kilns; efficient handling of the charcoal produced during packaging, storage, and transport to minimize waste; and consumption of the generated charcoal using improved cookstoves.

countries in Sub-Saharan Africa, is needed to coordinate the implementation of sustainable resource production and use. The inadequate capacity for analyses, planning, implementation, and monitoring and evaluation, which typifies many countries across the region, may constrain the ability to conduct appropriate resource planning and assimilate new technologies.

6.1.3 Mitigation Recommendations

To promote the development and implementation of efficient charcoal-production technologies in Sub-Saharan Africa, two major actions must be taken as part of a strategic framework. First, to discourage the increased use of unsustainable biomass resources for charcoal production, large charcoal-production facilities should only be approved for dedicated fuelwood plantations (i.e., sustainable biomass). Taking this action will not only earn emission credits from more energy-efficient charcoal production; carbon sequestration from the dedicated woodlot may also qualify for additional credits. Second, each country requires a sound institutional, policy, and regulatory framework to guide the organized development of this technology. Such a framework will provide a clear signal to project developers of governmental support for their business and thus aid in mobilizing the needed private-sector investment.

Chapter 7

Results Synthesis

Based on the technical assessment and inventory of the 22 technologies analyzed in chapters 3–6, this chapter synthesizes results for Sub-Saharan Africa. In this chapter, results are consolidated in two ways:

- A synthesis table per technology, detailing the number of potential projects and their potential contribution in terms of avoidance of greenhouse gas (GHG) emissions, additional energy supply, and associated investment cost (table 7.1); and

- Two investment cost curves: one for GHG abatement and the other for additional generation capacity (figure 7.1).[94]

Brief Analysis of Aggregated Results

The aggregated results presented for the 44 countries in Sub-Saharan Africa and the 22 technologies considered in this study clearly demonstrate the region's considerable potential for clean energy projects (table 7.1). Based on the size of similar projects in other non-Annex 1 countries that have already been submitted to the UNFCCC CDM secretariat for validation, this study estimates the region's technical potential at more than 5,000 clean energy projects. If similar small projects are aggregated into larger programs, known as Programs of Activities, global figures reach close to 2,800 projects and 361 Programs of Activities. This potential can be considered underestimated for two major reasons. First, the study approach focuses mainly on projects corresponding to already approved CDM methodologies (with the noticeable exception of Jatropha, for which a methodology has not yet been approved). Since the number of methodologies approved by the CDM Executive Board is increasing every two months, a significant number of new clean-energy activities might be applicable to Sub-Saharan Africa. Second, for various project types, the study team was unable to collect exhaustive data or estimate the potential. This was the case for small hydropower plants, wind farms, waste-to-energy projects, geothermal plants (for which the Rift Valley has a large potential), solar water heaters, concentrated solar power (South Africa is planning a 100-MW pilot plant), building and vehicle energy efficiency, ethanol from sugarcane, and improved household stoves, among others. Regarding the latter, only three countries

[94] A companion volume (vol. 2) to this report, entitled *Results per Country*, contains, for each of the 44 countries studied, a table synthesizing that country's potential for each of the 22 technologies considered and both types of investment curves presented in this chapter. A CD annexed to the report contains an Excel file with all of the databases used, as well as calculations, tables, and curves. Thus, readers can easily revise key assumptions and parameters as more accurate data become available.

could be investigated (Côte d'Ivoire, Guinea, and Senegal), which represent only a small share of that potential.

If fully implemented, the estimated technical potential could provide more than 170 GW of additional power-generation capacity, representing more than twice the region's current installed capacity. Not all projects would generate power; a portion would generate only thermal energy. The additional energy provided, both electrical and thermal, would equal nearly 4 times current regional production.

The achievable reduction in GHG emissions would total about 740 million tCO_2 per year, which exceeds the region's current level of GHG emissions (680 million tCO_2). Because the technical potential of clean-energy generation is larger than the region's current energy demand, this potential can meet future demand growth, thereby avoiding additional GHG emissions that would otherwise occur under a business-as-usual scenario. Assuming a price of US$10 per tCO_2 and the declared carbon-finance eligibility of all these projects, up to US$7.4 billion could be poured into the regional economy each year.

The study also assessed the financing needs to implement these potential clean energy projects. Such costs are difficult to estimate, and it was not possible to collect data for 8 project categories,[95] representing 36 percent of additional power-generation capacity and 21 percent of emission reductions. In particular, the costs of large flared, associated-gas recovery projects, which are especially difficult to estimate, could vary considerably. A conservative estimate of the capital cost required for the remaining 2,755 clean energy CDM projects is US$158 billion. If the capital cost of large flared, associated-gas recovery projects could be calculated, this figure would likely exceed US$200 billion.[96,97]

[95] Non-lighting electricity for industry (motors), energy-saving household appliances, grid-loss reduction, flared gas recovery, improved steam system, shift to Bus Rapid Transit (BRT), fuel switching in industry, and methane leakage reduction in pipelines.

[96] Since the intention was to remain on the safe side of the minimum financing required by this technical potential for clean energy projects, assumptions were made in the calculations to ensure that these figures would be conservative (i.e., at the lower range of the estimate). To reiterate, assumptions can be adjusted in the annexed Excel file as more accurate values become available.

[97] In the context of global climate change, this figure represent only 7–14 percent of the amount that former Vice President Al Gore says will be required to help the U.S., a single country, shift from conventional to clean energy over the next several decades ("Gore sets 'clean' energy goal for next president," *USA Today*, July 17, 2008).

Table 7.1: Consolidated Results of Potential Clean-energy Project Opportunities for Sub-Saharan Africa (All)

Technology	No. of projects	Projects' emissions reductions: millions tCO_2/yr	Projects' emissions reductions: % of country total	Reductions over projects' life span (millions tCO_2)[1]	Value of projects' emissions reductions (millions US$): US$5/tCO_2	Value of projects' emissions reductions (millions US$): US$10/tCO_2	Electricity generation: Projects (GWh/yr)	Electricity generation: Projects (% country total)	Added power of projects (MW): 90% load factor	Added power of projects (MW): % of total installed	Total investment cost of projects (billions US$)
Second-cycle addition to open-cycle gas turbine	204	36.1	5.3	360.8	1,804.0	3,608.1	51,912	0	5,931	8.6	7.1
Combined heat and power for industry	373	72.9	10.7	729.4	3,647.0	7,294.0	156,314	0	17,844	25.9	17.8
Combined heat and power in sugar mills	67	2.4	0.4	24.4	122.1	244.2	3,489	0	661	1.0	1.0
Agricultural residue	553	140.8	20.7	1,408.4	7,042.2	14,084.3	216,842	1	27,504	40.0	38.5
Forest residue[2]	321	62.6	9.2	625.8	3,128.9	6,257.9	98,415	0	12,483	18.1	17.5
Wood-processing residue[2]	406	20.3	3.0	203.4	1,029.9	2,053.9	31,987	0	4,057	5.9	5.7
Typha australis	40	3.1	0.5	31.0	155.1	310.3	4,675	0	593	0.9	0.8
Jatropha biofuel	555	176.8	26.0	3,712.0	18,560.0	37,120.0	218,767	1	27,748	40.3	53.6
Hydroelectricity	26	25.2	3.7	528.6	2,643.1	5,286.3	35,961	0	6,443	9.4	9.4
Landfill gas	3	0.9	0.1	9.0	44.8	89.6	49	0	10	0.0	0.0
Grid-loss reduction	20	1.1	2.2	11.3	56.6	113.2	31,974	0	4,056	5.9	--
Non-lighting electricity for industry	20	1.5	0.2	1.4	6.9	13.9	5,837	0	740	1.1	--
Switch to compact fluorescent lamps	49	13.3	2.0	132.7	663.4	1,326.8	17,269	0	15,246	22.1	4.8
Energy-saving household appliances	30	7.4	1.1	74.4	372.0	744.0	11,131	0	1,412	2.1	--
Flared gas recovery	55	91.8	13.5	917.6	4,588.0	9,176.1	353,409	1	44,826	65.1	--
Coal mine methane	18	2.5	0.4	24.7	123.6	247.2	809	0	109	0.2	0.1
Waste gases in crude oil refinery	26	4.3	0.6	43.4	216.9	433.8	5,777	0	659	1.0	0.9
Improved steam system	211	36.6	5.4	366.4	1,831.8	3,663.6	--	--	--	0.0	--
Reduced clinker use in cement manufacturing	46	2.8	0.4	28.4	142.1	284.1	--	--	--	0.0	0.1
Shift to Bus Rapid Transit (BRT)	63	12.4	1.8	260.2	1,301.0	2,602.0	--	--	--	0.0	--
Biodiesel from Jatropha	60	3.2	0.5	66.2	330.9	661.8	--	--	--	0.0	--
Improved charcoal production	68	22.5	3.3	224.8	1,123.8	2,247.5	--	--	--	0.0	0.2
Reduced methane leakage in pipelines[3]	13	0.1	0.0	0.7	3.6	7.2	--	--	--	0.0	--
Total	**3,227[4]**	**740.7**	**109.0**	**9,785.0**	**48,937.8**	**97,869.7**	**1,244,618**	**4**	**155,078**	**225.3**	**157.6**

Note: In 2003, the region's total electricity generation was 327,079 GWh per year and total installed power was 68,841 MW.

[1] With regard to projects' life span, a carbon-crediting period of 21 years was used for Jatropha biofuel, hydroelectricity, shift to BRT, and biodiesel from Jatropha; for all other technologies, a 10-year crediting period was assumed.

[2] Results for forest and wood-processing residues are disaggregated in this table.

[3] This technology does not have a corresponding chapter section.

[4] The 3,227 projects include 361 Programs of Activities.

Two interesting observations can be drawn from the results presented in table 7.1. First, regarding emission reductions, 64 percent of the potential is derived from biomass use, about half of which is from existing wasted biomass (e.g., bagasse, agricultural and agro-industry residues, Typha, and forest and wood-processing residues); while 34 percent is from Jatropha plantations for biodiesel use. The latter value should be used with caution as it is a preliminary estimate based on the hypothesis that Jatropha would be planted on 2 percent of land in the countries were it could be planted without irrigation. It should be emphasized that, using the annexed excel file, these estimates can easily be revised by directly changing the values adopted in this exercise for the key parameters with more accurate ones as they become available. Second, with regard to additional power-generation capacity, 53 percent of the potential is derived from the improved use of fossil fuels, 27 percent of which would come from improved energy efficiency and fuel switching in existing facilities and 26 percent from recovery of associated gas flared during production (table 7.2).

Table 7.2: Share of Potential Projects for Several Categories

Project category	*Emission-reduction potential (%)*	*Added power-generation capacity (%)*
Biomass use	64	43
Existing facilities	19	27
Fossil-fuel related (energy efficiency, fuel switching, associated gas, and recovery of coal mine methane)	28	53

It is also worth noting that clean energy projects that incur only incremental investment in already existing facilities (e.g., fossil fuel and sugarcane–based cogeneration for industry, efficient motors, improved lighting, and grid-loss reduction) could deliver a bit less than one-third (27 percent) of the potential additional capacity (e.g., 46 GW) and one-fifth the emission reduction (19 percent).

Investment Curves

The climate change community is usually more interested in marginal GHG abatement cost curves than in the types of investment curves presented below. Marginal GHG abatement cost curves are used to indicate the economic attractiveness of GHG mitigation options, along with the amount of GHG reductions achievable via those options. Economic attractiveness is measured in terms of unit cost of GHG reductions. It is derived by dividing the total cost associated with GHG abatement by the amount of GHG emissions reduced during the economic life of the GHG mitigation option or technology.

The costs of GHG abatement could be defined differently; however, the most consistent definition is the incremental cost due to GHG abatement, compared to what would occur without the abatement activities (referred to as the baseline). The abatement cost (AC) is calculated as follows:

$$AC = \frac{TC^{p} - TC^{b}}{E^{b} - E^{p}} \qquad (1)$$

$$TC = INV + OM + F \qquad (2)$$

where,

TC = total costs,

E = emissions,

p = project case,

b = baseline,

INV = investment cost,

OM = operation-and-maintenance cost, and

F = fuel cost.

