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Report No: 66363-KE

PROJECT APPRAISAL DOCUMENT

ON A

PROPOSED SERIES OF IDA PARTIAL RISK GUARANTEES
IN THE AGGREGATE AMOUNT EQUIVALENT TO US$166 MILLION

IN SUPPORT OF

THIKA POWER LIMITED,

TRIUMPH POWER GENERATING COMPANY LIMITED,

GULF POWER LIMITED,

AND

ORPOWER 4, INC.,

FOR THE PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

IN THE REPUBLIC OF KENYA

January 31, 2012

Energy Unit
Sustainable Development Department
Africa Region

CURRENCY EQUIVALENTS

(Exchange Rate Effective January 20, 2012)

Currency Unit	=	Kenya Shillings (KSh)
KSh 85.975	=	US$ 1
US$1.5343	=	SDR 1
US$1.282	=	Euro 1

FISCAL YEAR

January 1 – December 31

ABBREVIATIONS AND ACRONYMS

ABSA	South African subsidiary of Barclays Bank
AfDB	African Development Bank
BOO	Build, Own and Operate
CAGR	Compound Annual Growth Rate
CI	Commercial and Industrial Consumers
CPS	Country Partnership Strategy
CPMP	Cultural Property Management Plan
DC	Domestic Consumers
EAC	East Africa Community
EAPP	Eastern Africa Power Pool
EIRR	Economic Internal Rate of Return
EMP	Environmental Management Plan
EOI	Expressions of Interest
EPC	Engineering and Procurement and Construction
EPP	Emergency Power Plants
ERB	Electricity Regulatory Board
ERC	Energy Regulatory Commission
ESIA	Environment and Social Impact Assessment
ESMF	Environmental and Social Management Framework
ESRP	Energy Sector Recovery Project
FIRR	Financial Internal Rate of Return
FiT	Feed-in Tariffs
FSA	Fuel Supply Agreement
GDC	Geothermal Development Corporation
GDP	Gross Domestic Product
GoK	Government of Kenya
GPOBA	Global Partnership Output Based Aid

GPL	Gulf Power Limited
HFO	Heavy Fuel Oil
ICT	Information and Communication Technology
IDA	International Development Association
IFC	International Finance Corporation
IFMIS	Integrated Financial Management Information System
IPP	Independent Power Producers
ISP	Implementation Support Plan
IT	Interruptible off-peak supplies
KEEP	Kenya Electricity Expansion Project
KenGen	Kenya Electricity Generating Company Ltd.
KETRACO	Kenya Electricity Transmission Company
KPLC	Kenya Power and Lighting Company
KWS	Kenya Wildlife Service
LC	Letter of Credit
LCPDP	Least Cost Power Development Plan
LF	Load Factor
LRMC	Long Run Marginal Cost
MIGA	Multilateral Investment Guarantee Agency
MSD	Medium Speed Diesel
NPV	Net Present Value
O&M	Operations and Maintenance
ORAF	Operational Risk Assessment Framework
PCU	Project Coordination Unit
PEFA	Public Expenditure Financial Assessment
PFM	Public Financial Management
PPA	Power Purchase Agreement
PPP	Public Private Partnerships
PRG	Partial Risk Guarantee
REA	Rural Electrification Authority
REMP	Rural Electrification Master Plan
RFP	Request for Proposal
SCC	Small Commercial Consumers
SCADA/EMS	Supervisory Control and Data Acquisition/Energy Management System
SL	Street Lighting
TPGC	Triumph Power Generating Company
TPL	Thika Power Limited

Regional Vice President:	Obiageli Katryn Ezekwesili
Country Director:	Johannes Zutt
Sector Director:	Jamal Saghir
Sector Manager:	Lucio Monari
Guarantee Manager:	Pankaj Gupta
Task Team Leader:	Karan Capoor and Ritin Singh (Co-TTL)
Program Assistant:	Lily Wong Chun Sen

KENYA

Kenya Private Sector Power Generation Support Project

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Kenya Private Sector Power Generation Support Project

PROJECT APPRAISAL DOCUMENT

Region - AFRICA

Unit - AFTEG

Basic Information

Date:		Sectors:	Power (100%)
Country Director:	Johannes Zutt	Themes:	Infrastructure services for private sector development (100%)
Sector Director:	Jamal Saghir	EA Category:	A (Full Assessment)
Project ID:	P122671		
Lending Instrument:	IDA Partial Risk Guarantees		
Team Leader(s):	Karan Capoor and Ritin Singh		

Joint IFC:

.

Borrower: Kenya Power and Lighting Company (KPLC) and Government of Kenya (GoK)

Responsible Agency: Ministry of Energy (MoE) and Ministry of Finance (MoF)

Contact:	Mr. Patrick M. Nyoike Mr. John Murugu Mr. Joseph K. Njoroge	Title:	Permanent Secretary, MoE Director, Debt Management Department (MoF) Managing Director and CEO, KPLC
Telephone No.:	+254 20 225 0680 +255 20 252 2299 +254 20 320 1710	Email:	p.nyoike@kenya.go.ke jmurugu@treasury.go.ke jnjoroge@kplc.co.ke

Project Implementing Agencies:

(i) Thika Power Ltd., (ii) Triumph Power Generating Company Ltd, (iii) Gulf Power Limited; and (iv) OrPower 4 Inc.

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Project Implementation Period (for each PRG):	Start Date:	February 28, 2012	End Date:	June 30, 2030 (Each PRG will be for a maximum term of up to 17 years from the date of its effectiveness. Indicated date reflects expected date of expiry of the last PRG).

Expected Effectiveness Date:	March 15, 2012
Expected Closing Date:	December 31, 2016

Project Financing Data(US$M)

[ ]	Loan	[ ]	Grant	[ ]	Other
[ ]	Credit	[x]	Guarantee		

For Loans/Credits/Others

Total Project Cost :	US$623 million	Total Bank Financing :	NA
Total Cofinancing :	US$384 million	Financing Gap :	None.

	(excluding IFC)	
Terms of Financing:	IDA Guaranteed Amount:	US$166 million equivalent
	Final Maturity:	Up to 17 years from effectiveness of each PRG
	Amortization Profile:	NA
	Grace Period:	NA
Bank Group Participation	[X] IFC [X] MIGA IFC A, B & C Loan is proposed for Thika Power Ltd. and Gulf Power Ltd. (US$90 million equivalent). MIGA Termination Cover is proposed for Thika Power Ltd. and Triumph Power Generating Company Ltd. MIGA Termination Coverage for Gulf Power Ltd. has been discussed, but is not confirmed.	
Proposed Guarantee Coverage:	Each proposed Partial Risk Guarantee (PRG) will support the Power Purchase Agreement (PPA) of Kenya Power & Lighting Company's (KPLC) and the Letter of Support by the Government of Kenya (GoK) to be concluded with each of four Independent Power Producers (IPPs). A revolving standby letter of credit (L/C) for the account of KPLC will be issued by a commercial bank to each IPP as payment security for certain ongoing payment obligations by KPLC under its PPA and/or by GoK under its Letter of Support. Each PRG will backstop the debt obligation of KPLC and/or GoK to the commercial bank for any amount drawn by an IPP under the L/C as a result of breach by KPLC and/or GoK of its aforementioned payment obligations.	

Financing Source – Amount (Million US$ equivalent)	Thika Power Ltd.	Triumph Power Generating Co. Ltd	Gulf Power Ltd.	Orpower 4, Inc.	**Total**
Equity	**36**	**39**	**27**	**47**	**149**
Debt	**110**	**118**	**81**	**165**	**474**
- IFC A	36	-	22	-	58
- IFC B (Commercial loan)	-	-	27	-	27
- IFC C	-	-	5	-	5
- AfDB	37*	-	-	-	37
Commercial Bank	37*	118	27	-	181
OPIC	-	-	-	165	165
Total	**146**	**157**	**108**	**212**	**623**
* The numbers are rounded.					

Expected Disbursements (in US$ Million)

Fiscal Year	2012	2013	2014	2015	2016	2017			
Annual	NA	NA	NA	NA	NA	NA			
Cumulative	NA	NA	NA	NA	NA	NA			

Project Development Objective(s)

The Project Development Objective is to increase electricity generation through Independent Power Producers (IPP) in Kenya.

Project description

Kenya faces acute power supply shortages and KPLC, the public distribution company, expects to contract over 600 MW of new generation capacity over the next 12-18 months through the four IPPs supported in this Project as well as other IPPs in the pipeline. The proposed WBG risk mitigation framework for this Project is designed with complementary and efficient use of IDA PRGs and MIGA Guarantees that will provide support for distinct risks and for different components of the underlying financing, while substantially reducing the requirement for GoK sovereign guarantees.

Sub-Projects

The proposed Project consists of the following sub-projects, comprising three thermal IPPs and one integrated geothermal expansion IPP:

- Sub-project 1: Thika Power Plant (Total Cost Approx. US$146 million equivalent, IDA PRG US$35 million and Euro 7.7 million). The sub-project supports the construction of an 87 MW combined cycle Medium Speed HFO Power Plant, a fuel storage facility and associated interconnection facility in the Thika area, near Nairobi.

- Sub-project 2: Triumph Power Plant (Total Cost Approx. US$157 million, IDA PRG US$45 million). The sub-project will support the construction of an 82 MW combined cycle Medium Speed HFO plant, a fuel storage facility and associated inteconnection facility at Kitengela near the Athi River, approximately 25 km from Nairobi.

- Sub-project 3: Gulf Power Plant (Total Cost Approx. US$108 million equivalent, IDA PRG US$35 million and Euro 7 million.). The sub-project will support the construction of an 80.3 MW single cycle, Medium Speed HFO plant, a fuel storage facility and associated interconnection facility at Athi River Town on Mombasa Road, approximately 35 km from Nairobi.

- Sub-project 4 (a): Olkaria III Geothermal Expansion (Total Cost Approx. US$212 million, IDA PRG US$31 million). This sub project will involve a 36 MW expansion and integration with an existing 48 MW base-load geothermal power plant at the Olkaria Geothermal fields, increasing it to a total installed capacity of 84 MW. The project, located within Hell's Gate National Park in the Kenyan Rift Valley, 90 kilometers northwest of Nairobi, will involve the additional development of the geothermal field and the construction and integration of an additional 36 MW Plant.

- Sub-project 4 (b): Of the approved PRG amount, US$5 million is for a further addition of a 16 MW geothermal plant as an option, which if exercised by the project sponsor no later than September 2015, will result in an integrated geothermal plant with total installed capacity of 100 MW at the Olkaria III site.

Compliance

Policy

Does the project depart from the CAS in content or in other significant respects?	Yes	[ ]	No	[X]
Does the project require any waivers of Bank policies?	Yes	[ ]	No	[X]
Have these been approved by Bank management?	Yes	[ ]	No	[ ]
Is approval for any policy waiver sought from the Board?	Yes	[ ]	No	[X]
Does the project meet the Regional criteria for readiness for implementation?	Yes	[X]	No	[ ]

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

Legal Covenants			
Name	**Recurrent**	**Due Date**	**Frequency**
(1) Republic of Kenya (2) Each IPP (i.e., Thika Power Ltd., Triumph Power Generating Co. Ltd, Gulf Power Ltd., and Orpower 4, Inc.)	Yes	N/A	Ongoing

Description of Covenant

Exact terms of covenants are to be negotiated with the relevant parties, but are expected to include, *inter alia*, the following:

(1) Under the Indemnity Agreement, Kenya agrees: (a) to reimburse IDA immediately on demand or as IDA may otherwise direct in writing for any amount paid by IDA under the IDA Guarantee Agreement together with interest thereon; and (b) to indemnify IDA on demand for all losses, damages, costs, expenses etc. incurred by IDA in relation to or arising out of the IDA Guarantee Agreement.

(2) Under the Project Agreement, each IPP covenants: (a) to execute the Project so as to comply with all of its material obligations under the transaction documents, including the relevant environmental and social requirements consistent with applicable World Bank Safeguard Policies, (b) to provide certain information to IDA, including annual financial statements; and (c) not to engage in corrupt practices, fraudulent practices, coercive practices, collusive practices and obstructive practices in connection with the Project.

Team Composition

Bank Staff

Name	Title	Specialization	Unit
Karan Capoor	Senior Financial Specialist	Team Leader	AFTEG
Ritin Singh	Senior Operations Officer	Co-Team Leader	AFTEG
Farida Mazhar	Lead Financial Officer/Consultant	PRG Specialist	FEUFS
Kyran O’Sullivan	Senior Energy Specialist	Energy Economist	AFTEG
Atsuko Okubo	Senior Counsel	Counsel	LEGCF
Harvey Van Veldhuizen	Lead Environmental Specialist	Environmental Specialist	OPCQC
Teuta Kacaniku	Energy Financial Analyst	Energy Finance Specialist	FEUFS
Monica Teresa Restrepo	Senior Counsel	Counsel	LEGCF
Daniel Murphy	Senior Operations Officer	Operations Officer	AFTEG
Mitsunori Motohashi	Energy Specialist	Financial Specialist	AFTEG
Vongy Rakotondramanana	Energy Specialist	Power Engineer	AFTEG
Gibwa Kajubi	Senior Social Development Specialist	Social Development Specialist	AFTCS
Noreen Beg	Senior Environmental Specialist	Environmental Specialist	AFTEN
Bassem Abou-Nehme	Energy Financial Analyst	Energy Finance Specialist	FEUFS
Alexandra Planas	Energy Specialist/Consultant	Energy Specialist	AFTEG
Jean Jacques Raoul	Procurement Specialist/Consultant	Procurement	AFTEG
Shirmila Ramasamy	Counsel	Counsel	LEGFI
Lily Wong Chun Sen	Program Assistant	Program Assistant	AFTEG

I. STRATEGIC CONTEXT

A. Country Context

1. **Kenya has substantial potential for economic growth and can reach middle income country status by 2019.[1]** Kenya's economy is far more diversified than most other countries in Sub-Saharan Africa. About 55 percent of Kenya's GDP comes from services, transport, finance, tourism, information and communications technology (ICT) and trade -- sectors that are critically dependent on reliable electricity supply. Kenya has only recently overcome the multiple shocks of 2008 and 2009 (post-election violence, drought, and the global food and financial crises) and achieved higher than expected growth of 5.6 percent in 2010. The robust recovery was driven by agriculture, a booming financial sector and a fiscal stimulus. If growth accelerates to 6 percent, Kenya can expect to reach middle income status in 2019; however this projection is sensitive to oil and food prices. The World Bank estimates 5% growth for 2012 if sound macroeconomic policies (e.g. rebuilding fiscal resilience) are preserved.

2. **Fiscal adjustment in 2011 following the fiscal stimulus of the past two years will make it more difficult for the government to fully implement its development program.** In 2009 and 2010, government expenditure for the development budget supported a number of very large infrastructure projects (e.g. in road construction). This was in addition to a stimulus program of grants amounting to almost US$4.25 billion for rural roads, health and education facilities. The development budget grew from 6.7 percent in 2007-2008 to 10.1 percent in 2010-2011 financed largely from domestic borrowing. As a result, the debt to GDP ratio increased to about 47.9 percent in 2010-2011. Kenya's competitiveness declined so that weakness in exports combined with a strong domestic sector has created a large and growing current account deficit. Monetary and fiscal consolidation in 2011-2012 aims to rein in development spending but may be difficult to maintain in the run up to the 2012 general election. As a result, unless growth accelerates, indications are that fiscal deficit, current account and debt targets may be missed.

3. **Kenya has a dynamic private sector and is at the threshold of a major demographic transition, but the country faces serious infrastructure constraints**. Kenya's vibrant private sector has been a major source of economic growth, driven by expanding services in telecommunications and transport. Kenya's population will grow by more than 1 million people every year and by 2040 the country is projected to have an estimated 75 million people and become the 21st largest economy in the world. The share of the urban population will be 37 percent by 2020 and over 50 percent by 2033. This demographic transition will in turn facilitate further expansion of emerging industrial sectors as increasing agglomeration will generate markets for products and services to serve a growing middle class. Kenya benefits from a geographical location that is favorable to trade, with the port of Mombasa serving as the most important gateway for imports to the countries of the East African community, South Sudan and eastern DRC. Nevertheless, internal infrastructure bottlenecks, especially in electricity supply and transport, have prevented Kenya from maximizing its potential for private sector-led growth.

4. **Kenya's lack of reliable and affordable generation capacity increases the cost of doing business, undermines trade and competitiveness and diminishes job creation**

[1] Sources: Kenya Economic Update, Poverty Reduction and Economic Management Unit, Africa Region, World Bank, December 2010 and June 2011.

prospects. The World Bank's Poverty and Inequality Assessment (2008) concluded that improved infrastructure access is associated with movement out of poverty. As a result of insufficient investment in electricity infrastructure, Kenya suffers from chronic shortfalls in energy supply, which are amplified by climate variability. The electricity system has come to rely on expensive emergency diesel power, which places a heavy economic burden on the Kenyan economy, including households and industry.[2] Unreliable electricity supply reduces Kenya's annual GDP growth by about 1.5 percent.[3] In financial terms, the disruption of public power supply costs Kenyan firms about 7 percent of their annual sales revenues. This constrains their growth and ability to employ more people across industrial and other productive sectors, including SMEs and other employment-generation sectors. Without infrastructure constraints, the manufacturing sector (which represents 11 percent of total economic activity and whose competitiveness depends heavily on such infrastructure) would likely provide employment opportunities for nearly one million Kenyans entering the labor market every year. It is not surprising that *Vision 2030*, Kenya's long-term development strategy, targets expanded infrastructure access – and power generation – as a key element of achieving higher levels of economic growth. Infrastrucure access is central to the aspiration of transforming Kenya from a low income, agrarian economy into an industrialized middle-income country providing a high quality life to all its citizens by the year 2030.

B. Sectoral and Institutional Context

5. **Over-dependence on hydropower makes the system especially vulnerable to serious shortages during periods of drought** Kenya's current power sector fuel mix is comprised of hydropower (52 percent), diesel (22 percent), geothermal (10 percent), thermal (5 percent), and the balance (11 percent) of wind, gas, emergency plants and co-generation assets. The current installed capacity of the Kenyan grid is 1473 MW; however, available capacity on any given day is much lower and can vary on a weekly basis as certain generation units are overhauled or otherwise out of service.[4] Increasingly erratic rainfall patterns and the destruction of key water catchment areas have affected hydroelectricity output. In many weeks, more than 250 MW of this installed capacity was unavailable, leading to load-shedding of between 30-50 MW, despite operating 120 MW of expensive emergency diesel plants. Expanding Kenya's current installed power generation capacity will help to secure the sustainability of the current growth rate, to support future economic growth, and to improve the quality of life of the population.

6. **Power sector expansion is a key element of *Vision 2030*, the Government's national development strategy.** Less than 25 percent of Kenya's population is served by the electricity system, and rural grid access is only 5 percent. The Government has established ambitious

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[2] The emergency diesels, in place since 2006, have recently contributed over 14% of overall generation in the country. This emergency diesel came at a very high wholesale tariff of US$ 27 cents/kWh last year. As a comparison, end-customers in the Washington DC metropolitan area paid less than half of that as the average retail tariff. Average retail tariffs in Kenya (see Table 1) are one and a half times higher than what they are in the Washington DC metropolitan area.

[3] The Africa Infrastructure Country Diagnostic (2008) noted Kenya's under-investment in the power sector.

[4] To illustrate, Kenya had more than 250 MW that was unavailable in one week in June 2011. Olkaria 1 Unit 3 (15 MW) and Turkwell Unit 2 (33 MW) were under overhaul. Two gas turbines were being moved (2x 30 MW) from Mombasa to Nairobi and Mumias (26 MW) was out as bagasse was not available. Other units out that week were Kipevu 1, Tana and Iberafrica. Kenya also had reduced output from the hydropower stations on the Tana River that same week. Consequently, there was load shedding of as much as 43 MW the previous day. For this reason, maintaining a system reserve margin of at least 20 per cent is considered critical.

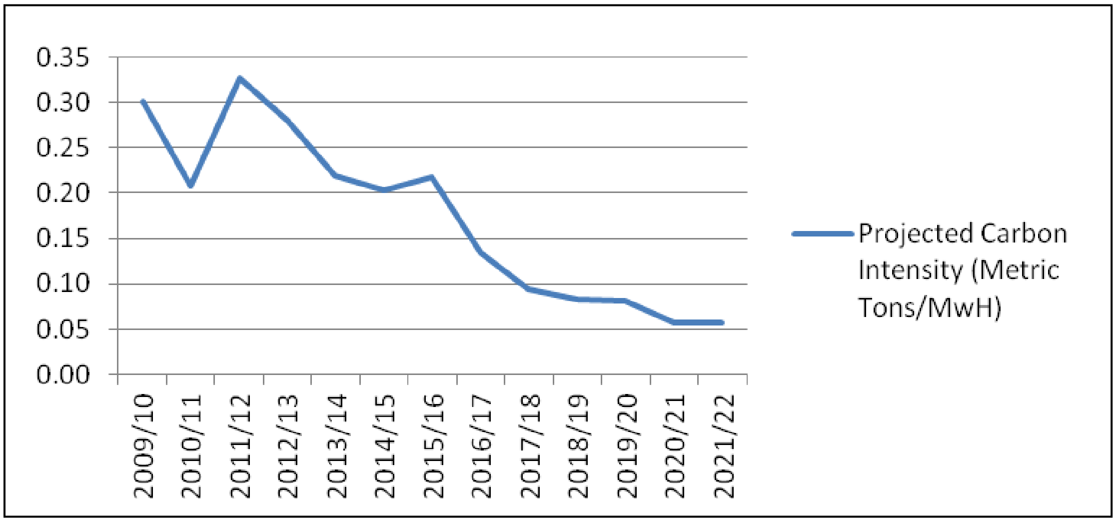
targets for scale-up and supply expansion with a goal of achieving 40 percent electrification by 2030 amid a rapidly growing and urbanizing population with increasing aspirations for a better quality of life. Intermediate targets include electrifying one million new customers in the next five years and extending electricity service to priority loads. In 2010, the Ministry of Energy developed the country's Least Cost Power Development Plan (LCPDP) for the next 20 years. The LCPDP forecasts an increase in power demand to 4,220 MW in 2020 and 11,510 MW in 2030 in a Low Case Scenario, and 4,755 MW in 2020 and 15,026 MW in 2030 in a Base Case Scenario, representing average energy growth rates of 14.5 percent for the period from 2010 to 2020, and 13.4 percent for the entire period.

7. **Kenya has prioritized the development of a diversified portfolio of complementary electricity assets -- including hydro imports through regional power trade -- which will result in a lower cost and lower carbon energy mix over time.** Kenya's LCPDP emphasizes the need to develop a diversified portfolio of generation assets that balances sources of power and types of technology. Kenya's generation capacity is expected to shift over time from unpredictable hydropower and fuel price-sensitive thermal power to more sustainable renewable energy options which will reduce Kenya's vulnerability to regional hydro variability and to global petroleum market volatility. As an interim measure, Kenya will turn to thermal and geothermal generation options to help meet urgent needs for base load generation until about 2016-2017. At that time, the thermal plants are expected to transition from base load to intermediate duty, as cleaner and lower cost generation from anticipated large scale geothermal and wind projects as well as regional hydro imports enter the grid.[5] From about 2016-2017 until 2020-2021, when demand again is expected to outstrip supply, the thermals will provide much-needed reserve margins for the stability of Kenya's grid and will also be available to dispatch for export elsewhere in the region through the East Africa Power Pool (EAPP).[6] Realization of Kenya's clean energy portfolio is expected to reduce the average electricity tariff in Kenya and also to contribute to a significant reduction in Kenya's projected grid carbon intensity. Figure 1 below shows the expected transition in Kenya's grid carbon intensity, which peaks in 2012-2013 reflecting the operation of the emergency diesels and the commissioning of the thermal IPPs, before declining sharply over the decade with a greater share of wind, geothermal and imported hydro generation in the energy mix.

[5] Kenya has considerable geothermal resources which are located in the Rift Valley with an estimated potential of between 7,000 MW to 10,000 MW. The World Bank, in FY2011, made a US$330 million commitment through the Kenya Electricity Expansion Project (KEEP) to a US$1.3 billion energy project that includes the development of about 280 MW of additional public sector geothermal generation capacity at Olkaria.

[6] Proposed hydro imports through the EAPP will require significant investment in the construction of transmission interconnection lines with countries in the region. The Bank is currently preparing a major new investment program to support the Regional East Africa Power Pool (Ethiopia-Kenya Interconnector).

Figure 1: Projected Carbon Intensity of Kenya's Electricity Grid



8. **Government policy has recognized the scale of the challenge and has encouraged competition and private participation to develop new generation capacity**. Kenya's power sector needs over US$5 billion of new investments by 2015 for electricity generation alone. The Government has also designed an investment program to strengthen and expand the national transmission and distribution grids to improve supply reliability and measures to increase demand side efficiency (such as energy saving light bulbs). This program includes the construction of 5,937 km of transmission lines with an investment cost of another US$3.0 billion until 2015. Raising this magnitude of capital, particularly at a time of global recession and unease in financial markets, poses a significant challenge. In this context, Kenya envisages a multipronged sector financing strategy that includes tapping local capital markets, Kenyan diaspora bond investors as well as global investors from a variety of public, private and concessional sources. GoK recognized that if it were able to attract substantial amounts of private capital investments into the sector through Independent Power Producers (IPPs), it could avoid diverting Government and donor financing from other priority needs. Table 1 below summarizes the approved resource contributions of development partners to the needs of Kenya's energy investment program. It excludes GoK's own budget allocations, World Bank Group (WBG) support, and private sector investments.

Table 1: Kenya Power Sector Investment Program: Development Partner Support (US$ million)

	AFD/ Proparco	**AfDB**	**EIB**	**China EXIM**	**Govt. Spain**	**JICA**	**KfW**	**Norway**
Generation	317	129	202	95	26	384	152	
Transmission	107	74	77			162		3
Distribution & Rural Electrification	82		55	95	13			
Total	**506**	**203**	**334**	**190**	**38**	**546**	**152**	**3**

9. **Major policy reforms have established an efficient and transparent institutional framework that provide the basis for sector sustainability.** Kenya's energy sector reform has advanced quickly, especially relative to other African countries. The Government established its long-term vision and policy framework for the sector in the late 1990s and early 2000s, culminating in the 2004 Energy Policy (Sessional paper No. 4 of 2004) and the 2006 Energy Act (Energy Act No.12 of 2006), which unbundled the key players in the electricity sector to ensure efficiency, established an effective framework for enabling the commercial viability of electricity companies and opened the door for competition in the electricity market. The Act maintains that all tariffs charged for electricity supplied shall be "just and reasonable," and established at a level that enables an electricity supply license holder to (i) maintain its financial integrity, (ii) attract capital, (iii) operate efficiently; and (iv) fully compensate investors for assumed risks. The Energy Act also established the Energy Regulatory Commission (ERC) as an autonomous body, which is empowered to autonomously set, review and adjust tariffs and tariff structures at levels that enable licensees to recover their costs.[7] Kenya's tariff structure fosters sector sustainability, as fuel costs and exchange rate fluctuations are passed through by bulk suppliers via KPLC to end-consumers on a monthly basis while adjustment for inflation takes place every six months. Electricity suppliers are thus protected from fuel market risk, while at the same time, the impact on consumers of inflation is delayed. Average electricity retail tariffs (revenue per unit sold) are high in Kenya compared with neighboring countries reflecting the fact that in Kenya prices are close to or at cost recovery levels (Table 2). Kenya's average tariffs are expected to decline as cheaper generation from wind, geothermal and regional hydro generation make up a greater share of the energy mix and as the relative share of thermals declines over time.

Table 2: Average Retail Tariffs (US cents/kWh)

Country	**Kenya**	**Ethiopia**	**Rwanda**	**Uganda**	**Tanzania**
Average Tariff (USc/kWh)	17	3	20	12	8

10. **Kenya has perhaps the best performing energy institutions in sub-Saharan Africa, including Kenya Electricity Generating Company (KenGen) for power generation, Kenya Power and Lighting Company (KPLC) for electricity distribution and Kenya Electricity Transmission Company (KETRACO) for transmission.** KenGen and KPLC are each majority owned by GoK with private minority shareholders and each operates on a sound commercial basis.[8] They are professionally managed, creditworthy institutions that enjoy strong reputations in the marketplace. KETRACO was created more recently and is a 100% state-owned company with a mandate to develop, build and operate new transmission assets. It is still in the process of fully developing its capacity as a transmission owner and operator and, in this regard, has a service agreement with KPLC to support it, particularly to manage dispatch. Geothermal Development Company (GDC) is a 100% state-owned company, formed by GoK as a Special Purpose Vehicle to fast track the development of geothermal resources.

[7] The tariff structures as well as its adjustment mechanisms were designed following a tariff study supported by the World Bank.
[8] Over an eight-year period (FY2004 to FY2011), KPLC has been able to expand its customer base, increase its profitability, improve its operational performance, and maintain a healthy financial position.

11. **While Kenya is perceived to present overall governance risks, the electricity sector's governance risk is assessed as moderate as a result of its reform trajectory and institutional set up.** Governance risk in the electricity sector was assessed as moderate for the Kenya Electricity Expansion Project approved by the Bank Board in May 2009. The assessment (see Annex 7) was conducted by the Bank project team with the assistance of the Preventative Services Unit of the Integrity Vice Presidency (INT) and was based on the following factors:

- *The regulatory framework is robust and resistant to interference.* The Energy Regulatory Commission (ERC), created in 2007, regulates wholesale and retail tariffs and issues licenses. The Commission has a successful track record on contested issues including approval of PPAs and tariff reform. A separate Energy Tribunal hears appeals to the decisions of the ERC.

- *The negotiations for tariff-setting and power purchase agreements are transparent* and ensure the pass-through of non-controllable costs, such as fuel costs, inflation and foreign exchange rate changes, to ensure financial sustainability of power entities such as KPLC.

- *Bid invitations* conducted under ongoing IDA investment lending projects have resulted in a good number of bidders and competitive prices. Private sector implementation of projects procured under the country's Public Procurement and Disposal Act provides additional comfort on accountability and governance issues.

- *Procurement oversight mechanisms* have been invoked on several major contract awards, leading to greater confidence in the procurement processes.

12. **The sector's sustainability and KPLC's reliability as an off-taker have encouraged private participation in generation: Kenya's previous efforts to attract IPPs successfully yielded 347 MW of installed power capacity over 12 years.** KPLC signed Power Purchase Agreements (PPAs) with six IPPs over the 12 year period between 1996 and 2008, which are currently contracted to provide 347 MW of capacity from a portfolio of different technologies and fuels, including diesel engines, gas turbines and geothermal (see Table 3). In the process of negotiating and sustaining these IPPs, KPLC has developed a well-deserved reputation as a reliable off-taker with a good payment record which has enabled investors and lenders to achieve their expected returns on investments.[9] The plants have generally operated with high availability rates and together, these IPPs have been able to supply power to meet a substantial part of demand, particularly during periods of shortfall due to drought.[10] These existing IPPs were principally supported by Development Finance Institutions (DFIs) and did not attract any lending from commercial lenders.

[9] These projects benefitted from payment security provided through Letters of Credit (L/Cs) that generally required KPLC to back these L/Cs with cash collateral that reduced its borrowing capacity for working capital and for investments in the distribution business together, in some cases, with GoK Letters of Support.

[10] Lower rainfall in recent years reduced volumes of bagasse produced by Mumias and resulted in lower power output.

Table 3: First Generation of IPPs in Kenya (1997-2009)

IPP Name	Type	Capacity	Commissioned	PPA Term	Current Status
Westmount	Gas Turbine (barge-mounted)	46 MW	1997	7 years	Closed in 2004 at end of PPA term
Iberafrica I	Medium Speed Diesel (MSD) using Heavy Fuel Oil (HFO)	56 MW	1997	7 years renewed for 15 years	Active
Iberafrica II		53 MW	2009	20 years	Active
Orpower / Olkaria III	Geothermal	48 MW	2000/2008 (full)	20 years	Active
Tsavo/ Kipevu 2	MSD using HFO	74 MW	2000	20 years	Active
Mumias	Bagasse cogeneration	26 MW	2009	12 years	Active
Rabai	MSD using HFO	90 MW	2009	20 years	Active

13. **Limited fiscal space and perceptions of political risk have made attracting new IPPs a challenge, despite Kenya's positive past experience with IPPs**. The risk perceptions of international investors in relation to Kenya deteriorated due to the civil disturbance that followed the December 2007 elections. Even though there has been a peaceful power sharing arrangement between the two major parties within the Government since then, investors still have some sense of uncertainty, particularly in light of upcoming elections. The risk appetite of project developers and commercial banks has further eroded in the wake of global economic recession and the financial crisis. It became increasingly clear to KPLC that it would not be able to procure the substantial urgent increase in installed generation capacity (almost a doubling of new capacity additions) from IPPs by providing the type of payment security it had provided in the past. KPLC therefore looked to GoK to provide sovereign guarantees in support of the proposed IPPs and proceeded to ask bidders to bid on that basis. Given the tighter macroeconomic environment and the debt ceilings agreed as part of the IMF Program, GoK was not in a position to offer sovereign guarantees and explored alternative risk mitigation options which could address the constraints of both GoK and KPLC to facilitate financing of the proposed IPPs. The proposed use of IDA PRGs and MIGA Guarantees has enabled the GoK to proceed with private sector participation in the power generation, while minimizing the requirements for sovereign guarantees.

14. **GoK has adopted the proposed WBG package of IDA PRGs and complementary MIGA Guarantees as a key element of the risk mitigation framework to be offered to support the Kenya IPP Program going forward.** KPLC expects to contract over 600 MW of new generation capacity over the next 12-18 months through its IPP Program.[11] Given the importance of the energy sector to the country in terms of the critical need for power in the short-term and its long-term investment needs, GoK's selected risk mitigation framework recognizes

[11] Kenya's IPP Program pipeline includes the proposed 300 MW Lake Turkana Wind Project, which is being processed for Board separately.

the need for a security scheme to engage IPPs in a coordinated and sustainable manner. The risk mitigation package offered to IPPs consists of (i) IDA PRGs in support of ongoing payment obligations of KPLC under the PPA and ongoing payment obligations of GoK under its Letter of Support together with (ii) complementary MIGA Breach of Contract guarantees to cover the termination payment obligations of KPLC under the PPA and of GoK under its Letter of Support. This option obviates the need for GoK to provide sovereign guarantees to the investors and lenders in support of KPLC's entire payment flows for the duration of the PPA and limits its provision only to counter-guarantees for IDA PRGs thereby substantially reducing its contingent liabilities. The IDA PRGs will be for much smaller amounts and for a shorter term than would have been the case with the sovereign guarantees.

15. **The proposed IPPs will help meet Kenya's urgent generation needs and will help pave the way to diversify and green Kenya's energy generation mix.** The IPPs proposed to be supported in this series as sub-projects are: Thika Power (Combined Cycle 87 MW Medium Speed Diesel), Triumph Power (Combined Cycle 82 MW Medium Speed Diesel), Gulf Power (Single Cycle 80.3 MW Medium Speed Diesel) and OrPower (36 MW Geothermal Expansion with an option for a further expansion of 16 MW). As the proposed thermal and geothermal IPPs are integrated into Kenya's generation portfolio, they will provide urgently needed base load to meet supply shortfalls in the short-term, allowing Kenya to immediately replace 120 MW of expensive and inefficient emergency power plants currently in operation. Over time, as additional renewable energy generation comes on to the grid, the existing thermal plants will transition to providing peaking power.[12] The proposed Olkaria III geothermal expansion will increase the supply of reliable and renewable base load electricity generation from an indigenous and readily available resource with strong resilence to hydro variability. The baseload capacity from the proposed plants will help stabilize the grid by providing adequate system reserves and, along with hydro resources, will help provide the necessary spinning reserves required in order to bring wind energy under development onto the grid successfully. An indicative pipeline of Kenya's proposed IPP projects currently under development is provided below:

Table 4: Kenya's Proposed Future IPP Pipeline and Imports from Ethiopia[13] (2014-2017)

IPP Name	Type	Proposed Capacity	Indicative Full Commissioning
Lake Turkana	Wind	300 MW	2014-2015
Aeolus–Kinangop	Wind	60 MW	2015-2016
AGIL-Longonot	Geothermal	140 MW	2015-2016
Menengai	Geothermal	4 X 100 MW	2015-2017
Imports from Ethiopia[14]	Hydro (regional)	400 MW	2016-2017

Source: LCPDP Update 2011.

16. **Rationale for WBG Support.** Kenya faces power supply shortages which are a constraint to its ability to sustain economic growth. Increased power supply will reduce the cost of doing business in key sectors, increase competitiveness and lead to employment creation.

[12] Gas turbine technology using natural gas when it becomes available would become the top ranked choice for intermediate and peak load. For this reason, the proposed thermal IPPs will have dual firing capability permitting their conversion to natural gas when it becomes available.
[13] Additional generation capacity is anticipated, in particular from KenGen.
[14] In a significant milestone, Kenya recently agreed on terms for a PPA with Ethiopia, which will open up the regional trading market.

Implementing the proposed IPPs, including the proposed 300 MW Lake Turkana Wind Project, will result in KPLC contracting twice as much generation capacity from IPPs than had been contracted over the past twelve years, with financing requirements of almost US$1 billion within a timeframe of between 12-18 months. Amounts of this magnitude could not be mobilized for Kenya within such a short span of time on the basis of the traditional payment security offered by KPLC to the IPPs without some form of credit enhancement. The proposed WBG risk mitigation framework for this Project is designed to provide an optimal risk mitigation package with complementary and efficient use of IDA PRGs and MIGA Guarantees that will provide support for distinct risks and for different components of underlying financing, while substantially reducing the need for GoK to provide sovereign guarantees. The Project will leverage US$166 million in IDA resources to mobilize US$623 million of financing, including US$357 million in private investments and commercial lending. It will deepen private sector engagement and will help set a new benchmark for commercial financing of infrastructure in Kenya and the region.

17. In the proposed package, each WBG instrument will be used to its comparative advantage. Scarce IDA resources will be conserved through the provision of minimal amounts of security to the lenders and investors by using IDA PRGs to backstop KPLC's payment security in the form of L/Cs. IDA's support for KPLC's ongoing payments will ensure it has continued involvement in the Project to be able to leverage the Bank's long-standing and continuing sector involvement and close relationship with KPLC and GoK to help address any project issues in a timely manner, thereby helping to ensure sustainability of the sub-projects. MIGA with its substantial resources is well equipped to cover the relatively larger amounts of support required for termination cover. IFC, for its part, will provide critical long-term funding, in a country environment where such funding tenor is scarce and will support South-South investors, with an appetite for investments in Africa but with relatively limited structuring and project implementation ability, to structure and monitor the sub-projects along with other co-financiers. The table below describes the proposed WBG risk mitigation package.

Table 5: WBG Proposed Risk Mitigation Package (US$ million)

IPPs	IFC Loans	IDA PRGs (Ongoing PPA Payments only)	MIGA Breach of Contract (Termination Cover only)
Thika	A Loan 36	45*	**Debt & Equity 105
Triumph	-	45	**Debt 118
Gulf	A, B & C Loans 54	45*	**Debt 52
Olkaria III***	-	31	-
Total	**90**	**166**	**275**

* Part of this amount will be in Euros.
** MIGA support for commercial debt only. Cover for Gulf Power is still under discussion.
*** MIGA provided OrPower 4 with equity cover for Transfer Restriction, Expropriation and War and Civil Disturbance, but no Breach of Contract cover for Termination is envisaged.

C. Higher Level Objectives to which the Project Contributes

18. Kenya's *Vision 2030* for economic and social development recognizes the need to reduce the cost of doing business in Kenya in order to compete in the world economy. The proposed Project is aligned with the need for infrastructure improvements necessary to support *Vision 2030*. The proposed Project will improve the quality of electricity supply and will generate urgently needed power to promote greater competitiveness and job creation in Kenya. This is especially important in the sectors expected to be the key drivers of economic growth, which include offshore services for global corporations and light industrial developments for the regional (East African) market, particularly in agro-processing and tourism.

19. The proposed Project supports the World Bank's new Africa strategy by harnessing private sector growth to close the infrastructure investment gap and will thereby help to further unlock Kenya's growth potential. In this regard, it will also contribute to improving resilience and increasing energy security by supporting Kenya to develop a diversified portfolio of generation assets.[15] The proposed Project is in line with the Country Partnership Strategy (CPS) for 2010-2013 by expanding electricity infrastructure based on the participation of the private sector as a key partner in development. It will contribute to the achievement of the following CPS outcomes: (a) improving core infrastructure, especially in roads, electricity and water supply (Outcome 1.2); and (b) expanding access to health care, education and basic infrastructure services (Outcome 2.1).

20. The PRGs will catalyze additional investment for generation in Kenya through IPPs with an almost 4:1 leveraging effect with US$166 million in IDA resources mobilizing over US$623 million of financing, of which US$357 million will be in the form of private investment and commercial lender resources under relatively difficult market conditions. The Project will help set a benchmark for long-term commercial financing for infrastructure in Kenya and more broadly for the region through IDA's leveraging effect.

II. PROJECT DEVELOPMENT OBJECTIVES

A. PDO

21. The Project Development Objective (PDO) is to increase electricity generation through Independent Power Producers (IPPs) in Kenya.

22. The immediate Project beneficiaries are current and prospective electricity consumers, including the poor, who face unreliable service due to generation, cost and access constraints. Additional power generated by the sub-projects will help increase productivity and spur economic growth among these beneficiaries. The GoK is also a key beneficiary since the proposed IPPs will save Kenya tens of millions of dollars in annual fuel costs alone by displacing

[15] The Project will help reduce Kenya's vulnerability to serious power shortages, which have been heightened, in part, because of reduced electricity output from hydropower during increasing periods of drought.

the emergency diesel projects.[16] The proposed IPPs would also reduce the need for more public resources for investment in power generation, enabling more funds to be deployed for poverty alleviation and other social needs.

B. PDO Level Results Indicators

23. The Project's proposed PDO indicators are: (i) Electricity generated by the IPPs proposed in this Series (Thika, Triumph, Gulf, Olkaria; GWh/year) available in Kenya's Interconnected Grid (Conventional; Renewable); (ii) Direct project beneficiaries (number), of which female (percentage).

24. The Project's intermediate outcomes relate to the commissioning of the sub-projects on time. The following intermediate outcome indicators will be monitored:

- Commissioning test completed (Y/N).
- Implementation progress in generation capacity constructed under each project (MW Conventional; Renewable).
- Incremental investment in generation (US$; equity and debt).

III. PROJECT DESCRIPTION

A. Overview

25. Kenya faces acute power supply shortages and KPLC, the public distribution company, expects to contract over 600 MW of new generation capacity over the next 12-18 months through the four IPPs supported in this Project and other IPPs in its pipeline.[17] GoK has nominated four competitively awarded IPPs to be supported under the proposed Project consisting of three thermal IPPs, namely Thika Power Limited (TPL or "Thika Power"), Triumph Power Generating Limited (TPGL or "Triumph Power" and Gulf Power Limited (GPL or "Gulf Power") and one geothermal IPP, namely OrPower 4 Inc. ("OrPower").

B. Sub-projects

26. The four sub-projects being developed by these IPPs are being processed together since they are all at an advanced preparation stage, have similar features in terms of project scope, and benefit from a harmonized security package offered by KPLC and GoK through the proposed IDA PRG risk coverage. Other IPPs will be included in a subsequent PRG series which will be processed separately from this Project, once these have been awarded to the private sector by the GoK and nominated for WBG support.[18]

[16] In a recent year (2009-2010), the proposed IPPs would have saved Kenya nearly US$100 million in fuel costs alone.
[17] These include the proposed 300 MW Lake Turkana Wind Project, which is being processed for Board separately.
[18] GoK is currently considering a second series of IPPs for which it may seek IDA PRG support.

