See Annex 9 | Economic Analysis

Document of
The World Bank,
International Finance Corporation, and
Multilateral Investment Guarantee Agency

Report No: 38421-UG

PROJECT APPRAISAL DOCUMENT

ON A PROPOSED
INTERNATIONAL DEVELOPMENT ASSOCIATION
PARTIAL RISK GUARANTEE
IN THE AMOUNT OF UP TO US$115 MILLION
FOR A SYNDICATED COMMERCIAL BANK LOAN

AND
ON A PROPOSED
INTERNATIONAL FINANCE CORPORATION FINANCING CONSISTING OF:
AN "A" LOAN IN THE AMOUNT OF UP TO US$100 MIILION AND
A "C" LOAN IN THE AMOUNT OF UP TO US$30 MILLION

AND
ON A PROPOSED MIGA GUARANTEE
IN THE AMOUNT OF UP TO US$115 MILLION
FOR SPONSOR'S EQUITY

TO BUJAGALI ENERGY LIMITED
FOR THE PRIVATE POWER GENERATION (BUJAGALI) PROJECT
IN THE REPUBLIC OF UGANDA

APRIL 2, 2007

Africa Region Energy Team, World Bank;
Infrastructure Department, IFC; and
Infrastructure Sector Team, MIGA

CURRENCY EQUIVALENTS
(Exchange Rate Effective (March 19, 2007)

Currency Unit	=	Uganda Shilling (USh)
USh1,759	=	US$1

FISCAL YEAR

Government	–	July 1 – June 30
Bujagali Energy Limited	–	January 1 – December 31
UETCL, UEDCL, UEGCL UMEME	–	January 1 – December 31

WEIGHTS AND MEASURES

1 meter (m)	=	3.28 feet
1 cubic meter (m^3)	=	35.31 cubic feet
1 gigawatt hour (GWh)	=	1 million kilowatt hours
1 hectare (ha)	=	10,000 m^2 or 2.4711 acres
1 kilometer (km)	=	0.62 miles
1 kilowatt hour (kWh)	=	1,000 watts hour
1 megawatt (MW)	=	1,000 kilowatts

ABBREVIATIONS AND ACRONYMS

ADB	African Development Bank
ADO	Automotive Diesel Oil
AESNP	AES Nile Power
AFD	Agence Française de Développement
AKFED	Aga Khan Fund for Economic Development
AMSL	Above Mean Sea Level
BEL	Bujagali Energy Limited
BP	Bank Procedures
BIU	Bujagali Implementation Unit
CO_2	Carbon Dioxide
CDAP	Community Development Action Plan
DEG	Deutsche Investitions- und Entwicklungsgesellschaft mbH
DFIs	Development Finance Institutions
DOTS	Development Outcome Tracking System
DSCR	Debt Service Coverage Ratio
EIB	European Investment Bank
EIRR	Economic Internal Rate of Return
EPC	Engineering-Procurement-Construction
ERA	Electricity Regulatory Authority
FMO	Nederlandse Financierings-Maatschappij voor Ontwikkelingslanden
GDP	Gross Domestic Product
HFO	Heavy Fuel Oil
IA	Implementation Agreement
ICSID	International Center for Settlement of Investment Disputes
IDA	International Development Association
IDC	Interest During Construction
IFC	International Finance Corporation
IPP	Independent Power Producers
IPS(K)	Industrial Promotion Services (Kenya) Ltd.
KfW	Kreditanstalt für Wiederaufbau
MEMD	Ministry of Energy and Mineral Development
MIGA	Multilateral Investment Guarantee Agency
NAFIRRI	National Fisheries Resources Research Institute
NEMA	National Environmental Management Agency
NGO	Non-Governmental Organization

O&M	Operation and Maintenance
OP	Operational Policy
PAPs	Project Affected Populations
PCDP	Public Consultation Disclosure Plan
PEAP	Poverty Eradication Action Plan
PPA	Power Purchase Agreement
PRG	Partial Risk Guarantee
Proparco	Promotion et Participation pour la Coopération Economique
PS	Performance Standard
RAP	Resettlement Action Plan
RCDAP	Resettlement and Community Development Action Plan
REA	Rural Electrification Agency
SEA	Social and Environmental Assessment
SEAP	Social and Environmental Action Plan
Sida	Swedish International Development Agency
SSEA	Strategic/Sectoral Social and Environmental Assessment
UEB	Uganda Electricity Board
UEDCL	Uganda Electricity Distribution Company Limited
UEGCL	Uganda Electricity Generation Company Limited
UETCL	Uganda Electricity Transmission Company Limited
UJAS	Uganda Joint Assistance Strategy
VAT	Value Added Tax
WTP	Willingness To Pay
WPH	World Power Holdings

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Sector Manager:	S. Vijay Iyer
Task Team Leader:	Malcolm Cosgrove-Davies

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Regional Vice President:	Edward A. Nassim
Industry Director:	Francisco Tourreilles
Regional Director:	Thierry Tanoh
Industry Manager:	Darius Lilaoonwala
Regional Manager:	Jean Philippe Prosper
Investment Officers:	Adil Marghub, Belen Castuera, Romani Curtis

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Director, Economics and Policy:	Frank J. Lysy
Task Team Leader:	Jason Z. Lu

Uganda: Private Power Generation (Bujagali) Project

CONTENTS

UGANDA
PRIVATE POWER GENERATION (BUJAGALI) PROJECT

PROJECT APPRAISAL DOCUMENT
AFRICA
AFTEG

Date: March 29, 2007	Team Leader: Malcolm Cosgrove-Davies
Country Director: Judy M. O'Connor	Sectors: Power (100%)
Sector Manager/Director: Subramaniam V. Iyer	Themes: Infrastructure services for private sector development (P)
Project ID: P089659	Environmental screening category: Full Assessment
Lending Instrument:	IDA Guarantee, IFC "A" Loan, IFC "C" Loan, and MIGA Guarantee
Investment Officers: Adil Marghub/ Belen Castuera	Acting Director, Operations Department: Philippe Valahu
Industry Director: Francisco Tourreilles	Director, Economics and Policy: Frank J. Lysy
Industry Manager: Darius Lilaoonwala	Task Team Leader: Jason Z. Lu
IFC Project ID: 24408	

Project Financing Data

[ ] Loan [ ] Credit [ ] Grant [X] Guarantee [X] Other: IFC Loan "A" and "C" and MIGA Guarantee

For Loans/Credits/Others: (US$m) 115 IDA PRG, 100 IFC A Loan and 30 IFC C Loan, 115 MIGA Guarantee

Total Bank support (US$m.): 360.00

Financing Plan (US$m)

FINANCING PLAN	**US$ 000**	**% of Total**
Equity		
Project sponsors	151,570	19.0
Government	20,000	2.5
Total Equity	**171,570**	**21.5**
Debt		
IFC	130,000	16.3
EIB	130,000	16.3
Commercial Banks (under IDA PRG)	115,000	14.4
ADB	110,000	13.8
European DFIs (*)	142,010	17.7
Total Debt	**627,010**	**78.5**
Total Debt and Equity	**798,580**	**100.0**

(*) The group of European DFIs includes Proparco, AFD, DEG, KfW, and FMO

Borrower: Bujagali Energy Limited
Guarantor: Republic of Uganda
Responsible Agency: Ministry of Energy and Mineral Development

Content		
For Guarantees:	**[] Partial Credit [X] Partial Risk [] Both Partial Credit & Risk**	
Proposed Coverage:	IDA PRG – The IDA PRG would cover the risk of debt service default for the covered lenders arising from the occurrence of certain events, for the life of the guarantee agreement.	
Nature of Underlying Financing:	Private commercial debt provided by a syndicate of lenders	
Terms of Financing for IBRD/IDA Guarantee:	**Principal Amount (US$m):**	Up to US$115
	Final Maturity:	16
	Amortization Profile:	Tailored
	Grace Period:	Up to 50 months
Financing available without Guarantee:	**[ ] Yes [X] No**	
If Yes, estimated Cost or Maturity:	N/A	
Estimated Financing Cost or Maturity with Guarantee:	16 years	
Bank Group Participation:	**[X] IFC [X] MIGA**	

Project implementation period: Start: 2007 End: 2011
Expected effectiveness date: July 2007

Does the project depart from the CAS in content or other significant respects? ***Ref. PAD I.A***	[ ]Yes [X] No
Does the project require any exceptions from Bank policies? ***Ref. PAD IV.I***	[ ]Yes [X] No
Have these been approved by Bank management?	NA
Is approval for any policy exception sought from the Board?	[ ]Yes [X] No
Does the project include any critical risks rated "substantial" or "high"? ***Ref. PAD III.E***	[ ]Yes [X] No
Does the project meet the Regional criteria for readiness for implementation? ***Ref. PAD IV.I***	[X]Yes [ ] No

Project development objective ***Ref. PAD II.B, Technical Annex 3***
The project's main objective is to provide least-cost power generation capacity that will eliminate power shortages at the time of its commissioning. The proposed project would represent an increase of 250 MW of least cost installed power generation capacity to the national grid.

Project description *[one-sentence summary of each component]* ***Ref. PAD II, Technical Annex 4***
The proposed Private Power Generation (Bujagali) Project is a 250 MW run of the river power plant with an adequate reservoir for daily storage, an intake powerhouse complex, and rock filled dam with a maximum height of about 30 meters, together with spillway and other associated works. The proposed project will be constructed on the Nile River, at Dumbbell Island, approximately 8 kilometers north of the existing Nalubaale and Kiira power plants, in the Republic of Uganda. The proposed project is structured as an Independent Power Producer (IPP) which will sell electricity to UETCL under a 30-year Power Purchase Agreement (PPA) signed

on December 13, 2005. The powerhouse will be constructed to house 5x50 MW Kaplan turbines. The small reservoir will have an estimated surface area of 388 hectares, extending back to the tailrace areas of the Nalubaale and Kiira. The proposed project will require 238 hectares of land take for the project facilities, of which 80 hectares would be for new inundated areas adjacent to the Nile River. The land take includes 113 hectares required for temporary and ancillary facilities including temporary haul roads, coffer dams, storage and quarries. Evacuation of electricity from the proposed project will require the construction of about 100 kilometers of transmission line, as well as the construction of a substation.
Which safeguard policies are triggered, if any? ***Ref. PAD IV.G, Technical Annex 15*** Environmental Assessment (OP/BP 4.01), Natural Habitats (OP/BP 4.04), Physical Cultural Resources (OP/BP 4.11), Involuntary Resettlement (OP/BP 4.12), Forests (OP/BP 4.36), Safety of Dams (OP/BP 4.37), and Projects on International Waterways (OP/BP 7.50)
Significant, non-standard conditions, **if any**, for: Board presentation: None Guarantee effectiveness: ***Ref. PAD III.F*** Implementation: None

I. STRATEGIC CONTEXT AND RATIONALE

A. COUNTRY AND SECTOR ISSUES

Recent Economic Developments in Uganda

1. **Country Context.** With per capita income of about US$280 in 2005, Uganda is one of the poorest countries in the world. Despite the progress in reducing the national level of poverty, from 56% in 1992 to 31% in 2006, the population in the rural areas as well as the Northern and Eastern regions remains vulnerable – rural poverty accounts for 90% of the national level, and about 61% and 36% of the population in the North and East, respectively, live below the poverty line. Uganda's demographic characteristics pose a challenge to future growth. The country has the third fastest natural population growth rate in the world (3.5% in 2005); very high fertility (about 7 children per woman) and the world's highest dependency ratio (111 dependants per 100 working people and rising). Life expectancy is low – 49 years at birth. Without commensurate growth in infrastructure, employment opportunities and productivity, these characteristics of Uganda's demographics could result in a reduction in savings, investment and growth.

2. Uganda has experienced robust macro-economic performance in recent years, with growth averaging 6.4% between 1990 and 2005. Domestic inflation was slightly above the 5% target for the third consecutive year due to pressures from weather, power shortages and energy price shocks. The Uganda Shilling (USh) depreciated by 4% against the US dollar due to higher demand for foreign exchange to finance the import bill. Overall, due to good macroeconomic management, there is an increase in savings, exports, and foreign direct investment. Within the region, Uganda has been a leader in the fight against HIV/AIDS, with prevalence dropping significantly during the past decade. The challenge for Uganda is now to deepen the reforms already underway and prevent their reversal.

3. Although Uganda has made substantial progress towards achieving the Millennium Development Goals, more needs to be done to sustain progress and to improve the prospects for meeting all the goals. Special efforts will be needed to improve the quality of education services to ensure that children complete primary education and to eliminate gender disparity at the post-primary levels of education. Greater access to quality health services is also essential to significantly reduce child and maternal mortality rates.

4. **Power Crisis Impacts on Economic Growth.** Although economic growth and Uganda's external position were largely consistent with the Government's program for 2005/06, the ongoing electricity crisis has placed a significant strain on growth over the medium term. This crisis in the power sector consists of substantial power shortages that are attributable to delays in adding new generation capacity, a significant regional drought over the past few years, which has reduced the output of existing hydropower plants, and annual demand growth for electricity of about 8%. As a consequence, businesses and consumers have been forced to endure prolonged service cuts, with some shifting production to times when power is available, and many larger businesses relying on high-cost back-up generators. Manufacturing, high-value agriculture (e.g., flowers) and processing industries (e.g., fish) are most affected by power cuts, and profits in these industries are being squeezed. Other macroeconomic consequences from the current power crisis were inflation that was slightly above projections through September 2006 due to higher energy costs and a widening of the trade deficit due to higher oil prices and increases in diesel fuel import volumes for electricity purchased from thermal power plants. The present situation, with extensive load-shedding blackouts, is not sustainable and further delays in augmenting Uganda's electricity generation capacity could undermine the economy. The cost of unserved energy is estimated at US$38.9¢/kWh.

5. Ugandan industrial growth has been constrained by spiraling energy and transportation costs, exacerbated by the current power shortages and both inadequate and poorly maintained infrastructure. By diversifying away from traditional exports and industries, such as the coffee sector, the Government is attempting to create a more stable and dynamic economic base. However, the infrastructure gap, particularly in energy and transportation, has placed extreme pressure on the cost of doing business in Uganda, especially for the manufacturing and horticultural sectors (see Box 1).

6. **Uganda's Poverty Eradication Action Plan (PEAP).** Uganda's development objectives are articulated in the 2004 PEAP, the third version of its poverty eradication action plan. The 2004 PEAP restates the country's ambitions of eradicating mass poverty and of becoming a middle income country in the next twenty years. It promotes a shift of policy focus from recovery to sustainable growth and structural transformation. The PEAP presents specific policies and measures to achieve its objectives, grouped under five pillars: (a) economic management; (b) enhancing competitiveness, production and incomes; (c) security, conflict resolution, and disaster management; (d) governance; and (e) human resources development.

Bank Group/Donor Support for PEAP and Power Sector

7. **Uganda Joint Assistance Strategy (UJAS).** The UJAS was approved by IDA's Board of Executive Directors in January 2006 as the country assistance strategy, which was jointly prepared with seven other development partners. The UJAS lays out the strategy for supporting the implementation of the third PEAP and achievement of the Millennium Development Goals. It promotes strong collaboration and harmonization among development partners and with the Government, as well as a stronger focus on results and outcomes. As part of the UJAS harmonization agenda, an exercise to ensure effective division of labor among development partners has been launched.

8. **Power Generation Investments.** Investments in power generation facilities will increase the reliability and lower the cost of electricity, thus contributing to the achievement of PEAP Pillar 2. This pillar has as a specific objective to "strengthen infrastructure in support of increased production of goods and services." The UJAS aims to help "... create infrastructure that reduces the cost of doing business, links isolated areas of the country to the broader economy, and promotes regional integration." This project will contribute directly to this pillar (see Box 1).

Box 1: Energy, Growth and Structural Transformation in Uganda

The recently completed Country Economic Memorandum concludes that Uganda's low level of electricity use could put a significant brake on structural transformation, and hence on future growth. Much of the Ugandan economy is rural and does not use electricity in production, mainly because it is unavailable in most rural areas. Since the mid-1990s, agriculture has been shedding labor, which has been finding employment in off-farm rural enterprises (mainly trading, distribution and retail). Average labor productivity is higher outside of farming, and this movement of labor has led to improvements in average output per worker.
Food crop prices started to decline by more than the increase in agricultural productivity – with poverty amongst farmers increasing between 1999 and 2002/03. This is due in part to the lack of significant industrial demand for processing Ugandan agricultural output. Another reason is that most of the labor which moved out of agriculture still lives in farming households, growing their own food. For significant structural transformation to occur, Uganda needs to develop its agro-processing industry to create more jobs for the increasing labor supply moving out of agriculture.

Given Uganda's population growth rate and current age structure, the workforce will more than double in the next 15 years. This makes it urgent to expand industry, tourism, and commercial services in order to create jobs for a growing labor force at higher average labor productivity, otherwise growth in average per capita income will slow down, reducing the prospects for poverty reduction. These sectors are currently the most energy intensive in Uganda and will therefore rely on a reliable, affordable and expanding supply of power.

Power Sector Context

Overall Government Strategy

9. The Government's power sector strategy has been to: (a) promote legal, regulatory and structural sector reforms, including leveraging private sector investment; (b) provide adequate, reliable and least cost power generation with the goal to meet urban and industrial demand and increase access; and (c) scale up rural access to underpin broad based development. The World Bank Group and the donor community have supported the Government's power sector strategy and reformed policy framework, including catalyzing private sector management and capital.

10. Over the past seven years, the Government has:

- Promulgated a new Electricity Act;
- Created an independent Electricity Regulatory Authority (ERA), which has established a strong track record in ensuring the financial viability of the sector (see Annex 1);
- Unbundled the state-owned Uganda Electricity Board into separate entities responsible for generation, transmission and distribution, and concessioned the generation and distribution facilities to the private sector (see Annex 1 for details on the Government's comprehensive power sector reform program);
- Increased the number of urban and rural households with direct access to electricity, promoted grid and off-grid private sector-led rural electrification and established a Rural Electrification Agency (REA);
- Pursued least cost power investments to provide adequate and reliable service; and
- Collaborated with the East Africa Community on regional power interconnection. This regional approach is expected to benefit all countries involved by diversifying supply sources and reducing investment costs.

11. In this context, the Government has supported the development of the proposed Private Power Generation (Bujagali) Project. The proposed project is structured as an Independent Power Producer (IPP) and will sell electricity to Uganda Electricity Transmission Company Limited (UETCL), under a 30-year Power Purchase Agreement (PPA), signed on December 13, 2005.

Main Sector Issues and Government Responses

12. In spite of the significant structural reforms implemented in the power sector, Uganda is confronted by a number of short and medium term challenges in this sector which are affecting growth. The main issues and the Government's responses are described below.

Issue 1: Power Shortages

13. Uganda's main source of power is from the Nalubaale and Kiira 380 MW[1] dam complex, located at the mouth of Lake Victoria. Electricity output from the Nalubaale/Kiira dam complex has declined from around 200 MW in April 2005, dropping gradually to reach 170 MW by January 2006, reducing further to 135 MW (equivalent to water discharges of $850m^3/s$) from February 2006 to August 20, 2006. Since then, hydropower production has dropped to 120 MW (equivalent to water discharges of $750m^3/s$). In contrast, current system demand is about 380 MW at peak times and about 290 MW at base load, resulting in persistent and acute power shortages which are impacting growth. The reasons for these power shortages are fourfold. First, there has been a significant delay in power infrastructure development and, in particular, in completing the financing of the previous Bujagali project, which is the next least-cost generation increment. As part of the previous effort to develop the project, construction was scheduled to commence in early 2002 and the power station was to be commissioned by the end of 2005. Second, the low Lake Victoria water levels, caused both by the recent regional drought as well as water over-abstraction for hydropower generation, have resulted in significantly reduced power generation output at the Nalubaale/Kiira dam complex. In this regard, the Government has decreased hydropower production in an effort to return to the principles embodied in the Agreed Curve[2]. A third contributor to current power shortages has been the high level of technical and non-technical losses of the distribution system, which are now being addressed by UMEME, the private sector concessionaire. Fourth, annual demand growth over the past several years increased by about 8%, placing additional pressure on the power system.

14. It is noteworthy that if the previous Bujagali project had been successfully financed in 2002, Uganda would have been able to avoid the current economic penalties. Moreover, the reductions in Lake Victoria water levels from over-abstraction for hydropower production may not have occurred. This is because the Bujagali project is downstream of the current Nalubaale/Kiira dam complex, and will re-use the upstream water releases. When commissioned, the proposed project will produce power at a cost significantly lower than what Uganda is now paying for the supply from thermal power plants running on imported fuel.

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[1] The current commissioned capacity of the dam complex is 300 MW. Two additional 40 MW Kiira units are scheduled for commissioning in April 2007.

[2] The Agreed Curve describes a water discharge rating curve which emulates the natural relationship between Lake Victoria levels and the flow of the Nile River through the Nalubaale and Kiira dam complex. It depicts the management of the Nalubaale and Kiira dams in which the volume of water released would remain consistent with what would have occurred under natural conditions, thereby ensuring no change in downstream discharges. Since the Agreed Curve functions as an operating rule for water discharge, such water releases are a function of the lake level at any given period.

15. **Government Actions Already Taken – Augmenting Power Supply.** The Government has contracted two 50 MW thermal generation plants running on Automotive Diesel Oil -- the only available short-term technical option given transportation and fuel logistics. The first 50 MW was commissioned in May 2005 and the second 50 MW was contracted in late 2006, and are being operated by the private sector. In addition, a proposed Power Sector Development Operation (US$306.5 million, of which US$6.5 million is from the Swedish International Development Agency (Sida) and US$300 million is from IDA), is scheduled for Board Presentation in April 2007. This Power Sector Development Operation will include: (a) the contracting of an additional 50 MW of thermal generation capacity to help meet existing electricity demand; (b) demand side management and energy efficiency measures; and (c) general budget support to assist the Government in absorbing a portion of the high costs of thermal power generation. The Operation will also help to finance a broad energy communications strategy. These three 50 MW thermal plants would operate until the proposed Private Power Generation (Bujagali) Project is commissioned in early 2011. Furthermore, the Government is negotiating an IPP for a 50 MW permanent thermal plant based on less costly Heavy Fuel Oil (HFO). This permanent plant will replace 50 MW of existing thermal plant running on Automotive Diesel Oil (ADO). This permanent plant would provide thermal complementation to the Ugandan power system over the long term and is consistent with the least cost plan for the power sector. The Government has also reported a domestic oil resource discovery in the Lake Albert region of western Uganda, which would need to be proven as economically viable; this is not expected to have any impact on power generation before 2011. The Government concluded an agreement with Kenya to import up to 10 MW on a non-firm capacity basis, i.e., depending upon availability. Some imports have already taken place.

16. The Government is also actively pursuing co-generation opportunities, accelerating its renewable energy program and geothermal potential, including the following:

- The Government entered into power supply arrangements with the Kilembe Mines to provide 2.3 MW of power to the grid for 24 hours per day and the Kakira Sugar Company will supply 12 MW to the grid in the near future for 18 hours per day. Beyond this, the Kakira Sugar Company will also self-generate 6 MW for its internal use, so that this capacity is not required from the national grid.

- Additional mini-hydro schemes are under active development with the support of the Energy for Rural Transformation Project (Credit 3588-UG).

- A Renewable Energy Policy Framework has been prepared for Cabinet approval. It aims to promote additional renewable energy development. By 2009, at least 3 mini-hydro transactions with a total capacity of 26 MW are expected to produce grid-based electricity.

- Indigenous geothermal investigations have been accelerated under the IDA supported Power IV Project (Credit 3545-UG).

17. **Improving Power Transmission & Distribution Performance**. A key element of the Government's power sector reform program has been to concession the power distribution facilities to the private sector as a means to underpin the commercial viability and sustainability of the power sector. In March 2005, UMEME, the private concessionaire, took over the operations of the distribution system under a concession agreement that includes financial incentives to increase the number of connections, reduce technical and non-technical losses and increase the collection rate (see Annex 1). At the time of UMEME's takeover, system technical and non technical losses were around 38% (or 43% including 5% transmission losses). The billing collection ratio was 80%, implying that prior to the UMEME concession only about 47% of the energy sent out to the national

grid was paid for. Since March 2005, UMEME has improved the collection rate from 80% to 92% (although the rate dropped to 82% in December 2006 since the June and November tariff increases), decreased technical and non-technical losses to about 34%, and connected about 36,000 new customers. During the first 22 months of the concession, UMEME invested US$13.6 million for system improvements, and has committed to invest a total of US$65 million during the first five years of the concession. Due to years of neglect of maintenance, inadequate investment, poor management practices and antiquated billing and accounting systems, it will take time and capital to lower technical and non technical losses. This requires implementing a customer verification program, installing new customer management and accounting systems, as well as replacing and installing meters, transformers and poles, which are under way.

18. The lack of power available for sale, and the 94% cumulative increase in average electricity tariffs that took place in 2006, have affected UMEME's viability. A major challenge, therefore, has been to ensure that UMEME's performance under conditions of stress is not further impeded by the impact of reduced electricity supply and high tariffs. To this end, the Government and UMEME recently renegotiated portions of the concession agreements to protect UMEME during the current power crisis from the impact of power shortages and the reduced revenue stream, which are factors beyond UMEME's control but have a bearing on UMEME's ability to meet its concession obligations. The Government and UMEME are cognizant that due to the expensive thermal costs in the current generation mix, there is an urgent need to achieve accelerated efficiency improvements in the short to medium term. The restructured concession agreement includes commercial incentives for the concessionaire to further reduce losses and non-collection rates.

Issue 2: Power Sector Finances

19. The impact of the high cost of thermal power on the Uganda power system is considerable, given the small size of Uganda's installed generation capacity, the low percentage of such installed capacity currently being used, and the high cost of thermal capacity. Electricity end user tariffs before Value Added Tax (VAT) would have to increase from US$17.2¢/kWh today to around US$26¢/kWh if consumers were to bear the full cost of electricity. This is mainly due to the change in generation mix, from a predominantly hydro-based system in mid-2005, to a hydro/thermal mix of 55/45 today. The share of thermal generation is expected to further increase when an additional 50 MW temporary thermal plant, to be financed under IDA's proposed Power Sector Development Operation, is commissioned later this year. Prior to the power crisis and consistent with the Government's reform program, the full cost of electricity supply was being borne by customers. The Government recognizes, however, that during this crisis period, there are affordability thresholds which if crossed, could have serious long-term impacts on the economy.

20. **Government Actions Already Taken.** In response to the current power crisis, the Government has developed a financing plan (2007-11) to meet the high cost of thermal power generation which includes: (a) deferment of USh128 billion (US$67 million) of debt service to the Government to 2011; the sector should be in a position to repay all of the deferred debt service by end 2011 and will be expected to meet all of its debt service obligations to the Government from 2011 onwards; (b) budgetary transfers of USh92 billion (US$49 million) annually in 2007 and 2008, USh28 billion (US$15 million) in 2009, and USh66 billion (US$34 million) in 2010; and (c) IDA support towards thermal power costs through the investment project of the proposed Power Sector Development Operation (US$206.5 million[3]). Electricity tariffs are expected to decline once the

[3] The total amount of the proposed Operation is US$ 300 million including US$ 80 million of general budget support and US$ 13.5 million of Technical Assistance, Energy Efficiency and Demand Side Management

proposed project is commissioned in early 2011 and the benefits of the loss reduction and efficiency improvements are realized. In real terms, under the base case scenario, the projected weighted average electricity tariff declines from the present US$17.2¢/kWh to US$13.8¢/kWh by 2011.

Issue 3: Long term Sector Expansion and Increased Urban/Rural Access to Electricity

21. The long term expansion of the power sector requires: (a) the addition of least cost sustainable power generation, transmission and distribution investments, (b) improving the currently low access to electricity, and (c) regional transmission integration.

22. **Addition of Least Cost Sustainable Power Generation.** In the long run, the Government recognizes the importance of planning and developing future power sector investments in a timely manner and on a least cost basis. Furthermore, since the recent drought period, which drastically reduced the availability of hydropower output from the Nalubaale/Kiira dam complex, the Government has also recognized the economic advantage of maintaining an appropriate level of thermal generation capacity to complement the hydropower system.

23. **Government Actions Already Taken.** The Government is proceeding with the proposed project, which represents an important long term least cost and sustainable generation expansion. When commissioned in 2011, the proposed project would immediately displace at least 738 GWh of diesel generation, thus demonstrating the economic penalty of the long delay in realizing its implementation. In addition, the Government is negotiating a 50 MW permanent thermal plant on an IPP basis to operate on less costly HFO. This plant will complement Uganda's power generation mix on a long term basis and in periods of low hydrology, in a more cost effective way than the existing Automotive Diesel Oil fired thermal generation plants.

24. **Low Electricity Access Levels.** Uganda has one of the lowest rates of per capita energy consumption in the world, with only 5% of the population having access to electricity. Service expansion in urban and rural areas has been hampered in the past by political, commercial and technical issues. The lack of adequate power generation capacity, which has been partially addressed through the commissioning of high-cost thermal power generation, has also hindered progress on expanding urban access to electricity.

25. **Government Actions Already Taken.** The Government is addressing low electricity access through: (a) the Energy for Rural Transformation Program (Credit 3588-UG), which aims to establish the institutional and legal framework for rural electrification and a Rural Electrification Fund and to facilitate scale-up of rural access which would otherwise not be a commercial proposition. This program supports the development of small and medium-scale renewable energy options, including both grid-connected and off-grid mini and micro-hydropower, bagasse based cogeneration, and biomass gasification; (b) an accelerated plan to reduce system losses and connect new customers; (c) support to UMEME through US$12 million for rehabilitation investments under the Power IV Project (Credit 3545-UG); and (d) IDA and MIGA risk mitigation for UMEME, the private distribution concessionaire[4].

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measures. However those additional US$93.5 million are not taken into account for the mitigation of the US$348 million operational shortfall.

[4] A Partial Risk IDA guarantee mechanism was approved under Privatization and Utility Sector Reform Project (Credit 3411-UG) in December 2004. MIGA also supported UMEME in 2004 (MIGA/R2004-0076) as well as the subsequent restructuring of the UMEME concession in 2006 (MIGA/R2006-0059).

26. Substantial improvements in urban and rural access rates are anticipated in the medium to long term. UMEME is obliged to invest US$65 million during the first five years of its concession, and the Energy for Rural Transformation (ERT) Program will begin with its second and third phase in the near future and will support the REA over the next 6 years.

B. RATIONALE FOR WORLD BANK GROUP INVOLVEMENT

27. Electricity is a critical element of the Government's PEAP. Even though the Government has implemented a comprehensive power sector reform program, established a positive track record in electricity regulation and privatized distribution and generation facilities, electricity service quality, availability and reliability have been major impediments to sustained private investments and economic growth. The combined financial resources of the World Bank Group and other international development financial institutions (DFIs)[5] are crucial to mobilize a considerable level of private funds and commercial bank lending for the proposed project (total project costs of US$798.6 million), which is the next least cost generation option for the country. The successful implementation of the proposed project will also help to underpin the financial viability of the power sector and the progress made on implementing a comprehensive power sector reform program, and will facilitate building private sector confidence in Uganda (see Annex 1).

28. **Fit within the World Bank Group Strategy**. The proposed project fits well with the UJAS as well as with IFC's strategy for the power sector in Sub-Saharan Africa, whereby IFC is focusing its efforts on the development, from an early stage, of Public Private Partnerships in countries with a clear commitment to sector reform; and with IFC's strategy for Uganda, which is centered on the following objectives (as outlined in the 2003 Strategic Initiative for Africa): (a) improving the investment climate, (b) enhancing support to small and medium-scale industries, and (c) proactively developing large private investments.

29. MIGA has undertaken projects in the agribusiness and power sectors in Uganda and has been working closely with IDA to support Uganda's power sector reform and stability. This project is consistent with MIGA's strategic priority of supporting infrastructure projects, as well as MIGA's objective of increasing its exposure in Africa. The proposed project will be one of the largest IPPs supported by MIGA in Uganda, as well as in Africa, and should have a positive demonstration effect for other potential foreign investments in the more regulated sectors of Uganda and other countries in the region.

30. The proposed project also complements the various programs currently being implemented in the sector by the World Bank Group (Annex 2). The proposed project is expected to make a significant contribution to improving Uganda's investment climate; not only will it provide much needed reliable generation in a cost effective manner, including for medium-scale industries, but it will also be Uganda's largest private sector investment to date. Therefore, it is expected that the successful completion of the project will promote further private sector investment in the country and establish a standard that can be replicated by other countries and investors in the region.

C. HIGHER LEVEL OBJECTIVES TO WHICH THE PROJECT CONTRIBUTES

31. A key objective of the UJAS is to reduce poverty through rapid economic growth, which depends upon increased foreign and domestic private investment. Access to infrastructure, specifically reliable and affordable power, is critical to attract investment and promote growth. The

[5] Other international Development Finance Institutions involved in the proposed project include: EIB, ADB, FMO, DEG, KfW, Proparco and AFD.

Government's strategy for the power sector is expected to improve service delivery and reliability of supply through private ownership and management; and expand access to reliable and clean electricity for households, industries, and social infrastructure such as schools, clinics, hospitals, and water systems. The execution of these measures will contribute to poverty alleviation through income and employment generation, thereby improving the quality of life in Uganda, and will increase growth in economic activity. In addition to placing the power sector on a commercial basis, the provision of least-cost power will foster economic activity and generate fiscal revenues, thereby increasing budgetary resources which the Government can direct to health, education and other activities benefiting the poor. Moreover, financing through private sector participation in the proposed project allows the Government to fund social and other sector expenditures for which private capital is not currently available.

D. ADDITIONALITY OF WORLD BANK GROUP INVOLVEMENT

32. The World Bank Group involvement in the proposed project is expected to provide: (a) comfort to first-time investors in Uganda's power sector (including sponsors, commercial lenders and DFIs); (b) access to long term financing, leading to a more affordable tariff for the proposed project; and (c) project structuring advice, based on international experience, which ensures the project's bankability. In addition, the World Bank Group has taken the lead among the DFIs in the environmental, social and economic due diligence related to the financing of the project.

33. The project is one of the largest private sector financings in the power sector in Sub-Saharan Africa. The funding market available to Bujagali Energy Limited (BEL, the private project company) includes commercial and development finance institutions. However, given the required level of debt financing (approximately US$627 million), the successful implementation of the project requires a coordinated approach and joint commitment of the World Bank Group and other key DFIs. Similarly, the MIGA guarantee is a precondition for one of the two project sponsors' approval to invest in the proposed project. It ensures the participation of an experienced power developer, who will play a particularly critical role during the project construction phase, when risks are the highest. IFC's investment in the proposed project would be among IFC's largest single-obligor exposures in Sub-Saharan Africa, once fully disbursed.

II. PROJECT DESCRIPTION

34. The proposed Private Power Generation (Bujagali) Project is a 250 MW run of the river power plant with an adequate reservoir for daily storage, an intake powerhouse complex, and a rock filled dam with a maximum height of about 30 meters, together with spillway and other associated works. The proposed project will be constructed on the Nile River, at Dumbbell Island, approximately 8 kilometers north of the existing Nalubaale and Kiira power plants, in the Republic of Uganda. The proposed project is structured as an IPP which will sell electricity to UETCL under a 30-year PPA signed on December 13, 2005. The powerhouse will be constructed to house 5x50 MW Kaplan turbines. The small reservoir will have an estimated surface area of 388 hectares, extending back to the tailrace areas of the Nalubaale and Kiira dam complex. The proposed project will require 238 hectares of land take for the project facilities, of which 80 hectares would be for new inundated areas adjacent to the Nile River. The land take includes 113 hectares required for temporary and ancillary facilities including temporary haul roads, coffer dams, storage and quarries. Evacuation of electricity from the proposed project will require the construction of about 100 kilometers of transmission line, as well as the construction of a substation at Kawanda, and the extension of the Mutundwe substation (the Interconnection project).

35. **Background**. A previous effort to develop a hydroelectric power project at Bujagali was undertaken by the AES Corporation (AES – a US power company). The World Bank and IFC's Board of Directors approved the Bujagali project being developed by AES on December 18, 2001. In the end, AES withdrew from the project which led to a termination of the agreements by the Government in September 2003. Subsequently, the Government initiated a transparent bidding process in adherence with the Government's procurement guidelines, to seek a new project sponsor to develop the Bujagali project.

36. The environment in which the current project is being developed has substantially changed from that in 2001. This includes: (a) a reformed power sector structure, in which an independent electricity regulator has been established, and generation and distribution has been unbundled and concessioned to the private sector; (b) increased demand for electricity in the face of declining generation output; (c) an improved sector financial structure, which is now under stress because of the current power sector crisis that has required expensive thermal power generation and has led to significant tariff increases; and (d) improved governance standards; the current sponsors have been selected following a transparent, international competitive bidding process. In turn, the sponsors selected the Equipment, Procurement, Construction (EPC) contractor on a competitive bidding basis and required the contractors to sign up to a Code of Conduct.

A. Bank Group Instruments

37. The proposed project, a major infrastructure investment in the East Africa Region, would benefit from an IDA partial risk guarantee, IFC lending and a MIGA guarantee. The Government has requested the provision of an IDA Partial Risk Guarantee of up to US$115 million to support the commercial lenders involved in financing the proposed project. In addition, BEL has requested an IFC A Loan of up to US$100 million and an IFC C Loan of up to US$30 million, while Sithe Global Power LLC, one of the two project sponsors, has applied to MIGA for political risk insurance for up to US$115 million through its wholly-owned subsidiary, World Power Holdings (Luxembourg) (WPH). The total World Bank Group exposure to the proposed Bujagali project would be of up to US$360 million. In view of the significant amount of private capital required, the perceived country and sector risks and Uganda's limited track-record in attracting private capital for large infrastructure investments, the proposed project would not be financeable for equity investors and commercial lenders without the direct support of the DFIs, MIGA, IFC and IDA. BEL and the commercial bank lender group have indicated that broad World Bank Group participation is also critical to mitigate the risks associated with the provision of long-term financing for a hydropower project in Sub-Saharan Africa. Given the significant capital required for the project, the limited availability of donor financing, and the benefits of mobilizing private investment, the proposed project has been developed as a Public Private Partnership.

Risk Sharing Arrangements

38. The contractual structure of the transaction and the allocation of the commercial, technical and political risk among the parties are consistent with industry standards for limited recourse project financing. As it is customary in project finance transactions, risks are allocated to the party best able to mitigate them. BEL ultimately bears the technical, commercial and financing risks of the project. BEL has signed a PPA with UETCL for the sale of electricity generated by the project, and an Implementation Agreement (IA) with the Government, which outlines the Government's project obligations, including the terms of the guarantee to back UETCL's payment obligations under the PPA.

39. The allocation of key risks among equity holders, lenders, the Government and the risks backed by the IDA Partial Risk Guarantee (PRG) and MIGA's guarantee are summarized in Table 1 below and in the subsequent paragraphs, as well as in Annexes 13 and 14.

Table 1: Allocation of Risks: Private Power Generation Project (Bujagali)

Phase	Risks/Obligations	Sponsors	Lenders	GOU	World Bank Group Risk Mitigation Package
Pre-Construction	Project Design	■			
	Debt and equity financing	■	■		
Construction	Cost overruns	■	■	■	
	Construction delays	■	■	■	
	Implementation of Environmental Management Plans and Resettlement Policy Frameworks	■	■	■	
Operation	Operation and maintenance	■	■		
	Output quality specifications	■	■		
	Hydrology			■	
	Payments under the IA and PPA	■	■	■	■
Concession term	Currency devaluation			■	
	Currency convertibility/transferability	■	■	■	■
	Political Force Majeure			■	■
	Changes in Law			■	■
	Natural Force Majeure	■	■	■	

40. **Pre-construction Risks.** The key risk during the pre-construction phase is BEL's potential inability to mobilize sufficient financing for the project and reach financial closure. The proposed project will be financed through equity and debt in approximately 21:79 proportion. Equity will be contributed up front by the Government (through its contribution of project assets) and by the project sponsors, in advance of loan disbursements. The sponsors have adequate resources to finance the proposed project, and have already posted a US$4.5 million bond with the Government. Most of the project debt financing is being provided by DFIs, with the remaining debt coming from commercial banks, with an IDA PRG enhancement. All of the lenders are planning to obtain management approval for their financing for the project during April/May 2007, consistent with the planned date of financial closure of mid 2007. In parallel the Government is also considering a bridge loan of about US$75 million to BEL so that BEL can lock in the current EPC contract price prior to expiration of the bid validity by the end of April 2007 and start construction prior to financial closure, in case there is an unforeseen delay in achieving this milestone in accordance with the above mentioned schedule. The bridge financing is expected to be repaid from the proceeds of the project permanent financing. The terms of bridge financing would be provided to the World Bank Group on finalization.

41. **Construction Risks.** The two key risks during the construction phase (i.e., cost overruns and construction delays) are discussed below:

- *Cost Overruns:* The EPC contract will be a fixed price turnkey contract between BEL and Salini Costruttori SpA (Italy) (with Alstom Power Hydraulique, France, being one of its key subcontractors), which has adequate experience of undertaking similar projects. Changes in the EPC contract price are only allowed under very specific circumstances, such as for changes in law, approved change orders by BEL and for geological/geotechnical conditions being worse than those determined in the baseline reflected in the EPC contract. Thus, there is limited likelihood of EPC cost increases once the EPC contract is finalized. Moreover, the PPA structure provides an incentive to BEL to minimize any cost increases, as BEL will only be allowed to recover 70% of such additional costs through the project tariff, while the remaining 30% will be absorbed by BEL. Conversely, BEL is incentivized to attain cost reductions, since 30% of such savings would be for BEL's benefit, with the remainder 70% contributing to reduce the project's tariff. While BEL would be able to recover additional costs resulting from a variation in the ground conditions relative to those initially identified, other costs, such as BEL's development costs, are capped.

- *Construction Delays:* BEL is entering into a date certain turnkey EPC contract for the construction of the hydropower plant that will require the EPC contractor to meet BEL's 44-month construction schedule and delays will result in the payment of penalties to BEL. The contractor obligation for delay penalties mitigates BEL's risk in case the commissioning of the power plant is delayed beyond 47 months (other than for reasons of force majeure and events of a similar nature), when BEL would be required to start paying penalties to UETCL. BEL would eventually face the risk of termination of the PPA if the delays were protracted and not resolved.

42. **Operation Risks.** BEL is required to provide a contracted capacity of 250 MW and achieve on average a target availability of 95% during its first year of operations, and 96% thereafter. Failure to achieve such targets is penalized in the PPA through reductions in the capacity payments. This risk is mitigated through the EPC and operations and maintenance (O&M) contracts, where the contractors are required to meet the relevant performance specifications. The proposed project is not complex from a technical point of view. Thus, the risk of not meeting the agreed plant availability is considered to be relatively low. The evacuation of maximum electricity output from the plant would require 100 km of transmission lines, the construction of a new substation at Kawanda, and the extension of the Mutundwe substation (the Interconnection Project). Since the construction period for the transmission lines and substations is significantly shorter than that of the power plant, there is a minimal risk of a completion mismatch. To mitigate this risk, the completion of 8 km of transmission line connecting the project to the Nalubaale/Kiira switchyard will enable the evacuation of approximately 180 MW from the proposed project, until the Interconnection Project is commissioned. The hydrology risk is borne by the power purchaser (UETCL), which has the right to terminate the agreements and purchase the hydropower plant in case of an extended period of extremely low hydrology.

Proposed IDA Partial Risk Guarantee

43. The proposed IDA PRG will provide a guarantee to commercial lenders against debt service payment defaults resulting from the Government's failure to meet its payment obligations as stipulated under the IA and the Government Guarantee. The proposed IDA PRG is non-accelerable; therefore, principal and interest on the IDA Guaranteed Facility between the commercial banks and BEL would be covered by IDA only as they become due.

44. The commercial and performance risks described above, as well as natural force majeure risks directly affecting the project, will ultimately be borne by BEL. The obligations of the Government under the project's contractual agreements (principally the PPA and IA) to be covered under the IDA PRG are discussed below, and explained in further detail in the IDA Guarantee Agreements Term Sheets (Annex 13). These covered obligations will form the basis of the IDA Guarantee Agreement between IDA and the Agent Bank, representing the IDA guaranteed commercial lenders. Under the IDA Guarantee Agreement, commercial lenders will be entitled to demand the portion of any principal and/or interest debt payment which has fallen due under the IDA guaranteed commercial loans and that has not been paid by BEL as a result of the failure of the Government to pay amounts due under either the IA or Government Guarantee. Government payments could be with respect to periodic capacity payments or termination payments, in the event

that the project was terminated. In the case of a dispute between the Government and BEL in respect of such payments, the IDA PRG would be callable only if the Government is obligated to pay and has failed to do so as provided under the relevant contractual dispute resolution provisions. If the Government, however, takes legal action to prevent dispute resolution in contravention of the applicable dispute resolution provisions, then the IDA guaranteed commercial lenders would be entitled to demand payment under the IDA Guarantee Agreement.

45. If IDA were called upon to make payments under the IDA Guarantee Agreement, IDA would seek reimbursement from the Government of any and all claims and other expenses it suffers under the Indemnity Agreement. Under the Indemnity Agreement between IDA and Uganda, the Government will: (a) indemnify IDA for all claims paid under the IDA Guarantee and related expenses; (b) carry out any obligations (e.g., environmental) the Government may have accepted for IDA's benefit; and (c) perform all of its obligations under the transaction documents. IDA would reserve its rights to demand immediate reimbursement from the Government in the event of an IDA payment under the IDA Guarantee. Consequently, there would be a clear financial incentive for the Government to avoid defaulting under the project and financing agreements so as to avoid a call on the IDA PRG. Any such Government default would also have an impact on other lenders and could lead to the eventual termination of the project and enforcement of the project security arrangements. As guarantor of the Government's performance, IDA's direct risks relate to project risks borne by the Government and covered under the IDA Guarantee. However, ultimately, IDA would bear the risk of non-payment by the Government under the Indemnity Agreement, for which IDA is well-suited in its role as a long-term lender to the Government.

46. IDA will enter into a Project Agreement with BEL. The Project Agreement will contain standard covenants, representations and warranties, including that BEL has acted and will continue to act in compliance with all applicable World Bank Group policies and procedures, including anti-corruption, and social and environmental policies, and will provide IDA with necessary project information.

Principal IDA-Guaranteed Risks

47. The IDA PRG would cover the risk of debt service default for the covered lenders arising from the following categories of events:

- Political force majeure events;
- Changes in law and events making the project contractual agreements unenforceable or void, or making the performance of BEL or its EPC contractor (and related parties, such as subcontractors) unlawful;
- Government imposed restrictions on the ability of BEL to be paid or to receive foreign currency or transfer funds abroad; and
- Failure by the Government to fulfil its payment obligations relating to UETCL's purchase of power and termination payments due by UETCL.

IFC Financing

48. The lenders' terms for the financing of the project will be documented as part of the project's Common Terms Agreement (see Annex 5). Terms specific to each of the lenders (such as loan amounts, maturity and interest rates) will be reflected in each of the lenders' loan agreements.

IFC is supporting the project through an US$100 million A Loan and a US$30 million C Loan to BEL.

49. The key parameters of IFC financing are:

A Loan (for IFC's account)	
Borrower:	Bujagali Energy Limited
Amount and Currency:	Up to US$100 million (senior loan)
Maturity:	Up to 16 years
Other Terms:	To be determined

C Loan (for IFC's account)	
Borrower:	Bujagali Energy Limited
Amount and Currency:	Up to US$30 million (subordinated loan)
Maturity:	Up to 20 years
Other Terms:	To be determined

MIGA Guarantee

50. MIGA proposes to offer World Power Holdings Luxembourg SarL (WPH or the Guarantee Holder, a Luxembourg incorporated company and a wholly-owned subsidiary of Sithe Global Power LLC), a guarantee covering its equity investment of up to US$127.8 million in BEL via SG Bujagali Holdings Ltd. (Mauritius), a wholly-owned subsidiary of WPH incorporated in Mauritius. The coverage would be offered for a period of up to 20 years against the risk of Breach of Contract by UETCL and the Government of certain obligations under the PPA, the IA and the Government Guarantee. In line with MIGA's standard policy, MIGA will guarantee 90% of WPH's equity (including a portion of the sponsor's return during the construction period on its initial paid-in equity, to be included in the tariff), which will translate into MIGA's gross exposure of up to US$115 million. MIGA's net exposure under this project would be up to US$57.5 million after treaty reinsurance. Annex 14 provides details on MIGA's Breach of Contract coverage.

Table 2: MIGA Underwriting Structure

	Term of Contract(s)	% of Total
Equity (90%)	Up to 20 years	115.0
Total Guarantee Issued (90%)		115.0
Less Cooperative Underwriting Program		0.00
Total MIGA (Gross)		115.0
Facultative Reinsurance		0.0
Treaty Reinsurance (50%)		57.5
Total MIGA (Net)		**57.5**

B. PROJECT DEVELOPMENT OBJECTIVE AND KEY INDICATORS

51. The project's main objective is to provide least-cost power generation capacity that will eliminate power shortages. The proposed project would represent an increase of 250 MW of least cost installed power generation capacity to the national grid. The project's outcome indicators are:

- BEL's electricity generated (GWh) from the proposed 250 MW power station;

- Levelized cost of electricity (¢/kWh) from the Bujagali power plant; and
- Unmet Demand (GWh/month).

52. The project's intermediate milestones/outputs related to the commissioning of the power plant on time and within budget. In particular, the following aspects would be monitored:

- Achievement of financial closure date;
- Plant construction progress;
- Plant construction costs;
- Trial run results; and
- Commissioning test results.

C. PROJECT COMPONENTS

Project Cost and Financial Plan

53. The total financing required for the proposed Private Power Generation (Bujagali) Project is estimated a US$798.6 million. This is based upon a fixed price EPC Contract between BEL and Salini Costruttori SpA (Italy), which represents approximately 65% of total project costs. Tables 3 and 4 provide the project cost and the financing plan.

Table 3: Private Power Generation (Bujagali) Project Costs by Component

	US$ 000	% of Total
Engineering Procurement Contract (civil works, electromechanical equipment and spares)	520,064	65.0
Government contributed assets	20,000	2.5
Project Development Costs	26,838	3.4
IDC(1) and financing fees	94,087	11.8
Contingencies and DSRA(2)	82,082	10.3
Initial Working Capital & Other Costs	55,509	7.0
Total Project Costs	**798,580**	**100.0**

(1) Interest During Construction; (2) Debt Service Reserve Account

Table 4: Private Power Generation (Bujagali) Project Financing Plan

	US$ 000	% of Total
Equity		
Project sponsors	151,570	19.0
Government	20,000	2.5
Total Equity	**171,570**	**21.5**
Debt		
IFC	130,000	16.3
EIB	130,000	16.3
Commercial Banks (under IDA PRG)	115,000	14.4
ADB	110,000	13.8
European DFIs (*)	142,010	17.7
Total Debt	**627,010**	**78.5**
Total Debt and Equity	**798,580**	**100.0**

(*) The group of European DFIs includes Proparco, AFD, DEG, KfW, and FMO. The precise amount of debt from each entity is still being finalized.

54. The World Bank Group and other project lenders have taken several steps to verify that costs for the proposed project are reflective of current market conditions. BEL has conducted the procurement of the EPC contractor under the EIB's procurement rules. In addition to the review of bid prices conducted by BEL's Owner Engineer, the EPC contract price and conditions are being reviewed by the lenders with the assistance of their Independent Engineer before finalization. It should be noted that the next higher bid received by BEL for the EPC Contract was approximately 43% above that of the winning bidder.

55. Costs for the Proposed Private Power Generation (Bujagali) Project have increased substantially compared to the EPC contract of six years ago. BEL's hard costs (i.e., the EPC costs) are 62% higher than those of the 2001 EPC price of US$315 million, and currently stand at US$511 million, excluding spares (i.e., US$2,044/kW in 2006 compared to US$1,260/kW in 2001). In addition to the impact of inflation, this cost increase is the result of the rapid increase in the price of raw materials driven by high worldwide demand, and a tight market for qualified EPC contractors. Second, equipment costs in Uganda are much higher than those for markets with a substantial indigenous manufacturing base for hydropower equipment and other construction materials (such as cement), a skilled and mobile labor force, and a more robust transportation network. Third, since Uganda is a land-locked country, land transport for imported equipment (likely through the port of Mombasa, Kenya) together with the recruiting of skilled labor for its installation, remain significant costs. Given the above circumstances, the relatively high cost per installed megawatt for the proposed project is considered to reflect current market prices.

56. **The Interconnection Project**, to be built as a separate project, will connect the generation facility to the national grid. It includes: (a) a 75 km 220kV transmission line, operating at 132kV, to convey the power generated at the power plant to a new substation located in Kawanda (on the outskirts of Kampala); (b) a 17 km 132 kV transmission line to connect the Kawanda substation to the existing Mutundwe substation, located in the southwest section of Kampala; (c) a 5 km 132 kV transmission line from the Bujagali switchyard to the existing 132 kV transmission line, currently connecting Nalubaale with the Tororo substation (in eastern Uganda); and (d) a 5 km 132 kV transmission line extending north from the Nalubaale dam to interconnect with the Bujagali switchyard. It will also require the construction of a 132 kV substation at Kawanda and the expansion of the Mutundwe substation.

57. The Government has requested financing for the Interconnection Project from ADB, also a lender to the proposed hydropower project. The Interconnection Project will be owned and operated by UETCL, although the procurement and construction process will be managed by BEL on behalf of UETCL. The construction cost of the Interconnection Project is estimated at approximately US$55 million. Actual project costs will be known once the competitive tender has been completed and the tendered EPC contract has been signed.

D. LESSONS LEARNED AND REFLECTED IN THE PROJECT DESIGN

58. The main lessons from the World Bank Group's energy sector operations and project finance transactions include the following:

- It is more efficient to initiate and implement a comprehensive power sector reform program in advance of major new investments. This approach helps to establish a sound legal and regulatory framework and underpin the financial viability and sustainability of the power sector and new investments;

- The financial viability of the power sector is enhanced by commercializing power sector operations and through private participation in the ownership and management of distribution facilities, whereby the private sector is provided with a suitable incentive and penalty structure for enhancing performance and achieving efficiency targets;

- Because of limited donor funding for large and complex infrastructure projects, World Bank Group support can help catalyze long term private sector financing for capital intensive projects by mitigating certain political risks for investments in developing countries where the power sector has not yet developed a consistently long and positive track record;

- Investment decisions should be made based on their technical, financial, social, environmental and economic merits, thereby ensuring that projects are consistent with the macro-economic and sector development objectives; and

- In order to ensure a project's long-term sustainability, it is important that there is an equitable allocation of project's risks between the various parties (e.g., the Government, private sponsors, lenders, consumers and other stakeholders).

59. In addition to the above, there are a number of specific lessons learned from the previous attempt to mobilize financing for the Bujagali Hydropower Project[6]. These are the importance of:

- *A strong project sponsor group and a robust financing plan* (the export credit agencies unexpectedly pulled out of the previous effort to develop the Bujagali project in January 2002, following approval of the project by a joint IFC/IDA Board meeting on December 18, 2001). An important share of the proposed project is currently being financed by DFIs and commercial banks. Lender/sponsor/commercial bank negotiations are proceeding according to schedule. The World Bank Group is satisfied that the sponsors, Industrial Promotion Services (Kenya) (IPS(K)) and Sithe Global Power LLC (Sithe Global), have the technical and financial strength and the capability to successfully manage and implement the proposed project. As a demonstration of the sponsors' commitment to the project, they have posted a

[6] A Project Completion Note was circulated to the Board of Directors in October 2005 on the earlier Uganda – Bujagali Hydropower Project (B-003-0 UG).

financing bond in favour of the Government for US$4.5 million, which will be replaced with an US$11.0 million bond at the time of financial closure.

- *The adoption of a transparent and competitive process for the selection of the project sponsors and EPC contractor and of sound governance practices (see Annex 8).* The project sponsors and the EPC contractor were selected following international competitive bidding procedures, the latter being conducted according to EIB's procurement rules. In addition, BEL has implemented a "Code of Conduct" for its operations and has required its key contractors and subcontractors to adopt similar ones in relation with their activities with BEL.

- *Ensuring measures are taken to support the efficient operations of the power sector's distribution business, including improved quality of supply and access, that help underpin reliable and adequate sector cash flows.* UMEME has managed and operated the power distribution facilities since March 2005. In spite of the lack of power to sell and significant tariff increases, performance improvements have been realized in both collections and in system loss reduction. A financially viable distribution business will, over time, help to mitigate the perceived risks of future private investors in the power sector.

- *2002 Inspection Panel Findings and Recommendations.* The World Bank Group's due diligence on the proposed Private Power Generation (Bujagali) Project has incorporated the recommendations of the Inspection Panel Report dated May 23, 2002 and of the Management's Response and Action Plan dated June 17, 2002 (Report No. 24272 (INSP/R2002-002/1). This includes undertaking a comprehensive Strategic/Sectoral Social and Environmental Assessment and Cumulative Impact study, ensuring adequate stakeholder consultations, adhering to the World Bank Group's operational procedures and policies with regard to the economic and risk analyses, as well as the examination of alternative generation investments, such as geothermal activities.

E. ALTERNATIVES CONSIDERED AND REASONS FOR REJECTION

60. The conclusion of a number of power planning studies, most recently the study entitled, "Bujagali II – Economic and Financial Evaluation Study" dated February 2007 and carried out by Power Planning Associates Ltd., in association with Coyne et Bellier (France) and ECON (Norway), is that the proposed project is the least-cost generation expansion option to meet Uganda's growing power generation requirements under various conditions of demand and hydrology. A wide range of options were reviewed in order to assess Uganda's power generation expansion options: (a) small and medium hydropower projects; (b) large hydropower projects beyond the feasibility stage (i.e., Bujagali and Karuma); (c) thermal generation options (various conventional thermal generation technologies and plant sizes were screened); (d) geothermal generation; and (e) other renewable sources such as bagasse based cogeneration. The feasibility of either importing firm electricity from the Kenya grid or locating a Uganda-specific thermal plant in Kenya, in order to economize on fuel transportation costs, was examined. Neither option is feasible until the commissioning of the proposed project. Therefore, firm electricity imports are not considered a feasible option within this timeframe.

61. Alternatives to the proposed Bujagali hydropower facility were assessed in three ways: (a) development alternatives; (b) location alternatives; and (c) alternative configurations of the Bujagali location (see Annex 15).

62. In addition, the Strategic/Sectoral, Social and Environmental Assessment (SSEA), dated February 2007, prepared by SNC Lavalin (Canada) and funded under the Nile Basin Initiative, was

undertaken to provide an overview analysis of the social and environmental issues surrounding possible regional power development options in the Nile Equatorial Lakes Region of Africa based on demand scenarios up to 2020, taking into account potential climate change and cumulative impacts from multiple investments. A regional stakeholder group consisting of representatives from academia, religious groups and non-governmental agencies was also established to provide input to all stages of the SSEA. The SSEA thus analyses and ranks identified power options based on a combination of estimated costs, social, environmental and risk considerations, so as to provide strategic/sectoral level guidance to decision making in the power sector at the regional and national levels. The findings and recommendations of this report support the implementation of the proposed Private Power Generation (Bujagali) Project.

III. IMPLEMENTATION

A. PARTNERSHIP ARRANGEMENTS

63. The proposed project is a Public Private Partnership between the private project sponsors (IPS(K) and Sithe Global), the Government (including UETCL), multilateral and bilateral development agencies (the ADB, EIB, the World Bank Group, AFD, Proparco, FMO, KfW and DEG), and commercial lenders (Absa Capital, of South Africa, and Standard Chartered Bank, of the UK) as beneficiaries of the proposed IDA PRG.

