PRICING OF ELECTRICITY BY BULK POWER PRODUCERS IN KENYA

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A management research project submitted in partial fulfilment of the requirements for the degree of Masters of Business Administration at the University of Nairobi

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DECLARATION

THIS PROJECT IS MY ORIGINAL WORK AND HAS NOT BEEN SUBMITTED FOR A DEGREE IN ANY OTHER UNIVERSITY.

SIGNED: .... DATE: 24 October 2002

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DEDICATION

This study is dedicated to my Lord and saviour Jesus Christ, my late parents Evanson and Elizabeth Kiiru Karanja whose encouragement I will dearly cherish forever.

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LIST OF ACRONYMS

Item	Abbreviation	Meaning
1.	Acres	Acres International - Canadian consultancy firm
2.	CAPM	Capital Assets Pricing Model
3.	CEC	California Energy Commission
4.	COMESA	Commission of Eastern and Southern Africa Countries - a trading block
5.	CPI	Consumer Price Index
6.	ERB	Electricity Regulatory Board
7.	GENSIM	Generation simulation program developed for KPLC by Acres
8.	GoK	Government of Kenya
9.	GWh	Gigawatt-hours (1,000,000 watt-hours)
10.	IDA	International Development Association of the World Bank
11.	IPP	Independent Power Producer
12.	IPPA	Interim Power Purchase Agreement
13.	KenGen	The Kenya Electricity Generating Company Limited
14.	KPC	Kenya Power Company Limited
15.	KPLC	The Kenya Power and Lighting Company Limited
16.	KShs.	Kenya Shillings
17.	kV	Kilovolt - 1000 volts
18.	KVDA	Kerio Valley Development Authority
19.	kW	Kilowatt - 1000 watts, a measure of demand
20.	kWh	Kilowatt-hour - 1000 watt-hours, a measure of energy
21.	LCPDP	Least-Cost Power Development Plan
22.	LRMC	Long-run marginal costs
23.	LPG	Liquefied Petroleum Gas
24.	MOE	Ministry of Energy
25.	MS Excel 97	Microsoft Excel 97 - a spreadsheet computer program package
26.	MVAr	Mega-var – a million vars – measure of reactive power
27.	MW	Mega-watt - a million watts – measure of power demand or capacity
28.	Nera	National Economics Research Associates
29.	NPDP	National Power Development Plan
30.	NSE	Nairobi Stock Exchange
31.	NSW	North South Wales, Australia
32.	O & M	Operation and Maintenance
33.	Ofgem	Office of Gas and Electricity Markets
34.	OR Power-4	Power generating company owned by ORMAT Inc. of USA
35.	PB Power	Merz and Mclellan - UK based power consultancy firm
36.	PPA	Power Purchase Agreement
37.	REF	Rural Electrification Fund
38.	SRMC	Short-run marginal costs
39.	TARDA	Tana and Athi Rivers Development Authority
40.	TRDC	Tana River Development Company
41.	UETC	Uganda Electricity Transmission Company
42.	V	Volt - a measure of electrical pressure
43.	Var	Var – a measure of reactive power
44.	W	Watt – measure of power demand or capacity

ABSTRACT

This is a study on the electric energy sub-sector, which falls under the energy sector in Kenya. The electric energy sub-sector has been undergoing restructuring since mid-1990s. A new Electric Power Act 1997 came into effect replacing the then existing act that had been in use for over 30 years. Under the new act, electric energy generation (bulk electric energy production) was completely liberalized while the transmission and distribution functions were lumped together under the Kenya Power and Lighting Company Limited (KPLC), the only retail company in the country. The act also established an independent regulator, Electricity Regulatory Board (ERB) whose role is to oversee the functioning of the industry and enforcement of policies of the Government of Kenya (GoK), formulated the Ministry of Energy (MOE) to govern the industry.

The study was specifically aimed at finding out how bulk energy prices are developed by the five bulk energy companies operating in Kenya, viz. Kenya Electricity Generating Company Limited (KenGen), Iberafrica Power (E A) Limited, Tsavo Power Limited, Westmont Power Limited and OR Power-4 Inc. During the study, however, the price of electric energy imported from Uganda through the Uganda Electricity Transmission Company Limited (UETC) was also analyzed. The study also aimed at finding out whether there were any differences in the methods adopted by each of the companies in the development of prices.

The broad findings of the study were that each of the electric energy generating company has signed a power purchase agreement (PPA) with the retail company, KPLC except KenGen which is still trading with KPLC under an interim power purchase agreement (IPPA). Each PPA and the IPPA have adopted a three tier pricing system comprising **capacity charge**, **energy charge** and **fuel cost**. Capacity charge is meant to cater for the bulk energy companies' return on equity, recouping of sunk costs, repayment of debt and interest, plant maintenance costs, remuneration for the permanent staff and other fixed costs. This component of charge is payable to the bulk energy company whether the company has sold energy or not on condition that the company maintains the guaranteed capacity otherwise punitive financial penalties are applied. Bonuses of up to 15% of guaranteed capacity are also allowed under the PPAs. Energy charge component is only applicable in respect of sold energy and is essentially meant to cater for recovery of variable costs, hence it is a function of energy sold covering items such as cost of spare parts, lubricants and variable labour. Fuel cost is a pass-through component that finally ends up with electricity consumer and is mainly influenced by international price of oil, heat conversion rate and efficiency of individual generators.

CHAPTER ONE

1.0 INTRODUCTION

1.1 Background

This study looks at the pricing of bulk electric energy by electric energy generating companies in Kenya. The bulk electric energy industry comes under the electricity energy sub-sector which is a regulated under the Electric Power Act, 1997. The electricity sub-sector then forms part of the energy sector, which is controlled by the Ministry of Energy (MOE). The other sub-sector controlled by MOE is the petroleum sub-sector, which falls outside the scope of the study.

The electric energy sub-sector comprises the following:

- Electric energy generation, also known as bulk energy; and
- Electric energy distribution and transmission, also known as retail.

The electric energy business, under both the generation and distribution divisions of the sub-sector, is capital intensive and heavily relies on imported capital. For this reason erection of generating plant and other systems that are necessary for its operation require large-scale financing which means that debt financing is most of the time necessary. Although the business is not subjected to high technological and business risks the private investors who are mostly foreign, view it as a high-risk investment when located in the developing countries. In this case therefore financing through debt is one way of spreading the risk. The debt providers do spread the risk further by inviting other financiers to form forming a syndicate where each of them provides a portion of the finance required for investment. In order for the project to be viable, the capital provided through equity and that which is provided through debt have to be able to attract adequate returns for the investors and debt providers. This is achieved through the unique price structures adopted within the electric energy industry.

This study looks at the pricing techniques used in Kenya by the bulk electric energy suppliers and the major structural and quantitative price differences that exist among different suppliers. It is important to note that under the current liberalized electric energy sub-sector, generating companies are appointed on competitive pricing basis. Under normal circumstances the Ministry of Energy (MOE) would advertise in key international press expressing desire to contract for supply of a given capacity of electricity on long-term concession basis. The long-term concession could be in the form of build-own-operate (BOO) or build-own-operate-transfer schemes. All the current independent power producers (IPPs) are contracted under BOO concessions.

After advertisement by the MOE, interested firms would submit applications in which they would provide as much information as possible regarding their experience in the bulk electric energy business. The MOE would shortlist the applicants and would then send out tenders (bids) to the short-listed firms. The tenders would as a minimum contain the following information:

- guaranteed capacity;
- availability of plant;
- type of fuel used by the generating plant;
- In the case of diesel plants, generator speed (low, medium or high);
- location of plant;
- off-take voltage level; and
- The number of years the supply contract (PPA) would run

The requirements of the MOE as built into the tender are as a result of rigorous economic considerations and modeling. This is necessary in order to arrive at the most economic plant size in line with future requirements of the country, effect of the proposed plant on the cost of energy and to the country's economy.

When responding to the tender, potential generating companies normally compete on price since the other variables such as size of plant, type of plant and fuel type are relatively easily achievable. Each competing firm will strive to meets the requirements of the tender with optimum investment since the contracted capacity has to be achieved with a minimum of 90% plant availability. This contracted capacity attracts serious penalties when the firm fails to achieve it. On the other hand, strict environmental conditions are imposed and regular monitoring by the government ensures that the plant continues to strictly perform within the set conditions to ensure that inferior generating units or fuel type are not employed for purposes of reducing the price.

In order to ensure that the competing firm will develop the most competitive price and to meet the strict technical specifications given by the MOE, the firm would strive to achieve the following:

- Minimize capital cost by:
  - Optimizing on the size and number of generating units
  - Borrowing from the cheapest source of credit
  - Minimizing on the cost of plant

- Establishing long-term maintenance contracts

- Install reliable and efficient plant
- Adopt environmentally acceptable technology

The price of bulk energy proposed by each of the competing firms is determined and more or less fixed long before the contract is signed with the winning firm. The method of determination of the price is the subject of this study. At the same the study looks at how firms that existed prior to the energy sector liberalization that took place in 1997 currently price the electric energy they produce as they are not subjected to competitive bidding process.

1.1.1 History and practice of the electric sub-sector

The electricity sub-sector has for the last ten years grown at an annual rate of 5 – 7%. This means that construction of new power stations, substations, transmission and distribution networks needs to be well planned and coordinated in order to meet this growth. Over the years, planning for the sector has been linked to the Government of Kenya (GoK) 5 and 20 years economic plans. Detailed planning has been included in the National Power Development Plan (NPDP) and is updated every 20 years or so. The current 20-years NPDP was last updated in 1992. The plans covered under the NPDP are then programmed in another GoK document known as the Least-Cost Power Development Plan (LCPDP). The LCPDP is also regularly updated in line with the NPDP and was last updated in 1998. LCPDP forms the basis of regular retail tariff updates as well as for pricing of bulk power by some power generating companies, which is the subject of this research.

The bulk energy portion of the electricity sub-sector was completely liberalized in 1997 when the Electric Power Act 1997 came into effect. The liberalization of the electricity sub-sector has come up through a number of GoK policy changes that took place in recent years. The GoK's policy objectives for the energy sector were set out under the Sixth National Development Plan (1989 – 1993) and also by the Ministry of Energy document of October 1991 entitled "Government of Kenya Power Sector Development: World Bank (IDA) Co-operation", which set out to:

- ensure that adequate supplies of energy are made efficiently available in line with national development needs and at reasonable costs;
- promote conservation of all forms of energy;
- intensify exploration for indigenous fossil fuels, particularly oil;

- continue rapid development of domestic hydro and geothermal electricity generation;
- increase wood production under both on-farm and plantation systems and to increase efficiency in woodfuel utilization;
- encourage domestic fuel substitution where possible; and
- introduce alternative energy sources to broaden the national energy mix and lessen reliance on imported energy.

These energy policy objectives generally favoured the development of Kenya's indigenous energy resources in lessening the country's dependence on imports.

The GoK's policy objectives for the electricity sub-sector as contained in the World Bank, 1997 include:

- promotion of an efficient allocation of resources with the application of Long-Run Marginal Costs (LRMC) tariffs and the implementation of loss reduction initiatives;
- financial viability of the power sector entities through the review of tariffs and development of Independent Power Producers (IPPs);
- accessibility to electricity of all income groups with the continuation of low tariff charges maintained for small energy consumers; and
- development of extension of rural electrification through the existing establishment of Rural Electrification Fund (REF).

In order to achieve these objectives, the Government embarked on the restructuring of the electricity sub-sector with a view to creating commercial-type relationships between companies operating within the sub-sector. Under the new liberalized regime the existing companies operating in the sector and new entrants are now monitored and regulated by an autonomous Electricity Regulatory Board (ERB). Prior to the restructuring there were three limited liability companies and two regional development authorities operating in the electricity sub-sector. The limited liability companies were:

- **The Kenya Power and Lighting Company Limited (KPLC)**, which owned the whole distribution network, most of the transmission network and some generation capacity (mainly conventional thermal and some mini-hydropower stations). KPLC is currently 51% owned by GoK while the rest of the shares are listed in the Nairobi Stock Exchange (NSE).

- **The Kenya Power Company (KPC)**, was originally created to purchase power from Uganda. Later it became the owner of two hydroelectric power stations (Tana and Wanjii), the geothermal power station at Olkaria, some transmission lines and major substations. KPC was wholy owned by GoK and managed by KPLC.

- **The Tana River Development Company Limited (TRDC)**, which owned three major hydroelectric power stations in the middle Tana River (Kamburu, Gitaru and Kindaruma), was wholly owned by GoK and managed by KPLC.

The regional development authorities were:

- **The Tana and Athi Rivers Development Authority (TARDA)**, which owned Masinga and Kiambere hydroelectric power stations and their associated transmission lines in the Tana and Athi river basins. TARDA was wholly owned by GoK. The power stations were operated and maintained by KPLC.

- **The Kerio Valley Development Authority (KVDA)**, which developed and owned the 106 MW Turkwel Gorge Hydropower station and associated transmission line to Lessos near Eldoret was wholly owned by GoK.

Before the advent of the energy sector reforms in May 1997, the electricity regulatory role was vested in the Minister for Energy. The Electric Power Act that was ruling prior to the 1997 one provided the Minister with broad powers since in addition to formulating sub-sector policies, he had control over electricity tariffs. The Minister who was also the dispenser of the licenses also had powers to revoke or modify the terms of license during its life. Such wide ranging powers were not conducive to the efficient operation of the sub-sector and were incompatible with today's accepted industry and business practices which are based on clear separation of ownership, regulation and operation of the sub-sector. Subsequently the enactment of the Electric Power Act 1997 created a legal and regulatory framework which included establishment of an autonomous Electricity Regulation Board (ERB) to oversee operations and pricing issues.