27. The three thermal sub-projects will involve: (i) the construction and installation of Medium Speed Diesel Power Plants (MSD) using Heavy Fuel Oil (HFO) on a Build, Own, and Operate (BOO) basis to include the design, finance, supply, erection, commissioning, operation, and maintenance of these plants for a 20 year-term extendable for a further five years; (ii) construction of a fuel storage facility at each site, (iii) installation of metering equipment; and (iv) construction of associated interconnection facility at each plant to deliver the power generated at the plant into the national grid. Each IPP will undertake the sub-projects on the basis of a 20 year Power Purchase Agreement (PPA) with KPLC which will provide for capacity and energy payments for available capacity and energy supplied. The Fuel costs will be a pass through in the tariff and will be payable by KPLC to the IPPs in US Dollars.

28. The geothermal expansion (Olkaria III) combines a new 36 MW expansion ("Plant 2") with an existing 48 MW base-load geothermal power plant undertaken on a Build, Own, Operate (BOO) basis which has been operating since 2009 at the Olkaria Geothermal fields. The sub-project is underpinned by a 20 year PPA concluded with KPLC which provides for capacity and energy payments only since there is no fuel requirement. The PPA was Amended and Restated in 2011 to provide for an expansion of the facility to 84 MW with an option for a further expansion to 100 MW, once the incremental geothermal resources required for the additional 16 MW ("Plant 3") is confirmed.

29. Sub-project 1: Thika Power Plant (Total Cost US$146 million equivalent, IDA PRG US$35 million and Euro 7.7 million, IDA allocation of US$11.25 million equivalent.[19])

The sub-project supports the construction of an 87 MW Medium Speed HFO Power Plant in the Thika area, near Nairobi. The Project will be developed by Thika Power Ltd (TPL) a special purpose company registered under the laws of Kenya. TPL will be 90% owned by Melec PowerGen (BVI), the international contracting arm of the Matelec Group of the Lebanon, incorporated in the British Virgin Islands, with similar project experience in Senegal. The balance of the 10% equity will be held by the local partner, Africa Energy Resources PTE Ltd. incorporated in Singapore.

The project total cost is expected to be around US$146 million equivalent and financing will be structured on a limited recourse basis with a debt equity ratio of 75:25, with US$110 million equivalent in debt and the balance of US$36 million equivalent in equity. Senior debt will be mobilized in equal amounts of US$36 million equivalent through A loans from IFC and African Development Bank, and a commercial tranche from ABSA Capital of South Africa. The overall levelized tariff is based on an internationally competitively bid price of US 22.2c/kW (inclusive of all anticipated energy, capacity, operational and fuel costs), and will be payable in Euros. TPL expects to execute its Engineering, Procurement and Construction (EPC) contract with a consortium consisting of Man Diesel and Turbo SE of Germany and Melec PowerGen Services, an affiliate of Matelec Group of the Lebanon. MAN is also expected to provide Operations and Maintenance (O&M) services for an intial term of six years with the support of local staff contracted by the company. MAN Deisel is the market leader for large diesel engines for use in power stations. TPL has already commenced construction and expects to commission the sub-project in the 12 months following anticipated Financial Closure in March 2012. (See Annex 2 & Annex 3 for more details on the sub-project).

[19] IDA "allocation" refers to the amount of the PRG that counts against Kenya's IDA allocation.

30. Sub-project 2: Triumph Power Plant (Total Cost US$157 million, IDA PRG US$45 million, IDA allocation of US$11.25 million).

The sub-project will support the construction of an 82 MW Medium Speed HFO plant, at Kitengela near the Athi River, approximately 25 km from Nairobi. The project will be developed by Triumph Power Generating Company (TPGC), a special purpose company that has been set up in Kenya by BoardHoldings Ltd. (UK) a family owned company whose principal shareholder is Abdirahman Haji Abass, a Kenyan national. BoardHoldings will own 40% of the company, with the majority of the balance of the shareholding to be held by other family-owned companies such as Tecaflex Ltd., Interpel Investments Ltd and Southern Intertrade Ltd. Tecaflex is a leading distributor of petroleum products, automotive and consumer products while Interpel Investments is one of the leading Container Freight Stations in East and Central Africa.

The total project cost is expected to be around US$157 million, which will be structured on a limited recourse basis with a debt equity ratio of 75:25 amounting to around US$118 million in debt and around US$39 million in equity. Standard Bank of South Africa is expected to underwrite the entire debt financing of the sub-project, which is expected to achieve Financial Closure in June 2012 and be commissioned thirteen months thereafter. The overall tariff of the sub-project is based on the internationally competitively bid price of US 23c/kW (inclusive of all anticipated energy, capacity, operational and fuel costs) and will be payable in Euros.

TPGC expects to execute the EPC contract with XJ International Engineering Corporation, part of the XJ Group of China which is one of China's largest manufacturers of power equipment and transmission and distribution technologies for the electric utility market and is owned by the State Grid Corporation which provides power to approximately 88% of China. The Group operates power facilities in 30 countries globally including Equatorial Guinea, Congo, and Ethiopia. The XJ Group will also be responsible for O&M of the plant for the initial five years of operation (See Annex 3 & Annex 4 for more details on the sub-project).

31. Sub-project 3: Gulf Power Plant (Total Cost US$108 million equivalent, IDA PRG US$35 million and Euro 7 million, IDA allocation of US$11.25 million equivalent).

The sub-project will support the construction of an 80.3 MW single cycle, Medium Speed HFO plant, on land adjacent to Highway A109 connecting Nairobi to Mombasa at Athi River Town, approximately 35 km from Nairobi. The project will be developed by Gulf Power Ltd, which is incorporated in Kenya. Gulf Power Ltd has the following shareholding: Gulf Energy Ltd. (50 percent), Multiple Hauliers Ltd. (30 percent), Noora Power (10 percent), and the shareholder accounting for the remaining 10 percent will be identified soon. GPL's principal shareholder, Gulf Energy Ltd. is an oil and gas trading company with operations in the East Africa Region.

The total sub-project cost is expected to be equivalent to about US$108 million. The financing which will be structured on a limited recourse basis consisting of 25 percent equity amounting to US$27 million equivalent and the balance of the debt financing consisting of 5 percent in subordinated debt through an IFC C loan amounting to US$5 million equivalent, an IFC A loan for US$22 million equivalent, and commercial financing for US$54 million equivalent from Standard Bank split between an IFC B loan tranche and a parallel loan. The sub-project is expected to achieve Financial Closure in June-July 2012 and be commissioned a year later. The overall tariff of the sub-project is based on the internationally competitively bid price of US$

23.5 cent/kW (inclusive of all anticipated energy, capacity, operational and fuel costs), and is payable in Euros. (See Annex 2 & Annex 3 for more details on the sub-project).

GPL has selected Wartsila Finland Oy as its EPC contractor and Wartsila East Africa Ltd. as its O&M contractor for a period of ten years. Wartsila has extensive experience as an engine supplier, as EPC contractor, and as supplier of O&M Services, both in Africa and worldwide.

32. <u>Sub-project 4: Olkaria III Geothermal Plant 2 Expansion Project</u> (Total Cost US$212 million, IDA PRG US$26 million to be subsequently increased to US$31 million for the option to add Plant 3 (see (b) below).

(a) This sub-project will initially involve combining a 36 MW expansion with an existing 48 MW base-load geothermal power plant ("Plant 1") at the Olkaria Geothermal fields increasing it to a total installed capacity of 84 MW. This will involve the additional development of the geothermal field, and modification of the existing plant and integration of the new Plant. The sub-project is located within Hell's Gate National Park in the Kenyan Rift Valley 90 kilometers northwest of Nairobi and was awarded to OrPower 4 Inc. (OrPower) following an internationally competitive bidding process on a Build Own Operate (BOO) basis. OrPower 4 ("OrPower"), is registered in the Cayman Islands and is owned by Ormat International Inc. ("Ormat") and Ormat Technologies (USA).

The existing facility, which has been operating successfully since 2009, consists of an electrical power generation complex, a geothermal energy production field, a geothermal gathering piping system, a geothermal condensate re-injection system and a 48 MW power plant which was undertaken in two phases. The existing facility was underpinned by a 20 year PPA concluded with KPLC in 1998 which provides for capacity and energy payments in US Dollars. In March 2011, KPLC and Orpower 4 entered into the second Amended and Restated PPA to expand the complex by up to 52 MW to be undertaken in two phases. The first phase will comprise of 36 MW Plant 2 and the second an optional phase, will increase the total aggregate capacity to 100 MW (see (b) below). Plant 2 is expected to be commissioned by April 2013.

The total cost of the expansion of Plant 2 will be around US$212 million, which will be funded by around US$31 million of new equity injection, through a US$165 million loan from Overseas Private Insurance Corporation (OPIC), and the balance through internal cash-flow. The expansion will initially be funded by Ormat's equity, which will be partly refinanced by a debt facility currently being negotiated with OPIC. Part of the OPIC debt facility will be used to refinance the debt on the existing facility. MIGA recently obtained Board approval for Transfer Restriction, Expropriation and War and Civil Disturbance coverage for Ormat's equity for the existing facility as well as for the expansion for a total amount of US$134 million. Ormat does not expect to obtain additional termination cover from MIGA as it is not an OPIC requirement.

The existing geothermal facilities and the US$212 million geothermal expansion are being considered as an integrated operation for the purposes of this sub-project and covered by the IDA PRG as such for the following reasons: (i) The expansion will involve the modification and integration of the existing plant with the new plant, as well as the drilling of the additional wells to support both the plants on the same site; (ii) some of the fixed costs associated with the existing Facility will help support the expansion and this efficiency is reflected in only a marginal increase in the levelized tariff of US$10.8 cent/kW for Plant 2 payable in US dollars (compared with a tariff under the 2008 PPA for the existing Facility of US$ 9.7 cent/kWh); and (iii) the existing Facility and the expansion are sole activities of Orpower 4, governed by the same PPA and managed by the same operating team. (See Annex 2 & Annex 3 for more details on the sub-project).

(b) A further expansion of a 16 MW plant ("Plant 3") is envisaged at the same site for which Ormat has an option that is to be exercised by September 2015. If this option is exercised, the addition of the 16 MW plant ("Plant 3") will increase the total aggregate geothermal capacity at Olkaria III to 100 MW. Following the completion of Plant 2, OrPower will assess the stability of the reservoir and will determine if Plant 3 can be sustained by the geothermal reservoir. The addition of Plant 3 and expansion of Olkaria III to a 100 MW geothermal facility will be considered as a further expansion of the sub-project for which PRG approval for US$5 million is being sought. Approval from the Board is sought at this time for the proposed processing procedure (described in para. 40 in the Section on Lending Instrument) for the US$5 million IDA PRG for the option to add Plant 3 to the integrated geothermal Olkaria III facility.

C. Project Cost and Financing

33. The overall cost of the proposed Project is expected to be around US$623 million equivalent with equity of US$149 million equivalent to be funded by private project sponsors from their own resources. The sponsors of the thermal IPPs are either local investors or originate from other emerging markets, thereby promoting South-South cooperation. OrPower is expected to fund its equity partly from Ormat group resources and partly from internally generated cash-flow. The total debt financing is expected to amount to the equivalent of US$474 million which will be mobilized through IFC A, B, and C loans amounting to around US$90 million, commercial loans of around US$208 million (including the IFC B loan of US$27 million equivalent) from commercial lenders such as ABSA and Standard Bank (both of South Africa) with the balance of US$202 million from DFIs such as OPIC and African Development Bank (see Table 6 below). The proposed Project will include the first IPPs in Kenya to attract commercial finance as all the thermal sub-projects are expected to have tranches of commercial debt, thereby establishing a track record for long-term Kenyan IPP risk in the market.

Table 6: Proposed Financing Plan (US$ million)

	Equity	Equity %	Debt	Total Debt %	Total	PRG
Thika Plant*	36	25	110	75	146	45**
Triumph Plant	39	25	118	75	157	45
Gulf Plant*	27	25	81	75	108	45**
Olkaria III***	47	22	165	78	212	4 (a) 26 4 (b) 5***
Total	149		474		623	166

* The original project cost for Thika and Gulf IPP are in Euros.
** The PRG amounts for Thika and Gulf are given in US dollar equivalent.
*** PRG amount for Olkaria III Plant 2 is US$26 million, which will be increased to US$31 million following exercise of the option for Plant 3.

Risk Allocation

34. The contractual structure of the transaction and the allocation of the commercial, technical, and political risks among the relevant parties are consistent with industry standards for limited recourse project financing. As is customary in project finance transactions, risks are allocated to the party best able to mitigate them. The allocation of key risks among the sponsors, lenders, KPLC, GoK, are summarized in Table 7 below as well as the risks that are expected to be backed by the IDA PRGs and MIGA guarantees. The sponsors and lenders will assume the pre-construction, construction and operations risks which will be mitigated through securing fixed price, turnkey contracts and O&M contracts with reputable companies. In addition, the thermal IPPs are expected to assume natural force majeure risks, which can be mitigated through insurance, as well as the convertibility and transferability risk, which generally is assumed by Governments. However, the latter risk will be mitigated by the fact that KPLC's payment obligations will be in foreign currency.

35. The security package for the proposed sub-projects is expected to provide the lenders with security interests in all the assets of the project companies, including plant and machinery, inventory and receivables, assignment of or a charge over the project's on-shore and off-shore accounts as well as a first ranking share pledge over the shares of the Project companies. The Lenders will also receive an assignment of each of the project companies' benefits under all material project documentation such as the PPA, GoK Letter of Support, EPC and O&M contracts. In addition the Lenders will enter into Direct Agreements with KPLC for the enforceability of their security.

36. Under the PPA, each IPP will undertake to make available power capacity to KPLC and sell electrical outputs. KPLC, in turn, has 'take or pay' obligations to make capacity payments for contracted capacity up to a maximum available plant capacity of 85% (which will be charged on the basis of the available capacity of the plant irrespective of the amount of power actually dispatched), as well as energy and fuel charges for power that is dispatched and delivered.

37. Force Majeure (FM) risks[20] are allocated between the IPPs, KPLC and GoK through the PPA and the GoK Letter of Support. In the event of a FM that impairs KPLC's ability to dispatch electricity from a thermal IPP or impairs the thermal IPP's ability to deliver electricity, then KPLC would only be obligated to make capacity payments to the extent that there is remaining capacity available, along with energy and fuel charges for the electricity delivered. Therefore, while the IPP would not receive full capacity payments under the PPA in the event of FM, these risks are partially mitigated because the GoK would assume the risk of the Political Event under its Letter of Support. Political Event could include political FM event affecting the IPP and political and natural FM event affecting KPLC. In particular, if KPLC is unable to make ongoing payment obligations under the PPA due to natural and political FM events that affect its funding availability ("KPLC Funding FM Event"), then the IPP could seek payments from GoK. For any other Political Event, the IPP can exercise its right under the GoK Letter of Support to seek compensation for the shortfall of payments (such as capacity payments for the unavailable plant), which the IPP would have received under the PPA had the Political Event not occurred.

[20] FM risks may be either political FM events such as war, change in law, expropriation, civil commotion or natural FM events such as act of god.

GoK is also responsible for termination amount under its Letter of Support in the event that the PPA is terminated due to a Political Event.[21]

38. FM risks are allocated slightly differently in the case of the geothermal sub-project due to differences in the nature of this plant from the thermal sub-projects.[22] In the case of Olkaria III, KPLC's ongoing payment obligations include payments for capacity during FM events, even if the plant is unavailable (although with some adjustment to payment amounts in certain cases). However, Olkaria III's PPA does not have provisions for a KPLC Funding FM Event and therefore GoK does not cover this risk under its Letter of Support.

39. IDA PRGs will back KPLC's ongoing payment obligations only (excluding termination payments) under the PPA and GoK's ongoing payment obligation under its Letter of Support (see paras. 45-47 below). MIGA will provide termination cover for KPLC's Breach under PPA and 'Political Events' under GoK Letter of Support.

Table 7: IPP Risk Matrix and IDA and MIGA Risk Mitigation

Phase	**Risks/Obligation**	**Contractual Responsibility**			**Risk Mitigation**	
		IPPs & Lenders	KPLC	GoK	PRG	MIGA
Pre-Construction	Site		X			
	Plant design	X				
	Debt & Equity Financing	X				
Construction Period	Cost overruns	X				
	Construction delays	X				
Operation	Operation & Maintenance	X				
	Power Capacity Availability	X				
	Output Quality Specifications	X				
	Fuel Supply and Maintenance of security stock	X				
	Fuel Price Changes		X			
Concession Term	KPLC System Availability		X		X	
	Payment of Energy and Capacity Payments and Fuel charge		X	X	X*	
	Force Majeure Events affecting KPLC		X	X	X****	
	Currency devaluation		X			
	Currency, Convertibility, Transferability	X				
	***Political Event (ongoing obligation)			X		
	Other Force Majeure Events	X**				
	Termination Payment due to KPLC		X			X

[21] This paragraph includes a discussion of allocation of risks between IPPs, KPLC and GoK, without reference to coverage from IDA and MIGA under the WBG risk mitigation package (covered in paras. 39 and 45-47 below).
[22] For Olkaria, KPLC assumes the natural force majeure risks as the geothermal facility includes the geothermal wells which are government assets. In addition, the Olkaria PPA was originally entered into in 1998 and since then, KPLC has allocated more risk to the IPPs.

Phase	Risks/Obligation	Contractual Responsibility			Risk Mitigation	
		IPPs & Lenders	KPLC	GoK	PRG	MIGA
	Default					
	Termination Payment due to ***Political Event			X		X

* For only 3 or 4 months of capacity and energy payments and 2 months of fuel payments plus contingencies.
** For Olkaria this risk will partially be borne by KPLC and IDA.
*** Political Event may include War and Civil Disturbance, Expropriation, Changes in Law, Regulation, Taxes and Licensing Arrangements.
**** KPLC Funding FM Event only for the three thermals.

D. Lending Instrument

40. It is proposed that the Project support a series of PRGs in an aggregate amount equivalent to US$166 million (involving an IDA allocation equivalent of US$41.5 million). IDA is expected to provide PRGs for a maximum amount of US$45 million equivalent supporting three months of energy and capacity payments and two months of fuel payments plus contingencies for each of the three thermal IPPs. The scope of PRG coverage for the thermal IPPs is detailed in the Term sheets in Annex 12 and is essentially the same for the three thermal IPPs. PRG support for the Thika Power and Gulf Power IPPs will be provided in US Dollars and Euros, while PRG support for Triumph Power will be in US dollars only.

41. In addition, PRG coverage is expected to be provided for a maximum amount of US$31 million for the Olkaria III geothermal expansion equivalent to four months of capacity and energy payments plus contingencies. This amount includes US$26 million for the proposed Plant 2 expansion, as well as US$5 million for the further Plant 3 expansion to be undertaken once OrPower exercises its option by September 2015 at the latest. Once the option is exercised and IDA completes its due diligence, then RVP and Board approval will be sought on an ‘Absence of Objection’ basis. The scope of coverage for Olkaria III is slightly different from the PRG coverage of the thermal IPPs as detailed in OrPower Term Sheet (Annex 12). Like Triumph, PRG support for Olkaria III will be provided in US dollars only. The scope of PRG coverage for the Plant 3 option will be the same as the terms detailed in the Olkaria Term Sheet (Annex 12).

Partial Risk Guarantee Structure

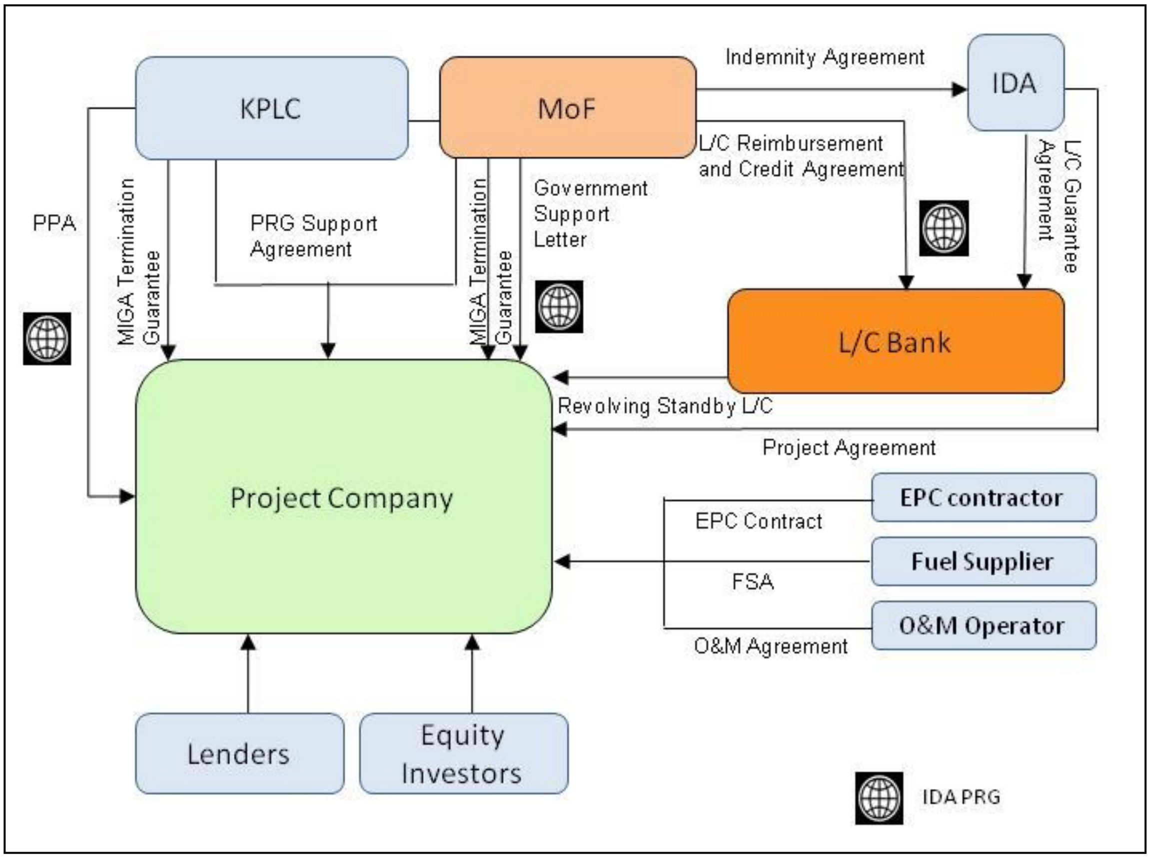
42. Under the proposed structure, IDA PRGs will backstop a Revolving Standby Letter of Credit (L/C) issued by a commercial bank on behalf of KPLC for each IPP as payment security for certain ongoing payment obligations of KPLC under its PPA and of GoK under its Letter of Support. Each PRG will backstop the debt obligation of KPLC and GoK, as applicable, to the commercial bank for any amounts drawn by an IPP under the L/C as a result of a breach by KPLC or GoK of its payment obligations. Each L/C is expected to be for a maximum term of around 15 years and 180 days from effectivness of each PRG to match the underlying financing term of the sub-projects and would be available for drawings from the Commissioning of the sub-projects. The actual amount made available for drawing under the L/C, would be determined annually within the maximum PRG amounts and would be with respect only to risks being covered by the PRG.

43. In the event of a failure by KPLC to make timely payments under the PPA, subject to certain grace periods, the IPP will be authorized to make a drawdown for the unpaid amounts under the L/C. The PRG would also backstop the GoK Letter of Support enabling each thermal IPP to draw under the L/C in the event of a failure by GoK to make the monthly payments payable by KPLC, but not paid due to the occurrence of a KPLC Funding FM Event. Following a drawing, depending on the reason for the breach, KPLC or GoK, will be obligated under a Reimbursement and Credit Agreement (to be entered into between KPLC, GoK, and the L/C bank) to make a repayment to the L/C bank for the amounts drawn (plus accrued interest) within a period of one year. If KPLC or GoK make the repayments within the one year period to the L/C bank for the amounts drawn, the L/C would be reinstated for the amounts repaid by KPLC or GoK. If KPLC or GoK should fail to repay the L/C bank within the one-year period, the L/C bank would have recourse to the PRG for the drawn amounts, plus any accrued interest, under the Guarantee Agreement, to be concluded between the L/C bank and IDA.[23] In such an event, the maximum L/C amount would be permanently reduced by the amount of payment made by IDA under the PRG. In the event of disputes, the IPP would be able to access the L/C for the disputed amounts only once the dispute has been resolved in its favor.

44. A guarantee payment under the PRG would trigger the obligation of Kenya to repay IDA in accordance with the terms of the Indemnity Agreement to be concluded between IDA and Kenya. The Indemnity Agreement will require Kenya to repay IDA on demand or as IDA may otherwise direct. Each PRG would be for a maximum term of up to 17 years from the effectiveness of each PRG, comprising the L/C term of around 15 years and 180 days, plus KPLC's one year repayment period plus the 60 day IDA claim period within which IDA would be obligated to pay the L/C bank following a call on the PRG. Each PRG would be priced at 75 basis points per annum on the annual guaranteed amount and would be payable six monthly in advance from the commissioning date of the sub-projects. No Standby Fee would be applicable as currently there is no Commitment Fee charged for IDA. In addition, there would be an Initiation Fee of 15 basis points or US$100,000, whichever is higher, and a Processing Fee capped at 50 basis points, of the guaranteed amount for reimbursable expenses for each sub-project. All PRG-related fees indicated would be payable by the project company and are consistent with the pricing policy of IDA guarantees. The terms and conditions of the PRGs for the four IPPs are expected to be essentially similar and are summarized in the Term Sheets in Annex 12. The project contractual structure and WBG risk mitigation structure is given below.

[23] In keeping with IDA Guarantee Policy of backstopping contractual obligations of government or governmental agencies, it is proposed that if KPLC ceases to be controlled by GOK, the IDA PRGs would be terminated unless GOK assumes KPLC's obligations under the IDA PRG Support Agreement and the L/C Reimbursement and Credit Agreement.

Figure 2: Project Contractual Structure and WBG Risk Mitigation Structure



Scope of PRG Risk Coverage

45. For the thermal IPPs, the proposed PRGs will cover only the risk of non-payment by KPLC capped at a maximum amount equivalent to three months of capacity and energy payments and two months of fuel payments plus contingencies. The PRGs will also backstop GoK's support for KPLC's payments under its Letter of Support in the event of a KPLC Force Majeure ("FM") Funding Event but within the same maximum amounts. However, the PRG will not back any compensation payable by GoK to the IPP for 'Political Events' affecting the IPP. For Olkaria, the PRG would cover KPLC's non-payment risk up to a maximum amount of four months of capacity and energy payments for the integrated facility (including the existing plant) for its ongoing payment obligations, including in the event of a political and natural force majeure events affecting OrPower, but excluding cover for the GoK Letter of Support.

46. For Olkaria III, KPLC has currently issued L/Cs to Olkaria up to March 2012 which are expected to be replaced by a PRG backed L/C both for the existing facility and for the expansion. The PRG coverage would exclude payments payable to the IPPs upon termination, following a breach by KPLC under the PPA or by GoK under its Letter of Support, which would be covered by MIGA.

47. KPLC has a strong track record of timely payments to IPPs over the last 12 year period. Since its financial restructuring in 2004, KPLC has been able to increase its profitability, improve its operational performance, and maintain a healthy financial position. Consequently, coverage of payment risk of KPLC is considered a manageable risk for IDA. There would be additional protection for the PRGs from the fact that KPLC enjoys cost reflective tariffs and each of the PPA concluded with the proposed IPPs has received the Electricity Regulator's approval and the assurance that KPLC will be able to reflect the IPP tariff in their retail tariff. Furthermore, KPLC and GoK are expected to undertake in the PRG Support Agreement (to be concluded between KPLC, GoK, and each IPP) to maintain at all times the equivalent balance of one month's capacity, energy and fuel payments in the L/Cs, thereby minimizing the risk of a call on the PRGs. As noted in para. 43 above, the PRG cannot be called until 12 months after an L/C drawing triggered by a KPLC or GoK breach which should give IDA ample time to work with and help ensure that KPLC or GoK, as the case may be, makes the necessary repayment to the L/C bank in a timely manner to avoid a call on the PRG. Should the funds in the L/C be exhausted prior to the 12 month period, then it will be the investors and the lenders who will bear the 'first loss' risk for a period of nine months before there could be a potential call on the PRG. Commercial risks, construction risks and operation risks will be assumed by the investors and the lenders in accordance with industry practice (see Table 7 above).

Value Added of the PRGs

48. The proposed risk mitigation package of PRG-backed revolving standby L/C structure with complementary MIGA termination Guarantees will enable Kenya to add almost 300 MW of urgently needed power generation capacity over a short time-frame. This generation capacity otherwise may not have been financeable because of Kenya's fiscal constraints and the perception of lenders regarding country risks. WBG's proposed risk mitigation package will help to substantially reduce contingent liabilities for Kenya as it will limit the provision of sovereign guarantees to counter-guarantees in support of PRGs to only (US$166 million) instead of the provision of sovereign guarantees for the entire payment flows due from KPLC to the IPPs under the PPA (estimated at US$4.3 billion), which would otherwise have been required by lenders and investors.

49. The proposed structure provides for efficient risk allocation between IDA and MIGA as their complementary coverage will be in support of different components of the underlying financing for different elements of the risk. IDA's limited payment support through the revolving L/C structure will help to ensure that there is pre-allocated pool of liquidity to help sustain the sub-projects in the event of any unforeseen interruptions in KPLC payments. At the same time, IDA's upfront support will strategically position IDA to work with KPLC and GoK to help ensure that remedial action is taken during the 12 month repayment period afforded to KPLC and GoK under the structure. This form of IDA's intermediation is expected to provide sufficient comfort to both lenders and investors to enable IDA to minimize its support and help make the operation bankable with MIGA's termination cover. This is the minimum level of support provided by IDA for any IPP project to date, thereby enabling IDA to leverage its scarce resources and Kenya's country allocation. With its minimal credit enhancement of US$166 million, IDA expects to mobilize US$623 million of financing under difficult market conditions, including US$357 million in private investments and commercial lending. This amount includes around US$208 million of long-term commercial financing support being offered to IPPs for the first time in Kenya.

50. Since the PRGs would be booked by the L/C banks against IDA limits and not against KPLC borrowing limits, an additional advantage to KPLC of the PRG L/C structure is that it will obviate the need for KPLC to arrange for the issuance of L/Cs which would be required by the investors and lenders if the PRG backed L/Cs were not being offered as part of the security package. Any issuance of stand-alone L/Cs from KPLC could require them to deposit 100 percent cash as collateral with banks, thereby diverting scarce KPLC resources from their investment projects.

E. Lessons Learned and Reflected in the Project Design

51. Lessons from outside Kenya incorporated in the Project design include the Bank's worldwide experience with IPP projects, in particular project experience in Pakistan, Jordan, Bangladesh and Cote d'Ivoire. The PRG for two of these IPP projects, Azito in Cote d'Ivoire and Uch Power Project in Pakistan have been successfully concluded without any instances of default or a call on the PRG while the PRG on the Bangladesh IPP is close to expiry. The project design for this Project not only incorporates the 'best practice' experience from these projects but further builds on this experience through the harmonization of the risk mitigation package and minimizing support to the extent appropriate for Kenya, given its relatively creditworthy energy institutions. The offer of a harmonized risk mitigation package by IDA under this project will help GoK offer a tested credit enhancement framework to attract investors.

IV. IMPLEMENTATION

A. Institutional and Implementation Arrangements

52. All four sub-projects will be implemented by special purpose companies who will have overall responsibility for the design, finance, supply, erection, commissioning, operation, and maintenance of the plant for the duration of the PPAs. Each Project Company will set up an appropriate management structure to undertake its respective projects.

53. **Thika Power Plant** will be implemented by Thika Power Ltd. which will be managed, controlled and operated by Melec PowerGen (MPG) a Holding Company incorporated in the British Virgin Islands and affiliated with the Matelec Group. MPG through Matelec, is part of the Doumet Group, and is the dedicated Group affiliate in charge of implementing power projects either on the basis of EPC contracts or O&M Services. MPG has already successfully completed and is operating the Kounoume power plant in Senegal and is expected to use many of its staff involved in that project to oversee the implementation of this sub-project. The construction of the plant will be undertaken by a Consortium consisting of MPG Services S.A.L., a subsidiary of Melec Power Gen and MAN Diesel & Turbo SE of Germany on the basis of a fixed price, turnkey contract. MAN Diesel is a leading manufacturer of diesel engines with expertise in the design and supply of equipment as well as in commissioning and supervision of plant operation and maintenance. The MAN 18V48/60 engine is a proven and reliable design that can be expected to operate safely and reliably and have been in service since 1989. MPG has already commenced construction and has entered into an O&M contracts with MAN for O&M services and spare parts for a term of six years. This will provide for MAN resident supervisors for planned or unplanned maintenance supervision and supply of parts (see more details in Annex 3).

54. **Triumph Power Plant** is the first power project being developed by Triumph Power Generating Company (TPGC). The sponsors have hired Mentor Consulting and a local Consultant as Owner's Engineer to help them implement the sub-project. Mentor Consulting of South Africa, consisting of a team of multi-disciplinary engineers that provides varied services into the industrial, manufacturing, and thermal engineering sectors, will partner with a local consultant to help the Company implement the Project. The local Consultant has considerable experience in the Kenya power sector and management of existing IPPs such as the Kipevu thermal plant and the Lamu diesel plant. Mr. Abdirahman Haji Abass, the principal shareholder of the project company, will be Chairman while all the other management positions are expected to be filled externally by professional experts. Construction of the plant will be undertaken through a fixed price, turnkey, Engineering, Procurement, and Construction contract (EPC) with the XJ International Engineering Corporation, part of the XJ Group of China, a subsidiary of State Grid Corporation of China, the world's largest utility. The XJ Group will also be responsible for the operation and maintenance of the plant for the initial five years of operation (see more details in Annex 3).

55. **Gulf Power Plant** will be implemented by Gulf Power Ltd. (GPL), which is making its entry into the power business. GPL has appointed a team of financial, technical, and legal advisers to support the company up to Financial Closure. Following Financial Closure, the company will be managed, controlled, and operated by a seven-member Board of Directors consisting of three directors from Gulf Energy Ltd, two from Multiple Hauliers Ltd. and one Director each from Noora Power Ltd. and the a new shareholder to be named. The Chief Executive Officer and the Chief Financial Officer of the company will be nominees of GPL appointed with the approval of the Board of Directors. It is contemplated that a senior professional with power generating experience will be brought on board either as Chief Operating Officer/General Manager. The company will be supported by OMS Solutions Ltd. as the Owner's Engineer during the development and construction phases of the project. OMS has extensive experience worldwide in this field and are expected to help the company ensure that the EPC contract execution complies with EPC contract requirements as well as with the technical interface relating to other Agreements. GPL has selected Wartsila Finland Oy as its EPC Contractor and Wartsila East Africa Ltd. as the O&M Contractor for a term of ten years. Wartsila has extensive experience as an engine supplier, as an EPC Contractor, and as supplier of O&M services both worldwide and in Africa (see more details in Annex 3).

56. **Olkaria III Geothermal Expansion** is being developed by OrPower 4 Inc., a special purpose company incorporated in the Cayman Islands, which was set up to develop, own, construct, and operate the Olkaria III project. It was established in October 1997 and its activities are solely devoted to the project which has been operating for 15 years. OrPower expects to enter into 'arms length' fixed price, turnkey contracts with its Group companies for the construction and maintenance of the expansion facility. It will enter into a Supply Contract with Ormat Systems Ltd. for the design of the power plant and for the supply of materials and equipment which will be backed by performance guarantees. In addition it will enter into a Pricing, Coordination and Security contract with another Group company, ORDA 6, under which it will guarantee the plant cost and any overruns for the supply, transportation and construction works. Orpower 4 will itself carry out the drilling and other development activities of the geothermal field required to support the expansion facility. The drilling program has already commenced and the onsite construction of the additional generating facility and the geothermal

piping will follow. The electricity transmission connector from Orpower 4 substation to KPLC switchyard which was completed in 2008 has been determined by KPLC as of sufficient capacity to accommodate the planned expansion (see more details in Annex 3).

57. **KPLC** is responsible for (i) facilitating coordination among all relevant institutions so that transaction and implementation costs can be minimized through streamlined arrangements, and (ii) serving as a single-point tracking of all project outcomes, accounts and safeguard compliance. Coordination and monitoring of implementation of the four IPPs will be carried out by the Energy Transmission Division of KPLC through the various Departments within the Division. The Chief Manager, Energy Transmission is the responsible manager reporting to the Managing Director. During the construction phase KPLC will receive a monthly report showing the extent to which each material task in the Construction Programme has been completed and the expected completion date for each outstanding task. These reports will be received and reviewed by KPLC's Energy Purchase Department in the Energy Transmission Division of KPLC. KPLC will facilitate connection of the Plants to the network and dispatch the Plants as required for the purposes of testing and commissioning. An independent engineer will issue certification on completion of commissioning. Key coordination and monitoring activities are detailed in Annex 3.

B. Results Monitoring and Evaluation

58. **Overall monitoring of Project outcomes and result indicators will be done by KPLC (and KETRACO, where relevant).** Data for monitoring project outcomes and results indicators will be generated by the IPPs in regular progress reports as well as by Lenders' Independent Engineer during the construction phase. IDA will monitor and supervise through the submission of reports by the IPPs required under IDA's Project Agreement with each IPP and submission of relevant reports by KPLC required under IDA's Indemnity Agreement with GoK as well as through regular field visits until the expiry of each PRG. Annex 1 presents the Project's Results Framework that defines specific outcomes and results to be monitored.

C. Sustainability

59. **The proposed Project is critical to meet the strong and growing demand for reliable electricity in Kenya.** Review of the demand/capacity balance of the public electricity system has determined that the additional generating capacity provided by the four proposed IPPs when commissioned in 2012 is essential to providing much needed short term generation to sustain economic growth and to maintaining acceptable reserve margins on the Kenyan power system. The importance of the IPPs to the sector is understood in context of anticipated future generation from renewable sources and, more broadly, the opportunities for import and export of power provided through power trading in the EAPP.

60. **The political economy of continued electricity shortfalls and the prohibitive economic and financial costs to Kenya of foregoing power generated from these sub-projects is an important mitigant for sustainability risk.** The economic cost (loss of output and productivity) of electricity demand that is un-served at system peak is estimated to be between US$1.0 cents and US$1.5 cents per kWh. By eliminating peak load shedding, the proposed plants will reduce this economic cost. The proposed more efficient Medium Speed

Diesel sub-projects will generate savings estimated by displacing the need for the existing emergency and high speed diesel units. Fuel consumption (grams per kWh) is about 12% higher in the existing plants than in the proposed plants. Without the four IPPs, the Kenya electricity grid system reserve margin would fall to zero in 2012. The system would not be able to meet demand with resulting significant load-shedding.

61. **The four proposed IPPs will ensure system stability by providing reserve margin approaching 20% from when they are commissioned until 2016/2017.** In their absence, the reserve margin in these years would disappear and a scheduled program of load shedding would be inevitable in these years as the available effective capacity would not be able to meet demand. In addition, the proposed integration of wind, an important but inherently intermittent resource, will require a spinning reserve system to obtain much-needed grid stability. The proposed sub-projects, along with hydro, will provide this reserve for system stability and will enable the development of wind resources for the grid.

62. **The sector's well-designed regulatory structure and KPLC's strong financial performance, track record and outlook support sustainability.** The electricity sector in Kenya is to a large extent financially self-sustainable due to sound regulatory policies that are applied to the terms of power purchase agreements between power generators and KPLC as well as to the design of the retail tariffs charged by KPLC. In particular, the retail tariff design provides an incentive to KPLC to make efficiency gains while at the same time passing through key cost elements beyond the control of KPLC (such as fuel costs, inflation and foreign exchange fluctuation) to consumers.

63. **KPLC's financial performance has been sound since its financial restructuring in FY2004**.[24] The company has been able to steadily improve profitability, improve operational performance (technical loss reduction, improved billing and collection, etc.), expand its customer base and maintain a healthy financial position, and it has not defaulted on any of its PPA commitments. The financial forecast under a base-case scenario shows that KPLC's operations, capital adequacy, and liquidity are expected to be sustained. KPLC will remain profitable despite taking on increased debt to finance power system expansion. Projected profitability ratios of KPLC are lower in some years but they are still expected to maintain levels comparable to utilities in higher income countries. Even though the company will be leveraged with the increased proportion of debt, its debt service coverage ratio is expected to stay above 1.3 assuming terms of borrowing will increasingly become commercial terms. KPLC's balance sheet reflects a healthy financial position, with equity financing of about 40 percent of its total assets at the end of FY2009. The regular financial reporting that is required of KPLC (it has currently 49.9 percent private shareholding) ensures that its operations and investment decisions are scrutinized by investors, bringing additional transparency to its financial performance.

64. **There is strong stakeholder support for increasing Kenya's energy security and resilience, continued sector reform and the IPP Program.** Kenya's fuel sources for electricity generation have historically been concentrated in hydropower, which accounts for just over half of the current generation portfolio. The main source of hydropower is found in only one

[24] KPLC incurred losses from 1999 until 2003 due in large part to the tariff setting formula at the time that did not allow fuel cost pass-through as well as the impact of drought conditions that reduced its sales and increased its costs at a time when its losses were also quite high.

catchment area, leaving more than 50 percent of KenGen's supply exposed to concentration risk associated with poor hydrology, including vagaries of weather fluctuations. This vulnerability was made especially clear to major stakeholders recently when extreme drought meant that hydro capacity was halved for part of 2009. Moreover, the drought drastically reduced KPLC's revenues and impaired its ability to invest in replacement assets as well as extend the power grid to serve new communities. The proposed project will help increase Kenya's energy security and resilience to climate variability by reducing the economic and financial impacts of Kenya's dependence on hydropower. The sector reform and the IPP Program enjoy strong support from the major parties in the current governing coalition, which provides comfort for continuity beyond the coming election cycle.

V. KEY RISKS AND MITIGATION MEASURES

A. Risk Ratings Summary Table

Stakeholder Risk	**Rating**
Implementing Agency Risk	
- Capacity (KPLC and IPPs)	Moderate
- Governance (IPPs)	Moderate
Project Risk	
- Design (Technical)	Moderate
- Social and Environmental	Moderate
- Program and Donor (Timely Financial Closure)	Moderate
- Delivery Monitoring and Sustainability	Moderate
Overall Implementation Risk	**Substantial**

B. Overall Risk Rating: Key risks and mitigation measures

65. A detailed ORAF has been prepared and is included as Annex 4. The overall risk of the operation is considered to be "Substantial" taking into account the country, sector and project risks.

66. **Political Risk:** Risk of instability after forthcoming elections. In the wake of widespread political violence in 2008, the country context has stabilized significantly. The next presidential and parliamentary elections are scheduled for the second half of 2012 with several safeguards being put into place, including international monitors and exit polls. Continued sector reform and the IPP Program enjoy strong support from the major parties in the current governing coalition, which provides comfort for continuity beyond the coming election cycle.

67. **Technical Risk:** Risk that sub-projects will not be implemented. This risk is mitigated by the fact that the proposed technologies for the three thermal IPPs follow international standards and practices for HFO plants. These are technically not complicated to implement, especially since experienced EPC and O&M contractors have been selected. Regarding the

Olkaria III expansion sub-project, the technical risk is also considered moderate since this will be the third extension of a successfully operating power plant. Phase 1 involved the construction of a 13 MW power plant, which subsequently was expanded to an aggregate capacity of 48 MW that was completed on time with no cost overrun and has been operating successfully since 2009.

68. **Timely Financial Closure Risk.** Risk that financing delays in a global financial crisis can delay the completion of the projects. Timely financing of the transactions rests upon several factors, including strong contractual arrangements. The risk of timely financial closure during a period of global financial crisis is partly mitigated by the strength of overall contractual arrangements, the support of KPLC and the GoK as well as credit enhancement offered by WBG risk mitigation instruments. Furthermore, a group of financial institutions comprising of IFC, African Development Bank, ABSA, and Standard Bank of South Africa have already committed to providing the necessary financing.