B. INSTITUTIONAL AND IMPLEMENTATION ARRANGEMENTS

64. The proposed project will be developed by BEL, a special purpose company incorporated under the laws of Uganda by the project sponsors, which will be responsible for financing, building and operating the proposed project on a Build-Own-Operate-Transfer basis. BEL will sell electricity to UETCL under a 30 year PPA. The project sponsors are: (a) Industrial Promotion Services (Kenya) Ltd. (IPS(K))[7], the Kenya subsidiary of IPS, the industrial development arm of the Aga Khan Fund for Economic Development (AKFED); and (b) Sithe Global Power LLC (US) (Sithe Global), an international development company formed in 2004 to develop, construct, acquire and operate strategic assets around the world, which is controlled by Blackstone Capital Partners, an affiliate of the Blackstone Group. Reservoir Capital Group, LLC, a privately held investment firm, and Sithe Global's management are also Sithe Global's shareholders.

65. Since the 1970's the World Bank Group has had an extensive and long-standing relationship with AKFED. The World Bank Group supported numerous AKFED related companies in the manufacturing, tourism, financial and power sectors. Also, IFC has held a seat in IPS(K)'s Board of Directors since 1984. IFC currently has 16 active projects with AKFED and/or AKFED related companies, for a total committed exposure of approximately US$154 million. IFC has also invested in power projects successfully implemented by IPS(K) in Sub-Saharan Africa, such as Azito Energie (Côte d'Ivoire) and Kipevu (Kenya). Sithe Global has an experienced management team, with a long track-record in developing power projects. Sithe Energies, where most of Sithe Global's management team them held key long term positions, was one of the world's leading independent power producers, with a total generating capacity of approximately 5,000 MW, and was involved in the development of the San Roque hydro plant in the Philippines (340 MW).

66. The EPC contractor for the proposed project is Salini Costruttori SpA (Italy), with Alstom Power Hydraulique (France) as one its key subcontractors, which were selected following a

[7] IFC and DEG, both lenders to the project, each have a participation in IPS(K) of approximately 15%, and hold a seat in IPS(K)'s Board.

competitive tender under EIB's procurement rules. The O&M operator of the plant will be an affiliate company of Sithe Global. The proposed Interconnection Project required for evacuation of electricity generated by the power plant will be owned and operated by UETCL. BEL will be responsible for managing the design, procurement and construction of the Interconnection Project on behalf of UETCL (see Annex 6).

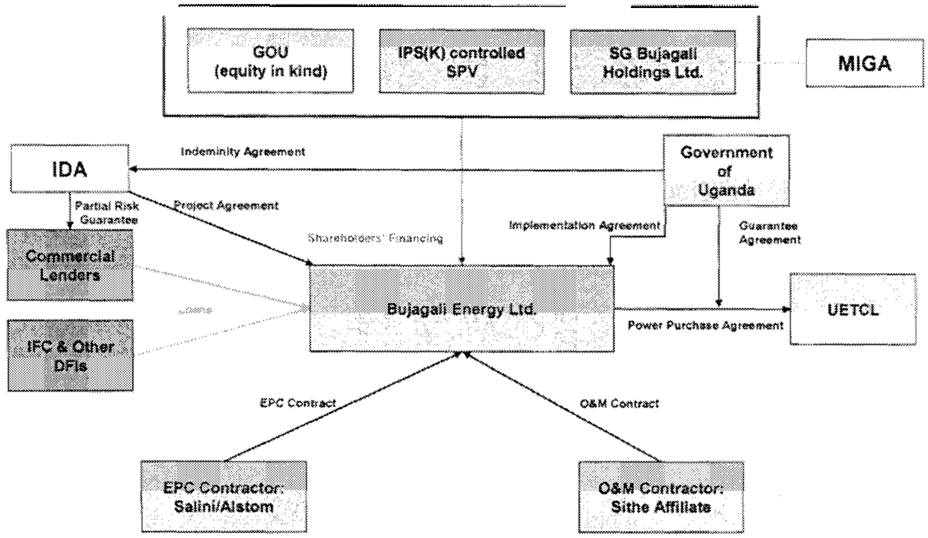
67. **Project Management.** BEL is responsible for developing, constructing, operating and maintaining the Bujagali hydropower plant. BEL will have a core team responsible for overseeing the work of the EPC contractor of the proposed project and of the Interconnection Project. BEL has established its headquarters in Kampala, to be headed by a project manager. BEL will also have a presence at the project site for supervision of the works by the EPC contractor. BEL's project organization will include: (a) a finance department, charged with accounting, financial management and control, reporting, internal audit, disbursement and contract administration; and (b) an operations department, staffed with experienced personnel responsible for the technical aspects during the construction and operational phases. BEL will have dedicated resources for implementation of the environmental action plan as well as resettlement related activities. BEL is recruiting staff to match the build-up of project activities. In order to ensure that project construction and operation are carried out in line with contracts, the lenders have appointed an experienced engineering firm, Colenco Power Engineering (Switzerland), as the lenders' Independent Engineer responsible for independently monitoring construction and operation activities on the lenders behalf. During the 44-month construction phase, the proposed project is expected to employ from 600 to 1,500 skilled and unskilled workers (of which around 10% are expected to be local workers) at the power plant and about 330 workers for the Interconnection Project. During the operational phase, BEL expects to employ about 30 staff.

68. A joint BEL-UETCL Coordinating Committee will be established prior to the project financial closing date. The Committee will have six members, with equal representation from BEL and UETCL; chairmanship of the Committee will rotate between both parties. The Committee will be responsible for coordinating the interface between BEL and UETCL as well as their respective obligations under the PPA and the IA.

69. BEL will be responsible for managing the construction of the Interconnection Project, on behalf of UETCL. Construction of the Interconnection Project is expected to commence in November 2007, and to be commissioned well in advance of the power plant.

70. **Project Contractual Arrangements.** The contractual structure of the project is consistent with industry practice for limited recourse project finance transactions. The project agreements allocate the commercial, technical and political risks amongst the parties, to those best able to manage them. Figure 1 provides an overview of the main project agreements. Further details are described in Annex 6.

Figure 1: The Principal Project Contractual Agreements



71. The security package for the proposed project provides the lenders with security interests in all assets of BEL, including real property/mortgageable assets (to the extent legally possible), plant and machinery, inventory, and receivables, as well as the assignment of or a charge over the project's on-shore and off-shore accounts (which will be placed under the control of a security trustee), as well as on any potential payments made by the Government due to a project termination event. The lenders would also receive an assignment of BEL's benefits under all material project documents, such as the PPA, IA, EPC and O&M contracts. In addition, lenders will enter into direct agreements with the parties to such agreements. The lenders will also be granted a first ranking pledge over the shares of BEL.

72. **Reporting Requirements and Project Monitoring**. Under the financing documentation, BEL is required to provide the following reports, together with all reasonable information that the lenders and IDA may require regarding the financing, construction and operation of the proposed project, including:

- Quarterly construction progress reports and semi-annual operation reports; annual status of insurance program; and the approved annual operating and maintenance plans;

- Annual monitoring reports on compliance with applicable national environmental requirements as well as with the lenders' environmental and social requirements, including the World Bank Group's safeguard policies, environmental, health and safety guidelines and on the Environmental and Social Action Plans; and

- Unaudited and annual audited financial statements for BEL.

73. **Auditing Arrangements.** BEL will have its annual financial statements prepared in accordance with International Financial Reporting Standards (IFRS), and audited by an independent auditor satisfactory to the lenders and IDA.

74. **Insurance Coverage.** BEL, together with the EPC contractor and O&M operator (during construction and operations, respectively) are required to obtain and maintain adequate insurance coverage in terms and by insurance companies acceptable to the Government, lenders and IDA. The insurance program is being developed by Marsh, the project insurance broker, and will be reviewed by Willis (FINEX Financial Solutions), an insurance advisory firm, and IFC's insurance team. The insurance program will reflect standard market practices for limited recourse finance projects of this nature.

C. MONITORING AND EVALUATION OF OUTCOMES/RESULTS

75. IDA's and IFC's key outcome indicators to be monitored and used in the evaluation of project impacts are presented in Annex 3.

D. SUSTAINABILITY

76. The sustainability of the project (as well as that of any other investment in the power sector) will depend upon: (a) the financial health of the power sector and its ability to generate sufficient revenues to fully cover costs, including capacity payment obligations to the proposed project; and (b) the Government's continued commitment to supporting the comprehensive power sector reform program which has been implemented over the past eight years. Moreover, the economic analysis establishes that the proposed project is the least-cost generation expansion option for Uganda and is affordable. The outlook for the project's economic and financial sustainability is also reinforced by: (a) the cautious forecasts of demand growth for electricity; (b) tariff levels that are consistent with the electricity prices underlying the demand forecasts; and (c) in the residential sector, the share of expenditure on electricity, relative to projected total household expenditure, is expected to remain in the range of 5% to 6%, which is considered affordable. The environmental and social assessment reflects the limited environmental footprint of the project.

77. The institutional, technical and financial assessments of the power sector and its positive track record over the past five years, demonstrate that the Government has instituted a sound legal and regulatory framework. In this regard, ERA has implemented substantial tariff increases to cope with the increasing costs of generation, and help maintain the financial viability of the sector. The Government has contributed budgetary support to the sector to cover a portion of the high cost of thermal generation essential for reducing severe load shedding, which is adversely affecting a number of key sectors of the economy. This clearly demonstrates the Government's ownership of the power sector reform program and the importance of electricity for economic growth. In addition, since the concessioning of power distribution facilities to a private operator, there have been improvements in the operational efficiency and performance of the distribution function even under the current adverse conditions.

E. CRITICAL RISKS AND POSSIBLE CONTROVERSIAL ASPECTS

78. The potential risks and possible controversial aspects are discussed below.

Risk	Mitigation
Failure of the proposed project due to an inability to mobilize financing.	The project has been designed as a Public Private Partnership. The PPA and IA have already been signed by the parties. The sponsors have posted a bid bond in the amount of US$4.5 million to confirm their financing commitment, to be replaced with a US$11 million bond upon reaching financial closure. Based on the due diligence performed the World Bank Group is satisfied with the sponsors' commitment to the project and BEL's

	ability to successfully manage the technical, operational and financing aspects of the project, as well as its implementation. The project is supported by a group of multilaterals and bilateral development finance institutions (EIB, ADB, AFD, Proparco, KfW, DEG, FMO, IFC, IDA and two commercial banks). These institutions are carrying out their due diligence and are expected to seek their respective Board/Credit Committee approvals at around the same time as the World Bank Group.
Demand growth for electricity is slower than expected.	Demand risk has been carefully evaluated by constructing demand forecasts based on a range of realistic outcomes for key underlying drivers, such as loss reduction, improved commercial discipline over billings and collections, tariff changes, household connection rates and GDP growth of the key electricity-using commercial and industrial sectors. The demand forecasts underlying this appraisal indicate low positive growth of end-use requirements and negative growth of generation requirements for some years before 2011, due to the existing situation of power shortages, high tariffs and the loss reduction program. While the probability of generation requirements growing lower than that of the low forecast (1.2% per year from 2005/15) is remote, if it were to occur, surplus energy could be exported since there is a regional shortage of supply which is likely to persist for years. When the proposed project is commissioned, it would replace expensive thermal generation: its capacity would be quickly absorbed in the power system and will allow for a reduction in the average electricity tariff.
A stable macro economic external environment (and liberalized foreign exchange regime) is not maintained.	The proposed project will provide adequate electricity supply that will remove shortage constraints, and would also replace high-cost thermal generation running on imported fuel. Hence the project is expected to place Uganda in a better position to handle any potential changes in the external environment to help Uganda maintain satisfactory macro-economic performance by reducing the foreign exchange burden of oil imports for electricity production, and eliminating electricity shortages as a deterrent to investment. Macro-performance and progress on power sector reform are underpinned by the World Bank and IMF macro-economic programs, as well as the Heavily Indebted Poor Country Initiative program. According to a December 2006 IMF report, solving the current power sector crisis is critical for Uganda's macro economic progress. The project's viability has been tested for a low electricity demand growth scenario that has, as one of its components, industrial and commercial GDP growth rates as low as 3.4% and 4% per year, compared with about 6.4% and 7% in the base case.
Government commitment to power sector reform is not maintained, thereby jeopardizing the financial viability of the power sector.	Since 1999, the Government has taken significant and irreversible steps to implement a comprehensive power sector reform program. The Government has also demonstrated its commitment to support the commercial viability of the sector, for instance, through the concessioning of its distribution assets to the private sector. Moreover, ERA has a strong track-record of independence, as reflected in the increases in the retail tariff by about 94% in 2006, thus helping to maintain the sector's financial viability.
UMEME, the private distribution concessionaire, terminates its concession.	UMEME has already invested US$13.6 million (well beyond its original contractual commitment) and has agreed to invest up to US$65 million during the first five years of the concession. IDA and MIGA are also providing UMEME coverage for regulatory and non-payment risks, and for breach of contract, respectively. The current concession structure was recently modified to protect UMEME from the impact of power shortages and the reduced revenue stream, which are factors beyond UMEME's control but have a bearing on UMEME's ability to meet its concession obligations, thereby reducing the likelihood of any termination of the concession.

Hydrology risk: Adequacy of water flows on the Nile River; Lake Victoria water levels do not improve, or even decline further.	▪ Significant due diligence has been undertaken on the hydrology of Lake Victoria and the Nile River by Coyne et Bellier, in coordination with Power Planning Associates. Even under the low hydrology scenario, which is based on 106 years of data, the proposed project: (a) would generate approximately 132 MW of firm power; and (b) has been established as the least cost power generation increment. In the event of a sustained period of extremely low hydrology preventing the proposed project from generating power supply, the Government has the option to purchase the plant. ▪ The proposed project does not create an incremental draw on Lake Victoria: it reuses the water released for the operation of the Nalubaale/Kiira dam complex. Furthermore, the Government is taking a number of measures to diversify supply in line with least cost planning principles. These include procuring 50 MW of permanent thermal generation capacity, adopting demand side management measures, as well as accelerating mini-hydro and co-generation prospects in the short term, and geothermal prospects in the long term.
Hydropower plant and Interconnection Project encounter construction delays and cost overruns; system not operated and maintained in line with international standards for hydropower plants.	▪ The sponsors' equity and returns are placed at risk for construction delays, inadequate project management and plant operational performance below the agreed targets. ▪ The EPC contract has been structured on a fixed-price turnkey, date-certain basis and includes payment of penalties in the event of delays. ▪ BEL will be undertaking the procurement and construction management of the associated Interconnection Project (being financed by ADB), on behalf of UETCL, and this should mitigate against construction delays. The construction period for the Interconnection Project is substantially shorter than that of the dam and powerhouse, thus minimizing the risk that it would not be commissioned in advance of the proposed project. ▪ In addition, the construction of an 8km transmission link from the Bujagali switchyard to the Nalubaale substation would enable the evacuation of 180 MW from the Bujagali plant, in the unlikely event of a delay in the commissioning of the Interconnection Project.
Impact of the project on the Government's contingent liabilities.	The Government has two options to build the power capacity: as a public project or a public private partnership. In the former case, the Government would take on direct liabilities for all financing and all risks. In the latter case, the construction financing and operation risk is transferred to the private sector while the Government provides certain guarantees. A vast number of project finance transactions in developing countries require similar Government guarantees relating to Government and public sector performance. These guarantees can only be called if the Government does not fulfill its obligations.
Increase in Project costs (including financing costs).	The EPC contract will be a fixed price turnkey contract with Salini Costruttori SpA (Italy), with Alstom Power Hydraulique (France) as a key subcontractor, both of which have adequate experience of undertaking similar projects. Changes in EPC contract prices are only allowed under very specific circumstances, such as changes in law, change orders instructed by BEL, and for geological/geotechnical conditions being worse than the baseline reflected in the EPC contract. The PPA structure also provides an incentive to BEL to minimize any EPC cost increases. A reasonable estimate of financing costs is incorporated into project costs, and will be firmed up at financial closure.

F. LOAN/CREDIT/GUARANTEE CONDITIONS AND COVENANTS

PRG Effectiveness Conditions

- Firm commitment for sufficient financing to complete the construction of the project;
- Execution, delivery and effectiveness of all project and financing agreements, including but not limited to the lenders' Common Terms Agreement, the individual loan agreements and the security documents, the IDA Indemnity Agreement and the IDA Project Agreement, each in form and substance satisfactory to IDA;
- Submission of the *Social and Environmental Assessment* and the *Social and Environmental Action Plan,* satisfactory to IDA;
- Effectiveness of all required insurances (to include IDA as an additional insured on third-party liability insurance);
- Provision of satisfactory legal opinions;
- Payment in full of the Initiation and Processing Fees, and the first installment of the Guarantee Fee and Standby Fee; and
- Satisfaction of all conditions precedent to the first disbursement under the Common Terms Agreement and the IDA Guaranteed Facility Agreement (the agreement between IDA and the "IDA guaranteed" lenders) including satisfactory progress on the financing and construction arrangements for the Interconnection Project.

Other

- Confirmation of the Government's acceptance of the Kalagala Offset.

IV. APPRAISAL SUMMARY

79. The proposed project is being supported by a joint team from IDA, IFC and MIGA. IDA and IFC have taken major responsibility for all aspects of project appraisal. IFC has played a lead role on lender coordination, while IDA has taken a lead role on the due diligence with regard to the power sector reform program and the power sector's financial situation and prospects.

A. ECONOMIC ANALYSIS

80. The project economic analysis covers a review of Uganda's power sector, including the impact of the current power shortages, electricity demand growth, the hydrology of Lake Victoria, generation alternatives and an assessment of the least cost power investment program for Uganda. It also covers the project's economic rate of return, the end-user tariff path and the macro-economic impact of the project. Through a transparent and competitive process, Power Planning Associates Ltd. (UK), in association with Coyne et Bellier (France) and ECON (Norway), was selected to undertake the economic analysis funded under IFC's Funding Mechanism for Technical Assistance and Advisory Services (FMTAAS). The findings and recommendations of Power Planning Associates' report entitled, "Bujagali II – Economic and Financial Evaluation Study", dated February 2007, are summarized below. The report was publicly disclosed on February 26, 2007 and is available on the following website: www.worldbank.org/Bujagali.

81. The key elements of the economic analysis include: (a) the impact of the current power crisis conditions on the power sector and the need for emergency thermal power; (b) the demand forecast, which is mainly influenced by new customer connection programs, commercial and industrial GDP growth, loss reduction targets for the power system and the tightening of commercial discipline over billings and collections; (c) the level of electricity tariffs; (d) hydrology of Lake Victoria and its impact on hydropower generation; (e) the supply alternatives and their costs; (f) environmental and social costs of Bujagali and its main alternative; and (g) the economic value of electricity to consumers, the end-user tariff path and its affordability. Risks arising from varying degrees of future uncertainty regarding these variables have also been evaluated. The main findings of the economic analysis are that:

- The proposed project is needed immediately, and its implementation presents minimal economic risk to its status as the least-cost option for the next major Ugandan grid system generation increment;

- Any delay in the proposed project scheduled commissioning time (2011) would be costly;

- The 250 MW configuration is preferred over 200 MW, and it is not economic to commission the Karuma hydropower project before the proposed project;

- Using a set of 72 generation expansion plans, taking into consideration the uncertainty surrounding the main economic determinants, commissioning the proposed project in 2011 has a risk-adjusted net present value advantage of US$184 million, at a 10% discount rate, relative to the alternative of not implementing the project; and

- The economic internal rate of return (EIRR) of the project is 22% in the Base Case and falls within a range of 11.3% to 26.4% taking into account a broad range of contributing assumptions about demand, costs and hydrology.

82. These conclusions encompass an evaluation of the relative merits of alternative projects, three demand projections, three scenarios for fuel price projections, environmental and social impacts, two hydrological scenarios (based on a 106 year hydrological record) and, through measuring the impact of electricity tariff increases on demand, the affordability of electricity in the vastly under-served Uganda market.

83. **Economic Context and the Current Power Supply Crisis.** Due to the inability to mobilize financing for the former Bujagali project in 2002, combined with the onset of poor hydrological conditions, it has become necessary for the Government to enter into short term supply arrangements using expensive diesel generating units on an emergency basis, and to ration electricity supply by means of massive load-shedding. About 43 MW of mini-hydropower schemes and around 15 MW in co-generation (bagasse) are to be commissioned in the 2007/09 timeframe. While these alternative sources will make a modest contribution to total generation needs, reliance on diesel based power generation (about 150 MW) will continue to be needed until the proposed project is commissioned in early 2011.

84. A detailed economic assessment of thermal generation requirements during the period 2006/10, highlighting the very large and costly contribution of thermal power, which carries around US$700 million in economic costs during this period. By comparison, the expected economic cost of the proposed Private Power Generation (Bujagali) Project will be about US$520 million for a project that will have an expected productive life of about 50 years and will generate at least 60% more annual energy than the thermal plants would produce in 2010. This indicates the economic penalty

that the long delay of the project implementation will have cost Uganda. It also highlights the important economic circumstance that if commissioned in 2011, the project would immediately displace at least 738 GWh of diesel generation – a substantial portion of the project's expected output of 1,165 GWh and 1,991 GWh for the low and high hydrology scenarios, respectively. This displacement contributes to a rapid build-up of economic capacity utilization which favors the project's economic rate of return.

85. **Demand for Power and Electricity Tariffs.** The demand forecast model explicitly recognizes the potential impact on consumption resulting from both the near doubling of tariffs implemented in 2006, which were required to accommodate the high cost of thermal generation program (2006/10), and a reduction in technical losses and an improvement in collection of billed sales expected from the private distribution concessionaire UMEME. The average annual base case growth rate of generation requirements for 2005/20 is projected to be 5.5%. The high and low average annual demand growth rate projections are 7.7% and 2.2%, respectively. The low demand projection implies a dire picture of economic and sector performance, with declining annual electricity generation requirements for the next five years, resulting from low per capita GDP growth (0.8% per annum), very low new consumer connection rates and poor performance in the commercial and industrial sectors. The spread between the base case and the low demand forecast ranges from 15% in 2011 to 27% by 2015, and continues increasing thereafter. Annex 9 provides details on the economic assumptions and results.

86. **Supply Options and Risk to the Investment Decision.** The economic analysis confirms that the proposed project is the next major least-cost generation expansion option for Uganda. The major generation alternatives considered include: small and medium-sized hydropower projects, large hydropower projects studied beyond the feasibility stage (i.e., Karuma), thermal options, bagasse based cogeneration and geothermal. The Government has reported a domestic oil resource to be developed and exploited with a small scale refinery. It will take several years to prove up the reserve, determine its daily productive capacity, define the costs of developing and producing wells, and to construct a refinery (without a refinery, it is unlikely that crude oil can be used for power generation). Hence, this recent oil discovery is not expected to have an impact on power generation options over the medium term. An in-depth investigation of Uganda's geo-thermal potential was conducted, the result of which is a vastly diminished estimate of future availability – one 40 MW facility. Apart from some committed small hydropower schemes that will make a modest contribution to supply between now and 2010, recourse to fossil fuel plants remains possible at lower investment cost per kW compared with much of the hydropower, but with very high operating costs, resulting in fully-allocated costs that are far above those of the proposed project or Karuma over the long term. The least-cost of the various fossil-fuel-based options is mostly medium speed diesel plant using heavy fuel oil, but reliance on this option above 50 MW is not feasible without major investments in Kenya to ease constraints of fuel supply logistics, as well as transportation constraints. The least-cost analysis was conducted for three demand projections (low, base and high), two hydrological scenarios (low and high), three project cost estimates (low, base and high), and three fuel price projections (low, base and high). In addition, the least-cost status of Bujagali was tested for 200 MW versus 250 MW project size, delayed commissioning and the Karuma hydropower project preceding it. The only cases where the proposed project is not part of the least-cost expansion plan are those where low demand is combined with high hydrology; such scenarios have a combined probability of occurrence of only 6%.

87. **Hydrology.** Two substantial reviews of the hydrology of Lake Victoria[8] indicate that the whole 1900 to 2005 hydrological record should be included in the analysis. Because there was a very distinct period of unusually high hydrologic performance between 1960 and 1999, it is sensible to perform the hydrologic risk analysis using two distinct scenarios: one is reflecting the "wet" period (1960-1999) and one the "dry" periods, which consisted of many more years surrounding the relatively "wet" period. The calculated probabilities of occurrence for the "dry" and "wet" periods are 79% and 21%, respectively (see Annex 10). The project remains viable in both scenarios. The risk of climate change on the hydrology of Lake Victoria was taken into consideration: the conclusion of both the economic study and the Strategic/Sectoral, Social and Environmental Assessment (February 2007) under the Nile Basin Initiative, is that there will be no adverse effect on water release due to climate change during the life of the proposed project.

88. **Affordability of Electricity to Consumers.** About 5% Ugandan households are currently supplied by the national power grid. These consumers generally have incomes in the middle to upper end of the income distribution for Uganda. A review was undertaken to determine whether individual households will be able to purchase electricity within their budgets. Based on ERA's and other household surveys regarding total household spending relative to electricity supplied per residential connection, it was assessed that the average residential customer spent in electricity in 2005 about 5.7% of household income, but this figure assumes (incorrectly) that there is only one household per connection. Based on information received from discussions with UMEME, the Ministry of Energy and Mineral Development (MEMD) and ERA, it is common for more than one household to be supplied from a single UMEME connection. This can range from "compound houses" with three or four individual households sharing a single compound and a single UMEME connection, to apartment blocks where only the landlord is metered, but the tenant households all consume electricity and pay an allocated share of the bill for the total supply to the building from the one connection. Based on available data, it is reasonable to infer that each connection supplies on average 1.8 households; on this basis, the annual proportion of household income spent on electricity would be reduced to 3.2% before the major tariff increases of 2006. The analysis also assessed whether electricity would be affordable in 2011, given the large 2006 tariff increases and the tariff trajectory utilized in the demand forecast. The base case demand forecast assumes a 2.3% real annual growth of household disposable income between 2005/11. Under this scenario, electricity prices will have more than doubled in real terms over the same time period and the average household expenditure on electricity will have increased from about 3.2% to 5.2% of household income, which is considered to be an affordable level of expenditure. This demonstrates the proposed project's positive impact on the financial sustainability of the power sector (see Annex 9).

89. **Environmental Considerations.** Environmental and social costs have been incorporated in the economic analysis and are based on the review of existing documentation and field research. This includes the environmental and social costs related to the dam, powerhouse and transmission line, which for the proposed project are approximately US$26 million. The social costs already paid-up in respect of the previous Bujagali project preparation are considered sunk, for economic purposes, and not included in this analysis. For purposes of least-cost system planning, environmental and social costs are capitalized as investment costs. Thus the results of the least-cost analyses include these project-associated incremental environmental and social costs.

90. The proposed project will avoid substantial amounts of Carbon Dioxide (CO_2) emissions that would be generated by thermal plants. Over the project's 50-year commercial life, the proposed

[8] The hydrological aspects were also reviewed, commented upon and found to be satisfactory by Professor Juan Valdes, an expert hydrologist from the University of Arizona, who was financed under the Bank Netherlands Water Partnership Program (BNWPP) to carry out this independent assessment.

project is estimated to avoid the emission of nearly 60 million tons of CO_2. Neither the benefits of avoided CO_2 for the hydropower plants nor the costs of CO_2 for the thermal plants are included in the least-cost calculations. The reasons for this approach are: (a) the importance of understanding comparative costs before accounting for this externality; (b) including such cost would simply augment the net least-cost advantage of the proposed project; and (c) similar benefits would accrue to both Bujagali and Karuma, so that where the latter is a counterfactual to the former, the size of the net effect favoring Bujagali is quite reduced. The impact of the CO_2 factor, however, is demonstrated in the EIRR analysis.

91. **Economic Internal Rate of Return (EIRR).** The economic analysis is designed to find the EIRR to a series of annual economic benefits and costs attributable to the project. The benefits are a combination of displacement of more expensive thermal power in the early years of the project's life and "consumer willingness-to-pay" for incremental electricity supply. The costs include constructing and operating the project and the incremental transmission and distribution works needed for delivering the project's energy to end-users, as well as managing environmental and social impacts. The EIRR is calculated over 2007 to 2061 inclusive, with project benefits and costs stabilized at the level reached by the year Bujagali's output is fully absorbed, which varies depending on the selected hydrology and demand forecast assumptions. The key risks to the EIRR are hydrology, fuel prices (which impact consumers' willingness to pay for alternatives to grid power), and the demand forecast, resulting in eighteen possible scenarios for the EIRR. Because the EIRR for each of the 18 scenarios is computed with and without a "greenhouse gas" benefit, there are 36 such scenarios. The results of the EIRR analysis are that the EIRR without any greenhouse gas credit has zero probability of being less than 11.3% or more than 26.4%. The EIRR to the base case (low hydrology, base demand, base fuel) is 22%. The greenhouse gas credit adds less than one percentage point to the EIRR.

92. **Macroeconomic Impact.** The project, as a part of a mainly hydro-based least cost expansion plan for power generation in Uganda, is expected to have a positive macroeconomic impact. Compared to a thermal oil-based expansion plan, the hydro-based expansion plan is expected to save the country's balance of payments over US$700 million from 2011 to 2020. The positive impact on the balance of payments is robust to sensitivity tests on the main assumptions. The hydro-based strategy would potentially save the country an estimated 3.6% of budget revenues and 6.0% of development expenditures over the same period in avoided subsidies to the power sector. Investment activity associated with the proposed project would not cause "excess investment demand" domestically nor have a significant impact on the exchange rate.[9]

B. Financial Analysis of Bujagali Energy Limited (BEL)

93. BEL is a privately owned and operated company established with the sole purpose of developing, constructing and operating the proposed Private Power Generation (Bujagali) Project, and managing the construction of the associated Interconnection Project. Financing for the project is being mobilized on a limited recourse basis.

94. BEL's main financial objective is to earn a competitive rate of return for its shareholders. This will depend on BEL's ability to construct, complete and commission the project on time and within budget, and ensure the efficient operations and maintenance of the power plant. BEL's sole source of revenues will be from the sale of electricity to UETCL under the 30-year PPA. Consistent with the nature of hydropower projects, the PPA has a capacity-based tariff, with a penalty regime if

[9] This assessment is based on analysis prepared by independent consultant John Holsen for IDA, using data from Power Planning Associates Ltd. and a model of the Uganda economy.

the required capacity and availability targets are not met. The electricity tariff from the hydropower plant is computed based on allowed project costs, operation and maintenance fees and debt and equity costs. UETCL, the power purchaser, is exposed to cost increases only for explicit pass-through costs. UETCL's payment obligations are guaranteed by the Government under the Government Guarantee, and this guarantee remains in force at least until the date on which the project debt has been repaid.

95. Under the PPA, BEL will be required to issue monthly bills for its capacity payments denominated in US Dollars. Payments by UETCL may be made in US Dollars or in Ugandan Shillings based on the USh/US$ exchange rate on the payment date. BEL's annual project revenues[10] range between US$137 million and US$187 million during the life of the senior loans, and decline after 2023 when a substantial portion of the project debt would be repaid. Figure 2 and Table 5 below indicate the estimated hydropower electricity tariff in nominal and levelized terms under both the low (base case) and high hydrology scenarios.

Figure 2: Project Tariff Structure

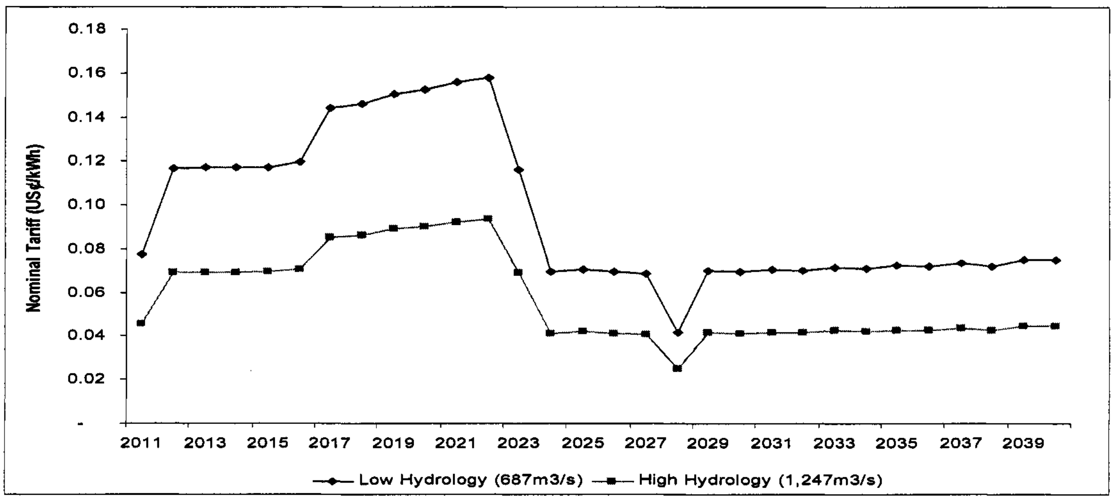


Table 5: Bujagali Hydropower Project Electricity Tariffs Profile
(Figures in US cents per kWh)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2023	2027
Low Hydrology												
Nominal	9.4	11.7	11.7	11.7	11.7	12.8	14.5	14.7	15.1	15.4	7.1	6.5
Levelized*	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
High Hydrology												
Nominal	5.6	6.9	6.9	6.9	6.9	7.6	8.6	8.7	9.0	9.1	4.2	3.8
Levelized*	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7

(*) The levelized tariff per kWh is the average annual nominal tariff over the life of the PPA, discounted at the project weighted average cost of capital and expressed as of 2006, assuming annual inflation of 2.5%.

96. **Project Financial Performance.** A forecast for the project's financial performance has been prepared, the results of which, along with the key assumptions, are presented in Annex 11. These financial projections demonstrate the project is financially sound, with a minimum Debt Service

[10] Payments made by UETCL to BEL will, in turn, be recovered by UETCL through its sale of electricity to UMEME.

Coverage Ratio (DSCR) of 1.5 over the term of the loans. The project's financial rate of return has been estimated at 11.2%.

97. A number of sensitivities have been undertaken to test the project's ability to withstand downside scenarios, including: (a) a 30% increase in the EPC contract cost, such that 30% of such increase is not recoverable by BEL through the project capacity payments; (b) a 25% increase in operating and maintenance costs above those for the base case, which would not be recoverable through the project capacity payments; (c) capacity testing at the time of commissioning is 50 MW below the 250 MW required under the PPA and BEL's capacity payments are reduced accordingly; and (d) the project's availability is 90% (i.e., below the 96% target required under the PPA) and BEL's capacity payments are reduced accordingly. As shown in Table 6, the sensitivity analysis indicates that the financial performance of the project remains acceptable within a reasonable range of outcomes.

Table 6: Bujagali Hydropower Project Sensitivity Analysis

Scenario	Minimum DSCR	Year
Base Case	1.5	2018
30% Increase in Construction Costs	1.3	2018
25% Increase in O&M Costs	1.4	2018
50 MW Capacity Shortfall	1.1	2022
Reduced Availability to 90% during project life	1.4	2018

98. An additional sensitivity that has been analyzed is a potential project delay of up to 6 months. Should that be the case, it is considered that the combination of project contingencies and the penalties, payable by the contractor to BEL, would be sufficient to cover BEL's fixed costs during such delay period and any penalties that BEL would owe to UETCL.

C. Financial Analysis of the Ugandan Power Sector

99. In June 1999, the Government approved a comprehensive power sector reform strategy focusing on improving efficiency through a structure that allows for a partnership between the public and private sectors in the operation of the power system's assets and investment in the system's development. Annex 1 provides an overview of the implementation of structural reforms in the power sector. The consolidated performance of the generation, transmission and distribution Ugandan power utilities is discussed here (Annex 12 provides more details on the financial performance of the sector).

100. **Power Sector Performance (2004-06).** The significant reduction in relatively inexpensive hydropower supply over the recent past and in the medium term, has forced the Government to implement an interim generation expansion plan (2005-10) to meet the country's power generation needs until the proposed project is commissioned in early 2011. As already described under Section I.A. above, this interim plan includes the installation of up to 150 MW of thermal generation capacity (further details also in Annex 1). This heavy reliance on very expensive thermal power combined with a reduced amount of kWh energy to sell has significantly increased the sector's overall revenue requirements as well as the average costs per kWh. Total revenue requirements in 2004 were US$76 million, at which time the sector was financially viable. However, the corresponding requirement in 2006 is approximately US$200 million, equivalent to an increase of 164% over two years. Thus, electricity tariffs had not kept pace with rising costs since 2005, and the gap between costs and revenues has widened considerably.

101. Since the power crisis begun, the Government has shown its commitment to the power sector by providing substantial support to UETCL (the single buyer in the power system) and in spite of significant power cuts, the ERA has also substantially raised tariffs (by a cumulative 151% since April 2005), to meet the revenue requirements of the sector (together with budgetary and donor support).

102. The power sector's key operational and financial performance indicators for 2004-06 are summarized in Table 7 below. The consolidated financial performance of Uganda Electricity Generation Company Limited (UEGCL), Uganda Electricity Transmission Company Limited (UETCL), and Uganda Electricity Distribution Company Limited (UEDCL) for 2004-06 and projections for the period 2007-16 are provided in Annex 12.

Table 7: Key Consolidated Operational and Financial Performance Indicators

	2004 Actual	2005 Actual	2006 Est Actual
Peak demand (MW)	334	354	347
Total units sent out (GWh)	1,892	1,887	1,610
of which:			
Hydro	99%	90%	72%
Thermal	0%	7%	23%
Geothermal	0%	0%	0%
Renewables & other	1%	3%	5%
Transmission losses	4.6%	4.8%	4.2%
Export sales (GWh)	196	64	53
Bulk supply to Umeme (GWh)	1,610	1,741	1,503
Distribution losses	36.0%	38.2%	34.1%
Billed Uganda sales (GWh)	1,030	1,075	990
Uganda sales growth	-0.5%	4.4%	-7.9%
Billed as % of units sent out to Uganda	61%	59%	64%
Uganda sales collected as % of sent out	50%	51%	54%
Ave. number of customers ('000)	254	278	295
Ave. number of employees	1,788	1,745	1,542
Customers per employee	142	159	191
Total electricity revenue (USh billion)	167	175	222
Uganda electricity revenue (USh billion)	145	168	213
Uganda electricity revenue (US$ million)	80	94	116
Uganda VAT revenue to GoU (US$ million)	14	16	21
Ave. Uganda electricity revenue (USh/kWh)	141	156	215
Ave. Uganda electricity revenue (US$/kWh)	0.078	0.088	0.117
Ave. operating income (USh/kWh)	23	-23	32
Ave. operating income (US$/kWh)	0.013	-0.013	0.018
Return on fixed assets	3.3%	-3.1%	4.0%
Debt service coverage	2.1	0.3	1.7
Current ratio	2.1	1.6	2.3
Debt/equity ratio	41%	43%	40%

103. **Electricity Tariffs.** After the takeover of the distribution business by UMEME, tariffs were increased effective April 1, 2005 by an average of 27%. This increase took account of UMEME's revenue requirements and also the costs of the first 50 MW thermal plant that was commissioned in May 2005. Tariffs were increased subsequently by an average of 2%, 37.5% and 41% on October 1, 2005, June 1, 2006, and November 1, 2006 respectively.

104. Despite those significant tariff increases, the domestic lifeline tariff for the first 15 kWh per month was only increased one time in the last five years and less significantly than the average retail tariff. The lifeline tariff was set at USh50/kWh (US$2.7¢/kWh) in 2001 and represents

approximately 5.5% of total consumption by end-use customers. In June 2006, the lifeline tariff was increased by 24% to USh62/kWh (US$3.4¢/kWh).

105. Retail electricity tariffs are now below costs of supply. Today's weighted average retail tariff excluding VAT is USh313/kWh (US$17.2¢/kWh and US$21¢/kWh including VAT). The estimated actual average for 2006 was USh215/kWh (US$11.7¢/kWh). Based on accrued revenue requirements, the required average tariff excluding VAT for 2006 was USh371/kWh (US$20.2¢/kWh). The estimated subsidy for 2006 is around USh156/kWh (US$8.5¢/kWh), equivalent to US$85 million for the calendar year. In 2006, the Government provided USh113 billion (US$62 million) in direct budget support towards thermal power costs of the power sector and in the Government's Fiscal Year 2006/07 the total amount of subsidies will reach US$84 million under base case assumptions. In addition to the Government's support, UETCL was directed by ERA to utilize the remaining balance of USh49 billion (US$27 million) in the Bulk Supply Tariff stabilization fund that had been collected from electricity customers in prior years. This fund was fully utilized in the first quarter of 2006.

106. **Uncollected Energy Bills.** Another important factor of Uganda's power sector is the amount of losses and uncollected energy bills. Since its take over of the distribution concession from the state owned UEDCL, the collection rate had already been improved by UMEME until May 2006 from 80% up to 92%, but since the large increases in tariffs in June and November 2006, the collection rate dropped again to 82% at the end of 2006. Equally the transmission and distribution losses remained at levels of about 4.5-5.0% (transmission losses of UETCL) and 34.1% (distribution losses of UMEME) since mid-2006. This means that at the end of 2006 approximately 49% of the energy sent out is not paid for. It will be crucial that loss numbers and collection rates improve again. UMEME is actively pursuing various measures to accelerate technical and non technical loss reduction and to improve collection rates. The distribution concession has recently been renegotiated between UMEME and the Government due to the current electricity crisis. The restructured concession agreement includes commercial incentives for the concessionaire to reduce losses and non-collection rates.

107. **Sector Revenue Requirements and Indicative Financing Plan (2007-16).** A summary of the base case forecast of the power sector revenue requirements and an indicative financing plan for 2007-16 is provided Annex 12, as well as the annual sector revenue requirements and the financing plan for 2007-16.

108. Total revenue requirements of the power sector for 2007-11 and 2012-16 are estimated at US$1,495 million and US$1,899 million, respectively. Based on the tariff levels effective from November 2006, the power sector will raise revenues of US$1,147 million during 2007-11, and US$1,627 million during 2012-16, leaving a shortfall of US$348 million during 2007-11[11], and US$272 million during 2012-16.

109. The shortfall during 2007-11 will be met as follows:

- Deferment of USh128 billion (US$67 million) of debt service by the Government to 2011; the sector should be in a position to repay all of the deferred debt service by the end of 2011 and will be expected to meet all of its debt service obligations to the Government from 2011 onwards.

[11] Please note that in addition to the shortfall in 2007-2012 of US$348 million, the sector also has to service a remaining shortfall of USh 8 billion (approx. US$5 million) that was carried forward from the previous calendar year 2005.

- USh92 billion (US$49 million) annually in 2007 and 2008, USh28 billion (US$15 million) in 2009, and USh66 billion (US$34 million) in 2010. On this basis, the projected direct Government budget support is estimated to reach USh278 billion (US$147 million), representing 10% of sector revenue requirements from 2007 to 2011. No Government support will be needed beyond 2011 if the estimated shortfall between 2012 and 2016 can be mitigated through additional small tariff increases as described in the following paragraph.

- IDA support (under the proposed Power Sector Development Operation) of US$206.5 million towards the capacity and energy charges of a 50 MW thermal plant. This financial assistance will comprise US$42.1 million towards capacity payments and US$164.4 million towards energy charges, including fuel.[12]

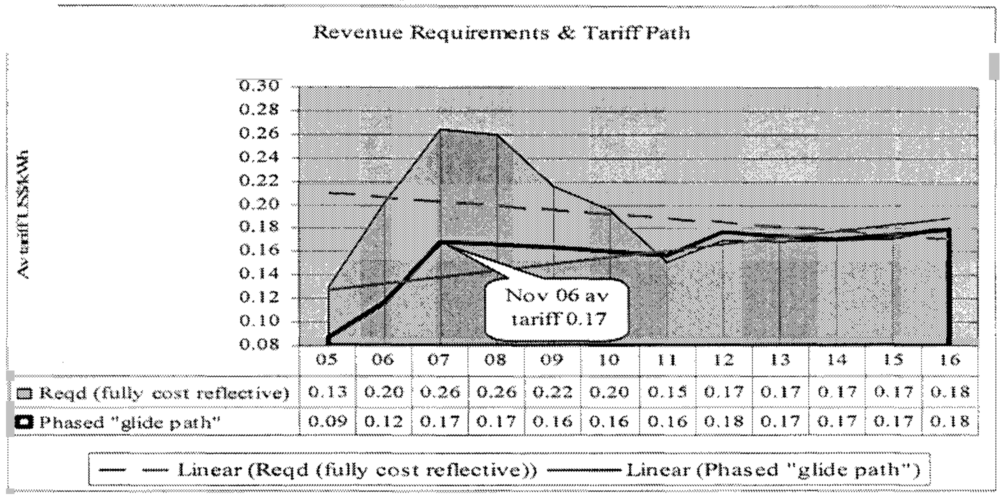
110. **Electricity Tariff Increases.** According to the World Bank's forecast, international prices of crude oil are expected to decline gradually over the coming years, to reach around US$45 per barrel by 2011 (in 2006 prices). Based on this oil price forecast, and after taking account of Government and IDA support towards thermal power costs as described above, the financial analysis indicates that there will be no need for further revisions in electricity tariffs through to 2011. This means that tariffs will fall in real terms over the course of the next five years from the present US$17.2¢/kWh to US$13.9¢/kWh by 2016. However, if crude oil prices from today to 2011 would slightly increase to US$73 per barrel (in 2006 prices), the projections show that an additional amount of US$92 million would have to be raised through additional tariff increases.

111. With regard to the period of 2012 to 2016, even in the current Base Case, tariffs would have to rise by an average of 15% on January 1, 2012 and by the assumed Uganda inflation rate of 4.5% in both 2014 and 2015 (or 26% cumulatively).

112. Figure 3 depicts the "glide path" of the average electricity tariff until 2016. The revenue requirements above the dark line show the amount of "tariff subsidy" being provided by the Government through direct budget support, debt service deferment and IDA support towards thermal costs. The projected revenue requirements and tariffs converge by the time the proposed project comes on line in 2011. Electricity tariffs would be fully cost reflective by then and subsidies would be removed, except for duty exemptions on generation fuel and transmission investments.

[12] The total amount of the proposed Operation is US$ 300 million including US$ 80 million of general budget support and US$ 13.5 million of Technical Assistance, Energy Efficiency and Demand Side Management measures. However those additional US$93.5 million are not taken into account for the mitigation of the US$348 million operational shortfall.

Figure 3: Revenue Requirements & Retail Tariff Path to 2016



113. Table 8 provides projected operational and financial performance indicators (2007-16).

Table 8: Key Consolidated Operational & Financial Performance Indicators (2007-16)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Peak demand (MW)	337	343	359	375	407	432	467	505	545	587
Total units sent out (GWh)										
of which:										
Hydro	52%	46%	45%	48%	82%	87%	82%	76%	70%	65%
Thermal	44%	47%	38%	36%	4%	0%	6%	4%	10%	16%
Geothermal	0%	0%	0%	0%	0%	0%	0%	9%	9%	9%
Renewables & other	4%	7%	17%	17%	14%	13%	12%	11%	11%	10%
Transmission losses	4.8%	4.6%	4.4%	4.2%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Export sales (GWh)	37	39	41	43	46	49	51	54	57	60
Bulk supply to Umeme (GWh)	1,773	1,820	1,913	1,995	2,199	2,287	2,478	2,682	2,901	3,132
Distribution losses	0	0	0	0	0	0	0	0	0	0
Billed Uganda sales (GWh)	1,179	1,255	1,388	1,521	1,707	1,874	2,026	2,187	2,361	2,546
Uganda sales growth	0	0	0	0	0	0	0	0	0	0
Billed as % of units sent out to Uganda	64%	67%	71%	75%	75%	79%	79%	79%	79%	79%
Uganda sales collected as % of sent out	55%	59%	65%	69%	70%	74%	75%	75%	75%	75%
Ave. number of customers ('000)	304	316	328	340	359	384	409	434	459	484
Ave. number of employees	1,445	1,486	1,503	1,542	1,596	1,652	1,706	1,743	1,764	1,785
Customers per employee	211	213	218	221	225	232	240	249	260	271
Total electricity revenue (USh billion)	374	398	440	482	541	682	737	796	898	1,011
Uganda electricity revenue (USh billion)	370	393	435	477	535	676	730	789	890	1,002
Uganda electricity revenue (US$ million)	199	209	227	244	269	332	353	373	413	457
Uganda VAT revenue to GoU (US$ million)	36	38	41	44	48	60	63	67	74	82
Ave. Uganda electricity revenue (USh/kWh)	313	313	313	313	313	360	360	360	377	394
Ave. Uganda electricity revenue (US$/kWh)	0.168	0.167	0.163	0.160	0.157	0.177	0.174	0.171	0.175	0.179
Ave. operating income (USh/kWh)	9	40	59	54	37	45	41	50	55	59
Ave. operating income (US$/kWh)	0.005	0.021	0.031	0.028	0.018	0.022	0.020	0.024	0.025	0.027
Return on fixed assets	1.2%	5.2%	8.4%	8.4%	6.0%	7.5%	7.2%	8.9%	10.1%	11.9%
Debt service coverage	1.2	2.1	2.7	2.9	3.0	2.2	2.3	2.1	1.9	2.2
Current ratio	1.8	1.7	1.6	1.6	1.5	1.4	1.4	1.4	1.4	1.3
Debt/equity ratio	39%	40%	41%	44%	45%	46%	47%	46%	48%	47%

114. **Government Support to Power Utilities.** Total Government support to the power sector over the period 2005-2011 is estimated at US$734 million. The composition of this support is shown in Table 9 below and in more detail in Annex 12.

Table 9: Government Support to Power Sector per Calendar Year 2005-2011 (in US$ millions)[13]

	2005	2006	2007	2008	2009	2010	2011	2005-11
Government subsidies								
1) Deferred debt service	0	6	17	17	17	17	0	73
2) Direct support	17	62	49	49	15	34	0	226
Total budget support	17	67	66	66	32	50	0	299
3) IDA support								
Capacity charges	0	0	5	12	12	12	2	42
Fuel	0	0	35	62	55	13	0	164
Total IDA support for operational costs	0	0	39	74	66	25	2	207
4) IDA & SIDA support for DSM & technical studies	0	0	3	6	7	3	1	19
Total Government support	17	67	108	145	105	78	3	524
Deferred debt service repaid in year	0	0	0	-9	-25	-21	-12	-67
RAP (Resettlement Action Plan) to be funded by GoU	0	1	2	12	5	0	3	23
Import duty exemtions:								
Generation fuel	10	27	59	54	41	40	5	235
Transmission investments realting to transmission investments	0	0	1	1	4	4	8	19
Total Support to Power Utilities	**27**	**96**	**170**	**204**	**130**	**101**	**6**	**734**

115. **Revenues Accruing to the Government.** The revenues accruing to the Government over 2005-11 are estimated at US$439 million, and a further US$597 million during 2012-16. This compares to total Government support to the power sector of US$734 million until 2011, and US$85 million during 2012-16. Over the entire period, 2005-16, the Government stands to collect net revenues of US$217 million. The power sector will be a drain on the Treasury until the proposed project is commissioned, but a net contributor thereafter.

D. TECHNICAL

116. The proposed project was reviewed by the lenders' Independent Engineer (Colenco Power Engineering, Switzerland), during project preparation to identify any issues that merited scrutiny during the implementation and operational phases. The review consisted of an overview of project documents and presentations by the EPC contractor, the sponsors and BEL's Owner Engineer (Montgomery Watson Harza, USA). The findings of the lenders' Independent Engineer are that the proposed project is technically well conceived and the sponsors and the EPC contractor are capable of completing the works. The technology used is known and proven, the overall design of the works is consistent with prevailing industry practice, and there are no significant technical issues identified that would undermine the project's viability. The project design addresses geologic risks, which could affect the construction schedule and cost. Hydrologic risks to the lenders are mitigated through the structure of the PPA, under which this risk is borne by UETCL and, ultimately, by the Government. The important technical aspects of the proposed project are discussed below.

117. **Geology.** Geo-technical investigations at the project site have been comprehensive and provide adequate information to understand the geologic conditions prevailing at the site and the principal factors most influencing construction costs and risk. Over twenty-six boreholes (totaling 900 meters), seventy-eight test pits, ten seismic refraction profiles and laboratory testing conclude that the site is appropriate for the construction of a dam. The risk of significant leakage from the

[13] Note that this table shows expenses per calendar year starting in 2005. Government's fiscal year is from July 1 – June 30.

reservoir is minimal. Reservoir slope stability is considered appropriate. Sources of suitable construction materials have been identified in sufficient quantities for construction of the proposed civil works. Seismicity criteria for the design of the proposed project have been established and considered appropriate. Values for Maximum Design Earthquake and Operating Basis Earthquake are included in the technical specifications of the EPC contract. These values will be used in the detailed design of the dam and other major structures.

118. **Hydrology.** The planning of the proposed Private Power Generation (Bujagali) Project and the assessment of the energy output have been based on the flow released from Lake Victoria through the Nalubaale/Kiira dam complex in accordance with the Agreed Curve (Annex 10). The Agreed Curve is the relationship between the release of water from Lake Victoria (at the Nalubaale/Kiira dam complex) and the water level of Lake Victoria. The Agreed Curve replicates the "rating curve" that used to be imposed by the situation of the Lake Victoria outlet before construction of the Nalubaale dam in the 1950s. Since then, the Agreed Curve has been used as the operating reference for discharges from the Nalubaale dam (and Kiira, once it was commissioned). The Agreed Curve, therefore, constitutes a "moving reference": in dry periods, the net inflow is steadily lower than the long term average and the opposite is true for wet periods. The proposed project is designed to be viable with water flows in accordance with the Agreed Curve release rule, since the Nalubaale/Kiira dam complex regulates the flow of water from Lake Victoria.

119. The hydrology of the Victoria Nile is complex due to the nature of the meteorological influences, the rainfall-runoff process, the scale of the evaporation losses, and the interaction between rainfall and evaporation within the watershed. The available reservoir inflow record comprises 106 years of data. The record includes several significant hydrological cycles with the seasonal and ten year cycles being most apparent. Given the length of the hydrological record at this site, hydrological risk for energy generation is considered to be definable from the available data set.

120. The long-term flow of the White Nile upstream from the Kiira dam has been extensively studied by Acres International (Canada) in 1990, the Institute of Hydrology (United Kingdom) in 1993, Electricité de France (France) in 1998, and Knight Piesold (United Kingdom) in 1999. More recently, the Power Planning Associates (United Kingdom) report dated February 2007, prepared in association with Coyne et Bellier (France) and ECON (Norway), has reviewed the hydrology of the White Nile. Except for the studies carried out by Acres International, all other studies present the lake level rise in the early 1960's as a consequence of the natural hydrologic regime of the lake, and the unusual aspect might only be the occurrence of several wet years in sequence.

121. Based on the historical record of the hydrological system, there are possibilities of long-term hydrological cycles that will cause significant changes in the available flow over ten-year cycles. The Lake Victoria levels, and thus the flow in the Nile River, will also continue to fluctuate seasonally as experienced in the past. Future high flow sequences are also possible along with the prospects of long low flow periods.

122. An analysis of Lake Victoria water levels during the 2003/05 period has concluded that the main origin of the drop in lake level during this timeframe is an exceptionally dry period, during which the mean net inflow was only 46% of the long term average net inflow, and only 60% of the mean net inflow of the low hydrology scenario (Annex 10). The consequence of this low inflow, combined with the over-release of water for power generation, exacerbated the reduction in the Lake Victoria water levels. Since the end of 2005, the Government has steadily decreased hydropower generation in an effort to return to the Agreed Curve operating regime. Water flows for power production are being scheduled is such a way that the return to the Agreed Curve is achieved as soon

as reasonably possible. This operation mode is being followed at a significant cost, associated with the running of available thermal generation.

123. Were the Bujagali dam currently in operation, the consequence of this exceptionally dry period, in terms of over-abstraction for power generation, could have been eliminated: the Bujagali site is located downstream of the existing Nalubaale and Kiira dam complex, and the same water release could have been used a second time at Bujagali and would have generated 1.2 times the power already generated by the turbines of Nalubaale/Kiira (the ratio is 1.2 due to the higher head available at Bujagali). Hence, with the joint operation of the existing hydropower and the proposed project, the generation of the same energy output currently generated by Nalubaale and Kiira would only require 45% of the current water release from Lake Victoria.

124. Planning and operation of hydro-based power systems is normally based on hydrological reliability of about 95% to 98%, depending on the nature of the economy served and the nature of the power system. In the case of Uganda, a 95% hydrological reliability is likely appropriate as Uganda is evolving to a higher standard of service. The 5% risk of experiencing some un-served energy will be mitigated by any system reserve capacity that is available: under the low hydrology scenario, the system reserve capability would be reduced before affecting the delivery of energy to customers.

125. **Hydrological Risks.** Hydrological risk in relation to the proposed project consists of possible variations in the long term flow of the Nile River. Based on available information, hydrologic risks due to long-term flow conditions appear to be well defined. The river is susceptible to some hydrological cycles, but these are included within the available record length of 106 years. The proposed project design has adopted a conservative approach for defining the firm energy capability of the proposed project based on the full hydrological record.

- *Changes in Seasonal Water Flows in any Given Year*: Seasonal variability at the project site is impacted by the size of the storage available in Lake Victoria. The lake regulates the seasonal inflow to permit a more uniform outflow than is normally available for power generation; and

- *Flood Risks During Construction and in the Operational Phase*: Flood risks are also consistent with industry design practice. The large lake storage mitigates these risks and provides a very long forecast of future high flows. Flood risks are believed to be well defined and acceptable for the project.

126. Under the PPA, given the nature of hydrologic risks (i.e., long-term variations and seasonal variations), the risk is borne by UETCL and, ultimately, the Government, since project capacity payments are based on the project available capacity.

127. **Dam Safety.** Dam safety concerns are an integral part of the World Bank Group's review of any hydropower development. Dam safety analyses are normally conducted as part of feasibility studies and later as part of detailed design. For large dams, a Panel of Experts is required to advise on the dam's design, construction, and operation. Periodic monitoring of dam operation, including safety, is normally conducted by independent specialists. This work is conducted separately from a project's social and environmental studies, and any recommendations are reflected in the project's social and environmental assessment.

128. The existing Nalubaale dam and powerhouse were constructed in the 1950's. Unexpected and significant deterioration subsequently occurred due to the effect of the alkali-silica reaction between the aggregates and the cement in the concrete. The Government engaged consultants to

review the safety of the dam structure (i.e., a post-construction audit) and to devise a plan and strategy for remedial works to correct deficiencies. These remedial works were concluded under the oversight of an international expert panel.

129. At the time of the appraisal of the former Bujagali project, the lenders' Independent Engineer (Harza Engineering, USA) reviewed the reports of the panel of experts for the remedial works of Nalubaale and concluded in its April 2001 report that the structures do not pose an unusual risk to the Bujagali project. The Dam Safety Panel at the time advised on the need to continue regular monitoring and dam safety reviews of Nalubaale in a manner consistent with good international practice. The Dam Safety Panel appointed by the previous sponsor conducted an independent review of Nalubaale remedial works and concluded that the remedial and strengthening works for the Nalubaale dam were satisfactory, since they increased the factor of safety to comply with current standards. The current lenders' Independent Engineer (Colenco Power Engineering, Switzerland) has endorsed the above recommendations of Harza Engineering in regards to Nalubaale.

130. As part of the studies and analysis done for the implementation of the remedial works of Nalubaale, Gibb (United Kingdom) presented an Emergency Preparedness Plan (November 2000). The Inspection Panel Report of May 23, 2002 found Management in compliance with OP 4.37. Monitoring of the Nalubaale structures is being addressed under the Power IV Project (Credit 3565-UG). According to the latest Annual Inspection Report, prepared by Lahmeyer International (Germany), there is no present risk in the condition and stability of the main dam, though it pointed to structural problems of the powerhouse and intake structures which are being addressed by Eskom Uganda (the current private concessionaire of the Nalubaale and Kiira dam complex). Currently, the intake of Unit No. 8 is undergoing repairs.

