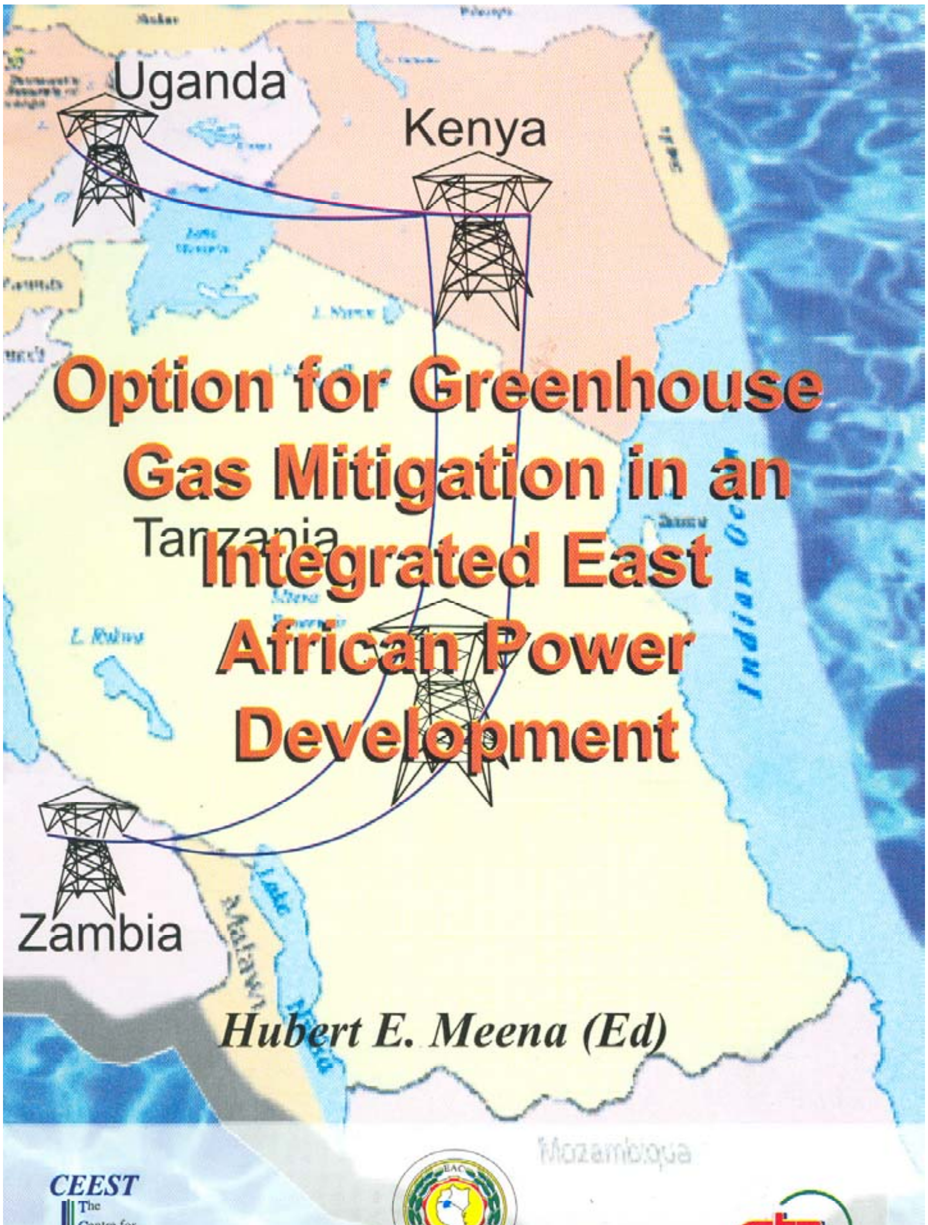
Option for Greenhouse Gas Mitigation in an Integrated East African Power Development



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Deutsche Gesellschaft für Technische Zusammenarbeit

OPTIONS FOR GREENHOUSE GAS MITIGATION IN AN INTEGRATED EAST AFRICAN POWER DEVELOPMENT

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CEEST
August 2002

PREFACE

Concern over global Climate Change has been growing over the past decade as scientific evidence indicates that increased concentration of GHGs in the atmosphere will cause changes in global temperature, precipitation, sea level and other weather related effects.

Developing countries, including East African countries will be seriously impacted due to their low capacity to adapt, lack of technologies and know-how and institutional and financial capacities. The long-term challenge is to establish atmospheric concentrations of GHGs at a level that does not harm the climate system.

Regional greenhouse gas mitigation analysis is a complex phenomenon that explores availability of synergies in cooperation and development objectives of the region with greenhouse gas mitigation. In this study electricity development and sharing among East African countries is analysed with the objective of exploring greenhouse gas and other environmental benefit associated with it.

Chapter 1 provides an introductory analysis and justifies the particular focus of the study.

Chapter 2 analyses the status quo of energy and power development in East Africa whereby in the absence of the regional energy policy and power master plan, each of the East African countries is analysed independently and later on aggregated into an East African analysis.

In Chapter 3 attention is focused on the current situation of the power sector in the three East African countries whereby electricity sources are analysed as well as current and potential power cooperation among the three countries through grid interconnections.

In Chapter 4 the baseline scenario is developed on the basis of projections made in power demand forecast and least cost development plans as per the individual countries' power master plans.

In Chapter 5 the mitigation analysis is made including the analysis of greenhouse gas reduction potentials as well as associated costs structures. A comparison of costs is made on the basis of the gross GHG mitigation expenses. Cost curves are constructed to analyse the relationship between the incremental cost of abatement and incremental reduction of greenhouse gases.

Chapter 6 summarises the conclusions of the study and the way forward towards implementation of identified mitigation options. In this chapter we conclude that the Regional Power Greenhouse Gas Abatement Costing Model developed in this study is a powerful tool in assessing GHG abatement benefits in regional power pooling. Furthermore, there exist some barriers to implementation of recommended options, which need to be addressed during implementation stage.

Hubert E. Meena
21 August 2002

1

INTRODUCTION

1.1 THE EAST AFRICAN COMMUNITY

1.1.1 Regional Background

Cooperation among the three East African countries, namely: Kenya, Tanzania and Uganda existed even during the colonial days. These countries used to share common services in the transport, communication, monetary, and energy sectors. After independence, cooperation continued and was strengthened by the formation of the East Africa Community (an economic grouping of the three countries). However, in 1977 the community broke up due mainly to political differences between the countries. Each country went its separate ways and started creating the infrastructure of the services that were provided on a community basis. Recently (in 1996), the East African Community has been revived. The Secretariat is in place in Arusha and the people of the sub-region can once again look to benefiting from the resources expertise, and services in the area.

The Secretariat is organised such that it holds tripartite ministerial level meetings regularly, under the chairmanship of the Minister of Foreign Affairs of the country holding chairmanship on a rotational basis. Heads of State Meeting is the supreme organ of the East African Community. They meet at least once a year.

The treaty establishing the East Africa Community was recently signed, and an East African Parliament put in place and is operational.

1.1.2 Socio-economic Profile

Economic and social development is one measure of a country's impact on climate change as well as its vulnerability to climate change impacts and related adaptation. Generally, the East African region is made up of poor countries in terms of industrial development as well as Gross Domestic Product indicators. In the year 2000 the region had a total estimated population of 83.4 million people and a total GDP of US$ 23,268. Therefore the aggregated GDP per capita was US$ 278, which shows the low level of development of the region. However, individual countries are not homogeneous in nature and development levels. Kenya has always been more advanced in terms of industrial development compared to Tanzania and Uganda. Recently Tanzania has shown some positive signs in mining development, which led to an increased rate of GDP growth.

Table 1.1 shows the selected social and economic indicators for the East African region.

Table 1.1: *Selected Social and Economic Indicators for East Africa*

Country	Population (yr.2000)	GDP (yr.2000)	GDP (yr.2000)	GDP percapita	Exchange rate
	(Million people)	(Shs. Million)	(US$ Million)	(US $)	(1 US$ = Shs)
Tanzania	31.9	6,663,685	8,329	261	800
Uganda	22.2	8,632,752	5,078	229	1,700
Kenya	29.3	788,917	9,861	337	80
	83.4		23,268		

Source: Tanzania, Uganda Kenya Statistical Abstract and Economic Surveys (2000)

1.2 PROJECT BACKGROUND

The project on Integrated East African Power Development as a Regional Greenhouse Gas Mitigation Option explores greenhouse gas mitigation and other Benefits from Integrated East African power development on the basis of the current global environmental concerns and in particular greenhouse gas mitigation.

1.2.1 Project Purpose

- To investigate the GHG mitigating possibilities through regional cooperation in power planning and development;
- Assess the impact of building/enlarging the interconnections between the electric grids in the three countries, including power pooling;
- To provide information on electricity demand projections until 2020 in the three countries;
- To provide information on the present power plant mix and the future power supply options in the three countries.

1.3 IMPLEMENTATION ISSUES

1.3.1 Project Organisation

CEEST has been co-operating with the following partners in the cause of the implementation of the project:-

- Ministries responsible for energy in East Africa;
- Ministries responsible for environment and climate change ;
- Power Utilities in East Africa;
- Donor agencies involved in the power sector;
- Meteorological departments;
- The Secretariat for East African Cooperation;
- Universities in East Africa where necessary.

Each country prepared a background report, which formed the basis for the development of the baseline scenario. In each country's background report baselines for the total electricity demand (in GWhs) and peak demand (in MW) was constructed until the year 2020. Since some countries had offered several baselines and one country only had a demand projection until 2011, we had to make some choices to develop the baselines. The power plant mix for the three countries were then projected until 2020 based on the local Power Master Plans as described in the country background reports. The final baselines were sent to the country teams for confirmation. The baseline scenario was then constructed using a modified model

(Regional Power Greenhouse Gas Abatement Costing Model RPGACMO).

Costing for the baseline and mitigation options was carried out on the basis of the investment, operation and maintenance costs for power plants, sub stations and transmission lines, including the interconnections. Costs for the baseline power plants were obtained from individual countries' power master plans. On the basis of the costing exercise cost curves were constructed for the East African Power Development as a GHG Mitigation Option.

1.3.2 Project Workshops

Project inception workshop took place in Arusha and was organised by the Centre for Energy, Environment Science and Technology (CEEST) under the leadership of Prof. M.J. Mwandosya. This workshop had the project planned in an indepth, constructive and friendly atmosphere between 15 to 16 March 1999 at Ilboru Safari Lodge in Arusha. Participants in the workshop came from ministries responsible for energy and environment, power utilities and other relevant institutions from Tanzania, Uganda and Kenya and GTZ was represented by Mr. Holger Liptow, Head of the Climate Protection Programme for Developing Countries (CaPP).

The workshop deliberations were based on the project proposal initiated by CEEST and a consensus was reached on a project-planning matrix, which was followed during the project implementation. The workshop further agreed on some follow up activities to start the project.

The second project workshop took place in October 2000 in Kampala whereby a detailed project workplan was developed. During the Kampala workshop, some related conceptual papers as well as each country component of the project were presented. After a lengthy discussion, the workshop came up with the detailed project workplan and implementation strategies. The workshop deliberations were based on a Memorandum of Understanding and Terms of Reference developed by CEEST and GTZ as a follow up to the project inception workshop. The terms of reference was translated to implementation activities and plans and assignment to relevant experts and stakeholders were identified.

The third project workshop took place in Nairobi to review progress, share experience, and plan the finalisation of the project outputs. The workshop took place in June 2001. The deliberations of the workshop took place on the basis of the draft report by individual experts from the three countries, as well as the project Memorandum of Understanding and Terms of Reference. After lengthy discussions, the workshop identified and ranked some of the East African power development options, which include, among others, hydropower, geothermal, clean coal, natural gas, biomass and power importation. The workshop recommended analysis of these options while considering the following concepts in the baseline and mitigation scenarios analysis:

- Hydro options as a scenario for EA as a whole, listed according to cost;
- Always two sides to be evaluated, the baseline scenario and a mitigation scenario;
- Scenarios should look at demand projections and then focus on supply options and power distribution/interconnection options;
- The requirements for transmissions lines in respect of a generation option should be analysed jointly with their costs inclusive;
- Several mitigation options were proposed for consideration in the final analysis.

A final project workshop was held in Dar es Salaam on 28 and 29 June 2002 with the objective of disseminating the information generated by this project to policy makers and energy planners in East Africa. It was also expected to obtain feedback on the same from the energy planners and policy makers.

The specific objectives of this workshop were:

(a) To improve understanding among key stakeholders (policy makers, private sector, NGOs and academic experts) by disseminating and explaining the main findings of the project reports and related summary reports;

(b) To discuss the impact of the project findings on the regional climate change response strategies with key policy makers;
(c) To discuss barriers to the implementation of the mitigation options identified in the study;
(d) To discuss policy harmonisation needs for the options identified in the study to be implementable;
(e) To disseminate major project findings and reports to government officials and other relevant authorities in East Africa;
(f) To explore the relevance of these project findings to the climate change mitigation challenges and opportunities in the power sector in East Africa;
(g) To build the capacity to apply the project findings for climate change mitigation activities in the power sector in East Africa.

The workshop had very constructive discussions of the project report, in which the barriers to the implementation of the mitigation options identified by the study were discussed and ways of removing them proposed. It was agreed that the report be disserminated to the relevant institutions including the East African Community, energy departments in East Africa as well as power utilities and regulators. It was also agreed that a side event be organised at a Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to discuss the findings of the project and disserminate them internationally.

1.4 CLIMATE CHANGE OVERVIEW

1.4.1 Climate Change: Conceptual Framework

Concern over global climate change has been growing over the past decade as scientific evidence indicates that increased concentration of GHGs in the atmosphere will cause changes in global temperature, precipitation, sea level and other weather related effects.

Below is a highlight of the key findings of the Intergovernmental Panel on Climate Change (IPCC) Working Group 1 in its latest report, which is part of the Third Assessment Report (TAR).

- Projected increase in global surface temperature of 1.4 – 5.8°C from 1990 to 2100;
- Global surface temperature increment of 0.6°C and 31% increase in atmospheric CO_2 concentrations since the mid-nineteenth century;
- Changes in rainfall patterns, increased frequency of El nino Phenomena;
- Sea level rise of 10 – 20 cm between 1900 and 2000 and future increase of 9-88 cm.;
- Anthropogenic climate warming during the past 50 years.

Some of the projected impacts include future large-scale and possibly irreversible alternatives in terms of water resources, terrestrial ecosystems, increased risks of floods, decline in future agricultural productivity in large parts of Africa and increase of infectious diseases.