69. **Governance Risks.** Risk of perceived governance and integrity concerns for investment in Kenya. As noted in Section E of the Appraisal Summary below, the IPPs were selected through a competitive procurement process in accordance with the Bank's procurement guidelines requiring economy and efficiency. A transparent, competitive procurement process for the selection of private sponsors as well as the multiplicity and diversity of the selected EPC and O&M suppliers and vendors minimizes the risk of conflicts of interest as well as price collusion on contracts. Technologies to be deployed in the sub-projects are relatively standard and are priced within global benchmarks. The participation of private sponsors in implementation as well as the supervision of commercial lenders provides additional comfort. Finally, the Bank in coordination with IFC, commercial lenders and MIGA, has concluded with satisfaction its integrity due diligence related to sub-project sponsors and the proposed ownership of the Special Purpose Vehicles (SPVs).

70. **Regulatory Risks.** Risk that autonomous energy regulator may not continue to allow regulatory approval of fuel cost pass-throughs. ERC, the autonomous energy regulator, has always passed through fuel costs and made adjustments for inflation or currency changes. ERC has recently re-committed to take into consideration the calculation of base tariff for projects as and when they are commissioned. As noted above, continued sector reform and the IPP Program enjoy strong support from the major parties in the current governing coalition which provides comfort for continuity beyond the coming election cycle.

71. **Sustainability risk.** Risk that delayed payments for power supply by KPLC can make sub-projects unsustainable. KPLC is a strong, financially stable off-taker with a good track record of timely payments for delivered energy, thereby providing considerable comfort for the sustainability of the IPP transactions. In addition, the proposed PRG risk mitigation structure will provide for a pool of pre-allocated liquidity through the commercial bank L/C which, could help to sustain the project in the event of temporary payment problems experienced by KPLC.

72. **Supply-Demand Balance.** Risk that energy supply will exceed demand between 2017 and 2021 when the supply from cheaper regional hydros may reduce the need for full availability of the thermals. Generation shortfalls and demand-supply imbalances will likely continue for the next five years until 2017, when Kenya expects to import cheap, regional power. This time period coincides with the payback period of the investors for the sub-projects and, therefore,

timely financial closure (see above) will reduce financial risk for the sub-projects. Analysis suggests that electricity supply is likely to outstrip demand for only four years (2017-2021). This risk is partly mitigated because of the urgent need for sufficient system reserves of 20% or more for system stability. Along with hydro, firm generation from the thermals will help to provide some of the spinning reserves to enable integration of wind into the network. These requirements will comfortably assure sustained demand for at least 35 percent of generation capacity from the thermal IPPs at which capacity factor they would still be viable.[25] The availability of this energy provides a way for Kenya to enjoy the option of a certain level of energy security. The availability of this capacity also gives Kenya added value with the option to export firm energy to its neighbors with higher average retail tariffs (e.g. Rwanda) through regional power trading.

VI. **APPRAISAL SUMMARY**

A. Economic and Financial Analyses

Economic Analysis Summary

73. A review of the demand/capacity balance of the public electricity system determined that the additional generating capacity that the proposed IPPs will provide when they are commissioned are essential to ensure adequacy of supply, including the reserve margin. Without the generation from the IPPs, the system reserve margin would fall to zero in 2012. The system would not be able to meet demand with resulting significant load-shedding. The proposed IPPs will ensure system reserve margin approaching 20% from when they are commissioned until 2017 and enable projected demand to be met. In their absence, the reserve margin in these years would disappear and a scheduled program of load shedding would be inevitable in these years as the available effective capacity would not be able to meet demand.

74. The Least Cost Power Development Plan (LCPDP) of March 2011 was prepared by the Ministry of Energy and the Regulator (ERC) in cooperation with the power utilities. The candidate generating plants and technologies considered for the inclusion in the plan were: (a) oil-fired thermal -- medium and high-speed diesels; (b) geothermal; (c) hydro power; (d) wind; (e) co-generation -- combined heat and power; and (f) coal-fired steam. Comparative life-cycle cost analysis, based on the data used in the LCPDP to ensure consistency, shows the relative merits of the various feasible candidates considered for the LCPDP as shown in Table 8 below.

[25] In case of Thika Power Project, lenders have taken an even more conservative approach, assuming 32% availability over the three-to-four year period in question in which case the project still remains financially viable.

Table 8: Results of Screening Curve Analysis of Candidate Technologies in the LCPDP

Candidate Plant and Technology	Levelized cost of Energy (US cents/kWh) at 12% discount rate	Load Factor assumptions of the LCPDP
Base Load Candidates		
Geothermal	9.2	93%
Wind	12.2	40%
Hydro (Low Grand Falls)	14.1	60%
Coal	14.9	55%
Imports (Eastern Corridor Interconnector)	6.8	70%
Peak Load Candidates		
Gas Turbine Natural Gas	17.0	20%
Medium-Speed Diesel (Reciprocating diesel engine technology using Heavy Fuel Oil – the three proposed thermal IPPs)	24.1	28%
Emergency High Speed Diesel	32.1	20%

75. The comparative analysis in Table 8 above confirms that construction of the Eastern Corridor interconnector for imports of electricity and the construction of 280 MW at the Olkaria I and Olkaria IV power stations and the expansion of the Olkaria III to be priority projects for provision of base load capacity in the LCPDP. In the case of the proposed thermal IPPs (i.e. "Medium Speed Diesel" in the table above), they are the lowest cost option for peaking duty and can provide necessary system and spinning reserves. If natural gas would become available enabling their conversion from fuel oil, their cost would fall further. It is important to note however that following their commissioning until 2016-2017 when there will insufficient supply from geothermal and hydropower sources, the thermal IPPs will perform a base-load role during this period. The economic cost (loss of output and productivity) of electricity demand that is unserved at system peak is estimated to be between US$1.0 cents and US$1.5 cents per kWh. The proposed thermal IPPs will address this economic cost since they will perform peaking duty after 2016-2017.

76. The four proposed IPPs were economically evaluated based on the following methodological approach: First, the need for additional generating capacity was analyzed based on a forecast of electricity supply and demand. Second, the evaluation examined if the four IPPs provided the least-cost solution to generation expansion. Third, the evaluation conducted a cost/benefit analysis to determine the economic viability of the investments in the incremental generation capacity, measured by the EIRR. The economic analysis conducted of the four proposed IPPs results in a Base Case Economic Internal Rate of Return (EIRR) of 25 percent and Net Present Value (NPV) of US$288 million for the three thermal IPPs and of US$79 million and 18 percent for the Ormat IPP extension. The findings are summarized in Table 9 below.

Table 9: Results of EIRR Analysis for Generation Sub-Projects

Thermal IPPs Case	**Net Present Value (US$ million)**	**EIRR (%)**
Base Case (65% capacity factor)	288	25
Sensitivity case 1: Increase in cost of HFO of 30%.	19	13
Sensitivity case 2: Capacity factor decreases from annual average 35% to 25% from 2016-2017 onward.	191	22
Sensitivity case 3: Capacity factor decreases from annual average 35% to 25% from 2016-2017 onwards and HFO cost increases by 30%.	Negative (43)	10
Ormat Geothermal IPP		
Base Case	79	18
Sensitivity case: Capacity factor decreases from annual average 96% to 85% from 2016-2017 onward.	54	16

77. The proposed thermal IPPs (two of them utilize steam to make generation more efficient) will also generate savings in fuel use compared to the existing older thermal plants. Between 2012 and 2016-2017 they will displace high speed diesel units that would otherwise need to be contracted. These existing units use expensive middle distillate fuel. After 2016-2017, the new thermal IPPs will displace generation from the existing older IPPs whose specific fuel consumption (grams per kWh generated) is about 12% higher than the proposed plants. About 74 percent of KPLC sales are to commercial and industrial customers (2010-2011). The willingness to pay by these customers during evening hours when the thermal IPPs will mainly operate has been estimated at about US$0.30 cents per kWh. The willingness to pay by domestic customers was estimated to be close to the average tariff for these customers of US$ 0.15 cents per kWh (2010-2011). The economic value of the output of the thermal IPPs was therefore estimated at US$ 0.24 cents per kWh.

78. The economic analysis assumes that the thermal IPPs will be operated until 2016-2017 as baseload plants (65% capacity factor) and thereafter when alternative lower costs supply sources including geothermal, wind and imports are commissioned as intermediate and peaking plants (35% availability). The economic return of the three thermal IPPs in Table 9 above, is sensitive to cost of HFO and to their assumed capacity factor. The base case analysis assumes HFO cost of US$700 per metric ton. A combined 30% increase in cost of HFO and a decrease in the average capacity factor from 35% to 25% would cause the NPV to be negative and the EIRR to fall to 10%.

79. The Ormat IPP was analyzed separately from the three thermal IPPs. As it will also be operated as a baseload plant, its annual average capacity factor is not expected to vary markedly during the period of the PPA and because the economic value of its output is calculated differently to that of the thermal IPPs. The costs of the four IPPs consist of: (a) the capital costs of construction of the power stations and associated transmission infrastructure to connect the stations to national grid; and (b) fixed and variable costs of operation and maintenance. The benefits for the Ormat IPP that will be operated as a baseload plant is the net energy output valued at the estimated long run marginal costs of generation of US$0.16 cents per kWh.

Financial Analysis Summary of KPLC

80. Private power generation now has a generally good track record of 14 years of in Kenya. KPLC signed the first two PPAs with IPPs in 1997 with Westmont and Iberafrica. Of the six IPPs signed with KPLC to date, all have been honored and none have been cancelled (the Westmont PPA expired after 7 years and the Iberafrica PPA was renegotiated). The electricity sector in Kenya is to a large extent financially self-sustainable due to sound regulatory policies that are applied to the terms of PPAs between power generators and KPLC as well as to the design of the retail tariffs charged by KPLC. In particular, the retail tariff design provides an incentive to KPLC to make efficiency gains while at the same time key cost elements, such as fuel costs, inflation and foreign exchange fluctuation, are passed through to consumers.

81. Reflecting such well-designed institutional and regulatory arrangements, KPLC's financial performance has been sound since its financial restructuring in FY2004. KPLC incurred losses from 1999 until 2003 due in large part to the tariff setting formula at the time that did not allow fuel cost pass-through as well as the impact of drought conditions that reduced its sales and increased its costs at a time when its losses were also quite high. The company has been able to steadily improve profitability, improve operational performance, (technical loss reduction, improved billing and collection, etc.) expand its customer base and maintain a healthy financial position, and it has not defaulted on its PPA commitments.

82. The financial forecast under a base case scenario (Annex 9) shows that KPLC's operations, capital adequacy, and liquidity are expected to be sustained. KPLC will remain profitable despite taking on increased debt in order to finance expansion of the power distribution system. The four IPPs combined will likely create manageable upward pressure on the level of electricity tariffs and fuel pass through estimated to be about US$ 0.50-0.86 cents, as calculated by their impacts on KPLC's annual revenue requirement. In the absence of these four power plants, the shortfall in electricity supply would need to be met by emergency power plants. The resulting fuel cost savings of US$0.26-0.67 cents per kWh each year between FY2013 and FY2020, would offset a large portion of the increase in electricity tariffs.

83. Even though KPLC will be obliged to pay the capacity charge rate for the four IPPs combined under take-or-pay terms, it will have a decreasing effect on the retail tariffs, estimated to be US$1.01 cents per kWh immediately after the commencement of their operation in FY2013 down to US$0.36 cents per kWh in FY2025. Projected profitability ratios of KPLC are lower in some years, but they are still expected to maintain levels comparable to utilities in higher income countries. Even though the company will be leveraged with the increased proportion of debt, its debt service coverage ratio is expected to stay above 1.3, assuming terms of borrowing will increasingly be on commercial terms. The regular financial reporting that is required of KPLC (it has currently 49.9% private shareholding) ensure that its operations and investment decisions are scrutinized by investors, bringing additional accountability and transparency to its financial performance.

84. Some risks that may impact the financial performance of the sector in the future are: the roles and responsibilities for electricity supply under the new Constitution; hydrological risks of severe drought affecting hydroelectric power generation; uncovered portion of inflation risks; issues related to crude oil price risks, currency depreciation risks, and the acceptability and affordability of gradually increasing tariff levels. For some of these risks, mitigation measures

are already identified or implemented. For example, the Energy Sector Committee on the New Constitution has been established by the Ministry of Energy and it is looking into the potential impacts of the devolved system under the New Constitution to the sector. The findings are periodically shared at quarterly Donor Coordination Meetings.

85. The alternative risk scenarios analyzed show that impacts of crude oil price rise above 25 percent could push up the fuel pass-through elements to more than US$8.12 cents per kWh in FY2012, which is higher than historical record in the sector. The impacts are larger in the short-run. It would therefore be necessary to monitor the impact of fuel price volatility on people's affordability of electricity, especially in the short-run. The impacts of up to 20 percent depreciation in Kenya Shillings could push up the foreign currency pass-through elements by up to US$1.63 cents per kWh. The risk of drought would put upward pressure onthe cost of electricity supply, which could be pushed up by US$2.0 cents per kWh mainly due to the fuel switch from hydroelectric to thermal power. As the country increases the share of geothermal and wind power in the grid and increase the share of electricity imported from Ethiopia, the financial impacts of crude oil price volatility and droughts are expected to become smaller in proportion.

Financial Analysis Summary of Sub-Projects

86. The following are the main financial indicators from the financial analysis[26] conducted for each sub-project. A more detailed analysis is given in Annex 10.

Sub-project 1: Thika Power Plant

87. Financing of the Thika Power Plant is conducted based on 75:25 debt-to-equity ratio. The financial analysis of Thika's cashflows shows a robust project based on sound financial structure and projected stream of cashflow. The sub-project internal rate of return (IRR) is estimated at 13.0 percent and net present value (NPV) at €50.9 million Euro. Debt service coverage ratio remains above 1.34 throughout life of the project limiting risk of debt service default, in addition to a debt service reserve account of 6 months. Shareholders are exptected to earn an IRR on their equity of 15.1 percent with a NPV of €10.7 million. A sensitivity analysis highlighted that the project can sustain variations in the range of 10% to 20% for most variables apart of the sensitivity related to plant availability and actual plant capacity delivered at commissioning, at which case the project becomes very sensitive (see Annex 10 for sensitivity analysis).

Sub-project 2: Triumph Power Plant

88. The financing of the project is conducted based on 75:25 debt-to-equity ratio. A financial analysis of Triumph's cash-flows demonstrates a robust project based on sound financial structure and projected stream of cash-flow. The sub-project internal rate of return (IRR) is estimated at 11.9 percent, and NPV at US$22.2 million. The minimum debt service coverage ratio (DSCR) is recorded at 1.42 limiting risk of debt service default, in addition to a debt service reserve account of 6 months. Shareholders are expected to earn an IRR on their equity of 14.7

[26] The financial analysis is based on final draft of the financial models as provided by IFC and Lenders. The financial models will be audited, but the team does not anticipate major changes.

percent with NPV of US$21.9 million. The sensitivity analysis showed similar results as Thika's project given the similar nature of the two plants (see above).

Sub-project 3: Gulf Power Plant

89. Similar to other two thermal plants, the financing for Gulf Power Plant is conducted based on 75:25 debt-to-equity ratio. The financial analysis of Gulf's cash-flows shows a solid project based on sound financial structure and projected stream of cash-flow. The sub-project internal rate of return (IRR) is estimated at 13.2 percent, and NPV at €35.8. million. Debt service coverage ratio remains above 1.36 throughout life of the project limiting risk of debt service default, in addition to a debt service reserve account of 6 months worth of debt service. Shareholders are expected to earn an IRR on their equity of 18.2 percent with a NPV of €13.3 million. The sensitivity analysis showed similar results as the other two thermal power plants.

Sub-project 4: Olkaria III (Expansion of the existing Plant)

90. Financial analysis of OrPower4's cash-flows shows a robust project based on sound financial structure and projected stream of cash-flow. Financing of OrPower4 expansion project, is more of a corporate finance nature rather than limited-recourse financing, as it can tap into revenues of the existing facility to finance part of the expansion. An analysis of the historical performance was carried out and it revealed acceptable level of operating indicators and liquidity ratios especially since the commissioning of phase 2 of current facility in 2009 (Return on Equity in 2009 of 29% and a current ratio of 2.33). The geothermal project has high upfront capital costs as a result of higher drilling costs and the drilling of back-up wells for the integrated project. Despite this higher upfront capital cost, the analysis of the projected cash flows for the whole project shows that the project will remain sustainable. A debt service coverage ratio above 1.72 throughout life of the project combined with the establishment of a debt service reserve account upfront, will contribute towards the mitigation of debt service default risk. Shareholders are expected to earn an IRR on their equity of 13 percent with a NPV of €6.7 million. The sensitivity analysis highlighted that the project can sustain variations of in the range of 10% to 20% for most variables apart of the sensitivity related to geothermal resource availability and actual capacity delivered at commissioning, at which case the project becomes very sensitive. However these risks are mitigated by the back-up wells that are being drilled within this expansion and the extensive experience the project company has acquired in operating the existing plant in Kenya.

91. The table below provides a summary of the main financial indicators for all sub-projects.

Table 10: Matrix of Main Project Finance Indicators

IPPs	Gulf	Thika	Triumph	OrPower4
Technology	HFO Plant			Geothermal
Capacity	80.3 MW	87 MW	82 MW	84 MW
Project Total Cost (M$)	108	146	157	212*
Capital cost ($ per kW)	1340	1678	1918	4750
Levelized Tariff (c$ per kWh)	22.5	22.2	23.0	10.1
Debt to Equity Ratio	75:25	75:25	75:25	2.12
Minimum DSCR	1.26	1.34	1.42	1.72
Project IRR	13.6%	13.0%	11.9%	NA[27]
Project NPV (M$)	53.6	50.9	22.2	NA
Equity IRR (%)	18.5%	15.1%	14.7%	13%
Equity NPV (M$)	14.0	10.7	21.9	6.7

*The cost is for the expansion only.

B. Technical

92. <u>Sub-project 1: Thika Power Plant</u>

- *Design and layout of Power Plant:* The proposed plant design by Melec PowerGen Inc. in consortium with MAN Diesel SAS has been reviewed as part of the preparation process and been found to be appropriate and the technical specifications follow international norms and standards. The configuration is complete for a well functioning system and the power plant would have the capacity to supply 87 MW at 132 kV. Moreover, the proposed layout and arrangement would not pose any major challenges. The proposed HFO power plant of 87 MW comprise of: (i) a set of power generation equipment based on 05 x MAN 18V equipped with cooling system, air intake and exhaust systems, fuel systems (LFO and HFO), air starting system, lubricating oil system, control and protection system and other systems; (ii) a steam turbine generator utilizing excess energy from the diesel units exhaust gasses; and (iii) a high voltage substation 15/132 kV. The proposed installation also includes appropriate civil works and structures, lifting equipment such as overhead crane and fire water system.

- *Generation Equipment:* The engine family MAN 18V has a well-proven service record in stationary power generation and has an advantage in terms of stability and performance due to its lower engine speed of 500 rpm and the generator sets would be suitable for a base load operation. The exhaust gas emission is in accordance with the pollution prevention and abatement handbook, Part III, of the World Bank, 1998.

- *Electrical System and Substation:* The proposed electrical system is equipped with proven technology including (i) SCADA (Supervisory Control And Data Acquisition), (ii) automated equipment (PLC) for managing among others start/stop sequence,

[27] This information is not disclosed here since the sponsor considered it as confidential.

interlocking function, parallel operation, fast decoupling in case of grid failure to ensure safe power plant operation; and (iii) UPS (uninterruptible power supply) to secure the voltage supply for control and protection system. The proposed substation would be equipped with two step-up transformers. The installation would also include appropriate civil works and structures, necessary lifting equipment such as overhead crane and the power plant is secured by fire water and earthing systems.

- *Operations and Maintenance:* The proposed methodology for operations and maintenance is deemed to be appropriate to ensure reliability.

93. Sub-project 2: Triumph Power Plant

- *Design and layout of Power Plant:* The proposed diesel combined cycle plant will comprise of 10 Hyundai Himsen 18H 32/40V MSD diesel engine driven generator sets supplied by ZGPT of China and a steam turbine generator (ca. 6 MW) with a total plant capacity of approximately 82 MW. The primary fuel will be heavy fuel oil (HFO) with distillate fuel oil (DFO) as a backup fuel. A heat recovery system will be equipped to extract heat from the exhaust gases and used for the generation of additional electricity via the steam turbine generator. The proposed layout and arrangement would not pose any major challenges. The layout follows a modular design configuration, which would allow each unit to run independently. Each unit would be equipped with (i) separate main equipments including double circuit radiator cooling, 25dB(A) muffler, lubricating pump, lube oil separator module, high and low temperature water pumps; and (ii) separate step up transformer. To complete the balance of the power station, common equipments such as heavy oil module, fuel supply module, air compressor, incinerator, overhead crane, deaerator, and auxiliary machine for black starting would be installed.

- *Generation Equipment:* The proposed HYUNDAI HiMSEN 18H32/40V heavy fuel oil generator set is among the Hyundai diesel unit ranging from 575 kW to 9600 kW that follows international norms and standards. In general, Hyundai diesel engines have been successfully proven and have strong track records. The 18H32/40V type unit utilizes the latest technology that was recently introduced in the market and has few performance and service records. As a reference, only one similar power plant of 70 MW has been commissioned in Bangladesh around August 2011. The engine supply contract has been signed between the EPC Contractor and the supplier. Four engines are ready for shipment. The remaining six engines will be ready for shipment in early 2012.

  All the diesel generating units will be tested individually prior to the issue of the Interim taking over Certificate and together prior to the issue of the Interim Taking-over Certificate in order to demonstrate the guaranteed capacity. All 10 Diesel Engines and the Diesel Combined Cycle will be tested together prior to issue of the Final Taking-Over Certificate in order to demonstrate compliance with each of the Performance Guarantees. To comply with norms and standards on gas and noise emissions, the Testing and Commissioning Plan would mention the detailed calculation and measurement methodologies to be used for the purposes of monitoring and measuring the exhaust gas emission and noise measurements shall be carried out in accordance with World Bank

Guidelines. The Contractor would take necessary mitigation measures in the event existing residents are affected by the noise levels.

- *Electrical System and Substation:* The proposed electrical system is equipped with proven technology including (i) SCADA (Supervisory Control And Data Acquisition), (ii) automated equipment (PLC) for managing among others start/stop sequence, interlocking function, parallel operation, fast decoupling in case of grid failure to ensure safe power plant operation and (iii) UPS (interruptible power supply) to secure the voltage supply for control and protection system. The proposed layouts of the power plant and the substation including the interconnection arrangement would follow prudent practices.

- *Operations and Maintenance:* For the first 5 years from the commissioning of the plant, the Project's company would sign a renewable O&M maintenance agreement with the same Contractor of the EPC contract. It would enable the Plant to operate safely and efficiently in accordance with best industry practices and would reduce significantly the risk of low reliability on the plant due to limited experience with the engine.

94. <u>Sub-project 3: Gulf Power Plant</u>

- *Design and Layout of Power Plant:* The proposed HFO power plant of 80.3 O&M is composed of: (i) complete power generation equipment based on 10x Wartsila 20V32 including cooling system, air intake and exhaust system, fuel systems (LFO and HFO) including metering systems, starting system, lubrication oil system, control and protection system, substation, earthing system, auxiliary system; (ii) appropriate civil works and structures; and (iii) fire water system. The proposed designs are technically sound and follow best practices and are in accordance with international standards.

- *Generation Equipment:* The engines are emission rated in accordance with the Bank guidelines.

- *Electrical System and Substation:* Gulf has proposed the use of two-step up transformer of 60 MVA 11/66 kV. The total capacity of 120 MVA is enough to send out the energy delivered by the power plant running at full capacity but would not be sufficient in case of failure of one of them.

- *Operations and Maintenance:* The proposed layouts of the power plant and the substation including the interconnection arrangement would follow prudent practices. The proposed layout of the power plant combined with the automated control system will facilitate the operation and the maintenance of the power plant and will ensure good operational conditions (ambient temperature). The proposed philosophy for operations and maintenance including the organization charts are appropriate.

95. <u>Sub-project 4: Olkaria III (Expansion of the existing Plant)</u>

- *Design and Layout of Power Plant:* The proposed expansion plant would consist of three binary energy converter units with a total capacity of 36 MW. The plant will be connected to the wells by pipelines conveying single or dual phase steam and water. The expansion would be less difficult since Ormat has adopted the use of similar and compatible technologies and configuration to those incorporated in the first Plant.

- *Generation Equipment:* The main equipment, including turbines, would be in accordance with applicable international norms to ensure that they would have the capacity (i) of operating under all variations of chemical and physical characteristics of geothermal steam; and (ii) of stable automatic transition to no load and of operating at no load for at least 15 minutes.

- *Electrical System and Substation:* The plant would have a fiber optical communication system with terminal equipment that would allow the use of SCADA technology for the integration of KPLC's communication system. The operating and dispatching procedures are adequate and would allow KPLC to respond, in a professional manner, to the demand of the networks. The interconnection arrangement and the metering system are adequate and are in line with best practices. The generators of the Plant would be equipped with individual step up transformers and then will be connected to the Olkaria II substation. The configuration would include a main metering system and a back up metering system.

- *Operations and Maintenance:* The Plant would be tested and commissioned in accordance with prudent practices and applicable norms and standards to ensure a well functioning and a well performing of the whole system. There is no issue foreseen on unusual scaling or fouling of the steam gathering system due to the long operational experience of Ormat. Spent geothermal water would be re-injected appropriately into the ground to minimize disturbance to the geothermal reservoir.

C. Financial Management

96. There are no traditional financial management-related fiduciary issues as there will be no World Bank-financed procurement or procurement-related disbursements under the project. Should the PRG be called, the World Bank would disburse to the relevant L/C bank and the Government would then be obligated to repay IDA in accordance with the terms of the Indemnity Agreement between Kenya and IDA. The IPPs will be primary implementing agencies for each sub-project, including responsibility for managing the finances of the sub-projects. They will install and maintain adequate financial management systems, including the system of accounting, reporting, auditing, and internal controls, and relevantly qualified staff. The annual financial statements will be prepared using internationally accepted accounting principles. In addition, they will be audited in accordance with international standards on auditing. The performance of each sub-project will be monitored through, *inter alia*, regular progress reports and audited annual financial statements to be submitted by each IPP. Overall the sub-projects' financial management risk is assessed as moderate.

D. Procurement

97. The Bank's procurement guidelines for IDA guarantees (World Bank's "Guidelines: Procurement under IBRD Loans and IDA Credits" dated May 2004, revised October 2006, May

2010, January 2011) require that goods and services must be procured with due regard to economy and efficiency.

98. KPLC, with the services of international consultants, conducted international competitive bidding in 2009 and 2010 in accordance with Kenya's Public Procurement and Disposal Act for the thermal IPPs supported by this Project. A request for Expressions of Interest (EOI) was published on May 29, 2009 by KPLC in the Daily Nation and Standard (Kenya daily newspapers) and on KPLC website. The EOI invited proposals for the design, financing, supply, erection, commissioning, operation and maintenance of three new 60-80 MW Medium Speed Diesel electricity generating plants on a Build, Own and Operate (BOO) arrangement, to be located at various locations around Nairobi City. The EOI stated that the successful bidder(s) for the Project was to become the signatory to a Power Purchase Agreement (PPA) obliging it to design, finance, supply, erect, commission, operate and maintain the plant(s) and to sell the electricity generated by the power plant(s) to KPLC. Thirty one (31) EOIs were received by the closing date, June 30, 2009. On the basis of objective evaluation criteria twenty two (22) firms were considered responsive. The main criteria used for qualification were (i) documentation establishing legal status of applicant; (ii) demonstrated access to competent construction, commissioning, operation and maintenance contractors; (iii) having strong balance sheet with minimum capital and demonstrated capability to undertake a project with a capital cost of up to US$100 million; and (iv) ability to mobilize funds with a debt/equity ratio of 75:25.

99. KPLC issued a Request for Proposals (RFP) dated July 27, 2009 to all twenty-two (22) prequalified candidates. The RFP was a comprehensive document including Instructions to Bidders, Procedure for Making Proposals, Description of the Projects, Contractual Arrangements (including a draft Lease and a draft Power Purchase Agreement), a description of the Electricity Industry in Kenya, the Legal Framework, and various annexes (mostly forms for tender presentation/submission). The RFP included specific qualification requirements and required bidders to submit a technical proposal and a financial proposal, the latter to be broken down as (a) Base Energy Charge Rate to cover the variable O&M cost component; (b) Base Capacity Charge Rate comprising a component to cover debt servicing and return on equity, and a component to cover fixed O&M costs, insurance and administration; and (c) Base Fuel Rate, the purpose of which is basically to pass through the cost of fuel consumed by the plant. Both technical and financial proposals were opened in a single session, in the presence of bidder's representatives who chose to attend. Bidders were required to give three price options based on the applicable conditions as follows: Option A with GoK sovereign guarantee; Option B with IDA Partial Risk and MIGA Termination guarantee; Option C with neither of the guarantees in Option A and B. The technical evaluation was on a pass or fail basis, whereas evaluation of the financial proposal was based on a comparison of the unit cost of energy under a specified operating regime for the Power Plant. A discounted Energy Cost was calculated for the term using a discount rate of twelve percent (12%) per annum for financial comparison. The Proposals were evaluated on the basis that in each year the plants will operate at 65% annual load factor.

100. The Bank´s review concluded that the overall procurement of the three thermal plants met general principles of industry-wide standards of economy, efficiency and transparency for this scale and timing of procurement. The prices obtained for the proposed three IPPs compare favorably with that from the existing thermal IPPs. The current weighted average capacity and energy charges for the three existing thermal IPPs are US$283 per kilowatt per annum and US$

0.0097 cents per kWh. This compares to the weighted average of US$290 per kilowatt per annum capacity charge and US$ 0.01 cents per kWh energy charge for the proposed three IPPs (using current US$ /Euro exchange rates for those PPAs denominated in Euros). Furthermore, the Bank review found that the procurement process followed the relevant applicable provisions of the Procurement Guidelines, on which basis the Bank could guarantee loans for the project made by other lenders.

101. Regarding the Olkaria III Expansion, in July 1996, the Government of Kenya through the Ministry of Energy published an international tender for development of a 64 MW geothermal plant on a build own and operate (BOO) basis at Olkaria III geothermal resources area. 20 bidders were prequalified but only five firms purchased bid documents and only two, Cal Energy Company Inc. of U.S.A. and Ormat International Inc. of U.S.A. submitted bids. Ormat's bid was evaluated as the technically responsive lowest cost bid. In November 1998 the tender was awarded to Ormat International Inc, and Ormat through Orpower 4 (a Special Purpose Company for the project), entered into a Power Purchase Agreement with KPLC.

102. An 8 MW Early Generation Facility was commissioned in July 2000 and enhanced to 12 MW in December 2000. The early generation facility made use of then existing wells drilled by the Government. Appraisal of the geothermal field completed in June 2001 revealed that the field could only support a plant of 48 MW at the time. The plant which was initially scheduled to be completed in 2002 was delayed due to difficulties in procuring financing and requirement for payment security. The full plant was finally commissioned in 2009. After gaining experience in operation of the field, OrPower determined that the field could support a higher capacity and in 2010 subsequently negotiated a Second Amendment PPA with KPLC for extension of the plant to 100 MW in two phases of 36 MW and 16 MW. Since OrPower was already operating at the site, it was determined that the PPA of the incremental expansion would be negotiated with the Project at a savings to the original PPA as some of the efficiencies from shared fixed costs would be passed on to the combined project as a whole, including minimal escalation on the tariff under the original PPA.

E. Governance and Integrity

103. The ongoing National Dialogue and Reconciliation Process has created the opportunity and momentum for governance reforms in Kenya. The Government has passed a considerable amount of legislation to combat corruption. Kenya has an independent media and strong civil society organizations. These are major assets in the drive for improved governance and accountability of public officials. The major energy sector institutions are well-run and professionally managed and there is an autonomous energy regulator that approves all tariffs.

104. Concerns for the Project are partly mitigated by the selection of IPPs through a competitive procurement process as well as by the participation of the private sector in project implementation. As noted in Section D above, the procurement of the IPPs was conducted in accordance with the Bank's procurement guidelines requiring economy and efficiency. The participation of private sponsors in implementation as well as the supervision of commercial lenders provides additional comfort.

105. The World Bank in coordination with IFC, commercial lenders and MIGA, has concluded its integrity due diligence related to the sponsors and the proposed ownership of the

Special Purpose Vehicles (SPVs) with satisfaction. In addition, the Anti-Corruption Guidelines for World Bank Guarantee and Carbon Finance Transactions will apply to this Project.

F. Environment and Social (including Safeguards)

106. The proposed PRG project is classified as Category A because it entails separate IPPs with investments in different locations in Kenya. Three of the subprojects are green-field projects located in industrial zones or along major highways; the fourth subproject is the expansion of an existing geothermal power plant. For all four IPPs, environmental and social assessments have determined that there are unlikely to be physical cultural resources that will be encountered; however, as per standard practice, construction contracts will include chance finds procedures. There are no vulnerable and marginalized ethnic groups in the proposed project sites. Screening has occurred, and no groups recognized by the Bank as Indigenous Peoples under OP 4.10 are on or near the project sites. Although the three thermal IPPs have no significant natural habitat impacts associated with them, OP 4.04 is triggered because the Olkaria III expansion project is located within a National Park as an approved activity (as described below in paras. 111 - 114).

ESIAs and Disclosure for Thermal IPPs

107. All three 80.3-87 MW Medium Speed Diesel (MSD) thermal plants will be constructed by IPPs under a 20 year Build Own Operate (BOO) arrangements, with the IPPs retaining the responsibility for compliance with Kenyan environmental regulation, World Bank Safeguard Policies, and IFC/MIGA Peformance Standards triggered by the respective sub-projects. Each of the thermal power IPPs is required under Kenyan environmental regulations and WBG policies to prepare an Environmental and Social Impact Assessment (ESIA).

108. A reasonable range of project alternatives have been evaluated, including a "no-project" alternative. There are constraints, however, on the range of reasonable alternatives that can be discussed because the project is a concession awarded to an IPP. KPLC initially identified a parcel of land in an Export Processing Zone (EPZ) on the southwest side of the town of Athi River for three proposed MSD thermal power plants to be built by IPPs. However, due to the potential cumulative environmental impacts of siting three such power plants within the same parcel of land, it was subsequently decided that land be acquired in three separate locations. KPLC used print media, estate agents, local authorities, and the public to identify suitable candidate sites. Key site selection criteria included: (a) minimal environmental and social impacts, (b) sites from which power could be easily evacuated; and (c) sites available for sale immediately. Each sub-project now has a selected site, which include: (a) the initial site within an unused part of the EPZ southwest of Athi River town, (b) a site near Thika town; and (c) a site along the Nairobi-Mombasa highway to the east of Athi River. Prior to the award of concessions to successful IPPs, KPLC conducted preliminary environmental and social assessment work and determined that there were likely to be no significant social and environmental risks associated with the sites in terms of land use, or other characteristics associated with the site itself. Given their respective generating capacities, prevailing winds, and distances from each other, the airsheds of the three projects are not expected to overlap such that cumulative adverse impacts occur on ambient air quality.

109. There are different agencies in Kenya responsible for power generation and for electrical transmission (KETRACO) and distribution systems (KPLC). Therefore, transmission lines are to be built separately under the authority of a different project proponent, and the project proponent is required to prepare a separate ESIA for its investment. For two of the thermal power plants, i.e. Thika and Triumph, the connection to the transmission line grid will occur within the purchased sites and will be part of the project boundary. For the third, as required by both Bank and IFC policy, the ESIA prepared by Gulf Power included a preliminary analysis of the likely social and environmental risks and impacts of the associated transmission lines serving the project, and it was concluded that the environmental and social impacts will be very minor. Transmission lines will follow existing road rights-of-way or cross unoccupied land designated for industrial use. There will not be any resettlement or compensation for lost assets at the three thermal power project sites.

110. ESIAs have been prepared and have been reviewed by the Bank in their final form for all the IPPs. Draft ESIA reports were prepared for the Triumph Plant in November 2010 and Gulf Power in April 2011, while a detailed scoping report of an ESIA was prepared for the Thika Plant in February 2011. It was determined that the Draft ESIA prepared for the Gulf Power plant could serve as a model of good practice for an ESIA suitable for power plants of this size using MSD or Heavy Fuel Oil (HFO). A modified version of Gulf's ESIA was adapted as an Environmental and Social Management Framework (ESMF) for the other two thermal power plants for which ESIA work was still in progress. The ESMF and the Gulf Power ESIA were disclosed locally on May 20, 2011 and in the InfoShop on May 23, 2011. Subsequently, the finalized ESIA for the Thika MSD thermal power plant was disclosed locally on October 24, 2011 and at the InfoShop on November 3, 2011. The final ESIA for the Triumph MSD thermal power plant was disclosed both locally and at the InfoShop on December 22, 2011.

ESIAs and Disclosure for the Olkaria III Geothermal Sub-Project Site

111. The Olkaria III project site is located within Hell's Gate National Park, which is designated as a Category II protected area by IUCN Hell's Gate. Given the absence of large predators such as lion and leopard, it is the only national park in Kenya in which hiking is encouraged. However, the park was only established after the Olkaria geothermal fields had been gazetted for geothermal power production and the first power plant (Olkaria I) had been built. Nonetheless, because of the location of the project within the park, OP 4.04 (Natural Habitats) is triggered. The park is divided into two sections: the western section in which geothermal production is permitted, and the eastern section in which hiking and recreational activities (primarily bird watching) are encouraged. The expansion is located within the western sector of the park in which geothermal field development is already permitted. A gorge separates the eastern and western sectors of the park, and topographical features west of the gorge (i.e., Olkaria Hill, Hobbley's Volcano, and Hell's Kitchen) effectively isolate the Olkaria III geothermal field from viewers in the eastern sector of the park.

112. The Olkaria III project area is located in a semi-arid landscape occupied predominantly by savanna grassland. The project area itself is characteristic of geothermally altered soils, with sparse vegetation. The primary habitat and recreational value for the park is bird nesting and bird-watching, especially large raptors and a large colony of swifts. The initial EIA for Olkaria III considered cumulative impacts of the three existing geothermal fields in the park, including the proposed expansion of Olkaria III. Geothermal field development and activities are closely

coordinated with the Kenya Wildlife Service (KWS), which is responsible for park management and protection. All geothermal operations within the park are required to enter into an Environmental Management Agreement with the KWS. The Olkaria III project's Environmental Management Plan will continue to be implemented as part of the Environmental Management Agreement with the KWS.

113. The Olkaria III project site is already connected to the grid and the expanded power output will be evacuated through increasing capacity on existing transmission lines. No resettlement or displacement of livelihood activities will occur as a result of the proposed expansion of the Olkaria III power plant or increase of capacity in the existing transmission lines.

114. MIGA has guaranteed an investment in Olkaria III since March 2002, with a second guarantee offered for the second phase expansion in December 2007. Therefore, information regarding WBG involvement in the Olkaria III project has been disclosed since 2002. Notwithstanding earlier disclosures, the Bank disclosed locally and in the InfoShop on June 9, 2011, the following key documents for the Olkaria III project:

(a) The initial (August 2000) EIA, which noted that the project would be expanded in phases over time to 100 MW and assessed from that perspective;
(b) The supplement to the EIA dated May 2001; and,
(c) The most recent (2010) environmental audit of the existing Olkaria III project operations.

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

115. The proposed PRG Project has triggered OP 4.01 (Environmental Assessment) and OP 4.04 (Natural Habitats), and is classified as Category A. An ESMF based on the draft ESIA for the Gulf Power was disclosed both in country and at the Bank's InfoShop in May 2011, prior to appraisal, as described above. Environmental assessments for the Olkaria III geothermal power plant have been re-disclosed and a recent environmental audit of existing operations has also been disclosed by the Bank as described above. The Kenyan environmental authorities on May 21, 2010, amended the September 14, 2007 EIA license for the Olkaria III project to approve the project to the final expansion to 100 MW, as originally proposed in the 2000 EIA for the Olkaria III project. The proposed project has also triggered OP 4.04, Natural Habitats for the geothermal

* *By supporting the proposed project, the Bank does not intend to prejudice the final determination of the parties' claims on the disputed areas*

expansion sub-project only, because of the location of the existing geothermal project in a national park, as discussed earlier in this section.

Monitoring

116. Environmental issues are key for monitoring during project implementation. During construction of all four IPP projects, the key concern will be implementation of good practices for construction management, such as dust, noise, and erosion control, safe work practices, and disposal of construction wastes. During operations of the three thermal power plants, the key concern will be compliance with the relevant (December 2008) WBG Environmental, Health & Safety Guidelines (EH&SG) for Thermal Power projects, and safe transport, off-loading and storage of fuel. For the three thermal power plants, given their size and the design of the plants, compliance with the relevant aspects of the EH & SG can be achieved by limiting sulfur content of fuel to 2%. For the expansion of the existing geothermal plant, the key issues to monitor during operations will be continued injection of spent geothermal fluids and noise control as documented in the annual environmental audits that have already been conducted for the existing operations.

117. There are multiple layers of ongoing environmental monitoring envisaged for these sub-projects. As the national environmental authority, NEMA has a role and responsibility for monitoring compliance with Kenyan environmental legislation for all industrial activities, including the four IPPs. KPLC has a more immediate responsibility in confirming that each IPP is complying with its contractual obligations to KPLC, which includes implementation of the NEMA-approved EMP for each respective IPP. Based on experience with other Bank-financed projects, KPLC has been found to have reasonable capacity for monitoring compliance. KPLC set up a dedicated environment unit about four years ago, which is quite thorough and prompt in responding to matters of non-compliance or grievances from local communities. In addition, since IFC will be involved in Thika and Gulf, the Bank team will seek to maximize efficiency and to avoid duplication in monitoring. IFC's approach to and budgetary resources for monitoring project compliance are very robust. In addition to periodic site visits for compliance monitoring, IFC requires for all its projects that the client prepare and submit to the IFC an Annual Monitoring Report (AMR). As this is a category A, IFC further requires that the client retain qualified and experienced external experts to verify the monitoring information. For these two IPPs, the Bank intends to coordinate with IFC's compliance monitoring during Project supervision by the Bank, and the Bank to request copies of Annual Monitoring Reports (AMRs) submitted to IFC for this IPP project. MIGA is expected to be involved in Triumph Power, and the Bank and MIGA intend to collaborate in monitoring compliance by this particular IPP during Project supervision. For the Olkaria III geothermal project, in which MIGA is also involved, third-party audits are arranged on an annual basis by the sponsor. The Bank intends to request copies of these annual audits as part of its Project supervision.

Annex 1: Results Framework and Monitoring

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Results Framework

Project Development Objective (PDO): To increase electricity generation through Independent Power Producers (IPPs) in Kenya.