As part of the restructuring of electricity sub-sector generation roles were separated from transmission and distribution. The Kenya Electricity Generating Company Limited (KenGen), a wholly GoK owned company was formed after which it took over all the assets of KPC, TRDC, TARDA and KVDA as well as the mini-hydropower stations previously owned by KPLC. Currently KPLC owns and operates transmission and distribution networks and deal in retail business. In this respect KPLC has signed an Interim Power Purchase Agreement (IPPA) with KenGen for purchase of energy in bulk. KenGen was initially also responsible for importing electricity from Uganda and selling it in bulk to KPLC but the agreement between the governments of Kenya and Uganda were revised after which KPLC signed Power Purchase Agreement (PPA) directly with the Uganda Electricity Transmission Company (UETC) with effect January 2002.

Following the restructuring of the sub-sector, private-sector participation in power generation made its debut with the licensing of the first Independent Power Producers (IPPs) in 1997. Since then three more IPPs have been licensed to generate and sell bulk energy to KPLC under individual Power Purchase Agreements (PPAs). Iberafrica and Westmont have been awarded 7 years PPAs under a fast track arrangement that was put in place during the days of electricity shortages of 1998. Close to the expiry of the 7 years, both have now applied for new PPAs. Other IPPs licensed later under 20 years PPAs are Tsavo and OR Power-4. All the IPPs except OR Power, generate electricity using fossil oil-fired generators. OR Power-4 has constructed an experimental geothermal generating plant producing 12 MW at Ol Karia but is in the process of upgrading the plant to 48 MW. All in all the following five generating companies have been licensed to operate in Kenya:

(i) KenGen
(ii) Iberafrica
(iii) Westmont
(iv) Tsavo
(v) OR Power-4

1.1.2 Theory relating to the study

This study falls under capital budgeting and for that reason several items used in the derivation and explanation of the project and which primarily fall under capital budgeting will be defined under this section.

1.1.2.1 Definition of Capital Budgeting

Capital budgeting is made up of two words: where the term *capital* refers to the long-term assets used in production, while a *budget* is a plan that details projected inflows and outflows during some future period. Thus *capital budgeting* is an outline of planned investments in fixed assets and can therefore be described as the whole process of analyzing the project and deciding which one to include in the capital budget.

1.1.2.2 Definition of return

1.1.2.2.1 Rate of return

With most investments, an individual or business spends money today with expectation of earning even more money in the future. The concept of *return* provides investors with a convenient way of expressing the financial performance of an investment.

Return should be able to capture scale and timing and for that reason it is often expressed as a rate of return, or percentage returns which is defined as follows:

$$Rate\ of\ return = \frac{Amount\ received - Amount\ invested}{Amount\ invested} \qquad eq.\ 1.1.2.1$$

1.1.2.2.2 Return on equity (ROE)

This is a profitability ratio analysis of a firm. It is the ratio of net income to common equity, which measures **return on common equity**, or the rate of return on stockholders' investment given by the following expression:

$$\text{Re}turn\ on\ common\ equity = ROE = \frac{Net\ income\ available\ to\ common\ stockholders}{Common\ equity} \qquad eq.\ 1.1.2.2$$

ROE is often expressed in percentage.

1.1.2.2.3 Return on total assets (ROA)

This is also a profitability ratio analysis of a firm. It is a measure of net income, after interest and taxes, to total assets and is given by the following expression:

$$\text{Re}turn\ on\ total\ assets = ROA = \frac{Net\ income\ available\ to\ common\ stockholders}{Total\ assets} \qquad eq.\ 1.1.2.3$$

ROA is often expressed in percentage.

1.1.2.3 Definition of risk

Risk refers to the chance that some unfavourable event will occur. An asset's risk can be analyzed in two ways:

1. On a stand-alone basis, where the asset is considered in isolation; and
2. On a portfolio basis, where the asset is held as one of a number of assets in a portfolio.

No investment can be undertaken unless the expected rate of return is high enough to compensate the investor for the perceived risk of the investment. If assets always produce their expected rate of return, they would not be risky. In this case a risky investment would not produce its expected rate of return.

Investment risk is related to the probability of earning less than the expected return. The greater the chance of low or negative return, the riskier the investment. The measure of risk is standard deviation (σ) or variance (σ^2).

1.1.2.3.1 Estimating project risk

Although it is clear that riskier projects should have a higher cost of capital, it is difficult to actually estimate project risk. Three separate and distinct types of risk exist in any project. These are:

1. **Stand-alone risk**: This is the project's risk disregarding the fact that it is just one of the firm's portfolio of assets and that the firm is just one stock in a typical investor's portfolio of stocks. Stand-alone risk is measured by the variability of the project's expected returns.

2. **Corporate or within firm risk**: This is the project's risk to the corporation, giving consideration to the fact that the project represents only one of the firm's portfolio of assets, hence that some of its risk effects will be diversified away. Corporate risk is measured by the project's impact on uncertainty about the firm's future earnings.

3. **Market or beta risk**: This is the riskiness of the project as seen by a well-diversified stock-holder who recognizes that the project is only one of the firm's assets and that the firm's stock is but one part of the investor's total portfolio. Market risk is measured by the project's effect on the firm's beta coefficient.

1.1.2.4 The cost of money

Money, like any other resources, has a price and in a free economy, capital is allocated through the price system. For example, interest rate is the price paid to borrow debt capital while in the equity market, dividends and capital gains are the components whose sum is the cost of equity money expected by investors.

There are four most fundamental factors that affect the cost of money. These are:

1. Production opportunities;
2. Time preferences for consumption;
3. Risk; and
4. Inflation

1.1.2.5 Cost of capital

When investors provide money for investment they expect the money to be invested only in projects that produce rates of return at least as high as the investors could get elsewhere. The returns investors could get elsewhere is their **opportunity cost of capital (OCC)**. In electric energy business, the utilities are natural monopolies in the sense that one firm can supply services at a lower cost than could two or more firms. This is the reason for the industry being regulated so as to reduce chances of exploitation of consumers. The regulator determines the cost of the capital investors have provided the utility and then sets rates designed to permit the company to earn its cost of capital.

It is possible to finance a firm entirely with common equity. However, most firms employ several types of capital, called capital components each with common and preferred stock as well as debt. The one feature in common for all the capital components is that the investors who provided the funds expect to receive a return on their investment.

If a firm's only investors were common stockholders, then the cost of capital used in capital budgeting would be the required rate of return on equity. However, most firms employ different types of capital and due to difference in risk, these different securities have different required rate of return. The required rate of return on each capital component is called component cost and the cost of capital used to analyze capital budgeting decisions should be *weighted average* of the various component costs. This is called the weighted average cost of capital (WACC). The WACC is dependent on the capital structure of the firm. Each firm has an optimal capital structure, defined as that mix of debt, preferred and common equity that causes its stock price to be maximized. Therefore, a value-maximizing firm will establish a *target (optimal) capital structure* and then raise new capital in a manner that will keep actual capital structure on target over time.

WACC can be described using capital structure weightings of debt (w_d), preferred stock (w_{ps}) and common stock (w_{cs}) as follows:

$$WACC = w_d k_d (1-T) + w_{ps} k_{ps} + w_{cs} k_{cs} \qquad eq.1\ 1.2.4$$

Where, k_d is before-tax cost of debt;

k_{ps} is the cost of preferred stock; and

k_{cs} is the cost of common stock

1.1.2.5.1 Adjusting the cost of capital for risk

Investors require higher returns for riskier investments. Consequently a company that is raising capital to take on risky projects will have a higher cost of capital than a company that is financing safer projects. The WACC for a firm represents the hurdle rate of a typical project for the firm. Different projects have different risks therefore the cost of capital rate (hurdle rate) for each project should reflect the risk of the project itself, not necessarily the risk associated with the firm's average project as reflected in its composite WACC.

Risk-adjusted costs of capital starts with composite WACC as the starting point and then the WACC is adjusted for each category of risk. For example a firm may establish three risk classes – high, average and low – then assign average-risk projects the average (composite) cost of capital, high-risk projects an above-average cost, and lower-risk projects below-average cost.

1.1.2.6 Time Value of money

The primary aim of financial management is to maximize the value of the firm's stock (shares). Stock values partly depend on the timing of the cash flows investors expect to receive from an investment – money expected soon is worth more than that which is expected in the distant future. Money expected in the distance future, due to the factors that affect the cost of money, discussed under 1.1.2.4 above, will affect asset values and rate of return.

Financial figures used to specify the cost and benefit streams of projects or energy related programmes do not indicate the relative difference in value over time of cost of benefit. Investment, in reality, is foregone consumption and investments are made with an expectation of receiving a return at some interest rate. This is equivalent to saying that consumption in the future is worth less than consumption today, hence, future consumption should be discounted at a rate equal to the time preference discount rate (TPDR) in order that it can be related to today's value. For lack of more specific information in the unknown and poorly predictable future, it is normal to assume that the TPDR is equal to the opportunity cost of capital discount rate which is used to discount cost and benefit streams.

Opportunity cost of capital (OCC) was defined under 1.1.2.5. OCC could alternatively be defined as the discount rate equal to the rate of return earned by the marginal project in an investment portfolio. The OCC is not a fixed interest rate similar to the rate applied on lending interest rate of a commercial bank. When the OCC is, for example, specified as 10 – 12% in real terms, it means that a stream of costs and benefits expressed in constant prices should be discounted at a rate of 10 – 12% to determine the present worth (or present value) of the cost and benefit streams.

The present value, PV of a cost or benefit is computed using the following formula:

$$PV = \frac{Cash\ flows\ in\ year\ n}{(1+k)^n} \qquad eq.1.1.2.5$$

Where, k is the opportunity cost of capital discount rate; and

n is the year of the cash flow

1.1.2.7 Discounting techniques

Discounting is performed through the use of a consistent set of prices expressed in constant border prices and discounted at a discount rate that reflects the opportunity cost of capital/TPDR. This is the basic technique for comparing alternative investments or programmes that have different patterns in time of costs and benefits. The essential tool of financial and economic evaluation is the discounted cash flow methodology.

1.1.2.7.1 Present value with discounting

The present value 'P' of a specific future payment 'F' can be computed by discounting future payment at the interest rate 'i' using the following formula:

$$P_{i,n} = \frac{F}{(1+i)^n} \qquad eq.1.1.2.6$$

Where a discounting rate is used instead of interest rate then the k is inserted instead of i.

1.1.2.7.2 Present value of annuities (PVA)

Often in financial-economic studies annual benefits or expenses recur for a number of years. Such sequence of annual payments or benefits of constant or uniform annual value is known as 'annuity'. It is more convenient in such cases to use a formula that computes the future value of the entire sequence of payments.

The present value 'P' at the start of the year 1 of a series of annual payments 'A' at the end of the year from 1 to n with interest rate 'i' can be computed using the following formula:

$$P_{i,n} = A\left[\frac{(1+i)^n - 1}{i(1+i)^n}\right] \qquad eq.1.1.2.7$$

Or using tables the expression can be written as follows:

$$P_{i,n} = A \times PVA\,(i\%, n\ yr) \qquad eq.1.1.2.8$$

1.1.2.7.3 Sinking fund factor (SFF)

The sinking fund factor is used to compute the uniform annual payment 'A' (annuity) required at the end of each year for 'n' years such that the total future value with compound interest 'i' will equal 'F' at the end of 'n' years. The formula is written as follows:

$$A_{i,n} = F\left[\frac{i}{(1+i)^n - 1}\right] \qquad eq.1.1.2.9$$

Or using sinking fund factor tables the expression can be written as follows:

$$A_{i,n} = F \times SFF\ (i\%, n\ yr) \qquad eq.1.1.2.10$$

1.1.2.7.4 Capital recovery factor (CRF)

The capital recovery factor is used in computing of the uniform annual payment 'A' (annuity) required at the end of each year for 'n' years such that the total discounted value at the start of the year1, discounted at i% will equal the present value 'P'. The expression for CRF is as follows:

$$A_{i,n} = P\left[\frac{i}{1 - \frac{1}{(1+i)^n}}\right] \qquad eq.1.1.2.11$$

Or using capital recovery factor tables the expression can be written as follows:

$$A_{i,n} = P \times CRF\ (i\%, n\ yr) \qquad eq.1.1.2.12$$

The capital recovery factor is useful for converting an initial capital cost into an equivalent levelized annual cost of capital over the lifetime of the capital investment.

1.1.2.7.5 Discounting inflation rate

The discounting techniques would require some modification if inflation were included or if there is a real cost escalation of some cost elements such as fuel prices for a thermal plant.