Developing countries including East African countries, will be seriously impacted due to their low capacity to adapt, lack of technologies and know-how and institutional and financial capacities. The long-term challenge is to establish atmospheric concentrations of GHGs at a level that does not harm the climate system.

The near term challenge is meeting the Kyoto Protocol targets. The Kyoto Protocol was adopted in the third Conference of the Parties to the UNFCCC (COP3), held in Kyoto, Japan, in December 1997. The Protocol outlines a general framework for some common actions, for example, targets and timeframes for GHG reductions by parties, frameworks for emission trading, joint implementation between developed countries and a “Clean Development Mechanism” to encourage joint emission reduction projects between developed and developing countries. Through this, nations can begin to effectively address the reduction of GHGs through the introduction of energy efficient practices towards development. The seventh Conference of the Parties that took place in Marakesh decided on the modalities and procedures for a Clean Development Mechanism (CDM) as defined in Article 12 of the Kyoto Protocol. Decision 17/CP.7 refers to the modalities and procedures for prompt start of a CDM. Other actions include:-

- Use of lower (or non) carbon fuels
- Controlling the emissions of GHGs emitted at various sources
- Creating offsets through investment in GHG emission sinks, or
- Use of market-based economic instruments to facilitate cost-effective compliance

These new approaches require improved policy environment and substantial financial and technical inputs.

There are many actions that can be taken to reduce GHG emissions in the power sector through improved efficiency in generation, distribution and end-use of electricity and the resource base used in the power generation.

In order to come up with proposals for technological and policy options to facilitate GHG emission mitigation, one needs to understand the key technological issues under the climate change convention, identify the general mitigation options in the energy sector and therefore draw plausible policy proposals.

1.4.2 Technological issues under UNFCCC

The UNFCCC's ultimate objective is "to achieve stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with climate system."

One great vehicle for helping developing countries implement the convention is through the transfer of environment-friendly sustainable technologies from the developed to developing countries. The climate change convention repeatedly calls for concerted transfer of technology vide articles 4.1(c), 4.1(h), 4.3, 4.5, 4.7 and 4.8. In addition, the Kyoto Protocol through articles 11(b) and 12 echoes a similar need for technology transfer and attendant capacity building. The Buenos Aires Plan of Action under Decision 4/CP.4 while affirming earlier decisions 13/CP.1, 7/CP.2 and 9/CP.3, agreed to strengthen capacities and capabilities of developing country parties Appropriate technologies are our essential pre-requisite to facilitate the aspirations by East African countries to develop sustainably.

2

EAST AFRICAN ENERGY RESOUCES

2.1 OVERVIEW OF THE EAC ENERGY SECTOR

The East African sub-region is endowed with a variety of energy resources, including: geothermal resources in Kenya and Tanzania, large hydropower resources in Tanzania and Uganda, and coal and natural gas in Tanzania. The present demand for electricity in the sub-region is low due to limited extension of the power networks and financial constraints to expand the systems. The populations that have access to electricity are also low.

The East Africa cooperation on energy is covered under Article 101 of the Treaty for the Establishment of the East African Community. Paragraph 1 of Article 101 states that: “The Partner States shall adopt policies and mechanisms to promote efficient exploitation, development, joint research and utilisation of various energy resources available within the region” (East African Community, 2000).

The Treaty furthermore states that, “ For the purposes of paragraph 1 of this Article, the Partner States shall in particular promote within the community:

(a) The least cost development and transmission of electric power, efficient exploration and exploitation of fossil fuels and utilisation of new and renewable energy sources;
(b) The joint planning, training and research in, and the exchange of information on the exploitation, development and utilisation of available energy resources;
(c) The development of integrated policy on rural electrification;

(d) The development of inter-Partner State electrical grid interconnections;
(e) The construction of oil and gas pipelines;
(f) All such other measures to supply affordable energy to their people taking cognisance of the protection of the environment as provided for by this Treaty".

Each of the East African countries has its own energy policy and master plan. Here we briefly consider the power sub-sector, and power master plans, which can be summarised as follows:

- Tanzania has load forecast covering period 1997-2025. Hydropower plays the dominant role taking 80% of the total system generation while thermal generation claims the balance. However, recently the role of thermal power has increased due to drought which led to unreliability of the hydro systems.
- Uganda also has a master plan with low, base and high forecast scenarios up to the year 2020. Uganda's power generation mix is dominated by hydroelectricity mainly from the Nile River system.
- Kenya has its power master plans covering 20 years from 1998 to 2017. The power generation menu for Kenya is a mixture of thermal, hydroelectricity and geothermal power.
- All the three countries have a history of cooperation in the power sector through interconnections, the most significant one being the Uganda-Kenya interconnection. There also exists potential for more power cooperation.

2.2 ENERGY MIX AND PLANNING

2.2.1 Estimating Energy Supply by Sources and Demand by Sector

Several methods can be used to create energy demand and forecast projections. The two main approaches in current use are based on either econometric or end-use (engineering oriented) models. Econometric models require less data than end-use models and have a good theoretical statistical base. However, they assume that the past relationship between income, price and demand will continue in future. Accordingly, the end-use models are preferred because they account for the changes in the technological structure of the energy demand. The econometric models are suitable only if the technological structure of energy demand remains constant. The end-use models are more detailed than the econometric models and are better suited to energy-efficiency projections.

The end-use models used in Africa are MEDEE-S and LEAP. These models have different energy demand structures. Each country has to make a choice of the end-use model it finds most appropriate for its needs. In East Africa the LEAP system has been used in Kenya and Tanzania. Uganda has started to adopt the LEAP system and has published the energy statistics in an energy statistics website.

Recently CEEST carried out a review of the Energy Demand Forecast for Tanzania, using LEAP, which revealed that firewood requirements will continue to account for more than 90% of the energy demand. The annual growth rate for electricity will be 5% for the years 2007-2025. This annual growth that can be deduced from the TANESCO PMP is 5% for the same period. Less than 6% households have access to electricity in Tanzania and it is estimated that for East Africa the figure is definitely less than 10%.

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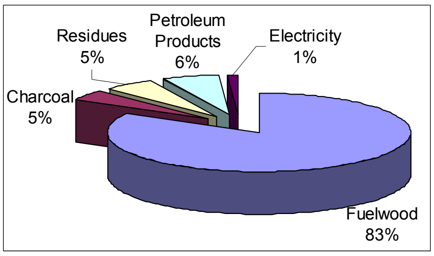
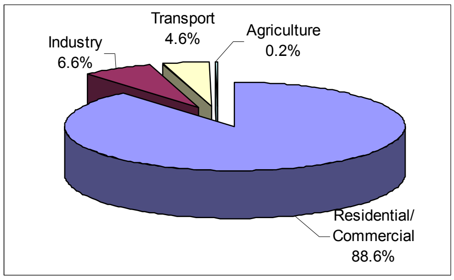
<tr><td>
</td><td>
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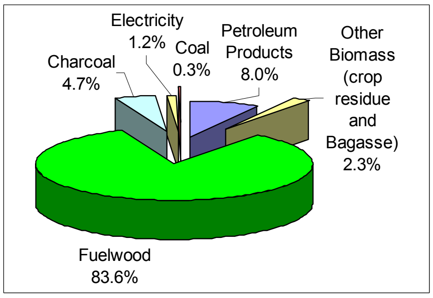
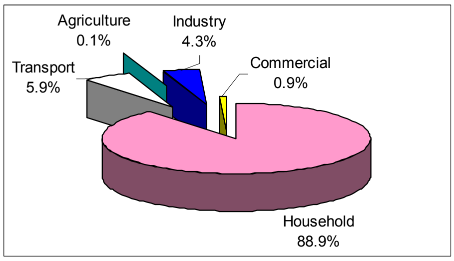
<tr><td>
</td><td>
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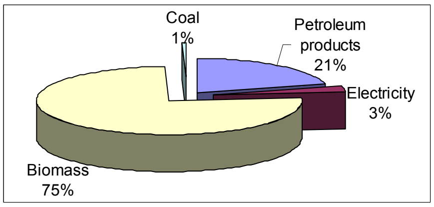
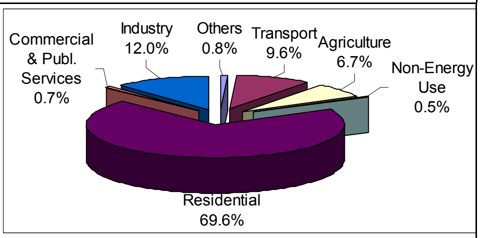
<tr><td>
</td><td>
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Figure 2.1: *East African Energy Supply by Source and Demand by Sector*

2.3 BIOMASS (FUELWOOD, CHARCOAL, BIOGAS, BIO-WASTES)

Biomass energy resources comprise fuelwood, charcoal and agricultural wastes. Woodfuel (fuelwood and charcoal) constitute the largest source of energy for the majority of East Africans especially those in the rural areas. It accounts for over 80% of total East African energy consumption. Table 2.1, indicates the relative proportions of each energy source in the national energy consumption statistics.

Table 2.1: *National energy consumption by percentage*

	Biomass	Petroleum fuels	Electricity	Others	Total
Kenya	75.0	21.0	3.0	1.0	100
Tanzania	90.6	8.0	1.2	0.3	100
Uganda	92.8	6.1	1.1	-	100

Source: Ministry of Energy(MOE), 2000 (Tanzania, Uganda, Kenya)

2.3.1 Biogas

Biogas technology was introduced in East Africa over 20 years ago. There has been a number of projects targeting the dissemination of this technology, the most recent one being the support obtained from China to construct 20 demonstration biogas digesters and also to train a number of technicians in Uganda. A number of individuals have constructed biogas digesters, especially those who keep cows on a zero grazing basis.

The difficulty with this technology, like many other renewable technologies, is the high initial capital outlay needed to construct the digester, which hampers the rural poor from its acquisition. There is also a need to perfect the designs so that the design of high integrity is popularised.

2.3.2 Industrial Biomass Residues

Extensive use of biomass residues has been in co-generation in sugar mills. In Uganda three sugar mills, Kakira Sugar Works Ltd., Sugar Corporation of Uganda and Kinyara Sugar Works co-generate power using bagasse. Kakira Sugar works is planning to expand their co-generation capacity from the present 2.5 MW to about 15 MW in phase 1, with the objective of selling excess power to the grid.

Some biomass residues are also used to provide process heat in building material production. However, there are a lot of crop residues which are left to waste which would otherwise be used to produce electricity, employing technologies like the gasifier technology. Other sugar factories in East Africa also generate electricity using bagasse from the sugar production process.

2.4 RENEWABLE ENERGY SOURCES

2.4.1 Solar Energy

Other renewable forms of energy apart from biomass and geothermal include: solar, wind, mini/micro hydro, among others. Most of these sources of energy have not been exploited to any significant degree considering the potential available. However, there is a mixed degree of exploitation that varies from one source to the other.

The use of solar energy, especially photovoltaic has taken some root in East Africa. In Kenya, for example, according to SolarNet (2000), over 150,000 solar PV units have been distributed countrywide, amounting to an installed capacity of 5MW. Almost all the success in the distribution of the solar PV modules is fully credited to private sector entities. While there are various solar module types in the market, the amorphous type seems to be predominant compared to both polycrystalline and mono-crystalline types. The reason for this is most likely due to the cost of the modules. Depending on the type, size or rating, the costs currently range from Ksh. 5,000 to over Ksh. 30,000. In terms of quality, the amorphous type is the lowest and hence the reason for the lower price.

In Uganda the private sector is the major actor in the development of solar resources. Several local companies have organised themselves into the Uganda Renewable Energy Association (UREA) and are actively participating in the solar industry. To-date, about ten thousand solar home systems have been installed in the country, through the private sector, donor support (especially to health units and institutions) and by organisations which require isolated stations.

Factors affecting the popularisation of solar energy include:

- The high upfront costs are out of reach for most consumers especially in rural areas;
- The lack of technical capacity to design, install and maintain the systems;
- The lack of local capacity to manufacture some of the solar systems' components locally;
- Limited awareness about the existence of the renewable energy technologies;
- Poor marketing skills on the part of the vendors;
- Inability of solar vendors to exploit the benefits of economies of scale; each vendor imports in limited quantities.

With the support of UNDP/GEF the Government of Uganda is implementing a pilot solar project called the Uganda Photovoltaic Pilot Project for Rural Electrification (UPPPRE), to address the barriers for photovoltaics technology dissemination. This project has made efforts to involve financial institutions in providing loans to both consumers and vendors of solar PV systems. There has also been an extensive awareness campaign which has led to an increase in sales of systems by the private sector. Several technicians including members of UREA have been trained in the design and installation of systems. Tanzania is implementing a similar project under the auspices of UNDP/GEF with similar objectives of removing barriers for solar photovoltaic technology dissemination.

2.4.2 Wind Energy

Wind energy technology, especially for mechanical application like water pumping has a long history but limited success in East Africa. Wind energy for electrical power application has also been quite dismal.

Kenya for example, has some 450 kW of wind power installed in two sites, Ngong (300 kW) and Marsabit 150 kW). There are no such installations in the other East African countries. Kenya’s success is attributed to the recent initiative of the Kenya government through its Ministry of Energy in collaboration with the Kenya Meteorological Department (KMD), of developing a national wind atlas. The wind atlas will provide useful information concerning suitable wind sites for exploitation through fostering investment in wind energy resource.

As for Tanzania the Ministry of Energy in collaboration with Tanzania Electric Supply Company Ltd. (TANESCO) and the Tanzania Meteorological Agency, has been undertaking a research on wind speeds in Dar es Salaam, Tanga, Arusha and Mtwara. Various sites were earmarked for possible development of wind energy, which include Gomvu in Dar es Salaam, Mkumbara in Korogwe, Bohai in Karatu and Litembo in Mtwara.

Although Uganda has not done a comprehensive wind mapping, available data from the meteorological department show that the wind regime is not conducive for electric power generation. However, the available winds can be utilised for water pumping and grain milling. Windmills have been successfully used in the Karamoja region. There are just a few isolated cases of wind generators installed in the country.

2.5 RESOURCES FOR POWER GENERATION

2.5.1 Major Hydro Power Potential for East Africa

A number of hydropower sites have been identified in East Africa for possible future development. Currently, about 1,464.5 MW of hydropower is installed and operational in East Africa while 5,036 MW of the identified potential is yet to be developed. Table 2.2 shows the location of the sites as well as their respective capacities.