131. The design of the proposed Bujagali dam has been reviewed by the technical advisors of the Government, the current Owner's Engineer (Montgomery Watson Harza) and Colenco Power Engineering. The preliminary dam design, including the selection of the project site, seismic design requirements, the general arrangement of the site, the location of the main structures, and the scheme for diversion of the river during construction, is considered appropriate for the site and its construction feasible without undue difficulties. This review has also included the evaluation of flood risks and their incorporation in the design of Bujagali and is considered to be consistent with industry design practice.

132. **Dam Safety Panel.** The World Bank's Operational Policy 4.37 requires a Dam Safety Panel to be appointed to review and advise BEL on matters relative to dam design and safety as part of the implementation of any dam greater than 15 m in height. A Dam Safety Panel, with terms of reference and staffing acceptable to the World Bank Group, has been established. The safety issues posed by the Nalubaale dam and its impact on the proposed project, as well as an extensive review of all technical matters, will be undertaken by the panel. This panel will also provide advice through final design, construction, initial filling, and start-up of the dam, including any design or operational precautions to ensure that the project, consistent with OP 4.01, Environmental Assessment and OP 4.04, Natural Habitats and OP 4.37.

133. **Construction Schedule.** The construction program establishes a guaranteed final unit performance acceptance date for the fifth 50 MW unit, 44 months from the date of issuance by BEL of the notice to proceed to the EPC contractor.

134. The construction of the Bujagali dam is on the critical path. The EPC contractor has built several dams and has experience in construction and transportation conditions in East Africa. Also,

Sithe Global is a well known name in the power generation industry and its management has proven capable of developing large independent power projects worldwide. To complement its capabilities and experience, BEL has retained Montgomery Watson Harza (US) to act as the Owner's Engineer. Montgomery Watson Harza has significant global experience in the development of hydropower projects as well as in Africa.

135. The construction schedule will be monitored by BEL and the lenders in order to identify any situations that might result in deviation from the scheduled completion date for the project. The EPC contract imposes penalties for late completion of the project and the contractor has accepted the milestone completion dates and the project schedule, together with associated penalties. Also, timely construction of the associated Interconnection Project does not present any significant issues. These facilities are part of a separate EPC scope of work, to be financed by ADB, and their completion schedule is not expected to represent a significant risk to the project.

E. FIDUCIARY

136. The World Bank Group has reviewed the selection process for the sponsor and the procurement process for the EPC contractor and established that the process was in accordance with World Bank Group guidelines. The overall financial management of the proposed project would be undertaken by a private entity according to commercial practices acceptable to the lenders. BEL has put in place an acceptable governance framework for its operations and for the EPC contractors (see Annex 8).

137. The IDA PRG is providing a guarantee to the commercial lenders. As such, there are no fiduciary issues as there will be no procurement or procurement-related disbursements under the proposed project. Should the IDA PRG be called, IDA would disburse to the beneficiary and the Government would then be obligated to repay IDA in accordance with the terms of the Indemnity Agreement between the Government of Uganda and IDA.

F. SOCIAL

138. The social and environment assessments carried out in 1999/2000 as part of the previous effort to develop the project, and later reconfirmed in the social and environment assessment disclosed in December 2006 for the proposed project, identify five key social issues: (1) resettlement and income/asset displacement; (2) physical cultural resources and cultural issues; (3) community development and vulnerable groups; (4) employment; and (5) safety and health. During the time between when the previous sponsor abandoned the project in 2003 and the arrival of the new sponsors, continuity of consultations with project affected populations (PAPs) and villagers surrounding the hydropower site and the associated Interconnection Project was maintained by staff from UETCL, through its Bujagali Implementation Unit (BIU). A core group of qualified specialists from the BIU, many of whom had been with the project since the first social surveys were conducted in 1998/99, not only periodically informed villagers about the project's status, but also managed to strengthen relationships with affected groups through community development activities. The continuous consultations by the BIU have proven to be critical for strengthening villagers' trust, especially during the transition period with BEL, the current project sponsor. The BIU staff has also completed surveys of households affected by UETCL's associated Interconnection Project[14]. Under the new proposed project, the sponsors have re-established a more systematic documentation and

[14] The associated Interconnection Project directly affects approximately 1,900 households. Of these, 120 families will be physically resettled. The average land area lost per affected family along transmission lines and substations is 0.1 hectares.

consultation process, consistent with IFC's Performance Standard 1. The project sponsors have engaged a witness Non-Governmental Organization ("NGO"), InterAid Africa, to monitor the stakeholder engagement activities of the social and environmental consultants. InterAid was also involved in the previous effort to develop the Bujagali project as the witness NGO.

139. **Land Acquisition and Involuntary Resettlement (Operational Policy (OP)/Bank Procedures (BP) 4.12; IFC's Performance Standards (PS) 5; MIGA Involuntary Resettlement Policy)**. The previous project sponsor carried out physical resettlement and payment of compensation associated with the hydropower facility in 2001. These activities directly affected 1,288 households (or 5,158 people). Of these, 85 households were physically displaced (634 people) – 34 households opted to live in the Naminya resettlement site, while 51 chose to re-establish their physical households on their own using cash compensation. The remaining 1,203 families received cash compensation for lost land and crops. All households were to receive assistance in livelihood restoration. Physical resettlement and compensation were completed prior to the departure of the previous sponsor. In June, 2006 BEL completed a draft *Assessment of Past Resettlement Activities and Action Plan* (APRAP), which contained findings from a review of the quality of the resettlement and the current status of the families resettled as part of the previous effort to develop the project. Based on the findings of this report, BEL committed to completing the required provisions of the original resettlement and community development program. These commitments were included in the new *Social and Environmental Action Plan* (SEAP) of December 2006 for the proposed project.

140. The majority of economic and physically displaced households took the cash option that had to be offered under the Uganda Land Acquisition Act (1965) and the Land Act, Section 78 (1998). As has been the World Bank Group's experience with cash compensation generally, this option did not lead consistently to restored livelihoods. Although villagers were advised about using the money for relocation and livelihood restoration, some expenditures appear to be made for luxury goods and entertainment. To assist in income restoration, BEL has committed to several income generating programs, initially providing support for intensification of the agricultural economy, but also expanding into linkages programs for the project and fisheries development once the reservoir has been filled. BEL has also committed to improve such public services as village-managed water wells and health centers.

141. Tourism operators and workers will adjust to changes from the hydropower project by moving their businesses. Rafting companies will move their operations further down the river, including locating some of their facilities around the offset site at Kalagala Falls. Other tourism operators, such as small arts and crafts shops, restaurants, four wheeler rentals, and locally owned enterprises will also be able to move their businesses nearer to Kalagala Falls.

142. **Cultural Heritage (OP/BP4.11; PS 8; MIGA Physical Cultural Resources Policy) and Cultural Issues**. The previous project sponsor prepared a *Cultural Property Management Plan* that documented the surveys and studies of cultural issues. These included family graves and ancestral shrines (*amasabo*) and ceremonies associated with the spiritual importance of Bujagali Falls and beliefs (e.g., movement of spirits to alternative locations). BEL will complete all of these commitments, including a non-denominational service in remembrance of those buried in unmarked graves that will be inundated. BEL is having on-going consultations with local traditional authorities and has committed to measures to ensure that these issues are properly addressed prior to and during construction. BEL will also institute a Code of Practice on cultural issues, along with training for workers and contractors during the construction and operation phases. Archaeological surveys were also completed in Namizi, Kikubamutwe, and Malindi villages; the Buloba quarry site; the Kaybirwa landing site on the Nile River; Dumbbell Island; and areas surrounding Bujagali Falls. No

concentrations of cultural or archaeological resources requiring pre-construction conservation were found. BEL will ensure that the EPC contractor develops and implements a chance finds procedure.

143. **Community Development and Vulnerable Groups (PS 1).** The *Community Development Action Plan* (CDAP) focuses on "supporting communities' needs based on culturally appropriate means of consultations." This document contains provisions to address the measures required under the APRAP and to address impacts on the eight project affected communities, but also goes beyond these requirements to provide other benefits. According to the APRAP, US$497,000, will be needed to finance the programs needed to complete resettlement and income restoration. BEL is committed to providing US$2.4 million on community development over a five-year period following the start of construction. These commitments cover health care facilities; employment opportunities; water supply and sanitation; fisheries; education; small-scale tourism; training and financial services. Whenever needed, village-based NGOs will be used to ensure that community works will be sustainable. For example, village water committees are being formed, and villagers will be trained in operating and maintaining water pumps. To be sustainable, the operation and maintenance costs are shared by the villagers and district (local) governments. Similar committees will be set up for health, agriculture, etc. There is a separate program for women, including a facility for maternal and child care. Many of the village committees are chaired by women. A persistent concern raised in the consultations was lack of access to basic services and resources, including electricity. BEL is committed to a feasibility study on the commercial viability of providing the communities with electricity in order to facilitate the process vis-à-vis UMEME.

144. **Employment (PS 2).** Since the appraisal conducted as part of the previous effort to develop the project, communities have expressed the hope that the project will provide jobs. Economic displacement caused by the project is being addressed through the community development programs. Community expectations about employment at the construction site are high. As a general rule, BEL and the EPC contractor will give priority to hiring local people for dam, road, and other construction. Realistically, the construction will not be able to provide jobs to all who may seek them from the project affected communities. The employment figure is estimated to be between 600 and 1,500. BEL has estimated that 10% of these jobs will be unskilled and available for local villagers (i.e., between 60 and 150). These will not be enough to provide all project affected people with employment. BEL is identifying additional employment opportunities in addition to the income restoration programs of the CDAP. BEL is developing a tree planting program for both the borders of the reservoir and the river banks between the hydropower project and the Kalagala Falls, and this may be a major source of additional employment.

145. BEL is a special purpose corporation set up for this project. BEL is committed to ensuring that the EPC contractor has a human resource policy and a grievance mechanism as indicated in the SEA.

146. **Safety and Health Concerns (PS 4).** The SEAP for the proposed project includes mitigating measures for reducing negative safety and health consequences from the project. First, the EPC contractor may encourage workers to seek housing in near-by Jinja, which can accommodate families and thus avoid a major risk factor for HIV/AIDS among the local communities. Second, the Ugandan AIDS/HIV NGO TASO will assist the project in developing an education and health campaign to inform the local communities and workers about communicable diseases. Third, a construction traffic management plan will be developed, especially along the western side of the river where construction traffic will be the heaviest. Fourth, a Dam Safety Panel will assess the design and construction quality of the dam and its operations. Finally, an Emergency Preparedness and Response Plan will be developed and implemented for the project.

147. **Consultation and Project-Affected Community Support.** Public meetings, focus group discussions, surveys and participatory appraisals were conducted in six phases: initial consultations; public consultation and disclosure; report consultations; action plan consultations; consultation planning; and ongoing project consultations. InterAid Africa serves as the independent monitor for the consultations and participates in the project's grievance process. There is a high level of project awareness, including from disclosure of project documents. Facilitating village outreach are sub-county consultation committees. Consultation records show that women were represented in most of the meetings. IFC has determined that the project sponsors did conduct free, prior, and informed consultations. IFC has also verified, through its own investigations, broad support for the project in the project-affected communities.

G. ENVIRONMENT (ENVIRONMENTAL CATEGORY: A)

148. **Environmental Assessment (OP 4.01).** The Private Power Generation (Bujagali) Project is a Category A project in accordance with the World Bank's OP 4.01 (Environmental Assessment), IFC's Sustainability Policy, and MIGA's environmental assessment policy. BEL conducted full SEAs for its proposed hydropower project and for the associated Interconnection Project (on behalf of UETCL).

149. **Impact Assessment Process.** Because the Interconnection Project is not part of the proposed project but an associated facility, BEL's consultant, R.J. Burnside International Limited, prepared two separate SEA Reports, one for each project. Several significant project documents, in particular the Public Consultation and Disclosure Plans, the APRAPs – for the hydropower project and a substation near Kampala, the Resettlement and Community Development Action Plan (RCDAP) – for the Interconnection Project, and the CDAP – for the Hydropower Project, are appendices within these documents. The findings from the APRAP were incorporated into the new SEAPs, which were completed in December 2006. The documentation was designed to fulfill regulatory and procedural requirements of IFC/IDA/MIGA, the Government of Uganda, ADB, EIB, and DEG.

150. **Disclosure.** The proposed project SEA has been disclosed, together with that of the Interconnection Project, in InfoShop and in-country on December 21, 2006. Also, a Strategic/Sectoral Social and Environmental Assessment has recently been completed under the Nile Basin Initiative and has been disclosed on February 23, 2007, in the InfoShop and in-country.

151. **Complementary Studies.** In addition, IFC/IDA conducted separate, complementary studies. IFC commissioned the "Bujagali II - Economic and Financial Evaluation Study" (Power Planning Associates Ltd, UK, February 2007) to provide an extensive economic due diligence study of the proposed project. During the course of the study, three workshops with agencies and other stakeholders were held in Kampala. This study was publicly released on February 26, 2007. The analysis includes a detailed assessment of the probability of occurrence of different hydrological scenarios related to Lake Victoria based on 106 years of hydrological records. The study provides detailed analyses of various power generation alternatives including mini-hydro power, geothermal and bagasse. Taking into account the assessment of the alternative generation options and the project's own economics, the study confirms that the proposed project is the least cost option for meeting demand for electricity. A second study, Strategic/Sectoral, Social and Environmental Assessment (SSEA) of Power Development Options in the Nile Equatorial Lakes Region (Nile Basin Initiative, February 2007) was also recently undertaken to provide guidance on the power generation options available in the region, based on an assessment of the electricity demand, project costs, and environmental and social issues surrounding such projects, among other factors. Consultation with Ugandan and other riparian stakeholders was a key component of the SSEA.

152. **Analysis of Hydropower Alternatives.** Alternatives to the Bujagali hydropower facility were extensively assessed as part of the previous effort to develop the project. The earlier project was based on studies by Rust Kennedy and Donkin (1997), Electricité de France (1998), Energy Strategy Management Assistance Strategy for a Rural Electrification Strategy Study (1999) and the Assessment of Generation Alternatives (Acres International, 1999, as finalized in May 2000), all of which concluded that large-scale hydropower was the most viable alternative for electricity generation. These conclusions have been reconfirmed by the complementary studies conducted as part of the ongoing effort to develop project, such as the Power Planning Associates economic study and the SSEA study. Power Planning Associates' economic study for the project evaluated the previous alternatives analyses (see Annex 9) and concluded that "Bujagali and Karuma therefore appear to be the only major hydro power candidates that can be developed in the coming years to contribute to meeting the power demand in the country by mobilizing the renewable energy of the Nile." Power Planning Associates investigated the Bujagali and Karuma projects in more detail, using updated information, and concluded that Bujagali is the least cost project.

153. **Transmission System Alternatives.** As part of the previous effort to develop the project, the former sponsor and its consultants conducted an extensive study of four options to evacuate electricity from Bujagali. As part of BEL's planning, new interconnection analyses were completed to ensure that project development was proceeding with the optimal interconnection option (Siemens PTI, 2006). The new study confirmed the overall conclusions from the earlier project's study, although the planned alignment of the proposed transmission system (as part of the Interconnection Project) has been slightly modified from the earlier design and is the preferred option from a social standpoint.

154. **Cumulative Impacts.** As part of the previous effort to develop the project, studies conducted for the project sponsor and additional studies commissioned by IFC addressed cumulative impacts. The assessment of cumulative effects was undertaken again for this new project. The Bujagali project SEA and the SSEA, recently completed by the Nile Basin Initiative (see above) include cumulative impact assessments of Bujagali in Uganda. Socioeconomic impacts were found to be generally local in extent. The studies also concluded that no major negative environmental cumulative impacts would occur if the proposed project is not developed in conjunction with additional hydropower projects on the upper reach of the Nile (i.e., at Kalagala Falls). Therefore, the long term protection of the Kalagala Falls and the preclusion of development of hydropower potential at Kalagala is a necessary offset for World Bank Group participation in the proposed project.

155. **Natural Habitats (OP 4.04; PS 6; MIGA Natural Habitats Policy) and the Kalagala Offset Agreement.** The loss of Bujagali Falls and portions of the Jinja Wildlife Sanctuary resulting from reservoir inundation would be an irreversible impact to significant natural habitat. In circumstances such as these, OP 4.04 allows for an "offset," i.e., protection of an area that is ecologically similar to the area lost as a result of a project. Kalagala Falls, the site of a potential future hydropower project on the upper Nile River, was determined to be the appropriate offset candidate. On the basis of cumulative effects assessment conducted as part of the previous effort to develop the project and the offset provision in OP 4.04, IFC/IDA and the Government of Uganda on April 25, 2001 reached an agreement known as the "Proposed Bujagali Hydropower Project: World Bank Group's Requirement of an Offset at Kalagala Falls." The Government also provided an additional commitment, to be included as part of IDA's Indemnity Agreement together with a letter by the Government (dated June 4, 2002), confirming its intention to preserve Kalagala and identify sustainable investment programs to facilitate tourism, with appropriate mitigation measures. The Government had fulfilled all of its commitments required under the agreement as of the time that the

project development came to a halt in 2003. The Government has agreed with the World Bank Group to reiterate its previous commitment, as per the terms of its letter dated June 4, 2002.

156. **Forests (OP 4.36), Forestry Offset and other Transmission Line mitigative measures (PS 6).** The Interconnection Project will pass through three central forest reserves in Mabira, Kifu and Namyoya, with natural, but not critical, habitat. The land take in the Kifu and Namyoya central forest reserves will be minor, 3.7 and 6.7 hectares, respectively. Land take in the Mabira will be more substantial, with 70.4 hectares to be affected, of which 59.2 hectares is forested. To comply with OP 4.36 the SEA proposes a number of measures to be taken by UETCL in order to minimize the impact of the Interconnection Project, along with payments to the National Forestry Authority to be used for enrichment planting to offset the loss of forest. BEL will monitor progress on these measures and will collaborate, as necessary, to ensure their implementation. The Interconnection Project's transmission line will also pass through the Lubiji Swamp, near Kampala, in order to avoid a greater impact on human habitation. The tower construction is designed to minimize impact on the hydrology of the wetland, which does not contain any critical habitat. A total of 0.7 hectares will be needed.

157. **Natural Habitats (OP 4.04; MIGA Natural Habitats Policy), Nile River Islands and Jinja Animal Sanctuary (PS 6).** The permanent land take for the proposed hydropower plant will be 125 hectares, of which 80 hectares will be inundated. The land take and the inundation will not impact critical natural habitat. The land take will affect 28.6 hectares of land within the Jinja Wildlife Sanctuary, including 15.8 hectares of land on the islands in the river that have relatively intact native vegetation (out of a total of 26.8 hectares of total island land). This impact on the islands will be off-set by the planting of a 100 meter strip around the edge of the reservoir with native and medicinal trees. The impact on the Jinja Wildlife Sanctuary and the loss of Bujagali Falls will also be offset by the enhanced protection of the Kalagala Falls and Nile Bank Central Forest Reserves. BEL will have a role in the development of this offset as an ecotourism site, in collaboration with the National Forestry Authority.

158. **Safety of Dams (OP 4.37; PS 4; MIGA Dam Safety Policy).** The hydropower facility meets the policy criteria for a large dam; a Dam Safety Panel has been established in accordance with the IFC/IDA safeguard requirements on dam safety. The terms of reference and staffing of the three panel members were reviewed and approved by the World Bank Group. This panel will provide advice on the adequacy of spillway discharge capacity; adequacy of back-up power systems for the spillway and main power station; effects of blasting at Bujagali on the existing Nalubaale and Kiira dam structures; and the final design, construction, initial filling, and start up phases of the project.

159. **Projects on International Waters (OP 7.50; PS 1; MIGA Projects on International Waterways Policy).** The Nile River is an international waterway, and pollution and other project-related effects from Bujagali could potentially affect downstream riparians. As noted above, the project is not expected to cause this to occur. Moreover, the proposed project is not expected to affect upstream riparians that border Lake Victoria, as any effects on the lake are determined solely by the operation of Nalubaale and Kiira. The World Bank Group has considered the international aspects of the project and has assessed that the project will not cause appreciable harm to the other Riparian States, and will not be appreciably harmed by the other Riparian States' possible water use. In May 2006, the Ugandan Government requested that Egypt provide a reaffirmation of its no-objection (already delivered for the previous effort to develop the project) for the proposed project. Upon that request a written no-objection was issued by the Government of Egypt on May 15, 2006 to the Government. Notifications regarding the intended development of the project were issued by the Ugandan Government to other Nile riparian states in September 2006, followed by an addendum in

March 2007 reflecting the available public information on the project and providing a March 30, 2007 closing date for responses. No additional responses were received as of the closing date.

160. **Effects of Climate Change on the Long-Term Viability of the Proposed Project.** The SSEA undertook a thorough analysis of the possible climate change impacts on power development options in the Nile Equatorial Lakes Region, including Bujagali. The SSEA climate change analysis examined potential values for temperature and precipitation change, and then runoff, to provide corresponding estimates of changes in net water yield in Eastern Africa. It used the best available general circulation models to assess the potential changes in temperature and precipitation in 2050 and 2100 relative to 2000. Outputs from various climate models were examined to determine the degree to which models agree or disagree on the direction and magnitude of change in temperature and precipitation in the region. A total of 16 general circulation models were examined to select those that best simulate East African climate. Bujagali is included in the north and west central region of the study area – for the Nile, Ruzizi and Kagera Rivers. The results of the climate change analysis were that temperature is expected to increase with greenhouse gas emission increases, and an increase in precipitation is the expected result from an increase in temperature, which will also increase evaporation and evapotranspiration losses. Net runoff will increase with increase in greenhouse gas emission levels. Increased emission levels will result in increased seasonal variability in runoff, with wet seasons providing most of the increased runoff and dry periods being less affected. Overall, for the northern and central-west regions of the study area, including Bujagali, there is a high probability of increases in runoff, and thus power generation potential, compared to historic data. Staff believes that the SSEA incorporated the best currently available climate change science and data in its analysis.

161. **Mitigation Plans.** SEAPs have been prepared for both the proposed project and the Interconnection Project that identify the responsibilities, schedules and budgets of the social and environmental management measures to be implemented. BEL has ultimate responsibility for the proposed project, and will support UETCL by playing a management role in the design, procurement, and construction phases of the Interconnection Project. The proposed project and Interconnection Project will be constructed under separate turnkey EPC contracts. In order to deal with unforeseen or unexpected changes during implementation, a change management process has been devised to ensure continued attention to social and environmental issues. The SEAPs are umbrella plans, comprised of several component plans that will be integrated and implemented by BEL and the EPC contractor. Components of the SEAPs to be implemented by BEL include the Public Consultation and Disclosure Plan, Assessment of Past Resettlement Activities and Action Plan, Community Development Action Plan, Labor Force Management Plan, Emergency Response and Preparedness Plan, and Environmental Mitigation and Monitoring Plan. Components of the SEAPs to be prepared by each EPC contractor include the Traffic/Access Management Plan, Waste Management Plan, Pollutant Spill Contingency Plan, Labor Force Management Plan, Hazardous Materials Management Program, Health and Safety Management Plan, and Environmental Mitigation and Monitoring Plan.

162. **Monitoring.** During construction, BEL will have the ultimate responsibility to ensure environmental monitoring and reporting procedures are being undertaken. The project's EPC contractors will also designate appropriately experienced and qualified Site Environmental Officers. These Site Environmental Officers will have overall responsibility for the activities of the contractor's environmental departments. BEL and the World Bank Group will agree on a suitable arrangement for independent review of monitoring information through construction and initial operations. BEL's Environmental Manager will develop environmental reports suitable for submission to the National Environmental Management Agency (as a requirement of the Ugandan

Environmental Impact Assessment Regulations) and to other stakeholders, as appropriate, and will make these reports available in its local offices as well as on its website (www.bujagali-energy.com).

H. SAFEGUARD POLICIES

Safeguard Policies Triggered by the Project	Yes	No
Environmental Assessment (OP/BP 4.01)	[X]	[ ]
Natural Habitats (OP/BP 4.04)	[X]	[ ]
Pest Management (OP 4.09)	[ ]	[X]
Physical Cultural Resources (OP/BP 4.11)	[X]	[ ]
Involuntary Resettlement (OP/BP 4.12)	[X]	[ ]
Indigenous Peoples (OP/BP 4.10)	[ ]	[X]
Forests (OP/BP 4.36)	[X]	[ ]
Safety of Dams (OP/BP 4.37)	[X]	[ ]
Projects in Disputed Areas (OP/BP 7.60)	[ ]	[X]
Projects on International Waterways (OP/BP 7.50)	[X]	[ ]

163. IFC has determined that the risks involved in this project should be addressed through adherence to Performance Standards 1, 2, 3, 4, 5, 6 and 8. For the purposes of Performance Standard 7: Indigenous People, neither the Buganda, on the western bank of the Nile, nor the Basoga, on the eastern bank, are considered indigenous people. MIGA Policies on Environmental Assessment and Disclosure have also been addressed. Risks and issues associated with this project are addressed through MIGA's (issue specific interim safeguard) Policies on Involuntary Resettlement, Physical Cultural Resources, Natural Habitats, Dam Safety, and Projects on International Waterways.

I. POLICY EXCEPTIONS AND READINESS

164. No exceptions to Bank policies, IFC Performance Standards, or MIGA policies are sought.

165. The EPC contract is expected to be signed in April 2007. Financial closure is currently scheduled for mid-2007. All other multilateral, bilateral and commercial banks financing the project are processing their respective approvals to meet this schedule.

Annex 1: Country and Sector Background

A. COUNTRY BACKGROUND

1. Uganda, with a per capita income in 2005 of about US$280, is one of the poorest countries in the world. Life expectancy is low (49 years at birth) while population growth, at 3.5% in 2005, is among of the highest in the world.

2. The Government has demonstrated a firm commitment to poverty reduction, as spelled out in its PEAP. The most current version aims at key strategic results in areas of increased GDP growth, reduced poverty and inequality, and improved human development. IDA's assistance to Uganda is aligned with the strategic direction given in the PEAP, and the UJAS, approved by IDA and other development partners in January 2006, provides the basis for their support of the PEAP's implementation.

3. IDA's and other Development Partners' contributions have brought the country closer to reaching the Millennium Development Goals of reduced HIV/AIDS prevalence, poverty reduction, and increased enrollment rates for primary schooling.

4. The Uganda country program was the first to utilize the Poverty Reduction Support Credits, which provide external finance to the budget to support the implementation of the reform agenda derived from the PEAP. Uganda was also the first to benefit from debt relief under the Heavily Indebted Poor Country Initiative, which resulted in cancellation of 100% of Uganda's IDA debt on July 1, 2006.

5. Uganda has experienced robust macro-economic performance in recent years, averaging 6.4% growth between 1990 and 2005. Strong macro-economic policies, a credible program to eradicate poverty and good financial discipline have led to falling poverty levels. Domestic inflation has been slightly above the 5% target for the third consecutive year due to inflationary pressures from weather, power shortages and energy price shocks. The Uganda Shilling (USh) depreciated by 4% against the US$ due to higher demand for foreign exchange to finance the import bill. Overall, due to good macroeconomic management, savings, exports, and foreign direct investment are increasing. The challenge for Uganda is now to deepen the reforms already underway and prevent their reversal.

B. SECTOR BACKGROUND

6. This section includes: (a) the key characteristics of the power sector; (b) a description of the Government's comprehensive power sector reform program; and (c) a description of ongoing and planned IDA-supported power sector operations (see Annex 12 on the power sector financial situation).

Key Characteristics the Power Sector

Hydrology, Supply and Demand

7. Uganda's main source of power is from the Nalubaale and Kiira 380 MW[1] dam complex, located at the mouth of Lake Victoria. Over the past several years, Lake Victoria water levels have dropped by 1.5 meters, and in October 2006 reached levels close to the historic low of March 1923.

[1] The current commissioned capacity of the dam complex is 300 MW. Two additional 40 MW units are scheduled for commissioning in April 2007.

However, by March 2007, the lake levels have recovered by about 0.7 meters. The low water levels have resulted in a decline in electricity output from the Nalubaale/Kiira dam complex from around 200 MW in April 2005, dropping gradually to reach 170 MW by January 2006, reducing further to 135 MW (equivalent to water discharges of $850m^3/s$) from February 2006 to August 20, 2006. Since then, the production has dropped to 120 MW (equivalent to water discharges of $750m^3/s$). In contrast, current system demand is about 380 MW at peak times and about 290 MW at base load, resulting in persistent and acute power shortages which are impacting growth.

8. The reasons for these power shortages are fourfold. First, there has been a significant delay in power infrastructure development, in particular, in completing the financing of the previous Bujagali project, which is the next least-cost generation increment. As part of the previous effort to develop the project, construction was scheduled to commence in early 2002 and the power station was to be commissioned by the end of 2005. Second, the low Lake Victoria water levels, caused both by the recent regional drought as well as water over-abstraction for hydropower generation, have resulted in significantly reduced power generation output at the Nalubaale/Kiira dam complex. In this regard, the Government has decreased hydropower production in an effort to return to the principles embodied in the Agreed Curve. A third contributor to current power shortages has been the high level of technical and non-technical losses of the distribution system, which are now being addressed by UMEME, the private sector concessionaire. Fourth, annual demand growth over the past several years increased by about 8%, placing additional pressure on the power system.

9. Lake Victoria is a shared transboundary resource of Kenya, Tanzania, and Uganda. Rwanda and Burundi are a part of the upper watershed that drains into Lake Victoria through the Kagera River. The lake is part of the Nile River Basin system shared by ten countries: Burundi, Democratic Republic of Congo, Egypt, Ethiopia, Eritrea, Kenya, Rwanda, Sudan, Tanzania, and Uganda. In addition to its environmental value, including biodiversity and the hydrological cycle, Lake Victoria supports a large fishing industry for export and local consumption, hydropower production, drinking and irrigation water, lake transport, and tourism. Because of low water levels, these benefits have been threatened by environmental degradation manifested in reduced fish stocks, the drying out of fish breeding areas and the loss of livelihood to many fishing communities; a decline of biodiversity; increased sedimentation and nutrient loads resulting in eutrophication; the drying out of wetlands and loss of littoral habitat; increased lake transportation costs, since ports and piers are left hanging on dry land, and water shortages for shoreline towns and farmers. Hence, the consequences of load shedding and depletion of Lake Victoria have been widespread, with macro, sectoral and environmental impacts affecting not only Uganda but the other Riparian States. Efforts to regulate and manage the activities threatening the lake are clearly insufficient at present, and widespread poverty in the basin exacerbates environmental stress. Even in its current perilous state, the lake is a valuable asset supporting the livelihoods of approximately three million people directly; and indirectly the entire population of the basin estimated recently at 30 million.

10. On July 26, 2006, the daily water outflow regime of the Nalubaale/Kiira dam complex was modified so as to optimize hydropower generation. Higher volumes of water are now discharged during the day and lower volumes at night, such that the total volume of water released during the 24 hour period is the same as if the release was at a constant pace (as was the case up to July 25, 2006). Hydropower output during the day and night is now at 145 MW and 79 MW respectively, rather than 120 MW continuous. The operating regime of the 2x50 MW short-term thermal plants is now also optimized during peak hours and during the day.

11. The power supply situation has slightly improved since the optimization of available generation capacity started in late July. However, the overall load shedding for the calendar year 2006 remained high, with 364 GWh of load shed in 2006. In fact, load shedding in 2006 increased by

over 370% compared to 2005 (98 GWh of load shed). Those numbers show the dramatic consequences of the overall capacity constraints in the system that the Government has now started to address.

12. The generation mix has changed from a predominantly hydro based system until mid-2005 to a hydro/thermal mix of 55/45 today and the share of thermal generation is expected to increase further when the additional 50 MW temporary thermal plant, to be financed under IDA's proposed Power Sector Development Operation, is commissioned later this year.

13. In spite of a very low electrification rate, the cost of load shedding to the economy is significant. The lack of reliable and available power supply and/or the need to run expensive back up generation has impacted on industrial production (many firms have limited back-up generation capacity). The cost of unserved energy has been estimated at US$38.9¢/kWh. Furthermore, the shortfall in generation has a knock-on effect on the rest of the power sector, since lower volumes in supply lead to lower retail electricity sales and revenues, which is affecting the viability of UMEME, the private distribution concessionaire.

Government's Interim Generation Plan (to Bujagali commissioning in early 2011)

14. The Government's interim generation expansion plan until the commissioning of the proposed project in early 2011 is summarized in the table below.

Table 1.1: Interim Generation Expansion Plan 2006 to early 2011

	Dependable Capacity (MW)	Fuel	Commissioning	Retirement
Thermal				
Aggreko I short-term (situated at Lugogo)	50	ADO	May 2005	Mar 2008[1]
Aggreko II short-term (situated at Kiira)	50	ADO	Oct 2006	Dec 2008
IDA financed plant (situated at Mutundwe)	50	ADO	Aug 2007	Feb 2011
Permanent (Heavy Fuel Oil (HFO))	50	HFO	Apr 2008	BOT
Mini-hydros				
Bugoye/Waki	19		Jan 2009	
Buseruka	9		Jan 2009	
Kikagati	10		July 2008	
Ishasha	5.5		Jan 2009	
Cogeneration				
Kakira Sugar	12		July2007	
Sugar Corp (SCOUL)	3		Jan 2009	

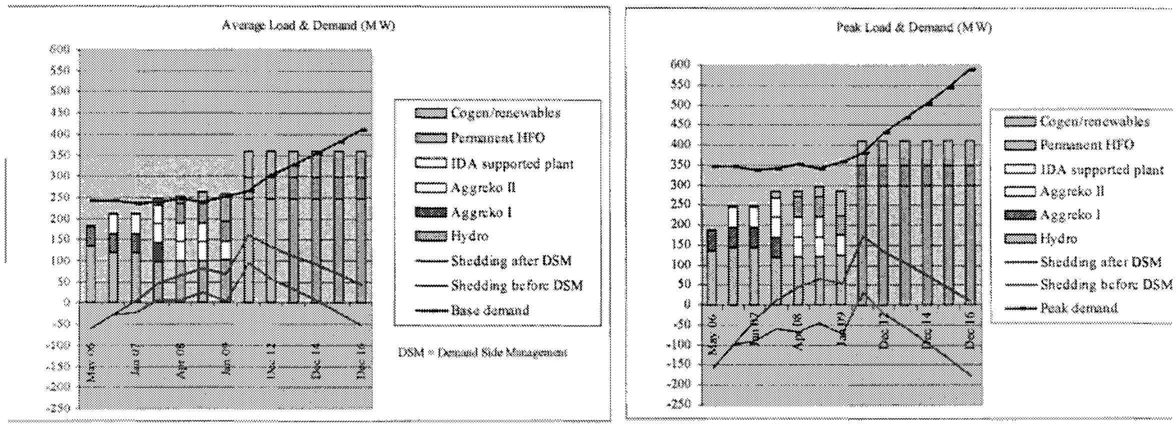
[1] Termination would coincide with the commissioning of the 50 MW permanent plant running on HFO.

15. Bids for the 50 MW short-term plant (to be operated on ADO) to be partly financed by IDA under this proposed Power Sector Development Operation are under evaluation. The Government is currently evaluating the procurement of a permanent 50 MW HFO plant on an IPP basis. In addition to procuring thermal capacity, the Government has reached final stage negotiations on a number of mini-hydro and co-generation schemes involving nearly 60 MW of capacity.

Peak and Base Load & Power Demand for Electricity

16. The charts below indicate the peak and base load and base case energy demand considering a number of thermal generation and demand side management and energy efficiency options. These graphs depict the generation expansion plan detailed above and also incorporate an estimated savings potential of about 50 MW through energy efficiency and demand side management initiatives.

Figure 1.1: Load & Demand 2006- 2016



Distribution Performance

17. The operational performance of UMEME has been satisfactory so far. UMEME's financial performance is also satisfactory, with healthy cash flows. The main features of its operational performance include:

- Distribution losses went down from 38% on takeover to around 34.1% as of December 2006.
- Overall collection rate went up from 80% on takeover to 92% by May 2006. Following the tariff increase of 37.5% in June 2006, the collection rate dropped to 85% from June to October 2006, and to 82% in November/December 2006, following another tariff increase of 41% in November 2006.
- A total of 36,000 new customers have been connected during the first twenty-two months of UMEME's operations to December 2006, against 22,000 committed under the concession. At present there are approximately 300,100 customers (270,000 domestic, 29,000 small commercial, 800 medium and large industry, and 300 street lights).
- During the first twenty-two months to December 31, 2006, UMEME invested USh24.7 billion (US$13.6 million) in the network and operational assets, and it paid USh2.5 billion (US$1.4 million) to the Government as reimbursement of costs of arranging the concession. Under the concession, UMEME had committed to invest a minimum of US$5 million in the first eighteen months of the concession.

18. The Government and UMEME have agreed that as long as the power crisis persists and until UETCL's bulk supply tariff has stabilized (i.e., the bulk supply tariff does not increase by (a) 10% or more of the retail tariff within a twelve month period or (b) by 20% or more of the retail tariff within a thirty-six months period), actual losses minus 1% and the actual non-collection rate (of the last quarter preceding any tariff change) will be applied in UMEME's tariff determination. There is downside protection for UMEME, but the benefits accruing from lower losses will be shared between UMEME and UETCL (see Annex 12).

19. Box 2 summarizes the main characteristics and key factors affecting Uganda's power system:

Box 2: Uganda's Power System Characteristics

- Uganda's total energy consumption is around 5 million tons of oil equivalent, of which 90% is biomass-wood, charcoal and agricultural residues. Per capita energy consumption is about 0.2 tons of oil equivalent, which is one of the lowest in the world.
- Uganda has one main hydropower complex, located on the Nile River: Nalubaale (180 MW), completed in the early 1950s, and Kiira (200 MW), a dam and powerhouse facility located 0.8 km downstream.
- To address the current power shortages, the Government has procured two 50 MW short-term thermal power plants, and is planning to procure an additional 50 MW thermal power plant under the proposed Power Sector Development Operation (FY07). An IPP of 50 MW running on HFO is also being procured. Thermal power generation represented 23% of total generation output in 2006.
- The power sector generated 1,887 GWh in 2005, which decreased to 1,610 GWh in 2006, due to the power crisis. Domestic electricity sales revenues were US$116 million in 2006.
- Uganda has the 23rd highest retail petroleum prices in the world – about the fifth highest in Africa. The average proportion of Ugandan transport costs attributed to fuel charges is estimated at about 50% (compared to an average of 30% for Africa).
- There were about 300,100 consumers connected to the national grid at the end of 2006. Efforts to expand rural access in areas far from the grid, as well as extending existing connections outside of UMEME's concession area, are being pursued under the Energy for Rural Transformation Project.

Key Factors Affecting the Power System

- A significant delay in power infrastructure development and, in particular, in completing the financing of the previous Bujagali project, which is the next least-cost generation increment. As part of the previous effort to develop the project, construction was scheduled to commence in early 2002 and the power station was to be commissioned by the end of 2005;
- The low Lake Victoria water levels, caused both by the recent regional drought as well as water over-abstraction for hydropower generation, have resulted in significantly reduced power generation output at the Nalubaale/Kiira dam complex (currently only 120 MW of the 300 MW installed capacity can be used);
- The high level of technical losses of the distribution system;
- Annual demand growth which has increased by about 8%; and
- Low access rate to electricity of approximately 5%.

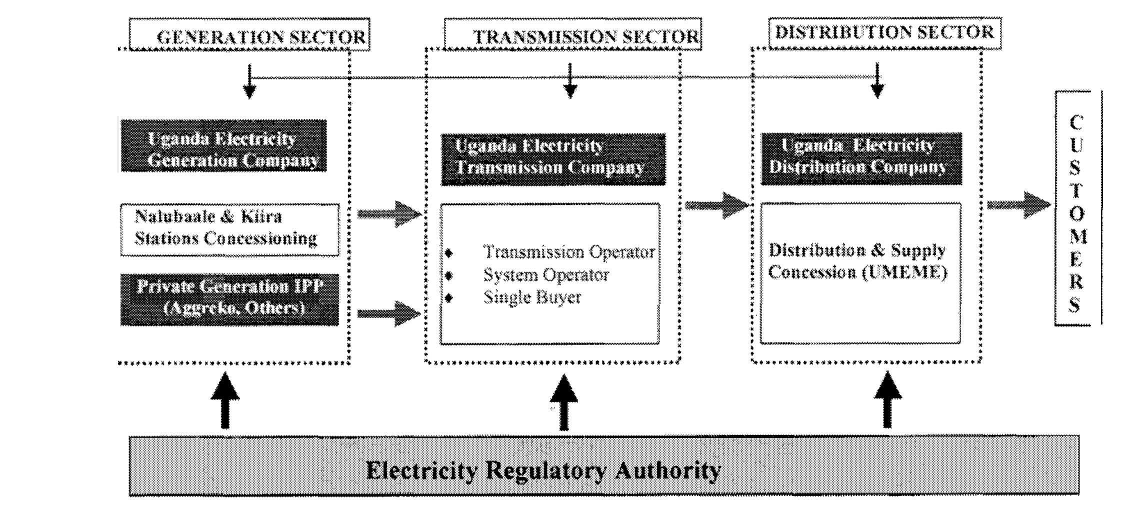
Government's Comprehensive Power Sector Reform Program

20. In June 1999, the Government approved a comprehensive power sector reform strategy that focused on improving efficiency through private participation in the sector. In November 1999, the Parliament passed a new Electricity Act, which provided the legal and administrative framework for reform and removed the legal monopoly of the Uganda Electricity Board (UEB). In April 2000, the Government created the ERA as an independent regulator. On March 31, 2001, the Government unbundled UEB into three separate corporate entities, one each for generation (the Uganda Electricity Generation Company Ltd. – UEGCL), transmission (the Uganda Electricity Transmission Company Ltd. - UETCL) and distribution/supply (the Uganda Electricity Distribution Company Ltd. - UEDCL). Subsequent to the unbundling of UEB, the private sector was granted separate concessions for the management of UEGCL's and UEDCL's assets and UEB was dissolved in early 2006.

21. **Concession of Power Generation Assets (April 2003).** In April 2003, Eskom Uganda (a subsidiary of Eskom Enterprises (Pty) Ltd, the state-owned utility of South Africa) was awarded a 20 year concession for the management of UEGCL's assets, which consisted of the Nalubaale and Kiira hydropower plants. UEGCL's function has since been limited to monitoring the activities of Eskom Uganda. UEGCL has a staff of eleven people and its administration costs are recovered through a concession fee charged to Eskom Uganda, which in turn, recovers its cost through its charges to UETCL for the sale of power. Eskom Uganda's charges to UETCL cover depreciation of capital, the concessionaire's return, annual operation and maintenance costs, and regulatory fees.

22. **Concession of Distribution Assets (March 2005).** The Government conducted an international competitive bidding process and awarded a 20-year concession for UEDCL's distribution assets to Umeme Ltd. (UMEME), a private company established in Uganda in which Globeleq Ltd. of Bermuda (Globeleq) and Eskom[2] had a 56% and 44% ownership, respectively. Globeleq is a wholly-owned subsidiary of Globeleq Ltd., (UK) which, in turn, is a wholly-owned subsidiary of Commonwealth Development Corporation of the UK. UMEME is the first unbundled electricity distribution network in Sub-Saharan Africa to be concessioned to the private sector. From the time of the handover of operations of the distribution network, UEDCL's function has been to monitor the activities of UMEME. UEDCL has staff of fourteen people and its administration costs are recovered through a lease payment charged to UMEME, which UMEME recovers through the electricity retail tariff. The figure below illustrates the current industry structure.

Figure 1.2: Current Structure of Uganda's Power Sector



Electricity Sector Regulatory Framework

23. The Ministry of Energy and Mineral development (MEMD) oversees Uganda's power sector. Its key functions include to: (a) provide policy guidance in the development and exploitation of Uganda's energy and mineral resources; (b) acquire, process and interpret technical data in order to establish the energy and mineral resource potential of the country; (c) create an enabling environment in order to attract investment in the development, provision and utilization of energy and mineral resources; and (d) inspect, regulate, monitor and evaluate activities of private companies in the energy

[2] Globeleq purchased ESKOM's shares in UMEME in November 2006.

and mineral sectors so that the resources are developed, exploited and used on a rational and sustainable basis.

24. With the approval of the Electricity Act (1999), the legal and administrative framework for the electricity sector was created to regulate the generation, transmission, distribution, sale, export and import of electricity in Uganda. Some of the key elements of the Electricity Act are:

- Establishment of the ERA as an independent body, specifying its structure, appointment of its members, functions, power and administrative duties;
- Creation of an application and implementation procedure for new projects, which is to be conducted in an open and public manner, and which allows for both unsolicited proposals to be presented to the ERA and for the ERA to invite applications for a particular license;
- Access to the transmission system to all licensees on a non-discriminatory basis, upon payment of the relevant fees and charges as approved by the ERA;
- Universal access to the distribution network to all existing and potential users, upon payment of the relevant fees and charges as approved by the ERA, subject to technical constraints;
- Creation of dispute mechanisms; and
- Commitment by the Government to promote and support rural electrification programs, including through the creation of a rural electrification fund, which has been established and is managed by the MEMD.

The Electricity Regulatory Authority (ERA)

25. The ERA commenced its functions in April 2000. The ERA is composed of five members (including a Chief Executive Officer) appointed by the MEMD, with the approval of the Cabinet. ERA members are appointed for 5-year terms and can hold a maximum of two terms. ERA has a total of twenty five permanent staff, including fifteen professionals.

26. The ERA key functions and responsibilities include the following:

- Issue licenses for generation, transmission, distribution and sale of electricity; licenses shall remain in force for a maximum period of 40 years and cannot be transferred without the written consent of the ERA;
- Ensure compliance with the licenses issued and the Electricity Act and, in doing so, protect the interest of consumers in respect of electricity tariffs, and quality, efficiency, continuity and reliability of electricity supply;
- Establish the sector tariff structure, approve electricity tariffs, and investigate tariff charges. The methodology for tariff calculation (which should be determined so that it covers all reasonable costs and provides a reasonable rate of return) must be approved by ERA and stated in the license;
- Develop and enforce performance standards for the electricity sector;
- Provide the procedure for investment programs by the transmission and distribution

companies;

- Appoint the system operator, which must be also a transmission licensee (currently UETCL); and

- Designate a bulk supplier, responsible for the transmission and sale of electricity in bulk to distribution and sales companies (currently UETCL), under the terms specified in the license issued by the ERA.

27. Although the Electricity Act allows direct funding for ERA from the Government and Parliament, ERA has not received any direct government financing nor does it rely on borrowings. Its primary funding (around 70% of its revenues) is through annual license fees, followed by permit fees and funds from development partners, such as IDA and Nordic Development Agency.

28. The ERA has played an important role in the oversight of the power utilities operating in Uganda. It has regulated electricity tariffs effectively since 2001. Since early 2005, the power crisis brought about by dry hydrological conditions in the region has created significant challenges for the Government, the ERA and the power utilities. The ERA has implemented substantial tariff increases in recent months; 37.5% in June 2006 and 41% in November 2006, in order to ensure the financial viability of the power sector. The power utilities now operate at arm's length. UMEME has achieved satisfactory operational improvements, although some of the efficiency gains have been reversed to some extent following the large increases in tariffs.

The Rural Electrification Agency

29. The Rural Electricity Agency was established in 2003 by the MEMD as a semi-autonomous agency. The Rural Electrification Agency is mandated to facilitate the Government's goal of achieving a rural electrification rate of at least 10% by the year 2012 from 1% at the beginning of this decade. The Rural Electrification Agency derives its revenues from a 5% levy applied on UETCL's bulk energy purchase costs. A Rural Electrification Fund was created to support the Rural Electrification Agency's activities. The Rural Electrification Fund was designed to partially subsidize initial capital costs and debt financing and provide financial incentives for private companies to bring electricity to unserved areas.

30. The Government's strategy in rural electrification is being supported by IDA through the implementation (in partnership with Global Environment Fund) of the Energy for Rural Transformation Program (Credit 3588-UG). One of the projects currently benefiting from this program's efforts is the West Nile Rural Electrification Company, a small off-grid project, which currently supplies electricity during 18 to 24 hours per day to around 1,500 rural clients in the West Nile area. The company is constructing a 3.5 MW mini-hydro plant and is currently operating a 1.5 MW diesel power plant, benefiting from a US$7.5 million subsidy under the IDA financed Credit 3588-UG.

Ongoing and Planned IDA-supported Power Sector Operations.

31. IDA has been involved in the power sector in Uganda for over 20 years through development of several projects, beginning in 1980 with emergency repairs to the Owen Falls Dam – now called Nalubaale dam (financed by the United Kingdom), which, along with the Owen Falls Extension (now called Kiira) is a complex on the Nile River constructed and extended over a period of about 50 years. Other projects include the Power II Project in 1985 for the rehabilitation the Owen Falls (Nalubaale) Dam, Power III in 1991 for the construction of the Owen Falls Extension (Kiira), a Supplemental

Credit to Power III in 2000; the Power IV Project in 2001, which has financed Unit 4 and Unit 5 (each of 40 MW) at the Kiira powerhouse, and the Energy for Rural Transformation Project in 2001, which aims to expand rural access to electricity.

32. Ongoing power projects financed by IDA are described below (see Annex 2 for a complete list of donor supported projects in the Uganda power sector).

- *Power IV Project (Credit 3565-UG):* US$62 million IDA credit to commission additional capacity (80 MW) at Kiira; geothermal investigations (shallow drilling), and US$12 million for urgent distribution investments, petroleum reform and capacity building.

- *Energy for Rural Transformation Project (Credit 3588-UG):* US$46.5 million IDA credit which aims to establish the institutional and legal framework for rural electrification and a Rural Electrification Fund, to facilitate scale-up of rural access which would otherwise not be a commercial proposition. The project supports the development of small and medium-scale renewable energy options, including both grid-connected and off-grid mini and micro-hydropower, bagasse based cogeneration plants, and biomass gasification.

- *Privatization and Utility Sector Reform Project (Credit 3411-UG):* This project was amended to include a PRG guarantee mechanism to provide risk mitigation support to UMEME, Uganda's private distribution concessionaire. IDA is providing limited risk coverage (up to US$5.5 million) to backstop a Liquidity Facility that could be drawn upon in the event of non-payment by the Government of its electricity bills and because of failure of the ERA to approve tariff adjustments according to the pre-agreed tariff methodology set forth in UMEME's distribution and supply license. MIGA is as well involved in that project through a Guarantee that covers a substantial part of the concessionaire's investments.

33. Along with the proposed project, IDA is also preparing the Power Sector Development Operation (FY07), which provides budget support to Government and also supports the financing of one 50 MW temporary thermal plant, as described earlier. In addition to these two projects, IDA is also supporting a regional power interconnection with the East Africa Community, which would benefit all countries involved by diversifying supply, reducing investment costs, and increasing electricity supply.

34. Table 1.2 below describes the World Bank Group's role in the Ugandan Power Sector and the development of the proposed project.

Table 1.2: World Bank Group Role in the Ugandan Power Sector

Role and Expected Contribution	Description & Indicators	Indicator Timing
Support for infrastructure development and mobilization of private sector investments	The World Bank Group is supporting the financing of the Bujagali project, which will provide much needed cost effective generation capacity to Uganda. Such capacity addition is not only critical for the long-term sustainability of the sector and, ultimately, to the country's economic growth and macroeconomic stability, but also, the successful implementation of the proposed project will underpin Uganda's reforms of the power sector. In this respect, a successful outcome is expected to act as a catalyst for private investments in the power sector in particular, and in the country in general.	At commitment and during supervision.
	IDA and MIGA are supporting UMEME, respectively, through: (a) a PRG mechanism covering Government non-payment and regulatory	Ongoing

	risk under Credit 3411-UG; and (b) political risk insurance MIGA/R2004-0076 and MIGA/R2004-0059.	
Support to Government's Power Sector Reform	IDA has supported the Government's power sector reform effort through financing of technical assistance and advisory support. Uganda is (a) the first country in Sub-Saharan Africa to have unbundled its electricity sector and to have the generation and distribution sectors managed by the private sector, and (b) has established a regulator with a strong track-record. The development of the proposed Bujagali project is key to sustainable sector reform.	Ongoing
Development of the Bujagali project	IFC has taken a leading role among the lender group in (a) initiating and funding the project's economic analysis (funded through IFC's FMTAAS), (b) the selection of lenders' advisors, and (c) coordinating environmental and social issues. The World Bank Group is also collaborating on a proactive communication strategy with respect to the project, in consultation with the Government, sponsors and lenders.	During Appraisal, until commitment.
Structuring of the project financing	The World Bank Group is sharing its knowledge and experience in Uganda's power sector with the sponsors and other lenders, ensuring that the project is financeable and establishes a standard that can be replicated in other infrastructure investments in Sub-Saharan Africa.	During Appraisal, until commitment.
Mobilizing long term financing to better match the project's needs and minimize impact on project's tariffs	IFC, along with the other DFIs lending to the project, is providing fixed rate A and C Loans with a 16-year and 20-year door-to-door maturity, respectively, among the longest provided by IFC in Sub-Saharan Africa, thereby ensuring the project sustainability. The proposed IDA PRG has allowed BEL to mobilize funds from commercial lenders with a 16-year maturity, thereby matching the maturity of other DFIs.	At commitment and disbursement.
Attracting experienced developers as equity investors in Uganda's power sector	MIGA's political risk insurance, provided for the benefit of Sithe Global (one of the project sponsors), ensures the participation of an experienced power developer. Sithe Global's investment, together with that of IPS(K), is one of the largest equity investments committed by the private sector in an private power project in Sub-Saharan Africa.	At commitment and disbursement.
Implementation of environment and social policies acceptable to the World Bank Group.	The proposed project is required to comply with the World Bank Group's and MIGA's Safeguard Policies/IFC Performance Standards.	At appraisal and during supervision.

Annex 2: Major Related Projects Financed by the Bank and/or Other Agencies

Project	Entity	Sector Issue	OED Rating	IP	DO
Closed					
Power III	WB	The project builds upon the rehabilitation work begun under the Second Power Project, and expands Uganda's hydro-resources and its transmission and distribution system to provide least cost reliable electricity to a greater population. It also aimed to improve the power sector's efficiency, in particular the Uganda Electricity Board's financial situation, through policy reforms, institutional strengthening and establishment or realistic tariffs.	MU		
Power III Supplemental	WB	As above.	Not rated		
Public Utility Reform	WB	Improve the quality, coverage and economic efficiency of commercial and utility services, through privatization, private participation in infrastructure, and an improved regulatory framework.	Not yet available	S	S
Ongoing					
Energy for Rural Transformation	WB	Put in place a functioning conducive environment and related capacity for commercially oriented, sustainable service delivery of rural/renewable energy and Information & Communication Technologies.		S	S
Power IV	WB	(a) Improve power supply to meet demand by supporting critically needed investments in the sub-sector; and (b) Strengthen Borrower capacity to manage reform, privatization, and development in the power and the petroleum sub-sectors.		MS	MS

Annex 3: Results Framework and Monitoring

IDA Results Framework:

Project Development Objective	Project Outcome Indicators	Use of Project Outcome Information
To add least-cost power generation capacity that will eliminate power shortages.	• Power generated (GWh) from proposed generation capacity; Levelized cost per kWh.	Gauge impact of the project on the overall power supply situation, including reduction/elimination of load shedding.
Intermediate Outcomes	**Intermediate Milestone/Output Indicators**	**Use of Intermediate Outcome Monitoring**
Power plant is commissioned on time and within budget.	• Achievement of Financial Closure; • Plant construction progress; • Trial run results; and • Commissioning test results.	Gauge likelihood of achieving the Project Development Objectives, and make changes in project implementation strategy

IFC Results Framework and Arrangements for Results Monitoring (DOTS):

Key Impacts	Impact Indicators	Timing of Impact	To be Tracked in PSR
Financial	Project completion on time and budget	Q1 2011	Yes
Financial/Economic	Annual ROIC > WACC of 8.9% and Economic ROIC > 10%	From 2012	Yes
Economic	Annual GWh generated by project, benchmark being 1,165 GWh	From 2011	Yes
Economic	Elimination of load shedding after project commissioning (before next expected generation capacity addition)	2011-2013	Yes
Social	Implementation of the Community Development Action Plans for the proposed project	2007-11	No, tracked in ESRR
Environmental	Implementation of Environmental Management Plan for the dam and power house	2007-11	No, tracked in ESRR
Environmental	Implementation of Kalagala offset agreement	Life of Project	No, tracked in ESRR
Private sector development: demonstration effect	Additionally IPPs commissioned in the power sector in Uganda	Life of Project	Not applicable

Note: WACC = Weighted Average Cost of Capital
ROIC = Return on Invested Capital
ESRR = Environmental and Social Risk Rating

IDA Results Monitoring Arrangements

		Target Values						Data Collection and Reporting		
Project Outcome Indicators	**Baseline**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**Frequency and Reports**	**Data Collection Instruments**	**Responsibility for Data Collection**
Power generated (GWh) from power station	Annual range estimate at appraisal 1,165 GWh	Plant under construction	Plant under construction	Plant under construction	Plant under construction	1165 GWh	1165 GWh	Quarterly	BEL report	BEL
Levelized cost per kWh from power station	Estimated range at appraisal 5.7-9.7¢/kWh[1]	Plant under construction	Plant under construction	Plant under construction	Plant under construction	5.7-9.7 ¢/ kWh	5.7-9.7¢/ kWh	Quarterly	BEL report	BEL
Level of unmet demand (GWh unserved monthly)2	N/A	N/A	N/A	N/A	N/A	0 GWh	0 GWh			
Intermediate Outcome Indicators										
Achievement of Financial Closure	All lenders and borrowers have indicated intent	Financial closure and first disbursement achieved	N/A	N/A	N/A	N/A	N/A	Once	BEL report	BEL
Plant construction progress	Construction to be completed in 44 months from Financial Closure	Start of Construction	Cofferdam construction completed	Powerhouse second stage completed and start electro-mechanical installation	Trial and Pre-Commissioning of the power station	Power station commissioned	N/A	Quarterly	BEL report	BEL

[1] The levelized cost depends on hydrology.
[2] The plant is expected to eliminate load shedding assuming all existing and planned capacity are operating according to Base Case assumptions.

Annex 4: Detailed Project Description

GENERAL PROJECT DESCRIPTION

1. The proposed Private Power Generation (Bujagali) project site is located at Dumbbell Island, approximately 8 km downstream of Jinja and 8 km north of the in the existing Nalubaale and Kiira dams, which are located at the outlet of Lake Victoria. At Dumbbell Island, the river will be dammed by an approximately 30 meter high rock filled dam and associated spillway works. The dam will impound a small reservoir that extends 8 km upstream, to the Nalubaale dam. The reservoir will have a surface area of approximately 388 hectares (ha) at Full Supply Level, which is considered to be at elevation 1,111.5 meters (m) above mean sea level. The reservoir will provide live storage of 12.8 million m^3 of water. The total volume of water at the Full Supply Level will be 54.0 million m^3.

2. A powerhouse will be constructed at the dam housing 5 x 50 MW vertical-mounted Kaplan turbine generation units that together will provide a maximum generating capacity of 250 MW of electricity. A high voltage substation, to be known as the Bujagali Substation, will be located on the west bank of the Victoria Nile, adjacent to the dam and power house. This substation will be designed and constructed to allow operation at 220 kV, but will initially be operated at 132 kV. In the future, switching operation to 220 kV would require installation of new step-up transformers, 220 kV bus and associated circuit breakers and protective equipment and, possibly, minor on-site relocations of some of the power lines. BEL will build and operate this facility as part of the project. All power from the project destined for the national grid will flow through this substation.