In the case of general inflation, an inflated discount rate would also have to be used, but the present discounted value of a series of inflated future costs, discounted at an inflated discount rate, would be the same as when real (non-inflated) costs are discounted at the real discount rate. This is shown below:

Let V_i be inflated value in year 'n'

V_r be real (non-inflated) value at current price

n be number of years from now

d_r be real discount rate

d_i be inflated discount rate

f be general rate of inflation

$$V_i = V_r(1+f)^n \qquad eq.\ 1.1.2.13$$

The inflated discount rate will be:

$$d_i = d_r + f + f \times d_r = (1+d_r)(1+F) - 1 \qquad eq.\ 1.1.2.14$$

The present value of V_i discounted at d_i is then equal to the present value of V_r discounted at d_r.

$$\frac{V_i}{(1+d_i)^n} = \frac{V_i}{(1+d_r+f+f\times d_r)n} = \frac{V_r(1+f)^n}{(1+d_r)^n(1+f)^n} = \frac{V_r}{(1+d_r)^n} \qquad eq.\ 1.1.2.15$$

Therefore, discounting inflated future values at a correctly computed inflated discount rate will be equal to discounting real values at the corresponding real discount rate.

Another application of discounting an inflating cost series would occur if real cost escalation affects one of the cost elements in a case study, such as thermal fuel costs. For such a case, a net discount rate can be computed using the following equation:

$$(1+d_r) = (1+d_n)(1+g) \qquad eq.\ 1.1.2.16$$

$$\therefore d_n = \frac{1+d_r}{1+g} - 1 \qquad eq.\ 1.1.2.17$$

Where, d_r is real (normal) discount rate

d_n is net discount rate

g is growth rate or escalation rate of real future costs or benefits

1.1.2.8 Consumer Price Index (CPI) adjustment

Consumer Price Index (CPI) is a way of tracking the cost of living. It is computed based on prices for the "market basket" of necessities including housing, food and beverages, transportation, apparel, entertainment, medical care and other goods and services. The CPI is updated monthly based on the US Department of Labor survey. To track the effects of price increases, the years 1982 to 1984 are set as basis (equal to 100). A price index of say 33, therefore, indicates that the price was one-third that of the average in 1982 – 1984.

The CPI is used in escalating agreements where adjustment to is necessary to components of labour or items whose cost is affected by wage changes in the USA. The CPI is thus used to adjust payments so as to track price changes. The most frequently used escalation applications are in private sector collective bargaining agreements, rental contracts, insurance policies with automatic inflation protection, alimony and child support payments etc.

1.2 Research Question

1.2.1 Need for the study

In Kenya, like elsewhere in the world today, electricity is increasingly becoming a popular form of energy. It is the most cost-effective form of energy as it is easily convertible to other forms such as heat, mechanical, light, etc. Because of these peculiar qualities, electricity has gained popularity as the energy of choice both in the urban and rural areas.

In a study conducted by NERA and GIBB, under the Review of Electricity Tariffs in Kenya Project, the cost of different forms of energy widely used in Kenya was evaluated. These forms of energy are: Kerosene, Butane (LPG), Diesel generators and solar-photo voltaic cells. Table 1.2.1 below shows the findings of the evaluation in terms of equivalent cost in $/kWh.

Table 1.2.1 - Comparison Between Electricity and Other Sources of Energy

Source	Equivalent Cost ($/kWh)	Electricity Marginal Cost ($/kWh)	Customer Class
Kerosene (lighting)	0.323	0.1363	Domestic (A0) (<3,000)
Butane (cooking)	0.017	0.1363	Domestic (A0) (<3,000)
Diesel generator	0.220	0.1363	Domestic (A0) (>3,000)
		0.1363	Small Commercial (A1)
Solar-photo voltaic	0.174	0.1363	Domestic (A0) (<3,000)
		0.1500	Domestic (A0) (>3,000)

Source: NERA/GIBB, 2002

As observed from Table 1.2.1 above, the cost of electricity in comparison with the other sources of energy is quite competitive. Only butane was found to have a lower cost than electricity since butane has higher energy (caloric) value but then it is unsuitable for lighting. Hence, most urban dwellers use butane for cooking and electricity for lighting.

Although the demand for electricity in Kenya has been increasing at the rate of 6% per annum, today only 10% of the population has access to this form of energy while demand has continued to outstrip supply and thereby causing frequent outages, blackouts and brownouts.

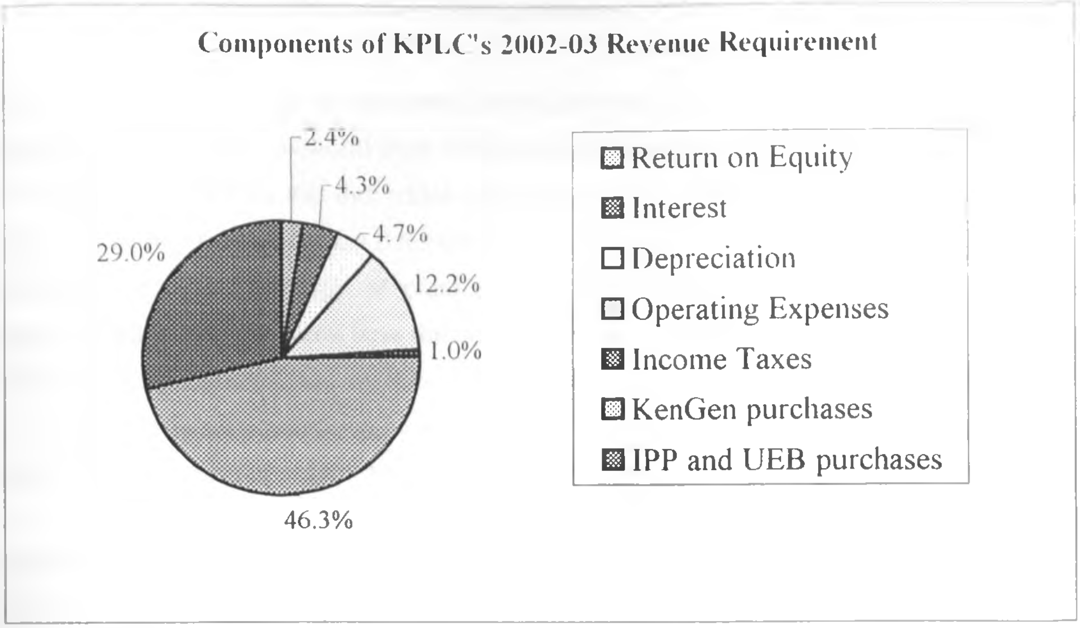
One of the causes of low rate of electrification in the country is the high cost of connection borne by new applicants and the high cost of electricity in general (Nera/GIBB, 2002). The policy of KPLC on new connections has not changed from pre-independence days when electricity was a luxury only reserved for the privileged. A new customer seeking to be connected to the national grid has to bear a large portion of the capital cost of the connection and is also expected to pay for subsequent monthly consumption costs. This policy has had negative effects on the electrification process and has even discouraged some potential large customers from investing in heavy machinery as the cost of obtaining electricity to power the machinery has invariably proved to be uneconomical. This situation has encouraged theft of electricity and has contributed to the high rate of non-technical losses that has then resulted in the current system losses of 19%.

The Government of Kenya introduced a rural electrification fund (REF) to assist the rural communities gain access to electricity. Due to political interference, general inefficiency and lack of adequate funds the REF is today not a success story. Some foreign governments such as the French, Spanish and Chinese have recently contributed in the boosting of the fund but the success of the programme is yet to be evaluated.

The cost of electricity has also been much of a burden to most consumers. This can be inferred from the high disconnection rate on non-payment of bills. Even with an existing lifeline tariff tailored for the low consumers, the rate of defaulting on payment of electricity bills has been extremely high.

In recent times the high cost of electricity in Kenya has become topical in the mass media and other forums. The manufacturing sector has attributed the lack competitiveness of the locally manufactured products in the Comesa market and other external markets to the high cost of energy in Kenya. Indeed some of the imports have been found to be cheaper than similar locally manufactured items even when the imports may be of much lower quality. This argument may be disputed since comparison of retail prices of electricity has shown Kenya to be among the most expensive.

The current retail electricity tariffs in Kenya indicate that that the largest component is due to the contribution by bulk power cost to the retail price. Hence it is fair to conclude that the cost of electricity in the country is mainly influenced by bulk electricity prices. From a study carried by out NERA/GIBB on the breakdown of KPLC's revenue requirement for the years 2002-03, the information represented in the pie chart below was gathered:



Source: NERA/GIBB, 2002

As observed from the above pie chart, 75.3% of KPLC's expenditure for the year will go towards purchase of bulk power from KenGen (46.3%) and IPPs/UETC (29%). From these statistics it can be concluded that the major component of the retail electricity price emanate from the cost of the bulk power purchases.

When KPLC started experiencing the current financial problems, the situation was blamed on the high cost of bulk energy. The generating companies in general and IPPs in particular are now being blamed for pricing their product excessively high and hence making electricity unattractive as a source of energy. The Institution of Engineers of Kenya (IEK) in its annual conference held in April this year blamed the high price of bulk energy charged by IPPs as the cause of the high electricity burden to consumers. This was lent more weight when the Minister for Finance informed parliament that the government plans to initiate re-negotiation of the IPP PPAs as a means of reversing KPLC's current financial decline. Recently KPLC has added its voice in the discussion by publicly expressing its wish to re-negotiate PPAs with the IPPs.

This study has been prompted by a desire to find out whether indeed the cost of bulk power impacts on the retail price of electrical energy in Kenya. The study will investigate how bulk power companies price their product and what factors influence pricing of bulk energy.

1.2.2 Statement of the problem

As already discussed, the price of retail electric energy is to a large extent affected by the cost of bulk energy. However, different bulk electricity companies charge different prices. This difference in prices is dictated by the individual company's costs, which comprise of capital and variable costs. Different companies use different types of fuel to generate electricity hence the difference in fuel costs, while the type of plant dictates the capital outlay and hence the difference in capacity charge. At the same time the companies send out different quantities of energy since the volume of scale would have an influence on production cost. All these factors would mean that the bulk energy generating companies are unlikely to charge the same price. The study will identify the key components of the prices adopted by each firm.

The near collapse of the manufacturing sector in Kenya has been blamed on the high cost of electric energy. Industrialists have blamed lack of competitiveness of their products in COMESA and other markets, to the high cost of electrical energy as an important input to the manufacturing processes. Due to this problem, low quality imports have gradually replaced locally manufactured goods in the market. The high cost experienced by the manufacturing and Jua Kali sectors due to high electricity cost needs to be investigated and incentives adopted in the pricing of electricity for the manufacturing and Jua Kali sectors. Despite the seemingly high price charged on electricity, the sector has been unable to finance its growth while its sustainability has been threatened as evidenced by the current poor financial health of KPLC.

From the above it can be concluded that pricing of electric energy in Kenya has not achieved the purpose of raising adequate cash-flows for growth and self-sustainability of the sub-sector and for spurring economic growth in the country. This has to a great extent negatively affected the growth of the entire energy sector and as such has failed to spur the manufacturing, Jua Kali and other sectors of the economy. On the overall the poor performance of the electric energy sub-sector has to a large extent contributed to the current poor performance of the Kenyan economy.

This study seeks to investigate how prices of the bulk electric energy in Kenya are determined and whether the same pricing terms are applied to all the generating companies.

1.2.3 Objective of the study

The broad objective of this study is to identify and isolate factors that would improve the effectiveness of the pricing of bulk electric energy in Kenya and thereby stabilize future electricity pricing policies and result in better predictability of the electricity retail price in Kenya.

To achieve this, the following specific objectives were addressed in details as they guided the activities of the study:

1. Determination of the pricing mechanism used to develop bulk electricity prices by each of the generating companies.

2. Establishing whether there are significant differences in the pricing methods used by the five generating companies and to explain the differences.

1.2.4 Importance of the Study

This study and its findings will benefit the following:

- business students by providing them with an insight into pricing of energy as a regulated commodity;
- planners within and outside the electricity sub-sector by providing them with basic rates that could be used in micro or macro-economic analysis;
- business-communities by giving them an insight into the effects that influence the cost of energy and hence adopt monitoring and forecasting techniques to avoid unforeseen losses;
- manufacturing and Jua Kali industries by providing them with comparative pricing methods adopted by each bulk producer so that they can be able to predict their future production costs;
- all electric energy consumers in general by providing them with the pricing techniques that were erstwhile un-available to them; and
- investors in the electric energy sub-sector who need to plan their investment and pricing prior to investing in the country and thereby avoid adopting unnecessarily high risk rates.

The study will help in shedding light to the methods used in setting the prices of bulk electric energy in Kenya and factors used to derive them. This will in turn help to shed light on the reasons of the current high retail prices of electricity as they have mainly been influenced by high cost of bulk energy purchases by the retail distribution company, KPLC.

1.3 An overview of sections

Chapter 1 - Introduction

Chapter 2 - Literature review

Chapter 3 – Research methodology

Chapter 4 – Data analysis and findings

Chapter 5 – Conclusions and recommendations

CHAPTER TWO

2.0 LITERATURE REVIEW

2.1 Overview of pricing theory

- Philip Kotler, 1999 in chapter 15 of his book provides theory on the development of prices. The article has however not dealt with pricing of regulated commodity such as electric energy but it assisted in understanding the general theory of pricing as applicable in the solution of the problem of this study.

2.2 General pricing of electricity

- Acres International Ltd, 1998 in the LCPDP document they produced, have provided details of the planned development in the power sub-sector in line with the current National Power Development Plan (NPDP).

- Joel B Klein, 1997 in his report has provided market clearing price (MCP) forecasts by simulating bidding process of the Western Energy Power Exchange (PX) and the system dispatch procedures of the Independent System Operator (ISO) which has helped CEC to develop forecasting software based on the simulation of the PX and ISO.