Table 2.2: *Hydro Power Potential Sites in East Africa*

Kenya	**MW**	**Tanzania**	**MW**	**Uganda**	**MW**
Sondu Miriu	60	Upper Kihansi	120	Kamdini/ Karuma	180
Ewaso Ngiro A	90	Rumakali	222	Kiira (Owen Falls Extension)	80
Ewaso Basin	90	Ruhudji	358	Ayago South	234
Mutonga		Mpanga	160	Ayago North	304
Low Grand Falls		Masigira	118	Bujagali	320
		Stiegler's Gorge Phase I	300	Kalagala	450
		Stiegler's Gorge Phase II	750	Murchison	642
		Stiegler's Gorge Phase III	350		
		Mandera	21		
Total	240		2,399		2,210

In Uganda the majority of hydropower potential is in the Nile River system. Owen Falls Power Station (Nalubale) was commissioned in 1954 and is rated at 180 MW. It was initially installed with 150 MW capacity before undergoing a rehabilitation in 1992 of the turbines and generator sets to upgrade them to a total capacity of 180 MW. This power station has been the major source of Uganda's electric power. There was no development in the country's hydropower generation capacity for a long time, so the load connected to Owen Falls Power Station has always exceeded the generating capacity, thus leading to load shedding up to 70 MW.

The extensive load shedding led to urgent need to augment total generation capacity, thus the initiation of the Owen Falls Extension Project at the east bank of the Nile.

Kiira Power Station is a 200 MW capacity station located at Jinja adjacent to the Owen Falls Power Station. It has an installed capacity of 80 MW, but this will soon be increased to 120MW and finally to 200 MW in 2003.

The commissioning of this plant in the year 2000, greatly helped reduce the generation inadequacy, thus reducing load-shedding and increasing reliability.

2.5.2 Small Hydro

A mini/micro hydro outfit is the one capable of generating not more than 500 kW of energy. Although during colonial times European settlers had installed a number of small and micro hydro turbines in East Africa, most of them fell into disuse due to lack of maintenance. The East African governments have been involved in implementing a number of mini/micro hydro projects at community levels. Examples include a GEF/UNDP funded Small Grants Programme at community level in South Meru District, Eastern Province in Kenya, and a GTZ funded district level project at Uwemba in Njombe District in Tanzania.

2.5.3 Geothermal Energy Resources

Geothermal energy is power obtained by the earth's natural heat. Geothermal means earth's heat. Boreholes are needed to reach the heat. Borehole heat increases by one degree centigrade every thirty six metres the deeper it gets. Geothermal energy is energy extracted for heating and electricity generation from natural steam, hot water, or hot dry rocks in the earth's crust. Water is pumped down through an injection well where it passes through joints in the hot rocks. It rises to the surface through a recovery well and may be converted to steam or run through a heat exchanger. Dry steam may be directed through turbines to produce electricity. It is an important source of energy in volcanically active areas.

In East Africa, geothermal resources are concentrated mainly in the Rift Valley. Apart from the famous geothermal resource in Kenya which is now being exploited for power generation, there exist geothermal resources in Uganda, located in the Rift Valley estimated at 450 MW. Three sites have been identified (Katwe field in the south, Buranga field near the Rwenzori Mountains and the Kibira field near

Lake Albert). The Katwe field is considered the most promising due to the presence of subsurface steam at 230°C and its location 35 km from a 132 kV transmission line at Kasese.

In Tanzania research undertaken at Luhoi, Utele, Luhembeto and Kisaki in Rufiji shows that there is a geothermal potential, which resembles that of Olkaria fields in Kenya. Its ground temperature reaches up to 120 – 140° Centigrade, which could produce 80 MW of power. Private companies are encouraged to invest in the exploitation of the geothermal resources and so far First Energy Company in collaboration with other investors have shown interest in developing the resource.

2.5.4 Power Generation from Geothermal Resources

As already mentioned, geothermal resources in East Africa, are concentrated mainly in the Rift Valley. Only Kenya has seriously exploited its geothermal power resources estimated at over 1700 MW. 5% of its power generation is geothermal and two projects, with a total of 116 MW, are under construction. The Olkaria I geothermal power station is currently supplying 45 MW, while Olkaria II, whose construction is still on-going has injected an additional 8 MW. Upon completion, Olkaria II will generate a total of 64 MW. Olkaria III has already reached a capacity of 12 MW and is being expanded to 64 MW by 2004.

2.5.5 Thermal Power Generation using Imported Hydrocarbons

So far, no country in East Africa has known petroleum deposits. All the petroleum products consumed in the region are imported either as refined products or as crude oil, which is then refined at available refinery facilities in the region. In the early 1990s individual countries in the region started liberalising the oil industry and there has been steady increase in the volume of refined (white oils) petroleum products imported. At the same time, domestic demand for petroleum products has grown steadily.

Thermal power generation using imported petroleum products is the second most significant power generation resource after hydropower, contributing to about 23 percent of the total generation.

Following a series of consecutive dry years in Tanzania, the country faced massive load shedding from 1992 to 1995. Urgent measures were taken to install gas turbines on a fast track schedule in 1994 and 1995. A total of 110 MW were installed. The installation of these units alleviated the load shedding problems but increased the cost of electricity generation in a system, which is hydro dominated. However, the increased cost of generating electricity is much less in comparison to the cost of the economy of load shedding.

The increase in thermal generation in Kenya is attributed to the thermal generation plants installed by Independent Power Producers (IPPs) in response to the emergence power generation programme following the instituted nation-wide power rationing in Kenya as a result of insufficient seasonal rains in 1999 and 2000. In Uganda thermal generation continues to be insignificant due to abundant hydro resources in the Nile basin.

2.5.6 Power Generation Using Natural Gas

In East Africa, natural gas reserves are found in Songo Songo and Mnazi Bay in Tanzania. Songo Songo has proven gas reserves of 540 billion cubic feet (bcf), probable gas reserves are estimated at 1,100 bcf. Mnazi bay gas reserves are estimated at 14 billion cubic metres (bcm). Tanzania has embarked on development and utilisation of natural gas from Songo Songo offshore gas fields to generate electricity and other industrial applications. It involves a construction of a 25 km. of marine pipeline (suspended on the sea bottom) and 207 km. of (buried) land pipeline from Songo Songo Island to Dar es Salaam where 120 MW gas turbines will use the natural gas. Also via a 16 km spur pipeline to the Wazo Hill Cement Factory will be constructed to supply the gas to the factory. Natural gas will be on stream in the year 2003. The Songas Project, a private entity is undertaking the investment through partial financial support from the World Bank. The Mnazi Bay gas is to be used for the generation of 15 MW.

2.5.7 Power Generation Using Coal

Tanzania is known to have vast reserves of coal. There is a 24 MW coal generation plant at Kiwira although its effective generation output is much smaller (6 MW). A 400 MW coal fired plant at Mchuchuma in Tanzania is under investigation. Mchuchuma coalfield has proven reserves amounting to 158 million metric tonnes out of an estimated 539 million metric tonnes. A colliery is to be constructed for coal extraction and a coal fired power plant is to be constructed using coal from the colliery. The project consortium for implementation of the project consists of National Development Corporation (NDC) of Tanzania, Siemens Limited, Grinaker-LTA Limited, and Cinergy Global Power Inc. Apart from the colliery and power station construction, the project involves construction of a 220 kV transmission line for connection to the grid, and total investment costs of the project are estimated at US$ 612 million. Table 2.3, shows power generation from various sources in East Africa.

Table 2.3: *Electricity Potential and Installed Capacity as of 2002*

POWER	Capacity Installed (MW)	Extra Potential (MW)
HYDRO		
Kenya	731	300
Tanzania	580	2,400
Uganda	300	2,200
TOTAL HYDRO	1611	5,724
THERMAL		
Kenyan (KPLC + IPP)	321	
Tanzania (Diesel)	317	
Tanzania (Coal)	6	
Uganda (Diesel)	3	
Total Thermal	647	
GEOTHERMAL		
Kenya	89	1,700
Tanzania	-	80
Uganda	-	450
Total Geothermal	89	2,230
WIND		
Kenya	0.4	?
Tanzania	-	?
Uganda	-	?
TOTAL WIND	0.4	
Total Capacity	**1,949.39**	

Source: KPLC, TANESCO and UEB

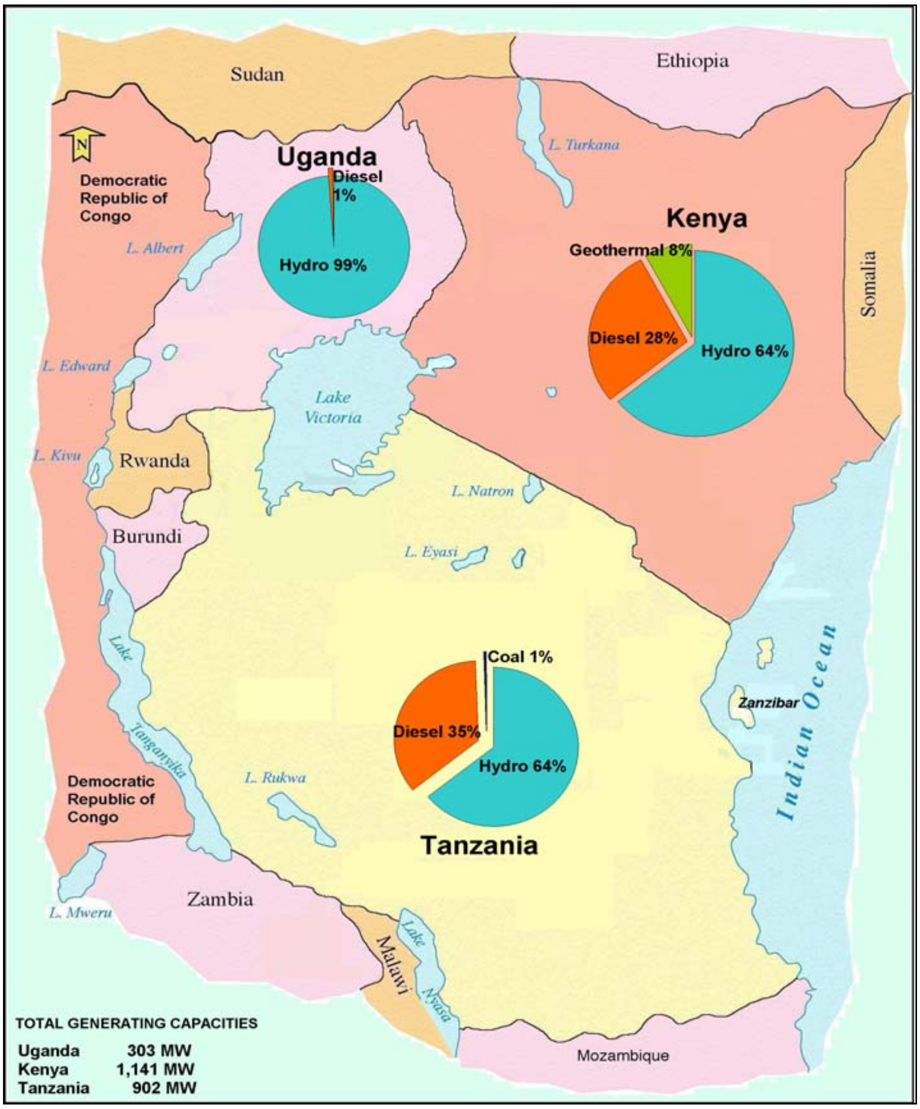

Figure 2.2: *East Africa electricity generation capacity by fuel*

2.6 GREENHOUSE GAS INVENTORIES FOR THE ENERGY SECTOR

The three East African countries, namely: Kenya, Tanzania and Uganda are signatories of, and have ratified, the United Nations Framework Convention on Climate Change (UNFCCC). They have also done their climate change studies including developing national inventories of emissions by sources and removal by sinks. The inventories were developed for the base years of 1990 and 1994. The national GHG emissions inventories for the energy sector in the three countries has been reviewed to provide the current status of GHG emissions as well as the comparison of the power sector emissions with the overall energy sector emissions.

It should be noted that Carbon dioxide (CO_2) is the largest greenhouse gas emitted from the energy sector. Methane (CH_4) is the second largest greenhouse gas in the sector followed by nitrous oxide (N_2O).

The inventory for Uganda and Tanzania includes emissions from the use of biomass fuels while for Kenya it only includes combustion of fossil fuels. Table 2.4 shows greenhouse emissions from the energy sector for the years 1990, 1994 and 2000, for the East African countries.

Table 2.4: *GHG emission from the Energy Sector 1990 -2000 (in Gg)*

Country	Gas	Activity	1990	1994	2000
Uganda	Carbon Dioxide	Power generation	5.44	5.44	8.00
		Other Energy	1,549.98	17,300.56	20,327.77
		Total	**15,497.42**	**17,306.48**	**20,333.21**
	Methane	Power generation	0.00027	0.00027	0.00027
		Other Energy	56.478	63.493	75.689
		Total	**56.4783**	**63.4936**	**75.69**
	Nitrous Oxide	Power generation	0.00006	0.00006	0.00006
		Other Energy	0.65	640.49	762.91
		Total	**0.65**	**640.49**	**762.910**
Kenya	Carbon Dioxide	Power generation	77.63	90.45	1,537
		Other Energy	3308.95	4432	5687.47
		Total	**3381.58**	**4522.45**	**6463.03**
	Methane	Power generation	-	-	-
		Other Energy	196.41	148.22	197.09
		Total	**196.41**	**148.22**	**197.09**
	Nitrous Oxide	Power generation	-	-	-
		Other Energy	0.78	1.31	1.69
		Total	**0.78**	**1.31**	**1.69**
Tanzania	Carbon Dioxide	Power generation	73.79	313.90	229.00
		Other Energy	61,670.00	58,627.00	60,506.00
		Total	**61,743.8**	**58,940.9**	**60,735.00**
	Methane	Power generation	0.003	0.008	0.013
		Other Energy	426.1	152.656	172.125
		Total	**426.103**	**152.664**	**172.138**
	Nitrous Oxide	Power generation	0.001	0.002	0.0026
		Other Energy	2.13	2.593	3.2536
		Total	**2.131**	**2.595**	**3.2562**

Source: CEEST (1997); US/Kenya Country Study on climate Change Project, 1998, UNDP/GEF Capacity Building Project, 1998; Own computation.