3. Two hundred and thirty eight hectares of land has been obtained for the project. Eighty hectares will be newly inundated land, with the balance of the acquired land needed for the facilities listed above as well as for temporary facilities needed during construction. These temporary facilities include haul roads, coffer dams, laydown and storage areas, and quarries.

4. The evacuation of maximum electricity output from the plant would require 100 km of transmission lines, the construction of a new substation at Kawanda, and the extension of the Mutundwe substation (the Interconnection Project). It will be built as a separate project from the proposed generation facility and will be financed by ADB. The transmission line includes: (a) a 75 km 220kV transmission line, operating at 132kV, to convey the power generated at the power plant to a new substation located in Kawanda (on the outskirts of Kampala), (b) a 17 km 132 kV transmission line to connect the Kawanda substation to the existing Mutundwe substation, located in the southwest section of Kampala, (c) a 5 km 132 kV transmission line from the Bujagali switchyard to the existing 132 kV transmission line, currently connecting Nalubaale with the Tororo substation (in eastern Uganda), and (d) a 5 km 132 kV transmission line extending north from the Nalubaale dam to interconnect with the Bujagali switchyard.

5. Table 4.1 provides a summary of the characteristics of the proposed hydropower facility:

Table 4.1: Summary of Characteristics of the Bujagali Hydropower Facility

Description	Specification
Nile River existing surface area from C/L of dam to Nalubaale dam (ha)	308.0 hectares (ha)
Reservoir area (ha) after inundation (excluding islands)	387.7 ha
Storage flows (in hours)	2.75 hours at peak output
Live storage volume of impoundment	12.8 Mm^3 Live 54.0 Mm3 Gross
Impoundment filling time	7 to 10 days (estimate)
Impoundment flow rate (m3/s)	63 m^3/s - 90 m3/s
Energy production at peak output (hrs)	5 hrs (250 MW)
Retention time of water in impoundment	0.7 - 1.2 days
Length of shoreline	About 28.7 km at FSL and about 37.5 km at extreme drawdown
FSL	1111.5 m Above Mean Sea Level (AMSL)
Minimum Operating Level	1109.5 m AMSL
Energy water head (m)	19.7 m - 21.9 m
Firm Energy (GWh) Min and max flows (100 yr) 95% probability	923 GWhr/yr 493 m^3/s - 605 m3/s
Average Energy (GWh) Min and max flows (100 yr) 50% probability	1438 GWhr/yr 797 m^3/s - 937 m3/s
Hydrology long term mean outflow range m3/s	660 m^3/s - 1200 m3/s
Median flow rate (100 yr data)	870 m^3/s
Plant load factor	0.66 (based on Flow of 840 m3/s)
Land Take	
Total land take, permanent + temporary (ha)	238 ha
Reservoir Characteristics: Full Supply Level Maximum Flood Level Minimum Operating Level Gross Storage Live Storage Maximum Tailwater Level	1111.5 m AMSL 1112.0 m AMSL 1109.5 m AMSL 54.0 Mm^3 (El 1111.5 m AMSL) 12.8 Mm^3 (El 1108.0 m AMSL) 1092.5 m AMSL (4500 m^3/s)
Permanent land take, inundated (ha)Total Islands; Riverbank	80.0 ha 35.28 ha 44.72 ha
Temporary land take (ha) Total West bank; East bank	113.0 ha 106.1 ha 6.9 ha
Area of access roads both temp and permanent (ha)	6.9 ha Temporary on East Bank 1.1 ha Permanent on West Bank
Description	**Specification**
Reservoir Characteristics: Full Supply Level Maximum Flood Level Minimum Operating Level Gross Storage Live Storage Maximum Tailwater Level	 1111.5 m AMSL 1112.0 m AMSL 1109.5 m AMSL 54.0 Mm^3 (El 1111.5 m AMSL) 12.8 Mm^3 (El 1108.0 m AMSL) 1092.5 m AMSL (4500 m^3/s)
Intake: Type Sill Invert Level Trash Screen Size Intake Stoplogs Intake Gates	 Integral Intake and Power Station 1081.5 m 2 -9 m wide x 17 m high 2 - 9 m wide x 17 m high 5 - module stoplogs 2 – 9 m wide x 10 m high wheel gates

Power Station: Location Total Installed Capacity Number of Turbines and Type	 Surface type in left channel around Dumbbell Island 250 MW 5, Vertical Axis Kaplan
Maximum Discharge Draft Tube Gate Size Tailwater Level at Station Output (250 MW)	1375 m^3/s approx. 2 - each 9 m wide x 6 m high approx. 1089.5 m approx.
Turbines: Reservoir level 1111.5 m Output at 22.0 m gross head Discharge at 22.0 m gross head	 50 MW 275 m^3/s
Generators: Maximum Output Transformer Type	 62 MVA (Power factor 0.85 lagging to 0.95 leading) Oil immersed
Spillways: Maximum Discharge – Total for all Spillways Gated Spillway: Maximum Discharge Sill level/Clear Width/Height Number of Gates/Type	 4500m^3/s Flap Gate 300m^3/s Radial Gates 3000m^3/s Radial Gates 1081.5m AMSL/19m/10.5m Flap Gate. 1 Flap, 2 Radial
Size of gates Siphon spillway: Maximum Discharge Crest Level/Clear Waterway Length	Flap gate: 12m wide x 8m high approx. Radial gate: 9.5m wide x 10.5m high approx. 1,200 m^3/s 1111.5m AMSL/80m
Dam: Type Height (estimated maximum) Crest Level/Length Extreme Drawdown Level	Clay core rock fill dam 30m 1114.5 AMSL/560m approx. 1106.5m AMSL
Bujagali Substation Voltage Type	 132 kV (initial phase) Outdoor Open Terminal, Double Busbar, Single Circuit Braker

Hydropower Facility Location and Layout

6. The advantages of constructing a dam at the site, where Dumbbell Island splits the river into two channels, include: (a) the steep banks that limit flooding to a small area and provide for good abutments for the dam itself; and (b) the presence of Dumbbell Island facilitates the construction of cofferdams during river diversion, and thus enables a shorter construction period.

7. The permanent facilities include an intake structure, a power station, housing 5x50 MW turbine generator units, services bay and control building; main gated spillway west of Dumbbell Island and a siphon spillway to the east of Dumbbell Island; rockfill embankment, with a maximum height of 30 meters; and abutments. The power plant includes a high voltage electrical substation. Other on-site facilities are: workshop, stores, emergency power generation; water treatment plant; and access roads.

8. The layout comprises an embankment across the eastern channel at the downstream end of Dumbbell Island, with the powerhouse and spillway located in the western channel.

The river will be diverted through the eastern channel to allow construction of the concrete structures, and then re-diverted through the spillway to allow the main embankment to be completed. The total construction time will be in the order of 44 months.

Power House

9. The power station is designed to house the complete generation plant and all five units, and to carry out all operational and maintenance related activities. There will also be provision for access for the maintenance and repair of the hydroelectric plant, and all essential services and components that may require frequent attention. The services and unloading bay will provide sufficient space to permit the future laydown, disassembly and working space for the overhaul and refurbishment of one turbine and one generator at the same time and will allow for normal access and unloading space for the routine maintenance of the remaining units in service. The power house will be arranged on levels creating sufficient floor area to accommodate all necessary power house and auxiliary services, including cooling water systems, hydraulic pumping sets, oil purification systems, small power, lighting and ventilation equipment, drainage and dewatering equipment, compressed air systems and control and ancillary electrical equipment.

10. The generator transformers will each be located in a dedicated bay, suitably separated by blast walls and confined to prevent the spread of fire. Each transformer will be mounted within a concrete enclosure capable of containing the entire contents of the oil in each unit.

11. The standby diesel generating set will be housed in a separate building. All drains for the standby diesel generator house and for the areas around the daily and main diesel storage tanks will be valved and routed through suitably sized oil separation tanks. A control building will be provided as an integral part of the power house structure.

Power Station Intake Structure

12. The power intakes will be capable of operating over the full range of Head Pond levels and turbine discharges without hydraulic instability or vortex formation. Adequate submergence will be maintained to prevent air being drawn into the water flow or floating trash being drawn against the screens from the water surface. The power intakes will be designed to operate entirely separately so that any one unit may be shutdown and dewatered while the other units remain in operation. An access bridge will be provided across the intake structure. A grouting and drainage gallery will be located at the upstream toe of the intake structure to enable secondary remedial grouting without taking the structure out of service. Floating trash, water hyacinth and other forms of buoyant matter will be removed from the reservoir and prevented from reaching the power intake structure.

Spillways

13. The capacity of the spillway system will be at least 4,500 m^3/sec at freeboard conditions. The maximum permitted water level in the reservoir under any flood condition will be 1,112 m. The spillway will be dimensioned such that the reservoir water level can be drawn down and held at 1,106.5 m with a continuous discharge of 1,500 m^3/s from the Nalubaale/Kiira stations. To achieve this, a proportion of the flow may be discharged through no more than two turbines, although this will be subject to the operational requirements specified by the manufacturer of the turbines.

Dam Embankment

14. The dam across the Nile River has been designed with a crest elevation of 1,114.5 meters above mean sea level (AMSL), assuming a Maximum Flood Level of 1,112.0 m and a full supply level of 1,111.5 m. The latter elevation will allow for a maximum discharge of 4,500 m^3/s. The height of the dam will be approximately 30 m. Access to the crest of the dam will be provided from the west bank. A turning area will be provided on the east bank and the passage of vehicular or pedestrian traffic beyond the turning area will be prevented by an immovable barrier and security fencing. Suitable vehicle guardrails will also be provided on the dam crest and access roads. Instrument houses, gallery access points, electrical installations and all similar operational facilities will be fully secured against unauthorized access.

Tailrace and Downstream River Bed

15. The tailrace canalization will be excavated down to 1,070.5 meters above mean sea level at the outlet of the draft tubes. Further downstream, the rock will be excavated on a slope to 1,084.0 meters above mean sea level, approximately 70 m downstream of the draft tubes, and continue at this level as far as the location of the (temporary) cofferdam.

Abutments

16. Abutments for the dam are required on the left and right banks. Both abutments will be based on the same design as the dam.

Substation

17. A 132 kV outdoor substation will provide the means by which the power station relays its power to the Ugandan national grid. The substation will be located on the left (west) bank, adjacent to the powerhouse and immediately upstream of the main access road. The substation will be designed for operation at 220 kV, but will be equipped and operated initially at 132 kV. Future operation at 220 kV would require installation of suitable transformers, circuit breakers, and protective equipment. The layout and location of substations and substation buildings and environs will be selected to minimize their visual impact and to provide the most suitable orientation for the outgoing transmission lines.

Access Roads

18. A site access road will be constructed from the Jinja to Kayunga state highway to the area of the power station and to the west abutment of the dam. All roads will be constructed within the boundaries of the land already acquired for the project. Where possible, existing roads that have been constructed on the west bank, at the site, will be utilized, with upgrades to take place as necessary. During construction, the road will be surfaced with a natural gravel wearing-course suitable for the requirements of the construction traffic. On completion of construction activities the road base will be refurbished and a black top wearing-course will be added. A corridor of land with a minimum width of 30 m runs from the Jinja to Ivuanmba road to the east bank of the project area. This corridor may be used by the EPC contractor for access to the site during construction.

Impoundment Area

19. The full supply level of the reservoir impounded by the Bujagali embankment will be 1,111.5 meters AMSL, the level of the Nalubaale dam tail water. This arrangement will command a gross head of 22 m and a corresponding installed capacity of 250 MW. With this arrangement, Dumbbell Island, the rapids in the vicinity of the island, the rapids at Bujagali Falls, and most of the small islands upstream to the Nalubaale/Kiira dams will be inundated. The higher elevations of a number of the larger islands upstream of Dumbbell Island (namely those at Bujagali Falls) will be preserved within the reservoir. The pre-inundation area of the islands to be inundated total 48.34 ha. Of the 48.34 ha, 13.06 ha will not be flooded and will form smaller islands than exist at present. The area of inundation will largely be confined within the banks of the present Nile channel, and will amount to 388 ha, excluding islands. This represents an increase of 80 ha over the current 308 ha river surface area between the proposed Bujagali dam and the Nalubaale/Kiira dams. In addition to 35.28 ha of islands that will be inundated, 44.72 ha along the riverbank will be inundated. The impoundment will have a relatively small live storage volume of 12.8 million m^3. Gross storage volume will be 54.0 million m^3. The retention time of water in the impoundment will be limited to 0.5 to 0.7 days, largely depending on the operating arrangements for the conjunctive use of Nalubaale/Kiira dam complex and the Bujagali power stations.

Engineering, Procurement and Transportation

20. Although much of the materials for the civil engineering components of the hydropower facility will be produced on site, the mechanical and electrical components will be imported to Uganda from locations around the world. Equipment and materials, that will be procured from outside East Africa will be shipped to the port of Mombasa in Kenya. For equipment and materials other than 'abnormal loads' (50-250 tons) and a small amount of materials unsuitable for rail transport, transportation from Mombasa to Uganda will be by rail to a bonded warehouse in Jinja, a distance of approximately 900 km. There will also be a bonded warehouse within the fenced boundary at the Bujagali project site, which will accept goods delivered by road from outside Uganda. Distribution from Jinja to the Bujagali hydropower facility site will be solely by road.

Reservoir Filling

21. The reservoir will be filled in such a way that no more than 2.5% of the discharge downstream of the Nalubaale and Kiira dams is retained in the Bujagali reservoir resulting in a 97.5% residual flow. Although the reservoir could in theory be filled in approximately one day, the ongoing checks of dam and riverbank stability will mean that the reservoir is filled slowly, and in a staged manner. In practice, the discharge downstream of Bujagali at any one time is likely to be considerably more than the 97.5% residual flow described above. The short term changes in flow are expected to be within the normal daily variability in flows as a result of the operations at Nalubaale and Kiira.

Annex 5: Project Costs and Financing Plan

Table 5.1: Project Costs

Private Power Generation (Bujagali) Project Costs by Component	US$000	% of Total
Engineering Procurement Contract (civil works, electromechanical equipment and spares)	520,064	65.0
Government contributed assets	20,000	2.5
Project Development Costs	26,838	3.4
IDC[(1)] and financing fees	94,087	11.8
Contingencies and DSRA[(2)]	82,082	10.3
Initial Working Capital & Other Costs	55,509	7.0
Total Project Costs	**798,580**	**100.0**

(1) Interest During Construction; (2) Debt Service Reserve Account

1. The total project costs have been estimated at approximately US$798.6 million; certain project costs, such as the financing costs, remain under discussion.

2. The project costs breakdown is as follows:

- The bulk of the project cost is made of the construction cost (65.0%), which includes the cost of civil works, supply of electromechanical equipment and spares.

- Government contributed assets (2.5%) represents the contribution of the Government to the project in the form of land, acquired during the previous effort to develop the project, and intellectual property.

- Development costs amount to 3.4% of total project cost and corresponds principally to sponsors' corporate costs in developing the project, consultants and advisors.

- Interest During Construction and Financing fees amount to 11.8% of the project costs, and correspond to the interest costs incurred by the company during the construction period, which are capitalized, together with standard lenders' fees.

- The project contingencies and the Debt Service Reserve Account (DSRA) amount to 10.3% of project costs. Project contingencies have been estimated in order to address potential cost overruns and/or project delays. The DSRA has been dimensioned to cover six months of debt service.

- The Initial working capital and other costs represent 7.0% of the total project costs. The initial work capital has been estimated at approximately two months of revenues. Other costs include principally engineering, operation and construction management costs and the cost of preparing the project environmental and social assessment documentation.

3. The Government's equity participation in the project will not attract an equity return and, therefore, will not affect the project tariff, until the project debt has been fully repaid. At that point, the Government's equity contribution will earn a return comparable to that of the private sponsors.

Figure 5.1: Financing of the Project

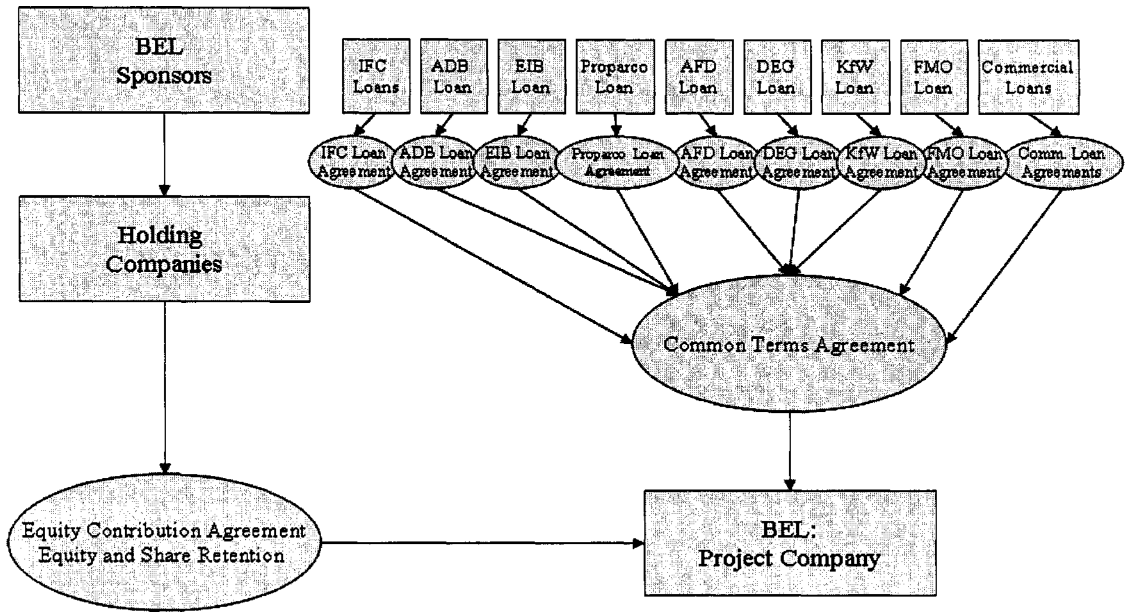


Table 5.2: Project Financing Plan

Private Power Generation (Bujagali) Project Financing Plan	US$ 000	% of Total
Equity		
Project Sponsors	151,570	19.0
Government	20,000	2.5
Total Equity	**171,570**	**21.5**
Debt		
IFC	130,000	16.3
EIB	130,000	16.3
Commercial Banks (under IDA PRG)	115,000	14.4
ADB	110,000	13.8
European DFIs (*)	142,010	17.7
Total Debt	**627,010**	**78.5**
Total Debt and Equity	**798,580**	**100.0**

4. All senior loans are expected to have a 16 year door-to-door maturity. Subordinated loans (i.e., IFC's US$30 million C Loan and, potentially, up to US$20 million from European DFIs) are expected to provide a door-to-door maturity of up 20 years.

5. BEL is in advanced discussion with two commercial banks (Absa Capital, of South Africa, and Standard Chartered Bank, UK) in relation to the provision of up to US$115 million commercial senior debt tranche that will be guaranteed by IDA's PRG. It is envisaged that the commercial tranche will have the same maturity than the senior loans being provided by the DFIs.

Annex 6: Implementation Arrangements

1. The 250 MW Bujagali power plant will be developed, financed, built, owned, and operated by Bujagali Electricity Limited (BEL), a special purpose company incorporated under the laws of Uganda. The project Implementation Agreement (IA) and Power Purchase Agreement (PPA) were signed by BEL and the Government/UETCL, respectively, on December 13, 2005.

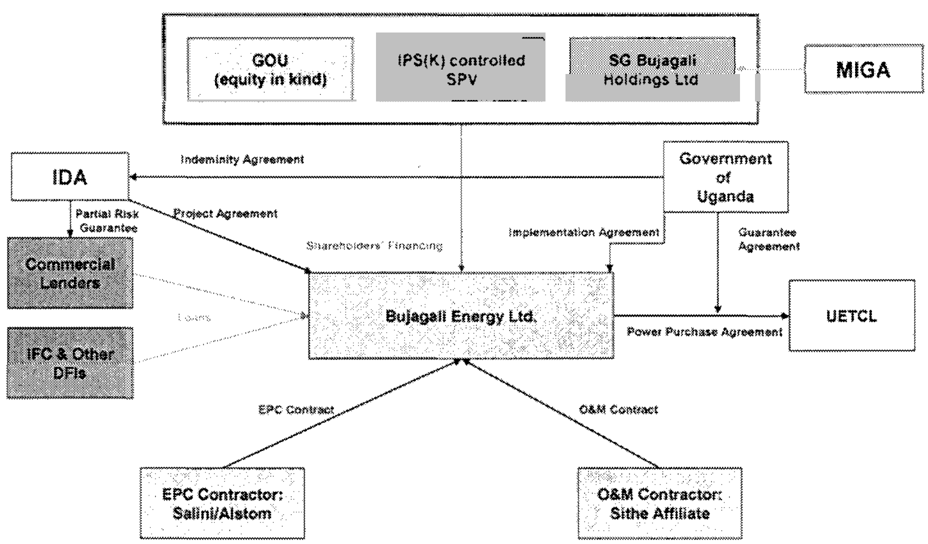
2. The IA sets out the terms on which the Government grants to BEL the concession to design, finance, construct, own, operate and maintain the project. The PPA sets out the terms as to how: (a) the construction and operation of the project will be conducted; and (b) the project contracted capacity (i.e., 250 MW) will be made available and sold. Under the PPA, BEL agrees to sell all of its production exclusively to UETCL and UETCL agrees to purchase the project's contracted capacity.

3. BEL will also be responsible for managing the construction of approximately 100 kilometers of 132 kV transmission line, a substation located at Kawanda, the expansion of the Mutundwe substation, and associated works (also referred to as the Interconnection Project), on behalf of UETCL, to strengthen the evacuation of electricity from the Bujagali hydropower plant. The Interconnection Project is an associated but separate project from the generation facility. The Interconnection Project will be financed by ADB, also a lender to the Bujagali project.

4. In addition to the PPA and IA, the key project documents include the Government Guarantee, the EPC Contract and the O&M Agreement.

5. The contractual structure of the proposed project is consistent with industry practice for limited recourse project finance transactions. Commercial, technical and political risks are allocated amongst the parties best able to manage them. Figure 6.1 describes the relationship between the key project agreements.

Figure 6.1: The Principal Project Contractual Agreements



6. **The Implementation Agreement** between BEL and the Government defines the rights and obligations of the Government and BEL. Under this agreement, the Government grants BEL the right to construct and operate the project at the plant site, and commits itself to convey all land and land rights necessary for the project, as well as to remedy any environmental conditions affecting the project site that may prevent BEL's compliance with the relevant environmental and social requirements. The Government provides BEL protection against a potential expropriation / nationalization of the power plant, the company, its shares or any of its assets. As part of BEL's obligations, the IA indicates that BEL will be responsible, among other things, for arranging the financing of the project, and for updating and complying with the Social and Environmental Assessment, and associated action plans, for the power plant. BEL will also make all necessary applications to the relevant authorities to obtain required consents for the project implementation, and provide the Government with monthly updates. The IA also includes the terms of the Government's guarantee covering UETCL's payment obligations to BEL.

7. **The Power Purchase Agreement** between BEL and UETCL provides for the bulk sale of power by BEL to UETCL for a term of 30 years from the time of the commissioning of the plant. Under the PPA, BEL is required to provide a contracted capacity of 250 MW and maintain an availability of at least 96% (95% during its first year of operations). UETCL, the power purchaser, will be required to purchase the capacity made available by BEL and will make monthly payments for available capacity on the basis of a capacity payment, to be calculated in accordance with the terms of the PPA, which allows for: (a) the repayment of the project's debt and associated interest, (b) a return on the shareholders' equity (in the case of (a) and (b), only to the extent that they finance allowed project costs), (c) recovery of development costs, up to an maximum cap set as per the terms of BEL's bid for the project, and (d) recovery of other costs, such as corporate income tax, all in accordance with the PPA detailed methodology for calculating the project's capacity payment. The PPA incorporates penalties in case BEL does not reach the required levels of capacity and/or availability. Therefore, BEL bears the commercial risk associated with the construction and operation of the proposed project. On the other hand, UETCL bears the hydrology risk. However, should there be prolonged adverse hydrological conditions, the PPA allows UETCL to eventually terminate the agreement and purchase the plant. The PPA does not include specific amounts for the capacity charge since this will be based on certain variables which can only be determined upon the commissioning of the project (e.g., allowed project costs), while others will need to be established on a monthly basis (e.g., availability). The PPA clearly defines the costs which will be passed through to the tariff.

8. **Engineering, Procurement and Construction (EPC) contract***:* The proposed project will be built pursuant to a fixed price, date certain, turnkey EPC Contract. The EPC contractor, Salini Costruttori SpA (Italy) (with Alstom Power Hydraulique (France) as a key subcontractor) has been selected pursuant to a competitive EPC selection process in accordance with the EIB procurement rules. According to the terms of the EPC contract, the EPC contractor would be required to commission the power plant within 44 months of the company issuing the relevant notice to proceed. The EPC contract also incorporates incentives (penalties) for the early (late) completion of the plant as well as penalties for the event that the power plant does not reach a capacity of at least 250 MW.

9. **Operation and Maintenance (O&M) Agreement**. The operation and maintenance of the power plant will be conducted by a Sithe Global affiliated company, incorporated in Uganda, which will also receive consultancy support from an offshore sister company. The terms of the O&M agreements are reflective of BEL's commitments under the PPA.

10. **Government Guarantee Agreement.** Under this contract, the Government agrees to (a) guarantee UETCL's payment obligations under the PPA to BEL until, at least, the time when the

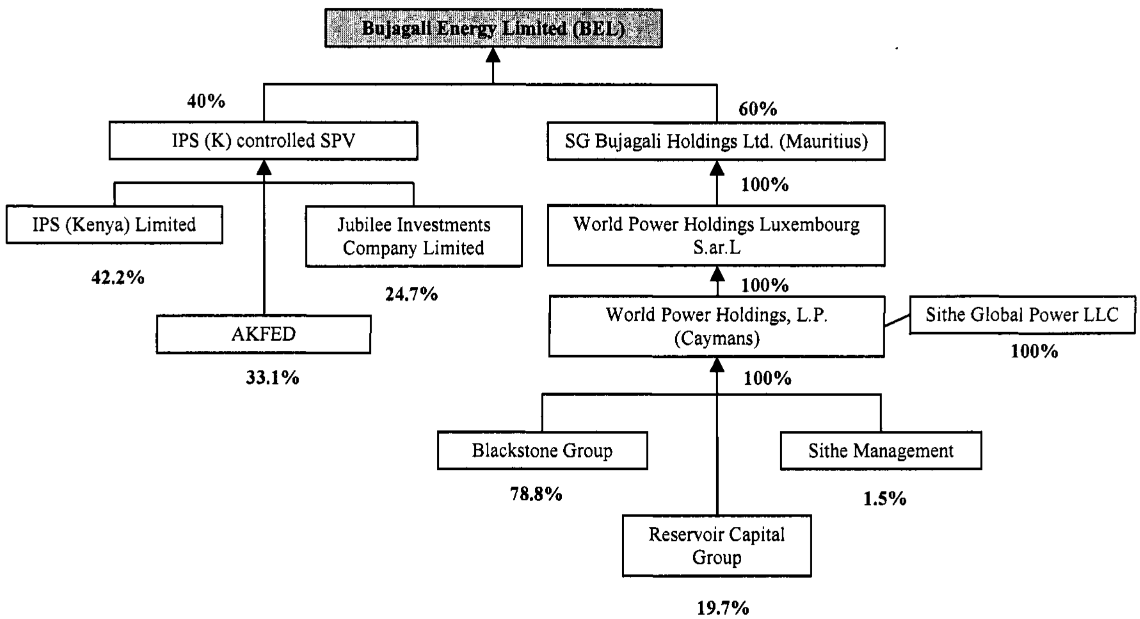
project debt has been fully repaid; and (b) indemnify BEL for any loss incurred as a result of UETCL's obligations under the PPA becoming void, unenforceable or ineffective.

11. **Direct Agreements**. The lenders will seek to enter into direct agreements with the parties' signatory to the PPA, IA, Government Guarantee, EPC Contract and O&M Agreement. The Government Direct Agreement is expected to include customary clauses, including Government's acknowledgements of the security interests created in the project for the benefit of the lenders and the step-in rights of the lenders in the project.

Annex 7: Bujagali Energy Ltd: Technical and Financial Capabilities of Sponsors

1. The equity structure of Bujagali Energy Limited (BEL) is described in the diagram below. The project sponsors of BEL are Industrial Promotion Services (Kenya) (IPS(K)) and Sithe Global Power LLC (Sithe Global). IPS(K) is a subsidiary of the Aga Khan Fund for Economic Development. Sithe Global's shareholders include the Blackstone Group, Reservoir Capital and Sithe Global's management.

Figure 7.1: Project Shareholding Structure[1]



2. **Aga Khan Fund for Economic Development (AKFED).** Under the leadership of HH the Aga Khan, the Aga Khan Development Network was created in order to address the needs of developing countries. Private sector investment within the Aga Khan Development Network is conducted through the Aga Khan Fund for Economic Development (AKFED), an international development agency dedicated to promoting new enterprises in the developing world. AKFED operates as a network of affiliates with more than 90 separate project companies in 16 countries, employing over 18,000 people. The main industries in which AKFED conducts its operations are financial services, tourism, industry and infrastructure, food and agro-processing, media and aviation.

3. Since the 1970's the World Bank Group has had an extensive and long-standing relationship with AKFED, with whom the World Bank Group has either invested in, or worked with, numerous companies in the manufacturing, tourism, financial and power sectors. IFC currently has 16 active projects with AKFED, for a total committed exposure of approximately US$154 million. Some of the power projects in which the World Bank Group has worked with AKFED and/or AKFED related companies include: Azito Energie (Côte d'Ivoire), Kipevu (Kenya) and Pamir Energy (Tajikistan).

4. **Industrial Promotion Services (Kenya) Ltd (IPS(K)).** In the early 1960's, AKFED established a group of companies under the corporate name Industrial Promotion Services (IPS) to provide venture capital, technical assistance and management support to encourage and expand private enterprise in emerging countries. IPS(K) is the industrial development arm of IPS for East

[1] At time of Appraisal.

Africa. IPS(K) is controlled by AKFED, and its shareholders include international development agencies such as IFC and DEG. IFC currently owns 15% IPS(K)'s share capital and has had a seat on its Board of Directors since 1984.

5. **Sithe Global Power LLC (Sithe Global).** Sithe Global is an international development company formed in 2004 by Reservoir Capital Group ("Reservoir") to develop, construct, acquire and operate strategic power assets around the world. Sithe Global's experienced management team worked together with Reservoir on a number of power-related investments, including Reservoir's direct investment in Sithe Energies, Inc. Until the restructuring of Sithe Energies, which was triggered in 1999 by the changing investment focus of Vivendi (its major shareholder at the time), Sithe Energies was one of the world's leading independent power producers, with a total generating capacity of approximately 5,000 MW, including San Roque hydro plant in the Philippines (340 MW). When Sithe Global was formed, Sithe Energies' capabilities to implement large-scale power generating projects were retained (i.e., the vast majority of Sithe Global's present management team held key long term positions at Sithe Energies).

6. **The Blackstone Group** is a private investment banking firm founded in 1985, with offices in New York, London, Paris and Hamburg. At the time of its investment in Sithe Global, the Blackstone Group committed to an investment of over US$500 million of equity to Sithe Global's portfolio of projects. The firm has raised a total of approximately US$63 billion for alternative asset investing since its formation, and around US$28 billion through its private equity Blackstone Capital Partners general funds.

7. **Reservoir Capital Group** is a privately held investment firm founded in 1997. Reservoir's investment funds currently have over US$2.8 billion under management.

Annex 8: Procurement and Governance

1. In September 2003, following the withdrawal of AES, the US based private sponsor for the previous Bujagali project, the Government initiated a transparent bidding process in adherence with the Government's procurement guidelines, to seek a new project sponsor for the new Bujagali project. The Government wanted to ensure that all aspects of the proposed new Private Power Generation (Bujagali) Project would be carried out in a transparent and competitive manner, consistent with the procurement regulations of Uganda and good international practice. The Government followed a two step process. In the first stage, the Government selected the sponsor and, in the second stage, the sponsor selected the EPC contractor through a competitive process under EIB procurement rules.

SECTION I – SPONSOR SELECTION

2. In 2004, the Government established the Bujagali Project Steering Group to oversee and manage the project, in general, including the sponsor selection process. In addition to providing oversight, this multi-institutional Project Steering Group enhanced the accountability and transparency of the sponsor selection process. In accordance with Ugandan anti-corruption and procurement laws - in particular the Leadership Code of Conduct Act of 2002, the Public Finance (Procurement) Regulations Act of 2000, and the Public Procurement and Disposal of Public Assets Act (PP&DA Act) No. 1 of 2003 - all of the representatives selected for the Project Steering Group were required to be in compliance with Uganda's Leadership Code[1]. In accordance with the PP&DA Act, approvals for the procurement of the advisory services, and later of the project sponsor, were granted by a Contract's Committee established by the MEMD. The Project Steering Group retained the services of Messrs. Hunton & Williams (an international law firm headquartered in the United States), to provide legal advisory services on the project and carry out overall coordination of the preparation of the bidding documents and the Government's evaluation report. The Government also retained the services of Messrs. Scott Wilson Piesold, a UK engineering firm, to advise the Project Steering Group on technical and engineering aspects.

3. A draft Request for Proposals (RFP)/Prospectus for prequalification stipulated the following sponsor selection process.

- *Phase I* – The Government will issue the RFP/prospectus in draft form to each potential sponsor interested in participating in the sponsor selection process. Each potential sponsor interested in participating shall submit the information on its/their credentials as stipulated in the RFP. The Government would review the information submitted and select those which are pre-qualified to develop the project.

- *Phase II* – The Government will solicit comments from the qualified sponsors on the key aspects of the project and, for this purpose, make available the draft of the Power Purchase Agreement (PPA) and the Implementation Agreement (IA) to them. The Government will open a data room (by March 1, 2004) so that the qualified developers can carry out due diligence for the project.

[1] The Uganda Leadership Code is established through an Act of Parliament and applies to all public officers of the Government of Uganda and is enforceable by the Government Ombudsman (the Inspector General of Government). It states requirements for the public declaration of assets by Government officials (bi-annually), stipulates the official conduct of these officials, and the penalties for the infringement of these stipulations. Several high ranking public officials, including a prominent Member of Parliament, have lost their appointments for non-compliance with this law.

- *Phase III* – Qualified sponsors interested in further participation were required to submit written comments on the IA and PPA by a defined date. Thereafter, the Government will issue a RFP/prospectus for the development of the Bujagali project which would include the draft of IA and PPA, other project related information and the evaluation criteria.

- *Phase IV* – Based on evaluation of the proposals received in response to Phase III, the Government will select the sponsor who will then post a bid bond and commence final negotiations to finalize the project documentation.

4. The RFP also stipulated that the Government would require the selected sponsor to undertake a transparent and competitive process for awarding the engineering, procurement and construction (EPC) contract for the project.

5. On January 16, 2004, the Government issued a Request for Proposals/Prospectus in relation to the prequalification of entities for the development of the Bujagali Hydroelectric Power Project (the "RFP/Prospectus"). Section 2 and Annex C of the RFP/Prospectus contemplated that potential sponsors would submit information demonstrating their credentials to develop the project by March 1, 2004. The RFP detailed the information required to be submitted. By the close of business on March 1, 2004, credentials had been received from five out of the eleven firms to whom the RFP had been sent. The firms which responded are listed below:

- Stucky Consulting Engineers Ltd of Switzerland (Stucky);

- Montgomery Watson Harza of the United States (MWH);

- Wakisi Hydro Consortium – composed of Eskom Enterprises (Pty) Ltd, Industrial Development Corporation, Netherlands Development Finance Company and the African Infrastructure Investment Fund (Wakisi);

- Madhvani International SA of Panama (MISA); and

- Industrial Promotion Services of Kenya (IPS(K)).

6. The evaluation of the prequalification submission was carried out by a consortium of three firms comprised of Hunton & Williams, Hammonds Associates, an engineering consulting firm located in Canada, and Fieldstone Africa (Pty) Limited, an investment bank and financial advisory services firm located in Johannesburg, South Africa. The Government's advisors evaluated the credentials provided by the above firms under the technical and financial criteria as described in the RFP/Prospectus. Four of the five potential sponsors made qualification submissions that complied materially with the requirements of the prequalification RFP/Prospectus. MWH also informed the Government that they were not interested to take on the role of a developer and did not participate in the process any more. The following three firms were selected and requested to submit their proposals for the development of the project on March 23, 2005:

- Stucky Consulting Engineers Ltd of Switzerland (Stucky);

- Wakisi Hydro Consortium (Wakisi); and

- Industrial Promotion Services of Kenya (IPS(K)).

7. Following the selection of these three qualified potential sponsors, the Government issued a revised version of the request for proposals/prospectus (the "RFP/Prospectus") that reflected those comments from the qualified potential sponsors that the Government found compelling. The RFP/Prospectus included drafts of the IA and PPA. In summary, the RFP/Prospectus mandated a transparent and competitive process for the selection of a qualified project sponsor based on the following financial evaluation criteria:

- The internal rate of return on the equity to be invested by the sponsor in the project, stated as a percentage and carried out to three decimal places;
- A cap on the Development Costs that the sponsor would be allowed to include in the tariff under the PPA;
- Sponsor acceptance of responsibility for the UETCL transmission line construction management; and
- The monthly operation and maintenance fee that the project company (to be formed by the selected sponsor) will earn under the PPA to the extent the plant's target availability is achieved.

8. Based on the recommendations of the Evaluation Report made by the Government's advisors, Industrial Promotion Services (Kenya) (IPS(K)) was selected and invited for further negotiations. A Power Purchase Agreement and Implementation Agreement were signed on December 13, 2005 with Bujagali Energy Limited (BEL), a company established under Ugandan law by the selected sponsor to implement the project. As required under the terms of the RFP, BEL has posted a bond of US$4.5 million.

SECTION II: SELECTION OF THE EPC CONTRACTOR

9. As mandated in the RFP, BEL undertook the selection of the EPC contractor through a competitive process. The sponsors have conducted a competitive EPC selection process in accordance with the European Investment Bank's (EIB) competitive tendering rules. The sponsors requested expressions of interest from potential EPC contractors through a public notification published in July 2005 in a number of international publications, including Development Business and the Official Journal of the European Union. In August 2005, the sponsors sent out Request for Qualifications packages to 32 potential contractors worldwide who had expressed an interest in participating in the EPC tendering process. By September 30, 2005, eight potential bidders had submitted their credentials for evaluation by the sponsors and EIB to be qualified for participation in the bidding process for the EPC contract.

10. In early April 2006, EIB approved a short-list of four candidates to participate in the RFP for the EPC: (a) SNC Lavalin (Canada) in conjunction with Jaiprakash (India); (b) Salini Cotruttori SpA (Italy) in conjunction with Alstom Power Hydraulique (France); (c) Voith Siemens (Germany), in conjunction with Belfinger & Berger (Germany) and Pihl & Sons A.S. (Denmark); and (d) Strabag SE (Austria) in conjunction with VA Tech Hydro GmbH (Austria).

11. Offers were received on October 26, 2006 from two bidders: (a) Salini Costruttori SpA/Alstom Power Hydraulique, and (b) SNC Lavalin/Jayprakash. Salini Costruttori SpA, in conjunction with Alstom Power Hydraulique, has been selected as the lowest evaluated bidder and EPC contractor based on the evaluation criteria detailed in the bidding documents. Negotiations are

currently underway to finalize the EPC contract. The project will be built by the selected bidder pursuant to a fixed price, date certain, turnkey EPC contract.

SECTION III: ADOPTION OF A CODE OF CONDUCT

12. As part of the Request for Proposals, all the EPC bidders were notified by the sponsor that they (and their principal subcontractors) will be required to adopt an anti-corruption Code of Conduct. The project sponsors and their external counsel (Chadbourne & Parke LLP) drafted the "Code of Conduct", which is satisfactory to the World Bank Group. BEL has implemented this "Code of Conduct" for its operations and also will require the EPC contractor and its principal sub contractors to adhere to this code.

Annex 9: Economic Analysis

1. Through a transparent and competitive process, Power Planning Associates Ltd.(UK), in consortium with Coyne et Bellier (France) and ECON (Norway), was selected to undertake the economic analysis of the proposed project, funded under IFC's Funding Mechanism for Technical Assistance and Advisory Services (FMTAAS). The findings and recommendations of Power Planning Associates' report entitled, "Bujagali II – Economic and Financial Evaluation Study" (the Economic Study), dated February 2007, are summarized below. The report was publicly disclosed on February 26, 2007 and is available on the following website: www.worldbank.org/Bujagali.

ECONOMIC CONTEXT: THE CURRENT POWER SUPPLY CRISIS

2. The combination of delays in developing additional hydropower generation capacity (including the previous Bujagali project), annual demand growth of about 8% and the onset of poor hydrological conditions, have resulted in the need for the Government to contract for electricity supply from two 50 MW thermal plants running on ADO, while rationing electricity supply by means of massive load-shedding. A third 50 MW thermal plant running on ADO is to be partially financed under the proposed Power Sector Development Operation (FY07). The Government is also planning to commission a 50 MW permanent thermal plant running on HFO. The power system is also investing in renewables and mini-hydropower to help fill the gap, but these represent only a small total contribution relative to the system needs. Hence reliance on diesel generation will continue until the proposed Private Power Generation (Bujagali) Project is commissioned.

3. Power Planning Associates conducted a detailed economic assessment of thermal generation requirements over the period from 2006 to 2010, indicating a very large and costly contribution of thermal power, as illustrated in Table 9.1.

Table 9.1: Interim Thermal Generation Requirements (2006/10)

	Energy Generated (GWh)				
	2006	**2007**	**2008**	**2009**	**2010**
50 MW Lugogo Thermal running on ADO	437	276	27		
50 MW Kiira Thermal running on ADO	110	370	166		
50 MW Mutundwe Thermal running on ADO		184	365	305	300
Kakira Sugar Works (bagasse)		40	79	79	78
50 MW of Thermal running on HFO			330	438	438
Kilembe / Renewables	26	26	62	273	273
Nalubaale/Kiira Dam Complex	1086	973	874	897	989
Electricity Imports from Kenya	40				
Total	**1699**	**1868**	**1903**	**1991**	**2078**
Unserved Energy	**218**				

4. The total cost of the fossil-fuel components of the 2006-10 interim power plan is about US$700 million. By comparison, the expected economic cost of the proposed project is about US$520 million. The proposed project has an expected productive life of about 50 years and will generate at least 60% more annual energy than the thermal plants would produce in 2010. This indicates the economic penalty that the long delay of the project implementation will have cost Uganda by the time the proposed project would be commissioned. It also highlights the important economic circumstance that if commissioned in 2011, the proposed project would immediately displace about 738 GWh of fossil- thermal production (about 35% of total 2010 generation) – a substantial portion of the proposed project's expected output, estimated at 1,165 GWh and

1,991 GWh for the low and high hydrology scenarios, respectively. This displacement contributes to a rapid build-up of capacity utilization, which in turn favors the project's economic rate of return.

DEMAND FORECAST, TARIFFS AND AFFORDABILITY

5. The base year for the demand forecast is 2005 since this was the last complete annual period for which actual data was available at the time the economic and financial due diligence was conducted. Table 9.2 provides supply/demand balances for electricity in Uganda for 2001-05.

Table 9.2: Power Sector Performance (2001-05)

	2001	2002	2003	2004	2005
Net generation for domestic market (GWh)	1,425	1,426	1,542	1,687	1,827
System technical losses (GWh)	287	281	301	331	354
Technical losses (% of net generation)	19.7%	19.4%	19.5%	19.6%	19.4%
Commercial losses (GWh)	271	212	309	325	397
Commercial losses (% of net generation)	19.0%	14.9%	20.0%	19.3%	21.8%
Billed sales (GWh)	867	933	1035	1031	1075
Collection ratio	83%	83%	77%	82%	86%
Billed sales collected (GWh)	720	774	797	845	924
Sales collected as % of net generation	50%	54%	52%	50%	51%

6. During 2001/05, billed sales grew by 5.5% per year and generation by 6.4%, the difference was accounted for by the growth of commercial losses. The collection ratio was in the range of 77% to 86%, which had deteriorated between 2001/04, and improved in 2005, when the distribution facilities were concessioned to the private sector. During this period, the increase in the weighted average of end-user tariffs, in real terms, was not significant.

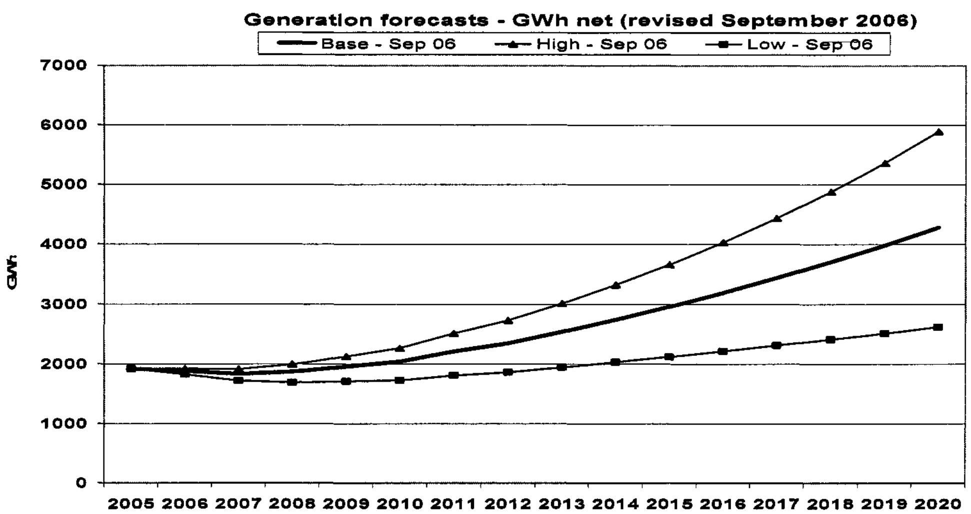
7. The demand forecast first projects end user demand, then the implied generation requirements on an energy and peak basis. The demand forecast incorporates the potential impact on consumption resulting from both the large tariff increases implemented in 2006 and potentially further required to accommodate the interim thermal generation program (2006-10). Generation requirements take into account the forecast reductions in technical and non-technical losses, and increases in collection of billed sales. They also include the connection commitments in UMEME's distribution concession agreements, which are currently constrained by the tight supply situation, expected to prevail until the proposed project is commissioned. As such, these demand projections are considerably lower than previously produced for the Uganda power system. By 2011, the difference between the demand forecast base and low cases is 15%, growing to over 27% by 2015 and increasing further thereafter. Apart from tariffs and commercial performance improvements, the other key determinants of the demand forecast are: (a) the number of new connections per year and consumption per connection for residential consumers; and (b) the expected growth of commercial and industrial GDP for the commercial and industrial sectors, for which economic projections agreed between IDA, the International Monetary Fund and the Government were used for the base case. Table 9.3 below shows the demand forecast assumptions for the base case as well as for the low and high cases. The low case for the demand forecast portrays a pessimistic economic scenario for Uganda, providing a test for the economic viability of the project. Under this scenario, Uganda's commercial and industrial GDP growth rates would be in the range of only 3% to 5% per year, the income-related growth of household energy use would only be 1.3% per year, and the total connection rate only 12,000 per year until 2011, including both UMEME's grid-related connections and the rural electrification program. Total net generation would only surpass the 2005 level in 2012.

Table 9.3: Demand Forecast Assumptions Summary

Demand Forecast Assumptions Summary			
Variable	**Base**	**Low**	**High**
New res. connections/yr	17000	12000	25000
2005 kWh/mo residential	134	134	134
kWh residential growth/yr	2.30%	-1.3 %pts	+1.o %pt
Residential price elasticity	-0.5	-0.5	-0.5
Commercial price elasticity	-0.3	-0.3	-0.3
Industrial price elasticity	-0.1	-0.1	-0.1
Income elasticity ind/comm	1.3	1.3	1.3
Energy efficiency %/yr on sales	0.3	0.3	0.3
Commercial GDP growth %/yr	7.9~8.35	-3 %pts	+2 %pts
Industrial GDP growth %/yr	6.15~7.25	-3 %pts	+2 %pts
System load factor (ratio)	0.62	0.62	0.62
% commercial losses monetized	70	70	70
Price elasticity improved collections	-0.3	-0.3	-0.3
System Losses (% of gen)	**2005**	**2012**	
Technical	19.4	16.0	
Commercial	21.8	5.0	
collections % billed	80.0	97.5	

8. The forecast of energy generation requirements is provided in Figure 9.1 and Table 9.4 below.

Figure 9.1: Forecast of Energy Generation Requirements



9. The compound average annual base case growth of Uganda's generation requirements is 5.5% per annum from 2005 to 2020. For the high and low cases, it is 7.7% and 2.2%, respectively. By 2011, the base case generation requirement for the domestic market would be 2,208 GWh, with a spread around the base case of about 14% above (high case) and 18% below (low case). By 2015, the base case demand would be 2,959 GWh, with a spread around the base case of about 24% above (high case) and 30% below (low case).

10. In the base and low cases, the period from now to 2011 reflects a substantial drag on projected demand growth due to: (a) low growth on connection rates, (b) significant increases in 2006 tariff (about 94%); (c) improvements in the collection ratio; and (d) reductions in technical and non-technical losses, which will narrow the relative gap between sales and generation. Because high demand elasticities are associated with price increases and improvement of commercial discipline, the affordability factor is internalized in the demand forecast, in the sense that as the tariff increases consumption decreases. This is particularly apparent in the residential sector, for which the demand forecast declines through 2007, followed by a gradual recovery, only to moderately exceed the 2005 level by 2010 under the base case. Indeed, this continues a trend apparent since 2004.

Table 9.4: Uganda Electricity Demand Forecast (Base, High and Low Scenarios)

Base:

Forecast Summary	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales before collection/loss adjustments:	**GWh**	**1131**	**1132**	**1130**	**1184**	**1279**	**1375**	**1531**	**1657**	**1791**	**1934**	**2087**	**2250**	**2425**	**2611**	**2811**	**3024**
Growth rate per year from 2005 Base	% p.a.		0.1	0.0	1.6	3.1	4.0	5.2	5.6	5.9	6.1	6.3	6.5	6.6	6.7	6.7	6.8
Residential	GWh	370	342	315	317	337	357	413	450	488	528	570	613	658	705	753	804
Commercial	GWh	139	138	134	138	148	157	176	189	204	219	236	254	273	294	316	340
Industrial	GWh	622	652	682	730	794	861	942	1017	1099	1186	1281	1383	1494	1613	1742	1881
Total sales	**GWh**	**1131**	**1159**	**1179**	**1255**	**1387**	**1521**	**1707**	**1874**	**2026**	**2188**	**2361**	**2546**	**2743**	**2954**	**3180**	**3421**
Residential	GWh	370	350	329	336	365	395	460	509	552	598	645	694	744	797	852	909
Commercial	GWh	139	141	140	146	160	174	196	214	231	248	267	287	309	332	357	384
Industrial	GWh	622	668	711	773	862	952	1051	1151	1243	1342	1449	1565	1690	1825	1970	2128
Exports (Tanzania/Rwanda)	GWh	35	53	56	58	61	64	67	68	74	77	83	85	93	94	99	107
Uganda demand	GWh	1921	1882	1831	1864	1950	2035	2208	2348	2539	2742	2959	3190	3438	3702	3985	4287
Total net generation	**GWh**	**1956**	**1935**	**1887**	**1922**	**2011**	**2099**	**2276**	**2417**	**2612**	**2819**	**3041**	**3275**	**3530**	**3796**	**4084**	**4394**
Exports (Tanzania/Rwanda)	MW	9.8	10	10	11	11	12	12	13	14	14	15	16	17	17	18	20
Uganda demand	MW	354	347	337	343	359	375	407	432	467	505	545	587	633	682	734	789
Peak Demand	**MW**	**363**	**356**	**347**	**354**	**370**	**386**	**419**	**445**	**481**	**519**	**560**	**603**	**650**	**699**	**752**	**809**
Growth rate (net generation)	% p.a.		-2.0	-2.4	-1.0	0.4	1.2	2.4	2.9	3.5	4.0	4.4	4.7	5.0	5.2	5.4	5.5
Total system losses	%	41.1%	38.4%	35.6%	32.7%	28.9%	25.2%	22.7%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%
New connections	#/year		17,000	17,000	17,000	17,000	17,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Use/year/new connection	kWh		1326	1356	1387	1419	1452	1485	1520	1555	1590	1627	1664	1703	1742	1782	1823

High:

Forecast Summary	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales before collection/loss adjustments:	**GWh**	**1131**	**1155**	**1179**	**1263**	**1393**	**1530**	**1740**	**1924**	**2125**	**2344**	**2584**	**2845**	**3131**	**3442**	**3783**	**4156**
Growth rate per year from 2005 Base	% p.a.		2.2	2.1	3.7	5.4	6.2	7.4	7.9	8.2	8.4	8.6	8.8	8.9	8.9	9.0	9.1
Residential	GWh	370	347	326	334	361	389	457	508	561	617	677	739	805	875	948	1025
Commercial	GWh	139	141	139	145	159	172	197	215	236	259	283	311	340	373	408	447
Industrial	GWh	622	667	715	783	873	968	1086	1201	1328	1468	1623	1795	1985	2195	2427	2683
Total sales	**GWh**	**1131**	**1183**	**1231**	**1338**	**1511**	**1692**	**1940**	**2176**	**2404**	**2652**	**2923**	**3218**	**3541**	**3894**	**4280**	**4702**
Residential	GWh	370	356	340	354	391	430	510	575	635	698	766	836	911	990	1073	1160
Commercial	GWh	139	144	145	154	172	191	219	244	267	293	321	351	385	422	462	506
Industrial	GWh	622	684	746	830	947	1071	1211	1358	1502	1661	1836	2031	2245	2483	2745	3036
Exports (Tanzania/Rwanda)	GWh	35.0	53	56	58	61	64	65	70	73	77	80	84	92	95	100	104
Uganda demand	GWh	1921	1921	1910	1987	2124	2264	2510	2728	3012	3323	3663	4033	4438	4880	5364	5892
Total Net Generation	**GWh**	**1956**	**1974**	**1966**	**2046**	**2185**	**2328**	**2575**	**2797**	**3085**	**3400**	**3742**	**4117**	**4530**	**4975**	**5464**	**5996**
Exports (Tanzania/Rwanda)	MW	9.8	10	10	11	11	12	12	13	14	14	15	16	17	17	18	20
Uganda demand	MW	354	354	352	366	391	417	462	502	555	612	674	743	817	899	988	1085
Peak Demand	**MW**	**363**	**363**	**362**	**377**	**402**	**429**	**474**	**515**	**568**	**626**	**690**	**758**	**834**	**916**	**1006**	**1104**
Growth rate (net generation)	% p.a.		0.0	-0.3	1.1	2.6	3.3	4.6	5.1	5.8	6.3	6.7	7.0	7.2	7.4	7.6	7.8
Total system losses	%	41.1%	38.4%	35.6%	32.7%	28.9%	25.2%	22.7%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%

Low;

Forecast Summary	Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Sales before collection/loss adjustments:	**GWh**	**1131**	**1096**	**1058**	**1072**	**1120**	**1165**	**1254**	**1312**	**1371**	**1433**	**1496**	**1561**	**1629**	**1699**	**1771**	**1845**
Growth rate per year from 2005 Base	% p.a.		-3.0	-3.3	-1.8	-0.2	0.6	1.7	2.1	2.4	2.7	2.8	3.0	3.1	3.2	3.3	3.3
Residential	GWh	370	334	298	292	301	311	349	369	389	409	430	450	472	493	515	537
Commercial	GWh	139	134	126	126	132	137	149	156	163	170	178	186	195	203	213	222
Industrial	GWh	622	628	633	654	686	717	757	788	820	854	889	925	963	1002	1043	1086
Total sales	**GWh**	**1131**	**1123**	**1104**	**1136**	**1214**	**1288**	**1399**	**1484**	**1551**	**1621**	**1692**	**1766**	**1843**	**1922**	**2003**	**2088**
Residential	GWh	370	342	311	309	327	344	389	417	440	463	486	510	533	558	582	607
Commercial	GWh	139	137	132	134	143	151	166	176	184	192	201	210	220	230	241	252
Industrial	GWh	622	644	661	693	744	793	844	891	927	966	1005	1046	1089	1134	1180	1228
Exports (Tanzania/Rwanda)	GWh	35	53	56	58	61	64	70	68	76	76	84	84	91	96	102	105
Uganda demand	GWh	1921	1823	1714	1687	1708	1723	1809	1860	1944	2031	2121	2214	2309	2408	2511	2616
Total Net Generation	**GWh**	**1956**	**1877**	**1770**	**1745**	**1769**	**1787**	**1879**	**1928**	**2020**	**2107**	**2205**	**2297**	**2401**	**2504**	**2612**	**2721**
Exports (Tanzania/Rwanda)	MW	10	10	10	11	11	12	12	13	14	14	15	16	17	17	18	20
Uganda demand	MW	354	336	316	311	314	317	333	342	358	374	390	408	425	443	462	482
Peak Demand	**MW**	**363**	**346**	**326**	**321**	**326**	**329**	**346**	**355**	**372**	**388**	**406**	**423**	**442**	**461**	**481**	**501**
Growth rate (net generation)	% p.a.		-5.1	-5.5	-4.2	-2.9	-2.1	-1.0	-0.5	0.2	0.6	1.0	1.3	1.5	1.8	1.9	2.1
Total system losses	%	41.1%	38.4%	35.6%	32.7%	28.9%	25.2%	22.7%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%	20.2%

SUPPLY OPTIONS

Conventional Hydropower Projects

11. In addition to the existing Nalubaale and Kiira plants, the only two large hydropower projects that have been developed beyond the feasibility stage in Uganda are the proposed project (Bujagali) and Karuma. The proposed project costs are based on the terms of the bid for its EPC contract and current estimates of the project development, environmental and social, and financing costs. Its economic cost is estimated at US$520.6 million (2006 money). On the same basis, the estimated global cost of the Karuma Hydropower project is US$587.8 million. A detailed assessment of the capital costs of both projects is available in the Economic Study, Chapter 5, and is summarized in Table 9.5 below.

Table 9.5: Economic Cost Estimate for Bujagali and Karuma

Item	Bujagali (250 MW) (US$ million)	Karuma (200 MW) (US$ million)
Direct construction costs		
- Civil Works	227	315
- Equipment	187	117
Connection to the grid	28	79
Engineering & Coordination	28	33
Environmental & Social Impacts	26	15
Development Costs	25	29
Total Implementation Cost (excluding Interest During Construction)	**521**	**588**

12. The hydrology of Lake Victoria and its impact on potential power generation at both the Bujagali and Karuma sites is explained in Chapter 3 of the Economic Study; it is also summarized in Annex 10.

Small Hydropower Projects

13. There are two existing small hydro plants; only Kilembe mines (3 MW) currently exports energy to UETCL. The Government is in the process of concluding PPAs with developers on a number of small hydro projects to be developed by 2011 on an IPP basis. The principal characteristics of these projects, the expected in-service dates and their projected tariffs (in 2006 prices) are shown in Table 9.6.

Table 9.6: Small Hydropower Projects

	Kilembe Mines	Bugoye	Waki	Buseruka	Kikagati	Ishasha
Capacity (MW)	3	13	6	9	10	5.5
Energy (GWh)	26.3	56.9	26.3	47.3	70.1	24.1
Service date	existing	Jan-2009	Jan-2009	Jan-2009	mid-2008	Jan-2009
Tariff (USc/kWh)	2.54 escalated	5.8 escalated	5.8 escalated	13.54 fixed	6.75 fixed	5.5 fixed

14. There are other potential small hydro sites in Uganda, but their costs and production characteristics are not sufficiently known at present for purposes of long term planning.