- Loi Lei Lai, 2002 in the book he edited, outlined the ongoing worldwide deregulation and restructuring of the power industry and general departure from the traditional monopolies towards greater competition in the form of increased numbers of independent power producers and an unbundling of the main service.

- London Economics Ltd, 1993 in their report of a study carried out on the method of retail electric energy tariff determination in Kenya introduced the LRMC pricing techniques since prior to the study there was no official policy on tariff determination.

- Mohan Munasinghe and Jeremy J Warford, 1982 in their publication, though old, it occupies an uncontestable position of being the first and only literature written on the topic of electric energy pricing from the perspective of the developing countries and gives theory and study reports on LRMC method of pricing.

- NSW, 1996 in their interim report gave recommendations on the options of introducing competition into all the sectors of the electricity industry.

- Ofgem, 2001 in their report describe a workshop conducted as a forum for educating the public about retail prices of electricity, competition in electricity retail industry, innovations in energy savings and money-saving offers, and electricity regulation.

- Ofgem, 2000 in their paper identified the methods and principles used in the setting up of electricity distribution charges and assessing the appropriateness of current methods and principles used in structuring and in operation of electricity industry.

- Ofgem, 1999 in its report spells out the activities of the Public Electricity Supplier (PES) and proposed forum for setting out final proposal for revision of electricity distribution price controls. The proposal was based on projections of operating and capital costs, quality of supply targets and conclusions on financial issues.

- PB Power Ltd, 1999 in their report based on the *long-run marginal costs* (LRMC) method of determination of electricity tariffs, introduced the concept of time-of-use tariff structure for the first time in Kenya.

- Richard Green and Martin Rodriguez Pardina, 1999 in their book, outlined the emerging regulatory bodies in the developing countries and covered issues of regulated pricing (price controls), different philosophies of price controls, present value calculations, investment and the regulatory asset base and revenues.

- World Bank, 1997 in its staff appraisal report gives an overview of the energy sector in Kenya and outlines the macroeconomic and other performance indicators from 1990 to 1998. It gives an insight into the GoK's reform programme spelt out in the government's Policy Framework Paper that highlighted poverty reduction as its principal objective and casts some light in GoK's reorganization of the energy sector.

2.3 Problems that have characterized current pricing mechanisms

- Ben Arikawa, 1997 in his paper provides a revised retail electricity price forecast that took into account the effects of regulatory and legislative reforms that had taken place in the electricity industry.

- CEC, 2002 in their report have provided an assessment to California's electricity system for the next ten years by focusing on the supply and demand forecasts, reliability, wholesale spot market and retail prices, price responsiveness, renewable generation initiatives and environmental issues.

- NERA/GIBB, 2002 in their report reviewed the existing retail tariff policy to make it more conducive to the current and future liberalized electric energy market as follows:

    1. Ensure the financial health of the sub-sector;
    2. Promote the efficient provision and expansion of electricity services; and
    3. Be compatible with the evolving structure of the electricity supply industry.

- NSW, 2000 in their paper, have reviewed a discussion paper prepared by the Market Implementation Group (MIG) entitled *Replacement for Vesting Contracts*. The paper considered options for managing retail risk associated with purchasing wholesale electricity for small retail customers who elect to take electricity under standard terms and conditions such as regulated tariffs under a government initiated Electricity Tariff Equalization Fund (ETEF).

- Ofgem, 1999 in their report have outlined the responsibility of Ofgem in protecting customers and in particular the disabled and chronically sick, pensioners, low income and rural customers by setting up policies for reducing the price of electricity to encourage competition while incorporating consumer powers in the law instead of dwelling on price controls to lower prices.

- UNDP/ESMAP, 2001 in their report, outlined the situation of the lack of sufficient and sustainable supplies of energy which constitutes what might be called an "energy poverty" that affects as much as 40% of people living in developing countries.

- World Bank, 2000 in its publication observed immediately in the 1960s and 1970s, Kenya had developed many secondary and tertiary industries that helped the country to attain an annual growth of real GDP exceeding 6%. The annual growth rate declined to less than 4% in the 1980s to about 1% in the 1990s. Macroeconomic data indicated that the decline in growth was due to a decrease of investment from approximately 15% of GDP in the 1980s to about 10% in the 1990s due to neglected infrastructure including telecommunication, electricity and transportation.

- World Bank, 2000 in its report in respect of a proposed SDR 55.1 million (US $ 72 million) credit to Kenya outlines the status of the power sub-sector and observes from available statistics that the generation system is characterized by a high level of dependence on hydro and a need to diversify the sources of electricity.

2.4 Bulk electricity pricing

- Hossein Gazavi, 1996 in his book provides valuable information and analysis on the mechanisms applied by multilateral, bilateral and commercial financiers in decision making as far as financing of gas and power projects in the developing countries is concerned. The availability of many sources of soft loans, credit, grants, tied loans and untied loans.

- KPLC's, 2002 in its draft PPA, a sample agreement is between the generating company (bulk electric energy seller) and KPLC (retail electric energy seller) is given including sample calculations for capacity and energy costs. Every PPA is however unique to the two parties, as it determined by the type of generation and associated cost (fixed and variable) and subsequent negotiations.

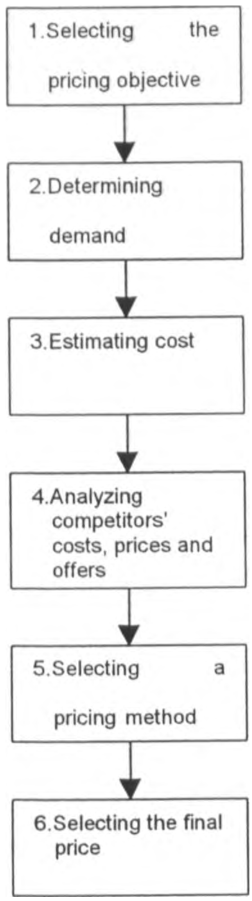
2.5 Basic pricing of electricity

2.5.1 Basic pricing process

All profit-making organizations and many nonprofit organizations set prices on their products or services. Individuals too set prices on their services, for example the "price" of an executive is a salary, the price of a salesperson may be a commission and the price of a worker is a wage.

The firm has to consider many factors when setting its pricing policy (Kotler, 1999). Commonly a six-step procedure is taken when setting up a price policy. This is described using Fig. 2.5.1 below.

Fig. 2.5.1 - Setting Price Policy



Source Philip Kotler, 1999

1. In **selecting the pricing objective** the company first decides where it wants to position its market. The clearer the company's objective the easier it is to set price.

2. In **determining demand** each price will lead to a different level of demand. The relationship between alternative prices and the resulting current demand is captured in a *demand curve*. Under normal circumstances, demand and price are inversely related, that is, the higher the price, the lower the demand except in the case of prestige goods where the opposite is sometimes true.

3. In **estimating costs** the company observes how demand sets a ceiling on the price that the company can charge for its product. Costs set the floor. The company would like to charge a price that covers its cost of producing, distributing and selling the product including a fair return for its effort and risk.

4. In **analyzing competitors' costs, prices and** offers the company takes the competitors' costs, prices and possible price reactions into consideration when determining its own range of possible prices.

5. In **selecting a pricing method** most companies mainly takes account of the three Cs. These Three Cs are:

   - customers' demand schedule;
   - the cost function; and
   - competitor's prices.

   Costs set a floor to the price. Competitors' prices and the price of substitutes provide an orientating point. Customers assessment of unique product features establishes the ceiling price. Companies select a pricing method that includes one or more of these three considerations by applying any of the following methods:

   (a) markup pricing;
   (b) target-return pricing;
   (c) perceived value pricing;
   (d) value pricing;
   (e) going-rate pricing; and
   (f) sealed-bid pricing.

6. In **selecting the final price** the company narrows down to the final price selection. In doing so the company must consider additional factors including the following:

   (a) psychological pricing
   (b) the influence of other marketing-mix elements on price
   (c) company pricing policies
   (d) the impact on other parties

2.5.2 Bulk electricity pricing

Electricity pricing by power generating firms is selected through company pricing policies that become incorporated in the individual company's PPA. The characteristics of electricity pricing originate from the requirement of large amounts of fund and investment costs that are necessary in electricity generation business. The pricing system used in Kenya is a combination of target-return and sealed-bid pricing.

- *Sealed-bid pricing* because an IPP is selected through competitive bidding on the basis of its competitive price in respect of efficiency of generating units proposed by the company in comparison with its competitors in the bidding process. In order to be competitive the firm must propose to supply efficient and relatively low priced generators; and

- *Target-return pricing* because the firm determines the price that would yield its target rate of return on investment (ROI) to enable the company meet its requirements to finance capital investment, cover its operation costs and make profit.

The general formula for target-return price is given as follows:

$$Target\ return\ price = unit\ cost + \frac{desired\ return \times invested\ capital}{unit\ sales} \qquad eq.2.5.2.1$$

Costs of electricity include operation costs and investment costs or the fuel costs and capacity costs. Operation costs are covered by the energy component of price, investment costs are covered by the capacity component of price while the fuel cost is covered by fuel component of price which is a pass-through item in Kenya. Determination of electricity costs involves optimization of system operation and reliability, because operation optimization is the basis of calculating fuel costs, while reliability is the basis of determining capacity investment. The price based on the long-run characteristics of the generation business is determined through a probabilistic production simulation of the power system to predict the operation of the generating plant and hence predict the costs involved in generation.

2.5.3 Basic theory of predicting electricity costs

In order to analyze electricity costs, an hour by hour probabilistic production simulation is normally run. From the probabilistic production simulation the fuel costs F(t) and loss of load probability LOLP(t), (t=1, 2, ..., 8760, ie hours in a year). This data is the basis of calculation of electricity costs.

Variable costs of electricity consist of fuel costs and capacity costs. Capacity costs can be represented by the following relationship:

$$I_G = W_b K_b + W_p K_p \qquad eq.2.5.3.1$$

Where: W_b is generation capacity for base load of the system

W_p is generation capacity for peak load of the system

K_b is the annual rate per-unit capacity for base load

K_p is the annual rate per-unit capacity for peak load

When predicting generation costs for each hour, the annual rate of base-load capacity should be evenly distributed among 8760 hours while the annual rate of peak-load capacity should be distributed according to LOLP(t) for each hour. Therefore, the cost of electricity for hour t is given by:

Where: F(t) is fuel cost of the power system in hour t

$$C(t) = F(t) + W_p K_p \frac{R(t)}{R_A} + \frac{W_b K_b}{8760} \qquad eq.2.5.3.2$$

R(t) is LOLP(t), the risk level in hour t

R_A is the risk level in the investigated year given by:

$$R_A = LOLP_A = \sum_{t=1}^{8760} LOLP(t) \qquad eq.2.5.3.3$$

Hence, the average cost of electricity for hour t is given by the following expression:

$$\bar{\rho}(t) = \frac{C(t)}{P(t)} \qquad eq.2.5.3.4$$

Where P(t) is the system load for hour t.

The marginal cost ρ(t) of electricity for hour t is given by:

$$\rho(t) = \frac{\partial C(t)}{\partial P(t)} \qquad eq.2.5.3.5$$

Substituting equation 2.5.3.2 into equation 2.5.3.5, we get

$$\rho(t) = \frac{\partial F(t)}{\partial P(t)} + \frac{\partial (W_p K_p R(t) / R_A)}{\partial P(t)} \qquad eq.2.5.3.6$$

The term

$$\frac{\partial F(t)}{\partial P(t)}$$

in equation 2.5.3.6 can be found by running a probabilistic production simulation. To find the second term of equation 2.5.3.6, we can use the following methods.

1. Maintain generation capacity W_p unchanged and increase I unit load for each hour, then run a probabilistic production simulation in this situation, LOLP(t).