It is assumed that the benefits (e.g., electricity for a hydropower project) are the same in the baseline and project cases. If benefits differ between the project and baseline cases, the incremental benefits between them must be taken into account.

Calculating GHG abatement cost is always challenging because it is difficult to predict the baseline precisely and obtain all of the required quantitative data related to investment and operation-and-maintenance (O&M) costs and benefits for both the baseline and the clean-energy options. The calculation is even more challenging in countries of Sub-Saharan Africa, where the data and information base are not easily available. Hence, this study uses a GHG investment curve, instead of a GHG abatement curve, approach. The investment curve approach uses total cost associated with low-carbon options instead of incremental costs imputable to GHG emission reductions, which the abatement curve approach uses.

On the one hand, the investment cost approach simplifies the abatement cost formula and can be expressed as follows:

$$INVC = \frac{INV^{p}}{E^{b} - E^{p}} \qquad (3)$$

On the other hand, the GHG investment cost curves can be as meaningful as the GHG abatement cost curves in developing countries, particularly countries in Sub-Saharan Africa. For governments in the region and donors, who are interested in both development and emission reductions and not solely emission reductions, the total investment information available from the GHG investment curves is more relevant than the incremental cost available from abatement curves.

The GHG investment cost curves provide information on the level of investment needed if developing countries pursue their development goal and, at the same time, want to follow the path of low-carbon economic growth. While an abatement cost curve only helps to rank GHG mitigation options based on their cost, an investment cost curve gives an entire picture of the investment needed to achieve development objectives without increasing emissions.

For this reason, it is important to generate a second curve that ranks the clean energy potential according to the investment cost per MW of additional power-generation capacity provided. Energy practitioners may view this second curve as even more important than the first. It should be stressed that clean energy projects simultaneously generate energy and emission reductions. Therefore, investment costs related to emission reductions cannot be isolated from investment costs related to power generation. A third curve could have been generated to present the result per energy unit (GWh) instead of capacity unit (MW), especially because certain of the clean-energy technologies considered produce thermal energy only and not power. However, energy costs depend substantially on O&M costs, which could not be taken into account in this study.

One advantage of investment cost curves over abatement cost curves is that the former also reflect the potential financial barriers. GHG abatement curves usually demonstrate that energy-efficiency options are the most attractive economically because they have either low or negative costs. In practice, however, financial barriers often prevent these options from being implemented (figure 7.1).

When investment cost data were not available, the physical potential of both emission reductions and additional power-generation capacity were indicated on the left side of the curve with no mention of unitary cost. It should be emphasized that this does not mean in any way that the activities have negligible net costs. In such a curve, all projects have a positive investment cost, which differs from the usual marginal abatement cost, where some potentials may have zero or negative net discounted costs.

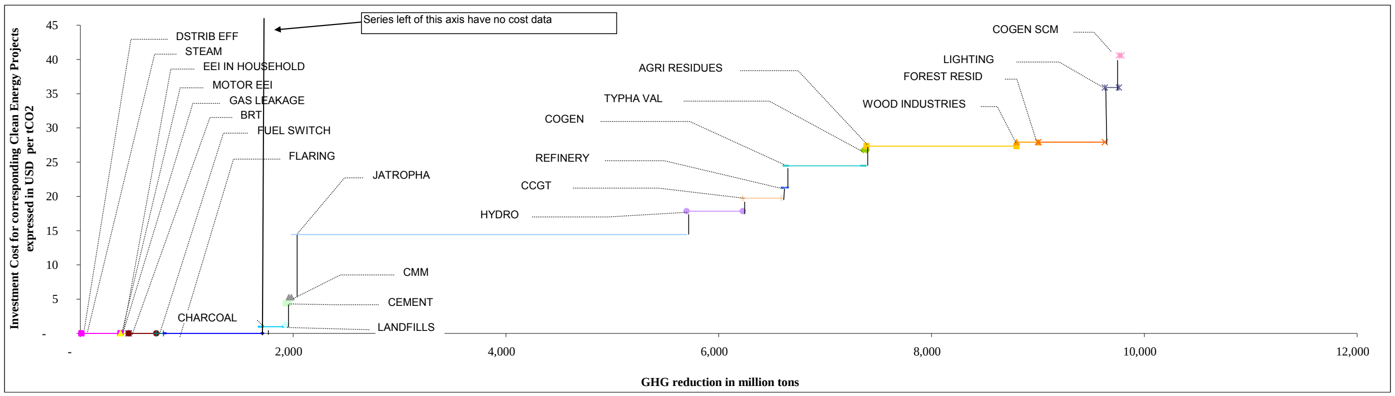
Figure 7.1: Consolidated Investment-curve Results for Sub-Saharan Africa

Potential for Emission Reductions

(Ranked by Investment Cost for Corresponding Clean Energy Projects expressed in USD per tCO2)

No cost data was available for the listed categories

Sector	Investment Cost ($/tCO2)	Reduction over project life (10 or 21 years) *
DISTRIB EFF IM	-	11
STEAM	-	366
EEI IN HOUSEH	-	74
MOTOR EEI	-	1
GAS LEAKAGE	-	1
BRT	-	260
FUEL SWITCH	-	66
FLARING	-	918
CHARCOAL	1	225
LANDFILLS	1	9
CEMENT	4	28
CMM	5	25
JATROPHA	14	3,712
HYDRO	18	529
CCGT	20	361
REFINERY	21	43
COGEN	24	729
TYPHA VAL	27	31
AGRI RESIDUE:	27	1,408
WOOD INDUST	28	203
FOREST RESID	28	626
LIGHTING	36	133
COGEN SCM	41	24

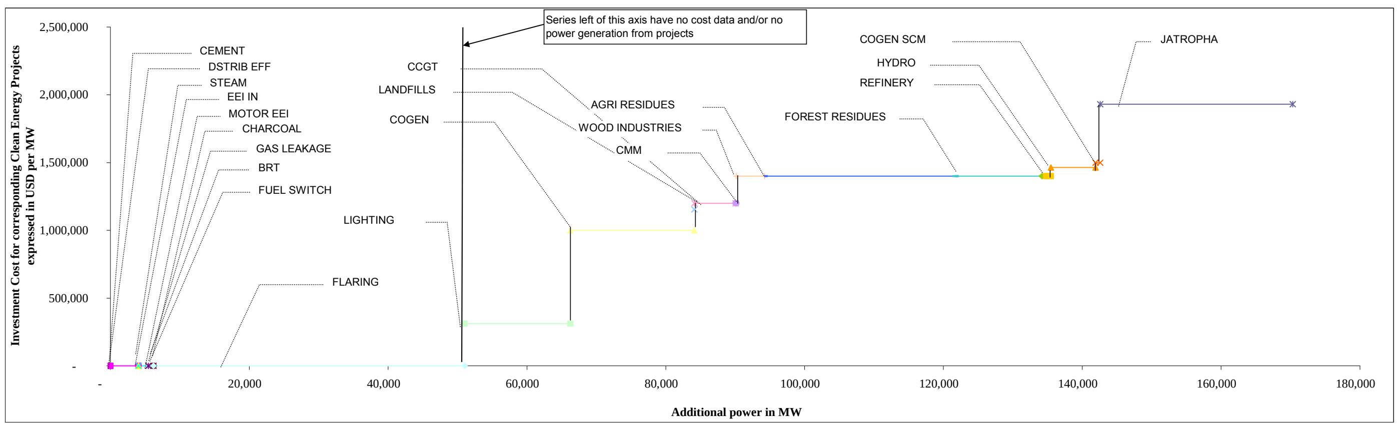


Potential for Additional Generation Capacity

(Ranked by Investment Cost for Corresponding Clean Energy Projects expressed in USD per MW)

No cost data and/or no power generation from projects

Sector	Investment Cost ($/MW)	Additional power due to the project implementation (load factor = 90%) MW
CEMENT	-	-
DISTRIB EFF IM	-	4,056
STEAM	-	-
EEI IN HOUSEH	-	1,412
MOTOR EEI	-	740
CHARCOAL	-	-
GAS LEAKAGE	-	-
BRT	-	-
FUEL SWITCH	-	-
FLARING	-	44,826
LIGHTING	312,500	15,246
COGEN	1,000,000	17,844
LANDFILLS	1,154,813	10
CCGT	1,200,000	5,931
CMM	1,200,000	109
WOOD INDUST	1,400,000	4,057
AGRI RESIDUE:	1,400,000	27,504
FOREST RESID	1,400,000	12,483
TYPHA VAL	1,400,000	593
REFINERY	1,400,000	659
HYDRO	1,463,517	6,443
COGEN SCM	1,500,000	661
JATROPHA	1,930,533	27,748



* A carbon crediting period of 10 years was used for all sectors with the exception of Jatropha, BRT, Hydro and Fuel Switch. For these the study assumed a crediting period of 21 years (3 x 7 years). This was done so as to reflect the difference in capital investment useful life accross sectors (up to 30 years for Hydro, etc.)

Note: Clean Energy projects simultaneously deliver power and generate emission reductions. Therefore, investment costs related to emission reductions cannot be isolated from investment costs related to power generation. As a consequence, unitary cost expressed in US$/tCO2 presented here are not marginal emissions abatement costs but investment costs corresponding to the associated clean energy projects divided by the volume of emission reductions generated by these projects during their lifetime as CDM projects activities generating certified emissions reductions (CERs). Lifetime considered for corresponding CDM project activities is the most probable crediting period as defined by the CDM, e.g. one single 10 years crediting period or 7 years renewed three times, depending of the type of project considered.

Expressing the results in terms of both emission reduction and additional capacity is especially relevant for measuring the efforts required to maximize either development output (more energy) or environmental output (more emissions avoided). Choosing an option that provides cheaper emission reductions may require paying more per megawatt installed and vice versa. For example, hydropower provides cheaper emission reductions than cogeneration in industry, but gaining additional capacity is cheaper through exploring cogeneration potential than building new power plants because industrial cogeneration generates emissions from the same fuel consumption and roughly doubles the energy output, while hydropower displaces 100 percent of the baseline emissions.[98]

However, one should use caution in interpreting investment cost curves as they do not contain the benefits achieved through fuel savings, which is the most important incentive for the energy-sector, GHG mitigation option. Nor do they reflect other differences in O&M costs and commercial revenues that may affect project developers' decision to choose clean-energy over conventional options. GHG mitigation technologies are usually more investment intensive than their counterparts in the baseline. Nonetheless, the GHG mitigation option could be attractive because of the fuel savings it can generate (e.g., hydropower, wind farms, and improved cookstoves).

In the case of large and small wind farms, many such projects have been submitted to the CDM for validation. But it has not been possible to assess Sub-Saharan Africa's potential for wind energy because the technology has been unevenly assessed among countries in the region. In addition, the range of windmill sizes is increasing each year, incurring a wide range of energy output, depending on the size mixes considered. It has not been possible to elaborate a simple methodology for converting incomplete data on wind potential into a reasonable estimate of the potential of wind-farm projects. Presented below is an example of a typical wind-farm project that could be implemented in Sub-Saharan Africa. This example has been developed using data from actual projects submitted to the CDM (table 7.3).

It should be noted that the investment cost curves provide only indicative results. Detailed, case-by-case economic and financial analyses are necessary when deciding on actual projects. At this stage, it has not been possible to include such economic analysis of the cost effectiveness of clean-energy technologies inventoried in this study. Such an analysis would require numerous economic comparisons of these alternatives with more conventional ones, which, in turn, would require the collection of many additional data. But such comparisons can be done, especially at the country level, where conventional and clean-energy alternatives can be clearly enough identified by project. Where possible, illustrative cases, using information collected from various projects, are presented in the technical sections of this report (chapters 3–6).[99]

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[98] Assuming that emissions from reservoirs, for which there is no scientific way to calculate the net anthropogenic balance, can be neglected.