3

CURRENT POWER SITUATION

3.1 TANZANIA POWER SITUATION

The power system in Tanzania consists of an interconnected transmission grid system and several dispersed isolated systems. Tanzania Electric Supply Company owns most of these generating facilities. However, there exist a number of IPPs facilities. The interconnected system consists of large hydroelectric and thermal generating facilities that provide power to major cities and towns. The nameplate hydro generating capacity rating (as of 2002) is 580 MW, or about 63% of the total available installed capacity in the interconnected system. The major hydropower plants are Kidatu (204 MW), Mtera (80 MW), Lower Kihansi (180 MW), Pangani Falls Redevelopment (66 MW) and Hale (21 MW). (Mwandosya *et al* 1997, Economic Surveys 2000).

The oil-powered thermal generating capacity in the grid system (as of 2002) has a nameplate rating capacity of approximately 334 MW or about 36% of the total available capacity. The major thermal power plants include the Ubungo Diesel Plant (49.6 MW), the Ubungo Gas Turbines (111 MW) and the Tegeta IPTL Plant (100 MW) owned by a Malaysian company, Independent Power Tanzania Ltd (IPTL). Other thermal diesel stations include Mbeya (13.9 MW), Mwanza (32.5 MW), Dodoma (7.4 MW), Tabora (7.4 MW) and Musoma (5.9 MW).

Another thermal power source is a coal power plant at Kiwira, which generates 6 MW or about 1% of the total available capacity, for the use of the coalmine the excess of which is sold to the grid. Figure 3.1 shows the power generation facilities and their contribution to the sector in the year 2002.

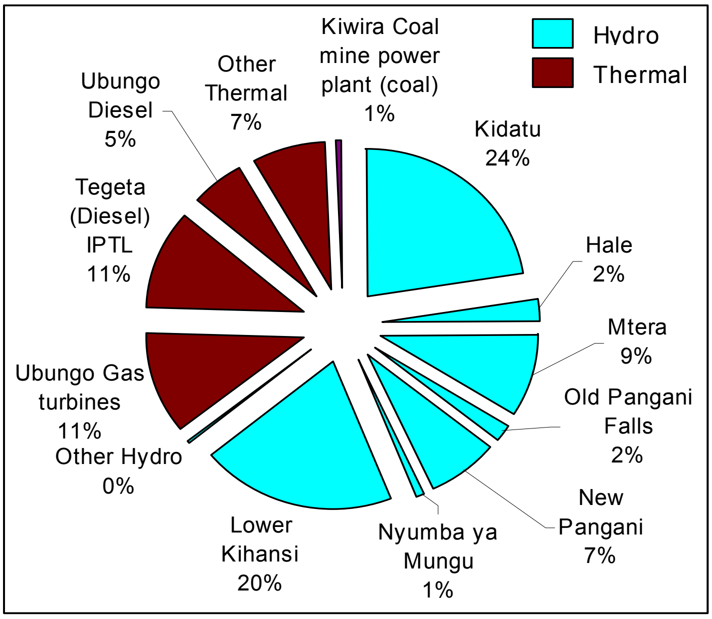

Figure 3.1: *Tanzania Power System (2002)*

3.1.1 Tanzania Power Sector Structure

In 1993 Tanzania, abolished the state monopoly of the power sector. Prior to that only a single utility was responsible for developing, generating, and distributing electricity in the country. This prompted the public and the private sector to consider promoting and enhancing development and use of alternative sources of power to areas not connected to the grid or where they are economically feasible. Already there are at least six IPPs supplying power in Tanzania.

The Ministry of Energy and Minerals is the present regulator. It approves tariff increases and regulates the industry. At present the TANESCO Board of Directors can authorise tariff increases of up to 5% without ministerial approval; the minister can also approve changes of up to 10%; and beyond 10% tariff increases requires cabinet approval. In both cases the increases can be done at most twice a year. In effect, therefore, tariff increases of up to 30% can be achieved without cabinet approval.

The new Act envisages the establishment of a regulatory board which will regulate tariff setting, approve Power Purchase Agreements (PPAs) and ensure orderly participation in the liberalised market. But at present, the Ministry would have to issue a license for any IPP. For those IPPs which wish to sell power to the TANESCO grid this license naturally, will only be issued after the conclusion of a PPA with TANESCO.

3.2 KENYA POWER SITUATION

In Kenya, electricity is the second most important source of commercial energy for the formal sector after petroleum fuels. Commercial and industrial establishments as well as institutions and households in the country use electricity. Kenya Power and Lighting Company (KPLC) is the institution responsible for supplying power in the country. The Kenya power interconnected system is made up of large hydro electric, thermal and geothermal generating facilities. Kengen owns most of these generating facilities, although there exists some Independent Power Producers who also generate power and sell to the KPLC. The nameplate hydro generating capacity rating (as of 2002) is 731 MW or about 56% of the total available installed capacity in the interconnected system. The major hydropower plants are Gitaru (145 MW), Gitaru III (72.5 MW), Kiambere (144 MW), Turkwel (106 MW), Kamburu (91.5 MW) and Sondu Miriu (60 MW), Masinga (40 MW), Kindaruma (44 MW), others (28 MW).

The nameplate thermal diesel generating capacity rating as of 2002 is 321 MW, while that of geothermal is 89 MW located at Olkaria geothermal fields. The major thermal diesel plants include, Kipevu I (75.5 MW), Kipevu II (Mombassa) (74.2 MW), Eldoret IPP (55 MW), Nakuru IPP (55 MW), others (61.4 MW). Figure 3.2 shows the power generation facilities and their contribution to the sector in the year 2002.

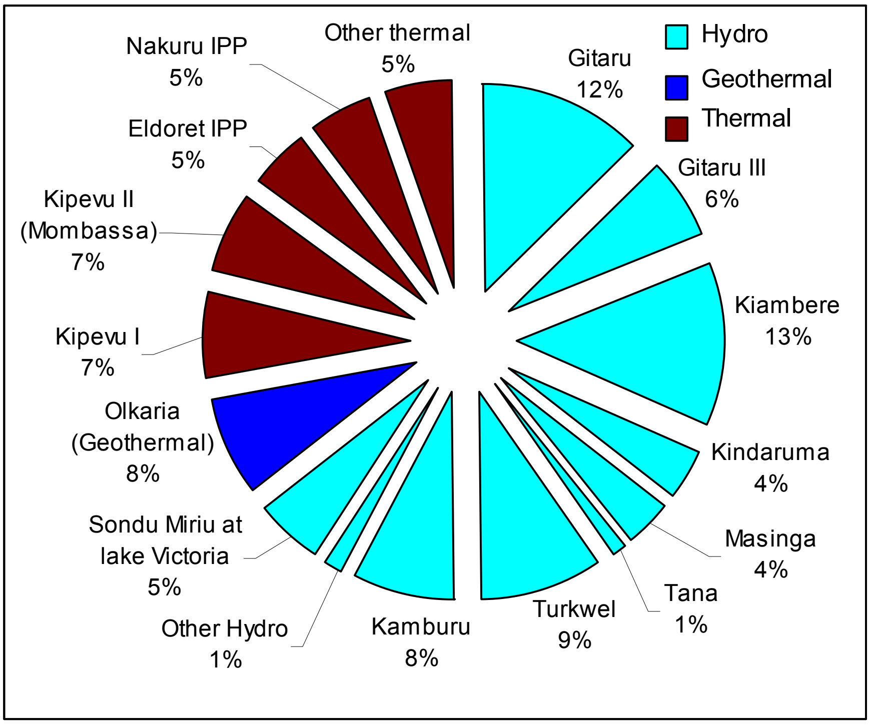

Figure 3.2: *Kenya Power System (2002)*

3.2.1 Kenya Power Sector Structure

Kenya has also transformed its power sector and thereby abolished the state monopoly in the sector. Prior to that only a single utility was responsible for developing, generating, and distributing electricity in the country. The new Electric Power Act of 1997 provides for the minister responsible for energy to issue licenses for the "generation, transmission and distribution of electric power" to any person or organisation which has met the requirements for granting such a license. This Act removes the monopoly on generation, transmission and distribution of electric power from the state power authority, which operated as a monopoly prior to the enactment of this Act. Qualification for the issuance of a license is determined for each application by the Electricity Regulatory Board. The board regulates the generation, transmission and distribution of electric power and its powers include setting, reviewing, and adjusting electricity tariffs from sources that generate, transmit or distribute electricity for sale. The board also ensures that there is free and fair competition in the industry, investigates complaints among actors and approves power purchase agreements proposed among suppliers, transmitters, distributors and with large consumers.

The Minister is empowered by the Electric Power Act of 1997, subject to approval by the National Assembly, to consider providing, and where expedient to provide funds for the construction of works necessary to effect the supply of power to a designated locale, in situation where it is reasonably considered uneconomic for the supplier to provide the works. In addition, the Act provides for the public utility to reimburse an IPP for costs associated with investments to interconnect the IPP supply base with the national network administered by the national utility. Kenya Power and Lighting Company (KPLC) is presently the sole buyer of electricity from the IPPs.

Recently IPPs have developed thermal plants that assisted Kenya to overcome the power crisis, which resulted from drought that affected the Hydropower stations. Current development of geothermal resources is also being undertaken partially by IPPs and KenGen, which is a generating company resulting from the unbundling process. Kenya has also put in place an independent Electricity Regulatory Board to regulate the sector.

3.3 UGANDA POWER SITUATION

Uganda power generation system is dominated by hydro generation facilities contributing to about 99% of the total generating capacity. Thermal generation facilities contribute only 1% of the available capacity. The Uganda Electricity Board (UEB) owns the generation, transmission and distribution facilities.

The generating capacity (as of 2002) is 303 MW out of which 300 MW is from one source located in River Nile, namely, Owen Falls, while 3 MW is from thermal diesel plants. Figure 3.3 shows the existing power generation facilities in Uganda and their respective capacities.

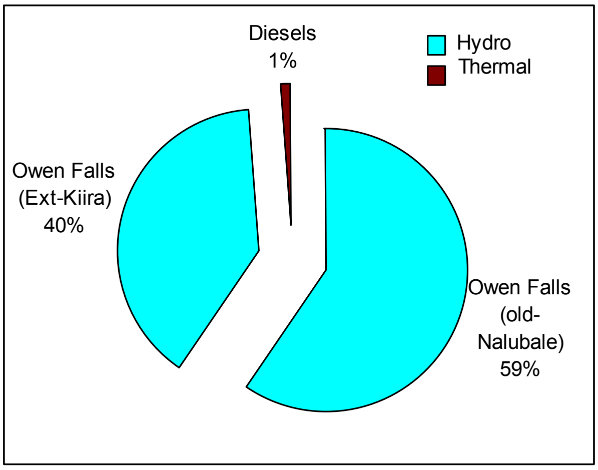

Figure 3.3: *Uganda Power system (2002)*

3.3.1 Uganda Power Sector Structure

In 1997 the Government of Uganda formulated a comprehensive and detailed Strategic Plan for transforming the Uganda power sector into a financially viable electricity industry, in order to make its full contribution to the economic and social development of Uganda.

This plan was revised into a new Strategic Plan in June 1999, which was designed to meet the following objectives for the power sector:

- Making the power sector financially viable and able to perform without subsidies from the Government Budget;
- Increasing the sector's efficiency;
- Improving the sector's commercial performance;
- Meeting the growing demands for electricity and increasing area coverage;
- Improving the reliability and quality of electricity supply;
- Attracting private capital and entrepreneurs; and
- Taking advantage of export opportunities.

The New Strategic Plan places particular emphasis on the role of competition in promoting efficiency within the power sector and on private sector participation as being a key driver to enhance the power sector's performance.

The key elements of the reform are:

- Increasing the scope of competition in the provision of new generating capacity and in the running of existing generation assets. New generating capacity to be competitively provided by the private sector through independent power projects;
- A separate Transmission Company, which in the medium term will remain in public hands, to be responsible for network maintenance, system operation and dispatch, and bulk purchase and supply of electricity. New transmission capacity will as far as possible be developed, financed, constructed, operated and owned by the private sector ; and
- A financially viable distribution system let out to the private sector under a concession.

In all these cases the existing assets will remain in public hands and in the case of the existing generation and distribution, the running of the business will be privatised.

A new Act, the Electricity Act, 1999 gave legal backing to those reforms and opened up the electricity industry to the private sector, removing the monopoly by the state utility, Uganda Electricity Board (UEB).

IPPs have started entering the sector. Already one IPP, AES Nile Power has been licensed to develop the 200 MW Bujagali Project which is located some 8 Km downstream of the existing Nalubale (formerly Owen Falls) power station. Work on this project is expected to be completed by the end of 2005 or early 2006. Another developer has shown interest to develop the 150 MW Karuma Project and has already conducted feasibility studies. Other developers have shown interest in developing the small hydropower sites. A study was conducted recently, to evaluate small hydropower sites in the 0.5 - 50 MW range. Nine sites, namely; Nyamabuye, Nengo Bridge, Bugoye, Kakaka, Sogahi, Rwizi, Buseruka, Siti and Sipi were considered under this study.

Two small hydro power plants, the 5.1 MW Paidha Project and the 1.5 MW Olewa Project are due for development to supply the fast growing West Nile region. These two projects will be developed by the private sector under the Government rural electrification programme called ‘Energy for Rural Transformation’ ERT. This is likely to be the first Proto-type Carbon Fund, PCF, project in Africa whereby the World Bank PCF will purchase certified emission reduction, CERs, certificates from this project.

In undertaking internal utility reforms, the Uganda Electricity Board (UEB) has been unbundled into three distinct companies for generation, transmission and distribution. It is envisaged that both the generation and distribution business will be taken over by private concessionaires. The generation operator will take over the existing Nalubaale and Kiira power plants, whereas the distribution concessionaire will take over the existing UEB network. In the medium term, the Transmission will remain in public hands. Both the generation and distribution assets will remain in public hands.

As for power sector regulation an independent regulator, the Electricity Regulatory Authority (ERA) has been put in place to regulate the sector.

3.4 EXISTING AND POTENTIAL EAST AFRICAN POWER COOPERATION

3.4.1 Existing Interconnections Between the East African Countries

Uganda supplies power to Kenya through an interconnection between the two countries, which has been in existence for a number of years, via a 132 kV double circuit line from the Owen Falls hydropower plant. The line has a capacity of carrying 80MW. Uganda also currently supplies the north western portion of Tanzania via a 132 kV line from Masaka to Bukoba. Tanzania until 1965 used to supply Mombasa via a 66 kV line from Tanga. This export was curtailed following Tanzania's acquiring all the shares that were held by KPCL.