2. Maintain LOLP(t) unchanged and increase 1 unit load. In this situation the peak load capacity W_p should increase.

Because it is difficult to get the cost of loss load, the second way is preferred. Under the above condition equation 2.5.3.6 can be rearranged as follows:

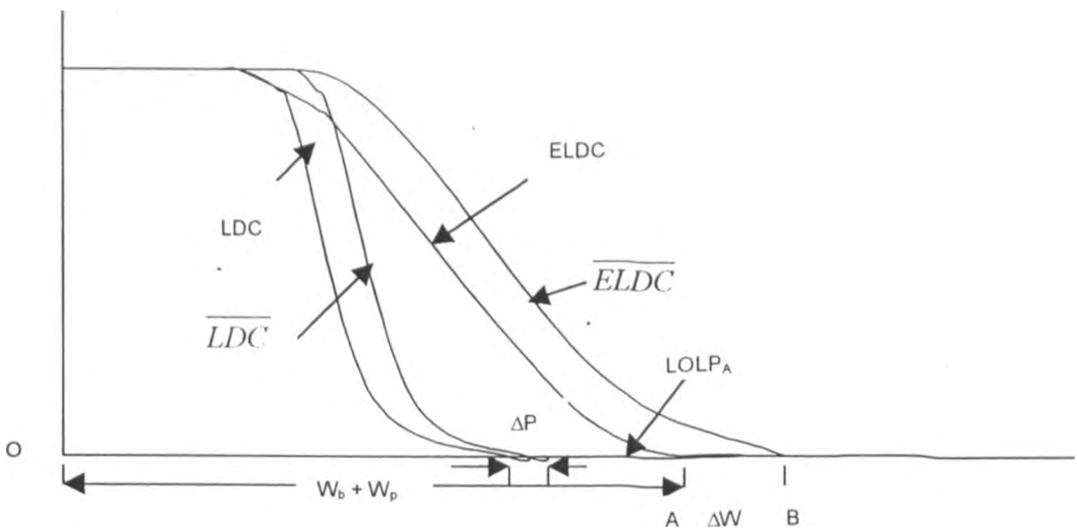
$$\rho(t) = \frac{\partial F(t)}{\partial P(t)} + K_p \frac{R(t)}{R_A} \times \frac{\partial W_p}{\partial P(t)} \qquad eq.2.5.3.7$$

Where the term

$$\frac{\partial W_p}{\partial P(t)}$$

can be approximately found by the following procedure as in the figure below:

Equivalent Duration Load Curve



LDC in the figure is the load duration curve formed from P(t). After running a probabilistic production simulation, the equivalent load duration curve ELDC is formed. The risk level of the whole year, $LOLP_A$, is determined by the abscissa of the expression:

$$Wb + Wp \times \overline{LDC}$$

The expression describes the load duration curve formed by P(t) + ΔP; where ΔP is an increment of the load. After running a probabilistic production simulation, the respective equivalent load duration curve becomes:

$$\overline{ELDC}$$

With the same $LOLP_A$ we can find a point in

$$\overline{ELDC}$$

the abscissa of which is OB. Therefore, the section of line AB represents the capacity increment ΔW. Thus the equation:

$$\frac{\partial W_p}{\partial P(t)} \approx \frac{\Delta W}{\Delta P}$$

can be substituted in equation 2.5.3.7 to calculate the marginal cost of electricity for each hour. This is the basis for development of bulk electricity prices that are incorporated in the PPA as covered in the following section.

2.5.4 Structure of electricity bulk charges

In the PPA the generating company electric energy price is normally converted into energy and capacity components. The following stage provide an overview of the process of conversions that are used within the PPA in order to protect the seller (generating company) and KPLC (buyer) from risks associated with the electricity business (KPLC, 2002).

2.5.4.1 Energy charges

(a) Calculation of energy charges

KPLC pays to the Seller Energy Charges in respect of the Net Electrical Output of the Plant in each month calculated as follows:

VOM is the aggregate amount of Energy Charges payable in respect of any month p,

$$VOM = ECR \times NEO_p$$

$$ECR = SP + LO + LB + CO$$

$$SP = SP_b \times \left\{1 + \frac{D_s + IDF - 2}{100}\right\}$$

$$LO = LO_b \times \left(1 + \frac{D_{lo}}{100}\right)$$

Where:

ECR	=	aggregate Energy Charge Rate (expressed in US$/kWh) for the month p
NEO_p	=	aggregate Net Electrical Output (expressed in kWh) of the Plant in the month p
SP	=	total spare parts component

SP_b	=	value agreed with the Seller as the base spare part price being xxxxxxx US$/kWh
LO	=	total lubricant component
LO_b	=	value agreed with Seller as the base lubricant price being xxxxxxx US$/kWh
LB	=	variable labour component
LB_b	=	value agreed with Seller as the base variable labour price being xxxxxxx US$/kWh
CO	=	chemicals and consumable component
CO_b	=	value agreed with Seller as the base chemicals and consumable price being xxxxxxx US$/kWh
D_s	=	rate of duty (%) chargeable on the importation of spare parts for the month 3 months prior to the month p
D_{lo}	=	rate of duty (%) chargeable on the importation of lubricating oil for the month 3 months prior to the month p
IDF	=	Import Declaration Fee (%) for the month 3 months prior to the month p

Spare parts duty, Ds, is calculated on the percentage duties chargeable on spare parts imported for the project, against documentation provided by the Seller. This value is calculated at the end of each Operating Year and the value calculated applies in the following Operating Year. At the end of each Operating Year the Seller calculates the percentage duty actually paid by the Seller and the percentage duty recovered from KPLC using the preceding Operating Year's value. If the difference between the two sums is positive, KPLC reimburses the Seller and if the difference between the two sums is negative, the Seller reimburses KPLC. For the first Operating Year, the value of D is taken as ten per cent (10%).

2.5.4.2 Capacity payments

(i) Capacity charge rate

The Capacity Charge Rate for the Plant during each month is calculated as follows:

$$CCR_p = \frac{FCR}{12}$$

where:

CCR_p = the Capacity Charge Rate for month p, (expressed in US$/kW/month)

FCR = xxxxx expressed in US$/kW/year the value agreed with the Seller as the Base Capacity Charge Rate

(ii) Calculation of capacity payments

The Seller is entitled to Capacity Payments in respect of Capacity in each month calculated as follows provided that if $AMA_{tp} < MTA_{tp}$, CP_p is calculated as follows:

$$CP_p = CCR_p \times CC \times 1000$$

where:

CP_p = the Capacity Payment for month p (expressed in US $)

CCR_p = the Capacity Charge Rate for month p, (expressed in US$/kW/month)

CC = the Contracted Capacity (expressed in MW)

(iii) Monthly availabilities

For each month in each Operating Year, starting with the month in which the Full Commercial Operation Date occurs, calculation of a target availability for each Month (Monthly Target Availability) and an actual availability which the Plant achieves in each month (Actual Monthly Availability) is done as follows:

1. Monthly target availability

$$MTA_p = (CC \times 1000 \times H_p) - SMA_p - USMA_p$$

where:

MTA_p = the Monthly Target Availability (expressed in kWh);

CC = the Contracted Capacity (expressed in MW);

H_p = the hours in month p;

SMA_p = Scheduled Maintenance Allowance in month p (expressed in kWh) representing the total energy not available for delivery in month p due to scheduled maintenance outages as provided in the PPA assuming the Plant would otherwise have been Dispatched at its Contracted Capacity;

$USMA_p$= Unscheduled Maintenance Allowance in month p (expressed in kWh) as calculated using the following formula:

$$USMA_p = \frac{\left(CC \times 1000 \times PPA_t \times H_y \times \frac{OA}{100}\right) - \sum_{m=1}^{PPA_t \times M_y} SMA_m}{PPA_t \times M_y}$$

where:

PPA_t = the duration in years of the period which begins at the Full Commercial Operation Date and ends at the expiry of the Term

H_y = the number of hours in a year being eight thousand seven hundred and sixty (8760)

M_y = the number of Months in a year being twelve (12)

OA = Annual Outage Allowance (100 - 85=15)

SMA_m = Scheduled Maintenance Allowance in any month m (expressed in kWh) representing the total energy not available for delivery in month p due to scheduled maintenance outages as provided in the PPA assuming the Plant would otherwise have been Despatched at its Contracted Capacity;

2. Actual monthly availability

The Actual Monthly Availability of the Plant in month p, AMA_p (expressed in kWh), is calculated using the following formula:

$$AMA_p = \sum_{y=1}^{2 \times H_p} \frac{AC_y}{2} \times F_y$$

where:

AC_y = the average Available Capacity in Settlement Period y (expressed in kW)

F_y = the Weighting Factor Applicable in Settlement Period y based on Table 2.5.2 below.

Where the Full Commercial Operation Date occurs part way through a month then the Monthly Target Availability shall be adjusted pro rata for the remaining number of hours in that month.

Table 2.5.1 - Availability Weighting Factors (F)

	Working Days		Weekend Periods	
	Peak Hours	Non Peak Hours	Sat	Sun
January	1.075	0.967	0.967	0.86
February	1.075	0.967	0.967	0.86
March	1.075	0.967	0.967	0.86
April	1.075	0.967	0.967	0.86
May	1.075	0.967	0.967	0.86
June	1.075	0.967	0.967	0.86
July	1.075	0.967	0.967	0.86
August	1.075	0.967	0.967	0.86
September	1.075	0.967	0.967	0.86
October	1.075	0.967	0.967	0.86
November	1.075	0.967	0.967	0.86
December	1.075	0.967	0.967	0.86

Peak-Hours (Working Days): 0700 to 2200

Non Peak Hours (Working Days): 2200 to 0700

The above factors may be adjusted, by mutual agreement, if future load patterns change significantly, subject to the proviso that the time averaged figure is always taken as unity.

For the avoidance of doubt, as an example, F_y for the Settlement Period which begins on a Monday in January at 08:00 hours is taken as 1.075 or that value as agreed by the parties which replaces 1.075.

(iv) Adjustment of capacity payments for monthly availability

At the end of each month the sum of the Actual Monthly Availabilities in the Operating Year to date (AMA_{tp}) is compared to the sum of the Target Monthly Availabilities in the Operating Year to date (MTA_{tp}) which is calculated using the following formulas:.

$$AMA_{tp} = \sum_{p=1}^{n} AMA_p$$

$$MTA_{tp} = \sum_{p=1}^{n} MTAp$$

where:

n is the number of months p in the year to date

If the sum of the Actual Monthly Availabilities to date is equal to or greater than the sum of the Target Monthly Availabilities to date then the Capacity Payment for that month is CP_p. However, if the sum of the Actual Monthly Availabilities to date is less than the sum of the Target Monthly Availabilities to date then an adjustment in the Capacity Payment is required, ie. if; AMA_{tp} < MTA_{tp}, then

1. For the First Month of Operating Year

If in the first month of an Operating Year, the Actual Monthly Availability is less than the Monthly Target Availability, the Capacity Payment for that month is multiplied by the factor:

$$\frac{AMA_p}{MTA_p}$$

2. For all Subsequent Months of Operating Year

If in any subsequent month m of an Operating Year, the sum of the individual Actual Monthly Availabilities in the Operating Year to date is less than the sum of the Individual Monthly Target Availabilities in the Operating Year to date, then the Capacity Payment for that month is adjusted such that

$$ACP_{tp} = \sum_{p=1}^{m} \left(CP_p \times \frac{AMA_p}{MTA_p} \right)$$

Where:

ACP_{tp} = the total of the Actual Capacity Payments received in the Operating Year for each month up to and including month p.

For the avoidance of doubt the monthly capacity payment CP_p shall be calculated using the following formula:

$$CP_p = ACP_{tp} - ACP_{tp(p-1)}$$

where:

$ACP_{tp(p-1)}$= the total of the Actual Capacity Payments received in the Operating Year for each month up to and including the month which ended immediately prior to month p;

Cp_p = the Capacity Payment for month p (expressed in US $); and

ACP_{tp} = the total of the Actual Capacity Payments received in the Operating Year for each month up to and including month p.

(v) Change in contracted capacity

In the event that the Contracted Capacity is altered under the provisions of the Agreement during any month, the calculation of payments is adjusted pro-rata to reflect the differing proportions of the month for which differing Contracted Capacities were agreed.

CHAPTER THREE

3.0 RESEARCH METHODOLOGY

3.1 Population

The study was based on bulk power producers in Kenya. Therefore the population comprised all the five electric energy generating firms and in addition, Uganda Electricity Transmission Company Ltd (UETC). UETC signed a PPA for supply of bulk electric energy to the Kenyan grid system in January 2002 that was built upon the existing 50 years supply agreement entered into by the Governments of Kenya and Uganda in the 1950s.

3.2 Sampling

Due to the small size of the population sampling was not necessary and therefore all the five bulk electric energy producers were surveyed. In addition to the five firms, UETC's prices were obtained and included in the analysis.

3.3 Data Collection

Primary data was collected from each company using the questionnaire in Appendix 1 to this thesis. Data was collected through interviews using the questionnaire. The respondents were CEOs of each of the companies who in some cases referred the questionnaire to their subordinate managers, mainly the Finance Managers and in one case, the Corporate Planning Manager.

In order to clarify or seek more information regarding the data collected through the questionnaire, the researcher obtained more data through telephone inquiries and face to face meetings with the CEOs and their designated subordinate managers. Further clarification and authentication of data was also made through other stake holders such as KPLC and ERB both of whom also provided key data to back up that already collected through the questionnaire. The two organizations also provided data for UETC since this was not collected through the questionnaire.

3.4 Data Analysis and Findings

The summary of data collected through the questionnaire is presented on the tables in Appendix 2 and 3. The data was qualitatively evaluated with a view to identifying the following:

- Pricing method adopted by each company
- Any differences in the pricing methods.

Pricing methods and differences were mainly given through answers to questions 18 to 22. The data collected through answers to the other questions was evaluated qualitatively to arrive at the price adopted by each company, which were then compared with each other to find out the difference. Reasons for the differences were then sought and explained from technical and environmental considerations of each type of generation.

CHAPTER FOUR

4.0 DATA ANALYSIS AND FINDINGS

4.1 Findings

Responses to the questionnaire are recorded in Appendices 2 and 3. From the findings of the study it was established that pricing of bulk power in Kenya is generally in three components. These are:

- Capacity charge;
- Energy (Variable O&M cost) charge; and
- Fuel cost.