Biomass Power Plants

15. There are three sugar factories in Uganda: the Kakira Sugar Works Ltd., the Sugar Corporation of Uganda at Lugazi, and Kinyara Sugar Works Ltd. All three plants generate electricity from bagasse (cane residue) to meet their own factory and irrigation needs. The total installed capacity of the three plants is 7.2 MW. Two more plants are expected to be commissioned before 2010 with a total capacity of 15 MW, as described below.

16. The Kakira Sugar Works (Kakira) is engaged on a project to install high pressure boilers and additional power generating plant that will result in a substantial increase in the electricity output. Kakira has signed a PPA with UETCL to supply electricity to the Ugandan grid. The agreement, signed in mid-2003, covers 6 MW per day during peak hours (6 pm to midnight) at a price of US$4.9¢/kWh for a period of 15 years. A second agreement, which is under negotiations, may include an additional 12 MW per day, from 6 am to 6 pm, and 6 MW from 6 pm to midnight at a price of US$5.6¢/kWh for a period of 10 years. Thus the total output of the two PPAs would be 12 MW exported to the grid every day from 6 am to midnight. The scheduled commissioning date for the new plant is mid-2007. The Kakira plant is projected to deliver 40 GWh in 2007 and 79 GWh per year thereafter.

17. UETCL has entered into a PPA with the Sugar Corporation of Uganda for the purchase of 3 MW and up to 22 GWh per year. This power supply is scheduled to commence in January 2009. There are no firm plans for power exports from the Kinyara Sugar Works.

18. There is some potential in Uganda for the generation of electricity from wood waste, coffee husks and rice husks, as identified in an ESMAP study entitled "Uganda: Rural Electrification Strategy Study", UNDP/World Bank, ESMAP; Report 221/99. These biomass resources, however, are considered to be too small and widely dispersed to be economically justifiable for large-scale power generation within the timescale of the Economic Study.

Geothermal Potential

19. A detailed review of geothermal prospects, contained in Appendix D of Power Planning Associates' report, indicates that historical estimates of the geothermal potential of Uganda being as much as 450 MWe are substantially over-stated. The true potential is likely to be about 10% of this figure. The key findings of the review of geothermal are summarized in the following paragraphs.

20. There are three principal geothermal resource areas in Uganda. Two of these, at Katwe and Buranga, are interpreted in the assessment carried out for this report to be low grade resources, with reservoir temperatures of only some 100°C and, consequently, with nil potential for commercial scale power generation. The third prospect, at Kibiro, is more promising and appears to be a medium grade geothermal resource, with reservoir temperatures of about 220°C. Kibiro is therefore currently considered to be the only geothermal resource in Uganda with clear potential for power development.

21. The size of a geothermal power plant that could be developed at Kibiro will depend on actual resource conditions that have yet to be proven by exploration drilling. Nonetheless, deep geothermal resource conditions can be inferred from the results of surface exploration surveys undertaken to date. By these means, it is assessed that the Kibiro resource may prove to be suitable for the future development of either a 20 MWe condensing steam power plant or a 40 MWe organic Rankin cycle binary plant, both with an operational life of at least 25 years.

22. The cost of developing a 40 MWe binary cycle geothermal power plant at Kibiro is assessed at US$120 million, which equates to a cost of US$3,000 per kWe installed. This cost includes all items for a full "greenfield" development, including project infrastructure, wells, steam field, power plant, transformers and transmission facilities.

23. A preliminary project schedule program, developed by Power Planning Associates, indicates that about US$9 million would be required for drilling two exploration wells, and about five and a half to six years would be needed to commission the facility, including drilling, testing, resource evaluation, feasibility study preparation, financing, production drilling, plant contracting, construction, commissioning, testing and commercial operations. An extensive amount of detailed analytical material on the geothermal potential and the costing and scheduling of an electric power plant is included in the Economic Study.

24. For illustrative purposes, a comparative costing framework of the major projects described above is shown in Table 9.7, which provides an economic comparison of supply prices assuming a uniform annual output rate specific to each facility being compared. It compares the economic cost of generation of the main long-term options for grid system expansion (in 2006 real terms), indicating that the proposed project is the least cost option under both hydrological scenarios. These supply prices are relevant, but the ultimate cost of a system expansion program depends not only on individual project costs, but also on the required sequencing and energy/capacity contribution from each unit dispatching into the system, which varies from year to year. This is why detailed least cost generation expansion plans for Uganda are derived to analyze if and how Bujagali would fit under such plans.

Table 9.7. Economic Comparison of Supply Prices

		Major Projects: Economic Profiles and Cost of Supply					
Item	Value	Bujagali Low	Bujagali High	Karuma Low	Karuma High	Geothermal	MS Diesel
Plant Size	MW	250	250	158	200	40	20
Plant Factor	ratio	0.53	0.91	0.96	0.92	0.84	0.873
Energy	GWh/yr	1165	1991	1324	1609	295	153
Investment	USD mm	683.4	683.4	801.4	801.4	170.1	23.0
Investment	USD/kW	2733	2733	5072	4007	4253	1151
Fuel	USc/kWh						8.80
O&M	USc/kWh	0.26	0.26	0.21	0.22	0.93	1.76
Supply Price	**USc/kWh**	**6.17**	**3.61**	**6.31**	**5.24**	**7.27**	**12.33**

Source: Cost input data for these calculations taken from PPA Report Chapter 7
Notes:
"Low" and "High" mean low and high hydrology respectively
Investment includesIDC on all capital employed at 10% discount rate
Investment includes generation-associated transmission and for hydro E&S costs
Karuma Low has less MW available on low vs. high hydrology, but it is 200MW installed
O&M includes variable and fixed cost at the stated plant factors

LEAST COST GENERATION EXPANSION PLANNING

25. A set of least cost generation expansion plans was developed for the Ugandan power system beyond 2010 based on candidate plants described above. These plants are then entered as candidates in the WASP[1] software, together with existing generation capacity, the load forecast and the cost of unserved energy[2]. WASP then generates the sequence of plants that meet demand at the lowest combination of capital and energy cost on an NPV basis, while maintaining a 0.5% loss of load probability, corresponding to capacity reserve margin of about 10%.

[1] Wien Automatic System Planning (WASP) Package, version IV, for carrying out power generation expansion planning, developed by the International Atomic Energy Agency.
[2] The cost of unserved energy for Ugandan consumers is estimated at US$38.9¢/kWh.

26. The least cost generation expansion analysis was undertaken for base, low and high demand forecasts; low and high hydrology scenarios; base, low and high fuel price projections; and base, low and high Bujagali cost estimates. The hydrology scenarios are as described in Annex 10 and the demand scenarios have been described above. The fuel cost projections are based on the mid-2006 World Bank crude oil price forecast for the period to 2015. Post-2015 prices are assumed to remain constant at the 2015 levels. The projected low and high crude forecasts are based on statistical analysis of actual prices since 1978, resulting in a risk factor applied to the base case. The base case investment cost estimate of the proposed project is as described above; the high and low scenarios include variations of +10% and -5% around the base case.

27. Alternative expansion plans were determined with and without the proposed project as a candidate plant. All other plants were retained as candidates in all cases. A total of 72 cases were evaluated to cover the risk associated with all combinations of factors listed above, and 13 further cases were considered for additional sensitivity analysis.

28. A full risk analysis matrix for the 'with the proposed project' and 'without the proposed project' cases (see Table 9.8 below) includes the following probabilities assigned to the key variables:

- Demand forecast: base/high/low - 40%/30%/30%
- Hydrology: high/low - 21%/79%
- Fuel Prices: base/low/high – 40%/30%/30%
- Bujagali Cost: base/low/high - 60%/20%/20%

Main Conclusions of Least Cost Planning

29. For the 72 cases[3] in the matrix, commissioning of the proposed project in 2011 has a risk-adjusted net present value advantage of US$184 million relative to not implementing the proposed project (see Table 9.8 below). The only cases where the proposed project is not part of the least cost expansion plan are those where low demand is combined with high hydrology; such scenarios have a combined probability of occurrence of only 6%.

30. The economic analysis also confirms that it is more economic to build the proposed project as a 5x50 MW project rather than 4x50 MW. The advantage to the 5x50 MW configuration has been estimated to have a present value of about US$27 million, under a low hydrology scenario, and US$65 million, under a high hydrology scenario.

31. The economic analysis indicates that it would not be economic to commission the Karuma hydropower project before the proposed Private Power Generation (Bujagali) Project. The penalty has been estimated to have a present value of about US$73 million (US$97 million) under the low (high) hydrology scenario. Moreover, under the base case, the proposed project's cost would have to increase by 49% while Karuma's cost remains unchanged, for Karuma to be selected ahead of the proposed project as the least cost project. Given the terms of the proposed project's EPC contract, such an outcome is very unlikely.

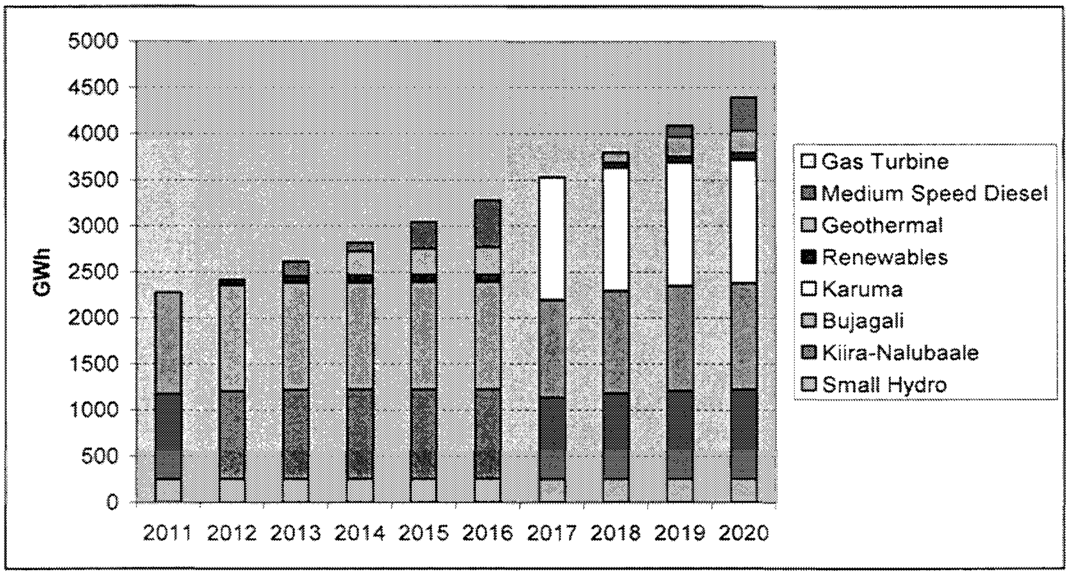
32. If the hydrology in 2011 were to be that of the low hydrology scenario, a one year delay of commissioning of the proposed project would cause an economic penalty of about US$49 million in

[3] This included 54 cases with Bujagali and 18 cases without Bujagali.

present value terms; however, with a high hydrology scenario, the one year delay would have a benefit of US$19 million in present value terms. Because the low hydrology has a 79% probability of occurrence versus 21% for the high hydrology scenario, it would not be economic to delay the proposed project.

33. The profile of Uganda's generation expansion program, in the base case[4] scenario is illustrated below in Figure 9.2.

Figure 9.2: Least Cost Expansion Plan



34. Figure 9.2 shows that from the time the proposed project is commissioned in 2011, the 50 MW of permanent diesel plant burning HFO[5] which the Government intends to commission in 2008, will be needed again by 2013 and the geothermal plant will be economic by 2014. With these two facilities, the Karuma hydropower project should be commissioned in 2017. This program is optimized for a demand forecast which includes the domestic market and two very small existing export contracts with Rwanda and Tanzania. A major economic export contract would accelerate the optimal timing of the Karuma project, but this must be weighed against Uganda's prospects for developing domestic crude oil production in the medium to long term.

35. With the least-cost system generation expansion plan identified (including the proposed project commissioned in 2011), the analysis undertaken has also been verified so that the resulting costs of meeting the demand forecast, as well as the incremental costs of transmission, distribution and losses, can be recovered at tariffs no higher than those on which the demand forecast itself was based.

[4] This is the case with the highest probability: it is a combination of low hydrology and base case demand, base case project cost and base case oil price.
[5] Based on current available information, it was assumed that heavy fuel oil would be imported. If Uganda's recent oil discoveries are developed and if refinery capacity is built in Uganda over the medium to long term, this would reduce the cost of thermal generation. The low fuel price scenario can be used as a proxy for such an outcome; Bujagali remains the next least cost option under such a scenario.

36. To test the coherence of the assumed tariff underlying the demand forecast with the required tariff coming out of the least-cost expansion program, Power Planning Associates conducted an extensive financial analysis for the entire power system to determine the required tariff path and compare it with the assumed tariff. The result of that analysis is that the tariff may drop by up to 10% in real terms after the commissioning of the proposed project.

Table 9.8: Least Cost Matrix of Outcomes "With" vs. "Without" Bujagali

With Bujagali in 2011					Probabilities of Occurrence					PW Cost	NPV	Prob weighted	Prob. Weighted
Case #	BUJ cost	Hydrology	Fuel cost	Demand	BUJ cost	Hydrology	Fuel cost	Demand	Weight	US$m	US$m	NPV cost US$m	PW cost US$m
1	H	H	H	H	0.2	0.21	0.3	0.30	0.004	997.2	362.2	1.4	3.8
2	H	H	H	B	0.2	0.21	0.3	0.40	0.005	683.8	102.2	0.5	3.4
3	H	H	H	L	0.2	0.21	0.3	0.30	0.004	483.8	-129.6	-0.5	1.8
4	H	H	B	H	0.2	0.21	0.4	0.30	0.005	967.2	289.1	1.5	4.9
5	H	H	B	B	0.2	0.21	0.4	0.40	0.007	664.4	97.0	0.7	4.5
6	H	H	B	L	0.2	0.21	0.4	0.30	0.005	483.8	-151.5	-0.8	2.4
7	H	H	L	H	0.2	0.21	0.3	0.30	0.004	944.3	235.5	0.9	3.6
8	H	H	L	B	0.2	0.21	0.3	0.40	0.005	646.8	79.2	0.4	3.3
9	H	H	L	L	0.2	0.21	0.3	0.30	0.004	483.8	-169.6	-0.6	1.8
10	H	L	H	H	0.2	0.79	0.3	0.30	0.014	1516.8	389.8	5.5	21.6
11	H	L	H	B	0.2	0.79	0.3	0.40	0.019	931.5	239.2	4.5	17.7
12	H	L	H	L	0.2	0.79	0.3	0.30	0.014	533.5	31.1	0.4	7.6
13	H	L	B	H	0.2	0.79	0.4	0.30	0.019	1439.0	282.1	5.3	27.3
14	H	L	B	B	0.2	0.79	0.4	0.40	0.025	914.2	180.0	4.6	23.1
15	H	L	B	L	0.2	0.79	0.4	0.30	0.019	531.1	18.8	0.4	10.1
16	H	L	L	H	0.2	0.79	0.3	0.30	0.014	1375.9	209.5	3.0	19.6
17	H	L	L	B	0.2	0.79	0.3	0.40	0.019	900.0	132.6	2.5	17.1
18	H	L	L	L	0.2	0.79	0.3	0.30	0.014	525.2	13.7	0.2	7.5
19	B	H	H	H	0.6	0.21	0.3	0.30	0.011	958.6	400.9	4.5	10.9
20	B	H	H	B	0.6	0.21	0.3	0.40	0.015	645.1	140.9	2.1	9.8
21	B	H	H	L	0.6	0.21	0.3	0.30	0.011	445.2	-91.0	-1.0	5.0
22	B	H	B	H	0.6	0.21	0.4	0.30	0.015	928.6	327.8	5.0	14.0
23	B	H	B	B	0.6	0.21	0.4	0.40	0.020	625.8	135.7	2.7	12.6
24	B	H	B	L	0.6	0.21	0.4	0.30	0.015	445.2	-112.9	-1.7	6.7
25	B	H	L	H	0.6	0.21	0.3	0.30	0.011	905.6	274.2	3.1	10.3
26	B	H	L	B	0.6	0.21	0.3	0.40	0.015	608.2	117.9	1.8	9.2
27	B	H	L	L	0.6	0.21	0.3	0.30	0.011	445.2	-130.9	-1.5	5.0
28	B	L	H	H	0.6	0.79	0.3	0.30	0.043	1478.1	428.4	18.3	63.1
29	B	L	H	B	0.6	0.79	0.3	0.40	0.057	892.9	277.8	15.8	50.8
30	B	L	H	L	0.6	0.79	0.3	0.30	0.043	494.8	69.8	3.0	21.1
31	B	L	B	H	0.6	0.79	0.4	0.30	0.057	1400.3	320.7	18.2	79.7
32	B	L	B	B	0.6	0.79	0.4	0.40	0.076	875.5	218.7	16.6	66.4
33	B	L	B	L	0.6	0.79	0.4	0.30	0.057	492.5	57.5	3.3	28.0
34	B	L	L	H	0.6	0.79	0.3	0.30	0.043	1337.3	248.2	10.6	57.0
35	B	L	L	B	0.6	0.79	0.3	0.40	0.057	861.4	171.2	9.7	49.0
36	B	L	L	L	0.6	0.79	0.3	0.30	0.043	486.5	52.4	2.2	20.8
37	L	H	H	H	0.2	0.21	0.3	0.30	0.004	939.3	420.1	1.6	3.6
38	L	H	H	B	0.2	0.21	0.3	0.40	0.005	625.9	160.1	0.8	3.2
39	L	H	H	L	0.2	0.21	0.3	0.30	0.004	425.9	-71.7	-0.3	1.6
40	L	H	B	H	0.2	0.21	0.4	0.30	0.005	909.3	347.0	1.7	4.6
41	L	H	B	B	0.2	0.21	0.4	0.40	0.007	606.5	154.9	1.0	4.1
42	L	H	B	L	0.2	0.21	0.4	0.30	0.005	425.9	-93.6	-0.5	2.1
43	L	H	L	H	0.2	0.21	0.3	0.30	0.004	886.4	293.4	1.1	3.4
44	L	H	L	B	0.2	0.21	0.3	0.40	0.005	588.9	137.1	0.7	3.0
45	L	H	L	L	0.2	0.21	0.3	0.30	0.004	425.9	-111.7	-0.4	1.6
46	L	L	H	H	0.2	0.79	0.3	0.30	0.014	1458.9	447.7	6.4	20.7
47	L	L	H	B	0.2	0.79	0.3	0.40	0.019	873.6	297.1	5.6	16.6
48	L	L	H	L	0.2	0.79	0.3	0.30	0.014	475.6	89.0	1.3	6.8
49	L	L	B	H	0.2	0.79	0.4	0.30	0.019	1381.1	340.0	6.4	26.2
50	L	L	B	B	0.2	0.79	0.4	0.40	0.025	856.3	237.9	6.0	21.6
51	L	L	B	L	0.2	0.79	0.4	0.30	0.019	473.2	76.7	1.5	9.0
52	L	L	L	H	0.2	0.79	0.3	0.30	0.014	1318.0	267.4	3.8	18.7
53	L	L	L	B	0.2	0.79	0.3	0.40	0.019	842.1	190.5	3.6	16.0
54	L	L	L	L	0.2	0.79	0.3	0.30	0.014	467.3	71.6	1.0	6.6
									1.000			184.0	869.5
Non-Bujagali Least Cost Option													
55		H	H	H		0.21	0.3	0.30	0.019	1359.5			25.7
56		H	H	B		0.21	0.3	0.40	0.025	786.0			19.8
57		H	H	L		0.21	0.3	0.30	0.019	354.2			6.7
58		H	B	H		0.21	0.4	0.30	0.025	1256.4			31.7
59		H	B	B		0.21	0.4	0.40	0.034	761.5			25.6
60		H	B	L		0.21	0.4	0.30	0.025	332.3			8.4
61		H	L	H		0.21	0.3	0.30	0.019	1179.8			22.3
62		H	L	B		0.21	0.3	0.40	0.025	726.0			18.3
63		H	L	L		0.21	0.3	0.30	0.019	314.3			5.9
64		L	H	H		0.79	0.3	0.30	0.071	1906.5			135.6
65		L	H	B		0.79	0.3	0.40	0.095	1170.7			111.0
66		L	H	L		0.79	0.3	0.30	0.071	564.6			40.1
67		L	B	H		0.79	0.4	0.30	0.095	1721.1			163.2
68		L	B	B		0.79	0.4	0.40	0.126	1094.2			138.3
69		L	B	L		0.79	0.4	0.30	0.095	550.0			52.1
70		L	L	H		0.79	0.3	0.30	0.071	1585.4			112.7
71		L	L	B		0.79	0.3	0.40	0.095	1032.6			97.9
72		L	L	L		0.79	0.3	0.30	0.071	538.9			38.3
									1.000				1053.6

NPV advantage of Bujagali	US$m	184.0

Residential Affordability

37. "Affordability" describes the percentage of household income expended on electricity. Less than 5% of Ugandan households are currently supplied by UMEME. These households would generally have incomes towards the upper end of the income distribution for the country.

38. Based on a study commissioned by ERA, the economic analysis estimates the average annual household income at US$3,952 and expenditure on electricity at US$226.7 for households that were connected to the grid in 2005. This corresponds to average electricity consumption of 134 kWh per household per month and a ratio of 5.7% of household income spent on electricity. Since most households do not use electricity for cooking, and tend to use wood, charcoal, kerosene or bottled gas for this purpose, this expenditure is generally for the provision of lighting, radio and TV, and fans. The 5.7% value is therefore towards the upper end of the expected range for such end uses.

39. Another parameter in the analysis, however, is the number of households actually being served by the average residential connection. *Statistics Norway* analysis of 2002 Uganda Bureau of Statistics survey data found that 451,000 households[6] were connected to the electricity grid, whereas 2005 UMEME data indicated just 255,000 official residential connections. This suggests that there are approximately 1.8 households supplied by each residential connection. Following enquiries with officials in the Ugandan electricity industry, it appears that it is not uncommon for more than one household to be supplied from a single UMEME connection. This can range from 'compound houses', with three or four individual households sharing a single compound and a single UMEME connection, to apartment blocks, where only the landlord is metered.

40. Reverting the average residential customer, if as the data indicates, on average each connection supplied 1.8 households, then the proportion of household income spent on electricity would be reduced to just 3.2%, which is much closer to expectations. The question remains, however, whether electricity will still be affordable in 2011, with the tariff trajectory that is expected and utilized in the demand forecast for the proposed project's due diligence.

41. Assuming a 2.3% real annual income growth over the 6 years between 2005 and 2011, average residential income will grow by 14.6% from US$3,952 to US$4,529 per year. Assuming an income elasticity of demand of 1.0 and setting aside other factors influencing demand, electricity consumption would also grow by 14.6% from 134 kWh per month to 154 kWh per month between 2005-11. With a 2011 residential tariff of US$23¢/kWh (2006 constant terms), the implicit expenditure on electricity increases to US$425 per year. This represents 9.4% of household income, on the basis of a single household per connection, or 5.2% on the basis of 1.8 households per connection. As noted above, 5.2% is within, but towards the upper end of, the range of expectations for the proportion of household income expended on electricity for non-cooking purposes, and should be sustainable.

42. When the proposed project is commissioned in 2011, the average electricity tariff is expected to drop by up to 10%, which would improve affordability compared to the period 2006-2010. Beyond 2011, as average household income continues to grow, affordability of electricity will also improve.

[6] This corresponds to 3% of rural households equating to 123,000 households, and 41% of urban households equating to 328,000 households, which produces a total of around 451,000 mains-connected households in 2002/03.

Environmental and Social Considerations

43. For purposes of least-cost system planning, environmental and social costs for Bujagali and Karuma are capitalized and added to investment costs and are thus incorporated into the least-cost analysis described above. These estimates of the environmental and social costs are based on review of documentation, field research and on the analysis carried out by R.J. Burnside International Ltd. in preparation of the Social and Environmental Assessment documentation for the project. The environmental and social costs for the proposed project for the period 2007-12 are estimated at US$26 million covering the dam, powerhouse and the associated transmission line (see Tables 23 and 24). These costs include the Resettlement and Community Action Plans for both the project and the associated transmission line. The social costs incurred in 2000/01 for dam site resettlement are considered sunk costs, from an economic perspective, and are not included in this analysis.

Table 9.9: Environmental Costs of Bujagali and Associated Transmission Line (US$million)

Item	2007	2008	2009	2010	Total
Dam and power house	0.89	0.78	0.78	1.11	3.56
Transmission line	0.23	0.23	0.23	--	0.69
Sub-Total	1.12	1.01	1.01	1.11	4.25
Contingencies (15%)	0.18	0.15	0.15	0.16	0.64
Total	**1.30**	**1.16**	**1.16**	**1.27**	**4.89**

Table 9.10: Social Costs of Bujagali and Associated Transmission Line (US$ million)

Item	2007	2008	2009	2010	Total
Dam and power house	0.60	1.21	1.21	0.60	3.62
Transmission line	4.21	4.21	4.21	2.10	14.73
Sub-Total	4.81	5.42	5.42	2.70	18.35
Contingencies (15%)	0.72	0.81	0.81	0.41	2.75
Total	**5.53**	**6.23**	**6.23**	**3.11**	**21.10**

44. The equivalent social and environmental cost for Karuma and its associated transmission line is estimated at US$15 million, based on its Environment and Social Impact Assessment of 1999 and updates by the consultant.

ECONOMIC INTERNAL RATE OF RETURN (EIRR)

45. The EIRR analysis framework is designed to find the EIRR of a series of annual economic values reflecting, on the one hand, cost savings due to displaced thermal power and benefits of the proposed project's energy output to end-users and, on the other hand, costs for constructing and operating the proposed project, managing environmental and social impacts and delivering the project's energy to end-users through the transmission and distribution system. The EIRR is calculated over 2007 to 2061 inclusive, with project benefits and costs stabilized at the level reached by the year the proposed project's output is fully absorbed, which varies depending on the selected hydrology and demand forecast assumptions.

46. The EIRR model was developed to calculate individual scenario EIRR values for the various combinations of hydrology, fuel prices, demand forecast and project cost, which are the key risks to the EIRR. They are described in the above section on least cost expansion planning. Regarding project benefits:

(a) The proposed project will displace a large amount of grid thermal generation, while catering to incremental demand. Each of these components has a different value – grid thermal being valued at its variable cost of production (fuel, operation and maintenance) and incremental demand being attributed the value of the energy to consumers.

(b) From a value perspective, there are four distinguishable categories of end-user consumption attributable to the project: (a) newly-connected households; (b) incremental residential consumption from previously connected customers; (c) incremental non-residential consumption; and (d) (a small volume of) contracted exports to Tanzania and Rwanda.

47. The value of project-associated electricity supply is different for each:

(a) At first, newly connected households use electricity to displace costlier sources of energy for relatively small amounts of their consumption; this opportunity cost is recognized in their willingness to pay, using a semi-log formulation of the income-compensated demand curve (to avoid over-weighting consumer-surplus);

(b) All demand of previously connected households is worth the tariff paid; newly connected households become previously connected households the year after they are connected;

(c) For non-residential loads, the value is a combination of the cost of self-supplied generation, which is high (the quantity for this component being set at one-third of the outages suffered on average in 2005) and grid-purchased generation, this being by far the largest component and valued at the tariff (the shape of the demand curve connecting the high self-supply value with the bulk of energy purchased at the grid tariff rate is defined by a double-log formulation which minimizes the weight of the high-value component); and

(d) For exports, value based on the opportunity cost of importers' alternative supply.

48. Each of these value streams is calculated and applied to the allocation of the demand forecast between each of these groups (see willingness to pay of end-users in Table 9.11).

Table 9.11: Summary of Willingness to Pay (WTP) Results
(Values are in real 2006 US ¢/kWh)

	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Real Increase/(Decrease) in Marginal Tariff	0%	37%	45%	15%	0%	0%	-28%	0%
Marginal Residential Tariff	14.1	19.3	27.9	32.1	32.1	32.1	23.0	23.0
Cumulative Price Growth Factor	1.00	1.37	1.99	2.28	2.28	2.28	1.63	1.63
WTP – Existing Residential Customers	14.1	19.3	27.9	32.1	32.1	32.1	23.0	23.0
WTP – Existing Residential Customers	41.9	50.5	61.6	66.2	66.1	66.1	56.7	56.5
WTP – Non Residential Customers	12.5	16.1	21.4	23.7	23.6	23.4	20.8	20.7
WTP – Exports	18.8	18.8	18.3	17.2	16.3	15.4	14.7	14.0

49. The result of all the calculations is that the proposed project's EIRR would be no less than 12.4% and no more than 25.8% in the series without greenhouse gas benefits (or no less than 12.9% or nor more than 26.4% with greenhouse gas benefits). The EIRR for the Base Case is 22.0% without the CO_2 benefits and 22.9% with these benefits. This is illustrated in the EIRR (Table 9.12).

50. The quantity of CO_2 emissions avoided as a result of the project is based on CO_2 emissions to generate equivalent energy in the corresponding least cost plan without the proposed project. They are

valued at US$25 per ton of CO_2, as estimated in the recent *Stern Review on the Economics of Climate Change*. This benefit stream makes little difference to the EIRR of the proposed project.

Table 9.12: Economic Internal Rates of Return[7]

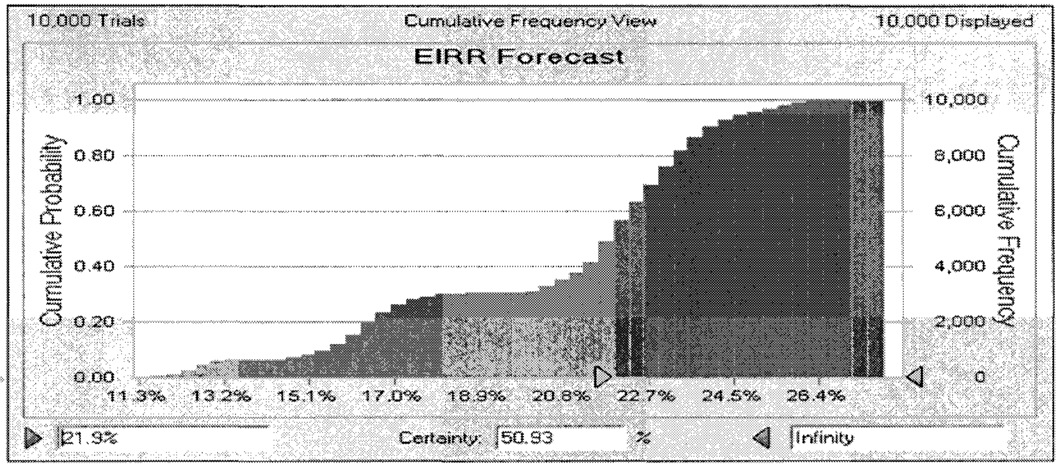
Run No.	Demand	Oil Price	Hydrology	Bujagali Capex	GHG	EIRR	Table Ref.
1	Base	Base	High	Base	Yes	22.0%	F.1
2	Base	Base	High	Base	No	21.7%	F.2
3	Base	Base	Low	Base	Yes	22.9%	F.3
4	Base	Base	Low	Base	No	22.0%	F.4
5	Base	High	High	Base	Yes	22.4%	F.5
6	Base	High	High	Base	No	22.1%	F.6
7	Base	High	Low	Base	Yes	23.6%	F.7
8	Base	High	Low	Base	No	22.7%	F.8
9	Base	Low	High	Base	Yes	21.7%	F.9
10	Base	Low	High	Base	No	21.4%	F.10
11	Base	Low	Low	Base	Yes	22.3%	F.11
12	Base	Low	Low	Base	No	21.4%	F.12
13	High	Base	High	Base	Yes	25.8%	F.13
14	High	Base	High	Base	No	25.3%	F.14
15	High	Base	Low	Base	Yes	24.5%	F.15
16	High	Base	Low	Base	No	23.1%	F.16
17	High	High	High	Base	Yes	26.4%	F.17
18	High	High	High	Base	No	25.8%	F.18
19	High	High	Low	Base	Yes	24.9%	F.19
20	High	High	Low	Base	No	23.6%	F.20
21	High	Low	High	Base	Yes	25.4%	F.21
22	High	Low	High	Base	No	24.9%	F.22
23	High	Low	Low	Base	Yes	24.1%	F.23
24	High	Low	Low	Base	No	22.8%	F.24
25	Low	Base	High	Base	Yes	13.0%	F.25
26	Low	Base	High	Base	No	12.6%	F.26
27	Low	Base	Low	Base	Yes	16.6%	F.27
28	Low	Base	Low	Base	No	16.4%	F.28
29	Low	High	High	Base	Yes	13.2%	F.29
30	Low	High	High	Base	No	12.8%	F.30
31	Low	High	Low	Base	Yes	17.4%	F.31
32	Low	High	Low	Base	No	17.2%	F.32
33	Low	Low	High	Base	Yes	12.9%	F.33
34	Low	Low	High	Base	No	12.4%	F.34
35	Low	Low	Low	Base	Yes	16.0%	F.35
36	Low	Low	Low	Base	No	15.8%	F.36
37	Base	Base	High	High	Yes	20.9%	F.37
38	Base	Base	High	High	No	20.6%	F.38
39	Base	Base	Low	High	Yes	21.3%	F.39
40	Base	Base	Low	High	No	20.5%	F.40
41	Base	Base	High	Low	Yes	22.6%	F.41
42	Base	Base	High	Low	No	22.3%	F.42
43	Base	Base	Low	Low	Yes	23.7%	F.43
44	Base	Base	Low	Low	No	22.8%	F.44

51. An alternative approach to calculating the risk to the EIRR is to specify probability functions for each of the uncertain variables (project cost, demand, oil price and hydrology) that resemble the shape of the range values used for deriving the results matrix and using Crystal Ball[8] to randomly select any combination of values for each variable within the specified ranges over a series of 10,000 iterations, producing a distribution of the EIRR according to the full array of possibilities within the

[7] Last column in the table, "Table Ref", refers to relevant tables in the Economic Study Appendices document.
[8] This is a program developed by Decisioneering Inc. for risk analysis and recommended for use within the World Bank Group.

assumption set. The results of this work for the cases without the greenhouse gas credit are illustrated in the graph below, indicating a minimum EIRR of 11.3% and a maximum EIRR of 26.4%. This range is slightly broader than that indicated in the matrix above, because the latter excludes the full variance analysis for the project cost.

Figure 9.3: EIRR Probability Distribution



52. To remove benefit calculations which include elements of "consumer surplus", an EIRR calculation has been carried out using the low hydrology scenario that assigns the simplest values of electricity to end-users: the 2007 average end-user tariff on all sales, staying constant in real terms, roughly as indicated by the tariff verification results above; it also assigns the lowest possible cost of thermal displacement to all thermal displacement usage: the variable cost of energy from diesel plants, with fuel based on the World Bank crude oil price projection; this results in a fuel plus operation and maintenance costs in the range of US$12-13¢/kWh, decreasing to US$9¢/kWh from 2011 onward. The result of this calculation is an EIRR of 17.7%. If the proposed project cost were increased by 10%, all else equal, the EIRR would be 16.6%. Even with a 10% project cost over-run the value of electricity to end users could be as low as US$8.5¢/kWh before the EIRR would fall below 10%, in the low hydrology scenario.

MACROECONOMIC IMPACT[9]

53. The key macro-economic concerns about the development of major infrastructure projects in relatively small economies are whether they would impose burdens on the balance of payments and the Government's budget that are difficult to manage. Given that a growing supply of electricity is a necessary condition for general growth and diversification of the Ugandan economy, these questions can be addressed by examining the comparative macro-economic implications of the proposed mainly hydro-based approach in Uganda (the base case least cost expansion plan described in Figure 9.2), versus an alternative electricity supply development path based on oil products. The cash flows of the proposed Private Power Generation (Bujagali) Project are put into perspective within their macro-economic context.

54. The macro-economic and power sector information are in constant 2006 money and are based primarily on data about the following power generation options: system expansion cases 32 (the least

[9] This section is based on analysis undertaken by an independent consultant (John Holsen), commissioned by IDA.

cost expansion plan, which includes Bujagali from 2011 and Karuma from 2017, the "Hydro case") versus case 82 (a purely thermal based expansion plan, the "Thermal case") provided in the Economic Report prepared by Power Planning Associates. The key findings of this analysis are:

- In the period, 2011-20, the needs of the power sector place a net burden on the balance of payments of US$1,288 million in the Hydro case and US$1,991 million in the Thermal case. The main contributor to the outflow in the Thermal case is the fuel cost of US$1,762. Hence, the Hydropower case saves about US$703 million of foreign exchange relative to the thermal alternative during 2011-20.

- A sensitivity analysis was carried out for major changes in both fuel and construction costs. A 35% decrease of fuel prices relative to those in the base case projection would reduce the foreign exchange savings from US$703 million to US$195 million. A 20% increase of construction costs would reduce the Hydro case savings to US$553 million; when combined with a 40% decrease of fuel prices, this would reduce the Hydro case savings to US$45 million.

- Based on budgetary performance in recent years, the cost savings of the Hydro case relative to the Thermal case during 2011-20 would average about 3.6% of budget revenues and 6.0% of development expenditures. These savings rise over time since, without new hydropower, Uganda becomes increasingly dependent on thermal power. Thus by 2020, the potential cost savings amount to 5.1% of budget revenues and 8.4% of development expenditures. The power sector should operate on a commercial basis without electricity costs being imposed on the Government budget. The data, however, indicates the extent of a potential budgetary burden if, absent the hydro strategy, the Government were pressured to subsidize the difference in the tariff between the cost of the thermal option relative to that of the hydro option.

- While sometimes short-term macro problems can arise from the growth in demand that accompanies major construction activities, this is not expected to occur with the proposed project. During the 3.5-year construction period, Uganda's total GDP is expected to be about US$41.3 billion, within which gross fixed investment expenditures will be nearly US$10.0 billion (both in 2006 prices). About 65% of the total economic cost of the proposed project is expected to be spent for imported goods and services. The residual demand upon national resources is only US$190 million. This amounts to 0.5% of GDP and about 1.9% of total investment expenditures over the 3.5 year period. Given these small percentages, the proposed project should not cause macro management problems related to "excess investment demand". While external financing will cover this draw on national resources, the foreign exchange inflow will be equivalent to about 2.3% of total imports (or 2% of total exports plus transfers) over the period. Hence there should be no concern about a "Dutch Disease" effect[10].

55. **Conclusions of the Economic Analysis.**

- Bujagali is a robust, long-overdue project with minimal economic risk to its status as the least-cost option for the next major Ugandan grid system generation increment;

- The EIRR to the project is highly satisfactory and the risks to its not reaching a 10%

[10] "Dutch Disease" is a phenomenon that occurs when one sector of the economy causes such a large influx of foreign exchange that the resulting exchange rate appreciation distorts competitiveness in other sectors.

benchmark are considered as very low;

- These conclusions include evaluation of the relative merits of alternative projects, environmental and social impacts, and affordability of electricity in the vastly under-served Ugandan market; and

- The overall impact of the proposed project on macroeconomic sustainability is expected to be positive.

Annex 10: Lake Victoria Hydrology[1]

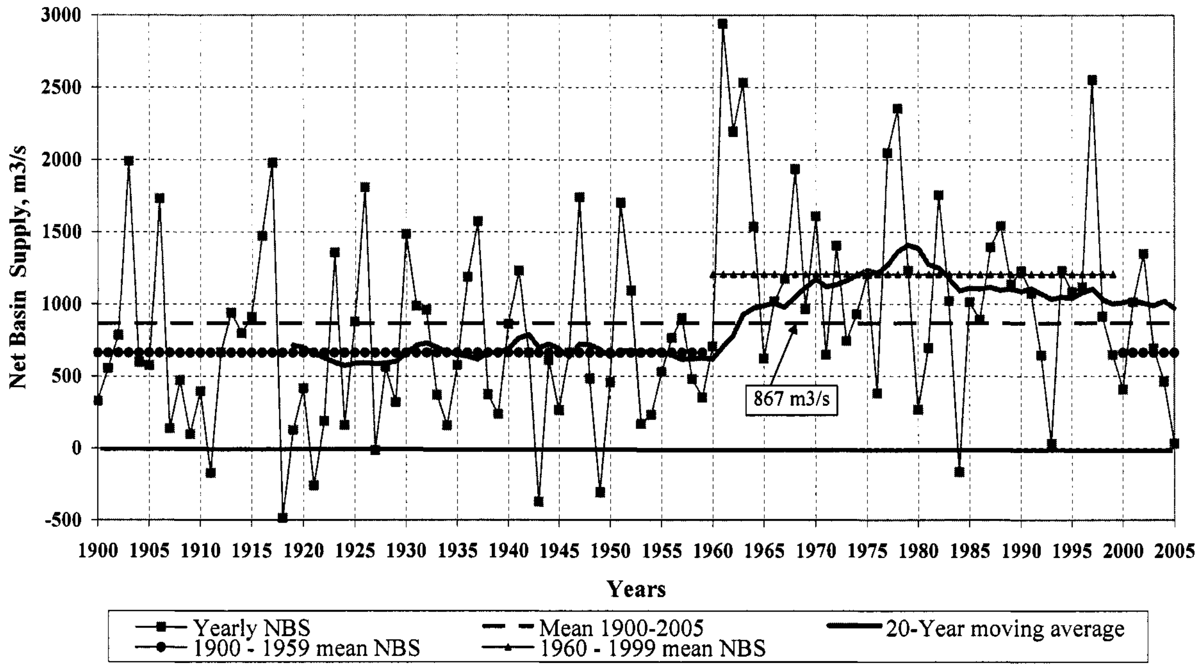
1. **Summary on Hydrological Performance of Lake Victoria.** The period of time after the commissioning of Bujagali, when the energy generation represents most of the benefits of the project, is approximately 20 years. This is the consequence of the discounting process in the economic evaluation of the project. Therefore, the hydrological scenarios considered for the calculation of energy generation and economic evaluation should be selected for being most representative of periods of 20 years of duration that are likely to occur again in the future.

2. In the 1900 – 2005 historical series of the net inflow into the lake, also called Net Basin Supply (NBS = Run-off + Direct Lake Rainfall – Lake Evaporation), three homogeneous periods can be observed:

- 1900 – 1959: average net inflow = 662 m^3/s
- 1960 – 1999: average net inflow = 1206 m^3/s
- 2000 – 2005: average net inflow = 659 m^3/s

3. Both periods 1900 – 1959 (60 year-duration) and 1960 – 1999 (40-year duration) appear to be homogeneous enough to define the two hydrological series that are most representative of the future net inflow pattern that is likely to occur for a period of approximately 20 years after commissioning of the next major hydropower plant on the Nile.

Figure 10.1: Lake Victoria Net Basin Supply – 20-Year Moving Average Net Basin Supply and Mean Yearly Net Basin Supply of each Reference Period



[1] An assessment of the hydrology of Lake Victoria undertaken for the proposed project was carried out by Power Planning Associates (UK) in consultation with Coyne et Bellier (France), and ECON (Norway).

4. A scenario that would consider the whole period 1900 – 2005, leading to a long term average of 867 m^3/s, is found not to be representative enough of 20-year periods, as shown by the 20-year moving average curve in the above figure, in which the Net Basin Supply is for most of the time clearly above or clearly below the long term average value. On the other hand, as no reason can be produced to discard the possibility that a future 20-year period will be similar to those observed in the historical record, the following scenarios are defined:

- Low Hydrology Scenario: the net inflow into the lake will be in broad agreement with what happened between 1900 and 1960, and again between 1998 and 2005, that is to say, annual variations around an average Net Basin Supply of 660 cubic meters per second (m^3/s);

- High Hydrology Scenario: the net inflow will be in accordance with the period that started with the exceptional inflows of 1961-1964 (average 2,300 m^3/s), followed by approximately 35 years of NBS averaging more than 1,000 m^3/s, with an average net inflow of 1,200 m^3/s during the whole period.

5. The reservoir operation studies performed on the basis of each of these two net inflow series produced the values of constant release that are guaranteed with 95% reliability:

- Low Hydrology: the firm release is 687 m^3/s

- High Hydrology: the firm release is 1,247 m^3/s.

6. Based on a combination of analysis of dry sequences and mean values, the probabilities associated to each of the above hydrology scenarios occurring during the period 2011 – 2030 are: 79% for the Low Hydrology and 21% for the High Hydrology. The possible influence of climatic changes was found not to be significant enough in the medium term (to 2030) to influence in one way or the other the hydrological scenarios.

7. **Departure from the Agreed Curve and Recent Fall in the Level of Lake Victoria.** The "Agreed Curve" is the relationship between the release at the Nalubaale/Kiira dam complex and the level of Lake Victoria, for the release to follow the "rating curve" that used to be imposed by the level of the lake outlet before the construction of the Nalubaale hydropower facility in the 1950s, based on the Jinja Gauge.

8. The consequence of meeting the Agreed Curve is that, the lower the lake level, the lower the release, and the higher the lake level, the higher the release. The two extreme situations that were experienced by the lake level are as follows:

- lake level = 1133.2 the release according to the Agreed Curve is: 400 m^3/s

- lake level = 1136.2 the release according to the Agreed Curve is: 1,850 m^3/s

9. The Agreed Curve therefore constitutes a "moving reference". If during a long dry period, when net inflows are consistently lower than the long term average, releases are consistently higher than the net inflow, then the drop in lake level is accelerated and the departure of release from the Agreed Curve is amplified. This is precisely what occurred during the period 2003 – 2005, and is illustrated in Figure 10.2 below:

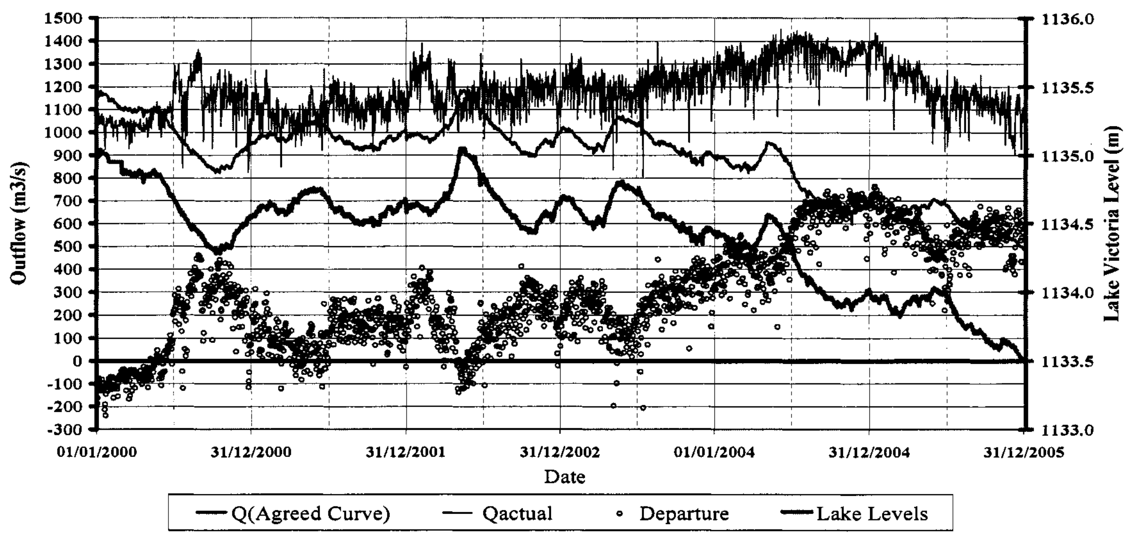
- The net inflow of these 3 years was consistently below the long term average: 80% of the long term average net inflow in 2003, 53% in 2004 and 3% in 2005.

- During the same period, the power demand in Uganda required a sustained release that was above the net inflow, thus accelerating the drop in lake level, and automatically increasing the departure from the Agreed Curve.

10. A main cause of the drop in lake level in the past few years was the exceptionally dry period during 2003 – 2005, when the mean net inflow was only 46% of the long term average net inflow, and only 60% of the mean net inflow of the Low Hydrology scenario. The consequence of this low inflow, combined with the release for power generation that was not reduced to the Agreed Curve level due to Uganda's lack of sufficient alternative sources of power generation resulted in a further drop in lake level.

11. Had the proposed project been in operation during the time, the consequence of this exceptionally dry period would have been much lower. Since the Bujagali site is downstream of the existing Nalubaale and Kiira plants, the same release could have been used a second time at Bujagali and would generate an additional 120% of the power already generated by the turbines of Nalubaale – Kiira (the ratio 1.2 is due to the higher head available at Bujagali). Therefore, with Bujagali in operation, the generation of the same total power and energy would require only 45% (=1/(1+1.2)x100) of the release from the lake as compared to the present situation without Bujagali.

Figure 10.2: Lake Victoria - Time Series of Outflows and Lake levels - 2000 to 2005 (the right scale applies to lake levels only)



12. **Lake Operation Modelling and Energy Generation Evaluation.** Reservoir operation modelling was performed to calculate the firm release and the firm energy generation in each of the hydrology scenarios. The results are summarized as follows:

Table 10.1: Energy Generation Capability of Each Hydropower Plant

Plants	Units (2)	Qmax m^3/s	Low Release / Low Hydrology: Available Capacity MW	Low Release / Low Hydrology: Firm Energy Generation GWh/yr	High Release/ High Hydrology: Available Capacity MW	High Release/ High Hydrology: Firm Energy Generation GWh/yr
Nalubaale - Kiira	**Units 1 to 15**	**2300**	**203 (1)**	**972**	**204 (1)**	**1740**
Bujagali HPP	Units 1 to 4	992	200	1 198	200	1 715
(candidate)	**Units 1 to 5**	**1240**	**250**	**1 198**	**250**	**2 132**
Karuma HPP	Units 1 to 3	594	150	1 295	150	1 302
(candidate)	**Units 1 to 4**	**792**	**158**	**1 360**	**200**	**1 722**
	Units 1 to 5	990	158	1 360	250	2 141
	Units 1 to 6	1188	158	1 360	296	2 523

(1) this value may vary depending on the downstream plants and on the optimum operation rule
(2) lines in bold characters indicate the plants considered as base options in the expansion plans modelling

Before the above figures were used in the economic evaluation and expansion plan modelling, adjustments were made to account for the impact of periods when the generating units are under maintenance. The decrease in energy output ranges between 2% and 7% of the above energy generation figures.

Annex 11: Bujagali Energy Limited Financial Projections

1. The Bujagali Energy Limited (BEL) financial model incorporates the terms of the project agreements and for the financing. The financial projections assume an accounting year-end of 31 December. Below is a list of key assumptions.

2. **Inflation.** Annual inflation is based on US Producer Price Index, which has been estimated at 2.5% per annum. Inflation is considered to be applicable primarily to operating and maintenance costs.

3. **Exchange Rates.** BEL revenues are denominated in US Dollars, but may also be paid in shillings. There is a requirement in the PPA that the actual US$/USh exchange rate at the time of payment be used in determining the actual amount that becomes due in shillings, if applicable. There is no provision for foreign exchange gains or losses in the model since the foreign exchange exposure is minimal.

INCOME STATEMENT

4. **Construction Schedule.** The model assumes BEL will start operations 44 months after the construction start date, currently projected to be August 2007.

5. **Project Revenue.** Operating project revenue is wholly in the form of annual capacity payments in respect of generating capacity made available to UETCL. The annual capacity payments are payable on a monthly basis by UETCL upon the issuance of invoices by BEL. The capacity payment covers all agreed costs associated with the generation of electricity, including the cost of debt, plus an equity return. The capacity payment is calculated according to the detailed provisions specified in the PPA.

6. **Operation and Maintenance (O&M) Costs.** As per the terms of the PPA, the company receives a monthly capacity payment that is indexed according to US Producer Price Index (subject to a maximum increase of 0.85% over one quarter and a maximum increase of 3.2% over a 12 month period). The actual O&M will vary due to the scheduled maintenance that occurs every other year over the project's life and major overhauls every eight years. In addition to this scheduled maintenance, O&M costs include annual routine equipment maintenance.

7. **Taxation.** BEL's corporate income tax rate is 30%. In the early years, BEL will be carrying forward the losses generated due to the application of accelerated tax depreciation and, therefore, it is not expected to have a corporate tax obligation.

8. **Dividend Withholding Tax.** All dividend distributions from BEL are subject to a withholding tax of 10%, calculated on the gross dividend distribution.

9. **Financing.** The project is being financed with a debt to equity ratio of approximately 79:21. The terms considered for the senior loans from the DFIs are as per the current discussions amongst lenders, including a 16 year maturity, including a grace period of approximately four years. Subordinated loans are expected to have a maturity of up 20 years, including a grace period of approximately four years. Under the assumption of a timely completion of the project, repayments would commence on September 2011. All senior loans would be repaid in 24 equal semi-annual repayments up to 2023.

10. **Equity.** Equity contributions, provided by IPS(K), Sithe Global and the Government, will be disbursed up-front in full before any disbursements are made by lenders.

Bujagali Energy Limited

Detailed Financial Projections

Profit and Loss Statement

(US$000s

FY End December 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Gross Revenue	82,689	137,155	137,342	137,533	137,729	149,986	170,577	172,616	177,621	180,350	184,250	187,099	82,922	81,965	83,376	82,104	76,28
Total Operating Costs	5,760	8,812	7,097	8,506	7,607	9,013	7,992	12,159	8,397	9,949	8,822	10,453	9,269	10,982	9,738	14,815	10,23
EBITDA	76,928	128,343	130,244	129,027	130,122	140,973	162,584	160,457	169,224	170,401	175,428	176,646	73,653	70,983	73,638	67,289	66,05
Depreciation	17,620	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,493	23,49
EBIT	59,309	104,850	106,751	105,534	106,629	117,480	139,091	136,964	145,731	146,908	151,935	153,153	50,160	47,490	50,145	43,796	42,55
Finance Charges	27,607	55,656	51,601	48,694	45,535	42,085	38,785	35,449	31,068	26,364	21,152	15,490	7,536	2,355	1,759	1,111	29
Earnings Before Tax	31,702	49,194	55,150	56,840	61,093	75,395	100,307	101,515	114,664	120,544	130,783	137,663	42,624	45,136	48,387	42,685	42,26
Tax	0	0	0	0	0	12,057	32,441	34,270	39,059	41,566	45,238	47,854	18,792	17,945	19,105	17,576	17,57
Profit After Tax	31,702	49,194	55,150	56,840	61,093	63,338	67,865	67,245	75,605	78,978	85,544	89,808	23,832	27,191	29,282	25,109	24,69

Balance Sheet

(US$000s

FY End December 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS																	
Cash	39,023	7,132	10,123	13,611	17,209	32,645	56,035	62,951	72,378	80,651	90,321	56,525	500	500	1,395	500	50
Debt Service Reserve Account	42,567	42,567	42,567	42,567	42,567	42,567	42,567	42,567	42,567	42,567	42,567	42,567	3,178	3,178	3,178	3,178	
Accounts Receivable	18,124	22,546	22,577	22,608	22,640	24,655	28,040	28,375	29,198	29,647	30,288	30,756	13,631	13,474	13,706	13,497	12,53
Inventory	8,823	9,044	9,270	9,501	9,739	9,982	10,232	10,488	10,750	11,019	11,294	11,577	11,866	12,163	12,467	12,778	13,09
Total Current Assets	108,536	81,288	84,536	88,287	92,155	109,849	136,874	144,381	154,893	163,883	174,469	141,425	29,175	29,315	30,745	29,953	26,13
Fixed Assets																	
Capitalized Project Costs	704,790	687,170	663,677	640,184	616,691	593,198	569,705	546,212	522,719	499,226	475,733	452,240	428,747	405,254	381,761	358,268	334,77
Accumulated Depreciation	(17,620)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493)	(23,493
Net Capitalized Project Costs	687,170	663,677	640,184	616,691	593,198	569,705	546,212	522,719	499,226	475,733	452,240	428,747	405,254	381,761	358,268	334,775	311,28
Government Contributed Assets	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,00
Total Fixed Assets	707,170	683,677	660,184	636,691	613,198	589,705	566,212	542,719	519,226	495,733	472,240	448,747	425,254	401,761	378,268	354,775	331,28
TOTAL ASSETS	815,707	764,965	744,720	724,978	705,353	699,555	703,086	687,101	674,119	659,616	646,710	590,172	454,430	431,076	409,014	384,729	357,42
LIABILITIES & EQUITY																	
Liabilities																	
Accounts Payable	415	502	428	540	462	574	485	824	510	633	536	665	563	699	591	1,004	62
Taxes Payable	0	0	0	0	0	12,057	32,441	34,270	39,059	41,566	45,238	47,854	18,792	17,945	19,105	17,576	17,57
Total Current Liabilities	415	502	428	540	462	12,630	32,927	35,094	39,569	42,199	45,774	48,519	19,355	18,644	19,696	18,580	18,19
Long Term Debt	612,020	580,100	545,401	507,675	466,651	422,033	373,497	320,689	263,224	200,679	132,590	58,453	17,101	13,016	8,334	2,969	
Total Long Term Liabilities	612,020	580,100	545,401	507,675	466,651	422,033	373,497	320,689	263,224	200,679	132,590	58,453	17,101	13,016	8,334	2,969	
Shareholder's Equity	203,272	184,363	198,892	216,764	238,240	264,892	296,663	331,318	371,326	416,739	468,346	483,200	417,974	399,417	380,984	363,180	339,22
TOTAL LIABILITIES & EQUITY	815,707	764,965	744,720	724,978	705,353	699,555	703,086	687,101	674,119	659,616	646,710	590,172	454,430	431,076	409,014	384,729	357,42

Annex 12: Financial Performance of the Uganda Power Sector

(Comprising UEGCL, UETCL, UEDCL and UMEME)

1. This annex covers the financial situation of the Ugandan power sector and future prospects, and complements the overview provided in the main section and in Annex 1.

2. The key areas covered in this annex include the following:

(a) Recent Performance of Individual Power Utilities (to 2006);
(b) Development of Retail Tariffs since 2004 and Future Tariff Outlook until 2011;
(c) Status of Government Electricity Bills;
(d) Key Elements to Restoration of Supply & Financial Sustainability;
(e) Principal Assumptions made in the Preparation of the Financial Projections to 2016;
(f) Sensitivity Analysis to the Base Case Projections; and
(g) Attachments for Sector Projections to 2016:
   1. Revenue requirements and financing plan to 2005-16;
   2. Operational and financial performance indicators 2004-16;
   3. Financial Statements 2004-16 in USh billions; and
   4. Financial Statements 2004-16 in US$ millions.

3. The financial forecasts are presented in nominal prices and are prepared on the basis of (a) base case load forecast; (b) base case hydrology (i.e., "low hydrology", (see Annex 10); (c) the Government's interim generation plan to 2010; (d) Bujagali hydropower plant (250 MW) commissioning in early 2011 and simultaneous decommissioning of the 50 MW thermal short-term plant financed under the proposed Bank project; and (e) base case crude oil price forecast, as per the Bank's forecast.

4. The consolidated performance of the following power utilities operating in Uganda is considered in the analysis presented in this document:

- UEGCL, wholly Government owned and owner of the Nalubaale and Kiira hydro power stations. The plants' operation was concessioned to Eskom (Uganda) Limited (wholly owned by Eskom Enterprise Pty. Ltd., of South Africa) for a period of twenty years starting April 2003.

- UETCL, wholly Government owned, owner of the transmission network and system operator of Uganda's power system.

- UEDCL, wholly Government owned and owner of the distribution network in Uganda. The network was concessioned to UMEME Limited for a period of twenty years starting March 2005.