3.4.2 Potential Interconnections

Interconnections between Kenya, Uganda and Tanzania have been studied previously and have the potential for significant economic and operational benefits. However, these studies need to be updated in order to unify the EA potentials as well as development of an interconnected system through an East African Power Master Plan. Potentials for electricity sharing between Kenya and Tanzania exist through a 350 km and a 400 km long 220 kV interconnection between Arusha and Nairobi and between Dar es Salaam and Mombasa respectively. The Arusha – Nairobi interconnection could also be used to exchange electric power between Tanzania and Uganda (wheeling through Kenya) via a 500 km long 220 kV line from Kampala to Nairobi. Another option is a 500 km 220 kV line from Kenya to Tanzania (Olkaria – Mwanza). At the present time neither Uganda nor Kenya have surplus energy available for export, except for local supply to smaller centres in border regions. Uganda may have surpluses in future, if and when future hydro resources currently under negotiations are constructed. (TANESCO ACRES, 1999).

Uganda could also share its electricity with Tanzania through radial 132 kV connectors or higher levels (100 to 200 MW) of electricity requiring a 700 km 220 kV interconnection from Kampala (Kampala – Mwanza).

As for the possibility of importing power from the Southern African Power Pool, TANESCO, ZESCO and Eskom completed a joint study in 1995 on proposed interconnection between Zambia and Tanzania. The study identified technical characteristics and costs of a single interconnector transmission line between the TANESCO and ZESCO power systems. A 700 km 330 kV line from the Pensulo Substation in Zambia via Kasama to the 220 kV substation in Mbeya has been recommended. The interconnector is designed to carry 200 MW with the assigned facilities (TANESCO ACRES International 1999). Table 3.1 shows the potential interconnections between the East African countries as well as with Zambia.

Table 3.1: *Potential Interconnections between EA Countries and Zambia*

Interconnections 35 years		Constr. Year	Capacity	Length
From	To		MW	km
Arusha	Nairobi	2005	200	350
Dar es Salaam	Mombassa	2015	200	400
Nairobi	Kampala	2010	200	700
Mwanza	Olkaria	2015	200	500
Mwanza	Kampala	2010	200	600
Zambia	Mbeya	2006	300	670

Source: TANESCO-ACRES (1999)

3.4.2 East African Power Cooperation

The three East African countries decided to plan for the combined development of their power systems. The benefits to be accrued from such combined development and interconnections include, *inter alia*, reduction in capacity and reserves requirements in the individual systems, reduction in imported fuel requirements for power generation, emergency support and optimisation of the utilisation of hydropower generation facilities in the area. In consideration of the above facts, a meeting of the High Level Tripartite Task Force of Energy Experts was held in Arusha 30-31 March 1998, under the auspices of the Secretariat of the Commission for East African Cooperation. One of the outcomes of the meeting was a proposal for the development of a regional power sector master plan. As a follow-up to this agreement EAC has solicited funds from the World Bank for carrying out a comprehensive feasibility study of the power sector to establish the East Africa Power Master Plan (East African Community, 2001). Figure 3.4 is an East African Map showing the interconnected system and potential interconnections.

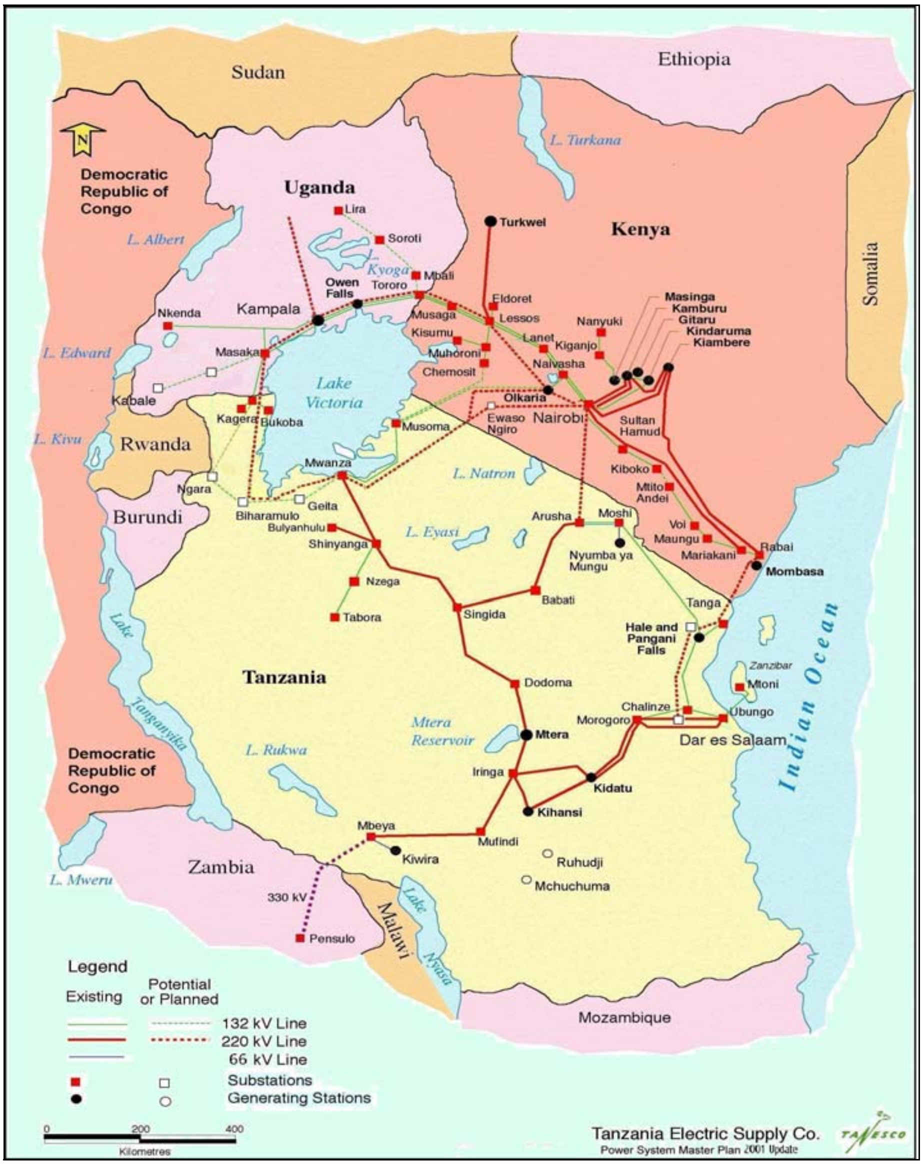

Figure 3.4: *East African Grid Systems and Potential Interconnections*

4

BASELINE SCENARIO

4.1 POWER DEMAND FORECASTS

Power demand forecast is the basis for understanding the future electricity consumption of a country. However, since this exercise involves power cooperation between the three East African countries the analysis was on the grid connected power demand and therefore off-grid electricity demand is not included accordingly, therefore:

- Each participating country developed an electricity demand forecast (both peak load MW and annual GWh consumption) until 2010. These forecasts were based on the most recent Power Master Plans of the respective countries.
- Each individual country's electricity demand forecast has linked factors like population increase, industrial development and mining development with the potential growth of the electricity sector supplies.

4.1.1 Tanzania Power Demand Forecast

Tanzania's new 25 – year Master Plan for the development of the TANESCO power system under the title " 1999 Power System Master Plan" (PSMP) was prepared by Acres in 1999. The load forecast developed for the 1999 PSMP was based on 1980 – 96 data and economic projections. It may be noted that in the years 1997 and 1998, Tanzania economy faced a lot of hardships including the 1997/98 heavy El-Nino rains that affected the overall infrastructure, followed by a severe drought experienced during the last half of 1998.

In the industrial sector the following factors have also contributed to the review of the forecast:

a) Mining loads have changed slightly from 1999 PSMP forecast both in-terms of timing and amount of power realistically expected to be on line. Of the eight major mining loads included in the 1999 PSMP, only two – Lusu (Golden Pride) and Kahama Mines are in operation.
b) Incentives given to mining industry recently have encouraged mining industries to generate their own power using diesel (autogeneration) rather than using TANESCO power since diesel fuel for power generation in mining industry is exempted from taxes making diesel generation competitive with grid power.
c) Gold prices in the market are at the moment not as high as they are expected to be and as such the rate of investment in large scale gold mining has fallen.

The 1999 PSMP forecast was reviewed in November 2000 to include the updates due to the 1997 – 1998 changes in power market demand and development in the Tanzania power sector and work plan to year 2000 level.

Two sensitivity cases have been prepared to establish expected upper and lower bounds for future electricity demand growth.

The low power demand growth case considered the following:

- The low growth economic scenario with an average long term GDP growth of at most 3.5%;
- The low growth industrial scenario which calculates the growth to full industrial capacity at new plants over 5 years;
- Customer growth rate of 4.0% per year and low growth in consumption per customer based on a growth rate of 0% per year;
- A case where only Kahama and Lusu mining loads were considered.

The high power demand growth case considered the following:

- The high growth economic scenario with an average long term GDP growth of at least 5.9%;

- The high growth industrial scenario which was also used in the reference case and calculates the growth to full industrial capacity at new plants over 3 years;
- Customer growth rate of 6.0% per year and high growth in consumption per customer based on regression analysis;
- The development of all mining loads is reflected in high elasticity of demand.

4.1.2 Kenya Power Demand Forecast

Kenya carried out the National Power Development Plan covering the period 1986 – 2006, which is the one currently under implementation. However, it has been partially updated severally to suit changing economic development scenarios. The purpose of the development plan was to develop updated and revised plan for an orderly and economic expansion of generation and transmission facilities over the plan period. This plan gave a shift from historic hydro-dominated generation and directed that investment of future generation facilities will take place close to major load centres in Nairobi, Mombasa, Western Kenya, bearing in mind a close balance between regional supply and regional demand thus reducing the need for high voltage transmission.

The plan emphasised greater attention to geothermal resources and the more promising hydro development, continued exploration of oil and gas in view of the likely emerging role of thermal generation around year 2000 and that a comprehensive update was to be made (around 1991). The overriding objectives of the plan were:

- To determine the projects to follow next after Turkwell hydro-electric project;
- To determine the long-term mix of geothermal, hydro and/or conventional thermal;
- To determine the potential benefits of power imports from neighbouring countries;

The growth of electricity sales in Kenya in the last 20 years has averaged 6.1% p.a, which has consistently been above the corresponding GDP growth, which has averaged 4.2% per annum. The capacity of generation was severely affected by the drought 1999/2000, which led to near-collapse of the power sector and precipitated unprecedented power rationing for all categories of consumers. Given that electricity sales is closely linked to GDP performance, the growth scenario for load forecast were formulated taking into consideration continuing economic reforms and long-term annual growth rate expectation of 5.1% p.a. This growth rate was used for the reference forecast case and is based on the mid-point between pessimistic and optimistic outlook of the GDP performance in the current development plan. Forecast models, prepared for four customer groups using regression analysis have remained structurally unchanged since 1997. The consumer categories are (i) Domestic (ii) Commercial/industrial (iii) off-peak and (iv) rural electrification.

4.1.3 Uganda Power Demand Forecast

Uganda has carried out some efforts to forecast the demand for electricity. Earlier work was done by Kennedy & Donkin Power Ltd. in association with Sir Alexander Gibbs & Partners Ltd and Kananura Melvin Consulting Engineers. Their report entitled 'Hydropower Development Master Plan' came out in November 1997 and covered the period 1995 to 2020. This report also ranked the various hydropower sites on the River Nile so that they are developed sequentially starting with the least cost.

Because it was felt that Kennedy and Donkin did not take into account certain parameters and assumptions, an optimisation study in another load forecast was conducted by Electricite De France, EDF looking at the hydrology of Lake Victoria and the load forecast.

The power demand and energy utilisation figures for Uganda domestic use and exports were based on sales figures for various categories of consumers, factoring in population growth and economic growth indices appropriately for High, Base and Low scenarios.

Table 4.1 *Power Demand Forecast (GWh)*

	2002	2010	2015	2020
Uganda	2,050	4,302	5,766	7,716
Tanzania	3,004	5,262	6,577	8,189
Kenya	5,147	7,968	10,496	13,632
East Africa	10,201	17,532	22,839	29,537

Table 4.1 and Figure 4.1 show electricity demand forecasts for the three East African countries from 1999 to 2020. It should be noted that from the word go Kenya consumes more electricity than Tanzania and Uganda. Uganda has the least electricity consumption although it currently exports electricity to Kenya and Tanzania. The reason might be the different industrial bases for the three countries. Kenya has a stronger industrial base than the rest followed by Tanzania, which has a considerable industrial base with mining loads posing a bigger potential. Uganda is an agricultural country with minimal potential industrial loads.

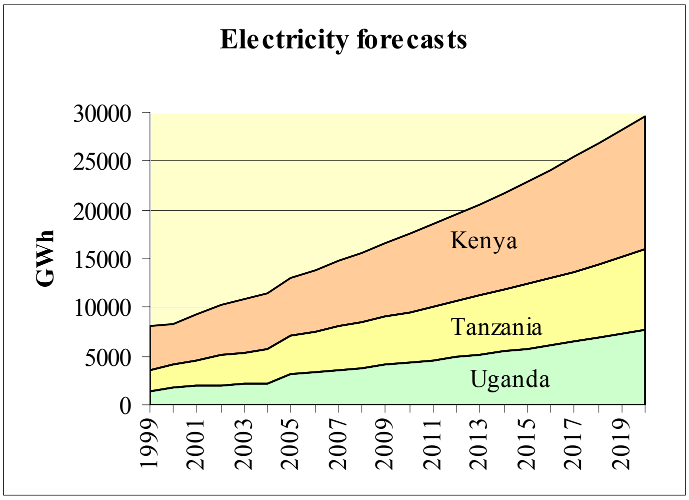

Figure 4.1: *Electricity Demand Forecasts 1999-2020*

4.2 POWER DEVELOPMENT IN THE BASELINE SCENARIO

As already mentioned the baseline scenario has been developed on the basis of the individual countries power demand forecasts and power master plans. The East African least cost power development scenario has been developed on the basis of individual country's power master plan and power demand forecasts up to 2020. Although some of the power master plan projections were not up to the year 2020, we developed projections on the basis of the demand growth projections and relevant assumptions in the relevant power master plans.

Using the Regional Power Greenhouse Gas Abatement Costing (RPGACMO) model, separate spreadsheets were developed for power generation for each country for the baseline scenario. The spreadsheets had power generating capacities by fuel and for each plant in the order of the least cost generating plants annual generation in MW. These were converted to GWh calculated using capacity factors of the plants. These factors were developed using historical data as well as other factors available in the individual countries' power master plans. Table 4.2 shows the planned new power plants in the baseline scenario.