[99] It should be noted that unitary costs have varied significantly over the past four years as a result of the substantial price increases for equipment and materials caused by global demand. Excel files used

Table 7.3: Typical Features of Potential Wind-farm Project

Parameter	*Value*	*Unit*
Installed capacity	19.5	MW
Investment cost	20.6	million US$
Net electricity revenue	1.7	million US$
Annual emission reduction	45,000	tCO_2
Price of tCO_2	10.0	US$
Carbon revenue (per year)	0.45	million US$
Total carbon revenue (3–7 years)	9.45	million US$
IRR without CERs	6.6	%
IRR with CERs	10.1	%

An economic and financial analysis would be especially important when comparing the conventional baseline and clean-energy options because the higher investment cost per megawatt associated with clean energy may be compensated by the added revenue from the sale of carbon credit received on top of the revenue from energy sales, which defines the baseline option. This is typically the case for landfill gas-to-energy projects, whose investment cost per megawatt may be higher than that of diesel generators; but because of the high value of avoided methane emissions, the sale of carbon credit significantly affects the projects' financial rate of return, making them economically attractive.

Two references may be especially helpful in performing detailed economic analyses, as follows:

- *Study of equipment prices in the energy sector*, by URS for the World Bank (Energy Sector Management Assistance Program), April 2008.
- *Technical and economic assessment: Off-grid, mini-grid, and grid electrification technologies*, by Chubu Electric Power Company, Toyo Engineering Corporation, Princeton Energy Resources International, Energy Technologies Enterprises Corporation, and The Energy and Resources Institute, for the World Bank, November 2005.

Although exhaustive cost-effectiveness assessments could not be performed in the context of this study, the increasing number of similar clean energy projects registered in the UNFCCC CDM pipeline now being implemented in the countries of other developing regions, thanks to the CDM and Carbon Finance, strongly indicates that such clean energy projects are usually not economically meaningless when taking carbon revenues into account, and thus are worth considering as plausible options.

to calculate and generate these curves are provided in the attached CD; thus, key values can be easily updated to generate revised estimates.

Part III

Unlocking Sub-Saharan Africa’s Clean Energy Projects Potential

Chapter 8

Recommendations for Sectoral Ministers and the Donor Community

The technical assessments in Part II fulfilled the first objective of this study: to inform energy-development practitioners in Sub-Saharan Africa of the large potential of efficient, clean-energy projects that can potentially benefit from carbon finance and the increasing variety of funds, including Climate Investment Funds (CIF), that contribute to reducing the region's energy supply-demand gap and future greenhouse gas (GHG) emissions. Taking the CDM as a methodological framework, these technical assessments demonstrate that Sub-Saharan Africa offers opportunities for investing in clean-energy development; at the same time, a number of barriers must be overcome. Building on the knowledge accumulated through these technical assessments, including team visits to 12 of the countries studied, this chapter offers preliminary recommendations to energy-sector authorities and the donor community—particularly the Energy Sector Operational Units (ESOUs) development agencies—that can begin to unlock the region's potential for clean-energy projects.[100]

I. Fill regulatory and logistics gaps that prevent market access

Without appropriate market access, the potential energy-development and global environmental benefits of clean-energy projects cannot be achieved.

Today, for example, 67 sugar mills are distributed across 21 countries in Sub-Saharan Africa. They represent more than 660 MW of additional generation capacity that would be made available if 67 cogeneration projects—similar to the more than 30 bagasse-based cogeneration projects already submitted to the CDM by the Brazilian sugar industry—were implemented. To date, only two have been submitted.

With regard to fossil fuel–based energy processes in the region's existing industrial facilities, the cogeneration potential is estimated at more that 350 projects, which would deliver more than 17,000 MW to these countries. But no projects have been submitted to the CDM to date.

Because cogeneration systems are usually sized to ensure that the industry's heat demand, which cannot be imported, is satisfied, excess electricity production often results. Thus, it is imperative that industrial companies aiming to implement cogeneration systems be able to sell the excess generation; otherwise, they are unlikely to produce more than they need, preferring the simpler solution of generating heat only. Conversely, if they could sell the excess power from a cogeneration plant, not only would they obtain revenue from electricity sales; they would also receive

[100] Given the breadth of the study scope in terms of the technologies and countries assessed, further analysis is warranted to improve on these preliminary recommendations.

carbon credits for displacing the conventional power generation (e.g., diesel-fired) needed to meet growing demand. This combination of revenues often makes cogeneration competitive with carbon-intensive alternatives.

While the market-access issue does not affect clean-energy projects built onto existing large power plants, such as those adding a second cycle to open-cycle gas turbines (the potential of which is estimated at 200 projects, totaling more than 5,500 MW), it is a serious concern for non-conventional, power-generation plants. The issue is valid not only for sugar-mill cogeneration, as discussed above, but for many other forms of renewable-energy power generation, including biomass, wind farms, and small-hydropower plants.[101] The potential power generation from biomass residues is estimated at more than 1,700 projects (from agriculture, forest and wood-industry residues, landfill gas, Typha, and Jatropha), adding more than 70,000 MW, equivalent to the region's current installed capacity. Such clean-energy options are generally dispersed and of small or medium size (5–50 MW); thus, they require access to existing local markets.

However, for more capital-intensive, indivisible clean-energy options, such as the recovery and use of flared gas at oil production facilities, existing local markets are usually too small to absorb the energy generated by these generally large projects. Instead, such projects require either access to the international gas market or strong development of the domestic gas market.

In all cases, ensuring market access—either local or international—requires overcoming both "soft" and "hard" barriers, the major ones of which are regulatory gaps and logistics bottlenecks, respectively.

Access to markets requires filling regulatory gaps in the region's energy sectors.

Market access means that independent power producers (IPPs) must be able to sell electricity at an acceptable price either through equitable regulated purchase tariffs (e.g., in the case of a monopolistic public utility) or more generally through power purchase agreements (PPAs) to a distribution company or distant consumer (wheeling).

Unfortunately, in many countries of Sub-Saharan Africa, purchase tariffs are non-existent, PPAs are poorly designed, and regulators do not allow the wheeling of excess power production through existing national grids. In short, key missing elements in the regulatory framework of the electricity sector prevent clean-energy projects from benefiting from CDM and Carbon Finance. Fair purchase tariffs for the diverse types of clean energy generated by IPPs and sound frameworks for PPAs between industries and power utilities must be put in place and endorsed at the highest level of government.

Appropriate purchase tariffs are needed for intermittent power-generation options. For example, cogeneration uses seasonally-available agricultural residues

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[101] The potential of wind-farm, small-hydropower, and other forms of renewable-energy power generation could not be estimated in this study.

and wind-farm output depends intrinsically on wind variability. Traditionally, public utilities have been reluctant to buy energy from such intermittent sources since it requires a more flexible generation capacity on their part. The non-permanent nature of these options triggers complex issues regarding how the electricity generated should be remunerated. In addition, the issue of integrating such local-energy production has often been ignored by sectoral authorities. But the electricity generated has a real value that can contribute to narrowing the supply-demand gap, and various tariff and contractual formulae have been tested and adopted in a number of countries. Lessons from such experience should be made available to energy authorities in all countries of the region, along with appropriate technical assistance enabling them to tap into their respective countries' low-carbon energy sources.

Such gaps in the regulatory framework are evident in other energy subsectors, preventing the implementation of other types of clean-energy projects. This is the case for biofuels, which, like bio-ethanol and bio-diesel, cannot be blended with fossil fuels without acceptable definitions of technical specifications and licensing procedures. In the absence of such regulations, biofuels are barred from the market, and potential investors cannot expect revenue from the sale of biofuels or carbon credits. Adapting lessons from international experience in this area—namely Brazil—to the countries of Sub-Saharan Africa would require appropriate technical support.

In this regard, the recovery and use of associated gas (AG) is no exception. Since AG is generally considered waste output in the production of crude oil, little or no relevant regulation has been developed regarding its use. AG ownership rights are either unclear or non-existent. In addition, many production contracts provide no rights for downstream sale or commercialization and prevent recovery of the costs incurred to harness AG output for productive uses. In such a context, it is often difficult to attract the required investment from local and international sources to develop gas infrastructure to a level that can reduce flaring significantly. The World Bank–hosted Global Gas Flaring Reduction (GGFR) program has already been helpful in this regard and will continue to play a relevant role in mitigating the barrier to gas flare-out projects in Sub-Saharan Africa.

Market access requires appropriate infrastructure planning and policies to overcome logistics bottlenecks.

Some potential clean-energy projects are located in places already well connected to energy transport infrastructure. For the power subsector, examples include the addition of a second cycle to an open-cycle power plant, cogeneration from fossil fuels or industrial biomass residues, and energy-efficiency measures (e.g., switching to compact fluorescent lamps and more efficient industrial equipment and household appliances). But in many cases, when added generation capacity is to be installed, the transmission capacity of the existing grid is insufficient to carry the additional power to the market. In many other cases (typically agriculture, forest and wood-industry residues, and other such biomass as Typha and Jatropha), the primary energy resource is dispersed and distant from the grid, incurring a dual logistics challenge: constructing high- or medium-tension transmission lines to bring power to the market and, in the case of dispersed biomass, collecting and transporting it to the transformation facility. Regarding power evacuation, if clean-energy project developers bear the total investment cost and financing of transmission-lines construction, the added burden is likely to render the project infeasible and unattractive to non-conventional players whose core businesses are unrelated to energy. Instead, development of the required infrastructure must be undertaken as part of overall transmission-system planning and development. In the same way that it is common practice to charge consumers tariffs calculated to reflect systemwide development costs, including the distribution and transmission of investments for which they are responsible, it is essential that investment in the transmission lines required to evacuate clean energy is borne collectively by the sector and then charged to clean-energy project developers via transmission tariffs. This arrangement requires appropriate planning of both clean-energy grid development and transmission and an appropriate cost-sharing policy. To achieve this objective, many countries in Sub-Saharan Africa require planning-capacity support provided by external technical assistance.

Another key bottleneck to the capture and market distribution of flared AG is the high investment cost of energy transport infrastructure. In all oil-producing countries of Sub-Saharan Africa, the local markets where natural AG can be used are either too small or located in dispersed areas far from gas-producing fields, requiring heavy investments in in-country transmission-and-distribution infrastructure. For the domestic energy market to play a significant role in the gas flare-out strategy, the required gas transport-and-distribution infrastructure must be in place. A related issue is the inertia of local gas markets. Fuel switching by the power sector can serve as the catalyst for using the gas in other sectors of the economy. This was demonstrated in Nigeria, where the power sector has acted as the anchor for demand and catalyst for boosting use within the country's economy. A country's power-generation requirements for natural gas can serve as the driving force for extending the gas network.

Lack of transport systems also inhibits development of biomass based–clean energy. For example, collection of biomass residues from agriculture and forest and wood-processing industries, usually located in remote areas, is often barred by poor transport infrastructure, rendering the residues unrecoverable. Poor transport also constrains the collection and use of Typhus by preventing the delivery of required mechanical-harvesting equipment at collection sites. Furthermore, without careful planning of the entire product chains, other infrastructure and logistics costs (e.g., storage and drying) can be expensive.

Summing up, overcoming such logistics bottlenecks requires adequate policy design and planning of the development of the production-transport-market gas chain. Planning is the initial critical step to formulating infrastructure development programs that can allow for the redistribution of investment costs to bearable levels. As discussed more generally in Part I of this report, the decision to undertake large transmission or gas-transport investment programs must be supported by a sound economic assessment that internalizes the global benefits of clean energy. An easy technique for achieving this is to allocate to those benefits the value that the carbon market is willing to pay for them. While not perfect from a theoretical perspective, this technique reflects the incentive perceived by economic agents.