- UMEME Limited, private operator of the distribution network.

A. RECENT PERFORMANCE OF INDIVIDUAL POWER UTILITIES (TO 2006)

UEGCL

5. From the time of handover of operations of the Nalubaale/Kiira dam complex, UEGCL's function is to monitor the activities of the operator, Eskom (Uganda) Limited. UEGCL has staff of

eleven people and its administration costs are recovered through a concession fee charged to Eskom (Uganda). In addition to administration costs, Eskom (Uganda)'s concession fee to UEGCL also includes: (a) UEGCL's debt service payable to Government on the generation debt vested to it from the former Uganda Electricity Board (UEB); and (b) investments that need to be funded from internal resources of UEGCL (e.g., counter-part funds for donor funded investments, vehicles, etc.). UEGCL does not earn any depreciation or returns on the leased assets. Eskom (Uganda)'s bulk supply charges to UETCL are comprised of: (a) recovery of the depreciation of its capital investments; (b) return (grossed-up for Uganda income tax) on investments (net of depreciation) made by Eskom (Uganda); (c) fixed annual O&M costs (fixed for the first seven years of the concession, as bid by Eskom (Uganda), and subject to indexation for inflation); (d) a small regulatory fee; and (e) UEGCL's concession fee.

6. UEGCL is financially sound, since it recovers all of its revenue requirements through the concession fee.

UETCL

7. UETCL earns its revenues from the sale of bulk power to UMEME. Its revenue requirements are comprised of bulk power purchase costs (hydro power from Eskom (Uganda), thermal power from private operators, power from small self-generators and non firm imports), its own operation and maintenance costs, investments to be funded from internal resources (in place of depreciation and returns on fixed assets), less revenues from small amounts of cross-border exports to Tanzania, Kenya and Rwanda. ERA determines the bulk supply tariff based on UETCL's revenue requirements. Government subsidies towards thermal power costs are provided to UETCL and passed on to UMEME through the bulk supply tariff and, therefore, are taken into account in the determination of end-use customer tariffs charged by UMEME.

8. Until the first quarter of 2005, the bulk supply tariff included an allowance for depreciation and return on equity. In addition, an annual allowance of USh17.5 billion (US$10 million) was made for the bulk supply tariff stabilization fund. The purpose of the bulk supply tariff stabilization fund was to provide a cushion against potential sudden price shocks in the electricity tariff resulting from large generation capacity additions or any other unforeseen events. During 2005, UETCL had accumulated a total of USh67 billion (US$36 million) in the bulk supply tariff stabilization fund and after use of parts of that fund in 2005 the balance of this fund was USh 49 billion (US$27 million) at the end of 2005. With the introduction of thermal power in Uganda and the resulting high electricity tariffs, ERA authorized UETCL to apply these resources towards thermal power costs. These bulk supply stabilization funds were fully utilized by April 2006.

9. UETCL has also applied its own surplus funds of USh25.4 billion (US$13.7 million) generated from its inception to mid-2005 towards thermal power costs. UETCL is now in a precarious financial situation. Since May 2006, UETCL has had to bridge its financing gap through higher budgetary support from Government. The Government is also hard pressed in making cash transfers to UETCL on a timely basis. As of December 31, 2006, Government owed UETCL USh24.6 billion (US$13.5 million).

10. The Government is currently providing substantial support to the power sector. In 2006, the Government provided (a) USh113 billion (US$62 million) in direct budget support towards thermal power costs of the power sector; and (b) USh12 billion (US$6.5 million) as security advance for the second ADO thermal plant.

UEDCL

11. From the time of handover of operations of the distribution network, UEDCL's function is to monitor the activities of the operator, UMEME Limited. UEDCL has staff of fourteen people and its administration costs are recovered through a lease payment charged to UMEME. In addition to administration costs, UEDCL's concession fee also includes (a) debt service payable to Government on the distribution debt vested to it from UEB, and (b) investments that need to be funded from internal resources of UEDCL (e.g., counter-part funds for donor funded investments, vehicles, etc). UEDCL does not earn any depreciation or returns on the leased assets.

12. UEDCL is financially sound since it recovers all of its revenue requirements through the lease payment.

UMEME

13. UMEME commenced operations under the concession on March 1, 2005. Following the power crisis, the Government and UMEME renegotiated UMEME's distribution and supply license in December 2006. Since the lack of power severely hindered UMEME's ability to meet its performance targets, under the restructured agreement, UMEME has been afforded certain protections for as long as the power crisis persists. These include, inter alia; (a) recovery of revenue shortfalls resulting from limited energy supplies; (b) protection against increases in losses or reduction in collection levels due to continued increases in tariffs; (c) additional incentives to enhance performance; and (d) risk coverage to safeguard all investments above US$5 million made during the extended "initial" eighteen month period of the concession, to as long as the power crisis persists (the end of the crisis currently expected to end when the proposed project comes into operation), except during the first year following the restructuring. The Government recruited international experts to assist in this restructuring exercise. IDA and MIGA reviewed the nature and substance of the renegotiated agreements, and concluded that they were not unreasonable given the current power crisis. This also included amendments to Credit 3411-UG in support of covering certain political risks relating to the UMEME concession.

14. UMEME's operational and financial performance has been satisfactory. The main features of its operational performance include:

- Distribution losses went down from 38% on takeover to around 34.1% as of end 2006;

- Overall collection rate went up from 80% on takeover to 92% by May 2006. Following the tariff increase of 37.5% in June 2006, the collection rate dropped to 85% from June to October 2006, and to 82% in November/December 2006, following another tariff increase of 41% in November 2006;

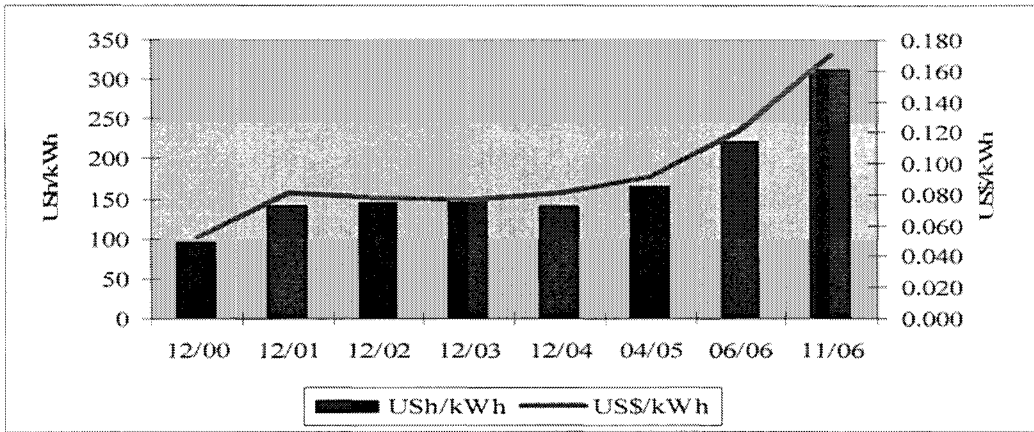
- A total of 36,000 new customers have been connected during the first twenty-two months of UMEME's operations to December 2006, against 22,000 committed under the concession. At present there are approximately 300,100 customers (270,000 domestic, 29,000 small commercial, 800 medium and large industry, and 300 street lights); and

- During the first twenty-two months to December 31, 2006, UMEME invested USh24.7 billion (US$13.6 million) in the network and operational assets, and it paid USh2.5 billion (US$1.4 million) to the Government as reimbursement of costs of arranging the concession. Under the concession, UMEME had committed to invest a minimum of US$5 million in the first eighteen months of the concession.

B. Development of Retail Tariffs since 2004 and Future Tariff Outlook until 2011

15. The weighted average retail tariff[1] over the past few years is illustrated in Figure 12.1.

Figure 12.1: Weighted Average Retail Tariff December 2000 – November 2006



(excluding Value Added Tax)

16. The development of end-use customer electricity tariffs are provided in Table 12.1. Electricity tariffs have risen significantly since April 2005 (around 151%)[2]. Domestic energy tariff for the first block up to 15kWh a month was increased by approximately 24% in June 2006 to 62USh/kWh (US$3.4¢/kWh); it had remained unchanged since 2001. The energy tariff for domestic consumption above 15 kWh a month was increased by 37.5% and 42.9% in June 2006 and November 2006, and by 149% cumulatively since 2004. For commercial, medium and large industrial customers, the average energy tariffs were increased between 37.7% and 64% in June 2006, and between 39% and 55% in November 2006, giving cumulative increases of between 142% and 210% since 2004; large industry was hit the hardest. In view of supply constraints, the time-of-use tariffs for non-domestic customers were substantially narrowed since June 2006.

[1] The weighted average retail tariff quoted throughout this Annex is exclusive of 18% Value Added Tax (VAT), unless otherwise stated which is added to customer bills. The term "retail" tariff refers to end-use customer tariffs.

[2] This percentage represents the accumulated increase of the weighted average end consumer tariff. However certain increases for different tariff categories may have been higher or lower as presented in the table below.

Table 12.1: Development of End-Use Customer Tariffs 2004 - June 2006

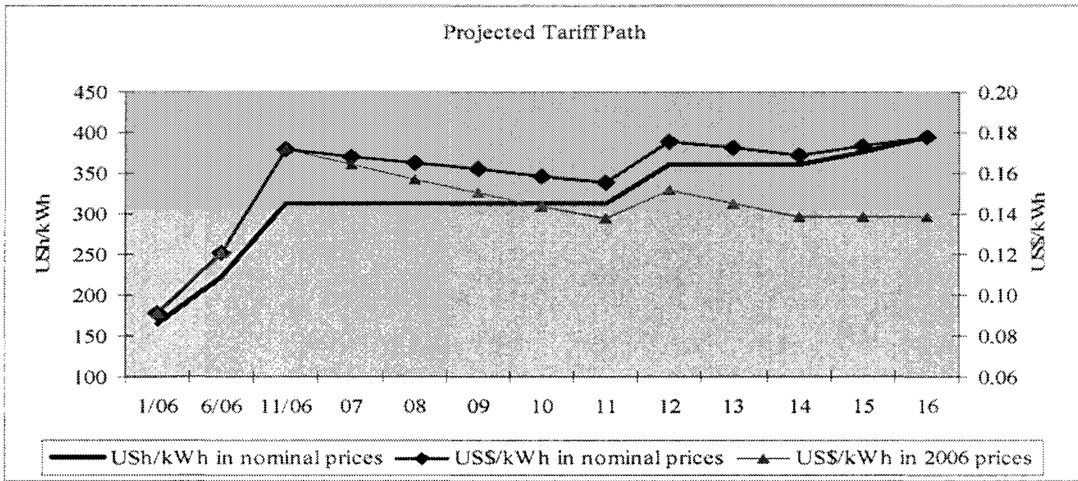
	Tariff Rates					Percentage Change				
	Effective 01-Nov-06 Shs	Effective 01-Jun-06 Shs	Effective 01-Oct-05 Shs	Effective 01-Apr-05 Shs	Effective 2004 Shs	Cumulative since Apr 05	01 Nov 06	01 Jun 06	01 Oct 05	01 April 05
Code 10.1 (single Phase - 240 Volts)										
First 15 kWh - per kWh	**62.0**	**62.0**	**50.0**	**50.0**	**50.0**	**24%**	**0.0%**	**24.0%**	**0.0%**	**0.0%**
Above 15 kWh - per kWh	**426.1**	**298.2**	**216.9**	**212.5**	**171.4**	**149%**	**42.9%**	**37.6%**	**2.1%**	**24.0%**
Fixed Monthly Service Charge	2,000.0	2,000.0	2,000.0	2,000.0	1,000.0		0.0%	0.0%	0.0%	100.0%
Code 10.2 - Commercial (Three Phase - 415 Volts)										
Peak - per kWh	464.9	327.6	265.9	259.9	196.6		41.9%	23.2%	2.3%	32.1%
Shoulder	399.3	287.0	204.3	200.5	162.8		39.1%	40.5%	1.9%	23.2%
Off-Peak - per kWh	306.6	223.9	100.6	100.8	104.3		36.9%	122.6%	-0.2%	-3.4%
Average tariff per month	***398.8***	***286.8***	***208.3***	***204.4***	***164.8***	***142%***	***39.1%***	***37.7%***	***1.9%***	***24.0%***
Fixed Monthly Service Charge	2,000.0	2,000.0	2,000.0	2,000.0	1,000.0		0.0%	0.0%	0.0%	100.0%
Code 20 - Medium Scale Industries - (Low Voltage 415 Volts with a Maximum Demand of up to 500 kVA)										
Peak - per kWh	434.3	300.9	238.2	232.1	180.1		44.3%	26.3%	2.6%	28.9%
Shoulder	370.3	261.8	178.8	175.0	148.3		41.4%	46.4%	2.2%	18.0%
Off-Peak - per kWh	260.7	201.9	80.0	80.2	94.5		29.0%	152.4%	-0.2%	-15.1%
Average tariff per month	***369.7***	***261.5***	***182.8***	***178.9***	***150.3***	***146%***	***41.4%***	***43.1%***	***2.2%***	***19.0%***
Fixed Monthly Service Charge	20,000.0	20,000.0	20,000.0	20,000.0	10,000.0		0.0%	0.0%	0.0%	100.0%
Maximum Demand Charge	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0		0.0%	0.0%	0.0%	0.0%
Code 30 - Large Industrial Users - (High Voltage 11,000 V or 33,000 V with a Maximum Demand exceeding 500kVA but up to 10,000 kVA										
Peak - per kWh	238.7	148.3	119.6	116.3	75.3		61.0%	24.0%	2.8%	54.4%
Shoulder	192.7	123.5	84.6	82.5	59.4		56.0%	46.0%	2.5%	38.9%
Off-Peak - per kWh	138.3	91.2	34.3	34.1	32.9		48.4%	165.9%	0.6%	3.6%
Average tariff per month	***187.2***	***120.8***	***73.6***	***71.9***	***60.4***	***210%***	***56.0%***	***64.1%***	***2.4%***	***19.0%***
Fixed Monthly Service Charge	30,000.0	30,000.0	30,000.0	30,000.0	15,000.0		0.0%	0.0%	0.0%	100.0%
Maximum Demand Charge - up to 2,000 kVA	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0		0.0%	0.0%	0.0%	0.0%
Maximum Demand Charge - 2,000 kVA -10,000 kVA	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0		0.0%	0.0%	0.0%	0.0%
Code 50 - Street Lighting										
Average tariff per month	***403.0***	***282.8***	***206.3***	***201.5***	***162.6***	***148%***	***42.5%***	37.7%	1.9%	***24.0%***
Overall increase in weighted average tariff						***151%***	***41.0%***	***37.5%***	***2.0%***	***27.0%***

17. Table 12.2 and Figure 12.2 show the projected levels of the weighted average retail tariff from 2006 to 2016.

Table 12.2: Projected Retail Tariff Path 2006-2016 (Base Case

	Jan 06	June 06	Nov 06	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average tariff increase		37.5%	41%	0%	0%	0%	0%	0%	15%	0%	0%	5%	5%
Cumulative tariff increase		37.5%	94%	94%	94%	94%	94%	94%	123%	123%	123%	133%	143%
Weighted average tariff at December 31													
USh/kWh in nominal prices	165	222	313	313	313	313	313	313	360	360	360	377	394
US$/kWh in nominal prices	0.091	0.121	0.172	0.168	0.165	0.162	0.159	0.156	0.176	0.172	0.169	0.173	0.178
US$/kWh in 2006 prices	0.091	0.121	0.172	0.164	0.157	0.150	0.144	0.138	0.151	0.145	0.139	0.139	0.139

Figure 12.2: Projected Electricity Tariff Path (2006-16)



18. ERA implemented two tariff increases during 2006 of about 94% (cumulative increase). Bulk supply tariffs of UETCL were increased at the same time. The base case assumptions indicate that there should be no need for further revisions in electricity tariffs through to 2011. Subsequently, tariffs would have to rise by an average of 15% on January 1, 2012 and by the assumed Uganda inflation rate of 4.5% in both 2014 and 2015 (or 26% cumulatively). This means that tariffs will fall in real terms over the course of next five years. However, if crude oil prices were to increase gradually over the years, to reach around US$80 per barrel (in 2006 prices), the projections show that tariffs would need to increase by 10% in 2009, 5% in 2010, 4.5% in 2014, 4.5% in 2015, and 10% in 2015 (or 39% cumulatively).

19. ERA kept the domestic Lifeline tariff of 50USh/kWh (US$2.7¢/kWh) for the first 15 kWh/month unchanged since 2001, and revised it only from June 2006 to 62USh/kWh (US$3.4¢/kWh). The lifeline consumption represents approximately 5.5% of total consumption by end-use customers.

C. Government Electricity Bills

20. The Government's consumption of electricity represents 7% of UMEME's total revenues, and the Government currently pays approximately 64% of its electricity bills. The outstanding balance as at end December 2006 was USh6.2 billion, after set-offs. Under the concession, UMEME has the right to offset overdue bills of Government against its lease payments due to UEDCL. Thus far, UMEME has deducted USh8.3 billion against UEDCL's lease payment. The amounts withheld by UMEME are in turn deducted by UEDCL from its debt service obligations to Government. This means that ultimately the Treasury pays for the unpaid bills of Government agencies.

21. Possible actions that the Government may consider to reduce the number of unpaid Government bills, include: (a) adequate budgetary provision, (b) support to UMEME to disconnect non-paying agencies (e.g., defense, police and prisons are major defaulters), (c) specially earmarked bank accounts for electricity bills, and (d) prepaid meters. UMEME has indicated that it would require Government/donor support to install and service prepaid meters for Government customers.

D. Key Elements to Restoration of Supply &Financial Sustainability

Power Supply & Demand

22. In order to secure supply and curtail consumer demand, the following actions are necessary:

- Government to secure additional short-term thermal capacity running on ADO (maximum 150 MW, of which 100 MW has been contracted), until the commissioning of the proposed project. The proposed Power Sector Development Operation (FY07) would secure the need for an additional 50 MW of generation capacity. In addition, the Government is evaluating an IPP for 50 MW power plant running on HFO. This permanent plant will displace 50 MW of existing thermal plant running on more expensive ADO.

- Government to encourage development of alternative sources of energy generation, such as renewables and cogeneration. In this regard, UETCL is in advanced stages of negotiating power purchase agreements involving 58 MW of new capacity, to be commissioned between mid-2007 and early 2009.

- Commissioning of 250 MW Bujagali hydropower plant by early 2011.

- Demand side management to curtail demand. Preliminary analysis indicates that between 30 MW to 70 MW could be reduced in the short to medium term. With the support of IDA and Sida, energy efficiency studies and audits will be initiated; 800,000 energy saving bulbs (compact florescent lamps) will be acquired and distributed free of charge; capacitors will be installed to correct power factors; 3,000 inefficient public lighting points will be replaced; and 50,000 solar panels for water heating will be installed.

- Government/UMEME commitment to accelerate reductions in distribution losses and to increase collection rates.

Financial Support & Tariff Measures

23. The existing and projected financing gap between the sector revenue requirements and electricity revenues will need to be closed by both tariff and non-tariff measures, as summarized below:

- Government budgetary support towards thermal power costs until Bujagali is commissioned;

- Deferment of debt service due to Government in the short to medium term;

- Donor support towards thermal power costs; and

- Tariff increases, as needed, to meet the remaining sector revenue requirements (as explained earlier, under the Base Case no further tariff increases are expected until 2012). However, should there be major variations in the Base Case assumptions in the future, further tariff increases may be required.

Distribution Losses & Uncollected Billing

24. One of the biggest challenges currently facing Uganda's power sector are the high level of distribution losses (34.1%) and non-collection rate (18%) as of December 2006. The need to reduce

such losses has become more urgent in recent times due to increased power shortages, the use of expensive fuel and the resulting high electricity prices for all consumers – industry, commerce and households. One of the principal aims of privatization of the distribution business was to accelerate the introduction of efficiency improvements. UMEME is focused on these issues and is in discussions with the MEMD to develop joint strategies aimed at an accelerated reduction in losses. In addition, the tariff methodology gives strong incentives for UMEME to reduce losses and improve billing collection. UMEME's investments by December 2006 amounted to US$13.6 million, and it is committed to invest at least US$65 million during the first five years of its operations, although UMEME plans to exceed the minimum investment commitments. A new billing system is expected to be procured and installed by end 2007. IDA is also providing about US$12 million (to UEDCL) for the procurement of poles and transformers and for 13,500 new customer connections. Such levels of investments will help to reduce technical losses over the medium term.

25. The Government and UMEME have agreed to jointly develop an Action Plan to reduce losses and non-collections, based on the strategy summarized below:

- Implement business processes that enable the revenue cycle (measure consumption, bill correctly and on time and collect revenue) to be effectively carried out and managed;
- Procure a new billing system;
- Analyze the network, and plan and implement repairs and upgrades/restoration in overloaded areas;
- Set objectives, measure performance and implement actions to achieve and sustain desired outcomes;
- Recognize loss reduction as a core business imperative; and
- Improve cooperation between the Government and UMEME.

26. UMEME's concession agreement contains targets for losses and non-collection rates for the first seven years of the concession. Under the restructured concession, there will be a downside protection for UMEME, and benefits accruing from lower losses will be shared between UMEME and UETCL as long as the power crisis persists.

27. Distribution losses and non-collection rates assumptions are provided in Table 12.3.

Table 12.3: Distribution Losses & Non-Collection Rates 2006-2016 (average numbers per CY)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Losses (as % of bulk supply to Umeme)	38.2%	34.1%	33.5%	31.1%	27.5%	23.8%	22.4%	18.1%	18.3%	18.4%	18.6%	18.7%
Non-collection rate	14.0%	15.8%	15.0%	12.0%	9.0%	7.5%	7.0%	6.0%	5.0%	5.0%	5.0%	5.0%
= Uncollected bulk supply	*46.9%*	*44.6%*	*43.5%*	*39.3%*	*34.0%*	*29.5%*	*27.8%*	*23.0%*	*22.3%*	*22.5%*	*22.7%*	*22.8%*

E. PRINCIPAL ASSUMPTIONS MADE IN THE PREPARATION OF THE FINANCIAL PROJECTIONS TO 2016

Macroeconomic Assumptions

28. The financial projections are prepared in current Uganda Shillings, using the inflation and exchange rate forecasts below. Exchange rate of the Uganda Shilling against the US dollar has been projected forward on the basis of the inflation differential.

Table 12.4: Macro-economic Assumptions

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Inflation (%):										
Domestic	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
US	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Exchange rate:										
(USh/1US$):										
At Dec 31	1863	1899	1936	1974	2012	2052	2092	2132	2174	2216
Average in year	1861	1881	1918	1955	1993	2032	2072	2112	2153	2195

Energy and Sales

29. The forecast of energy requirements is based on the base case load forecast, as presented in the Power Planning Associates Ltd. report of February 2007. The Government's interim generation plan to 2010 has been adopted in the financial analysis (see Annex 1 for details). In addition, it is assumed that the proposed project will be commissioned by April 2011.

30. The forecast peak demand, energy sent out, losses, energy sales and sales growth rates are provided in Attachment 2 to this Annex.

31. Concerning hydrology assumptions, median or average inflow conditions are assumed from August 1, 2006 to December 2010 and low inflow conditions are assumed for 2011 (post Bujagali). Available hydro capacity (MW continuous) and hydro generation (GWh) under these inflow conditions for 2006-10 and beyond 2010 are based on the Power Planning Associates Ltd "Bujagali II – economic and financial evaluation study, Final Report, February 2007". Under these conditions, hydropower output from the Nalubaale/Kiira dam complex is assumed at 120 MW up to July 31, 2007 (until the proposed IDA financed short-term thermal plant is commissioned), about 100 MW in 2007 to 2009, and 113 MW in 2010. Upon the proposed project's commissioning, the total annual average output of Nalubaale/Kiira and Bujagali is forecasted at 248 MW.

32. Cross-border exports to Tanzania and Rwanda are assumed to grow from their current low levels by 5% annually. No imports from or exports to Kenya are assumed in the projections.

Uganda Electricity Tariffs

33. Uganda retail electricity tariffs 2007-2016 are indicated under (B) above and in Attachment 2 to this Annex. Tariffs are set at levels to meet the sector revenue requirements, net of assumed Government subsidies. Any revenue surpluses are assumed to be utilized to pay-off Government deferred debt service.

Government Subsidies

34. Government subsidies to the power sector are provided in the text of this document and in Attachment 1 to this Annex.

Fuel Prices

35. The underlying crude oil prices are based on the World Bank's forecast, as shown in the table below. Fuel transport costs to Kampala for ADO and HFO are based on estimates prepared by Power Planning Associates Ltd. It is assumed that ADO will be delivered through the pipeline from Mombasa to Eldoret and then trucked from Eldoret to Kampala. In the case of HFO, it is assumed that the fuel will be trucked from Mombasa to Kampala. The Government's existing duty exemptions on generation fuel will continue through to 2016.

Table 12.5: Projected Crude Oil Prices 2007-2016

US$/barrel in nominal prices	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Base Case - World Bank forecast (declining prices)	66.8	62.4	58.5	54.9	51.6	48.5	45.5	42.8	40.2	41.2

Power Purchase Costs

36. Power purchases costs for Uganda's power sector have been forecasted as follows:

- Eskom (Uganda)'s capacity costs are provided in accordance with the tariff formula provided in its concession agreement. Capacity and energy charges of thermal plants are based on the contracted prices, as per the terms of the bids;
- Fuel costs are calculated on the basis of fuel consumption rates and transport costs, and assumed underlying oil prices;
- Bujagali capacity costs are based on the latest available estimates; and
- Costs of small-scale renewable energy generators (small scale hydro and bagasse based cogeneration) are based on indicative prices agreed upon between UETCL and third parties.

Rural Electrification Levy

37. The rural electrification levy is provided as per the provisions of the Electricity Act. Under the current legislation, UETCL is required to pay 5% of power purchase costs and 0.3% of export revenues to the Rural Electrification Agency.

Other Operating Expenses

38. Payroll costs are based on assumed numbers of employees and present payroll costs per employee, escalated for Uganda inflation. UMEME's employee numbers are based on its estimates of average annual growth of 3.5% over the forecast period. Employee numbers for UEGCL, UETCL and UEDCL are kept constant throughout. O&M costs of UETCL and UMEME are based on US$ unit cost of energy transmitted and energy sales, respectively. In recognition of inadequate maintenance of the network in the past, UETCL's costs are assumed to increase by 23% in 2007 and by the rate of

international inflation thereafter. UMEME's estimates are based on its projections. All other operating costs of UEGCL, UETCL and UEDCL are assumed to increase in line with inflation, and UMEME's costs are based on the company's estimates. For purposes of retail tariff determination, UMEME's operating costs are based on contracted costs for the first seven years.

Depreciation

39. Depreciation is provided on the closing gross value of fixed assets in service. Fixed assets of the Uganda Electricity Board were transferred to its successor companies (i.e., UEGCL, UETCL and UEDCL) in 2001 at professional valuations carried out at the time. The following depreciation rates are assumed.

Table 12.6: Depreciation Rates

	UEGCL	UETCL	UEDCL	UMEME
Assets acquired up to December 2001	2.88%	4.91%	6.58%	Not applicable
Additions since 2002	2.50%	2.50%	4.00%	3.33%

Bad Debts

40. Provision for bad debts is made in full at the assumed retail non-collection rates in each year. The assumed collection rates are indicated in Attachment 2 to this Annex.

Corporate Income Tax

41. Corporate income tax is based on the present tax rate of 30% and applied to taxable income according to current legislation. Deductions for capital allowances are based on current rates. UMEME is expected to pay taxes in 2009. No provision has been made for deferred tax.

Concessionaires' Costs and Returns

42. The projected sector revenue requirements (and required retail tariffs) include all operating costs, recovery of capital investments, and returns for Eskom (Uganda) and UMEME in accordance with the tariff methodology specified in their respective concession agreements.

Dividends

43. It is assumed that UEDCL will pay a dividend of USh18.8 billion (US$10 million) to the Government in 2008. This will utilize about 50% of surplus funds remaining in UEDCL. In the case of UMEME, it is assumed that the company could declare and pay dividends equivalent to 60% of its annual after-tax profits, starting in 2009. This assumes improvements in distribution system efficiency in line with contract requirements.

Investments, Fixed Assets and Work in Progress

44. Projected investments and financing plans are summarized in Table 12.7 below. Investments in generation represent remaining disbursements for Units 4 and 5 at Kiira (Credit 3565-UG), together with committed and assumed investments to be undertaken by Eskom (Uganda) at the Nalubaale/Kiira dam complex. Transmission investments include connections to all new generation

projects in the least-cost expansion plan and ongoing transmission and distribution investments under Credit 3565-UG. Investments in distribution are based on UMEME's forecasts.

Table 12.7: Projected Investments & Financing Plans 2007-16

	2007	2008	2009	2010	2011	2007-11		2012	2013	2014	2015	2016	2012-16	
Investments														
Generation	6	2	2	1	1	11	4%	1	1	1	1	1	3	1%
Transmission	25	24	33	49	35	166	55%	26	18	37	61	48	190	60%
Distribution	35	22	20	23	23	124	41%	23	25	24	26	26	124	39%
Total Investments	67	47	55	73	58	300	100%	49	44	61	89	74	317	100%
Financing Plan														
Borrowing	24	7	26	45	29	132	44%	21	15	27	54	41	159	50%
Concessionaires (Eskom & Umeme)	32	23	22	24	23	124	41%	23	26	25	27	26	127	40%
Government	2	12	5	0	3	23	8%	2	0	5	6	4	17	5%
UEGCL, UETCL & UEDCL	8	5	2	4	3	22	7%	2	2	4	2	4	14	4%
Total Financing	67	47	55	73	58	300	100%	49	44	61	89	74	317	100%

45. Investments to be undertaken by Eskom (Uganda) and UMEME are shown as investments by concessionaires in Table 12.7. Borrowing requirements and funding from own resources mainly relate to UETCL's transmission investments. Government contributions of US$23 million (2007-11) and US$17 million (2012-16) relate to resettlement costs.

46. Assets under construction are shown under work in progress in the balance sheet. The cost of assets is transferred from work in progress to fixed assets on their commissioning.

Bulk Supply Tariff Stabilization Fund

47. The Bulk Supply Tariff Stabilization Fund is retained within UETCL's balance sheet for purposes of smoothing the retail tariff path and avoiding frequent increases and decreases in tariffs from year to year.

Accounts Receivable and Payable

48. Accounts receivable are assumed at 60 days of annual billing, inclusive of VAT. A deduction is made in UMEME*'s* receivables from end-use customers for billings that are not expected to be collected.

49. Accounts payable for power purchase costs and other operational costs are assumed at 60 days of annual costs, inclusive of VAT. Project related creditors are assumed at 30 days of annual investments that are forecast to be funded from UMEME's and UETCL's internal resources.

Inventory

50. Inventory at the balance sheet closing date is forecast at 2.5% for UETCL, and at 2.0% for UMEME, of opening gross fixed asset value.

Long-term Loans

51. All existing on-lent loans between the Government and UEGCL, UETCL and UEDCL are accounted for on the basis of on-lending agreements. All future borrowing requirements of UETCL are assumed to be on-lent by the Government at 6.5% annual interest, repayable over 15 years after a

5 year grace period. IDC for any investment project made to UEGCL, UETCL and UEDCL will be added to loan principal and repaid with loan principal and capitalized to fixed assets on project commissioning. No borrowing is assumed for UMEME.

F. SENSITIVITY ANALYSIS TO THE BASE CASE PROJECTIONS

52. Sensitivities were conducted on the base case forecasts presented above and the results are shown in Table 12.8. Each of the sensitivities is considered in isolation, with all other assumptions in the base case remaining unchanged.

Table 12.8: Sensitivity Analysis to Base Case Projections

	Increase/(decrease) in base case revenue shortfalls before tariff support (2007-11)		Tariff Impact (based on Nov 06 av tariff) (2007-11)	Increase/(decrease) in base case revenue shortfalls before tariff support (2012-16)		Tariff Impact (based on Nov 06 av tariff) (2012-16)
	USh billions	US$ millions		USh billions	US$ millions	
Downside Risks						
1. High oil price forecast applies	176	92	8.0%	167	77	4.8%
2. Distribution losses as per Umeme concession targets	59	29	2.7%	204	98	6.3%
3. Capacity additions of renewables not available	83	44	4.1%	163	77	4.8%
4. If Permanenet HFO plant is delayed by 3 months	11	6	0.5%	6	3	0.2%
5. High demand forecast	53	28	2.3%	16	7	0.4%
Upside Potential						
6. If Mutundwe plant is delayed by 3 months	(10)	(5)	-0.4%	0	0	0.0%
7. Maintain hydro output at 120MW throughout	(180)	(95)	-8.2%	-81	-38	-2.4%
8. High hydrology scenario throughout forecast period	(580)	(302)	-26.4%	(507)	(237)	-14.8%

53. The key sensitivity scenarios from Table 12.8 are discussed below:

- High oil price forecast scenario (Scenario 1) assumes underlying oil prices to increase to 83US$/barrel by 2016 (in 2006 prices).

- High demand scenario (Scenario 5), which envisages growth rates of -0.5% in 2007, 4.0% in 2008, 6.9% in 2009, 6.6% in 2010, and 10.9% in 2011. Thereafter, the annual growth averages 10.0%.

- High hydrology scenario (Sensitivity 8): The High Hydrology sensitivity assumes all model inputs being as in the base case except for Lake Victoria water levels being at the highest end as described in the *Bujagali II- Economic and Financial Evaluation Study*, by Power Planning Associates Ltd. This scenario has a probability of occurrence 21% (compared to the probability for the low hydrology scenario of 79%). Although this scenario has a low probability of occurrence, it shows that in the high hydrology scenario the total hydropower output (1,991 GWh, when the proposed project has come online) leads to important cost savings by reducing the overall power sector's revenue requirements by US$302 million, between 2007/11, and by another US$237 million between 2012/16. Those additional revenues also assume 50 MW of exports to Kenya when the proposed project comes on line. In the case of the high hydrology scenario, any thermal generation capacity would only be used during peak teams (pre-Bujagali).

54. The assumptions on the hydrology and fuel prices have the most impact on the revenue requirements of the power sector. Higher consumer demand would require higher tariffs since the incremental demand would have to be met through thermal power generation. A slower than forecasted reduction in distribution losses will also have a significant impact. The financial loss will also be high if the planned displacement of thermal capacity with less expensive renewables (i.e., mini-hydros and bagasse based power plants) is delayed.

G. ATTACHMENTS FOR THE FINANCIAL PROJECTIONS TO 2016

55. The following detailed financial and operational information on the power sector is provided as Attachments:

1. Revenue Requirements and Financing plan to 2016
2. Operational and Financial Performance Indicators 2004-16
3. Financial Statements 2004-16 in USh billions
4. Financial Statements 2004-16 in US$ millions

Attachment 1

Revenue Requirements & Financing Plan 2005-2016

Financial Requirements (all figures in USh billions unless otherwise indicated)

	2005	2006	2007	2008	2009	2010	2011	2007-11	2012	2013	2014	2015	2016	2012-16
	Actual	Est Actual	Forecast					Forecast	Forecast					Forecast
Total Sector requirements (before subsidies)														
Eskom/UEGCL	25	32	31	31	32	33	33	161	34	36	37	38	40	185
UETCL	107	204	389	407	364	367	288	1,814	399	446	500	561	672	2,578
Total bulk supply	132	236	420	438	396	400	321	1,975	433	481	537	599	712	2,763
Umeme/UEDCL	116	131	161	176	179	182	194	893	216	228	250	272	299	1,264
Total Sector requirements before subsidy	248	367	581	614	575	582	515	2,867	649	709	786	871	1,012	4,027
of which, thermal:														
Capacity payments	11	22	50	72	54	54	27	258	21	21	51	48	67	206
Fuel & O&M	49	135	292	273	214	211	31	1,022	7	43	-13	32	3	72
Total thermal costs	60	157	342	346	268	266	58	1,279	27	64	38	79	69	278
Thermal costs as % of total sector requirements	24%	43%	59%	56%	47%	46%	11%	45%	4%	9%	5%	9%	7%	7%
Required average retail tariff*														
USh/kWh (present, Nov 2006 = 316)	231	371	493	489	414	383	302	407	346	350	359	369	397	366
US$/kWh (present, Nov 2006 = 0.171)	0.1298	0.2017	0.2648	0.2603	0.2160	0.1959	0.1514	0.2117	0.1705	0.1690	0.1702	0.1713	0.1810	0.1734
Shortfall compared with present tariff	40%	18%	57%	56%	32%	22%	-4%	30%	11%	12%	15%	18%	27%	17%
Retail revenue based on present average tariff	168	213	370	393	435	477	535	2,209	587	635	686	740	798	3,446
Revenue shortfall in year (before subsidies and tariff increases)														
In USh billions	(81)	(154)	(212)	(221)	(140)	(106)	20	(658)	(62)	(74)	(101)	(131)	(214)	(582)
In equivalent US$ millions	(45)	(84)	(114)	(117)	(73)	(54)	10	(348)	(30)	(36)	(48)	(61)	(97)	(272)
* Tariffs quoted in these tables are exclusive of 18% VAT														

Indicative Financing Plan (all figures in USh billions unless otherwise indicated)

	2005	2006	2007	2008	2009	2010	2011	2007-11	2012	2013	2014	2015	2016	2012-16
Revenue shortfall in year (before subsidies and tariff increases)														
In USh billions	(81)	(154)	(212)	(221)	(140)	(106)	20	(658)	(62)	(74)	(101)	(131)	(214)	(582)
In equivalent US$ millions	(45)	(84)	(114)	(117)	(73)	(54)	10	(348)	(30)	(36)	(48)	(61)	(97)	(272)
Indicative Financing Plan														
I. Government support														
1) Deferred debt service	0	11	32	32	32	33	0	128	0	0	0	0	0	0
2) Direct support	30	113	92	92	28	66	0	278	0	0	0	0	0	0
Total budget support	30	124	124	124	61	98	0	407	0	0	0	0	0	0
3) IDA support														
Capacity charges	0	0	9	22	23	23	4	81	0	0	0	0	0	0
Fuel	0	0	64	116	105	26	0	311	0	0	0	0	0	0
Total IDA support for operational costs	0	0	73	138	127	49	4	392	0	0	0	0	0	0
Total Government support	30	124	197	262	188	148	4	799	0	0	0	0	0	0
II. Other tariff support														
Utilization of BST stabilization funds	8	49	0	0	0	0	0	0	0	0	0	0	0	0
UETCL support from surplus funds (to Nov 2005)	25	0	0	0	0	0	0	0	0	0	0	0	0	0
Remianing revenue (shortfall) after tariff support														
In USh billions	(17)	19	(15)	41	48	42	24	141	(62)	(74)	(101)	(131)	(214)	(582)
In equivalent US$ millions	(9.4)	10	(8)	22	25	21	12	73	(30)	(36)	(48)	(61)	(97)	(272)
III. Tariff increases														
% increases in year														
First increase	10.5%	37.5%	0.0%	0.0%	0.0%	0.0%	0.0%		15.0%	0.0%	0.0%	4.5%	4.5%	
Second increase		40.9%	0.0%	0.0%	0.0%	0.0%	0.0%		0.0%	0.0%	0.0%	0.0%	0.0%	
Cumulative % increase since 2006	10.5%	93.8%	93.8%	93.8%	93.8%	93.8%	94%	90%	123%	123%	123%	133%	143%	18%
Dates of tariff increases														
First increase	4/1/05	6/1/06	0.00	1/1/08	1/1/09	1/1/10	1/1/11		1/1/12	1/1/13	1/1/14	1/1/15	1/1/16	
Second increase	0.00	11/1/06	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	
Average tariff at December 31 (nominal prices)														
USh/kWh	165	313	313	313	313	313	313	313	360	360	360	377	394	370
US$/kWh	0.091	0.172	0.168	0.165	0.162	0.159	0.156	0.163	0.176	0.172	0.169	0.173	0.178	0.175
Additional revenues from tariff increases		0	0	0	0	0	0	0	88	95	103	149	204	640
Changes in revenue requirements post Nov 06 tariffs		(10)	(2)	(1)	0	0	0	(2)	(6)	(8)	(9)	(12)	(16)	(51)
Net tariff impact (additional cash collected)		(10)	(2)	(1)	0	0	0	(2)	82	87	94	138	188	589
Remaining surplus/(shortfall)														
In year	(17)	9	(16)	41	48	42	24	138	20	13	(6)	6	(26)	7
Cumulative from 2005	(17)	(8)	(24)	16	64	106	130	130	151	163	157	163	137	137
Deferred debt service repaid in year	0	0	0	(16)	(48)	(42)	(24)	(130)	(9)	0	0	0	0	(9)
Remaining cumulative cash surplus/(shortfall)														
after payment of deferred debt service	(17)	(8)	(24)	0	0	0	0	0	12	24	18	24	(1)	(1)
Accumulated unpaid deferred service due to GoU	0	11	42	58	42	33	9	9	0	0	0	0	0	0

Attachment 2

Key Consolidated Operational & Financial Performance Indicators (UEGCL, UETCL, UEDCL & UMEME)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Est Actual	Forecast					Forecast				
Peak demand (MW)	334	354	347	337	343	359	375	407	432	467	505	545	587
Total units sent out (GWh)	1,892	1,887	1,610	1,870	1,905	1,993	2,079	2,322	2,419	2,615	2,821	3,043	3,277
of which:													
Hydro	99%	90%	72%	52%	46%	45%	48%	82%	87%	82%	76%	70%	65%
Thermal	0%	7%	23%	44%	47%	38%	36%	4%	0%	6%	4%	10%	16%
Geothermal	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%	9%	9%
Renewables & other	1%	3%	5%	4%	7%	17%	17%	14%	13%	12%	11%	11%	10%
Transmission losses	4.6%	4.8%	4.2%	4.8%	4.6%	4.4%	4.2%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Export sales (GWh)	196	64	53	37	39	41	43	46	49	51	54	57	60
Bulk supply to Umeme (GWh)	1,610	1,741	1,503	1,773	1,820	1,913	1,995	2,199	2,287	2,478	2,682	2,901	3,132
Distribution losses	36.0%	38.2%	34.1%	33.5%	31.1%	27.5%	23.8%	22.4%	18.1%	18.3%	18.4%	18.6%	18.7%
Billed Uganda sales (GWh)	1,030	1,075	990	1,179	1,255	1,388	1,521	1,707	1,874	2,026	2,187	2,361	2,546
Uganda sales growth	-0.5%	4.4%	-7.9%	19.1%	6.4%	10.6%	9.6%	12.3%	9.8%	8.1%	8.0%	7.9%	7.8%
Billed as % of units sent out to Uganda	61%	59%	64%	64%	67%	71%	75%	75%	79%	79%	79%	79%	79%
Uganda sales collected as % of sent out	50%	51%	54%	55%	59%	65%	69%	70%	74%	75%	75%	75%	75%
Ave. number of customers ('000)	254	278	295	304	316	328	340	359	384	409	434	459	484
Ave. number of employees	1,788	1,745	1,542	1,445	1,486	1,503	1,542	1,596	1,652	1,706	1,743	1,764	1,785
Customers per employee	142	159	191	211	213	218	221	225	232	240	249	260	271
Total electricity revenue (USh billion)	167	175	222	374	398	440	482	541	682	737	796	898	1,011
Uganda electricity revenue (USh billion)	145	168	213	370	393	435	477	535	676	730	789	890	1,002
Uganda electricity revenue (US$ million)	80	94	116	199	209	227	244	269	332	353	373	413	457
Uganda VAT revenue to GoU (US$ million)	14	16	21	36	38	41	44	48	60	63	67	74	82
Ave. Uganda electricity revenue (USh/kWh)	141	156	215	313	313	313	313	313	360	360	360	377	394
Ave. Uganda electricity revenue (US$/kWh)	0.078	0.088	0.117	0.168	0.167	0.163	0.160	0.157	0.177	0.174	0.171	0.175	0.179
Ave. operating income (USh/kWh)	23	-23	32	9	40	59	54	37	45	41	50	55	59
Ave. operating income (US$/kWh)	0.013	-0.013	0.018	0.005	0.021	0.031	0.028	0.018	0.022	0.020	0.024	0.025	0.027
Return on fixed assets	3.3%	-3.1%	4.0%	1.2%	5.2%	8.4%	8.4%	6.0%	7.5%	7.2%	8.9%	10.1%	11.9%
Debt service coverage	2.1	0.3	1.7	1.2	2.1	2.7	2.9	3.0	2.2	2.3	2.1	1.9	2.2
Current ratio	2.1	1.6	2.3	1.8	1.7	1.6	1.6	1.5	1.4	1.4	1.4	1.4	1.3
Debt/equity ratio	41%	43%	40%	39%	40%	41%	44%	45%	46%	47%	46%	48%	47%

Attachment 3

Consolidated Income Statements
(UEGCL, UETCL, UEDCL & UMEME)
(in nominal USh billions)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Est Actual	Forecast					Forecast				
Operating revenue													
Electricity revenue													
Domestic	145	168	213	370	393	435	477	535	676	730	789	890	1,002
Exports	21	7	9	5	5	5	6	6	7	7	8	8	9
Total	167	175	222	374	398	440	482	541	682	737	796	898	1,011
Tariff stabilization & escrow funding	(18)	(18)	0	16	(24)	0	0	0	(12)	(13)	6	(6)	26
Government subsidy & tariff support (thermal powe	0	39	173	197	262	188	148	4	0	0	0	0	0
Other operating revenue	3	14	6	6	6	6	6	7	7	7	8	8	9
Total operating revenue	152	210	401	593	642	634	636	552	678	732	810	899	1,045
Operating expenses													
Power purchase costs, excluding fuel	14	34	70	89	121	144	146	242	354	364	408	416	455
Generation fuel (including IPPs)	1	64	132	274	255	198	195	25	2	36	26	70	133
Operating Expenses excluding depreciation	53	72	76	81	85	88	92	99	105	113	120	127	134
Rural electrification levy	1	4	8	19	20	18	18	14	19	21	23	25	30
Depreciation	41	40	40	47	52	55	57	62	63	68	72	75	77
Bad debts	12	23	40	70	56	46	42	44	48	43	47	52	59
Total operating expenses	122	236	366	581	588	548	551	486	590	644	696	765	888
Operating income before exceptional items	29	(27)	34	11	52	85	84	64	86	86	113	132	155
Exceptional revenue & charges	(69)	(6)	50	0	0	0	0	0	0	0	0	0	0
Finance charges													
Interest	19	18	22	25	25	24	22	20	27	26	31	35	32
Foreign exchange losses/(gains)	(28)	17	0	0	0	0	0	0	0	0	0	0	0
Total finance charges	(9)	36	22	25	25	24	22	20	27	26	31	35	32
Net income before tax	(29)	(67)	63	(13)	28	63	64	46	60	62	84	99	125
Corporate income iax	0	0	0	0	0	6	12	8	8	8	11	17	27
Net income after tax	(30)	(67)	63	(13)	28	57	51	38	52	54	72	82	98
Dividends	0	0	0	0	19	40	34	27	29	30	34	39	45
Retained income	(30)	(67)	63	(13)	10	17	18	11	23	24	39	43	52

Attachment 3

Consolidated Balance Sheets at December 31
(UEGCL, UETCL, UEDCL & UMEME)
(in nominal USh billions)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Est Actual	Forecast					Forecast				
Non-current assets													
Fixed assets in service	1,005	1,027	1,055	1,276	1,333	1,380	1,432	1,644	1,708	1,863	2,008	2,080	2,147
Less: Accumulated depreciation	144	183	222	270	322	377	434	496	559	627	699	774	850
Net fixed assets	862	844	833	1,006	1,011	1,004	999	1,148	1,149	1,236	1,309	1,306	1,297
Work in progress	77	100	116	19	47	105	203	119	162	106	97	222	331
Tariff stabilization fund	39	40	1	-15	9	9	9	9	21	34	27	34	8
Project & escrow funds	19	23	18	24	29	35	41	41	41	41	41	41	41
Investments	15	12	12	1	1	1	1	1	1	1	1	1	1
Non-Current assets	1,012	1,019	981	1,035	1,099	1,155	1,253	1,318	1,373	1,418	1,475	1,604	1,678
Current assets													
Cash & bank	115	91	106	110	102	125	119	113	112	108	116	118	128
Accounts receivable	43	25	58	62	68	78	87	98	125	136	147	166	186
Other debtors	35	72	109	79	70	58	52	30	30	31	31	32	33
Stock	24	26	18	9	12	13	14	15	20	21	25	28	30
Total current assets	216	213	291	259	252	274	272	256	286	296	320	344	378
Current liabilities													
Bank overdraft	0	1	1	0	0	0	0	0	0	0	0	0	0
Trade & other creditors	19	35	75	88	89	104	103	88	107	118	128	142	167
Corporate tax	0	0	0	0	0	3	6	4	4	4	6	9	14
Debt service	69	82	29	31	31	31	31	32	41	42	49	55	55
Current portion of long-term loans	14	19	23	25	27	30	32	45	45	45	45	45	45
Total current liabilities	103	136	128	145	148	168	173	168	198	208	227	251	281
Net current assets/(liabilities)	114	77	163	115	104	106	100	88	88	88	92	93	97
Total Assets	1,125	1,096	1,143	1,150	1,202	1,261	1,353	1,406	1,462	1,506	1,568	1,697	1,775
Equity	665	622	689	700	726	748	759	768	786	802	842	888	936
Long-term liabilities													
Loans	321	335	343	360	354	384	456	502	516	519	534	598	640
Less: Current portion	14	19	23	25	27	30	32	45	45	45	45	45	45
Long-term portion	307	317	320	335	327	354	424	457	471	474	489	553	595
Provisions	23	13	12	1	2	2	2	2	3	3	3	4	4
Deferred liabilities	71	80	51	40	70	76	81	81	93	106	99	106	80
Consumer deposits	15	17	20	21	23	26	28	33	39	45	51	57	64
Deferred consumer contributions	45	48	52	53	55	56	58	64	70	77	83	90	97
Total long-term liabilities	460	474	454	450	476	513	593	638	675	704	725	809	839
Total Invested Capital	1,125	1,096	1,143	1,150	1,202	1,261	1,353	1,406	1,462	1,506	1,568	1,697	1,775

Attachment 3

Consolidated Cash Flows
(UEGCL, UETCL, UEDCL & UMEME)
(in nominal USh billions)

	2004	2005	2006	2007	2008	2009	2010	2011	2007-11	2012	2013	2014	2015	2016	2012-16
	Actual	Actual	Est Actual			Forecast						Forecast			
Funds from operations															
Operating income after exceptional items	(39)	(31)	84	12	54	87	86	66	304	87	88	115	134	157	581
Corporate income tax	(0)	0	(0)	0	0	(6)	(12)	(8)	(26)	(8)	(8)	(11)	(17)	(27)	(72)
Adjustments for non-cash items:															
Depreciation	41	40	40	47	52	55	57	62	274	63	68	72	75	77	354
Provisions & other	(2)	(10)	(2)	(1)	(1)	(1)	(2)	(2)	(7)	(2)	(2)	(2)	(2)	(3)	(11)
Unrecoverable assets & write-off of debt service lia	65	10	(50)	0	0	0	0	0	0	0	0	0	0	0	0
Internal cash generation	65	9	72	58	104	134	129	119	544	140	145	173	189	204	852
(Increase)/decrease in working capital (excl cash)	5	(18)	(31)	49	1	18	(2)	(6)	59	(12)	(3)	(3)	(6)	6	(19)
Customer deposits & capital contributions	9	8	8	5	6	6	6	13	35	14	15	15	16	6	66
Funds from operations	78	(1)	48	111	111	157	133	126	638	142	157	185	199	227	909
Other sources of funds															
Equity contribution - Government	1	2	1	4	22	10	0	6	43	4	1	11	13	8	36
Equity contribution - Concessionaires	0	12	11	22	0	0	0	0	22	0	0	0	0	0	0
Borrowing	55	20	21	35	14	49	89	58	245	43	32	58	116	89	338
Project, escrow & tariff stabilization funds	13	6	14	1	0	0	0	0	1	0	0	0	0	0	0
Total Sources of Funds	148	38	95	174	147	217	222	190	950	189	189	254	328	324	1,284
Debt service															
Interest to operations	19	18	22	25	25	24	22	20	116	27	26	31	35	32	151
IDC	4	1	1	2	0	3	7	13	25	8	11	8	8	15	48
Repayment of loan capital	12	14	20	23	25	28	30	33	139	45	49	59	70	74	297
Total debt service due	35	33	43	50	51	54	59	66	280	80	85	98	112	122	497
Less: Interest financed	(0)	(0)	(1)	(0)	(0)	(3)	(7)	(13)	(23)	(8)	(11)	(8)	(8)	(15)	(48)
Less: Unpaid debt service - (increase)/decrease	(0)	(12)	(6)	(2)	0	(0)	(0)	(0)	(3)	(10)	(0)	(7)	(6)	(0)	(24)
Debt service paid	34	21	37	48	51	51	52	53	254	63	74	83	98	106	425
Capital expenditure (excluding IDC)	72	41	44	122	85	103	142	115	567	99	89	129	189	162	667
Dividends to Concessionaires	0	0	0	0	0	40	34	27	101	29	30	34	39	45	176
Dividends to GOU	3	1	0	0	19	0	0	0	19	0	0	0	0	0	0
Total Applications of Funds	109	63	80	169	155	194	228	196	941	191	193	245	326	314	1,269
Increase/(decrease) in cash balances	39	(25)	15	5	(8)	23	(6)	(6)	9	(2)	(4)	8	2	10	15
Net cash balance at year end	115	90	105	110	102	125	119	113	113	112	108	116	118	128	128

Attachment 4

Consolidated Income Statements
(UEGCL, UETCL, UEDCL & UMEME)
(in nominal US$ millions)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Est Actual	Forecast					Forecast				
Operating revenue													
Electricity revenue													
Domestic	80	94	116	199	209	227	244	269	332	353	373	413	457
Exports	12	4	5	2	3	3	3	3	3	3	4	4	4
Total	92	98	121	201	212	230	247	272	336	356	377	417	461
Tariff stabilization & escrow funding	(10)	(10)	0	9	(13)	0	0	0	(6)	(6)	3	(3)	12
Government subsidy & tariff support (thermal powei	0	22	94	106	139	98	75	2	0	0	0	0	0
Other operating revenue	2	8	3	3	3	3	3	3	3	4	4	4	4
Total operating revenue	84	118	218	319	341	331	326	277	333	353	384	418	476
Operating expenses													
Power purchase costs, excluding fuel	8	19	38	48	64	75	75	121	174	176	193	193	207
Generation fuel (including IPPs)	0	36	72	147	135	103	100	12	1	17	12	32	61
Operating Expenses excluding depreciation	29	40	42	44	45	46	47	49	52	54	57	59	61
Rural electrification levy	1	2	5	10	10	9	9	7	9	10	11	12	14
Depreciation	23	22	22	26	28	28	29	31	31	33	34	35	35
Bad debts	7	13	22	38	30	24	22	22	24	21	22	24	27
Total operating expenses	67	132	199	312	313	286	282	244	290	311	329	355	405
Operating income before exceptional items	16	(15)	18	6	28	44	43	32	42	41	53	61	71
Exceptional revenue & charges	(38)	(3)	27	0	0	0	0	0	0	0	0	0	0
Finance charges													
Interest	11	10	12	13	13	12	11	10	13	12	15	16	15
Foreign exchange losses/(gains)	(16)	10	0	0	0	0	0	0	0	0	0	0	0
Total finance charges	(5)	20	12	13	13	12	11	10	13	12	15	16	15
Net income before tax	(16)	(37)	34	(7)	15	33	33	23	30	30	40	46	57
Corporate income iax	0	0	0	0	0	3	6	4	4	4	5	8	12
Net income after tax	(16)	(37)	34	(7)	15	30	26	19	25	26	34	38	44
Dividends	0	0	0	0	10	21	17	14	14	14	16	18	21
Retained income	(16)	(37)	34	(7)	5	9	9	5	11	12	18	20	24

Attachment 4

Consolidated Balance Sheets at December 31
(UEGCL, UETCL, UEDCL & UMEME)
(in nominal US$ millions)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	Actual	Actual	Est Actual	Forecast					Forecast				
Non-current assets													
Fixed assets in service	576	567	577	685	702	713	726	817	832	891	942	957	969
Less: Accumulated depreciation	82	101	122	145	170	194	220	247	273	300	328	356	384
Net fixed assets	494	466	456	540	532	518	506	570	560	591	614	601	585
Work in progress	44	55	64	10	25	54	103	59	79	51	45	102	150
Tariff stabilization fund	23	22	1	-8	5	5	5	5	10	16	13	15	4
Project & escrow funds	11	12	10	13	15	18	21	20	20	20	19	19	18
Investments	8	7	7	1	1	1	1	1	0	0	0	0	0
Non-Current assets	580	563	537	556	579	597	635	655	669	678	692	738	757
Current assets													
Cash & bank	66	50	58	59	54	64	60	56	54	52	55	54	58
Accounts receivable	25	14	32	33	36	40	44	49	61	65	69	76	84
Other debtors	20	40	60	42	37	30	27	15	14	15	15	15	15
Stock	13	14	10	5	6	7	7	7	10	10	12	13	14
Total current assets	124	118	159	139	133	142	138	127	139	142	150	158	171
Current liabilities													
Bank overdraft	0	0	1	0	0	0	0	0	0	0	0	0	0
Trade & other creditors	11	19	41	47	47	54	52	44	52	56	60	65	75
Corporate tax	0	0	0	0	0	2	3	2	2	2	3	4	6
Debt service	40	45	16	17	16	16	16	16	20	20	23	25	25
Current portion of long-term loans	8	10	13	14	14	15	16	22	22	22	21	21	20
Total current liabilities	59	75	70	78	78	87	87	84	96	100	107	116	127
Net current assets/(liabilities)	65	43	89	62	55	55	51	44	43	42	43	43	44
Total Assets	645	606	626	617	633	651	685	699	712	720	735	781	801
Equity	381	344	377	376	383	386	385	382	383	383	395	408	422
Long-term liabilities													
Loans	184	185	188	193	186	198	231	249	252	248	250	275	289
Less: Current portion	8	10	13	14	14	15	16	22	22	22	21	21	20
Long-term portion	176	175	175	180	172	183	215	227	230	226	229	255	268
Provisions	13	7	7	1	1	1	1	1	1	1	2	2	2
Deferred liabilities	41	44	28	21	37	39	41	40	45	50	47	49	36
Consumer deposits	8	9	11	11	12	13	14	17	19	21	24	26	29
Deferred consumer contributions	26	27	28	29	29	29	29	32	34	37	39	41	44
Total long-term liabilities	264	262	248	242	251	265	301	317	329	336	340	372	378
Total Invested Capital	645	606	626	617	633	651	685	699	712	720	735	781	801

Attachment 4

Consolidated Cash Flows (UEGCL, UETCL, UEDCL & UMEME) (in nominal US$ millions)

	2004	2005	2006	2007	2008	2009	2010	2011	2007-11	2012	2013	2014	2015	2016	2012-16
	Actual	Actual	Est Actual	Forecast						Forecast					
Funds from operations															
Operating income after exceptional items	(21)	(17)	45	6	29	45	44	33	157	43	42	54	62	72	273
Corporate income tax	(0)	0	(0)	0	0	(3)	(6)	(4)	(13)	(4)	(4)	(5)	(8)	(12)	(34)
Adjustments for non-cash items:	0	0	0	0	0	0	0	0		0	0	0	0	0	0
Depreciation	23	22	22	26	28	28	29	31	142	31	33	34	35	35	168
Provisions & other	(1)	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(4)	(1)	(1)	(1)	(1)	(1)	(5)
Unrecoverable assets & write-off of debt service lia	36	6	(27)	0	0	0	0	0	0	0	0	0	0	0	0
Internal cash generation	36	5	39	31	56	70	66	60	282	69	70	82	88	93	402
(Increase)/decrease in working capital (excl cash)	3	(10)	(17)	26	0	9	(1)	(3)	32	(6)	(2)	(2)	(3)	3	(9)
Customer deposits & capital contributions	5	4	4	2	3	3	3	7	18	7	7	7	7	3	31
Funds from operations	43	(0)	26	60	59	82	68	63	332	70	76	88	92	103	429
Other sources of funds															
Equity contribution - Government	1	1	1	2	12	5	0	3	23	2	0	5	6	4	17
Equity contribution - Concessionaires	0	6	6	12	0	0	0	0	12	0	0	0	0	0	0
Borrowing	30	11	11	19	7	26	45	29	126	21	15	27	54	41	159
Project, escrow & tariff stabilization funds	7	3	7	1	0	0	0	0	1	0	0	0	0	0	0
															0
Total Sources of Funds	81	21	52	94	78	113	114	95	494	93	91	120	152	148	604
Debt service															
Interest to operations	11	10	12	13	13	12	11	10	60	13	12	15	16	15	72
IDC	2	0	0	1	0	1	4	6	13	4	5	4	4	7	23
Repayment of loan capital	6	8	11	13	14	14	15	16	72	22	24	28	32	34	140
Total debt service due	19	19	24	27	27	28	30	33	146	40	41	46	52	55	235
Less: Interest financed	(0)	(0)	(0)	(0)	(0)	(1)	(4)	(6)	(12)	(4)	(5)	(4)	(4)	(7)	(23)
Less: Unpaid debt service - (increase)/decrease	(0)	(7)	(3)	(1)	0	(0)	(0)	(0)	(1)	(5)	(0)	(3)	(3)	(0)	(11)
Debt service paid	19	12	20	26	27	27	27	26	132	31	36	39	46	48	200
Capital expenditure (excluding IDC)	39	23	24	65	45	54	73	58	295	49	43	61	88	74	314
Dividends to Concessionaires	0	0	0	0	0	21	17	14	52	14	14	16	18	21	83
Dividends to GOU	2	1	0	0	10	0	0	0	10	0	0	0	0	0	0
															0
Total Applications of Funds	60	35	44	91	82	101	116	98	489	94	93	116	151	143	597
Increase/(decrease) in cash balances	21	(14)	8	3	(4)	12	(3)	(3)	5	(1)	(2)	4	1	5	7
Exchange difference on conversion to USS	5	(2)	(0)	(1)	(1)	(1)	(1)	(1)	(6)	(1)	(1)	(1)	(1)	(1)	(5)
Net cash balance at year end	66	50	57	59	54	64	60	56	56	54	52	55	54	58	58

Annex 13: IDA Guarantee Agreements

1. The Partial Risk Guarantee Agreements consist of (a) an IDA Guarantee Agreement, entered into by IDA and the commercial lenders to BEL; (b) the Indemnity Agreement, entered into between IDA and the Government of Uganda; and (c) a Project Agreement, entered into between IDA and BEL. In addition, the IDA guaranteed lenders will enter into an IDA Guaranteed Facility Agreement with BEL. Below is a summary of the indicative terms and conditions of these agreements.