The detailed firm-by-firm price is shown under the three price categories on Table 4.1.1 below:

Table 4.1.1 – Bulk Energy Prices

Bulk Energy Supplier	Total Capital (US $)	Plant Rating (MW)	Contract Period (Years)	Price			
				Capacity Charge (US$/kW/yr)	Energy Charge		Overall
					Variable O & M (UScts/kWh)	Fuel (UScts/kWh)	UScts/kWh
Tsavo	86,000,000	74	20	250.39	0.61	2.79	6.26
KenGen	697,172,000	919					
Hydro & geothermal		800	Interim	0.00	3.15	0.00	3.15
Kipevu Thermal		60	Interim	0.00	3.15	5.91	9.06
Kipevu Diesel		69	Interim	0.00	3.15	3.33	6.48
Kipevu Gas Turbine		60	Interim	0.00	3.15	11.05	14.20
Westmont	48,000,000	43	7	212.21	0.62	9.69	12.73
Iberafrica	65,000,000	57	7	395.00	0.62	5.58	10.71
OR Power-4	156,000,000	48	20	502.90	1.56	0.00	7.30
UETC - Peak	N/A	30	50	0.00	6.10	0.00	6.10
Off-Peak	N/A	30	50	0.00	4.60	0.00	4.60

From Table 4.1.1, it is clear that the largest of the three components of price (charge) is capacity charge. In this respect it is the component that influences the overall price (charge) of the bulk energy producers except UETC and some of KenGen's plants.

4.1.1 Capacity charge

Under the PPA, capacity charge is payable whether the firm supplies energy to the grid or not. Under normal circumstances the firm could only supply energy on request by the National Control Centre, the department within the retail company that coordinates and controls the incoming supply of electricity from bulk suppliers and its dispatch to consumers. At any time, the decision to call any of the bulk suppliers is dictated by demand and the price charged by each supplier. In this case the firm with the lowest price would be the first to be called followed by the next lowest up to the highest in that order. Due to economic reasons however, firms with high capacity charge prices are more likely to be called than those without or with low capacity charge because even in idle state the firms with high capacity charge prices attract high payments.

Capacity charge in most cases is a fixed charge but some portions of it may be escalated at some rate, eg. CPI, to compensate for items that occasionally change with international trends eg. Labour cost. Capacity charge is fixed for the guaranteed capacity and therefore if the supplier falls short of the guaranteed capacity a heavy penalty is imposed on the capacity not met. At the same time suppliers earn bonuses for over capacity to a maximum of 15% of guaranteed capacity.

Capacity charge for Westmont is fixed throughout the PPA period while that of Tsavo, OR Power-4 and Iberafrica is on a two-tier structure having escalable (escalating) and unescalable (non-escalating) components. The escalable component varies in accordance with the US Consumer Price Index (CPI) while the unescalable component is fixed. The proportions of the two components in respect of the three firms are different since each depends on the source of escalable items such as labour. The values given in Table 4.1.1 are shown as fixed because they are the mean charges as at August 2002 worked out by the firms and authenticated by ERB.

KenGen has no capacity charge due to its diversity of types of plant. At the same time debt for most of the plant has already been repaid and the investment recouped. It is therefore prudent for the company to tie its price on production. The situation could however change when negotiations for the final PPA get on the way. Currently the company sells energy to the retail company through an interim PPA (IPPA).

UETL has no capacity charge since under the current 50 years agreement, which will expire in 2004, there is no requirements for guaranteed capacity.

Generally, capacity charge is developed at the bidding stage of the project when competing firms try to out do each other by giving the best offer in order to win the bid. Apart from complying with the minimum technical requirements or surpassing them, the competing firms try to keep their prices at a minimum. Through capacity price component, competitive pricing is achieved through optimal sizing of the plant by optimizing on the number and sizes of the generators and through the use of cheap capital financing.

Capacity charge is the component that helps the firm to recoup its capital investment, fixed labour expenses, O&M expenses, repayment of debt and return on equity. The price is fixed throughout the term of the power purchase agreement (PPA) and is payable to the firm whether there was production or not. This is however on condition that the capacity agreed upon under the PPA is maintained. If the capacity is not maintained, the firm is penalized heavily by having a portion of payments withheld. The firm is therefore forced to retain a high degree of serviceability of its plant and to maintain insurance against unforeseen and prolonged breakdowns.

Capacity charge to a large extent reduces the business risk but since the price is developed long before production commences and is valid throughout the entire PPA period, which in most cases, runs for 20 years, capacity charge has to be carefully and correctly developed. If not properly done, there would be no chance to correct it after the PPA has been signed. For this reason both the investors and the financiers in the sector tend to require very high returns on equity and on debt.

Before deciding on the investment, the competing firms first undertake rigorous economic analysis of the optimum plant sizes and type of technology given the climatic conditions the plant will be expected to operate in. The firm then undertakes risk assessment to establish different levels of risk arising from political, business, financial, interest rates, tax changes etc. Since the project has a long payback period the investment dollar is locked up for many years, hence the project is relatively illiquid. At the same time the project cash flows must be forecast far out into the future, hence the project is probably risky. Exchange risk is reduced by fixing the price in US dollars. Although the business would most likely be part of an international diversified portfolio, which means that the diversifiable risk of the portfolio is greatly reduced (Bruno H Solnic, 1974), the stand-alone risk of the business is analyzed in order to factor risk in the financial analysis.

Financial analysis of the optimal plant is performed by applying discounted cash flows (DCF) capital budgeting techniques with a view to establishing positive NPV. In this case discounting of cash flows is done using opportunity cost of capital (OCC) which is arrived at after factoring in risk, expenses, expected returns, tax liabilities, debt repayment and interest repayment to the project cost of capital. A rate of return of 12% has been adopted in all the bulk energy company projects except Iberafrica (18%). This is because the rate of 12% has been recommended by the World Bank for energy generation projects in developing countries (Acres, 1985).

Development of capacity charge is done through discounting of project cash flows over the entire period of the PPA as explained below:

Table 4.1.2 below shows the steps taken when discounting benefits (energy requirements) and expenses for purposes of price determination. In this case discounting is done over the period of period of construction and the PPA period. In Kenya a typical construction period is 3 years while most of the current PPAs run for periods of 20 years.

Most investors and financiers would prefer to recoup their investment and at the same time receive returns over the entire period of the PPA. The years are listed under column 1. Column 2 shows the computed discounting factors over the PPA years at a 12% OCC. This is the OCC is applied by most of the firms and is the WACC that is able to capture the following parameters:

- Interest rate on loans (ranging between 9 and 11% for all but Iberafrica (18%);
- Business risk and financing risk;
- Inflation; and
- Return on assets including return on equity

Energy requirements over the entire period of the PPA are listed under column 3. These quantities are estimated based on the requirements of the MOE and based on the optimized plant size with 90% availability. This means that the value of A_4 to A_{23} may be equal or not. These energy requirements are then discounted over the years by multiplying each with the corresponding discounting factor and the results recorded under column 4. The values under column 4 are the discounted benefits.

Streams of expenses are then recorded for each year in columns 5 to 8. Construction cost and O&M costs in columns 5 and 6 respectively. Streams of debt repayment (without interest) are recorded under column 7 assuming equal payment 'D' every year. It, however, does not have to be so. All the other fixed costs such as labour costs etc. are recorded under column 8 All the expenses are then summed up in column 9 and discounted in column 10.

Table 4.1.2 – Discounting of Benefits and Costs

Year 1	Discounting Factors at 12% Rate of Return 2	Energy Requirements (GWh) 3	Discounted Energy Requirements (GWh) 4	Stream of Construction cost (US $) 5	Stream of O&M cost (US $) 6	Stream of Debt Repayment (US $) 7	Stream of other fixed costs (US $) 8	Stream of Total Costs (US $) 9	Discounted Streams of Total Costs (US $) 10
1	0.8929	0	0	B_1	-	-	F_1	B_1+F_1	0.8929 (B_1+F_1)
2	0.7972	0	0	B_2	-	-	F_2	B_2+F_2	0.7972 (B_2+F_2)
3	0.7118	0	0	B_3	-	-	F_3	B_3+F_3	0.7118 (B_3+F_3)
4	0.6355	A_4	0.6355 A_4	-	C_4	D	F_4	C_4+D+F_4	0.6355 (C_4+D+F_4)
5	0.5674	A_5	0.5674 A_5	-	C_5	D	F_5	C_5+D+F_5	0.5674 (C_5+D+F_5)
-									
-									
-									
20	0.1037	A_{20}	0.1037 A_{20}	-	C_{20}	D	F_{20}	$C_{20}+D+F_{20}$	0.1037 ($C_{20}+D+F_{20}$)
21	0.0926	A_{21}	0.0926 A_{21}	-	C_{21}	D	F_{21}	$C_{21}+D+F_{21}$	0.0926 ($C_{21}+D+F_{21}$)
22	0.0826	A_{22}	0.0826 A_{22}	-	C_{22}	D	F_{22}	$C_{22}+D+F_{22}$	0.0826 ($C_{22}+D+F_{22}$)
23	0.0738	A_{23}	0.0738 A_{23}	-	C_{23}	D	F_{23}	$C_{23}+D+F_{23}$	0.0738 ($C_{23}+D+F_{23}$)
			Total Discounted Benefits						**Total Discounted Costs**

By discounting the energy requirements over the entire period of 23 years and summing up all the values (column 4) gives **Total Discounted Benefits** in GWh. Similarly, by discounting the streams of total costs over the same period and summing up all the values (column 10) gives **Total Discounted Costs** in US dollars. By dividing the value of Total Discounted Costs with that of Total Discounted Benefits we obtain the average cost of energy or capacity charge.

$$Capacity\ Charge\ (US\$/kWh) = Average\ Cost = \frac{Total\ Discounted\ Cost\ (US\ \$)}{Total\ Discounted\ Benefits\ (GWh) \times 10^6} \quad eq.4.1.1.1$$

The value of US $/kWh can be converted to US $/kW/yr by simply multiplying by the number of hour in a year which is 8760.

Since the interest rate (cost of debt) for all the firms is known, it is possible to compute the rate of return on equity for each firm using eq. 1.1.2.4 applying corporate tax rate of locally incorporated company of 30%. This calculated rate contains components of return on assets which includes all the risks borne by the investors. Since four of the firm under study are owned by multinational companies while one is owned by the government, the ownership can be assumed to be on common stock basis. The calculated values are shown on Table 4.1.3 below:

Table 4.1.3 – Computation of Return on Equity

Firm	Time Prefered Discount Rate (TPDR) %	Cost of Debt %	Debt/Equity %	Computed Return On Equity %
Tsavo	12	10	50/50	12.00
Westmont	12	11	40/60	14.67
Iberafrica	18	18.	40/60	21.00
OR Power-4	12	11	40/60	14.67

From the above analysis it could be concluded that the capacity charge component of bulk price is directly proportional to the following parameters:

- Total capital invested;
- Total debt;
- Cost of debt;
- Debt repayment period;
- Required rate of return on equity;
- Perceived risk;
- Discounting rate of return
- O&M cost: and
- Other fixed costs

Capacity charge is inversely proportional to the following parameters:

- Plant rating (Capacity); and
- Length of plant's production period, assumed to be the same as the length of the PPA.

From the above conclusions the capacity charge for the respective firms are summarized in Table 4.1.4 below:

Table 4.1.4 – Firm-by-firm Explanation of Capacity Charges

Firm	Capacity Charge (US$/kW/yr)	Plant Rating (MW)	Length of PPA (years)	Cost of Debt (%)	OCC (%)	Rate of return on equity (%)	Remarks
OR Power-4	502.90	57	20	11	12	14.87	• High investment cost due to geothermal steam exploration works • High required rate of return on equity • High interest rate
Iberafrica	395.00	43	7	18	18	21 60	• Relatively small investment but short payback period (7 years) • High interest rate and short repayment period • High required rate of return on equity
Tsavo	250.39	74	20	10	12	17.00	• High required rate of return on equity • High interest rate • High required rate of return on equity
Westmont	212.21	48	7	11	12	14.87	• Relatively small investment but short payback period (7 years) • High O&M cost on gas-turbine unit • High required rate of return on equity
KenGen	0	918.9	Interim		12	N/A	Not easy to come up with uniform rate due to: • High diversity of plant type • Loans on most of the plants have been repaid • Some plants are running beyond their useful life
UETC	0	30	50			N/A	• No guaranteed capacity hence capacity charge does not exist

4.1.2 Energy charge

This is a charge that applies to the quantity of energy produced. The term energy charge should in theory refer to the variable O&M and fuel costs but in reality it is only applicable to the variable O&M cost while fuel is charged separately.

Energy charge is calculated using the following expression:

$$VOM = ECR \times NEO_p \qquad eq. 4.1.2.1$$

Where, VOM is the aggregate amount of energy charges in respect of any month (period) p;

NEO_p is the aggregate net electrical output (expressed in kWh) of the plant in month p;

ECR is the aggregate charge rate (expressed in US $/kWh) of the plant in month p. ECR is described by the following expression:

$$ECR = SP + LO + LB + CO \qquad eq. 4.1.2.2$$

Where, SP is the total spare parts component described by the following expression:

$$SP = SP_b \times \left[1 + \frac{D_s}{100} + \frac{IDF - 2}{100} \right] \qquad eq. 4.1.2.3$$

SP_b is the value agreed in the PPA as the base spare parts price in US \$/kWh;

LO is the total lubricant component;

LO_b is the value agreed in the PPA as the base lubricant price in US \$/kWh described by the following expression:

$$LO = LO_b \times \left[1 + \frac{D_{lo}}{100} \right] \qquad eq. 4.1.2.4$$

LB is the variable labour component at the rate agreed in the PPA;

CO is the chemical and consumable component at the rate agreed in the PPA;

D_s is the rate of duty (%) chargeable on the importation of spare parts for the month p;

D_{lo} is the rate of duty (%) chargeable on the importation of lubricating oil for the month p;

and IDF is the import declaration fee (%) for the month p

Energy charge is the component of price that compensates the producer for the variable production costs. Examples of these costs are:

- Variable labour;
- Spare parts;
- Lubricants and other variable costs.