PDO Level Results Indicators*	Core Indicator	Unit of Measure	Baseline	Cumulative Target Values					Frequency	Data Source/ Methodology	Responsibility for Data Collection	Description (indicator definition etc.)
				YR 1	YR 2	YR 3	YR 4	YR 5				
Electricity generated through IPPs available in Kenya's Interconnected Grid - Conventional (65% capacity factor down to 35% in Year 5) - Renewable (88% capacity factor)		GWh/year	0	0	Conv: 1,423 Renew: 277	Conv: 1,423 Renew: 277	Conv: 1,423 Renew: 277	Conv: 766 Renew: 277	Annually	KPLC statistics, IPPs reports	KPLC	
Direct project beneficiaries (number),[28] of which female (percentage)	X		0	0	332,134 (49.5%)	332,134 (49.5%)	332,134 (49.5%)	202,169 (49.5%)	Annually	KPLC statistics	KPLC	See Footnote 1
INTERMEDIATE RESULTS												
Intermediate Result (Sub-project One): Thika Power Plant and associated infrastructure constructed												
Commissioning test completed		Y/N	No	Yes	Yes				Quarterly	Progress reports	TPL, KPLC	
Conventional generation capacity constructed under the project		MW	0	80.5	87				Quarterly	Progress reports	TPL, KPLC	

[28] Generation capacity in Kenya stands at 7,303 GWh prior to the sub-projects coming on line. The sub-projects' additional generation will represent a percentage increase that is to be fed into the Interconnected Grid, which KPLC reports show has a customer base of 1,444,061. Direct beneficiaries are therefore the percentage of additional generation multiplied by the number of existing customers.

Incremental investment in generation (equity and debt)		US$ mil	0	124	22	NA	NA	NA		Progress reports	TPL, KPLC	
Intermediate Result (Sub-project Two): Triumph Power Plant and associated infrastructure constructed												
Commissioning test completed		Y/N	No	Yes	Yes				Yearly	Progress reports	TPGC, KPLC	
Conventional generation capacity constructed under the project		MW	0	77	82				Quarterly	Progress reports	TPGC, KPLC	
Incremental investment in generation (equity and debt)		US$ mil	0	120	37	NA	NA	NA		Progress reports	TPGC, KPLC	
Intermediate Result (Sub-project Three): Gulf Power Plant and associated infrastructure constructed												
Commissioning test completed		Y/N	No	No	Yes				Yearly	Progress reports	GPL, KPLC	
Conventional generation capacity constructed under the project		MW	0		80.3				Yearly	Progress reports	GPL, KPLC	
Incremental investment in generation (equity and debt)		US$ mil	0	72	36	NA	NA	NA		Progress reports	GPL, KPLC	
Intermediate Result (Sub-project Four): Olkaria III Expansion												
Commissioning test completed		Y/N	No	No					Yearly	Progress reports	OrPower, KPLC	
Renewable generation capacity constructed under the project		MW	0	0	36				Yearly	Progress reports	OrPower, KPLC	
Incremental investment in generation (equity and debt)		US$ mil	0	200	12	NA	NA	NA		Progress reports	OrPower, KPLC	

Annex 2: Detailed Project Description

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

1. The proposed Project consists of four Independent Power Producer (IPP) operations to be developed as a portfolio of new generation options for Kenya. Three of these are greenfield power projects competitively awarded to Thika Power Ltd., Triumph Power Generating Co, and Gulf Power Ltd. The fourth IPP is an expansion of an existing geothermal project competitively awarded and operated by OrPower 4 Inc. The thermal IPPs will involve: (i) the construction and installation of three 80.3 to 87 MW Medium speed Heavy Fuel Oil (HFO) Power Plants on a Build, Own, and Operate (BOO) basis to include the design, finance, supply, erection, commissioning, operation, and maintenance of these plants for a 20 year-term extendable for a further five years; (ii) construction of a fuel storage facility at each site; (iii) the supply and installation of the KPLC Connection Facilities and the Back Up Metering Equipment prior to transferring it to KPLC, and the maintenance of the Security Stock; and (iv) in some cases, construction of an associated transmission line between the facility and the interconnection point to deliver the electricity generated from the plant into the national grid. The plants will be dispatched in a manner consistent with a least cost merit order and will be affected by the availability of the hydro plants on the KPLC system. These plants may, therefore, operate as base load stations or standby back-up to the hydro and geothermal plants. The plants would need to be capable of a wide range of operating regimes from minimal to full load and be capable of responding speedily to load variations.

2. Sub-project 1: Thika Power Plant The sub-project will support the construction of an 87 MW Medium Speed HFO Power Plant, including a steam turbine generator with a net output of about 6.5 MW utilizing excess energy from the diesel units exhaust gasses, a fuel storage facility and two underground cable interconnectors to the KPLC substation at the project site, in the Thika area, near Nairobi. The total project cost is estimated at US$146 million (Euro 112 million) of which 25 percent or US$36 million (Euro 28 million) will be subscribed as equity and the balance of US$110 million (Euro 84 million) in debt provided in equal amounts by IFC, African Development Bank, and ABSA Capital of South Africa.

3. The construction of the power plant will be undertaken through a fixed price turnkey Engineering, Procurement, and Construction (EPC) contract with a Consortium consisting of Man Deisel and Turbo SE, a leading manufacturer of diesel engines with expertise in the design and supply of the main equipment and supervision of plant operation and maintenance (as described in Section IV and Annex 3). The plant will consist of five 18V48/60 MAN 500 rpm gensets capable of running on heavy fuel or diesel, with a steam recuperation turbine for combined cycle operation, allowing for a high thermal efficiency. The MAN DCC uses engine exhaust (waste heat) for steam production and generation of additional electricity. The sub-project will also have a steam turbine for the use of exhaust heat which will add approximately 7 MW of generation when all engines are at full load, thereby improving project efficiency. The electrical output from the Thika project will be sent to the KPLC transmission system by way of two underground cable interconnectors to the KPLC 132/66 kV substation at the project site. The responsibility for the construction of the substation will be KPLC's. The Delivery Point will

be the point of common coupling to KPLC's system and is the tie in to the incoming terminals of the incoming isolator of the circuit breaker assembly at the 132 kV substation. The metering point will be at the Delivery Point, and the Company will be responsible for the O&M of the complex and the main metering equipment. The sub-project is expected to be commissioned in March 2013.

4. Sub-project 2: Triumph Power Plant. The sub-project will support the construction of an 82 MW Medium Speed HFO combined cycle plant, and a fuel storage facility KPLC will be responsible for the construction of a 66 kV transmission line to connect the plant to the line and to the Embakasi and Juja substations. The total project cost is expected to be around US$157 million, which is structured on a limited recourse basis with a debt equity ratio of 75:25 amounting to around US$118 million in debt and US$39 million in equity. Standard Bank of South Africa is expected to underwrite the entire debt financing of the project.

5. The proposed diesel combined cycle plant will comprise of 10 Hyundai Himsen 18 H 32/40V MSD diesel engine driven generator sets supplied by ZGPT of China and a steam turbine generator (ca. 6 MW) with a total plant capacity of approximately 82 MW. The primary fuel will be heavy fuel oil (HFO) with distillate fuel oil (DFO) as a back-up fuel. A heat recovery system will be equipped to extract heat from the exhaust gasses and used for the generation of additional electricity via the steam turbine generator. The main components of a diesel combined cycle plant are the diesel engines, the heat recovery system, the steam turbine generator, the fuel conditioning system and the water cooling system. The plant will be designed for continuous baseload operation with a capability of running at 10% over load for very short periods for governing purposes during grid disturbances; all engines would be able to operate at full output with the exception for maintenance outages. A desulphurization unit will be included which will enable the plant to use a higher viscosity and cheaper fuel should the need arise to help reduce fuel costs. Construction of the power plant will be undertaken through a fixed price turnkey EPC contract with the XJ International Engineering Corporation part of the XJ Group of China. The XJ Group will also be responsible for the operation and maintenance of the plant for the initial five years of operation. The XJ Group was founded in 1970 and is owned by the State Grid Corporation, which provides power to approximately 88% of China and is the largest utility in the world. The sub-project is expected to be commissioned in June-July 2013.

6. Sub-project 3: Gulf Power Plant. The sub-project will support the construction of an 80.3 MW single cycle, Medium Speed HFO plant, and a fuel storage facility on land adjacent to Highway A109 connecting Nairobi to Mombasa at Athi River Town, approximately 35 km from Nairobi. The total project cost is expected to be in Euros amounting to the equivalent of US$108 million of which 25% or around US$27 million will be in the form of equity and US$5 million in subordinated debt through an IFC C Loan. The balance of US$76 million will be provided, in equal amounts`, through IFC A Loan, a commercial loan from Standard Bank under the IFC B Loan 'umbrella' and through a parallel commercial loan from Standard Bank. The plant will consist of ten Wärtsilä 20V32 engine generating units capable of running on HFO as well as Light Fuel Oil (LFO). The project incorporates the Wärtsilä's standard plant configuration. The engines are housed in a powerhouse. The engine generators are grouped into two sets, feeding two main step-up transformers. The layout for the power block is conventional and arranged to fit the site. HFO will be imported to the port of Mombasa by ship and will be delivered by truck

to the site. The trucks will be unloaded at the site, with fuel stored in consignment storage tanks capable of supplying 30 full-power days operation and a minimum stock. Wärtsilä will be the EPC contractor (Wärtsilä Finland Oy) as well as O&M contractor (Wärtsilä East Africa Limited). The sub-project is expected to achieve commercial operations in June 2013. KPLC will be responsible for the construction of a 66 kV transmission line to connect the Plant to the Embakasi and Juja substations.

7. Sub-project 4 (a): Olkaria III Expansion Project. This sub-project will involve the expansion of an existing Geothermal Facility from 48 MW to 84 MW. The total cost of the expansion of Plant 2 will be around US$212 million, which will be funded by around US$31 million of new equity injection, a US$165 million loan from Overseas Private Insurance Corporation (OPIC), and the balance through internal cash-flow. The existing project was developed in phases and was initially awarded on the basis of an international tender process to Ormat International, Inc in 1998. Ormat through its subsidiary Orpower 4 Inc, incorporated in the Cayman Islands, undertook the construction, ownership, and operation of the 'Early Geothermal Facility' using existing local geothermal resources. Ormat is a member of the Ormat Group of companies, a USA based developer and owner-operator of geothermal projects worldwide.

8. The sub-project, located within Hell's Gate National Park, consists of an electrical power generation complex, a geothermal energy production field, a geothermal gathering piping system and a geothermal condensate re-injection system. Phase 1 involved the construction of a 13 MW power plant which subsequently was expanded to an aggregate capacity of 48 MW which was completed and has been operating successfully since 2009. The project is underpinned by a 20 year PPA concluded with KPLC which provides for capacity and energy payments to Orpower 4 in US dollars. In March 2011, KPLC and Orpower 4 entered into the second Amended and Restated PPA to expand the complex to 84 MW with an option for a further increase to a total aggregate capacity of 100 MW. This sub-project will involve the expansion by an additional 36 MW. The drilling program has already commenced and the onsite construction of the additional generating facility and the geothermal piping will follow. This sub-project is expected to be commissioned by April 2013.

9. Sub-project 4 (b): Olkaria III Expansion Project. A further expansion of 16 MW is expected to be processed subsequently once the option is exercised by OrPower by September 2015 at the latest, although Orpower is expected to exercise the option earlier by 2013. OrPower 4 will use the same proven technology as for the existing plants and will continue to be operator of the plants.

Annex 3: Implementation Arrangements

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Project Institutional and Implementation Arrangements

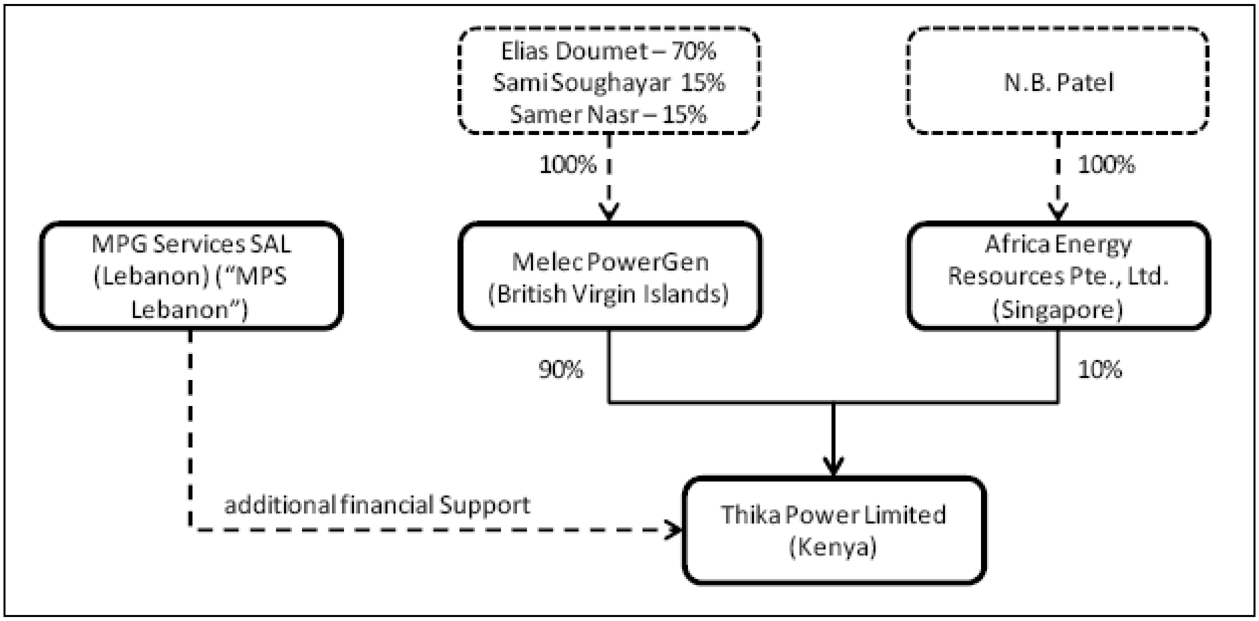
Project Implementation

Thermal IPPs

1. The three thermal sub-projects will be implemented by special purpose companies incorporated in Kenya and the contractual structure of the three sub-projects is consistent with industry standards in respect of the allocation of commercial and technical risks. The project companies will have overall responsibility for the design, finance, supply, erection, commissioning, operation, and maintenance of the plant (including the drilling of water wells as required) under a 20 year PPA term from operations start-up date, extendable for a further five years. Details of each project company's shareholding structure is as follows:

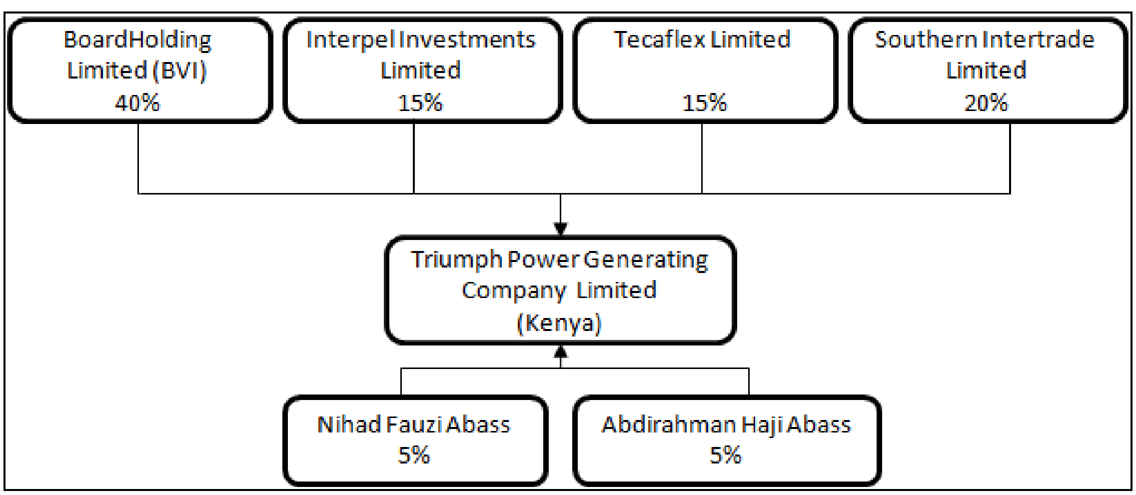
2. Thika Power Ltd. incorporated in Kenya will be owned 90 percent by Melec PowerGen (BVI) a holding company incorporated in the British Virgin Islands (BVI) and affiliated with the Matalec group and controlled by Mr. Elias Doumet (70%), Mr. Sami Soughayer (Matelec S.A.L. General Manager (15%) and Mr. Samer Nasr (IPP Business Development Director of the Matelec group, 15%). The remaining 10% will be owned by Africa Energy Resources Pte. Ltd., a local partner, owned by Mr. Narendrabhai Bhailalbhai Patel. MPG Services SAL of the Lebanon, an affiliate of Melec PowerGen Inc. with common shareholders, will be providing support to the Project in the event of cost overruns. As the Sponsor intends to develop its global power generating business under one holding company, BVI was selected as the appropriate jurisdiction to take advantage of the legal and business infrastructure available given that it is relatively simple and cost efficient to add operating subsidiaries. The revenues of the Project will be subject to tax in Kenya, and distributions will be subject to a withholding tax by Kenya. IFC is a lender to the company and has performed its due diligence and is satisfied that from a transactional stand point the corporate structure was put in place for legitimate reasons and that the British Virgin Islands is an eligible Intermediate Jurisdiction for this project. The Company's shareholding structure is given below.

Figure 1: Thika Power Limited Ownership Structure



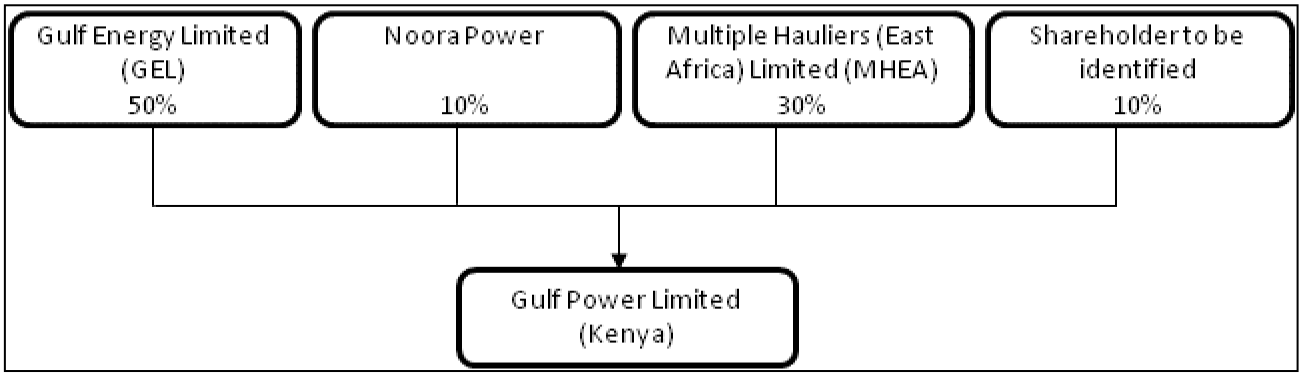
3. Triumph Power Generating Company Ltd. incorporated in Kenya will be owned by Mr. Abdirahman Haji Abass and his family-owned group of companies with Mr. Abdirrahman as Chairman of the company. The majority of the shareholding will be held by family owned group companies such as BoardHolding, Interpel Investment Ltd., Tecaflex Ltd., and Southern Intertrade Ltd., together comprising 90% of the shares. The balance of the 10% of shares will be owned equally by Mr. Abdirahman and Nihad Fauzi Abass. Tecaflex is a leading distributor of Petroleum products, automotive and consumer products while Interpel Investments is one of the leading Container Freight Stations in East and Central Africa. The company's shareholding structure is given below.

Figure 2: Triumph Power Generating Company Limited Ownership Structure



4. Gulf Power Ltd. is a special purpose company incorporated in Kenya set up by a consortium of companies who wish to enter into the power generation business in Kenya. Its shareholding is as follows:

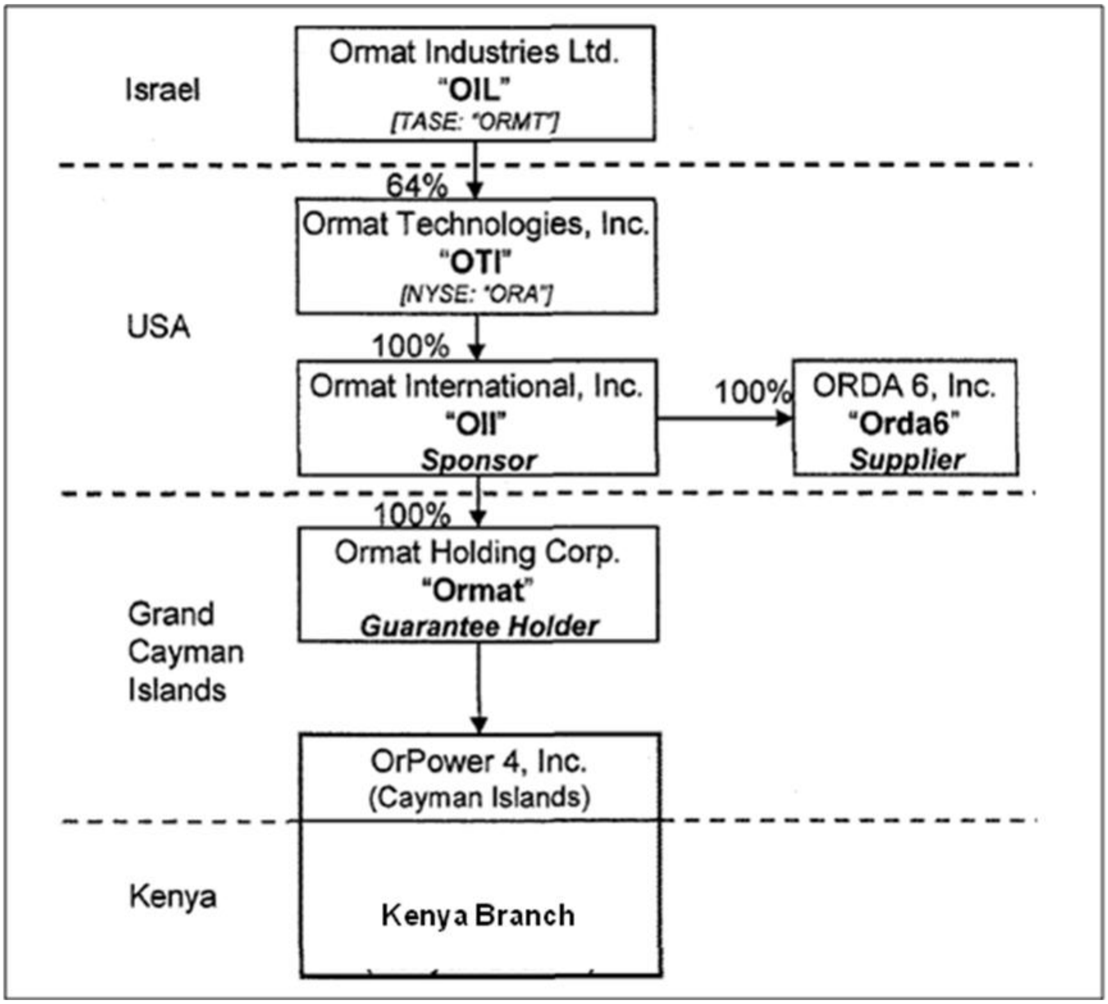
Figure 3: Gulf Power Limited Ownership Structure



5. Gulf Energy Ltd., (GEL) with controlling interest in Gulf Power Ltd., was incorporated in Kenya in 2005, and is an oil and gas trading company with operations in the East African region and among Kenya's top three importers of crude oil and refined petroleum products. Multiple Hauliers Ltd. (MHL) with 30% interest in the project company was incorporated in Kenya as a family business. Its principal activity is cross border haulage of general merchandise and petroleum products. Noora Power Ltd. (NPL) with 10% shareholding is a company incorporated in the Isle of Man. The company will be managed, controlled, and operated, by a seven-member board of directors consisting of three Directors from GEL, two directors from MHL, and one Director from NPL and one from the new shareholder.

6. OrPower 4, incorporated in the Cayman Islands, was set up to own, construct, and operate the Olkaria III project including the Olkaria sub-project. It is 100% owned by Ormat Holding Corp. incorporated in the Cayman Islands which in turn is owned by Ormat Technologies Inc. of the US. Under the new WBG policy, Cayman Islands are an acceptable intermediation jurisdiction. Orpower has set up a Kenyan branch office to undertake the Olkaria project. The shareholding structure is given below:

Figure 4: OrPower 4 Ownership Structure



Key Contractual Agreements

7. The contractual structure of the sub-projects is consistent with industry practice for limited recourse project finance transactions. A summary of key Project Agreements is given below.

Thermal IPPs

8. **Power Purchase Agreements** to be concluded will provide for the IPPs to supply power to KPLC on the basis of 'take or pay' obligations based on 85 % available plant capacity. If the IPP fails to deliver the power then KPLC will not have any obligation to pay but if the IPP can deliver but KPLC does not dispatch then KPLC would be obligated to pay capacity charges to the IPP. In the event of a force majeure event affecting the IPP, KPLC would be obligated to pay capacity payments only for the available power remaining. In the event of a 'Political Event' event, GoK would be obligated to compensate the IPP for any adverse financial impact of such an event under its Letter of Support. PPA Payments will consist of the following components: (i) a fixed capacity charge; (ii) a European or US$ CPI linked escalating capacity

charge depending on the currency of the PPA; (iii) energy charge; and (iv) fuel charge payable in US Dollars.

9. Capacity payments are fixed monthly payments made on the availability of the project. The fixed component of capacity charge represents reimbursement for debt service payments, and equity return. These charges are payable irrespective of dispatch, on the basis of contracted capacity, but subject to plant availability. The escalable component of the capacity charge represents reimbursement of costs related to fixed O&M, fixed overhead costs and insurance and is indexed to the European CPI for the Gulf and Thika PPAs which are in Euros and US CPI for Triumph whose PPA is in US Dollars. These costs are payable on the basis of the contracted c apacity of the plant, irrespective of dispatch, and adjusted according to plant availability. Energy Charges cover non-fuel variable costs that are directly related to electricity production and are based on kWh of electricity produced. Fuel costs are a pass through on the basis of a heat rate stipulated in the PPA.

10. The PPA also provides for a commissioning and testing plan for the plant for both interim Commercial Operations Date and full Commercial Operations Date. A Construction Security of US$4 million is one of the Conditions Precedent (CPs) to the PPAs. In addition, Liquidated Damages of US$25,000 per day would be payable to KPLC by Gulf and Triumph and US$45,000 per day for Thika if the IPPs do not begin construction by the Long Stop Construction Start Date or do not achieve Full/Interim Commercial Operation date within 13 months of the Effective Date of the PPA. The Long Stop Construction Date is 60 days from the Effective Date of the PPA, once the Conditions Precedent (CPs) have been met. Successful completion of the commissioning tests will be certified by an Independent Engineer. Following Commissioning, an annual Contracted Capacity Test must be conducted to demonstrate capacity, which must not exceed the Contracted Capacity at signature unless the parties agree otherwise. In the event of Force Majeure (FM) that affects the plant, the IPP will receive payments under the PPA only for the power delivered. However, if the FM event continues for 180 days then the IPP would have the right to terminate the PPA following a 90 day consultation period. If the FM event is cured before the 180 days then the PPA would be extended by the period of FM.

11. **Government Letter of Support:** GoK expects to issue to each of the IPPs a Letter of Support in which GoK will undertake to backstop KPLC's payment obligations under the PPA in the case of a KPLC FM Funding Event if KPLC is unable to make the necessary payments under the PPA as a result of Force Majeure events affecting KPLC. Under this Letter, GoK could also undertake to compensate the IPP for any 'Political Events' affecting the IPP which may include the standard political force majeure events such as war, revolution, civil commotion, expropriation, or any changes in law, taxation, regulations, that could adversely affect the IPP. If the Political Event is not eliminated or resolved within 180 days the IPP would have a right to terminate the PPA and seek a termination payment for the plant from GoK.

12. **Fuel Supply Agreement** which the IPP will enter into with Fuel Suppliers for the supply of fuel in accordance with fuel specifications stipulated in the PPA of a Maximum Sulphur Content of not more than 2%, a Minimum Calarofic Value of not less than 41,100 kj/kg, and Maximum Viscosity of 380 centi-stoke (c-St) at 50 degrees Centigrade. The IPPs are required to enter into Fuel Supply Agreements for the term of the PPA on the basis of competitive tenders,

which are approved by KPLC. Under the PPA, the IPPs are also required to ensure that they maintain fuel stock supply at the project site, which is sufficient to operate the plant at full load capacity for a continuous period of at least 20 days. Should the companies not maintain the 'Security Stock' they would be liable for Liquidated Damages and in which case KPLC would have the right to adjust the fuel charges. The fuel charges will be a direct pass through, payable in US Dollars.

13. **Land Lease Agreements:** Each of the thermal IPPs will enter into Land Lease Agreement for the term of the PPA. The Land Lease Agreements will be as follows:

- *Thika Power Plant:* The Thika Project site is adjacent to and west of the Nairobi-Thika highway, approximately 30 km north of Nairobi city. The land was acquired by KPLC from Agro Tropical and will be leased to TPL for 20 years for the duration of the PPA term.

- *Triumph Power Plant:* The Triumph Project site is situated on the Athi River in Mavoko Municipal Council on approximately 10 hectares in the Export Processing Zone (EPZ), comprising Plots No. 6 & 7, which are located behind East African Portland Cement Company. The company has negotiated two leases with the Export Processing Zones Authority (EPZA) in Kenya with respect to adjoining pieces of land for a term of 50 years. The leases have been executed by Triumph and EPZA and have been lodged for registeration.

- *Gulf Power Plant*: GPL will enter into a lease agreement with KPLC, who is the owner of the land on which the plant will be located, for use of the land over the term of the PPA. KPLC and the project sponsors are close to finalizing the final suitability and lease arrangements for the site.

14. **Engineering and Procurement and Construction (EPC) Contract**: The EPC contracts for the three thermal Projects will be a fixed price, turnkey, contract for the plant with provisions for Liquidated Damages (L/Ds) for delays and for plant performance and incentives for early completion.

15. **Operations and Maintenance (O&M) Contracts will range from** 5 to 10 years with a five year contract between Triumph and XJ Group for the Triumph Power Plant, a six year contract between Thika and MAN Diesel & Turbo France SAS for the Thika Power Plant, and a ten year contract between Gulf and Wartsila Eastern Africa Ltd. for the Gulf Power Plant. The scope of the contracts includes routine operation, maintenance of the plants, as well as services during scheduled outages and major overhauls, including the provision of spare parts. The performance parameters are stipulated in the contract in terms of availability, capacity, and efficiency and also liquidated damages in case of non-compliance.

16. **Direct Agreements.** The lenders expect to enter into Direct Agreements with KPLC and GoK, which will include customary clauses for such an Agreement, including acknowledgement of security interests and enforcement rights under the project agreements for the benefit of the lenders.

Olkaria IPP

17. OrPower will implement the Olkaria III expansion through the additional development of the geothermal field, modification of the existing Plant I and construction and integration of Plant 2 through a turnkey, fixed price, date-certain construction of the expanded Facility. Orpower will conduct the geothermal field development activities, import the equipment and materials and undertake through local subcontracts the construction of the expanded Facility. In addition it will enter into the following Agreements:

- **Supply Contract** with Ormat Systems Ltd (OSL) a Group company. Under this contract, OSL will be responsible for the conceptual design of the power plant and for the supply of materials and equipment from outside of Kenya, and will guarantee performance and warranty material and equipment.

- **Pricing, Coordination and Security Contract** with Orda 6, a Group company. Under this contract, Orda will guarantee the plant costs and will cover cost overruns for the supply, transportation, and construction works.

- **Amended and Restated PPA**. KPLC and Orpower entered into the original Power Purchase Agreement in November 1998 with subsequent Supplemental Agreements dated July, 2000 and the Second Supplemental Agreement dated April 2003 relating to the existing Facility and the Amended and Restated Power Purchase Agreement dated January 19, 2007 which amended all the prior Agreements relating to the existing Facility. In March 2011, KPLC and Orpower entered into an Amended and Restated Power Purchase Agreement with the purpose of extending the Agreement to cover the expansion Facility as well as the option for Plant 3 which Orpower is contractually expected to exercise by September 2015 at the latest. Under this Agreement OrPower was required to undertake the Geothermal Reservoir Development, design, procure, construct, finance, test, commission, the transmission interconnector, design, procure, construct, finance, test, commission, operate, and maintain the generation facilities, and sell the Net Electrical Output to KPLC. KPLC on its part undertook to purchase and pay for Available Plant Capacity and Net Electrical Output of the generation facilities in US Dollars. Unlike in the case of the thermal IPPs, KPLC has the obligation under the PPA to make capacity payments to the IPP in the event of both natural and political force majeure events regardless of availability of the plant (with some adjustments for capacity payments for the unavailable part of the plant in certain force majeure events). However, the cure period for termination for force majeure events is longer than for the thermal IPPs of 270 days following a 90 day consultation period.

- **Amended and Restated Security Agreement.** Under an Amended and Restated Security Agreement dated March 2011, KPLC agreed to provide security in the form of Letters of Credit issued for a year (renewable) for payments due from KPLC for the existing facility and the expansion with a view for these to be replaced by an IDA Guaranteed L/C once IDA's Board approval is obtained and the relevant L/Cs become due for renewal.

- **Government Letter of Support:** As in the case of the thermal IPPs, GoK will issue its Letter of Support to Olkaria to compensate it for any shortfall in payments by KPLC in the event of a 'Political Event'. GoK will backstop any shortfall of KPLC's payment obligation only in the event of a 'Political Event'. However, unlike in the case of the thermal IPPs, GoK has no obligation relating to a KPLC FM Funding Event for Olkaria III.

<u>KPLC Implementation Plan</u>

18. As stated above, once the PPA becomes effective, the implementation of the sub-projects is contractually the responsibility of the IPPs. The role of KPLC includes (i) facilitating coordination among all relevant institutions so that transaction and implementation costs can be minimized through streamlined arrangements; and (ii) serving as a single-point tracking of all project outcomes, accounts and safeguard compliance. Coordination and monitoring of implementation of the four IPPs will be carried out by the Energy Transmission Division of KPLC through the various Departments within the Division. The Chief Manager (Energy Transmission) is the responsible executive reporting to the Managing Director. The key coordination and monitoring activities are detailed below.

19. During the construction phase, KPLC will receive a monthly report showing the extent to which each material task in the Construction Programme has been completed and the expected completion date for each outstanding task. These reports are received and reviewed by KPLC's Energy Purchase Department in the Energy Transmission Division of KPLC. KPLC will facilitate connection of the Plant to the network and dispatch the Plant as required for the purposes of testing and commissioning. Also an independent engineer will issue a certificate on completion of commissioning.

(a) **Construction**

- KPLC monitors the construction through monthly progress reports provided by the Seller.
- Where necessary, KPLC carries out inspection at Site of all plans and designs to confirm compliance with the PPA.
- All protection schemes for the interconnector are approved by KPLC prior to installation.
- After construction the Seller is required to provide KPLC with copies (both reproducible and white prints) of all 'as built" plans and designs relating to operation and maintenance of the plant.

(b) **Commissioning**

- KPLC approves the appointed of an Independent Engineer to witness the commissioning of the plant.
- KPLC reviews the commissioning procedures. The procedures are provided by the Seller and are subject to agreement between KPLC and the Seller.
- The commissioning tests are witnessed by KPLC representatives.

- The seller is obliged to give KPLC notice whenever a commissioning test is to be conducted.

- The commissioning tests include:
    - Tests prior to synchronisation of each unit
    - Capacity demonstration tests
    - Reliability tests
    - Black start tests
    - Environmental performance tests

- On completion of each test, the Seller provides to KPLC test reports with the Independent Engineers certificates.
- Full commercial Operation only occurs when the minimum criteria specified for each test has been certified.

(c) **Operation**

- KPLC inspects and tests the metering system at least once in every period of six months.
- KPLC participates in fuel procurement by reviewing the tender documents and approving the tender award.
- All maintenance programmes for the plant are reviewed and approved by KPLC.
- KPLC ensures that the Seller conducts the annual contracted capacity tests which are witnessed by KPLC.
- KPLC's National Control Centre issue dispatch instructions to Seller through:
    - Year ahead, month ahead, week ahead and day ahead notifications
    - Actual performance of the plant is monitored on half hourly basis by comparing the actual output against dispatch instructions.

Financial Management, Disbursements and Procurement

20. Financial Management monitoring is not applicable for a PRG operation, where IDA resources are not utilized for direct financing and procurement. Discussion on procurement and selection of the three IPPs is contained in Annex 11 on Procurement Arrangements**.**

Environmental and Social (including safeguards)

21. The proposed project has triggered OP 4.01, Environmental Assessment, and is assigned the environmental category A, given that there are four different power plants in different locations, three of which will be green field projects. Draft ESIA reports were prepared for the Triumph Plant in November 2010 and Gulf Power in April 2011, while a detailed scoping report of an ESIA was prepared for the Thika Plant in February 2011. It was determined that the Draft ESIA prepared at that time for the Gulf Power plant could serve as a model of good practice for an ESIA suitable for power plants of this size using MSD or Heavy Fuel Oil (HFO). A modified version of Gulf's ESIA was adapted as an Environmental and Social Management Framework (ESMF) for the other two thermal power plants for which ESIA work was still in progress at that time. An ESMF based on the draft ESIA for the Gulf Plant has been prepared for the three green

field thermal power plants, and complies with IFC and World Bank requirements. The ESMF, and all other relevant safeguard documents for the expansion of the existing geothermal power project, have been disclosed both in country, and at the Bank's InfoShop, prior to appraisal and 120 days prior to Board approval.

22. The ESMF and the Gulf Power ESIA were disclosed locally and in the InfoShop on May 23, 2011. Subsequently, the finalized ESIA for the Thika MSD thermal power plant was disclosed locally and at the InfoShop on November 3, 2011. The final ESIA for the Triumph MSD thermal power plant was disclosed locally and at the InfoShop on December 22, 2011. MIGA has guaranteed an investment in the Olkaria III geothermal project since March 2002, with a second guarantee offered for the second phase expansion in December 2007. Therefore, information regarding WBG involvement in the Olkaria III project has been disclosed since 2002. Notwithstanding earlier disclosures, the Bank disclosed locally and in the InfoShop on June 9, 2011, the following key documents for the Olkaria III project: (1) the initial (August 2000) EIA, which noted that the project would be expanded in phases over time to 100 MW and assessed from that perspective; (2) the supplement to the EIA dated May 2001; and, (3) the most recent (2010) environmental audit of the existing Olkaria III project operations.

23. Spot sampling of air quality parameters at all three sites indicate they lie in non-degraded airsheds, and the majority of air quality measurements lie within acceptable World Health Organization and Kenyan guidelines. It is understood that fuel oil used shall be of no more than 2% sulphur content, as per WBG Environmental Health and Safety Guidelines and the PPA.

24. The Environmental Management Plan (EMP) for each IPP describes monitoring programs and reporting procedures to the authorities. In the case of Triumph Plant, the project proponents will continue to liaise with Kenya Wildlife Service (KWS) and Nairobi National Park, given the proximity of the Park to the Plant, and provide regular summaries of meetings and any concerns of the KWS or Park officials. In the case of the Gulf Plant, once the plant is operational, bi-annual passive monitoring of ambient SO_2 and NO_2 shall be conducted at Lukenya School and the Superior Homes housing estate to ensure ground-level concentrations are within the relevant limits. If after two sampling campaigns (one month in summer and one month in winter) the relevant limits are not exceeded, monitoring will be discontinued. If levels repeatedly exceed limits at these sites, mitigation measures may need to be adopted. Bank staff will supervise the project as is normal practice with PRGs.

Monitoring & Evaluation

25. Data for monitoring Project outcomes and results indicators will primarily be generated by the IPPs and compiled by KPLC in progress reports, annual reports, etc. as well as by Lenders' Independent Engineers during the construction phase. IDA will monitor and supervise through submission of reports by the IPPs required under IDA's Project Agreement with each IPP and submission of relevant reports by KPLC required under IDA's Indemnity Agreement with GoK as well as through regular field visits until the expiry of each PRG. Annex 1 presents the Project's results framework that defines specific outcomes and results to be monitored.

Annex 4: Operational Risk Assessment Framework (ORAF)

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Stage: Board

1. Project Stakeholder Risks		**Rating**	**Moderate**
Description: There could be a perception that the technology choice is sub-optimal in terms of its environmental impact and that it is relatively high-cost, potentially adversely affecting consumer tariffs. The Sponsors for the thermal IPPs have limited or no experience of managing and implementing power projects.	**Risk Management:** The choice of technology corresponds with urgent, short-term needs for power generation in Kenya until cheaper, cleaner options come on line. As such, the strategic decision to support the three thermal IPPs is justified until the planned geothermal, wind, and low-cost imported hydropower from Ethiopia are commissioned. Once these other cleaner sources of supply are available, the three thermal IPPs will be utilized to provide power during periods when demand is highest. KPLC will undertake strategic communications outreach to clarify the technology choice to stakeholders. The political economy of continued electricity shortfalls and the prohibitive economic and financial costs to Kenya of foregoing power generated from these sub-projects is, more broadly, a risk mitigant. As part of its communications plan, KPLC will clarify that analysis suggests that electricity supply is likely to outstrip demand for only four years (2017-2022), when the supply from cheaper regional hydros may reduce the need for full availability of the thermals. The Sponsors have contracted experienced EPC and O&M contractors as well as experienced 'Owner's Engineers' to help them manage and implement the sub-projects. In addition, the project financiers will be closely monitoring the sub-projects as well as IFC, IDA and MIGA through regular supervision. **Resp: Client | Stage: Implementation| Due Date : Continuous | Status: Ongoing**		
2. Implementing Agency Risks (including fiduciary)			
2.1 Capacity		**Rating:**	**Low**
Description: Risk of a lack of competent staff at KPLC with adequate skills and technical knowledge to oversee the projects.	**Risk Management** : KPLC has a well-established technical and fiduciary track record. Key KPLC staff include seasoned professionals with solid technical backgrounds in the sector. KPLC managerial staff are subject to performance contracting that facilitates their accountability. As a publicly traded company KPLC undergoes considerable public scrutiny of its operations. Resp: Client | Stage: Implementation | Due Date : Continuous| Status: Ongoing		

2.2 Governance	**Rating**	**Moderate**
Description: (a) The risk that ERC, Kenya's energy regulator, may not continue to allow regulatory approval of fuel cost pass-throughs in the Power Purchase Agreemnts (PPAs) and in the retail electricity tariffs. (b) The risk of KPLC payment delays for power supply can make sub-projects unsustainable. (c) Integrity remains a source of risk for any investment in Kenya.	**Risk Management** : (a) IPPs are able to pass-through costs of fuel through their PPAs to KPLC. Additional amounts as contingencies have been added to the PRGs amounts to accommodate high fuel price volatility. ERC, the autonomous energy regulator, has always applied fuel cost adjustment provisions in PPAs and in the retail tariff as well as adjustments for inflation and currency changes. (b). KPLC has a good track record of making timely payments for delivered energy from KenGen and IPPs, thereby providing considerable comfort for the sustainability of the IPP transactions. KPLC is deploying new metering and billing technologies that will improve its collections from customers and thereby improving its cash collections and mitigating the risk of delayed or lost revenues. The PRGs will further reinforce KPLC's payment security through the L/C structure, which provides liquidity in the event of unforeseen payment interruptions. (c). A transparent, competitive procurement process for private sponsors as well as multiplicity and diversity of the selected EPC and O&M suppliers and vendors minimizes the risk of conflicts of interest as well as price collusion on contracts. Technologies are relatively standard and are priced at or below recent global benchmarks. World Bank Group has been proactive on integrity issues. Close coordination of conducting integrity and background checks of sponsor groups (both individuals and companies) with IFC, MIGA and other DFI and commercial lenders provides additional comfort on the issue of integrity associated with the sub-projects. **Resp: Client| Stage: Implementation | Due Date: Continuous| Status: Ongoing**	
3. Project Risks		
3.1 Design	**Rating:**	**Moderate**
Description: **Technical Risk:** Risk that sub-projects will not be implemented properly because of technical reasons or capacity constraints.	**Risk Management**: Technical risk is mitigated by the fact that the technology (reciprocating diesel engine technology using HFO) of the three thermal IPPs is standard and that there is worldwide experience of its successful operation in diverse environments. In the case of the Olkaria III expansion sub-project, the technical risk is also considered moderate since this will be the third extension of a successfully operating power plant. Phase 1 involved the construction of a 13 MW power plant, which subsequently was expanded to an aggregate capacity of 48 MW that was completed on time with no cost overrun and has been operating successfully since 2009. **Resp: Client | Stage: Implementation | Due Date: Continuous| Status: Not yet Due**	

Operational Risks: Market demand and prices of Heavy Fuel Oil may increase significantly, no longer making it a cost-effective option for electricity generation.	Operational risks are mitigated by the ability to pass-through fuel costs. IPPs are able to pass-through costs of fuel through their PPAs. Additional contingencies and indexation have been added to IDA coverage for L/C structure to accommodate high fuel price volatility. **Resp: Client | Stage: Implementation | Due Date: Continuous| Status: Not yet Due**		
3.2 Social & Environmental		**Rating:**	**Moderate**
Description: The risk that EMPs related to the selected sites are not adequately implemented by the private developers.	**Risk Management:** KPLC is experienced in the application of the World Bank's environmental safeguards. KPLC's Environment Unit has sufficient capacity to monitor the mitigation of potential adverse environmental and social impacts through regular environmental monitoring and periodic environmental audits. WB/MIGA/IFC will also monitor through regular supervision. **Resp: Client | Stage: Implementation | Due Date: 05/02/2012| Status: Not yet Due**		
3.3 Program and Donors		**Rating:**	**Moderate**
Description: The risk that delays in financial closure could delay the completion of the sub-projects.	**Risk Management**: The Sponsors have already secured much of the agreed terms for the necessary financing from a diverse group of financial institutions comprising of IFC, African Development Bank, ABSA, Standard Bank, and OPIC. **Resp: Client | Stage: Prep | Due Date: 05/02/2012| Status: Not yet Due**		
3.4 Delivery Monitoring and Sustainability		**Rating**	**Low**
Delayed payments for power supply could undermine delivery and threaten sustainability.	**Risk Management:** KPLC is a strong off-taker with a good track record of timely payments for delivered energy, thereby providing considerable comfort for the sustainability of the IPP transactions. The WBG risk mitigation framework further strengthens KPLC's ability to stand by PPA obligations. The L/C structure provides security to the IPPs and their lenders about timely payments under the PPA. **Resp: Client | Stage: Implementation | Due Date: Continuous| Status: Not yet Due**		
4. Overall Risk Following Review			
Implementation Risk Rating: Substantial			
Comments: A "substantial" risk rating has been assigned largely due to the country context and exogenous factors that could impact the project performance. The risks of the sub-projects are considered manageable during implementation.			