II. Support local capacity development

Development of clean-energy projects in countries of Sub-Saharan Africa requires the operation and use of modern technologies (usually not cutting-edge techniques) that are not readily available. Such technology transfer requires selected capacity-development activities that depend on the clean-energy potentials targeted. These activities range from research and development to training and information dissemination.

Technical information dissemination is needed on mature, clean-energy technologies.

Sustainable clean-energy development in Sub-Saharan Africa is hindered by a lack of knowledge, information, capacity, and effective communication on the development of clean-energy technologies, including the necessary background data and inventory of potential energy sources and financial options. The effects of such gaps on decision-making were exemplified in the case of cogeneration potential. Most small- and medium-sized industries in the region ignore the opportunity for improved profitability and competitiveness provided by the cogeneration option. The technical facts, often not captured in the decision-making process, are that the best thermal efficiency from a stand-alone system is about 55 percent, compared to a minimum of 85 percent from today's more advanced combined heat and power (CHP) system.[102]

Similarly, in industry, lack of knowledge about more energy-efficient alternatives (e.g., efficient electric motors, steam and cooling systems, and lighting), which are theoretically attractive even without carbon revenue, contributes to the ongoing use of inefficient devices. Even technologies widely used abroad, such as mechanical recompression for waste-gas power generation in oil refineries, is not commonly applied in Sub-Saharan Africa.

Distorted perceptions about cleaner-energy options can also prevent clean-energy development. For example, in addition to the lack of inventory of coal mine methane (CMM) sources, lack of interest in investing in CMM projects is impeded by the perception of many coal industry officials and mine operators, who regard CMM as a safety hazard rather than a valuable energy resource. In the case of agro-industry and the wood-processing industry, a similar perception persists with regard to industrial biomass residues (e.g., sugarcane bagasse, groundnut shell, rice husk, and palm fiber).[103] Such residues are viewed as a waste-disposal issue, or at best, are partially burned in an inefficient manner to generate a limited amount of process heat as a way to eliminate an undesirable byproduct. However, as the technical chapters in

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[102] In such countries as Brazil and India, the commercial dissemination of CHP began more than 15 year ago.

[103] More complete listings of agricultural and agro-industry residues are provided in chapter 3 (sections 3.4 and 3.5).

Part II of this report demonstrate, there is an enormous potential for agricultural and agro-industrial processing. Not only can certain of these processes halt electricity consumption. Indeed, they can result in more than 44,000 MW of net power production.[104] This is also the case with regard to the blended cement option versus the energy-intensive Ordinary Portland Cement.[105]

Therefore, the first step to engage potential developers of clean-energy projects in Sub-Saharan Africa who current run inefficient facilities or waste bio-energy is to disseminate information to them on technologies that would become attractive to them via carbon revenues (and sometimes even without them). One approach might be to jointly organize technology-focused national or multinational information campaigns with equipment and technical-services providers, targeting the specific technologies that match the region's available clean-energy potentials and decision makers of corresponding companies. To this end, organizations created to promote certain technologies, such as COGEN Europe or World Alliance for Decentralized Energy (WADE), could be enrolled.

Training programs are needed to fill technical-skills gaps related to mature, clean-energy technologies.

In Sub-Saharan Africa, a significant share of GHG emissions is derived from inappropriate maintenance schemes, which itself derives from a labor force that lacks adequate skills. For example, as explained in technical assessments in Part II, many refineries currently run at low-capacity utilization because of improperly implemented maintenance standards, which result in frequent breakdowns of facilities.

Similarly, the region's primary barrier to implementing industrial steam-system, energy-efficiency improvement projects is lack of adequate repair capacity. That is, when steam traps malfunction, they are not immediately repaired or replaced; as a result, condensate are released routinely into drainage lines, and considerable amounts of enthalpy, which should have been put into productive use in industrial processes, are lost.

Clean-energy development often requires training and capacity and skills building of operators and users of clean-energy technologies. It is important that the staff responsible for the operation and management of the energy-related equipment be trained in its use so that countries across the region can build national capacity for clean-energy technology applications. If based on the traditional turnkey approach of imported technology, scaling up and efficiency will be limited.

In the area of bio-energy, a lack of mastery of certain techniques by the labor force also generates certain bottlenecks that limit the development of corresponding clean-energy potential. For example, for Jatropha farming targeted at bio-diesel production, the key question is whether the introduction of Jatropha farming techniques will permit high enough yields to make the bio-diesel production

[104] Cumulated potential generation capacity from bagasse, agricultural and agro-industrial residues, and forest and wood-processing industry.
[105] See chapter 4 (section 4.5).

competitive with petrol-diesel. In this context, agricultural extension services are needed.

Research and development (R&D) is needed to enable clean-technology efficiency and sustainability.

In Sub-Saharan Africa, the capacity to adapt technologies to local resources is relatively low compared to other regions. For example, biomass products usually require drying and size reduction to become a usable fuel. In other applications, it may be necessary to carbonize the biomass (use it to produce charcoal) before it can be readily used as fuel for domestic and commercial end-uses. At the extreme end is the gasification route, which requires intensive technical know-how. The equipment required to capture the full energy potential from local biomass is not readily available in most countries of the region. As a result, R&D activities are required to adapt efficient pre-use transformation solutions and combustion equipment to the specific characteristics of the region's biomass residue types.

Research and knowledge should be gathered on how to reduce time and costs associated with biomass collection, transport, and related infrastructure and logistics issues. For example, the capacity of the manual method (using a sickle) for harvesting Typha is 40 kg per person hour. Inadequate water and road transport networks can make access to resource harvesting for fuel difficult and expensive. Collection and mechanical harvesting require amphibian vehicles with working platforms on which mechanical harvesting units can be mounted.

Another option for addressing the logistics challenge is to develop local use of local clean-energy potential. For example, the development of cooling systems for crops conservation uses heat energy that agricultural residues can easily provide, using low-pressure boilers. Since the conservation is done on-site, the agricultural residues are used at the site, eliminating the collection and transport problems.

The need for R&D extends beyond bio-energy. More conventional industries also depend on country-specific R&D in order to explore emission-reduction potentials. This is the case for the production and use of blended cement, for which R&D is usually required before product marketing, including extensive testing, can be launched.

Local research is required not only to get the most from the local clean-energy potential at the lowest costs, but also to ensure sustainability of its use. With regard to biomass residue—one of the most attractive clean-energy potentials because of its numerous potential benefits for both the local energy sector (e.g., reduced dependency on high-priced petroleum products) and the economy (e.g., new income-generation activities)—environmental and social impacts assessments are particularly important. With regard to subsistence farming practices in Sub-Saharan Africa, agricultural productivity is particularly sensitive to the amount of post-harvesting residues left on the farm. Key functions of residues on such farms include protection against soil erosion, reduced compaction resulting from heavy rains, moisture conservation (thereby reducing the need for irrigation), maintenance of a more even soil temperature, and weed-growth prevention. The expanded use of residues for energy may grossly affect farming activities. Therefore, it is critical that agricultural research be conducted to strike an optimal balance between use as a fuel and alternative utilization.

Local CDM and Carbon Finance expertise and institutional procedures must be developed.

Based on the experience of this report's authors, who participated in many activities aimed at promoting CDM in Sub-Saharan Africa, a key obstacle during the project-identification stage is the relevant actors' inadequate information and knowledge base with regard to CDM and Carbon Finance (CF) opportunities and procedures. In many countries across the region, the CDM process is known to only a few individuals, most of whom are not authorized to identify projects. Many past capacity-building programs involved seminars and workshops that were either too theoretical or that targeted a limited group of professionals, mostly from already established institutions in the environment community, such as representatives of environmental ministries or Designated National Authorities (DNAs). While certain countries in the region require support in appropriately establishing DNAs, past CDM capacity-building activities have focused disproportionately on DNA and not enough on potential project participants and other stakeholders positioned to remove certain barriers. During its 12-country, data-collection visits, for example, the study team discovered that technical personnel and management staff of industries in the region had heard about the CDM and Kyoto Protocol but lacked in-depth knowledge of the CDM process. Ensuring that potential project developers are informed and convinced of CDM opportunities is vital for developing such projects.

Like many other developing regions, Sub-Saharan Africa has traditionally viewed global environmental benefits as a topic exclusive to environmental ministries. As a result, energy-sector stakeholders have remained largely unaware of the potential sectoral support available from climate change–related mechanisms and funds. One way to mobilize these stakeholders is to offer awareness-raising activities that can reveal the alignment between potential sectoral benefits and national sectoral strategies (e.g., eliminating dependence on high-priced petroleum products, developing the use of local energy resources, integrating alternative resources into the sector, and managing demand).

Most, if not all, countries in Sub-Saharan Africa have well-trained professionals who could, if properly trained, assist potential project developers in the preparation of clean energy CDM projects (so that they can be integrated into carbon-fund portfolios) and completion of the required steps in the CDM process, including preparation of the Project Design Document, development and approval of a new methodology or variation thereof, contracting an accredited certifier (known as a Designated Operational Entity), and project validation and registration.

One critical lesson from international experience is that capacity building must target the right groups. In this context, the recommended core targeted groups are decision makers from industries and local engineering consulting firms. Technical capacity building covering project identification, design, and implementation should involve learning-by-doing strategies involving local consultants together with project developers. In addition, relevant institutions should be informed of their potential CDM-development role within their respective countries. In the case of energy-sector authorities, this role would involve taking appropriate actions to remove specific sectoral barriers that discourage potential project developers from investment.

Appendix 8.1 presents a seven-step strategy to begin to unlock the potential of clean energy projects. This strategy has been developed and tested by the World Bank in Haiti and Senegal, with respective financial support provided by the World Bank and Japanese Policy and Human Resources Development Fund (PHRD).

It is necessary to consider the timely creation of new institutions, as well as widening the competency of existing ones. This may be the case for implementing large-scale, energy conservation programs. Even in more developed countries like South Africa, it remains unclear who should manage large-scale, energy-efficiency and/or demand side–management programs. Depending on the type of technical opportunity considered, more precise, country-specific assessments of institutional gaps should be conducted.

III. Earmark post-2012 carbon funds and concessional financing to overcome investment financing barrier.

With the exception of cases where the cleanest energy alternative is the most cost effective, clean energy options usually incur costs beyond those of conventional options. Thus, in addition to the general investment barriers faced by all projects in the region requiring external development funding, most clean energy options require additional support, reflecting their global environment benefits, in order to compete with more conventional, carbon-intensive options.

Post-Kyoto carbon funds are required to internalize the global benefit in investment decisions and level the playing field for clean-energy technologies.

As explained in Part II of this report, certain clean-energy options, particularly those based on renewable energy, are not competitive when the energy market gives zero value to the global environmental benefits such alternatives provide. This is the case for biomass-based power generation and fuel production. While the cost-effectiveness of renewable options has improved with higher oil prices, biomass-to-energy facilities are smaller than conventional fossil fuel–power plants, not allowing the same economies of scale. Other cost components specific to biomass systems, such as extra collection costs and requirements of pre-fired biomass handling and processing units, are incremental costs compared to those of conventional fossil fuel–power plants. While many similar projects already submitted to the CDM by such emerging economies as Brazil, China, and India are being implemented, in Sub-Saharan Africa, the costs of adaptation, learning, and training are unavoidable for first-of-a-kind technologies, creating an added burden for such clean energy projects.

In the context of competition for limited investment capacity, even clean energy projects involving more mature, economically viable technologies are losing against more attractive options. For example, the gas-infrastructure investments required to use flared associated gas or coal mine methane (CMM)-to-energy projects are characterized by a lower return on investment compared to opportunities in the development of oil or coal production. It is therefore necessary to develop clean energy projects in Sub-Saharan Africa so that their global environment benefits can be monetized and internalized in investment decisions.