Table 4.2: *Planned new power plants in the baseline scenario*

Name of New Power Plant	Capacity (MW)	Commencement Date
Uganda		
(Hydro)		
Bujagali	200	2005
Karuma	150	2007 - 2009
Kalagala	350	2009 - 2011
(Thermal)		
New Oil Steam	350	2018 - 2020
Kenya		
(Hydro)		
Sondu Miriu	60	2004
Ewaso Ngiro A	90	2008
Ewaso Basin	90	2008 - 2009
(Geothermal)		
Olkaria II	64	2003
Olkaria III	64	2004
(Thermal)		
New Oil Steam	1,790	2006 – 2020
Tanzania		
(Hydro)		
Upper Kihansi	120	2006
Ruhudji	358	2010
(Natural Gas)		
Kinyerezi	180	2005
(Coal)		
Mchuchuma	400	2017 – 2019
New Oil Steam	365	2003 - 2017

5

MITIGATION SCENARIO ANALYSIS

5.1 METHODOLOGICAL ISSUES

In carrying out the mitigation analysis, the Greenhouse gas Abatement Costing Model (GACMO) (Fenham, 1999), was modified to handle the particular nature of an interconnected system since this task could not be handled on a project-to-project basis, as is carried out in the GACMO model. GACMO is an EXCEL spreadsheet notebook containing various spreadsheets including: Main, Graph, Assumptions, Prices, Option1, Option2, ……Option N. Therefore, while in the GACMO model, specific mitigation options are contrasted with a reference option in the baseline, the modified model considered the mitigation options as one package. The model developed in this study is therefore named Regional Power Greenhouse Gas Abatement Costing (RPGACMO) Model. The spreadsheets developed in this particular study included: Factors; Baseline (Tanzania); Baseline (Uganda); Baseline (Kenya); Mitigation (Tanzania); Mitigation (Uganda); Mitigation (Kenya); Energy; CO_2; Expenses, and Cost curve.

5.1.1 Basic Assumptions

The following were the major assumptions for the construction of the cost curve:

- The same boundary has been assumed for both the baseline and the mitigation scenario, whereby:
  - No change in electricity demand;
  - Time series were made for 1999-2020 for capacities of all plants.

- Capacity factors for oil, nat. gas, hydro and geothermal used to calculate future electricity production;
- A 70% capacity factor has been assumes for interconnections;
- Standard efficiencies were used to calculate fossil fuel use;
- Plants in the baseline scenario are units which have been decided;
- Costs for plants existing in both scenarios were not included;
- Assumptions have been made on the cost for fossil fuels. Low constant fossil fuel prices were used which were 4.1 US$/GJ for Diesel, 1.35 US$/GJ for coal, and 2.65 US$/GJ for natural gas;
- All investments were levelised with a 10% discount rate and the technical lifetime which were:
  - Interconnection 35 years
  - Hydropower plant 50yr,
  - Geothermal & natural gas 25 yr,
  - Diesels 20 or 25 yr.
- Investments are saved when fossil plants in the baseline are not built or renewed in the mitigation scenario;
- We look at the total annual cost at the last year in the period (2020);
- The costs include annual fuel cost, levelized investment cost and annual operating and maintenance cost in the year 2020. We assume that the annual O&M cost for interconnections is 2% of the investment costs. All other costs are for project documents or as provided in countries' power master plans;
- We have tried to make the mitigation costs transparent: first we show the abatement expenses and then the net abatement costs.

5.1.2 Electricity projections for the mitigation scenario

The RPGACMO analysis package takes on board all resources available in the region for power generation while mitigating greenhouse gas emissions. These include hydroelectricity, geothermal and natural gas.

Different spreadsheets for the mitigation scenarios for the three countries were constructed for the years 2000 to 2020. In the mitigation scenario the least cost power development was reviewed so that future fossil plants in the baseline scenario were omitted, and in their place more renewable plants were placed. This was done on the basis of available excess renewable electricity sources capacities in the individual countries. Using the same renewable plants the countries with excess electricity were made to export it to countries with deficit, therefore, synchronising with interconnections between the electrical grids in the three countries, as well as with Zambia, making it possible to import CO_2 free electricity.

This study does not look at electricity saving/efficiency options. Therefore, the same electricity forecasts are used both in the baseline and in the mitigation scenarios.

Table 5.1 shows a comparison between electricity generation in the baseline and mitigation scenario by fuel and associated CO_2 emissions for selected years.

Table 5.1: *Electricity generation with associated CO_2 Emissions*

		Hydro electricity (GWh)	Geothermal (GWh)	Natural gas (GWh)	Oil & coal (GWh)	Emissions (k ton CO_2)
2002	Baseline	7235	663	0	2463	1879
	Mitigation	7336	663	0	1998	1524
2006	Baseline	9322	1288	1367	3102	3056
	Mitigation	9423	1765	1752	1864	2307
2010	Baseline	13321	1288	1367	4088	3807
	Mitigation	13485	2241	1752	1864	2307
2020	Baseline	13694	1288	1367	13067	10836
	Mitigation	20080	3224	1752	4009	4098

Therefore, the mitigation scenario developed in this model shows a significant increase in the use of hydroelectricity, geothermal and natural gas and decline in the use of oil and coal, which implies a decline in CO_2 emissions as well. Figure 5.1 is a comparison of electricity generation by fuel in the baseline and mitigation scenario.

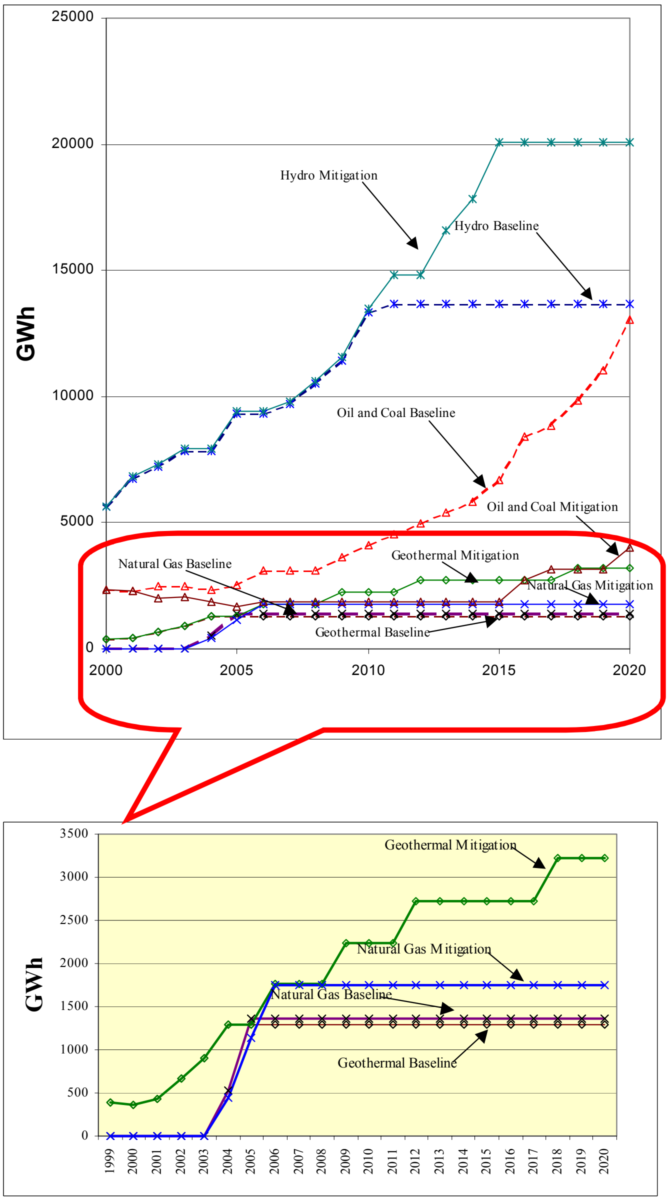

Figure 5.1: *Comparison electricity generation by fuel type between the baseline and the mitigation scenarios*

5.1.3 Projections of CO_2 Emissions

Using the RPGACMO model electricity generation were computed by fuel on the basis of the projections made in the power demand forecast. The CO_2 emissions were calculated at the bottom of the spreadsheets for each of the three countries (both for the baseline and the mitigation scenarios) where the amount of fossil fuel (coal, diesel and natural gas) was calculated in Terajoule (TJ). The amounts of fossil energy were then multiplied with the CO_2-emission factors in the first spreadsheet (Called "factors"). Here the emission factor for e.g. diesel was 74.1 kgCO2/GJ. If one looks at the formula behind this value it was calculated as 20.2 kgC/GJ *44/12. The factor 20.2kgC/GJ is the default IPCC emission factor from Table I-I in the Revised IPCC Guidelines for National Greenhouse Gas Inventories (Volume 3) (IPCC, 1996). Other emission factors applied were 94.6 kgCO_2/GJ, for coal and 56.1 kgCO_2/GJ for natural gas. The emission factors in the IPCC table is per ton of carbon (C), so in order to get the emission factor in ton of CO_2 it is necessary to multiply with molecular weight of CO_2 (44) and divide with the atomic weight of carbon (12). All emissions for each year from 1992 to year 2020 were summed up both for baseline and mitigation scenarios to obtain the respective annual emissions.

It should be noted that the substitution of fossil fuels in the mitigation scenario leads to about 7000 ktCO_2 emissions lower in the mitigation compared to the baseline scenario. Figure 5.2 shows the comparison of emissions between the baseline and mitigation scenario.

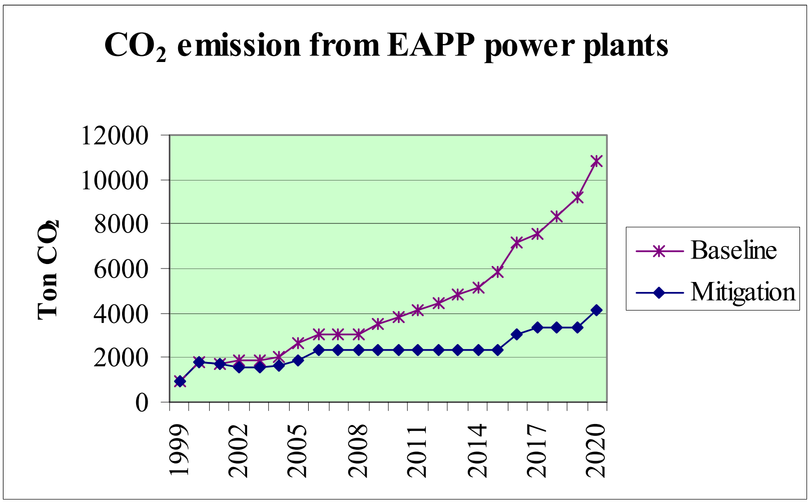

Figure 5.2: *Comparison of emissions between the baseline and mitigation scenarios*

5.2 ELECTRICITY FLOWS IN THE MITIGATION SCENARIO

The mitigation scenario has been constructed such that the power development options were considered as a package and the interconnection as a conditional investment for the mitigation options to work. This is because without the interconnections the importation and exportation of CO_2 free electricity would not take place.

Figure 5.3 shows electricity flows in the year 2020 as a result of interconnection made in the mitigation scenario between the three countries and between Tanzania and Zambia.

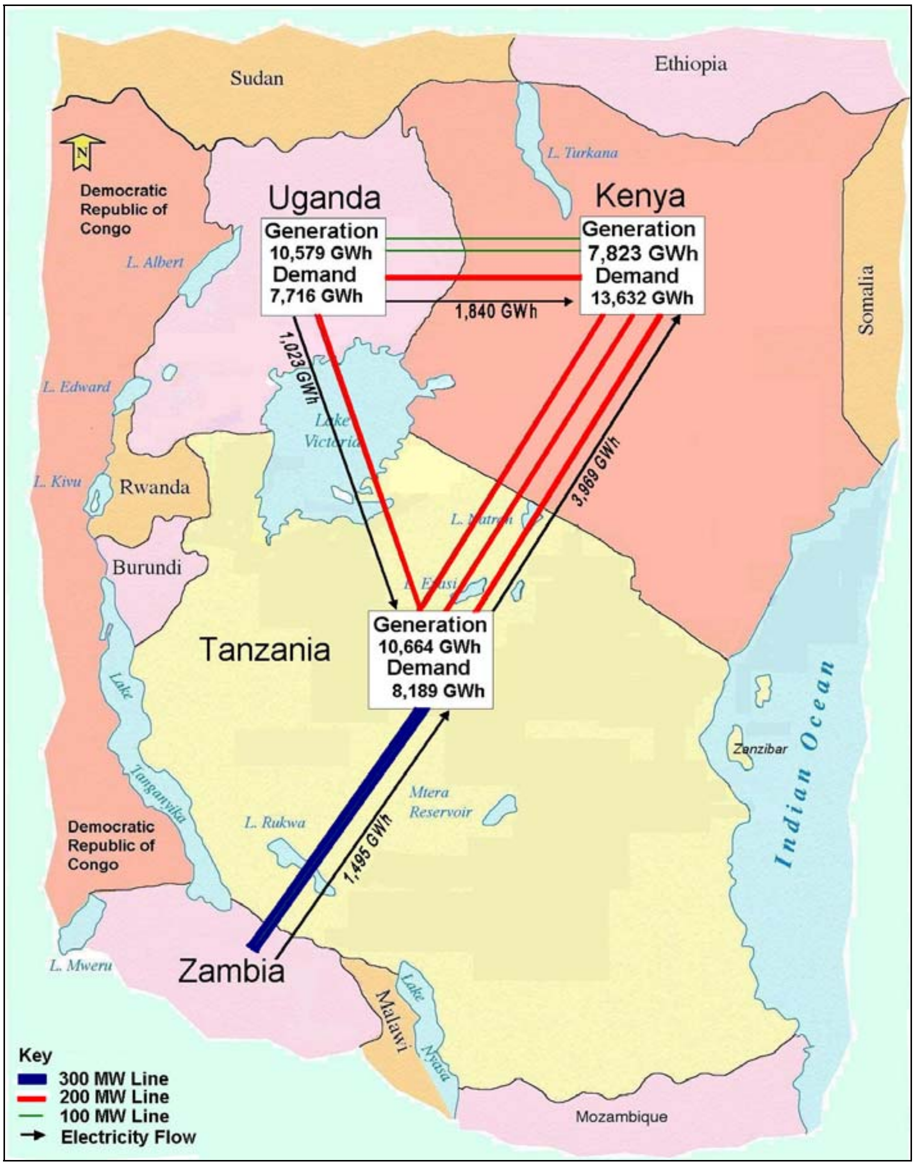

Figure 5.3: *Interconnections and electricity flows in the mitigation scenario in 2020*

5.3 COSTING AND COST CURVE FOR THE MITIGATION OPTIONS

When analysing the costs of the mitigation options the assumptions mentioned earlier have been observed. Both the investment costs and operation and maintenance costs of the options have been included in the analysis and levelised using discount rate of 10% to show the present value worth of annual packages of the investment.