IDA Guaranteed Facility Agreement

Borrower:	Bujagali Energy Limited
Lenders:	A syndicate of commercial banks[, with.____[TBD][1]______ acting as Facility Agent or Trustee]
Term:	16 years including a 50 month grace period [subject to final Lender confirmation]
Loan Amount:	up to US$115 million (the "IDA-Guaranteed Loan Amount")
Availability:	The IDA-Guaranteed Loan (or Facility) will be available for drawing during the Availability Period (as defined in the Common Terms Agreement) subject to the satisfaction of all conditions precedent listed in the Common Terms Agreement (CTA) and the IDA-Guaranteed Facility Agreement. The minimum disbursement under the Facility will be US$[TBD – to be conformed with CTA].
Repayment of loan:	To be based on Repayment/Interest Payment Dates under the Common Terms Agreement
Loan Interest Rate:	[TBD]
Currency:	US Dollars or other freely convertible currency acceptable to the World Bank
Use of Proceeds:	Proceeds to be used only for the design, engineering, procurement, construction and financing costs of the Project[2]. Proceeds may not be used for developer fees, taxes, duties, financing costs payable under other loans/facilities, acquisition costs for nuclear, military or luxury items or for goods or services from the territory of any country which is not a member of the World Bank.
Drawdown	Pro rata with other loans for the Project
Other Terms:	Other terms applicable to the Facility (including representations, conditions of disbursement, covenants, events of default and remedies under the CTA)

[1] As some details of the IDA Guarantee Agreements have not been finalized yet, those details are indicated in this Annex by the acronym TBD (To Be Determined).

[2] The term "Project" refers to the Private Power Generation (Bujagali) Project.

IDA Guarantee Agreement

Beneficiaries: Lenders, or the Facility Agent on their behalf, under the IDA-Guaranteed Facility Agreement

Guarantor: International Development Association (IDA)

Purpose: To catalyze debt finance in support of the Project through commercial loans

Maximum IDA Liability: An amount equal to the Maximum IDA-Guaranteed Loan Amount (the aggregate of the principal amount of the IDA-Guaranteed Loan committed or, at the end of the Availability Period, disbursed, under the Facility (not to exceed US$ 115,000,000) and the Maximum Guaranteed Interest (interest due and payable on any advances made pursuant to the IDA-Guaranteed Facility Agreement).

Currency: US Dollars (or other currency of the Facility acceptable to IDA)

Term: 16 years (through Loan maturity) with up to an additional 3 years after Loan maturity if there is an ongoing Dispute with the Government (GOU) – [subject to final Lender confirmation]

Guarantee: IDA will guarantee to the Facility Agent (on behalf of the Lenders) scheduled principal and interest payments not paid by the Borrower as a result of the Government's failure to pay (after any applicable grace or cure period) any amount due to the Borrower under the Implementation Agreement ("IA") or the Government Guarantee as a consequence of, relating to or in connection with:

(a) a GOU Event of Default;

(b) a UETCL Event of Default; or

(c) a Political Risk Event (each, a "Guaranteed Event"), *provided* that the following shall not be Guaranteed Events:

(i) events or circumstances under Implementation Agreement Section 14.2 (e) (GOU Event of Default) and Section 13.1 (a)(iv) (Definition of Force Majeure);

(ii) events or circumstances under Power Purchase Agreement Sections 4.3 (c)-(e) (UETCL Events of Default) in respect of Uganda Electricity Transmission Company Limited ("UETCL") obligations under the Liquidity Facility Agreement ("LFA"); and

(iii) any other event or circumstance under the Project Agreements or Financing Agreements which is outside the control or ability of the Government to remedy or cure (including Other Force Majeure Events and Hedging Transactions).

Additional Guarantee Terms

The IDA Guarantee is not accelerable.

If there is a dispute, the IDA Guarantee is callable only in respect of amounts that the Government is obligated to pay and fails to pay following the making of an award which is stated to be final in accordance with the dispute resolution procedures contained in the relevant Project Agreement.

The amount for which IDA is liable may include interest accruing during an arbitration but shall be reduced by any amount that the Lenders are entitled at such time to instruct (and no action or omission by a Public Sector Entity exists preventing such instructions being executed by) the Facility Agent to withdraw for application to

	repayment of the IDA-Guaranteed Loan by operation of the provisions of the Project Accounts Agreement (applying sums in the Debt Service Payment Account and the Debt Service Reserve Account).
IDA Fees:	
(i) Guarantee Fee:	Currently, 0.75% per annum of the IDA-Guaranteed Loan Amount outstanding
(ii) Standby Fee[3]:	Currently, 0.20% per annum on any undisbursed IDA-Guaranteed Loan Amount
(iii) Upfront Fees:	(a) An Initiation Fee of 0.15% of the Maximum IDA-Guaranteed Loan Amount (but not less than USD100,000) for internal Project preparation and development costs (b) Processing Fee of up to 0.50% of the Maximum IDA-Guaranteed Loan Amount to cover IDA-designated reimbursable expenses, payable upon receipt of invoice(s)
Conditions precedent to the Effectiveness of the IDA Guarantee:	Usual and customary conditions for project financings of this type, including the following: (a) Firm commitment for sufficient financing to complete the construction of the Project, including satisfactory contribution of equity by the Shareholders; (b) Execution, delivery and effectiveness of all Project Agreements and Financing Agreements, including but not limited to the Common Terms Agreement, other Loan Agreements and Security Documents, the Indemnity Agreement and the IDA Project Agreement, each in form and substance satisfactory to IDA; (c) Delivery of environmental documentation, including a *Social and Environmental Assessment* and a *Social and Environmental Action Plan,* that are satisfactory to IDA; (d) Effectiveness of all required insurances (to include IDA as an additional insured on third-party liability insurance); (e) Provision of satisfactory legal opinions; (f) Payment in full of the Initiation Fee and Processing Fee, and the first installment of the Guarantee Fee and Standby Fee; and (g) Satisfaction of all conditions precedents under the Financing Agreements
IDA Guarantee Agreement:	The terms and conditions of the IDA Guarantee will be embodied in a Guarantee Agreement between the Lenders (or Facility Agent on their behalf) and IDA
Indemnity Agreement:	The Government will enter into a separate Indemnity Agreement with IDA. Under the Indemnity Agreement, the Republic of Uganda will undertake to indemnify IDA on demand, or as IDA may otherwise determine, for any payment made by IDA under the terms of the Guarantee Agreement. The Indemnity Agreement will follow the legal regime, and include dispute settlement provisions, which are customary in agreements between member countries and IDA.
IDA Project Agreement:	Bujagali Energy Limited will enter into a Project Agreement with IDA whereby, *inter alia*, Bujagali Energy Limited will agree to use the proceeds of each advance of the IDA-Guaranteed Loan (or portion thereof) in accordance with the terms and conditions of the IDA Project Agreement and the IDA-Guaranteed Facility

[3] The fee is determined annually and is applicable for the life of the guarantee. The current fee amount is for guarantees approved in Bank's FY07.

Agreement, to provide reports (including audit reports) and other Project information to IDA, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable environmental laws and World Bank Guidelines.

Suspension of Coverage:

If any of the following events occurs and is continuing prior to the end of the Availability Period, IDA may, by written notice to the Lenders/Facility Agent, deny guarantee coverage to any subsequent drawdowns:

(a) any GOU Event of Default, Company Event of Default or UETCL Event of Default, or Event of Default under the Financing Agreements;

(b) material default by the Borrower under the IDA Project Agreement which is continuing after the expiry of the relevant cure period (if any);

(c) suspension of lending by IDA or the International Bank for Reconstruction and Development (IBRD) to the Government; or

(d) suspension or lapse of the Government from membership in IDA, IBRD or the International Monetary Fund.

Termination by IDA:

Except in respect of demand notices already delivered to IDA, default in payment of Standby Fees or Guarantee Fees will automatically terminate the IDA Guarantee. The IDA Guarantee will also terminate in the event that any material changes or waivers are made without IDA's prior consent to those provisions of the Project Agreements or Financing Agreements in respect of which IDA's consent is required (specific provisions to be specified in the IDA Guarantee Agreement) or if it is finally determined by a competent authority that any of the material Project Agreements or Financing Agreements is invalid, illegal, or unenforceable; or if there is a material default by the Borrower under the IDA Project Agreement of certain specified obligations (e.g., environmental) which is continuing after the expiry of the relevant cure period (if any).

In addition, if the Lenders have engaged in corrupt, fraudulent or other prohibited practices, or the Borrower has done so and the IDA-Guaranteed Lenders knew or should have known of such practices, IDA will be entitled to cause immediate termination of the IDA Guarantee.

Subrogation:

If and to the extent that IDA makes any payment under the IDA Guarantee and Government has failed to reimburse IDA for the amount so paid in accordance with the terms of the Indemnity Agreement, and such failure has continued for at least 60 days after notice from IDA, IDA will be subrogated immediately to the IDA-Guaranteed Lenders' rights in respect of such payment, except that IDA shall not have any voting rights or any rights to seek enforcement of security prior to (a) payment by IDA to the IDA-Guaranteed Lenders of the Maximum IDA Liability or (b) where, following an acceleration, IDA has agreed to make payments in accordance with the repayment schedule. IDA in its discretion may elect to waive its subrogation rights.

Claims and Disputes

Claims by the Facility Agent/IDA-Guaranteed Lenders must be made within 90 days of non-payment, with IDA paying within 60 days thereafter. If there is a dispute between the Government and the Borrower as to the Government's obligation to pay or the amount of the liability, the IDA Guarantee would be callable only in respect of amounts that the Government is obligated to pay, and fails to pay, in accordance with the dispute resolution procedures contained in the Implementation Agreement (or other applicable Project Agreement).

IDA Optional Offer to Purchase:

Upon (a) the failure of the Borrower to pay any amount due under the IDA-Guaranteed Facility Agreement; (b) payment by IDA of such loan amount under the IDA Guarantee Agreement pursuant to a demand thereunder; and (c) failure by the Government to reimburse IDA under the Indemnity Agreement in respect of such

	payment, IDA may, if such failure by the Government has continued for at least 60 days, offer to purchase at par plus accrued interest from all (but not less than all) of the IDA-Guaranteed Lenders all of their rights, title and interests in the IDA-Guaranteed Loan outstanding on the purchase date (less any amount paid pursuant to the IDA Guarantee).
Other Provisions:	As part of its appraisal process, IDA will carry out a review of the financing structure of the Project and Financing Agreements, and the proposed risk coverage, as deemed relevant by IDA. Bujagali Energy Limited would be expected to comply with all applicable Bank policies and requirements, including those governing disclosure of information, and applicable environmental, social, fiduciary and anti-corruption safeguards.
Choice of Law	Laws of England and Wales

Indemnity Agreement

Parties:	IDA and Government of Uganda (GOU)
Indemnity:	GOU will reimburse and indemnify IDA on demand, or as IDA may otherwise direct, for all payments under the IDA Guarantee and all losses, damages, costs, and expenses incurred by IDA relating to or arising from the IDA Guarantee.
Remedies:	If the Government fails to perform under this agreement, IDA may suspend or cancel, in whole or in part, the Government's rights to make withdrawals under any other loan with IBRD or credit agreement with IDA or any IBRD loan or IDA credit to a third party guaranteed by the Government.
Dispute Resolution:	Disputes will be settled by arbitration under the UNCITRAL Arbitration Rules.
Choice of law	The Indemnity Agreement will follow the usual legal regime and include dispute settlement provisions customary for agreements between member countries and IDA.

IDA Project Agreement

Parties:	IDA and Bujagali Energy Limited (the Company).
Representations and Warranties:	The Company will represent that it is in compliance with Applicable World Bank Environmental and Social Guidelines and other applicable requirements, if any.
Covenants:	The Company will covenant that it will use the proceeds of the guaranteed debt only for the agreed purposes and will comply with Applicable World Bank Environmental and Social Guidelines and other applicable requirements, if any, and provide regular accounts and reports to IDA.

Annex 14: MIGA Guarantee

MIGA Standard Description of Risk: Breach of Contract

1. Breach of Contract Coverage protects against losses arising from a repudiation or breach by the host government of a contract entered into with the guarantee holder, provided that a final and binding arbitration award or judicial decision has been rendered in favor of the guarantee holder and cannot be enforced against the host government. Compensation is based on the amount that the guarantee holder is entitled to recover from the host government in accordance with the terms of the arbitration award or judicial decision.[1]

MIGA Breach of Contract Risk Assessment

2. MIGA proposes to offer World Power Holdings SarL (Luxembourg) (WPH), a Luxembourg incorporated company (the Guarantee Holder), a guarantee covering its equity investment of up to US$115 million in BEL via SG Bujagali Holdings Ltd. (Mauritius), a wholly-owned subsidiary of WPH incorporated in Mauritius. The coverage would be offered for a period of up to 20 years against the risk of Breach of Contract by UETCL and the Government of certain obligations under the Power Purchase Agreement (PPA), the Implementation Agreement (IA) and the Government Guarantee Agreement (GA). Specifically, WPH is seeking coverage for payment default by the Government of the Termination Payment that would be owed by UETCL under the PPA when that Termination Payment is not paid by the Government in accordance with its guarantee of UETCL's payment obligation under the GA.

3. MIGA's liability to pay a claim will be triggered under specified conditions, if:

   a. A final and binding Arbitration Award (the "Award") is rendered for a breach by the Government of its Termination Payment obligation under the GA, which occurs after one of the specified UETCL or Government events of default or political force majeure events under the PPA or IA, which events are covered by MIGA under the MIGA Contract of Guarantee;

   b. the Award is in favor of WPH and/or BEL and, if in favor of BEL, the Award is assignable in whole or in part by BEL to WPH so that WPH is able to assign (in a form acceptable to MIGA) the portion of the Award corresponding to the amount of compensation due under the MIGA Contract of Guarantee to MIGA; and

   c. WPH and/or BEL have made all reasonable efforts to exhaust all remedies to enforce the Award against the Government during the waiting period.

4. Disputes under the PPA, IA and GA are to be resolved by arbitration under the Arbitration Rules of the United Nations Commission on International Trade Law ("UNCITRAL") in London, the United Kingdom.

5. Uganda provides for fair and equitable treatment for foreign investments. The laws treat local and foreign investors equally. Property and contractual rights are recognized and respected in Uganda and the judicial process allows for investment disputes and provides adequate safeguards for the enforcement of these rights. Under the Ugandan Investment Code, foreign investors may seek

[1] MIGA's Convention provides for coverage under Breach of Contract in three different scenarios: (i) when the Guarantee Holder does not have recourse to a judicial or arbitral forum to determine the claim; (ii) a decision by such forum is not rendered within a reasonable period of time; or (iii) such a decision cannot be enforced.

settlement of disputes before the International Centre for the Settlement of Investment Disputes (ICSID). Uganda is also a signatory to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards. It has also signed several Bilateral Investment Treaties (BITs).

Main Risks

- Viability of the energy sector in Uganda, and the ability of UETCL to meet its payment obligations under the PPA.

- Ability and willingness of the Government to honour its obligations under the IA or the payment obligations of UETCL guaranteed by the Government under the GA.

- The Government does not readily recognize a final decision rendered by UNCITRAL arbitration and pay the Award.

Risk Mitigants

- The reform of the energy sector in Uganda is well underway with the assistance of the Bank Group. This includes reforming utilities, restructuring the market and setting up public-private partnerships. Amongst the donor community, the Bank Group has taken the lead in the energy sector, and this project, together with other regional and country specific projects, will continue to support energy sector reforms in the region.

- Uganda's membership of International Center for Settlement of Investment Disputes (ICSID) is a clear indication that the country is willing to submit itself to international arbitration and to honor its commitments to investors. The project is actively supported by the New Partnership for African Development (NEPAD) and is fully supported by the Government, represented by its 12% shareholding in BEL.

- This is an important, over-due project for the Government as it brings in urgently needed, least cost electricity generation capacity to the country, which will replace some of the more expensive, emergency thermal plants. The project will help breakdown one of the major bottlenecks to the country's economic growth and improve the country's electricity accessibility and affordability. Uganda will also benefit directly from the project through taxes and dividend payments throughout the life of the project. Uganda also benefits indirectly through generation of employment and ancillary economic and infrastructure benefits. Due to the project's strong development impacts, especially in the context of the current severe power shortages in the country, the project has broad public support in general.

- The controlling project sponsor has been selected by the Government through international competitive bidding while the EPC contractor has been selected by the project company following the EIB's procurement rules. Thorough social and environmental due diligence has been conducted with broad community development action plans in place. Unprecedented public disclosure and broad public consultation have also been conducted.

- Financial and economic benefits are significant for customers, the Government, and for the private sponsors; the distribution of these benefits is considered to be broadly equitable.

- MIGA is further protected by the standard waiting period from the date the arbitral decision becomes final, during which time the Guarantee Holder is obligated to take actions to enforce the Award.

Annex 15: Safeguard Policy Issues

I. BACKGROUND

1. The project sponsors have prepared a comprehensive Social and Environmental Assessment (SEA) and conducted additional formal and informal consultations in Uganda regarding the new circumstances of the project.

2. The project sponsors are Industrial Promotion Services (Kenya) Ltd. ("IPS (K)") and SG Bujagali Holdings, Ltd., an affiliate of Sithe Global Power LLC (US) ("Sithe Global"), (collectively the "Sponsors"). The project will be built under an Engineering, Procurement, Construction ("EPC") contract issued by BEL; the O&M operator of the plant is expected to be an affiliate company of Sithe Global. UETCL will award the Interconnection Project EPC contract, and own, operate, and maintain the transmission facilities. Under the project PPA, BEL is to play a management role in the design, procurement, and construction phases of the Interconnection Project.

3. The hydropower facility will consist of a power station, housing up to 5x50 MW turbine generators within a 30 m high earth-fill dam and spillway works. The proposed project will require 125 ha of permanent land take and 113 ha of temporary land take for the project's ancillary facilities. The dam will impound a reservoir extending back to the tailrace area of the Nalubaale and Kiira facilities, inundating Bujagali Falls. The reservoir will be 388 ha (3.88 km^2) in surface area, comprising existing 308 ha of the Victoria Nile, and 80 ha of newly inundated land. The reservoir waters will be contained within the steeply incised banks of the Victoria Nile, between Dumbbell Island and Nalubaale, thereby minimizing the amount of newly inundated land.

4. The associated Interconnection Project, being developed for UETCL, involves the proposed construction and operation of the high voltage electrical transmission infrastructure needed in part to interconnect the proposed Bujagali project to the national electrical grid and to strengthen the evacuation of electricity from the project. The proposed Interconnection Project includes: (a) a 75 km transmission line to convey power generated to a new substation to be located in Kawanda, on the outskirts of Kampala; (b) a 17 km transmission line to connect the Kawanda substation to the existing Mutundwe substation, located in the southwest section of Kampala, where some upgrades will be needed to accept the new line; and (c) two 5 km transmission lines to establish interconnections between Bujagali and the Tororo substation in eastern Uganda and the Nalubaale substation in Jinja.

II. ENVIRONMENTAL AND SOCIAL CATEGORY AND APPLICABLE OPERATIONAL POLICIES AND PERFORMANCE STANDARDS

5. The project is classified as Category A. The following World Bank safeguard policies apply: Environmental Assessment (OP/BP4.01); Natural Habitats (OP/BP4.04); Forests (OP/BP4.36); Physical Cultural Resources (OP/BP4.11); Involuntary Resettlement (OP/BP4.12); Safety of Dams (OP/BP4.37); and Projects in International Waterways (OP/BP7.50). The IFC's Policy on Social & Environmental Sustainability and Policy on Disclosure of Information were applied to this project. The impacts from the project will need to be managed in a manner consistent with the following IFC Performance Standards: PS 1: Social and Environmental Assessment and Management Systems; PS 2: Labor and Working Conditions; PS 3: Pollution Prevention and Abatement; PS 4: Community Health and Safety; PS 5: Land Acquisition and Involuntary Resettlement; PS 6: Biodiversity Conservation and Sustainable Natural Resource Management; and P8: Cultural Heritage. MIGA Policies on Environmental Assessment and Disclosure apply, as well as MIGA's (issue specific interim safeguard) Policies on Involuntary Resettlement, Physical and Cultural Resources, Natural Habitats, Dam Safety, and Projects on International Waterways.

A. Impact Assessment Process

6. **Previous Effort to Develop the Bujagali Project.** ESG International and WS Atkins prepared the Environmental Impact Assessment (EIA) and related resettlement documentation for AES Nile Power (AESNP), the previous project sponsor, for both the proposed hydropower facility and the transmission system. AESNP began the impact assessment in 1997 and sought IDA/IFC comments on the Terms of Reference. At the request of IFC, AESNP retained an independent Panel of Experts to advise it during the preparation of EIA documents and the public consultation process. AESNP conducted extensive consultations in Uganda and in particular with project-affected people. AESNP also formed the Bujagali Dam Safety Panel.

7. **Private Power Generation (Bujagali) Project.** For the current Bujagali project, the current project company, BEL, conducted full SEAs for its proposed Hydropower Project and (on behalf of UETCL) for the associated Interconnection Project, which will be owned and operated by UETCL. As part of the SEAs, BEL also conducted an assessment of the activities under the Resettlement and Community Development Action Plan for the previous effort to develop the Bujagali project. The full SEAs built on the empirical findings of the previous EIAs, took into account IDA's revised safeguard policies and the full set of IFC's new Performance Standards, as well as MIGA's (issue specific interim safeguard) Policies. BEL's consultants conducted field studies and analyses where the need for updated information had been identified, such as water quality, fisheries, terrestrial ecology, resettlement and compensation, and cultural resources. Other recent information compiled by others on hydrology and river flow was also incorporated in the December 2006 SEA for the Hydropower Project. Existing baseline information in such areas as climate, ambient noise, and air-borne particulates is not expected to have changed significantly, and those data are considered representative of current conditions. Because the project is now split between the Hydropower Project and the Interconnection Project, BEL's consultant, R.J. Burnside International Limited, prepared two *Social and Environmental Assessment ("SEA") Reports*, one for each project. Several significant project documents, in particular the Public Consultation and Disclosure Plans, *Assessments of Past Resettlement and Action Plan* ("APRAP") – for both projects, the Resettlement Action Plan ("RAP") – for the IP, and the Community Development Plans ("CDAP"), are appendices within these documents. The findings from the APRAPs were incorporated into the new *Social and Environmental Action Plans* (SEAP) which were completed in December 2006. The documentation was designed to fulfill regulatory and procedural requirements of IDA/IFC/MIGA, the Government of Uganda, African Development Bank (ADB), European Investment Bank (EIB), and Deutsche Investitions - Und Entwicklungsgesellschaft Mbh (DEG).

B. Social and Environmental Assessment and Management System (OP 4.01; PS 1, MIGA Environmental Assessment Policy)

8. Development of the hydroelectric potential of Bujagali requires construction of two linked projects: BEL's Bujagali Hydropower Project and UETCL's Interconnection Project. SEAs have been prepared for both projects to address the requirements of the National Environmental Management Authority (NEMA) in Uganda, the World Bank Group, and other development finance institutions (DFIs).

9. Draft Terms of Reference (TOR) for the two SEA reports were circulated to potential lenders in February 2006 and in Uganda in July and August 2006, as part of BEL's community engagement program. Issues identified during the consultations are addressed in the SEA reports, and are summarized below:

- Past resettlement activities and commitments of the previous project sponsor.

- APRAP report outlines the concerns/issues and proposed actions to be undertaken. The APRAP is Appendix I to the December 2006 Hydropower Project SEA.
- BEL is committed to completing the required provisions of the original resettlement and community development program. These commitments were included in the new SEAP of December 2006 for the Bujagali project.

- Community development opportunities for local residents and governments.
  - The CDAP is Appendix J to the December 2006 Hydropower Project SEA.
  - BEL is committed to CDAP activities over a five-year period following the start of construction.
  - These commitments cover health care facilities; employment opportunities; water supply and sanitation; fisheries; education; small-scale tourism; training and financial services.
- Completion of activities to mitigate spiritual and cultural impacts.
  - The previous project sponsor prepared a Cultural Property Management Plan that documented the surveys and studies of cultural issues and actions to be taken. Commitments that remain from the previous project were identified as part of the APRAP process.
  - BEL will complete all of these commitments, including a non-denominational service in remembrance of those buried in unmarked graves that will be inundated.
  - BEL is having on-going consultations with local traditional authorities and has committed to measures to ensure that these issues are properly addressed prior to and during construction.
- Construction workforce impacts - social and health consequences of migrant workers coming into the communities.
  - The EPC contractor will encourage workers to seek housing in near-by Jinja, which can accommodate families and thus avoid a major risk factor for HIV/AIDS among the local communities.
  - The Ugandan AIDS/HIV Non-Governmental Organization TASO will assist the project in developing an education and health campaign to inform the local communities and workers about communicable diseases.
- Local community access to electricity as a community development initiative.
  - BEL is committed to conduct a feasibility study on the commercial viability of providing the communities with electricity in order to facilitate the process vis-à-vis UMEME.
- Employment opportunities/training and priority in employment opportunities.

  - BEL and the EPC contractor will give priority to hiring qualified local people for dam, road, and other construction. The EPC contractor will also implement an apprenticeship program to build a local skills base.

  - BEL is identifying employment opportunities in addition to the income restoration programs of the CDAP. BEL is developing a tree planting program for both borders of the reservoir and the river banks between the hydropower project and the Kalagala Falls. This will provide additional local employment.

- Consultation with communities and Non-Governmental Organizations in finalizing and implementing the CDAP.

  - The CDAP focuses on "supporting communities' needs based on culturally appropriate means of consultations."

  - BEL is committed to undertake ongoing consultation activities with the local community to help prioritize community needs and to finalize the CDAP. A finalized plan will be a disbursement condition of the World Bank Group investment.

- Potential for job loss by the tourism industry employees and by self-employed and informal workers in the tourism industry.

  - Tourism operators and workers will adjust to changes from the hydropower project by moving their businesses downriver. Other tourism operators, such as small arts and crafts shops, restaurants, four wheeler rentals, and locally owned enterprises are expected to move their businesses nearer to Kalagala Falls.

  - Consultation with the tourism company owners has not indicated that they expect to experience significant decreases in tourist numbers - in fact, many are anticipating growth.

  - Actions are proposed as part of the CDAP, and developed in consultations with the communities, to increase opportunities for local people in the hydropower project area.

- Safety issues from construction traffic along the west bank road, as the road is heavily used by pedestrians including school children.

  - The EPC contractor will implement a Construction Traffic Management Plan that addresses all construction-related traffic on both the east and west banks.

  - BEL and the EPC contractor will consult with local community leaders in the development of this plan.

- Local community benefits from the project.

  - The CDAP is based on ongoing consultation with the communities regarding their future needs.

  - The proposed project employment benefits (direct and indirect) and induced economic benefits from the project are expected to be significant for these communities.

- Concerns from the east bank communities that they will not benefit as much as the west bank communities (construction activities will be focused on the west bank).
    - BEL is committed to providing programs and opportunities to both east and west bank communities.
    - As part of the CDAP, resource centers will be developed on both banks of the river.
- Local institution interest in participating in the project, through assisting in the delivery of the CDAP and environmental monitoring of mitigation/restoration activities.
    - BEL will work with local institutions as part of the process to finalize the CDAP and develop other project implementation plans.
- Loss of access to the river by fishermen once the construction period begins.
    - Although fencing along the west bank has been installed, access to the river has not been cut off and use of the river in the vicinity of the project for fishing access has continued.
    - As detailed in the CDAP, once construction is initiated more formal facilities will be developed so as to allow access the river for fishing.
- Impact of Bujagali on the low water levels in Lake Victoria and on the releases from Lake Victoria.
    - Water levels in Lake Victoria will continue to be determined by rainfall, evaporation and rate of discharge at the Nalubaale/Kiira dam complex.
    - The Bujagali project will reuse water already released through the Nalubaale/Kiira dam complex upstream.
    - Through this water use efficiency, Bujagali will assist the Government in its commitment to using the water of Lake Victoria in a sustainable manner.
- Safety issues associated with the aging Nalubaale facilities.
    - The Government, with the assistance of IDA, has conducted remedial works to correct deficiencies at Nalubaale. These remedial works were concluded under the oversight of an international expert panel.
    - Monitoring of the affected structures is conducted annually by independent specialists, and corrective actions are implemented as needed.
    - BEL has appointed the Dam Safety Panel for Bujagali in March 2007; safety risks from Nalubaale are part of this panel's terms of reference.

10. BEL is a special purpose company established solely for the development, construction, and operation of the Bujagali hydropower project. Therefore, during the current development phase, management systems are being developed by BEL's project implementation team with assistance from the project sponsors. BEL's in-country team currently includes the Social and Environmental

Manager, Technical Coordinator, and Public Relations Coordinator. Assistance is provided by the Bujagali Implementation Unit as well as Ugandan and international consultants to BEL.

11. BEL has engaged independent advisors to the project through a Social and Environmental Panel of Experts to assist in the assessment process, as well as a Dam Safety Panel (see PS 4/OP 4.37 discussion below). Consisting of an internationally-recognized social specialist and environmental specialist, respectively, the Panel of Experts is providing ongoing advice to BEL, including the areas identified in the relevant Safeguard Policies and Performance Standards. BEL has also engaged an experienced witness Non-Governmental Organization to manage its grievance process for external stakeholders.

12. **Social and Environmental Action Plan (SEAP).** BEL will have overall responsibility for design and building of the hydropower facilities, and is currently finalizing its EPC contract. The ultimate responsibility for the project's compliance with Ugandan legislation and international lenders' guidelines for environmental and social performance will lie with BEL. However, day-to-day responsibility for implementing environmental and social mitigation, compensation and monitoring actions will, in many cases, be devolved to the EPC contractor or to third parties. The SEAP specifies the means by which environmental and social management will occur during the construction phase, and will be finalized in coordination with the EPC contractor. UETCL will be similarly responsible for the associated Interconnection Project. UETCL will contract BEL to play a management role in the design, procurement, and construction phases of the Interconnection Project.

13. BEL has prepared SEAPs that address the construction of both the Hydropower Project and the Interconnection Project as well as the operational phase of the Hydropower Project for a 30-year period. UETCL will develop its own SEAP for operation of the Interconnection Project. The hydropower SEAP is an umbrella plan that comprises several components that are to be integrated and implemented by BEL and the EPC contractor. The hydropower SEA includes working versions of three of BEL's Action Plans (namely, the Public Consultation and Disclosure Plan (PCDP), Assessment of Past Resettlement Activities and Action Plan (APRAP), and Community Development Action Plan (CDAP)), as well as frameworks and commitments to other SEAP components; those which are the responsibility of the contractor will be developed in consultation with the EPC contractor. BEL has committed to regular updates and disclosure of its SEAPs, as appropriate, going forward.

14. To comply with its commitments under the SEAP, BEL has designated a suitably qualified and experienced Social and Environmental Manager, who will report directly to BEL's Implementation Manager, and will be provided with sufficient support staff and facilities. A final staffing plan will be a disbursement condition of the World Bank Group Investment. It is likely that a subset of the environmental management team for implementation will transition to the operations team over the course of the project. The project's EPC contractor will also designate an appropriately experienced and qualified Site Environmental Officer, who will be responsible for implementation of the measures set out in the contractor's Action Plan.

15. **BEL Monitoring and Reporting.** During construction, BEL will have the ultimate responsibility to ensure environmental monitoring and reporting procedures are being undertaken. The Site Environmental Officer will have overall responsibility for the activities of the contractor's environmental department. On a day-to-day basis the emphasis of the Site Environmental Officer's work will require working with BEL's Environmental Manager and with relevant authorities, local residents and Non-Governmental Organizations on environmental issues (i.e., external liaison). BEL and IDA/IFC/MIGA will agree on a suitable arrangement for independent review of monitoring information through construction and initial operations.

16. BEL's Social and Environmental Manager will develop environmental reports suitable for submission to NEMA (as a requirement of the Ugandan Environmental Impact Assessment Regulations) and to other stakeholders as appropriate, and will make these reports available in its local offices as well as on its website (www.bujagali-energy.com). Reporting the results of environmental monitoring allows the responsible agencies to identify if any mitigation measure is not being effective and will enable corrective action to be taken.

17. **WBG Monitoring and Supervision.** IDA/IFC/MIGA will undertake field based supervision of the project (including the hydropower facility and the Interconnection Project) quarterly during construction. Annual IDA/IFC/MIGA monitoring/supervision will be carried out thereafter. The overall Supervision Plan for the proposed project will include the participation of IDA/IFC/MIGA environmental, social and cultural heritage staff, or appropriately qualified consultants, in major missions, to review progress in implementation of the umbrella SEAPs. Supervision of the project will incorporate independent third party review. The performance of BEL and its EPC contractor, as well as cooperating Government organizations, in the implementation of these activities under the proposed project will be a standard element of project supervision reports and included in the Mid-Term Review and the Implementation Completion Report. Project Status Reports will include evaluation of compliance with the safeguard policies triggered for the proposed project.

C. Labor and Working Conditions (PS 2)

18. The application of IFC's Performance Standard on Labor and Working Conditions (PS 2) to BEL is a major difference from the previous effort to develop project. BEL is a special purpose corporation set up for this project. As such, BEL is effectively a start-up operation that will need to develop its own human resources policy and procedures with respect to the requirements of PS 2. Uganda is a signatory to the core International Labor Organization labor standards. Thus, national law includes the fundamental principles with respect to non-discrimination, freedom of association, forced and child labor. General conditions of employment (e.g., wages, working hours, child labor) in Uganda are covered by The Employment Act, 2006 (Act No 6). Legal provisions for worker health and safety are covered by The Occupational Safety and Health Act 2006 (Act No 9). BEL will follow these laws. A draft of the Human Resource Policy and the procedures will be reviewed by IFC before the start of project construction.

19. BEL will use an EPC contractor to build the hydropower dam and related facilities. BEL will, through its EPC contract, require the contractor to apply the same standards with respect to national law, PS 2, and international practice as it has committed itself. Under the SEA Report BEL is committed to ensuring that the EPC contractor has a human resource policy and a grievance mechanism as indicated in the SEA. Contractors will not be required to have a retrenchment plan when construction is finished and the workforce is demobilized. BEL will monitor the performance of its contractors with respect to these standards, and the EPC contract will contain provisions to ensure that BEL can enforce those provisions. IFC will review the relevant EPC contract to ensure that these provisions are met, and will also review BEL's monitoring of compliance with the provisions. The EPC contract issued by BEL will also specify occupational health and safety commitments to be observed by the EPC contractor and subcontractors, as well as monitoring responsibilities.

20. BEL will be responsible for managing the construction of the Interconnection Project, and the commitments described above will apply to this project as an associated facility. UETCL will, however, operate the transmission line.

III. Compliance with Operational Policies

A. Biophysical Impacts (OP 4.01, OP 4.04, OP 4.36, PS 6, MIGA Natural Habitats Policy)

21. **Natural habitats.** The construction phase of the project will require a temporary land take of 113 hectares. The EPC contractor will be required by its contract to revegetate this area. The Uganda Land Commission will determine whether project affected people will be allowed to return the land to cultivation, its previous predominant use.

22. The permanent land take will be 125 hectares, of which 80 hectares will be inundated. The land take and the inundation will not impact critical natural habitat. The land take will affect 28.6 hectares of land within the Jinja Wildlife Sanctuary, including 15.8 hectares of land on the islands in the river that have relatively intact native vegetation (out of a total of 26.8 hectares of total island land). This impact on the islands will be off-set by the planting of a 100 meter strip around the edge of the reservoir with native and medicinal trees. The impact on the Jinja Wildlife Sanctuary and the loss of Bujagali Falls will also be offset by the enhanced protection of the Kalagala Falls and Nile Bank Central Forest Reserves. BEL will have a role in the development of this offset as an ecotourism site, in collaboration with the National Forestry Authority.

23. Construction of the Bujagali dam will have a negligible impact on the flow regime of the Nile. Habitat for haplochromines, an indigenous fish genus of the Nile River basin, may be improved by the impoundment, but this improvement may be offset by predation from Nile perch and fishing pressure. Migratory species have already been affected by the Nalubaale hydro dam and the adjacent Kiira dam. All the same, the company will monitor migratory fish to identify any changes in population levels.

24. The SEA considers alternative designs within the Bujagali hydropower project. BEL has, thus, considered the costs and benefits to alternative designs, including the impact on natural habitats and protected areas, and will mitigate, primarily through offsets, the impacts of the project. BEL has consulted with key stakeholders on this issue, in this case the Uganda Wildlife Authority and the National Forestry Authority.

25. The Interconnection Project will pass through three Central Forest Reserves, Mabira Kifu and Namyoya, with natural, but not critical, habitat. The land take in the Kifu and Namyoya Cultural Forest Reserves will be minor, 3.7 and 6.7 hectares, respectively. Land take in the Mabira will be more substantial with 70.4 hectares to be affected, of which 59.2 hectares is forested. The SEA study has determined that there is no reasonable alternative to this route. The SEA proposes a number of measures for UETCL to take in order to minimize the impact, along with payments to the National Forestry Authority to be used for enrichment planting to offset the loss of forest. The primary stakeholders - the local communities and the National Forestry Authority - have been consulted on the impact and its mitigation measures. Responsibility for implementing the mitigation measures rests with the National Forestry Authority. UETCL will contribute to the on-going management of the Mabira Central Forest Reserve by paying ground rent to National Forestry Authority and covering its incremental costs. BEL will monitor the progress of these measures and will collaborate, as necessary, to ensure their implementation.

26. The Interconnection Project line will also pass through Lubiji Swamp near Kampala to avoid a greater impact on human habitation. The tower construction is designed to minimize impact on the hydrology of the wetland, which does not contain any critical habitat. A total of 0.7 hectares will be needed.

27. **Hydrology and Water Quality.** During construction, the flow of the Nile will remain governed by the operating regime of Nalubaale and Kiira. Due to its minimal reservoir storage capacity, the Bujagali project will have negligible impacts on Nile River flows. Construction phase impacts on water quality are not expected to result in suspended sediment levels that will be detrimental to aquatic species. Effluent from construction operations will be treated so as to achieve effluent quality in compliance with Ugandan standards and the WBG guidelines for effluent discharge.

28. The Power Planning Associates Ltd. team of consultants evaluating the Bujagali project economic viability included the firm Coyne et Bellier, who are hydrology experts. Their analysis is based on the full 106 year hydrological record for Lake Victoria. Coyne et Bellier developed "high" and "low" hydrology scenarios, the latter with a much higher probability of occurrence (79%); these scenarios take account of the current water levels of Lake Victoria.

29. **Fisheries.** The possible impact of the proposed Bujagali project on fisheries was recognized early on in the processing of the project. AESNP commissioned the Fisheries Resources Research Institute (FIRRI), based in Jinja, Uganda, to carry out a series of surveys of fish stocks and commercial fishing on the upper Nile River throughout the year 2000, at four sites located both upstream and downstream of the proposed dam site. Operation of the proposed project would change the habitat type (fast flowing zone) within the inundation reach (approximately a 7-kilometer reach upstream of Bujagali) down to a slow flowing zone. However, the fast flowing zone habitat would remain for approximately a 32-kilometer reach downstream of Dumbbell Island. The Fisheries Resources Research Institute concluded that the project will result in only minor changes to the balance between populations of certain species upstream of the dam. Of species deemed to be of conservation value, the haplochromines were identified, due to recent impacts of Nile perch predation. Subsequent monitoring of haplochromines (November 2001 Report) confirms that habitat and food availability for the haplochromines would be intact after construction both upstream and downstream. Fisheries studies for the project were conducted for BEL in April 2006 by the National Fisheries Resources Research Institute (NAFIRRI, former FIRRI), based in Jinja, Uganda. NAFIRRI's 2006 conclusions were consistent with its earlier analyses in 2001. The Kalagala offset agreement will assist in the preservation of species of conservation value (including the haplochromine Neochromis simotes) over the longer term by preserving their habitat.

B. Pollution Prevention and Abatement (PS 3)

30. BEL and the EPC contractor will establish organizations and systems to implement their respective SEAPs, under BEL's overall control. The EPC contractor will have responsibility for traffic, waste, labor force, environmental monitoring, health and safety, spill contingency, and hazardous materials management. Construction and operation of hydroelectric facilities, such as the proposed project, involves activities and materials for which pollution prevention and abatement practices are well established.

31. **Air quality and noise.** Changes in air quality will result from increased dust during construction, emissions from an asphalt plant and emissions from heavy equipment and project-associated vehicles. Monitoring will be carried out for dust emissions, which will be controlled by use of water sprays or other control measures. Emissions from the operation of heavy equipment are not expected to exceed Ugandan standards for emissions and IDA/IFC/MIGA guidelines. General construction related noise is expected to be below the level permitted under the draft noise standards of Uganda. Drilling and blasting will create intermittent noise.

32. **Traffic.** Traffic generated during construction will not have major effects, because highway volumes will be comparatively light and not concentrated in any one area at one time. More frequent transport of heavy goods is expected along the West Bank Road between Jinja and the site and safety measures will be applied to reduce impacts. The EPC contractor will implement a Construction Traffic Management Plan that addresses all construction-related traffic on both the east and west banks.

33. **Emissions of greenhouse gases (GHGs).** GHG emissions from hydroelectric facilities occur primarily during construction, from exhaust emissions from construction machinery, and during early operation as a result of decomposition of organic material caught in the impoundment. BEL estimates that one-time GHG emissions from Bujagali would be about 240,000 tons of Carbon Dioxide (CO_2) equivalent. BEL also estimates that a thermal generating plant burning fossil fuels generating the same amount of electricity per year as Bujagali would release about 1.2 million tons of CO_2 to the atmosphere. Over its 50-year commercial life, Bujagali will avoid the emission of nearly 60 million tons of CO_2. Bujagali will also avoid the potential local health risks of particulate matter, nitrous oxides and sulfur dioxide emissions from the thermal plants.

C. Community Health and Safety (PS 4), including Dam Safety (OP 4.37, MIGA Dam Safety Policy)

34. Public safety is the responsibility of BEL and the contractor. The safety and security procedures will conform to government standards in public highways and access roads, transmission lines, all construction sites, storage yard, etc. A construction traffic management plan will be developed, especially along the western side of the river, where construction traffic will be the heaviest. A Health and Safety Manager will be assigned by BEL to ensure that these procedures are carried out and monitored.

35. Incidence of HIV/AIDS is high, with HIV/AIDS related illnesses accounting for 30% of hospital admissions, on average, each year. The proposed project is not expected to increase the incidence of HIV/AIDS: the emphasis on local hiring and the ability of non-local workers to house their families in Jinja reduces the main risk factors. Still, the project will undertake an awareness and public education campaign. The Ugandan AIDS/HIV Non-Governmental Organization TASO will assist the project in developing an education and health campaign to inform the local community and workers about communicable diseases. Several village health centers are also planned.

36. Malaria and respiratory infections account for about one-half of all outpatient illnesses in the project area. In general, hydropower reservoirs with steep sides, such as Bujagali, negatively affect both mosquito and snail-borne diseases, such as malaria and schistosomiasis, because of the lack of shallow water and fluctuating water levels. Bujagali will actually lessen the amount of vector-breeding shoreline. Anti-malarial medicines and prophylaxis will be made available to workers and local community members. The project will seek to avoid any increase in growing vector habitat, particularly for schistosomiasis in the reservoir area. Although the risk of infection is low, the project will clear floating vegetation that is the habitat for the disease-bearing snail. Impacts on the local villages from in-migration of workers will be carefully monitored by the Bujagali EPC contractor Health and Safety Manager.

37. BEL will implement, prior to initiation of work by the EPC contractor, its Emergency Preparedness and Response Plan (EPRP) that will set out the methods for dealing with emergencies arising during both construction and operation, and particularly those with potential effects on the neighboring and wider communities (i.e., persons not directly involved with the project). The EPRP will also set out the means by which these measures will be communicated to affected communities in

a culturally appropriate manner. Site security will initially be the responsibility of the EPC contractor, and revert to BEL during facility operation. Normal security levels for a facility of this type will be used (e.g., armed, uniformed guards). BEL will ensure that security personnel have a clear protocol for the use of force and are appropriately trained on that protocol. Access to construction work areas will be controlled, with provisions made for the needs of the local population. BEL and the EPC contractor will establish procedures through the witness Non-Governmental Organization to respond to grievances.

38. BEL engaged a Dam Safety Panel to review the investigation, design and construction of the proposed hydroelectric dam and the start of its operations. The panel will advise BEL on dam safety matters and other matters such as its structures, catchment area, reservoir surroundings and downstream areas. As needed, the panel will provide expert review of associated issues such as the safety of the power generation facilities, river diversions during construction, the implications on safety of the upstream dams (Nalubaale and Kiira), and potential effects of a failure at either of these facilities on the Bujagali dam.

D. Projects on International Waterways (OP 7.60, MIGA Projects on International Waterways Policy) and Transboundary Impacts (PS 1)

39. **Notification Process.** The Nile River is an international waterway, and pollution and other project-related effects from Bujagali could potentially affect downstream riparians. As noted above, the project is not expected to cause this to occur. Moreover, Bujagali is not expected to affect upstream riparians that border Lake Victoria, as any effects on the lake are determined solely by the operation of Nalubaale and Kiira. IDA/IFC/MIGA have considered the international aspects of the project and have assessed that the project will not cause appreciable harm to the other Riparian States, and will not be appreciably harmed by the other Riparian States' possible water use.

40. On February 24, 2000, the Government of Uganda, consistent with IDA/IFC/MIGA policy for projects on international waterways (OP/BP 7.50) notified all nine upstream and downstream Riparian States (the Governments of Tanzania, Kenya, Ethiopia, Eritrea, Sudan, Egypt, the Democratic Republic of the Congo, Rwanda and Burundi) of its intention to proceed with the Bujagali project on the Nile River. The Government noted that the Bujagali hydropower plant would not result in any change to the discharge pattern in the Victoria Nile River. Also, the Government provided the Riparian States with copies of the technical drawings and the designs of the proposed Bujagali hydropower plant, and asked for views and comments from the Riparian States before October 2000. On May 31, 2000, in line with the agreed operating procedure governing the water discharge pattern in the Victoria Nile River, the Government of Egypt gave its no objection to the Government of Uganda to proceed with the project. There were no other responses from Riparian States.

41. The Government requested that Egypt provide a reaffirmation of its no-objection to the Bujagali project in May 2006, and written no-objection was issued by the Government of Egypt on May 15, 2006. Notifications regarding the intended development of the now proposed Bujagali project were issued by the Government of Uganda to other Nile Riparian States in September 2006, followed by a recent addendum, in March 2007, noting the available public information on the project and providing a March 30, 2007 closing date for responses. No additional responses were received as of the closing date.

E. Land Acquisition and Involuntary Resettlement Impacts (OP 4.12/PS 5, MIGA Involuntary Resettlement Policy) and Other Social Impacts (PS 1, 2 and 8)

42. **Involuntary Resettlement.** The proposed project will require approximately 238 hectares, of which 125 hectares will be a permanent land take and 113 hectares are to be used temporarily during construction. Access roads to the dam will be from Jinja town to Kayunga road on the west bank, although the power station will be fenced on both sides of the river. Forty-five hectares of land will be used for project facilities and the 113 ha of temporary land take will be used for the project's ancillary facilities, such as the concrete and asphalt batching plants, roads, cofferdams, rock quarries and stockpile areas. For the Interconnection Project, a total of 381 ha of land will be allocated for transmission line wayleaves, transmission line rights-of-way, and lands acquired for the Kawanda substation.

43. **Project Affected Persons.** AESNP carried out the physical resettlement and payment of compensation associated with the hydroelectric facility in 2001 as part of the Resettlement and Community Development Action Plan (RCDAP) implementation. The project identified what it called "project affected villages." These villages are in and around the proposed site for the dam and spillway, ancillary facilities, and access roads. The villages were and are divided geographically and culturally into two groups. On the eastern side are the Basogans in Jinja District, covering the villages of Bujagali, Ivunamba, Kyabirwa and Namizi. The Bugandans, on the western Mukono District, are in Naminya (which is also the resettlement village), Buloba, Malindi and Kikubamutwe.

44. A retrospective Assessment of Past Resettlement Activities and Action Plan (APRAP), prepared for BEL in June 2006 (and disclosed in December 2006 as part of the SEA) found that 1,288 households (or 5,158 people) were project affected. These households can be further broken down into two groups: (a) 85 households (634 individuals) were physically displaced, of which, 34 households chose to move into the Naminya LC1 resettlement site and 51 opted for the cash compensation; and (b) 1,203 households whose livelihoods were affected and where the resettlement policy on livelihood restoration applies. There are indirectly affected households, and together with the PAPs, comprise the eight "project affected villages" described above. Economic displacement was minimal for the majority of affected people: the average area of land lost is less than 0.1 hectare.

45. The dam site is within the vicinity of the town of Jinja, Uganda's second largest urban center. It is a major commercial hub for textiles, beer, plastics, food processing, and flour milling industries. Results of social surveys conducted in 1998/99 by the previous project sponsor, AESNP, and updated in a follow-up survey for the SEA Report by the Bujagali Implementation Unit and BEL, show that most of the project affected households engage in some form of subsistence agriculture. The agricultural farms are primarily small, labor intensive, inter-cropped, and rain-fed systems. The main crops are coffee and sugar cane, although recently more farms started planting fruit trees and vanilla. In most poly-cultural home gardens, a variety of food crops can be found, such as bananas, cassava, sweet potatoes, maize, beans, millet, and yams.

46. IDA/IFC/MIGA resettlement policies give a preference for land-based options, but under Ugandan law, people must be offered cash compensation for their assets. The majority of people relocated chose the cash option out of the belief that they would be able to find better housing for themselves and because it was probably easier for household heads to obtain consent from other members with the cash option. The prior project had completed the planned compensation prior to AESNP's departure. The resettlement housing was also completed, and the 34 families have moved into it. Several activities under the RCDAP were not completed at the time AESNP departed the project; these were primarily income generation activities.

47. Cash compensation for lost crop land was intended to be used to purchase new agricultural land. However, many recipients of the compensation money spent it on things that either had no relationship to future income generation or on business assets that proved to be failures. BEL has committed to three programs toward the goal of income restoration: agricultural improvement, fisheries, and small business support and microcredit. Many of the project affected communities rely on the Nile for their income. At the consultations, some fishermen expressed concern about access to the river once the dam was built. They were told that except for the fenced area surrounding the dam site, access will not be restricted. The project will also build landing sites downstream that fishermen can use. The EPC contractor Site Environmental Officer will be responsible for tracking changes in access to boats and fishing landing sites at Buloba, Kikubamutwe, and Namizi villages. BEL has allocated US$114,000 to cover the costs of constructing new landing sites downstream to assist tourism operators, fishermen, etc. The BEL programs are in the community development action plan (CDAP), but with specific budgets earmarked for the project affected persons.

48. Four rafting enterprises use Bujagali Falls as part of their operations. BEL is in negotiations with the companies, including measures such as offering to assist the companies in moving their operations farther down river. According to a tourism study undertaken as part of the SEA report, this relocation will not economically affect the enterprises. The rafting operators in the area employ local residents and provide opportunities for small tourism related businesses (e.g., small art and crafts shops, restaurants, four wheeler rentals, and locally owned enterprises). To assist those local villages who will be affected by the relocation of the rafting enterprises, BEL is proposing to develop a cultural center near the site of Bujagali Falls and a visitor center at the dam. These centers will provide opportunities for small businesses similar to those near the current Bujagali Falls tourism opportunities. The tourism and services related operators noted in the consultations that they are satisfied with the proposed alternative of moving their businesses downstream, with their activities now being more centered around Kalagala Falls.

49. The associated Interconnection Project, which is under consideration for funding by ADB, will pass through several villages along the 70 km transmission line to the substation at Kawanda in the outskirts of Kampala; will include a 17 km transmission line connecting the Kawanda substation to the existing Mutundwe substation, in the southwest section of Kampala; and will also have two 5 km transmission line between Bujagali and the Tororo substation in eastern Uganda and the Nalubaale substation in Jinja.

50. The RAP for the Interconnection Project provides measures to overcome the problems with cash compensation observed in the hydropower project resettlement. The RAP procedure calls for a greater effort to encourage people to take the land-based compensation rather than cash. BEL will be involved in the actual compensation and resettlement along the transmission line, but UETCL will be responsible for the long-term outcomes. IDA/IFC/MIGA staff has reviewed the RAP and believes that it will lead UETCL to meet the requirements of PS 5, OP 4.12, and MIGA's Involuntary Resettlement Policy. BEL will monitor the implementation of measures under the responsibility of UETCL, and will collaborate, as necessary, with UETCL to ensure their completion.

51. **Community Development.** Aside from the required livelihood restoration measures, BEL developed a comprehensive CDAP. This plan identifies specific actions that would directly benefit not only PAPs, but also the other people in the project affected communities. The objectives of the CDAP are to: (a) provide opportunities for improved livelihood; (b) improve overall quality of life through practical support in areas like health, water and sanitation, and education; and (c) provide mechanisms for dealing with vulnerable people. BEL has committed to providing US$2.4 million for community development over a period of five years.

52. Each community program is designed using the following criteria: (a) needs-based and participatory assessment, ensuring culturally appropriate programs; (b) sustainable approaches, making sure that communities perform their own operation and maintenance functions; and (c) participatory monitoring that can be done with the assistance of local Non-Governmental Organizations. Programs will be monitored and evaluated on a periodic basis by the Bujagali Implementation Unit and BEL.

53. **Social Development Issues.** Specific development issues that were identified for follow-up are discussed below.

54. **Inclusion and Equity.** The social surveys noted the presence of vulnerable groups in the project affected communities. Women were one such group. Women were active in village committees and often voiced their opinions during consultations. The CDAP has provisions to address the needs expressed during consultations. To support women's needs in Naminya, a maternal and childcare health facility will be constructed. One of the CDAP programs is for women's small businesses, including home industries, like vegetable gardening. The APRAP identified orphans, widows and disabled people as vulnerable groups, but noted that the original resettlement plan did not make special provisions for them. As a result, no monitoring of vulnerable peoples took place. The new project will be re-identified, monitored, and appropriate assistance packages provided. Local committees to identify vulnerable peoples will be established during the pre-construction period. Of the single headed households, several household heads were victims of HIV/AIDS, so a separate program to address their needs has been included in the CDAP.

55. The hydropower project SEA noted that the cultural differences between populations in the east and west banks of the river would require that project activities be implemented in an equitable manner. For example, the CDAP, to the extent possible, will make available an equal amount of resources to villages on both sides, though consultations have shown that their needs differ. There will also be equity considerations for dealing with different groups of women, including by gender, ethnicity, age, and physical condition (e.g., disabled people).

56. **Social Accountability.** The CDAP approach focuses on establishing mechanisms for strengthening village self-governing capacities. It also allows for significant participation of local governments and partnerships between village committees and country and district offices. Village leaders will participate in CDAP decision making.

57. Making the project accountable to affected communities is a difficult task. The project will support two types of community monitoring. One is through involvement of a witness Non-Governmental Organization. As mentioned earlier, under the grievance and mediation process, the Non-Governmental Organization will document all consultations and grievances, including the process of dispute resolution. The other mechanism is through the village committees. The project meets regularly with village leaders where an assessment of the CDAP will be made.

58. **Social and Resettlement Costs and Benefits.** The estimates of costs and benefits of resettlement in the Bujagali dam site are taken from the report submitted to IFC, *Bujagali II - Economic and Financial Evaluation Study*, by Power Planning Associates Ltd. The number of affected people and the cost estimates were based on the latest figures, as of September 2006. Although they represent the closest approximation of resettlement costs, they are preliminary, and actual costs may differ. Under the previous effort to develop the Bujagali project, resettlement at the hydropower site took place, and ASNP had already completed all compensations and the funding was disbursed, so these were considered as "sunk costs" from an economic perspective.

59. **Estimated Social and Resettlement Costs.** Under the proposed Bujagali project, the audit of past resettlement was made and summarized in the APRAP report in the hydropower project SEA. The report shows a budget of US$497,000 allocated for "dealing with outstanding resettlement issues." Of this amount, US$320,000 (or 64%) was reserved for income restoration activities under the project's CDAP. Another US$125,000 is assigned for direct assistance to vulnerable peoples. Other costs are for administration and small repairs. Costs associated with public service provisions are not included in this budget but are part of the CDAP, since they have an affect on more than just the Naminya resettlement community.

60. The costs of the CDAP were estimated at US$2.4 million. As noted earlier, US$320,000 was already allocated to the resettlement budget, so the net amount that the project will use for funding community development programs is about US$2.1 million, in the initial five years of the project.