The number and wide range of clean energy projects submitted to the CDM worldwide have demonstrated that carbon finance is effective in achieving such internalization. But most CF transactions are limited to the first commitment period of the Kyoto Protocol, which ends in 2012. Because of uncertainty regarding the post-Kyoto regime, it has become difficult for CDM projects to monetize their post-2012 GHG emission reductions. Because of Sub-Saharan Africa's delayed start in CDM implementation, by 2012, most of the CDM-eligible, clean energy projects implemented in the region are expected to deliver only a small fraction of their emission reductions. Without financial instruments in place to monetize these projects' environmental contribution, the prospects for such clean energy projects to become cost effective are poor; and conventional, carbon-intensive solutions will continue to be implemented. Even worse, in certain countries, inefficient and costly fossil fuel–based power plants will require repeated repair, and power outages will continue to spread.

Thus, the creation of financial instruments to provide financial value to future emission reductions from clean energy projects in Sub-Saharan Africa (e.g., new carbon funds buying post-2012 CERs) appears to be an absolute condition for countries in the region to develop their large potential of clean energy projects and thereby move ahead on a cleaner development path. Featuring such carbon funds to facilitate access for projects in the region would be desirable. Most CDM projects in the region are smaller than the minimum size required by many existing carbon funds. Although this issue can be addressed, in part, by bundling together many similar smaller projects under the CDM's Program of Activities, such aggregation can trigger difficult coordination challenges, especially when similar projects are located across borders in countries in conflict or post-conflict situations. Therefore, special windows streamlining access for smaller clean energy projects located in least-developed countries, such as those in Sub-Saharan Africa, remains a desirable feature for post-2012 carbon funds.

But Carbon Finance alone will not solve the investment financing gap: Earmarked Climate Investment Funds are essential.

Lack of investment and financing capacity is a chronic barrier for any capital-intensive infrastructure in Sub-Saharan Africa. While the local commercial banking sector is liquid in many of the region's countries, high risk adversity regarding any long maturity projects prevents commercial banks from offering the required long-term loans. These countries' poor credit ratings prevent local and foreign project developers from capturing financial resources on the international financial market, whether involving conventional or innovative, clean energy projects.

It should be noted that carbon finance will not significantly help to resolve this issue for clean energy projects. Carbon funds provide neither equity nor investment financing. Commercial banks welcome Emission Reduction Purchase Agreements (ERPAs) signed with highly rated entities, such as the World Bank carbon funds, and there is some experience in emerging economies issuing guarantees or bonds against future carbon revenues. But in most cases, carbon finance would provide only a limited share of the cash flow expected by clean energy projects. Thus, the core issue of how to finance the region's clean-energy infrastructure investments remains.

Today, only central government budgets or ODA provided by the donor community can help infrastructure projects, whether conventional or clean energy, reach financial closure. However, these resources are too limited, which contributes to a lack of planning with regard to future required investments. As a result, electric power companies in countries of Sub-Saharan, which are mainly public companies, are under political pressure to generate at all cost to serve suppressed demand. Hence, they find themselves trapped in an emergency-response mode. In the context of a permanent looming crisis, governments and electric power companies usually seek quick fixes and less capital-intensive options to meet more immediate power needs. Certain innovative, clean-energy options, such as efficient lamps (e.g., CFLs and LEDs) can offer quick, cheap fixes to reduce the supply-demand gap. However, with regard to new generation-capacity needs, low-investment solutions, featuring shorter implementation time frames, are generally expensive to run and more intensive in GHG emissions. In many smaller, poor countries (e.g., Burkina Faso, Burundi, Cape Verde, Chad, and Senegal), such solutions often entail the multiplication of small-diesel or heavy-fuel-oil generators (less than 10 MW each) and even the short-term repair of outdated, inefficient gensets. In such larger countries as Kenya and Nigeria, power-utility decision makers are more likely to implement Greenfield single-cycle facilities, which are cheaper to implement and quicker to build compared to combined-cycle systems. Similarly, given the higher unit investment costs of most hydropower projects and the longer time frame required for their development, much of the region's hydropower potential has not been realized.

A similar logic applies to non-conventional, clean-energy alternatives, such as industrial cogeneration or energy-efficiency measures. Many industries currently face a structural financial crisis and thus avoid investing in performance improvements or non-core business activities, preferring to reserve virtually all of their liquidity for the purchase of raw materials, which are usually paid for in cash.

Breaking this vicious circle, which harms both the countries' economies and the global environment, requires solutions that extend beyond the current financing of short-term needs and carbon funds to internalize global benefits. Investment-financing instruments, earmarked to promote medium-term clean and efficient solutions, are required (boxes 8.1, 8.2, and 8.3). Ensuring the compatibility of the new Climate Investment Funds (CIF) and other financing instruments with the CDM is vital since many clean energy projects in Sub-Saharan Africa will need to overcome a lack of investment financing and low returns compared to other investment opportunities and thus remain eligible for the CDM and new carbon funds like the Carbon Partnership Facility (CPF). The expected grants, concessional loans, and risk-mitigation instruments to be provided by the CIF should not be viewed as a market distortion against conventional, fossil fuel–based energy projects. Rather, they represent the internalization of environmental benefits, which must be shaped in efficient ways along the investment decision chains. In short, the CIF can extend the range of available instruments beyond carbon funds to ensure a fair remuneration of the global environment benefits provided by clean energy projects.

Box 8.1: Climate Investment Funds

In July 2008, the World Bank Board of Executive Directors formally approved the creation of Climate Investment Funds (CIF), paired international instruments designed to provide interim, scaled-up funding to help developing countries' efforts to mitigate GHG emissions and adapt to climate change.

The two trust funds created under the CIF—the Clean Technology Fund and Strategic Climate Fund—have total investments targeted at US$5 billion each. The Clean Technology Fund provides large-scale financial resources for projects and programs that contribute to the demonstration, deployment, and transfer of low-carbon technologies. Such projects and programs must have a significant potential for long-term GHG savings. The Strategic Climate Fund, broader and more flexible in scope, is an overarching fund for various programs to test innovative approaches to increasing resilience to climate change.

To be disbursed as grants, highly concessional loans, and/or risk-mitigation instruments, the funds are administered through multilateral development banks and the World Bank Group for quick, flexible implementation of country-led programs and investments. Developing countries will have an equal voice in the funds' governance structures, and decisions on their use will be reached by consensus. At annual Partnership Forums, the first of which is scheduled for September 2008, stakeholders are provided a venue for discussing the funds' strategic directions, results, and impacts.

The CIF were designed through inclusive and extensive consultations in support of the Bali Action Plan. Potential donors and recipients, the United Nations family, multilateral development banks, civil society organizations, and the private sector all took part. At a culminating design meeting, held in Potsdam, Germany in May 2008, representatives of some 40 developing and industrialized countries agreed to create the CIF. Participants have taken care to recognize the primacy of the UNFCCC in global climate negotiations.

Box 8.2: Carbon Partnership Facility

The World Bank Carbon Partnership Facility (CPF), approved by the Bank's Board of Directors in September 2007, promotes long-term investments in low-carbon growth by purchasing emission reductions, primarily in the post-2012 period. The Facility is designed to scale up carbon finance through programmatic and sector-based approaches to GHG mitigation that will catalyze a downward shift in emission trends in certain sectors at the country level.

A partnership between buyer and seller governments and private-sector entities from developed and developing countries in envisioned whereby sellers and buyers participate on an equal basis—that is, sellers pledge emission-reduction opportunities for development into carbon assets, while buyers pledge to purchase these assets. A partnership committee, co-chaired by seller and buyer representatives, periodically endorses the pricing approach and form of Emission Reduction Purchase Agreement (ERPA), including general conditions.

The CPF consists of two instruments, structured as World Bank Trust Funds: 1) Carbon Asset Development Fund and 2) Carbon Fund. The Carbon Asset Development Fund holds funds generated from fee payments from buyer and seller participants and donor contributions; its purpose is to develop programs that yield emission reductions for their later purchase on behalf of the buyer. The Carbon Fund uses financial contributions from buyer participants (governments or public- and eligible private-sector entities) to pay for emission reductions as they are received.

The target size of the CPF over the next five years of operation is estimated at €5 billion.

Box 8.3: Japan's Cool Earth Partnership

In January 2008, Japan unveiled its Cool Earth Partnership, a five-year, US$10 billion fund through which the country cooperates actively with developing countries' efforts to reduce GHG emissions and assist those countries that suffer severe adverse effects of climate change. Based on policy consultations between Japan and respective developing countries, assistance is provided for reducing GHG emissions, while achieving compatible economic growth.

Up to $8 billion is directed toward assistance in climate-change mitigation. A climate-change ODA loan amounting to $4 billion is used to implement programs to address global warming in developing countries. The other $4 billion finances projects to reduce GHG emissions in developing countries via capital contribution and guarantee of Japan Bank for International Cooperation, trade and investment insurance, and government support, together with private funds. The Asian Clean Energy Fund of the Asian Development Bank is used to promote energy conservation in the Asia-Pacific region.

Another $2 billion is set aside for assistance in adaptation to climate change and improved access to clean energy. Grants, aid, and technical assistance are provided to developing countries switching to clean energy. A new grant-aid scheme, called the Environment Program Grant Aid, is a key component of this package.

Regarding adaptation to climate change, vulnerable countries, including African and Pacific island nations, are assisted in planning and taking adaptive measures to prevent or mitigate such climate change–related disasters as floods and droughts. With regard to improved access to clean energy, communities lacking access to sufficient modern-energy supplies are provided assistance in economic-development activities using solar power, small-scale hydropower, and other forms of clean energy. Upcoming activities feature a feasibility study on rural electrification projects using geothermal energy and co-benefit projects that address climate change.

IV. Donors' Energy Sector Operational Units have a unique set of organizational features to overcome most barriers.

While countries in Sub-Saharan Africa may have a smaller global volume of emission-reduction opportunities than emerging economies, the international donor community annually finances or guarantees numerous energy infrastructure projects in countries across the region. The World Bank alone approves about US$1 billion in loans or guarantees for energy-sector investment projects in the region every year. The African Development Bank (AfDB), German Development Bank (KfW), and French Development Agency (AFD) also provide significant energy-project financing in countries of the region. In short, the smaller share of worldwide foreign direct investment (FDI) is nonetheless significant for Sub-Saharan Africa.[106] Moreover, the private sector is developing many energy projects in the region, though fewer than desired by governments and donors who stimulate private-sector participation via guarantee instruments.

All of these investments offer opportunities for reducing emissions by factoring in one or more of the clean-energy CDM activities presented in Part II of this report (box 8.4). But to date, only a marginal share of these projects has explored such opportunities. Despite the CF community's notable offer to purchase emission reductions at more attractive prices than in other regions, Sub-Saharan Africa's meager share of projects in the official records of the UNFCCC CDM pipeline remains remarkable.

Box 8.4: Integrating Carbon Finance into the IPP Bidding Process

Appropriate design of the bidding process for Independent Power Producers (IPPs) can ensure that less emitting options can compete and benefit from carbon revenues. For example, if a project needs to select an IPP to install and run additional capacity required by demand development or decommission older facilities, preparatory studies can consider and prepare two options: 1) the least-cost option that would have been considered without the CDM/CF (e.g., a diesel plant in Senegal or a gas-fired open cycle in Ghana) and 2) a less emission-intensive option (e.g., combined cycle) that may be less profitable because of its lower financial IRR, higher capital requirements, or other risks that may require an offer with more attractive conditions.

For both options, CO_2 emissions and potential GHG emissions avoided would be calculated. According to the price conditions offered by carbon funds, potential carbon revenues would be calculated and the financial analysis revised. If the calculations show that option 2 can compete with option 1, an Emission Reduction Purchase Agreement (ERPA) could be prepared with a carbon fund. This ERPA would then be integrated into the bidding documents to select the IPP. Adequate bid-evaluation modalities would be prepared, and bidders would be authorized to make offers on either option, but only option 2 would offer the carbon revenues detailed in the ERPA.

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[106] In 2006, countries in Sub-Saharan Africa received US$17 billion as net FDI inflow (with the exception of South Africa, which had a 2006 net inflow of about zero), inclusive of all sectors, which represented 3.7 percent of total FDI received by non-Annex 1 countries (World Development Indicators online).