These costs are generally low hence the relatively low values of capacity charge in respect of the following firms: Tsavo, Westmont, Iberafrica and OR Power-4

KenGen and UTCL have relatively high energy charge components because most of their charges have been tied to production since they have no guaranteed capacity charge which means therefore that they have developed their energy charge components using different methods. KenGen uses the long-run marginal costs (LRMC) analysis to develop its energy charge component. Marginal cost is defined as the change in total cost with respect to small change in output (Nera/GIBB, 2002). The LRMC could therefore be broadly defined as the incremental cost of all adjustments in the electric energy system expansion plan and system operations attributable to an incremental change in demand sustained into the future.

On the basis of the above definitions it can be concluded that KenGen has based its energy charge component on macro and micro-economy factors, its future capital and recurrent expenditures and future debt repayments. All these parameters are then converted to LRMC using rigorous economic analysis. To quantify the marginal costs of electricity service it is necessary to find out the additional costs that would be incurred with changes in kilowatt-hours (kWh) of energy and kilowatt (kW) of power (demand). The LRMC is the best method of passing on realistic cost to the retail market on the basis of actual consumption.

The long run marginal costs are usually lower than average marginal costs since they have been stabilized over time. In this respect therefore tariffs that are derived from LRMC must be financially adjusted upwards in order to meet actual requirements in terms of revenue. KenGen uses a factor of 1 – 1.5 of the LRMC to arrive at the optimum energy charge.

No information was obtained from the UETC but since the current agreement was signed between the governments of the two countries in the 1950s it is unlikely that modern financial analysis was carried out to arrive at the price. A new 20 years PPA has now been negotiated and will commence in 2004 when the current agreement comes to an end. The reason that UETC's charge are double that of KenGen may have been to cover the opportunity cost of selling energy within Uganda and to compensate UETC for the uncertainties of maintaining the same price over the last 50 years. Transmission line cost is not factored in the price since billing for payment purposes is done at Tororo, Uganda which is very near Jinja, the source of energy.

Table 4.1.5 – Energy Charge Component

Bulk Energy Supplier	Total Capital (US $)	Plant Rating (MW)	Energy (Variable O & M) charge (UScts/kWh)	Remarks
Tsavo	86,000,000	74	0.61	Low production cost
KenGen	697,172,000	919	3.15	Lumped charge Government owned firm Low debt/equity
Westmont	48,000,000	43	0.62	Low production cost
Iberafrica	65,000,000	57	0.62	Low production cost
OR Power-4	156,000,000	48	1.56	High production cost
UETC - Peak	N/A	30	6.10	Lumped charge Imported energy
Off-Peak		30	4.60	Lumped charge Imported energy

From Table 4.1.5 above it is observed that KenGen and UETC have fixed their prices only on the basis of energy charge. This means that KenGen has converted all its costs and price requirements into variable costs using the LRMC method. Of the other four, OR Power-4 has the highest charge. This is because OR Power-4 uses geothermal steam to produce electric energy and the cost of developing geothermal steam well fields and harnessing the steam is exorbitant due to cost of variable labour, lubricants, spare parts and other costly consumables.

The remaining three suppliers have almost the same energy charge. This is because the same mode of generation (thermal) is used. The charge is not dependent on the capacity of the plant or size of investment.

4.1.3 Fuel cost

Like the energy charge component, fuel charge is a variable cost and is derived from the current cost of fuel in the world market. This is however a pass-through component and therefore does not affect the final profitability of the firm. The fuel cost varies from time to time depending on the world price of fuel. The rates shown on Table 4.1.6 below are based on the August 2002 oil prices. The fuel cost rate is computed using the price of fuel for the month and handling costs and devided with the energy produced. The rate is however a function of the heat conversion rates and efficiency of the generators.

Table 4.1.6 – Fuel Cost Component

Bulk Energy Supplier	Total Capital (US $)	Plant Rating (MW)	Fuel (UScts/kWh)	Remarks
Tsavo	86,000,000	74	2.79	Modern efficient generators
KenGen	697,172,000	919		
Hydro & geothermal plants		800	0.00	Mainly hydropower and geothermal. Relatively small portion of oil fired generation
Kipevu Thermal		60	5.91	Less efficient generators
Kipevu Diesel		69	3.33	Modern efficient generators
Kipevu Gas Turbine		60	11.05	Inefficient gas-turbine generator
Westmont	48,000,000	43	9.69	Inefficient gas-turbine generator
Iberafrica	65,000,000	57	5.58	Less efficient generators
OR Power-4	156,000,000	48	0.00	Geothermal power. No cost on fuel
UETC - Peak	N/A	30	0.00	Hydropower. No cost on fuel
Off-Peak		30	0.00	Ditto

As observed from Table 4.1.6, all the generating firms that do not use oil-fired generators have no fuel cost. OR Power-4, UETC and some of KenGen's plants. Out of the four firms operating oil-fired generators, KenGen gas turbine has the highest rate followed by Westmont who have also installed gas turbines. Gas turbines an extremely low efficiency of 32%. KenGen's thermal plant is the second in efficiency along with Iberafrica whose with generators having an efficiency of 93% while Tsavo and KenGen have the most modern diesel units operating at 99% efficiency and a combined station efficiencies of 98%. Other than conversion factor and efficiency of generators and price of fuel, the most important factor that influences the fuel cost is the mode of purchasing of fuel and storage. KenGen procures fuel from spot-market while Tsavo has long-term contract of supply, which is paid for by the retail company. Westmont and Iberafrica have very little storage capacity and therefore they have to procure fuel at shorter intervals. All these conditions have largely influenced the wide differences in the fuel charge among the firms.

4.2 Market model

From the findings under 4.1, it can be concluded that in order to reduce the price of bulk energy to a minimum and by extension achieve much lower electricity retail tariffs the following parameters would have to be applied:

4.2.1 Capacity charge

From table 4.1.1 the two companies with the highest overall prices are Westmont and Iberafrica. Both companies have the shortest PPA of 7 years. They are then followed by OR Power-4 which has a 20-year PPA but whose fixed costs are high due to the high cost of developing geothermal steam well fields. All this means that capacity charge is the component with the highest influence on the overall price. In order to achieve a reduced capacity charge, therefore, the following parameters would have to be considered and varied accordingly:

1. **Total capital**: The higher the invested capital the higher the benefit but also the higher the cost. The capital investment should be in the ratio of higher benefit than cost where benefit is given by the capacity of the plant. In this case in order to reduce the price, the cost/kW should be reduced to a minimum. Due to smallness of the Kenyan power system, available international benchmarks cannot not be accurately used to estimate the optimum cost/kW but as a guide the following statistics can be applied or improved upon:

Gas Turbine generator: US $ 500 – 700 per kW

Medium speed diesel generator: US $ 1000 – 1300 per kW

2. **Debt**: Although the capital structure of the firm may not be a major issue since the main influence would be the relative cost of the debt vis-à-vis the return on equity. The magnitude of debt is likely to increase risk and lead to the investor demanding higher returns resulting in higher cost of equity (Modigliani-Miller, 1969). Most of the projects of this nature remain within the debt/equity factor of 40/60%.

3. **Cost of debt**: Increasing interest rate would result in the increase of the opportunity cost of capital (OCC) and hence higher discounted cash flows. Negotiation for minimum interest rates would be necessary.

4. **Length of period of debt repayment**: A longer period of debt repayment would translate into lower cash outflows. However, since the period of payment is limited by the period of the PPA, which would mean that any periods of debt repayment that are lower than the PPA period should be discouraged.

5. **Required rate of return on equity**: The higher the required rate of return on equity the higher the price. The investors should be given confidence that their investment will provide a constant return over the period of the PPA. This would ensure that they do not demand an unduly high return hence a lower price level could be achieved. Using CAPM, based on the USA stock market and risk-free rate of return the return on equity of KenGen was worked out as 16.2% (Nera/GIBB, 2002). Of the five firms, KenGen has the average overall price. As a rule of thumb, a rate of return on equity of 15 – 20% should be targeted in order to maintain a reasonable price level.

6. **Perceived risk**: Risk should be kept to a minimum. This is achievable by ensuring that investments of this nature are protected through legislation, sound government economic, monetary and fiscal policies, good political environment, maintenance of stability within the energy sector, control of domestic inflation and interest rates etc.

7. **O&M cost**: Maintaining low levels of O&M cost would keep the price low. One way of achieving this is by entering into long-term contracts with highly experienced O&M firms.

8. **Labour expenses**: Low labour expenses would ensure a low price. This could be achieved by maintaining a lean and mean company structure and contracting out non-core functions especially those that are dependent on production so that they could be priced through energy charge. Another way to achieve this is to train and employ local staff instead of expensive expatriate staff.

4.2.2 Energy charge

In order to achieve a reduced energy charge the following parameters need to be considered:

1. **Variable Labour**: The lower the variable labour cost the lower the energy charge would be. This can be achieved by engaging local staff instead of expatriate staff.

2. **Spare parts**: In order to reduce energy price the cost of spare parts should be kept at a minimum. This can be achieved by establishing long-term contracts with suppliers and by ensuring that only high quality spare parts are bought and stocked. Maintaining low inventory levels by establishing a good supply line would cut down on cost.

3. **Lubricants and other consumables**: Maintaining a low cost would ensure a low price. This can be achieved by establishing long-term contracts, maintaining low inventory levels and high quality products.

4.2.3 Fuel cost

This is a pass through component and although it does not affect the profitability of the firm it has an impact on cash flows. In this case it would be necessary to maintain a low price because it also impacts on the competitiveness of the business and on the opinion of the consumers. In order to achieve a reduced fuel cost the following parameters needs to be considered:

1. **Purchase Price of fuel**: The lower the purchase price of fuel the lower the cost to the firm and hence the lower would be the component of fuel cost. This can be achieved by establishing long-term supply contracts with renowned oil supply companies and having sufficient fuel storage capacity.

2. **Efficiency of generating units**: In order to reduce the fuel cost component it is necessary that efficiency of the generating units be maintained at a high level. This can be achieved by installing good quality generators, contracting well-experienced O&M firm and ensuring that the units are well serviced.

3. **Good quality fuel**: Use of good quality fuel would ensure efficient running of units and cuts down on maintenance cost while ensuring that the firm is not penalized for issues related to environmental degradation. This can be achieved by establishing long-term contracts with renowned oil supply companies.

4.2.4 Current market trends

With the expiration of the fast track 7-year PPAs for Iberafrica and Westmont both firms have applied for new 20-year PPAs which will commence in the year 2004. Since the two firms are likely to have already achieved payback on their investment they should now be able to ask much lower prices since their capacity charges should be fairly low if not zero. The two firms pioneered the IPP bulk power business in Kenya and due to uncertainties that are normal with any new business, both firms must have built into their prices very high risk levels. Since the market has now attracted new entrants whose prices are lower, these two firms have no choice but to drastically reduce their prices. As already discussed under 4.1.1 firms with low capacity charge may not necessarily be the most economical to be utilized in energy generation, a fact that should motivate the two firms to reduce their energy charges and fuel costs to a minimum in order to remain in business.

In the year 2004 the current 50-year contract for supply of un-guaranteed 30 MW of electrical power from Uganda will be coming to an end. A new 20-year PPA has already been negotiated and due to availability of modern energy pricing and risk evaluation techniques, the newly agreed prices are much lower than current ones.

KenGen is currently trading on an interim power purchase agreement (IPPA). The company has been pressing for higher prices even for its cheaper plant in line with current price levels charged by IPPs. If the firm finally becomes privatized in accordance with the government's plan, new owners will demand higher returns so as to be adequately compensated for their investment in the new acquisition. It is likely that the new owners of the company will negotiate for certain covenants with the government to protect themselves against being out-priced by other entrants in the industry. In this respect, it is expected that KenGen being the largest of the electrical energy producers, would influence an upward trend in prices.

The demand for electrical energy in Kenya has reduced drastically over the last 3 years due to downward trend of the economy. Consequently entry of new electrical energy bulk producers is unlikely in the near future. This trend may mean that there is unlikely to be real competition in the industry and hence prices may remain fairly high for a long time.

With the above arguments it is difficult to tell the future trends of bulk electric energy prices. It is therefore difficult to tell whether prices will reduce or increase but all indications are that at retail level they may continue to rise until a time when the industry will be fully stabilized.

CHAPTER FIVE

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The study involved collection of data from five bulk electric energy companies in Kenya. Questionnaires were sent out to the five firms and all the five responded. While evaluating the data from the five firms and counterchecking the data with the retail distribution company (KPLC) and ERB, the rates for Uganda Electricity Transmission Company Ltd (UETC) were obtained and included in the evaluation. After evaluation it was established that pricing of bulk power in Kenya is generally in three components as follows:

- Capacity charge;
- Energy (Variable O&M cost) charge; and
- Fuel cost.

5.1.1 Capacity charge:

Capacity charge is in most cases a fixed charge but in some cases it may be divided into escalable and unescalable components. The scalable component is escalated using the US Consumer Price Index (CPI).