61. Assuming a start-up construction in 2007, and a four-year construction period, Table 15.1 below shows the approximate expenditures for social and resettlement programs by year.

Table 15.1: Annual Estimated Social and Resettlement Costs (US$ thousands)

Item	2007	2008	2009	2010	Total
Proposed dam and power house:					
Resettlement (includes compensation)	170	170	157	-	497
Community development (CDAP activities)	304	520	630	630	2,084
Total	**474**	**690**	**787**	**630**	**2,581**
Total for transmission line*	3,000	3,000	3,000	350	9,350
Total (dam and transmission line)	**3,474**	**3,690**	**3,787**	**980**	**11,931**

*Funded by ADB

Source: Power Planning Associates, *Bujagali II - Economic and Financial Evaluation Study*, December 2006, Table 6-5

62. **Estimated Benefits.** The CDAP activities are expected to have numerous benefits to PAPs and other affected communities. Living conditions will improve when access to basic services like electricity, water and sanitation, health, and education improve. Livelihood restoration programs, such as availability of micro financing for small-scale agriculture, fishing, and tourism related businesses, will also be available to others in the project affected communities, broadening their impact. The CDAP will also provide opportunities for training in small business management and capacity building in community management and leadership. During construction, the project EPC contractor will hire local residents and some 600 to 1,500 jobs are anticipated to become available from various forms of construction related labor requirements. Of these, around 10% will be unskilled and easily filled by local community members.

63. The household benefits, mainly from increased consumption, were estimated by Power Planning Associates Ltd. in their benefit cost analysis. Electricity consumption represents about 5% of total household expenditures, so this would have only minor effects on households. However, electricity has higher anticipated benefits to businesses, especially to local tourism, which could translate into more employment opportunities as tourism expands.

64. **General Improvements in Quality of Life.** Although quality of life measures are difficult to apply, especially for attributing changes solely to the proposed project, it is anticipated that the CDAP activities will improve peoples' lives. Two notable programs under the CDAP are expected to have positive benefits.

65. One is the comprehensive approach to community development, where a longer term perspective is adopted. Instead of providing one-time grants to villages, the CDAP support is supplemented by initiatives that build local capacities for managing and monitoring. The lessons learned from the first effort to develop the project are important for understanding why benefits could be more sustainable. Under the previous effort to develop the Bujagali project, water pumps were given to each village, responding to a priority need that villagers expressed during the consultations. However, after one or two years, the pumps started to break down, so they were left unused. The strategy adopted under the current CDAP is to repair the pumps or replace them, but to first establish operations and maintenance procedures that would be the responsibility of the village and the local authorities. BEL sponsored training sessions and helped the villagers organize themselves into committees. To date, the combination of local government-and-village partnerships in water seems to have worked, but BEL will monitor to ensure that timely support is provided when problems arise. A similar approach will be applied in the provision of health services, schools, sanitation, and roads.

66. The second program is for micro financing. Micro financing for purchasing agricultural inputs, or for setting up small business enterprises, will be especially helpful to households who moved into the new resettlement sites. Local transportation is one sector where additional business could be developed. Currently, only a small fleet of mini buses operates in the area. This fleet may increase with improved roads and greater traffic once construction starts.

67. Benefits to local tourism operators and small businesses will increase. Measures to help the sector include coordination with the Jinja Tourism Development Association to build upon existing facilities and assist in information sharing and public advertising. Other proposed facilities include a visitor center and launching areas for whitewater rafting, etc., downstream of the dam.

68. **Local Employment.** Some 600 to 1,500 jobs will be available at the peak period of construction. BEL has estimated that 10% of these jobs will be unskilled and available for local villagers. The EPC contractor will also implement an apprenticeship program to build a local skills base. BEL is also planning a tree planting program around the reservoir – part of the biodiversity offset – and from the Bujagali dam to Kalagala Falls. BEL intends to use local labor for planting and to possibly support the development of small businesses to provide the seedlings.

F. Cultural Resources (OP/BP4.11, PS 8, MIGA Physical Cultural Resources Policy)

69. AESNP prepared a Cultural Property Management Plan based on the archaeological reconnaissance and surveys conducted prior to 2001. The survey team was led by the Commissioner for Antiquities and Museums of Uganda, two Ugandan Conservators of Antiquities, and project staff. The survey was conducted at various sites in Namizi, Kikubamutwe, and Malindi villages; the Buloba quarry site; the Kaybirwa landing site on the Nile River; Dumbbell Island; and areas surrounding Bujagali Falls. A separate reconnaissance of the proposed project area was made at the inundation areas, dam footprint, and construction sites. These surveys did not find sizeable concentrations of cultural or archaeological importance. The impoundment area is characterized by steep slopes; the land above these slopes that will be used for borrow materials and other project footprints has been heavily cultivated for many decades. Commitments that remain from the previous project were identified as part of the APRAP process.

70. BEL will conduct archaeological surveys of the inundated area, borrow areas, dam footprint, and construction areas, once vegetation is cleared from the area in preparation for construction. BEL has committed to a thorough and careful approach to chance finds. Detailed procedures for chance find events will be followed by the EPC contractor as part of their legal obligations.

71. No archeological sites have been identified within the proposed corridor of the Interconnection Project. The resettlement action plan for the Interconnection Project includes provisions for the compensation for and relocation of graves and shrines within the right-of-way.

72. A detailed survey of gravesites, shrines, and other sacred places in the project sites was conducted as part of the previous effort to develop the Bujagali project. There is a possibility that human remains will be found (e.g., people plowing fields do from time to time find contemporary human remains). BEL has committed to an ecumenical service to be performed near the proposed dam site to commemorate all people buried in the area.

73. The project covers some physical features that are culturally significant to local people. These consist of various types of rocks, trees, and land sites that are associated with spiritual forces. Local beliefs attached to these spirits influence events in peoples' lives. For example, residents believe that the spirits are contacted by mediums or local practitioners or traditional spiritual leaders. During the preparation of the previous Bujagali project, local spirit mediums contacted the spirits and reported that if appropriate ceremonial procedures were financed by AESNP and carried out, the spirits would accept project-induced changes to the spiritual landscape of the project area. The previous project undertook extensive consultations with local people, religious leaders, and relevant government authorities in order to reach a consensus on this issue. AESNP carried out these ceremonies. BEL has carried out additional consultations, especially with the Kingdoms of Buganda and Busoga, and has learned that some additional ceremonies may be needed. BEL will also institute a Code of Practice on cultural issues, along with training, for workers and contractors during the construction and operation phases. Many households construct small hut-like structures (known as *amasabo*), which serve as shrines to ancestor sprits (these spirits are family-related, as opposed to the universal spirit forces discussed above). AESNP had mapped all such shrines and initiated a compensation procedure for their reconstruction and associated ritual procedures. BEL will complete any unfulfilled commitments.

IV. CONSULTATIONS AND DISCLOSURE

74. **Previous Effort to Develop the Bujagali Project.** Public consultation on and participation in the Bujagali project were carried out in accordance with the Government's and IDA/IFC's requirements and were documented in the EIA prepared as part of the previous effort to develop the Bujagali project. Public consultations on that project commenced in April 1997. The then project sponsor, AESNP, employed a number of consultation methods: targeted briefings, usually for a selected stakeholder group with a specific interest; displays, exhibitions and drop-in sessions; progress reports and newsletters; advertising in the local press; open public meetings; interviews with key people; informal at-home meetings, used to discuss concerns with women, elderly and disabled people likely to be affected by the project; surveys; and focus group discussions. Both AESNP and IFC had project-specific web sites to facilitate interactions with concerned Non-Governmental Organizations and stakeholders.

75. The March 2001 Bujagali EIA suite of seven documents was released in country and to the InfoShop on April 30, 2001. During preparation of the EIA there were more than 200 consultations with over 7,000 local residents from affected areas; and numerous consultations with over 100 representatives of Ugandan cultural institutions; more than 100 meetings with local government officials and Non-Governmental Organizations. Public notices informing the public of EIA availability, inviting public comment and announcing a public hearing were issued. Translated versions of the issues and radio announcements inviting the public to attend the public hearing were also made in two local languages, Lusoga and Luganda. The public hearing was held in August 1999, attended by over 700 people. For the transmission line EIA, NEMA solicited comments from lead

agencies in January 2001, issued a public notice in March, and solicited comments from the public. Following NEMA procedures and the results of agency and public comments, a public hearing did not need to be held for the transmission line EIA.

76. In addition to the public consultations and participation activities undertaken by AESNP and its consultants, IDA/IFC and AESNP conducted additional consultations both to provide information about the IDA/IFC processing of the project and to solicit feedback from interested parties. Consultation events included third-party facilitated workshops/forums that involved local stakeholders, PAPs, representatives of the national and international Non-Governmental Organizations, industry, etc.

- *June 2000 Workshop.* A stakeholder workshop was held in Washington, D.C., for international Non-Governmental Organizations.

- *June 2001 Forum.* An IDA/IFC-sponsored stakeholders' forum was held in Jinja.

- *July 2001 Forum.* A second international Non-Governmental Organizations forum was convened in Washington, DC by IDA/IFC, primarily for members of Ugandan civil society.

77. **Private Power Generation Project (Bujagali).** Starting in 2006, and throughout the SEA process, the Public Consultation and Disclosure Plan (PCDP) for the proposed Bujaglai project is being implemented in six phases of consultations and disclosure activities. Consultations were held with numerous government officials, Non-Governmental Organizations and the eight project affected communities within Uganda. The APRAP used focus groups made up of stakeholders in the Naminya resettlement community as one methodology in its assessment, including groups composed exclusively of project-affected women. The focus in the SEA was to strengthen feedback from affected populations, making sure that their needs were addressed. BEL and Bujagali Implementation Unit/UETCL maximized community awareness and participation. As a result, villagers began to organize themselves, including local committees for operating and maintaining water pumps, health center equipment, roads, etc. During preparation of the SEA, there were village meetings, but this time, there was greater involvement of district and sub-county level government officials. Sub-county consultation committees, which included women and other vulnerable groups (like youth, disabled, orphans), assisted in the conduct of public meetings and consensus building. Consultations to date on the project are as follows:

- *January 2006*: Initial consultations on the draft SEA terms of reference and the draft PCDP; government agencies in Kampala and Jinja.

- *January 2006*: Economic Study workshop with key stakeholders of Uganda's power sector on electricity demand forecast; Kampala.

- *March 2006*: Consultations on draft SEA terms of reference with potential lenders; Washington, D.C.

- *March 2006*: Consultations on the draft SEA terms of reference, draft PCDP, and tourism study; government agencies and tourism operators in Kampala and Jinja.

- *March 2006*: Economic Study workshop with key stakeholders of Uganda's power sector to present interim report; Kampala.

- *March 2006*: Meetings/interviews with PAPs resettled by AESNP as part of the APRAP preparation; Hydropower Project site area.

- *May 2006*: Consultations on the draft SEA terms of reference and the draft PCDP; government agencies and Non-Governmental Organizations in Kampala.

- *July 2006*: Meetings/interviews with PAPs resettled by AESNP as part of the APRAP preparation; Interconnection Project, Kawanda substation.

- *August 2006*: Public notice (newspapers, newspaper website) announcing the draft SEA terms of reference and the draft PCDP, Kampala.

- *July/August 2006*: Meetings with Non-Governmental Organizations and information package sent on the draft SEA terms of reference and the draft PCDP; Kampala.

- *July/August 2006*: Meetings by Sub-County Level (LC3) consultation committees with communities potentially affected by the proposed Bujagali project; hydropower and Interconnection Project site areas.

- *August 2006*: Meetings with representatives of the Kingdoms of Busoga and Buganda on the draft SEA terms of reference and the draft PCDP; hydropower Project site area.

- *August-October 2006*: Socio-economic survey of the Interconnection Project corridor; Interconnection Project site area.

- *September 2006*: Consultations on preliminary draft SEA report with potential lenders; Washington, D.C.

- *September 2006*: Presentation by the Bujagali Implementation Unit at the Nile Basin Discourse (NBD) Forum; Kampala.

- *September 2006*: Public notice (newspaper) and distribution of the SEA Consultation Summary Report; Kampala, Jinja, and hydropower and Interconnection Project site areas.

- *October 2006*: Public meetings held with affected communities on the initial findings of the SEA; Budondo Sub-County and Wakisi Sub-County.

- *October 2006*: Meeting with employees of whitewater rafting and tourism industries; Jinja.

- *October 2006*: Meeting with Ugandan Non-Governmental Organization, the AIDS Support Organization (TASO); Kampala.

- *January 2007*: Economic Study workshop with key stakeholders of Uganda's power sector to present draft final report; Kampala.

- *March 2007*: Public meetings held with affected communities; Hydropower Project site area.

78. IFC has reviewed the record of consultations, particularly the meetings with the project-affected communities in October 2006, and concluded that the project sponsor did carry out free, prior, and informed consultations. This conclusion was further confirmed by the observations of a MIGA specialist present at the October meetings.

79. Based on the free, prior, and informed consultations of BEL, and on its own, independent investigations, IFC verified during a field visit with consultative meetings (March 1/2, 2007) that there is broad community support for the proposed Bujagali project.

80. **Grievance and Dispute Resolution Mechanisms.** The project will meet the requirements for a grievance mechanism under IFC's PS 1. The main mechanism will be through a witness Non-Governmental Organization which will be in charge of receiving complaints and documenting grievance procedures until resolution. InterAid was the witness Non-Governmental Organization on the previous effort to develop the Bujagali project and has continued to serve this role in the new project. InterAid would set up a meeting of all parties concerned, including an independent legal counsel. Village elders and other traditional forms of dispute resolution may also be used, particularly to resolve disputes. If an amicable settlement is not reached, the aggrieved parties have the option of bringing the case to a tribunal or court. Complaints may also be raised with the IFC or MIGA, through the Compliance Advisor Ombudsman, or in the case of IDA, by submitting a formal complaint to the Inspection Panel.

81. **Timeline of Key Events.** Key events in the preparation of the Hydropower Project and Interconnection Project assessments, both for the previous effort to develop the Bujagali project and the current proposed Private Power Generation (Bujagali) Project are noted below.

- Previous effort to develop the Bujagali project:
  - 1997: Scoping report submitted to National Environmental Management Authority (NEMA) in July and comments received in October.
  - 1997-early 1998: Early consultations and scoping sessions resulted in 1998 Inception Report, which summarized consultations and culminated in the final draft of the Terms of Reference for the hydropower facility.
  - July 1998: Main assessment for hydropower facility, including ecological fieldwork, social surveys and consultations, commenced.
  - March -June 1999: Hydropower facility "EIS" (now EIA) submitted to NEMA in March and reviewed by the IDA/IFC (comments on deficiencies sent in June 1999).
  - November 1999: NEMA approves, with conditions, hydropower facility EIS.
  - April 2001 - March 2001: Bujagali Project EIA (7 volume suite of documents), addressing IDA/IFC comments, submitted to IDA/IFC and disclosed.
  - June 2001: Complaints (2) filed with the IFC/MIGA Compliance Advisor Ombudsman.
  - July 2001: Inspection Panel Request (Accepted October 2001).
  - September 2001: CAO Assessment Reports issued.
  - December 2001: IDA/IFC Board.
  - May 2002: Inspection Panel Report.
  - June 2002: Management Response to Inspection Panel Report.

  - September 2003: AES formal withdrawal from the project.

- Private Power Generation (Bujagali) Project

  - January 2004: Government commences the selection of new sponsor for the project.
  - April 2005: IPS(K) consortium selected as new sponsor.
  - December 2005: Power Purchase Agreement and Implementation Agreement signed between BEL and the Government.
  - January 2006: Initiation of consultations and fieldwork on new SEA.
  - January 2006: Economic Study workshop in Kampala on electricity demand forecast.
  - March 2006: Terms of Reference finalized with IDA/IFC/MIGA.
  - March 2006: Economic Study workshop in Kampala to present interim report.
  - August 2006: Interim draft SEA documents submitted to IDA/IFC/MIGA for comments.
  - December 2006: Bujagali Hydropower Project SEA document, addressing IDA/IFC/MIGA comments submitted to IDA/IFC/MIGA and disclosed on December 21, 2006 in the Bank's Info Shop and at 11 locations in country.
  - January 2007: Economic Study workshop in Kampala to present draft final report.
  - February 2007: Strategic/Sectoral, Social and Environmental Assessment (SSEA) of Power Development Options in the Nile Equatorial Lakes Region, by SNC-Lavalin for Nile Basin Initiative, disclosed on February 23, 2007, in InfoShop and in-country.
  - February 2007: Bujagali II - Economic and Financial Analysis Study, by Power Planning Associates Ltd., UK, final report disclosed by IFC on February 26, 2007.

- Bujagali's transmission system (as part of the previous effort to develop the Bujagali Project)

  - December 1998: Scoping report and Terms of Reference for the transmission system EIS produced, following site visits and consultations with stakeholders.
  - January 1999: Main assessment for transmission system, including ecological field work and consultations, commenced.
  - March 1999: Interim draft transmission system EIS submitted to NEMA and IDA/IFC and circulated to other stakeholders for comment.
  - December 2000: Transmission system EIS submitted to NEMA for approval.
  - April 2001: Bujagali Hydropower Project EIA (7 volume suite of documents), addressing IDA/IFC comments, submitted to IDA/IFC and disclosed.
  - July 2001: NEMA approved transmission system EIS.

- Interconnection Project
  - January 2006: Initiation of consultations and fieldwork on new SEA.
  - March 2006: Terms of Reference finalized with IDA/IFC/MIGA.
  - August 2006: Interim draft SEA documents submitted to IDA/IFC/MIGA for comments.
  - December 2006: Bujagali Hydropower Project SEA document, addressing IDA/IFC/MIGA comments submitted to IDA/IFC/MIGA and disclosed on December 21, 2006 in the Bank's Info Shop and in country.

V. ANALYSIS OF ALTERNATIVES

82. **Development Alternatives.** Assessment of the alternatives for electricity generation and supply in Uganda was conducted through the Hydropower Development Master Plan (Rust Kennedy and Donkin, 1997), Electricité de France load forecast report (1998), and the Energy Sector Management Assistance Program Rural Electrification Strategy Study (1999). Acres International (2000) undertook comprehensive assessments and least-cost analyses of all practical alternatives for meeting Uganda's future power requirements. The alternatives studied included hydroelectric potential (including 5 major, 10 medium and 20 mini/micro hydro sites), thermal generation alternatives (including diesel, small, large and combined cycle gas turbines), cogeneration, geothermal, wind, solar and electricity imports. The costing of all projects was brought to as comparable a basis as the data allowed, facilitating valid comparison in least cost analysis. Based on these studies, large-scale hydropower development emerged as the most viable way forward for Uganda in the short to medium term.

83. For the currently proposed Bujagali project, Power Planning Associates' Economic Study included detailed analyses of various power generation alternatives including small-scale hydro, geothermal, bagasse burning power plants, etc. The study includes a detailed review of Uganda's geothermal options, which was one of the topics of contention in the past. Also investigated were interim supply arrangements to provide electricity until more substantial projects with longer lead times can be put in place, in about 2011. The analysis concluded that small (50 MW) temporary and longer term thermal plants fueled by oil, mini-hydro plants, and cogeneration facilities fueled by biomass offered the best solution during the interim period. For the long term, Power Planning Associates' analysis reaffirmed the conclusion that the proposed Bujagali project is the least cost project for Uganda.

84. **Alternative Hydropower Development Sites.** The Rust Kennedy and Donkin Hydropower Master Plan included a comparative, first stage environmental analysis of hydropower locations on the Victoria Nile in Uganda at Murchison Falls, Ayago North, Ayago South, Kamdini (also known as Karuma), Kalagala and Bujagali, including their potential compliance with the safeguard policies. This study concluded that Bujagali or Karuma were the sites that would be least damaged by development. Acres International reviewed potential hydropower development for IFC (May 2000) at Murchison Falls, Ayago, Karuma, Masindi, Kalagala and Bujagali. Murchison Falls was identified as the least cost option in terms of capital cost per MW generated, excluding social and environmental impacts. Bujagali was identified as the overall preferred location for hydropower development, due to comparatively lower social and environmental impacts and its generation capacity. The Murchison Falls and Ayago locations were dismissed by Acres as each was in the Murchison Falls National Park, a proposed World Heritage site. Masindi, a diversion scheme, was also dismissed due to cost and preclusion of any other downstream hydropower development. Kalagala, Karuma and Bujagali

remained as potential options to meet growing electricity demand. Of the three, Kalagala is no longer a candidate as this location as been set aside for power development as part of the Kalagala Offset. The EIA for the previous effort to develop the Bujagali project found that Karuma was likely to have the least overall environmental impact but the lowest amount of power, while Bujagali had relatively low environmental impact while generating substantial amounts of power.

85. Power Planning Associates' Economic Study for the proposed Bujagali project evaluated the previous alternatives analyses and concluded that "Bujagali and Karuma therefore appear to be the only major hydro power candidates that can be developed in the coming years to contribute to meeting the power demand in the country by mobilizing the renewable energy of the Nile." Power Planning Associates investigated the Bujagali and Karuma projects in more detail, using updated information, and concluded that Bujagali will be the least cost project.

86. **Alternative Hydropower Facility Configurations.** The EIA for the previous effort to develop the Bujagali project included a comprehensive analysis of alternatives, based on an evaluation by WS Atkins (with Knight Piesold) completed in 1998 and a further review by WS Atkins in 1999/2000. These reviews examined five configurations of the Bujagali dam considered by Acres International in 1990 and two additional configurations. The configurations included different locations for a dam across the Nile River in the vicinity of the preferred project site at Dumbbell Island (approximately 8 kilometers downstream of the Nalubaale/Kiira dam complex) as well as a diversion canal configuration that would avoid placing a dam across the Nile River. The analysis of the social, environmental, technical, economic and financial impacts of each of these seven configurations concluded that a 30-meter high structure across the Nile River at the downstream end of Dumbbell Island was the preferred configuration.

87. Studies conducted by BEL and others, and summarized in the December 2006 SEA, reviewed alternative project configurations at, and around, the Bujagali hydropower site to compare the potential power output of the different options, their financial costs and their relative environmental and socioeconomic implications. The various analyses have led to the hydropower facility configuration put forward by BEL. Minor modifications to the configuration are expected by the EPC contractor; which will be reviewed by the World Bank Group and may be subject to a supplemental SEA, as appropriate.

88. **Alternative Transmission System Configurations.** As part of the previous effort to develop the Bujagali project, AESNP and its consultant completed an analysis of four options for electricity transmission from Bujagali and concluded that connection at 220kV (as opposed to a more constraining 132kV connection) to a new substation located in Kawanda, north of Kampala, was preferable. AESNP evaluated alternative transmission lines, using a range of social, environmental, technical, economic and financial criteria to identify the potential key impacts of alternative corridors, and selected a preferred alternative. An alternative paralleling the northern existing transmission line from the Nalubaale substation to Kampala was preferred, as impacts on settlement and property would be lower, it is shorter and this routing would not require any crossing of existing transmission lines. AESNP's Panel of Experts concurred in the selection of the transmission route.

89. As part of the ongoing planning for the proposed project, new interconnection analyses were completed to ensure that project development was proceeding with the optimal interconnection option (Siemens PTI, 2006). Siemens PTI conducted extensive load flow, stability and economic evaluation studies for each of the interconnection options in the short, medium and long term, as well as testing each option's sensitivities to the uncertainties associated with the predicted load growth, the installation of new generation in Uganda, Lake Victoria hydrology and costs of fuel, among others. Field reconnaissance and analysis of recent satellite imagery completed as part of the recent SEA

process confirmed that there have been no major changes to environmental or social conditions in the area that would affect the overall conclusions set out above. Building on the work completed for AESNP, five alternatives were formulated for the interconnection of the project. The planned alignment, described in the Background section of this Annex, is slightly modified from AESNP's, and is the preferred option from a social standpoint. The Interconnection Project will pass through three forest reserves as well as the Lubiji Swamp near Kampala. Environmental offsets for these impacts are discussed in the Natural Habitats section of this Annex.

A. Cumulative Effects

90. As part of the previous effort to develop the project, studies conducted for AESNP and additional studies commissioned by IFC addressed cumulative impacts. The Acres assessment defined three cumulative impact regions: (a) Upper Reach of the Victoria Nile, including the Nalubaale and Kiira dam complex, the Bujagali project and a potential project at Kalagala Falls, 11 kilometers downstream of Bujagali; (b) Lower Reach of the Victoria Nile, where there is potential for Murchison Falls, Ayago and Karuma hydropower projects and a Masindi diversion project; and (c) Combined Upper plus Lower Reach of the Victoria Nile. The study concluded that hydropower projects on the Nile River were the least cost options for meeting unmet demand for electricity, but that the construction of a cascade of new hydropower projects on the Nile River in Uganda would result in significant to major environmental and social cumulative impacts. The ESG study found that while Ugandan stakeholders attached value to the development of the Nile River for the purpose of generating electricity, they also wanted to see this resource used for other purposes, in particular recreational/tourism uses and did not see value in the Nile River in Uganda being transformed into a cascade of hydropower projects.

91. The EIA prepared for the previous effort to develop the Bujagali project (March 2001) presented the cumulative impacts of three cascade scenarios: Nalubaale/Kiira (as already built), Bujagali and Kalagala; Nalubaale/Kiira, Bujagali and Karuma; and all four locations. Key conclusions reached were that: (a) cumulative effects of all project being developed were likely to be excessive; (b) cumulative impacts associated with Kalagala compared to Bujagali or Karuma appeared to be the highest; and (c) cumulative effects of the Bujagali project were intermediate between those of scenarios for Kalagala and Karuma. For the Upper Nile, the cumulative effects of the existing Nalubaale and Kiira, Bujagali and Kalagala would result in major cumulative impacts.

92. For the now proposed Bujagali project, the hydropower project SEA assesses cumulative impacts of hydropower and other development on the Victoria Nile in Uganda, including other hydropower dams (Nalubaale, Kiira, and Karuma, and their associated transmission facilities), and other initiatives (environmental offsets, natural areas, parks, reserves, etc.). The potential environmental cumulative effects investigated include:

- possible change in flow regime,
- likelihood of sedimentation, erosion and degradation of water quality effects,
- possible proliferation of invasive aquatic vegetation, and
- loss of natural habitats and resources.

93. Socioeconomic impacts were found to be generally local in extent.

94. Nalubaale, Kiira, and Bujagali are separated by Lake Kyoga from Karuma Falls and other potential hydropower locations downstream on the Nile. Further, Lake Albert is located further downstream of any identified hydropower options in Uganda, and will minimize any changes in the flow regime at the border with Sudan. Effects of daily peaking would not likely be seen after 5 km downstream of the Bujagali tailrace. The sediment load in the Victoria Nile River is very limited, as most sediment is retained upstream in Lake Victoria. Changes in urban population densities and changes in agricultural practices in the Victoria Lake Basin could have an effect on the water quality flowing to the Victoria Nile, and together with effects induced by the power plants could lead to possible cumulative effects. Water hyacinths are trapped upstream from the Nalubaale dam and will not create a cumulative impact downstream. The combined presence of Bujagali and Kalagala on the same stretch of river would have a cumulative impact on issues such as resettlement of people, aesthetics, existing and potential tourism, and biodiversity. Therefore, the long term protection of the Kalagala Falls and the preclusion of development of hydropower potential at Kalagala is a necessary offset for World Bank Group participation in the Bujagali project.

B. Kalagala Offset Agreement

95. **Offset Concept.** The loss of Bujagali Falls and portions of the Jinja Wildlife Sanctuary resulting from reservoir inundation would be an irreversible impact to a significant natural habitat (OP 4.04, Natural Habitats and PS 6, Biodiversity Conservation and Sustainable Natural Resource Management). In circumstances such as these, OP 4.04 and PS 6 allow for an "offset," i.e., protection of a similar environmental/social area to the area lost as a result of a project. Kalagala Falls, the site of a defined future hydropower project on the upper Nile River, was determined to be the appropriate offset candidate.

96. **Elements of the Kalagala Offset.** On the basis of the cumulative effects assessment and the offset provision in OP 4.04, IFC/IDA and the Government of Uganda on April 25, 2001 reached an agreement known as the "Proposed Bujagali Hydropower Project: World Bank Group's Requirement of an Offset at Kalagala Falls." The agreement noted that both Bujagali Falls and Kalagala Falls are natural habitats and cultural properties of significance to the people of Uganda. As the implementation of the Bujagali Project would inundate Bujagali Falls, the World Bank Group concluded that Kalagala Falls must be conserved for its spiritual, natural habitat, environmental, tourism and cultural values.

97. The Inspection Panel, however, felt that the commitments made under this agreement were not sufficient to protect Kalagala Falls. The Government then provided an additional commitment as part of IDA's Indemnity Agreement together with a letter by the Government (June 4th, 2002) confirming its intention to preserve Kalagala and identify sustainable investment programs to facilitate tourism, with appropriate mitigation measures. The Government had fulfilled all of its commitments required under the agreement as of the time that the previous effort to develop the Bujagali project stopped.

98. The Government has confirmed that it will honor its commitment regarding the Kalagala Offset conveyed to IDA in its letter of June 2002 and included in the related provision in the Indemnity Agreement then finalized. The Indemnity Agreement with the Government for the proposed project will include a provision defining Government commitment regarding the Kalagala Offset consistent with the requirements of OP 4.04.

99. BEL has independently confirmed the Government's previous commitment to not develop Kalagala Falls as a hydroelectric power site. Additionally, a developer recently expressed interest in

developing the Kalagala site for power generation purposes, but was denied permission by the ERA on the basis of the Government's commitment to the World Bank Group.

100. **Effects of Climate Change on the Long-Term Viability of Bujagali.** The Strategic/Sectoral, Social and Environmental Assessment of (SSEA), commissioned by the Nile Basin Initiative, undertook a thorough analysis of the possible climate change impacts on power development options in the Nile Equatorial Lakes Region, including Bujagali. The SSEA climate change analysis examined potential values for temperature and precipitation change, and then runoff, to provide corresponding estimates of changes in net water yield in Eastern Africa. It used the best available general circulation models to assess the potential changes in temperature and precipitation in 2050 and 2100 relative to 2000. Outputs from various climate models were examined to determine the degree to which models agree or disagree on the direction and magnitude of change in temperature and precipitation in the region. A total of 16 general circulation models were examined to select those that best simulate East African climate. Two scenarios were considered, one representing a medium level of CO_2 emissions, and the other a relatively high level of emissions. One estimate of climate change was developed for the north and west central regions of the study area – for the Nile, Ruzizi and Kagera Rivers – and the other for the southern region in Tanzania – for the Ruhudji and Rumakali Rivers. A regional water balance model was then used to calculate evaporation losses and net basin yields based on the predicted temperature and precipitation values.

101. The results of the climate change analysis were:

- The predictions of temperature and precipitation changes are consistent with other modeling results in that temperature is expected to increase with greenhouse gas emission increases.
- An increase in precipitation is the expected result from an increase in temperature, which will also increase evaporation and evapotranspiration losses.
- Changes will be more significant for the high emission scenario than for the medium emission scenario, again because of the expected link between emission levels and temperature.
- Net runoff will increase with increase in greenhouse gas emission levels.
- Increased emission levels will result in increased seasonal variability in runoff, with wet seasons providing most of the increased runoff and dry periods being less affected.
- Increased variability in runoff is most evident in the southern Tanzania region. It is relatively modest in the northern and central west regions.

102. Overall, for the northern and central-west regions of the study area, there is a high probability of increases in runoff, and thus power generation potential, compared to historic data. This area includes the watershed above the proposed Bujagali project site. For the southern region, there is a high likelihood of changes in the seasonality of runoff, resulting in lower effectiveness for flow regulation of smaller reservoirs. Staff believes that the SSEA incorporated the best currently available climate change science and data in its analysis.

VI. Legislative, Regulatory and Policy Requirements

103. **Government of Uganda.** The SEAs for the hydropower project and the Interconnection Project address the applicable laws, regulations and agreements. The Constitution of the Republic of

Uganda was established in 1995. The National Environment Act (1995) specifies requirements for environmental impact studies and provides for setting of environmental standards. Regulations issued in 2000 under the National Environment Act provide for the protection of river banks and lake shores for the common good of the citizens of Uganda. Other statutes and regulations of the Government relevant to the proposed Bujagali project include; Electricity Act (1999); Water Act (CAP 152); Rivers Act (CAP 347); Land Act (1998); Public Health Act (CAP 281); Fish Act (CAP 197) and Fish (Beach Management Rules (2003); Uganda Wildlife Act (CAP 200); National Forestry and Tree Planting Act (2003); Acts related to occupational health and safety and labor conditions; and the Riparian Agreements respecting the River Nile. Full details of compliance with these requirements are presented in Chapter 2 of both the Bujagali project SEA and the Interconnection Project SEA.

104. **IDA, IFC, and MIGA.** The policies and procedures of IDA have been addressed with respect to the safeguard policies for Environmental Assessment, Natural Habitats, Forests, Involuntary Resettlement, Cultural Property, Safety of Dams and Projects on International Waterways. IFC Policies on Social & Environmental Sustainability and on Disclosure of Information have also been addressed. Risks and issues associated with the proposed Bujagali project will be addressed through the Social and Environmental Performance Standards for Social and Environmental Assessment and Management, Labor and Working Conditions, Pollution Prevention and Abatement, Community Health, Safety and Security, Land Acquisition and Involuntary Resettlement, Biodiversity Conservation and Sustainable Natural Resource Management, and Cultural Heritage. MIGA Policies on Environmental Assessment and Disclosure have also been addressed. Risks and issues associated with this project will be addressed through MIGA's (issue specific interim safeguard) Policies on Involuntary Resettlement, Physical Cultural Resources, Natural Habitats, Dam Safety, and Projects on International Waterways. The specific implications of these requirements are addressed below and in Chapter 2 of both the Bujagali project and Interconnection Project SEA Reports. The documentation also responds to the Environmental and Social Review Procedure (IFC, 2006), Guidance for Preparation of a Public Consultation and Disclosure Plan (IFC, 1998), Occupational Health and Safety Guidelines (IFC, 1998), Guidance for Preparation of a Resettlement Plan (World Bank, 1998), World Bank Operational Manual (World Bank, 1998), and the Pollution Prevention and Abatement Handbook (World Bank Group, 1998). If it is determined during project implementation that herbicides would be required for vegetation control on the wayleave of the transmission line, a pest management plan in accordance with OP 4.09 and applicable Ugandan procedures would be prepared and submitted to IDA/IFC/MIGA for approval.

105. **Other.** It is expected that compliance of the proposed Bujagali project with National Environmental Management Authority requirements in Uganda and with those of IDA/IFC/MIGA will result in compliance with ADB's policies, procedures and guidelines, and the requirements of other potential project lenders. The Bujagali project SEA provides a concordance analysis of lenders policy requirements.

106. Uganda is party to several international conventions potentially relevant to the proposed Bujagali project. These are the 1968 African Convention on the Conservation of Nature and Natural Resources, Convention on Wetlands of International Importance Especially as Waterfowl Habitat, Vienna Convention for the Protection of the Ozone Layer, Montreal Protocol on Substances that Deplete the Ozone Layer, Convention on International Trade in Endangered Species of Fauna and Flora, International Convention to Combat Desertification, Convention on Biological Diversity, Convention on Climatic Changes, Lusaka Agreement on Cooperative Enforcement of Operations Directed at Illegal Trade in World Flora and Fauna, and the Intergovernmental Authority on Drought and Desertification.

VII. COMPLEMENTARY STUDIES

107. **ESG Strategic Assessment.** In parallel with AESNP's environmental and social assessment studies, IDA/IFC conducted studies to address specific provisions in OP 4.01 and the requirements of IFC's Environmental and Social Review Procedure (1998). The *Victoria Nile Strategic Impact Assessment - Uganda* (ESG International Ltd., January, 2000) was commissioned, using Canadian Trust Funds, to provide guidance on assessing the benefits and costs of the project from the perspective of Ugandan stakeholders as well as to provide criteria for assessing the environmental and social appropriateness of future developments and cumulative impacts on the Nile River in Uganda in a post-Bujagali era. This guidance was developed on the basis of consultations with stakeholders in Uganda.

108. **Acres International Report.** A second study, *Assessment of Generation Alternatives – Uganda* (Acres International Ltd., May 2000), using Canadian Trust Funds, concluded that hydropower projects on the Nile River were the least cost options for meeting unmet demand for electricity. This study also concluded that the Bujagali project, subject to completion of an EIA demonstrating its compliance with the safeguard policies, was the least cost hydropower project. Consultation with Ugandan stakeholders was a key component of this study.

109. **Power Planning Associates Economic Study.** IFC commissioned an Economic Study for the proposed Bujagali project, a key piece of work required to provide an updated assessment of the country demand's and load forecasts and the least cost power generation alternatives in Uganda, and to understand the impact of hydrology on the Project's economic and financial viability. Through the use of IFC's Funding Mechanism for Technical Assistance and Advisory Services ("FMTAAS"), IFC hired a consortium led by Power Planning Associates Ltd. (UK), together with Coyne et Bellier (France) and ECON (Norway), to conduct the economic analysis that is of benefit to the entire project lender group, the sponsors, BEL and the Government. Power Planning Associates' final report was publicly released on February 26, 2007.

110. **SNC-Lavalin SSEA (initiated and monitored by the Nile Basin Initiative).** OP 4.01 requires that when a project is likely to have sectoral or regional impacts, a sectoral or regional environmental assessment, including a cumulative impact assessment, is required. Preparation of a Strategic/Sectoral Social and Environmental Assessment (SSEA) for the Nile Basin Initiative was supported by IDA as part of the Nile Equatorial Lakes Subsidiary Action Program (NELSAP) Program. The SSEA was prepared, using Canadian trust funds, by SNC-Lavalin as an element of the work program for the Nile Basin Initiative. The final SSEA report was publicly disclosed on February 23, 2007. Cumulative impacts assessment was addressed in the Bujagali project SEA as well as in SSEA.

Annex 16: Project Preparation and Supervision

	Planned	Actual
PCN review	10/18/2006	10/18/2006
Initial PID to PIC	10/10/2006	01/16/2007
Initial ISDS to PIC	10/10/2006	01/16/2007
Appraisal	01/15/2007	03/19/2007
Negotiations	NA for a Guarantee	
Board/RVP approval	04/26/2007	
Planned date of effectiveness	NA for a Guarantee	
Planned date of mid-term review	12/15/2009	
Planned closing date	06/30/2012	

Key institutions responsible for preparation of the project:

- From the Government of Uganda: MEMD and MOF.
- The project sponsors IPS (Kenya) and Sithe Global are responsible for developing constructing, managing and operating the new facility.

Bank staff and consultants who worked on the project include:

Name	Title	Unit
Malcolm Cosgrove-Davies	Team Leader and Sr. Energy Specialist	AFTEG
Suman Babbar	Sr. Advisor	FEU
Karen Rasmussen	Lead Financial Analyst	AFTEG
Robert Schlotterer	Infrastructure Specialist	AFTEG
Gulam Dhalla	Consultant (Finance)	AFTEG
Mark Segal	Consultant (Economics)	AFTEG
Helena Kofi	Procurement Analyst	AFTEG
Janine Speakman	Operations Analyst	AFTEG
Raymond Bourdeaux	Sr. Infrastructure Specialist	FEU
Richard Olowo	Senior Procurement Specialist	AFTPC
Patrick Piker Umah-Tete	Sr. Financial Management Specialist	AFTFM
Paul Baringanire	Consultant	AFTEG
Warren Waters	Regional Environmental and Safeguards Advisor	AFTQK
Robert Robelus	Consultant	AFTU2
Kristine Ivarsdotter	Senior Social Development Specialist	LCSSO
Maria C.J. Cruz	Senior Social Development Specialist	SDV
Agnes Kaye	Program Assistant	AFMUG
Tigest Tirfe	Program Assistant	AFTEG

IFC staff who worked on the project include:

Name	Title	Unit
Francisco Tourreilles	Director	CINDR
Thierry Tanoh	Director	CAFDR
Rachel Kyte	Director	CESDR
Darius Lilaoonwala	Senior Manager	CININ
Jean Philippe Prosper	Senior Manager	CAFE1
Patricia Miller	Manager	CESIG

Adil Marghub	Principal Investment Officer	CININ
Saleem Karimjee	Principal Investment Officer	CAFS1
Belen Castuera	Investment Officer	CININ
Dan Kasirye	Investment Officer	CAFE1
Romani Curtis	Investment Analyst	CININ
Carlos Algandona	Principal Power Engineer	CININ
John C. Kittridge	Principal Environmental Specialist	CESIG
Nicholas E. Flanders	Senior Environmental Specialist	CESIG
Moez Cherif	Economist	CINDR
John R. Coogan	Manager	CLEIP
Yeages Cowan	Counsel	CLEDC
Martha Yebra-Bryant	Senior Insurance Officer	CESIS
Jill D. Partington	Insurance Analyst	CESIS
Ann Pasco	Communications Officer	CEXCM
Lucie Cecile Giraud	Communications Officer	CESKI
Sandra Estrada	Team Assistant	CININ

MIGA staff who have worked on the project include:

Name	Title	Unit
Philippe Valahu	Acting Director	MIGOP
Zhengrong Lu	Sr. Underwriter	MIGOP
Thomas Vis	Sr. Risk Management Officer	MIGEP
Srilal Perera	Chief Counsel	MIGLC
Michael Silverman	Lead Counsel	MIGLC
Robert McDonough	Sr. Environmental Specialist	MIGEP
Deniz Baharoglu	Sr. Social Sector Specialist	MIGEP
Angela Gentile	Sr. Communications Officer	MIGEO
Judith Pearce	Lead Operations Officer	MIGEO
Lorie Henson	Program Assistant	MIGOP

Bank funds expended to date on project preparation:

1. Bank resources: 532,667.93
2. Trust funds: 14,400.00
3. Total: 547,067.93

Estimated Approval and Supervision costs: Remaining costs to approval are US$50,000;
Estimated annual supervision cost: US$130,000

IFC funds expended to date on project preparation:

1. Bank resources: 850,640.00
2. Trust funds: 750,000.00
3. Total: 1,600,640.00

Annex 17: Documents in the Project File

ENVIRONMENT

1. Agreed Curve -- Letter dated May 12, 1991 from the Government of Egypt.
2. Letter from the government of Egypt on May 15, 2006 to the Government giving its no objection to the new Bujagali project proposal.
3. Copy of the Riparian Notifications regarding the intended development of Bujagali II that were sent by the Government to all other Nile Riparian states in September 2006.
4. Copy of the Government of Uganda (additional) Notices to the Riparian States, dated March 9, 2007.
5. Strategic/Sectoral, Social and Environmental Assessment of Power Development Options in The Nile Equatorial Lakes Region, Final and disclosed report prepared by SNC-Lavalin for the Nile Basin Initiative.
6. Social Environmental Assessment report for the Bujagali Hydropower Project (HPP) prepared by: R.J. Burnside International Limited; (disclosed final report December 2006); (Report includes also all relevant Resettlement Action Plans).
7. Social Environmental Assessment report for the Bujagali Interconnection Project (IP/ Transmission Line) prepared by: R.J. Burnside International Limited; (disclosed final report December 2006) (Report includes also all relevant Resettlement Action Plans).
8. Documentation on Kalagala Offset -- April 2001.

ECONOMIC

9. Bujagali II – Economic and Financial Evaluation Study prepared by Power Planning Associates Ltd. (Final report dated and publicly disclosed on February 26, 2007).
10. Bujagali Project and Uganda's Balance of Payments by John A. Holsen, March 2007.

TECHNICAL

11. Technical Project Review and Assessment Report, prepared by Colenco Power Engineering Ltd.; Draft Report February 2007.
12. Bujagali Hydroelectric Power Project Transmission Interconnection Study Economic and Risk Analysis, prepared by Siemens Power Transmission & Distribution, Inc.; Final report August 2007.

FINANCIAL

13. Lenders' Financial Model.
14. Uganda Power Sector Financial Model; prepared by an independent Consultant for IDA.

Contractual Documents

15. Request for Proposals (RfP)/Prospectus in relation to the prequalification of entities for the development of the Bujagali Hydroelectric Power.
16. Project Implementation Agreement dated December 13, 2005.
17. Power Purchase Agreement dated December 13, 2005.
18. Lender's Term Sheet, Draft February 2007.
19. EPC Contract for the generation facility, Draft February 2007.
20. Draft Operation and Maintenance Agreement.
21. Preliminary Legal Review of Basic Contractual Documents, prepared by Linklaters LLP (draft March 2007).

Documents from Previous Effort to Develop a Hydropower Station at Bujagali Falls

22. Environmental Impact Assessment prepared by ESG International and WS Atkins International, March 2001.
23. Resettlement and Community Development Action Plan, March 2001.
24. Energy Sector Management Assistance Program Rural Electrification Strategy Study (Report 221/99), September 1999.
25. Energy Sector Management Assistance Program Uganda Energy Assessment (Report No 193/96), December 1996.
26. The Kalagala Offset Agreement – Government of Uganda, July 2001.
27. Plan from Permanent Secretary, Ministry or Tourism & Industry, for Kalagala Offset.
28. EIA – Seven Volumes – Prepared by ESG International and WS Atkins, March 2001.
29. Uganda Load Forecast Review (Update 2000) prepared by EdF, October 2000.
30. Uganda Load Forecast Review prepared by ERM Energy, December 2000.
31. Uganda Load Forecast Review (Update 2001) prepared by EdF, January 2001.
32. Uganda Assessment of Generation Alternatives by Acres International, May 2000.
33. Bujagali Hydropower Feasibility Study – Knight Piesold, and Merz and McLellan Consulting engineers, July 1998.
34. Bujagali Hydroelectric Power Project, Independent Engineer's Report, Review and Assessment – Harza Engineering Company International, May 2001.
35. Hydropower Development Master Plan – Kennedy & Donkin, November 1997.
36. Bujagali Hydropower Project Cost Estimate – Knight Piesold, Merz and McLellan, July 1998.

Annex 18: Statement of IBRD Loans and IDA Credits

Uganda

Operations Portfolio (IBRD/IDA and Grants)

As Of Date 03/26/2007

Closed Projects	79
IBRD/IDA *	
Total Disbursed (Active)	542.09
of which has been repaid	0.00
Total Disbursed (Closed)	3,609.52
of which has been repaid	478.05
Total Disbursed (Active + Closed)	4,151.61
of which has been repaid	478.05
Total Undisbursed (Active)	527.96
Total Undisbursed (Closed)	0.84
Total Undisbursed (Active + Closed)	528.80

Active Projects

	Last PSR Supervision Rating							Difference Between Expected and Actual Disbursements	
Project Name	Development Objectives	Implementation Progress	Fiscal Year	IDA	GRANT	Cancel.	Undisb.	Orig.	Frm Rev'd
Priv Sec Competitiveness 2	S	S	2005	70.0			65.7	36.7	
UG-Agr Rsrch & Training SIL 2 (FY99)	S	S	1999	26.0			1.8	1.1	0.2
UG-EMCBP SIL 2 (FY01)	S	S	2001	22.0			4.8	2.0	-1.0
UG-Energy for Rural Transform (FY02)	S	S	2002	49.2			34.4	26.6	8.5
UG-GEF Energy for Rural Transf (FY02)	S	S	2002		12.5	0.1	5.7	5.5	
UG-GEF PAMSU SIL (FY03)	S	MS	2003		8.0		2.2	2.0	
UG-Loc Gov Dev 2 (FY03)	S	S	2003	50.0	75.0		5.2	-6.3	-16.0
UG-Millennium Science Init (FY06)	MS	MS	2006	30.0			31.6		
UG-N Uganda Soc Action Fund (FY03)	S	MS	2003	100.0			41.3	20.2	9.0
UG-Nat Agr Advisory Srvcs SIL (FY01)	S	S	2001	45.0			36.8	15.3	
UG-Natl Re Dev TAL (FY04)	S	MS	2004	25.0			22.8	13.1	0.5
UG-PAMSU SIL (FY03)	S	MS	2003	27.0			17.0	12.7	
UG-Power SIL 4 (FY02)	MS	MS	2002	62.0			14.0	5.9	5.9
UG-Priv & Utility Sec Reform (FY01)	S	S	2001	48.5			20.5	17.2	8.8
UG-Pub Serv Perform Enhance (FY06)	S	S	2006	70.0			73.1	0.0	
UG-Road Dev APL 3 (FY05)	S	S	2005	67.6	40.0		108.0	39.7	39.3
UG-Road Dev Phase 2 APL (FY02)	S	S	2002	64.5			18.0	7.4	7.4
UG-Road Sec & Inst Supt (FY98)	S	S	1998	30.0			5.2	4.7	1.0
UG-Roads Dev APL (FY99)	S	S	1999	91.0			27.7	22.8	22.8
PRSC 5 DPL (FY06)	N/A	N/A	2006	135.0			0.0		
Overall Result				**1,012.8**	**135.5**		**535.8**	**226.5**	**86.3**

STATEMENT OF IFC's Held and Disbursed Portfolio
(Millions of US Dollars)

FY	Institution Short Name	LN Cmtd-IFC	ET Cmtd-IFC	QL+QE Cmtd-IFC	GT Cmtd-IFC	RM Cmtd-IFC	All Cmtd-Part	LN Out Bal-IFC	ET Out-IFC	QL+QE Out-IFC	GT Out-IFC	RM Out-IFC	All Out-Part
1996	AEF Agro Mgmt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	AEF Clovergem	0.84	0.00	0.00	0.00	0.00	0.00	0.84	0.00	0.00	0.00	0.00	0.00
1999	AEF Gomba	0.41	0.00	0.00	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00
1998	AEF White Nile	0.08	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00
1984/ 1992/ 2001/ 2005	DFCU	10.00	0.00	0.00	0.00	0.00	0.00	10.00	0.00	0.00	0.00	0.00	0.00
2006	GTFP Orient Bank	0.00	0.00	0.00	1.37	0.00	0.00	0.00	0.00	0.00	1.37	0.00	0.00
1998	Tilda Rice	0.36	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.00
2005	UMU	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Portfolio:		**11.68**	**0.00**	**0.00**	**2.37**	**0.00**	**0.00**	**11.68**	**0.00**	**0.00**	**1.37**	**0.00**	**0.00**

Statement of MIGA'S Exposure

including this and other projects approved by the Board in Uganda as of February 28, 2007

1. MIGA'S EXPOSURE (CONTINGENT LIABILITY)

US$ million	*Transfer Restriction*	*Expropriation*	*War & Civil Disturbance*	*Breach of Contract*	*Maximum*
Gross Exposure	39.6	3.0	42.6	154.6	157.6
% of total portfolio	1.2	0.1	1.6	8.5	3.2
Net Exposure	19.8	2.7	22.5	77.3	80.0
% of total portfolio	1.0	0.1	1.3	7.2	2.6
CUP	0.0	0.0	0.0	0.0	0.0
Current Amount*	13.8	3.0	17.9	13.8	17.9

* On a gross basis

2. NET EXPOSURE BY SECTOR

	Uganda		MIGA Worldwide	
	US$ million	%	*US$ million*	%
Agribusiness	2.7	3.3	178.1	5.7
Construction	0.0	0.0	17.9	0.6
Financial	0.0	0.0	799.3	25.7
General Banking	0.0	0.0	751.0	24.2
Investment Fund	0.0	0.0	0.0	0.0
Leasing	0.0	0.0	44.6	1.4
Mortgage	0.0	0.0	3.7	0.1
Infrastructure	77.3	96.7	1,283.8	41.3
Electric, Gas & Sanitary Services	0.0	0.0	39.4	1.3
Power	77.3	96.7	635.8	20.4
Telecommunication	0.0	0.0	360.2	11.6
Transportation	0.0	0.0	115.2	3.7
Water Supply	0.0	0.0	132.9	4.3
Water Transportation	0.0	0.0	0.3	0.0
Manufacturing	0.0	0.0	234.1	7.5
Mining	0.0	0.0	120.9	3.9
Oil and Gas	0.0	0.0	227.0	7.3
Services	0.0	0.0	151.9	4.9
Tourism	0.0	0.0	96.2	3.1
TOTAL	80.0	100.0	3,109.1	100.0

3. List of Active Projects in Uganda

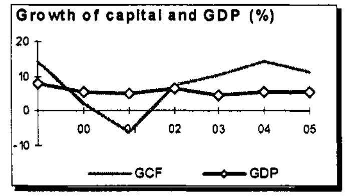
Project Name	Investor Name	Investor Country	Business Sector
Uganda Electricity Distribution Concession	Globeleq Holdings (ConCO) Limited	Bermuda	Infrastructure
Uganda Electricity Distribution Concession	Globeleq Holdings (ConCO) Limited	Bermuda	Infrastructure
Kyoga Limited	Millco Limited	St. Kitts and Nevis	Agribusiness

Annex 19: Country at a Glance

STRUCTURE of the ECONOMY

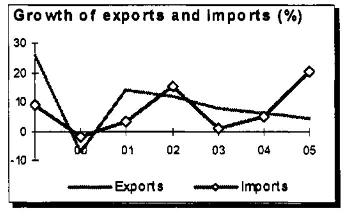
	1985	1995	2004	2005
(% of GDP)				
Agriculture	52.7	49.4	32.2	33.5
Industry	9.9	14.3	21.2	20.9
Manufacturing	5.8	6.8	9.2	9.0
Services	37.4	36.3	46.6	45.6
Household final consumption expenditure	78.0	84.0	76.4	76.7
General gov't final consumption expenditure	14.5	11.2	14.5	14.2
Imports of goods and services	15.0	20.8	27.5	27.7

Growth of capital and GDP (%)



	1985-95	1995-05	2004	2005
(average annual growth)				
Agriculture	4.0	4.0	5.2	5.1
Industry	9.3	8.4	5.6	9.1
Manufacturing	9.8	8.5	4.0	6.7
Services	6.8	7.2	6.3	7.2
Household final consumption expenditure	5.4	5.2	3.0	5.0
General gov't final consumption expenditure	4.8	5.5	6.1	7.5
Gross capital formation	7.6	5.3	14.0	11.5
Imports of goods and services	3.9	5.5	5.1	20.2

Growth of exports and imports (%)



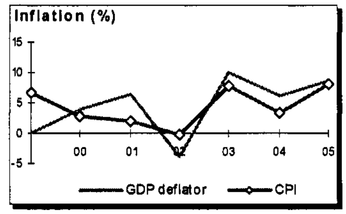
Note: 2005 data are preliminary estimates.
This table was produced from the Development Economics LDB database.
* The diamonds show four key indicators in the country (in bold) compared with its income-group average. If data are missing, the diamond will be incomplete.

Uganda

PRICES and GOVERNMENT FINANCE

	1985	1995	2004	2005
Domestic prices				
(% change)				
Consumer prices	157.7	8.6	3.3	8.2
Implicit GDP deflator	120.3	9.4	6.1	8.6
Government finance				
(% of GDP, includes current grants)				
Current revenue	9.1	9.8	12.6	..
Current budget balance	0.3	0.6	-0.7	..
Overall surplus/deficit	-4.3	-6.9	-10.6	..

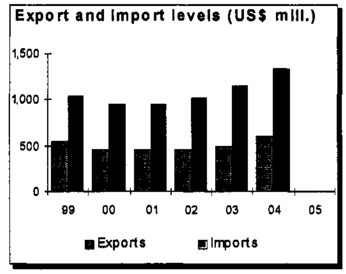
Inflation (%)



TRADE

	1985	1995	2004	2005
(US$ millions)				
Total exports (fob)	383	595	603	..
Coffee	353	457	108	..
Cotton	..	3	29	..
Manufactures	..	..	..	..
Total imports (cif)	404	1,085	1,336	..
Food	..	..	..	..
Fuel and energy	76	64	144	..
Capital goods	..	..	..	..
Export price index *(2000=100)*	247	188	86	..
Import price index *(2000=100)*	62	96	94	..
Terms of trade *(2000=100)*	395	196	91	..

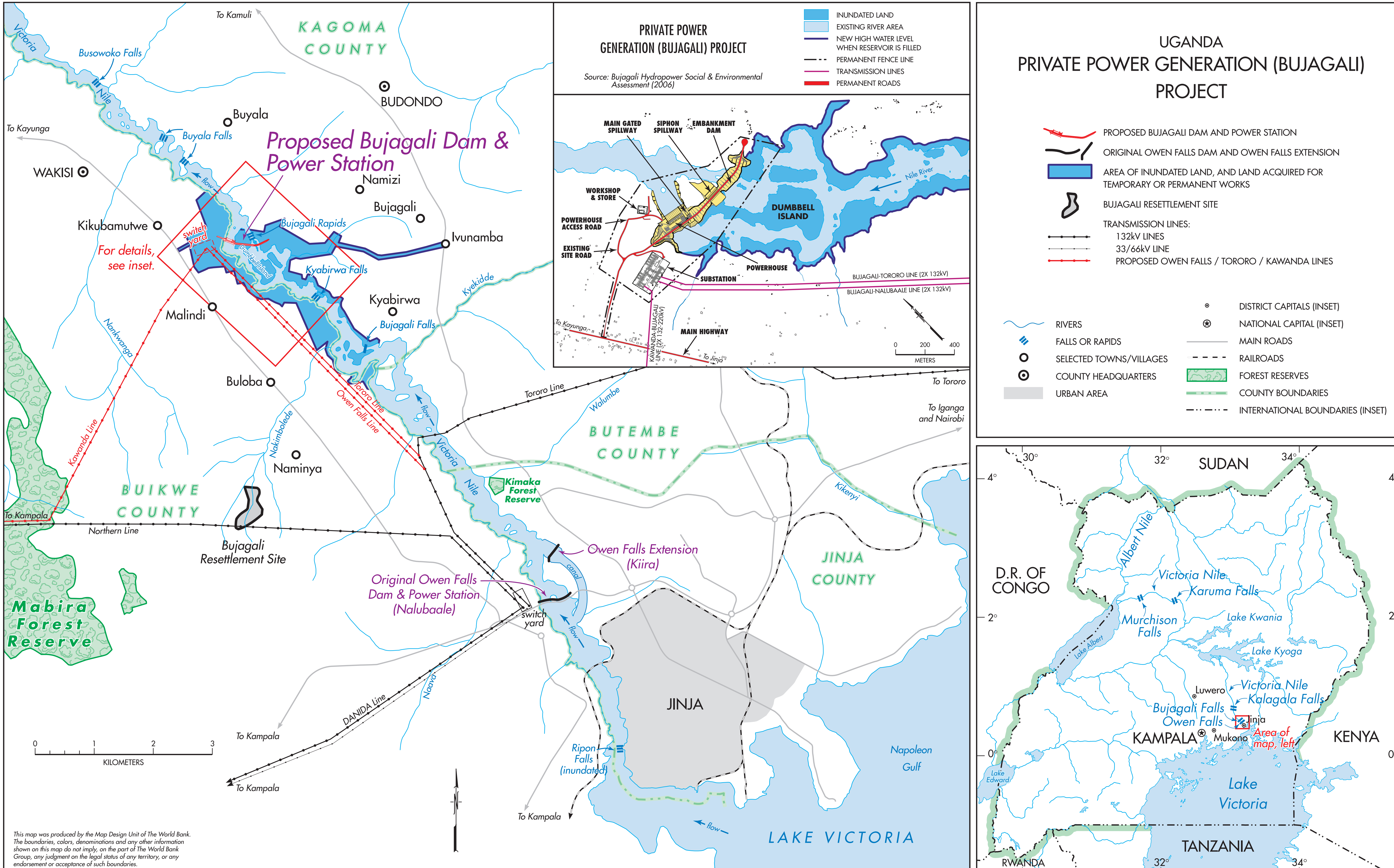
Export and import levels (US$ mill.)



Annex 20: Maps

Uganda Private Power Generation Project

IBRD 35423



APRIL 2007