The costs analysed include purchasing prices, shipping, erection, engineering and management and physical contingencies. Not included are taxes, duties, local transport and interest during construction. Cost estimates of major equipment include civil costs and all ancillaries such as disconnect switches, potential and current transformers. Substation site preparation is included in base station cost estimate (Acres International, 1999).

Table 5.2 shows the new interconnections with their cost implications.

Table 5.2: *Cost Implication of Transmission Interconnections in 2020*

Interconnections 35 years		Investment Cost	Annualised Investment Cost	Annual Maintenance Cost	Total Costs
From	To	Mill. US$	Mill. US$/year	Mill. US$/year	Mill. US$/year
Arusha	Nairobi	48.3	5.0	1.0	6.0
Dar es Salaam	Mombassa	54.6	5.7	1.1	6.8
Nairobi	Kampala	92.1	9.5	1.8	11.4
Mwanza	Olkaria	67.1	7.0	1.3	8.3
Mwanza	Kampala	79.6	8.3	1.6	9.8
Zambia	Mbeya	164.0	17.0	3.3	20.3
Total			53	10	63

The analysis of investment in new power plants in the mitigation scenario and associated costs and emission reductions is as shown in Table 5.3, which also shows the retirement of CO_2 emitting plants as a mitigation option.

Table 5.3: *Mitigation Scenario Analysis (year 2020)*

Options and capacity (MW)	Country	Extra cost	Reduction	Abatement Expenses	Net Abatement Costs
		Mill. US$/year	$ktCO_2$	US$/t CO_2	US$/t$CO_2$
Rumakali (Hydro) 222 MW	Tanzania	39.4	767	51.4	-30.7
Ayago North (Hydro) 304 MW	Uganda	98.3	1787	55.0	-27.1
Masigira (Hydro) 118 MW	Tanzania	22.6	408	55.4	-26.7
Ayago South (Hydro) 234 MW	Uganda	88.4	1375	64.3	-17.8
Kinyerezi (Natural Gas) 135 MW	Tanzania	20.9	304	68.8	-13.3
Mpanga (Hydro) 144 MW	Tanzania	36.3	497	72.9	-9.2
Geothermal260 MW	Kenya	128.6	1527	84.2	2.1
Mandera (Hydro) 21 MW	Tanzania	6.4	73	88.6	6.5
New oil steam plant saved1600 MW	Kenya	-184.9		-23.6	
New oil steam plant saved350 MW	Uganda	-40.4		-5.2	
Ubungo diesel not renewed49.4 MW	Tanzania	-8.9		-1.1	
Mwanza diesel not renewed32.5 MW	Tanzania	-5.8		-0.7	
Mbeya diesel not renewed13.9 MW	Tanzania	-2.5		-0.2	
Tabora diesel not renewed7.4 MW	Tanzania	-1.3		-0.1	
Musoma diesel not renewed5.9 MW	Tanzania	-1.1		-0.1	
Saved oil power plants		-245			-36.4
Saved oil		-367			-54.5
Saved coal		-4			-0.6
Interconnection costs		63			9.3
Regional Total		-112.3	6,737	-16.7	

Figure 5.4 compares the gross abatement costs (abatement expenses) of individual options as well as cost savings from retired and saved power plants and avoided fossil fuels.

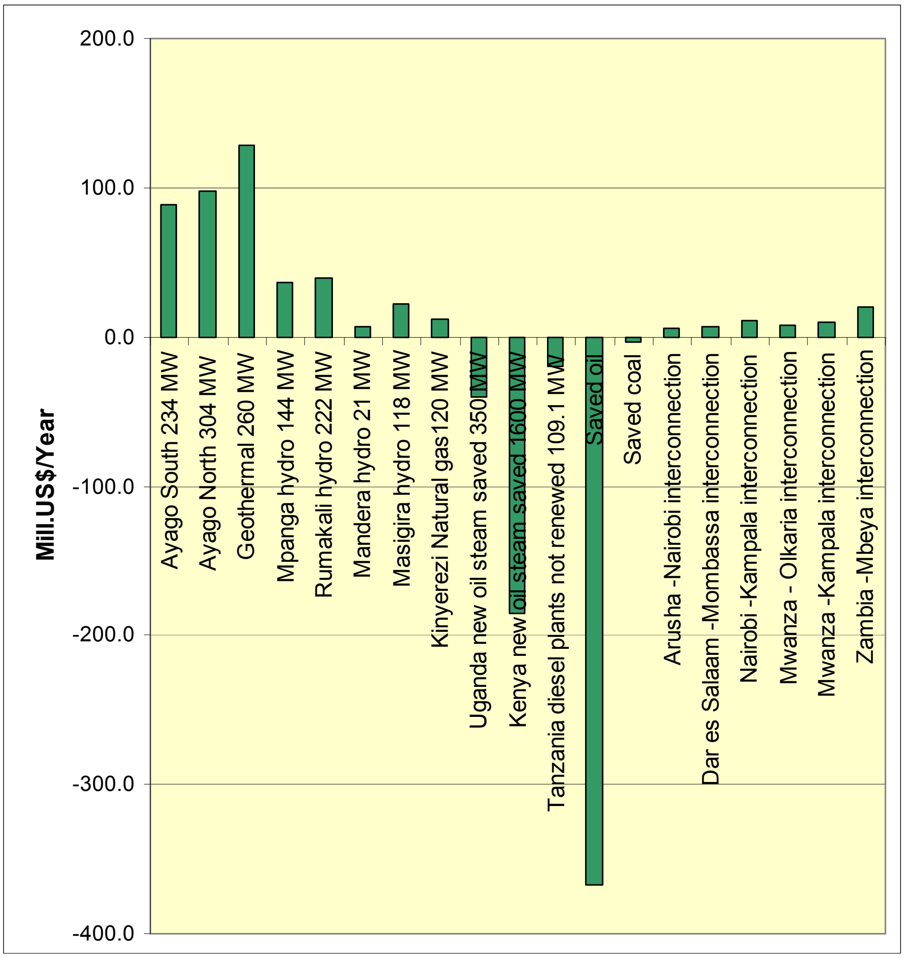

Figure 5.4: *Gross abatement expenses and savings*

Since we are taking regional power development as a mitigation option we are not relating a specific mitigation option to a particular reference option in the baseline scenario. This is not possible since the basis for the mitigation in the study is the interconnections, which is a prerequisite to all the mitigation options included. All the options have been included in one package. Therefore, the package would include the new power plants, the saved oil plants with associated saved fuels, as well as the interconnections.

In constructing the cost curve the vertical steps in the cost curve are incremental costs for the options identified while the horizontal steps are related incremental emissions reductions. The options are constrained with the saving of CO_2 emissions and associated costs savings by retiring the thermal plants in the region as well as the costs of interconnections, which is a prerequisite if any of the options have to work. Therefore, it should be noted that the abatement expenses are netted against savings in terms of power plants and fuel as well as against the interconnection costs in the cost curve.

The cost curve has been constructed for the year 2020. Other years would show the same picture. The cost curve is shown in Figure 5.5.

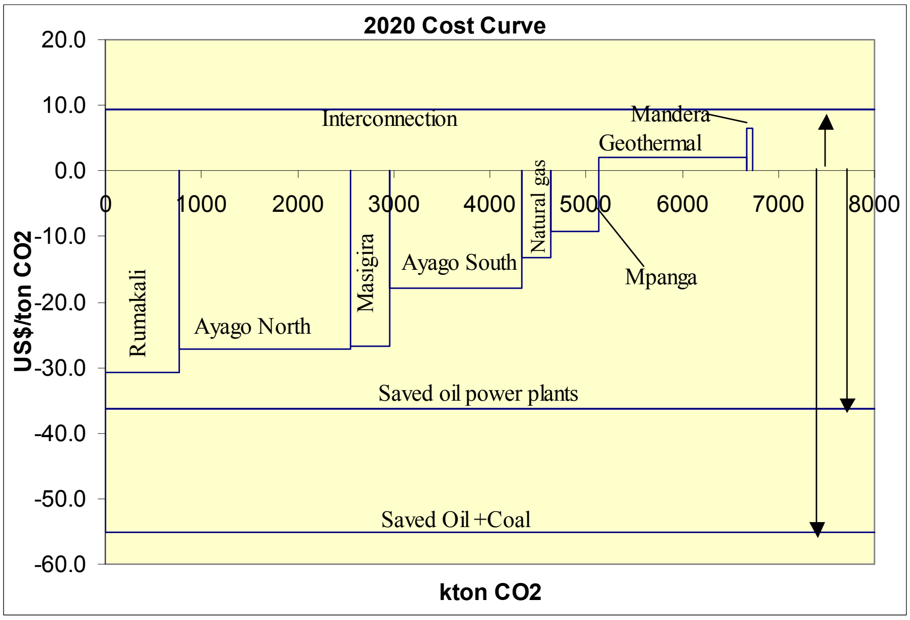

Figure 5.5: *Cost Curve for the East African power Development in 2020*

The average cost for the whole mitigation package is –16.7 US$/ton$CO_2$. It is therefore a no regret package-option.

6

CONCLUSIONS

6.1 RESULTS OF THE RPGACMO ANALYSIS

The Regional Power Greenhouse Abatement Costing Model developed in this study is a powerful tool for assessing regional greenhouse gas emission abatement as well as other benefits associated with regional power pooling. The analysis is comprehensive in that it takes the mitigation options as one package that include development of new power plants, new interconnections and retirement of GHG emitting power plants and avoidance of future use of fossil fuels.

The results of the study indicate that the East African regional greenhouse gas abatement is a no –regret –package with –16.7 US$/ton$CO_2$ abatement costs. However, it should be noted that there are a number of other costs not included related to the necessary harmonisations of policies, legislation and standards etc.

As already mentioned, there are ongoing initiatives to liberalise the power utilities in East Africa and in the process it is anticipated that the utilities will be unbundled and privatised. These changes are expected to influence regional power trading and this would facilitate smooth operation of the mitigation options. Since the utilities would operate using specific rules for dispatching the cheapest power to the market.

6.2 OTHER BENEFITS FROM INTEGRATED E.A POWER PLANNING

- Higher security of supply, also after low rains;
- Lower emissions of local pollutants;
- Development of East African power market; and
- Availability of cheap electricity to all East African countries and hence poverty alleviation.

6.3 CLEAN DEVELOPMENT MECHANISM OPPORTUNITIES

Although this has not been within the scope of the regional greenhouse gas mitigation through cooperation in power development in East Africa, the results in this report show a potential for big CDM project/s. Furthermore, there exist opportunities for small scale (less than 15 MW) CDM in the power sector especially through small hydro projects. Individual projects from specific countries could be bundled to regional projects. We have provided a list of small hydro potential projects for reference.

6.4 BARRIERS TO IMPLEMENTATION OF THE MITIGATION OPTIONS

Barriers to the implementation of the mitigation options include, among others, the following:

- Institutional barriers
  - Regulatory authority, including the national and East African authorities;
  - Climate change focal point including national focal point and East African focal point;
  - Institutional and capacity inadequacy for the implementation of the regional mitigation options;
- Technical barriers
  - Implementation of power plants;
  - National upgrading of interconnection and service provision to facilitate regional sharing of electricity;
  - Power sector reforms are country specific and therefore a need for regional context of the reforms;

  - Communications problem;
  - Baseline is put at stake when the power master plan change over a year or two;
  - Inadequacy of regional hardware and software;
  - Lack of regional power master plan;
- Political will to implement the options
  - Political perspective of electricity security may be against importing electricity from neighbouring country;
  - National self sufficiency in power generation may be against regional power sharing;
  - Sceptism on import of electricity from outside a country; and
  - Consideration of importation of electricity from a neighbouring country as a opportunity or threat;
- Financial barriers
  - Uncertainty of funding for the implementation of the mitigation options;
  - Financing of these capital projects has a tendency of over dependency on donor money and might affect prioritisation;
  - Commercial factors;
  - Payments for electricity in the countries have not been done properly;
- Political factors;
- Uncertainty on the timing in implementation of the options;
- Change of priorities of projects;
- Inadequacy of regional power policies;
- Lack of supportive legal and regulatory framework;
- Inadequate negotiation skills;

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Appendices

Table 2.2 (a) *: Mini-hydropower potential sites in Tanzania*

Site	Location	Installed Capacity	Annual Firm Energy	Capital Cost	Level of study
		kW	GWh	$ Millions	
Mto wa Simba	Arusha region	3,900	4	3.0 (1981)	Preliminary
Hainu-Nambisi	Arusha Region	8,100	40	4.1 (1981)	Preliminary
Pinying	Ngorongoro Distr.	450	1.9	2.7 (1983)	Identified
Njombe Falls-Ruhudji	Iringa Region Njombe district	2,000	13	5.0	Conceptual
Kifunga -Ruhudji	Njombe district	3,600	24	11.0	Preliminary
Kaonjuba – Kamwanana	Kagera Region Muleba distr.	800	5	2.5 (1984)	Preliminary
Kasongenye	Biharamulo Distr.	840	3.5	3.0 (1984)	Pre-feas.97/2000
Kikuletwa	Kilimanjaro Reg.	11,000	55.9	12.3	Feas. 89 & 1997
Malagarasi	Kigoma region	7,600	67. 2	32.7	Feasibility 1983
Sanda Project – Mtambo River	Rukwa Region Mpanda district	2,000	12.25 (Avg.)	4.37	Pre-feas Dec. 97 &Recon.Sep.98
Nzovwe	Sumbawanga Di.	3,000	3.9	16.4	Reconnaissance
Nakatuta Ruvum	Ruvuma Region	9,200	38.4	50.95	Feasib.May,1997
Luwika	Mbinga District	2,400	16. 4	4.6	Pre-feas.Dec. 00
Kwitanda Project Muhuwesi River	Ruvuma Region, Tunduru District	2,000	13	4.83	Pre-feasibility Dec. 1997
Lower Kapongo-Mgombezi River	Wino Ward	622	2.45	1.954	Reconnaissance
Limkerenge	Wino Ward	367	1.44	1.133	Reconnaissance
Upper Litowa - Ibuta Falls	Wino Ward	433	1.71	1.081	Reconnaissance
Upper Kapongo-Mgombezi	Wino Ward	233	0.92	1.000	Reconnaissance
Welela	Wino Ward	97	1.30	0.280	Reconnaissance