Annex 5: Implementation Support Plan

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Strategy and Approach for Implementation Support

1. The Implementation Support Plan (ISP) described in the table below explains how the Bank and other development partners will support the implementation of the risk mitigation measures which has been identified in the ORAF annex. It is also linked to the results/outcomes identified in the result framework annex.

Implementation Support Plan

2. Implementation Support Plan. The level of technical support needed includes staff with energy sector knowledge and expertise; specialized commercial PRG expertise including commercial legal counsel and financial experts; safeguards specialists; power engineering as well as Monitoring and Evaluation (M&E) expertise. The main focus in terms of support during implementation is summarized in the table below:

Time	***Focus***	***Skills Needed***	***Resource Estimate***	***Partner Role***
First twelve months	Effectiveness, financial closure, selection of L/C banks, safeguards, construction progress, political developments	Sector Safeguards Commercial (Financial, Legal) Engineer Country team	$150,000	The IPP Program is facilitated and coordinated by KPLC. The 4 IPPs will implement the sub-projects. AfDB, IFC and MIGA will also supervise these 4 sub-projects and share inputs with IDA team.

12-60 months	Review of progress in construction and generation by the 4 IPPs; review of sector technical and financial performance; safeguards; development of Kenya's generation expansion plans, financial performance of KPLC and the 4 IPPs sub projects.	Sector Power Engineer Commercial Financial Legal Safeguards Environment Social Economist	$100,000	AfDB, IFC and MIGA will supervise these 4 sub-projects and contribute inputs to maximize efficiency of IDA supervision.
Mid-term review	Review implementation progress of KPLC and the 4 IPPs sub-projects against indicators.	Sector Economist Commercial Financial Legal Engineer Safeguards Environment Social M & E	$100,000	AfDB, IFC and MIGA provide inputs on sub-projects for mid-term review.
Completion report	Review status of Completion against indicators and PDO.	Sector Economist Commercial Financial Legal Engineer Safeguards Environment Social M & E	$75,000	Provide inputs for completion review and reporting.

3. I. Skills Mix Required

Skills Needed	***Number of Staff Weeks***	***Number of Trips per year***	***Comments***
Team leader	4	2	
Power engineer	4	0	
Energy sector specialist	4	1	
PRG Specialist (Commercial)	4	2	
Financial analyst	4	1	
Energy economist	4	1	
M & E expert	4	1	
Lawyer	6	2	
Environment specialist	4	2	Category A projects require two annual supervision missions (combined with other supervision missions if possible).
Social specialist	2	0	Staff are based in country offices.

4. II. Partners

Name	***Institution/Country***	***Role***
Mr. Patrick Nyoike	Ministry of Energy, Kenya	Coordinator, Energy Sector, GoK
Mr. John Murugu	Ministry of Finance, Kenya	Director of Debt Management at Treasury, GoK
Mr. Joseph K. Njoroge	KPLC	MD & CEO, KPLC
Mrs. Laurencia K. Njagi	Company Secretary, KPLC	Counterpart at KPLC
Mr. Richard Claudet (Thika)	African Development Bank	Co-financier
Mr. Elam Muchira (Thika) Mr. Yuji Kano (Gulf)	IFC	Co-financier
Mr. Zhengrong Lu (Thika) Mr. Alan Narayadu (Triumph)	MIGA	PRI Provider

Annex 6: Sector Reform, Challenges and World Bank Support

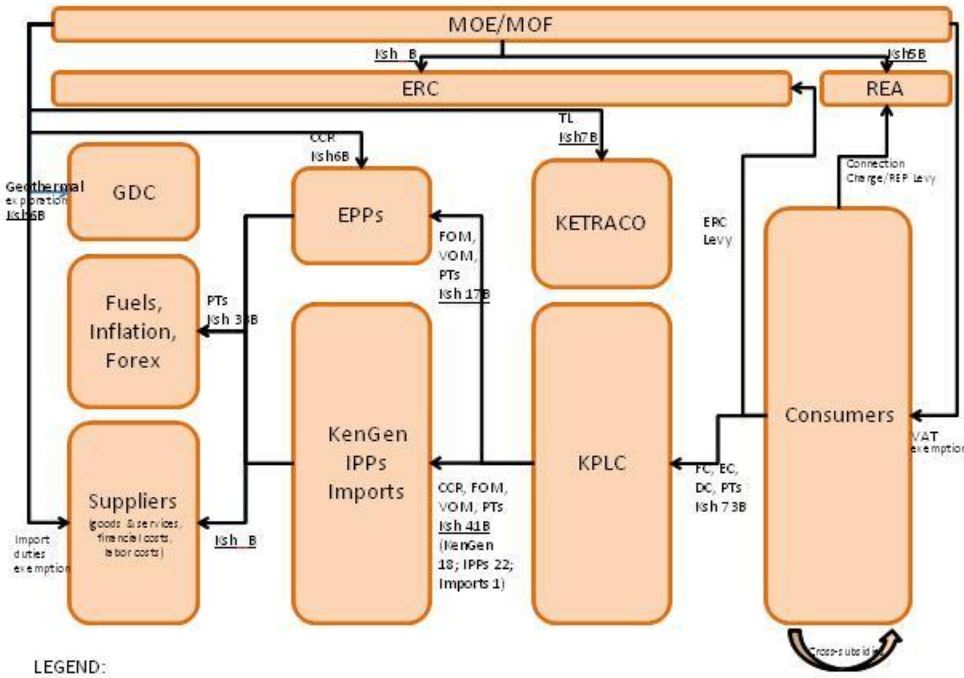
KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

I. Sector Reform

1. **The electricity sector in Kenya is to a large extent financially self-sustainable** due to sound regulatory policies that are applied to the terms of power purchase agreements between power generators and KPLC as well as to the design of the retail tariffs charged by KPLC. Currently, operational fund flows in the electricity sector (Figure 1) is sufficient to meet debt repayment and interest payment obligations of about US$60 million (KSh 5.3 billion) at current tariff levels due to the institutional and regulatory set up of the sector as described below.

2. **Regulation of Tariffs.** The Energy Act of 2006 mandates the ERC to "set, review and adjust electric power tariffs and tariff structures, and investigate tariff charges". The Act maintains that all tariffs charged for electricity supplied shall be "just and reasonable," that enables an electricity supply license holder to (i) maintain its financial integrity, (ii) attract capital, (iii) operate efficiently; and (iv) fully compensate investors for the risks assumed. The existing electricity tariff structures as well as its adjustment mechanisms were designed following a tariff study in 2006 supported by the World Bank. The types of electricity tariffs can be broadly classified as bulk (wholesale) generation and retail. The current tariffs were established effective July 2008 for a period of three years. The Retail Electricity Tariff Review for the period 2012-2014 is ongoing (and is addressing such issues as wheeling charges and time of use). In the interim, pending the outcome of the Tariff Review the ERC will take into consideration any projects that are commissioned (such as the proposed IPPs). The Bank-funded Kenya Electricity Expansion Project (KEEP) is financing a cost of service study that will be an input to the next Tariff Review.

Figure 1: Operational Fund Flows in the Electricity Sector in Kenya (2010)



LEGEND:
Organizations: Ministry of Energy (MOE); Ministry of Finance (MOF); Energy Regulatory Commission (ERC); Rural Electrification Authority (REA); Kenya Electricity Generating Company (KenGen); Kenya Electricity Transmission Company (Ketraco); Kenya Power and Lighting Company (KPLC); Geothermal Development Company (GDC); Independent Power Producers (IPPs)
Retail Tariffs: Fixed Charges (FC); Energy Charges (EC); Demand Charges (DC)
Wholesale Tariffs: Capacity Charge Rate (CCR); Fixed O&M (FOM); and Variable O&M (VOM)
Pass-Through (PTs): Fuel, inflation, and foreign exchange; Transmission Line Investment (TL); Rural Electrification Program (REP).

3. **Key Features of Tariff Mechanisms.** As elaborated in subsequent paragraphs, the electricity tariff mechanism in Kenya broadly allows KPLC to cover the full cost of service provision, except for a few items described in the paragraphs on subsidies and risks below. A key feature of the current mechanisms is that fuel costs and exchange rate fluctuations are passed through by bulk suppliers via KPLC to end-consumers on a monthly basis and adjustment for inflation takes place every six months. This arrangement shields the electricity suppliers from some of their market risk exposures. It is acknowledged that consumers face considerable volatility[29] arising from the Fuel Cost Charge in their monthly electricity bills arising from changes in international oil prices and the share of thermal generation in the total. Nevertheless, it is important that the monthly bill accurately reflects the cost of power generation and supply in order to give consumers incentives to use electricity efficiently. The tariff regime in Kenya thus reflects international best practice with regard to adjustment of costs that are not in the control of KPLC (fuel, inflation and foreign exchange). The adjustments for local inflation cover 50 percent of the actual rates, making the regulation resemble a type of incentive regulation,

[29] The electricity bill for households consuming 120 kWh per month, increased from the equivalent of US$18 in January 2011 to US$28 in December 2011 before falling to US$22 in January 2012.

although, the efficiency gain factor assumed (i.e. 50 percent of the local inflation) may be rather stringent.

4. **Fuel Oil Procurement.** Heavy fuel oil (the main fuel used by IPPs) is procured on the open market (i.e. it is not subject to the price control regime that governs kerosene, automotive diesel and petrol). In the case of IPPs, they must obtain KPLC's consent prior to entering into a Fuel Supply Agreement. The procurement process defined in the PPAs require that IPPs tender on the open market and KPLC reviews the Bid Evaluation Reports.

5. **Regulation of Bulk Tariffs.** The bulk electricity supply by generators to KPLC is guided by PPAs, which are reviewed and approved by ERC. Under a PPA, the fixed costs of investment for generation by developers are compensated through capacity payments while variable costs of electricity generation are covered through energy payments. The capacity payment consists of (i) capacity charge rate (depreciation on assets in operation, weighted average cost of capital on the regulatory rate base, and taxes), (ii) fixed O&M charge (salaries and administrative expenses, overheads, insurance and maintenance, and other fixed costs), while the energy payment includes (iii) variable O&M charge (fuel expenses, spare parts, chemicals, consumables, and other variable costs). A generator is entitled to receive the capacity payments in full as long as it meets the contractual target for generating plant availability. The energy payments, on the other hand, are based on the volume of electricity generated. Merit order of electricity dispatch is established by comparing the variable cost of generation (including fuel costs) for consumers. The actual dispatch also takes into account demand and voltage support requirements of the grid. Currently, the export and import of electricity with neighboring countries are charged at the rate of emergency supply, making it higher than other sources of power.

6. **Regulation of Retail Tariffs.** The current retail tariff was prepared based on the Retail Electricity Tariff Review Policy in September 2005 by the Electricity Regulatory Board (ERB), the predecessor of the ERC, with inputs from a Bank-supported tariff study finalized in January 2007. The retail tariff is organized by the following consumer categories: domestic consumers (DC), small commercial consumers (SC), commercial and industrial consumers (CI), interruptible off-peak supplies (IT), and street lighting (SL). In each category, fixed charge, energy charge, and/or demand charge are applied. The fixed charge is designed to recover the customer-related cost of metering, inspection, maintenance, billing and customer accounting; the demand charge is intended to recover the costs of the transmission and distribution network, and is currently applied to the commercial and industrial (CI) consumer category; and the energy charge is set to recover the variable costs associated with electricity supply. As mentioned above, other charges including fuel cost, foreign exchange fluctuation, and inflation are adjusted and passed through to end consumers separately and uniformly on per kWh-basis, irrespective of consumer categories.

7. **Feed-in-Tariffs.** Besides the regular tariff mechanisms, the Ministry of Energy has introduced feed-in-tariffs (FiTs) in 2008 to promote private investment in small scale renewable energy. The policy was revised in 2010, and it now includes electricity generated from biogas, biomass, geothermal, small hydro, solar, and wind. The FiTs are fixed in levelized terms by technology types, based on the average estimated cost of renewable energy sources. The system operators are obliged to guarantee priority off-take from FiT-eligible renewable sources, and

70% of the FiT costs (85 percent in the case of solar photovoltaic and solar thermal) are passed through to consumers. To date, there have been 49 proposals of which 42 proposals are approved (20 wind; 4 biomass; 16 hydro; 1 biogas; and 1 cogeneration).

8. **Subsidies and Cross-subsidies.** To a large extent, the Kenyan electricity sector is financially autonomous due to its tariff designs. However, a few subsidies are provided by the Government as follows: (i) a subsidy is provided for the capacity payment of emergency power plants (EPPs) while fuel costs are borne by consumers; (ii) VAT applied to energy consumption (reduced from 16 percent to 12 percent in 2009, only for electricity and electrical equipment) is exempt for the domestic consumption charges up to 200 kWh per month; (iii) import duties are exempted for electricity and electrical equipment; (iv) new investment in transmission lines implemented by KETRACO; and (v) geothermal exploration and drilling conducted by GDC are supported by Government-funding. In addition to the public financial support, there are some cross-subsidies, such as: (i) the uniform tariff structure applied across the country irrespective of geography (and time of use) suggests a cross-subsidy from current customers to new customers that require investment in grid extension; and (ii) within the domestic consumer (DC) category, lifeline consumption of up to 50 kWh per month is cross-subsidized by consumers of higher consumption categories.

9. **Hydrological Impacts.** Even though more than half of Kenya's installed generation capacity is hydroelectric, the country experienced in 2008 and 2009 the worst hydrological condition for hydroelectric power in more than past 60 years, as measured by the average annual river inflows at Tana River. Accordingly, the electricity generated from hydro sources was reduced from 3,488 GWh in FY2008 to 2,170 GWh in FY2010. To compensate for this reduction, thermal generation from IPPs increased by 963 GWh and emergency power by 540 GWh, resulting in higher costs particularly of fuels. Although this risk is addressed by the Government's policy to diversify electricity generation sources, the adverse hydrology is posing the risks of: (i) the system becoming unreliable, (ii) reduced revenues particularly for KenGen, and (iii) some burden of capacity payment subsidy for the Government and tax payers; and (iv) higher electricity cost for consumers. However, in FY2011, hydroelectricity generation regained a level of 3,427 GWh, reducing the dependency on emergency power generation by 833 GWh and thereby also cutting the cost of fuels, which on average came down from KSh 5.28 (US$ 5.29 cents) per kWh in FY2010 to KSh 3.79 (US$3.80 cents) per kWh in FY2011.

10. **Affordability.** According to a socio-economic survey of 1,776 households carried out in preparation for the Rural Electrification Master Plan in 2008, a sample of non-electrified Kenyans spend about KSh 1,128 per month (US$14) for energy substitutable by electricity. Mechanically applying the current tariff structure, prevailing as of December 2010, this amount of money would theoretically allow a domestic electricity consumption of about 90 kWh per month. This compares slightly favorably with the average monthly consumption enjoyed by KPLC's current domestic customers (KSh 1,400 for 85 kWh per month). However, with an expected trend of increasing tariffs, the issues of willingness and ability to pay need to be monitored closely.

II. Sector Issues

In spite of the significant structural reforms implemented in the power sector and the financial health of the major power offtaker-KPLC, Kenya is confronted by a number of short and medium-term challenges.

11. **Emergency generation capacity is required to reduce electricity shortfalls in the short-term (until 2013 when the proposed IPPs are commissioned).** Currently, of the total installed capacity of 1,430 MW, of which hydropower accounts for about 51 percent. This capacity, most of which is on one river system is prone to drought, such as occurred in 2009 and again in 2011. Beginning in July 2011 hydropower production has been reduced by about one third below normal levels of production. In order to meet demand, the Government has contracted 60 MW of "emergency" generation capacity -- consisting of containerized units running on diesel oil -- has a relatively rapid installation time but the cost of power from emergency units is more than double that of geothermal units (about US$0.25 cents per kWh compared to US$0.10 cents per kWh from the geothermal units operated by KenGen). In the first half of 2011 there was daily load shedding (as much as 100 MW during evening peak times). The electricity demand outlook through 2015 anticipates that supply will be inadequate without 288 MW that will be provided by the four proposed thermal IPPs to be commissioned in 2013. The energy balance (Annex 8) shows that until significant additional generation capacity (including imports) is commissioned starting in FY2016-FY2017 there would be extensive load shedding and insufficient reserve margin without these four thermal IPPs. The four IPPs will enable all emergency generation to be discontinued in 2012 once the plants are commissioned.

12. **Dependence on thermal generation will be reduced in the medium-term (by 2016), when additional wind and geothermal capacity projects are commissioned and the Eastern Corridor is operational**. The development of additional wind and geothermal capacity will permit imports of low-cost hydro-power from the region (initially from Ethiopia) and enables sharing of reserve generation capacity between countries. Until these projects are commissioned, there is need to moderate the cost by avoidance of emergency generation that is the most costly of all sources. The proposed IPPs, by avoiding emergency generation, will moderate the cost.

13. **Currently, high electricity prices are a significant item of household expenditure especially for poor households.** For those households with electricity service from the national grid that consume the modest amount of 120 kWh per month the average cost per unit (kWh) was about US$0.19 cents, which can absorb an estimated 20 percent of the monthly budget of lower-income households. This compares to an average price of US$11.5 cents per kWh for residential customers in the United States in 2009. The World Bank's Poverty and Inequality Assessment for Kenya of 2008[30] concluded that improved infrastructure access, including electricity access is associated with movement out of poverty.

14. **Pro-poor policies address the high cost of electricity service for lower income households**. The cost of household connection, paid up-front to KPLC, starts at around KSh 35,000 (about US$460), which is prohibitive for poor households. To address the issue of affordability GoK and KPLC are testing a number of pro-poor policies and operational practices.

[30] *Kenya Poverty and Inequality Assessment*, World Bank, July 2008, report No. 44190-KE.

These include a policy of a low connection fee for households in slums amounting to about US$16 equivalent. In its initial roll-out, GPOBA, IDA and KPLC will share the cost of the subsidy for a given number of connections under the IDA Electricity Expansion Project. In additional a lifeline energy charge of about US$ 2.3 cents is applied to the first 50 kWh of consumption benefiting poor households.

15. **The low level of electricity access constrains the achievement of national socioeconomic objectives, which emphasize greater equity of opportunity.** The countrywide access rate (defined as households with a connection to the national power grid) is presently about 25 percent, with the rest having to rely on fuel-based lighting, dry cell batteries, and other electricity substitutes that are costly and often unreliable. Electricity access in Kenya is low when compared to the country's peers. For example, Ghana has per capita income of US$590, which is 4 percent lower than that of Kenya (US$680) but more than 50 percent of its population has access to electricity. The Government has set a target of 40 percent household access by 2020 to enable the planned level of economic development and to reduce imbalances among regions and between urban and rural areas.

III. World Bank Support for Government Strategy in the Electricity Sector

16. **The Bank has an active role of support for the government's strategy across a broad front of interventions.** Through its ongoing investments projects (the Electricity Expansion Project (KEEP) and the Energy Sector Recovery Project) it is financing the expansion of geothermal generation capacity along with other donors that will add 280 MW capacity to the system. When commissioned in 2014 this will account for 11% of generation. In the same projects it is financing electricity network (transmission and distribution infrastructure in urban and rural areas) that will improve the reliability of electricity supply and help meet the government goal of increasing electricity access to 40% of households from 25% in 2009. It is catalyzing slum electrification through output based financing of KPLC's program that utilizes technologies and innovation in billing and collection that are adapted to low income consumers.

17. **Technical assistance in the Bank's ongoing projects is supporting a number of key initiatives to further power sector reform and sector regulation**. These include the following: development of a power market (through preparation of regulations for supply contracts between eligible consumers and authorized generators); development of regulatory instruments and technical guidelines needed to effectively integrate electricity generated by small-scale electricity generation using renewable energy technologies; cost of service study that will be the basis for tariff determination; and study and identification of optimization measures and necessary improvements for the power supply system to meet agreed system reliability standards.

18. **The Bank has supported the development of a Renewable Energy Investment Plan (IP)**. The Plan identifies the strategic priorities for renewable energy development and the criteria for selecting specific activities for inclusion in the IP. This has been prepared in the context of the Scaling-Up Renewable Energy Program in Low Income Countries (SREP) program for which the Bank is acting as the lead institution in Kenya. The Plan targets two groups of interventions (a) greenfield geothermal resource development and mobilizing large

scale public and private financing; and (b) renewable energy hybrid mini-grid systems in dispersed communities based on public private partnerships.

19. **Bank support for regional power grid integration through support for the development of the Eastern Africa Power Pool and its flagship transmission interconnection projects.** Integration of Kenya with the power systems of the other countries of East Africa will bring numerous benefits. By favoring development renewable resources, integration will displace thermal generation that would otherwise be constructed in Kenya and elsewhere. Integration will support supply security and reliability and bring costs savings through system optimization. The Bank is active in the ongoing technical planning being carried out to realize the EAPP and has initiated preparation of investment projects for transmission infrastructure that will link the Kenya electricity system to that of Ethiopia and Tanzania. The 2nd Phase of the Regional Power Trade Project under the Nile Basin Trust fund is undertaking an integrated approach to water and power resource planning in East Africa. The project is conducting a Comprehensive Basin-wide Study of Long-term Power Supply, Demand and Power Trade Opportunities in the region, including the evaluation of multi-purpose hydropower projects within a mix of regional generation options.

Annex 7: Assessment of Governance Risk in Kenyan Power Sector

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

1. This section reviews some indicators that can be used to assess the level and risk of poor governance and corruption in the Power sector as recommended in the Sourcebook for Deterring Corruption and Improving Governance in the Electricity Sector, issued to staff in April 2009. This assessment relates to the following issues:

- Regulatory environment;
- Sector performance;
- Sector operations; and
- Disclosure of information and social accountability.

2. The specific indicators for each item, their status, and risk ratings are shown in Table 1 below. INT has advised the Bank team that prepared the Electricity Expansion Project approved by the Board in May 2010 in the preparation of this assessment. Some details of the assessment have been updated to highlight issues that are more relevant to the proposed project and to take account of events since May 2010 but the overall assessment is unchanged.

Table 1: Assessment of Electricity Sector Regulatory and Institutional Framework

Indicator	Status	Risk Assessment
Regulatory Environment:		**Medium**
Institutional framework for regulatory decisions	**The Energy Regulatory Commission (ERC) has the authority to regulate.** This mandate was established through an Act of Parliament. Its specific mandate is defined in the Energy Act, 2006. Its jurisdiction with regard to setting KenGen's generation prices was challenged by KenGen in mid-2008 in the Energy Tribunal when it made its first tariff ruling. Following an initial ruling by the Tribunal, the matter was resolved amicably and KenGen and KPLC negotiated Power Purchase Agreements, which were subsequently reviewed and approved by ERC. **The ERC has adequate technical capacity.** ERC's technical staff are professionally qualified. The Chairman is a former general manager of an electric utility abroad and has the requisite stature to exercise authority. The required qualifications of the Chairman and the General Manager are stated in the Energy Act 2006. The Chairman (a) must be a holder of an university degree in engineering, energy, economics, law, finance or physical sciences; and (b) must have at least seven years of experience, five of which at a senior managerial level. **ERC's performance is monitored through a performance contract with the Government**. ERC also participates in the regulatory peer review of African electricity entities led by experts from the Cape Town university. The latest review in 2009 concluded favorably and identified areas for improvement. ERC also carries out annual satisfaction surveys of its clients, the regulated entities.	

Indicator	Status	Risk Assessment
	The ERC is operationally independent. First, the ERC finances its activities from a levy in electricity tariffs (85% in 2009), license fees, the petroleum levy and appropriations by Parliament. The Commission's Chairman is appointed by the President for four years with a possibility of reappointment for another four years. The President may terminate the appointment of the Chairman on the advice of the Commission for specific reasons stated in the Energy Act 2006.	
Mechanism of appeal	**Interested parties can appeal regulatory decisions.** Any interested party can -- according to paragraph 26 of the Energy Act, 2006 -- appeal the decision of ERC to the Energy Tribunal, which comprises High Court Judges and Technical Specialists. The Tribunal has only been involved in one case, see above.	
Tariff policy	**The tariff policy allows for cost recovery**. **Subsidies are few and targeted.** No constituency, except slum dwellers and low-income households, are given tariff subsidies. In FY2009 and FY2010 there is a small government subsidy to mitigate the cost of emergency generation that was brought in because the worst drought in decades has reduced hydropower output. **The tariff review policy is public and has been supported by the Bank.** The Tariff Review Policy is available for inspection at ERC's website and explains the principles of formation of the tariff. The regulator reviews tariffs every three years. The 2011 review is currently underway and the ERC has requested the regulated entities to submit data on their costs, revenues and investment plans. An international consultant financed from an IDA credit has advised ERC on the tariff calculation methods.	
Licensing (for generation, importation or exportation, transmission or distribution of electrical energy and supply of electrical energy to consumers)	**Requirements for private sector entry into the sector appear transparent and subject to some independent scrutiny**. The Draft Energy (Electricity Licensing) Regulations, 2009 set out requirements to be fulfilled by any person desiring a license or permit authorizing him to carry out any undertaking in the generation, transmission, distribution or supply of electrical energy in Kenya. The Regulation is available at ERC's website. ERC approves each Power Purchase Agreement (PPA) between KPLC and generators. Even though the PPAs are not available to the general public (as is the case in most countries), the media generally reports widely on their contents and the pass-through fuel cost element of each is available on KPLC's website and the Kenya Gazette on a monthly basis.	
Dissemination of decisions	**ERC decisions, fuel price adjustments and other key decisions are made public.** Regulatory instruments, ERC's decision, and Gazette notices are posted on ERC's website. ERC advertizes requests for stakeholder feedback on its proposed decisions in local newspapers. Changes in fuel price adjustments in the electricity tariff are published in the Kenya Gazette monthly and are available on KPLC's website. Changes in inflation and foreign exchange adjustments are published in the Kenya Gazette semi-annually.	
Sector Performance:		**Low to medium**
Electricity coverage	**Electricity coverage is lower than in countries with similar GDP.** About 20-25% of Kenyan households have electricity in their homes. **KPLC is making it more affordable to get connected.** Following management	

Indicator	Status	Risk Assessment
	changes in KPLC, the company has focused more on its commercial operations since 2006 and has increased electricity connections rapidly. Since the relatively high connection charge can deter lower income households from obtaining a connection, KPLC has introduced two initiatives to reduce the burden: it has teamed up with a commercial bank to offer loans for the connection charge and it has recently introduced an installment payment mechanism for lower income customers who would not be able to obtain the commercial loans. Furthermore, in slum areas, KPLC has set a reduced connection fee of US$15 equivalent in place of the standard connection fee of US$460 equivalent. **Rural connections have increased** after the creation of the Rural Electrification Authority (REA) in 2007.	
System losses	**System losses are lower than in comparator countries.** Losses for the annual reporting period FY2010 were about 16% (physical and commercial transmission and distribution losses combined) and are forecast to be at about the same level in FY2011. Losses are lower than in comparator countries such as Ghana 26%, Nigeria 34%, Ethiopia 19%, Madagascar 24%, Benin 17%, Tanzania 24%, Uganda 30%, and Rwanda 22% though higher than in South Africa (10%) and Vietnam (11% in 2006). **KPLC has taken steps to address increasing power theft.** The recent financial slow-down and the 2008 tariff increase have led to increased pilferage. In response, KPLC has begun replacing credit meters with pre-payment meters, installing feeder and transformer meters to identify high loss areas, installing security seals in meters for large power consumers and it has initiated a program to convert illegal connections in slums into legal connections through specific technical solutions and lowering both the connections fee and the energy charge. It has also intensified media coverage for raids and arrests as deterrent. **Investments under the ongoing IDA financed ESRP and KEEP projects will help reduce technical losses.** Under these projects the Bank is financing new substations, rehabilitation of old substations, upgrading of distribution lines, and the automation of the monitoring and control of networks.	
Collection ratio	**KPLC's collection ratio is better than in comparator countries.** KPLC collects about 99% of all billed energy, compared to 92% in Tanzania, 93% in Uganda, and 98% in Rwanda. **KPLC has taken steps to increase collections.** KPLC has automated its meter reading, billing, and collection processes. Meter readings are recorded on hand held computers instead of paper. Consumers can pay their bills at supermarket check-outs, branch offices of commercial banks, at post offices and by using their mobile phones. In 2011, KPLC has also started to roll-out debit metering technology (i.e. pre-paid metering). This technology allows customers to pay for their electricity use in advance and in smaller installments in a similar manner they pay for the "pre-paid" mobile phone service.	
Financial viability of KenGen and KPLC	In FY2009 KPLC's and KenGen's profits before taxation were KSh 5.7 billion (US$76 million) and KSh 5.1 billion (US$68 million), respectively.	

Indicator	Status	Risk Assessment
Sector Operations:		**Medium**
Number of customers per one staff **Proportion of utility operating costs spent on salaries**	**KPLC's staffing is higher than in comparator countries.** KPLC's number of customers per staff (201 in FY2010) is higher than in some comparator countries e.g. Uganda's private distribution company, UMEME has 264 customers per staff but is improving steadily (in FY2009 it was 181). Tanzania and Ethiopia rank below Kenya with 167 and 155 customers per staff respectively. However, because of differences in the customer base and the configuration of the distribution networks, caution should be exercised in making country comparisons. **The proportion of operating costs spent on salaries is higher** for KPLC (10.7%) than for Uganda's UMEME (5%). However, as was the case for the previous indicator, one should be cautious in drawing conclusions of cross-country comparisons.	
Financial management and budgeting	KPLC has in place satisfactory FM and budgeting systems and arrangements. KPLC uses SAP for transaction processing and accounting. For KPLC, all major elements of internal control are in place including segregation of duties and internal audit committee. KPLC has an anti-corruption policy.	
Audit reports	**KPLC uses credible private sector auditing firms (**Ernst &Young that audits the company's financial statement. The auditors are not allowed to sell consulting services. KPLC makes its annual audited financial statements and semi-annual management reports available to the public as per the Capital Market Authority's rules. KPLC distributes its annual report and accounts to their shareholders. All shareholders are allowed to attend the company's Annual General Meeting for which notice is posted 21 days before the meeting.	
Procurement **Mechanism of appeal**	All bid invitations are advertized in local newspapers and in KPLC's websites. Donor financed procurements are advertized also in Dg Market. All bids are opened in public. KPLC's Tender Committee (TC) is by law responsible for review and approval of bid evaluation reports and contract awards. The company's Board, through its Procurement Oversight Committee (POC) endorses the TC approval for contracts over KSh 50 million (US$650,000). The TC invites representatives from professional bodies as observers during its deliberations. There is a National Procurement Appeals Board. Losing bidders frequently refer to the Appeals Board to challenge contract awards by KPLC. Appeals usually are from losing bidders contesting contract awards.	

Indicator	Status	Risk Assessment
Disclosure and social accountability:		**Medium**
Disclosure of performance data	**There is a general availability of information on the agency web sites.** Information of sector performance is available for investors and the public that is able to access the Internet. KPLC publishes key performance data in its semi-annual management reports and annual reports. The website of KPLC provides general information about the entity and its development strategy, its audited financial statement, technical performance data, energy saving tips, press releases, tendering opportunities, and accepts reader feedback. Complaint statistics are not published. KPLC has published its service standards in local newspapers with clear timelines for how long it takes to deliver various services, e.g. connecting to the grid and rectifying a service disruption.	
Media coverage	**Media coverage -- TV and press -- on energy sector issues is extensive**. It appears unbiased though may contain technical errors.	
Consumer and staff satisfaction surveys	**KPLC carries out annual customer and staff satisfaction surveys** through independent auditors. KPLC uses the results to develop corporate strategies to improve its customer service.	
Performance monitoring	**KPLC has an annual performance contract with Government that sets targets for its performance over the coming year**. The Inspectorate of State Corporations, which is part of the Prime Minister's Office, monitors achievement of the targets quarterly. The performance contracts are not public but the entities are ranked each year based on their achievement of the targets in the contracts.	
Third-party oversight	KPLC is quoted in the Nairobi Stock exchange and therefore subject to high levels of surveillance by market regulators in terms of corporate governance and financial reporting. KPLC provides data on its financial performance to the Stock Exchange.	
Transparency of donor engagement	Draft feasibility studies and other technical assistance documents are shared by KPLC with key private and public sector stakeholders in workshops which help ensure that their views are considered in the final recommendations.	
Consultations for environmental and social assessments	**Public consultations are mandatory part of Environmental Impact Assessments as per the Kenya Environmental Management and Co-ordination Act 1999**. The National Environmental Management Authority makes available all draft EAs and provides the public 40 days for feedback. The addressing of the feedback by the project proponent is generally included as a condition for approval of the EA. The government has prepared a Strategic Environmental Assessment for the electricity sector, which included consultations with stakeholders.	

Annex 8: Economic Analysis

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

1. Kenya's Least Cost Power Development Plan (revised March 2011) is a long-term least-cost power generation expansion plan that was prepared by the MoE and ERC in collaboration with the power utilities. It also contains proposed transmission investments and rural electrification. The candidate generating plants and technologies considered for the inclusion in the plan were: (a) oil-fired thermal -- medium and high-speed diesels; (b) geothermal; (c) hydro power; (d) wind; (e) co-generation -- combined heat and power; and (f) coal-fired steam.

2. Computer planning models using long-term dynamic optimization methodology were applied to establish the long-term generating expansion program. Comparative life-cycle cost analysis, based on the data used in the LCPDP to ensure consistency, shows the relative merits of the various feasible candidates considered for the LCPDP as shown in the table below.

Table 1: Results of Screening Curve Analysis of Candidate Technologies in the LCPDP

Candidate Plant and Technology	Levelized cost of Energy (US cents/kWh) at 12% discount rate	Load Factor assumptions of the LCPDP
Base Load Candidates		
Geothermal	9.2	93%
Wind	12.2	40%
Hydro (Low Grand Falls)	14.1	60%
Coal	14.9	55%
Imports (Eastern Corridor Interconnector)	6.8	70%
Peak Load Candidates		
Gas Turbine Natural Gas	17.0	20%
Medium-Speed Diesel (Reciprocating diesel engine technology using Heavy Fuel Oil – the three proposed thermal IPPs)	24.1	28%
Emergency High Speed Diesel	32.1	20%

3. The above comparison confirms that construction of the Eastern Corridor interconnector for imports of electricity and the construction of 280 MW at the Olkaria I and Olkaria IV power stations and the expansion of the Olkaria III to be priority projects for provision of base load capacity in the LCPDP. In the case of the proposed thermal IPPs (i.e. "Medium Speed Diesel" technology in the table above) they are the lowest cost option for peaking duty. It is important to note however baseload supply will be constrained until 2016-2017 and that therefore the proposed IPPs will perform a baseload role from the time they are commissioned until 2016-2017. After 2016-2017 the proposed IPPs will provide both peaking power and will provide the system with necessary system reserves for stability going forward. Along with hydro, they will enable sufficient spinning reserve that will facilitate operation of large scale wind capacity at

Lake Turkana to be commissioned by 2015-2016. The thermal IPPs can be converted to run on natural gas if it were to come available (either indigenous or imports).

Electricity Generating Capacity Additions through 2022

4. Additions to the generating system to meet projected electricity demand and to provide for adequate reserve margin are at various stages of implementation so the supply side of the balance was adjusted based on the present status of preparation of the various generation projects. Projects for which financing has been secured or for which feasibility studies have been prepared were included through 2016/2017. These include the following "firm" projects Olkaria I (140 MW) and Olkaria IV (140 MW), Olkaria III expansion (36 MW) for which construction has commenced, Lake Turkana Wind (300 MW) to be developed in two phases and expected to be commissioned in 2014/2015, and the Eastern Corridor (2,000 MW of which 400 MW for Kenya) to be commissioned in 2016/2017. KenGen will commission additional wind capacity (Ngong 22 MW) in 2012/2013 and hydropower at Kindaruma (32 MW) before decommissioning 60 MW of costly gas turbine units in 2014/2015. Other generation capacity projects at different stages of feasibility study include geothermal capacity at Menengai (400 MW geothermal generation as four separate IPPs (4 x 100 MW) and Olkaria (70 MW conventional and between 30 and 70 MW wellhead generation), wind capacity at Kinangop (60 MW) and thermal capacity at Rabai.

5. The transmission line interconnector between Kenya and Ethiopia that is the first phase of the Regional East Africa Power Pool Program is expected to be commissioned by December 2016 with 2,000 MW transfer capacity. Firm power imports by Kenya are assumed to grow from about 400 MW in the first few years after the line is commissioned to 800 MW by 2020/2021.

Electricity Supply in 2011/2012

6. The available electricity for consumption is currently dictated by the production of the hydropower plants, which currently account for 750 MW or approximately 50 percent of total installed power generating capacity. Production from the hydropower plants is critically dependent on hydrological conditions in the Tana River basin catchment area where 75% of the installed hydropower capacity is located in 6 stations on a cascade below the Masinga dam. Drought conditions in the Tana River catchment have become more frequent affecting output from these stations in five of the past 10 years. Whereas the capacity factor (the ratio of the actual annual output to output if hydro plants had operated at full nameplate capacity) of all hydro power plants averaged 58% in the 13 years up to 1998/1999, since then it has declined to 45%.

7. The other sources of electricity generation are geothermal (150 MW), thermal (140 MW) and wind (5 MW) generating capacity owned by KenGen. Five existing thermal IPPs account for 299 MW. Whereas total installed capacity is currently (2011/2012) about 1,608 MW, net reliable available capacity is approximately 1,447 MW due to scheduled and unscheduled plant maintenance. With unconstrained peak demand estimated at 1,341 MW this implies that the reserve margin (ratio of available capacity to peak demand) for 2011/2012 is no more than about

7.9%. A reserve margin of about 20% is necessary to maintain reliable service. In early 2011/2012 even this reserve margin was lost due to a combination of unscheduled plant outages, relocation of generators and reduced hydropower plant availability. Consequently load shedding (whereby KPLC temporarily switches off distribution of energy to different geographical areas) amounting to between 50 and 100 MW has been the norm during evening hours on week days in 2011/2012.

GDP and Energy demand projections for the Load Forecast

8. Electricity consumption (i.e. KPLC sales) in the interconnected system grew from 4,379 GWh in 2004/2005 to 6,103 GWh in 2010/2011. Recorded coincident peak demand grew from 884 MW to 1,194 MW, about (10-15 percent below the unconstrained demand) during the period. In FY2011, GDP growth was 6 percent while electricity demand measured by KPLC sales grew at 9.2 percent. Electricity sales increased on average over the past three years at 1.4 times GDP growth. Suppressed demand is estimated at up to 200 MW or about 15 percent of system peak demand. As new supply sources are commissioned in 2012 through 2016, enabling this suppressed demand to be met, it will be reflected in higher KPLC sales growth[31] than would be predicted on the basis of the historical relationship between GDP and electricity sales growth. KPLC electricity sales growth is assumed to grow at 9 percent per annum on average in the base case energy supply and demand balance (Table 2 below) on the assumption that GDP growth will average 6 per cent per annum. Electricity demand will therefore grow from 6.1 TWh in 2010/2011 to 15.7 TWh in 2021/2022 and to 37 TWh by 2031/2032. This forecast is more conservative in terms of electricity sales growth assumptions than is shown in the low scenario case of the LCPDP (March 2011) prepared by the Government that shows energy demand of 28 TWh in 2021. It may be noted that 6.7 per cent electricity demand growth has been assumed for the financial analysis of the proposed thermal IPPs. Whereas 9 percent annual demand growth was used for the energy supply and demand projections as it is closer to the assumptions of the LCPDP, it is appropriate to consider a more conservative demand growth projection for the base case financial analysis. The more conservative 6.7 per cent electricity demand growth translates into a more conservative lifetime average capacity factor of the proposed thermal IPPs that is used for the financial analysis.

9. In the forecast below, 45% availability from hydropower plants has been assumed from 2011/2012 onwards. It should also be noted that once significant wind capacity is installed near Lake Turkana (300 MW by 2014-2015) reserve hydropower resources or thermal resources will need to be maintained to substitute for intermittent output from wind projects.

Assumptions about Capacity Factor of proposed thermal IPPs Energy Supply Projections.

10. In the supply and demand projections shown in Table 2, the key assumptions with respect to utilization of the proposed thermal IPPs are as follows:

(a) A capacity factor of 40% is assumed for the hydropower plants operated by KenGen through the forecast period. This is less than the average utilization rate of the past 10 years which was 45%. It assumes less than average hydrology and assumes that

[31] KPLC sales and electricity demand are synonymous as KPLC is the sole distributor in the interconnected system.

the operating regime for hydropower will need to be adjusted once significant windpower is introduced into the system in 2015/2016.

(b) The proposed three thermal IPPs are expected to rank higher than existing thermal IPPs in the merit order. This is because their better efficiency of about 10% (200 grams approximately of fuel per kWh produced compared to 220 grams for the older plants on average) outweighs the small disadvantage of the proposed plants in terms of capacity and energy charges. The proposed three IPPs will have a cost advantage of approximately US$ 1 cent per kWh compared to the older plants.

(c) Following their commissioning, the proposed thermal IPPs will be operated as baseload plants (capacity factor of 65%) until 2016 when additional baseload generation including 280 MW of geothermal generation at Olkaria (KenGen) will be commissioned. The technical specifications of the proposed thermal IPPs, and their proximity to the major load centers of Nairobi and Thika where load is growing rapidly, make them suitable for load following and peaking duty after 2016. In the base case analyzed, the capacity factor for the proposed three thermal IPPs (254 MW) from 2016 onwards is assumed to be 35%.