A series of objective reasons accounts for the region's poor portfolio of clean-energy CDM projects and CF transactions. Chapters 3-6 present many of the specific barriers for the 22 technologies considered in this study. Interestingly, the Energy Sector Operational Units (ESOUs) of Multilateral Financial Institutions have a history of confronting and overcoming most barriers that currently limit the development of such projects in the region.

Sub-Saharan Africa's private sector is weak, but ESOUs have a history of promoting private-sector participation.

To date, clean-energy CDM projects in other developing regions have been developed mainly by private sponsors, and most ERPAs have been signed with private companies undertaking the principal investment on their own. The limited flow of independent private investment in Sub-Saharan Africa explains, in large part, the region's lack of such projects. At the same time, the Energy Sector Operational Units (ESOUs) of donor agencies have a history of designing projects that aim at attracting and supporting private investment. Typical examples are donor-supported projects facilitating Independent Power Producers. Thus, ESOUs are well equipped with the expertise and organizational experience required to facilitate the development of private-based, clean energy projects in the region's energy sector.

Clean energy projects in Sub-Saharan Africa require external technical expertise, and ESOUs are used to providing large amounts of technical assistance.

Carbon funds lack the sectoral expertise required by most clean energy projects in Sub-Saharan Africa; furthermore, they cannot divert resources to finance it. ESOUs, on the other hand, have a history of providing such technical assistance, either from their own staff or technical-assistance funds available for project preparation. Good examples that could be applied in the Sub-Saharan Africa context include technical and non-technical loss-reduction projects in public utilities, community-based projects to develop sustainable agroforestry for woodfuel and charcoal production, and decentralized rural electrification projects using photovoltaics.

Donor community–financed energy investment projects usually devote millions of dollars for technical assistance. Thus, if recipient countries are willing, future ESOU-supported projects could easily incorporate technical assistance to address many of the above-mentioned needs for capacity development, especially if additional funds are made available for that purpose. For example, ESOUs could support the development of missing elements in a country's energy-sector regulatory framework by purchasing tariffs for excess power generated by auto-producers. Or they could disseminate information on clean technologies compatible with carbon finance that contribute to increased energy supply, such as cogeneration in industry. In short, there are numerous opportunities to offer technical-assistance activities that serve the development objectives of such projects.

Clean energy projects in Sub-Saharan Africa require ODA financing, which ESOUs can channel to the project level.

Because of the myriad investment barriers previously described (e.g., poor country ratings and weak financial markets), both private- and public-based energy projects are difficult to finance in Sub-Saharan Africa. In most cases, financial closure can only be reached with the financial support of Multilateral Financial Institutions. While carbon funds cannot provide investment financing, ESOUs are the main ODA providers for energy projects in Africa. The ESOUs' long experience and know-how in directing large volumes of financing to conventional energy projects can be instrumental in channeling resources of the newly created Climate Investment Funds (CIF) to finance clean energy projects.

Decades of trust building and direct access to key decision makers position ESOUs to assist sector authorities to fill the awareness gap and remove policy barriers.

This study's analysis of the barriers that prevent CDM-eligible, clean energy projects from being developed in Sub-Saharan Africa underscore the importance of filling regulatory gaps in the region's energy sector. The lack of purchase tariffs for auto-producers, technical specifications for blending biofuels, licensing processes for the use of waste gases, and many other concrete examples presented in this report suggest what actions energy-sector authorities in the region must take to mitigate barriers for clean energy projects. As discussed above, because global environmental benefits have been viewed as a topic exclusive to environmental ministries, energy-sector stakeholders have remained largely unaware of the support the sector could obtain from climate change–related mechanisms and funds. The extensive networking and trust built by the ESOUs with the region's energy-sector ministries, public utilities, and private decision makers over several decades of policy dialogue and financial support well position them to fill these gaps and channel the capacity-building activities required to develop and implement measures that can unlock these benefits.

Many large, clean-energy projects in Sub-Saharan Africa require multi-country coordination, and ESOUs are organized to partner with several countries at the same time.

As discussed previously, many smaller countries in Sub-Saharan Africa require international coordination to enable the development of large, clean-energy projects. This is the case for regional grid-transmission systems and gas pipelines needed to convey large volumes of energy generated by hydropower plants to regional markets. The Global Gas Flaring Reduction (GGFR) program of the World Bank is a good example of how multilateral development agencies can catalyze the effective coordination of large private and public actors.

The transaction costs of numerous dispersed, small-scale clean energy projects—from energy-efficient motors and steam traps for industry to small-scale hydropower plants and diverse biomass-based energy—might be streamlined via large national or multinational Programs of Activities. Unbiased coordination may also be required when carbon revenues deriving from an entire chain of activities must be shared among various countries and stakeholders. This would be the case for the hydro-energy development chain, construction of transmission corridors, and consumer-market regulatory adjustment. This would also be true for the use of agricultural residue, in which case carbon revenue can be used to generate collection value, in addition to being used at the industrial production stage.

In other cases, coordination is required between sectors that have no previous experience working together. This is the case for landfill-gas capture for energy generation. As discussed previously, in Sub-Saharan Africa, where uncontrolled waste dumping is still common, the capture of methane to generate energy could not occur without incorporating it into a broader waste management project that addressed such issues as scavenging and local environment impacts. Interestingly, a waste-gas or waste-to-energy project could create a new dynamic to facilitate development of the waste management project via cash revenues from energy and carbon-credit sales.

Across Sub-Saharan Africa, ESOUs are already playing an unbiased role to catalyze coordination. Such regional capacity further positions them as natural partners to prepare and implement needed complex projects and programs. Furthermore, ESOUs can facilitate South-South cooperation to help countries in Sub-Saharan Africa benefit from the successes achieved in other developing countries (e.g., biomass cogeneration in Brazil and India). Moreover, because a significant share of industries belongs to foreign multinational companies, with decision processes distant from local operational conditions, it is difficult to internalize local opportunities. The ability of ESOUs to communicate with both local stakeholders and multinational companies can help to resolve such coordination issues.

In summary, because of their experience in overcoming most of the barriers identified in this report, the Energy Sector Operational Units (ESOUs) of donor agencies are strategically positioned to help unlock Sub-Saharan Africa's large potential of clean-energy projects. Because of their long history of maintaining policy dialogue across the region and providing the energy sector needed technical assistance and financing at both national and regional levels, ESOUs may not only help to change current high-emission energy projects into high-emission-reduction energy projects. They can unlock non-conventional, clean-energy projects that can benefit from the large volume of eco-dollars provided by carbon finance and climate investment funds.

Appendix 8.1: Main Steps in a Strategy To Unlock Clean-Energy-Project Potential in Small Countries

The following strategy has been developed and tested by the World Bank in Haiti and Senegal, with respective financial support provided by the World Bank and Japan's Policy and Human Resources Development Fund (PHRD).

Step 1: Hire a pair of international and local experts to create country momentum.

Hire a pair of consultants—one experienced internationally and the other well-connected locally—to identify key stakeholders: energy, environment, agriculture, and transport ministries; public utilities; selected industrial companies; energy, agriculture, and natural-resources consultants; and financing institutions, including private-sector branches of international aid agencies.

Using the reputation capital of the donor (e.g., World Bank), facilitate the team's contacts with key individuals. Then organize an initial workshop for these and other key individuals where the project purpose and objectives are announced and awareness-raising presentations are given on the success of CDM/CF in the energy sectors of other countries and the international financial instruments available (e.g., carbon funds and CIF). Have one or two representatives of international carbon funds present on CF opportunities and procedures.

Such a workshop helps to identify the best local consultants interested in developing their capacity in this area.

Step 2: Develop local CDM expertise.

Select a small group of local consultants and organize an in-depth training session in which the international consultant familiarizes the local consultants on core CDM concepts and the most relevant CDM methodologies for their country. Request that the local consultants select sectors and opportunities with which they already familiar in order to adapt the training and develop a pragmatic work plan to identify additional opportunities.

Step 3: Reveal the breadth of the potential benefits of CDM/CF in the energy sector of the country and identify key barriers.

Applying a methodology similar to the one used in this study, collect data with the selected local consultants to determine how many clean-energy CDM projects relevant to the country could be developed using already approved methodologies. (Use similar projects already submitted to the UNFCCC CDM secretariat for validation as a reference.) Calculate these potential projects' contribution to the energy sector and the flow of carbon revenue they would channel into it.

Step 4: Identify barriers and recommendations to overcome them.

For each segment of the clean energy potential, identify existing and future barriers to project development. (The barriers identified for each technology in Part II [chapters 3-6] of this report can be used as an initial checklist.)

Based on international experience in overcoming such barriers, request the lead pair of consultants (assisted by the local consultant) to adapt the recommendations based on consultations with relevant stakeholders. (The recommendations proposed for each technology in Part II [chapters 3-6] can be used as a starting point.)

Step 5: Bring international experience to bear on streamlined DNA-approval procedures.

Based on a diagnosis of the DNA's current status, provide advice, if needed, on simple legal solutions to finalize its creation. (The minimum requirement would be a simple ministerial decree from the Ministry of Environment.)

Bring international best-practices examples to bear on streamlining DNA-approval procedures. Through consultations with relevant government representatives, request that the international consultant adapt such examples to the local institutional context.

Step 6: Demonstrate the effect on selected key projects.

Hire the selected local consultants that have successfully completed the technical training session. Have them prepare one or two Project Idea Notes (PINs) on real-life projects to present to interested carbon funds or at the annual carbon-market fair. These local consultants should select, together with the lead consultant pair, project opportunities with which they are already familiar, including key contacts for the potential project developer to establish.

Have the pair of lead consultants (with support of the donor representative, if needed) accompany the local consultants in their initial contacts with the potential project developer.

Request that the international consultant coach the local consultants both individually and as an interactive team, together with interested project developers, in their PIN development. Have the international consultant introduce examples of best practices for similar projects. Seek early feedback from carbon-fund representatives to raise the PINs to the required quality level.

When ready, the PINs are submitted to the carbon funds by project developers, presented at the annual carbon fair by national-delegation participants, or otherwise appropriately disseminated. To date, Senegal has developed 12 demonstration PINs, while 7 have been developed in Haiti.

Step 7: Organize a national seminar to share results and provide recommendations for further development.

When the output of steps 3-6 are ready for presentation, organize a national seminar. Invite the key stakeholders initially identified to present the following: 1) potential for clean energy projects in the country, including the expected effect on improving the demand-supply balance; 2) demonstration projects, with the participation of the project developers and local consultants that assisted them, as well as interested representatives of carbon funds and financial institutions potentially interested in project co-financing; 3) the approval procedure, with the participation of the DNA; 4) the sectoral accompanying measures recommended to overcome certain barriers, with the participation of the Ministry of Energy and public utility; 5) further capacity development or technical-assistance support required to overcome the remaining barriers, with the participation of representatives of international capacity-development programs, such as CF-Assist and donor-community, sectoral operational units (e.g., energy specialists from Multilateral Financial Institutions working in the country).

Beyond the presentation of the results, this national seminar should be seen as an opportunity to facilitate contact between key stakeholders—including project developers, financial institutions, and carbon funds—who will need to work together.

Chapter 9

Conclusion

The initial motivation of this study was to evaluate Sub-Saharan Africa's potential for clean energy projects under the Clean Development Mechanism (CDM) of the Kyoto Protocol. The region's meager representation in the CDM validation pipeline of the United Nations Framework Convention on Climate Change (UNFCCC)—only 53 out of about 3,500 projects to date—contradicts the field perception of energy practitioners that the region's share of projects should be larger. Given that skyrocketing oil prices have become unbearable for the poor, clean energy could play a significant role in the region's energy development.