Table 2.2(b): *Uganda Non-Nile Mini Hydropower Sites*

Site	District	Installed Capacity	Potential (Estimated)	Status
		(MW)	(MW)	
Maziba	Kabale	1.0	-	In operation
Kuluva	Moyo	0.12	-	In operation
Kagando	Kasese	0.06	-	In operation
Kisizi	Rukungiri	0.06	-	In operation
Mobuku 1	Kasese	5.0	-	In operation
Mobuku 3	Kasese	10	-	Operated by Kasese Cobalt
Mobuku 2	Kasese	-	11.1	Pre-feasibility studies comp.
Muzizi	Kibale/Kabalore	-	4-10	Estimate
Paidha	Nebbi	-	5.1	Feasibility study completed
Rwizi	Mbarara	-	0.5	Pre-investment studies
Kakaka	Kabarole	-	3.0	Estimate
Nsongezi	Mbarara	-	2.0	Estimate
Nyamabuye	Kisoro	-	2.2	Pre-investment studies
Siti	Kapchorwa	-	1.0	Full feasibility to commence
Sipi	Kapchorwa	-	5.4	Pre-investment studies
Anyau/Olewa	Arua	-	1.5	Feasibility study complete
Haisesero	Kabale	-	1.0	Estimate
Kitumba	Kabale	-	0.2	Estimate
Mpanga	Kabarole	-	0.4	Estimate
Nyakibale	Rukungiri	-	0.1	Estimate
Leya	Moyo	-	0.12	Estimate
Amua	Moyo	-	0.18	Estimate
Narwodo	Nebbi	-	0.4	Estimate
Mvepi	Arua	-	2.4	Estimate
Esia	Moyo	-	0.24	Estimate
Ala	Arua	-	1.5	Estimate
Agoi	Arua	-	0.35	Estimate
Nkussi	Mbarara	-	0.9	Estimate
Mitano	Kabale	-	2.0	Estimate
Sezibwa	Mukono	-	0.5	Estimate
Tokwe	Bundibugyo	-	0.2	Estimate
Mgiita	Bundibugyo	-	0.15	Estimate

Miria Adua	Arua	-	0.1	Estimate
Soghai	Kabarole	-	2.0	Estimate
Ishasha	Rukungiri	-	4.0	Feasibility studies complete
Buseruka	Hoima	-	15.3	Pre-feasibility studies comp.
Nengo Bridge	Rukungiri	-	7.7	Pre-feasibility studies comp.

Table 4.2(a): *Uganda Baseline Scenario Electricity Capacity Projections (MW installed)*

Power Plant	**1999**	**2000**	**2003**	**2005**	**2007**	**2009**	**2011**	**2015**	**2018**	**2019**	**2020**
Owen Falls (old)	180	180	180	180	180	180	180	180	180	180	180
Owen Falls (Ext)	0	80	200	200	200	200	200	200	200	200	200
Bujagali	0	0	0	200	200	200	200	200	200	200	200
Karuma	0	0	0	0	50	150	150	150	150	150	150
Kalagala	0	0	0	0	0	50	150	150	150	150	150
Total hydro	***180***	***260***	***380***	***580***	***630***	***780***	***880***	***880***	***880***	***880***	***880***
Diesels	3	3	3	3	3	3	3	3	3	3	3
New oil steam									100	250	350
Total thermal	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***103***	***253***	***353***
Capacity Available	**183**	**263**	**342**	**522**	**562**	**702**	**792**	**794**	**884**	**1019**	**1109**
Total peak demand	**180**	**263**	**363**	**515**	**585**	**656**	**741**	**935**	**1114**	**1181**	**1251**

Table 4.2(b): *Kenya Baseline Scenario Electricity Capacity Projections (MW installed)*

Power Plant	1999	2002	2003	2004	2006	2008	2010	2011	2017	2018	2020
Gitaru	145	145	145	145	145	145	145	145	145	145	145
Kiambere	144	144	144	144	144	144	144	144	144	144	144
Turkwel	106	106	106	106	106	106	106	106	106	106	106
Kamburu	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5
Kindaruma	44	44	44	44	44	44	44	44	44	44	44
Masinga	40	40	40	40	40	40	40	40	40	40	40
Tana	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
Wanjii	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
KPLC	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Gitaru III	0	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
Sondu Miriu	0	60	60	60	60	60	60	60	60	60	60
Ewaso Ngiro A	0	0	0	0	0	90	90	90	90	90	90
Ewaso Basin	0	0	0	0	0	36	90	90	90	90	90
Total hydro	***598.5***	***731***	***731***	***731***	***731***	***857***	***911***	***911***	***911***	***911***	***911***
Olkaria I	45	45	45	45	45	45	45	45	45	45	45
Olkaria II	0	32	64	64	64	64	64	64	64	64	64
Olkaria III	0	12	12	64	64	64	64	64	64	64	64
Total Geothermal	***45***	***89***	***121***	***173***	***173***	***173***	***173***	***173***	***173***	***173***	***173***
Kipevu I	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5
Kipevu II	30	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2
Nairobi South	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
IPP diesels	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Ruiru	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
New Autoproducers	0	20	20	20	20	20	20	20	20	20	20
Eldoret IPP	55	55	55	55	55	55	55	55	55	55	55
Nakuru IPP	55	55	55	55	55	55	55	55	55	55	55
Autoproducers	15	15	15	15	15	15	15	15	15	15	15
New oil steam	105	105	105	105	235	235	460	560	1305	1460	1750
Total thermal	***361***	***426***	***426***	***426***	***556***	***556***	***781***	***881***	***1626***	***1781***	***2071***
Capacity Available	**915**	**1121**	**1150**	**1197**	**1314**	**1427**	**1678**	**1768**	**2439**	**2578**	**2839**
Total peak demand		**877**	**922**	**967**	**1084**	**1220**	**1367**	**1446**	**2018**	**2130**	**2354**

Table 4.2 (c): *Tanzania Baseline Scenario Electricity Capacity Projections* **(***MW installed)*

Power Plant	**1999**	**2002**	**2003**	**2005**	**2006**	**2010**	**2017**	**2018**	**2019**	**2020**
Kidatu (Morogoro)	204	204	204	204	204	204	204	204	204	204
Mtera	80	80	80	80	80	80	80	80	80	80
Hale (Tanga)	21	21	21	21	21	21	21	21	21	21
Old Pangani Falls	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
New Pangani	66	66	66	66	66	66	66	66	66	66
Nyumba ya Mungu	8	8	8	8	8	8	8	8	8	8
Lower Kihansi	180	180	180	180	180	180	180	180	180	180
Ruhudji						358	358	358	358	358
Kikuletwa (Moshi)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Tosamaganga (Iringa)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Uwemba (Njombe)	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Total Hydro	***579***	***579***	***579***	***579***	***579***	***937***	***937***	***937***	***937***	***937***
Ubungo Gas (Ngas)	100	100	100	100	100	100	100	100	100	100
Kinyerezi (Ngas)				160	160	160	160	160	160	160
Tegeta (Diesel) IPTL		100	100	100	100	100	100	100	100	100
New Oil Steam			20	20	140	140	140	140	140	140
Ubungo Diesel	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4	49.4
Dodoma (Diesel)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Mbeya Iyunga	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Musoma	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Mwanza	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5	32.5
Tabora	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Kiwira (coal)	6	6	6	6	6	6	6	6	6	6
Mchuchuma (Coal)							200	200	200	400
- total oil	216	316	336	236	356	356	356	356	356	356
- total natural gas				260	260	260	260	260	260	260
- total coal	6	6	6	6	6	6	206	206	206	406
Total Thermal	***222***	***322***	***342***	***502.5***	***622.5***	***622.5***	***822.5***	***822.5***	***822.5***	***1022***
Total Installed Capacity	**802**	**902**	**922**	**1082**	**1202**	**1560**	**1760**	**1760**	**1760**	**1960**
Capacity Available	**721**	**811**	**829**	**973**	**1081**	**1404**	**1584**	**1584**	**1584**	**1764**

Table 5.1(a): *Kenya Mitigation Scenario Electricity Capacity Projection (MW installed)*

Power Plant	1999	2000	2002	2003	2006	2007	2008	2009	2012	2015	2018	2020
Gitaru	145	145	145	145	145	145	145	145	145	145	145	145
Kiambere	144	144	144	144	144	144	144	144	144	144	144	144
Turkwel	106	106	106	106	106	106	106	106	106	106	106	106
Kamburu	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5
Kindarumama	44	44	44	44	44	44	44	44	44	44	44	44
Masinga	40	40	40	40	40	40	40	40	40	40	40	40
Tana	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
Wanjii	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
KPLC	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Gitaru III	0	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
Sondu Miriu	0	0	60	60	60	60	60	60	60	60	60	60
Ewaso Ngiro A	0	0	0	0	0	0	90	90	90	90	90	90
Ewaso Basin	0	0	0	0	0	0	36	90	90	90	90	90
Total hydro	***598***	***671***	***731***	***731***	***731***	***731***	***857***	***911***	***911***	***911***	***911***	***911***
Olkaria I	45	45	45	45	45	45	45	45	45	45	45	45
Olkaria II	0	0	32	64	64	64	64	64	64	64	64	64
Olkaria III	0	12	12	12	64	64	64	64	64	64	64	64
Other geoth.					64	64	64	128	192	192	260	260
Total Geoth.	***45***	***57***	***89***	***121***	***237***	***237***	***237***	***301***	***365***	***365***	***433***	***433***
Kipevu I	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5	75.5
Kipevu II	30	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2
Nairobo South	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
IPP diesels	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Ruiru	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
New Autoprod	0	20	20	20	20	20	20	20	20	20	20	20
Eldoret IPP	55	55	55	55	55	55	55	55	55	55	55	55
Nakuru IPP	55	55	55	55	55	55	55	55	55	55	55	55
Autoproducers	15	15	15	15	15	15	15	15	15	15	15	15
New oil steam		105										
Total thermal	***256***	***426***	***321***	***321***	***321***	***321***	***321***	***321***	***321***	***321***	***321***	***321***
Capacity Avail.	**810**	**1038**	**1026**	**1055**	**1160**	**1160**	**1273**	**1379**	**1437**	**1437**	**1498**	**1498**
Tot. pk. demand		**816**	**877**	**922**	**1084**	**1152**	**1220**	**1288**	**1526**	**1806**	**2130**	**2354**

Table 5.1(b): *Tanzania Mitigation Scenario Electricity Capacity Projection* **(***MW)*

	1999	**2002**	**2003**	**2004**	**2005**	**2006**	**2010**	**2011**	**2014**	**2016**	**2020**
Kidatu (Morogoro)	204	204	204	204	204	204	204	204	204	204	204
Mtera	80	80	80	80	80	80	80	80	80	80	80
Hale (Tanga)	21	21	21	21	21	21	21	21	21	21	21
Old Pangani Falls	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5	17.5
New Pangani	66	66	66	66	66	66	66	66	66	66	66
Nyumba ya Mungu	8	8	8	8	8	8	8	8	8	8	8
Lower Kihansi	180	180	180	180	180	180	180	180	180	180	180
Ruhudji							358	358	358	358	358
Mpanga									144	144	144
Rumakali								222	222	222	222
Mandera									21	21	21
Masigira									118	118	118
Kikuletwa (Moshi)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Tosamaganga (Iringa)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Uwemba (Njombe)	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Total Hydro	***579***	***579***	***579***	***579***	***579***	***579***	***937***	***1159***	***1442***	***1442***	***1442***
Ubungo (Ngas)	100	100	100	100	100	100	100	100	100	100	100
Kinyerezi (Ngas)					160	160	160	160	160	160	160
Kinyerezi (Ngas)						140	140	140	140	140	140
Tegeta (Diesel) IPTL		100	100	100	100	100	100	100	100	100	100
New Oil Steam			20	20	20	140	140	140	140	140	364
Ubungo Diesel	49.4	49.4	49.4	49.4							
Dodoma (Diesel)	7.4	7.4	7.4	7.4							
Mbeya Iyunga	13.9	13.9	13.9	13.9							
Musoma	5.9	5.9	5.9	5.9							
Mwanza	32.5	32.5	32.5	32.5							
Tabora	7.4	7.4	7.4	7.4							
Kiwira (coal)	6	6	6	6	6	6	6	6	6	6	6
Mchuchuma (Coal)										200	400
- total oil	216	316	336	236	120	240	240	240	240	240	464
- total natural gas				100	260	400	400	400	400	400	400
- total coal	6	6	6	6	6	6	6	6	6	206	406
Total Thermal	***222***	***322***	***342***	***342***	***386***	***646***	***646***	***646***	***646***	***846***	***1270***

Total Inst. Capacity	**802**	**902**	**922**	**922**	**965**	**1225**	**1583**	**1805**	**2088**	**2288**	**2713**
Capacity Available	**721**	**811**	**829**	**829**	**869**	**1103**	**1425**	**1625**	**1879**	**2059**	**2442**
Total pk demand	**394**	**525**	**574**	**624**	**674**	**723**	**922**	**969**	**1112**	**1218**	**1452**

Table 5.1(c): *Uganda Mitigation Scenario Electricity Capacity Projection (MW installed)*

Power Plant	**1999**	**2000**	**2002**	**2003**	**2005**	**2007**	**2008**	**2009**	**2010**	**2011**	**2013**	**2015**	**2020**
Owen Falls	180	180	180	180	180	180	180	180	180	180	180	180	180
Owen Falls	0	80	120	200	200	200	200	200	200	200	200	200	200
Bujagali	0	0	0	0	200	200	200	200	200	200	200	200	200
Karuma	0	0	0	0	0	50	100	150	150	150	150	150	150
Kalagala	0	0	0	0	0	0	0	50	100	150	150	150	150
Ayago South											234	234	234
Ayago North												304	304
Murchinson													
Total hydro	***180***	***260***	***300***	***380***	***580***	***630***	***680***	***780***	***830***	***880***	***1114***	***1418***	***1418***
Diesels	3	3	3	3	3	3	3	3	3	3	3	3	3
New oil steam													
Total thermal	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***	***3***
Capacity Available	**183**	**263**	**263**	**342**	**522**	**562**	**607**	**702**	**747**	**792**	**1005**	**1278**	**1278**
Total peak demand	**180**	**263**	**351**	**363**	**515**	**585**	**619**	**656**	**696**	**741**	**832**	**935**	**1251**