Table 2: Energy Supply and Demand Balance FY11 to FY22

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Net Energy Generation (TWh)	**Actual**	**Forecast**									
Hydropower (KenGen)	2.2	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Oil-fired Thermal (KenGen)	0.9	0.9	0.8	0.8	0.8	0.5	0.5	0.5	0.5	0.5	0.5
Geothermal (KenGen)	1.4	1.6	2.9	3.3	3.4	3.9	3.6	4.4	4.4	4.4	4.4
Wind (KenGen)	0.02	0.07	0.07	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
KenGen-Total (TWh)	4.4	5.4	6.6	7.1	7.1	7.4	7.1	7.9	7.9	7.9	7.9
Thermal IPPs Existing in 2011	1.6	1.6	0.9	0.9	1.5	1.2	0.6	0.5	0.6	0.2	0.3
Geothermal IPPs (Olkaria III + Menengai)	0.4	0.4	0.4	0.7	0.7	0.7	1.2	1.7	1.6	2.2	3.0
Wind IPP (LTWP)					0.3	0.9	0.9	0.9	0.9	0.9	0.9
Proposed Thermal IPPs (Triumph, Gulf & Melec)	0.0	0.9	1.4	1.4	1.4	0.8	0.8	0.8	0.8	0.8	0.8
IPPs-Total (TWh)	2.0	2.9	2.8	3.0	3.9	3.6	3.5	3.9	3.9	4.1	5.0
Emergency Power Producers (TWh)	1.5	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports (TWh)						1.0	2.5	2.5	3.7	4.9	5.5
Total Sent Out Energy (TWh)	7.9	8.6	9.3	10.1	11.0	12.0	13.0	14.2	15.5	16.9	18.4
Estimated Consumption (KPLC sales) (TWh)[1]	6.7	7.3	7.9	8.6	9.4	10.2	11.2	12.2	13.3	14.4	15.7
Total Losses %	16.0	15.7	15.4	15.1	14.8	14.5	14.5	14.5	14.5	14.5	14.5
Total Losses (TWh)2	1.3	1.4	1.4	1.5	1.6	1.7	1.9	2.1	2.2	2.5	2.7
Calculated Gross demand (TWh)	7.9	8.6	9.3	10.1	11.0	12.0	13.0	14.2	15.5	16.9	18.4
Installed Capacity (MW)4											
Net Available Reliable Capacity (MW)	1600	2010	2262	2303	2293	3059	3374	3418	4221	4214	5200
System Peak Demand (Recorded) MW	1194										
Est. Unconstrained Demand (MW)	1453	1586	1750	1950	2172	2418	2722	3065	3452	3887	4376
System Reserve Margin (%)	10.1	26.8	29.2	18.1	5.6	26.5	23.9	11.5	22.3	8.4	18.8
System Load factor	0.62	0.62	0.61	0.59	0.58	0.57	0.55	0.53	0.51	0.50	0.48

Source: LCPDP and World Bank estimates

11. The estimated output of the power stations and other parameters used in the cost benefit analysis are as follows:

Table 3: Operational Parameters

Three Thermal IPPs	
Parameter	**Value**
Total Installed Nameplate Capacity (three thermal plants: Thika, Triumph, and Gulf)	250 MW
Capital Cost (provided by the sponsors)	US$446 million
Variable O&M Costs	US$8.2 per MWh
Fixed O&M Costs (US$2 million x 3)	US$6.0 million per annum
HFO Fuel Oil Cost	US$700 per tonne
Average specific fuel consumption	200 grams per kWh
Olkaria III Expansion	
Parameter	**Value**
Capital Cost (provided by the sponsor)	US$211.5 million
Installed Capacity	36 MW
Annual Output at 96% Capacity Factor	302.75 GWh per annum
Total operational and maintenance cost (provided by the sponsor)	US$3.4 million per annum

Economic Cost Benefit Analysis

12. The determination of economic viability for the four IPPs followed a standard approach of comparing costs and benefits to arrive at the EIRR. The Ormat IPP was analyzed separately to the three thermal IPPs since it will be operated as a baseload plant, its annual average load factor is not expected to vary markedly during the period of the PPA. The costs of the four IPPs consist of: (a) the capital costs of construction of the power stations and associated transmission infrastructure to connect the stations to national grid; and (b) fixed and variable costs of operation and maintenance.

13. The benefits for the Ormat IPP that will be operated as a baseload plant is the net energy output valued at the estimated long run marginal cost of generation of US$ 0.16 cents per kWh. The analysis assumes that the thermal IPPs will be operated until 2016/2017 as baseload plants and thereafter when alternative lower costs supply sources including geothermal, wind and imports are commissioned as intermediate and peaking plants. About 74% of KPLC sales are to commercial and industrial customers (2010/2011). The willingness to pay by these customers during evening hours when the thermal IPPs will mainly operate has been estimated at about US$ 0.30 cents per kWh. The willingness to pay by domestic customers was estimated to be close to the average tariff for these customers of US$ 0.15 cents per kWh (2010/2011). The economic value of the output of the thermal IPPs was therefore estimated at US$ 0.255 cents per kWh.

Summary Results of Economic Analysis for the three proposed thermal plants

14. The economic analysis conducted has resulted in a Base Case Economic Internal Rate of Return (EIRR) of 25 percent and Net Present Value (NPV) of US$288 million for the three thermal IPPs and of US$33 million and 15% for the Ormat IPP extension. The economic returns of the three thermal IPPs projects are very sensitive to cost of HFO. The base case analysis assumes HFO cost of US$700 per metric ton (current cost in Kenya). A 30% increase in cost of HFO would cause the NPV to approach zero and the EIRR to fall to 13%. Tables 4 and 5 below summarize the results of the cost benefit analysis for the three thermal IPPs and for the Olkaria III expansion.

15. **Timing of the three proposed thermal IPPs and Olkaria III expansion.** Other than the three proposed IPPs only approximately 60 MW (of which 21 MW is wind) additional planned capacity will be commissioned before mid 2014 when 280 MW geothermal capacity (Olkaria I and IV that is in part financed by IDA through the KEEP project approved in 2010) will be commissioned. The three proposed thermal IPPs that will provide 254 MW of additional capacity will ensure system reserve margin of over 20 percent in 2012 to 2016 and enable demand to be met. In their absence, the reserve margin in these years would disappear and a scheduled program of load shedding would be inevitable in these years as the available effective capacity would not be able to meet demand.

Table 4: Results of EIRR Analysis

Thermal IPPs		
Case	**Net Present Value (US$ million)**	**EIRR (%)**
Base Case	288	25
Sensitivity case 1: Increase in cost of HFO of 30%	19	13
Sensitivity case 2: Load factor decreases from annual average 35% to 25% from 2016 onwards	191	22
Sensitivity case 3: Load factor decreases from annual average 35% to 25% from 2016 onwards and HFO cost increases by 30%	Negative (43)	10
Ormat Geothermal IPP		
Base Case	79	18
Sensitivity case: Load factor decreases from annual average 96% to 85% after 2016.	54	16

Table 5: Proposed thermal IPPs - Thika, Triumph, Gulf (in US$ million)

Year	Capex	Fxd O&M	Var O&M	Fuel Cost	T-Cst	Sntout Egy (GWH)	Value US$/kWh	TotalBnft	NtBfnt
2009/10									
2010/11									
2011/12	446				446				-446
2012/13		6	7.6	126	139	921	0.255	235	96
2013/14		6	11.9	197	215	1446	0.255	369	154
2014/15		6	11.9	197	215	1446	0.255	369	154
2015/16		6	11.9	197	215	1446	0.255	369	154
2016/17		6	6.4	106	119	779	0.255	199	80
2017/18		6	6.4	106	119	779	0.255	199	80
2018/19		6	6.4	106	119	779	0.255	199	80
2019/20		6	6.4	106	119	779	0.255	199	80
2020/21		6	6.4	106	119	779	0.255	199	80
2021/22		6	6.4	106	119	779	0.255	199	80
2022/23		6	6.4	106	119	779	0.255	199	80
2023/24		6	6.4	106	119	779	0.255	199	80
2024/25		6	6.4	106	119	779	0.255	199	80
2025/26		6	6.4	106	119	779	0.255	199	80
2026/27		6	6.4	106	119	779	0.255	199	80
2027/28		6	6.4	106	119	779	0.255	199	80
2028/29		6	6.4	106	119	779	0.255	199	80
2029/30		6	6.4	106	119	779	0.255	199	80
2030/31		6	6.4	106	119	779	0.255	199	80
2030/31		6	6.4	106	119	779	0.255	199	80

Net Present Value at 12% discount rate: US$288 million
Economic Internal Rate of Return: 25%

Abbreviations: Capex - Capital Cost; Fxd & Var O&M - Fixed & Variable Operations & Maintenance costs; SntoutEgy - Energy Produced; NtBnft - Net Benefit

Table 6: Olkaria III Expansion - 36MW (in US$ million)

Year	Total Cost	O&M	Total Cost	SntoutEgy (GWH)	Value US$/kWh	TotalBnft	NtBfnt
2009/10							
2010/11							
2012/13	211.5		211.5				-212
2013/14		3.4	3.4	76	0.16	12	9
2014/15		3.4	3.4	303	0.16	48	45
2015/16		3.4	3.4	303	0.16	48.5	45
2016/17		3.4	3.4	303	0.16	48.5	45
2017/18		3.4	3.4	303	0.16	48.5	45
2018/19		3.4	3.4	303	0.16	48.5	45
2019/20		3.4	3.4	303	0.16	48.5	45
2020/21		3.4	3.4	303	0.16	48.5	45
2021/22		3.4	3.4	303	0.16	48.5	45
2022/23		3.4	3.4	303	0.16	48.5	45
2023/24		3.4	3.4	303	0.16	48.5	45
2024/25		3.4	3.4	303	0.16	48.5	45
2025/26		3.4	3.4	303	0.16	48.5	45
2026/27		3.4	3.4	303	0.16	48.5	45
2027/28		3.4	3.4	303	0.16	48.5	45
2028/29		3.4	3.4	303	0.16	48.5	45
2029/30		3.4	3.4	303	0.16	48.5	45
2030/31		3.4	3.4	303	0.16	48.5	45
2031/32		3.4	3.4	303	0.16	48.5	45
2032/33		3.4	3.4	303	0.16	48.5	45

Present Value at 12% discount rate: **US$79 million**
Economic Internal Rate of Return: **18%**
Abbreviations: O&M - Operations & Maintenance costs; SntoutEgy - Energy Produced; NtBnft - Net Benefit

Annex 9: Financial Sustainability of KPLC

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Recent Performance of KPLC

1. **Performance Summary.** Over an eight-year period (FY2004 to FY2011), KPLC has been able to increase its profitability, improve its operational performance, expand its customer base and maintain a healthy financial position as shown in Table 1 below. Since its financial restructuring FY2004 (KPLC incurred losses from 1999 until 2003 due in large part to the tariff setting formula at the time that did not allow fuel cost pass-through as well as the impact of drought conditions that reduced its sales and increased its costs at a time when its losses were also quite high), KPLC has not defaulted on its PPAs.

Table 1: KPLC Income Statement and Balance Sheet Summary, FY2004-2011

(US$ million)	2004	2005	2006	2007	2008	2009	2010	2011
Income Statement Summary								
Revenues	239	291	351	386	420	666	750	714
Operating Expenses	231	273	328	362	385	609	690	643
Operating Income	9	18	22	24	35	57	60	71
Net Income	5	13	16	17	18	32	37	42
Balance Sheet Summary								
Current Assets	97	136	160	191	208	204	197	353
Non-current Assets	227	224	229	284	392	505	608	850
Total Assets	324	359	388	475	600	709	805	1,202
Current Liabilities	86	106	122	179	186	234	188	305
Non-current Liabilities	63	64	61	72	175	205	329	499
Equity and Reserves	175	190	206	223	240	269	288	399
Total Equity and Liabilities	324	359	388	475	600	709	805	1,202

2. **IDA Monitoring of KPLC Financial Performance**. In the Electricity Expansion Project (KEEP) approved in May 2010 and Energy Sector Recovery Project (ESRP) approved in July 2004, the Bank has financial covenants as terms of their Credits. KPLC is required to maintain (a) debt service coverage ratio over 1.2, (b) current ratio over 1.0, (c) self-financing ratio over 25 percent, and (d) number of days in accounts receivables less than 50 days. In addition, KPLC is required to submit regular progress report, furnish the Bank with certified copies of audited financial statements including the auditor's opinion as well as Financial Management Reports (FMRs). KPLC has been in compliance with these financial covenants except for the Accounts Receivable index in FY2011, which exceeded the target by three days. This was mainly attributable to the accumulation of outstanding bills for some of government ministries and local authorities that is being addressed by KPLC with support of MOE and MOF.

Table 2: KPLC's Financial Performance Compared to Targets Agreed with IDA

Financial Ratios	Target Values	FY 07	FY 08	FY 09	FY 10	FY 11
Debt Service Coverage	≥ 1.2	6.8	4.1	5.3	2.3	4.8
Current Ratio	≥ 1.0	1.1	1.2	0.9	1.0	1.2
Self Financing Ratio	≥ 25%	23%	54%	161%	29%	49%
Accounts Receivables	≤ 50 days		50	45	43	53

Source: KPLC

3. **Corporate Governance.** KPLC is a public company, incorporated under the Companies Act, listed on the Nairobi Stock Exchange since 1954. Following the recent capital restructuring (described below in para. 7), the Government of Kenya holds 50.1 percent of its shares. The company is under policy guidance by the Ministry of Energy as well as the Treasury under the State Corporations Act. It is also under the regulatory oversight of the ERC under the Energy Act of 2006 and the Capital Market Authority under the Capital Markets Act. KPLC produces regular financial reports in accordance with the requirements stipulated in these legislations. The company is led and managed by the Board of Directors, several Board Committees as well as the Executive Management Team. Between July 2006 and June 2008, supported by the Bank, the company had a management services contract with Manitoba Hydro, which helped to strengthen and turnaround the company's technical and financial capabilities as well as management practices.

4. **Customer Base.** Between FY2004 and FY2011, the number of KPLC's customers has doubled from less than 0.6 million to over 1.4 million; a rapid growth in number is taking place in the domestic customer category (15.5 percent). In terms of revenue per customer, however, KPLC earns from an average commercial and industrial customer (above KSh 13 million) over 800 times an average domestic customer (less than KSh 17,000). This suggests that faster growth in KPLC's customer base is taking place in relatively lower-revenue generating segments.

5. **Recent Performance.** Despite the increase in the number of lower-revenue generating segments and the drought that affected the country's hydro power generation, KPLC has nonetheless been able to improve its financial positions. The company's return on total assets has increased from 1.4 percent in FY2004 to 4.2 percent in FY2011 (Table 3), a level higher than some electric utilities (e.g., ESKOM in South Africa: 2.2 percent in 2010; and Meralco in the Philippines: 3.7 percent in FY2009). This improvement consists of the larger share of profit component in revenues (i.e., return on sales) from 2.0 percent to 6.1 percent, which suggests a stronger contribution made from the company's improved operational performance. In the same period, KPLC's net income has grown at a CAGR of 37 percent and its operating profit at 35 percent. This remarkable performance is attributable to the following factors: (i) the volume of sales has steadily increased by a CAGR of 5.7 percent in the same period; (ii) the average tariff yield has continued to improve, especially after the tariff review of 2008, increasing by 2.3 times; (iii) the increase in power purchase costs was kept relatively low compared to the average tariff yield; and (iv) system losses have been constantly reduced until FY2010 (Table 3).

Table 3: Key Financial Ratios of KPLC

FY	2004	2005	2006	2007	2008	2009	2010	2011
Operating Indicators								
Return on Total Assets	1.4%	3.7%	4.4%	4.0%	3.3%	4.9%	4.9%	4.2%
Return on Equity	5.1%	7.0%	8.3%	8.0%	7.7%	12.7%	13.4%	12.3%
Return on Sales (Profit element of revenues)	2.0%	4.5%	4.8%	4.5%	4.3%	4.9%	5.1%	6.1%
Gross Profit Margin	-10.8%	3.6%	6.3%	6.3%	6.2%	8.4%	8.6%	8.0%
Asset Turnover	0.74	0.83	0.91	0.88	0.76	1.00	0.97	0.70
Return on Net Fixed Assets	1.4%	5.2%	5.4%	7.4%	7.6%	10.1%	7.8%	7.8%
Capital Adequacy Indicators								
Debt Service Coverage Ratio	1.22	9.24	4.64	9.30	1.23	6.10	2.27	4.80
Debt to Equity	0.8	0.9	0.9	1.1	1.5	1.6	1.8	2.0
Debt to Assets	0.46	0.47	0.47	0.53	0.60	0.62	0.64	0.67
Liquidity Ratios								
Current Ratio	1.1	1.3	1.3	1.1	1.1	0.9	1.0	1.2
Average Days' Electricity Receivables	-	67	65	70	50	45	43	53
Average Days' Payables	-	93	78	109	145	79	78	137

6. **Revenue Collection.** Following the tariff review in 2008, which resulted in a general increase of tariffs, the impairment of electricity receivables more than doubled in FY2009. However, KPLC has been putting extra effort in improving its revenue collection from customers, and its average electricity receivables collection days improved from 50 days in FY2008 to 43 days in FY2010, before it deteriorated to 53 days in FY2011. As mentioned above, this was mainly due to the accumulation of outstanding bills for some of government ministries and local authorities that is being addressed by KPLC with support of MOE and MOF. The revenue collection rates in recent years are over 100 percent, indicating some outstanding payments from the past are collected. The company disconnects customers in arrears over three months after attempting several channels of notifications. It also takes enhanced measures such as prepaid metering (also supported by the Bank), enhanced bill payment service in partnership with telecommunication companies mobile phone-based money transfer mechanisms, and direct debit service mode of payment with commercial banks. Moreover, in the on-going Project, development partners, including the Bank and EIB, are supporting the upgrading of KPLC's Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS) solutions to optimize the management of its distribution systems, which are expected to further reduce the system losses. More than half of electricity receivables are provided for and KPLC writes off the assets, in accordance with its policy, when the cost of recovery actions exceeds the benefits to be derived.

Table 4: Key Operational Indicators of KPLC

	Units	2005	2006	2007	2008	2009	2010	2011
Electricity sold	GWh	4,215	4,444	4,818	5,082	5,182	5,345	5,816
Average Tariff Yield	KSh/kWh	6.72	7.64	7.88	8.05	12.58	13.69	11.99
	US$/kWh	0.07	0.08	0.08	0.08	0.13	0.14	0.12
Electricity Purchased	GWh	5,334	5,472	5,838	6,045	6,149	6,315	6,895
Average Costs	KSh/kWh	3.57	4.45	5.10	4.83	7.66	8.53	6.72
	US$/kWh	0.04	0.04	0.05	0.05	0.08	0.09	0.07
(power purchase)	KSh/kWh	2.27	2.19	2.63	1.98	3.05	3.25	2.93
	US$/kWh	0.02	0.02	0.03	0.02	0.03	0.03	0.03
(fuel)	KSh/kWh	1.30	2.26	2.47	2.85	4.61	5.28	3.79
	US$/kWh	0.01	0.02	0.02	0.03	0.05	0.05	0.04
Losses	%	18.1%	19.6%	17.9%	16.6%	16.3%	16.0%	16.2%
Number of Customers	persons	633,351	691,525	791,282	899,029	1,061,911	1,212,584	1,444,061
Customer-employee ratio	Ratio	103	112	124	135	151	167	169

7. **Capital Restructuring.** KPLC restructured its capital in November-December 2010 to reduce its financial leverage and support its further expansion plan. In the process, the following steps were taken: (i) KPLC's authorized share capital was increased from KSh 18 billion to KSh 20.8 billion; (ii) 794,962,500 redeemable non-cumulative preference shares held by the Government was converted into 76,622,891 ordinary shares; (iii) the ordinary shares of KSh 20 were split into eight shares of Ksh 2.5 each; and (iv) rights offering of 488,630,245 ordinary shares (20 ordinary shares for every 51 existing ordinary shares), in which the Government renounced all its rights to dilute its shareholding. Consequently, the company's ordinary share (book value) has increased by a multiple of 2.7, giving more room for the company's expansion plans, and the Government's share has become 50.1 percent of the company. While the steps (i)-(iii) above do not affect tariffs per se, as they are basically reallocation within shareholders' equity, the rights issue would theoretically put upward pressure on the retail tariffs. However, the impact is relatively small, preliminarily estimated to be about Ksh0.1/kWh.

Financial Projection of KPLC

8. Financial projection has been prepared for a base case as well as for scenarios incorporating risks of drought.

9. **Base Case Assumptions.** Some of the key assumptions for the base case financial projection are briefly discussed below:

- As in the economic analysis section, base case GDP growth rates assumed for the electricity demand projection are: 6.3 percent in FY2012, 6.5 percent in FY2013, 7.4

percent in 2014, 8.1 percent in FY2015 through FY2017, and 9 percent from FY2018 onwards. Income elasticity of electricity demand is assumed to be 1.4. The capacity installation plan is aligned to the energy supply projections in the same section.

- The number of customers is assumed to increase by 200,000 per year in accordance with KPLC's strategic plan.

- The existing retail tariff levels are assumed to be adjusted annually to new levels, in accordance with the basic tariff formula (i.e. Allowed Rate of Return on Regulatory Asset Base + O&M Expenditures + Depreciation Expenses + Taxes) to meet KPLC's revenue requirement, in accordance with the tariff review arrangements communicated by the ERC.

- Power purchase costs are assumed at the PPA rates as of September 2010 with allowance for escalation for existing power plants and estimated rates for new power plants.

- Fuel price is assumed to be at the level as of October 2011 (US$81.43/bbl) and were multiplied by fuel factors for those power plants that use fuels.

- Indicative levels of average tariff yields assumed in this analysis are shown in Table 5. The combined average tariff yield has a range of US$ 12.53 cents per kWh and US$ 17.13 cents per kWh. Applying the retail tariff formula, the combined total level is assumed to peak in FY2013 and gradually decrease thereafter.

Table 5: Average Tariff Yield Assumptions (US cents/kWh)

	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020
Electricity	8.15	8.13	9.46	10.24	11.91	12.02	12.25	12.58	12.80	12.80	12.80
Fuel	6.91	4.22	6.35	6.71	4.97	4.48	4.50	3.41	2.88	2.74	2.52
Forex	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Total	15.24	12.53	15.99	17.13	17.06	16.68	16.92	16.17	15.86	15.72	15.50

- Given the deterioration of average number of receivable days and payable days in FY2011, which is not in line with the overall trend, they are assumed to improve at accelerated rates. The number of days in receivables is assumed to improve by 6 percent per year in FY2012 and FY2013, 4 percent in FY2013, 2 percent in FY2014 and 1 percent thereafter. Similarly, the number of days in payables is assumed to improve by 20 percent per year in FY2012 and FY2013, by 10 percent per year in FY2014, and by 5 percent per year thereafter.
- Investment in plant, property and equipment is assumed to take place in proportion to the growth in revenues.
- Investment is assumed to be financed by loans with increasingly commercial terms, with the average interest rate gradually increasing from 5 percent in FY2011 to 12 percent in FY2018. Long-term loans are used as a plug to balance the projected balance sheets.
- Corporate tax rate is assumed to be 30%.

10. Table 6 summarizes the base case projection of key financial ratios of KPLC between FY2012 and FY2020. The impacts of this Project are incorporated in the projection of electricity generation.

Table 6: Projection of Key Financial Ratios (Base Case)

Financial Ratios \FY	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating Indicators									
Return on Total Assets	1.9%	1.7%	1.0%	2.0%	1.5%	3.3%	1.1%	1.9%	1.8%
Return on Equity	5.5%	5.0%	3.3%	7.1%	5.6%	12.8%	4.4%	7.5%	7.6%
Cost of kWh purchased (US cents/kWh)	13.1	14.3	13.9	13.0	13.3	11.8	12.2	11.8	11.7
Revenue per unit sold (US cents/kWh)	16.0	17.1	17.1	16.7	16.9	16.2	15.9	15.7	15.5
Return on Sales (Profit element of revenues)	2.3%	1.8%	1.1%	2.2%	1.6%	3.8%	1.3%	2.1%	2.0%
Gross Profit Margin	4.0%	3.4%	3.4%	5.3%	4.9%	9.0%	5.2%	6.9%	6.7%
Asset Turnover	0.81	0.92	0.88	0.90	0.91	0.88	0.91	0.90	0.92
Return on Net Fixed Assets	4.1%	4.0%	3.7%	6.3%	5.8%	10.6%	6.3%	8.2%	8.2%
Capital Adequacy Indicators									
Debt Service Coverage Ratio	2.37	1.90	1.51	1.77	1.51	1.94	1.36	1.49	1.45
Debt to Equity	1.8	2.3	2.5	2.7	3.0	2.7	3.0	3.0	3.2
Debt to Assets	0.64	0.69	0.72	0.73	0.75	0.73	0.75	0.75	0.76
Liquidity Ratios									
Current Ratio	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Average Days' Electricity Receivables	50	47	45	44	44	43	43	42	42
Average Days' Payables	123	99	89	84	80	76	72	69	65

11. The base case financial forecast (Table 6) shows that KPLC's operations, capital adequacy, and liquidity are expected to be sustained. The four IPPs combined will likely create manageable upward pressure on the level of electricity tariffs and fuel pass though estimated to be about US$ 0.50- 0.86 cents, as calculated by their impacts on KPLC's annual revenue requirement. Supposing that in the absence of these four power plants the deficit in electricity supply would need to be met by emergency power plants, and increased capacity factor of thermal plants, they save costs of US$ 0.24-0.67 cents per kWh each year between FY2013 and FY2020, which would offset a large portion of the increase in electricity tariffs. Moreover, even though KPLC will be obliged to pay the capacity charge rate for the four IPPs combined under take-or-pay terms, it will have a decreasing effect on the retail tariffs, estimated to be US$ 1.01cent per kWh immediately after the commencement of their operation in FY2013 down to US$ 0.36 cents per kWh in FY2025.

12. KPLC will remain profitable despite taking on increased debt to finance power system expansion. Profitability ratios are lower in some years but they are still expected to maintain levels comparable to utilities in higher income countries. Even though the company will be

leveraged with the increased proportion of debt, its debt service coverage ratio is expected to stay above 1.3, even when assuming KPLC's borrowing will increasingly become commercial terms.

13. **Risk Scenarios.** Some risks that may impact the financial performance of the sector in the future are: the roles and responsibilities for electricity supply under the new Constitution; hydrological risks of severe drought affecting hydroelectric power generation; uncovered portion of inflation risks; and issues related to crude oil price fluctuations and the acceptability and affordability of gradually increasing tariff levels. For several of these risks, some mitigation measures are already identified or implemented. For example, Energy Sector Committee on the New Constitution has been established by the Ministry of Energy and it is looking into the potential impacts of the devolved system under the New Constitution to the sector. The findings are periodically shared at quarterly Donor Coordination Meetings. To assess the impacts of major potential risks, this section analyzes the risks of fuel cost inflation, currency depreciation, and droughts.

14. **Fuel Price Risk.** The base case scenario assumed the fuel price at the level as of October 2011 (US$81.43/bbl), which was used to calculate fuel costs for thermal power generation based on different fuel conversion factors by power plants. To assess the potential impacts of increase in the crude oil price, three sensitivity scenarios were constructed: +25 percent (US$109.25/bbl), +50 percent (US$131.10/bbl), and +100 percent (US$174.80/bbl). The last case is above the highest crude price recorded in July 2008 (slightly over US$145/bbl).

Table 7: Sensitivity of Average Retail Tariff to Crude Price (US cents/kWh)

Crude Oil Price (US$/bbl)	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020
87.40 (base case)	6.35	6.71	4.97	4.48	4.50	3.41	2.88	2.74	2.52
109.25 (+25%)	8.12	8.55	6.36	5.71	5.72	4.35	3.67	3.50	3.21
131.10 (+50%)	13.00	13.54	10.18	9.09	9.07	6.98	5.89	5.62	5.12
174.80 (+100%)	31.39	31.82	24.65	21.91	21.56	17.13	14.59	13.92	12.59

15. If the crude price would reach the highest case under consideration, its impact on tariff would be enormous that the affordability will become a serious concern (for example, + US$ 31.82 cents on average in FY2013). Even under other risk scenarios, the impacts in FY2012 and FY2013 could be quite severe as the levels go beyond the highest fuel cost pass-through level that occurred in FY2010 when it marked US$ 5.29 cents per kWh. It would therefore be necessary to monitor the impact of fuel price volatility on people's affordability of electricity, especially in the short-run. In the long-run, however, with diversification of energy sources, including further development of geothermal and wind power as well as import of electricity in particular from Ethiopia, the impact is expected to become less and manageable.

16. **Currency Depreciation Risk**. The base case scenario assumed that the Kenya Shillings will be stable against major convertible currencies (e.g. KSh 89.825/US$). If the Kenya Shillings were to be depreciated, the higher levels of foreign currency-denominated expenditures will be passed through to consumers. To assess the potential impact of currency depreciation on retail tariffs, five sensitivity scenarios were prepared: (i) 5 percent depreciation (KSh 94.316/US$); (ii) 10 percent depreciation (KSh 98.808/US$); (iii) 20 percent depreciation (KSh 107.790/US$);

(iv) 50 percent depreciation (KSh 134.738/US$); and (v) 100 percent depreciation (KSh 179.650/US$).

Table 8: Currency Depreciation Sensitivity (US cents/kWh)

US$/Ksh	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
-5%	0.31	0.33	0.38	0.38	0.39	0.40	0.41	0.41	0.41
-10%	0.61	0.66	0.76	0.77	0.78	0.80	0.81	0.81	0.81
-20%	1.23	1.32	1.51	1.53	1.56	1.60	1.62	1.63	1.62
-50%	3.07	3.30	3.78	3.83	3.90	4.00	4.05	4.07	4.06
-100%	6.13	6.60	7.55	7.65	7.80	8.00	8.11	8.13	8.12

17. For depreciation below 10 percent, the expected impacts on retail tariffs will be within the magnitude of approximately US$0.80 cents per kWh. In an extreme case, if Kenya Shillings were to depreciate by 100 percent, the foreign currency pass through elements could be higher than US$ 8 cents per kWh.

18. **Drought Risk**. As described earlier, drought could challenge the sector performance by (i) making the system unreliable, (ii) reducing revenues particularly for KenGen, and (iii) imposing some burden of capacity payment subsidy for the Government and tax payers, and (iv) raising electricity cost for consumers. To assess the potential impact of such a drought, a scenario was constructed that assumes a drought of a similar magnitude as in FY2010 to occur, as an illustration, in FY2013. Approximately 25 percent reduction in hydropower generation is assumed, which is compensated for by increased production in emergency power plants. To stress-test the resilience against the shock, no additional compensatory price adjustment is assumed.

19. Table 9 summarizes the projection of key financial ratios of KPLC between FY2011 and FY2020 under the drought risk scenario.

Table 9: Projection of Key Financial Ratios (Drought in 2013)

Financial Ratios \ FY	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Operating Indicators										
Return on Total Assets	4.2%	1.9%	1.0%	0.5%	1.9%	1.4%	3.3%	1.1%	1.8%	1.8%
Return on Equity	12.3%	5.5%	3.3%	1.9%	7.1%	5.6%	13.0%	4.3%	7.4%	7.6%
Cost of kWh purchased (US cents/kWh)	8.9	13.1	16.3	13.9	13.0	13.3	11.8	12.2	11.8	11.7
Revenue per unit sold (US cents/kWh)	12.5	16.0	18.7	17.1	16.7	16.9	16.2	15.9	15.7	15.5
Return on Sales (Profit element of revenues)	6.1%	2.3%	1.1%	0.6%	2.1%	1.5%	3.7%	1.2%	2.0%	1.9%
Gross Profit Margin	10.0%	4.0%	2.3%	3.4%	5.3%	4.9%	9.0%	5.2%	6.9%	6.7%
Asset Turnover	0.70	0.81	0.96	0.84	0.90	0.91	0.88	0.91	0.90	0.92
Return on Net Fixed Assets	7.9%	4.1%	2.6%	3.6%	6.3%	5.8%	10.6%	6.3%	8.2%	8.2%
Capital Adequacy Indicators										
Debt Service Coverage Ratio	3.54	2.37	1.50	1.30	1.71	1.47	1.88	1.32	1.45	1.42
Debt to Equity	2.0	1.8	2.6	2.6	2.8	3.1	2.8	3.2	3.2	3.4
Debt to Assets	0.67	0.64	0.72	0.72	0.74	0.76	0.74	0.76	0.76	0.77
Liquidity Ratios										
Current Ratio	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Average Days' Electricity Receivables	53	50	47	45	44	44	43	43	42	42
Average Days' Payables	154	123	99	89	84	80	76	72	69	65

20. The results of the drought risk in FY2013 (Table 9) scenario show that it pushes up the cost of electricity, including the fuel costs for increased thermal power generation, by US$ 2.0 cents per kWh from the base case scenario in FY2013 (Table 6). Most (95 percent) of the increase in the cost of supply is due to the effect of fuel switching cost from hydroelectric to emergency power plants. The return on total assets deteriorates from 1.7 percent to 1.0 percent. Many other ratios are also negatively impacted: return on equity decreases from 5.0 percent to 3.3 percent; the debt service coverage ratio decreases from 1.90 to 1.50; and debt to equity ratio jumps from 2.3 to 2.6. However, as the country increases the share of geothermal power in the grid or the electricity imported from Ethiopia, the impacts of droughts are expected to become smaller in proportion.

Annex 10: Financial Analysis of the IPPs

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

Sub-project 1: Thika Power Limited (TPL)

1. Thika Power Limited (TPL) is a Special Purpose Company (SPC), established to undertake design, financing, construction, and operation, on a build-own-operate (BOO) basis, a 87 MW diesel engine powered thermal power plant. The plant will be located along Thika – Nairobi road in Thika. The financing for the project is secured on a limited recourse basis, underpinned by a 20 year Power Purchase Agreement (PPA) signed between TPL and Kenya Power and Lighting Company Limited (KPLC). This financial analysis is based on final draft IFC's financial model. The following are the assumptions used in the model.

Macroeconomic assumptions

2. The financial model utilizes the following assumptions:

(a) Inflation: The model utilizes European Consumer Prices Index, estimated at 2%, which reflects ten year average historical rate between 2000 and 2010, as published by Eurostat. The EU CPI is applied to revenues as per PPA requirements and operations and maintenance cost.

(b) Exchange rate: The financing for the project is provided in Euro. TPL's operation and maintenance costs are denominated in Euro, except for fuel, which is denominated in US Dollar. For comparison purpose, the model applies a 1.35 Euro/US$ exchange rate to convert US$ based fuel price into Euro.

Costs and Financing Plan

3. The total sub-project costs are estimated at €112.4 million (Table 1). The bulk of these costs are made of the construction costs (81%), followed by Debt Service Reserve Account (5%), interest and fees during construction (4%), development costs (2%), and the remaining 8% is split between operations and mobilizations start up costs, contingencies, and initial fuel supply.

Table 1: Costs Breakdown and Financing

Source of funds	€ million	%	Use of funds	€ million	%
Equity	28.1	*25%*	EPC contract	90.6	*81%*
			Development cost	2.6	*2%*
Debt:			O&M mobilization, start up WC	1.0	*1%*
IFC	28.1	*25%*	Initial fuel supply	3.0	*3%*
ABSA	28.1	*25%*	Contingencies	5.0	*4%*
AfDB	28.1	*25%*	Interest and fees during construction	4.9	*4%*
			DSRA*	5.3	*5%*
Total	**€ 112.4**	***100%***	**Total**	**€112.4**	***100%***

*Debt Service Reserve Account

4. *Financing plan:* The debt-to-equity ratio used for the financing of this sub-project is 75:25. The debt portion consists of three equal tranches of senior debt provided by AfDB, IFC, and ABSA bank (see Table 1). All three loans are issued under same financing terms, which include 15 years door-to-door maturity, and variable interest rate based on 6-month EURIBOR of 2.34 plus 500 bps spread. The loan amortization follows a mortgage style schedule, with both, interest and principal repayment done on a quarterly basis.

5. The equity portion of the financing equals €28 million. Howereve, the Sponsor will provide additional "Surplus Equity" contribution in the sum of €15 million upfront and prior to disbursement of senior debt. This excess equity will serve to cover costs overruns during construction phase and will be released upon project completion only to the extent of amounts not utilized for cost overrun. All equity contributions are assumed to be made up-front, while senior loans will be disbursed on a pro-rata basis.

Table 2: Financing terms for loan facilities

Loan facility	Amount (€ million)	Tenor (yrs)	Grace period (yrs)	Annual Interest rate
				Spread*
AfDB	28.1	15	1.5	up to 500bps
IFC	28.1	15	1.5	up to 500bps
ABSA	28.1	15	1.5	up to 500bps

*Spred over Euribor currently at 2.34%

6. *Debt Service Reserve Account (DSRA)*: The DSRA is funded upfront and it amounts to € 5.3 million. The maintenance of the DSRA will be conducted from sub-project cash flow, while ensuring that it will cover six month of debt service (principal and interest payment) at all times.

Operating Costs and Revenues

7. The power plant is expected to be fully commissioned in March 2013. The technical and operational assumptions used in the model for this 87 MW of installed capacity thermal power plant are shown in Table 3 below. The model assumes that the plant will operate under a

declining dispatch rate starting with 65% for the first few years of opeartion down to 35% onwards. Lenders have taken a more conservative approach by using a lower dispatch factor towards the end of the project life reaching 32%. Nevertheless, even under this approach the sub-project remains financially viable. Operations and maintenance cost and revenues will both be reflective of the variable capacity factor.

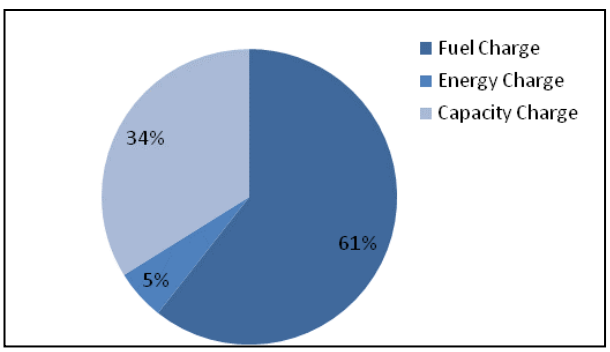
Table 3: Thika Power dispatch schedule

Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Load factor	65%	65%	65%	65%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Availability Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
GWh	495	495	495	495	267	267	267	267	267	267	267	267	267	267	267

8. *Operation and Maintenance (O&M) costs:* According to the above assumptions, the total operations and maintenance costs for the life of the project are estimated at €820 million. Out of this total, €48 million are fixed O&M, €62 million are variable O&M, and the balance €710 consists of fuel costs. In terms of annual O&M, fixed portion is estimated at € 1.7 million at 2011 prices, variable costs are estimated at €3.6 million, after adjustment for inflation (or €0.00693/kWh). Fuel costs are based on fuel price of 700 US$/ton (or 519 €/ton) and estimated to reach an average of €30.7 million per annum.

9. *Revenues:* The sub-project revenues consist of three components – capacity charge, energy charge, and fuel charge. The base capacity charge is estimated at €193.5/kW per year, and it consists of non-escalable portion of 157.5 €/kW and escalable part of 36.0 €/kW. Energy charge is assumed at 0.0074 €/kWh. The energy charge and escalable part of the capacity payment are adjusted annually for EU inflation, estimated at 2%. Average revenues per year are estimated at €51.7 million, whereas total revenues for the life of the project are estimated at €1,188 million. Out of this total around €727 million are from fuel charges, €64.9 million in energy charges, and €396 million in capacity charges (see figure 1).

Figure 1: Weight of each component in total sub-project revenues

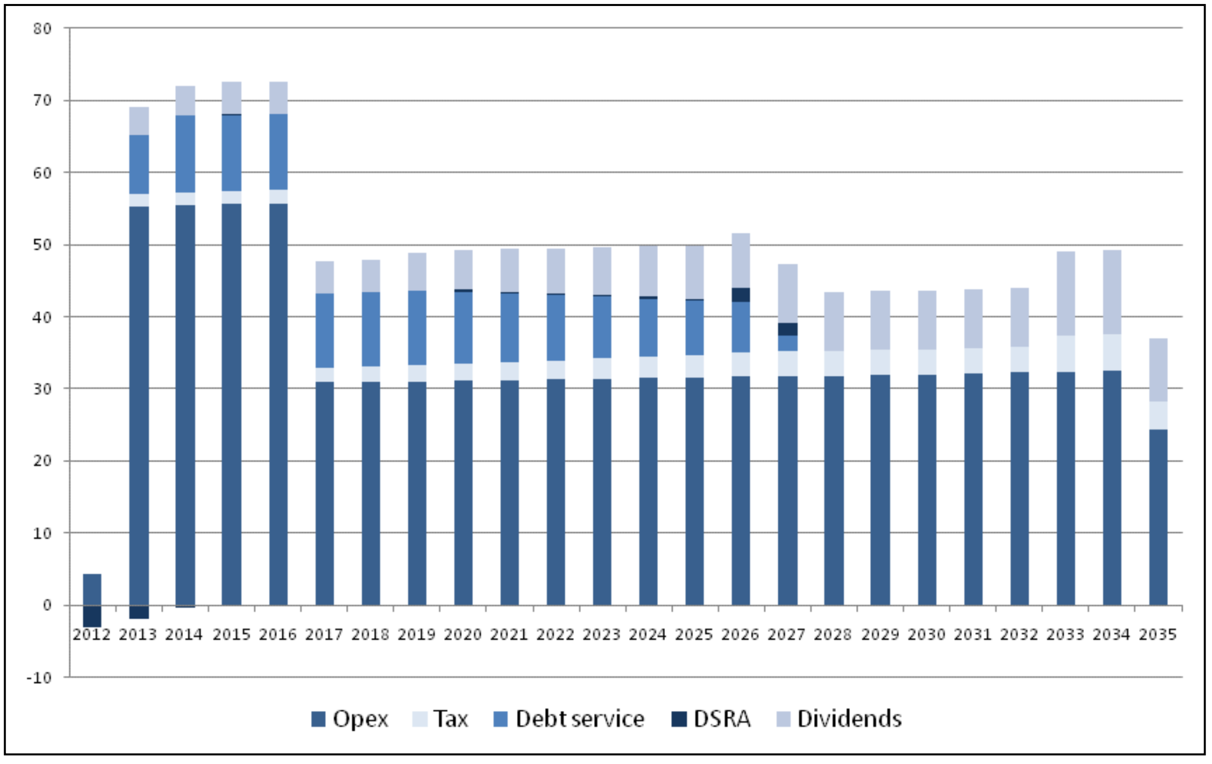


10. *PPA (levelized) tariff*: Based on the above revenue description and assumed annual dispatch rate, the tariff on the first few years of operation is estimated at 0.15 €c/kWh increasing to 0.18 €c/kWh afterwards. The levelized tariff, using a 12% discount rate, is estimated at 0.17 €c/kWh.

Cash flow Utilization

11. The cash flow generated by the project will be distributed through a following order of priorities: (i) operations and maintenance costs, (ii) debt service, (iii) adjustment to debt service reserve account (if any), (iv) income tax; and (v) dividends. The dividend payment is determined based on the maintenance of the minimum Debt Service Cover Ratio (DSCR) of 1.30x.

Figure 2: Cashflow Utilization



12. As indicated above the total gross revenues that sub-project is expected to generate throughout the project life, are estimated at € 1,188 million. Out of this amount, around €820 million will be used to cover total operations and maintenance costs, around € 68.1 million will be paid for income taxes, and debt service payments will equal to €132.9 million. Dividends to be transferred to shareholders are estimated at €159 million, and the remaining balance will be used as cash for sub-project 1 operations.