The technical assessment and inventory presented in Part II of this report clearly confirm Sub-Saharan Africa' large potential for clean energy projects in terms of their contribution to the region's energy development, volume of future greenhouse gas (GHG) emissions avoided, and amount of carbon revenue channeled into the region's economies. For the overall set of 44 countries and 22 technologies considered, this study estimated a technical potential of more than 3,200 clean energy projects, including 361 large programs, termed Programs of Activities, each consisting of hundreds, or even thousands, of single activities. If fully implemented, this estimated technical potential could provide more than 170 GW of additional power-generation capacity—more than twice the region's current installed capacity. The added energy, both electrical and thermal, would equal roughly four times the region's current modern-energy production. The achievable reduction in GHG emissions would total about 740 million tCO_2 per year, more than the region's current level of GHG emissions. Because the technical potential of clean-energy generation is larger than the current energy demand, it could meet future demand growth, thus avoiding additional GHG emissions.

As discussed in chapter 7, the main potential for emission reduction is from biomass (64 percent), about half of which is from existing wasted biomass (bagasse, agricultural and agro-industrial residues, Typha, and forest and wood-processing residues).[107] The main potential for additional power-generation capacity is from the improved use of fossil fuels (53 percent), either consumed via energy-efficiency improvements and fuel switching in existing facilities (27 percent) or wasted in the

[107] The emission reductions considered and estimated are those that would be consistent with CDM calculation rules and delivered during the crediting period. CDM additionality, a concept applied at the project level on a case-by-case basis, could not be checked in the context of this study; it would need to be tested separately for every future project applying for registration under the CDM.

production stage via flared associated gas and coal mine methane (26 percent) (table 7.2). As previously discussed, clean energy projects that incur incremental investments in already existing facilities only could deliver about one-third of potential additional generation capacity and one-fifth of emission reductions. Assuming a price of US$10 per tCO_2, and the declared eligibility of these projects for carbon finance, up to US$7.4 billion per year in carbon revenues could be poured into the region's economy.

At this stage, it has not been possible to include an economic analysis of the cost effectiveness of the clean-energy-project opportunities inventoried in this study. That would require numerous economic comparisons of these alternatives with more conventional ones at the local level, requiring, in turn, the collection of much additional data. But the accelerating number of similar clean energy projects already registered in the CDM pipeline and being implemented in other countries, mainly by the private sector, strongly indicates that such projects can be attractive when carbon revenues are taken into account.[108]

While unexpectedly large, this potential is not inconsistent with the rapid scaling up of the CDM worldwide, which is roughly doubling every year. Indeed, it may be considered as underestimated for several reasons. First, the number of methodologies approved by the CDM Executive Board is increasing every two months, meaning that a significant number of new clean-energy activities might be applicable to Sub-Saharan Africa. Second, for various project types, the study team was unable to obtain exhaustive data or estimate the potential. This was the case for small hydropower plants, wind farms, and waste-to-energy projects, among others. Regarding the latter, only three countries could be investigated (Côte d'Ivoire, Guinea, and Senegal), which represent only a small share of that potential.

Summary of Solutions

Given the region's large potential for clean energy projects under the CDM, what obstacles hinder their implementation? Based on field visits to 12 countries and numerous exchanges with potential project developers, energy-sector authorities, Designated National Authorities, and other stakeholders, the study team investigated the major barriers to project implementation and identified ways to mitigate them. For each of the technologies considered, the team developed a preliminary list of the major barriers and mitigation measures. Based on these individual assessments, more general recommendations were formulated for energy-sector authorities and the donor community (chapter 8). While complementary analyses are required for certain technologies and countries, it is already possible to draw the following conclusions.

[108] This point is illustrated by the exemplary cases based on data collected from various projects, which are presented as boxes in Part II of this report.

1) It is essential to fill the regulatory and logistics gaps that prevent clean energy projects from access to energy markets.

Without appropriate market access, the energy development and global environmental benefits of clean energy projects cannot be achieved. Current regulatory gaps in the region's energy sectors (e.g., lack of purchase tariffs in vertically integrated, monopolistic public-power sectors) hinder, or even prevent, clean energy projects from selling their energy production. Filling these gaps is a priority, requiring technical support that incorporates international best practices.

2) Market access requires appropriate infrastructure planning and policies to overcome logistics bottlenecks.

In many cases, typically for cogeneration and biomass power generation, the primary energy resource is dispersed, which presents a dual logistics challenge: collection and transport to the transformation facility and line construction to transmit the power generated to market.

Meeting this challenge requires appropriate clean-energy and infrastructure development planning and supporting policy and financing mechanisms. In many countries of Sub-Saharan Africa, external technical assistance is needed to support the building of planning capacity.

3) Technical information on mature, clean-energy technologies must be appropriately disseminated.

In Sub-Saharan Africa, sustainable, clean-energy development is hindered by a lack of technical knowledge and information sharing, capacity, and effective communications, including necessary background data and inventory of potential energy sources. For example, most of the region's small- and medium-sized industries ignore the opportunity provided by energy-efficient options for improved profitability and competitiveness. Such missed opportunities contribute to the continued use of outdated, polluting equipment. In the case of agro-industry and wood-processing industries, residual biomass (e.g., sugarcane bagasse, groundnut shell, rice husk, and palm fiber) is viewed as a waste-disposal issue or, at best, is partially burned in an inefficient manner to generate a limited amount of process heat as a way to eliminate an undesirable byproduct.

To engage the region's potential clean-energy project developers who currently run inefficient facilities or waste bio-energy, the first step is to disseminate information to them on existing technologies that, thanks to carbon revenue (and sometimes without it), are economically attractive. One approach might be to organize joint technology-focused, national or multinational information campaigns with equipment and technical-services providers, targeting specific technologies that match the region's available clean-energy potential with decision makers of corresponding companies.

4) Local skills development is required to operate specific mature, clean technologies.

In Sub-Saharan Africa, a significant share of GHG emissions results from improper maintenance schemes, caused by a labor force lacking appropriate skills. For example, the region's most critical barrier to industrial steam-system efficiency is the lack of adequate repairs. When steam traps malfunction, they often are not immediately repaired or replaced; as a result, condensate are released routinely into drainage lines, causing the loss of energy that should have been put into productive use in the industrial processes. With regard to bio-energy, a lack of mastery of certain techniques (e.g., those for achieving yields that are high enough to make production competitive) also generates bottlenecks that limit the development of clean-energy potential. Traditional turnkey approaches that import technology limit scaling up and efficiency. Thus, the region's countries must be assisted in building their own national capacity for clean-energy use.

5) Specific technical assistance and research and development are required to enable clean-energy technologies to achieve full efficiency and sustainability.

Sub-Saharan Africa's capacity to adapt technologies to local resources is low compared to other developing regions. For example, to become usable fuels, biomass products usually require drying and size reduction. In such applications as charcoal production, carbonization may be needed to prepare the biomass for domestic and commercial fuel use. Because most countries in the region lack the appropriate equipment for getting the full energy potential from local biomass, technical-assistance and research and development (R&D) activities are required to adapt efficient pre-use transformation solutions and combustion equipment to the unique characteristics of the diverse types of biomass residue found in the region. Local research and knowledge should be gathered to reduce the time and costs associated with collection, transport, and other infrastructure and logistics issues.

Local research is also required to ensure sustainable resource use. For example, while biomass residue offers an especially attractive, clean-energy option because of its numerous potential benefits for both the local energy sector (e.g., reduced dependency on high-priced petroleum products) and the economy (e.g., new income-generation activities), environmental and social impacts assessments are vital. In the context of African subsistence farming, agricultural productivity is particularly sensitive to the amount of post-harvest residue left on the farm. Therefore, the agricultural research conducted must strike an optimal balance between fuel use and alternative utilization.

6) Support is still required to develop local expertise and institutional procedures to facilitate Sub-Saharan project developers' access to the benefits offered by an increasing range of climate change–earmarked financial resources.

In Sub-Saharan Africa, a key obstacle in the early stages of CDM project identification is the relevant actors' inadequate knowledge and information base with regard to CDM and Carbon Finance (CF) opportunities and procedures. Past capacity-building programs involved seminars and workshops that were sometimes too theoretical and targeted a limited group of professionals, mostly from the environment community. Most, if not all, countries in Sub-Saharan Africa have enough well-trained professionals who could, if properly trained in the CDM and CF, help potential project developers to prepare clean energy projects—at least develop them to a point where they could be integrated into carbon fund portfolios and receive assistance in undergoing the CDM process. The same would probably remain valid for accessing the new Climate Investment Funds (CIF).

A critical lesson from previous capacity-building efforts is that such programs must target the right groups; that is, decision makers from industries and local engineering consulting firms. Technical capacity-building activities should involve learning-by-doing strategies involving local consultants together with project developers. In addition to these core groups, relevant institutions should be informed of their potential CDM-development role in their respective countries (e.g., energy-sector authorities taking appropriate actions to remove the sectoral barriers that discourage project developers from making investment decisions).

7) Post-Kyoto carbon funds are required to internalize the global benefit in investment decisions and level the playing field for clean-energy technologies in Sub-Saharan Africa.

Certain clean-energy options, particularly those based on renewable energy, have not been found to be competitive when the energy market gives zero value to their global environmental benefits. The number and wide range of clean energy projects submitted to the CDM worldwide have demonstrated that CF is effective in achieving such internalization. But most CF transactions are limited to the first commitment period of the Kyoto Protocol, which ends in 2012. Because of lingering uncertainty regarding the post-Kyoto regime, it has become difficult for CDM projects to monetize their post-2012 GHG emission reductions. Because Sub-Saharan Africa had a delayed start in CDM implementation, most of the region's CDM-eligible, clean energy projects are expected to deliver only a small fraction of their emission reductions before 2012.

If Sub-Saharan Africa is to develop its large potential for clean energy projects and thus move ahead on a cleaner development path, financial instruments must be created that provide financial value to future emission reductions from clean energy projects in the region (e.g., new carbon funds buying post-2012 certificates of emission reduction). Featuring such carbon funds to facilitate access for projects in Sub-Saharan Africa would be desirable. Most CDM projects in the region are smaller than the minimum size required by many existing carbon funds. While this issue can be addressed, in part, by the bundling together of many similar, smaller projects under the CDM's new Program of Activities, such aggregation also triggers coordination challenges that may be difficult to address, especially when similar projects are located across borders where countries are in conflict or post-conflict situations. Therefore, special windows streamlining access for small, clean energy projects located in least developed countries like those in Sub-Saharan Africa remains a desirable feature for post-2012 carbon funds.

8) But Carbon Finance alone will not solve the investment financing gap: Earmarked Climate Investment Funds are essential.

In Sub-Saharan Africa, the lack of investment and financing capacity is a chronic barrier for any capital-intensive infrastructure—whether conventional or innovative clean energy projects. By itself, carbon finance, which provides neither equity nor investment financing, cannot solve the problem for clean energy projects. While Emission Reduction Purchase Agreements signed in hard currency with a highly credit-rated entity may help leverage a certain amount of commercial financing, the carbon revenue strain is usually insufficient to ensure financial closure. Thus, the core issue of how to finance clean-energy infrastructure investments in the region remains.

Given the region's resource constraints and, in the case of public utilities, political pressure to contain a looming energy crisis, most industrial companies seek quick fixes and less capital-intensive options, which are usually more carbon intensive. In many smaller poor countries (e.g., Burkina Faso, Burundi, Cape Verde, Chad, and Senegal), such options often include the multiplication of small-diesel and heavy-fuel-oil generators (less than 10 MW each) and even short-term repairs of outdated, inefficient gensets. In such larger countries as Kenya and Nigeria, power-utility decision makers are more likely to implement Greenfield single-cycle facilities, which are cheaper to implement and quicker to build, compared to combined-cycle systems or large hydropower plants.

Breaking this vicious circle, which harms both these countries' economies and the global environment, requires solutions beyond the current means to finance immediate short-term needs and carbon funds to internalize global benefits. In addition, new investment-financing instruments, earmarked to promote clean and efficient medium-term solutions, are needed. Ensuring the compatibility of Climate Investment Funds (CIF) and other financing instruments with the CDM would be important to many of the region's clean energy projects needing to remain eligible for the CDM and new carbon funds like the Carbon Partnership Facility (CPF) (because of the simultaneous need to overcome a lack of investment financing and a low return compared to other investment opportunities).