Capacity charge is payable to the generating firm whether it has been called to supply energy or not. It is a charge based on guaranteed capacity under the Power Purchase Agreement (PPA) and it is therefore fixed over the entire PPA period. The bulk energy company is heavily penalized if it fails to meet its guaranteed capacity but could also earn a bonus of up to 15% of its guaranteed capacity if it surpasses its guaranteed capacity.

Capacity charge is meant to help the firm to meet its fixed and sunk costs. It is normally expressed in US $/kW/year and is a function of the following:

- Total capital investment;
- Capacity of plant
- Interest rate on debt;
- Debt repayment period;

- Length of the PPA;
- Fixed labour costs (salaries & wages);
- Plant operation and maintenance (O&M) cost;
- Expected return on equity; and
- Opportunity cost of capital (OCC) or time preference discount rate (TPDR) (or discounting rate of return)

5.1.2 Energy charge

Energy charge is a variable cost charge payable only when the plant has been in operation. It is made up of costs that are dependent on the quantity of energy generated. It is quoted in US cts/kWh and is a function of the following:

- Cost of consumables such as lubricants, spare parts, chemicals; and
- Cost of variable labour.

5.1.3 Fuel cost

The fuel cost is a pass through component and is normally passed on to the end consumers by the retail distribution company. It is normally expressed in US cts/kWh and is a function of the following:

- Market price of fuel;
- Generator heat conversion factor;
- Efficiency of the generator; and
- Quantity of energy generated.

5.2 Recommendations

The following steps should be undertaken in order to reduce price components to a minimum:

5.2.1 Capacity charge

Capacity charge can be kept low by the following measures:

1. Ensuring low cost/kW investment levels
2. Long PPA period
3. Low debt levels

4. Negotiating a low interest rate
5. Offering comfort to investors to reduce risk and hence reduce required rate of return on equity
6. Applying escalation on labour and other escalable components as a measure of reducing their loading on OCC
7. Utilizing local labour instead of expatriates
8. Any labour that can be tied to production should be engaged as variable labour and charged under variable charge
9. Engaging long-term O&M contractors
10. Maintain insurance policy against unforeseen and prolonged plant breakdowns

Since capacity charge is the highest component on overall bulk price, reducing it to a minimum is likely to ensure a minimum price.

5.2.2 Energy charge

Energy charge can be kept low by the following measures:

1. Signing long-term spare part, lubricant, chemical etc supply agreements with reliable companies
2. Reducing to a minimum reliance of variable labour

Since energy charge is a lesser component on overall bulk price, it should be used to load most of the items that cannot be estimated over the entire period of the PPA. This way risk on investment would be further reduced.

5.2.3 Fuel cost

Fuel charge can be kept low by the following measures:

1. Establishing long-term supply contracts with reliable oil supply company
2. Maintain good quality assurance measures to reduce risk of poor quality fuel
3. Have storage capacity
4. Negotiate with the retail company to pay for the fuel and maintain the stock (inventory) instead of the bulk supply company
5. Install high efficiency generators
6. Install generators with good conversion factors

7. Have good maintenance to ensure continued high efficiency of the plant
8. Maintain insurance policy against risk of poor oil quality, environmental pollution and related litigation action

Since capacity charge is the highest component on overall bulk price, reducing it to a minimum is likely to ensure a minimum price.

5.3 Limitations

One of the limitations of the study was lack of basic capital budgeting data. This is because parent companies of the independent power producers (IPPs) operating in Kenya are foreign. The data and basic assumptions used in developing of prices are kept by the parent companies and unavailable to the management of the locally incorporated companies.

5.4 Suggestions for further research

Research on the following related areas is recommended:

1. Since the bulk prices of electric energy eventually have an effect on the retail prices, research to find out how the bulk prices impact on the retail tariffs would be necessary.

2. Research into how the bulk prices of electric energy translate into cash flows for the respective companies and how the actual cash flows compare with the capital budgeting cash flows.

APPENDICES

APPENDIX 1

REFERENCES

APPENDIX 1

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APPENDIX 2

QUESTIONNAIRE

APPENDIX 2

QUESTIONNAIRE

RESEARCH TITLE: Pricing of Electricity by Bulk Power Producers in Kenya

ADMINISTERED TO: Electricity Generating Companies operating in Kenya

1. Type of generation: 1) hydro [ ]
   2) diesel [ ]
   3) geothermal [ ]
   4) gas-turbine [ ]
   5) combine cycle [ ]
   6) others ....
2. Number of generating units ....
3. If all the units are the same size state the size per unit .... MW, ... MVAr, if not go to question 4.
4. All the units are assumed to be of the same size. If not, please specify the units and their sizes in the schedule below:

   Unit size (MW) .... Number of units ....

   Unit size (MW) .... Number of units ....

   Unit size (MW) .... Number of units ....

   Unit size (MW) .... Number of units ....
5. Type of fuel used in generation ....
6. Efficiency of each generator unit ....%, combined station efficiency ....%
7. Total Capital invested in the company ....
8. Capital Structure of the Firm:
   1) 100% equity [ ]
   2) 10-50% equity and 50-90% debt [ ]
   3) 50-90% equity and 10-50% debt [ ]
   4) 100% debt [ ]

9. How many long-term debt instruments is the company financed with? ....

10. Interest rate on main debt pa:

    1) 0-10%[ ]

    2) 10-20[ ]

    3) 20-30%[ ]

    4) 30-40%[ ]

    5) 40-50%[ ]

    6) Over 50%[ ]

11. Estimated proportion of main debt to total debt ....

12. Cost of capital pa:

    1) 0-10%[ ]

    2) 10-20[ ]

    3) 20-30%[ ]

    4) 30-40%[ ]

    5) 40-50%[ ]

    6) Over 50%[ ]

13. Is the cost of capita adjusted for inflation?

    1) Yes [ ]

    2) No [ ]

14. If the answer to question 13 is YES, what is the rate of interest pa?

    1) 0-10%[ ]

    2) 10-20[ ]

    3) 20-30%[ ]

    4) 30-40%[ ]

    5) 40-50%[ ]

    6) Over 50%[ ]

15. Does the company undertake regular price reviews?

1) Yes [ ]

2) No [ ]

16. If the answer to question 15 is YES, how often is the review undertaken? ....

17. Is the review a percentage or fixed amount? ....If YES, what is the percentage rate? ....%

18. Briefly describe the process used by your company to develop prices

....

....

....

....

....

....

19. Give reasons for your choice of the above process

....

....

....

20. What are the components of the capacity price?

....

....

....

....

....

21. What are the components of the energy price?

....

....

....

....

....

22. What are the components of the fuel price?

....

....

....

....

....

23. Duration of PPA (years) ....

24. Efficiency of plant:
    1) 95-100%[ ]
    2) 90-95%[ ]
    3) 85-90%[ ]
    4) 80-85%[ ]
    5) below 80%[ ]

25. Availability of plant:
    1) 95-100%[ ]
    2) 90-95%[ ]
    3) 85-90%[ ]
    4) 80-85%[ ]
    5) below 80%[ ]

26. Contracted capacity (MW): ....

27. Average monthly capacity charge rate in US$/kW/month:
    1) 0-5 [ ]
    2) 5-10 [ ]
    3) 10-15 [ ]
    4) 15-20 [ ]
    5) over 20 [ ]

28. Annual base capacity charge rate in US$/kW/year:

1) 0-5 [ ]
2) 5-10 [ ]
3) 10-15 [ ]
4) 15-20 [ ]
5) over 20 [ ]

29. Average monthly energy charge rate in US$/kW/month:

1) 0-5 [ ]
2) 5-10 [ ]
3) 10-15 [ ]
4) 15-20 [ ]
5) over 20 [ ]

30. Average monthly fuel charge rate in US$/kW/month:

1) 0-5 [ ]
2) 5-10 [ ]
3) 10-15 [ ]
4) 15-20 [ ]
5) over 20 [ ]

APPENDIX 3

SUMMARY OF QUESTIONNAIRE RESPONSE TO CODED ANSWERS

APPENDIX 3 - SUMMARY OF QUESTIONNAIRE RESPONSE TO CODED ANSWERS

No.	Question	Response									
		Tsavo		KenGen		Westmont		Iberafrica		OR Power-4	
		coding	quantity	code	quantity	code	quantity	code	quantity	code	quantity
1.	Type of generation	2		1,2,3,4&6		4		2		3	
2.	Number of generating units		7		47		1		10		3
3.	Size per unit (MW)		10.9	various	various		46.26				
	Size per unit (MVAr)			various	various		28.66				
4.	Units	N/A	N/A	N/A	N/A	N/A	N/A		5.712		5.4
	size								8		2
	units								6.12		3 75
	size								2		1
5.	Type of fuel		HFO	various	various		Gas condensate		HFO		Geothermal
6.	Efficiency of each generator unit		99.90%	various	various		32%				99%
	Combined station efficiency		98%	various	various						98%
7.	Total Capital invested		$86,000,000		KES 55,076,574,000		$48,000,000		$65,000,000		
8.	Capital Structure of the Firm	2		3		1		2		1	
9.	The number of long-term debt instruments		1		8		None		1		None
10.	Interest rate on main debt	2		2		N/A		2		N/A	
11.	Proportion of main debt to total debt		10%		27%		N/A		100%		N/A
12.	Cost of capital	1		1		N/A		2			
13.	Whether the cost of capital is adjusted for inflation	1		1		N/A		2			
14.	Rate of interest of 13 above	1		3	24%	N/A					
15.	Whether regular price review are undertaken	2		2		2		2		2	
16.	How often the reviews are undertaken on 15 above		N/A	N/A		Fixed at PPA					monthly
17.	Whether the review on 15 is a percentage or fixed amount		N/A	N/A		Fixed at PPA					ratio
	The rate of review of 15		N/A	N/A							
18.	Process used by the company to develop prices		Table 2		Table 2		Table 2				Table 2
19.	Reasons for the company's choice of the process used in 18		Table 2		Table 2		Table 2				Table 2
20.	Components of the capacity price		Table 2	none	none		Table 2		Table 2		Table 2
21.	Components of the energy price		Table 2		Table 2		Table 2		Table 2		

No.	Question	Response									
		Tsavo		KenGen		Westmont		Iberafrica		OR Power-4	
		coding	quantity	code	quantity	code	quantity	code	quantity	code	quantity
22.	Components of the fuel price		Table 2		Table 2		Table 2		Table 2		N/A
23.	Duration of PPA (years)		20		2		7		7		25
24.	Efficiency of plant (*repeat of 6b*)	1		various	various	5		2		1	
25.	Availability of plant	1		various	various	3		2		1	
26.	Contracted capacity (MW)		74		N/A		46.26		56		13
27.	Average monthly capacity charge rate in US$/kW/month	1		N/A		4		5		3	
28.	Annual base capacity charge rate in US$/kW/year			N/A		5		1		N/A	
29.	Average monthly energy charge rate in US$/kW/month	1			0.0363	1		1		1	
30.	Average monthly fuel charge rate in US$/kW/month		0.038		0.0316	1		5		N/A	

APPENDIX 4

SUMMARY OF QUESTIONNAIRE RESPONSE TO DESCRIPTIVE ANSWERS

APPENDIX 4 - SUMMARY OF QUESTIONNAIRE RESPONSE TO DESCRIPTIVE ANSWERS

No.	Question	Response				
		Tsavo	KenGen	Westmont	Iberafrica	OR Power-4
18.	Process used by the company to develop prices	Formular worked out from fixed component of US$/kW/yr and escalating cost component in US $ based on the Consumer Price Index (CPI)	1. LRMC analysis is performed	Based on OPEX and CAPEX		Details not available, but agreed rates are adjusted using the CPI with a base reference point of the month the PPA was signed
			2. Analysis of financial commitment to capital and recurrent expenditures and debt servicing			
			3. Analyse whether LRMC would finance all in 2 above without reverting to customers			
			4. Work out the level of revenue to finance 2 above in line with World Bank covenants			
			5. Work out the tariff to within 1 - 1.5 times of the LRMC			
			6. The final tariff becomes an input to KPLC tariff			
19.	Reasons for the company's choice of the process used in 18	It ensures that the company will be able to pay the loan without worries over the PPA poeriod of 20 years	LRMC has elements of macro and micro-economic efficiency	To recoup investment cost, expenses and marginal profit		As in 18 above
20.	Components of the capacity price	1. Base escallation charge rate US$/kW/yr	None	Investment cost, marginal profit and fixed O&M cost	1. Salaries	Agreed rate with adjustment factor of the CPI referenced to the month the PPA was signed

No.	Question	Response				
		Tsavo	KenGen	Westmont	Iberafrica	OR Power-4
		2. CPI for the 3 months to month P (Month of Pricing)			2. Fees	
		3. CPI for June 1996			3. Interest	
					4. Fixed overhead costs	
21.	Components of the energy price	1. Net electrical output (kWh)	1. Energy	Non-fuel variable O&M cost adjusted to USA PCI and fuel	1. Freight	As in 20 above
		2. Energy charge rate (US$/kWh)	2. Foreign exchange adjustment		2. FOB plants quotations	
					3. Taxes	
					4. Transport	
					5. Profit, overheads for fuel suppliers	
22.	Components of the fuel price	1. Net electrical output (kWh)	Pass-through	Not applicable. Fuel is purchased by KPLC		Not applicable since this is a geothermal plant
		2. Guaranteed heat rate (8990 kJ/kWh)				
		3. Lower heating value (kg/kJ) of the fuel				
		4. Cost of fuel per kg for the month				