Debt service

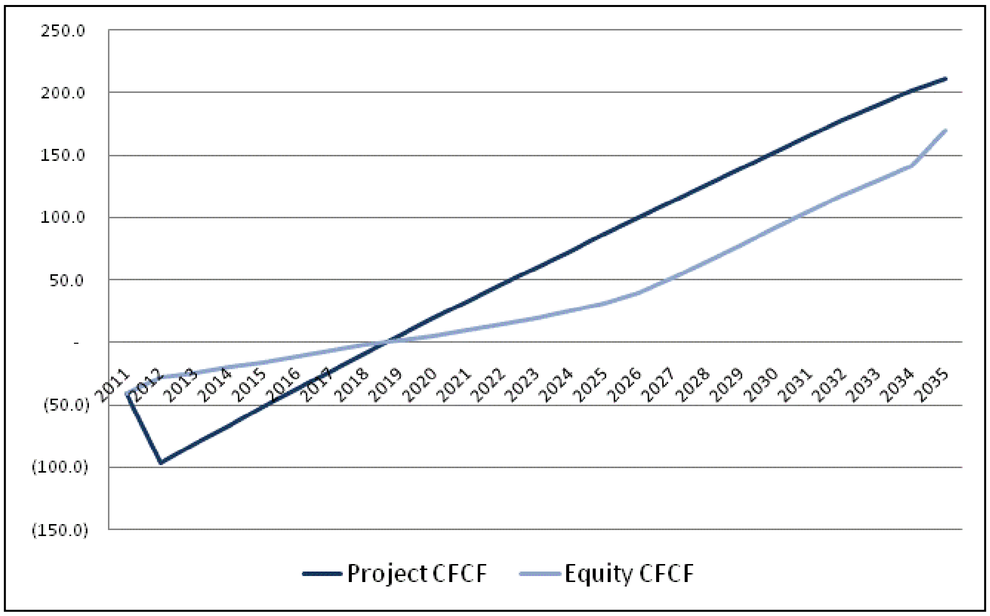
13. In order to assess the project's capacity for debt service, the most widely used indicators are Debt Service Coverage Ratio (DSCR) and Loan Life Coverage Ratio (LLCR). The minimum annual DSCR for this project is estimated at 1.34x (Jan 2015), with an average annual DSCR of 1.54x. Both of these ratios are considered to be within industry range and represent a strong indicator of the sub-project's ability to service its debt from the cash flow generated by the project. The minimum annual LLCR derived from the model is estimated at 1.16x, with an

average annual of 1.45x. The average annual LLCR and average annual DSCR are close to each other, which is considered good practice and provides a strong indicator. The LLCR shows that TPL's cashflow generated from the project and available for debt service, are not only able to cover the debt service, but on a discounted basis are also sufficient to cover the outstanding debt.

Financial Analysis

14. From the Net Present Value perspective, Thika Power sub-project is expected to generate a financial net present value (FNPV) of about € 50.9 million, discounted at project WACC of 6.85%, and a project FIRR of 13.0%. The FNPV for equity holders is expected to be around €10.7 million and FIRR of 15.1%. The graph below shows the cumulative free cash flow (CFCF) to the project as a whole, and equity holders, which also demonstrates that the payback period for both project and equity holders, is around 6 years.

Figure 3: Payback period to TPL and Equity investors



15. Based on this analysis, sub-project appears to be financially viable, both from the overall perspective of the project and for equity investors. However, project viability, as well as equity returns to shareholders, is relatively sensitive to adverse changes in key variables. To assess the potential impact of changes in these variables, a sensitivity analysis has been undertaken under which the FIRRs and minimum annual DSCR, are calculated under a range of adverse scenarios.

Sensitivity Analysis

16. A detailed sensitivity analysis has been conducted under number of variations on the key variables such as: increase in capital expenditure, increase in operation and maintenance costs, increase in heat rate of power plant above the level provided by EPC contract, output shortfall due to degradation after acceptance, lower net installed capacity, lower plant availability, output shortfall, and delays in construction. Table 4 below provides a summary of different scenarios used and the impact on minimum DSCR, project FIRR, and equity FIRR.

Table 4: Sensitivity Analysis

	Minimum DSCR	Sub-Project FIRR	Equity IRR
Base case	1.34x	13.0%	15.1%
Increase in Opex: 20%	1.28	12.3%	13.2%
Increase in Capex: 10%	1.25	11.8%	11.1%
Increase in Heat Rate: 3%	1.26	12.2%	12.3%
Lower Net Installed capacity: 78.3MW*	1.23	11.6%	10.3%
Lower Plant Availability: 79%	1.03	8.6%	7.3%
Output shortfall: 1% arising from degradation	1.33	12.5%	14.5%
Delay (6 months)	1.37	12.9%	14.0%

* *Corresponds to 90% of signature plant capacity.*

17. The minimum DSCR and project and equity FIRR are most sensitive to lower availability of the plant and lower net installed capacity in which case the DSCR falls to 1.03 and 1.23, respectively. Howerver, this risk is expected to be mitigated by project copmany through contracting experienced EPC and O&M contractors. The analysis has showed that the minimum DSCR is not very sensitive to an increase in capex of 10% and opex of 20%. The same applies to project FIRR and equity FIRR. Regarding delay in project completion, the sensitivity analysis assumes the plant is commissioned with a 6 months delay. While the EPC provides back to back LD for TPL's obligation to KPLC, TPL's loss of revenue, administrative expenses and fixed cost including interest and insurance will not be covered by the EPC contractor. It is estimated that the Company will incur additional costs totaling US$3.9 million on account of increased interest during construction (IDC), insurance, and project management costs. This cost is assumed to be funded through the "Surplus Equity". The resulting DSCR in this scenario would remain stable at 1.37, but the equity IRR would decrease to 14.0 and Project IRR to 12.9%.

Sub-Project 2: Triumph Power Limited

18. Triumph Power Generating Company Ltd (TPGC) is a Special Purpose Company (SPC) established to undertake design, financing, construction, and operation, on a build-own-operate (BOO) basis a 82 MW heavy fuel oil (HFO) power plant. The plant will be located at Athi River, approximately 25 km from Nairobi. The financing for the project is secured on a limited-recourse basis, underpinned by a 20 year Power Purchase Agreement (PPA) signed between TPGC and Kenya Power and Lighting Company Limited (KPLC). The financial analysis is based on the lenders final draft financial model.

Macroeconomic assumptions

19. The model utilizes US Consumer Prices Index (CPI), estimated at 2% as published by the United States Department of Labor, Bureau of Labor Statistics. The base fuel price used in the model is US$600 per metric ton with an escalation rate of 5%. Salary growth rate is assumed to follow local CPI of 2%.

Costs and Financing Plan

20. The total sub-project costs are estimated at US$157 million (Table 5). The bulk of the project costs is made of the construction costs (86.0%), followed by interest during construction (5.9%), Debt Service Reserve Account (DSRA) (3.6%), working capital (3.4%), and financing fees (2% of the total project cost).

Table 5: Costs Breakdown and Financing

Source of funds	**US$ million**	***%***	**Use of funds**	**US$ million**	***%***
Equity	2.9	*1.9%*	Construction Cost	135.3	*86.0%*
Shareholder Loans	36.4	*23.1%*	Interest During Construction	9.2	*5.9%*
Senior Debt	118.0	*75.0%*	Financing Fees	1.8	*1.1%*
			Working Capital	5.4	*3.4%*
			DSRA*	5.6	*3.6%*
Total	**157.3**	***100%***	**Total**	**157.3**	***100%***

*Debt Service Reserve Account (DSRA)

21. *Financing plan:* The debt-to-equity ratio used for the financing of the sub-project will be 75:25. The debt portion consists of a single senior debt tranche, fully underwritten by Standard Bank of South Africa. The financing terms include 15 years door-to-door maturity, and an all in interest rate of 8.78%[32] per annum. The loan amortization follows a level principle payment schedule, with both, interest and principal repayment done on a semi-annual basis. The 25% of the equity portion consist of equity contribution in an amount of US$2.9 million and shareholder loan in amount of US$36.4 million. The shareholder loan, which is structured as subordinated debt facility, includes a 20 year door-to-door maturity, with 10 years of grace period for principal repayment, and fixed interest rate of 18%. The disbursement of funds will be carried out on a pro-rata basis between equity and debt.

Table 6: Financing terms for loan facilities

Loan facility	**Amount (US$ million)**	**Tenor (years)**	**Grace period (years)**	**Interest rate (p.a.)**
Standard Bank	118	15	1.5	8.78%
Shareholder loan	36.4	20	10	18.0%

[32] The interest rate is based on 6-month LIBOR of 0.75% and a spread of 803 bps.

22. *Debt Service Reserve Account (DSRA):* The DSRA is funded upfront and it amounts to US$5.6 million. The DSRA will be maintained from project cash flow, to cover six month of debt service (principal and interest payment) at all times.

Operating Costs and Revenues

23. The commissioning of the Triumph Power Plant is expected in second half of 2013. The technical and operational assumptions used in the model for this 82 MW of installed capacity thermal power plant are as follows:

Table 7: Triumph Power dispatch schedule

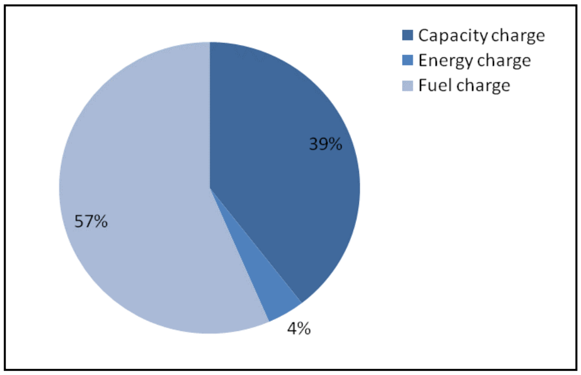
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2022**	**2027**
Load factor	65%	65%	65%	65%	35%	35%	35%	35%	35%	35%
Availability Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
GWh	467	467	467	467	251	251	251	251	251	251

24. As shown in the table above, the power plant is assumed to operate as a base load in the beginning of operational period, transitioning to peak load plant afterwards.

25. *Operation and Maintenance (O&M) costs:* According to above assumptions, the total operations and maintenance costs for the life of the project are estimated at US$ 921 million. Out of this total, US$56 million are fixed O&M, US$82 million are variable O&M, and the rest, i.e. US$783 million, consists of fuel costs. In terms of annual O&M, fixed portion is estimated at US$2.7 million, variable portion is estimated at an average of US$3.9 million, after adjustment for inflation (or US$0.00523/kWh). Fuel costs, which are based on fuel price of 600 US$/ton, escalated at a rate of 5%, are estimated to reach an average of US$37 million per annum.

Revenues: The project revenues consist of three components – capacity charge, energy charge, and fuel charge. The base capacity charge is US$290/kW per year, which consists of non-escalable portion of 237.8 €/kW and escalable part of 52.2 €/kW. Energy charge is assumed at 0.00899 US$/kWh. Both, the energy charge and escalable part of the capacity payment, are adjusted annually for US based CPI of 2%. Total revenues generated from operation during the life of the project are estimated at US$1,440 million, with a yearly average of US$69 million. The total revenues can be further broken down to US$593 million in capacity charge; US$56 million in energy charges, and US$790 million in fuel charges (see figure 4).

Figure 4: Weight of each component in total sub-project revenues

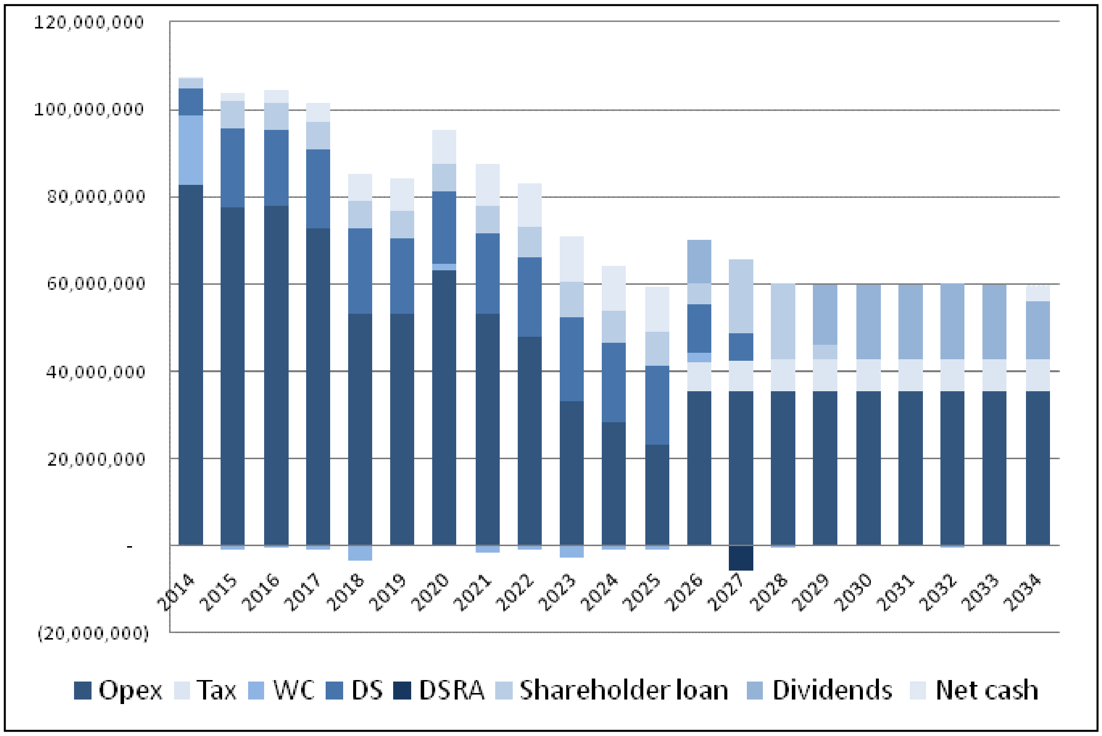


26. *PPA (levelized) tariff*: Based on the total revenues generated, and assumed annual dispatch rate, the tariff on the first year of operation is estimated at 0.20 US$ 0.20 cents per kWh increasing to US$ 0.25 cents per kWh (from 2017). The levelized tariff, using a 12 discount rate, is estimated at US$ 0.23 cents per kWh.

Cash flow Utilization

27. The cash flow generated by the project will be distributed through a following order of priorities: (i) operations and maintenance costs;(ii) income tax; (iii) adjustment to working capital (if any); (iv) debt service; (v) adjustment to debt service reserve account (if any); (vi) payment of shareholder loan; and (vii) dividends. The dividend payment is determined based on the maintenance of the minimum Debt Service Cover Ratio (DSCR) of 1.42x.

Figure 5: Cashflow Utilization



28. The total income to the project company throughout the project life is estimated at US$1,440 million revenues generated directly through operations, and US$0.76 million in interest income. Out of this amount, around US$921 million will be used to cover total operations and maintenance costs, around US$67 million will be paid for income taxes, working capital adjustment will amount to US$8 million, debt service payments will equal to US$221 million, shareholders loan servicing will equal to US$121 million. Dividends to be transferred to shareholders are estimated at US$106 million, and the remaining balance will be used as cash for project company operations. As can be seen from the chart above the project is expected to generate enough cashflow to cover debt service, without the need to tap into DSRA. Upon debt maturity the amount of DSRA is transferred to the project company and will be used towards servicing shareholders debt.

Debt service

29. The project is expected to maintain relatively stable debt service coverage ratio, with minimum DSCR of 1.42x and an average DSCR of 1.57x. The minimum Loan Life Coverage Ratio (LLCR) is estimated at 1.48x and an average of 1.50x. Both the minimum level of these ratios, and the close range between them, are considered as good practice and provide a strong indicator of project company's financial strength and ability to service the debt from the cash flow generated by the project.

Table 8: DSCR and LLCR for 2014 - 2027

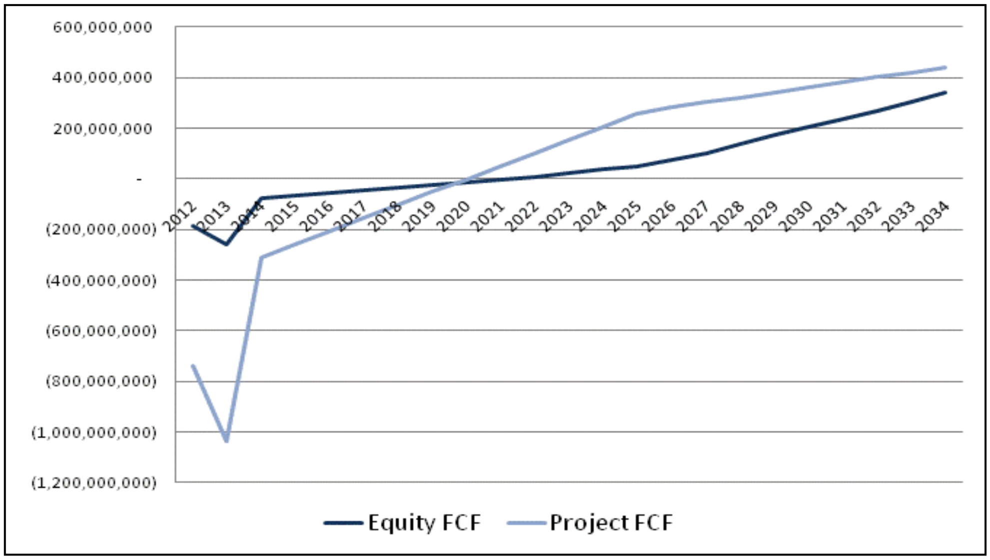
Year	2014*	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
DSCR	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	1.42	3.57
LLCR	1.52	1.51	1.51	1.50	1.50	1.49	1.49	1.48	1.48	1.48	1.48	1.51	1.60	0.00

*Since the operation is expected to start on second half of 2013, the DSCR and LLCR are shown from 2014 as a full year of operation.

Financial Analysis

30. From the Net Present Value perspective, the Triumph Power sub-project as a whole is expected to generate a financial net present value (FNPV) of about US$22.2 million, discounted at 10%, and a project FIRR of 11.9%. The FNPV of equityholders is expected to be around US$21.9 million and FIRR of 14.7%. The graph below shows the cumulative free cash flow to the project and equity holders. The payback period for both, project and equity investors, is expected to be 8.4 years and 9.4 years, respectively.

Figure 6: Payback period to TPGC and Equity Investors



31. Based on this analysis, the project appears to be financially viable, both from the overall perspective of the project and for equity investors. However, project viability, as well as equity returns to shareholders, is relatively sensitive to adverse changes in key variables. To assess the potential impact of changes in these variables, a sensitivity analysis has been undertaken under which the FIRRs and minimum annual DSCR, are calculated under a range of adverse scenarios.

Sensitivity Analysis

32. A detailed sensitivity analysis has been conducted under number of variations on the key variables such as: increase in capital expenditure, increase in operation and maintenance costs, increase in heat rate of power plant above the level provided by EPC contract, lower net installed capacity, lower plant availability, output shortfall due to degradation, and delays in construction. The table below provides a summary of different scenarios used and the impact on minimum DSCR, project FIRR, and equity FIRR.

Table 9: Sensitivity Analysis

	Minimum DSCR	Project FIRR	Equity IRR
Base case	1.42x	10.9%	14.7%
Increase in Opex: 20%	1.35x	10.4%	13.7%
Increase in Capex: 10%	1.30x	9.8%	12.6%
Increase in Heat Rate: 3%	1.33x	10.2%	13.4%
Lower Net Installed capacity: 73.8MW*	1.27x	9.7%	11.9%
Lower Plant Availability: 79%	1.08x	8.2%	8.1%
Output shortfall: 1% arising from degradation	1.42	10.9%	14.6%
Delay (6 months)	1.40x	9.9%	12.8%

*Corresponds to 90% of signature plant capacity.

33. As summarized by the table above, the minimum DSCR and project and equity FIRR are most sensitive to lower availability of the plant and lower net installed capacity, however, this risk is expected to be mitigated by the sub-project company through contracting experienced EPC and O&M contractors. The sensitivity analysis showed that sub-project is not very sensitive to an increase in capex of 10% and opex of 20%. Regarding delay of project completion, the sensitivity analysis assumes the plant is commissioned with a 6 months delay. While the EPC provides back to back LD for TPGC's obligation to KPLC, TPGC's loss of revenue, administrative expenses and fixed cost including interest and insurance will not be covered by the EPC contractor. The resulting DSCR in this scenario would remain stable at 1.4, but the equity IRR would decrease to 12.8 and Project IRR to 9.9%.

Sub-Project 3: Gulf Power Limited (GPL)

34. Gulf Power limited (GPL) is a Special Purpose Company (SPC) established to undertake design, financing, construction, and operation, on a build-own-operate (BOO) basis a 80.3 MW heavy fuel oil (HFO) plant. The plant will be located adjacent to Highway A109 connecting Nairobi to Mombasa at Athi River Town, approximately 35 km from Nairobi. The financing of the sub-project is secured on a limited recourse basis underpinned by a 20 year PPA concluded with Kenya Power and Lighting Company limited (KPLC). The analysis is based on the IFC final draft financial model.

Macroeconomic assumptions

35. The financial model utilizes the following assumptions:

(a) Inflation: The model utilizes European Consumer Prices Index, estimated at 2%, which reflects ten year average historical rate between 2000 and 2010, as published by

Eurostat. The EU CPI is applied to revenues as per PPA requirements and operations and maintenance cost.

(b) Exchange rate: The financing for the project is provided in Euro. GPL's operation and maintenance costs are denominated in Euro, except for fuel, which is denominated in US Dollar. The base fuel price used in the model is US$700 per metric ton, with an escalation rate of 1%. The exchange rate used assumed for this analysis is 1.30 US$ per Euro.

Cost and Financing Plan

36. The total estimated base project cost borne by Gulf, including all development costs, construction costs and financing costs of this 80.3 MW plant is expected to be about €82.8 million. Of this total amount, direct EPC costs account for €56.3 Million (68%), which is equivalent to €700 per kW. The project cost incorporates a 6-month senior Debt Service Reserve Account. Construction would start by June 2012 and would last about a year. Projected commercial operation date is June 2013. Economic lifetime of the plant is estimated at 20 years.

Table 10: Cost Breakdown and Financing

Source of funds	**€ Million**	***%***	**Use of funds**	**€ Million**	***%***
Equity	20.7	*25%*	EPC Contract	56.3	*68%*
IFC Sub-Debt	4.1	*5%*	Lender's Expenses	2.8	*3%*
			Development Costs	6.2	*8%*
Senior Debt:			Costs During Construction	2.7	*3%*
IFC A Loan	16.6	*20%*	Fuel Inventory	5.0	*6%*
IFC B Loan	20.7	*25%*	Debt Service Reserve	4.5	*5%*
Parallel Loan	20.7	*25%*	Interest During construction	1.4	*2%*
Sub-Total	57.9	*70%*	Contingencies	3.9	*5%*
Total	**82.8**	***100%***	**Total**	**82.8**	***100%***

37. *Financing plan:* The debt-to-equity ratio used for the financing of sub-project is 75:25. IFC and Standard Bank are the two senior debt providers. Standard Bank is planning to underwrite a commercial senior loan for the amount equivalent to 50% of project total cost (€41.4 million), split into two tranches: IFC B Loan tranche and parallel loan tranche. The balance will be provided through IFC A Loan. The senior financing is provided under similar terms, which include 15 years door-to-door maturity. The interest rate is based on a swap rate equivalent to 3-month Euribor, currently at 3.49, plus 475 bps spread. IFC is also financing 5% of the project cost through a C Loan, which is a sub-ordinated debt and has a bullet repayment. The door-to-door maturity for subordinated debt follows the same terms as senior debt i.e. 15 year. The interest rate for the sudordinated debt is based on Euribor plus 100pbs spread. There will be additional return on the C loan targeted at 15%. Table 11 below provides a summary of financing terms.

Table 11: Financing Terms for Loan Facilities

	IFC A-loan	IFC B-loan	IFC C-loan (Sub Debt)	Parallel loan
Payment Profile	Level principal	Level principal	Bullet	Level principal
Euribor	3.49%			
Spread	475bp	475bp	100bp	475bp
Target rate of return (Sub-Debt)			15%	
Loan Tenor (years)	15	15	15	15
Grace (years)	1.50	1.50	14.75	1.50
Repayment Periods	quarterly	quarterly	0	quarterly

38. The funding for the sub-project will be disbursed in order of equity first followed by sub-debt and then senior debt.

Operating Costs and Revenues

39. The power plant is expected to be commissioned early June 2013. According to the WB team's projections of demand-supply balance, the plant is expected to be serving as a base-load in the first four years of operation in the context of a power shortage. By 2017, as imports from Ethiopia become available and new geothermal and wind plant production is increasingly integrated into the dispatch, Gulf plant will be dispatched less frequently by system operator. Its capacity factor is assumed to reach 35% by 2017, thus becoming a peaking plant.

Table 12: Gulf Power Dispatch Factor

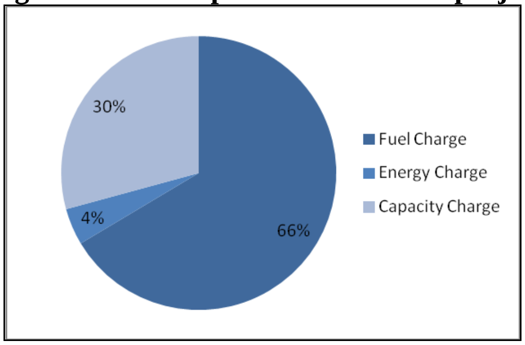
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load factor	65%	65%	65%	65%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	32%
Availability Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
GWh	457	457	457	457	246	246	246	246	246	246	246	246	246	246	246

40. *Operations and Maintenance costs:* Operation and maintenance costs consist of three components. An annual fixed portion estimated at €1.2 million at 2011 prices, variable costs assumed at €6.59 per MWh at 2011 prices, and fuel costs estimated to reach an average of €36.9 million per annum. The total annual operation expenditures range from €33.3 million to €59.6 million, reflecting lowest and highest dispatch rate respectively.

41. *Revenues:* The sub-project revenues consist of three types of payment to the project company: on year 1 of operation, a capacity charge set at €203/kW/year, a fuel charge of 116 €/MWh and a variable O&M charge of 6.92 €/MWh. Capacity charge includes an escalable component set at €38.5 /kW/year as well as a non-escalable component set at 164.5 €/kW/year. Revenues generated in the first year of operation reach around €72.4 million with an average per year being €55.7 million. The total revenues for the life of the project are estimated to reach an

amount of €1,113 million, out of which around €727 million come from fuel charges, €47 million in energy charges, and €339 million in capacity charges (see figure 7).

Figure 7: Weight of each component in total sub-project 3 revenues

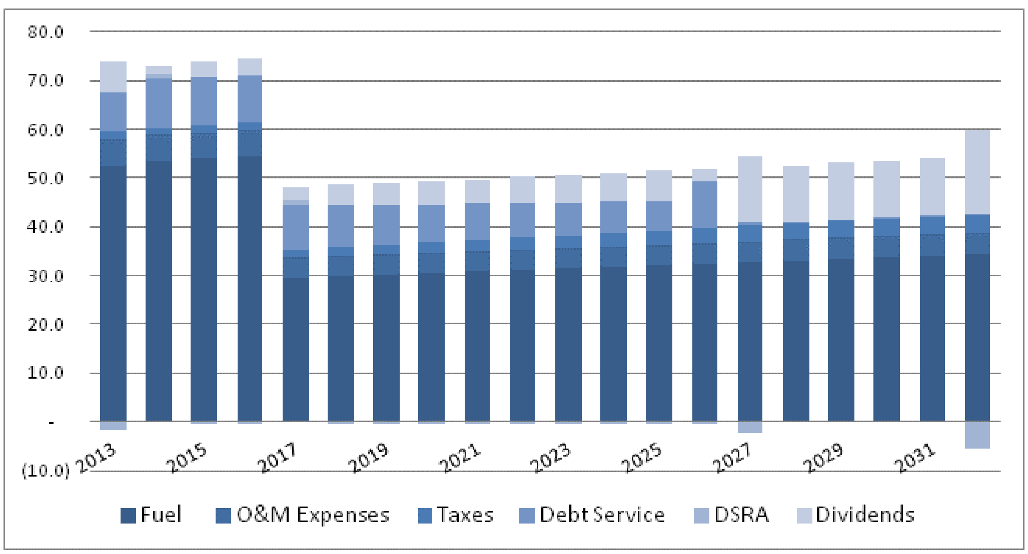


42. *PPA (levelized) tariff:* As mentioned earlier, revenues accruing to the sub-project are categorized into three types: capacity, energy and fuel charge. Combining all three of these elements, the levelized tariff of one unit of electricity generated by the HFO plant is estimated at €-cent 18/kWh over the period 2013-2033 using a 12% discount rate.

Cashflow utilization

43. As with typical project finance operations, gross revenues arising out of the capacity, fuel and energy payments will be used to fund project expenses in the following order of priority: (i) fuel and O&M expenses; (ii) income taxes; (iii) debt service payments; (iv) adjustment to debt service reserve account (if any); and (v) dividends. Dividends are paid out if the Company has a current ratio greater than 1.2x, liabilities to tangible net worth less than 3.0x and a senior Debt Service Coverage Ratio (DSCR) greater than 1.30x.

Figure 8: Cashflow Utilization



44. From the total gross revenues of about €1,113 million which sub-project 3 is estimated to generate over the 20-year PPA period, about €727 million will be spent by Gulf on fuel and €89 million on operation and maintenance of the plant[33]. Another €117 million will go to debt service payments (principal and interest). The government of Kenya will receive about €50 million from the sub-project as income taxes. The remaining cash flow of about €138 million is expected to be transferred as dividends (€118 million) to the shareholders and net cash (€21 million) for the project company operations needs. The above chart provides an overview of the cash flow utilization.

Debt Service

45. Debt service was amortized using a level principal repayment over the sub-project cycle while ensuring reasonable senior debt service cover ratios (DSCR). In the base case scenario, the minimum DSCR is 1.36 reached on second year of operation. The average DSCR over the loan life is 1.84. Both of these ratios are considered to be within industry range and represent a strong indicator of the sub-project's ability to service its debt from the cash flow generated by the project. The model estimates a minimum LLCR of 1.76 and an average LLCR of 2.12. Hence, the LLCR is considered to be at the satisfactory level and provide a good indicator of the sub-project's capacity to service its debt.

Table 13: DSCR and LLCR over debt repayment cycle

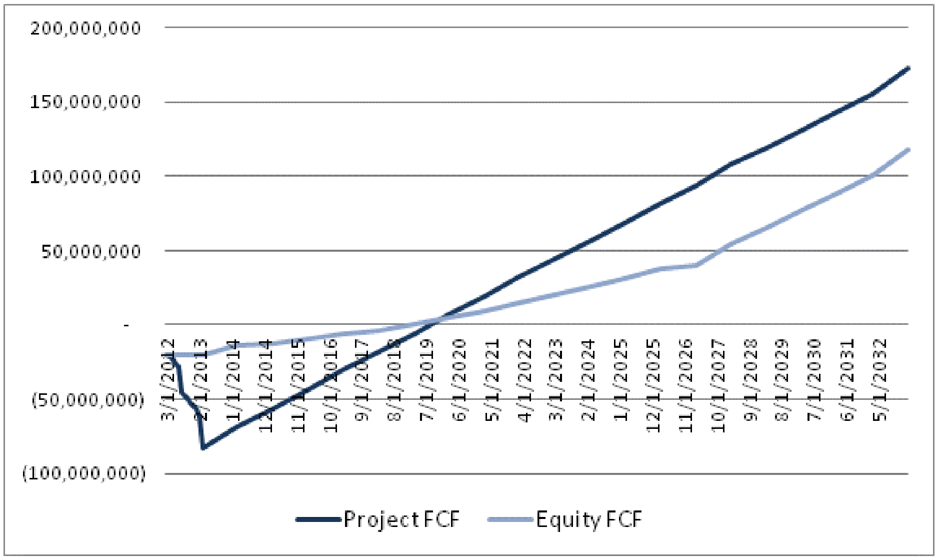
Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
DSCR	1.72	1.36	1.42	1.47	1.54	1.61	1.68	1.77	1.87	1.97	2.10	2.24	2.40	2.58
LLCR	1.78	1.76	1.82	1.87	1.93	1.99	2.05	2.12	2.19	2.27	2.35	2.43	2.52	2.61

Financial Analysis

46. Based on the financial analyses, the Gulf Power sub-project appears to be financially viable, both from the overall perspective of the sub-project and from the perspective of equity holders. In the base case scenario, the FIRR post-tax of the sub-project is expected to be about 13.2 percent and the sub-project NPV of €35.7 million[34]. Payback period for the sub-project is achieved by end of year 6 of operation. For equity investors, financial rate of return is projected at 18.2 percent with NPV of €13.2 million[35] over the project life. Payback period for equity holders is also achieved by end of year 6 of operation.

[33] Including insurance and administrative expenses.
[34] Cost of capital used (WACC) for project NPV calculation is 8%.
[35] Cost of equity used for equity NPV calculation is 12%.

Figure 9: Payback to GPL and Equity Investors



47. However, the viability, as well as equity returns to shareholders, is relatively sensitive to adverse changes in key variables. To assess the potential impact of changes in these variables, a sensitivity analysis has been undertaken under which the FIRRs are calculated under a range of adverse scenarios.

Sensitivity Analysis

48. A detailed sensitivity analysis has been conducted on key variables for the new sub-project such as: increase in capital expenditure, increase in operation and maintenance costs, increase in heat rate of power plant above the level provided by EPC contract, lower net installed capacity, lower plant availability, output shortfall due to degradation, and delays in construction. As seen in the table below, returns are not significantly sensitive to operating costs but are sensitive to variations in capital costs. Fuel cost does not have much impact on project's returns as it is a pass through for the project. On the other hand, the sensitivity analysis has shown that sub-project is most sensitive to the lower plant availability, in which case the DSCR drops to 1.09. Howerver, this risk is expected to be mitigated by the sub-project company through contracting experienced EPC and O&M contractors.

Table 14: Sensitivity Analysis

	Equity IRR (%)	Minimum DSCR	Project IRR (%)
Base case	18.1	1.36	13.2
Increase in Opex: 20%	16.0	1.28	12.3
Increase in Capex: 10%	16.1	1.29	12.3
Increase in Heat Rate: 3%	15.6	1.24	12.1
Lower Net Installed Capacity: 72.3 MW	14.8	1.24	11.7
Lower plant availability: 79%	10.9	1.09	10
Output shortfall: 1% arising from fuel degradation	17.4	1.33	12.8
Delay (6 months)	15	1.27	11.4

<u>Sub-Project 4: OrPower 4 Limited - Geothermal Plant</u>

49. Financial analysis of OrPower4's cashflows shows a robust project based on sound financial structure and projected stream of cash-flow. The financing of the OrPower4 expansion project, is more of a corporate finance nature rather than limited-recourse financing, as it can tap into revenues of existing facility to finance part of the expansion. An analysis of the historical performance was carried out and it revealed acceptable level of operating indicators and liquidity ratios especially since the commissioning of phase 2 of current facility in 2009 (Return on Equity in 2009 of 29% and a current ratio of 2.33). The projected cash flows for the whole project shows that the project will remain sustainable despite an increase in capital cost per kW (resulting from higher drilling costs and the drilling of back-up wells for integrated project). A debt service coverage ratio above 1.72 throughout life of the project combined with the establishment of a debt service reserve account upfront, will contribute towards the mitigation of debt service default risk. Shareholders are expected to earn an IRR on their equity of 13 percent with a NPV of €6.7 million. The sensitivity analysis highlighted that the project can sustain variations of in the range of 10% to 20% for most variables apart of the sensitivity related to geothermal resource availability and actual capacity delivered at commissioning, at which case the project becomes very sensitive. However these risks are mitigated by the back-up wells that are being drilled within this expansion and the extensive experience the project company has acquired in operating the existing plant in Kenya.

50. *Although the Team has undertaken a more detailed Financial Analysis of Orpower and has satisfied itself as to the viability of the sub-project, the data cannot be included in the PAD as Orpower has disclosed to the Bank that this information is confidential. The Analysis would be available for Board members upon request.*

Annex 11: Procurement Arrangements

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

1. The Bank's procurement guidelines for IDA guarantees require that goods and services must be procured with due regard to economy and efficiency. KPLC, as the offtaker, is responsible for selecting the bidder for building, owning, and operating the power station.

Procurement Process for the 3 Thermal IPPs

2. KPLC, with the services of international consultants, conducted international competitive bidding for the three thermal IPPs in 2009 and 2010. A request for Expressions of Interest (EOI) was published on May 29, 2009 by KPLC in the Daily Nation and Standard (Kenya daily newspapers) and on KPLC website. The EOI invited proposals for the design, financing, supply, erection, commissioning, operation and maintenance of three new 60-80 MW Medium Speed Diesel electricity generating plants on a Build, Own and Operate (BOO) arrangement, to be located at various locations around Nairobi City. The EOI stated that the successful bidder(s) for the Project was to become the signatory to a Power Purchase Agreement (PPA) obliging it to design, finance, supply, erect, commission, operate and maintain the plant(s) and to sell the electricity generated by the power plant(s) to KPLC.

3. Thirty one (31) EOIs were received by the closing date, June 30, 2009. On the basis of objective evaluation criteria twenty two (22) firms were considered responsive. The main criteria used for qualification were (i) documentation establishing legal status of applicant, (ii) demonstrated access to competent construction, commissioning, operation and maintenance contractors, (iii) having strong balance sheet with minimum capital and demonstrated capability to undertake a project with a capital cost of up to US$100 million, and (iv) ability to mobilize funds with a debt/equity ratio of 75%:25%.

Request for Proposals

4. KPLC issued a Request for Proposals (RFP) dated July 27, 2009 to all twenty-two (22) prequalified candidates. The deadline for tender submission initially set on October 26, 2009 was subsequently postponed to December 15, 2009 through an Addendum No 1 issued on November 25, 2009. The RFP was a comprehensive document including Instructions to Bidders, Procedure for Making Proposals, Description of the Projects, Contractual Arrangements (including a draft Lease and a draft Power Purchase Agreement), a description of the Electricity Industry in Kenya, the Legal Framework, and various annexes (mostly forms for tender presentation/submission).

5. The RFP included specific qualification requirements and required bidders to submit a technical proposal and a financial proposal, the latter to be broken down as (a) a Base Energy Charge Rate to cover the variable O&M cost component, (b) a Base Capacity Charge Rate comprising a component to cover debt servicing and return on equity, and a component to cover fixed O&M costs, insurance and administration: and (c) a Base Fuel Rate, the purpose of which is basically to pass through the cost of fuel consumed by the plant. Both technical and financial

proposals were opened in a single session, in the presence of bidder's representatives who chose to attend.

6. Bidders were required to give three price options based on the applicable conditions as follows: Option A with GOK sovereign guarantee; Option B with IDA Partial Risk and MIGA Termination guarantee; Option C with neither of the guarantees in Option A and B.

7. The RFP stated in Para 2.7.11: "Bidders must … provide a marked-up copy of the Draft PPA ... KPLC prefers minimal modifications to the Draft PPA... If a Bidder wishes to propose changes to any provision hereof, the same must be indicated in its Proposal".

8. The technical evaluation was on a pass or fail basis, whereas evaluation of the financial proposal was based on a comparison of the unit cost of energy under a specified operating regime for the Power Plant. A discounted Energy Cost was calculated for the term using a discount rate of twelve percent (12%) per annum for financial comparison. The Proposals were evaluated on the basis that in each year the plants will operate at 65% annual load factor.

Tenders Received and Evaluated

9. Two tenders for Plant 1 (location Thika Road, Thika) and five tenders each for Plant 2 (location EPZ Athi River) and Plant 3 (location Mombasa Road, Athi River) were received and opened on the deadline for bid submission. One bid (from Daewoo for Plant 3) was rejected for non-responsiveness because the associated bid security was from an insurance company, whereas the RFP required that the security be from an internationally recognized bank. All other bids passed technical and qualification evaluation. Option A, B and C bids were all evaluated and ranked.

10. For Plant 2, Triumph Power Generating Co Ltd (Special Project Vehicle) was the lowest evaluated bidder under the three price options at a unit energy cost ranging from Euro 0.1052 to 0.1085 per kWh for 82 MW capacity offered, depending on the pricing option. For Plant 3, Consortium (Special Project Vehicle) Gulf Power Ltd was the lowest evaluated bidder under the three price options at a unit energy cost ranging from Euro 0.1097 to 0.1144 per kWh for 80.3 MW capacity offered, depending on the pricing option. The Bank has confirmed the ranking based on computations of unit energy cost in the bids was properly carried out. The Tender Committee of KPLC approved the recommendations to award Plant 2 and Plant 3 to the respective lowest evaluated bidders.

11. The Tender Committee of KPLC decided that Plant 1 should be retendered with the expectation of eliciting better competition (since it had only attracted two bidders) and lower prices. In the retendering Bidders were required to give two price options based on the applicable conditions as follows: Option A with GoK sovereign guarantee, and Option B with IDA Partial Risk and MIGA Termination guarantee.

12. The process of evaluation was as previously carried out for Plants 2 and 3. Nine tenders were received and opened on the deadline for bid submission. One bidder, Aldwych International holdings limited was disqualified for providing a copy of the bid bond that it had submitted in December 2009 as part of the initial tender; hence there was no valid bid bond,

which is a valid cause for rejection of the bid. All the remaining eight bids passed technical and qualification evaluation. Option A and Option B bids were all evaluated and ranked. M/S Melec PowerGen (a JV of MATELEC Group (Panama) and MAN Diesel SAS (France) was the lowest evaluated bidder for price option B at a unit energy cost of Euro 0.1358 per kWh for 87 MW capacity offered, whereas M/S Athi River Power Company was the lowest evaluated bidder for price option A at a unit energy cost of Euro 0.1334 per kWh for 80 MW capacity offered.

13. The Tender Committee of KPLC approved the recommendation to award the tender to MELEC Powergen on April 1, 2010 for price option B. However, following the notification of award, one of the unsuccessful bidders M/S Athi River Power Company appealed to the Public Procurement Administrative Review Board (PPARB) who ruled on May 25, 2010 that the financial evaluation was not done strictly as per the RFP and directed KPLC to reevaluate the financial proposals. The Board also noted that the GoK Sovereign Guarantee — which was the basis for Option A bidding—was no longer available (as per a letter of the Ministry of Energy dated May 5, 2010). Subsequently, only Bidders' prices for Option B (with IDA Partial Risk and MIGA Termination Guarantees) were considered for evaluation by KPLC. The reevaluation determined that M/S Melec PowerGen remained the lowest evaluated bidder under Price Option B at a unit energy cost of Euro 0.1358 per kWh for 87 MW capacity offered (with adjustment to price equivalent of 80 MW as specified in the RFP), which was endorsed by the Tender Committee. The Bank has confirmed the ranking based on computations of unit energy cost in the bids was properly carried out. Subsequently M/S Athi River Power Company appealed again to PPARB who ruled on July 14, 2010 dismissing the latter claim from M/S Athi River Power Company. The Bank considers that the review and findings of the PPARB is confirmation of procurement due process in the award of Plant 1.

Conclusion of the Bank's Review of the Procurement Process for the three Thermal IPPs

14. The Bank´s review concluded that the overall procurement of the three thermal plants met general principles of industry-wide standards of economy, efficiency and transparency for this scale and timing of procurement. The prices obtained for the proposed three IPPs compare favorably with that from the existing thermal IPPs. The current weighted average capacity and energy charges for the three existing thermal IPPs are US$283 per kilowatt per annum and US$ 0.0097 cents per kWh. This compares to the weighted average of US$290 per kilowatt per annum capacity charge and US$ 0.01 cents per kWh energy charge for the proposed three IPPs (using current US$/Euro exchange rates for those PPAs denominated in Euros). Furthermore, the review found that the procurement process followed the provisions of the Procurement Guidelines, on which basis the Bank could guarantee loans for the project made by other lenders.