Since financing and implementing capacity may not be enough to explore the region's large range of clean-energy opportunities, the policy dialogue, generally structured around a country's most relevant strategic objectives, would permit prioritizing the various options identified and strengthening ownership of those projects that best serve the sector policy.

Role for Donors

As discussed above, for a series of objective reasons, Sub-Saharan Africa has performed poorly under the CDM and thus has been deprived of the financial mechanism's associated benefits. Overcoming the identified barriers is challenging, but the required solutions are clear. Interestingly, the Energy Sector Operational Units (ESOUs) of Multilateral Financial Institutions are well prepared to confront most of these barriers. ESOUs are endowed with a unique set of organizational features, which, in combination with those of local counterparts, well position them as key contributors to unlocking Sub-Saharan Africa’s large clean-energy-project potential.

1) Decades of trust building and direct access to key decision makers position ESOUs to assist sector authorities in bridging the awareness gap and removing policy barriers.

The above analysis shows how important it is to fill regulatory gaps in Sub-Saharan Africa’s energy sectors in order to surmount the major barriers to the region’s development of CDM-eligible, clean energy projects. Over decades of policy dialogue and financial support, ESOUs have built extensive networking and trust with the region’s energy-sector ministries, public utilities, and many private decision makers, uniquely placing them to convey strategic messages and facilitate the development and implementation of the measures required to unlock these benefits. ESOUs often offer the region’s decision makers the only option for gaining access to expertise and benefiting from international lessons and best practices. Thus, it is important that strategic opportunities related to carbon-based benefits be integrated into the policy dialogue that ESOUs regularly maintain with the region’s energy-sector authorities.

2) Clean energy projects in Sub-Saharan Africa require external technical expertise, and ESOUs have a history of providing large amounts of technical assistance.

While carbon funds lack the sectoral expertise and ability to divert resources to finance clean energy projects, ESOUs have a history of providing the external expertise required by the region, either from their own staff or outside sources knowledgeable of international best practices. Good examples include support in preparing technical and non-technical loss-reduction projects in public utilities, community-based agroforestry projects for sustainable woodfuel and charcoal production, and decentralized rural electrification projects using photovoltaics. Energy investment projects financed by international development agencies usually include millions of dollars in technical-assistance components. Provided that recipient countries are willing, future ESOU-financed projects could easily incorporate the technical assistance required to build capacity in the efficient and sustainable implementation of clean-energy technologies, especially if additional funds targeted for that purpose. Such technical-assistance activities can further serve the development objectives of these projects.

3) Logistics bottlenecks and sustainability issues require multi-sectoral coordination and support.

International development agencies are used to coordinating their support across sectors (e.g., agricultural development and rural road construction to extract production). Frequently, external support has created an incentive to overcome communication barriers between administrative divisions.

4) Many larger, clean energy projects in Sub-Saharan Africa require multi-country coordination, and ESOUs are organized to partner with multiple countries at the same time.

Because many countries in Sub-Saharan Africa are small in size, international coordination is usually required to enable the implementation of larger, clean energy projects. This is the case for regional grid-transmission systems, gas pipelines built to convey large volumes of hydropower-generated clean energy to regional markets, and flared-gas recovery projects. It may also be true for transaction-cost reduction of multiple dispersed, smaller-scale projects (e.g., industrial energy efficiency of motors and steam traps, small hydropower plants, and diverse biomass-based energy) via large national or multinational Programs of Activities. Across the subcontinent, ESOUs are already playing such a neutral coordination role. The Global Gas Flaring Reduction (GGFR) program of the World Bank is a prime example of the catalytic role multilateral development agencies can play to facilitate the working together of large private and public actors. Such capacity positions ESOUs as natural partners to help countries in Sub-Saharan Africa develop and implement complex projects and programs.

5) Sub-Saharan Africa's private sector is weak, but ESOUs are used to promoting private-sector participation.

To date, clean energy projects implemented under the CDM in other developing regions have been developed mainly by private sponsors; most Emission Reduction Purchase Agreements have been signed with private companies undertaking the principal investment on their own. Sub-Saharan Africa's limited free flow of private investments largely explains the region's lack of clean energy CDM projects. At the same time, ESOUs have a history of designing projects that aim precisely at attracting and supporting private investments. Donor-supported projects that facilitate Independent Power Producers are a typical example. In short, ESOUs already have the expertise and experience required to facilitate the implementation of private-based, clean energy projects in the region's energy sector.

6) Clean energy projects in Sub-Saharan Africa require external financing from donors, which ESOUs are used to channeling to the project level.

Because of the myriad investment barriers identified, from poor country ratings to weak financial markets, both private- and public-based energy projects are difficult to finance in Sub-Saharan Africa. In most cases, financial closure can be reached only with the financial support provided by international development agencies. While carbon funds cannot provide investment financing, the Energy Sector Operational Units of donor agencies (ESOUs) are the main financing providers for energy investment projects in Sub-Saharan Africa. In this context, the cumulative experience and know-how of ESOUs in directing large volumes of financing to conventional energy projects can be instrumental in channeling resources of the newly created CIF to finance clean energy projects. To avoid duplication and wastage of resources, the roles and contributions of the various donors, particularly those of the ESOUs, should be coordinated, for example, under the Nairobi Framework.

Closing Remarks

It is difficult to estimate the financing required to implement the potential clean energy projects identified in this study. As previously noted, the potential estimated is technical, and an economic assessment of the various segments of this technical potential is beyond the study scope. Thus, at this stage, it is not possible to determine what share of this technical potential could be achieved by overcoming the barriers identified by the study or a timeline for its realization.

As discussed in chapter 7, it was not possible to collect data for 8 project categories, representing 36 percent of the additional power-generation capacity and 21 percent of emission reductions. A conservative estimate of the capital cost required to finance the remaining 2,755 clean energy CDM projects is US$158 billion. If the capital cost of large flared, associated-gas recovery projects could be calculated, this figure would likely exceed US$200 billion. While this figure may be perceived as large, in the context of global climate change, it represents only a small fraction of recently estimated amounts required for industrialized countries to shift from conventional to cleaner energy over the next several decades.

In conclusion, this study has demonstrated Sub-Saharan Africa’s large potential for clean energy projects. In this context, the new climate change–related financial instruments offer an unprecedented opportunity to explore this overlooked potential for the socioeconomic benefit of the region’s countries. With appropriate coordination of the new and most needed climate change–based aid, along with conventional energy sector–based support provided by the development aid agencies, this goal is within reach. Without such coordination, economies in Sub-Saharan Africa will be further hindered, or even prevented, from receiving their share of the carbon revenues that already flow to the world’s other developing regions.

Annex A: Countries in Study

This study considered a total of 44 countries in Sub-Saharan Africa (because of incomplete data, 4 countries (Eritrea, Lesotho, Reunion, and São Tome e Principe) are not included here. The 44 countries covered are as follows:

Angola
Benin
Botswana
Burkina Faso
Burundi
Cameroon
Cape Verde
Central African Republic
Chad
Comoros
Congo, Dem. Rep.
Congo, Rep.
Côte d'Ivoire
Equatorial Guinea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea Bissau
Kenya
Liberia
Madagascar
Malawi
Mali
Mauritania
Mauritius
Mozambique
Namibia
Niger
Nigeria
Rwanda
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
Sudan
Swaziland
Tanzania
Togo
Uganda
Zambia
Zimbabwe

Annex B: Key Contacts

Below are key contacts in the 12 Sub-Saharan Africa countries visited by the study team.

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  tel: 97-19-64-22
- Afeitom Passem
  tel: (228) 918-79-41

Beninese Society of Electricity and Water (SBEE)
- Appolinaire Alladaye
  tel: (229) 21-3121-45

Burkina Faso

- Emmanuel Nonyarma, Director General of Energy
  tel: (229) 50-30-79-78

Economic and Monetary Union for West Africa (UEMOA), Ouagadougou
- Ibrahima Konate, Head of Energy
  tel: (226) 50-31-88-73

Ethiopia

Environmental Protection Agency
- Director General; Addis Ababa
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Institute for Sustainable Development
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Ethio Resource Group, PLC
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Institute of Development Research
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Ghana

Ghana Environmental Protection Agency
- Jonathan Allotey, Executive Director
- Yaw Sarfu-Afriyie, Principal Program Officer
- Emmanuel Tachie-Obeng, Senior Program Officer

Ghana *(continued)*

Association of Ghana Industries
- Cletus J. Kosiba, Executive Director

Accra Metropolitan Assembly
- Stanley Nii Adjiri Blankson, Mayor of Accra and Chief Executive
- J. A. Tufuor, Director, Administration
- Frank Chinbuah, Chief Environmental Health Officer, Waste Management

Ministry of Energy
- Chief Director
- J. B. Okai, Deputy Director, PPME
- Eric Kumi Antwi-Agyei, Program Officer
- Kwaku Boateng, Project Analyst

Kumasi Institute of Technology and Environment
- H. Amissah-Arthur, Director
- Solomon Quansah, Program Officer

Private Enterprise Foundation
- Osei Boeh-Ocansey, Director General

Kenya

Kenya Association of Manufacturers
- Bernard Osawa, Bamburi Cement, Nairobi
- Tom Owino, ECM Center, Nairobi
- Joash Obare, ECM Center, Nairobi
- Anjali Saini, Integrated Energy Solutions, Ltd., Nairobi

Kenyan DNA
- A. Muusya Mwinzi,
  Director General
  NEMA, Nairobi

SAROC International
- Suresh A. Patel

United Nations Industrial Development Organization (UNIDO)
- Alexander Varghese, Representative for Kenya and Eritrea, Nairobi
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- Katharina Swirak, Programme Officer, Nairobi
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Liberia

Environmental Protection Agency of Liberia
- Ben Turtur Donnie, Executive Director
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Mali *(continued)*

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Niger

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Ministry of Environment and Nature Protection
- Safiri Ibouraima, Technical Adviser on Environment

Ministry of Mines and Energy
- Maidagi Issa, Manager of Non-renewable Energy Data

Nigeria

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- Emmanuel Ibhafidon, Deputy General Manager, Environment
- Kayode Lawore, Deputy General Manager

Office of the Special Adviser to the President of Nigeria on Energy, Lagos
- Anthony Adegbulugbe, Special Adviser to the President
- A. Adenikinju, Senior Assistant to SA

Presidential Implementation Committee on CDM (PIC CDM), Abuja
- Collins Gardner, Chairman,
  PIC CDM

UNIDO Country Office, Abuja
- K. Mazushita, Resident Representative
- Gboyega Ajani, Program Officer
- Jossy Thomas, Program Officer

Manufacturers Association of Nigeria, Lagos
- Rasheed Adegbenro, Deputy Director
- John Egwuonwu
- Femi Gbadegun
- Agatha Odwoza
- Ambrose Oruche
- H. N. Salaudeen
- Ayo Adegoroye, Honeywell Flour Mills, Ltd.
- Yemi Shoyele, Cadbury Nigeria PLC
- A. Shoyoye, WAPCO-Lafarge Cement, Sagamu

Senegal

Ministry of Environment
- Ndiaye Cheikh Sylia, Environment Director

Senegal DNA
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NOVASEN
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Sococim Industries
- Moctar Diaw, Environment Director
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Program on Rural Electrification Promotion and Sustainable Household Supply
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South Africa

The Energy Research Center, University of Capetown
- Allison Hughes
- Debbie Sparks
- Denis Van Es
- Gerswynn Mckuur
- Mascha Botha
- Mkhululi Magwaca
- Philip Lloyd
- Pule Monamodi
- Stanford Mwakasonda

South South North
- Steve Thorne

South African DNA

Togo

ECOWAS Bank for Investment and Development
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African Biofuels and Renewable Energy Fund
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