Procurement Process for Olkaria III Geothermal IPP

15. On July 1996, the Government of Kenya through the Ministry of Energy published an international Tender for development of a 64 MW geothermal plant on a build own and operate (BOO) basis at Olkaria III geothermal resources area. 20 bidders were prequalified but only five firms purchased bid documents and only two, Cal Energy Company Inc. of U.S.A. and Ormat International Inc. of U.S.A. submitted bids. Ormat's bid was evaluated as the technically responsive lowest cost bid. In November 1998 the tender was awarded to Ormat International

Inc, and Ormat through Orpwer, a special purpose company for the project, entered into power purchase agreement with KPLC.

16. An 8 MW Early Generation Facility was commissioned in July 2000 and enhanced to 12 MW in December 2000. The early generation facility made use of then existing wells drilled by the Government. Appraisal of the geothermal field completed in June 2001 revealed that the field could only support a plant of 48 MW at the time. The plant which was initially scheduled to be completed in 2002 was delayed due to difficulties in procuring financing and requirement for payment security. The full plant was finally commissioned in 2009. After gaining experience in operation of the field, OrPower determined that the field can support a higher capacity and in 2011 negotiated a Second Amendment PPA with KPLC for extension of the plant to 100 MW in two phases of 36 MW and 16 MW.

Annex 12: PRGs Term Sheets

KENYA PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

SUMMARY OF TERMS AND CONDITIONS OF
IDA PARTIAL RISK GUARANTEE
IN SUPPORT OF THIKA POWER LTD. IN KENYA

L/C Applicant:	KPLC
IDA Guaranteed L/C:	Revolving, standby letter of credit (L/C) issued in favor of the L/C Beneficiary by the L/C Bank at the request of KPLC to backstop certain payment obligations of KPLC or GoK, as the case may be. Obligations of KPLC or GoK to repay the L/C Bank amounts drawn under the L/C would be guaranteed by the International Development Association (IDA). Amounts drawn by the L/C Beneficiary under the L/C that are repaid by KPLC or GoK as applicable to the L/C Bank within the L/C Reimbursement Period would be reinstated as further described below.
L/C Beneficiary:	Thika Power Limited, a project company set up to undertake the Thika Power Plant, (The Project).
L/C Bank:	A commercial bank acceptable to IDA, GoK, KPLC and the L/C Beneficiary, selected through a competitive bidding process.
L/C Form:	The L/C would be issued in a form satisfactory to the L/C Beneficiary, GoK, KPLC and IDA.
Purpose:	The IDA Guarantee would backstop the obligation by KPLC or GoK, as the case may be, to repay the L/C Bank for amounts drawn by the L/C Beneficiary under the L/C following the occurrence of any of the Guaranteed Events.
Guaranteed Events for a Draw on the L/C:	(i) KPLC's failure to comply with its ongoing payment obligations (including amounts determined by Expert or arbitral dispute resolution proceedings to be payable by KPLC) under the PPA in respect of Capacity Payments, Energy Charges and/or Fuel Charges (excluding any amounts payable in connection with the transfer of the Plant following termination of the PPA); and (ii) GoK's

	failure to comply with its payment obligations under the GoK Letter issued by the GoK for the benefit of the L/C Beneficiary, following the occurrence of a KPLC FM Funding Event (as defined in the PPA), in respect of Capacity Payments, Energy Charges and/or Fuel Charges that would have been otherwise payable by KPLC under the PPA but for the occurrence of a KPLC FM Funding Event (but excluding any Transfer Amount (as defined in the GoK Letter) or any other amounts payable in connection with the termination of the PPA); as further described in the PRG Support Agreement to be concluded between KPLC, GoK and the L/C Beneficiary.
Maximum L/C Amount:	The L/C would be capped at the total of US$35 million and EUR 7.7 million, based on three months of Capacity and Energy Payments and two months of Fuel Charges (plus a contingency amount and escalation elements in relation to Fuel Price and Capacity and Energy Payments). The annually adjustable amount within the Maximum L/C Amount is to be agreed between KPLC and the L/C Beneficiary (see Annual L/C Amount below).
Annual L/C Amount:	Actual amount made available for drawing under the L/C would be determined annually within the Maximum L/C Amount.
Currency of the L/C	US Dollars for Fuel Charges and Euro for Capacity Payments and Energy Charges. Notwithstanding the foregoing, if the amount in the L/C for the relevant currency is not sufficient to cover any outstanding payable amounts in that currency with respect to any Guaranteed Event, the L/C Beneficiary may make a cross currency draw in the other currency in order to cover the payable amounts.
Validity Period of the L/C:	Up to a maximum term of around 15 years and 180 days from effectiveness of the L/C which will become available for drawing after the Commissioning Date. (Overall term of the LC is expected to match the financing term of the Project. Should the L/C Bank not be able to issue the L/C for the required term, there would be roll-over provisions in the IDA Guarantee).
KPLC's obligation to Replenish the L/C under the	KPLC will undertake under the PRG Support Agreement to maintain at all times the minimum balance

PRG Support Agreement:	of one month of Capacity Payment, Energy Charge and Fuel Charge to be available for drawing under the L/C; provided that a failure to maintain such balance will not constitute a KPLC's Default under the PPA as long as (i) KPLC is current on its payment obligations under the PPA, and (ii) KPLC or GoK, as the case may be, repays the L/C Bank and replenishes any amount drawn under the L/C within 12 months after the date of the drawing (see also L/C Reimbursement Period under the L/C Reimbursement and Credit Agreement below).
L/C Reimbursement Period under the Reimbursement and Credit Agreement:	Following a drawing under the L/C by the L/C Beneficiary, KPLC or GoK, as the case may be, would be obligated to repay the L/C Bank the amount drawn under the L/C together with accrued interest thereon within a period of 12 months under the Reimbursement and Credit Agreement to be concluded between GoK, KPLC and the L/C Bank (the "**L/C Reimbursement Period**"). If KPLC or GoK has repaid to the L/C Bank on or before the expiry of the L/C Reimbursement Period, the L/C would be reinstated for such amount. If the amount remains unpaid after the expiry of the L/C Reimbursement Period, the L/C Bank would have the right to call on the IDA Guarantee for the principal amount (equal to the amount drawn under the L/C) plus accrued interest due from KPLC or GoK as applicable. Any amount paid by IDA to the L/C Bank under the IDA Guarantee would be deducted from the IDA Guaranteed Amount and even if the payment default by KPLC or GoK is subsequently remedied after the payment under the IDA Guarantee, the amount paid by IDA would not be reinstated under the L/C.
Interest Rate Charged by the L/C Bank under the Reimbursement and Credit Agreement:	An appropriate 'spread' above LIBOR and EURIBOR, as applicable, to reflect IDA risk, and acceptable to, GoK, KPLC and IDA, and payable by KPLC.
Maximum IDA Guarantee Period:	The Validity Period of the L/C plus 14 months.
Maximum IDA Guaranteed Amount:	US$35 million and EUR 7.7 million (the Maximum "**IDA Guaranteed Principal Amount**"), plus accrued interest charged by the L/C Bank.
Annual IDA Guaranteed Amount:	The actual amount made available for drawing under the L/C and guaranteed by IDA would be determined annually within the Maximum IDA Guaranteed

	Principal Amount, pursuant to a formula to be included in the PRG Support Agreement and Project Agreement (see also Annual L/C Amount above).

IDA Related Guarantee Fees

IDA Guarantee Fees:	IDA will charge a guarantee fee of 0.75% per annum on the Annual IDA Guaranteed Amount, payable semi-annually in advance by the L/C Beneficiary from the Commissioning Date.
IDA Front-end Fees:	IDA will charge the following front-end fees for guarantees: (a) An Initiation Fee of 0.15% of the Maximum IDA Guaranteed Principal Amount (but not less than US$l00,000) for internal Project preparation, payable by the L/C Beneficiary. (b) Processing Fee of up to a maximum cap of 0.50% of the Maximum IDA Guaranteed Principal Amount to cover IDA's reimbursable expenses and third party costs, payable by the L/C Beneficiary.
L/C Bank Fees:	To be determined through a competitive bidding process and payable by the L/C Beneficiary to the L/C Bank.

Conditions Precedent to the IDA Guarantees:

Conditions Precedent:	IDA's effectiveness conditions would include the following: (a) Firm commitment for proposed equity and debt financing for the Project. (b) Execution, delivery and effectiveness of the GoK Letter, PPA (other than in respect of the condition that the L/C has been issued), the PRG Support Agreement, and all other project financing agreements in form and substance satisfactory to IDA. (c) Payment of the Initiation and Processing Fees, if such amount is invoiced by IDA as due on or prior to the effectiveness. (d) Conclusion of the Guarantee Agreement between

	the L/C Bank and IDA, the Reimbursement and Credit Agreement between L/C Bank, GoK and KPLC, the PRG Support Agreement between GoK, KPLC and the L/C Beneficiary, the Project Agreement between the L/C Beneficiary and IDA, and the Indemnity Agreement between IDA and Kenya, all in form and substance satisfactory to IDA. (e) Provision of satisfactory legal opinions from: (i) the Attorney General of Kenya relating to the Indemnity Agreement, the PRG Support Agreement, the Reimbursement and Credit Agreement and the GoK Letter; (ii) counsel to KPLC relating to the PRG Support Agreement, the Reimbursement and Credit Agreement, and the PPA; (iii) counsel to the L/C Beneficiary relating to the Project Agreement and the PRG Support Agreement.

IDA Documentation:

Guarantee Agreement:	The terms and conditions of the IDA Guarantee would be embodied in a Guarantee Agreement between the L/C Bank and IDA with respect to the L/C facility.
Project Agreement:	The L/C Beneficiary would enter into a Project Agreement with IDA, under which the L/C Beneficiary would provide relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable Kenyan environmental laws and IDA environmental and social safeguard requirements and World Bank requirements relating to Sanctionable Practices.
PRG Support Agreement:	KPLC and GoK would enter into a PRG Support Agreement relating to the L/C with the L/C Beneficiary, under which KPLC or GoK, as the case may be, would undertake to provide an L/C under which the L/C Beneficiary would be entitled to draw for the failure by KPLC or GoK, as the case may be, to pay an amount due to the L/C Beneficiary resulting from the occurrence of a Guaranteed Event. Following a drawing by the L/C Beneficiary, GoK or KPLC, as the case may be, would undertake to repay to the L/C Bank the amount drawn,

	as soon as practicable and in no event later than 12 months after the date of drawing; provided that KPLC will at all times maintain a minimum balance of one month of Capacity Payment, Energy Charge and Fuel Charge to be available for drawing, and will immediately replenish the L/C as necessary to maintain such minimum balance (see also KPLC's Obligation to Replenish the L/C under the PRG Support Agreement above).
L/C Reimbursement and Credit Agreement:	KPLC and GoK would enter into a Reimbursement and Credit Agreement with the L/C Bank, under which KPLC or GoK as applicable would undertake to repay the L/C Bank the amounts drawn under the L/C, together with accrued interest, within a period of twelve (12) months from the date of each drawing.
Indemnity Agreement:	Kenya would enter into an Indemnity Agreement with IDA. Under the Agreement, Kenya would undertake to indemnify IDA on demand, or as IDA may otherwise direct, for any payments made by IDA under the terms of the IDA Guarantee. The Indemnity Agreement would follow the legal regime, and include dispute settlement provisions, which are customary in agreements between Member countries and IDA.

SUMMARY OF TERMS AND CONDITIONS OF
IDA PARTIAL RISK GUARANTEE
IN SUPPORT OF TRIUMPH POWER GENERATING CO. LTD. IN KENYA

L/C Applicant:	KPLC
IDA Guaranteed L/C:	Revolving, standby letter of credit (L/C) issued in favor of the L/C Beneficiary by the L/C Bank at the request of KPLC to backstop certain payment obligations of KPLC or GoK, as the case may be. Obligations of KPLC or GoK to repay the L/C Bank amounts drawn under the L/C would be guaranteed by the International Development Association (IDA). Amounts drawn by the L/C Beneficiary under the L/C that are repaid by KPLC or GoK as applicable to the L/C Bank within the L/C Reimbursement Period would be reinstated as further described below.
L/C Beneficiary:	Triumph Power Generating Company Limited, a project company set up to undertake the Kitengela Power Plant, (The Project).
L/C Bank:	A commercial bank acceptable to IDA, GoK, KPLC and the L/C Beneficiary, selected through a competitive bidding process.
L/C Form:	The L/C would be issued in a form satisfactory to the L/C Beneficiary, GoK, KPLC and IDA.
Purpose:	The IDA Guarantee would backstop the obligation by KPLC or GoK, as the case may be, to repay the L/C Bank for amounts drawn by the L/C Beneficiary under the L/C following the occurrence of the Guaranteed Events.
Guaranteed Events for a Draw on the L/C:	(i) KPLC's failure to comply with its ongoing payment obligations (including amounts determined by Expert or arbitral dispute resolution proceedings to be payable by KPLC) under the PPA in respect of Capacity Payments, Energy Charges and/or Fuel Charges (excluding any amounts payable in connection with the transfer of the Plant following termination of the PPA); and (ii) GoK's failure to comply with its payment obligations under the GoK Support Letter issued by the GoK for the benefit of

	the L/C Beneficiary, following the occurrence of a KPLC FM Funding Event (as defined in the PPA), in respect of Capacity Payments, Energy Charges and/or Fuel Charges that would have been otherwise payable by KPLC under the PPA but for the occurrence of a KPLC FM Funding Event (excluding any Transfer Amount (as defined in the GoK Letter) or any other amounts payable in connection with the termination of the PPA); as further described in the PRG Support Agreement to be concluded between KPLC, GoK and the L/C Beneficiary.
Maximum L/C Amount:	The L/C would be capped at US$45 million, based on three months of Capacity and Energy Payments and two months of Fuel Charges (plus a contingency amount and escalation elements in relation to Fuel Price and Capacity and Energy Payments). The annually adjustable amount within the Maximum L/C Amount is to be agreed between KPLC and the L/C Beneficiary (see Annual L/C Amount below).
Annual L/C Amount:	Actual amount made available for drawing under the L/C would be determined annually within the Maximum L/CAmount.
Currency of the L/C	US Dollars.
Validity Period of the L/C:	Up to a maximum term of around 15 years and 180 days from effectiveness of the L/C. which will be available for drawing after the Commissioning Date (Overall term of the L/C is expected to match the financing term of the Project. Should the L/C Bank not be able to issue the L/C for the required term, there would be roll-over provisions in the IDA Guarantee).
KPLC's Obligation to Replenish the L/C under the PRG Support Agreement:	KPLC will undertake under the PRG Support Agreement to maintain at all times the minimum balance of one month of Capacity Payment, Energy Charge and Fuel Charge to be available for drawing under the L/C; provided that a failure to maintain such balance will not constitute a KPLC's Default under the PPA as long as (i) KPLC is current on its payment obligations under the PPA, and (ii) KPLC or GoK, as the case may be, repays the L/C Bank and replenishes any amount drawn under the L/C within 12 months after the date of the drawing (see also L/C Reimbursement Period under the L/C

	Reimbursement and Credit Agreement below).
L/C Reimbursement Period under the Reimbursement and Credit Agreement	Following a drawing under the L/C by the L/C Beneficiary, KPLC or GoK, as the case may be, would be obligated to repay the L/C Bank the amount drawn under the L/C together with accrued interest thereon within a period of 12 months under the Reimbursement and Credit Agreement to be concluded between GOK, KPLC and the L/C Bank (the **"L/C Reimbursement Period"**). If KPLC or GoK has repaid to the L/C Bank on or before the expiry of the L/C Reimbursement Period, the L/C would be reinstated for such amount. If the amount remains unpaid after the expiry of the L/C Reimbursement Period, the L/C Bank would have the right to call on the IDA Guarantee for the principal amount (equal to the amount drawn under the L/C) plus accrued interest due from KPLC or GoK as applicable. Any amount paid by IDA to the L/C Bank under the IDA Guarantee would be deducted from the IDA Guaranteed Amount and even if the payment default by KPLC or GoK is subsequently remedied after the payment under the IDA Guarantee, the amount paid by IDA would not be reinstated under the L/C.
Interest Rate Charged by the L/C Bank under the Reimbursement and Credit Agreement:	An appropriate 'spread' above LIBOR, to reflect IDA risk, and acceptable to, GoK, KPLC and IDA, and payable by KPLC.
Maximum IDA Guarantee Period:	The Validity Period of the L/C plus 14 months.
Maximum IDA Guaranteed Amount:	US$45 million (the "Maximum IDA Guaranteed Principal Amount"), plus accrued interest charged by the L/C Bank.
Annual IDA Guaranteed Amount:	The actual amount made available for drawing under the L/C and guaranteed by IDA would be determined annually within the Maximum IDA Guaranteed Principal Amount, pursuant to a formula to be included in the PRG Support Agreement and Project Agreement (see also Annual L/C Amount above).

IDA Guarantee Related Fees:

IDA Guarantee Fees:	IDA will charge a guarantee fee of 0.75% per annum on the Annual IDA Guaranteed Amount, payable semi-annually in advance by the L/C Beneficiary from Commisssioning Date.
IDA Front-end Fees:	IDA will charge the following front-end fees for guarantees: (a) An Initiation Fee of 0.15% of the Maximum IDA Guaranteed Principal Amount (but not less than US$100,000) for internal Project preparation, payable by the L/C Beneficiary. (b) Processing Fee of up to a maximum cap of 0.50% of the Maximum IDA Guaranteed Principal Amount to cover IDA's reimbursable expenses and third parties costs, payable by the L/C Beneficiary.
L/C Bank Fees:	To be determined through a competitive bidding process and payable by the L/C Beneficiary to the L/C Bank.

Conditions Precedent to the IDA Guarantees:

Conditions Precedent:	IDA's effectiveness conditions would include the following: (a) Firm commitment for proposed equity and debt financing for the Project. (b) Execution, delivery and effectiveness of the GoK Support Letter, PPA (other than in respect of the condition that the L/C has been issued), the PRG Support Agreement, and all other project financing agreements in a form and substance satisfactory to IDA. (c) Payment of the Initiation and Processing Fees, if such amount is invoiced by IDA as due on or prior to the effectiveness. (d) Conclusion of the Guarantee Agreement between the L/C Bank and IDA, the Reimbursement and Credit Agreement between L/C Bank, GoK and KPLC, the PRG Support Agreement between GoK, KPLC and the L/C Beneficiary, the Project

	Agreement between the L/C Beneficiary and IDA, and the Indemnity Agreement between IDA and Kenya, all in a form and substance satisfactory to IDA. (e) Provision of satisfactory legal opinions from: (i) the Attorney General of Kenya relating to the Indemnity Agreement, the PRG Support Agreement, the Reimbursement and Credit Agreement and the GoK Support Letter; (ii) counsel to KPLC relating to the PRG Support Agreement, the Reimbursement and Credit Agreement, and the PPA; (iii) counsel to the L/C Beneficiary relating to the Project Agreement and the PRG Support Agreement.

IDA Documentation:

Guarantee Agreement:	The terms and conditions of the IDA Guarantee would be embodied in a Guarantee Agreement between the L/C Bank and IDA with respect to the L/C facility.
Project Agreement:	The L/C Beneficiary would enter into a Project Agreement with IDA, under which the L/C Beneficiary would provide relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable Kenyan environmental laws and IDA environmental and social safeguard requirements and World Bank requirements relating to Sanctionable Practices.
PRG Support Agreement:	KPLC and GoK would enter into a PRG Support Agreement relating to the L/C with the L/C Beneficiary, under which KPLC or GoK, as the case may be, would undertake to provide an L/C under which the L/C Beneficiary would be entitled to draw for the failure by KPLC or GoK, as the case may be, to pay an amount due to the L/C Beneficiary resulting from the occurrence of a Guaranteed Event. Following a drawing by the L/C Beneficiary, GoK or KPLC, as the case may be, would undertake to repay to the L/C Bank the amount drawn, as soon as as practicable and in no event later than 12 months after the date of drawing; provided that KPLC

	will at all times maintain a minimum balance of one month of Capacity Payment, Energy Charge and Fuel Charge to be available for drawing, and will immediately replenish the L/C as necessary to maintain such minimum balance (see also KPLC/s Obligation to Replenish the L/C under the PRG Support Agreement above).
Reimbursement and Credit Agreement:	KPLC and GoK would enter into a Reimbursement and Credit Agreement with the L/C Bank, under which KPLC or GoK as applicable would undertake to repay the L/C Bank the amounts drawn under the L/C, together with accrued interest, within a period of twelve (12) months from the date of each drawing.
Indemnity Agreement:	Kenya would enter into an Indemnity Agreement with IDA. Under the Agreement, Kenya would undertake to indemnify IDA on demand, or as IDA may otherwise direct, for any payments made by IDA under the terms of the IDA Guarantee. The Indemnity Agreement would follow the legal regime, and include dispute settlement provisions, which are customary in agreements between Member countries and IDA.

SUMMARY OF TERMS AND CONDITIONS OF
IDA PARTIAL RISK GUARANTEE
IN SUPPORT OF GULF POWER LTD. IN KENYA

L/C Applicant:	KPLC
IDA Guaranteed L/C:	Revolving, standby letter of credit (L/C) issued in favor of the L/C Beneficiary by the L/C Bank at the request of KPLC to back stop certain payment obligations of KPLC or GoK, as the case may be. Obligations of KPLC or GoK to repay the L/C Bank amounts drawn under the L/C would be guaranteed by the International Development Association (IDA). Amounts drawn by the L/C Beneficiary under the L/C that are repaid by KPLC or GoK as applicable to the L/C Bank within the L/C Reimbursement Period would be reinstated as further described below.
L/C Beneficiary:	Gulf Power Limited, a project company set up to undertake the Athi River Power Plant, (The Project).
L/C Bank:	A commercial bank acceptable to IDA, GoK, KPLC and the L/C Beneficiary, selected through a competitive bidding process.
L/C Form:	The L/C would be issued in a form satisfactory to the L/C Beneficiary, GoK, KPLC, and IDA.
Purpose:	The IDA Guarantee would backstop the obligation by KPLC or GoK, as the case may be, to repay the L/C Bank for amounts drawn by the L/C Beneficiary under the L/C following the occurrence of any of the Guaranteed Events.
Guaranteed Events for a Draw on the L/C:	(i) KPLC's failure to comply with its ongoing payment obligations (including amounts determined by Expert or arbitral dispute resolution proceedings to be payable by KPLC) under the PPA in respect of Capacity Payments, Energy Charges and/or Fuel Charges (excluding any amounts payable in connection with the transfer of the Plant following termination of the PPA); and (ii) GoK's failure to comply with its payment obligations under the GoK Support Letter issued by the GoK for the benefit of the L/C Beneficiary, following the occurrence of a KPLC FM Funding Event (as defined in the PPA), in respect of Capacity Payments, Energy Charges and/or

	Fuel Charges that would have been otherwise payable by KPLC under the PPA but for the occurrence of a KPLC FM Funding Event (excluding any Transfer Amount (as defined in the GoK Support Letter) or any other amounts payable in connection with the termination of the PPA); as further described in the PRG Support Agreement to be concluded between KPLC, GoK and the L/C Beneficiary.
Maximum L/C Amount:	The L/C would be capped at the total of US$35 million and EUR7 million, based on three months of Capacity and Energy Payments and two months of Fuel Charges (plus a contingency amount and escalation elements in relation to Fuel Price and Capacity and Energy Payments). The annually adjustable amount within the Maximum L/C Amount is to be agreed between KPLC and the L/C Beneficiary (see Annual L/C Amount).
Annual L/C Amount:	Actual amount made available for drawing under the L/C would be determined annually within the Maximum L/C Amount.
Currency of the L/C	US Dollars for Fuel Charges and Euro for Capacity Payments and Energy Charges. Notwithstanding the foregoing, if the amount in the L/C for the relevant currency is not sufficient to cover any outstanding payable amounts in that currency with respect to any Guaranteed Event, the L/C Beneficiary may make a cross currency draw in the other currency in order to cover the payable amounts.
Validity Period of the L/C:	Up to a maximum term of around 15 years and 180 days from the effectiveness of the L/C which will be available for drawing from the Commissioning Date (Overall term of the L/C is expected to match the financing term of the Project. Should the L/C Bank not be able to issue the L/C for the required term, there would be roll-over provisions in the IDA Guarantee).
KPLC's obligation to Replenish the L/C under the PRG Support Agreement:	KPLC will undertake under the PRG Support Agreement to maintain at all times the minimum balance of one month of Capacity Payments, Energy Charges and Fuel Charge to be available for drawing under the L/C; provided that a failure to maintain such balance will not constitute a KPLC Default under the PPA as long as (i) KPLC is current on its payment obligations under the PPA; and (ii) KPLC or GoK, as the case may

	be, repays the L/C Bank and replenishes any amount drawn under the L/C within 12 months after the date of the drawing (see also L/C Reimbursement Period under the L/C Reimbursement and Credit Agreement below).
L/C Reimbursement Period under the Reimbursement and Credit Agreement:	Following a drawing under the L/C by the L/C Beneficiary, KPLC or GoK, as the case may be, would be obligated to repay the L/C Bank the amount drawn under the L/C together with accrued interest thereon within a period of 12 months under the Reimbursement and Credit Agreement to be concluded between GoK, KPLC and the L/C Bank (the "**L/C Reimbursement Period**"). If KPLC or GoK has repaid to the L/C Bank on or before the expiry of the L/C Reimbursement Period, the L/C would be reinstated for such amount. If the amount remains unpaid after the expiry of the L/C Reimbursement Period, the L/C Bank would have the right to call on the IDA Guarantee for the principal amounts (equal to the amount drawn under the L/C) plus accrued interest due from KPLC or GoK as applicable. Any amount paid by IDA to the L/C Bank under the IDA Guarantee would be deducted from the IDA Guaranteed Amount and even if the payment default by KPLC or GoK is subsequently remedied after the payment under the IDA Guarantee, the amount paid by IDA would not be reinstated under the L/C.
Interest Rate Charged by the L/C Bank under the Reimbursement and Credit Agreement:	An appropriate 'spread' above LIBOR and EURIBOR as applicable, to reflect IDA risk, and acceptable to GoK, KPLC and IDA, and payable by KPLC.
Maximum IDA Guarantee Period:	The Validity Period of the L/C plus 14 months.
Maximum IDA Guaranteed Amount:	The total of US$35 million and EUR7 million (the "**Maximum IDA Guaranteed Principal Amount**"), plus accrued interest charged by the L/C Bank.
Annual IDA Guaranteed Amount:	The actual amount made available for drawing under the L/C and guaranteed by IDA would be determined annually within the Maximum IDA Guaranteed Principal Amount, pursuant to a formula to be included in the PRG Support Agreement and Project Agreement (see also Annual L/C Amount above).

IDA Guarantee Related Fees:

IDA Guarantee Fees:	IDA will charge a guarantee fee of 0.75% per annum on the Annual IDA Guaranteed Amount, payable semi-annually in advance by the L/C Beneficiary from Commissioning.
IDA Front-end Fees:	IDA will charge the following front-end fees for guarantees: (a) An Initiation Fee of 0.15% of the IDA Maximum Guaranteed Principal Amount (but not less than US$ l00,000) for internal Project preparation, payable by the L/C Beneficiary. (b) Processing Fee of up to a maximum cap of 0.50% of the Maximum IDA Guaranteed Principal Amount to cover IDA's reimbursable expenses and third party costs, payable by the L/C Beneficiary.
L/C Bank Fees:	To be determined through a competitive bidding process and payable by the L/C Beneficiary to the L/C Bank.

Conditions Precedent to the IDA Guarantees:

Conditions Precedent:	IDA's effectiveness conditions would include the following: (a) Firm commitment for proposed equity and debt financing for the Project. (b) Execution, delivery and effectiveness of the GoK Support Letter, PPA (other than in respect of the condition that the L/C has been issued), the PRG Support Agreement, and all other project financing agreements in form and substance satisfactory to IDA. (c) Payment of the Initiation and Processing Fees, if such amount is invoiced by IDA as due on or prior to the effectiveness. (d) Conclusion of the Guarantee Agreement between the L/C Bank and IDA, the Reimbursement and Credit Agreement between L/C Bank, GoK and KPLC, the PRG Support Agreement between GoK, KPLC and the L/C Beneficiary, the Project Agreement between

	the L/C Beneficiary and IDA, and the Indemnity Agreement between IDA and Kenya, all in form and substance satisfactory to IDA. (e) Provision of satisfactory legal opinions from: (i) the Attorney General of Kenya relating to the Indemnity Agreement, the PRG Support Agreement, the Reimbursement and Credit Agreement and the GOK Support Letter; (ii) counsel to KPLC relating to the PRG Support Agreement, the Reimbursement and Credit Agreement, and the PPA (iii) counsel to the L/C Beneficiary relating to the Project Agreement and the PRG Support Agreement.

IDA Documentation:

Guarantee Agreement:	The terms and conditions of the IDA Guarantee would be embodied in a Guarantee Agreement between the L/C Bank and IDA with respect to the L/C facility.
Project Agreement:	The L/C Beneficiary would enter into a Project Agreement with IDA, under which the L/C Beneficiary would provide relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable Kenyan environmental laws and IDA environmental and social safeguard requirements and World Bank requirements relating to Sanctionable Practices.
PRG Support Agreement:	KPLC and GoK would enter into a PRG Support Agreement relating to the L/C with the L/C Beneficiary, under which KPLC or GoK, as the case may be, would undertake to provide an L/C under which the L/C Beneficiary would be entitled to draw for the failure by KPLC or GoK, as the case may be, to pay an amount due to the L/C Beneficiary resulting from the occurrence of a Guaranteed Event. Following a drawing by the L/C Beneficiary, GoK or KPLC, as the case may be, would undertake to repay to the L/C Bank the amount drawn, as soon as practicable and in no event later than 12 months after the date of drawing; provided that KPLC will maintain at all times the minimum balance of one month of Capacity Payments, Energy Charges and Fuel Charge to be available for drawing under the L/C and will immediately replenish the L/C as necessary to

	maintain such minimum balance (see also KPLC's Obligation to Replenish the L/C under the PRG Support Agreement above).
Reimbursement and Credit Agreement:	KPLC and GoK would enter into a Reimbursement and Credit Agreement with the L/C Bank, under which KPLC or GoK as applicable would undertake to repay the L/C Bank the amounts drawn under the L/C, together with accrued interest, within a period of twelve (12) months from the date of each drawing.
Indemnity Agreement:	Kenya would enter into an Indemnity Agreement with IDA. Under the Agreement, Kenya would undertake to indemnify IDA on demand, or as IDA may otherwise direct, for any payments made by IDA under the terms of the IDA Guarantee. The Indemnity Agreement would follow the legal regime, and include dispute settlement provisions, which are customary in agreements between Member countries and IDA.

SUMMARY OF TERMS AND CONDITIONS OF
IDA PARTIAL RISK GUARANTEE
IN SUPPORT OF <u>ORPOWER 4 INC.</u> IN KENYA

L/C Applicant:	KPLC.
IDA Guaranteed L/C:	Revolving, standby, letter of credit (L/C) issued in favor of the L/C Beneficiary by the L/C Bank at the request of KPLC to backstop certain payment obligations of KPLC. KPLC's obligations to repay the L/C Bank amounts drawn under the L/C would be guaranteed by IDA. Any amounts drawn by the L/C Beneficiary under the L/C that are repaid by KPLC to the L/C Bank within the L/C Reimbursement Period would be reinstated as further described below.
L/C Beneficiary:	Or Power 4 Inc., a project company undertaking the Olkaria III Geothermal Expansion Project, (The Project).
L/C Bank:	A commercial bank acceptable to IDA, KPLC and the L/C Beneficiary, selected through a competitive bidding process.
L/C Form:	The L/C would be issued in a form satisfactory to the L/C Beneficiary, KPLC, and IDA.
Purpose:	The IDA Guarantee would backstop KPLC's obligation to repay the L/C Bank for amounts drawn by the L/C Beneficiary under the L/C following the occurrence of any of the Guaranteed Events.
Guaranteed Events for a Draw on the L/C:	KPLC's failure to comply with its ongoing payment obligations (including amounts determined by Expert or arbitral dispute resolution proceedings to be payable by KPLC) under the second amended and restated Power Purchase Agreement between the L/C Beneficiary and KPLC (the PPA), in respect of Energy Charges and Capacity Payments due under the PPA (but excluding any amounts payable in connection with the transfer of the Plant following termination of the PPA) with respect to the First and Second Plants; as further described in the PRG Support Agreement to be concluded between KPLC and the L/C Beneficiary.
Maximum L/C Amount:	The L/C would be capped at US$26 million (Plants I

	and 2) based on four months of Capacity Payments and Energy Charges plus contingencies relating to the escalation elements of the Capacity and Energy payments). The annually adjustable amount within the Maximum L/C Amount is to be agreed between KPLC and the L/C Beneficiary (see Annual L/C Amount).
Annual L/C Amount:	Actual amount made available for drawing under the L/C would be determined annually within the Maximum L/C Amount.
Currency of the L/C:	US Dollars
Validity Period of the L/C:	Up to a maximum term of around 15 years and 180 days from effectiveness of the L/C or from Commissioning Date. (Overall term of the L/C is expected to match the financing term of the Project. Should the L/C Bank not be able to issue the L/C for the required term, there would be roll-over provisions in the IDA Guarantee).
KPLC's obligation to Replenish the L/C under the PRG Support Agreement:	KPLC will undertake under the PRG Support Agreement to maintain at all time the minimum balance of one month of Capacity Payment and Energy Charge to be available for drawing under the LC; provided that a failure to maintain such balance will not constitute a KPLC's Default under the PPA as long as (i) KPLC is current on its payment obligations under the PPA, and (ii) KPLC repays the L/C Bank and replenishes any amount drawn under the L/C within 12 months after the date of the drawing (see also L/C Reimbursement Period under the L/C Reimbursement and Credit Agreement below).
L/C Reimbursement Period under the Reimbursement and Credit Agreement:	Following a drawing under the L/C by the L/C Beneficiary, KPLC would be obligated to repay the L/C Bank the amount drawn under the L/C together with accrued interest thereon within a period of 12 months under the Reimbursement and Credit Agreement to be concluded between KPLC and the L/C Bank (the "**L/C Reimbursement Period**"). If KPLC has repaid to the L/C Bank on or before the expiry of the L/C Reimbursement Period, the L/C would be reinstated for such amount. If the amount remains unpaid after the expiry of the L/C Reimbursement Period, the L/C Bank would have the right to call on the IDA Guarantee for the principal amount (equal to the amount drawn under the L/C) plus accrued interest due from KPLC. Any

	amount paid by IDA to the L/C Bank under the IDA Guarantee would be deducted from the IDA Guaranteed Amount and even if KPLC's payment default is subsequently remedied after the payment under the IDA Guarantee, the amount paid by IDA would not be reinstated under the L/C.
Interest Rate Charged by the L/C Bank under the Reimbursement and Credit Agreement:	An appropriate 'spread' above LIBOR, to reflect IDA risk, and acceptable to KPLC and IDA, and payable by KPLC.
Maximum IDA Guarantee Period:	The Validity Period of the L/C plus 14 months.
Maximum IDA Guaranteed Amount:	US$26 million[36] (the Maximum IDA Guaranteed Principal Amount), plus accrued interest charged by the L/C Bank.
Annual IDA Guaranteed Amount:	The actual amount made available for drawing under the L/C and guaranteed by IDA would be determined annually within the Maximum IDA Guaranteed Amount, pursuant to a formula to be included in the PRG Support Agreement and Project Agreement (see also Annual L/C Amount above).

IDA Guarantee Related Fees:

IDA Guarantee Fees:	IDA will charge a guarantee fee of 0.75% per annum on the Annual IDA Guaranteed Amounts, payable six monthly in advance by the L/C Beneficiary from effectiveness of the L/C or Commissioning Date.
IDA Front-end Fees:	IDA will charge the following front-end fees for guarantees: (a) An Initiation Fee of 0.15% of the Maximum IDA Guaranteed Principal Amount (but not less than US$ l00,000) for internal Project preparation, payable by the L/C Beneficiary. (b) Processing Fee of up to a maximum cap of 0.50% of the Maximum IDA Guaranteed Principal Amount to cover IDA's reimbursable expenses and third party costs, payable by the L/C Beneficiary.

[36] The PRG amount of US$5 million will be processed separately.

L/C Bank Fees:	To be determined through a competitive bidding process and payable by the L/C Beneficiary to the L/C Bank.

Conditions Precedent to the IDA Guarantees:

Conditions Precedent:	IDA's effectiveness conditions would include the following: (a) Firm commitment for equity and debt financing for the Project. (b) Execution, delivery and effectiveness of the PRG Support Agreement, [GoK Letter] and other relevant project financing agreements in a form and substance satisfactory to IDA. (c) Payment of the Initiation and Processing Fees, if such amount is invoiced by IDA as due on or prior to the effectiveness. (d) Conclusion of the Guarantee Agreement between the L/C Bank and IDA, the Reimbursement and Credit Agreement between L/C Bank and KPLC, the PRG Support Agreement between KPLC and the L/C Beneficiary, the Project Agreement between the L/C Beneficiary and IDA, and the Indemnity Agreement between IDA and Kenya, all in a form and substance satisfactory to IDA. (e) Provision of satisfactory legal opinions from: (i) the Attorney General of Kenya relating to the Indemnity Agreement, the PRG Support Agreement and the Reimbursement and Credit Agreement; (ii) counsel to KPLC relating to the PRG Support Agreement, the Reimbursement and Credit Agreement and the PPA (iii) counsel to the L/C Beneficiary relating to the Project Agreement and the PRG Support Agreement.

IDA Documentation:

Guarantee Agreement:	The terms and conditions of the IDA Guarantee would be embodied in a Guarantee Agreement between the L/C Bank and IDA with respect to the L/C.

Project Agreement:	The L/C Beneficiary would enter into a Project Agreement with IDA, under which the L/C Beneficiary would provide relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable Kenyan environmental laws and IDA environmental and social safeguard requirements and World Bank requirements relating to Sanctionable Practices.
PRG Support Agreement:	KPLC would enter into a PRG Support Agreement relating to the L/C with the L/C Beneficiary, under which KPLC would undertake to provide an L/C under which the L/C Beneficiary would be entitled to draw for the failure by KPLC to pay an amount due to the L/C Beneficiary resulting from the occurrence of a Guaranteed Event. Following a drawing by the L/C Beneficiary, KPLC would undertake to repay to the L/C Bank the amount drawn, as soon as practicable and in no event later than 12 months after the date of drawing; provided that KPLC will at all times maintain a minimum amount available of at least the amount of one month's invoice for Capacity Payment and Energy Charge, and will immediately replenish the L/C as necessary to maintain such minimum amount (see also KPLC/s Obligation to Replenish the L/C under the PRG Support Agreement above).
Reimbursement and Credit Agreement:	KPLC would enter into a Reimbursement and Credit Agreement with the L/C Bank, under which KPLC would undertake to repay the L/C Bank the amounts drawn by the L/C Beneficiary under the L/C, together with accrued interest, within a period of twelve (12) months from the date of each drawing.
Indemnity Agreement:	Kenya would enter into an Indemnity Agreement with IDA. Under the Indemnity Agreement, Kenya would undertake to indemnify IDA on demand, or as IDA may otherwise direct, for any payments made by IDA under the terms of the IDA Guarantee. The Indemnity Agreement would follow the legal regime, and include dispute settlement provisions, which are customary in agreements between IDA and its member countries.

IBRD 38982

KENYA

PRIVATE SECTOR POWER GENERATION SUPPORT PROJECT

PROJECT POWER STATIONS

MAIN CITIES AND TOWNS

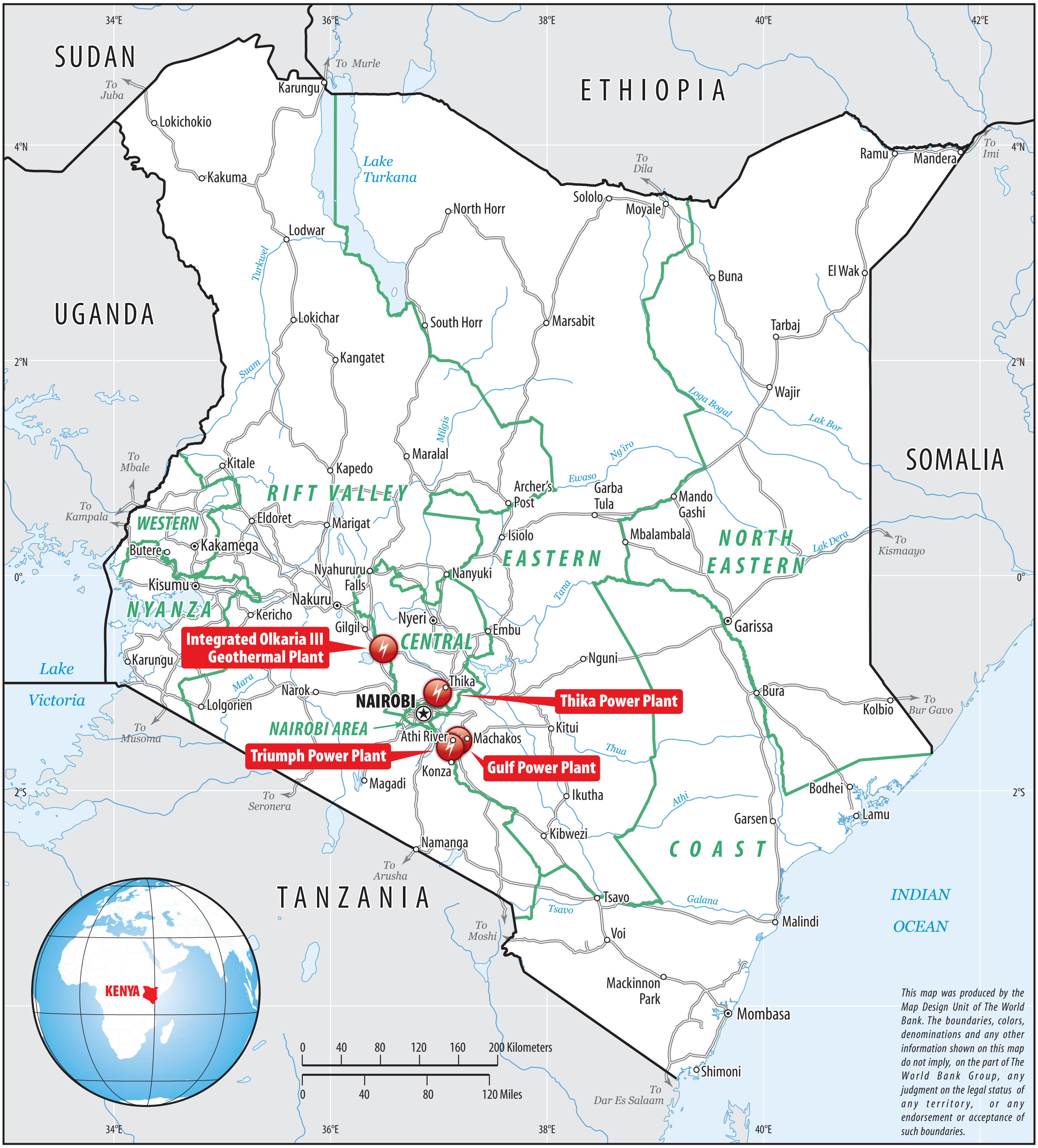
PROVINCE CAPITALS

NATIONAL CAPITAL

MAIN ROADS

PROVINCE BOUNDARIES

INTERNATIONAL BOUNDARIES



DECEMBER 2011